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) for the plant design lifetime.

5.2.1 COMPLIANCE WITH CODES AND CODE CASES

5.2.1.1 Compliance with 10CFR50, Section 50.55a

A table which shows compliance with the rules of 10CFR50 is included in Section 3.2, (See Table 3.2-1). Code edition, applicable addenda, and component dates are in accordance with 10CFR50.55a. Table 5.2-10 lists those RCPB components which comply with the rules of 10CFR50 in accordance with 10CFR50.55(a)(2)(ii).

5.2.1.2 Applicable Code Cases

The reactor pressure vessel and appurtenances, and the RCPB piping, pumps and valves, have been designed, fabricated, and tested in accordance with the applicable edition of the ASME Code, including addenda that were mandatory at the order date for the applicable components. Section 50.55a of 10CFR50 requires code case approval only for Class 1 components. These code cases contain requirements or special rules which may be used for the construction of pressure-retaining components of Quality Group Classification A. The various ASME code case interpretations that were applied to components in the RCPB are listed in Table 5.2-1.

5.2.2 OVERPRESSURE PROTECTION

This section provides evaluation of the system that protects the RCPB from overpressurization.

5.2.2.1 Design Basis

Overpressure protection is provided in conformance with 10CFR50, Appendix A, General Design Criteria 15. Preoperational and startup instructions are given in Chapter 14.

5.2.2.1.1 Safety Design Bases

The nuclear pressure-relief system has been designed:

(1) To prevent overpressurization of the nuclear system that could lead to the failure of the reactor coolant pressure boundary.

(2) To provide automatic depressurization for small breaks in the nuclear system occurring with maloperation of the high pressure coolant injection (HPCI) system so that the low pressure coolant injection (LPCI) and the core spray (CS) systems can operate to protect the fuel barrier.

(3) To permit verification of its operability.

(4) To withstand adverse combinations of loadings and forces resulting from normal, upset, emergency and faulted conditions.

5.2.2.1.2 Power Generation Design Bases

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

(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 Boiler and Pressure Vessel Code requires that each vessel designed to meet Section III be protected from overpressure under upset conditions. The code allows a peak allowable pressure of 110% of vessel design pressure under upset conditions. The code specifications for safety valves require that: (1) the lowest safety valve set point be set at or below vessel design pressure and (2) the highest safety valve set point be set so that total accumulated pressure does not exceed 110% of the design pressure for upset conditions. The safety/relief valves are designed to open via either of two modes of operation as described in Section 5.2.2.4.1.
The safety (spring lift) set points are listed in Table 5.2-2. These setpoints satisfy the ASME Code specifications for safety valves, because 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 safety relief valves:

(1) Must meet requirements of ASME Code, Section III;

(2) Valves must qualify for 100% of nameplate capacity credit for the overpressure protection function;

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

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

5.2.2.1.4 Safety Valve Capacity

The safety valve capacity of this plant is adequate to limit the primary system pressure, including transients, to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels (up to and including Summer 1970 Addenda for Unit 1 and Unit 2).

It is recognized that the protection of vessels in a nuclear power plant is dependent upon many protective systems to relieve or terminate pressure transients. Installation of pressure relieving devices may not independently provide complete protection. The safety valve sizing evaluation assumes credit for operation of the scram protective system which may be tripped by one of two sources; i.e., a direct or high neutron flux trip signal. The direct scram trip signal is derived from position switches mounted on the main steam line isolation valves or the turbine stop valves or from pressure switches mounted on the dump valve of the turbine control valve hydraulic actuation system. The position switches are actuated when the respective valves are closing and following 10% travel of full stroke. The pressure switches are actuated when a fast closure of the turbine control valves is initiated. Further, no credit is taken for power operation of the pressure relieving devices. Credit is taken for the dual purpose safety/relief valves in their ASME Code qualified (spring lift) mode of safety operation.

The rated capacity of the pressure relieving devices are sufficient to prevent a rise in pressure within the protected vessel of more than 110% of the design pressure (1.10 x 1250 psig = 1375 psig) for events defined in Subsection 5.2.2.2.2.2.

Full account is taken of the pressure drop on both the inlet and discharge sides of the valves. All combination safety/relief valves discharge into the suppression pool through a discharge pipe from each valve which is designed to achieve sonic flow conditions through the valve; thus providing flow independence to discharge piping losses.

Table 5.2-6 lists the systems which could initiate during the design basis overpressure event.

5.2.2.2 Design Evaluation

The overpressure protection analysis is performed using cycle specific inputs. Hence, the overpressurization analysis must be evaluated for each reload cycle. This section contains the reload analysis results for both units.

5.2.2.2.1 Method of Analysis

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

Unit 2 cycles starting with Cycle 13 through Cycle 20 and Unit 1 Cycles starting with Cycle 15 through Cycle 22 use the method of analysis and models described in References 5.2-14 and 5.2-15. For subsequent Unit 1 and Unit 2 cycles, the method of analysis and models are described in References 5.2-14 and 5.2-16. Safety/relief valves are simulated in the models.

In addition to determining the pressure in the pressure vessel, the model determines the pressure in the following components that comprise the reactor coolant pressure boundary.

	Design Pressure psig	Maximum Pressure psig
Recirculation Suction Pipe	1250	1375
Main Steam Piping	1250	1375
Recirculation Discharge Piping	1500	1650

The pressure at the bottom of the pressure vessel is explicitly calculated by the model as are the pressures in the other components listed above.

The safety/relief valve characteristic as modeled is shown in Figure 5.2-2 for the spring mode of operation. Typical valve characteristics are reflected in Figure 5.2-2A. The associated bypass, turbine control valve, and main steam isolation valve characteristics are also simulated in the model.

Closure time of the MSIVs is conservatively assumed to be less than or equal to the minimum closure time given in the Technical Specifications.

5.2.2.2.2 System Design

Reload specific evaluations are conducted to determine the required steam flow capacity of the safety/relief valves based on the following assumptions:

5.2.2.2.2.1 Operating Conditions

(1) operating power see Table 5.2-9

(2) vessel dome pressure $\leq$ 1050 psig, and

(3) core coolant flow = 108 million lbs/hr.

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

5.2.2.2.2.2 Transients

The overpressure protection system must accommodate the most severe pressurization transient. There are two major transients, the closure of all main steamline isolation valves and a turbine/generator trip with a coincident failure of the turbine steam bypass system valves that represent the most severe abnormal operational transient resulting in a nuclear system pressure rise. The evaluation of transient behavior with final plant configuration has shown that the isolation valve closure is slightly more severe when credit is taken only for indirect derived scrams. Therefore, it is used as the overpressure protection basis event. Typical results for Units 1 and 2 are shown in Figures 5.2-13 and 5.2-14 for Units 1 and 2, respectively. Cycle specific results may be found, by reference, in Chapter 15C and Chapter 15D for Unit 1 and Unit 2, respectively. The peak pressures are determined for each of the components listed in Section 5.2.2.2.1 and the minimum margin to their respective design limits can also be determined. Calculated pressures are all within the respective acceptance criteria of 110% of the design pressure for the reactor

pressure vessel and the reactor pressure boundary components. Table 5.2-9 lists the sequence of events of the various systems assumed to operate during the main steam line isolation closure with high neutron flux scram event for Units 1 and 2.

5.2.2.2.2.3 Scram

The scram times assumed for the overpressure protection analysis are based on the maximum allowable values given in the Technical Specifications.

5.2.2.2.2.4 Safety/Relief Valve Transient Analysis Specifications

(1) valve groups: spring-action safety mode - 3 groups

(2) pressure setpoints: see Table 5.2-2

The setpoints are assumed at a conservatively high level above the nominal setpoints. This is to account for initial setpoint errors and any instrument setpoint drift that might occur during operation. The assumed setpoints in the analysis are 3% above the actual nominal setpoints. Conservative safety/relief valve response characteristics as shown in figure 5.2-6 are assumed.

For the analysis, the safety valves that were assumed to be out of service were those that had the lowest pressure setpoints. The assumed minimum number of operable S/RVs is in accordance with the Technical Specifications.

5.2.2.2.2.5 Safety Valve Capacity

Sizing of the safety valve capacity and the number of valves allowed to be out-of-service was based on assuring that the peak vessel pressure is less than the vessel code limit (1375 psig) in response to the reference transients Subsection 5.2.2.2.2.2. In addition, the analyses that are performed under Subsection 5.2.2.2.2.2 are also used to confirm that the capacity of the safety valves is adequate to assure that the component peak pressures during the transient are less than the limits listed in Subsection 5.2.2.2.1.

5.2.2.2.3 Evaluation of Results

5.2.2.2.3.1 Safety Valve Capacity

The required safety valve capacity is determined by analyzing the pressure rise from a MSIV closure with flux scram transient. The plant is assumed to be operating at the turbine-generator design conditions at a maximum vessel dome pressure equal to the maximum dome pressure allowed by Technical Specifications. The reactor power assumed is given in Table 5.2-9. The analysis hypothetically assumes the failure of the direct MSIV position scram. The reactor is shut down by the backup, indirect, high neutron flux scram. The analysis indicates that the design valve capacity is capable of maintaining adequate margin below the peak ASME code allowable pressures in the reactor vessel and associated components as described above. Figure 5.2-13 shows typical curves produced by these analyses.

Under the General Requirements for Protection Against Overpressure as given in Section III of the ASME Boiler and Pressure Vessel Code, credit can be allowed for a scram from the reactor protection system. In addition, credit can also be taken for the protective circuits which are indirectly derived when determining the required safety valve capacity. However, only the backup

reactor high neutron flux scram is conservatively applied as a design basis in determining the required capacity of the pressure relieving safety valves. Application of the direct position scrams in the design basis could be used since they qualify as acceptable pressure protection devices when determining the required safety valve capacity of nuclear vessels under the provisions of the ASME code.

5.2.2.2.3.2 Pressure Drop in Inlet and Discharge

Pressure drop on the piping from the reactor vessel to the valves is taken into account in calculating the maximum vessel pressures. Pressure drop in the discharge piping to the suppression pool is limited by proper discharge line sizing to prevent backpressure on each safety/relief valve from exceeding 40% of the valve inlet pressure, thus assuring choked flow in the valve orifice and no reduction of valve capacity due to the discharge piping, (Reference 5.2-7). Each safety/relief valve has its own separate discharge line.

5.2.2.3 Piping & Instrument Diagrams

Dwgs. M-141, Sh. 1 and M-141, Sh. 2 are the P&ID for the Nuclear Boiler System including pressure-relieving devices.

5.2.2.4 Equipment and Component Description

5.2.2.4.1 Description

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

The safety/relief valves provide three main protection functions:

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

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

(3) Depressurization operation. The ADS valves open automatically as part of the emergency core cooling system (ECCS) for events involving small breaks in the nuclear system process barrier. The location and number of the ADS valves can be determined from Figure 5.1-2.

Chapter 15 discusses the events which are expected to activate the primary system safety/relief valves. The chapter also summarizes the number of valves expected to operate during the initial blowdown of the valves and the expected duration of this first blowdown. For several of the events it is expected that the lowest set safety/relief valve will reopen and reclose as generated heat drops into the decay heat characteristics. The pressure increase and relief cycle will continue with lower frequency and shorter relief discharges as the decay heat drops off and until such time as the RHR system can dissipate this heat. The duration of each relief discharge should in most cases be less than 30 seconds. Remote manual actuation of the valves from the control room is recommended to minimize the total number of these discharges, with the intent of achieving extended valve seat life.

A schematic of the safety/relief valve is shown in Figure 5.2-7. It is opened by either of two modes of operation:

(1) The spring mode of operation which consists of direct action of the steam pressure against a spring-loaded disk that will pop open when the valve inlet pressure force exceeds the spring force. Figure 5.2-6 diagrams the valve lift vs time characteristic.

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

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

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

To prevent backpressure, which results in the discharge line when the valve is open and discharging steam, from causing valve cycling and chatter with resulting set pressure variances, each valve contains an internal part/feature that has been factory adjusted by test to provide for proper valve blowdown/reclosure. The factory blowdown adjustment is compatible to the expected plant specific backpressure range to be realized under normal operating conditions.

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

For overpressure relief valve operation (power actuated mode), each valve is provided with a pressure sensing device which operates at the setpoints designated in Chapter 15. When the set pressure is reached, it operates a solenoid valve which in turn actuates the pneumatic piston/cylinder and linkage assembly to open the valve.

When the piston is actuated, the delay time, maximum elapsed time between receiving the overpressure signal at the valve actuator and the actual start of valve motion, will not exceed 0.1 seconds. The maximum full stroke opening time will not exceed 0.15 seconds.

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

Each safety/relief valve is provided with its own pneumatic accumulator and inlet check valve. The accumulator capacity is sufficient to provide one safety/relief valve actuation, which is all that is required for overpressure protection. Subsequent actuations for an overpressure event can be spring actuations to limit reactor pressure to acceptable levels.
The safety/relief valves are designed to operate to the extent required for overpressure protection for the accident environment referenced in section 3.11.

The Automatic Depressurization System (ADS) utilizes selected safety/relief valves for depressurization of the reactor (See Section 7.3). Each of the safety/relief valves utilized for automatic depressurization is equipped with an air accumulator and check valve arrangement. These accumulators assure that the valves can be held open following failure of the air supply to the accumulators. They are sized to be capable of opening the valves and holding them open against a peak calculated drywell pressure of 48.6 psig with the reactor completely depressurized. The accumulator capacity is sufficient for each ADS valve to provide two actuations against 34.0 psig, which represents 70% of the peak calculated drywell pressure.

Each safety/relief valve discharges steam through a discharge line to a point below the minimum water level in the suppression pool. Safety relief valve discharge line piping from the safety relief valve to the suppression pool consists of two parts. The first part is attached at one end to the safety relief valve and attached at its other end to the containment diaphragm slab through a pipe anchor. The main steam piping, including this portion of the safety relief valve discharge piping, is analyzed as a complete system. This portion of the safety relief valve discharge lines is therefore classified as quality group C and Seismic Category I.

The second part of the safety relief valve discharge piping extends from the upstream anchor to the suppression pool. Because of the upstream anchor on this part of the line, it is physically decoupled from the main steam header and is therefore analyzed as a separate piping system. In analyzing this part of the discharge piping in accordance with the requirements of quality Group C and Seismic Category I, the following load combination will be considered as a minimum:

Pressure and temperature
Dead weight
Fluid dynamic loads due to S/R valve operation
Anchor relative seismic (SSE) movement

Movement of the safety relief valve discharge line will be monitored as a part of the preoperational and startup testing of the main steam lines, in accordance with the requirements of Chapter 14.

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

The nuclear pressure relief system automatically depressurizes the nuclear system sufficiently to permit the LPCI or CS 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, and in Subsection 7.3.1.1.1.

5.2.2.4.2 Design Parameters

Table 5.2-3 lists design temperature, pressure, and maximum test pressure for the RCPB components. The specified operating transients for components within the RCPB are given in Table 3.9-4. Refer to Section 3.7 for discussion of the input criteria for design of Seismic Category I structures, systems, and components.

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

5.2.2.4.2.1 Safety/Relief Valve

The discharge area of the valve is 16.117 square inches and the coefficient of discharge K is equal to 0.966. The diameter and length of the discharge pipe from each valve to the discharge device in the suppression pool is defined in the Design Assessment Report (DAR), Table 1.3-2. The discharge pipe routing within the suppression chamber is shown in the DAR, Figures 1.3-2, 1.3-3 and 1.3-4. The design pressure and temperature of the valve inlet and outlet are 1250 psig @ 575°F and 550 psig @ 500°F, respectively.

Cyclic testing has demonstrated that the valves are capable of at least 60 actuation cycles between required maintenance.

See Figure 5.2-7 for a schematic cross section of the valve.

5.2.2.5 Mounting of Pressure Relief Devices

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

(1) The thermal expansion effects of the connecting piping.

(2) The dynamic effects of the piping due to SSE.

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

(4) The dynamic effects of the piping and branch connection due to the turbine stop valve closure.

In no case will allowable valve flange loads be exceeded nor will 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 is contained in Subsection 3.9.3.3.

5.2.2.6 Applicable Codes and Classification

The vessel overpressure protection system is designed to satisfy the requirements of Section III, Nuclear Vessels, of the ASME Boiler and Pressure Vessel Code. The general requirements for protection against overpressure as given in Article 9 of Section III of the 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 protective system as a complementary pressure protection device. The NRC has also adopted the ASME Codes as part of their requirements in the Code of Federal Regulations (10CFR50.55A).

5.2.2.7 Material Specification

Pressure retaining components of valves in Quality Group A are constructed only from ASME designated materials.

5.2.2.8 Process Instrumentation

Overpressure protection process instrumentation is shown on Figure 5.1-2.

5.2.2.9 System Reliability

This system is designed to satisfy the requirements of Section III of the ASME Boiler and Pressure Vessel code, therefore, it has high reliability. The consequences of failure are discussed in Subsections 15.1.4 and 15.6.1.

5.2.2.10 Inspection and Testing

The Main Steam Relief Valves were installed after certification from the valve manufacturer that design and performance requirements were met. This includes capacity and blowdown requirements. The set points are adjusted, verified, and indicated on the valves by the manufacturer. Specified manual and automatic actuation relief mode of each safety/relief valve is verified during the preoperational test program. Valve operability is verified during the preoperational test program in accordance with the requirements of Chapter 14.

The valves are mounted on 1500-lb primary service rating flanges. They can be removed for maintenance or bench checks and reinstalled during normal plant shutdowns.

The valves are tested in accordance with the ASME Code, requirements and, the approved request.

5.2.3 REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

5.2.3.1 Material Specifications

Table 5.2-4 lists the principal pressure retaining materials and the appropriate material specifications for the reactor coolant pressure boundary components.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 PWR Chemistry of Reactor Coolant

Not applicable to BWRs.

5.2.3.2.2 BWR Chemistry of Reactor Coolant

The SSES Reactor Coolant System (RCS) Chemistry program is consistent with the EPRI BWR Water Chemistry Guidelines. The coolant chemistry requirements discussed in this subsection remain consistent with the requirements of Regulatory Guide 1.56 (6/73). The EPRI BWR Water Chemistry Guidelines are periodically revised by industry expert panels. Incorporated parameter limits are as or more conservative than those found in the original plant licensing documents. The EPRI BWR Water Chemistry Guideline document has been developed and routinely revised to reflect industry experience and research and have been shown to be effective over time with their widespread use as a water control document.

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 gives an indication of abnormal conditions and the presence of impurities in the coolant. Chloride limits are specified to prevent stress corrosion cracking of stainless steel. For further information, see Reference 5.2-2. Reference Subsection 9.5.9 for a description of the Hydrogen Water Chemistry System.

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 of Williams (Reference 5.2-3), 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.

When BWR RCS conductivity is in its normal range, pH, chloride and other impurities affecting conductivity will also be within their normal range. When conductivity becomes abnormal, sampling and analysis measurements are made to determine whether or not EPRI recommended sample parameters are also out of their normal operating values. Conductivity could be high due to the presence of corrosive benign ions such as chromate, iron or zinc that would not have an adverse effect on pH. In such a case, high conductivity alone is not a cause for shutdown or other corrective action. In some types of water-cooled reactors, conductivities are high because of the purposeful use of additives. In BWRs, additives may be 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 a warning so 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 system and reduction of impurity source term(s). In some circumstances of abnormal chemistry, risk decisions may dictate it desirable to maintain power operation under HWC (maintain mitigation) during the transient and allow the impurity to cleanup. In other cases, it may be prudent to place 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 reestablish 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 SSES BWR Water Chemistry control program is continually improving based on the EPRI BWR Water Chemistry Guideline reviews and revisions. SSES adheres to the Guideline Control Parameter limits, unless justification for deviation is forwarded to the BWRVIP in accordance with approved BWRVIP reporting guidance.

For normal operation starting with the condenser-hotwell, condensate water is processed through a condensate treatment system. This process consists of condensate filtration to remove iron, followed by demineralization in the resin polisher system. When condensate system polisher resin becomes depleted, it is discarded and replaced.

The effluent from the condensate treatment system is pumped through the feedwater heater train, and enters the reactor vessel at an elevated temperature. Feedwater (FW) zinc and iron injection are used as needed to control radiation field buildup on ex-core surfaces. FW hydrogen injection is used to mitigate reactor vessel and internals stress corrosion cracking. Approved modifications to supplemented HWC injection with noble metal injection may be implemented as necessary. Condensate system oxygen injection may be used to control balance of plant Flow Assisted Corrosion rates in the event air in leakage is not sufficient to maintain dissolved oxygen levels.

A reactor water cleanup system is provided for removal of impurities 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 essentially 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.

No other inputs of water or sources of oxygen are routinely present during normal plant operation. During off normal plant conditions, additional inputs may result as outlined in the following section.

(2) Plant Conditions Outside Normal Operation

During periods of plant conditions other than normal power production, transients may take place, particularly with regards to the oxygen levels in the primary coolant. Systems other than the reactor are not affected significantly enough to cause any impact on primary system components or subsequent operation. In essence, depending on what the plant condition is, i.e., hot standby with/without reactor vessel venting or plant shutdown, the hotwell condensate will absorb oxygen from the air when vacuum is broken in 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 steam jet air ejector (SJAE) operation and condensate recirculation. During these plant conditions, continuous input of control rod drive (CRD) cooling water takes place as described previously.

a) Plant Depressurized and Reactor Vented

During certain periods such as during 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 about 8 ppm. Equilibrium between the atmosphere above the reactor water surface, the CRD cooling water input, any residual radiolytic effects, and the bulk reactor water will be established after some time. The specific conductivity of reactor water may increase to values of approximately 1 μS/cm due to the absorption of atmospheric carbon dioxide that is normally present in the atmosphere. No other changes in water chemistry of significance take place during this plant condition because no appreciable inputs take place.

b) Plant Transient Conditions - Plant Startup/Shutdown

During these conditions, no significant changes in water chemistry other than oxygen concentration take place.

(i) Plant Startup

Depending on the duration of the plant shutdown prior to startup and whether the reactor has been vented, the oxygen concentration could be that of air saturated water, i.e., ≈ 8 ppm oxygen.

Following nuclear heatup initiation, the oxygen level in the reactor water will decrease rapidly as a function of water temperature increase and corresponding oxygen solubility in water. The oxygen level will reach a minimum of about 20 ppb (0.02 ppm) at a coolant temperature of about 380°F, at which point an increase will take place due to significant radiolytic oxygen generation. For the elapsed process up to this point the oxygen is degassed from the water and is displaced to the steam dome above the water surface.

Further increase in power increases the oxygen generation as well as the temperature. The solubility of oxygen in the reactor water at the prevailing temperature controls the oxygen level in the coolant until rated temperature (540°F) is reached. Thus, a gradual increase from the minimum level of 20 ppb to a maximum value of about 200 ppb oxygen takes place. At, and after this point (540°F) steaming and the radiolytic process control the coolant oxygen concentration to a level of around 200 ppb. When in service, HWC injection will reduce the reactor coolant dissolved oxygen concentration.

(ii) 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, while some steaming still will take 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 essentially oxygen saturation at the coolant temperature will take place.

(iii) Oxygen in Piping and Parts Other Than the Reactor Vessel Proper

As can be concluded from the preceding descriptions, the maximum possible oxygen concentration in the reactor coolant and therefore in contact with the reactor or any other directly related or associated parts is that of air saturation at ambient temperature. In the water phase, dissolved oxygen levels will be a nominal value of 8 ppm. As temperature is increased and hence, oxygen solubility decreased 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, water inventory dissolved oxygen concentration may vary.

Primary coolant conductivity is continuously monitored with an instrument connected to redundant sources which include the reactor water recirculation loop and the reactor water cleanup system inlet. The effluent from the reactor water cleanup system is also monitored for conductivity on a continuous basis. These measurements provide adequate surveillance of the reactor coolant.

Grab sample capability is provided, for the locations shown on Table 5.2-7, for special and non-continuous measurements such as pH, oxygen, chloride and radiochemical measurements.

The relationship of chloride concentration to specific conductance measured at 25ºC for chloride compounds such as sodium chloride and hydrochloric acid can be calculated, see Figure 5.2-9. 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 the reactor water chemistry program, limits, monitoring and sampling requirements are imposed on the condensate, condensate treatment system and feedwater by EPRI Water Chemistry Guideline specifications. Thus, a total plant water quality surveillance program is established providing assurance that off specification conditions will quickly be detected and corrected.

The sampling frequency when reactor water has a low specific conductance is adequate for routine monitoring. When specific conductance increases, and higher chloride concentrations are possible, or when continuous conductivity monitoring is unavailable, increased sampling, analysis and monitoring is performed.

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

c. Water Purity During a Condenser Leakage

The condensate cleanup system was originally designed to maintain the reactor water chloride concentration below 200 ppb during a condenser tube leak of 23 gallons per minute indefinitely. The condensate cleanup system was originally designed to sustain an effluent conductivity of 0.15 micromho with a 46 gpm condenser leak when the circulating water contains 1000 ppm of TDS. Refer to Subsection 10.4.6.

To protect against a major condenser tube leak, sufficient instrumentation is provided to maintain a reserve of 50 percent of the theoretical ion exchange capacity during normal operation per Regulatory Guide 1.56.

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 and Inconel 750X.

(3) Carbon steel and low alloy steel.

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

(5) Colmonoy and Stellite hardfacing material.

All of these materials of construction are resistant to stress corrosion in the BWR coolant. 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.

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 austentitic stainless steels. Types 304, 304L and 316.

(2) Carbon and low alloy steel.

(3) Nickel alloy and austenitic stainless weld metal.

Two types of external insulation are employed on BWRs. Reflective metal insulation used does not contribute to any surface contamination and has no effect on construction materials. Nonmetallic insulation used on stainless steel piping and components complies with the requirements of either 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 are within acceptable levels. 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 pumps, piping, and valves of the reactor coolant pressure boundary are as follows:

The pump components except for the bolting, are austenitic stainless steel. The bolting meets Section III of ASME B&PV Code, Summer 1971 Addenda which requires impact testing to be performed at 10ºF.

Safety/Relief Valves were exempted from fracture toughness requirements because Section III of the 1971 ASME Boiler and Pressure Vessel Code did not require impact testing on valves with inlet connections of 6 inches or less nominal pipe size.

Main Steam Isolation Valves were also exempted because the Code existing at the time of the purchase, ASME Section III Summer 1971 Addenda did not require brittle fracture testing on ferritic pressure boundary components when the system temperature was in excess of 250ºF at 20% of the design pressure.

Main Steam Piping was tested in accordance with and met the fracture toughness requirements of paragraph NB-2300 of the 1972 Summer Addenda to ASME Code, Section III, the applicable code at the time of the purchase order.

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 ASME Code and Addenda to and including the Summer 1970 Addenda. From an operational standpoint, this Code would require that for any significant pressurization (taken to be more than 20% of Code hydrostatic test pressure = 312 psig) the minimum metal temperature of all vessel shell and head material be 100ºF (NDTT +60ºF).

5.2.3.3.1.2 Acceptable Fracture Energy Levels

Operating limits on reactor vessel pressure and temperature during normal heatup and cooldown, and during inservice hydrostatic testing, were established using as a guide Appendix G, Summer 1972 Addenda, of Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition.

These operating limits will assure that a large postulated surface flaw, having a depth of one-quarter of the material thickness, can be safely accommodated in regions of the vessel shell remote from discontinuities. In addition the specific additional margins required by 10CFR50, Appendix G, paragraph IV.A.2.c are included in the operating limits for core operations.

For the purpose of setting these operating limits, the reference temperature, RT_{NDT}, was determined from the impact test data taken in accordance with requirements of the Code to which this vessel is designed and manufactured. The dropweight NDT temperature was used as the reference temperature.

The highest reference temperature of any part of the reactor pressure vessel pressure boundary material was used as the reference temperature for calculating one set of operating temperature and pressure limits for the shell remote from the core beltline region. A second set of temperature and pressure limits for the core beltline region was calculated based on the core beltline region material reference temperature.

The requirements of the Code to which the vessel was designed and manufactured results in a third set of vessel shell temperature pressure limits; namely, NDTT +60°F or CVN +60°F at pressure greater than 20% of preoperational system hydrostatic test pressure. The more conservative of the above three limits was used to set pressure and temperature limits for the vessel shell.

5.2.3.3.1.3 Operating Limits During Heatup, Cooldown, and Core Operation

Since 100°F/hour is the maximum average normal heatup or cooldown rate for which the reactor vessel is designed, a conservative fracture toughness analysis was done for this assumed rate.

The maximum temperature gradient through the wall corresponding to this rate was considered. The results of this analysis are a set of operating limits for non-nuclear heatup or cooldown following nuclear shutdown, and another set for operating limits for operation whenever the core is critical (except for low level physics tests).

5.2.3.3.1.4 Temperature Limits for ISI Hydrostatic or Leak Pressure Tests

The fracture toughness analysis for pressure tests resulted in the curves shown on Figure 5.3-4A, 5.3-4B, 5.3-4C, and 5.3-4D of minimum vessel shell and head temperatures versus vessel pressure as measured in vessel top head. The dashed line curve, beltline region, is based on an assumed initial RT_{NDT} of +10°F, the predicted shift in the RT from Figure 5.3-5 based on neutron fluence at 1/4 of vessel wall thickness must be added to the beltline curve to account for the effect of fast neutrons on the beltline material properties. The curve for areas remote from the beltline (upper curve) is based on an assumed RT_{NDT} of +40°F. The controlling minimum temperature for a desired pressure is then selected as the greater of the solid curve or the dashed curve plus the shift.

5.2.3.3.1.5 Temperature Limits for Boltup

Minimum closure flange and closure stud temperatures of 70°F (NDTT + 60°F) are required whenever the closure studs are under preload or are being tensioned.

5.2.3.3.1.6 Reactor Vessel Annealing

In-place annealing of the reactor vessel because of radiation embrittlement is unnecessary since the predicted value in transition of adjusted reference temperature will not exceed 200°F - see 10CFR50, Appendix G, Paragraph IV.C.

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.(Rev. 0)

The use of low alloy steel is restricted to the reactor pressure vessel. Other ferritic components in the reactor coolant pressure boundary are fabricated from carbon steel materials.

Preheat temperatures employed for welding of low alloy steel meet or exceed the recommendations of ASME Section III, Subsection NA. Components were either held for an extended time at preheat temperature to assure removal of hydrogen, or preheat was maintained until post weld 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.

For repair welding utilizing the ASME Section XI temperbead welding methods, the preheat temperatures and supplemental nondestructive examination shall be in accordance with the temperbead welding rules as provided in Section XI and applicable Code Cases.

5.2.3.3.2.2 Control of Electroslag Weld Properties Regulatory Guide 1.34. (Rev. 0)

No electroslag welding was performed on BWR components.

5.2.3.3.2.3 Welder Qualification for Areas of Limited Accessibility. Regulatory Guide 1.71.(Rev. 0)

For non-NSSS items, refer to response to Regulatory Guide 1.71 in Section 3.13.

There are few restricted access welds involved in the fabrication of NSSS reactor coolant pressure boundary components. Welder qualification for welds with the most restricted access was accomplished by mock-up welding. Mock-ups were examined with radiography or sectioning.

5.2.3.3.3 Nondestructive Examination of Ferritic Tubular Products

For non-NSSS items, refer to response to Regulatory Guide 1.66 in Section 3.13.

Wrought tubular products were supplied in accordance with applicable ASTM/ASME material specifications. These specifications require a hydrostatic test on each length of tubing or pipe.

These components met the requirements of the ASME Codes existing at the time of placement of order which predate Regulatory Guide 1.66 (Rev.0).

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steels

For non-NSSS items, refer to response to Regulatory Guide 1.44 in Section 3.13

5.2.3.4.1 Avoidance of Stress Corrosion Cracking

5.2.3.4.1.1 Avoidance of Significant Sensitization

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% maximum, and cooling rates from solution heat treating temperatures were required to be rapid enough to prevent sensitization.

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% 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 re-solution heat treated.

These controls were used to avoid severe sensitization. Compliance with Regulatory Guide 1.44 (5/73) is discussed in Section 3.13.

5.2.3.4.1.2 Process Controls to Minimize Exposure to Contaminants

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

Special care was exercised to insure 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 was 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 1.44 (5/73) and 1.37 (3/73).

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

For non-NSSS items, refer to response to Regulatory Guide 1.31 in Section 3.13.

5.2.3.4.2.1 Avoidance of Hot Cracking

All austenitic stainless steel filler materials were required by specification to have a minimum of 5% ferrite. This amount of ferrite is considered adequate to prevent hot cracking in austenitic stainless steel welds.

An extensive test program performed by General Electric Company, with the concurrence of the Regulatory Staff, has demonstrated that controlling weld filler metal ferrite at 5% minimum produces production welds which meet the requirements of Regulatory Guide 1.31, (Rev. 1). A total of approximately 400 production welds in five BWR plants were measured and all welds met the requirements of the Interim Regulatory Position to Regulatory Guide 1.31.

5.2.3.4.2.2 Electroslag Welds

Electroslag welding was not employed for reactor coolant pressure boundary components.

5.2.3.4.2.3 Welder Qualification for Areas of Limited Accessibility Regulatory Guide 1.71 (Rev. 0)

For non-NSSS items, refer to response to Regulatory Guide 1.71 in Section 3.13.

There are few restrictive welds involved in the fabrication of NSSS reactor coolant pressure boundary components. Welder qualification for welds with the most restrictive access was accomplished by mock-up welding. Mock-ups were examined with radiography or sectioning.

5.2.3.4.3 Nondestructive Examination of Tubular Products Regulatory Guide 1.66 (Rev. 0)

For non-NSSS items, refer to response to Regulatory Guide 1.66 in Section 3.13.

Wrought tubular products were supplied in accordance with applicable ASTM/ASME material specifications. These specifications require a hydrostatic test on each length of tubing. Additionally, the specification for the tubular product used for CRD housings specified ultrasonic examination to paragraph NB-2550 of ASME Code Section III.

These components met the requirements of ASME Codes existing at time of placement of order.

5.2.4 IN-SERVICE INSPECTION AND TESTING OF REACTOR COOLANT PRESSURE BOUNDARY

The construction permits for the Susquehanna SES were issued in November, 1973. Relating this date to the requirements of 10CFR50.55a(g), the preservice examination program with provisions for design and access should comply, as a minimum, with the 1971 Edition of the ASME B&PV Code Section XI including the Summer 1972 Addenda. The Susquehanna SES preservice examination program will not be conducted to the minimum requirements of 10CFR50.55a(g) but rather to the more current 1974 Edition of Section XI including the Winter 1975 Addenda for the RPV and the Summer 1975 addenda as modified by Appendix III from the Winter 1975 addenda and IWA-2232 from the Summer 1976 addenda for the piping systems to the extent practical within the limitations of design, geometry, and materials of construction of the component. Preservice examination of piping integrally welded supports, category B-K-1, and piping pressure retaining bolting categories B-G-1 and B-G-2, will be in accordance with ASME Section XI, 1977 edition including addenda through Summer 1978.

Throughout the service life of the Susquehanna SES, components and their supports classified as ASME Code Class 1, Class 2 or Class 3, except for components excluded under IWB-1220, IWC-1220, and IWD-1220, and IWF-1230, will meet the requirements, except design and access provisions, set forth in Editions of Section XI of the ASME B&PV Code and Addenda that became effective subsequent to the editions specified above and are incorporated by reference in 10CFR50.55 a(g), and to the extent practical within the limitations of design, geometry, and materials of construction of the component.

The initial in-service examinations conducted during the first 120 months will comply, to the extent practical, with the requirements of the ASME B&PV Code Section XI Edition and Addenda incorporated by reference in 10CFR50.55a (b) on the date 12 months prior to the date of issuance of the operating license, subject to modifications listed by the reference sections.

The in-service examinations conducted during successive 120-month periods throughout the service life of the Susquehanna SES will comply, to the extent practical with the requirements of the ASME B&PV Code Section XI Edition and Addenda incorporated by reference in 10CFR50.55a(b) 12 months prior to the start of the 120 month inspection interval, subject to limitations listed by the reference sections.

Details of the inservice inspection program for the inspection interval are contained in the "Inservice Inspection Program Plan."
This document will be updated, as a minimum, every ten (10) years to reflect program commitments for subsequent ten (10) year intervals.

5.2.4.1 System Boundary Subject to Inspection

The inspection requirements of Section XI of the Code are met for all Class 1 pressure-containing components (and their supports) except for components excluded under IWB-1220 of Section XI. Note that Code Case N-716-1 will be utilized for implementing the risk-informed inservice inspection program. The risk-informed program scope will be implemented as an alternative to the ASME Section XI examination program for Class 1 Examination Categories B-F and B-J welds in accordance with 10CFR50.55a(z)(1). The risk-informed inservice inspection program has been expanded to include welds in the break exclusion region piping, also referred to as the high energy line break region, which includes several non-class welds that fall within the break exclusion region augmented inspection program. Additional guidance

for adaptation of the risk-informed inservice inspection evaluation process to break exclusion region piping is given in EPRI TR-1006937 Rev. 0-A. The system boundary includes all pressure vessels, piping, pumps, and valves that are part of the reactor coolant system, or connected to the reactor coolant system, up to and including:

a) The outermost containment isolation valve in system piping that penetrates the primary reactor containment

b) The second of two valves normally closed during normal reactor operation in system piping that does not penetrate primary reactor containment

c) The reactor coolant system safety and relief valves.

5.2.4.2 Accessibility

The design and arrangement of system components are in accordance with IWA-1500, "Accessibility", of the 1971 Edition of Section XI. Adequate clearances for general access are provided as follows:

a) Sufficient space is provided for personnel and equipment to perform inspections.

b) Provisions are made for the removal and storage of structural members, shielding components, and insulating materials, to permit access to the components being inspected.

c) Provisions are made for hoists and other handling machinery needed to handle items in (b), above.

d) Provisions are made for alternative examinations if structural defects or indications reveal that such examinations are required.

e) Provisions are made for the necessary operations associated with repair or replacement of system components and piping.

Piping systems requiring volumetric ultrasonic inspection are designed so that welds requiring inspection are physically accessible for inspection and ultrasonic equipment. Access is provided by leaving adequate space around pipes at these welds and by removing insulation and shielding as required.

The surfaces of welds requiring ultrasonic examination have been ground and contoured to permit effective use of ultrasonic transducers, and to minimize geometric reflectors that could be misinterpreted as flaws.

Piping systems requiring surface or visual examination are designed to allow access and visibility adequate for performance of such examinations.

Access is provided to reactor vessel components to meet, as a minimum, the examination requirements of ASME Section XI as outlined above.

Because high potential radiation levels in the vicinity of the reactor vessel limit access to the vessel, considerations for meeting ASME Section XI have been incorporated into the plant design as follows:

a) An annular space (8-in. minimum) sufficient to accommodate remotely operated inspection equipment is provided between the reactor vessel shell and the thermal insulation for areas behind the reactor shield wall.

b) Removable sections of thermal insulation and openings in the reactor shield with hinged shield plugs are provided to allow access for remote or manual examination of the reactor vessel nozzle-to-shell, nozzle-to-safe-end, and safe-end-to-pipe welds.

c) Access to full penetration vessel welds, nozzle welds above the reactor shield, and all top head welds is provided by removable, freestanding thermal insulation.

d) Openings in the reactor shield and removable insulation are provided to allow access to the reactor skirt-to-bottom head welds.

e) Openings in the reactor skirt, removable insulation panels, and walk-on grating are provided to allow access to the bottom head welds inside the support skirt.

f) The reactor vessel closure head is stored dry in an accessible area to provide direct access for inspection.

g) Reactor vessel studs, nuts, and washers are removed to dry storage for inspection.

In-service inspection access to other major reactor coolant system components is provided as follows:

a) Working platforms are provided to facilitate access to inspection areas.

b) The insulation covering component and piping welds and adjacent base metal is designed for easy removal and reinstallation in areas where inspection is required.

c) The physical arrangement of pipe, pumps, valves, and other components allows personnel access to welds requiring in-service inspection in accordance with ASME Section XI.

5.2.4.3 Examination Techniques and Procedures

The methods, techniques, and procedures used in the Susquehanna SES in-service inspection program comply with the requirements of ASME Section XI,. Subarticle IWA-2200

The visual, surface, and volumetric examination techniques are in compliance with IWA-2210, 2220, and 2230, respectively. In accordance with IWA-2240, if any alternative examination methods, combination of methods, or newly developed techniques are substituted for the above-described methods, results will be provided that demonstrate that the alternative methods are equivalent to or superior to those methods specified in Section XI.

If, as a result of the preservice or in-service examinations, flaw indications are found to have developed and/or propagated beyond the acceptance standards of IWB-3000, then further

examinations will be conducted, as needed, to determine the exact condition. Following evaluation of this evidence, a decision will be made regarding repair requirements related to plant safety. Any repairs, if needed, will be performed to the rules of IWB-4000.

5.2.4.4 Inspection Intervals

In-service inspections will primarily be performed during plant outages such as refueling shutdowns or maintenance shutdowns. With the exception of the examinations that may be deferred until the end of the inspection interval, the required examinations will be completed in accordance with Table IWB-2412-1 (Inspection Program B).

A combination of manual and mechanized techniques will be used for in-service examinations. Preservice (or baseline) data will be generated accordingly using the methods/techniques similar to those which will be used for in-service examinations.

Specific details of the inservice inspection program are contained in the "Inservice Inspection Program Plan."

5.2.4.5 Evaluation of Examination Results

a) Examination evaluation shall be performed in accordance with the requirements of Section XI, IWB-3000, "Acceptance Standards" Acceptance of components for continued service shall be in accordance with IWB-3122 IWB-3123, and IWB-3124.

b) The program regarding repairs of unacceptable indications or replacement of components containing unacceptable indications is in accordance with the requirements of Section XI, IWA-4000, "Repair/Replacement Activities."

5.2.4.6 System Leakage and Hydrostatic Pressure Tests

The pressure retaining Code Class 1 component leakage and hydrostatic pressure test program is in accordance with the requirements of Section XI, IWB-5000, "System Pressure Tests".

5.2.4.7 Augmented Inservice Inspection To Protect Against Postulated Piping Failures

The augmented inservice inspection program to provide 100 percent volumetric examination of circumferential and longitudinal pipe welds in high energy systems between containment isolation valves will be reviewed and implemented as described in Subsection 6.6.8. Commencing with the Third Ten Year Inspection Interval, the risk-informed break exclusion region program methodology, described in EPRI TR-1006937, Rev. 0-A, will be used to define the inspection scope in lieu of the 100% examination of all piping welds in the previous break exclusion region augmented program. Therefore, all welds in the original augmented program for the break exclusion region will be evaluated under the risk-informed inservice inspection program using an integrated risk-informed approach.

5.2.5 DETECTION OF LEAKAGE THROUGH REACTOR COOLANT PRESSURE BOUNDARY

5.2.5.1 Leakage Detection Methods

The nuclear boiler leak detection system consists of temperature, pressure, and flow sensors with associated instrumentation and alarms. This system detects, annunciates, and isolates (in certain cases) leakages in the following systems:

(1) Main steam lines

(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

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

Small leaks into the drywell (5 gpm and less) are detected by temperature and pressure changes and floor drain sump levels. Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

The 5 gpm leakage rate is a technical specification limit on unidentified leakage into the drywell. The containment floor drain sump collection system, which is part of the leak detection system, is capable of monitoring flowrates with an accuracy of one gpm. Thus, the SSES design is in compliance with Paragraph C.2 of Regulatory Guide 1.45.

5.2.5.1.1 Detection of Abnormal Leakage Within the Primary Containment (NSS-Systems)

Abnormal leakage may result in a decrease of reactor water level. Low reactor water level will cause isolation of the RHR shutdown cooling suction line (level 3), the RWCU suction line (level 2) and the main steam lines (level 1). Reactor water level monitoring is also described in FSAR Section 7.3.1.1a.2.4.1.1.

The RCIC and HPCI steam lines are monitored for large leaks inside containment by pressure switches installed on each leg of the elbow tap flow elements. Low pressure will close the isolation valves in the respective line and initiate an alarm in the control room. Closing the isolation valves will not isolate the leak, but the alarm will alert the operators. This leakage will also be detected by the drywell leak detection systems described in Section 5.2.5.1.2. Leakage downstream of the elbow tap flow elements (inside or outside containment) will be detected by high flow switches, causing an alarm and closing the isolation valves. RCIC and HPCI leak detection is also discussed in FSAR Sections 7.6.1a.4.3.3 and 7.6.1a.4.3.8.

Abnormal leakage from the core spray discharge line will result in a pressure differential between the discharge line and the vessel shroud. High differential pressure will initiate an alarm in the control room in the event of a leak.

5.2.5.1.2 Detection of Abnormal Leakage Within the Primary Containment (Non-NSSS)

Leakage through the reactor coolant pressure boundary within the primary containment is detected by monitoring temperatures, pressures, airborne gaseous and particulate radioactivity, and changes of levels in the floor drain sumps. These monitors and their respective locations are listed in Table 5.2-14.

The following systems are used to monitor these variables:

a) Primary containment and suppression pool temperature monitoring system.

b) Primary containment and suppression chamber pressure monitoring system

c) Primary containment atmosphere monitoring system (containment radiation detection)

d) Drywell floor drain sump level monitoring and drywell equipment drain tank level monitoring system.

The above-mentioned leak detection systems are designed in accordance with recommendations of Regulatory Guide 1.45 except as noted in Subsection 5.2.5.1.2.4.6.

The drywell leak detection system is not intended to be qualified as a post LOCA system; it is designed for use during power operation as implied by the Technical Specifications. There would be no practical way of recalibrating the system after the LOCA transient.

For the post accident condition, separate monitoring systems are provided for both the primary containment drywell and suppression chamber pressure and the primary containment and suppression pool temperatures. Details of the design are discussed in Subsections 7.6.1b.1.1.2, 7.6.1b.2.2, 7.6.1b.2.3 and 7.6.1b.1.2.4.2.

5.2.5.1.2.1 Primary Containment Temperature Monitoring System

Temperatures within the drywell are monitored at various elevations. A drywell ambient temperature rise will indicate the presence of reactor coolant or steam leakage. Temperature monitoring of the containment provides an indirect indication of leakage as defined in regulatory position (3) of Regulatory Guide 1.45.

A detailed description of the system, sensitivity and response time, and the system reliability is discussed in Subsection 7.6.1b.1.2.

Limiting temperature conditions are included in the Technical Specifications.

Provisions for testing and calibration are described in Subsection 7.6.2b.

5.2.5.1.2.2 Primary Containment Pressure Monitoring System

Pressure monitoring within the containment provides an indirect method of detecting leakage.

The drywell pressure fluctuates slightly during reactor operation as a result of barometric pressure changes and out-leakage. A pressure increase above normal values indicates a RCS leak in the primary containment.

The primary containment monitoring system and instrumentation is described in Subsection 7.6.1b.

Subsection 7.5.1b identifies safety-related display instrumentation.

5.2.5.1.2.3 Primary Containment Atmosphere Monitoring - Airborne Radioactivity Monitoring

The primary containment is continuously monitored for airborne radioactivity. A sample is drawn from the primary containment and a sudden increase of activity indicates a steam or reactor water leakage.

5.2.5.1.2.3.1 Sensitivity and Response Time

The objective of the drywell leak detection monitors as indicated in Regulatory Guide 1.45 is to be able to detect less than 1 gpm of unidentified primary coolant pressure boundary leakage in 1 hour. Several detection systems supplied to accomplish this are the drywell sump level monitor (see Subsection 5.2.5.1.2.4), a noble gas radiation monitor, and a particulates radiation monitor. A radioiodine collector is also provided. The two radiation monitors sample drywell for the activity levels on the assumption that flashing coolant leakage will result in radioactivity in the atmosphere. The radioiodine collector provides a means for laboratory analysis of a containment air sample for radioiodine activity.

The reliability, sensitivity and response times of radiation monitors to detect 1 gpm in 1 hour of Reactor Coolant Pressure Boundary leakage will depend on many complex factors. The major factors are discussed below:

A. Source of Leakage

1) Location of Leakage

The amount of activity which would become airborne following a 1 gpm leak from the RCPB will vary depending upon the leak location and the coolant temperature and pressure. For example, a feedwater pipe leak will have concentration factors of 100 to 1000 lower than a recirculation line leak. A steam line leak will be a factor of 10 to 100 lower in iodine and particulate concentrations than the recirculation line leak, but the noble gas concentrations may be comparable. A RWCU leak upstream of the demineralizers and heat exchangers will be a factor of 10 to 100 higher than downstream, except for noble gases. Differing coolant temperatures and pressures will affect the flashing fraction and partition factor for iodines and particulates. Thus, an airborne concentration cannot be correlated to a quantity of leakage without knowing the source of the leakage.

2) Coolant Concentrations

Variations in coolant concentrations during operation can be as much as several orders of magnitude within a time frame of several hours. These effects are mainly due to spiking during power transients or changes in the use of the RWCU system. Examples of these transients for I-131 can be found in NEDO-10585 (8/72), Behavior of Iodine in Reactor Water During Plant Shutdown and Startup. Thus, an increase in the coolant concentrations could give increased containment concentrations when no increase in unidentified leakage occurs.

3) Other Sources of Leakage

Since the unidentified leakage is not the sole source of activity in the containment, changes in other sources will result in changes in the containment airborne concentrations. For example, identified leakage is piped to the equipment drain tank in the drywell, but the tank is vented to the drywell atmosphere allowing the release of noble gases and some small quantities of iodines and particulates from the drain tank.

B. Drywell Conditions Affecting Monitor Performance

1) Equilibrium Activity Levels

During normal operation the activity release from acceptable quantities of identified and unidentified leakage will build up to significant amounts in the drywell air. Conversations with several operating plants indicate that levels as high as .1 to 10 times MPC are not uncommon for noble gases and iodines. (MPC refers to "maximum permissible concentration" as defined by 10CFR20, MPC is used here only as a convenient reference.) Due to these high equilibrium activity levels the small increases due to a 1 gpm increase in leakage may be difficult to see within an hour. Typical MPC ranges are:

	1 MPC to 10 MPC
Noble Gases	$1x10^{-6}$ - $1x10^{-4}$ μ Ci/cc
Particulates	$1x10^{-6}$ - $1x10^{-4}$ μ Ci/cc
Iodines	$5x10^{-7}$ - $5x10^{-5}$ μ Ci/cc

Fresh fuel backgrounds were not considered because no fission products are available at that point in time. The numbers given above include amounts of failed and/or irradiated fuel. These numbers also include normal expected leakage rates.

2) Purge and Pressure Release Effects

Changes in the detected activity levels have occurred during periodic drywell purges to lower the drywell pressure. These changes are of the same order of magnitude as approximately a 1 gpm leak, and are sufficient to invalidate the results from particulate monitors and iodine collector analysis.

3) Plateout, Mixing, Fan Cooler Depletion

Plateout effects on iodines and particulates will vary with the distance from the coolant release point to the detector. Larger travel distances would result in more plateout. In addition the pathway of the leakage will influence the plateout effects. For example, a leak from a pipe with insulation will have greater plateout than a leak from an uninsulated pipe. Although the drywell air will be mixed by the fan coolers, it may be possible for a leak to develop in the vicinity of the radiation detector sample lines. In addition, condensation in the coolers will remove iodines and particulates from the air. Variations in the flow, temperature and number of coolers will affect the plateout fractions. Plateout within the detector sample tube will also add to the reduction of the iodine and iodine and particulate activity levels. The uncertainties in any estimate of plateout effects could be as much as one or two orders of magnitude.

C. Physical Properties and Capabilities of the Detectors

1) Detector Ranges

The detectors were chosen to ensure that the operating ranges covered the concentrations expected in the drywell. The operating ranges are:

Noble Gases	1×10^{-6} to 1×10^{-2} μ Ci/cc
Particulates	1×10^{-9} to 1×10^{-4} μ Ci/cc

2) Sensitivity

In the absence of background radiation and equilibrium drywell activity levels, the detectors have the following minimum sensitivity.

Noble Gas	1×10^{-6} μ Ci/cc
Particulates	1×10^{-9} μ Ci/cc

3) Counting Statistics and Monitor Uncertainties

In theory these radioactivity monitors are statistically able to detect increases in concentration as small as 2 or 3 times the square root of the count rate, i.e., at 10^6 cpm an increase of 2×10^3, or 0.2%, is detectable; at 10^2 cpm an increase of 20, or 20% is detectable. In addition at high count rates the monitors have dead-time uncertainties and the potential for saturating the monitor or the electronics. Uncertainties in calibration ($\pm$5%) sample flow ($\pm$10%) and other instrument design parameters tend to make the uncertainty in a count rate closer to 20% to 40% of the equilibrium drywell activity.

4) Monitor Setpoints

Due to the uncertainty and extreme variability of the concentrations to be measured in the containment the use of alarm setpoints on the radioactivity monitors would not be practical or useful. As indicated in the following section the setpoints which would be required to alarm at 1 gpm would be well within the bounds of uncertainty of the measurements. The use of such setpoints would

result in many unnecessary alarms and the frequent resetting of setpoints. A setpoint alarm on the sump level monitor alone is used; the radioactivity monitors are for supporting information to confirm that the leak is radioactive. The alarm setpoints for the radiation monitors will be set significantly above background to prevent nuisance alarms. The actual setpoint will be changed as background increases. At these levels, the radiation monitors will provide no warning of a 1 gpm leak in one hour.

5) Estimated Monitor Responses

Table 5.2-13 estimates the expected monitor responses for several types of leaks and several types of monitors. As indicated in column 3, the added activity in containment from a 1 gpm leak for 1 hour is less than the nominal 20% increase which could be meaningfully detected. The final columns estimate the detectable leakage in 1 hour.

6) Operator Action

There is no direct correlation or known relationship between the detector count rate and the leakage rate, because the coolant activity levels, source of leakage, and background radiation levels (from leakage alone) are not known and cannot be cost-effectively determined in existing reactors. There are also several other sources of containment airborne activity (e.g. safety relief valve leakage) which further complicate the correlation.
Thus, the recommended procedure for the control room operator is to set an alarm setpoint at 1 gpm in 1 hour on the sump level monitor (measuring water collected in the sump which may not exactly correspond to water leaking from an unidentified source). When the alarm is actuated, the operator will review all other monitors (e.g., noble gas, particulates, temperature, pressure, fan cooler drains, etc.) to determine if the leakage is from the primary coolant pressure boundary and not from an SRV or cooling water system, etc. Appropriate actions will then be taken in accordance with Technical Specifications. The review of other monitors will consist of comparisons of the increases and rates of increase in the values previously recorded on the strip chart recorders. Increases in all parameters except sump level will not be correlated to a RCPB leakage rate. Instead, the increases will be compared to normal operating limits and limitations (e.g., 2 psi maximum pressure for ECCS initiation) and abnormal increases will be investigated.

Since the Technical Specification limit for leakage is allowed to be averaged over 24 hours, quick and accurate responses are not necessary unless the leakage is very large and indicative of a pipe break. In this case, the containment pressure and reactor vessel water level monitors will alarm within seconds, and the sump level monitor would alarm within minutes or tens of minutes.

The radiation monitor alarms will not be set to levels that correspond to RCPB leakage levels since the correlations can't be made. Also, since the containment airborne activity levels vary by orders of magnitude during operation due to power transients, spiking, steam leaks, and outgassing from sumps, etc., an appropriate alarm setpoint, if one is used, should be determined by the operator based on experience with the specific plant. A setpoint level of 2 to 3 times the

background level during full power steady state operation may be useful for alarming large leaks and pipe breaks, but it would not always alarm for 1 gpm in 1 hour.

7) Conclusion

Due to the sum total of the uncertainties identified in the previous paragraphs the iodine collector analysis, gaseous, and particulate monitors will not be relied upon for leak detection purposes but only as supporting instrumentation. These monitors will be used to give supporting information to that supplied by the sump level monitors and would be able to give an early warning of a major leak especially if equilibrium containment activity levels are low. However, the uncertainties and variations in noble gas leaks and concentrations would preclude the setting of a meaningful set point on the monitors.

5.2.5.1.2.4 Drywell Floor Drain Sump Monitoring System

The drywell floor drain sump monitoring system is designed to permit leak detection in accordance with Regulatory Guide 1.45.

5.2.5.1.2.4.1 System Description

Two drywell floor drain sumps are located in the primary containment for collection of leakage from vent coolers, control rod drive flange leakage, chilled water drains, cooling water drains, and overflow from the equipment drain sump.

The drywell floor drain sump is located at the drywell diaphragm slab low point. Unidentified leakages will, by gravity, flow down the slab surface into the floor drain sump. No floor drain piping system is employed for this purpose. Piped inputs to the drywell floor drain sump are from clean system drains. No surveillance program is planned to detect piped equipment drain system blockage.

Small, unidentified leakages of concern flowing into the drywell floor drain sump will not be masked by larger, acceptable, identified leakages overflowing from the drywell equipment drain tank. The drywell equipment drain tank drains by gravity. During conditions of acceptable identified leakage rates, the gravity flow from the drywell equipment drain tank will be capable of preventing the drywell equipment drain tank from overflowing to the drywell floor drain sump.

Water flow rate greater than 0.5 gpm can be detected by monitoring changes of level over a time period. The following method of flow rate measurement was selected to comply with the requirements of Regulatory Guide 1.45. The necessary sensitivity is obtained by measuring the changes of level during a fixed time interval. For this purpose, a stepped level measurement system is installed in each of the sumps. The level of each sump is recorded by stepped pen recorders located in the Main Control Room. The change in sump level per unit of time determines the leak rate.

There is no reliable quantitative relationship between the sump level and the leakage rate from any source. The quantity is dependent upon the temperature and pressure of the containment and the leak and the location of the leak. Part of the leak will flash to steam; it may be partially trapped between insulation layers. Presumably the leakage will get to an equilibrium level where most of it ends up in the sump, unless the drywell is vented to relieve the pressure

buildup. Since the Technical Specification allows 24-hour averaged leak limits, short term variations in the ability to relate the sump quantity to the leaked quantity are ignored, and it is assumed that all leakage reaches the sump. The errors introduced will not impair the ability to detect larger leaks which could rapidly result in severe accidents.

The upper drywell area, above the refueling bellows and seal plate, is capable of accumulating a quantity of water not monitored by the drywell sump leak detection system.

The presence of a leakage liquid accumulation reservoir in the upper drywell is not a safety concern for leaks that are possible in any significant quantity from the reactor coolant pressure boundary. Any leak of significance from the vessel head area would be in the form of steam, condensing in some relatively small quantities, with the rest pressurizing the area and flowing out to the lower drywell area via the drywell cooling system head area returns.

Once in the lower drywell, the chillers will condense the steam and the leakage would be identified and quantified in the conventional manner. The reservoir may contain, and may eventually fill with, water, but the detection and mitigation of the leak is not directly affected by the unmonitored accumulation of leakage.

Less quantifiable leak detection means are also available from the temperature, pressure, particulate and Noble Gas monitoring instrumentation.

Liquid leakage in the vessel head area would be expected only under shutdown/hydro conditions or under unusual or EOP conditions (vessel flooding accident response) when leakage is of relatively minor consequences or concern. During normal operation, relatively small amounts of liquid water could come from an instrument line leak. Such a leak would quickly develop into a steam leak, to be detected by normal means. Head spray lines are normally shut off from sources of water, and are normally open only briefly when preparing for vessel disassembly.

Some leakage will no doubt be trapped in insulation etc., but no other large reservoirs for leakage have been found.

Each sump is equipped with two pumps which operate in an alternating mode. High sump level starts the pump automatically. Remote manual control of the pump is provided in the control room. Both pumps will be operating as soon as an abnormal, high level is detected. The capability of each pump is such that normal expected flow rates can be easily accommodated.

As discussed above for the drywell sump monitoring system and as discussed in section 5.2.5.1.2.3 for Primary Containment Atmosphere – Airborne Radiation Monitoring system ability to detect leakage is reduced during containment inerting and purging. These systems are not credited in any FSAR safety analysis. Therefore, the reduction in detection capability during containment inerting and purging evolutions is not safety significant. Note that FSAR Section 7.3.1.1b.1.1 identifies that the containment purge line will isolate on high radiation at the SGTS exhaust stack. This isolation feature provides additional protection of the public from any significant radiological release during inerting and purging activities.

<u>5.2.5.1.2.4.2 Instrumentation</u>

Magnetic float type continuous level probes are used to measure the fluid level and provide the signal for the recording of the actual sump level in the control room and for the starting and

stopping of the drywell sump pumps. Excessive sump level is alarmed in the control room. The sump level can be observed by the control room operator.

5.2.5.1.2.4.3 Drywell Equipment Drain Tank Level Monitoring System

The drywell equipment drain tank collects identified leakage within the primary containment from reactor head seal leak off, bulkhead drain, refueling bellows drain, RPV head vent, recirculation pump seals, reactor recirculation pump cooler drains, and RPV bottom drain(Unit 1 only).

All identified leakages which may have temperatures of 212°F or above are hard-piped directly to the drywell equipment drain tank. These leakages will tend to partially flash into steam and then condense in the drain pipe. This approach minimizes the possibility that leakage will escape as steam into the containment atmosphere prior to measurement in the equipment drain tank.

The drywell equipment drain tank drains by gravity. The drain tank's discharge valves automatically open when a predetermined high level in the tank is reached. The discharge valves close at a predetermined low level.
Water flow rate better than 0.5 gpm can be obtained by monitoring changes of level over a time period. The following method of flow rate measurement was selected to comply with the requirements of Regulatory Guide 1.45. The necessary sensitivity is obtained by measuring the changes of level during a fixed time interval. For this purpose a continuous level measurement system is installed in the tank. An electronic signal directly proportional to the actual tank level is applied to one pen of a multi-pen recorder, to an electronic sample and hold device, and to an electronic differential switch. The sample and hold device, upon command from a timer, applies its output signal to the second pen of the multi-pen recorder and to the second input of the electronic differential switch. The sample and hold unit's output signal level is regularly updated to the reference tank level signal.

The actual level signal of the tank and the reference level signal are continuously displayed on the multi-pen recorder. The same signals are being monitored by the electronic differential switch. When the level signals differ by 216 gallons or more during a 50 minute period (equal to 4.3 gpm) an alarm is actuated on the local panel and on the control board in the main control room. The change in tank level per unit of time determines the leak rate and is available from the recorder.

5.2.5.1.2.4.4 Sensitivity and Response Time of Measurement

The method for liquid leak detection in the primary containment is designed to meet the recommended water leak rate changes of 0.5 to 1.0 gpm as defined in Regulatory Guide 1.45.

The following assumptions and design considerations were incorporated:

a) Leak rate is directly proportional to the associated change in sump level.

b) The selected measurement period T for the average change in level is 50 minutes (not available on Unit 1 drywell floor drain sump).

c) The drywell floor drain sumps have a capacity of 150 gal with a depth of 5 in. The drywell equipment drain tank useful capacity is 842 gal with a useful depth of 36 in.

d) Recorder response is equal to 1 second for full range.

e) The electronic differential switch setpoint can alarm at rates less than or equal to one gpm (not available on Unit 1 drywell floor drain sump).

These design factors allow a detection of 1 gpm flow rate within a 50-minute time period (not available on Unit 1 drywell floor drain sump).

The operator can verify this leak rate on the recorder in the control room by observation of the average change of level (not available on Unit 1 drywell floor drain sump).

<u>5.2.5.1.2.4.5 Signal Correlation and Calibration</u>

<u>Drywell Floor Drain Sump</u>

The sump depth of 0-5 in. is displayed on a 0-100 percent recorder chart, which relates to the sump nominal capacity of 0-150 gal.

<u>Drywell Equipment Drain Tank</u>

The measured tank depth of 36 in. is displayed on a 0-100 percent recorder chart. This relates directly to the measured tank capacity of 842 gal.

<u>5.2.5.1.2.4.6 Seismic Qualifications</u>

The drywell floor drain sump, all drywell drain piping, and all instrumentation used to monitor drywell floor drain sump are qualified to operate following an OBE. The drywell equipment drain tank, drywell equipment drain tank level instrumentation, and drywell floor drain sump pumps are not qualified to operate following an OBE.

Credit will be taken for monitoring unidentified leakage following an OBE thru the use of the drywell floor drain sump level monitoring system. The proper functioning of at least one leakage detection system following an SSE is provided by the design of the air borne radioactivity monitoring system. Refer to Subsection 7.6.1b for description.

<u>5.2.5.1.2.4.7 Testing and Calibration</u>

Calibration of level sensors is possible by observing the change in level during the periodic pump down operations of the drywell floor drain sump, and periodic draining of the drywell equipment drain tank.

For the drywell floor drain sump, the pumps are automatically started and stopped by electronic level switches which receive their signals from the level probes in the sumps, but can also be operated manually, at any time, to check the calibration of the level sensors. In the event that the high-high level is reached, two pumps will operate. The drain tank discharge valves are opened automatically on high level and can be operated manually at any time, to check the calibration of the level sensors.

5.2.5.1.3 Detection of Abnormal Leakage Outside the Primary Containment

The method used to monitor for leakage for each reactor coolant pressure boundary component is listed in Table 5.2-8. Leak detection systems are also described in FSAR Section 7.3.1.1a.2 and 7.6.1a.4.

(1) Ambient and Differential Room Ventilation Temperature

Outside drywell, the piping within each system which interfaces with the reactor coolant pressure boundary is installed in compartments or rooms, separate form other systems where feasible, so that leakage may be detected by area temperature measurement. Ambient and differential temperature sensors are installed in the HPCI, RCIC, RHR and RWCU equipment rooms, the HPCI/RCIC Piping Area and the Reactor Building Main Steam Tunnel. Ambient temperature sensors are installed in the Turbine Building Main Steam Tunnel.

Ambient temperature switches, connected to the respective sensors, initiate an alarm or system isolation when the temperature rises to a preset value. Differential temperature switches initiated a system isolation and an associated isolation alarm if differential temperature reached the isolation setpoint. This leak detection isolation feature has been disabled and the instrumentation remains in place. Differential temperature switches, connected to respective to respective sensors, initiate a pre-isolation alarm to alert operators of a potential reactor coolant release. The high ambient set points include sufficient margin above the post LOCA or normal design maximum temperature to preclude inadvertent isolation signals. The setpoints isolation and alarm are designed to detect a leakage rate below the leak rate corresponding to critical crack size for the smallest high energy line in the room which is part of the respective system. The HPCI, RCIC, and RWCU equipment rooms, HPCI/RCIC Piping Area and Main Steam Tunnel ambient and differential temperature switch set points are based on the temperature rise resulting from a leak at system conditions corresponding to full reactor power. The RHR Pump Room ambient and differential temperature switch set points are based on the temperature rise resulting from a leak at system conditions corresponding to Hot Shutdown (Reactor Condition 3). The RHR Pump Room ambient and differential temperature instruments have been removed from the Technical Specifications. The RHR Pump Room ambient and differential temperature instruments initiate an alarm only when temperature rises to a preset value.

(2) Visual and Audible Inspection

Accessible areas are inspected periodically and the temperature indicators discussed above are monitored regularly as required by Chapter 16. Alarms provide visual and audible indication in the control room of leakage. Any indication of abnormal leakage will be investigated.

(3) Differential Flow Measurement (Reactor Water Cleanup System Only)

Because of the arrangement of the reactor water cleanup system, differential flow measurement provides an accurate leakage detection method. The flow from the reactor vessel is compared with the flow back to the vessel. An alarm in the control room and an isolation signal are initiated when higher flow out of the reactor vessel indicates a leak may exist.

(4) Equipment Room Flood (Water Level) Detection

The HPCI, RCIC Core Spray and RHR Equipment Rooms are monitored for water level on the floor of the room. When the water level reaches a preset value, an alarm is initiated in the control room. The level switches are designed to detect water accumulation resulting from a leak. For a water leak, the accumulation will account for nearly 100% of the leaking fluid. For a steam leak, the water accumulation will consist of the percentage of leaking steam which condenses to water within the room.

(5) Detection of Large Leaks (High Flow and Low Reactor Water Level)

The main steam line, HPCI steam line, RCIC steam line, RHR Shutdown Cooling suction line and RWCU suction line are all monitored for high flow. A high flow signal will initiate an alarm in the control room and isolation of the system. Low reactor water level will isolate the main steam, RHR and RWCU lines. High flow or low reactor water level can indicate a break or large leak in the reactor coolant piping.

5.2.5.2 Leak Detection Devices for NSS-System

(1) Reactor Vessel Head Closure

The reactor vessel head closure is provided with double seals with a leak off connection between seals that is piped through the normally closed manual valves to the equipment drain tank. Leakage through the first seal is indicated locally in the reactor building. The second seal then operates to contain the vessel pressure.

(2) Reactor Water Recirculation Pump Seal

As discussed in Subsection 5.4.1.3, the reactor recirculation pump shaft is provided with two seals. Leakage past each seal is piped to the Drywell Equipment Drain Tank. Leakage past the first stage seal is designed to flow at approximately 0.75 gpm normally. The first stage seal leakoff line is provided with a high/low flow alarm which actuates at 0.9 gpm increasing or 0.5 gpm decreasing. The second stage pump seal is designed for zero leakage normally. The second stage seal leakoff line is provided with a high flow alarm which actuates at 0.1 gpm.

(3) Safety/Relief Valves

Temperature sensors connected to a multipoint recorder are provided to detect safety/ relief valve leakage during reactor operation. Safety/relief valve temperature elements are mounted, using a thermowell, in the safety/relief valve discharge piping several feet from the valve body. Temperature rise above ambient is annunciated in the main control room. See the nuclear boiler system P&ID, Dwgs. M-141, Sh. 1 and M-141, Sh. 2.

(4) Valve Packing Leakage

Power-operated valves in the nuclear boiler system and recirculation system were originally provided with valve stem packing leakoff connections. These leakoffs were either plugged or provided with normally closed isolation valves and capped. It was thought by keeping these leakoff connections isolated and thereby providing two sets of valve packing, that stem leakage would be limited. Recent research and testing has,

in fact, shown that one set of graphite packing provides a more effective seal than two independent sets of packing. As a result, a programmatic replacement of the two sets of packing with one set of graphite packing has been undertaken. As part of this effort leakoff isolation valves will be removed and the leakoff lines will be permanently capped.

5.2.5.3 Limits for Reactor Coolant Leakage

5.2.5.3.1 Total Leakage Rate

The total leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain sumps and the equipment drain tank. 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 25 gpm. The total leakage rate limit is also set low enough to prevent overflow of the drywell sumps.

5.2.5.3.2 Normally Expected Leakage Rate

The pump packing glands, valve stems, and other seals in systems that are part of the reactor coolant pressure boundary and from which normal design leakage is expected are provided with drains or auxiliary sealing systems. Nuclear system valves and pumps inside the drywell are equipped with double seals. The double seals on valves are systematically being replaced with single sets of graphite packing. A single set of graphite packing has been shown to produce a more effective seal than a double set of standard packing. Leakage from the primary recirculation pump seals is piped to the drywell equipment drain tank as described in Subsections 5.2.5.2(2) and 5.4.1.3. Leakage from the safety/relief valves is identified by temperature sensors in the discharge line that transmit to the control room. Any temperature increase above the drywell ambient temperature detected by these sensors indicates valve leakage.

Except for the leakoffs from the reactor recirculation pumps, all drains routed to the Drywell Equipment Drain Tank are normally isolated by closed valves. Therefore, any leakage measured during normal plant operation in the Equipment Drain Tank is attributable to the recirculation pumps.

The leakage rates from the recirculation pumps, plus any other leakage rates measured while the drywell is open, are defined as identified leakage rates. Table 5.2-11 lists normal and maximum identified leakage rates directed into the Drywell Equipment Drain Tank, and the associated activity concentrations.

5.2.5.4 Unidentified Leakage Inside the Drywell

5.2.5.4.1 Unidentified Leakage Rate

The unidentified leakage rate is the portion of the total leakage rate received in the drywell 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 5.2-10). Safety limits and safety limit settings are discussed in Chapter 16.
Table 5.2-12 lists unidentified leakage rates directed into the Drywell Floor Drain Sump, and the associated Activity Concentrations.

5.2.5.4.2 Sensitivity and Response Times

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

5.2.5.4.3 Length of Through-Wall Flaw

Experiments conducted by GE and Battelle Memorial Institute, (BMI), permit an analysis of critical crack size and crack opening displacement (Reference 5.2-4). This analysis relates to axially oriented through-wall cracks.

(1) Critical Crack Length

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

$$\ell_c = \frac{15000\,D}{\sigma_h}$$

where

ℓ_c = critical crack length (in.)
D = mean pipe diameter (in.)

σ_h = nominal hoop stress (psi).

(2) Crack Opening Displacement

The theory of elasticity predicts a crack opening displacement of

$$w = \frac{2\ell\sigma}{E} \quad \text{(Eq. 5.2-1)}$$

where

ℓ	=	crack length
σ	=	applied nominal stress
E	=	Young's Modulus

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

$$c = \mathrm{SEC}\,\frac{\pi\sigma}{2\sigma_f}$$

The crack opening area is given by

$$A = C\,\frac{\pi}{4}\,wl\,\frac{\pi l^2 \sigma}{2E}\quad \mathrm{SEC}\,\frac{\pi\sigma}{2\sigma_f}$$

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

(3) Leakage Flow Rate

The maximum flow rate for blowdown of saturated water at 1000 psi is 55 lb/sec-in^2. and for saturated steam the rate is 14.6 lb/sec-in^2, (Reference 5.2-5). Friction in the flow passage reduces this rate, but for cracks leaking at 5 gpm (0.7 lb/sec) the effect of friction is small. The required leak size for 5 gpm flow is

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

From this mathematical model, the critical crack length and the 5 gpm crack length have been calculated for representative BWR pipe size (Schedule 80) and pressure (1050 psi).

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

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

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

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

It is important to recognize that the failure of ductile piping with a long, through-wall crack is characterized by large crack opening displacements which precede unstable rupture. Judging from observed crack behavior in the GE and BMI experimental programs, involving both circumferential and axial cracks, it is estimated that leak rates of hundreds of 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 sq in. 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 5.2-10 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 would be initiated and the reactor would be placed in a cold shutdown condition within 24 hours.

5.2.5.4.4 Margins of Safety

The margins of safety for a detectable flaw to reach critical size are presented in Subsection 5.2.5.4.3. Figure 5.2-10 shows general relationships between crack length, leak rate, stress and line size using the mathematical model.

5.2.5.4.5 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 drywell and reactor building as shown in Table 5.2-8. 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 will satisfactorily detect unidentified leakage of 5 gpm. Sensitivity, including sensitivity testing and response time of the leak detection system, and the criteria for shutdown if leakage limits are exceeded, are covered in Section 7.6.1.

5.2.5.5 Differentiation Between Identified and Unidentified Leaks

Subsection 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 Subsections 5.2.5.1, 5.2.5.4 and 7.6.1.

5.2.5.6 Sensitivity and Operability Tests

Testability of the leakage detection system is contained in Subsection 7.6.1.

5.2.5.7 Safety Interfaces

The Balance of Plant-GE Nuclear Steam Supply System safety interfaces for the Leak Detection system are the signals from the monitored balance of plant equipment and systems which are part of the nuclear system process barrier, and associated wiring and cable lying outside the Nuclear Steam Supply System Equipment. These balance of plant systems and equipment include the main steam line tunnel, the safety/relief valves, and the drywell sumps and equipment drain tank.

5.2.5.8 Testing and Calibration

Provisions for Testing and Calibration of the leak detection system is covered in Chapter 14.

5.2.6 References

5.2-1 R. Linford, "Analytical Methods of Plant Transient Evaluation for the General Electric Boiling Water Reactor," NEDO-10802, April, 1973.

5.2-2 J. M. Skarpelos and J. W. Bagg, "Chloride Control in BWR Coolants," June, 1973, NEDO-10899.

5.2-3 W. L. Williams, Corrosion, Vol. 13, 1957, p. 539t.

5.2-4 GEAP-5620, Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flows, by M. B. Reynolds, April, 1968.

5.2-5 "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," NUREG-76/067, NRC/PCSG, dated October, 1975.

5.2-6 F. Odar, "Safety Evaluation for General Electric Topical Report: Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," NEDO-24154, NEDE-24154-P Vol. I, II, III, dated June, 1980.

5.2-7 Faynshtein, K., and D. R. Pankratz, "Power Uprate Engineering Report for Susquehanna Steam Electric Station, Units 1 and 2," General Electric Report NEDC-32161P, as revised by PP&L Calculation EC-PUPC-1001, Revision 0, March, 1994.

5.2-8 Not Used

5.2-9 Not Used

5.2-10 Not Used

5.2-11 Not Used

5.2-12 Not Used

5.2-13 Not Used

5.2-14 XN-NF-80-19(P)(A) Volume 4, Revision 1, Exxon Nuclear Methodology for Boiling Water Reactors: Application of the ENC Methodology to BWR Reloads, Exxon Nuclear Company, June 1986.

5.2-15 ANF-913(P)(A) Volume 1 Revision 1 and Volume 1 Supplements 2,3, and 4 COTRANSA2: A Computer Program for Boiling Water Reactor Transient Analyses, Advanced Nuclear Fuels Corporation, August 1990.

5.2-16 ANP-10300P-A Revision 1, AURORA-B: An Evaluation Model for Boiling Water Reactors; Application to Transient and Accident Scenarios, Framatome, January 2018.

TABLE 5.2-1

REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

CODE CASE INTERPRETATIONS

For GE supplied equipment, the following applicable Code Case Interpretations are listed below:

A. Vessel Fabrication: Section III Cases

1.	1141-1	Foreign Produced Steel
2.	1332-5	Requirements for Steel Forgings
3.	1420	Nickel-Chromium-Iron Alloy Pipe or Tube
4.	1441-1	Waiving of 3S Limit for Section III Construction
		As the need arises, we intend to permit the use of the following code cases:
5.	1492	Postweld Heat Treatment, Section I, III and VIII, Div. 1 and 2

B. System Assembly Cases That May Be Applied: Section III Cases

1.	1424	Requirements for Stamping of Field Installation for Section III, Class A, Vessels
2.	1428	Field Welding of Joints Between Components
3.	1429	Completion of Components in the Field
4.	1430	Owner's Certificate of Authorization
5.	1442	Pressure Tests of Nuclear Components

C. Pressure Integrity of Piping and Equipment

1. Code Case 78, ANSI B31, Documentation for pipe and fittings 3/4 inch nominal pipe size and smaller.
2. Code CASE 1388, Requirements for stainless steel - precipitation hardening. Control valves.
3. Code Case 1555, Certification of Liquid Pressure Safety Relief Valves on Liquids for which NV Code Symbol Stamp applies.
4. Code Case N-242, Materials Certification, Alternate rules used for Section III, Division 1, Classes 1,2,3,MC and CS Component Construction.

TABLE 5.2-2

NUCLEAR SYSTEM SAFETY /RELIEF SET POINTS*

UNITS 1 AND 2

No. of Valves	Spring Set Pressure (psig)	ASME Rate Capacity at 103% Spring Set Pressure (lbs/hr)
2	1175	883,950
6	1195	898,800
8	1205	906,250

* Six of the Safety Relief Valves Serve in the Automatic Depressurization Function.

TABLE 5.2-3

DESIGN TEMPERATURE, PRESSURE AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS

Component	Design Temperature (F°)	Design Pressure (psig)	Maximum Test Pressure (psig)
REACTOR VESSEL	575	1250	1563
RECIRCULATION SYSTEM			
Pump Discharge Piping	575	1500	(1)
Pump Suction Piping	575	1250	(1)
Pump	575	1500	(2)
Discharge Valves	575	1525	(2)
Suction Valves	575	1275	(2)
MAIN STEAM SYSTEM			
Reactor Vessel to Second Isolation	575	1250	(1)
Valve Piping	575	1250	(3)
Valves			
RESIDUAL HEAT REMOVAL SYSTEM			
Shutdown Suction			
Recirculation Suction Piping through Second Isolation Valve			
Piping	565	1250	
Valves	565	1250	(1)
Recirculation Discharge Piping Through Second Isolation Valves			(2)
Piping	565	1500	
Valves	565	1500	(1)
			(2)
REACTOR FEEDWATER			
Reactor Vessel to Maintenance Valve (F011)	575	1250	(1)
Piping		1250	
Maintenance Valve through Outboard Isolation Valve			
Piping	546	1350	
Valves	546	1350	

TABLE 5.2-3

DESIGN TEMPERATURE, PRESSURE AND MAXIMUM TEST

PRESSURE FOR RCPB COMPONENTS

Component	Design Temperature (F°)	Design Pressure (psig)	Maximum Test Pressure (psig)
REACTOR CORE ISOLATION COOLING SYSTEM			
Main Steam Line Through Second Isolation Valve	585	1250	(1)
Piping	585	1250	(2)
Valves			
RCIC Steam Supply Break Detection Instrumentation Line	585	1350	(1)
Piping	585	1350	(2)
Valves			
HIGH-PRESSURE COOLANT INJECTION SYSTEM			
Main Steam Line Through Second Isolation Valve	585	1250	(1)
Piping	585	1250	(2)
Valves			
HPCI Steam Supply Break Detection Instrument Line	585	1350	(1)
Piping	585	1350	(2)
Valves			
CORE SPRAY SYSTEM			
DCA-107 Injection Lines to Reactor Vessel	575	1250	(1)
Piping	575	1250	(2)
Valves			
DCA-109 Injection Lines to Second Isolation Valve	400	1250	(1)
Piping	400	1250	(2)
Valves			
STANDBY LIQUID CONTROL SYSTEM			
Reactor Vessel to Second Isolation Valve	575	1250	(1)
Piping	575	1250	(2)
Valves			

TABLE 5.2-3

DESIGN TEMPERATURE, PRESSURE AND MAXIMUM TEST PRESSURE FOR RCPB COMPONENTS

Component	Design Temperature (F°)	Design Pressure (psig)	Maximum Test Pressure (psig)
REACTOR WATER CLEANUP SYSTEM			
Pump Suction			
Recirculation Suction Piping to Isolation Valve Outside Drywell	565	1250	(1)
Piping	565	1250	(2)
Valves			
Vessel Drain to Pump Suction	565	1250	(1)
Piping	565	1250	(2)
Valves			

(1) Test pressure is calculated at 1.25 x design pressure.

(2) Test pressure is calculated at 1.50 x design pressure.

(3) Test pressure is based on interpolation of ANSI B16.5 tables for design pressure and temperature designated.

TABLE 5.2-4

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Component	Form	Material	Specification (ASTM/ASME)
Reactor Vessel Heads, Shells	Rolled Plate	Low Alloy Steel	SA-533 Gr. B
	Welds	Low Alloy Steel	SFA-5.5
RPV Top Head and Shell Closure Flange	Forged Ring	Low Alloy Steel	SA-508 Cl.2
	Welds	Low Alloy Steel	SFA-5.5
RPV Closure Flange Studs	Bar	Alloy Steel	SA-540 Grade B24
RPV Closure Flange Nuts and Washers	Smls Tubing	Alloy Steel	SA-540 Grade B23
RPV Nozzles (N1 through N9, N15)	Forged Shapes	Low Alloy Steel	SA-508 Cl.2
(N10, N11, N12, N13, N16)	Forgings	Ni-Cr-Fe Alloy	SB-166
	Welds	Low Alloy Steel	SFA-5.5
RPV Nozzle Safe Ends (N1, N2, N5 Safe End Ext., N8, N10)	Forgings or Plate	Stainless Steel	SA-182, F 316L SA-336, F8 SA-240, 304 or 316
	Welds	Stainless Steel	SFA-5.9 TP.308L or 316L SFA-5.4 TP.308L or 316L
RPV Nozzle Safe Ends/Cap (N5, N9 Cap)	Forgings	Ni-Cr-Fe	SB-166
	Welds	Ni-CR-Fe	SFA-5.14 TP. ERNiCr-3 or SFA-5.11 TP. ENiCrFe-3
RPV Nozzle Safe Ends (N3, N4, N11, N12, N16)	Forgings	Carbon Steel	SA-105 Gr. 2, SA-106 Gr. B or SA-508 Cl.1
	Welds	Carbon Steel	SA-508 Cl. 1 w/309, 308L overlay SFA-5.1, SFA-5.18 Gr. A,
RPV Cladding	Weld Overlay	Austenitic Stainless Steel	SFA-5.9 or SFA-5.4
Control Rod Drive Housings	Pipe	Austenitic Stainless Steel	SA-312, Type 304
	Welds	Austenitic Stainless Steel	SFA-5.9 or SFA-5.4
	Forgings	Stainless Steel	SA-182, F304
In-Core Housings	Tube	Austenitic Stainless Steel Ni-Cr-Fe	SA-213, Type 304 SB-167
	Welds	Inconel	SFA-5.11, Type ENiCrFe-3 or SFA-5.14, Type ERNiCr-3
		Austenitic Stainless Steel	SFA-5.9 or SFA-5.4
	Forgings	Stainless Steel	SA-182, F304

TABLE 5.2-4

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

Component	Form	Material	Specification (ASTM/ASME)
Nozzle Weld Overlay (N1B)	Welds	Inconel	SFA-5.11, Type ENiCrFe-7 or SFA-5.14, Type ERNiCrFe-7
Nozzle Weld Overlay (U1 N2J)	Welds	Inconel	SFA-5.11, Type ENiCrFe-7 or SFA-5.14, Type ERNiCrFe-7
Additional RCPB component materials and specifications to be used are specified below. Depending on whether impact tests are required and, depending on the lowest service metal temperature when impact tests are required, the following ferritic materials and specifications are to be used:			
Pipe	SA-106 Grade B; SA-333 Grade 6 and SA-155 Grade KCF-70		
Valves	SA-105 Grade II; SA-350 Grade LF2 and SA-216 Grade WCB		
Fittings	SA-105 Grade II; SA-350 Grade LF1 or LF2; SA-234 or WPB; and SA-420 Grade WPL6		
Bolting	SA-193 Grade B7; SA-194 Grades 7 and 2H; SA-194 Grades 4 and 7 impact tested per NB-2300		
Welding	SFA 5.1 (E 7015, 7016 and E 7018 only),		
Material	SFA 5.4, SFA 5.9, SFA 5.18		
For those systems or portions of systems, such as the reactor recirculation system, which require austenitic stainless steel, the following materials and specifications are to be used:			
Pipe	SA-376 Type 304; SA-312 Type 304, Type 304 (0.030 Carbon Max.) and 304L; SA-358 Type 304, Type 304 (0.030 Carbon max.)		
Valves	SA-182 Grade F-304, F304L, and F-316; SA-351 Grades CF-8, CF-8M; CF3, and CF3M; SA-240 Type 316		
Pump	SA-351 Grade CF-8M		
Flanges	SA-182 Grade F-316 and F-316L		
Bolting	SA-193 Grade B7; SA-194 Grades 7 and 2H; SA-194 Grades 4 and 7 impact tested per NB-2300		
Welding	SFA-5.4 (E308-15, E308L-15, E316-15, E308L-16); SFA-5.9 (ER-308, ER 308L, ER-316)		
Fittings	SA-182 Grade F-304 and F-304L; SA-403 Grades WP-304, 304W and WP-304L; SA-479 Type 316		

TABLE 5.2-5

BWR WATER CHEMISTRY

	Concentrations – Parts Per Billion (ppb)				Conductivity	
	IRON	COPPER	CHLORIDE	OXYGEN	μmho/cm @ 25°C	pH @ 25°C
Condensate (1)* (1) (2)	15-30	3-5	≤20	20-50	≈0.1	≈7
Condensate Treatment Effluent (2)*	5-15	<1	≈0.2	20-50	<0.1	≈7
Feedwater (3)*	5-15	<1	≈0.2	20-50	<0.1	≈7
Reactor Water (4)*						
(a) Normal Operation	10-50	<20	<20	100-300	0.2-0.5	≈7
(b) Shutdown	-	-	<20		<1	≈7
(c) Hot Standby	-	-	<20	See Outline	<1	≈7
(d) Depressurized	-	-	<20	8000	<2	6-6.5
Steam (5)*	0	0	0	10000-30000	≈0.1	--
Control Rod Drive Cooling Water (6)*	-	-	<20	≤50	≤0.1	≈7

*Numerals in parenthesis refer to location delineated on Figure 5.2-8

(1) Typical radioactivity concentrations range from 10^{-4} to 10^{-3} uCi/ml.
(2) Typical nickel concentrations are 5 ppb for normal operation.

TABLE 5.2-5

BWR WATER CHEMISTRY

COOLANT CHEMISTRY LIMITING CONDITION FOR OPERATION	COOLANT CHEMISTRY SURVEILLANCE REQUIREMENTS
a. Prior to startup and during reactor operation, when the reactor is pressurized, or above 212°F, and at less than 1% of rated steam flow, including hot standby, the reactor coolant shall not exceed the following limits: Conductivity at 25°C — 2 μmho/cm Chloride — 0.1 ppm	a. Reactor coolant shall be continuously monitored to conductivity 1. Whenever the continuous conductivity monitor is inoperable an in-line conductivity measurement shall be obtained at least once every 4 hours. 2. Once a week the continuous monitor shall be checked with an in-line flow cell. This in-line conductivity calibration shall be performed every 24 hours whenever the reactor coolant conductivity is >1.0 μmho/cm at 25°C.
b. During reactor operation in excess of 1% of rated steam flow, the reactor coolant shall not exceed the following limits: Conductivity at 25°C — 1 μmho/cm Chloride — 0.2 ppm	b. During startup prior to pressuring the reactor above atmospheric pressure, measurements of reactor water quality shall be performed to show conformance with Paragraph a. of limiting conditions.
c. During reactor operation in excess of 1% of rated steam flow, the reactor coolant may exceed the limits of Paragraph b only for the time limits specified here. Exceeding these time limits or the following maximum limits shall be cause for immediately shutting down and placing the reactor in the cold shutdown condition. Conductivity — Time above 1 μmho/cm at 25°C 2 weeks/year. Maximum limit – 10 μmho/cm at 25°C Chloride — Time above 0.2 ppm 2 weeks/year Maximum limit – 0.5 ppm The reactor shall be shutdown if pH is <5.6 or >8.6 for a 24-hour period.	c. Whenever the reactor is operating (including hot standby conditions), measurements of reactor water quality shall be performed according to the following schedule: 1. Chloride ion content shall be measured at least once every 96 hours. 2. Chloride ion content shall be measured at least every 8 hours whenever reactor conductivity is >1.0 μmho/cm at 25°C.
d. When the reactor is not pressurized (i.e., at or below 212°F), reactor coolant shall be maintained below the following limits: Conductivity at 25°C — 10 μmho/cm Chloride — 0.5 ppm And pH shall be between 5.3 and 8.6.	d. Whenever the reactor is not pressurized, a sample of the reactor coolant shall be analyzed at least every 96 hours for chloride ion content and pH.
e. When the time limits or maximum conductivity or chloride concentration limits are exceeded, an orderly shutdown shall be initiated immediately. The reactor shall be brought to the cold shutdown condition as rapidly as cooldown rate permits.	

TABLE 5.2-6

SYSTEMS WHICH MAY INITIATE DURING OVERPRESSURE EVENT

SYSTEM	INITIATING/TRIP SIGNAL(S)
Reactor Protection System	Reactor trips "OFF" on High Flux
RCIC	"ON" when Reactor Water Level <L2
	"OFF" when Reactor Water Level >L8
HPCI	"ON" when Reactor Water Level <L2
	"OFF" when Reactor Water Level >L8
Recirculation System	"OFF" when Reactor Water Level <L2
	"OFF" when Reactor Pressure >1125 psi
RWCU	"OFF" when Reactor Water Level <L2

TABLE 5.2-7

WATER SAMPLE LOCATIONS

Sample Origin	Sensor Location	Indicator Location	Recorder** Location	Range µmho/cm	Alarm	Minimum*** Accuracy
Reactor Water Recirculation Loop	Sample Line	Sample Station	Control Room	0-10*	1.0	0.5%
Reactor Water Cleanup Inlet	Sample Line	Sample Station	Control Room	0-10*	1.0	0.5%
Reactor Water Cleanup Outlet	Sample Line	Sample Station		0.5	0.1	0.5%
Control Rod Drive Supply Water	Sample Line	Sample Station		0.1*	0.1	0.5%

* The instrument has auto output scaling change : when selected shifts the output scaling by a factor of 10 when the measured value is less than 10% of the selected output scaling range high limit.

** The output of each sample analyzer is recorded by the Water Chemistry Data Acquisition System.

*** The accuracy is expressed as percent of full scale range. The instruments are sensitive to within or less than the accuracy, and are periodically (1/week) calibrated against laboratory calibration instruments.

Table 5.2-8
SUMMARY OF ISOLATION/ALARM OF SYSTEM MONITORED
AND THE LEAK DETECTION METHODS USED

Security-Related Information
Table Withheld Under 10 CFR 2.390

Table 5.2-9

SEQUENCE OF EVENTS FOR MSIV ISOLATION CLOSURE (TYPICAL)

Security-Related Information
Table Withheld Under 10 CFR 2.390

TABLE 5.2-10

RCPB COMPONENTS IN COMPLIANCE WITH 10CFR50.55(a) (2) (ii)

COMPONENT	CODE APPLIED	CODE REQUIRED BY 10CFR50.55 (a)
*RPV	70S	71S
Recirculation Piping	71S	72S
Recirculation Pumps	71S	71W
MSIV	71S	71W
MSRV	71S	71W

*RPV 10CFR50.55 (a) (2) (ii) compliance is based on the following:

(a) Meeting the requirements of Section NB-2152 of the 1971 edition including the Summer 1971 Addenda of the ASME Code Section III for the work at the SSES site.

(b) Meeting the requirements of Section NB-2400 of the 1971 edition including the Summer 1971 Addenda of the ASME Code Section III for work at the SSES site.

(c) Performing on ASME site audit as required by the 1971 edition of the ASME Code Section III.

Table 5.2-11

IDENTIFIED LEAKAGES INTO THE DRYWELL EQUIPMENT DRAIN TANK

Security-Related Information
Table Withheld Under 10 CFR 2.390

Table 5.2-12

UNIDENTIFIED LEAKAGES INTO THE DRYWELL FLOOR DRAIN SUMP

Security-Related Information
Table Withheld Under 10 CFR 2.390

Table 5.2-13

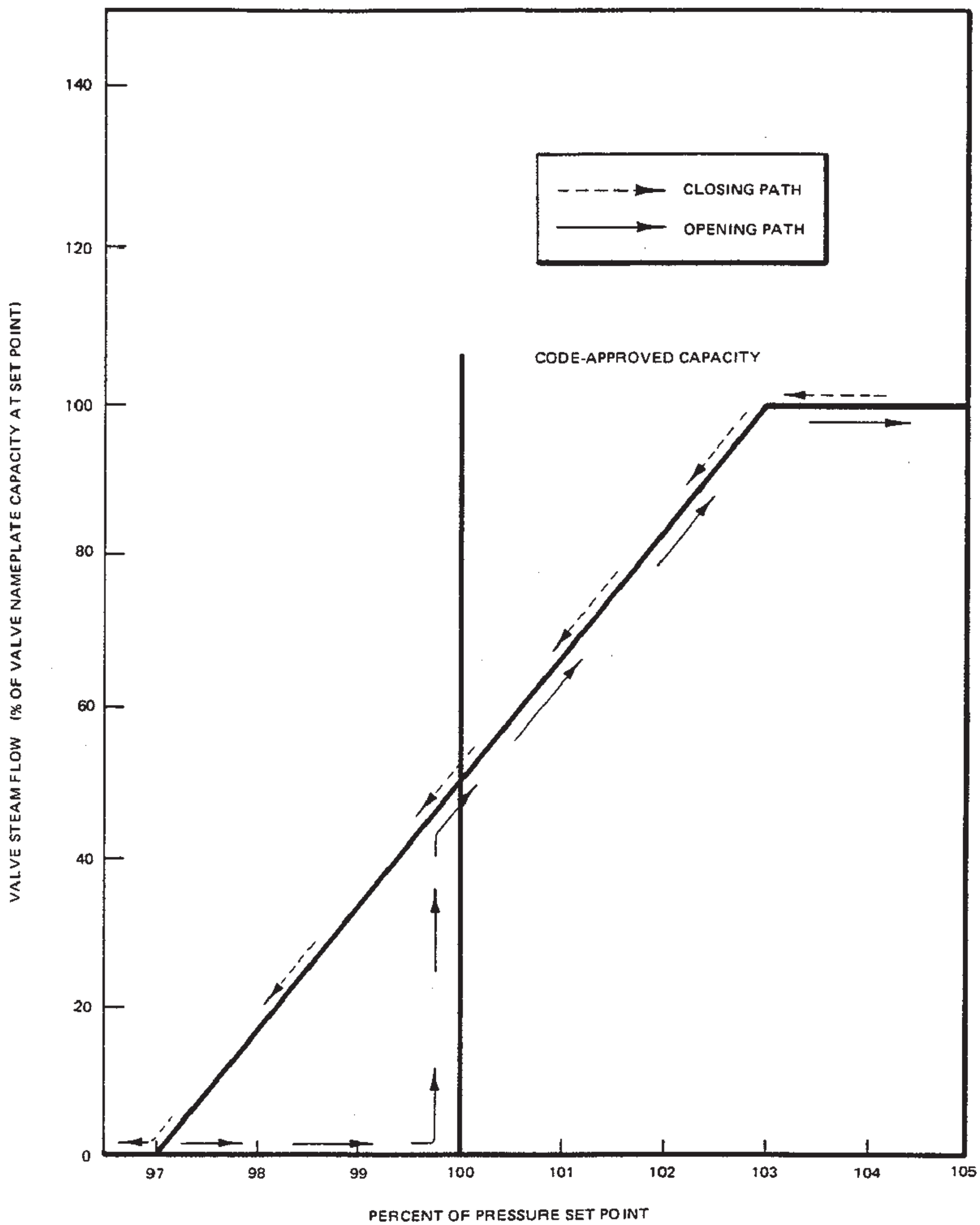
ESTIMATED MONITOR RESPONSES

Security-Related Information

Table Withheld Under 10 CFR 2.390

Table 5.2-14
RCPB LEAK DETECTION MONITORS INSIDE
PRIMARY CONTAINMENT DRYWELL

Security-Related Information
Table Withheld Under 10 CFR 2.390



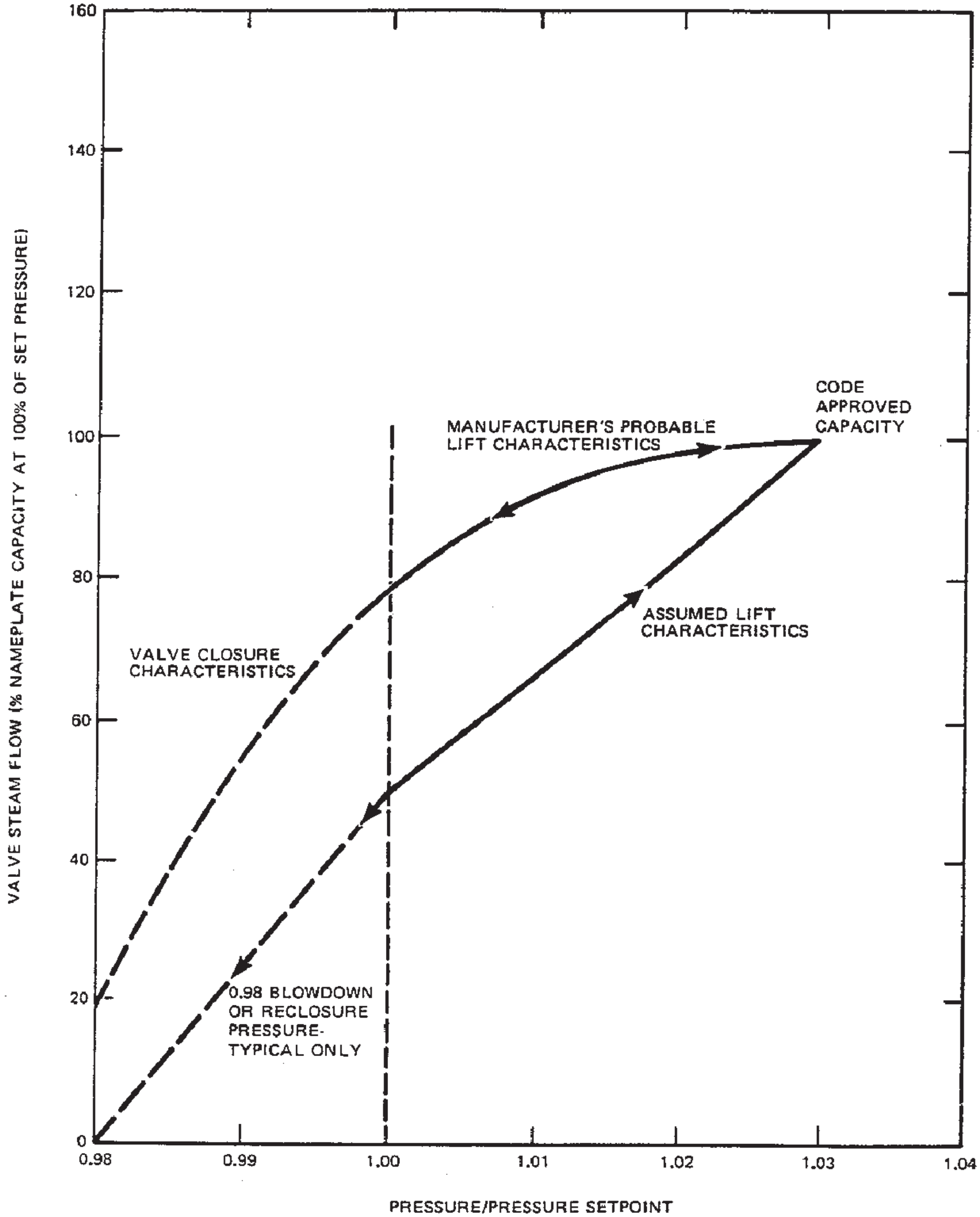
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

SIMULATED SAFETY/RELIEF VALVE
SPRING MODE CHARACTERISTIC
USED FOR CAPACITY SIZING
ANALYSIS

FIGURE 5.2-2, Rev. 49

Atuo Cad: Figure Fsar 5_2_2.dwg



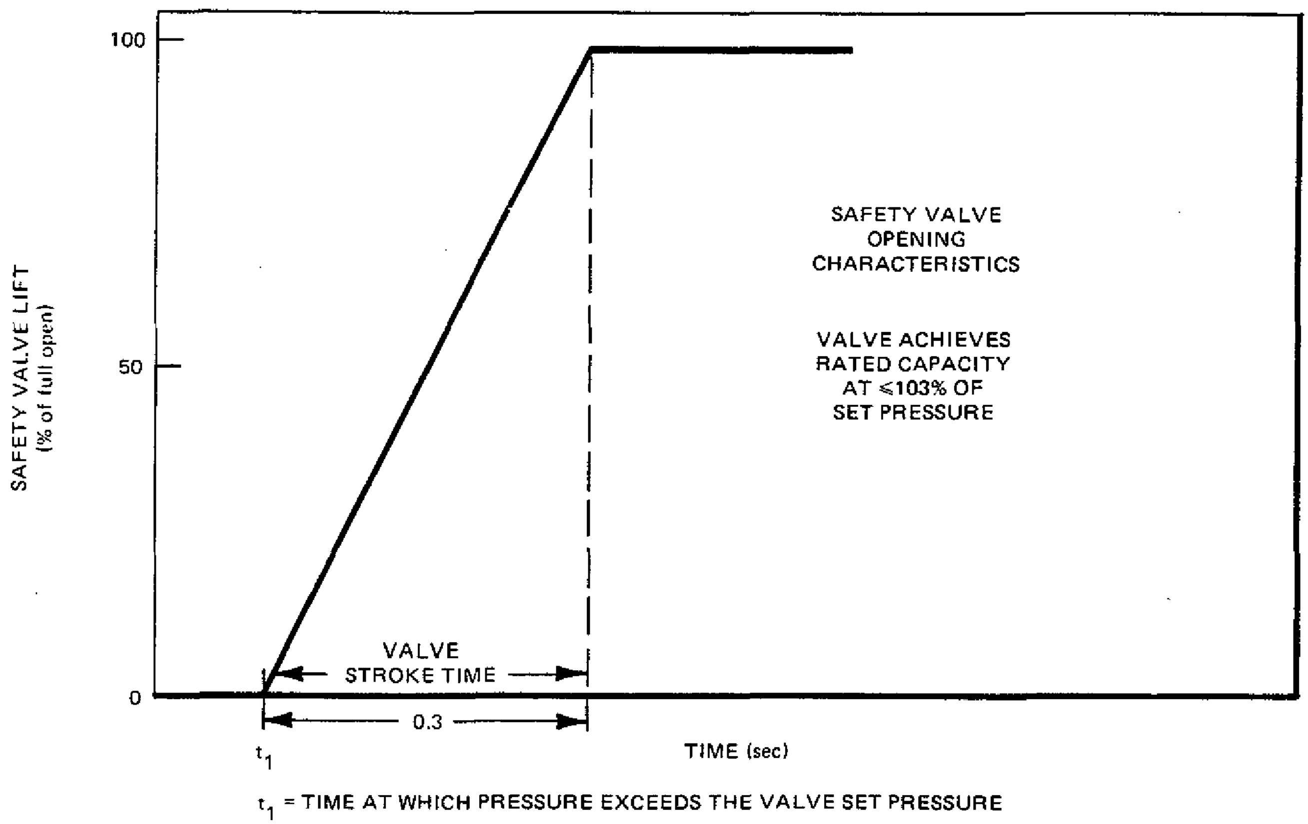
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

SIMULATED SAFETY/RELIEF VALVE
SPRING MODE
CHARACTERISTIC

FIGURE 5.2-2A, Rev.49

AutoCAD: Figure Fsar 5_2_2A.dwg



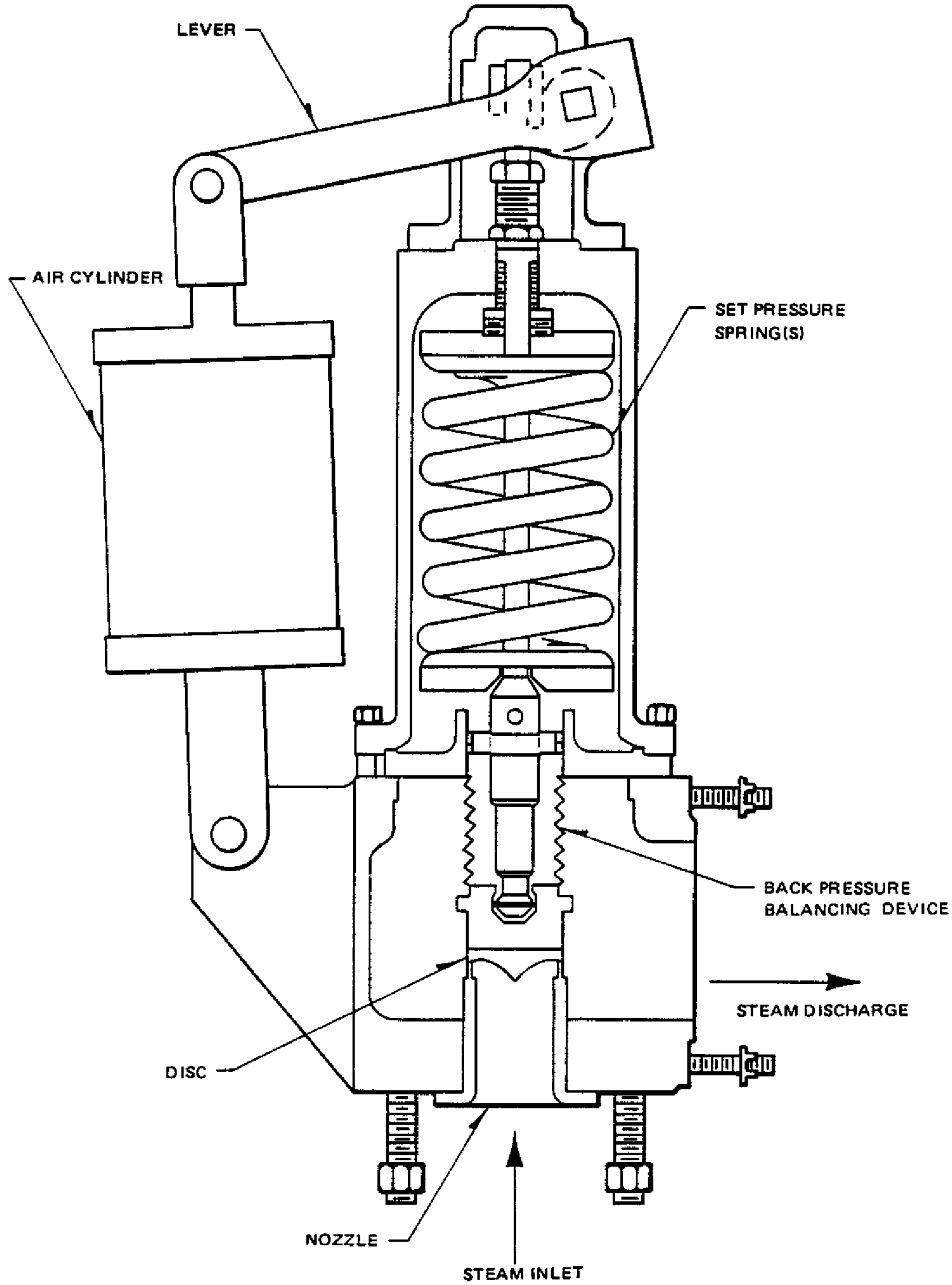
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

SAFETY VALVE LIFT
VERSUS
TIME CHARACTERISTIC

FIGURE 5.2-6, Rev.49

AutoCAD: Figure Fsar 5_2_6.dwg



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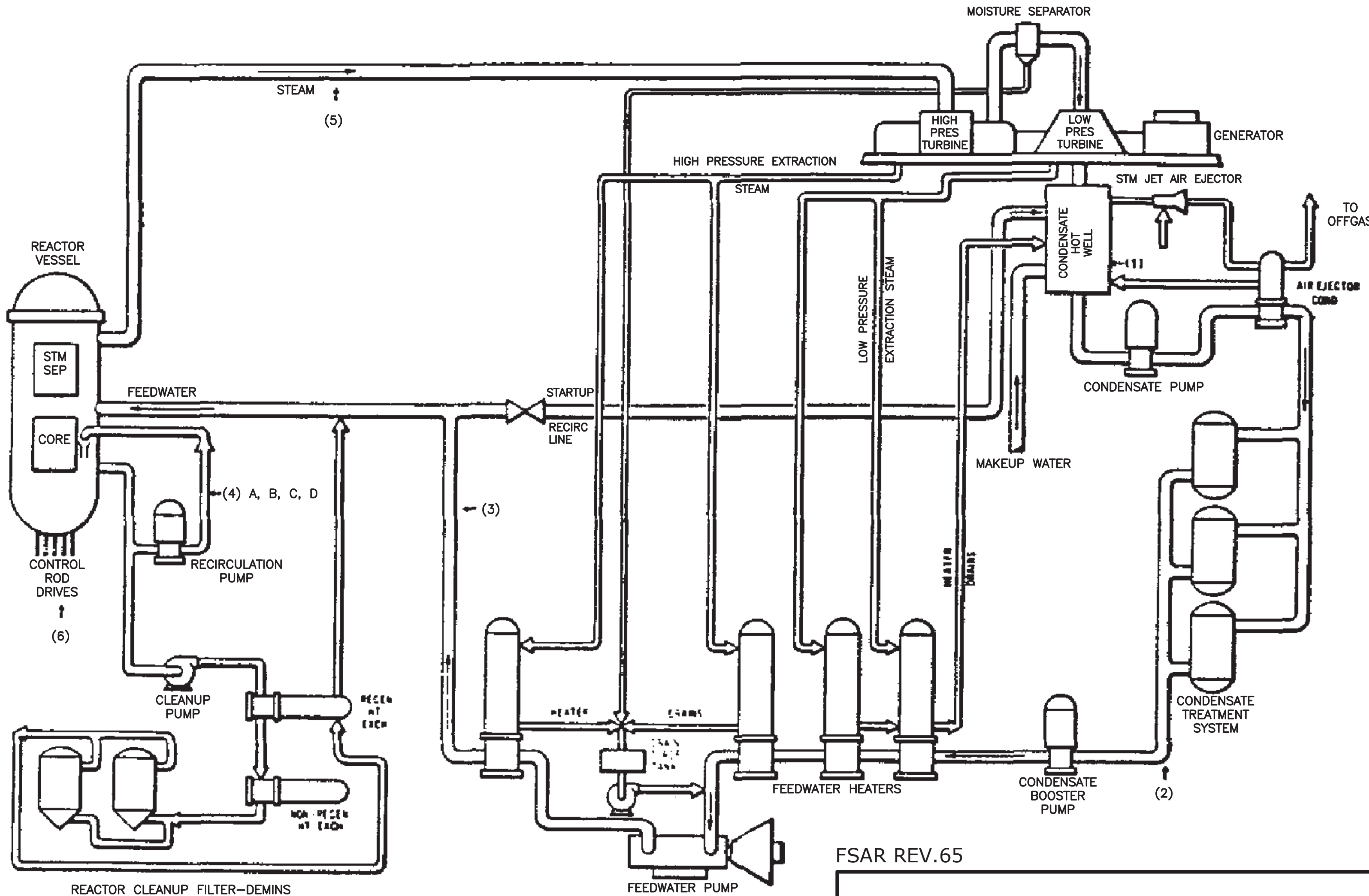
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

SCHEMATIC OF SAFETY VALVE
WITH
AUXILIARY ACTUATING DEVICE

FIGURE 5.2-7, Rev.49

AutoCAD: Figure Fsar 5_2_7.dwg



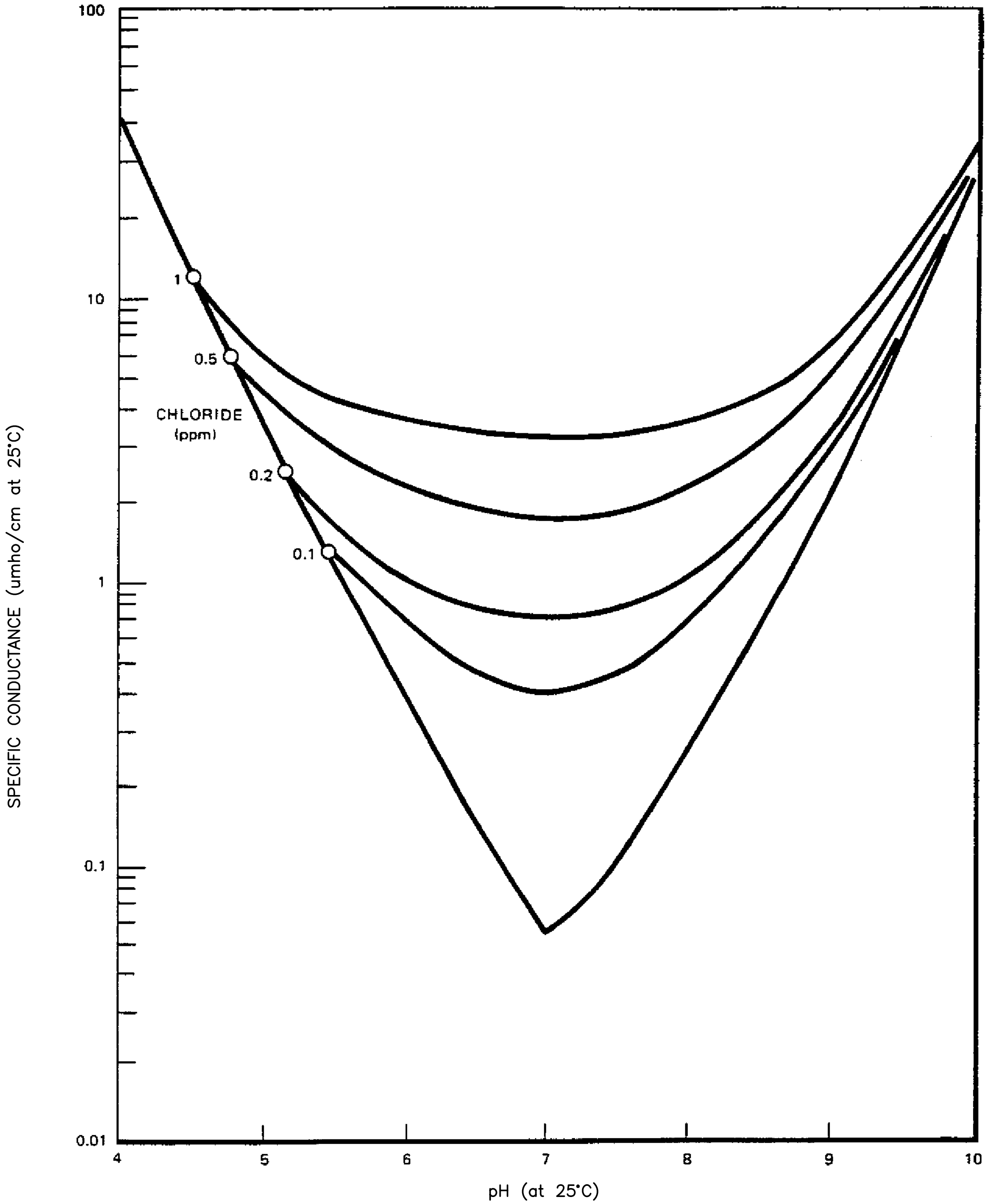
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

TYPICAL BWR FEEDWATER CYCLE

FIGURE 5.2-8, Rev.49

AutoCAD: Figure Fsar 5_2_8.dwg



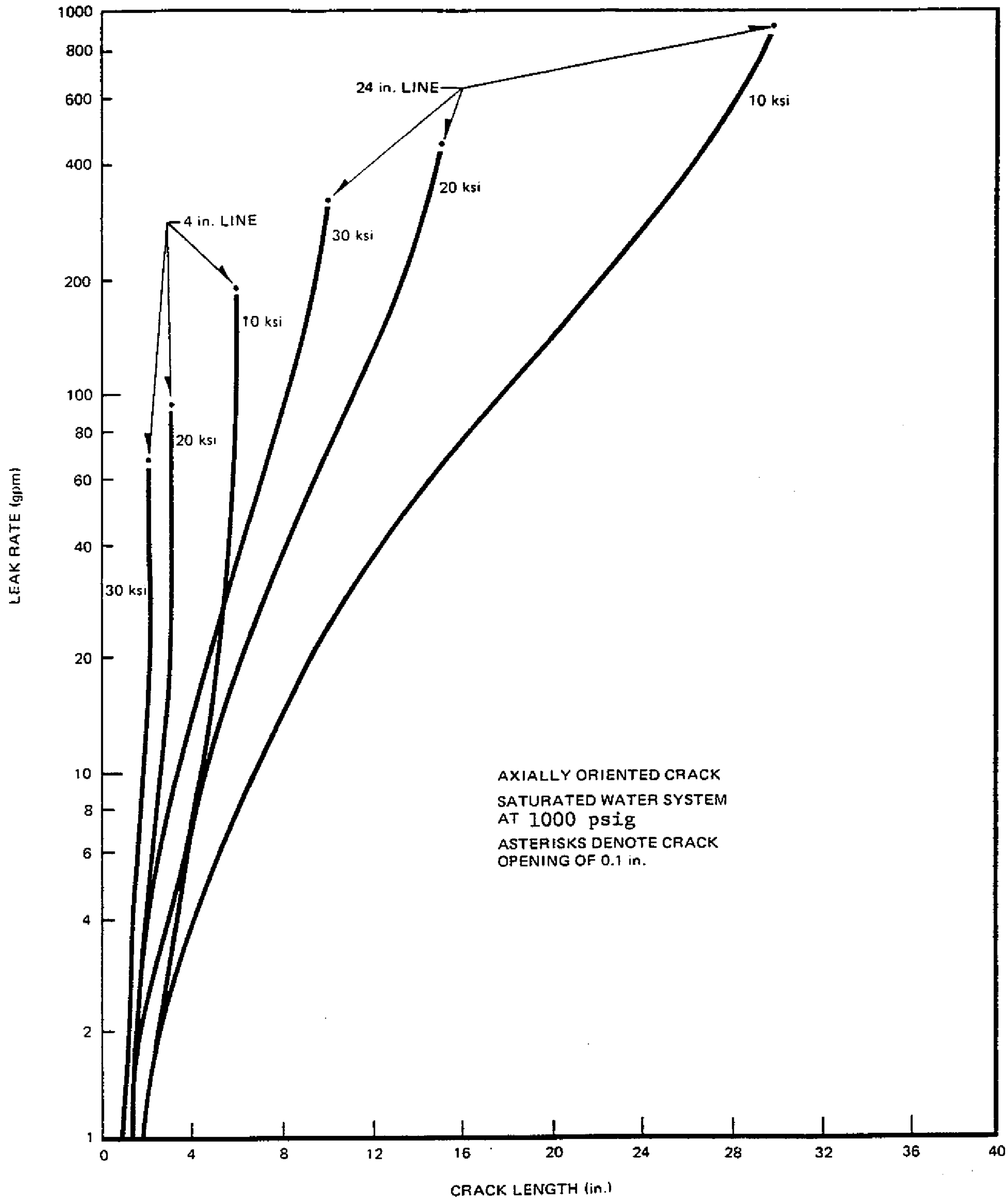
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

CONDUCTANCE VS. PH AS A
FUNCTION OF CHLORIDE
CONCENTRATION OF AQUEOUS
SOLUTION AT 25° C

FIGURE 5.2-9, Rev.49

AutoCAD: Figure Fsar 5_2_9.dwg



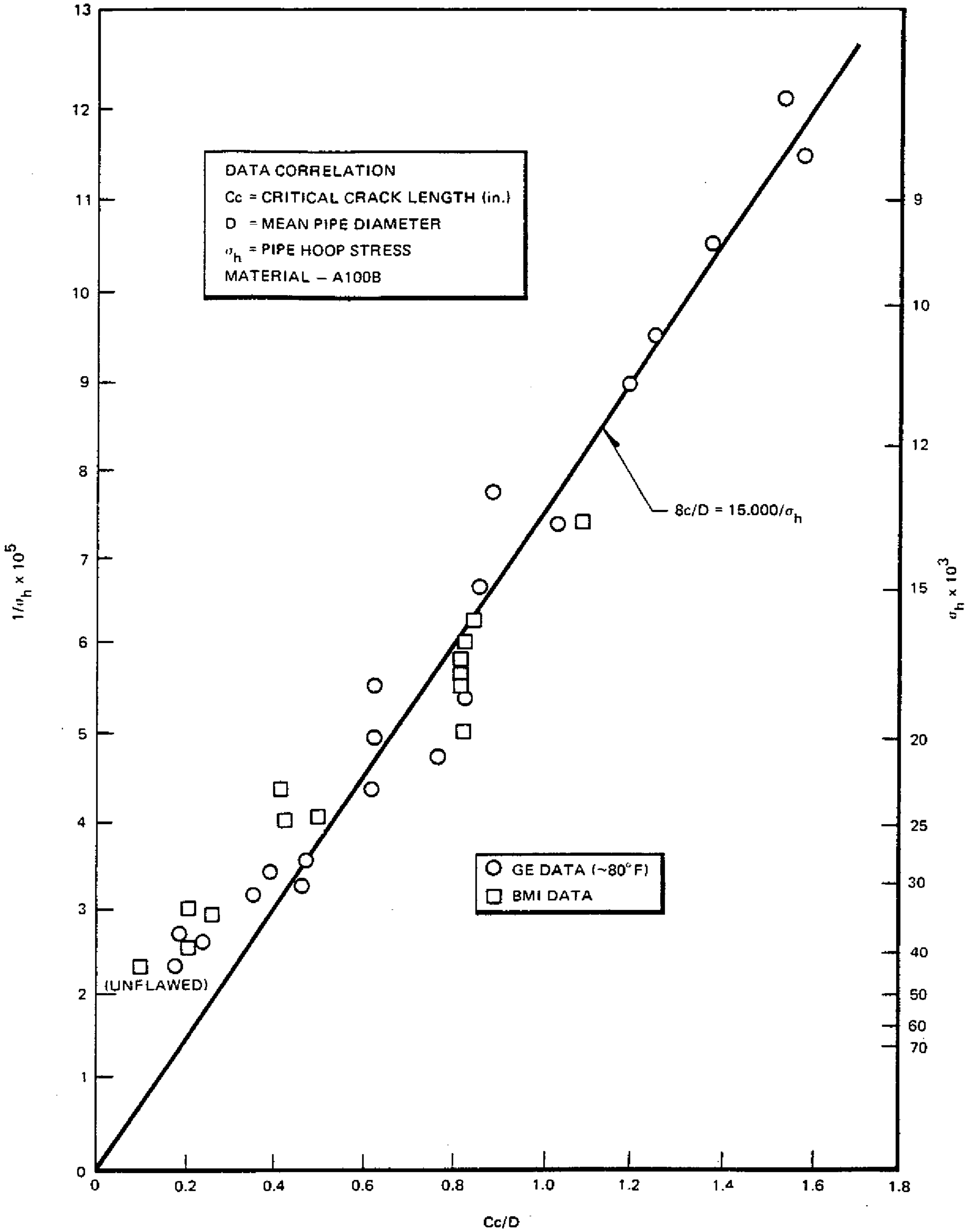
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

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

FIGURE 5.2-10, Rev. 49

Atuo Cad: Figure Fsar 5_2_10.dwg



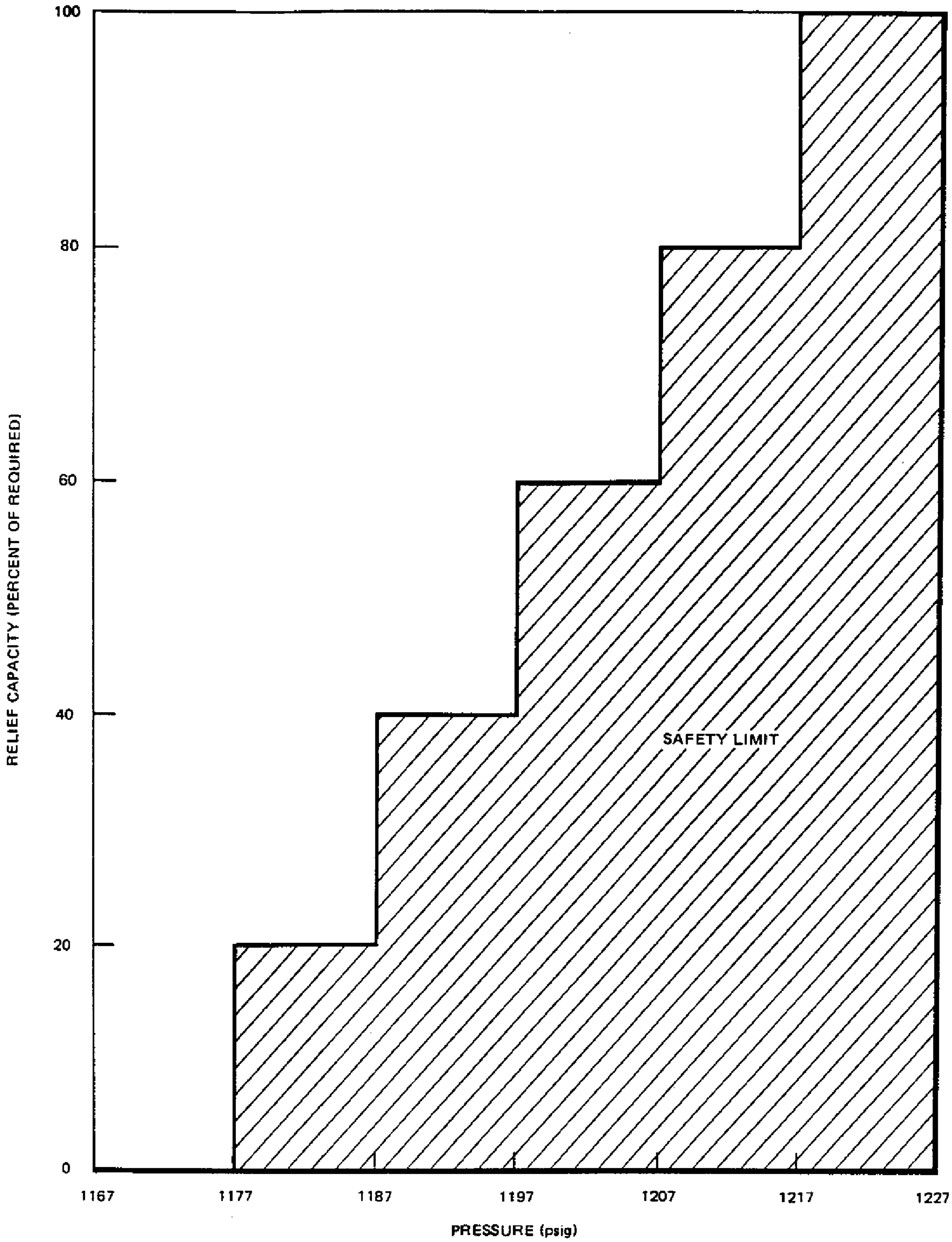
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

AXIAL THROUGH-WALL
CRACK LENGTH
DATA CORRELATION

FIGURE 5.2-11, Rev. 49

Atuo Cad: Figure Fsar 5_2_11.dwg



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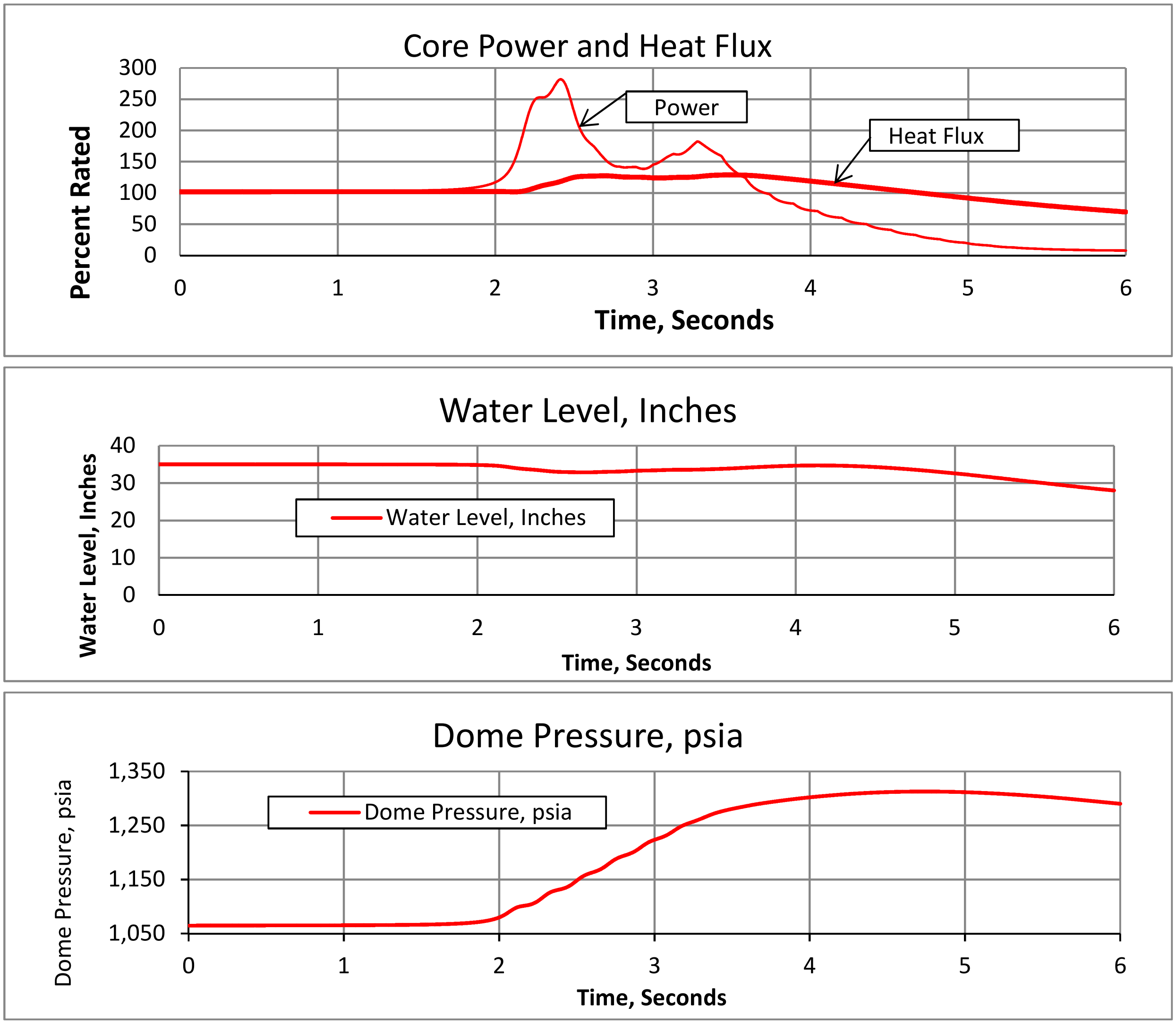
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

REGION FOR SPRING SAFETY
MODE NOMINAL SETPOINT

FIGURE 5.2-12, Rev. 49

Atuo Cad: Figure Fsar 5_2_12.dwg

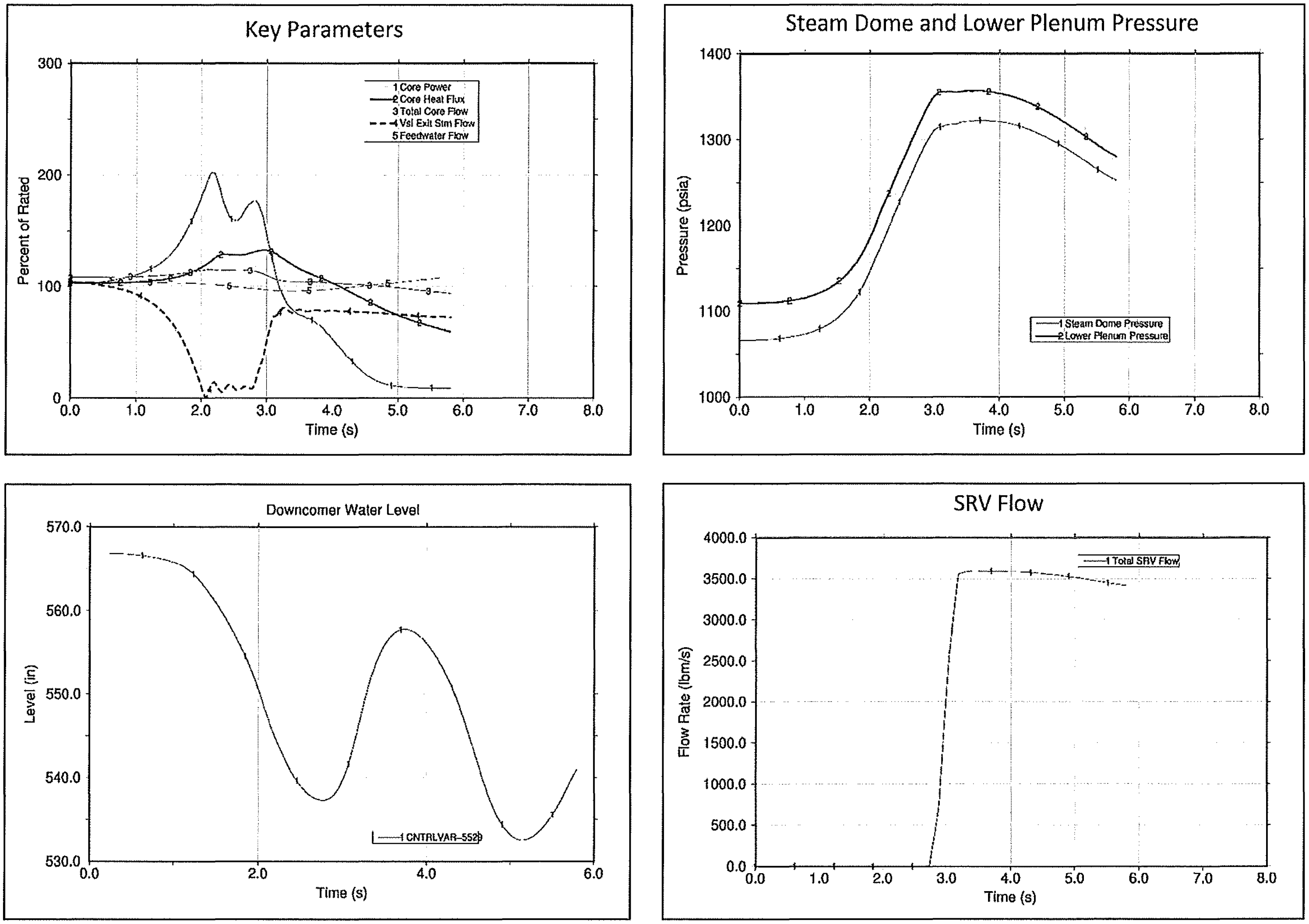


FSAR REV. 69

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

OVERPRESSURE PROTECTION ANALYSIS
(MSIV CLOSURE WITH HIGH FLUX SCRAM TRIP)
TYPICAL OF UNIT 1

Figure 5.2-13, Rev 64



FSAR REV. 70

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

OVERPRESSURE PROTECTION ANALYSIS
(MSIV CLOSURE WITH HIGH FLUX SCRAM TRIP)
TYPICAL OF UNIT 2

FIGURE 5.2-14, Rev 67