6.2 CONTAINMENT SYSTEMS

6.2.1 PRIMARY CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Pressure Suppression Containment

6.2.1.1.1 Design Basis

The pressure suppression containment system is designed to have the following functional capabilities:

a. The containment has the capability to maintain its functional integrity during and following the peak transient pressures and temperatures which would occur following any postulated loss-of-coolant accident (LOCA). The LOCA scenario used for containment functional design includes the worst single failure (which leads to maximum coincident containment pressure and temperature), postulated to occur simultaneously with loss of offsite power and a safe shutdown earthquake (SSE). A detailed discussion of the LOCA events is contained in Subsection 6.2.1.1.3.3.

b. The containment, in combination with other accident mitigation systems, limits fission product leakage during and following the postulated design basis accident (DBA) to values less than leakage rates which would result in offsite doses greater than those set forth in 10CFR 50.67.

c. The containment system can withstand coincident fluid jet forces associated with the flow from the postulated rupture of any pipe within the containment.

d. The containment design permits removal of fuel assemblies from the reactor core after the postulated LOCA.

e. The containment system is protected from or designed to withstand missiles from internal sources and excessive motion of pipes which could directly or indirectly endanger the integrity of the containment.

f. The containment system provides means to channel the flow from postulated pipe ruptures in the drywell to the pressure suppression pool.

g. The containment system is designed to allow for periodic testing at the peak pressure calculated to result from the postulated DBA to confirm the leaktight integrity of the containment and its penetrations.

6.2.1.1.2 Design Features

Section 3.8 describes the design features of the containment structure and internal structures. Dwgs. C-331, Sh. 1, C371, Sh. 2, C-1932, Sh. 3, C-1932, Sh. 4, and C-1932, Sh. 5 show the general arrangement of the containment and internal structures.

6.2.1.1.2.1 Protection from Dynamic Effects

The containment structure and ESF system functions have been protected from dynamic effects of postulated accidents as described in Sections 3.5 and 3.6.

6.2.1.1.2.2 Codes, Standards, and Guides

Table 3.8-1 lists the applicable codes, standards, guides, and specifications for the containment structure and internal structures.

6.2.1.1.2.3 Functional Capability Tests

The functional capability of the containment structure is verified by pressurizing the containment to 1.15 times the design accident pressure as required by NRC Regulatory Guide 1.18 (Rev. 1). Refer to Subsections 3.8.1.7, 3.8.2.7, and 3.8.3.7 for a description of the structural acceptance test.

6.2.1.1.2.4 External Pressure Loading Conditions

The containment structure has been designed for an external differential pressure of 5 psi.

6.2.1.1.2.5 Trapped Water that Cannot Return to Containment Sump

Not applicable to pressure suppression containment.

6.2.1.1.2.6 Containment and Subcompartment Atmosphere

Subsection 9.4.5 describes the pressure, temperature, and humidity limits and the system which will maintain these limits during normal plant operation.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Summary Evaluation

The key design parameters and the maximum calculated accident parameters for the pressure suppression containment are as follows:

	Paramenter	Design Parameter	Calculated Accident Parameter
a.	Drywell Pressure	53 psig	48.6 psig
b.	Drywell Temperature	340°F	337°F
c.	Suppression Chamber Pressure	53 psig	36.5 psig
d.	Suppression Chamber Temperature	220°F	211.2°F

The foregoing design and maximum calculated accident parameters are not determined from a single accident event but from an envelope of accident conditions. As a result, there is no single DBA for this containment system.

The maximum drywell pressure occurs during the short-term blowdown phase of the LOCA. The maximum suppression chamber pressure occurs during the pool swell phase of the transient when the suppression chamber air space is compressed by the rising pool slug. Both the break of the main steam line and recirculation line were evaluated to determine the most severe pressure transients.

For the long-term suppression pool temperature response to the applicable design basis scenarios were analyzed. The result for the most limiting case concluded that the peak calculated temperature remains within the design limit of 220°F.

The maximum drywell temperature occurs during the short-term blowdown from a main steam line break. A small steam line break was also evaluated and the results show that the main line steam break is bounding. The peak drywell temperature remains within the design limit of 340°F.

The analyses assume that the primary system and containment are initially at the maximum normal operating conditions. References 6.2-1, 6.2-24, and 6.2-26 that describe relevant experimental verification of the analytical models used to evaluate the containment system response.

6.2.1.1.3.2 Containment Design Parameters

Table 6.2-1 provides a listing of the key design parameters of the primary containment system including the design characteristics of the drywell, suppression pool, and the pressure suppression vent system.

A diagram showing the geometric configuration of the downcomer is shown in Figure 6.2-56. The five downcomers that have vacuum breakers attached are closed at the bottom end by a pipe cap with a three (3) inch drain line as shown in Figure 6.2-56. The head loss coefficient for the downcomer vent is evaluated by General Electric Co. for use in containment pressure and temperature transient response calculations using the 82 open downcomers. The method used is similar to the vent head loss evaluation performed in NEDO-10320, Supplement 2. See Reference 6.2-1.

The normally closed vacuum breaker valves start to open under a preset differential pressure. The setpoint of each valve is verified by preoperational tests at the manufacturers shop. The set pressure is determined by applying slowly increasing pressure to the valve inlet side, and observing the peak manometer reading across the valve. Inservice testing to verify the opening time and setpoint will not be conducted and is not necessary because:

a. The valves are simple mechanical devices qualified for the environment,
b. The setpoint and opening time are verified in manufacturers preoperational tests, and
c. The valves are exercised and inspected in accordance with the Technical Specifications.

The containment depressurization rate analysis for a postulated inadvertent spray actuation assumed that the vacuum breakers begin to open at a wetwell to drywell –P of 2.81 psid and are fully open when the wetwell to drywell –P is 4.48 psid. These vacuum breaker opening pressures are based upon actual valve opening data increased by the amount of other flow losses in the wetwell to drywell flow path. These pressure choices are conservative for both the Phase IIIa vacuum breaker valve designs. One set out of five sets of vacuum breakers was assumed not to open in the analysis.

The orifice diameter of the valves is 19.4 inches based on flow measurement. The loss coefficient was calculated based on actual flow measurements conducted in the manufacturer's shop. Refer to Subsection 6.2.1.1.3.2.2. Each of the inboard vacuum breakers is connected to a common alarm which indicates when any valve is not closed. Each of the outboard vacuum breakers is connected to a common alarm which indicates when any valve is not closed. There is individual vacuum breaker position indication in the main control room for each valve.

Table 6.2-2 provides the performance parameters of the related engineered safety feature systems which supplement the design conditions of Table 6.2-1 for containment cooling purposes during post blowdown long term accident operation. Performance parameters given include those applicable to full capacity operation and to conservatively reduced capacities assumed for containment analyses.

6.2.1.1.3.2.1 Downcomer Vent Flow Loss Coefficient

The downcomer vent flow loss coefficient, K, is defined by:

$$\Delta P = K\frac{\rho V^2}{2g}$$

is calculated from standard references (6.2-19, 6.2-20). In the above equation –P is the total pressure drop across the downcomer, Ψ is the fluid density, and V is the flow velocity. The total downcomer flow loss coefficient is modeled as the sum of three contributors: an entrance loss, a length loss, and an exit loss. The entrance loss coefficient is calculated from Reference 6.2-19 using a hooded duct entrance geometry which very nearly approximates the standoff je reflector shield feature of the SSES downcomer. The entrance loss is calculated to be 0.84. The length loss is represented by an fL/D loss with f calculated from Reference 6.2-20. The length loss is calculated to be 0.33. The exit loss coefficient is calculated to be 1.0 from Reference 6.2-20, which when combined with the above yields an overall loss coefficient value of K=2.17.

6.2.1.1.3.2.2 Vacuum Breaker Flow Loss Coefficient

The loss coefficient for the wetwell to drywell flowpath includes losses due to the vacuum breaker inlet, vacuum breaker valves, turning and downcomer inlet. The loss coefficient calculated for this flow path is 0.495 based on the vacuum breaker flow area.

The loss coefficient of the vacuum breaker is calculated based on actual flow measurements conducted by the manufacturer. The valve was mounted on a test rig, a differential pressure established across the valve, the flow measured and then K calculated for 24" pipe size based on the measured flow rate. For a single valve, K = 2.65. For two valves mounted in series, K = 5.30 as prescribed by the manufacturer (Reference 6.2-21).

The manufacturer's shop test for these valves consisted basically of an induction flow system in which dry, saturated air was drawn through the valve system and the corresponding flow rate pressure drops and fluid temperature measured. The tests were conducted for varying flow rates and pressure drops. From these data, one can calculate the loss factor, "K", for the valve system.

The calculated "K" factor is somewhat sensitive to flow at low flow rates. This is due to the increasing influence of fluid compressibility, as well as setting up the flow pattern through the valve system. The manufacturer's tests were, therefore, conducted up to a condition sufficient to set up the fully-developed flow pattern through the valve system as well as include the effects of compressibility. At this condition, the calculated "K" factor reaches a maximum and exhibits no further sensitivity to increase in flow.

The anticipated condition of operation for these valves would differ from those for which they were tested only in the type of fluid passing through the system. It is expected that the valve system will be required to pass a dispersed steam-air mixture during the postulated transient. The anticipated fluid state would, therefore, have a density different from that of the test. However, the effect of fluid density is incorporated in the calculations of "K". Thus, compressibility, density and flow pattern effects have been suitably represented in the tests so as to yield a valve system "K" factor which is appropriate to conservatively model these valves in their anticipated condition of service.

6.2.1.1.3.3 Accident Response Analysis

The containment functional evaluation is based upon the consideration of several postulated accident conditions resulting in release of reactor coolant to the containment. These accidents include:

a. an instantaneous guillotine rupture of the recirculation suction line

b. a main steam line rupture.

Energy release from these accidents is reported in Subsection 6.2.1.3.

6.2.1.1.3.3.1 Recirculation Line Rupture

Immediately following the rupture of the recirculation line, the flow out both sides of the break will be limited to the maximum allowed by critical flow considerations. Figure 6.2-1 shows a schematic view of the flow paths to the break. In the side adjacent to the suction nozzle, the flow will correspond to critical flow in the pipe cross-section. In the side adjacent to the injection nozzle, the flow will correspond to critical flow at the 10 jet pump nozzles associated with the broken loop. In addition, the cleanup line crosstie will add to the critical flow area.

6.2.1.1.3.3.1.1 Assumptions for Reactor Blowdown

The response of the reactor coolant system during the blowdown period of the accident is analyzed using the following assumptions:

a. The initial conditions for the recirculation line break accident are such that the system energy is maximized That is:

   1) The reactor is operating at 102 percent of the uprated reactor thermal power.

   2) The service water temperature is the maximum UHS Design Temperature.

3) The suppression pool level and mass are at the value corresponding to the maximum Technical Specification limit for the short term evaluation and the minimum Technical Specification limit for the long term evaluation. These conditions result in maximizing the drywell pressure response for the short term analysis and the suppression pool temperature response for the long term analysis.

4) The suppression pool temperature is equal to the maximum Technical Specification limit.

b. The recirculation suction line is considered to be severed instantly. This results in the most rapid coolant loss and depressurization of the vessel, with coolant being discharged from both ends of the break.

c. Reactor power generation ceases at the time of accident initiation because of void formation in the core region. Scram also occurs in less than one second from receipt of the high drywell pressure signal. The difference between the shutdown times is negligible.

d. The vessel depressurization flow rates are calculated using Moody's critical flow model (Reference 6.2-3) assuming "liquid only" outflow, since this assumption maximizes the energy release to the drywell. "Liquid only" outflow implies that all vapor formed in the reactor pressure vessel (RPV) by bulk flashing rises to the surface rather than being entrained in the existing flow. In reality, some of the vapor would be entrained in the break flow which would significantly reduce the RPV discharge flow rates. Further, Moody's critical flow model, which assumes annular, isentropic flow, thermodynamic phase equilibrium, and maximized slip ratio, accurately predicts vessel outflows through small diameter orifices. Actual rates through larger flow areas, however, are less than the model indicates because of the effects of a nearly homogeneous two-phase flow pattern and phase nonequilibrium. These effects are conservatively neglected in the analysis.

e. The core decay heat and the sensible heat released in cooling the fuel to 545°F are included in the RPV depressurization calculation. The rate of energy release is calculated using a conservatively high heat transfer coefficient throughout the depressurization period. The resulting high energy release rate causes the RPV to maintain nearly rated pressure for approximately 10 seconds. The high RPV pressure increases the calculated blowdown flow rates, which is again conservative for analysis purposes. The sensible energy of the fuel stored at temperatures below 545°F is released to the vessel fluid along with the stored energy in the vessel and internals as vessel fluid temperatures decrease below 545°F during the remainder of the transient calculation.

f. For the recirculation suction line break evaluation, the main steam isolation valves start closing at 0.5 seconds after the accident. They are fully closed at two seconds. By assuming rapid closure of these valves, the RPV is maintained at a high pressure, which maximizes the calculated discharge of high energy water into the drywell.

g. Reactor Feedwater Flow into the vessel continues until all of the high energy feedwater (above 198°F) is injected into the vessel. This is conservative for the recirculation suction line break because it maximizes the duration of single-phase liquid blowdown to the drywell, thus maximizing the peak drywell pressure. This assumption is also conservative for the long term evaluation because it maximizes the suppression pool temperature.

h. A complete loss of offsite power occurs simultaneously with the pipe break. This condition results in the loss of power conversion system equipment and also requires that all vital systems for long-term cooling be supported by onsite power supplies.

6.2.1.1.3.3.1.2 Assumptions for Containment Pressurization

The pressure response of the containment during the blowdown period of the accident is analyzed using the following assumptions:

a. Thermodynamic equilibrium exists in the drywell and suppression chamber. Since nearly complete mixing is achieved, the analysis assumes complete mixing.

b. The fluid flowing through the drywell-to-suppression pool vents is formed from a homogeneous mixture of the fluid in the drywell. The use of this assumption results in complete carryover of the drywell air and a higher positive flow rate of liquid droplets which conservatively maximizes vent pressure losses.

c. The fluid flow in the drywell-to-suppression pool vents is compressible except for the liquid phase.

d. No heat loss from the gases inside the primary containment is assumed. In reality, condensation of some steam on the drywell surfaces would occur. Additional assumptions are provided in Table 6.2-4a.

6.2.1.1.3.3.1.3 Assumptions for Long-Term Cooling

Following the blowdown period, the emergency core cooling system (ECCS) discussed in Section 6.3 provides water for core flooding, containment spray, and long-term decay heat removal. The containment pressure and temperature response is analyzed using the following assumptions:

a. The LPCI pumps are used to flood the core prior to 600 seconds after the accident. The HPCI is assumed available for the entire accident, but no credit is taken for operation.

b. After 600 seconds, the LPCI pump flow may be diverted from the RPV to the containment spray. This is a manual operation. Actually, the containment spray need not be activated at all to keep the containment pressure below the containment design pressure. Prior to activation of the containment cooling mode (assumed at 600 seconds after the accident) all of the LPCI pump flow will be used to flood the core.

c. The effects of decay energy, stored energy, and energy from the metal-water reaction on the suppression pool temperature are considered.

d. The initial suppression pool mass is the value corresponding to low water level. Additional assumptions are listed in Table 6.2-5a.

e. After approximately 600 seconds, the RHR heat exchangers are activated to remove energy from the containment via recirculation cooling from the suppression pool with the RHR service water systems.

f. The performance of the Containment System during the long-term cooling period is evaluated for each of the following four cases of interest.

Case A	Offsite power available - all ECCS equipment and containment spray operating.
Case B	Loss of offsite power minimum diesel power available for ECCS and containment spray.
Case C	Same as Case B except no containment spray.
Case D	Loss of Offsite Power – All Pumps Running

6.2.1.1.3.3.1.4 Initial Conditions for Accident Analyses

Tables 6.2-3a and 6.2-4a provide the initial reactor coolant system and containment conditions used in the accident response evaluations. The tabulation includes parameters for the reactor, the drywell, the suppression chamber and the vent system.

The mass and energy release sources and rates for the containment response analyses are given in Subsection 6.2.1.3.

6.2.1.1.3.3.1.5 Short Term Accident Response

The calculated containment pressure and temperature responses for the recirculation line break are shown on Figures 6.2-2 and 6.2-3, respectively.

The suppression chamber is pressurized by the carryover of noncondensables from the drywell and by heatup of the suppression pool. As the vapor formed in the drywell is condensed in the suppression pool, the temperature of the suppression pool water peaks and the suppression chamber pressure stabilizes. The drywell pressure stabilizes at a slightly higher pressure, the difference being equal to the downcomer submergence. Drywell pressure decreases as the rate of energy dumped to the suppression pool via the downcomers exceeds the rate of energy released into the drywell from the primary system. During the RPV depressurization phase, most of the noncondensable gases initially in the drywell are forced into the suppression chamber. However, following the depressurization the noncondensables will redistribute between the drywell and suppression chamber via the vacuum breaker system. This redistribution takes place as steam in the drywell is condensed by the relatively cool ECCS water which is beginning to cascade from the break causing the drywell pressure to decrease.

Two cases leading to potentially rapid drywell depressurization were considered for wetwell-to-drywell vacuum breaker sizing. These are:

1. The inadvertent actuation of one containment spray train (10700 gpm @ 50°F, assumed),

2. Maximum ECCS spillage (7750 lbm/sec @ 140°F exit temperature, assumed) during the depressurization phase of the large recirculation outlet line break LOCA.

Each case was considered to determine the adequacy of the vacuum breaker valve assemblies to ensure that the maximum differential pressure across the diaphragm slab does not exceed allowables. The present design allowable across the diaphragm slab is 28 psid downward and 27.8 psid upward.

In the analysis done for both cases 1 & 2, it has been conservatively assumed that all non-condensables have been removed to the wetwell vapor region prior to drywell depressurization. The details of the analysis performed for the Case 1 study are presented in Subsection 6.2.1.1.4. Case 1 results are also presented in this section and indicate a worst-case differential upward pressure of 4.6 psid across the diaphragm slab for this case - well below the 27.8 psid upward design allowable. This time-dependent differential pressure response is illustrated in Figure 6.2-65.

The analysis for Case 2 assumes a drywell temperature of 262°F, an ECCS drop fall height of 42 feet, an average drop diameter of 1 inch (for calculating condensation heat transfer to the falling ECCS spillage), and an average heat transfer coefficient of 2300 BTU/Hr,Ft^2,F. (For calculating heat transfer from the drywell vapor region to the pool of ECCS spillage collected on the drywell floor). These considerations, combined with the assumptions regarding non-condensables and ECCS spillage rate and temperature, yield a net drywell energy removal rate of approximately 320,000 BTU/Sec for an ECCS spillage spray effectiveness of 34%.

The two cases yield energy removal rates of the same order of magnitude, with the inadvertent containment spray case being the larger, 400,000 BTU/Sec. As such, this inadvertent spray actuation case controls the vacuum breaker sizing. Four vacuum breaker valve assemblies, having a seat I.D. of 19.4 inches, are adequate to ensure a diaphragm slab differential pressure below design allowables. An additional fifth valve assembly is employed to cover single-active failure concerns.

After the RPV is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow of water (steam flow is negligible) transports the core decay heat out of the RPV, through the broken recirculation line, in the form of hot water which flows into the suppression chamber via the drywell-to-suppression chamber vent system. This flow provides a heat sink for the drywell atmosphere, and thereby causes the drywell to depressurize.

The results of the short-term analyses are summarized in Table 6.2-6a. The short-term containment pressure response is shown in Figure 6.2-2. The peak calculated drywell-to-wetwell pressure response is shown in Figure 6.2-4. The short-term containment temperature response is shown in Figure 6.2-12.

During the blowdown period of the LOCA, the pressure suppression vent system conducts the flow of the steam-water gas mixture in the drywell to the suppression pool for condensation of the steam. The pressure differential between the drywell and suppression pool controls this flow. Figure 6.2-5 provides the mass flow versus time relationship through the vent system for this accident.

6.2.1.1.3.3.1.6 Long Term Accident Responses

To assess the adequacy of the containment following the initial blowdown transient, an analysis was made of the long term temperature and pressure response following the accident. The analysis assumptions are those discussed in Subsection 6.2.1.1.3.3.1.3. The initial pressure response of the containment (the first 600 seconds after break) is the same for each case. Operator performance during Emergency Procedure validation exercises shows that under accident conditions alignment of an RHR heat exchanger for containment cooling within 10 minutes is difficult to achieve. Consequently, a sensitivity analysis has been performed which demonstrates that if operator actions are delayed for up to 20 minutes, the peak suppression pool temperatures calculated in the long term DBA/LOCA containment analyses discussed herein (which are based on an operator response time of 10 minutes) would remain valid and bounding. Although the sensitivity analysis was performed for the Case D (worst case) scenario, the analysis results apply to the Case A through C long term DBA/LOCA containment analyses included herein as well. The sensitivity analysis assumes that average RHRSW temperatures would be at or below 91 F for the first two hours of the transient, which remains below the average UHS (THTSW) design temperatures for this time frame, rather than at the peak RHRSW temperature of 97 F assumed throughout the containment analyses. Although the containment analyses were not rerun with an operator response time of 20 minutes, the sensitivity analysis demonstrates that this short term reduction in assumed RHRSW temperature offsets the impact of increasing operator response time to 20 minutes on peak suppression pool temperatures for the Case A – D long term containment analyses and justifies an operator response time of up to 20 minutes to establish the containment heat removal function.

CASE A: All ECCS equipment operating - with containment spray-

This case assumes that offsite ac power is available to operate all cooling systems. During the first 600 seconds following the pipe break, the HPCI, CS and all LPCI pumps are assumed operating. All flow is injected directly into the reactor vessel.

After 600 seconds, an operator initiates the containment cooling mode by activating the RHR heat removal system to maintain containment pressure and temperature within specified limits. Suction is drawn from the suppression pool, passed through a RHR heat exchanger, and discharged to the containment via the drywell and wetwell spray spargers. There are two RHR loops, each includes two pumps and one heat exchanger. One pump operating in one RHR loop is sufficient to provide the containment cooling function.

After the initial blowdown and subsequent depressurization due to core spray and LPCI core flooding, energy addition due to core decay heat results in a gradual pressure and temperature rise in the containment. When the energy removal rate of the RHR System exceeds the energy addition rate from the decay heat, the containment pressure and temperature reach a second peak value and decrease gradually.

CASE B: Loss of Offsite Power - With Containment Spray

This case assumes no offsite power is available following the accident with only minimum diesel power. The containment spray is operating and spraying water into the containment after 600 seconds. During this mode of operation the LPCI flow through only one RHR heat exchanger is directed to the containment spray nozzles.

CASE C: Loss of Offsite Power - No Containment Spray

This case assumes that no offsite power is available following the accident with only minimum diesel power. For the first 600 seconds following the accident, two LPCI pumps are used to cool the core. After 600 seconds the spray may be manually activated to further reduce containment pressure if desired. This analysis assumes that the containment spray is not activated. After 600 seconds, one RHR heat exchanger is activated to remove energy from the containment. During this mode of operation, one of the two LPCI pumps is shut down and the service water pumps to the RHR heat exchanger are activated. The LPCI flow is cooled by the RHR heat exchanger before being discharged into the reactor vessel.

CASE D: Loss of Offsite Power – All Pumps Running

This case assumes that no offsite power is available following the accident and no operation of the HPCI pump. All four CS pumps and all four LPCI pumps are injecting into the vessel for the duration of the event. A single active failure prevents RHRSW cooling water flow through one of the RHR heat exchangers. At 600 seconds, one loop of LPCI flow is cooled by a single RHR heat exchanger before being discharged into the reactor vessel.

These four cases were analyzed using the initial plant conditions listed in Table 6.2-3a. The inputs and assumptions for these cases are provided in Tables 6.2-2 and 6.2-5a. Of these cases, Case D produces the highest suppression pool temperature. The resulting calculated peak bulk suppression pool temperature is given in Table 6.2-6a. The long-term containment pressure response is shown in Figure 6.2-6, the long term drywell temperature response is shown in Figure 6.2-7, and the long-term suppression pool temperature response is shown in Figure 6.2-8.

6.2.1.1.3.3.1.7 Energy Balance During Accident

To establish an energy distribution in the containment as a function of time (short term, long term) for this accident, the following energy sources and sinks are required:

a. Blowdown energy release rates
b. Decay heat rate and fuel relaxation sensible energy
c. Sensible heat rate (vessel and internals)
d. Pump heat rate
e. Heat removal rate from suppression pool (Figure 6.2-9)
f. Metal-water reaction heat rate.
g. Passive heat sinks in containment

6.2.1.1.3.3.2 Main Steamline Break

The assumed sudden rupture of a main steamline between the reactor vessel and the flow limiter would result in the maximum flow rate of primary system fluid and energy to the drywell. This would in turn result in the maximum drywell temperature. The sequence of events immediately following the rupture of a main steamline between the reactor vessel and the flow limiter have been determined. For the short term main steam line break evaluation, feedwater flow into the vessel is assumed to stop at the start of the event. This is conservative since continued feedwater flow would result in a reduction in the RPV pressure and the blowdown flow rates. The flow in both sides of the break will accelerate to the maximum allowed by the critical flow considerations. The break flow rates are calculated based on the Moody Slip flow critical model. The vessel model of Reference 6.2.1 and 6.2.26 is used in calculating these break flow rates. The Mark III analytical model from Reference 6.2.26 is made applicable to the Mark II containment analysis by reducing the horizontal portion of the vent to zero. In the side adjacent to the reactor vessel, the flow will correspond to critical flow in the steamline break area. Blowdown through the other side of the break will occur because the steamlines are all interconnected at a point upstream of the turbine. This interconnection allows primary system fluid to flow from the three unbroken steam lines, through the header, and back into the drywell via the broken line. Flow will be limited by critical flow in the steamline flow restrictor. A slower closure rate of the isolation valves in the broken line would result in a slightly longer time before the total valve area of the three unbroken lines equals the flow limiter area in the broken line. Subsection 6.2.1.3 provides the mass and energy release rates.

Immediately following the break, the total steam flow rate leaving the vessel would be approximately 8400 lb/sec, which exceeds the steam generation rate in the core of 3931 lb/sec. This steam flow to steam generation mismatch causes an initial vessel depressurization of the reactor vessel at a rate of approximately 48 psi/sec. Void formation in the reactor vessel water causes a rapid rise in the water level, and it is conservatively assumed that the water level reaches the vessel steam nozzles one second after the break occurs. The water level rise time of one second is the minimum that could occur under any reactor operating condition. From that time on, a two-phase mixture would be discharged from the break. During the first second of the blowdown, the blowdown flow will consist of saturated steam. This steam will enter the containment in a superheated condition of approximately 340°F.

Figures 6.2-11 and 6.2-12 show the pressure and temperature responses of the drywell and suppression chamber during the primary system blowdown phase of the steamline break accident.

Figure 6.2-12 shows that the drywell atmosphere temperature approaches 337°F at approximately one second of primary system steam blowdown. At that time, the water level in the vessel will reach the steamline nozzle elevation and the blowdown flow will change to a two-phase mixture. This increased flow causes a more rapid drywell-pressure rise. The peak differential pressure occurs shortly after the vent clearing transient.

As the blowdown proceeds, the primary system pressure and fluid inventory will decrease and this will result in reduced break flow rates. As a consequence, the flow rate in the vent system and the differential pressure between the drywell and suppression chamber begin to decrease.

At this time in the accident scenario, the drywell will contain primarily steam, and the drywell and suppression chamber pressures will stabilize. The pressure difference corresponds to the hydrostatic pressure of vent submergence.

The drywell and suppression pool will remain in this equilibrium condition until the reactor vessel refloods. During this period, the emergency core cooling pumps will be injecting cooling water from the suppression pool into the reactor. This injection of water will eventually flood the reactor vessel to the level of the steamline nozzles and the ECCS flow will spill into the drywell. The water spillage will condense the steam in the drywell and thus reduce the drywell pressure. As soon as the drywell pressure drops below the suppression chamber pressure, the drywell vacuum breakers will open and noncondensable gases from the suppression chamber will flow back into the drywell until the pressure in the two regions equalize.

6.2.1.1.3.3.3 Hot Standby Accident Analysis

The containment pressure design parameters based on hot standby accident analyses are enveloped by the full reactor power operating condition analysis.

6.2.1.1.3.3.4 Intermediate Size Breaks

The failure of a recirculation line results in the most severe pressure loading on the drywell structure. However, as part of the containment performance evaluation, the consequences of intermediate breaks are also analyzed. This classification covers those breaks for which the blowdown will result in reactor depressurization and operation of the ECCS. This section describes the consequences to the containment of a 0.1 sq. ft. break below the RPV water level. This break area was chosen as being representative of the intermediate size break area range. These breaks can involve either reactor steam or liquid blowdown.

Following the 0.1 sq. ft. break, the drywell pressure increases at approximately 1 psi per second. This drywell pressure transient is sufficiently slow so that the dynamic effect of the water in the vents is negligible and the vents will clear when the drywell-to-suppression chamber differential pressure is equal to the vent submergence hydrostatic pressure.

The ECCS response is discussed in Section 6.3. Approximately 5 seconds after the 0.1 sq. ft break occurs, air, steam, and water will start to flow from the drywell to the suppression pool; the steam will be condensed and the air will enter the suppression chamber free space. The containment will continue to gradually increase in pressure due to the long-term pool heatup.

The ECCS will be initiated as a result of the 0.1 sq. ft break and will provide emergency cooling of the core. The operation of these systems is such that the reactor will be depressurized in approximately 600 seconds. This will terminate the blowdown phase of the transient.

In addition, the suppression pool end of blowdown temperature will be the same as that of the DBA because essentially the same amount of primary system energy is released during the blowdown. After reactor depressurization and reflood, water from the ECCS will begin to flow out the break. This flow will condense the drywell steam and eventually cause the drywell and suppression chamber pressures to equalize in the same manner as following a recirculation line rupture.

The subsequent long term suppression pool and containment heat-up transient that follows is essentially the same as for the recirculation line break.

From this description, it can be concluded that the consequences of an intermediate size break are less severe than from a recirculation line rupture. This conclusion remains unchanged for the power uprate conditions because the effect of power uprate on the intermediate size break

analysis is expected to be similar to the power uprate effect on the recirculation suction line rupture. Therefore, the intermediate size break peak drywell pressure will still be bounded by the recirculation suction line peak drywell pressure value.

6.2.1.1.3.3.5 Small Size Breaks

6.2.1.1.3.3.5.1 Reactor System Blowdown Considerations

This subsection discusses the containment transient associated with small breaks in the primary system. The sizes of primary system ruptures in this category are those blowdowns that will not result in reactor depressurization due either to loss of reactor coolant or automatic operation of the ECCS equipment. Following the occurrence of a break of this size, it is assumed that the reactor operators will initiate an orderly plant shutdown and depressurization of the reactor system. The thermodynamic process associated with the blowdown of primary system fluid is one of constant enthalpy. If the primary system break is below the water level, the blowdown flow will consist of reactor water. Blowdown from reactor pressure to the drywell pressure will flash approximately one-third of this water to steam and two-thirds will remain as liquid. Both phases will be at saturation conditions corresponding to the drywell pressure.

If the primary system rupture is located so that the blowdown flow consists of reactor steam only, the resultant steam temperature in the containment is significantly higher than the temperature associated with liquid blowdown. This is because the constant enthalpy depressurization of high pressure, saturated steam will result in superheated conditions. For example, decompression of 1000 psia saturated steam to atmospheric pressure will result in 298°F superheated steam (86°F of superheat).

A small reactor steam leak (resulting in superheated steam) will impose the most severe temperature conditions on the drywell structures and the safety equipment in the drywell. For larger steamline breaks, the superheat temperature is nearly the same as for small breaks, but the duration of the high temperature condition for the larger break is less. This is because the larger breaks will depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to terminate the small break.

6.2.1.1.3.3.5.2 Containment Response

For drywell design considerations, the following sequence of events is assumed to occur. With the reactor and containment operating at the maximum normal conditions, a small break occurs that allows blowdown of reactor steam to the drywell. The resulting pressure increase in the drywell will lead to a high drywell pressure signal that will scram the reactor and activate the containment isolation system. The drywell pressure will continue to increase at a rate dependent upon the size of the steam leak. The pressure increase will lower the water level in the vents until the level reaches the bottom of the vents. At this time, air and steam will start to enter the suppression pool. The steam will be condensed and the air will be carried over to the suppression chamber free space. The air carryover will result in a gradual pressurization of the suppression chamber at a rate dependent upon the size of the steam leak. Once all the drywell air is carried over the suppression chamber, pressurization of the suppression chamber will cease and the system will reach an equilibrium condition. The drywell will contain only superheated steam, and continued blowdown of reactor steam will condense in the suppression pool. The suppression pool temperature will continue to increase until the RHR heat exchanger heat removal rate is greater than the decay heat release rate.

6.2.1.1.3.3.5.3 Recovery Operations

The reactor operators will be alerted to the incident by the high drywell pressure signal and the reactor scram. For the purposes of evaluating the duration of the superheat condition in the drywell, it is assumed that their response is to shut the reactor down in an orderly manner using the main condenser while limiting the reactor cooldown rate to 100°F per hour. This will result in the reactor primary system being depressurized within six hours. At this time, the blowdown flow to the drywell will cease and the superheat condition will be terminated. If the plant operators elect to cool down and depressurize the reactor primary system more rapidly than 100°F per hour, then the drywell superheat condition will be shorter.

6.2.1.1.3.3.5.4 Drywell Design Temperature Considerations

For drywell design purposes, it is assumed that there is a blowdown of reactor steam for the six-hour cooldown period. The corresponding design temperature is determined by finding the combination of primary system pressure and drywell pressure that produces the maximum superheat temperature. This temperature is then assumed to exist for the entire six-hour period. The maximum drywell steam temperature occurs when the primary system is at approximately 450 psia and the drywell pressure is maximum. For design purposes, it is assumed that the drywell is at 35 psig; which results in a temperature of 340°F.

6.2.1.1.3.4 Accident Analysis Models

6.2.1.1.3.4.1 Short Term Pressurization Model

The analytical models, assumptions, and methods used by General Electric to evaluate the containment response during the reactor blowdown phase of a LOCA are described in Refs. 6.2-1, 6.2-23, and 6.2-26. For the recirculation line suction break, a detailed vessel blowdown model which determines the break mass and energy flows is based on Reference 6.2.23. For the main steam line break the vessel model in References 6.2.1 and 6.2.26 are used in the analysis.

References 6.2.1 and 6.2.26 provide the following additional models for use in the evaluation of the short term containment response to a postulated major pipe rupture:

1. The drywell model which determines the thermodynamic conditions as a result of the mass and energy flows into and out of the drywell.

2. The downcomer model which determines the clearing time and downcomer flow rate. The Mark III analytical model was made applicable to the Mark II containment by reducing the horizontal portion of the vent to zero length.

3. The suppression pool model for the temperature response by a mass and energy balance.

4. The suppression chamber airspace model which is used to calculate the airspace pressure and temperature response.

6.2.1.1.3.4.2 Long Term Cooling Mode

Once the RPV blowdown phase of the LOCA is over, the long term suppression pool temperature response was evaluated for the recirculation suction line break. The analysis was performed at 102% of the uprated power. A coupled reactor pressure vessel and containment model, based on the models provided in References 6.2.1 and 6.2.26, was used to calculate the containment transient response during long term events which add heat to the suppression pool. The model performs fluid mass and energy balances on the reactor primary system and the suppression pool, and calculates the reactor vessel water level, pressure and the long term suppression pool bulk temperature. During the long term, post-blowdown containment cooling transient, the ECCS flow path is a closed loop and the suppression pool mass will be constant. Schematically, the cooling model loop is shown on Figure 6.2-16. Since there is no change in mass storage in the system (the RPV is reflooded during the blowdown phase of the accident), the mass flow rates shown in the figure are equal, thus:

$$M_{D_o} = M_{s_o} = M_{eccs} \qquad \text{(Eq. 6.2-1)}$$

6.2.1.1.3.4.3 Analytical Assumptions

The key assumptions employed in the short term model are as follows:

(1) Fluid inventory depressurizes and a single-phase liquid blowdown to the drywell occurs maximizing the energy release to the containment.

(2) The initial suppression pool volume is at the maximum Technical Specification limit to maximize the drywell pressure response.

(3) Thermodynamic equilibrium exist between the liquid and gases in the drywell, and between the suppression pool and the suppression chamber airspace. Heat and mass transfer between the gases and the liquid in the drywell and suppression chamber airspace is calculated with containment spray operation.

(4) No credit is taken for passive heat sinks in the drywell, suppression chamber airspace, or in the suppression pool.

The key assumptions employed in the long term model are as follows:

(1) The drywell and suppression chamber atmosphere are both saturated (100 percent relative humidity).

(2) The drywell atmosphere temperature is equal to the temperature of the coolant spilling from the RPV, or to the spray temperature if the sprays are activated.

(3) The initial suppression pool volume is at the minimum Technical Specification limit to maximize the suppression pool temperature response.

(4) Thermodynamic equilibrium exist between the liquid and gases in the drywell, and between the suppression pool and the suppression chamber airspace. Heat and mass transfer between the gases and the liquid in the drywell and suppression chamber airspace is calculated without containment spray operation.

(5) Credit is taken for passive heat sinks in the drywell, suppression chamber airspace, and the suppression pool.

6.2.1.1.3.4.4 Energy Balance Considerations

The rate of change of energy in the suppression pool, E_p, is given by:

$$\frac{d}{dt}(E_p) = \frac{d}{dt}(M_{W_S} \bullet U_S)$$

$$= U_S \bullet \frac{d}{dt}(M_{W_S}) + M_{W_S} \bullet \frac{d}{dt}(U_S)$$

Since

$$\frac{d}{dt}(M_{W_S}) = 0$$

(because there is no change in mass storage, and at the conditions that will exist in the containment:

$$\frac{d}{dt}(U_s) = C_v \bullet \frac{d}{dt}(T_s)$$

where:

C_v	=	1.0 for the constant volume specific heat of water, Btu/lb-°F
T_s	=	pool temperature, °F

The pool energy balance yields:

$$M_{w_s} \bullet C_v \bullet \frac{d}{dt}(T_s) = \dot{M}_{D_o} \bullet h_D - \dot{M}_{s_o} \bullet h_s$$

This equation can be rearranged to yield:

$$\frac{d}{dt}(T_s) = \frac{\dot{M}_{D_o} \bullet h_D - \dot{M}_{s_o} \bullet h_s}{C_v \bullet M_{w_s}} \qquad \text{(Eq. 6.2-2)}$$

An energy balance on the RHR heat exchanger yields

$$hc = H_s - \frac{-q_{H_x}}{\dot{M}_{s_o}} \qquad \text{(Eq. 6.2-3)}$$

where,

h_c = enthalpy of ECCS flow entering the reactor, BTU/lb.

Similarly, an energy balance on the RPV will yield:

$$h_D = h_c + \frac{\dot{q}_D + \dot{q}_e}{\dot{M}_{eccs}} \qquad \text{(Eq. 6.2-4)}$$

Combining Equations 6.2-1, 6.2-2, 6.2-3, and 6.2-4 gives

$$\frac{d}{dt}(T_s) = \frac{\dot{q}_D + \dot{q}_e - q_{H_x}}{C_v \ M_{w_s}} \qquad \text{(Eq. 6.2-5)}$$

This differential equation is integrated by finite difference techniques to yield the suppression pool temperature transient.

6.2.1.1.3.4.5 Containment Thermodynamic Conditions

Once the energy equations are solved, the drywell and suppression chamber atmospheric temperatures can be calculated.

For the case in which no containment spray is operating, the suppression chamber temperature, T_w, at any time will be equal to the current temperature of the pool, T_s, and the drywell temperature, T_D, will be equal to the temperature of the fluid leaving the RPV. Thus:

$$T_D = T_s + \frac{\dot{q}_D + \dot{q}_e - \dot{q}_{H_x}}{C_p \ \dot{M}_{eccs}} \ \text{and} \ T_w = T_s$$

Where C_p = Constant pressure specific heat of water, BTU/lb-°F.

For the case in which the containment spray is assumed to be operating, both the drywell and suppression chamber atmosphere will be at the spray temperature, T_{sp}, where:

$$T_{sp} = T_s - \frac{\dot{q}_{H_x}}{C_p \ \dot{M}_{eccs}} \ \text{and} \ T_D = T_w = T_{sp}$$

Using the suppression chamber and drywell atmosphere temperatures, and assumption (1) of Subsection 6.2.1.1.3.4.3 (drywell and suppression chamber saturated), it is possible to solve for the containment total pressures, since:

$$P_D = P_{a_D} + P_{V_D} \qquad \text{(Eq. 6.2-6)}$$

$$P_S = P_{a_S} + P_{V_s} \qquad \text{(Eq. 6.2-7)}$$

Where:

P_D	=	drywell total pressure, psia
P_{a_D}	=	partial pressure of air in drywell, psia
P_{V_D}	=	partial pressure of water vapor in drywell, psia
P_S	=	suppression chamber total pressure, psia
P_{a_S}	=	partial pressure of air in the suppression chamber, psia
P_{V_S}	=	partial pressure of water vapor in the suppression chamber, psia

and from the Ideal Gas Law:

$$P_{a_D} = \frac{M_{a_D} \bullet RT_D}{V_D \bullet 144} \qquad \text{(Eq. 6.2-8)}$$

$$P_{as} = \frac{M_{as} \bullet RT_s}{V_s \bullet 144} \qquad \text{(Eq. 6.2-9)}$$

M_{a_D}	=	mass of air in the drywell, lb.
M_{a_s}	=	mass of air in the suppression chamber, lb.
R	=	gas constant for air, ft-lbf/lb-°R.
V_D	=	drywell free Volume, ft^3.
V_S	=	suppression chamber free volume, ft^3.

With known values of T_D and T_S, Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9 can be solved by transient analysis and iteration. This iteration procedure is also used to calculate the unknown quantities M_{a_D} and M_{a_s}.

6.2.1.1.3.4.6 Solution of Equations

The transient analysis is based on successive time step integration of the suppression pool temperature. When this integration has been performed and the value of T_s at the end of a time step has been calculated, a pressure balance is made. Using values of M_{a_D} and M_{a_s} from the end of the previous time step and the updated values of T_D and T_S, a check is made to see if P_S is greater than or equal to P_D using Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9. If P_S is greater than or equal to P_D, then the two values are made equal. The vacuum breakers between the drywell and suppression chamber ensure that P_S cannot be significantly greater than P_D .

Hence, with $P_D = P_s$ and knowing that: $M_{a_D} + M_{a_s}$ = constant where the constant is the known total initial mass of air in the suppression chamber and drywell prior to the accident, Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9 can be solved for M_{a_s}, M_{a_D}, and P_s/P_D. It is conservatively assumed that the total mass of air remains constant, which ignores any containment leakage that might occur during the transient.

If, as a result of the end-of-time-step pressure check,

$$P_s \leq P_D \leq P_s + \frac{H \bullet g}{\nu_w \bullet 144 \bullet g_c} \qquad \text{(Eq. 6.2-10)}$$

where:

g	=	acceleration of gravity, ft/sec^2
g_c	=	constant of proportionality in Newton's Second Law, ft-lb/lbf-sec^2
0	=	submergence of vents, ft
]w	=	specific volume of fluid in vent ft^3;/lb

then the pressure in the drywell is higher than the pressure in the suppression chamber but not sufficiently so to depress the water to the bottom of the vents and thus permit air to flow from the drywell to the suppression chamber. Under these circumstances, no air transfer is assumed to have occurred during the time step, and Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9 are solved during the time step, and Equations 6.2-6, 6.2-7, 6.2-8 and 6.2-9 are solved using the updated temperatures with the same M_{a_s} and M_{a_D} values from the previous time step.

If the end-of-time-step pressure check shows:

$$P_D > P_s + \frac{H \bullet g}{\nu_w \bullet 144 \bullet g_c}$$

then the drywell pressure is set to the value:

$$P_D = P_s + \frac{H \bullet g}{\nu_w \bullet 144 \bullet g_c} \qquad \text{(Eq. 6.2-11)}$$

This requires that the drywell pressure can never exceed the suppression chamber pressure by more than the hydrostatic head associated with the submergence of the vents. To maintain this condition, some transfer of drywell air to the suppression chamber will be required. The amount of air transfer is calculated by using Equation 6.2-10 and combining Equations 6.2-6, 6.2-7, 6.2-8, 6.2-9, and 6.2-11 to give:

$$P_{v_D} + \frac{M_{a_D} \bullet RT_D}{144\, V_D} = P_{v_S} + \frac{M_{as} \bullet RT_W}{144\, V_s} + \frac{H \bullet g}{\nu_w \bullet 144 \bullet g_c}$$

which can be solved for the unknown air masses. The total pressures can then be determined.

6.2.1.1.4 Negative Pressure Design Evaluation

The primary containment has been designed for a pressure of -5 psi. The worst case for this consideration results from the inadvertent actuation of the drywell sprays. During such a transient, cold spray water is passed through the drywell atmosphere resulting in a drop in vapor region temperature and a corresponding drop in vapor region pressure. This condition has been analyzed for Susquehanna SES. A peak pressure of -4.72 psi was obtained.

To determine the temporal pressure and temperature of the primary containment, the conservation equation of mass and energy, along with the state equations for steam and nitrogen (noncondensable) are written for the drywell and wetwell regions. A schematic of these two regions is presented in Figure 6.2-61. The various terms for the mass and energy transfer mechanisms are also presented in this figure. The system of differential equations for each region are as follows (definition of nomenclature is provided in Subsection 6.2.1.1.4.1):

Drywell Region

As indicated in Figure 6.2-61, there are several mass transfer terms for this region. These are: drywell spray rate, M'_{spray}, drywell vapor region condensation rate (or rainout due to dripping saturation temperature), M'_{cond}, and wetwell-to-drywell vacuum breaker flow rate, M'_{VB}. A mass balance on the drywell vapor region yields,

$$\frac{dM_D}{dt} = \frac{dM_{NC}}{dt} + \frac{dM_{stm}}{dt} = [\dot{M}_{VB} + \dot{M}_{spray}]_{in} - [\dot{M}_{cond} + \dot{M}_{spray}]_{out} \qquad (1)$$

The spray water is assumed to be removed directly to the wetwell liquid region so as to disallow any potential for re-evaporation to the drywell, as well as maintain a larger drywell vapor region volume - both of which serve to induce conservations in the analysis. The requirement of maintaining saturation conditions for the steam component is imposed and results in the following relationship:

$$M_{stm} = \frac{V_D}{v_g(T_D)} \text{ or } \frac{dM_{stm}}{dt} = \frac{-V_D}{v_g^2(T_D)} \bullet \frac{d\,v_g}{dT_D} \bullet \frac{dT_D}{dt} \qquad (2)$$

The energy balance for this region is,

$$\begin{aligned} \frac{dE_D}{dt} &= [\dot{M}_{spray} C_p (T_{out} - 32) + \dot{Q}_{VB}]_{in} \\ &\quad - [\dot{M}_{spray} C_p (T_f - 32) \\ &\quad + \dot{M}_{cond} h_f(T_f)]_{out} \\ &= \dot{M}_{spray} C_p (T_{out} - T_f) - \dot{M}_{cond} h_f(T_f) \bullet + \dot{Q}_{VB} \end{aligned}$$

But,

$$\frac{dE_D}{dt} = \left[C_V^* T_D^* \frac{dM_{NC}}{dt} + u_g\,(T_D) \frac{dM_{stm}}{dt} \right] + \left[M_{NC} C_V^* + M_{stm} \frac{d\,u_g}{dT_D} \right] \frac{dT_D}{dt}$$

So,

$$\left[C_V^* T_D^* \frac{dM_{NC}}{dt} + u_g\,(T_D) \frac{dM_{stm}}{dt} \right] + \left[M_{NC} C_V^* + M_{stm} \frac{d\,u_g}{dT_D} \right] \frac{dT_D}{dt}$$

$$= \dot{M}_{spray} C_P (T_{out} - T_f) - \dot{M}_{cond}\, h_p\,(T_f) + \dot{Q}_{VB} \qquad (3)$$

The spray effectiveness, ς is defined as follows:

$$\xi = \frac{T_f - T_{out}}{T_D - T_{out}} = f(M_{stm} / M_{NC})$$

The functional relationship is determined in the work of Reference 6.2-14 and is illustrated in Figure 6.2-62.

<u>WETWELL REGION</u>

The wetwell region is modeled in much the same way as the drywell region except that, due to the presence of the suppression pool, two subregions are identified: one to represent the wetwell vapor region, and one to represent the wetwell liquid region (suppression pool). The vapor region is denoted by subscript sv. Mass and energy balances on this subregion yield the following:

$$\frac{dM_{SV}}{dt} = \frac{d(M_{NC})_{SV}}{dt} + \frac{d(M_{stm})_{SV}}{dt} \tag{5}$$
$$= [\dot{M}_{evap}]_{in} - [\dot{M}_{VS} + (\dot{M}_{cond})_{SV} + \dot{M}_{drop}]_{out}$$

As was the case in the drywell region, the wetwell vapor region is assumed to maintain saturated conditions. Therefore,

$$(M_{stm})_{SV} = \frac{V_{SV}}{v_g(T_{SV})} \text{ or } \frac{d(M_{stm})_{SV}}{dt} \tag{6}$$
$$= \frac{1}{v_g(T_{SV})} \bullet \frac{dV_{SV}}{dt} - \frac{V_{SV}}{v_g^2(T_{SV})} \bullet \frac{d\,v_g}{dT_{SV}} \bullet \frac{dT_{SV}}{dt}$$

From volume consideration, V_{SV} can change less than 2% and does so gradually throughout the transient. Therefore, the approximation is made that,

$$\frac{dV_{SV}}{dt} \sim 0 \tag{7}$$

The suppression pool represents a large surface for condensation and evaporation thus resulting in a net mass transfer between the liquid and vapor subregions. This effect serves to maintain the wetwell vapor region in a saturated state and is therefore modeled with the terms in $\dot{M}_{evap}$ and M_{drop}. The kinetic theory of condensation (Reference 6.2-15) is used to determine these mass transfer rates. This results in the following expressions:

$$(\dot{M}_{cond})_{sv} = 144\, \Gamma\, A_{cond} \sqrt{\frac{g_c}{2\pi R_{stm}}} \bullet \frac{(P_{stm})_{sv}}{\sqrt{T^*_{sv}}} \tag{8}$$
$$\dot{M}_{evap} = 144\, A_{cond} \sqrt{\frac{g_c}{2\pi R_{stm}}} - \frac{P_g(T_\ell)}{\sqrt{T_{\ell^*}}}$$

$$where,\ \Gamma = -w\sqrt{\pi}\ [1 + erf(w)] - e^{-w^2}$$

$$w = \frac{G_{net}}{G_{std}} = \frac{\sqrt{2\pi}\left(\dot{M}_{evap} + (\dot{M}_{cond})_{sv}\right)}{(144) - A_{cond}\ \rho_{stm}\sqrt{2\,g_c\,R_{stm}\,T^*_{sv}}} \qquad (9)$$

$$erf(w) = \frac{2}{\sqrt{\pi}}\int_o^w e^{-z^2}\,d_z$$

For the energy balance,

$$\frac{dE_{sv}}{dt} = C_v^*\,T_{sv}^*\,\frac{d(M_{NC})_{sv}}{dt} + d(M_{NC})_{sv}\,C_v^*\,\frac{dT_{sv}}{dt} + U_g(T_{sv})\,\frac{d(M_{stm})_{sv}}{dt}$$
$$+ (M_{stm})_{sv}\,\frac{dU_g}{dT_{sv}} - \frac{dT_{sv}}{dt} \qquad (10)$$
$$= [\dot{M}_{evap}\,h_g(T_s)]_{in} - [\dot{Q}_{VB} + (\dot{M}_{cond_{sv}}\,h_f(T_{sv}) + \dot{M}_{drop}\,h_g(T_{sv})]_{out}$$

The suppression pool region is denoted by subscript s. Mass and energy balances on this subregion yield the following:

$$\frac{dM_s}{dt} = [\dot{M}_{drop} + \dot{M}_{cond} + (\dot{M}_{cond})_{sv}]_{in} - [\dot{M}_{evap}]_{out} \qquad (11)$$

$$\frac{dE_s}{dt} = C_v\,(T_s - 32)\,\frac{dM_s}{dt} + M_s\,C_v\,\frac{dT_s}{dt}$$
$$= [\dot{M}_{cond}\,h_f(T_v) + (\dot{M}_{cond})_{sv}\,h_f(T_{sv}) + \dot{M}_{drop}\,h_g(T_{sv}) \qquad (12)$$
$$+ \dot{M}_{spray}\,[h_f(T_f - T_s)]_{in} - [\dot{M}_{evap}\,h_g(T_s)]_{out}$$

Two additional mass and energy transfer mechanisms need further definition. These are:

Vacuum Breaker Flows

When sufficient differential pressure has built up across the diaphragm slab, the wetwell-to-drywell vacuum breaker assemblies will open allowing for transfer of mass and energy between these two regions. This transfer is described as follows:

(13)

$$\dot{M}_{VB} = C_{VB}^{*} A_{VB}\left[\frac{2g_c k_{sv}}{k_{sv}-1}\rho_{sv}P_{sv}\left\{1-\left(\frac{P_D}{P_{sv}}\right)^{\frac{k_{sv}+1}{k_{sv}}}\right\}\right]^{1/2} \text{for} \left(\frac{P_D}{P_{sv}}\right) > \left(\frac{2}{k_{sv}+1}\right)^{\frac{k_{sv}}{k_{sv}-1}}$$

Subcritical Flow

$$\dot{M}_{VB} = C_{VB}^{*} A_{VB}\left[g_c k_{sv} p_{sv}\rho_{sv}\left(\frac{2}{k_{sv}+1}\right)^{\frac{k_{sv}+1}{k_{sv}-1}}\right]^{1/2} \text{for} \left(\frac{P_D}{P_{sv}}\right) \leq \left(\frac{2}{k_{sv}+1}\right)^{\frac{k_{sv}}{k_{sv}-1}}$$

Critical Flow

$$(\dot{M}_{VB})_{stm} = \left(\frac{M_{stm}}{M_{stm}+M_{NC}}\right)_{sv}\dot{M}_{VB}$$

$$(\dot{M}_{VB})_{NC} = \left(\frac{M_{NC}}{M_{stm}+M_{NC}}\right)_{sv}\dot{M}_{VB} \qquad (14)$$

$$k_{sv} = \left(\frac{P_{NC}}{P_{tot}}\right)_{sv}k_{NC} + \left(\frac{P_{stm}}{P_{tot}}\right)_{sv}k_{stm}$$

and,

$$\dot{Q}_{VB} = (\dot{M}_{vs})_{stm}h_g(T_{sv}) + (\dot{M}_{VB})_{NC}C_P^{*}T_{sv}^{*} \qquad (15)$$

RHR Heat Exchangers

In the drywell spray mode, the RHR system draws water from the suppression pool, passes it through the RHR heat exchangers, and injects it into the drywell vapor region. As such, the RHR heat exchangers must be modeled to reflect this condition. Therefore,

$$\text{where } \dot{Q}_{HX} = \dot{M}_{spray}C_p(T_s - T_{out} = \zeta E C_p(T_s - T_{sw})$$

$$\zeta = \min(\dot{M}_{spray}, \dot{M}_{sw}) \qquad (16)$$

$$\text{Combining yields, } T_{out} = T_s - \frac{\zeta E}{\dot{M}_{spray}}(T_s - T_{sw})$$

These equations, combined with the state equations for steam and nitrogen, yield a set of coupled equations which, when reduced and solved simultaneously, determine the temporal response of the primary containment system to the postulated inadvertent drywell spray accident.

The inherent conservatisms of this model are: neglect transfer of sensible heat energy from equipment and structures to the drywell vapor region, disallow re-evaporation of the condensed drywell steam, maintain a large volume for the drywell region by transferring condensed steam mass directly to the suppression pool, and require saturated conditions in the primary containment vapor regions. Expanding on this last conservatism, for conditions during which a super heated environment is present initially, it is possible to get a low "short term" drop in vapor region pressure. This drop is associated with desuperheating the steam component; the energy for this process comes from the non-condensable component. This reduces the vapor region temperature--and hence pressure--and proceeds until the vapor region is saturated. For relatively hot spray water (e.g., 80°F), this short-term pressure drop can, in fact, give the maximum negative pressure. However, for cases wherein relatively cold spray water is used (e.g., 50°F) the maximum negative pressure is the "long-term" pressure. For this situation, a high relative humidity is conservative. This is the case for Susquehanna SES and, hence, justifies the assumption of saturated conditions for the primary containment vapor regions - both initially and throughout the transient.

In addition to the modeling conservatism, initial conditions for the primary containment are also chosen to induce conservatism in the analysis. The presence of any non-condensables $_{NC}$ in the drywell tends to "hold-up" the depressurization of this region following spray actuation. Thus, a condition is postulated wherein a small break occurs within the drywell serving to pressurize this region and drive all the non-condensables to the wetwell vapor space. This sets the initial pressure distribution (and, along with the assumptions regarding saturated conditions for the steam phase, the temperature distribution) for all three regions - drywell, wetwell vapor region, and suppression pool. These initial conditions are presented in Table 6.2-23.

The results of this analysis are illustrated in Figures 6.2-63 and 6.2-64. Again, these results indicate a maximum negative drywell pressure of -4.72 psig.

The differential pressure experienced across the diaphragm slab during this transient is illustrated in Figure 6.2-65. As indicated in this figure, a maximum –P of 4.6 psid results. This is well below the 28 psid design value for this slab.

6.2.1.1.4.1 Glossary of Terms Used in Subsection 6.2.1.1.4

A_{COND}	=	Suppression Pool Free Surface Area, ft^2
A_{VB}	=	Vent Area Through Vacuum Breakers, ft^2
C_{VB}	=	Vacuum Breaker Flow Coefficient
C_p	=	Specific Heat at Const. Press. for H_2O, 1 Btu/lb°F
C_p^*	=	Specific Heat at Const. Press. for N_2, 0.247 Btu/lb°R
C_v	=	Specific Heat at Const. Vol. for H_2O, 1 Btu/lb°F
C_v^*	=	Specific Heat at Const. Vol. for N_2, 0.176 Btu/lb°R
E	=	Energy Content, Btu
g_c	=	Gravitational Constant, 32.174 ft/sec^2
h	=	Specific Enthalpy, Btu/lb
k	=	Ratio of Specific Heats
M	=	Mass, lbs

M_{NC}	=	Non-Condensable Mass, lbs
M_{cond}	=	Condensate Mass, lbs
M_{drop}	=	Droplet Mass, lbs
M_{evap}	=	Evaporated Steam Mass, lbs
M_{stm}	=	Steam Mass, lbs
P	=	Pressure, psi
R	=	Gas Constant, ft-lbf/lb°R
Q	=	Transferred Energy, Btu
T	=	Temperature, °F
T*	=	Absolute Temperature, °R
t	=	Time, Sec
u_{stm}	=	Steam Specific Energy, Btu/lb
V	=	Volume, ft^3
ν	=	Specific volume, ft^3/lbm
w	=	Mass flux ratio, dimensionless
T_P	=	Liquid tempertaure, °R
u	=	Specific internal energy, BTU/lbm
P_g	=	Saturated pressure, psi

Greek Symbols

>	=	Spray Efficiency
γ	=	Hx Effectiveness
.	=	Minimum Hx Flowrate, lbs/sec
Δ	=	Density, lbs/ft^3

Subscripts

D	=	Drywell Region
f	=	Final; Saturated Liquid
g	=	Saturated Vapor
S	=	Suppression Pool Liquid Region, Sump
sat	=	Saturated Conditions
spray	=	Spray
SV	=	Suppression Pool Vapor Region
VB	=	Vacuum Breaker

6.2.1.1.5 Suppression Pool Bypass Effects

6.2.1.1.5.1 Protection Against Bypass Paths

The pressure boundary (diaphragm slab) between drywell and suppression chamber including the vent pipes, is fabricated, erected, and inspected by nondestructive examination methods in accordance with and to the acceptance standards of the ASME Code Section III, Subsection NC, 1971 Edition, including addenda through Summer 1972. This special construction, inspection and quality control ensures the integrity of this boundary. The design basis downward pressure differential and temperature for this boundary was established at 28 psid and 340°F which is substantially greater than conditions during a DBA. Actual peak accident differential pressure and temperature for this boundary (diaphragm slab) is provided in Table 6.2-6a.

All penetrations of this boundary except the vacuum breaker seats are welded. All penetrations are available for periodic visual inspection.

All potential bypass leakage paths (such as the purge and vent system) have been considered. Every path has at least two isolation valves in the leakage path. These valves are high quality leaktight containment isolation valves which are all normally closed. Other potential paths are discussed below:

1. Leakage through the diaphragm slab is minimized by the liner plate.

2. Leakage through the downcomers is prevented by the use of seamless pipe.

3. Leakage around the downcomers is minimized because each downcomer is attached to the liner plate by a continuously welded ring plate which is vacuum box tested after welding.

4. Leakage around the SRV discharge piping is minimized by the use of flued head connections.

6.2.1.1.5.2 Reactor Blowdown Conditions and Operator Response

In the event of a small break accident in the drywell, steam released will be collected in the drywell air space, and condensed in the suppression pool after passing through the downcomers. However, it is postulated that a portion of the steam can "bypass" the downcomers, passing directly to the suppression chamber air space via vacuum breaker leakage, diaphragm penetration seals leakage or cracks in the diaphragm concrete. The suppression chamber design pressure could be exceeded unless the blowdown is isolated or the wetwell sprays are actuated. To mitigate this accident, the wetwell sprays are manually operated. Procedures specify spray actuation at a suppression chamber pressure of 13 psig. Analysis shows that there is sufficient time for manual actuation of the sprays to prevent the suppression chamber atmosphere pressure from exceeding the design limit of 53 psig.

6.2.1.1.5.3 Analytical Assumptions

The transient was analyzed in three phases. During the first phase, the drywell is pressurized to the point needed to clear the downcomers. The second phase is the air clearing phase during which the drywell air moves to the suppression chamber. The third phase assumes steam only in the drywell, no further clearing of the downcomer vents, and only steam leaking to the suppression chamber atmosphere.

The drywell and suppression chamber were modelled using two single volume models with the "COPATTA" program. The drywell model was used during Phase I, with two bypass leak sizes of 0.05 and 0.0535 ft^2 studied. Credit was taken for the drywell walls as heat sinks, using the Uchida coefficient as the condensing coefficient. For the small break accident considered, 10 seconds were needed to pressurize the drywell sufficiently to clear the downcomers. The air and steam state points were used as initial conditions for Phase II, air clearing phase. All of the drywell air was assumed to be cleared in one second. In passing through the suppression pool, the air was cooled to the pool temperature before entering the suppression chamber air space. All steam entrained during clearing was assumed to be condensed in the suppression pool.

During Phase I, the air and steam leaked from the drywell model were added to the suppression chamber model. During Phase II, the air cleared was added to the suppression chamber model vapor region at the pool temperature, over a one-second period. During Phase III, the drywell would be filled with only steam. The team leakage into the suppression chamber was based on a 5.18 psid and calculated with the homogeneous frozen flow equation. The drywell steam properties ranged from saturated steam at 35.18 psig to 58.18 psig over a period of 1000 seconds. The upper limit, rather than reflecting the drywell design pressure, accounts for the 5 psig required to clear the downcomers. Credit was taken for suppression chamber walls being heat sinks, with Uchida condensing coefficient used. All 87 downcomers and 6 of 16 main steam relief valve discharge lines were treated as heat sources in the suppression chamber model. During Phase III, steam will be filling the downcomers and 6 SRV discharge lines, and thus a net transfer of heat from the tube surfaces to the suppression chamber atmosphere occurs. Table 6.2-24 lists drywell and suppression chamber initial and boundary conditions.

6.2.1.1.5.4 Analytical Results

For a 0.0535 ft^2 bypass leakage path, it takes 22.6 minutes for the suppression chamber to pressurize from 30 psig to 53 psig.

For a 0.05 ft^2 path, it takes 24.2 minutes to pressurize from 30 psig to 53 psig. Table 6.2-25 summarizes the blowdown data and calculated leakage.

6.2.1.1.6 Suppression Pool Dynamic Loads

Hydrodynamic loads due to main steam safety relief valve discharge and LOCA are described in Reference 6.2-28.

6.2.1.1.7 Asymmetric Loading Conditions

Asymmetric loads considered for the design of the containment structure include horizontal seismic and localized missile and pipe rupture loads. Refer to Section 3.7 for a description of the seismic analysis methods. Refer to Sections 3.6 and 3.8 for a description of the analytical methods used for missile and pipe rupture loads.

6.2.1.1.8 Containment Environment Control

The functional capability of the containment ventilation system to maintain the temperature, pressure, and humidity of the containment and subcompartments is discussed in Subsection 9.4.5.

6.2.1.1.9 Post-Accident Monitoring

A description of the post-accident monitoring systems is provided in Section 7.5.

6.2.1.2 Containment Subcompartments

The containment subcompartments considered for SSES were the biological shield annulus and the drywell head region. The modeling procedures and considerations are presented in Appendix 6A.

6.2.1.3 Mass and Energy Release Analyses for Postulated Loss-of-Coolant Accidents

This section presents information concerning the transient energy release rates from the reactor primary system to the containment system following a LOCA. Where the emergency core cooling systems enter into the determination of energy released to the containment, the single failure criteria has been applied to maximize the energy release to the containment following a LOCA.

6.2.1.3.1 Mass and Energy Release Data

Table 6.2-9 provides the mass and enthalpy release data for the recirculation line break. Figure 6.2-18 shows the blowdown flow rates for the recirculation line break graphically. This data was employed in the DBA containment pressure-temperature transient analyses reported in Subsection 6.2.1.1.3.3.1.

Table 6.2-10 provides the mass and enthalpy release data for the main steamline break. Figure 6.2-20 shows the vessel blowdown flow rates for the main steamline break as a function of time after the postulated rupture. This information has been employed in the containment response analyses presented in subsection 6.2.1.1.3.3.2.

Table 6.2-26 presents the long-term mass and energy release rates for the recirculation line break. This information is shown graphically in Figure 6.2-70.

6.2.1.3.2 Energy Sources

The reactor coolant system conditions prior to the line break are presented in Table 6.2-3a. Reactor blowdown calculations for containment response analyses are based upon these conditions during a LOCA.

The energy released to the containment during a LOCA is comprised of the:

a. Stored energy in the reactor system
b. Energy generated by fission product decay
c. Heat transfer from piping, vessel walls, and non-fuel hardware.
d. Sensible energy stored in the reactor structures
e. Energy being added by the ECCS pumps
f. Energy released from hydrogen generation and cladding oxidation.

All but the pump heat energy addition is discussed or referenced in this section. The pump heat rate used in evaluating the containment response to the LOCA is discussed in Table 6.2-5a.

Following each postulated accident event, the stored energy in the reactor system and the energy generated by fission product decay will be released. The rate of release of core decay heat for the evaluation of the containment response to a LOCA is provided in Table 6.2-11 as a function of time after accident initiation.

Following a LOCA, the sensible energy stored in the reactor primary system metal will be transferred to the recirculating ECCS water and will thus contribute to the suppression pool and containment heatup.

6.2.1.3.3 Reactor Blowdown Model Description

The reactor primary system blowdown flow rates were evaluated with the models described in References 6.2-1, 6.2-23 and 6.2-26.

6.2.1.3.4 Effects of Metal-Water Reaction

The containment systems are designed to accommodate the effects of metal-water reactions and other chemical reactions which may occur following a LOCA. The amount of metal-water reaction which can be accommodated is consistent with the performance objectives of the ECCS. Subsection 6.2.5.3 provides a discussion on the generation of metal water hydrogen within the containment.

6.2.1.3.5 Thermal Hydraulic Data for Reactor Analysis

Sufficient data to perform confirming thermodynamic evaluations of the containment has been provided in Subsection 6.2.1.1.3.3 and associated tables.

6.2.1.4 Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures Inside Containment

Not Applicable to BWR.

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies on Emergency Core Cooling System

Not Applicable to BWR.

6.2.1.6 Testing and Inspection

Preoperational containment testing and inspection programs are described in Section 3.8 and Chapter 14. Operational containment testing and inspection programs are described in Subsection 6.2.6. The requirements and bases for acceptability are described in the Technical Specifications.

6.2.1.7 Instrumentation Requirements

Containment pressure and temperature sensing and the associated actuating input to the ESF systems is discussed in Section 7.3. Refer to Section 7.5 for a discussion of the display instrumentation.

Containment airborne radioactivity monitoring is described in Subsection 12.3.4. Containment hydrogen monitoring is described in Subsection 6.2.5.

6.2.1.8 Response to NRC Generic Letter (GL) 96-06

GL 96-06 was issued on September 30, 1996, to address the following issues of concern:

1. Cooling water systems serving the containment air coolers may be exposed to the hydrodynamic effects of water hammer during either a loss-of-coolant accident (LOCA)

or a main steam line break (MSLB). These cooling water systems were not designed to withstand the hydrodynamic effects of water hammer.

2. Cooling water systems serving the containment air coolers may experience two-phase flow conditions during postulated LOCA and MSLB scenarios. The heat removal assumptions for design-basis accident scenarios are based on single-phase flow conditions.

3. Thermally induced overpressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident-mitigating systems to perform their safety functions and could lead to a breach of containment integrity through bypass leakage.

PPL's response and NRC's acceptance are documented in Reference 6.2-31 through 6.2-42. The following sections are a summary of PPL's response to Generic Letter 96-06.

6.2.1.8.1 Drywell Cooling Water hammer and Two-Phase Flow

6.2.1.8.1.1 Containment Cooling

The SSES drywell cooling system is a non-safety-related system which is used to maintain containment temperature within acceptable limits during normal plant operations. The drywell cooling system automatically isolates on a Loss of Coolant Accident (LOCA) signal, and is not required to mitigate the consequences of a LOCA. Since the drywell cooling system is not credited in the SSES design bases, the potential for a drywell cooling water hammer or two-phase flow to affect containment cooling is not a concern.

6.2.1.8.1.2 Containment Integrity

Although the drywell cooling system is non-safety-related, it represents a viable form of containment heat removal during specific plant transients. The SSES Emergency Operating Procedure allow for its restoration and operation under transient conditions.

An evaluation of the restoration and operation of the drywell cooling system under transient conditions identified the possibility for a hydraulic transient during the restoration of drywell cooling. A calculation was performed, and concluded that the loads induced by the postulated hydraulic transient are relatively small and would not result in pipe or component stresses above allowable values. Therefore, the loads induced by a postulated water hammer will not impact containment integrity.

6.2.1.8.1.3 Closed Loop System Overpressurization

An evaluation of containment piping networks revealed that the only systems susceptible to this phenomenon are the non-safety related Reactor Building Closed Cooling Water (RBCCW) and Reactor Building Chilled Water (RBCW) systems, and the Drywell Floor Drain Sump discharge lines.

6.2.1.8.1.3.1 Reactor Building Closed Cooling Water/Reactor Building Cooling Water (RBCCW/RBCW)

The RBCCW and RBCW systems supply non-safety-related cooling loads. The potential for the rupture of these systems due to overpressurization does not threaten the availability of safety-related equipment needed to mitigate Design Basis Accidents. Further, this piping is assumed to be available during Design Basis Accidents, and is not credited in any SSES safety analyses.

6.2.1.8.1.3.2 Drywell Floor Drain Sump

The Drywell Floor Drain Sump system is a non-safety-related system and is not required for the accident mitigation. The pump discharge piping is subject to thermally induced pressurization between the pump discharge check valves and the inboard containment isolation valve. However, this piping will only pressurize if all four pump discharge check valves are leak tight. These check valves prevent gross leakage during sump pump operation and are not leak tight. Based on the valve not being leak tight, the failure of this piping due to excessive pressurization is not expected.

6.2.1.8.2 Containment Penetration Overpressurization

An evaluation of containment penetrations revealed that a total of twelve penetrations (per unit) are susceptible to the thermal pressurization phenomenon. These penetrations are:

1. X-23 & X-24 – the RBCCW supply and return lines to the recirculation pump seals and motor oil coolers;
2. X-53, X-54, X-55 & X-56 – the RBCW supply and return lines to the drywell coolers
3. X-85A, X-85B, X-86A, X-86B – the RBCW supply and return lines to the recirculation pump motor coolers;
4. X-61A – the Demineralization Water line to the drywell; and,
5. X-17 – the Residual Heat Removal (RHR) head spray line.

The RBCCW and RBCW containment penetrations support non-safety-related loads and automatically isolate on conditions indicative of a LOCA. The Demineralized Water system provides a source of clean water to the drywell for refueling outage maintenance activities, and is isolated prior to and during postulated accidents. Although the head spray line is part of the RHR system, it does not perform any safety-related function. Therefore, the potential for overpressurization of all susceptible penetrations does not affect the availability of safety-related equipment needed to mitigate Design Basis Accidents. The only safety-related function of these penetration assemblies (i.e., piping and valves) is to act as a containment barrier; in the post accident environment, these penetrations are not required to support any active safety-related function.

Since the RHR system will be operating during the post-accident time frame, the potential for overpressurization of the head spray penetration to impact the RHR systems, pressure boundary was also evaluated. Various failure modes were considered and it was determined that the worst case rupture induced by overpressurization of this penetration will not result in a breach of the operating system's pressure boundary. As such, RHR system operation, as well as primary containment integrity is unaffected.

The process piping located between the containment isolation valves associated with each penetration was evaluated using the criteria provided in the ASME Boiler & Pressure Vessel Code, Section III, Appendix F. Paragraph F-1430 has been used as a basis for calculating the allowable stresses. The results of the evaluation are:

- The predicted maximum pressures for all of the lines are within the allowable pressure limits
- All of the piping stresses are within allowable Appendix F limits
- For all of the penetrations, pressure relief will occur via a leakage path rather than through a catastrophic pressure boundary failure
- Gross failure of the valves is not expected

6.2.2 CONTAINMENT HEAT REMOVAL SYSTEM

6.2.2.1 Design Basis

The containment heat removal system, consisting of the containment cooling system, is an integral part of the RHR system. This system prevents excessive containment temperatures and pressures following a LOCA so that containment integrity is maintained. To fulfill this purpose, the containment cooling system meets the following safety design bases:

a. The system shall limit the long term bulk temperature of the suppression pool without spray operation when considering the energy additions to the containment following a LOCA. (See Reference 6.2-4.) These energy additions, as a function of time, are provided in the previous section.

b. The single failure criteria shall apply to the system.

c. The system shall be designed to safety grade requirements including the capability to perform its function following a Safe Shutdown Earthquake.

d. The system shall maintain operation during those environmental conditions imposed by the LOCA.

e. Each active component of the system shall be testable during normal operation of the nuclear power plant.

6.2.2.2 Containment Cooling System Design

Containment cooling is initiated in loop A or B by manually starting the RHR service water pump, opening the service water valve at the heat exchanger and opening the pool return valve. The containment cooling system is an integral part of the RHR system. Water is drawn from the suppression pool, pumped through one or both RHR heat exchangers and delivered to the suppression pool, to the containment spray header, or to the suppression pool vapor space spray header. Water from the RHR service water system is pumped through the heat exchanger tube side to exchange heat with the processed water. Two cooling loops are provided; each is mechanically and electrically separate from the other to achieve redundancy. P&ID is provided in Section 5.4. The process diagram, including the process data, is provided in Section 5.4 for all design operating modes and conditions.

All portions of the containment cooling system are designed to withstand operating loads and loads resulting from natural phenomena. All operating components can be tested during normal plant operation so that reliability can be ensured. Construction codes and standards are covered in Subsection 5.4.7.

The containment cooling function is aligned manually. There are no signals that automatically initiate the containment cooling function. LPCI mode is automatically initiated from ECCS signals and the RHR system aligned for containment cooling when directed by emergency procedures. As an alternative, with one LPCI injection pump in service in an RHR loop, an RHR heat exchanger may be manually aligned for long term containment cooling by limiting LPCI Injection flow to 10,000 gpm and directing flow through the RHR heat exchanger by closing the HV151F048A(B) valve. The RHRSW system must also be manually initiated to supply cooling water to the heat exchanger. Only one RHR heat exchanger is credited for long term cooling in the SSES containment analysis. If a single failure has occurred, and the action which the plant operator is taking does not result in system initiation, then the operator will place the other totally redundant system into operation by following the same initiation procedure. Containment spray is also manually aligned when directed by Emergency Procedures.

In addition to the post-accident heat removal function, the RHR system may be utilized in the suppression pool cooling mode for periods during normal plant operation. LOCA Analyses which account for a delayed LPCI injection due to the automatic realignment from suppression pool cooling indicate that acceptable peak cladding temperatures are maintained. Further, design and licensing basis analyses which address the system's response to design basis LOCA/LOOP events, while in the suppression pool cooling configuration, demonstrate that a usage of up to 10% (maximum allowed without management review) is acceptable.

Preoperational tests are performed to verify individual component operation, individual logic element operation, and system operation up to the drywell spray spargers. A similar sparger nozzle is bench-tested in the manufacturer's laboratory to substantiate the performance data established from hydraulic calculations. Finally, the spargers are tested by air, and some visible indication means is provided to verify that all nozzles are clear.

6.2.2.3 Design Evaluation of the Containment Cooling System

In the event of the postulated LOCA, the short term energy release from the reactor primary system will be dumped to the suppression pool. This will cause a pool temperature rise of approximately 35°F. Subsequent to the accident, fission product decay heat will result in a continuing energy input to the pool. The containment cooling system will remove this energy, which is input to the primary containment system, thus resulting in acceptable suppression pool temperatures and containment pressures.

The insulation used within containment is predominantly all metal, reflective type. The other insulation types used in containment are phenolic foam insulation, fibrous insulation and Min-K insulation.

The reflective metallic insulation consists of large assemblies held in place by stainless steel latches. The latches are equipped with positive locking devices. The maximum weight for each assembly is 40 pounds. Each assembly consists of two half segments which overlap each other at longitudinal joints.

Phenolic foam insulation is a closed cell, low specific gravity material which, if transported to the suppression pool, would float. The phenolic foam is only used on the Reactor Building Chilled Water piping and is jacketed with stainless steel wherever practical.

Fibrous insulation is used in miscellaneous applications where the use of other insulation types is not practical. The total quantity of fibrous insulation is minimal.

Min-K insulation is used under pipe whip restraints and is significantly shielded from direct jet impact. All Min-K insulation is encapsulated in stainless steel cassettes.

For a representative large pipe break inside containment, it is difficult to estimate the actual amount of insulation that would be dislodged. But, assuming that several segments would be removed from the broken pipe and several more from the pipes in close proximity to the impingement jet, there would be a relatively small amount of insulation loose in the drywell area. This loose insulation could accumulate in many areas of the drywell including platforms, other piping and equipment. Another possible area would be the downcomer openings through the diaphragm floor. It would be unlikely that the relatively larger pieces of insulation would pass through the small openings at the top of the 87 downcomers. These openings are made smaller by the presence of jet deflectors as shown in Figure 6.2-56. Even so, the suction strainers on the CS and RHR pumps are sized assuming that conservative amounts of insulation transport to the suppression pool after a LOCA and that the insulation is filtered by the strainers.

Small pipe breaks are not expected to create significant debris. In addition, the drywell floor flood-up rate would be low for small breaks and the water height above the 87 downcomer weirs would be small. Therefore, the potential for any debris created by a small pipe break to be transported to the suppression pool is minimal. HPCI is designed to support small pipe breaks that do not cause rapid depressurization of the reactor vessel. The HPCI suppression pool suction strainers are conservatively designed for 50% plugging, even though small pipe breaks are not expected to result in significant debris in the suppression pool.

The RCIC suppression pool suction strainers are also designed for 50% plugging. RCIC is not an ECCS system. As such, accident analyses do not assume that RCIC will respond to any events (pipe breaks) that would result in the generation of debris or transport of debris to the suppression pool. Nonetheless, RCIC may be called upon to mitigate the effects of small pipe breaks. Such pipe breaks would not result in significant debris in the suppression pool as explained above.

The primary suction source for HPCI and RCIC is the Condensate Storage Tank (CST). This further reduces the probability that the HPCI and RCIC suppression pool suction strainers would be fouled even if the debris resulting from a small pipe break reached the suppression pool.

6.2.2.3.1 Summary of Containment Cooling Analysis

When calculating the long term, post LOCA pool temperature transient, it is assumed that the initial suppression pool temperature is at its maximum Technical Specification value. The containment analyses also assume RHR service water is at its peak design temperature of 97 F throughout the transient. Note however that a sensitivity analysis has been performed which credits a lower, yet conservative, RHR service water temperature for the first 2 hours of the containment analyses (91 F). This change justifies an increase in operator response time to initiate containment cooling during accident conditions from 10 minute to 20 minutes. Although the containment analyses were not rerun with an operator response time of 20 minutes at the

reduced RHRSW temperature for the first two hours, the sensitivity analysis concludes that the peak suppression pool temperatures calculated in the long term DBA/LOCA containment analyses (which are based on an operator response time of 10 minutes) remain valid and bounding. These assumptions maximize the heat sink temperature to which the containment heat is rejected and thus maximizes the containment temperature. In addition, the RHR heat exchanger is assumed to be in a fully fouled condition at the time the accident occurs. This conservatively minimizes the heat exchanger heat removal capacity. The resultant suppression pool temperature transient is described in Subsection 6.2.1.1.3.3.1 and is shown on Figure 6.2-8. Even with the degraded conditions outlined above, the maximum temperature is 211.2^{o}F. This peak occurs at approximately 9.6 hours after the accident.

When evaluating this long term suppression pool transient, all heat sources in the containment are considered. These heat sources are discussed in Subsection 6.2.1.3. Figure 6.2-9 shows the actual heat removal rate of the RHR heat exchanger.

The conservative evaluation procedure described above demonstrates that the RHR system in the suppression pool cooling mode limits the post-DBA containment temperature transient.

6.2.2.4 Tests and Inspections

The preoperational test program of the containment cooling system is described in Chapter 14.

Inservice testing of the pumps and valves in the containment heat removal systems will be in accordance with ASME Code as discussed in FSAR Section 3.9.6. An 18-inch line which is routed from the combined pump discharge back to the suppression pool is provided for RHR pump testing. Installed instrumentation is provided for measuring pump inlet and discharge pressure, and flow rate. Temperature of the pumped fluid at the pump inlet and combined discharge is recorded. All pump bearings are lubricated by the fluid being pumped; therefore, indication of bearing temperature is not required by the Code. Portable equipment will be required for testing vibration amplitude.

Leak rate testing of containment isolation valves is discussed in Section 6.2.6. All power-operated valves in the RHR system/containment cooling mode may be exercised during normal operation. The RHR pump discharge check valve has local disc position indicators on the valve hinge pin for verification of operability.

Inservice inspection will be in accordance with ASME Code Section XI, as discussed in FSAR Section 5.2.4.

6.2.2.5 Instrumentation Requirements

The details of the instrumentation are provided in Section 7.3. The suppression pool cooling mode of the RHR system is manually initiated from the control room.

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

The secondary containment comprises the exterior structure of reactor building and the interior walls and floors that separate the three ventilation zones.

Zones I and II are the portions of the reactor building below elevation 779 ft. 1 in. surrounding the Unit 1 and Unit 2 primary containments, respectively.

Zone III consists of the portion of the reactor buildings above elevation 779 ft. 1 in. with the exception of the HVAC equipment rooms which are not part of the secondary containment.

The secondary containment houses the refueling and reactor servicing equipment, the new and spent fuel storage facilities, and other reactor auxiliary or service equipment, including the Reactor Core Isolation Cooling System, Reactor Water Cleanup System, Standby Liquid Control System, Control Rod Drive System equipment, the Emergency Core Cooling System, and electrical equipment components.

6.2.3.1 Design Bases

The functional capability of the ventilation system to maintain negative pressure in the secondary containment with respect to outdoors is discussed in Subsections 6.5.1.1 and 9.4.2.

The conditions that could exist following a LOCA require the establishment of a method of controlling the leakage from the primary into the secondary containment.

6.2.3.2 System Design

6.2.3.2.1 Secondary Containment Design

The reactor building is designed and constructed in accordance with the design criteria outlined in Chapter 3. The base mat, floor slabs and exterior walls below the refueling floor are constructed of reinforced concrete. Above the refueling floor at elevation 818 ft. 1 in., the building consists of a structural steel frame supporting an insulated metal roof deck and insulated siding wall panels.

Joints in the superstructure paneling are designed to ensure leaktightness. Penetrations of the reactor building are designed with leakage characteristics consistent with leakage requirements of the entire building. The reactor building is designed to limit the inleakage to 225 percent of the secondary containment free volume per day at -¼ in. wg, while operating the SGTS. The building structure above the refueling floor is also designed to contain a negative interior pressure of 0.25 in. wg.

Following a loss-of-coolant accident, all affected volumes of the secondary containment will be maintained at a negative pressure of 0.25 in. w.g. All these volumes are identified on Figures 6.2-24, 6.2-25, 6.2-26, 6.2-27, 6.2-28, 6.2-29, 6.2-30, 6.2-31, 6.2-32, 6.2-33, 6.2-34, 6.2-35, 6.2-36, 6.2-37, 6.2-38, 6.2-39, 6.2-40, 6.2-41, 6.2-42, and 6.2-43 as Ventilation Zones I, II and III.

An analysis of the post LOCA pressure transient in the secondary containment has been performed to determine the length of time following LOCA signal that the pressure in the secondary containment would exceed -¼ in. wg. The analysis assumed that the normal ventilation system was operating at the design pressure of -¼ in. w.g. until the E.S.F. signal isolated the system and initiated SGTS startup. An inleakage rate of 225% of secondary containment per day was used. A single failure of one SGTS train was assumed as well as a loss of offsite power to maximize the drawdown time. Heat loads from operating equipment and the heat transferred through the drywell head were considered. Each SGTS fan has a

rated capacity of 10,500 CFM at a 17 in. w.g. pressure. Figure 6.2-60 shows the secondary containment pressure vs time for the drawdown under worst conditions. The secondary containment pressure recovers to -¼ in. w.g. within 5 minutes. The completion of the leakage path resulting from the activity release mechanisms inside the containment, leakage through the primary containment and possible leakage through the secondary containment would require a significantly greater period of time than would exist until the -¼ in. w.g. was restored.

Entrance to the reactor building is through the turbine building with air locks provided for separation. Access doors between building ventilation zones and into the control structure are provided with airlocks. Secondary containment access doors which are not provided with airlocks are administratively controlled to maintain secondary containment integrity.

The railroad access shaft, provided in Unit 1 only, is accessible to Zones I and III through access hatches that are normally kept closed and will not be opened without proper controls to maintain secondary containment integrity during normal plant operation. Ventilation supply and return ducting to the railroad access shaft is provided with manual isolation dampers to provide for opening the exterior railroad access door after closing the dampers, thus converting to an airlock and retaining secondary containment integrity. Operation of these dampers and the railroad access doors and hatches is administratively controlled. Doors within the secondary containment may be used for personnel ingress and egress during normal plant operation. The truck bay is part of Zone II. The truck bay access hatch will be normally closed. Opening of this hatch and the truck bay door (No. 102) will be administratively controlled.

The boundaries of the three zones of the secondary containment are shown on Figures 6.2-24, 6.2-25, 6.2-26, 6.2-27, 6.2-28, 6.2-29, 6.2-30, 6.2-31, 6.2-32, 6.2-33, 6.2-34, 6.2-35, 6.2-36, 6.2-37, 6.2-38, 6.2-39, 6.2-40, 6.2-41, 6.2-42 and 6.2-43.

The secondary containment design data can be found in Table 6.2-17.

A simplified air flow diagram for the secondary containment normal plant operation is shown on Figure 6.2-53. Figure 6.2-52 shows the simplified air flow diagram when Zone I or II and Zone III are isolated. An air flow diagram for Zone III isolation is shown on Figure 6.2-54.

6.2.3.2.2 Secondary Containment Isolation System

Isolation dampers and the plant protection signals that activate the secondary containment isolation system are described in Subsection 9.4.2.1.3.

6.2.3.2.3 Secondary Containment Bypass Leakage (SCBL)

The secondary containment structure completely encloses the primary containment structure such that a dual-containment design is utilized to limit the spread of radioactivity to the environment during a design basis LOCA. Following a LOCA, the secondary containment structure is maintained at a negative pressure, so that leakage from primary containment to secondary containment can be collected and filtered prior to release to the environment. SGTS performs the function of maintaining a negative pressure within secondary containment, as well as, collecting and filtering the leakage from primary containment, as described in Section 6.5.

The use of a dual-containment design results in the potential for Secondary Containment Bypass Leakage (SCBL). SCBL is defined as that leakage from primary containment which can bypass the leakage collection/filtration systems of secondary containment and escape

directly to the environment. Similarly, a potential SCBL pathway is defined as any process line that penetrates both primary and secondary containment, or a process line that penetrates primary containment only, with a branch line connection that penetrates secondary containment. Consequently, a valid SCBL pathway is any process line or branch line that penetrates both primary and secondary containment which does not contain a barrier that eliminates bypass leakage from being released directly to the environment.

All potential SCBL pathways have been evaluated. It has been determined that the bypass leakage which could occur following the design basis LOCA results in a conservatively calculated dose within regulatory limits, as described in Section 15.6.5.

Table 6.2-15 identifies those lines penetrating primary containment which do not terminate inside Secondary Containment, as well as, those lines that penetrate primary containment with branch line connections that penetrate secondary containment. The potential SCBL pathways listed in Table 6.2-15 were evaluated to determine if the leakage barriers utilized in these act to eliminate or only limit SCBL. Leakage from those lines terminating in the secondary containment will be collected during the LOCA since the secondary containment is maintained at subatmospheric pressure and all exhaust is processed by the SGTS during these modes (Section 6.5). Therefore, lines terminating within the secondary containment are not considered potential bypass leakage paths and are not listed in Table 6.2-15.

The types of bypass leakage barriers employed by these lines are:

a. Isolation valve(s) inside and/or outside primary containment

b. Leakage collection system

c. Water seal in line

Leakage barriers of types B or C are considered to effectively eliminate any bypass leakage. Type C barriers have sufficient water volume available to maintain the seal for 30 days, as described in Section 6.2.3.2.3.1. Type B barriers insure that any leakage through containment isolation valves is routed through the SGTS filter train before being exhausted to the environment. Type A leakage barriers are considered to limit but not eliminate bypass leakage. Consequently, any potential SCBL pathways that contain only Type A leakage barriers are identified as valid SCBL pathways in Table 6.2-15. Closed systems with non-seismic piping are not relied upon as barriers to eliminate bypass leakage.

Leakage barriers in those lines confirmed to be valid SCBL pathways are periodically tested in a manner consistent with the guidance provided in Subsection 6.2.6 for performing 10CFR50, Appendix J Type B or C tests. The total combined leakage from all valid SCBL pathways is maintained less than or equal to the value specified for SCBL in the Technical Specifications and the DBA LOCA dose analysis value described in Section 15.6.5. Those penetrations for which credit is taken for water seals as a means of eliminating bypass leakage (Table 6.2-15) are tested as described in section 6.2.3.2.3.1.

As shown on Table 6.2-15, the only containment penetrations with lines penetrating both primary and secondary containment are:

- X-9A/B Feedwater Lines
- X-16A/B Core Spray Injection
- X-17 RHR Head Spray
- X-25 Drywell Purge & N_2 Supply*
- X-39A/B RHR Drywell Spray
- X-61A Demineralized Water Connection to Drywell
- X-88A N_2 Make-up to Drywell
- X-201A Wetwell Purge & N_2 Supply*
- X-220B N_2 Make-up to Wetwell

*(Only when the spectacle flange is not closed, see Table 6.2-15)

A valve maintenance and test program limits the total combined leakage through the primary containment isolation valves for these paths to less than that assumed for SCBL in the DBA LOCA Dose analysis described in Section 15.6.5. The test program and leakage limits are given in the Technical Specifications. All other lines listed in Table 6.2-15 were investigated as potential SCBL pathways but, for the reasons given in the table, were shown not to be valid SCBL paths.

6.2.3.2.3.1 Water Seals

Where water seals are used to eliminate the potential of secondary containment bypass leakage, the location of the water seal relative to the system isolation valves can be seen on the system P&IDs and also in Figures 6.2-66B, 6.2-66C, 6.2-66D, 6.2-66H, 6.2-66F, and 6.2-66G. In each case, either a loop seal is present or the water for the seal is replenished from a large reservoir; water seal maintenance is not dependent on a water sealing system.

Where maintenance of the water/loop seal is dependent upon the performance of the primary containment isolation valves, the penetrations have Technical Specification leakage rates for periodic testing given as water leak rates which meet the requirements for hydraulic testing in 10CFR50 Appendix J. Those penetrations for which credit is taken for water seals that do not meet the requirements of Appendix J for water sealing systems or do not rely upon containment isolation valves to maintain the water seal, are conservatively tested to meet pneumatic Technical Specification leakage rates for periodic testing.

A description of the water seals used to eliminate potential SCBL pathways is contained in the notes to Table 6.2-15.

6.2.3.3 Design Evaluation

The design evaluation of the secondary containment ventilation system is given in Subsections 6.5.1 and 9.4.2. The high energy lines within the secondary containment are identified and pipe ruptures analyzed in Section 3.6.

6.2.3.4 Tests and Inspections

The program for initial performance testing is described in Chapter 14. The program for periodic functional testing of the secondary containment isolation system and system components is described in the Technical Specifications.

6.2.3.5 Instrumentation Requirements

The control systems to be employed for the actuation of the reactor building Engineered Safety Feature air handling systems are described in Section 7.3.

The control and monitoring instrumentation for the above systems is discussed in Subsections 6.5.1 and 9.4.2.

6.2.4 CONTAINMENT ISOLATION SYSTEM

The containment isolation system consists of piping, valves and valve actuating means that provide capability for closing penetrations of the primary containment.

6.2.4.1 Design Bases

a. Containment isolation valves provide the necessary isolation of the containment in the event of accidents or other conditions. They limit the release of radioactive materials from the containment by maintaining leakage within the limits specified in the Leak Rate Test Program. For the DBA LOCA dose consequence analysis (see Section 15.6), the assumption is made that all containment isolation valves that are required to be closed (valves listed in Table 6.2-12 that are closed during LOCA) have completed their travel prior to the assumed release of gap activity from the fuel. The gap activity release is assumed to occur 2 minutes following the initiation of the event.

b. Nuclear steam supply system isolation valve closure speed limits radiological effects from exceeding guideline values established by 10CFR 50.67.

c. The design of isolation valving for lines penetrating the containment follows the requirements of General Design Criteria 55 through 56 as described in Subsection 6.2.4.3, Table 6.2-12, and Figures 6.2-44 through 6.2- 44M. Deviations from the explicit requirements of GDC 54 through 56 are discussed in Section 6.2.4.3 and Table 6.2-12, including the notes.

d. Isolation valving for instrument lines that penetrate the containment conforms to the requirements of Regulatory Guide 1.11 (3/71).

e. Containment isolation valves and associated piping including closed piping systems used as isolation barriers, meet the requirements of the ASME Boiler and Pressure Vessel Code Section III Classes 1 or 2, as applicable.

f. Design of the containment isolation valves and associated piping and penetrations shall be Seismic Category I.

g. The primary containment isolation systems have the capability to withstand the design pressure and temperature, which are derived from the design basis LOCA.

h. The primary containment can withstand both normal and accident metal/water reactions without degradation of capability below design limits.

i. Redundancy and physical separation are provided in the electrical and mechanical design. This ensures that no single failure in the Containment Isolation system (i.e. barriers or actuation systems) prevents the system from performing its intended functions.

j. Isolation valves, actuators, and controls are protected against loss of safety function from missiles, pipe whip, jet impingement and accident environments. See Subsection 3.6.2 for protection of containment penetration isolation valves and piping.

k. The containment isolation systems close those fluid penetrations that support systems not required for emergency operation. Fluid penetrations supporting engineered safety feature systems have remote manual isolation valves that may be closed from the control room. Appropriate isolation valves (other than check valves) are automatically closed by the signals listed in Table 6.2-12. The criteria for assigning isolation signals to their associated isolation valves are described in Subsection 7.3.1.1.2. Once the isolation function is initiated, it operates to completion.

6.2.4.2 System Design

The general criteria governing the design of the Containment isolation systems are provided in Subsections 6.2.4.1 with related criteria in Subsection 3.1.2. Table 6.2-12 lists the containment penetrations which are Type C tested and presents design information about each. Table 6.2-12a lists those penetrations which contain instrument lines isolated by excess flow check valves.

Accompanying this table is Figure 6.2-44, which consists of diagrams for the various isolation valve arrangements. For the particular systems that penetrate the containment, listed in Table 6.2-12, a cross reference is provided to depict the respective isolation valve arrangement in Figures 6.2-44A, 6.2-44B, 6.2-44C, 6.2-44D, 6.2-44E, 6.2-44F, 6.2-44G, 6.2-44H, 6.2-44I, and 6.2-44J.

Isolation valves are designed to be operable under environmental conditions such as maximum differential pressures, extreme seismic occurrences, steam laden atmosphere, high temperature, and high humidity. The normal and accident environmental conditions are described in Section 3.11. Electrical redundancy is provided for power operated valves. Power for the actuation of two isolation valves in a line (inside and outside containment) is supplied by two redundant, independent power sources without cross ties. In general, outboard isolation valves receive power from the Division II power supply, while isolation valves within the containment or containment extensions receive power from the Division I power supply. ECCS penetrations are exceptions. In each case the supply may be ac and/or dc, depending upon the system under consideration.

All power-operated containment isolation valves are capable of being remote-manually operated from the main control room. Note #2 to Table 6.2-12 identifies all the automatic signals which effect containment isolation; these actuation signal codes are listed in the column in the table

entitled "Actuation Signal." Therefore, where no actuation signal code is listed for a particular power-operated valve, reliance for effecting containment isolation is upon remote-manual operation.

Leakage detection is discussed in Section 5.2.5. In addition to the leak detection provisions discussed therein, ECCS and ESF pump rooms are provided with flooding alarms which annunciate in the control room. Floor drains in these rooms are normally isolated, such that any leakage is confined to the respective room. Certain power-operated valves which are not provided with automatic isolation signals are physically located within those rooms. Consequently, leakage to the reactor building from any of the corresponding lines can be identified by the control room operator, who can then remote-manually isolate the affected system.

The other category of power-operated valves which are not provided with automatic isolation signals are those in ECCS systems (other than the valves just described) which are required to operate after an accident. Each ECCS system is designed with two 100% redundant loops. Sometime after initiation of the ECCS systems, the control room operator can exercise his discretion to isolate unnecessary ECCS loops. Additionally, ECCS system return lines (including recirculation lines) are provided with check valves which afford short-term leakage control in event of a passive failure outside containment until positive closure of associated power operated containment isolated valves can be achieved by operator action. Some of these lines may also rely upon a closed system to provide a redundant long-term barrier in addition to or instead of a positive closure valve.

The third category of non-automatic power-operated valves are those in lines which, although not ECCS systems, provide a positive inflow of water to the reactor. These lines are equipped with check valves which will provide short-term leakage control until positive closure of associated power-operated containment isolation valves is achieved by operator action after the lines are no longer contributing water to the reactor.

All of the lines discussed above are designed as Class B, Seismic Category I, and missile protected outside primary containment. Thus, only one passive failure is postulated in all of these lines. The reactor building will contain any postulated leakage, and the standby gas treatment system will filter any airborne release.

The containment instrument gas supply to the MSS/RVs with auto depressurization function will be at a higher pressure than the post-accident containment atmosphere, thus, small leaks outside containment will not create a radioactive release. In the event of a passive failure outside containment, the check valve inside containment will provide short-term leakage control. When the instrument gas header pressure falls below the low pressure setpoint, an alarm will be actuated in the main control room to alert the operator to remote-manually isolate the affected line. The standby gas treatment system can filter any leakage until positive isolation is obtained by operator action.

Standby liquid system isolation provisions are discussed in Subsection 6.2.4.3.2.5. The RHR heat exchanger vent valves are discussed in Subsection 6.2.4.3.6.4.

The main steamline isolation valves are spring-loaded, pneumatic, piston operated globe valves designed to fail closed on loss of pneumatic pressure or loss of power to the solenoid operated pilot valves. Each valve has two independent pilot valves supplied from independent power sources. Each main steamline isolation valve has a gas accumulator to assist in its closure

upon loss of air supply, loss of compressed gas supply, loss of electrical power to the pilot valves, and/or failure of the loading spring. The separate and independent action of either gas pressure or spring force is capable of closing an isolation valve.

Motor-operated isolation valves will remain in their last position upon failure of valve power, and air operated containment isolation valves will close upon loss of air or electrical power.

The design of the isolation valve system (i.e., valves and piping between the valves) gives consideration to the possible adverse effects of sudden isolation valve closure when the plant systems are functioning under normal operation.

6.2.4.3 Design Evaluation

6.2.4.3.1 Evaluation Against General Design Criterion 54

All piping systems penetrating containment, other than instrument lines, are designed in accordance with Criteria 54.

6.2.4.3.1.1 Operability and Leak Tests

Operability and leak rate testing of isolation valves is discussed in Subsection 6.2.4.4. Leak detection for piping between inboard and outboard isolation valves is discussed in Subsection 5.4.5.

6.2.4.3.1.2 Testing of Instrument Root Valves

The Instrument Isolation Valves associated with the Technical Specification Bases Section B 3.6.1.1 and TABLE B 3.6.1.1-1 shall be tested in accordance with Susquehanna's LEAKAGE RATE TEST PROGRAM. The Instrument Root Valves' leak rate are not added to the 10CFR50, Appendix J limits since the valves are only used during maintenance activities.

6.2.4.3.2 Evaluation against General Design Criterion 55

6.2.4.3.2.1 Feedwater Line

Each feedwater line forming a part of the reactor coolant pressure boundary is provided with three check valves for containment isolation. A nonslam type check valve is located inside the containment, while a simple swing check valve is located immediately outside containment, followed by a motor operated stop check valve which provides long term isolation capability. Three containment isolation valves are provided for each feedwater line since the operability of the check valve inside containment cannot be assured following a feedwater line break inside containment (see Subsection 3.6.1.2.2).

During a postulated LOCA, it is desirable to maintain reactor coolant makeup from all available sources. It would not improve safety to install a feedwater isolation valve that closed automatically on signals indicating a LOCA and thereby eliminate a source of reactor makeup. The provision of the check valve, however, ensures the prevention of a significant loss of reactor coolant inventory and offers immediate isolation if a break occurs in the feedwater line. For this reason, the outermost valve does not automatically isolate upon signal from the protection system. The valve is remote manually closed from the main control room to provide redundant isolation means and long term leakage protection. The operator will determine if

make-up from the feedwater system is unavailable by use of the Feedwater Flow Indicator which will show high flow or no flow for feedwater pipe break or no flow for feedwater pump trip.

The operator will determine whether make-up from the feedwater system is unnecessary if the ECCS is functioning properly and reactor water is at normal level. ECCS operation signals are provided in the main control room and a level indicator continuously monitors the water level in the reactor vessel.

Since it is not necessary to isolate the feedwater, there is no need to alert the operator to initiate the isolation signal. However, for long-term isolation purposes, the operator may manually close the motor-operated check valve at any convenient time.

The RCIC, HPCI, and Reactor Water Cleanup System (RWCU) pump discharges connect to the feedwater system between the two outside containment isolation valves in each feedwater line. The HPCI and RCIC systems are provided with a remote manual motor operated stop valve for isolating the system from the feedwater system, and to provide positive long term containment isolation. RWCU is provided with a simple check valve to provide automatic short term containment isolation, and a manual motor operated valve for long term containment isolation. These valves also serve as the second isolation valve for a feedwater line break inside primary containment. Also, these lines connect to the feedwater lines within the reactor coolant pressure boundary (RCPB), which stops at, but includes the outermost stop check valve.

6.2.4.3.2.2 Recirculation Pump Seal Water Supply Line

The recirculation pump seal water line extends from the recirculation pump through the drywell and connects to the CRD supply line outside the primary containment.

The seal water line forms a part of the reactor coolant pressure boundary, therefore the consequences of failing this line have been evaluated. This evaluation shows that the consequences of breaking this line are less severe than those of failing an instrument line. The recirculation pump seal water line is I in, Class B from the recirculation pump through a check valve located inside the containment and an excess flow check valve outside the containment. From this valve to the CRD connection the line is Class D. Should this line be postulated to fail and either one of the check valves is assumed not to close (single active failure), the flow rate through the broken line would be substantially less than that permitted for a broken instrument line. Therefore, the two check valves in series provide sufficient isolation capability for postulated failure of this line.

6.2.4.3.2.3 Control Rod Drive Lines

The control rod drive system insert and withdraw lines penetrate the drywell.

The CRD insert and withdrawal lines are not part of the reactor coolant pressure boundary, since they do not directly communicate with the reactor coolant. The classification of these lines is quality group B, and they are designed in accordance with ASME Section III, Class 2. The basis on which the CRD insert and withdrawal lines are designed is commensurate with the safety importance of maintaining the pressure integrity of these lines.

It has been accepted practice not to provide automatic isolation valves for the CRD insert and withdrawal lines to preclude a possible failure mechanism of the scram function. The control rod drive insert and withdrawal lines can be isolated by the solenoid valves outside the primary

containment. The lines that extend outside the primary containment are small and terminate in a system that is designed to prevent out-leakage. Solenoid valves normally are closed, but open on rod movement and during reactor scram. In addition, a ball check valve located in the control rod drive flange housing automatically seals the insert line in the event of a break. Finally, manual shutoff valves are provided. To preclude the possibility of post-LOCA leakage entering the Turbine Building via the CRD insert/withdrawal lines, check valves have been installed near the Reactor/ Turbine Building Wall in a segment of CRD piping designed in accordance with ASME Section III, Class 3. These check valves maintain a 30 day water seal in the CRD pump discharge header and are tested as described in Section 6.2.3.2.3.1.

6.2.4.3.2.4 RCIC System Steamlines

The RCIC turbine steam supply line from main steamline C is provided with two motor-operated, normally-open gate valves - one inside and one outside the containment - and one normally-closed, air operated bypass valve inside containment. The RCIC turbine exhaust isolation is described in Subsection 6.2.4.3.3, and the pump discharge in Subsection 6.2.4.3.2.1.

6.2.4.3.2.5 Standby Liquid Control System Lines

The standby liquid control system line penetrates the drywell and connects to the reactor pressure vessel. In addition to a simple check valve inside the drywell, a motor operated normally open globe stop check valve is located outside the drywell. Because the standby liquid control line is a normally closed, nonflowing line, rupture of this line is extremely remote. A third valve provides an absolute seal for long term leakage control as well as preventing leakage of sodium pentaborate into the reactor pressure vessel during normal reactor operation.

6.2.4.3.2.6 Reactor Water Cleanup System

The RWCU system line from the recirculation loop and RPV drain to the RWCU pumps suction is provided with normally open motor operated gate valves, one inside and one outside the containment. The return line from the pumps discharge and the regenerative heat exchangers to the feedwater line is described in Subsection 6.2.4.3.2.1. An additional check valve is provided in the return line so that a break in the RWCU system will not cause a loss of coolant inventory.

6.2.4.3.2.7 HPCI System Steamlines

The HPCI system turbine steam supply line from main steamline B is provided with motor operated normally open gate valves, one inside and one outside containment. A normally-closed, air-operated globe valve is also provided in parallel with the inboard gate valve. These valves are closed on receipt of a HPCI isolation signal. The HPCI turbine exhaust isolation is described in Subsection 6.2.4.3.3.3, and the pump discharge in Subsection 6.2.4.2.1.

6.2.4.3.2.8 Main Steamlines

Each of the four main steam lines is provided with normally open air operated y-pattern globe valves, one inside and one outside containment. The isolation provisions for the main steamlines are further described in Subsection 5.2.5.

6.2.4.3.2.9 CS Influent Penetrations

The CS influent lines are each isolated by a normally closed remote manually operated, gate valve external to the containment and a testable check valve inside the containment. The check valve is provided with a bypass having a normally closed remote manually operated globe valve.

6.2.4.3.2.10 RHR Penetrations Connected to the RPV

The RHR shutdown supply line is provided with normally closed gate valves, one inside containment and one outside.

The piping between the isolation valves is provided with a relief valve with a relieving pressure setting greater than 1.5 times the maximum containment pressure.

The RHR Shutdown Cooling return line containment penetrations {X-13A(B)} are provided with a normally closed gate valve {HV-1(2)51F015A(B)} and a normally open globe valve {HV-1(2)51F017A(B)} outside containment and a testable check valve {HV-1(2)51F050A(B)} with a normally closed parallel air operated glove valve {HV-1(2)51F122A(B)} inside containment. The gate valve is manually opened and automatically isolates upon a containment isolation signal from the Nuclear Steam Supply Shutoff System or RPV low level 3 when the RHR System is operated in the Shutdown Cooling Mode only. The LPCI subsystem is an operational mode of the RHR System and uses the same injection lines to the RPV as the Shutdown Cooling Mode.

The design of these containment penetrations is unique in that some valves are containment isolation valves while other perform the function of pressure isolation valves. In order to meet to 10 CFR 50 Appendix J leakage testing requirements, the closed system outside containment is the only barrier tested in accordance with the Leakage Rate Test Program. HV1(2)51F015A(B) are not required to be Appendix J leak rate tested since the Appendix J testing exemption requirements are met. Since these containment penetrations {X-13A and X-13B} include a containment isolation valve outside containment and a closed system outside containment that meets the requirements of USNRC Standard Review Plan 6.2.4 (September 1975), paragraph II.3.e, the containment isolation provisions for these penetrations provide an acceptable alternative to the explicit requirements of 10CFR50, Appendix A, GDC 55.

Containment penetrations X-13A(B are also high/low pressure system interfaces. In order to meet the requirements to have two (2) isolation valves between the high pressure and low pressure systems, the HV-1(2)51F050A(B), HV-1(2)51F122A(B), and HV-1(2)51F015A(B) valves are used to meet this requirement and are tested in accordance with the pressure test program.

A cross-tie line exists between the LPCI Injection lines and the RHR Shutdown Cooling suction line. This 1” line is installed to provide a positive pressure drop across the LPCI Injection Check Valves to hold the valves closed. The positive pressure drop is accomplished by relieving pressure from the upstream side of check valves HV151F050A and HV151F050B, and diverting the excess fluid to the RHR Shutdown Cooling suction line, which is at a lower pressure than at the point downstream of the check valves. A check valve is installed in the cross-tie line which functions as a pressure isolation valve, and normally open isolation valves are used for LPCI Injection Check Valve testing and isolation of either the ‘A’ or ‘B’ RHR loop.

The RPV spray line is provided with a normally-closed ac motor-operated gate valve inside containment and a normally-closed, dc motor-operated globe valve outside containment. Both valves close automatically upon receipt of a containment isolation signal.

6.2.4.3.3 Evaluation Against General Design Criterion 56

6.2.4.3.3.1 Containment Purge

The drywell and suppression chamber purge lines have isolation capabilities commensurate with the importance of safely isolating these lines. Each line has two normally closed, air opened, spring closed valves located outside the primary containment. Containment isolation requirements are met on the basis that the purge lines up to the outboard isolation valves are normally closed, low pressure lines, constructed to the same quality standards as the containment. The isolation valves for the purge lines are interlocked to preclude opening of the valves while a containment isolation signal exists as noted in Table 6.2-12 and fail closed on loss of electrical signal with the following exceptions:

1. Keylock handswitches are provided to override the containment isolation signal on valves HV-15703, HV-15705, HV-15711 and HV-15713 to allow emergency venting of the containment.

2. Key lock handswitches permit the 45 minute time delay and the LOCA isolation signal to be overridden on valves HV-15703, HV-15705, HV-15711, and HV-15713, to allow emergency venting or purging of the containment.

3. Key lock hand switches are provided to override the SGTS Exhaust High Radiation isolation signal on valves HV-15703, HV-15705, HV-15711, and HV-15713 to allow emergency venting or purging of the containment.

4. Target Rock valves, SV-15742A,B; SV-15740A,B; SV-15752A,B; SV-15750A,B; SV-15774A,B; SV-15776A,B; SV-15734A,B; SV-15736A,B; SV-15782A,B and SV-15780A,B can be opened 10 minutes after receipt of a LOCA isolation signal by using the valve hand switches.

Screens are provided on the drywell inlet and outlet purge lines. The purpose of the screens is to prevent debris generated by an accident, such as a pipe break, from entering the purge lines and preventing the containment isolation valves from closing. The screen is an expanded metal mesh with openings of .750 by 1.687 inches. The screens are safety-related components designed to withstand the design basis earthquake.

Purge line debris screens are not required in the wetwell since the wetwell contains no high energy lines or insulation. Additionally, there is no mechanism that would allow debris, such as insulation from the drywell, to reach the penetrations in the wetwell before the containment isolation valves close. Therefore, debris screens have been provided in the drywell only.

6.2.4.3.3.2 RCIC Turbine Exhaust, Vacuum Pump Discharge, and RCIC Pump Minimum Flow Bypass

These lines which penetrate the containment and discharge to the suppression pool, are each equipped with a motor-operated, remote manually actuated gate valve located as close to the containment as possible. There is a simple check valve upstream of the gate valve, which

provides positive actuation for immediate isolation in the event of a break upstream of this valve. The gate valve in the RCIC turbine exhaust is designed to be key-locked open in the control room and interlocked to preclude opening of the inlet steam valve to the turbine while the turbine exhaust valve is not in a full open position. The RCIC vacuum pump discharge line is also normally key-locked open but has no requirement for interlocking with the steam inlet to the turbine. The RCIC pump minimum flow bypass line is isolated by a normally closed, remote manually actuated valve with a check valve installed upstream. The motor-operated valve will open only when the RCIC pump is running and flow rate at the pump discharge is below the low flow setpoint.

The justification taken for the approach for isolating these lines is that the check valves with the water seal provided by the suppression pool provide leakage control in the short term. Long-term leakage control is supplied by the control room operator closing the motor-operated valves remote-manually. This arrangement enhances the reliability of RCIC for those accident scenarios where high pressure coolant injection is required while still providing the required isolation capability.

6.2.4.3.3.3 HPCI Turbine Exhaust and HPCI Pump Minimum Flow Bypass

These lines penetrate the containment and discharge to the suppression pool. They are equipped with a motor operated, remote manually actuated gate valve located as close to the containment as possible. In addition, there is a simple check valve upstream of the gate valve, which provides positive actuation for immediate isolation in the event of a break upstream of this valve. The gate valve in the HPCI turbine exhaust is designed to be key-locked open in the control room and interlocked to preclude opening of the inlet steam valve to the turbine while the turbine exhaust valve is not in a full open position. The HPCI pump minimum flow bypass line is isolated by a normally closed, remote manually actuated valve with a check valve installed upstream. The motor-operated valve will open when the HPCI pump is running and the flow rate at the pump discharge is below the low flow setpoint.

The justification taken for the approach for isolating these lines is that the check valves with the water seal provided by the suppression pool provided leakage control in the short term. Long-term leakage control is supplied by the control room operator closing the motor-operated valves remote-manually. This arrangement enhances the reliability of HPCI for those accident scenarios where high pressure coolant injection is required while still providing the required isolation capability.

6.2.4.3.3.4 RCIC and HPCI Turbine Exhaust Vacuum Breaker Lines

These lines are provided with power operated isolation valves, outside containment. The valves close on a containment isolation signal.

6.2.4.3.3.5 Reactor Building Closed Cooling Water and Reactor Building Chilled Water Supplies and Returns

The influent lines and effluent lines are provided with two normally-open, power-operated valves. The valve inside containment is a butterfly valve, while the valve outside containment is a gate valve. The power operated valves are automatically closed on receipt of a containment isolation signal.

6.2.4.3.3.6 Post-LOCA Atmosphere Sampling Lines

The Post Accident Sampling System (PASS) shares the same containment penetrations with the H_2O_2 Analyzers. The lines that penetrate the containment and connect to the drywell and suppression chamber air volume are equipped with two normally open, failed closed solenoid operated valves in series. These valves are located outside and as close to the containment as possible. While two valves are provided in series for each penetration, both valves are powered from the same electrical division in order to prevent a single electrical failure from resulting in a loss of both divisions of H_2O_2 Analyzers. However, this results in the valves being susceptible to a single electrical failure, as described in Section 7.3.2a.2.2.3.1.2 (multiple hot shorts), which could result in both valves failing open or failing to remain closed. For all other conditions, the valves will provide redundant containment isolation barriers.

The susceptibility of the valves to a single electrical failure is offset by the fact that the external piping and components beyond the containment isolation valves up to and including the PASS/ H_2O_2 Analyzer System boundary valves are considered an extension of primary containment. Consequently, the design of the H_2O_2 Analyzer system outside primary containment meets the design and testing requirements for a closed system as specified in USNRC Standard Review Plan 6.2.4 (September 1975), Containment Isolation Provisions, paragraph II.3.e, except as clarified by Tables 3.2-1, 6.2-12, and 6.2-22. Therefore, the containment isolation barriers for these penetrations consist of two primary containment isolation valves and a closed system.

6.2.4.3.3.7 Liquid Radwaste System Equipment and Floor Drains

These lines are equipped with two normally-closed, solenoid-actuated, air-operated gate valves, both located outside containment. Inasmuch as the containment penetrations are just above the drywell floor slab, locating the inboard isolation valves inside containment would have been impractical, since the valves might have been underwater as a result of an accident. Thus, the inboard valves are attached directly to their respective containment penetration sleeves.
In both cases, the piping between the isolation valves is designed as seismic Category I, ASME Section III, Class 2; the two valves are separated by only 1.5 feet of piping.

6.2.4.3.3.8 Suppression Pool Cleanup and Drain

The suppression pool cleanup and drain line is provided with two normally closed, motor operated remote manually actuated gate valves that are interlocked to close on receipt of a containment isolation signal. Since this line penetrates the suppression pool floor, locating a valve inside containment would be impractical; thus, both valves are outside containment.
The piping between the isolation valves is designed as seismic Category I, ASME Section III, Class 2; the two valves are separated by one foot of piping. Inasmuch as these valves are located in the core spray pump room, flooding alarms will provide indication of gross leakage.

6.2.4.3.3.9 Containment Instrument Gas Supply To Containment Vacuum Relief Valves

The containment instrument gas supply line to the containment vacuum relief valve assemblies is provided with a check valve (inboard) and a normally-closed, solenoid-operated globe valve (outboard), both located outside containment. Another check valve is located inside the suppression chamber; however, credit for this check valve as a containment isolation valve is not taken, since its operability during a postulated pool swell due to LOCA cannot be assured. Both valves outside containment are located as close to the containment penetration as practicable.

6.2.4.3.3.10 Traversing Incore Probe (TIP) Guide Tubes

Isolation of the TIP drive guide tubes normally is accomplished by a solenoid-operated ball valve whenever the TIP cable and fission chamber are retracted. An explosive shear valve is also provided as a backup to ensure integrity of the containment in the unlikely event that the other isolation valve fails to close or the drive cable fails to retract if it should be extended in the guide tube during the time that containment isolation is required. This valve is designed to shear the cable and seal the guide tube upon a manual actuation signal. The valve is an explosive type valve, dc-operated, with monitoring of each actuating circuit provided. TIP drive cables are normally retracted except during an actual TIP mapping operation.

TIP System Guide Tube isolation valve controls (Figure 6.2-72) are non-Class 1E. This design provides a degree of confidence commensurate with the design requirement that the Guide Tube penetrations, of which there are five parallel lines, will isolate and remain isolated under normal and accident conditions. Should the Ball Valve be unable to isolate under accident conditions, the Shear Valve is provided to perform that function.

Because of their natural functional diversity, the pair of valves for each penetration provides an appropriate level of protection of the primary containment integrity. The existing design does not, however, provide the deterministic assurance of safety and defense in depth normally required of protective functions to ensure penetration integrity in accordance with GDC 56.

The existing isolation system is a standard GE BWR design, and has been evaluated by Licensing Topical Report NEDC-22253. This design has been reviewed for all standard GE BWRs, including those with Mark II Containment designs, as meeting the requirements of Regulatory Guide 1.11.

Because the Guide Tube isolation scheme has not been designed as a protective function, most of the provisions of 7.3.2a.2 do not apply to the isolation actuation circuits, their components or operation. Operator actions cannot override a valve OPEN signal from the local TIP probe position sensor.

Indications and controls required to assure timely operator actions to close the Guide Tubes are non-Class 1E and are located on back panels in the control room. A common indicator for the set of Guide Tube Valve Assemblies will indicate if any of the five parallel paths are not fully closed. Open ball valves are not annunciated. Leakage through open TIP Guide Tubes would create high radiation conditions that would be annunciated in the control room via the non-Class 1E Area Radiation Monitoring System.

6.2.4.3.3.11 Hardened Containment Vent System

The vent line has two spring-to-close, air-to-open butterfly valves located outside of the primary containment. The gas to the two valve actuators is normally isolated and power to the actuator solenoid valves is normally de-energized.

6.2.4.3.4 Evaluation Against General Design Criterion 57

This criteria was not used in the design of containment penetrations for Susquehanna SES.

6.2.4.3.5 Evaluation Against Regulatory Guide 1.11 (Rev. 1)

Instrument lines that penetrate the containment from the reactor coolant pressure boundary conform to Regulatory Guide 1.11. They are equipped with a restricting orifice except the reactor water level reference leg instrument lines which are restricted by a ½" pipe located inside the drywell and as close as practicable to the connection on the process pipe and with an excess flow check valve located outside as close as practicable to the containment. A manua isolation valve exists between each penetration and its associated excess flow check valve. These manual isolation valves serve no containment isolation function. Isolation valves 142002A&B and 242002A&B, in the instrument reference legs, which are backfilled by CRD water, are disabled in the open position by design, to preclude the possibility of pressurization of the reference legs to CRD pressure, resulting in false pressure and level signals. Should an instrument line which forms part of the RCPB develop a leak outside containment, a flow rate which results in a differential pressure across the excess flow check valve of 3 to 10 psi will cause the check valve to close automatically. Should an excess flow check valve fail to close when required, the main flow path through the valve has a resistance to flow at least the equivalent of a sharp-edged orifice of 0.375 inch diameter. Valve position indication and excess flow alarm are provided in the control room. Excess flow check valves in instrument lines penetrating reactor containment undergo periodic inservice testing as discussed in FSAR Subsection 3.9.6.

Instrument lines that do not connect to the reactor coolant pressure boundary conform to Regulatory Guide 1.11 through their qualification and installation in accordance with ASME Section III, Class 2 requirements. They are designated as "extensions of containment" as discussed in FSAR Subsection 3.13.1 and Tables 6.2-12a and 6.2-22. They are equipped with isolation and excess flow check valves whose status will be indicated in the control room.

6.2.4.3.6 GDC 56 Isolation Provisions with a Single Isolation Valve Outside Containment

Containment isolation provisions for certain lines in engineered safety feature or engineered safety feature-related systems may consist of a single isolation valve outside containment. A single isolation valve is considered acceptable if it can be shown that the system reliability is greater with only one isolation valve in the line, the system is closed outside containment, and a single active failure can be accommodated with only one isolation valve in the line.

When credit is taken for a single containment isolation valve, the closed system outside containment is protected from missiles, designed to seismic Category I standards, classified Safety Class 2 and has a design temperature and pressure rating of least equal to that for the containment. The closed system outside containment will be leak tested in accordance with the Leak Rate Test Program.

6.2.4.3.6.1 Core Spray (CS) Influent Penetrations

The CS pump minimum flow line valve is normally open and closes when pump flow is established or by a remote manual signal. For this reason, flow rate is appropriately the only parameter sensed for initiation of containment isolation. The pump test and flush line isolation valves are normally closed and remote manually operated. The piping external to the primary containment provides a second isolation barrier as a closed system. All piping in the core spray system is seismic Category I, ASME Section III, Class 2 from the first restraints inside the containment penetrations outward.

6.2.4.3.6.2 Containment Spray and RHR Pump Test and Minimum Flow Lines

The containment sprays (drywell and wetwell) and the RHR pump test lines are each provided with a normally-closed, remote-manually operated isolation valve outside containment. The RHR minimum flow line valve is normally open and closes when pump flow is established or by remote manual signal. For this reason, flow rate is appropriately the only parameter sensed for initiation of containment isolation. The external pipe provides the second isolation barrier as a closed system for all of these penetrations. Additionally, the containment spray and RHR pump test lines utilize the second valve outward from the containment instead of the valve closest to the containment wall as the isolation valve (see Figures 6.2-44B, detail (d) and Figure 6.2-44J, detail (x)).

6.2.4.3.6.3 HPCI, RCIC, CS, and RHR Pump Suction Lines

Although strictly speaking the HPCI, RCIC, CS, and RHR pump suction lines do not connect directly to the primary containment, they are nevertheless evaluated to GDC 56. These lines are each provided with one remote manually motor operated gate valve external to the containment and use the respective piping systems (i.e., closed system) as the second isolation barrier. For the RHR and CS valves the hand switches are key locked.

Inasmuch as the pump suction valves are located in their respective pump rooms, flooding alarms will provide indication of gross leakage.

6.2.4.3.6.4 RHR Combined Relief Valve Discharge and Heat Exchanger Vent Lines

The relief valve discharge lines are isolated by the relief valves themselves in a fashion similar to a check valve. The external piping provides the second barrier. The relief setting on these valves is more than 1.5 times the containment design pressure.

The RHR heat exchanger vent lines discharge to the suppression chamber via the relief valve discharge lines and are provided with two remotely controlled motor-operated globe valves. Credit for one of these two valves is taken for effecting containment isolation; the external piping provides the second barrier. Justification for this alternative method is as follows: The RHR heat exchanger vent valves will be opened only during system filling and venting. Therefore, the probability that an accident requiring isolation of the vent line will occur while the vent valves are open is small. Since the valve motors are controlled from separate switches, two operator errors or one operator error and a single active failure would be required in order for both valves to be opened during other operating modes. In any event, should isolation be required during filling and venting, potential leakage would be contained by the external piping.

6.2.4.3.7 Failure Mode and Effects Analyses for Containment Isolation

The following discussion pertains to the evaluation of single failure of those components and systems credited with performing a containment isolation function. It is not intended to be applied to components on systems performing any safety function other than containment isolation.

A single failure can be defined as a failure of a component in any safety system that results in a loss of, or degradation of the system's capability to perform its safety function. Active components are defined in Regulatory Guide 1.48 (Rev. 1) as components that must perform a mechanical motion while accomplishing a system safety function. Appendix A to 10CFR50

requires that electrical systems also are designed against passive single failures as well as active single failures.

In single failure analysis of electrical systems, no distinction is made between mechanically active or passive components; all fluid system components such as valves are considered "electrically active" whether or not "mechanical" action is required.

Electrical systems as well as mechanical systems are designed to meet the single failure criterion for both mechanically active and passive fluid system components, regardless of whether that component is required to perform a safety action in the nuclear safety operational analysis outline in Appendix 15A. Even though a component such as an electrically operated valve is not designed to receive a signal to change state (open or closed) in a safety scheme, it is assumed as a single failure that the system component changes state or fails. Electrically operated valves include valves that are electrically piloted but air operated as well as valves that are directly operated by an electrical device. In addition, all electrically operated valves that are automatically actuated can also be manually actuated from the main control room. A single failure in any electrical system is analyzed regardless of whether the loss of a safety function is caused by either component failing to perform a requisite mechanical motion, or component performing an unnecessary mechanical motion.

6.2.4.4 Tests and Inspections

The containment isolation system was preoperationally tested in accordance with the requirements of Chapter 14. The containment isolation system is periodically tested during reactor operation. The functional capabilities of power operated isolation valves are tested remote manually from the control room. By observing position indicators and changes in the affected system operation, the closing ability of a particular isolation valve is demonstrated.

A discussion of testing and inspection, including leak tightness testing, pertaining to isolation valves is provided in Subsection 6.2.6 and in the Technical Specifications. Table 6.2-12 lists all isolation valves in process lines required by GDC 55 or 56. Vents, drains and test connections are not listed in this table.

Instruments are periodically tested and inspected. Test and/or calibration points are supplied for each instrument.

Excess flow check valves which are in instrument sensing lines not considered an extension of containment shall be periodically tested by opening a test drain valve downstream of the excess flow check valves and verifying proper operation.

With the exception of the CRD insert and withdrawal lines and penetrations with Note# 34, the penetrations listed in Table 6.2-12 are Type C tested. The test methods and acceptance criteria are listed in Subsections 6.2.6 and 3.9.6.2. Table 6.2-22 identifies testing type for all penetrations.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

The combustible gas control system is provided, in accordance with the requirements of General Design Criterion 41 of Appendix A to 10CFR50, 10 CFR 50.44 “Combustible Gas Control for Nuclear Power Reactors” and regulatory Guide 1.7 Revision 3 “Control of

Combustible Gas Concentrations in Containment" to control the concentration of hydrogen within the containment following a loss-of-coolant accident (LOCA).

A design basis LOCA hydrogen release is no longer defined in 10 CFR 50.44 or Regulatory Guide 1.7 Revision 3 and these documents establish the requirements for the hydrogen control systems to mitigate such a release.

To meet the regulatory requirements, systems to monitor and control the concentration of hydrogen are provided as follows:

a. A system to monitor the concentrations of hydrogen and oxygen within the containment

b. Containment mixing to prevent local hydrogen concentration buildup.

c. Inerted primary containment (less than 4% oxygen concentration) during power operation.

d. Limiting use of materials within the containment that would yield hydrogen gas by corrosion (mainly aluminum and zinc).

The following system is not required by the regulations but is provided to ensure hydrogen levels remain below the level that could endanger containment integrity.

e. A containment hydrogen purging subsystem to limit the concentration of hydrogen.

6.2.5.1 Design Bases

The combustible gas control system has been designed based on the following criteria:

a. The containment hydrogen and oxygen monitoring system is designed to monitor the hydrogen and oxygen concentrations in both the drywell and wetwell.

b. Containment mixing prevents buildup of local hydrogen gas concentrations within the drywell or wetwell during accident conditions.

c. The containment hydrogen monitoring system is designed to Seismic Category I requirements, and meets the requirements of ASME Section III, where applicable.

d. The components of the hydrogen monitoring system are separated or protected to ensure that missiles and pipe whip will not disable required functions.

e. The hydrogen monitoring system is testable during normal operation.

f. The containment hydrogen purge system is available in both units and designed to maintain the hydrogen concentration below the required limit.

g. The containment is inerted during operation, within operating mode limitations and concentration limits prescribed by Technical Specifications, to maintain a low level of oxygen.

6.2.5.2 System Design

Combustible gas control depends on the following functions and subsystems:

a. Hydrogen mixing

b. Hydrogen and oxygen monitoring system

c. Containment hydrogen purge system (not a safety related function)

d. Containment nitrogen inerting system

Hydrogen Mixing

A well mixed atmosphere in the drywell and wetwell ensures that local concentrations of hydrogen greater than four percent do not occur.

Post-LOCA mixing of the drywell atmosphere is accomplished by the safety-related portion of the containment ventilation system (see Subsection 9.4.5). Wetwell mixing will be accomplished by the blowdown to the wetwell and operation of the RHR system suppression chamber spray header (see Subsections 5.4.7 and 6.2.2.2).

Hydrogen and Oxygen Monitoring System

Primary Containment Atmosphere Monitoring System Hydrogen and Oxygen Analyzers

Two redundant systems are provided and are able to continuously monitor the gas concentration within the primary containment and the suppression chamber, to indicate, record, and alarm detection of excessive hydrogen or oxygen.
This system is part of the primary containment atmosphere monitoring system and is operated during normal operation during start up, and after a LOCA for post accident monitoring. Refer to Section 7.5 for safety-related display instrumentation.

Each redundant system is designed with independent, separate gas analyzers, located in panels outside the primary containment in the reactor building.

a. Operating principle of gas analyzers:

   The analyzer for each division has separate sample lines. Each analyzer can sample either of two points in the drywell or one point in the wetwell. The gas sample is pumped through the analyzer cells to determine the amount of hydrogen and oxygen.

   Reagent gas is added to the sample stream because of the wide variation in the composition of the containment atmosphere. For hydrogen analysis the reagent gas is 100% oxygen. A catalyst in the reference side of the analysis cell causes any hydrogen present in the sample gas to combine with the reagent oxygen to form water vapor before reaching the analysis filament. The cell temperature is maintained above saturation to prevent condensation. The thermal conductivity of the reacted sample in the reference side of the cell, with no hydrogen, is compared to the conductivity of the unreacted sample measured by the other side of the cell to yield an indication of volume percent hydrogen.

The oxygen analyzer functions essentially the same as the hydrogen analyzer, except that it uses hydrogen as the reagent gas. This analysis technique is quite reliable and accurate. After analysis, the gas samples are returned to the drywell or wetwell.

When the reactor is in startup or at power both of the redundant analyzer systems are either operating or maintained in standby. If in standby an analyzer will be activated from the control room after a LOCA. The analyzers are calibrated and tested periodically during normal operation in accordance with Technical Requirement Manual.

The analyzer systems are designed for the following modes of operation:

1. During startup.

2. During normal reactor operation to monitor for excessive oxygen concentration.

3. To monitor the containment atmosphere after a LOCA for excessive hydrogen or oxygen concentration.

b. Description of tests to demonstrate the performance capability of the analyzers.

1. Seismic qualification test:

   The gas analyzer system panel was tested in accordance with IEEE 344-1975 to satisfy the requirements for Seismic Category I.

2. Gas analyzer operational test:

   A preoperational test verified the performance of the analyzers in accordance with the technical specifications of the system. The analyzers are calibrated and tested periodically during normal operation in accordance with Technical Requirement Manual.

c. Location of sampling points within the primary containment:

The Division I (System A) drywell gas sampling points are located approximately at Elevation 790 feet, Azimuth 303°, 2 feet from the containment wall; and at elevation 714 feet, azimuth 292°, 5 feet from the containment wall. The Division II (System B) drywell sampling points are located approximately at elevation 750 feet, azimuth 155°, 2 feet from the containment wall; and at Elevation 728 feet, inside the reactor pedestal just under the RPV.

The wetwell (suppression chamber) sampling points are located at the containment wall approximately at elevation 688 feet; Division I System A at azimuth 287° and Division II System B at azimuth 109°.

d. System independence:

The primary containment monitoring system is a separate, independent gas analyzer system with the capability to monitor the combustible gas concentration independent of the operation of the combustible gas control system.

e. Failure modes and effect analysis:

The system level failure mode and effects analysis for the containment atmosphere monitoring system is provided in Table 6.2-14.

Containment Hydrogen Purge System

The containment purge system is provided in each unit and would only be used post-LOCA on a high hydrogen concentration in containment, as indicated by the hydrogen analyzers or by sample analysis. This could only occur in the event of accidents or failures beyond the design basis or if inadequate containment mixing permitted a local high concentration at the sample point. The purge system controls the hydrogen concentration by dilution of the post-LOCA containment atmosphere. The containment atmosphere is purged through a two inch bypass valve. Nitrogen gas is added to containment as required to support the purge.

During normal operation the two inch purge exhaust line may be used intermittently for containment pressure control. The system design, however, prevents any purged gases from being exhausted directly to the environs. All purged gases are processed through the Standby Gas Treatment System (SGTS). Operating procedures require the SGTS to be operational before the inboard isolation valve and the two inch bypass valve are opened for the purge. The outboard isolation valve will remain shut. The purge valves are shown on Dwg. M-157, Sh. 1. M-157, Sh. 2, M-157, Sh. 3 and the SGTS System and its quality requirements are described in Section 6.5.1.1. Valve closure times are given in Table 6.2-12. Even in the very unlikely event of a LOCA occurring simultaneously with purge, the volume of air exhausted to the secondary containment before the redundant isolation valves close is only a small fraction of the capacity of the SGTS.

Containment Nitrogen Inerting System

An inerted containment was specified during the early design for Susquehanna, based on calculations using early Revision s of Regulatory Guide 1.7. When the post-LOCA hydrogen generation rate and hydrogen concentration within the containment were recalculated based on Regulatory Guide 1.7, Rev. 1, the worst case concentrations indicated that an inerted containment would not have been required. However, an inerted containment was retained:

a) To meet requirements of 10CFR50.44(c)(3)(i) for resolution of Unresolved Safety Issue A-48 (TMI-II Issues II.B.7 and II.B.8), which requires all BWR Mark I and Mark II containments to be inerted for combustible gas control, and

b) To meet 10CFR50 Appendix R fire suppression requirements. See the Fire Protection Review Report (FPRR).

Nitrogen gas will be used for primary containment atmosphere control. The Containment Nitrogen Inerting System and its quality requirements are shown on Dwg. M-157, Sh. 1. The oxygen concentration of the inerted atmosphere during reactor operation will not exceed four percent by volume. The oxygen concentration will be monitored by a portable gas analyzer, or by grab sample or by the hydrogen and oxygen analyzers. During normal operation the analysis frequency will be as required to maintain oxygen at less than four percent.

6.2.5.3 Design Evaluation

A design basis LOCA hydrogen release is no longer defined in 10 CFR 50.44 or Regulatory Guide 1.7 Revision 3 and these documents establish the requirements for the hydrogen control systems to mitigate such a release. Hydrogen recombiners are no longer required to mitigate a hydrogen release post-LOCA and are abandoned in place.

Start Historical

The analysis of the combustible gas in the containment following a LOCA assumed the following sources of hydrogen.

a. An assumed metal-water reaction with the zircalloy cladding surrounding the active portion of the fuel. The clad was assumed to react to a depth of .00023 in. in accordance with Regulatory Guide 1.7, because the ECCS analysis (Subsection 6.3.3) showed that five times the calculated metal water reaction would produce less hydrogen.

b. Radioloysis of the reactor coolant and injection water

c. Corrosion of the aluminum, zinc and zinc paint in the containment

d. The release of the free hydrogen already in the reactor coolant.

Reagent hydrogen returned to containment from the oxygen analyzers is a fraction of the least of these four sources and is not included in calculations. Hydrogen generated by radiolysis of sump water is distributed between the drywell and the wetwell in proportion to the volume of sump water present in each. Since almost all the sump water will be in the wetwell, it is assumed that 93.6% of the sump radiolysis hydrogen will be in the wetwell and 6.4% in the drywell.

Since no caustics will be added to the containment by the spray system, the pH of the water after a LOCA should be approximately 7.

Corrosion of zinc in contact with water at pH 7 with no additives is caused by two processes:

$$Zn + 2\,H_2O \rightarrow Zn\,(OH)_2 + H_2 \qquad (1)$$

$$2\,Zn + 2\,H_2O + O_2 \rightarrow 2\,Zn\,(OH)_2 \qquad (2)$$

Both reactions will be present in the post-LOCA atmosphere of the containment. The relative amount of corrosion due to Reaction (1) compared to Reaction (2) will depend on the availability of oxygen. Galvanized steel and zinc-based paint surfaces that are not submerged will be in contact with atmospheric oxygen along with the spray water; therefore, Reaction (2) should be a major contributor to the corrosion of zinc. For the submerged surfaces, the oxygen present will depend on the solubility of oxygen, which decreases with increasing temperature. Thus, Reaction (1) should dominate corrosion of submerged zinc surfaces at high temperature.

A search of the literature available on the subject of zinc corrosion at a pH of 7 gives data for corrosion as weight loss of zinc (References 6.2-6, 6.2-16, and 6.2-28) and also as hydrogen evolved (References 6.2-7 and 6.2-9). van Rooyen (Reference 6.2-8) surveyed the available literature and formulated a corrosion rate. The data given as weight loss of zinc should be viewed carefully to determine which corrosion reaction is seen. Other data is available for corrosion in water at higher pH levels or in water with Na OH additives. However, this data is not applicable to a BWR, which does not have borated reactor coolant, nor caustic or buffered containment sprays.

Baylis (Reference 6.2-7) determined the hydrogen generated from a sample of zinc submerged in distilled water for different time periods. This study was performed for temperatures of 100°F and lower. Therefore, the lower temperature corrosion domain can be inferred from this data.

Franklin Institute Research Laboratories performed a study of hydrogen evolution from zinc under simulated LOCA conditions and gave corrosion data for 2-hour and 24-hour periods (Reference 6.2-9). This data shows that corrosion is faster for the 2 hour period than for the 24-hour period for the same temperature, except at high temperatures (260°-300°F), where the corrosion rates are comparable. This effect is due to the build-up of a corrosion-resistant zinc hydroxide protective layer which inhibits corrosion after an extended period of time.

Burchell (Reference 6.2-6) and Cox (Reference 6.2-16) present corrosion as weight loss of zinc. In both cases, the corrosion rate is higher at the lower temperature domain, peaking at approximately 110°F and then decreasing with increasing temperature. Since the solubility of oxygen decreases with increasing temperature, the decrease in the corrosion rates can be attributed to the depletion of oxygen available. Thus, these corrosion rates show that reaction (2) is dominant in the oxygen-rich lower temperature water, and reaction (1) becomes dominant with increasing temperature.

van Rooyen (Reference 6.2-8) determined the corrosion rate of zinc from the available data, but did not differentiate between reactions (1) and (2). van Rooyen's calculated corrosion rate therefore does not accurately represent hydrogen generated from zinc corrosion.
The data of References 6.2-7 and 6.2-9 on hydrogen generation from zinc corrosion were therefore used to develop the following bounding corrosion rate:

$$R_{Zn} = 3.76 \times 10^{-9}\, e_{(2.18x10-2T)}\ lb\text{-}moles/\,ft^2\text{-}hr \qquad (T\ in\ ^\circ F) \tag{3}$$

Reaction (2) produces no free hydrogen. To obtain the most conservative hydrogen generation rate, all corrosion was therefore assumed to be Reaction (1), which produces one mole of free hydrogen per mole of zinc. The zinc reaction rate predicted by Equation (3) is therefore also the hydrogen generation rate from this process (i.e., $R(H_2)_{ZN}=R_{ZN}$). Equation (3) was therefore used to calculate the hydrogen released due to corrosion of both zinc and zinc-painted surfaces. See Table 6.2-13.

Hydrogen generated from corrosion of aluminum in containment was also included. A corrosion rate for aluminum at pH 7 was obtained from References 6.2-8, and the following rate equation was developed:

$$R_{Al} = 1.03 \times 10^{-4}\, e^{(-3491/T)}\ lb\text{-}moles/ft^2\text{-}hr \quad (T\ in\ ^\circ K) \tag{4}$$

Aluminum is assumed to corrode in water by the following reaction:

$$2\,A1 + 3\,H_2O \rightarrow A1_2O_3 + 3\,H_2 \tag{5}$$

Reaction (5) shows that 3 moles of hydrogen are generated for every 2 moles of aluminum corroded. Therefore, multiplying Equation (4) by 3/2, the hydrogen generation rate due to aluminum corrosion will be:

$$R(H_2)A1 = 1.54 \times 10^{-4}\, e^{(-3491/T)}\ lb\text{-}moles/ft^2\text{-}hr \quad (T\ in\ ^\circ K) \tag{6}$$

As indicated in Figure 6.2-48, the quantity of hydrogen generated from corrosion of zinc and aluminum is small compared to that generated by radiolysis. Any uncertainties in hydrogen generation from zinc and aluminum which were not accounted for by the conservative assumption of Reaction (1) for zinc, and by the conservative methods of determining the corrosion rates, would not result in significantly larger quantities of hydrogen; and the four volume percent hydrogen criterion would not be exceeded.

The mass and area of zircalloy cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, are given in Table 6.2-13.

During power operation, free hydrogen exists in the reactor water and steam as a consequence of the radiolytic decomposition of water. Additionally, hydrogen gas may be injected into the reactor coolant system with the feedwater to inhibit stress corrosion cracking. This process is known as Hydrogen Water Chemistry (HWC). The total quantity of free hydrogen that can be released to containment at the time of a LOCA would include the hydrogen inventory in the reactor coolant system as well as that of the feedwater and main steam lines inside containment. The normal operating hydrogen concentration for feedwater remains at 2.0 ppm. At this level, reactor water hydrogen concentration will be in the range of 320 to 400 ppb and steam hydrogen concentration will be 2.24 ppm. However, the total amount of hydrogen available for release to the containment from these sources under post LOCA conditions is negligible compared to the other sources such as metal water reaction, radiolysis of water and other corrosion reactions.

The total fission product adsorbed energy used to determine hydrogen generated by radiolysis is calculated based on Reference 6.2-17. The beta and gamma energy absorption rates and integrated energy releases are given in Figures 6.2-46 and 6.2-47. The assumptions used to calculate the energy releases are given in Table 6.2-13. The assumptions of Table 1 of Regulatory Guide 1.7 were followed.

The Figures 6.2-3, 6.2-7, and 6.2-8 curves of wetwell and drywell temperature versus time were used to calculate aluminum and zinc corrosion rates and thereby the hydrogen generation rates from these sources. The drywell and wetwell pressures at peak drywell pressure from Figure 6.2-2 were used to estimate the initial inventory of water vapor for determining the initial hydrogen concentrations, and thereby the recombination rates, at start of recombiners. Changes in these pressure and temperature profiles for power uprate were evaluated and found to have negligible effects on either hydrogen generation (Figure 6.2-48) or post-LOCA hydrogen concentration (Figures 6.2-49, 6.2-50, and 6.2-51).

The results of the analysis are given in the following figures:

a. The integrated production of hydrogen vs time - Figure 6.2-48.

b. The hydrogen concentrations vs time in the drywell with and without a recombiner operating - Figures 6.2-49 and 6.2-50.

c. The hydrogen concentrations vs time in the wetwell with and without a recombiner operating - Figure 6.2-51.

The recombiner system is activated when the hydrogen concentration reaches 3.5 vol percent. These times are given in Table 6.2-13.

The hydrogen recombiners have been designed to withstand the forces and pressures imposed during a LOCA. A system level failure modes and effects analysis for the recombiner system is given in Table 6.2-16.

End Historical

Purge Site Dose Analysis

For plants for which a notice of hearing on the application for a construction permit was published after November 5, 1970, an incremental post-LOCA purge dose calculation for the purge system is not required, as stated in Standard Review Plan, 15.6.5 Revision 1, Appendix C, "Radiological Consequences of a Design Basis Loss-of-Coolant Accident: Post-LOCA Purge Contribution."

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6.2.5.5 Instrumentation Requirements

See Section 7.5 for descriptions of instrumentation and controls for other elements of the combustible gas control system.

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6.2.5.5.2 Containment Hydrogen Purge Subsystem

Operation of the containment hydrogen purge subsystem is manually initiated from the control room. Refer to Section 7.6 for the description of the containment hydrogen purge subsystem controls and instrumentation.

The line penetrating the primary reactor containment is provided with power-operated isolation valves with controls in the control room to allow operator control during post-LOCA operation. A complete discussion of the isolation valve provisions is presented in Subsection 6.2.4.

Purge is exhausted through the Standby Gas Treatment System (SGTS). Differential pressure gages are provided across the SGTS vent filters to allow detection of filter clogging. Local temperature and pressure indicators are provided in the exhaust line to aid in the operation of the system. See the description of the SGTS in Section 6.5.1.1.

6.2.5.5.3 Instrumentation Requirements for Primary Containment Atmosphere Monitoring System (Hydrogen and Oxygen Analyzer)

The instrumentation and control of the primary containment monitoring system indicates the containment gas concentration during startup, during normal operation and after a LOCA. The unit will be manually placed into service following the 10 minute time delay resulting from the LOCA isolation (Table 6.2-12).

The two redundant systems are divisionalized and powered by respective Class IE power sources.

The analyzer units can be controlled locally or from the control room. Indicators for hydrogen and oxygen concentration of the containment are provided in the control room with system trouble annunciators to alert the operator. In addition a historical record is maintained by a two channel recorder. Refer to Section 7.5 for safety-related display instrumentation.

During normal operation the analyzers are tested periodically and calibrated against standard gases in accordance with Technical Requirement Manual. If possible each analyzer is also calibrated before being aligned for analysis.

The hydrogen and oxygen analyzer units are located outside the primary containment in the reactor building. These units are qualified to withstand the environmental conditions described in Section 3.11.

6.2.6 PRIMARY REACTOR CONTAINMENT LEAKAGE RATE TESTING

This section presents the testing program for the following leak rate tests:

- Type A Test, Primary containment integrated leak rate test (ILRT)
- Type B Test, Primary containment penetration leak rate test
- Type C Test, Primary containment isolation valve leak rate test

These leak rate tests comply with 10CFR50 Appendix A, General Design Criteria, and Appendix J, Primary Reactor Containment Leakage Rate Testing for Water Cooled Power Reactors.

Section 6.2.3.2.3 and Table 6.2-15 identifies the leak rate testing requirements for those penetrations that are Secondary Containment Bypass Leakage pathways.

Dwg. M-159, Sh. 1 shows the system used to perform the ILRT.

6.2.6.1 Primary Reactor Containment Integrated Leakage Rate Test

When the construction of the primary containment including all portions of systems that penetrate the containment was complete and the structural integrity test described in Subsection 3.8.1.7 was completed satisfactorily, the preoperational containment integrated leak rate test (ILRT) was performed. The preoperational ILRT was performed in accordance with the requirements of Chapter 14 to verify that the actual containment leak rate did not exceed the design limits. After the preoperational ILRT, periodic Type A tests are performed at the intervals specified in the plant Technical Specifications.

A general visual inspection of the accessible interior and exterior surfaces of the primary containment structure and components is performed. The inspection is performed prior to a periodic Type A test. In addition, when the Type A test is on a 10 year frequency, a general visual inspection is performed in 2 other refueling outages between Type A tests. If required, corrective action is taken and results are reported in accordance with 10CFR50 Appendix J Option B. Repairs and modifications to the containment structure shall meet the requirements of NEI 94-01, Rev. 0, Section 9.2.4 and ANSI/ANS-56.8-1994.

To ensure a successful ILRT, local leak rate tests, Type B and C tests, are performed on penetration boundaries and containment isolation valves. If necessary, repairs are made to Type B and C tested components between Type A tests. This ensures that the leakage through containment isolation barriers does not exceed design limits.

Periodic Type A tests are performed to ensure that the total leakage from containment does not exceed design limits. This is assured by limiting leakage to less than La when tested at Pa per the plant Technical Specifications. Table 6.2-19 contains the pertinent Type A test data including test pressures, test duration, and definitions of terms.

The Type A test acceptance criteria is in the plant Technical Specifications.

The absolute method described in ANSI/ANS-56.8-1994 or BN-TOP-1 is used to perform the Type A test. The leak rate and the associated 95% confidence limit are calculated in accordance with ANSI/ANS-56.8-1994 or BN-TOP-1. The calculated leak rate and the 95% confidence limit are to be contained in the post refuel outage report.

Prior to the start of any Type A test, the following pretest requirements must be met:

a. The containment isolation valves are closed by normal means and without adjustment (e.g., do not tighten a valve using the manual handwheel after the valve is closed by the motor operator). Identify in the Type A test final report any valve closure malfunctions or any valve adjustments made to reduce containment leakage.

b. The Appendix J pathways are vented and drained in accordance with NEI 94-01, Rev. 0, Section 8.0. Table 6.2-21 identifies the systems required for proper conduct of the Type A test and systems that are operable under post-accident conditions.

c. After test pressure is reached prior to the start of the Type A test, the containment atmosphere is stabilized in accordance with ANSI/ANS-56.8-1994 or BN-TOP-1. As necessary, the containment ventilation and cooling water systems are run prior to and during the Type A test to keep the containment atmosphere stabilized.

When the Type A test is complete, a verification test is performed in accordance with ANSI/ANS-56.8-1994 or BN-TOP-1. A known leak rate is imposed on containment through a calibrated flow measurement device. The verification test validates the Type A test results.

If during a Type A test or verification test, an unisolable leak is identified, the following steps are performed:

a. Stop the Type A test or verification test.
b. Depressurize, if needed, to fix the repair.
c. Repair the leak.
d. Start the Type A test over again.
e. Document the repairs in the post refuel outage report.

The Type A test frequency is in accordance with the Leakage Rate Test Program.

Table 6.2-22 (the Type Test column) identifies the penetrations that are Type A tested.

6.2.6.2 Primary Containment Penetration Leakage Rate Test

The following containment penetration designs are Type B tested:

- resilient seals, gaskets, or sealant compounds
- air locks and air lock door seals
- equipment and access hatch seals
- electrical canisters.

Preoperational Type B tests were performed and periodic Type B tests are performed in accordance with 10CFR50 Appendix J Option B. Table 6.2-22 identifies the penetrations that are Type B tested.

The air lock contains penetrations with threaded caps, penetrations with equalizing valves (described in Subsection 3.8.2.1.2), and electrical penetrations. The penetrations with threaded caps permit testing of the door seals and the entire air lock. Figures 6.2-57A-1, 6.2-57A-2, and 6.2-57A-3 show the locations of the penetrations in the air lock. Figures 6.2-58-1 and 6.2-58-2 show the details of the door seals and the pressure test connection. Table 6.2-22, Notes 2 and 3, specify the pressures used to test the air lock and the door seals. The air lock is periodically tested at Pa in accordance with the plant Technical Specifications. The door seals are tested at 10 psig at a frequency in accordance with the Leakage Rate Test Program.

The test pressure for all Type B tests, except the air lock door seals, is Pa, defined in Table 6.2-19. The Type B test acceptance criteria is in the plant Technical Specifications. The test methods are described in Subsection 6.2.6.3.

6.2.6.3 Primary Containment Isolation Valve Leakage Rate Tests

Table 6.2-22 identifies the containment isolation valves that are Type C tested in accordance with 10CFR50 Appendix J.

Some of the containment isolation valves are tested in a direction other than the accident direction. These valves are discussed below.

1. X-7A, B, C, D: Main Steam Line Penetrations, See Dwgs. M-141, Sh. 1 and Figure 5.4-8.

   The MSIVs can be tested by two methods. One of these methods applies pressure in between the MSIVs. In this test method, the pressure is applied to the inboard MSIVs, HV141F022A, B, C, D, in the reverse direction. This tends to unseat the inboard MSIV valve disc, making this a more conservative test for the inboard MSIVs. Since the y-globe valves are inside primary containment, any leakage through the valve packing and seals would not leave primary containment.

2. X-10, 11: HPCI and RCIC Turbine Steam Line Penetrations, See Dwgs. M-149, Sh. 1 and M-155, Sh. 1.

   Based on valve closure calculations, leakage through the HPCI gate valve, HV155F002, and the RCIC gate valve, HV149F007, in the reverse direction is equivalent to the leakage through the valves in the accident direction. The 1 in. bypass globe valves, HV155F100 and HV149F088, around the gate valves exhibit equivalent or more conservative leakage in the reverse direction. Since the gate and globe valves are inside primary containment, any leakage through the valve packing and seals that could leave primary containment is captured through reverse testing the valves.

3. X-12: RHR Shutdown Supply Penetration, See Dwg. M-151, Sh. 3.

   This penetration is no longer Type C tested.

4. X-25, 26, 201A, 201B, 202: Purge Supply and Exhaust Line Penetrations, See Dwgs. M-157, Sh. 1 and M-157, Sh. 9.

   Test pressure is applied to CAC butterfly valves, HV15722, HV15713, HV15725, HV157113 and HV15703, in the reverse direction. Butterfly valves exhibit equivalent or more conservative leakage in the reverse direction. The valve packing is tested during the Type A test.

5. X-210, 215: HPCI and RCIC Turbine Exhaust Line Penetrations, See Dwgs. M-155, Sh. 1 and M-149, Sh. 1.

   Test pressure is applied to the HPCI gate valve, HV155F066, and the RCIC gate valve, HV149F059, in the reverse direction. The discs of gate valves are symmetrical and therefore testing in either direction produces similar results. The valve packing and seals are tested during the Type A test. In addition, these valves are tested with water. The valve leakage is not included in the Type B and C test acceptance criteria.

6. X-217: RCIC Pump Discharge Line Penetration, See Dwg. M-149, Sh. 1.

Test pressure is applied to the RCIC globe valve, HV149F060, in the reverse direction. This tends to unseat the valve disc, making this a more conservative test for the valve. The valve packing and seals are tested during the Type A test. In addition, these valves are tested with water. The valve leakage is not included in the Type B and C test acceptance criteria.

7. X-243: Suppression Pool Cleanup and Drain, See Dwg. M-157, Sh. 1.

   Test pressure is applied to the gate valve, HV15766, in the reverse direction. The discs of gate valves are symmetrical and therefore testing in either direction produces similar results. The valve packing and seals are tested during the Type A test. In addition, these valves are tested with water. The valve leakage is not included in the Type B and C test acceptance criteria.

8. X-244, 245: HPCI and RCIC Vacuum Breaker Line Penetration. Refer to Dwgs. M-149, Sh. 1, M-150, Sh. 1, M-155, Sh. 1 and M-156, Sh. 1.

   The HPCI and RCIC vacuum breaker lines have symmetrical discs for the gate valves HV-2F079 and HV-2F084. Therefore, imposing the test pressure onto the valves from either direction procedures similar leakage rates.

8a. X-244: HPCI Breaker Penetration

   The HPCI inboard vacuum valve HV-1F079 is a flexwedge gate valve that is tested between the disc. Both disc and packing are exposed to the test pressure.

8b. X-245: RCIC Vacuum Breaker Penetration

   The RCIC inboard vacuum valve HV-1F084 is a flexwedge gate valve that is tested between the disc. Both disc and packing are exposed to the test pressure.

9. X-17: RPV Head Spray, See Dwg. M-151, Sh. 1.

   This penetration is no longer Type C tested.

The method by which these penetrations are tested and how the measured leakage is assigned is discussed below. The min path and max path leak rates are assigned to these penetrations in accordance with ANS-56.8-1994.

1. Penetrations X-7A, B, C, D: The MSIVs can be tested by two methods. The first method is by pressurizing between the MSL plugs and the MSIVs to Pa through test connection valves 141F017 and 141F018. This method determines the leak rate through each individual MSIV. The second method is to pressurize between the inboard and outboard MSIVs to 1/2 Pa through test connection valves 141F025A,B,C,D and 141F026A,B,C,D. This leakage would be assigned according to ANS-56.8-1994. Pressurizing upstream from the inboard MSIV to a pressure less than the test pressure while pressurizing between the inboard and outboard MSIVs to the test pressure will isolate leakage through the inboard MSIVs and measure leak rate solely through the outboard MSIVs. Leak rate through the inboard MSIVs is calculated by subtracting the outboard MSIV leak rate from the combined leak rate for the inboard and outboard MSIVs.

2a. Penetration X-10: Pressurize between HV149F007, HV149F088, and HV148F008 through test connection valves 149F036 and 149F037. This determines the leak rate for the penetration.

2b. Penetration X-11: Pressurize between HV155F002, HV155F100, and HV155F003 through test connection valves 155F014 and 155F015. This determines the leak rate for the penetration.

3. Penetration X-12: This penetration is no longer Type C tested.

4a. Penetration X-25 and X-201A: Pressurize between HV15722, HV15725, HV15721, HV15723 and HV15724 through test connection valve 157018. This determines the leak rate for the penetration.

4b. Penetrations X-26: Pressurize between HV15713, HV15711 and HV15714 through test connection valve 157001. This determines the leak rate for the penetration.

4c. Penetration X-202: Pressurize between HV15703, HV15704 and HV15705 through test connection valve 157167. This determines the leak rate for the penetration.

4d. Penetration X-201B: Pressurize between HV157113 and HV157114 through test connection valves 157320 and 157321. Pressurize the inlet flange of HV157113 between two sealing O-rings. These tests determine the leak rate for the penetration.

5a. Penetration X-210: Pressurize between HV155F066, HV155F075 and 155F049 through test connection valve 155F013. This determines the leak rate for the penetration.

5b. Penetration X-215: Pressurize between HV149F059, HV149F062 and 149F040 through test connection valve 149F041. This determines the leak rate for the penetration.

6. Penetration X-217: Pressurize between HV149F060 and 149F028 through test connection valve 149F055. This determines the leak rate for the penetration.

7. Penetration X-243: Pressurize between HV15766 and HV15768 through test connection valve 157122. This determines the leak rate for the penetration.

8a.2 Penetration X-244: Pressurize between HV-2F079 and HV-2F075 through Valve 2F092. Assign total leakage to that penetration.

8a.1 Penetration X-244: Pressurize between Disc for HV-1F079 through Valve 155802. Assign total leakage for that test to HV-1F079. Valve HV-1F075 is tested separately.

8b.2 Penetration X-245: Pressurize between HV-2F084 and HV-2F062 through Valve 2F065. Assign total leakage to that penetration.

8b.1 Penetration X-245: Pressurize between Disc for HV-1F084 (Unit1) and HV-2F084 (Unit 2) through Valve 149025 (Unit 1) and 249026 (Unit 2). Assign total leakage for that test to HV-1F084 (Unit 1) and HV-2F084 (Unit 2). Valve HV-1F062 (Unit 1) and HV-2F062 (Unit 2) is tested separately.

9. Penetration X-17: This penetration is no longer Type C tested.

Type B and C tests are performed by local pressurization. Use one of the following two methods: pressure decay or make-up flowrate. These methods of testing are described in ANSI/ANS-56.8-1994 Section 6.4. For most of the containment isolation valves, test pressure is applied in the accident direction. This means that pressure is applied in the same direction as the pressure experienced by the valve during a design basis accident. For a few containment isolation valves, test pressure is applied in a direction other than the accident direction (i.e., reverse testing). Due to generic BWR valve arrangements, reverse testing has been used for previously licensed plants. More details on reverse testing is provided above.

All containment isolation valve seats that are exposed to containment atmosphere following a LOCA are tested with air or nitrogen. The valves are to be tested at Pa as defined in Table 6.2-19.

Some penetrations contain lines that are designed to be water filled or sealed for at least 30 days following a LOCA, without a qualified seal water system. Table 6.2-22 identifies containment isolation valves that are in water filled or water sealed lines. The containment isolation valves in these lines are not required to be leak rate tested in accordance with 10CFR50, Appendix J. These valves are tested with water using the make-up flowrate method. These valves are tested at a pressure of 1.1 P_a. The leak rates are not included in the Type B and C running totals. The leak rates are included in the primary to secondary containment water leakage.

The Type C test acceptance criteria is in the plant Technical Specifications.

<u>6.2.6.4 Scheduling and Reporting of Periodic Tests</u>

The Leakage Rate Test Program specifies the periodic Type A, B, and C leak rate test frequencies.

Type B and C tests are conducted during normal plant operations or during plant shutdowns. However, the frequency between any individual Type B or C test shall not exceed the appropriate test interval specified in the Leakage Rate Test Program. Each time a Type B or C test is completed, the overall total leak rate for Type B and C tests is updated.

Post-refuel outage reports are prepared. The reports are available on-site for inspection.

<u>6.2.6.5 Special Testing Requirements</u>

<u>6.2.6.5.1 Drywell to Pressure Suppression Chamber Atmosphere Bypass Area Test</u>

<u>6.2.6.5.1.1 High Pressure Leak Test</u>

A Structural Integrity Test (SIT) was performed on the Unit 1 primary containment in January 1977. The SIT did not include a preoperational high pressure leak test to detect leakage from the drywell to the suppression chamber. Regulatory Guide 1.18 and 10CFR50 Appendix J do not require this high pressure leak test.

A SIT was performed on the Unit 2 primary containment in October 1983. The Unit 2 SIT was identical to the Unit 1 SIT with the following 3 exceptions:

1. It was performed during the ILRT.
2. Concrete strains were not measured.
3. A high pressure bypass test was performed.

6.2.6.5.1.2 Low Pressure Leak Test

Drywell to suppression chamber bypass tests are performed to determine the overall bypass area. The overall bypass area is the area that would allow drywell atmosphere to flow directly into the suppression chamber atmosphere without passing through the suppression pool water following a LOCA. The plant Technical Specifications specify the testing frequency for the bypass test.

At the start of the bypass test, the suppression chamber atmosphere is at atmospheric pressure. Based on the suppression pool water level, the drywell atmosphere is pressurized. The drywell pressure is maintained below a level that would force air through the downcomers and suppression pool water into the suppression chamber atmosphere. The bypass test then measures the pressure increase of the suppression chamber atmosphere. During the test, the suppression chamber atmosphere is isolated from the outside atmosphere. The drywell pressure is maintained at the desired differential pressure by adding or venting air to the drywell as required.

During refuel outages where a drywell to suppression chamber bypass test is not performed, a drywell to suppression chamber vacuum breaker leak test is performed on each set of vacuum breakers. This leak test is performed by pressurizing a downcomer with air to a pressure based on the suppression pool water level. The make-up flow required to maintain the test pressure is measured. The measured flow is the leak rate through the set of drywell to suppression chamber vacuum breakers.

The bypass test and vacuum breaker leak test acceptance criteria is in the plant Technical Specifications.

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TABLE 6.2-1

CONTAINMENT DESIGN PARAMETERS

	DRYWELL	SUPPRESSION CHAMBER
DRYWELL AND SUPPRESSION CHAMBER		
1. Internal Design Pressure, psig	53	53
2. External Design Pressure, psig	5	5
3. Drywell Deck Design Differential Pressure a. Download, psid b. Upload, psid	 28 5.5	
4. Design Temperature,°F	340	220
5. Drywell (including vents) Net Free Volume, ft^3	239,600	-
6. Design Leak Ratio, %/day	1.0	1.0
7. Maximum Allowable Leak Rate, %/day	1.0	1.0
8. Suppression Chamber Free Volume, ft^3		159,130 (low water) 148,590 (high water)
9. Suppression Chamber Water Volume. Minimum, ft^3 Maximum, ft^3		 122,410 131,550
10. Pool Free Cross-sectional Area, ft^2		5,277
11. Pool Depth (normal), ft		23
12. Drywell Free Volume/Pressure Suppression Chamber Free Volume		1.51 to 1.61
13. Primary System Volume/Pressure Suppression Pool Volume		.15
VENT SYSTEM		
1. No. of Active Downcomers		82
2. No. of Capped Downcomers		5
3. Nominal Downcomer Diameter, ft.		2
4. Total Downcomer Vent Area, ft^2		257
5. Downcomer Submergence, ft - high water level - normal water level - low water level		12 11 10
6. Downcomer Loss Factor		2.17

Table 6.2-2

ENGINEERED SAFETY SYSTEMS INPUTS AND ASSUMPTIONS FOR CONTAINMENT RESPONSE ANALYSES

	Analysis Value Case D[1]
ECCS Systems	
A. High Pressure Coolant Injection (HPCI)	
1. No. of Pumps	1
2. No. of Lines	1
3. Flowrate, gpm	0
B. Core Spray (CS)	
1. No. of Pumps	4
2. No. of Lines	2
3. Flowrate (runout), gpm/line	7,900
4. No. of Headers	2
C. Low Pressure Coolant Injection (LPCI)	
1. No. of Pumps	4
2. No. of Lines	2
3. Flowrate (runout), gpm/line	22,000
D. RHR Heat Exchangers	
1. Overall Heat Transfer Coefficient, Btu/sec.-°F/Unit	317.5

Notes:

1. Per Section 6.2.1.1.3.3.1.6, Case D produces the limiting results for the long-term containment analysis; therefore, only Case D values will be listed.

TABLE 6.2-3a

Initial Plant Conditions for
DBA-LOCA Containment Response

Parameter	Units	Value
Rated Power	MWt	3952
Rated Core Flow	Mlbm/hr	100
Rated Steam Dome Pressure	psig	1035
Rated Turbine Steam Flow	Mlbm/hr	16.532
Rated Feedwater Flow	Mlbm/hr	16.500
Final Feedwater Temperature	°F	399.3
Drywell Pressure	psig	2.0
Drywell Temperature	°F	135
Drywell Relative Humidity	percent	20
Wetwell Pressure	psig	2.0
Wetwell Temperature	°F	90
Wetwell Relative Humidity	percent	100
Suppression Pool Temperature	°F	90

TABLE 6.2-4a

Input and Assumptions for the Short Term DBA-LOCA Analysis

1. In the LAMB calculations of break flow rates and enthalpies, the Moody Slip flow model is used, consistent with Appendix K ECCS-LOCA modeling.

2. The power level for each power/flow point analysis includes an additional 2%, consistent with Regulatory Guide 1.49.

3. The recirculation suction line break area is 4.17 sq. ft. and the main steam line break area is 3.9 sq. ft.

4. The break is an instantaneous double-ended rupture of a recirculation suction line or main steam line. MSIVs are completely closed within 2 seconds into the event for an RSLB and within 12 seconds for an MSLB.

5. No credit is taken for the passive structural heat sinks in the containment.

6. The initial vent submergence and the suppression pool water volume are determined to the High Water Level (HWL).

7. Initial containment conditions are assumed that maximize the initial mass of noncondensable gases, which result in conservative peak drywell and wetwell pressures. For the MSLB event, initial containment conditions are assumed that minimize the initial mass of non-condensable gases, which result in conservative peak drywell temperatures. These include minimum drywell and wetwell initial pressure of –1.0 psig, maximum drywell initial temperature of 135°F, and maximum drywell relative humidity of 90%.

8. For analyses performed to provide containment results for input to the hydrodynamic loads assessment, nominal initial containment conditions are assumed.

9. The wetwell airspace is in thermal equilibrium with the suppression pool.

10. The decay heat values are based on the ANS 5.0 + 20%, as used in Appendix K ECCSLOCA evaluations.

11. Feedwater flow is assumed to continue at 100% rated flow and enthalpy for 10 seconds following initiation of the event, which results in conservative peak drywell and wetwell pressures.

12. In analyzing wetwell pressure results, a polytropic exponent for air of 1.4 is used. For these cases, bubble burst is assumed to occur when wetwell pressure exceeds drywell pressure by 2.5 psid, or at maximum wetwell airspace pressure if peak wetwell pressure never exceeds drywell pressure by this amount.

TABLE 6.2-5a

Input and Assumptions for the
Long Term DBA-LOCA Analysis

1. The DBA-LOCA is an instantaneous double-ended guillotine break of the recirculation suction line at the reactor vessel nozzle safe-end to pipe weld.

2. The reactor is operating at 102% of EPU power at rated steam dome pressure. A reactor scram occurs concurrent with the occurrence of the break.

3. The reactor core power following reactor scram includes fission energy, fuel stored energy, metal-water reaction energy, and ANS 5.1 + 2σ decay heat evaluated for ATRIUM – 10 fuel with 24-month fuel cycle.

4. Reactor blowdown flow rates are based on the Moody Slip model.

5. The reactor vessel control volume is assumed to include the fluid and structural masses of the primary system components including reactor vessel, recirculation loops, main steam lines to the inboard isolation valve, and other piping systems attached to the reactor vessel, such as ECCS lines up to the inboard isolation valves.

6. The portion of the feedwater (FW) inventory initially at a temperature higher than 198°F is injected into the vessel, after absorbing heat from the FW piping metal. This assumption is used to maximize the suppression pool (SP) temperature. Upstream FW, which is initially at lower temperature, will be heated up due to downstream pipe metal at higher temperature even if no steam flows to heaters from the turbine. This assumption is conservative because the coldest water injected into the vessel with this assumption is at a temperature higher than the peak SP temperature.

7. The wetwell airspace and suppression pool are assumed to be in thermal equilibrium and the wetwell airspace is saturated throughout the event.

8. The initial suppression pool water volume corresponds to the Low Water Level (LWL) to maximize the suppression pool temperature response.

9. All four CS and four LPCI pumps are assumed to provide reactor coolant makeup soon after low water level in the reactor vessel occurs. Operators are assumed to establish containment cooling with one heat exchanger no earlier than 10 minutes following initiation of the break.

10. A constant RHR heat exchanger K-value is conservatively assumed for containment cooling. The heat exchanger K-value would be expected to increase as the suppression pool (SP) temperature increases during the event due to changes in water properties with increasing temperature. The K-value assumed for this analysis corresponds to a value at the low end of the SP temperature excursion during operation of the heat exchanger.

11. The containment cooling heat exchanger service water temperature is assumed at the maximum value anticipated during a DBA-LOCA.

12. Credit is taken for passive heat sinks in the drywell, wetwell airspace and suppression pool.

13. All operating CS and RHR pumps have 100% of their motor horsepower rating converted to pump heat, which is added to the flow downstream of the pump.

14. Conservative values for MSIV closure are assumed. Rapid closure of the MSIV results in higher peak suppression pool temperature, since the shorter closure time would retain more water mass and energy in the vessel for blowdown to the containment.

15. Condensate Storage Tank (CST) water inventory is not available for vessel makeup.

Passive Containment Heat Sings		
Parameter	Units	Value
Drywell		
Steel Heat Capacity	BTU/°F	176,000
Steel Surface Area	sqft	71,000
Concrete Heat Capacity	BTU/°F	211,104
Concrete Surface Area	sqft	14,660
Wetwell Airspace		
Steel Heat Capacity	BTU/°F	97,932
Steel Surface Area	sqft	25,358
Concrete Heat Capacity	BTU/°F	0
Concrete Surface Area	sqft	0
Suppression Pool		
Steel Heat Capacity	BTU/°F	58,940
Steel Surface Area	sqft	15,557
Concrete Heat Capacity	BTU/°F	0
Concrete Surface Area	sqft	0

TABLE 6.2-6a

Containment Performance
For DBA-LOCA

Parameter	Units	Value
Peak Drywell Pressure	psig	48.6[1]
Peak Drywell Temperature	°F	337[2]
Peak Bulk Pool Temperature	°F	211.2[3]
Peak Wetwell Pressure	psig	36.5[1]
Peak Drywell-to-Wetwell (Down) Differential Pressure	psig	25.6[1]

Notes

1. Based on the Short-Term RSLB analysis
2. Based on the Short Term MSLB analysis
3. Based on the Case D Long-Term RSLB analysis

TABLE 6.2-9

RPV BREAK FLOW DATA FOR
RECIRCULATION LINE BREAK
(102% P / 100% F)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
0.000	12210	525.0
0.003	52790	523.1
0.112	51280	523.3
0.300	50440	523.9
0.362	50150	524.1
0.456	49770	524.4
0.628	48920	525.0
0.756	48210	525.4
0.873	47520	525.8
0.951	47020	526.1
1.029	46500	526.3
1.123	45860	526.6
1.279	44770	527.1
1.435	43670	527.5
1.592	42570	527.9
1.779	41140	528.3
2.029	39620	529.0
2.310	38520	529.7
2.748	37820	530.6
3.060	37860	531.2
3.373	38270	531.9
3.685	38820	532.6
4.060	39430	533.5
4.498	39600	540.6
5.123	38090	547.5
6.123	37530	550.3
7.123	37390	545.9
8.029	33179	635.9
9.060	18430	726.3
10.029	18536	692.7

TABLE 6.2-9

RPV BREAK FLOW DATA FOR
RECIRCULATION LINE BREAK
(102% P / 100% F)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
12.498	17445	674.9
15.123	16650	647.0
17.623	14851	634.7
20.123	12901	626.5
25.123	8580	624.1
30.123	4858	616.7
35.002	2539	600.1
40.002	1189	613.7
45.010	522	677.2
50.017	188	759.8

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TABLE 6.2-10

RPV BREAK FLOW DATA FOR
MAIN STEAM LINE BREAK
(102% P / 100% F)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
0.001	9991	1191.0
0.007	11650	1191.0
0.011	11650	1191.0
0.065	11610	1191.0
0.112	11580	1191.0
0.215	8454	1191.0
0.309	8444	1192.0
0.402	8431	1192.0
0.512	8417	1192.0
0.605	8404	1192.0
0.715	8390	1192.0
0.809	8378	1192.0
0.875	8368	1192.0
1.000	29214	570.4
1.004	29215	570.4
1.262	29233	572.1
1.512	29239	573.6
1.731	29241	574.9
2.012	29233	576.6
2.481	29227	579.5
3.043	29199	583.0
3.481	29175	585.8
4.043	29117	589.5
4.543	29063	592.9
5.106	28963	597.1
6.043	28782	603.9
7.043	28493	611.7
8.043	28094	619.0

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TABLE 6.2-10

RPV BREAK FLOW DATA FOR
MAIN STEAM LINE BREAK
(102% P / 100% F)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
9.043	27606	626.2
10.043	27028	633.1
13.543	19425	656.2
15.168	18573	666.4
17.418	17177	678.3
20.168	15251	688.6
25.168	11583	702.9
30.168	8203	715.7
35.168	5458	731.5
40.043	3512	758.0
45.043	2142	806.9
50.043	1255	894.2

TABLE 6.2-11
CORE DECAY HEAT FOLLOWING LOCA
FOR CONTAINMENT ANALYSIS

Time sec	+2 Sigma Decay Heat =SIL636	LOCA Fission Power	+2 Sigma Decay Heat +SIL636 +LOCA Fission Power	Time sec	+2 Sigma Decay Heat =SIL636	LOCA Fission Power	+2 Sigma Decay Heat +SIL636 +LOCA Fission Power
0	0.0722	0.9278	1.000	1000.0	0.0217	0	0.0217
0.5	0.0695	0.3334	0.4029	1.25E+03	0.0205	0	0.0205
1.0	0.0668	0.2042	0.2711	1.50E+03	0.0194	0	0.0194
1.5	0.0643	0.1781	0.2424	1.80E+03	0.0185	0	0.0185
2.0	0.0626	0.1911	0.2537	2.00E+03	0.0178	0	0.0178
2.5	0.0612	0.1828	0.2440	2.50E+03	0.0166	0	0.0166
3.0	0.0600	0.1885	0.2485	3.00E+03	0.0157	0	0.0157
3.6	0.0588	0.2207	0.2795	3.50E+03	0.0149	0	0.0149
4.0	0.0580	0.2437	0.3018	4.00E+03	0.0143	0	0.0143
4.4	0.0574	0.2491	0.3065	5.00E+03	0.0133	0	0.0133
5.0	0.0564	0.1990	0.2555	6.00E+03	0.0126	0	0.0126
6.0	0.0551	0.0300	0.0851	7.00E+03	0.0120	0	0.0120
7.0	0.0540	0.0183	0.0723	8.00E+03	0.0116	0	0.0116
8.0	0.0530	0.0166	0.0696	9.00E+03	0.0112	0	0.0112
9.0	0.0521	0.0149	0.0669	1.00E+04	0.0109	0	0.0109
10.0	0.0513	0.0127	0.0640	1.25E+04	0.0103	0	0.0103
12.5	0.0496	0.0102	0.0598	1.50E+04	9.79E-03	0	9.79E-03
15.0	0.0482	0.0099	0.0581	2.00E+04	9.10E-03	0	9.10E-03
20.0	0.0461	0.0072	0.0533	2.50E+04	8.61E-03	0	8.61E-03
25.0	0.0444	0.0054	0.0498	3.00E+04	8.24E-03	0	8.24E-03
30.0	0.0431	0.0044	0.0475	3.50E+04	7.95E-03	0	7.95E-03
35.0	0.0419	0.0037	0.0456	4.00E+04	7.68E-03	0	7.68E-03
40.0	0.0410	0.0032	0.0442	5.00E+04	7.27E-03	0	7.27E-03
50.0	0.0394	0.0025	0.0419	6.00E+04	6.95E-03	0	6.95E-03
60.0	0.0381	0.0021	0.0401	7.00E+04	6.69E-03	0	6.69E-03
70.0	0.0370	0.0018	0.0388	8.00E+04	6.48E-03	0	6.48E-03
80.0	0.0361	0.0016	0.0377	9.00E+04	6.30E-03	0	6.30E-03

TABLE 6.2-11
CORE DECAY HEAT FOLLOWING LOCA
FOR CONTAINMENT ANALYSIS

Time sec	+2 Sigma Decay Heat =SIL636	LOCA Fission Power	+2 Sigma Decay Heat +SIL636 +LOCA Fission Power	Time sec	+2 Sigma Decay Heat =SIL636	LOCA Fission Power	+2 Sigma Decay Heat +SIL636 +LOCA Fission Power
90.0	0.0353	0.0014	0.0367	1.00E+05	6.15E-03	0	6.15E-03
100.0	0.0346	0.0012	0.0358	1.25E+05	5.84E-03	0	5.84E-03
125.0	0.0331	0.0009	0.0340	1.50E+05	5.60E-03	0	5.60E-03
150.0	0.0320	0.0007	0.0327	2.00E+05	5.26E-03	0	5.26E-03
200.0	0.0303	0.0004	0.0307	2.50E+05	5.04E-03	0	5.04E-03
250.0	0.0291	0.0002	0.0293	3.00E+05	4.87E-03	0	4.87E-03
300.0	0.0281	0.0001	0.0282	3.50E+05	4.75E-03	0	4.75E-03
350.0	0.0273	0.0001	0.0273	4.00E+05	4.65E-03	0	4.65E-03
400.0	0.0266	0.0000	0.0266	5.00E+05	4.52E-03	0	4.52E-03
500.0	0.0254	0	0.0254	6.00E+05	4.44E-03	0	4.44E-03
600.0	0.0245	0	0.0245	7.00E+05	4.35E-03	0	4.35E-03
700.0	0.0237	0	0.0237	8.00E+05	4.19E-03	0	4.19E-03
800.0	0.0229	0	0.0229	9.00E+05	4.06E-03	0	4.06E-03
900.0	0.0223	0	0.0223	1.00E+06	3.89E-03	0	3.89E-03

Normalized Power = 3952 Mwt

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TABLE 6.2-12

CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position: Normal	Valve Position: Shut-down	Valve Position: LOCA	Valve Position: Power Fails	Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
X-5	Ctmt. Rad. Det.,	Air/N_2	1	56	No	SV157100A	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	7'	(33)
(Unit 1 Only)	Supply Sample					SV157101A	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	8'	(33)
X-5	Ctmt. Rad Det.,	Air/N_2	1	56	No	SV157102A	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	7'	(33)
(Unit 1 Only)	Return Sample					SV157103A	Ac Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	8'	(33)
X-5	Ctmt. Rad. Det.,	Air/N_2	1	56	No	SV257100A	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	8'	(33)
(Unit 2 Only)	Supply Sample					SV257101A	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	9.5'	(33)
X-5	Ctmt. Rad. Det.,	Air/N_2	1	56	No	SV257102A	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	9'	(33)
(Unit 2 Only)	Return Sample					SV257103A	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	10.5'	(33)
X-7A	Main Steam	Steam	26	55	Yes	1F028A	Compressed Air	Spring	II/RPSB	O	a	GB	Open	Closed	Closed	Closed	3-5	(a)		(3)(26)
			26			1F022A	Inst Gas	Spring	I/RPSA	I		GB	Open	Closed	Closed	Closed	3-5	(a)		(26)(37)
X-8	Main Steam Drain	Water	3	55	No	1F016	AC Mot	Manual	I	I	g	GT	Closed	Open	Closed	As Is	10	(a)	6'	(38)
			3			1F019	DC Mot	Manual	II	O		GT	Closed	Open	Closed	As Is	15	(a)	0	(38)
X-9A	Feed Water and	Water	24	55	Yes	1F032A	AC Mot	Manual	I	O	b	CK	Open	Closed	--	As Is	120	--	17	(14)(11)
	HPCI, RCIC, and		14			1F006	DC Mot	Manual	II	O		GT	Closed	Closed	Open	As Is	20	--		X-9B Only
	RWCU pump					155038	Manual	--	--	O		GB	Closed	Closed	Closed	Closed	--	--		X-9B Only
	discharge		6			1F013	DC Mot	Manual	I	O		GT	Closed	Closed	Open	As Is	15	--		X-9A Only
						149020	Manual	--	--	O		GB	Closed	Closed	Closed	Closed	--	--		X-9A Only
			3			14182A	AC Mot	Manual	I	O		GT	Open	Open	Open	As Is	30	--		(11)(43)
			24			1F010A	Flow	--	--	I		CK	Open	Open	--	--	--	--		(11)(5)
			3			141F039A	Flow	--	--	O	b	CK	Open	Open	--	--	--			(11)(5)
			24			141818A	Flow	--	--	O	b	CK	Open	Open	--	--	--			(11)(5)
			3			241F039A	Flow	--	--	O	b	CK	Open	Open	--	--	--			(11)
X-10	Steam to	Steam	4	55	No	1F007	AC Mot	Manual	II	I	c	GT	Open	Closed	Open	As Is	20	(k)		(4)(15)
	RCIC																			
	Turbine		1			1F088	Inst Gas	Spring	II	I		GB	Closed	Closed	Open	Closed	20	(k)		(4)(15)
			4			1F008	DC Mot	Manual	I	O		GT	Open	Closed	Open	As Is	20	(k)	0'	(15)
X-11	Steam to	Steam	10	55	Yes	1F003	DC Mot	Manual	II	O	c	GT	Open	Closed	Open	As Is	50	(l)	0'	(15)
	HPCI		1			1F100	Inst Gas	Spring	I	I		GB	Closed	Closed	Closed	Closed	6	(l)		(15)(4)
	Turbine		10			1F002	AC Mot	Manual	I	I		GT	Open	Closed	Open	As Is	50	(l)		(15)(4)
X-12	RHR Shutdown	Water	20	55	No	1F008	DC Mot	Manual	II	O	h	GT	Closed	Open	Closed	As Is	100	(b)	0	(44)(45)
	Supply		20			1F009	AC Mot	Manual	I	I		GT	Closed	Open	Closed	As Is	100	(b)		(44)(45)
			1			PSV1F126	Water	--	--	I		RLF	Closed	Closed	Closed	--	--	--		(44)

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TABLE 6.2-12

CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position				Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
													Normal	Shut-down	LOCA	Power Fails				
X-13A	RHR Shutdown Return	Water	24	55	Yes	1F015A	AC Mot	Manual	I	O	n	GT	Closed	Open	Open	As Is	24	--	0	(11)(6)(42)(44)(45)
			24			1F050A	Flow	Spring	I	I		TCK	Closed	Open	Open	--	--	--		(11)
			1			1F122A	Inst Gas	Spring	I	I		GB	closed	Closed	Closed	Closed	3	--		(11)
X-14	Reactor Water Clean Up Supply	Water	6	55	No	1F001	AC Mot	Manual	I	I	g	GT	Open	Open	Closed	As Is	30	(c)	0	
			6			1F004	DC Mot	Manual	II	O		GT	Open	Open	Closed	As Is	30	(c), I		
X-16A	Core Spray	Water	12	55	Yes	1F005A	AC Mot	Manual	I	O	n	GT	Closed	Closed	Open	As Is	19	--	0	(11)
			12			1F006A	Flow	--	I	I		TCK	Closed	Closed	Open	--	--	--		(11)(5)
			1			1F037A	Inst Gas	Spring	I	I		GB	Closed	Closed	Closed	--	3	--		(11)
X-17	RPV Head Spray	Water	6	55	No	1F023	DC Mot	Manual	II	O	u	GB	Closed	Open	Closed	As Is	20	(d)	0	(44)(45)
(41)			6			1F022	AC Mot	Manual	I	I		GT	Closed	Open	Closed	As Is	30	(d)		(44)(45)
X-19	Instrument Gas	N_2/Air	3	56	No	SV12651	AC Coil	--	I	O	i	GB	Open	Open	Closed	Closed	2	F,G		(33)
		Mix				126074	Flow	--	--	I		CK	Open	Open	Closed	--	--	--		(5)
X-21	Instrument Gas	N_2/Air	1	56	Yes	SV12654B	DC Coil	--	I	O	i	GB	Open	Open	Open	Open	1	--		(33)
		Mix				126152	Flow	--	--	I		CK	Open	Open	Open	--	--	--		(5)
X-23	Closed Cooling Water Supply	Water	4	56	No	HV11314	AC Mot	Manual	I	O	z	GT	Open	Closed	Closed	As Is	30	F,G		
(41)						HV11346	AC Mot	Manual	II	I		GT	Open	Closed	Closed	As Is	30	F,G		
X-24	Closed Cooling Water Return	Water	4	56	No	HV11313	AC Mot	Manual	I	O	z	GT	Open	Closed	Closed	As Is	30	F,G	0	
(41)						HV11345	AC Mot	Manual	II	I		GT	Open	Closed	Closed	As Is	30	F,G		
X-25	Drywell Purge Supply	Air/N_2	24	56	No	HV15722	Comp Air	Spring	I	O(IB)	Y	BF	Closed	Closed	Closed	Closed	15	B,F,R	0	(4)
			24			HV15723	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	14	(8)
			6			HV15721	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	10	(8)(32)
			18			HV15724	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	10	(8)(32)
X-26	Drywell Purge Return	Air/N_2	24	56	No	HV15713	Comp Air	Spring	I	O(IB)	e	BF	Closed	Closed	Closed	Closed	15	B,F,R	0	(23) HS-17508AA (24) HS-15713A
			24			HV15714	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R		
			2			HV15711	Comp Air	Spring	II	O		GB	Closed	Closed	Closed	Closed	15	B,F,R		(23) HS-17508BA (24) HS-15711B
X-31B	Recirc Pump Seal Water Supply	Water	1	55	No	XV1F017B	Flow	-	-	O	BB	XFC	Open	Open	Open	-	-	-	0	(20)
						1F013B	Flow	-	-	I		CK	Open	Open	Open	-	-	-		(20)
X-31B (Unit 2 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV257100B	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F		(33)
						SV257101B	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F		(33)

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CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position: Normal	Valve Position: Shut-down	Valve Position: LOCA	Valve Position: Power Fails	Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
X-31B	Ctmt. Rad. Det.,	Air/N_2	1	56	No	SV257102B	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F		(33)
(Unit 2 Only)	Return Sample					SV257103B	AC Coil	Spring	II	O	DD	GT	Open	Open	Closed	Closed	1	B,F		(33)
X-35A	TIP Drivers		3/8	56	No	J004	AC Coil	None		O(IB)	w	BL	Closed	Closed	Closed	Closed	5	A,F	2'	(21)
and C thru F						J004	DC Explosion	None		O		Shear	Open	Open	Open	Open	1	--	2'	(21)
X-37A,B,C,D	CRD Insert	Water	1	55	Yes															(19)
X-38A,B,C,D	CRD Withdrawal	Water	3/4	55	Yes															(19)
X-39A	Drywell Spray	Water	12	56	No	1F016A	AC Mot	Manual	I	O	d	GB	Closed	Closed	Closed	As Is	90	F,G	7'	(6)(11) (44)
X-41	Instrument Gas	N_2/Air	1	56	Yes	SV12654A	DC Coil	--	I	O	i	GB	Open	Open	Open	Open	1	--		(33)
		Mix				126154	Flow	--	--	I		CK	Open	Open	Open		--	--		(5)
X-42	Standby Liquid	Water	1-	55	Yes	1F006	AC Mot	Manual	I	O	k	GCK	Open	Open	Open	As Is	34	--	6'	
	Control		1/2			1F007	Flow	--	--	I		CK	Closed	Closed	Closed	--		--	16'	(5)
X-53	Chilled Water Supply	Water	8	56	No	HV18781B1	Comp Air	Spring	II	O	l	GT	Open	Open	Closed	Closed	40	F,G	0	
(41)	"B"					HV18782A1 (Unit 1)	Inst Gas	Spring	I	I		BF	Open	Open	Closed	Closed	12	F,G		
						HV28782A1 (Unit 2)		Spring	I	I		BF	Open	Open	Closed	Closed	12	F,G		
X-54	Chilled Water	Water	8	56	No	HV18781B2	Comp Air	Spring	II	O	l	GT	Open	Open	Closed	Closed	40	F,G	0	
(41)	Return "B"					HV18782A2 (Unit 1)	Inst Gas	Spring	I	I		BF	Open	Open	Closed	Closed	12	F,G		
						HV28782A2 (Unit 2)		Spring	I	I		BF	Open	Open	Closed	Closed	12	F,G		
X-55	Chilled Water Supply	Water	8	56	No	HV18781A1	Comp Air	Spring	I	O	l	GT	Open	Open	Closed	Closed	40	F,G	0	
(41)	"A"					HV18782B1 (Unit 1)	Inst Gas	Spring	II	I		BF	Open	Open	Closed	Closed	12	F,G		
						HV28782B1 (Unit 2)		Spring	II	I		BF	Open	Open	Closed	Closed	12	F,G		
X-56	Chilled Water	Water	8	56	No	HV18781A2	Comp Air	Spring	I	O	l	GT	Open	Open	Closed	Closed	40	F,G	0	
(41)	Return "A"					HV18782B2 (Unit 1)	Inst Gas	Spring	II	I		BF	Open	Open	Closed	Closed	12	F,G		
						HV28782B2 (Unit 2)		Spring	II	I		BF	Open	Open	Closed	Closed	12	F,G		
X-60A	Sample & Analyzer	Gas	1	56	Yes	SV15740A	AC Coil	Spring	I	O(1B)	q	GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15750A	AC Coil	Spring	I	O(1B)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15742A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15752A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
X-60A	Recirc Pump Seal	Water	1	55	No	XV1F017A	Flow	--	--	O	BB	XFC	Open	Open	Open	--	--	--	0	(20)
	Water Supply					1F013A	Flow	--	--	I		CK	Open	Open	Open	--	--	--		(20)
X-60B	Sample & Analyzer	Water	3/4	55	No	1F019	Inst Gas	Spring	I	I	EE	GB	Open	Closed	Open	Closed	9	B,C		
			1			1F020	Comp Air	Spring	II	O		GB	Open	Closed	Open	Closed	2	B,C	2'	

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CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position: Normal	Valve Position: Shut-down	Valve Position: LOCA	Valve Position: Power Fails	Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
X-61A	Demin. Water	Water	1	56	No	141018	Manual	--	--	I	FF	GB	Closed	Closed	Closed	Closed	--	--		
(41)						141017	Manual	--	--	O		GB	Closed	Closed	Closed	Closed	--	--		
X-61A	ILRT Leak Verification	Gas	1	56	No	157193 (Unit 1)	Manual	--	--	I	FF	GB	Closed	Closed	Closed	Closed	--	--		
						257200 (Unit 2)														
						157194 (Unit 1)	Manual	--	--	0		GB	Closed	Closed	Closed	Closed	--	--		
						257199 (Unit 2)														
X-72A	Equipment Drain	Water	3	56	No	HV16116A1	Comp Air	Spring	I	O(IB)	f	GT	Closed	Closed	Closed	Closed	15	B,F	0	
						HV16116A2	Comp Air	Spring	II	O		GT	Closed	Closed	Closed	Closed	15	B,F		
X-72B	Floor Drain	Water	3	56	No	HV16108A1	Comp Air	Spring	I	O(IB)	f	GT	Closed	Closed	Closed	Closed	15	B,F	0	
						HV16108A2	Comp Air	Spring	II	O		GT	Closed	Closed	Closed	Closed	15	B,F	1	
X-80C	H_2O Analyzer	Gas	1	56	Yes	SV15750B	AC Coil	Spring	II	O(IB)	q	GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15740B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15776B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15742B	AC Coil	Spring	II	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15752B	AC Coil	Spring	II	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
						SV15774B	AC Coil	Spring	II	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10 Min. (33) (40)
X-85A	Chilled Water to Recirc Pump A	Water	3	56	No	HV18791A1	Comp Air	Spring	I	O	l	GT	Open	Closed	Closed	Closed	15	B,F	6	
(41)						HV18792B1 (Unit 1)	Inst Gas	Spring	II	I		BF	Open	Closed	Closed	Closed	8	B,F		
						HV28792B1 (Unit 2)		Spring	II	I		BF	Open	Closed	Closed	Closed	8	B,F		
X-85B	Chilled Water from Recirc Pump A	Water	3	56	No	HV18791A2	Comp Air	Spring	I	O	l	GT	Open	Closed	Closed	Closed	15	B,F	6	
(41)						HV18792B2 (Unit 1)	Inst Gas	Spring	II	I		BF	Open	Closed	Closed	Closed	8	B,F		
						HV28792B2 (Unit 2)		Spring	II	I		BF	Open	Closed	Closed	Closed	8	B,F		
X-86A	Chilled Water to Recirc Pump B	Water	3	56	No	HV18791B1	Comp Air	Spring	II	O	l	GT	Open	Closed	Closed	Closed	15	B,F	0	
(41)						HV18792A1 (Unit 1)	Inst Gas	Spring	I	I		BF	Open	Closed	Closed	Closed	8	B,F		
						HV28792A1 (Unit 2)		Spring	I	I		BF	Open	Closed	Closed	Closed	8	B,F		
X-86B	Chilled Water from Recirc Pump B	Water	3	56	No	HV18791B2	Comp Air	Spring	II	O	l	GT	Open	Closed	Closed	Closed	15	B,F	0	
(41)						HV18792A2 (Unit 1)	Inst Gas	Spring	I	I		BF	Open	Closed	Closed	Closed	8	B,F		
						HV28792A2 (Unit 2)		Spring	I	I		BF	Open	Closed	Closed	Closed	8	B,F		
X-87	Instrument Gas Return	N_2/Air Mix	2	56	No	SV12605	AC Coil	Spring	II	O	t	GB	Open	Closed	Closed	Closed	1	F,G	0	(33)
						HV12603	AC Mot	Manual	I	I		GB	Open	Closed	Closed	As Is	20	F,G	--	
X-88A	Drywell N_2 Makeup	N_2	1	56	No	SV15767	AC Coil	--	I	O(IB)	q	GB	Closed	Closed	Closed	Closed	1	B,F,R		(33)
						SV15789	AC Coil	--	II	O		GB	Closed	Closed	Closed	Closed	1	B,F,R	3	33)
X-88B	H_2O_2 Analyzer & Ctmt.Rad.Det.Return	Gas	1	56	Yes	SV15776A	AC Coil	Spring	I	O(IB)	q	GB	Closed	Open	Closed	Closed	1	B,F	O	(22)10Min.(33) (40)
			1	56	Yes	SV15774A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)

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CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position				Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
													Normal	Shut-down	LOCA	Power Fails				
X-91A (Unit 1 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV157100B	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	11'	(33)
						SV157101B	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	12'	(33)
X-91A (Unit 1 Only)	Ctmt. Rad. Det., Return Sample	Air/N_2	1	56	No	SV157102B	AC Coil	Spring	I	O(IB)	DD	GT	Open	Open	Closed	Closed	1	B,F	11'	(33)
						SV157103B	AC Coil	Spring	II	O		GT	Open	Open	Closed	Closed	1	B,F	12'	(33)
X-93	TIP Instruments	N_2/Air Mix	1	56	No	SV12661	Coil	Spring	I	O	i	GB	Open	Closed	Closed	Closed	1	B,F		(33)
						126072	Flow	--		I		CK	Open	Closed	--	--	--	--	--	
X-201A	Suppression Chamber Purge Supply	Air/N_2	18	56	No	HV15725	Comp Air	Spring	I	O(IB)	Y	BF	Closed	Closed	Closed	Closed	15	B,F,R	0	(4)
			18			HV15724	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	10	(8)
			6			HV15721	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R		(8)
			24			HV15723	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	14	(8)
X-201B	Hardened Containment Vent System	Steam/H_2	12	56	No	HV157113	Compressed Gas (via SV)	Compressed Gas (via bypass to SV)	—	O(IB)	XX1	BF	Closed	Closed	Closed	Closed	—	—	11 Ft	
			12			HV157114			—	O		BF	Closed	Closed	Closed	Closed	—	—		
X-202	Suppression Chamber Purge Exhaust	Air/N_2	18	56	No	HV15703	Comp Air	Spring	I	O(IB)	e	BF	Closed	Closed	Closed	Closed	15	B,F,R	0	
																				(24)HS-15703A
																				(23)HS-17508AA
			18			HV15704	Comp Air	Spring	II	O		BF	Closed	Closed	Closed	Closed	15	B,F,R	15	
			2			HV15705	Comp Air	Spring	II	O		GB	Closed	Closed	Closed	Closed	15	B,F,R		
																				(23)HS-17508BA
																				(24)HS-15705B
X-203A	RHR Pump Suction	Water	24	56	Yes	1F004A	AC Mot	Manual	I	O	o	GT	Open	Closed	Open	As Is	200	--	0	(6)(29)(34)
X-204A	RHR Pump Test Line	Water	18	56	Yes	1F028A	AC Mot	Manual	I	O	X	GT	Closed	Closed	Closed	As Is	90	F,G	24	(8)(6)(11)(28) (44)
			4		No	1F011A	Manual	-	I	O		GT	Closed	Closed	Closed	As Is			150	(8)(6)(11) (44)
X-205A	Containment Spray	Water	18	56	Yes	1F028A	AC Mot	Manual	I	O	X	GT	Closed	Closed	Closed	As Is	90	F,G		(8)(6)(11)(28) (44)
			4		No	1F011A	Manual	-	I	O		GT	Closed	Closed	Closed	As Is			137	(8)(6)(11) (44)
X-206A	Core Spray Pump Suction	Water	16	56	Yes	1F001A	AC Mot	Manual	I	O	o	GT	Open	Open	Open	As Is	83	--	0	(6)(11)(34)
X-207A	Core Spray Pump Test & Flush	Water	10	56	Yes	1F015A	AC Mot	Manual	I	O	r	GB	Closed	Closed	Closed	As Is	80	F,G	0	(6)(11)(34)
X-208A	Core Spray Pump Min. Recirc.	Water	3	56	Yes	1F031A	AC Mot	Manual	I	O	r	GT	Open	Closed	Closed	As Is	20	--		(6)(11)(34)
X-209	HPCI Pump Suction	Water	16	56	Yes	1F042	DC Mot	Manual	II	O	o	GT	Closed	Closed	Open	As Is	115	(I)	0	(16)(34)

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CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position				Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
													Normal	Shut-down	LOCA	Power Fails				
X-210	HPCI Turb Exhaust	Steam	20	56	Yes	1F066	DC Mot	Manual	II	O(IB)	m	GT	Open	Open	Open	As Is	111	--	0	(4)
						1F049	Flow	--		O		CK	Closed	Closed	Open	--				(5)
X-211	HPCI Pump	Water	4	56	Yes	1F012	DC Mot	Manual	II	O(IB)	m	GT	Closed	Closed	Closed	As Is	10	--	0	(34)
	Min. Recirc.					1F046	Flow	--		O		CK	Closed	Closed	Closed	--				(5)(34)
X-212 (Unit 2 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV257104	AC Coil	Spring	I	O(IB)	DD	GT	Closed	Closed	Closed	Closed	1	B,F		(33)
						SV257105	AC Coil	Spring	II	O		GT	Closed	Closed	Closed	Closed	1	B,F		(33)
X-214	RCIC Pump Suction	Water	6	56	No	1F031	DC Mot	Manual	I	O	o	GT	Closed	Closed	Open	As Is	35	--		(16)(34)
X-215	RCIC Turb Exhaust	Steam	10	56	No	1F059	DC Mot	Manual	I	O(IB)	m	GT	Open	Open	Open	As Is	60	--	0	(4)
						1F040	Flow	--	--	O		CK	Closed	Closed	Open	--		--		(5)
X-216	RCIC Pump Recirc.	Water	2	56	No	1F019	DC Mot	Manual	I	O(IB)	m	GB	Closed	Closed	Closed	As Is	5	--		(34)
						1F021	Flow	--	--	O		CK	Closed	Closed	Closed	--	--	--		(5)(34)
X-217 (Unit 1 Only)	RCIC Vacuum Pump Disch.	Air	2	56	No	1F060	DC Mot	Manual	I	O(IB)	m	GB	Open	Open	Open	As Is	32	--		(4)
						1F028	Flow	--		O		CK	Closed	Closed	Open	--	--	--		(5)
X-217 (Unit 2 Only)	RCIC Vacuum	Air	2	56	No	2F060	DC Mot	Manual	I	O(IB)	m	GB	Open	Open	Open	As Is	25	--		(4)
						2F028	Flow			O		CK	Closed	Closed	Open	--	--	--		(5)
X-218	Instrument Gas	N_2	1	56	No	SV12671	AC Coil	Spring	I	O	CC	GB	Closed	Closed	Closed	Closed	1	B,F		(33)
						126164	Flow	--	--	O(IB)		CK	Closed	Closed	Closed	--	--	--		(5)
X-220A (Unit 1 Only)	Ctmt. Rad. Det., Return Sample	Air/N_2	1	56	No	SV157106	AC Coil	Spring	I	O(IB)	DD	GT	Closed	Closed	Closed	Closed	1	B,F	8'	(33)
						SV157107	AC Coil	Spring	II	O		GT	Closed	Closed	Closed	Closed	1	B,F	9'	(33)
X-220B	Wetwell N_2 Makeup	N_2	1	56	No	SV15737	AC Coil	--	I	O(IB)	DD	GB	Closed	Closed	Closed	Closed	1	B,F,R		(33)
						SV15738	AC Coil	--	II	O		GB	Closed	Closed	Closed	Closed	1	B,F,R		(33)
X-221A	H_2O_2 Analyzer, Ctmt. Rad Det.,	N_2/Air	1	56	Yes	SV15780A	AC Coil	Spring	I	O(IB)	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40) (11-Unit 2 Only)
	Sample Pts	Mix				SV15782A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40) (11-Unit 2 Only)
X-221B (Unit 2 Only)	H_2O_2 Analyzer	N_2/Air	1	56	Yes	SV25780B	AC Coil	Spring	II	O(IB)	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
	Ctmt. Rad. Det., Sample Pts.	Mix				SV25782B	AC Coil	Spring	II	O	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-226A	RHR Min. Recirc	Water	6	56	Yes	1F007A	AC Mot	Manual	I	O	r	GT	Open	Closed	Closed	As Is	38	--	0	(6)(11)(34)
X-228A (Unit 1 Only)	Ctmt. Rad. Det., Supply Sample	Air/N_2	1	56	No	SV157104	AC Coil	Spring	I	O(IB)	DD	GT	Closed	Closed	Closed	Closed	1	B,F	8'	(33)
						SV157105	AC Coil	Spring	II	O		GT	Closed	Closed	Closed	Closed	1	B,F	9'	(33)
X-229B (Unit 2 Only)	Ctmt. Rad. Det., Return Sample	Air/N_2	1	56	No	SV257106	AC Coil	Spring	I	O(IB)	DD	GT	Closed	Closed	Closed	Closed	1	B,F		(33)
						SV257107	AC Coil	Spring	II	O		GT	Closed	Closed	Closed	Closed	1	B,F		(33)

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CONTAINMENT PENETRATION DATA

Penetration	Service	Fluid	Pipe Size (In.)	NRC Des. Crit.	E. S. F. (30)	Valve Number (36)	Primary Actuation Method	Second-ary Actuation Method	Power Source (17)	Valve Location (13)	Arrangement (12)	Valve Type (1)	Valve Position: Normal	Valve Position: Shut-down	Valve Position: LOCA	Valve Position: Power Fails	Closure Time (Secs)	Actuation Signal (2)	Length Pipe to Valve (Outer)	Remarks
X-233 (Unit 1 Only)	H_2O_2 Analyzer, Ctmt. Rad Det., Sample Pts.	N_2/Air Mix	1	56	Yes	SV15782B	AC Coil	Spring	II	O	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
						SV15780B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-238A	H_2O_2 Analyzer Return, Ctmt.Rad. Det. & Post-Accident Sample	N_2/Air Mix	1	56	Yes	SV15736A	AC Coil	Spring	I	O(IB)	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
						SV15734A	AC Coil	Spring	I	O		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-238B (Unit 1 Only)	H_2O_2 Analyzer & Ctmt.Rad.Det.Return	N_2/Air Mix	1	56	Yes	SV15734B	AC Coil	Spring	II	O	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
						SV15736B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-238B (Unit 2 Only)	H_2O_2 Analyzer & Cont Rad Det.Return	N_2/Air Mix	1	56	Yes	SV25734B	AC Coil	Spring	I	O	DD	GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
						SV25736B	AC Coil	Spring	II	O(IB)		GB	Closed	Open	Closed	Closed	1	B,F		(22)10Min.(33) (40)
X-243	Suppression Pool Cleanup & Drain	Water	6	56	No	HV15766	AC Mot	Manual	I	O(IB)	s	GT	Closed	Closed	Closed	As Is	35	B,F	0	(4)
						HV15768	DC Mot	Manual	II	O		GT	Closed	Closed	Closed	As Is	30	B,F	1	
X-244	HPCI Vacuum Breaker	N_2/Air Mix	3	56	Yes	1F079	DC Mot	Manual	I	O(IB)	pl	GT	Open	Open	Closed	As Is	15	F, LB	0	
						1F075	DC Mot	Manual	II	O	pl	GT	Open	Open	Closed	As Is	15	F, LB	7	(39)
X-245	RCIC Vacuum Breaker	Air/N_2	2	56	No	1F084	DC Mot	Manual	II	O(IB)	pl	GT	Open	Open	Closed	As Is	10	F, KB		(39)
						1F062	DC Mot	Manual	I	O	pl	GT	Open	Open	Closed	As Is	10	F, KB		
X-246A	RHR Relief Valve Discharge	Water/ Steam/	1	56	Yes	PSV15106A	Water Press	--		O	j	RLF	Closed	Closed	Closed	--		--		(6)(11)
		Air/ Gas	1			HV1F103A	AC Mot	Manual	I	O		GB	Closed	Closed	Closed	As Is		--		(6)(11)(31)

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CONTAINMENT PENETRATION DATA

NOTES:

(1) Valve Type

Ball	BL
Butterfly	BF
Check	CK
Gate	GT
Globe	GB
Globe Stop Check	GCK
Pressure Relief	RLF
Testable Check	TCK
Excess Flow Check	XFC
Explosive (Shear)	SHEAR

(2) Isolation Signal Codes

All power-operated isolation valves are capable of being operated remote-manually from the control room.

Automatic isolation signals are listed and described below:

Signal	Description
A	Reactor Vessel Water Level - Low Level 3
B	Reactor Vessel Water Level - Low, Low Level 2
C	Main Steam Line Radiation - High
D	Main Steam Line Flow - High
EA	Reactor Building Steam Line Tunnel Temperature - High
EC	Turbine Building Steam Line Tunnel Temperature - High
F	Drywell Pressure - High
G	Reactor Vessel Water Level - Low, Low, Low Level I
I	Standby Liquid Control System Manual Initiation
JA	RWCS Differential Flow - High
JB	RWCS Differential Pressure (Flow) - High
KA	RCIC Steam Line Differential Pressure (Flow) High
KB	RCIC Steam Supply Pressure - Low

TABLE 6.2-12

CONTAINMENT PENETRATION DATA

KC	RCIC Turbine Exhaust Diaphragm Pressure - High
KD	RCIC Equipment Room Temperature - High
KF	RCIC Pipe Routing Area Temperature - High
KH	RCIC Emergency Area Cooler Temperature - High
LA	HPCI Steam Line Differential Pressure (Flow) High
LB	HPCI Steam Supply Pressure - Low
LC	HPCI Turbine Exhaust Diaphragm Pressure - High
LD	HPCI Equipment Room Temperature - High
LF	HPCI Emergency Area Cooler Temperature - High
LG	HPCI Pipe Routing Area Temperature – High

Signal	Description
MC	RHR System Flow - High
P	Main Steam Line Pressure - Low
R	SGTS Exhaust Radiation - High
UA	Main Condenser Vacuum - Low
UB	Reactor Vessel Pressure - High
WA	RWCS Area Temperature - High

Isolation Actuation Groupings

(a)	G, D, EA, EC, P, UA
(b)	A, MC, UB
(c)	B, JA, JB, WA
(d)	A, F, MC, UB
(k)	KA, KB, KC, KD, KF, KH
(l)	LA, LB, LC, LD, LF, LG

(3) Test pressure is less than operating pressure - see Section 6.2.6.

(4) Test pressure is applied in reverse direction.

(5) Unassisted check valve is used as one containment boundary.

(6) External piping system provides one containment boundary.

(7) Intentionally deleted.

TABLE 6.2-12

CONTAINMENT PENETRATION DATA

(8) Valve isolates two piping penetrations.

(9) Intentionally deleted.

(10) Intentionally deleted.

(11) 'B' penetration data is identical with 'A' penetration data but with 'B' suffix except that, where applicable, power for 'A' penetration isolation valves are supplied from Division I power and power for 'B' penetration isolation valves are supplied from Division II.

(12) See Figures 6.2-44 and 6.2-44A through 6.2-44L. Letters in this column refer to details in the figures.

(13) For valve location, I indicates a valve inside the primary containment; 0 indicates a valve outside the primary containment. (IB) indicates the inboard of two or more series isolation valves located outside the containment.

(14) Check valve closed on reverse flow if feedwater is not available. Closure may be assisted remote-manually with motor-operator.

(15) Valve does not receive a LOCA signal but does receive a closure signal (k or l) for a break in the steam line to the turbine.

(16) Opens on condensate storage tank low level or suppression pool high level, and system isolation signal is not present.

(17) For air or gas operated valves, the power source listed is for the associated solenoid valve.

(18) These valves do not receive an isolation signal but they cannot be opened when a steam line break signal (k or l) is open.

(19) No containment isolation valves are provided. For explanation, refer to Subsections 4.6.1 and 6.2.4.3.2.3.

(20) The containment isolation scheme for this penetration has been analyzed "on some other defined basis" than GDC 55. See Subsection 6.2.4.3.2.

(21) Isolation of the Traversing Incore Probe (TIP) guide tube is normally accomplished by a solenoid-operated ball valve when the TIP cable is withdrawn. The explosive (shear) valve is fired only when the cable jams in the inserted position and a containment isolation is required. See Subsection 6.2.4.3.3.3.10.

(22) Interlock of the valve is designed to close upon LOCA signal but can be reopened after noted time (See 7.3.l.lb.1.3 and 6.2.4.3.3.1).

(23) Interlock of the valve is designed to close upon LOCA signal, but that signal can be bypassed and the valve can be reopened by noted handswitch (HS). LOCA bypass has no effect on High High Radiation closure and High High Radiation override has no effect on LOCA closure.

TABLE 6.2-12

CONTAINMENT PENETRATION DATA

(24) Interlock of the valve is designed to close upon high radiation signal from the Standby Gas Treatment System exhaust, but that signal can be overridden and the valve reopened by noted handswitch (HS). LOCA bypass has no effect on High High Radiation closure and High High Radiation Override has no effect on LOCA closure.

(25) Intentionally deleted.

(26) Data in table for A penetration and valve also applies to B, C, and D penetrations and valves.

(27) Intentionally deleted.

(28) These valves can be opened post-LOCA if LPCI injection valve E11-F015 is closed or by manual isolation signal bypass, E11A-S18.

(29) 'C' penetration data is identical to 'A' penetration data but with 'C' suffix. 'B' and 'D' penetration data is identical to 'A' penetration data but with 'B' and 'D' suffixes and power supplied by Div. II.

(30) Engineered safety features systems are defined in Section 6.0. This column lists engineered safety features (ESF) systems. ESF systems are defined in Section 6.0. All containment isolation valves in this table have an ESF function whether or not their respective systems are ESF.

(31) Valve HV-F103A must be remote-manually opened when taking liquid samples post-accident.

(32) For these valves the first closure time is for Unit 1 valves and second is for the Unit 2 valves.

(33) For purposes of Inservice Inspection per the ASME Code, such valves are classified as Rapid-Acting Valves (RAV) or valves which operate in an extremely short period of time. The specified FSAR values are representative of valve design limits rather than the installed stroke times. Specific acceptance criteria for these valves are specified in the Inservice Inspection Program Plan.

(34) This penetration is not Type C tested. This line terminates below the minimum water level in the Suppression Pool.

(35) These valves will be opened for collecting samples during normal and shutdown conditions.

(36) Valves in vents, drains and test connections that represent containment boundary are not listed in this table. Such valves are identified on the appropriate system P&ID with a “CB” designation.

(37) When testing in between MSIVs, test pressure is applied in the reverse direction.

(38) Deleted

TABLE 6.2-12

CONTAINMENT PENETRATION DATA

(39) Test pressure is applied between the valve disc.

(40) External piping system provides redundant containment boundary as described in Note 31 to Table 6.2-22.

(41) Protection is susceptible to the thermal pressurization phenomenon as discussed in NRC Generic Letter 96-06.

(42) The containment isolation scheme for this penetration has been analyzed “on some other defined basis” than GDC 55. See Section 6.2.4.3.2.10 for details.

(43) Valves HV-14182A&B and HV-24182A&B are not relied upon for short-term containment isolation. See Section 6.2.4.3.2.1 for details. The closure times listed for these valves are nominal closure times. These times are neither stroke time limits nor design requirements that are relied upon in any analyses.

(44) This penetration is not Type C tested. This line remains water filled post-LOCA.

(45) High pressure to low pressure isolation valve subject to hydraulic leakage rate testing.

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-3B	RHR	151085 15110A	VA VA	GB XFC	0 ACAP
X-3B	RHR	151084 15110C	VA VA	GB XFC	0 ACAP
X-27A	NUC. BLR. VESSEL INST.	142009R 1F059R 142009L 1F059L 142009N 1F059N	V V V V V V	GB XFC GB XFC GB XFC	0 ACAP 0 ACAP 0 ACAP
X-27B	NUCLEAR BOILER	1F066C 1F070C 1F069C 1F073C	V V V V	GB XFC GB XFC	0 ACAP 0 ACAP
X-28B	CORE SPRAY	1F017A 1F018A	V V	GB XFC	0 ACAP
X-29B	RWCU	144001C 14411C 144001D 14411D	V V V V	GB XFC GB XFC	0 ACAP 0 ACAP
X-30A	REACTOR RECIRC	1F058A 1F057A	V V	GB XFC	0 ACAP
X-31A X-31A X-31A X-31A X-31A (UNIT 2 ONLY) X-31A (UNIT 2 ONLY)	RCIC NUC. BLR. VESSEL INST.	1F043A 1F044A 1F043C 1F044C 242009G 2F059G	V V V V V V	GB XFC GB XFC GB XFC	0 ACAP 0 ACAP 0 ACAP
X-31B	REACTOR RECIRC	1F016B 1F017B	VB VB	GB XFC	0 ACAP
X-32A	RHR	151086 15110B 151087 15110D	VA VA VA VA	GB XFC GB XFC	0 ACAP 0 ACAP
X-33A	RHR	151025 15109C 151022 15109D	V V V V	GB XFC GB XFC	0 ACAP 0 ACAP
X-33B	RHR	151020 15109A 151021 15109B	V V V V	GB XFC GB XFC	0 ACAP 0 ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-34A	HPCI	1F023A	V	GB	0
		1F024A	V	XFC	ACAP
		1F023C	V	GB	0
		1F024C	V	XFC	ACAP
X-34B	HPCI	1F023B	V	GB	0
		1F024B	V	XFC	ACAP
		1F023D	V	GB	0
		1F024D	V	XFC	ACAP
X-40A	NUC. BLR. VESSEL INST.	142005C	V	GB	0
		1F053C	V	XFC	ACAP
		142009T	V	GB	0
		1F059T	V	XFC	ACAP
		142006C	V	GB	0
		1F051C	V	XFC	ACAP
X-40B	NUCLEAR BOILER	1F067A	V	GB	0
		1F071A	V	XFC	ACAP
		1F068A	V	GB	0
		1F072A	V	XFC	ACAP
X-40C (UNIT 1 ONLY)	NUC. BLR. VESSEL INST.	142005A	V	GB	0
		1F053A	V	XFC	ACAP
		142009G	V	GB	0
		1F059G	V	XFC	ACAP
		142006A	V	GB	0
		1F051A	V	XFC	ACAP
X-40D	NUC. BLR.	142009E	V	GB	0
		1F059E	V	XFC	ACAP
		142009A	V	GB	0
		1F059A	V	XFC	ACAP
		142009C	V	GB	0
		1F059C	V	XFC	ACAP
X-40E	NUC. BLR. VESSEL INST.	142005D	V	GB	0
		1F053D	V	XFC	ACAP
		142009U	V	GB	0
		1F059U	V	XFC	ACAP
		142006D	V	GB	0
		1F051D	V	XFC	ACAP
X-40F	NUC. BLR. VESSEL INST.	142009M	V	GB	0
		1F059M	V	XFC	ACAP
		142009P	V	GB	0
		1F059P	V	XFC	ACAP
		142009S	V	GB	0
		1F059S	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-40G	NUC. BLR. VESSEL INST.	142005B	V	GB	0
		1F053B	V	XFC	ACAP
		142009H	V	GB	0
		1F059H	V	XFC	ACAP
		142006B	V	GB	0
		1F051B	V	XFC	ACAP
X-40H	NUC. BLR. VESSEL INST.	142009B	V	GB	0
		1F059H	V	XFC	ACAP
		142009D	V	GB	0
		1F059D	V	XFC	ACAP
		142009F	V	GB	0
		1F059F	V	XFC	ACAP
X-48B (UNIT 2 ONLY)	NUCLEAR BOILER	2F066B	V	GB	0
		2F070B	V	XFC	ACAP
		2F069B	V	GB	0
		2F073B	V	XFC	ACAP
X-49A	REACTOR RECIRC	1F041A	V	GB	0
		1F009A	V	XFC	ACAP
		1F009B	V	XFC	ACAP
		1F042A	V	GB	0
		1F010A	V	XFC	ACAP
		1F010B	V	XFC	ACAP
X-49B	REACTOR RECIRC	1F041C	V	GB	0
		1F009C	V	XFC	ACAP
		1F009D	V	XFC	ACAP
		1F042C	V	GB	0
		1F010C	V	XFC	ACAP
		1F010D	V	XFC	ACAP
X-50A	REACTOR RECIRC	1F041B	V	GB	0
		1F011A	V	XFC	ACAP
		1F011B	V	XFC	ACAP
		1F042B	V	GB	0
		1F012A	V	XFC	ACAP
		1F012B	V	XFC	ACAP
X-50B	REACTOR RECIRC	1F041D	V	GB	0
		1F011C	V	XFC	ACAP
		1F011D	V	XFC	ACAP
		1F042D	V	GB	0
		1F012C	V	XFC	ACAP
		1F012D	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-51A	REACTOR RECIRC	1F039A	V	GB	0
		1F040A	V	XFC	ACAP
		1F039C	V	GB	0
		1F040C	V	XFC	ACAP
X-51B	REACTOR RECIRC	1F039B	V	GB	0
		1F040B	V	XFC	ACAP
		1F039D	V	GB	0
		1F040D	V	XFC	ACAP
X-52A	REACTOR RECIRC	1F005A	VB	GB	0
		1F003A	VB	XFC	ACAP
		1F006A	VB	GB	0
		1F004A	VB	XFC	ACAP
X-52B	REACTOR RECIRC	1F005B	VB	GB	0
		1F003B	VB	XFC	ACAP
		1F006B	VB	GB	0
		1F004B	VB	XFC	ACAP
		1F058B	V	GB	0
		1F057B	V	XFC	ACAP
X-58A	RWCU	144001A	V	GB	0
		14411A	V	XFC	ACAP
		144001B	V	GB	0
		14411B	V	XFC	ACAP
X-59A	NUC. BLR. VESSEL INST.	142001	V	GB	0
X-59A		1F041	V	XFC	ACAP
X-59A		142002A	V	GB	0
X-59A (UNIT 2 ONLY)		242002A[4]	V	GB	0
X-59A		1F043A	V	XFC	ACAP
X-59B	NUC. BLR. VESSEL INST.	142002B	V	GB	0
X59B (UNIT 2 ONLY)		242002B[4]	V	GB	0
X-59B		1F043B	V	XFC	ACAP
X-59B		142011	V	GB	0
X-59B		14202	V	XFC	ACAP
X-60A	REACTOR RECIRC	1F016A	VB	GB	0
		1F017A	VB	XFC	ACAP
X-61A (UNIT 2 ONLY)	NUC. BLR. VESSEL INST.	242005A	V	GB	0
		2F053A	V	XFC	ACAP
X-61B	NUCLEAR BOILER	1F066D	V	GB	0
		1F070D	V	XFC	ACAP
		1F069D	V	GT	0
		1F073D	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-62A (UNIT 1 ONLY)	NUC. BLR. VESSEL INST.	142010	V	GB	0
		1F061	V	XFC	ACAP
X-62A	NUCLEAR BOILER	1F067B	V	GB	0
		1F071B	V	XFC	ACAP
		1F068B	V	GB	0
		1F072B	V	XFC	ACAP
X-62B	NUCLEAR BOILER	1F066A	V	GB	0
		1F070A	V	XFC	ACAP
		1F069A	V	GB	0
		1F073A	V	XFC	ACAP
X-63A	NUCLEAR BOILER	1F067C	V	GB	0
		1F071C	V	XFC	ACAP
		1F068C	V	GB	0
		1F072C	V	XFC	ACAP
X-63B (UNIT 1 ONLY)	NUCLEAR BOILER	1F066B	V	GB	0
		1F070B	V	XFC	ACAP
		1F069B	V	GB	0
		1F073B	V	XFC	ACAP
X-63B	CORE SPRAY	1F017B	V	GB	0
		1F018B	V	XFC	ACAP
X-64A	NUCLEAR BOILER	1F067D	V	GB	0
		1F071D	V	XFC	ACAP
		1F068D	V	GB	0
		1F072D	V	XFC	ACAP
X-64A (UNIT 2 ONLY)	NUC. BLR. VESSEL INST.	242006A	V	GB	0
		2F051A	V	XFC	ACAP
X-64B (UNIT 1 ONLY)	NUC. BLR. VESSEL INST.	142007	V	GB	0
		1F055	V	XFC	ACAP
		14201	V	XFC	ACAP
		142008	V	GB	0
		1F057	V	XFC	ACAP
		1F045	V	GB	0
		1F046	V	XFC	ACAP
X-65A	NUC. BLR. VESSEL INST.	142003A	V	GB	0
		1F047A	V	XFC	ACAP
X-65B	NUC. BLR. VESSEL INST.	142003B	V	GB	0
		1F047B	V	XFC	ACAP
X-66A	NUC. BLR. VESSEL INST.	142004A	V	GB	0
		1F045A	V	XFC	ACAP
X-66B	NUC. BLR. VESSEL INST.	142004B	V	GB	0
		1F045B	V	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT[5]

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT[1]	VALVE TYPE[2]	LENGTH PIPE TO VALVE[3]
X-80B	RCIC	1F043B	V	GB	0
		1F044B	V	XFC	ACAP
		1F043D	V	GB	0
		1F044D	V	XFC	ACAP
X-80B (UNIT 2 ONLY)	NUCLEAR BOILER	242010	VB	GB	0
		2F061	VB	XFC	ACAP
X-84A	NUC. BLR. VESSEL INST.	141005	V	GB	ACAP
		1F009		XFC	0
X-90A	CNTMT. ATMOS.	157017	VA	GB	0
	CONTROL	15710A	VA	XFC	ACAP
		157209	VA	GB	0
		15709A	VA	XFC	ACAP
X-90A (UNIT 1 ONLY)		157210	VA	GB	0
	CNTMT. ATMOS.	15728A	VA	XFC	ACAP
	CONTROL	257210	VA	GB	0
		25728A1	VA	XFC	ACAP
X-90D	CNTMT. ATMOS.	157077	VA	GB	0
	CONTROL	15710B	V	XFC	ACAP
		157207	VA	GB	0
		15709B	VA	XFC	ACAP
		157208	VA	GB	0
		15728B	VA	XFC	ACAP
X-91A (UNIT 2 ONLY)	NUC. BLR. VESSEL INST.	242007	V	GB	0
		2F055	V	XFC	ACAP
		24201	V	XFC	ACAP
		242008	V	GB	0
		2F057	V	XFC	ACAP
X-91A (UNIT 2 ONLY)	RWCU	2F045	V	GB	0
		2F046	V	XFC	ACAP
X-219A	HPCI	155021	VA	GB	0
		15516	VA	XFC	ACAP
X-219B	HPCI	155022	VA	GB	0
		15517	VA	XFC	ACAP
X-223A	CNTMT. ATMOS.	157022	VA	GB	0
	CONTROL	15701A	VA	XFC	ACAP
X-232A	CNTMT. ATMOS.	157023	VA	GB	0
	CONTROL	15775A	VA	XFC	ACAP
X-232B	CNTMT. ATMOS.	157024	VA	GB	0
	CONTROL	15778A	VA	XFC	ACAP
X-234A	CNTMT. ATMOS.	157011	VA	GB	0
	CONTROL	15776	VA	XFC	ACAP

TABLE 6.2-12a

DATA ON INSTRUMENT LINES PENETRATING CONTAINMENT(5)

PENETRATION NUMBER	SERVICE	VALVE NUMBER	VALVE ARRANGEMENT(1)	VALVE TYPE(2)	LENGTH PIPE TO VALVE(3)
X-234B	CNTMT. ATMOS. CONTROL	157012 15777	VA VA	GB XFC	0 ACAP
X-235A	CNTMT. ATMOS. CONTROL	157010 15775B	VA VA	GB XFC	0 ACAP
X-235B	CNTMT. ATMOS. CONTROL	157013 15778B	VA VA	GB XFC	0 ACAP

NOTES

(1) Valve Arrangement

See Figure 6.2-44I, Detail (v). Valve arrangements designated as "VA" differ from the figure in that their associated pipes communicate directly with the containment atmosphere (or do not connect to the reactor coolant pressure boundary), and thus do not have an orifice inside containment. Furthermore, those instrument lines with "VA" valve designations are "extensions of primary containment", as designated by CB or ICB on the P&ID (see Figure 6.2-44M, Detail (22)). "VB" indicates a valve arrangement similar to the figure except that no orifice is provided.

(2) Valve Type

Globe GB
Excess Flow Check XFC

(3) Length Pipe to Valve

0: Globe valves are welded directly to the flued head at the containment penetration.
ACAP: "As close as possible" to the glove valve.

(4) These valves are disabled in the open position.

(5) All valves listed in this table are Type A tested with the exception of Penetrations X-31B and X-60A (See Table 6.2-22)

Start Historical

TABLE 6.2-13

PARAMETERS USED FOR THE EVALUATION OF COMBUSTIBLE GASES IN THE CONTAINMENT AFTER A LOCA

ITEM	VALUE	
Zinc Corrosion Rate $\frac{\text{(lb-mole)}}{\text{ft}^2\text{–hr}}$		
90°F	2.67×10^{-8}	
300°F	2.60×10^{-6}	
Zinc Corrosion Rate $\frac{\text{(lb-mole)}}{\text{ft}^2\text{–hr}}$		
90°F	2.67×10^{-8}	
300°F	2.60×10^{-6}	
Aluminum Corrosion Rate $\frac{\text{(lb-mole)}}{\text{ft}^2\text{–hr}}$		
100°F	1.36×10^{-9}	
200°F	7.49×10^{-9}	
300°F	2.63×10^{-8}	
	Drywell	Wetwell
Mass of zinc in galvanized steel (lb.)	9500	2770
Area of zinc in galvanized steel (sq ft.)	103,258	29,898
Mass of zinc paint (lb)*	5690	1004
Area of zinc paint (sq ft.)*	82,439	23,819
Percentage of zinc paint which is zinc	86	87.2
Mass of Aluminum (lb.)	1269	100
Mass of zircalloy cladding surrounding the fuel (lb)	69,325	
Reactant Mass of Zircalloy (lb.)	683.03	
Volume of free hydrogen normally in the coolant (scf @ 60°F)	Negligible	

* Surrounding active fuel only, not including plenum volumes.

TABLE 6.2-13

PARAMETERS USED FOR THE EVALUATION OF COMBUSTIBLE GASES IN THE CONTAINMENT AFTER A LOCA

ITEM	VALUE	
Reactor Operating Thermal Power	4031 Mwt*	
Fraction of fission product radiation energy absorbed by the coolant:		
Betas from fission products in the fuel	0.0	
Betas from fission products mixed with the coolant	1.0	
Gammas from fission products in the fuel	0.1	
Gammas from fission products mixed with the coolant	1.0	
Hydrogen yield rate G (H_2) molecules/100 ev	0.50	
Oxygen yield rate G (O_2) molecules/100 ev	0.25	
Fission product distribution:		
Coolant	1% solids + 50% halogens	
Air	100% noble gases	
Core	All others	
Drywell volume (cu ft.)	239,600	
Wetwell volume (cu ft.)	148,600	
Time to reach 3.5 vol. percent hydrogen in the drywell (days)	0.8	
Time to reach 3.5 vol. percent hydrogen in the wetwell (days)	0.5	

* 102% Rated Reactor operating thermal power

End Historical

TABLE 6.2-14

PRIMARY CONTAINMENT ATMOSPHERE MONITORING SYSTEM
(HYDROGEN/OXYGEN ANALYZER)
SYSTEM LEVEL

FAILURE MODE AND EFFECT ANALYSIS

Failure Mode	Effect on System	Detection	Remarks
Loss of one division of Class 1E power source	Loss of one analyzer unit. Loss of redundancy.	Annunciation in control room	Redundant analyzer available. Manual initiation by operator.
Loss of one division of instrument power	Loss of control room display instrumentation. Loss of redundancy.	Annunciation in control room	Manual initiation of redundant analyzer.
Analyzer failure (line break, etc)	Loss of one analyzer unit. Loss of redundancy.	Annunciation in control room	Manual initiation of redundant analyzer.

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description(1)	Leakage Barriers(2)	Valid Path
X-7A-D	Main Steam Lines: 24”-GBB-102	B (See Note 3)	NO
X-8	Main Steam Line Drain: 3”-EBD-114	B (See Note 12)	NO
X-9A/B	Feedwater Line: 30”-DBD-101 to Feedpumps	A	YES
	HPCI / RCIC Injection to ECCS keepfill CST and HPCI / RCIC Injection to ECCS keepfill to RHR fire protection connection: 2”-DBB-120 & 2”-DBB-121 to 2”-HCD-110 to 6”-HCD-105 and ; 10”-DBB-117 & 4”-DBB-112 to 10”-HCD-110 and; 2”-DBB-120 & 2”-DBB-121 to 2” -HCD-110 to 4”-HCD-111 to 4”-HCD-112 to 3”-HBD-174 to 3”-KBF-102 to 6”-KBF-102	A C (See Note 6)	YES NO
	RWCU Return Line via blowdown to condenser and other branch lines: 4”-EBC-104 to 4”-HBD-127 & 4”-HBD-131; 4”-EBC-101 to 2”-HBD-163 3”-EBC-103 to 4”-HBD-160 & 6”-HCD-105		
X-10	RCIC Steam Supply via Steam Line Drain to condenser: 1”-DBD-113 to 1”-EAD-114 to 3”-EBD-114	B (See Note 12)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description[1]	Leakage Barriers[2]	Valid Path
X-11	HPCI Steam Supply via Steam Line Drain to condenser: 1”-DBD-107 to 1”-EAD-114 to 3”-EBD-114	B (See Note 12)	NO
X-12	RHR Shutdown Cooling via keepfill and RHR Shutdown Cooling to keepfill to fire protection piping: 4”-HCD-112 & 2”-HBD-174 to 6”-HCD-105 and; 4”-HCD-112 & 2”-HBD-174 to 3” –HBD-174 to 3” KBF-102 to 6”-KBF-102	C (See Note 7)	NO
X-13A/B	RHR LPCI Injection via ECCS keepfill and RHR LPCI Injection to ECCS keepfill to fire protection piping: 2”-DBB-107 to 2”-HBD-174 to 4”-HCD-112 to 6”-HCD-105 and; 2”-DBB-107 to 2”-HBD-174 to 3”-HBD-174 to 3”-KBF-102 to 6”-KBF-102	C (See Note 4)	NO
X-14	RWCU Supply via blowdown to condenser and other branch lines: From pen X-14 to same paths as X-9A/B	C (See Note 8)	NO
X-16A/B	Core Spray Injection via keepfill, Core Spray Injection to keepfill to fire protection piping and keepfill tank to demineralizer water supply: 2” GBB-101 to 2”-HCD-111 to 4”-HCD-111 to 6” HCD-105 and; 2”-GBB-101 to 2”-HCD-111 to 4”-HCD-111 to 4”-HCD-112 to 3”-HBD-174 to 3”-KBF-102 to 6”-KBF-102 and; 2”-GBB-101 to 1”-HCD-111 to tank 1T274 to 1”-JCD-107	A	YES

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description(1)	Leakage Barriers(2)	Valid Path
X-17	RHR Head Spray via keepfill and RHR Head Spray to keepfill to fire protection piping: 2”-GBB-117 to 3”-HBD-174 to 4”-HCD-112 to 6”-HCD-105 and; 2”-GBB-117 to 3”-HBD-174 to 3”-KBF-102 to 6”-KBF-102	C (See Note 15)	YES
	RHR Head Spray via ESW: 12”-GBB-118 to 18”-GBB-109 to 12”-GBB-113 to 12” & 8”-GBC-105 to 2”-HCC-103 to 2” & 10”-HRC-108 to 12” & 14”-HRC-102 and 2”-HCC-103 to 2” & 10”-HRC-110 to 12” & 14”-HRC-101	C (See Note 16)	NO
	RHR Head Spray via RHRSW: 6”-GBB-117 to 6”-GBB-108 to 18”-GBB-109 to 24” & 20”-GBB-106 to 6”-GBB-119 to 6”-HRC-113 to 20”-HRC-112	C (See Note 16)	NO
X-23	RBCCW Supply via connection to Offgas system & air compressors: 4”-JBD-141 to 8”-JBD-139 to 3”-JBD-108	C (See Note 5)	NO
X-24	RBCCW Return via connection to Offgas system & air compressors: 4”-JBD-137 to 8”-JBD-137 to 3”-JBD-109	C (See Note 5)	NO
X-25 X-201A	Drywell Purge Supply N_2 Supply (6”): 24”& 18”-HBB-118 to 6”-HBD-182	B or A (See Note 9)	NO Except when inerting
X-26 X-202	Drywell Purge Return: 24”-HBB-117 to 24”-HBD-1111	B (See Note 9)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description(1)	Leakage Barriers(2)	Valid Path
X-31B X-60A	Recirc Pump Seal Mini-Purge: 1”-DCD-101 to 3”-DBD-108 to 3”-DBC-108	C (See Note 10)	NO
X-37A-D X-38A-D	CRD Insert & Withdrawal lines: CRD I/W lines to 3”-DBC-108	C (See Note 10)	NO
X-39A/B	RHR Drywell Spray via keepfill and RHR Drywell Spray to keepfill to fire protection piping: 12”-GBB-118 to 24”-GBB-115 to 4”-GBB-114 to 4” - HBD-184 and; 12”-GBB-118 to 6” –GBB-108 to 2” GBB-117 to 2”-HBD-174 to 3” –HBD-174 to 4”-HCD-112 to 6”-HCD-105 and; 6”-GBB-108 to 2”-GBB-117 to 2”-HBD-174 to 3”-HBD-174 to 3”-KBF-102 to 6”-NBF-102	C (See Note 15)	YES
	RHR Drywell Spray via ESW: 12”-GBB-118 to 18”-GBB-109 to 12”-GBB-113 to 12” & 8”-GBC-105 to 2”-HCC-103 to 2” & 10”-HRC-108 to 12” & 14”-HRC-102 and 2”-HCC-103 to 2” & 10”-HRC-110 to 12” & 14”-HRC-101	C (See Note 16)	NO
	RHR Drywell Spray via RHRSW: 6”-GBB-117 to 6”-GBB-108 to 18”-GBB-109 to 24” & 20”-GBB-106 to 6”-GBB-119 to 6”-HRC-113 to 20”-HRC-112	C (See Note 16)	NO
X-42	Standby Liquid Control: 1½”-DCA-106 to 1½”-DCB-101 to 3”-HCB-105 to 2”-JCD-107	C (See Note 13)	NO
X-53	RBCW Supply to “B Loop” DW Coolers via connection to RBCCW: 8”-JBD-114 to RBCCW supply (see X-23)	C (See Note 5)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description(1)	Leakage Barriers(2)	Valid Path
X-54	RBCW Return from "B Loop" DW Coolers via connection to RBCCW: 8"-JBD-119 to RBCCW return (see X-24)	C (See Note 5)	NO
X-55	RBCW Supply to "A Loop" DW Coolers via connection to RBCCW: 8"-JBD-114 to RBCCW supply (see X-23)	C (See Note 5)	NO
X-56	RBCW Return from "A Loop" DW Coolers via connection to RBCCW: 8"-JBD-119 to RBCCW return (see X-24)	C (See Note 5)	NO
X-60A X-80C X-88B X-221A X-221B(U2) X-233(U1) X-238A,B	Post Accident Sampling System (PASS) via connections to the H_2O_2 Analyzer System: 1"-HCB-106 1"-HCB-108 1"-HCB-109 1"-HCB-122 1"-HCB-127	B (See Note 14)	NO
X-17 X-39A,B	PASS via connections to RHR: 1"-GBB-106	B (See Note 14)	NO
X-61A	Demineralized Water connection to Drywell: 1"-HCB -145 to 1"-JCD-107	A	YES
X-85A	RBCW Supply to Recirc Pump A via connection to RBCCW: 8"-JBD-114 to RBCCW supply (see X-23)	C (See Note 5)	NO
X-85B	RBCW Return from Recirc Pump A via connection to RBCCW: 8"-JBD-119 to RBCCW return (see X-24)	C (See Note 5)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description[1]	Leakage Barriers[2]	Valid Path
X-86A	RBCW Supply to Recirc Pump B via connection to RBCCW: 8”-JBD-114 to RBCCW supply (see X-23)	C (see Note 5)	NO
X-86B	RBCW Return from Recirc Pump B via connection to RBCCW: 8”-JBD-119 to RBCCW return (see X-24)	C (See Note 5)	NO
X-88A	N_2 Make-up to Drywell: 1”-HCB-156 to 1”-HBD-195 to 2”-HBD-57	A	YES
X-201B	Wetwell vent pipe to rupture disc PSE15701. 18"-HBB-159 to 12"-HBD-1571	A and B (See Note 17)	NO
X-205A/B	RHR Wetwell Spray via keepfill: 6” to 18” GBB-109 to Drywell Spray line (see X-39A/B)	C (See Note 4)	NO
X-204A/B	RHR Suppression Pool Cooling: 18”-GBB-109 to Drywell Spray Line (see X-39A/B)	C (See Note 4)	NO
X-206A/B	Core Spray Pump Suction via connection to CST: 16”-HBB-104 to 16”-HCD-115 to 16”-HCB-102	C (See Note 11)	NO
X-209	HPCI Pump Suction via connection to CST: 16”-HBB-109 to 16”-HBB-107 to 16”-HCB-103	C (See Note 11)	NO
X-214	RCIC Pump Suction via connection to CST: 6”-HBB-102 to 6”-HBB-103 to 6”-HCB-104	C (See Note 11)	NO

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

Pen. No.	Pathway Description(1)	Leakage Barriers(2)	Valid Path
X-220B	N_2 Make-up to Wetwell: 1”-HCB-157 to 1”-HBD-195 to 2”-HBD-57	A	YES
X-243	Suppression Pool C/U: 6”-HBB-121 to 4”-HBD-172 to 4”-HBD-173	C (See Note 11)	NO

Notes:

1. Unit 1 line numbers are provided, however, pathway applies to both units. Unit 2 line numbers begin with 2, e.g. if the Unit 1 line number is 24”-GBB-102, then the Unit 2 line number is 24”-GBB-202.

2. The following isolation barriers are used to limit or eliminate SCBL as discussed in Section 6.2.3.2.3. Details regarding how the barriers eliminate SCBL for specific penetrations is discussed in the referenced Note.

   A. Isolation valve(s) inside and/or outside primary containment.
   B. Leakage is collected and filtered prior to release.
   C. Water seal in line.

3. Leakage is routed to condenser where “scrubbing” is credited as part of MSIVLCS elimination. Valves are leak rate tested to be less than 300 scfh in accordance with Technical Specifications, and the radiological impact of this leakage is considered in the DBA LOCA dose analysis. Since the leakage is not released directly to the environment, and is considered separately from SCBL in the DBA LOCA dose analysis, these lines are eliminated as SCBL pathways.

4. Refer to Dwgs. M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3, M-151, Sh. 4, M-155, Sh. 1, M-152, Sh. 1, M-149, Sh. 1 and M-150, Sh. 1.

   The SCBL pathway for penetrations X-13A/B RHR LPCI Injection, X-204A/B RHR Wetwell Spray, and X-205 RHR Suppression Pool, Cooling is via the ECCS keepfill connection to condensate transfer.

   The piping configuration for these RHR penetrations is such that they will remain filled with water following a LOCA, and/or a loop seal will be maintained between the drywell atmosphere the ECCS keepfill connections. For the LPCI Injection penetrations, a loop seal will be maintained inside primary containment. For Wetwell Spray and Suppression Pool Cooling lines, the piping configurations creates a loop seal which spans the penetrations and creates a water seal between the penetrations and the keepfill connections. Therefore, SCBL via these penetrations is precluded.

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

5. Refer to Dwgs. M-113, Sh.1, M-187, Sh. 1, M-187, Sh. 2, and Figures 6.2-66H, and 6.2-66F.

The potential SCBL pathway for the RBCCW penetrations (X-23 & 24) is via the RBCCW supply and return lines through the turbine/radwaste buildings to the Offgas system (Charcoal Treatment System). The potential SCBL pathway for the RBCW penetrations (X-53, -54, -55, -56, -85A/B & -86A/B) is through these same lines via the RBCCW cross-tie to RBCW. The RBCCW and RBCW piping inside primary containment, while not designed to ASME Section III, is designed to Seismic Category I standards and therefore, is likely to remain intact following a large break LOCA. Furthermore, in the case of RBCCW and RBCW penetrations X-85A/B & 86A/B, all of the components served are also designed to Seismic Category I Standards.

For RBCCW, the pipe routing both inside and outside primary containment is such that a loop seal will be formed at the penetration, thereby sealing both sides of the valves with water such the valve discs will not be exposed to containment atmosphere. Consequently, SCBL through the RBCCW penetrations is precluded by the loop seal at the primary containment boundary (see FSAR Figure 6.2-66F). For RBCW, only 6 of the 14 drywell coolers served by the other RBCW penetrations are seismically qualified. This, coupled with an unfavorable pipe routing at the penetration, results in the inability to credit a loop seal at the penetrations similar to RBCCW.

An assessment of the RBCCW supply/return lines at the reactor to turbine building interface concluded that the piping will remain intact following a DBA LOCA. Consequently, the RBCCW supply/return lines to the turbine building will not be subject to a rapid draindown, thus preserving the water volume within secondary containment for both RBCCW and RBCW (see FSAR Figure 6.2-66E). This coupled with the presence of a head tank in the RBCCW system will ensure that the piping of concern in both RBCCW and RBCW will remain full of water, even if a small leak were to develop in the piping outside of secondary containment. Additionally, the pipe routing of the RBCW system within secondary containment is such that a loop seal capable of resisting long term containment pressure will exist, thereby precluding the potential for SCBL through the RBCW system. For RBCCW, SCBL is precluded by the loop seal at the containment penetration, as well as, the presence of water in the remainder of the system located within secondary containment discussed above. Therefore, SCBL via the RBCCW and RBCW penetration is precluded and the leakage from these penetrations need not be compared to the SCBL limit.

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

6. Refer to Dwgs. M-144, Sh. 1, M-144, Sh. 2, M-145, Sh. 1 and Figures 3.6-17-1, 3.6-17-2, and 3.6-17-3.

   The water between the RWCU heat exchangers and secondary containment is sufficiently cold (120°F) such that it will maintain water in the various pathways identified. Based on the large water volume available and the pipe routing, a water seal will be maintained between the feedwater penetrations and the secondary containment boundary.

7. Refer to Dwgs. M-151, Sh. 1, M-151, Sh. 2, M-151, Sh. 3, and M-151, Sh. 4.

   RHR Shutdown cooling line to RHR pump suction will remaining water filled post-LOCA. This is due to the pipe routing from the containment penetration to the Reactor Recirculation piping inside primary containment and the water volume contained within this line. Additionally, the leakage through this penetration will be eliminated based on the water seal described in Note 4.

8. Refer to Dwgs. M-144, Sh. 1, M-144, Sh. 2 and Figures 3.6-17-1, 3.6-17-2, 3.6-17-3, and 6.2-66B.

   Eliminated by a loop seal inside primary containment with an inexhaustible source of water. CIV testing is not required based on the loop seal and the supply of water available. Water is maintained in the line DBA-101 by having minimum piping heights at elev. 720' and 704', the penetration of primary containment at elev. 751' and the RPV penetrations at elev. 732', 746', and 747'. The minimum water level in the reactor vessel, post-LOCA, is 10 feet below Bottom of Active Fuel (BAF). BAF is at elevation 750'. Water level will be restored to elevation 762' at 200 seconds, post-LOCA. Thus, a loop seal sufficient to resist long-term containment pressure is maintained.

9. The drywell purge supply pipe connects to non-Seismic Category I ductwork in secondary containment. This ductwork becomes the recirculation supply post-accident, thereby preventing leakage out of secondary containment via these lines from the subject penetrations. SCBL via the N_2 supply line is eliminated by the spectacle flange, which prevents through-pipe leakage. Therefore, a pathway through secondary containment does not exist when the flange is in the closed position.

   Primary containment inerting can be performed during power operations via the 6” N_2 supply line. This requires the spectacle flange to be in the open position and in this configuration SCBL is no longer eliminated. Thus a SCBL pathway will exist via the 6” N_2 supply line under these circumstances. The leakage through this pathway, when combined with that for the other SCBL pathways identified in this table, must be maintained within the SCBL limit assumed in the DBA LOCA Dose Analysis described in Section 15.6.5. Consequently, if the spectacle flange is placed in a position other than closed during power operation, the SCBL criteria must be met when the maximum

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

pathway 10CFR50, Appendix J leakage for valves HV-1(2)5721, HV-1(2)5722, HV-1(2)5723, HV-1(2)5724 & HV-1(2)5725 is added to the total minimum pathway leakage for the other SCBL pathways identified in this table. Alternatively, an acceptable testing configuration is to use the lesser leakage from either valve HV-1(2)5721 or the combination of valves HV1(2)5722 and HV1(2)5725 and add this minimum pathway leakage to the running minimum pathway leakage (as-found) for the other SCBL pathways and to use the greater leakage from either valve HV-1(2)5721 or the combination of valves HV1(2)5722 and HV1(2)5725 and add this maximum pathway leakage to the running maximum pathway leakage (as-left) for the other SCBL pathways identified in this table. This is an acceptable configuration for the following reason. Valves HV-1(2)5723 and HV-1(2)5724 provide isolation to the Reactor Building recirculation plenum. These valves do not isolate a potential Secondary Containment Bypass Leakage pathway since the Reactor Building recirculation plenum is part of Secondary Containment. Since the valves do not isolate a SCBL pathway, leakage testing of these valves represents unnecessary conservatism with respect to SCBL. This configuration will still accommodate a single failure since either valve HV-1(2)5721 or the combination of valves HV(1)5722 and HV1(2)5725 will provide the appropriate SCBL leakage protection. Valve HV(1)5721 is a divison II valve and HV-1(2)5722 and HV-1(2)5725 are division I valves. This divisional separation accommodates a single failure. Note that including the leakage from either HV-1(2)5723 and/or HV-1(2)5724 is conservative and therefore acceptable.

10. Refer to Dwgs. M-146, Sh. 1 M-143, Sh. 1, M-143, Sh. 2, and Figure 6.2-66G.

A potential water bypass leakage path exists due to the CRD insert/withdrawal lines penetrating primary containment and the CRD supply line penetrating secondary containment. In this case, post-LOCA water from the reactor vessel could escape by draining out the bottom of the reactor at elevation 732'-04" into the insert/withdrawal lines; through the hydraulic control units (HCU's), supply headers and master control station on elevation 719'-0"; down the CRD supply piping and through secondary containment into the Turbine Building at elevation 662'-9".

In addition to the potential for water bypass leakage from the CRD supply line, pneumatic SCBL is possible from penetrations X-31B and 60A (Recirculation Pump seal Mini-Purge lines). These lines are supplied with water from the CRD pump, and have the potential to leak into secondary containment via the CRD supply line.

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

These pathways are eliminated by a "Seismic Island" consisting of ASME Section III, Class 3 piping, two (2) ASME Section III check valves and the necessary test connections and block valves (see figure 6.2-66G). The island is located just inside of secondary containment so as to prevent bypass leakage from reaching the Turbine Building. This is accomplished by using the clean water trapped between the Seismic Island and the reactor vessel as a 30-day water seal against the post-LOCA water reaching the Turbine Building. The Seismic Island check valves are periodically tested to ensure leakage is limited to less than 508 ml/hr to ensure a 30 day water seal is maintained. This leakrate was determined by dividing the volume of water in the CRD piping between the seismic island and the HCU's by 30 days.

Therefore, the water seal maintained in the CRD piping by the CRD Seismic Island precludes SCBL from occurring via the CRD supply line penetrating secondary containment.

11. Refer to Dwgs. M-157, Sh. 1, M-157, Sh. 2, M-157, Sh. 3, M-152, Sh. 1, M-155, Sh. 1, M-149, Sh. 1, M-150, Sh. 4, and Figure 6.2-66C.

    SCBL is eliminated for penetrations X-206A/B (Core Spray Pump Suction), X-209 (HPCI Pump Suction), X-214 (RCIC Pump Suction) and X-246 (Suppression Pool Purification line) based on a water seal provided by the suppression pool. The suction piping for these penetrations is located sufficiently below the minimum suppression pool water level so as to prevent the lines from being exposed to drywell atmosphere.

12. Leakage is routed to condenser where "scrubbing" is credited as part of MSIVLCS elimination. Valves are leak rate tested and maintained such that the combined leakage from these valves and the MSIV's is less than the 300 scfh limit specified for the MSIV's in Technical Specifications. The radiological impact of leakage scrubbed via the condenser is considered in the DBA LOCA Dose analysis. Since this leakage is not released directly to the environment, these lines are eliminated as SCBL pathways.

13. The Standby Liquid Control (SLC) line terminates inside the reactor vessel below the post-accident water level. Therefore, an inexhaustible water seal is provided to prevent containment atmosphere from reaching the SLC containment penetrations. Additionally, the SLC explosive valves provide an impenetrable barrier with regard to leakage through the valves.

14. The affected lines penetrate the reactor building, but terminate within a panel mounted on the turbine building side of the reactor/turbine building wall. However, the panel is vented to the reactor building. Consequently, any leakage from these lines is collected and treated by SGTS (ref. FSAR Section 18.1.21.5.3 & Dwg. M-123, Sh. 12).

Table 6.2-15

Evaluation Of Potential Secondary Containment Bypass Leakage Pathways

15. The following two (2) isolation barriers are used to limit SCBL from these valid pathways:

    a. Note that these penetrations contain a water seal via RHR operation. In order to ensure adequate water inventory is available in the water seal, isolation valves HV151F040 and HV151F049 are outside of primary containment that will limit SCBL through the RHR line to LRW. The valves have an automatic isolation signal for low water level or high drywell pressure. The valves have separate power supplies, one is AC and the other is DC. The valves and associated piping are designed in accordance with ASME Section III, Class 2. The valves will be tested per 10CFR50 Appendix J requirements, and

    b. A "Seismic Island" consisting of ASME Section III, Class 3 piping, two (2) ASME Section III check valves, will limit SCBL from RHR through the Condensate System and the Fire Protection System. The check valves will close if there is no flow from the Condensate or Fire Protection water supply to RHR. The valves will be tested per 10CFR50 Appendix J requirements. Even though water leakage is a concern for these penetrations, the valves will be conservatively tested to air SCBL criterion.

16. These lines are eliminated by loop seals established by RHR operation or ESW/RHRSW loop operation. Single failure does not eliminate the water seal.

17. The vent pipe pathway penetrates secondary containment in two locations:

    a. Rupture disc PSE15701 is a barrier for SCBL and prevents leakage from line HBD-1571 to the Reactor Building roof. Therefore, a pathway through secondary containment does not exist when disc PSE15701 has not ruptured.

    b. The tubing leading to the ROS is vented to secondary containment. Consequently, primary containment leakage is vented to secondary containment where it is collected and treated by SGTS.

TABLE 6.2-17

	INFORMATION FOR THE SSES SECONDARY CONTAINMENT
I.	Secondary Containment Ventilation Zones I, II and III
A.	Approximate Free Volume, ft^3 – Zone I 1,488,600 Zone II 1,598,600 Zone III 2,668,400
B.	Pressure, inches of water, gage 1. Normal Operation – ¼ 2. Post-accident – ¼
C.	Leak Rate at Post-Accident Pressure – 225% per day
D.	Exhaust Fans – common 1. Number – 2 2. Type – Centrifugal, SISW
E.	Filters – common 1. Number – 2 2. Type – prefilter, HEPA, charcoal, HEPA
II.	Transient Analysis
A.	Initial Conditions 1. Pressure, - ¼ in. wq 2. Temperature - 104°F 3. Outside Air Temperature - 92°F 4. Thickness of Secondary Containment Wall - 36 in. 5. Thickness of Primary Containment Wall – 72 in.
B.	Thermal Characteristics 1. Primary Containment Wall a. Thermal Conductivity, Btu/hr-ft-°F - .5 b. Thermal Capacitance, Btu/ft^3 - °F – 25 2. Secondary Containment Wall a. Thermal Conductivity, Btu/hr-ft-°F - .5 b. Thermal Capacitance, Btu/ft^3-°F – 25 3. Heat Transfer Coefficients a. Primary Containment Atmosphere to Primary Containment Wall, Btu/hr-ft^2 - °F – 1.46 b. Primary Containment Wall to Secondary Containment Atmosphere, Btu/hr-ft^2 - °F – 1.46 c. Secondary Containment Wall to Secondary Containment Atmosphere, Btu/hr-ft^2 - °F – 1.46 d. Primary Containment Emissivity, Btu/hr-ft^2 - °F – .9 e. Secondary Containment Emissivity, Btu/hr-ft^2 - °F – .9

TABLE 6.2-19

TYPE A TEST DATA		
A	Peak Test Pressure The calculated peak containment pressure related to the design basis loss of coolant accident.	Pa = 48.6 psig
B	Maximum Allowable Leakage Rate The maximum allowable leakage rate at peak accident pressure from the drywell and pressure suppression chamber.	La = 1.0 /day
C.	Measured Leakage Rate Overall measured leakage rate during Type A test from drywell and suppression chamber.	Lam
D.	Imposed Leakage Rate The leakage rate imposed on the containment during the verification test. Li is 75% to 125% of La.	Li
E.	Verification Test Leakage Rate The total containment leakage, including Li, measured during the verification test.	Lvm
F.	Test Duration 1) After the containment atmosphere has stabilized, the integrated leakage rate test period begins. The duration of the test period must be sufficient to enable adequate data to be accumulated and statistically analyzed so that a leakage rate and upper confidence limit can be accurately determined. 2) The Type A test shall last a minimum of 8 hrs after stabilization and shall have a total of not less than 30 sets of data points at approximately equal time intervals. 3) The Type A test cannot be successfully terminated until the acceptance criteria of the plant Technical Specifications are met.	
G.	Drywell Temperature Limits During Type A Test	40-120°F
H.	Free Air Volume Drywell Suppression Chamber	239,600 ft^3 159,130 ft^3 (low water level) 148,590 ft^3 (high water level)

Table 6.2-21

SYSTEM VENTING AND DRAINING FOR PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE TEST

	The Reactor Building Chilled Water System (RBCWS) located inside primary containment does not meet the criteria for a closed system for purposes of containment isolation. The RBCWS is not vented during the Type A test and may be operated in its normal mode to maintain the containment atmosphere in a stabilized condition.
	Systems that are normally filled with water and operating under post-LOCA conditions are not specifically vented to the containment atmosphere or to the outside atmosphere. They remain water filled during the Type A test. These systems are listed below. (Note: Venting to the primary containment atmosphere does not occur for these systems, since the reactor vessel is vented to the primary containment atmosphere and/or system penetrations are open to the suppression pool or containment atmospheres). <u>System</u> Reactor Core Isolation Cooling * Residual Heat Removal Core Spray High Pressure Coolant Injection * * HPCI and RCIC will initially operate post DBA LOCA, but will subsequently be shutdown due to RPV depressurization. They are listed here since the penetrations within these systems terminate below the suppression pool minimum water level and therefore, do not communicate with post-accident containment atmosphere. This only applies to the water side of HPCI and RCIC.

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LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-1	Equip. Access Hatch	B	Double O-ring	1	-	-	
X-2	Equip. Access Hatch With Personnel Lock	B	Double O-ring	1	-	-	
X-2	Personnel Lock Barrel	B	Inner Door/Barrel	1, 2	Outer Door/Barrel	1, 2	
X-2	Personnel Lock Inner Door	B	Double O-ring	1, 3	-	-	
X-2	Personnel Lock Outer Door	B	-	-	Double O-ring	1, 3	
X-3A	Spare	A	Cap (3)	-	-	-	
X-3B	Primary Containment Pressure Inst.	A	Cap (1) Instrument Line (2)	- 10, 11, 30	-	-	
X-3C	Spare	A	Cap (3)	-	-	-	
X-3D	Spare	A	Cap (3)	-	-	-	
X-4	Drywell Head Access Manhole	B	Double O-ring	1	-	-	
-	Drywell Head	B	Double O-ring	1	-	-	
X-5	Ctmt. Rad. Det. Supply Sample	C	SV-157100A	11	SV-157101A	11	
X-5	Ctmt. Rad. Det. Return Sample	C	SV-157102A	11	SV-157103A	11	
X-6	CRD Removal Hatch	B	Double O-ring	1	-	-	
X-7A	Main Steam	C	HV-1F022A	4, 5, 16	HV-1F028A	4, 16	Yes
X-7B	Main Steam	C	HV-1F022B	4, 5, 16	HV-1F028B	4, 16	Yes
X-7C	Main Steam	C	HV-1F022C	4, 5, 16	HV-1F028C	4, 16	Yes
X-7D	Main Steam	C	HV-1F022D	4, 5, 16	HV-1F028D	4, 16	Yes
X-8	Main Steam Line Drain	C	HV-1F016	16	HV-1F019	16	
X-9A	Feedwater	C	1F010A	16	HV-1F032A, HV-1F013, HV-14182A, 1-49-020, 141F039A, 141818A, 241F039A	16	
X-9B	Feedwater	C	1F010B	16	HV-1F032B, HV-1F006, HV-14182B, 1-55-038, 141F039B, 141818B, 241F039B	16	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-10	Steam To RCIC Turbine	C	HV-1F007, HV-1F088	6, 7, 16, 22	HV-1F008	16	Yes
X-11	Steam To HPCI Turbine	C	HV-1F002, HV-1F100	6, 7, 16, 22	HV-1F003	16	Yes
X-12	RHR Shutdown Supply	A	HV-1F009, PSV-1F126	18	HV-1F008	18	
X-13A	RHR Shutdown Return	A	HV-1F015A	9, 11, 18	Closed System	16, 17	
X-13B	RHR Shutdown Return	A	HV-1F015B	9, 11, 18	Closed System	16, 17	
X-14	Reactor Water Cleanup Supply	C	HV-1F001	14, 18	HV-1F004	14, 18	
X-15	Spare	A	Cap	-	-	-	
X-16A	Core Spray	C	HV-1F037A, HV-1F006A	16, 17	HV-1F005A	16,17	
X-16B	Core Spray	C	HV-1F037B, HV-1F006B	16, 17	HV-1F005B	16, 17	
X-17	RPV Head Spray	A	HV-1F022	18	HV-1F023	18	
X-18	Spare	A	Cap	-	-	-	
X-19	Instrument Gas	C	1-26-074	-	SV-12651	-	
X-20	Spare	A	Cap	-	-	-	
X-21	Instrument Gas	C	1-26-152	-	SV-12654B	-	
X-22	Spare	A	Cap	-	-	-	
X-23	Closed Cooling Water Supply	C	HV-11346	16	HV-11314	16	
X-24	Closed Cooling Water Return	C	HV-11345	16	HV-11313	16	
X-25,201A	Purge Supply	C	HV-15722, HV-15725	8, 11	HV-15724, HV-15721, HV-15723	11	
X-26	Drywell Purge Exhaust	C	HV-15713	8, 11	HV-15714, HV-15711	11	
X-27A	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-27B	Main Steam C Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-28A	Spare	A	Cap (4)	-	-	-	
X-28B	Jet Pump Inst.	A	Cap (3) Excess Flow Check Vlv (1)	10, 11, 27	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-29A	Spare	A	Cap (4)	-	-	-	
X-29B	RWCU Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-30A (Unit 1)	Recirc Loop Inst.	A	Exess Flow Check Vlv (1)	10, 11, 27	-	-	
X-30A (Unit 2)	Recirc Loop Inst.	A	Cap (3) Excess Flow Check Vlv (1)	10, 11, 27	-	-	
X-30B	Spare	A	Cap	-	-		
X-31A (Unit 1)	Main Steam Inst.	A	Cap (2) Excess Flow Check Vlv (2)	10, 11, 27	-	-	
X-31A (Unit 2)	Main Steam Inst.	A	Cap (1) Excess Flow Check Vlv (3)	10, 11, 27	-	-	
X-31B	Recirculation Pump Seal Water Supply Line	C	1F013B	16	XV-1F0I7B	10, 16, 23	Yes
X-31B (Unit 1)	Spare	A	Cap (2)				
X-31B (Unit 2)	Ctmt. Rad. Det. Supply Sample	C	SV257100B	11	SV257101B	11	
X-31B (Unit 2)	Ctmt. Rad. Det. Return Sample	C	SV257102B	11	SV257103B	11	
X-32A	RHR Suction From R.P.V. Leak Det. Inst	A	Cap (2) Instrument Line	10, 11, 30	-	-	
X-32B	Spare	A	Cap (3)	-	-	-	
X-33A (Unit 1)	RHR Pump Inst.	A	Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-33A (Unit 2)	RHR Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-33B	RHR Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-34A	Main Steam Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-34B	Main Steam Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-35A	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11, 19	Yes
X-35B	Spare	A	Cap	-	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-35C	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11, 19	Yes
X-35D	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11,19	Yes
X-35E	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11, 19	Yes
X-35F	TIP Drive	B,C	Double "O" Ring, Ball Valve	11	Shear Valve	11, 19	Yes
X-36	Spare	A	Cap	-	-	-	-
X-37A	CRD Insert	A	-	20	-	-	Yes
X-37B	CRD Insert	A	-	20	-	-	Yes
X-37C	CRD Insert	A	-	20	-	-	Yes
X-37D	CRD Insert	A	-	20	-	-	Yes
X-38A	CRD Withdraw	A	-	20	-	-	Yes
X-38B	CRD Withdraw	A	-	20	-	-	Yes
X-38C	CRD Withdraw	A	-	20	-	-	Yes
X-38D	CRD Withdraw	A	-	20	-	-	Yes
X-39A	Containment Spray	A	HV-1F016A	9, 11, 18	Closed System	9, 11, 18	
X-39B	Containment Spray	A	HV-1F016B	9, 11, 18	Closed System	9, 11, 18	
X-40A	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-40B	Main Steam Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-40C (Unit 1)	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-40C (Unit 2)	Spare	A	Cap (4)	10, 11, 27	-	-	
X-40D	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-40E	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-40F	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-		

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-40G	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-		
X-40H	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-41	Instrument Gas	C	1-26-154	-	SV-12654A	-	
X-42	Stby. Liquid Control	C	1F007	14, 18	HV-1F006	14, 18	
X-43	Not Used	-	-	-	-	-	
X-44	Spare	A	Cap	-	-	-	
X-45	Spare	A	Cap	-	-	-	
X-46	Spare	A	Cap	-	-	-	
X-47	Spare	A	Cap	-	-	-	
X-48A (Unit 1)	Spare	A	Cap	-	-	-	
X-48A (Unit 2)	Spare	A	Cap (3)	-	-	-	
X-48B (Unit 1)	Spare	A	Cap (3)	-	-	-	
X-48B (Unit 2)	Main Steam Inst.	A	Cap (1) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-49A (Unit 1)	Recirc. Loop Inst.	A	Cap (1) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-49A (Unit 2)	Recirc. Loop Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-49B	Recirc. Loop Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-50A	Recirc. Loop Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-50B	Recirc. Loop Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-51A (Unit 1)	Recirc. Pump Inst.	A	Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-51A (Unit 2)	Recirc. Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-51B	Recirc. Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-52A (Unit 1)	Recirc. Pump Inst.	A	Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-52A (Unit 2)	Recirc. Pump Inst.	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-52B	Recirc. Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-53	Chilled Water Supply	C	HV-18782A1	16, 17	HV-18781B1	16, 17	
X-54	Chilled Water Return	C	HV-18782A2	16, 17	HV-18781B2	16, 17	
X-55	Chilled Water Supply	C	HV-18782B1	16, 17	HV-18781A1	16, 17	
X-56	Chilled Water Return	C	HV-18782B2	16, 17	HV-18781A2	16, 17	
X-57	Spare	A	Cap	-	-	-	
X-58A	RWCU Inst (2)	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-58B	Spare	A	Cap (4)	-	-	-	
X-59A	Reactor Level Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-59B	Reactor Level Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-60A	O_2 Sample	C	SV-15740A, SV-15742A	11	Closed System	31	
X-60A	Recirculation Pump Seal Water Supply Line	C	1F013A	16	XV-1F017A	10, 16, 23	Yes
X-60A	O_2 Sample	C	SV-15750A, SV-15752A	11	Closed System	31	
X-60B	Reactor Water Sample	C	HV-1F019	16	HV-1F020	16	
X-60B (Unit 1)	Spare	A	Cap (3)				
X-60B (Unit 2)	Spare	A	Cap (2)				
X-61A	Demin. Water	C	1-41-018	16	1-41-017	16	
X-61A (Unit 1)	ILRT Leak Verification	C	1-57-193	-	1-57-194	-	
X-61A (Unit 2)	ILRT Leak Verification	C	2-57-200	-	2-57-199	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-61A (Unit 1)	Spare	A	Cap (2)				
X61A (Unit 2)	Jet Pump Inst.	A	Cap (1) Excess Flow Check Vlv. (1)	10, 11, 27			
X-61B	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-62A (Unit 1)	Main Steam Inst	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-62A (Unit 2)	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-62B	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-63A	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-63B (Unit 1)	Main Steam, Core Spray Inst	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-63B (Unit 2)	Main Steam Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-64A (Unit 1)	Main Steam Inst	A	Cap (2) Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-64A (Unit 2)	Main Steam Inst	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-64B (Unit 1)	Pressure Inst	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-64B (Unit 2)	Spare	A	Cap (4)	10, 11, 27	-	-	
X-65A	Reactor Level Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-65B (Unit 1)	Reactor Level Inst	A	Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-65B (Unit 2)	Reactor Level Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-66A	Reactor Level Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-66B	Reactor Level Inst	A	Cap (3) Excess Flow Check Vlv. (1)	10, 11, 27	-	-	
X-72A	Liquid Radwaste	C	HV-16116A1	11, 16	HV-16116A2	11, 16	
X-72B	Liquid Radwaste	C	HV-16108A1	11, 16	HV-16108A2	11, 16	
X-80A	Spare	A	Cap	-	-	-	
X-80B (Unit 1)	Main Steam Inst.	A	Excess Flow Check Vlv. (2)	10, 11, 27	-	-	
X-80B (Unit 2)	Main Steam Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27	-	-	
X-80C	H_20_2 Analyzer	C	SV-15750B, SV-15752B	11	Closed System	31	
X-80C	H_2O_2 Analyzer	C	SV-15740B, SV-15742B	11	Closed System	31	
X-80C	H_2O_2 Analyzer	C	SV-15776B, SV-15774B	11	Closed System	31	
X-81A	Spare	A	Cap (3)	-	-	-	
X-81B	Spare	A	Cap (3)	-	-	-	
X-82A	Spare	A	Cap (4)	-	-	-	
X-82B	Spare	A	Cap (3)	-	-	-	
X-83A	Spare	A	Cap (3)	-	-	-	
X-83B	Spare	A	Cap (3)	-	-	-	
X-84A	Vessel Leak Detect. Inst	A	Cap (3) Excess Flow Check Vlv (1)	10, 11, 27	-	-	
X-84B	Spare	A	Cap (3)	-	-	-	
X-85A	Chilled Water To Recirc Pumps	C	HV-18792B1	16	HV-18791A1	16	
X-85B	Chilled Water To Recirc Pumps	C	HV-18792B2	16	HV-18791A2	16	
X-86A	Chilled Water To Recirc Pumps	C	HV-18792A1	16	HV-18791B1	16	
X-86B	Chilled Water To Recirc Pumps	C	HV-18792A2	16	HV-18791B2	16	
X-87	Instrument Gas	C	HV-12603	-	SV-12605	-	
X-88A	Drywell N_2 Makeup	C	SV-15767	11	SV-15789	11	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-88B	H_2O_2 Sample	C	SV-15776A, SV-15774A	11	Closed System	31	
X-89	Not Used						
X-90A	Level Inst	A	Cap (1) Instrument Line (3)	10, 11, 30	-	-	
X-90B (Unit 1)	Spare	A	Cap (3)	-	-	-	
X-90B (Unit 2)	Spare	A	Cap (4)	-	-	-	
X-90C	Spare	A	Cap	-	-	-	
X-90D (Unit 1)	Press. Inst	A	Cap (1) Instrument Line (3)	10, 11, 30	-	-	
X-90D (Unit 2)	Press. Inst	A	Instrument Line (3)	10, 11, 30	-	-	
X-90E (Unit 1)	Spare	A	Cap (4)	-	-	-	
X-90E (Unit 2)	Spare	A	Cap (3)	-	-	-	
X-90F (Unit 1)	Spare	A	Cap	-	-	-	
X-90F (Unit 2)	Spare	A	Cap (4)	-	-	-	
X-91A (Unit 1)	Spare	A	Cap (2)	-	-	-	
X-91A (Unit 1)	Cmt. Rad. Det. Supply Sample	C	SV157100B	11	SV157101B	11	
X-91A (Unit 1)	Cmt. Rad. Det. Return Sample	C	SV157102B	11	SV157103B	11	
X-91A (Unit 2)	RWCU Inst., Main Steam Inst.	A	Cap (1) Excess Flow Check Vlv. (3)	10, 11, 27			
X-91B	Spare	A	Cap	-	-	-	
X-92	Spare	A	Cap (3)	-	-	-	
X-93	TIP Inst Gas	C	1-26-072	-	SV-12661	-	
X-94	Spare	A	Cap	-	-	-	
X-100A	Neut. Monitoring	B	Canister	12	-	-	
X-100B	Neut. Monitoring	B	Canister	12	-	-	
X-100C	Neut. Monitoring	B	Canister	12	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-100D	Neut. Monitoring	B	Canister	12	-	-	
X-100E (Unit 1)	Neut. Monitoring	B	Lead Shield/Support Plate	24	Double O-Ring Compression fitting	25	
X-100E (Unit 2)	Spare	A	Cap				
X-100F (Unit 1)	Communications	B	Lead Shield/Support Plate	24	Double O-Ring Compression fitting	25	
X-100F (Unit 2)	Spare	A	Cap				
X-100G	Spare	A	Cap	-	-	-	
X-100H (Unit 1)	Spare	A	Cap	-	-	-	
X-100H (Unit 2)	Communications	B	Lead Shield/Support Plate	24	Double O-Ring Compression Fitting	25	
X-101A	M.V. Power	B	Canister	13	Double O-ring	13	
X-101B	M.V. Power	B	Canister	13	Double O-ring	13	
X-101C	M.V. Power	B	Canister	13	Double O-ring	13	
X-101D	M.V. Power	B	Canister	13	Double O-ring	13	
X-101E	M.V. Power	B	Canister	13	Double O-ring	13	
X-101F	M.V. Power	B	Canister	13	Double O-ring	13	
X-102A	Low Level Signal/Temp.	B	Canister	13	Double O-ring	13	
X-102B	Low Level Signal/Temp.	B	Canister	13	Double O-ring	13	
X-103A	Low Level Signal/Temp.	B	Canister	13	Double O-ring	13	
X-103B	Low Level Signal/Temp.	B	Canister	13	Double O-ring	13	
X-104A	RPIS	B	Canister	13	Double O-ring	13	
X-104B	RPIS	B	Canister	13	Double O-ring	13	
X-104C	RPIS	B	Canister	13	Double O-ring	13	
X-104D	RPIS	B	Canister	13	Double O-ring	13	
X-104E (Unit 1)	Spare	A	Cap	-	-	-	

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Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-104E (Unit 2)	Neut. Monitoring	B	Lead Shield/Support Plate	24	Double O-ring Compression Fitting	25	
X-104F	Spare	A	Cap	-	-	-	
X-104G	Spare	A	Cap	-	-	-	
X-104H	Spare	A	Cap	-	-	-	
X-105A	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-105B	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-105C	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-105D	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-106A	Low Volt. Control	B	Canister	13	Double O-ring	13	
X-106B	Low Volt. Control	B	Canister	13	Double O-ring	13	
X-106C	Low Volt. Control	B	Canister	13	Double O-ring	13	
X-106D	Low Volt. Control	B	Canister	13	Double O-ring	13	
X-107	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-108	Low Volt. Power	B	Canister	13	Double O-ring	13	
X-200A	Access Hatch	B	Double O-ring	1	-	-	
X-200B	Access Hatch	B	Double O-ring	1	-	-	
X-201A	See Penetration X-25	-	-	-	-	-	
X-201B	Hardened Containment Vent System	B and C	HV-157113	8, 11, 32	HV-157114	11	
X-202	Purge Exhaust	C	HV-15703	8, 11	HV-15705, HV-15704	11	
X-203A	RHR Pump Suction	A	HV-1F004A	9, 11, 18	Closed System	9, 11, 18	
X-203B	RHR Pump Suction	A	HV-1F004B	9, 11, 18	Closed System	9, 11, 18	
X-203C	RHR Pump Suction	A	HV-1F004C	9, 11, 18	Closed System	9, 11, 18	
X-203D	RHR Pump Suction	A	HV-1F004D	9, 11, 18	Closed System	9, 11, 18	
X-204A	RHR Pump Test Line	A	HV-1F028A, HV-1F011A	9, 11, 18	Closed System	9, 11, 18	

Table Rev. 68

TABLE 6.2-22

LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-204B	RHR Pump Test Line	A	HV-1F028B, HV-1F011B	9, 11, 18	Closed System	9, 11, 18	
X-205A	Containment Spray	A	HV-1F028A, HV-1F011A	9, 11, 18	Closed System	9, 11, 18	
X-205B	Containment Spray	A	HV-1F028B, HV-1F011B	9, 11, 18	Closed System	9, 11, 18	
X-206A	Core Spray Pump Suction	A	HV-1F001A	9, 11, 18	Closed System	9, 11, 18	
X-206B	Core Spray Pump Suction	A	HV-1F001B	9, 11, 18	Closed System	9, 11, 18	
X-207A	Core Spray Pump Test	A	HV-1F015A	9, 11, 18	Closed System	9, 11, 18	
X-207B	Core Spray Pump Test	A	HV-1F015B	9, 11, 18	Closed System	9, 11, 18	
X-208A	Core Spray Pump Recirc	A	HV-1F031A	9, 11, 18	Closed System	9, 11, 18	
X-208B	Core Spray Pump Recirc	A	HV-1F031B	9, 11, 18	Closed System	9, 11, 18	
X-209	HPCI Pump Suction	A	HV-1F042	9, 11, 18	Closed System	9, 11, 18	
X-210	HPCI Turbine Exh.	C	HV-1F066	7, 11, 21	1F049	11, 21	Yes
X-211	HPCI Pump Recirc	A	HV-1F0l2	11, 18	1F046	11, 18	
X-212 (Unit 1)	Spare	A	Cap	-	-	-	
X-212 (Unit 2)	Ctmt. Rad. Det. Supply Sample	C	SV-257104	11	SV-257105	11	
X-213	Spare	A	Cap	-	-	-	
X-214	RCIC Pump Suction	A	HV-1F031	9, 11, 18	Closed system	9, 11, 18	
X-215	RCIC Turbine Exh.	C	HV-1F059	7, 11, 21	1F040	11, 21	Yes
X-216	RCIC Pump Recirc	A	FV-1F019	11, 18	1F021	11, 18	
X-217	RCIC Vac. Pump Disch.	C	HV-1F060	6, 11, 21	1F028	11, 21	
X-218	Instrument Gas	C	1-26-164	11	SV-12671	11	
X-219A	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-219B	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-220A (Unit 1)	Ctmt. Rad. Det. Return Sample	C	SV-157106	11	SV-157107	11	
X-220A (Unit 2)	Spare	A	Cap	-	-	-	
X-220B	Wetwell N_2 Makeup	C	SV-15737	11	SV-15738	11	

Table Rev. 68

TABLE 6.2-22

LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier		Outboard Isolation Barrier		Exemption to 10CFR50 Appendix J Required
			Barrier Description/ Valve No. (28)	Notes	Barrier Description/ Valve No.	Notes	
X-221A	H_2O_2 Analyzer	C	SV-15780A, SV-15782A	11	Closed System	31	
X-221B (Unit 1)	Spare	A	Cap	-	-	-	
X-221B (Unit 2)	H_20_2 Analyzer	C	SV-25780B, SV-25782B	11	Closed System	31	
X-222	Spare	A	Cap	-	-	-	
X-223A	Suppression Pool Press Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-223B	Spare	A	Cap	-	-	-	
X-224	Spare	A	Cap	-	-	-	
X-225	Spare/Sit Test Conn.	A	Cap	-	-	-	
X-226A	RHR Recirc	A	HV-1F007A	9, 11, 18	Closed System	9, 11, 18	
X-226B	RHR Recirc	A	HV-1F007B	9, 11, 18	Closed System	9, 11, 18	
X-227	Spare	A	Cap	-	-	-	
X-228A (Unit 1)	Ctmt. Rad. Det. Supply Sample	C	SV-157104	11	SV-157105	11	
X-228A (Unit 2)	Spare	A	Cap	-	-	-	
X-228B	Spare	A	Cap	-	-	-	
X-228C	Spare	A	Cap	-	-	-	
X-228D	Spare	A	Cap	-	-	-	
X-229A	Spare	A	Cap	-	-	-	
X-229B (Unit 1)	Spare	A	Cap	-	-	-	
X-229B (Unit 2)	Ctmt. Rad. Det. Return Sample	C	SV-257106	11	SV-257107	11	
X-230A	Spare	A	Cap	-	-	-	
X-231A	Spare	A	Cap	-	-	-	
X-231B	Spare	A	Cap	-	-	-	
X-232A	Level Inst.	A	Instrument Line (1)	10, 11, 30		-	
X-232B	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-233 (Unit 1)	H_20_2 Analyzer	C	SV-15780B, SV-15782B	11	Closed System	31	

Table Rev. 68

TABLE 6.2-22

LEAKAGE RATE TEST LIST

Penetration	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (28)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No.	Outboard Isolation Barrier: Notes	Exemption to 10CFR50 Appendix J Required
X-233 (Unit 2)	Spare	A	Cap	-	-	-	
X-234A	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-234B	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-235A	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-235B	Level Inst.	A	Instrument Line (1)	10, 11, 30	-	-	
X-236	Spare	A	Cap	-	-	-	
X-237	Spare	A	Cap	-	-	-	
X-238A	H_2O_2 Analyzer Return	C	SV-15736A, SV-15734A	11	Closed System	31	
X-238B	H_2O_2 Analyzer Return /	C	SV-15736B, SV-15734B	11	Closed System	31	
X-239	Not Used	-	-	-	-	-	
X-240	Not Used	-	-	-	-	-	
X-241	Not Used	-	-	-	-	-	
X-242	Not Used	-	-	-	-	-	
X-243	Supp. Pool Cleanup & Drain	C	HV-15766	7, 11, 14, 18,	HV-15768	11, 14, 18	Yes
X-244	HPCI Vac. Breaker	C	HV-1F079	11, 16, 29	HV-1F075	11, 16	Yes
X-245	RCIC Vac. Breaker	C	HV-1F084	11, 16, 29	HV-1F062	11, 16	Yes
X-246A	RHR Relief Valve Discharge	C B	Blind Flange, PSV-15106A HV-1F103A Spectacle Flange 1S299A	9, 11, 16 26	Closed System N/A	9, 11	Yes
X-246B	RHR Relief Valve Discharge.	C B	Blind Flange, HV-1F103B PSV-15106B Spectacle Flange 1S299B	9, 11, 16 32	Closed System N/A	9,11	Yes
X-247-299	Not Used	-	-	-	-	-	-
X-300	Low Voltage Control	B	Canister	13	Double O-ring	13	
X-301	Low Voltage Control	B	Canister	13	Double O-ring	13	
X-330B	Inst. & Control	B	Canister	13	Double O-ring	13	

TABLE 6.2-22

LEAKAGE RATE TEST LIST

NOTES:

1. The penetration is sealed by a blind flange or door with double o-ring seals. The seals are leak rate tested by pressurizing between the o-rings.

2. The personnel air lock volume is pressurized to Pa. The air lock is tested periodically in accordance with the Leakage Rate Test Program. During the air lock test, tie downs are installed on the inner door. The normal locking mechanisms for the air lock doors are not designed to withstand a differential pressure greater than 5 psi across the door in the reverse direction. Figure 6.2-59 shows the details of the tie downs for the inner door. The tie downs are installed from within the air lock. The force exerted by the tie downs on the inner door is not mentioned. The mechanical and electrical penetrations in the air lock are tested by pressurizing the air lock barrel.

3. Double rubber seals are provided on both air lock doors. These seals are tested at 10 psig, a pressure less than the containment peak accident pressure. Testing at a pressure greater than 10 psig forces the gasket material out of the groove. The 10 psig test pressure is in accordance with the plant Technical Specifications. The test pressure is also permitted by NEI 94-01, Rev. 0, Section 10.2.2.1. Additionally, as mentioned in Note 2, the entire air lock, including the doors, is tested periodically at Pa.

4. If the MSIVs are tested together (i.e., between valves), they are tested at 1/2 Pa. Higher pressure will unseat the inboard MSIV. If the MSIVs are tested individually, they are tested at Pa. MSIVs are also tested together at a pressure of at least ½ Pa where inboard MSIV leakage is isolated by pressurizing upstream of the inboard MSIV to a pressure less than the test pressure, outboard MSIV leakage is measured, and then inboard MSIV leakage is calculated by subtracting outboard leakage from the combined leak rate for the inboard and outboard MSIVs.

5. If the MSIVs are tested together, the inboard globe valve is tested in the reverse direction. This is a conservative test since the test pressure tends to unseat the disc.

6. The globe valve is tested in the reverse direction.

7. The gate valve is tested in the reverse direction.

8. The butterfly valve is tested in the reverse direction. Butterfly valves exhibit equivalent or more conservative leakage in the reverse direction.

TABLE 6.2-22

LEAKAGE RATE TEST LIST

9. The containment isolation for this penetration consists of a containment isolation valve and a closed system outside containment. This is in compliance with 10CFR50 Appendix A GDC 54 and the US NRC Standard Review Plan 6.2.4, Containment Isolation Provisions, paragraph II.3.e. The standard review plan allows the use of a single isolation valve outside containment in conjunction with a closed system outside containment. A single active failure can be accommodated. The closed system is missile/pipe whip protected, Seismic Category I, Safety Class 2, and has a temperature and pressure rating in excess of that for the containment. Closed system integrity is maintained and verified in accordance with the Leakage Rate Test Program.

10. The installation is in accordance with US NRC Regulatory Guide 1.11 (Safety Guide 11).

11. All containment isolation barriers and/or valves are outside the containment.

12. The electrical canister is Type B tested by pressurizing with dry nitrogen. The canister is welded to the penetration nozzle.

13. The electrical canister is bolted to the penetration nozzle. The bolted connection contains a double o-ring with a test connection. The electrical canister and double o-ring are Type B tested by pressurizing with dry nitrogen.

14. The isolation barrier remains water filled or a water seal remains in the line post-LOCA. The containment isolation valve is tested with water. The containment isolation valve leak rate is not included in the Type B and C test acceptance criteria. The acceptance criteria for water tested valves is in the plant Technical Specifications.

15. The relief valve is tested in the reverse direction. This is a conservative test since the test pressure tends to unseat the valve plug.

16. To expose the containment isolation valve seating surface to the containment atmosphere, the piping system is drained of fluid to the extent necessary.

17. The system remains water filled and operational during the ILRT. The penetration leak rate is added to the Type A test result. For RBCW, only 1 loop remains water filled.

18. The system is designed to remain water filled post-LOCA. The system remains water filled during the ILRT.

TABLE 6.2-22

LEAKAGE RATE TEST LIST

19. The TIP shear valves are not Type C tested. The shear valve isolates the TIP tubing by shearing the tube and drive cable and jamming the sheared ends of the tubing into a teflon coating on the shear valve disc. The shear valve cannot be Type C tested without destroying the drive tube. However, a valve from each lot of shear valves is leak rate tested prior to delivery. If the valve fails to meet the leakage criteria, the entire lot of shear valves is rejected. The explosive charges that operate the shear valves are in-service tested in accordance with the requirements of the ASME Code.

20. The CRD insert and withdraw line design does not facilitate Type C testing.

    The lack of a Type C test is justified because there is not a credible failure mode that could cause air to be released through the subject containment penetrations. The insert and withdraw lines are connected to the CRDs that are located at the bottom of the reactor pressure vessel. Analyses have shown that the insert and withdraw lines will not fail as a result of a LOCA. The lines are always water filled.

21. The valve is required to operate post-accident. When the valve is closed, any leakage through the valve is into a seismically qualified, Class B system. The system does not communicate with the environment and is in an area served by the Standby Gas Treatment system. A water seal is maintained in the piping submerged in the suppression pool. The containment isolation valve is tested with water. The containment isolation valve leak rate is not included in the Type B and C test acceptance criteria. The acceptance criteria for water tested valves is in the plant Technical Specifications.

22. The inboard valve is tested in the reverse direction during the Type C test. The inboard valve is tested at Pa in the accident direction during the Type A test.

23. Refer to Table 6.2-12 Note 20 and Subsection 6.2.4.3.2.2. Installation of this penetration is justified under Regulatory Guide 1.11.

24. A lead radiation shield inside the penetration nozzle and an electrical feedthrough assembly support plate act as the non-pressure retaining barrier.

25. Electrical feedthrough assemblies are screwed/compression fitted into the penetration header plate. The header plate with a double o-ring seal is bolted to the containment nozzle. The electrical feedthrough assemblies and the double o-ring are Type B tested by pressurizing with dry nitrogen.

26. The spectacle flange is installed inboard of the containment isolation valves to provide a pressurization barrier. The spectacle is normally open. The spectacle is locally testable via dual o-ring seals with an intermediate pressure tap.

27. See Table 6.2-12a for the excess flow check valve number(s).

28. The number in parenthesis indicates the number of individual caps or excess flow check valves in the penetration.

TABLE 6.2-22

LEAKAGE RATE TEST LIST

29. Test pressure is applied between the valve disc.

30. For these penetrations, the instrument line outside the primary containment (including the associated instrument(s)) forms the isolation barrier as an "extension of primary containment." The containment boundary includes the instrument line, the respective instrument(s), and any branch lines up to and including the first closed isolation valve designated as CB or ICB on the P&ID (also see Figure 6.2-44M, detail (ZZ)).

31. For each penetration, the H_2O_2 Analyzer lines outside primary containment (including the components within the analyzer panels) provide a redundant isolation barrier in the event of a single electrical failure of both Primary Containment Isolation Valves (PCIVs). These lines up to and including the first normally closed valve are an "extension of primary containment", and are subject to the design and testing requirements for closed systems. The design of the H_2O_2 Analyzer Analyzer closed system outside primary containment is in accordance with the design requirements for such systems specified in USNRC Standard Review Plan 6.2.4 (September 1975), Containment Isolation Provisions, paragraph II.3.e, as clarified by Table 3.2-1. The integrity of the closed system and boundary valves are verified in accordance with the Leakage Rate Test Program. The closed system boundary for H_2O_2 Analyzer penetrations include the main process lines, branch connections up to the first normally closed isolation or check valve, and the analyzer panels (including the internal components and branch connections up to the first normally closed isolation or check valve). The closed system boundary between PASS and the H_2O_2 Analyzer System ends at the PASS solenoid operated isolation valves that form the Seismic Category I boundary between the systems (i.e.,SV-1(2)2361, SV-1(2)2365, SV-1(2)2366, SV-1(2)2368 & SV-1(2)2369).

32. The valve inlet flange is sealed with double o-ring seals. The flange is leak rate tested (Type B) by pressurizing between the o-rings.

TABLE 6.2-23

INITIAL AND BOUNDARY CONDITIONS FOR INADVERTENT SPRAY ACTUATION STUDY

	t_{-00}	Time Zero t_0
Drywell		
Volume (Ft^3)	239600	239600
Pressure (PSIA)	13.7	34.553
Temperature (F)	135	258.5
Relative Humidity (%)	90	100
Spray Rate (GPM/ TRAINS)	0/0	10700/1
Wetwell		
Volume - Vapor Region (Ft^3)	148590	145900
- Suppression Pool (Ft^3)	131550	131550
Pressure (PSIA)	13.7	30.06
Temperature (F)	50	50
Relative Humidity (%)	100	100
Suppression Pool Free Surface Area (Ft^2)	5277	5277
Wetwell-to-Drywell Vacuum Breakers		
Number of Valve Assemblies		4 of 5
Flow Area Per Assembly (Ft^2)		2.05
Flow Coefficient		0.495
Assumed Vacuum Breaker Lifting ΔP* (psid)		2.81
Assumed Vacuum Breaker Full Open ΔP* (psid)		4.48
RHR System - Drywell Spray Mode		
Service Water Flow Rate (GPM)		9000
Service Water Temperature (F)		32
Heat Exchange Effectiveness		0.245

*Δ P measured between wetwell and drywell.

TABLE 6.2-24

INITIAL AND BOUNDARY CONDITIONS FOR DRYWELL - WETWELL BYPASS LEAKAGE STUDY

DRYWELL	
VOLUME (ft^3)	239,337
PRESSURE (psia)	16.2
TEMPERATURE (°F)	135
RELATIVE HUMIDITY (%)	20
WALL SURFACE AREA (ft^2)	19,453
LINER THICKNESS (inch)	0.25
CONCRETE (ft)	6.0
CONDENSING COEFFICIENT	UCHIDA
BYPASS LEAKAGE AREA $A/\sqrt{k}$ (ft^2) (TWO CASES)	0.0535 0.05
SUPPRESSION CHAMBER AIR SPACE	
VOLUME (ft^3)	148,589 (HIGH WATER LEVEL)
PRESSURE (psia)	16.2
TEMPERATURE (°F)	90
RELATIVE HUMIDITY (%)	100
DOWNCOMER SURFACE AREA ABOVE WATER LEVEL (ft^2)	15,902
MAIN STEAM RELIEF LINES SURFACE AREA (ft^2)	1,419.48
DOWNCOMER THICKNESS (INCH)	0.375
WALL SURFACE AREA (ft^2)	7,803
LINER THICKNESS (inch)	0.25
CONCRETE (ft)	6.0
CONDENSING COEFFICIENT	UCHIDA
CONVECTIVE COEFFICIENT	2.0
DOWNCOMER SUBMERGENCE (ft)	12
OUTSIDE AIR TEMPERATURE (°F)	105
SUPPRESSION POOL	
TEMPERATURE (°F)	90
MASS OF WATER (lbm)	8,171,315

TABLE 6.2-25

BLOWDOWN DATA AND BYPASS LEAKAGE

PHASE I (INTO DRYWELL MODEL)

MASS BLOWDOWN (lbm/sec)	212
ENTHALPY (Btu/lbm)	1,191.5

PHASE III

$A/\sqrt{k} = 0.0535\ ft^2$

Time (sec)	MASS RATE (lbm/sec)	ENTHALPY (Btu/lbm)
0	3.78	1,174.1
1000	4.61	1,181.4

$A/\sqrt{k} = 0.05\ ft^2$

Time (sec)	MASS RATE (lbm/sec)	ENTHALPY (Btu/lbm)
0	3.53	1,174.1
1000	4.31	1,181.4

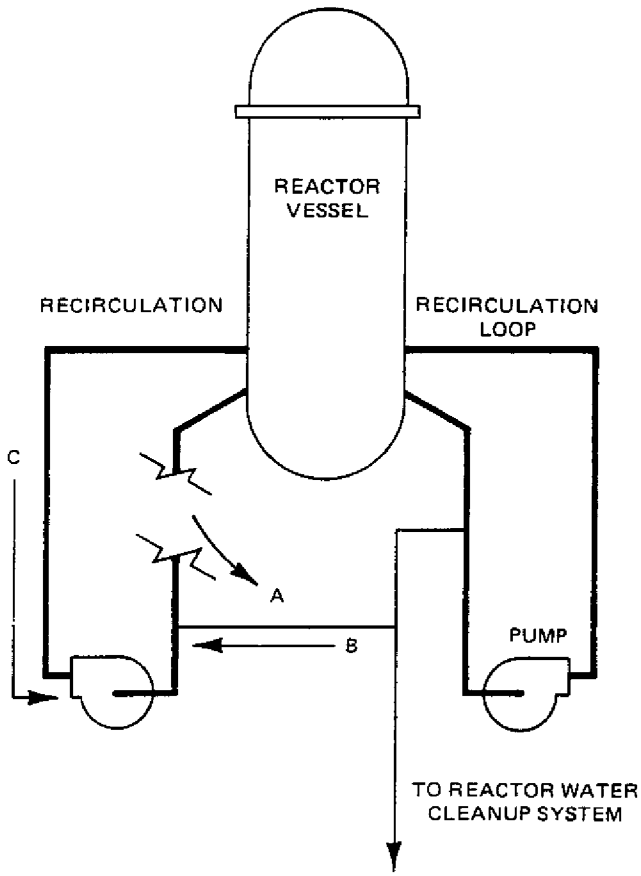
TABLE 6.2-26

LONG-TERM BLOWDOWN DATA FOR A
RECIRCULATION LINE BREAK
(CASE D)

TIME (sec)	TOTAL FLOW (lbm/sec)	FLOW ENTHALPY (Btu/lbm)
0	34830	550.0
303	8346	128.4
607	8309	134.5
1204	8324	136.9
2426	8314	143.5
3612	8317	148.9
5424	8310	155.1
7236	8319	160.0
9047	8307	163.9
10797	8315	167.1
10859	8316	167.2
10922	8318	167.3
12609	8320	169.8
14416	8316	171.9
16229	8312	173.7
18041	8309	175.2
19791	8318	176.3
21603	8322	177.2
23416	8318	177.9
25228	8312	178.5
27041	8313	179.0
28791	8316	179.3
30603	8312	179.5
32478	8314	179.7
34228	8314	179.7
36041	8316	179.7
37853	8315	179.6
39603	8313	179.4
41415	8315	179.3

POINT OF CRITICAL FLOW

A. RECIRCULATION LINE
B. CLEANUP LINE
C. COMBINED AREA OF ALL JET PUMP NOZZLES ASSOCIATED WITH THE BROKEN LOOP



SCHEMATIC SHOWING COMPOSITION OF TOTAL RECIRCULATION LINE BREAK AREA

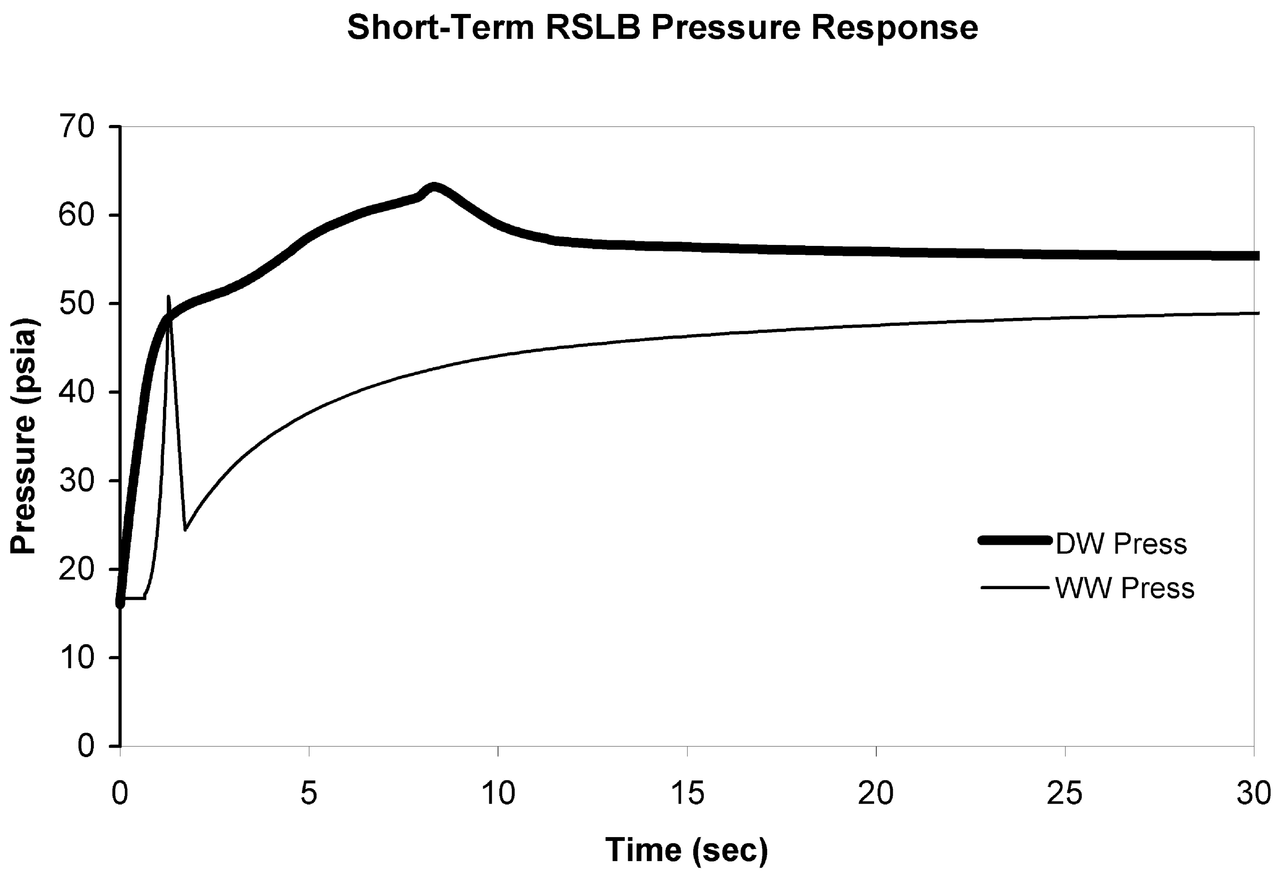
FSAR REV. 65

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

DIAGRAM OF THE
RECIRCULATION
LINE BREAK LOCATION

FIGURE 6.2-1, Rev. 49

Auto Cad: Figure Fsar 6_2_1.dwg



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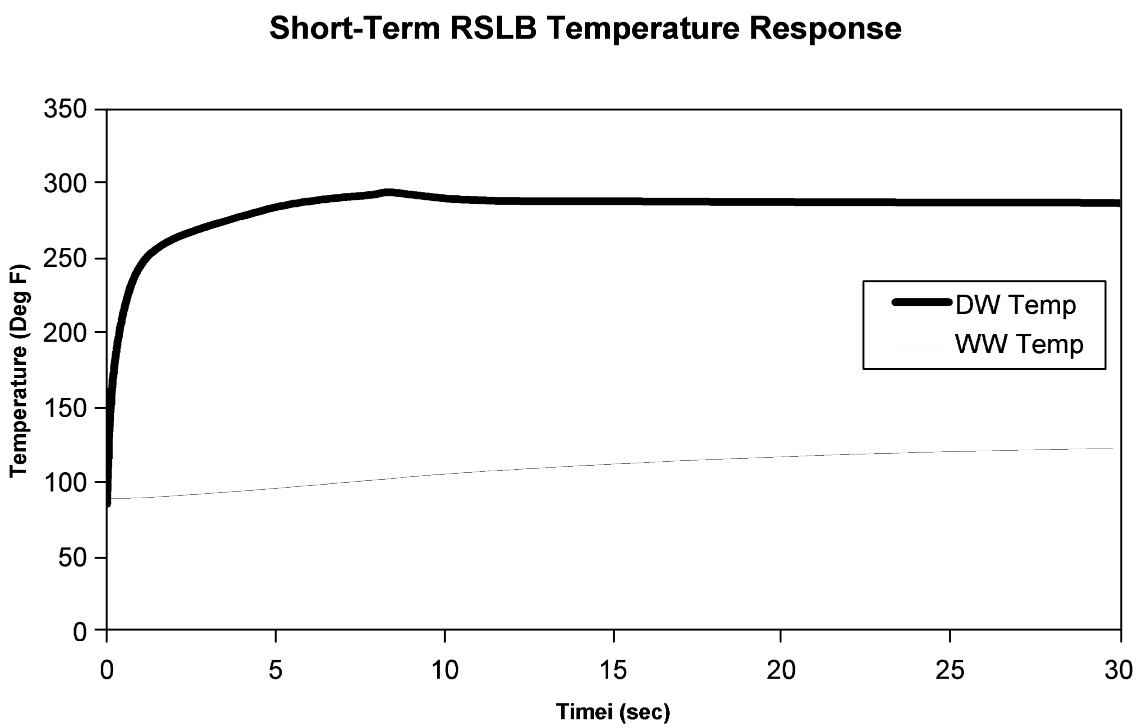
PRESSURE RESPONSE FOR
RECIRCULATION LINE BREAK

FIGURE 6.2-2, Rev. 56

Auto Cad: Figure Fsar 6_2_2.dwg



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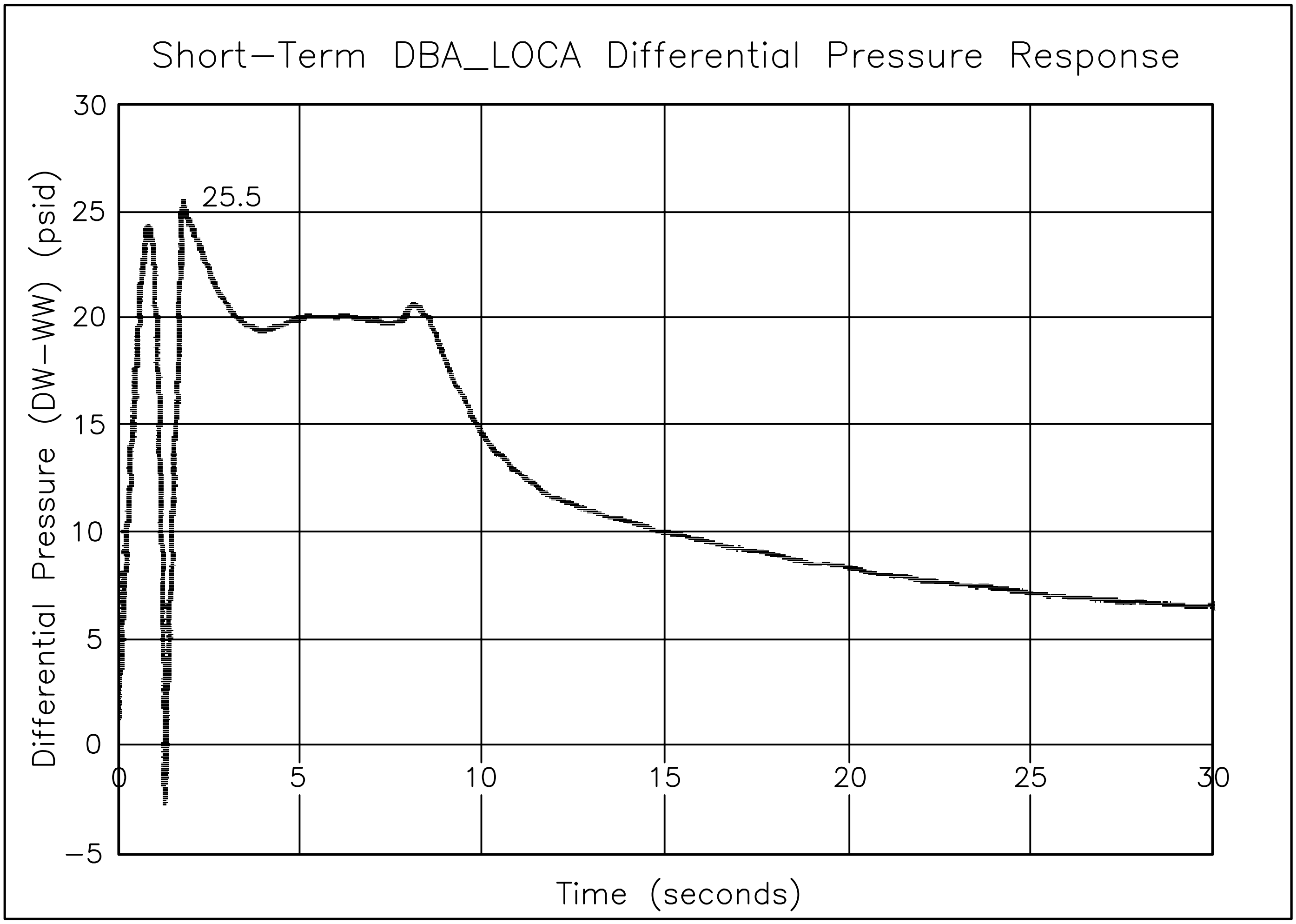
TEMPERATURE RESPONSE FOR
RECIRCULATION LINE BREAK

FIGURE 6.2-3, Rev. 56

Auto Cad: Figure Fsar 6_2_3.dwg



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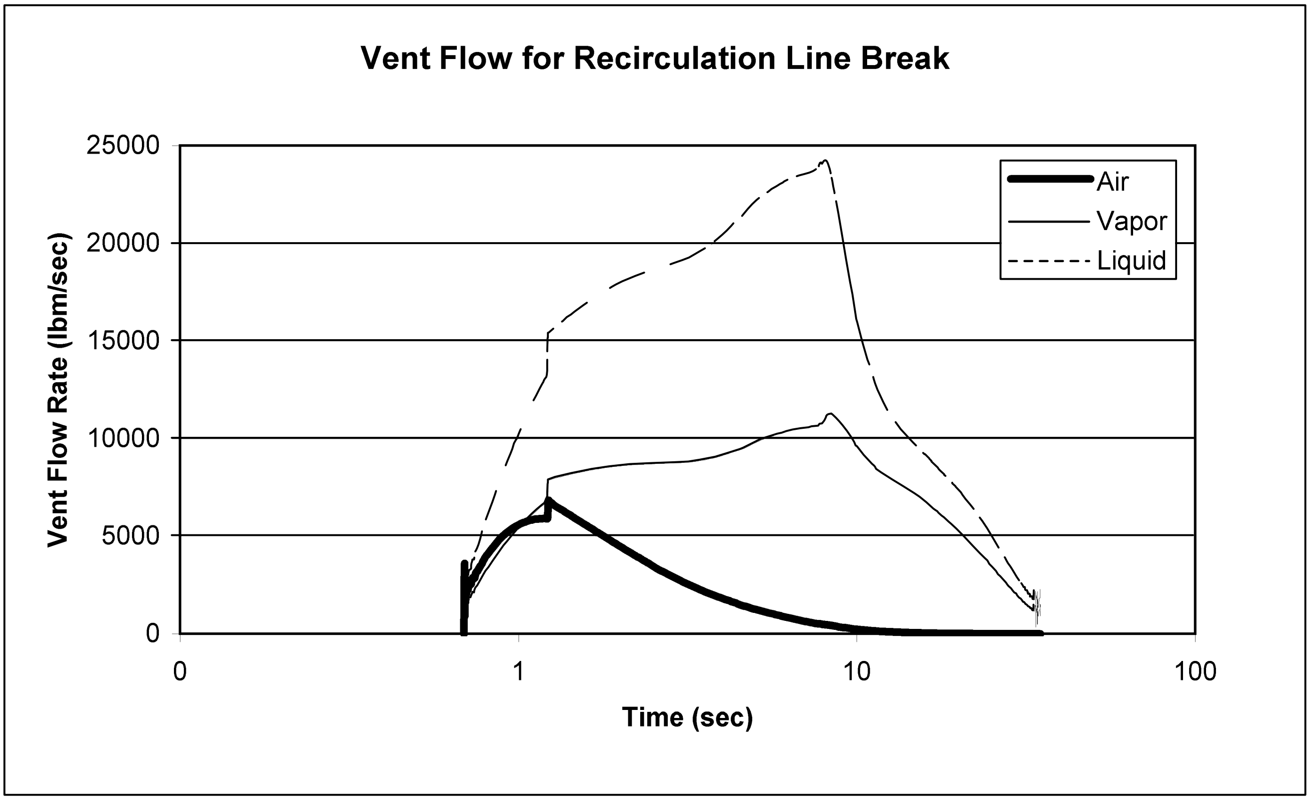
SHORT-TERM DBA-LOCA DIFFERENTIAL PRESSURE RESPONSE

FIGURE 6.2-4, Rev. 56

Auto Cad: Figure Fsar 6_2_4.dwg



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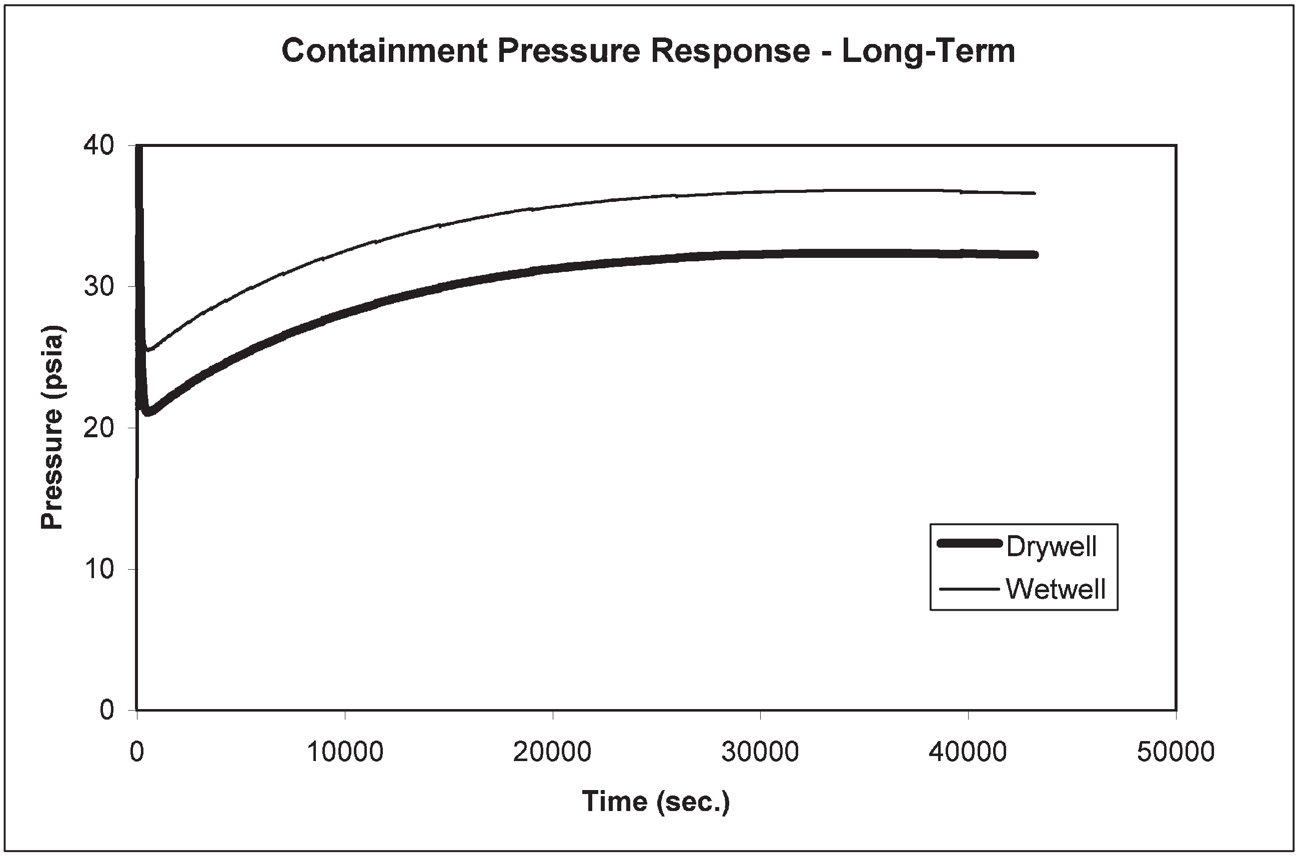
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

VENT FLOW FOR RECIRCULATION
LINE BREAK

FIGURE 6.2-5, Rev. 56

Auto Cad: Figure Fsar 6_2_5.dwg



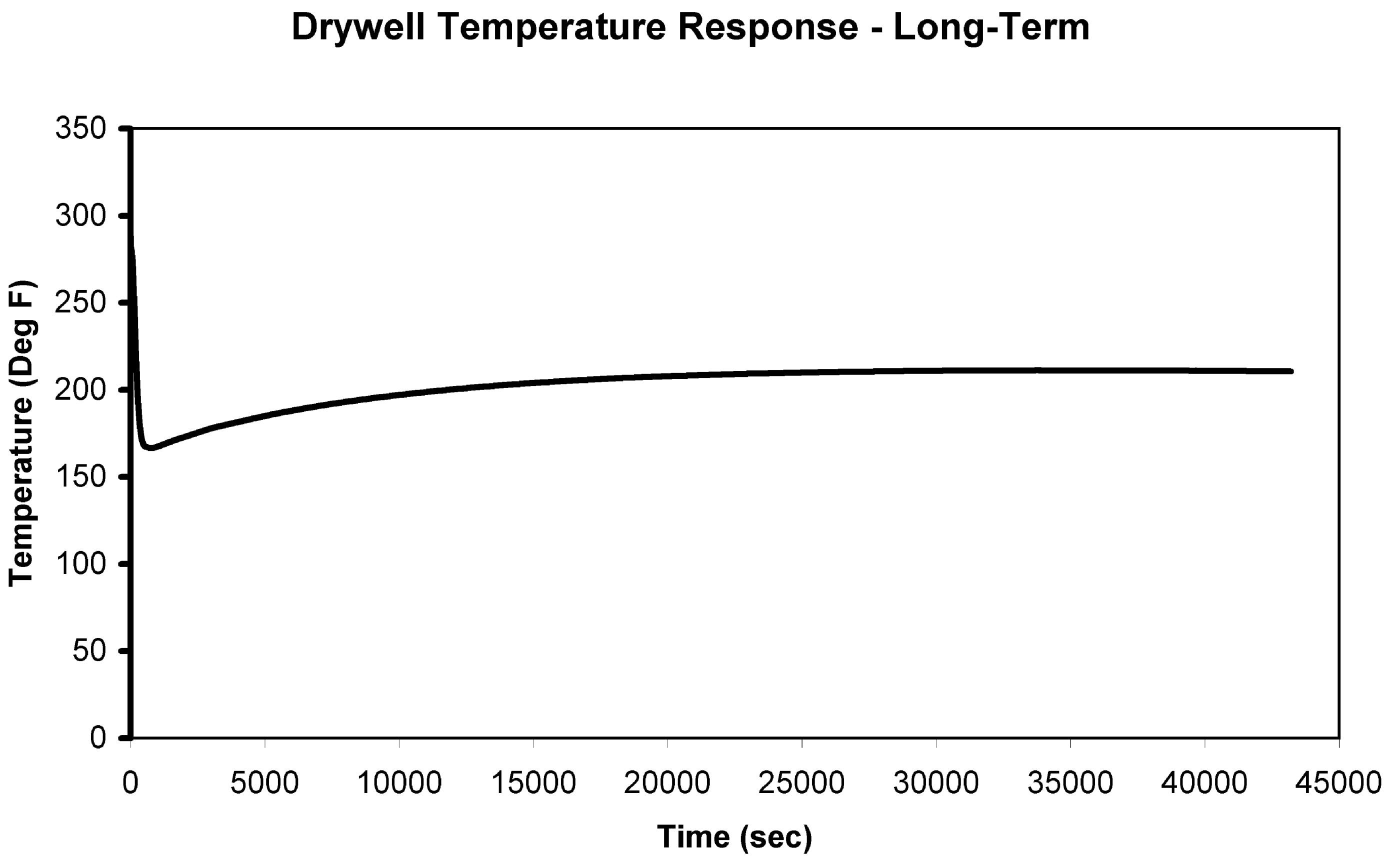
FSAR REV. 66

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

CONTAINMENT PRESSURE RESPONSE
LONG-TERM

FIGURE 6.2-6, Rev. 52

Auto-Cad: Figure Fsar 6_2_6.dwg & .tif



THIS FIGURE REPLACES FIG.
6.2-7-1, 6.2-7-2 & 6.2-7-3

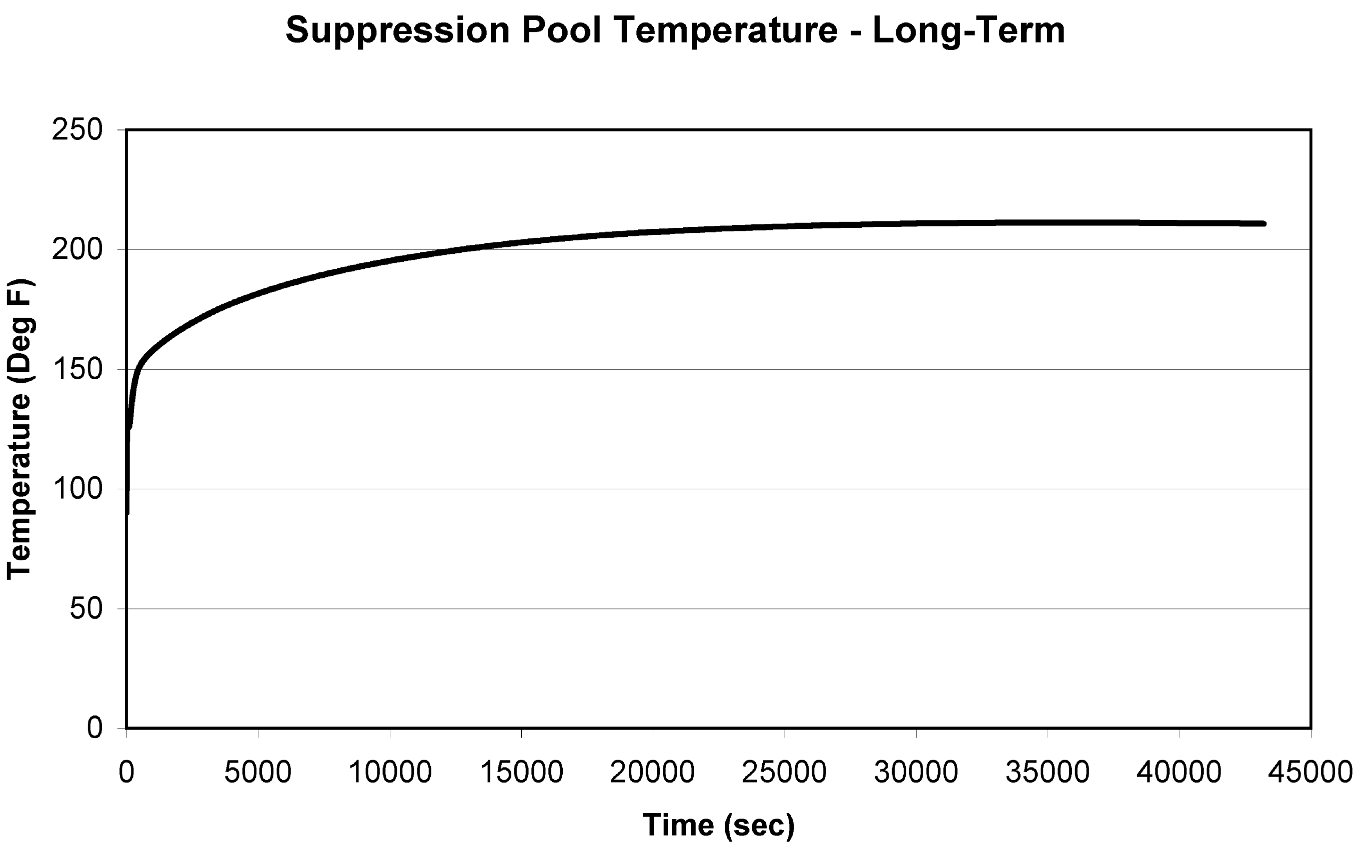
FSAR REV. 65

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

DRYWELL TEMPERATURE RESPONSE
LONG-TERM

FIGURE 6.2-7, Rev. 56

Auto Cad: Figure Fsar 6_2_7.dwg



THIS FIGURE REPLACES FIGS.
6.2-8-1, 6.2-8-2 AND 6.2-8-3

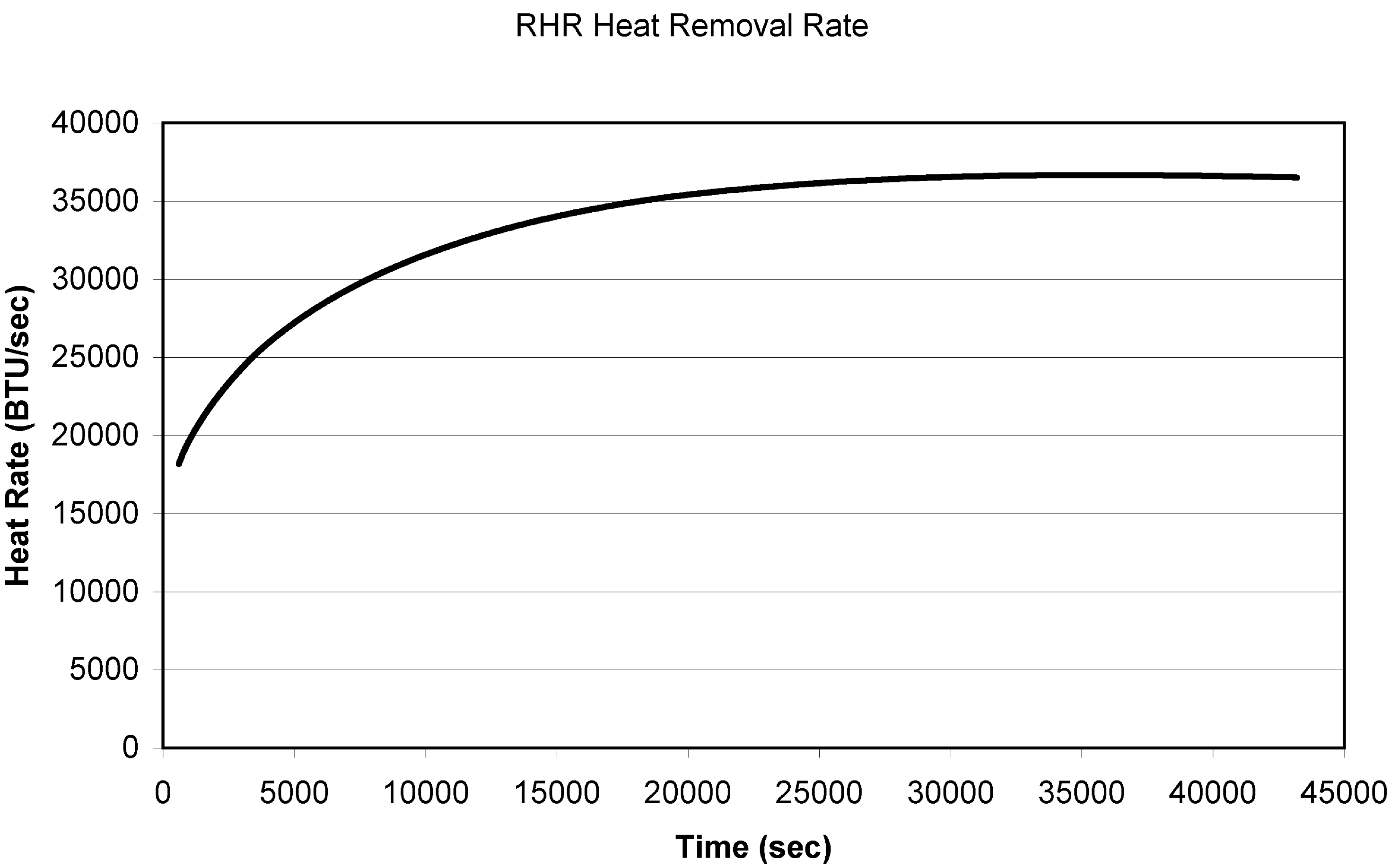
FSAR REV. 65

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

SUPPRESSION POOL TEMPERATURE
RESPONSE LONG-TERM

FIGURE 6.2-8, Rev. 52

Auto Cad: Figure Fsar 6_2_8.dwg

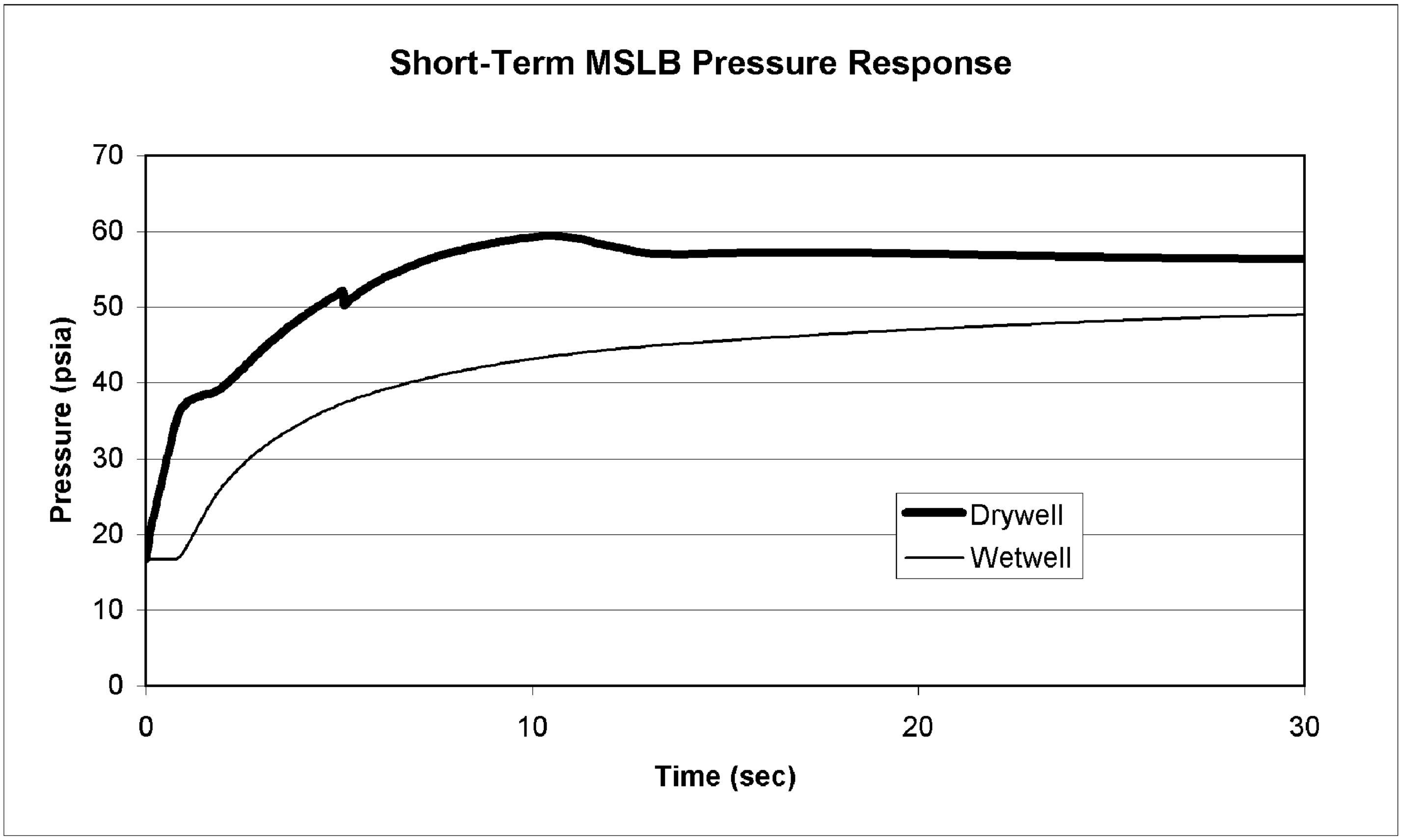


THIS FIGURE REPLACES FIGS.
6.2-9-1, 6.2-9-2 AND 6.2-9-3

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
RHR HEAT REMOVAL RATE FIGURE 6.2-9, Rev. 52

Auto Cad: Figure Fsar 6_2_9.dwg



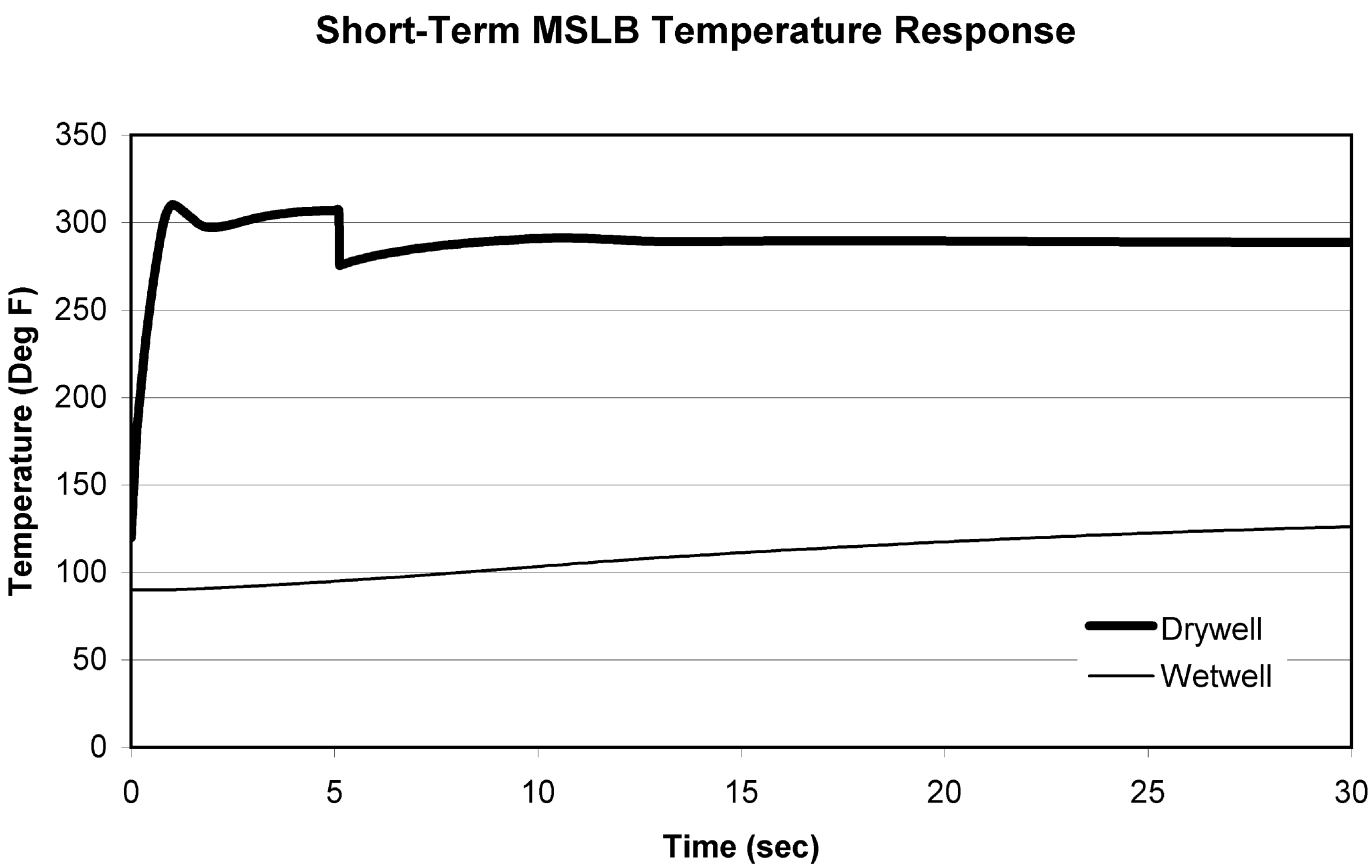
FSAR REV. 65

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

PRESSURE RESPONSE FOR
STEAMLINE BREAK

FIGURE 6.2-11, Rev. 51

Auto Cad: Figure Fsar 6_2_11.dwg



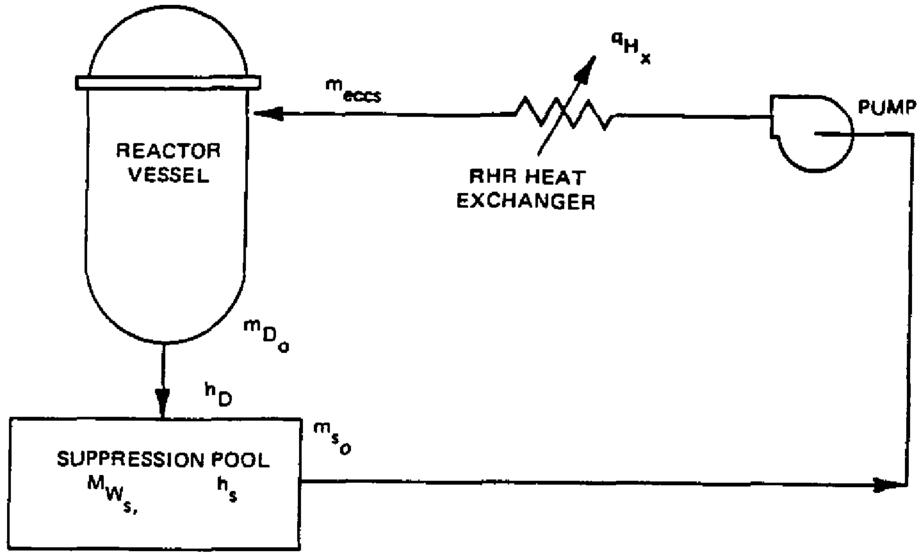
FSAR REV. 65

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

TEMPERATURE RESPONSE FOR MAIN STEAMLINE BREAK

FIGURE 6.2-12, Rev. 51

Auto Cad: Figure Fsar 6_2_12.dwg



h_D = ENTHALPY OF WATER LEAVING REACTOR, Btu/lb
m_{D_o} = FLOW RATE OUT OF REACTOR, lb/sec
h_s = ENTHALPY OF WATER IN SUPPRESSION POOL, Btu/lb
m_{s_o} = FLOW OUT OF SUPPRESSION POOL, lb/sec
q_{H_x} = HEAT REMOVAL RATE OF HEAT EXCHANGER, Btu/sec
M_{W_s} = MASS OF WATER IN SUPPRESSION POOL
q_D = CORE DECAY HEAT RATE, Btu/sec
q = STORED ENERGY RELEASE RATE, Btu/sec

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

SCHEMATIC OF ECCS LOOP

FIGURE 6.2-16, Rev. 49

Auto Cad: Figure Fsar 6_2_16.dwg

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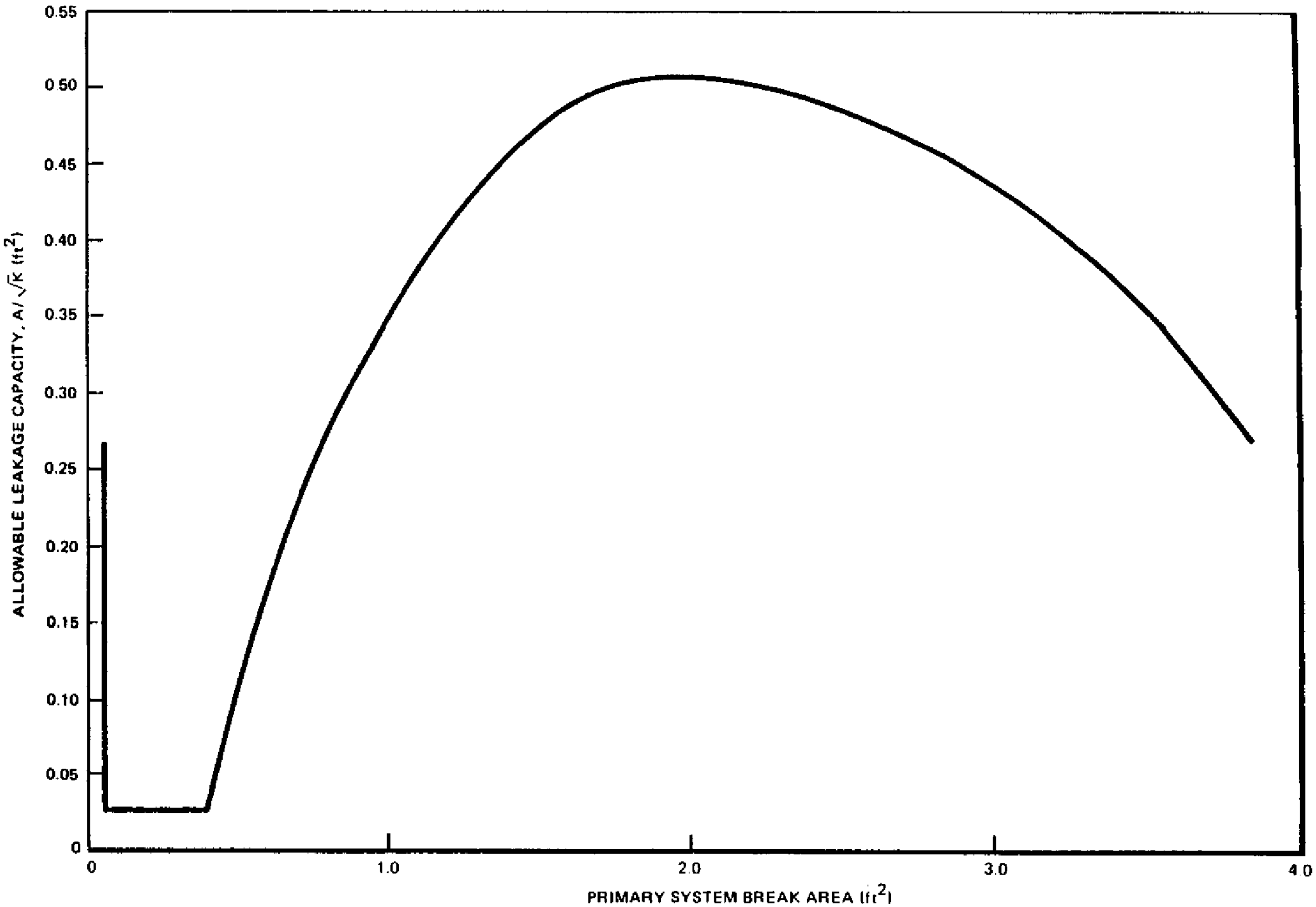
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

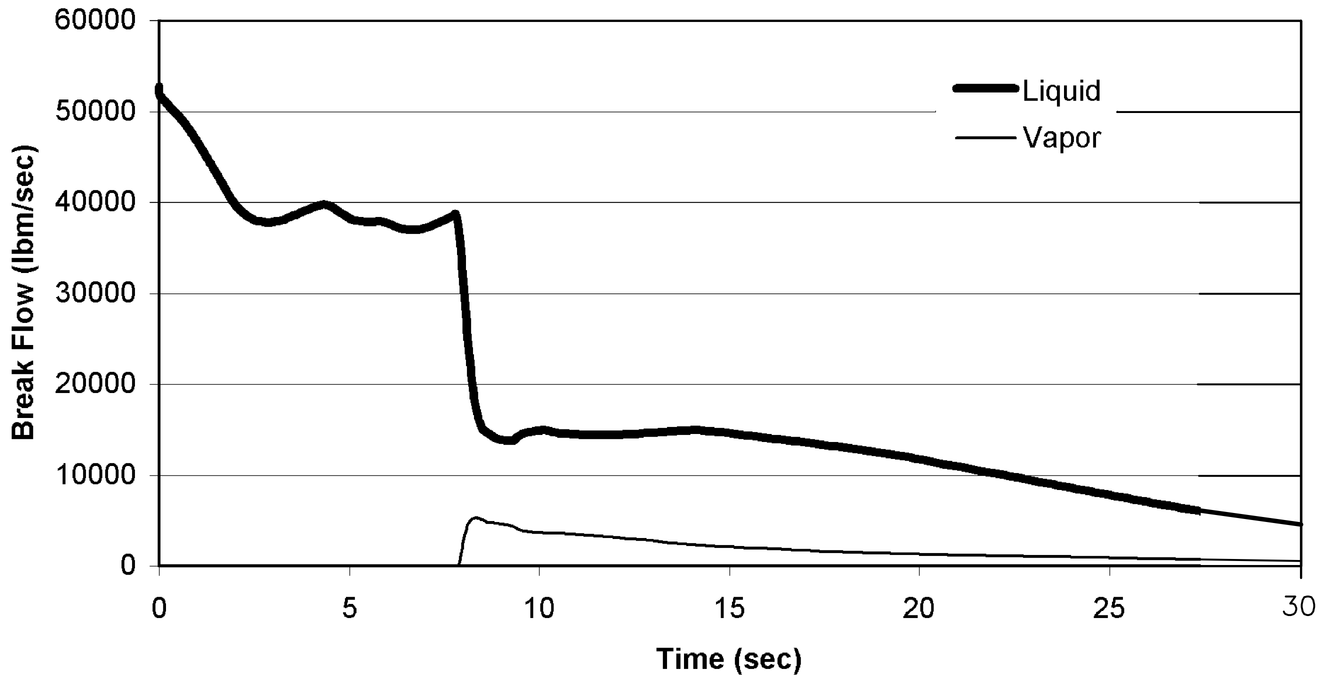
ALLOWABLE LEAKAGE CAPACITY

FIGURE 6.2-17, Rev. 49

Auto Cad: Figure Fsar 6_2_17.dwg



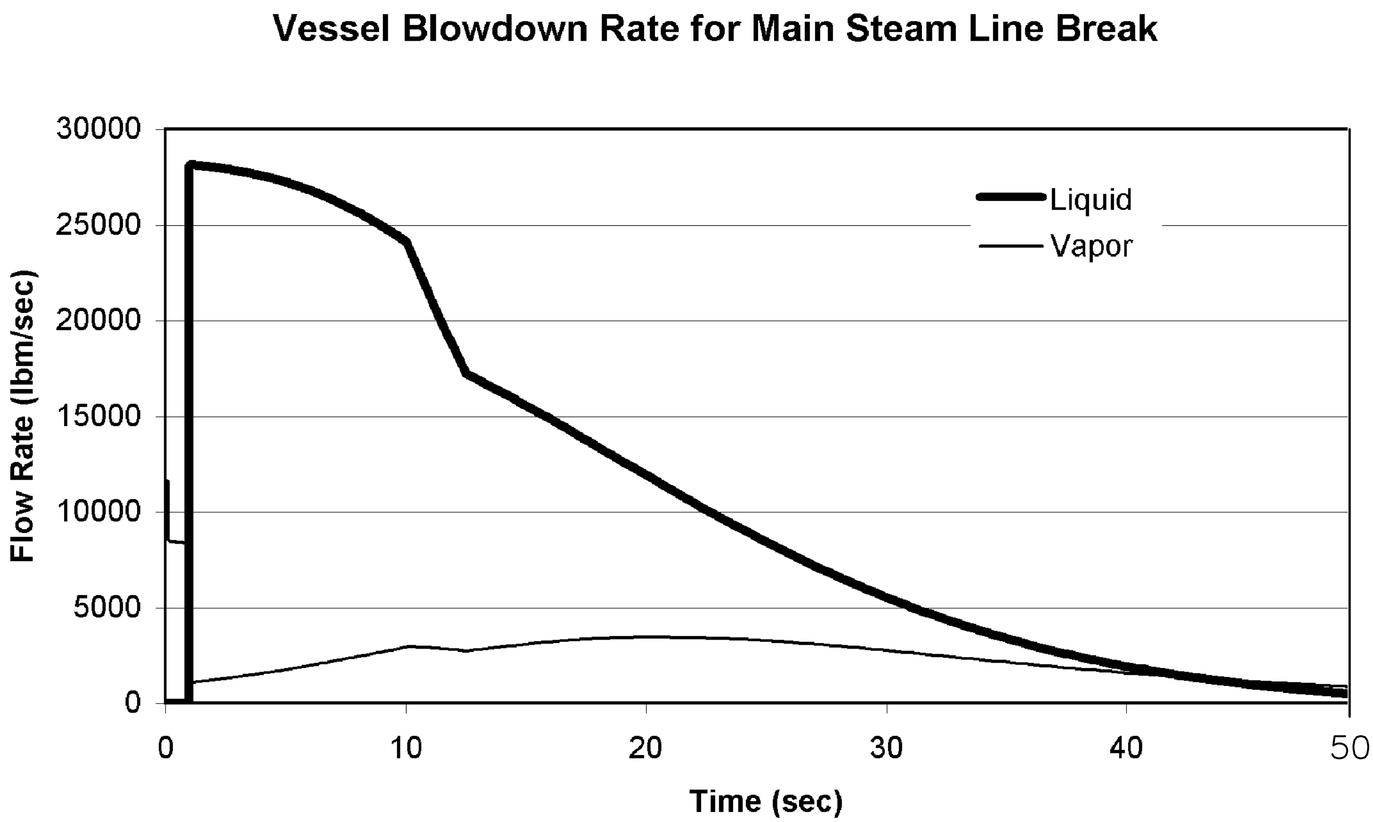
Vessel Blowdown Rate for Recirculation Line Break



FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
VESSEL BLOWDOWN RATE FOR RECIRCULATION LINE BREAK FIGURE 6.2-18, Rev. 51

Auto Cad: Figure Fsar 6_2_18.dwg



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

VESSEL BLOWDOWN RATE FOR MAIN STEAMLINE BREAK

FIGURE 6.2-20, Rev. 51

Auto Cad: Figure Fsar 6_2_20.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 EL. 645'-0" FIGURE 6.2-24

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 1
EL. 670'-0"

FIGURE 6.2-25

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 EL. 683'-0" FIGURE 6.2-26

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 EL. 719'-0" FIGURE 6.2-27

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 EL. 749'-1" FIGURE 6.2-28

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE FIGURE 6.2-29

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 EL. 818'-1" FIGURE 6.2-30

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 SECTION A-A FIGURE 6.2-31

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 SECTION B-B FIGURE 6.2-32

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 1 EL. 799'-1" FIGURE 6.2-33

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 645'-0" FIGURE 6.2-34

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 670'-0" FIGURE 6.2-35

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 683'-0"
FIGURE 6.2-36

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 719'-1" FIGURE 6.2-37

Security-Related Information
Figure Withheld Under 10 CFR 2.390

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

SECONDARY CONTAINMENT
BOUNDARY OUTLINE - UNIT 2
EL. 749'-1"

FIGURE 6.2-38

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 779'-1" FIGURE 6.2-39

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 818'-1" FIGURE 6.2-40

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 SECTION A-A FIGURE 6.2-41

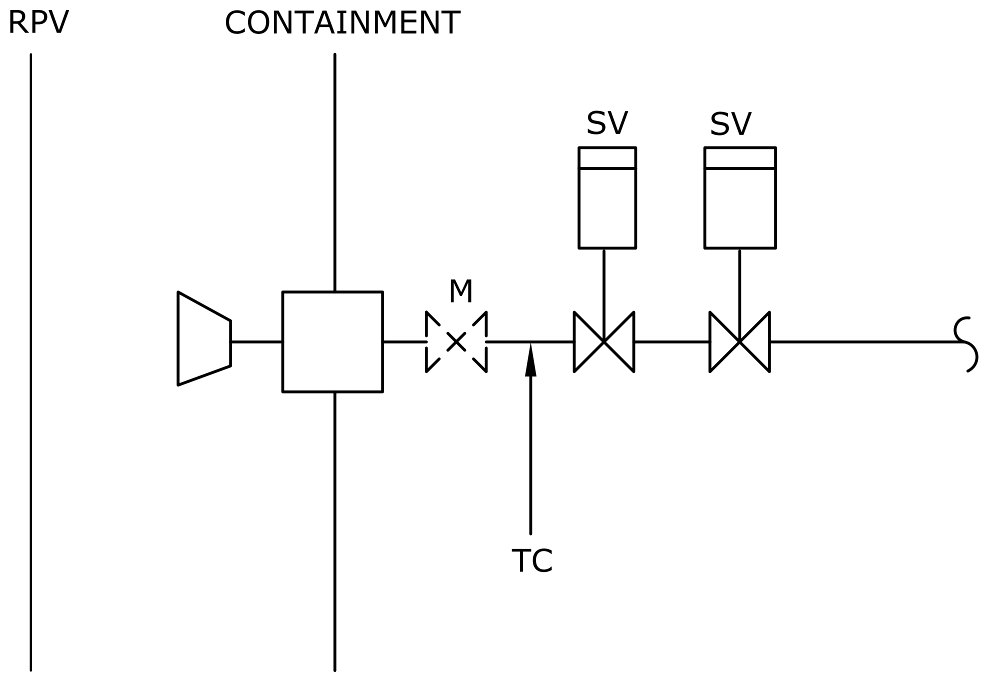
Security-Related Information

Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 SECTION B-B FIGURE 6.2-42

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
SECONDARY CONTAINMENT BOUNDARY OUTLINE - UNIT 2 EL. 799'-1" FIGURE 6.2-43



DETAIL (DD)

SV - Solenoid Valve
TC - Test Connection
M - Manual Valve

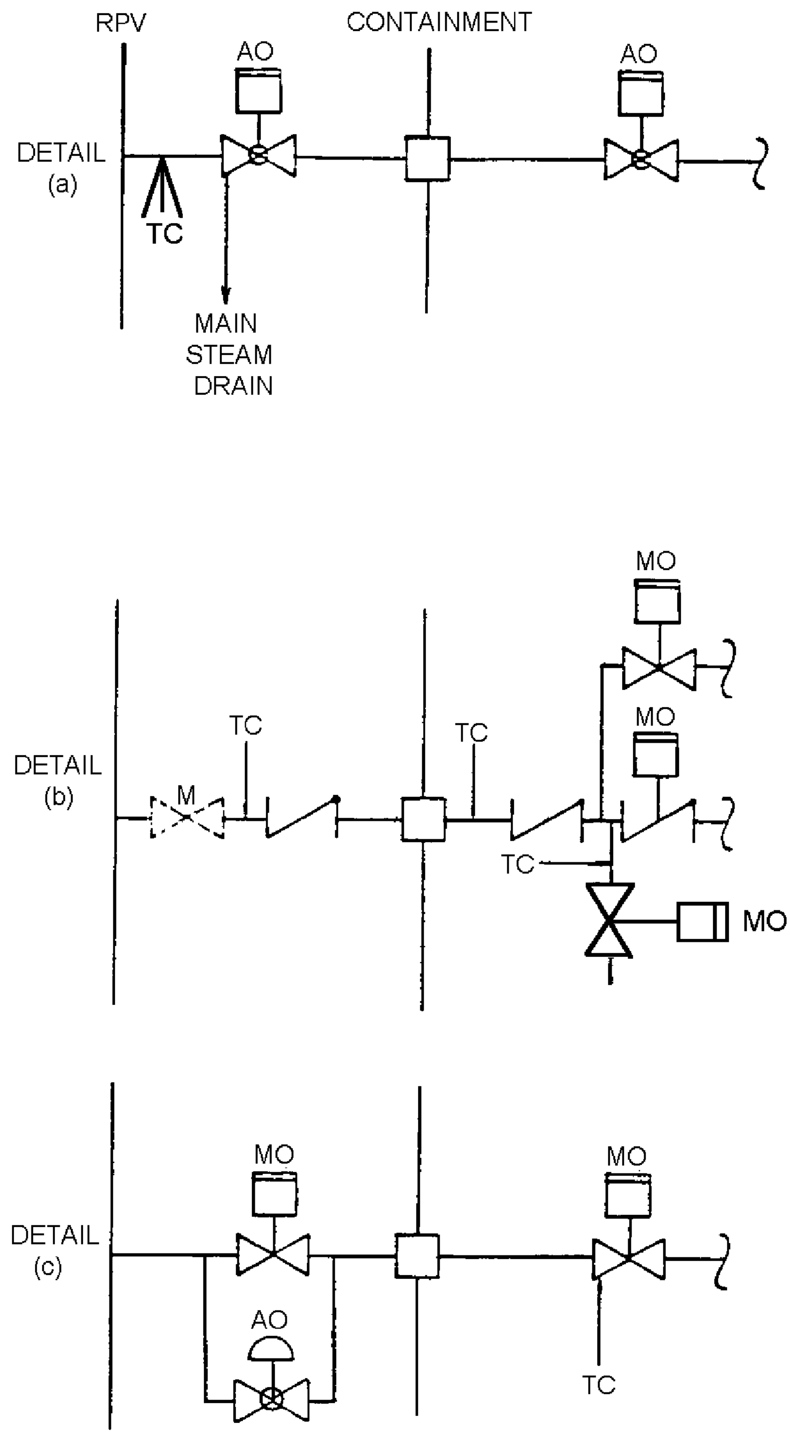
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44, Rev. 54

Auto Cad: Figure Fsar 6_2_44.dwg



MO– MOTOR OPERATED
AO– AIR OPERATED
M– MANUAL
TC– TEST CONNECTION

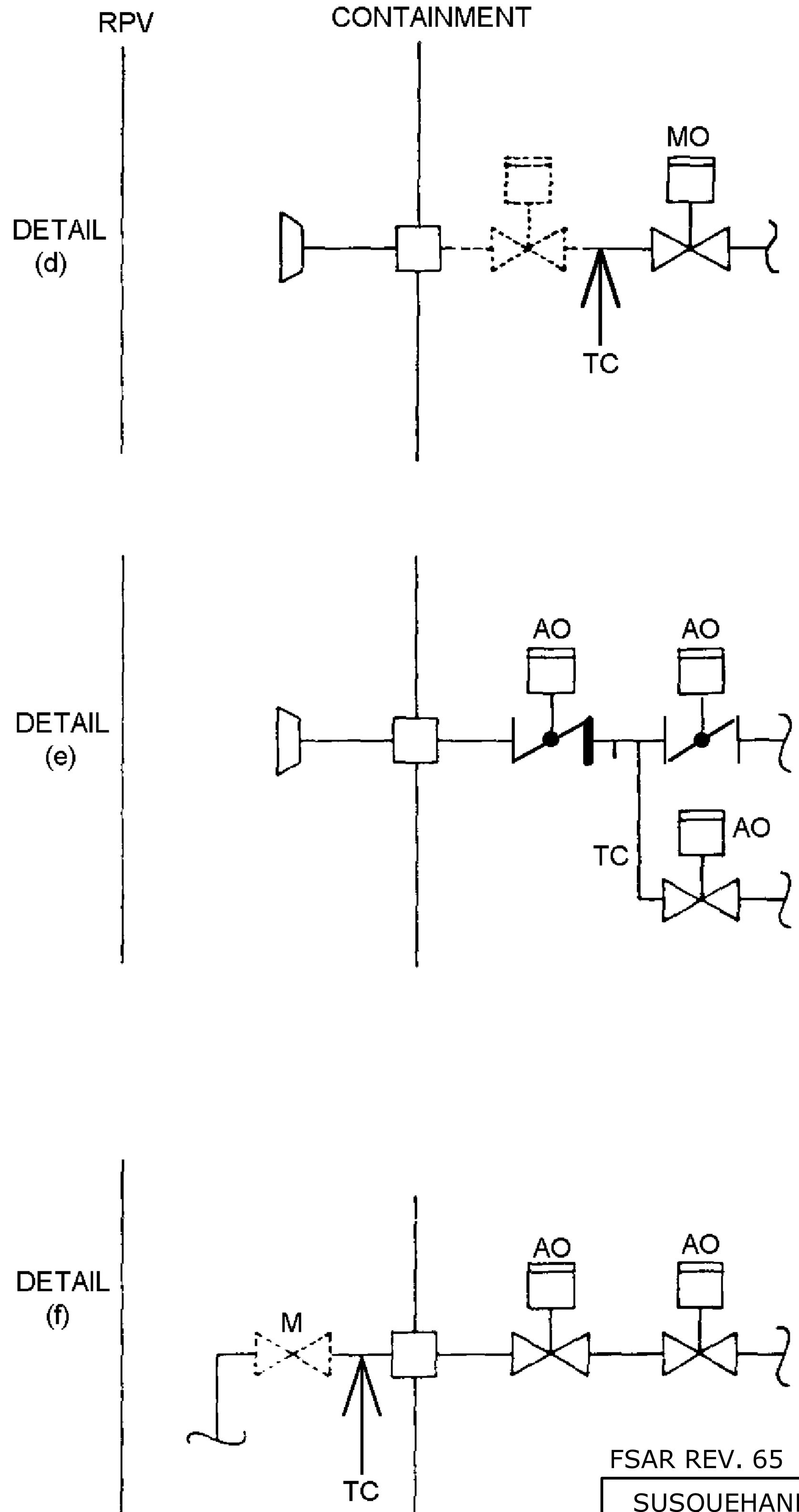
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44A, Rev. 55

Auto Cad: Figure Fsar 6_2_44A.dwg



MO– MOTOR OPERATED
AO– AIR OPERATED
TC– TEST CONNECTION
M – MANUAL

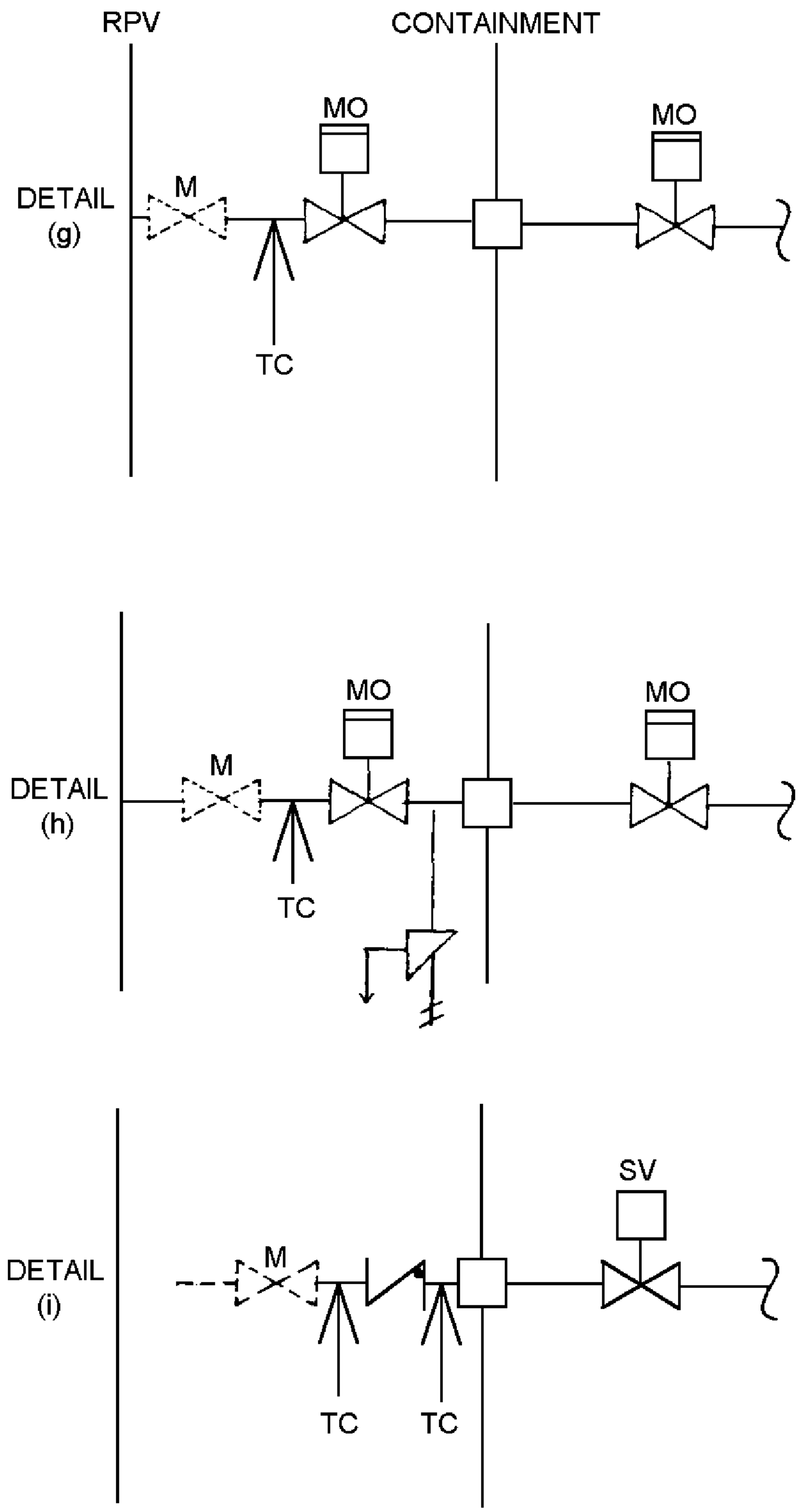
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44B, Rev. 54

Auto Cad: Figure Fsar 6_2_44B.dwg



MO - MOTOR OPERATED
TC - TEST CONNECTION
SV - SOLENLID VALVE
M - MANUAL

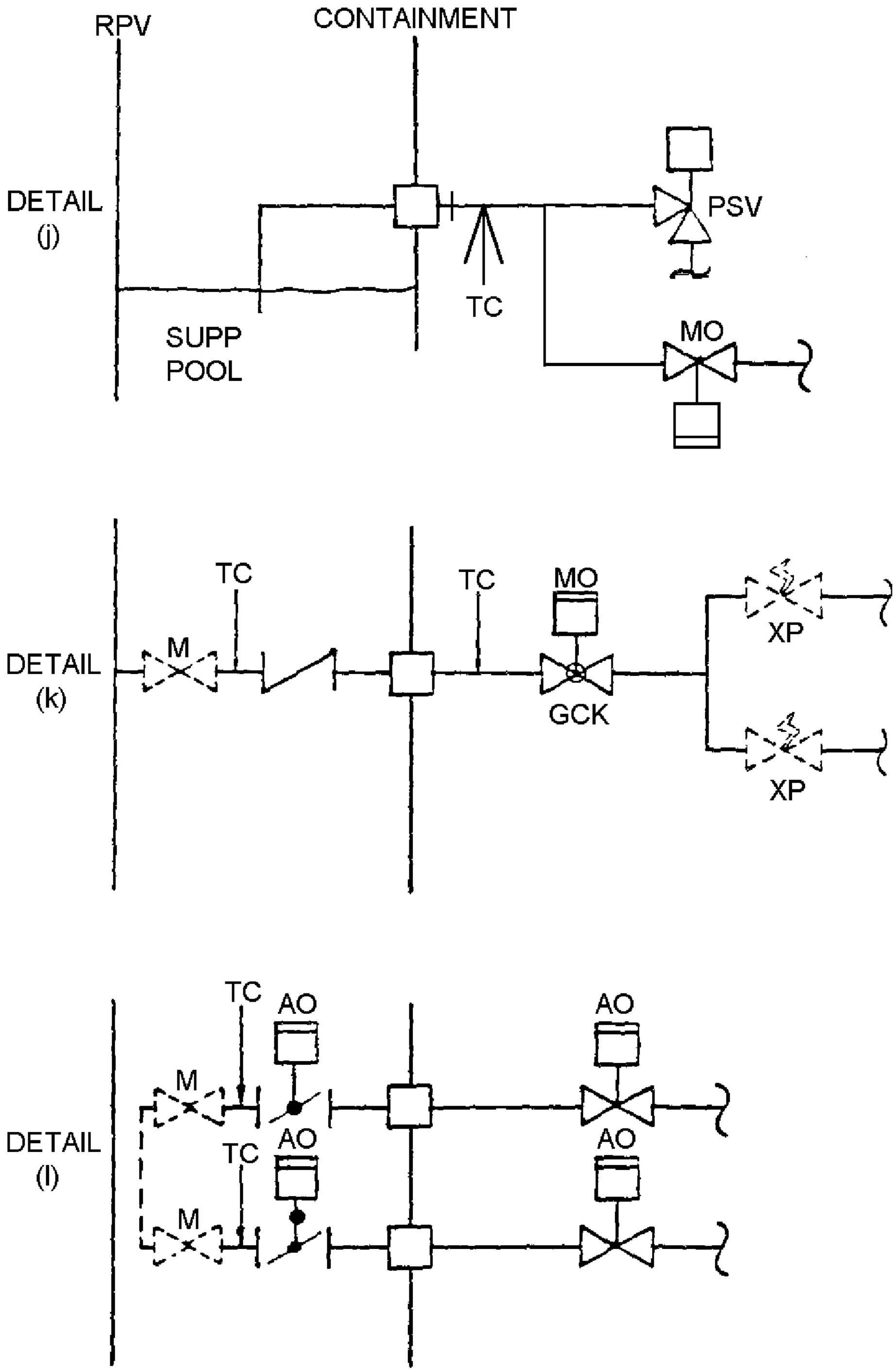
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44C, Rev. 54

Auto Cad: Figure Fsar 6_2_44C.dwg



PSV - PRESSURE SAFETY VALVE
MO - MOTOR OPERATED
M - MANUAL
TC - TEST CONNECTION
GCK - GLOBE STOP-CHECK
XP - EXPLOSIVE VALVE
AO - AIR OPERATED

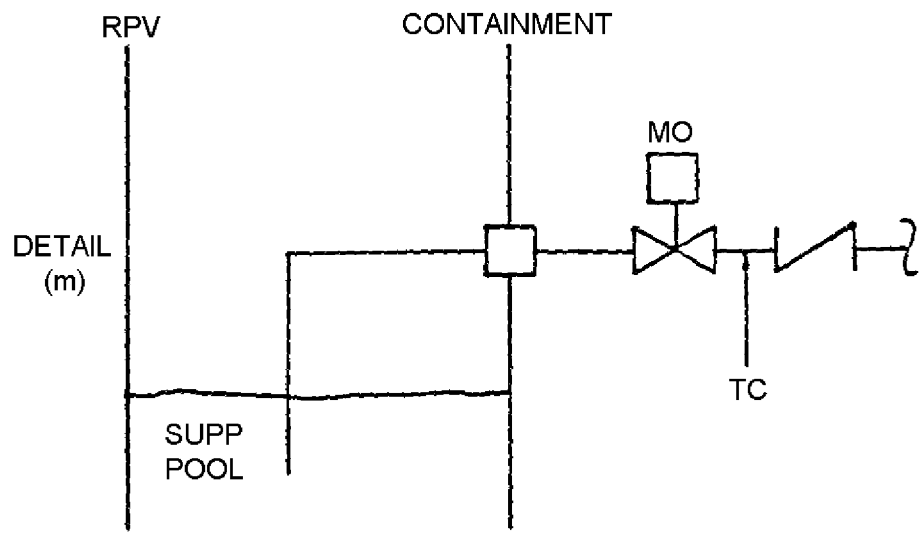
FSAR REV. 65

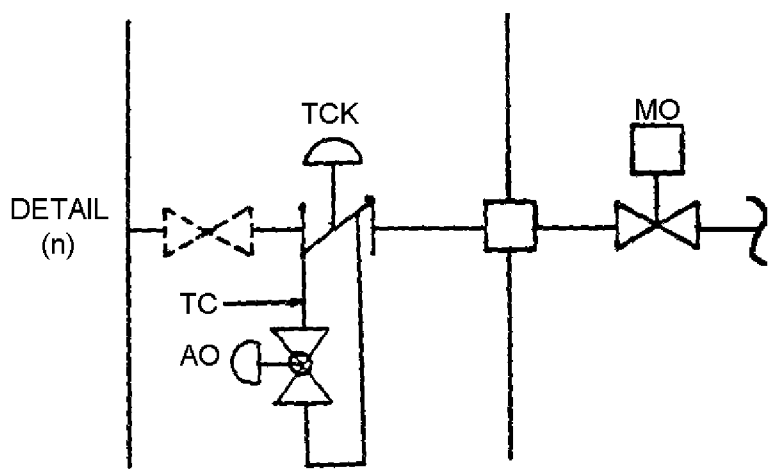
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44D, Rev. 54

Auto Cad: Figure Fsar 6_2_44D.dwg





MO - MOTOR OPERATED
TC - TEST CONNECTION
TCK - TESTABLE CHECK
AO - AIR OPERATED
M - MANUAL

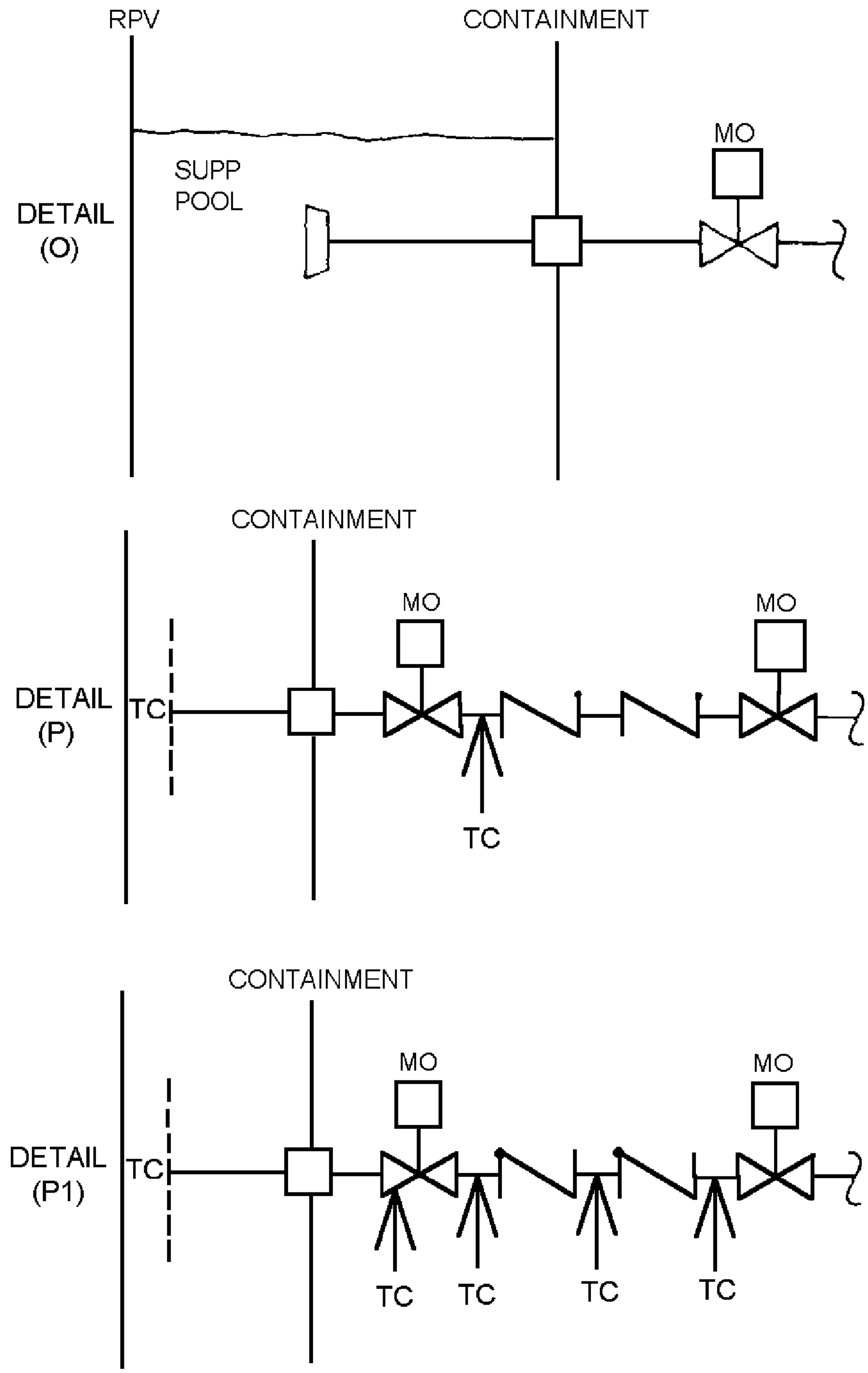
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44E, Rev. 54

Auto Cad: Figure Fsar 6_2_44E.dwg



MO - MOTOR OPERATED
TC - TEST CONNECTION

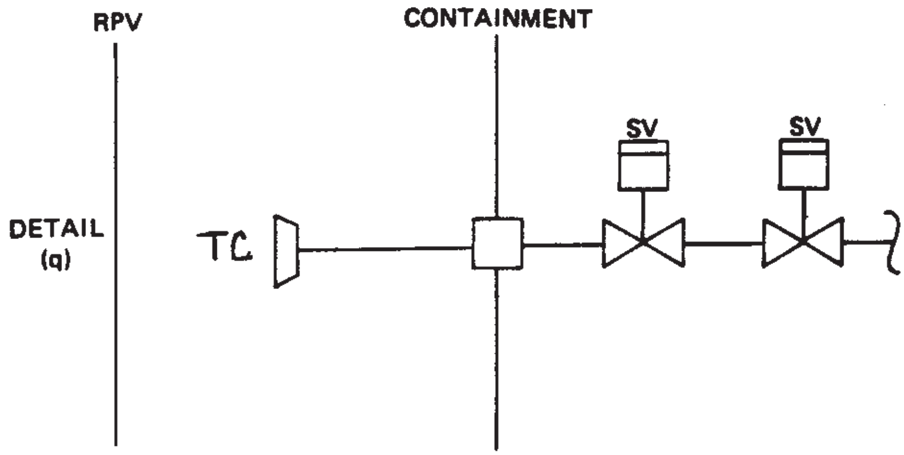
FSAR REV. 65

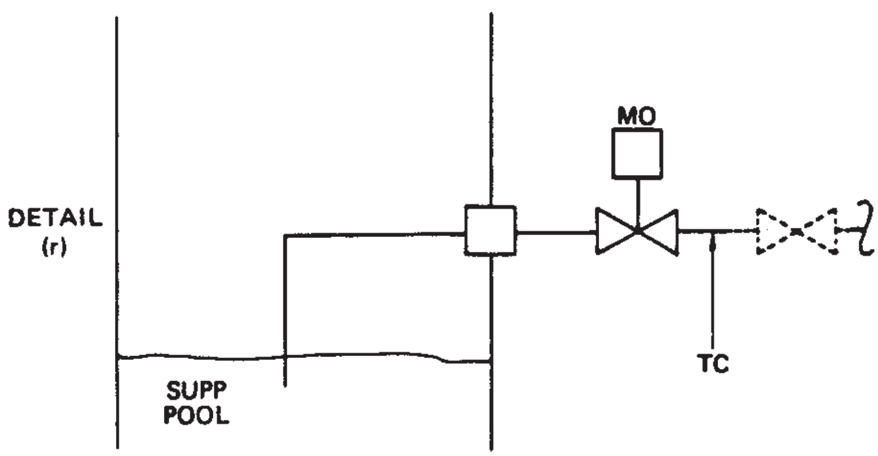
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44F, Rev. 55

Auto Cad: Figure Fsar 6_2_44F.dwg





MO – MOTOR OPERATED
SV – SOLENOID VALVE
TC – TEST CONNECTION

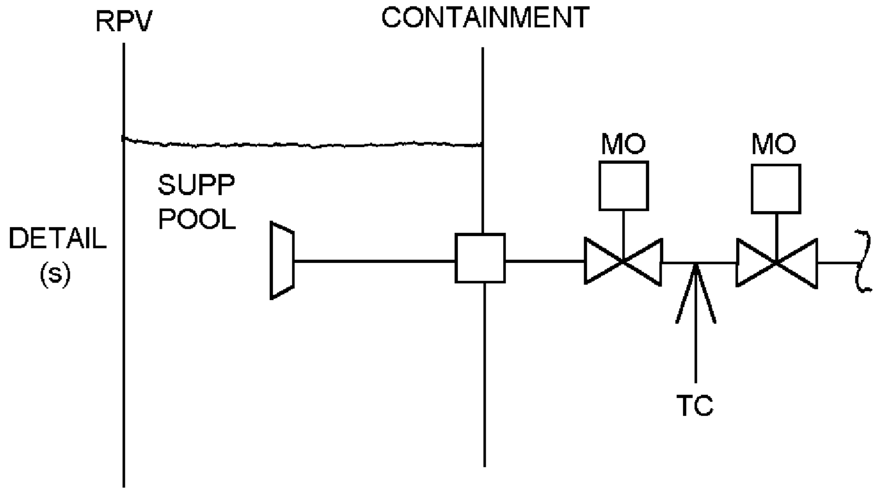
FSAR REV. 65

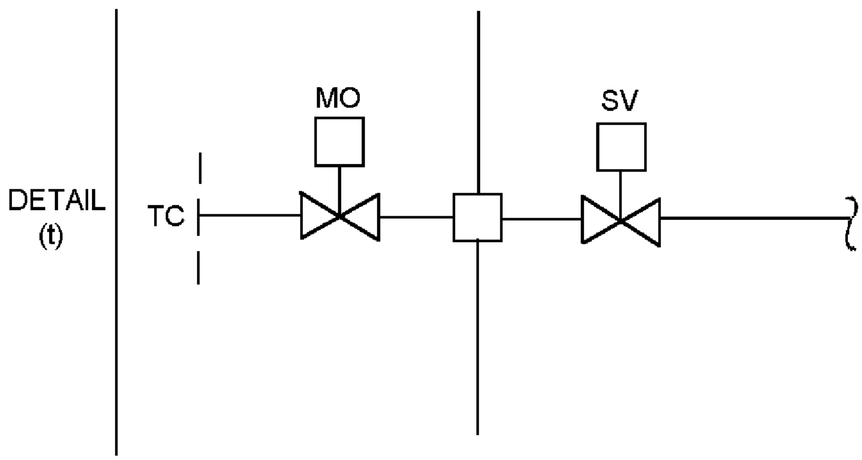
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44G, Rev. 49

Auto Cad: Figure Fsar 6_2_44G.dwg





MO - MOTOR OPERATED
SV - SOLENOID VALVE
TC - TEST CONNECTION

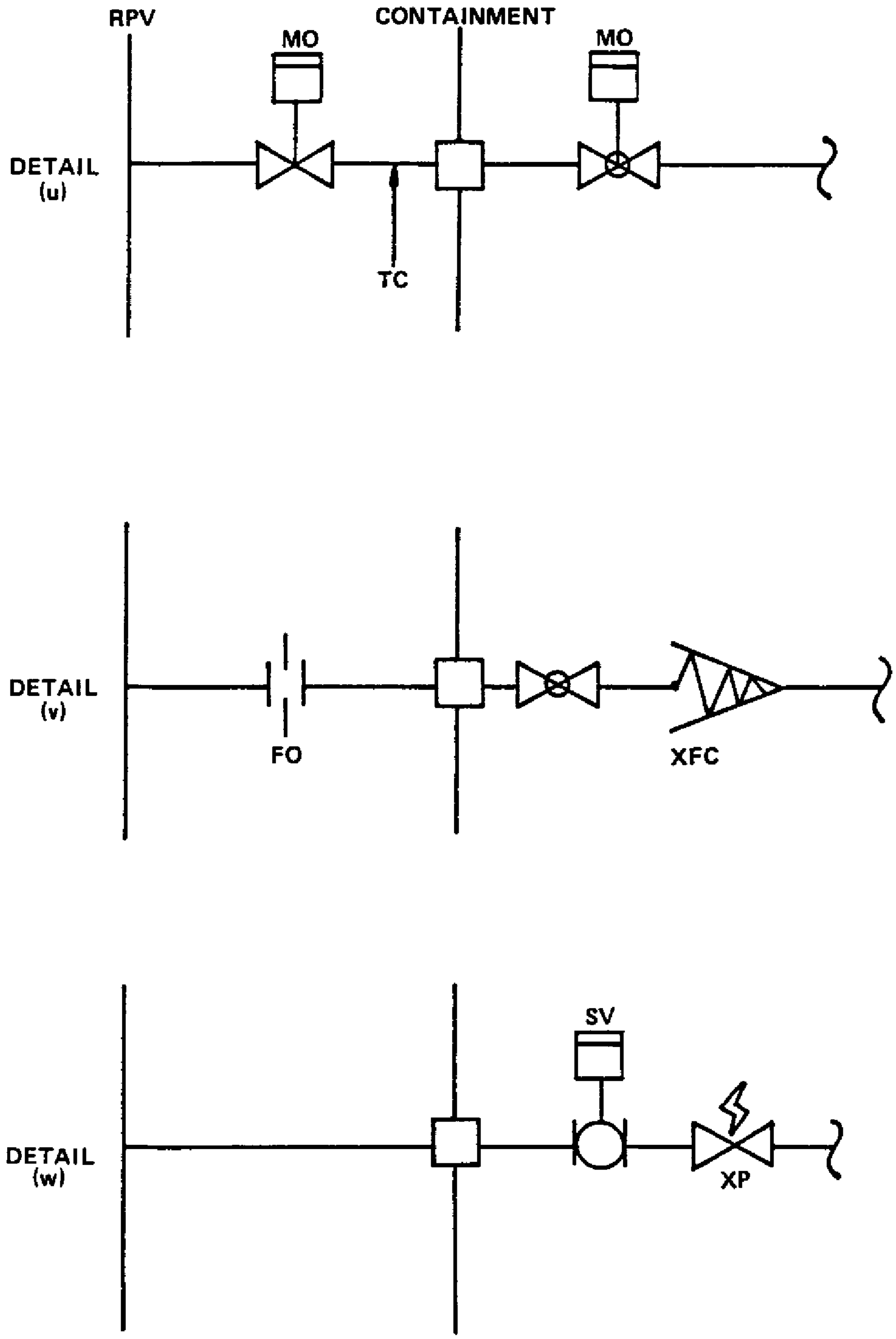
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44H, Rev. 54

Auto Cad: Figure Fsar 6_2_44H.dwg



MO – MOTOR OPERATED
SV – SOLENOID VALVE
TC – TEST CONNECTION
FO – FLOW ORIFICE
XFC – EXCESS FLOW CHECK VALVE
XP – EXPLOSIVE (SHEAR) VALVE

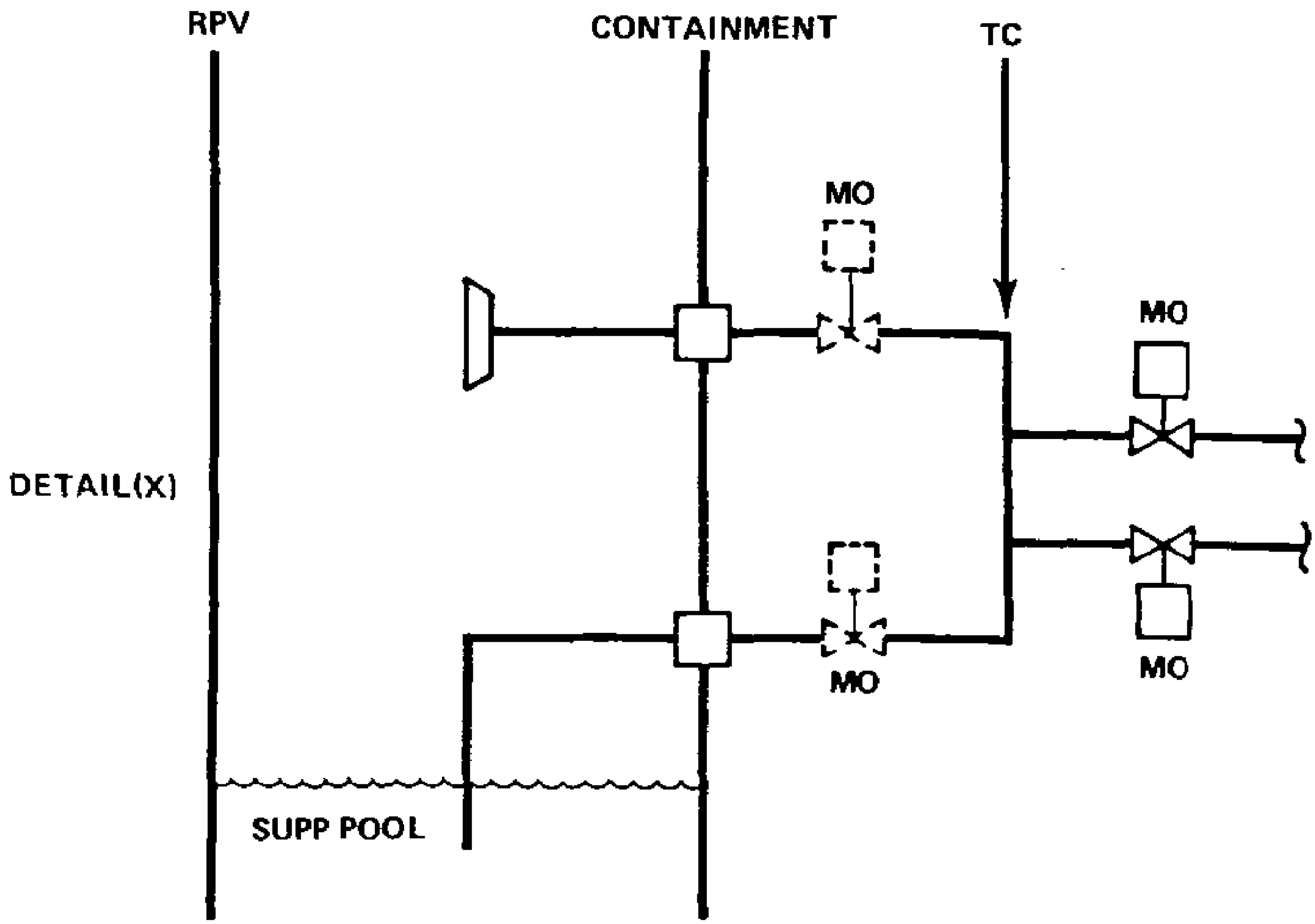
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44I, Rev. 49

Auto Cad: Figure Fsar 6_2_44I.dwg



MO - MOTOR OPERATED VALVE
TC - TEST CONNECTION

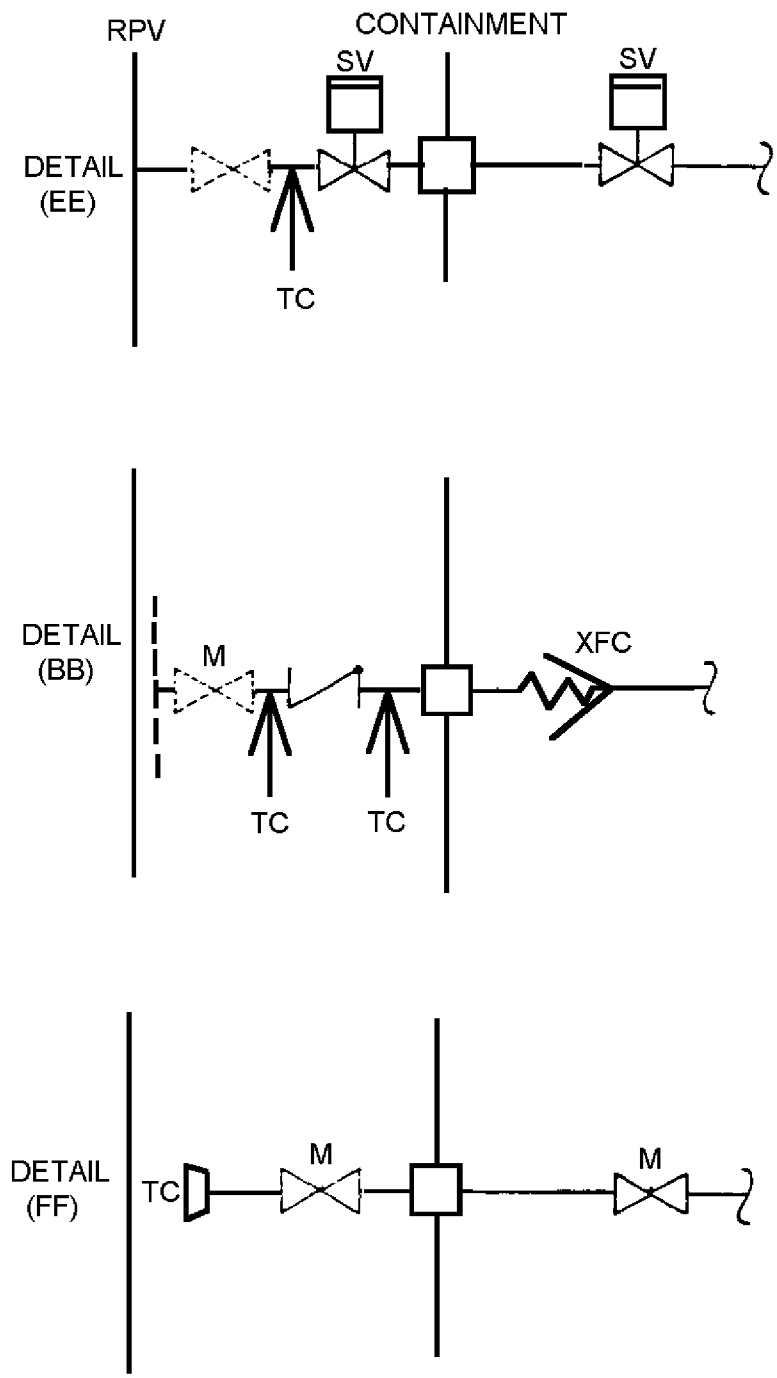
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44J, Rev. 54

Auto Cad: Figure Fsar 6_2_44J.dwg



SV - SOLENOID VALVE
M - MANUAL
TC - TEST CONNECTION
XFC - EXCESS FLOW CHECK VALVE

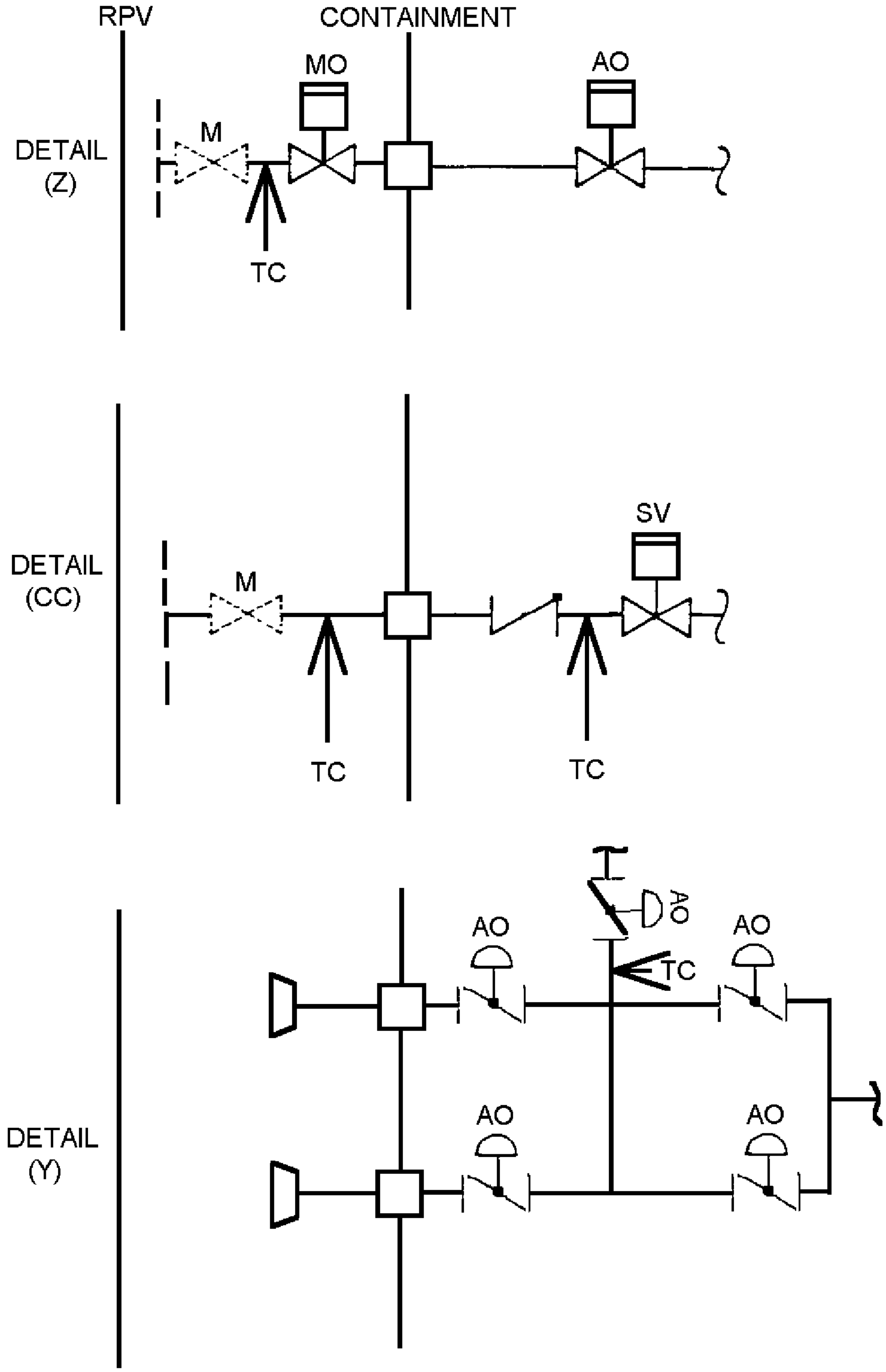
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44K, Rev. 54

Auto Cad: Figure Fsar 6_2_44K.dwg



MO - MOTOR OPERATED
M - MANUAL
TC - TEST CONNECTION
SV - SOLENOID VALVE
AO - AIR OPERATED

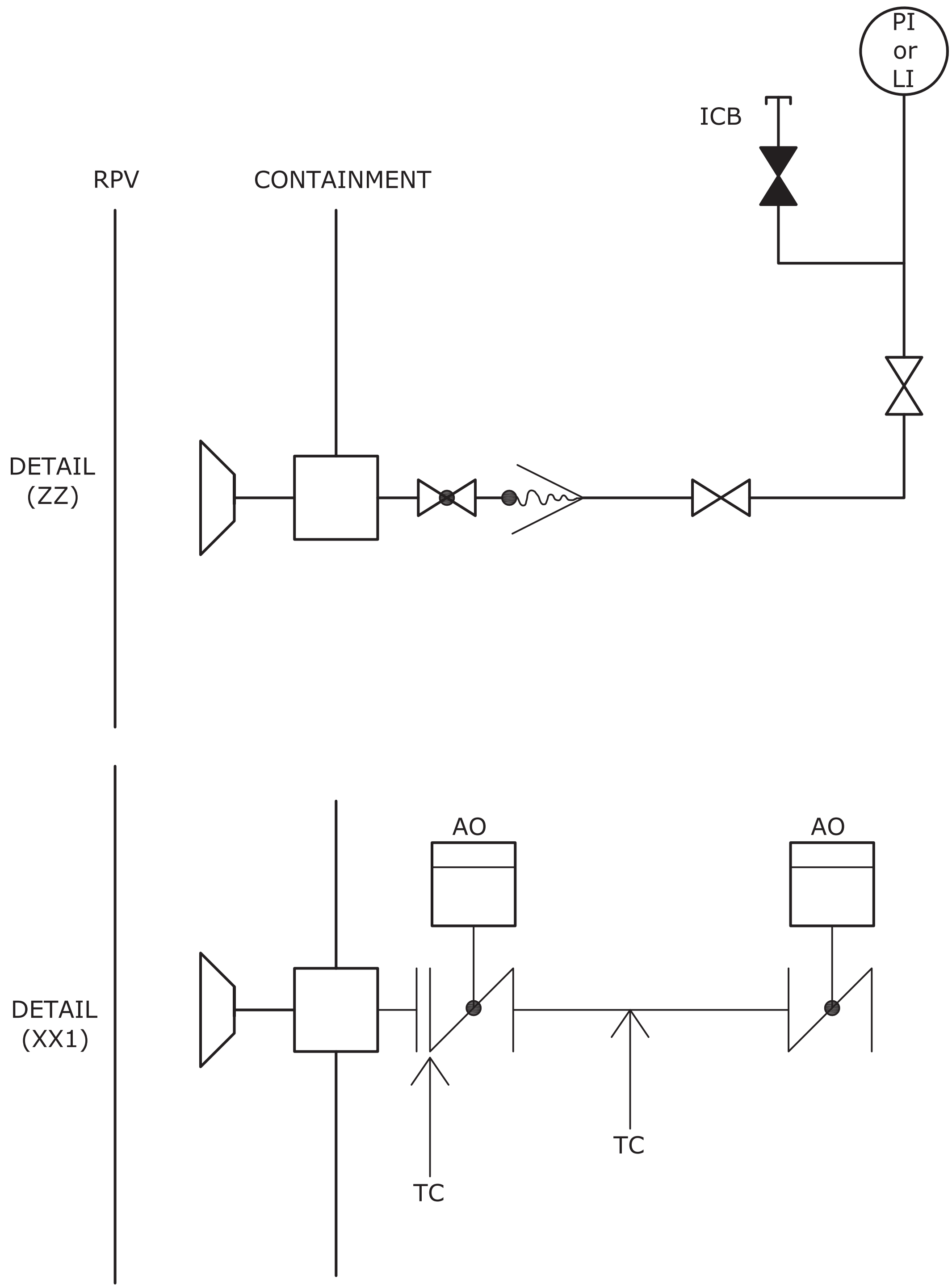
FSAR REV. 65

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44L, Rev. 54

Auto Cad: Figure Fsar 6_2_44L.dwg



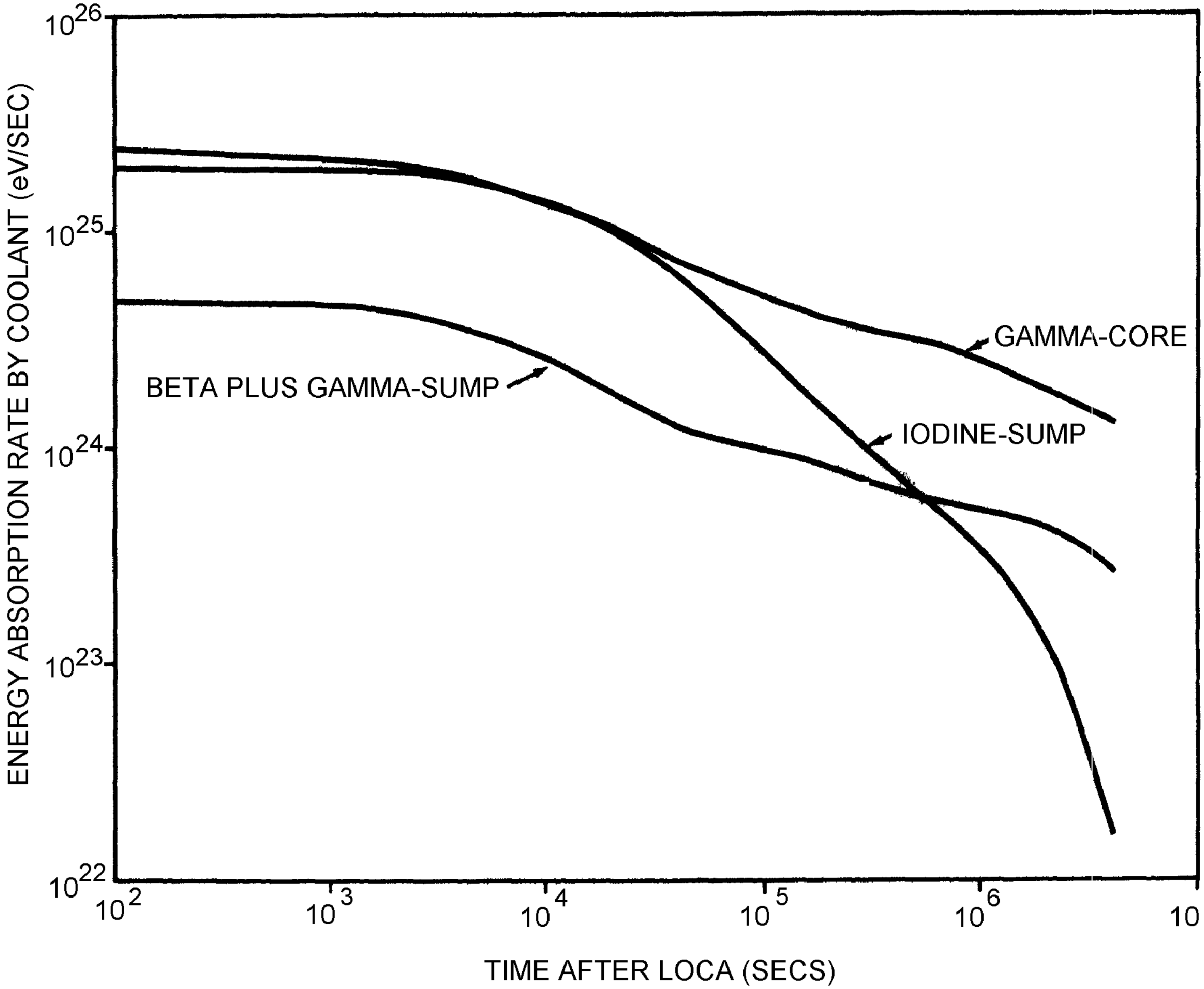
FSAR REV. 68

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

CONTAINMENT PENETRATION
DETAILS

FIGURE 6.2-44M, Rev. 56

Auto Cad: Figure Fsar 6_2_44M.dwg

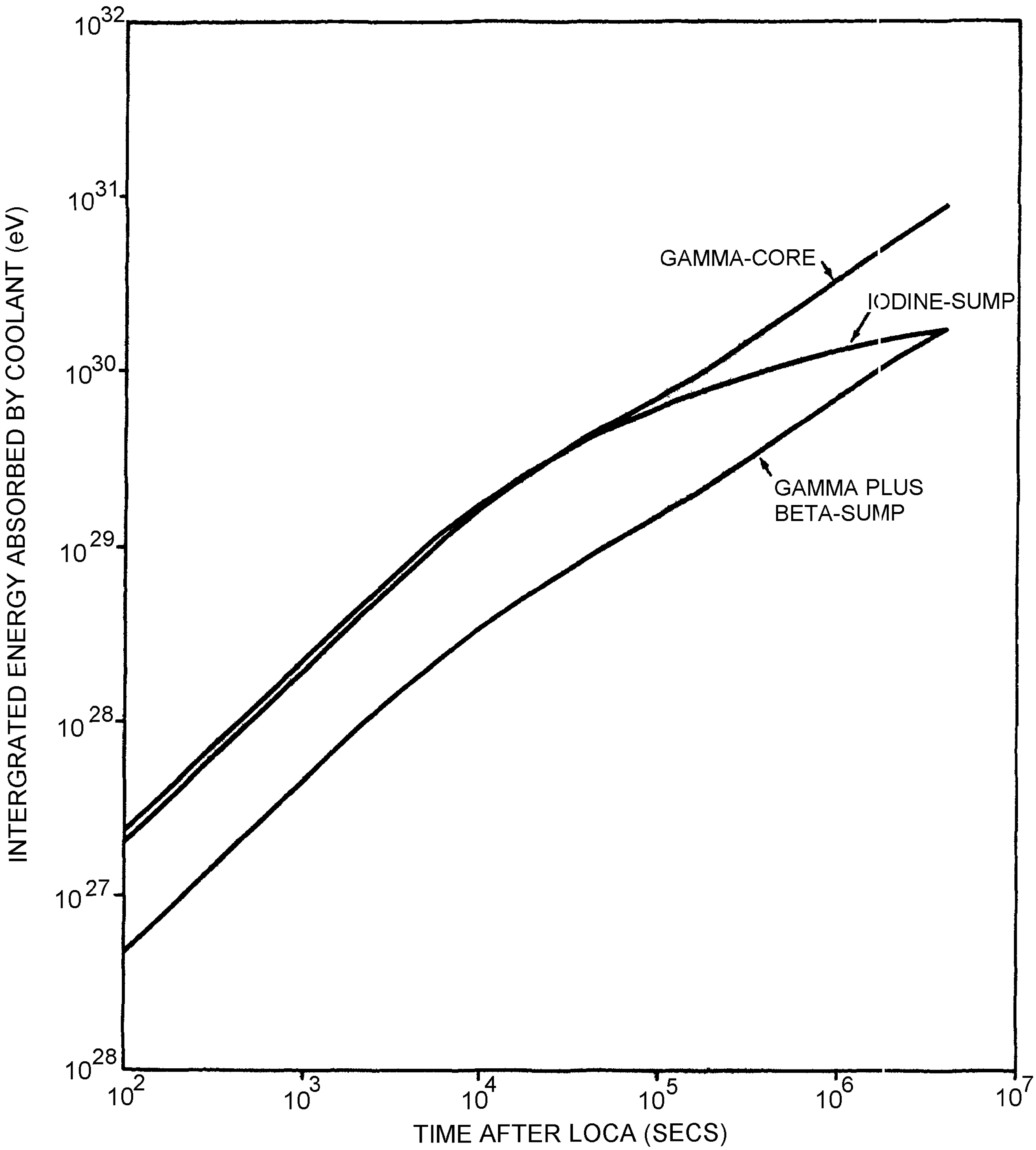


These curves are not maintained. Adsorbed energy for radiolytic hydrogen generation is now based on 102% of uprated power (101.5% of these curves).

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
ENERGY ABSORPTION RATE BY THE COOLANT VS. TIME AFTER LOCA FIGURE 6.2-46, Rev. 55

Auto Cad: Figure Fsar 6_2_46.dwg



These curves are not maintained. Adsorbed energy for radiolytic hydrogen generation is now based on 102% of uprated power (101.5% of these curves).

FSAR REV. 65

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

INTEGRATED ENERGY ABSORBED
BY COOLANT VS.
TIME AFTER LOCA

FIGURE 6.2-47, Rev. 55

Auto Cad: Figure Fsar 6_2_47.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
REACTOR BUILDING VENTILATION RECIRCULATION & STANDBY GAS TREATMENT SYSTEMS ZONE 1 & ZONE III ISOLATION FIGURE 6.2-52

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
REACTOR BUILDING VENTILATION RECIRCULATION & STANDBY GAS TREATMENT SYSTEMS NORMAL PLANT OPERATION FIGURE 6.2-53

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
REACTOR BUILDING VENTILATION RECIRCULATION & STANDBY GAS TREATMENT SYSTEMS ZONE III ISOLATION FIGURE 6.2-54

FIGURE 6.2-55A REPLACED BY DWG. M-157, SH. 1

FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
FIGURE 6.2-55A REPLACED BY DWG. M-157, SH. 1
FIGURE 6.2-55A, Rev. 56

AutoCAD Figure 6_2_55A.doc

FIGURE 6.2-55B REPLACED BY DWG. M-157, SH. 2

FSAR REV. 65

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

FIGURE 6.2-55B REPLACED BY DWG. M-157, SH. 2

FIGURE 6.2-55B, Rev. 55

AutoCAD Figure 6_2_55B.doc

FIGURE 6.2-55C REPLACED BY DWG. M-157, SH. 3

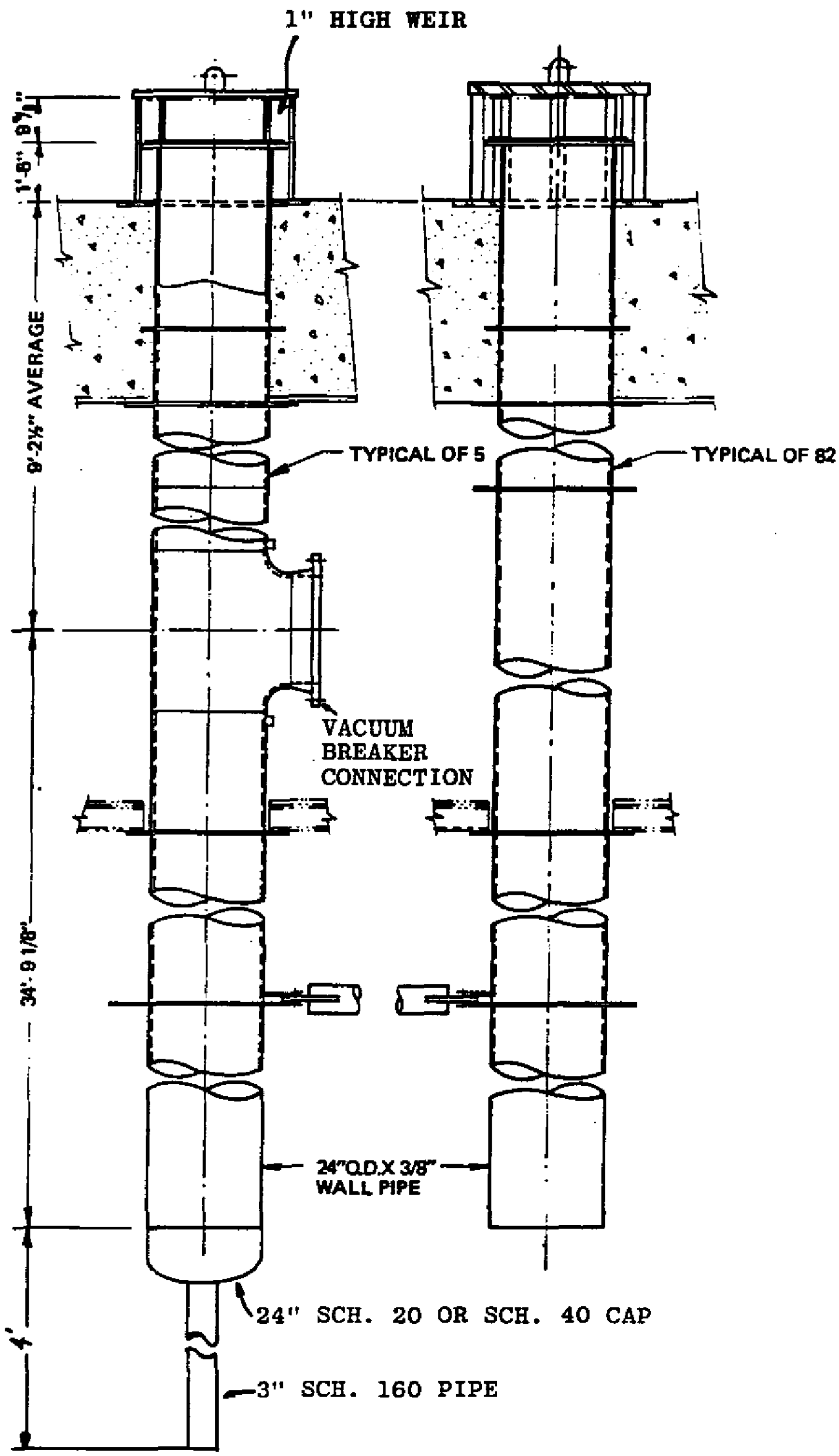
FSAR REV. 65

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

FIGURE 6.2-55C REPLACED BY DWG. M-157, SH. 3

FIGURE 6.2-55C, Rev. 55

AutoCAD Figure 6_2_55C.doc



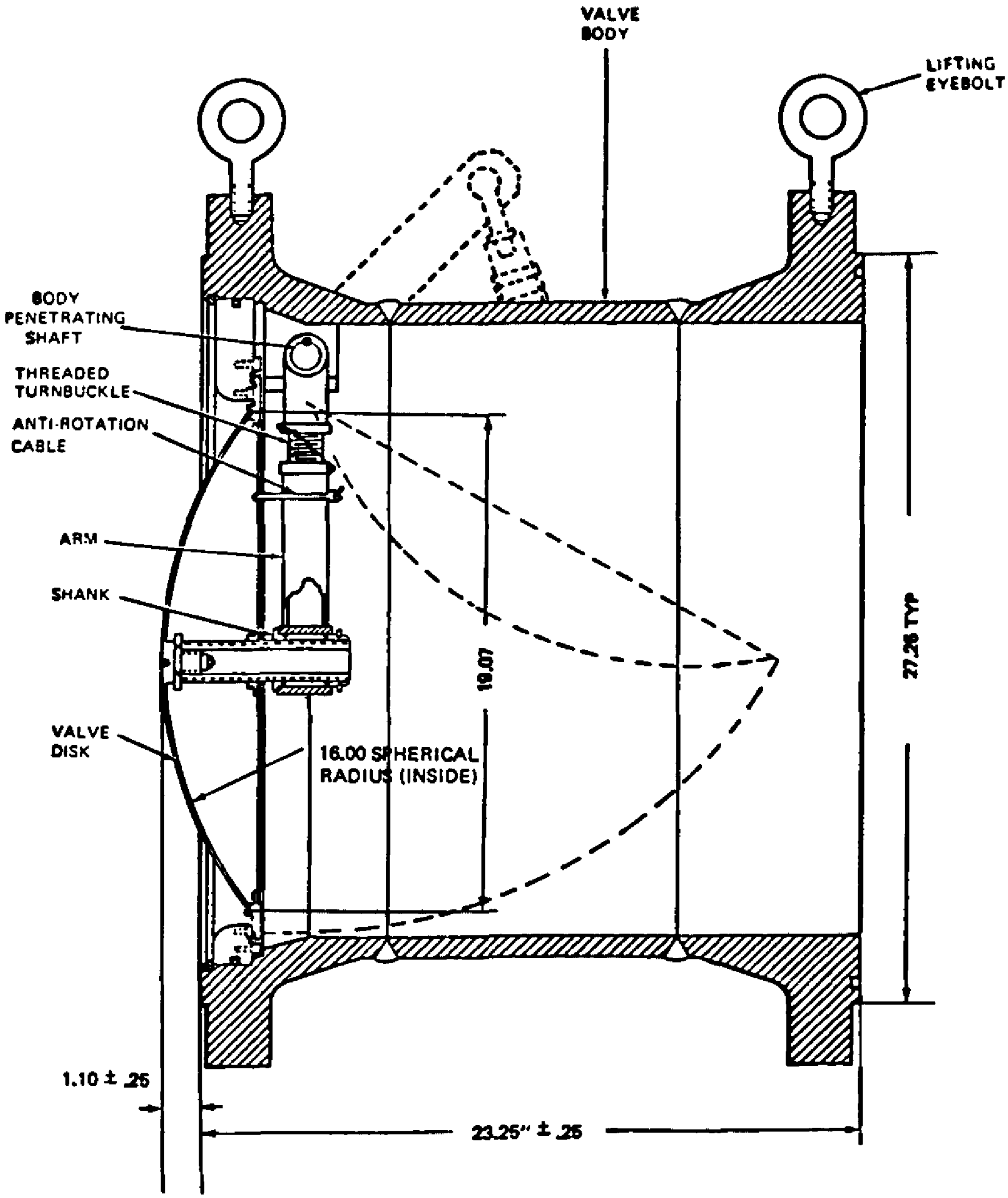
FSAR REV. 65

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

DRYWELL TO WETWELL
DOWNCOMERS

FIGURE 6.2-56, Rev. 49

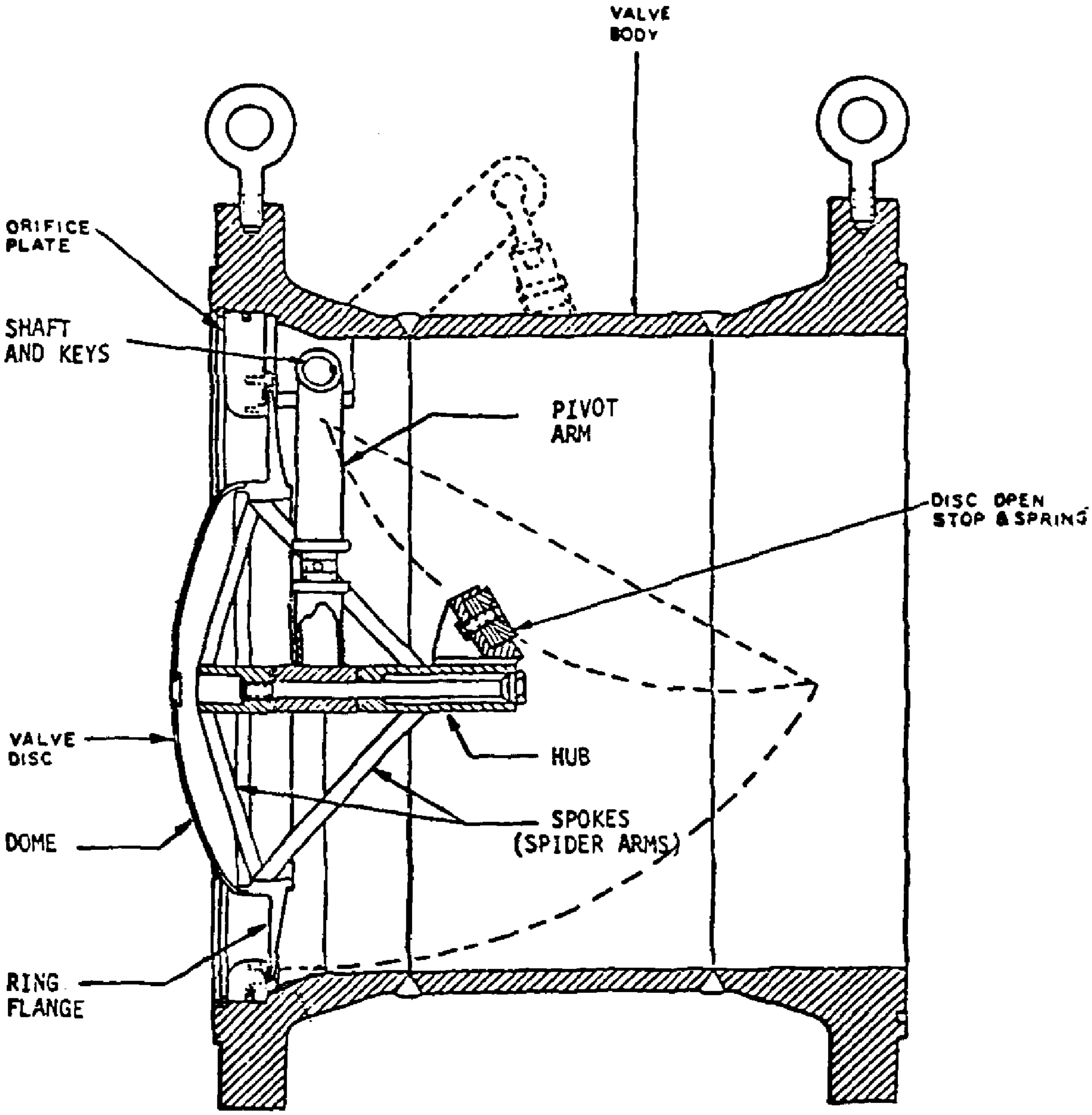
Auto Cad: Figure Fsar 6_2_56.dwg



FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 AND 2 FINAL SAFETY ANALYSIS REPORT
VACUUM BREAKER DISC/ARM ASSEMBLY UNIT 1 FIGURE 6.2-57-1, Rev. 48

Auto Cad: Figure Fsar 6_2_57_1.dwg



FSAR REV. 65

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

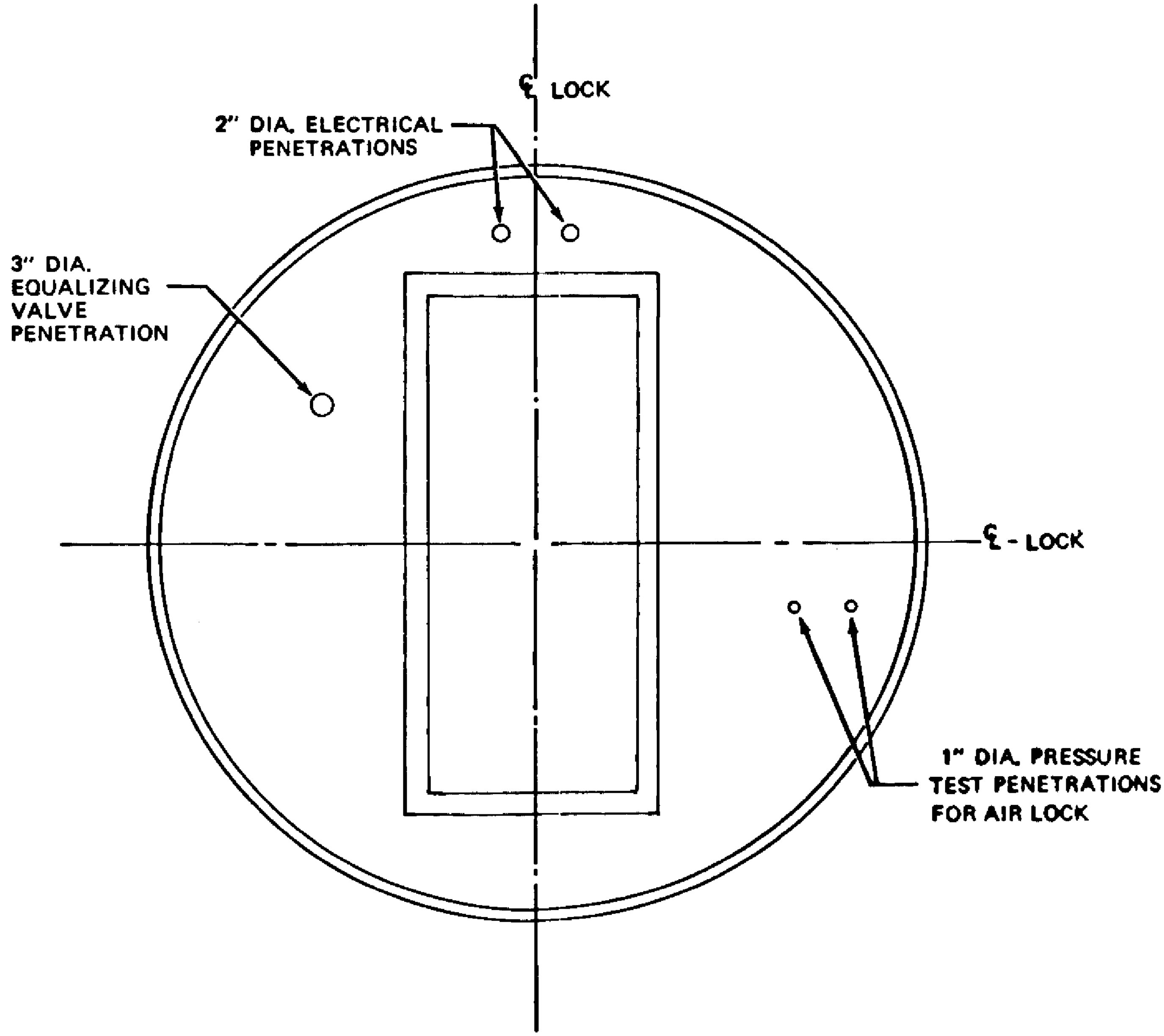
VACUUM BREAKER
DISC/ARM ASSEMBLY
UNIT 2

FIGURE 6.2-57-2, Rev. 48

Auto Cad: Figure Fsar 6_2_57_2.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
CONTAINMENT PERSONNEL LOCK DOOR PENETRATIONS FIGURE 6.2-57A-1



ELEVATION VIEW OF
EXTERIOR BULKHEAD

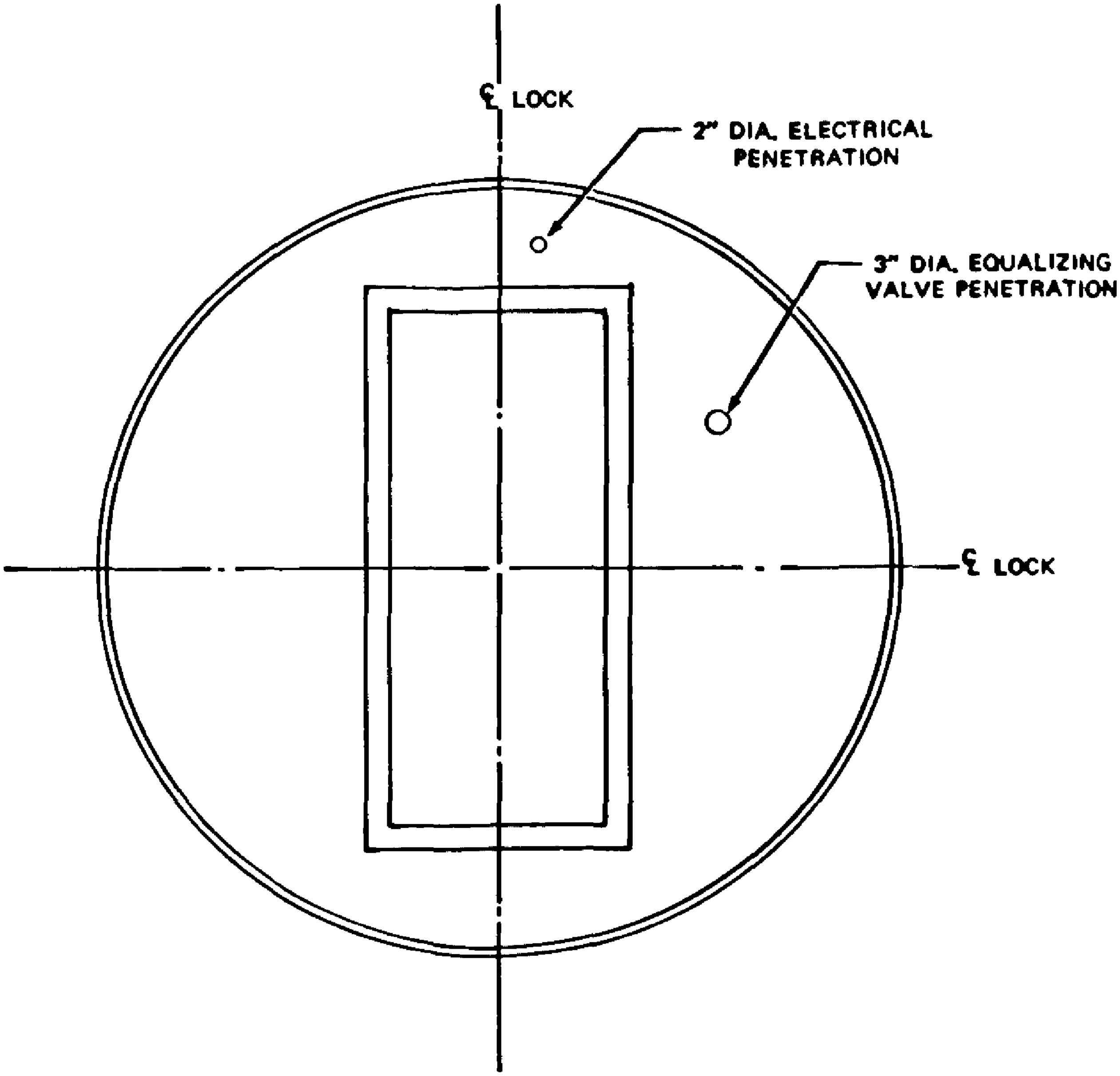
FSAR REV. 65

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

CONTAINMENT PERSONNEL
LOCK DOOR PENETRATIONS

FIGURE 6.2-57A-2, Rev. 48

Auto Cad: Figure Fsar 6_2_57A_2.dwg



ELEVATION VIEW OF INTERIOR BULKHEAD

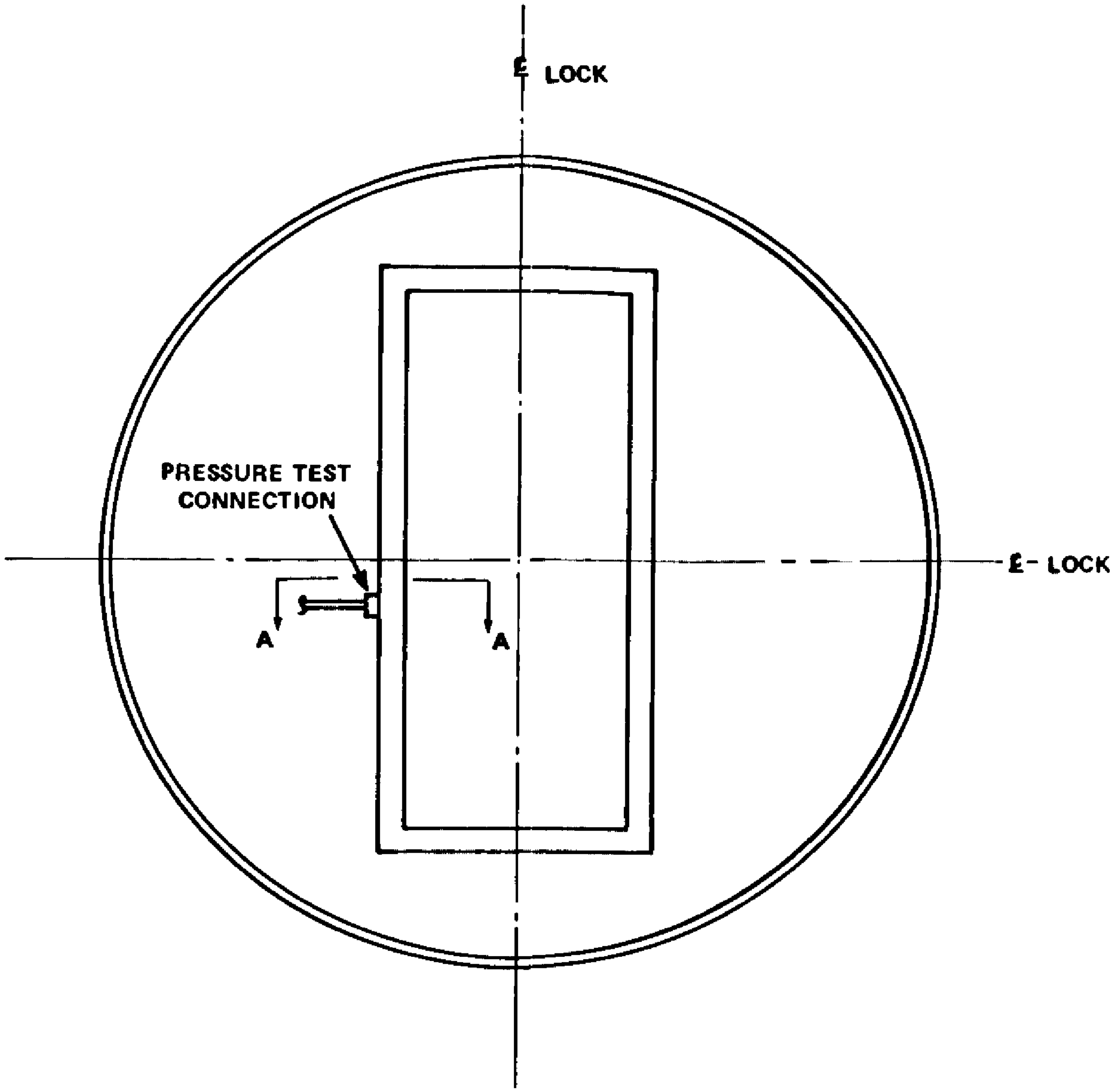
FSAR REV. 65

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

CONTAINMENT PERSONNEL
LOCK PENETRATIONS

FIGURE 6.2-57A-3, Rev. 48

Auto Cad: Figure Fsar 6_2_57A_3.dwg



ELEVATION VIEW OF
INTERIOR OR EXTERIOR BULKHEAD

FSAR REV. 65

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

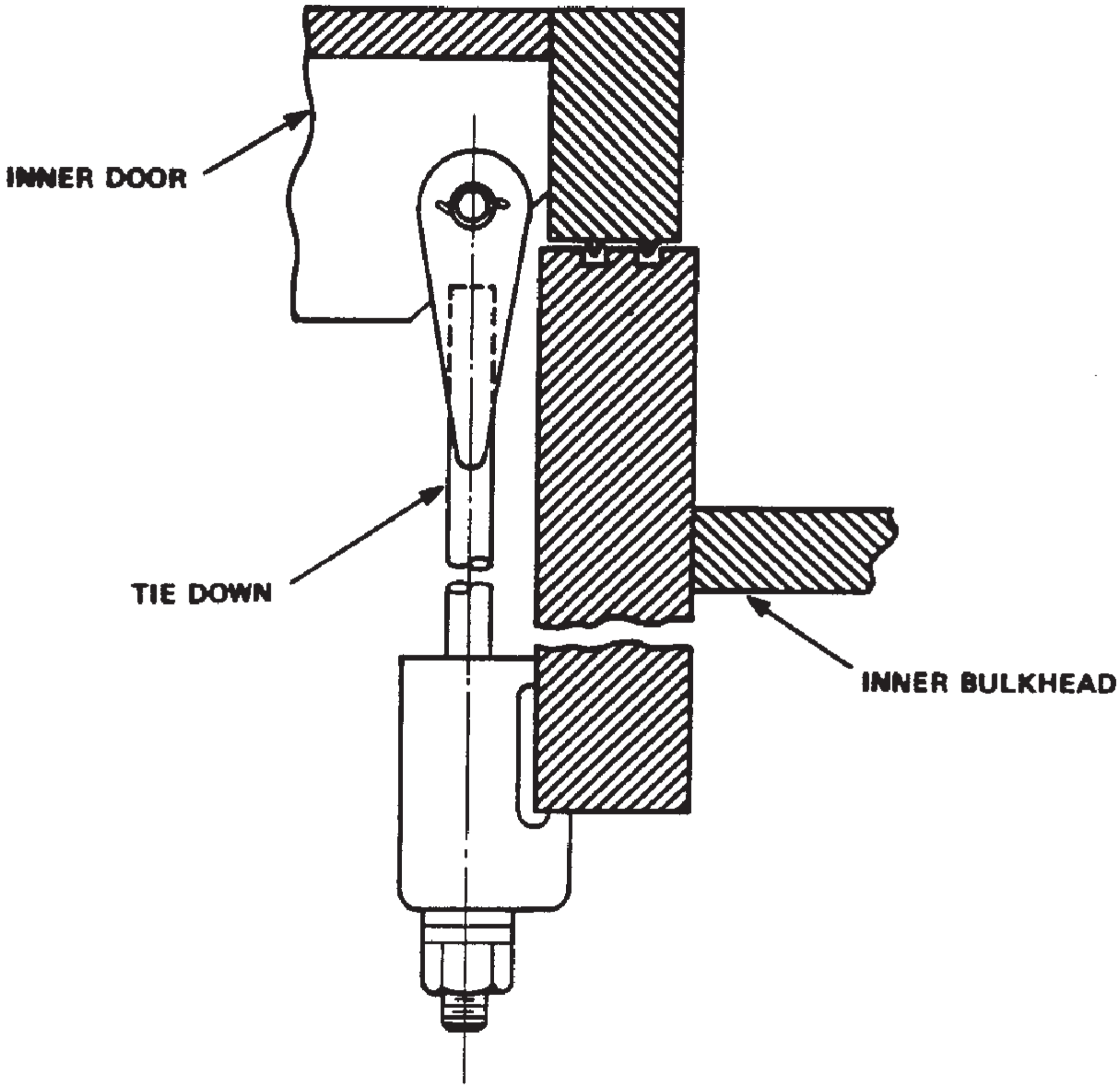
CONTAINMENT PERSONNEL
LOCK DOOR SEALS

FIGURE 6.2-58-1, Rev. 48

Auto Cad: Figure Fsar 6_2_58_1.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
CONTAINMENT PERSONNEL LOCK DOOR SEALS
FIGURE 6.2-58-2



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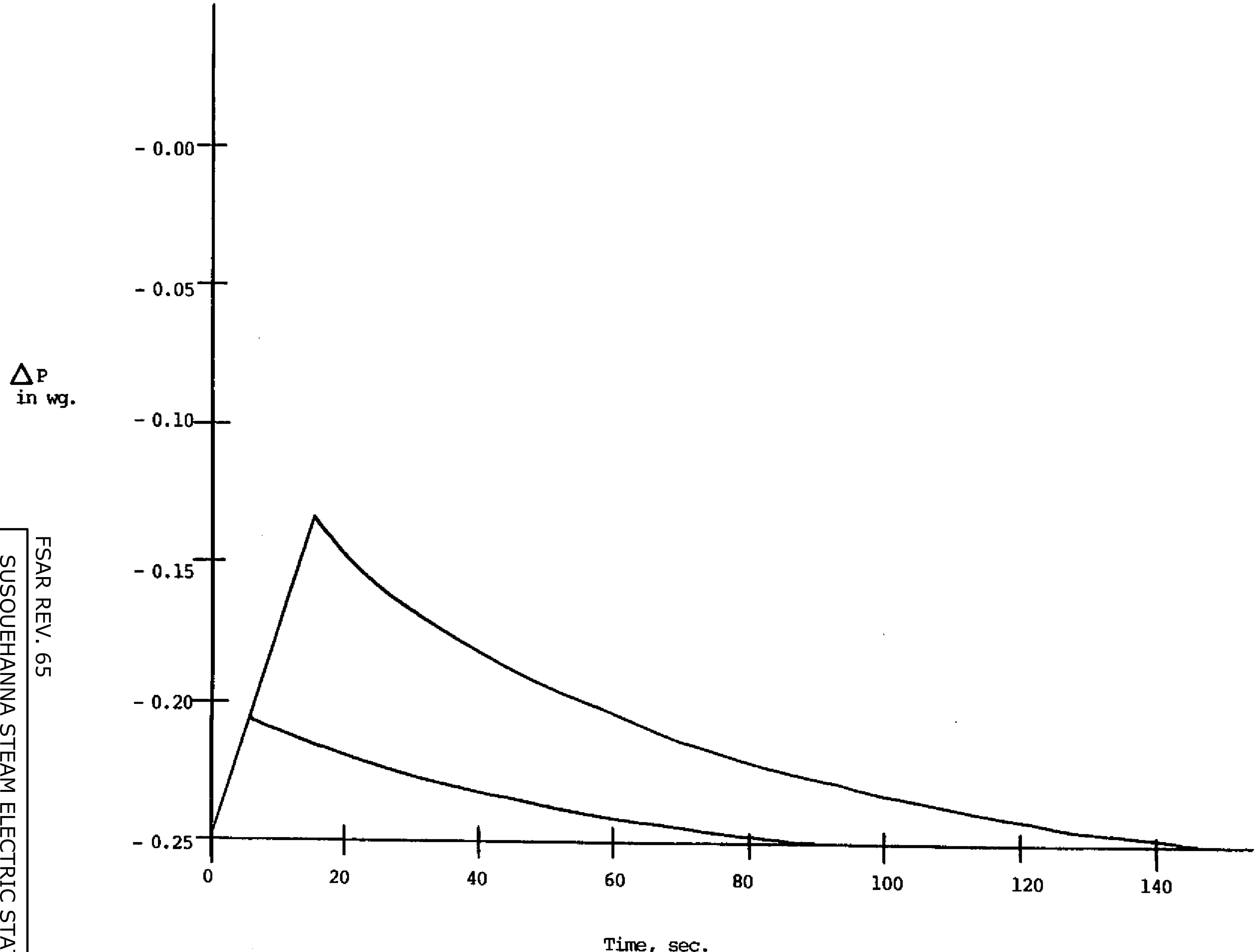
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

PERSONNEL LOCK INNER
DOOR TIE DOWNS

FIGURE 6.2-59, Rev. 49

Auto Cad: Figure Fsar 6_2_59.dwg



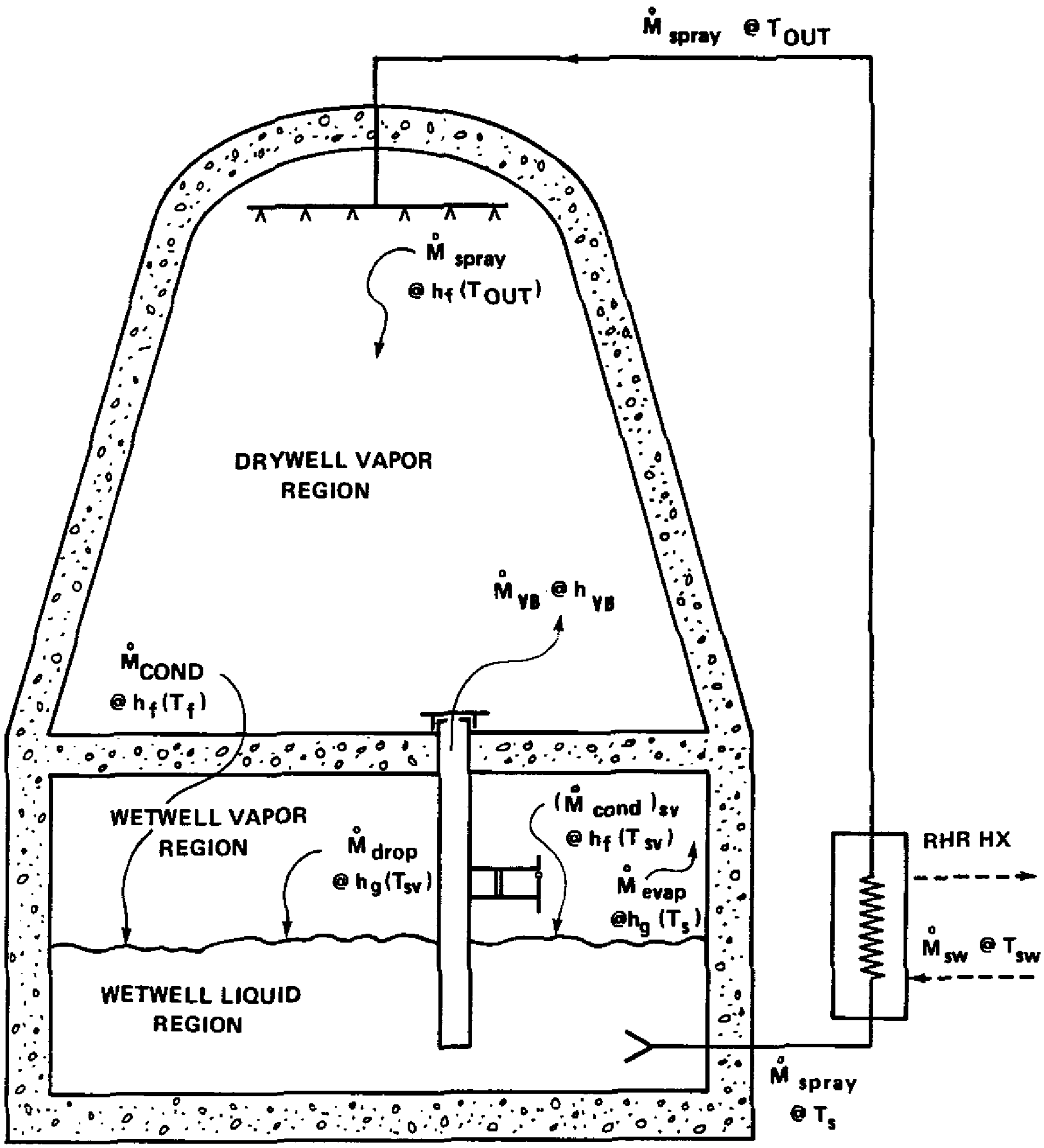
FSAR REV. 65

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

SECONDARY CONTAINMENT
PRESSURE TRANSIENT
POST-LOCA

FIGURE 6.2-60, Rev. 49

Auto Cad: Figure Fsar 6_2_60.dwg



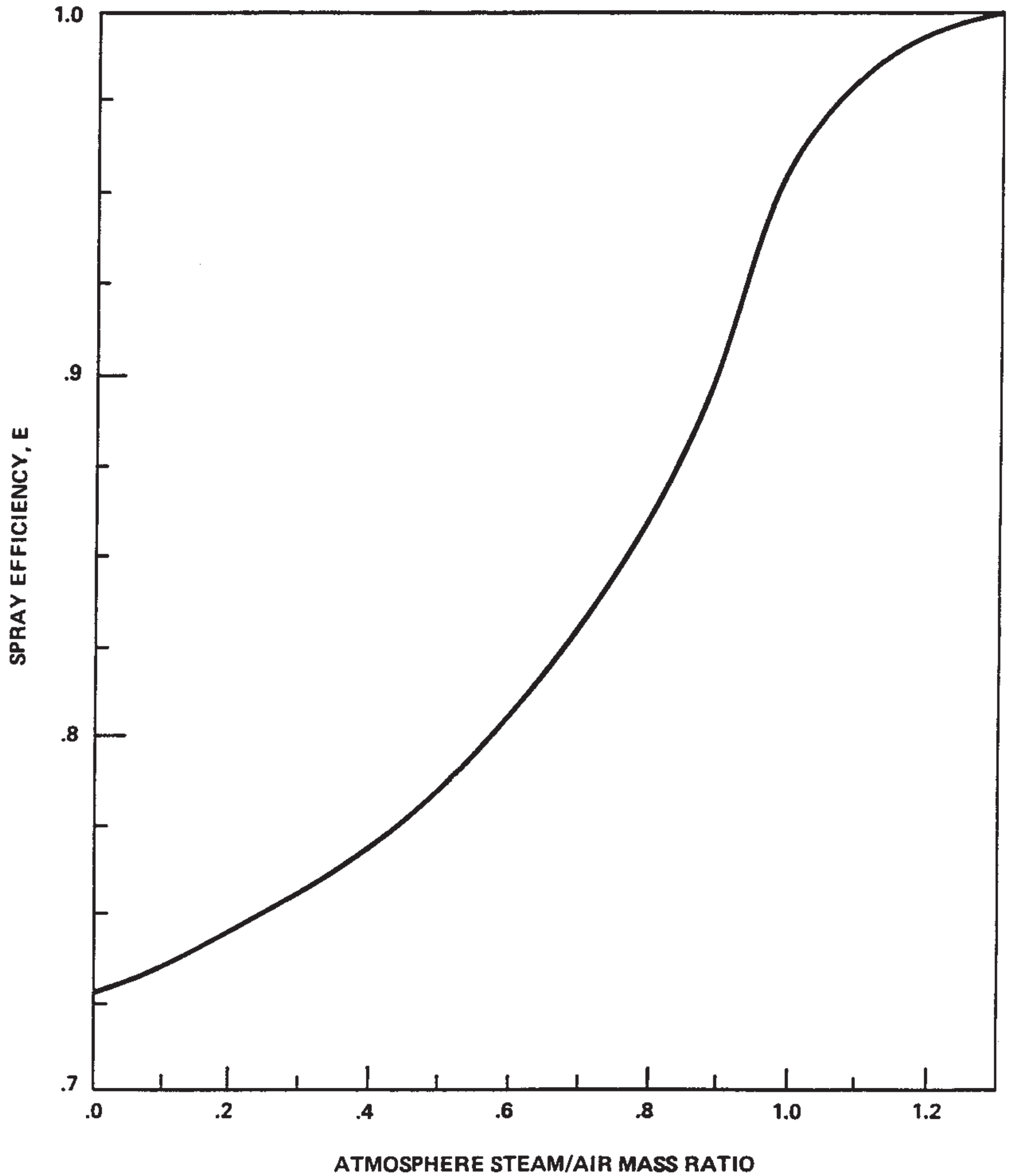
FSAR REV. 65

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

MODEL FOR INADVERTENT
SPRAY ACTUATION

FIGURE 6.2-61, Rev. 49

Auto Cad: Figure Fsar 6_2_61.dwg



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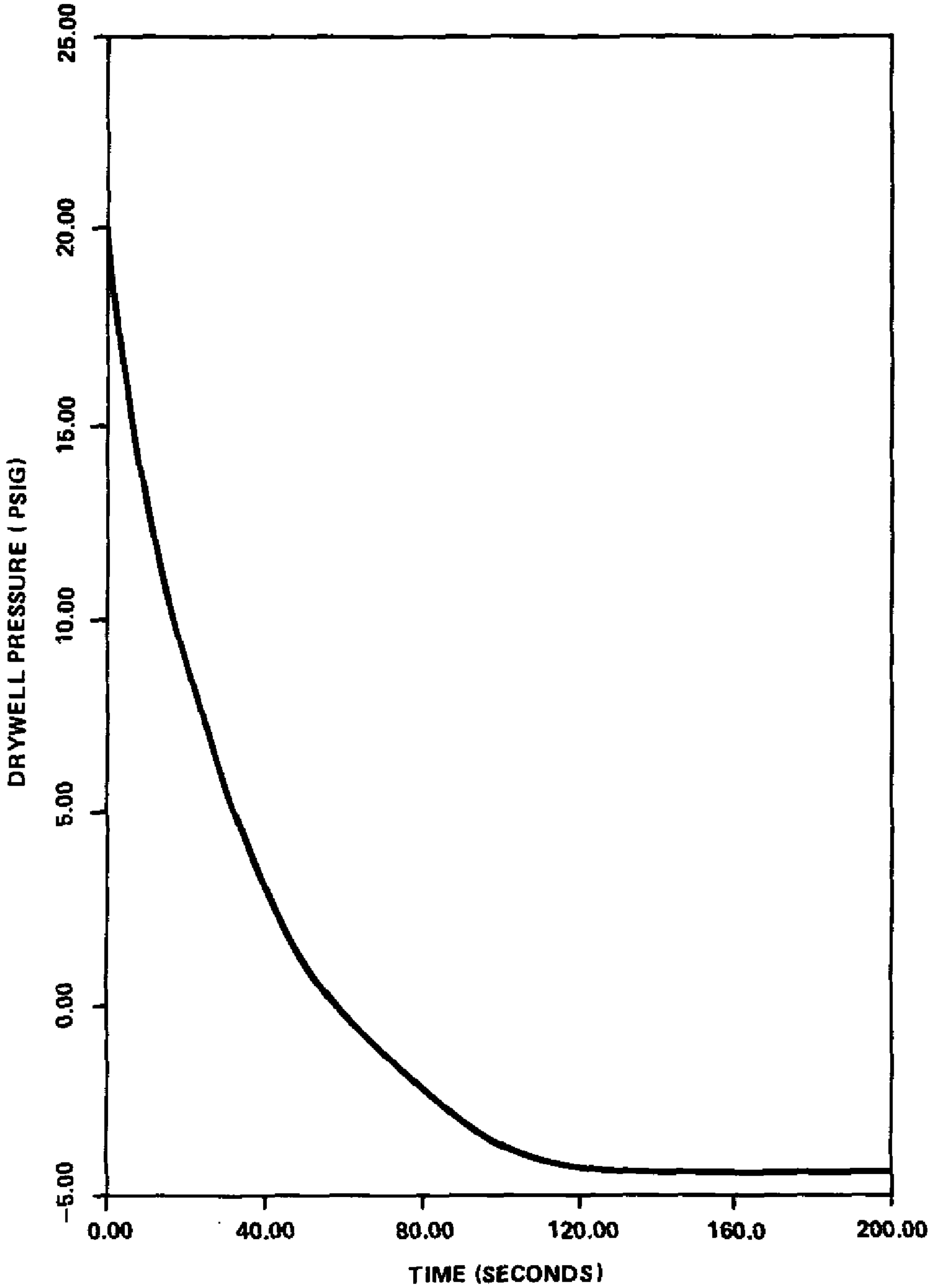
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

THERMAL HEAT REMOVAL
EFFICIENCY OF CONTAINMENT
ATMOSPHERE SPRAY

FIGURE 6.2-62, Rev. 49

Auto Cad: Figure Fsar 6_2_62.dwg



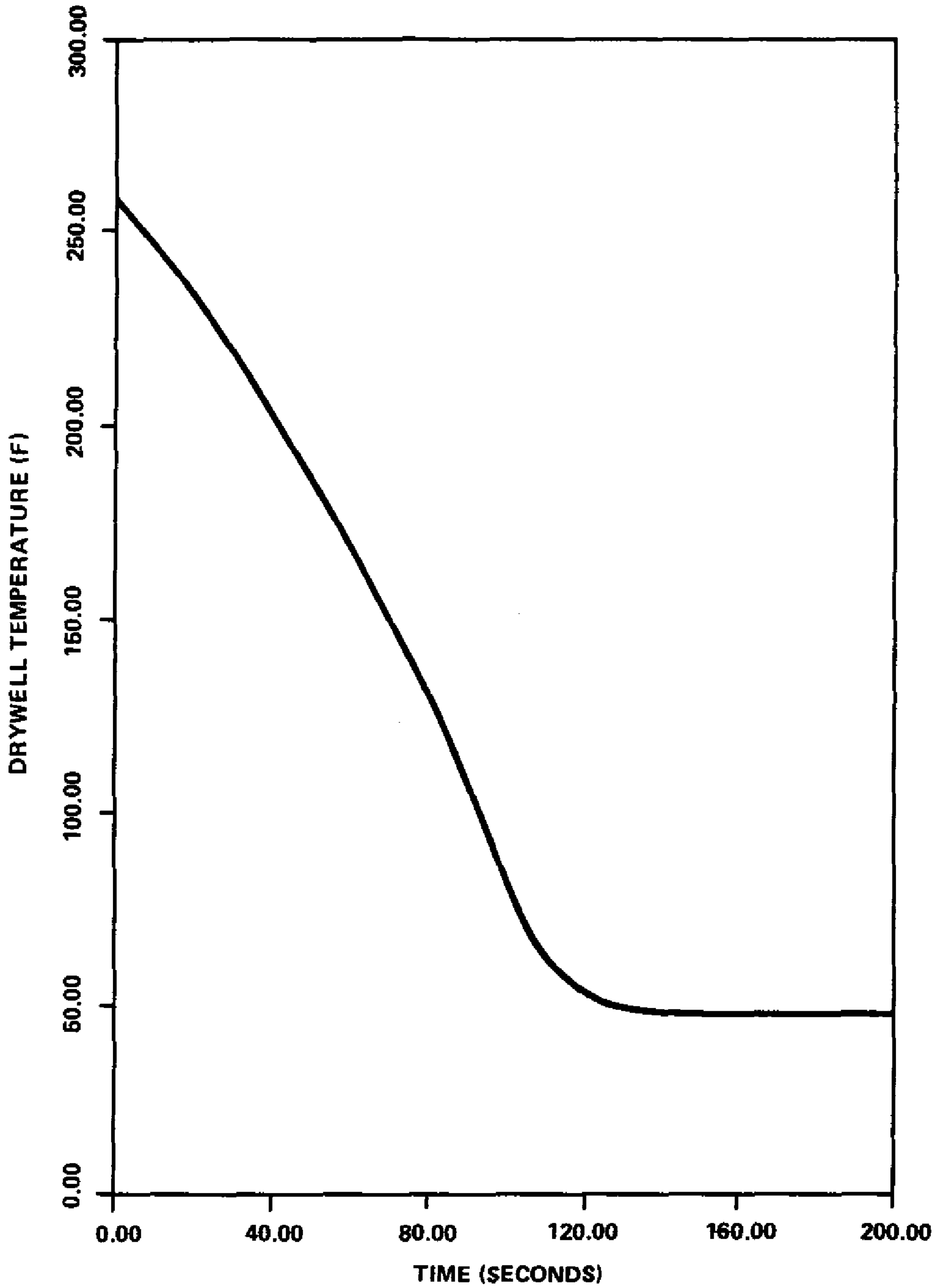
FSAR REV. 65

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

DRYWELL PRESSURE RESPONSE
FOR INADVERTENT SPRAY
ACTUATION

FIGURE 6.2-63, Rev. 49

Auto Cad: Figure Fsar 6_2_63.dwg



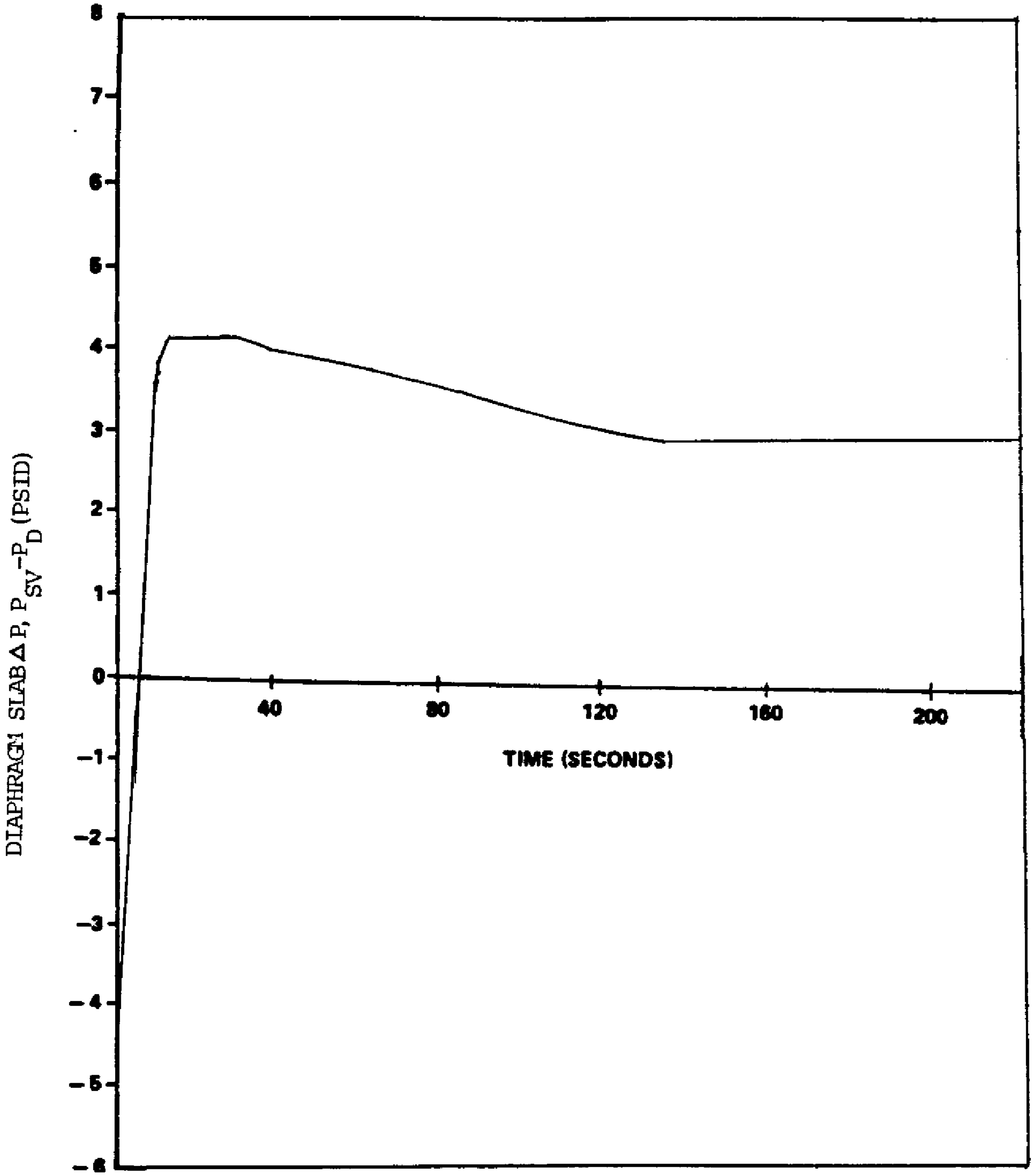
FSAR REV. 65

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

DRYWELL TEMPERATURE
RESPONSE FOR
INADVERTENT SPRAY
ACTUATION

FIGURE 6.2-64, Rev. 49

Auto Cad: Figure Fsar 6_2_64.dwg



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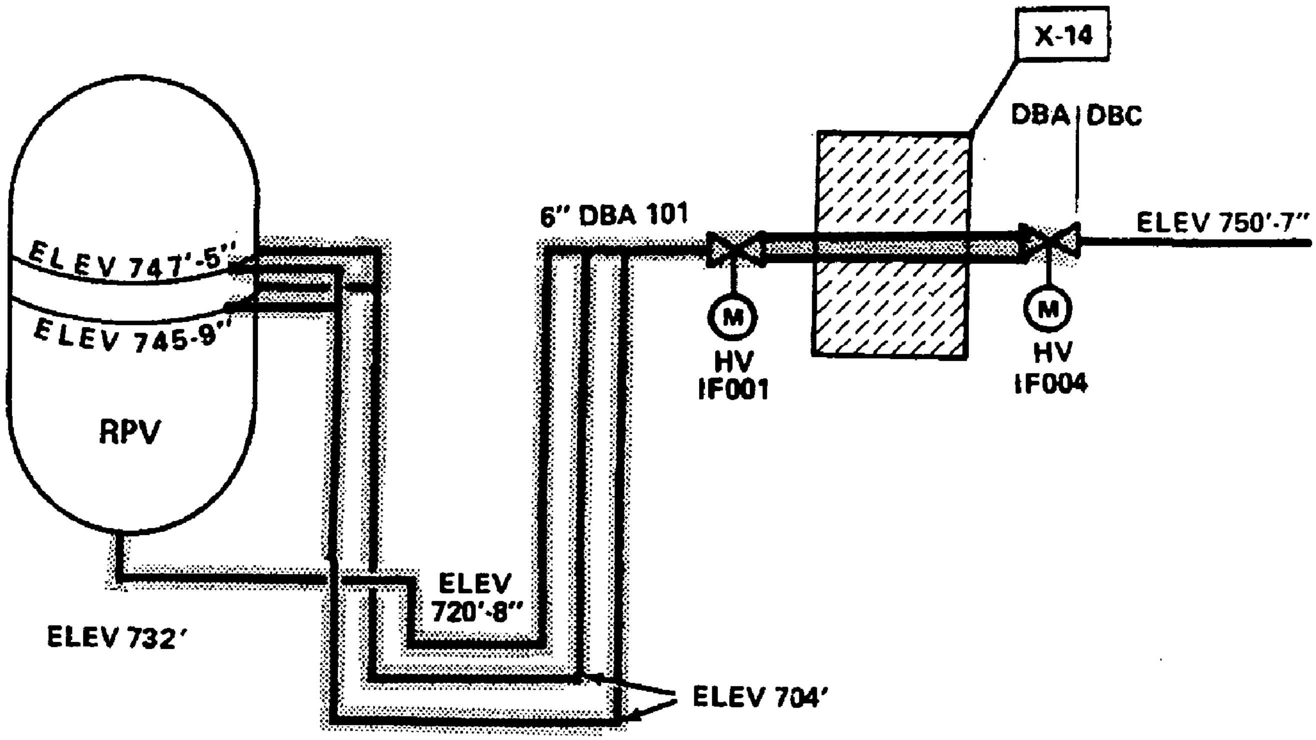
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

DIFFERENTIAL PRESSURE EXPERIENCED ACROSS THE DIAPHRAGM SLAB DURING INADVERTENT ACTUATION OF THE DRYWELL SPRAY

FIGURE 6.2-65, Rev. 49

Auto Cad: Figure Fsar 6_2_65.dwg



NOTE 1: ALL PIPING SEISMIC CAT. 1

NOTE 2: DBA PIPING IS QUALITY GROUP A.

NOTE 3: WATER SEALED PIPING.

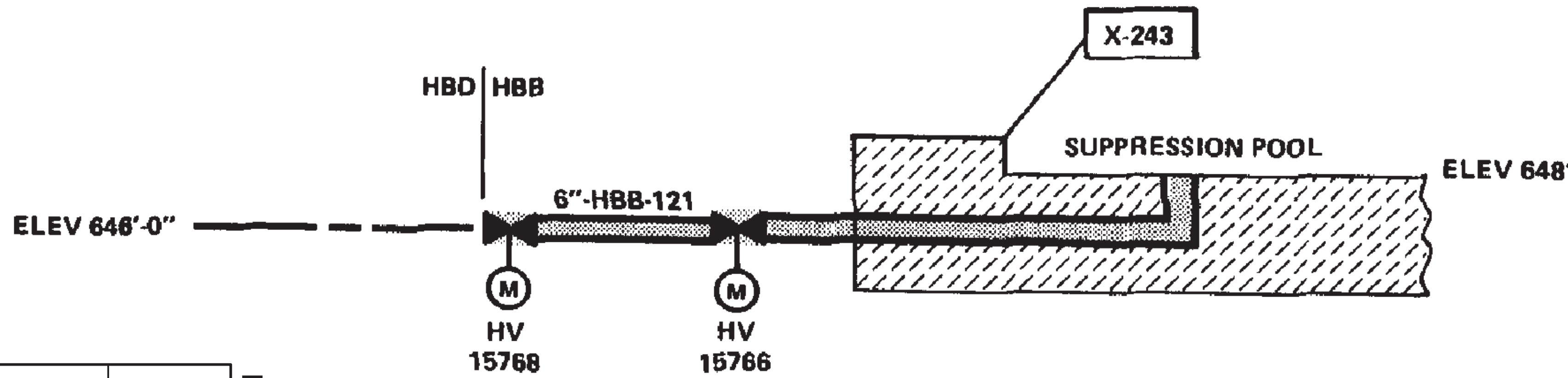
FSAR REV. 65

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

RWCU LINE PENETRATION

FIGURE 6.2-66B, Rev. 49

Auto Cad: Figure Fsar 6_2_66B.dwg



NOTE 1: ALL PIPING SEISMIC CAT. 1

NOTE 2: HBB PIPE IS QUALITY GROUP B.

NOTE 3: WATER SEALED PIPING.

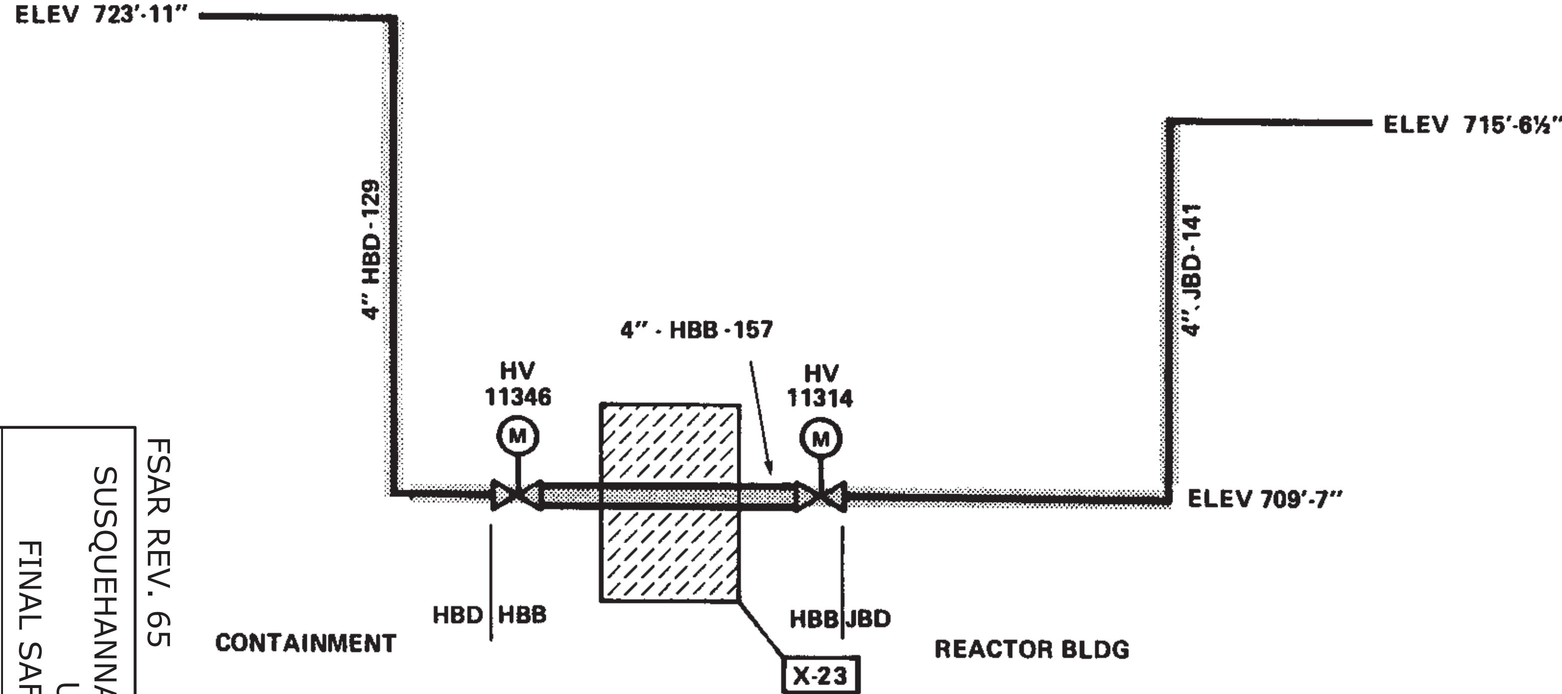
FSAR REV. 65

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

SUPPRESSION POOL
PURIFICATION LINE
PENETRATION

FIGURE 6.2-66C, Rev. 49

Auto Cad: Figure Fsar 6_2_66C.dwg



NOTE 1: TYPICAL FOR PENETRATIONS X-23 and X-24.

NOTE 2: ALL PIPING INSIDE CONTAINMENT IS SEISMICALLY ANALYZED

NOTE 3: HBB PIPE IS QUALITY GROUP B.
HBD PIPE IS QUALITY GROUP D.

NOTE 4: WATER SEALED PIPING.

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SUSQUEHANNA STEAM ELECTRIC STATION
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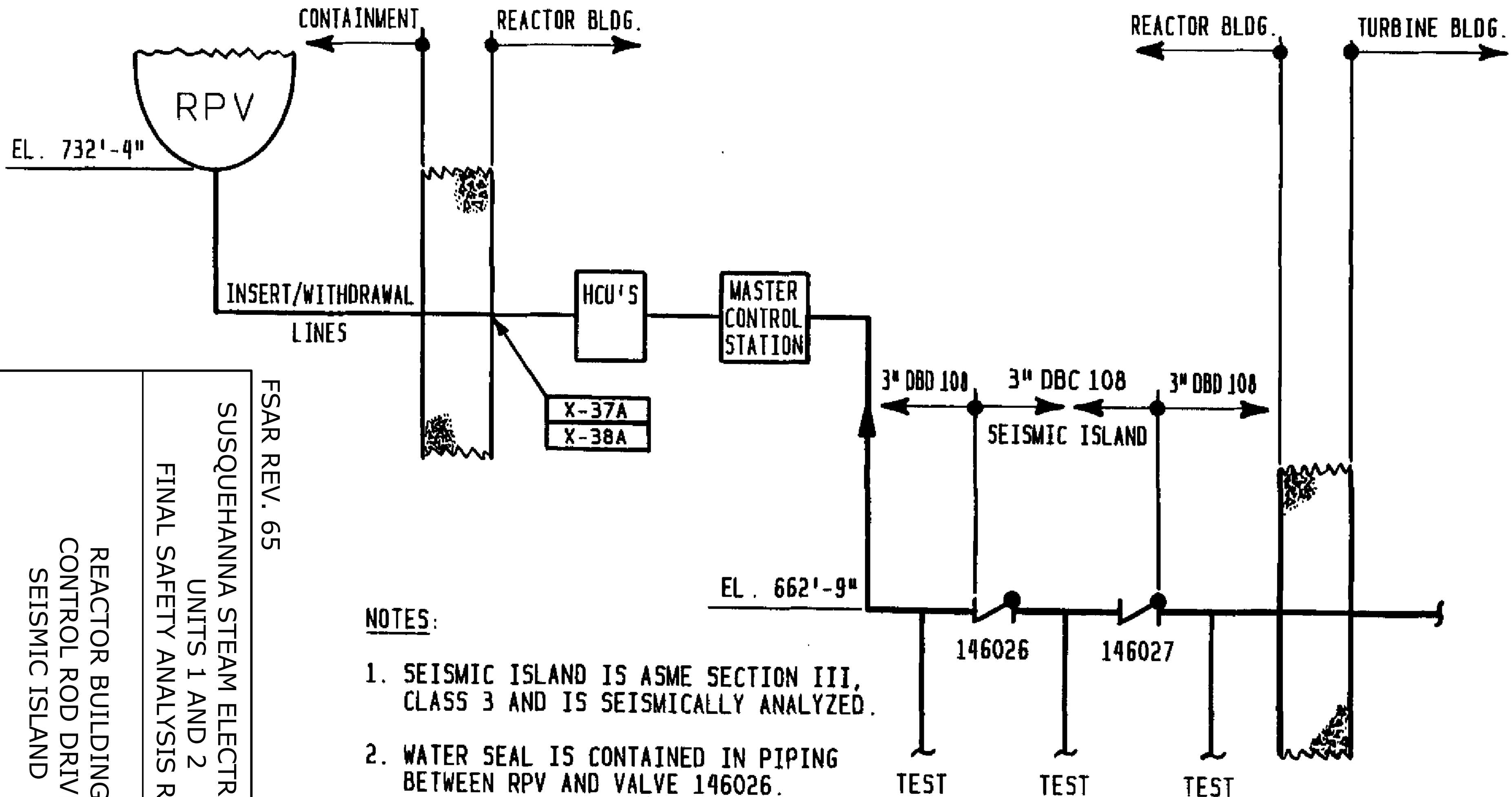
REACTOR BUILDING CLOSED
COOLING WATER LINE
PENETRATION

FIGURE 6.2-66F, Rev. 49

Auto Cad: Figure Fsar 6_2_66F.dwg



NOTES:

1. SEISMIC ISLAND IS ASME SECTION III, CLASS 3 AND IS SEISMICALLY ANALYZED.

2. WATER SEAL IS CONTAINED IN PIPING BETWEEN RPV AND VALVE 146026.

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SUSQUEHANNA STEAM ELECTRIC STATION
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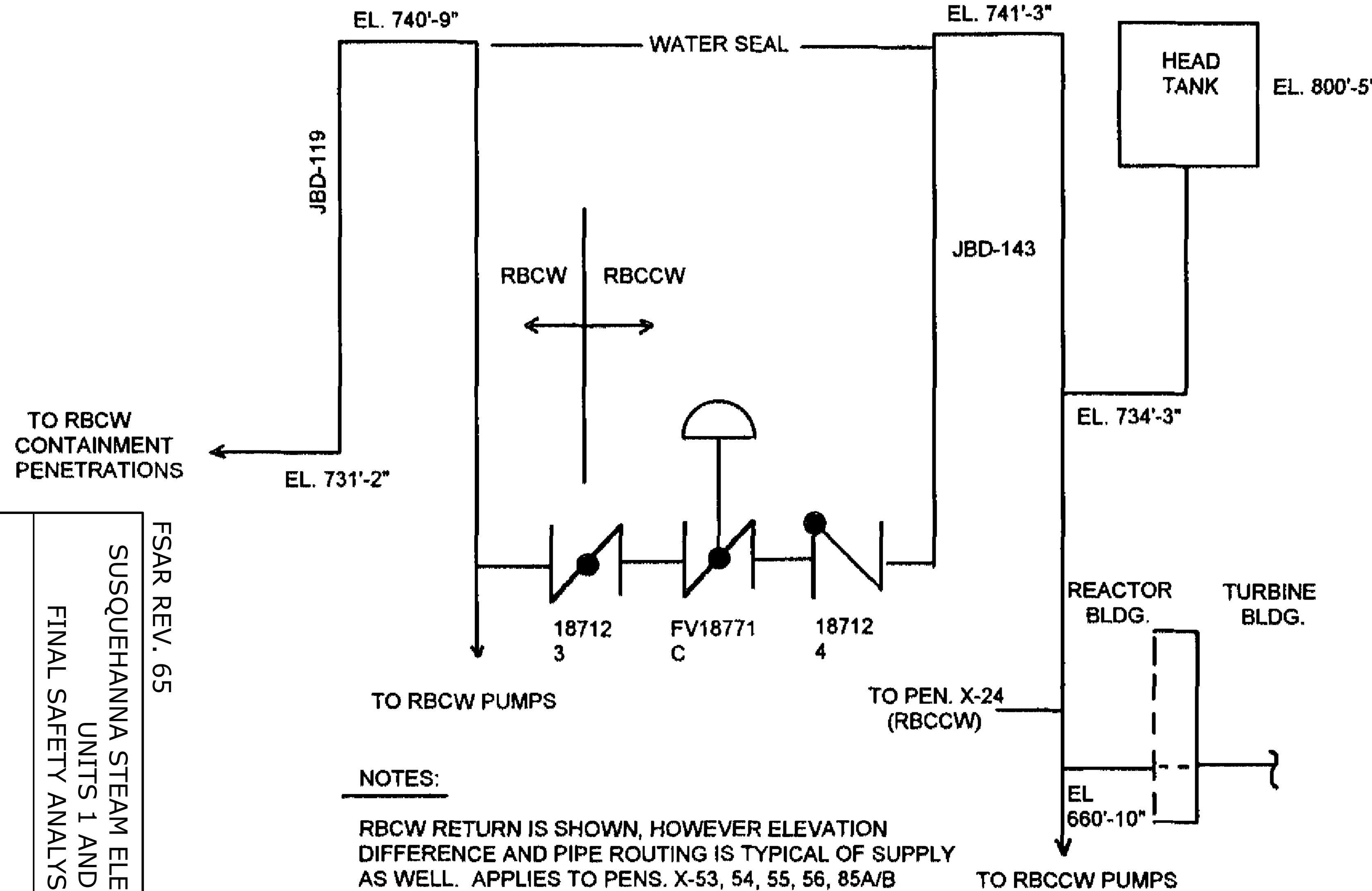
REACTOR BUILDING
CONTROL ROD DRIVE
SEISMIC ISLAND

FIGURE 6.2-66G, Rev. 49

Auto Cad: Figure Fsar 6_2_66G.dwg



NOTES:

RBCW RETURN IS SHOWN, HOWEVER ELEVATION DIFFERENCE AND PIPE ROUTING IS TYPICAL OF SUPPLY AS WELL. APPLIES TO PENS. X-53, 54, 55, 56, 85A/B AND 86A/B.

CHECK VALVE IS REVERSED IN SUPPLY LINE.

PIPING FORMING WATER SEAL IS NON-SIESMIC CATEGORY I, BUT LOCATED WITHIN SECONDARY CONTAINMENT

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

RBCCW SUPPLY/RETURN LINES
AT THE REACTOR BLDG. TO TURBINE
BLDG. INTERFACE

FIGURE 6.2-66H, Rev. 54

Auto Cad: Figure Fsar 6_2_66H.dwg

FIGURE 6.2-67 REPLACED BY DWG. M-159, SH. 1

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SUSQUEHANNA STEAM ELECTRIC STATION
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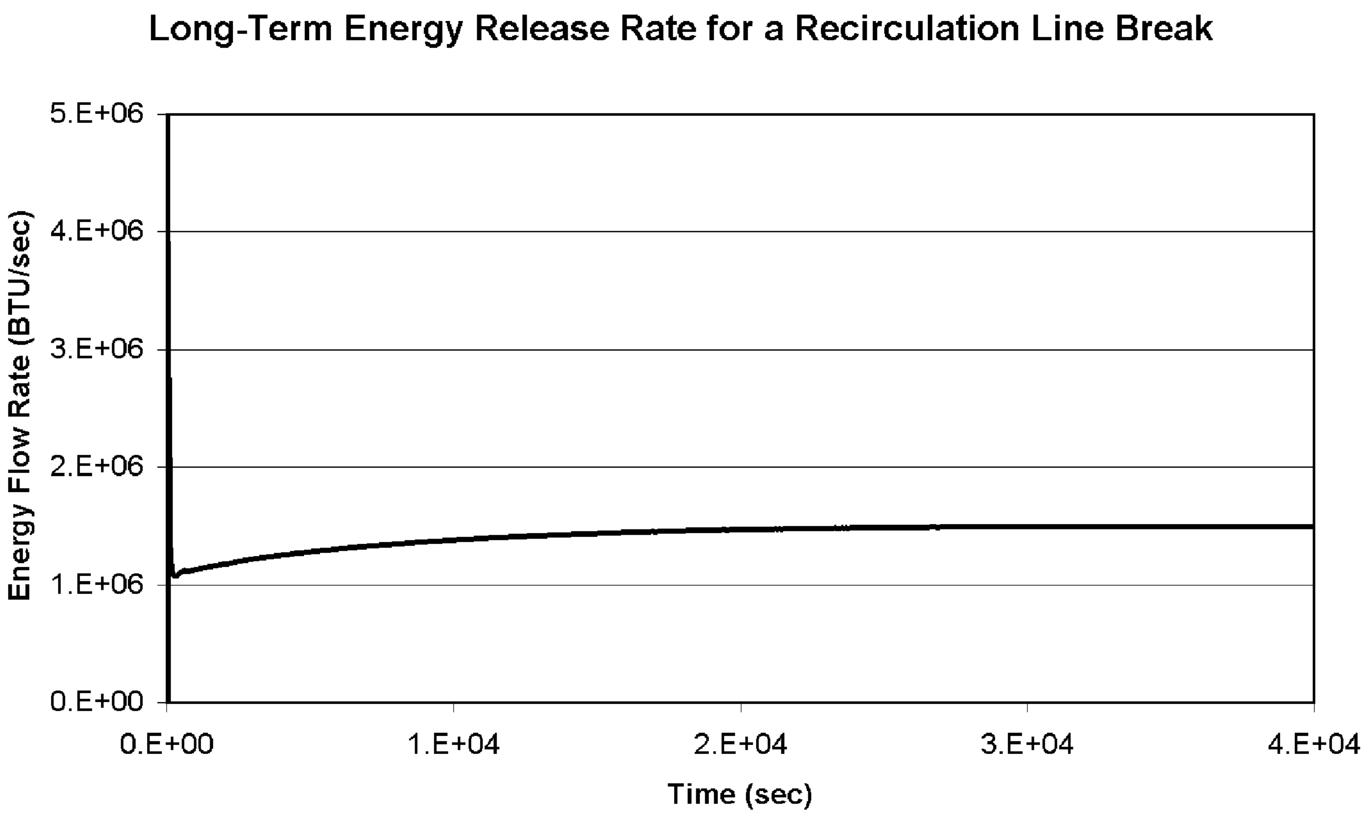
FINAL SAFETY ANALYSIS REPORT

FIGURE 6.2-67 REPLACED BY DWG. M-159, SH. 1

FIGURE 6.2-67, Rev. 55

AutoCAD Figure 6_2_67.doc



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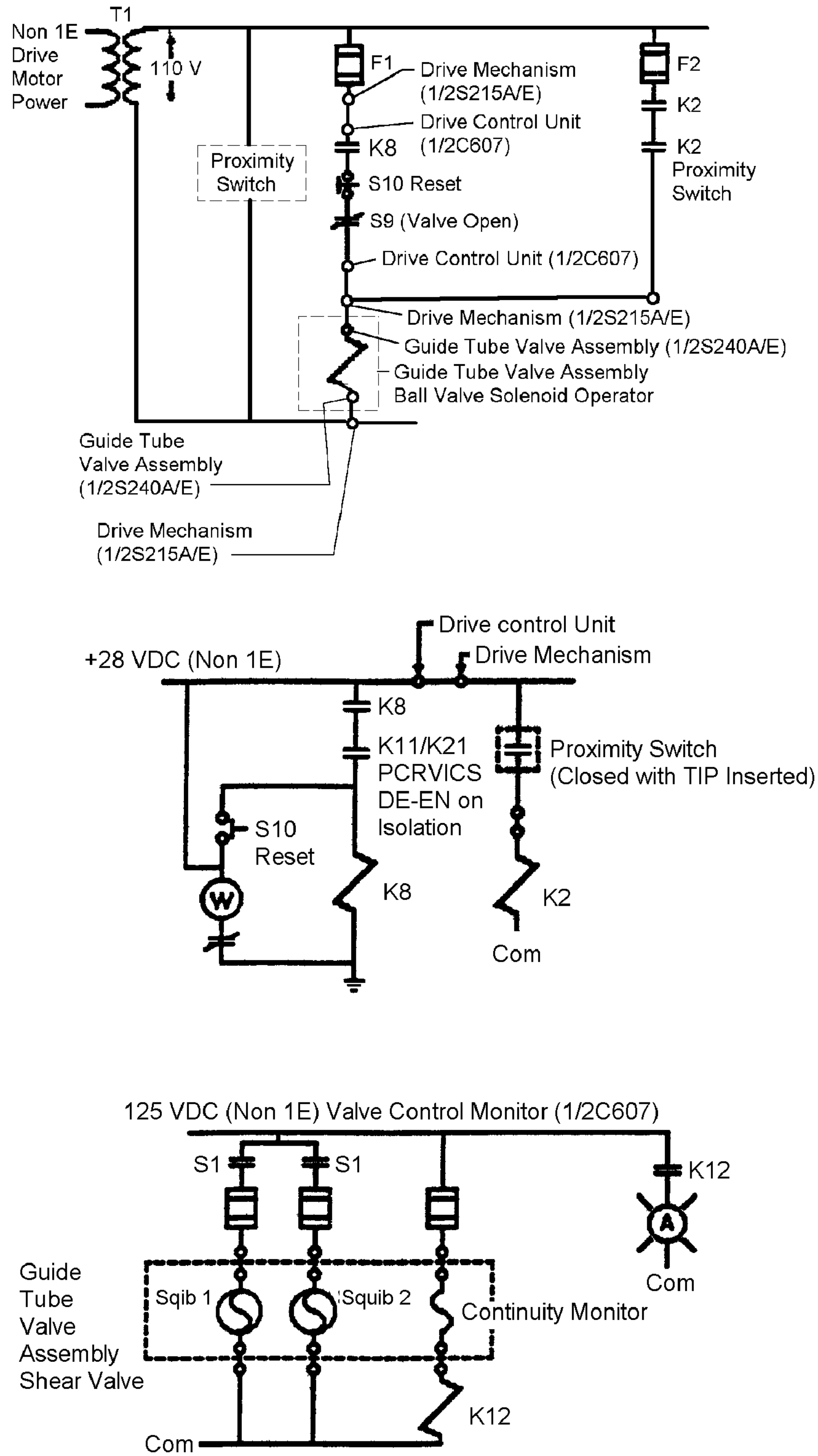
SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
FINAL SAFETY ANALYSIS REPORT

LONG-TERM ENERGY RELEASE RATE
FOR A RECIRCULATION LINE BREAK

FIGURE 6.2-70, Rev. 51

Auto Cad: Figure Fsar 6_2_70.dwg



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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 AND 2
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TIP GUIDE TUBE
ISOLATION CONTROL

FIGURE 6.2-72, Rev. 50

Auto Cad: Figure Fsar 6_2_72.dwg