SECTION 5

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

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SECTION 5

REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The Reactor Coolant System (RCS) includes those systems and components that contain or transport fluids coming from, or going to, the reactor core. These systems form a major portion of the reactor coolant pressure boundary (RCPB). This section of the FSAR provides information regarding the RCS and pressure containing appendages out to and including isolation valves. This group of components, defined as the RCPB, is described in Section 50.2(V) of 10CFR50: "The RCPB includes all those pressure-containing components such as pressure vessels, piping, pumps, and valves, which are either:

1. Part of the RCS

2. Connected to the RCS; up to and including any and all of the following:

   a. The outermost containment isolation valve in piping, which penetrates primary reactor containment

   b. The second of the two valves normally closed during normal reactor operation in system piping, which does not penetrate primary reactor containment

   c. The RCS safety/relief valve (SRV) and piping.

This section also deals with various subsystems that are closely allied to the RCPB. Section 5.4 deals with these subsystems more specifically.

The various subsystems discussed below include:

1. Nuclear Pressure Relief System

2. RCPB Leak Detection System

3. Reactor pressure vessel (RPV)

4. Reactor Recirculation System

5. Main steam line and flow restrictors

6. Reactor Core Isolation Cooling (RCIC) System

7. Residual Heat Removal (RHR) System

8. Reactor Water Cleanup (RCWU) System

9. Feedwater system lines.

Design and performance characteristics of the RCS and its various components are found in Table 5.4-1.

5.1.1 Schematic Flow Diagram

Schematic flow diagrams of the reactor coolant system (RCS) denoting all major components, principal pressures, temperatures, flow rates, and coolant volumes for normal steady-state operating conditions at rated power, are presented on Figures 5.1-1 and 5.1-2.

5.1.2 Piping and Instrumentation Diagrams

The piping and instrumentation diagrams (P&IDs) covering the systems included within the Reactor Coolant System (RCS) and connected systems correspond to the following Plant Drawings:

1. Nuclear boiler system: M-41-1

2. Nuclear boiler vessel instrumentation: M-42-1

3. Main steam: M-01-1

4. Feedwater: M-06-1

5. Recirculation system: M-43-1

6. Reactor Core Isolation Cooling (RCIC) System: M-49-1 and M-50-1

7. Residual Heat Removal (RHR) System: M-51-1

h. Reactor water cleanup (RWCU) system: M-44-1

5.1.3 Elevation Drawings

A section drawing of the reactor enclosure and primary containment is presented on Plant Drawing P-0011-0.

5.1.4 Nuclear Pressure Relief System

The Nuclear Pressure Relief System, described in Section 5.2.2, which is part of the Nuclear Boiler System, protects the reactor coolant pressure boundary (RCPB) from damage due to overpressure. To protect against overpressure, pressure operated main steam safety (SRV) relief valves are provided to discharge steam from the Nuclear Steam Supply System (NSSS) to the suppression pool. Part of the Nuclear Pressure Relief System, the Automatic Depressurization System (ADS), also acts to automatically depressurize the NSSS in the event of a loss-of-coolant accident (LOCA) in which the high pressure coolant injection (HPCI) system fails to maintain reactor pressure vessel (RPV) water level. Depressurization of the NSSS allows the

low pressure core cooling systems to supply enough cooling water to adequately cool the fuel.

5.1.5 Reactor Coolant Pressure Boundary Leak Detection System

The reactor coolant pressure boundary (RCPB) leak detection system, described in Section 5.2.5, establishes the limits on nuclear system leakage inside the drywell so that appropriate action can be taken before the integrity of the nuclear steam system process barrier is impaired.

5.1.6 Reactor Pressure Vessel

The reactor pressure vessel (RPV) and appurtenances are described in Section 5.3. The major safety functions of the RPV are to maintain water over the core and to act as a radioactive material barrier. Various combinations of loading are considered in the vessel design. The vessel meets the requirements of applicable codes and criteria. The possibility of brittle fracture is considered; suitable design, material selection, material surveillance activity, and operational limits have been established to avoid conditions where brittle fracture is possible.

5.1.7 Reactor Recirculation System

The Reactor Recirculation System, described in Section 5.4.1, provides coolant flow through the core. Adjustment of the core coolant flow rate changes reactor power output, providing a means of following plant load demand without adjusting control rods. The reactor recirculation system is designed to provide a slow coastdown of flow so that fuel thermal limits cannot be exceeded as a result of recirculation system malfunctions. The arrangement of the recirculation system routing is such that a piping failure cannot compromise the integrity of the floodable inner volume of the reactor vessel, thereby helping to ensure adequate core cooling following a loss-of-coolant accident (LOCA).

5.1.8 Main Steam Lines and Flow Restrictors

The Main Steam System, described in Section 5.4.4, is designed to accomplish the following objectives during stable and transient reactor power operation throughout the entire load range, from zero to full power:

1. Receive the steam generated continuously by the nuclear boiler and convert the heat energy to mechanical energy in the turbine.

2. Bypass to the condenser excess steam over and above that required by the turbine generator and auxiliaries.

Main steam line flow restrictors of the venturi type are installed in each main steam line inside the primary containment. The restrictors are designed to limit the loss of coolant resulting from a main steam line break outside the primary containment. The coolant loss is limited so that reactor vessel water level remains above the top of the core during the time required for the main steam line isolation valves (MSIVs) to close. This action protects the fuel barrier.

Two isolation valves (MSIVs) are installed on each main steam line; one located inside, and the other outside of the primary containment. The main steam stop valve (MSSV), located downstream of the outboard MSIV, performs no active safety function. The portion of the main steam supply system between the outboard MSIV and the MSSV provides a deposition surface to limit the release of fission products which leak from the MSIVs after a postulated accident and is discussed further in Sections 5.4 and 6.2.4. In the event that a main steam line break occurs inside the containment, closure of the isolation valve inside or outside the primary containment acts to seal the primary containment itself. The MSIVs automatically close to isolate the reactor coolant pressure boundary (RCPB) in the event a pipe break occurs downstream of the outboard isolation valve. This action limits the loss of coolant

and the release of radioactive materials from the Nuclear Steam Supply System (NSSS).

5.1.9 Reactor Core Isolation Cooling System

The Reactor Core Isolation cooling (RCIC) System, described in Section 5.4.6, provides makeup water to the core during a reactor shutdown in which feedwater flow is not available. The system is started automatically upon receipt of a low reactor water level signal, or manually by the operator. Water is pumped to the core by a turbine-driven pump using reactor steam. The RCIC system pump normally takes suction from the condensate storage tank through a common line to the high pressure coolant injection (HPCI) pump suction. The RCIC system can also take suction from the suppression pool.

5.1.10 Residual Heat Removal System

The Residual Heat Removal (RHR) System, described in Section 5.4.7, consists of four pumps, two heat exchangers, and associated piping, valves, and instrumentation that can be used to cool the Nuclear Steam Supply System (NSSS) in a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. One mode of RHR operation allows the removal of heat from the primary containment following a loss-of-coolant accident, (LOCA). Another operational mode of the RHR system is low pressure coolant injection (LPCI). LPCI operation is an engineered safety feature (ESF) for use during a postulated LOCA. This operation is described in Section 6.3.

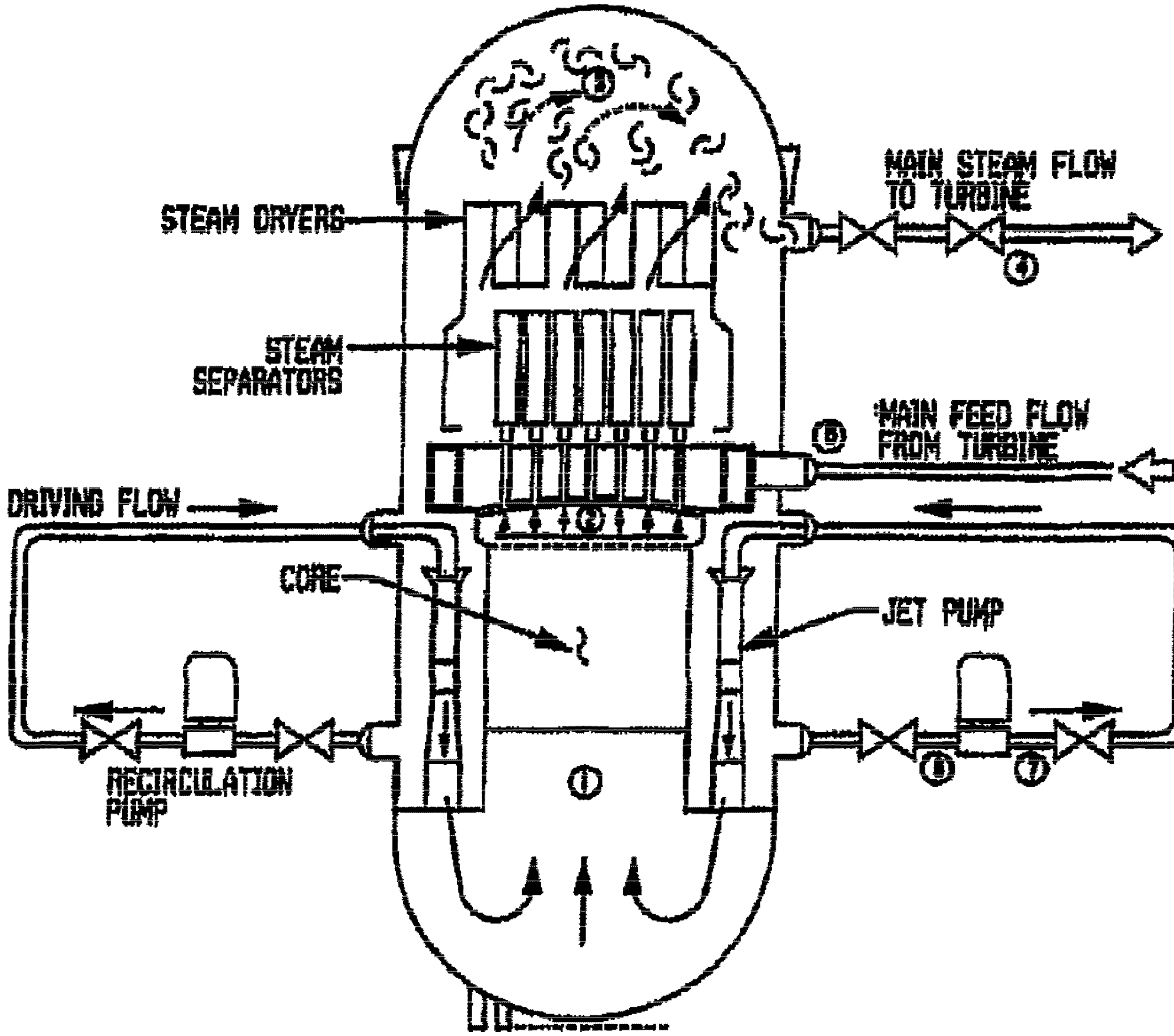
5.1.11 Reactor Water Cleanup System

The Reactor Water Cleanup (RWCU) System, described in Section 5.4.8, recirculates a portion of reactor coolant through filter demineralizers to remove particulate and dissolved impurities from the reactor coolant. This maintains the required

quality of reactor coolant. It also removes excess coolant from the reactor system under controlled conditions.

5.1.12 Feedwater System Lines

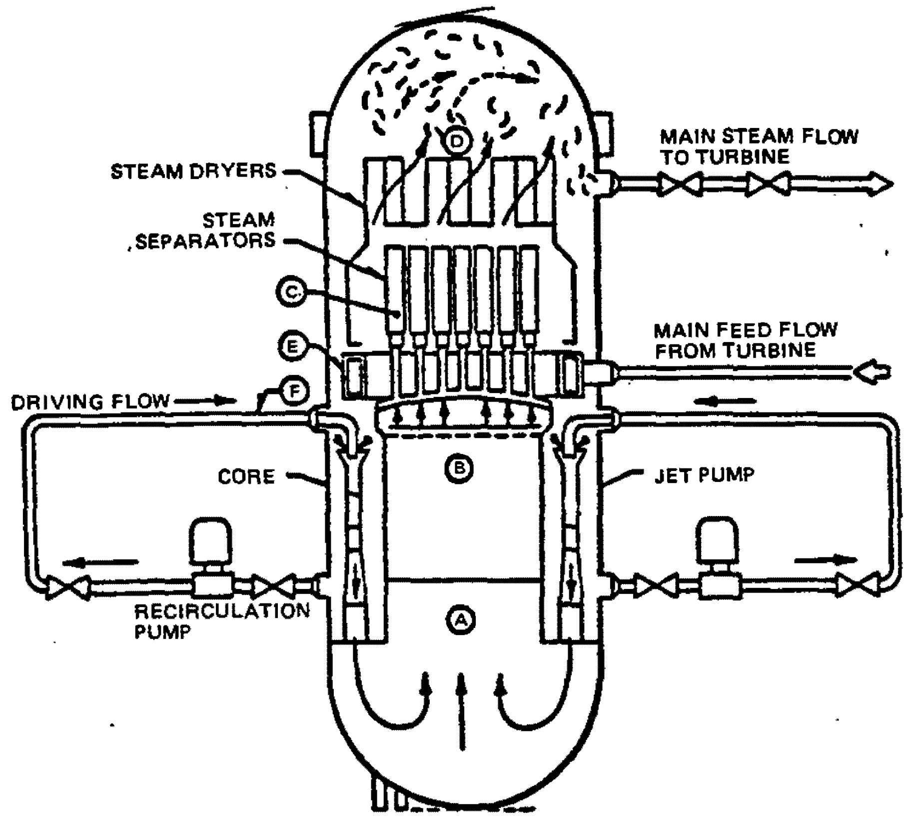
The feedwater system, described in Section 5.4.9, continuously delivers the design feedwater flow to the reactor vessel. The portion of the feedwater system that forms part of the reactor coolant pressure boundary (RCPB) and penetrates the containment has three isolation valves. Detailed description of the feedwater system is presented in Sections 10.4.7 and 6.2.4.



	PRESSURE (PSIA)	FLOW LBS/HR	TEMPERATURE °F	ENTHALPY BTU/LB
1. CORE INLET	1067	100×10^6	531	525.1
2. CORE OUTLET	1035	100×10^6	549	659.8
3. SEPARATOR OUTLET (STEAM DOME)	1020.0	16.77×10^6	547	1191.5
4 STEAM LINE TURBINE STOP VALVE	943	16.77×10^6	537	1191.5
5. FEED WATER INLET	1050	16.74×10^6	431.6	410.3
6. RECIRCULATION PUMP SUCTION	1034	34.2×10^6	530.8	525.0
7. RECIRCULATION PUMP DISCHARGE	1229	34.2×10^6	531.7	526.1

Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station RATED OPERATING CONDITIONS OF THE BOILING WATER REACTOR
	Updated FSAR — Figure 5.1-1



	VOLUME OF FLUID (ft^3)
A Lower plenum	3860
B Core	2000
C Upper plenum and separators	2300
D Dome (above normal water level)	7260
E Downcomer region	5150
F Recirculation loops and jet pumps	1400

REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

COOLANT VOLUMES
OF THE BOILING WATER REACTOR

UPDATED FSAR

FIGURE 5.1-2

Figure F5.1-3 SH 1-2 intentionally deleted.

Refer to Plant Drawing M-41-1 for both sheets in DCRMS

Figure F5.1-4 SH 1-2 intentionally deleted.

Refer to Plant Drawing M-42-1 for both sheets in DCRMS

Figure F5.1-5 intentionally deleted.

Refer to Plant Drawing P-0011-0 in DCRMS

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

This section discusses measures employed to provide and maintain the integrity of the reactor coolant pressure boundary (RCPB) and other fluid systems important to safety for the plant design lifetime.

5.2.1 Compliance with Codes and Code Cases

5.2.1.1 Compliance with 10CFRPart 50, Section 50.55a

A table that shows compliance with Regulatory Guide 1.26 is included in Section 3.2. ASME B&PV Code, edition, applicable addenda, and component dates are in accordance with 10CFR50.55a, with the exceptions noted in Table 5.2-1.

5.2.1.2 Applicable Code Cases

NOTE:

The use of Code Cases during construction was governed by the paragraphs below. Use of Code Cases for inservice inspections and repair or replacement activities is governed by either the Inservice Inspection Program or the NBU Repair Program. Please refer to these programs for Code Case applicability or incorporation of new Code Cases into these programs. New Code Cases must be reviewed for acceptability against the current revision of Regulatory Guides 1.84, 1.85, or 1.147; as applicable.

5.2.1.2.1 NSSS Components

The reactor pressure vessel (RPV) and appurtenances, and the RCPB piping, pumps, and valves have been designed, fabricated, and tested in accordance with the applicable edition of the ASME B&PV Code, including addenda that were mandatory at the order date for the applicable components. ASME B&PV Code Case approval is required by 10CFR50.55a only for Class 1 components. These Code Cases contain requirements or special rules that may be used for the construction of pressure retaining components of Quality Group Classification A. The various ASME B&PV Code Cases that were applied to components in the RCPB are listed in Table 5.2-2.

5.2.1.2.1.1 Regulatory Guides 1.84 and 1.85

A general compliance description is provided below. For specific commitment, revision numbers, and scope, see FSAR Section 1.8.

These guides provide a list of ASME B&PV Design and Fabrication Code Cases that have been generically approved by the Nuclear Regulatory

Commission (NRC) staff. ASME Code Cases on this list may, for design purposes, be used until appropriately annulled. Annulled cases are considered "active" for equipment that has been contractually committed to fabrication prior to the annulment.

GE's procedure for meeting the regulatory requirements is to obtain NRC approval for ASME Code Cases applicable to Class 1 components only. NRC approval of Class 2 and 3 ASME Code Cases was not required at the time of the design of Hope Creek Generating Station and is not required by 10CFR50.55a.

5.2.1.2.2 Non-NSSS Components

All Subsection NC - Class 2 Components, Subsection ND - Class 3 Components, Subsection NE - Class MC Components, Subsection NF - Component Supports, and Subsection NG - Core Support Structures have also been designed to ASME B&PV Code or ASME approved Code Cases. These ASME Code Cases are also listed in Table 5.2-2. Description of their compliance with Regulatory Guides 1.84 and 1.85 is provided in Section 1.8.

This provision, together with the quality control programs, ensures adequate safety equipment function.

5.2.1.3 <u>SRP Rule Review</u>

5.2.1.3.1 NSSS Assessment

5.2.1.3.1.1 SRP Section 5.2.1.1 Acceptance Criterion II.1 and II.2

Acceptance criterion II.1 and II.2 of SRP Section 5.2.1.1 require compliance with requirements of 10CFR50, GDC 1, 10CFR50.55a, and Regulatory Guide 1.26. Subsection 5.2.1.1 of the FSAR demonstrates compliance with 10CFR50, Section 50.55a by stating "A table which shows compliance with Regulatory Guide 1.26, is included in Section 3.2. Code edition, applicable addenda, and component dates are in accordance with 10CFR50.55a." The FSAR deviates from the

SRP acceptance criteria in that Tables 3.2-1, 3.2-2, and 3.2-3, referenced in Section 3.2 of the FSAR, show compliance with Regulatory Guide 1.26 to satisfy 10CFR50, GDC 1, but do not demonstrate compliance with 10CFR50.55a because these tables do not contain data on code edition, applicable addenda and component order dates.

Although this specific information is not provided in Section 3.2, HCGS does comply with 10 CFR 50.55a, except as indicated in Table 5.2-1. Use of the components identified in Table 5.2-1 is justified, because the HCGS components were purchased before 10CFR50.55a was invoked. The "grandfather" clauses of 10CFR50.55a, paragraph A.2.I waives compliance with regulation of 10CFR50.55a if these requirements result in unusual difficulties without a compensating increase in the level of quality and safety.

The components of the RCPB, and other fluid systems important to safety, identified in Table 5.2-1, were purchased under earlier editions and addenda of the code than those required by the rules of 10CFR50.55a. The components were purchased based on the recognized codes and standards in effect at the time of the order.

Table 5.2-1 provides sufficient information to demonstrate acceptable levels of safety and quality.

5.2.1.3.1.2 SRP Section 5.2.1.2, Acceptance Criteria II.2

Acceptance criterion II.2 of SRP Section 5.2.1.2 requires compliance with 10CFR50, Appendix A, GDC 1, and 10CFR50, 50.55a by verifying that the table in FSAR Section 5.2.1.2, specifying those ASME Code Cases applied to Section III, Div 1 and Div 2 components, comply with the list of acceptable code cases in Regulatory Guides 1.84, 1.85, and 1.147. FSAR Section 5.2.1.2 references Table 5.2-2, which lists code cases 1441-1 and 1464. These code cases are not in compliance with the lists of acceptable code cases identified in Regulatory Guides 1.84, 1.85, and 1.147, thus constituting a deviation from the SRP 5.2.1.2 acceptance

criterion II.2. The justification for this deviation is that, although Code Cases 1441-1 and 1464 are not found in Regulatory Guide 1.84 or 1.85, as referenced in FSAR Section 5.2.1.2, Table 5.2-2, they are acceptable because they have been incorporated into the ASME B&PV Code, 1974 edition. Code case 1441-1 is found in Section III, NB 3228. Code case 1464 is found in Section III, NA 8000.

5.2.1.3.2 Non-NSSS Assessment

5.2.1.3.2.1 SRP Section 5.2.1.1 Acceptance Criteria II.2

Acceptance criterion II.1 and II.2 of SRP Section 5.2.1.1 requires that compliance with the requirements of 10CFR50.55a be demonstrated. Components that are not specifically identified in Table 5.2-1 were purchased according to the requirements of 10CFR50.55a, even though information on the specific code edition, code addenda, and component order data is not provided.

5.2.1.3.2.2 SRP Section 5.2.1.2 Acceptance Criteria II.2

Acceptance Criteria II.2 of Standard Review Plan 5.2.1.2 requires that the code cases used for the design, fabrication, erection, construction, testing, and inspection of the components important to safety conform to Regulatory Guides 1.84, 1.85, and 1.147. These guides list those Section III ASME codes cases concerned with design, fabrication, erection, construction, testing, and inspection that are acceptable to the NRC for use in plant construction. Hope Creek Generating Station is using Code Case N253-1, "Construction of Class 2 or Class 3 components for Elevated Temperature Service, Section III, Division 1," for the design and fabrication of containment hydrogen recombiner. This code case is not listed in Regulatory Guide 1.85. There is a portion of the hydrogen recombiner that operates above 800°F and, therefore, is not covered by the ASME code. Specifically, the ASME B&PV Code, Section III does not cover construction above 800°F. HCGS uses Code Case N362-2, "Pressure Testing of Containment Items Section III,

Division 1, Classes 1, 2 and MC," for pressure testing of containment items. This code case is not listed in Regulatory Guide 1.84.

Code Cases N-411 and N-413 have been added to Table 5.2-2 for use during As-Built Reconciliation. Due to their recent issue dates, these code cases are not listed in Regulatory Guides 1.84 or 1.85. The NRC has approved their use on Hope Creek but indicated that it may be several months before they are added to Regulatory Guide 1.84 or 1.85.

See Section 1.8.1 for further discussion of Regulatory Guide compliance.

5.2.2 Overpressure Protection

Overpressure protection for the reactor coolant pressure boundary (RCPB) is provided by the Nuclear Pressure Relief System, which includes the following:

1. Main steam line safety/relief valves (SRVs)
2. SRV discharge lines and T-quenchers
3. Discharge line vacuum relief valves
4. Check valves and pneumatic accumulators.

The overpressure protection evaluation is described in section 5.2.2.2

5.2.2.1 Design Bases

Overpressure protection is provided in conformance with 10CFR50, Appendix A, GDC 15, Reactor Coolant System Design.

5.2.2.1.1 Safety Design Bases

The Nuclear Pressure Relief System is designed to:

1. Prevent overpressurization that could lead to the failure of the RCPB.

2. Provide automatic depressurization for small breaks in the RCPB occurring with mal-operation of the High Pressure Coolant Injection (HPCI) System, so that the Residual Heat Removal (RHR) System in the low pressure coolant injection (LPCI) mode and core spray system can operate to protect the fuel barrier.

3. Permit verification of its operability

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

5. Accommodate structural and component loadings resulting from relief valve action.

6. Minimize internal vacuum conditions in the discharge piping.

5.2.2.1.2 Power Generation Design Bases

The Nuclear Pressure Relief System SRVs have been designed to:

1. Discharge to the containment suppression pool

2. Correctly reclose following operation so that maximum operational continuity can be obtained.

5.2.2.1.3 Discussion

The ASME B&PV Code requires that each vessel designed to meet Section III be protected from overpressure during upset conditions as discussed in Subsection S.3 of GESTAR II (Reference 5.2-1).

The SRV setpoints are listed in Table 5.2-3. These setpoints satisfy the ASME B&PV Code specifications for safety valves, since all valves open at less than the nuclear system design pressure of 1250 psig.

The automatic depressurization capability of the Nuclear System Pressure Relief System is evaluated in Section 6.3 and in Section 7.3.

The following detailed criteria are used in selection of SRVs:

1. Must meet requirements of ASME B&PV Code, Section III, Class 1

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

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

The SRV discharge piping and the pneumatic supply connections are designed, installed, and tested in accordance with ASME B&PV Code, Section III, Class 3.

5.2.2.1.4 SRV Capacity

SRV capacity is adequate to limit the primary system pressure, including transients, to the requirements of the ASME B&PV Code, Section III, Rules for Construction of Nuclear Power Plant Components, up to and including the Summer 1969 Addenda. The essential ASME requirements that are met by this analysis follow.

It is recognized that the protection of the RCPB in a nuclear power plant is dependent upon protective systems to relieve or terminate pressure transients. Installation of pressure relieving devices does not independently provide complete protection. The safety valve sizing evaluation assumes credit for operation of the Reactor

Protective System (RPS), which may be tripped by either a direct or flux trip signal. The direct scram trip signal is derived from one of the following:

1. Position switches mounted on the main steam isolation valves (MSIVs)

2. Position switches mounted on the main stop valves

3. 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. Furthermore, no credit is taken for power operation of the pressure relieving devices. Credit is taken for the dual purpose SRVs in their ASME B&PV Code qualified mode (spring lift) of safety operation.

The rated capacity of the pressure-relieving devices is sufficient to prevent a rise in pressure within the protected vessel of more than 110 percent of the design pressure (1.10 x 1250 psig = 1375 psig) for events defined in Section 15.2.

Full account is taken of pressure drop on both the inlet and discharge sides of the valves. Each SRV discharges into the suppression pool through a separate discharge pipe. The discharge pipe is designed to achieve choked flow conditions through the valve, thus providing flow independent of discharge piping losses.

Table 5.2-4 lists the systems that could initiate during the design basis overpressure event.

5.2.2.2 Design Evaluation

The overpressure protection evaluation is performed on a cycle specific basis with NRC approved methodology. The cycle-specific evaluation is presented in Appendix 15D.

The results of the overpressurization event presented in this section are from the original safety evaluation performed prior to cycle 1. However, despite this event being considered cycle-specific, the overpressurization event has been found to exhibit only a small dependence upon changes in core configuration. Therefore, it is generally acceptable to treat the results within this section to be typical for this event. Appendix 15D confirms that the peak pressures are within the acceptable requirements. Additional results are also provided for the EPU condition (Reference 5.2-12).

5.2.2.2.1 Method of Analysis

The model used to analyze overpressurization is referenced in Subsection S.3 of Reference 5.2-1.

The typical valve characteristic, as modeled, is shown on Figure 5.2-1. The associated turbine bypass, turbine control, and MSIV 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 SRVs under operating conditions, based on the following assumptions.

5.2.2.2.2.1 Operating Conditions

1. Operating power = 102 percent of nuclear boiler rated power
2. Vessel dome pressure ≤1020 psig
3. Steam flow = 102.3 percent of nuclear boiler rated steam flow

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

For HCGS, the overpressure protection analysis was performed at a maximum dome pressure of 1020 psig. The nominal operating dome pressure at 100 percent power is expected to be 1005 psig, therefore, the assumed initial operating pressure of 1020 psig is

expected to be conservative relative to actual operation. In addition, the nominal high pressure scram setpoint is expected to be set at 1037 psig (analytical upper limit of 1071 psig). A study has been performed for a typical BWR to investigate the effects of increasing the initial reactor pressure relative to the initial value used in the overpressure protection analysis on the peak system pressure. The conclusion made was that increasing the initial operating pressure results in an increase of the peak system pressure which is less than half the initial pressure increase as shown in Figure 5.2-14 for the overpressure design transient (i.e., all MSIV closure with indirect high neutron flux scram). The same general trend is expected to exist for HCGS. Since there is a significant margin (135 psi by comparing the peak vessel pressure of 1204 psig with the ASME code limit of 1375 psig) for HCGS, no safety concern would result from the assumption of initial dome pressure.

5.2.2.2.2.2 Transients

The Overpressure Protection System accommodates the most severe pressurization event, which is referenced in Subsection S.3 of Reference 5.2-1. The results of the sizing transients are shown on Figure 5.2-2. Table 5.2-5 lists the sequence of events for the MSIV closure event with flux scram and with the installed SRV capacity. The sequence of events for this event at EPU conditions is very similar.

5.2.2.2.2.3 Scram

The scram reactivity curve and control rod driven scram motion are shown on Figure 5.2-3.

5.2.2.2.2.4 SRV Transient Analysis Specifications

Valve groups and setpoints of the SRVs are as follows:

1. Valve group: 3

2. Pressure setpoint (maximum safety limit): 1121 to 1141 psig.

The setpoints are assumed at a conservatively high level above the nominal setpoints. This allows for initial setpoint errors and any instrument setpoint drift that might occur during operation. Analyses were performed to justify SRV setpoint tolerances of ±3%. Highly conservative SRV response characteristics are also assumed.

5.2.2.2.2.5 SRV Capacity

Sizing of the SRV capacity is based on establishing an adequate margin from the peak vessel pressure to the ASME B&PV Code limit, 1375 psig, in response to the previously discussed transients.

5.2.2.2.3 Evaluation of Results

The required SRV capacity is determined by analyzing the pressure rise from an MSIV closure with flux scram transient, as documented in Subsection S.3 of Reference 5.2-1. The results of this analysis are shown on Figures 5.2-2 and 5.2-4.

The parametric relationship between peak vessel (bottom) pressure and safety valve capacity for the MSIV transient with high flux and position trip scram is shown on Figure 5.2-5. Figure 5.2-5 also shows the parametric relationship between peak vessel (bottom) pressure and safety valve capacity for the turbine trip, with a coincident closure of the turbine bypass valves and direct scram, which is the most severe transient when direct scram is considered. Pressures shown for flux scram will result only with multiple failures in the redundant direct scram system.

The time response of the vessel pressure to the MSIV transient with flux scram and turbine trip, with a coincident closure of the

turbine bypass valves and direct scram with 14 valves open, is illustrated on Figure 5.2-2. The figure shows that the pressure at the vessel bottom exceeds 1200 psig for less than 5 seconds. The results of the MSIV transient with flux scram at EPU conditions are similar. This is not long enough to transfer any appreciable amount of heat into the vessel metal. Metal temperature before the transient is normally well below 550°F.

The pressure drop in the piping from the reactor vessel to the SRV 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. This prevents back pressure on each SRV from exceeding 40 percent of the valve inlet pressure after reaching steady state flow conditions, thus ensuring choked flow in the valve orifice and no reduction of valve capacity due to the pressure drop in discharge piping. Each SRV has its own separate discharge line.

5.2.2.3 Piping and Instrument Diagrams

Plant Drawing M-41-1 and Figure 5.2-6 show the schematic location of pressure relieving devices for

1. Reactor Coolant System

2. Primary side of the auxiliary or emergency systems interconnected with the primary system

3. Blowdown and heat dissipation system connected to the discharge side of the pressure relieving devices.

The schematic arrangements of the SRVs are shown on Figures 5.2-6 and 5.2-7.

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Description

The Nuclear Pressure Relief System consists of SRVs located on the main steam lines between the reactor vessel and the inboard MSIV in the drywell. These SRVs protect against overpressurization of the RCPB.

The SRVs have two main protection functions:

1. Overpressure safety operation - The valves open automatically to limit a pressure rise

2. Depressurization operation - The Automatic Depressurization System (ADS) valves open automatically as part of the Emergency Core Cooling System (ECCS) for events involving small breaks in the RCPB.

Section 15 discusses the events that are expected to activate the RCPB SRVs. Section 15 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 events, it is expected that decay heat will be generated at a rate greater than what can be dissipated by the RHR system. In such a case, it is expected that the lowest set SRVs will reopen and reclose to relieve the pressure. The pressure increase and relief cycle will continue with lower frequency and shorter relief discharges as the amount of the decay heat generated decreases and is dissipated by the RHR system. Remote manual actuation of the valves from the control room is recommended to minimize the total number of these discharges in order to achieve extended valve seat life.

A schematic of an SRV is shown on Figure 5.2-8. It is opened by either of the following modes of operation:

1. The spring mode of operation, which consists of direct action of the steam pressure against a spring loaded pilot disk that will pop open when the valve inlet pressure force exceeds the spring force, and allows a force balance to be established across the main piston to actuate main disk motion

2. The power actuated mode of operation, which involves the use of an auxiliary actuating device consisting of a pneumatic piston/cylinder and mechanical linkage assembly that opens the valve by overcoming the pilot spring force, and allows opening of the main stage as long as inlet pressure is greater than 50 psig.

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

The SRVs can be operated in the power actuated mode by remote-manual controls from the main control room.

In the event that the main control room becomes uninhabitable, three Channel B SRVs can be operated in the power actuated mode by remote manual controls from the remote shutdown panel (RSP). The SRV control switches on the RSP are interlocked with the Channel B RSP transfer switch and will only function when the transfer switch is in the "emergency" position (see Section 7.4.1.4).

Two Channel D SRVs can be operated in the power-actuated mode by keylocked switches located on the ADS control panel, 10C631, located in the control equipment room (Auxiliary Building, Elevation 102 ft). The capability for local operation of these SRVs has been provided as a backup to control at the RSP (see Section 7.4.1.4).

The SRVs are provided with positive position indication in the main control room, as recommended by TMI Action Plan Item II.D.3 of NUREG 0737, Reference 5.2-2. Acoustic monitors provide output to display lights, with isolated outputs to the annunciator and plant computer, conforming with the requirements of Regulatory Guide 1.97.

The SRVs are designed to operate to the extent required for overpressure protection in the accident environments described in Table 5.2-6. The discharge line vacuum relief valves are designed to operate in the same environment.

The ADS uses selected SRVs for depressurization of the reactor, as described in Section 6.3. Each of the SRVs used for automatic depressurization is equipped with an air accumulator and check valve arrangement. These accumulators ensure 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 62 psig. The accumulator capacity is sufficient for each ADS valve to provide two actuations against 70 percent of the maximum drywell design pressure.

Each SRV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. The SRV discharge lines are classified as ASME Class 3 (Quality Group C) and Seismic Category I. SRV discharge line piping from the SRV to the suppression pool consists of the two following parts:

1. The first part is attached at one end to the SRV and at its other end to a pipe anchor. The main steam piping, including this portion of the SRV discharge piping, is analyzed as a complete system.

2. The second part of the SRV discharge piping extends from the pipe anchor to the suppression pool. Because the second part is isolated from the first part by means of an

anchor, it is physically decoupled from the main steam header and is therefore analyzed as a separate piping system.

The SRV discharge piping is designed to limit valve outlet pressure to 40 percent of maximum valve inlet pressure with the valve wide open at steady state flow. Water in the line more than a few feet above the suppression pool water level causes excessive pressure at the valve discharge when the valve is opened again. For this reason, two vacuum relief valves are provided on each SRV 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 SRVs are located on the main steam line piping rather than 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 LPCI mode of RHR and core spray systems to operate as a backup for the HPCI system. Further descriptions of the operation of the automatic depressurization feature are found in Section 6.3, Emergency Core Cooling Systems, and in Section 7.3, Emergency Core Cooling Systems Control and Instrumentation.

5.2.2.4.2 Design Parameters

The specified operating transients for components within the RCPB are given in Section 3.9.1. Refer to Section 3.7 for a discussion of the input criteria for the design of Seismic Category I structures, systems, and components.

The design requirements established to protect the principal components of the Reactor Coolant System (RCS) 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 20.63 in.^{2} and the coefficient of discharge K(D) is equal to 0.8 (K = 0.9 K(D)).

The design pressure and temperature of the valve inlet and outlet are 1250 psig at 575°F and 500 psig at 470°F, respectively.

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

See Figure 5.2-8 for a cross section of the valve.

5.2.2.4.2.1.1 Valve and Valve Operator Type and Assembly

1. Description. The main steam safety relief valves (SRVs) are the Target Rock pilot operated 6x10, model 7567F, two stage SRVs (see Figure 5.2-8). They actuate when the steam line pressure reaches the SRV spring setpoint pressure, but they can be actuated at pressures below the setpoint pressure with the electro pneumatic actuator.

   The electro pneumatic actuator consists of solenoid valves plus the air operator. The main pneumatic seals are silicone rubber. The air operator diaphragm is silicone rubber reinforced with Nomex fabric. The diaphragm has proven itself to be reliable in two stage SRVs currently in service.

2. Comparison with Operating Plant SRVs. When the Target Rock two stage valve was chosen, the operating plants utilized either Target Rock three stage or the Dresser Electromatic pilot operated SRVs. The two stage SRV is a modification of the three stage SRV using the high reliable first (main) stage of the three stage SRV and replacing the less reliable second and third stages with a single, simplified pilot stage.

   The two stage SRV was designed to avoid the spurious lifting as a result of leakage past the pilot seat, as had been experienced with the three stage SRVs. The setpoint of the two stage SRVs is not affected by leakage in the pilot stage or in the bellows area and thus minimizes spurious plant blowdown. The two stage design also eliminated the problems associated with the three stage valve's pressure sensing bellows and the bellows failure pressure switch. This design has been in use at the Browns Ferry, Hatch, Pilgrim, Millstone, and Fitzpatrick plants with satisfactory operating experience. The SRVs for the HCGS are of the same generic design as those installed in these plants. Differences are due to the need for compatibility of blowdown reseat requirements with plant specific discharge line back-pressure.

3. Improvements in the 2-Stage Valve Design Since Initial Design

   a. The setpoint reliability was improved by increasing the included angle of the seat from 60° to 72°.

   b. The sizes of the bellows and the reseating orifice were optimized to control blowdown of the SRVs over the range of the plant specific backpressure conditions.

c. Forged bodies were used to avoid the potential of subsurface damage and residual stress from weld repair.

d. The solenoid valve "O-ring" seal material was changed to be compatible with the environment and lubricant used.

e. A new design for the solenoid spring minimizes the possibility of high pneumatic supply transients that could result in a stuck open SRV.

4. Pneumatic Supply Design. The pneumatic supply system and its pressure sensing devices are not integral to the SRVs.

5.2.2.4.2.1.2 Purchase Specification Qualification Requirements

The purchase specification required that the valves be typed tested in order to demonstrate compliance with the performance requirements under conditions that include expected normal, abnormal, and design-basis-earthquake conditions. The details of the type tests and the results are discussed in Section 5.2.2.4.2.1.3.

5.2.2.4.2.1.3 Testing

1. Life-Cycle Tests. The test valves were subjected to about 300 safety and relief actuations of which 150 were manual and 150 were pressure induced. The purpose was to verify acceptability of the design to meet the requirements for: set pressure, opening and closing response time, blowdown, seat tightness, achievement of flow rated capacity lift. These tests were performed at reactor conditions using a test facility that had the capability of providing full steam flow through the SRV when it opened. During the

course of the test program, it was noted that the delay time on opening was erratic, and the ΔP between the setpoint and reclosure was not large enough. All other performance parameters were acceptable even at the extremes of slow and fast pressurization rates and at the extremes of ambient temperatures. The same valve was operated another 150 cycles to identify the causes of the observed anomalies. After the design changes, a new test program consisted of 300 cycles on one valve and 60 cycles on each of the three additional valves. The satisfactory test results qualified the SRV design and established and qualified the service life.

2. Environmental Qualification. The acceptability of the design of the electro pneumatic actuator assembly for an upset, emergency, or faulted condition was demonstrated by subjecting a test unit to: a reference frame test to determine leakage, response time, and solenoid electric characteristics for subsequent comparison purposes; radiation aging to a cumulative radiation dosage of 19.6×10^6 rads; reference mechanical aging for 8,000 cycles under normal ambient conditions of 150°F and 100 percent relative humidity; thermal aging to 285°F at 100 percent relative humidity for 480 hours in an air atmosphere; a reference frame test for the post aging condition; a simulated LOCA environmental test; a reference frame test for the post-LOCA condition; an accident radiation exposure of 13x10 rads; and final reference frame tests. These tests established that the actuator assembly design was acceptable and compatible with the service environments.

3. Seismic Qualification. The test unit was subject to seismic tests to simulate normal, upset, emergency and faulted conditions. The test program consisted of:

(a) a resonant frequency determination test, (b) nozzle loading tests, (c) Operating-Basis Earthquake (OBE) tests, (d) Safe-Shutdown Earthquake (SSE) tests, and (e) reference frame tests.

The resonant frequency determination test subjected the test unit to a sine sweep from 1 Hz. to 150 Hz. using a small force input to identify major resonances for each test configuration. The sweep rate was no greater than one octave per minute. The resonant frequencies were also confirmed by observing the force and acceleration Lissajous figures on an oscilloscope. Since the lowest natural frequencies were well above 60 Hz, a sine is not required.

Testing was also performed to determine the effect of nozzle loads on the test unit. The loads induced into the inlet and outlet flanges represented combined static and dynamic loads anticipated at the piping interfaces for either normal or abnormal conditions. The range of nozzle loads was from zero to 800,000 and 600,000 inch-pounds in the inlet and outlet flanges, respectively. The moments were applied simultaneously by a loading arm and a hydraulic cylinder attached to the outlet flange. Inlet and outlet flange studs were instrumented with strain gages to monitor the effects of the applied moments on the studs. The test unit was then subjected to five OBE simulations and a SSE simulation in each of two test orientations to demonstrate operability assurance. The OBE test consisted of 30-second-duration, phase-incoherent inputs of random motion simultaneously in the horizontal and vertical directions. The horizontal and vertical inputs had frequency bands spaced one-third octave apart over the required frequency range. The amplitude of each one-third octave band was independently adjusted in each

axis until the test response spectra enveloped the required response spectra. The resulting table motion was analyzed by a spectrum analyzer using one-sixth octave band widths. The test unit was then subjected to a SSE simulation similar to the OBE test except to a higher load input.

Post-OBE and post-SSE reference frame tests were performed to determine the operability after repeated combinations of seismic simulations, nozzle loadings, temperature, and pressure. Set pressure during safety actuation, response time during relief actuation, and valve leakage were determined with induced nozzle loads applied. To evaluate the design capability of the test unit, the OBE and SSE tests were repeated using a higher input level. A reference frame test was performed at the conclusion of the high level OBE and high level SSE tests to determine the effects of the simulation. The test results were found to be acceptable.

4. Quality Assurance

The safety relief valves were all individually manufactured and tested according to the General Electric (GE) quality assurance program accepted by the NRC (Reference 7.1). The program was developed to assure that each valve met the requirements of the purchase specification. Quality assurance records documenting compliance with the purchase specification are on file at GE.

Quality assurance review of certification and/or witnessing of inspection of parts and tests performed by the manufacturer assured compliance to the specification requirements. In addition, ASME-certified Boiler

Inspectors performed independent inspections and reviews for manufacturer's compliance to American Society of Mechanical Engineers (ASME) requirements. Customer reviews and inspections of the manufacturer further assured achievement of the compliance needed.

The manufacturer has performed ASME-required tests and obtained ASME certification of the prototype valve design for flow capacity, set pressure, and blowdown. Prior to delivery to the HCGS, all production valves were tested and met the GE design specification for the power and safety actuation mode, for set pressure, for blowdown capacity, and for seat leakage.

Note: The blowdown capacity is a function of the valve's main disc seat diameter. Capacity is controlled by controlling this dimension within appropriate tolerances.

5. Valve Operability

a. SRV Performance Monitoring

1. Thermocouples are installed in the discharge line of each SRV. A temperature increase in the discharge piping indicates leakage through the pilot disc. Valves leaking detectably are replaced at the next opportunity.

2. The SRVs are fully tested during startup of the reactor prior to commercial operation. Following refueling activities, valve operability is verified by TS surveillance testing.

Included in the SRV technical manual are directions for creating an SRV historical data base. Valve performance history is valuable for tracing valve problems and can improve future operability.

3. Frequency of Tests and Operations. Operating experience at other plants has established that the HCGS can achieve optimum SRV operability by disassembly and inspection of the pilot section of at least 50 percent of the operating valves after each cycle. The valves are relapped and recertified before reuse.

   Every five years, elastomeric seals and other environmentally sensitive materials are replaced.

4. Service Information Letter 196 (SIL 196). General Electric issues and maintains SIL 196 and its supplements to inform operating utilities of recommendations and product improvements that may be used to enhance valve operability, for the Target Rock two- and three-stage SRVs.

5.2.2.5 Mounting of Pressure Relief Devices

The SRVs are located on the main steam piping header. The mounting consists of a contour nozzle and an oversized flange connection. This provides a high integrity connection that withstands the thrust, bending, and torsional loadings to which the main steam pipe and relief valve discharge pipe are subjected, including:

1. Thermal expansion effects of the connecting piping

2. Dynamic effects of the piping due to a safe shutdown earthquake

3. Reactions due to transient unbalanced wave forces exerted on the SRVs 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 brought into equilibrium automatically by the valve discharge piping.)

4. Dynamic effects of the piping and branch connection due to the main 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 in accordance with the requirements of Section III of the ASME B&PV Code. The general requirements for protection against overpressure, as given in NB 7000 of Section III of the ASME B&PV Code, recognize that reactor vessel overpressure protection is one function of the reactor protective systems and allows the integration of pressure relief devices with the protective systems of the nuclear reactor. Hence, credit is taken for the scram protection system as a complementary pressure protection device. The NRC has also adopted the ASME B&PV Code as part of its requirements in the Code of Federal Regulations, 10CFR50.55a.

5.2.2.7 Material Specification

Material specifications of pressure retaining components of SRVs are reported in Table 5.2-7.

The nuclear pressure relief system is designed to meet the relevant requirements of GDC 31, Fracture Prevention of Reactor Coolant Pressure Boundary, and Appendix G of 10CFR50. This is discussed in Section 5.3.

5.2.2.8 Process Instrumentation

Process instrumentation is shown on Plant Drawings M-41-1 and M-42-1.

5.2.2.9 System Reliability

The system is designed in accordance with the requirements of Section III of the ASME B&PV Code. Therefore, it has high reliability. The consequences of failure are discussed in Section 15.1.4.

5.2.2.10 Inspection and Testing

The operational adequacy of the SRV design was ensured in testing recommended by Task Action Plant Item II.D.1 of NUREG-0737, Reference 5.2-3. Results of this testing are found in NEDO-24988, Reference 5.2-4.

To ensure that individual SRVs are free of defects and operable prior to installation, they are tested at the vendor's shop in accordance with quality control procedures. The following tests are conducted:

1. Hydrostatic test at specified test conditions

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

3. Set pressure test, where the valve is pressurized with saturated steam, with the pressure rising to the valve set pressure. The valve must open at the nameplate set pressure ±3%.

4. Response time test, where each SRV is tested to demonstrate acceptable response time.

The valves are installed as received from the factory. The NSSS 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 and automatic actuation relief mode of each SRV is verified during the preoperational test program.

It is not feasible to test the SRV setpoints while the valves are in place. The valves are mounted on 1500 pound primary service rating flanges. They can be removed for maintenance or bench checks and reinstalled during normal plant shutdowns. The valves are tested to check set pressure in accordance with the requirements of ASME B&PV Code, Section XI. The external surface and seating of all SRVs are 100% visually inspected when the valves are removed for maintenance or bench checks. Valve operability is verified during the preoperational test program. The preoperational and startup instructions are discussed in Section 14.

Testing is performed at an approved test facility with the manufacturer's representative in attendance to witness the tests and provide technical guidance during the tests and during any

disassembly, repair and adjustment. Valve inspection and parts replacement is in accordance with the manufacturer's recommendations. Indications of abnormalities observed during the operating cycle are corrected in accordance with the station administrative control procedures.

For further discussion of inservice inspection and testing of RCPB components, see Section 5.2.4.

5.2.3 Reactor Coolant Pressure Boundary Materials

5.2.3.1 Material Specifications

Table 5.2-7 lists the principal pressure retaining materials and the appropriate material specifications for the RCPB components.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Pressurized Water Reactor Chemistry of Reactor Coolant

Not applicable to boiling water reactors (BWRs).

5.2.3.2.2 BWR Chemistry of Reactor Coolant

Materials in the primary system are primarily austenitic stainless steel and Zircaloy cladding. The reactor water chemistry limits are established to provide an environment favorable to these materials.

Limits are placed on conductivity and chloride concentrations. Conductivity is limited because it can be continuously and reliably measured and it gives an indication of abnormal conditions and the presence of unusual materials in the coolant. Chloride limits are specified to prevent stress corrosion cracking of stainless steel. For further information, see Reference 5.2-5.

Several investigations have shown that in neutral solutions some oxygen is required to cause stress corrosion cracking of stainless steel, while in the absence of oxygen no cracking occurs. One of these is the chloride-oxygen relationship found by Williams, Reference 5.2-6, where it is shown that at high chloride concentration, little oxygen is required to cause stress corrosion cracking of stainless steel, and at high oxygen concentration, little chloride is required to cause cracking. These measurements were determined in a wetting and drying situation using alkaline phosphate treated boiler water and, therefore, are of limited significance to BWR conditions. They are, however, a qualitative indication of trends.

The water quality requirements are further supported by GE stress corrosion test data summarized as follows:

1. Type 304 stainless steel specimens were exposed in a flowing loop operating at 537°F. The water contained 1.5 ppm chloride and 1.2 ppm oxygen at pH 7. Test specimens were bent beam strips stressed over their yield strength. After 2100 hours exposure, no cracking or failures occurred.

2. Welded Type 304 stainless steel specimens were exposed in a refreshed autoclave operating at 550°F. The water contained 0.5 ppm chloride and 1.5 ppm oxygen at pH 7.

   Uniaxial tensile test specimens were stressed at 125 percent of their 550°F yield strength. No cracking or failures occurred at 15,000 hours exposure.

When conductivity is in its normal range, pH, chloride, and other impurities affecting conductivity will also be within their normal range. When conductivity becomes abnormal, chloride measurements are made to determine whether or not these factors are also out of their normal operating values. This would not necessarily be the case. Conductivity could be high due to the presence of a neutral salt which would not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water cooled reactors, conductivities are high because of the purposeful use of additives. In BWRs, however, where minimal additives are used, and where near neutral pH is maintained, conductivity provides a good and prompt measure of the quality of the reactor water. Significant changes in conductivity provide the operator with a warning mechanism so (s)he can investigate and remedy the condition before reactor water limits are reached. Methods available to the operator for correcting the off-standard condition include operation of the Reactor Water Cleanup (RWCU) System, reducing the input of impurities, and placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature dependent corrosion rates and provide time for the cleanup system to re-establish the purity of the reactor coolant.

The following is a summary and description of BWR water chemistry for various plant conditions:

1. Normal plant operation The BWR system water chemistry is conveniently described by following the system cycle as shown on Figure 5.2-9. Typical BWR water chemistry values for various plant conditions may be found in the EPRI BWR Water Chemistry Guidelines.

   For normal operation starting with the condenser-hotwell, condensate water is processed through a condensate treatment system. This process consists of filtration and demineralization, resulting in high quality effluent water.

   Hydrogen is added at the suction of the secondary condensate pumps to lower recirculation and reactor water oxygen concentration, assisting in the mitigation of IGSCC.

   Oxygen is added at the suction of the primary condensate pumps to increase its concentration in the condensate and feedwater to reduce flow-assisted corrosion (FAC).

The effluent from the condensate treatment system is pumped through the feedwater heater trains and enters the reactor vessel at an elevated temperature. As required, a dilute suspension of zinc oxide and iron in water is injected into the reactor feedwater at the suction of the reactor feedwater pumps to inhibit the corrosion of stainless steel and control RCS Co-60 transport to reduce the buildup of Co-60 on the reactor coolant pressure boundary piping and components. Iron and zinc concentrations will be maintained within fuel warranty limits and EPRI guideline recommendations.

During normal plant operation, boiling occurs in the reactor, decomposition of water takes place due to radiolysis, and oxygen and hydrogen gas are formed. Due to steam generation, stripping of these gases from the water phase takes place, and the gases are carried with the steam through the turbine to the condenser. At the condenser, deaeration takes place and the gases are removed from the process by means of steam jet air ejectors (SJAEs).

A Reactor Water Cleanup System (RWCS) is provided for removal of impurities resulting from fission products and activated corrosion products formed in the primary system. The cleanup process consists of filtration and ion exchange and serves to maintain a high level of water purity in the reactor coolant.

Additional water input to the reactor vessel originates from the control rod drive (CRD) cooling water. The CRD water is of approximately feedwater quality. Separate filtration for purification and removal of insoluble corrosion products takes place within the CRD system prior to entering the drive mechanisms and reactor vessel.

With the exception of condensate system oxygen injection, no other inputs of water or sources of oxygen are present during normal plant operation. During plant conditions other than normal operation, additional inputs and mechanisms are present as outlined in the following section.

2. Plant conditions outside normal operation During periods of plant conditions other than normal power production, transients take place, particularly with regard to the oxygen levels in the primary coolant. Oxygen levels in the primary coolant deviate from normal during plant startup, plant shutdown, hot standby, and during reactor venting and depressurization. The hotwell condensate will absorb oxygen from the air when vacuum is broken on the condenser. Prior to startup and input of feedwater to the reactor, vacuum is established in the condenser, and deaeration of the condensate takes place by means of mechanical vacuum pump and SJAE operation and condensate recirculation. During these plant conditions, continuous

input of CRD cooling water takes place as described previously.

a. Plant depressurized and reactor vented During certain periods, such as refueling and maintenance outages, the reactor is vented to the condenser or atmosphere. Under these circumstances, the reactor cools and the oxygen concentration increases to a maximum value of 8 ppm. Equilibrium is established after a period of time between the atmosphere above the reactor water surface, the CRD cooling water input, any residual radiolytic effects, and the bulk reactor water. No other significant changes in water chemistry take place during this plant condition because no appreciable inputs take place.

b. Plant transient conditions during plant startup/shutdown - Under these conditions, no significant changes in water chemistry other than oxygen concentration take place.

   (1) Plant startup - Depending on the duration of the plant shutdown prior to startup, and whether the reactor has been vented, the oxygen concentration may be that of air saturated water, i.e., approximately 8 ppm oxygen.

   Following nuclear heatup initiation, the oxygen level in the reactor water decreases rapidly as a function of the higher water temperature and correspondingly reduces oxygen solubility of the water.

(2) Plant shutdown - Upon plant shutdown following power operation, the radiolytic oxygen generation essentially ceases as the fission process is terminated. Because oxygen is no longer generated, though some steaming still takes place due to residual energy, the oxygen concentration in the coolant will decrease to a minimum value determined by steaming rate temperature. If venting is performed, a gradual increase to what is essentially oxygen saturation at the ambient coolant temperature will take place, reaching a maximum value of <8 ppm oxygen.

(3) Oxygen in piping and parts other than the reactor pressure vessel (RPV) - As can be concluded from the preceding descriptions, the maximum possible oxygen concentration in the reactor coolant, and any other directly related or associated parts, is that of air saturation at the ambient temperature. At no time or location in the water phase do oxygen levels

exceed the nominal value of 8 ppm. As temperature increases and oxygen solubility decreases accordingly, the oxygen concentration will be maintained at this maximum value or reduced below it, depending on available removal mechanisms, i.e., diffusion, steam stripping, flow transfer, or degassing.

Depending on the location, configuration, etc, such as dead legs or stagnant water, inventories may contain approximately 8 ppm dissolved oxygen or some other value below this maximum limitation.

Conductivity of the reactor coolant is continuously monitored. These measurements provide reasonable assurance for adequate surveillance of the reactor coolant.

The relationship of chloride concentration to specific conductance, measured at 25°C for chloride compounds such as sodium chloride and hydrochloric acid, can be calculated as shown on Figure 5.2-10. Values for these compounds essentially bracket values of other common chloride salts or mixtures at the same chloride concentration. Surveillance requirements are based on these relationships.

In addition to this program, limits, monitoring, and sampling requirements are imposed on the condensate, condensate treatment system, and feedwater by warranty requirements and specifications. Thus, a

total plant water quality surveillance program is established, ensuring that off-specification conditions are quickly detected and corrected.

The sampling frequency when reactor water has a low specific conductance is adequate for calibration and routine audit purposes. When specific conductance increases and higher chloride concentrations are possible, or when continuous conductivity monitoring is unavailable, increased sampling is provided. (See Section 5.2.3.2.2.2.)

For the higher than normal limits of <1 µmho/cm, more frequent sampling and analyses are invoked by the coolant chemistry surveillance program.

c. Water Purity During a Condenser Leakage

The maximum impurity level is set by a condenser leak rate that can be operationally accommodated by the demineralizer units. The loading time or exhaustion rate is longer than the time required to regenerate the resin beds of all the other operating demineralizers.

5.2.3.2.2.1 Compliance with Regulatory Guide 1.56

For a discussion of general compliance with Regulatory Guide 1.56 (including commitment revision number and scope), see Section 1.8.

5.2.3.2.2.2 Reactor Coolant System

At all times, the chemistry of the reactor coolant system shall be maintained within the limits specified in Table 5.2-8. Operational conditions are defined in plant Technical Specifications.

ACTION:

a. In OPERATIONAL CONDITION 1:

   1. With the conductivity, chloride concentration or pH exceeding the limit specified in Table 5.2-8 for more than 72 hours during one continuous time interval or with the conductivity and chloride concentration exceeding the limit specified in Table 5.2-8 for more than 336 hours per year, be in at least STARTUP within the next 6 hours.

   2. With the conductivity exceeding 10 mmho/cm at 25°C or chloride concentration exceeding 0.5 ppm, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

b. In OPERATIONAL CONDITION 2 and 3 with the conductivity, chloride concentration or pH exceeding the limit specified in Table 5.2-8 for more than 48 hours during one continuous time interval, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

c. At all other times, with the:

   1. Conductivity or pH exceeding the limit specified in Table 5.2-8, restore the conductivity and pH to within the limit within 72 hours, or

   2. Chloride concentration exceeding the limit specified in Table 5.2-8, restore the chloride concentration to within the limit within 24 hours, or

   perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the reactor coolant system. Determine that the structural integrity of the reactor coolant system remains acceptable for continued operation prior to proceeding to OPERATIONAL CONDITION 3.

Surveillance Requirements

The reactor coolant shall be determined to be within the specified chemistry limit by:

a. Measurement prior to pressurizing the reactor during each startup, if not performed within the previous 72 hours.

b. Analyzing a sample of the reactor coolant for:

   1. Chlorides at least once per:

      a) 72 hours, and

      b) 8 hours whenever conductivity is greater than the limit in Table 5.2-8.

   2. Conductivity at least once per 72 hours.

   3. pH at least once per:

      a) 72 hours, and

      b) 8 hours whenever conductivity is greater than the limit in Table 5.2-8.

c. Continuously recording the conductivity of the reactor coolant, or, when the continuous recording conductivity monitor is inoperable, obtaining an in-line conductivity measurement at least once per:

   1. 4 hours in OPERATIONAL CONDITIONS 1, 2 and 3, and

   2. 24 hours at all other times.

d. Performance of a CHANNEL CHECK of the continuous conductivity monitor with an in-line flow cell at least once per:

   1. 7 days, and

   2. 24 hours whenever conductivity is greater than the limit in Table 5.2-8.

5.2.3.2.3 Compatibility of Construction Materials with Reactor Coolant

The materials of construction exposed to the reactor coolant consist of the following:

1. Solution annealed austenitic stainless steels (both wrought and cast) - Types 304, 304L, 316, and 316L

2. Nickel base alloys - Inconel 600, Inconel 750X, and Inconel 690 Alloy 52 Alloy 52M

3. Carbon steel and low alloy steel

4. Some 400 series martensitic stainless steel (all tempered at a minimum of 1100°F)

5. Colmonoy and Stellite hardfacing material.

All of these materials of construction are resistant to stress corrosion in the BWR coolant. Examples of systems in contact with reactor coolant and their materials of construction are provided herein: Type 304L grade stainless steel was used in the control rod drive hydraulic supply, standby liquid control, and refueling water transfer systems, while carbon steel was used in the core spray, reactor water cleanup, and high pressure coolant injection systems. General corrosion on all materials, except carbon and low alloy steel, is negligible. Conservative corrosion allowances are provided for all exposed surfaces of carbon and low alloy steels.

Contaminants in the reactor coolant are controlled to very low limits by the reactor water quality specifications. No detrimental effects occur on any of the materials from allowable contaminant levels in the high purity reactor coolant. Expected radiolytic products in the BWR coolant have no adverse effects on the construction materials, except oxygen and hydrogen peroxide concentrations that are controlled by the addition of hydrogen.

5.2.3.2.4 Compatibility of Construction Materials with External Insulation and Reactor Coolant

The materials of construction exposed to external insulation are:

1. Solution annealed austenitic stainless steels - Types 304, 304L, 316, and 316L

2. Carbon and low alloy steel.

The reflective metal insulation used does not contribute to any surface contamination and has no effect on construction materials.

The nonmetallic insulation used on stainless steel piping and components complies with the requirements of the following industry standards:

1. ASTM C692-71, Standard Methods for Evaluating Stress Corrosion Effects of Wicking Type Thermal Insulation on Stainless Steel (Dana Test)

2. RDT-M12-1T, Test Requirements for Thermal Insulating Materials for Use on Austenitic Stainless Steel, Section 5 (KAPL Test).

Chemical analyses are required to verify that the leachable sodium, silicate, and chloride meet the requirements of Regulatory Guide 1.36. Insulation is packaged in waterproof containers to avoid damage or contamination during shipment and storage.

Since there are no additives in the BWR coolant, leakage would expose materials to high purity, demineralized water. Exposure to demineralized water would cause no detrimental effects.

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

Fracture toughness requirements for the ferritic materials used for piping and valves of the RCPB (there are no ferritic pumps in the RCPB) were as follows.

Safety/relief valves were exempted from fracture toughness requirements because the Summer 1970 Addenda to Section III of the ASME B&PV Code did not require impact testing on valves with inlet connections of 6 inches or less nominal pipe size.

Main steam isolation valves (MSIVs) were also exempted because the March 1970 Addenda to Section III of the ASME B&PV Code, in effect at the time of the purchase order, did not require brittle fracture testing on ferritic pressure boundary components when the system temperature was in excess of 250°F at 20 percent of the design pressure. The rational to show HCGS MSIV materials have adequate toughness to meet current requirements is provided in Appendix 5A.

Main steam piping between the reactor pressure vessel (RPV) and the outboard MSIV, part of the Nuclear Steam Supply System (NSSS) is tested to meet the fracture toughness requirements of paragraph NB 2300 of the Summer 1972 Addenda to the ASME B&PV Code, Section III.

Main steam piping between the outboard MSIV and the main steam stop valve (MSSV), non-NSSS supplied, is tested to meet the fracture toughness requirements of paragraph NC 2300 of ASME B&PV Code, Section III, 1974 Edition with Addenda through Winter 1974.

5.2.3.3.1.1 Compliance with Code Requirements

The ferritic pressure boundary material of the reactor pressure vessel was qualified by impact testing in accordance with the 1968 edition of Section III of the ASME B&PV Code, and addenda to and

including the Winter 1969 Addenda. From a vessel pressurization standpoint, the minimum temperature limits defined by the Summer 1972 Addenda, Appendix G, Protection Against Nonductile Failure, are used as the basis for compliance.

5.2.3.3.2 Control of Welding

5.2.3.3.2.1 Control of Preheat Temperature Employed for Welding of Low Alloy Steel - Regulatory Guide 1.50.

The following is a general compliance assessment; for commitment, revision number, and scope, see Section 1.8.

This guide delineates preheat temperature control requirements and welding procedure qualifications, supplementing those in ASME B&PV Code, Sections III and IX.

The use of low alloy steel is restricted to the RPV. Other ferritic components in the RCPB are fabricated from carbon steel materials.

Preheat temperatures employed for welding of low alloy steel meet or exceed the recommendations of ASME B&PV Code, Section III, Subsection NA. Components were either held for an extended time at preheat temperature to ensure that removal of hydrogen, or preheat, was maintained until postweld-heat treatment. The minimum preheat and maximum interpass temperatures were specified and monitored.

All welds were nondestructively examined by radiographic methods. In addition, a supplemental ultrasonic examination was performed.

5.2.3.3.2.2 Control of Electroslag Weld Properties - Compliance with Regulatory Guide 1.34

No electroslag welding was performed on BWR components.

5.2.3.3.2.3 Welder Qualification for Areas of Limited Accessibility - Compliance with Regulatory Guide 1.71

Qualification for areas of limited accessibility is discussed in Section 5.2.3.4.2.3.

5.2.3.3.2.4 Control of Stainless Steel Weld Cladding of Low Alloy Steel Components - Compliance with Regulatory Guide 1.43

RPV specifications require that all low alloy steel be produced to fine grain practice. The requirements of Regulatory Guide 1.43 are not applied to BWR vessels.

5.2.3.3.3 Nondestructive Examination of Ferritic Tubular Products

5.2.3.3.3.1 Regulatory Guide 1.66

The following is a general compliance assessment; for commitment, revision number, and scope, see Section 1.8.

This guide describes a method of implementing requirements acceptable to the NRC regarding nondestructive examination requirements of tubular products used in RCPB.

Wrought tubular products were supplied in accordance with applicable ASTM/ASME material specifications. Additionally, the specification for the tubular product used for control rod drive (CRD) housings specified ultrasonic examination to paragraph NB-2550 of ASME B&PV Code, Section III.

These RCPB components met the requirements of ASME B&PV Codes existing at the time of placement of orders, which predated Regulatory Guide 1.66. At the time the orders were placed, 10CFR50, Appendix B, requirements and the ASME B&PV Code requirements assured adequate control of quality for the products.

This Regulatory Guide was withdrawn by the NRC on September 28, 1977, because the additional requirements imposed by the guide were satisfied by the ASME B&PV Code.

5.2.3.3.4 Moisture Control for Low Hydrogen, Covered Arc Welding Electrodes.

All low hydrogen, covered welding electrodes are stored in controlled storage areas, and only authorized persons are permitted to release and distribute electrodes. Electrodes are received in hermetically sealed canisters. After removal from the sealed containers, electrodes that are not immediately used are placed in storage ovens that are maintained at about 250°F (generally 200°F minimum).

Electrodes are distributed from sealed containers or ovens as required. At the end of each work shift, unused electrodes are returned to the storage ovens. Electrodes that are damaged, wet, or contaminated are discarded. If any electrodes are inadvertently left out of the ovens for more than one shift, they are discarded or reconditioned in accordance with the manufacturer's instructions.

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

5.2.3.4.1 Avoidance of Stress Corrosion Cracking

5.2.3.4.1.1 Avoidance of Significant Sensitization - Compliance with Regulatory Guide 1.44 and NUREG-0313, Revision 1

For a discussion of general compliance with Regulatory Guide 1.44 (including commitment, revision number, and scope), see Section 1.8.

All austenitic stainless steel was purchased in the solution heat treated condition in accordance with applicable ASME and ASTM specifications. Carbon content was limited to 0.08 percent maximum, and cooling rates from solution heat treating temperatures were required to be rapid enough to prevent sensitization.

Measures were taken to minimize the possibility of intergranular stress corrosion cracking (IGSCC) of austenitic stainless steel piping in accordance with NUREG-0313, Revision 1. The RPV nozzle safe ends and extensions were replaced with corrosion resistant materials and redesigned to eliminate the thermal sleeves that were part of the pressure boundary and formed crevices. Corrosion resistant cladding was applied to field weld connections of the type 304 stainless steel piping in the recirculation system, and all of the shop welds were furnace solution heat treated before installation. To minimize the number of stagnant lines, the recirculation system bypass line and control rod drive return line were eliminated. The stainless steel piping in the core spray system and Residual Heat Removal (RHR) System (low pressure coolant injection line) was replaced with impact tested carbon steel piping from the RPV to the outboard isolation valve of the containment. The RHR shutdown cooling suction and return lines have type 316L stainless steel transition pieces between the recirculation line connections and the impact tested carbon steel pipe that extends to the containment outboard isolation valve.

Welding heat input was restricted to 110,000 joules per inch maximum, and interpass temperature to 350°F. High heat welding processes, such as block welding and electroslag welding, were not permitted. All weld filler metal and castings were required by specification to have a minimum of 5 percent ferrite.

Whenever any wrought austenitic stainless steel was heated to temperatures over 800°F, by means other than welding or thermal cutting, the material was again solution heat-treated.

These controls were used to avoid severe sensitization and to comply with the intent of Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel and NUREG-0313, Revision 1, Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping.

5.2.3.4.1.2 Process Controls to Minimize Exposure to Contaminants

Exposure to contaminants capable of causing stress corrosion cracking of austenitic stainless steel components was avoided by carefully controlling all cleaning and processing materials that contact the stainless steel during manufacture and construction.

Special care was exercised to ensure removal of surface contaminants prior to any heating operations. Water quality for cleaning, rinsing, flushing, and testing was controlled and monitored. Suitable packaging and protection were provided for components to maintain cleanliness during shipping and storage.

The degree of surface cleanliness obtained by these procedures meets the requirements of Regulatory Guides 1.37 and 1.44.

5.2.3.4.1.3 Cold Worked Austenitic Stainless Steels

Austenitic stainless steels with a yield strength greater than 90,000 psi are not used.

5.2.3.4.2 Control of Welding

5.2.3.4.2.1 Avoidance of Hot Cracking

Written welding procedures that are approved by GE are required for all primary pressure boundary welds. These procedures comply with the requirements of Sections III and IX of the ASME B&PV Code and applicable NRC Regulatory Guides.

All austenitic stainless steel weld filler materials were required by specification to have a minimum of 5 percent ferrite. Prediction of ferrite content was made by using the chemical composition in conjunction with the Schaeffler diagram. The use of the 5 percent minimum limit for ferrite content determined by the Schaeffler diagram has been shown to be adequate to prevent hot cracking in austenitic stainless steel welds. An extensive test program

performed by GE, with the concurrence of the regulatory staff, demonstrated that controlling weld filler metal ferrite at 5 percent minimum (by Schaeffler diagram) resulted in production welds that met the requirements of Regulatory Guide 1.31, Control of Stainless Steel Welding. A total of approximately 400 production welds in five BWR plants were measured, and all welds met the requirements of Branch Technical Position MTEB No.5-1, Interim Regulatory Position on Regulatory Guide 1.31, Control of Stainless Steel Welding.

For an assessment of alternate approaches, see Section 1.8.

5.2.3.4.2.2 Electroslag Welds - Compliance with Regulatory Guide 1.34

Electroslag welding was not employed for the RCPB.

5.2.3.4.2.3 Welder Qualification for Areas of Limited Accessibility - Compliance with Regulatory Guide 1.71

For a discussion of general compliance with Regulatory Guide 1.71, including commitment, revision number, and scope, see Section 1.8.

Regulatory Guide 1.71 requires that weld fabrication and repair for wrought low alloy and high alloy steels, or other materials such as static and centrifugal castings and bimetallic joints, should comply with fabrication requirements of Sections III and IX of the ASME B&PV Code. It also requires additional performance qualifications for welding in areas of limited access.

All ASME B&PV Code, Section III welds were fabricated in accordance with the requirements of Sections III and IX of the ASME B&PV Code. There are few restrictive welds involved in the fabrication of BWR components. Welder qualification for welds with the most restrictive access was accomplished by mockup welding. Mockups were examined with radiography or sectioning.

5.2.3.4.3 Nondestructive Examination of Tubular Products

Wrought tubular products were supplied in accordance with applicable ASTM/ASME material specifications. The specification for the tubular product used for CRD housings requires ultrasonic examination in compliance with Paragraph NB-2550 of ASME B&PV Code, Section III.

5.2.3.5 SRP Rule Review

5.2.3.5.1 NSSS Assessment

5.2.3.5.1.1 Acceptance Criterion II.1, Paragraph 1

SRP 5.2.3 acceptance criterion II.1, paragraph 1 states that the specifications for permitted materials are those identified in ASME Code Section III, Appendix I, or described in ASME Code Section II, Parts A, B and C. Appendix I of ASME Code Section III gives design stress limits for materials specified in Section II of the Code. The design stress limits are not addressed in FSAR Section 5.2.3, which deals only with material selection. Material specifications presented in FSAR Table 5.2-7 comply with the requirements in parts A and C of Code Section II.

5.2.3.5.1.2 Acceptance Criterion II.4.b, Paragraph 2

SRP 5.2.3 acceptance criterion II.4.b., paragraph 2 asks for verification that the quality of water used for final cleaning or flushing of finished surfaces during installation is in accordance with Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water Cooled Nuclear Power Plants." Vented tanks with deionized or demineralized water are an acceptable source of water for final cleaning or flushing of finished surfaces. The oxygen content of the water need not be controlled (Applicable to water specified in Regulatory Guide 1.44 used for final cleaning or flushing of finished stainless steel surfaces).

The provisions of Regulatory Guide 1.37 are not specifically addressed in the Hope Creek FSAR design. However, as stated in FSAR Section 5.2.3.4.1.1, exposure to contaminants capable of causing stress corrosion cracking in austenitic stainless steel components was avoided by carefully controlling all cleaning and processing materials which contact the stainless steel during manufacturing and construction. Water quality for cleaning, rinsing, and flushing was controlled and monitored. The degree of cleanliness obtained using these controls meet the requirements of Regulatory Guide 1.44.

5.2.3.5.2 Non-NSSS Assessment

5.2.3.5.2.1 Acceptance Criteria II.3.b(3) and II.4.d

In SRP Section 5.2.3, Acceptance Criteria, II.3.b(3) and II.4.d refer to Regulatory Guide 1.71 for welder performance qualification for areas of limited accessibility. Regulatory Position C.1 states that welder performance qualification should require testing of welder under simulated access conditions when physical conditions restrict welder's access to a production weld to less than 12 to 14 inches in any direction from the joint. Position C.2 requires welder to be requalified if significantly different accessibility conditions occur.

At HCGS, welders are not tested under simulated access conditions when welder's access is limited. Consequently, welders are not requalified if significant differences in accessibility occur. Welders are qualified in accordance with the applicable requirements of ASME B&PV Code, Sections III and IX. In addition, all limited access welding is performed by the most highly skilled welders under the supervision of the plant welding engineer.

All welding conducted in areas of limited access is subjected to the required nondestructive testing, and no waiver or relaxation of examination methods or acceptance criteria because of the limited access is permitted.

Welder requalification is required whenever any of the essential variables of ASME B&PV Code, Section IX, are changed, or when any authorized inspector questions the ability of the welder to perform satisfactorily in accordance with the requirements of the Code.

5.2.3.5.2.2 Acceptance Criteria II.4.d

In SRP Section 5.2.3, Acceptance Criteria II.4.d refers to Regulatory Guide 1.31 for acceptance criteria for delta ferrite in austenitic stainless steel weld filler material. Position C.1 of this guide states that delta ferrite verification should be made by tests using magnetic measuring devices.

On Hope Creek, the amount of delta ferrite in each lot of austenitic stainless steel filler material is based on the chemical analysis provisions of the ASME B&PV Code Section III, NE-2430, using the Schaeffler diagram. In the Code, this method is described as an alternate method to ferrite readings taken with a magnetic measuring instrument. Ferrite readings are taken by magnetic measuring devices for comparative purposes. Based on the satisfactory agreement of the two methods, the chemical analysis method is considered acceptable for process welds.

5.2.4 Inservice Inspection and Testing of the Reactor Coolant Pressure Boundary

The construction permit for Hope Creek Generating Station (HCGS), issued in November 1974, requires that the inservice inspection program meet the 1974 ASME B&PV Code, Section XI, with Addenda through Summer 1975.

In accordance with the provisions of 10CFR50.55a(g), which allows for the use of subsequent effective editions and Addenda of the Code, the preservice inspection program is written to meet the requirements of the 1977 ASME B&PV Code, Section XI with Addenda through Summer 1978 (hereafter referred to as ASME XI, 77S78), to the extent practicable. The inservice inspection program will be

prepared to the requirements of the edition and addenda of ASME XI in effect 12 months prior to the date of the operating license.

Should certain Code Section XI requirements be determined impractical in the course of inspecting the components, PSE&G will submit a request for relief from the requirements to the NRC, in accordance with the provisions of 10CFR50.55a(g)(5).

The inservice inspection program described is for the first 120 month interval following start of commercial operation. If later editions and Addenda of the ASME B&PV Code become effective prior to 12 months before this interval, the inspection program will be revised accordingly.

The inservice testing of Class 1 pumps and valves in accordance with the requirements of Subsections IWP and IWV of Section XI is addressed in Section 3.9.6.

5.2.4.1 System Boundary Subject to Inspection

The scope of the program encompasses those components within the reactor coolant pressure boundary (RCPB), as defined in 10CFR50.2(v) and 10CFR50.55a, footnote 2, that are not exempt from inspections in accordance with IWB-1220. Class 1 pressure retaining components and their specific boundaries are shown on Inservice Inspection Boundary Diagrams. These drawings are system piping and instrumentation diagrams (P&IDs), marked up and coded to reflect inservice inspection boundaries, and are included in the examination plan.

5.2.4.2 Accessibility

Access for the purpose of inservice inspection is defined as the design of the plant with the proper clearances for examination personnel to perform inservice examination during shutdown. The RCPB for HCGS reactor pressure vessel (RPV) piping, pumps, and valves is designed in compliance with the provisions for access, as

required by Subarticle IWA-1500 of ASME XI, 77S78. Platforms and ladders are provided to facilitate access to the RPV nozzles and pipe requiring examinations.

5.2.4.2.1 Reactor Pressure Vessel

Access for the inspection of the RPV is as follows:

1. Access to the reactor vessel shell welds is provided by openings in the biological shield wall to a system of tracks permanently affixed to the inside of the biological shield wall. A minimum 8-inch clearance for the remotely operated inspection devices is provided between the vessel exterior surface and the insulation interior surface.

2. Access to the exterior surface of the RPV nozzles for inservice inspection is provided by removable insulation and shield plugs. Hinged shield plugs around all nozzles except those for the recirculation outlet and control rod drive (CRD) return nozzle (capped) are used to gain access for remote nozzle inspection devices. Removable flow diverter shields that permit unobstructed examinations are designed for the outlet recirculation pipe penetrations. A nonhinged, removable shield plug permits access to the capped CRD nozzle. Sufficient clearances are provided for the fitting and adjustment of temporary track and adjustment of permanent tracks. Examinations that are performed from the tracks include the required coverage of the nozzle to shell welds, the nozzle inner radius, nozzle to safe end welds, and the safe end to pipe welds. Platforms and ladders are provided to facilitate access to the nozzles.

3. Using ultrasonic techniques, the vessel flange area and vessel closure head can be examined during refueling outages. The removal of the vessel closure head also enables examination of vessel internal components and

surfaces by remote visual techniques. The ultrasonic examination of the vessel to flange weld is performed manually by applying the search units to the seal surface.

4. The closure head is in dry storage during refueling, which facilitates direct manual examination. Removable insulation allows examination of head welds from the outside surface. Reactor vessel nuts and washers are removed to dry storage during refueling so that all studs can be examined during the inspection interval.

5. Openings in the biological shield wall and the RPV support skirt are provided to permit access to the RPV bottom head for inservice examination. The examinations to be performed include mechanized ultrasonic examinations of circumferential welds, meridional welds, dollar plate longitudinal welds, and visual examination of accessible penetration welds. Access in the lower head region facilitates mounting of the lower head mechanized inspection device on the support tracks.

5.2.4.2.2 Piping, Pumps, and Valves

The physical arrangement of piping, pumps, valves, and other components allows personnel access to welds requiring inservice inspection, except for the 2-inch RPV drain piping within the array of the CRD housings. The insulation that covers components, piping welds, and adjacent base metal is designed for easy removal and reinstallation in areas where inspection is required. Weld identification numbers are scribed adjacent to all piping welds requiring examination. Additionally, the weld number of a weld enclosed by insulation is identified on that section of insulation covering the weld with a weld identifier tag. Personnel platforms and storage areas are provided to facilitate examinations. Welds are located to permit ultrasonic examinations from at least one side, but where component configurations permit, access from both sides is provided. During design and fabrication, consideration was

given to the weld joint configuration and surface finish to permit an adequate surface for ultrasonic examination.

Components exempt from surface or volumetric examinations, as permitted by ASME Code Section XI IWB 1200, such as the 2-inch RPV drain line and the 1-inch and smaller lines (CRD lines and RPV instrumentation), are accessible for visual examination for evidence of leakage during the system leakage and hydrostatic tests described in Section 5.2.4.7 herein.

5.2.4.3 Examination Techniques and Procedures

Examination methods and procedures, including any special method and procedures, will be written in accordance with subarticle IWA-2200 of ASME Code Section XI. The categories of examination and method employed for the RPV, system piping, pumps, valves, and other ASME Section III, Class 1, components within the RCPB will be in accordance with IWB-2000.

5.2.4.3.1 Equipment for Inservice Inspection

The equipment for inservice inspection of the RPV has been designed to maximize examination coverage. All RPV full penetration welds have been reviewed for the application of mechanized inspection techniques. The RPV welds, nozzle welds, and nozzle inner radius area may be examined, using a remotely operated device. An electronic system with a receiver or data channel for each ultrasonic transducer is used for acquiring and storing data when using remote automated examination equipment.

The track system utilized for the pre-service examination of the RPV was installed between the vessel outside surface and the insulation. The inspection device was loaded at selected openings in the bioshield wall and at the base of the RPV outside the support skirt. The track system was designed to meet the requirements of ASME XI, 74S75. In cases where additional coverage can be provided without excessive cost, provisions exist to permit examination of approximately 85 percent

of the RPV welds during the first inspection interval. Essentially full coverage, in accordance with the requirements of Table IWB-2500-1 of ASME XI, pursuant to 10CFR50.55a(g), is provided for the second, third, and fourth intervals.

Nozzles N1, N2, N4, N5, and N17 may be examined, using the mechanical inspection device. The nozzle to shell weld, nozzle inner radius, nozzle to safe end weld, and safe end to pipe weld may be examined using remotely operated devices. The only exception will be N5B N2K and N2A which can also be examined using manual inspection processes. The remainder of the nozzles requiring examination are examined manually.

5.2.4.3.2 Coordination of Inspection Equipment with Access Provisions

Access to areas of the plant requiring inservice inspection is provided to allow the use of standard equipment wherever practical. Generally, design provides for free space envelopes, both radially and axially from welds to be examined, so that standard manual examination equipment may be used. Any special equipment or techniques used achieve the sensitivities required by the ASME B&PV Code.

Access is provided for the installation of remote examination devices on the vessel tracks by means of hinged, nozzle shield doors; removable hatches and panels; or personnel access hatches in the biological shield wall.

5.2.4.3.3 Manual Examination

In areas where manual ultrasonic examination is performed, all reportable indications are mapped and recorded. The data compilation format allows comparison of data from subsequent

examinations. In areas where manual surface or direct visual examinations are performed, all reportable indications are mapped with respect to size and location in a manner that also allows comparison of data from subsequent examinations.

5.2.4.4 Inspection Intervals

Inservice inspection intervals will be in accordance with subarticle IWA-2400 in Section XI of the ASME Boiler and Pressure Vessel Code. Each interval is divided into inspection periods in accordance with either Table IWB-2411-1 or Table IWB-2414-1 in Section XI. The inservice schedule and inspections, to be performed during each period and interval are defined by the Inservice Inspection Plan, as required by 10CFR50.55a.

5.2.4.5 Examination Categories and Requirements

Examination categories and requirements are defined in Table IWB-2500-1 of ASME XI, pursuant to 10CFR50.55a(g).

5.2.4.6 Evaluation of Examination Results

The evaluation of examination results is conducted in accordance with Article IWB-3000, Acceptance Standards for Flaw Indications, of ASME B&PV Section XI, pursuant to 10CFR50.55a(g).

When evaluations indicate repairs are required, the repair will be performed in accordance with Article IWA-4000 and IWB-4000 of ASME B&PV Code, Section XI.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

The hydrostatic test for the reactor is conducted in accordance with the requirements of Articles IWA-5000 and IWB-5000 of ASME XI, pursuant to 10CFR50.55a(g). The frequency of leak tests is specified in Table IWB-2500-1, Examination Category B-P.

Examination is conducted without the removal of insulation. Hope Creek technical specification requirements on operating limits during heatup, cooldown, and system hydrostatic pressure testing are employed for these tests.

5.2.4.8 SRP Rule Review

SRP Section 5.2.4.II.7 allows exemption from code examinations if the criteria in IWB-1220 are met, provided the exemptions taken are listed. Components exempt from surface or volumetric examinations as permitted by ASME Code Section XI IBW 1200 are the 2-inch RPV drain piping within the array of control rod drive housings and the 1-inch and smaller lines (CRD lines and RPV instrumentation) which are accessible for visual examination for evidence of leakage during the system leakage and hydrostatic tests described in paragraph 5.2.4.7.

5.2.5 Detection of Leakage through the Reactor Coolant Pressure Boundary and from the Emergency Core Cooling System

5.2.5.1 Leakage Detection Methods

The Nuclear Boiler Leak Detection System consists of temperature, pressure, flow, airborne gaseous fission product, and process radiation sensors with associated instrumentation. The system indicates and alarms leakage from the reactor coolant pressure boundary (RCPB) and, in certain cases, initiates signals used for automatic closure of isolation valves to shut off leakage external to the primary containment. The system piping and instrumentation diagram is shown on Plant Drawing M-25-1.

Within the primary containment, and within selected areas of the plant outside the primary containment, abnormal leakage is detected, indicated, alarmed, and, in certain cases, automatically isolated in the following systems:

1. Main steam lines (MSL)

2. Reactor Water Cleanup (RWCU) System

3. Residual Heat Removal (RHR) System

4. Reactor Core Isolation Cooling (RCIC) System

5. Feedwater System

6. High Pressure Coolant Injection (HPCI) System

7. Cooling systems within the primary containment

8. Core Spray System

9. Reactor pressure vessel (RPV)

10. Reactor Recirculation System

Leak detection methods used differ for plant areas inside the primary containment, as compared to those areas located outside the primary containment. These areas are considered separately below.

5.2.5.1.1 Detection of Leakage within the Primary Containment

The primary detection methods for small unidentified leaks within the primary containment include monitoring of containment floor drain sump level to determine flow rate, containment cooler condensate flow rate increases, and airborne gaseous radioactivity increases.

These variables are continuously indicated and recorded in the main control room. If the unidentified leakage increases to a total of 5 gpm, the detecting instrumentation channels will trip and activate an alarm in the main control room. No isolation trip will occur.

The secondary detection methods, i.e., the monitoring of pressure and temperature of the primary containment atmosphere and fillup/pumpout time of the drywell sump, are used to detect gross unidentified leakage. High primary containment pressure will alarm and trip the isolation logic, which will result in closure of the primary containment isolation valves, as discussed in Section 7.3.

The detection of small identified leakage within the primary containment is accomplished by monitoring containment equipment drain sump level to determine flow rate. These measurements will activate an alarm in the main control room when total leak rate reaches 25 gpm.

Certain RCPB components within the drywell are, by the nature of their design, normally subject to a limited amount of leakage. These components include pump seals, valve stem packings collectively, and other equipment that cannot practicably be made completely leaktight. Leakages from these components are piped directly to the drywell equipment drain sump. These components are identified on Figure 9.3-4, Sheet 2. All of these equipment drains are open to only the equipment they serve, thereby receiving leakage only from identified sources. Normal leakage to this equipment drain sump is determined during initial plant operation and monitored during plant operation.

Excessive leakage inside the primary containment, e.g., process line break or loss-of-coolant accident (LOCA) within primary containment, is detected by high primary containment pressure, low reactor water level, or high 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 that will close appropriate isolation valves (see Table 5.2-10).

The alarms, indications, and isolation trip functions initiated by the leak detection system are summarized in Tables 5.2-10 and 5.2-11.

5.2.5.1.2 Detection of Leakage External to the Primary Containment (within Reactor Building)

The detection of leakage within the Reactor Building (outside the primary containment) is accomplished by detection of decreases in reactor building floor drain sump and Reactor Building equipment drain sump fillup time and increased pumpout time. The Reactor Building floor drain sump monitors will detect unidentified leakage increases and activate an alarm in the main control room. The Reactor Building equipment drain sump monitors will also detect identified leakage increase and will activate an alarm in the main control room when excessive leakage is identified.

5.2.5.1.3 Detection of Leakage External to Containment

The areas outside the containment that are monitored for primary coolant leakage are equipment areas in the Reactor Building and the main steam tunnel. Where feasible, the process piping for each system to be monitored for leakage is located in compartments or rooms separate from other systems, so that leakage may be detected by area temperature indication. Each leakage detection system will detect leak rates that are less than the established leakage limits.

1. The monitored areas are monitored by dual element thermocouples for sensing high ambient temperature in the areas and high differential temperature between the inlet and outlet ventilation ducts that service the individual areas. The temperature elements are located or shielded so that they are sensitive only to air temperatures 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. The temperature trip setpoints will be a function of room size and the type of ventilation provided. These monitors provide alarm, indication, and recording in the control room and will trip the isolation logic to close selected isolation

valves (e.g., the main steam tunnel monitors will close the main steam line and MSL drain isolation valves and others; see Table 5.2-11).

2. 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 will trip the isolation logic to cause closure of appropriate system isolation valves on indication of excess leakage (see Table 5.2-11).

5.2.5.1.4 Intersystem Leakage Monitoring

A radiation sensor is used to detect intersystem leakage of primary side process fluid into the secondary side cooling water (SACS water) of the RHR heat exchangers. The process fluids cooled by the RHR heat exchangers in its different modes of operation are: reactor coolant, fuel pool water and suppression pool water. The sensor monitors radiation emanating from a continuously flowing SACS cooling water sample taken at a point just downstream of the RHR heat exchangers.

Another radiation sensor is used to detect intersystem leakage of primary side reactor coolant into the secondary side cooling water (RACS water) of the RWCU non-regenerative heat exchangers, the RWCU pump heat exchangers and the reactor recirculation pump seal and jacket cooling heat exchangers. The RACS sensor monitors radiation emanating from a continuously flowing RACS water sample which is taken at a point downstream of the RACS pumps.

High radiation in the SACS water or the RACS water indicates intersystem leakage. The affected sensor and its associated monitoring channel will activate an alarm in the main control room

when the radiation exceeds a predetermined limit. No isolation trip functions are performed by these channels.

These radiation channels are part of the Process Radiation Monitoring System described in Section 11.5.

High levels in the SACS or RACS head tanks may also indicate intersystem leakages from the sources given above. High level in either head tank will activate an alarm in the main control room.

5.2.5.2 Leak Detection Instrumentation and Monitoring

5.2.5.2.1 Leak Detection Instrumentation and Monitoring Inside Primary Containment

1. Floor drain sump level and flow - The normal design leakage collected in the floor drain sump includes unidentified leakage from the control rod drives (CRDs), valve flange leakage, component cooling water, service water, air cooler drains, and any leakage not connected to the equipment drain sump.

   A Class 1E level transmitter is used to monitor the drywell floor drain sump with the level signal being supplied to a Class 1E radiation processor of the Class 1E Radiation Monitoring System (RMS) (panel 10C604) located in the main control room. A level change in the sump is converted to a flow rate by the processor and leakage rates can be displayed continuously at panel 10C604 and are available, via data link, at the operator's console CRT. An increase in unidentified leakage in excess of technical specification limits is alarmed in the main control room.

The floor drain sump level monitoring instrumentation is qualified to remain functional following a safe shutdown earthquake (SSE).

2. Equipment drain sump level and flow - The equipment drain sump collects only identified leakage and valve stem packing leakoff collectively. This sump receives piped drainage from pump seal leakoff and reactor vessel head flange vent drainage. The equipment drain sump instrumentation is identical to the floor drain sump instrumentation.

3. Drywell air cooler condensate drain flow - Condensate from the drywell air cooler is routed to the floor drain sump.

   Flow in each of the two drain headers from the eight drywell coolers (four coolers per header) is monitored by a flow sensor. The flow signal from each flow sensor is processed by a local radiation processor which transmits the flow data to the main control room, via the central radiation processor, for indicating and alarm functions. Any flowrate increase exceeding technical specification limits will be alarmed in the main control room.

   This flow monitoring instrumentation is capable of operation following seismic events which do not require plant shutdown.

4. Drywell temperature - The Drywell Cooling System circulates the drywell atmosphere through air coolers to maintain the drywell at its designed operating temperature. An increase in the drywell atmosphere temperature would increase the temperature rise in the chilled water passing through the coils of the air

coolers. Thus, an increase in the chilled water temperature difference between inlet and outlet to the air coolers will indicate the presence of RCPB leakage.

A temperature rise in the drywell, which may result from RCPB leakage, is detected by monitoring both the drywell temperature at various elevations, and inlet and outlet air temperature to and from the drywell coolers.

High temperatures are alarmed in the main control room.

5. Drywell airborne gaseous radioactivity - Samples of the drywell atmosphere are continuously withdrawn from the drywell through a roughing filter and into a gas sampler that continuously monitors the radioactivity concentration of the sampled gas. The samples are discharged back into drywell.

   An increase of airborne radioactivity, which may be attributed to RCPB leakage, is annunciated in the main control room.

6. Drywell pressure - The primary containment is maintained at a slightly positive pressure during reactor operation and is monitored by pressure sensors. The pressure fluctuates slightly as a result of barometric pressure changes and outleakage. A pressure rise above the normally indicated values will indicate a possible leak within the primary containment. Pressure exceeding the preset values will be alarmed in the main control room. Separate instrumentation described in Section 7.2 and Section 7.3 will initiate a reactor scram and actuate engineered safety features.

7. Reactor vessel head seal pressure - The reactor vessel head closure is provided with double seals with a leakoff connection between seals. The leak off is piped through a normally closed manual valve to the floor drain sump.

Leakage through the first seal is monitored by measuring high pressure between the seals and is alarmed in the main control room. When pressure between the seals increases, the second seal contains the vessel pressure to maintain reactor vessel pressure boundary integrity.

8. Reactor water recirculation pump seal flow - Reactor water recirculation pump seal leaks are detected by monitoring flow in the seal drain line. Leakage, which is detected by measurement of high flow rate, causes alarms in the main control room. Any leakage is piped to the equipment drain sump. A block diagram depicting the recirculation pump leak detection monitors is shown on Figure 5.2-11.

9. Safety/relief valve discharge temperature - Temperature sensors connected to a multipoint recorder are provided to detect safety/relief valve (SRV) leakage during reactor operation. SRV temperature elements are mounted in the SRV discharge piping several feet downstream from the valve body. Temperature increases above ambient are alarmed in the main control room. In addition, an acoustic sensor is provided for each SRV to monitor for valve actuation. Depending upon the characteristics associated with leakage, it may also serve as leakage indication. Should high noise level result from an SRV leak, it will alarm in the main control room. Refer to the nuclear boiler system piping and instrumentation diagram, Plant Drawing M-41-1.

10. 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.

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

12. HPCI steam line flow (for leaks downstream of flow elements) - The steam supply line for the HPCI turbine motive power is monitored downstream of the nuclear boiler main steam lines by differential pressure steam flow sensors. Steam flows and pressures exceeding preset values initiate annunciation and isolation of the HPCI steam lines. Line pressure sensing is primarily for turbine shutoff.

13. RCIC steam line flow (for leaks downstream of flow elements) - The steam supply line for the RCIC turbine is monitored for abnormal flows. Steam flows exceeding preset values initiate alarm and isolation of the RCIC steam line.

14. Refueling pool - Leakage is detected by the reactor building floor drain sump monitoring and alarmed in the control room.

15. High differential pressure between Emergency Core Cooling System (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:

    a. Loop A and Loop C of the RHR system

    b. Loop B and Loop D of the RHR system

    c. Core spray loops

Indicators and alarms are located in the main control room. Tables 5.2-10 and 5.2-11 summarize the actions taken by each leakage detection function. The tables show that those systems that detect gross leakage initiate immediate automatic isolation. The systems that are capable of detecting small leaks initiate an alarm in the control room. The operator may manually isolate the leakage source or take other appropriate action.

5.2.5.2.2 Leak Detection Instrumentation and Monitoring External to Primary Containment

1. Reactor Building sump flow measurement - Instrumentation monitors and indicates the amount of unidentified leakage into the reactor building floor drainage system outside the primary containment. Background leakage is identified during preoperational tests. Abnormal leakage is alarmed in the control room. Identified leakage within the reactor building outside the primary containment includes the refueling pool liner leakage, which is piped to the reactor building equipment drain sump. The reactor equipment drain sump instrumentation is identical to the reactor floor drain sump instrumentation.

2. Visual and audible inspection - Accessible areas are inspected periodically, and the flow indicators discussed above are monitored regularly. Any instrument indication of abnormal leakage will be investigated.

3. Differential flow measurement (RWCU) - Because of its arrangement, the RWCU 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 from the system.

4. Main steam line area temperature monitors, HPCI and RCIC pipe routing area temperature monitors - High temperatures in the main steam line tunnel area and pipe routing areas are detected by dual element thermocouples. Some of the dual element thermocouples are used for measuring ambient temperatures and are located in the area of the main steam, HPCI, and RCIC lines. The remaining dual elements are used in pairs to provide measurement of differential temperature across (inlet to outlet) the tunnel area and pipe routing 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 the hot equipment. One thermocouple of each differential temperature pair is located so as to be unaffected by pipe routing or tunnel temperature. High ambient temperature in the main steam tunnel will alarm in the control room and provide a signal to close the main steam line and drain line isolation valves. High differential temperature in the main steam tunnel will alarm in the control room. High ambient temperature in the HPCI and RCIC pipe routing areas will alarm in the control room and provide signals to close the appropriate HPCI and RCIC steam line isolation valves. A high main steam tunnel temperature or differential temperature alarm may also indicate leakage in the reactor feedwater line that passes through the main steam tunnel.

5. 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, HPCI, and RWCU system 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 and provide trip signals for closure of the appropriate isolation valves of the respective

system for RCIC, HPCI and RWCU systems. For the RHR system, high ambient and high differential temperature are alarmed in the control room.

6. Intersystem leakage monitoring - Intersystem leakage monitoring is included in the process radiation monitoring system to satisfy the requirements of that system, as described in Section 11.5.

7. Large leaks external to the primary containment - The main steam line high flow, HPCI steam line high flow, RCIC steam line high flow, reactor vessel low water level monitoring, and RHR excess flow discussed in Section 5.2.5.2.1, can also indicate large leaks from the reactor coolant piping external to the primary containment.

8. Flooding alarm - Flooding alarm circuits are provided for the following rooms and structures:

    a. RCIC pump room

    b. HPCI pump room

    c. Core spray pump rooms

    d. RHR pump rooms

    e. SACS pump rooms

    f. RACS pump rooms

    g. Diesel generator rooms

    h. Service water intake structure.

In case of flooding, level switches initiate the alarms in the main control room.

5.2.5.2.3 Summary

Table 5.2-10 summarizes alarms provided for leakage sources inside and outside the primary containment and the monitored variable that initiates the alarm. Table 5.2-11 summarizes systems isolated and the leak detection variable(s) that initiates system isolation. Plant operating procedures will dictate the action an operator is to take upon receipt of an alarm from any of these systems. A time delay is provided before automatic isolation of the HPCI system or RCIC system on high ambient temperature in the steam supply piping area, so that spurious isolation of these systems can be eliminated. A time delay is also provided for the RWCU system differential flow to prevent normal system surge from isolating the system.

The leak detection system is redundantly designed so that failure of any single element will not interfere with a required detection of leakage or isolation. For further discussion, see Section 7.3.1.1.2.

5.2.5.3 Indication in Main Control Room

Leak detection methods are discussed in Section 5.2.5.1. Details of the Leakage Detection System indications are included in Section 7.6.1.3.

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 drywell floor drain and equipment drain sumps. The criterion for establishing the total leakage rate limit is based on the makeup capability of the RCIC system. The total leakage rate limit is established at 30 gpm. The identified

and unidentified leakage rate limits are established at 25 gpm and 5 gpm, respectively.

The total leakage rate limit is established low enough to prevent overflow of the sumps. The equipment drain 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 Primary Containment

The pump packing glands valve stems collectively, and other seals in systems that are part of the RCPB, and from which normal design identified source leakage is expected, are provided with leak-off drains. Nuclear system valves and pumps inside the primary containment are equipped with double seals. Leakage from the primary recirculation pump seals is monitored for flow in the drain line and piped to the drywell equipment drain sump, as described in Sections 5.4.1.3 and 5.2.5.2.1.8. Leakage from the main steam SRVs discharging to the suppression pool is monitored by temperature sensors that transmit to the control room. Any temperature increase above the ambient temperature detected by these sensors indicates valve leakage.

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

5.2.5.5 Unidentified Leakage Inside the Primary Containment

5.2.5.5.1 Unidentified Leakage Rate

The unidentified leakage rate is the portion of the total leakage rate received in the primary containment 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 5.2-12). Safety limits and safety limit settings are discussed in the Technical Specifications.

5.2.5.5.2 Sensitivity and Response Times

Sensitivities and response times for the three separate and diverse leak detection methods in conformance with Regulatory Guide 1.45, Position C.3, with the exception of item 2 concerning the airborne particulate radioactivity monitor are:

1. Drywell floor drain sump monitor, 1 gpm in 1 hour or less.

2. Drywell air cooler condensate flow monitor, 1 gpm in 1 hour or less.

Drywell atmosphere noble gas monitor sensitivity is approximately 10 gpm leakage equivalent. This is not in compliance with the Regulatory Guide 1.45 requirement of 1 gpm. For a discussion of response time see Section 1.8.1.45.

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 as indicated in Reference 5.2-7. This analysis relates to axially oriented through wall cracks.

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

$$L_C = \frac{15,000D}{r_h}$$ (see data correlation on Figure 5.2-12)

where:

L_C = critical crack length (in.)

D = main pipe diameter (in.)

r_h = nominal hoop stress (psi)

2. Crack opening displacement - The theory of elasticity predicts a crack opening displacement of

$$x = \frac{2Lr}{E}$$

where:

L = crack length

r = 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 r approaches the failure stress. A suitable correction factor for plasticity effects is:

$$C = \sec \frac{p}{2}\frac{r}{r_f}) \qquad (5.2\text{-}2)$$

where:

r = failure stress

The crack opening area is given by

$$A = C\frac{p}{4}xL = \frac{pL^2 r}{2E} \sec \frac{p}{2}\frac{r}{r} \qquad (5.2\text{-}3)$$

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

3. Leakage flow rate - The maximum flow rate for blowdown of saturated water at 1000 psi is 55 lb/s-in^2, and for saturated steam, the rate is 14.6 lb/s-in^2. as indicated in Reference 5.2-8. Friction in the flow passage reduces this rate, but for cracks leaking at 5 gpm (0.7 lb/s), 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 boiling water reactor (BWR) pipe size (Schedule 80) and pressure (1050 psi).

The lengths of through wall cracks that would leak at the rate of 5 gpm, given 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	Crack Length L, in. 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 Steam Line	Nominal Pipe Size (Sch 80), in Water Line	Ratio L/L_C
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 that 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 gpm will precede crack instability. Measured crack opening displacements for the BMI experiments were in the range of 0.1 to 0.2 in. at the time of incipient rupture, corresponding to leaks of the order of 1 in^2. in size 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 5.2-13 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 "Leakage Flow Rate". 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 total 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 5.2-13 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 Tables 5.2-10 and 5.2-11. The instrumentation is designed so it can be set to provide alarms at established leakage rate limits and isolate the affected system, if necessary. 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 with significant compromise.

The Leak Detection System sensitivity and response time is such that an unidentified leakage rate increase of 1 gpm in less than 1 hour will be detected.

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 Sections 5.2.5.4, 5.2.5.5, and 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, is 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 (NSSS) safety interfaces for the leak detection system are the signals from the monitored balance of the plant equipment and systems that are part of the nuclear system process barrier, and associated wiring and cable lying outside the NSSS equipment.

5.2.5.9 Testing and Calibration

Testing and calibration will be in conformance with the technical specifications and will consist of channel checks and channel functional tests during power operation. Channel calibration will be done during refueling outages.

Testing and calibration of the noble gas monitor is discussed in Section 11.5.2.15.

5.2.5.10 Conformance to Regulatory Guide 1.45

For a discussion of compliance with Regulatory Guide 1.45, see Section 1.8.1.45.

5.2.5.11 SRP Rule Review

SRP 5.2.5 acceptance criterion II.1 requires that leak detection system integrity must be maintained following an earthquake, as per GDC2. This is met through Regulatory Guide 1.29 positions C-1 and C-2.

The drywell floor drain sump, drywell cooler condensate monitors, and noble gas monitor systems are not qualified for seismic events as discussed in Section 1.8.1.45.

5.2.6 References

5.2-1 "General Electric Standard Application for Reactor Fuel," including the "United States Supplement," NEDE-24011-P-A and NEDE-24011-P-A-US, (latest approved revision)

5.2-2 Nuclear Regulatory Commission, Task Action Plan Item II.D.3, "Direct Indication of Relief and Safety-Valve Position," Clarification of TMI Action Plan Requirements, NUREG-0737, November 1980.

5.2-3 Nuclear Regulatory Commission, Task Action Plan Item II.D.1, "Performance Testing of Boiling Water and Pressurized Water Reactor Relief and Safety Valves," Clarification of TMI Action Plan Requirements, NUREG-0737, November 1980.

5.2-4 General Electric, "Analysis of Generic BWR Safety/Relief Valve Operability Test Results," NEDO-24988, October 1981.

5.2-5 J.M. Skarpelos and J.W. Bagg, "Chloride Control in BWR Coolants," NEDO-10899, General Electric, June 1973.

5.2-6 W.L. Williams, "Corrosion," Vol 13, p. 539t, 1957.

5.2-7 M.B. Reynolds, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flows," GEAP-5620, April 1968.

5.2-8 "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," NUREG 76/067/NRC/PCSG, October 1975.

5.2-9 General Electric, "Nuclear Energy Business Operations Boiling Water Reactor Quality Assurance Program Description," NEDO-11209-OA, Revision 4, December 31, 1982.

5.2-10 Deleted

5.2-11 Deleted

5.2-12 NEDC-33076P, Rev. 2, “Safety Analysis Report For Hope Creek Constant Pressure Power Uprate,” August 2006.

TABLE 5.2-1

REACTOR COOLANT PRESSURE BOUNDARY AND SAFETY-RELATED FLUID SYSTEM COMPONENTS NOT IN COMPLIANCE WITH REQUIREMENTS OF 10CFR50

Equipment	Purchase Order Date	Code to Which Equipment Was Built	10 CFR 50 Applicable Code
Reactor pressure vessel	May 7, 1970	ASME III, 1968 Edition with Winter 1969 Addenda*	ASME III, 1971 Edition with Summer 1972 Addenda
Control rod drive housings	January 5, 1971	ASME III, 1968 Edition with Summer 1970 Addenda	ASME III, 1971 Edition with Summer 1972 Addenda
Control rod drive	August 18, 1971	ASME III, 1968 Edition with Winter 1970 Addenda	ASME III, 1971 Edition with Summer 1972 Addenda
Power range monitor in-core housing	January 5, 1971	ASME III, 1968 Edition with Summer 1970 Addenda	ASME III, 1971 Edition with Summer 1972 Addenda
Jet pump instrumentation penetration	January 5, 1971	ASME III, 1968 Edition with Summer 1970 Addenda	ASME III, 1971 Edition with Summer 1972 Addenda
Main steam line safety relief valves	January 28, 1971	Nuclear Pump and Valve Code, 1968 Edition with Summer 1970 Addenda	ASME III, 1971 Edition with Winter 1972 Addenda
Main steam line isolation valves	October 8, 1969	Nuclear Pump and Valve Code, 1968 Edition	ASME III, 1971 Edition with Winter 1972 Addenda
Main steam line pipe	January 27, 1972	ASME III, 1971 Edition with Summer 1971 Addenda	ASME III, 1971 Edition with Winter 1972 Addenda
Main steam line flow elements	February 5, 1973	ASME III, 1971 Edition with Summer 1972 Addenda	ASME III, 1971 Edition with Winter 1972 Addenda
Reactor Recirculation System pump	May 7, 1971	Nuclear Pump and Valve Code, 1968 Edition with March 1970 Addenda	ASME III, 1971 Edition with Winter 1972 Addenda
Reactor Recirculation System shutoff valves	February 23, 1971	Nuclear Pump and Valve Code, 1968 Edition with March 1970 Addenda	ASME III, 1971 Edition with Winter 1972 Addenda
Reactor Recirculation System, pipe	February 25, 1971	ASME III, 1968 Edition with Summer 1970 Addenda	ASME III, 1971 Edition with Winter 1972 Addenda

* See Note 11 of Table 5.2.2

TABLE 5.2-2

APPLICABLE CODE CASES

NSSS Components - GE-Supplied (See Note 11)

Code Case No.	Subject
1141	Foreign-Produced Steel
1332-5	Requirements for Steel Forgings, Section III and VIII, Division 2
1361(4)	Socket Welds, Section III.
1441-1	Waiving of 3S Requirements for Section III Construction
1464	Requirement for Stamping for Section III.
1516-2(1)	Welding of Seats or Minor and Internal (N-24) Permanent Attachments in Vessels for Section III Applications
1588	Electroetching (or vibroetching) of the Section III Code Symbol
1820	Alternate Ultrasonic Examination Technique, Section III, Division 1
N-319	Alternate Procedure for Evaluation of Stresses in Butt Weld Elbows in Class 1 Piping, Section III, Division 1

Code Case No.	Subject
1745 (N-122)	Stress Indices for Structural Attachments, Class 1, Section III, Division 1.
Non-NSSS Components - Bechtel Supplied[(2)]	
1141-1	Foreign Produced Steel
1481-1	Elevated Temperature Design of Section III, Division 1, Class 2 and 3 Components
1557	Steel Products Refined by Secondary Remelting Section III and VIII, Divisions 1 and 2
1567	Testing Lots of Carbon and Low-Alloy (N-38) Steel Covered Electrodes, Section III
1568 (N-39)	Testing Lots for Flux Cored and Fabricated Carbon and Low Alloy Steel Welding Electrodes, Section III
1571 (N-41)	Additional Material for SA-234 Carbon Steel Fittings, Section III
1573	Vacuum Relief Valves
1588 (N-46)	Electroetching of Section III Code Symbol
1590	Permits SA-336 Check Analysis to Be Used for SA-182

Code Case No.	Subject
1606-1 (N-53)	Stress Criteria Section III, Classes 2 and 3 Piping Subject to Upset, Emergency, and Faulted Operating Conditions.
1607/1607-1[(4)] (N-54)	Stress Criteria for Section III, Division 1, Class 2 and 3 Vessels Design to NC/ND-3300 Excluding the NC-3200 Alternate
1609-1 Welding, (N-55)	Inertia and Continuous Drive Friction Sections I, III, IV, VIII - Divisions 1 and 2, and IX
1622[(3)]	Postweld Heat Treatment (PWHT) of Repair Welds in Carbon Steel Castings, Section III, Classes 1, 2, and 3
1634-2 (N-68)	Use of SB-359 for Section III, Division 1, Class 3 Construction
1635-1	Stress Criteria for Section III, Class 2 and 3 Valves Subject to Upset, Emergency and Faulted Operating Conditions
1636-1[(4)] (N-70)	Stress Criteria for Section III, Class 2 and 3 Pumps Subjected to Upset, Emergency, and Faulted Operating Conditions
1644/ 1644-1,2.3[(4)(8)]	Additional Materials for Component Supports - Section III Subsection NF Class 1,2,3, and MC Construction

Code Case No.	Subject
1644-4,5,6(4)(8)	Additional Materials for Component Supports and Alternate Design Requirements for Bolted Joints Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Construction
1644-7 (N-71-7)(4)(8) (N-71-8)1,2,3	Additional Materials for Component Supports, Section III Division 1, Subsection NF, Class 1644-8 and MC Component Supports
1644-9(4)(8) (N-71-9)	Additional Materials for Component Supports Fabricated by Welding, Section III, Division I, Subsection NF Class 1,2,3, and MC Component Supports
N-71-11(4)	Additional Materials for Component Supports Fabricated by Welding, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Component Supports
645	Use of Delong Diagrams for Calculating Delta Ferrite Content of Welds
1648	SA-537 Plates from 2-1/2 to 4 Inches, Inclusive
1651(3) (N-74)	Interim Requirements for Certification of Component Support, Section III, Subsection NF
1657 (N-75)	Stress Criteria for Class 2 and 3 Atmospheric and Low Pressure (0 to 15 psig) Steel Storage Tanks

Code Case No.	Subject
1677	Classification of Flange Design Loads, (N-82) Section III, Classes 1, 2, and 3
1678 (N-83)	Butterfly Valves of Circular Cross-Section Larger than 24 Inches, NPS for Section III, Class 2 and 3 Construction
1682-1	Alternate Rules for Material Manufacturers and Suppliers (Section III, NA-3700)
1683	Bolt Holes: Alternative Rules
1685 (N-85)	Furnace Brazing, Section III, Class 1,2,3, and MC Construction
1686 (N-86)	Furnace Brazing, Section III, Subsection NF Components
1690 (N-88)	Stock Material for Construction, Section III, Division 1
1695-1 (N-91)	Brazing, Section III, Division 1, Class 3
1701-1 (N-95-1)	Determination of Capacities of Vacuum Relief Valves, Section III, Division 1 and 2, Class MC
1702	Flanged Valves Larger Than 24 Inches for Section III, Classes 1, 2, and 3
1706	Data Report Forms for Component Supports

Code Case No.	Subject
1711[(4)(6)] III, (N-100)	Pressure Relief Valve Design Rules, Section Division 1, Classes 1, 2, and 3
1712 (N-101)	Nameplates and Stamping as Referenced in Section III, NA-8530
1713	Small Material Items
1724 (N-108)	Deviation from Specified Silicon Ranges in ASME Material Specifications Section III, Division I, and VIII, Divisions 1 and 2
1728	Steel Structural Shapes and Small Material Products for Component Supports, Section III, Division 1 Construction
1729 III, (N-111)	Minimum Edge Distance - Bolting for Section Division 1, Class 1, 2, 3, and MC Construction of Component Supports
1734[(4)] (N-116)	Welding Design for Use in Section III, Division 1, Class 1, 2, 3, and MC Construction of Component Support
1739-2 (N-119-2)	Pump Internal Items, Section III, Division 1, Classes 1, 2, and 3
1744 Inches, (N-121)	Carbon Steel Pipe Flanges Larger Than 24 Section III, Division 1, Class 2 and 3 Construction

Code Case No.	Subject
1745 (N-122)	Stress Indices for Structural Attachments, Class 1, Section III, Division 1
1748 (N-125)	Low Carbon Austentic Stainless Steel Pipe Welded with Filler Metal, Section III, Division 1 Construction
1761/1761-1 (N-133)	Use of SB-148 Alloy CA954, Section III, Division 1, Class 3
1791 (N-154)	Projection Resistance Welding of Valve Seats, Section III, Division 1, Class 1, 2, and 3 Valves
1810 (N-172)	Testing Lots of Carbon Steel Solid, Bare Welding Electrodes or Wires, Section III, Division 1, Classes 1, 2, 3, MC, and CS
1818(4) (N-175)	Weld Joints in Component Standard Supports, Section III, Division 1
N-178	Use of ASTM B271, CDA954, Alloy 9C for Class 3 Construction
N-180	Examination of Springs for Class 1 Component Standard Supports, Section III, Division 1
N-188-1	Use of Welded Alloy 825 and Alloy 625 Tubing, Section III, Division 1, Classes 2 and 3
N-192/N-192-1(4)(7)	Use of Flexible Hose for Section III, Division 1, Class 2 and 3 Construction

Code Case No.	Subject
N-199(4)	Intervening Elements Section III, Division 1, Classes 1, 2, 3, and MC Component Construction
N-224-1	Use of ASTM A500 Grade B and ASTM A501 Structural Tubing for Welded Attachments for Section III, Class 2 and 3 Construction
N-225	Certification and Identification of Material for Component Support, Section III, Division 1
N-226	Temporary Attachment of Thermocouples, Section III, Division 1, Class 1, 2, and 3 Component
N-234	Time Between Ultrasonic Calibration Checks, Section XI, Division 1
N-235	Ultrasonic Calibration Checks per Section V Section XI, Division 1
N-236	Repair and Replacement of Class MC Vessels, Section XI, Division 1
N-237-2	Hydrostatic Testing of Internal Piping, Section III, Division 1, Classes 2 and 3
N-240	Hydrostatic Testing of Open-Ended Piping, Section III, Division 1
N-241	Hydrostatic Testing of Piping, Section III, Division 1

Code Case No.	Subject
N-242/N-242-1(4)	Material Certification, Section III, Division 1, Classes 1, 2, 3, MC, and CS Construction
N-247	Certified Design Report Summary for Component Standard Supports Section III, Division 1, Class 1,2,3, and MC
N-249/N-249-1(4)(9) N-249-2	Additional Material for Component Supports Fabricated Without Welding, Section III, Division 1, Subsection NF, Class 1, 2, 3, and MC Component Supports
N-252(4)	Low Energy Capacitive Discharge Welding Method for Temporary or Permanent Attachments to Components and Supports, Section III, Division I, and XI
N-253-1(10)	Construction of Class 2 or Class 3 Components for Elevated Temperature Service, Section III, Division 1
N-275(4)	Repair of Welds, Section III, Division 1
N-282	Nameplates for Valves, Section III, Division 1, Classes 1, 2, and 3.
N-284(4)	Metal Containment Shell Buckling Design Methods, Section III, Division 1, Class MC.
N-302	Tack Welding Section III, Division 1 Construction

Code Case No.	Subject
N-307	Revised Ultrasonic Examination Volume for Class 1 Bolting, Examination Category B-G-1, Division 1, When the Examinations Are Conducted from the Center-Drilled Hole.
N-308	Documentation of Repairs and Replacement of Components in Nuclear Power Plants
N-313	Alternative Rules for Half-Coupling Branch Connections, Section III, Division 1, Class 2 Construction
N-316	Alternative Rules for Fillet Weld Dimensions for Socket Welded Fittings, Section III, Division I, Class 1, 2, and 3.
N-362-2	Alternative Rules for Pressure Testing of Containment Items, Section III, Division 1
N-377	Effective Throat Thickness of Partial Penetration Groove Welds for Section III, Division 1, Classes 1, 2 and 3 Linear Type Component Supports
N-413[(5)]	Minimum Size of Fillet Welds for Linear Type Supports, Section III, Division 1, Subsection NF.
N-411[(4)]	Alternative Damping Values for Seismic Analysis of Piping, Section III, Division I, Class 1, 2, 3
N-438-1, N-438-3	Permits Use of UNS N08367 Materials, Section III, Division 1, Class 2 and 3 Construction
N-439	Permits Use of 20Cr-18Ni-6Mo (Alloy UNS S31254) Forgings, Plate, Seamless and Welded Pipe, and Welded Tube, Class 2 and 3 Construction, Section III, Division 1
N-441	Permits Use of 20Cr-18Ni-6Mo (Alloy UNS S31254) Fitting, Class 2 and 3 Construction, Section III, Division 1

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(1) These ASME Code Cases are also applicable to the components supplied by Bechtel.

(2) This list includes Code Cases applied to ASME III, Division 1, Subsection NB - Class 1 Components, Subsection NC - Class 2 Components, Subsection ND - Class 3 Components, Subsection NE - Class MC Components, Subsection NF - Components Supports, Subsection NG - Core Support Structures and ASME XI, Division 1

(3) Use of this Code Case is permitted for certain design specifications. To date it has not been invoked.

(4) Use of this Code Case is subject to the restrictions, interpretations, and clarifications in Regulatory Guides 1.84, 1.85, and/or 1.147. HCGS complies with these additional regulatory requirements, except as noted in Section 1.8.

(5) For use during As-Built Reconciliation only.

(6) Code Case 1711 (N-100) was invoked in the design of a number of safety-related safety relief valves. Regulatory Guide 1.84 states the design guidance in this code case is acceptable subject to the requirement that the FSAR demonstrate how the pressure relief function is assured if the stress limits utilized for the upset operating condition are in excess of those specified in the code case. This additional regulatory requirement is not applicable to the HCGS. All the safety relief valves designed in accordance with Code Case 1711 utilized stress limits that are below those specified for the upset operating condition.

(7) Code Case N-192 was invoked in the fabrication of certain flexible metal instrument hose assemblies and on certain standby diesel generator skid to facility connectors. Regulatory Guide 1.84 states that this code case is acceptable subject to the requirement that the applicant should provide design data to demonstrate compliance with Paragraph NC/ND-3649.

Information to comply with this additional regulatory requirement has been submitted under separate cover (letter from R. L. Mittl, PSE&G, to A. Schwencer, NRC, dated July 30, 1984).

(8) Code Case 1644 and its various revisions has been invoked in numerous applications. Regulatory Guide 1.85 states that this code case is acceptable subject to the limitations on maximum ultimate tensile strength and, in the case of Code Case 1644-9 (N-71-9), the additional requirements for electrode dispersal.

Most of the HCGS specifications, which invoke Code Case 1644 (N-71), invoke a specific revision of the Code Case, and direct the vendor to comply with the additional regulatory requirements. For those specifications that did not identify a specific revision and direct conformance with the additional regulatory requirements, a review has been performed to confirm that the ultimate tensile strength of the materials is below 170 ksi. A review has also been performed to confirm that the welding electrode dispersal requirements given in Regulatory Guide 1.85 are satisfied.

(9) Use of Code Case N-249 is permitted for the containment hydrogen recombiner technical specification. To date, this code case has not been invoked.

(10) Code Case N-253-1 provides rules for the construction of ASME components that experience elevated temperatures. This code case was invoked in the design of the containment hydrogen recombiners. This code case was invoked on HCGS because there are portions of the containment hydrogen recombiners that operate at temperatures in excess of 800°F.

(11) Safe end to N5B Core Spray nozzle repair performed in October 1997 which was designed in accordance with 1989 Edition ASME Section XI, IWB-3641, NUREG 0313, Revision 2 and installed using ASME Code Cases N432, N504-1, 2142, 2143, N416-1 as modified for use in accordance with USNRC SER (TAC # M99755). Safe end to N2K Reactor Recirculation nozzle repair performed in December 2004 which was designed in accordance with ASME Code Section XI 1998 Edition, including Addenda through 2000, IWB-3640, NUREG 0313, Revision 2 (which was implemented by Generic Letter 88-01) and installed using ASME Code Cases N504-2 and N638 as modified for use in accordance with USNRC Safety Evaluation Report (SER) as tracked by SAP operations 228 and 279 for DCP 80076353. Safe end to N2A Reactor Recirculation nozzle repair performed in October 2007 via DCP 80094209, which was designed in accordance with ASME Code Section XI 1998 Edition, including Addenda through 2000, IWB-3640, NUREG 0313, Revision 2 (which was implemented by Generic Letter 88-01) and installed using ASME Code Cases N504-3 and N638-1 as modified for use in accordance with USNRC Safety Evaluation Report (SER).

TABLE 5.2-3

NUCLEAR SYSTEM SRV SETPOINTS

Number of Valves[1]	Spring Set Pressure, psig	ASME-Rated Capacity at 103 Percent Spring Set Pressure, lbm/h each
4	1108	884,000
5	1120	893,000
5	1130	901,000

(1) Five of the SRVs serve in the automatic depressurization function. These particular valves are identified on Figure 5.1-3.

TABLE 5.2-4

SYSTEMS THAT MAY INITIATE DURING OVERPRESSURE EVENT

System	Initiating/Trip Signal(S)[1]
Reactor Protection System	Reactor trips "OFF" on high flux
Reactor Core Isolation Cooling	"ON" when reactor water level is at L2
	"OFF" when reactor water level is at L8
High Pressure Coolant Injection	"ON" when reactor water level is at L2
	"OFF" when reactor water level is at L8
Recirculation System	"OFF" when reactor water level is at L2
	"OFF" when reactor pressure is at 1125 psig
Reactor Water Cleanup System	"OFF" when reactor water level is at L2

(1) Vessel level trip settings are shown on Figure 5.1-4.

TABLE 5.2-5

SEQUENCE OF EVENTS FOR MSIV CLOSURE WITH HIGH FLUX TRIP

(FIGURE 5.2-2)

Time, s	Events
0	Closure of all MSIVs is initiated
0.3	MSIVs reach 90 percent open and initiate reactor scram; however, hypothetical failure of this position scram was assumed in this analysis
1.66	Neutron flux reaches the high APRM flux scram setpoint and initiates reactor scram
2.28	Steamline pressure reaches the setpoint of the first SRV group, and SRVs start to open
2.37	All SRVs open
2.42	Recirculation pumps trip on high pressure
3.0	MSIVs completely close
3.96	Vessel bottom pressure reaches its peak value
≥20 (est)	SRVs close

TABLE 5.2-6

ENVIRONMENTAL CONDITIONS

1. Normal conditions:

	Temperature, °F	Pressure, psig	Humidity Percent
Average	135	0	50
Maximum	150	+2.0	90
Minimum	40 (not operating)	-0.5	
	60 (operating)		

2. Abnormal conditions

Time	Temperature, °F	Pressure, psig	Humidity, Percent
0 - 20 s	340	0 - 62	100
20 s - 5 min	340	62	100
5 min - 3 h	340	40	100
3 - 6 h	320	40	100
6 - 24 h	250	25	100
1 - 4 days	200	25	100
4 - 100 days	200	10	100

TABLE 5.2-7

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Reactor Vessel Materials			
Shell	Rolled plate	Low alloy steel	SA-533 Grade B Class 1
Head	Rolled plate	Low alloy steel	SA-533 Grade B Class 1
Closure flange	Forging	Low alloy steel	SA-508 Class 2
Shroud components	-	Nickel based alloy	Inconel SB-168
Head bolting materials			
Cap	-	Stainless steel	SA-193 Grade B8
Plug	Bar	Stainless steel	SA-182 Grade F304
Stopper bolt	Bar	Stainless steel	SA-182 Grade F304
Stud bolt, nut, and washer	Bar	Low alloy steel	SA-540 Grade B24
O-ring gaskets	-	Nickel-based alloy	Inconel INCO-718
Recirculation outlet nozzle	Forging	Low alloy steel	SA-508 Class 2
Safe end material	Piping	Stainless steel	SA-182 Grade F304L
Mating pipe material	Piping	Stainless steel	SA-358 Grade 304L Class 1
Recirculation Piping			
28-inch pipe	Welded pipe	Stainless steel	Type 304 A 358 Class 1 with A 240 Basemat

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
28-inch pipe	Welded fitting	Stainless steel	Type 304 A 403 with A 240 Basemat
Hanger lug	Plate	Stainless steel	A 240 Type 304
Nozzle, half coupling, cap, sweepolet, reducer	Fittings	Stainless steel	A 182 Grade 304
Tee, cap, cross, elbow	Fittings	Stainless steel	SA 403 Type 304
Flanges	Fittings	Stainless steel	A 182 Grade 316
4-inch pipe	Pipe	Stainless steel	A 376 Type 304
22-inch pipe	Welded pipe	Stainless steel	A 358 Type 304
12-inch pipe	Welded pipe	Stainless steel	A 358 Type 304
Plug	Fitting	Stainless steel	SA 479 Type 316L
Recirculation bypass line cap	Forging	Stainless steel	SA-403 Grade WP304 (weld rod 308L with 8% ferrite min)
Recirculation gate valves			
Body, upper gland, bonnet	Casting	Stainless steel	SA-351 Grade CF8M
Pressure retaining bolts and studs	Bar stock	Low alloy steel	A 193 Grade B7
Body to bonnet stud nut	Bar	Steel	A 540 Grade B22
Stem	Bar	Stainless steel	A 461 Grade 630 Condition H-1150
Disc	Casting	Stainless steel	SA-351 Grade CF3A
Other pressure retaining nuts	Bar	Steel	A 194 Grade 2H
Yoke	Casting	Carbon steel	SA-216 Grade WC8
Decontamination connection flange	Forging	Stainless steel	SA-182 Grade F316L
Decontamination connection flange bolting	Bar	Steel	SA-193 Grade 37

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Decontamination connection flange bolting	Bar	Steel	SA-194, Grade 24
RWCU flow element			
Venturi body	Forging	Stainless steel	SA-182 Grade F316L (with 0.02% maximum carbon)
Transition sections	Forging	Carbon steel	SA-350, Grade LF2
Recirculation pumps			
Pump case and cover	Casting	Stainless steel	SA-351 Grade CF8M
Lower flange ring of motor support	Forging	Carbon steel	A 216 Grade WCB
Cover to case stud	Bar	Alloy steel	A 540 Grade B23 Class 4
Seal flange	Forging	Stainless steel	SA-182 Grade F316
Seal flange bolts	bar	Alloy steel	A 540 Grade B23 Class 4
Fitting, heat exchanger	Forging	Stainless steel	SA-479 TP 316
RHR return testable check valves			
Body	Casting	Steel	SA-352 Grade LCB
Disc	Casting	Steel	SA-352 Grade LCB
Shaft	Bar	Age hardened stainless steel	SA-564 Type 630 Condition H-1100
Nuts, valve cover	Bar stock	Alloy steel	SA-540 Grade B23 Class 5
Bolts, valve cover	Bar stock	Alloy steel	SA-540 Grade B23 Class 5
Nuts, bearing cover	Bar stock	Alloy steel	SA-194 Grade 2H
Bolts, bearing cover	Bar stock	Alloy steel	SA-193 Grade B7
Bearing cover	Forging	Stainless steel	SA-350 - LF1

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
RHR containment isolation valves	Casting	Carbon steel	SA-216 Grade WCB
Bolts	Bar	Steel	SA-320 Grade L43
Nuts	Bar	Steel	SA-194 Grade 4
RHR shutdown cooling relief valve			
Base and disc	Forging	Stainless steel	SA-479 Type 316L
Spindle and adjustment bar	Bar	Stainless steel	SA-193 Grade B6
Spring	Bar	Carbon steel	A 229 Class 1
Washer	Forging	Stainless steel	SA-479 Type 410
Cylinder	Casting	Carbon steel	SA-216 Grade WCB
Inlet nozzle	Forging	Low alloy steel	SA-508 Class 2
Safe end material	Piping	Stainless steel	SA-182 Type F316L
Thermal sleeve material	Forging	Stainless steel	SA-182 Type F316L
Mating pipe material	Piping	Stainless steel	SA-358 Grade 304L Class 1
Headspray nozzle	Forging	Low alloy steel	SA-508 Class 2
Safe end material (and flange)	Forging	Low alloy steel	SA-508 Class 2
Blind Flange	Forging	Carbon Steel	SA-508 Class 1
Flange bolts	Bar	Steel	SA-193 Grade B7
Flange nuts	Bar	Steel	SA-194 Grade 7
Core spray inlet nozzle	Forging	Low alloy steel	SA-508 Class 2
(See Note 11, Table 5.2.2 for additional information for nozzle N5B)			
Safe end material	Piping	Nickel base alloy	SB-166
Safe end extension	Piping	Carbon steel	SA-508 Class 1

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Thermal sleeve material	-	Stainless steel	SA-182 Grade F304
Mating pipe material	Piping	Carbon steel	SA-333 Grade 6
Standby liquid control stop check valve	Forging	Stainless steel	SA-182 Grade F316L
Testable check valves			
Body	Casting	Stainless steel	SA-352 Grade LCB
Disc	Casting	Stainless steel	SA-352 Grade LCB
Bearing cover	Forging	Steel	SA-350 LFI
Stud	Bar stock	Alloy steel	SA-540 Grade B23 Class 5 and SA-193 Grade B7
Hex nut	Bar stock	Alloy steel	SA-540 Grade B23 Class 5 and SA-194-SH
Shaft	Bar	Age hardened stainless steel	SA-564 Type 630 Condition H-1100
Containment isolation valves (body)	Casting	Stainless steel	SA-351 Grade CF8M
Feedwater nozzle	Forging	Low alloy steel	SA-508 Class 2
Thermal sleeve material	-	Stainless steel	SA-182 Grade F316L
Safe end material	Piping	Carbon steel	Stainless steel Type 308L cladded on the side
Mating pipe material	Piping	Carbon steel	SA-333 Grade 6
Containment isolation valve (body)	Casting	Carbon steel	SA-216 Grade WCB
Main steam nozzle	Forging	Low alloy steel	SA-508 Class 2
Safe end material	Piping	Carbon steel	SA-541 Class 1
Mating pipe material	Piping	Carbon steel	SA-155 Grade KCF60 Class 1

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Main steam line flow restrictor			
Upstream casting	Casting	Austenitic stainless steel	SA-351 Grade CF8 Type 304
Downstream casting	Casting	Carbon steel	SA-216 Grade WCB
Nozzle	Forging	Carbon steel	-
Instrument tube	Seamless tube	Stainless steel	ASME Type 304
Main steam piping			
2-inch socket weld nozzle	Forging	Carbon steel	SA-105 Grade II
26-inch pipe	Seamless pipe	Carbon steel	SA-106 Grade B
26-inch 90° SR elbow	Seamless pipe	Carbon steel	SA-106 Grade B
Hanger lug	Plate	Carbon steel	SA-516 Grade 70
8-inch pipe	Seamless pipe	Carbon steel	SA-106 Grade B
26-inch 45° elbow	Seamless pipe	Carbon steel	SA-106 Grade B
26-inch 90° LR elbow	Seamless pipe	Carbon steel	SA-106 Grade B
26-inch x 10-inch SOL SCH 100	Seamless pipe	Carbon steel	SA-234 Grade WFB with A105 Grade II
26-inch x 8-inch SOL SCH 100	Seamless pipe	Carbon steel	SA-234 Grade WCB with A105 Grade II
26-inch x 4-inch SOL SCH 80	Seamless pipe	Carbon steel	SA-234 Grade WCB with A105 Grade II
6-inch x 8-inch 1500 LB expander flange	-	Carbon steel	SA-105 or SA-181 Grade II
Flow elements (HPCI & RCIC steamlines)			
Body	Forging	Stainless steel	SA-182 Grade F304L
Instrument connection	Forging	Stainless steel	SA-182 Grade F304L
Band (HPCI only)	Forging	Carbon steel	SA-105

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Main steam safety relief valve			
Body	Casting	Carbon steel	A 216 WCB
Pilot body	Forging	Carbon steel	SA-105
Base	Forging	Carbon steel	SA-105
Disc (main)	Forging	Stainless steel	SA-182
Seat (main)	Forging	Carbon steel	SA-576 & SA-105
Pilot rod	Rod	Inconel 625	SB-446
Disc (pilot)	Hot formed	Stellite 6B or Stellite 21	Commercial
Guide	Rod	Stainless steel	SA-479
Bonnet	Forging	Carbon steel	SA-105
Stud	Rod	Alloy steel	SA-193 Grade B7 or B16
Bolt	Rod	Alloy steel	SA-193 Grade B7 or B16
Nut	Rod	Alloy steel	SA-194 Grade 7
Spherical collar	Hot formed	Stellite 6B	Commercial
Spring	Forging	Inconel 750	SA-637 Grade 688 Type 2 HR
Adjusting ring	Forging	Carbon steel	SA-105
Main steam isolation valve			
Valve body	Casting	Carbon steel	A 216 WCB
Poppet	Forging	Carbon steel	A 105 Grade II
Cover	Forging	Carbon steel	A 105 Grade II
Valve stem	Rod	Low alloy steel	A 276 Type 410
Stud	Rod	Low alloy steel	A 193 B7
Hex nuts	Rod	Low alloy steel	A 194 2H

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Pipe	Piping	Carbon steel	A 106 Grade B
Drain boss	Forging	Carbon steel	A 105 Grade II
CRD return nozzle	Forging	Low alloy steel	SA-508 Class 2
Safe end material (capped)	-	Nickel base alloy	Inconel SB 166 MS-16
Core instrumentation nozzle	Forging	Nickel base alloy	Inconel SB 166
Safe end material	-	Stainless steel	SA-182 Grade F304L
Mating pipe material	Piping	Stainless steel	SA-312 Grade TP304L
Instrumentation nozzles	Forging	Carbon steel	SA-541 Class 1
Mating pipe material	-	Stainless steel	SA-312 Grade TP304L
Seal leak detection nozzle	Plate	Low alloy steel	SA-508 Class 2
Safe end material	Piping	Carbon steel	SA-106 Grade B
Safe end extension material	Piping	Carbon steel	SA-541 Class 1
Mating pipe material	Piping	Stainless steel	SA-312 Grade TP304L
RPV drain nozzle	-	Carbon steel	SA-541 Class 1
Mating pipe material	Piping	Carbon steel	SA-106 Grade B
LPCI inlets nozzle	Forging	Low-alloy steel	SA-508 Class 2
Safe end material	-	Carbon steel	SA-541 Class 1
Thermal sleeve	-	Stainless steel	SA-312 Grade SS304L (Flange: Grade SS304)
Mating pipe material	Piping	Carbon steel	SA-333 Grade 6
Testable check valves			
Body	Casting	Stainless steel	SA-352 Grade LCB
Disc	Casting	Stainless steel	SA-352 Grade LCB
Bearing cover	Forging	Steel	SA-350 LFI

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Stud	Bar stock	Alloy steel	SA-540 Grade B23 Class 5 and SA-193 Grade B7
Hex nut	Bar stock	Alloy steel	SA-540 Grade B23 Class 5 and SA-194-SH
Shaft	Bar	Age hardened stainless steel	SA-564 Type 630 Condition H-1100
Containment isolation valve	Casting	Carbon steel	SA-216 Grade WCB (body)
Containment isolation valve	Forging	Carbon steel	SA-350 LFI (cover)
Jet pump instrumentation nozzle	Forging	Low alloy steel	SA-508 Class 2
Safe end material	Piping	Stainless steel	SA-182 Grade F304L
Mating pipe material	Piping	Stainless steel	SA-312 Grade TP304L
RPV vent nozzle	Forging	Low alloy steel	SA-508 Class 2
Safe end material and flanges	Piping	Carbon steel	SA-541 Class 1
Mating pipe material	Forging	Stainless steel	SA-312 Grade TP304L
Mating pipe flange material	Forging	Stainless steel	SA-182 Grade F316L or SA-105
Flange bolts	Bar	Carbon steel	SA-193 Grade B7
Flange nuts	Bar	Carbon steel	SA-194 Grade ZH
Spare connection nozzle	Forging	Low alloy steel	SA-508 Class 2
Safe end material	Forging	Carbon steel	SA-541 Class 1
Blind flange	Forging	Carbon steel	SA-541 Class 1
In-core housings			
Pipe (seamless)	Piping	Stainless steel	SA-312 Type 316 or 304
Tubing (welded)	Piping	Stainless steel	SA-249 Type 316 or 304
Tubing (seamless)	Piping	Stainless steel	SA-213 Type 316 or 304
Forged and rolled parts	Forging/rolled	Stainless steel	SA-182 Grade F316 and/or F304

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Control rod drive			
Flange	Forging	Stainless steel	SA-182 Grade 304
Plug (small)	Forging/bar	Stainless steel	SA-182 Grade 304
Plug (large)	Forging/bar	Stainless steel	SA-182 Grade 304
Indicator tube	Tube	Stainless steel	SA-312 Grade 304
Cap screw	-	Austenitic stainless steel	SA-193 Grade B6
Cap	Forging/bar	Stainless steel	SA-182 Grade 304
Head	Forging/bar	Stainless steel	SA-182 Grade 304
Nut	Forging/bar	Austenitic stainless steel	SA-193 Grade B8
Ring flange	Forging/bar	Stainless steel	SA-182 Grade 304
Housing	Seamless pipe	Stainless steel	SA-312 Grade 304
	Forging	Stainless steel	SA-182 Grade F304
	Welds	Stainless steel	SFA-5.4 or 5.9 Grade 308L
CRD stub	Piping	Nickel-base alloy	Inconel SB-166
In-core housing	Seamless tubing	Stainless steel	SA-213 Grade 304
	Forging	Stainless steel	SA-182 Grade F304
	Weld	Stainless steel	SFA 5.4 or 5.9 Grade 308L
Instrument line components			
Restrictor orifice	Forging	Stainless steel	SA-654 Grade F304L
Excess flow check valves			
Body	Forging	Stainless steel	SA-182 Grade F316L
Disc	Forging	Stainless steel	SA-479 Type 316

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Core tube	Forging	Stainless steel	SA-479 Type 316
Core tube disc	Forging	Stainless steel	SA-479 Type 316
Condensation chambers			
Chamber	Forging	Stainless steel	SA-479 Type 316L
Recirculation outlets			
Test connection pipe	Piping	Stainless steel	SA-312 Grade TP304L Class 1
Decontamination connection line	Piping	Stainless steel	SA-312 Grade TP304L
RWCU pipe	Piping	Carbon steel	SA-106 Grade B
RHR shutdown cooling lines	Piping	Stainless steel	SA-358 Grade TP304L Class 1
RHR shutdown cooling lines	Piping	Carbon steel	SA-333 Grade 6
RHR check valve test line	Piping	Carbon steel	SA-106 Grade B
Recirculation sample lines	Piping	Stainless steel	SA-312 Grade TP304L
Steam outlets			
MSRV connection lines	Piping	Carbon steel	SA-106 Grade B
Main steam line drains	Piping	Carbon steel	SA-106 Grade B
Test and instrument lines	Piping	Stainless steel	SA-312 Grade TP304L
Sealing system pipe	Piping	Carbon steel	SA-106 Grade B
HPCI and RCIC steam supply lines	Piping	Carbon steel	SA-106 Grade B
Feedwater line inlets			
Test connections	Piping	Carbon steel	SA-106 Grade B
Core spray inlets			
Test connections	Piping	Carbon steel	SA-106 Grade B
Standby liquid control	Piping	Stainless steel	SA-312 Grade TP304L

TABLE 5.2-7 (Cont)

Component	Form	Material	Specification - ASTM(A)/ASME(SA)
Vent outlets			
Connecting vent lines	Piping	Carbon steel	SA-106 Grade B
LPCI inlets			
Test connections	Piping	Carbon steel	SA-106 Grade B
Instrumentation connections	Piping	Stainless steel	SA-316 Grade TP304L

TABLE 5.2-8

REACTOR COOLANT SYSTEM
CHEMISTRY LIMITS

OPERATIONAL CONDITION*	CHLORIDES	CONDUCTIVITY (mmhos/cm @ 25°C)	PH
1	≤ 0.2 ppm	≤ 1.0	5.6 ≤ pH ≤ 8.6
2 & 3	≤ 0.1 ppm	≤ 2.0	5.6 ≤ pH ≤ 8.6
All other times	≤ 0.5 ppm	≤ 10.0	5.3 ≤ pH ≤ 8.6

* Operational conditions are defined in the plant Technical Specifications.

TABLE 5.2-9

THIS TABLE HAS BEEN DELETED

TABLE 5.2-10

SUMMARY OF ALARMS FOR SOURCES MONITORED AND THE LEAK DETECTION METHOD USED

(Summary of Variable Alarms and Leakage Source vs Affected Variable Monitored)

Source of Leakage \ Affected Variable Monitored	Located, inside containment	Located, outside containment	Drywell pressure, high	Reactor water level, low	Drywell floor drain sump level and flow rate, high	Drywell equipment drain level and sump flow rate, high	Fission product radiation, high	Drywell temperature, high	Safety/relief valve discharge pipe temp, high	Pump seal flow, high	Seal pressure, high	Air cooler condensate flow, high	Flow rate, high	Reactor building equip or drain sump, high fillup/pumpout	Tunnel ambient or differential temp, high	Equipment Area Ambient and differential temp, high	RWCU differential flow, high	Seal drain flow, high	Intersystem leakage (radiation), high	ECCS injection line leakage (Internal to reactor vessel) differential pressure	Pump room level, high
Main Steam Line	X		A	A	A		A	A	A			A	A								
		X		A									A		A						
HPCI/Steam Line	X		A	A	A		A	A				A	A								
		X		A									A		A	A					
RCIC Steam Line	X		A	A	A		A	A				A	A								
		X		A									A		A	A					
RWCU Water	X		A	A	A		A	A				A	A								
		X		A									A	A	A	A	A				
HPCI Water	X				A																
		X																			A
Core Spray	X				A															A	
		X											A								A
Recirculation Pump Seal	X		A			A	A	A		A								A			
		X																			
Feedwater	X		A	A	A		A	A				A									
		X													A						
RHR Water	X		A		A			A				A	A							A	
		X											A	A		A			A		A
Reactor Vessel Head Seal	X										A										
		X																			
Refueling Pool	X																				
		X												A							
Miscellaneous Leaks	X				A																
		X												A							
RCIC Water	X				A																
		X																			A

A = Alarm and indicate (or record) only. X = Location of leakage source.

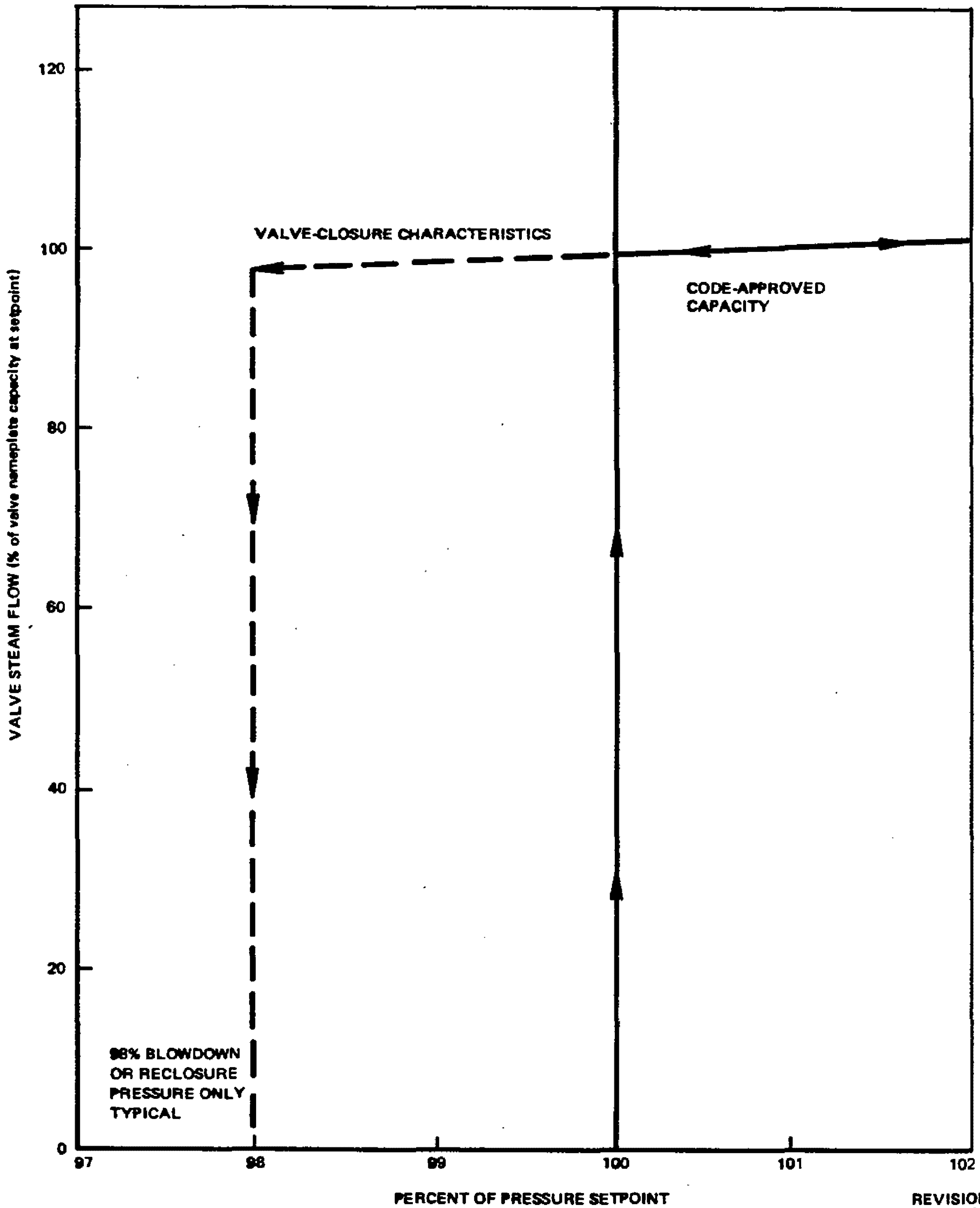
TABLE 5.2-11

SUMMARY OF ISOLATION SIGNALS AND ALARMS FOR SYSTEMS ISOLATED AND THE LEAK DETECTION METHOD USED

(Summary of Isolation Signals and Alarms (Note 3) and System Isolation vs Variable Monitored)

System Isolated \ Variable Monitored	Reactor vessel water level, low (Note 4) (Note 2)	Reactor pressure, high		MS tunnel ambient temp, high		Flow rate, high	Drywell pressure, high		Torus compartment temp, high	RCIC equipment area ambient temp, high	RCIC equipment area differential temp, high	RCIC exhaust diaphragm pressure, high	HPCI steam supply differential pressure (High flow)	RCIC steam supply differential pressure (High flow)	RWCU process piping differential flow, high	RWCU equipment area ambient temp, high	RWCU equipment area differential temp, high	HPCI equipment area ambient temp, high	HPCI equipment area differential temp, high	HPCI exhaust diaphragm pressure, high	RCIC steam supply piping area AMB. temp., high	HPCI steam supply piping area amb. temp., high
Main Steam	1			I		I																
Recirculation (Sample Line)	2																					
RHR	3	I																				
RCIC									I	I	I	I		I							I	
RWCU	2														I	I	I					
Balance of Plant	1,2						I															
HPCI									I				I					I	I	I		I

Note 1 I = Isolate, alarm and indicate (or record).
Note 2 These leak detection signals are provided by other systems.
Note 3 An alarm is associated with each isolation signal.
Note 4 Numerals in this column correspond to reactor water levels as shown on condensate and feedwater Specification MPL-C34 and are levels at which isolation valves of the related system are closed.



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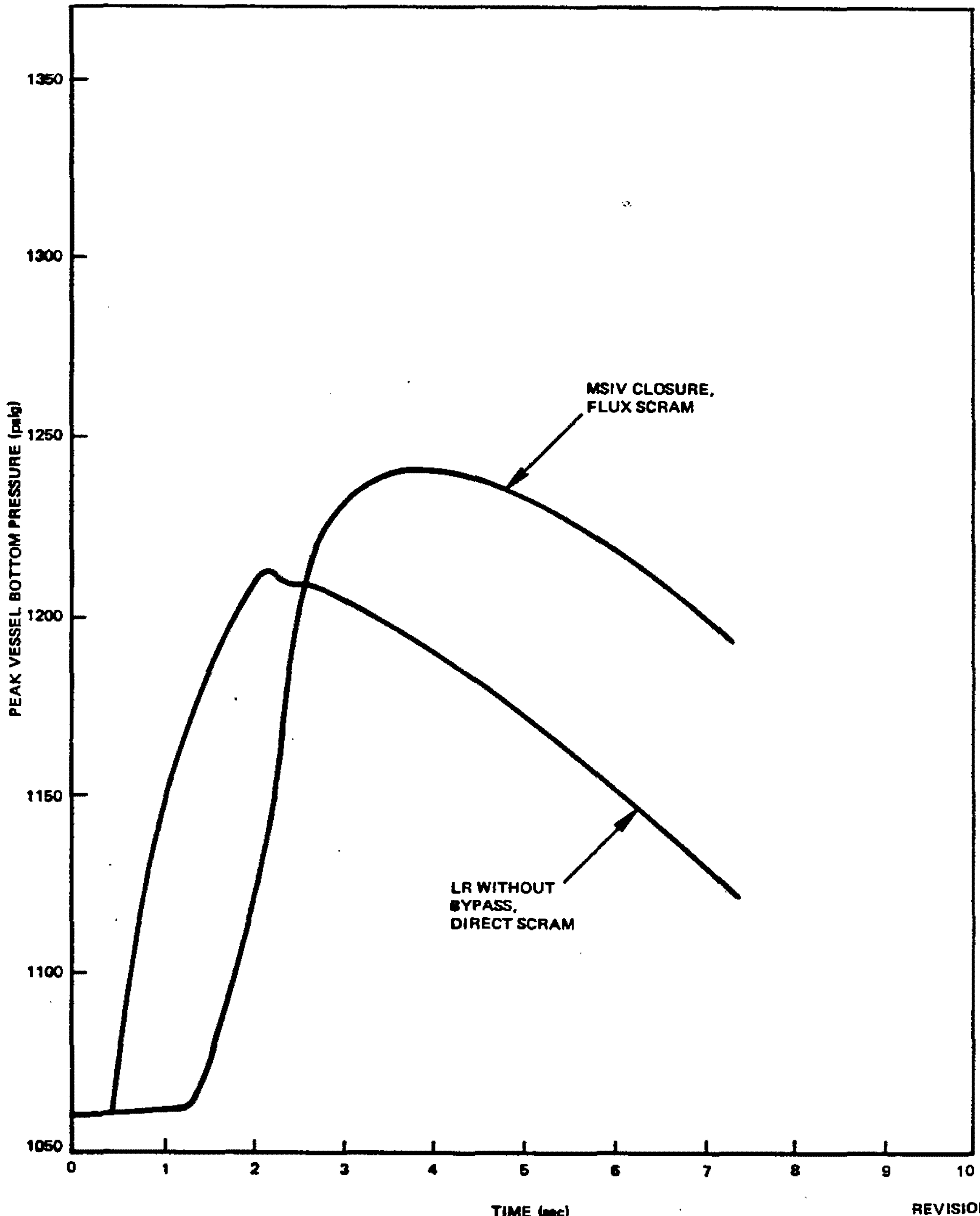
HOPE CREEK NUCLEAR GENERATING STATION

SIMULATED SAFETY/RELIEF
VALVE CHARACTERISTICS

UPDATED FSAR

FIGURE 5.2-1



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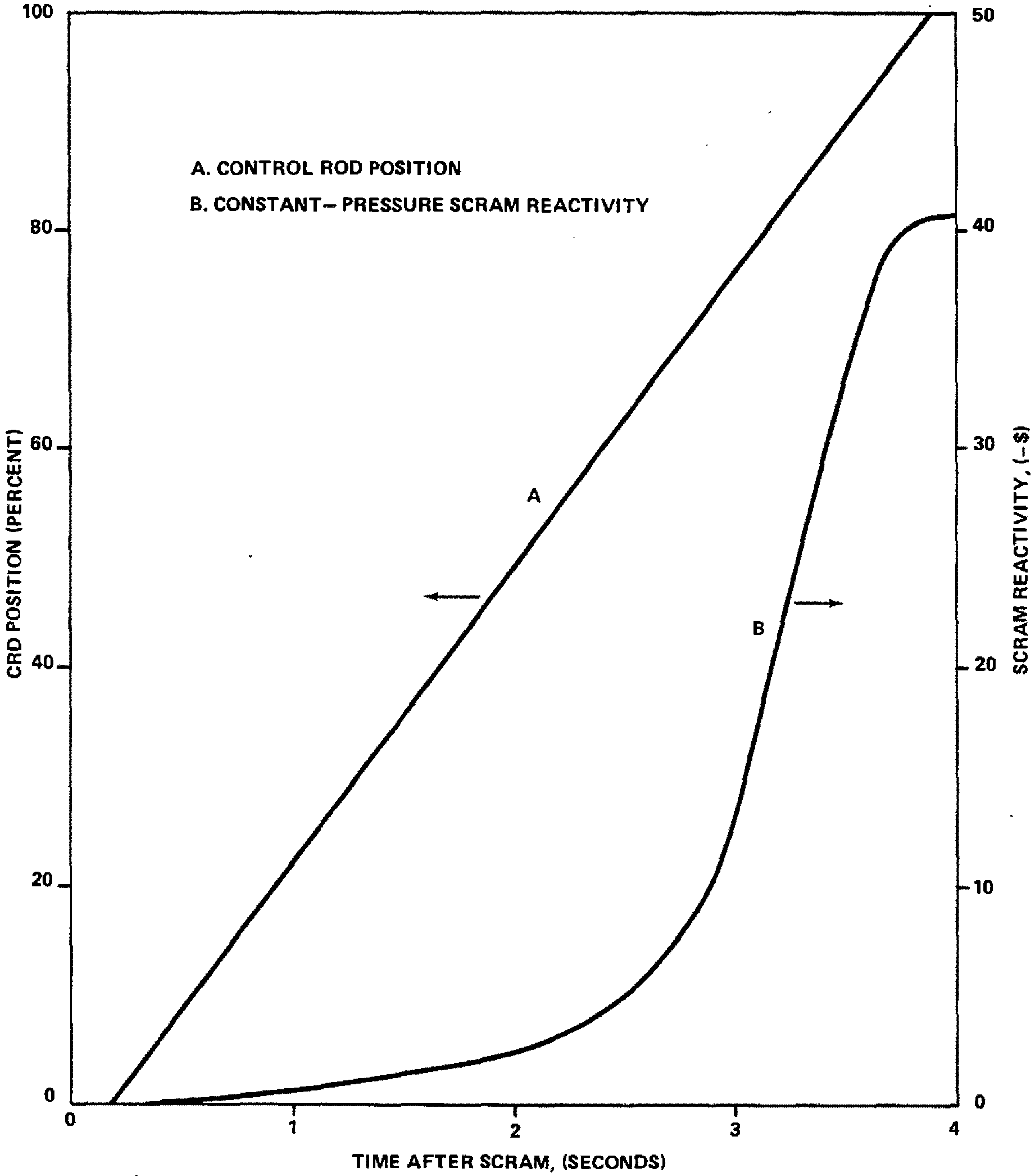
VESSEL PRESSURE VERSUS TIME FOR MSRV CAPACITY SIZING TRANSIENTS

UPDATED FSAR

FIGURE 5.2-2



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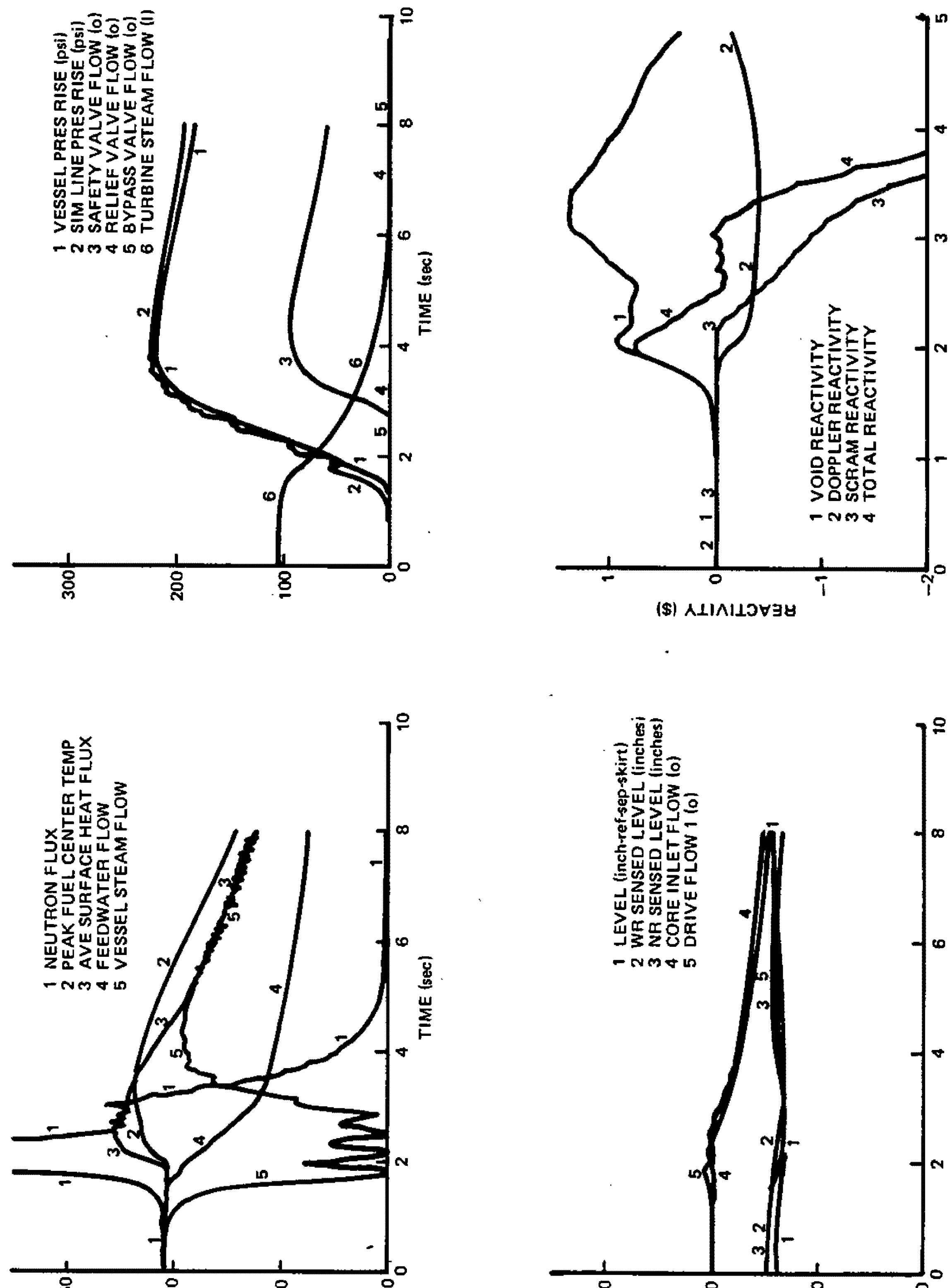
CONTROL ROD POSITION AND SCRAM REACTIVITY VERSUS TIME CHARACTERISTICS

UPDATED FSAR

FIGURE 5.2-3



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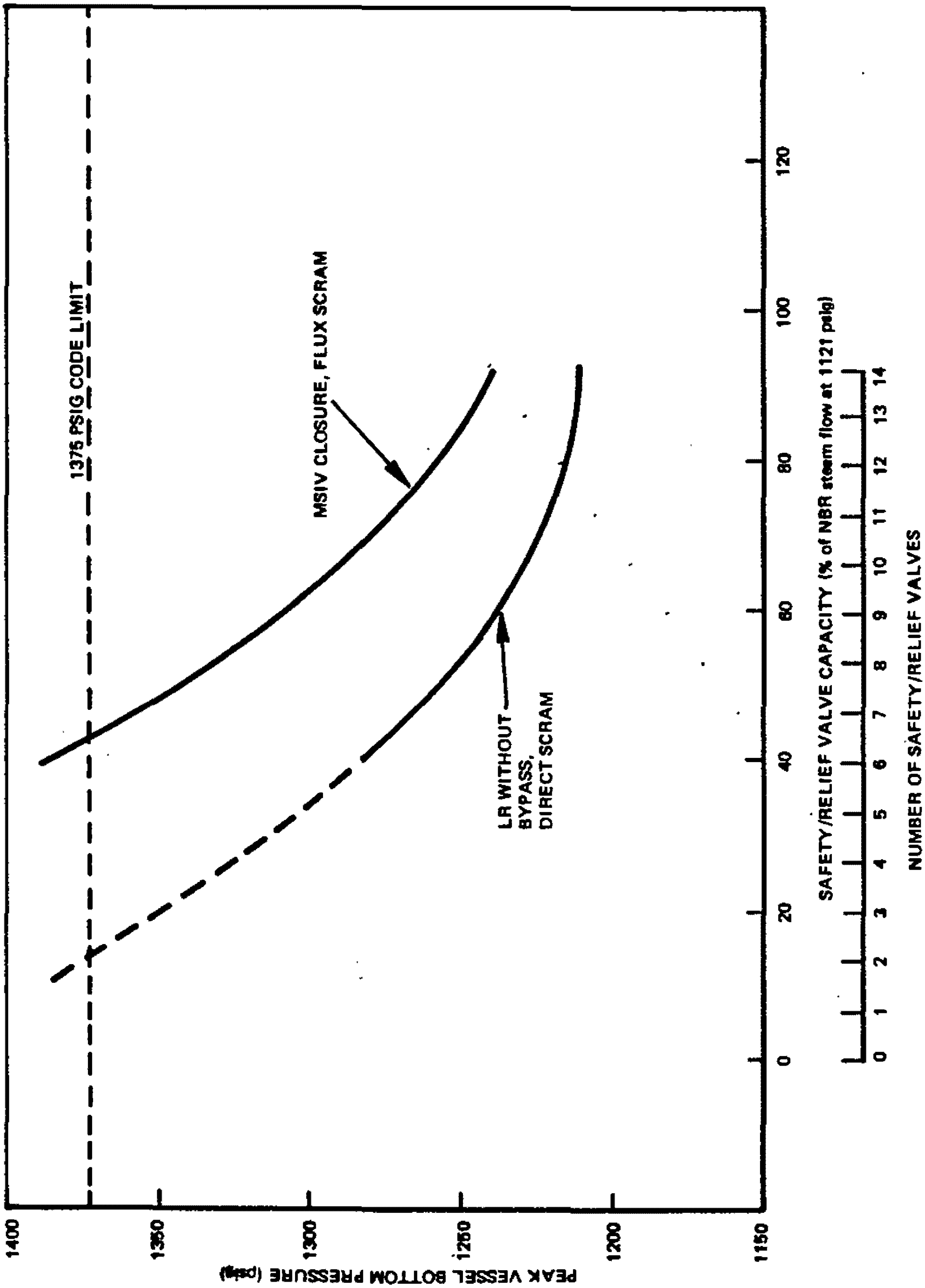
SAFETY VALVE CAPACITY
SIZING TRANSIENT MSIV
CLOSURE WITH HIGH FLUX TRIP

UPDATED FSAR

FIGURE 5.2-4



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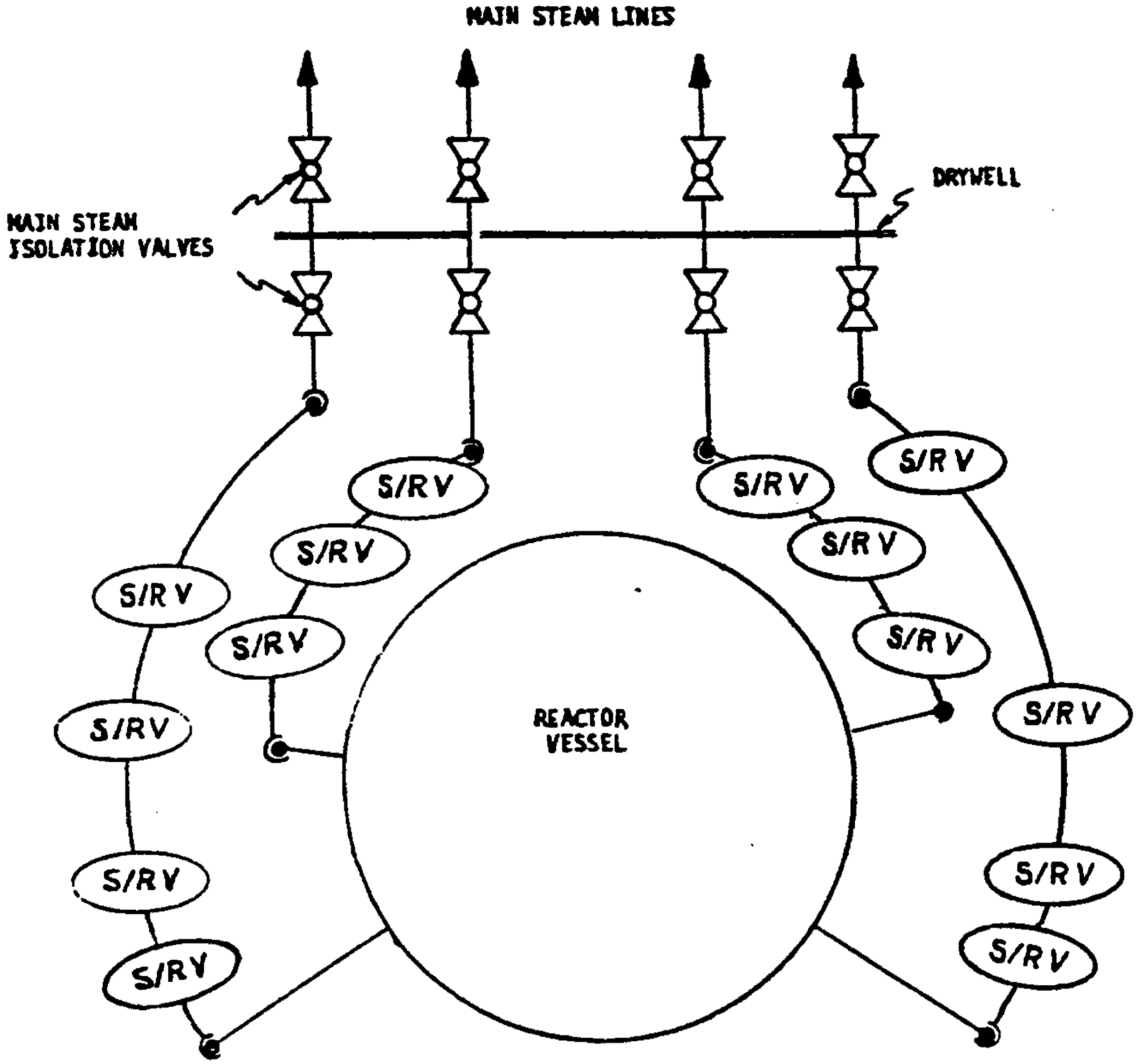
HOPE CREEK NUCLEAR GENERATING STATION

PEAK VESSEL PRESSURE
VERSUS
SRV CAPACITY

UPDATED FSAR

FIGURE 5.2-5



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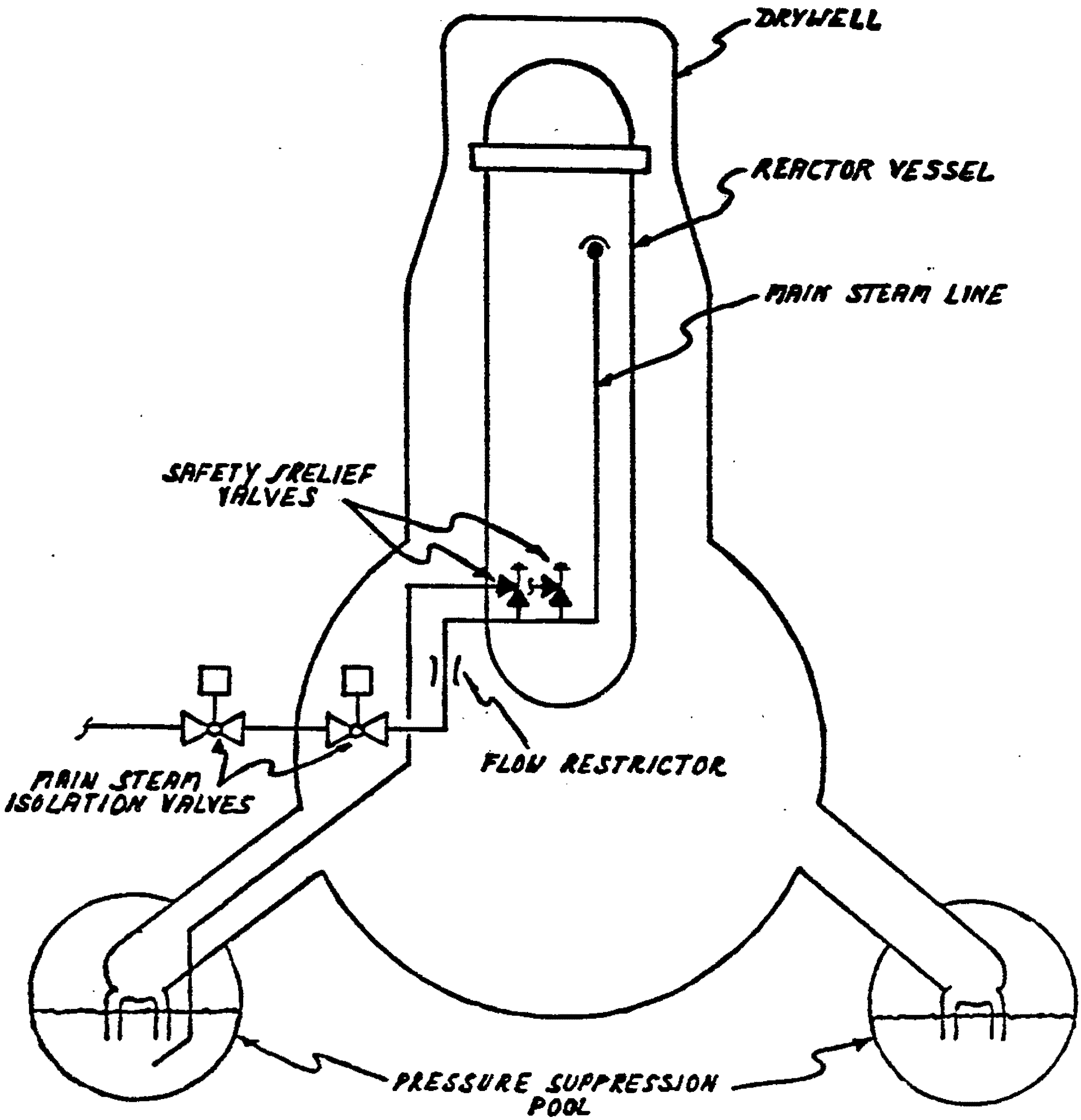
HOPE CREEK NUCLEAR GENERATING STATION

SRV AND STEAMLINE SCHEMATIC

UPDATED FSAR

FIGURE 5.2-6



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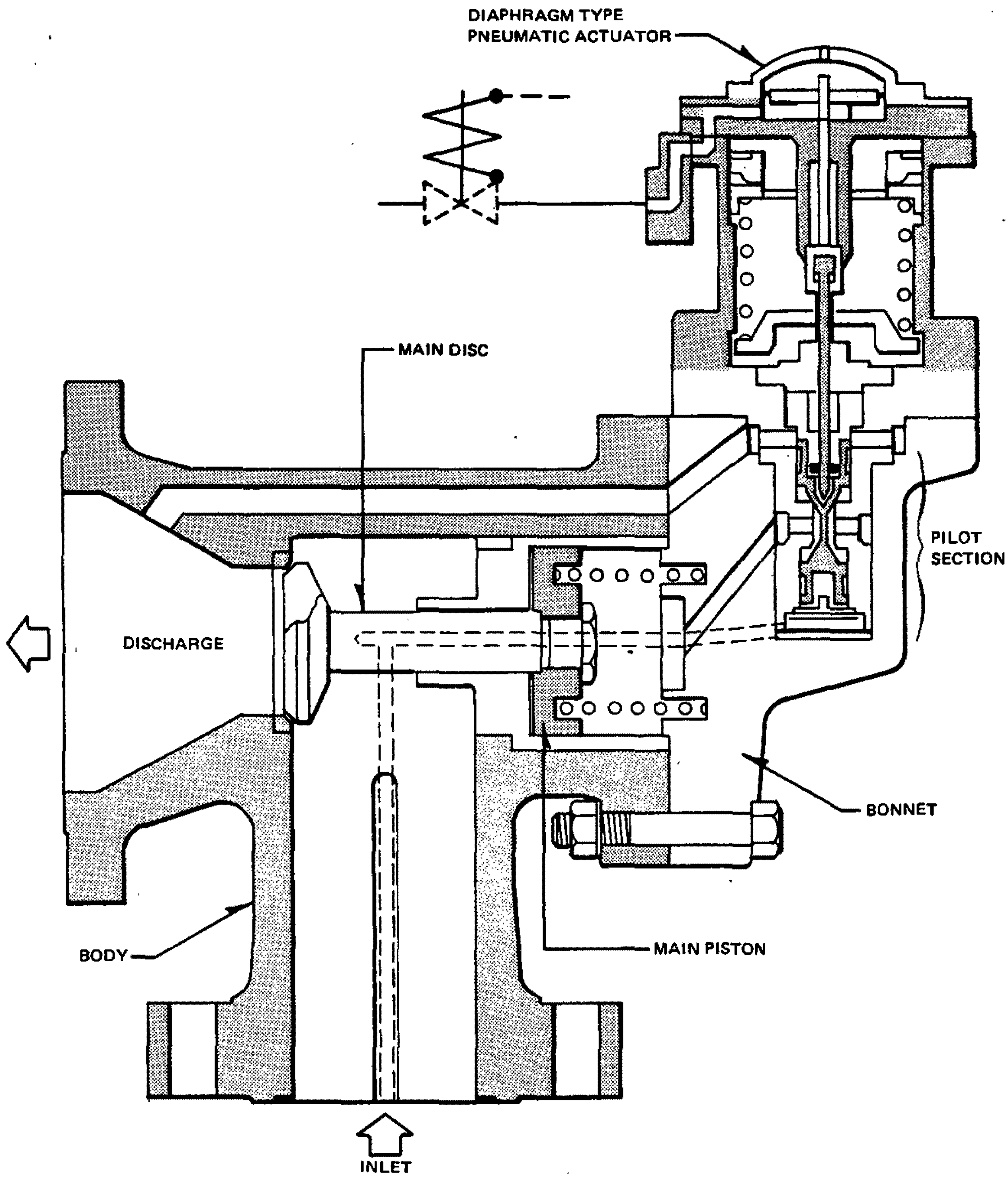
SAFETY/RELIEF VALVE
SCHEMATIC ELEVATION

UPDATED FSAR

FIGURE 5.2-7



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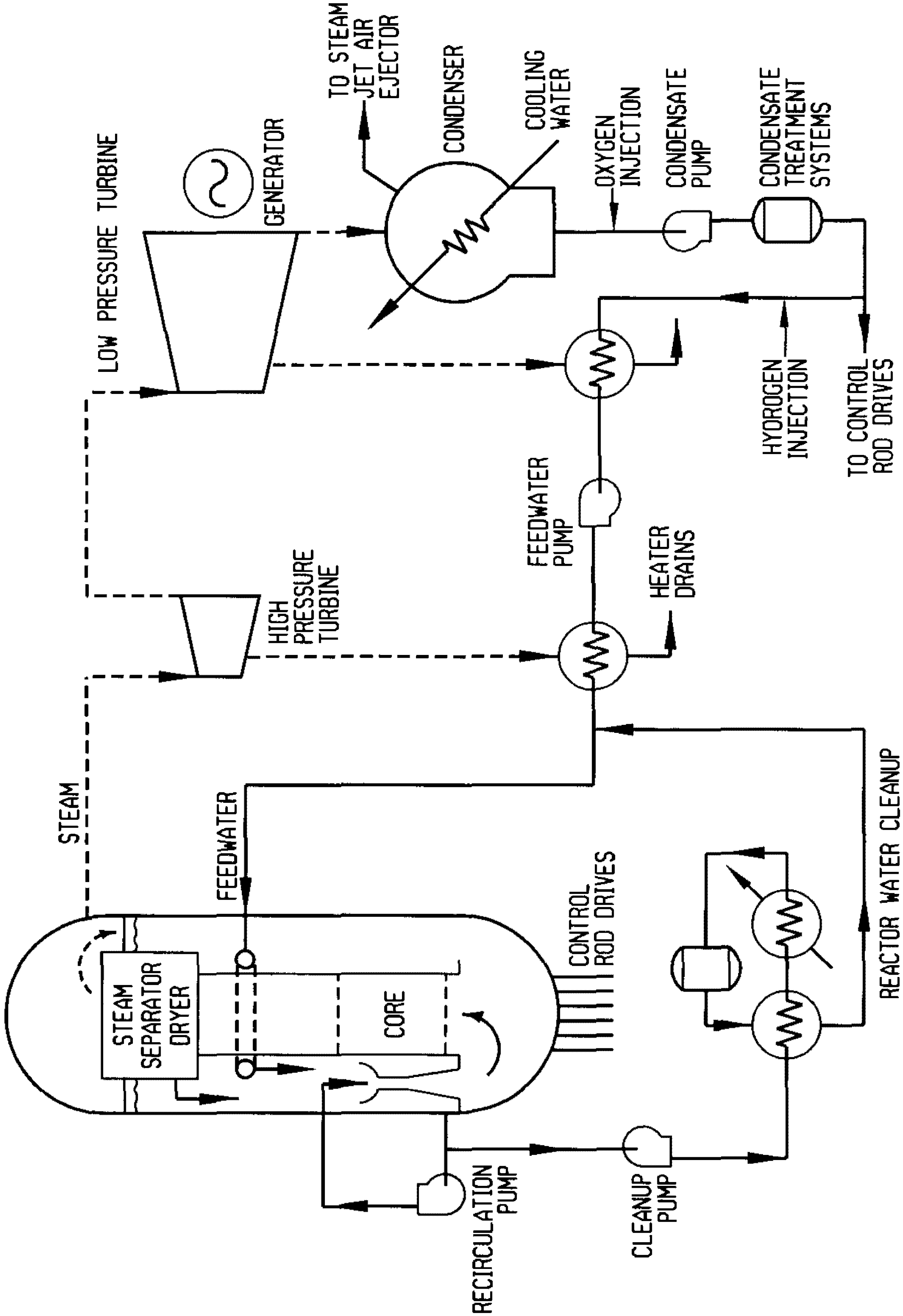
SCHEMATIC OF AN SRV
WITH AUXILIARY
ACTUATING DEVICE

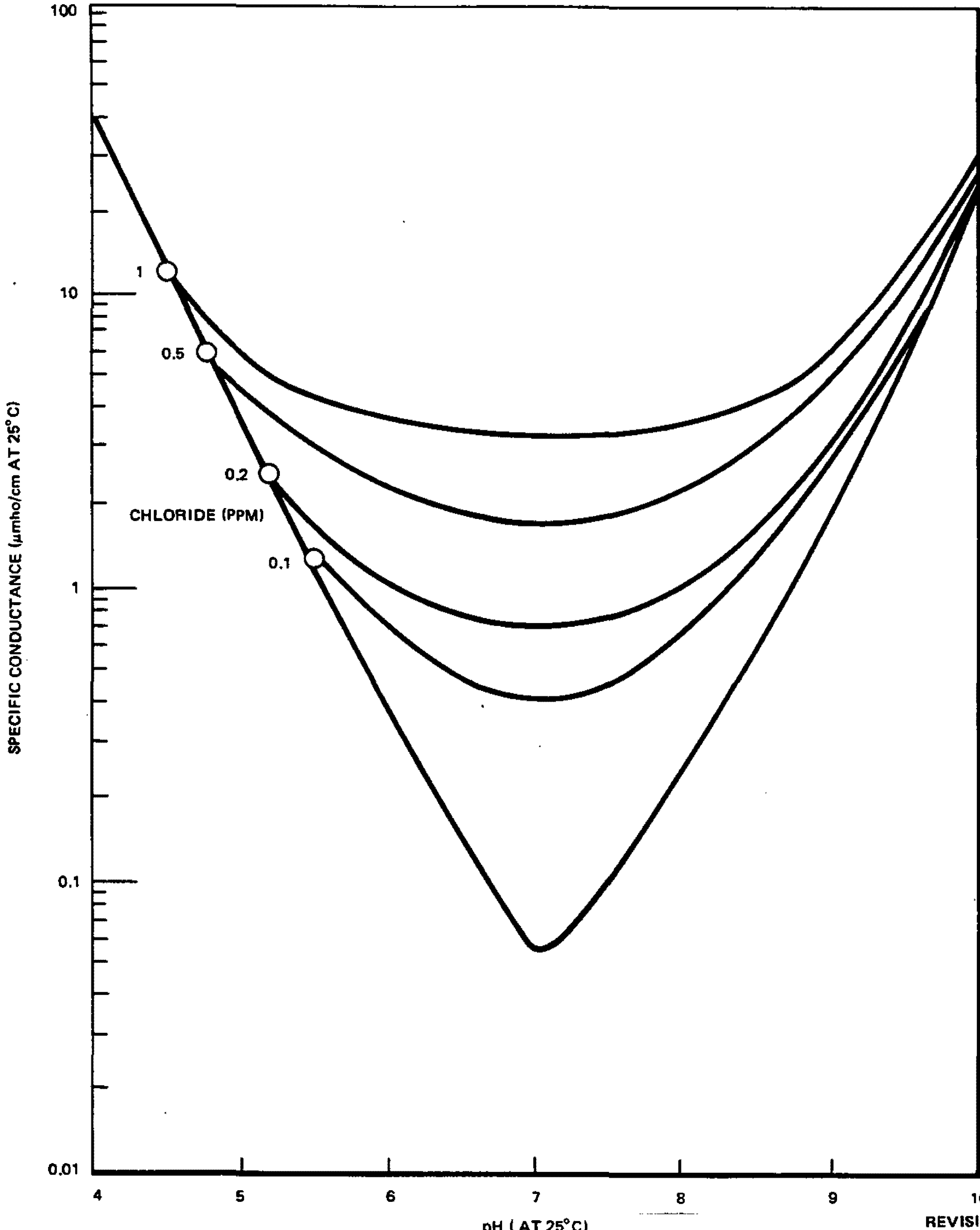
UPDATED FSAR

FIGURE 5.2-8



Revision 12, May 3, 2002

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station TYPICAL BWR FLOW DIAGRAM	
	Updated FSAR	Figure 5.2-9



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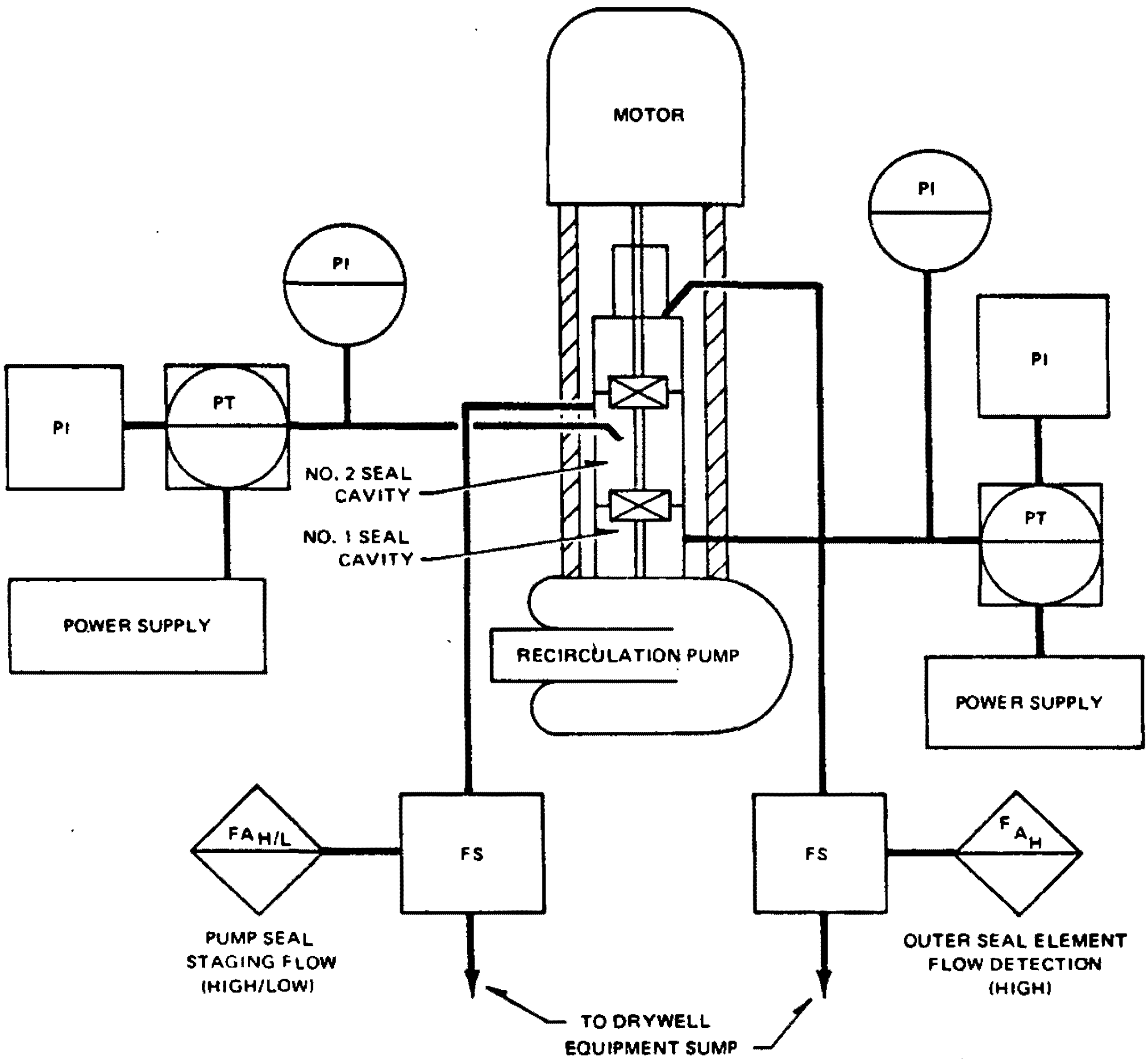
HOPE CREEK NUCLEAR GENERATING STATION

CONDUCTANCE vs pH AS A FUNCTION OF CHLORIDE CONCENTRATION, AQUEOUS SOLUTION AT 25°C

UPDATED FSAR

FIGURE 5.2-10



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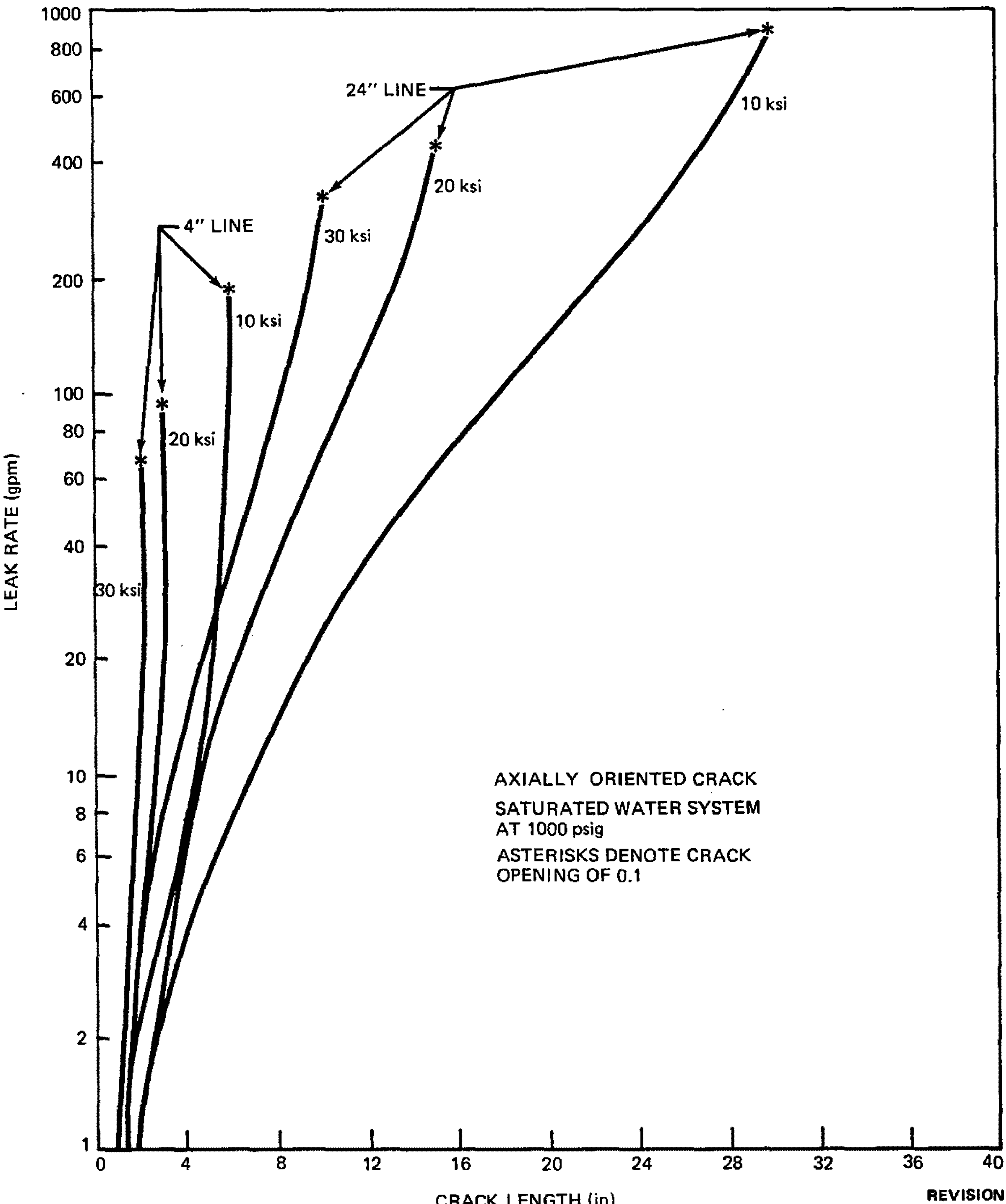
HOPE CREEK NUCLEAR GENERATING STATION

RECIRCULATION PUMP LEAK DETECTION BLOCK DIAGRAM

UPDATED FSAR

FIGURE 5.2-11



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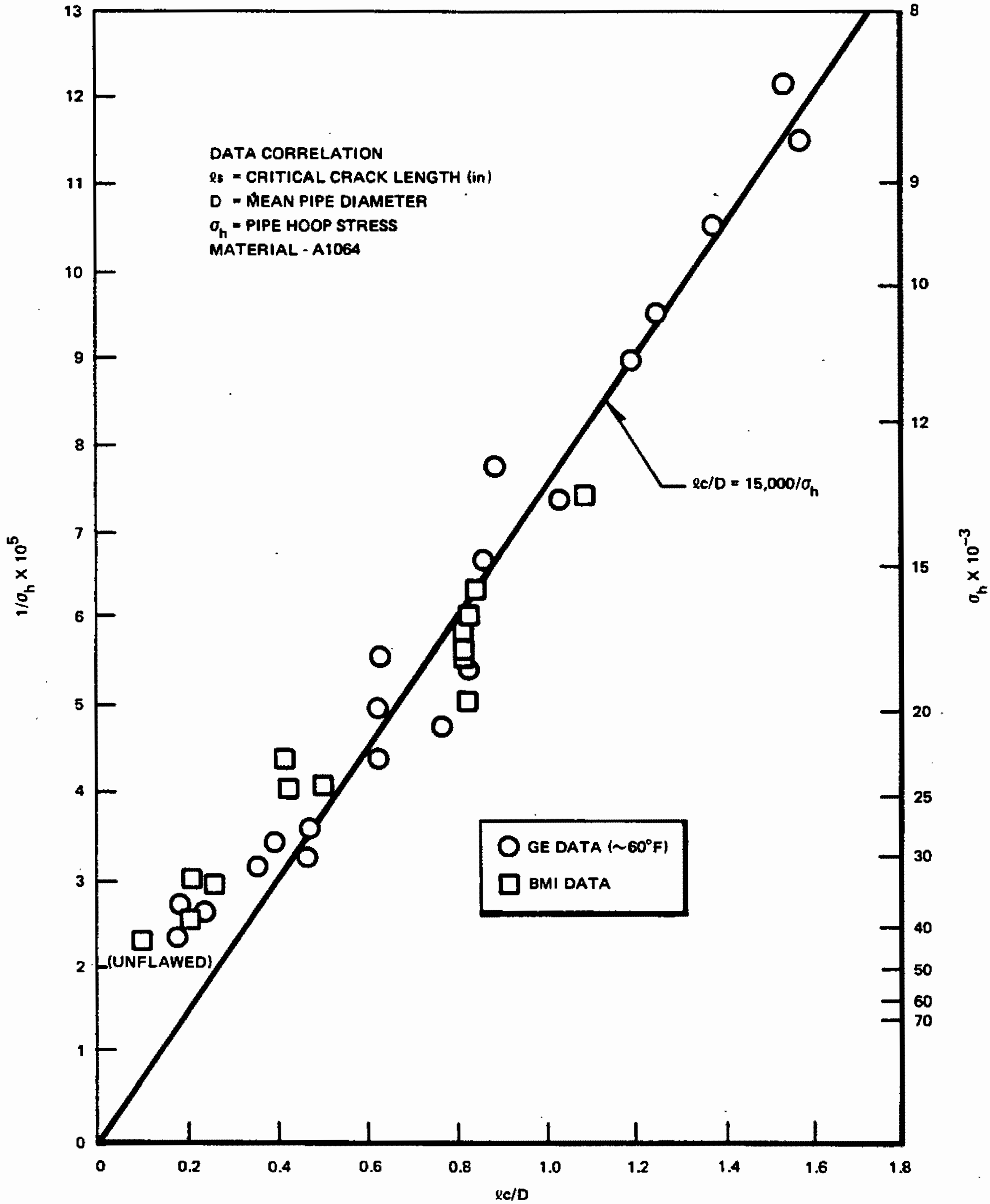
HOPE CREEK NUCLEAR GENERATING STATION

CALCULATED LEAK RATE vs CRACK LENGTH AS A FUNCTION OF APPLIED HOOP STRESS

UPDATED FSAR

FIGURE 5.2-12



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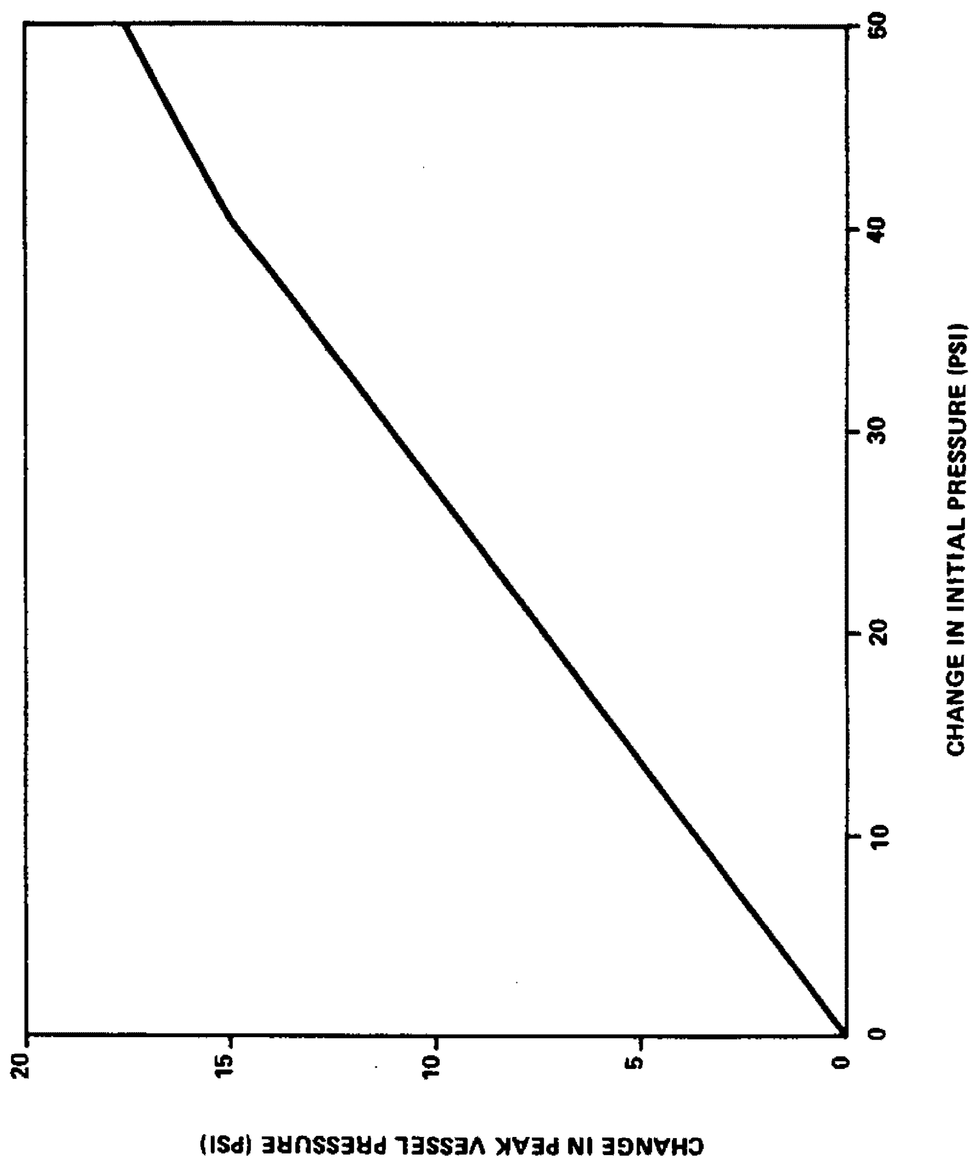
HOPE CREEK NUCLEAR GENERATING STATION

AXIAL THROUGHWALL
CRACK LENGTH DATA CORRELATION

UPDATED FSAR

FIGURE 5.2-13



PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TYPICAL BWR PRESSURE RESPONSE CHARACTERISTICS FOR MSIV CLOSURE FLUX SCRAM EVENT

UPDATED FSAR | FIGURE 5.2-14

5.3 REACTOR VESSEL

5.3.1 Reactor Vessel Materials

5.3.1.1 Materials Specifications

The materials used in the reactor pressure vessel (RPV) and appurtenances are shown in Table 5.2-7 together with the applicable specifications.

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

The RPV is constructed primarily from low alloy, high strength steel plate and forgings. Plates are ordered to ASME SA 533 Grade B, Class 1, and forgings to ASME SA 508, Class 2. These materials are melted to fine grain practice and are supplied in the quenched and tempered condition. Further restrictions include a requirement for vacuum degassing to lower the hydrogen level and improve the cleanliness of the low alloy steels.

Studs, nuts, and washers for the main closure flange are ordered to ASME SA 540, Grade B23 or Grade B24. Welding electrodes are low hydrogen type ordered to ASME SFA 5.5.

All plate, forgings, and bolting are 100 percent ultrasonically tested and surface examined by magnetic particle methods or liquid penetrant methods in accordance with ASME B&PV Code, Sections II, III and XI, standards. Fracture toughness properties are also measured and controlled in accordance with Section III requirements.

All fabrication of the RPV is performed in accordance with GE approved drawings, fabrication procedures, and test procedures. The shells and vessel heads are made from formed plates, and the flanges and nozzles are made from forgings. Welding performed to join these vessel components is in accordance with procedures qualified per ASME B&PV Code, Sections III and IX,

requirements. Weld test samples are required for each procedure for major vessel full penetration welds. Tensile and impact tests are performed to determine the properties of the base metal, heat affected zone, and weld metal.

Submerged arc and manual stick electrode welding processes are employed. Electroslag welding is not permitted. Preheat and interpass temperatures employed for welding of low alloy steel meet or exceed the requirements of ASME B&PV Code, Section III. Postweld heat treatment at 1100°F minimum is applied to all low alloy steel welds.

In accordance with requirements of ASME B&PV Code, Section III, Paragraph N 624, radiographic examination is performed on all pressure containing welds. In addition, all welds are given a supplemental ultrasonic examination.

The materials, fabrication procedures, and testing methods used in the construction of boiling water reactor (BWR) pressure vessels meet or exceed requirements of ASME B&PV Code, Section III, Class 1 vessels.

5.3.1.3 Special Methods for Nondestructive Examination

The materials and welds on the RPV were examined in accordance with prescribed methods and meet the requirements specified by ASME B&PV Code, Section III. In addition, the pressure retaining welds were ultrasonically examined using manual techniques. The ultrasonic examination method including calibration, instrumentation, scanning sensitivity, and coverage was based on the requirements specified by ASME B&PV Code, Section XI, in Appendix I. Acceptance standards were equivalent or more restrictive than required by ASME B&PV Code, Section XI.

5.3.1.4 Special Controls For Ferritic and Austenitic Stainless Steels

5.3.1.4.1 Compliance With Regulatory Guides

5.3.1.4.1.1 Regulatory Guide 1.31, Control of Stainless Steel Welding

Controls on stainless steel welding are discussed in Section 5.2.3.

5.3.1.4.1.2 Regulatory Guide 1.34, Control of Electroslag Weld Properties

Electroslag welding was not employed for the RPV fabrication.

5.3.1.4.1.3 Regulatory Guide 1.43, Control of Stainless Steel Weld Cladding of Low Alloy Steel Components

RPV specifications require that all low alloy steel be produced to fine grain practice. The requirements of Regulatory Guide 1.43 are not applicable to BWR vessels.

5.3.1.4.1.4 Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel

Controls to avoid severe sensitization are discussed in Section 5.2.3.

5.3.1.4.1.5 Regulatory Guide 1.50, Control of Preheat Temperature for Welding Low Alloy Steel

Section 5.2.3 provides a general compliance assessment for Regulatory Guide 1.50 regarding preheat temperature controls.

5.3.1.4.1.6 Regulatory Guide 1.71, Welder Qualification for Areas of Limited Accessibility

A general compliance assessment for Regulatory Guide 1.71 regarding welder qualification for areas of limited accessibility is presented in Section 5.2.3.

5.3.1.4.1.7 Regulatory Guide 1.99, Effects of Residual Elements on Predicted Radiation Damage to Reactor Pressure Vessel Materials

A general compliance assessment for Regulatory Guide 1.99 is that predictions for changes in reference transition temperature and upper shelf energy were made in accordance with the requirements of the Guide as discussed in Section 1.8.

5.3.1.5 <u>Fracture Toughness</u>

5.3.1.5.1 Compliance with 10CFR50, Appendix G

A major condition necessary for full compliance to Appendix G is satisfaction of the requirements of the Summer 1972 Addenda to the ASME B&PV Code, Section III. This is not possible with components which were purchased to earlier Code requirements. A discussion of the extent of compliance is provided in Appendix 5A.

Ferritic materials complying with 10CFR50, Appendix G, must have both drop weight tests and Charpy V-notch (CVN) tests with the CVN specimens oriented transverse to the maximum material working direction to establish the RT_{NDT} (reference temperature nil ductility transition). The CVN tests must be evaluated against both an absorbed energy and a lateral expansion criterion. The maximum acceptable RT_{NDT} must be determined in accordance with the analytical procedures of ASME B&PV Code Section III, Appendix G. Appendix G of 10CFR50 requires a minimum of 75-foot-pound upper shelf CVN energy for beltline material. It also requires at least 45-foot-pound CVN energy and 25 mils lateral expansion for bolting material at the lower of the preload or lowest service temperature.

By comparison, materials for the HCGS reactor vessel were qualified by drop weight tests and/or longitudinally oriented CVN tests (both not required), confirming that the material nil ductility transition temperature (NDTT) is at least 60°F below the lowest service temperature. When the longitudinal CVN test was applied, a 35-foot-pound energy level was used in defining the NDTT. There was no upper shelf CVN energy requirement on the beltline material. The bolting material was qualified to a 30-foot-pound CVN energy requirement at 60°F below the minimum preload temperature.

From the above comparison, it can be seen that the fracture toughness testing performed on the HCGS reactor vessel material cannot be shown to comply with 10CFR50, Appendix G. However, to determine the original operating limits in accordance with 10CFR50, Appendix G, estimates of the beltline material RT_{NDT} and the highest RT_{NDT} of all other material were made, as explained in Section 5.3.1.5.1.2. The method for developing these operating limits is also described therein.

On the basis of the last paragraph on page 19013 of the July 17, 1973, Federal Register, the following is considered an appropriate method of compliance.

5.3.1.5.1.1 Method of Compliance

The intent of the proposed special method of compliance with Appendix G for this vessel is to provide operating limitations on pressure and temperature based on fracture toughness. These operating limits ensure that a margin of safety against a nonductile failure of this vessel is very nearly the same as that for a vessel built to the Summer 1972 Addenda to ASME B&PV Code, Section III.

The original specific temperature limits for operation when the core is critical are based on a proposed modification to 10CFR50, Appendix G, Paragraph IV, A.3.

5.3.1.5.1.2 Methods of Obtaining Operating Limits Based on Fracture Toughness

Operating limits that define minimum metal temperatures versus reactor pressure during normal heatup and cooldown, and during inservice hydrostatic testing, were established using the methodology specified in 1989 ASME Code Section XI Appendix G, 10CFR50 Appendix G, and WRC-175 (reference 5.3-9) and includes ASME Code Cases N-588 and N-640 (references 5.3-10 and 5.3-11). Instrument uncertainties for pressure, 20.5 psi, and temperature, 9°F, were included in the limits. The results are shown on Figures 5.3-1A, 5.3-1B, and 5.3-1C.

All the vessel shell and head areas remote from discontinuities were evaluated, and the operating limit curves are based on the limiting location. The boltup limits for the flange and adjacent shell regions are based on a minimum metal temperature of RT_{NDT} + 60°F. The boltup limit does not include the temperature instrument uncertainty since the 60°F is an additional margin for non-ductile failure protection and thus adequately encompasses instrument uncertainty. The maximum through wall temperature gradient from continuous heating and cooling at 100°F per hour was considered. The safety factors applied were as specified in ASME B&PV Code, Section XI Appendix G, and Reference 5.3-9.

For the purpose of setting the original operating limits, the RT_{NDT} is determined from the toughness test data taken in accordance with requirements of the ASME B&PV Code to which the vessels are designed and manufactured. These toughness test data, CVN, and/or dropweight NDT are analyzed to permit compliance with the intent of 10CFR50, Appendix G. Because all toughness testing needed for strict compliance with Appendix G was not required at the time of vessel procurement, some toughness results are not available (The details of the impact toughness data available for the beltline material are provided in Appendix 5A, Table 5A-1 and 5A-2). For example, longitudinal CVNs instead of transverse in many cases were tested, usually at a single test temperature of +10°F or +40°F, for absorbed energy. Also, at the time either CVN or NDT testing was permitted; therefore, in many cases both tests were not performed as is currently required. To substitute for this absence of certain data, toughness property correlations were derived for the vessel

materials in order to operate upon the available data to give a conservative estimate of RT_{NDT}, compliant with the intent of Appendix G criteria.

These toughness correlations vary, depending upon the specific material analyzed, and were derived from the results of Welding Research Council Bulletin 217, Properties of Heavy Section Nuclear Reactor Steels, and from toughness data from the HCGS vessel and other reactors. In the case of vessel plate material (SA-533 Grade B, Class 1), the predicted limiting toughness property is either NDT or transverse CVN 50-foot-pound transition temperature minus 60°F.

Where NDT results are missing, NDT is estimated as the longitudinal CVN 35 foot-pound transition temperature. The transverse CVN 50 foot-pound transition temperature is estimated from longitudinal CVN data in the following manner. The lowest longitudinal CVN foot-pound value is adjusted to derive a longitudinal CVN 50 foot-pound transition temperature by adding 2°F per foot-pound to the test temperature. If the actual data equals or exceeds 50 foot-pounds, the test temperature is used. Once the longitudinal CVN 50 foot-pound transition temperature is derived, an additional 30°F is added to account for orientation effects and to estimate the transverse CVN 50 foot-pound transition temperature minus 60°F, estimated in the preceding manner. In the cases where transverse CVN data are available, the lowest value is adjusted to derive a transverse CVN, 50-foot-pound transition temperature by conservatively adding 3° per foot-pound to the test temperature. Again, as for the longitudinal CVN data, if the actual data equals or exceeds 50 foot-pounds the test temperature is used.

For forgings (SA-508 Class 2), the predicted limiting property is the same as for vessel plates. The RT_{NDT} is estimated in the same way as for vessel plate.

For the vessel weld metal, CVN 50 foot-pound transition temperature minus 60°F, is derived in the same way as for the vessel plate material, except the 30°F addition for orientation effects is omitted since there is no principal working direction. When NDT values are available, they are also considered; and the RT_{NDT} is taken as the higher of NDT or the 50 foot-pound transition temperature minus 60°F. When NDT is not available, the RT_{NDT} shall not be less than -50°F because lower values are not supported by the correlation data.

For vessel weld material in the heat affected zone (HAZ), the RT_{NDT} is assumed to be the same as for the base material since ASME B&PV Code weld procedure qualification test requirements and postweld heat treatment indicate this assumption is valid.

Closure bolting material (SA-540 Grade B24) toughness test requirements were for 30 foot-pound at 60°F below the boltup temperature. Current 10CFR50, Appendix G requirements are for 45 foot-pound and 25 mil lateral expansion at the preload or lowest service temperature, including boltup. All closure stud materials meet current requirements at +10°F. Thus, 60°F is added to the specified test temperature for HCGS to derive the boltup temperature.

Using this general approach, an initial RT_{NDT} of +19°F was established for the core beltline region.

The effect of the main closure flange discontinuity was considered by adding 60°F to the RT_{NDT} to establish the minimum temperature for boltup and pressurization. The minimum boltup temperature of +79°F, shown on Figures 5.3-1A and 5.3-1B is based on an initial RT_{NDT} of +19°F for the shell plate that connects to the closure flange.

Revised fluence values, which were obtained using the fluence methodology described in sections 5.3.1.6.2 and 4.3.2.8, were used to revise the adjusted reference temperatures which are then used to revise the beltline P-T curves.

The effect of the reactor vessel and nozzle discontinuities was considered by using HCGS specific material properties.

The reactor vessel closure studs have a minimum Charpy impact energy of 45 foot-pounds and a 25 mil lateral expansion at 10°F.

Actual Charpy test results are presented in Appendix 5A.

5.3.1.6 Material Surveillance

5.3.1.6.1 Compliance with Reactor Vessel Material Surveillance Program Requirements

The materials surveillance program monitors changes in the fracture toughness properties of ferritic materials in the reactor vessel beltline region resulting from their exposure to neutron irradiation and thermal environment.

Materials for the program are selected to represent materials used in the reactor beltline region. The specimens are manufactured from a plate actually used in the beltline region and a weld typical of those in the beltline region and thus represent base metal, weld metal, and the transition zone between base metal and weld. The plate and weld are heat treated in a manner that simulates the actual heat treatment performed on the core region shell plates of the completed vessel.

The surveillance program includes three capsule holders in the reactor vessel. Each holder is loaded with six capsules that contain the following surveillance specimens:

1. First holder - 36 Charpy impact specimens, including 12 longitudinal base metal, 12 weld metal, and 12 longitudinal weld HAZ material; six tensile specimens, including two base metal, two weld metal, and two weld HAZ material.

2. Second holder - 36 Charpy impact specimens, including 12 transverse base metal, 12 weld metal, and 12 transverse weld HAZ material; six tensile specimens, including two base metal, two weld metal, and two weld HAZ material.

3. Third holder - 36 Charpy impact specimens, including 12 longitudinal base metal, 12 weld metal, and 12 longitudinal weld HAZ material; six tensile specimens including two base metal, two weld metal, and two weld HAZ material.

A set of out of reactor baseline CVN specimens is provided with the surveillance test specimens.

Charpy impact specimens for the reactor vessel surveillance programs are of the longitudinal orientation consistent with the ASME requirements prior to the issue of the 1972 Addenda and ASTM E 185-73. Based on GE's experience, the amount of shift measured by these irradiated longitudinal test specimens will be essentially the same as the shift in an equivalent transverse specimen.

Each set of surveillance specimens is loaded in six small capsules rather than one large capsule. Therefore, each capsule holder, which contains all six small capsules, can be considered to be the same as one surveillance capsule as defined in 10CFR50, Appendix H. Three capsule holders are included in the reactor vessel. Since the predicted adjusted reference temperature of the beltline region is less than 100°F at end of life, the use of three capsule holders meets the requirements of 10CFR50, Appendix H.

The program for implementation of the scheduling and testing of the surveillance specimens is governed and controlled by BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP). The ISP is defined in BWRVIP-86 Revision 1-A, "BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan" (Reference 5.3-12). The NRC has issued a safety evaluation for the BWRVIP ISP and is included in BWRVIP-86 Revision 1-A.

The withdrawal schedule will be in accordance with the BWRVIP ISP and is:

1. The first set at the 30° azimuth was withdrawn during the 5th refueling outage at 6.01 EFPY.

2. The second set at the 120° azimuth will be withdrawn when the accumulated neutron fluence of the capsule corresponds to the projected EOL ¼ T reactor vessel fluence. This is projected to be withdrawn at approximately 23 EFPY.

3. The third set is considered a standby capsule. The ISP considers this set a license renewal candidate.

A discussion of the extent of compliance to 10CFR50, Appendix H is provided in Appendix 5A.

5.3.1.6.2 Neutron Flux and Fluence Calculations

A description of the methods of analysis is contained in Sections 4.1.4.5 and 4.3.2.8. Future neutron fluence calculations will be performed in accordance with Regulatory Guide 1.190.

5.3.1.6.3 Predicted Irradiation Effects on Vessel Beltline Materials

Estimated maximum changes to initial RT_{NDT} and upper shelf

fracture energy as a function of the end of life (EOL) fluence at the 1/4 vessel wall thickness (T) depth of the vessel beltline materials are listed in Appendix 5A. The predicted peak EOL fluence at the 1/4 T depth of the vessel beltline is 7.63×10^{17} n/cm^2 after 40 years of service. Reference transition temperature

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changes were calculated in accordance with the rules of Regulatory Guide 1.99, Revision 2. Reference temperatures were established in accordance with 10CFR50, Appendix G and Section NB2330 of the ASME B&PV Code.

5.3.1.6.4 Positioning of Surveillance Capsules and Method of Attachment

Surveillance specimen capsules are located at three azimuths at a common elevation in the core beltline region. The sealed capsules are not attached to the vessel but are in welded capsule holders. The capsule holders are mechanically retained by capsule holder brackets welded to the vessel cladding as shown on Figure 5.3-3. The capsule holder brackets allow the capsule holder to be removed at any time in the life of the plant for specimen testing. These brackets are designed, fabricated, and analyzed to the requirements of Section III of the ASME B&PV Code. A positive, spring loaded locking device is provided to retain the capsules in position throughout any anticipated event during the lifetime of the vessel.

5.3.1.6.5 Time and Number of Dosimetry Measurements

GE provides a separate neutron dosimeter so that fluence measurements may be made at the vessel inside diameter during the first fuel cycle to verify the predicted fluence at an early date in plant operation. This measurement is made over this short period to avoid saturation of the dosimeters now available. Once the fluence to thermal power output is verified, no further dosimetry is considered necessary because of the linear relationship between fluence and power output.

5.3.1.7 Reactor Vessel Fasteners

The reactor vessel closure head (flange) is fastened to the reactor vessel shell flange by multiple sets of threaded studs and nuts. The lower end of each stud is installed in a threaded hole in the vessel shell flange. A nut and washer are installed on the

upper end of each stud. The proper amount of preload can be applied to the studs by a sequential tensioning using hydraulic tensioners. The design and analysis of this area of the vessel is in full compliance with all ASME B&PV Code, Section III, Class I requirements. The material for studs, nuts, and washers is SA-540 Grade B24. The maximum reported ultimate tensile strength for the bolting material is less than the 170,000 psi limitation in Regulatory Guide 1.65. Also the Charpy impact test recommendations in Paragraph IV.A.4 of Appendix G to 10CFR50 were not specified in the vessel order since the order was placed prior to issuance of Appendix G to 10CFR50. However, impact data from the certified materials report shows that all bolting materials have met the Appendix G impact properties. The nondestructive examinations prescribed by the revision of the ASME B&PV Code in effect at the time the fasteners were ordered were conducted by the fabricator. All fasteners were found to be acceptable.

Regulatory Guide 1.65 defines acceptable materials and testing procedures with regard to reactor vessel closure and stud bolting for light water cooled reactors. The design and analysis of these reactor vessel bolting materials is in full compliance with ASME Code Section III, 1968 Edition Class 1 requirements which do not have NB-designated subarticles.

In relationship to regulatory position C.2 of Regulatory Guide 1.65, the bolting materials were ultrasonically examined in accordance with ASME Section III, N-322 after final heat treatment and prior to threading. The specified requirement for examination according to SA-388 was complied with. Straight beam examination was performed on 100 percent of cylindrical surfaces, and from both ends of each stud using a 3/4 maximum diameter transducer. In addition to the Code required notch, the reference standard for the radial scan contains a 1/2-inch diameter flat bottom hole with a depth of 10 percent of thickness, and the end scan standard contains a 1/4 diameter flat bottom hole 1/2 inch deep. Also, angle beam examination was performed on the outer cylindrical

surface in both axial and circumferential directions. Any indication greater than the indication from the applicable calibration feature is unacceptable. A distance amplitude correction curve per N-325 was used for the longitudinal wave examination. Surface examinations were performed on the studs and nuts after final heat treatment and threading, as specified in the regulatory guide, in accordance with N-626 or N-627 of the applicable ASME Code.

Specifications for ordering replacement/spare nuts and studs are in compliance with Regulatory Guide 1.65.

A phosphate coating was applied to threaded areas of studs, nuts and bearing areas of nuts, and washers to act as a rust inhibitor and to assist in retaining lubricant on these surfaces.

5.3.1.8 SRP Rule Review

5.3.1.8.1 Acceptance Criterion II.2

SRP 5.3.1 acceptance criterion II.2 requires that the reactor vessel and its appurtenances be fabricated and installed in accordance with ASME B&PV Code, Section III, Paragraph NB-4100. The manufacturer or installer of such components is required to certify, by application of the appropriate Code symbol and completion of an appropriate data report in accordance with ASME B&PV Code, Section III, Paragraph NA-8000, that the materials used comply with the requirements of NB-2000, and that the fabrication or installation comply with the requirements of NB-4000.

The HCGS RPV and appurtenances were manufactured in accordance with the 1968 edition of the ASME B&PV Code, Section III, which does not have NB-designated subarticles. In light of HCGS's compliance with 1968 ASME B&PV Code, Section III, and information appearing in FSAR Section 5.3.1.2, the plant is essentially in compliance with the acceptance criterion.

5.3.1.8.2 Acceptance Criterion II.3

SRP 5.3.1 acceptance criterion II.3, for examination of the reactor vessel and its appurtenances by nondestructive examination (NDE) are those specified in ASME B&PV Code, Section III, NB-5000, for normal methods of examination. When special techniques or procedures are developed, they must be equivalent or superior to the techniques described in Appendix IX-6000 of ASME B&PV Code, Section III, and must be proven so, by demonstration on the specific type of component part.

The HCGS RPV and appurtenances were manufactured to the 1968 edition of the ASME B&PV Code, which does not include NB-designated articles.

5.3.1.8.3 Acceptance Criterion II.4.a

SRP 5.3.1 acceptance criterion II.4.a states that, for ferritic and austenitic stainless steels, only those welding processes capable of producing welds in accordance with the welding procedure qualification requirements of ASME B&PV Code, Sections III and IX, may be used. Any process used shall be such that the records required by NB-4300 of Section III can be made, with the exception of stud welding, which is acceptable only for minor nonpressure attachments.

For HCGS, welding procedures were qualified to the then current editions of ASME B&PV Code, Sections III and IX. This edition did not contain the actual article NB-4300; however, welding records were maintained to the then applicable standards.

5.3.1.8.4 Acceptance Criterion II.4.e

Compliance with SRP 5.3.1 acceptance criterion II.4.e requires meeting the positions of Regulatory Guides 1.44, and 1.37. Compliance with Regulatory Guide 1.44 is covered in FSAR Section 5.3.1.4.1.4.

FSAR Section 5.2.3.4.1.2 covers procedures for surface cleanliness to the requirements of Regulatory Guide 1.44. However, at the time of fabrication of the HCGS RPV the requirements of Regulatory Guide 1.37 were not in affect. Hence, the HCGS RPV design does not address the specific requirements of Regulatory Guide 1.37.

5.3.1.8.5 SRP Acceptance Criteria Related to Appendixes G and H

SRP acceptance criteria II.5 and II.6 refer to Appendixes G and H of 10CFR50. Appendix G requires that the reactor vessel and appurtenances there to made of ferritic materials meet various requirements for fracture toughness during conditions of normal operation, during system hydrostatic tests, and during anticipated operational occurrences. Appendix H requires an appropriate material surveillance program for the reactor vessel. These requirements did not exist at the time of design and procurement of the HCGS vessel.

The extent of compliance with Appendixes G and H is discussed in Sections 5.3.1.5 and 5.3.1.6 respectively, and in Appendix 5A.

5.3.2 Pressure Temperature Limits

5.3.2.1 <u>Limit Curves</u>

The basis for the operational limits on pressure and temperature for normal, upset, and test conditions is described in Section 5.3.1.5 for the RPV.

5.3.2.1.1 Temperature Limits for Boltup

A minimum temperature of 79°F is required for the closure studs. The flanges and adjacent shell are required to be warmed to minimum temperatures of 79°F before being stressed

by the full intended bolt preload. The fully preloaded boltup limits are shown on Figures 5.3-1A and 5.3-1B.

5.3.2.1.2 Temperature Limits for Preoperational System Hydrostatic Tests and Inservice Inspection Hydrostatic or Leak Pressure Tests

Based on the NRC general revision to 10CFR50, Appendix G, Document Number [7590-01] Paragraph IV.A.4, the preoperational system hydrostatic test at 1563 psig prior to fuel load may be performed at a minimum temperature of 100°F without fuel in the reactor. This temperature is established by the RT_{NDT} of the bottom head and other discontinuities. The fracture toughness analysis for system pressure tests as described in section 5.3.1.5.1.2 results in the curve shown in Figure 5.3-1A. The curves labeled "beltline" are based on an initial RT_{NDT} of 19°.

The predicted shift in RT_{NDT} (based on the neutron fluence at one-fourth of the vessel wall thickness) was added to the beltline curves to account for the effect of fast neutrons.

5.3.2.1.3 Operating Limits During Heatup, Cooldown, and Core Operation

The fracture toughness analysis is done for the maximum heatup or cooldown rate of 100°F/h. The temperature gradients and thermal stress effects corresponding to this rate are included. The result of the analyses as described in section 5.3.1.5.1.2 is a set of operating limits for nonnuclear heatup or cooldown shown as the curve shown in Figure 5.3-1B. The curve shown in Figure 5.3-1C applies whenever the core is critical.

5.3.2.1.4 Reactor Vessel Annealing

Inplace annealing of the reactor vessel due to radiation embrittlement is not anticipated to be necessary because of the existence of an equivalent safety margin throughout the vessel service life of 40 years or 32 EFPY as discussed in 10CFR50, Appendix G, Paragraph IV.A.

5.3.2.2 Operating Procedures

Comparison of the pressure temperature limits in Section 5.3.2.1 with intended normal operating procedures for the most severe upset transient shows that the limits will not be exceeded during any foreseeable upset condition. Reactor operating procedures have been established such that actual transients will not be more severe than those for which the vessel design adequacy has been demonstrated. Of the design transients, the upset condition producing the most adverse temperature and pressure condition anywhere in the vessel head and/or shell areas yields a minimum fluid temperature of 250°F and a maximum pressure peak of 1180 psig. Scram automatically occurs with initiation of this event, prior to the reduction in fluid temperature, and the applicable operating limits are shown in Figure 5.3-1A. For a temperature of 250°F, the maximum allowable pressure exceeds 1180 psig for the intended margin against nonductile failure. The maximum transient pressure of 1180 psig is therefore within the specified allowable limits.

5.3.3 Reactor Vessel Integrity

The HCGS reactor vessel was fabricated for GE by Hitachi and was subject to the requirements of GE's quality assurance program.

Assurance was made that measures were established requiring that purchased material, equipment, and services associated with the reactor vessel and its appurtenances conform to the requirements of the subject purchase documents. These measures included

provisions, as appropriate, for source evaluation and selection, objective evidence of quality furnished, inspection at the vendor source, and examination of the completed reactor vessel.

GE provided inspection surveillance of the reactor vessel fabricator's inprocess manufacturing, fabrication, and testing operations, in accordance with GE's quality assurance program and approved inspection procedures. The reactor vessel fabricator is responsible for the first level inspection of manufacturing, fabrication, and testing activities, and GE is responsible for the first level of audit and surveillance inspection.

Adequate documentary evidence that the reactor vessel material, manufacture, testing, and inspection conforms to the specified quality assurance requirements contained in the procurement specification is available at the fabricator's plant.

Regulatory Guide 1.2 states that a suitable program be followed to ensure that the reactor pressure vessel will behave in a nonbrittle manner under loss-of-coolant accident (LOCA) conditions.

If it should be considered at any time during vessel life that the margin of safety against reactor pressure vessel (RPV) brittle fracture is unacceptable due to Emergency Core Cooling System (ECCS) operation, the regulatory guide states that an engineering solution, such as annealing, could be applied to ensure adequate recovery of the fracture toughness properties of the vessel material.

An analysis of the structural integrity of boiling water reactor pressure vessels during a design basis accident (DBA) has been performed. While the analysis specifically addressed the BWR/6 vessels only, the analysis was determined to be applicable to the HCGS vessel.

The analysis included:

1. Description of the LOCA event

2. Thermal analysis of the vessel wall to determine the temperature distribution at different times during the LOCA

3. Determination of the stresses in the vessel wall including thermal, pressure, and residual stresses

4. Consideration of radiation effect on material toughness; nil ductility transition temperature (NDTT) and changes in toughness

5. Fracture mechanics evaluation of vessel wall for different postulated flaw sizes.

This analysis incorporated conservative assumptions in all areas, particularly in the areas of heat transfer, stress analysis, effects of radiation on material toughness, and crack tip stress intensity factor evaluation. The analysis concluded that even in the presence of large flaws, the vessel will have considerable margin against brittle fracture following a LOCA.

The criteria of 10CFR50, Appendix G are interpreted as establishing the requirements for annealing. Paragraph IV.B of Appendix G states that if the fracture toughness requirements do not include the existence of an equivalent safety margin, the vessel beltline may be given a thermal annealing treatment to recover the fracture toughness of the material. The HCGS vessel is predicted to have the equivalent safety margin throughout the vessel service life of 40 years or 32 EFPY. Therefore, in place annealing is not anticipated and a design for annealing is not required.

For further discussion of fracture toughness of the reactor pressure vessel, refer to Section 5.3.1.5.

5.3.3.1 Design

5.3.3.1.1 Assessment of Compliance to Regulatory Guide 1.2

The following is a general compliance assessment for Regulatory Guide 1.2. For commitment, revision number, and scope, see Section 1.8.

5.3.3.1.1.1 Description

5.3.3.1.1.1.1 Reactor Vessel

The reactor vessel shown on Figure 5.3-4 is a vertical, cylindrical, pressure vessel of welded construction. The vessel is designed, fabricated, tested, and inspected, in accordance with the ASME B&PV Code, Section III, Class 1, 1968 edition including the Winter Addenda of 1969 except that the vessel does not have an ASME B&PV Code "N" stamp. Design of the reactor vessel and its support system meets Seismic Category I equipment requirements. The materials used in the reactor vessel are shown in Table 5.2-7.

The cylindrical shell and bottom head sections of the reactor vessel are fabricated of low alloy steel, the interior of which is clad with stainless steel weld overlay. Nozzles and nozzle weld zones are not clad, except for the recirculation inlet and outlet, the core spray, the jet pump instrumentation, and CRD return line nozzles.

Inplace annealing of the reactor vessel is unnecessary because shifts in NDTT caused by irradiation during its 40 year life can be accommodated by raising the minimum pressurization temperature. Radiation embrittlement is not a problem outside of the vessel beltline region because of the low fluence in those areas.

Quality control methods used during fabrication and assembly of the reactor vessel and its appurtenances ensure that design specifications are met.

The vessel top head is secured to the reactor vessel by studs and nuts. These nuts are tightened with a stud tensioner. The vessel flanges are sealed with two concentric metal seal rings designed to permit no detectable leakage through the inner or outer seal at any operating condition, including heating to operating pressure and temperature at a maximum rate of 100°F/h in any 1-hour period. To detect seal failure, a vent tap is located between the two seal rings. A monitor line is attached to the tap to provide an indication of leakage from the inner seal ring seal.

Regulatory Guide 1.2 states that potential RPV brittle fracture, which may result from ECCS operation need not be reviewed in individual cases if no significant changes in presently approved core and pressure vessel designs are proposed. If it is concluded that the margin of safety against RPV brittle fracture due to ECCS operation is unacceptable, an engineering solution, such as annealing, could be applied to ensure adequate recovery of the fracture toughness properties of the vessel material. Regulatory Guide 1.2 requires that available engineering solutions be outlined and requires that it be demonstrated that the design does not preclude their use.

Regarding commitment, revision number, and scope of general compliance to Regulatory Guide 1.2, see Section 1.8.

The RPV employs no significant core or vessel design changes from previously approved BWR pressure vessels such as Browns Ferry, all units.

An investigation of the structural integrity of boiling water RPVs during a design basis accident (DBA) has been conducted and is

included in Reference 5.3-1. It has been determined based on methods of fracture mechanics, that no failure of the vessel by brittle fracture as a result of a DBA will occur.

The investigation included:

1. A comprehensive thermal analysis considering the effect of blowdown and the low pressure coolant injection (LPCI) system reflooding

2. A stress analysis considering the effects of pressure, temperature, seismic load, jet load, dead weight, and residual stresses

3. The radiation effect on material toughness (NDTT shift and critical stress intensity)

4. Methods for calculating crack tip stress intensity associated with a non-uniform stress field following the DBA.

This analysis incorporated very conservative assumptions in all areas, particularly in the areas of heat transfer, stress analysis, effects of radiation on material toughness, and crack tip stress intensity. Therefore, the results reported in NEDO 10029 provide an upper bound limit on brittle fracture failure mode studies. Because of the upper bound approach, it is concluded that catastrophic failure of the pressure vessel due to the DBA is shown to be impossible from a fracture mechanics point of view. In the case studies, even if an acute flaw does form on the vessel inner wall, it will not propagate as the result of the DBA.

The criteria of 10CFR50, Appendix G, are interpreted as establishing the requirements for annealing. Paragraph IV.B of Appendix G states that if the fracture toughness requirements do not include the existence of an equivalent safety margin, the vessel beltline may be given a thermal annealing treatment to recover the fracture toughness of the material. The HCGS vessel is predicted to have the equivalent safety margin throughout the vessel service life of 40 years or 32 EFPY. Therefore, in place annealing is not anticipated.

For further discussion of fracture toughness of the reactor pressure vessel, refer to Section 5.3.1.

5.3.3.1.1.2 Shroud Support

The shroud support is a circular plate welded to the vessel wall. This support is designed to carry the weight of the shroud, shroud head, peripheral fuel elements, neutron sources, core plate, top guide, steam separators, and jet pump diffusers, and to laterally support the fuel assemblies. Design of the shroud support also accounts for pressure differentials across the shroud support plate, for the restraining effect of components attached to the support, and for earthquake loadings. The shroud support design is specified to meet appropriate ASME B&PV Code stress limits.

5.3.3.1.1.3 Protection of Closure Studs

The BWR does not use borated water for reactivity control during normal operation. This subsection is therefore not applicable.

5.3.3.1.2 Safety Design Basis

The design of the reactor vessel and its appurtenances meets the following safety design bases:

1. The reactor vessel and its appurtenances can withstand adverse combinations of loading and forces resulting from operation under normal and accident conditions.

2. To minimize the possibility of brittle fracture of the nuclear system process barrier, the following criteria are met:

a. Impact properties at temperatures related to vessel operation are specified for materials used in the reactor vessel.

b. Expected shifts in NDTT during design life, as a result of environmental conditions such as neutron flux, are considered in the design. Operational limitations ensure that NDTT shifts are accounted for in reactor operation.

c. Operational margins to be observed with regard to the NDTT are specified for each mode of operation.

5.3.3.1.3 Power Generation Design Basis

The design of the reactor vessel and appurtenances meets the following power generation design bases:

1. The reactor vessel is designed for a useful life of 40 years.

2. External and internal supports that are integral parts of the reactor vessel are located and designed so that stresses in the vessel and supports that result from reactions at these supports are within ASME B&PV Code limits.

3. Design of the reactor vessel and appurtenances allows for a suitable program of inspection and surveillance.

5.3.3.1.4 Reactor Vessel Design Data

The reactor vessel design pressure is 1250 psig and the design temperature is 575°F. The maximum installed test pressure is 1563 psig (+50/-0 psig).

5.3.3.1.4.1 Vessel Support

The reactor vessel support assembly consists of a ring girder and various bolts and shims necessary to position and secure the assembly between the reactor vessel support skirt and the support pedestal. The concrete and steel support pedestal is constructed as an integral part of the structure foundation. Steel anchor bolts are set in the concrete with their threads extending above the surface. The anchor bolts extend through the ring girder bottom flange. High strength bolts are used to secure the flange of the reactor vessel support skirt to the top flange of the ring girder. The ring girder is fabricated of ASTM A-36 structural steel according to AISC specifications.

5.3.3.1.4.2 Control Rod Drive Housings

The control rod drive (CRD) housings are inserted through the CRD penetrations in the reactor vessel bottom head and are welded to the reactor vessel. Each housing transmits loads to the bottom head of the reactor. These loads include the weights of a control rod, a CRD, a control rod guide tube, a four lobed fuel support piece, and the four fuel assemblies that rest on the fuel support piece. The housings are fabricated of Type 304 austenitic stainless steel.

5.3.3.1.4.3 In-Core Neutron Flux Monitor Housings

Each in-core neutron flux monitor housing is inserted through the in-core penetrations in the bottom head and is welded to the inner surface of the bottom head.

An in-core flux monitor guide tube is welded to the top of each housing and either a source range monitor/intermediate range monitor (SRM/IRM) drive unit or a local power range monitor (LPRM) is bolted to the seal ring flange at the bottom of the housing. See Section 7.6 for further information.

5.3.3.1.4.4 Reactor Vessel Insulation

The reactor vessel top head insulation is of a stainless steel encased fiberglass design. This encasement permits complete submersion in water during shutdown without loss of insulation material, contamination of the water, or adverse effect on the insulation efficiency after draining. The reactor vessel bellows insulation is of a stainless steel mirror design and all other reactor vessel insulation, which includes the upper reactor vessel and bottom head, is of a stainless steel encased fiberglass design. The top head insulation framework is designed to Seismic Category I requirements and is used as an anchor point for reactor vessel vent piping.

The insulation above the reactor vessel stabilizer brackets is close fitting, freestanding insulation designed to be 100 percent removable for inservice inspection of the reactor vessel.

The insulation below the stabilizer brackets is attached to brackets on the bioshield wall to allow a minimum of 8 inches annular clearance between the reactor vessel and the insulation for remote inservice inspection of the reactor vessel. The suspended insulation is also equipped with removable access ports.

Reactor vessel bottom head insulation includes horizontal flat panels connected to a cylindrical shell covering the inside of the reactor support skirt. The top row of the cylindrical shell panels is removable to expose the bottom head for inservice inspection.

Quick removable insulation is provided around all reactor vessel nozzles to allow manual or remote automatic examination of nozzle to vessel and nozzle to piping welds.

5.3.3.1.4.5 Reactor Vessel Nozzles

All piping connected to the reactor vessel nozzles has been designed so as not to exceed the allowable loads on any nozzle.

The vessel top head nozzles are provided with flanges with large groove facing. The drain nozzle is of the full penetration weld type. The recirculation inlet nozzles (located as shown on Figure 5.3-4), feedwater inlet nozzles, LPCI inlet and the core spray inlet nozzles, all have thermal sleeves.

Nozzles connecting to stainless steel piping have safe ends made of stainless steel. These safe ends are welded to the nozzles after the pressure vessel has been heat treated to avoid furnace sensitization of the stainless steel safe ends. The material used is compatible with the material of the mating pipe.

The nozzle for the standby liquid control pipe is designed to minimize thermal shock effects on the reactor vessel. However, the standby liquid control system discharge has not been routed to this nozzle.

5.3.3.1.4.6 Materials and Inspections

The reactor vessel is designed and fabricated in accordance with the appropriate ASME B&PV Code as defined in Section 5.2.1. Table 5.2-4 defines the materials and specifications. Section 5.3.1 defines the compliance with reactor vessel material surveillance program requirements.

5.3.3.1.4.7 Reactor Vessel Schematic (BWR)

The reactor vessel is shown schematically on Figure 5.3-4. Trip system water levels are indicated as shown on Figure 5.3-5.

5.3.3.2 Materials of Construction

All materials used in the construction of the RPV conform to the requirements of ASME B&PV Code, Section II materials. The vessel heads, shells, flanges, and nozzles are fabricated from low alloy steel plate and low alloy and carbon steel forgings purchased in accordance with ASME specifications SA533 Grade B Class 1 and

SA508 Class 2. The leak detection nozzle is fabricated from SA 106 Grade B. Instrument nozzles and the RPV drain nozzle are fabricated from SA-541 Class 1 (Code Case 1332-5) and the core differential pressure and liquid control nozzle is fabricated from SB 166. Special requirements for the low alloy steel plate and forgings are discussed in Section 5.3.1.2. Cladding employed on the interior surfaces of the vessel consists of austenitic stainless steel weld overlay.

These materials of construction were selected because they provide adequate strength, fracture toughness, fabricability, and compatibility with the BWR environment. Their suitability has been demonstrated by long term successful operating experience in reactor service.

5.3.3.3 Fabrication Methods

The RPV is a vertical cylindrical pressure vessel of welded construction fabricated in accordance with ASME B&PV Code, Section III, Class 1 requirements. All fabrication of the reactor pressure vessel was performed in accordance with GE-approved drawings, fabrication procedures, and test procedures. The shell and vessel head were made from formed low alloy steel plates, and the flanges and nozzles from low alloy steel forgings. Welding performed to join these vessel components was in accordance with procedures qualified per ASME B&PV Code, Section III and IX requirements. Weld test samples were required for each procedure for major vessel full penetration welds.

Submerged arc and manual stick electrode welding processes were employed. Electroslag welding was not permitted. Preheat and interpass temperatures employed for welding of low alloy steel met or exceeded the requirements of ASME B&PV Code, Section III, subsection NA. Postweld heat treatment of 1100°F minimum was applied to all low alloy steel welds.

All previous BWR pressure vessels have employed similar fabrication methods. These vessels have operated for an extensive number of years, and their service history is excellent.

5.3.3.4 Inspection Requirements

All plate, forgings, and bolting were 100 percent ultrasonically tested. Forgings and bolting were also surface examined by magnetic particle methods or liquid penetrant methods. All nondestructive examination (NDE) methods were done in accordance with ASME B&PV Code, Section III requirements. Welds on the RPV were examined in accordance with methods prescribed and meet the acceptance requirements specified by ASME B&PV Code, Section III. In addition, the pressure retaining welds were ultrasonically examined using acceptance standards that are required by ASME B&PV Code, Section XI.

5.3.3.5 Shipment and Installation

The completed reactor vessel was given a thorough cleaning and examination prior to shipment. The vessel was tightly sealed for shipment to prevent entry of dirt or moisture. Preparations for shipment were in accordance with detailed written procedures. Upon arrival at the reactor site, the reactor vessel was carefully examined for evidence of any contamination as a result of damage to shipping covers. Suitable measures were taken during installation to ensure that vessel integrity was maintained, e.g., access controls were applied to personnel entering the vessel, weather protection was provided, and periodic cleaning was performed.

5.3.3.6 Operating Conditions

Procedural controls on plant operation are implemented to hold thermal stresses within acceptable ranges. The limitations on coolant temperature are as follows:

1. The average rate of change of reactor coolant temperature during normal heatup and cooldown shall not exceed 100°F during any 1-hour period.

2. If the coolant temperature differential between the dome (inferred from P(sat)) and the bottom head drain exceeds 145°F, neither reactor power level nor reactor recirculation flow shall be increased.

3. The pump in an idle reactor recirculation loop shall not be started unless the coolant temperature in that loop is within 50°F of average reactor coolant temperature.

The limit regarding the normal rate of heatup and cooldown (item 1.) ensures that the vessel closure, closure studs, vessel support skirt, and CRD housing and stub tube stresses and usage remain within acceptable limits. The vessel coolant temperature limit on recirculation pump operation and power level increase restriction (item 2.) augments item 1. in further detail by ensuring that the vessel bottom head region will not be warmed at an excessive rate caused by rapid sweep out of cold coolant in the vessel lower head region by recirculation pump operation or natural circulation. (Cold coolant can accumulate as a result of control drive inleakage and/or low recirculation flow rate during startup or hot standby.) The item 3. limit further restricts operation of the recirculation pumps to avoid high thermal stress effects in the pumps and piping, while also minimizing thermal stresses on the vessel nozzles.

The above operational limits, when maintained, ensure that the stress limits within the reactor vessel and its components are within the thermal limits to which the vessel was designed for normal operating conditions. To maintain the integrity of the vessel in the event that these operational limits are exceeded, the reactor vessel is also designed to withstand a limited number of transients caused by operator error. Under abnormal operating conditions where safety systems or controls provide an automatic

temperature and pressure response in the reactor vessel, the reactor vessel integrity is maintained since the severest anticipated transients have been included in the design of the reactor vessel. Therefore, it is concluded that the vessel integrity will be maintained during the most severe postulated transients since all such transients for which the vessel has been designed are shown on Figure 5.2-2 and discussed in Section 5.2.2.

5.3.3.7 Inservice Surveillance

Preservice inspection of the RPV will be in accordance with the requirements of the 1977 edition of the ASME B&PV Code, Section XI, including the Summer 78 Addenda. Subsequent inservice inspection will be scheduled and performed in accordance with the requirements of 10CFR50.55a, Subparagraph g.

The materials surveillance program will monitor changes in the fracture toughness properties of limiting ferritic materials in the reactor vessel beltline region resulting from their exposure to neutron irradiation and thermal environment. Specimens of actual reactor beltline material will be exposed in the reactor vessel and periodically withdrawn for impact testing. Operating procedures will be modified in accordance with test results to ensure adequate brittle fracture control.

Material surveillance programs and inservice inspection programs are in accordance with applicable ASME B&PV Code requirements, and ensure that brittle fracture control and pressure vessel integrity will be maintained throughout the service lifetime of the RPV.

5.3.3.8 SRP Rule Review

5.3.3.8.1 Acceptance Criterion II.1

SRP 5.3.3 acceptance criterion II.1 requires RPV design in accordance with the ASME B&PV Code. The HCGS reactor vessel was

designed, fabricated, tested, and inspected in accordance with this Code, Section III, Class A, but the vessel does not have an ASME B&PV Code "N" stamp.

5.3.3.8.2 Acceptance Criterion II.2

SRP 5.3.3 acceptance criterion II.2 states that currently acceptable materials for reactor vessel parts are SA 533 Grade B Class 1, SA 508 Class 2, and SA 508 Class 3. FSAR Sections 5.3.3.1.4.6 and 5.3.3.2 list additional materials used in the HCGS reactor vessel, but all additional materials comply with ASME B&PV Code, Section III.

The vessel heads, shells, flanges, and nozzles are fabricated from low alloy steel plate and low-alloy forgings purchased in accordance with ASME specifications SA 533 Grade B Class 1 and SA 508 Class 2. Instrument nozzles as well as the RPV drain nozzle are fabricated from material in accordance with ASME specification SA 541 Class 1 (Code Case 1332-5). The leak detection nozzle is fabricated from material in accordance with ASME specification SA 106 Grade B and the core differential pressure and liquid control nozzle is fabricated from material in accordance with SB 166.

5.3.3.8.3 Acceptance Criterion II.4

SRP 5.3.3 acceptance criterion II.4 requires flaw evaluation criteria compatible with Section XI of the ASME B&PV Code. Section XI for preservice and flaw evaluation criteria did not exist during reactor vessel fabrication. The Summer 1970 Addendum of Section XI of the ASME B&PV Code was applicable to inspection requirements at that time.

All plate, forgings, and boltings were 100 percent ultrasonically tested. Forgings and boltings were also surface-examined by magnetic particle or liquid penetrant methods. All NDE methods were done in accordance with ASME B&PV Code Section III

requirements. Welds on the RPV were examined in accordance with methods prescribed and meet the acceptance requirements specified by ASME B&PV Code, Section III.

5.3.4 References

5.3-1 General Electric Company, "An Analytical Study on Brittle Fracture of GE-BWR Vessel Subject to the Design Basis Accident," NEDO 10029, July 1969.

5.3-2 Watanabe, H., "Boiling Water Reactor Feedwater Nozzle/Sparger Final Report," NEDE 21821-2 (Proprietary Version) and NEDO 21821-2 (Non-Proprietary Version), General Electric Company, August 1979.

5.3-3 Cooke, F., "Transient Pressure Rises Affecting Fracture Toughness Requirements for Boiling Water Reactors," NEDO 21778-A, General Electric Company, December 1978.

5.3-4 General Electric Company, "BWR Radiation Effects Design Curve," NEDO 20651, Figure 4-1, March 1975.

5.3-5 General Electric Company, "RPV Surveillance Materials Testing and Fracture Toughness Analysis," GE-NE-A164-1294, R1, DRF 137-0010-7, December 1997.

5.3-6 General Electric Company, "10CFR50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 through BWR/6 Vessels," NEDO-32205-A, Rev. 1, February 1994.

5.3-7 General Electric Company, "Basis for GE RTNDT Estimation Method," NEDC-32399-P, September 1994.

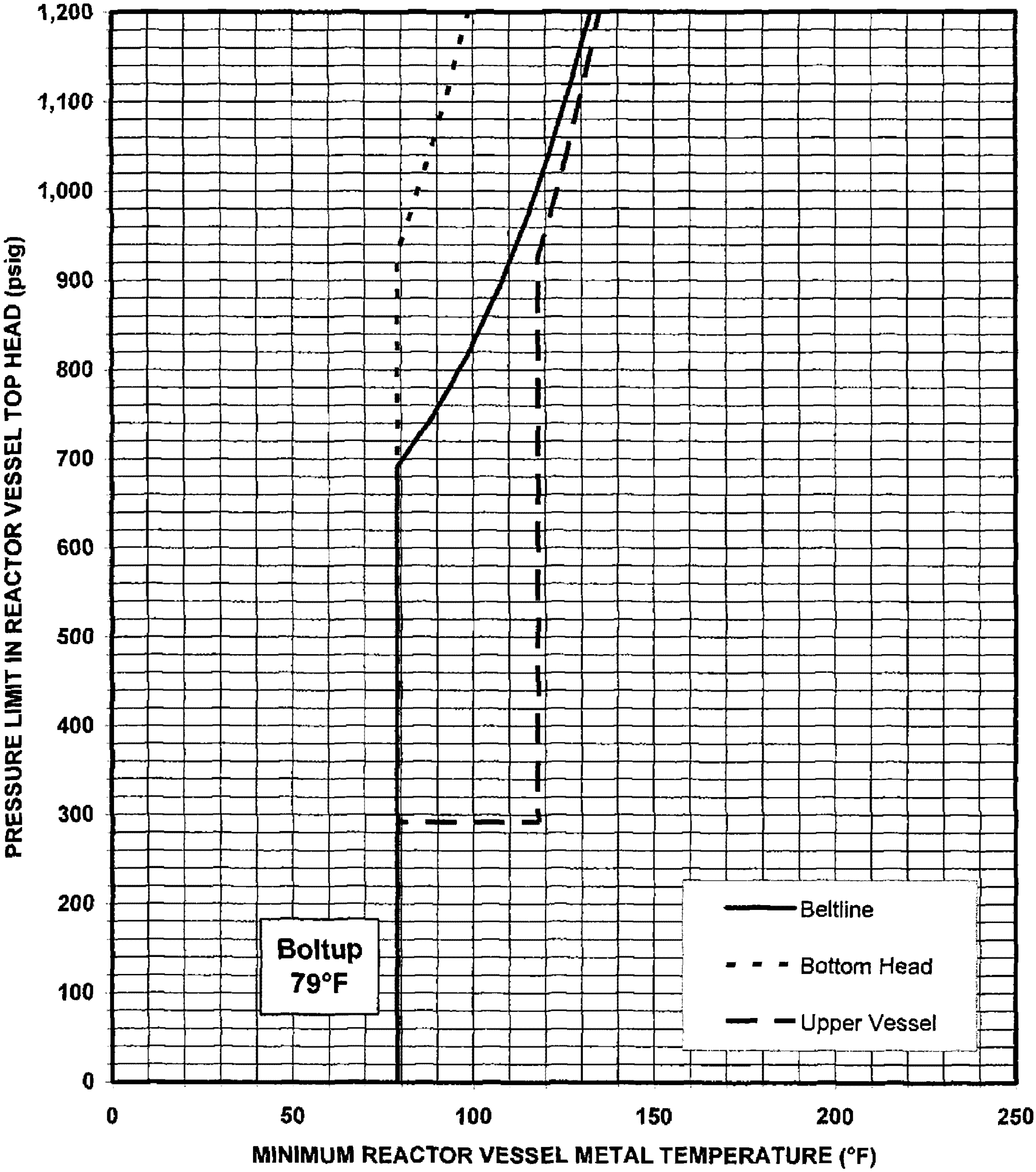
5.3-8 Structural Integrity Associates, Inc., “Revised Pressure-Temperature Curves for Hope Creek,” SIR-00-136, Rev. 1, March 23, 2004.

5.3-9 Welding Research Council, PVRC Ad Hoc Group on Toughness Requirements, “PVRC Recommendations on Toughness Requirements for Ferritic Materials,” WRC Bulletin 175, August 1972.

5.3-10 ASME Boiler and Pressure Vessel Code, Code Case N-588, “Alternative Reference Flaw Orientation of Appendix G for Circumferential Welds in Reactor Vessels,” Section XI, Division 1, Approved December 12, 1997.

5.3-11 ASME Boiler and Pressure Vessel Code, Code Case N-640, “Alternative Reference Fracture Toughness for Development of P-T Limit Curves,” Section XI, Division 1, Approved February 26, 1999.

5.3-12 EPRI 1025144, BWRVIP-86 Revision 1-A: “BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan”, October 2012.

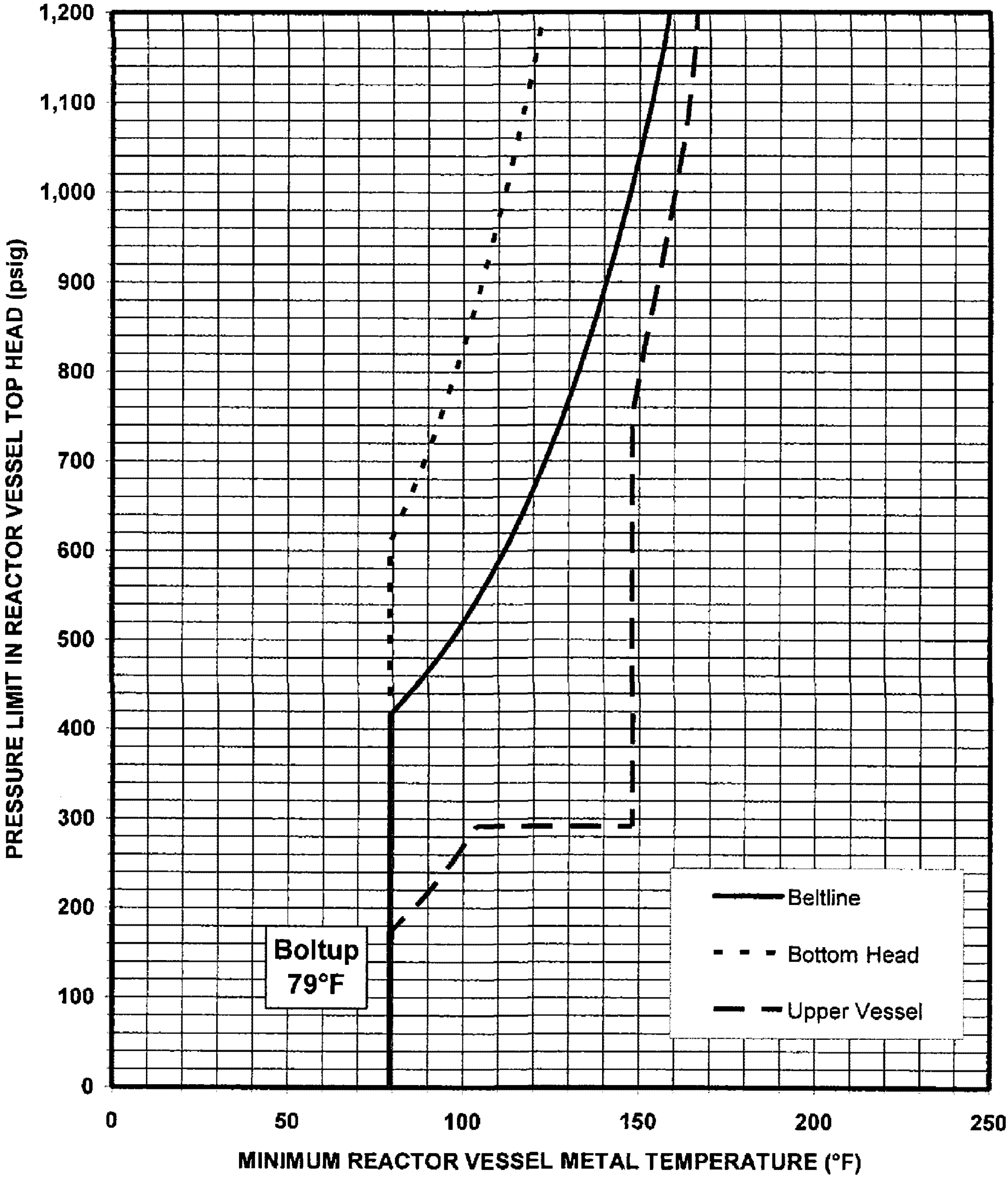


All system leakage and hydrostatic pressure tests performed during the service *life of the pressure boundary in compliance with ASME Code Section XI.*

This *figure is valid for* 32 EFPY *of* operation.

Revision 14, July 26, 2005

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station HYDROSTATIC PRESSURE AND LEAK TESTS PRESSURE/TEMPERATURE LIMITS
	Updated FSAR — Figure 5.3-1A

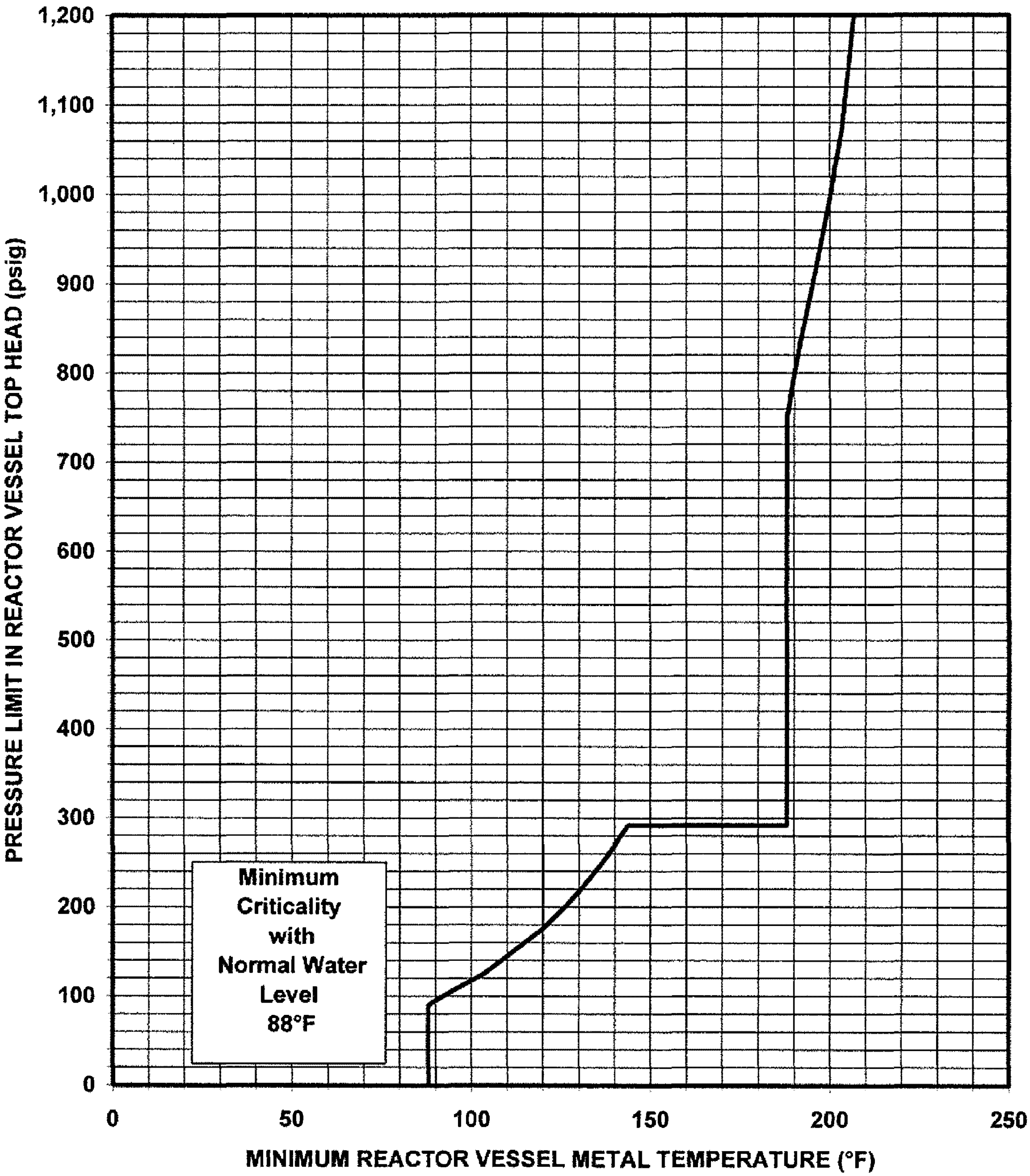


All heatup and cooldowns that are performed when the reactor is not critical at the normal heatup and cooldown rate.

This figure is valid for 32 EFPY of operation.

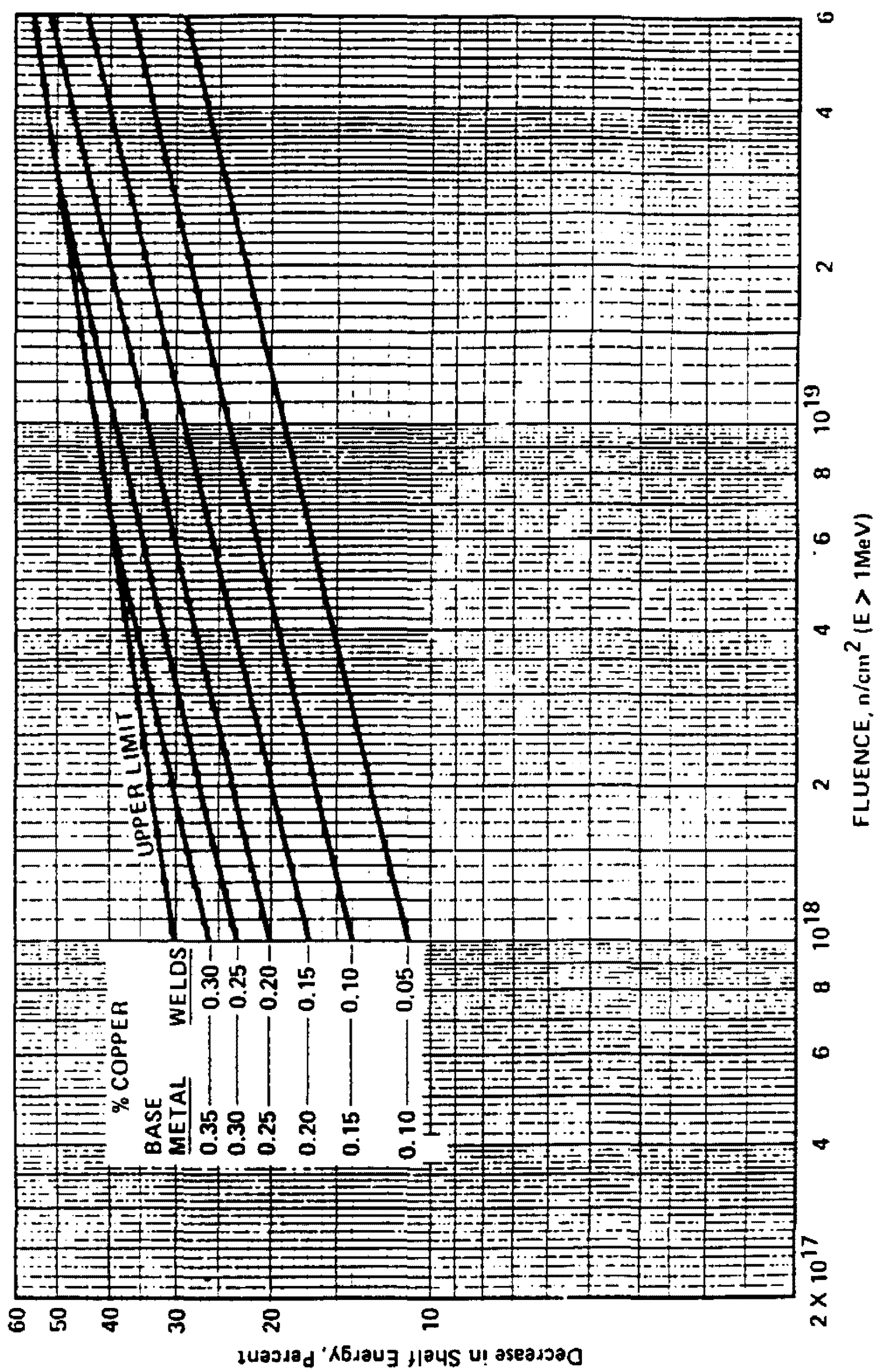
Revision 14, July 26, 2005

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station NON-NUCLEAR HEATUP AND COOLDOWN PRESSURE/TEMPERATURE LIMITS
	Updated FSAR — Figure 5.3-1B

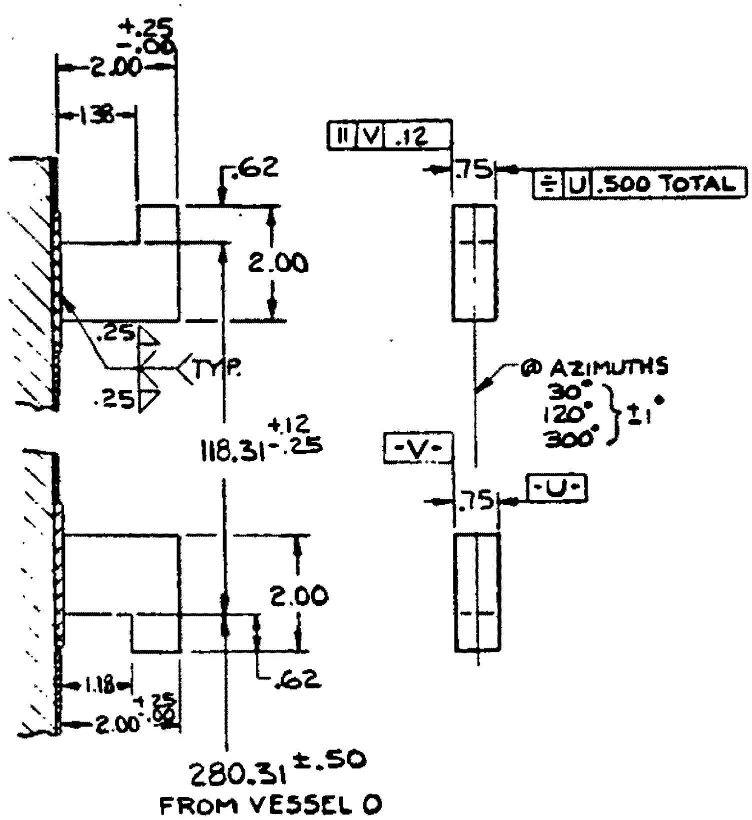


All heatup and cooldowns that are performed when the reactor is critical at the normal heatup and cooldown rate.

This figure is valid for 32 EFPY of operation.



PUBLIC SERVICE ELECTRIC AND GAS COMPANY HOPE CREEK NUCLEAR GENERATING STATION	PREDICTED ADJUSTMENT OF REFERENCE TEMPERATURE A AS A FUNCTION OF FLUENCE AND COPPER CONTENT
	Updated FSAR Revision 8 September 25, 1996 — Figure 5.3-2



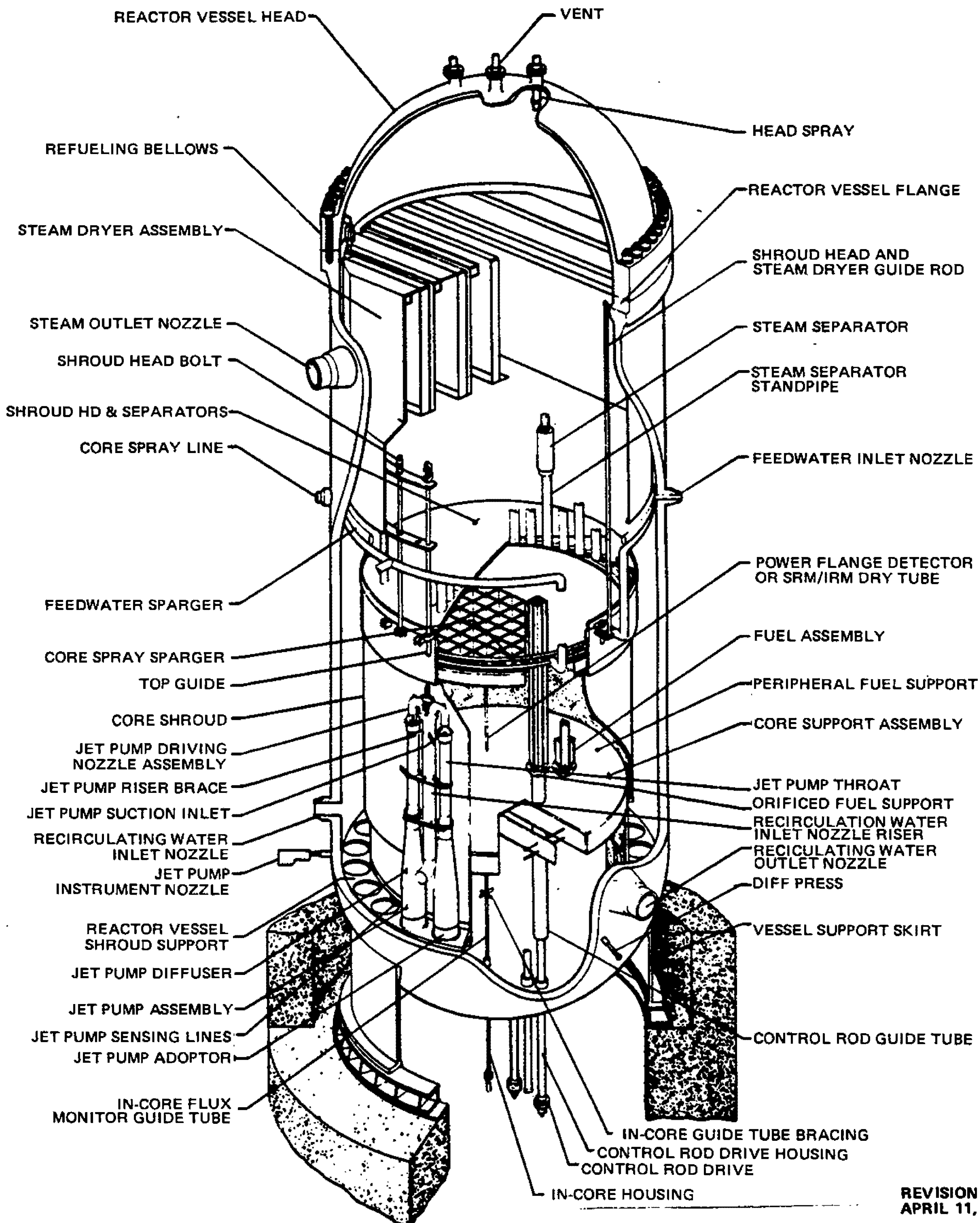
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

BRACKET FOR HOLDING SURVEILLANCE CAPSULE

UPDATED FSAR

FIGURE 5.3-3



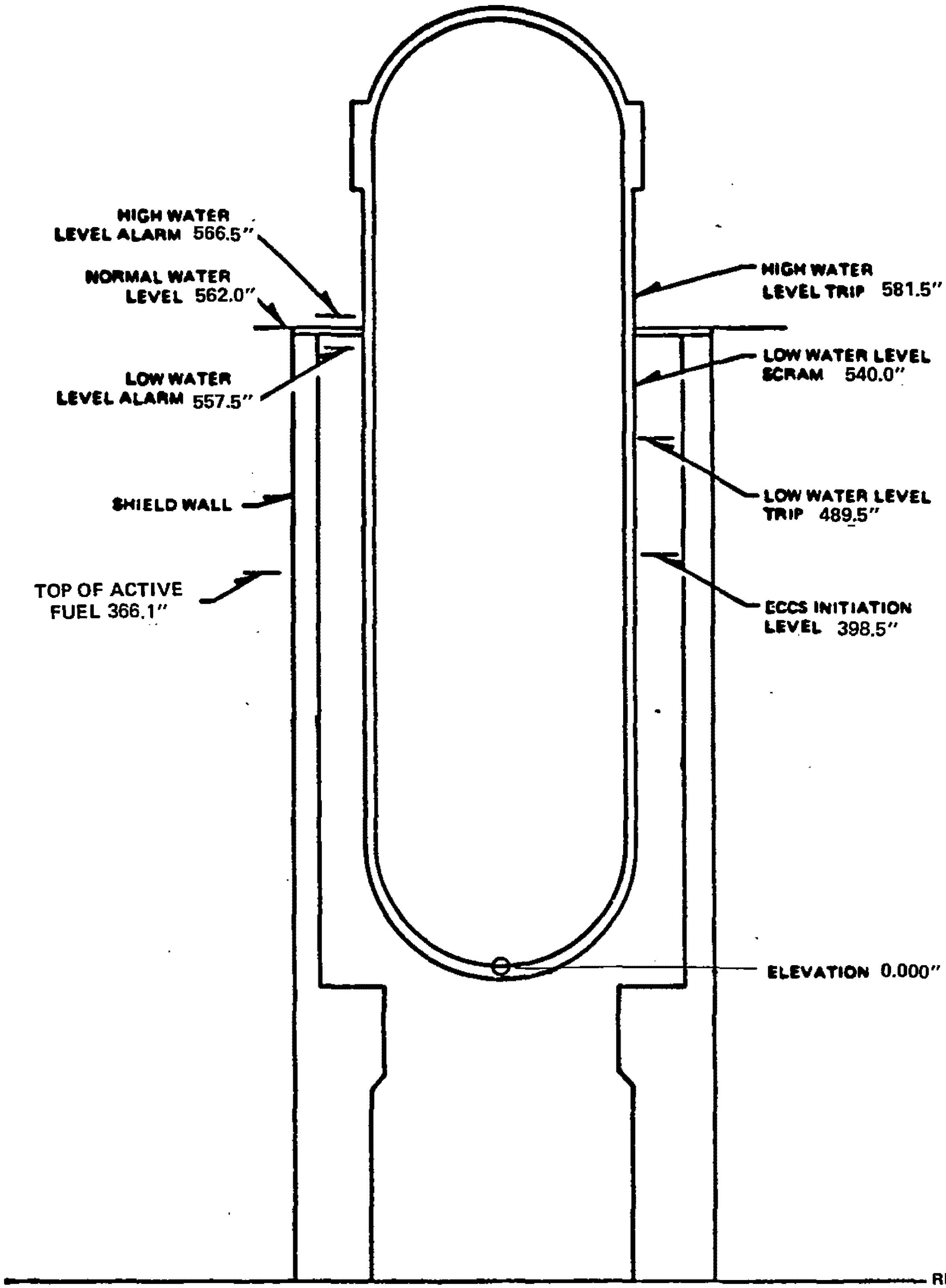
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

REACTOR VESSEL
CUTAWAY DIAGRAM

UPDATED FSAR

FIGURE 5.3-4



REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

REACTOR VESSEL NOMINAL
WATER LEVEL TRIP AND
ALARM ELEVATIONS

UPDATED FSAR

FIGURE 5.3-5

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 Reactor Recirculation Pumps

5.4.1.1 Safety Design Bases

The Reactor Recirculation System is designed to meet the following safety design bases:

1. An adequate fuel barrier thermal margin is ensured during postulated transients.

2. A failure of piping integrity does not compromise the ability of the reactor vessel internals to provide a refloodable volume.

3. The system maintains pressure integrity during adverse combinations of loadings and forces occurring during abnormal, accident, and special event conditions. Loading combinations are defined in Section 3.9.3. Missile protection is discussed in Sections 3.5 and 3.6.

5.4.1.2 Power Generation Design Bases

The Reactor Recirculation System meets the following power generation design bases:

1. Provides sufficient flow to remove heat from the fuel

2. Provides a load following capability over the range of 65 to 100 percent rated power

3. Minimizes maintenance situations that require core disassembly and fuel removal.

5.4.1.3 Description

The Reactor Recirculation System, as shown on Figure 5.4-1 and Plant Drawing M-43-1, consists of the two reactor recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains one high capacity variable speed motor driven recirculation pump and two motor operated gate valves for pump maintenance. Each loop also contains a flow measuring system. These recirculation loops are part of the reactor coolant pressure boundary (RCPB) and are located inside the drywell structure. The jet pumps, however, are reactor vessel internals. Their location and mechanical design are discussed in Section 3.9.5 with the exception of certain operational characteristics, which are discussed in this section. Important design and performance characteristics of the reactor recirculation system are tabulated in Table 5.4-1. The head, net positive suction head (NPSH), flow, and efficiency curves are shown on Vendor Technical Document PN1-B31-C001-0031. Instrumentation and control description is provided in Section 7.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high-pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the driven flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The flows, both driving and driven, are mixed in the jet pump throat section and result in partial pressure recovery. The balance of recovery is obtained in the jet pump diffuser as shown on Figure 5.4-4. The adequacy of the total flow to the core is discussed in Section 4.4.

The allowable heatup rate for the recirculation pump casing is the same as that for the reactor vessel. If one loop is shut down, the idle loop can be kept hot by leaving the discharge and suction gate valves open. This permits the reactor pressure, plus the active jet pump head, to cause reverse flow in the idle loop.

Returning a pump to service involves starting it at slow speed with the discharge valve cracked slightly open and the nuclear system at full pressure. Pump speed is not increased until after the discharge valve opening is increased. There is a very low probability that a recirculation loop that has been allowed to cool would need to be placed in service again with the nuclear system hot. Since the reason for shutting a loop down is usually for maintenance on the recirculation pump, the suction gate valve, or the discharge gate valve, this maintenance cannot be accomplished without shutting the plant down to permit access to the drywell. Therefore, the nuclear system is cooled, in all probability, prior to performing the required maintenance.

Because the removal of the reactor recirculation gate valve internals requires unloading the core due to the resulting draining of reactor coolant, the objective of the valve trim design is to minimize the need for maintenance of the valve internals. The valves are provided with high quality backseats that permit replacement of stem packing while the system is full of water.

The feedwater flowing into the reactor vessel annulus during operation provides subcooling for the fluid passing to the recirculation pumps and jet pumps, thus providing the additional NPSH available beyond that provided by the pump location below the reactor vessel water level. If feedwater flow is below the minimum value that provides adequate NPSH for full speed recirculation pump operation, the pump speed is automatically limited by the motor generator set control system.

When preparing for hydrostatic tests, the nuclear system temperature must be raised above the vessel nil ductility transition temperature (NDTT) limit. The vessel is heated by operating the recirculation pumps and/or by core decay heat.

Each recirculation pump is a single stage, variable speed, vertical, centrifugal pump equipped with mechanical shaft seal assemblies. The pump is capable of stable and satisfactory performance while operating continuously at any speed corresponding to a power supply frequency range of 11.5 to 57.5 hertz for 60 hertz power supply.

The recirculation pump shaft seal assembly consists of two individual seals built into a cartridge or cartridges that can be readily replaced without removing the motor from the pump. The seal assembly is designed to require minimum maintenance over a long period of time, regardless of whether the pump is stopped or is operating at various speeds with water at various pressures and temperatures. Each seal is designed for a life of 1 year, based on a 90 percent probability factor. Each individual seal in the cartridge is capable of sealing against pump operating pressure so that any one seal can adequately limit leakage in the event that the other seal fails. A breakdown orifice is provided in the pump casing to reduce leakage in the event of a gross failure of both shaft seals. Provision is made for monitoring the pressure drop across each individual seal as well as the cavity temperature of each seal. Provision is also made for piping the seal leakage to a flow measuring device.

Each recirculation pump motor is a vertical, variable speed ac electric motor that can drive the pump over a controlled range of 20 to 115 percent of rated pump speed. The motor is designed to operate continuously at any speed within the power supply frequency range of 11.5 to 57.5 hertz for 60 hertz power supply. Electrical equipment is designed, constructed, and tested in accordance with the applicable sections of the NEMA standards.

A variable frequency ac motor generator set, located outside the drywell, supplies power to each recirculation pump motor. The pump motor is electrically connected to the generator and is started by engaging the variable speed coupling between the generator and the motor.

The combined rotating inertias of the recirculation pump and motor, motor generator set, and the variable speed coupling are chosen to provide a slow coastdown of flow following loss of power to the drive motors, so that the core is adequately cooled during the transient.

The reactor recirculation pump motors are totally enclosed air-water-cooled type induction motors. The motors are equipped with thrust and guide bearings that are self-lubricating. The Reactor Auxiliary Cooling System (RACS) that supplies cooling water to the motors and the seals is discussed in Section 9.2.8.

Pump casing and valve bodies are designed for a 40-year life and are welded into the piping system with no plans to remove them from the system for maintenance or overhaul. Removable parts of the pump such as wear rings, impellers, bearings, etc, are designed for as long a life as practical, and as a design objective, they have a life between overhaul or major maintenance cycle of more than 5 years. Pump seals and valve packings are expected to have a useful service life in excess of one refueling cycle, in order to allow convenient replacement during the refueling outage.

The recirculation system piping is of all-welded construction and is designed and constructed to meet the requirements of ANSI B31.7 and of the ASME B&PV Code Section III, Class 1. Design codes and standards are discussed in Section 3.2.

The Reactor Recirculation System pressure boundary equipment is designed as Seismic Category I, as discussed in Section 3.2.1.

Snubbers located at the top of the motor and at the bottom of the pump casing are designed to provide restraint for the pump/motor set during a seismic event.

The recirculation piping, valves, and pumps are supported by hangers to avoid the use of piping expansion loops that are required if the pumps are anchored. In addition, the recirculation loops are provided with a system of restraints designed so that reaction forces associated with the postulated pipe breaks do not jeopardize primary containment integrity. This restraint system provides adequate clearance for normal thermal expansion movement of the loop. In addition, two A/E designed pipe whip restraints are designed to absorb the impact energy of the pipe during the postulated pipe breaks without jeopardizing the integrity of primary containment. A more detailed discussion of the recirculation piping restraints can be found in Section 3.6.

The recirculation system piping, valves, and pump casings are covered with thermal insulation having a total maximum heat transfer rate of 65 $Btu/h/ft^2$ with the system at rated operating conditions.

The insulation consists of blankets of fiberglass wool covered by fiberglass cloth sheets. Blankets are secured by means of a hook and loop system, i.e., nylon loop and stainless steel hooks. The insulation is prefabricated into components for field installation. Removable insulation is provided at various locations to permit periodic inspection of the equipment.

5.4.1.4 Safety Evaluation

Reactor recirculation system malfunctions that pose threats of damage to the fuel barrier are described and evaluated in Section 15, where it is shown that none of the malfunctions result in significant fuel damage. The recirculation system has sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients.

The core flooding capability of a jet pump design plant is discussed in detail in the Emergency Core Cooling Systems (ECCS) document filed with the NRC as a GE topical report, Reference 5.4-1. The ability to reflood the boiling water reactor (BWR) core to the top of the jet pumps is shown schematically on Figure 5.4-5 and discussed in Reference 5.4-1.

Piping and pump design pressures for the reactor recirculation system are based on peak steam pressure in the reactor dome, appropriate pump head allowances, and the elevation head above the lowest point in the recirculation loop. Piping and related equipment pressure parts are chosen in accordance with applicable codes. Use of the listed code design criteria ensures that a system designed, built, and operated within design limits has an extremely low probability of failure caused by any known failure mechanism. Applicable code design criteria is listed in Section 3.9.3.

GE purchase specifications require that the recirculation pumps' first critical speed not be less than 130 percent of operating speed. Calculations are reviewed by GE design engineering.

GE purchase specifications require that integrity of the pump case be maintained through all transients and that the pump remain operable through all normal and upset transients. The design of the pump and motor bearings are required to be such that dynamic load capability at rated operating conditions is not exceeded during the safe shutdown earthquake (SSE). Calculation submittal is required.

Pump overspeed occurs during the course of a loss-of-coolant accident (LOCA) due to blowdown through the broken loop pump. Design studies, found in Reference 3.5-1, have determined that the overspeed is not sufficient to cause destruction of the motor, consequently no provision is made to decouple the pump from the motor for such an event.

See Reference 5.4-4 for analysis of loss of ac power on recirculation pump seals.

5.4.1.5 Inspection and Testing

Quality control methods are used during fabrication and assembly of the reactor recirculation system to ensure that design specifications are met. Inspection and testing is carried out as described in Section 3.9. The Reactor Coolant System (RCS) is thoroughly cleaned and flushed before fuel is loaded initially.

During the preoperational test program, the reactor recirculation system is hydrostatically tested at 125 percent reactor vessel design pressure. Preoperational tests on the reactor recirculation system also include checking operation of the pumps, flow control system, and gate valves, and are discussed in Section 14.

During the startup test program, horizontal and vertical motions of the reactor recirculation system piping and equipment are observed; supports are adjusted, as necessary, to ensure that components are free to move as designed. Nuclear system responses to recirculation pump trips (RPTs) at rated temperatures and pressure are evaluated during the startup tests, and plant power response to recirculation flow control is determined.

Inservice inspection requirements for reactor recirculation pumps, valves, and piping, as well as the extent of compliance to 10CFR50.55a, are discussed in Sections 3.9.6 and 5.2.1. Nondestructive examination (NDE) requirements are covered in Section 5.2.4.

5.4.2 Steam Generators

This section does not apply to generating stations using boiling water reactors.

5.4.3 Reactor Coolant Piping

The reactor coolant piping is discussed in Sections 3.6.2, 3.9.1, 3.9.2, 3.9.3, and 5.4.1. The recirculation loops are shown on Figure 5.4-1 and Plant Drawing M-43-1. The design characteristics are presented in Table 5.4-1. Avoidance of stress corrosion cracking is discussed in Section 5.2.3.

5.4.4 Main Steam Line Flow Restrictors

5.4.4.1 Safety Design Bases

The main steam line flow restrictors are designed:

1. To limit the loss of coolant from the reactor vessel following a steam line rupture outside the containment to the extent that the reactor vessel water level remains high enough to provide cooling within the time required to close the main steam isolation valves (MSIVs).

2. To withstand the maximum pressure difference expected across the restrictor, following complete severance of a main steam line.

3. To limit the amount of radiological release outside of the drywell prior to MSIV closure.

4. To provide a trip signal for MSIV closure.

5.4.4.2 Description

A main steam line flow restrictor, as shown on Figure 5.4-6, is provided for each of the four main steam lines. The restrictor, which is located in the drywell, is a complete assembly, welded into the main steam line.

The restrictor limits the coolant blowdown rate from the reactor vessel in the event a main steam line break occurs outside the containment to the maximum (choke) flow of 7.16 x 10^6 lb/h at 1,020 psig upstream pressure. The restrictor assembly consists of a venturi type nozzle insert welded, in accordance with applicable code requirements, into the main steam line. The flow restrictor is designed and fabricated in accordance with Reference 5.4-2.

The flow restrictor has no moving parts. Its mechanical structure can withstand the velocities and forces associated with a main steam line break. The maximum differential pressure is conservatively assumed to be 1375 psi, the limit pressure of the reactor vessel according to the ASME B&PV Code.

The ratio of venturi throat diameter to steam line inside diameter of approximately 0.55 results in a maximum pressure differential (unrecovered pressure) of about 11.6 psig at 100 percent of rated flow. This design limits the steam flow in a severed line to less than 170 percent rated flow, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow to initiate closure of the MSIVs when the steam flow exceeds preselected operational limits.

5.4.4.3 Safety Evaluation

In the event a main steam line should break outside the containment, the critical flow phenomenon would restrict the steam flow rate in the venturi throat to 170 percent of the rated value. Prior to isolation valve closure, the total coolant losses from the vessel are not sufficient to cause core uncovering; consequently, the core remains adequately cooled.

Analysis of the steam line rupture accident, as discussed in Section 15.6.4, shows that the core remains covered with water and that the amount of radioactive materials released to the environs through the main steam line break does not exceed the guideline values of published regulations.

Tests on a scale model determined final design and performance characteristics of the flow restrictor. The characteristics include maximum flow rate of the restrictor corresponding to the accident conditions, unrecoverable losses under normal plant operating conditions, and discharge moisture level. The tests showed that flow restriction at critical throat velocities is stable and predictable.

The steam flow restrictor is exposed to steam of about 0.2 percent moisture flowing at velocities from 173 ft/s (steam piping inside diameter) to 580 ft/s (steam restrictor throat). ASTM A351 (Type 304) cast stainless steel was selected for the steam flow restrictor material because it has excellent resistance to erosion-corrosion in a high velocity steam atmosphere. A protective surface film forms on the stainless steel, which prevents any further surface attack. This film is not removed by the high velocity steam.

Hardness has no significant effect on erosion-corrosion. For example, hardened carbon steel or alloy steel erodes rapidly in applications where soft stainless steel is unaffected.

Surface finish has a minor effect on erosion-corrosion. If very rough surfaces are exposed, the protruding ridges or points will erode more rapidly than a smooth surface. Experience shows that a machined or ground surface is sufficiently smooth and that no detrimental erosion will occur.

5.4.4.4 Inspection and Testing

Because the flow restrictor forms a permanent part of the main steam line piping and has no moving components, no testing program is planned. Only very slow erosion occurs with time, and such a slight enlargement has no safety significance. Stainless steel resistance to erosion has been substantiated by turbine inspections at the Dresden Unit 1 facility, which revealed no noticeable effects from erosion on the stainless steel nozzle

partitions. The Dresden inlet velocities are about 300 ft/s, and the exit velocities are 600 to 900 ft/s. However, calculations show that, even if the erosion rates are as high as 0.004 in./yr, after 40 years of operation the increase in restrictor choked flow rate would be no more than 5 percent. A 5 percent increase in the radiological dose calculated for the postulated main steam line break accident is not significant.

5.4.5 Main Steam Line Isolation System

5.4.5.1 Safety Design Bases

The main steam isolation valves (MSIVs), individually or collectively:

1. Close the main steam lines within the time established by design basis accident (DBA) analysis to limit the release of reactor coolant.

2. Close the main steam lines slowly enough so that simultaneous closure of all steam lines will not induce transients that exceed the nuclear system design limits.

3. Close the main steam line when required despite single failure in either valve or in the associated controls, to provide a high level of reliability for the safety function.

4. Use separate energy sources as the motive force to close independently the redundant isolation valves in the individual main steam lines.

5. Use local stored energy (compressed air and/or springs) to close at least one isolation valve in each main steam line without relying on the continuity of any variety of electrical power to furnish the motive force to achieve closure.

6. Close the main steam lines, either during or after seismic loadings, to ensure isolation if the nuclear system is breached.

7. Have capability for testing, during normal operating conditions, to demonstrate that the valves will function.

5.4.5.2 Description

The Main Steam Line Isolation System consists of the following:

1. Two isolation valves (MSIVs) welded in a horizontal run of each of the four main steam pipes with one valve as close as possible to the inside of the drywell and the other as close as possible to the outside of the primary containment

2. One main steam line stop valve (MSSV) welded in a horizontal run of each of the main steam pipes downstream and as close as possible to the outboard isolation valve (Non-Nuclear Steam Supply System (NSSS) scope of supply)

The MSIVs form a process barrier for pipe breaks both outside and inside the primary containment barrier. The MSSV is a remote manually motor operated valve and performs no active safety function. The general requirements for the MSSV are discussed in Sections 3.2 and 5.4.12.

Figure 5.4-7 shows an MSIV. Each is a 26-inch, Y-pattern globe valve. Rated steam flow through each valve is 4.34×10^6 lb/h. The main disk or poppet, hangs on the lower end of the

stem. Normal steam flow tends to close the valve, and higher inlet pressure tends to hold the valve closed. The bottom end of the valve stem closes a small pressure balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve differential pressure forces on the poppet. Valve stem travel is sufficient to give flow areas past the wide open poppet that are greater than the seat port area. The poppet travels approximately 90 percent of the valve stem travel to close the main seat port area. Approximately the last 10 percent of valve stem travel closes the pilot valve. The gas cylinder actuator can open the poppet with a maximum differential pressure of 200 psi across the isolation valve in a direction that tends to hold the valve closed.

The 45-degree angle permits the inlet and outlet passages to be streamlined; this minimizes pressure drop during normal steam flow and helps prevent debris blockage. The pressure drop at 102 percent of rated thermal power (3917 MWt) is 9 psid, maximum. The valve stem penetrates the valve bonnet through a stuffing box that has a set of replaceable packing. The MSIVs have leakoff drain lines that have closed isolation valves. The leakoff drain lines on the outboard MSIVs are capped downstream of the closed isolation valves.

A gas cylinder operator with a hydraulic dashpot that controls the valve closing speed is attached to the upper end of the stem to open and close the valve. The speed is adjusted by a valve in the hydraulic return line bypassing the dashpot piston. Valve closing time is adjustable to between 3 and 10 seconds.

The gas cylinder operator is supported on the valve bonnet by an actuator support and spring guide shafts. Helical springs around the spring guide shafts close the valve if gas pressure is insufficient to hold the valve open. The motion of the spring seat member actuates switches in the near open and near closed valve positions.

The valve is operated by pneumatic pressure and by the action of compressed springs. The pneumatic pressure is operated by a cylinder operator. This control unit consists of two solenoid valves, energized by ac from bus A and ac from bus B, that open and close the main valve, and a third solenoid valve that exercises the main valve at low speed. Remote switches in the control room enable the operator to operate the valves.

Operating air is supplied to the outboard MSIVs from the compressed air system. The inboard MSIVs are supplied from the Primary Containment Instrument Gas System, which gets nitrogen from the containment. An accumulator between the control valve and a check valve provides backup operating gas.

Each valve is designed to accommodate saturated steam at plant operating conditions, with a moisture content of approximately 0.25 percent, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm. The valves are furnished in conformance with a design pressure and temperature rating in excess of plant operating conditions to accommodate plant overpressure conditions.

In the worst case, if the main steam line should rupture downstream of the valve, steam flow would quickly increase to approximately 170 percent of rated flow. Further increase is prevented by the venturi flow restrictor inside the primary containment.

During approximately the first 75 percent of closing, the poppet has little effect on flow reduction because the flow is choked by the valve seat. After the valve is approximately 75 percent closed, flow is reduced as a function of the valve curtain area versus travel characteristic.

The design objective for the valve is a minimum of 40 years of service at the specified operating conditions. Operating cycles,

excluding exercise cycles, are estimated to be 50 cycles per year during the first year and 20 cycles per year thereafter.

In addition to the minimum wall thickness required by applicable codes, a minimum corrosion allowance of 0.120 inch is added to provide for 40 years of service.

Design specification ambient conditions for normal plant operation are 150°F maximum temperature and 100 percent humidity, in a radiation field of 15 rad/h gamma and 25 rad/h neutron plus gamma, continuous for design life. The inboard valves are not continuously exposed to maximum conditions, particularly during reactor shutdown, and valves outside the primary containment are in ambient conditions that are considerably less harsh.

The environmental conditions, both normal and abnormal, to which the MSIVs are exposed, are further discussed in Section 3.11. MSIV qualification to these environments is also discussed in Section 3.11.

The MSIVs are designed to close under accident environmental conditions and they are designed to remain closed under post-accident environment conditions.

To sufficiently resist the response motion from the safe shutdown earthquake (SSE), the MSIV installations are designed as Seismic

Category I equipment. The valve assembly is manufactured to withstand the SSE forces applied at the mass center of the extended mass of the valve operator, assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are assumed to act simultaneously. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress for this combination of loads is based on a percentage of the allowable yield stress for the material. The parts of the MSIVs that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as required by the 1968 Edition of the Draft Nuclear Pump and Valve Code. Design codes and standards are discussed in Section 3.2.

The MSIV compliance with the requirements of 10CFR50, Appendix A, General Design Criteria 54 is discussed in Section 6.2.4.

5.4.5.3 Safety Evaluation

In a direct cycle nuclear power plant, the reactor steam goes to the turbine and to other equipment outside the containment. Radioactive materials in the steam could escape to the environs through process openings like leaks in the steam system or through pipe breaks or failure of the integrity of the components. A large break in the steam system could drain the water from the reactor core faster than it is replaced by feedwater.

The analysis of a complete, sudden steam line break outside the containment is described in Section 15.6.4, Accident Analyses. The analysis shows that the fuel barrier is protected against loss of cooling if the MSIV closure is within 5.5 seconds, including instrumentation delay to initiate valve closure after the break. The calculated radiological effects of the radioactive material assumed to be released with the steam are shown to be well within the guideline values for such an accident.

The shortest closing time (approximately 3 seconds) of the MSIVs is also demonstrated to be satisfactory, as discussed in Section 15.2.4. The switches on the valves initiate reactor scram when specific conditions, e.g., extent of valve closure, number of steam lines included, and reactor power level, are exceeded. See Section 7.2.1 for more detail. The pressure rise in the system from stored and decay heat may cause the nuclear system relief valves to open briefly, but the rise in fuel cladding temperature is insignificant. No fuel damage results.

The ability of this 45-degree, Y-design globe valve to close in a few seconds after a steam line break, under conditions of high pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of dynamic tests. A full size, 20-inch valve was tested in a range of steam water blowdown conditions simulating postulated accident conditions. See Reference 5.4-3 for more detail.

The following minimum specified hydrostatic, leakage, and stroking tests are performed by the valve manufacturer in shop tests:

1. To verify its capability to close at settings between 3 and 10 seconds, with response time for full closure set prior to plant operation at 3 seconds minimum and 5 seconds maximum, each valve is tested at a rated pressure of 1000 psig, and no flow. The valve is stroked several times, and the closing time is recorded. The valve is closed by spring only and by the combination of gas cylinder and springs. The closing time is slightly greater when closure is by springs only.

2. Leakage is measured with the valve seated and backseated. The specified maximum seat leakage, using cold water at design pressure, is 2 cm^3/h/in. of nominal valve size. In addition, an air seat leakage test is conducted using 50 psi pressure upstream. Maximum permissible leakage is 0.1 scf/h/in. of nominal valve size. There must be no visible

leakage from either set of stem packing at hydrostatic test pressure. The valve stem is operated a minimum of three times from the closed position to the open position, and the packing leakage still must be zero by visual examination.

3. Each valve is hydrostatically tested in accordance with the requirements of the applicable edition and addenda of the Draft Nuclear Pump and Valve Code. During valve fabrication, extensive nondestructive tests and examinations are conducted. Tests include radiographic, liquid penetrant, or magnetic particle examinations of casting, forgings, welds, hardfacings, and bolts.

4. The spring guides, the guiding of the spring seat member on support shafts, and rigid attachment of the seat member ensure correct alignment of the actuating components. Binding of the valve poppet in the internal guides is prevented by making the poppet in the form of a cylinder longer than its diameter and by applying stem force near the bottom of the poppet.

After the valves are installed in the nuclear system, each valve is tested as discussed in Section 14.

Two isolation valves provide redundancy in each steam line so that either one can perform the isolation function, and either one can be tested for leakage after the other is closed. The inboard valve, the outboard valve, and their respective control systems are separated physically. The main steam stop valve (MSSV) backs up both isolation valves and provides redundant volumes for seal air.

The design of the MSIV has been analyzed for earthquake loading. The cantilevered support of the gas cylinder, hydraulic cylinder, springs, and controls is the key area. The increase in loading caused by the specified earthquake loading does not result in

stresses exceeding material allowables, or prevent the valve from closing as required.

Electrical equipment that is associated with the isolation valves and operates in an accident environment is limited to the wiring, junction box, terminal blocks, solenoid valves, and position switches on the isolation valves. The expected pressure and temperature transients following an accident are discussed in Section 15.

The MSIV control system is discussed in Sections 7.2.1 and 7.3.1.

5.4.5.4 Inspection and Testing

The MSIVs can be functionally tested for operability during plant operation and refueling outages. The test provisions are listed below. During refueling outages, the MSIVs can be functionally tested, leak tested, and visually inspected.

During plant operation, the MSIVs can be tested and exercised individually to the 87 percent open position and still pass rated steam flow.

The MSIVs can also be tested and exercised individually to the fully closed position if reactor power is reduced sufficiently to avoid scram from reactor overpressure or high flow through the other steam line flow restrictors.

Leakage from the valve stem packing can be detected during reactor operation from measurements of leakage into the drywell, or from observations or similar measurements in the steam tunnel, as discussed in Section 9.3.3. During shutdown, while the nuclear system is pressurized, the leak rate through the inner packing can be measured by collecting and timing the leakage. Leakage through the inner packing can be collected from the packing drain line.

The MSIVs perform containment isolation functions and are required to meet specific leakage testing requirements. See Section 6.2.4.4 for discussion of MSIV leak testing.

During prestartup tests following an extensive shutdown, the valves receive the same hydrotests, at approximately 1000 psi, that are imposed on the primary system.

Such a test and leakage measurement program ensures that the valves are operating correctly and that a leakage trend is detected.

5.4.6 Reactor Core Isolation Cooling (RCIC) System

5.4.6.1 Design Bases

The Reactor Core Isolation Cooling (RCIC) System is a safety-related system consisting of a steam turbine, turbine driven pump, piping, valves, controls, and instrumentation designed to ensure that sufficient reactor water inventory is maintained in the reactor vessel to allow for adequate core cooling. This prevents reactor fuel from overheating during the following conditions:

1. When the vessel is isolated and maintained in the hot standby condition.

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

3. When a complete plant shutdown is started under conditions of loss of the normal feedwater system and before the reactor is depressurized to the level for the operation of the shutdown cooling system.

Following a reactor scram, steam generation continues at a reduced rate due to the core fission product decay heat. At this time, the Turbine Bypass System diverts the steam to the main condenser, and the feedwater system supplies makeup water required to maintain reactor vessel inventory.

In the event that the reactor vessel is isolated, and the feedwater supply is unavailable, main steam safety/relief valves (SRVs) are provided to automatically or remote-manually maintain reactor pressure within prescribed limits by relieving steam to the suppression pool. The reactor water level drops due to continuous steam generation by decay heat and release of steam through the SRVs. Upon reaching a predetermined low water level, the RCIC system is initiated automatically. The turbine driven pump supplies demineralized makeup water from the condensate storage tank (CST) to the reactor vessel. Suppression pool water is available as an alternate source. The RCIC system includes an automatic switchover feature that will change the pump suction from the CST to the suppression pool. The safety-grade switchover will automatically occur upon receipt of a low level signal from the CST. Suppression pool water is not maintained as demineralized water, but is demineralized water when added. The turbine is driven by a portion of the decay heat steam from the reactor vessel, and exhausts to the suppression pool.

During RCIC operation, the suppression pool serves as the heat sink for steam generated by reactor decay heat. This results in a rise in pool water temperature. The RHR heat exchangers are used to maintain the suppression pool temperature within acceptable limits by cooling the pool water.

5.4.6.1.1 Residual Heat and Isolation

5.4.6.1.1.1 Residual Heat

The RCIC system is designed to initiate and, within 30 seconds, discharge a specified constant flow into the reactor vessel over a specified pressure range. The temperature of the RCIC water discharged into the reactor varies from 40°F up to and including 140°F. The mixture of the cool RCIC water and the hot steam results in the following:

1. Quenches the steam

2. Removes reactor residual heat

3. Replenishes the reactor vessel inventory.

The High Pressure Coolant Injection (HPCI) System can perform these same RCIC functions, thereby providing single failure protection. Both systems use different electrical power sources of high reliability that permit operation with either onsite or offsite power. In addition, the RHR system performs its residual heat removal function.

The RCIC system design includes interfaces with redundant leak detection devices. The steam supply to the RCIC steam turbine is automatically isolated upon the receipt of any one of the following leak detection signals:

1. A high differential pressure across a flow device in the steam supply line equivalent to 300 percent of the steady state steam flow at 1135 psia operating through a time delay relay set at between 3 and 13 seconds to prevent spurious trips during system startup.

2. A high area temperature, using temperature switches as described in the Leak Detection System (High area temperature is also alarmed in the main control room).

3. High pressure between the turbine exhaust rupture diaphragms signaled by pressure sensors.

4. Low reactor pressure of 50 psig minimum.

The trip settings for the plant leak detection system have been established based on the need to alarm and/or isolate a specified system when required, while at the same time, avoiding an inadvertent isolation when the system is needed. The calculations performed to determine the leak detection instrumentation setpoints considered, among other things, room volume, leakage rate, normal

and minimum room temperatures and differential temperature, and purpose of the setpoint (i.e.; alarm function only, or alarm and isolation).

The equipment area high temperature setpoint for RCIC isolation is significantly above the normal maximum room temperature. This avoids inadvertent isolation when the system is needed. The differential temperature setpoint for isolation of RCIC is large enough to avoid inadvertent isolation if the ventilation supply to the room is at the minimum normal temperature and the room is at the maximum normal temperature.

The instrument setpoints for the isolation of RCIC are provided in the HCGS Technical Specifications.

Other isolation bases are defined in Section 5.4.6.1.2. The leak detection devices are activated by the redundant power supplies. These devices and control logic satisfy the requirements of General Design Criterion (GDC) 54.

5.4.6.1.1.2 Isolation

Isolation valve arrangements include the following:

1. Two RCIC lines penetrate the reactor coolant pressure boundary (RCPB). The first is the RCIC steam line, which branches off one of the main steam lines between the reactor vessel and the main steam isolation valve (MSIV). This line has two automatic motor operated isolation valves. One is located inside and the other is outside primary containment. An automatic motor operated inboard RCIC isolation bypass valve is used. The isolation signals noted earlier close these valves. The above arrangement satisfies GDC 55 for RCPB lines penetrating containment.

2. The RCIC pump discharge line is the other line; however, it indirectly penetrates the reactor pressure vessel (RPV). This line enters the main feedwater line, described elsewhere, which provides required isolation valves inside the primary containment.

3. The RCIC turbine exhaust line vacuum breaker system line has two automatic motor operated valves and two check valves. This line runs between the suppression pool air space common with the HPCI turbine exhaust line vacuum breaker system and the RCIC turbine exhaust line downstream of the exhaust line check valve. Positive isolation is automatic via a combination of low reactor pressure and high drywell pressure. The design satisfies GDC 56 for primary containment isolation.

   The vacuum relief valve complex is placed outside primary containment due to the more desirable environment. The valves are readily accessible for maintenance and testing.

4. The RCIC pump suction line, minimum flow pump discharge line, and turbine exhaust line all penetrate the primary containment and are submerged in the suppression pool. The isolation valves for the lines are all outside primary containment and require remote manual operation except the minimum flow valves, which actuate automatically. Additionally, the turbine gland seal system vacuum pump discharges into the suppression pool below normal water level after penetrating the primary containment. The isolation valve for the line is located outside the primary containment and requires remote-manual operation. This arrangement satisfies GDC 57 for primary containment isolation.

5.4.6.1.2 Reliability, Operability, and Manual Operation

5.4.6.1.2.1 Reliability and Operability

As shown in Table 3.2-1, the RCIC system components are designed to criteria commensurate with their relative safety importance. Each component is individually tested to confirm compliance with system requirements. The system is tested as a whole during both the preoperational and startup phases of the plant to set a base mark for system reliability. Functional and operability testing is performed periodically to confirm that the system maintains this base mark.

A design flow functional test of the RCIC system can be performed during normal plant operation by drawing suction from the CST and discharging through a full flow test return line to the CST. The isolation valve, E51-HV-F013, in the pump discharge to the feedwater line, remains closed during testing, and reactor operation remains undisturbed. All components of the RCIC system are capable of undergoing individual functional testing during normal plant operation. The system control logic provides automatic alignment from test to operating mode if system operation is required. However, operator action is needed to return from test mode for the following exceptions:

1. The automatic/manual switch on the flow controller is in manual. This feature is provided to allow the operator to directly control the turbine governor control valve and thereby control the system flow rate.

2. The steam supply inboard and outboard isolation valves, E51-HV-F007 and E51-HV-F008, are closed. Closure of either one or both of these valves requires operator action to properly sequence their opening. A system level alarm sounds in the control room when either of these valves leaves the full-open position.

3. Portions of the system may be bypassed or deliberately rendered inoperable. These conditions are automatically indicated in the control room at the system level. The capability for manual initiation of system level indication exists for portions of the system that are not automatically indicated.

See Section 5.4.6.2.4 for more detail on system reliability.

5.4.6.1.2.2 Manual Operation

In addition to the automatic operational features, provisions are included for remote-manual startup, operation, and shutdown of the RCIC system where initiation or shutdown signals do not exist.

5.4.6.1.3 Loss of Offsite Power

The RCIC system electrical power is obtained from a highly reliable source that is maintained by either onsite or offsite power. Refer to Sections 5.4.6.1.1 and 5.4.6.2.4. For further details, see Sections 8.2 and 8.3.

5.4.6.1.4 Physical Damage

The system is designed to meet the requirements of Table 3.2-1 commensurate with the safety importance of the system and its equipment. Moreover, the RCIC is located in a physically different area of the reactor building, a Seismic Category I structure, and uses different divisional power and separate electrical routings from its redundant system, HPCI, as discussed in Sections 5.4.6.1.1 and 5.4.6.2.4. Further discussion can be found in the sections listed below:

1. Protection from wind and tornado effects - Section 3.3

2. Flood design - Section 3.4

3. Missile protection - Section 3.5

4. Protection against dynamic effects associated with the postulated rupture of piping - Section 3.6

5. Seismic events - Section 3.7

6. Environmental design - Section 3.11

7. Fire protection - Section 9.5.1.

5.4.6.1.5 Environment

The RCIC system is designed to operate for the time intervals and the environmental conditions specified in Section 3.11.

5.4.6.2 System Design

5.4.6.2.1 General Description

A summary description of the RCIC system is presented in Section 5.4.6.1, which defines the system functions and components in general terms. A detailed description of the system, its components, and operation follows.

5.4.6.2.1.1 Diagrams

The following diagrams show details of the RCIC system:

1. Piping and instrumentation diagrams (P&IDs), Plant Drawings M-49-1 and M-50-1, show all system components, piping, points where interface systems and subsystems tie together, and instrumentation and controls associated with subsystem and component actuation.

2. A schematic process diagram, Figure 5.4-10, shows temperatures, pressures, and flow rates for RCIC operation and system hydraulic requirements.

5.4.6.2.1.2 Interlocks

The following defines the various electrical interlocks:

1. There are four keylocked switches controlling valves - E51-HV-F007, E51-HV-F008, E51-HV-F059, and E51-HV-F060; and two keylocked resets, the "isolation resets," E51-HS-S16 and E51-HS-S25.

2. E51-HV-F031's limit switch actuates when the valve is fully open and closes E51-HV-F010 and E51-HV-F022.

3. E51-HV-F059's limit switch activates when the valve is fully open and clears a permissive signal so E51-HV-F045 can open.

4. E51-HV-F045's limit switch actuates when E51-HV-F045 is not fully closed and energizes, (1) a 15-second time delay for low pump suction pressure trip and (2) a time delay relay which initiates the reopening of E51-HV-F045.

   E51-HV-F045's externally mounted limit switch interrupts the opening of E51-HV-FD45 upon an initiation signal. After the time relay times out E51-HV-F045 fully opens.

5. E51-HV-F045's limit switch activates when the valve is fully closed and permits E51-HV-F004, E51-LV-F005, E51-HV-F025, and E51-HV-F026 to open. E51-HV-F045’s limit switch activates when E51-HV-F045 opens (field set) to initiate the startup ramp function and open E51-SV-F019/4405.

6. The turbine trip throttle valve (part of E51-C002) limit switch activates when fully closed and closes E51-SV-F019/4405.

7. The combined pressure switches at reactor low pressure and high drywell pressure, when activated, closes E51-HV-F062 and E51-HV-F084.

8. High turbine exhaust pressure, low pump suction pressure, or an isolation signal actuates and closes the turbine trip throttle valve. When the signal is cleared, the trip throttle valve must be reset from the control room.

   The receipt of a high water level signal actuates and closes the steam supply valve, thus terminating RCIC flow, but permitting auto restart without resetting the turbine trip throttle valve.

9. Overspeed of 121 percent trips the mechanical trip at the turbine, which closes the trip throttle valve. The mechanical trip is reset at the turbine.

10. An isolation signal closes E51-HV-F007, E51-HV-F008, E51-HV-F076, and other valves as noted above in items f. and h.

11. An initiation signal opens E51-HV-F010 (if closed), E51-HV-F013, and E51-HV-F045; starts the barometric condenser vacuum pump; and closes E51-HV-F022.

12. High and low inlet RCIC steam line drain pot levels, respectively, open and close E51-LV-F054.

13. The combined signal of low flow plus pump discharge pressure opens and, with increased flow, closes E51-SV-F019/4405. See also items 5. and 6. above.

5.4.6.2.2 Equipment and Component Description

5.4.6.2.2.1 Design Conditions

Operating parameters for the components of the RCIC system are shown on Figure 5.4-10. The RCIC components are:

1. One 100 percent capacity turbine and accessories

2. One 100 percent capacity pump assembly and accessories

3. Piping, valves, and instrumentation for:

    a. Steam supply to the turbine

    b. Turbine exhaust to the suppression pool

    c. Makeup supply from the CST to the pump suction

    d. Makeup supply from the suppression pool to the pump suction

    e. Pump discharge to the feedwater line, feedwater spray nozzle, including a test line to the CST; a minimum flow bypass line to the suppression pool, and a coolant water supply to accessory equipment.

4. One line fill jockey pump, and associated piping, valves, and instrumentation.

5.4.6.2.2.2 Design Parameters

Design parameters for the RCIC system components are listed below. See Plant Drawings M-49-1 and M-50-1 for cross-reference of component numbers listed below:

1. RCIC pump operation (E51-C001)

Flow rate

Injection flow	600 gpm
Cooling water flow	16 gpm
Total pump discharge (includes no margin for pump wear)	616 gpm

Water temperature range	40 to 140°F
Net positive suction head (NPSH) required	20.3 feet minimum at 4650 rpm
NPSH available as suction from suppression pool	23.9 feet minimum
NPSH available as suction from CST	57.3 feet minimum [Ref. Calc. BD-0001, Rev. 4]
Developed head	2801 feet at 4650 rpm, 1156 psia reactor pressure 482 feet at 2150 rpm, 165 psia reactor pressure
Brake horsepower (BHP)	663 hp at 2801-foot head 98 hp at 482-foot head
Design pressure	1280 psig
Design temperature	140°F

2. RCIC condenser vacuum pump

Flow rate	17 cfm
Process fluid temp	70°F
Discharge pressure	15 psig
BHP	3 hp
Design pressure	15 psig
Design temperature	212°F

3. RCIC barometric condenser

Design pressure	50 psig
Design temperature	650°F

4. RCIC condenser vacuum tank

Design pressure	15 psig
Design temperature	212°F

5. RCIC condensate pump

Flow rate	23 gpm
Process fluid temperature	70°F
Discharge pressure	50 psig
BHP	3 hp
Design pressure	50 psig
Design temperature	212°F

6. RCIC suction strainer

Maximum flow rate (with 50 percent strainer plugged)	600 gpm
Pressure drop (with 50 percent strainer plugged)	1 foot

7. RCIC turbine operation (E51-C002)

	High Pressure Condition	Low Pressure Condition
Reactor pressure (saturation temperature)	1156 psia	165 psia
Steam inlet pressure	1141 psia	150 psia
Turbine exhaust pressure	15 to 25 psia	
Design inlet pressure	1250 psig at saturated temperature	
Design exhaust pressure	165 psig at saturated temperature	

8. RCIC orifice sizing

   a. Coolant loop orifice (E51-D009) - Sized with piping arrangement to ensure maximum pressure of 75 psia at the lube oil cooler inlet, and a minimum pressure of 45 psia at the spray nozzles on the barometric condenser.

   b. Minimum flow orifice (E51-D005) - Sized with a piping arrangement to ensure minimum flow of 100 gpm with E51-HV-F019 fully open.

   c. Test return orifice (E51-D006) - Sized with a piping arrangement to simulate the pump discharge pressure required when the RCIC system is injecting design flow with the reactor vessel pressure at 165 psia.

d. Leakoff orifices (E51-D008 and E51-D010) - Sized for 1/8-inch diameter.

e. Steam exhaust drain pot orifice (E51-D004) - Sized for 1/8-inch diameter.

f. Jockey pump minimum flow orifice (FE-4274) - Sized for minimum jockey pump flow and located in a pipe run of sufficient length to act as a heat sink, permitting continuous jockey pump operation without pump overheating.

9. Valve operation requirements

a. Steam supply valve (E51-HV-F045) - Opens or closes against full pressure within 15 seconds. An adjustable time delay temporarily interrupts the opening of E51-HV-F045 during the RCIC initiation.

b. Pump discharge valves (E51-HV-F012 and E51-HV-F013) - Open or close against full pressure within 15 seconds.

c. Pump minimum flow bypass valve (E51-SV-F019/4405) - Open or close against full pressure within 5 seconds.

d. Steam supply isolation valves (E51-HV-F007 and E51-HV-F008) - Close against full pressure at a minimum rate of 12 in./min.

e. Cooling water pressure control valve (E51-PCV-F015) - Self-contained downstream sensing control valve capable of maintaining constant downstream pressure of 75 psia.

f. Pump suction relief valve (E51-PSV-F017) - 100 psig relief setting; 10 gpm at 10 percent accumulation.

g. Cooling water relief valve (E51-PSV-F018) - Sized to prevent overpressurizing piping, valves, and equipment in the coolant loop in the event of failure of pressure control valve, E51-PCV-F015.

h. Pump test return valve (E51-HV-F022) - Capable of throttling against 1339 psi differential pressure.

i. Relief valve barometric condenser (E51-PSV-F033) - SRV capable of retaining 10 inches of mercury vacuum at 140°F ambient, with a set pressure of 5 to 7 psig and a flow of 20 gpm at 25 percent accumulation.

j. Turbine exhaust isolation valve (E51-HV-F059) - Opens or closes against 50 psi differential pressure at a temperature of 360°F. Located at the highest point in the exhaust line on a horizontal run, as close to the primary containment as practical.

k. Turbine vacuum pump discharge valve (E51-HV-F060) - Opens or closes against 50 psi pressure differential at a temperature of 360°F. Located at the highest point in the line on a horizontal run, as close to the primary containment as practical.

l. Check valve, vacuum pump discharge (FC-V010) - Located in the vacuum discharge line between the gland seal condenser and the containment isolation valve HV-F060.

m. Check valve, turbine exhaust (FC-V003) - Located at the highest point in the line on a horizontal run, with adjacent piping arranged to provide a

continuous downward slope, from the upstream side of the check valve to the turbine exhaust drain pot and downstream of the check valve to the suppression pool.

n. Vacuum breaker isolation valves (E51-HV-F062 and E51-HV-F084) - Open or close against pressure differential of 200 psi at a minimum rate of 12 in./min.

o. Vacuum relief valves (E51-PSV-F063 and E51-PSV-F064) - Open with minimum pressure drop of less than 0.5 psi across the valve seat.

p. Steam warmup line isolation valve, (E51-HV-F076) – Shall open and/or close against full pressure.

10. Rupture disk assemblies (E51-PSE-D001, E51-PSE-D002) - Used for turbine casing protection, including a mated vacuum support to prevent the rupture disk from reversing under a vacuum.

    Rupture pressure is 150 psig ~ 10 psig.
    Flow capacity is 60,000 lb/h at 165 psig.

11. CST requirements - Total reserve storage of 135,000 gallons for both HPCI and RCIC systems (see Section 9.2.6.21).

12. RCIC piping water temperature - The maximum water temperature range for continuous system operation does not exceed 140°F. However, due to potential short term operation at higher temperatures, piping expansion calculations were based on 170°F.

13. Turbine exhaust vertical reaction force - The turbine exhaust sparger is capable of withstanding a vertical

pressure unbalance of 20 psi. This pressure unbalance is due to turbine steam discharge below the suppression pool water level.

14. Ambient room conditions can be found in the Hope Creek Environmental Design Criteria (EDC), Document no. D7.5.

15. RCIC jockey pump

Flow rate	20 gpm
Process fluid temperature	140°F (continuous)
	170°F (intermittent)
Total dynamic head	232 feet
BHP	10 hp
Design pressure	150 psig
Design temperature	212°F

5.4.6.2.3 Applicable Codes and Classifications

The RCIC system components within the drywell up to and including the outer isolation valves are designed in accordance with ASME B&PV Code, Section III, Class 1. The RCIC system is also designed as Seismic Category I. The RCIC system and CST component classifications are given in Table 3.2-1.

5.4.6.2.4 System Reliability Considerations

To ensure that the RCIC operates when necessary and in time to prevent inadequate core cooling, the power supply for the system is taken from immediately available energy sources of high reliability. In the event of the loss of offsite power (LOP), dc battery supplies ensure that system operation is not affected. Added assurance is given by the capability for periodic testing during station operation. The RCIC system instrumentation has been designed so that failure of a single initiating sensor neither prevents system start nor falsely starts the system.

To ensure HPCI or RCIC availability for the operational events previously noted, the following considerations are used in the design of both systems:

1. Physical independence - The two systems are located in separate areas of the reactor building enclosure. Piping runs are separated and the water delivered from each system enters the reactor vessel through different nozzles.

2. Prime mover diversity and independence - Prime mover independence is achieved by using separate steam lines to drive the HPCI and RCIC steam turbines. In addition, separate divisions of power are used for both HPCI and RCIC systems.

3. Control independence - Control independence is secured by using different battery systems to provide control power to each system. Separate detection initiation logics are also used for each system. See Sections 7.4 and 7.6 for detailed discussion.

4. Environmental independence - Both systems are designed to meet Seismic Category I requirements. Separate auxiliary systems control the environment in the equipment rooms. See Section 9.4.2 for detailed discussion.

5. Periodic testing - A design flow functional test of the RCIC can be performed during plant operation by taking suction from the CST and discharging through the full flow test return line back to the CST. The discharge valve to the reactor feedwater line remains closed during the test, and the reactor continues to operate undisturbed by the testing. Control system design provides automatic return from the test to operating mode if system initiation is required during testing.

6. A jockey pump and associated piping, valves, and instrumentation are included in the RCIC system design in order to prevent pipe damage from water hammer in the discharge line upon system initiation. The design and function of this pump and associated piping is identical to that of the HPCI jockey pump. See Section 6.3.2 for detailed discussion.

7. General - Periodic inspections and maintenance of the turbine-pump unit are conducted in accordance with manufacturers' instructions. Valve position indication and instrumentation alarms are displayed in the control room.

Water may be trapped in the piping which carries steam to the turbine from the RCIC system if the steam isolation valves are closed or the steam drain system fails, as indicated by high drain pot water level. Both of the occurrences result in alarms to the control room, requiring operator action to correct the annunciated condition. The steam drain system in the steam supply piping to the RCIC turbine is the principal design feature for eliminating the possibility of condensate water accumulation in the steam supply piping to the RCIC turbine. This drain system is piped to the main condenser.

The administrative control regarding the opening of the steam isolation valves after closure for maintenance or isolation will include a specific procedure for eliminating accumulation of steam condensate in the steam supply piping to the RCIC turbine. Keylock switches, for opening the isolation valves, will also be administratively controlled. Operating procedures involve opening the outboard isolation valve, warming the steam line by throttling open the warm-up valve located on a 1 inch bypass line around the inboard isolation valve, and then opening the inboard isolation valve after the steam supply line has been pressurized to the same pressure as the pressure in the reactor.

By these design features, including control room alarms and administrative and procedural controls, the accumulation of steam condensate in the steam supply piping to the RCIC turbine will be virtually eliminated.

Proper sloping of the turbine exhaust line can preclude the collection of condensate in the line and eliminate the possibility of water hammer damage. HCGS provides a continuous downward slope from the upstream side of the turbine exhaust check valve to the turbine exhaust drain pot. Except for a short section of pipe immediately adjacent to the turbine exhaust check valve, which is horizontal, the remainder of the line is sloped downward to the suppression pool.

In addition, potential damage from water hammer in the RCIC turbine exhaust is prevented by the use of design features such as exhaust line vacuum breakers, a drain pot downstream of the turbine and a sparger in the turbine exhaust line in the suppression pool.

5.4.6.2.5 System Operations

Actions required for the various modes of RCIC are discussed in the following paragraphs. These actions provide a functional description of the actions which are detailed in approved plant procedures.

5.4.6.2.5.1 Automatic Operation

Automatic startup of the RCIC system due to an initiation signal from low water level in the RPV requires no operator action.

5.4.6.2.5.1.1 Aligning the System for Automatic Initiation

To ensure that automatic operation occurs, the operator verifies that the following actions have been taken to prepare the system for the Automatic Standby Mode:

1. Verify the flow controller has the correct flow setpoint and is in automatic.

2. Verify that the turbine trip throttle valve, part of E51-C002, is in the full open position.

   The trip for the turbine is a mechanical overspeed trip. The overspeed trip must be reset out of the control room at the turbine itself. Once the overspeed trip is reset, the trip throttle valve is reset. See Plant Drawings M-49-1 and M-50-1 for component identification.

3. Verify that power is available to all components.

4. Verify that the two RCIC steam isolation valves have been properly sequenced open.

5. Verify that the RCIC turbine exhaust line isolation valve and vacuum breaker valves are open.

6. Verify that the two isolation logic "reset" devices have been reset.

7. Verify that a method of "keep-fill" is in service.

8. Verify that the manual valves are positioned correctly and administratively controlled. Administrative control minimizes subsequent checks.

9. Verify that water is available in the CST.

10. Verify that the turbine and pump are ready to run as defined by the technical manuals for the turbine and pump.

5.4.6.2.5.1.2 Operation After Automatic Initiation

1. During extended periods of operation and when the normal RPV water level is reached, the HPCI system may be removed from service and RPV level maintained by manual operation of RCIC. This prevents unnecessary cycling of the two systems. Should automatic shutdown of the RCIC system occur due to high water level in the RPV, the system will automatically restart on recurrence of low water level. Trips of the RCIC system due to other conditions must be operator controlled. If the RCIC flow is inadequate, HPCI flow may be initiated manually by the operator or automatically by low RPV water level signal.

2. The flow controller setpoint is adjusted as required to maintain desired reactor water level.

3. When RCIC operation is no longer required it may be removed from service and restored to Standby IAW approved plant procedures. The following steps provide guidance on the steps that should be included in the plant procedures.

4. Close the turbine steam supply valve, E51-HV-F045.

5. Reset the turbine trip throttle valve.

6. Stop the barometric condenser vacuum pump.

7. Close the cooling water supply valve E51-HV-F046.

8. Verify that valves E51-HV-F004, E51-HV-F025, and E51-HV-F026 reopen automatically after valve E51-HV-F045 is closed. Valve E51-LV-F005 opens as required by a level signal from barometric condenser.

9. Verify that the system is in the Standby configuration as provided for in the approved plant procedures. Plant Drawings M-49-1 and M-50-1 provide a typical alignment.

5.4.6.2.5.2 Test Loop Operation

This operating mode is manually initiated by the operator and typical operator actions are described below:

1. Complete the verification of alignment for Standby Mode IAW plant procedures. Plant Drawings M-49-1 and M-50-1 provide a typical alignment.

2. To provide a flow path during turbine startup, throttle open E51-HV-F022 as directed by approved plant procedures.

3. Start the barometric condenser vacuum pump.

4. Open E51-HV-F046.

5. Open E51-HV-F045.

6. Verify that valves E51-HV-F004, E51-LV-F005, E51-HV-F025, and E51-HV-F026 are automatically closed after valve E51-HV-F045 has opened.

7. Adjust E51-HV-F022 to obtain a turbine speed as required by the approved plant IST Program.

8. While the turbine is running, check and record all parameters as required by Technical Specifications and the Plant IST Program. The following is a typical list of measured parameters:

   a. Pump suction pressure

   b. Pump discharge pressure

   c. Turbine steam exhaust pressure

   d. Turbine steam inlet pressure

   e. Pump flow

   f. Turbine speed

   g. Bearing temperatures.

9. When the test is complete shutdown the system IAW approved plant procedures.

10. When the turbine speed indicator reaches zero rpm, close E51-HV-F022 the test bypass valve to the CST.

11. Restore the system to Standby Mode IAW with approved plant procedures.

5.4.6.2.5.3 Limiting Single Failure

The most limiting single failure with the RCIC system and its HPCI backup system is the failure of HPCI. With a HPCI failure, if the capacity of the RCIC system is adequate to maintain reactor water level, the operator follows steps outlined in Section 5.4.6.2.5.1. However, if the RCIC capacity is inadequate, those steps still apply, but the operator can also initiate the ADS system described in Section 6.3.2.

5.4.6.3 Performance Evaluation

The analytical methods and assumptions in evaluating the RCIC system are presented in Section 15. The RCIC system provides the flows required from the analysis as shown on Vendor Technical Document PN1-E51-1020-0033 within a 30-second interval based upon considerations noted in Section 5.4.6.2.

5.4.6.4 Preoperational Testing

The preoperational and initial startup test program for the RCIC system is presented in Section 14.

5.4.6.5 Safety Interfaces

The non-NSSS/NSSS safety interfaces for the RCIC system are:

1. Preferred water supply from the CST

2. All associated wire, cable, piping, sensors, and valves that are outside the NSSS scope of supply

3. Air supply for solenoid actuated valves.

5.4.7 Residual Heat System

5.4.7.1 Design Bases

The Residual Heat Removal (RHR) System consists of four independent loops A, B, C and D as shown in Plant Drawing M-51-1. Each loop contains a motor driven pump, piping, valves, instrumentation, and controls. Each loop takes suction from the suppression pool and is capable of discharging water to the reactor vessel via separate low pressure coolant injection (LPCI) nozzles, or back to the suppression pool via a full flow test line. Loops A and B have heat exchangers that are each cooled by an independent loop of the Safety Auxiliaries Cooling System (SACS). In addition, the loops A and C pump discharge headers and the loops B and D pump discharge headers are each cross-tied via two manual isolation valves. The purpose of these cross-ties is to permit the use of C pump with RHR heat exchanger A and the use of D pump with RHR heat exchanger B for alternate decay heat removal. The two RHR heat exchanger loops can also take suction from the

reactor recirculation system suction or the fuel pool and can discharge into the reactor recirculation pump discharge, fuel pool cooling discharge, or to the suppression pool and drywell spray spargers. For a comparison of the HCGS RHR system with other plants of similar RHR design, see Section 1.3.

5.4.7.1.1 Functional Design Basis

The RHR system has five subsystems or modes of operation, each of which has its own functional requirements. Each subsystem is discussed separately to provide clarity.

5.4.7.1.1.1 Residual Heat Removal Mode (Shutdown Cooling Mode)

1. The functional objective of the shutdown cooling mode is to have the capability to remove decay and sensible heat from the reactor primary system so that the reactor outlet temperature is reduced to 125°F, 20 hours after the control rods have been inserted, to permit refueling when the maximum SACS water temperature is 95°F, the core is "mature", and the tubes have reached maximum design fouling. See Section 5.4.7.2.2 for exchanger design details. The capacity of the heat exchangers is such that the time to reduce the vessel outlet water temperature to 212°F corresponds to a cooldown rate in excess of 100°F per hour with both loops in service. However, the flushing operation associated with shutdown prevents attaining 212°F coolant temperature at the minimum time.

   If the flushing time is assumed to be 2 hours, the minimum time required to reduce vessel coolant temperature to 212°F is as shown on Figure 5.4-11.

   Notes:

   1) During Operational Condition 5 with the reactor cavity flooded and the spent fuel pool gates removed, alternate decay heat removal may be provided by the alternate RHR-FPCC assist mode and FPCC pumps and heat exchangers. Reactor coolant circulation will be provided by a reactor recirculation pump. This alternate decay heat removal method satisfies Technical Specification 3/4.9.11.1 action statement requirements for residual heat removal and coolant circulation requirements during refueling operations. The time after shutdown that this alternate decay heat removal method may be used or taken credit for is dependent on the reactor core and spent fuel pool total decay heat load and the SACS supply temperatures.

2) Also during Operational Condition 5, various alignments of the FPCC pumps and heat exchangers and RWCU pumps and non-regenerative heat exchanger may be used as an alternate decay heat removal method in the event that one or both of the RHR shutdown cooling loops are out of service or become inoperable. Core circulation will be provided as required. The time after shutdown when specific combinations of heat exchangers and pumps may be used is dependent on the core and spent fuel decay heat load and the SACS/RACS temperatures.

2. The design basis for the most limiting single failure for the RHR system shutdown cooling mode, is that the shutdown line can be made usable by manual action, as discussed in

Section 5.4.7.1.5, and the plant is then shut down using the capacity of a single RHR heat exchanger and related SACS water capability. Figure 5.4-12 shows the minimum time required to reduce vessel coolant temperature to 212°F using one RHR heat exchanger and allowing 2 hours for flushing.

5.4.7.1.1.2 Low Pressure Coolant Injection Mode

The functional design basis for the low pressure coolant injection (LPCI) mode is to pump a total of 10,000 gpm of water per loop, using the separate pump loops, from the suppression pool into the core region of the vessel when the vessel pressure is 20 psid over drywell pressure. Injection flow commences at 295 psid vessel pressure above drywell pressure.

The initiating signals are reactor vessel water level at level 1 or high drywell pressure as shown in the plant Technical Specifications. The pumps attain rated speed in 27 seconds and injection valves will be fully open in 40 seconds. These times include diesel generator initiation time.

5.4.7.1.1.3 Suppression Pool Cooling Mode

The functional design basis for the suppression pool cooling mode is that it has the capacity to ensure that the suppression pool temperature immediately after a blowdown does not exceed 170°F.

5.4.7.1.1.4 Containment Spray Cooling Mode

The functional design basis for the containment spray cooling mode is that there

are two redundant means to spray into the drywell and suppression pool vapor space to reduce internal pressure to below design limits.

5.4.7.1.1.5 Alternate Decay Heat Removal Mode

This mode provides an alternate method to remove reactor decay heat during the cold shutdown and refueling modes of operation. In this mode, the C RHR pump is manually cross-tied to the A RHR heat exchanger, and the C RHR pump suction is manually aligned to draw from the reactor pressure vessel. The D RHR pump can also be manually cross-tied to the B RHR heat exchanger, and the D RHR pump suction is manually aligned to draw from the reactor pressure vessel.

5.4.7.1.2 Design Basis for Isolation of RHR System from the Reactor Coolant System

The low pressure portions of the RHR system are isolated from full reactor pressure whenever the primary system pressure is above the RHR system design pressure. See Section 5.4.7.1.3 for further details. In addition, automatic isolation may occur for reasons of vessel water inventory retention, which is unrelated to line pressure rating. See Section 5.2.5 for an explanation of the Leak Detection System and the isolation signals.

The RHR pumps are protected against damage from a closed discharge valve by means of automatic minimum flow valves, which open upon low main line flow and close upon high main line flow. This function is rendered unavailable during the Shutdown Cooling, Fuel Pool Cooling Assist, and Alternate Fuel Pool Cooling Assist Modes, to prevent potential draindown from the Reactor Pressure Vessel or Spent Fuel Pool to the suppression pool. The short period of time between starting an RHR pump and establishing system flow for one of these modes will not cause any damage to the pump.

5.4.7.1.3 Design Basis for Pressure Relief Capacity

The relief valves in the RHR system are sized on the basis of either thermal relief protection or isolation valve bypass leakage capacity (i.e., excessive leakage past the isolation valves).

Valves E11-PSV-F025, -F029, -F030, are set at the design pressure specified in the process data drawing plus 10 percent accumulation. Valve E11-PSV-4425 is set at the maximum design pressure of the shutdown suction line.

Redundant interlocks prevent opening valves to the low pressure suction piping when the reactor pressure is above the shutdown range. These same interlocks initiate valve closure on increasing reactor pressure.

Interlocks are provided to prevent opening the low pressure injection valves whenever the pressure downstream of the injection valve could potentially overpressurize the low pressure piping immediately downstream of the pump.

In addition, a high pressure check valve in each discharge line to the vessel closes to prevent reverse flow from the reactor if the reactor pressure increases above the RHR system pressure. Relief valves in the discharge piping are sized to account for leakage past the check valve.

5.4.7.1.4 Design Basis with Respect to General Design Criterion 5

The RHR system for this unit does not share equipment or structures with any other nuclear unit.

5.4.7.1.5 Design Basis for Reliability and Operability

The design basis for the shutdown cooling mode of the RHR system is that this mode is controlled by the operator from the control room. The only time significant operation performed outside of the control room for a normal shutdown is that required to control flushing of the shutdown portions of the RHR system with clean water.

Two separate shutdown cooling loops are provided with the exception of the common suction line from the reactor recirculation loop. Although both loops are used for shutdown under normal circumstances, the reactor coolant can be brought to 212°F in less than 20 hours with only one loop in operation. With the exception of the shutdown suction, shutdown return, and head spray line, the entire RHR system is part of the Emergency Core Cooling System (ECCS) and the containment cooling function, and is therefore required to be designed with the redundancy, flooding protection, pipe whip protection, and power separation required of such systems. See Section 6.3 for an explanation of the design bases for ECCS systems. Shutdown suction and discharge valves are required to be powered from both offsite and standby emergency power for purposes of isolation and shutdown following a loss of offsite power (LOP). In the event either of the two shutdown supply valves, E11-HV-F008 or E11-HV-F009, fail to operate, the design basis for this plant is that an operator is sent to open the valve by hand. If this is not

feasible, the shutdown line is isolated using manual valve E11-F077 (BC-V078) shown on Plant Drawing M-51-1, and repairs are made to the shutdown valves so that they can be opened to supply shutdown suction to the RHR pumps. Residual heat is absorbed by the main condenser or by the suppression pool with pool cooling by the RHR system while repairs are in process. If the normal shutdown flow path cannot be restored or if the shutdown cooling supply and return valves isolate due to a loss of offsite power, the alternate shutdown cooling flow path discussed in Section 15.2.9 is used for plant shutdown.

5.4.7.1.6 Design Basis for Protection from Physical Damage

Evaluation of the RHR system with respect to the following areas is discussed in the following sections:

1. Protection from wind and tornado effects - Section 3.3

2. Flood design - Section 3.4

3. Missile protection - Section 3.5

4. Protection against dynamic effects associated with the postulated rupture of piping - Section 3.6

5. Seismic events - Section 3.7

6. Environmental design - Section 3.11

7. Fire protection - Section 9.5.

5.4.7.2 <u>Systems Design</u>

5.4.7.2.1 System Diagrams

All of the components of the RHR system are shown on Plant Drawing M-51-1. A description of the controls and instrumentation is presented in Section 7.3.1, Emergency Core Cooling Systems Control and Instrumentation.

The RHR process diagram, Figure 6.3-12, contains both the process diagram and process data. All of the sizing modes of the system are shown in the process data. The functional control diagram for the RHR system is provided in Section 7.3.

Interlocks are provided:

1. To prevent draining vessel water to the suppression pool during shutdown. This interlock is not available in the pump C and pump D alternate decay heat removal mode using RHR loop A to loop C cross-tie and RHR loop B to loop D cross-tie respectively. The closed position of all valves in the lines between suppression pool and pump discharge is controlled administratively prior to and during operation of the cross-tie.

2. To prevent opening vessel suction valves above the suction line design pressure or the discharge line design pressure, with the pumps at shutoff head

3. To prevent inadvertent opening of drywell spray valves while in shutdown

4. To prevent pump start when suction valve(s) are not open, with the exception of pump C alternate decay heat removal mode using RHR loop A to loop C cross-tie and pump D alternate decay heat removal mode using RHR loop B to loop D cross-tie, in which interlocks are not provided. Open position of the pump suction valves are controlled administratively for these modes of operation.

5. To prevent opening the low pressure injection valves whenever the pressure downstream of the injection valves could potentially overpressurize the low pressure piping downstream of the pump.

5.4.7.2.2 Equipment and Component Description

1. Main system pumps - The RHR main system pumps are motor driven, vertical, deepwell, can type pumps with mechanical seals and cyclone separators. The motors are air cooled by the room ventilating system. The pumps are sized on the basis of the LPCI mode A and the minimum flow mode G, shown on Figure 6.3-12. Design pressure for the pump suction structure is 220 psig, with a temperature range from 40 to 360°F. Design pressure for the pump discharge structure is 500 psig. The bases for the design temperature and pressure are maximum shutdown cut in pressures and temperature, minimum ambient temperature,

and maximum shutoff head. The pump pressure vessel is carbon steel; the shaft and impellers are stainless steel. A comparison between the available and the required net positive suction head (NPSH) can be obtained from the representative pump characteristic curve provided on Figure 6.3-13. Available NPSH is calculated according to Regulatory Guide 1.1. Additional information can be found in Section 6.3.

2. Heat exchangers - The RHR system heat exchangers are sized on the basis of the duty for the shutdown cooling mode, i.e., Mode D of the process data. All other uses of these exchangers require less cooling surface.

   Flow rates are 10,000 gpm (rated) on the shell side and 9000 gpm (rated) on the tube side, which is the SACS water side. Rated inlet temperatures are 125°F shell side and 85°F tube side. The overall heat transfer coefficient is 375 Btu/h-ft^2-°F. The exchangers contain 3550 square feet of effective surface. The design temperature range of both the shell and tube sides is 32 to 470°F. Design pressure is 450 psig on both sides. Fouling factors are 0.0005 shell side and 0.0005 tube side. The construction materials are carbon steel for the pressure vessel with 304L stainless steel tubes and stainless steel clad tube sheet.

3. Valves - All of the directional valves in the system are gate, globe, and check valves designed for nuclear service. The injection valves, reactor coolant isolation valves, and pump minimum flow valves are high speed valves, as operation for LPCI injection or vessel isolation requires. Valve pressure ratings, as necessary, provide the control or isolation function, i.e., all vessel isolation valves are rated as ASME B&PV Code, Section III, Class 1 nuclear valves rated at the same pressure as the primary system.

4. ECCS and containment cooling portions of the RHR system:

   a. The ECCS portions of the RHR system include those sections described through mode A-1 of Figure 6.3-12. The route includes suppression pool suction strainers, suction piping, RHR pumps, discharge piping, injection valves, and drywell piping into the vessel nozzles and core region of the reactor vessel.

   b. Suppression pool cooling components include pool suction strainers, suction piping, pumps, heat exchangers, and pool return lines.

   c. Containment spray components are the same as pool cooling except that the spray headers replace the pool return lines.

5. RHR suction strainers - Each of the four 24-inch RHR pump suction nozzles penetrates the torus wall at a point on the circumference 30 degrees up from the bottom of the pool. The suction nozzles extend 6 inches beyond the torus interior surface, and the strainers are mounted on top of the nozzle penetration end. Each upgraded strainer is designed to accommodate the maximum expected amount of debris at a flow of 10,500 gpm. At these limiting conditions strainer head loss will be within acceptable limits so as to maintain a positive NPSH margin. See Section 6.3.2.2.4 for a full discussion of NPSH. The strainer mesh is sized to screen out all particles greater than 0.125 inches in diameter. Particles equal to or smaller than 0.125 inches in diameter do not impair RHR pump, heat exchanger, drywell spray, and suppression pool spray performance.

   The minimum height of the suppression pool water level above the centerline of the strainer base is 11 feet 6 1/2 inches.

The RHR suction strainer details are shown on Figures 5.4-15 and 5.4-16.

5.4.7.2.3 Controls and Instrumentation

Controls and instrumentation for the RHR system are described in Sections 7.3.1 and 7.4.1.

The RHR system incorporates relief valves to prevent the components and piping from inadvertent overpressure conditions. The relief valve setpoint, capacity, and method of collection are shown in Table 5.4-2.

5.4.7.2.4 Applicable Codes and Classifications

The quality group classification and corresponding applicable codes and standards that apply to the design of the RHR system are discussed in Section 3.2.

5.4.7.2.5 Reliability Considerations

The RHR system includes the redundancy requirements discussed in Section 5.4.7.1.5. Two completely redundant loops are provided to remove residual heat, each powered from a separate emergency bus. With the exception of the common shutdown suction line, all mechanical and electrical components are separate. Either loop is capable of shutting down the reactor within a reasonable length of time.

The following design is incorporated to assure that systems connected to the RHR system do not degrade the reliability of the RHR system:

1. LPCI initiation causes automatic recovery of all required system automatic valves from any other mode to their LPCI alignment.

2. Valves are provided to isolate RHR from various other systems by the following methods:

    a. Normally closed manually operated valves are provided which require the operator to follow operating and maintenance guidelines.

    b. Normally closed remote manually motor operated valves are provided with position indication lights in the control room.

    c. Simple check valves in series with normally open stop check valves are provided.

Electrical separation is described in Section 8.1.4.

5.4.7.2.6 Manual Action

1. RHR (shutdown cooling mode) - In shutdown operation, when the vessel pressure is 100 psig or less, the RHR pump in the loop selected for shutdown cooling is started, the appropriate test return valve E11-HV-F024, is opened and the loop flushed for approximately five minutes with torus water.

    After flushing, the RHR pump is secured, E11-HV-F004 and F024 are shut, and E11-HV-F006 is opened. When reactor pressure is less than 82 psig E11-HV-F009 is opened, the RHR pump is started and E11-HV-F015 is throttled for 3000

gpm flow. After 10 minutes of flow at 3000 gpm, E11-HV-F015 is throttled open for rated flow to prevent pump runout and the cool down rate is controlled using E11-HV-F048, heat exchanger bypass flow valve. Control of cool down may also be performed by throttling E11-HV-F003 when E11-HV-F048 is fully open.

In the event that the main control room becomes uninhabitable, the RHR shutdown cooling mode can also be initiated from the remote shutdown panel (RSP) on RHR loop B (see Section 7.4.1.4). Operation from the RSP is totally operator controlled and all RHR loop B automatic initiation signals are disabled when the Channel B RSP transfer switch is placed in the "Emergency" position.

The RHR shutdown cooling mode can be manually initiated locally on RHR loop A as a backup to operation of RHR loop B from the RSP. The RHR loop A local pump and valve controls are identified on Table 7.4-3.

The manual actions required for the most limiting failure are discussed in Section 5.4.7.1.5.

2. A non-NSSS intertie between the Station Service Water System (SSWS) and the RHR system piping allows an additional source of water to flood the reactor containment during the period following a LOCA. If the operators determine that this action is desirable, manual operator action from the control room initiates reactor flooding. Refer to Section 9.2.1 for details of this intertie.

5.4.7.3 Performance Evaluation

Thermal performance of the RHR heat exchangers is based on the residual heat generated at 20 hours after rod insertion, a 125°F reactor vessel outlet (exchanger inlet) temperature, and the flow of two loops in operation. Because shutdown is usually a

controlled operation, maximum SACS water temperature (95°F) less 10°F is used as the SACS water inlet temperature, i.e., 85°F. These are nominal design conditions; if the SACS water temperature is higher, the exchanger cooldown capabilities are reduced, and the shutdown time may be longer and vice versa.

5.4.7.3.1 Shutdown with All Components Available

No typical curve is included here to show vessel cooldown temperatures versus time due to the infinite variety of such curves that may be due to:

1. Non-nuclear steam systems that may allow the main condenser to be used as the heat sink when nuclear steam pressure is insufficient to maintain steam air ejector performance

2. The condition of fouling of the exchangers

3 Operator use of one or two cooling loops

4. SACS water temperature

5. System flushing time.

Since the exchangers are designed for the fouled condition with relatively high SACS water temperature, the units have excess capability to cool when first cut in at high vessel temperatures. Total flow and mix temperature must be controlled to avoid exceeding a cooldown rate of 100°F per hour. See Section 5.4.7.1.1.1 for minimum shutdown time to reach 212°F.

5.4.7.3.2 Shutdown with Most Limiting Failure

Shutdown under conditions of the most limiting failure is discussed in Section 5.4.7.1.1.1. The capability of the heat exchanger for any time period is balanced against residual heat,

pump heat, and sensible heat. The excess over residual heat and pump heat is used to reduce the sensible heat.

5.4.7.4 Preoperational Testing

The preoperational test program and startup test program as discussed in Section 14 are used to generate data to verify the operational capabilities of each piece of equipment in the system: each instrument, each setpoint, each logic element, each pump, each heat exchanger, each valve, and each limit switch. In addition, these programs verify the capabilities of the system to provide the flows, pressures, cooldown rates, and reaction times required to perform all system functions as specified for the system or component in the system data sheets and process data. Logic elements are tested electrically. Valves, pumps, controllers, and relief valves are tested mechanically. Limit switches are tested for correct adjustment and operation. Finally, the system is tested for total system performance against the design requirements as specified above using both the offsite power and standby emergency power. Preliminary heat exchanger performance can be evaluated by operating in the pool cooling mode, but a vessel shutdown is required for the final check due to the small temperature differences available with pool cooling.

5.4.8 Reactor Water Cleanup System

The Reactor Water Cleanup (RWCU) System is classified as a primary power generation system (not an engineered safety feature), a small part of which is part of the reactor coolant pressure boundary (RCPB). Those portions of the system are not part of the RCPB and are isolable from the reactor. The RWCU system may be operated at any time during planned reactor operations, or it may be shut down if reactor coolant quality is within the limits in Section 5.2.3.2.2.2.

5.4.8.1 Design Bases

5.4.8.1.1 Safety Design Bases

The RWCU system meets the requirements of Regulatory Guides 1.26 and 1.29 (See FSAR Section 3.2) in order to:

1. Prevent excessive loss of reactor coolant

2. Prevent the excessive release of radioactive material from the reactor

3. Isolate the pumps, filter demineralizer units, and heat exchangers of the RWCU system from the RCPB.

5.4.8.1.2 Power Generation Design Bases

The RWCU system performs the following functions:

1. Removes solid and dissolved impurities from reactor coolant, and measures the reactor coolant conductivity, in accordance with Regulatory Guide 1.56.

2. Discharges excess reactor coolant during startup, shutdown, and hot standby conditions to the main condenser hotwell or the Liquid Waste Management System.

3. Minimizes temperature gradients in the main recirculation piping and in the reactor pressure vessel (RPV) during periods when the main recirculation pumps are unavailable.

4. Minimizes the RWCU system heat loss.

5. Enables the pumps and filter-demineralizers of the RWCU system to be serviced during reactor operation.

6. Prevents the standby liquid reactivity control material from being removed from the reactor coolant when required for shutdown.

7. Provides an alternate method to remove reactor decay heat during the cold shutdown and refueling modes of operation. During refueling mode, the RWCU system may be used in conjunction with the fuel pool cooling and cleanup system to dissipate reactor decay heat to the ultimate heat sink.

8. Provide a means of monitoring reactor coolant electrochemical corrosion potential and the durability of the NobleChem deposition by a Mitigating Monitoring System which taps into the RWCU suction and discharge piping.

5.4.8.2 System Description

The system takes its suction from the inlet of each reactor main recirculation pump, from the RPV bottom head drain line and from the NobleChem Mitigation Monitoring System discharge. During periods when the recirculation pumps are unavailable, suction is taken from the bottom head drain line. The reactor coolant is circulated by the cleanup pumps through the regenerative and nonregenerative heat exchangers for cooling, through the filter demineralizers for cleanup, and back through the regenerative heat exchanger for reheating. The processed reactor coolant is normally returned to the RPV via the feedwater lines. Part or all of the RWCU flow may also be diverted to the main condenser or the liquid waste management system, depending on the operational mode. A full-flow bypass line is provided around the shell side of the regenerative heat exchangers. During cold shutdown and refueling modes, the processed reactor coolant can be bypassed around the regenerative heat exchangers before returning to the RPV, thus dissipating reactor decay heat to the ultimate heat sink through the nonregenerative heat exchangers. The bypass line may also be used to maintain reactor water temperature below 200°F during reactivity testing of fuel in Operational Condition 2, start up. The RWCU system (exclusive of the filter demineralizer equipment) is shown on Plant Drawing M-44-1 and Vendor Technical Documents PN1-G33-1030-0388 and PN1-G33-1030-0389.

The major equipment of the RWCU system is located outside the drywell. This equipment includes pumps, regenerative and nonregenerative heat exchangers, and filter demineralizers with precoat equipment. Flow rate capacities for the major pieces of equipment are presented in Table 5.4-3.

The operating temperature of the filter demineralizer units is limited by the allowable resin operating temperature (140°F). Therefore, the reactor coolant must be cooled before being processed in the filter demineralizer units. The regenerative heat exchanger transfers heat from the tube side (hot process inlet) to the shell side (cold process inlet). The shell side flow returns to the reactor. The tube side flow is cooled further by the nonregenerative heat exchanger, which transfers heat to the Reactor Auxiliaries Cooling System (RACS).

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The filter demineralizer units shown on Plant Drawing M-45-1 and Figure 5.4-20 are pressure-precoat type filters using premixed Ion exchange resin and binder. The vendor verifies resin capacity and size prior to shipment. Spent resins are nonregenerable and are sluiced from the filter demineralizer units to a backwash receiving tank, from which they are transferred to the solid waste management system for disposal. To prevent resins from entering the reactor if there is failure of a filter demineralizer resin support, a strainer is installed in the effluent line of each filter demineralizer unit. High differential pressure across the strainers and filter demineralizer vessels is annunciated locally and in the main control room. If the differential pressure across a filter demineralizer vessel, or its respective effluent strainer, continues to increase beyond the alarm setpoint, the affected filter demineralizer unit is automatically isolated.

The backwash and precoat cycle for a filter-demineralizer unit is entirely automatic to preclude human operational errors, such as inadvertent opening of valves that would initiate a backwash or contaminate reactor coolant with resins. The filter demineralizer piping configuration is arranged to ensure that transfers are complete and crud traps are eliminated. A bypass line is provided around the filter demineralizer units.

If there is low flow or loss of flow in the system, flow is maintained through each filter demineralizer vessel by its own holding pump to prevent loss of filter resin.

Sample points are provided in the common influent header and in each effluent line of the filter demineralizer units for continuous indication and recording of system conductivity to ensure that the reactor coolant quality is within limits, and as a check of filter demineralizer effectiveness. High conductivity is annunciated in the control room. The control room alarm set points for conductivity at the inlet and outlet of the filter demineralizers are 1.0 μmhos/cm and 0.1 μmhos/cm, respectively. The

effluent set point indicates impending resin exhaustion, and therefore, forestalls breakthrough of solubles, usually chlorides. The influent sample point is also used as the normal source of reactor coolant grab samples. Reactor water chloride content will be determined from inline instrumentation or grab samples taken and analyzed in accordance with approved plant procedures. Additional water quality limits and corrective actions to be taken are specified in Section 5.2.3.2.2.2.

The suction line (RCPB portion) of the RWCU system contains two motor operated isolation valves, which automatically close in response to the following:

1. Reactor vessel low water level

2. Actuation of the Standby Liquid Control (SLC) System

3. Nonregenerative heat exchanger high outlet temperature (outboard isolation valve HV-F004 only)

4. High differential flow between RWCU influent and effluent

5. RWCU equipment compartment high ambient temperature

6. High differential temperature across the RWCU equipment compartment ventilation ducts.

This isolation limits the loss of reactor coolant, the release of radioactive material from the reactor, and prevents the removal of liquid reactivity control material by the RWCU system if the SLC system is operating. It also prevents degradation of the filter-demineralizer resins due to high temperature. Details of the leak detection requirements for the RWCU system are discussed in Section 7.6 and summarized in Table 5.2-10. The RCPB isolation valves can also be remote manually operated to isolate the system equipment for maintenance or servicing. The requirements for the RCPB portion of the RWCU system are specified in Section 5.2.

A remote manually operated globe valve in the return line to the reactor provides long term leakage control. Instantaneous reverse flow isolation is provided by a check valve in the RWCU return piping.

Operation of the RWCU system is controlled from the main control room. Resin changing operations, which include backwashing and precoating, are controlled from a local control panel. The time required to remove a filter demineralizer unit from the line, backwash, and precoat is less than 1 hour.

A functional control diagram for the RWCU system is provided in Vendor Technical Document PN1-G33-1020-0416.

5.4.8.3 System Evaluation

The RWCU system, in conjunction with the condensate treatment system and the fuel pool cooling and cleanup system, maintains reactor coolant quality during all reactor operating modes, i.e., normal, hot standby, startup, shutdown, and refueling.

This type of pressure precoat cleanup system was first put into operation in 1971 and is used in all operating BWR plants constructed since then. Operating plant experience has shown that a RWCU system designed in accordance with these criteria provides the required BWR coolant quality. The nonregenerative heat exchanger is sized to maintain the required process temperature for filter demineralization, even when the cooling capacity of the regenerative heat exchanger is reduced due to partially bypassing a portion of the return flow to the main condenser or the liquid waste management system. The control requirements of the RCPB isolation valves are designed to the requirements of Section 7.3.1. The component design data are presented in Table 5.4-3. All components are designed to the requirements of Section 3.2, as delineated by the system P&IDs on Plant Drawings M-44-1 and M-45-1.

5.4.8.4 SRP Rule Review

SRP 5.4.8 acceptance criterion II.1.a requires that reactor water purity be maintained in accordance with Regulatory Guide 1.56 and the Technical Specifications for water chemistry (relocated to Section 5.2.3.2.2.2). Additionally, the RWCU should provide demineralization of reactor water at approximately 1 percent of the main steam flow rate. While this rate is feasible with parallel pumps in operation, normal operation of the RWCU maintains water purity in accordance with Regulatory Guide 1.56 using less than 1 percent of the main steam flow rates.

5.4.9 Main Steam Lines and Feedwater Lines

5.4.9.1 Safety Design Bases

To satisfy the safety design bases, the main steam and feedwater lines have been designed:

1. To accommodate operation stresses such as those resulting from internal pressures and safe shutdown earthquake (SSE) loads, without a failure that could lead to the release of radioactivity in excess of the 10CFR50.67 guidelines

2. With suitable access to permit inservice testing and inspections.

5.4.9.2 Power Generation Design Bases

To satisfy the design bases:

1. The main steam lines have been designed to conduct steam from the reactor vessel over the full range of reactor power operation.

2. The feedwater lines have been designed to conduct water to the reactor vessel over the full range of reactor power operation.

5.4.9.3 Description

The main steam and feedwater piping are shown on Plant Drawing M-41-1.

5.4.9.3.1 Main Steam Lines

The main steam lines extend from the reactor vessel up to and including the outboard main steam isolation valve (MSIV), and include connected piping of 2-1/2-inch nominal diameter or larger, up to and including the first valve that is either normally closed or capable of automatic or remote manual closure during all modes of reactor operation. The portion of the piping from the outboard MSIV up to and including the main steam stop valve (MSSV) is a part of the main steam supply system (Section 10.3), but it is discussed here since it performs a safety function. The passive safety function is to provide a deposition surface to limit the release of fission products after a postulated loss-of-coolant accident, as discussed in Section 6.2.4. The MSSV performs no active safety function.

The main steam lines consist of four 26-inch pipes that penetrate the primary containment. Each line includes a steam flow restrictor and two MSIVs. The design pressure and temperature between the reactor vessel and the outboard MSIV of the main steam piping is 1250 psig and 575°F. Seismic Category I design requirements are placed on the main steam lines from the reactor vessel up to and including the MSSV and connected piping of 2-1/2-inch or larger nominal diameter, up to and including the first isolation valve in the connected piping.

The materials used in the main steam lines up to the MSSV are in accordance with the applicable code and supplementary requirements described in Sections 3.2 and 5.2.3. The general requirements of the nuclear steam supply control system are described in Section 7.

5.4.9.3.2 Feedwater Lines

The feedwater lines consist of two 24-inch outside diameter pipes that penetrate the primary containment. Each 24-inch line branches into three 12-inch lines that connect to the reactor

vessel. Each 24-inch line includes one motor operated check valve and one spring loaded, piston-actuated, check valve outside the primary containment, and one check valve and one motor operated gate valve inside the primary containment. The three check valves are isolation valves, and the motor-operated gate valve is a maintenance valve.

The design pressure and temperature of the feedwater piping between the reactor vessel and the maintenance valve is 1500 psig and 425°F. Seismic Category I design requirements are placed on the feedwater piping from the reactor vessel through the outboard isolation valve and connected piping of 2-1/2-inch or larger nominal pipe size, up to and including the first isolation valve in the connected piping.

The materials used in the piping are in accordance with the applicable design code and supplementary requirements described in Sections 3.2 and 5.2.2.

The general requirements of the feedwater control system are described in Section 7.

5.4.9.4 Safety Evaluation

Differential pressure on reactor vessel internals under the assumed accident condition of a ruptured main steam line is limited by the use of flow restrictors and by the use of four main steam lines. The main steam piping, including the section between the outboard MSIV and the MSSV, and feedwater piping is designed in accordance with the requirements defined in Section 3.2; Classification of Structures, Components, and Systems; and Section 3.6; Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping. Design of the piping in accordance with these requirements ensures meeting the safety design bases.

5.4.9.5 Inspection and Testing

Inspection and testing are carried out in accordance with Section 3.9 and Section 14. Inservice inspection is considered in the design of the main steam (including the piping between the outboard MSIV and MSSV) and feedwater piping. This consideration ensures adequate working space and access for the inspection of selected components.

5.4.10 Pressurizer

This section is not applicable to Hope Creek Generating Station (HCGS).

5.4.11 Pressurizer Relief Discharge System

This section is not applicable to Hope Creek Generating Station (HCGS).

5.4.12 Valves

See Section 1.10 for Reactor Coolant System high point vents.

5.4.12.1 Safety Design Bases

Line valves such as gate, globe, and check valves are located in the fluid systems to perform mechanical functions such as general shutoff, containment isolation, reactor coolant isolation, and backflow mitigation. Valves are components of the system pressure boundary and, having moving parts, are designed to operate efficiently to maintain the integrity of this boundary.

The valves operate under the internal pressure/temperature loading as well as the external loading experienced during the various system transient operating conditions. The design criteria, the design loading, and acceptability criteria are as required in Section 3.9.3 for ASME B&PV Code, Class 1, 2, and 3 valves.

Compliances with ASME B&PV Codes are discussed in Section 5.2.1.

5.4.12.2 Description

The line valves are manufactured standard types, designed and constructed in accordance with the requirements of ASME B&PV Code, Section III for Class 1, 2, and 3 valves. All materials, exclusive of seals, packing, and wearing components, are designed to endure throughout the 40-year plant life under the environmental conditions applicable to the particular system when appropriate maintenance is periodically performed.

Power operators have been sized to operate successfully under the maximum differential pressure across the valve seat under operation of the valve.

5.4.12.3 Safety Evaluation

Line valves have been shop tested by the manufacturer for conformity to specifications. Pressure retaining parts are subject to the testing and examination requirements of Section III of the ASME B&PV Code. To minimize internal and external leakage past seating surfaces, maximum allowable leakage rates are stated in the design specifications for both the back seat and the main seat for gate and globe valves. The functional testing of active valves is covered in Section 3.10.

Valve construction materials are compatible with the maximum anticipated radiation dosage, as listed in Section 3.11, for the service life of the valves.

5.4.12.4 Inspection and Testing

Valves serving as containment isolation valves that must remain closed or open during normal plant operation are operationally exercised as defined in Section 6.2.4 to ensure their operability at the time of an emergency or faulted condition. Preoperational

testing of valves is discussed in Section 14. Inservice testing of valves is discussed in Section 3.9.6.

Leakage from valve stems on control valves, 4 inches and larger, and block valves, 2-1/2 inches and larger, can be monitored by double packed stuffing boxes with an intermediate lantern leakoff connection for detection and measurement of leakage rates.

Motors used with valve actuators have been furnished in accordance with applicable industry standards. Each motor actuator has been assembled, factory tested, and adjusted on the valve for proper operation, position, and torque switch setting, position transmitter function (where applicable), and speed requirements. Additionally, representative valve assemblies have been statically tested to demonstrate operability during seismic and hydrodynamic events. Tests verified no mechanical damage to valve components during full stroking of the valve. Suppliers were required to furnish assurance of acceptability of the equipment for the intended service based on any combination of:

1. Test stand data

2. Prior field performance

3. Prototype testing

4. Engineering analysis.

Preoperational and operational testing performed on the installed valves consists of total circuit checkout and performance tests to verify speed requirements.

5.4.12.5 <u>SRP Rule Review</u>

SRP 5.4.12, acceptance criterion II.9 specifies that the operability of the reactor coolant ventilation system valve components be testable in accordance with subsection IWV of

Section XI of the ASME Code for Category B valves. FSAR Sections 5.4.12.4 and 5.4.13.4 discuss valves and safety/relief valve operational testing and do not specify operability testing of reactor coolant ventilation system valves as specified by criterion II.9 of SRP 5.4.12. Valves that function as containment isolation valves are exercised in accordance with the plant Technical Specifications in FSAR Chapter 16. Although no provisions are made for in-line testing of 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 the removal of the component. The reactor head ventilation valve is exercised at every startup to vent noncondensible gases from the reactor head, and no further testing of this line is anticipated. The HPCI and RCIC systems are tested monthly.

5.4.13 Safety and Relief Valves

5.4.13.1 Safety Design Bases

Overpressure protection is provided at isolable portions of the subsystems closely allied with the RCPB in accordance with the rules set forth in the ASME B&PV Code, Section III for Class 1, 2, and 3 components.

5.4.13.2 Description

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

Table 3.2-1 lists the applicable code classes for valves. The design criteria, design loading, and design procedure are described in Section 3.9.3.

5.4.13.3 Safety Evaluation

The use of pressure relieving devices ensures that overpressure does 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 is determined on this basis.

5.4.13.4 Inspection and Testing

No provisions are made for in-line testing of pressure 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. The valves will be removed periodically and bench tested in accordance with the program discussed in Section 3.9.6.

5.4.14 Component Supports

Support elements are provided for those components included in the reactor coolant pressure boundary (RCPB) and the connected systems.

5.4.14.1 Safety Design Bases

5.4.14.1.1 NSSS Safety Design Bases

Design loading combinations, design procedures, and acceptability criteria are as described in Section 3.9.3. Flexibility calculations and seismic analysis for Class 1, 2, and 3 components conform with the appropriate requirements of ASME B&PV Code, Section III.

Support types and materials used for fabricated support elements conform with Sections NF-2000 and NF-3000 of ASME B&PV Code, Section III. Pipe support spacing guidelines of Table 121.1.4 of ANSI B31.1 Power Piping Code were followed.

5.4.14.1.2 Non-NSSS Safety Design Bases

Design loading combinations, design procedures, stress analysis criteria, and acceptability criteria are performed in accordance with ASME B&PV Code, Section III, Classes 1, 2, and 3, as described in Section 3.9.3. The remainder of the plant's piping supports conform to the requirements of ANSI B31.1.

The spacing and size of pipe support elements, together with supporting engineering calculations, are based on piping stress analyses performed in accordance with ASME B&PV Code, Section III, and ANSI B31.1, as described further in Section 3.7.

Piping supports are designed as described in Section 3.9.3 and the installation of nuclear pipe support elements are in accordance with Section III, Subsection NF, of the ASME B&PV Code, 1974 issue, including Addenda through Winter 1974. The nondestructive examination (NDE) of field welds for NF support elements shall be performed using the requirements noted in Paragraph NF-5200 of Section III, of the ASME B&PV Code, 1977 issue with Addenda through Winter of 1978. The code effective date for the manufacture of home office furnished nuclear pipe support elements is the date in effect at the time of issue of the purchase orders, including the code cases referenced therein. Typical pipe support element NF boundaries are shown on Figure 5.4-21. Supplementary structural steel members outside the NF boundary are designed in accordance with ASME B&PV Code, Section III, Subsection NF and Appendix XVII. Material and welding except NDE, are specified to ASME B&PV Code requirements.

Design and installation for all other home office-furnished and field installed nonnuclear pipe supports is in accordance with the code for power piping, ANSI B31.1, 1973 issue, including Addenda through Winter 1974 (1977 Edition for the design of 2 inches and smaller pipe supports). The code effective date for fabrication of home office furnished and field installed nonnuclear support

elements is the date in effect at the time of issue of the purchase orders.

The code effective date for design, fabrication, and installation for vendor supplied and installed pipe support elements is in accordance with the vendor contract.

5.4.14.2 Description

The use and location of rigid type supports, variable or constant spring type supports, snubbers, and anchors or guides are determined by stress analysis performed on the piping system. Component standard support elements within the NF boundaries and ANSI B31.1 are manufacturers' standard items.

5.4.14.3 Safety Evaluation

Design loadings, including steady-state and transient loading conditions, are used for the determination of component support systems. Provisions are also made to prevent damage to the piping system and the spring type supports due to initial deadweight loading during hydrostatic testing.

5.4.14.4 Inspection and Testing

After installing the support system, individual component supports are visually examined and adjusted, if necessary, to the cold setting position. Component support verification is performed in accordance with the requirements of Section 14.

5.4.15 References

5.4-1 P.W. Ianni, "Effectiveness of Core Standby Cooling Systems for General Electric Boiling Water Reactors," APED-5458, General Electric, March 1968.

5.4-2 Howard S. Bean, "Fluid Meters, Their Theory and Application," Report of ASME Research Committee on Fluid Meters, Fifth Edition, 1959.

5.4-3 General Electric, Atomic Power Equipment Department, "Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves," APED-5750, March 1969.

5.4-4 General Electric, "BWR Owners' Group NUREG-0737 Implementation: Analyses and Positions Submitted to USNRC" NEDO-24951, June 1981.

TABLE 5.4-1

REACTOR RECIRCULATION SYSTEM DESIGN CHARACTERISTICS

LOOP A, B

Single loop Piping Description	Quantity	Approx Length, feet	Nominal Size, inches
Pump suction line			
Straight pipe	-	38	28
Elbows	3	-	28
Gate valves	1	-	28
Discharge line			
Straight pipe	-	22	28
Elbows	1	-	28
Gate valves	1	-	28
Discharge manifold			
Pipe	-	35	22
Reducer cross	1	-	28x22
Contour nozzle	5	-	22x12
Caps	2	-	22
External risers			
Straight pipe	-	43	12
Elbows	5	-	-

Piping description	Design Pressure, Design Temperature, psi/ °F
Suction piping and valve up to and including pump suction nozzle	1250/575

TABLE 5.4-1 (Cont)

Piping description	Design Pressure, Design Temperature, psi/ °F
Pump, discharge valves, and piping between	1500/575
Piping after discharge blocking valve up to vessel	1500/575
Vessel bottom drain	1250/575

Design values and Operational Values at 3952 MWt and 105% core flow are as follows:

Recirculation Pump	Design	3952 MWt
Flow, gpm	45,200	47,973
Flow, lb/h	$17.1x10^6$	$18.2x10^6$
Total developed head, ft	710	654
Suction pressure (static), psia	1034	1033
Required NPSH, ft	138	151
Water temperature (max), °F	540	533
Pump brake hp (min)	7050	6963
Flow velocity at pump suction, fps	28.4	30.2

Jet Pumps		
Number	20	20
Total driving flow, lb/h/jet pump	$1.76x10^6$	$1.82x10^6$
Throat inside diameter, in.	8.18	8.18
Tailpipe inside diameter, in.	19	19
Nozzle inside diameter (representative), in.	3.14	3.14
Diffuser exit velocity, fps	15	15.7
Jet pump head, ft	81.5	89.0

TABLE 5.4-1 (Cont)

Recirculation Block Valve, Discharge

Type	Gate
Actuator	Motor operator
Material	stainless steel
Valve size diameter, in.	28

Recirculation Block Valve, Suction

Type	Gate
Actuator	Motor operator
Material	stainless steel
Valve size diameter, in.	28

Pump Motor

Voltage rating	3920
Speed, rpm	1680
Motor rating, hp	7500
Phase	3
Frequency	56
Rotational inertia, $lb\text{-}ft^2$	14,710

Drive Motor and Power Supply

Frequency Hz (at rated)	56
Frequency Hz (operating range)	11.5-57.5

Total Required Power to Motor Generator Sets, kW	Design	3952 MWt
Set	7290	6352
Total	14,580	12,704

TABLE 5.4-2

RHR SYSTEM RELIEF VALVE DATA

Valve Location	Valve	Setpoint psig	Capacity[1] gpm	Method of Collection[3]
Shutdown cooling suction line (outside containment)	PSV-F029	170	10	DRW
Pump suction line	PSV-F030 A,B,C&D	170	10	DRW
Heat exchanger inlet line[4]	PSV-F055 A,B			
Heat exchanger outlet line to RCIC[4]	PSV-F097			
Pump discharge line	PSV-F025 A,B,C,D	410	10	Suppression pool
Heat exchanger (shell side)[2]	PSV-4431 A,B	450	Thermal relief only	Suppression pool
Thermal relief valve on shutdown cooling suction line (inside containment)	PSV-4425	1250	0.1	DRW
Heat exchanger vent vacuum breaker[4]	PSV-151 A,B PSV-152 A,B			

(1) Capacity is based on setpoint plus 10-percent accumulation.
(2) GE-supplied valves.
(3) DRW = dirty radwaste collection.
(4) Deactivated as a consequence of RHR steam condensing mode elimination.

TABLE 5.4-3

REACTOR WATER CLEANUP SYSTEM EQUIPMENT DESIGN DATA

System flow rate, lbm/h	133,000

<u>Main Cleanup Recirculation Pumps</u>

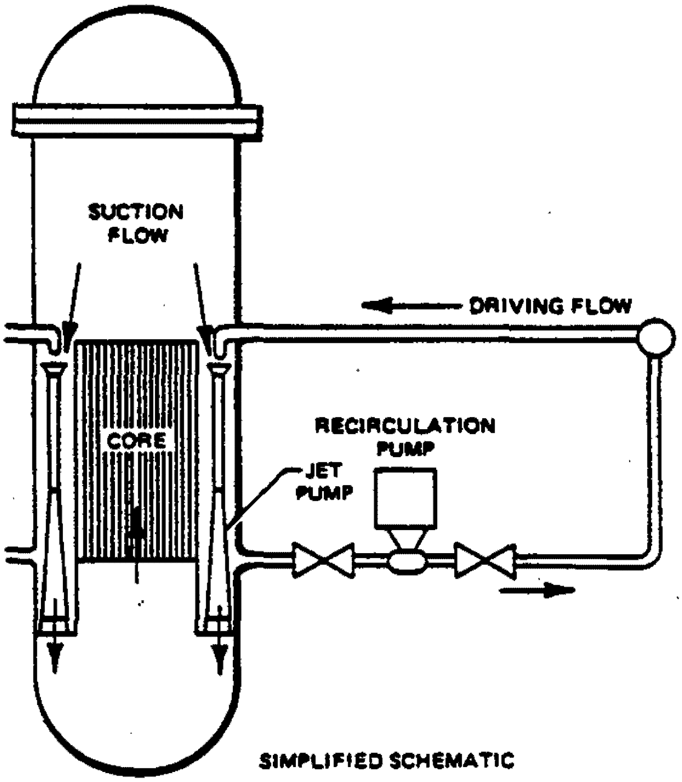
Quantity	2
Capacity each, percent	50
Design temperature, °F	575
Design pressure, psig	1400
Discharge head at shutoff, ft	600 (max)
Minimum available NPSH, ft	7.36

<u>Heat Exchangers</u>

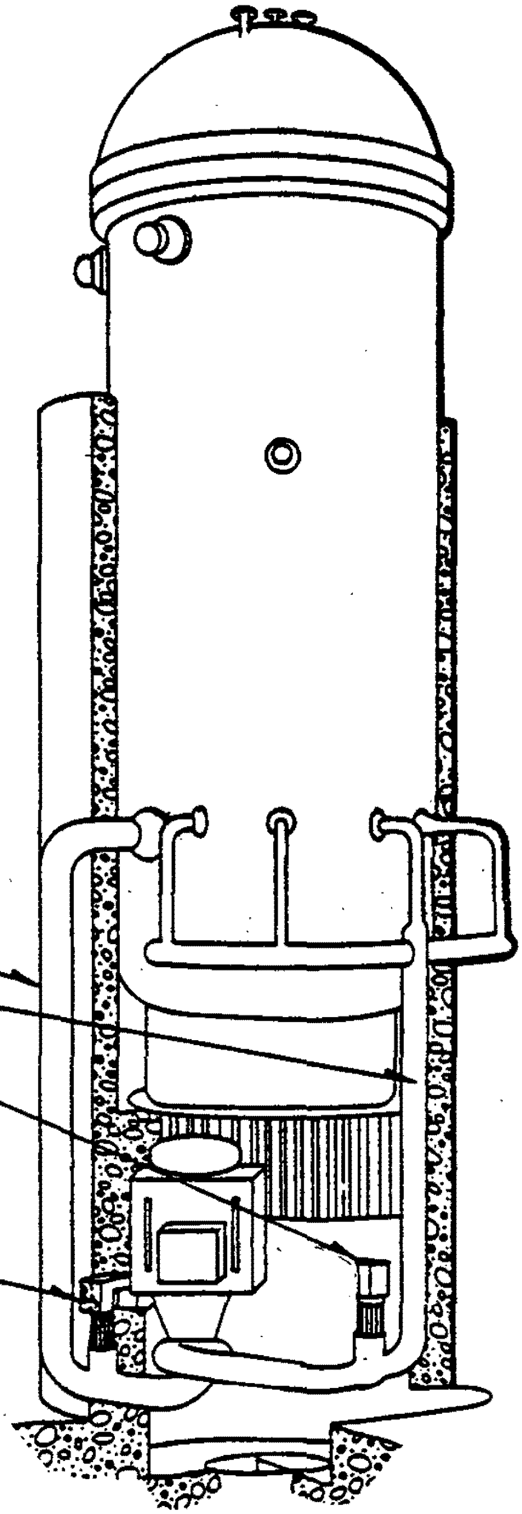
	Regenerative	Nonregenerative
Quantity	3	2
Rated capacity, percent	100	100
Shell side design pressure, psig	1450	150
Shell side design temperature, °F	575	370
Tube side design pressure, psig	1450	1450
Tube side design temperature, °F	575	575
Shell-side flow, lbm/h	133,000	256,000
Tube-side flow, lbm/h	133,000	133,000

<u>Filter-Demineralizers</u>

Quantity	2
Capacity each, percent	50
Flow/unit, lbm/h	74,000
Design temperature, °F	150
Design pressure, psig	1450



SIMPLIFIED SCHEMATIC



PICTORIAL VIEW

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

RECIRCULATION SYSTEM
ELEVATION AND ISOMETRIC

UPDATED FSAR

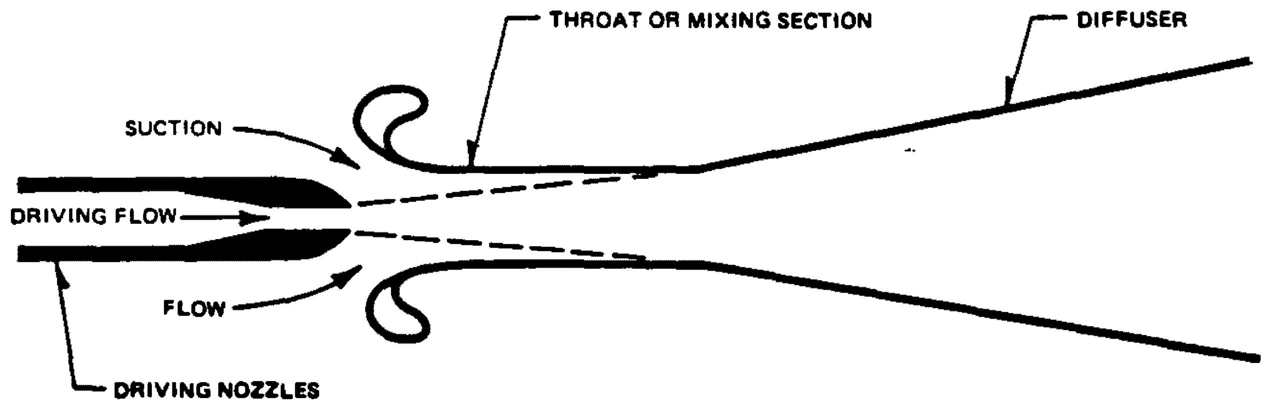
FIGURE 5.4-1

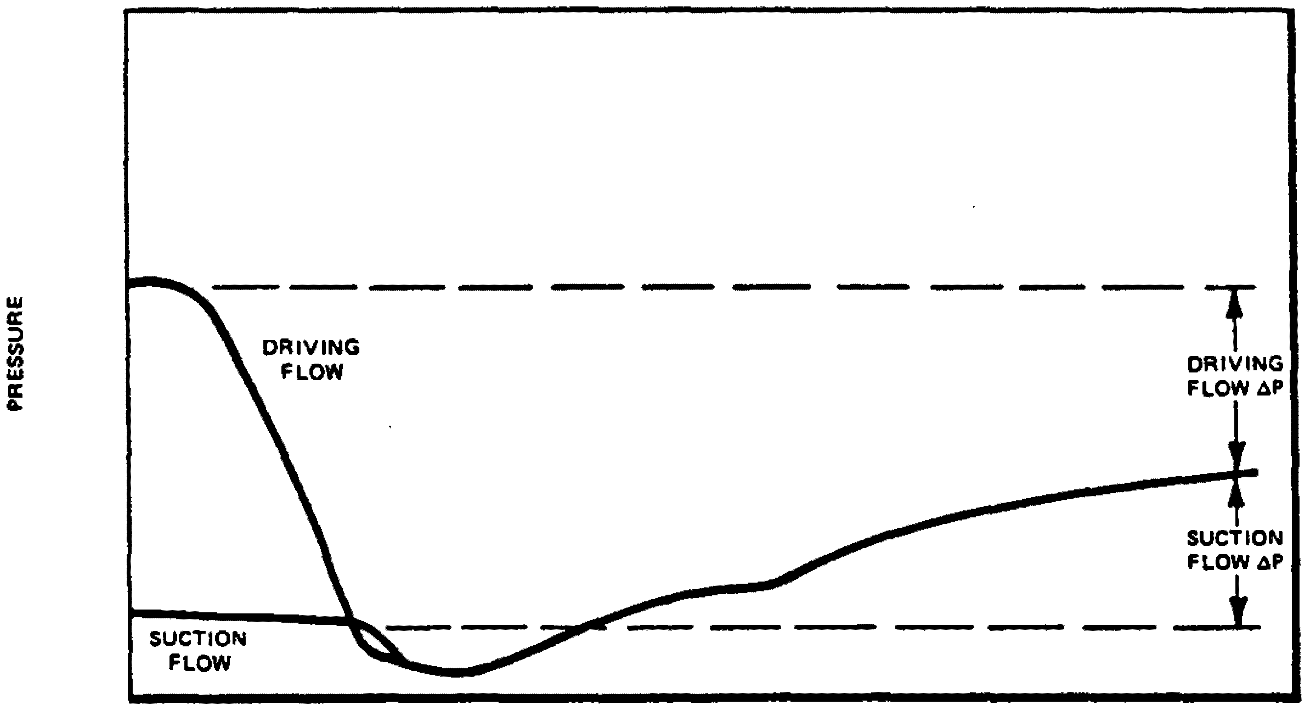
Figure F5.4-2 SH 1-2 intentionally deleted.

Refer to Plant Drawing M-43-1 for both sheets in DCRMS

Figure F5.4-3 intentionally deleted.

Refer to Vendor Technical Document PN1-B31-C001-0031 in DCRMS





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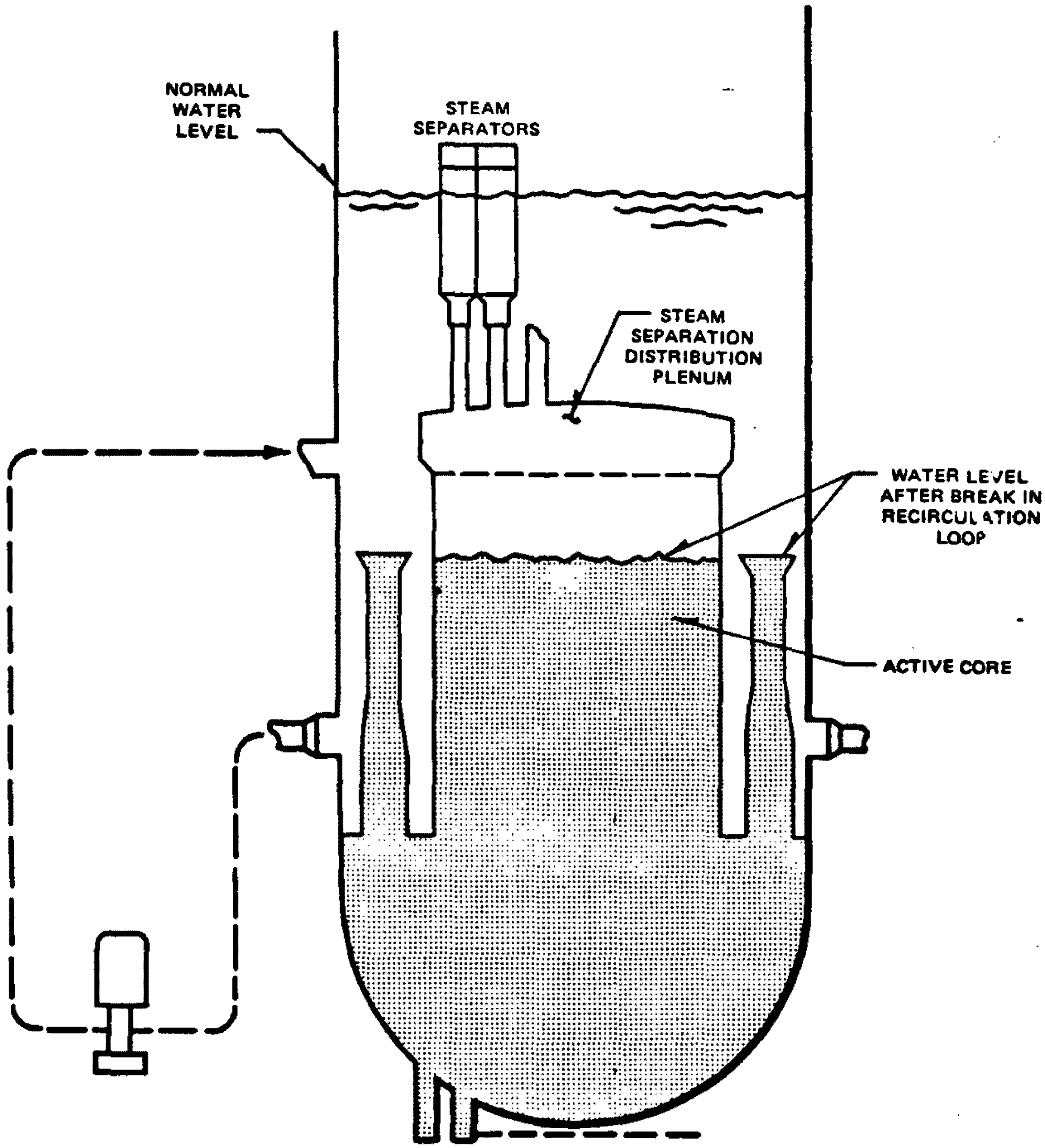
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

OPERATING PRINCIPLE
OF JET PUMP

UPDATED FSAR

FIGURE 5.4-4



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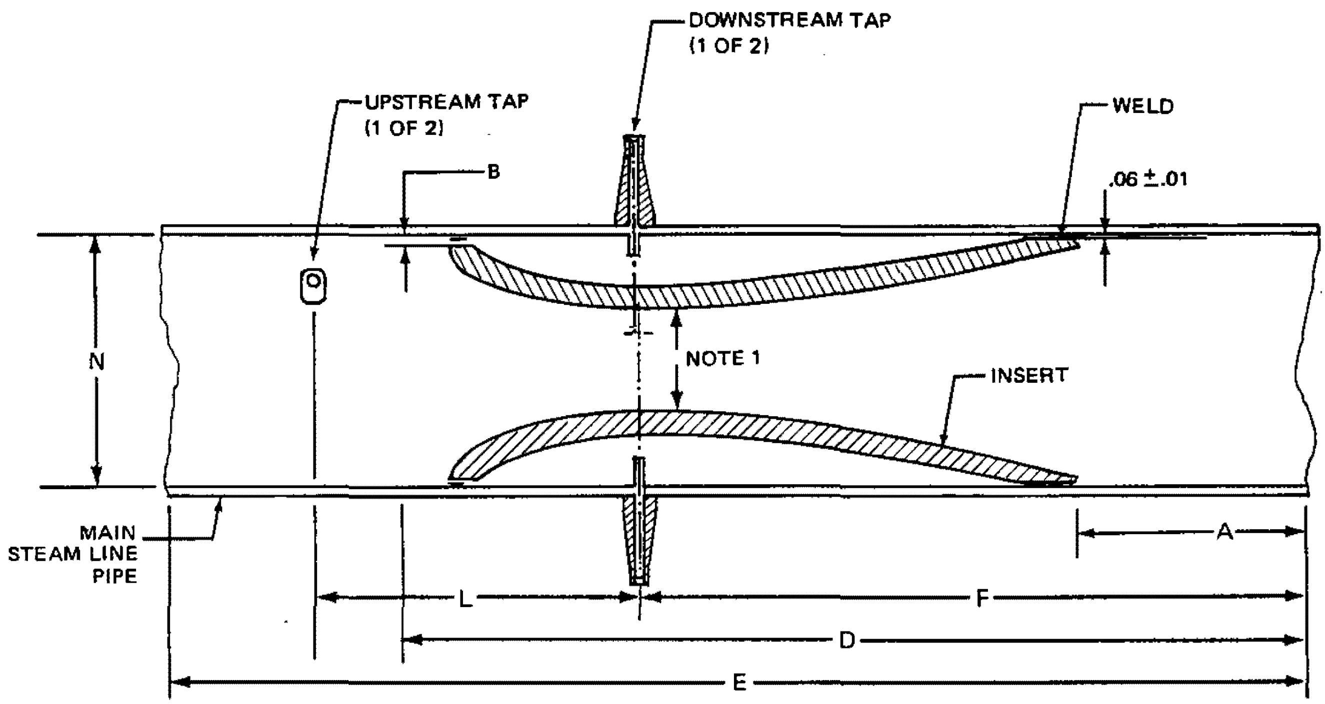
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

CORE FLOODING CAPABILITY OF RECIRCULATION SYSTEM

UPDATED FSAR

FIGURE 5.4-5



MPL No.	A ±.12	B +.012 −.000	D ±.50	E ±.12	F ±.06	L ±.06	N +0.010 −0.020	NOM PIPE SIZE	MIN WALL THICK.
B 21–NO51,54	6.00	.042	96.00	123.12	48.41	40.287	23.647	26	1.013
B 21–NO52,53	6.00	.042	96.00	149.00	48.41	40.287	23.647	26	1.013

NOTE 1: THROAT DIAMETER IS APPROXIMATELY 55% OF PIPE INSIDE DIAMETER.

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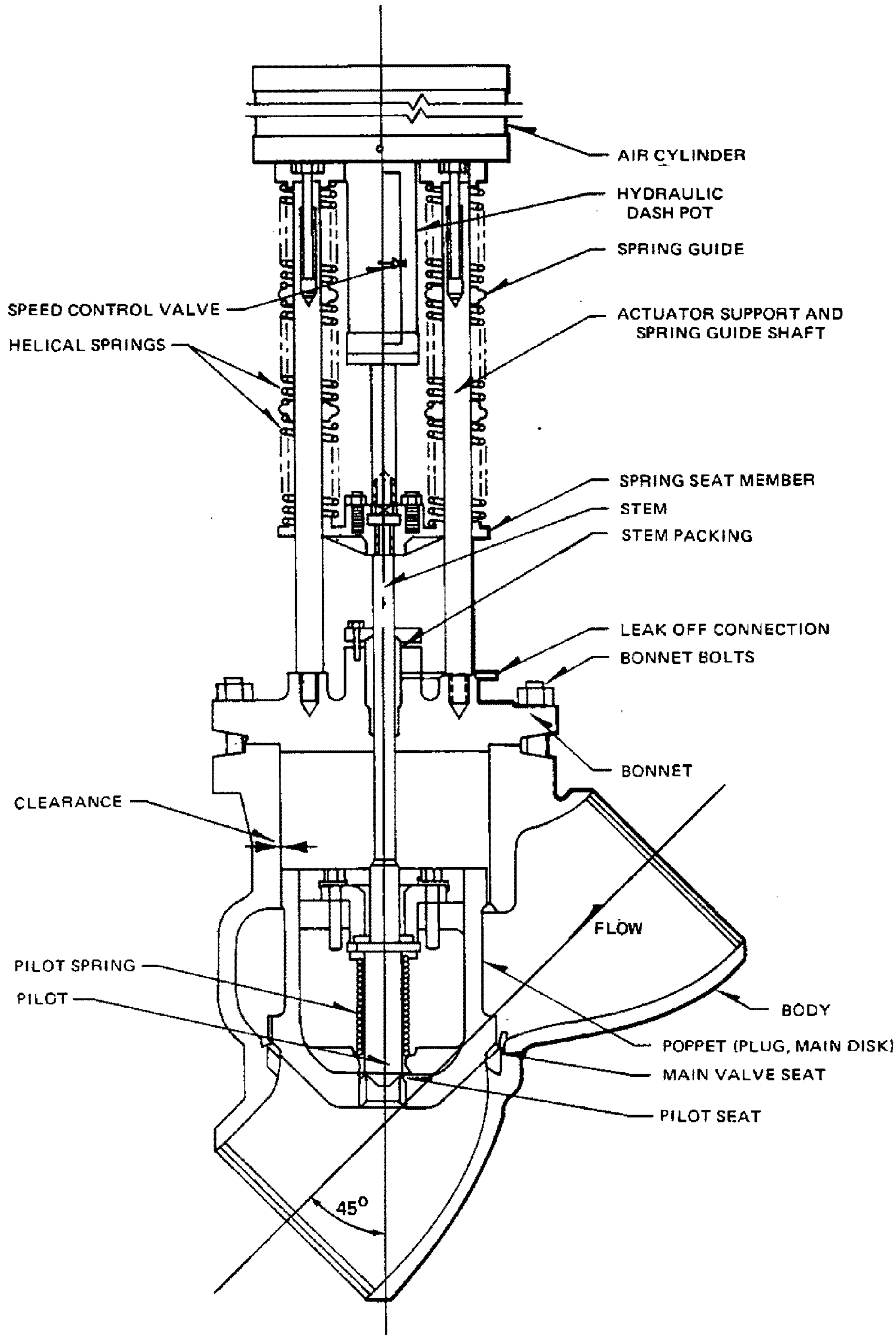
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

MAIN STEAM LINE FLOW RESTRICTORS

UPDATED FSAR

FIGURE 5.4-6



Revision 15, October 27, 2006

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station MAIN STEAM ISOLATION VALVE Updated FSAR Figure 5.4-7

Figure F5.4-8 intentionally deleted.

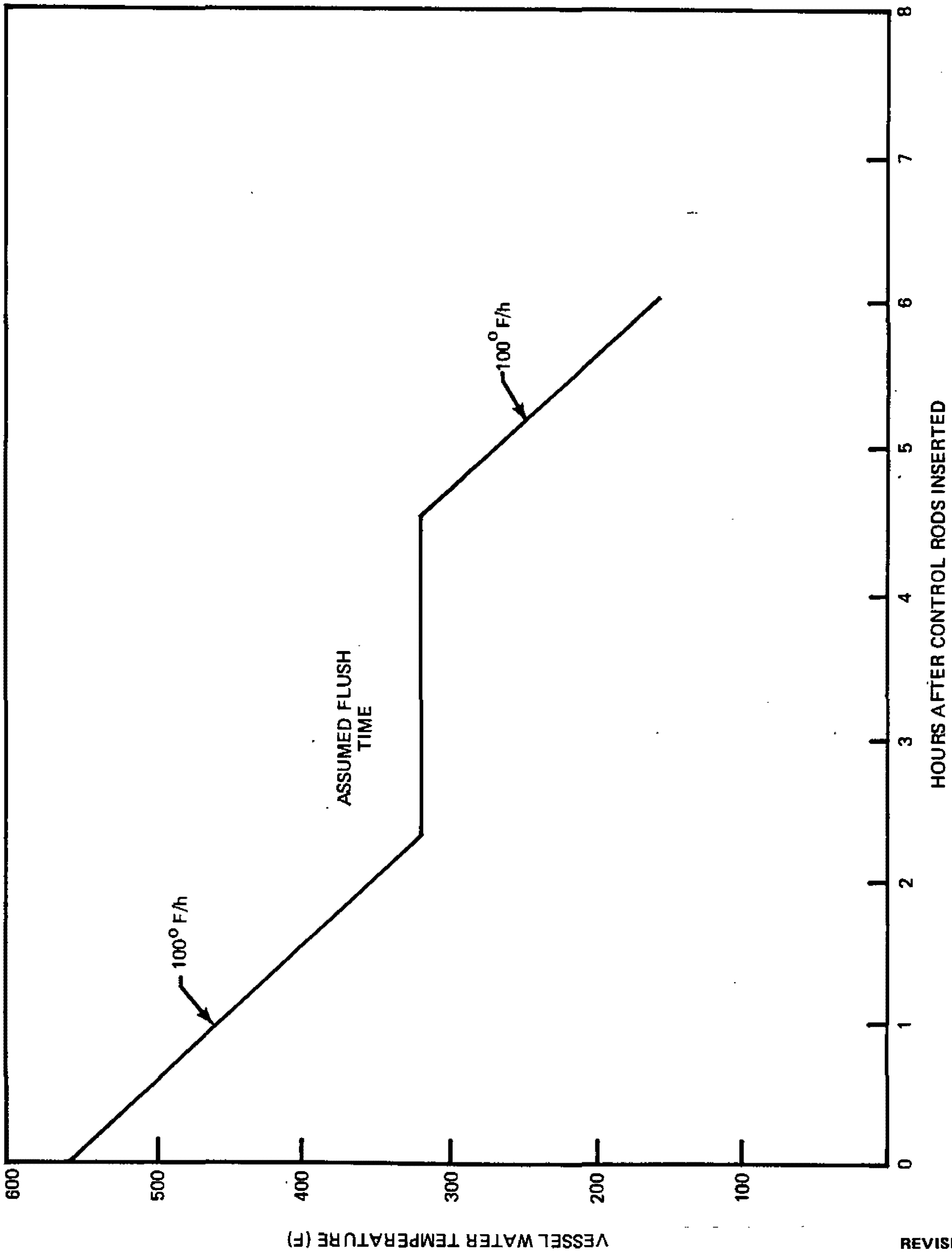
Refer to Plant Drawing M-49-1 in DCRMS

Figure F5.4-9 intentionally deleted.

Refer to Plant Drawing M-50-1 in DCRMS

Figure F5.4-10 SH 1 & 2 intentionally deleted.

Refer to Vendor Technical Document PN1-E51-1020-0033 in DCRMS



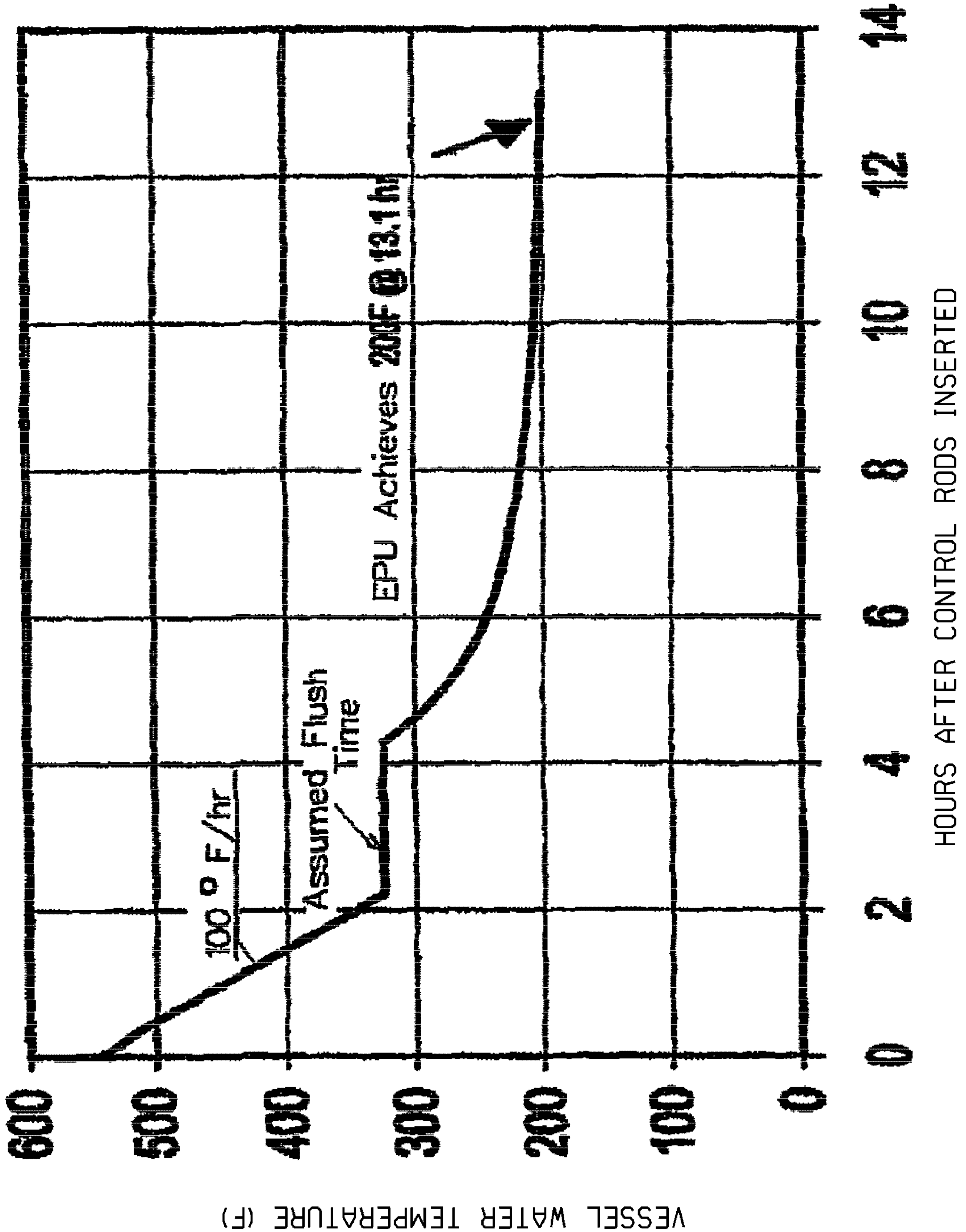
REVISION 0
APRIL 11, 1988

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

VESSEL COOLANT
TEMPERATURE vs TIME
(TWO HEAT EXCHANGERS AVAILABLE)

UPDATED FSAR

FIGURE 5.4-11



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station VESSEL COOLANT, TEMPERATURE vs TIME (ONE HEAT EXCHANGER AVAILABLE)
	Updated FSAR Figure 5.4-12

Figure F5.4-13 SH 1-2 intentionally deleted.

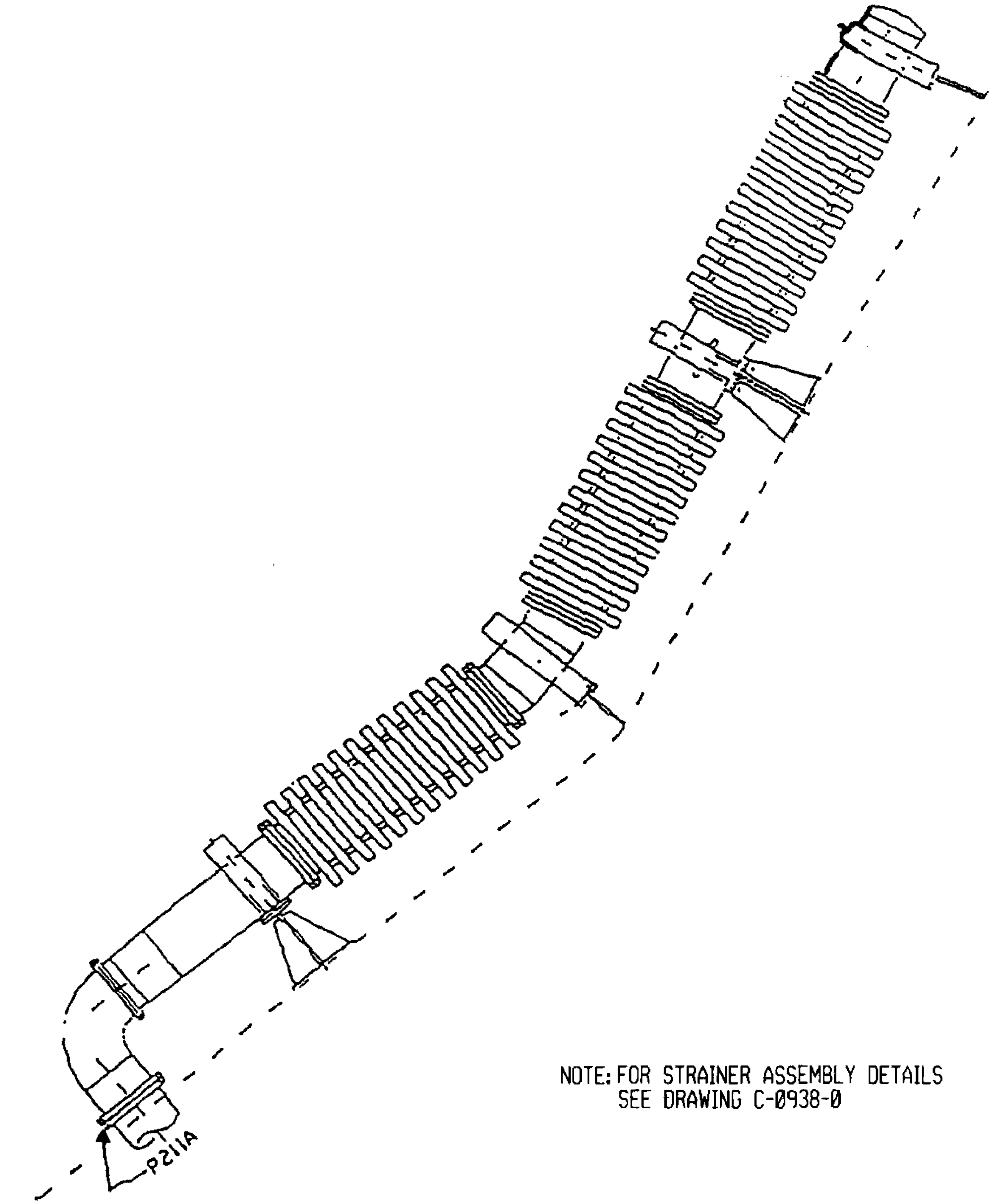
Refer to Plant Drawing M-51-1 for both sheets in DCRMS

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 11 SHEET 1 OF 1

November 24, 2000 F5.4-14



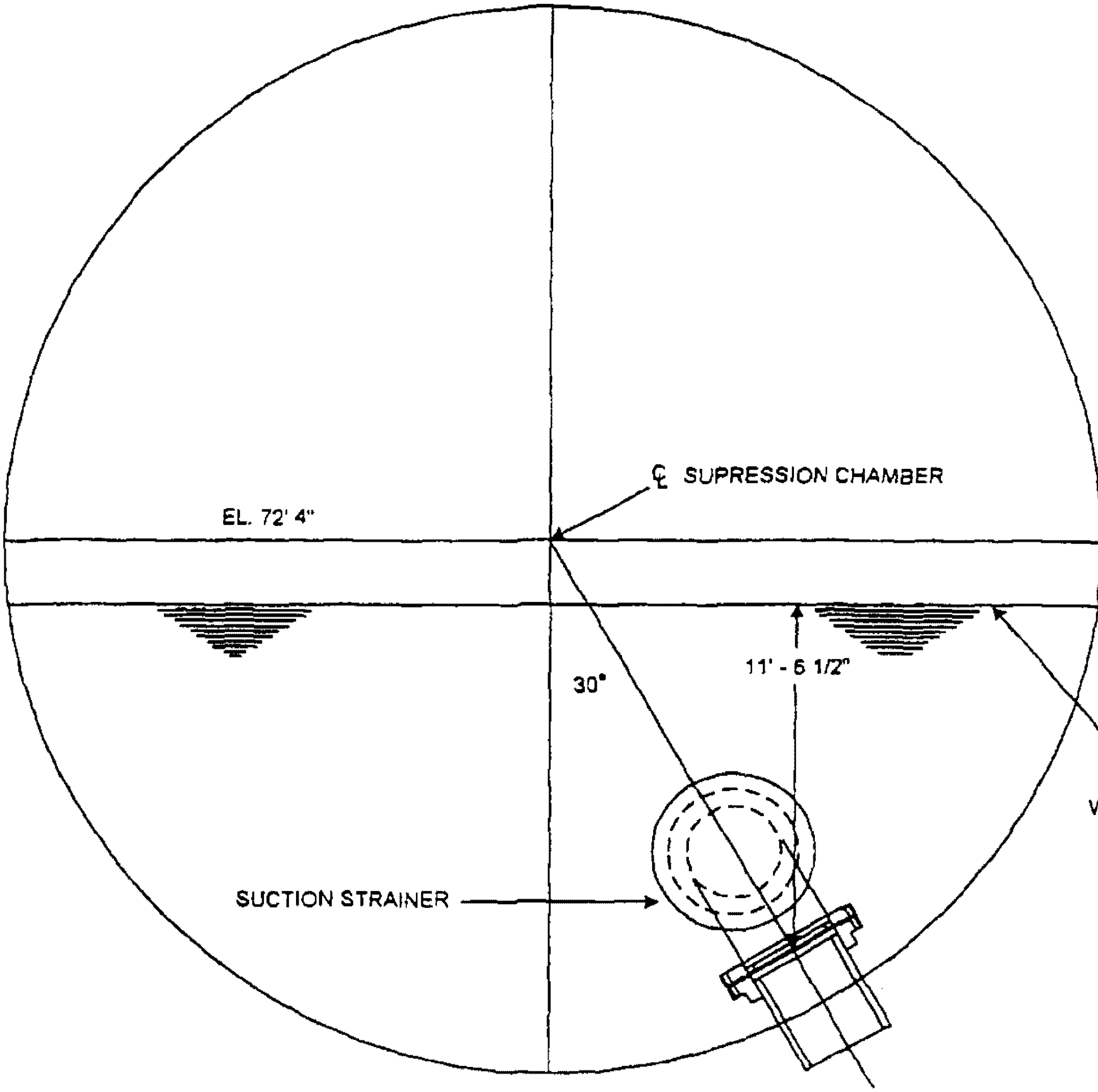
NOTE: FOR STRAINER ASSEMBLY DETAILS
SEE DRAWING C-0938-0

November 24, 2000

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station RHR SUCTION STRAINER DETAILS [REPRESENTATIVE]
	Updated FSAR - Revision 11 Figure 5.4-15

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION	
HOPE CREEK UFSAR - REV 11	SHEET 1 OF 1
November 24, 2000	F5.4-15D



NOT TO SCALE

November 24, 2000

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station RHR SUCTION STRAINER INSTALLATION DETAIL
	Updated FSAR - Revision 11 Figure 5.4-16

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C.
HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 11 SHEET 1 OF 1
November 24, 2000 F5.4-16A

THIS FIGURE HAS BEEN DELETED

PSEG NUCLEAR L.L.C. HOPE CREEK GENERATING STATION
HOPE CREEK UFSAR - REV 11   SHEET 1 OF 1 November 24, 2000   F5.4-16B

Figure F5.4-17 intentionally deleted.

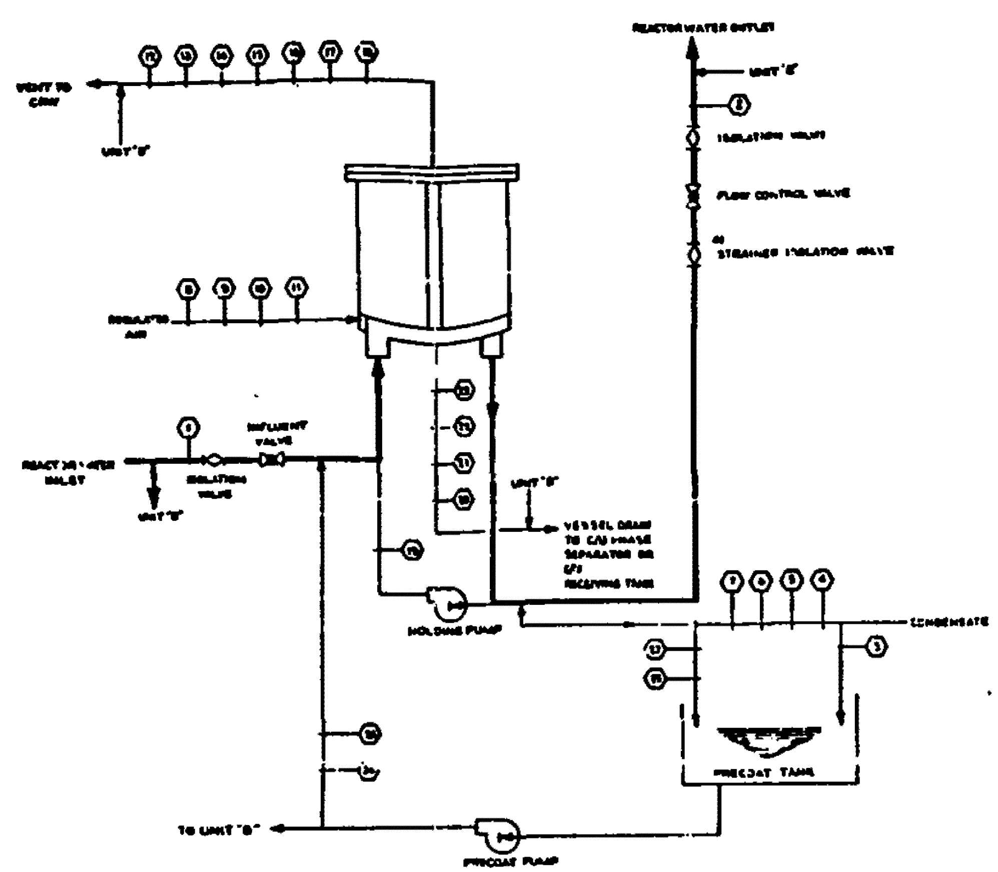
Refer to Plant Drawing M-44-1 in DCRMS

Figure F5.4-18 SH 1-2 intentionally deleted.

Refer to Vendor Technical Document PN1-G33-1030-0389 for sheet 1 in DCRMS
Refer to Vendor Technical Document PN1-G33-1030-0388 for sheet 2 in DCRMS

Figure F5.4-19 intentionally deleted.

Refer to Plant Drawing M-45-1 in DCRMS



F/D AREA = 135 FT²

TYPE REQUIREMENT			STATION SERVICES									EXHAUST AIR HANDLING							PROCESS PIPE SIZING								
COMMODITY			CONDENSATE					SERVICE AIR				RADIOACTIVE AIR							REACTOR WATER OR COND	REACTOR WATER + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	COND + F/D SOLIDS	SLURRY COND + RESIN	CNDS	CNDS	CNDS
POSITION	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
PROCESS STEP	NORMAL OPER	NORMAL OPER	PRECOAT SLURRY	SLOW BKWSH	FILL & WASH	REWASH	FILL	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	SLOW BKWSH	SLOW DRAIN	FILL & WASH	REWASH	DRAIN	FILL	HOLD	DRAIN	SLOW DRAIN	REWASH	DRAIN	RESIN PRECOAT	PRECOAT RETURN	PRECOAT RETAIN	PRECOAT RETAIN RETURN
PRESSURE, PSIG	SEE NOTE 1	SEE NOTE 1	25	25	25	25	25	20	20	20	20	0	5	5	5	5	0	5	GO TO SYSTEM [illegible]	20	20	20	20	35	35	85	85
TEMPERATURE, °F			80 TO 120	80	80	80	80	60	60	60	60	60	60	60	60	60	60	60	80 TO 120	120	80	80	80	80	80	80	80
FLOW RATE			50 GPM	25 GPM	135 GPM	135 GPM	15 GPM	201 SCFM	201 SCFM	201 SCFM	201 SCFM	113 SCFM	201 SCFM	201 SCFM	201 SCFM	201 SCFM	113 SCFM	5.5 SCFM	11.5 GPM	83 GPM	15 GPM	125 GPM	83 GPM	335 GPM	335 GPM	200 GPM	200 GPM
FLOW TIME, MIN.	—	—	1.8	10	2	2	10	10	10	1	2	3	10	10	1	2	3	12	—	3	10	2	3	13	13	1	1
TOTAL FLOW	—	—	90 GAL	250 GAL	250 GAL	250 GAL	150 GAL	2010 SCF	2010 SCF	400 SCF	400 SCF	334 SCF	2010 SCF	2010 SCF	400 SCF	400 SCF	334 SCF	[illegible] SCF	---	250 GAL	250 GAL	250 GAL	250 GAL	4350 GAL	4350 GAL	[illegible]	[illegible]
TOTAL LBS SOLIDS	—	—	25 #	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	31 #	RESIDUAL	RESIDUAL	RESIDUAL	25 #	—	—	—

SEE NOTE 2

FILTER/DEMINERALIZER BACKWASH & PRECOATING SEQUENCE

FUNCTIONS:

- SERVICE
- ISOLATE & HOLD
- DRAIN
- SLOW BACKWASH (FILL)
- SLOW DRAIN
- FILL & WASH
- REWASH (DRAIN & FILL)
- DRAIN
- FILL
- PRECOAT
- PRECOAT RETAIN
- HOLD UNTIL RETURN TO SERVICE
- SERVICE

NOTES:

1. FOR THESE VALUES AND [illegible] OF SYSTEM VALVES SEE REACTOR WATER CLEAN-UP SYSTEM PD.
2. DRY WEIGHT VALUES; AS [illegible] RESINS CONTAIN 50% MOISTURE [illegible]

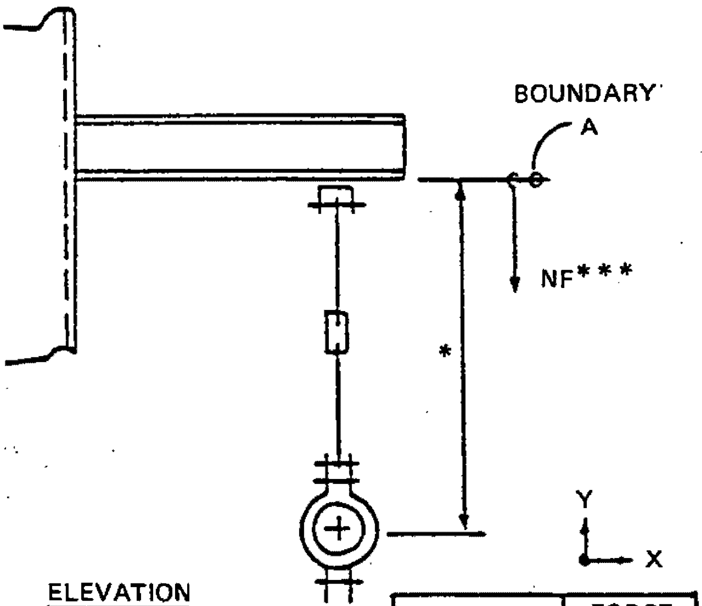
PN1-G33-Z001-0013 sht. 1 REV. 2

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK GENERATING STATION

FILTER/DEMINERALIZATION SYSTEM PROCESS DIAGRAM

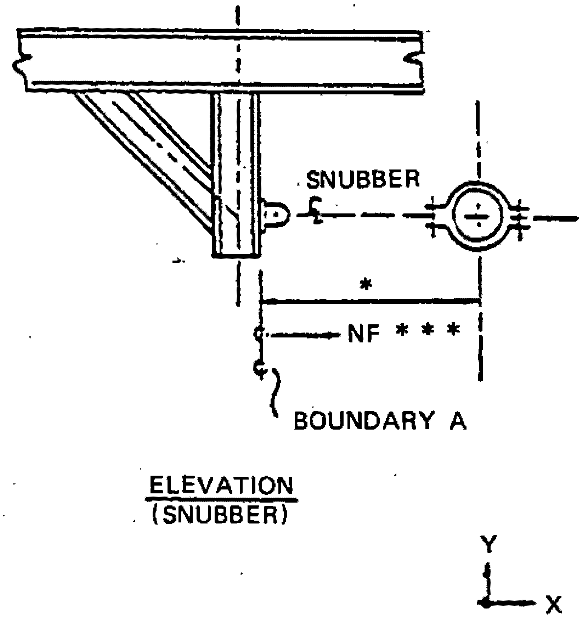
Updated FSAR
Rev. 7, December 29, 1995

Sheet 1 of 1
Figure 5.4-20



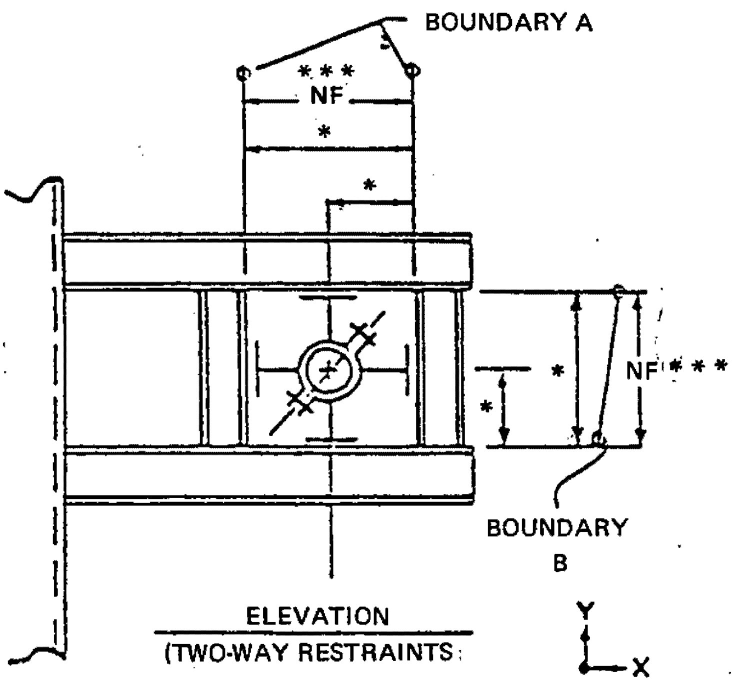
ELEVATION
(HANGER)

BOUNDARY	FORCE Fy
A	**



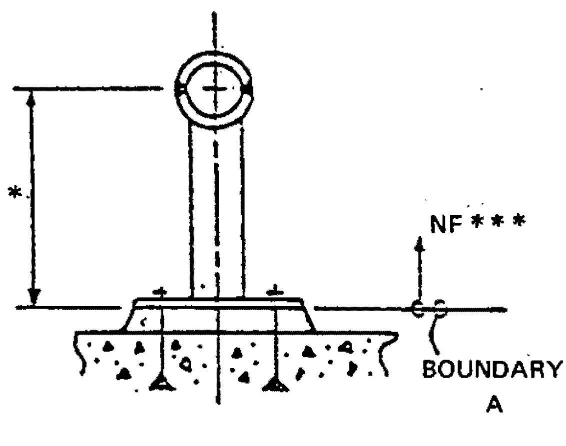
ELEVATION
(SNUBBER)

BOUNDARY	FORCE Fx
A	**



ELEVATION
(TWO-WAY RESTRAINTS)

BOUNDARY	FORCES	
	Fx	Fy
A	**	
B		**



ELEVATION
(ANCHOR)

BOUNDARY	FORCE			MOMENT		
	Fx	Fy	Fz	Mx	My	Mz
A	**	**	**	**	**	**

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* INDICATES DIMENSIONAL LOCATION OF NF ELEMENTS
** INDICATES LOADS IMPOSED ON THE NF BOUNDARY
*** INDICATES NF BOUNDARIES (INCLUDING WELD, IF ANY)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

NF JURISDICTIONAL BOUNDARY BETWEEN PIPE SUPPORTS AND SUPPORTING STRUCTURE

UPDATED FSAR

FIGURE 5.4-21