CHAPTER 5.0 - REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

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* The listed drawings are included as "General References" only; i.e., refer to the drawings to obtain additional detail or to obtain background information. These drawings are not part of the UFSAR. They are controlled by the Controlled Documents Program.

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CHAPTER 5.0 - REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.1 SUMMARY DESCRIPTION

The reactor coolant system includes those systems and components which contain or transport fluids coming from or going to the reactor vessel. These systems form a major portion of the reactor coolant pressure boundary. This chapter of the Updated Final Safety Analysis Report provides information regarding the reactor coolant system and pressure-containing appendages out to and including the isolation valve. This grouping of components is defined as the reactor coolant pressure boundary (RCPB) and is indicated below.

Reactor coolant pressure boundary (RCPB) means all those pressure-containing components such as pressure vessels, piping, pumps, and valves, which are:

a. part of the reactor coolant system, or

b. connected to the reactor coolant system, up to and including any and all of the following:

    1. the outermost containment isolation valve in system piping which penetrates the primary containment,

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

    3. the reactor coolant system safety/relief valves.

Section 5.4 deals with various subsystems which are closely allied to the RCPB.

The nuclear system pressure relief system protects the reactor coolant pressure boundary from damage due to overpressure. To protect against overpressure, pressure-operated relief valves are provided that can discharge steam from the nuclear system to the suppression pool. The pressure relief system also acts to automatically depressurize the nuclear system in the event of a loss-of-coolant accident in which the high-pressure core spray (HPCS) system fails to maintain reactor vessel water level. Depressurization of the nuclear system allows the low-pressure core cooling systems to supply enough cooling water to cool the fuel adequately.

Subsection 5.2.5 describes the bases for nuclear system leakage inside the drywell so that appropriate action can be taken before the integrity of the nuclear system process barrier is impaired.

The reactor vessel and appurtenances are described in Section 5.3. The major safety consideration for the reactor vessel is the ability of the vessel to function as a radioactive material barrier. Various combinations of loading were considered in the vessel design. The vessel meets the requirements of various applicable codes and criteria. The possibility of brittle fracture is considered, and suitable design and operational limits are established that avoid conditions where brittle fracture is possible.

The reactor recirculation system provides coolant flow through the core. Adjustment of the core coolant flow rate changes reactor power output, thus providing a means of following plant load demand without adjusting control rods. The recirculation system is designed to provide a slow coastdown of flow so that fuel thermal limits cannot be exceeded as a result of recirculation system malfunctions. The arrangement of the recirculation system routing is such that a piping failure cannot compromise the integrity of the floodable inner volume of the reactor vessel.

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

The main steamline isolation valves automatically isolate the reactor coolant pressure boundary in the event a pipe break occurs downstream of the isolation valves. This action limits the loss of coolant and the release of radioactive materials from the nuclear system. Two isolation valves are installed on each main steamline, one inside and the other outside the primary containment.

The reactor core isolation cooling (RCIC) system provides makeup water to the core during a reactor shutdown in which feedwater flow is not available. The system is started automatically upon receipt of low reactor water level signal or manually by the operator. Water is pumped to the core by a turbine-pump driven by reactor steam.

The residual heat removal (RHR) system includes a number of pumps and heat exchangers that can be used to cool the nuclear system under a variety of situations. During normal shutdown and reactor servicing, the RHR system removes residual and decay heat. The RHR system allows decay heat to be removed whenever the main heat sink (main condenser) is not available (e.g., hot standby). One mode of RHR operation allows the removal of heat from the primary containment following a loss-of-coolant accident. Another operational mode of the RHR system is low-pressure coolant injection (LPCI). LPCI operation is an engineered safeguard for use during a postulated loss-of-coolant accident. This operation is described in Section 6.3.

The reactor water cleanup system recirculates a portion of reactor coolant through a filter-demineralizer to remove particulate and dissolved impurities from the reactor coolant. It also removes excess coolant from the reactor system under controlled conditions.

5.1.1 Schematic Flow Diagram

A schematic flow diagram of the reactor coolant system denoting all major components, principal pressures, temperatures (or enthalpies), and flowrates is given in Figure 1.2-1. Figure 5.1-2 shows the typical coolant volumes for a BWR-5 plant under steady state full power operating conditions.

5.1.2 Piping and Instrumentation Diagrams

Piping and instrumentation diagrams covering the systems included within the reactor coolant system and connected systems are presented in the following:

a. the nuclear boiler shown on Drawing Nos. M-93 and M-139,

b. main steam shown on Drawing Nos. M-55 and M-116,

c. feedwater shown on Drawing Nos. M-57 and M-118,

d. recirculation system shown on Drawing Nos. M-93 and M-139,

e. reactor core isolation cooling system shown on Drawing Nos. M-101 and M-147,

f. residual heat removal system shown on Drawing Nos. M-96 and M-142,

g. reactor water cleanup system shown on Drawing Nos. M-97 and M-143.

5.1.3 Elevation Drawing

An elevation drawing showing the principal dimensions of the reactor coolant system in relation to the containment is shown in Figure 5.1-3.

5.1.4 References

1. Power Uprate Project Tasks 100 / 101, “Power Uprate Nominal Heat Balance / Power Uprate Offrated Heat Balance,” GE-NE-A1300384-01, Revision 0, July 1999.

1a. Design Analysis L-003559, Rev. 0, "Reactor Heat Balance," July 2010.

5.2 INTEGRITY OF REACTOR COOLANT PRESSURE BOUNDARY

5.2.1 Compliance with Codes and Code Cases

5.2.1.1 Compliance with 10 CFR 50, Section 50.55a

The reactor pressure vessel for Unit 1 was originally ordered in January 1967 and applied to LSCS in November 1970. Unit 2 RPV was initially ordered for LSCS in January 1970. Design and fabrication had progressed on the basis of ASME 1968 Section III for both these units with respect to materials, welding, and quality control requirements. By the time 10 CFR 50.55a originated, updating these RPV's to the 1971 edition of the code was impossible. This was due primarily to the absence of the earlier requirements for subcontractor material certification and certifications on procedures, test equipment, inspectors' qualifications, etc.

In PSAR Amendment 11 Commonwealth Edison identified this noncompliance with the subsequently issued codes and standards rule. The commission granted approval for relief therefrom for LSCS RPV's and acceptance in lieu thereof the ASME Section III codes and addenda specified in PSAR Amendment 11.

A table which shows compliance with the rules of 10 CFR 50.55a is included in Section 3.2, code edition, applicable addenda, and component dates are in accordance with 10 CFR 50.55a except for those reactor coolant pressure boundary components listed in Table 5.2-2. The design, fabrication, and testing of the reactor coolant pressure boundary components listed in Table 5.2-2 was in accordance with the recognized codes and standards in effect at the time the components were ordered as shown in the table. The code edition and applicable addenda that would be required by strict interpretation of the rules set forth in 10 CFR 50.55a are identified in Table 5.2-2.

The LaSalle application for a construction permit was filed with the Commission in November 1970. At that time, a construction permit was expected before the end of 1971. As is common practice in the utility industry, Commonwealth Edison proceeded with the design engineering, and long-term material and component procurement in anticipation of the Commission's granting a construction permit to meet the filed project schedules. Had the Commission issued the construction permit as initially expected, the requirements of 10 CFR 50.55a would have been met to the letter of the law for the RCPB equipment.

The last reactor recirculation piping was ordered in October 1971 to the 1971 Edition of the ASME Section III Code including the 1971 Summer addenda. A close scrutiny of the 1971 Winter and 1972 Summer addenda has not detected any additional requirements applicable to the fabrication of the recirculation piping. Therefore, updating to the 1972 Summer addenda would produce no noticeable effect on the quality or reliability of the piping and would only incur added expense. This conclusion is in keeping with the recirculation piping code exception granted to

Susquehanna for piping designed to 1971 Code with the Summer addenda and required by purchase order date to comply with the 1972 Summer addenda.

The reactor recirculation gate valves were ordered in April and June of 1971 to the 1971 Edition of the ASME Section III Code. A detailed evaluation of the changes through the 1971 Winter addenda (presented in Table 5.2-2a), has identified no additional requirements applicable to the fabrication of the valves. Therefore, updating to the 1971 Winter addenda would produce no effect on the quality or reliability of the valves and would only incur added expense.

The reactor recirculation pumps were ordered in May 1971 to the 1971 edition of the ASME Section III Code. There were no changes introduced through the 1971 Winter addenda (Table 5.2-2a) which would have a substantive effect on the recirculation pumps. Therefore, upgrading to the 1971 Winter addenda would merely incur added expense with no effect on the design and configuration of the pumps.

As noted in the preceding discussion, the addenda changes have been reviewed with the conclusion that the addenda required by the rules of 10 CFR 50.55a affect documentation format but impose no new technical requirements or changes in quality control procedures from the code version applied in the procurement of the components. The level of safety and quality provided by conformance to the earlier code edition and addenda applied in the actual equipment procurement is technically equivalent to that which would be required by strict application at the rules of 10 CFR 50.55a. The effort and expense of recertification for these RCPB components would not provide any increase in the level of safety and quality, but only add paper with new formatting.

Analyses have been provided by CECo to the NRC which demonstrated the safety integrity of the LSCS RCPB components. Details of the anlayses and NRC evaluation and acceptance are discussed in Subsection 5.2.3.3.

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 Nuclear Pump and Valve Code of ASME Code, Section III, including the addenda that were mandatory at order date for the applicable components.

Table 5.2-2 lists the procurement date for LSCS primary pressure boundary components along with specific version of the ASME Section III Code cited in the purchase order. For comparison purposes, the 10 CFR 50.55a reference is also listed. The various ASME Code case interpretations that were applied to components in the RCPB are listed in Table 5.2-1 (Historical). Also a code case exemption for hydrostatic testing of open-ended LSCS piping is tabulated there for reference purposes.

5.2.2 Overpressurization Protection

5.2.2.1 Design Basis

Overpressure protection is provided in complete conformance with 10 CFR 50, Appendix A, General Design Criterion 15. Preoperational and startup instructions are given in Chapter 14.0. The overpressure protection report is provided in Attachment 5A to Chapter 5.0 in the FSAR. The report contains sufficient information and documentation to show compliance with all the requirements of Article 9 of ASME Code Section III, 1968, including 1970 addenda. Included is the design basis for the sizing of the safety/relief valve, the overpressure protection analysis, and the analysis of safety valve-reactor protection system availability. The analyses and assumptions presented in Section 5.2.2 are part of the historical analyses performed by GE for the initial core. These analyses were performed to show compliance to the ASME code at the design steam flow conditions and design inputs for the initial core. Parametric studies were performed to demonstrate adequate safety valve sizing. This historical information has been retained for information as it relates to system design and the trends of the results are considered typical.

Compliance to the ASME code is verified every cycle for the reload fuel. The cycle specific results represent the ASME licensing basis for each cycle. On a cycle specific basis the applicable fuel vendor evaluates the limiting pressurization event for the ASME code on overpressure. The ASME code requires that the direct scram on valve position is bypassed and that only the safety valve function is credited for pressure relief. The peak pressure for the limiting overpressure event shall be less than 110% of design pressure (1250 psig) which is 1375 psig. The methods and sample calculations for the cycle specific analyses are presented below.

GE Analysis

The ODYN model (Reference 11) may be used in GE analysis for compliance to the ASME code on a cycle specific basis. GE has determined that the MSIV closure event with the bypass of the direct scram on valve position is the limiting event for overpressure. This event takes credit for the high neutron flux scram. The initial conditions assumed for this analysis are consistent with 102% of original licensed power to account for input uncertainties. The MSIVs are conservatively assumed to close in 3 seconds consistent with the minimum speed allowed by tech specs. Additional conservatism is applied in the analysis in that the MSIV area is assumed to close to 1% open in 1.7 seconds and the final 1% MSIV area closes in the final 1.3 seconds. This closure rate provides a large pressure wave to the vessel, which produces a large neutron and heat flux power excursion. The high pressure recirculation pump trip is assumed and the Technical Specification minimum control rod insertion speed is assumed for conservatism. These assumptions will tend to increase the calculated peak pressure. The safety function only of the dual function safety/relief valves is assumed to occur for this

analysis at the maximum allowed technical specification setpoints. No credit is taken for the relief function

Figure 5.2-13 shows the typical results from the GE MSIV flux scram analysis with ODYN.

The 1999 LaSalle County Station Power Uprate Project included re-evaluating a broad set of most limiting transient events at the power uprate conditions (uprate from 3323 MWt to 3489 MWt). The transient events which are re-analyzed with power uprate conditions are summarized in UFSAR Table 15.B-1 and Reference 18.

Cycle Specific analyses may be performed using either ODYN or TRACG methods. The primary difference between TRACG and ODYN overpressure analyses are that TRACG overpressure cases are initiated from 100% license power as initial power uncertainties are incorporated using a pressure adder. Additionally, TRACG is a 3-dimensional code while ODYN is 1-dimensional. TRACG may be used with, or instead of, ODYN codes for AOO analyses as consistent with References 23 and 24.

5.2.2.1.1 Safety Design Bases

The nuclear pressure-relief system has been designed:

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

b. to provide automatic depressurization for small breaks in the nuclear system occurring with malfunction of the high-pressure core spray (HPCS) system, so that low-pressure coolant injection (LPCI-mode of RHR) and low-pressure core spray (LPCS) systems can operate to protect the fuel barrier;

c. to permit verification of its operability; and

d. to withstand adverse combinations of loadings and forces resulting from operation during abnormal, accident, or special event 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:

a. discharge to the containment suppression pool, and

b. 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. The code allows a peak allowable pressure of 110% of vessel design pressure. The code specifications for safety valves require that: (1) the lowest safety valve be set at or below vessel design pressure, and (2) the highest safety valve be set so that total accumulated pressure does not

exceed 110% of the design pressure. The safety/relief valves are set to open automatically (relief function) at pressure settings indicated in Table 5.2-9. The safety function (spring action, safety mode) of the safety/relief valves is analyzed at higher pressures than these nominal operating setpoints. This satisfies the ASME Code specifications for safety valves, because all valves open at less than 1250 psig (nuclear system design pressure).

Two major transients, the closure of all main steamline isolation valves and a turbine trip with a coincident closure of the turbine steam bypass system valves, provide the most severe abnormal operational transients resulting in a nuclear system pressure rise.

The transient produced by the closure of all main steamline isolation valves represents the most severe abnormal pressure transient resulting in a nuclear system pressure rise when direct scrams are ignored. The required safety valve capacity is determined by analyzing the pressure rise from such a transient. The plant is assumed to be operating at the turbine-generator design conditions at an analytically conservative vessel dome pressure. The analysis hypothetically assumed the failure of the direct MSIV position scram. The reactor is shut down by the backup, indirect, high neutron flux scram. Cycle specific analyses assume that the self-actuated safety/relief valves initiate at the Technical Specification value plus 3% for the SRV opening range. For the results for a specific cycle, refer to the cycle specific Supplemental Reload Licensing Report (SRLR).

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

The loadings which the main steam pipe and relief valve discharge pipe impose on the safety/relief valve include:

a. the thermal expansion effects of the connecting piping;

b. the dynamic effects of the piping due to earthquake;

c. the jet force exerted on the safety/relief valves during the first millisecond 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); and

d. the dynamic effects of the kinetic energy of the piston disc assembly when it impacts on the base casting of the valve.

In no case are allowable valve flange loads or the stress at any point in the piping to exceed code limitations for any specified combination of loads.

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

Detailed criteria for selection of safety/relief valves are as follows:

a. must meet requirements of ASME Code, Section III;

b. must qualify for 100% of nameplate capacity credit for overpressure protection function; and

c. must meet additional performance criteria such as response time, etc., 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, 1968, Nuclear Vessels (up to and including Winter 1969 Addenda for Unit 1 and Winter 1970 Addenda for Unit 2). The essential ASME requirements which are all met by this analysis are as follows.

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 protection system which may be tripped by any one of three sources: directly, by

flux, or by pressure signals. The direct scram signal is derived from position switches mounted on the main steamline isolation valves, from 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 attain 10% travel of full stroke. The pressure switches are actuated when a fast closure of the 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 mode of safety operation.

The nominal pressure setting of at least one safety/relief valve connected to any vessel or system shall not be greater than a pressure at the safety/relief valves corresponding to the design pressure (1250 psig) anywhere in the protected vessel.

The rated capacity of the pressure-relieving devices shall be 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 4.3.1.

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.

5.2.2.2 Design Evaluation

5.2.2.2.1 Method of Analysis

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

The ODYN model of early pressurization aspects of this event is used as input to the nonlinear dynamic model of the BWR systems response to transients.

A detailed description of this model is documented in licensing topical reports NEDO-10802 and NEDO-24154 (References 1 and 11). Dual safety/relief valves are simulated in the nonlinear representation, and the model thereby allows full investigation of the various valve response times, valve capacities, and actuation setpoints that are available in applicable hardware systems.

Typical capacity characteristics as modeled are represented in Figure 5.2-1 for the safety/relief valves. The associated bypass, turbine control valve, and main steam isolation valve characteristics are also fully represented in the model.

5.2.2.2.2 System Design

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

5.2.2.2.2.1 Operating Conditions

a. operating power - 3464 MWt (104.25% of rated power),

b. vessel dome pressure $\leq$ 1020 psig, and

c. steam flow - 14.98 x 10^6 1b/hr (105% of rated steam flow).

The conditions above are used only for the parametric study to determine the steam flow capacity of the SRVs and are not the values used in reload analysis. See section 15.A for the cycle specific safety analysis process.

These conditions are the most severe because the maximum stored energy exists at these conditions. At lower power conditions the transients would be less severe. High pressure recirculation pump trip (RPT) is included in the analysis.

5.2.2.2.2.2 Transients

As discussed in Section 5.2.2.1, this section presents historical GE analyses that are retained as they describe system design. The overpressure protection system must accommodate the most severe pressurization transient. Both the closure of all main steam isolation valves and a turbine trip with bypass failure represent the most severe abnormal operational transients resulting in vessel pressure rise. The ODYN evaluation of transient behavior of the initial pressure pulse 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.

This analysis will be reverified for each operating cycle through the cycle specific safety analysis process (See Section 15.A) to validate the system design. The historical analysis uses General Electric's ODYN computer code, which is consistent with the reload licensing analysis methodology. The SRV safety mode opening pressures analyzed were +3% above the nominal valve spring setpoints. Initial core thermal power was at 102% (of 3323 MWt), initial core flow at 105% of rated, the event is initiated as the MSIVs begin to close. The resulting pressure increase in the reactor vessel increases the neutron flux, causing the reactor to scram on a high neutron flux signal. The calculated peak vessel pressure at the

bottom of the reactor vessel is significantly below the ASME Code limiting pressure of 1375 psig. See Table 5.2-13 and Figure 5.2-4d for a summary of the analysis results.

5.2.2.2.2.3 Scram

a. typical scram reactivity curve - Figure 5.2-2, and

b. typical control rod drive scram motion - Figure 5.2-2.

5.2.2.2.2.4 Safety/Relief Valve Transient Analysis Values

a. valve groups - 5, each with spring action mode;

b. pressure setpoint - 1177-1217 psig (includes +3% for reload analysis).

The setpoints are assumed at a conservatively high level above the nominal setpoints for conservatism in the analysis. This accounts for initial setpoint tolerances and any instrument setpoint drift that accumulates during operation. The response characteristics assumed for the valve actions are also highly conservative.

5.2.2.2.2.5 Safety/Relief Valve Capacity

Sizing of the safety valve capacity is based on establishing an adequate margin from the peak vessel pressure to the vessel code limit (1375 psig) in response to the reference transients. Table 5.2-9 identifies the SRV capacities for the setpoints of these direct-acting safety valves.

5.2.2.2.3 Evaluation of Results

5.2.2.2.3.1 Safety Valve Capacity

As discussed in Section 5.2.2.1, this section presents historical GE analyses that are retained as they describe system design. The required safety/relief valve capacity is determined by analyzing the pressure rise resulting from MSIV closure of flux scram transient origin. The plant is assumed to be operating at 104% rated power and 100% steam flow with a maximum vessel dome pressure of 1045 psig (errors are included for conservatism). The analysis arbitrarily assumes the failure of the direct isolation valve position scram and relies instead on reactor shutdown from the backup high neutron flux scram. The sequence of events assumed in this analysis was established in conformance to code requirements to evaluate the pressure relief system exclusively. That sequence is as follows:

Time (sec)	Event
0	Closure of all MSIV's initiated.
0.3	MSIV's attain 93% open position; failure of this direct position scram was assumed.
1.7	Neutron flux reaches APRM high flux setpoint and reactor scram is initiated.
2.4	Sensed reactor vessel dome pressure reaches setpoint of ATWS-RPT.
2.7	Steamline pressure reaches SRV Group 1 pressure setpoint (spring action - safety mode). (The power actuated and ADS relief modes were ignored.)
2.7	RPT initiates recirculation system coast down.
3.2	All safety/relief valves open due to high pressure.
3.6	Vessel bottom pressure reaches its peak value.

5.2.2.2.3.2 SRV Time Reponse

As discussed in Section 5.2.2.1, this section presents historical GE analyses that are retained as they describe system design. Figure 5.2-4b depicts typical results of the ODYN analysis of the MSIV rapid closure event from 104% power and 100% rated flow conditions. The high flux scram initiated reactor shutdown according to the sequence of events listed immediately above. Figure 5.2-4 indicates the time response of the pressure variable with approximately 3 seconds duration of over 1250 psig at the bottom of the vessel.

The parametric relationship between peak vessel (bottom) pressure and safety/relief valve capacity for the MSIV transient with direct, high-flux, and high pressure tripped scram is described in Figure 5.2-3. Design-basis pressurization events in all cases result in the initiation of the direct scram signal, and the expected system response is depicted in Figure 5.2-3 for that case (position scram). Pressures shown for flux scram will result only with multiple failure in the redundant direct scram system. Even more remotely expected are the pressures shown for pressure scram, which will occur only with the multiple failures of both the redundant direct scram and the redundant flux scram systems.

From the ODYN model, the time response of the vessel pressure to the MSIV transient with both flux and typical pressure scram is illustrated in revised Figure 5.2-4. This shows that the pressure at the vessel bottom exceeds 1250 psig for less than 6 seconds, which is not long enough to transfer any appreciable amount of heat into the vessel metal which was at a temperature well below 550° F at the start of the transient.

This analysis will be reverified for each operating cycle through the cycle specific safety analysis process (See Section 15.A) to validate the system design. The historical analysis uses General Electric's ODYN computer code, which is consistent with the reload licensing analysis methodology. The SRV safety mode opening pressures analyzed were +3% above the nominal valve spring setpoints. Initial core thermal power was at 102% (of 3323 MWth), initial core flow at 105% of rated, the event is initiated as the MSIVs begin to close. The resulting pressure increase in the

reactor vessel increases the neutron flux, causing the reactor to scram on a high neutron flux signal. The calculated peak vessel pressure at the bottom of the reactor vessel is significantly below the ASME Code limiting pressure of 1375 psig. See Table 5.2-10 and Figure 5.2-4d for a summary of the analysis results.

5.2.2.2.3.3 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 reported previously.

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. Each safety/relief valve has its own separate discharge line.

5.2.2.3 Piping and Instrument Diagrams

Drawing Nos. M-93 (sheets 3, 4, 5) and M-139 (sheets 3, 4, 5) and Figure 5.2-5 show the schematic location of pressure-relieving devices for:

a. the reactor coolant system, and

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

The schematic arrangement of the safety/relief valves is shown in Figures 5.2-6 and 5.2-7.

5.2.2.4 Equipment and Component Descriptions

5.2.2.4.1 Description

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

The safety/relief valves provide three main protection functions:

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

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

c. Depressurization operation - The ADS valves open automatically as part of the emergency core cooling system (ECCS) for events involving small breaks in the nuclear system process barrier. The location and number of the ADS valves can be determined from Figure 5.2-5.

Chapter 15.0 describes the events in which the primary system safety/relief valves are activated. Also indicated there are 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 regime. The pressure increase and relief cycle will continue with lower frequency and shorter relief discharges as the sensible heat drops off and until such time as the RHR-system can dissipate the decay heat. Remote manual actuation of the valves from the control room is utilized to minimize the total number of these discharges,

with the intent of extending valve seat life. This also assists in managing the thermal input into the suppression pool.

Low-Low Setpoint Relief Function

In order to assure that no more than one safety/relief valve reopens following the initial portion of a reactor isolation event, seven safety/relief valves are provided with lower closing and/or reopening setpoints for the relief mode of operation. The setpoints override the normal setpoints following the initial opening of more than one relief valve and act to hold these valves open longer, thus preventing more than one single valve from reopening subsequently. This safety grade logic is referred to as low-low set relief logic, and functions to minimize containment fatigue duty cycles resulting from relief valve cycling during the decay-heat-dominant period late in an isolation transient.

The low-low set relief function is armed when any two or more safety/relief valves are signaled to open by their normal relief pressure switches. Thus, the low-low set valves will not actuate during normal plant operation even though the reopening setpoint of one of the valves is in the normal reactor operating pressure range. This arming method results in the low-low set safety/relief valves opening initially during an overpressure transient at the normal relief opening setpoint. (Essentially second-pop protection.)

The lowest low-low set valve will cycle with lower reopen and reclose setpoints to remove decay heat. Since this valve will have a larger differential between its reopen and reclose set pressures than assured by the normal relief function, the number of single safety/relief valve actuations during isolation events will be reduced. Table 5.2-9 shows the opening and closing setpoints for the low-low set safety/relief valves.

The assumptions used in the calculations of the pressure transient after the initial opening of the safety/relief valves are:

a. The transient event is a 3-second closure of all MSIV's with position scram.

b. Nominal relief valve setpoints are used.

c. The maximum expected relief capacity is used.

d. Safety/relief valve opening and closing response times shown in Figure 5.2-1a are used.

e. The closing setpoint of the safety/relief valves is 75 psi below the opening setpoint.

f. ANS plus 20% decay heat at infinite exposure is used.

The resulting reactor vessel pressure transient using the above assumptions is shown in Figure 5.2-4a. Despite the conservative input assumptions which tend to maximize the pressure peaks on subsequent actuations, there is a 74 psi margin for avoiding the second pop of more than one valve. The system is single-failure-proof since a failure of one of the low-low set valves still gives enough margin for avoiding multiple valve actuations.

A graphic of the safety/relief valve is shown in Figure 5.2-4c. The Crosby dual function safety/relief valve is designed to perform either as a safety valve or as a relief valve. The safety mode of operation is independent and separate from the relief mode of operation.

a. The safety mode of operation is initiated when the increasing static inlet steam pressure overcomes the restraining spring and frictional forces acting against the inlet steam pressure to move the disc in the opening direction at a faster rate than corresponding disc movements at higher or lower inlet steam pressures. This action is termed the "popping" pressure and corresponds to the "set" pressure value stamped on the nameplate of the valve.

b. The relief mode of operation is initiated when an electrical signal is received at any or all of the solenoid valves located on the pneumatic actuator assembly. The solenoid and the air control valve will open to allow an air source to pressurize the lower side of the piston in the pneumatic cylinder to push it upwards. This action is transmitted through the lever arm and dog pivot mechanism which in turn pulls the lifting nut upwards thereby opening the valve to allow inlet steam to discharge through the valve. Upon deenergization of the solenoid, the air valve will reposition to allow the pressurized air in the cylinder to vent to atmosphere and thus close the valve.

<u>Safety Mode of Operation</u>

The pneumatic operator is so arranged that if it malfunctions it will not prevent the valve disc from lifting when 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; set to open at

values recorded in Table 5.2-9. In accordance with the ASME code, the full lift in this mode of operation is attained at a pressure no greater than 3% above the setpoint. The spring-loaded valves are designed and constructed in accordance with ASME III, NB-7640 as safety valves with auxiliary actuating devices that are entirely independent and non-compromising of the safety function.

The safety function of the safety/relief valve provides a mechanical spring backup to the automatic or manual relief function described below.

Relief Mode of Operation

For power actuated relief valve operation, each valve is provided with a pressure sensing device which operates at the setpoints designated in Table 5.2-9. When the set pressure is reached, a solenoid air valve actuates the pneumatic piston/cylinder and linkage assembly to open the valve.

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

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. For a description of the safety/relief valves and accumulators, refer to section 5.2.2.4.2.1.

Overpressure Protection (Design Safety Function)

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

a. 340° F for 3 hours at drywell pressure ≤ 45 psig.

b. 320° F for an additional 3 hour period, at drywell pressure ≤ 45 psig.

c. 250° F for an additional 18 hour period at 25 psig.

d. Duration of operability is 2 days at 200° F and 20 psig, following which the valves are to remain fully open or closed for 97 days provided air and power supplies are

available. No power/air supply is required to keep the valve closed.

The automatic depressurization system (ADS) utilizes selected safety/relief valves for depressurization of the reactor as described in Section 6.3, "Emergency Core Cooling System." Each of the safety/relief valves utilized for automatic depressurization is equipped with an air accumulator and check valve arrangement. For a description of the safety/relief valves and accumulators, refer to Section 5.2.2.4.2.1.

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

The second part of the safety/relief valve discharge piping extends from the anchor to the suppression pool. Because of the upstream anchor on this part of the line, it is physically decoupled from the main steam header and is therefore analyzed as a separate piping system.

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 void 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 pressure core spray (HPCS) system. Further descriptions of the operation of the automatic depressurization feature are found in Section 6.3, "Emergency Core and LPCS system to operate as a backup for the high Cooling Systems," and in Subsection 7.3.1., "Emergency Core

Cooling Systems Control and Instrumentation."

5.2.2.4.2 Design Parameters

The design temperature, pressure, and maximum test pressure for the RCPB components are administratively controlled. The specified operating transients for components within the RCPB are given in Table 5.2-4. Refer to Section 3.7 for discussion of the input criteria for seismic design of Seismic Category I structures, systems, and components. See Table 3.2-1 for component classification.

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 and Safety/Relief Valve Accumulator Descriptions

5.2.2.4.2.1.1 Safety/Relief Valves

These valves were manufactured by Crosby Valve and Gauge Company to ASME Section III, 1971 up to and including Summer 1972 Addenda. They comply with ASME Section III, Paragraph NB-7640 as safety valves with auxiliary actuating devices.

The Crosby Dual Function Safety/Relief Valve Model HB-65-BP is designed to perform either as a safety valve or as a relief valve. The safety mode of operation is independent and separate from the relief mode of operation.

The discharge area of the valve is 16.117 square inches and the coefficient of discharge K(D) is equal to 0.966 (K = 0.9 K(D)).

The design pressure and temperature of the valve inlet and outlet are 1250 psig at 575° F and 625 psig at 500° F, respectively.

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

See Figure 5.2-4c for a graphic representation of the valve.

5.2.2.4.2.1.2 Safety/Relief Valve Accumulators

Non-ADS Accumulators

Each of the safety/relief valves on each unit is provided with its own pneumatic accumulator and inlet check valve. These accumulators assure that the valves can be opened in the event of a failure of the Drywell Pneumatic System.

These accumulators are sized to meet the requirement of the GE Design Specification Data Sheet for the Nuclear Boiler System in that they are capable of providing one actuation of the SRVs against normal drywell pressure (0.75 psig) with the reactor at approximately 1000 psig. These accumulators are not required to be able to actuate the SRVs with the reactor depressurized (0 psig) or with the drywell pressurized above normal drywell pressure.

For further information on the air supply to the SRV air accumulators, refer to UFSAR section 9.3.1.2.2, Drywell Pneumatic System.

ADS Accumulators

In addition to the Non-ADS accumulators described above, each of the seven safety/relief valves that make up the Automatic Depressurization System (ADS) is provided with its own ADS accumulator and inlet check valve. These accumulators assure that the valves can be opened to perform their ADS function in the event of a failure of the non-safety related Drywell Pneumatic System.

These accumulators are sized to meet the requirement of the GE Design Specification Data Sheet for the Nuclear Boiler System in that they are capable of providing one actuation of the ADS SRVs against maximum drywell pressure (45 psig) with the reactor at 0 psig, and two actuations against a drywell at 70% of drywell design pressure. These accumulators are backed up by banks of Nitrogen bottles with a similar check valve arrangement to assure ADS operability through the cooldown/decay heat removal period.

For further information on the air supply to the ADS air accumulators, refer to UFSAR Section 9.3.1.2.2, Drywell Pneumatic System. For further information regarding ADS accumulator sizing, refer to FSAR Appendix L, Art. L.68.

5.2.2.4.2.2 Design Transients

5.2.2.4.2.2.1 Loading and Stress Criteria

5.2.2.4.2.2.1.1 RCPB Components Designed by Stress Analysis

The loading conditions for pressure-containing components of the RCPB may be divided into four categories: normal, upset, emergency, and faulted conditions. These categories are generally described in the Summer 1968 Addenda to the 1968 ASME Code, Section III, Paragraph N-412. A summary of the number of cycles for

transients used in design and fatigue analysis is listed in Table 5.2-4. The design transients listed in Table 5.2-4 are categorized under the appropriate design condition (i.e., normal, upset, emergency, and faulted). Table 5.2-5 provides the loading conditions considered for design of Group A components of the RCPB.

Environmental fatigue analyses were performed for ASME Code Class 1 components for License Renewal that used revised numbers of thermal transients that are imposed as limits in the Fatigue Monitoring Program. See UFSAR Appendix P, Section A.3.1.1, "Fatigue Monitoring Program," and Section A.4.3.3, "Environmental Fatigue Analyses for RPV and Class 1 Piping," for more information.

5.2.2.4.2.2.1.2 Components Designed Primarily by Empirical Methods

There are some structural and electrical non-pressure-containing parts of equipment which are not normally designed directly by stress analysis techniques. Simple stress analyses are sometimes used to augment the design of these components, but the primary design work does not depend upon detailed stress analysis. These components are usually designed from tests and empirical data. Field experience and testing are used to support the design. Where the structural or mechanical integrity of components is essential to safety, the components referred to in these criteria must be designed to accommodate the events of the safe shutdown earthquake, a design-basis pipe rupture, or a combination of these events where appropriate. The reliability requirements of such components cannot be quantitatively described in a general criterion because of the varied nature of each component and its specific function in the system.

5.2.2.4.2.2.2 Detailed Analyses (RCPB Pressure Parts)

5.2.2.4.2.2.2.1 Reactor Vessel

The reactor vessel is designed in accordance with the ASME Boiler and Pressure Vessel Code, Section III, its interpretations and applicable requirements for Class A vessels, as defined therein, as of the order date, January 1967 for Unit 1 and April 1971 for Unit 2. The vessels were subsequently upgraded to the 1968 edition with Winter 1969 Addenda for Unit 1 and to the 1968 edition with Winter 1970 Addenda (excluding Appendix I) for Unit 2. The vessels are designed for a useful life of 40 years. Table 5.2-1 (Historical) gives the applicable code cases. See Appendix P, Sections 4.2 and 4.3 for additional information regarding qualification of the reactor vessel and internal components for 20 additional years of service through the period of extended operation.

5.2.2.4.3 Identification of Active Pumps and Valves

5.2.2.4.3.1 Classification of Pumps and Valves

Pumps and valves within the reactor coolant pressure boundary are classified as active or passive in Table 5.2-6.

Active components are those whose operability is relied on to perform a safety function during the transients or accidents.

Passive components are those whose operability (e.g., valve opening or closure, pump operation or trip) is not relied on to perform the system's safety function during the transients or accidents.

The isolation signals which activate the isolation valves are as described in Subsection 7.3.1 and 7.3.2. The times for closed or open cycles are listed in Table 6.2-21.

Leaktightness capability requirements for all active valves are included in the applicable valve specifications. Valve parts forming the pressure boundary are pressure tested per the requirements of the applicable code.

5.2.2.4.3.2 Pipe Break

The design criteria employed to assure that components will function as designed in the event of a pipe rupture are described in the following subsections.

5.2.2.4.3.2.1 Reactor Recirculation Pump and Motor

See Subsection G.3.2 of Appendix G.

5.2.2.4.3.2.2 Recirculation Flow Control Valve

See Subsection G.3.2 of Appendix G.

5.2.2.4.3.2.3 Safety/Relief Valves

It is not required that the safety/relief valves operate during a LOCA pipe rupture.

5.2.2.4.3.2.4 Isolation Valves

a. All power-operated isolation valves are capable of closing at any time during normal, abnormal, or test conditions. During accident conditions, adequate isolation exists to ensure that site boundary limits are not exceeded.

b. Valves required for emergency cooling systems shall remain operable, for both opening or closing as required for system functions, after an accident.

c. Valve operation shall be controlled by the signals described in Subsection 7.3.1.3 and in Table 6.2-21.

5.2.2.4.3.2.5 Pipe Rupture

Protection against dynamic effects of pipe rupture is described in Section 3.6. Protection has been provided on the assumption that either longitudinal or circumferential breaks may occur at the locations specified in Subsection 3.6.1.

5.2.2.4.4 Design of Active Pumps and Valves

In order to assure the functional performance of active valves of the RCPB, stringent design requirements were applied. There are no active pumps in the RCPB. Valve operability was demonstrated as described in the following paragraphs.

All active valves are qualified for operability assurance by first being subjected to the following tests:

a. Shop tests which include hydrostatic tests and seal leakage tests as specified in the applicable code.

b. The valves were required to open and close within specified time limits when subjected to design or environmental conditions as required by applicable codes. There are also other tests, such as the cold hydro tests and the hot functional tests, which were performed. Preoperational tests on each system were performed on site.

Valves are considered rigid under seismic disturbances and were analyzed as described in Section 3.9. Seismic testing of selected motor operators was also done.

With the loads known from above, the structural analyses were performed with other conservative loads to meet the stress criteria. This will assure that the critical parts of the concerned component will not be damaged during and after the faulted condition.

Finally, active valves are also required to be operated periodically as specified in the Technical Specifications. This repeated operability requirement throughout the life of the specified valve further provides a complete operability assurance program.

The list of RCPB Class 1 active valves is given in Table 5.2-6.

The representative combination of loads and analysis to assure operability is referenced by category in Table 5.2-5.

5.2.2.4.5 Inadvertent Operation of Valves

A discussion of the design-basis events and their appropriate limits for this plant is given in Chapter 15.0. The events in Chapter 15.0 have been selected to envelope the most severe change in critical parameters from events which have been postulated to occur during planned operation.

5.2.2.4.6 Stress and Pressure Limits

Paragraphs NB-3655 and NB-3656 (Piping Sections) of ASME Section III are not directly applicable to pumps and valves. On the basis of the utilized method of establishing system design pressures, however, it can be stated that the permissible pressure requirements of NB-3655.1 and NB-3556.1 are met.

The allowable stress limits and design loads based on applicable codes for RCPB components are summarized in FSAR Tables 3.9-2 through 3.9-12. Modifications, performed after licensing, that affects any calculated stress or design value will be evaluated against accepted allowables at the time of the modification. Results of these evaluations will be listed in the applicable stress report or analysis. Active or passive components of the RCPB are delineated in Table 5.2-6.

5.2.2.4.7 Stress Analysis for Structural Adequacy

Stress analysis was used to determine structural adequacy of pressure components of the reactor coolant pressure boundary under various operating conditions and earthquakes.

Significant discontinuities were considered such as nozzles, flanges, etc. In addition to the design calculations required by the ASME codes, stress analysis was performed by methods outlined in the code appendices or by other methods applicable to the design conditon through reference to analogous codes or other published literature.

5.2.2.4.8 Analysis Method for Faulted Condition

Elastic stress analysis methods in conjunction with elastic system analysis were generally used for reactor coolant pressure boundary components. In the event that an inelastic stress analysis was performed, the elastic (linear) system analysis was checked.

5.2.2.4.9 Protection Against Environmental Factors

The design requirements established to protect the principal components of the reactor coolant system against environmental effects are discussed in Section 3.11. Missile protection is discussed in Section 3.5. Protection against fire is discussed in Section 9.5 and protection against flooding in Section 3.4.

5.2.2.4.10 Compliance with Code Requirements

For components that are constructed in accordance with Section III of the ASME Code, Subsection NB, analytical calculations or experimental testing is performed to demonstrate compliance with the code. In addition, brief descriptions of the mathematical or test models and the methods of calculaton or testing, including any simplifying assumptions with summary of results, are provided in Subsection 3.9.1.

5.2.2.4.11 Stress Analysis for Emergency and Faulted Condition Loadings

The types of loads that were evaluated for the emergency and faulted conditions are given in FSAR Table 3.9-2 for selected components. Any modification, performed after licensing, that affects any calculated stress or design value will be evaluated against accepted allowables at the time of the modification. Results of these evaluations will be listed in the applicable stress report or analysis.

5.2.2.4.12 Stress Levels in Seismic Category I Systems

Seismic analysis of Seismic Category I components of the RCPB was performed in accordance with code requirements, and the results for selected components are documented in FSAR Table 3.9-2. Any modification, performed after licensing, that affects any calculated stress or design value will be evaluated against accepted allowables at the time of the modification. Results of these evaluations will be listed in the applicable stress report or analysis.

5.2.2.4.13 Analytical Methods for Stresses in Pumps and Valves

The methods and criteria for analysis of stresses and deformations in the pressure-boundary portions of Class A pumps are in accordance with the Nuclear Pump and Valve Code.

The methods and criteria for design and acceptability of stresses and deformations, as determined for the pressure-boundary portions of Class A line valves and safety/relief valves, are those described in the applicable portions of NB-3500 of Section III or, in some cases, those of the Nuclear Pump and Valve Code.

In the event that components are supplied with geometries or design conditions for which code limits have not been developed, a complete description of the analytical methods and criteria used for evaluation of stresses and deformations was submitted by the manufacturer to the Applicant and/or his authorized agent.

The summary of the detailed analyses of the RCPB components (analytical models, methods of calculation, and a summary of results) is provided in Tables 3.9-2 through 3.9-12.

5.2.2.4.14 Analytical Methods for Evaluation of Pump Speed and Bearing Integrity

See Subsection G.3.2 of Appendix G.

5.2.2.4.15 <u>Operation of Active Valves Under Transient Loadings</u>

The qualification test program used to verify that active valves (whose operability is relied upon to perform safety function or shut down the reactor) within the RCPB will operate under the transient loadings experienced during service life is described in the following subsections.

5.2.2.4.15.1 <u>Main Steamline Isolation Valves (MSIV)</u>

Components of the MSIV which are required to operate during transient conditions and whose functional capabilities are sensitive to the abnormal ambient pressure

and temperature associated with the transient, are subjected to a test sequence which simulates the abnormal ambient condition. Function requirements are verified throughout the test sequence. Components tested are fully representative of production components.

5.2.2.4.15.2 Safety/Relief Valves

The safety/relief valves are subjected to tests that simulate conditions experienced during service life.

5.2.2.4.15.3 Other Provisions to Assure Operability

Valves in the reactor coolant pressure boundary have been tested in accordance with the applicable codes. Thermal transient loadings on pressure boundary valves will not be simulated.

To assure operability of active valves under the transient loadings to be experienced during plant service life, design specifications include the following requirements:

a. Valve bodies and yoke structure have been designed to withstand seismic forces.

b. Valve operators have been sized to open or close under the maximum differential pressure across the valve seat, dictated by the transient service conditions.

c. Valves have been fully cycled at the vendor's shop before delivery to substantiate the vendor's guarantee that they will operate under actual service pressure conditions.

d. All motor-operated valves have been equipped with handwheels so that motors can be declutched and valves cycled manually after installation.

5.2.2.4.16 Field Run Piping

The following shows the breakdown by pipe size and group designation of pipe installed at LaSalle County Station:

a. 2-1/2 inches and larger - shop fabricated;

b. 2 inches and larger - Groups A and B, field fabricated; and

c. 2 inches and smaller - Groups C and D, field fabricated.

All piping within the RCPB and connected systems with boundaries as defined in Section 5.1 is Seismic Category I, Group A or B. There is no field run piping within the RCPB.

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:

a. the thermal expansion effects of the connecting pipe;

b. the dynamic effects of the piping due to earthquake;

c. 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.); and

d. 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 the ASME Code, Section III. 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 (10 CFR 50.55a).

5.2.2.7 Material Specification

Pressure retaining components of valves in Quality Groups A, B, and C are constructed only from ASME-designated materials, such as:

Plate	ASME SA-516 Grade 70
Forgings	ASME SA-105 Grade II ASME SA-350 Grade LF1, LF2
Pipe	ASME SA-106 Grade B ASME SA-333 Grade 6
Fittings	ASME SA-234 Grade WPB, WPBW ASME SA-420 Grade WPL-6, WPL-6W ASME SA-105
Castings	ASME SA-216 Grade WCB, WCC ASME SA-352 Grade LCB
Bolting	ASME SA-193 Grade B7, B16 ASME SA-194 Grade 2H, 7 ASME SA-540 Grade B23, B24

Austenitic Stainless Steel

Wrought Austenitic Stainless Steel. Wrought austenitic stainless steel materials shall be limited to Types 304, 304L, 316, and 316L.

Cast Austenitic Stainless Steel. Cast austenitic stainless steel materials shall be limited to Grades CF8, CF3, CF3A, and CF8M.

5.2.2.8 Process Instrumentation

Overpressure protection process instrumentation is listed in Table 1 of the Nuclear Boiler System P&ID Data Sheet Figure 5.2-5 and shown on the Nuclear Boiler and Reactor Recirculating P&ID, Drawing Nos. M-93 and M-139.

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.

5.2.2.10 Inspection and Testing

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

a. hydrostatic test,

b. valve response test,

c. set pressure test, and

d. seat leakage test.

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

It is not feasible to test the safety/relief valve setpoints while the valves are in place. The valves are mounted on 6-inch diameter, 1500-pound primary service rating flanges. They can be removed for maintenance or bench checks and reinstalled during normal plant shutdowns. Valves were tested in accordance with IWV 3510 of Section XI of the ASME Code during the initial 120 month Inservice Testing Interval.

During the second 120 month Inservice Testing Interval, safety/relief valve testing compiled with the 1989 Edition of ASME Section XI, except in cases where relief was granted by the NRC.

During the third 120 month Inservice Testing Interval, safety/relief valve testing will comply with ASME OM Code 2001 Edition through 2003 Addenda and Mandatory Appendix I, except in cases where relief has been granted by the NRC.

In response to NUREG 0737 Item II.D.1, an additional generic test program to demonstrate the operability of Crosby SRVs was conducted by the BWR Owners Group. The satisfactory test results were submitted in a September 25, 1981 letter, T. Dente (BWR Owners Group) to D. G. Eisenhut (NRC), "Transmittal of Valve Operability Test Report from Generic BWR Safety Relief Valve (SRV) Test Program.

5.2.3 Reactor Coolant Pressure Boundary Materials

5.2.3.1 Material Specifications

5.2.3.1.1 General Material Considerations

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

5.2.3.1.2 Compatibility with Reactor Coolant

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

a. solution annealed austenitic stainless steels (both wrought and cast) Types 304, 304L, 316 and 316L;

b. nickel base alloys - Inconel 600 and Inconel X750;

c. carbon steel and low alloy steel;

d. some 400 series martensitic stainless steel (all tempered at a minimum of 1110° F); and

e. Colmonoy and Stellite hardfacing materials.

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 or low alloy steels.

Contaminants in the reactor coolant are controlled to very low limits by the reactor water quality specifications. No detrimental effects will occur on any of the materials from allowable contaminant levels in the high purity reactor coolant. Radiolytic products in a BWR have no adverse effects on the construction materials.

5.2.3.1.3 Compatibility with External Insulation and Environmental Atmosphere

Except as noted in Subsection 6.1.1.1, reflective metal insulation is used on the external surfaces of all hot piping and equipment located in the drywell and such piping exterior to the drywell which is contiguous to piping within the drywell.

Reflective metal insulation, where required, will be designed for removability to meet the inservice inspection requirements.

The design of the insulation will permit a useful life of 40 years.

The areas outside the drywell not insulated with reflective metal are insulated with mass-type insulations which also, where required, are designed for removability to meet inservice inspection requirements.

The materials of construction used for the reactor coolant pressure boundary are listed in Subsection 5.2.3.2. All of these materials are compatible with the external insulation and the environmental atmosphere in the event of coolant leakage. Reflective metal insulation does not contribute to any surface contamination and has no effect on construction materials. The mass insulation is specified to provide adequate leachable sodium silicate to protect against any detrimental effects on the construction materials. In the event of coolant leakage, the construction materials may be exposed to high purity, demineralized water which contains limited additives (zinc, hydrogen and noble metals) and which may contain potentially high soluble-iron metallic impurities. Exposure to this water is not harmful to these construction materials.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Chemistry of Reactor Coolant

Materials in the primary system are primarily Type 304 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 unusual materials in the coolant. Chloride limits are specified to guard against conditions conducive to corrosion cracking of stainless steel (Reference 2).

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 3), where it is shown that at high chloride concentration little oxygen is required to cause stress corrosion cracking of stainless steel, and that at high oxygen concentration little chloride is required to cause cracking. These measurements were determined in a wetting and drying situation using alkaline phosphate-treated boiler water and are therefore of limited significance to BWR conditions. They are, however, a qualitative indication of trends.

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

a. Type 304 stainless steel specimens were exposed in a flowing loop operating at 537° F. The water contained 1.5 ppm chloride and 1.2 ppm oxygen at pH 7. Test specimens were bent beam strips stressed over their yield

strength. After 2,100 hours exposure, no cracking or failures occurred.

b. Welded Type 304 stainless steel specimens were exposed in a refreshed autoclave operating at 550° F. The water contained 0.5 ppm chloride and 1.5 ppm oxygen at pH 7. Uniaxial tensile test specimens were stressed at 125% of their 550° F yield strength. No cracking or failures occurred at 15,000 hours exposure.

The purpose of the Hydrogen Water Chemistry (HWC) program is to reduce rates of intergranular stress corrosion cracking (IGSCC) in recirculation piping and reactor internals. Suppression of dissolved oxygen reduces the susceptibility of reactor piping and internal materials to IGSCC. For more details on HWC, see Section 5.4.15. In addition, through General Electric's noble metal chemical application (NMCA) and online noble chem application (OLNC) NobleChem™ process, noble metal compounds (platinum and rhodium for NMCA, and platinum only for OLNC) are periodically injected into the reactor vessel. The NobleChem™ process deposits a minute, discontinuous layer of noble metal compounds that is much less than the allowable manufacturing tolerance of any reactor internals or other parts and components exposed to the process. This minute, discontinuous layer of noble metal compounds significantly reduces the oxidant potential, which allows for significantly lower HWC hydrogen addition rates, which could in turn result in significantly lower operational dose rates from main steam line radiation. Another potential benefit of noble metals is that additional components, which may not achieve the recommended electrochemical corrosion potential (ECP) value with HWC alone, may do so with noble metals. Two panels, a Material Monitoring System (MMS) and a Data Acquisition System (DAS), measure the ECP and monitor the durability and effectiveness of noble metal compounds deposited on reactor vessel and piping surfaces to determine the most effective re-application schedule. For details on this monitoring system and its sampling connection into the RWCU system, see Section 9.3.2.2.

When conductivity is in its normal range, pH, chloride, and other impurities affecting conductivity are also within their normal range. When conductivity becomes abnormal, an optional deduction for the contribution of soluble iron is permitted, since soluble iron is benign to stress corrosion cracking. A potential soluble-iron increase is a phenomenon that has been introduced by the implementation of NMCA and OLNC. Except for soluble iron, when conductivity becomes abnormal, chloride measurements are made to determine whether or not they are also out of their normal operating values. This would not necessarily be the case. Conductivity could be high due to the presence of a neutral salt which would not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water-cooled reactors, conductivities are high

because of the purposeful use of additives. In BWR's, however, where limited additives (zinc, hydrogen and noble metals) are used and where near neutral pH is maintained, conductivity provides a good and prompt measure of the quality of the reactor water. Significant changes in conductivity provide the operator with a warning mechanism so 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, reduction of additives, and placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature-dependent corrosion rates and provide time for the cleanup system to reestablish the purity of the reactor coolant.

The conductivity of the reactor coolant is continuously monitored. The samples of the coolant which are taken periodically serve as a reference for calibration of these monitors and are considered adequate to assure accurate readings of the monitors. If conductivity is within its normal range, chlorides and other impurities are also within their normal ranges.

During reactor startup and hot standby, the dissolved oxygen content of reactor water may be higher than during normal power operation. During this period more restrictive limits are established. After power operation has been established, boilng deaerates the reactor water, reducing the influence of oxygen on potential chloride stress corrosion cracking.

The relationship of chloride concentration to specific conductance measured at 25° C for chloride compounds such as sodium chloride and hydrochloric acid can be calculated. 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. Specific information on the sampling frequency and on the coolant chemistry requirements is found in the Technical Requirements Manual

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

5.2.3.3.1.1 Compliance with Code Requirements (Historical)

The ferritic pressure boundary material of the reactor pressure vessels was qualified by impact testing in accordance with the 1968 edition of Section III ASME Code and Winter 1969 Addenda for Unit 1 and Winter 1970 Addenda for Unit 2. From an operational standpoint, the minimum temperature limits for pressurization defined by the Summer 1972 Addenda, Appendix G, Protection Against Nonductile Failure, are used as the basis for compliance with the 1968 Edition of ASME Code Section III.

5.2.3.3.1.2 Compliance with 10 CFR 50 Appendix G, Fracture Toughness Requirements

5.2.3.3.1.2.1 Historical Compliance with 10 CFR 50 Appendix G (Historical

A major condition necessary for full compliance to Appendix G is satisfaction of the requirements of the Summer 1972 Addenda to Section III. This is not possible with components which were purchased to earlier Code requirements.

Ferritic material complying with 10 CFR 50 Appendix G must have both drop weight tests and Charpy V-notch (CVN) tests with the CVN specimens oriented transverse to the maximum material working direction to establish the RT_{NDT}. The CVN tests must be evaluated against both an absorbed energy and a lateral expansion criteria. The maximum acceptable RT_{NDT} must be determined in accordance with the analytical procedures of ASME Code Section III, Appendix G. Appendix G of 10 CFR 50 requires a minimum of 75 ft-lb upper shelf CVN energy for beltline material. It also requires at least 45 ft-lb CVN energy and 25 mils lateral expansion for bolting material at the lower of the preload or lowest service temperature.

By comparison, material for the LSCS reactor vessels was qualified by either drop weight tests or longitudinally oriented CVN tests (both not required), confirming that the material nil ductility transition temperature (NDTT) is at least 60°F below the lowest service temperature. When the CVN test was applied, a 30 ft-lb energy

level was used in defining the NDTT. There was no upper shelf CVN energy requirement on the LSCS beltline material. The bolting material was qualified to a 30 ft-lb CVN energy requirements at 60°F below the minimum preload temperature.

From the previous comparison it can be seen that the fracture toughness testing performed on the LSCS reactor vessel material cannot be shown to comply with the letter of 10 CFR 50 Appendix G. However, pursuant to 10 CFR 50.12, Commonwealth Edison proposed, and the NRC has accepted, an alternate method of compliance with the intent of Appendix G for the LSCS vessels which provides operating limitations on pressure and temperature based on fracture toughness considerations. These operating limits assure that a margin of safety against a nonductile failure of this vessel is very nearly the same as a vessel built to the Summer 1972 Addenda. The method for developing these limits during original licensing is summarized in Subsection 5.2.3.3.1.4.1. The data is included in Tables 5.2-10 and 5.2-11.

The original detailed analysis and the results are given in GE Licensing Topical Report NEDO-21778A. NRC acceptance of the analyses was granted in NUREG 0519, Supplement No. 1 for the Unit 1 vessel and in Supplement No. 2 for the Unit 2 vessel.

5.2.3.3.1.2.2 Alternative Compliance with 10 CFR 50 Appendix G

Since original licensing an alternative methodology has been utilized to establish the current operating limits for LSCS Unit 1 and 2 Reactor Pressure vessels. This alternative methodology is described in detail in Reference 15 for Unit 1 and Reference 16 for Unit 2. NRC acceptance of this alternative methodology has been granted in Reference 17.

5.2.3.3.1.3 Acceptable Fracture Energy Levels

The original LSCS approach is given in Subsection 5.2.3.3.1.1. The alternative approach is given in 5.2.3.3.1.2.2.

5.2.3.3.1.4 Operating Limits Based on Fracture Toughness

5.2.3.3.1.4.1 Original Operating Limits Based on Fracture Toughness (Historical)

Operating limits which define minimum reactor vessel metal temperatures versus reactor pressure during normal heatup, cooldown, inservice hydrostatic testing, and anticipated operational occurrences were established using the methods of Appendix G of Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition (Appendix G first appeared in the Summer 1972 Addenda). The Pressure

Temperature operating limit curves, shown in Figures 5.2-8 and 5.2-8a for Unit 1 and 5.2-9 and 5.2-9a for Unit 2, have been updated based on the requirements of 10CFR50 Appendix G 1983 and the actual fluence data for LSCS (Reference 8 and 9).

Established RT_{NDT} values and temperature limits are given in this section for the limiting locations in the reactor vessel.

All the vessel shell and head areas remote from discontinuities plus the feedwater nozzles are evaluated, and the operating limit curves are based on the most limiting location. The boltup limits for the flange and adjacent shell region are based on a minimum metal temperature of RT_{NDT} +60° F. The maximum through-wall temperature gradient from continuous heating or cooling at 100° F per hour was considered. The safety factors applied were as specified in ASME Code Appendix G and GE Licensing Topical Report NEDO-21778A.

For the purpose of setting these operating limits the reference temperature, RT_{NDT}, was determined from the toughness test data taken in accordance with requirements of the Code to which each vessel was designed and manufactured. This toughness test data, Charpy V-notch (CVN) and/or dropweight nil ductility transition temperature (NDT) was analyzed to permit compliance with the intent of 10 CFR 50 Appendix G. Because all toughness testing needed for strict compliance with Appendix G was not required at the time of vessel procurement some toughness results are not available. For example, longitudinal CVN's, instead of transverse CVN's, were tested, usually at a single test temperature of +10°F or +40°F, for absorbed energy. Also, at the time neither transverse CVN nor NDT testing was permitted; therefore, in many cases both tests were not performed as is currently required. To substitute for this absence of certain data, toughness property correlations were derived for the vessel materials in order to operate upon the available data to give a conservative estimate of the RT_{NDT}, compliant with the intent of Appendix G criteria.

These toughness correlations vary depending upon the specific material analyzed. They were derived from the results of WRC Bulletin 217, "Properties of Heavy Section Nuclear Reactor Steels," and from toughness data from the LSCS vessels and other reactors. In the case of vessel plate material (SA-533 Grade B), Class 1, the predicted limiting toughness property is either NDT or transverse CVN 50 ft-lb temperature minus 60° F. NDT values are available for all LSCS Unit 1 vessel plates and for beltline LSCS Unit 2 vessel plates. Where NDT results are missing, NDT is taken as the longitudinal CVN 35 ft-lb transition temperature.

The transverse CVN 50 ft-lb transition temperature is estimated from longitudinal CVN data in the following manner. The lowest longitudinal CVN ft-lb value is adjusted to derive a longitudinal CVN 50 ft-lb transition temperature by adding 2° F per ft-lb to the test temperature. If the actual data equals or exceeds 50 ft-lb, the test temperature is used. If sufficient data are available the 50 ft-lb temperature is derived by interpolation. Once the longitudinal 50 ft-lb temperature is derived, an additional 30° F was added to account for orientation effects and to estimate the transverse CVN 50 ft-lb temperature. The RT_{NDT} was taken as the higher of the NDT or the transverse CVN 50 ft-lb temperature minus 60° F, estimated in the preceding manner. For forgings (SA-508 Class 2), the predicted limiting property is the NDT, since quite high CVN values can be achieved at NDT for this material. NDT values are available for the vessel flange, closure head flange, and feedwater nozzle materials for LSCS Units 1 and 2, and are used as RT_{NDT}. For the vessel weld metal the predicted limiting property is the CVN 50 ft-lb transition temperature minus 60° F, as the NDT values are -50° F or lower for these materials. This temperature is derived in the same way as for the vessel plate material, except the 30° F addition for orientation effects is omitted because there was no principal working direction. When NDT values are available, they were also considered and the RT_{NDT} was taken as the higher of NDT or the 50 ft-lb temperature minus 60° F. When NDT was not available the RT_{NDT} was not less

than -50°F, since lower values have not been supported by the correlation data. For vessel weld heat affected zone (HAZ) material the RT_{NDT} was assumed the same as for the base material based upon ASME Code weld procedure qualification test requirements and post-weld heat treatment which indicates this assumption is valid. Closure bolting material (SA-540 Grade B24) toughness test requirements for LSCS Units 1 and 2 were for 30 ft-lb at 60° F below the boltup temperature. Current Code requirements are for 45 ft-lb and 25 mils lateral expansion (MLE) at the preload or lowest service temperature, including boltup. Therefore, since CVN values as low as 40 ft-lb exist for LSCS closure bolts, 60° F was added to the test temperature in order to derive the boltup temperature.

Using this general approach, an initial RT_{NDT} of 23° F was established for the core beltline region for LSCS Unit 1 and 52° F for LSCS Unit 2.

The effect of the main closure flange discontinuity was considered by adding 60° F to the RT_{NDT} to establish the minimum temperature for boltup and pressurization. The minimum boltup temperature of 80° F for LSCS Unit 1, which is shown on Figures 5.2-8 and 5.2-8a, is based on an initial RT_{NDT} of +20°F for the closure flange forgings. The minimum boltup temperature of 86°F for LSCS Unit 2, which is shown on Figures 5.2-9 and 5.2-9a, is based on an initial RT_{NDT} of +26°F for the shell plate which connects to the lower flanges.

The effect of the feedwater nozzle discontinuities was considered by adjusting the results of a BWR/6 reactor discontinuity analysis to the LSCS reactors. The adjustment was made by increasing the minimum temperatures required by the difference between the LSCS and BWR/6 feedwater nozzle forging RT_{NDT}'s. The feedwater nozzle adjustment was based on an RT_{NDT} of 40° F for LSCS Unit 1 and an RT_{NDT} of -10°F for LSCS Unit 2.

The reactor vessel closure studs have a minimum Charpy impact energy of 43 ft-lb and a 23 mil lateral expansion at 10° F for LSCS Unit 1. The studs for LSCS Unit 2 have a minimum Charpy energy of 40 ft-lb and 25 mils lateral expansion at 10° F.

5.2.3.3.1.4.2 Current Operating Limits Based on Fracture Toughness

Since original licensing alternative methodologies have been utilized to establish the current operating limits for LSCS Unit 1 and 2 Reactor Pressure vessels. These alternative methodologies are described in detail in Reference 15 for Unit 1 and Reference 16 for Unit 2. The current operating limits are reflected in the curves shown in the LaSalle County Station Units 1 and 2 Technical Specifications and Technical Requirements Manual. NRC acceptance of these curves and the alternative methodologies used to generate them has been granted in Reference 17 for Unit 2 and Reference 21 for Unit 1.

5.2.3.3.1.5 Temperature Limits for Boltup

A minimum temperature of 70° F is required for the closure studs. A sufficient number of studs may be tensioned at 70° F to seal the closure flange 0-rings for the purpose of raising reactor water level above the closure flanges in order to assist in warming them. The flanges and adjacent shell are required to be warmed to minimum temperatures of 72° F (LSCS Unit 1) and 86°F (LSCS Unit 2) before they are stressed by the full intended bolt preload. The fully preloaded boltup limits are shown in the Technical Specifications.

5.2.3.3.1.6 Temperature Limits for Preoperational System Hydrostatic Tests and ISI Hydrostatic or Leak Pressure Tests

Based on 10 CFR 50 Appendix G IV.A.2.d, which allows a reduced safety factor for tests prior to fuel loading, the preoperational system hydrostatic test at 1563 psig may be performed at a minimum temperature of 118°F (LSCS Unit 1) and 112°F (LSCS Unit 2) which is established by the RT_{NDT} of the non-beltline cylinder plate (LSCS Unit 1) and the beltline plate (LSCS Unit 2) plus 60°F. The fracture toughness analysis for system pressure tests resulted in the curves shown in the LaSalle County Station Units 1 & 2 Technical Specifications and Technical Requirements Manual. The curves are based on an initial beltline RT_{NDT} of 23° F (LSCS Unit 1) or 52°F (LSCS Unit 2). For LSCS Unit 1, the beltline weld material IP3571 is expected to be more limiting at end-of-service fluence levels, and this weld material has an initial RT_{NDT} of -30°F.

5.2.3.3.1.7 Operating Limits During Heatup, Cooldown and Core Operation

The fracture toughness analysis was done for the normal heatup or cooldown rate of 100°F/hour. The temperature gradients and thermal stress effects corresponding to this rate were included. The results of the analyses are a set of operating limits for non-nuclear heatup or cooldown and core critical operation shown in the LaSalle County Station Units 1 & 2 Technical Specifications and Technical Requirements Manual. The basis for these Curves is described in References 15, 16, 17 and 21. The current licensed pressure-temperature curves for Unit 2 are bounding for MUR uprate (Reference 20). The Unit 1 curves were revised post-MUR to reflect surveillance capsule testing as discussed in Section 4.1.4.5.

5.2.3.3.1.8 Reactor Vessel Annealing

Inplace annealing of the reactor vessel because of radiation embrittlement is unnecessary because the predicted value in transition of adjusted reference temperature will not exceed 200° F (see 10 CFR 50, Appendix G, Paragraph IV.C)

5.2.3.3.1.9 Compliance with 10 CFR 50 Appendix H (Historical information)

Tables 5.2-11a and 5.2-11b for LaSalle 1 and 2 respectively in the FSAR indicated the level of compliance of the material surveillance program to the requirements of 10 CFR 50 Appendix H. The items of non-compliance indicated therein were reworked via an expanded program (1) to provide base-line Charpy V-notch data on unirradiated specimens, and (2) to provide base-line tensile data on unirradiated specimens. Additionally, an upgraded surveillance test program now includes additional test specimens as indicated below:

a. For Charpy V-Notch Testing

Specimen	Basket #1	Basket #2	Basket #3
HAZ	12	8 + (4)	8 + (4)

Weld	12	8 + (4)	8 + (4)
Base Metal	12	8 + (4)	8 + (4)
TOTAL	36	36	36

where (4) means the upgraded base-line specimens which were added to constitute the expanded program for LaSalle.

b. For Tensile Testing

Specimen	Basket #1	Basket #2	Basket #3
HAZ	2	2	3
Weld	2	3	2
Base Metal	2	3	3
TOTAL	6	8	8

This expanded program enables the correlation of transverse data to longitudinal data with sufficient specimens in all baskets to more accurately define the upper shelf energy for irradiated conditions.

NRC acceptance of the LSCS material surveillance program pursuant to 10 CFR 50.12, was granted in NUREG 0519 Supplements 1 and 2 for Units 1 and 2 respectively.

5.2.3.3.1.10 Compliance with 10 CFR 50 Appendix H, Reactor Vessel Material Surveillance Program Requirements

The current surveillance program requirements are discussed in UFSAR Section 5.3.1.6.1.

5.2.3.3.2 Control of Welding

All welding performed on the RCPB is qualified in accordance with ASME B&PVC Section IX. All welds are inspected by the vendor and surveillance inspected by the owner in accordance with the procedures and the quality assurance program.

5.2.3.3.3 Nondestructive Examination

The LSCS primary pressure boundary equipment was examined nondestructively during manufacture, and following installation a Section XI baseline inspection was accomplished. The RPV's were purchased to Section III Code requirements. They were also subjected to in-process UT examination to Section XI standards. After the vessel was set, the RPV's were subjected to a Section XI ultrasonic baseline inspection. All Code Class 1 equipment also received this baseline inspection.

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

5.2.3.4.1 Avoidance of Sensitization

5.2.3.4.1.1 Carbon Content and Temperature Control

Stainless steels used for the reactor vessel (except for vessel cladding) were of solution annealed stainless steels. The stainless steel is not heated above 800° F except for welding or thermal cutting.

Furnace sensitization of wrought austenitic stainless steel was avoided for piping and RCPB pumps and valves. Austenitic stainless steel was considered to be furnace sensitized if it had been heated by means other than welding to 800° F or higher regardless of subsequent cooling rate. Such stainless steel was solution heat treated. When heated above 1800° F, the austenitic stainless steel was rapidly cooled through the range 1800° F to below 800° F by water quench to produce an acceptable grain structure. Since severe sensitization of austenitic stainless steel is to be avoided, AISI Type 304 and Type 316 (0.08% maximum carbon) materials were used. Where severe sensitization cannot be avoided, such as for parts which are required to be hard surfaced, low carbon AISI Type 304 cast material is used.

5.2.3.4.1.2 Unstabilized Austenitic Stainless Steels

Unstabilized austenitic stainless steel materials for the reactor coolant pressure boundary, core support components, and components important to safety were purchased and fabricated in accordance with the following requirements. Types 304 and 316 wrought austenitic stainless steels and their cast counterparts were used with both low carbon and regular carbon chemistry depending on the application and availability.

5.2.3.4.1.3 Material Inspection Program

A raw material inspection program was used to verify that unstabilized austenitic stainless steels were properly solution heat treated and not susceptible to intergranular attack.

a. No testing was required when valid documentation was furnished which proved that the stainless steel was given a suitable water quench from a temperature above 1800° F, and that no subsequent heating was employed.

b. If documentation to verify adequate water quenching was not available, the material was tested in accordance with ASTM A-262, Practice E.

5.2.3.4.1.4 Solution Heat Treatment Requirements

All austenitic stainless steel materials were purchased in the solution heat treated condition. The degree of control for the solution heat treatment varied depending on the service condition, product form and chemistry as follows:

a. For wrought austenitic stainless steels which are exposed to the BWR coolant at temperatures in excess of 200° F, solution heat treatment control was as follows: the material was heated to solution heat treat temperatures, held for a sufficient time to put grain boundary carbides in solution and, thereafter, cooled rapidly by either (1) water quenching, or (2) by a process other than water quenching which was qualified by demonstration samples as required to meet the acceptance limits of ASTM A-262, Practice E.

b. For the following conditions of service temperature, product form and material chemistry, solution heat treatment was in accordance with the requirements of the applicable ASME/ASTM specification:

    1. all cast austenitic stainless steels,

    2. all low carbon austenitic stainless steels, and

    3. all austenitic stainless steels regardless of chemistry or form which are to be exposed to the BWR coolant at temperatures at 200° F and below.

5.2.3.4.1.5 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitizing Temperatures

No retesting of as-welded unstabilized austenitic stainless steel was performed.

If unstabilized austenitic stainless steel was subjected to heating in excess of 800° F by any means other than welding, the material was solution heat treated as discussed in Subsection 5.2.3.4.1.

5.2.3.4.1.6 Control of Delta Ferrite

The procedures and requirements that were used for the control of delta ferrite in austenitic stainless steel welds to avoid microfissuring are discussed in Subsection 5.2.3.4.2.

5.2.3.4.1.7 Cleaning and Contamination Protection Procedures

During fabrication, shipment, storage, and assembly, materials which are potentially harmful to austenitic stainless steel were controlled either by preventing contact or by removal of the contaminant at appropriate times during fabrication or assembly. Special attention was given those parts which have crevices or areas which are difficult to clean. Suitable protection was given to components to maintain cleanliness during shipping, storage, testing, and operation.

5.2.3.4.1.8 Design Changes to Avoid Sensitized Material Exposure

As a result of concerns expressed by the NRC in NUREG-0313, design changes were made to LSCS to reduce the potential for intergranular stress corrosion cracking (IGSCC). The following changes were made to the LaSalle plant to minimize the chances for IGSCC:

a. The recirculation bypass line was eliminated.
b. The CRD return line was eliminated.
c. The stainless steel was removed from the core spray, LPCI and feedwater nozzles to the lines.
d. All jet pump riser pipe was heat treated after fabrication of elbows to pipe.
e. The CRD drive water was rerouted to a low oxygen source.
f. A redesigned feedwater sparger with new spray nozzles was installed.

The steps taken to eliminate or minimize the chance of IGSCC at LaSalle addressed the specifics of NUREG-0313 to incorporate the best possible solutions during the construction stage.

5.2.3.4.2 Control of Welding

5.2.3.4.2.1 Welding Controls

All welding was qualified in accordance with ASME Section IX. During stainless steel welding, the interpass temperature was controlled to a maximum of 350° F. Welds were cleaned free of slag, flux, and other foreign material prior to depositing subsequent beads. No peening was allowed.

Austenitic weld materials were selected and controlled to produce welds containing at least 3.0% ferrite in the as-deposited condition.

5.2.3.4.3 Nondestructive Examination

NDE techniques used on stainless steels for LSCS include particle detection, penetration testing, ultrasonic examination, and radiography. Applicable parts of Sections III and XI of ASME Code requirements were met.

5.2.4 Inservice Inspection and Testing of Reactor Coolant Pressure Boundary

5.2.4.1 Inservice Inspection Program

The initial inservice inspection programs for both Units 1 and 2 are based on Section XI of the ASME code, 1980 edition, including Addenda through Winter 1980, which CECO submitted in letters dated July 13, 1982 (Unit 1) and December 21, 1982 (Unit 2). The inservice examinations conducted during the second 120 month Inspection Interval will comply with the 1989 Edition of ASME Section XI, except in cases where relief has been granted by the NRC. The inservice examinations conducted during the third 120 month Inspection Interval will comply with the 2001 Edition through the 2003 addenda, including the December of 2003 Erratum of ASME Section XI, except in cases where relief has been granted by the NRC. All references to ASME XI in this section are to the applicable edition and addenda of the ASME Section XI Code. LaSalle maintains an independent program to manage cracking due to Intergranular Stress Corrosion Cracking (IGSCC) of Austenitic Stainless Steel piping in accordance with NRC Generic Letter 88-01, NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping for normal water chemistry plants. (Reference 22) This program governs the examination methods, examination frequency, and sample expansion of those components that fall under the scope of GL 88-01. Some welds within the scope of GL 88-01 cannot be fully examined due to access limitations caused by design, geometry, or materials of construction of the components. Limitations are typically encountered in welds to cast components, valves, and fitting where access to the weld for examination from both sides of the weld is restricted. Ultrasonic examinations (UT) are performed to the maximum extent practical considering the configuration and design using the latest approved ultrasonic techniques, procedures, equipment, and personnel qualified to the requirements of the Performance Demonstration Initiative (PDI) Program in accordance with 10 CFR 50.55a(g)(4) and 10 CFR 50.55a(g)(6)(ii)(C). Typically the side of the weld more susceptible to IGSCC is adequately examined and the limitation is encountered on the cast side of the weld that is less susceptible to IGSCC. These welds are part of a larger population of welds examined in which examination coverage is not limited, and the required coverage of greater than 90% is attained. When considered in aggregate with the entire sample population, an adequate level of examination occurs to provide reasonable assurance that a pattern of IGSCC degradation that, if present, would be detected. BWRVIP-75-A (Reference 26) provides alternate requirements for the extent and schedule of examinations for IGSCC Categories B through G. The Risk-Informed Inservice Inspection Program subsumes all

Class 1 and 2 BWRVIP-75 Category A welds. The Risk-Informed Inservice Inspection Program subsumes all Class 1 and 2 BWRVIP-75 Category A welds.

Inspection and Enforcement Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," and Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," addressed the issue of pipe wall thinning in single-phase and two-phase high-energy carbon steel systems. In response to these letters, LaSalle Station has implemented a comprehensive long-term Flow Accelerated Corrosion (FAC) inspection program.

5.2.4.2 Provisions for Access to Reactor Coolant Pressure Boundary

5.2.4.2.1 Reactor Pressure Vessel

Access to the exterior surface of the reactor pressure vessel for inservice inspection is provided by removable insulation and shield plugs. Access is provided at four quadrants in the shield wall and free standing reflective insulation. A minimum annular space of 8 inches is provided between the vessel exterior surface and the insulation. Access is available to essentially 100% of the vessel exterior surface.

With the vessel head removed, access is afforded to the upper interior cladding surface by removal of the steam dryer and steam separator assembly. Removal of these components also enables inspection of remaining internal components by remote visual techniques.

5.2.4.2.2 Pipe, Pumps, and Valves

Access to pipe, pumps, and valves is provided by removable insulation and planned clearances around components requiring examination. Piping insulation is removable for a minimum of 9 inches on each side of the inspected area. If the inspected area includes a longitudinal weld, the insulation is removable for a minimum distance of 16 inches on each side of the inspected area.

5.2.4.3 Equipment for Inservice Inspection

The reactor vessel and nozzles are inspected volumetrically by the use of automatic ultrasonic devices having the capability for control by remote means.

5.2.4.4 Inspection Intervals

The reactor pressure vessel, system piping, pumps, valves and components within the reactor coolant pressure boundaries, as defined in the ASME Code Section XI, are designed and fabricated to permit full compliance with Section XI. Access is provided for volumetric examination of pressure-containing welds from the external surfaces. The examination procedures have been considered in the design of components, weld joint configurations, and system arrangements to assure inspectability.

5.2.4.5 Inservice Inspection Program Categories and Requirements

The inservice inspection program for LSCS includes the baseline inspection of the RPV's and all Class 1 pressure boundary components and piping. The baseline covered the requirements of Section XI of the ASME Boiler and Pressure Vessel Code.

Specific written requests for relief from ASME code requirements determined to be impractical were contained in the initial inservice inspection program. The NRC granted relief from these requirements. Detailed evaluation is included in Appendix C of NUREG 0519 Supplement No. 5, Safety Evaluation Report, related to the operation of LaSalle County Station, Units 1 and 2.

5.2.4.6 Evaluation of Examination Results

5.2.4.6.1 Recording and Comparing Data

Data obtained from inservice inspection examination with the reactor pressure vessel in place at the site are used as the baseline data for the reactor vessel. The State of Illinois requires ISI baseline examination with RPV in place at the site. Baseline data for remaining portions of the reactor coolant pressure boundary are obtained after installation. All data are recorded and these records are maintained for comparison with data from subsequent examinations.

5.2.4.6.2 Reactor Vessel Acceptance Standards

Acceptance standards used for evaluation of the ultrasonic baseline examination of the reactor vessel were in accordance with the requirements of Section XI, ASME Boiler and Pressure Vessel Code, 1974 Edition, Summer of 1975 Addenda. The baseline (preservice) examination program has since been upgraded to be in accordance with the 1980 Edition, Winter 1980 Addenda of ASME XI.

5.2.4.7 System Leakage and Hydrostatic Pressure Tests

These tests on LSCS equipment are made in strict accordance with Section III and Section XI requirements of the ASME Boiler and Pressure Vessel Code.

5.2.4.8 Coordination of Inspection Equipment with Access Provisions

Development of remotely controlled inspection equipment is followed closely to assure that inservice inspection access provisions are adequate to permit its use.

Inspection locations, inspection techniques, inspection frequencies, and evaluation are in accordance with Section XI, ASME Boiler and Pressure Vessel Code.

5.2.5 Reactor Coolant Pressure Boundary Leakage Detection Systems

5.2.5.1 Leakage Detection Methods

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

a. nuclear boiler system,

b. main steamlines,

c. reactor water cleanup (RWCU) system,

d. residual heat removal (RHR) system,

e. reactor core isolation cooling (RCIC) system,

f. feedwater system,

g. fuel pool cooling system, and

h. instrument lines associated with these systems.

Isolation and/or alarm of affected systems and the methods used are summarized in Table 5.2-8. Drawing Nos. M-155, M-156 (sheets 1-4), M-157, M-86 (sheet 1), M-129 (sheet 1), M-93 (sheets 1,2,4), M-2101, M-2055 (sheets 1, 3-7), M-2096 (sheet 5), M-2091 (sheets 2-5), M-91 (sheet 4), M-2080 (sheet 1), M-2105 (sheet 1), M-2106 (sheet 1), M-2103 (sheet 30), M-98, M-153, and M-2097 (sheet 2), and M-2143 (sheet 2) depict the P & ID or C & ID for the leakage detection systems.

Small leaks (5 gpm and less) are detected by temperature and pressure changes and by drain activities. Large leaks are also detected by changes in reactor water level and changes in flow rates in process lines.

5.2.5.1.1 Detection of Abnormal Leakage within the Primary Containment

Leaks within the drywell are detected by monitoring for abnormally high pressure and temperature within the drywell, high fill-up rates of equipment and floor drain sumps, excessive temperature difference between the inlet and outlet cooling water for the two drywell fan-coil coolers and the six area coolers, increased flow rate of the cooler condensate, a decrease in the reactor vessel water level, and high levels of fission products in the drywell atmosphere. Temperatures within the drywell are monitored at various elevations. Also, the temperature of the inlet and exit air to the atmosphere coolers is monitored. Excessive temperatures in the drywell, increased drain sump filling rate, increased cooler condensate flow, and drywell high pressure are annunciated by alarms in the control room and, in certain cases, cause automatic isolation of the containment. In addition, low reactor vessel water level will isolate the main steamlines. The systems within the drywell share a common area; therefore, their leakage detection systems are common. Each of the leakage detection systems inside the drywell is designed with a capability of detecting leakage less than established leakage rate limits.

5.2.5.1.2 Detection of Abnormal Leakage Outside the Primary Containment

Outside the drywell, the equipment and piping within each system monitored for leakage is in compartments or rooms separate from other systems where feasible, so that leakage may be detected by area temperature indications. Each leakage detection system discussed in the following is designed to detect leak rates as discussed in Section 7.6. The method used to monitor for leakage on systems which may contain reactor coolant outside containment are given in Table 5.2-8.

a. Ambient and Differential Room Ventilation Temperature - An ambient and differential temperature sensing system is installed in each room containing equipment may contain reactor coolant hot enough to actuate the sensors during a leak. These rooms are the RCIC, and reactor water cleanup systems equipment rooms and the main and RCIC steamline tunnels. Piping outside these rooms is monitored for leakage by other means described in the following subsections.

   Temperature sensors are placed in the inlet ventilation supply source and outlet ventilation ducts. Other sensors are installed in the equipment areas to monitor ambient temperature. All of the thermocouples are terminated on Digital Recorders located in the control room, which compute and display differential temperatures for the rooms as well as the ambient temperatures. Output relays from the recorders will initiate alarms and isolations when the associated temperatures exceed predefined setpoints.

   The ambient temperature and differential temperature alarm and isolation setpoints are established by calculating a heat balance for the design room environment at normal operating conditions, and then introducing the heat release caused by an alarm limit leak (5-gpm) or isolation limit leak (25-gpm). Since the temperatures in the rooms being monitored are indirectly affected by outside ambient conditions, the ambient and differential temperatures monitored will not be a precise indication of leakage conditions within the room.

Therefore, actual leakage rates may be slightly above the leak limits during off-design conditions.

b. Sump Flow Measurement - Instrumentation monitors and indicates the amount of leakage into the floor drainage

system. The normal design leakage collected in the system consists of leakage from the reactor water cleanup, CRD systems, and from other miscellaneous vents and drains.

c. Visual and Audible Inspection - Accessible areas are inspected periodically. The temperature and flow indicators discussed previously are monitored regularly. Any instrument indication of abnormal leakage will be investigated.

d. Differential Flow Measurement (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 (75 gpm) out of the reactor vessel indicates that a leak may exist.

e. Flow Measurement - High flow in the RWCU system, RCIC steam supply, or RHR system will indicate a leak/break in these systems, and will initiate control room alarms and automatic system isolation.

f. Radiation Levels - High radiation levels from the area radiation monitors or the continuous air monitors may provide supplemental system leak detection indication.

5.2.5.2 Leak Detection Devices Within Primary Containment

Table 5.2-8 summarizes the actions taken by each leakage detection function. The table shows that those systems which detect gross leakage initiate immediate automatic isolation. The systems which are capable of detecting small leaks initiate an alarm in the control room. The operator can manually isolate the violated system or take other appropriate action.

a. Drywell Floor Drain Sump Measurement - The normal design leakage collected in the floor drain sump consists of leakage from the control rod drives, valve flange leakage, valve stem packing leakage floor drains, chilled cooling water system, and drywell cooling unit drains.

b. <u>Drywell Equipment Drain Sump</u> - The equipment drain sump collects only identified leakage. This sump receives condensate drainage from pump seal leakoff, reactor vessel heat flange vent drain, and valve packing leakoff. Collection in excess of background leakage would indicate reactor coolant leakage.

c. <u>Drywell Cooler Drain</u> - Condensate from the drywell coolers is routed to the floor drain sump and is monitored by use of a flow transmitter mounted locally while having indicating and alarm instrumentation in the control room. An adjustable alarm is set to annunciate on the condensate flow rate approaching the technical specification limit.

d. <u>Drywell Pressure Measurement</u> - The drywell is at a slightly positive pressure during reactor operation. The pressure fluctuates slightly as a result of barometric pressure changes and outleakage. A pressure rise above the normally indicated values will indicate the presence of a leak within the drywell.

e. <u>Drywell Temperature Measurement</u> - The drywell cooling system circulates the drywell atmosphere through heat exchangers (air coolers) to maintain the drywell at its designed operating temperature and also provides cooling water to the air coolers. An increase in drywell atmosphere temperature would increase the temperature rise in the chilled cooling water passing through the coils of the air coolers. Thus, an increase in the chilled cooling water temperature difference between inlet and outlet to the air coolers will indicate the presence of reactor coolant or steam leakage. Also, a drywell ambient temperature rise will indicate the presence of reactor coolant or steam leakage. A temperature rise in the drywell is detected by monitoring the drywell temperature at various elevations, the inlet and outlet air to the coolers, and the chilled cooling water temperature increase between inlet and outlet to the coolers.

f. <u>Drywell Air Sampling</u> - The drywell air sampling system is used to supplement the temperature, pressure and flow variation method (described previously) and to detect leaks in the nuclear system process barrier. The system continuously monitors the drywell atmosphere for airborne radioactivity. The sample is drawn from the

drywell. A sudden increase of activity, which may be attributed to steam or reactor water leakage, is annunciated in the control room. (Refer to Subsection 7.6.2.2.)

g. Reactor Vessel Head Closure - The reactor vessel head closure is provided with double seals with a leakoff connection between seals that is piped through a normally closed manual valve to the equipment drain sump. Leakage through the first seal is annunciated in the control room. When pressure between the seals increases, an alarm in the control room is actuated. The second seal then operates to contain the vessel pressure.

h. Reactor Water Recirculation Pump Seal - Reactor water recirculation pump seal leaks are detected by monitoring the drain line. Leakage, indicated by high flow rate, alarms in the control room. Leakage is piped to the equipment drain sump. (See the nuclear boiler reactor recirculating P&ID, Drawing Nos. M-93 (sheets 1 & 2) and M-139 (sheets 1 & 2).

i. Safety/Relief Valves - Temperature sensors connected to a multipoint recorder are provided to detect safety/relief valve leakage during reactor operation. Safety/relief valve temperature elements are mounted, using a thermowell, in the safety/relief valve discharge piping several feet from the valve body. Temperature rise above ambient is annunciated in the main control room. (See the nuclear boiler and reactor recirculating P&ID, Drawing Nos. M-55, M-116 (sheet 1), M-2055, (sheets 1 and 3), and M-2116 (sheets 1 and 3).

j. Valve Packing Leakage - Valve stem packing leaks of certain power-operated valves in the nuclear boiler system, reactor water cleanup system, residual heat removal system, and recirculation system are detected by monitoring packing leakoff for high temperature and are annunciated by an alarm in the control room.

5.2.5.3 Indication in Control Room

Leak detection methods are discussed in Subsection 5.2.5.1 and 5.2.5.2. Details of the leakage detection system indications are included in Subsection 7.6.2.2.

5.2.5.4 Limits for Reactor Coolant Pressure Boundary Leakage

5.2.5.4.1 Total Leakage Rate

The total leakage rate consists of all leakage, identified and unidentified, that flows to the drywell floor drain and equipment drain sumps. The criterion for establishing the total leakage rate limit is based on the makeup capability of the RCIC systems and is independent of the feedwater system, normal a-c power, and the emergency core cooling systems. The total leakage rate limit is at 25 gpm per Technical Specifications.

5.2.5.4.2 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 pumps and certain valves inside the drywell are equipped with double seals. Leakage from the primary recirculation pump seals is piped to the equipment drain sump as described in Subsection 5.2.5.2. Leakage from the main steam safety/relief valves is identified by temperature sensors that transmit to the control room. Any temperature increase above the drywell ambient temperature detected by these sensors indicates valve leakage. Leakage from the reactor vessel head flange is also monitored (Subsection 7.6.2.2.). Thus, the leakage rates from pumps, certain ECN PFL-736-LS valve seals, and the reactor vessel head seal are measurable during plant operation. These leakage rates, plus any other leakage rates measured while the drywell is open, are defined as identified leakage rates.

5.2.5.5 Unidentified Leakage Inside the Drywell

5.2.5.5.1 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 at 5 gpm per Technical Specifications 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 5.2-11).

5.2.5.5.2 Length of Through-Wall Flaw

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

Critical Crack Length

Both the GE and the BMI test results indicate that theoretical fracture mechanics formulas do not predict critical crack length, but that satisfactory empirical expressions may be developed to fit test results. A simple equation which fits the data in the range of normal design stresses (for carbon steel pipe) is:

$$\ell_c = \frac{15000D}{\sigma_R}$$ (data correlation on Figure 5.2-12) (5.2-1)

where:

ℓ_c = critical crack length (inches),

D = mean pipe diameter (inches), and

σ_R = nominal hoop stress (psi).

Crack Opening Displacement

The theory of elasticity predicts a crack opening displacement of:

$$W = \frac{2\ell\sigma}{E} \qquad (5.2\text{-}2)$$

Where:

ℓ = crack length,

σ = applied nominal stress, and

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

$$C = \sec \frac{\pi}{2} \frac{\sigma}{\sigma_f} \tag{5.2-3}$$

The crack opening area is given by:

$$A = C \frac{\pi}{4} W\ell = \frac{\pi \ell^2 \sigma}{2E} \sec \frac{\pi}{2} \frac{\sigma}{\sigma_f} \tag{5.2-4}$$

For a given crack length $\ell, \sigma_f = 15{,}000 \, D/\ell$

Leakage Flow Rate

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

A = 0.0126 in^2 (saturated water) and

A = 0.0475 in^2 (saturated steam).

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

Crack ℓ, (inches)

Nominal Pipe Size (Sch 80), inches	Average Wall Thickness, inches	Steamline	Waterline
4	0.337	7.2	4.9
12	0.687	8.5	4.8
24	1.218	8.6	4.6

Ratio ℓ / ℓ_c

Nominal Pipe Size (Sch 80), inches	Steamline	Waterline
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 inch at the time of incipient rupture, corresponding to leaks of the order of 1 in^2 in size for plain carbon steel piping. For austenitic stainless steel piping, even larger leaks are expected to precede crack instability, although there are insufficient data to permit quantitative prediction.

The results given are for a longitudinally oriented flaw at normal operating hoop stress. A circumferentially oriented flaw could be subjected to stress as high as the 550° F yield stress, assuming high thermal expansion stresses exist. A good mathematical model which is well supported by test data is not available for the circumferential crack. Therefore, 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 5.2-11 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 inch, 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.

5.2.5.5.3 Margins of Safety

The margins of safety for a detectable flaw to reach critical size are presented in Subsection 5.2.5.5.3. Figure 5.2-11 shows general relationships between crack length, leak rate, stress, and line size using the mathematical model.

5.2.5.5.4 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, reactor building, and auxiliary building, as shown in Table 5.2-8. As discussed in Subsection 5.2.5.1.2, 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.

As discussed in Subsection 5.2.5.5, 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 reactor coolant pressure boundary, corrective action could be taken before the integrity of the barrier would be threatened with significant compromise.

The leak detection system satisfactorily detects unidentified leakage of 5 gpm. Any holdup caused by construction irregularities in the Drywell Floor will not cause a significant delay in detection of unidentified leakage.

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

The leak detection system is discussed in Subsection 5.2.5, while its subsystems, instrumentation, and operation theory are described in Subsection 7.6.2.2. The system component requirements are given in Table 3.2-1.

5.2.5.6 Differentiation Between Identified and Unidentified Leaks

Subsection 5.2.5.1 describes the systems that are monitored by the leak detection equipment. The ability of the leak detection system to differentiate between identified and unidentified leakage is discussed in Subsection 5.2.5.4.

5.2.5.7 Sensitivity and Operability Tests

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

5.2.5.8 Safety Interfaces

The balance-of-plant 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 all associated wiring and cable lying outside the nuclear steam supply system equipment. These balance-of-plant systems and equipment include the main steamline tunnel, the safety/relief valves, and the turbine building sumps.

5.2.5.9 Testing and Calibrations

Provisions for testing and calibration of the leak detection system are covered in Chapter 14.0 and in the Technical Specifications.

5.2.5.10 Main Steam Line Leak Detection Outside the Primary Containment

The Main Steam Line Leak Detection System outside the primary containment was modified during L1R07 and L2R07 to reduce spurious isolations of the main steam lines. The main steam line tunnel ambient temperature sensors now provide alarm function only. The differential temperature logic provides alarm and isolation functions. Supporting calculations for these change are contained in reference 10 of Section 5.2.6.

5.2.6 References

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

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

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

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

5. F. J. Moody, "Maximum Two-Phase Vessel Blowdown from Pipes," APEO-4827, April 1965.

6. "General Electric Standard Application for Reactor Fuel (GESTAR II)," NEDE-24011-P-A, Rev. 22.

7. Deleted.

8. Regulatory Guide 1.99 Rev. 2, "Radiation Embrittlement of Reactor Vessel Materials dated May 1988.

9. Generic Letter 88-11, "NRC Position on Radiation Embrittment of Reactor Vessel Materials and the Impact on Plant Operations" dated July 12, 1988.

10. LaSalle OSR Report 96-003, "License Amendment Request for Main Steam Tunnel Leak Detection Isolations," dated January 12, 1996.

11. "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," NEDO-24154, Vol. 1 and 2, October 1978 and NEDE-24154-P, Volume 3, October 1978.

12. COTRANSA2: A Computer Program for Boiling Water Reactor Transient Analysis, ANF-913(P)(A), Revision 2 and Supplements, Advanced Nuclear Fuels Corporation, November 1990.

13. Deleted

14. Safety Evaluation Report (SER) by NRC, dated 06-03-99, for Amendment Nos. 133 and 118 for LaSalle County Station Units 1 & 2, respectively.

15. Pressure-Temperature Limits Report for Exelon Nuclear, LaSalle County Station Unit 1, GE Hitachi Nuclear Energy, 0000-0148-2850, R2, January 2013.

16. Pressure-Temperature Curves for Exelon LaSalle Unit 2, GE Nuclear Energy, GE-NE-0000-0003-5526-01R1, May 2004.

17. Letter from NRC to Mr. Michael J. Pacilio, Issuance of Amendments Regarding Reactor Coolant System Pressure–Temperature (P/T) Limits, dated April 15, 2011.

18. Power Uprate Project Task 300, "Nuclear Boiler system," GE-NE-A1300384-28-01, including Overpressurization Protection Report, 22A4342, Rev. 5 / DC22A4342, Rev. 4.

19. BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (BWRVIP-75).

20. Design Analysis L-003561, Rev. 0, "T300 Series – Reactor Internals," July 2010.

21. Safety Evaluation related to Amendment 210 to Facility Operating License No. NPF-11, dated 11/25/14.

22. Letter from NRC to Com. Ed. Co., Review of the Response to Generic Letter 88-01, NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping, LaSalle County Station Units 1 and 2, August 1990.

23. "Migration to TRACG04 / PANAC11 from TRACG02 / PANAC10 for TRACG AOO and ATWS Overpressure Transients," NEDE-32906P Supplement 3-A Revision 1, April 2010.

24. "TRACG Application for Anticipated Operational Occurrences (AOO) Transient Analyses," NEDE-32906P-A, Revision 3, September 2006.

TABLE 5.2-1
(Historical)
(SHEET 1 OF 4)

CODE CASE INTERPRETATIONS

1.	1332 - Rev. 4 and 5	Requirements for Steel Forgings
2.	1401- Rev. 0	Welding Repairs to Cladding of Class 1 Section III Components After Heat Treating
3.	1420 - Rev. 0	5B-167 Ni-Cr-Fe Alloy Pipe or Tube
4.	1441 - Rev. 1	Waiving of 3 S_m Requirements for Section III Construction
5.	N-32 - Rev. 4	Regulatory Guide 1.84
6.	N-71 - Rev. 9	Regulatory Guide 1.85
7.	N-192	Regulatory Guide 1.84
8.	N-234	NRC approval letter dated November 1, 1979 (O.D. Parr to D. L. Peoples).
9.	N-235	NRC approval letter dated November 1, 1979 (O.D. Parr to D. L. Peoples).
10.	N-240	Hydrostatic test exemption for Section III Division 1 Class 2 and 3 piping with open atmosphere terminations, either upstream or downstream of an isolation valve. Applicable to the following systems: DG & HP exhaust lines to the atmosphere; RH, DG, HP & FC suction and discharge from the CSCS Cooling pond; OG & VG discharge lines from the off-gas and SGTS to the vent stack; and FC various spargers, drain lines, and vents going from or into the spent fuel pool, reactor well, transfer canal, and shipping-cask washdown area on the refueling floor.
11.	N-241	NRC approval letter dated March 17, 1980 (O.D. Parr to D. L. Peoples).

TABLE 5.2-1
(Historical)
(SHEET 2 OF 4)

12.	N-272	Regulatory Guide 1.84
13.	N-282	Regulatory Guide 1.84
14.	N-308	Telecon confirmed by Commonwealth Edison letter dated July 6, 1982 (C. W. Schroeder to A. Schwencer).
		The following ASME Section XI, Division 1, Code Cases are listed in paragraph C., REGULATORY POSITION, of Regulatory Guide 1.147, INSERVICE INSPECTION CODE CASE ACCEPTABILITY ASME SECTION XI DIVISION 1, as being acceptable to the NRC staff for implementation in the inservice inspection of components and supports, within any limitations stated in the Reg. Guide or the individual Code Case. The Code Cases listed are only those that apply, or may apply, to LSCS. LSCS may not currently utilize all of the Code Cases listed here, but reserves the right to use any of these Code Cases when applicable.
15.	N-389	Alternative rules for Repairs, Replacements, or Modifications, Section XI, Div. 1.
16.	N-411	"Alternative Damping Values for Seismic 2, and 3 Piping Sections, Section III, Division 1"
17.	N-498	"Alternative Rules for 10 Year Hydrostatic Pressure Testing for Class 1 and 2 Systems Section XI, Division 1", Regulatory Guide 1.147.
18.	N-98	Calibration Block Tolerances.
19.	N-211	Recalibration of Ultrasonic Equipment Upon Change of Personnel .
20.	N-235	Ultrasonic Calibration Checks per Section V.
21.	N-236-1	Repair and Replacement of Class MC Vessels.
22.	N-278	Alternative Ultrasonic Calibration Block Configuration I-3131 and T-434.3
23.	N-307-1	Revised Ultrasonic Examination Volume for Class 1 Bolting, Table IWB-2500-1, Examination Category B-G-1, When the Examinations Are Conducted From the Center Drilled Hole.

TABLE 5.2-1
(Historical)
(SHEET 3 OF 4)

24.	N-335-1	Rules for Ultrasonic Examination of Similar and Dissimilar Metal Piping Welds.
25.	N-408-2	Alternative Rules for Examination of Class 2 Piping.
26.	N-409-2	Procedure and Personnel Qualification Requirements for Ultrasonic Detection and Sizing of Intergranular Stress Corrosion Cracking in Austenitic Piping Welds.
27.	N-415	Alternative Rules for Testing Pressure Relief Devices.
28.	N-416	Alternative Rules for Hydrostatic Testing of Repair or Replacement of Class 2 Piping.
29.	N-419	Extent of VT-1 Examinations, Category B-G-1 of Table IWB-2500-1.
30.	N-426	Extent of VT-1 Examinations, Category B-G-2 of Table IWB-2500-1.
31.	N-427	Code Cases and Inspection Plans
32.	N-429-1	Alternative Rules for Ultrasonic Instrument Calibration.
33.	N-432	Repair Welding Using Automatic or Machine Gas Tungsten-Arc Welding (GTAW) Temperbead Technique.
34.	N-435-1	Alternative Examination Requirements for Vessels With Wall Thickness 2 in. or Less.
35.	N-437	Use of Digital Readout and Digital Measurement Devices for Performing Pressure Tests.
36.	N-457	Qualification Specimen Notch Location for Ultrasonic Examination of Bolts and Studs.
37.	N-458	Magnetic Particle Examination of Coated Materials.
38.	N-460	Alternative Examination Coverage for Class 1 and Class 2 Welds.
39.	N-461	Alternative Rules for Piping Calibration Block Thickness.
40.	N-463-1	Evaluation Procedures and Acceptance Criteria for Flaws in Class 1 Ferritic Piping that Exceed the Acceptance Standards of IWB-3514.2.
41.	N-465	Alternate Rules for Pump Testing.

TABLE 5.2-1
(Historical)
(SHEET 4 OF 4)

42.	N-472	Use of Digital Readout and Digital Measurement Devices for Performing Pump Vibration Testing.
43.	N-479-1	Boiling Water Reactor (BWR) Main Steam Hydrostatic Test.
44.	N-481	Alternative Examination Requirements for Cast Austenitic Pump Casings.
45.	N-485-1	Eddy Current Examination of Coated Ferritic Surfaces as an Alternative to Surface Examination.
46.	N-489	Alternative Rules for Level III NDE Qualification Examinations.
47.	N-490-1	Alternative Vision Test Requirements for Nondestructive Examiners.
48.	N-491	Alternative Rules for Examination of Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants.
49.	N-494	Pipe Specific Evaluation Procedures and Acceptance Criteria for Flaws in Class l Ferritic Piping that Exceed the Acceptance Standards of IWB-3514.2
50.	N-495	Hydrostatic Testing of Relief Valves.
51.	N-496	Helical-coil Threaded Inserts.

TABLE 5.2-2

EXCEPTIONS TO CONFORMANCE TO 10 CFR 50.55a
FOR REACTOR COOLANT PRESSURE BOUNDARY COMPONENTS

COMPONENT DESCRIPTION	PLANT IDENTIFICATION SYSTEM NUMBER	PURCHASE DATE	CODE SPECIFIED	CODE REQUIRED IN ACCORDANCE WITH 10 CRF 50, SECTION 55a
Recirculation pump	B33-C001	5/71	ASME III, 71	ASME III, 71W
Recirculation gate valve	B33-F023	6/71	ASME III, 71	ASME III, 71W
Recirculation gate valve	B33-F067	4/71	ASME III, 71	ASME III, 71W
Recirculation piping	B33-G001	10/71	ASME III, 71S	ASME III, 72S

NOTE:
Refer to Section 3.2 for those RCPB components which are in compliance with 10 CFR 50.55a.

TABLE 5.2-2a
(SHEET 1 OF 3)

ASME SECTION III, 1971, SUMMER AND WINTER ADDENDA CHANGES

SUMMER ADDENDA CHANGES

The 1971 Summer Addenda provides errata and "Alphabetical Index" for the ASME III Code, editorial corrections and the following:

1. Clarified effective date for the ASME III 1971 Edition Code - mandatory July 1, 1971.
2. Implemented Data Report Forms for Piping Subassemblies, Field Work, and Forms of Certificate of Authorization.
3. Clarified Design Specification content requirements, NA-3252.
4. Clarified intent of QA Maintenance and Control Measures, NA-4442.1, to prevent the use of incorrect or defective materials.
5. Clarified Code Intent on General Inspection Duties, NA-5210.
6. Clarified NB-2121(d) to exclude material controls on items such as shafts, stems, trim, bearings, bushings, wear plates, seals, packing, gaskets, valve seats, and safety valve discs and nozzles when internally contained.
7. Clarified MP & LP evaluation of indications and Acceptance Standards NB-2545.2(b) and (c), and NB-2546.2(b) and (c); NB-5341 and NB-5351.
8. General design rules for Minimum Wall Thickness of cylindrical shells and tubular products under external pressure have been clarified; NB-3133.3(a) and (b).
9. Stress limits for Upset Conditions were clarified; NB-3223(a).
10. Interface nozzle to piping requirements were clarified; NB-3227.5.
11. Weld surface requirements were clarified; NB-4424.
12. Thickness of Weld Reinforcement requirements redefined; NB-4426.1 and NB-4426.2.
13. Additional materials were approved and added to the list of Code-approved materials.
14. Manufacturer's Data Report forms were revised to include space for National Board Number and other editorial changes were made.

TABLE 5.2-2a
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WINTER ADDENDA CHANGES

The 1971 Winter Addenda provides errata to ASME III for editorial corrections, additional materials, and the following:

1. Acceptable Materials for use in valve discs have been added, NB-2121(e).
2. Tables I-1.1 and I-1.2 for special requirements specifications were clarified to satisfy NB-2200 and NB-2500; see NB-2122.
3. Volumetric examination requirements have been invoked for forged and cast pumps and valves with inlet piping connections over 2 inches up to and including 4 inches. It also permits MP or LP in lieu of volumetric examination, except for welding ends for cast pumps and valves, NB-2510.
4. Reference for radiographic examination methods have been clarified and cross-referenced to IX-3300; NB-2541, NB-2553, and NB-2561.
5. Stress differences due to operational cycles have been clarified; NB-3215 and NB-3222.4(e).
6. Requirements for specially designed welded seals have been specified (NB-3228.2(d) need not apply). Paragraphs NB-3227.7 and NB-6127 were added.
7. Acceptance Standards and Qualification Requirements of specialty designed welded seals were specified; Paragraphs NB-4360 and NB-5370 were added.
8. Ratings for flanged end and welding end valves of Types 347, 321, and 316 have been uprated from 300°F to 600°F, and for Type 310 from 300°F and 500°F, Tables NB-3531-2 through NB-3531-7 were corrected.
    a. Coefficients for valve design rules were clarified; NB-3534.
    b. Minimum wall thickness requirements for valve weld end prep transitions have been specified; NB-3542.1
    c. Valve body primary and secondary stress limits were specified; NB-3545.2 and NB-3545.3.
    d. Valve cyclic loading requirements were specified to include verification of adequacy, defined excluded cycles, fatigue usage and method for cyclic stress calculations; NB-3550.

TABLE 5.2-2a
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9. Hard-surfacing examination methods and acceptance standards have been clarified; NB-5273.
10. Acceptance standards for soap bubbles tests were specified; Paragraph NB-5380 added.
11. Alternative rules for nozzle design have been specified, Paragraph NB-3339 added.

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TABLE 5.2-4
(SHEET 1 OF 2)

PLANT EVENTS

NORMAL, UPSET, AND TESTING CONDITIONS			NUMBER OF CYCLES
1.	Bolt Up*		123
2.	Design Hydrostatic Test (Pressurized to ≥ 930 psig and ≤ 1250 psid)		130
3.	Heat up and cooldown cycles 70°F to 560°F to 70°F**		120
4.	75% Power to 100% to 75% of Rated Thermal Power*		10,000
5.	Power change cycles (50% to 100% to 50% of Rated Thermal Power)*		2,000
6.	Control Rod Pattern Change*		400
7.	Loss of Feedwater Heaters (80 Step Change Cycles Total):		80
8.	Operating-Basis Earthquake Event		1****
9.	Scram:		
	A.	Turbine Generator Trip, Feedwater On, Isolation Valves Stay Open	40
	B.	Other Scrams	140
	C.	Loss of Feedwater Pumps, Isolation Valves Closed	10
10.	Reactor trip cycles (100% to 0% of Rated Thermal Power)		190
11.	Reduction to 0% Power, Hot Standby, Shutdown (100° F/hr Cooldown Rate)**		111
12.	Unbolt		123
EMERGENCY CONDITIONS			
13.	Scram:		
	A.	Reactor Overpressure with Delay Scram, Feedwater Stays On, Isolation Valves Stay Open	1***
	B.	Automatic Blowdown	1***
	C.	Single Safety/Relief Valve Blowdown	8

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* Applies to reactor pressure vessel only.
** Bulk average vessel coolant temperature change in any 1-hour period, excluding flooding.
*** The 40-year encounter probability of the one cycle events is <10-1 for emergency and <10-3 for faulted events.
**** Includes 10 maximum load cycles per event.
Note: Environmental fatigue analyses were performed for ASME Code Class 1 components for License Renewal that used revised numbers of thermal transients that are imposed as limits in the Fatigue Monitoring Program. See UFSAR Appendix P, Section A.3.1.1, "Fatigue Monitoring Program," and Section A.4.3.3, "Environmental Fatigue Analyses for RPV and Class 1 Piping," for more information.

TABLE 5.2-4
(SHEET 2 OF 2)

NORMAL, UPSET, AND TESTING CONDITIONS		NUMBER OF CYCLES
14.	Improper Start of Cold Recirculation Loop	1***
15.	Sudden Start of Pump in Cold Recirculation Loop	1***
16.	Improper Startup with Reactor Drain Shut Off Followed by Turbine Roll and Increase to Rated Power	1***
17.	Safe Shutdown Earthquake (at Rated Operating Conditions)	1***
FAULTED CONDITION		
18.	Pipe Rupture and Blowdown	1***
19.	Safe Shutdown Earthquake (Including Jet Forces Due to a Pipe Rupture)	1***

*** The 40-year encounter probability of the one cycle events is $<10^{-1}$ for emergency and $<10^{-3}$ for faulted events.

TABLE 5.2-5

REACTOR COOLANT PRESSURE BOUNDARY LOADING COMBINATIONS

A. REACTOR PRESSURE VESSEL

PLANT CONDITIONS	LOADING COMBINATIONS
Normal	W + (P+J) for Events* 3-7 and 10
	W For Events* 1 and 11
Upset	W + (P+J) for Events* 9A-9C
	W + (P+J) + OBE (Event* 8) at Rated Operating Conditions
Emergency	W + (P+J) for Events* 12-15
	W + (P+J) for Event* 16
Faulted	W + (P+J) + Events* 17 and 18
	W + (P+J) SSE for Event* 18

Where W is the weight, superimposed, handling, vibration and reaction loads applied to the component during the event indicated, SSE is the maximum seismic load caused by the safe shutdown earthquake. (P+J) are the combined pressure and hydraulic loads during the events indicated.

B. LOADING AND STRESS CRITERIA FOR THE FOLLOWING RCPB COMPONENTS ARE SPECIFIED IN THE LISTED TABLES

COMPONENT	TABLE
1. Recirculation Loop Piping	Table 3.9-6
2. Main Steamline Piping	Table 3.9-5
3. Safety/Relief Valves	Table 3.9-8
4. Main Steam Isolation Valves	Table 3.9-9
5. Recirculation Loop Pumps and Valves	Tables 3.9-10 and 3.9-11

* For definition of event(s), refer to Table 5.2-4.

** The peak pressure is within 110% of design pressure for these emergency plant conditions and the resultant stresses fall within condition limits for upset. No special analysis is required.

TABLE 5.2-6
(SHEET 1 OF 3)

RCPB PUMP AND VALVE DESCRIPTION

LOCATION VALVE DESCRIPTION	ACTIVE/PASSIVE	VALVE NUMBER
RHR/LPCI	Active	E12-F041
	Active	E12-F042
RHR/Shutdown Cooling Line	Active	E12-F050
	Active	E12-F053
RHR/Head Spray	Active	E12-F019
	Active	E12-F023
RHR/Shutdown Cooling Line Suction	Active	E12-F009
	Active	E12-F008
	Active	E12-F460
RCIC Steam Supply	Passive	E51-F064
	Active	E51-F063
RCIC Head Spray	Active	E51-F066
	Active	E51-F065
	Active	E51-F013
(Nuclear Boiler)	Passive	B21-F001
Reactor Vessel Head Vent	Passive	B21-F002
	Passive	B21-F005
Feedwater Injection	Active	B21-F010
	Passive	B21-F011
	Active	B21-F032
Safety Relief	Active	B21-F013
Main Steamline Drains	Active	B21-F016
	Active	B21-F019
	Active	B21-F067
MSIV	Active	B21-F022

TABLE 5.2-6
(SHEET 2 OF 3)

LOCATION	ACTIVE/PASSIVE	VALVE NUMBER
MSIV	Active	B21F028
Reactor Water Cleanup System Suction	Passive	G33F103
	Passive	G33F100
	Passive	G33F101
	Passive	G33F106
	Active	G33F001
	Active	G33F004
Recirculation Pump Suction	Passive	B33F023
Reactor Water Sample	Active	B33F019
	Active	B33F395
	Active	B33F020
Reactor Vessel Drain	Passive	B33F029/F030
Recirculation Pump Discharge	Passive	B33F060
Pump Discharge	Passive	B33F067
HPCS Injection	Active	E22F005
	Active	E22F004

TABLE 5.2-6
(SHEET 3 OF 3)

LOCATION	ACTIVE/PASSIVE	VALVE NUMBER
LPCS Injection	Active	E21F006
	Active	E21F005
Standby Liquid	Active	C41F007
Control Injection	Active	C41F004
	Active	C41F006
PUMP DESCRIPTION		
Recirculation Pump	Passive	B33C001

TABLE 5.2-7

REACTOR COOLANT PRESSURE BOUNDARY MATERIALS

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Reactor Vessel	Rolled Plate	Low Alloy Steel	SA-533 Grade B
Heads, Shells	Forgings		SA-508 Cl.2
	Welds	Low Alloy Steel	SFA-5.5
Closure Flange	Forged Ring	Low Alloy Steel	SA-508 Cl.2
	Welds	Low Alloy Steel	SFA-5.5
Nozzles	Forged Shapes	Low Alloy Steel	SA-508 Cl.2
	Welds	Low Alloy Steel	SFA-5.5
Cladding	Weld Overlay	Austenitic Stainless Steel	SFA-5.9 or SFA-5.4 TP 309 with carbon content on final surface limit to 0.08% maximum
Control Rod Drive Housings	Pipe	Austenitic Stainless Steel	SA-312 Type 304
	Welds	Stainless Steel	SFA-5.9 or SFA-5.4 TP 308
Incore	Pipe	Austenitic	SA-213 Type 304
Housings		Stainless Steel	
	Welds	Stainless Steel	SFA-5.9 or 5.4 TP 308L

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 - Normalized; SA-333 Grade 6
Valves - SA-105 Grade II, Normalized; SA-216 Grade WCB, Normalized; SA-350 Grade LF2; SA-352 Grade LCB

Fittings - SA-105 Grade II - Normalized; SA-350 Grade LF-2, Normalized; SA-234, Grade WPB, Normalized; SA-420 Grade WPL6 (or WPL1)

Bolting - SA-193 Grade B7; SA-194 Grade 7 and 2H, SA-540 Grades B22, B23, and B24.

Welding Material - Welding materials conform to the applicable SFA specifications listed in ASME Boiler and Pressure Vessel Code Section IIc. Individual selection of filler metals are reviewed for conformity to the base materials being welded by the Consulting Engineers' review of welding procedures.

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; SA-358 Type 304
Valves	SA-182 Grade F-304; SA-351 Grades CF-8 and CF-8M
Pump	SA-182 Grade F-304; SA-351 Grades CF-8 and CF-8M
Flanges	SA-182 Grade F-316
Bolting	SA-193 Grade B8A and SA-194 Grades 8 and 2H; SA-540 Grades B22, B23 and B24
Welding Material	SFA-5.4 (E308-15, E308L-15, E316-15); SFA-5.9 (ER-308, ER-308L, ER-316)

TABLE 5.2-8

SUMMARY ISOLATION OF/ALARM OF SYSTEM MONITORED AND THE LEAK DETECTION METHODS USED

		VARIABLE MONITORED										
RESULTING ACTION		A	A	A	A/I	A/I	A	A	A/I	A/I	A/I	A/I
Source of Leakage (2)	Location	High PC Temperature	PC Sump High Flow Rate	High/PC Air Cooler CCWΔT or High Condensate Flow	Equipment Area High T(4) & ΔT	Low Steamline Pressure	RB Sump or Drain High Flow Rate	PC Pressure (High)	High Flow Rate (1)	RCIC Diaphragm Height-Exhaust Line Pressure	CU– Flow (High)	Reactor Low Water Level
Main Steamline	PC	X	X	X		X[3]		X	X			X
	RB				X[5]	X[3]	X		X			X
RHR	PC	X	X	X		X		X				X
	RB						X		X			X
RCIC Steam	PC	X	X	X		X		X	X			
	RB				X		X		X	X		
RCIC Water (Check Valves)	PC		X									
	RB						X					
Cleanup Water (Check Valves On Inlet)	PC	X	X	X				X[1]	X		X	X
	RB Hot				X		X		X		X	X
	RB Cold						X		X		X	X
Feedwater (Check Valves)	PC	X	X	X				X				
	RB				X[4]		X					

LEGEND

PC - primary containment
RB - reactor building
CU - cleanup
CCW - closed cooling water
A - alarm
I - isolation

1. Break downstream of flow element will isolate the system.
2. All systems within the drywell share a common base detection system which is designed to detect leakage at less than established limits.
3. In run mode only.
4. Alarm only (steam tunnel)
5. Ambient temperature provides alarm only in steam tunnel.
6. Break between the flow elements will isolate the system.

TABLE 5.2-9
(SHEET 1 OF 2)

NUCLEAR SYSTEM SAFETY/RELIEF

A. SET PRESSURES AND ASME RATED CAPACITIES

NO. OF VALVES	NOMINAL SPRING SET PRESSURE (psig) *	ASME RATED CAPACITY AT 103% SPRING SET PRESSURE (lb/hr each)	RELIEF PRESSURE CONTROLLER SET PRESSURE (psig) **	LOW-LOW SET RELIEF	
				NO. OF VALVES	SETPOINT OPEN/CLOSE
2	1150	865,725	1076	1	1006/896 (low)
				1	1046/926 (medium)
4	1175	884,314	1086	4	1086/946 (high)
2	1185	891,750	1096	1	1096/946 (high)
3	1195	899,185	1106		
2	1205	906,621	1116		

* Analysis is based on nominal + 3%.

** Analysis includes allowance for setpoint uncertainty.

TABLE 5.2-9
(SHEET 2 OF 2)

B. DURATION OF BLOWDOWN

EVENTS RESULTING IN PRESSURE (SAFETY) ACTUATION OF SRV	(TYPICAL RESULTS) MAXIMUM NUMBER OF VALVES EXPECTED* TO OPERATE ON FIRST BLOWDOWN*	(TYPICAL RESULTS) DURATION OF FIRST BLOWDOWN
1. Generator Load Reject with Bypass	18	5.6 sec
2. Loss of Condenser Vacuum	14	6
3. Turbine Trip with Bypass (25%)	18	6.4
4. MSIV Closure	18	6.2
5. Pressure Regulator Fail Open	0	0
6. Loss of Auxiliary Power	18	5.3
7. Feedwater Controller Failure (Maximum flow)	18	3.5 to 6
8. Inadvertent Opening of SRV	1	Operator response

* Cycle-specific reload Licensing analysis may assume fewer SRVs operable. Additionally, a new analysis based on 13 installed SRV's has been performed and accepted by the NRC, see References 13 and 14.

TABLE 5.2-10

(Historical)

LASALLE UNIT 1
REACTOR VESSEL TOUGHNESS

BELTLINE								
COMPONENT	MATERIAL TYPE OR WELD SEAM IDENTIFICATION	HEAT#/SLAB# OR HEAT#/LOT#	CU(%)	P(%)	HIGHEST STARTING RT NDT (°F)	MAXIMUM Δ RT NDT (°F)	MIN. UPPER SHELF (ft-lb)	MAX. EOL RT NDT
Plate	SA-533, Gr. B, C1.1	C5978-2	0.11	0.010	+23	30**	118	
Plate	SA-533, Gr. B, C1.1	C6345-2	0.15	0.012	-35**	49	153	+72
Weld	3-308-A, B, C	1P3571/3978	0.37	0.017	-30	124	***	+94

NON-BELTLINE COMPONENT	MATERIAL TYPE OR WELD SEAM IDENTIFICATION	HEAT#/SLAB# OR HEAT#/LOT#	HIGHEST STARTING RT NDT (°F)
Shell Ring	SA-533, Gr. B, C1.1	C6003-2	+12
Bottom Head Dollar Plate	SA-533, Gr. B, C1.1	C6003-3	+58
Bottom Head Radial Plates	SA-533, Gr. B, C1.1	G5328-1	+10
Top Head Dollar Plate	SA-533, Gr. B, C1.1	C7343-1	-10
Top Head Side Plates	SA-533, Gr. B, C1.1	C7376-2	-10
Top Head Flange	SA-508, C1.2	ACT-USS-4P	+20
Vessel Flange	SA-508, C1.2	2V-659ATF-112	+20
Feedwater Nozzle	SA-508, C1.2	#174W-3, Q2Q14W	+40
Weld	15-308	NA/K01B	0
Closure Stud	POH-16C, Gr. B and ATSM-A-540	14716	+70

* Combination of the highest starting RT_{NDT} plate and the highest ΔRT_{NDT} plate.
** These values are given only for the benefit of calculating the end-of-life (EOL) RT_{NDT}.
*** Not available.

TABLE 5.2-11

(Historical)

LASALLE UNIT 2
REACTOR VESSEL TOUGHNESS

BELTLINE COMPONENT	MATERIAL TYPE OR WELD SEAM IDENTIFICATION	HEAT#/SLAB# OR HEAT#/LOT#	CU(%)	P(%)	HIGHEST STARTING RT NDT (°F)	MAXIMUM Δ RT NDT (°F)	MIN. UPPER SHELF (ft-lb)	MAX. EOL RT NDT
Plate	SA-533, Gr. B, C1.1	C9404-2	0.07	0.008	+52*	13*	29	+65
Plate	SA-533, Gr. B, C1.1	C9425-1	0.12	0.009	+30*	28*	39	+58
Weld	1NMW/E8018-G	3P4966/1214	0.03	0.010	-6*	17*	28	+11

NON-BELTLINE COMPONENT	MATERIAL TYPE OR WELD SEAM IDENTIFICATION	HEAT#/SLAB# OR HEAT#/LOT#	HIGHEST STARTING RT NDT (°F)
Shell Ring	SA-533, Gr. B, C1.1	C9481-1	**
Top Head Flange	SA-508, C1.2	BWR-446	+20
Vessel Flange	SA-508, C1.2	BRC-424	+26
Feedwater Nozzle	SA-508, C1.2	Q2Q25W	-6
Weld	???1NMW	3P4966/1214	-6
Closure Stud	SA-540, Grade B-24	82552 and 82750	**

* These values are given only for the benefit of calculating the end-of-life (EOL) RT_{NDT}.
** Not available.

TABLE 5.2-12

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM-WITHDRAWL SCHEDULE

Unit 1

SPECIMEN HOLDER*	VESSEL LOCATION	LEAD FACTOR	WITHDRAWAL TIME (EFFECTIVE FULL POWER YEARS)
Capsule 1	300º		6
Capsule 2	120º	1.01	18.9 in 2010
Capsule 3	30º	1.01	Plant Life Extension – 33 (approximately 2030), whichever is later
Neutron Dosimeter	30º		1st Refueling Outage

Unit 2

SPECIMEN HOLDER*	VESSEL LOCATION	LEAD FACTOR	WITHDRAWAL TIME (EFFECTIVE FULL POWER YEARS)
Capsule 1	300º		6
Capsule 2	120º		15.44 **
Capsule 3	30º	0.99	Spare
Neutron Dosimeter	30º		1st Refueling Outage

*Each capsule includes three Cu, three Fe, and three Ni flux wires. The neutron dosimeter contained three Cu and three Fe flux wires.
** Holder and contents must be kept in the fuel pool indefinitely. See Section 5.3.1.6.2.

TABLE 5.2-13

MSIV CLOSURE FLUX SCRAM EVENT
ANALYSIS RESULTS (2)

Power/Flow	SRV Configuration	Peak Neutron Flux (% NBR)	Peak Heat Flux (% NBR)	Peak Steamline Pressure psig	Peak Vessel Bottom Pressure psig
102/105[(1)]	Nom. + 1%, 17 SRVs	486	132	1240	1275
102/105	Nom. + 3% 10 SRVs	486	132	1316	1341

Notes: (1) Based on LaSalle Unit 2 Cycle 7 reload analysis, with –3%/+1% setpoint tolerance range.
(2) From Reference 13.

5.3 REACTOR VESSEL

5.3.1 Reactor Vessel Materials

5.3.1.1 Material Specifications

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

5.3.1.2 Special Processes Used for Manufacturing and Fabrication

The basic manufacturing and fabrication controls for the LSCS RPV's were based on Section III, with radiography as the in-process and finished product inspection technique. During fabrication the advances in UT testing enabled the utilization of these techniques first as feasibility tests and then as confirmatory inspections on the RPV's.

5.3.1.3 Special Methods for Nondestructive Examination

The LSCS RPV's were fabricated to Section III requirements of the ASME Boiler and Pressure Vessel Code. They were also subjected to Section XI in-process ultrasonic inspection in addition to the standard NDE for Section III. Following completion of fabrication, each vessel was hydrostatically tested and then completely examined ultrasonically prior to shipping. A second hydro test and an ultrasonic baseline inspection per Section XI were performed following vessel set at LSCS.

5.3.1.4 Special Controls for Ferritic and Austenitic Stainless Steel

The specialized quality controls for cleaning, welding, slug control, and weld clad processes were applied for the austenitic stainless steel used in LSCS. Certifications of these controls were the responsibility of the NSSS vendor (GE).

5.3.1.5 Fracture Toughness

LSCS compliance with 10CFR50 Appendices G and H is discussed in Subsection 5.2.3.3.1.

5.3.1.6 Material Surveillance

5.3.1.6.1 Compliance with "Reactor Vessel Material Surveillance Program Requirements"

A materials surveillance program was developed and initiated at the beginning of nuclear operation of LSCS. This surveillance program was designed to be in

conformance with the requirements of 10 CFR 50 Appendix H, as discussed in UFSAR Section 5.2.3.3.1.9.
Charpy impact specimens installed for the original reactor vessel surveillance programs are of the longitudinal orientation consistent with the ASME requirements prior to the issue

of the Summer 1972 Addenda and ASTM E 185-73. Based on General Electric Company (GE) experience, the amount of shift measured by these irradiated longitudinal test specimens will be essentially the same as shift in an equivalent transverse specimen. The original material surveillance program for LaSalle reactor pressure vessels included three sets of specimens in each reactor. The specimens were manufactured from a plate actually used in the beltline region and a weld typical of those in the beltline region and thus represent base metal, weld metal, and the transition zone between base metal and weld. The expanded surveillance program includes: 12 additional samples in baskets No. 2 and 3 to give a total of 36 samples in each of the baskets. The 12 samples include 4 base metal, 4 weld metal, and 4 HAZ material. Additionally, 15 transverse samples are included in the baseline definition of both lower and upper shelf energies. These were examined prior to initial criticality. Sufficient tensile and Charpy V-notch specimens are provided in each of the three in-reactor sets and in the out-of- reactor set to measure strength, ductility, and toughness of each of the three materials (base, weld, HAZ), both in the unirradiated and irradiated conditions.

In 2003, the NRC approved LSCS participation in the BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) as described in BWRVIP-78 and BWRVIP-86 (Reference 1). The NRC approved the ISP for the industry in Reference 1 and approved LSCS participation in Reference 2. The ISP meets the requirements of 10 CFR 50 Appendix H and provides several advantages over the original program. The surveillance materials in many plant-specific programs do not represent the best match with the limiting vessel beltline materials since some were established prior to 10 CFR 50 Appendix H requirements. Also, the ISP allows for better comparison to unirradiated material data to determine actual shifts in toughness. Finally, for many plants, ISP data will be available sooner to factor into plant operations since there are more sources of data.

The current withdrawal schedule for both units is given in UFSAR Table 5.2-12 and is based on the NRC-approved revisions of BWRVIP-86 (Reference 1). The surveillance capsule withdrawal schedule remains unchanged as a result of MUR uprate (Reference 5).

5.3.1.6.2 Positioning of Surveillance Capsules

The sealed capsules are not attached to the vessel but are in welded capsule holders. The capsule holders are mechanically retained by capsule holder brackets welded to the vessel cladding. The capsule holder brackets allow the capsule holder to be removed at any desired time in the life of the plant for specimen testing. These brackets are designed, fabricated and analyzed to the requirements of Section III of the ASME Code. The capsule withdrawal schedule is given in Table 5.2-12.

During the Spring 2005 outage at LaSalle (L2R10), the surveillance capsule holder at the 120° azimuth moved from its design location. The spring inside the capsule

holder failed which allowed the capsule holder to extend in total length. In addition to the capsule holder extending to full length, the flow in the annulus had dislodged the bottom of the capsule holder out to the end of the capsule holder bracket attachment.

This surveillance capsule was removed from the reactor during the Unit 2 outage, L2R11, in February 2007. In accordance with the requirements of the Generic Aging Lessons Learned (GALL) Report (NUREG-1801, Section XI.M31), LaSalle will store the surveillance capsule and specimens contained within the capsule in the fuel pool indefinitely. The Unit 2 surveillance capsule had been in the reactor approximately 15.44 Effective Full Power Years (EFPY). (Reference 3)

During the Spring 2010 outage on Unit 1 (L1R13), the surveillance capsule holder at the 120° azimuth was removed in support of the ISP, as required by the schedule on Table 5.2-12. The contents were evaluated for their impact on the fracture toughness of the Unit 1 reactor vessel in the ISP and the results are documented in BWRVIP-250NP. (Reference 8)

5.3.1.6.3 Time and Number of Dosimetry Measurements

The NSSS vendor provided a separate neutron dosimeter which contains Cu flux wires and Fe flux wires. At the end of the first cycle the dosimeter is removed and a determination is made of the fluence of the vessel inside diameter during the first cycle, by measurements from these wires, to verify the predicted fluence at an early date in plant operation. This measurement is made over this short period to avoid saturation of the dosimeters now available. Once the fluence-to-thermal power output is verified, no further dosimetry is considered necessary because of the linear relationship between fluence and power output.

5.3.1.7 Reactor Vessel Fasteners

The boiling water reactor does not use borated water for reactivity control. Therefore, this subsection is not applicable.

5.3.2 Pressure-Temperature Limits

The basis for the operational pressure-temperature limits is provided in the Technical Specifications.

5.3.3 Reactor Vessel Integrity

The Unit 1 and 2 reactor vessels were fabricated for General Electric's Nuclear Energy Division by Combustion Engineering and CBI Nuclear Co., respectively and were subject to the requirements of General Electric's Quality Assurance program.

Assurance was made that measures were established requiring that purchased material, equipment, and services associated with the reactor vessels and appurtenances conform to the requirements of the subject purchase documents. These measures included provisions, as appropriate, for source evaluation and selection, objective evidence of quality furnished, inspection at the vendor source and examination of the reactor vessels upon delivery at the construction site.

General Electric provided inspection surveillance of the reactor vessel fabricator's in-process manufacturing, fabrication, and testing operations in accordance with GE's Quality Assurance program and approved inspection procedures. The reactor vessel fabricator was responsible for the first-level inspection of his manufacturing, fabrication, and testing activities, and General Electric is responsible for the first level of audit and surveillance inspection.

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

5.3.3.1 Design

5.3.3.1.1 Description

The reactor vessel (Figure 5.3-1) is a vertical, cylindrical pressure vessel of welded construction. The vessel is designed, fabricated, tested, inspected, and stamped in accordance with the ASME Code Section III, Class A, including the addenda in effect at the date of order placement: Unit 1, January 1967; and Unit 2, April 1971. The vessels were subsequently upgraded to the 1968 edition with Winter 1969 Addenda for Unit 1 and to the 1968 edition with Winter 1970 Addenda (excluding Appendix I) for Unit 2. Design of the reactor vessel and its support system meets Seismic Category I equipment requirements. The materials used in the reactor pressure vessel are shown in Table 5.2-7.

The cylindrical shell and top and bottom heads of the reactor vessel are fabricated of low-alloy steel, the interior of which is clad with stainless steel weld overlay. Nozzle and nozzle weld zones are clad through at least the vessel wall thickness.

In-place annealing of the reactor vessel is unnecessary because shifts in transition temperature caused by irradiation during the 40-year life can be accommodated by raising the minimum pressurization temperature. Radiation embrittlement is not a problem outside of the vessel beltline region because the irradiation measured in those areas is substantially less than 10^{17} n/cm^2 with neutron energies in excess of 1 MeV.

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

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

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

5.3.3.1.2 Safety Design Bases

Design of the reactor vessel and appurtenances meet the following safety design bases:

a. The reactor vessel and appurtenances will withstand adverse combinations of loading and forces resulting from operation under abnormal and accident conditions.

b. To minimize the possibility of brittle fracture of the nuclear system process barrier, the following are required:

    1. Impact properties at temperatures related to vessel operation have been specified for materials used in the reactor vessel.

    2. Expected shifts in transition temperature during design life as a result of environmental conditions, such as

neutron flux, are considered in the design. Operational limitations assure that nil ductility transition temperature shifts are accounted for in reactor operation.

3. Operational margins to be observed with regard to the transition temperature shall be specified for each mode of operation.

5.3.3.1.3 Power Generation Design Basis

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

a. The reactor vessel has been designed for a useful life of 40 years.

b. External and internal supports that are integral parts of the reactor vessel are located and designed so that stresses in the vessel and supports that result from reactions at these supports are within ASME code limits.

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

5.3.3.1.4 Reactor Vessel Design Data

5.3.3.1.4.1 Vessel Support

The reinforced concrete RPV support pedestal is constructed as a monolithic part of the building foundation. The Unit 1 reactor vessel skirt is connected to a ring girder adapter via 60 bolts. The ring girder adapter is connected to the reactor vessel support pedestal via 120 anchor bolts. The Unit 2 reactor vessel skirt is connected directly to the reactor vessel support pedestal via 120 anchor bolts. Upper vessel support is provided by a system of stabilizer brackets.

5.3.3.1.4.2 Control Rod Drive Housings

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

5.3.3.1.4.3 Incore Neutron Flux Monitor Housings

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

An incore flux monitor guide tube is welded to the top of each housing (Subsection 4.2.2) and either a source range monitor/intermediate range monitor (SRM/IRM) drive unit or a local power range monitor (LPRM) is bolted to the seal ring flange at the bottom of the housing (Sections 7.6 and 7.7).

5.3.3.1.4.4 Reactor Vessel Insulation

The reactor vessel insulation has an average maximum heat transfer rate of approximately 65 Btu/hr/ft^2 at the operating conditions of 550° F for the vessel and 135° F for the drywell air. The insulation panels for the cylindrical shell of the vessel are held in place by insulation supports located on the biological shield. The insulation shall be designed to be removable over those portions of the vessel where inspection is required by the inservice inspection code.

5.3.3.1.4.5 Reactor Vessel Nozzles

All piping connecting to the reactor vessel nozzles has been designed not to exceed code-allowable loads on any nozzle.

The vessel top head nozzles are provided with flanges. The drain nozzle is of the full-penetration weld design. The recirculation inlet nozzles (located as shown in Figure 5.3-1), feedwater inlet nozzles, core spray inlet nozzles, and the LPCI nozzles all have thermal sleeves.

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

The nozzle for the standby liquid control pipe is designed to minimize thermal shock effects on the reactor vessel, in the event that use of the standby liquid control system is required.

5.3.3.1.4.6 Materials and Inspections

The reactor vessels were designed and fabricated in accordance with the appropriate ASME Boiler and Pressure Vessel Code as defined in Subsection 5.2.1.

Table 5.2-7 defines the materials and specifications. Subsection 5.2.3.3.1.10 defines the compliance with reactor vessel material surveillance program requirements.

5.3.3.1.4.7 Reactor Vessel Schematic (BWR)

The reactor vessel schematic is contained in Figure 5.3-2. Trip system water levels are indicated as shown.

5.3.3.2 Materials of Construction

See Table 5.2-7 and descriptive material in Subsection 5.3.1.

5.3.3.3 Fabrication Methods

See Subsection 5.3.1 for this description.

5.3.3.4 Inspection Requirements

See Subsection 5.3.1 for this description.

5.3.3.5 Shipment and Installation

RPV shipment and installation are controlled through General Electric quality specifications under the cognizance of GE's Quality Assurance Program.

5.3.3.6 Operating Conditions

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

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

b. If the coolant temperature difference between the dome (inferred from P_{sat}) and the bottom head drain exceeds 145°F, neither reactor power level nor recirculation pump flow shall be increased.

c. The pump in an idle reactor recirculation loop shall not be started unless the coolant temperature in that loop is within 50° F of average reactor coolant temperature and the operating loop flow rate is less than or equal to 50% of rated loop flow.

The limit regarding the normal rate of heatup and cooldown (P-T Curves for Hydrostatic or Leak Testing) assures that the vessel closure, closure studs, vessel support skirt, and control rod drive housing and stub tube stresses and usage remain within acceptable limits. The limit regarding a vessel temperature limit on recirculating pump operation and power level increase restriction (P-T Curves for Heatup by Non-Nuclear Means, Cooldown Following a Nuclear Shutdown and Low Power Physics Testing) augments the hydrostatic limits in further detail by assuring that the vessel bottom head region will not be warmed at an excessive rate caused by rapid sweepout of cold coolant in the vessel lower head region by recirculating pump operation or natural circulation (cold coolant can accumulate as a result of control drive inleakage and/or low recirculation flow rate during startup or hot standby). The P-T Curves for Operation with a Core Critical further restrict operation of the recirculating pumps to avoid high thermal stress effects in the pumps and piping, while also minimizing thermal stresses on the vessel nozzles.

5.3.4 References

1. BWRVIP-86-A: “BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP),” Final Report, October 2002.

2. Safety Evaluation related to Amendment 160 to FOL No. NPF-11 and Amendment 146 to FOL No. NPF-18, dated 8/13/2003.

3. Letter RA06-058 from Daniel J. Enright, LaSalle County Station Plant Manager to the US Nuclear Regulatory Commission dated 8/31/06.

4. Deleted

5. Design Analysis L-003561, Rev. 0, "T300 Series – Reactor Internals," July 2010.

6. Design Analysis L-003510, Rev. 0, "Vessel Fluence for LaSalle MUR Power Uprate," July 2010.

7. "LaSalle 1 & 2 Nuetron Flux Evaluation", GE-NE-0000-0002-5244-02, Rev. 0, GE Nuclear Energy, June 2002.

8. BWRVIP-250NP, " Testing and Evaluation of the LaSalle Unit 1 120° Surveillance Capsule".

5.4 COMPONENT AND SUBSYSTEM DESIGN

5.4.1 Reactor Recirculation Pumps

See Subsection G.2.1 of Appendix G.

5.4.2 Steam Generators (PWR)

Subsection 5.4.2 is not applicable to this UFSAR.

5.4.3 Reactor Coolant Piping

The reactor coolant piping description and design characteristics are presented in Subsection G.2.1 of Appendix G. The recirculation loops are shown in Figures G.2.1-1 through G.2.1-5 and Drawing Nos. M-93 (sheets 1, 2) and M-139 (sheets 1, 2).

5.4.4 Main Steamline Flow Restrictors

5.4.4.1 Safety Design Bases

The main steamline flow restrictors were designed:

a. to limit the loss of coolant from the reactor vessel following a steamline rupture outside the containment to the extent that the reactor vessel water level remains high enough to provide cooling within the time required to close the main steamline isolation valves; and

b. to withstand the maximum pressure difference expected across the restrictor, following complete severance of a main steamline.

5.4.4.2 Description

A main steamline flow restrictor (Figure 5.4-1) is provided for each of the four main steamlines. The restrictor is a complete assembly welded into the main steamline. It is located within the primary containment upstream of the MSIV and is downstream of the main steamline safety/relief valves. In the event a main steamline break occurs outside the containment, the restrictor limits the coolant blowdown rate from the reactor vessel to the maximum (choke) flow of 7.12×10^6 lb/hr at 1015 psig upstream pressure. The restrictor assembly consists of a venturi-type nozzle insert welded, in accordance with applicable code requirements, into the main steamline. The flow restrictor is designed and fabricated in accordance with ANSI B31.7 Code and ASME "Fluid Meters," 6th edition, 1971.

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

The ratio of venturi throat diameter to steamline inside diameter of approximately 0.514 results in a maximum pressure differential (unrecovered pressure) of about 11 psi at rated flow. This design limits the steam flow in a severed line to approximately 200% rated flow, yet it results in negligible increase in steam moisture content during normal operation. The restrictor is also used to measure steam flow to initiate closure of the main steamline isolation valves when the steam flow exceeds preselected operational limits.

5.4.4.3 Safety Evaluation

In the event a main steamline should break outside the containment, the critical flow phenomenon would restrict the steam flow rate in the venturi throat to 200% of the rated value. Prior to isolation valve closure, the total coolant losses from the vessel are not sufficient to cause core uncovering, and the core is thus adequately cooled at all times.

Analysis of the steamline rupture accident (Chapter 15.0) shows that the core remains covered with water and that the amount of radioactive materials released to the environs through the main steamline break does not exceed guideline values.

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

If moisture forms in the nozzle throat due to a momentary large static pressure reduction, the droplets of wet steam would have to be at saturation temperature corresponding to throat static pressure. When proceeding to the downstream region where vapor temperatures are higher, the droplets of wet steam partially vaporize and reach equilibrium with vapor at a lower pressure. The moisture is then reduced and is actually negligible and has negligible corrosion effect on the highly corrosion-resistant material (A351) used for the inlet and throat sections. High velocity or impingement also has negligible erosion effect on this material.

The steam flow restrictor is exposed to steam of 1/10% to 2/10% moisture flowing at velocities of 150 ft/sec (steam piping inside diameter) to 600 ft/sec (steam restrictor throat). ASTM A351 (Type 304) cast stainless steel was selected for the steam flow restrictor material because it has excellent resistance to erosion-corrosion in a high-velocity steam atmosphere. The excellent performance of stainless steel in

high-velocity steam appears to be due to its resistance to corrosion. A protective surface film forms on the stainless steel which prevents any surface attack, and this film is not removed by the steam.

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

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

5.4.4.4 Inspection and Testing

Because the flow restrictor forms a permanent part of the main steamline piping and has no moving components, no testing program is planned. Only very slow erosion will occur with time, and such a slight enlargemement has no safety significance. Stainless steel resistance to corrosion has been substantiated by turbine inspections at the Dresden Unit 1 facility, which have shown no noticeable effects from erosion on the stainless steel nozzle partitions. The Dresden inlet velocities are about 300 ft/sec; the exit velocities are 600 to 900 ft/sec. However, calculations show that, even if the erosion rates are as high as 0.004-inch per year, after 40 years of operation the increase in restrictor choked flow rate would be no more than 5%. A 5% increase in the radiological dose calculated for the postulated main steamline break accident is not significant. See Appendix P, Section A.4.7.2 for additional information regarding evaluation of the main steam line flow restrictions for 20 years of additional operation through the period of extended operation.

5.4.5 Main Steamline Isolation System

5.4.5.1 Safety Design Bases

The main steamline isolation valves, individually or collectively:

a. close the main steamlines within the time established by design-basis accident analysis to limit the release of reactor coolant;

b. close the main steamlines slowly enough that simultaneous closure of all steamlines does not exceed the nuclear system design limits;

c. close the main steamline when required despite single failure in either valve or in the associated controls, to provide a high level of reliability for the safety function;

d. use separate energy sources as the motive force to close independently the redundant isolation valves in the individual steamlines;

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

f. are able to close the steamlines, either during or after seismic loadings, to assure isolation if the nuclear system is breached; and

g. have capability for testing, during normal operating conditions, to demonstrate that the valves function properly.

5.4.5.2 Description

Two isolation valves are welded in a horizontal run on each of the four main steam pipes; one valve is as close as possible to the inside of the drywell and the other is just outside the containment.

Figure 5.4-2 shows a main steamline isolation valve. Each is a 26-inch Y-pattern, globe valve. Rated steam flow rate through each valve is 3.786×10^6 lb/hr (Reference 3). The main disc or poppet is attached to the lower end of the stem. Normal steam flow tends to close the valve, and higher inlet pressure tends to hold the valve closed. The bottom end of the valve stem closes a small pressure-balancing hole in the poppet. When the hole is open, it acts as a pilot valve to relieve differential pressure forces on the poppet. Valve stem travel is sufficient to give flow areas past the wide open poppet approximately equal to the seat port area. The poppet travels approximately 90% of the valve stem travel; approximately the last 10% of travel closes the pilot hole. The air cylinder can open the poppet with a maximum differential pressure of 200 psi across the isolation valve in a direction that tends to hold the valve closed.

A 45° angle permits the inlet and outlet passages to be streamlined; this minimizes pressure drop during normal steam flow and helps prevent debris blockage. The pressure drop at 105% of rated flow is 7.8 psi maximum. The valve stem penetrates the valve bonnet through a stuffing box that has two sets of replaceable packing. A lantern ring and leakoff drain are located between the two sets of packing. To help prevent leakage through the stem packing, the poppet backseats when the valve is fully open.

Attached to the upper end of the stem is an air cylinder that opens and closes the valve and a hydraulic dashpot that controls its speed. The speed is adjusted by a

valve in the hydraulic return line bypassing the dashpot piston. Valve closing time is adjustable to between 3 and 10 seconds.

The air cylinder is supported on the valve bonnet by actuator support and spring guide shafts. Helical springs around the spring guide shafts close the valve if air pressure is not available. The motion of the spring seat member actuates switches in full open, 92% open, and full closed valve positions.

The valve is operated by pneumatic pressure and by the action of compressed springs. The control unit is attached to the air cylinder. This unit contains three types of control valves: pneumatic; a-c; and a-c from another source that open and close the main valve and exercise it at slow speed. Remote manual switches in the control room enable the operator to operate the valves.

Operating air is supplied to the valves from the plant air system through a check valve. An air tank accumulator provides backup operating air.

Each valve is designed to accommodate saturated steam at 1250 psig and 575° F, with a moisture content of approximately 0.23%, an oxygen content of 30 ppm, and a hydrogen content of 4 ppm.

In the worst case, if the main steamline should rupture downstream of the valve, steam flow would quickly increase to 200% of rated flow. Further increase is prevented by the venturi flow restrictor inside the containment.

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

The design objective for the valve is a minimum of 40 years service at the specified operating conditions. Operating cycles are estimated to be 100 cycles per year during the first year and 50 cycles per year thereafter.

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

Design specification ambient conditions for normal plant operation are 135° F normal temperature, 150° F maximum temperature, 100% humidity, in a radiation field of 15 rad/hr gamma and 25 rad/hr neutron plus gamma, continuous for design life. The inside valves are not continuously exposed to maximum conditions, particularly during reactor shutdown, and valves outside the primary containment and shielding are in ambient conditions that are considerably less severe.

The main steamline isolation valves are designed to close under accident environmental conditions of 340° F for 1 hour at drywell design pressure. In addition, they are designed to remain closed under the following postaccident environmental conditions:

a. 340° F for 3 hours at drywell design pressure of 45 psig maximum,

b. 320° F for an additional 3 hours at 45 psig maximum,

c. 250° F for an additional 18 hours at 25 psig maximum, and

d. 200° F during the next 99 days at 20 psig maximum.

To resist sufficiently the response motion from the safe shutdown earthquake, the main steamline valve installations are designed as Seismic Category I equipment. The valve assembly is manufactured to withstand the safe shutdown earthquake forces applied at the mass center of the extended mass of the valve operator. The stresses caused by horizontal and vertical seismic forces are assumed to act simultaneously and are added directly. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads, including the operating loads. The allowable stress for this combination of loads is based on the ordinary allowable stress set forth in applicable codes. The parts of the main steam isolation valves that constitute a process fluid pressure boundary are designed, fabricated, inspected, and tested as required by the ASME Section III, Class I Code, 1971 Edition with Winter 1971 Addendum.

5.4.5.3 Safety Evaluation

In a direct cycle nuclear power plant the reactor steam goes to the turbine and to other equipment outside the containment. Radioactive materials in the steam are released to the environs through process openings in the steam system or escape from accidental openings. A large break in the steam system can drain the water from the reactor core faster than it is replaced by feedwater.

The analysis of a complete, sudden steamline break outside the containment is described in Chapter 15.0. The analysis shows that the fuel barrier is protected against loss of cooling if main steam isolation valve closure takes 10.5 seconds or less (including as much as 0.5 second for the instrumentation to initiate valve closure after the break). The calculated radiological effects of the radioactive material assumed to be released with the steam are shown to be well within the guideline values for such an accident.

The shortest closing time (approximately 3 seconds) of the main steam isolation valves is also shown in Chapter 15.0 to be satisfactory. The switches on the valves

initiate reactor scram when specific conditions (extent of valve closure, number of pipelines involved, and reactor power level) are exceeded (Subsection 7.2.1). The pressure rise in the system from stored and decay heat may cause the nuclear system relief valves to open briefly, but the rise in fuel cladding temperature will be insignificant. No fuel damage results.

The ability of this 45°, Y-design globe valve to close in a few seconds after a steamline break, under conditions of high-pressure differentials and fluid flows with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of tests in dynamic test facilities. A full-size 20-inch valve was tested in a range of steam-water blowdown conditions simulating postulated accident conditions (Reference 1).

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

a. To verify its capability to close between 3 and 10 seconds, each valve is tested at rated pressure (1000 psig) and no flow. The valve is stroked several times, and the closing time is recorded. The valve is closed by spring only and by the combination of air cylinder and springs. Usually the closing time is slightly greater when closure is by springs only.

b. Leakage is measured with the valve seated and backseated. The specified maximum seat leakage, using cold water at design pressure, is 2 cm /hr/in of nominal valve size. In addition, an air seat leakage test is conducted using 50 psi pressure upstream. Maximum permissible leakage is 0.1 scfh/in of nominal valve size. There must be no visible leakage from either set of stem packing at hydrostatic test pressure. The valve stem is operated a minimum of three times from the closed position to the open position, and the packing leakage still must be zero by visual examination.

c. Each valve is hydrostatically tested in accordance with the requirements of the 1971 Edition of the ASME Code. During valve fabrication, extensive nondestructive tests and examinations are conducted. Tests include radiographic, liquid penetrant, or magnetic particle examinations of casting, forgings, welds, hardfacings, and bolts.

d. The spring guides, the guiding of the spring seat member on the support shafts, and rigid attachment of the seat member assure correct alignment of the actuating components. Binding of the valve poppet in the internal guides is prevented by making the

poppet in the form of a cylinder longer than its diameter and by applying stem force near the bottom of the poppet.

After the valves are installed in the nuclear system, each valve is tested several times in accordance with the preoperational and startup test procedures.

Two isolation valves provide redundancy in each steamline so that either can perform the isolation function, and either can be tested for leakage after the other is closed. The inside valve, the outside valve, and their respective control systems are separated physically.

The isolation valves and their installation are designed as Seismic Category I equipment.

Electrical equipment that is associated with the isolation valves and operates in an accident environment is limited to the wiring, solenoid valves, and position switches on the isolation valves. The expected pressure and temperature transients following an accident are discussed in Chapter 15.0.

5.4.5.4 Inspection and Testing

The main steam isolation valves can be functionally tested for operability during plant operation and refueling outages. The test operations are listed below. During refueling outage the main steam isolation valves can be functionally tested, leak tested, and visually inspected.

The main steam isolation valves can be tested and exercised individually to the 85% open position, because the valves still pass rated steam flow when 85% open.

The main steamline isolation valves can be tested and exercised individually to the fully closed position if reactor power is reduced sufficiently to avoid scram from reactor overpressure or high flow through the steamline flow restrictors.

Leakage from the valve stem packing will become suspect during reactor operation from measurements of leakage into the drywell, or from observations or similar measurements in the steam tunnel. During shutdown while the nuclear system is pressurized, the leak rate through the inner packing can be measured by collecting

and timing the leakage. Leakage through the inner packing would be collected from the packing drain line.

The leak rate through the pipeline valve seats (pilot and poppet seats) is accurately measured during shutdown.

During prestartup tests following an extensive shutdown, the valves undergo the same hydro tests (approximately 1000 psi) that are imposed on the primary system.

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

5.4.6 Reactor Core Isolation Cooling (RCIC) System

5.4.6.1 Design Bases

5.4.6.1.1 Safety Design Bases

The RCIC system is not a safety system, hence it has no safety design bases. The RCIC system meets the following functional design bases:

a. The system operates automatically in time to maintain sufficient coolant in the reactor vessel so that the integrity of the radioactive material barrier is not compromised during conditions noted in Subsection 5.4.6.1.1 (c), (d), and (e).

b. Piping and equipment, including support structures, are designed to withstand the effects of the SSE without a failure that could lead to a significant radioactive release.

c. The system assures that adequate core cooling takes place to prevent the reactor fuel from overheating in the event the reactor isolation is accompanied by loss of flow from the reactor feedwater system.

d. The system allows complete plant shutdown under conditions of loss of normal feedwater by maintaining sufficient water inventory until the reactor is depressurized to a level where the shutdown cooling system is placed in operation.

e. The system assures that adequate core cooling takes place to prevent the reactor fuel from overheating in the event the reactor is isolated and maintained in the hot standby condition.

5.4.6.1.2 Power Generation Design Bases

The RCIC system meets the following power generation design bases:

a. The system operates automatically in time to maintain sufficient coolant in the reactor vessel as noted in Subsection 5.4.6.1.1 (a).

b. Design is provided for remote-manual operation of the system by an operator.

c. To provide a high degree of assurance that the system operates when necessary:

    1. The power supply for the system is from immediately available energy sources (d-c batteries) of high reliability.

    2. Design is provided for periodic testing during plant operation.

5.4.6.2 System Design

5.4.6.2.1 Schematic Piping and Instrumentation Diagrams

The RCIC system consists of a steam-driven turbine-pump unit and associated valves and piping capable of delivering makeup water to the reactor vessel. The RCIC P&ID is shown in Drawing Nos. M-101 and M-147.

Quantitative information on steam and delivery water conditions is given in the system process diagram for all operating modes of the RCIC system (Figure 5.4-3).

5.4.6.2.2 Applicable Codes and Classifications

The RCIC system components within the drywell up to and including the outer isolation valve are designed in accordance with ASME Code, Section III, Class 1, Nuclear Power Plant Components. The RCIC system is also designed as Seismic Category I equipment.

The reactor core isolation cooling system component classifications are given in Table 3.2-1.

5.4.6.2.3 System Reliability Considerations

To assure that the RCIC will operate when necessary and in time to prevent inadequate core cooling, the power supply for the system is taken from immediately available energy sources of high reliability. Added assurance is given in the capability for periodic testing during station operation. Evaluation of reliability of the instrumentation for the RCIC shows that no failure of a single initiating sensor either prevents or falsely starts the system. Operation of the RCIC system in the event of loss of offsite power is discussed in Section 15.9.

Reactor core isolation cooling system steam leaks outside the containment are detected by low steamline pressure, high flow rate in the flow element, and high reactor core isolation system turbine exhaust pressure. High differential temperature in the equipment area ventilation inlet and exhaust, high differential temperature in pipe routing area, high ambient temperature in the equipment and pipe areas, and high flow rate in the containment building sump indicate leakage. Low steamline pressure, high flow rate in the flow element, high turbine exhaust pressure, and high ambient temperature or high differential temperature initiate an alarm in the main control room and automatic isolation of the system. In response to NUREG 0737, Section II.K.3.15, a time delay of 4 seconds was added to the RCIC Steamline Isolation Systems to avoid spurious isolations that may occur as a result of flow peaks occurring during a normal system start transient. Sections 6.2 and 7.4 discuss isolation of the containment.

The RCIC system may provide the ability to mitigate the consequences of small pipe breaks, but it is not provided primarily for such purpose. The emergency core cooling systems provide redundant protection for the entire spectrum of pipe breaks. For small breaks this protection would be provided by HPCS plus ADS.

Both the RCIC and the HPCS provide decay heat removal capability when the main condenser is unavailable (isolated from the nuclear system) for heat sink purposes. The RCIC is not a portion of the emergency core cooling system; the HPCS is a part of this system.

Long-term heat-removal capability may be provided by the RCIC or HPCS during the following operational events: scram, pressure relief, core cooling, reactor vessel isolation, and to restore a-c power. The RHR system may be used for long-term heat removal during any long-term isolation. These events are all situations in which the reactor vessel is isolated from the main condenser. None of these events are pipe break (loss-of-coolant) situations requiring immediate reactor water level restoration.

In order to assure HPCS or RCICS availability for the operational events noted previously, certain design considerations are utilized in design of both systems.

a. Physical Independence - The two systems are located in separate areas in different corners of the reactor building. Piping runs are separated, and the water delivered from each system enters the reactor vessel via different nozzles.

b. Prime Mover Diversity and Independence - Prime mover independence is achieved by using a steam turbine to drive the RCIC system and an a-c motor to drive the HPCS system. The HPCS motor is supplied from either normal a-c power or a separate diesel generator.

c. Control Independence - Control independence is secured by using a different battery system to provide control power to each unit. Separate detection initiation logics are also used for each system.

d. Environmental Independence - Both systems are designed to meet ASME Section III Class 2 requirements. Environment in the equipment rooms is maintained by separate auxiliary systems.

A design flow functional test of the RCIC is performed during plant operation by taking suction from the condensate storage tank and discharging through the full flow test return line back to the condensate storage tank. A design flow functional test of the RCIC System can also be performed during plant operation by taking suction from the suppression pool and discharging through the full flow test return line back to the suppression pool. The discharge valve to the headspray line remains closed during the test, and reactor operation is undisturbed. Control system design provides automatic return from test to operating mode if system initiation is required during testing of individual components. Periodic inspections and maintenance of the turbine pump unit are conducted in accordance with manufacturers' recommendations. Valve position indication and instrumentation alarms are displayed in the control room.

5.4.6.2.4 Manual Actions

Manual actions required to be taken by an operator in order for the RCIC system to operate properly are discussed in Subsection 5.4.6.3.

In addition to the automatic operational features, provisions are included for remote-manual startup, operation, and shutdown of the RCIC system provided initiation or shutdown signals do not exist.

5.4.6.3 Performance Evaluation

The pump discharges either to the headspray nozzle, the full flow test return line to the condensate storage tank or to the suppression pool. A minimum flow bypass line to the suppression pool is provided to protect the pump during startup and shutdown. The makeup water is delivered into the reactor vessel through the headspray nozzle. Cooling water for the RCIC turbine lube oil cooler and gland seal condenser is supplied from the discharge of the pump (Drawing Nos. M-101 and M-147).

Following any reactor shutdown, steam generation continues from the heat produced by the radioactive decay of fission products. Initially the rate of steam generation is augmented during the first few seconds by delayed neutrons and some of the residual energy stored in the fuel. Steam normally flows to the main condenser through the turbine bypass or, if the condenser is isolated, to the suppression pool. The fluid removed from the reactor vessel is normally made up by the feedwater pumps supplemented by leakage from the control rod drive system. If makeup water is required to supplement these primary sources of water, the RCIC turbine-pump unit starts automatically on receipt of a reactor vessel low-water level signal (Figure 5.4-11) or is started by the operator from the control room. The RCIC delivers its design flow within 30 seconds after actuation at rated reactor pressure. To limit the amount of fluid leaving the reactor vessel, the reactor vessel low-water level signal also actuates the closure of the main steam isolation valves.

Pump suction normally is taken from the condensate storage tank. The volume of water stored for the RCIC is sufficient to allow operation for 8 hours after shutdown, assuming that none of the steam generated in the reactor vessel can be returned to the reactor vessel as condensate. Other systems that use the same reservoir and could jeopardize the availability of this quantity of water can be isolated. A low-level alarm is energized when the level in the storage volume falls to the minimum required to meet the design requirements of the RCIC.

The RCIC system is sized to provide adequate makeup for breaks outside the containment, thus precluding actuation of the automatic depressurization system thereby reducing total mass lost from the RPV for this situation.

The backup supply of cooling water for the RCIC is the suppression pool. When the condensate storage tank level is low, pump suction is automatically switched over to the suppression pool in accordance with NUREG 0737, Item II.K.3.22. The turbine-pump assembly is located below the level of the condensate storage tank and below the minimum water level in the suppression pool to assure adequate net positive suction head to the pump.

All components required for initiating the RCIC are completely independent of auxiliary a-c power, plant service air, and external cooling water systems; they

require only power derived from the station battery to operate the valves and motors. The power source for the turbine-pump unit is the steam generated in the reactor vessel by the decay heat in the core. The steam is piped directly to the turbine, and the turbine exhaust is piped to the suppression pool.

Throughout the period of RCIC operation, the exhaust from the RCIC turbine is condensed in the suppression pool, which results in a slow temperature rise (approximately 3° F/hr) in the pool. One RHR heat exchanger can be used to cool the suppression pool after approximately 1-1/2 hours, if necessary.

If for any reason the RCIC is unable to supply sufficient flow for core cooling, the emergency core cooling systems provide the required barrier boundary protection (Chapter 6.0).

The RCIC turbine-pump unit is located in a shielded area to assure that personnel access areas are not restricted during RCIC operation. The turbine controls provide for automatic shutdown on the RCIC turbine on receipt of the following signals:

a. turbine overspeed - prevents damage to the turbine and turbine casing,

b. pump low suction pressure - prevents damage to the turbine pump unit that results from loss of cooling water,

c. turbine high exhaust pressure - indicates turbine or turbine control malfunction, and

d. system isolation signal - indicates need to shut down equipment.

Because the steam supply line to the RCIC turbine is a pressure barrier boundary, certain signals automatically isolate this line and cause shutdown of the RCIC turbine.

The RCIC turbine has a speed governor that is positioned by the demand signal from the flow controller. Maximum output from the controller corresponds to maximum turbine speed.

The analytical methods and assumptions used in evaluating the RCIC system are presented in Chapter 15.0 and Appendix D.

5.4.6.4 Preoperational Testing

The preoperational and initial startup test program for the RCIC system is presented in Chapter 14.0.

5.4.6.5 Safety Interfaces

The balance of plant-GE steam supply system safety interfaces for the reactor core isolation cooling system are: (1) preferred water supply from the condensate storage tank; and (2) all associated wire, cable, piping, sensors, and valves which lie outside the nuclear steam supply system scope of supply.

5.4.7 Residual Heat Removal System

5.4.7.1 Design Bases

The RHR operates in three modes. For clarity, each mode is discussed separately. It is shown how each mode contributes toward satisfying all the design bases of the RHR system.

The major equipment of the RHR system consists of three independent closed loops, two heat exchangers, three main system pumps, and a service water supply. The equipment is connected by associated valves and piping. Controls and instrumentation are provided for correct system operation.

Safety Design Bases

The engineered safety function of the RHR system is the low pressure coolant injection (LPCI) mode, which is one of the LaSalle ECCSs to mitigate LOCA as discussed in Section 6.2. The safety design bases for the RHR containment cooling mode are discussed there also, where it is concluded that the design objective is to safely terminate the post-DBA containment temperature transient. Note that other design features of the RHR system are essentially backup capabilities to the primary ESF design feature of LPCI. These features are manually initiated post-DBA to employ RHR equipment should the primary ESF capabilities not be present. For example, with the successful operation of the LaSalle ECCSs (HPCS, ADS, LPCS, and LPCI), no need exists, and no safety credit is claimed for the long-term cooling mode, nor the reactor vessel head spray, nor the fuel pool auxiliary cooling capability of RHR equipment in an accident mode. These features are included with power generation bases as discussed below.

Power Generation Design Bases

The RHR system has been designed to meet the following power generation design bases:

a. The system was evaluated for power uprate to 3489 MWt in Reference 4, and has enough heat removal capacity to cool the reactor to 125°F in less than 32 hours after shutdown.

Since the normal heat removal function is not safety related, the increase in the shutdown time from the original design basis of 20 hours, to approximately 32 hours, will be limited to an impact on plant availability, which is not a safety concern. (See Subsection 7.4.3.2 for shutdown cooling mode.)

b. Fuel pool connections are provided so that the “B” RHR pump and heat exchanger can be used in a fuel pool cooling capacity. (See also Chapter 9.0 on auxiliary plant systems.)

5.4.7.2 System Design

5.4.7.2.1 Schematic Piping and Instrumentation Diagrams

A process diagram of the RHR system is shown in Figure 5.4-5. A description of the controls and instrumentation is presented in Subsection 7.3.1. Figure 5.4-5 indicates the RHR heat exchanger duties/capabilities for the principal modes of operation. The operation of the RHR equipment with other emergency core cooling systems to protect the core in case of a loss-of-coolant accident is described in Chapter 6.0. A description of the controls and instrumentation is presented in Chapter 7.0.

5.4.7.2.2 Equipment and Component Description

5.4.7.2.2.1 General

The components of the RHR system located inside the drywell required for LPCI operation are designed to operate in the following environmental conditions:

a. 340° F for 3 hours at 45 psig,

b. 320° F for an additional 3 hours at 45 psig,

c. 250° F for an additional 18 hours at 25 psig, and

d. 200° F during the next 99 days at 20 psig.

The main system pumps are sized for the flow required during low-pressure coolant injection (LPCI) operation. (See Chapter 6.0 for discussion of the LPCI.) The pumps are arranged and located so that adequate suction head is assured for all operating conditions. The pump motor is air cooled by the ventilation and heating system.

The heat exchangers are sized on the basis of required duty for the shutdown mode. The heat exchanger shell and tube sides are provided with drain connections. The shell side is provided with a vent to remove noncondensable gases. Relief valves on the heat exchanger shell side, on the RHR pump discharge, and on the RCIC supply line protect the heat exchanger from overpressure.

The most limiting duty is that associated with the shutdown mode. The performance of this type of heat exchanger operating in this mode (water to water) is well established by currently operating BWR facilities.

Heat exchanger shell side and tube side codes and standards are provided in Section 3.2. Classification information for the RHR heat exchanger is presented in Table 3.2-1.

The shutdown cooling piping may be connected to the fuel pool system (Drawing Nos. M-96 and M-142 (sheet 2)) so that the "B" RHR pump and heat exchanger can provide fuel pool cooling if necessary. (See Section 9.1.3 concerning fuel pool cooling and cleanup system.)

An alternate method of removing decay heat during cold shutdown and refueling modes of operation can be established by gravity draining through a RHR heat exchanger to the suppression pool and returning water to the reactor using a low pressure ECCS pump.

5.4.7.2.2.2 Shutdown Cooling and Reactor Vessel Head Spray Mode

The shutdown cooling and reactor vessel head spray mode is an integral part of the RHR system. It is operated during a normal shutdown and cooldown. The initial phase of nuclear system cooldown is accomplished by dumping steam from the reactor vessel to the main condenser. When nuclear system temperature has decreased to where the steam supply pressure is not sufficient to maintain the turbine shaft gland seals, vacuum in the main condenser cannot be maintained and the RHR system is placed in the shutdown cooling mode of operation. The shutdown cooling subsystem is able to complete cooldown to 125° F in less than 32 hours after the control rods have been inserted and can maintain the nuclear system at or below 125° F for reactor refueling and servicing.

Reactor coolant is pumped from recirculation loop A by the RHR main system pump and discharged through the RHR heat exchanger, where cooling occurs by heat being transferred to the service water. Part of the flow can be diverted to a spray nozzle in the reactor head (from loop A only) (Figure 5.4-5). This spray maintains saturated conditions in the reactor vessel head volume by condensing steam being generated by the hot reactor vessel walls and internals. The spray also decreases thermal stratification in the reactor vessel coolant. This ensures that the water level in the reactor vessel can rise. The higher water level provides conduction cooling to more of the mass of metal of the reactor vessel.

The RHR system is warmed up prior to placing it in the shutdown cooling mode of operation. Water used for warm up is taken from the Reactor Recirculation system and is discharged to the radioactive waste disposal system or main condenser. The warm-up procedure may be conducted during the steam dumping portion of nuclear

system cooldown, so as not to deter or delay the system from accomplishing cooldown within 32 hours.

The RHR System warmup may be waived during emergency or transient conditions when action to bring the unit to cold shutdown quickly is deemed appropriate. RHR SDC may then be placed on line with no warming if the temperature differential between the RHR SDC piping and the Reactor Moderator does not exceed 250 deg F. This condition has been analyzed for a total 120 thermal cycles with no adverse effect on the suction and discharge tees to the recirculation loops.

The heat exchanger design provides for rated performance of the heat exchanger under fouled conditions. Fouling beyond the extent specified in the heat exchanger design results in a decrease in the heat transfer rate.

These fouling factors are a function of the nature of the fluids, the temperatures involved, and the fluid velocities. The heat exchanger design includes the fouling factors in calculating this overall thermal resistance and provides sufficient surface area to allow the required heat transfer rate at fouled conditions.

5.4.7.2.2.3 Steam Condensing Mode

On-Site Review 92-37 was performed by LaSalle Station to delete the Steam Condensing Mode of Residual Heat Removal System Operation from use at LaSalle (AIR 373-160-92-00108). The procedures governing Steam Condensing Mode Operation have been deleted and a review of other procedures that operate the below listed valves, concluded that these valves are not required to operate in plant emergency procedures. The active safety related function of the actuators has been deleted and the valves will only be opened in Operating Conditions 4, 5, and Defueled to support infrequent non-safety related functions. To ensure that the position of these valves will not impact a design basis event and to prevent inadvertent operation from the control room, actions have been taken to administratively control them in the closed position with power removed during Operating Conditions 1, 2, and 3. Otherwise, the valve(s) must be declared inoperable for all associated safety related functions.

These controls permit the Steam Condensing valves to be deleted from the Generic Letter (GL) 89-10 Testing and Environmental Qualification Programs (Engineering Letter Chron # 122980 dated November 15, 1993).

Steam Condensing Valves

1(2)E12-F011A/B A(B) RHR Hx Drain to Sup Chamber Stop Valve

1(2)E12-F026A/B A(B) RHR Hx Drain Outlet to RCIC Stop Valve

1(2)E12-F051A/B	A(B) RHR Hx Steam Inlet Pressure Control Valve
1(2)E12-F052A/B	A(B) RHR Hx Steam Inlet Stop Valve
1(2)E12-F065A/B	A(B) RHR Hx Drain Outlet Valve
1(2)E12-F073A/B	A(B) RHR Hx Shell Side Vent Downstream Stop Valve
1(2)E12-F074A/B	A(B) RHR Hx Shell Side Vent Upstream Stop Valve
1(2)E12-F087A/B	A(B) RHR Hx Steam Inlet PCV Bypass Stop Valve
1(2)E51-F064	RCIC Steam Inlet to RHR Heat Exchanger Valve, have been replaced by spectacle flange 1(2)E51-D324. The blind flange side of the spectacle will be in place during operating conditions 1, 2, and 3.
1(2)E12-F055A/B	RHR Heat Exchanger RCIC Steam Inlet Header Relief Valves. These valves are permanently gagged in place and are not performing relief function.

5.4.7.2.2.4 Low-Pressure Coolant Injection Mode

The low-pressure coolant injection (LPCI) mode is an integral part of the RHR system. It operates to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a loss-of-coolant accident. A detailed discussion of the requirements and response of the LPCI for a loss-of-coolant accident is included in Section 6.3. A detailed discussion of the requirements and response of LPCI controls and instrumentation during a loss-of-coolant accident is found in Subsection 7.3.1.

LPCI is a low-head, high-flow function that delivers flow to the reactor vessel when the differential pressure between the vessel and drywell is less than 225 psid (rated flow is injected at 20 psid). LPCI is designed to reflood the reactor vessel to at least two-thirds core height and to maintain this level. After the core has been flooded to this height, the capacity of one RHR main system pump is sufficient to make up for shroud leakage and boil-off.

During LPCI operation, the main system pumps take suction from the suppression pool and discharge to the core region of the reactor vessel through separate vessel piping penetrations. Any spillage through a break in the lines within the primary containment returns to the suppression pool. A minimum flow bypass line to the suppression pool is provided so the pumps are not damaged by overheating if operated with the discharge valves closed.

Service water flow to the RHR heat exchangers is not required immediately after a loss-of-coolant accident, because heat rejection from the containment is not needed during reactor flooding. Power for the main system pumps comes from normal a-c power. If this source is not available, power is available from standby a-c power.

The acceptability of utilizing the LPCI path as a return path to the reactor pressure vessel during operation of the RHR System in the shutdown cooling mode has been

determined to be adequate (Reference 2) as a backup loop to satisfy the requirements of the Technical Specifications. A normally aligned loop would be utilized to perform the active cooling function, with the backup loop to be used only in case of failure of the primary loop.

The LSCS equipment cooling water piping is crosstied to the discharge piping through the emergency fuel pool makeup pumps to provide a source of water in case any postaccident flooding of the primary containment occurs. This connection is provided with a spool piece connection to prevent inadvertent injection of cooling lake water into the RHR system.

5.4.7.2.2.5 Containment Cooling Mode

The containment cooling mode is an integral part of the RHR system. It consists of two subparts, the suppression pool cooling part and the containment spray part. Suppression pool cooling is discussed in detail in Subsection 6.2.2.

During reactor operation, the containment cooling mode limits the temperature of the water in the suppression pool so that after the design-basis LOCA, pool temperature does not exceed 200 F. Test data shows that at 210°F - 220°F, complete condensation of blowdown steam from the design-basis LOCA can be expected. (Reference 10 in section 6.2.7, also refer to section 6.2.1.8) For the containment spray (cooling) mode of operation, the shell side inlet temperature to the RHR heat exchanger is the maximum suppression pool temperature expected at postaccident conditions.

The containment spray cooling subsystem provides an alternate method of containment cooling for postaccident conditions. Water pumped through the RHR heat exchangers can be diverted to spray headers in the drywell and above the suppression pool. The spray removes energy from drywell atmosphere by condensing the water vapor. The spray collects in the bottom of the drywell until the water level rises to the level of the pressure suppression vent lines. The water then overflows to the suppression pool. Approximately 5% of the total pump flow can be directed to the suppression chamber spray ring to cool any noncondensable gases collected in the free volume above the suppression pool.

The containment spray cooling subsystem of the RHR system normally would not be operated unless the core flooding requirements of the LPCI subsystem have been satisfied.

5.4.7.2.3 Applicable Codes and Classification

a. American National Standards Institute (ANSI)

   1. B31.10 Code for Pressure Piping, Power Piping

2. B31.7 Code for Pressure Piping, Nuclear Power Piping

b. American Society of Mechanical Engineers (ASME)

1. Standard Code for Pumps and Valves for Nuclear Power, Class 2

2. Boiler and Pressure Vessel Code, Sections III and VIII, Class A, C

c. Standard of Tubular Exchanger Manufacturers Association (TEMA) Class C.

5.4.7.2.4 System Reliability Considerations

Two loops, each consisting of a heat exchanger, main system pump, and associated piping, are located in separate protected areas.

The third loop, made up of a pump and associated piping, is located in an area associated with the other Division II RHR pump, to minimize the possibility of a single physical event causing the loss of the entire system. The loops of the RHR are not connected so any failure of one loop cannot cause failure of another.

Impaired post-LOCA RHR system performance due to broken or loose parts in the suppression pool is avoided by providing suction strainers above the suppression pool bottom. The mesh is sized to pass no particles greater than 3/32 inch. Particles passing through the strainers will not cause pump damage or blockage of system flow openings.

In order to avoid water hammer damage, water is supplied by a fill pump to ensure that the RHR discharge piping is continuously filled. The design of the onsite and offsite electrical power systems provides compatible independence and redundancy to ensure an available source of power to the RHR system (Section 8.3).

A potential for water hammer exists due to drain down of the RHR System if a LOOP/LOCA occurs during suppression pool cooling (SPC) operation. The A/B RHR System is anticipated to be in the SPC mode for only a small fraction of time during normal plant operation. The total SPC operating time is anticipated to be less than 2% of the total plant operating time in a fuel reload cycle.

Consistent with the philosophy in Reference 5, an operational period is considered “short” if the fraction of time that the system operates within the pressure-temperature conditions specified for high-energy fluid systems is about 2% of the

time, then the system operates as a moderate-energy fluid system. The "short operational period" defined in Reference 5 is not directly applicable to SPC mode since the RHR system will not be operating at conditions which would qualify as a high-energy fluid system subject to the 2% criteria. However, the 2% criteria of the "short operational period" philosophy is an acceptable definition for an intermittent mode of operation assumed to be only a low fraction of operating time. Since RHR is only operated in SPC mode for "short operational periods", a LOOP/LOCA water hammer is not postulated to occur as an initial condition of the accident analysis and a specific water hammer analysis to address the drain down concern is not required per 10 CFR 50, Appendix A, General Design Criterion 4.

5.4.7.3 Performance Evaluation

Because the LPCI mode acts with other emergency core cooling systems to satisfy the safety objective, it is evaluated in conjunction with the other emergency core cooling systems in Chapter 6.0. The safety evaluation of the controls and instrumentation of the LPCI subsystem is in Subsection 7.3.1.

5.4.7.3.1 Reactor Shutdown with Crack in RHR Cooling Loop

The RHR system is a low pressure system; it is interlocked so that an RHR cooling loop can be connected to the reactor vessel only when the reactor pressure is 135 psig or less. All of the piping outside of the primary coolant pressure boundary is classified as "moderate energy" piping, therefore, only cracks rather than pipe breaks need to be considered. If a crack is postulated in one of the two loops in the RHR shutdown cooling system, the pipe which would cause the greatest leak rate is a 24-inch Schedule 40 suction pipe. A crack in this pipe, corresponding to the maximum postulated size, would produce a leakage flow rate of 1443 gallons per minute with no allowance for flow reduction due to two-phase flow. This large leakage rate is possible only at the beginning of reactor shutdown when the internal pressure is the highest. A crack of this magnitude would be detected by the area radiation monitors and sump alarms. Isolation of the reactor from the leaking RHR loop would occur by operator action or automatically from the NSSS system on level 3 reactor low level.

The main steam isolation valves are not slammed shut at the start of a normal reactor shutdown sequence, therefore, vessel pressure does not increase; establishment of shutdown cooling is possible by activation of an RHR cooling loop. If that loop subsequently cracked, recovery of shutdown cooling is possible via activation of a redundant RHR loop. RHR cooling establishment in the normal situation requires less than 10 minutes after warming up the discharge line, recovery time for an alternate RHR loop is less than 30 minutes. If the postulated crack should occur in the common line supplying suction to RHR loops A and B, its leak rate would be lower because it is a 20-inch Schedule 40 line. An alternate cooling configuration would be established using ADS discharge lines to circulate vessel water to the suppression pool from which individual separate suctions, are available for RHR loops A, B, and C (or the ECCS pumps) to circulate coolant back to the vessel. These individual suctions would be isolated from the RHR shutdown cooling suctions, assumed to be cracked, by remotely operated MO valves. Recovery time to use RHR loop C is less than 30 minutes; recovery time to configure the alternate RHR cooling system is less than 1 hour. The time in which operator action is required is discussed in Subsection 5.4.7.3.2.

If condenser vacuum has been lost and the MSIV's have already closed prior to the postulated crack occurrence the recovery routine would require more time. Up to 2 hours is needed to reestablish condenser vacuum, reopen the MSIV's, control the

vessel inventory, and reestablish the steam dump to the main condenser via the bypass valves. Vessel inventory can be controlled by blowdown through the reactor water cleanup system assuming feedwater is functional if the level is too high. If too low, the feedwater/condensate pumps or HPCS/LPCS/LPCI can provide needed water. Vessel pressure is controlled as required by manual initiation of relief valves following MSIV closure.

The time in which reactor operator action is required is discussed in the following.

5.4.7.3.2 Required Operator Response Time

The RHR moderate energy pipe crack during operation in the shutdown cooling mode is not a limiting event with respect to Suppression Pool temperature limits or required operator response time. This event was not re-analyzed for Power Uprate conditions; i.e., a starting Suppression Pool temperature of 105°F or an initial reactor power level of 3489 MWt. The original analysis, using a Suppression Pool starting temperature of 100°F and an initial reactor power level of 3323 MWt, is presented in this subsection as historical information.

As shown in Figure 5.4-4, the minimum time to begin normal shutdown cooling is four hours after scram. If the water level in the vessel is normal and the main steam isolation valves are closed when shutdown is started, the RHR shutdown suction valves will isolate the reactor 3.1 minutes after the crack flow begins. Assuming instantaneous repressurization of the reactor vessel provides a very conservative basis, in that case, level 2 water-level will be reached in 2.4 minutes and HPCS will reach a minimum of 550 gpm in 13.1 minutes. The vessel water level will reach level 8 and shut off HPCS in 35 minutes. HPCS will cycle between level 2 and 8 until operator action is taken to reestablish other means of core cooling. Under the same set of conservative assumptions, it would take 6 hours of blowdown from the vessel to the pool to raise the pool temperature from 100° F to 180° F. During this time, no pool cooling is assumed. Therefore, there is ample time for an operator to take appropriate action in response to a crack in RHR cooling loop piping. For long-term cooling cases with lesser energy removal requirements, even greater periods of time are available for operator response in reestablishing an RHR cooling loop for shutdown cooling.

5.4.7.4 Preoperational Testing, Inservice Inspection and Testing

Preoperational tests were conducted during the final stages of plant construction prior to initial startup. These tests assured correct functioning of all controls, instrumentation, pumps, piping, and valves. System reference characteristics such as pressure differentials and flow rates were documented during the preoperational testing and were used as base points for measurements obtained in subsequent operational tests.

For the suppression pool cooling mode, the preoperational tests verified that the RHR heat exchanger shell side design flow rate can be obtained while circulating water from the suppression pool, through the RHR pump and the RHR heat exchanger, and back to the suppression pool. During the test, head versus flow curves were developed for reference in evaluating the future performance of the suppression pool cooling mode and the RHR pumps.

The preoperational and initial startup test program for the RHR system is discussed in Chapter 14.0 of the FSAR.

A design flow functional test of the RHR main system pumps is performed separately for each pump during normal plant operation by taking suction from the suppression pool and discharging through a full flow test line back to the suppression pool. All other discharge valves remain closed during this test; reactor operation is undisturbed.

All motor-operated valves required to operate for safety reasons are capable of being exercised periodically during normal power operation. The layout and arrangement of critical equipment, such as drywell wall penetrations, piping, and valves, are designed to permit access for appropriate equipment used in testing and inspection system integrity.

Sequencing of the LPCI mode is tested after the reactor is shut down. Valves required for the remaining subsystems may be tested at this time.

Drains are provided outside the drywell wall in the piping between the isolation valves for reactor process system leakage testing. Relief valves on the low-pressure lines are removable for testing. A line is provided on the pump discharge line to take water samples.

Periodic inspection and maintenance of the main system pumps, pump motors, and heat exchangers are conducted in accordance with the manufacturer's guidelines and ASME Section XI requirements.

5.4.8 Reactor Water Cleanup System

The reactor water cleanup system is an auxiliary system, a small part of which is part of the reactor coolant pressure boundary up to and including the outermost containment isolation valve. The other portions of the system are not part of the reactor coolant pressure boundary and are isolatable from the reactor.

5.4.8.1 Design Bases

5.4.8.1.1 Safety Design Bases

The RCPB portion of the RWCU system:

a. prevents excessive loss of reactor coolant, and

b. prevents the release of radioactive material from the reactor.

5.4.8.1.2 <u>Power Generation Design Bases</u>

The reactor water cleanup system:

a. removes solid and dissolved impurities from recirculated reactor coolant;

b. discharges excess reactor water during startup, shutdown, and hot standby conditions;

c. minimizes temperature gradients in the recirculation piping and vessel during periods of low flow rates;

d. conserves reactor heat; and

e. enables the major portion of the RWCU system to be serviced during reactor operation.

5.4.8.2 <u>System Description</u>

The reactor water cleanup system (Drawing Nos. M-97 and M-143) purifies the reactor water. The system removes water from the suction line of each reactor recirculation pump and from the reactor bottom head. The processed water is returned to the nuclear system or to storage.

A regenerative heat exchanger is provided to limit the loss of heat from the nuclear system. The cleanup system can be operated at any time during planned operations, or it may be shut down when not required to clean up reactor coolant.

All the major equipment of the reactor water cleanup system is located near the reactor. This equipment includes pumps, regenerative and nonregenerative heat exchangers, and two filter-demineralizers with supporting equipment. The entire system is connected by associated valves and piping; controls and instrumentation provide proper system operation. Design data for the major pieces of equipment are presented in Table 5.4-1.

The reactor water clean-up pump motors are cooled by reactor building closed cooling water via a small heat exchanger supplied by the pump manufacturer. The pumps are also supplied with a small amount of purge flow from the control rod drive system, charging water header, at the base of the motor cavity. This was put in by the pump vendor to help prevent sediment from settling in the base of the pumps. However this purge flow is not required for operation of the pump. (Drawing M-90, Sheet 3, M-97, Sheet 1, M-100, Sheet 1, M-136 Sheet 3, M-143 Sheet 1, and M-146 Sheet 1).

Reactor water is cooled in the regenerative and nonregenerative heat exchangers, then filtered, demineralized, and returned to the reactor through the shell side of the regenerative heat exchanger. A process diagram of the reactor water cleanup system is shown on Figure 5.4-6.

Because the temperature of the filter-demineralizer units is limited by the resin operating temperature, the reactor coolant must be cooled before being processed in the filter-demineralizer units. The regenerative heat exchanger transfers heat from the influent water to the effluent water. The effluent returns to the reactor. The nonregenerative heat exchanger cools the influent water further by transferring heat to the closed cooling water system. The nonregenerative heat exchanger is designed to maintain the lower temperature even when the effectiveness of the regenerative heat exchanger is reduced by diversion of excess reactor water from the filter-demineralizer effluent to either the main condenser or the radioactive waste system.

The filter-demineralizer units (Figure 5.4-7) are pressure precoat type filters using filter aid and finely ground, mixed ion-exchange resins as a filter and ion-exchange medium. Spent resins are not regenerable and are sluiced from a filter-demineralizer unit to a resin receiver tank from which they are transferred in the radioactive waste system for processing and disposal. The suction line of the RCPB portion of the RWCU system contains two motor-operated isolation valves which automatically close in response to signals from the RCPB leak detection system. (Sections 5.2 and 7.6 describe the system, and it is summarized on Table 5.2-8). This action prevents the loss of reactor coolant and release of radioactive material from the reactor.

The outboard isolation valve also closes automatically to prevent removal of liquid poison in the event of standby liquid control system actuation and to prevent damage of the filter-demineralizer resins if the outlet temperature of the nonregenerative heat exchanger is high. These isolation valves may be remote manually operated to isolate the system equipment for maintenance or servicing.

A remote manual-operated gate valve on the return line to the reactor provides long-term leakage control. Instantaneous reverse flow isolation is provided by at least one check valve in the RWCU or feedwater piping (Drawing Nos. M-97 and M-143).

Two panels, a Material Monitoring System (MMS) and a Data Acquisition System (DAS), monitor the durability and effectiveness of noble metal compounds deposited on reactor vessel and piping surfaces.

The MMS panel samples reactor coolant from the common discharge header of the RWCU pumps and returns reactor coolant to the common suction header of the RWCU pumps. The MMS panel contains metal coupons which are exposed to the

noble metal compounds during the NMCA and OLNC NobleChem™ injection process. Periodically during the operating cycle, a coupon is removed from the MMS and analyzed for residual noble metals. The amount of residual metal is used in determining the most effective re-application schedule.

5.4.8.3 Safety Evaluation

The RCPB isolation valves and piping are designed to the requirements defined in Section 3.2 and the requirements of Subsection 7.1.2.2. To prevent resins from entering the reactor recirculation system in the event of failure of a filter-demineralizer resin support, a strainer is installed on the outlet of each filter-demineralizer unit. Each strainer has a control room alarm that is energized

by high differential pressure. A bypass line is provided around the filter-demineralizer units for bypassing when necessary.

In the event of low flow or loss of flow in the system, flow is maintained through each filter-demineralizer by its own holding pump. Sample points are provided in the influent header and effluent line of each filter-demineralizer unit for continuous indication and recording of system conductivity. High conductivity is annunciated in the control room. The influent sample point is also used as the normal source of reactor coolant samples. Sample analysis also indicates the effectiveness of the filter-demineralizer units.

Operation of the reactor water cleanup system is controlled from the main control room. Resin-changing operations, which include backwashing and precoating, are controlled from a local control panel in the reactor building. Figure 5.4-8 shows the control and instrumentation logic.

5.4.9 Main Steamlines and Feedwater Piping

5.4.9.1 Safety Design Bases

The main steam and feedwater lines have been designed:

a. to accommodate operational stresses, such as internal pressures and safe shutdown earthquake loads, without a failure that could lead to the release of radioactivity in excess of the guideline values in published regulations; and

b. with suitable accesses to permit inservice testing and inspections.

5.4.9.2 Power Generation Design Bases

The main steam and feedwater lines have been designed with the following power generation design bases:

a. The main steamlines have been designed to conduct steam from the reactor vessel over the full range of reactor power operation.

b. The feedwater lines have been designed to conduct water to the reactor vessel over the full range of reactor power operation.

5.4.9.3 Description

Steam piping is shown on Drawing Nos. M-55 and M-116 and is described in Section 10.3. The feedwater piping is described in Subsection 10.4.7 and shown on Drawing Nos. M-57 and M-118.

The feedwater piping consists of two 24-inch nominal lines from the high pressure feedwater heaters to the reactor.

Each line includes three containment isolation valves consisting of one check valve inside the drywell and one check valve and one motor-operated gate valve outside the containment. The design pressure and temperature rating of the feedwater piping between the reactor and manual valve is the same as that of the reactor feedwater nozzles (1300 psig and 575° F). The Seismic Category I design requirements are placed on the feedwater piping from the reactor through the outboard isolation valve and connected piping of 2-1/2 inches or larger nominal pipe size, up to and including the first isolation valve in the connected piping.

The materials used in the piping are in accordance with the applicable design code and supplementary requirements described in Section 3.2.

The general requirements of the feedwater system are described in Subsections 7.7.4 and 10.4.7.

5.4.9.4 Safety Evaluation

Differential pressure on reactor internals under the assumed accident condition of a ruptured steamline is limited by the use of flow restrictors and by the use of four main steamlines. All main steam and feedwater piping is designed in accordance with the requirements defined in Section 3.2. Design of the piping in accordance with these requirements ensures meeting the safety design bases.

5.4.9.5 Inspection and Testing

Inspection and testing are carried out in accordance with Subsection 3.2.2. Inservice inspection is considered in the design of the main steam and feedwater piping. This consideration assures adequate working space and access for the inspection of selected components.

5.4.10 Pressurizer

Subsection 5.4.10 is not applicable to this BWR power plant.

5.4.11 Pressurizer Relief Tanks

Subsection 5.4.11 is not applicable to this BWR power plant.

5.4.12 Valves

5.4.12.1 Safety Design Bases

Line valves such as gate, globe, and check valves are located in the fluid systems to perform a mechanical function. Valves are components of the system pressure boundary. Having moving parts, they are designed to operate efficiently to maintain the integrity of this boundary. The valves operate under the internal pressure/temperature loading as well as the external loading experienced during the various system transient operating conditions. The criteria are as required in Subsection 3.9.3 for ASME Class 1, 2, and 3 valves. Compliance with ASME Codes is discussed in Subsection 5.2.1.

5.4.12.2 Description

Line valves are the standard manufactured types, designed and constructed in accordance with the requirements of Section III of the ASME Code for Class 1 and Class 2 valves. All materials, exclusive of seals and packing, are designed for the 40-year plant life when appropriate maintenance is periodically performed.

Power operators have been sized to operate under the maximum differential pressures determined in the design specification, and are designed as Class 1E components, in compliance with the requirements of IEEE-308.

5.4.12.3 Safety Evaluation

Line valves have been production tested in the shop by the manufacturer for performability. Pressure-retaining parts are subject to the testing and examination requirements of Section III of the ASME Code. To minimize leakage past seating surfaces, maximum allowable leakage rates are stated in the design specifications for both the back seat and the main seat for gate and globe valves.

Valve construction materials are compatible with the maximum anticipated radiation dosage and the environmental conditions for the service life of the valves.

5.4.12.4 Inspection and Testing

Valves serving as containment isolation valves and which must remain closed or open during normal plant operation may be partially exercised during this period to assure their operability at the time of an emergency or faulted conditions. Other

valves, serving as system block or throttling valves, may be fully exercised without jeopardizing system integrity for the same reason.

Leakage from certain valve stems is monitored by use of double-packed stuffing boxes with an intermediate lantern leakoff connection for detection and measurement of leakage rates.

Motors used with valve actuators have been furnished in accordance with NEMA Standard MG-1, Parts 10.35, 10.36, and 10.61, as applicable. Each motor actuator has been assembled, factory tested, and adjusted on the valve for proper operation, position and torque switch setting, position transmitter function (where applicable), and speed requirements. Valves have been tested to demonstrate adequate stem thrust (or torque) capability to operate the valve within the specified time at the specified differential pressure. Tests also verified that no mechanical damage occurred to valve components during full stroking of the valve. Suppliers were required to furnish assurance of acceptability of the equipment for the intended service based on any combination of:

a. test stand data,

b. prior field performance,

c. prototype testing, and

d. engineering analysis.

Representative models of motor operators have been subjected to special seismic qualification tests in order to ensure compliance with the LSCS plant requirements.

5.4.13 Safety/Relief Valves

5.4.13.1 Safety Design Bases

Overpressure protection has been provided at isolatable portions of systems in accordance with the rules set forth in the Nuclear Pump and Valve Code. An overpressure protection report was written to document compliance with the requirements of Article NB-7000 of Section III of the ASME Code.

5.4.13.2 Description

Pressure relief valves have been designed and constructed in accordance with the same code class as that of the line valves in the system.

Table 3.9-2 lists the applicable code classes for valves and system design pressures and temperatures. The design criteria, design loading, and design procedure are as described in Subsection 3.9.2.

5.4.13.3 Safety Evaluation

The use of pressure-relieving devices assures that overpressure does not exceed 110% of the design pressure of the system. The number of relieving devices on a system or portion of a system was determined on an individual component basis.

5.4.13.4 Inspection and Testing

No provisions are made for in-line testing of pressure relief valves. Certified set pressures and relieving capacities are stamped on the body of the valves by the manufacturer, and further examinations would necessitate removal of the component.

5.4.14 Component Supports

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

5.4.14.1 Safety Design Bases

Design loading combinations, design procedures, and acceptability criteria are described in Subsection 3.9.3. Flexibility calculations and seismic analysis for Classes 1, 2, and 3 piping components conform with the appropriate requirements of ASME Section III.

Spacing and size of pipe support elements were based on the piping analysis performed in accordance with ASME Section III and further described in Section 3.7. Standard manufacturer hanger types were used and fabricated of materials per ANSI 3.1.7 for hangers released for fabrication prior to December 1973, and per ASME Section III, Subsection NF for hangers released for fabrications after that date.

5.4.14.2 Description

The use and location of rigid-type supports, variable or constant spring-type supports, and anchors or guides were determined by flexibility, stress, and seismic analysis. Component support elements are manufacturers' standard items.

5.4.14.3 Safety Evaluation

Design loadings used for flexibility and seismic analysis toward the determination of adequate component support systems included all transient loading conditions expected by each component. Provisions were made to provide spring-type supports for the initial deadweight loading due to hydrostatic testing of steam systems to prevent damage to this type of support.

5.4.14.4 Inspection and Testing

After completion of the installation of a support system, all hanger elements were visually examined to assure that they were in correct adjustment to their cold setting position. When hot startup operations began, thermal growth was observed to confirm that spring-type hangers functioned properly between their hot and cold setting positions. Final adjustment capability was provided on all hanger or support types.

5.4.15 Hydrogen Water Chemistry System

The purpose of the Hydrogen Water Chemistry (HWC) program at LaSalle County Station is to reduce rates of intergranular stress corrosion cracking (IGSCC) in recirculation piping and reactor vessel internals. This is accomplished by injecting hydrogen into each unit's condensate booster pump suction header to suppress the formation of radiolytic oxygen in the reactor coolant. Suppression of dissolved oxygen, coupled with high purity reactor water, reduces the susceptibility of reactor piping and internal materials to IGSCC. The HWC system is designed to provide up to a 0.45 ppm feedwater hydrogen level (25 scfm design maximum injection rate). Oxygen, as a constituent of air, is injected into the off-gas system as part of this process in order for it to combine with excess hydrogen prior to entering the off-gas recombiners. The HWC system is non-safety related.

Intergranular stress corrosion cracking is discussed in Section 5.2.3.2.1.

In addition, through General Electric's noble metal chemical application (NMCA) NobleChem™ process, noble metal compounds (platinum and rhodium) are periodically injected into the reactor vessel. The NobleChem™ process deposits a minute, discontinuous layer of noble metal significantly reducing the oxidant potential, which allows for significantly lower HWC hydrogen addition rates, which could in turn result in significantly lower operational dose rates from main steam line radiation. Another potential benefit of noble metals is that additional components, which may not achieve the recommended ECP value with HWC alone, may do so with noble metals.

5.4.15.1 Hydrogen Injection System

5.4.15.1.1 Design Basis

The hydrogen injection system is designed to be capable of attaining and maintaining the following water chemistry limits in the reactor coolant to mitigate the potential for IGSCC.

A. Electrochemical Corrosion Potential below –230 mv (SHE);

B. Reactor water conductivity of less than 0.3 mS/cm.

5.4.15.1.2 Description

Hydrogen is supplied from a cryogenic hydrogen storage system installed approximately 2012 feet northwest of the nearest safety-related structure. An excess flow check valve at the hydrogen supply site restricts flow from a broken downstream line. The HWC system is designed to operate down to approximately 2% power.

The Hydrogen Flow Control Module 1(2)P73-P100 provides flow control, flow measurement, pressure indication and isolation of hydrogen flow for the hydrogen gas supply system. The Hydrogen Injection Module 1(2)P73-P150 provides a location for hydrogen injection and permissive based on sufficient condensate flow through the injection device. The Hydrogen Isolation Panel 1(2)P73-P400 provides shutoff of hydrogen near the hydrogen lines entrance into the Turbine Building facility.

A single flow control valve train is used for hydrogen injection into the condensate/feedwater stream through a side stream water path across the condensate booster pump. This path results in a net loss of approximately 100 gpm of water from the condensate booster system downstream of this injection loop. The single hydrogen injection point contains a check valve to prevent water from entering the hydrogen line. Connections are provided to allow hydrogen piping to be completely purged of air before hydrogen is introduced into the line. The purge inlet is near the injection point and the purge outlet is near the 1(2)P73-P400 panel. Suitable valves are provided to cross connect the purge outlet to the hydrogen vent line, which is routed to the Turbine Building exterior to a flame arrestor.

5.4.15.2 Oxygen/Air Injection System

5.4.15.2.1 Design Basis

The oxygen/air injection system is designed to inject sufficient oxygen (in air) into the off-gas system to ensure that the excess hydrogen in the off-gas stream is recombined. This prevents the hydrogen concentration from reaching the combustibility limit of hydrogen in air.

5.4.15.2.2 Description

A cryogenic oxygen storage system installed approximately 680 feet northwest of the nearest safety-related air intakes previously supplied oxygen to the Oxygen Flow Control Module 1(2) P73-P200. This oxygen supply has been isolated and abandoned in place or removed, and service air with oxygen as a constituent is supplied instead.

The Oxygen Flow Control Module 1(2)P73-P200 provides flow control, flow measurement, pressure indication and isolation of air flow. A single flow control valve train is used for air injection into the off-gas system between the last stage steam jet air injector and off-gas preheater for each recombiner train. Each injection point contains a check valve to prevent off-gas from entering the air line. The normal oxygen injection rate is 50% of the hydrogen injection rate but may be adjusted between 40% to 60% of the hydrogen injection rate. There is a delay in the air injection to compensate for the transport time from the hydrogen injection point to the air injection point. Automatic isolation is provided for all HWC system trips. An outside vent is provided for the oxygen flow control module to facilitate testing and calibration activities.

5.4.15.3 Tests and Inspections

The functional operability of the HWC system, including verification of the appropriate time delay for hydrogen and air ramp rates, was initially tested at time of system installation.

The station preventative maintenance program includes inspections of the HWC system. Retesting requirements for the system are based upon General Electric recommendations, and consider extended HWC system shutdown periods and other factors not consistent with normal system operation.

5.4.15.4 Instrumentation Applications

The HWC Control Panel 1(2)P73-P500 provides processing of signal inputs, determination of alarm and shut down conditions and output of data and shutdown signals. The panel supplies alarm status and display, process parameter displays and operator interface capabilities. Output terminals are supplied that provide

signals to the control room for remote (plant control room) shutdown and alarm status. Process data is stored locally in the 1(2)P73-P500 panel computer and can be output on a portable disk drive. The hydrogen and air flow rates can be controlled manually or automatically. In the Automatic Power Determined Setpoint mode the controller varies hydrogen and delayed airflows as a function of reactor power, which is based on feedwater flowrate, to maintain a constant hydrogen concentration in the feedwater. A constant hydrogen injection flow is maintained when reactor power is 20% or lower. The controller also initiates a variety of alarms and HWC isolations, which are summarized in Table 5.4-2. Control room interfaces for the HWC system are provided on off-gas panels 1(2)N62-P600 and 1(2)N62-P601.

5.4.15.5 Performance Analysis

Station personnel will maintain water quality consistent with Corporate and Site Specific Procedures in order to maximize the effectiveness of the HWC system in mitigating the occurrence of IGSCC.

Combination dissolved hydrogen/oxygen monitors are installed on the reactor feedwater, reactor recirculation loop "B" and reactor water clean-up inlet sample lines. Inputs from this new equipment in conjunction with other existing station chemistry inputs are used during HWC system operation as secondary parameters to determine the effectiveness of the HWC system for protection of reactor core internals. In-situ tests for the Electrochemical Corrosion Potential levels in the reactor vessel were performed to validate the effectiveness of these parameters.

Combustible gas monitoring is discussed in Section 7.7.10.

5.4.16 References

1. "Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves," APED-5750, General Electric Co., Atomic Power Equipment Department, March 1969.

2. Letter from R. E. Spencer (General Electric) to W. R. Huntington (CECo) on RHR System Operation dated October 31, 1986.

3. Power Uprate Project Task 300, “Nuclear Boiler,” GE-NE-A1300384-28-01, Revision 0, October 1999.

4. Power Uprate Project Task 310. “Residual Heat Removal System,” GE-NE-A1300384-12-01, Revision 0, October 1999.

5. NUREG-0800, Section 3.6.2, BTP MEB 3-1, Revision 1 – July 1981.

TABLE 5.4-1

REACTOR WATER CLEANUP SYSTEM EQUIPMENT DESIGN DATA*

MAIN CLEANUP RECIRCULATION PUMPS					
Number Required	-	1	Design temperature (°F)	-	575
Capacity (each)	-	100%	Design pressure (psig)	-	1450
			Discharge head at rated flow (feet)	-	500
			Minimum available NPSH (feet)	-	13

HEAT EXCHANGERS	REGENERATIVE	NONREGENERATIVE
Shell design pressure (psig)	1425	150
Shell design temperature (°F)	575	370
Tube design pressure (psig)	1425	1425
Tube design temperature (°F)	575	575

FILTER-DEMINERALIZERS

Type - pressure precoat

Number required - 3 (2 active, 1 standby)

Capacity (each) - 50%

Flow rate per unit (lb/hr) - 66,500

Design temperature (°F) - 150

Design pressure (psig) - 1400

* System Flow Rate (lb/hr) - 133,000

TABLE 5.4-2

HYDROGEN WATER CHEMISTRY SYSTEM
ALARMS AND ISOLATIONS

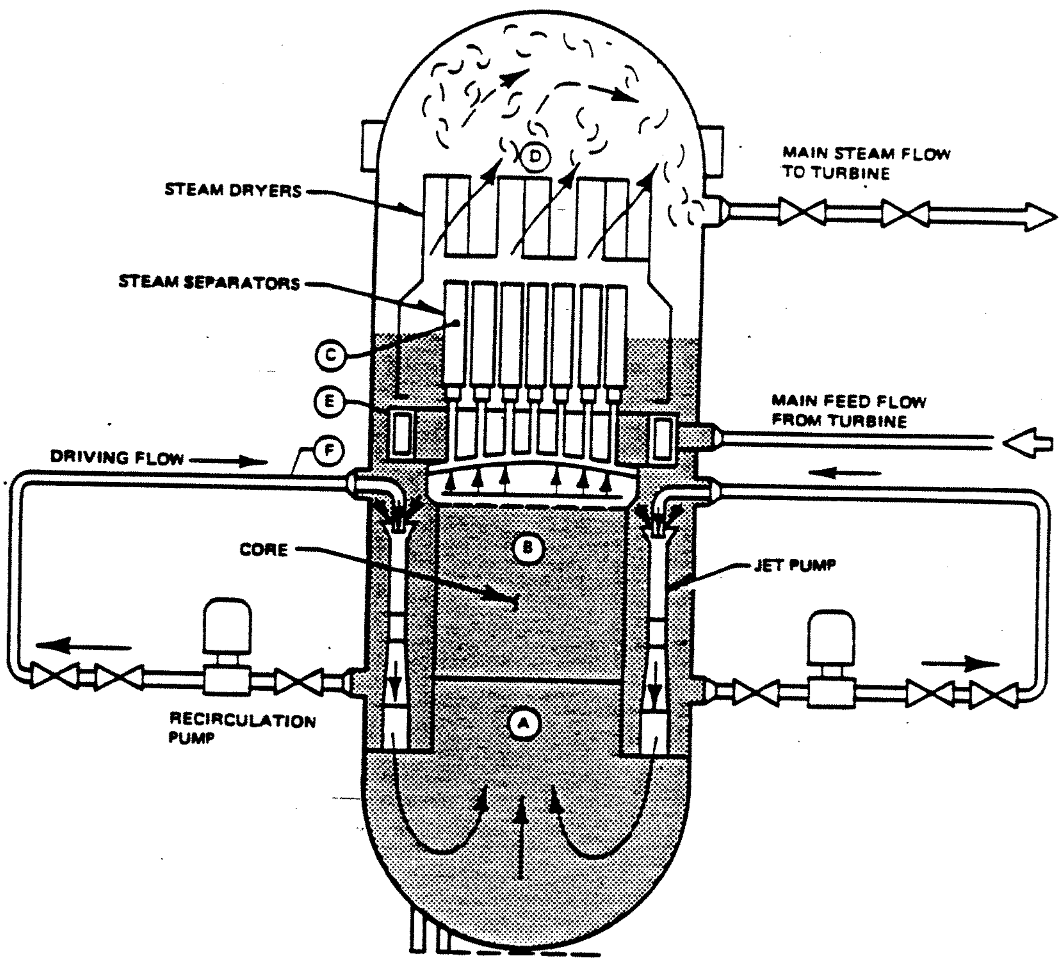
Parameter	Alarm	Isolation
Hydrogen Flow	Setpoint error, High	
Hydrogen Pressure	Low, High	
Air Pressure	High, Low	
Air Flow	Setpoint error	
Hydrogen Area	High, High-High, Monitor Malfunction	High-High
Hydrogen Supply System	Trouble	
Offgas Hydrogen Monitor	Trouble, Isolation, Monitors in Test	High hydrogen
Hydrogen Injection Module Water Flow Differential Pressure	Low	
HWC System Purge	Purge Circuit Activated	
Programmable Logic Controller	Operator Interface Unit Trip, Programmable Logic Controller Fault	Programmable Logic Controller Fault
Local	Local Demand Shutdown Pushbutton Depressed	Manual
Control Room	Control Room Shutdown Switch in Shutdown, Trouble, Trip	Manual
Reactor Scram	N/A	Reactor Scram

FIGURE 5.1-1

Intentionally Deleted.

See Figure 1.2-1 for Unit 1 and Unit 2 operating conditions.

		VOLUME OF FLUID (ft^3) *
A.	Lower Plenum	3790
B.	Core	2065 ± 30 ft^3**
C.	Upper Plenum and Separators	2300
D.	Dome (Above normal water level)	7340
E.	Downcomer Region	5320
F.	Recirculation Loops and Jet Pumps	1030



* The values in this table are typical coolant volumes for a BWR-5.
** Fuel/Channel type dependent value.

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FIGURE 5.1-2

COOLANT VOLUMES

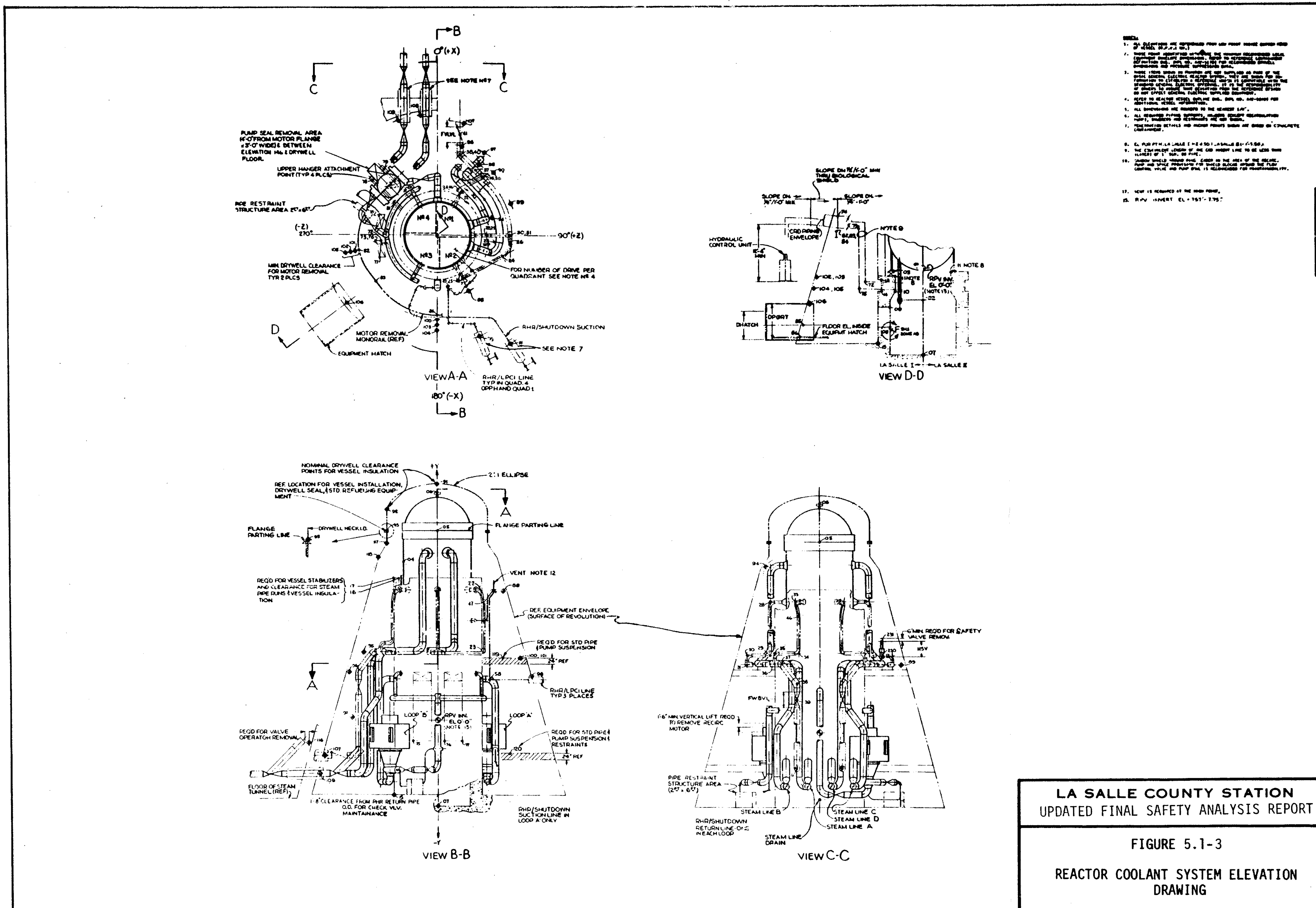

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FIGURE 5.1-3

REACTOR COOLANT SYSTEM ELEVATION DRAWING

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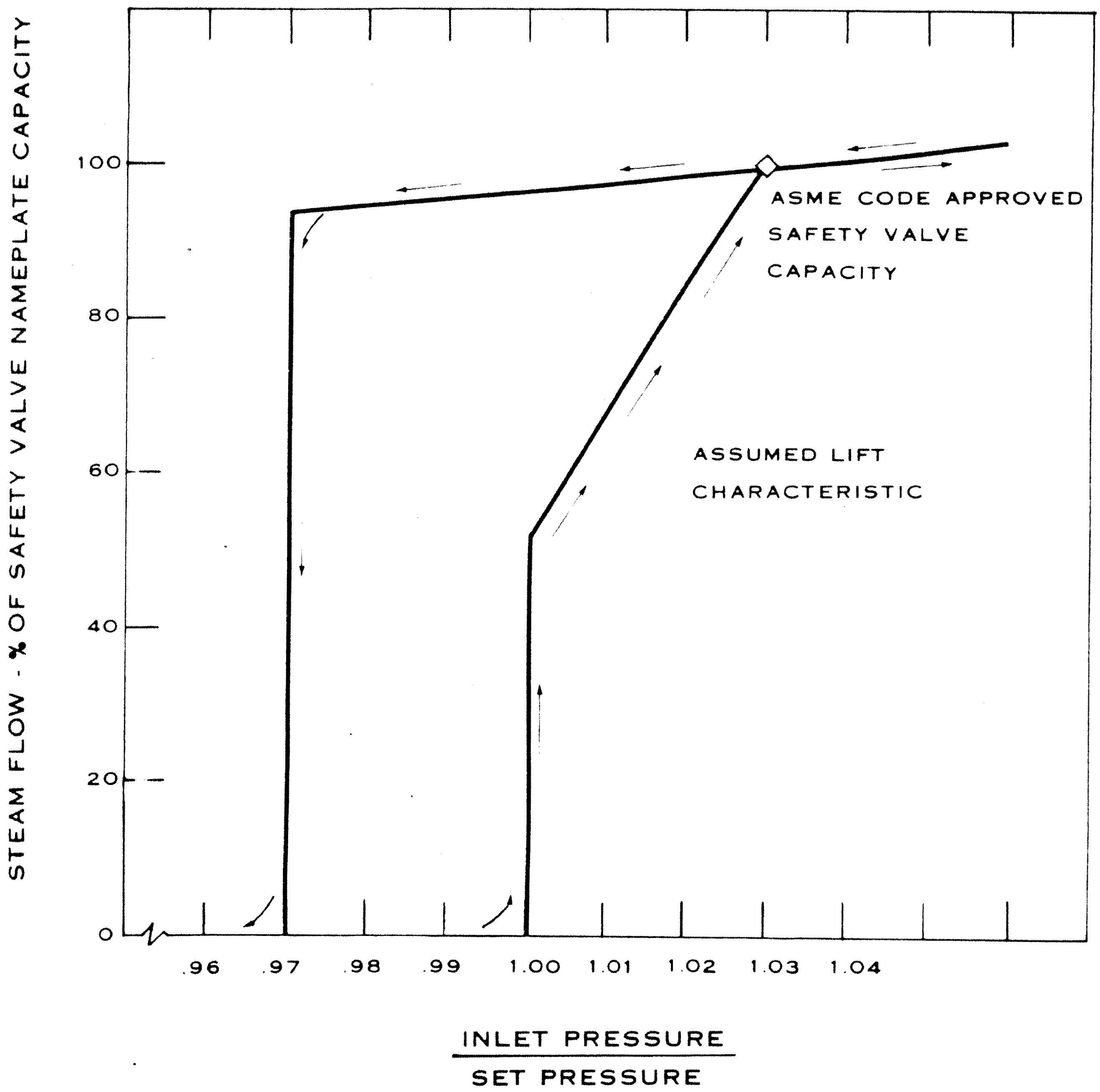

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FIGURE 5.2-1

TYPICAL DUAL SAFETY/RELIEF POP VALVE CAPACITY CHARACTERISTICS

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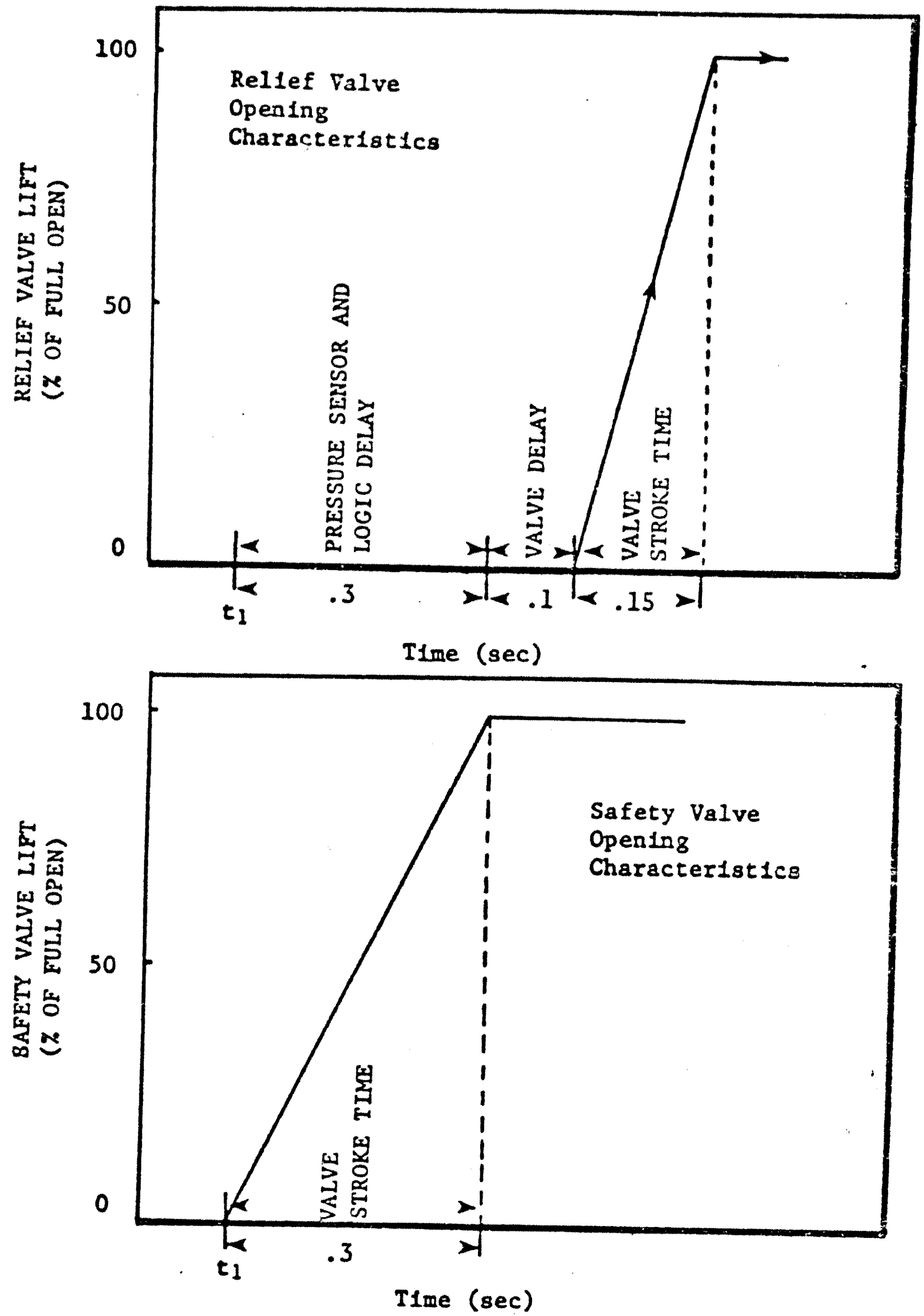

t_1 = Time at which pressure exceeds the valve set pressure

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FIGURE 5.2-1a

POWER ACTUATED AND SAFETY ACTION VALVE LIFT CHARACTERISTICS

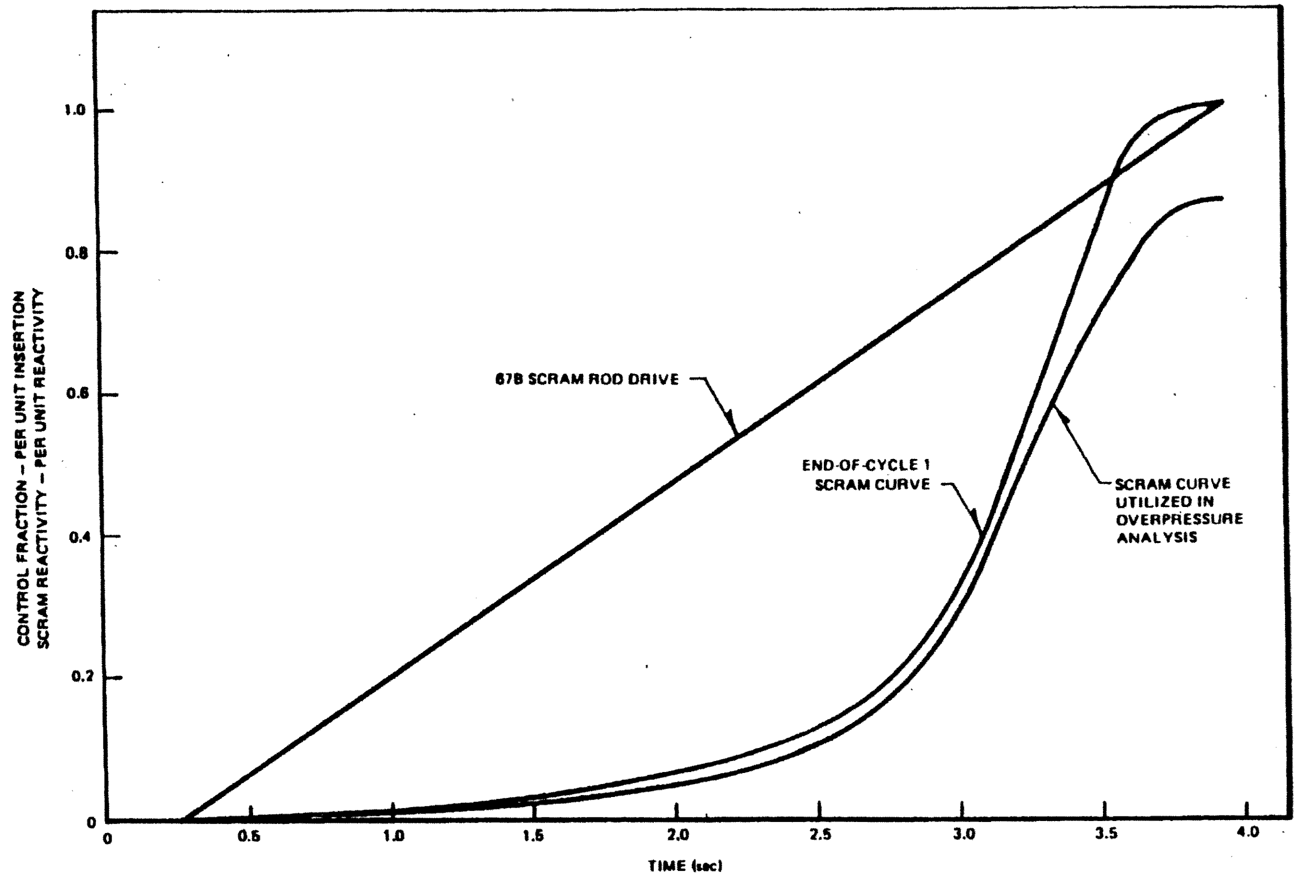

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FIGURE 5.2-2

TYPICAL
SCRAM ROD DRIVE AND SCRAM REACTIVITY TIME CHARACTERISTICS
(INITIAL CORE)

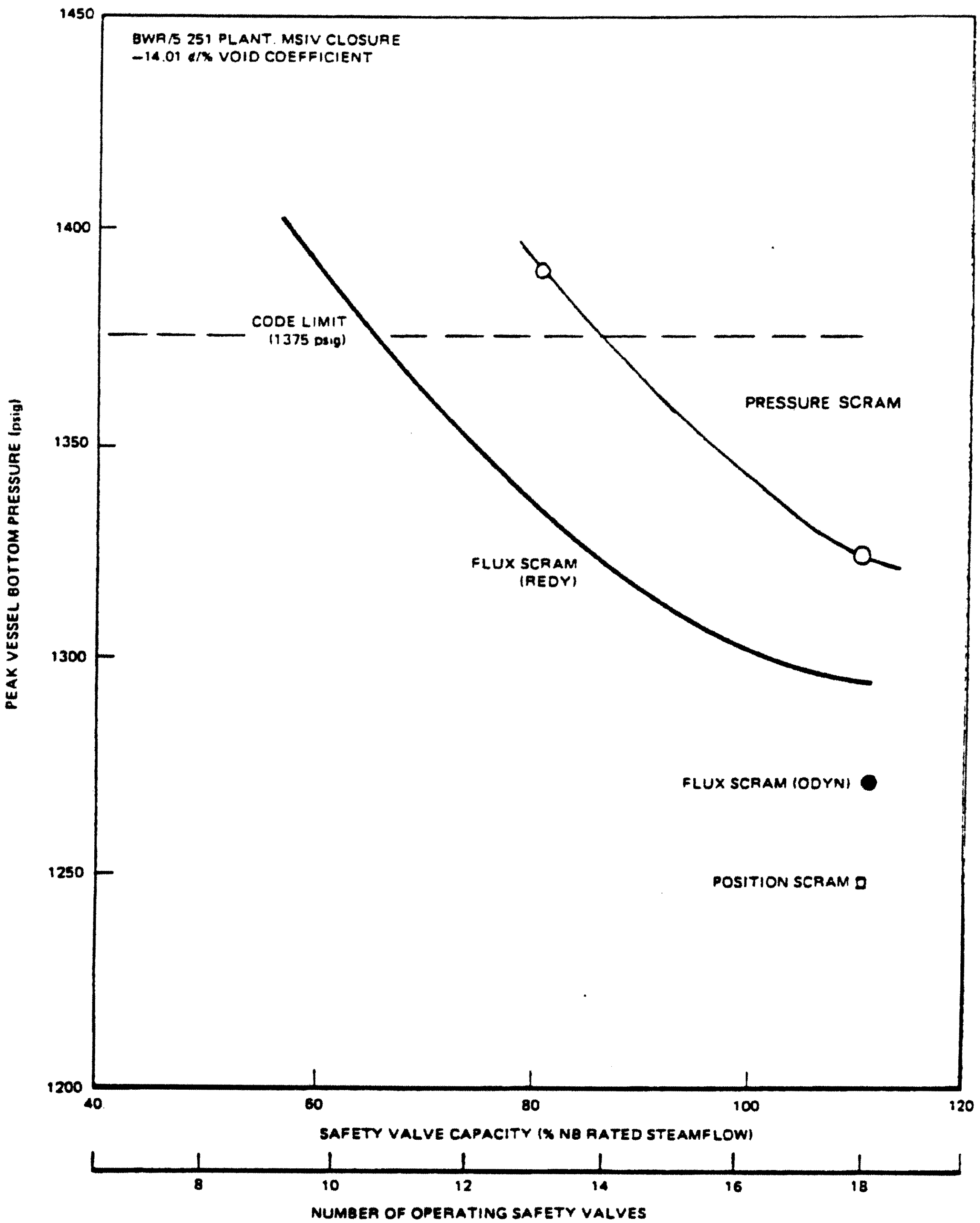

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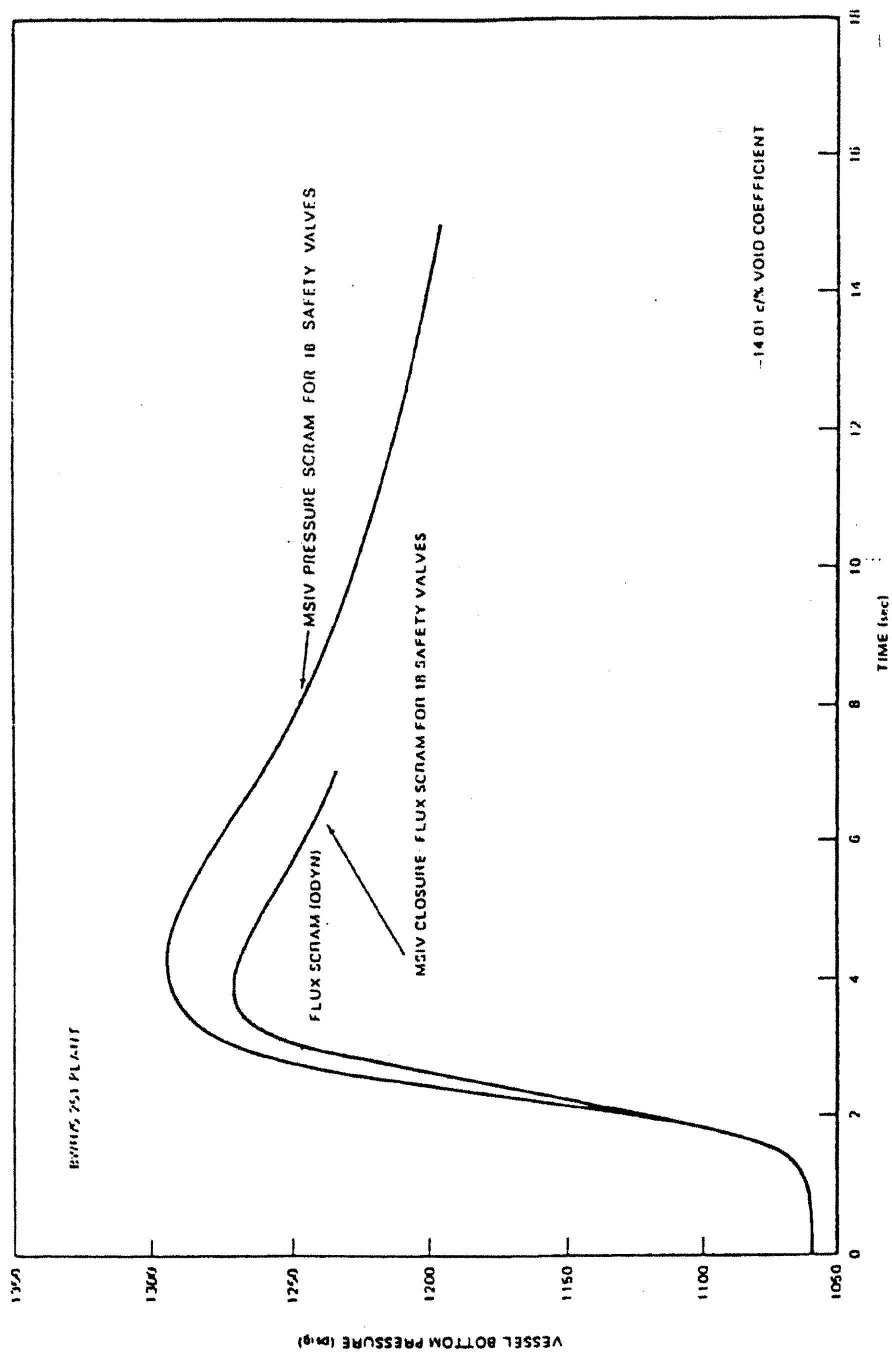
FIGURE 5.2-3 (TYPICAL) PEAK VESSEL PRESSURE VS. SAFETY/RELIEF VALVE CAPACITY



* Less than 18 SRVs may be assumed in cycle-specific reload analyses. The information shown is historical, a new analysis based on 13 installed SRV's has been performed and accepted by the NRC, see References 13 and 14.

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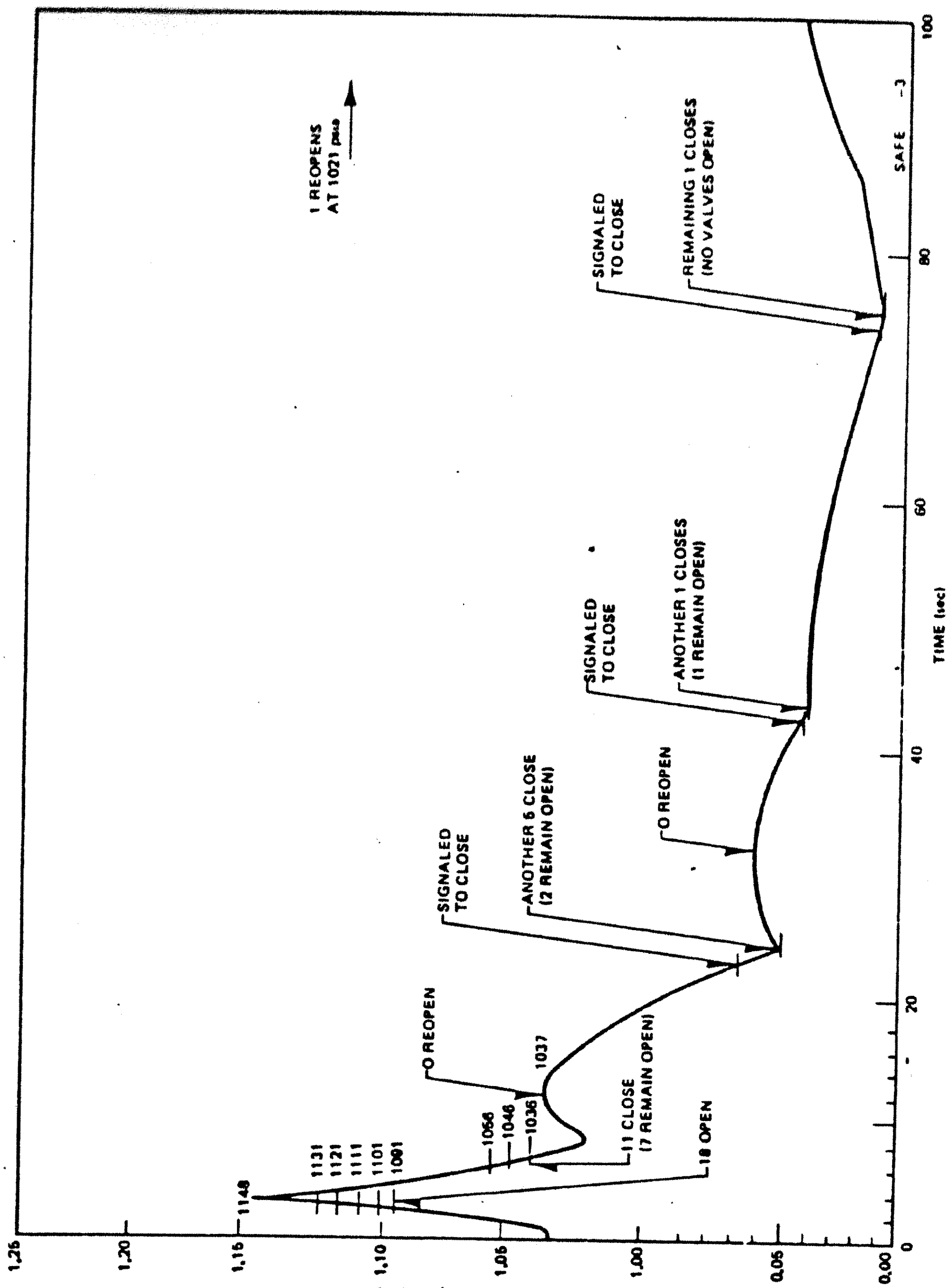
FIGURE 5.2-4

(INITIAL CORE)

TIME RESPONSE OF VESSEL PRESSURE FOR MSIV CLOSURE TRANSIENTS



The information shown is historical, a new analysis based on 13 installed SRV's has been performed and accepted by the NRC, see References 13 and 14.

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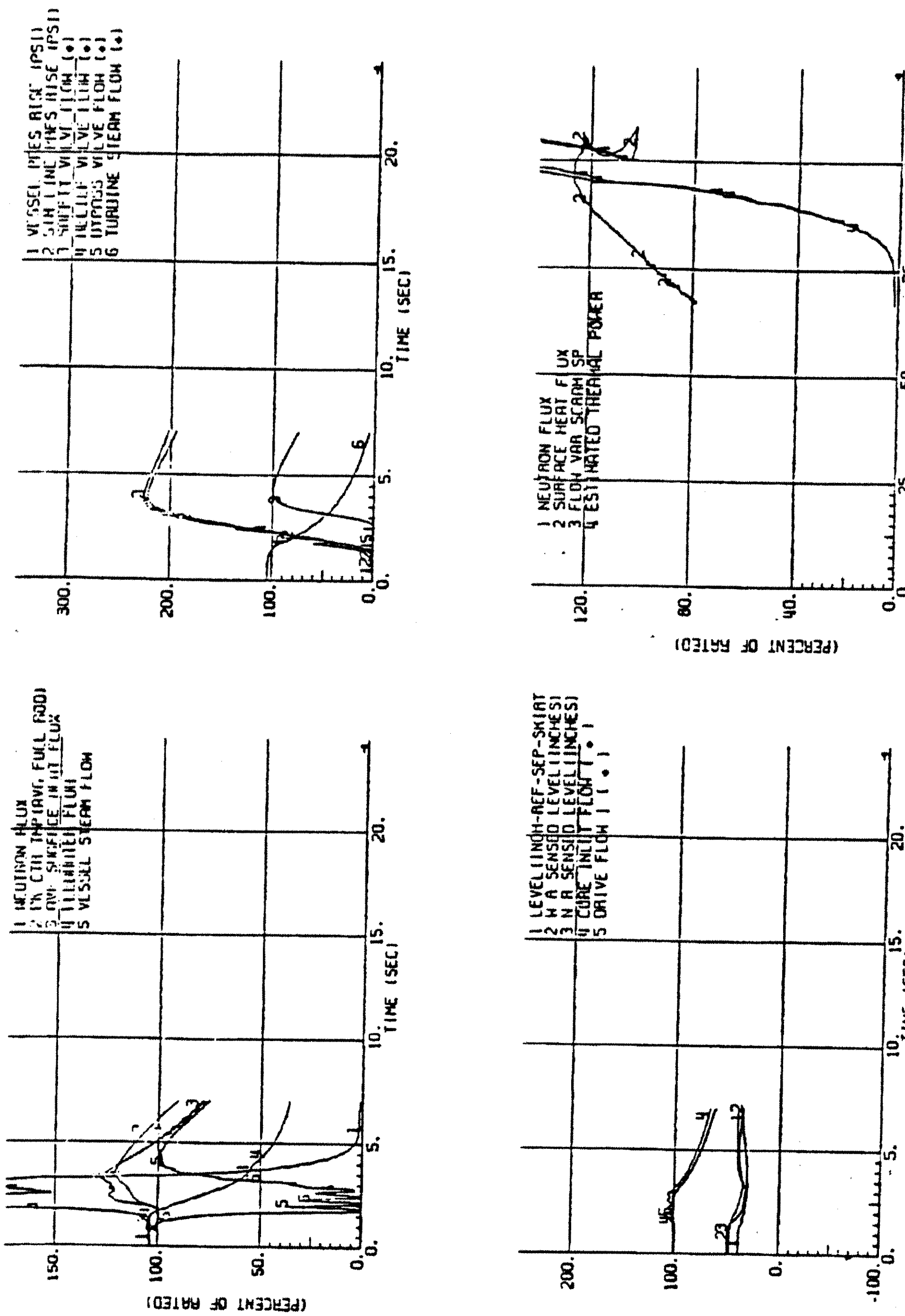
FIGURE 5.2-4a TYPICAL BWR-5 REACTOR VESSEL PRESSURE FOLLOWING TRAINSIENT ISOLATION EVENT



The information shown is historical, a new analysis based on 13 installed SRV's has been performed and accepted by the NRC, see References 13 and 14.

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FIGURE 5.2-4b

(INITIAL CORE)

MSIV CLOSURE, HIGH FLUX SCRAM, 104% POWER

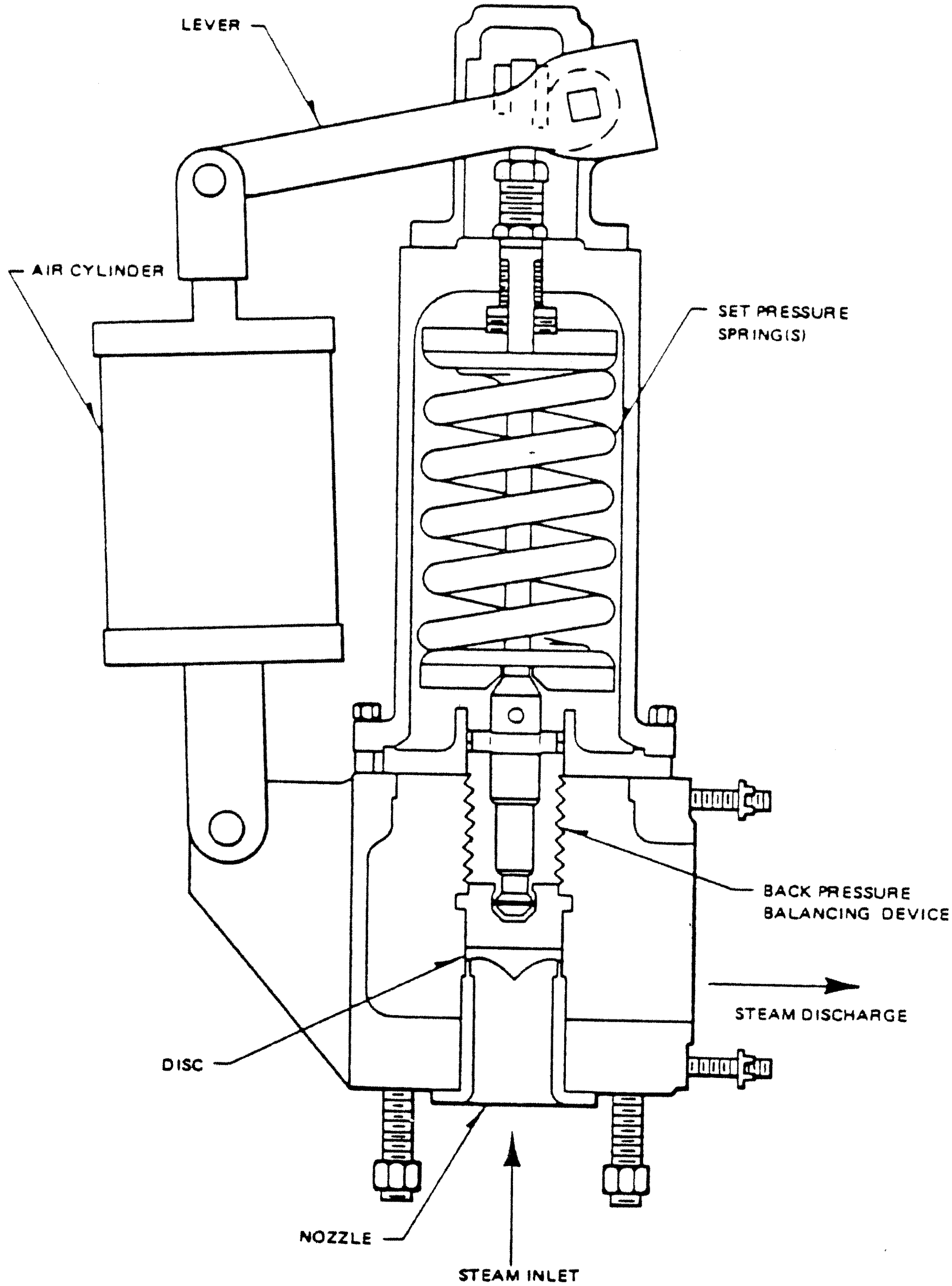

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FIGURE 5.2-4c

GRAPHIC OF SAFETY/RELIEF VALVE
WITH AUXILIARY ACTUATING DEVICE

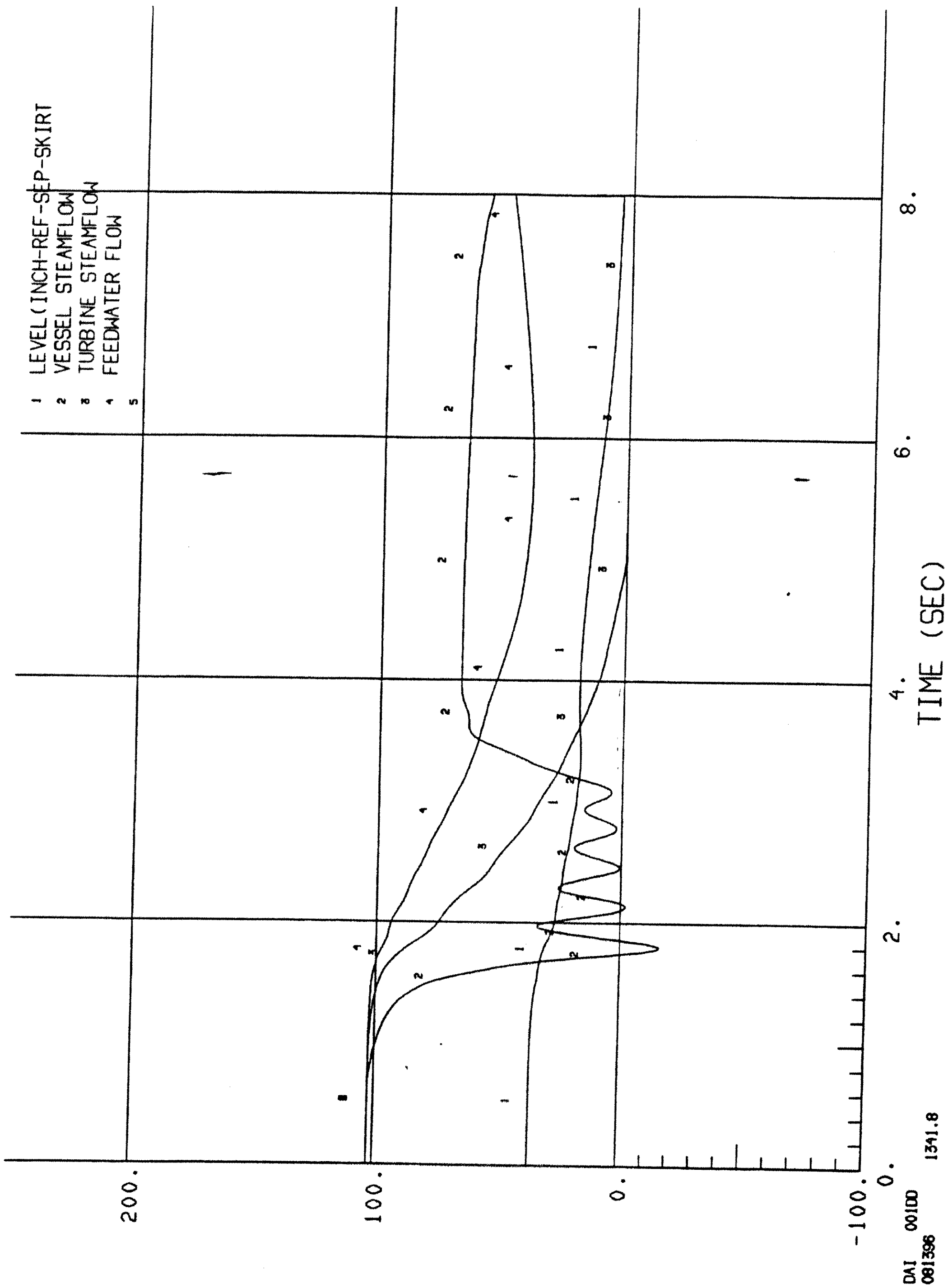

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FIGURE 5.2-4d

MSIV CLOSURE FLUX SCRAM EVENT
102P/105F, NOMINAL +3%, 8 SRVs OOS

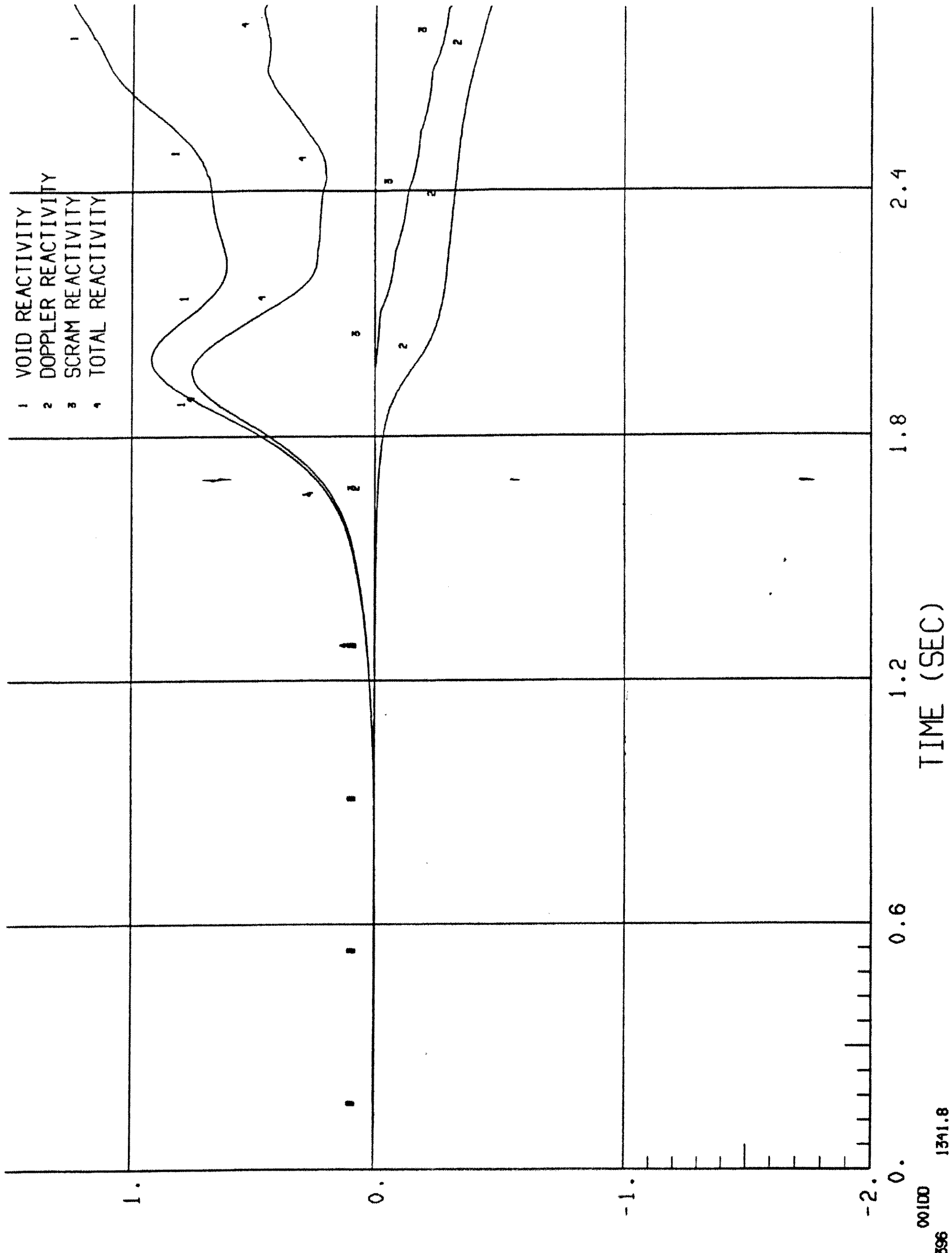

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FIGURE 5.2-4e

MSIV CLOSURE FLUX SCRAM EVENT
102P/105F, NOMINAL +3%, 8 SRVs OOS

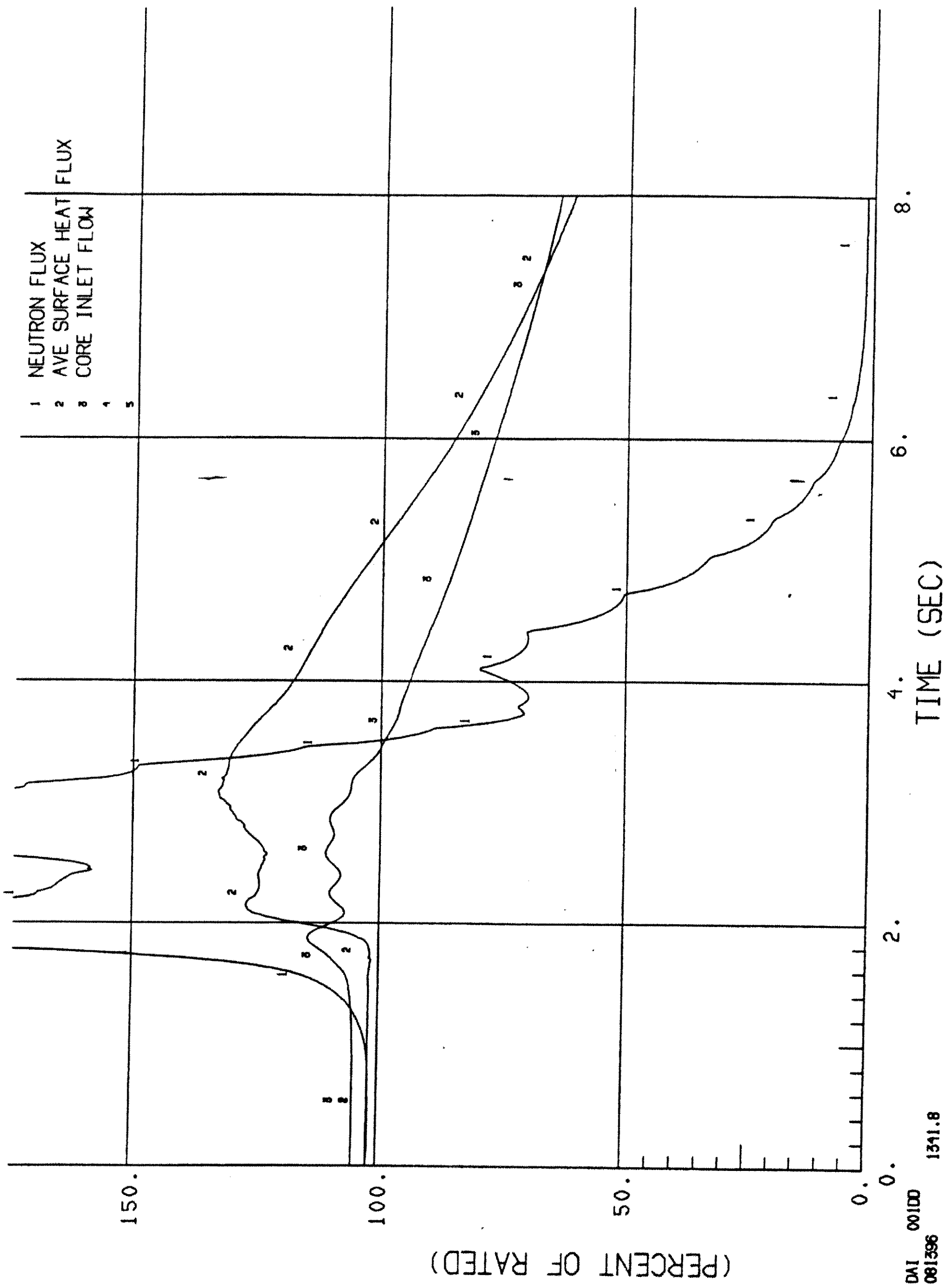

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FIGURE 5.2-4f

MSIV CLOSURE FLUX SCRAM EVENT
102P/105F, NOMINAL +3%, 8 SRVs OOS

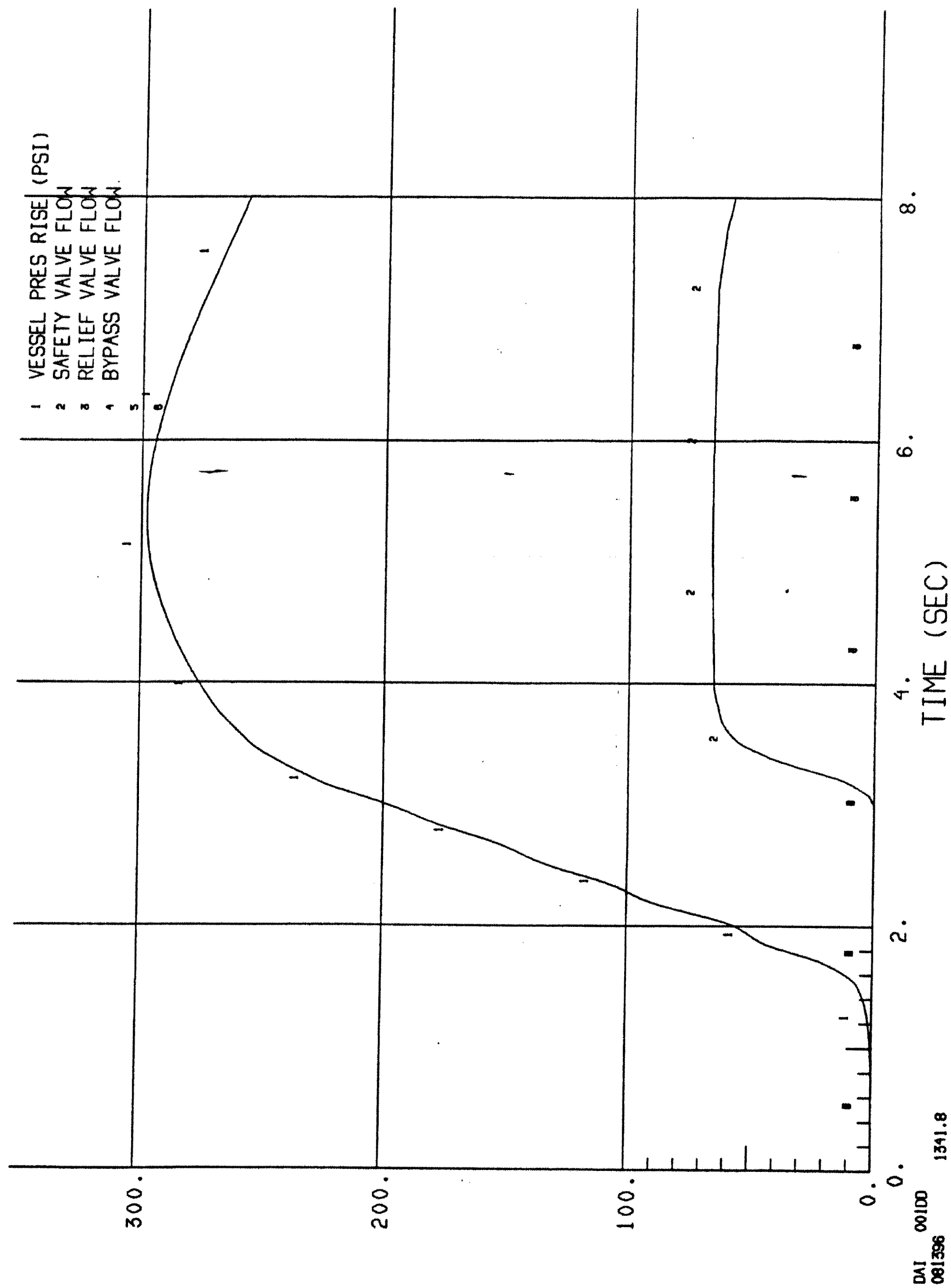

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FIGURE 5.2-4g

MSIV CLOSURE FLUX SCRAM EVENT
102P/105F, NOMINAL +3%, 8 SRVs OOS

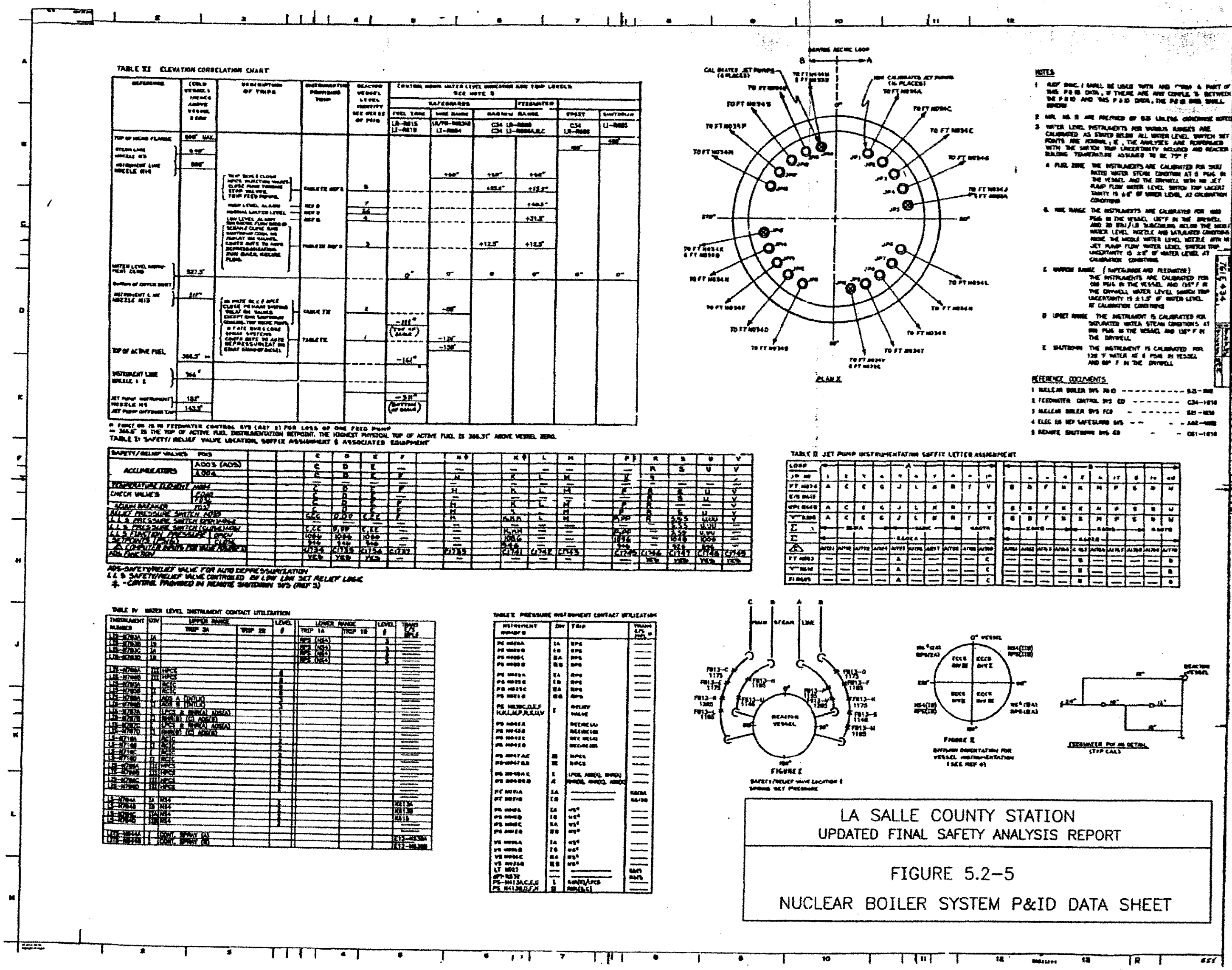

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FIGURE 5.2-5
NUCLEAR BOILER SYSTEM P&ID DATA SHEET

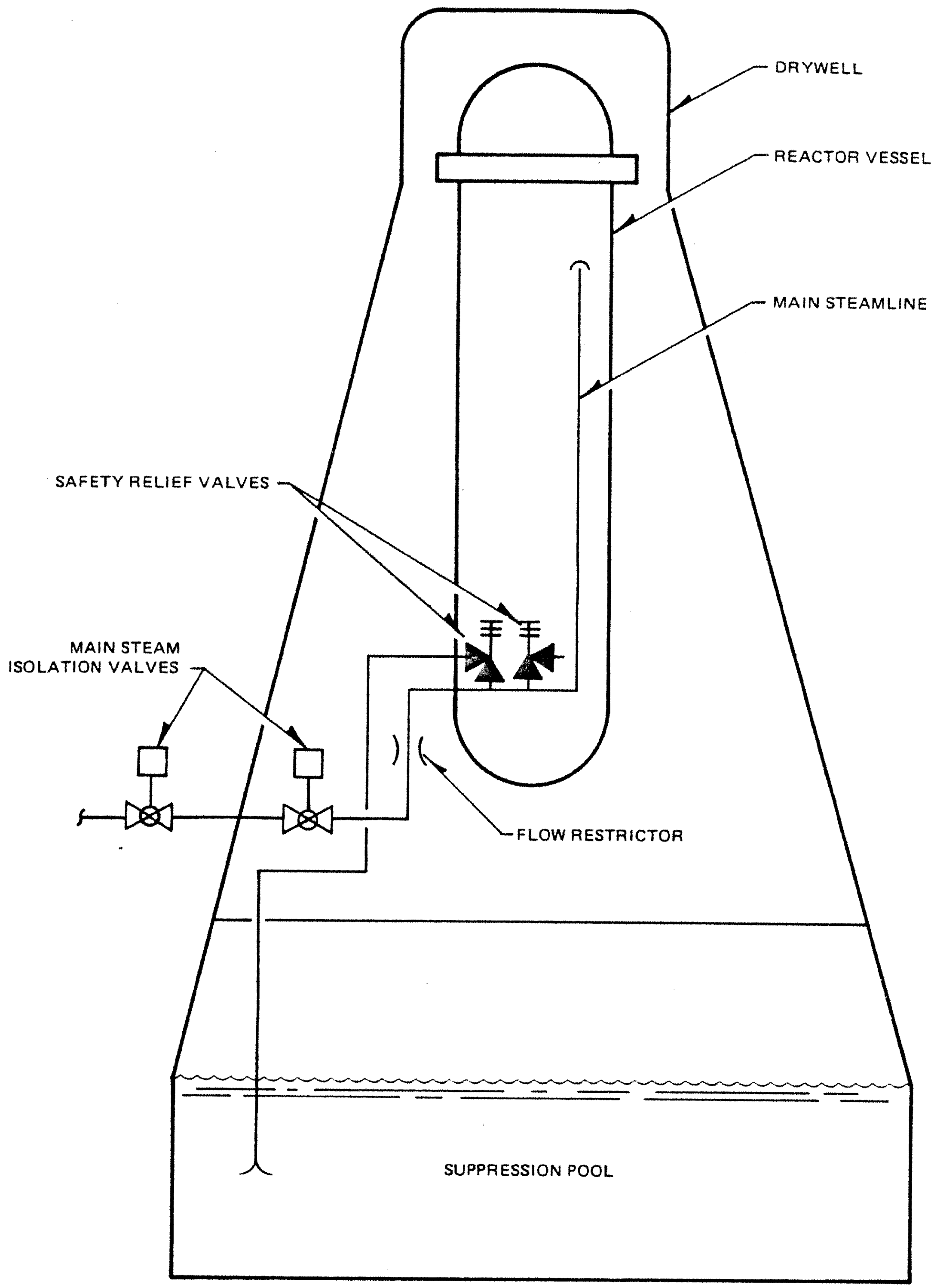

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FIGURE 5.2-6

SAFETY/RELIEF VALVE SCHEMATIC ELEVATION

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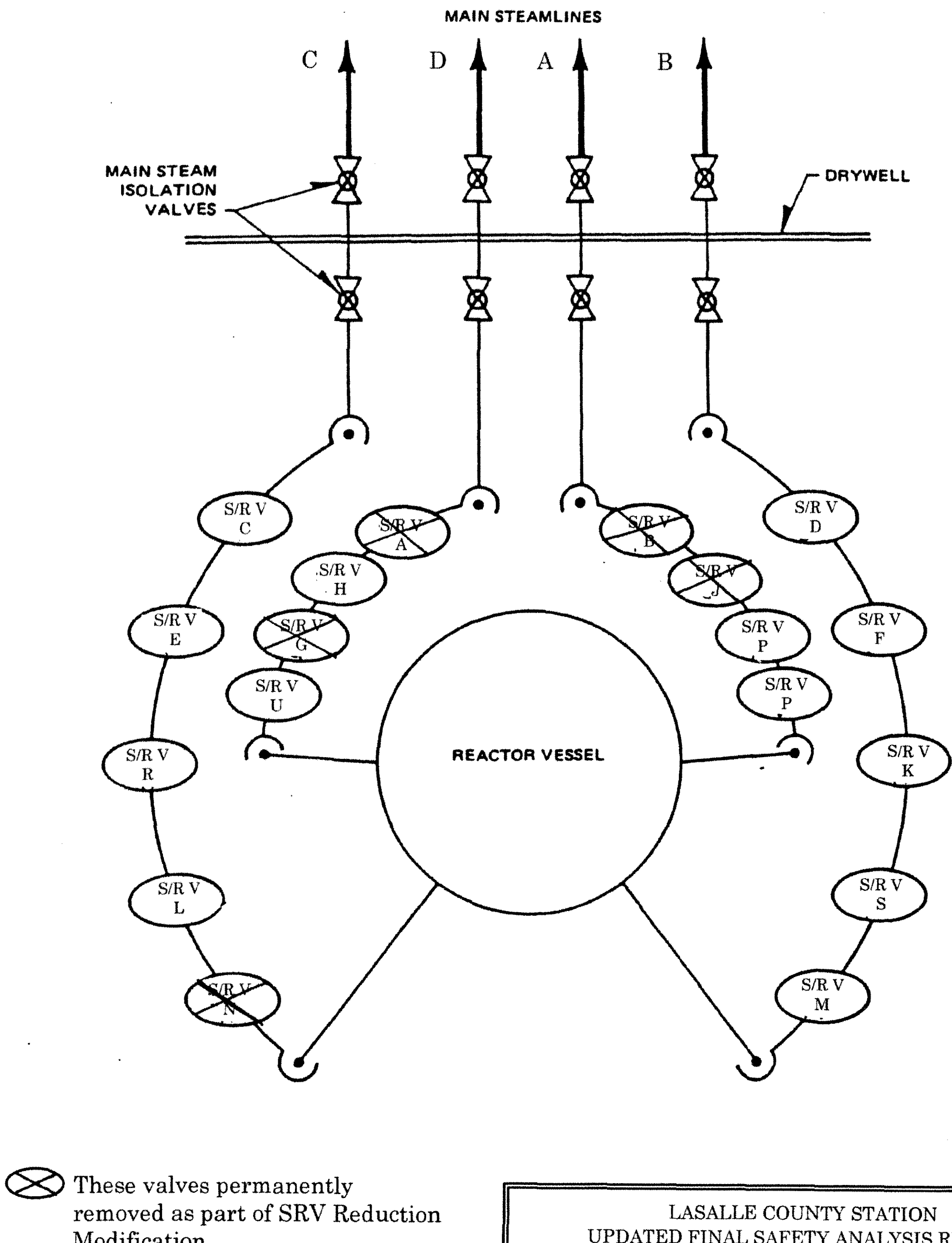

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FIGURE 5.2-7 SAFETY/RELIEF VALVE SCHEMATIC PLAN

[HISTORICAL]

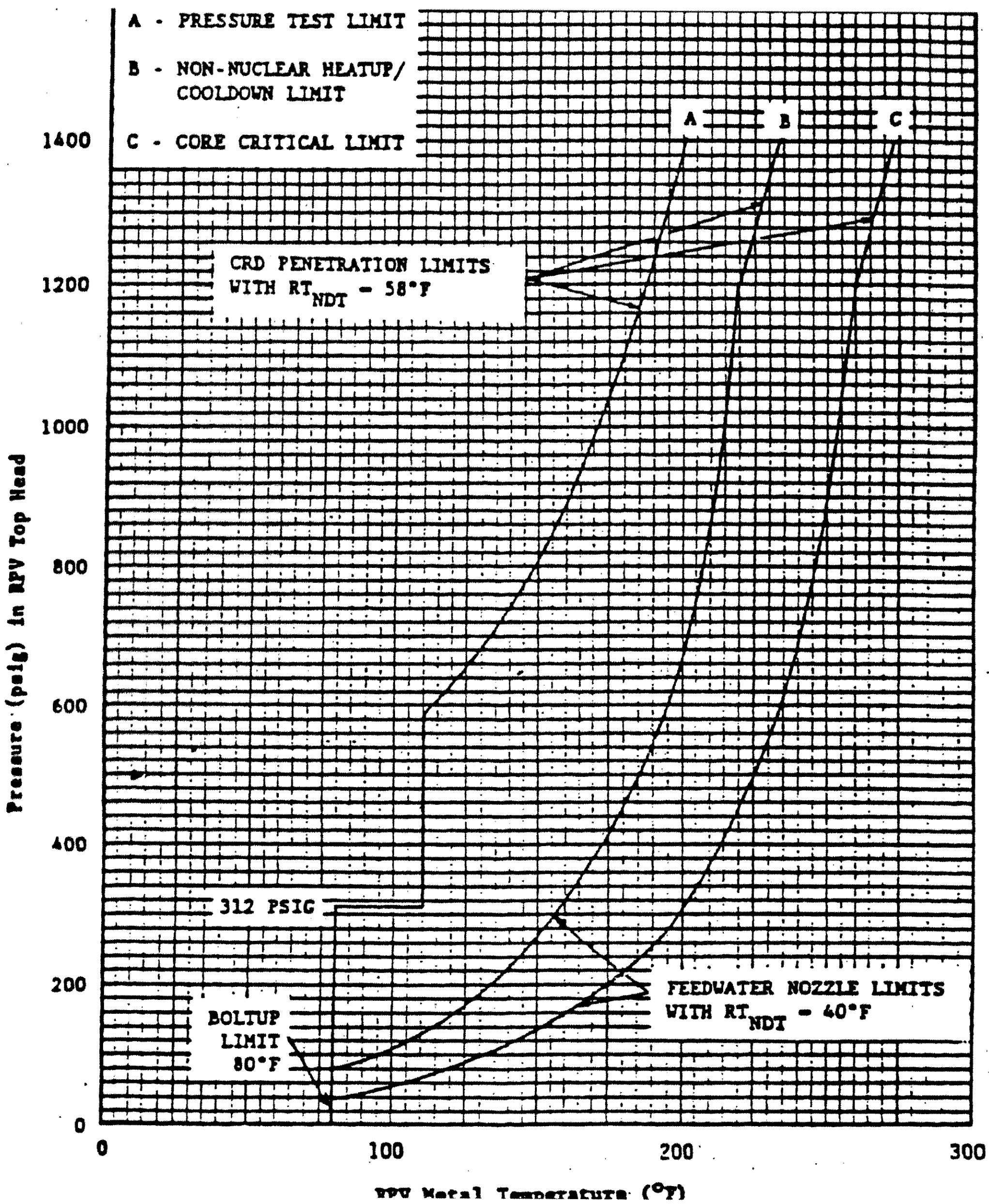

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FIGURE 5.2-8 Unit 1 Pressure-Temperature Operating Limits Valid to 16 EFPY

[HISTORICAL]

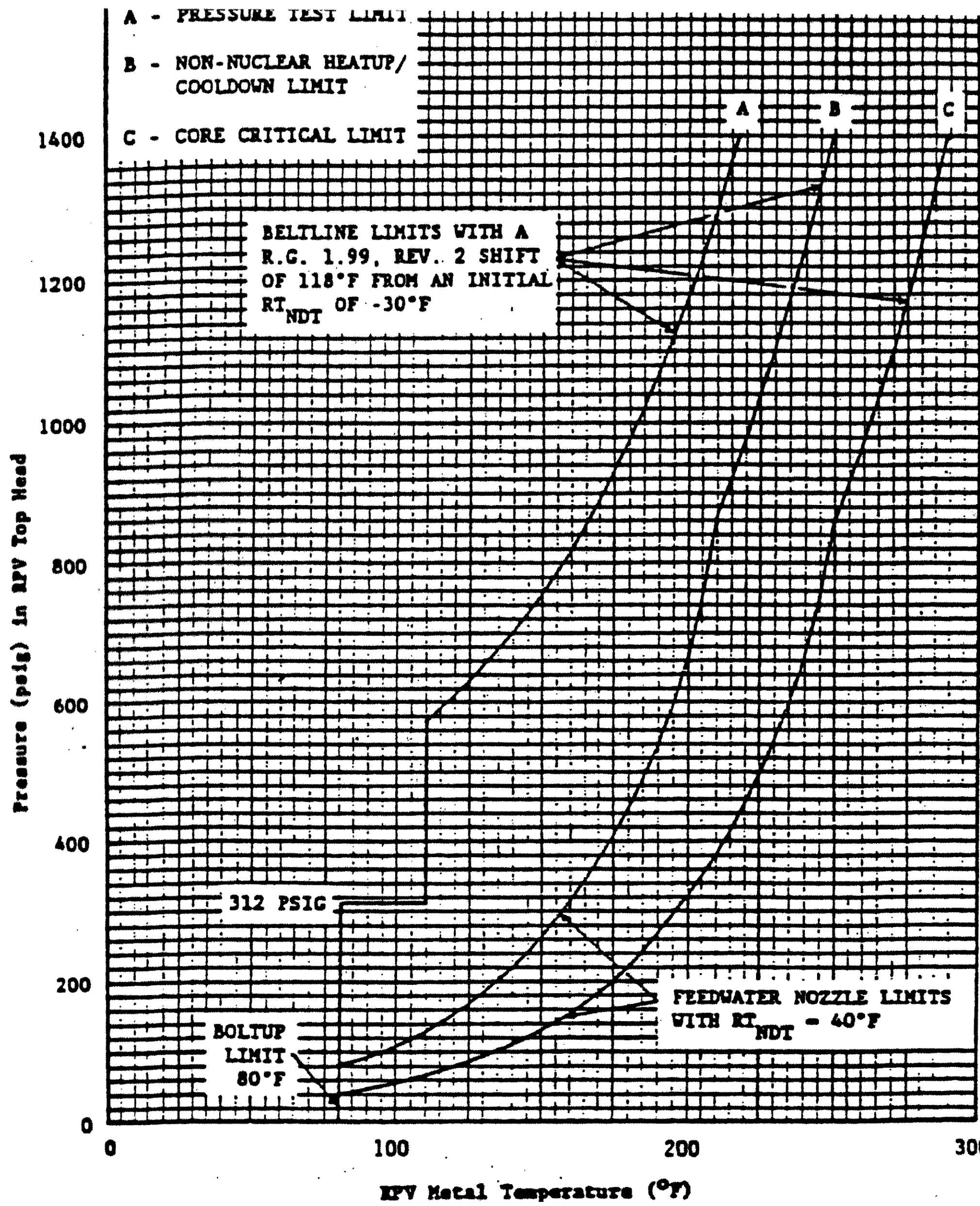

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FIGURE 5.2-8a

Unit 1

Pressure-Temperature Operating Limits

Valid to 32 EFPY

[HISTORICAL]

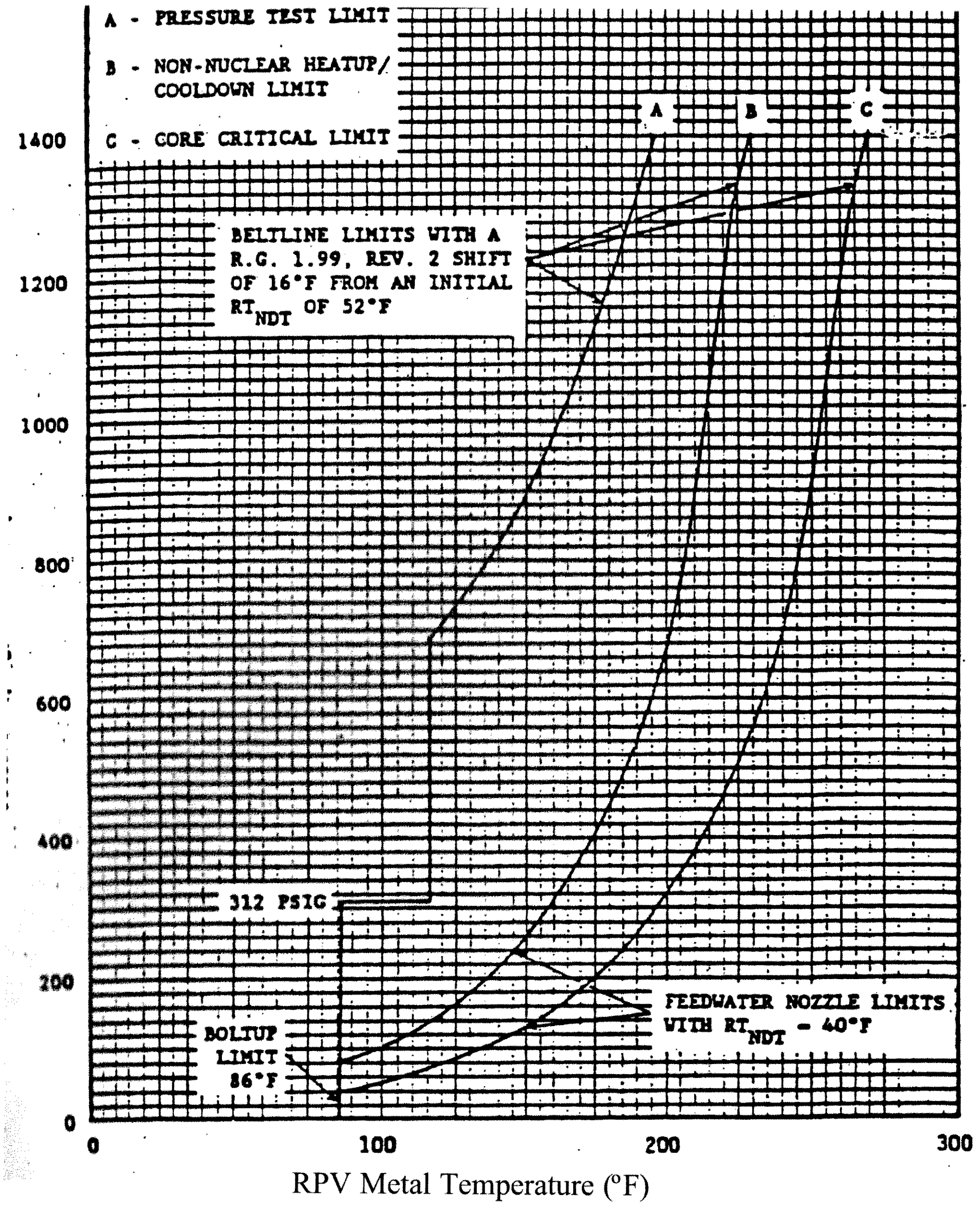

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FIGURE 5.2-9 Unit 2 Pressure-Temperature Operating Limits Valid to 16 EFPY

[HISTORICAL]

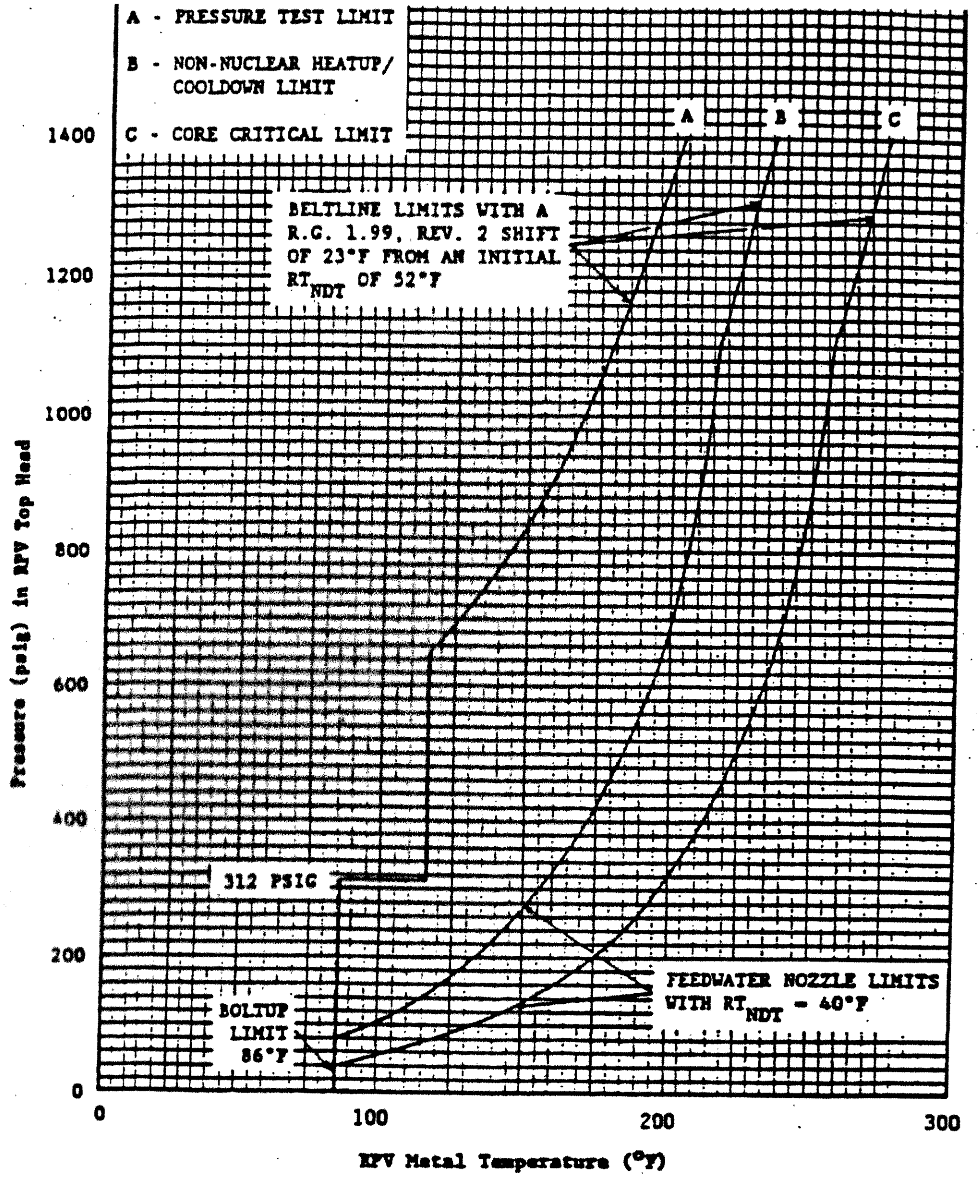

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FIGURE 5.2-9a

Unit 2

Pressure-Temperature Operating Limits

Valid to 32 EFPY

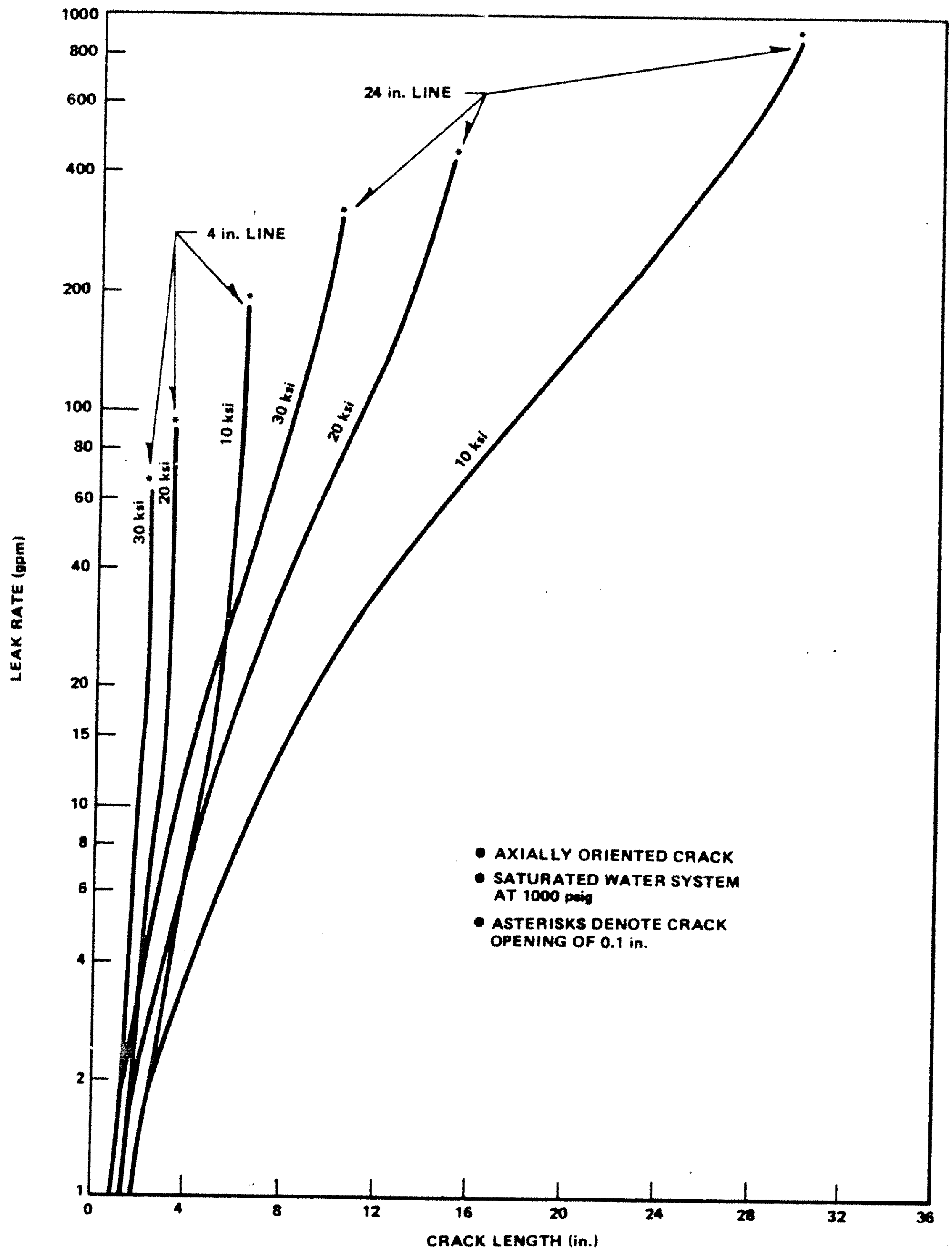

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FIGURE 5.2-11 CALCULATED LEAK RATE AS A FUNCTION OF CRACK LENGTH AND APPLIED HOOP STRESS

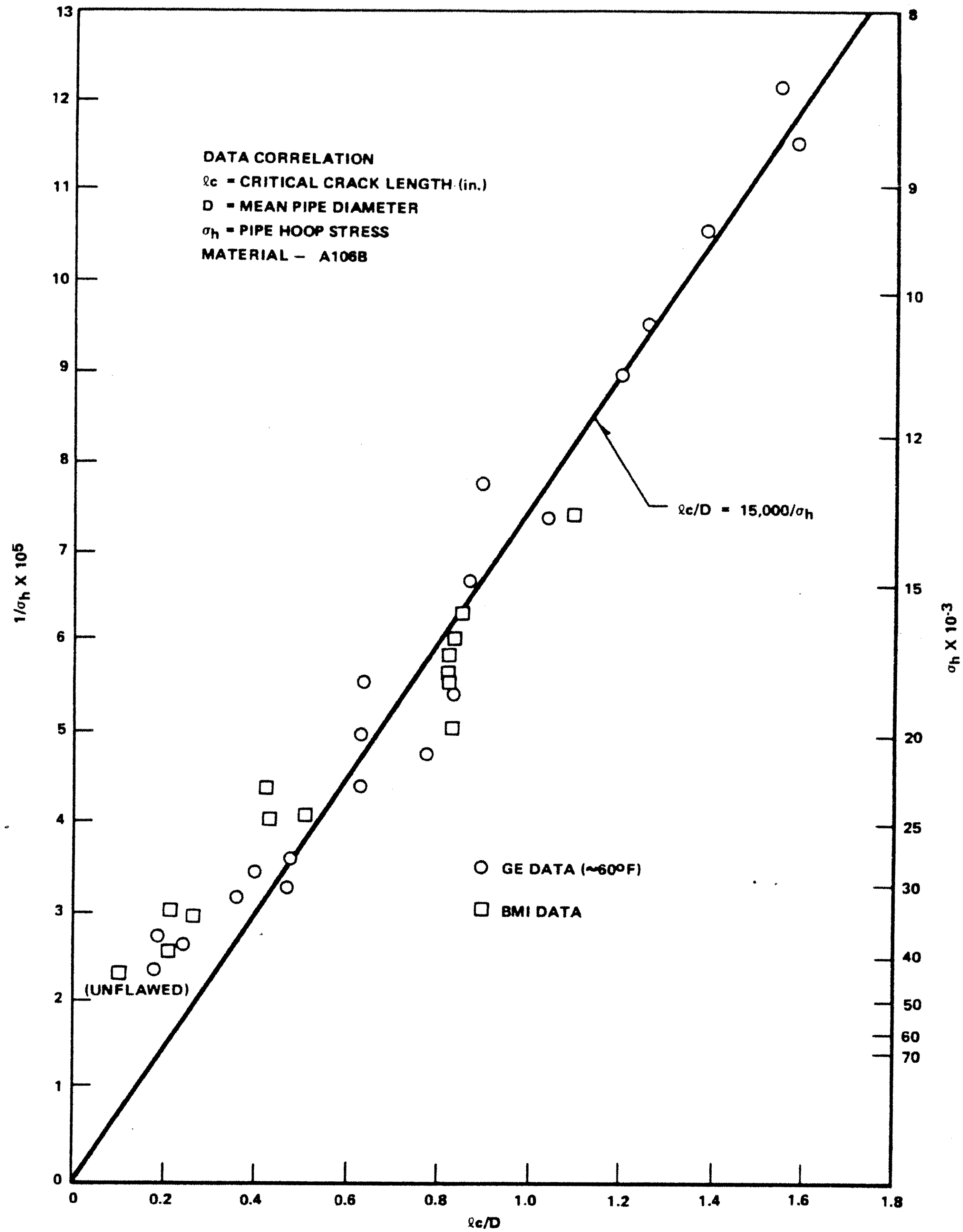

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FIGURE 5.2-12

AXIAL THROUGH-WALL CRACK

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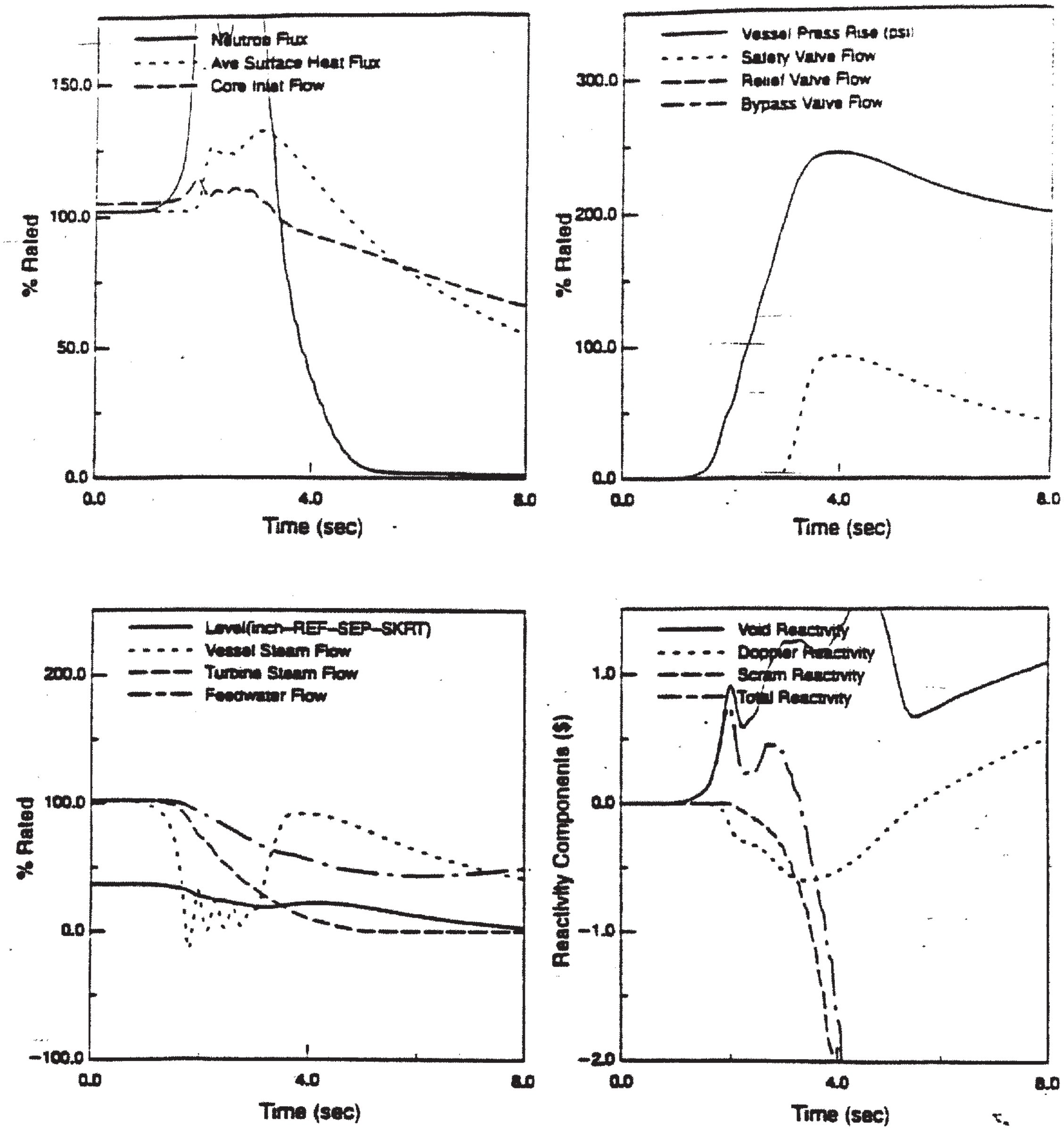

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FIGURE 5.2-13 TYPICAL GE MSIV CLOSURE, HIGH FLUX SCRAM

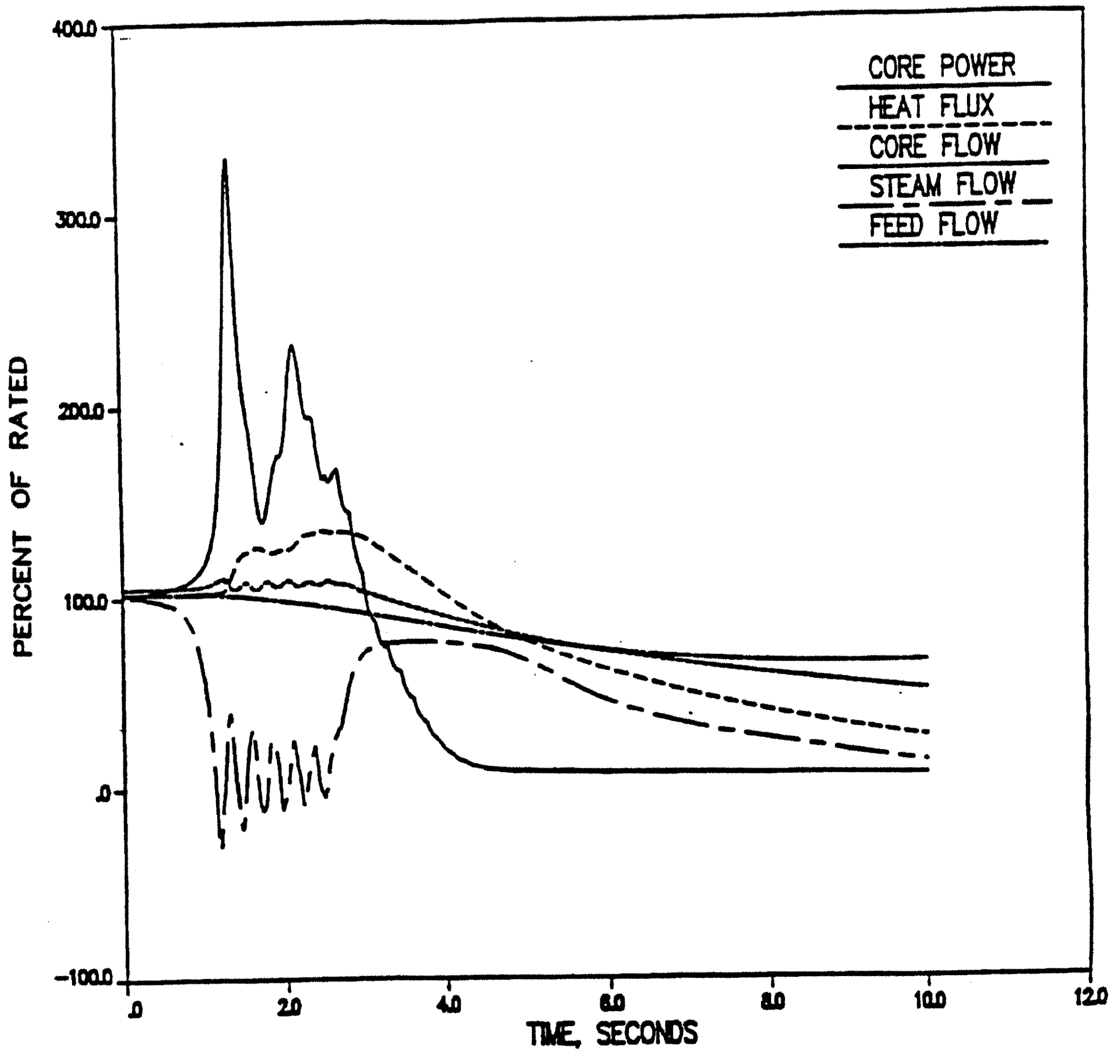

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FIGURE 5.2-14 SPC MSIV CLOSURE, HIGH FLUX SCRAM SYSTEM RESPONSE (TYPICAL)

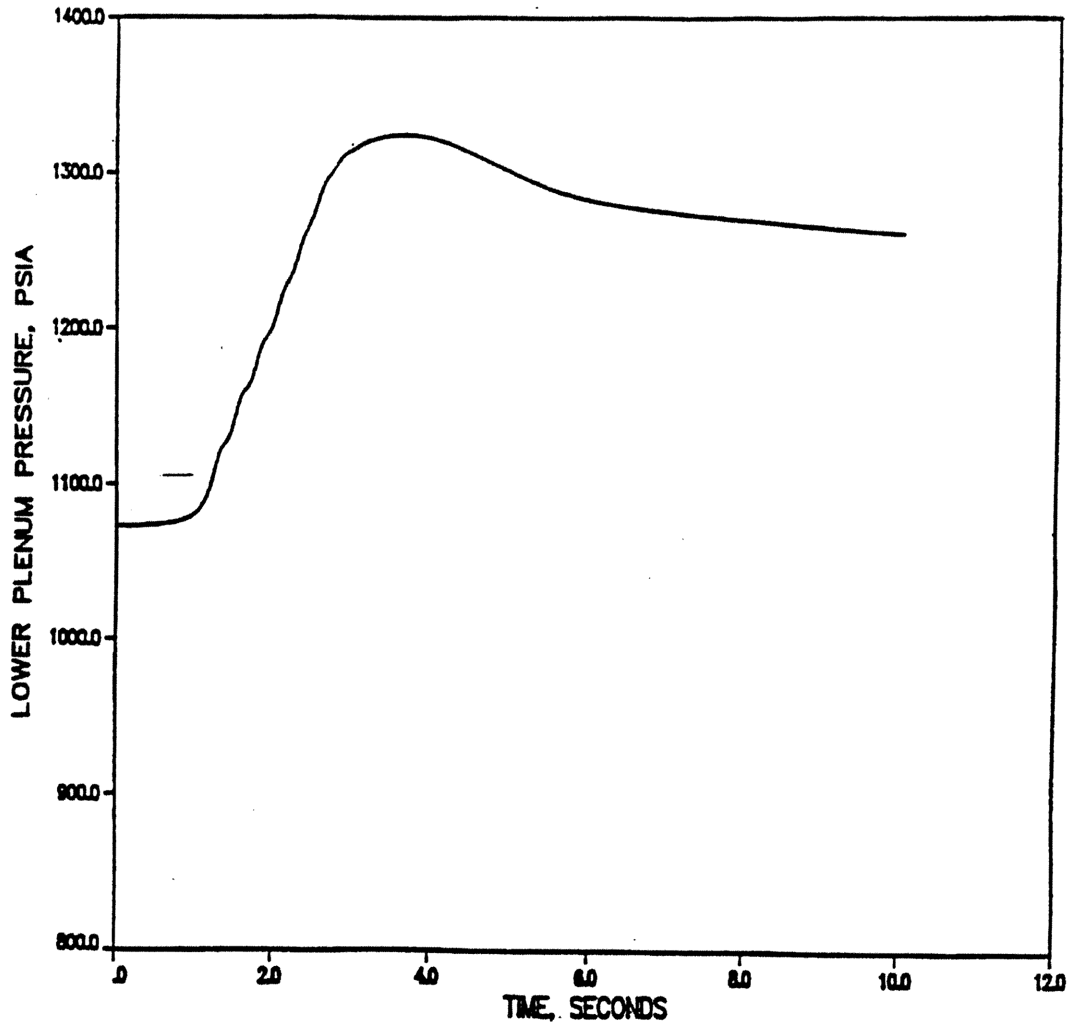

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FIGURE 5.2-15

SPC MSIV CLOSURE, HIGH FLUX SCRAM PRESSURE RESPONSE (TYPICAL)

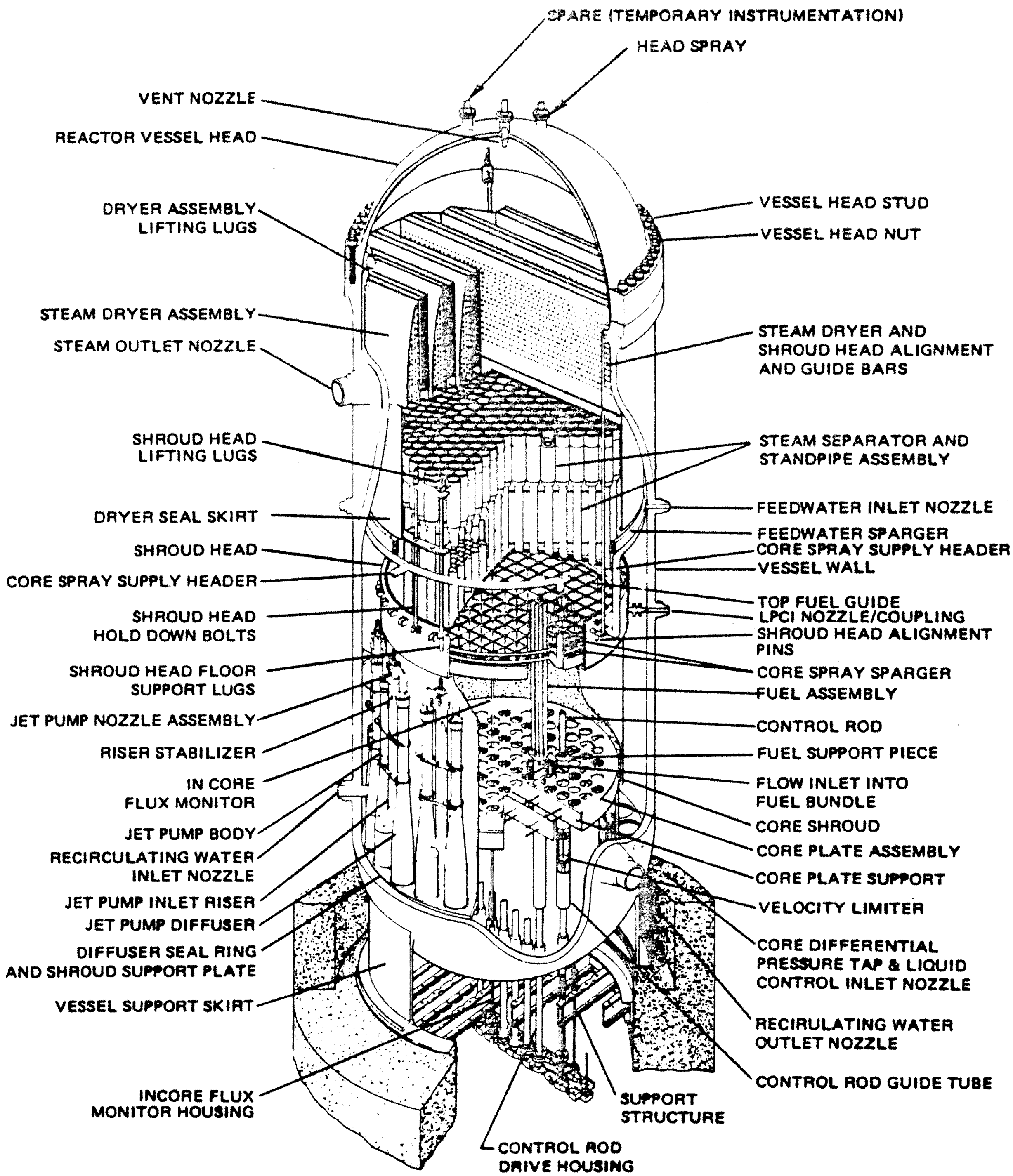

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FIGURE 5.3-1

REACTOR VESSEL CUTAWAY

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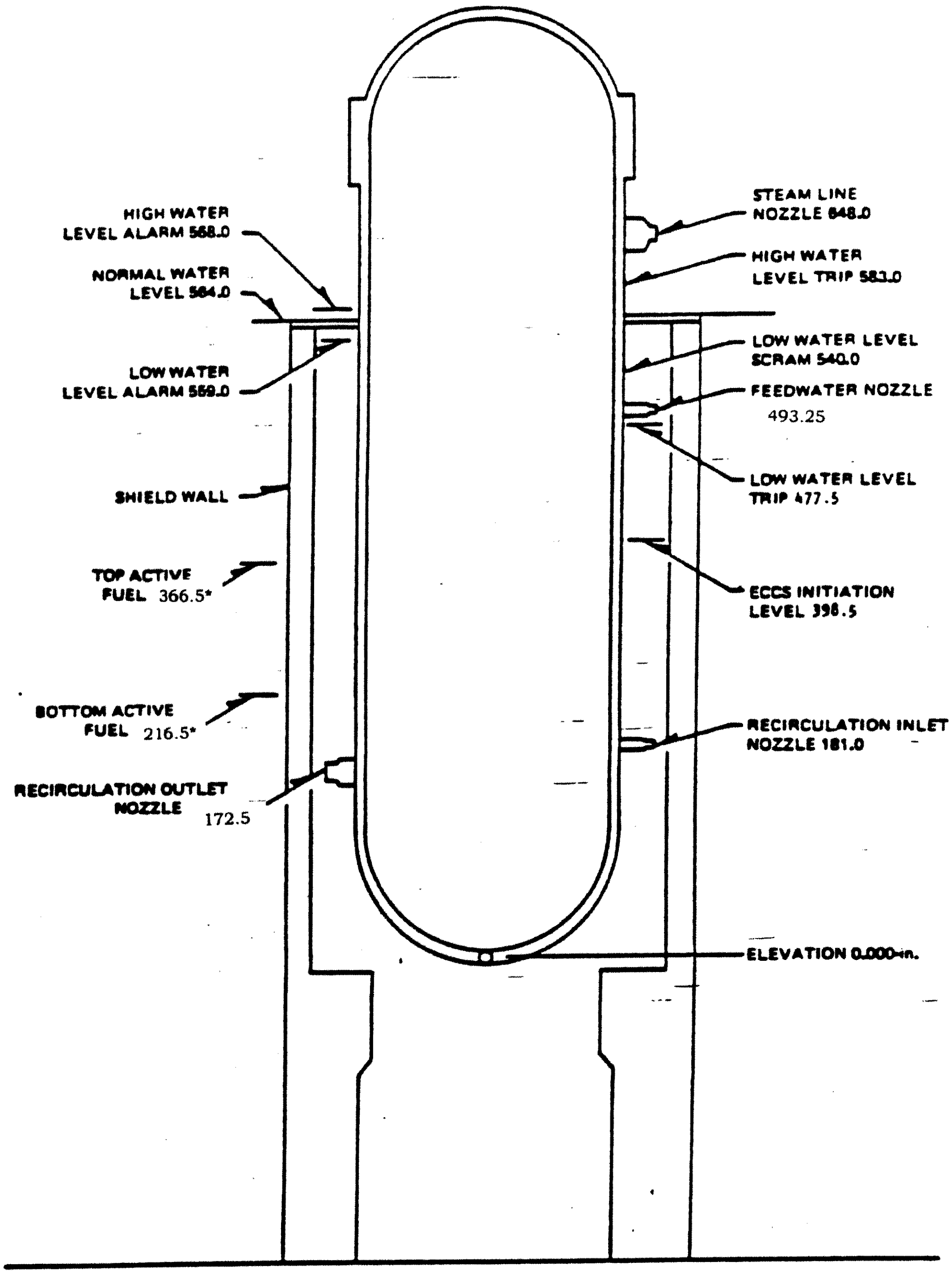

* 366.5 and 216.5 are instrumentation setpoints for TAF and BAF, respectively. The physical top of active fuel is ≤ 366.31" above vessel zero. The physical bottom of active fuel is 216.31" above vessel zero.

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FIGURE 5.3-2

REACTOR VESSEL NOMINAL WATER LEVEL TRIP AND ALARM ELEVATIONS

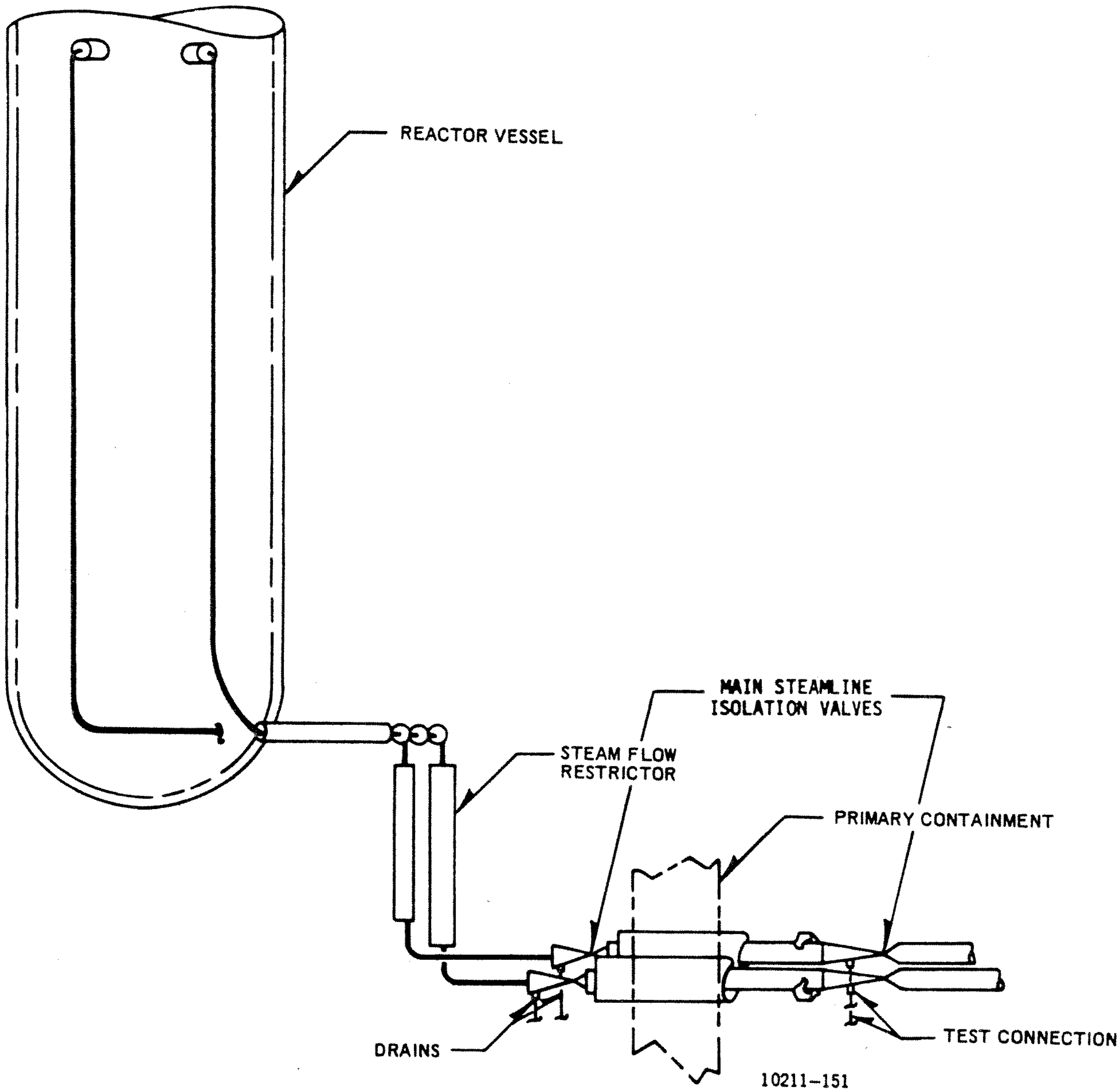

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FIGURE 5.4-1

MAIN STEAMLINE FLOW RESTRICTOR LOCATION

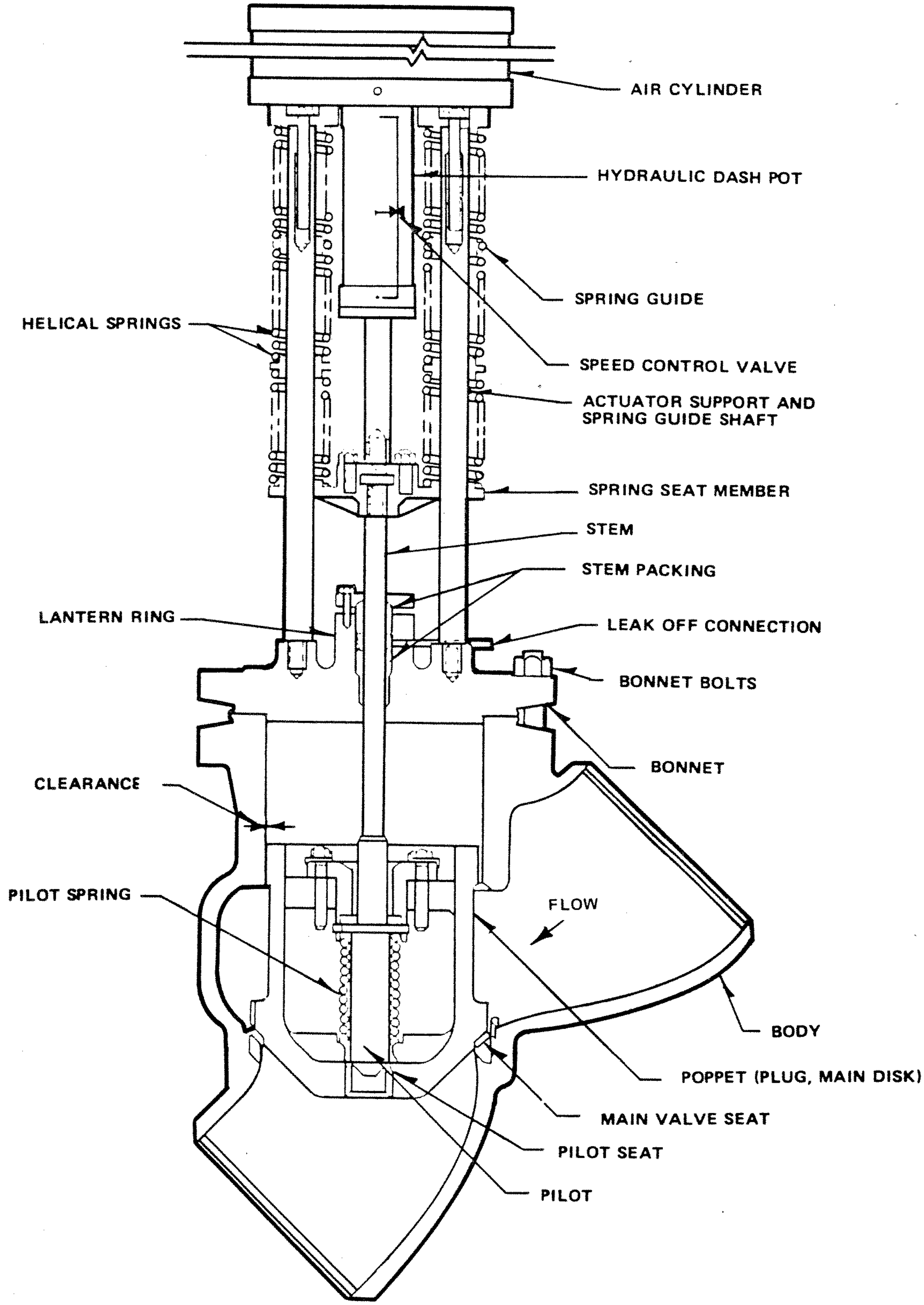

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FIGURE 5.4-2

MAIN STEAMLINE ISOLATION VALVE

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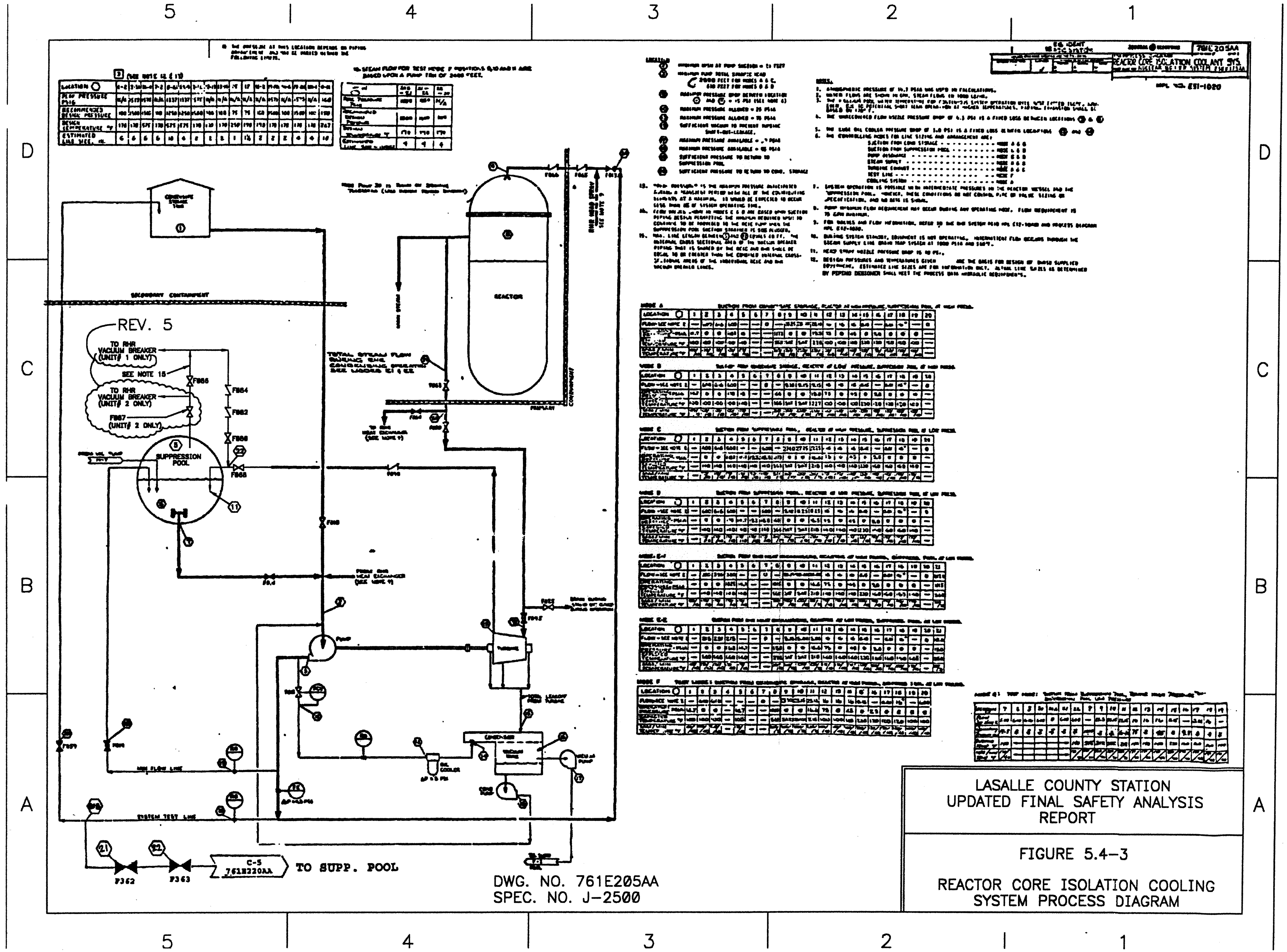

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FIGURE 5.4-3

REACTOR CORE ISOLATION COOLING SYSTEM PROCESS DIAGRAM

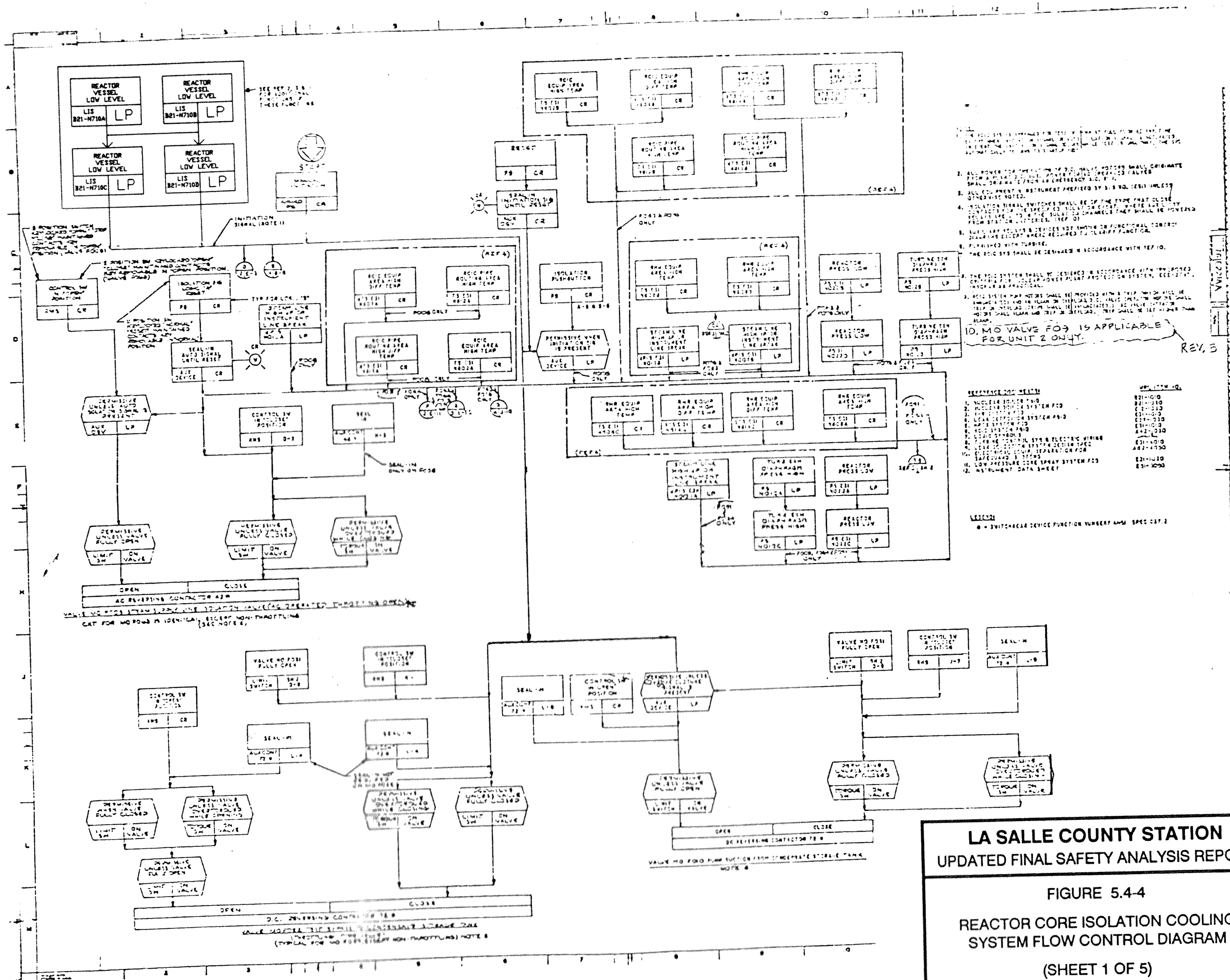

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FIGURE 5.4-4

REACTOR CORE ISOLATION COOLING SYSTEM FLOW CONTROL DIAGRAM

(SHEET 1 OF 5)

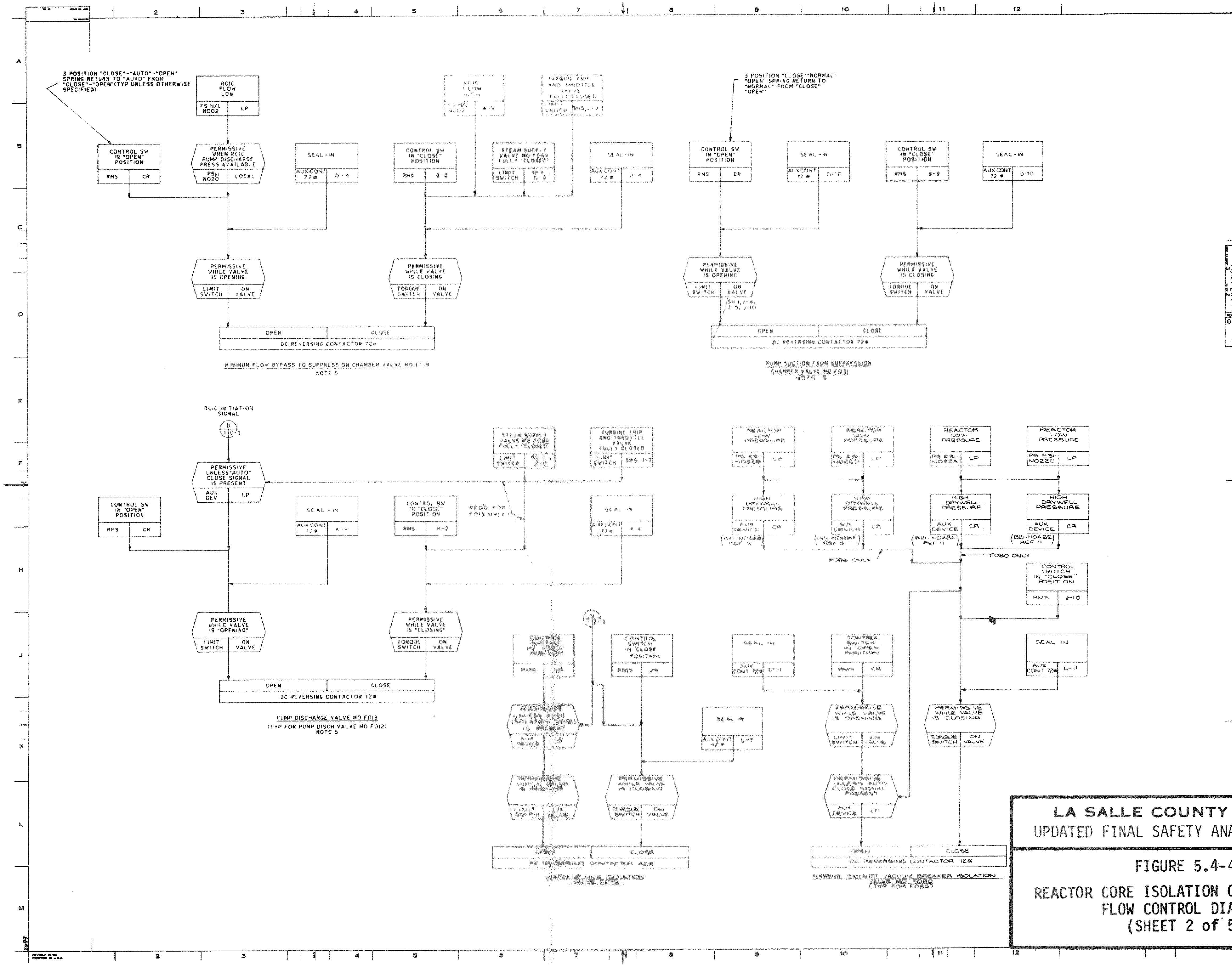

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FIGURE 5.4-4

REACTOR CORE ISOLATION COOLING SYSTEM FLOW CONTROL DIAGRAM (SHEET 2 of 5)

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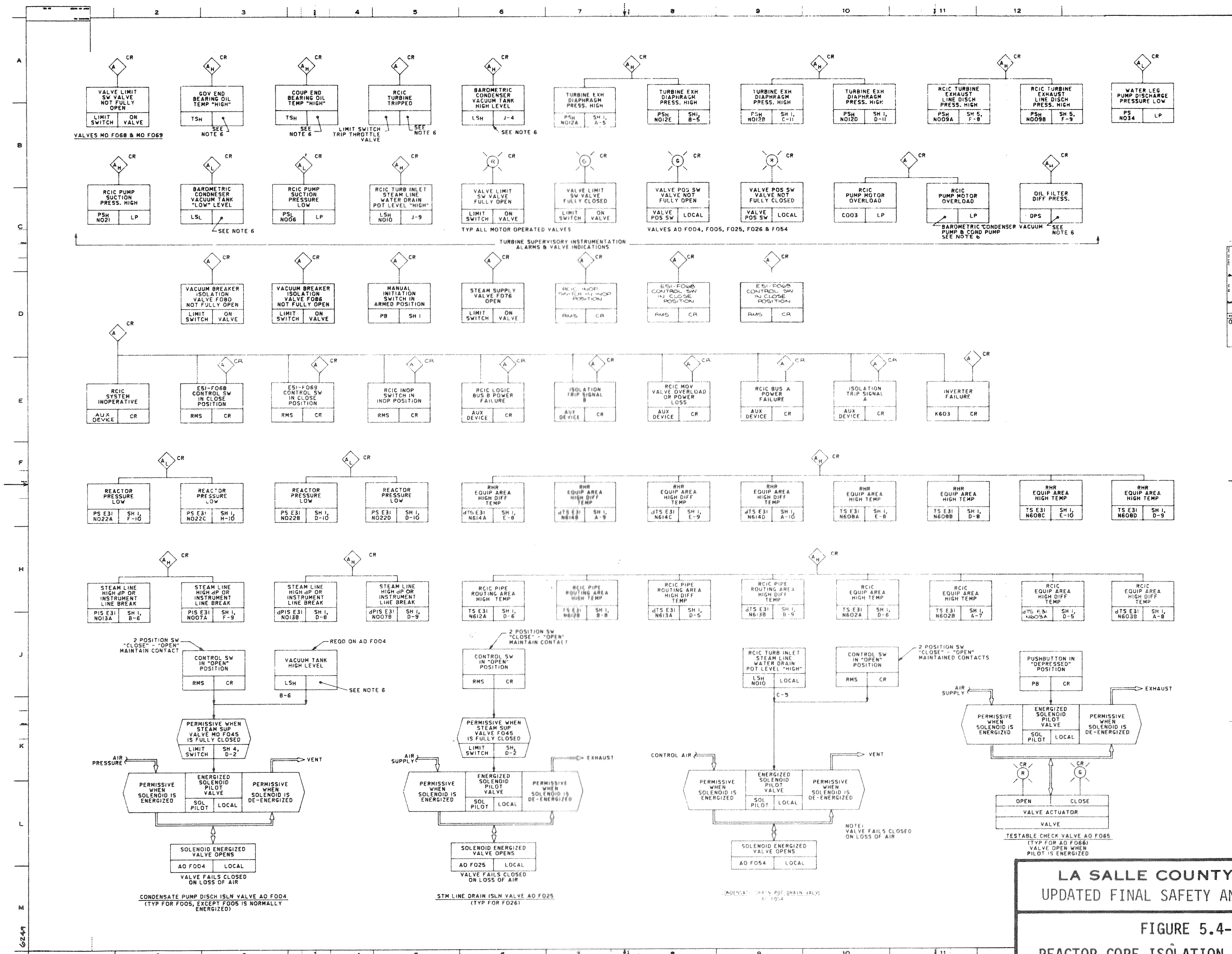

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FIGURE 5.4-4

REACTOR CORE ISOLATION COOLING SYSTEM FLOW CONTROL DIAGRAM

(SHEET 3 of 5)

REV. 0 - APRIL 1984

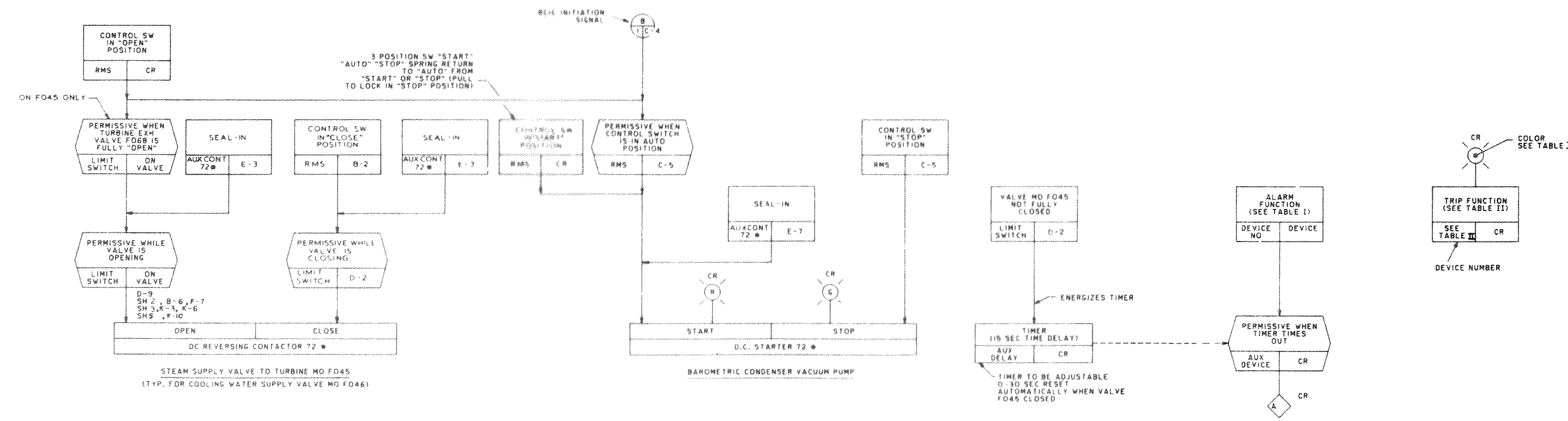

TABLE I

TURBINE CONTROL SUPERVISORY ALARMS

ALARM FUNCTION	INITIATING DEVICE NO.	DEVICE LOCATION	TYPE OF ALARM
TURBINE BRG. OIL PRESSURE LOW	PS	SEE NOTE 6	LOW
VACUUM TANK PRESS. HIGH	PSH	SEE NOTE 6	HIGH
RCIC FLOW LOW	FSL N002	LP	LOW

TABLE II

TURBINE INDICATING LIGHTS

ACTUATING DEVICE	TRIP FUNCTION	COLOR
REF 8	TRIP THROTTLE VALVE OPEN TRIP THROTTLE VALVE CLOSED GOVERNOR VALVE OPEN GOVERNOR VALVE CLOSED	RED GREEN RED GREEN

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FIGURE 5.4-4

REACTOR CORE ISOLATION COOLING SYSTEM
FLOW CONTROL DIAGRAM

(SHEET 4 of 5)

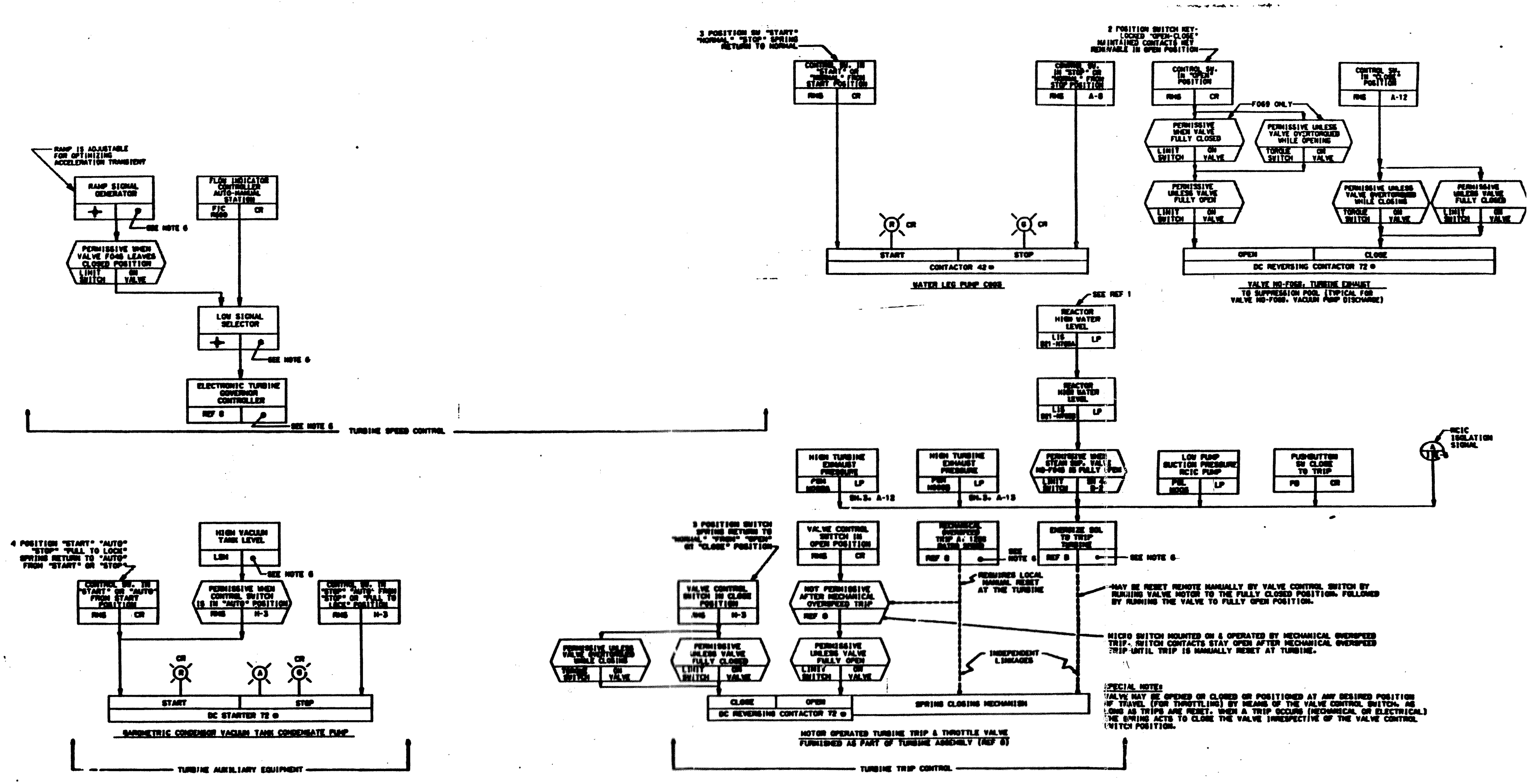

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FIGURE 5.4-4

REACTOR CORE ISOLATION COOLING SYSTEM FLOW CONTROL DIAGRAM

(SHEET 5 OF 5)

MODE F

POSITION ○	1	2	3	4	5	6	49	7	8	9	10	13	24	1
FLOW GPM	—	7450 *	←									→	7450	—
PRESS PSIA	14.7	X	X	X	X	X	X	X	X	X	X			14.7
TEMP °F	—	20/40	←									→	120/40	—
MAX PRESS DROP FEET					TDH=267									

LOOP A & B TEST
LOOP C TEST

Rx PRESS. 110 PSIG MODE G

POSITION ○	29	25	55	26	4	5	6	43 A,B	24 A,B	1		1	2	3	4	5	6	62	43 A,B	24 A,B	1
FLOW-GPM	—	550	←					→	550	—		—	550	←					→	550	—
PRESS PSIA	125	X	X	X	X			X		14.7		14.7	X	X	X	X				X	14.7
TEMP °F	—	344	←					→	344	—		—	125/40	←					→	125/40	—
MAX PRESS DROP FEET						TDH 625 FT SEE NOTE 22										TDH 625 FT SEE NOTE 22					

LOOP A & B
LOOP A
B&C LOOPS

MODE S

POSITION ○	1	2	3	4	5	6	18 A,B	19 A,B	20 A,B	9	10	[illegible]	11	48 A,B	21 A,B	50 A,B	27 A,B	51	33	52 A,B	53 A,B
FLOW GPM	N/A	←																		→	N/A
PRESS PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	1015	X	15.5	X	1015	X	1015	X	X
TEMP °F	90/40	←									→	90/40	547	90/40	135	90/40	547	90/40	547	90/90	90/90
MAX PRESS DROP FEET																					

MODE S (CONT'D)

POSITION ○	54	56	55 A,B		34	35	36 A,B	37 A,B	17 A,B		20 A,B	39 A,B	40 A,B	41	42
FLOW GPM	N/A	N/A	N/A		N/A	←		→	N/A		N/A	←		→	N/A
PRESS PSIA	X	X	X		X	X	X	X	X		X	X	X	X	X
TEMP °F	AMB	AMB	AMB		AMB	AMB	AMB	90/40	90/40		90/40	90/40	AMB	AMB	AMB
MAX PRESS DROP FEET															

MODE E

RX PRESS 0 PSIG

POSITION ○	29	25	26	561	4	5	6	18 A,B	19 A,B	9	10	16 A,B	11	27 A,B	28 A,B	29		60 A,B	61 A,B
FLOW-GPM	—	[illegible]	14,500	7450	←									→	7450	—		7400	7400
PRESS PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X			X	14.7		X	X
TEMP °F	—	120/AMB	←				→	120/AMB	188.8	← LOOPS A & B ONLY				→	188.8	—		90	181.3
MAX PRESS DROP FEET						TDH=267		ΔH=23.3							ΔH=18			ΔH=23.1	

DUTY PER HX 41.8×10^6 BTU/HR (2HX'S OPERATING)
LOOP A
LOOP A&B TEST
LOOP C TEST

(SEE NOTE 14) MODE A-1

POSITION ○	1	2	3	4	5	6	7	8	9	10	16	11	29
FLOW-GPM	—	7450 *	←								→	7450	—
PRESS PSIA	59.7/14.7	X	X	X	X								85.7/40.7
TEMP °F	—	170/40	←								→	170/40	—
MAX PRESS DROP FEET					TDH=267				ΔH=17			ΔH=40	

LOOP A & B
LOOP C

(SEE NOTE 14) MODE A-2

POSITION ○	1	2	3	4	5	6	7	8	9	10	16	11	29
FLOW-GPM	—	8400	←								→	8400	—
PRESS PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	14.7
TEMP °F	—	80/90	←								→	80/90	—
MAX PRESS DROP FEET					TDH=235								

LOOP A & B
LOOP C

MODE B

POSITION ○	1	2B	3B	4B	5B	6B	7B	17B	18B	19B	20B	8B	9B	10B	13B	14	15B	21B	22	23B	1		60B	61B
FLOW-GPM	—	8400	←													→	8400	7950	—	450	—		7400	7400
PRESS PSIA	59.7/14.7					X	X	X	X	X	X	X	X	X	X	X			59.7/14.7		59.7/14.7		X	X
TEMP °F	—	212	←					→	212	178.4	←						→	178.4	—	178.4	—		100	142
MAX PRESS DROP FEET					TDH=235																			

HEAT REMOVAL PER HX 155×10^6 SEE NOTE 16 (1 HX OPERATING) (SEE NOTE 21)
INDICATES FLOW PASSING THRU ABOVE POSITIONS (TYP)
SEE NOTE 7 (TYP)

MODE D

SEE NOTE 23
RX PRESS 110 PSIG

POSITION ○	29	25	26	5A	6A	7A	18A	19A	8A	9A	10A	14	30	31	66	33	29	47A	16A	27A	28	29	60 A,B	61 A,B
FLOW-GPM	—	7450	7450	7450	7450	7450	≤7400	≤7400	7450	←	→	7450	870/0	870/0	870/0	870/0	—	7450/8580	7450/8580	7450/8580	7450/8580	—	7400	7400
PRESS PSIA	125			X	X	X	X	X	X	X	X	X					125	X	X	X	X	125	X	X
TEMP °F	—	344	←		→		344	252.5 ←							252.5	REF 3	—	252.5	252.5	252.5	252.5	—	90	182.1
MAX PRESS DROP FEET				TDH 267									ΔH=17			ΔH=[illegible]								

HEAT REMOVAL PER HX 35.2×10^6 BTU/HR (1HX OPERATING) (SEE NOTE 21)
HEAD SPRAY
SEE REF 3
VESSEL COOLANT
HEAD SPRAY & VESSEL COOLANT

MPL NO. E12-1020

MODES:
A-1. ACCIDENT WITH RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMP OPERATION. ONE STRAINER 50% PLUGGED.
A-2. ACCIDENT WITH RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMP OPERATION. (10 MIN.)
B. POST ACCIDENT CONTAINMENT SPRAY WITH HEAT REJECTION WITH ONE PUMP OPERATION AND STRAINER 50% PLUGGED. (PEAK SUPPRESSION POOL TEMPERATURE.)
D. NORMAL SHUTDOWN AFTER FLOWDOWN TO MAIN CONDENSER.
E. CONTINUATION OF NORMAL SHUTDOWN FROM PLANT MODE "D" (AT 0 PSIG) AND FUNCTIONAL PUMP TEST AFTER SHUTDOWN.
F. RHR SYSTEM TEST DURING PLANT OPERATION.
G. MINIMUM FLOW BYPASS MODE.
S. SYSTEM ON STANDBY DUTY.

LEGEND
RX PRESS ---- REACTOR VESSEL PRESSURE
TDH ---------- TOTAL DYNAMIC HEAD
SOH ---------- SHUTOFF HEAD
ΔH ----------- HEAD LOSS
ΔP ----------- PRESSURE LOSS
SUPPLEMENTAL DOCUMENTS UNDER THE FOLLOWING IDENTITIES ARE TO BE USED IN CONJUCTION WITH THIS DRAWING.

REFERENCE DESIGNATOR
1. RESIDUAL HEAT REMOVAL P&ID ------ E12-1010
2. RESIDUAL HEAT REMOVAL DESIGN SPEC. - E12-4010
3. RCIC P&ID ------------ E51-1020
4. RECIRC. SYSTEM FLOW ---------- B33-1040
5. LOW PRESSURE CORE SPRAY PFD ----- E21-1020

NOTES:
1. DELETED.
2. PIPING BETWEEN POINTS WITH EMPTY DATA BLANKS (SEE ALSO TABLE 3) SHALL BE SIZED BY OTHERS BASED ON SPECIFIED OPERATING CONDITIONS. EMPTY DATA BLANKS CAN BE FILLED IN BASED ON ACTUAL ARRANGEMENT BY OTHERS.
   ▭ — INDICATES THE DATA IS NOT SIGNIFICANT.
3. SHOWN AS TYPICAL FOR ONE LOOP. IF LOOP ON SIDE I AND SIDE II ARE NOT SYMETRICALLY ARRANGED, VALUES FOR BOTH SIDES SHALL BE SUBMITTED.
4. ΔH VALUES FOR EQUIPMENT WITHIN GE-BWRSD SCOPE ARE AS NOTED.
5. ELEVATIONS ARE NOT INCLUDED IN ΔP, VALUES GIVEN, ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.
6. ▭ INDICATES MAXIMUM (X) AND MINIMUM (Y) VALUES FOR THE MODE SPECIFIED.
7. DASHED LINES INDICATE FLOW DOES NOT PASS THRU THESE POINTS.
8. THE NPSH AVAILABLE IN MODES B & D AT CENTERLINE OF PUMP SUCTION NOZZLE MUST EQUAL OR EXCEED 15.7 FT.
9. FLOODING LINE SHALL BE SIZED TO FLOW 300 GPM. HEAD MUST BE SUFFICIENT TO FLOOD THE PRIMARY CONTAINMENT.
10. THIS PORTION OF PIPING TO BE SIZED BASED ON FLOW SHOWN ON FUEL POOL COOLING AND FILTERING SYSTEM.
11. TABLE I INDICATES VALVE POSITIONS DURING VARIOUS MODES OPERATION.
12. DELETED.
13. DELETED.
14. TYPICAL VALUES FOR MAX. AND MIN. SUPPRESSION POOL TEMP. SHOWN. FINAL TEMPERATURES DEPEND ON INITIAL POOL WATER TEMPERATURE & POOL WATER VOLUME.
15. WATER FLOWS ARE IN GPM, STEAM FLOWS ARE IN 1000 LBS/HR.
16. HEAT EXCHANGER HEAT REMOVAL AND SPRAY BASED UPON 7450 GPM SHELL SIDE FLOW.
17. FOR LINE SIZING INFORMATION SEE REF. 5.
18. THE WEIGHT OF WATER IN THE SHUTDOWN COOLING SUBSYSTEM PIPING, INCLUDING THE HEAT EXCHANGRES AND PUMPS SHALL NOT EXCEED 225,000 LBS. AT 70°F TO PREVENT DILUTION OF STANDBY LIQUID CONTROL NEUTRON ABSORBER BELOW MINIMUM REQUIREMENTS.
19. DELETED.
20. PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIGN PRESSURE & TEMPERATURE AND LINE SIZES AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DATA HYDRAULIC REQUIREMENT.
21. Hx HEAT REMOVAL SHOWN FOR FULL FLOW AND MAXIMUM TEMPERATURE DIFFERENCE UNDER NORMAL OPERATING CONDITIONS THE TUBE SIDE OUTLET TEMPERATURE SHOULD NOT EXCEED 125F.
22. SOH = 790 FT. MAX.
23. ONLY ONE LOOP IS REQUIRED AT THIS STAGE OF SHUTDOWN. THA A LOOP IS SHOWN AS TYPICAL OF EITHER A OR B EXCEPT FOR THE HEAD SPRAY.
24. THE Hx INLET PRESSURE SHALL BE GREATER THAN 60 PSIA TO MINIMIZE THE POSSIBILITY OF FLOW INDUCED VIBRATION.

* AS DISCUSSED IN SECTION 6.2.2.3.4, THE EFFECT OF AN RHR PUMP FLOW OF 7200 GPM HAS BEEN SUCCESSFULLY EVALUATED FOR ITS EFFECT ON PEAK SUPPRESSION POOL TEMPERATURE. THE CURRENT ANALYSES PEAK POOL TEMPERATURE WAS NOT EXCEEDED.

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FIGURE 5.4-5

RESIDUAL HEAT REMOVAL SYSTEM
PROCESS DIAGRAM
(SHEET 1 OF 3)

REV. 13

SEE NOTE 20

POSITION ○	3.1	3.2	4	5	6	7	8	9	10	47	16	46	11
DESIGN PRESS. IN PSIG	125	220	220	RHR PUMP	500	500	500	500	500	500	500	1250	1250
DESIGN TEMP IN °F	212	358	358	RHR PUMP	358	358	358	358	358	358	480	575	575
ESTIMATED LINE SIZE	24"	24"	24"	RHR PUMP	18"	18"	18"	18"	18"	18"	12"	12"	12"
	LPCI LINE (VIA RHR Hx BYPASS)												

POSITION ○	7	7.1	18		19	20	8
DESIGN PRESS. IN PSIG	500	500	500	RHR Hx	500	500	500
DESIGN TEMP IN °F	358	358	358	RHR Hx	358	358	358
ESTIMATED LINE SIZE	18"	18"	18"	RHR Hx	18"	18"	18"
	Hx LINE						

POSITION ○	3.1	4 C	5 C		6	9	10	16	46	11
DESIGN PRESS. IN PSIG	220	220	220	RHR Hx	500	500	500	580	1250	1250
DESIGN TEMP IN °F	212	212	212	RHR Hx	212	212	212	480	575	575
ESTIMATED LINE SIZE	24"	24"	24"	RHR Hx	18"	18"	18"	18"	12"	12"
	LPCI LINE (DIRECT TO REACTOR)									

POSITION ○	25	54.1	26	4 A,B	5 A,B
DESIGN PRESS. IN PSIG	SEE REF 4 M5/12	220	220	220	220
DESIGN TEMP IN °F	SEE REF 4 M5/12	358	358	358	358
ESTIMATED LINE SIZE	20"	20"	18"	24"	24"
	SHUTDOWN SUCTION				

POSITION ○	16	50	27
DESIGN PRESS. IN PSIG	500	500	SEE REF 4 M511-16
DESIGN TEMP IN °F	480	480	SEE REF 4 M511-16
ESTIMATED LINE SIZE	12"	12"	12"
	SHUTDOWN RETURN LINE		

POSITION ○	56	56.1	4	49	49.1	45	6C	6.1C	6.2	43	6 A,B	6.1 A,B	43
DESIGN PRESS. IN PSIG	125	125	125	500	125	125	500	125	125	125	500	125	125
DESIGN TEMP IN °F	212	212	212	212	212	212	212	212	212	212		212	212
ESTIMATED LINE SIZE	18"	18"	18"	18"	18"	18"	3"	3"	3"	3"	3"	3"	3"
	SYSTEM TEST LINES (LOOP C)						MIN FLOW BYPASS LINES (LOOP C)				MIN FLOW BYPASS (LOOP A,B)		

TABLE I - VALVE POSITION CHART

SEE NOTE 11

LOOP A & B / F004 C		STRAINER AB	STRAINER C
MODE A-1	O O O O O	1-50% P	
MODE A-2	O O O O O	1-50% P	
MODE B	O O O O O O O	[illegible]	---
MODE D	O O O T O T O O O O		
MODE E	O O O O O O O O O		
MODE F	O O O O O	CLEAR	CLEAR
MODE G	[illegible]	CLEAR	CLEAR
MODE S	O O O O O O	CLEAR	CLEAR

O - VALVE OPEN
T - VALVE THROTTLED
P - STRAINER PLUGGED
T-C - VALVE THROTTLED OR CLOSED
O-T - VALVE OPEN OR THROTTLED
BLANK SPACE INDICATES VALVE IS CLOSED

TABLE 3 LIMITING LINE LOSSES (NUMBERS REFER TO POSITION ○)

MODE A-1	6-11 PUMP DISCHARGE LINE TO RPV FLOODING PENETRATION
MODE A-2	NONE
MODE B	1-2-5 (SUCTION LINE SUPPRESSION POOL TO PUMP), 47-21 & 15-23 (CONTAINMENT SPRAY LINES PUMP DISCHARGE TO TO SPRAY HEADERS)
MODE D	16-51-53-29 (VESSEL HEAD SPRAY LINE) SEE NOTE 10 29-25-5 (SHUTDOWN SUCTION LINE RPV TO PUMP) 56-4 (SHUTDOWN SUCTION LINE TEST BRANCH TO PUMP)
MODE E	16-27 (SHUTDOWN DISCHARGE LINE LPCI BRANCH TO RECIRC LOOP)
MODE F	13-43-24-14 49-45 (TEST LINE TO SUPPRESSION POOL)
MODE G	6-43 (PUMP MINIMUM BYPASS LINE)

1E-1-4 73E-966AA

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FIGURE 5.4-5

RESIDUAL HEAT REMOVAL SYSTEM PROCESS DIAGRAM

(SHEET 2 of 3)

REV. 9 - APRIL 1993

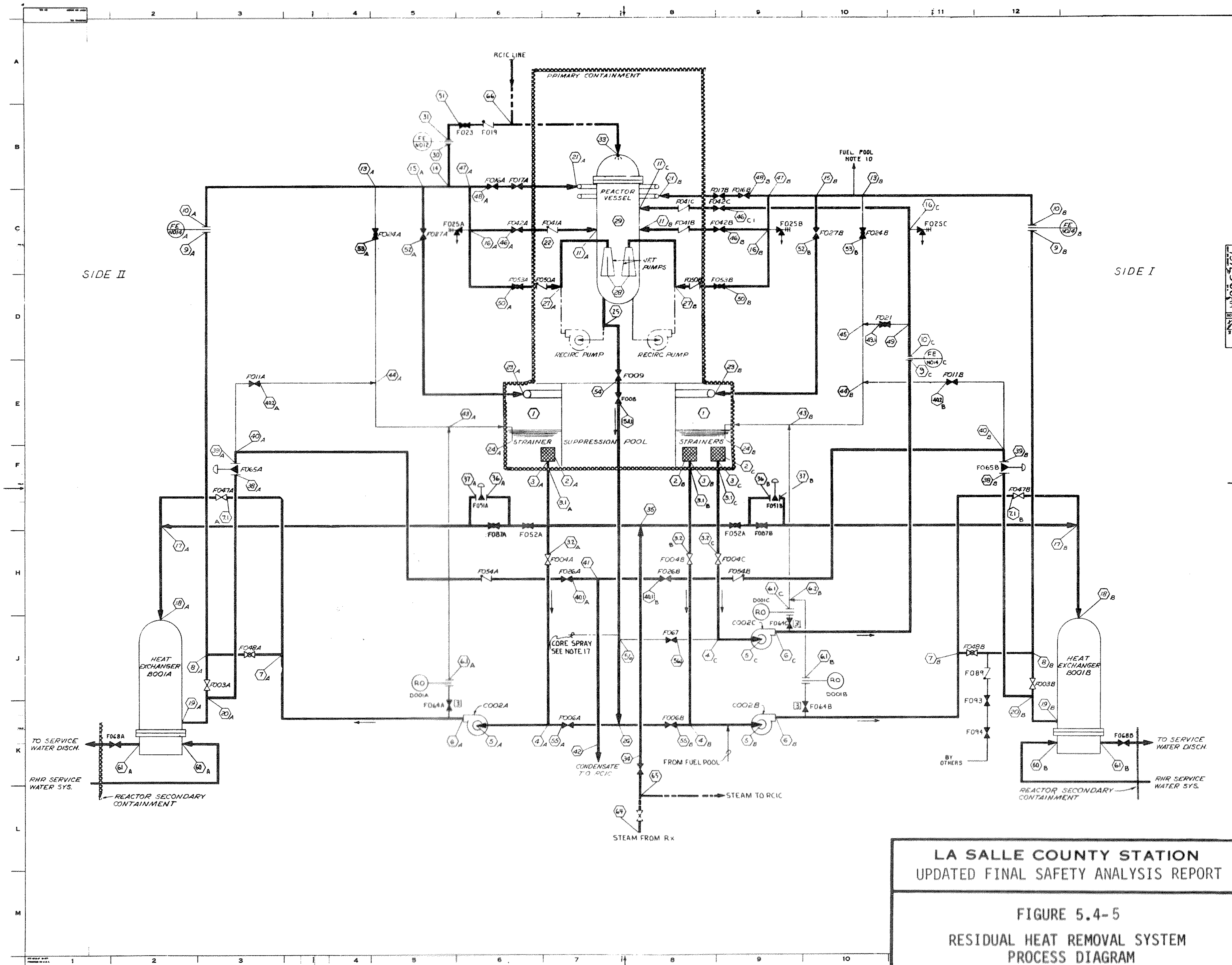

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FIGURE 5.4-5

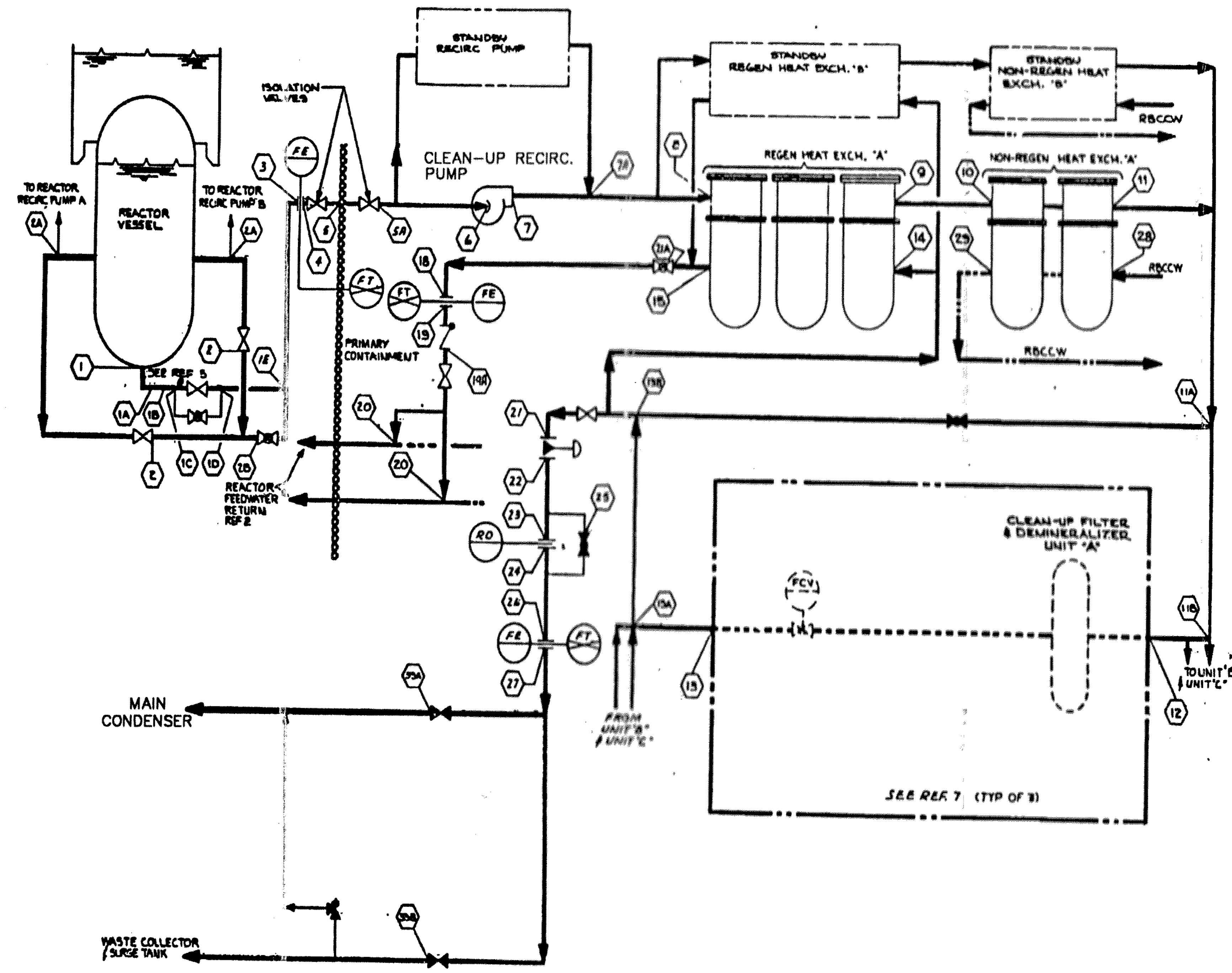
RESIDUAL HEAT REMOVAL SYSTEM
PROCESS DIAGRAM
(SHEET 3 of 3)

REV. 0 - APRIL 1984

GENERAL ELECTRIC 922D263

PROCESS DIAGRAM
REACTOR WATER CLEAN-UP SYSTEM
(BLACK START)

G33-1030



NOTES:

1. POSITION 28 & 29 INDICATE CLEAN-UP CONDITIONS WITH VARIOUS RBCCW INLET TEMPERATURES.
2. VALVES ARE SHOWN IN THEIR NORMAL OPERATING POSITIONS.
3. THE MAXIMUM ALLOWABLE PIPE FRICTION DROP FOR THE SIZING OF THE CLEAN-UP RECIRCULATION PUMPS SUCTION PIPING FROM POSITIONS 1-4 SHALL BE CONTROLLED BY MODE "B" AND THE NPSH SHALL NOT BE BELOW THE MINIMUM AS SHOWN IN THE REFERENCE DOCUMENTS. MODE "A" SHALL CONTROL THE SIZING OF THE DISCHARGE PIPING AND THE MAXIMUM ALLOWABLE PIPE FRICTION DROP AS SHOWN SHOULD NOT BE EXCEEDED.
4. FOR DATA PERTAINING TO NUMBERS WITHIN HEXAGONS, REFER TO PROCESS DATA REF. 1.
5. MODE "A" DESIGN BASIS FOR HEAT EXCHANGERS AND NO FLOW IS REQUIRED AT POSITION 21, 22-27, 33A & 33B.
6. MODE "B" DESIGN BASIS FOR MAIN CLEAN-UP PUMP (MAX. CAPACITY AND MIN. NPSH) AND SIZING OF MAIN PUMPS SUCTION PIPING. NO FLOW REQD. IN MODE "B" POSITION 11B-13A, 21, 22-27, 33A & 33B.

REFERENCE DOCUMENTS:

1. REACTOR WATER CLEAN-UP SYSTEMS PROCESS DATA------G33-1030
2. REACTOR WATER CLEAN-UP SYS P&ID------------------G33-1010
3. REACTOR WATER CLEAN-UP SYSTEMS DESIGN SPEC.------G33-4010
4. REACTOR SYSTEM OUTLINE DWG.---------------------A62-2050
5. REACTOR VESSEL OUTLINE DWG.---------------------B13-D003
6. FILTER/DEMIN SYS PD-------G33-1030
7. FILTER/DEMIN SUB SYS DEVICE LIST ITEM 200------G33-2001

REVIEWED FOR
LA SALLE COUNTY STATION
UNITS 1 & 2
COMMONWEALTH EDISON CO.
SARGENT & LUNDY
ENGINEERS

SPEC J-2500
DWG# 922D263

LASALLE COUNTY STATION
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FIGURE 5.4-6

REACTOR WATER CLEANUP SYSTEM PROCESS DIAGRAM (SHEET 1 OF 2)

REVISION 13

GENERAL ELECTRIC

922D263AA

TITLE PROCESS DATA
REACTOR WATER CLEAN-UP SYSTEM

MPL NO. G33-1030

MODE A NORMAL OPERATION

R.S.S. 1020. PSIA

(SEE NOTES 1, 3, AND 5 OF PROCESS DIAGRAM)

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	28	29	28	29	28	29	28	29
FLOW, GPM	63	145	352	352	352	352	352	352	280	280	269	124	134	269	318	/	/	318	318	159	/	/	/	/	/	/	/	468	475	516	524	610	678	678	686	785	762
TEMP. °F.	533	533	533	533	533	533	534	534	233	233	120	120	120	120	437	/	/	437	437	437	/	/	/	/	/	/	/	85	150	95	184	100	150	105	150	110	0
MAXIMUM PRESSURE DROP PSID			4			165 TDH		10		10		59		10				4										10									

ALLOWABLE PIPE FRICTION DROPS (SEE NOTE 3 OF PROCESS DIAGRAM) 36.7

MODE B HOT SHUTDOWN OPERATION (WITH LOSS OF RPV RECIRC PUMPS)

R.S.S. 1003. PSIA

(SEE NOTES 1 AND 6 OF PROCESS DIAGRAM)

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
FLOW, GPM	85	136.5	358	358	358	358	358	/	/	/	/	/	/	/	/	358	358	358	358	179	/	/	/	/	/	/	/	/	/
TEMP. °F.	540	545	544	544	544	544	545	/	/	/	/	/	/	/	/	545	545	545	545	545	/	/	/	/	/	/	/	/	/
MAXIMUM PRESSURE DROP PSID			4			161 TDH												4											

ALLOWABLE PIPE FRICTION DROPS (SEE NOTE 3 OF PROCESS DIAGRAM) DELTA P

DESIGN PRESSURE AND TEMPERATURE GIVEN BELOW IS FOR INFORMATION ONLY AND IS THE BASIS FOR PIPING DESIGN. ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL LINE SIZES AS DETERMINED BY THE PIPING DESIGNER SHALL MEET THE PROCESS DATA HYDRAULIC REQUIREMENTS.

LOCATION ⬡	1—1A*	1A-1B**	1C-1D	1B-1E	2A-2B	2B-5A	5A-6	7-7A	7A-8	9-10	11-11B	11A-13B	11B-13A	13A-14	13A-33A	27-33B	15-21A	19A-20 (SEE NOTE F)
DESIGN PRESS. (PSIG)	1250	1250	1250	1250	1250	1250	1150	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	***
DESIGN TEMP. (DEG. F)	575	575	575	575	575	575	575	575	575	575	150	150	150	150	150	150	575	***
ESTIMATED LINE SIZE (IN.)	2	2.5	1	4	4	6	4	4	4	4	4	4	3	4	4	4	4	4

- ALL AUXILIARY PIPING IS DESIGNED TO 150 PSIG AND 150 DEG. F.

* LOCATION 1A IS THE POINT WHERE THE BOTTOM DRAIN LINE CONNECTION EXITS FROM C.R.D. HOUSING AREA.

** LOCATION 1B IS THE POINT WHERE THE BOTTOM DRAIN LINE CONNECTION EXITS FROM THE REACTOR VESSEL PEDESTAL.

***TO THE SAME CONDITIONS AS THE FEEDWATER PIPING (BY OTHERS)

NOTES:

A) PROCESS DIAGRAM 922D263 SHALL BE USED WITH & FORM A PART OF THIS PROCESS DATA. IF THERE ARE ANY CONFLICTS BETWEEN THE PROCESS DIAGRAM AND THIS PROCESS DATA, THE PROCESS DATA SHALL GOVERN.

B) / INDICATES CONDITIONS FOR 0 FLOW RATE.

C) THE MINIMUM REQUIRED NPSH OF THE CLEANUP RECIRC PUMPS IS 13 FEET OF WATER AT 544°F BASED ON CONDITION SHOWN IN MODE B.

D) SEE PARAGRAPH 4.2.3 OF 22A3015 FOR STARTUP PROCEDURE.

E) DURING HOT STANDBY, WITH ONE CLEANUP PUMP IN OPERATION, BLOWDOWN RATE IS APPROXIMATELY 126 GPM AT 545° F.

F) RELOCATION OF CHECK VALVE TO PROTECT FLOW ELEMENT. (F.W. PIPING DESIGNED BY OTHERS TO APPROXIMATELY 2350 PSIG).

DWG# 922D263AA
SPEC J-2500

LASALLE COUNTY STATION
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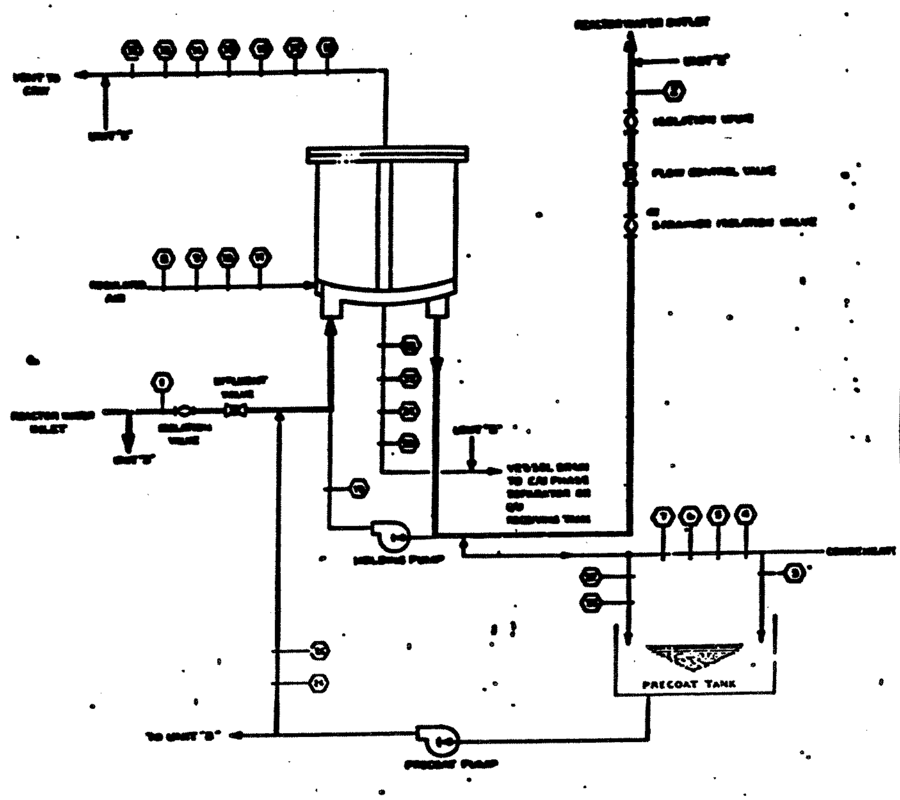
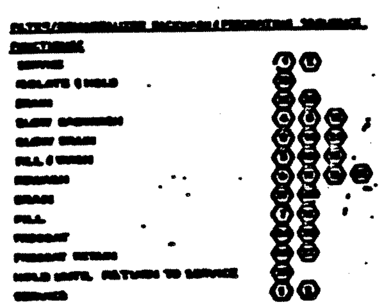
FIGURE 5.4-6

REACTOR WATER CLEANUP SYSTEM
PROCESS DIAGRAM (SHEET 2 OF 2)





LASALLE COUNTY STATION UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE 5.4-7
FILTER/DEMINERALIZATION SUBSYSTEM PROCESS DIAGRAM

NOTES:

1. FOR REACTOR WATER CLEANUP SYSTEM OPERATING PARAMETERS, SEE CURRENT STATION PROCEDURES.

2. SOURCE DOCUMENT: J-2500, 761E549.

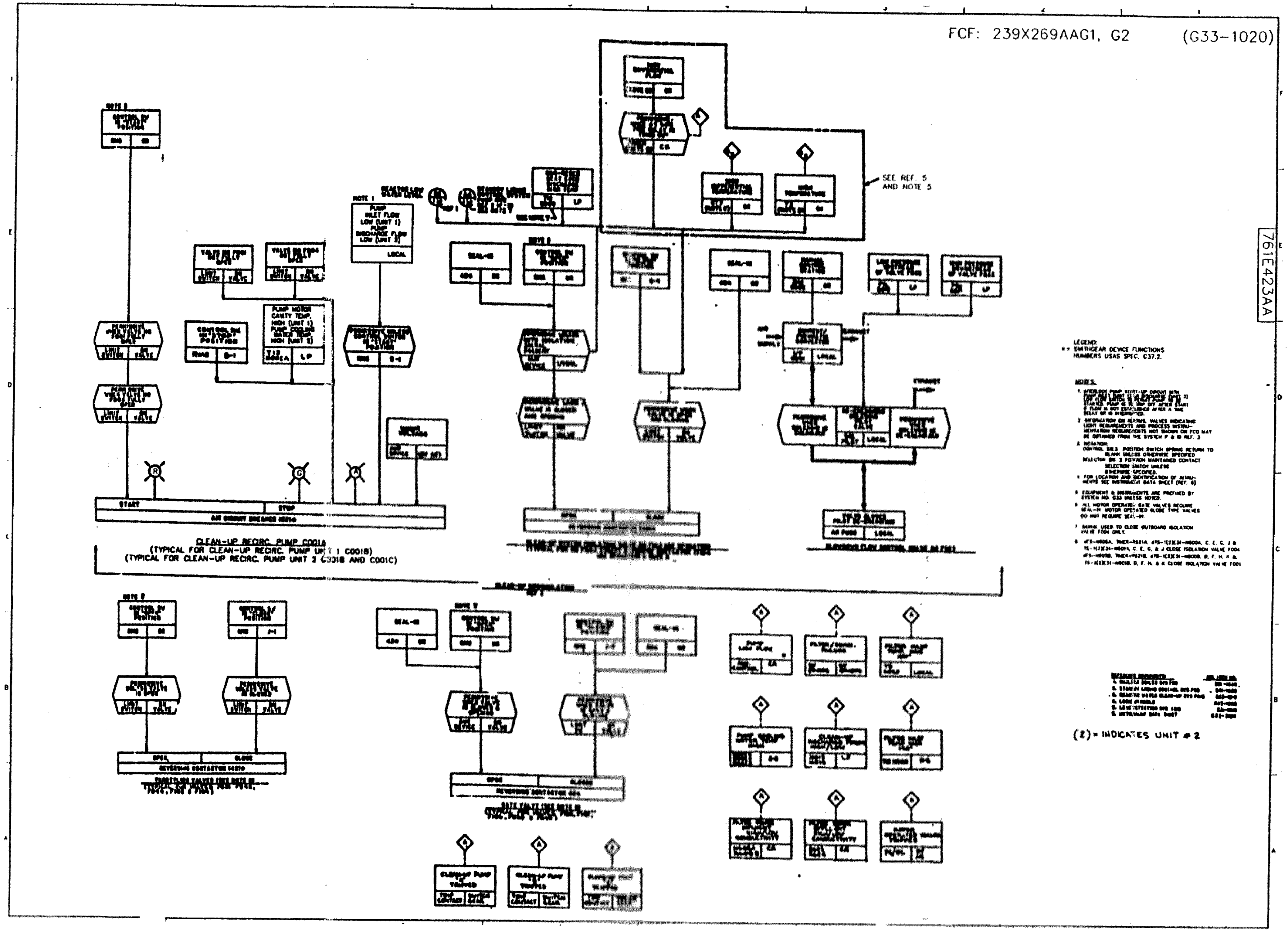


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FIGURE 5.4-8

REACTOR WATER CLEANUUP SYSTEM FLOW CONTROL DIAGRAM