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CHAPTER 6 ENGINEERING SAFETY FEATURES

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CHAPTER 6.0 ENGINEERED SAFETY FEATURES

6.0 ENGINEERED SAFETY FEATURES SYSTEMS

The following plant systems are classified as being engineered safety features (ESF) systems:

a. Emergency Core Cooling Systems (ECCS)

    1. High Pressure Core Spray (HPCS)

    2. Low Pressure Core Spray (LPCS)

    3. Automatic Depressurization System (ADS)

    4. Low Pressure Core Injection (LPCI) mode of operation of the Residual Heat Removal (RHR) System

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

c. Main Steam Line Isolation Valve Leakage Control System (MSIV-LCS)

d. Containment Spray mode of operation of RHR

e. Feedwater Leakage Control System (FWLC)

f. Standby Gas Treatment System (SGTS)

g. Suppression Pool Makeup System

h. Control Room Atmospheric Control and Isolation System

i. Combustible Gas Control System (CGCS)

6.1 ENGINEERED SAFETY FEATURE MATERIALS

Materials used in the engineered safety feature (ESF) components have been evaluated to ensure that material interactions will not occur that could potentially impair operation of the ESF. Materials have been selected to withstand the environmental conditions encountered during normal operation and any postulated accident.

6.1.1 Metallic Materials

6.1.1.1 Material Selection and Fabrication

6.1.1.1.1 Specifications for Principal ESF Pressure Retaining Materials

ASME specifications for the principal ESF pressure retaining materials are listed in Table 6.1-1.

6.1.1.1.2 Engineered Safety Features Construction Material

All ESF materials are resistant to stress corrosion in the BWR coolant. Conservative corrosion allowances are provided for all exposed surfaces of carbon steel. General corrosion on all other materials is negligible. Demineralized water, with no additives, is employed in the core cooling water and containment spray. Following a LOCA, this high purity water will have no detrimental effect on any of the ESF materials; therefore, the materials have not been listed.

6.1.1.1.3 Integrity of Engineered Safety Feature Components During Manufacture and Construction

6.1.1.1.3.1 Control of Sensitized Stainless Steel

All engineered safety feature components comply with the requirements of Regulatory Guide 1.44 in the following manner:

Austenitic stainless steel material used to fabricate pressure retaining components of the engineered safety features has been purchased in the solution heat-treated condition.

All welding performed on austenitic stainless steel was done with low heat input welding processes. Intergranular corrosion tests have not been performed on a routine basis as specified in Paragraph C.6 of Regulatory Guide 1.44 since all materials used are in the solution-annealed condition. The following safeguards are taken:

a. Vendor fabrication procedures are reviewed to ensure that unstabilized austenitic stainless steel is not exposed to the temperature range of 800 to 1500 F other than when welding.

b. The maximum preheat and interpass temperature for hardsurfacing and welding austenitic stainless steel is 350 F.

c. Postweld heat treatment in the range of 800 F to 1500 F is strictly forbidden.

Since severe sensitization is avoided by the above-listed safeguards, testing to determine susceptibility to intergranular attack is not performed.

6.1.1.1.3.2 Cleaning and Contamination Protection Procedures

Specifications for ESF piping and components specify requirements for cleanliness and contamination protection during fabrication, shipment, and storage as recommended by Regulatory Guide 1.44.

Contamination of austenitic stainless steels by compounds that can alter the physical or metallurgical structure and/or properties of the material are avoided during all stages of fabrication. Painting of stainless steels is prohibited. Grinding is accomplished with resin or rubber bonded aluminum oxide or silicon carbide wheels that have not previously been used on materials other than stainless steel.

Internal surfaces of completed components are cleaned to produce an item that is clean to the extent that grit, scale, corrosion products, grease, oil, wax, gum, adhered or embedded dirt, or extraneous material are not visible to the unaided eye.

Cleaning agents and demineralized rinse water in contact with austenitic stainless steel contains less than 200 ppm of inorganic halogens.

Onsite and preoperational cleaning of ESF components is in accordance with the recommendations of Regulatory Guide 1.37. Refer to Appendix 3A for the position on Regulatory Guides.

6.1.1.1.3.3 Cold Worked Stainless Steel

Austenitic stainless steel with a yield strength greater than 90,000 psi is not used in ESF systems.

6.1.1.1.3.4 Nonmetallic Insulation

Refer to Appendix 3A, Project Position to Regulatory Guide 1.36, regarding the use of nonmetallic insulation materials on stainless steel tubing/piping and components.

6.1.1.1.4 Weld Fabrication and Assembly of Stainless Steel ESF Components

The recommendations of the Interim Position on Regulatory Guide 1.31 (as specified in NRC Branch Technical Position MTEB 5-1) for the ESF have been followed except as discussed below:

a. Paragraph B.1.b of Interim Position

   Austenitic stainless steel welding materials used in the fabrication and installation of ASME Code, Section III, Class 1, 2, and 3 parts and components are controlled to deposit metal containing 8 to 25 percent delta ferrite except for Type 309 and 309L welding materials. Type 309 and 309L materials are controlled to deposit weld metal containing 5 to 15 percent delta ferrite and are used only for welding carbon and low alloy steel to austenitic stainless steels. Use of Type 309L welding materials is further limited to the overlay deposit on carbon and low alloy steel component nozzles or connecting pipe when postweld heat treatment is required.

   These limits for delta ferrite in austenitic stainless steel welding materials comply with the Interim Position because the upper limit of 20 percent delta ferrite does not apply for welds that are not heat treated after welding (Paragraph 3b) except for solution annealing heat treatment. Solution heat treatment, although not required after welding, is permitted to avoid sensitization.

   The procedure for determining the amount of delta ferrite in each heat or lot of austenitic stainless steel welding material does not comply with the Interim Position. Determination of delta ferrite is in accordance with ASME Code Section III, Division 1, Paragraph NB-2433, 1971, with Summer 1973 Addenda or later editions, except that an undiluted weld deposit is required for each heat or bare wire used with the gas-metal-arc (GMA) process.

b. Paragraph B.3.a of Interim Position

Magnetic measurements of production welds for delta ferrite content are unnecessary when austenitic stainless steel welding materials are controlled to deposit 8 to 25 percent delta ferrite, based on chemistry, except for Type 309 and 309L welding materials, which are controlled to deposit 5 to 15 percent delta ferrite based on chemistry.

c. Paragraphs B.4.a, B.4.b, and B.4.c of Interim Position

Measurement of production welds for delta ferrite is not performed.

6.1.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

Demineralized water, with no additives, is employed in the core cooling water and containment sprays. No detrimental effects will occur on any of the ESF materials from this high purity water. In addition, following an accident, the containment and drywell atmospheres are maintained below 4 percent (by volume) hydrogen in accordance with Regulatory Guide 1.7.

6.1.2 Organic Materials

The total amount of protective coatings and organic materials used inside containment that does not meet the requirements of ANSI N101.2 (1972) and Regulatory Guide 1.54 are addressed in subsections 6.1.2.1 and 6.1.2.2, Table 6.1-2, and Table 6.2-53.

6.1.2.1 Protective Coatings

The use of organic protective coating within the containment is kept to a minimum.

Certain items of mechanical equipment and miscellaneous supports are painted with unqualified organic coatings. The total weight of unqualified coatings has been evaluated by GGNS. This amount of unqualified coatings is not considered a detriment to safety for the following reasons:

a. The sources of the unqualified coatings are several relatively small components spread throughout the containment interior.

b. The suction strainer is qualified for greater quantities of debris.

c. As discussed in subsection 6.2.2.2, ECCS analyses have been conservatively performed assuming the strainers are fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials).

d. The ECCS system suction strainers are designed to prevent passage of particles larger than 0.1 inch in diameter. This value is less than the diameter of the RHR heat exchanger tubes, containment and ECCS spray nozzles, reactor coolant flow channels, and the ECCS pump running clearances so that paint particles which could potentially block engineered safety features are filtered out.

e. As discussed in subsection 6.2.2.2, the low approach velocity for the strainers minimizes the possibility of paint particles migrating toward the strainers and causing clogging.

Approximately 72,500 square feet of concrete surface is coated within the containment. Out of this, approximately 52,400 square feet of concrete floors and wall surfaces are coated with a thick film surfacer and catalyzed epoxy, approximately 12,100 square feet of concrete wall surfaces are coated with 12.0 mils of catalyzed epoxy, and approximately 8,000 square feet of concrete walls are sealed. All significant protective coatings applied to surfaces within the containment and drywell have been tested to demonstrate that they will remain intact on the surface to which they are applied during postulated LOCA conditions. Tests are performed in accordance with Section 4 of ANSI N101.2, Protective Coatings (Paints) for Light-Water Nuclear Reactor Containment Facilities, to meet or exceed DBA conditions described in subsection 6.2.1.

Major carbon steel components, such as the containment liner plates, structural and miscellaneous steel, polar crane, etc. are protected with an inorganic zinc primer only, with no organic topcoat (with exception of approximately 11,500 square feet which is topcoated with catalyzed epoxy). The suppliers of inorganic zinc primer have issued written statements certifying that any coating leaving the surface during a LOCA would be in the form of a powder that would not clog the ECCS suction strainers in the absence of other debris. Paint debris even in the form of powder could contribute to strainer clogging when combined with other

fibrous debris. See subsection 6.2.2.2 for a discussion of the methodology used for determining debris generation and the treatment of miscellaneous debris such as paint.

All organic coatings applied to steel and concrete surfaces are controlled by a quality assurance program which ensures that the coatings are applied in accordance with project specifications and manufacturers' recommendations.

Documentation required by the quality assurance program provides the same degree of documentation as listed in Section 7, ANSI N101.4. The project position on Regulatory Guide 1.54 is discussed in appendix 3A to this FSAR.

6.1.2.2 Other Organic Materials

A listing of exposed insulation, lubricants, plastics, etc. in the containment is included in Table 6.1-2.

A conservative analysis was performed to determine the effects of radiolysis of the organic material listed in Table 6.1-2. The assumed total energy absorbed for both the drywell and containment material was taken to be the six-month integrated dose of 2.6 x 107 rads. This is very conservative because the radiation absorbed by the organic material would be some factor less than 2.6 x 107 rads since the energy absorbed depends on the actual location of the material and also the fact that the thickness of the material is less than an infinite absorbing thickness for the gamma radiation.

When the six-month integrated accident dose of 2 x 107 rads is compared to the values given in Table 3.11-2, the six-month accident values given in Table 3.11-2 are less than 2.6 x 107 rads.

All gases produced are assumed to be released instantly to the compartment in which they are produced, i.e., the containment or the drywell. This is conservative because a large portion of the gas produced would take a long time to migrate out of its parent material since most of the organic material consists of electrical cable (EPR core jacketed with Hypalon).

As given in Table 5.1 of Reference 1, G values of 1.0 for hydrogen (H_2) and 0.4 for methane (CH_4) were used in the analysis. The amount of organic material capable of releasing hydrogen in the

containment and drywell was conservatively taken from Table 6.1-2 of the FSAR to be 180,000 lbs and 15,000 lbs, respectively. The results obtained are given in Table 6.1-3.

A more rigorous analysis taking into account the energy actually deposited would give significantly less yield in the containment and drywell. However, even for the extremely conservative results presented here it is obvious that the contribution to combustible gas from the radiolysis of the organic material is negligible.

The generation rate of hydrogen that can be formed from the unqualified organic materials under DBA conditions as a function of time is addressed in subsection 6.2.5.3.2 and Figure 6.2-20. The calculation on the hydrogen generation rate of organics used a conservative value of G = 5.0 obtained from the insulation vendor.

The amount of solid debris that can be formed from the unqualified organic materials under DBA conditions that can reach the containment sump is discussed in subsection 6.1.2.1.

6.1.3 Post-Accident Chemistry

Not applicable to Grand Gulf since chemicals are not added to containment sprays or primary cooling systems.

6.1.4 References

1. "Effect of Radiation on Materials and Components" Edited by J. F. Kircher and R. E. Bowman, Reinhold Publishing Corp., 1964 (L.C. No. 64-16977)

TABLE 6.1-1: PRINCIPAL ESF PRESSURE RETAINING MATERIALS

Product Form	ASME Specifications
Plate	SA-516 Gr. 55
	SA-516 Gr. 70
	SA-240 TP. 304
Forgings	SA-105
	SA-182 TP 304
	SA-182 TP 316
Castings	SA-216 Gr. WCB
	SA-351 Gr. CF-8
	SA-351 Gr. CF-3M
	SA-351 Gr. CF-8M
	SA-352 Gr. LCB
Pipe	SA-106 Gr. B
	SA-106 Gr. C
	SA-312 TP. 304
	SA-312 TP 304L
	SA-155 Gr KC 70 Class 1
	SA-155 Gr KCF 70 Class 1
	SA-358 Gr 304 Class 1
Bolting	SA-193 Gr. B7
	SA-307 Gr. B
Nuts	SA-194 Gr. 2H
	SA-194 Gr. 7
Weld rod	SFA 5.1 E7018
	SFA 5.1 E6010
	SFA 5.18 E70S-2
	SFA 5.20 E70T-1

TABLE 6.1-1: PRINCIPAL ESF PRESSURE RETAINING MATERIALS (Continued)

Product Form	ASME Specifications
Weld Rod (Continued)	SFA 5.4 E308L-16
	SFA 5.4 E309L-16
	SFA 5.9 ER308L
	SFA 5.9 ER309
	SFA 5.11 E-NiCrFe-3
	SFA 5.14 ER-NiCr-3

TABLE 6.1-2: OTHER ORGANIC MATERIALS

Containment Building (Excluding Drywell)

Item	Material	Amount	Remarks
HVAC duct insulation	Fiberglass	200 lbs.	
Electrical cable insulation	EPR, Hypalon, or cross-linked polyethylene	176,400 lbs.	Designed to withstand radiation dose
Motor electrical insulation	Synthetic enamel or plastic film	90 lbs.	*
Activated charcoal	Coconut base	4,370 lbs.	*
Lubricating oil	Petroleum base	125 gals.	*
Rodo Foam II joint filler	Polyethylene	270 lbs.	
Protective Coatings	Unqualified paint	326.8 lbs.	

Drywell Section

Item	Material	Amount	Remarks
Electrical cable insulation	EPR, Hypalon, or cross-linked polyethylene	9,835 lbs.	Designed to withstand radiation dose
Motor electrical insulation	Synthetic enamel or plastic film	3,815 lbs.	*

TABLE 6.1-2: OTHER ORGANIC MATERIALS (Continued)

Item	Material	Amount	Remarks
Lubricating oil	Petroleum base	110 gals.	Rustinhibiting, i.e., Shell Ensis 10W.*
Rodo Foam II joint filler	Polyethylene	35 lbs.	
Protective Coatings	Unqualified Paint	550.6 lbs	

*Contained within an enclosure or vessel

TABLE 6.1-3: RESULTS OF ORGANIC RADIOLYSIS ANALYSIS

		Drywell			Containment		
Gas	**G Value**	**Lb-moles**	**% of Total Post-LOCA H_2 at Day 15**	**Vol% Produced[1]**	**Lb-moles**	**% of Total Post-LOCA H_2 at Day 15**	**Vol % Produced[1]**
H_2	1.0	0.43	<1.5	0.07	5.2	<5.0	0.15
CH_4	0.4	0.17	-	0.03	0.03	-	0.06

[1]Volume % produced is based on the following:

	Drywell	Containment
Volume (ft^3)	2.7×10^5	1.4×10^6
Temperature (°F)	135	80
Relative humidity (%)	0.0	0.0
Pressure (psia)	14.7	14.7

6.2 CONTAINMENT SYSTEMS

The containment systems include containment structure (subsection 6.2.1), containment heat removal systems (subsection 6.2.2), secondary containment structure (subsection 6.2.3), combustible gas control system (subsection 6.2.5), containment isolation system (subsection 6.2.4), and the containment leakage testing system (subsection 6.2.6).

This section provides the design criteria and evaluations necessary to demonstrate that the above systems will function within the specified limits throughout the operating lifetime of the plant, including postulated accident analyses.

[HISTORICAL INFORMATION] [The baseline analyses were performed based on the initial core, which was a GEH 8x8 fueled core. The adequacy of containment systems design was verified for Feedwater Heater out of service [(FWHOS), Appendix 15B], Single Loop Operation (Appendix 15C), operation in the Maximum Extended Operating Domain (MEOD) (Appendix 15D), and operation with reload cores.]

As part of the EPU extended power project, LOCA recirculation-break Cases A and B, as described in this subsection, were re-evaluated and the models were re-performed. The results of the EPU analysis were not included in the PUSAR and not submitted to the NRC for review. Therefore, the Cases A and B descriptions, assumptions and results as noted in the subsection’s narrative, tables and figures were not revised by the EPU analysis. The EPU analysis did determine that a new Case C existed that had more limiting conditions than either existing Case A and B. The results, assumptions, and description of Case C were added to this USFAR subsection. Additionally, the MELLA+ analysis determined that the EPU Case C short-term analysis was affected by the MELLLA+ operation in the extended region. The MELLLA+ Case C short-term analysis results, description, and assumptions, were included in the following USFAR subsection. Another analysis, the main stream line break, within this subsection was affected by the EPU analysis. The EPU results, description and assumptions associated with the main stream line break analysis was included in the subsection’s narrative, tables and figures.

GGNS is currently licensed to operate up to 115% (4408 MWt) of Original Licensed Thermal Power at the same constant steam dome pressure of 1040 psia. The baseline analyses have been re-

evaluated for Extended Power Uprate (EPU) conditions and Maximum Extended Load Line Limit Analysis Plus (MELLLA+), based on a representative core design utilizing the GNF2 fuel. The adequacy of containment systems has been verified for currently licensed flexibility options and equipment out-of-service (OOS) options evaluated for continued applicability with EPU. These options included:

- MEOD (MELLLA+ (See Notes))
- Recirculation Pump Trip OOS
- Safety Relief Valves OOS, ADS Valve OOS, MSIV OOS (below 75% power)
- Turbine Bypass Valves (TBVs) OOS are not credited in fast transient analyses
- The ATWS-RPT is only considered in the ATWS analysis
- Power and Flow Dependent Limits

Notes:

1. Single Loop Operation is not allowed in the MELLLA+ domain (Reference COLR Figure 4).
2. Feedwater Heater OOS operation is not allowed in the MELLLA+ domain, because analyses have not been performed to demonstrate compliance with applicable criteria under these conditions.
3. MELLLA+ allows GGNS to expand the operating power/flow map of the current MEOD.
4. MELLLA+ conditions affect the EPU Containment DBA LOCA short-term response, while EPU affects the Containment DBA LOCA long-term response.

6.2.1 Containment Functional Design

6.2.1.1 Deleted

6.2.1.1.1 Design Basis

The pressure suppression containment system is designed with the following functional capabilities and design:

a. The containment and drywell shall have 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 includes the worst single failure (which leads to maximum containment and drywell pressure and/or temperature) and is further postulated to occur simultaneously with loss of offsite power and a safe shutdown earthquake (SSE). A detailed discussion of the LOCA response analysis is contained in subsection 6.2.1.1.3.3.

b. The sources and amounts of mass and energy release as well as the post-accident time dependence of the mass and energy release for the most severe of the postulated loss-of-coolant accidents (LOCA) are described in subsection 6.2.1.3.

c. Energy released to the containment atmosphere, as a result of the postulated accidents referred to in Paragraph b above, is removed by the containment heat removal systems (i.e., containment spray system and suppression pool cooling system) discussed in subsections 6.2.2 and 6.5.2.

The description of the containment spray system is discussed in subsections 6.2.2 and 6.5.2. The suppression pool cooling system is described in subsection 6.2.2.

For the purpose of the containment peak pressure analysis and the peak suppression pool temperature analysis, the containment heat removal systems were assumed to be affected by the most restrictive single active failure resulting in the minimum heat removal capability. This failure was determined to be the loss of either Division 1 or Division 2 emergency ac electrical power source; however, the division that is not lost has the capability of handling 100 percent of the capacity for the heat removal system.

d. The design containment leakage rate specified in Table 6.2-13 was established as the minimum practicable rate based on consideration of reactor power level, site characteristics, type of containment, iodine removal capability, constructability, testability, meteorology, and dose assessment.

The validity of the established design leakage rate is verified by analysis of the offsite and control room operator radiological consequences of the design basis LOCA as discussed in Chapter 15.

e. The capability for energy removal from the containment under the worst single failure condition is discussed in paragraph c above.

f. The containment in combination with other accident mitigation systems, shall limit fission product leakage during and following the postulated design basis accident

to values less than leakage rates which would result in offsite doses greater than those set forth in 10 CFR 50.67.

g. The containment system and drywell shall withstand coincident fluid jet forces associated with the flow from the postulated rupture of any pipe within the containment or drywell.

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

i. 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.

j. The containment system is designed with means to channel the flow from postulated pipe ruptures in the drywell to the pressure suppression pool.

k. The containment system is designed to allow for periodically conducted tests at the peak pressure calculated to result from the postulated design basis accident in order to confirm the leaktight integrity of the containment and its penetrations.

6.2.1.1.2 Design Features

The design features of the containment structure and internal structures are described in the text and figures of subsections 3.8.1 and 3.8.3 respectively.

6.2.1.1.2.1 Protection from the Dynamic Effects of Postulated Accidents

The containment structure, internal structures, and engineered safety feature systems are protected from loss of safety function due to the dynamic effects of postulated accidents. Containment design has provided separation and inclusion of barriers and restraints when required to protect essential structures and safe-shutdown systems and components from internally generated missiles, pipe whip, and jet impingement forces. The detailed criteria, locations, and descriptions of devices used for protection are given in Sections 3.5 and 3.6.

6.2.1.1.2.2 Codes and Standards

Codes and standards applied to the design, fabrication, and erection of the containment and internal structures are discussed in subsection 3.8.1.2 for the containment and in subsection 3.8.3.2 for the internal structures. In each case, the codes and standards used are consistent with the equipment safety function.

6.2.1.1.2.3 Qualification Tests

[HISTORICAL INFORMATION] [The General Electric Mark III Analytical Model was used in the design of the containment at Grand Gulf. This analytical model was verified in large-scale tests performed by GEH. This ongoing test program and the results are discussed in detail in GE Topical Reports NEDO 20201A, 20345, 20550, 20732, and 20853.]

6.2.1.1.2.4 Protection Against External Pressure Loads

No special provisions for protection against loss of containment integrity under external loading conditions are required. Consideration given to inadvertent operation of containment heat removal systems and other possible modes of plant operation that could potentially result in significant external structural loading has resulted in pressures lower than the design containment external pressure (refer to Table 6.2-13). Refer to subsection 6.2.1.1.4.2 for discussion of the margin between the design value and the lowest expected internal pressure.

6.2.1.1.2.5 Potential Water Traps Inside Containment

The only location within the containment which could trap water is the cavity inside the weir wall. However, any water trapped in this cavity during normal plant operation would be drained via floor drains to a sump under the RPV and pumped to the auxiliary building and finally to the radwaste building. During Design Basis Accidents, water could be trapped in this cavity because the floor drains system is automatically isolated. This condition is included in the analyses for various accidents.

6.2.1.1.2.6 Containment Cooling and Ventilation Systems

During normal reactor operation, the containment average air temperature is maintained below Technical Specification limits by continuous operation of the containment cooling system. A detailed description of the normal containment cooling system is

provided in subsection 9.4.7. This system is not safety-related since a total failure of the containment cooling system will not result in exceeding design conditions inside containment.

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 shown in Tables 6.2-1, 6.2-2, and 6.2-13.

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 Design Basis Accident (DBA) for this containment system.

The maximum drywell pressure occurs during the blowdown phase of a main steam line break. The peak containment pressure occurs during the short-term containment pressure response.

The most severe drywell temperature condition (peak temperature and duration) occurs during a long-term containment response to a recirculation line break that results in the blowdown of reactor steam to the drywell. In order to demonstrate that breaks smaller than the rupture of the largest primary system pipe will not exceed the containment design parameters, the containment system responses to an intermediate size liquid break and a small size steam break are evaluated. The results show that the containment design conditions are not exceeded for these smaller break sizes.

All of the analyses assume that the primary system and containment are initially at the maximum normal operating conditions. References are provided 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.

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 those conservatively reduced capacities assumed for containment analyses.

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 a recirculation line (Limiting case for a long-term cooling analysis)

b. An instantaneous guillotine rupture of a main steam line (Limiting case for a short-term cooling analysis)

c. An intermediate size liquid line rupture

d. A small size steam line rupture

The following is a summary of GEH computer codes used in the DBA LOCA analyses of containment pressure and temperature responses. The M3CPT code was used to model the short-term containment pressure and temperature response. The modeling used in the M3CPT analyses is described in references 12 and 32. References 12 and 32 describe the basic containment analytical models used in GEH codes. Reference 31 describes the more detailed Reactor Pressure Vessel model (LAMB) used for determining the vessel break flow in the containment analyses for the uprated power condition at off-rated conditions. The LAMB code models the recirculation loop as a separate pressure node. It also allows for inclusion of flashing in the pipe and vessel during the blowdown and flow choking at the jet pump nozzles when the conditions warrant. The SHEX code was used to model the long-term containment pressure and temperature response. The key models in SHEX are based on models described in Reference 12.

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 12 jet pump nozzles associated with the broken loop. In addition, the cleanup line crosstie will add to the critical flow area. Table 6.2-3 provides a summation of the break areas.

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 and the system mass is minimized. That is:

   1. The reactor is operating at 102 percent of rated core power. This maximizes the post-accident decay heat.

   2. The standby service water temperature is at the maximum which is 90 F.

   3. The suppression pool mass is at the low water level.

   4. The suppression pool temperature is at the maximum for normal conditions, which is 100 F.

b. The recirculation 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 flowrates are calculated using Moody's critical flow model (Ref. 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 flowrates. 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 near homogeneous two phase flow pattern and phase non-equilibrium. 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 reactor pressure vessel 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 20 seconds. The high RPV pressure increases the calculated blowdown flowrates 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. The main steam isolation valves start closing at 0.5 second after the accident. They are fully closed in the shortest possible time of three seconds following closure initiation. In actuality, the closure signal for the main steam isolation valves will occur from low reactor water level, so the valves will not receive a signal to close for greater than four seconds, and the closing time may be as long as five 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. Analysis shows that no safety relief valves will open following either a main steam or recirculation line DBA.

g. Reactor feedwater is assumed to flow into the reactor vessel continuously, at varying rates, for a total flow of 18.935 Mlb/hr and an enthalpy of 525.1 Btu/lbm.

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.

i. A single active failure (loss of offsite power) is assumed during the accident.

j. The operator action time for RHR heat exchanger initiation is 30 minutes.

k. Upper pool dump is initiated at 30 minutes.

l. All motor-driven ECCS pumps are available and start according to design. When not injecting, they switch to minimum pump flow to the suppression pool. This maximizes pool temperature response with pump heat.

m. The reactor pressure vessel control volume includes the fluid and structural masses and energy of the primary system components including the reactor vessel, recirculation loops and the attached system lines to the first isolation valve.

n. The control rod drive flow is assumed to be zero after initiation of the event; this maximizes the reactor coolant enthalpy.

o. Passive heat sinks are credited in the drywell and wetwell airspace. No through-wall heat transfer is credited from the drywell to containment or from containment to environs.

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 containment. Since highly turbulent conditions are expected due to the blowdown flow, the analysis conservatively 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 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 occurs from the gases inside the containment. In reality, condensation of some steam on the drywell surfaces would occur.

The short-term analysis for MELLLA+ included several new assumptions note used in previous analyses. These included an instantaneous pipe break occurring at the nozzle safe end to the pipe weld, the fluid inventories initially occupying the broken lines were included in the blowdown calculations, the primary fluid and piping lines were included as part of the initial vessel fluid and metal energy (e.g., recirculation, main steam, feedwater, etc.) and no heat sinks were credited in the drywell or containment. These assumptions maximized the drywell pressure response.

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 during this period is analyzed using the following assumptions for Cases A and B:

a. The LPCI pumps are used to flood the core prior to 600 seconds after the accident. The HPCS is available for the entire accident.

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

c. The suppression pool is the only heat sink available in

the containment system.

d. After approximately 1800 seconds, the RHR heat exchangers are activated to remove energy from the containment via recirculation cooling of the suppression pool with the standby service water systems.

e. The performance of the ECCS equipment during the long-term cooling period is evaluated for each of the following cases of interest.

The following assumptions for Case C:

a. The operator action time for RHR heat exchanger initiation is 30 minutes. Operators switch one RHR pump from LPCI mode to coolant injection cooling mode at 30 minutes.

b. Upper pool dump is initiated at 30 minutes.

c. All motor-driven ECCS pumps are available and start according to design. When not injecting, they switch to minimum pump flow to the SP. This maximizes pool temperature response with pump heat.

d. The RPV control volume includes the fluid and structural masses and energy of the primary system components including the reactor vessel, recirculation loops and the attached system lines to the first isolation valve (main steam, RCIC, HPCS, RWCU, RHR/LPCI, and LPCS).

e. Thermal equilibrium exists between the wetwell airspace and the suppression pool for the first 30 seconds from the initiation of the event. The mixing between the containment air space and the suppression pool and the resulting air space heat-up is modeled mechanistically by realistic heat and mass transfers between the suppression pool and the wetwell airspace after 30 seconds.

f. Each wetwell-drywell vacuum breaker set is fully open at 1.0 psid.

g. The initial drywell pressure is at the maximum Technical Specification (TS) limit.

h. The initial drywell and wetwell relative humidity is at its minimum expected value of 20%. This maximizes the containment pressure response.

i. The initial wetwell pressure is at the maximum TS limit and temperature is at its minimum value. This maximizes the containment pressure response.

j. The control rod drive (CRD) flow is assumed to be zero after initiation of the event. The CRD flow is relatively cold compared to the reactor coolant. The assumption of zero CRD flow maximizes the reactor coolant enthalpy.

k. Passive heat sinks credited in the drywell and wetwell airspace. No through-wall heat transfer is credited from the drywell to containment or from containment to environs passive exposure to the containment airspace.

Case A. Offsite power available - all ECCS equipment operating.

Case B. Loss of offsite power - minimum diesel power available for ECCS.

Case C. Loss of offsite power – only one RHR heat exchanger available.

6.2.1.1.3.3.1.4 Initial Conditions for Accident Analyses

Table 6.2-4 provides the initial reactor coolant system and containment conditions used in all the accident response evaluations. The tabulation includes parameters for the reactor, the drywell, the containment, and the vent system.

Table 6.2-3 provides the initial conditions and numerical values assumed for the recirculation line and main steam line break and the postulated pipe rupture. The assumed conditions for the reactor blowdown are also provided.

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 in Figures 6.2-2 and 6.2-3, respectively. Following the break, the drywell pressure increases rapidly due to the injection of the break flow. The peak drywell pressure occurs during the vent clearing phase of the transient as suppression pool water is being cleared from the vents. Following vent clearing, the drywell pressure decreases as the break flow decreases.

The containment is pressurized early in the transient by the carryover of noncondensables from the drywell. As the transient continues, break flow is injected into the suppression pool, and the temperature of the suppression pool water increases, causing the containment pressure to increase. To address Humphrey Issue 7.3 (Grand Gulf Action Plan 40), the effects of differences between the containment air-space temperature and pool temperature on short-term pressures in the containment were evaluated. These non-equilibrium effects increase the containment pressure by about 10 percent for the interval between 2 and 20 seconds into the transient. The containment design is still limited by the long-term pressure response driven by the suppression pool temperature where the assumption of thermal

equilibrium between the suppression pool and containment is conservative. At the end of the blowdown, the drywell pressure stabilizes at a slightly higher pressure than the containment, the difference being equal to the hydrostatic head of vent submergence. During the RPV depressurization phase, most of the noncondensable gases initially in the drywell are forced into the containment. However, following the depressurization the noncondensables will redistribute between the drywell and containment 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.

The ECCS supplies sufficient core cooling water to control core heatup and limit metal-water reaction to less than 1 percent. 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 pool via the drywell-to-suppression pool vent system.

Table 6.2-5 provides the peak pressure, temperature, and time parameters for the recirculation and main steam line breaks as predicted for the conditions of Table 6.2-1 and in correspondence with Figures 6.2-2 and 6.2-3. Figure 6.2-2 shows the time dependent response of the drywell differential pressure.

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 6.2-4 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

The analysis assumptions are those discussed in subsection 6.2.1.1.3.3.1.3 for the three cases of interest. The initial pressure response of the containment (the first 1800 seconds after break) is the same for each case.

CASE A: All ECCS equipment operating

This case assumes that offsite ac power is available to operate all cooling systems. During the first 1800 seconds following the pipe break, the high pressure core spray (HPCS), low pressure core spray (LPCS), and all LPCI pumps are assumed operating. All flow is injected directly into the reactor vessel.

After 1800 seconds, both RHR heat exchangers are activated to remove energy from the containment. During this mode of operation the flow from two of the LPCI pumps is routed through the RHR heat exchanger where it is cooled before being injected into the reactor vessel.

The containment pressure response to this set of conditions is shown as curve A in Figure 6.2-5. The corresponding drywell and suppression pool temperature responses are shown in Figure 6.2-6. 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 RHRS exceeds the energy addition rate from the decay heat, the containment pressure and temperature reach a second peak value and decrease gradually. Table 6.2-6 summarizes the cooling equipment operation, the peak long term containment pressure and the peak suppression pool temperature.

CASE B: Loss of offsite power - minimum ECCS equipment operating

This case assumes no offsite power is available following the accident with only minimum diesel power. Only the HPCS and one LPCI are operating during this event. During this mode of operation the LPCI flow through only one RHR heat exchanger is directed to the reactor pressure vessel. The containment pressure response to this set of conditions is shown as curve B in Figure 6.2-5. The corresponding drywell and suppression pool temperature responses are shown in Figure 6.2-7. A summary of this case is given in Table 6.2-6.

Figure 6.2-8 shows the integrated decay heat and heat exchanger rejection as a function of time (subsection 6.2.2 describes the rate shown for the two cases). The first assumes that all the ECCS equipment is available, including both RHR heat exchangers and the associated standby service water pumps. The second case is for the very degraded minimum cooling condition that would limit the

heat removal capacity to one heat exchanger. For both cases, it was very conservatively assumed that at the time of the accident the standby service water (SSW) temperature was 90 F. This is the maximum that will occur at this site and is unlikely to exist for more than a limited period in the summer.

Case C: One RHR heat exchanger operating – all ECCS equipment operating

For this analysis, as described on Table 6.2-6, all ECC pumps are assumed available and operate in accordance with their design requirements throughout the event. A single failure is still assumed, which renders only one RHR heat exchanger available for containment cooling. This event scenario results in maximum pump heat while maintaining the minimum RHR heat exchanger heat removal capacity. It is assumed that operators initiate containment cooling no earlier than 30 minutes from the initiation of the event. The containment cooling in RHR LPCI mode is assumed at 30 minutes from the initiation of the event. Service water is also provided to the RHR heat exchanger with a temperature of 90°F. All remaining available ECCS pumps, including one HPCS pump, one LPCS pump, and two LPCI pumps are assumed to continue operation to maintain reactor vessel coolant make-up for the entire event. The key results for the long-term DBA LOCA RSLB Containment Response are given below:

The analysis for Long-Term Containment DBA LOCA response indicates that the post-LOCA RHR system heat load increases due to an increase in the maximum suppression pool temperature that occurs following a LOCA. The post-LOCA containment and suppression pool responses were calculated based on an energy balance between the post-LOCA heat loads and the existing heat removal capacity of the RHR system and the standby service water system.

Figures 6.2-5a, 6.2-101 through 6.2-106 provide graphic representation of the drywell, wetwell(containment), and suppression pool response to this bounding DBA LOCA a double-ended break of a recirculation suction line (RSLB)event Case C. Peak values shown in these figures are for times beyond the first 30 minutes of the event.

6.2.1.1.3.3.1.7 Energy Balance During Accident

In order 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 6.2-8)

f. Metal-water reaction heat rate.

Items a, b, c, and d are provided in subsection 6.2.1.3, Mass and Energy Releases Analyses for Postulated Loss-of-Coolant Accidents. A complete energy balance for the recirculation line break accident is given in Table 6.2-7 for the reactor system, the containment, and the suppression pool cooling system at time zero, at the time of peak drywell pressure, at the end of reactor blowdown, and at the time of the long term peak pressure in the containment.

6.2.1.1.3.3.2 Main Steam Line Break

A complete description of the containment response to the design basis steam line break is given in this subsection. Results for this accident are shown in Figures 6.2-5 through 6.2-8, 6.2-10, and 6.2-11. A chronological sequence of events for this accident (Cases A and B) from time zero is provided in Table 6.2-8. Containment vent response for Case C is shown in Figure 6.2-107.

The response of the reactor coolant system during the blowdown period of the accident is analyzed using the assumptions listed in subsection 6.2.1.1.3.3.1.1 for the recirculation line break (with the exception of items b and d). The vessel depressurization flow

rates are calculated using Moody's critical flow model. During the first second of blowdown, the flow consists of saturated steam.

Analysis shows that no safety relief valves will open following either a main steam or recirculation line DBA. Figure 6.2-100 shows the reactor vessel pressure as a function of time for the two events. In either case, the pressure increase after the MSIVs close is not large enough to cause any SRVs to open.

The assumed sudden rupture of a main steam line 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 differential pressure The sequence of events immediately following the rupture of a main steam line between the reactor vessel and the flow limiter have been determined. The flow in both sides of the break will accelerate to the maximum allowed by the critical flow considerations. In the side adjacent to the reactor vessel, the flow will correspond to critical flow in the steam line break area. Blowdown down through the other side of the break will occur because the steam lines are all interconnected at a point upstream of the turbine by the bypass header. 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. The total effective flow area is given in Figure 6.2-9 which is the sum of the steam line cross-sectional area and the flow restrictor area. 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. The effective break area in this case would start to reduce at 5 seconds rather than 4.2 seconds as demonstrated in Figure 6.2-9. The peak drywell pressure occurs before the reduction in effective break area and is therefore insensitive to a possible slower closure time of the isolation valves 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 13520 lb/sec, which exceeds the steam generation rate in the core of 4500 lb/sec. This steam flow to steam generation mismatch causes an initial vessel depressurization of the reactor vessel at a rate of approximately 60 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 drywell in a super-heated condition of approximately 330 F.

Figures 6.2-10 and 6.2-11 show the pressure and temperature responses of the drywell and suppression chamber during the primary system blowdown phase of the steam line break accident.

Figure 6.2-11 shows that the drywell atmosphere temperature approaches 330 F after one second of primary system steam blowdown. At that time, the water level in the vessel will reach the steam line 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 resulting 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.

Table 6.2-5 presents the peak pressures, peak temperatures, and times of this accident as compared to the recirculation line break.

Approximately 100 seconds after the start of the accident, the primary system pressure will have dropped to the drywell pressure and the blowdown will be over. At this time the drywell will contain saturated steam, and the drywell and containment 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 steam line 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 containment pressure, the drywell vacuum breakers will open and noncondensable gases from the containment will flow back into the drywell. This process will continue until the pressure in the two regions equalize.

6.2.1.1.3.3.2.1 Drywell Pool Formation

The containment accident response analyses assume that the ECCS pumps will continue to operate until water flows out the break and spills onto the drywell floor. This results in a pool on the drywell floor which is assumed to be mixed with the main bulk of the suppression pool. To assess Humphrey Issue 4.1 (Grand Gulf Action Plan 10), the inventory of the drywell pool was assumed to be thermally isolated and the remainder of the heat rejected to the suppression pool. An analysis was performed to evaluate the maximum effect on bulk suppression pool temperature. GEH Company's long-term containment response code SHEX, described in References 11 and 12, was used for analysis to maximize heat additions to the suppression pool. This analysis assumed that the drywell pool is formed from 135 F water. This is a very conservative assumption since the actual drywell pool temperature is expected to be over 200 F and the drywell pool at 135 F contains substantially less energy than it is expected to contain. All energy flowing from the break is assumed to pass into the suppression pool instead of into the drywell pool.

The analysis showed that the maximum increase in bulk pool temperature is 10°F. This is within identified margins in long-term suppression pool temperature response analysis.

Humphrey Issue 4.2 (Grand Gulf Action Plan 12) postulated that formation of the drywell pool may never occur due to operator action to throttle the ECCS and stop flow out of the break. If the plant operator throttles ECCS flow to the vessel to maintain vessel level after a postulated break, as required by the emergency procedures, the drywell pool will not be formed from relatively cool ECCS water as postulated in current accident analyses. This will potentially affect the peak containment pressure, long-term peak suppression pool temperature, and maximum suppression pool level.

To evaluate the effect on containment pressure, a simple end-point calculation was performed to evaluate the containment pressure at the peak calculated containment temperature of 181°F. This was based on the conservative assumption of thermodynamic

equilibrium between the suppression pool and containment air space and no redistribution of air between the drywell and containment. Additional assumptions are listed in subsection 6.2.2.3.1. The long-term containment pressure, as calculated at the peak temperature, is 8.5 psig which is below the design limit of 15 psig.

The peak pool temperature resulting from a realistic analysis of a main steam line break was calculated to be 189°F assuming:

a. Drywell pool was not formed due to ECCS throttling

b. Only one train of RHR is available

c. Break flow energy is introduced directly into the drywell

The peak suppression pool temperature for this analysis is thus below the peak suppression pool temperature for the design basis accident. Thus failure to form the drywell pool reduces the suppression pool and containment response.

If the drywell pool is not formed, then the additional water volume will raise the height of the suppression pool. The maximum suppression pool level is 26.2 feet. This is based upon initial suppression pool level at the normal high water level, upper pool dump, and the weir annulus level equal to the level of the top vent. While ECCS flow is throttled, a postulated break may be releasing saturated steam into the drywell. Humphrey Issue 9.1 (Grand Gulf Action Plan 11) analyzed the effect of not redistributing air from the containment back to the drywell. A more realistic analysis using GEH Code VACBR04 was performed to show that even with no redistribution of containment air to drywell, adequate margin exists between the peak calculated and design containment pressures.

6.2.1.1.3.3.3 Hot Standby Accident Analysis

Both the short term and long term response to the containment system have been evaluated assuming the reactor has been operating in the hot standby mode prior to the blowdown. The potential exists for very slight increases in the peak containment pressure when evaluated with the reactor at full power.

The peak drywell pressure is dependent upon the rise time of the reactor water level and therefore the time at which the two phase blowdown begins.

A one second level rise time is a conservative bounding condition and therefore represents the level rise time for the hot standby blowdown since the reactor is at a reduced power and pressure level. The peak drywell pressure will be lower than that shown for a full power DBA (Figure 6.2-10).

In the event of a recirculation line break, the short term blowdown flow rate is essentially independent of the reactor power level if the same initial reactor pressure is assumed for all power levels. In practice, the lower reactor pressures associated with reduced reactor power would result in lower blowdown flow rates and peak drywell pressures less than the value presented in Figure 6.2-2. The short term drywell response to either a steam line or recirculation line break is insensitive to the suppression pool water temperature. This is because the transient is dominated by the rate at which energy is dumped to the drywell and the rate at which vent clearing can be accomplished. Neither is sensitive to pool temperature.

The short term containment response is changed somewhat by assuming that the reactor has been in a hot standby condition prior to the blowdown. During a period of hot standby operation, the pool could reach 122 F. In the event of a LOCA the post-blowdown pool temperature would be approximately 167 F. This compares with the post blowdown temperature of 145 F shown for both the steam and recirculation line break. As a result of the higher air temperature, there could be an increase in post blowdown containment pressure of up to 4-1/2 psi. However, since the maximum pool temperature and containment pressure would still occur during the long term transient, any potential increase in the post blowdown containment temperature and pressure is unimportant.

The long term suppression pool and containment transient is only affected very slightly by a period of hot standby operation prior to a blowdown. Figure 6.2-12 shows a comparison of the pool temperature transients following a blowdown at:

a. Maximum power/maximum normal pool temperature

b. Following 1/2 hour of hot standby operation

c. Following 1-1/2 hours of hot standby operation

If a blowdown were to occur after a period of hot standby, it is possible for the subsequent peak suppression pool temperature to be slightly higher than the peak value associated with the full power blowdown. A blowdown at 1/2 hour after an isolation results in the greatest increase in the peak long term temperature. This is because it is arbitrarily assumed that no heat is rejected from the system for 1/2 hour after the start of an isolation event. After a 1/2 hour period of hot standby operation during which all decay heat is rejected to the suppression pool via relief valve steam flow, the pool would be at 110 F. If the blowdown (either a steam or recirculation line break) occurs at this time, the end of blowdown pool temperature would be the same as the pool temperature 1/2 hour following a blowdown at full power. This is because both cases started at the same point (reactor at full power and pool at maximum normal temperature), and in both cases no heat is removed from the system for the first 1/2 hour. If it is now assumed that, for the blowdown that has occurred at hot standby, the operators wait an additional 10 minutes before initiating containment cooling, the effect on the peak suppression pool temperature would be equivalent to assuming that the operators waited 40 minutes after full power blowdown before activating the heat exchangers. This would result in an increase in the peak suppression pool temperature of no more than 1/2 F. This would translate into a peak containment pressure increase of approximately 0.1 psi. Despite the fact that subsequent to the first 1/2 hour of hot standby the suppression pool temperature would increase to approximately 115 F at 1-1/2 hours, a blowdown during this time would not result in a long term peak suppression pool temperature increase greater than the 1/2 F associated with a blowdown after 1/2 hour of hot standby operation.

It should be emphasized that the peak containment pressure increase of 0.1 psi for a blowdown occurring during hot standby operation represents a grossly conservative bounding calculation. That is, a loss of offsite power at a time when the reactor is at 105 percent rated steam flow, when the suppression pool temperature is at the maximum normal value, when only one RHR heat exchanger (in a fully fouled condition) is available and when the standby service water temperature is at its maximum value

represents a highly improbable sequence of events. To further assume that under these conditions the plant operators prepare for a period of hot standby rather than immediately initiating an orderly shutdown is not a very realistic assumption. In fact, with only one heat exchanger available, the plant operators would not be able to maintain a hot standby condition and would certainly initiate a shutdown. With both heat exchangers available the peak long term pool temperature following a hot standby blowdown would be up to 20 F less than the peak of 181 F shown on Figure 6.2-12.

6.2.1.1.3.3.4 Intermediate Size Breaks

The failure of a main steam 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 square foot 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 square-foot 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-containment differential pressure is equal to the vent submergence hydrostatic pressure.

Figures 6.2-13 and 6.2-14 show the drywell and containment pressure and temperature response, respectively. The ECCS response is discussed in Section 6.3. Approximately 5 seconds after the 0.1 square foot 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 containment-free space. The continual purging of drywell air to the containment will result in a gradual pressurization of both the containment and drywell to about 3 and 6 psig, respectively. The containment will continue to gradually increase in pressure due to the long-term pool heatup.

The ECCS will be initiated by the 0.1 square foot 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 containment pressures to equalize in the same manner as following a main steam line rupture.

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

From this description, it can be concluded that the consequences of an intermediate size break are less severe than from a main steam line rupture.

6.2.1.1.3.3.5 Small Size Breaks

6.2.1.1.3.3.5.1 Reactor System Blowdown Considerations

This section discusses the containment transient associated with small primary systems blowdowns. 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. Thus, if the drywell is at atmospheric pressure (for example) the steam and liquid associated with a liquid blowdown would be at 212 F.

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).

It can be seen then, that 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 steam line 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 containment isolation. 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 annulus until the level begins to clear 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 containment-free space.

The air carryover will result in a gradual pressurization of the containment at a rate dependent upon the size of the steam leak. Once all the drywell air is carried over to the containment, pressurization of the containment 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 at 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. Thus, for design purposes, it is assumed that the drywell is at 30 psig; this results in a temperature of 330 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 GEH to evaluate the containment response during the reactor blowdown phase of a LOCA are described in References 11 and 12.

6.2.1.1.3.4.2 Long-Term Cooling Mode

Once the RPV blowdown phase of the LOCA is over, a fairly simple model of the drywell and containment may be used. 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 in Figure 6.2-15. Since there is no change in mass storage in the system (the RPV is reflooded during the blowdown phase of the accident), the mass flowrates shown in the figure are equal thus:

$$\dot{m}_{D_0} = \dot{m}_{S_0} = \dot{m}_{ECCS} \qquad \text{Equation 6.2-1}$$

6.2.1.1.3.4.3 Analytical Assumptions

The key assumptions employed in the model are as follows:

a. The drywell and containment atmosphere are both saturated (100% relative humidity).

b. The drywell atmosphere temperature is equal to the temperature of the coolant spilling from the RPV.

c. The containment atmosphere temperature is equal to the suppression pool temperature.

d. No credit is taken for heat losses from the containment or to the containment internal structures.

The assumption that the suppression pool is in thermal equilibrium with the containment air space provides a conservative response of the containment long-term temperature.

6.2.1.1.3.4.4 Energy Balance Considerations

[HISTORICAL INFORMATION] [The rate of change of energy in the suppression pool, Ep, is given by:

$$\frac{d}{dt}(E_p) = \frac{d}{dt}(M_{W_s} h_s)$$

$$= h\frac{d}{dt}(M_{W_s}) + M_{W_s}\frac{d}{dt}(h_s)$$

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:

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

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:

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

This equation can be rearranged to yield:

$$\frac{d}{dt}(T_S) = \frac{\dot{m}_{D_o} h_D - \dot{m}_{s_o} h_s}{C_v M_{w_s}} \qquad \text{Equation 6.2-2}$$

An energy balance on the RHR heat exchanger yields

$$h_c = h_s - \frac{\dot{q}_{H_X}}{\dot{m}_{s_o}} \qquad \text{Equation 6.2-3}$$

where,

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

Similarly, an energy balance on the RPV will yield:

$$h_D = h_c + \frac{\dot{q}_D + \dot{q}_e}{\dot{m}_{ECCS}} \qquad \text{Equation 6.2-4}$$

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

$$\frac{d}{dt}(T_s) = \frac{\dot{q}_D + \dot{q}_e - \dot{q}_{H_X}}{C_v M_{w_s}} \qquad \text{Equation 6.2-5}$$

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.

The containment temperature at any time will be equal to the current temperature of the pool, T; and the drywell temperature, T_D, will be equal to the temperature of the fluid leaving the RPV. Thus:

$$T_D = T_s + \frac{\dot{q}_D + \dot{q}_e - \dot{q}_{H_X}}{C_p \dot{m}_{ECCS}}$$

where C_p = Constant pressure specific heat of water, Btu/lb-F

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

$$P_D = P_{a_D} + P_{V_D} \qquad \text{Equation 6.2-6}$$

$$P_c = P_{a_c} + P_{V_c} \qquad \text{Equation 6.2-7}$$

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_c = containment total pressure, psia

P_{a_c} = partial pressure of air in the containment, psia

P_{v_c} = partial pressure of water vapor in the containment, psia

and, from the Ideal Gas Law

$$P_{a_D} = \frac{M_{a_D} R T_D}{V_D (144)} \qquad \text{Equation 6.2-8}$$

$$P_{a_c} = \frac{M_{a_c} R T_s}{V_c (144)} \qquad \text{Equation 6.2-9}$$

where

M_{a_D} = mass of air in the drywell, lb

M_{a_c} = mass of air in the containment, lb

R = gas constant for air, ft-lb_f/lb-R

V_D = drywell free volume, ft^3

V_c = containment 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_C}.]

6.2.1.1.3.4.6 Solution of Equations

[HISTORICAL INFORMATION] [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 Ts at the end of a time step has been calculated, a pressure balance is made. Using values of M_{a_D} and M_{a_c} 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_C 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_C is greater than or equal to P_D, then the two values are made equal since the vacuum breakers between the drywell and containment ensure that P_C cannot be greater than P_D.

Hence, with P_D = P_C and knowing that:

$$M_{a_D} + M_{a_c} = \text{constant}; \qquad \text{Equation 6.2-10}$$

where the constant is the known total initial mass of air in the containment and drywell prior to the accident, equations 6.2-6, 6.2-7, 6.2-8, and 6.2-9 can be solved for ${}^{M}a_C$, ${}^{M}a_D$, and P_c / 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,

$$P_c \leq P_D \leq P_c + \frac{Hg}{\nu_w (144) g_c}$$

where: g = acceleration of gravity, ft/sec^2

g_c = constant of proportionality in Newtons Second Law, ft-lb/lb$_f$-sec^2

H = submergence of vents, feet

ν_w = specific volume of fluid in vent ft^3/lb

then the pressure in the drywell is higher than the pressure in the containment 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 containment. 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 using the updated temperatures with the same ${}^{M}a_C$ and ${}^{M}a_D$ values from the previous time step.

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

$$P_D > P_c + \frac{Hg}{\nu_w (144) g_c}$$

then the drywell pressure is set to the value:

$$P_D = P_c + \frac{Hg}{\nu_w (144) g_c} \qquad \text{Equation 6.2-11}$$

This assures that the drywell pressure can never exceed the containment pressure by more than the hydrostatic head associated with the submergence to the top of the upper row of vents. To

maintain this condition, some transfer of drywell air to the containment 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:

$$P_{V_D} + \frac{M_{a_D} R T_D}{(144) V_D} = P_{V_c} + \frac{M_{a_c} R T_s}{(144) V_C} + \frac{Hg}{\nu_w (144) g_c}$$

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

The analytical model for the Mark III containment is thoroughly discussed in References 11 and 12. Applicable test data to support the selected analytical methods are referenced in these reports.]

6.2.1.1.3.5 High-Energy Line Rupture in Mark III Containment

In order to pass from the drywell to the auxiliary building, some primary system pipes pass through the containment (the main steam lines for example). If these pipes were unguarded, rupture within the containment would result in a direct release of primary system fluid to the containment atmosphere. The pressure suppression features of the containment would thus be bypassed and the potential would exist for a pipe rupture to produce significant containment pressures.

Because of this potential, all reactor coolant pressure boundary pipes of a size which would result in containment overpressurization which pass through the containment, with the exception of the LPCI, HPCS, and LPCS, are provided with guard pipes that vent to the drywell. Refer to Section 3.6 for a discussion of these breaks. Thus, in the event of a pipe rupture, the blowdown flow will pass through the suppression pool vent system, and the steam will condense. The traversing in-core probe (TIP), control rod drive (CRD) insert and withdraw, Reactor Water Cleanup System and instrument lines could also discharge primary system coolant to the containment in the event of a rupture. The unisolatable instrument line rupture results in the maximum discharge of primary system coolant to the containment. This accident is discussed in Chapter 15, where it is shown that the containment pressure increase would be less than 2 psi. Each instrument line contains a 1/4” diameter flow restricting orifice.

The LPCI, LPCS, and HPCS lines have check valves inboard of the drywell penetration that will prevent blowdown to the containment. The major components of the reactor water cleanup system are located within the containment. The system suction line penetrates the drywell and is provided with a guard pipe. The cleanup system components located inside the containment are provided with break detection and isolation systems that will limit the total blowdown fluid flow to the containment to acceptable values.

6.2.1.1.4 Negative Pressure Design Evaluation

6.2.1.1.4.1 Evaluation of Drywell Negative Pressure

[HISTORICAL INFORMATION] [Somewhere between 100 and 600 sec the ECCS system will flood the vessel causing instantaneous condensation of steam in the drywell. At this time all the air initially in the drywell will have been purged into the containment. To evaluate the containment pressure at this time, the initial quantity of air in both the drywell and containment is needed.

Initial mass in drywell, $M_D = \dfrac{144(P_D - P_v)V_D}{RT_D}$

where

P_D = Pressure in drywell initially = 14.7 psia

P_v = Partial pressure of vapor = φP_{sat}

T_D = Temperature of drywell = 135°F = 595°R

R = Gas constant = 53.34 ft-lb_f/lb_m-R

V_D = Volume of drywell = 270,000 ft^3

φ = Relative humidity = 0.40

P_{sat} = Sat. pressure at 135°F = 2.54 psia

Therefore,

MD = 16,761 lbm of air

Initial mass in containment, $M_c = \dfrac{144(P_c - P_v)V_c}{RT_c}$

where

P_c = Pressure in containment initially = 14.7 psia

P_v = Partial pressure vapor = φP_{sat}

V_c = Volume of containment = 1,400,000 ft^3

R = Gas constant = 53.34 ft-lb_f/lb_m-R

T_c = Initial temperature = 80°F = 540°R

φ = Relative humidity = 0.20

P_{sat} = Sat pressure = 0.51 psia

Therefore,

M_c = 102,177 lbm of air

From the above air masses the post-blowdown containment pressure can be calculated.

$$P_C = \frac{\Sigma M(RT_p)}{144V_c} + P_{sat}$$

where,

ΣM = Summation of initial air mass in containment and drywell = 118,938 lbm air

R = Gas constant = 53.34 ft-lb_f/lb_m-R

T_p = Final temperature = temperature of pool = 170°F = 630°R

V_c = Containment volume = 1,400,000 ft^3

φ = Final relative humidity = 1.0

P_{sat} = Saturation pressure at 170°F = 5.99 psia

Therefore,

$P_C = 25.82$ psia

To evaluate the minimum drywell pressure at this time the following assumptions are made:

a. All steam in the drywell is condensed

b. ECCS flow out of vessel is at temperature of 170°F

c. Assume all the air has been purged out of drywell pressure

d. No vacuum breakers

Using these assumptions the final drywell pressure is equal to the saturation pressure at 170°F.

$$P_D = P_{sat_{170}} = 5.990 \text{ psia}$$

Therefore, the negative pressure load across the drywell wall is the difference in the final pressures of the containment and drywell.

$$\Delta P_D = P_D - P_C$$

$$= 5.990 - 25.82$$

$$\approx -19.8 \text{ psid}$$

This calculation represents a very conservative bounding calculation of the maximum theoretical negative pressure. The assumptions that no noncondensibles return to the drywell via the vacuum relief system and that the steam temperature in the drywell instantaneously drops to the suppression pool temperature are both very conservative. In addition, the realistic estimate of relative humidity in containment is 50 percent rather than the 100 percent assumed.]

6.2.1.1.4.2 Evaluation of Containment Negative Pressure

[HISTORICAL INFORMATION] [The transients which could result in significant negative pressure within the containment all involve the inadvertent actuation of the containment spray while the containment atmosphere is at high temperature and humidity. The

greatest negative pressure condition would occur if there is a break in the reactor water cleanup (RWCU) system followed by actuation of containment spray.

The calculated maximum negative containment pressure for this case is less than l psid. The very conservative initial conditions assumed for the evaluation are:

Containment free air volume	1.4×10^6 ft^3
Temperature	80°F
Pressure	14.7 psia
Relative humidity	60%
Drywell free air volume	0.27×10^6 ft^3
Temperature	135°F
Pressure	14.7 psia
Relative humidity	50%
Suppression pool temperature	60°F

The peak containment pressure resulting from the break would be less than 4 psig. The steam released to the containment is assumed to result in a change of temperature and relative humidity at the time of spray initiation to the following:

Temperature	141°F
Relative humidity	100%

Assumptions used for this calculation of negative pressure are as follows:

a. There is no heat transfer between the suppression pool and the containment atmosphere. This assumption is conservative because the suppression pool is the source for the containment spray fluid, and the lower the spray temperature, the greater the value of the negative pressure.

b. Both containment spray trains are assumed to actuate simultaneously and to be 100 percent efficient to maximize the negative pressure.

c. The decay heat input and/or metal-to-water reaction heat input after blowdown is neglected. This is conservative because any additional energy would tend to reduce the magnitude of the negative pressure.

d. The drywell is treated as a compartment having vacuum relief valves permitting flow only from the containment to the drywell. When the containment pressure exceeds the drywell pressure by 0.5 psi, the containment vents to the drywell in order to maintain this differential pressure.

In response to Humphrey Issue 8.2, the effect of operating at the Technical Specification limit for containment internal pressure on the containment negative pressure transient was evaluated. The Technical Specification range for containment internal pressure is -0.1 psid to 1.0 psid. The small allowable negative pressure would allow the final negative pressure to be 0.1 psi higher. This would still be well within the design negative pressure of the containment. If the initial pressure was 1 psi higher, the negative pressure transient would be milder than the result calculated for the RWCU line break.

To evaluate the worst case containment negative pressure transient, a bounding analysis of containment low air mass conditions was performed in response to Humphrey Issue 8.4 (Grand Gulf Action Plan 27). This analysis assumed an initial containment air temperature of 95˚F and evaluated an RWCU line break with blowdown to the containment. The analysis allows the containment pressure to equalize to atmospheric pressure with a steam and air mixture. This minimizes the containment air mass since air and steam are displaced. The analysis then assumes the containment is isolated and the containment air space is cooled instantaneously to 80˚F. The resulting net pressure differential across the containment is less than the design negative pressure of -3.0 psid.

Note: (The differential pressure of 0.5 psi was used as a conservative value for the containment analysis.)

With maximum negative containment pressure for the RWCU break calculated to be less than 1 psid, which is less than the 3 psid negative limit determined by liner plate deformation without exceeding the allowable stress level, a containment vacuum breaker system is not required.]

6.2.1.1.5 Steam Bypass

6.2.1.1.5.1 Introduction

The concept of the pressure suppression reactor containment is that any steam released from the primary system will be condensed by the suppression pool and will not have an opportunity to produce a significant pressurization effect on the containment. This is accomplished by channeling the steam into the suppression pool through a vent system. This arrangement forces any steam released from the primary system to be condensed in the pool. If a leakage path were to exist between the drywell and the containment, the leaking steam would produce pressurization of the containment. To mitigate the consequences of any steam which bypasses the suppression pool, a high containment pressure signal and a high drywell pressure signal will automatically initiate the containment spray system any time after LOCA + ≈10 minutes. Realignment logic and interlocks affecting operation of containment sprays are discussed in subsection 7.3.1.

The following presents the results of calculations performed to determine the allowable leakage capacity between the drywell and containment.

6.2.1.1.5.2 Criteria

The allowable bypass leakage is defined as the amount of steam which could bypass the suppression pool without exceeding the design containment pressure of 15 psig. In calculating this value, a stratified atmosphere model is used to ensure conservatism.

6.2.1.1.5.3 Analysis

[HISTORICAL INFORMATION] [The allowable drywell leakage capacity has been evaluated for the complete spectrum of credible primary system rupture areas. It is expressed in terms of the parameter $\left(A\sqrt{K}\right)$, where

A = Flow area of leakage path, ft^2

K = Geometric and friction loss coefficient

This parameter is dependent only on the geometry of drywell leakage paths and is a convenient numerical definition of the overall drywell leakage capacity. It results from a consideration of the flow process in the leakage paths. Assuming steady state, noncompressible fluid flow theory to be applicable to the leakage flow, the pressure loss between the drywell and containment can be written

$$P_D - P_c = K \frac{V^2}{2g_c} \frac{1}{144v} \quad \frac{lb}{in.^2}$$

where

P_D = Drywell pressure, psia

P_c = Containment pressure, psia

K = Total loss coefficient of the flow path between the drywell and containment. These losses include entrance, exit, discontinuities, and friction. The latter is somewhat dependent upon the Reynolds Number of the fluid flow but, for drywell leakage considerations, it can be considered constant.

V = Velocity of flow, ft/sec.

g_c = Proportionality constant, lbm-ft/lbf-sec^2

v = Specific volume of fluid flowing in the leakage path, ft^3/lbm

If the leakage path flow rate is M lb/sec and the flow area is A ft^2, the above equation can be rewritten to give

$$M = \frac{A}{\sqrt{K}} \sqrt{2g_c (P_D - P_c)\ 144/v} \quad \frac{lb}{sec}$$

Thus, for a given drywell to containment pressure differential, the leakage flow (capacity) is dependent only on $A/\sqrt{K}$.

The use of the existing effective steam bypass area $A/\sqrt{K}$ value of 0.9 ft^2 at EPU conditions resulted in a containment pressure that exceeded the containment design pressure. For this reason, the steam bypass analyses were reevaluated to establish the maximum allowable effective steam bypass area that would maintain the peak calculated containment pressure within the design limit with EPU conditions. The new effective steam bypass area was found to be 0.8 ft^2 (See GGNS-NE-10-00075).

6.2.1.1.5.4 Results - Bypass Capability Without Containment Spray and Heat Sinks

Although containment spray will be automatically initiated on high containment and high drywell pressure if required any time after LOCA + ≈10 minutes, this analysis demonstrates the allowable bypass leakage capability without containment spray. Figure 6.2-16 shows the allowable leakage as a function of primary system break area. It is a composite of two curves. Large primary system ruptures generate high pressure differentials across the assumed leakage path which in turn give proportionally higher leakage flow rates. However, large primary system breaks also rapidly depressurize the reactor and terminate the blowdown.

Once this has occurred, there will no longer be a pressure differential across the drywell leakage path so that leakage flow and containment pressurization will cease. The key point is that large primary system breaks cause leakage into the containment of limited duration. Hence, the magnitude of the allowable leakage path is large. Assuming a primary system rupture of 4 ft^2, Figure 6.2-16 shows the allowable leakage flow path could have an $A/\sqrt{K}$ of 4.3 ft^2.

As the size of the assumed primary system rupture decreases, the magnitude of the differential pressure across any leakage path also decreases. However, smaller breaks result in an increasingly longer reactor blowdown period which, in turn, results in longer durations of the leakage flow. The limiting case is a very small reactor system break which will not automatically result in reactor depressurization. For this case, it is assumed that the

response of the plant operators is to shut the reactor down in an orderly manner at 100 F/hr cooldown rate. This would result in the reactor being depressurized and the break flow being terminated within approximately 6 hours. During this 6-hour period, the blowdown flow from the reactor primary system would have swept all the drywell air over to the containment. The blowdown steam would be condensed in the suppression pool, but in order for this to occur, the water level in the vent annulus would have to be depressed to the top of the upper row of vents. This would result in a continuous pressure differential combined with a 6-hour duration that results in the most severe drywell leakage requirement. In the case of this facility, the maximum allowable leakage capacity under these circumstances is an $A/\sqrt{K}$ of 0.048 ft. Note that the assumption of a 6-hour shutdown is an arbitrary, conservative assumption resulting in a relatively small allowable leakage rate. From a safety viewpoint, however, it can readily be assumed that the plant operators initiate a more rapid depressurization. For example, a one-hour reactor shutdown would result in a minimum allowable drywell leakage capacity ($A/\sqrt{K}$) of 0.3 ft^2.

Based on the above numbers, the allowable drywell leakage rate as established by the small break accident is 200 percent of the drywell free volume in 6 hours at 3 psid. The fact that the leak rate is not exceeded will be verified by periodic tests on a schedule specified in the Technical Specifications. (See also Subsection 6.2.6.5)

A study has been made of potential cracking of the reinforced concrete drywell due to shrinkage, thermal gradients, seismic events, small break and LOCA accidents, and combinations of these (Ref. 14). The report indicates no significant cracking of the drywell walls.]

6.2.1.1.5.5 Bypass Capability with Containment Spray and Heat Sinks

An analysis has been performed which evaluates the bypass capability of the containment for small primary system breaks considering containment sprays and containment heat sinks as means of mitigating the effects of bypass leakage.

The flow rate of one containment spray loop is 5,650 gpm and is assumed to be initiated no sooner than 10 minutes after the accident (this analysis assumes that the sprays are activated by

13 minutes). The suppression pool water passes through the RHR heat exchanger and is injected into the upper containment region. The spray will rapidly condense the stratified steam and would therefore create a homogeneous air-steam mixture in the containment. The available containment heat sinks shown in Table 6.2-9 were considered with variable convective heat transfer coefficients based on the local instantaneous air-steam ratio. The shutdown rate was assumed to be 100°F/hr and the standby service water temperature was 90°F. The shutdown rate corresponds to the maximum rate which does not thermally cycle the reactor vessel. This analysis results in an allowable drywell leakage capability of $A/\sqrt{K}$ of 0.8 ft^2. The corresponding pressure transient is shown in Figure 6.2-24.

The assumptions for allowable bypass calculations utilizing heat sinks are as follows:

a. Following the occurrence of a pipe line break within the drywell, air is purged through the vents into the containment.

b. Prior to containment spray operation, the bypassed steam is assumed to stratify in the upper containment.

c. The air in the containment is compressed by the incoming steam.

d. The containment sprays are activated at 13 minutes.

e. The efficiency of the sprays are based upon the local steam to air ratio as defined in Bechtel Topical Report BN-TOP-3, Performance and Sizing of Dry Pressure Containments, Dec. 1972.

f. Following the spray activation, the air and steam in the containment become mixed.

g. Heat is transferred to exposed concrete and steel in the containment. The Uchida convective heat transfer coefficients used are based on the local steam to air ratio.

h. No energy is assumed to leave the containment except through the RHR heat exchanger.

[HISTORICAL INFORMATION] [The following analysis provides an illustration of the methods used to calculate steam condensing capability under typical post LOCA conditions. For the conditions defined below the containment spray can condense about 38 lb/sec of steam when the containment is at its design limits. The condensation capability was calculated using the following equation:

$$\dot{m}_c = \dot{m}_s \frac{\eta_s (T_c - T_s)}{h_{f_g}} c_p$$

where

$\dot{m}_c$ = steam condensation rate

$\dot{m}_s$ = spray flow rate 785 lb/sec (5,650 gpm = degraded flow of 1 RHR Pump)

η_s = spray efficiency

T_c = containment temperature

T_s = spray temperature at the nozzles

h_{f_g} = latent heat of vaporization

c_p = constant pressure specific heat of water

The spray water temperature was calculated from:

$$T_s = T_p + - \frac{KHX}{\dot{m}_s} \frac{(T_p - T_{sw})}{c_p}$$

where

T_p = suppression pool temperature

KHX = heat exchange capacity = 454 Btu/sec-F (84% of rated)

T_{sw} = standby service water temperature = 90°F.

In response to Humphrey Issues 5.1 and 9.2 (Grand Gulf Action Plan 19), a sensitivity study of various break sizes from SBA to DBA was conducted to determine containment pressurization prior to the initiation of containment sprays. This assessment assumed that the bypass flow area was equal to an area of $A/\sqrt{K} = 0.9\ ft^2$ and allowed for structural heat sinks, RPV level being controlled to prevent overflow through the break to maximize the period of drywell pressurization, and conservative heat transfer coefficients to minimize heat sink effectiveness. The results of this analysis for a full spectrum of break sizes demonstrates that the peak containment pressure is less than the containment design pressure of 15 psig.

Additional drywell pressurization caused by upper pool dump will cause the bypass leakage to increase and subsequently the containment pressure will begin to rise. This effect was analyzed in response to Humphrey Issue 5.6 (Grand Gulf Action Plan 19). This increased leakage will be controlled by containment sprays or the driving pressure will be reduced by reactor vessel depressurization. Vessel depressurization will lower the drywell pressure and eliminate the bypass leakage.

Containment sprays have a significant effect on the allowable bypass capacity. Use of sprays increases the maximum allowable bypass rate by an order of magnitude and represents an effective backup means of condensing bypass steam.

Minimum submergence of all lines which terminate in the suppression pool and which discharge steam is sufficient to ensure that effective condensation of the steam discharge occurs in the suppression pool. Humphrey Issue 3.2 (Grand Gulf Action Plan 7) postulated that after ECCS drawdown of the suppression pool the submergence of the RHR heat exchanger relief valve discharge line would have a very shallow submergence. If this shallow submergence affected the condensation of any relief valve discharge of steam, then uncondensed steam could escape to the containment and result in containment pressurization. The Humboldt Bay pressure suppression test data (Reference 19) demonstrated the relationship of discharge submergence on condensation effectiveness. These tests investigated condensation effectiveness at vent submergences from 12 to -3 feet (i.e., 3 feet clearance between the discharge of the 14-inch-diameter vertical vent and the pool surface) at vent steam mass fluxes up to 250 lbm/ft sec. This mass flux considerably exceeds the mass flux associated with the GGNS RHR heat exchanger relief valve

discharges. The testing performed at Humboldt Bay showed that for mass fluxes greater than 82 lbm/sec ft, complete steam condensation would occur even with the discharge pipe located 3 feet above the water surface. For low mass flux flow rates, it is necessary to consider the PSTF full scale tests (Reference 20). Four tests were run with the initial submergence of the top of the top vent between 9 to 12 inches. When the water above the top vent centerline in the weir and vent system is moved into the pool, approximately 3 inches are added to the initial submergence. These tests covered a large range of mass fluxes, ranging from the initial pool swell transient to chugging with a mass flux approaching zero. Wetwell air-space pressure measurements show that from the end of the pool swell transient to the end of the test, there was no steam carryover. Thus, complete condensation will occur as demonstrated by these low mass flux, low submergence tests.

Since the minimum submergence of the RHR SRV discharge line is 8 inches below the pool surface, even after ECCS drawdown, no steam bypass during SRV action is expected.]

6.2.1.1.5.6 Localized Heating from Bypass

Localized temperature increases in containment caused by drywell bypass leakage will not affect the function of any safety-related equipment in containment. A survey of all non-NSSS and NSSS safety-related essential equipment was performed to evaluate Humphrey Issue 5.5 (Grand Gulf Action Plan 21). All non-NSSS safety-related essential equipment located in the containment near the drywell wall was qualified for drywell temperatures except for the drywell purge compressors. Localized hot spots due to leakage through drywell penetrations will not affect any drywell isolation valve, electrical penetration, cable, or instrumentation due to previous qualification to the drywell environment. Since the purge compressors are not located near any drywell penetration, local increases in temperature from drywell bypass in the vicinity of this equipment will not occur.

The NSSS-supplied safety-related essential equipment in containment was qualified to various temperature profiles. The survey of this equipment indicates the only NSSS equipment which is sufficiently near the drywell wall to be affected by higher local temperatures is mounted on an instrument rack. The minimum distance from this rack to the nearest drywell penetration is 7 feet. This distance is sufficient to diffuse any warmer air or

steam filtering through the drywell wall. In addition, the relatively cool drywell wall will act as a heat sink which will reduce the temperature of any leakage.

Therefore, localized heating in the containment due to bypass will not adversely affect safety-related essential equipment near drywell penetrations.

6.2.1.1.5.7 Bypass Effect on Drywell Temperature

[HISTORICAL INFORMATION] [Drywell leakage paths can allow the drywell temperature to increase in the presence of small reactor coolant pressure boundary piping leaks without causing a high drywell pressure scram. This effect of this temperature increase was analyzed in response to Humphrey Issue 5.8 (Grand Gulf Action Plan 22). This analysis assumed:

a. Drywell high pressure scram signal at 2 psig

b. Initial drywell temperature of 135˚F

c. Drywell bypass leakage of $A/\sqrt{K} = 0.8\ ft^2$

d. Total loss of drywell fan coolers

e. Effect of drywell heat sinks

The maximum temperature predicted by this analysis 10 minutes after the occurrence of a postulated break is less than the drywell design temperature of 330°F. The 10-minute interval is a conservatively, long period of time for the plant operator to determine that a pipe break has occurred in the drywell and to execute required actions.]

6.2.1.1.5.8 Miscellaneous Bypass Sources

To address Humphrey Issue 14.0 (Grand Gulf Action Plan 32), a failure in the LPCI injection check valve (F041A, F041B) during transfer from injection into the vessel (LPCI mode) to the containment spray mode was analyzed. This analysis was conducted to give a bounding value for containment air space pressurization which could occur due to postulated backflow through a failed open LPCI check valve into the containment spray piping. Containment spray may either be manually or automatically initiated ≈10 minutes after a LOCA signal. Automatic initiation will occur if

the containment and drywell pressures are greater than or equal to the pressure set points as defined by the Technical Specifications. Actuation of containment spray will cause a simultaneous signal to close the LPCI injection valve and to open the containment spray header valve. Backflow can only occur during the time it takes the LPCI injection valve to close and while the containment spray header valve is opening. Conservative assumptions made for this analysis include:

a. Reactor pressure is 375 psig. This is conservative since LPCI injection does not occur above this pressure.

b. The containment air mass includes all of the air which was initially in the drywell.

c. The containment pressure is at 9 psig analytical limit when containment spray is initiated.

An analysis was performed using 18.5 seconds for the LPCI injection valve closing time which is based on GGNS Startup Data. The results of this analysis indicated that the containment would experience an increase in pressure of 0.8 psi for a maximum pressure of 9.8 psig. A further analysis was performed using a valve stroke time of 30 seconds which is the same as the analytical stroke time used in ECCS injection analysis. This results in an additional 1.0 psi increase in the containment pressure for a total containment pressure of 10.8 psig. Therefore, both of these analyses result in pressures well below the 15 psig design pressure. In addition, no credit for subcooling of the reactor coolant by the spray flow water was considered in this analysis.

6.2.1.1.6 Suppression Pool Dynamic Loads

The containment and internal structures are designed to withstand all suppression pool dynamic effects including SRV discharge, vent clearing, and vent chugging. These loads are discussed in subsection 3.8.1.3.1 for the containment and subsection 3.8.3.3.1 for the internal structures. These loads were combined with the loads from the postulated seismic events (described in subsections 3.8.1.3.3 and 3.8.1.3.4) in the load combinations specified in subsection 3.8.1.3.8 and 3.8.3.3.2.

The structures and structural surfaces subjected to suppression pool dynamic effects are shown in Figures 3.8-1 and 3.8-60. Structures located within 20 feet of the suppression pool surface

are described in subsection 3.8.3.1.7 and shown in Figures 3.8-66 and 3.8-66a. The equipment subjected to pool dynamic loads are identified in Table 6.2-14. This equipment is shown on Figures 6.2-22 and 6.2-23. A diagrammatic representation of the pool swell illustrating the various states is found in the GE document ICLR 22A4365, Figure 2.2-1. The corresponding loads associated with this figure are found in Figure 10.7 of the above referenced NEDO document.

In response to Humphrey Issue 11.0 (Grand Gulf Action Plan 31), an assessment of the change in the load definition due to normal differences in the water levels in the suppression pool and the drywell weir annulus has been made. Three conditions are possible as follows:

Case A - The water levels are equal as assumed in the existing load definition.

Case B - The water level in the weir annulus is depressed lower than the suppression pool level due to a positive drywell to containment differential pressure.

Case C - The water level in the weir annulus is elevated higher than the suppression pool level due to a negative drywell to containment differential pressure.

For Case A, the existing load definitions in Appendix 6A of the FSAR are based on an equal level and are acceptable as shown.

For Case B, if the drywell pressure is greater than the containment air-space pressure, the water level in the weir annulus will be depressed and consequently, the liquid inertia above the top vent will be reduced. This will cause the top vent to clear earlier in a postulated LOCA resulting in lower drywell pressure when the vents clear and a lower peak drywell pressure than has been calculated in the existing accident analyses. The lower driving pressures decrease the pool swell velocities, accelerations, and loads.

For Case C, if the initial containment air-space pressure is greater than the initial drywell pressure, top vent clearing would be delayed which would increase the peak drywell pressure. An analysis was performed to address the effect for GGNS using a negative differential pressure of -0.25 psid. This corresponds to an increase in weir annulus water level above suppression pool level of 7 inches. The calculated effect of this pressure

difference is to delay top vent clearing by approximately 0.03 seconds and to increase the drywell pressure by approximately 0.3 psi at the time of top vent clearing. The peak drywell pressure is increased approximately 0.35 psi. The changes in the drywell pressure produce very small changes in the driving conditions for submerged structure bubble loads and pool swell. This small increase is on the order of 1½ percent and is considered negligible when compared with the conservatisms incorporated into the drywell break analysis and subsequent pool dynamic effects.

A graphical representation of the dynamic loading due to SRV discharge is found in Figure A5.11 of the GEH document ICLR 22A4365. This diagram, correlated with the corresponding pressures given in Appendix 6A of the FSAR, represents the dynamic loadings for the containment and internal structures. The dynamic pressure load due to upper vent chugging is found in Figure 5.4a of ICLR 22A4365. This load is applicable for the structures in the weir annulus. These loads are defined in subsections 3.8.1.3 and 3.8.3.3. A dynamic analysis was performed on the applicable structures subject to pool swell using the ASHSD computer program. The results from this analysis (force vectors) were then multiplied by the appropriate load factors and included in the load combinations with other design loads to produce final design stresses. The load factors used for the dynamic loads applied to the containment structure are shown, with the applicable load terms, in subsections 3.8.1.3.8.5, 3.8.1.3.8.6, and 3.8.1.3.8.7. A complete description and justification for the dynamic load histories and in-phase versus out-of-phase SRV loading are found in Attachment M of the G.E.H document ICLR 22A4365. In-phase SRV bubble loading methodology is used for the containment and internal structures qualification. Out-of-phase SRV bubble loading methodology is used for containment equipment qualification.

6.2.1.1.7 Non-Axisymmetrical Containment Loads

The containment and internal structures were designed for the non-axisymmetrical loads listed in subsection 3.8.1.4.1.1. The internal structures are not subject to the design wind and tornado wind and are therefore not designed for these loads. The nonaxisymmetrical loads are defined in subsection 3.8.1.3 for the containment and subsection 3.8.3.3 for the internal structures. These loads are then included in the applicable load combinations in subsections 3.8.1.3 and 3.8.3.3.

The tornado and design winds, localized pipe forces, pool swell, and safety relief valve actuation are non-axisymmetrical pressure loads acting on the containment and internal structures. The wind loads and their magnitudes are described in Section 3.3. The pool swell and safety relief valve (SRV) pressures are described in subsections 3.8.1.3 and 3.8.3.3. The magnitudes of these loads are shown graphically on the applicable figures referenced in the above subsections. The loads imparted by brackets, etc. attached to embedded plates are concentrated forces and moments which differ according to the type of structure or equipment being supported. The earthquake loads (OBE and SSE) are inertial loads caused by the seismic accelerations. The magnitude of these loads is discussed in Section 3.7. The non-axisymmetric loads are included in the load combinations specified in subsections 3.8.1.3 and 3.8.3.3. The containment and internal structures are designed for these loads as discussed in subsections 3.8.1.4 and 3.8.3.4 within the acceptance criteria specified in subsections 3.8.1.3.8, 3.8.3.3.2, 3.8.1.5, and 3.8.3.5.

The maximum containment pressure increase associated with the bubble formation that follows vent clearings is specified as 10 psi. The basis for this specification is data from the large-scale air blowdown tests that were conducted as part of the Mark III test program. Circumferential variations in this relatively small pressure increase could result from either seismically induced submergence variations or variations in the vent flow composition (15 air/steam and mixture variations). Increased submergence could lead to an increase in the load. However, pressure suppression test facility (PSTF) data shows a very weak relationship between submergence and the containment pressure increase caused by bubble formation. A survey of the PSTF data shows that, for tests having the same drywell pressure at vent clearing, variations of up to 8 feet in submergence lead to variations in the bubble load to 2 to 3 psi. It is concluded that variations in suppression pool depth will not lead to significant asymmetric containment bubble loads.

The analytical models used to evaluate the containment and drywell responses to the postulated accidents and transients are discussed in subsection 3.8.1.4.1.1 for the containment structure and in subsection 3.8.3.4.1 for the drywell. The assumptions used in modeling these structures are also discussed in the above subsections. The finite element programs used, SAP (drywell), ASHSD (containment and drywell), and FINEL (containment), were chosen based on satisfactory results obtained from previous

calculations made on similar structures. The analysis of the factored load equations provides sufficient conservatism for design.

The sensitivity of the analysis to changes in key parameters are discussed in subsection 3.8.1.4.1.1.4.

6.2.1.1.8 Containment Environment Control

The function capability of the normal containment ventilation system to maintain the temperature, pressure, and humidity in the containment and subcompartments within the prescribed limits, the maximum allowable containment conditions, and the action to be taken if these conditions are exceeded are discussed in subsections 9.4.7 and 9.4.8. Since the loss of these systems will not result in exceeding the design operating conditions for the safety-related equipment inside the containment, they are not classified as safety-related. The safety-related containment systems described in subsections 6.2.2 and 6.5.2 maintain required containment atmosphere conditions.

6.2.1.1.9 Instrumentation

Refer to subsections 6.2.1.7, 7.2, 7.3, 7.5, 7.6.1.2 and 7.6.1.11 for a discussion of instrumentation inside the containment used for monitoring various containment parameters.

6.2.1.1.10 Penetration Cooling

An evaluation of the temperature of the concrete that surrounds high-temperature lines such as main steam, feedwater, etc., was performed during the design of the plant. The results of the evaluation demonstrated that some cooling would be required for selected penetrations. For these penetrations, cooling will be provided by either cooling fins or water jackets. For increased heat transfer, surface area cooling fins were added to the following:

Penetration Number	System
9, 10	Nuclear boiler, main feedwater
14	Residual heat removal
17	RCIC
88	RWCU

For increased cooling capacity, water jackets were added to the following:

Penetration Number	System
83	Reactor water cleanup

Ambient air provides the cooling medium for the finned penetrations. Plant Chilled Water provides the cooling medium for the water jacketed penetrations. For the main steam line, the guard pipe and flued head provide enough heat transfer surface area so that cooling fins or water jackets are not required.

Further evaluation has determined that Containment Penetration 87 does not require forced water cooling at any time to maintain the concrete surrounding the penetration below 200˚F. During RWCU Post-Pump operations, Containment Penetration 88 does not require forced cooling since RWCU pump suction flow is cooled by the Regenerative and/or Non-regenerative Heat Exchangers prior to passing through this penetration. Containment Penetration 83 requires forced water cooling during both modes of RWCU operation when RWCU water temperature is above 200˚F.

The model predicts that the most limiting concrete temperatures will be in the vicinity of the RCIC steam supply line, containment/auxiliary building penetration number 17, a finned penetration.

The RWCU penetration 87 and main steam line penetrations between the containment and auxiliary buildings were determined to be the most limiting non-water cooled penetrations.

A startup test abstract (14.2.12.3.40) has been provided in Chapter 14 to evaluate the adequacy of penetration cooling.

For all other high-temperature penetration lines where analysis indicated no cooling was required, the following are provided:

a. Evaluation Methodology

   The penetrations have been evaluated using a computer program to predict the temperature in the concrete containment wall. The analysis was a two-dimensional analysis that modeled the piping, the concrete liner plate, and surrounding ambient temperature. The program has the capability to have as many as 1,750 lattice

points, 100 regions, 50 materials, and 50 boundary conditions. The analysis assumed steady-state, maximum operating conditions. The "Extrapolated Liebmann Method" and a modification of the "Aitken 8 Extrapolation Process" were used to solve the finite difference equations which approximate the partial differential equations for this steady-state analysis.

b. Maximum Concrete Temperature Criteria

A temperature of less than 200°F anywhere in the concrete adjacent to the penetration was used as acceptance criteria.

c. Assumed Heat Transfer Coefficients

See Table 6.2-55.

6.2.1.2 Subcompartment Analysis

6.2.1.2.1 Design Basis

a. A pressure response analysis was performed for each containment subcompartment containing high energy piping in which breaks, either circumferential or longitudinal, were postulated. The definition of high energy and the criteria for postulating breaks are outlined in Section 3.6. Refer to Section 3.8 for the different methodologies used to determine the analyzed loads.

The break which produced the greatest release of blowdown mass and energy into the subcompartment, during normal operation and hot standby, was selected for the design evaluation.

The breaks used in the design evaluations are listed in subsection 6.2.1.2.3.

b. All break locations were considered to be fully double ended in the case of circumferential breaks, and no credit for limiting blowdown generation was taken due to pipe restraint locations.

The effective cross-sectional flow area of the pipe is used in the jet discharge evaluation for circumferential and longitudinal breaks.

c. The differential pressures resulting from the calculated responses are discussed in subsection 6.2.1.2.3.

6.2.1.2.2 Design Features

a. Compartment Description

1. Reactor Pressure Vessel Shield Wall Annulus

The circular shield wall which surrounds the reactor pressure vessel (RPV) has an outside diameter of 32'-8” and extends from the vessel pedestal to El. 173-3. Breaks in the recirculation return and suction piping and feedwater piping were analyzed.

In addition, a break in the main steam piping was analyzed to verify which break imposes the most limiting overturning moment and the most limiting lateral forces on the RPV. The main steam line is not enclosed by the subcompartment formed by the RPV and the shield wall.

2. Drywell Head

The drywell head is located above the RPV head, extends downward, and surrounds the RPV head, connecting to the drywell bulkhead at approximately El. 184-6. Four normally open hatches having an opening of 20 inches in diameter are located in the bulkhead at azimuths 30˚, 105˚, 240˚, and 315˚ venting into the drywell. (The hatches are closed only during refueling.) Breaks were postulated in the RPV head spray line.

In addition, a main stream line break directly below the drywell bulkhead was investigated to determine the effects on the bulkhead.

3. Main Steam Tunnel

The main steam tunnel is located between the drywell and containment at El. 140-0 along azimuth 0˚. Breaks were postulated in the reactor water cleanup (RWCU) lines (the only lines not encapsulated by

guardpipes). The venting is through an access opening in the bottom of the RWCU heat exchanger room directly above the main steam tunnel.

4. RWCU Heat Exchanger Room

   The RWCU heat exchanger room located at El. 170 in the containment vents through the wire door in the south wall into the containment. RWCU line breaks were analyzed in this room.

5. RWCU System Pipe Chase Transfer

   RWCU piping from the heat exchanger room extends, by means of a concrete pipe transfer chase, along the outside drywell wall just below a concrete floor (El. 184'-6”) and enters a valve nest room. RWCU breaks which vented into the containment through an opening the full length of the chase were investigated.

6. RWCU Valve Nest Room and Filter Demineralizer Room

   The valve nest room is located at azimuth 90˚, El. 161 - 10. From this location, the RWCU piping enters the RWCU holding pump room located above at El. 184 - 6 prior to penetrating the adjacent RWCU filter demineralizer room. RWCU breaks were analyzed in each compartment.

b. Drawings depicting piping, equipment, and compartment/ venting locations are provided in FSAR Section 3.6. The volumes and vent areas are discussed in subsection 6.2.1.2.3.

c. The subcompartments described above contained no vent areas that become available after the pipe break pressure rise (i.e., blow out panels).

6.2.1.2.3 Design Evaluation

The breaks utilized in the design evaluation of the containment subcompartments are listed on the following page. The numbers of the tables and figures which contain the nodal parameters for each subcompartment, as well as the results for each analysis are also listed.

[HISTORICAL INFORMATION] [The subcompartment analyses were performed using Bechtel computer programs COPDA. A complete description of COPDA is provided in Bechtel Topical Report BN-TOP-4, Rev. 1, which was filed with the NRC in October 1977 (Ref. 1).

a. The blowdown mass and energy releases for each of the breaks have been provided (see preceding list of analyses). The blowdown for the recirculation inlet line break is based upon conservative methodology developedby GEH using the Moody Steady Slip Flow Model with subcooling, as described in Appendix 6C.

   The blowdown for all other breaks analyzed is based on the Calculated Moody Blowdown Model. This model is applicable to liquid blowdown at an enthalpy lower than the saturated liquid enthalpy (Ref. 10).

b. The assumed initial conditions for the subcompartment volumes were conservatively chosen so as to maximize the transient pressure responses. The initial conditions are given in the nodal description tables.

c. The description of and justification for the subsonic and sonic flow models used in COPDA, and the degree of entrainment used in vent flow calculations, is given in BN-TOP-4, Rev. 1 (Ref. 1).

d. The piping systems assumed to rupture in the subcompartments have been identified in the list of breaks on the following page. Break locations are discussed in Section 3.6.

e. The subcompartment nodalization schemes have been tabulated and provided. The nodalization schemes were selected to maximize differential pressures across node boundaries. Restrictions resulting from structural components on equipment placement were selected as node boundaries for the flow model. The nodal models for the recirculation inlet, recirculation suction, andfeedwater line breaks are shown in Figures 6.2-26a, 6.2-26b, and 6.2-26c, respectively.

		Tables			Figures				
Compartment	Line Break	Nodal Description	Vent Path Description	Blowdown	Schematic Flow	Nodal Model	Pressures	Differential Pressure	Additional
RPV-shield wall annulus	Recir-culation return	6.2-15a	6.2-16a	6.2-33a	6.2-25a	6.2-26a	6.2-27aa through 6.2-27ax	6.2-27aa through 6.2-27ax	RPV: Forces-6.2-28aa, ab,ba,bb,ca,cb Moment-6.2-29aa, ab,ba,bb,ca,cb Forces-6.2-30aa, ab,ba,bb,ca,cb Moment-6.2-31aa, ab,ba,bb,ca,cb
	Recir-culation suction	6.2-15b	6.2-16b	6.2-33b	6.2-25b	6.2-26b	6.2-27ba through 6.2-27by	6.2-27ba through 6.2-27by	
	Feedwater	6.2-15c	6.2-16c	6.2-33c	6.2-25c	6.2-26c	6.2-27ca through 6.2-27cv	6.2-27ca through 6.2-27cv	
	Main Steam	NA	NA	6.2-11	NA	NA	NA	NA	The forces on RPV are shown in Figure 6.2-87
RWCU Hx room	RWCU	6.2-20	6.2-21	6.2-34	6.2-47	-	6.2-49	6.2-50	
Main steam tunnel	RWCU	6.2-20	6.2-21	6.2-35	6.2-48	-	6.2-51	-	
RWCU filter deminera-lizer room	RWCU	6.2-22	6.2-23	6.2-36	6.2-52	6.2-53	6.2-54	-	
RWCU holding pump room	RWCU	6.2-24	6.2-25	6.2-37	6.2-56	6.2-57	6.2-58	-	
RWCU pipe chase transfer	RWCU	6.2-26	6.2-27	6.2-38	6.2-60	6.2-61	6.2-64	-	
RWCU valve nest room	RWCU	6.2-26	6.2-27	6.2-38	6.2-62	6.2-63	6.2-66	-	
Drywell head	RCIC	6.2-28	6.2-29	6.2-39	6.2-68		6.2-69	6.2-70	
	Main steam	6.2-30	6.2-31	6.2-40	6.2-71	6.2-72a,b	6.2-73a,b and 6.2-74a,b,c	6.2-75	

f. A nodalization sensitivity study was performed for the recirculation inlet line break (which was the worst break) in the RPV shield wall annulus to ensure that adequate subcompartmentalization was incorporated into the nodal model. The base model, as depicted in Figure 6.2-26a, consisted of 25 volumes nodes. The sensitivity nodal model utilized a 29-node scheme in which volumes 15, 13, 23, and 11 of the base model were divided in half to create 8 smaller volumes. These particular volumes were chosen because they were located in the immediate vicinity of the break. Any changes in pressurization would be more pronounced in this area than at a point farther from the break.

   The results of the sensitivity study confirmed that adequate nodalization had been used in the 25-node recirculation inlet line model. The net forces upon the reactor pressure vessel peaked at 0.023 seconds in each analysis, with the values differing by only 1 percent. The maximum peak differential pressure across the shield was 19.1 psid for the sensitivity study. This represents an increase of less than 2 psid when compared to the maximum peak differential pressure experienced in the base analysis, and is still well below the design differential pressure of 56 psid.

g. The pressure response graphs of all subnodes within each subcompartment have been provided, with the figure numbers given in the subcompartment analyses list at the beginning of this section. This list also contains the net x- and y-force and moment components which act on the reactor pressure vessel and the shield wall, resulting from a recirculation inlet line, recirculation outlet line, or feedwater line break. For the recirculation inlet line break analysis, the assumed break location is at the intersection of four subcompartments in the annulus: subcompartments 3, 5, 13, and 23 (see Figure 6.2-26a). While some of the blowdown from the break would be expected to flow directly through the penetration in the shield wall to the annulus, it is conservatively assumed that 100 percent of the blowdown is released in the annulus, divided equally among the four subcompartments. In addition, no credit was taken for any penetrations through the shield wall which might have allowed

additional venting out of the annulus. All mass flow from the annulus was required to vent through the area at the top of the shield wall. Since a finite time is required to accelerate the blowdown mass in that direction, a pressure differential will be established across the shield wall as the annulus quickly pressurizes. As mass flow into the drywell is established, the pressure differentials will decrease to values well below the peaks.

In order to minimize the asymmetric loads resulting from pressurization of the RPV-shield wall annulus, flow diverters have been incorporated into the shield wall penetration sleeves for the six feedwater lines and the two recirculation outlet lines. No flow diverters were designed for the recirculation inlet lines. The flow diverter designs are described in subsection 3.8.3.4.5.4. The flow diverters for both the recirculation outlet line and the feedwater line have been designed so as to allow less than 15 percent of the total blowdown to flow into the annulus. It was conservatively assumed in the subcompartment analyses for these breaks that 15 percent of the total blowdown was released directly in the annulus. The remaining 85 percent of the blowdown was released to the drywell via the flow diverter. As in the case of the recirculation inlet line break, the nozzles of the lines which are assumed to break are at the intersection of two or more subcompartments. For the recirculation outlet line break, as shown in Table 6.2-15b and Figure 6.2-26b, the flow from the break to the annulus is split equally between subcompartments 1 and 11. For the feedwater line break, as shown in Table 6.2-15c and Figure 6.2-26c, the flow from the break to the annulus is split among subcompartments 14, 16, and 20. Due to the inclusion of flow diverters into the shield wall design, the recirculation inlet line break results in the greatest mass and energy release into the annulus. Therefore, the greatest forces upon the RPV and the greatest differential pressures across the shield wall are experienced during this transient.

To calculate the forces and moments upon the RPV and shield wall, a three-level beam model was devised. Referring to the nodal model in Figures 6.2-26a, 6.2-26b, and 6.2-26c, the three-level model was constructed as follows:

1. Force level 1 starts at elevation 122.0 ft and ends at elevation 137.8 ft,

2. Force level 2 goes from elevation 137.8 ft to elevation 163.9 ft, and

3. Force level 3 is from elevation 163.9 ft to elevation 173.3 ft.

The resulting force beam is shown in Figures 6.2-33a, 6.2-33b, and 6.2-33c. The net x- and y- force components were calculated by summing the components from each level. The force histories for the reactor pressure vessel and the shield wall are shown in Figures 6.2-28aa through 6.2-28cb and Figures 6.2-29aa through 6.2-29cb. The plots labeled "FORCE X" show the force in the x- direction, and the plots labeled "FORCE Y" show the force in the y-direction. Figure 6.2-32 depicts the coordinate system utilized. The net x- and y- moment components were calculated by summing the force component multiplied by that component's moment arm. The moment arms are calculated relative to a reference point at elevation 121.33 ft, which is where the shield wall attaches to the RPV pedestal. The moment histories for the reactor pressure vessel and the shield wall are shown in Figures 6.2-30aa through 6.2-30cb and Figures 6.2-31aa through 6.2-31cb. The plots labeled "MOMENT X" show the moment due to the force in the x- direction and the plots labeled "MOMENT Y" show the moment due to force in the y-direction. Tables 6.2-17a, 6.2-17b, 6.2-17c, 6.2-18a, 6.2-18b, and 6.2-18c provide the projected areas and the moment arms for the RPV and shield wall, respectively. Figure 6.2-32 depicts the coordinate system utilized. For a more complete description of flow coefficient determination, see Reference 1.

h. Vent paths where choked flow occurs are indicated in the vent path description tables for the COPDA analyses.

i. The flow coefficient (C) for a particular geometry is determined as a function of the equivalent head loss coefficient (K_{eff}) for the flow system. The flow coefficient is expressed as:

$$C = 1 / \sqrt{K_{eff}}$$

The value of K_{eff} is simply the sum of the head losses for separate parts of the system. For the analyses performed in the reactor vessel shield annulus and drywell head regions, these head losses are defined as follows:

Entrance loss or contraction - This loss is determined as a function of the ratio of the upstream cross-sectional area to the cross-sectional area of the contraction.

Resistance of bends to flow of fluid - This resistance is determined by the angle and length of the bend.

Friction losses - These, although generally very small, are calculated as an f ℓ/d term.]

The losses listed above are defined specifically in References 1, 2, and 3. Values for the respective components are listed in the vent path description table for each break analyzed. For a more complete description of flow coefficient determination, see Reference 1.

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 in order to maximize the release.

A detailed description of the analytical models and assumptions for both steam and liquid blowdowns is contained in Reference 11 of subsection 6.2.8. For the intermediate- and small-size breaks, the break area is assumed to remain constant as a function of time, and the vessel pressure is assumed to remain constant at the initial value until depressurization is initiated by automatic actuation of ECCS (intermediate break) or by operator action (small break).

6.2.1.3.1 Mass and Energy Release Data

Table 6.2-10 provides the mass and enthalpy release data for the recirculation line break. Blowdown steam and liquid flow rates and their respective enthalpies are reported for a 60-second

period following the accident. This data was employed in the DBA containment pressure-temperature transient analyses reported in subsection 6.2.1.1.3.3.

Table 6.2-11 provides the mass and enthalpy release data for the main steam line break. Blowdown data is presented for a 99-second period following the accident. This information has been employed in the containment response analyses presented in subsection 6.2.1.1.3.3.5.2.

[HISTORICAL INFORMATION] [A detailed description of the analytical model used to evaluate mass and energy release rates for annulus pressurization was provided in Attachment 6.A of the LaSalle County Station FSAR, along with a demonstration of overall conservatism through comparison of the resulting breakflows with those predicted by the use of RELAP4/MOD5.]

6.2.1.3.2 Energy Sources

The reactor coolant system conditions prior to the line break are presented in Tables 6.2-3 and 6.2-4. Reactor blowdown calculations for containment response analyses are based upon these conditions during a loss-of-coolant accident.

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. Energy from fuel relaxation

d. Sensible energy stored in the reactor structures

e. Energy being added by the ECCS pumps

f. Metal-water reaction

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 conservatively selected as a constant input of 4520 Btu/sec to the system. The pump heat rate is added to the decay heat rate for inclusion in the analysis.

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 6.2-12 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. Figure 6.2-21 shows the variation of the sensible heat content of the reactor vessel and internal structures during a recirculation line break accident based upon the temperature transient responses.

6.2.1.3.3 Reactor Blowdown Model Description

The reactor primary system blowdown flow rates were evaluated with the model described in Reference 13. However, for the main steam line break analysis, the time at which the reactor water level would reach the steam line nozzles was evaluated with the model described in Appendix B of Reference 12. The decision to use the Long-Term Thermal-Hydraulic model of the reactor described in Appendix B rather than the Short-Term Thermal-Hydraulic model of Appendix A was based in part in the more detailed level rise and phase separation calculations performed by the Long-Term model.

Analyses using this model indicated that for the reactor power level used in the SAR analyses, the level rise would in fact be on the order of three seconds. For mass and energy release calculations, it is conservatively assumed that the level rise time is one second.

Sections B1, B2, and B3 of Reference 12 provide a physical description of how the entire primary system is nodalized and the analytical methods and assumptions used to simulate either a recirculation or steam line break inside containment. Specifically, section B.3.15 describes the level swell model.

Insofar as no modifications were made to the model described in Reference 15, there are no conservative assumptions which are incorporated in the model for analysis purposes. Section B.4 of the report shows that the model agrees well with test data; it can be concluded that the predictions of level rise time are realistic.

The input parameters required to define the reactor primary system include system volumes, fluid and energy node elevations, heat transfer characteristics, initial operating power levels and flow rates, and definitions of the transient boundary conditions for steam flow, feedwater flow, and reactor power level.

When simulating the short term response to a loss-of-coolant accident, a design basis assumption is that the break flow rate is defined by the Moody critical flow model using saturated fluid at reactor pressure with no credit taken for friction losses. The conservatism of this assumption has been clearly demonstrated by comparison of predicted flow rates with experimentally measured values. In addition, analytical simulation of past tests show gross overprediction of measured system pressures when the Moody model is used to calculate the blowdown flow rate.

In theory, the 25 Btu/lb of subcooling existing in the recirculation loops would, if used in the Moody model, result in slightly higher predicted blowdown flow rates than those used in the recirculation line break analysis presented in the SAR (approximately a 6 percent increase).

Although the higher flow rates are offset somewhat by the reduced enthalpy of the blowdown flow, the net result would be a slight increase in the calculated drywell pressure response. However, the main steam line break would still be the limiting event for peak drywell pressure.

Given the overall conservatism of the vessel blowdown model, as demonstrated in Reference 11 of subsection 6.2.8, use of the saturated Moody break flow model is appropriately conservative.

However, in terms of peak containment pressure, these higher flow rates are offset to some extent by the reduced enthalpy of the blowdown flow rate.

The saturated Moody break flow model was also used for the asymmetric pressure analysis (annulus pressurization). This model was conservatively applied for the annulus pressurization analysis by ignoring the effects of backpressure within the flow diverter for the recirculation suction and feedwater line breaks. (The backpressure can be on the order of 90 percent of the system operating pressure.)

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 loss-of-coolant accident. The amount of metal-water reaction which can be accommodated is consistent with the performance objectives of the emergency core cooling systems (ECCS). Subsection 6.2.5.3 provides a discussion on the generation of metal-water hydrogen within the containment. In evaluating the containment response 271 Btu/sec of heat from metal-water reaction is included for the first 800 seconds.

6.2.1.3.5 Thermal Hydraulic Data for Reactor Analysis

Sufficient data to perform confirming thermodynamic evaluations of the containment has been provided within the Accident Response Analysis subsection, 6.2.1.1.3.3, and associated tables, in particular Table 6.2-4.

6.2.1.4 PWR - Not Applicable

6.2.1.5 PWR - Not Applicable

6.2.1.6 Testing and Inspection

Testing and inspection requirements for the containment and drywell are discussed in subsections 6.2.6 (Drywell and Containment Leakage Testing), 3.8.1.7 (Containment Structural Proof Testing) and 3.8.3.7 (Drywell Structural Proof Testing). No other special tests of either the drywell or containment structure is planned. Testing and inspection of other engineered safety features inside the containment that interface with the containment structures are discussed along with the applicable system description sections. Suppression pool relief valve testing to determine pressure distributions inside the pool and strain on selected safety-related systems inside the pool are discussed in Appendix 6B. The periodic Inservice Inspection requirements for the primary containment are discussed in subsection 6.2.1.6.1 (Inservice Inspection of the Primary Containment).

6.2.1.6.1 Inservice Inspection of the Primary Containment

Inservice inspection and repair/replacement activities of the primary containment are in accordance with ASME Section XI, Subsections IWE and IWL as stipulated in 10CFR50.55a except where

relief request or alternatives have been approved by the Nuclear Regulatory Commission. The specific boundaries of the containment for which the requirements of ASME Section XI, Subsections IWE and IWL apply are identified in Program Plan GGNS-M-489.8, Grand Gulf Nuclear Station Program Plan for ASME Section XI Inservice Inspection of Containment.

The drywell and drywell penetration liners are not part of the primary containment boundary, and are not included in Program Plan GGNS-M-489.8. The drywell basemat and drywell basemat liner are classified as ASME Code Class CC and MC respectively and form part of the primary containment boundary, and therefore are included in Program Plan GGNS-M-489.8.

In accordance with 10CFR50.55a, the examinations specified in ASME Section XI, Subsection IWE, Examination Category E-B Pressure Retaining Welds, and Examination Category E-F, Pressure Retaining Dissimilar Metal Welds, are optional. GGNS does not include these Examination Categories in Program Plan GGNS-M-489.8 because these welds are considered part of the Containment Surface and are inspected in accordance with Examination Category E-A.

6.2.1.7 Instrumentation Requirements

The following containment parameters are monitored by redundant, safety-related instrumentation:

Drywell pressure
Containment pressure
Suppression pool level
Suppression pool temperature
Containment and drywell area temperatures
Containment and drywell hydrogen concentration
Containment and drywell ventilation exhaust radiation

Refer to Section 7.2 for a description of drywell pressure as an input to the reactor protection system. Refer to Section 7.3 for a description of containment and drywell pressure and suppression pool level as inputs to the engineered safety features systems. Suppression pool temperature monitoring and the ventilation exhaust radiation monitoring system are discussed in Section 7.6. The display instrumentation for all containment parameters, including the number of channels, recording of parameters, and instrument range and accuracy, and post-accident monitoring equipment is discussed in Section 7.5.

6.2.2 Containment Heat Removal System

6.2.2.1 Design Bases

The containment heat removal system, consisting of the suppression pool cooling and containment spray systems, is an integral part of the RHR system. The purpose of this system is to prevent excessive containment temperatures and pressures, thus maintaining containment integrity following a LOCA. To fulfill this purpose, the containment heat removal system meets the following safety design bases:

a. The system shall limit the long term bulk temperature of the suppression pool to 185 F without spray operation when considering the energy additions to containment following a LOCA. These energy additions, as a function of time, are provided in the previous section.

b. The single failure criteria applies to the system.

c. The system is 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 is testable during normal operation of the nuclear power plant.

6.2.2.2 Containment Heat Removal System Design

The containment heat removal 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 or to the containment spray header. Water from the standby service water system is pumped through the heat exchanger tube side to exchange heat with the processed water. Two cooling loops are provided; each being mechanically and electrically separate from the other to achieve redundancy. A process and instrumentation diagram 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 heat removal 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 assured. Construction codes and standards are covered in subsection 5.4.7.

Results from several transient calculations for Grand Gulf are shown on Table 6.2-56. From an isolated condition with only one RHR heat exchanger available and under the worst case conditions assumed in the analysis, a rapid depressurization is performed, if required (>100 F/hr) to ensure suppression pool temperature is maintained within limits. Under these worst case conditions, this analysis would be bounded by Event 2A. The assumptions and event descriptions are described on Table 6.2-56. The maximum suppression pool temperature for each event is shown in Table 6.2-57 and the suppression pool temperature, vessel pressure, and SRV flow rate time histories are shown on Figures 6.2-91 through 6.2-99.

As shown in Table 6.2-57, the maximum expected bulk pool temperature is 181 F which is below the design value of 185 F. These analyses, combined with our determination of the difference between local and bulk pool temperature, result in our conclusion that the local temperature criterion of 200 F will not be exceeded.

The containment spray subsystem is started manually or automatically. The LPCI mode is automatically initiated from ECCS signals and the RHR system realigned for containment cooling by the plant operator after the reactor vessel water level has been recovered (see subsection 6.2.1). The RHR pumps are already operating. The SSW pumps started automatically when RHR was initiated. Containment cooling can be initiated in loop A or B by closing the heat exchanger bypass valve, opening the service water valve at the heat exchanger, closing the LPCI injection valve and opening the pool return valve. In the event that 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. If the operator chooses to utilize the containment spray, he must depress the containment spray manual initiation pushbuttons. This will cause the LPCI injection valves to automatically close and the containment spray valves to automatically open if a high drywell pressure signal is present. The containment spray portion

is also initiated automatically on high containment and high drywell pressure with an interlock to delay initiation until ≈10 minutes after a LOCA. Automatic initiation is provided to protect the containment in the event of suppression pool bypass leakage as is described in subsection 6.2.1.1.5.4.

Preoperational tests are performed to verify individual component operation, individual logic element operation, and system operation up to the drywell spray spargers. A sample of the sparger nozzles are bench tested for flow rate versus pressure drop to evaluate the original hydraulic calculations. Finally, the spargers are tested by air and some visible indication means to verify that all nozzles are clear.

Each ECCS pump takes suction directly from the suppression pool, which does not have a sump. To prevent foreign objects in the suppression pool from entering the ECCS flow path, strainers are located on the ECCS suction lines in the suppression pool as shown in Figures 3.6A-14 and 3.6A-19. The conical stainless steel basket strainer portion of the suction strainer (see Figure 6.2-86) extends from one side of the horizontally oriented tee of the suction piping at an elevation of 103'-4”; the closest proximity of the conical basket portion of the suction strainer to the suppression pool floor is approximately 8½ feet. The conical basket portion of the suction strainer fabrication consists of a No. 8 mesh stainless steel wire cloth screen welded over a steel cone perforated with 5/8-inch holes. The square holes in the screen are designed to prevent the passage of particles larger than 0.10 inch.

In response to NRC Bulletin 96-03, a large passive strainer was installed for the ECCS (and RCIC) pumps. The strainer is located on the floor of the suppression pool and completely circumscribes the suppression pool. The ECCS/RCIC suction strainer connects to each of the ECCS (and RCIC) suction piping tees on the opposite side of the tee from the conical basket portion of the ECCS (and RCIC) suction strainers. The ECCS/RCIC suction strainer is fabricated from stainless steel plate and perforated (3/32”holes) stainless steel plate providing the same filtering capability as the conical basket portion of the suction strainer. The ECCS/RCIC suction strainer is semi-circular in cross-section with two separate flow channels separated by an open central channel. The three ECCS divisions which connect to the ECCS/RCIC suction strainer are physically separated through the use of internal divider plates in the flow channels; two divider plates are

installed at each divisional interface location. The ECCS/RCIC suction strainer rests on the floor of the suppression pool and the top of the ECCS/RCIC suction strainer is approximately 3'-2" above the suppression pool floor.

Although the suppression pool water quality will be monitored and controlled, debris resulting from accident conditions can be postulated to enter the suppression pool. To ensure that system function is maintained, the strainers are designed with sufficient strainer surface area to provide very low fluid approach velocities (~0.02 fps). This will minimize head loss under postulated debris loading conditions in the event the strainers become fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials).

Based on flow test data, the maximum pressure drop across the strainer for any of the ECCS pumps is 0.35 psi when clean. Based on flow test data, calculations show a maximum pressure drop across the strainer for any of the ECCS pumps of 6.58 psi when the strainers are fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials). For conservatism, a clean strainer pressure drop of 1 foot H2O (0.43 psi) is assumed across the strainers in all NPSH calculations and the fully loaded pressure drops determined for each pump are utilized in the individual pump's NPSH calculations, ensuring adequate available NPSH to the ECCS pumps at all times. Approach velocity for the strainers is approximately 0.017 ft/sec at a maximum runout flow of 9100 gpm.

The ECCS pump suction strainers located in the containment suppression pool meet the following safety design basis:

a. The strainer is designed to prevent the introduction of objects greater than 0.10 inch diameter into the reactor pressure vessel.

b. Adequate net positive suction head to the ECCS pumps shall be provided with the strainers fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials).

c. The strainer is designed to withstand any loads during suppression pool transients, such as temperature, pressure, and water level. The strainers are designed to withstand a differential pressure of 7.3 psi. All strainers are seismically qualified.

d. The strainer is designed to permit testing in conjunction with the periodic ECCS testing to demonstrate strainer operability.

The mechanism for transport of insulation from the drywell into the containment suppression pool following an accident involves a series of occurrences, as discussed below.

The following types of insulation are used for piping and equipment within the containment:

a. Metal-reflective insulation for the reactor pressure vessel, main steam lines, feedwater lines, reactor recirculation system, and safety-related nuclear stainless steel piping

b. Metal-jacketed calcium silicate for hot piping and equipment

c. Metal-jacketed fiberglass (antisweat) for cold piping and equipment

d. Removable blanket insulation encapsulated with aluminized fiberglass cloth/wire mesh for inservice inspection and/or interferences involving metal reflective insulation

e. Flexible fiberglass blanket insulation for containment cooling system supply ductwork

Metal-reflective and metal-encapsulated removable insulation is installed in sections with overlapping edges and quick release latches with keepers. Metallic jacketed calcium silicate piping insulation is installed in two-foot sections with wire or metal bands. Metallic jacketed fiberglass antisweat piping insulation is installed in two-foot sections with a factory-applied overlapping fiberglass jacket with adhesive. Metallic jacketing is installed over the calcium silicate and fiberglass insulation in approximately three-foot overlapping sections with metal bands. Encapsulated removable blanket insulation is installed with webbed straps, buckles, and/or lacing wire.

Reg. Guide 1.82 (Position 2.3.1.1) states that, consistent with the requirements of 10 CFR 50.46, debris generation should be calculated for a number of postulated LOCAs of different sizes, locations, and other properties sufficient to provide assurance that the most severe postulated LOCAs are calculated. Reg. Guide 1.82 (Position 2.3.1.2) states an acceptable method for determining the shape of the zone of influence (ZOI) of a break is described in NUREG/CR-6224. The volume contained within the zone of influence should be used to estimate the amount of debris generated by a postulated break.

GGNS utilized Utility Resolution Guidance (URG) for ECCS Suction Strainer Blockage, Section 3.2.1.2.3 Method 3 (Reference 29), to estimate the size of a spherical ZOI. GGNS selected the worst case break configuration based on the latest available information contained in Reference 29. Specific pipe break locations were used to identify the most severe zone of influence by a LOCA. Break locations were compared for the greatest volume of insulation affected; Kaowool and calcium silicate were considered in the analysis. The analysis takes no credit for any fraction of fibrous and calcium silicate debris that is considered non-transportable (i.e., all debris generated is 100% transportable).

Reference 29 (Section 3.2.1.2.3, Method 3) was used to calculate the volume of fibrous and calcium silicate insulation available for transport. GGNS has only considered fiber and calcium silicate insulation quantities with respect to transportable insulation materials from the drywell. Metal jacketing and reflective metal insulating materials and components at GGNS have been considered to be of sufficient density that they would sink to the bottom of the drywell or accumulate within the weir annulus or the reactor vessel bioshield wall. Based on the very low approach velocity of the strainer, the design is not sensitive to any volume of reflective metal insulation generated as the result of a LOCA. Hence, the effects of pipe breaks inside the bioshield are bounded by the pipe breaks outside the bioshield which generate significantly greater amounts of fibrous and calcium silicate insulation debris.

The quantity of “other” LOCA-generated debris (debris resulting from painted surfaces, fibrous, cloth, plastic, or particulate materials within the zone of influence that may produce debris) is based on the recommendations contained in the Reference 29. The debris quantities used in the strainer testing and design are considered very conservative.

Strainer testing (using 50% of the full complement of drywell fiber and calcium silicate insulation debris, and other debris quantities based on URG recommendations) performed for the ECCS/ RCIC suction strainer design indicates that strainer head loss is most affected by the volume/mass of fibrous insulation and calcium silicate debris, as compared to other debris types. Therefore, use of Reference 29 Method 3 to determine the volume of fibrous and calcium silicate debris and use of Reference 29 recommended quantities of other debris generated as the result of a LOCA, represents a conservative debris volume.

The Quarter Scale Test Facility (QSTF) used 50% of the full complement of drywell fiber and calcium silicate insulation and other debris quantities based on URG recommendation. The QSTF test provides bounding head loss for NPSH calculations. The Small-Scale Test Apparatus (SSTA) test used Referenced 29 Method 3. The SSTA test provides a distribution of debris quantities that have a head loss bounded by the QSTF test.

Due to low approach velocities associated with the large, passive strainer, metal tags and metallic insulation materials were assumed to settle in the Suppression Pool. GGNS takes no credit for settling of fiber insulation material, corrosion products/ sludge, paint or coating debris, and plastic debris materials at the onset of a LOCA; however, significant debris settling was observed in a test program utilizing a 1/4-scale model of the strainer. The settling observed in the testing program is considered prototypical of the settling which would occur in the suppression pool after chugging and condensation oscillation have ceased.

A Small-Scale Test Apparatus (SSTA) for ECCS suction strainer head loss testing was constructed for small-scale modeling and conservative performance testing of the large toroidal passive Grand Gulf strainer design. Testing has been performed in the SSTA to assess the effects of large amounts of coatings and debris on the strainer mesh differential pressure. Multiple tests with various amounts of fiber, iron oxide, epoxy paint and zinc oxide primer debris have been performed. The testing used insulation debris quantities determined using the URG recommended (and NRC endorsed) zone of influence (ZOI) methodology, (Reference 29) with additional amounts of epoxy paint, zinc oxide and additional amounts of sludge. Utilizing the SSTA testing allowed larger amounts of sludge and paint to be postulated for a LOCA event ans

still remains within the head loss for the original QSTF scale test. NPSH and ECCS performance calculations are conservatively based on original QSTF scale test values.

The QSTF test provides bounding head loss for NPSH calculations. The SSTA test data provides head loss information that is used as a basis for changing the debris loading on the suction strainer. The head loss of the QSTF is used because it is conservative and bounding in the NPSH and ECCS performance calculations. The SSTA test data debris loading will be used to determine the amounts of sludge, unqualified coatings and fiber that can be allowed in the suppression pool and containment.

With respect to debris transport, 100% of the drywell fiber and calcium silicate insulation is considered to be transported to the suppression pool, without credit for any holdup time in the drywell. Similarly, the other amounts of debris are also assumed to be completely transported to the pool. It is assumed that the hydrodynamic actions during the first few minutes of a LOCA are sufficient to completely mix all debris which enters the pool from the drywell and to fully disperse all pre-existing debris resident in the suppression pool prior to LOCA occurrence. GGNS utilized the methods prescribed in the Reference 29 to establish the quantities of pre-LOCA debris in the suppression pool.

Prior to the initiation of suppression pool cooling, and once the suppression pool has settled from the initial hydrodynamic disturbances, the debris will either settle, be drawn to the strainer, or both. Since the 0.02 fps design approach velocity of the strainer is approximately the same as fiber settling velocities, fiber will be drawn to the strainer locally or else settle, with minimal tangential movement of the debris. This is potentially true to an even greater extent with the denser, particulate debris types such as ferrous materials, paint chips, etc. since their settling velocities are higher than fiber. However, these materials are also basically attracted to the strainer because of their dispersion within the fiber debris. Particulate materials which are initially resident in the pool water nearest the strainer may also be expected to be preferentially drawn to the strainer mesh surface in lieu of settling, to be trapped by the fiber material which forms there.

The strainer design is such that debris will tend to collect first on the surface near the source of suction. As the debris bed thickness increases, the head loss will tend to increase through

that portion of the strainer, and as a result the primary debris accumulation points will tend to migrate along the strainer; i.e., the strainer will be self-regulating with regards to debris accumulation and head loss. This process would continue until all debris has been captured by the strainer or has settled in the pool. If less than the maximum quantity of debris is generated, portions of the strainer may remain uncovered. Therefore, rate of accumulation of debris on the strainer is of no consequence.

The ECCS/RCIC suction strainer has been designed to preclude the potential for loss of NPSH caused by debris blockage during the period that the ECCS is required to maintain long-term cooling. The large toroidal passive ECCS/RCIC suction strainer results in a very low approach velocity for water entering the strainer. Debris collected on the strainer surface is not expected to compact significantly (due to very low approach velocity), resulting in minimal head loss. The testing of a 1/4-scale model of the ECCS/RCIC suction strainer design confirmed the performance of the strainer and the behavior of the postulated debris bed as a function of time after the postulated LOCA. Because the debris bed will not be significantly compacted, flow will continue to pass through the debris (and the strainer) and thus the overall differential pressure will remain low. Maintaining a low differential pressure will ensure adequate NPSH for the ECCS pumps.

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 released into the primary containment system, thus resulting in acceptable suppression pool temperatures and containment pressures.

In order to evaluate the adequacy of the RHR system, the following sequence of events is assumed to occur.

a. With the reactor initially at maximum power, a LOCA occurs.

b. A loss of offsite power occurs and one emergency diesel fails to start and remains out of service during the entire transient. This is the worst single failure.

c. Only three ECCS pumps are activated and operated as a result of there being no offsite power and minimum onsite power. (Section 6.3 describes the ECCS equipment.)

d. After 30 minutes it is assumed that the plant operators activate one RHR heat exchanger in order to start containment heat removal. Once containment cooling has been established, no further operator actions are required.

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 and the RHR service water temperature are at their maximum values. This assumption maximizes 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 in Figure 6.2-7. Even with the very degraded conditions outlined above, the maximum temperature is 181°F. This peak occurs 5.5 hours after the accident.

It should be noted that, when evaluating this long-term suppression pool transient, all heat sources in the containment are considered with no credit taken for any heat losses other than through the RHR heat exchanger. These heat sources are discussed in subsection 6.2.1.3. Figure 6.2-8 shows the actual heat removal rate of the RHR heat exchanger.

A decrease in RHR heat exchanger heat transfer rates due to a reduction in flow through the RHR heat exchanger will occur when the RHR system is transferred from the suppression pool cooling mode to the containment spray mode. An analysis of this reduction was conducted in response to Humphrey Issues 4.8 and 5.3 (MP&L (SERI) Action Plans 17 and 18). This analysis assumed the following:

a. Drywell bypass area of $A/\sqrt{K}$ equal to 0.8 ft^2

b. Lower heat transfer rate from the pool which would result from reduced flow through the heat exchanger

c. Structural heat sinks, and heat and mass transfer between the suppression pool and containment air space were modeled

d. Period of drywell pressurization is maximized due to throttling of ECCS flow

e. Main steam line break modeled

The results of this realistic analysis demonstrated that the peak containment pressure remained below the design pressure of 15 psig and that the long-term suppression pool temperature does not exceed 185°F.

To address Humphrey Issue 4.9 (MP&L (SERI) Action Plan 18) concerning the use of the RHR system to control containment pressure/temperature and suppression pool temperature when one train of RHR is available, an analysis was performed using the following assumptions:

a. Full capability drywell bypass of $A/\sqrt{K}$ of 0.8 ft^2

b. One train of RHR in the containment spray mode

c. Structural heat sinks modeled

The analysis of these conditions demonstrated that with only one RHR system operating in the containment spray mode, the containment design pressure is not exceeded. Even allowing for reduced heat transfer through the RHR heat exchanger, the suppression pool temperature remains below the design temperature of 185°F. This analysis demonstrates that cycling of the containment spray to maximize suppression pool cooling would not be required. In addition, the operator has other options available through the Emergency Procedures to simultaneously control containment pressure and temperature and suppression pool temperature without cycling the containment sprays.

It can be concluded that the conservative evaluation procedure described above clearly demonstrates that the RHR system in the suppression pool cooling mode limits the post-DBA containment temperature transient.

6.2.2.3.2 Suppression Pool Stratification and Mixing

Containment heat removal analysis assumes the suppression pool is perfectly mixed and at a uniform temperature when the RHR suppression pool cooling mode is actuated. Humphrey Issue 4.3 postulated that the suppression pool temperature may be lower than the bulk pool temperature resulting in a lower heat removal rate of the RHR heat exchangers due to a smaller approach temperature. To evaluate this issue, a study to quantify the effects of major conservations was conducted. It was determined from this study that the following licensing assumptions account for the majority of the pressure/temperature conservatisms contained in the current analyses in Section 6.2.1.1.3.3.

a. The isothermal assumption that the containment air-space temperature equals the pool temperature

b. No credit for heat sinks

c. Decay heat (Using ANS-5 20/10 instead of ANS 5.1)

Using realistic assumptions for items a through c above reduces the containment air-space peak pressure and temperature by 5.6 psi and 48°F respectively, in addition to reducing the peak suppression pool temperature by 20°F.

Also the temperature stratification of the suppression pool is very small due to induced bulk pool motion from operation of the RHR system in the suppression pool cooling mode. In-plant SRV tests (Reference 21) indicate that suppression pool cooling mode reduces the pool thermal stratification from 12°F to 5°F at a rate of 1.8°F per minute after initiation. This result supports the analytical evaluation of the Mark III containment standard configuration conducted to model suppression pool thermal stratification using the RELAP/MOD5 code. The simulation assumed that an intermediate break accident (IBA) which uncovers only the top row of the vent produces the most severe thermal stratification and used standard FSAR Licensing assumptions. The simulation included vent, SRV, RCIC exhaust, and RHR flows. Details of this analysis and verification of the RELAP modeling with PSTF test data are documented in Section 3B0.3.2.28 (Question/Response 3B.28) in Appendix 6D. This analysis predicted that RHR operation should reduce vertical thermal stratification between RHR suction and return locations by 1.6°F per minute which is in good agreement with the test data. The Mark III RELAP analysis predicted a 24°F temperature difference between the RHR

suction and return locations at the start of RHR operation. The 15 minutes of RHR operation reduced the calculated temperature difference to 2°F. From an energy balance, the 15 minutes of RHR operation to reduce thermal stratification to 2°F results in a 3°F increase in peak bulk pool temperature. This is small compared to the 20°F of conservatisms contained in the FSAR licensing assumptions.

In-plant tests and sophisticated analysis have demonstrated that the RHR system can effectively eliminate vertical temperature stratification in very short time intervals. Consequently, the initial degree of stratification will not have a significant impact on the long-term suppression pool temperature response.

The increase in suppression pool surface temperature, due to stratification effects, will result in a higher containment air-space temperature and pressure since the long-term analysis of the containment pressure/temperature response assumes that the wetwell air space is in thermal equilibrium with the suppression pool water. This item was evaluated as part of Humphrey Issues 4.4 and 7.1 (MP&L (SERI) Action Plan 13), and the maximum stratification which could occur has less than a .1 psi effect on containment atmosphere pressure response. The evaluation of Humphrey Issue 4.5 (MP&L (SERI) Action Plan 14) demonstrated that chugging through the main vents aided in providing a uniform bulk pool temperature. Data from the 1/3-Area Scale Condensation and Stratification Tests (Test Series 5807) performed in GEH Pressure Suppression Test Facility (PSTF) show that chugging is effective in mixing the suppression pool. These tests are described completely in Reference 22 and prove that chugging through the top row of horizontal vents provides an exceptional mechanism for thoroughly mixing the Mark III suppression pool. The pool volume is turned over completely as frequently as once every 10 minutes. Since chugging will be present under all accident conditions when the containment temperature or pressure requires activation of the containment sprays, adequate pool mixing will be present even when RHR is diverted to containment spray. Chugging will also be sufficient to completely mix the pool even after upper pool dump. Upper pool dump is also a very turbulent event which will induce further pool mixing. Therefore, adequate assurance exists that sufficient mixing will occur and effectively prevent excessive stratification.

Humphrey Issue 4.6 (MP&L (SERI) Action Plan 15) raised the concern that RHR might be required to operate continuously in order to maintain the suppression pool temperature below the Technical Specification value of 95°F due to high service water temperature. The only possible mechanism which could raise the pool temperature to the Technical Specification limit is leakage through the main steam safety-relief valves. A simplified analysis of suppression pool temperature assuming 20 pounds per hour steam leakage from each of the 20 main steam safety-relief valves and a maximum service water temperature of 75°F was performed to evaluate this condition. The results of this calculation revealed it would take 10 days for the suppression pool temperature to rise from 90°F to 95°F and 2.38 hours (with 80°F service water temperature) to cool the pool back down to 90° F. The heat input from the suppression pool will raise the SSW basin temperature less than 1°F.

The analyses which predicted the peak shutdown service water temperature contain numerous conservatisms. The conservatisms include the following:

a. The use of the worst 24-hour and worst 30-day meteorological conditions

b. The assumption that the return water temperature to the plant is the same as the cold water temperature in the plant

c. The use of maximum average heat rejection rates for the 30-day period

It is concluded that the RHR system is easily capable of coping with any situations which may raise the suppression pool temperature during normal plant operations. In particular, substantial margins exist in the definition of the peak temperature of the shutdown service water system. Thus, no problems should develop which would mandate long-term operation of the RHR system to control suppression pool temperature.

The arrangement of the GGNS RHR discharge and suction points was analyzed in response to Humphrey Issues 4.7 and 4.10 to ensure that flow interactions of these points did not adversely affect pool mixing. This analysis is detailed in Reference 23 and gives a detailed geometric description of the suction and discharge arrangement of the Grand Gulf Nuclear Station.

Comparison of the angle, direction, and distance between RHR discharges and suction along with the test data confirms the Grand Gulf geometry precludes short-circuiting and provides effective thermal mixing of the suppression pool.

6.2.2.4 Tests and Inspections

The preoperational test program of the containment heat removal system is described in subsection 6.2.2.2.

The following test functions are performed during the normal power plant operation to verify individual system components operation and to verify the capability of the system to perform its proper function:

a. A design flow functional test of the RHR main system pumps is separately performed for each pump during normal plant operation by taking suction from the suppression pool and discharging through the test line back to the suppression pool. The discharge valves to the reactor recirculation loops, the spray spargers, and injection nozzles remain closed during this test; reactor operation is undisturbed.

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

Sequencing of the LPCI subsystem's operation is tested after the reactor is shut down and the RHR system has been drained and flushed. A system can be tested using main system pumps when the reactor is shut down. Valves required for the remaining subsystems are tested at this time.

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

Periodic inspection and maintenance of the main system pumps, pump motors, and heat exchangers are conducted to assure reliable system performance.

During plant operations, the pumps, valves, piping, instrumentation, wiring, and other components outside the drywell can be inspected visually at any time. Components inside the drywell can be inspected when the drywell is open for access. Testing frequencies are generally correlated with testing frequencies of the associated controls and instrumentation. When a pump or valve control is tested, the operability of that pump or valve and its associated instrumentation is generally tested by the same action. When a system is tested, operation of the components is indicated by installed instrumentation.

Because it is not advisable to overpressurize the reactor primary system for testing, relief valves are removed as scheduled at refueling outages for bench tests and setting adjustments.

The containment spray subsystem spray spargers and nozzles can be tested by connecting a smoke generator to a normally capped test connection on the spray header, or by attaching streamers to the nozzle and blowing air out the nozzles.

6.2.2.5 Instrumentation Requirements

The details of the instrumentation are provided in subsection 7.4.1.3. The suppression pool cooling mode of the RHR system is manually initiated from the control room.

6.2.3 Secondary Containment Functional Design

A secondary containment consisting of the auxiliary building and the enclosure building is incorporated into the design of the Grand Gulf Nuclear Station. The auxiliary building is a reinforced concrete structure which completely surrounds the lower portion of the containment, and the enclosure building is a metal-siding structure which completely surrounds the containment above the auxiliary building roofline. The fuel handling area and the auxiliary building ventilation systems maintain the secondary containment at a slightly negative pressure during normal operation. The standby gas treatment system (SGTS) also maintains the secondary containment at a negative pressure and provides cleanup of the potentially contaminated secondary containment volume following a design basis accident. These systems are described in subsections 9.4.2, 9.4.6, and 6.5.3, respectively.

6.2.3.1 Design Bases

6.2.3.1.1 Safety Design Bases

a. The secondary containment, in conjunction with operation of the standby gas treatment system (SGTS) is designed to limit the thyroid dose and the whole body dose to within the guidelines of 10 CFR 50.67 at the site boundary and the low population zone and 10 CFR 50 General Design Criterion 19 for the control room operator doses during the design basis accident.

b. The secondary containment, in conjunction with operation of the SGTS, is designed to maintain a 1/4-inch w.g. negative pressure in the boundary region, and prevents exfiltration at wind speeds less than or equal to 10 mph.

c. The secondary containment, in conjunction with operation of the SGTS, is designed to achieve the design negative pressure within 120 seconds after actuation.

d. The secondary containment is of seismic Category I design.

e. The secondary containment is designed to provide a dilution and hold-up volume for fission products which may leak from the primary containment following a postulated accident.

f. The secondary containment is designed to permit periodic inspection and testing of principal system components such as fans, dampers, and filters.

Refer to Section 3.8 for a discussion of secondary containment structural design.

6.2.3.1.2 Power Generation Design Bases

The secondary containment houses equipment, components, piping, cables, and instrumentation necessary for power generation.

6.2.3.2 System Design

The secondary containment consists of the reinforced concrete auxiliary building surrounding the lower primary containment and a low-leakage, metal-siding enclosure building surrounding the primary containment above the auxiliary building roofline.

The boundary of the secondary containment is shown in the following figures:

Figure	Title
1.2-2	General Arrangement, Plan at EI. 93'-0” & 100'-9”
1.2-3	General Arrangement, Plan at EI. 113'-0”, 111'-0”, 119'-0”, 120'-10”, & 114'-6”
1.2-4	General Arrangement, Plan at 133'-0”, 148'-0”, 139'-0”, 135'-4”, & 147'-7”
1.2-5	General Arrangement, Plan at EI. 166'-0”,161'-0”, & 170'-0”
1.2-6	General Arrangement, Plan at EI. 184'-6”, 185'-0”, 189'-0”
1.2-7	General Arrangement, Plan at EI. 208'-10”
1.2-8	General Arrangement Sections “A-A” and “B’B”

A tabulation of the design and performance data of the secondary containment structure is given in Table 6.2-41.

The performance objective of the secondary containment is to provide a volume completely surrounding the primary containment which can be used to hold up and dilute fission products that might otherwise leak to the environment following a design basis accident. To achieve this, the entire auxiliary building, which is an inherently low-leakage structure due to its reinforced concrete construction with walls several feet thick, is utilized as the hold-up volume for the fission products that are postulated to leak from the lower portion of the primary containment. A low-leakage, metal-siding enclosure building is provided to completely surround the upper portion of the primary containment. Following a design basis accident, the SGTS functions to provide a mixing of these volumes, and maintains the volume at a slightly negative pressure. The exhaust air required to maintain the negative pressure is discharged through the SGTS charcoal filter trains, which are designed to obtain credit for 99 percent removal of elemental iodine and organic iodides (refer to subsections 6.5.1 and 6.5.3 for a discussion of the SGTS filter trains).

In order to minimize the amount of radioactive material that leaks to the secondary containment following a design basis accident, all primary containment penetrations, except ECCS systems, are provided with redundant, ASME Code, Section III, Class 2, seismic Category I isolation valves. The containment isolation system is discussed in subsection 6.2.4. The containment and reactor vessel isolation control system is discussed in subsection 7.3.1.1.2.

The program for leakage rate testing of the primary containment structure and containment components is described in subsection 6.2.6. Primary containment integrity is verified and assured in accordance with the Technical Specifications, Chapter 16.0.

The primary containment leakage rate will not exceed the value stated in subsection 6.2.1.

To maintain secondary containment integrity and eliminate leakage bypassing the SGTS, all lines 2-1/2 inches and larger, penetrating the secondary containment and not performing a safety function or supplying a source of makeup to the RPV, are provided with redundant (except as noted below) ASME Code, Section III, Class 3, seismic Category I isolation valves. Rupture discs and blind flanges are also used to provide isolation protection. Plant protection system signals that isolate and/or activate these secondary containment isolation valves are described in subsection 7.6.1.12.

The failure of lines 2 inches and smaller penetrating the secondary containment plus the following additional failures will not jeopardize the functional integrity of the secondary containment by providing a leakage path which exceeds the capacity of the standby gas treatment system.

System	Failure
Fire Protection (water)	Critical Crack
Fire Protection (carbon dioxide)	Critical Crack
Plant Service Water	Critical Crack
Plant Chilled Water	Critical Crack
Instrument Air	Critical Crack

Analysis has shown that in addition to building leakage paths, the SGTS has the capacity to maintain secondary containment negative pressure assuming the failure of all non-qualified lines 2 inches and smaller. In the absence of other active failures, analyses

have shown that the required negative pressure can be maintained given the additional failure of a single, non-isolated line as large as four inches. As a result, the following lines which penetrate the secondary containment and terminate there (i.e., they do not continue through the secondary containment and also penetrate the primary containment) are provided with a single ASME Code, Section III, Class 3 isolation valve, rather than two, at the secondary containment penetration:

a. 4-inch makeup water supply line

b. 3-inch domestic water supply line

c. 4-inch fire protection system supply line (two)

d. 4-inch RHR backwash line

e. 3-inch backwash transfer pump discharge line

f. 3-inch floor and equipment drain line

The single isolation valve for each of the above lines (except item c.) is an air-operated valve which fails closed; in addition, each operator is provided with redundant solenoid valves which receive actuation signals from redundant sources (refer to subsection 7.6.1.12). In this manner, it is ensured that, given any single failure, only one of the above lines will be non-isolated; this is within the capacity of the standby gas treatment system.

The 4-inch fire protection system supply lines in item c above are isolated by remote manual motor-operated valves. Position indication for these valves is provided in the control room. Isolation of these supply lines is not required to ensure the secondary containment design basis is maintained.

To preclude air inleakage into the SGTS region, the floor drains provided for the railroad bay in the auxiliary building have been permanently sealed. Therefore, these lines are not furnished with isolation valves.

The main steam and feedwater lines are provided with leakage control systems discussed in Section 6.7 and are not provided with auxiliary building isolation valves.

Lines which penetrate the primary and secondary containment were evaluated for potential bypass leakage paths as summarized in Table 6.2-42. The guidelines of BTP CSB 6-3 were addressed in considering potential bypass leakage paths. Designs provided to preclude through-line leakage are dependent upon the working fluid in the associated system, i.e., air or water.

For lines carrying ventilation air, adequate openings are provided in the ductwork between the primary and secondary containment isolation valves to ensure that any leakage through the primary containment isolation valves will be vented into the auxiliary building. These vent paths are identified with placards placed on plant equipment. All lines that vent into the auxiliary building will be treated by the SGTS. The compressed air lines penetrating the primary containment represent a potential post-accident bypass leak path; however, a specific analysis which credits aerosol settling and halogen deposition in the piping system inside secondary containment demonstrates that the source terms released to the environment following a design basis accident are very small. The dose contribution from these sources is included in the doses reported in UFSAR Table 15.6-14.

Lines that penetrate the primary and secondary containment which normally contain water will provide a water seal between the containment and the environment upon primary and secondary isolation valve closure. For the Plant Chilled Water System, the piping configuration combined with primary containment leakage limits allows the loop seals in the system to prevent bypass leakage. The volume of water maintained is sufficient to provide at least a 30-day seal. Several of the lines listed in Table 6.2-42 are not seismically qualified within the auxiliary building. However, if a break were to occur in the non-seismic portion of the line, the water would evacuate into the auxiliary building, and any leakage through the failed line would be processed by the SGTS. Therefore, with the exception of the compressed air systems discussed above, there is no bypass leakage of the secondary containment due to through-line leakage.

Lines which penetrate the primary and secondary containment where bypass leakage is assumed to not occur fall into one or more of the categories listed below:

a. Operate post-LOCA at a pressure higher than the primary containment pressure

b. Are provided with leakage control systems

c. Are vented to the secondary containment

d. Are provided with a water seal assessed against primary containment valve leakage characteristics

Therefore, the primary containment isolation valve leak rate tests and SGTS operability tests are adequate to ensure that bypass leakage will not occur and separate leakage testing of the secondary containment isolation valves is not required.

The design and construction codes, standards and guides applied to the auxiliary and enclosure buildings are discussed in Section 3.8.

6.2.3.3 Design Evaluation

The SGTS will maintain the secondary containment at a negative pressure with respect to the environment following the design basis loss-of-coolant accident. The design flow rate of the exhaust system is based on the following criteria:

a. The exhaust flow rate is based on the sum of all possible inleakages when a 1/4-inch w.g. negative pressure is maintained in the subject areas.

b. Inleakages have been calculated based on the leakage rate data presented in AEC Research and Development Report NAA-SR-10100, "Conventional Buildings for Reactor Containment." Calculations are based on maintaining a 1/4-inch w.g. negative pressure within the building, with a wind speed of 10 mph.

All lines 2 1/2-inches and larger (except those noted in subsection 6.2.3.2) that penetrate the secondary containment are provided with redundant, ASME Section III, Class 3, seismic Category I isolation valves, unless the line is a safety-related source of makeup water to the RPV or is required to effect a safe shutdown of the plant. In the event of the single failure of any isolation valve, the redundant valve will operate, and the integrity of the secondary containment boundary will be maintained. Lines 2 1/2-inches and larger that penetrate the secondary containment and are provided with single ASME Section III, Class 3, seismic Category I isolation valves are listed in subsection 6.2.3.2.

The isolation valve in each of these lines, except for the two fire protection system supply lines, is provided with redundant solenoid valves, which receive actuation signals from redundant sources. The worst single failure, therefore, would be the failure of the largest (4-inch) valve to close. An analysis of the SGTS has indicated that in the absence of other active failures, the system has the capability to maintain the design negative pressure with a single non-isolated line as large as 4-inches and, therefore, the integrity of the secondary containment is not compromised.

All lines 2-inches and smaller which are not provided with secondary containment isolation valves are within the capability of the SGTS to maintain the design parameters.

For a description of the main steam isolation valve and feedwater line leakage control systems, refer to subsections 6.7.1 and 6.7.2. The infiltration from the MSIV leakage control systems is within the capability of the SGTS.

The sizing of the SGTS equipment and components is based on the results of an infiltration analysis as well as an exfiltration analysis of the secondary containment structures. The internal pressure of the secondary containment will be maintained at negative 1/4-inch w.g. when the system is in operation, which represents the internal negative pressure required to insure zero exfiltration of air from the building when exposed to a 10-mph wind blowing at an angle of 45 degrees to the building. [HISTORICAL INFORMATION] [According to "Wind Tunnel Studies of Pressure Distribution on Elementary Building Forms," by Chien, et al., for a similar building configuration and a specific wind direction, there are portions of the building which would be subjected to external negative pressures as high as a factor of five times the velocity pressure of the associated wind speed.] The negative 1/4-inch wg internal pressure, therefore, corresponds to the pressure required to prevent the external pressure from being below the internal pressure, up to a wind speed of 10 mph.

The infiltration required to maintain the boundary region at 1/4-inch w.g. negative pressure has been calculated based on the leakage rate data presented in AEC Research and Development Report NAA-SR-10100, "Conventional Buildings for Reactor Containment." This flow rate corresponds to the long-term exhaust

rate required for the SGTS charcoal filter train exhaust fans. A sizable factor of conservatism has been applied to the calculated value to size the exhaust fan.

As stated above, exfiltration from the enclosure building and the auxiliary building may occur at wind speeds in excess of 10 mph due to the amplification effects associated with the building geometry. A specific exfiltration analysis was performed for a windspeed of 15.9 mph, which represents the upper five percent windspeed at the elevation of the enclosure building roof, to determine the impact of exfiltration on the site boundary dose. Exfiltration rates were calculated for those areas of the building where the resulting external pressure was below that in the building, as generated by SGTS operation. A conservative factor of two was applied to the exfiltration rate, and the resulting rate was used in analyzing the consequences of this occurrence.

This analysis of exfiltration potential has shown that the expected exfiltration rate is less than one scfm.

An analysis of the dose effects of one scfm exfiltration using χ/Q developed from the 15.9-mph windspeed and Pasquill E conditions has shown that the doses would be insignificant. A leakage of even 100 scfm at the above conditions would result in a total two-hour dose at the site boundary well within the limits of 10 CFR 50.67; therefore, the exfiltration contribution even at a rate much larger than the calculated value falls within acceptable guidelines.

Similarly, the control room doses are low when evaluated against 10 CFR 50 General Design Criterion 19.

A drawdown analysis of the secondary containment has been performed and it has been conservatively calculated that a 1/4-inch w.g. negative pressure can be achieved within the Technical Specification requirement. This analysis is based on the following:

a.	Free volume of enclosure building, ft	863,625
b.	Free volume of auxiliary building, ft	3,263,626
c.	Total free volume of boundary areas, ft	4,127,251
d.	Diesel start time, sec.	10

e.	Time to load fan motors from bus, sec.	6
f.	Fan startup time, sec.	3
g.	Exhaust rate during drawdown, cfm	>4,000

Inleakage is calculated as a function of pressure difference across the building. The pressure difference includes a contribution due to an assumed constant wind load of 10 mph. The calculated inleakage at design negative pressure is less than 2300 cfm. Outleakage is not considered since the auxiliary building never reaches a positive pressure. No heat transfer is assumed into the secondary containment or into the environment, since such a heat transfer would have no significant effect during an approximate 100-second transient. The walls of the primary containment are reinforced concrete, 3'-6” thick, and will not offer a contribution due to heat transfer during the transient. The analysis for the drawdown time considered all possible heat loads inside the auxiliary building. The rooms containing equipment (e.g., the ECCS pumps) that operate post-LOCA have room coolers. The coolers have been conservatively designed to remove the heat at the rate at which it is being generated during full operation of the equipment. Cooler initiation occurs concurrent with equipment operation. Internal heat loads include contributions from artificial lighting, mechanical and electrical equipment, and free convection from the main steam and feedwater lines. An initial average building temperature of 110 F is assumed at the start of the transient. A tabulation of secondary containment pressure versus time is given in Table 6.2-43.

As noted above, primary containment wall temperature as a function of time has not been evaluated because of the nature of the construction of the wall (3'-6” concrete). No significant heat gains will be made to the secondary containment from this source during the drawdown period. Similarly, the effect on secondary containment pressure due to thermal expansion of the primary containment is insignificant. Table 6.2-41 includes a tabulation of significant drawdown analysis parameters.

Since the secondary containment consists of the auxiliary and enclosure buildings, all high energy lines are contained within vented subcompartments of these buildings. Analyses have been performed to show that the pressure response within these

subcompartments may be vented to prevent overpressure. A detailed discussion of these subcompartments analyses is presented in subsection 3.6.1.

6.2.3.4 Tests and Inspections

Tests and inspections of the primary containment isolation system are discussed in subsections 6.2.4, 6.2.6, and 7.3.1.1.2. Tests and inspections of the secondary containment isolation control system are discussed in subsection 7.6.1.12. Tests and inspections of the standby gas treatment system are discussed in subsection 6.5.1.4. Primary containment leak-rate testing is discussed in the Technical Specifications and subsection 6.2.6.

Secondary containment and SGTS preoperational testing is discussed in subsection 14.2.12.1.34. Doors and hatches are provided with sufficient instrumentation and/or administrative controls, as described in subsection 6.2.3.5 to assure that they will be normally closed and have no adverse impact on operation of the SGTS and the integrity of the secondary containment. Periodic testing of the secondary containment and the SGTS is discussed in the Technical Specifications.

As noted in subsection 6.5.3, the outer walls of the secondary containment boundary region are the pressure interface. The drawdown rates and long-term exhaust rates have been individually determined for the several discrete volumes of the region which are adjacent to the boundary region, in order to account conservatively for the differences in building construction and hence, leaktightness of the structure. By properly apportioning the exhaust rates throughout the building the entire boundary region is uniformly maintained at the design negative pressure. Preoperational testing will include system airflow balancing to assure proper flow distribution for uniformity of negative pressure. The pressure sensors monitoring the secondary containment negative pressure are located in the enclosure building and measure the differential pressure across the enclosure building at approximate elevation 288'-0”. Because the enclosure building provides the major contribution to inleakage (the auxiliary building walls are concrete and are subterranean below elevation 132'-6”), the sensor locations provide a representative induction of secondary containment pressure.

6.2.3.5 Instrumentation Requirements

The SGTS operates in response to the following signals:

a. High pressure in the drywell

b. Low water level in the reactor vessel

c. High radiation in the fuel handling area ventilation system exhaust or the fuel pool sweep system exhaust

d. Manual initiation from the control room.

Design details and logic of the instrumentation are discussed in subsection 7.3.1.1.8. Details of the auxiliary building isolation valve control system are discussed in subsection 7.6.1.12.

The following openings provide means for gaining access into the secondary containment:

	Unit 1
Door	IA101
Door	lA201
Door	lA301
Door	lA308
Door	lA316
Door	lA318
Door	lA319
Door	lA401
Door	IA501
Door	lA502
Door	lA504

Main steam tunnel blowout shaft

RHR A blowout shaft

RHR B blowout shaft

Hatch cover to radwaste building pipe tunnel

Hatch covers (4) in roof at El. 185'-0”

The openings are illustrated in Figures 9.A-10 through 9.A-15. Each door is provided with position switches which are monitored utilizing electrically supervised circuits. The opening and closing times will be logged by the computer. Readout capability of the open/close status of the doors is provided at a CRT console in the main control room. There are no other monitoring or control devices on these doors. Excessive opening times will be indicated at a panel monitored by station personnel. Procedures governing door access have been written in accordance with Technical Specifications. Excessive opening times will be investigated by appropriate station personnel. Opening of the exterior doors, interior doors, and all hatches of the railroad access will be in accordance with Technical Specifications.

In addition, the panels which cover the RHR A, RHR B, and main steam tunnel blowout shafts each have a switch which is monitored utilizing electrically supervised circuits. Readout capability of the open/close status of the panels is provided at a CRT console in the control room. There are no other monitoring or control devices on these doors. If an inspection reveals a blowout panel to be open, the action statement in the applicable Technical Specification LCO will be followed.

6.2.4 Containment Isolation System

The containment isolation system consists of the piping, valves, and actuators required to isolate the containment following a loss-of-coolant accident, steam line rupture, or fuel handling accident inside the containment.

6.2.4.1 Safety Design Bases

a. Containment isolation valves shall provide the necessary isolation of the containment in the event of accidents or other conditions when the unfiltered release of containment contents cannot be permitted.

b. The design of isolation valving for lines penetrating the containment shall follow the requirements of General Design Criteria 54 through 56 to the greatest extent practicable consistent with safety and reliability. General Design Criterion 57 is not utilized.

c. Isolation valving for instrument lines which penetrate the containment shall conform to the requirements of Regulatory Guide 1.11.

d. Isolation valves, actuators, and control shall be protected against damage by missiles and postulated effects of high- and moderate-energy line breaks.

e. Design of the containment isolation valves and associated piping and penetrations are designed to remain functional during and following the safe shutdown earthquake.

f. Containment isolation valves and associated piping and penetrations shall meet the requirements of ASME Code, Section III, Classes 1 or 2, as applicable.

g. Air-operated containment isolation valves are designed to fail to the required position for containment isolation upon loss of the instrument air supply.

h. For power operated valves used in series, no single event can interrupt motive power to both closure devices.

i. System lines which could provide an open path from the containment to the environs during normal operation are equipped with screens on the open end to keep debris from entering the line and preventing closure of the isolation valve.

j. Closure times and leaktightness for containment isolation valves limit radiological effects from exceeding the guidelines established by 10 CFR 50.67. Leaktightness of the valves is verified by type C test.

k. Distances of the outermost isolation valves are minimized as much as practicable based on pipe stress analysis as described in subsection 3.9.3 to ensure pipe integrity and valve operability.

6.2.4.2 System Design

6.2.4.2.1 Introduction

The containment isolation system consists of the valves and controls required for the isolation of lines penetrating the containment. Table 6.2-44 shows the pertinent data for the containment isolation valves. The arrangement of these valves and their locations with respect to the containment wall are shown in

Figures 6.2-76 through 6.2-80. A detailed discussion of the controls associated with the containment isolation system is included in subsection 7.3.1.1.2.

Power-operated containment isolation valves have limit switches which indicate in the control room when the valve is open or closed. Loss of power to each motor-operated valve is detected and annunciated. Air-operated containment isolation valves are designed to fail in a safe position upon loss of control air or power to the solenoid pilot valve. Power for valves used in series originates from physically independent sources to assure that no single event could interrupt motive power to both closure devices. Containment isolation valves are either automatically actuated by the various signals shown in Table 6.2-44 or are remote-manually operated, as appropriate.

Primary and secondary modes of operation are shown in Table 6.2-44. Some containment isolation check valves are provided with air operators which will be used for testing purposes. These valves are identified in Table 6.2-44.

6.2.4.2.2 Compliance with General Design Criteria

In general, all requirements of NRC Criteria 55 and 56 are met; however, specific deviations from the explicit requirements of these general criteria and the justification for each deviation are discussed in subsection 6.2.4.3. As discussed in subsection 6.2.4.2.7, NRC General Design Criterion 57 is not applicable to the Grand Gulf Nuclear Station.

6.2.4.2.3 Containment Isolation Valve Closure Times

Containment isolation valve closure times were established by determining the isolation requirements necessary to keep radiological effects from exceeding the guideline values established in 10 CFR 50.67. For those system lines which can provide an open path from the containment to the environment, a discussion of valve closure time bases is provided in Chapter 15. Closure times in accordance with the above criteria are listed in Appendix 16B1, Table 3.6.1.3-1.

6.2.4.2.4 Instrument Lines Penetrating Containment

Sensing instrument lines penetrating the containment follow all the recommendations of Regulatory Guide 1.11. Each line has a 0.25-inch orifice inside the containment, as close to the beginning of the instrument line as possible, and a motor operated isolation valve just outside the containment.

Sensing lines which penetrate both the containment and drywell have a 0.25-in. orifice inside the drywell as close to the beginning of the instrument line as possible, a manually operated isolation (root) valve just outside the drywell, and a motor-operated isolation valve just outside the containment.

Sampling instrument lines that are not covered by Regulatory Guide 1.11 have remotely operated isolation valves both inside and outside of the containment.

All of these remotely operated isolation valves are controlled and their position is indicated in the control room.

6.2.4.2.5 Regulatory Guide Compliance

Discussion of compliance with regulatory requirements relative to the containment isolation system (including Regulatory Guide 1.11, Instrument Lines Penetrating Primary Reactor Containment; Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing

Components of Nuclear Power Plants; and Regulatory Guide 1.29, Seismic Design Classification) may be found in Appendix 3A.

Containment isolation for system lines which can provide an open path from the containment to the environs during normal operation is in accordance with NRC Branch Technical Position CSB 6-4, “Containment Purging During Normal Plant Operations.”

6.2.4.2.6 Operability Assurance, Codes and Standards, and Valve Qualification and Testing

All containment isolation valves will be located either inside the containment or inside the auxiliary building. Both structures are of Category I design, and will be protected against damage from missiles. A discussion on the turbine missile design criteria for these structures is presented in subsection 3.5.1.3.

The containment isolation system is designed in accordance with seismic Category I requirement as defined in Section 3.7 using the techniques of subsection 3.9.2.

Section 3.11 presents a discussion of the environmental conditions, both normal and accidental, for which the containment isolation valve system is designed. The section also discusses the qualification tests that are required to assure the performance of the isolation valves under those environmental conditions.

Containment isolation valves are designed in accordance with the requirements of ASME Code, Section III. Where necessary, a dynamic system analysis which covers the impact effect of rapid valve closures under operating conditions is included in the design specifications of piping systems that require containment isolation valves. Specifically, this analysis applies to lines containing main steam isolation valves (MSIV) and isolation valves lines containing relief valves. Vibration operational testing is discussed in subsection 3.9.2 and will be conducted during the startup of the plant.

Valve operability assurance testing is discussed in subsection 3.9.3.

6.2.4.2.7 Closed Systems

The Grand Gulf Nuclear Station does not use “closed system inside containment” criteria to qualify any systems as isolation barriers.

6.2.4.2.8 Redundancy and Modes of Valve Actuation

The main objective of the containment isolation systems is to provide protection by preventing releases of radioactive materials to the environment. This is accomplished by complete isolation of system lines penetrating the containment. Redundancy (except for instrument lines) is provided in all design aspects to satisfy the requirement that any active failure of a single valve or component does not prevent containment isolation.

Mechanical components, including isolation valve arrangements, are redundant to provide backup in the event of accident conditions. Isolation valve arrangements satisfy all requirements specified in General Design Criteria 54, 55, and 56 and Regulatory Guide 1.11.

The isolation valves have redundancy in their mode of actuation; the primary mode is automatic and the secondary mode is remote manual, except where "Remote Manual Only" is more desirable (see Table 6.2-44, isolation signal, for specific exceptions).

The design specifications require each isolation valve to be operable under the most severe operating conditions that it might experience. Each isolation valve is protected from the consequences of potential missiles by separation and/or adequate barriers between the missile source and the valves.

Electrical redundancy is provided in isolation valve arrangements. This redundancy eliminates dependence on one power source to attain isolation. Electrical cables for isolation valves in the same line are routed separately. Cables are selected and based on the specific environment to which they may be subjected, such as high radiation, high temperature, and high humidity.

Provisions for administrative control and/or locks ensure that the position of all non-powered isolation valves is maintained and known. For all power-operated control valves, the position is indicated in the control room. Discussion of instrumentation and controls for the isolation valves is included in Section 7.3.

6.2.4.2.9 Leakage Detection

Leak detection capability for containment lines which are either needed for safe shutdown of the plant, or are part of the engineered safety features, and that have a remote manual valve or check valve inside containment and a remote-manual valve outside containment is as follows:

Penetration Numbers (Ref. Table 6.2-44)	Item
9,10	Nuclear boiler - feedwater A, B
11*, 12*, 13*	RHR suction A, B, C
20	RHR A to LPCI
21	RHR B to LPCI
22	RHR C to LPCI
23*	RHR A test line to suppression pool
25	HPCS pump suction
26	HPCS pump discharge

Penetration Numbers (Ref. Table 6.2-44)	Item
27	HPCS test line
28	RCIC pump suction
29	RCIC turbine exhaust
30	LPCS pump suction
31	LPCS pump discharge
32	LPCS pump test line
33	CRD pump discharge
48*	RHR heat exchanger B relief valve vent header to suppression pool
67*	RHR B test line to suppression pool
77*	RHR heat exchanger A relief valve vent header to suppression pool
89	Standby service water A and B supply and return
90	Standby service water A and B supply and return
91	Standby service water A and B supply and return
92	Standby service water A and B supply and return

*Lines through penetrations 11, 12, 13, 48, 67 and 77 have only an outboard remote manual isolation valve as found acceptable per SSER 1 (Supplement 1 to NUREG 0831, Section 6.2.4).

Penetration Numbers	Leak Detection Method
9 & 10	MSL pipe tunnel T, area temperature (Figure 7.6-17) and containment floor drain sump (subsection 5.2.5.1.2)
11, 12, 13, 20, 21, 22, 23, 25, 26, 27, 28, 29, 30, 31, 32, 33, 48, 67, 77	ECCS pump room sump and wall level switch (subsection 9.3.3.2.3 and Figure 7.6-17) as well as ambient temperature for RHR and RCIC (subsection 5.2.5.1.2)
89, 90, 91, 92	Containment sumps (Figure 9.3-20 and subsection 5.2.5.1.2) Leakage from penetrations 90 and 91 will collect in either the containment sumps or the suppression pool.

All areas inside the drywell are monitored by drywell temperature, pressure, and sump level (both fill up and pump out).

Leakage detection capabilities for remote-manual valves are discussed further in subsections 5.2.5 and 9.3.3.

6.2.4.2.10 Valve Operability and Seal Systems

Provisions for demonstrating the operability of isolation valves are discussed in subsection 3.9.3. Subsection 6.2.6 describes leakage rate testing of containment isolation barriers. Pump and Valve Inservice Testing Program, SEP-GGNS-IST-2, identifies the valves and their test requirements that must be performed to demonstrate their operability.

Main steam and feedwater systems isolation valves are provided with a system for leakage control. Subsections 6.7.1 and 6.7.2 describe the functional capabilities for each respective seal system relative to containment isolation.

6.2.4.2.11 Materials

There are twelve 24-in, eight 36-in, twelve 3-in, and eight 20-in. butterfly-type containment isolation valves, including those connecting the drywell to the containment, which have seats fabricated from a rubber-like material.

These isolation valves have a basic polymer seat material known as EPT (ethylene-propylene-terepolymer rubber). It was selected after performance tests with preestablished requirements for butterfly valves, i.e., natural rubber, polyurethane, nitrile, chlorobytyl, and six other elastomers. The EPT rubber combined the following necessary characteristics:

a. 300°F continuous temperature rating

b. Radiation resistance 1 x 10^8 rads (at ambient temperature)

c. Excellent resistance to boiling water

Butterfly valves with this type of seat material are used at Arkansas Nuclear One, Calvert Cliffs, Prairie Island, Kewaunee, 3 Mile Island, Crystal River, and St. Lucie nuclear power plants.

6.2.4.3 Evaluation Against NRC Criteria

6.2.4.3.1 Evaluation Against Criterion 55

The reactor coolant pressure boundary [as defined in 10 CFR 50, Section 50.2 (v)] consists of the reactor pressure vessel, pressure-retaining appurtenances attached to the vessel, and valves and pipes which extend from the reactor pressure vessel up to and including the outermost isolation valve. The lines of the reactor coolant pressure boundary which penetrate the containment are capable of isolating the containment thereby precluding any significant release of radioactivity.

6.2.4.3.1.1 Influent Lines

Influent lines which penetrate the containment and connect directly to the reactor coolant pressure boundary (RCPB) are equipped with at least two isolation valves, one inside the drywell and the other as close to the external side of the containment as possible.

6.2.4.3.1.1.1 Feedwater Line

The feedwater line has three isolation valves. The isolation valve inside the drywell is a lift check valve. Outside the containment are a positive-closing check valve and a motor-operated gate valve. Should a break occur in the feedwater line, the check valves prevent significant loss of inventory and offer immediate isolation. During the postulated loss-of-coolant accident, it is desirable to maintain reactor coolant makeup from all sources of supply. For this reason, the outermost isolation valve does not automatically isolate upon signal from the protection system. However, this valve can be remotely closed from the control room to provide leakage protection when the operator judges that continued makeup from the feedwater source is unnecessary. Long-term leakage protection is provided by the feedwater leakage control system (see subsection 6.7.2).

The leakage rate test limit for each feedwater line is limited to 1 gpm of water leakage. The motor operated isolation valve and the outboard containment isolation positive closing check valve are each limited to 1 gpm water leakage. These leakage rate limits ensure functionality of the feedwater leakage control system.

6.2.4.3.1.1.2 HPCS Line

The HPCS line penetrates both the containment and the drywell to inject directly into the reactor pressure vessel. Isolation is provided by a testable check valve with a position indicator located inside the drywell and a remote-manually actuated gate valve located as close as possible to the exterior wall of the containment. Long-term leakage control is maintained by this gate valve. If a loss-of-coolant accident occurred, this gate valve would also receive an automatic signal to open.

6.2.4.3.1.1.3 LPCI and LPCS Line

Satisfaction of isolation criteria for the A and B LPCI loops is accomplished by use of two automatic remote-manually operated gate valves. The outboard valve is normally open and the inboard valve is normally closed with the inboard valve receiving an automatic signal to open at the appropriate time to assure that acceptable fuel design limits are not exceeded in the event of a loss-of-coolant accident. Each loop also has a testable check valve with a position indicator located inside the drywell. The check valves are located as close as practicable to the RPV.

Satisfaction of isolation criteria for the LPCS system and LPCI loop C is accomplished by use of an automatic remote-manually operated gate valve and a testable check valve with a position indicator. Both valves are normally closed with the gate valve receiving an automatic signal to open at the appropriate time to assure that acceptable fuel design limits are not exceeded in the event of a loss-of-coolant accident. The check valves are located as close as practicable to the RPV.

6.2.4.3.1.1.4 Control Rod Drive Lines

The control rod drive system, located between the reactor vessel and the containment, has two influent lines: (a) the supply line that penetrates the containment, (b) the insert and withdraw lines that penetrate the drywell.

a. Isolation in the supply line is provided by a simple check valve inside containment and a block valve located as close to the external side of the containment as practical.

b. The CRD insert and withdraw 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 therefore designed in accordance with ASME Code, Section III, Class 2. The basis to which the CRD insert and withdraw lines are designed is commensurate with the safety importance of maintaining pressure integrity of these lines.

   In the design of this system, it has been accepted practice to omit automatic valves for isolation purposes as this introduces a possible failure mechanism into the shutdown (scram) function. As a means of providing isolation, manual shutoff valves are used. In the event of a break in these lines, the manual valves would provide isolation capability. 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. Containment overpressurization will not result from a line break in the containment since these lines contain small volumes, resulting in relatively small blowdown masses.

6.2.4.3.1.1.5 Deleted

6.2.4.3.1.1.6 Standby Liquid Control System Lines

The standby liquid control system is located between the containment and drywell, and its line penetrates the drywell and connects to the reactor pressure vessel via the HPCS injection line. In addition to two check valves inside the drywell, a check valve and an explosive-actuated valve are located outside the drywell. The explosive-actuated 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.

6.2.4.3.1.1.7 RHR Shutdown Cooling Return Lines

Three return path options are available:

The RHR shutdown cooling return line discharges into the upper containment pool, which penetrates the containment. Isolation for this line is provided by an automatic remote-manually operated gate valve outside the containment and an automatic remote-manually operated globe valve inside the containment.

The RHR shutdown cooling return line discharges into the LPCI line, which subsequently penetrates the containment and drywell. See subsection 6.2.4.3.1.1.3 for details on isolation of the LPCI lines.

The RHR shutdown cooling return line discharges into the feedwater line, which subsequently penetrates the containment and the drywell. See subsection 6.2.4.3.1.1.1 for details on isolation of the feedwater lines.

6.2.4.3.1.1.8 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 just inside the containment. The recirculation pump seal water supply line does not penetrate the containment and, therefore, is not subject to the General Design Criteria concerning containment isolation.

6.2.4.3.1.2 Effluent Lines

Effluent lines which form part of the reactor coolant pressure boundary and penetrate containment, drywell, or both are equipped with at least two isolation valves, one inside the drywell and the other outside the containment and located as close to the containment as practicable.

6.2.4.3.1.2.1 Main Steam and RHR/RCIC Steam Lines

The main steam lines extend from the reactor pressure vessel to the main turbine and condenser system, penetrating both the drywell and containment. The main steam drain lines also penetrate both the containment and the drywell. The RHR/RCIC steam line connects to the main steam line inside the drywell and

penetrates both the drywell and containment. For this line, isolation is provided by automatically actuated block valves, one inside the drywell and one just outside the containment.

6.2.4.3.1.2.2 Reactor Water Cleanup System Lines

The reactor water cleanup (RWCU) system is located between the containment and drywell; however, the RWCU pumps are located in the auxiliary building. The suction line from the recirculation system penetrates the drywell and containment walls. Two automatically actuated isolation valves, one located inside the drywell and one outside the containment, are provided to prevent releases to the auxiliary building; both valves are located as close to their respective walls as possible.

The discharge line from the RWCU pumps penetrates the containment. Inside the containment the line feeds the RWCU regenerative heat exchangers. Isolation criteria are satisfied by means of automatically actuated block valves inside and outside the containment.

A blowdown line off the regenerative heat exchanger bypass line penetrates the containment. Outside the containment the line tees to connect separate lines to the condenser and radwaste system. Isolation criteria are satisfied by means of automatically actuated block valves inside and outside the containment.

The reactor water cleanup (RWCU) pumps, heat exchangers, and filter demineralizers are located outside the drywell. The return line from the filter demineralizers connects to the feedwater line outside the containment between the containment wall and the outside containment feedwater check valve. Isolation of this line is provided by the feedwater system check valve inside the containment and a check valve and motor-operated gate valve outside the containment. The motor-operated gate valve functions as a third isolation valve.

During the postulated loss-of-coolant accident, it is desirable to maintain reactor coolant makeup. For this reason, valves which automatically isolate upon a LOCA signal are not included in the design of the system. Consequently, a third valve is required to provide long-term leakage control. Should a break occur in the reactor water cleanup return line, the check valves would prevent significant loss of inventory and offer immediate isolation, while the outermost isolation valve would provide long-term leakage control.

6.2.4.3.1.2.3 Recirculation System Sample Lines

A sample line from the recirculation system penetrates the drywell. The sample line is 3/4 in. in diameter and, therefore, designed to meet the requirements of ASME Code, Section III, Class 2. A sample probe with a 1/8-in. diameter hole is located inside the drywell. In addition this line is provided with one motor-operated valve inside the containment and one motor-operated valve outside the containment.

6.2.4.3.1.3 Summary

In order to assure protection against the consequences of accidents involving the release of radioactive material, pipes which form the reactor coolant pressure boundary have been shown to provide adequate isolation capabilities on a case-by-case basis. In all cases, a minimum of two barriers was shown to protect against the release of radioactive materials.

In addition to meeting the isolation requirements stated in Criterion 55, the pressure-retaining components which comprise the reactor coolant pressure boundary are designed to meet other appropriate requirements which minimize the probability or consequences of an accident pipe rupture. The quality requirements for these components ensure that they are designed, fabricated, and tested to the highest quality standards of all reactor plant components. The classification of components which comprise the reactor coolant pressure boundary is in accordance with ASME Code, Section III, Class 1.

It can, therefore, be concluded that the design of piping systems which comprise the reactor coolant pressure boundary and penetrate containment satisfies NRC General Design Criterion 55.

6.2.4.3.2 Evaluation Against Criterion 56

Criterion 56 requires that lines which penetrate the containment and communicate with the containment interior must have two isolation valves, one inside the containment, the other outside. It should be noted that this criterion does not reflect consideration of the BWR suppression pool design. For instance, those lines which connect to the suppression pool do not have an isolation valve located inside the containment as this would necessitate placement of the valve under water. All of the lines which connect to the suppression pool are to or from the individual watertight ECCS pump rooms.

6.2.4.3.2.1 Influent Lines to Suppression Pool

6.2.4.3.2.1.1 LPCS, HPCS, and RHR Test Lines

The LPCS, HPCS, and RHR test lines have isolation capabilities commensurate with the importance to safety of isolating these lines. Each line has a normally closed motor-operated valve located outside the containment. Containment isolation requirements are met on the basis that the test lines are normally closed, low-pressure lines constructed to the same quality standards as the containment. Furthermore, the consequences of a break in these lines result in no significant safety consideration, as all of these lines terminate below the minimum drawdown level in the suppression pool.

The test return lines are also used for suppression pool return flow during other modes of operation. In this manner the number of penetrations is reduced minimizing the potential pathways for radioactive material release. Typically, pump minimum flow bypass lines join the test return lines downstream of the test return isolation valve. The bypass lines are isolated by motor-operated valves which fail as is, with a restricting orifice downstream of the motor-operated valve. In addition, in the RHR system check valves downstream of these valves are provided.

6.2.4.3.2.1.2 RCIC Turbine Exhaust and Pump Minimum Flow Bypass

These lines which penetrate the containment and discharge to the suppression pool are equipped with a normally open, motor-operated, gate valve located as close to the containment as possible. In addition, there is a positive closing swing check valve upstream of the RCIC turbine exhaust gate valve which provides positive actuation for immediate isolation when the RCIC system is not operating or in the event of a break upstream of this valve. The gate valve in the RCIC turbine exhaust is 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 pump minimum flow bypass line is isolated by a normally closed, remote-manually actuated valve with a check valve installed upstream.

6.2.4.3.2.1.3 RHR Heat Exchanger Vent Lines

The RHR heat exchanger vent lines discharge to the suppression pool via a discharge line from the RHR heat exchanger pressure relief valve and are isolated from it by two remotely controlled

motor-operated globe valves. Connections to the relief discharge lines are isolated by the relief valves themselves in a way similar to a check valve. The addition of block valves for isolation would, therefore, defeat the purpose for which the relief valves are installed. The set pressure for the relief valves is greater than 1.5 times the design pressure of the containment.

6.2.4.3.2.2 Effluent Lines from Suppression Pool

6.2.4.3.2.2.1 RHR, RCIC, LPCS, and HPCS Suction Lines

In each of these systems one motor-operated, remote-manually operated gate valve is provided to assure isolation of each line in the event of a break and to provide long-term leakage control. In addition, the suction piping from the suppression pool is considered an extension of containment since it must be available for long-term use following a design basis loss-of-coolant accident. As a result, it is designed to the same quality standards as the containment. Thus, the need for isolation is obviated to some degree by providing a high-quality system and by the fact that the piping runs to the watertight ECCS pump rooms. In addition, the ECCS discharge line fill system takes suction from the RHR effluent line from the suppression pool downstream of the isolation valve. The ECCS discharge line fill system suction line has a locked open manual valve for Loop C and remotely operated MOVs for Loops A and B.

6.2.4.3.2.3 Purge Radiation Detection and Combustible Gas Control

Other influent and effluent lines which are evaluated against criterion 56 belong to standby service water system, component cooling water system, plant chilled water system, suppression pool cleanup system, condensate and refueling water storage and transfer system, service air system, instrument air system, containment cooling system, combustible gas control system, from floor and equipment drains, and sampling instrument lines that are not covered by Regulatory Guide 1.11. These lines are listed in Table 6.2-44 and their valve arrangement is shown on Figure 6.2-76 through 6.2-80.

6.2.4.3.2.4 Summary

To assure protection against the consequences of accidents involving release of significant amounts of radioactive materials, pipes that penetrate the containment have been demonstrated to provide isolation capabilities on a case-by-case basis in accordance with Criterion 56.

In addition to meeting isolation requirements, the pressure retaining components of these systems are designed to the same quality standards as the containment. In some respects, providing a high-quality system obviates the need for isolation because of the diminished probability of a rupture in these lines.

6.2.4.3.3 Evaluation Against Branch Technical Position CSB 6-4

The containment purge system is designed to meet the objectives given in BTP CSB 6-4. Isolation valves in the purge system are capable of isolating the containment within 5 seconds. A description of the system is given in subsections 6.2.4.1, 6.2.4.2, and 9.4.7.

The radiological consequences of purging the containment during operation have been evaluated. One case evaluated the impact of high volume containment purge operation at the onset of a LOCA while another case considered operation of drywell purge during a low-volume containment purge. The major assumptions in these dose analyses are:

1. A double-ended guillotine break of the recirculation line is assumed to occur instantaneously. This accident was chosen because it represents the worst break and consequently the highest doses.

2. Closure of the isolation valves in the purge system will isolate the containment within 10 seconds.

3. Forty percent of the blowdown was assumed to flash into steam. Conservatively, it was assumed that the entire iodine activity in the flashed fraction of the total blowdown was instantaneously released to the containment atmosphere at the instant of the accident. Plating out of iodine was ignored. Furthermore, retention of iodines in the suppression

pool was ignored, though in actuality the flashed activity would be at first dumped into the pool and would evolve into the containment only subsequently.

4. Iodine specific activity in the reactor coolant was conservatively assumed to be 4 µCi/g of I-131 dose equivalent, which corresponds to spike conditions.

5. Turbulence resulting from the high blowdown rates and the operation of fan coolers in the containment was assumed to ensure good mixing in the entire containment volume.

6. Based on the guidance in Regulatory Guide 1.183, only reactor coolant source terms are assumed to be released in the first 2 minutes of the accident. The 5-second valve closure guidance in Branch Technical Position CSB 6-4 is outdated considering recent timing insights associated with the NUREG-1465 alternative source term.

7. No credit was allowed for iodine removal by 99 percent efficient charcoal adsorbers on the containment exhaust lines.

These calculations determined that the offsite and control room doses associated with this short-term release of reactor coolant are less than 1 millirem TEDE, which are negligible relative to the acceptance criteria in 10 CFR 50.67. Therefore, the analysis is conservative and demonstrates that, if necessary, intermittent operation of the drywell purge mode of the containment purge during power operation would not significantly affect safety of the plant.

6.2.4.4 Tests and Inspections

A program for the leaktightness testing of primary containment isolation valves, including definition of test boundaries and connections added to facilitate leak rate testing, is described in subsections 6.2.6. Functional testing of the containment isolation valves is conducted in accordance with the Technical Specifications. In addition, components in the containment isolation system were tested for correct functional performance during the preoperational test program.

An inservice inspection program for the valves in the reactor coolant pressure boundary is described in subsection 5.2.4.

6.2.5 Combustible Gas Control

Three (3) systems are provided to control the concentration of hydrogen which may be released in the drywell and containment following an accident. These systems are a drywell purge system, a hydrogen control system consisting of a hydrogen ignition system, and a backup containment purge system which together form the combustible gas control system which functions to assure that containment integrity is maintained. The hydrogen ignition system is used to control the excessive quantity of hydrogen generated during the very unlikely occurrence of a degraded core accident.

GGNS design had originally also included redundant hydrogen recombiners. However, final 10 CFR 50.44 rule making in September 2003 eliminated the requirement for recombiners. While the regulatory requirement has been dropped, GGNS has currently retained the recombiners in order to provide an alternate means of hydrogen control in the unlikely event both divisions of hydrogen igniters were to be declared inoperable.

6.2.5.1 Design Bases

6.2.5.1.1 Safety Design Bases

a. Provide the capability to control combustible gas generated from a metal-water reaction involving 75% of the fuel cladding surrounding the active fuel region so there is no loss of containment structural integrity.

b. Hydrogen generated from the metal-water reaction and radiolysis is assumed to evolve to the drywell atmosphere and form a homogeneous mixture. Several natural forces support this assumption. These natural forces include molecular diffusion and natural convection. Natural convection is promoted by temperature gradients existing in the drywell and the cascading effect of the ECCS water exiting through the break. These forces offset the natural buoyancy force of hydrogen and promote mixing in the drywell. Mixing is promoted in the containment by these same natural forces. The initiation of the containment sprays will create turbulence in the containment which will enhance mixing.

c. The systems meet the requirements of 10 CFR 50, Appendix A, General Design Criterion 41, with respect to their capability to control the concentration of hydrogen following postulated accidents.

d. The primary means of hydrogen control has the capability of purging the hydrogen released in the drywell from the metal-water reaction and radiolysis into the larger containment volume without presenting a drywell bypass path. In addition, control over the long-term hydrogen concentration is made without reliance on purging of the containment.

e. To control the long-term buildup of hydrogen in the containment, igniters are provided. There are two 100 percent divisions of igniters.

f. As a backup to the igniters, a single recombiner in conjunction with the drywall purge system can provide the hydrogen control function.

g. The drywell purge and hydrogen control systems are designed to the quality assurance, redundancy, energy source, and instrumentation requirements for engineered safety features (refer to Table 3.2-1, Section XXVIII).

h. All components in the drywell purge and hydrogen control systems are of seismic Category I design and are capable of withstanding the temperature and pressure transients resulting from a LOCA. They can also withstand the humidity conditions and radiation environment in which the combustible gas control system components are located (refer to Section 3.11).

i. Protection from postulated missiles and pipe whip is provided as required to ensure proper system operation. All active components of the drywell purge and hydrogen control systems are located in the containment outside the drywell. The major system components and associated performance data are listed in Table 6.2-45.

j. Since operation of only one of the two independent combustible gas control systems is required, a single failure will not prevent the system from fulfilling its design function. The combustible gas control system failure analysis is presented in Table 6.2-46.

k. The capability to periodically inspect and test systems and system components is discussed in subsection 6.2.5.4.

l. The hydrogen recombiners are freestanding units located in the containment. Therefore, the protection of personnel from radiation in the vicinity of the recombiners is not required.

m. The hydrogen ignition system is designed to periodically burn hydrogen that is released to the containment and drywell during a degraded core accident.

n. The hydrogen ignition system is designed to burn hydrogen at concentrations below its detonable limit. The containment pressure increase associated with the hydrogen combustion takes place too slowly for dynamic effects to be of concern.

o. The system is designed to have an ample number of igniters fed from two Class IE ESF power distribution panels, each from one of two different divisions. Each panel supplies one-half of the igniters, which are further divided into two trains, each from one of two breakers.

p. The hydrogen igniters are distributed throughout the containment and drywell. Together with the operation of containment sprays and the drywell purge system, any significant pocketing of hydrogen will be precluded.

q. The glow plugs of the hydrogen igniter assemblies exposed to the containment sprays are protected by spray shields where required.

r. The design basis for the drywell vacuum relief function is to prevent backflow over the weir wall following a postulated small break LOCA. The vacuum relief system also serves to control rapid weir wall overflow following a postulated large break LOCA. Bounding calculations using conservative assumptions have shown that there would be no damage to safety- related equipment in the drywell above the weir wall from drag and impact loads due to water backflow over the weir wall. Present drywell negative pressure analysis for rapid weir wall overflow in a large break LOCA assumes a vacuum relief capability of $A/K = 0.38\ ft^2$. This relief capability requires a minimum

of two 10 inch drywell vacuum relief paths out of the three installed. Drywell vacuum relief is not required to assist in hydrogen dilution or to protect the structural integrity of the drywell following a large break LOCA.

6.2.5.2 System Design

The combustible gas control system has the following design features:

a. Following either a postulated large or small break LOCA, drywell vacuum relief is provided by two drywell post-LOCA and two drywell purge vacuum relief subsystems. This vacuum relief is provided to prevent backflow over the weir wall following a postulated small break LOCA. In addition, it serves to control rapid weir wall overflow following a large break LOCA. An independent vacuum relief capability (normal drywell vacuum relief line) is provided by a separate system for normal operating transients.

b. Three 10 inch lines penetrate the drywell so that containment air will have a flow path into the drywell and allow vacuum relief during a postulated LOCA. Two of the 10 inch lines are part of the Combustible Gas Control Drywell Purge Subsystem and the remaining 10 inch line is part of the Post-LOCA Vacuum Relief System. Each 10 inch vacuum relief line in the Combustible Gas Control Drywell Purge Subsystem contains a drywell vacuum relief purge subsystem. Each of the two purge subsystems consists of a motor operated isolation valve and two check valves arranged in series. The motor-operated butterfly valves on each drywell vacuum relief purge subsystem inlet line are opened automatically when the drywell pressure falls below the +0.87 high differential pressure setpoint after a LOCA. Vacuum relief will then initiate at a differential pressure across the check valves of one psi.

   The 10 inch drywell vacuum relief line that is a part of the Post-LOCA Vacuum Relief System contains two subsystems arranged in parallel. The subsystems are redundant in that operability of either one will ensure operability of the associated 10 inch drywell post-LOCA vacuum relief line. Each drywell post-LOCA vacuum relief subsystem consists of a motor operated isolation valve and a check valve arranged in series. The motor-operated butterfly valves on

each drywell post-LOCA vacuum relief subsystem inlet line are opened automatically when the drywell pressure falls below the -0.88 low differential pressure setpoint after a LOCA. Vacuum relief will then initiate at a differential pressure across the check valves of one psi.

c. Coincident with the motor-operated butterfly isolation valves' actuation and prior to relief of the vacuum in the drywell, the two redundant compressors of the drywell purge system will automatically begin to pressurize the drywell. When the drywell has been sufficiently pressurized, the noncondensibles (including hydrogen) will begin to be forced through the horizontal vents into the containment suppression pool at a rate designed to maintain the hydrogen concentration below the flammable limits. The hydrogen gas will eventually permeate into the containment atmosphere.

d. Redundant divisions of igniters are provided for hydrogen control in the containment. The hydrogen ignition system will be manually initiated when directed by the emergency procedure to reduce the hydrogen concentration in the containment.

e. A nonsafety-related containment hydrogen purge system in accordance with Regulatory Guide 1.7 is provided in the unlikely event both hydrogen recombiners are inoperative. The containment can be purged through the charcoal and HEPA filters of the containment filtration system and discharged to the environment (see Figures 9.4-11 and 12).

f. Monitoring of the drywell and containment atmospheres is done by the hydrogen analyzer systems described in subsections 6.2.5.5 and 7.5.

g. A tabulation of the design and performance data for each system component is located in Table 6.2-45.

h. A detailed discussion of instrumentation features is provided in subsection 7.3.1.1.5.

i. Electrical requirements for equipment associated with this system are in accordance with the appropriate IEEE standards as referenced in Section 8.1.

j. The hydrogen ignition system will be manually energized from the control room when directed by the emergency procedures. The energized igniters will maintain a minimum of 1500°F surface temperature for a minimum of 7 days to burn the hydrogen.

6.2.5.2.1 Drywell Purge System

The drywell purge system is provided to purge the hydrogen produced within the drywell into the larger containment volume. This results in a dilution of the hydrogen and maintains the drywell hydrogen concentration below the flammability limit. The drywell purge compressor also performs the function diluting the drywell source term with the containment and suppression pool environment by pressurizing the drywell and discharging the drywell source term through the drywell suppression pool vents. With the implementation of the Alternative Source Term (Amendment 145), this dilution of drywell source term is no longer credited in the Equipment Qualification analysis which is presented in FSAR Section 3.11.

This system consists of redundant components so that any single active failure cannot prevent the purging of the drywell volume. Each division consists of one compressor, two isolation valves (one check and one motor-operated butterfly), and the required instrumentation. All of these components are designed as safety-related equipment. The physical location of each division is shown in Figures 6.2-83 and 6.2-84.

As shown in Figure 6.2-81, the system draws from the containment volume and discharges into the drywell. To relieve the vacuum in the drywell due to steam condensation following a postulated LOCA, a separate 10 inch line for vacuum relief is provided with an additional check valve. This vacuum relief system serves to prevent backflow over the weir wall following a postulated small break LOCA. It also serves to control rapid weir wall overflow following a postulated large break LOCA. Following vacuum relief, the continued operation of the compressors causes flow of the drywell atmosphere through the horizontal vent system and into the containment. A prototype drywell purge compressor has been tested under LOCA conditions to ensure operation following a LOCA. The seismic qualification procedure for drywell purge compressor is addressed in subsections 3.9.2 and 3.9.3 and environmental qualification described in Section 3.11.

To address Humphrey Concern 5.7 (Grand Gulf Action Plan 48), the ability to establish flow through the vents after an upper pool dump was analyzed. It was determined that even after an upper pool dump, the discharge pressure of the hydrogen purge compressor is sufficient to depress the water in the weir annulus and establish flow through the upper vents. In addition, the suppression pool level is expected to be approximately 2 feet above the top of the upper horizontal vent after ECCS drawdown of the pool occurs. This is a small hydrostatic head compared to the discharge pressure of the compressors.

6.2.5.2.2 Hydrogen Control System

6.2.5.2.2.1 Hydrogen Recombiner System

The hydrogen recombiner system was fully redundant and consisted of two 100 percent capacity hydrogen recombiners. Currently, a recombiner in conjunction with the drywell purge system can provide the hydrogen control function if both divisions of igniters are inoperable.

a. Each recombiner subsystem consists of controls located in the control room, and a power supply cabinet in the auxiliary building. The recombiner is located on the operating deck of the containment. Air flows by natural convection through the unit. The recombiner is a completely passive device.

b. The power supply cabinet located in the auxiliary building contains an isolation transformer plus a controller to regulate the power to the recombiner. The controls for the power supply are located in the control room and are manually actuated.

c. Each hydrogen recombiner consists of the following design features:

    1. A preheater section consisting of a shroud placed around the central heaters to take advantage of heat conduction through the central walls for preheating incoming air

    2. An orifice plate to regulate the rate of air flow through the unit

3. A heater section consisting of four banks of metal sheathed electric resistance heaters to heat the air flowing through it to hydrogen-oxygen recombination temperatures. Each bank contains 60 individual U-type heating elements

4. A mixing chamber which mixes and dilutes the hot effluent with containment air to lower the temperature of the discharge stream

5. An outer enclosure to protect the unit from impingement by containment spray

6. Except for electrical power, there is no need of any plant service

d. Containment atmosphere is heated within the recombiner in a vertical duct causing it to rise by natural convection. As it rises, replacement air is drawn through intake louvers downward through a preheater section which will temper the air and lower its relative humidity. The preheated air then flows through an orifice plate, sized to maintain a 100 scfm flow rate, to the heater section. The air flow is heated to a temperature above 1,150°F, the reaction temperature for the hydrogen-oxygen reaction, and any free hydrogen present reacts with atmospheric oxygen to form water vapor. After passing through the heater section, the flow enters a mixing section which is a louvered chamber where the hot gases are mixed and are discharged directly into the containment. The air-discharge louvers are located on three sides of the recombiner. To avoid short circuiting of previously processed air, no discharge louvers are located on the intake side of the recombiner.

Tests have verified that the hydrogen-oxygen recombination is not a catalytic surface effect associated with the heaters, but occurs due to the increased temperature of the process gases. As the phenomenon is not a catalytic effect, saturation of the unit cannot occur. Results of testing a prototype electric hydrogen recombiner are given in References 4 and 5 and production unit test results are given in References 6 and 7. There are no differences between the recombiner system on which the qualification tests were conducted and the recombiner system which was purchased for Grand Gulf.

6.2.5.2.2.2 Hydrogen Ignition System

The hydrogen ignition system is a system of igniters installed within the containment. This system is required to function only in the unlikely event that large quantities of hydrogen are generated as a result of a postulated, severely degraded core accident. The system is designed to induce the combustion of hydrogen in such a manner that hydrogen detonations and containment overpressurization are precluded.

The hydrogen ignition system consists of 90 igniter assemblies distributed throughout the containment and drywell. There are 18 igniters in the drywell and 12 igniters located in a circular pattern above the suppression pool. The remaining 60 igniters are located at different elevations of the containment. Eighteen of these are installed in the upper dome region mounted on the containment spray ring header supports. For enclosed areas within the containment, at least two igniters, each powered from a different ESF division, are installed. Refer to Table 6.2-54 and Figures 6.2-88a through 6.2-88g for the location of the hydrogen igniters.

The igniters used are glow plugs powered directly from a 120/12 V ac transformer that has multitap capability.

The igniter assembly includes the igniter enclosure and the junction box. The igniter enclosure consists of a stainless steel box with 1/8-inch-thick walls, which houses the transformer and the associated electrical connections and partially encloses the igniter. The sealed box uses a hooded spray shield to reduce water impingement on the glow plug where required. The components of the hydrogen ignition system are seismically supported and will maintain functional capability under post-accident conditions.

The igniters are powered from Class IE power panels that have a normal offsite and an alternate onsite diesel ac power supply. In addition, the hydrogen ignition system is designed as a seismic Category I system.

The hydrogen ignition system is manually initiated from the control room when directed by the emergency procedures. The igniters are required to remain operable for a minimum of 7 days following a postulated LOCA.

6.2.5.2.3 Containment Purge System

The redundant drywell purging and hydrogen control systems ensure control of the post-accident hydrogen concentration. However, in the interest of conservatism of design, a non-redundant controlled containment hydrogen purge system shown in Figure 6.2-81 is provided. In accordance with Regulatory Guide 1.7, this system is not designed to seismic Category I requirements, except those portions of the purge system which constitute the containment boundary.

The containment is purged through the containment filtration system charcoal filter trains. The containment purge system takes outside air as make up through a compressor into the containment. The purge is through an electric heater, a pre-filter, a charcoal filter, and a high efficiency particulate air (HEPA) filter to reduce the activity released.

6.2.5.3 Design Evaluation

6.2.5.3.1 Degraded Core Accident

Evaluations have been performed based on a degraded core accident with a metal-water reaction of 75 percent of the core cladding. The evaluations show that the ignition system will control hydrogen concentrations to below its detonable limit.

[HISTORICAL INFORMATION] [In October of 1980, the Nuclear Regulatory Commission (NRC) published a proposed hydrogen control rule. The NRC published the final version of this rule by amending the hydrogen control requirements of 10CFR50.44 on January 25, 1985. The final hydrogen control rule requires that each BWR licensee with a Mark III containment submit an analysis to the NRC that demonstrates compliance. The Rule requires that the analysis provide an evaluation of the consequences of releasing large amounts of hydrogen into the primary containment during a postulated degraded core accident. The analysis must address recovery from the degraded condition, use scenarios that are accepted by the NRC, support the design of the hydrogen control system, demonstrate that the containment structural integrity will be maintained, and that systems and equipment necessary to establish and maintain safe shutdown will be capable of performing their function if exposed to the environmental conditions created by the burning of hydrogen.

Since the hydrogen control program inception, Grand Gulf Nuclear Station (GGNS) and the Hydrogen Control Owners Group (HCOG) have completed a significant amount of testing and analysis to demonstrate compliance with the Hydrogen Control Rule (10CFR50.44). In addition to significant analyses, the HCOG hydrogen control program led to design and construction of a large (1/4-scale) test facility and the performance of plant-specific modeling and testing to define the hydrogen combustion phenomena and the attendant effects in a Mark III containment during a postulated degraded core accident.]

Specific details of the Hydrogen Control Program, both plant-specific and generic, are contained in the GGNS Hydrogen Control final Analysis Report (Ref. 28) This final analysis has provided, by reference or inclusion, and evaluation of the consequences of hydrogen released from a recoverable degraded core accident, including the recovery period, using a postulated accident accepted by the NRC. The analysis supports the design of the hydrogen control system installed at GGNS, shows that containment structural integrity is maintained, and demonstrates survivability of systems and components necessary to establish and maintain safe shutdown and containment integrity. This final GGNS-specific hydrogen control system analysis meets or exceeds the requirements specified in 10CFR50.44.

6.2.5.3.2 Controlled Purge Site Doses

In the event of a design basis loss-of-coolant accident, the redundant drywell purging and hydrogen control systems of the combustible gas control system will operate so that no containment purging will be required. Eventually, however, the containment must be purged of the residual combustible gases and fission products prior to reentry by personnel.

Since the controlled purge would not be initiated until some time in excess of 30 days after the LOCA, site boundary and low population zone doses resulting from a controlled purge would be very small in comparison to that which has been calculated due to containment leakage following the LOCA (see Chapter 15).

6.2.5.3.3 Loss of Coolant Accident Description (Historical)

Calculations have been performed to determine the following: the hydrogen generated in the post-LOCA environment, and the resultant drywell and containment concentrations as a function of time if uncontrolled.

The 2003 combustible gas control rule making established that hydrogen control following a LOCA was not risk significant. On that basis, the requirement for recombiners was eliminated. This discussion of post LOCA hydrogen generation has been retained as historical information only.

A complete description of the post-LOCA conditions is found in Section 6.3. A brief description is given here to explain the basis for hydrogen generation and control:

a. Complete severance of a recirculation line or a main steam line coupled with the worst single failure leaving two RHR pumps, one RHR heat exchanger, and HPCS in operation.

b. Drywell pressurization causes noncondensibles in the drywell to be swept through the suppression pool to the containment atmosphere.

c. The postulated zirconium-water reaction begins and hydrogen is produced. The extent of reaction is determined using the calculation method stated in Regulatory Guide 1.7.

d. Fission products may be released from the core and are assumed to be dissolved or suspended in the drywell portion of the suppression pool and the drywell sump. Hydrogen from this source is released to the drywell and containment regions based on the pool surface areas in the respective regions. Hydrogen produced from in-core radiolysis is released into the drywell region.

e. Assuming initial operating pressure and temperature conditions within the drywell, the hydrogen concentration will reach four percent by volume if uncontrolled. Prior to this time the compressors of the drywell purge system will have pressurized the drywell forcing the drywell atmosphere through the horizontal vents into the containment, thereby maintaining the hydrogen concentration in the drywell below the flammability limit.

f. As the radiolytic hydrogen continues to be produced, the containment hydrogen concentration gradually increases. When the hydrogen concentration in the drywell has reached 3 volume percent, one of the two redundant recombiners will be or would have been started. Using conservative assumptions and if it is assumed that recombiners are not

started until the hydrogen concentration is 3 volume percent, the initiation of recombining would not be required until 4 days following the LOCA.

Based on loss-of-coolant calculational procedures established by the NRC in the Interim Acceptance Criteria for Emergency Core Cooling Systems, the extent of metal-water reaction in the core for a BWR/6 is 0.16 percent (see Section 6.3 of this report and also GE topical reports NEDO-10569A and NEDO 11013-77, references 8 and 9, respectively). The design of the BWR-6 ECCS is such that the peak zirconium clad temperature is limited and results in insignificant amounts of hydrogen from metal-water reaction. Realistically, therefore, insignificant amounts of hydrogen would be generated in the BWR-6 core as a result of the metal-water reaction. With the introduction of advanced fuel designs with larger cladding surface areas, the limiting metal-water reaction has become based on the reaction of the outer 0.00023 inches of the active cladding. The analysis demonstrates the combustible gas control system can accommodate the hydrogen release from a full core of either ATRIUM-10, GE14, or GNF2 fuel with an additional 20% margin. The recombiner capacity is verified to be adequate for reload cores. Also, long-term hydrogen generation in the drywell is produced by radiolysis in the core and in the drywell pool.

Hydrogen generated from the radiolysis of organic matter in the drywell and the containment is calculated based on the six months integrated dose.

The generation of hydrogen due to radiolysis begins immediately following the LOCA but proceeds at a much slower rate than the metal-water reaction.

Hydrogen will be produced by radiolytic decomposition of post-LOCA cooling waters in the core region and the drywell sump. Hydrogen generation in the core region will result from solution radiolysis induced by fission product gamma radiation. In addition, radiolytic hydrogen will be produced by fission products which are released from the core and become dissolved or suspended in the drywell sump.

In determining the hydrogen generation due to radiolysis, Regulatory Guide 1.7 and Standard Review Plan 6.2.5 assumptions and parameters were used.

For aluminum and zinc, the corrosion rates are used from References 17 and 18, respectively, and are shown in Table 6.2-52. The surface areas applied in the analysis of the corrodibles are identical to or bound those reported in Table 6.2-53.

Hydrogen generated from the metal-water reaction and radiolysis is assumed to evolve to the drywell atmosphere and form a homogeneous mixture. Several natural forces support this assumption. These natural forces include molecular diffusion and natural convection. Natural convection is promoted by temperature gradients existing in the drywell and the cascading effect of the ECCS water exiting through the break. These forces offset the natural buoyancy force of hydrogen and promote mixing in the drywell.

Mixing is promoted in the containment by these same natural forces. The initiation of the containment sprays will create turbulence in the containment which will enhance mixing. Based on the above hydrogen generation sources and the accident description, the curves for Hydrogen Generated vs. Time were developed. Figure 6.2-20 is based on a postulated main steam line break which generates slightly higher quantities of hydrogen than for the postulated recirculation line break. To calculate the hydrogen concentration in the drywell and containment as a function of time, a three region computer model was used. This model includes hydrogen generation from the metal-water reaction and radiolysis and also drywell purging and recombination in the containment.

6.2.5.4 Testing and Inspections

Each active component of the combustible gas control system that is provided to operate after a design basis accident is testable during normal reactor power operation. The drywell purge compressors and valves, the hydrogen recombiners, the hydrogen igniters, and the containment purge system are tested periodically to ensure that the combustible gas control system will operate.

[HISTORICAL INFORMATION] [Preoperational tests of the combustible gas control system were conducted during the final stages of plant construction prior to initial startup (see Chapter 14.2). These tests ensure correct functioning of all controls, instrumentation, compressors, recombiners, igniters, igniter power supply, piping, and valves. System reference

characteristics, such as pressure differentials, flow rates, igniter surface temperature, and igniter train current are documented during the preoperational tests and are used as base points for measurements in subsequent operational tests.]

During plant operation, the compressors, piping, recombiners, accessible igniters, igniter power supply, valves, instrumentation, wiring, and other components outside the drywell can be inspected visually at any time. Testing frequencies of the combustible gas control system components are generally correlated with testing frequencies of the associated controls and instrumentation. When a compressor or valve control is tested, the operability of that compressor or valve and its associated instrumentation is generally tested by the same action.

All hydrogen igniter assemblies are tested to verify operability per Grand Gulf Nuclear Station Technical Specifications.

In addition, inservice inspection of all ASME, Section III, Class 3 components is done in accordance with Section 6.6.

6.2.5.5 Instrumentation and Application

Subsection 7.3.1.1.5 describes the instrumentation and control for the drywell purge system which is automatically initiated. Hydrogen-analyzing systems, as described in subsection 7.5.1.2.8.3 indicate post-accident hydrogen concentrations in the drywell. The location of the hydrogen sample points is shown in Table 6.2-51. When the drywell pressure falls below the high differential pressure setpoint following an accident, the drywell purge system initiates automatically or can be manually initiated by the operator in the control room. The opening of the motor-operated butterfly isolation valves for the compressor discharge actuates alarms in the control room. The normally closed system isolation valves receive closing signals on drywell high pressure and/or reactor low water level as described in subsection 7.3.1.1.5. The separate post-LOCA vacuum relief lines are opened when the drywell pressure has fallen below the low differential pressure setpoint. The valves close before the containment and drywell pressures equalize.

The response of the compressors and butterfly valves is indicated by lights in the control room. Low compressor differential pressure is annunciated in the control room. In addition, the

response of the drywell purge system and post-LOCA vacuum relief check valves are indicated by valve status lights and alarm annunciation in the control room.

The hydrogen recombiners are controlled manually from the control room. Hydrogen analyzers, as described in subsection 7.5.1.2.8.3, indicate post-accident hydrogen concentration in the containment. The hydrogen recombiners do not require any instrumentation inside the drywell or containment for proper operation after a LOCA. A thermocouple readout instrument is provided in the control room for convenience in test and periodic checkout of the recombiner. A controller is operated from the control room to regulate the power supply to the recombiner.

The hydrogen ignition system is manually initiated from the control room. Instrumentation for the system consists of two control room handswitches, one for each of the two Class IE power divisions. Each handswitch energizes the igniters in its respective division.

6.2.6 Primary Reactor Containment and Drywell Leakage Rate Testing

This section presents the testing program for determination of the primary reactor containment integrated leakage rate (Type A tests), primary containment penetration leakage rates (Type B tests), and primary containment isolation valve leakage rates (Type C tests) that complies with 10 CFR 50 Appendix A, General Design Criteria, and Appendix J, Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors. This section also presents the testing program for determination of the drywell integrated leakage rate.

Testing requirements for piping penetration isolation barriers and valves have been established by using the intent of GDC 54 as interpreted in Appendix J to 10 CFR 50. Exceptions taken to Appendix J for Type A, B, or C tests are described and justified in Table 6.2-49.

Structural integrity tests of the containment structure and the drywell substructure, as described in subsection 3.8.1.7, and 3.8.3.7 are satisfactorily completed prior to performance of the preoperational integrated leakage rate tests.

Periodic Type A, B, and C tests are performed to assure that leakage through the primary reactor containment and systems and components penetrating primary containment do not exceed allowable leakage rate values specified in the Technical Specifications and that proper maintenance and repairs are performed during the service life of the primary containment and systems and components penetrating primary containment.

6.2.6.1 Primary Reactor Containment Integrated Leakage Rate Test

[HISTORICAL INFORMATION] [Upon completion of construction of the primary reactor containment, including installation of all portions of mechanical, fluid, electrical, and instrumentation systems penetrating containment associated with containment integrity, and upon satisfactory completion of the structural integrity tests described above, the preoperational containment integrated leakage rate test is performed to verify that the actual containment leakage rate does not exceed the design limits.

The preoperational containment integrated leakage rate test shall be performed at pressure P_a (12.1 psig) to measure the leakage rate L_{am} which shall be less than 0.75 L_a.]

Prior to the performance of any Type A test, a general inspection of the accessible interior and exterior surfaces of the primary containment structures and components is performed to discover any evidence of structural deterioration which may affect either the containment structural integrity or leaktightness. If there is evidence of structural deterioration, the Type A test is not performed until corrective action is taken in accordance with repair procedures, nondestructive examinations, and tests as specified in the construction codes discussed in Section 3.8. Any corrective action taken is reported in accordance with the requirements of 10 CFR 50, Appendix J. During the period between the completion of one Type A test and the initiation of the containment inspection for the subsequent Type A test, repairs are made, if necessary, to assure that leakage through the containment isolation barriers does not exceed design limits. The as-found Type A test result will be calculated by adjusting the as-left Type A test result for leakage improvements made to Type B or C tested components.

Type A tests are performed to determine that the total leakage from the containment does not exceed the maximum allowable leakage rate, L_a, at a calculated peak containment internal pressure, P_a, as defined in 10 CFR 50, Appendix J. Pertinent test data, including test pressures, test duration, and definitions of terms are presented in Table 6.2-47. Acceptance criteria are given in the Technical Specifications.

The Type A test is conducted using the Absolute Method as described in ANSI/ANS Standard 56.8-2002, "Containment System Leakage Testing Requirements" (Ref. 16). Analysis is in accordance with ANSI/ANS 56.8-2002 for mass point or in accordance with Bechtel Topical Report BN-TOP-1, Rev. 1, "Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants" (Ref. 27) for total time. Values of primary containment atmosphere drybulb temperature, water vapor pressure and total air pressure are used in the leakage rate calculations. A standard statistical analysis of the data is performed using linear regression analysis by the method of least squares to calculate the leakage rate and associated 95 percent confidence interval. The calculated leakage rate and upper 95 percent confidence limit are documented and maintained in accordance with the requirements of 10 CFR 50, Appendix J.

The quantity and types of sensors associated with the primary containment integrated leakage rate instrumentation are listed in Table 6.2-48.

Prior to commencement of any Type A test the following pretest requirements are met:

a. Closure of containment isolation valves is accomplished by normal operation and without any preliminary exercising or adjustments (e.g., no tightening of valve with manual handwheel after closure by valve motor). Valve closure malfunctions or valve position adjustments necessary to reduce containment leakage are reported in conjunction with the Type A test final report.

b. The primary reactor containment atmosphere is allowed to stabilize for a period of about four hours after reaching test pressure prior to the start of the Type A test. The containment cooling system and the chilled water system are run, as necessary, prior to and during the Type A test

to maintain stabilized containment atmospheric conditions. The relative humidity, temperature, and absolute pressure of the containment atmosphere are monitored so vapor pressure correction can be made. The containment atmosphere is considered stabilized when the stabilization criteria of ANSI/ANS 56.8-2002 or BN-TOP-1 are met.

c. Those portions of fluid systems that are part of the reactor coolant pressure boundary and are open directly to the primary reactor containment atmosphere under post-accident conditions and become an extension of the boundary of the primary reactor containment are opened or vented to the containment atmosphere prior to and during the Type A test. Portions of closed systems inside containment that penetrate primary containment and are not relied upon for containment isolation purposes following loss-of-coolant accident are vented to the containment atmosphere. Leakage testing of the closed ESF systems outside containment will be performed in accordance with Section XI of the ASME Code.

   Since all of the closed ESF systems outside containment are within the secondary containment boundary, any airborne radioactivity resulting from leakage is processed through the SGTS filters, and the offsite radiological doses are negligible. Additionally, since safety grade filters are supplied, doses resulting from leakage from ESF components need not be considered.

   Specific leakage limits to limit offsite doses will not be employed for the reason stated above.

d. All vented systems are drained of water to the extent necessary to assure exposure of the system primary containment isolation valves to containment air test pressure.

e. Those portions of fluid systems that penetrate primary containment, that are external to containment and are not designed to provide a containment isolation barrier are vented to the outside atmosphere, as applicable, to assure that full post-accident differential pressure is maintained across the containment isolation barrier.

f. Systems that are not designed to operate post LOCA, but are required to maintain the plant in a safe condition during the Type A test are operable in their normal mode and are not vented. The measured leakage rates (Type C) for containment isolation valves in these systems are reported in the Type A test final report. Refer to Table 6.2-49 for the systems in this category.

g. Systems that are normally filled with water and operate under post-LOCA conditions are not vented. Systems that are sealed from the primary containment atmosphere post LOCA because their lines terminate below the suppression pool are not vented.

h. System pathways that have been Type B or C tested within the previous 24 calendar months need not be drained or vented during the Type A test. The Type A test result will be adjusted in accordance with 10 CFR 50 Appendix J requirements.

Upon completion of the Type A test, a verification test is performed to confirm the capability of the integrated leakage rate instrumentation to satisfactorily determine the containment integrated leakage rate. The verification test is accomplished by imposing a known leak on the containment through a calibrated flow measurement device. Verification test acceptance criterion is in accordance with 10 CFR 50 Appendix J.

If, during a Type A test, including the verification test, excessive leakage paths are identified which interfere with satisfactory completion of the test, or which result in the Type A test not meeting the acceptance criteria of the Technical Specifications the Type A test is terminated until repairs and/or adjustments can be made. When repairs and/or adjustments are completed the Type A test is performed and the repairs and/or adjustments documented in the Type A test final report.

If any Type A test fails to meet the acceptance criteria, the test schedule applicable to subsequent Type A tests is established in accordance with the 10 CFR 50 Appendix J Testing Program.

6.2.6.2 Primary Containment Penetration Leakage Rate Test

Containment penetrations whose design incorporates resilient seals, bellows, gaskets, or sealant compounds; air locks and lock door seals; equipment and access hatch seals; and electrical

canisters received preoperational and is currently receiving periodic Type B leakage rate tests in accordance with the 10 CFR 50, Appendix J Testing Program. A list of all containment penetrations subject to Type B tests is provided in Table 6.2-49.

All Type B tests are performed at containment peak accident pressure, Pa, as defined in Table 6.2-47. The acceptance criteria is given in the Technical Specifications. Test methods are described in subsection 6.2.6.3 below.

For the containment personnel locks, the lock design incorporates provisions for testing between the door seals and between the doors (refer to Figure 6.2-85). The provisions are:

a. Testing of Annulus Between Seals

   A test connection has been provided on each door. The annulus between the seals can be pressurized and the pressure decay monitored to calculate the leaktight integrity of the seals.

b. Overall Lock Pressure Test

   A test connection has been provided on the outer face of each bulkhead. The entire lock interior can be pressurized and the pressure decay monitored to calculate the overall lock leakage.

Both tests can be run at a pressure of P_a. Four test clamps are provided, with only three required for the inner doors to keep the doors sealed during the overall lock test. The clamps are 5-foot-long beams which are held in place by test clamp pins. The clamps must be installed from the outside of the lock and cannot be operated from within the air lock. The clamps have been designed to restrain the doors during a full pressure test of P_a or greater. Since the restraining force on the door is not critical for the performance of the overall lock pressure test on a lock with inflatable seals, no mechanism for monitoring the force has been provided.

6.2.6.3 Primary Containment Isolation Valve Leakage Rate Tests

Those containment isolation valves which are Type C tested in accordance with 10 CFR 50, Appendix J, are listed in Table 6.2-49. Certain valves are not required to be Type C tested by Appendix J, although they meet the GDC definitions of containment isolation valves.

Type C (and B) tests are performed by local pressurization using either the pressure-decay or flowmeter method. The test pressure is applied in the same direction as that when the valve would be required to perform its safety function, unless it can be shown that results from tests with pressure applied in a different direction are equivalent or conservative. For the pressure decay method, the test volume is pressurized with air or nitrogen to at least P_a. The rate of decay of pressure of the known test volume is monitored to calculate leakage rate. For the flowmeter method, the required test pressure is maintained in the test volume by making-up air, nitrogen, or water (if applicable) through a calibrated flowmeter. The flowmeter fluid flow rate is the isolation valve (or Type B test volume) leakage rate.

All isolation valve seats which are exposed to containment atmosphere subsequent to a loss-of-coolant accident are tested with air or nitrogen at containment peak accident pressure, P_a, as defined in Table 6.2-47.

Those valves which are in lines designed to be, or remain, filled with a liquid for at least 30 days subsequent to a loss-of-coolant accident are leakage rate tested with that liquid. The liquid leakage measured is not converted to equivalent air leakage nor added to the Type B and C test total.

Isolation valves tested with liquid are identified in Table 6.2-49.

For Type C testing of containment penetrations, all testing, with the exception of the ECCS systems (for a detailed testing description of ECCS valves, see Table 6.2-49), will be done in the correct direction unless it can be shown that testing in the reverse direction is equivalent, or more conservative. For Grand Gulf, the correct direction is defined as flow from inside the containment to outside the containment.

With the exception of the ECCS systems, all gate valves will be tested so that any leakage will be from inside the containment to outside the containment or the valve will be pressurized between the valve discs.

The acceptance criteria for leakage through all penetrations and isolation valves subject to Type B and C tests are given in the Technical Specifications.

6.2.6.4 Scheduling and Reporting of Periodic Tests

The periodic leakage rate test schedules for Type A, B, and C tests are established in accordance with the 10 CFR 50, Appendix J, Testing Program.

Type B and C tests may be conducted at any time during normal plant operations or during shutdown periods so long as the time interval between tests for any individual Type B or C test does not exceed the maximum allowable interval specified in accordance with the 10 CFR 50 Appendix J, Testing Program. Each time a Type B or C test is completed, the overall total leakage rate for all required Type B and C tests is updated to reflect the most recent test results. Type A, B, and C test results will be documented and maintained in accordance with 10 CFR 50, Appendix J.

6.2.6.5 Special Testing Requirements

6.2.6.5.1 Drywell Leakage Test

[HISTORICAL INFORMATION] [Immediately following the drywell structural integrity test described in subsection 3.8.3.7; a preoperational drywell leakage test is performed at drywell design pressure. Periodic drywell leakage tests at a reduced pressure, defined in the Technical Specifications, are performed in addition to the preoperational and periodic Type A tests described above.

These drywell leakage tests verify, over the design life of the plant, that no paths for gross leakage from the drywell to the containment air space bypassing the pressure suppression feature exist. The combination of the design pressure and reduced pressure leakage tests also verifies that the drywell will perform adequately for the full range of postulated primary system break sizes. The drywell leakage limit specified in the Technical Specifications is based on 10 percent of the design leak rate for the parameter of A/K = 0.80 ft for small break accidents.

Preoperational drywell leakage tests were performed with the drywell isolated from the containment. The upper containment and suppression pools were filled to normal water level, and the containment air space external to the drywell was vented to the secondary containment atmosphere. The horizontal vents were capped for the design pressure tests to achieve the design drywell internal pressure. The reduced pressure test pressure was less than that required to cause drywell air to bubble through the horizontal vents to the wetwell. The drywell atmosphere was allowed to stabilize for a period of one hour after attaining test pressure. The leakage rate test commenced after the stabilization period.]

The periodic reduced pressure drywell leakage tests required by the Technical Specifications are performed in the same manner as the preoperational reduced pressure test, except that the upper containment pool need not be filled.

The maximum allowable in leakage rate into the secondary containment and the means to verify that the inleakage rate has not been exceeded and the bypass leakage rate is discussed in subsection 6.2.3.

The test method is based on drywell atmosphere pressure observations and the known drywell free air volume specified in Table 6.2-47. Leakage rate is calculated from the pressure data, drywell free air volume, and elapsed time.

The periodic drywell leakage test pressure, test intervals, and acceptance criteria are specified in the Technical Specifications. In addition, a qualitative assessment of drywell leakage is conducted at least once per refueling cycle by running the drywell purge compressors and verifying an increase in drywell pressure.

[HISTORICAL INFORMATION] [The preoperational drywell leakage test shall be limited to the maximum allowable leakage rate of 84,000 scfm at drywell design pressure (30 psig) test and maximum allowable leakage rate of 3,072 scfm at drywell reduced pressure (3 psig) test. Preoperational drywell leakage tests are performed as late as is practical in the construction sequence, but before initial operation. Test duration shall be for a minimum of four (4) hours for a flow makeup test, or a minimum of one (1) hour for a pressure drop test.]

6.2.7 Suppression Pool Makeup System

The suppression pool makeup system provides water from the upper containment pool to the suppression pool by gravity flow following a LOCA. The quantity of water provided is sufficient to account for all conceivable post-accident entrapment volumes (i.e., places where water can be stored while maintaining long-term drywell vent water coverage).

6.2.7.1 Design Basis

The following criteria were used in the design of suppression pool makeup system:

a. The system is redundant with two 100 percent capacity lines. The redundant lines are physically separated and the electrical power and control is separated into two divisions in accordance with IEEE Std 279.

b. The system is Safety Class 2, seismic Category I, and quality group B.

c. The minimum long-term post-accident suppression pool water coverage over the top of the top drywell vent is 2 ft.

d. The minimum normal operation LWL suppression pool height above the top drywell vent centerline is 7 ft.-1/12 in.

e. The maximum normal operation HWL suppression pool height above the top drywell vent centerline is 7 ft.-5 3/4 in.

f. The suppression pool volume, between normal LWL and the minimum post-accident pool level, plus the makeup volume from the upper pool is adequate to supply all possible post-accident entrapment volumes for suppression pool water.

g. The post-accident entrapment volumes causing suppression pool level drawdown include:

    1. The free volume inside and below the top of the drywell weir wall.

2. The added water volume needed to fill the vessel from a condition of normal power operation to a post-accident complete fill of the vessel, including the top dome.

3. Volume in the steam lines out to the first MSIV for three lines and out to the second MSIV on one line.

4. An allowance for containment spray holdup on equipment and structural surfaces.

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h. No credit for feedwater or HPCS injection from condensate is taken in calculating minimum post-accident suppression pool level.

i. The minimum freeboard distance from suppression pool HWL to the top of the weir wall is adequate to store the upper containment pool makeup volume and minimize the probability of flooding into the drywell over the weir wall in case of an inadvertent upper pool dump.

j. The minimum normal operation suppression pool volume at LWL is adequate to act as a short-term energy sink without taking credit for upper pool dump. The short-term energy load on the pool consists of hot standby operation for 1-1/2 hours followed by a LOCA.

k. The long-term containment pressure and suppression pool temperature takes credit for the volume added post-accident from the upper containment pool.

l. The upper pool makeup volume dumps within a period so that a minimum vent coverage of 2 feet above the top edge of the top vent is maintained, considering 1) maximum runout flow of all five ECCS pumps, 2) the initial suppression pool water level is at LLWL, and 3) inventory addition to the drywell is through the postulated pipe break.

6.2.7.2 System Design

The piping system consists of two lines which penetrate the separator end of the upper containment pool through the side walls. One line is on either side of the separator pool and then routed down to the suppression pool on opposite sides of the steam tunnel. The elevation of the separator pool penetrations is such as to limit the volume of water which can be dumped to the lower pool. This volume limitation along with adequate weir wall freeboard minimizes the probability of drywell flooding over the weir wall occurring for an inadvertent opening of the valves on the suppression pool makeup lines.

The volume of the upper containment pool which is available for suppression pool makeup consists of a 7'-1-1/8”-thick slice across the entire upper pool surface area plus the separator pool volume between the top of the separator wall and the bottom of the makeup system penetration to the upper pool when at normal level

(see Table 6.2-50 for suppression pool geometry). The volume of the shortest makeup system dump line to the first isolation valve is also included in the makeup volume. This requires that the refueling gates leading to the dryer storage, fuel transfer pool, and the separator wall extension gates be removed during power operation.

Each suppression pool makeup line has two normally closed motor-operated butterfly valves in series. The power supply to valves on one line is on the same electrical division. The power supply to the valves on the second line is on a second electrical division. Electrical power is powered from onsite emergency power sources which have divisional separation and redundancy.

The upper pool is dumped by gravity flow after opening the two normally closed valves in series in each line. The valves on both lines receive divisionally separate signals to open. The open signal for each division is derived from either of two suppression pool level sensors. There are a total of four level sensors, two per division.

The dump of the upper pool on low-low suppression pool level insures adequate water volume to keep the suppression pool vents covered for all break sizes. In addition to the low-low suppression pool level dump signal, the upper pool will also be dumped automatically from a timer set for LOCA plus 30 min. This upper pool dump at 30 min. post accident insures that adequate heat sink is available long-term regardless of break size or energy dump sequence. There is also a permissive permitting valve opening only when the LOCA signal exists. This LOCA signal is the same signal which initiates actuation of the ECCS pumps. This combination provides high reliability for the upper containment pool dumping when required but low probability of inadvertent dump by spurious signals. See Figure 6.2-82 for the system P&ID.

The two valves in series on each of the two makeup system dump lines are located near the top of the drywell (approximate elevation 170 ft.) and outside the range of pool swell effects. The makeup system pipes are routed along-side and supported from the drywell wall.

The pipes terminate just below the lowest operating floor support beams to provide an unobstructed free fall to the suppression pool surface. The termination is above the pool high water level to eliminate air clearing loads. The pool swell loading on the makeup

system pipe is expected to be relatively small due to the minimum drag cross section of the vertical open-ended cylindrical geometry. Representative tests in the Mark III test facility will help determine the magnitude of side loads from pool swell. The pipe schedule and support design include the effects of internal pressure, seismic loads, and pool swell loads near the suppression pool surface.

Table 6.2-50 gives suppression pool geometry values consistent with the suppression pool makeup system.

6.2.7.3 Design Evaluation

6.2.7.3.1 Initiation

The opening of the makeup system valves is signaled by a series combination of low-low suppression pool level and a LOCA signal permissive (further discussion in subsection 6.2.7.2). The low-low level initiation setpoint is selected such that it is low enough to prevent inadvertent initiation of the SPMU system, but high enough to ensure significant margin is maintained between the actual setpoint and the setpoint assumed in the safety analyses (analytical limit). The difference between the allowable value specified in the Technical Specifications and the analytical limit is the margin established to account for instrument inaccuracies and calibration uncertainties. The trip setpoint (also specified by the Technical Specifications) has additional margin to account for setpoint drift during the calibration intervals.

Assuming the maximum ECCS pump flow (suppression pool level reduced at approximately 0.86 ft./min.), the nominal trip setpoint for the suppression pool level instruments, and the vessel inventory mass added to the suppression pool from steam condensation, there is a significant delay between start of ECCS flow and dumping of the upper pool. This built-in volume integrated delay ensures that the drywell pressure transient due to vessel blowdown has ended prior to dumping of the upper pool and corresponding increase of vent submergence.

The makeup system dump valves can also be signaled to open by a LOCA signal in series with a 30-min. timer where the timer itself is started by the LOCA signal. This path of initiation logic is in parallel with the suppression pool low level along with a LOCA permissive and is specifically directed towards insuring that the combined upper pool and suppression pool volumes are available as

a heat sink for small breaks which do not lower the suppression pool to the LLWL trip, but continue to dump vessel blowdown energy into the pool. The minimum suppression pool volume, without upper pool dump is adequate to meet all heat sink requirements for any combination sequence of vessel blowdown energy and decay heat energy out to 30 min. A pool dump initiated from the LOCA plus 30 min. timer could result in higher vent submergence than the initial maximum of 7 ft. 5-3/4 in. This is no problem in terms of pool swell since all the air would have been purged out of the drywell by the small break flow and only a small steam suppression pool vent flow will persist out to 30 min. Note that action of the drywell vacuum breakers which might re-introduce air into the drywell prior to 30 min. post accident will occur only after complete vessel depressurization and drywell steam condensation on the cold ECCS break overflow of a relatively large break. The hypothesized high vent submergence will also have no effect on peak drywell pressure since the high submergence will occur only during small break flow events and after suppression pool vent clearing had already been established.

6.2.7.3.2 Flow

The suppression pool makeup volume is dumped in approximately 7.5 min. through one of two dump lines. The valves on the suppression pool makeup lines are fully opened within 79.2 seconds of opening signal application.

6.2.7.3.3 Inadvertent Dump

The design of the opening signal for the suppression pool makeup valves assures high probability that no inadvertent dump will occur. The suppression pool level signal (LLWL) to open the valves is in series with a permissive which allows only the open signal to pass through when a LOCA signal exists on that division. Only a simultaneous signal of suppression pool LLWL and LOCA will automatically open both valves to allow gravity drain of the upper pool to the suppression pool until 30 minutes have passed.

The automatic LOCA signal which provides a permissive for upper pool dump is paralleled with the manual ECCS initiation signal for the respective Divisions 1 and 2. Thus, the upper pool can be dumped manually in accordance with IEEE Std 279; however, there is still single failure protection against inadvertent dump. The LOCA signal plus the timer signal after 30 min. will dump the upper pool. However, the LOCA signal itself is a one-out-of-two-

twice combination of high drywell pressure and low vessel water level and a double failure is required to give a spurious LOCA signal.

There are four level switches indicating suppression pool water level with two switches per electrical division. The two level switches in one division are paralleled so that either switch will initiate suppression pool makeup flow (pending LOCA permissive) from the makeup line whose series valves are on the same electrical division as the level switches. Level switches on one electrical division cannot initiate flow from the makeup line whose valves are in a separate electrical division.

There is a remote possibility that a single failure of a suppression pool level switch and a concurrent LOCA event can initiate suppression pool makeup flow from one line so that the makeup flow started at the instant of LOCA.

For a large break DBA, the peak drywell pressure occurs at about 1 sec. after the break with the pressure being reduced to the steady flow submergence of the top vent by about 100 sec. Any pool swell induced loading will occur during the first few seconds while drywell air purge is taking place. Thus, the structural loading which will occur following a DBA will occur prior to any significant flow of water from a makeup line which was erroneously signaled to open at the same instant as the DBA.

The peak structural loadings associated with breaks smaller than the DBA are all less than the DBA case and only slightly extended in time. The drywell pressure for all size breaks is reduced to steady flow top vent submergence by 2 min. after the break.

The conclusion is thus that there is no increase in maximum structural loading due to a LOCA when an erroneous signal to initiate suppression pool makeup flow occurs at the instant of LOCA.

An inadvertent dump of the upper pool during any period of plant operation with a pressurized vessel does not represent, in and of itself, any hazard to the public, the plant operating personnel or any plant equipment. The drywell weir wall has sufficient freeboard height between the suppression pool surface and the top of the weir wall to store the entire upper pool makeup volume on top of the normal suppression pool HWL while minimizing the probability of flooding over the weir wall into the drywell.

In order for overflow to occur, the following conditions must simultaneously exist:

1. Containment pressure must exceed drywell pressure by at least 0.16 psi, and
2. The suppression pool and upper containment pool water levels must be near their upper operating ranges, and
3. An inadvertent upper pool dump must occur.

The probability of an upper pool dump resulting in weir wall overflow has been determined in a very conservative analysis (Reference 24). The calculated range of probabilities of weir wall overflow occurring was from 3.0E-7 to 4.5E-6 events per year. These probabilities are governed primarily by operator actions. If overflow were to occur, drawing reviews, calculations and walkdowns have shown that the overflow water contacting safety-related equipment would not present a safety concern. Reference 25 provides the Staff's safety evaluation of this issue. The only other concern is for the extremely low probability that a LOCA might occur during this period of high vent submergence following inadvertent dump. The dumped upper pool makeup volume can be transferred back to the upper pool through the RHR pumps with a 13 min. pumping time at maximum flow, thus restoring the initial suppression pool water level.

Although no fuel is stored in the Upper Containment Pool during plant operation, other components such as control rods, control rod guide tubes, fuel sipping containers, blade guides and defective fuel storage canisters (without fuel) may be permanently stored in one end of the pool. Defective spent fuel canisters (with fuel), and fuel can be temporarily stored in the Upper Pool during refueling operations.

This storage pool has sufficient depth that adequate shielding is maintained over the fuel and the other identified components even following inadvertent dump of the upper pool makeup volume to the suppression pool. During refueling operations gates can be installed in the 18-inch high separator wall extension making the wall effectively 17.5 feet high. These gates, when installed, limit the water drop over the Upper Containment Pool Fuel Storage area to a change of 5 feet 9-1/4 inches from minimal level. If the gates are not installed, there still is approximately 20 feet of shielding over the top of active fuel temporarily stored even after an inadvertent dump.

The only inadvertent dump event which represents a possible hazard to plant operating personnel is a dump event which occurs while fuel is in an elevated position, such as for transit between the reactor cavity and the fuel transfer pit. With the separator wall gates removed, an approximate 8 ft. upper pool level drop would occur. With one bundle in the highest position, approximately 1 ft. of water shielding over the top of active fuel would be available. This is adequate for bundle cooling but represents a potential hazard for the plant operating personnel. Radiation alarms at the top of the upper pool will warn personnel to evacuate from the edge of the pool. Several minutes will be available for personnel to step to a safe shielding area out of line of sight of the suspended fuel bundle which is 9 ft. below the operating floor. The valve initiation logic is designed with interlocks so that neither automatic nor manual action can open the suppression pool makeup valves while the plant is in the refueling mode.

6.2.7.3.4 Long Term Heat Sink Capability

The capacity of the RHR heat exchangers to safely limit the long-term, post-LOCA suppression pool heatup transient is evaluated on the basis that the drawdown makeup system is activated early in the transient. Specifically, the evaluation assumes that the heat exchangers are activated one-half hour after the LOCA and that at this time the drawdown makeup system water has been added to the main suppression pool inventory. The makeup 30-min. timer will ensure that this condition will exist. The 3.75-min. dump period (8 min. if only one line is operative) is not significant compared to the several hours it takes for the suppression pool peak temperature to be reached.

6.2.7.4 Testing

The suppression pool makeup valves will be periodically manually tested, one at a time, during plant power operation. An interlock prevents this manual testing unless the other valve in series on the same line is closed. The test will verify that the valve will open and close.

Instruments will be periodically tested and inspected.

Preoperational testing will include a complete flow test of the system including a timed dump of the entire makeup volume. Similar flow testing can be performed at any plant shutdown outage; however, the need of such testing is only necessary a few times in the plant lifetime.

6.2.7.5 Instrumentation

There are four wide range suppression pool level sensors, and four wide range suppression pool instrumentation channels, two per division. Level sensor actuation signals for suppression pool makeup in a single electrical division are parallel so that either level sensor provides a signal to open the series valves on only the suppression pool makeup line in the same electrical division as the level sensors.

The four wide range level channels are used to continuously monitor suppression pool level and, at the LLWL setpoint, will annunciate and provide a signal to actuate the suppression pool makeup flow. Two narrow range instrumentation channels, one per division, are provided to monitor suppression pool level during normal operation. These narrow range level channels will annunciate at the HWL and LWL setpoints. Two of the four wide range level channels and both narrow range level channels are recorded in the control room.

Each level channel consists of 1) a differential pressure transmitter, mounted locally in the auxiliary building, that senses suppression pool level via sensing lines that penetrate the containment; 2) power supply located in the control room; and 3) information and alarm outputs located in the control room.

The impulse lines from the sensor to local transmitter are routed so that they will not be damaged by pool swell.

The four wide range level sensors are distributed around the suppression pool with an approximately 90 degree azimuth between them.

An erroneous suppression pool LLWL signal coincident with a LOCA signal which thus results in the initiation of the suppression pool inventory makeup system early in a postulated LOCA has no effect on peak structural loading. The drywell peak pressure for a large break DBA occurs in approximately one second with drywell pressure being reduced to a value equivalent to steady flow against the hydrostatic submergence of the top vents by

approximately 100 sec. Peak pool swell loading also occurs in the first few seconds of the DBA while drywell air purge is taking place. No significant increase in vent submergence due to suppression pool makeup flow initiated at the instant of LOCA can occur prior to these peak structural loads.

A level indication for the upper pool is also required to obtain the attention of plant operating personnel if the level drops below that needed for the makeup volume. Level in the upper pool is normally maintained by a continuous overflow of level control weirs. The level is expected to stay nearly constant during plant power operation.

The upper pool and suppression pool temperatures are monitored to insure that the temperature does not exceed technical specification values. This ensures adequate heat sink capability of the suppression pool water, both short and long term.

The position of all upper containment pool gates will be visually verified to be properly stored or removed from the upper containment pool when the suppression pool makeup system is required to be "OPERABLE" as defined by the Technical Specifications. These gates are removed during plant conditions where suppression pool makeup from the upper pool may be required.

6.2.7.6 Materials

The piping which penetrates the separator pool, and welds to the stainless steel pool liner is stainless steel. Piping and valves beyond penetration of the upper containment pool are carbon steel.

6.2.8 References

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TABLE 6.2-1: CONTAINMENT DESIGN PARAMETERS

	Drywell	Containment
A. Drywell and Containment		
Internal pressure, psig	30	15
External design pressure differential, psid	21	3.0
Design temperature, F	330	185
Net free volume, ft^3	270,000	1,400,000
Maximum allowable leak rate, %/day	NA	0.385**
Suppression pool water volume		
Minimum, ft^3	13041*	122250***
Maximum, ft^3	13303*	125398***
Pool cross-section area, ft^2	554	6666
Pool depth (normal)	18'7"	18'7"

* Including horizontal vents

** Based on containment free air volume @ 12.1 psig. Combining this value with the MSIV leakage criteria of 250 scfh (total for four steam lines) yields an overall leakage criteria, based on total volume of containment and drywell, of 0.682%/ day.

*** In response to NRC Bulletin 96-03, ER 97/0089-00-00 installed a new ECCS/RCIC suction strainer, which rests on the floor of the suppression pool, to replace one of the conical basket strainers on each of the ECCS and RCIC system suction strainers. The ECCS/RCIC suction strainer displaces ~500 ft^3 of suppression pool water.

TABLE 6.2-1: CONTAINMENT DESIGN PARAMETERS (CONTINUED)

	Containment
B. Vent System	
1. No. of vents	135
2. Nominal vent diameter, ft	2.33
3. Total vent area, ft^2 (gross)	577.3
4. Net vent area, ft^2 (unobstructed)	552.0
5. Vent centerline elevation	
Top row	11’4”
Middle row	7’2”
Bottom row	3’0”
Pool bottom (assumed datum)	0’0”
6. Vent loss coefficient (fL/D)	
Varies with the number of vents open	2.5 - 3.5

TABLE 6.2-2: ENGINEERED SAFETY SYSTEMS INFORMATION FOR CONTAINMENT RESPONSE ANALYSES

	Full Capacity	Containment Case A	Analysis Value Case B	Analysis Value **Case C**
A. Suppression Pool Cooling				
(RHR system)				
1. No. of pumps	2	2	1	2
2. No. of lines	2	2	1	2
3. Flow rate, gpm/pump	7450	7450	7450	7450
B. Emergency Cooling Water System				
1. Number of RHR pumps	2	2	1	2
2. RHR Flow capacity, gpm/loop min	7450	7450	7450	7450
3. RHR heat exchangers				
a. Type - Inverted U-tube single pass shell multi-pass tube vertical mounting				
b. Number	2	2	1	1
c. Heat transfer area, ft^2/unit	21250	21250	21250	21250
d. Overall heat transfer coefficient Btu/hr - ft^2 - F	212			
e. Standby Service Water flow rate per exchanger, lb/hr	3.93×10^6	3.93×10^6	3.93×10^6	3.93×10^6
f. Design standby service water temperature				
Maximum, F	90	90	90	90
Minimum, F	40			
g. Containment heat removal capability per loop, using 90°F service water and 189°F pool temperature; and at rated flow	184.7×10^6 Btu/Hr			

*Cases A, B, and C defined in Table 6.2-6

TABLE 6.2-2: ENGINEERED SAFETY SYSTEMS INFORMATION FOR CONTAINMENT RESPONSE ANALYSES (CONTINUED)

	Full Capacity	Containment Case A	Analysis Value Case B	Analysis Value **Case C**
C. ECCS System				
1. High pressure core spray (HPCS)				
a. No. of pumps	1	1	1	1
b. No. of lines	1	1	1	1
c. Flow rate, gpm	7115	7115	7115	7115
2. Low pressure core spray (LPCS)				
a. No. of pumps	1	1	1	1
b. No. of lines	1	1	1	1
c. Flow rate, (rated, gpm/line)	7115	7115	7115	7115
3. Low pressure coolant injection (LPCI)				
a. No. of pumps	3	3	1	3
b. No. of lines	3	3	1	3
c. Flow rate, gpm/line	7450	7450	7450	7450
D. Automatic Depressurization System				
1. Total number of safety/relief valves	20			
2. No. actuated on ADS	8			

TABLE 6.2-3: ACCIDENT ASSUMPTIONS AND INITIAL CONDITIONS FOR LARGE LINE BREAKS

A.	Effective accident break area (total), recirculation line break, ft^2	3.181
B.	Effective accident break area, main steam line break, ft^2	3.538
C.	Components of effective break area (recirculation line break):	
1.	Recirculation line area, ft^2	2.598
2.	Cleanup line area, ft^2	.080
3.	Jet pump area, ft^2	.503
D.	Primary steam energy distribution (1)	
1.	Steam energy, Btu/lbm	31.4
2.	Liquid energy, Btu/lbm	341.4
3.	Sensible energy, 10^6 Btu	
a.	Reactor vessel	111.0
b.	Reactor internals (less core)	58.1
c.	Primary system piping	37.7
d.	Fuel(2)	27.6
E.	Other assumptions used in analysis	
1.	Deleted	
2.	MSIV Closure time (sec)(main steam line break)	5.5
2a.	MSIV Closure time (sec) (recirculation line break)	3.0
3.	Scram time (sec)	<1
4.	Liquid carryover,%	100

1. All energy values except fuel are based on a 32°F datum.

2. Fuel energy is based on a datum of 285°F.

TABLE 6.2-4: INITIAL CONDITIONS EMPLOYED IN CONTAINMENT RESPONSE ANALYSES

A. Reactor Coolant System (at design overpower of 102.0% and at normal liquid levels)

1. Reactor power level, MWT	4,996
2. Average coolant pressure, psia	1,066
3. Average coolant temperature, F	551
4. Mass of reactor coolant system liquid, lbm	6.815×10^5
5. Mass of reactor coolant system steam, lbm	24,000
6. Liquid plus steam energy, Btu	372.8×10^6
7. Volume of liquid in vessel, ft^3	13,771
8. Volume of steam in vessel, ft^3	9,295
9. Volume of liquid in recirculation loops, ft^3	827
10. Total reactor coolant volume, ft^3	25,820

B. Containment

	Drywell	Containment
1. Pressure, psig	1.5	1.5
2. Inside temperature	100	100
3. Relative humidity, %	20 to 90	60
4. Service water temperature, F	90	90

TABLE 6.2-5: SUMMARY OF SHORT-TERM ACCIDENT RESULTS FOR CONTAINMENT RESPONSE TO RECIRCULATION LINE AND STEAM LINE BREAKS

A. Accident Parameters

	Recirculation[1] Line Break	Steam Line Break
1. Peak drywell pressure, psig	26.0	27.0
2. Time(s) of peak pressures, sec	1.2668	3.1865
3. Peak drywell temperature, F	255.7	306.8
4. Peak suppression pool temperature during blowdown, F	120	120
5. Calculated drywell margin,%	13	10
6. Energy released to containment at time of short term peak pressure, 10^6 Btu	240	240
7. Energy absorbed by passive heat sinks at time of peak pressure, 10^6 Btu	0	0

1. See Figures 6.2-2 and 6.2-5 for plots of pressures vs time. See Figures 6.2-3 and 6.2-7 for plots of temperatures vs time.

TABLE 6.2-6: LOSS OF COOLANT ACCIDENT LONG TERM PRIMARY CONTAINMENT RESPONSE SUMMARY

Case*	LPCI/LPCS Pumps	Service Water Pumps	Containment Spray (gal/min)	HPCS (gal/min)	LPCI/LPCS (gal/min)	Peak Pool Temp. F	Secondary Peak Pressure (psig)
A	3/1	2	0	7115	7450/7115	155.5	7.6
B	1/1	1	0	7115	7450/7115	171.3	9.9
C	3/1	2	0	7115	7450/7115	189.0	8.5

*A - Assumes offsite power available
B - Assumes loss of offsite power
C - Assumes loss of offsite power with only one RHR heat exchanger available

TABLE 6.2-7: [HISTORICAL INFORMATION] ENERGY BALANCE FOR DESIGN BASIS RECIRCULATION LINE BREAK

Energy Levels vs Time (Minimum ECCS - Missile Break) Energy in 10 Btu

Parameter	Initial (t = 0)	Peak Δp (t=1.1865 sec)	End Blowdown (t=130.62 sec)	Maximum Containment Pressure (t=18305.7 sec)
Reactor coolant	390.0	377.0	29.2	174.0
Fuel*	39.6	40.3	5.86	3.75
Cladding*	3.14	3.14	1.30	0.831
Reactor vessel	101.0	101.0	88.3	26.7
Reactor internals	96.3	96.3	85.9	25.5
Drywell air	1.70	2.02	~0.0	1.31
Drywell steam	0.817	13.3	16.8	3.76
Drywell liquid	0.0	1.33	26.7	530.0
Containment air	8.95	9.14	11.3	8.53
Containment steam	3.61	3.63	9.98	24.1
Containment liquid suppression pool**	1200.0	1200.0	1610.0	1370.0

TABLE 6.2-7: [HISTORICAL INFORMATION] ENERGY BALANCE FOR DESIGN BASIS RECIRCULATION LINE BREAK (CONTINUED)

Energy Levels vs Time (Minimum ECCS - Missile Break) Energy in 10 Btu

Parameter	Initial (t = 0)	Peak Δp (t=1.1865 sec)	End Blowdown (t=130.62 sec)	Maximum Containment Pressure (t=18305.7 sec)
Decay heat	0.0	0.380	23.5	932.0
Metal water heat	0.0	~0.0	0.035	0.463
Pump heat	0.0	0.0	0.512	88.3
Heat transferred RHR heat exchanger	0.0	0.0	0.0	634.0

*Evaluations performed for reload cores have shown that the containment analysis remains applicable for reload cores.

**In response to NRC Bulletin 96-03, ER 97/0089-00-00 installed a new ECCS/RCIC suction strainer, which rests on the floor of the suppression pool, to replace one of the conical basket strainers on each of the ECCS and RCIC system suction strainers. The ECCS/RCIC suction strainer displaces ~500 ft^3 of suppression pool water. Analysis has shown that the displacement of the water does not invalidate the short-term or long-term containment LOCA response analyses.

TABLE 6.2-8: [HISTORICAL INFORMATION] ACCIDENT CHRONOLOGY-DESIGN BASIS MAIN STEAM LINE BREAK ACCIDENT

	Event	Time (sec) Case A All ECCS in Operation	Time (sec) Case B Min ECCS Available
1.	1st row vent cleared	0.86	0.86
2.	2nd row vent cleared	1.08	1.08
3.	3rd row vent cleared	1.44	1.44
4.	Drywell reaches peak pressure	1.09	1.09
5.	Maximum positive differential pressure occurs	1.08	1.08
6.	3rd row vent recovered	29	29
7.	Initiation of the ECCS	30	30
8.	2nd row vent recovered	40	40
9.	1st row vent recovered	99	99
10.	End of blowdown	99	99
11.	Vessel reflooded	279	455
12.	Initiation of RHR heat exchanger loop	1800	1800
13.	Containment reaches peak pressure	4936	23176

TABLE 6.2-9: AVAILABLE HEAT SINKS

Item	Volume	Surface Area	Material
Drywell structure	91,000 ft^3	19,500 ft^2	Concrete
Containment shell	1,525 ft^3	73,236 ft^2	Steel
Misc. structures[1] & equipment	2,933 ft^3	398,514 ft^2	Steel
Misc. structures	34,870 ft^3	11,718 ft^2	Concrete

Note:

1. In response to NRC Bulletin 96-03, ER 97/0089-00-00 installed a new ECCS/RCIC suction strainer, which rests on the floor of the suppression pool, to replace one of the conical basket strainers on each of the ECCS and RCIC system suction strainers. The ECCS/RCIC suction strainer adds ~500 ft^3 of steel to the suppression pool, however, the strainer displaces ~500 ft^3 of suppression pool water. Analysis has shown that the addition of the strainer's steel and displacement of the water results in a negligible effect on the passive heat sinks available in the suppression pool and does not invalidate existing analyses.

TABLE 6.2-10: [HISTORICAL INFORMATION] REACTOR BLOWDOWN DATA FOR RECIRCULATION LINE BREAK

Time (sec)	Liquid Flow (lbs/sec)	Liquid Enthalpy (Btu/lbm)	Steam Flow (lbs/sec)	Steam Enthalpy (Btu/lb)
0.0	30,450	550.9	0.0	0.0
0.795	30,390	550.3	0.0	0.0
1.45	30,370	550.0	0.0	0.0
1.889	30,380	550.0	0.0	0.0
1.905	25,410	550.0	0.0	0.0
2.264	25,430	550.4	0.0	0.0
4.0	25,640	554.3	0.0	0.0
6.0	25,850	558.0	0.0	0.0
8.0	26,000	559.2	0.0	0.0
10.25	26,080	560.6	0.0	0.0
17.25	25,850	556.2	0.0	0.0
17.26	11,330	556.2	4382.0	1188.3
20.37	8,808	530.1	4005.0	1195.3
25.12	5,896	487.7	3297.0	1202.5
30.0	3,699	441.4	2473.0	1205.5
35.0	2,533	391.4	1526.0	1203.6
40.0	2,004	340.8	890.0	1196.8
45.0	1,922	290.4	420.0	1185.8
50.0	1,695	251.2	167.0	1174.7
54.6	1,405	224.7	73.0	1166.2
54.7	0	0.0	208.0	1166.2
57.4	0	0.0	106.0	1160.7
59.1	0	0.0	25.0	1159.0
59.4	0	0.0	0.0	0.0

TABLE 6.2-11: [HISTORICAL INFORMATION] REACTOR BLOWDOWN DATA FOR MAIN STEAM LINE BREAK

Time (sec)	Liquid Flow (lbs/sec)	Liquid Enthalpy (Btu/lbm)	Steam Flow (lbs/sec)	Steam Enthalpy (Btu/lb)
0.0	0.0	0.0	13,520.0	1190.0
0.182	0.0	0.0	13,320.0	1990.6
0.186	0.0	0.0	9,989.0	1190.6
0.999	0.0	0.0	9,749.0	1191.7
1.0	32,220.0	545.1	1,345.0	1191.7
2.0	31,860.0	546.7	1,523.0	1191.2
3.0	31,400.0	549.1	1,708.0	1190.6
4.0	30,850.0	549.1	1,899.0	1190.6
5.0	25,760.0	547.9	1,772.0	1190.8
6.09	22,920.0	547.9	1,758.0	1190.8
8.09	21,830.0	545.5	2,034.0	1191.5
10.09	20,640.0	542.7	2,266.0	1192.3
15.09	17,030.0	524.0	2,715.0	1196.0
20.3	12,720.0	499.6	2,873.0	1200.9
25.3	8,805.0	467.2	2,673.0	1204.4
30.0	5,888.0	433.4	2,278.0	1205.6
35.0	3,819.0	388.1	1,587.0	1203.3
40.0	2,628.0	346.1	1,033.0	1197.8
45.0	2,244.0	306.1	601.0	1189.6
50.0	2,062.0	273.9	330.0	1181.3
55.2	1,937.0	252.3	188.0	1175.0
60.2	1,845.0	239.0	122.0	1170.9
65.2	1,756.0	230.8	85.0	1168.3
70.2	1,689.0	223.7	62.0	1165.9
75.2	1,620.0	218.6	47.0	1164.2
80.7	1,546.0	214.0	35.0	1162.6
90.7	1,430.0	207.4	22.0	1160.3
97.7	440.0	203.4	5.0	1158.9

TABLE 6.2-11: [HISTORICAL INFORMATION] REACTOR BLOWDOWN DATA FOR MAIN STEAM LINE BREAK (CONTINUED)

Time (sec)	Liquid Flow (lbs/sec)	Liquid Enthalpy (Btu/lbm)	Steam Flow (lbs/sec)	Steam Enthalpy (Btu/lb)
98.7	0.0	0.0	0.0	0.0

TABLE 6.2-12: [HISTORICAL INFORMATION] CORE DECAY HEAT FOLLOWING LOCA FOR CONTAINMENT ANALYSES

Time (sec)	Normalized Core Heat	Time (sec)	Normalized Heat Flux
0	1.0	30.0	0.0471
0.3	0.9987	50.0	0.0426
0.6	0.9725	10^2	0.0381
1.2	0.8863	10^3	0.0223
2.4	0.7300	10^4	0.0119
5.0	0.5005	10^5	0.00668
9.03	0.2955	10^6	0.00267
12.03	0.2124	3×10^6	0.00190
15.03	0.1589		

*Normalized Power = 3995 MWt

TABLE 6.2-13: MAXIMUM CALCULATED ACCIDENT FOR CONTAINMENT DESIGN

Parameter	Design Parameter	Calculated Accident Parameter
Containment Design Pressure	15 psig	12.1 psig
Containment Design Temperature	210 F	181 F
Drywell Design Pressure	30 psig	22 psig
Drywell Design Temperature	330 F	330 F
External Design Pressure	3 psid	< 1 psid
Design Leak Rate, Percent Free Volume Per Day at 12.1 psig*	NA	0.385%

* Based on containment free air volume @ 12.1 psig. Combining this value with the design MSIV leakage value of 250 SCFH (total for four steam lines) yields an overall design leakage value, based on a total containment and drywell free air volume of 1,670,000 ft^3, of 0.682% per day.

TABLE 6.2-14: [HISTORICAL INFORMATION] PIPING AND COMPONENTS IN SUPPRESSION POOL SWELL AREA

Size (in.)	Line No.	System	Function	Distance Above Normal High Water Level	Reference Figure	Drawing Location	Physical Description
10	117	Nuclear boiler	Safety/relief valve discharge	-	6.2-22	Various	Always below normal water level
24	81	RHR	A pump suction strainer	-	6.2-22	C-3	
24	73	RHR	B pump suction strainer	-	6.2-22	F-3	
24	74	RHR	C pump suction strainer	-	6.2-22	E-8	
24	8	LPCS	Pump suction strainer	-	6.2-22	D-8	
24	21	HPCS	Pump suction strainer	-	6.2-22	G-3	
6	49	RCIC	Pump suction strainer	-	6.2-22	D-2	
12	1	-	Suppression pool drain strainer	-	6.2-22	B-7	
18[a]	82	RHR	A pump test return line to suppression pool	See Note	6.2-22	C-3	The major portion of the piping run is below the normal water level
18[a]	76	RHR	B pump test return line to suppression pool	See note	6.2-22	F-3	
18[a]	75	RHR	C pump test return line to suppression pool	See note	6.2-22	E-8	The piping descends vertically into the pool immediately after it enters the suppression pool
14[a]	9	LPCS	Pump test return line to suppression pool	See note	6.2-22	D-8	

TABLE 6.2-14: [HISTORICAL INFORMATION] PIPING AND COMPONENTS IN SUPPRESSION POOL SWELL AREA (CONTINUED)

Size (in.)	Line No.	System	Function	Distance Above Normal High Water Level	Reference Figure	Drawing Location	Physical Description
10	84	RHR	Heat exchanger A relief valve discharge piping	-	6.2-22	C-3	
10	79	RHR	Heat exchanger B relief valve discharge piping	-	6.2-22	F-3	The piping descends vertically into the pool immediately after it enters the suppression pool
14	32	HPCS	HPCS pump minimum flow and test return line to suppression pool		6.2-22	F-3	The piping descends vertically into the pool immediately after it enters the suppression pool.
6	101	Floor & equipment drain system	Floor drains piping to auxiliary building transfer tanks		6.2-22	B-3	The piping enters the containment and immediately ascends to an elevation that is greater than 19.5 feet above the suppression pool before traversing the containment
6	102		Equipment drains piping to auxiliary building transfer tanks		6.2-22	B-3	
3	16		Drywell floor drain sump pump discharge piping		6.2-22	F-4	

TABLE 6.2-14: [HISTORICAL INFORMATION] PIPING AND COMPONENTS IN SUPPRESSION POOL SWELL AREA (CONTINUED)

Size (in.)	Line No.	System	Function	Distance Above Normal High Water Level	Reference Figure	Drawing Location	Physical Description
3	95		Drywell equipment drain pump discharge piping		6.2-22	B-5	
20	53	RCIC	RCIC turbine exhaust		6.2-22 6.2-23	C-3	Piping enters containment 20'-9 1/2" above the suppression pool and then descends vertically into the pool
14	5	HPCS	Pump discharge to reactor pressure vessel		6.2-23	F-3	Piping enters containment 18'-8" above the suppression pool and immediately ascends vertically to a level that is greater than 19'-6" above the normal pool level

Note: (a) The piping enters the containment at EL.5'-2" above the normal water level and then descends vertically into the pool.

The following piping is located below the HCU floor (El. 135'-4") and greater than El. 19'-6" above the suppression pool:

3	6	Service air	Supply air	19'-9 1/4”	6.2-23	C-8	
4	763, 757	Floor and equipment drains	To auxiliary building transfer tanks	19'-8 1/2”	6.2-23	B-4	
2	31, 19		Chemical waste to auxiliary building transfer tanks	19'-8 1/2”	6.2-23	B-4	
4	95		To auxiliary building transfer tanks	19'-8 1/2”	6.2-23	B-4	

TABLE 6.2-14: [HISTORICAL INFORMATION] PIPING AND COMPONENTS IN SUPPRESSION POOL SWELL AREA (CONTINUED)

Size (in.)	Line No.	System	Function	Distance Above Normal HighWater Level	Reference Figure	Drawing Location	Physical Description
6, 4	753, 766			19'-8 1/2"	6.2-23	C-3	
14	28	RHR	LPCI B to RPV	20'-1"	6.2-23	G-5	
14	1	LPCS	LPCS to RPV	20'-11"	6.2-23	D-8	
12	38	RHR	LPCI C to RPV	20'-11"	6.2-23	E-8	
18	81	RHR	LPCI B	20'-11"	6.2-23	F-2	
18	20	RHR	LPCI A to RPV	20'-11"	6.2-23	C-2	
20	53	RCIC	Turbine exhaust	20'-9 1/2"	6.2-23	B-3	
4	152	RWCU	Backwash tank to radwaste	22'-8"	6.2-23	D-2	
20	64	RHR	Shutdown suction	21'-2"	6.2-23	E-2	
6	30	RCIC	To RPV head spray	21'-2"	6.2-23	E-2	
30	162	Suppression pool makeup	To suppression pool	21'	6.2-23	8-4, F-4	

TABLE 6.2-15A: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION RECIRCULATION RETURN LINE BREAK RPV - SHIELD WALL ANNULUS

Node #	Volume* (ft^3)	Initial Temp(F)	Conditions Press(psia)	Humidity	DBA Break % Break in vol.	Conditions Break Line	Break Area (ft^2)	Break Type	Time of Peak Diff. Press. (sec)	Calc. Peak Diff. Press. (psid)	Design Peak Diff. Press. (psid)
1	437.91	150.0	14.7	0.5					0.08	13.8	56
2	225.2	150.0	14.7	0.5		12" recirc. return line	1.44	Double ended	0.08	12.5	56
3	225.2	150.0	14.7	0.5	25%				0.04	17.4	56
4	225.2	150.0	14.7	0.5					0.07	12.1	56
5	225.2	150.0	14.7	0.5	25%				0.029	17.7	56
6	225.2	150.0	14.7	0.5					0.1	12	56
7	225.2	150.0	14.7	0.5					0.028	15.3	56
8	225.2	150.0	14.7	0.5					0.06	12.2	56
9	225.2	150.0	14.7	0.5					0.07	13	56
10	884.33	150.0	14.7	0.5					0.07	12.3	56
11	859.85	150.0	14.7	0.5					0.09	11.3	56
12	861.85	150.0	14.7	0.5					0.08	10.5	56
13	556.62	150.0	14.7	0.5	25%				0.08	13.3	56
14	859.12	150.0	14.7	0.5					0.1	11.1	56
15	859.12	150.0	14.7	0.5					0.09	11.7	56
16	863.84	150.0	14.7	0.5					0.08	10.9	56
17	304.35	150.0	14.7	0.5					0.09	4.0	56
18	304.35	150.0	14.7	0.5					0.11	4.0	56
19	304.35	150.0	14.7	0.5					0.09	4.0	56
20	304.35	150.0	14.7	0.5					0.1	3.9	56
21	752.8	150.0	14.7	0.5					0.402	2.7	56
22	2.43 E+5	150.0	14.7	0.5					-	-	56

TABLE 6.2-15A: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION RECIRCULATION RETURN LINE BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Node #	Volume* (ft^3)	Initial Temp(F)	Conditions Press(psia)	Humidity	DBA Break % Break in vol.	Conditions Break Line	Break Area (ft^2)	Break Type	Time of Peak Diff. Press. (sec)	Calc. Peak Diff. Press. (psid)	Design Peak Diff. Press. (psid)
23	307.09	150.0	14.7	0.5	25%				0.08	13	56
24	304.35	150.0	14.7	0.5					0.08	3.7	56
25	304.35	150.0	14.7	0.5					0.09	3.9	56

*Subcompartments are physically described in subsection 6.2.1.2.2.

TABLE 6.2-15B: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION RECIRCULATION SUCTION LINE BREAK RPV - SHIELD WALL ANNULUS

Node #	Volume* (ft^3)	Initial Temp(F)	Conditions Press (psia)	Humidity	DBA Break % Break in vol.	Conditions Break Line	Break Area (ft^2)	Break Type	Time of Peak Diff. Press. (sec)	Calc. Peak Diff. Press. (psid)	Design Peak Diff. Press. (psid)
1	438.9	150.0	14.7	0.5	7.5%				0.013	7.2	56
2	225.2	150.0	14.7	0.5		24" recirc. suction line	5.4	Double ended	0.018	5.5	56
3	225.2	150.0	14.7	0.5					0.018	5.5	56
4	225.2	150.0	14.7	0.5					0.022	5.0	56
5	225.2	150.0	14.7	0.5					0.022	5.0	56
6	225.2	150.0	14.7	0.5					0.029	4.3	56
7	225.2	150.0	14.7	0.5					0.029	4.3	56
8	225.2	150.0	14.7	0.5					0.03	3.9	56
9	225.2	150.0	14.7	0.5					0.03	3.9	56
10	885.3	150.0	14.7	0.5					0.05	3.5	56
11	860.9	150.0	14.7	0.5	7.5%				0.026	3.6	56
12	861.9	150.0	14.7	0.5					0.025	3.4	56
13	864.9	150.0	14.7	0.5					0.025	3.4	56
14	860.1	150.0	14.7	0.5					0.05	2.7	56
15	860.1	150.0	14.7	0.5					0.05	2.7	56
16	864.2	150.0	14.7	0.5					0.05	2.6	56
17	305.4	150.0	14.7	0.5					0.019	1.4	56
18	305.4	150.0	14.7	0.5					0.03	0.9	56
19	305.4	150.0	14.7	0.5					0.03	0.9	56
20	305.4	150.0	14.7	0.5					0.06	0.8	56
21	752.8	150.0	14.7	0.5					0.015	0.4	56
22	2.43 E+5	150.0	14.7	0.5					-	-	56

TABLE 6.2-15B: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION RECIRCULATION SUCTION LINE BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Node #	Volume* (ft^3)	Initial Temp (F)	Conditions Press (psia)	Humidity	DBA Break % Break in vol.	Conditions Break Line	Break Area (ft^2)	Break Type	Time of Peak Diff. Press. (sec)	Calc. Peak Diff. Press. (psid)	Design Peak Diff. Press. (psid)
23	35.9	150.0	14.7	0.5	85%				Flow diverter -	design -	system pressure
24	305.4	150.0	14.7	0.5					0.07	0.9	56
25	305.4	150.0	14.7	0.5					0.06	0.8	56

*Subcompartments are physically described in subsection 6.2.1.2.2.

TABLE 6.2-15C: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION FEEDWATER LINE BREAK RPV - SHIELD WALL ANNULUS

Node #	Volume* (ft^3)	Initial Temp(F)	Conditions Press(psia)	Humidity	DBA Break % Break in vol.	Conditions Break Line	Break Area (ft^2)	Break Type	Time of Peak Diff. Press. (sec)	Calc. Peak Diff. Press. (psid)	Design Peak Diff. Press. (psid)
1	438.9	150.0	14.7	0.5					0.06	0.7	56
2	225.2	150.0	14.7	0.5		12" feedwater line	1.4	Double ended	0.07	0.7	56
3	225.2	150.0	14.7	0.5					0.1	-0.7	56
4	225.2	150.0	14.7	0.5					0.06	0.5	56
5	225.2	150.0	14.7	0.5					0.07	0.7	56
6	225.2	150.0	14.7	0.5					0.11	-0.6	56
7	225.2	150.0	14.7	0.5					0.07	0.7	56
8	225.2	150.0	14.7	0.5					0.05	0.7	56
9	225.2	150.0	14.7	0.5					0.06	0.6	56
10	885.3	150.0	14.7	0.5					0.05	0.7	56
11	860.9	150.0	14.7	0.5					0.05	0.4	56
12	861.9	150.0	14.7	0.5					0.03	0.6	56
13	864.9	150.0	14.7	0.5					0.05	0.5	56
14	860.1	150.0	14.7	0.5	3.75%				0.02	1.5	56
15	860.1	150.0	14.7	0.5					0.03	0.6	56
16	864.2	150.0	14.7	0.5	3.75%				0.021	1.5	56
17	305.4	150.0	14.7	0.5					0.008	0.3	56
18	305.4	150.0	14.7	0.5					0.03	0.4	56
19	305.4	150.0	14.7	0.5					0.03	0.3	56
20	610.7	150.0	14.7	0.5	7.5%				0.008	1.3	56
21	752.8	150.0	14.7	0.5					0.009	0.4	56
22	2.43 E+5	150.0	14.7	0.5					-	-	56

TABLE 6.2-15C: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION FEEDWATER LINE BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Node #	Volume* (ft^3)	Initial Temp(F)	Conditions Press(psia)	Humidity	DBA Break % Break in vol.	Conditions Break Line	Break Area (ft^2)	Break Type	Time of Peak Diff. Press. (sec)	Calc. Peak Diff. Press. (psid)	Design Peak Diff. Press. (psid)
23	4.55	150.0	14.7	0.5	85%				Flow diverter -	design -	system pressure
24	305.4	150.0	14.7	0.5					0.03	0.4	56
25	8.3	150.0	14.7	0.5					Flow diverter -	design -	system pressure

* Subcompartments are physically described in subsection 6.2.1.2.2

TABLE 6.2-16A: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION RECIRCULATION INLET LINE BREAK RPV - SHIELD WALL ANNULUS

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Friction	Head Loss, K Turning Loss	Expansion	Contraction	Total
1	1	2	Unchoked	40.87	0.2004	-	0.129	1.0	0.01	1.139
2	1	3	Unchoked	40.87	0.2004	-	0.129	1.0	0.01	1.139
3	1	11	Unchoked	16.84	0.6930	0.078	-	1.0	0.24	1.318
4	2	4	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
5	2	11	Unchoked	1.18	8.6929	0.078	-	1.0	0.47	1.548
6	2	12	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108
7	3	5	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
8	3	11	Unchoked	1.18	8.6929	0.078	-	1.0	0.47	1.548
9	3	23	Unchoked	11.26	1.6632	0.078	-	1.0	0.1	1.178
10	4	6	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
11	4	12	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
12	5	7	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
13	5	13	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
14	6	8	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
15	6	12	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
16	6	14	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
17	7	9	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
18	7	13	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
19	7	15	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
20	8	10	Unchoked	40.87	0.3345	-	0.214	1.0	0.01	1.224
21	8	14	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
22	9	10	Unchoked	40.87	0.3345	-	0.214	1.0	0.01	1.224
23	9	15	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128

TABLE 6.2-16A: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION RECIRCULATION INLET LINE BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Head Loss, K Friction	Turning Loss	Expansion	Contraction	Total
24	10	14	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108
25	10	15	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108
26	10	16	Unchoked	16.84	0.5940	0.078	-	1.0	0.18	1.258
27	11	12	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
28	11	17	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
29	12	14	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
30	12	18	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
31	13	15	Unchoked	66.06	0.1542	-	0.2	1.0	0.01	1.21
32	13	19	Unchoked	18.65	0.7388	0.078	-	1.0	0.08	1.158
33	13	23	Unchoked	66.06	0.0939	-	0.1	1.0	0.02	1.12
34	14	16	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
35	14	20	Unchoked	24.11	0.5040	0.067	-	1.0	0.13	1.197
36	15	16	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
37	15	25	Unchoked	24.11	0.5040	0.067	-	1.0	0.13	1.197
38	16	24	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
39	17	18	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
40	17	19	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
41	17	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
42	18	20	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
43	18	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
44	19	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
45	19	25	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
46	20	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
47	20	24	Unchoked	21.17	0.5224	-	0.5	1.0	0.06	1.26

TABLE 6.2-16A: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION RECIRCULATION INLET LINE BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Head Loss, K Friction	Turning Loss	Expansion	Contraction	Total
48	22	25	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
49	23	11	Unchoked	66.06	0.1274	-	0.1	1.0	0.02	1.12
50	23	19	Unchoked	8.58	1.4112	0.066	-	1.0	0.1	1.166
51	24	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
52	24	25	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26

TABLE 6.2-16B: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION RECIRCULATION SUCTION BREAK RPV - SHIELD WALL ANNULUS

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Head Loss, K: Friction	Turning Loss	Expansion	Contraction	Total
1	1	2	Unchoked	40.87	0.2004	-	0.129	1.0	0.01	1.139
2	1	3	Unchoked	40.87	0.2004	-	0.129	1.0	0.01	1.139
3	1	11	Unchoked	16.84	0.6930	0.078	-	1.0	0.24	1.318
4	2	4	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
5	2	11	Unchoked	1.18	8.6929	0.078	-	1.0	0.47	1.548
6	2	12	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108
7	3	5	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
8	3	11	Unchoked	1.18	8.6929	0.078	-	1.0	0.47	1.548
9	3	13	Unchoked	11.26	1.6632	0.078	-	1.0	0.01	1.178
10	4	6	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
11	4	12	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
12	5	7	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
13	5	13	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
14	6	8	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
15	6	12	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
16	6	14	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
17	7	9	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
18	7	13	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
19	7	15	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
20	8	10	Unchoked	40.87	0.3345	-	0.214	1.0	0.01	1.224
21	8	14	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
22	9	10	Unchoked	40.87	0.3345	-	0.214	1.0	0.01	1.224
23	9	15	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128

TABLE 6.2-16B: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION RECIRCULATION SUCTION BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Head Loss, K: Friction	Turning Loss	Expansion	Contraction	Total
24	10	14	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108
25	10	15	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108
26	10	16	Unchoked	21.86	0.594	0.078	-	1.0	0.18	1.258
27	11	12	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
28	11	17	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
29	12	14	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
30	12	18	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
31	13	15	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
32	13	19	Unchoked	27.74	0.5040	0.078	-	1.0	0.08	1.158
33	11	13	Unchoked	66.06	0.1878	0.078	0.2	1.0	0.01	1.21
34	14	16	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
35	14	20	Unchoked	24.11	0.5040	0.067	-	1.0	0.13	1.197
36	15	16	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
37	15	25	Unchoked	24.11	0.5040	0.067	-	1.0	0.13	1.197
38	16	24	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
39	17	18	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
40	17	19	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
41	17	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
42	18	20	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
43	18	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
44	19	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
45	19	25	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
46	20	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
47	20	24	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26

TABLE 6.2-16B: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION RECIRCULATION SUCTION BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Head Loss, K: Friction	Turning Loss	Expansion	Contraction	Total
48	22	25	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
49	23	22	Choked	6.98	0.3653	-	-	1.0	-	1.00
50	23	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
51	24	25	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26

TABLE 6.2-16C: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION FEEDWATER LINE BREAK RPV - SHIELD WALL ANNULUS

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Friction	Head Loss, K Turning Loss	Expansion	Contraction	Total
1	1	2	Unchoked	40.87	0.2004	-	0.129	1.0	0.01	1.139
2	1	3	Unchoked	40.87	0.2004	-	0.129	1.0	0.01	1.139
3	1	11	Unchoked	16.84	0.6930	0.078	-	1.0	0.24	1.318
4	2	4	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
5	2	11	Unchoked	1.18	8.6929	0.078	-	1.0	0.47	1.548
6	2	12	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108
7	3	5	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
8	3	11	Unchoked	1.18	8.6929	0.078	-	1.0	0.47	1.548
9	3	13	Unchoked	11.26	1.6632	0.078	-	1.0	0.1	1.178
10	4	6	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
11	4	12	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
12	5	7	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
13	5	13	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
14	6	8	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
15	6	12	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
16	6	14	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
17	7	9	Unchoked	40.87	0.1336	-	0.086	1.0	0.01	1.096
18	7	13	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
19	7	15	Unchoked	6.22	2.7712	0.078	-	1.0	0.05	1.128
20	8	10	Unchoked	40.87	0.3345	-	0.214	1.0	0.01	1.224
21	8	14	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
22	9	10	Unchoked	40.87	0.3345	-	0.214	1.0	0.01	1.224
23	9	15	Unchoked	12.44	1.3856	0.078	-	1.0	0.05	1.128
24	10	14	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108

TABLE 6.2-16C: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION FEEDWATER LINE BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Head Loss, K Friction	Turning Loss	Expansion	Contraction	Total
25	10	15	Unchoked	11.26	1.6627	0.078	-	1.0	0.03	1.108
26	10	16	Unchoked	21.86	0.5940	0.078	-	1.0	0.18	1.258
27	11	12	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
28	11	17	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
29	12	14	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
30	12	18	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
31	13	15	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
32	13	19	Unchoked	27.74	0.5040	0.078	-	1.0	0.08	1.158
33	11	13	Unchoked	66.06	0.1878	0.078	0.2	1.0	0.01	1.21
34	14	16	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
35	14	20	Unchoked	24.11	0.5040	0.067	-	1.0	0.13	1.197
36	15	16	Unchoked	66.06	0.1878	-	0.2	1.0	0.01	1.21
37	15	24	Unchoked	24.11	0.5040	0.067	-	1.0	0.13	1.197
38	16	20	Unchoked	27.24	0.5040	0.078	-	1.0	0.08	1.158
39	17	18	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
40	17	19	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
41	17	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
42	18	20	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
43	18	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
44	19	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018
45	19	24	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
46	20	22	Unchoked	70.56	0.0333	0.018	-	1.0	-	1.018
47	20	24	Unchoked	21.17	0.5224	-	0.2	1.0	0.06	1.26
48	22	25	Unchoked	4.14	0.2414	0.018	-	1.0	-	1.00
49	23	25	Unchoked	4.14	0.3145	-	-	1.0	0.27	1.27

TABLE 6.2-16C: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION FEEDWATER LINE BREAK RPV - SHIELD WALL ANNULUS (CONTINUED)

Vent Path No.	From Vol. Node No.	To Vol. Node No.	Description of Flow Choked/ Unchoked	Area (ft^2)	ℓ/a (ft^{-1})	Head Loss, K Friction	Turning Loss	Expansion	Contraction	Total
50	24	22	Unchoked	35.28	0.1333	0.018	-	1.0	-	1.018

TABLE 6.2-17A: [HISTORICAL INFORMATION] RECIRCULATION INLET LINE BREAK PROJECTED AREAS FOR FORCE CALCULATIONS ON THE RPV

Force Level	Vol. Node No.	Coefficient (in^2) Fx	Fy	Moment arm (ft)*
1	1	22115.76	0.0	8.55
	2	8867.72	-7079.42	8.55
	3	8867.72	7079.42	8.55
	4	4921.22	-10153.46	8.55
	5	4921.22	10153.46	8.55
	6	0.0	-11249.30	8.55
	7	0.0	11249.30	8.55
	8	-4921.22	-10153.46	8.55
	9	-4921.22	10153.46	8.55
	10	-39851.22	0.0	8.55
2	11	42303.87	0.0	29.50
	12	21151.92	-36636.21	29.50
	13	9081.93	26190.06	29.50
	14	-21151.92	-36636.21	29.50
	15	-21151.92	36636.21	29.50
	16	-42303.87	0.0	29.50
	23	12070.02	10446.15	29.50
3	17	15199.41	0.0	47.27
	18	7600.32	-13164.39	47.27
	19	7600.32	13164.39	47.27
	20	-7600.32	-13164.39	47.27
	24	-15199.41	0.0	47.27
	25	-7600.32	13164.39	47.27

*Reference elevation = 121.33 ft

TABLE 6.2-17B: [HISTORICAL INFORMATION] RECIRCULATION SUCTION LINE BREAK PROJECTED AREAS FOR FORCE CALCULATIONS ON THE RPV

Force Level	Vol. Node No.	Coefficient (in^2) Fx	Fy	Moment arm (ft)*
1	1	22115.76	0.0	8.55
	2	8867.72	-7079.42	8.55
	3	8867.72	7079.42	8.55
	4	4921.22	-10153.46	8.55
	5	4921.22	10153.46	8.55
	6	0.0	-11249.30	8.55
	7	0.0	11249.30	8.55
	8	-4921.22	-10153.46	8.55
	9	-4921.22	10153.46	8.55
	10	-39851.22	0.0	8.55
2	11	42303.87	0.0	29.50
	12	21151.92	-36636.21	29.50
	13	21151.92	36636.21	29.50
	14	-21151.92	-36636.21	29.50
	15	-21151.92	36636.21	29.50
	16	-42303.87	0.0	29.50
3	17	15199.41	0.0	47.27
	18	7600.32	-13164.39	47.27
	19	7600.32	13164.39	47.27
	20	-7600.32	-13164.39	47.27
	24	-15199.41	0.0	47.27
	25	-7600.32	13164.39	47.27

*Reference elevation = 121.33 ft

TABLE 6.2-17C: [HISTORICAL INFORMATION] FEEDWATER LINE BREAK PROJECTED AREAS FOR FORCE CALCULATIONS ON THE RPV

Force Level	Vol. Node No.	Coefficient (in^2) Fx	Fy	Moment arm (ft)*
1	1	22115.76	0.0	8.55
	2	8867.72	-7079.42	8.55
	3	8867.72	7079.42	8.55
	4	4921.22	-10153.46	8.55
	5	4921.22	10153.46	8.55
	6	0.0	-11249.30	8.55
	7	0.0	11249.30	8.55
	8	-4921.22	-10153.46	8.55
	9	-4921.22	10153.46	8.55
	10	-39851.22	0.0	8.55
2	11	42303.87	0.0	29.5
	12	21151.92	-36636.21	29.5
	13	21151.92	36636.21	29.5
	14	-21151.92	-36636.21	29.5
	15	-21151.92	36636.21	29.5
	16	-42303.87	0.0	29.5
3	17	15199.41	0.0	47.27
	18	7600.32	-13164.39	47.27
	19	7600.32	13164.39	47.27
	20	-22801.39	-13164.39	47.27
	24	-7600.32	13164.39	47.27

*Reference elevation = 121.33 ft

TABLE 6.2-18A: [HISTORICAL INFORMATION] RECIRCULATION INLET LINE BREAK PROJECTED AREAS FOR FORCE CALCULATIONS ON THE SHIELD WALL

Force Level	Vol. Node No.	Coefficient (in^2) Fx	Fy	Moment arm (ft)*
	1	27393.61	0.0	8.55
1	2	10983.97	-8768.90	8.55
	3	10983.97	8768.90	8.55
	4	6095.65	-12576.55	8.55
	5	6095.65	12576.55	8.55
	6	0.0	-13933.91	8.55
	7	0.0	13933.91	8.55
	8	-6095.65	-12576.55	8.55
	9	-6095.65	12576.55	8.55
	10	-49361.57	0.0	8.55
	11	52399.54	0.0	29.50
2	12	26199.75	-45379.31	29.50
	13	11249.3	32440.23	29.50
	14	-26199.75	-45379.31	29.50
	15	-26199.75	45379.31	29.50
	16	-52399.54	0.0	29.50
	23	14950.49	12939.09	29.50
	17	18826.70	0.0	47.27
3	18	9414.11	-16306.03	47.27
	19	9414.11	16306.03	47.27
	20	-9414.11	-16306.03	47.27
	24	-18826.70	0.0	47.27
	25	-9414.11	16306.03	47.27

*Reference elevation = 121.33 ft

TABLE 6.2-18B: [HISTORICAL INFORMATION] RECIRCULATION SUCTION LINE BREAK PROJECTED AREAS FOR FORCE CALCULATIONS ON THE SHIELD WALL

Force Level	Vol. Node No.	Coefficient (in^2) Fx	Fy	Moment arm (ft)*
	1	27393.61	0.0	8.55
1	2	10983.97	-8769.90	8.55
	3	10983.97	8768.9.90	8.55
	4	6095.65	-12577.55	8.55
	5	6095.65	12577.55	8.55
	6	0.0	-13934.91	8.55
	7	0.0	13934.91	8.55
	8	-6095.65	-12577.55	8.55
	9	-6095.65	12577.55	8.55
	10	-49361.57	0.0	8.55
	11	52399.54	0.0	29.50
2	12	26199.75	-45379.31	29.50
	13	26199.75	45379.31	29.50
	14	-26199.75	-45379.31	29.50
	15	-26199.75	45379.31	29.50
	16	-52399.54	0.0	29.50
	17	18826.70	0.0	47.27
3	18	9414.11	-16306.03	47.27
	19	9414.11	16306.03	47.27
	20	-9414.11	-16306.03	47.27
	24	-18826.70	0.0	47.27
	25	-9414.11	16306.03	47.27

*Reference elevation = 121.33 ft

TABLE 6.2-18C: [HISTORICAL INFORMATION] FEEDWATER LINE BREAK PROJECTED AREAS FOR FORCE CALCULATIONS ON THE SHIELD WALL

Force Level	Vol. Node No.	Coefficient (in^2) Fx	Fy	Moment arm (ft)*
	1	27393.61	0.0	8.55
1	2	10983.97	-8768.90	8.55
	3	10983.97	8768.90	8.55
	4	6095.65	-12576.55	8.55
	5	6095.65	12576.55	8.55
	6	0.0	-13933.91	8.55
	7	0.0	13933.91	8.55
	8	-6095.65	-12576.55	8.55
	9	-6095.65	12576.55	8.55
	10	-49361.57	0.0	8.55
	11	52399.54	0.0	29.50
2	12	26199.75	-45379.31	29.50
	13	26199.75	45379.31	29.50
	14	-26199.75	-45379.31	29.50
	15	-26199.75	45379.31	29.50
	16	-52399.54	0.0	29.50
	17	18826.7	0.0	47.27
3	18	9414.11	-16306.03	47.27
	19	9414.11	16306.03	47.27
	20	-28240.81	-16306.03	47.27
	24	-9414.11	16306.03	47.27

*Reference elevation = 121.33 ft

TABLE 6.2-19: DELETED

TABLE 6.2-20: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION

1) RWCU Break in Heat Exchanger Room
2) RWCU Break in Main Steam Tunnel

Volume #	Volume (ft^3) psia*	Temp F	Press Psia	Humid %	Break Loc. Vol Number	Break Line	Break Area (ft^2)	Break Type	Calc Peak Press. Psig	Design Peak Press. Diff. Psid
	Initial Conditions				DBA Break Conditions					
		Break in RWCU			Heat Exchanger Room					
1	10500	80.0	14.7	50	1	RWCU line in RWCU HX room (suction)	0.362	Double ended	3.7	5
2	16800	80.0	14.7	50					3.7	5
3	1.4×10^6	80.0	14.7	50					3.3	5
		RWCU Line Break in Main Steam Tunnel								
1	16800	80.0	14.7	50	1	RWCU pump discharge line in main steam tunnel	0.160	Double ended	5.1	10
2	10500	80.0	14.7	50					4.8	10
3	1.4×10^6	80.0	14.7	50					4.1	10

* See subsection 6.2.1.2.2 for subcompartment physical description

TABLE 6.2-21: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION

1) RWCU Line Break in Heat Exchanger Room

2) RWCU Line Break in Main Steam Tunnel

From Vol. Node #	To Vol Node #	Description Of Vent Path Flow Chocked/ Unchoked	Area ft^2	L/A	Friction K, $f\ell/d$	Turning Loss, K	Expansion, K	Contraction, K	Total
		BREAK IN RWCU HEAT EXCHANGER ROOM							
1	2	Unchoked	33.75	.1898	0.0	0.0	1.0	.42	1.42
1	3	Unchoked	20.93	.1953	0.0	0.0	1.0	.4	1.4
		BREAK IN MAIN STEAM TUNNEL							
1	2	Unchoked	33.75	.1898	0.0	0.0	1.0	.42	1.42
2	3	Unchoked	20.93	.1953	0.0	0.0	1.0	.4	1.4

TABLE 6.2-22: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION

RWCU Break In the Filter/Demineralizer Room

		Initial Conditions			DBA Break Conditions					
Volume #	Volume (ft^3)*	Temp F	Press Psia	Humid%	Break Loc. Vol Number	Break Line	Break Area (ft^2)	Break Type	Calc Peak Press. Psig	Design Peak Press. Diff. Psid
1	2287	80.0	14.7	50	1	6" RWCU line in Filter/ denim. room	0.362	Double ended	8.3	12.2
2	1070	80.0	14.7	50					5.3	12.2
3	2287	80.0	14.7	50					5.3	12.2
4	1.4×10^6	80.0	14.7	50					5.3	12.2

*See subsection 6.2.1.2.2 for subcompartment physical description

Table 6.2-23: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION

RWCU Break In Filter/Demineralizer Room

				Head Loss, K			
From Vol. Node No.	To Vol. Node No.	Area ft^2	Friction K, $F\ell/d$	Turning Loss, K	Expansion, K	Contraction, K	Total
1	2	15	0.0	0.0	1.0	0.44	1.44
2	3	15	0.0	0.0	1.0	0.44	1.44
2	4	45.0	0.22	0.0	1.0	0.0	1.22

Table 6.2-24: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION

RWCU Holding Pump Room

		Initial Conditions			DBA Break Conditions					
Volume #	Volume (ft^3)#	Temp F	Press Psia	Humid%	Break Loc. Vol Number	Break Line	Break Area (ft^2)	Break Type	Calc Peak Press. Psig	Design Peak Press. Diff. Psia
1	4000	104.0	14.7	100	1	6″ RWCU line in holding pump room	0.362	Double ended	4.9	12.2
2	840	104.0	14.7	100					4.9	12.2
3	7685	104.0	14.7	100					4.9	12.2
4	1.4×10^6	104.0	14.7	100					4.8	12.2

*See subsection 6.2.1.2.2 for subcompartment physical description.

Table 6.2-25: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION

RWCU Holding Pump Room

				Head Loss, K			
From Vol. Node No.	To Vol. Node No.	Area ft^2	Friction K, Fℓ/d	Turning Loss, K	Expansion, K	Contraction, K	Total
1	2	60	0.0	0.7	1.0	0.32	2.02
2	3	70	0.0	0.0	1.0	0.0	1.0
2	4	28	0.0	0.0	1.0	0.43	1.43

TABLE 6.2-26: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION

1) RWCU Pipe Chaser Transfer
2) RWCU Valve Nest Room

Volume #	Volume (ft^3)*	Temp (F)	Press Psia	Humid%	Break Loc. Vol Number	Break Line	Break Area (ft^2)	Break Type	Calc Peak Press. Psig	Design Peak Press. Diff. Psid
	Initial Conditions				DBA Break Conditions					
					RWCU Pipe Chase Transfer					
1	252	80.0	14.7	100	1	6" RWCU line in pipe chase	0.362	Double ended	5.3	**
2	7,290	80.0	14.7	100					5.3	**
3	3,895	80.0	14.7	100					5.3	
4	772	80.0	14.7	100					5.3	
5	3,447	80.0	14.7	100					5.3	
6	10,528	80.0	14.7	100					5.2	
7	16,783	80.0	14.7	100					5.2	
8	1.4×10^6	80.0	14.7	100						
					RWCU Valve Nest Room					
1	2,686	80.0	14.7	90	1	6" RWCU line in valve nest room	0.362	Double ended	5.6	5.9
2	369	80.0	14.7	90					5.6	6.0

TABLE 6.2-26: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION (Continued)

1) RWCU Pipe Chaser Transfer
2) RWCU Valve Nest Room

Volume #	Volume (ft^3)*	Temp (F)	Press Psia	Humid%	Break Loc. Vol Number	Break Line	Break Area (ft^2)	Break Type	Calc Peak Press. Psig	Design Peak Press. Diff. Psid
	Initial Conditions				DBA Break Conditions					
3	154	80.0	14.7	90					5.3	5.8
4	1.4×10^5	80.0	14.7	90					5.1	5.3

* See subsection 6.2.1.2.2 for subcompartment physical description

** The area is capable of withstanding peak overpressure of 11 psid across its walls, roof, and floor.

Table 6.2-27: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION

1) RWCU Pipe Chase Transfer
2) RWCU Valve Nest Room

From Vol. Node No.	To Vol. Node No.	Area ft^2	Head Loss, K Friction K, $F\ell/d$	Expansion, K	Contraction, K	Total
Break In Pipe Chase						
1	2	60.5	0.0	1.0	0.18	1.180
2	3	424.9	0.013	1.0	0.05	1.063
2	6	21.0	0.094	1.0	0.41	1.504
2	8	70.8	0.188	2.0	0.41	2.598
3	4	21.	0.075	1.0	0.40	1.475
3	8	27.	0.225	2.0	0.40	2.625
4	5	21.	.056	1.0	0.36	1.416
6	7	33.9	.081	1.0	0.42	1.501
6**	8	177.65	0.025	1.0	0.22	1.245
Break In Valve Nest Room						
1	2	61	0.0	1.0	0.25	1.25
1	4	3.6	0.044	1.0	0.44	1.484
2	3	22	0.0	1.0	0.28	1.28
3	4	16.8	0.0	1.0	0.33	1.33

**Blowout panel

TABLE 6.2-28: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION

Drywell Head 1) RCIC Line Break

		Initial Conditions			DBA Break Conditions					
Volume #	Volume (ft^3)*	Temp F	Press Psia	Humid%	Break Loc. Vol Number	Break Line	Break Area (ft^2)	Break Type	Calc Peak Press. Psig	Design Peak Press. Diff. Psid
1	7,331.80	135	14.7	50	1	RCIC Line Break	0.160	Double Ended	See Figure 6.2-69	42
2	248,349.71	135	14.7	50						12

*See subsection 6.2.1.2.2 for subcompartment physical description

TABLE 6.2-29: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION

Drywell Head 1) RCIC Line Break

From Vol. Node #	To Vol. Node #	Description of Vent Path Flow Chocked/ Unchoked	Area ft^2	L/A	Friction K,Fℓ/d	Head Loss K Turning Loss, K	Expansion, K	Contraction	Total
1	2	Unchoked	9.54 orifice	.0341		orifice			

TABLE 6.2-30: [HISTORICAL INFORMATION] SUBCOMPARTMENT NODAL DESCRIPTION

Drywell Head 1) Main steam Line Break

		Initial Conditions			DBA Break Conditions					
Volume #	Volume (ft^3)*	Temp F	Press Psia	Humid %	% Break in Volume Number	Break Line	Break Area (ft^2)	Break Type	Calc Peak Psia	Design Peak Press. Psid
1	382.41	135	14.7	50	50	MSLB	3.45	Double	See Figures	See Notes
2	1030.14				50			ended	6.2-73 a, b and	1, 2, 3.
3	2652.66								6.2-74 a,b,c.	
4	61705.02									
5	10253									
6	41043.24									
7	102997.1									
8	28286.65									
9	7331.8									
10, 11	1.4×10^6	80	14.7	60						

*See subsection 6.2.1.2.2 for subcompartment physical description Notes:

1. This table summarizes the pressure response, i.e., the drywell bulkhead cavity, due to a main steam line break directly below the bulkhead. The design parameters for the pressure suppression containment are shown in Tables 6.2-1, 6.2-2, and 6.2-13. The pressure responses and evaluations in other subcompartments are tabulated in subsection 6.2.1.2.3.

2. The nodalization scheme was chosen so as to accurately model the upper portion of the drywell and the drywell head region.

3. The bulkhead and the reactor cavity (9-1.2.3) have a peak design load spike of 34.03 psid at 0.065 second and continuous at 12 psid.

TABLE 6.2-31: [HISTORICAL INFORMATION] SUBCOMPARTMENT VENT PATH DESCRIPTION

Drywell Head 1) RCIC Line Break

From Vol. Node #	To Vol. Node #	Description of Vent Path Flow Chocked/Unchoked	Area ft^2	L/A	Friction $K, F\ell/d$	Turning Loss, K	Head Loss, K Expansion, K	Contraction	Total
1	2	unchoked	37.58	0.3036	0.0	0.11	1	0.11	1.22
1	3	unchoked	37.58	0.6504	0.0	0.23	1	0.11	1.34
1	4	choked; 0.0105-0.014sec	67.07	0.082	0.05	0.0	1	0.16	1.21
1	5	unchoked	25.03	1.1525	0.21	0.0	1	0.0	1.21
1	9	unchoked	2.18	1.1414			orifice		
			orifice						
2	3	unchoked	49.75	0.7804	0.0	0.27	1	0.0	1.27
2	4	unchoked	174.15	0.033	0.03	0.0	1	0.12	1.15
2	5	unchoked	62.57	0.4945	0.17	0.0	1	0.0	1.17
3	4	unchoked	447.01	0.0127	0.03	0.0	1	0.12	1.15
3	5	unchoked	162.69	0.1902	0.15	0.0	1	0.04	1.19
4	6	unchoked	2354.84	0.0053			orifice		
		unchoked	orifice						
6	7	unchoked	2356.8	0.0072			orifice		
		unchoked	orifice						
7	8	unchoked	1681.75	0.0083			orifice		
		unchoked	orifice						
2	9	unchoked	2.18	0.8832			orifice		
		unchoked	orifice						
3	9	unchoked	4.36	0.4217			orifice		
		unchoked	orifice						

TABLE 6.2-32: SUBCOMPARTMENT VENT PATH DESCRIPTION

Drywell Head 1) RCIC Line Break

From Vol. Node #	To Vol. Node #	Description of Vent Path Flow Chocked/Unchoked	Area ft^2	L/A	Head Loss, K: Friction $K, F\ell/d$	Head Loss, K: Turning Loss, K	Head Loss, K: Expansion, K	Head Loss, K: Contraction	Head Loss, K: Total
10	11	unchoked	900	0.1					
7	10	unchoked	184.05	1.22	0.04	0.0	1	0.44	1.48
7	11	unchoked	368.1	1.22	0.04	0.0	1	0.44	1.48

TABLE 6.2-33: DELETED

TABLE 6.2-33A: [HISTORICAL INFORMATION] BLOWDOWN FOR A FULL DOUBLE-ENDED RECIRCULATION RETURN LINE BREAK

Time (sec)	Mass Release Rate (lbm/sec)	Enthalpy (Btu/lb_m)	Total Energy Releaser Rate (Btu/sec)
$0.0 \leq t \leq 9.12E-3$	9907.6	530.0	5.251 E+6
$9.12E-3 \leq t \leq 8.74E-2$	14,861.4	530.0	7.877 E+6
$t \geq 8.74E-2$	11,057.8	530.0	5.861 E+6

TABLE 6.2-33B: [HISTORICAL INFORMATION] BLOWDOWN FOR A FULL DOUBLE-ENDED RECIRCULATION RETURN LINE BREAK

Time (sec)	Mass Release Rate (lbm/sec)	Enthalpy (Btu/lb_m)	Total Energy Release Rate (Btu/sec)
$0.0 \leq t \leq 8.37$ E-4	2.3625 E+4	530.0	1.252 E+7
8.37 E-4 $\leq t \leq 0.591$	3.5437 E+4	530.0	1.348 E+7
$0.591 \leq t \leq 1.0$	2.4342 E+4	530.0	1.290 E+7

TABLE 6.2-33C: [HISTORICAL INFORMATION] BLOWDOWN FOR A FULL DOUBLE-ENDED FEEDWATER LINE BREAK

Time (sec)	Mass Release Rate (lbm/sec)	Enthalpy (Btu/lb_m)	Total Energy Release Rate (Btu/sec)
0.0 ≤ t ≤ 1.58 E-2	1.4993 E+4	430.2	6.449 E+6
1.58 E-2 ≤ t ≤ 1.8 E-2	2.2403 E+4	430.2	9.637 E+6
1.8 E-2 ≤ t ≤ 1.0	1.8131 E+4	426.1	7.725 E+6

TABLE 6.2-34: [HISTORICAL INFORMATION] BLOWDOWN TABLE

RWCU Heat Exchanger Room Break

Time (sec)	Lbs-mass/sec	BTU's/lb-mass	BTU's/sec
0	1460.0	470.0	6.862×10^5
1.3	1460.0	470.0	6.862×10^5
1.3	730.0	470.0	3.431×10^5
9.7	730.0	470.0	3.431×10^5
9.7	301.5	470.0	1.417×10^5
58.2	301.5	470.0	1.417×10^5
59.7	0	470.0	0.0

TABLE 6.2-35: [HISTORICAL INFORMATION] BLOWDOWN TABLE

RWCU Break In Main Steam Tunnel

Time (sec)	Lbs-mass/sec	BTU's/lb-mass	BTU's/sec
0.0	626.5	470.0	2.945×10^5
48.0	626.5	470.0	2.945×10^5
49.5	0.0	470.0	0

TABLE 6.2-36: [HISTORICAL INFORMATION] BLOWDOWN TABLE

Filter/Demineralizer Room - RWCU Break

Time (sec)	Lbs-mass/sec	BTU's/lb-mass	BTU's/sec
0	1100.0	470.0	5.170×10^5
5.7	1100.0	470.0	5.170×10^5
5.7	560.0	470.0	2.632×10^5
34.6	560.0	470.0	2.632×10^5
34.6	300.0	540.0	1.620×10^5
100.0	300.0	540.0	1.620×10^5
100.1	0.0	NA	0.0

TABLE 6.2-37: [HISTORICAL INFORMATION] BLOWDOWN TABLE

RWCU Holding Pump Room

Time (sec)	Lbs-mass/sec	BTU's/lb-mass	BTU's/sec
0.0	1100.0	470.0	5.170×10^5
5.7	1100.0	470.0	5.170×10^5
5.7	560.0	470.0	2.632×10^5
34.6	560.0	470.0	2.632×10^5
34.6	300.0	540.0	1.620×10^5
100.0	300.0	540.0	1.620×10^5
100.1	0.0	NA	0.0

TABLE 6.2-38: [HISTORICAL INFORMATION] BLOWDOWN TABLE

1)RWCU Pipe Chase Transfer
2)RWCU Valve Nest Room

Time (sec)	Lbs-mass/sec	BTUs/lb-mass	BTUs/sec
	Case 1 RWCU Pipe Chase Transfer		
0.0	1100.0	470.0	5.170×10^5
5.70	1100.0	470.0	5.170×10^5
5.70	560.0	470.0	2.632×10^5
34.6	560.0	470.0	2.632×10^5
34.6	300.0	540.0	1.620×10^5
100.0	300.0	540.0	1.620×10^5
100.1	0.0	NA	0.0
	Case 2 RWCU Valve Nest Room		
0.0	1100.0	470.0	5.170×10^5
5.70	1100.0	470.0	5.170×10^5
5.70	560.0	470.0	2.632×10^5
34.6	560.0	470.0	2.632×10^5
34.6	300.0	470.0	1.620×10^5
100.0	300.0	0.0	1.620×10^5
100.1	0.0	NA	0.0

TABLE 6.2-39: [HISTORICAL INFORMATION] BLOWDOWN TABLE

Drywell Head, RCIC Line Break*

Time (sec)	Lbs-mass/sec	BTU's/lb-mass	BTU's/sec
0.0	400.0	400.0	4.76×10^5
10.0	400.0	400.0	4.76×10^5

*For this case, mass-energy release is constant and undiminished through the time of peak occurrence.

TABLE 6.2-40: [HISTORICAL INFORMATION] BLOWDOWN TABLE

Drywell Head, Main Steam Line Break

Time (sec)	Lbs-mass/sec	BTU's/lb-mass	BTU's/sec
0.0	13520	1190.0	1.609×10^7
0.182	13320	1190.6	1.586×10^7
0.186	9989	1190.6	1.189×10^7
0.999	9749	1191.7	1.162×10^7
1.00	33565.0	571.0	1.917×10^7
2.00	33383.0	571.0	1.906×10^7
3.00	33108.0	582.2	1.928×10^7

TABLE 6.2-41: SECONDARY CONTAINMENT

I. Secondary Containment Design	
A. Free Volume, ft^3	
1. Auxiliary Building	3,263,626
2. Enclosure Building	863,625
B. Pressure, inches of water gauge	
1. Normal Operation	
a. Auxiliary Building (Note: Drawdown analysis does not take credit for an initial negative pressure)	1/8 inch, w.g. negative
b. Enclosure Building	0.0 inch, w.g.
2. Post-accident	
a. Auxiliary building	1/4 inch, w.g. negative
b. Enclosure building	1/4 inch, w.g. negative
C. Out Leak Rate at Post-accident Pressure, I/day	
1. Auxiliary building	1
2. Enclosure building	1
D. Exhaust Fans	
1. Number	
a. Auxiliary Building	1
b. Enclosure building	1
2. Type	centrifugal & vaneaxial
E. Filters	
1. Number	1
2. Type	Charcoal adsorbers (see subsections 6.5.1, 6.5.3)
II. Transient Analysis	
A. Initial Conditions	
1. Pressure, psia	14.7

TABLE 6.2-41: SECONDARY CONTAINMENT (CONTINUED)

2. Temperature, F	110, average
3. Outside air temperature, F	40
4. Thickness of secondary/containment wall	
a. Auxiliary Building	3’-0", average
b. Enclosure Building	5-5/8" (composite, including exterior siding and inner liner plate)
5. Thickness of primary/containment wall	3'-6"
B. Thermal Characteristics	
1. Primary Containment Wall	
a. Coefficient of linear expansion	NA
b. Modulus of elasticity	NA
c. Thermal conductivity Btu/hr- ft^2-F	0.17
d. Thermal capacitance Btu/ft^3-F	22.5
2. Secondary Containment Wall	
a. Thermal conductivity Btu/hr-ft^2-F	
1. Auxiliary Building	0.18
2. Enclosure Building	0.18
b. Thermal capacitance, Btu/ft^3-F	
1. Auxiliary Building	22.5
2. Enclosure Building	58.7
3. Heat Transfer Coefficients	
a. Primary containment atmosphere to primary containment wall, Btu/hr-ft^2-F	0.74
b. Primary containment wall to secondary containment atmosphere, Btu/hr-ft^2-F	0.21

TABLE 6.2-41: SECONDARY CONTAINMENT (CONTINUED)

c. Secondary containment wall to secondary containment atmosphere, Btu/hr-ft^2-F	
1. Auxiliary Building	0.74
2. Enclosure Building	0.74
d. Primary containment emissivity, Btu/hr-ft^2-F	
1. Auxiliary Building	0.20
2. Enclosure Building	0.20
e. Secondary containment emissivity, Btu/hr-ft^2-F	
1. Auxiliary Building	0.20
2. Enclosure Building	0.20

TABLE 6.2-42: EVALUATION OF POTENTIAL SECONDARY CONTAINMENT BYPASS LEAKAGE PATHS

Primary Ctmt. Penetration		Line Size Penetrating Primary Containment	Bypass Leakage Barrier[1]
5.	Main Steam Line A	28"	C,V,(2),(4)
6.	Main Steam Line B	28"	C,V,(2),(4)
7.	Main Steam Line C	28"	C,V,(2),(4)
8.	Main Steam Line D	28"	C,V,(2),(4)
9.	Feedwater A	24"	C,V,(2),P
10.	Feedwater B	24"	C,V,(2),P
19.	Main Stm. Drain to Condenser	3"	C,A,V
33.	CRD Pump Disch.	2"	C,L,(2)
34.	Supply Air (HVAC)	20"	C,A,V
35.	Exhaust Air (HVAC)	20"	C,A,V
36.	Drywell Chilled Water Return	4"	C,A,L
37.	Drywell Chilled Water Supply	4"	C,A,L
38.	Plant Chilled Water Supply	4"	C,L,(8)
39.	Plant Chilled Water Return	4"	C,L,(8)
41.	Service Air	3"	C,(9)
42.	Instrument Air	2-1/2"	C,(9)
43.	RWCU to Condenser	4"	C,A,L
47.	Post-accident sample line	3/4"	C,L,(7)
49.	RWCU Backwash to Res. Stge	4"	C,A,L
54.	To and From Refuel Wtr St. Tk	12"	C,A,L
56.	Demin. Wtr to Upper CTMT Pool	6"	C,A,L
57.	FPC&CU to Upper Pool	8"	C,A,L
58.	Pool Skimmer Tks. to FPC&CU Sys.	8"	C,A,V
60.	Aux. Bldg. Floor Drain Transfer Pumps Disch	4"	C,A,(3),(6)
65.	CTMT HVAC Supply	6"	C,A,V
66.	CTMT HVAC Exhaust	6"	C,A,V
69.	Supp. Pool Drain	12"	C,A,(6)
70.	Comp. Air (ADS)	1"	C,(9)

TABLE 6.2-42: EVALUATION OF POTENTIAL SECONDARY CONTAINMENT BYPASS LEAKAGE PATHS (CONTINUED)

Primary Ctmt. Penetration		Line Size Penetrating Primary Containment	Bypass Leakage Barrier[1]
71B.	Post-Accident Sample Line	1"	L,(6),(7)***
81.	Post-Accident Sample Line	3/4"	C,L,(7)
85.	Suppression Pool Clean-up	12"	C,A,L
86.	Demin. Water	4"**	C,A*,L
89.	SSW Supply A	2"	C,(5),(3)
90.	SSW Return A	2"	C,(5),(3)
91.	SSW Return B	2"	C,(5),(3)
92.	SSW Supply B	2"	C,(5),(3)
109A.	Post-Accident Sample Line	3/4"	C,(7)
109B.	Post-Accident Sample Line	3/4"	C,(7)
109D.	Post-Accident Sample Line	3/4"	C,(7)
117.	Post-Accident Sample Line	3/4"	L,(6),(7)***

*Single, valve, double solenoid
**This is a 2” line that enlarges to 4" for just the penetration.
***This sample line penetrates into the suppression pool and has one closed motor-operated valve.

NOTES

1. Bypass Leakage Barriers

   C - Redundant primary containment isolation valves

   A - Redundant secondary containment isolation valves
   L - Water seal
   V - Vented to secondary containment

   P - Pressurized water seal system (reference subsection 6.7.2)

2. Third Isolation Valve (remote manual) provided.

3. Required to operate post-accident; hence no through-line leakage.

4. Leakage control system provided (reference subsection 6.7.1).

TABLE 6.2-42: EVALUATION OF POTENTIAL SECONDARY CONTAINMENT BYPASS LEAKAGE PATHS (CONTINUED)

5. Auxiliary building isolation valves not provided since entire system is seismic Category I and is operable continuously during a LOCA at a pressure higher than the peak containment pressure.

6. These lines penetrate containment below the elevation of the suppression pool.

7. These lines consist of 3/8" O.D. tubing. This tubing runs to the Post-Accident Sample Station that is located inside a room in the turbine building. This room is vented through a 99 percent efficient (radioiodine) filter train consisting of HEPA and charcoal filters. therefore, because of the ventilation system and the size of the tubing, no bypass leakage will occur through these lines. See subsection 7.7.1.11 for a description of the Post-Accident Sampling System.

8. The auxiliary building piping contains loop seals which precludes post accident bypass leakage.

9. Penetration specific leakage limits are imposed on this penetration. Dose contribution included in Table 15.6-14.

TABLE 6.2-43: SECONDARY CONTAINMENT DRAWDOWN ANALYSIS

Time* (Sec)	Pressure (inches w.g.)	Time* (Sec)	Pressure (inches w.g.)
0	0	43.2	-0.15235
1.0	-0.00554	44.2	-0.15512
2.2	-0.01108	45.2	-0.15789
3.2	-0.01385	46.2	-0.16066
4.3	-0.01939	47.2	-0.1662
5.8	-0.02493	48.2	-0.16897
7.0	-0.03047	49.2	-0.17174
8.4	-0.03601	50.2	-0.17451
10.2	-0.04432	51.2	-0.17728
11.2	-0.04709	52.2	-0.17728
12.2	-0.04986	53.2	-0.18005
13.2	-0.0554	54.2	-0.18282
14.2	-0.05817	55.2	-0.18559
15.2	-0.06094	56.2	-0.18836
16.2	-0.06648	57.2	-0.19113
17.2	-0.06925	58.2	-0.1939
18.2	-0.07202	59.2	-0.19667
19.2	-0.07756	60.2	-0.19944
20.2	-0.08033	61.2	-0.20221
21.2	-0.0831	62.2	-0.20498
22.2	-0.08587	63.2	-0.20775
23.2	-0.09141	64.2	-0.21052
24.2	-0.09418	65.2	-0.21329
25.2	-0.09695	66.2	-0.21606
26.2	-0.09972	67.2	-0.21606
27.2	-0.10526	68.2	-0.21883
28.2	-0.10803	69.2	-0.2216
29.2	-0.1108	70.2	-0.22437
30.2	-0.11357	71.2	-0.22714
31.2	-0.11634	72.2	-0.22991
32.2	-0.11911	73.2	-0.23268
33.2	-0.12188	74.2	-0.23545
34.2	-0.12742	75.2	-0.23545
35.2	-0.13019	76.2	-0.23822
36.2	-0.13296	77.2	-0.24099
37.2	-0.13573	78.2	-0.24376
38.2	-0.1385	79.2	-0.24653
39.2	-0.14127	80.2	-0.2493

TABLE 6.2-43: SECONDARY CONTAINMENT DRAWDOWN ANALYSIS (CONTINUED)

Time* (Sec)	Pressure (inches w.g.)	Time* (Sec)	Pressure (inches w.g.)
40.2	-0.14404	81.2	-0.2493
41.2	-0.14681	82.2	-0.25207
42.2	-0.14958		

* - Does not include time associated with items d, e, & f on page 6.2-73.

These values are within the technical specification requirement.

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outer-most Iso Valve	Valve: Type	Valve: Operator (2)	Valve Actuation Mode: Primary	Valve Actuation Mode: Secondary	Valve Position: Normal (6)	Valve Position: Shut-down	Valve Position: Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
2	56	Locks & Hatches	Air	3/8″	No	M23FX015	1(22)	Yes	8 7/8″	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or out
				3/8″		M23FX016	0	Yes	1 7/8″	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or out
				3/8″		M23FX017	1(22)	Yes	8 7/8″	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or out
				3/8″		M23FX018	0	Yes	1 7/8″	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or out
3	56	Locks & Hatches	Air	3/8″	No	M23FX011	1(22)	Yes	12 7/8″	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or out
				3/8″		M23FX012	0	Yes	3 1/4″	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or out
				3/8″		M23FX013	1(22)	Yes	12 7/8″	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or out
				3/8″		M23FX014	0	Yes	3 1/4″	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or out
4	56	Fuel Pool Cooling & Cleanup - Transfer Tube	Pool Water	36	No	F11E015	I	Yes	11′-0″	Closure Door	Manual	Manual	None	Locked Closed	Open	Locked Closed	N/A	Manual	N/A	In or out
5	55	Nuclear Boiler - Main Steam Lines	Primary Coolant	28	Yes	B21F028A	0	Yes	8′-9″	Globe	Pneumatic	Piston	Self	Open	Closed	Closed	Closed	C,F,P, E,N,RM (1)	(17)	Out
				28		B21F022A	I	Yes	N/A	Globe	Pneumatic	Piston	Self	Open	Closed	Closed	Closed	C,F,P, E,N,RM (1)	(17)	
				1 1/2		B21F067A-A (18)	0	Yes	5′-3 3/16″	Globe	Electric Motor	Electric	Manual	Open	Closed	Closed	As Is	C,E,F, P,N,RM	A	
				1 1/2		E32F001A-A	0	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	ZA	A	
				3/4		B21F025A	0	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Valve Position Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
6	55	Nuclear Boiler - Main Steam Lines	Primary Coolant	28	Yes	B21F028B	0	Yes	9'-9"	Globe	Pneumatic	Piston	Self	Open	Closed	Closed	Closed	C,F,P, E,N,RM (1)	(17)	Out
				28		B21F022B	I	Yes	N/A	Globe	Pneumatic	Piston	Self	Open	Closed	Closed	Closed	C,F,P, E,N,RM (1)	(17)	
				1 1/2		B21F067B-A[18]	0	Yes	5'-2 1/8"	Globe	Electric Motor	Electric	Manual	Open	Closed	Closed	As Is	C,E,F, P,N,RM	A	
				1 1/2		E32F001E-A	0	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	ZA	A	
				3/4		B21F025B	0	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
7	55	Nuclear Boiler - Main Steam Lines	Primary Coolant	28	Yes	B21F028C	O	Yes	9'-9"	Globe	Pneumatic	Piston	Self	Open	Closed	Closed	Closed	C,F,P, E,N,RM (1)	(17)	Out
				28		B21F022C	I	Yes	N/A	Globe	Pneumatic	Piston	Self	Open	Closed	Closed	Closed	C,F,P, E,N,RM (1)	(17)	
				1 1/2		B21F067C-A[18]	O	Yes	5'-9 11/16"	Globe	Electric Motor	Electric	Manual	Open	Closed	Closed	As Is	C,E,F, P,N,RM	A	
				1 1/2		E32F001J-A	O	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	ZA	A	
				3/4		B21F025C	O	No(19)	N/A	Globe	Manual	Manual	None	Locked	Locked	Locked	N/A	None	None	
8	55	Nuclear Boiler - Main Steam Lines	Primary Coolant	28	Yes	B21F028D	O	Yes	9'-9"	Globe	Pneumatic	Piston	Self	Open	Closed	Closed	Closed	C,F,P, E,N,RM (1)	(17)	Out
				28		B21F022D	I	Yes	N/A	Globe	Pneumatic	Piston	Self	Open	Closed	Closed	Closed	C,F,P, E,N,RM (1)	(17)	
				1 1/2		B21F067D-A[18]	O	Yes	4'-9 3/32"	Globe	Electric Motor	Electric	Manual	Open	Closed	Closed	As Is	C,E,F, P,N,RM	A	
				1 1/2		E32F001N-A	O	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	ZA	A	
				3/4		B21F025D	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
9	55	Nuclear Boiler - Feedwater Inlet	Primary Coolant	24	Yes	B21F065A-A	O	Yes	55'-6 7/16"	Gate	Electric Motor	Electric	Manual	Open	Closed	Closed or Open	As Is	N/A	A	In
				24		B21F032A	O	Yes	N/A	Check	Process	(3)	None	Open	Closed	Closed or Open	N/A	Reverse Flow	N/A	
				24		B21F010A	I	No(19)	N/A	Check	Process	Process	None	Open	Closed	Closed or Open	N/A	Reverse Flow	N/A	
				3/4		B21F030A	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		B21F063A	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
10	55	Nuclear Boiler - Feedwater Inlet	Primary Coolant	24	Yes	B21F065B-A	O	Yes	55'-6 7/16"	Gate	Electric Motor	Electric	Manual	Open	Closed	Closed or Open	As Is	N/A	A	In
				24		B21F032B	O	Yes	N/A	Check	Process	(3)	None	Open	Closed	Closed or Open	N/A	Reverse Flow	N/A	
				24		B21F010B	I	No(19)	N/A	Check	Process	Process	None	Open	Closed	Closed or Open	N/A	Reverse Flow	N/A	
				3/4		B21F063B	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		B21F030B	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
11	56	RHR Pump - "A" Suction	Supp Pool Water	24	Yes	E12F004A-A	O	No(19)	1'-11 3/16"	Gate	Electric Motor	Electric	Manual	Open	Closed	Open	As Is	N/A	A	Out
				1		E12F017A	O	No(19)	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	In
12	56	RHR Pump - "B" Suction	Supp Pool Water	24	Yes	E12F004B-B	O	No(19)	1'-11 3/16"	Gate	Electric Motor	Electric	Manual	Open	Closed	Open	As Is	N/A	A	Out
				1		E12F017B	O	No(19)	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	In
13	56	RHR Pump - "C" Suction	Supp Pool Water	24	Yes	E12F004C-B	O	No(19)	5'-11"	Gate	Electric Motor	Electric	Manual	Open	Closed	Open	As Is	N/A	A	Out
				1		E12F017C	O	No(19)	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	In
				3/4		E12F439C	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In
				3/4		E12F440C	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F441C	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F442C	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Actuation Mode: Operator (2)	Valve Actuation Mode: Primary	Valve Actuation Mode: Secondary	Valve Position: Normal (6)	Valve Position: Shut-down	Valve Position: Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
14	55	RHR Reactor Shutdown Cooling Suction	Reactor Water	20	Yes	E12F008-A	O	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Open	Closed	As Is	A,U,M, RM	A	Out
				20		E12F009-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Open	Closed	As Is	A,U,M, RM	B	Out
				3/4		E12F308	I	Yes	N/A	Stop-Check	Process	Thermal Relief	None	Closed	Closed	Closed	N/A	N/A	N/A	Bypass F009-B
				3/4		E12F002	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F445	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F446	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
17	55	Steam Supply to RHR and RCIC Turbine	Steam	10	No	E51F063-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Open	Open	As Is	J,K,T, F,M,I, RM	B	Out
				10		E51F064-A	O	Yes	2'-2 3/4"	Gate	Electric Motor	Electric	Manual	Open	Open	Open	As Is	J,K,T, F,M,I, RM	A	
				1	Yes	E51F076-B(18)	I	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	J,K,T, F,M,I, RM	B	
				3/4		E51F072	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
19	55	Nuclear Boiler - Main Steam Drains	Primary Coolant	3	Yea	B21F019-A(18)	O	Yes	5'-6"	Gate	Electric Motor	Electric	Manual	Open	Closed	Closed	As Is	C,F,P, E,N,RM	A	Out
				3		B21F016-B(18)	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Closed	Closed	As Is	C,F,P, E,N,RM	B	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
20	55	RHR Heat Exch "A" to LPCI	Supp Pool Water	18	Yes	E12F027A-A	O	Yes	6'- 1/2"	Gate	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	
				14		E12F042A-A	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	V,RM	A	In
				4		E12F044A	I	Yes	37'-11"	Gate	Manual	Manual	None	Locked Closed	Open	Locked Closed	N/A	None	None	
				1		E12F025A	I	Yes	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	
				18		E12F028A-A	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	RM,C,G,(20)	A	
				12		E12F037A-A	I	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Open	Closed	As Is	A,M,RM,G	A	
				3/4		E12F107A	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
21	55	RHR Heat Exch "B" to LPCI	Supp Pool Water	18	Yes	E12F027B-B	O	Yes	8'-4 3/4"	Gate	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	
				14		E12F042B-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	V,RM	B	In
				1		E12F025B	I	Yes	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	
				18		E12F028B-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	RM,C,G,(20)	B	
				12		E12F037B-B	I	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Open	Closed	As Is	A,M,RM,G	B	
				4		E12F044B	I	Yes	N/A	Gate	Manual	Manual	None	Locked Closed	Open	Locked Closed	N/A	None	None	
				3/4		E12F107B	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
22	55	RHR Pump "C" to LPCI	Supp Pool Water	12	Yes	E12F042C-B	O	Yes	2'-4"	Gate	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	N/A	B	In
				12		E12F041C-B	I	Yes	N/A	Check	Process	Note 3	None	Closed	---	Open	N/A	Reverse Flow	N/A	
				3/4		E12F056C	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F234	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
23	56	RHR - "A" Pump Test Line to Supp Pool	Supp Pool Water	18	Yes	E12F024A-A	O	No(19)	32'-7 1/2"	Gate	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	C,C,X, V,RM (20)	A	
				4		E12F011A-A	O	No(19)	38'-2"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	C,G,RM (20)	A	In
				4		E12F064A-A	O	No(19)	60'-5"	Gate	Electric Motor	Electric	Manual	Open	Closed	Open or Closed	As Is	N/A	A	
				1 1/2		E12F290A-A	O	No(19)	84'-8 1/4"	Globe	Electric Motor	Electric	Manual	Open	Closed	Open or Closed	As Is	N/A	A	
				3/4		E12F322	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F259	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F261	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F227	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F228	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F338	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F339	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F336	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F349	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F348	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F262	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1	Yes	E12F260	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
24	56	RHR - "C" Test Line to Supp Pool	Supp Pool Water	14	Yes	E12F021-B	O	No(19)	14'-5 3/8"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	C,G,RM (20)	B	In
				4		E12F064C-B	O	No(19)	35'-7"	Gate	Electric Motor	Electric	Manual	Open	Closed	Open or Closed	As Is	N/A	B	
				1		E12F280	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F281	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2		E12F311	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2		E12F304	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
25	56	HPCS Pump Suction	Supp Pool Water	24	Yes	E22F015-C	O	No(19)	7'-4"	Gate	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	N/A	C	Out
				3/4		E22F014	O	No(19)	N/A	Relief	Process	Process	Process	Closed	Closed	Closed	N/A	None	None	In
				3/4		E22F800	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E22F801	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
26	55	HPCS Pump Disch	Cond/Supp Pool Water	12	Yes	E22F004-C	O	Yes	12'-5 9/16"	Gate	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	N/A	C	In
				14		E22F005	I	Yes	N/A	Check	Process	Note 3	None	Closed	Closed	Open	N/A	Reverse Flow	N/A	In
				1		E22F218	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E22F201	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E22F021	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

										Valve		Valve Actuation Mode		Valve Position						
Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Type	Operator (2)	Primary	Secondary	Normal (6)	Shut-down	Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
27	56	HPCS Test Line	Supp Pool Water	12	Yes	E22F023-C	O	No(19)	21'-1 1/2"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	B,G,RM	C	In
				4		E22F012-C	O	No(19)	12'-7"	Gate	Electric Motor	Electric	Manual	Closed	Closed	Closed or Open	As Is	N/A	C	
				1		E22F035	O	No(19)	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	In
				1		E22F302	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E22F301	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2		E22F303	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2		E22F304	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
28	56	RCIC Pump Suction	Supp Pool Water	6	No	E51F031-A	O	No(19)	1'-0"	Gate	Electric Motor	Electric	Manual	Closed	Open	Open	As Is	J,K,T, F,M,I, RM	A	Out
				3/4		E51F269	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E51F270	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E51F272	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E51F273	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
29	56	RCIC Turbine Exhaust	Steam	20	No	E51F068-A	O	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Open	Open	As Is	G,J,RM	A	In
				20		E51F040	O	Yes	7'11"	Check	Process	Note 7	None	Closed	Closed	Closed or Open	N/A	N/A	None	In
				2 1/2		E51F077-A	O	Yes	34'-4"	Gate	Electric Motor	Electric	Manual	Open	Open	Open	As Is	G,J,RM	A	
				3/4		E51F212	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E51F258	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2		E51F257	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
30	56	LPCS Pump Suction	Supp Pool Water	24	Yes	E21F001-A	O	No(19)	6'-0"	Gate	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	Out
				3/4		E21F031	O	No(19)	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	In

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
31	55	LPCS Pump Disch	Supp Pool Water	14	Yes	E21F005-A	O	Yes	1'-5 3/4"	Gate	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	In
				14		E21F006	I	Yes	N/A	Check	Process	Note 3	None	Closed	Closed	Open	N/A	Reverse Flow	N/A	
				3/4		E21F013	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E21F200	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E21F207	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
32	56	LPCS Test Line	Supp Pool Water	14	Yes	E21F012-A	O	No(19)	13'-10"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	C,G,RM (20)	A	In
				4		E21F011-A	O	No(19)	17'-10 11/16"	Gate	Electric Motor	Electric	Manual	Open	Closed	Closed or Open	As Is	N/A	A	
				3/4		E21F217	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E21F218	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2		E21F222	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2		E21F221	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
33	56	CRD Pump Disch	Water	2	Yes	C11F083-A	O	Yes	5'-2 1/2"	Globe	Electric Motor	Electric	Manual	Open	Open	Closed or Open	As Is	N/A	A	In
				2		C11F122	I	Yes	N/A	Check	Process	Process	None	Open	Open	Closed or Open	N/A	Reverse Flow	N/A	
				3/4		C11F128	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
34	56	Ctmt Purge and Vent Air Supply (5)	Air	20	No	M41F011-A	O	Yes	1'-3 1/2"	Butterfly	Pneumatic	Piston	Manual	Closed	Open	Closed	Closed	B,G,Z, C,RM	A	In
				20		M41F012-B	I	Yes	N/A	Butterfly	Pneumatic	Piston	Manual	Closed	Open	Closed	Closed	B,G,Z, C,RM	B	
				3/4		M41F042	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
35	56	Ctmt Purge and Vent Air Exhaust (5)	Air	20	No	M41F034-B	I	Yes	N/A	Butterfly	Pneumatic	Piston	Manual	Locked Closed	Locked Closed	Locked Closed	Closed	B,G,Z, C,RM	B	Out
				20		M41F035-A	O	Yes	1'-3 1/2"	Butterfly	Pneumatic	Piston	Manual	Closed	Open	Closed	Closed	B,G,Z, C,RM	A	
				3/4		M41F051	O	No(19)	N/A	Globe	Manual	Manual	None	Closed	Open	Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
36	56	Drywell Chilled Wtr Return	Water	4	No	P72F123-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	RM,B,G (20)	B	Out
				4		P72F122-A	O	Yes	1'-0"	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	RM,B,G (20)	A	
37	56	Drywell Chilled Wtr Supply	Water	4	No	P72F121-A	O	Yes	1'-0"	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	RM,B,G (20)	A	In
				4		P72F165	I	Yes	N/A	Check	Process	Process	None	Open	Open	Closed	N/A	Reverse Flow	N/A	
				3/4		P72F167	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
38	56	Plant Chilled Wtr Supply	Water	4	No	P71F150-A	O	Yes	1'-6"	Gate	Pneumatic	Piston	Manual	Open	Closed	Closed	Closed	B,G,RM (20)	A	In
				4		P72F151	I	Yes	N/A	Check	Process	Process	None	Open	Open	Closed	N/A	Reverse Flow	N/A	
				3/4		P71F232	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2		P71FX359	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Close	Locked Close	Locked Close	N/A	None	None	
39	56	Plant Chilled Wtr Return	Water	4	No	P71F148-A	O	Yes	5'-0"	Gate	Pneumatic	Piston	Manual	Open	Closed	Closed	Closed	B,G,RM (20)	A	Out
				4		P71F149-B	I	Yes	N/A	Gate	Pneumatic	Piston	Manual	Open	Closed	Closed	Closed	B,G,RM (20)		
				3/4		P71F246	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None		
				1/2		P71FX358	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Close	Locked Close	Locked Close	N/A	None	None	
40	56	Integrated Leak Rate Test Conn (Ctmt Press & Depress)	Ctmt Atmos	6	No	Blind Flange	O	Yes	N/A											In or Out
41	56	Service Air Supply	Air	3 4" diam sleeve	No	P52F105-A	O	Yes	2'-3 3/16"	Gate	Pneumatic	Piston	Manual	Open	Closed	Closed	Closed	B,G,RM (20)	A	In
				3		P52F122	I	Yes	N/A	Check	Process	Process	None	Open	Closed	Closed	N/A	Reverse Flow	N/A	
				3/4		P52F258	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
42	56	Instr Air Supply	Air	2 1/2 3" diam sleeve	No	P53F001-A	O	Yes	2'-2 7/8"	Gate	Pneumatic	Piston	Manual	Open	Closed	Closed	Closed	B,G,RM (20)	A	In
				3		P53F002	I	Yes	N/A	Check	Process	Process	None	Open	Closed	Closed	N/A	Reverse Flow	N/A	
				3/4		P53F036	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
43	56	RWCU to Main Cond	Reactor Water	4	No	G33F034-A	O	Yes	2'-2 11/16"	Gate	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	B,F,L, H,RM (20)	A	Out
				4		G33F028-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	B,F,L, H,RM (20)	B	
				3/4		G33F070	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/4	No	G33F264	O	Yes	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	
44	56	Comp Cooling Wtr Supply	Water	10	No	P42F066-A	O	Yes	1'-0"	Gate	Electric Motor	Electric	Manual	Open	Open	As Is	As Is	N/A	A	In
				10		P42F035	I	Yes	N/A	Check	Process	Process	None	Open	Open	Reverse Flow	N/A	Reverse Flow	N/A	
				3/4		P42F161	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
45	56	Comp Cooling Wtr Return	Water	10	No	P42F067-A	O	Yes	1'0"	Gate	Electric Motor	Electric	Manual	Open	Open	As Is	As Is	N/A	A	Out
				10		P42F068-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Open	As Is	As Is	N/A	B	
				3/4		P42F162	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
46	56	RCIC Pump Disch Min.-Flow Bypass	Water	2	Yes	E51F019-A	O	No(19)	N/A	Globe	Electric Motor	Electric	Manual	Closed	Open	Open or Closed	As Is	N/A	A	In
				1		E51F251	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E51F252	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
47	56	Reactor Recirc Post Accident Sampling	Reactor Water	3/4	No	B33F128-B	I	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed or Open	As Is	N/A	B	Out
				3/4		B33F127-A	O	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed or Open	As Is	N/A	A	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
48	56	RHR Heat Exch "B" Relief Vlv Vent Header to Supp Pool	Non-Con-densables	6	Yes	E12F055B	O	No(19)	66'-7 1/2"	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	In
				2		E12F073B-B	O	No(19)	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	N/A	B	
49	56	RWCU Backwash Transfer Pump to Spent Resin Tank	R.A. Wtr 0.8% Suspended Solids by Wt.	4	No	G36F106-B	I	Yes	N/A	Gate	Pneumatic	Piston	None	Open	Open	Closed	Closed	B,G,RM (20)	B	Out
				4		G36F101-A	O	Yes	2'-0"	Gate	Pneumatic	Piston	None	Open	Open	Closed	Closed	B,G,RM (20)	A	
50	56	Drywell & Ctmt Equip Drain Sump Pump Disch	Water Equipment Drains	6	No	P45F067-B	I	Yes	N/A	Gate	Pneumatic	Piston	None	Open	Closed	Closed	Closed	B,G,RM (20)	B	Out
				6		P45F068-A	O	Yes	5'-6"	Gate	Pneumatic	Piston	None	Open	Closed	Closed	Closed	B,G,RM (20)	A	
51	56	Drywell & Ctmt Floor Drain Sump Pumps Disch	Water Floor Drains	6	No	P45F061-B	I	Yes	N/A	Gate	Pneumatic	Piston	None	Open	Closed	Closed	Closed	B,G,RM (20)	B	Out
				6		P45F062-A	O	Yes	6'-6 1/16"	Gate	Pneumatic	Piston	None	Open	Closed	Closed	Closed	B,G,RM (20)	A	
54	56	To & From Refuel Wtr Storage Tank-Upper Ctmt Pool	Pool Water	12	No	G41F053	O	Yes	1'-6 1/4"	Gate	Manual	Manual	None	Locked Closed	Open	Locked Closed	N/A	Manual	N/A	In or Out
				12		G41F201	I	Yes	N/A	Gate	Manual	Manual	None	Locked Closed	Open	Locked Closed	N/A	Manual	N/A	

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TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve: Type	Valve: Operator (2)	Valve Actuation Mode: Primary	Valve Actuation Mode: Secondary	Valve Position: Normal (6)	Valve Position: Shut-down	Valve Position: Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
56	56	Cond Supply to Ctmt	Cond	6	No	P11F075-A	O	Yes	1'-6"	Gate	Pneumatic			Open	Open	Closed	Closed	B,G,RM (20)	A	In
				6		P11F004	I	Yes	N/A	Check	Process	Process	None	Open	Open	Closed	N/A	Reverse Flow	N/A	
				3/4		P11F095	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
57	56	To Upper Ctmt Pool From Fuel Pool Cooling & Cleanup System	Fuel Pool Water	8	No	G41F028-A	O	Yes	2'-3 3/4"	Globe	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,G,RM (20)	A	In
				8		G41F040	I	Yes	N/A	Check	Process	Process	None	Open	Open	Closed	N/A	Reverse Flow	N/A	
				3/4		G41F340	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
58	56	From Upper Ctmt Pool to Fuel Pool Drain Tank	Fuel Pool Water	8	No	G41F029-A	O	Yes	2'-8 3/4"	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,G,RM (20)	A	Out
				8		G41F044-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,G,RM (20)	B	
60	56	From Aux Bldg Flr and Equip Drain Transfer Tanks to Supp Pool	Water	4	No	P45F273-A	O	Yes	6'-4"	Gate	Electric Motor	Electric	Manual	Closed	Closed	Closed or Open	As Is	B,G,RM (20)	A	In
				4		P45F274-B	O	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Closed	Closed or Open	As Is	B,G,RM (20)	B	
				3/4		P45F275	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		P45F290	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
61	56	From Standby Liquid Control Sys Mixing Tank (Future Use)	Borated Water	2	No	C41F151	I	Yes (Note 15)	N/A	Check	Process	Process	None	Locked Closed	Locked Closed	Locked Closed	N/A	N/A	None	
				3		C41F150	O	Yes (Note 15)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	N/A	None	
				3/4		C41F152	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
65	56	Combust Gas Control Ctmt Purge (Outside Air Supply)	Air	6	No	E61F009-A	O	Yes	2'-0 1/2"	Butterfly	Pneumatic	Piston	Manual	Closed	Closed	Closed	Closed	B,G,E, RM	A	
				6		E62F010-B	I	Yes	N/A	Butterfly	Pneumatic	Piston	Manual	Closed	Closed	Closed	Closed	B,G,E, RM	B	
				3/4		E61F017	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
66	56	From Purge Radiation Air Detect Sys to Ctmt Exh Charcoal Fltr Train	Air	6	No	E61F056-B	I	Yes		Butterfly	Pneumatic	Piston	Manual	Closed	Closed	Closed	Closed	B,G,E, RM	B	
				6		E61F057-A	O	Yes	1'-3 1/2"	Butterfly	Pneumatic	Piston	Manual	Closed	Closed	Closed	Closed	B,G,E, RM	A	
				3/4		M41F054	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
67	56	RHR Pump "B" Test Line to Supp Pool	Supp Pool Water	18	Yes	E12F024B-B	O	No (19)	28'-5 3/4"	Gate	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	C,G,X, V,RM (20)	B	
				4		E12F011B-B	O	No (19)	30'-11 1/2"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	C,G,RM (20)	B	
				4		E12F064B-B	O	No (19)	60'-7"	Gate	Electric Motor	Electric	Manual	Open	Closed	Open or Closed	As Is	N/A	B	
				1 1/2		E12F290B-B	O	No (19)	80'-4 3/4"	Globe	Electric Motor	Electric	Manual	Open	Closed	Open or Closed	As Is	N/A	B	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
67	56	RHR Pump "B" Test Line to Supp Pool	Supp Pool Water	3/4		E12F321	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F351	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F276	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F277	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F212	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F213	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F249	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F250	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F334	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1		E12F335	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F331	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F350	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F430B	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F432B	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F434B	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F436B	O	No(19)	N/A	Gate	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
69	56	Refueling Wtr Transfer Pump Suction	Refuel Water	12		P11F130-A	O	Yes	N/A	Butterfly	Pneumatic	Piston	None	Open	Open	Closed	Closed	B,G,RM (20)	A	Out
				12		P11F131-B	O	Yes	12'-1 1/2"	Butterfly	Pneumatic	Piston	None	Open	Open	Closed	Closed	B,G,RM (20)	B	
				3/4		P11F132	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		P11F425	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
70	56	Inst Air Supply to ADS Receivers	Air	1	No	P53F003-A	O	Yes	5'-5"	Globe	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,G,RM (20)	A	In
				3/4		P53F006	I	Yes	N/A	Check	Process	Process	None	Open	Open	Closed	N/A	Reverse Flow	None	
				3/4		P53F043	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
71A	56	LPCS Relief Valve Vent Header to Supp Pool	Non-Cond	1 1/2		E21F018	O	No(19)	53'-2"	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	N/A	In
71B	56	RHR "C" Relief Vlv Vent Header to Supp Pool & Post-Accident Sample Return	Non-Cond	1	No	E12F025C	O	No(19)	10'-8"	Relief	Process	Process	None	Closed	Closed	Open	N/A	None	N/A	In
				1		E12F346-B	O	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	N/A	B	
				1		E12F406	O	Yes	N/A	Check	Process	Process	None	Closed	Closed	Closed	N/A	Reverse Flow	N/A	
				3/4		E12F409	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		E12F408	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
75	56	RCIC Turbine Exh Vacuum Bkr	Steam	1 1/2	No	E51F078-B	O	Yes	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	G,J,RM	B	Out
76B	56	RHR Shtdwn Suction Relief vlv Disch	Non-Cond	1	Yes	E12F005	O	Yes	108'-0"	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	N/A	In
77	56	RHR Heat Exch "A" Relief Vlv Vent Header to Supp Pool	Non-Cond	6	Yes	E12F055A	O	No(19)	65'-8 7/16"	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	N/A	In
				2		E12F073A-A	O	No(19)	73'-1 1/2"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed	As Is	N/A	A	
81	56	Reactor Recirc Post Accident Sampling	Reactor Water	3/4	No	B33F126-B	I	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed or Open	As Is	N/A	B	
				3/4		B33F125-A	O	Yes	N/A	Globe	Electric Motor	Electric	Manual	Closed	Closed	Closed or Open	As Is	N/A	A	
82	56	Integrated Leak Rate Test Connect (Drywell Press and Depress)	Ctmt Atmos	4	No	Blind Flange	O	Yes	N/A										In or Out	
				6		Blind Flange	I	Yes	N/A											
				3/4		M61F010	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Actuation Mode Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
83	56	RWCU Line From Regen. Heat Exch to Fdwtr	Reactor Water	6	No	G33F040-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,F,H, L, RM (20)	B	
				6		G33F039-A	O	Yes	2'-0 3/16"	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,F,H, L, RM (20)	A	
				3/4		G33F055	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		G33F075	I	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
84	56	Chemical Waste Sump Pump Disch	Water	3	No	P45F098-B	I	Yes	N/A	Gate	Pneumatic	Piston	None	Open	Closed	Closed	Closed	B,G,RM (20)	B	Out
				3		P45F099-A	O	Yes	6'-8 1/8"	Gate	Pneumatic	Piston	None	Open	Closed	Closed	Closed	B,G,RM (20)	A	
85	56	Supp Pool Cleanup Return		12	No	P60F009-A	O	Yes	5'-11 9/16"	Gate	Pneumatic	Piston	None	Open	Open	Closed	Closed	B,G,RM (20)	A	In
				12		P60F010-B	O	Yes	N/A	Gate	Pneumatic	Piston	None	Open	Open	Closed	Closed	B,G,RM (20)	B	
				3/4		P60F011	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		P60F034	O	No(19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
86	56	Demin Wtr Supply to Ctmt	Demin Water	2	No	P21F017-A	O	Yes	1'-6"	Globe	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,G,RM (20)	A	In
				2		P21F018-B	I	Yes	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,G,RM (20)	b	
				1/2	No	P21F390	I	Yes	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	
87	56	RWCU Pump Suction	Reactor Water	6	No	G33F001-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Closed	Open	Closed	As Is	B,F,Y, H,L,RM (20)	B	
				6		G33F252-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Closed	Closed	As Is	B,F,Y, H,L,RM (20)	B	Out
				6		G33F004-A	O	Yes	1'-11 27/32"	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,F,Y, H,L,RM (20)	A	
				3/4		G33F002	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				3/4		G33F267	O	No (19)	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
88	56	RWCU Pump Disch	Reactor Water	4	No	G33F053-B	I	Yes	N/A	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,F,H, L,RM (20)	B	In
				4		G33F054-A	O	Yes	2'-0"	Gate	Electric Motor	Electric	Manual	Open	Open	Closed	As Is	B,F,H, L,RM (20)	A	
				3/4		G33F061	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
				1/2	No	G33F263	I	Yes	N/A	Relief	Process	Process	None	Closed	Closed	Closed	N/A	None	None	
				3/4		G33F077	I	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
89	56	Standby Service Wtr Supply "A"	Treated Water	2	No	P41F159A-A	O	No (19)	2'-7 13/16"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	N/A	A	In
				2		P41F169A	I	No (19)	N/A	Check	Process	Process	None	Closed	Closed	Open	N/A	Reverse Flow	N/A	
				3/4		P41F163A	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
90	56	Standby Service Wtr Return "A"	Treated Water	2	No	P41F168A-A	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	Out
				2		P41F160A-A	O	No (19)	1'-7 13/16	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	N/A	A	
91	56	Standby Service Wtr Return "B"	Treated Water	2	No	P41F168B-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	Out
				2		P41F160B-B	O	No (19)	1'-7 3/16"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	N/A	B	
92	56	Standby Service Wtr Supply "B"	Treated Water	2	No	P41F159B-B	O	No (19)	2'-7 13/16"	Globe	Electric Motor	Electric	Manual	Closed	Closed	Open	As Is	N/A	B	In
				2		P41F169B	I	No (19)	N/A	Check	Process	Process	None	Closed	Closed	Open	N/A	Reverse Flow	N/A	
				3/4		P41F163B	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
101C	RG1.11	Drywell Pressure Inst (Narrow Range)	Air	3/4	Yes	M71F593-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	None
101F	RG1.11	Drywell Pressure Inst (Wide Range)	Air	3/4	Yes	M71F591A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	None

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
102D	RG1.11	Drywell Pressure Inst (Wide Range)	Air	3/4	Yes	M71F591B-B	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	None
103D	RG1.11	Containment Press Inst (Wide Range)	Air	3/4	Yes	M71F592A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	None
104D	RG1.11	Containment Press Inst (Wide Range)	Air	3/4	Yes	M71F592B-B	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	None
105A	56	Ctmt Hydrogen Analyzer Sample	Air	3/4	Yes	E61F596C-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	Out
				3/4	Yes	E61F596D-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	
105D	56	Flex Ctmt Vent N2 Supply	Nitrogen	3/4	No	M41F103	O	Yes	1'-10'	Globe	Manual	Manual	Manual	Locked Closed	Locked Closed	Locked Closed (23)	N/A	N/A	N/A	In
				3/4	No	M41F101	I	Yes	N/A	Check	Process	Process	None	Closed	Closed	Closed (23)	N/A	N/A	N/A	
106A	56	Drywell Hydrogen Analyzer Sample	Air	3/4	Yes	E61F595C-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	Out
				3/4	Yes	E61F595D-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	
106B	56	Drywell Hydrogen Analyzer Sample Rtrn	Air	3/4	Yes	E61F597C-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	In
				3/4	Yes	E61F597D-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	
106E	56	Ctmt Hydrogen Analyzer Sample Rtrn	Air	3/4	Yes	E61F598C-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	In
				3/4	Yes	E61F598D-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	
107B	56	Ctmt Hydrogen Analyzer Sample Rtrn	Air	3/4	Yes	E61F598A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	In
				3/4	Yes	E61F598B-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
108A	56	Ctmt Hydrogen Analyzer Sample	Air	3/4	Yes	E61F596A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	Out
				3/4	Yes	E61F596B-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	
107D	56	Drywell Hydrogen Analyzer Sample	Air	3/4	Yes	E61F595A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	Out
				3/4	Yes	E61F595B-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	
107E	56	Drywell Hydrogen Analyzer Sample Rtrn	Air	3/4	Yes	E61F597A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	In
				3/4	Yes	E61F597B-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	
109A	56	Drywell Fission Product Monitor Sample Post Accident Sample	Air	3/4	No	D23F592-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open or Closed	As Is	RM,B,G	A	Out
				3/4	No	D23F591-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open or Closed	As Is	RM,B,G	B	
109B	56	Drywell Fission Product Monitor Sample Rtrn and Post Accident Sample Rtrn	Air	3/4	No	D23F594-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open or Closed	As Is	RM,B,G	A	In
				3/4	No	D23F593-B	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open or Closed	As Is	RM,B,G	B	
109D	56	Ctmt Press Inst (Narrow Range) - Post Accident Sample	Air	3/4	Yes	M71F594-B	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open or Closed	As Is	RM,B,G	A	Out
				3/4	Yes	M71F595-A	I	No (19)	N/A	Globe	Electric Motor	Electric	Manual	Open	Open	Open or Closed	As Is	RM,B,G	B	

TABLE 6.2-44: CONTAINMENT ISOLATION VALVE INFORMATION (CONTINUED)

Ctmt Pene No. (10)	Applicable General Design Criteria or Reg Guide	System Name	Fluid	Line Size (inch)	Engineered Safety Feature System (12)	Sys No. and Iso Vlv No.	Loc Inside/ Outside Ctmt	Type "C" Tests (16)	Length of Pipe from Ctmt to Outermost Iso Valve	Valve Type	Valve Operator (2)	Valve Actuation Mode Primary	Valve Actuation Mode Secondary	Valve Position Normal (6)	Valve Position Shut-down	Valve Position Post Accident	Power Failure (4)	Isol Signal	Power Source IE Bus A or B or C	Normal Direct of Flow
110A	56	Integrated Leak Rate Test Drywell Press Inst	Ctmt Atmos	1	No	M61F015	I	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or Out
				1		M61F014	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
110C	56	Integrated Leak Rate Test Verificatio n Flow Inst	Ctmt Atmos	1	No	M61F019	I	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or Out
				1		M61F018	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
110F	56	Integrated Leak Rate Test Ctmt Press Inst	Ctmt Atmos	1	No	M61F017	I	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	In or Out
				1		M61F016	O	No (19)	N/A	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	
111C	56	Suspended Fl/Eq Drain	Boron Solution	3/4	No	P48F009	I	Yes	5'-0"	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	Out
111C	56	Suspended Fl/Eq Drain	Boron Solution	3/4	No	P48F010	O	Yes	5'-0"	Globe	Manual	Manual	None	Locked Closed	Locked Closed	Locked Closed	N/A	None	None	Out
113	RG1.11	Supp Pool Level Inst	Water	3/4	No	E30F593A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	None
114	RG1.11	Supp Pool Level Inst	Air	3/4	Yes	E30F592A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	None
115	RG1.11	Supp Pool Level Inst	Water	3/4	No	E30F594A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	None
116	RG1.11	Supp Pool Level Inst	Air	3/4	Yes	E30F591A-A	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	A	None
117	RG1.11	Supp Pool Level Inst	Water	3/4	No	E30F593B-B	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	None
118	RG1.11	Supp Pool Level Inst	Air	3/4	Yes	E30F592B-B	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	None
119	RG1.11	Supp Pool Level Inst	Water	3/4	No	E30F594B-B	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	None
120	RG1.11	Supp Pool Level Inst	Air	3/4	Yes	E30F591B-B	O	No (19)	3'-0"	Globe	Electric Motor	Electric	Manual	Open	Open	Open	As Is	N/A	B	None

TABLE 6.2-44: NOTES

General:

a. Refer to Figures 6.2-76 through 6.2-80 for containment isolation valve arrangements. System number and isolation valve number are indicated on these figures.

b. Refer to subsection 6.2.3 for a discussion of through-line leakage classification.

c. The maximum isolation times of automatic containment isolation valves are given in Appendix 16B.

d. The containment isolation valves that have been determined to have analytical closure times are listed below along with the analytical isolation times.

Valve Number	Maximum Isolation Times (Seconds)
B21-F028A, B, C, D	5 (See Note 1 Below)
B21-F022A, B, C, D	5 (See Note 1 Below)
E12-F008-A	40
E12-F009-B	40
E12-F024A-A, B-B	144
M41-F011	4
M41-F012	4
M41-F034	4
M41-F035	4
E51-F063-B	60
E51-F064-A	60
G33-F028-B	35
G33-F034-A	35
G33-F039-A	35
G33-F040-B	35
G33-F001-B	35
G33-F004-A	35
G33-F252-B	35
G33-F053-B	35
G33-F054-A	35

The following notes are keyed by number to correspond to numbers in parentheses, in Table 6.2-44.

TABLE 6.2-44: NOTES (CONTINUED)

1. Main steam isolation valves require that both solenoid pilots be de-energized to close valves. Accumulator air pressure plus spring act together to close valves when both pilots are de-energized. Voltage failure at only one pilot does not cause valve closure. The valves are designed to close fully in 5.5 seconds and a minimum closure time of 3 seconds. This value of 5.5 seconds is composed of a maximum MSIV closure time of 5.0 seconds plus 0.5 second for instrument response for the case of the high steam line flow signal.

2. AC motor-operated valves required for isolation functions are powered from the ac standby power buses. DC-operated isolation valves are powered from the station batteries.

3. Testable check valves are designed for remote opening with zero differential pressure across the valve seat. The valves will close on reverse flow even though the test switches may be positioned for opening. The valves open when pump pressure exceeds reactor pressure even though the test switch may be positioned for closing.

4. All motor-operated isolation valves remain in the last position upon failure of valve power. All air-operated valves close on motive air failure.

5. Containment and drywell vent exhaust high radiation (Signal Z) is generated by two trip systems. This requires two high radiation or inoperative trips on one trip system and two high radiation or inoperative trips on second trip system to initiate isolation.

6. Normal status position of valve (open or closed) is position during normal power operation of the reactor (see Normal valve position column).

7. Valve is counter weighted to ensure positive closing force is applied when RCIC system is not operating.

8. Deleted.

9. The auxiliary building is part of the boundary for the Standby Gas Treatment System (SGTS). To maintain auxiliary building integrity, isolation is provided on all lines larger than 2 inches not performing a safety function or supplying a source of makeup to the RPV. The valves will be seismic Category I and ASME Section III, Class 3. Lines 2 inches and smaller are small enough so that, if failure of the line would occur, the failure will not jeopardize SGTS operation. (Refer to subsection 6.2.3 for details.)

TABLE 6.2-44: NOTES (CONTINUED)

10. Penetrations not listed are "spare" and are capped, except numbers 1, 2 & 3 which are used for equipment hatch and personnel air locks. Penetration numbers 93 through 100 and 112 are not used. (Penetration numbers 201 through 251 are electrical.)

11. Abbreviations noted in table are as follows:

    I- Location inside the containment

    O- Location outside the containment

    N/A- Not applicable Process - Actuated by fluid pressure

    RG- NRC regulatory guides

12. The column for engineered safety feature system includes support systems required for shutdown.

13. Deleted.
14. Deleted.

15. Penetration is for future use, with welded caps on both ends.

16. Refer to Table 6.2-49 for a description of how Type "C" testing is performed.

17. Powered from RPS Buses A and B.

18. See SEP-GGNS-IST-1, GGNS Inservice Testing Bases Document, for Inservice Testing Program maximum stroke time.

19. This valve does not meet the criteria of 10 CFR 50, Appendix J, for designation as a containment isolation valve that is required to be Type C tested although it is classified as a containment isolation valve per General Design Criterion 55, 56, or 57.

20. Operability for primary containment isolation is required during the following conditions:

    a. Modes 1, 2, and 3

    b. Modes 4 and 5 for RHR Shutdown cooling system suction from the reactor vessel isolation valves when associated isolation instrumentation is required to be operable

    c. During movement of recently irradiated fuel assemblies in primary or secondary containment and operations with a potential for draining the reactor vessel.

21. Deleted

TABLE 6.2-44: NOTES (CONTINUED)

22. Isolation valve located inside airlock barrel.

23. Open for post-Beyond Design Basis External Event operation.

TABLE 6.2-44: NOTES (CONTINUED)

ISOLATION SIGNAL LOSS

Signal	Description
A*	Reactor vessel low water level - level 3. (A scram occurs at this level also. This is the highest of the three isolation low water level signals.)
B*	Reactor vessel low water level - level 2. (This is the second of the three low water level signals. (The RCIC and HPCS systems are initiated at this level.
C*	Reactor vessel low water level - level 1. (This is the lowest of the three water level signals, and main steam line isolation occurs at this level. The LPCS and LPCI systems are also initiated at this level.
D*	Deleted
E*	Line break - main steam line (steam line high steam flow)
F*	Line break in main steam tunnel (steam line tunnel high space temperature)
G*	High drywell pressure
H*	Line break in reactor water cleanup system - (high space temperature)
I*	Line break - RCIC/RHR steam line (steam line high steam flow)
J*	Line break in RCIC system steam line to turbine (low steam line pressure)
K*	Line break in RCIC system steam line to turbine (high steam line space temperature)
L*	High differential flow in the reactor water cleanup system
M*	Line break in RHR shutdown and head cooling (high space temperature)
N*	Low main condenser vacuum
O	RCIC pump discharge flow - high
P*	Low main steam line pressure at inlet to turbine (RUN mode only)
T	High pressure RCIC turbine exhaust diaphragm
U	High reactor vessel pressure

TABLE 6.2-44: NOTES (CONTINUED)

V	Containment spray system actuated
W	High temperature at outlet of cleanup system non-regenerative heat exchanger
X	High containment pressure
Y	Standby liquid control system actuated
Z*	High radiation, containment and drywell ventilation exhaust
ZA*	High reactor pressure and high main steam line pressure
RM*	Remote manual switch from control room (All automatic initiated isolation valves are capable of remote manual operation from the control room.)

*These are the isolation functions of the containment, and reactor vessel isolation control system; other functions are given for information only.

TABLE 6.2-45: COMBUSTIBLE GAS CONTROL SYSTEM COMPONENT DESCRIPTION

Drywell Purge Compressors

Quantity	2-100% capacity units
Capacity (minimum), cfm	1000
Drive	Direct
Motor, hp	100
Manufacturer	Turbonetics

Hydrogen Recombiners

Type	Thermal
Quantity	2-100% capacity units
Capacity, scfm - air	100
Process rate, scfm - hydrogen	4 (approx)
Rated Power, kW	75 each
Manufacturer	Westinghouse

Containment Purge Compressor

Type	Liquid ring
Quantity	1
Capacity, scfm	65
Static pressure, psig	10
Drive	Direct
Motor, hp	15
Manufacturer	Nash

Hydrogen Igniter Assemblies

Quantity	90
Operating Temperature (°F)	1700
Operating Voltage (VAC)	120 @ 60 Hz
Manufacturer	Power Systems

TABLE 6.2-46: COMBUSTIBLE GAS CONTROL SYSTEM FAILURE ANALYSIS

Component	Malfunction	Comments
Drywell purge compressors	Failure of compressor resulting in inability to purge the drywell of combustible gases	Should operating compressor fail, subsystem will be manually shutdown. Redundant subsystem will maintain system capabilities.
Valve control power	Failure of valve control power resulting in inability to open dampers	Should valve control power fail, dampers will remain shut: redundant subsystem will maintain system capabilities.
Hydrogen recombiner	Failure of recombiner to operate resulting in loss of hydrogen removal capability	Hydrogen igniters will have the lead hydrogen control function. A redundant recombiner can act as a backup.

TABLE 6.2-47: CONTAINMENT LEAK RATE TEST DATA

Type A Test Definitions

A. Peak Test Pressure — P_a = 12.1 PSIG

The calculated peak containment internal pressure related to the design basis accident.

B. Maximum Allowable Leakage Rate — L_a = 0.385%/Day*

The maximum allowable leakage rate at pressure P_a

C. Measured Leakage Rate — L_{am}

The total measured containment leakage rate at pressure Pa obtained from testing the containment with components and systems in the station as close as practical to that which would exist under design basis accident conditions.

D. Imposed Leakage Rate — L_o

The known leakage rate superimposed on the containment during the verification test. L_o is 75% to 125% of L_a.

E. Composite Test Leakage Rate — L_c

The composite leakage rate measured using the ILRT instruments after L_o is superimposed.

F. Test Duration

1. After the containment atmosphere has stabilized, the integrated leakage rate test period begins. The duration of the test period is sufficient to enable adequate data to be accumulated and statistically analyzed so that leakage rate and upper confidence limit can be accurately determined.

*Based on containment free air volume @ 12.1 psig. Combining this value with the MSIV leakage criteria of 250 scfh (total for four steam lines) yields an overall leakage criteria, based on total volume of containment and drywell, of 0.682%/day.

TABLE 6.2-47: CONTAINMENT LEAK RATE TEST DATA (CONTINUED)

	2. Test duration shall meet one of the following:	
	• A BN-TOP-1 test using a total time analysis shall last a minimum of six (6) hours after stabilization and shall have a total of not less than 20 sets of data points at approximately equal intervals	
	• An ANSI/ANS 56.8-2002 test using mass point analysis shall last a minimum of eight (8) hours after stabilization and shall have a total of not less than 30 sets of data points at approximately equal intervals.	
	3. A Type A test cannot be successfully terminated until the acceptance criteria of the Technical Specifications are met.	
G.	Containment Atmosphere Temperature Limits During Type A Test	40-120 F
H.	Containment Free Air Volume	1,670,000 ft^3 (includes drywell free air volume)
I.	Drywell Free Air Volume	270,000 ft^3

TABLE 6.2-48: PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE INSTRUMENTATION

The following instrumentation was original plant supplied equipment to perform the Type A test:

Item	No. Required	Description
SM61-PIT-N003-1&2	2	Precision pressure transducer Range: 0-30 psia Accuracy: 0.020% of reading in test pressure range Sensitivity: 0.001% of full scale or better Repeatability:0.001% of full scale
SM61-TE-N001-01 thru TE-N001-22	22	Resistance temperature detectors Calibrated Range: 60 to 120 F Accuracy: ± 0.5 F or better Repeatability: ± 0.1 F
SM61-ME-N002-01 thru ME-N002-06	6	Dewpoint temperature detectors Calibrated Range: 40-100 F Calibrated Accuracy: ± 2.0 F or better Repeatability: ± 0.5 F over the range of 40 to 100 F
SM61-FT-N004-1&2*	2**	Mass flow meters Range: 2-20 scfm: Accuracy: ± 2% of full scale Sensitivity: 1% of full scale Repeatability: 0.1 scfm

Note: Vendor supplied equipment that meets 10 CFR 50 Appendix J requirements may be used in lieu of the original plant supplied instrumentation.

Minimum quantities are:

- One (1) precision pressure transducer/indicator
- Ten (10) temperature sensors/thermistors
- Three (3) dewpoint or relative humidity sensors/RH meters
- One (1) flow meter.

* Used for imposed leakage verification test only.

** One meter is an installed spare.

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST

			Inboard Isolation Barrier		**Outboard Isolation Barrier**	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	**Notes**	**Barrier Description/ Valve No. (Note 15)**	**Notes**
1	Equipment hatch	A,B	Double O-ring	1	-	-
2	Personnel lock	A,B	Inner door	2	Outer door	2
		A,B	Double gasket	1	Double gasket	1
		A,C	Relief valve	-	-	-
		A,C	Equalizing valve	-	Equalizing Valve	
		B	-	-	EPDM Gasket	20
		C	M23FX015 & M23FX017	-	M23FX016 & M23FX018	-
3	Personnel lock	A,B	Inner door	2	Outer door	2
		A,B	Double gasket	1	Double gasket	1
		A,C	Relief valve	-	-	-
		A,C	Equalizing valve	-	Equalizing Valve	
		B	-	-	EPDM Gasket	20
		C	M23FX011 & M23FX013	-	M23FX012 & M23FX014	-
4	Fuel transfer tube	A,C	Double O-ring	1	-	-
		A,B	Bellows	5	-	-
5	Main steam line A	A,C	B21F022A	3,4	B21F028A	4
					B21F067A-A	-
					E32F001A-A	-
					B21F025A	10
6	Main steam line B	A,C	B21F022B	3,4	B21F028B	4
					B21F067B-A	-
					E32F001E-A	-
					B21F025B	10
7	Main steam line C	A,C	B21F022C	3,4	B21F028C	4

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Inboard Notes	Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Outboard Notes
					B21F067C-A	-
					E32F001J-A	-
					B21F025C	10
8	Main steam line D	A,C	B21F022D	3,4	B21F028D	4
					B21F067D-A	-
					E32F001N-A	-
					B21F025D	10
9	Feedwater	A,C	B21F010A	10	B21F032A	25
					B21F063A	-
					B21F065A-A	27
					B21F030A	10
10	Feedwater B	C	B21F010B	10	B21F032B	25
					B21F065B-A	27
					B21F063B	10
					B21F030B	10
11	RHR pump A suction	A	E12F004A-A	6,10,11, 23	Closed system	7
			E12F017A	6,10,11, 23	Closed system	7
12	RHR pump B suction	A	E12F004B-B	6,10,11, 23	Closed system	7
			E12F017B	6,10,11, 23	Closed system	7
13	RHR pump C suction	A	E12F004C-B	6,10,11, 23	Closed system	7

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Notes	**Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)**	**Notes**
			E12F017C	6,10,11, 23	Closed system	7
			E12F439C	10	E12F440C	10
			E12F441C	10	E12F442C	10
14	RHR shutdown cooling suction	C	E12F009-B	25,29	E12F008-A	29
			E12F308	25,29	E12F002	10
					E12F445	10
					E12F446	10
15	Spare	A	Welded Cap	-	-	-
16	Spare	A	Welded Cap	-	-	-
17	Steam supply to RCIC turbine @ RHR heat exchanger	A,C	E51F063-B	-	E51F064-A	-
		A,C	E51F076-B	3	E51F072	10
18	RHR B to containment	A	Blind Fitting	-	-	-
19	Main steam line drain	A,C	B21F016-B	-	B21F019-A	-
20	RHR A to LPCI	C	E12F042A-A	29	E12F027A-A	29
			E12F025A	8,29		
			E12F044A	29		
			E12F037A-A	3,29		
			E12F028A-A	29,30		
			E12F107A	10		
21	RHR B to LPCI	C	E12F042B-B	29	E12F027B-B	29
			E12F025B	8,29		
			E12F044B	29		

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Notes	Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Notes
			E12F037B-B	3,29		
			E12F028B-B	29,30		
			E12F107B	10		
22	RHR C to LPCI	C	E12F041C-B	29	E12F042C-B	29
					E12F056C	10
					E12F234	10
23	RHR A pump test line to suppression pool	A	E12F011A-A	3,6,10, 22	Closed system	7
			E12F064A-A	6,10,22	Closed system	7
			E12F024A-A	6,10,22	Closed system	7
			E12F290A-A	3,6,10, 22	Closed system	7
			E12F322	10	E12F348	10
			E12F261	10	E12F262	10
			E12F259	10	E12F260	10
			E12F228	10	E12F227	10
			E12F336	10	E12F349	10
			E12F338	10	E12F339	10
24	RHR C pump test line to suppression pool	A	E12F064C-B	6,10,22	Closed system	7
			E12F021-B	6,10,22	Closed system	7
			E12F280	10	E12F281	10
			Double O-rings	19	E12F304	10
			Double O-rings	19	E12F311	10
25	HPCS pump suction	A	E22F015-C	6,10,11, 23	Closed system	7

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Outboard Isolation Barrier: Notes
			E22F014	6,10,11, 23	Closed system	7
			E22F800	10	E22F801	10
26	HPCS pump discharge to RPV	C	E22F005	29	E22F004-C	29
			E22F218	10	E22F021	10
			E22F201	10		
27	HPCS test line to suppression pool	A	E22F023-C	6,10,11, 22	Closed system	7
			E22F035	6,10,11, 22	Closed system	7
			E22F012-C	6,10,11, 22	Closed system	7
			E22F302	10	E22F301	10
		A	Double O-rings	19	E22F303	10
		A	Double O-rings	19	E22F304	10
28	RCIC pump suction	A	E51F031-A	6,10,11, 23	Closed system	7
			E51F269	10	E51F270	10
			E51F272	10	E51F273	10
29	RCIC Turbine Exhaust	A,C	E51F068-A	11,30	E51F040	11
				-	E51F212 and E51F258	10
			E51F077-A	11,30	Closed System and E51F257	10
30	LPCS pump suction	A	E21F001-A	6,10,11, 23	Closed system	7
			E21F031	6,10,11, 23	Closed system	7

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
31	LPCS pump discharge to RPV	C	E21F006	29	E21F005-A	29
			E21F200	10	E21F013	10
			E21F207	10		
32	LPCS test line to sup	A	E21F012-A	6,10,22	Closed system	7
			E21F011-A	6,10,22	Closed system	7
			E21F217	10	E21F218	10
			Double O-rings	19	E21F222	10
			Double O-rings	19	E21F221	10
33	CRD pump discharge	A,C	C11F122	-	C11F083-A	-
					C11F128	10
34	Containment purge supply	A,C	M41F012-B	12	M41F011-A	-
					M41F042	10
35	Containment purge exhaust	A,C	M41F034-B	12	M41F035-A	-
					M41F051	10
36	Drywell chilled water return	C	P72F123-B	-	P72F122-A	-
37	Drywell chilled water supply	C	P72F165	-	P72F121-A	-
					P72F167	10
38	Plant Chilled water supply	C	P71F151	17	P71F150-A	17
					P71F232	10
					P71FX359	10
39	Plant Chilled water return	C	P71F149-B	17	P71F148-A	17
					P71F246	10
					P71FX358	10
40	ILRT - Containment pressurization/depressurization	C	Flexitallic gasket	20	Flexitallic gasket	20
		C	M61F009	10		

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Notes	Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Notes
41	Service air	A,C	P52F122	-	P52F105-A -	10
					P52F258	
42	Instrument Air	A,C	P53F002	-	P53F001-A -	
					P53F036	10
					P53FX003	10
43	RWCU to main condenser	A,C	G33F028-B	-	G33F034-A -	
					G33F070	10
					G33F264	
44	Component cooling water supply	A,C	P42F035	-	P42F066-A -	
					P42F161	10
45	Component cooling water return	A,C	P42F068-B	-	P42F067-A -	
			P42F162	10	-	
46	RCIC pump minimum flow line	A	E51F019-A	6,10,22	Closed system	7
			E51F251	10	E51F252	10
47	Reactor recirc. post-accident sampling	A,C	B33F128-B		B33F127-A	
48	RHR heat exchanger B relief valve discharge to suppression pool	A,C	E12F073B-B	3,6,10, 11,22	Closed system	7
			E12F055B	6,10,11, 22	Closed system	7
49	RWCU backwash transfer pump discharge	A,C	G36F106-B	-	G36F101-A -	

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
50	Drywell and containment equipment drain sump pump discharge	A,C	P45F067-B	-	P45F068-A -	
51	Drywell and containment floor drain sump pump discharge	A,C	P45F061-B	-	P45F062-A -	
52	Spare	A	Welded Cap	-	-	-
53	Spare	A	Welded Cap	-	-	-
54	Upper containment pool to and from refueling storage tank	A,C	G41F201	-	G41F053	31
55	Spare	A	Welded Cap	-	-	-
56	Condensate makeup to upper containment pool	C	P11F004	-	P11F075-A	-
					P11F095	10
57	Fuel pool cooling and cleanup system discharge to upper containment pool	C	G41F040	-	G41F028-A	-
			G41F340	10		
58	Fuel pool cooling and cleanup system return from upper containment pool to fuel pool drain tank	A,C	G41F044-B	-	G41F029-A	-
59	Spare	A	Welded Cap	-	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
60	Return from auxiliary building floor and equipment drain transfer tanks	A,C	P45F274-B	-	P45F273-A	-
			P45F275	10	P45F290	10
61	Standby liquid control system mixing tank (future use)	A,C	C41F151	18	C41F150	18
					C41F152	10
62	Spare	A	Welded Cap	-	-	-
63	Spare	A	Welded Cap	-	-	-
64	Spare	A	Welded Cap	-	-	-
65	Containment normal ventilation and combustible gas control purge supply	A,C	E61F010-B	12	E61F009-A	-
					E61F017	10
66	Containment normal ventilation and combustible gas control purge exhaust	A,C	E61F056-B	12	E61F057-A	-
					M41F054	10
67	RHR B pump test line to suppression pool	A	E12F011B-B	6,10,22	Closed system	7
			E12F064B-B	6,10,22	Closed system	7
			E12F024B-B	6,10,22	Closed system	7
			E12F290B-B	6,10,22	Closed system	7
			E12F321	10	E12F351	10
			E12F249	10	E12F250	10
			E12F334	10	E12F335	10
			E12F334	10	E12F350	10

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Notes	Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Notes
			E12F276	10	E12F277	10
			E12F430B	10		
			E12F432B	10		
			E12F212	10	E12F213	10
			E12F432B	10		
			E12F436B	10		
			E12F434B	10		
		A	Double O-rings	19		
		A	Double O-rings	19		
68	Spare	A	Welded Cap	-	-	-
69	Refueling water transfer pump suction from suppression pool	C	P11F130-A	11	P11F131-B	11
			P11F132	10	P11F425	10
70	Instrument air for ADS	C,A	P53F006	-	**P53F003-A**	-
					P53X004	10
					P53F043	10
71A	LPCS relief valve discharge to suppression pool (2")	A	E21F018	6,10,11, 22	Closed system	7
71B	RHR C relief valve discharge to suppression pool (1") and post-accident sample return	A,C	E12F025C	6,10,11, 22	Closed system	7
			E12F406	6,11	E12F346-B	3,6,11
			E12F409	10	E12F408	10
72	Spare	A	Welded Cap	-	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Inboard Notes	Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Outboard Notes
74	Spare	A	Welded Cap	-	-	-
75	RCIC pump turbine exhaust vacuum breaker	C,A	E51F078-B	3	Closed system	7
76A	Spare	A	Welded Cap	-	-	-
76B	RHR shutdown suction relief valve discharge relief valve discharge	A,C	E12F005	8,22,29	Closed system	7
77	RHR heat exchanger A relief valve discharge to suppression pool	A,C	E12F073A-A	3,6,10,11,22	Closed system	7
			E12F055A	6,10,11,22	Closed system	7
78	Spare	A	Welded Cap	-	-	-
79	Spare	A	Welded Cap	-	-	-
80	Spare	A	Welded Cap	-	-	-
81	Reactor recirc. post-accident sampling	A,C	B33F126-B	-	B33F125-A	-
82	ILRT - drywell pressurization/ depressurization	C	Flexitallic gasket	20	Flexitallic gasket	20
		C	M61F010	10		
83	RWCU return to feedwater	A,C	G33F040-B	-	G33F039-A	-
			G33F075	10	G33F055	10

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TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Inboard Notes	Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Outboard Notes
84	Drywell and containment chemical waste sump pumps discharge	A,C	P45F098-B	-	P45F099-A	-
85	Suppression pool cleanup return	A,C	P60F010-B	30	P60F009-A	-
					P60F011	10
					P60F034	10
86	Demineralized water supply to containment	A,C	P21F018-B	-	P21F017-A	-
			P21F390			
87	RWCU pump suction from recirculation loops	A,C	G33F001-B	-	G33F004-A	-
			G33F252-B	-	G33F002	10
					G33F267	
88	RWCU pump discharge to RWCU heat exchanger	A,C	G33F053-B	-	G33F054-A	-
			G33F263		G33F061	10
			G33F077	10		
89	Standby service water supply A	C	P41F169A	6,10	P41F159A-A	6,10
					P41F163A	6,10
90	Standby service water return A	C	P41F168A-A	6,10	P41F160A-A	6,10
91	Standby service water return B	C	P41F168B-B	6,10	P41F160B-B	6,10
92	Standby service water return B	C	P41F169B	6,10	P41F159B-B	6,10
					P41F163B	6,10
93 thru 100	Not used					
101A,B	Spare	A	Welded Cap	-	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
101C	Drywell pressure instr.(narrow range)	A	M71F593-A	10,13	-	-
101D,E	Spare	A	Welded Cap	-	-	-
101F	Drywell pressure instr.(wide range)	A	M71F591A-A	10,13	-	-
102A,B,C	Spare	A	Welded Cap	-	-	-
102D	Drywell pressure instr.(wide range)	A	M71F591B-B	10,13	-	-
102E,F	Spare	A	Welded Cap	-	-	-
103A,B,C	Spare	A	Welded Cap	-	-	-
103D	Containment pressure instr. (wide range)	A	M71F592A-A	10,13	-	-
103E,F	Spare	A	Welded Cap	-	-	-
104A,B,C	Spare	A	Welded Cap	-	-	-
104D	Containment pressure instr. (wide range)	A	M71F592B-B	10,13	-	-
104E,F	Spare	A	Welded Cap	-	-	-
105A	Containment H^2 analyzer sample	A	E61F596D	10	E61F596C	10
105D	FLEX Ctmt Vent N_2 Supply	A	M41F101	-	M41F103	-
105B,C,E,F	Spare	A	Welded Cap	-	-	-
106A	Drywell H^2 analyzer sample	A	E61F595D-B	10	E61F595C-A	10
106B	Drywell H^2 analyzer sample return	A	E61F597D-B	10	E61F597C-A	10
106C	Spare	A	Welded Cap	-	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
106D	Spare	A	Welded Cap	-	-	-
106E	Containment H^2 analyzer sample return	A	E61F598D-B	10	E61F598C-A	10
106F	Spare	A	Welded Cap	-	-	-
107A	Spare	A	Welded Cap	-	-	-
107B	Containment H^2 analyzer sample return	A	E61F598B-B	10	E61F598A-A	10
107C	Spare	A	Welded Cap	-	-	-
107D	Drywell H^2 analyzer sample	A	E61F595B-B	10	E61F595A-A	10
107E	Drywell H^2 analyzer sample return	A	E61F597B-B	10	E61F597A-A	10
107F	Spare	A	Welded Cap	-	-	-
108A	Containment H^2 analyzer sample	A	E61F596B-B	10	E61F596A-A	10
108B thru F	Spare	A	Welded Cap	-	-	-
109A	Drywell fission product monitor sample	A,C	D23F591-B	-	D23F592-A	-
109B	Drywell fission product monitor sample return	A,C	D23F593-B	-	D23F594-A	-
109C	Spare	A	Welded Cap	-	-	-
109D	Containment pressure instr. (narrow range)	A,C	M71F595-A	-	M71F594-B	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
109E,F	Spare	A	Welded Cap	-	-	-
110A	ILRT drywell pressure instr.	-	M61F015	10	M61F014	10
110B	Spare	A	Welded Cap	-	-	-
110C	ILRT verification flow instr.	A	M61F019	10	M61F018	10
110D,E	Spare	A	Welded Cap	-	-	-
110F	ILRT containment pressure instr.		M61F017	10	M61F016	10
111A&B	Spare	A	Welded Cap			
111C	Suspended Floor and Equipment Drain	C	P48F009		P48F010	
111D thru F	Spare	A	Welded Cap			
112	Not used					
113	Suppression pool level instr.	A	E30F593A-A	6,10,13	-	-
114	Suppression pool level instr.	A	E30F592A-A	10,13	-	-
115	Suppression pool level instr.	A	E30F594A-A	6,10,13	-	-
116	Suppression pool level instr.	A	E30F591A-A	10,13	-	-
117	Suppression pool level instr.	A	E30F593B-B	6,10,13	-	-
118	Suppression pool level instr.	A	E30F592B-B	10,13	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
119	Suppression pool level instr.	A	E30F594B-B	6,10,13	-	-
120	Suppression pool level instr.	A	E30F591B-B	10,13	-	-
201	Reactor protection system - Div. 1	A,B	Double O-rings	14	-	-
202	Low voltage power - Div. 1	A,B	Double O-rings	14	-	-
203	Instrumentation - ESF Div. 1	A,B	Double O-rings	14	-	-
204	Instrumentation - Div. 1	A,B	Double O-rings	14	-	-
205	Neutron monitoring	A,B	Double O-rings	14	-	-
206	Low voltage power & control Div. 1	A,B	Double O-rings	14	-	-
207	Power & control - BOP/D	A,B	Double O-rings	14	-	-
208	Instrumentation - Div 1	A,B	Double O-rings	14	-	-
209	Low voltage power - BOP/D	A,B	Double O-rings	14	-	-
210	Radiation monitoring (BOP/D instr.)	A,B	Double O-rings	14	-	-
211	Control - Div. 1	A,B	Double O-rings	14	-	-
212	Instrumentation - BOP/D	A,B	Double O-rings	14	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
213	Rod position indication Div. 1	A,B	Double O-rings	14	-	-
214	T.I.P. - BOP/D	A,B	Double O-rings	14	-	-
215	6.9 kV power - Reactor recirc. pump A	A,B	Double O-rings	14	-	-
216	Misc. Test Sys. & Comm. - BOP/D	A,B	Double O-rings	14	-	-
217	Low voltage power and control - Div. 1	A,B	Double O-rings	14	-	-
218	Neutron monitoring - Div. 3	A,B	Double O-rings	14	-	-
219	Instrumentation - BOP/D	A,B	Double O-rings	14	-	-
220	Instrumentation - Div. 3 (computer)	A,B	Double O-rings	14	-	-
221	Control - BOP/D	A,B	Double O-rings	14	-	-
222	Reactor protection system - Div. 3	A,B	Double O-rings	14	-	-
223	Low voltage power and A,B control - BOP/D	A,B	Double O-rings	14	-	-
224	Instrumentation	A,B	Double O-rings	14	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
225	Low voltage power - BOP/E	A,B	Double O-rings	14	-	-
226	Control - BOP/E	A,B	Double O-rings	14	-	-
227	Instr. - BOP/E (vessel vibration monitoring)	A,B	Double O-rings	14	-	-
228	Instrumentation - BOP/E (TIC from RPIS)	A,B	Double O-rings	14	-	-
229	Low voltage power and control - Div. 2	A,B	Double O-rings	14	-	-
230	Reactor protection sys tem - Div. 2	A,B	Double O-rings	14	-	-
231	Instrumentation - Div. 2	A,B	Double O-rings	14	-	-
232	Instrumentation - Div. 2	A,B	Double O-rings	14	-	-
233	Rod position indication	A,B	Double O-rings	14	-	-
234	CRD Hydraulic System - BOP/E	A,B	Double O-rings	14	-	-
235	Instrumentation - Div 4	A,B	Double O-rings	14	-	-
236	Spare		Double O-rings	14	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

Penetration No.	Description	Type Test	Inboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Inboard Isolation Barrier: Notes	Outboard Isolation Barrier: Barrier Description/ Valve No. (Note 15)	Outboard Isolation Barrier: Notes
237	Instrumentation - BOP/E (computer)	A,B	Double O-rings	14	-	-
238	Reactor protection system - Div. 4	A,B	Double O-rings	14	-	-
239	Control - Div. 2	A,B	Double O-rings	14	-	-
240	Instrumentation - BOP/E	A,B	Double O-rings	14	-	-
241	Low voltage power & control Div. 2	A,B	Double O-rings	14	-	-
242	Low voltage power - BOP/E	A,B	Double O-rings	14	-	-
243	Instrumentation - Div. 4	A,B	Double O-rings	14	-	-
244	Low voltage power - Div. 2	A,B	Double O-rings	14	-	-
245	Low voltage power & control - BOP/E	A,B	Double O-rings	14	-	-
246	Radiation monitoring (BOP/E instr.)/FLEX Ctmt Vent N_2 Supply Control Cables	A,B	Double O-rings	14	-	-
247	6.9 kV power - reactor recirc. pump B	A,B	Double O-rings	14	-	-
248	Spare	A,B	Double O-rings	14	-	-
249	Control - BOP/E	A,B	Double O-rings	14	-	-

TABLE 6.2-49: PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST (CONTINUED)

			Inboard Isolation Barrier		Outboard Isolation Barrier	
Penetration No.	Description	Type Test	Barrier Description/ Valve No. (Note 15)	Notes	Barrier Description/ Valve No. (Note 15)	Notes
250	Grounding rod	A	Double O-rings	-	-	-
251	Grounding rod	A	Double O-rings	-	-	-
See Note 28	Guard pipe inspection ports	A	Weld	1	-	-

TABLE 6.2-49: NOTES (CONTINUED)

1. Penetration is sealed by a blind flange or door with double O-ring seals, double expandable seals, double gasket seals or a weld. These seals are leakage rate tested by pressurizing between the seals or gaskets. Because the guard pipe inspection ports inboard seal is a weld, Type B testing is not required.

2. The personnel air lock volume is pressurized to primary containment peak accident pressure and tested periodically as given in the Technical Specifications. During the air lock test, tie downs are installed on the inner door since normal locking mechanisms are not designed to withstand a differential pressure across the door in the reverse direction in excess of 5 psig. Pressurizing the lock barrel also tests the lock mechanical and electrical penetrations.

3. Globe valve may be tested in the reverse direction. The difference in seating/unseating force due to reversing the direction of test is insignificant compared to the force applied on the stem to seat the disc as the valve is closed in the normal manner. In addition, for most valves, including MSIVs, reverse testing is a conservative test since the test pressure tends to unseat the disc.

4. MSIV seat leakage rate shall not exceed Technical Specification leakage limits.

5. Double-walled bellows assembly is tested by pressurizing between the double walls.

6. System remains water filled and designed to operate post LOCA.

7. The redundant containment isolation provisions for this penetration consist of an isolation valve and a closed system outside containment which is in compliance with 10 CFR 50, Appendix A, GDC 54 and with U.S. NRC Standard Review Plan 6.2.4, Containment Isolation Provisions, Paragraph II.6.e. SRP 6.2.4, Paragraph II.6.e allows the use of a single isolation valve outside containment. A single active failure can be accommodated. The closed system is missile protected, seismic Category 1, Safety Class 2, and has a temperature and pressure rating in excess of that for the containment. As stated in SRP 6.2.4, paragraph II.6.e, the closed system outside containment should be leak tested, unless it can be shown that the system integrity is being maintained during normal plant operations.

8. Relief valve tested in reverse direction; overpressure device for a closed system. Conservative test; test pressure tends to unseat disc. Tested in correct direction during Type A test.

TABLE 6.2-49: NOTES (CONTINUED)

9. Globe valve may be tested in the reverse direction. The difference in unseating force due to reversing the direction of test is insignificant compared to the force applied on the stem to seat the disc as the valve is closed in the normal manner.

10. This valve does not meet the criteria of 10 CFR 50, Appendix J, for designation as a containment isolation valve that is required to be Type C tested. It is not Type C tested.

11. System is sealed from the primary containment atmosphere because its line terminates below the water level of the suppression pool, and the isolation valve is tested with water when applicable. Leakage is not included in 0.60 La Type B and C test totals.

12. Butterfly valve tested in reverse direction. This is the conservative direction, based on tests performed on a specimen valve.

13. This instrument line is designed to remain functional in the Post-Accident environment. It consists of a closed instrument and line outside containment which is missile protected, Seismic Category 1, Safety Class 2 and has temperature and pressure rating in excess of that for the containment. The containment isolation provisions are in accordance with NRC Regulatory Guide 1.11 and consist of a single isolation valve outside containment, which is capable of remote operation by the operator in the control room, and a flow restricting orifice. The instrument line is left open to containment pressure during Type A tests.

14. Modular type electrical penetration with header plate bolted to penetration nozzle. Double O-ring seals with test connection are provided at interface. Test volume continuously pressurized with dry N_2 at a pressure $>P_a$. Instrumented to provide monitoring of nitrogen supply pressure.

15. Figures 6.2-76 through 6.2-80 show the containment isolation valves and the associated system/valve number in this table.

16. Deleted

17. System is not designed to operate post-LOCA but is required to operate to maintain the plant in a safe condition during the Type A test.

18. Associated line is for future use.

TABLE 6.2-49: NOTES (CONTINUED)

19. O-ring seals are associated with restriction orifices and are not required to be Type tested because the penetration is water sealed.

20. Penetration is sealed by a test connection flange with EPDM gasket.

21. Deleted

22. These lines are always filled with water on the outboard side of the containment, thereby forming a water seal. They are maintained at a pressure that is always higher than primary containment pressure by jockey pumps or hydrostatic head; thus precluding any outleakage from primary containment. However, even if outleakage did occur, it would be into an ESF system which forms a closed loop outside primary containment. Thus, any leakage from primary containment would return to primary containment through this closed loop.

23. The ECCS and RCIC suction lines are normally filled with water on both the inboard and outboard side of containment, thereby forming a water seal to the containment environment. The valves are open during post-LOCA conditions to supply a water source for the ECCS pumps. Since a break in an ECCS line need not be considered in conjunction with a DBA, the only possible situation requiring one of these valves to be closed during a DBA is an unacceptable leakage in an ECC system. However, because these ECC systems are constantly monitored for excessive leakage, this is not a credible event.

24. Hydrostatically tested during system functional tests.

25. During Type A test, this penetration is operational to provide shutdown cooling via the RHR system.

26. Deleted

27. Refer to Subsection 6.2.4.3.1.1.1 for a description of these penetration lineups. This valve is outboard of valve F032 and is Type C tested with water at a P_a of 12.1 psig. P_a is the containment pressure with the feedwater piping filled with water.

28. Guard pipes for high energy lines through penetrations 5-10, 14, 17-19, and 07. Two in-service inspection ports in each guard pipe are each sealed by a weld between the inner cover and the guard pipe. These inspection ports have the capability of being tested by pressurizing the space between the gaskets and the weld.

TABLE 6.2-49: NOTES (CONTINUED)

29. Valve and penetration were previously tested with water. As stated in MP&L letter AECM-83/0540, dated September 12, 1983, this penetration does not meet the requirements of a strict application of the NRC single active failure criterion for water filled systems. Future testing will be with air at Pa, 12.1 psig, and the leakage will be added to the 0.60La Type Band C test totals.

30. This valve is a flexible-wedge gate valve with a test connection between the wedge discs. Credit can be taken for the inboard disc performing an inboard isolation function for the test connection valve. This inboard disc may be tested in the reverse direction. An analysis has demonstrated that pressure applied in the accident direction does not deflect the disc off the seat face due to the available stem thrust preload. Due to this wedging effect, the application of low pressure in either direction will not cause deflection from the seats. As a result, any leakage measured during testing in the reverse direction can be attributed to other variables such as seat face imperfections, incorrect torque switch settings, etc. Therefore, testing at low pressure in the reverse direction is considered an equivalent test method.

31. The G41F201 valve operator is a motor actuator which is not normally powered and is to be energized via local battery to support Beyond-Design-Basis External Event FLEX mitigation strategies only or for testing when primary containment integrity is not required.

TABLE 6.2-50: SUPPRESSION POOL GEOMETRY GRAND GULF NUCLEAR STATION

Weir wall height	24'-3-3/4"
Pool depth, HWL (max.) Pool	18'-9-3/4"
depth, LWL (min.) Minimum	18'-4-1/12"
freeboard	5'-6"
Drawdown height	3'-9.42"
Top vent CL submergence, HWL	7'-5-3/4"
Top vent coverage, LWL	5'-10-1/12
Minimum post drawdown vent coverage	2'-0"
Height of bottom vent lower edge	1'-10"
Vertical vent spacing	4'-2"
Height of top vent CL	11'-4"
Minimum post drawdown pool depth	14'-6"
Freeboard after inadvertent dump	4.31"
Pool volume, LWL, ft^3	135,291
Added make-up volume (min), ft^3	36,163
Total long-term volume, ft^3	171,454
Max bulk suppression pool temp	95 F
Max make-up pool temp	125 F
Equivalent initial long-term heat sink temp	101 F
Drawdown volume, ft^3	
Weir wall	49,261
Containment spray	1,500
RPV + steam lines	12,540
Total	63,301

Note: In response to NRC Bulletin 96-03, ER 97/0089-00-00 installed a new ECCS/RCIC suction strainer, which rests on the floor of the suppression pool, to replace one of the conical basket strainers on each of the ECCS and RCIC system suction strainers. The ECCS/RCIC suction strainer displaces ~500 ft' of suppression pool water. Analysis has shown that the displacement of the water does not invalidate the short-term or long-term containment LOCA response analyses.

TABLE 6.2-51: [HISTORICAL INFORMATION] LOCATION OF HYDROGEN SAMPLE POINTS

BUILDING	ELEVATION	AZIMUTH
Drywell	130'-0"	307°
Drywell	180'-0"	140°
Containment	143'-0"	52°
Containment	218'-9"	276°

TABLE 6.2-52: CORROSION RATES OF ALUMINUM AND ZINC

Corrodible Surface	Temperature (F)	Corrosion Rate (lb mole/ft^{2}hr)
Aluminum	60-350	2.68×10^{-7}
Zinc (galvanized and	68	1.36×10^{-7}
zinc-based paint)	104	2.40×10^{-7}
	≥149	4.48×10^{-7}

TABLE 6.2-53: SURFACE AREA OF CORRODIBLES

Source	Source Surface Area In Containment (ft^2)	Volume of Corrodible Material (See Notes)	Source Surface Area in Drywell (ft^2)	Volume of Corrodible Material (See Notes)
Galvanized steel	6,104.0	a	6,104.0	a
	18,874.0	a	1,642.0	a
	9,743.0	c	612.0	a
	11,260.0	c	6,558.0	c
	11,792.0	c	16,490.0	c
	98,300.0	b	11,625.0	c
	5,032.0	a	--	--
	13,100.0	a, d	--	--
Total	174,205.0 ft^2	25.76 ft^3	43,031.0 ft^2	6.17 ft^3
Zinc-based paint				
Dome	24,153.0	a		
Containment liner (excluding suppression pool)	46,520.0	a	10,750.0-Drywell liner	a
Struct. Steel				
Elev. 208'	10,400.0	a	21,000.0-Total	a
184'	5,000.0	a		

TABLE 6.2-53: SURFACE AREA OF CORRODIBLES (CONTINUED)

Source	Source Surface Area In Containment (ft^2)	Volume of Corrodible Material (See Notes)	Source Surface Area in Drywell (ft^2)	Volume of Corrodible Material (See Notes)
161'	10,250.0	a		
142'	14,500.0	a		
117'	17,600.0	a		
Misc. steel, supports, hangers, equipment, piping	52,686.0	a	22,608.0	a
Total	181,109.0 ft^2	60.37 ft^3	54,358 ft^2	18.12 ft^3
Aluminum	50,854.0 ft^2		58,742	
Organic paint				
Unqualified	7,564.0 ft^2			
Qualified	11,500.0 ft^2		133	
Total	17,724.0 ft^2	5.908 ft^3, a		

TABLE 6.2-53: SURFACE AREA OF CORRODIBLES (CONTINUED)

Source	Source Surface Area In Containment (ft^2)	Volume of Corrodible Material (See Notes)	Source Surface Area in Drywell (ft^2)	Volume of Corrodible Material (See Notes)

Notes: Corrodible material thicknesses as follows:

a. 2-5 mils; average 4 mils used in calculation

b. 0.625 oz/ft^2 = 0.731 mils   1.0 mil, conservative value used

c. 1.0 oz/ft^2 = 1.17 mils

d. 31,000 oz total; average 4-mil thickness calculated.

TABLE 6.2-54: [HISTORICAL INFORMATION] HYDROGEN IGNITER LOCATIONS

Floor Elevation	Igniter No.	Azimuth	Dimension to Elevation	Centerline of Reactor
114'-6"	E61D106	0	146'-3"	26'-6"
114'-6"	E61D107	63	145'-7"	29'-3"
114'-6"	E61D108	120	146'-2	29'-8"
114'-6"	E61D109	180	147'-1"	26'-3"
114'-6"	E61D110	240	145'-7"	29'-2"
114'-6"	E61D111	313	145'-7"	25'-1¼"
114'-7"	E61D112	0	160'-6"	27'-4"
114'-7"	E61D113	60	160'-6"	29'-9"
114'-7"	E61D114	135	160'-6"	27'-1"
114'-7"	E61D115	180	160'-6"	26'-10"
114'-7"	E61D116	232	160'-6"	26'-1"
114'-7"	E61D117	324	160'-6"	26'-5"
161'-10"	E61D118	0	179'-0"	26'-4"
161'-10"	E61D119	65	179'-0"	26'-4"
161'-10"	E61D120	125	179'-0"	26'-4"
161'-10"	E61D121	180	179'-0"	26'-4"
161'-10"	E61D122	245	179'-0"	26'-4"
161'-10"	E61D123	305	179'-0"	26'-4"
120'-10"	E61D124	21	136'-0"	26'-4"
120'-10"	E61D125	47	132'-10"	26'-4"
120'-10"	E61D126	75	51'-9"	57'-0"
120'-10"	E61D127	107	132'-10"	53'-0"
120'-10"	E61D128	135	51'-9"	51'-9"
120'-10"	E61D129	165	132'-10"	51'-9"
120'-10"	E61D130	195	132'-10"	51'-9"
120'-10"	E61D131	220	145'-7"	60'-0"
120'-10"	E61D132	253	134'-4"	51'-9"
120'-10"	E61D133	285	134'-4"	51'-9"
120'-10"	E61D134	317	134'-4"	52'-8"

TABLE 6.2-54: [HISTORICAL INFORMATION] HYDROGEN IGNITER LOCATIONS (CONTINUED)

Floor Elevation	Igniter No.	Azimuth	Dimension to Elevation	Centerline of Reactor
120'-10"	E61D135	349	136'-0"	51'-9"
135'-4"	E61D136	16	166'-0"	51'-9"
135'-4"	E61D137	36	160'-4"	53'-6"
135'-4"	E61D138	70	157'-10"	51'-9"
135'-4"	E61D139	100	157'-10"	51'-9"
135'-4"	E61D140	135	160'-4"	51'-2"
135'-4"	E61D141	164	155'-10"	51'-9"
135'-4"	E61D142	196	155'-10"	51'-9"
135'-4"	E61D143	226	155'-10"	61'-4"
135'-4"	E61D143	260	160'-4"	54'-2"
135'-4"	E61D145	285	159'-4"	51'-5"
135'-4"	E61D146	321	159'-4"	51'-5"
135'-4"	E61D147	344	166'-0"	51'-9"
161'-10"	E61D148	30	182'-9"	61'-0"
161'-10"	E61D149	41	167'-8"	42'-0"
161'-10"	E61D150	70	168'-10"	42'-0"
161'-10"	E61D151	105	168'-10"	42'-0"
161'-10"	E61D152	70	178'-10"	46'-2"
161'-10"	E61D153	109	178'-10"	51'-5"
161'-10"	E61D154	136	182'-4"	51'-9"
161'-10"	E61D155	254	182'-4"	55'-9"
161'-10"	E61D156	274	183'-4"	48'-0"
161'-10"	E61D157	293	182'-4"	58'-11"
161'-10"	E61D158	320	183'-4"	53'-2"
184'-6"	E61D159	21	202'-0"	50'-4"
184'-6"	E61D160	35	202'-0"	46'-0"
184'-6"	E61D161	59	207'-9"	44'-2"
184'-6"	E61D162	74	202'-0"	55'-8"
184'-6"	E61D163	88	202'-0"	48'-0"

TABLE 6.2-54: [HISTORICAL INFORMATION] HYDROGEN IGNITER LOCATIONS (CONTINUED)

Floor Elevation	Igniter No.	Azimuth	Dimension to Elevation	Centerline of Reactor
184'-6"	E61D164	92	202'-0"	48'-0"
184'-6"	E61D165	106	202'-0"	55'-8"
184'-6"	E61D166	93	202'-0"	45'-0"
184'-6"	E61D167	86	202'-0"	37'-6"
184'-6"	E61D168	86	202'-0"	34'-0"
184'-6"	E61D169	96	202'-0"	34'-0"
184'-6"	E61D170	135	207'-7"	34'-0"
184'-6"	E61D171	216	206'-0"	46'-9"
184'-6"	E61D172	252	204'-11"	26'-0"
184'-6"	E61D173	256	204'-4"	53'-8"
184'-6"	E61D174	284	204'-11"	53'-8"
184'-6"	E61D175	298	201'-11"	53'-8"
184'-6"	E61D176	310	207'-9"	56'-6"
184'-6"	E61D176	341	202'-0"	55'-0"
208'-10"	E61D178	6	262'-0"	55'-5"
208'-10"	E61D179	48	262'-0"	55'-5"
208'-10"	E61D180	91	262'-0"	55'-0"
208'-10"	E61D181	140	262'-0"	55'-0"
208'-10"	E61D182	183	262'-0"	55'-0"
208'-10"	E61D183	225	262'-0"	55'-0"
208'-10"	E61D184	268	262'-0"	55'-0"
208'-10"	E61D185	333	262'-0"	55'-0"
208'-10"	E61D186	349	283'-10"	39'-9"
208'-10"	E61D187	34	283'-10"	39'-9"
208'-10"	E61D188	81	283'-10"	39'-9"
208'-10"	E61D189	127	283'-10"	39'-9"
208'-10"	E61D190	152	283'-10"	39'-9"
208'-10"	E61D191	199	283'-10"	39'-9"
208'-10"	E61D192	242	283'-10"	39'-9"

TABLE 6.2-54: [HISTORICAL INFORMATION] HYDROGEN IGNITER LOCATIONS (CONTINUED)

Floor Elevation	Igniter No.	Azimuth	Dimension to Elevation	Centerline of Reactor
208'-10"	E61D193	286	283'-10"	39'-9"
208'-10"	E61D194	349	295'-0"	15'-3"
208'-10"	E61D195	158	295'-0"	15'-3"

TABLE 6.2-55: [HISTORICAL INFORMATION] ASSUMED THERMAL PROPERTIES FOR PENETRATION ANALYSIS

Material	Temp. (F)	Conductivity Btu / hr - ft^2 - F	Surface Emissivity
Reinforced Concrete	-	1.0	.75
Reflective Insulation	-	.056 - .118*	.15
Calcium-Silicate Insulation	300	.42	.15
	700	.60	.15
Air	100	.0157	-
	300	.0203	-
	500	.0246	-
	700	.0284	-
Carbon Steel	212	30.	.15
	392	28.	.15
	572	26.	.15

*Calculated from overall conductance (depends on geometry and thickness)

TABLE 6.2-56: [HISTORICAL INFORMATION] SUMMARY OF INITIAL CONDITIONS, EVENT SEQUENCES AND ASSUMPTIONS

PARAMETERS	Stuck-Open SRV Event 1(a) During Power 1 RHR	Depressurization From Isolation Event 2(a) 1 RHR (>100 F/hr)	Small Break Accident Event 3(a) Accident Mode 1 RHR
1. <u>INITIAL CONDITIONS</u>			
1.01 Reactor Power (% Rated)	←	102%	→
1.02 Service Water Temp. (F)	←	Max. Plant Data	→
1.03 Initial Pool Temp, Ti (F)	←	Max. Tech. Spec.	→
1.04 Initial Pool Volume (cu. ft)	←	Min. Tech. Spec.	→
1.05 Drywell Pressure and Temp. (psig, F)	←	135 F and normal operating pressure	→
1.06 Wetwell Air Pressure (psig)	←	Normal operating pressure	→
2. <u>EVENT SEQUENCE</u>			
2.01 Reactor Scram, Manual at Pool	T_P = 100 F	N/A	N/A
2.02 Reactor Scram, Automatic	N/A	t=o	High Drywell Pressure
2.03 Isolation Time, T_i (Sec.)	Note (1)	3.5	3.5
2.04 Feedwater Stops, Motor Driven Pumps		Note (2)	
2.05 Feedwater Stops, Turbine Driven pumps		Note (2)	
2.06 Add'l SRVs Opened	Note (3)	Note (3)	Note (4)
2.07 Time to Turn RHR on in Pool Cooling Mode (See Note 11)	10 Min.	10 Min.	10 Min.
2.08 Bypass Valves to Main Condenser Opened (See Note 5)	20 Min.	No	No

TABLE 6.2-56: [HISTORICAL INFORMATION] SUMMARY OF INITIAL CONDITIONS, EVENT SEQUENCES AND ASSUMPTIONS (CONTINUED)

PARAMETERS	Stuck-Open SRV Event 1(a) During Power 1 RHR	Depressurization From Isolation Event 2(a) 1 RHR (>100 F/hr)	Small Break Accident Event 3(a) Accident Mode 1 RHR
2.09 Shutdown Cooling Initiated	Note (7, 8)	Note (7, 8)	Note (6)
2.10 Maximum Pool Temperature	173 F	180 F	181 F
2.11 Time Max. Pool Temp. Reached	5834 sec.	5303 sec.	8900 sec.
3. ASSUMPTIONS			
3.01 Auxiliary Power Available	Yes	Yes	No
3.02 Condensate Storage Tank Water Temp. (F)		← Max. Plant Data (Note 9) →	
3.03 HPCS Available	Yes	Yes	Note (10)
3.04 RCIC Available	Yes	Yes	Yes
3.05 Condensate Storage Tank Avail.	Yes	Yes	No
3.06 Drywell Fan Coolers Available			
3.07 RHR Heat Exchanger Duty		← Based on Maximum Observed Equilibrium Crud Buildup →	
3.08 Number of RHR Loops Avail.	1	1	1
3.09 SRV Capacities (% of ASME Rated)		← 122.5% →	
3.10 Decay Heat Curve		← Decay Heat Curves for Containment Analysis (22A5792) →	

TABLE 6.2-56: [HISTORICAL INFORMATION] SUMMARY OF INITIAL CONDITIONS, EVENT SEQUENCES AND ASSUMPTIONS (CONTINUED)

PARAMETERS	Stuck-Open SRV Event 1(a) During Power 1 RHR	Depressurization From Isolation Event 2(a) 1 RHR (>100 F/hr)	Small Break Accident Event 3(a) Accident Mode 1 RHR

NOTES:

N/A = Not Applicable

1. In Event 1(a), the turbine control valves (TCV) will close on low turbine throttle pressure approximately 20 seconds after the SORV occurs, effectively isolating the reactor from the main condenser. The MSIVs will not close because the low steam line pressure trip is bypassed when the operator scrams the plant by changing the mode switch from the RUN to the SHUTDOWN position. In the other events, 3.5 seconds is the isolation time (one-half second closure signal delay time plus MSIV closure time).

2. It is assumed that the containment accepts the "hot" portion of the feedwater in the feedwater system.

3. When the pool temperature reaches 120 F as required by the Technical Specifications.

4. All ADS SRVs are manually opened when suppression pool temperature reaches 120 F.

5. In Event 1(a), the main condenser is assumed to be made available as a heat sink for reactor steam 20 minutes after the TCVs initially closed (see Note 1). The main condenser is assumed to be available until the reactor pressure is less than approximately 150 psia.

6. Shutdown cooling is not used. Shutdown cooling would decrease maximum pool temperature.

TABLE 6.2-56: [HISTORICAL INFORMATION] SUMMARY OF INITIAL CONDITIONS, EVENT SEQUENCES AND ASSUMPTIONS (CONTINUED)

PARAMETERS	Stuck-Open SRV Event 1(a) During Power 1 RHR	Depressurization From Isolation Event 2(a) 1 RHR (>100 F/hr)	Small Break Accident Event 3(a) Accident Mode 1 RHR

7. When reactor pressure interlock pressure.

8. The 16-minute switchover time assumes no flushing of the RHR loops to maintain water chemistry standards.

9. The CST water temperature is assumed to be 80 F.

10. HPCS available except if the small line break is the HPCS line.

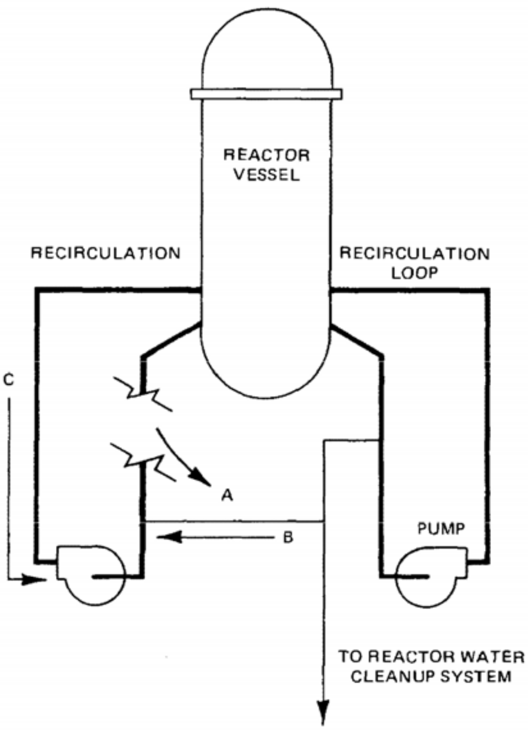
11. The RHR is assumed to be in operation in the pool cooling mode 10 minutes after the maximum pool temperature allowed by the Technical Specifications during normal power operation is exceeded.

TABLE 6.2-57: [HISTORICAL INFORMATION] MAXIMUM SUPPRESSION POOL TEMPERATURE RESULTS

1A	SORV from power (1 RHR)	173 F
2A	Depressurization from Isolation (1 RHR)	180 F
3A	Small Break Accident (1 RHR)	181 F

POINT OF CRITICAL FLOW

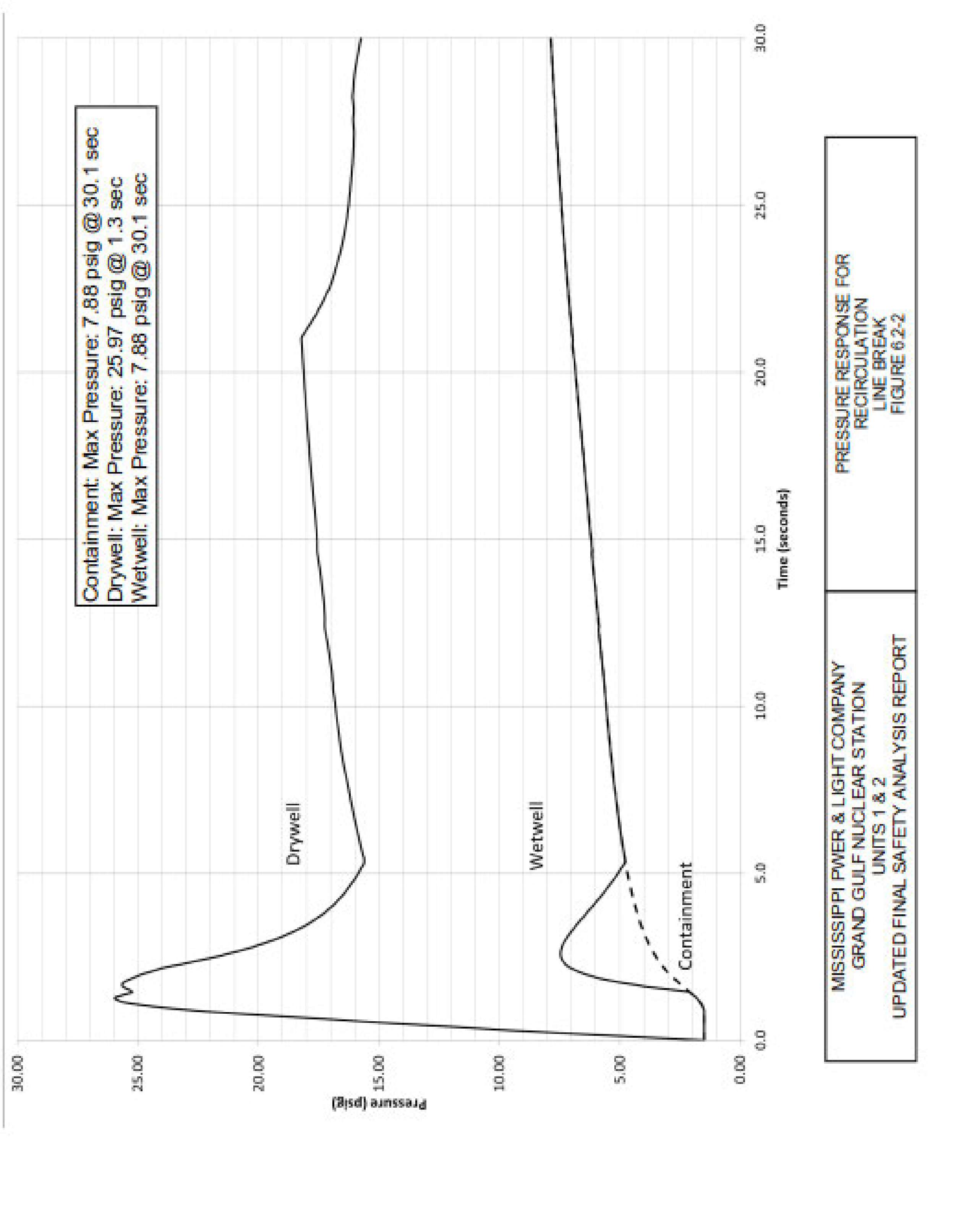
A. RECIRCULATION LINE
B. CLEANUP LINE
C. COMBINED AREA OF ALL JET PUMP NOZZLES ASSOCIATED WITH THE BROKEN LOOP

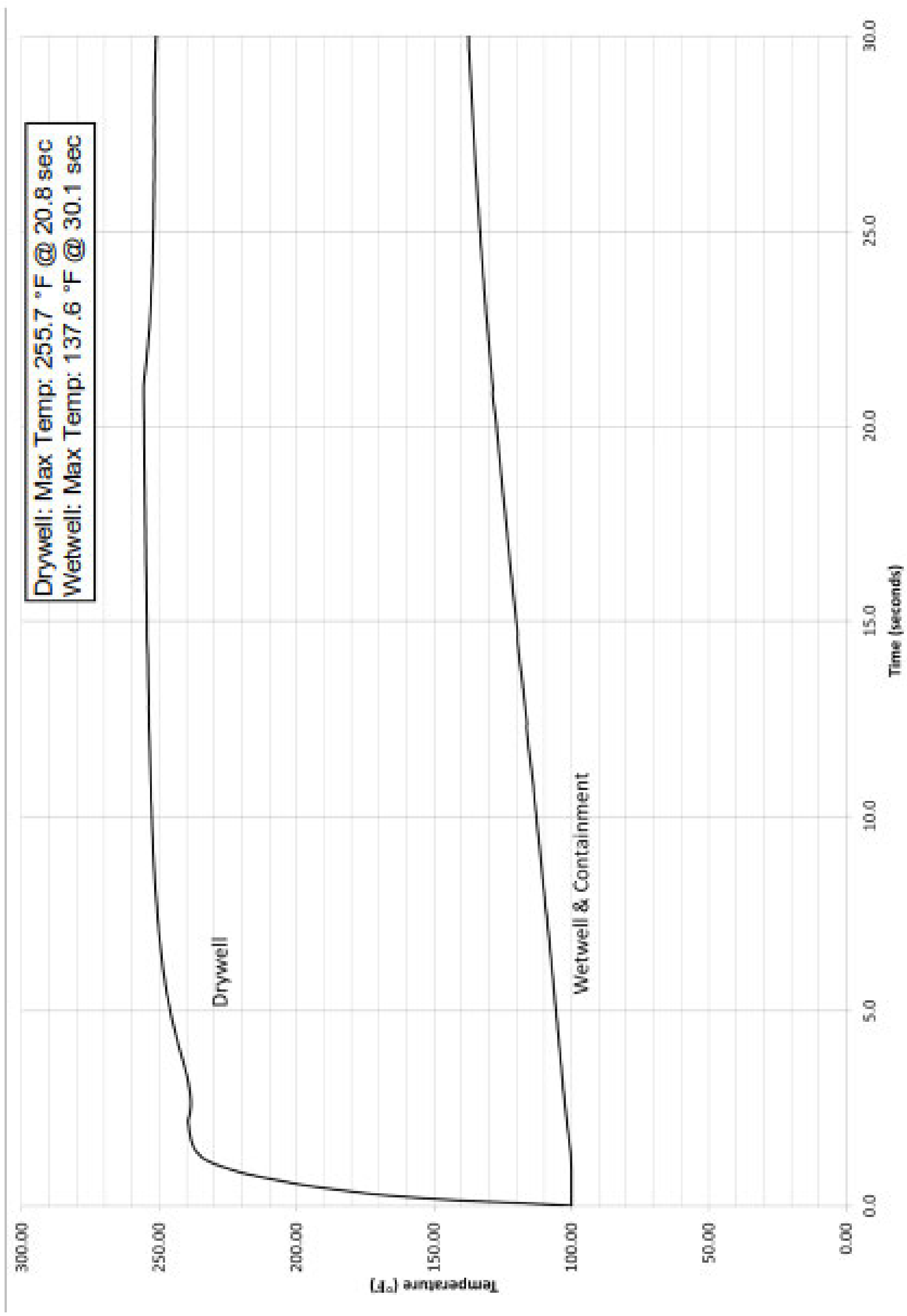


SCHEMATIC SHOWING COMPOSITION OF TOTAL RECIRCULATION LINE BREAK AREA

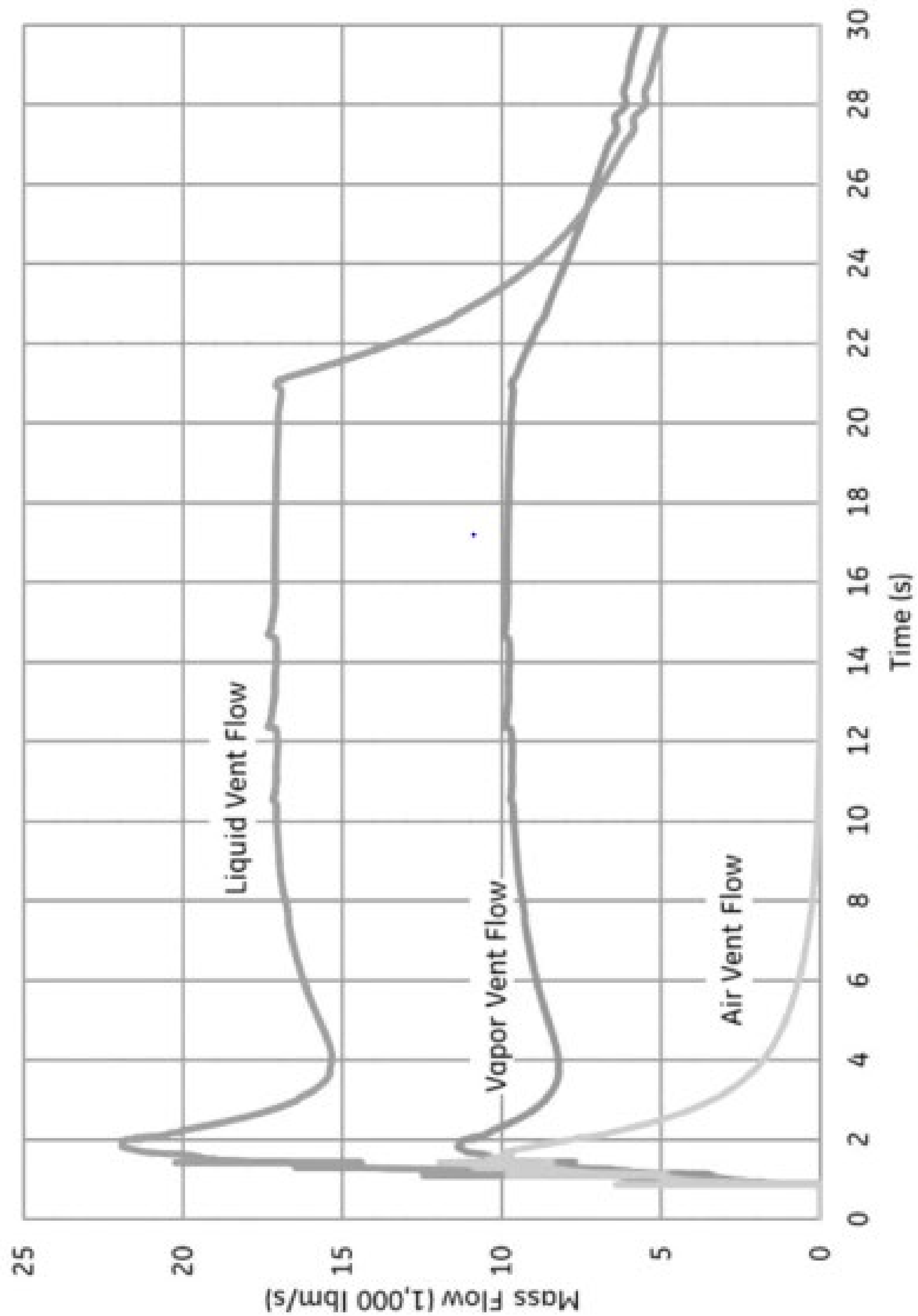
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	DIAGRAM OF THE RECIRCULATION LINE BREAK LOCATION FIGURE 6.2-1


Containment: Max Pressure: 7.88 psig @ 30.1 sec
Drywell: Max Pressure: 25.97 psig @ 1.3 sec
Wetwell: Max Pressure: 7.88 psig @ 30.1 sec
Drywell
Wetwell
Containment
Pressure (psig)
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Time (seconds)
0.0
5.0
10.0
15.0
20.0
25.0
30.0
MISSISSIPPI PWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT
PRESSURE RESPONSE FOR
RECIRCULATION
LINE BREAK
FIGURE 6.2-2



MISSISSIPPI PWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	TEMPERATURE RESPONSE FOR RECIRCULATION LINE BREAK FIGURE 6.2-3



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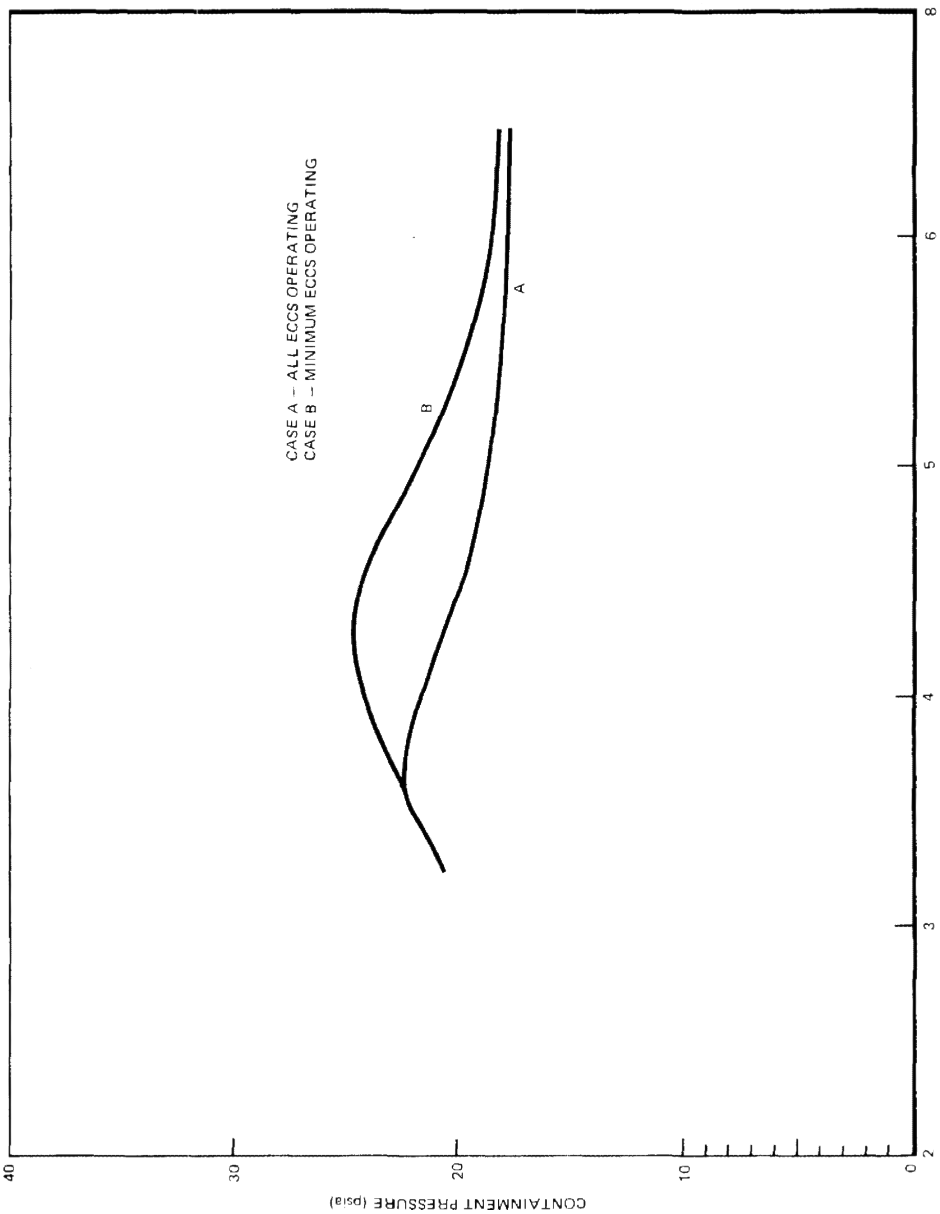
VENT FLOW FOR
RECIRCULATION
LINE BREAK
FIGURE 6.2-4



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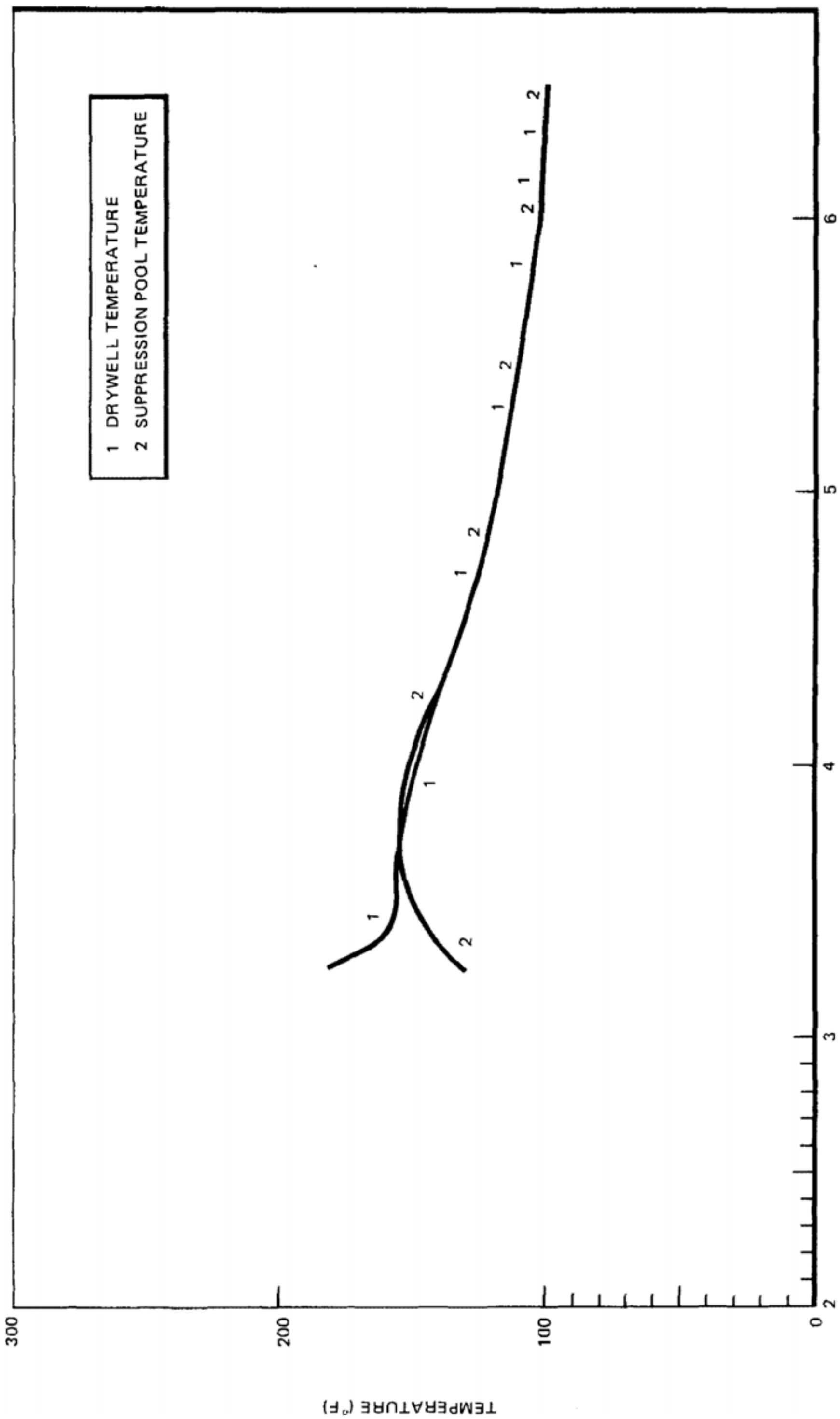
CONTAINMENT PRESSURE RESPONSE

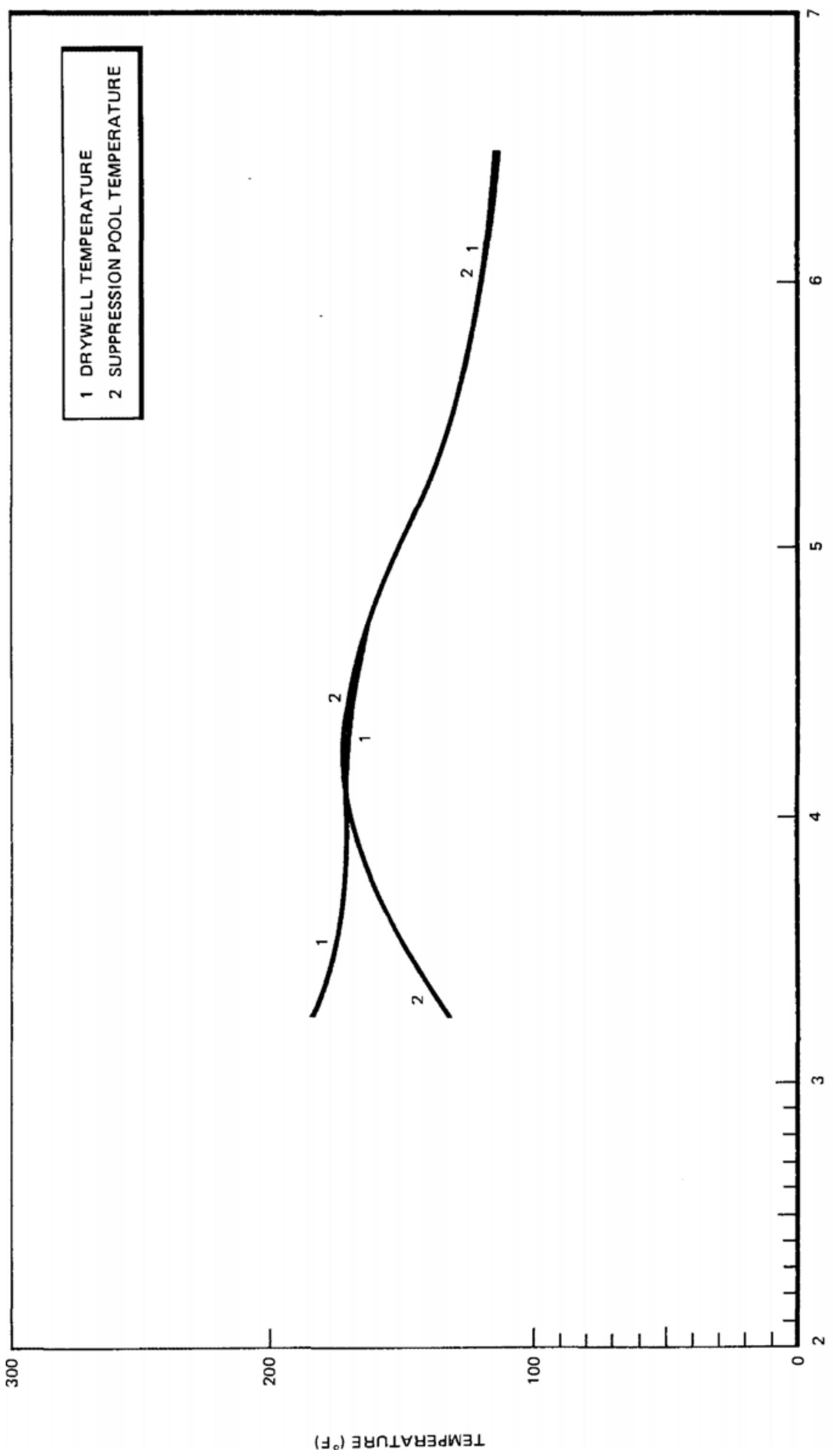
FIGURE 6.2-5



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL AND SUPPRESSION POOL TEMPERATURE (ALL ECCS)
FIGURE 6.2-6



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
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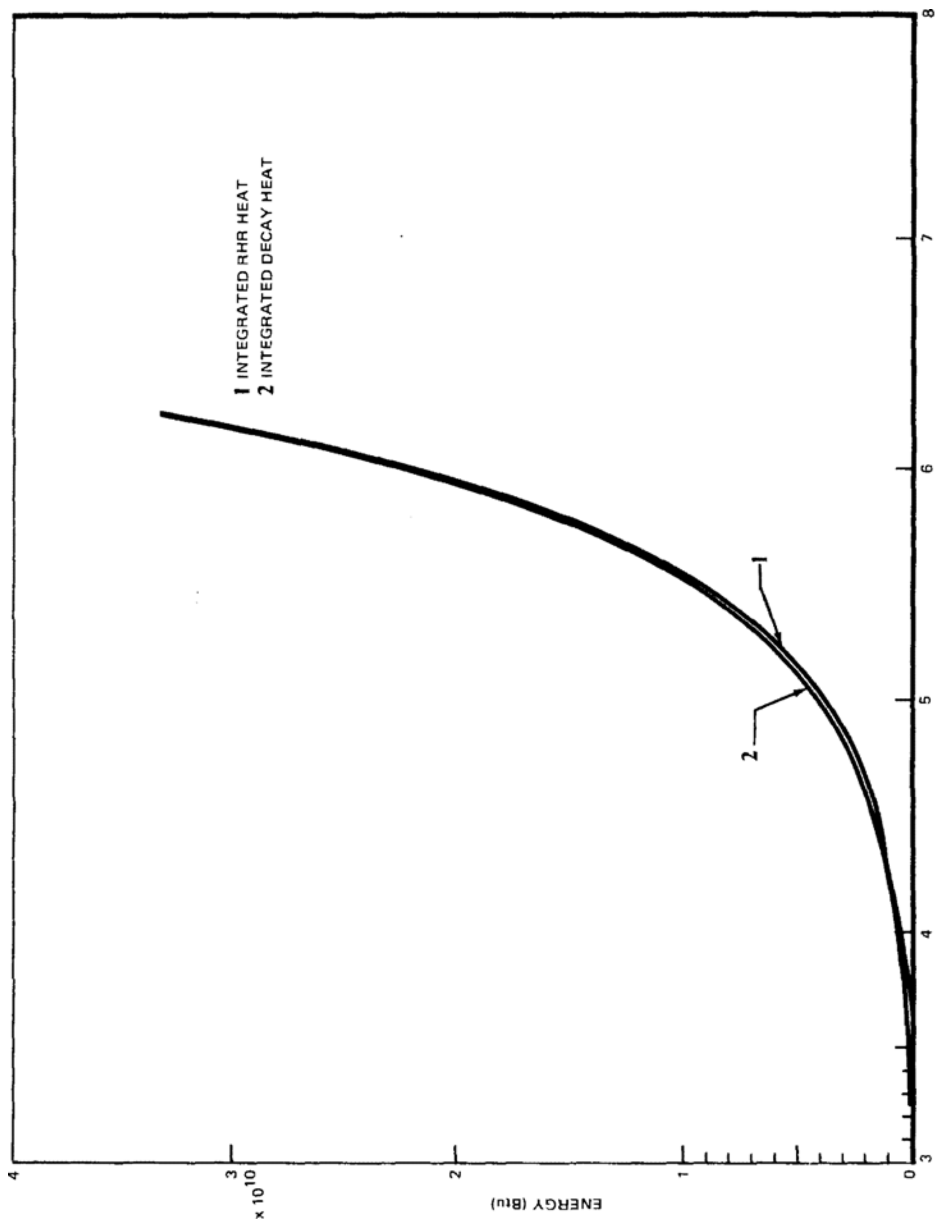
DRYWELL AND SUPPRESSION POOL TEMPERATURE (MINIMUM ECCS)
FIGURE 6.2-7



[HISTORICAL INFORMATION]

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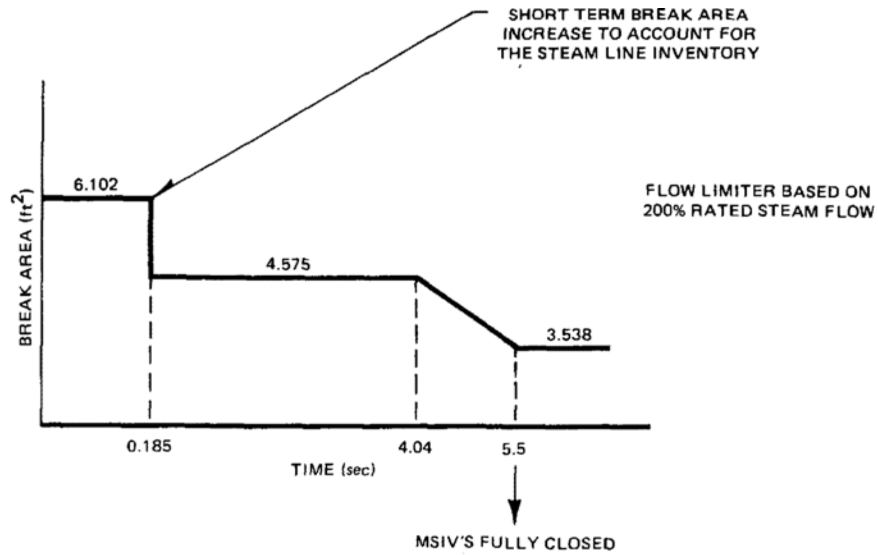
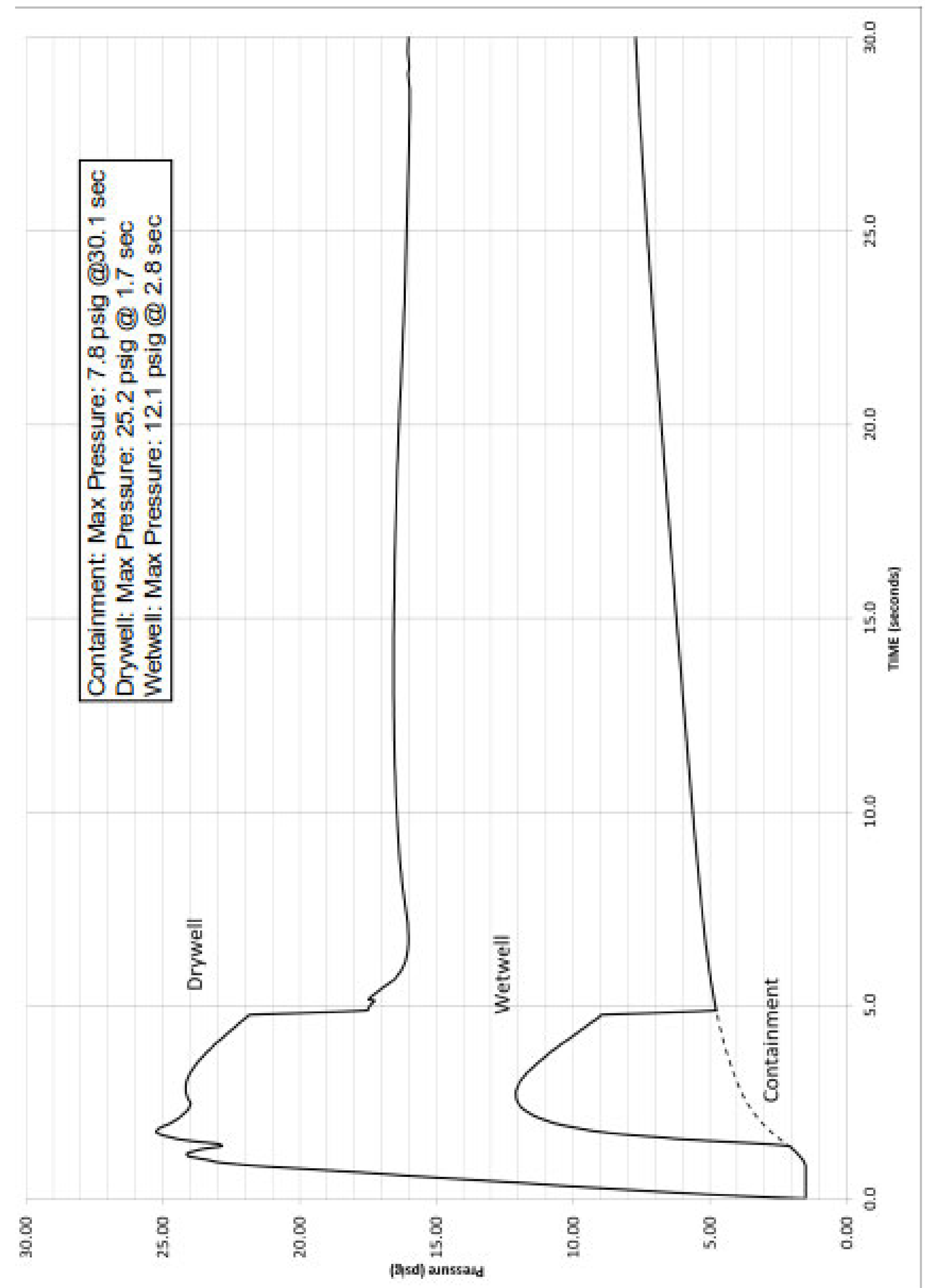
INTEGRATED DECAY HEAT AND
INTEGRATED HEAT EXCHANGER
HEAT REJECTION
FIGURE 6.2-8

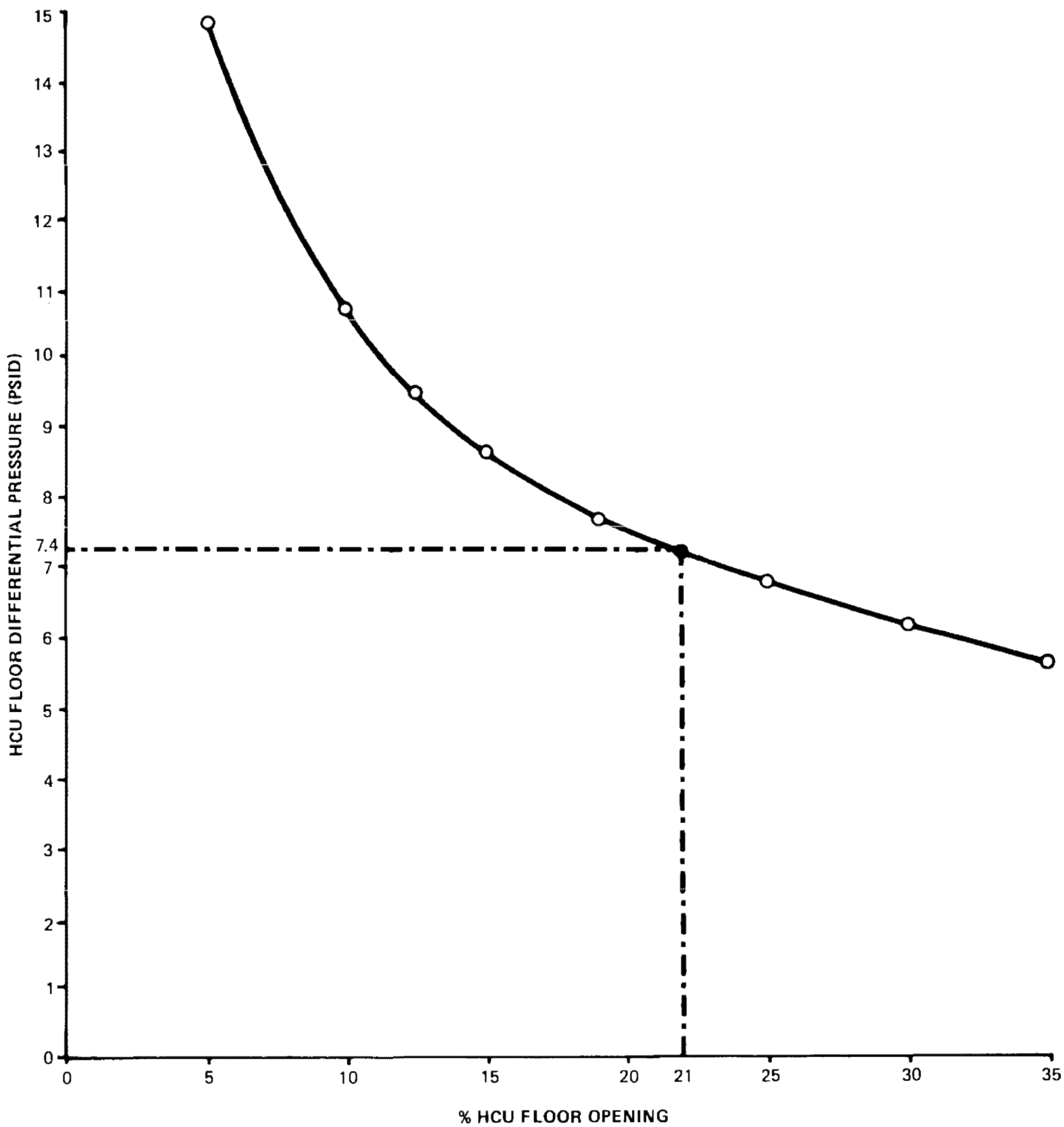


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	EFFECTIVE BLOWDOWN AREA ASSOCIATED WITH MSL RUPTURE FIGURE 6.2-9



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE TO A STEAM LINE BREAK FIGURE 6.2-10



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	HCU FLOOR PRESSURE DIFFERENTIAL, ΔP, DUE TO WETWELL PRESSURIZATION FIGURE 6.2-10a

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UNITS 1 & 2
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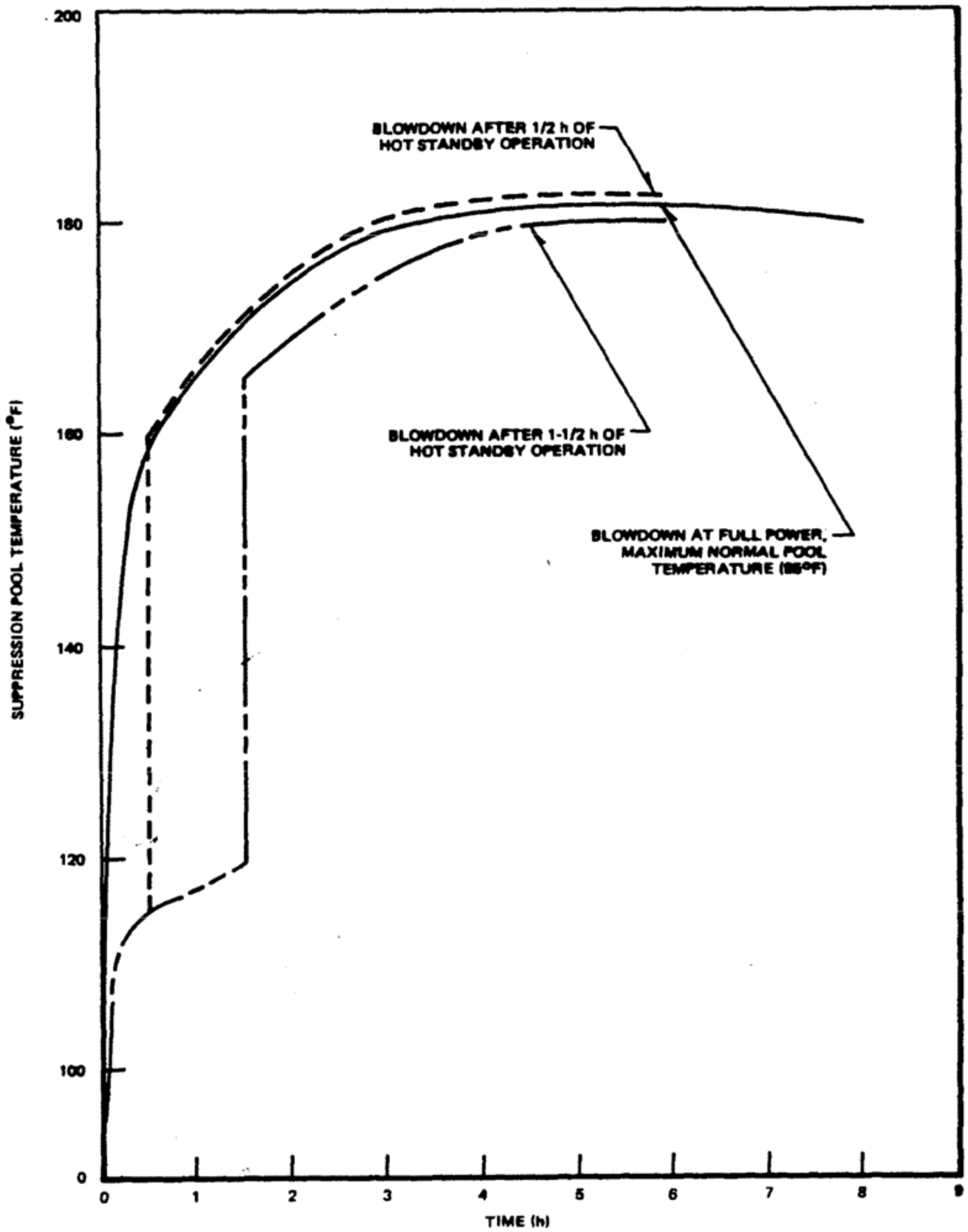
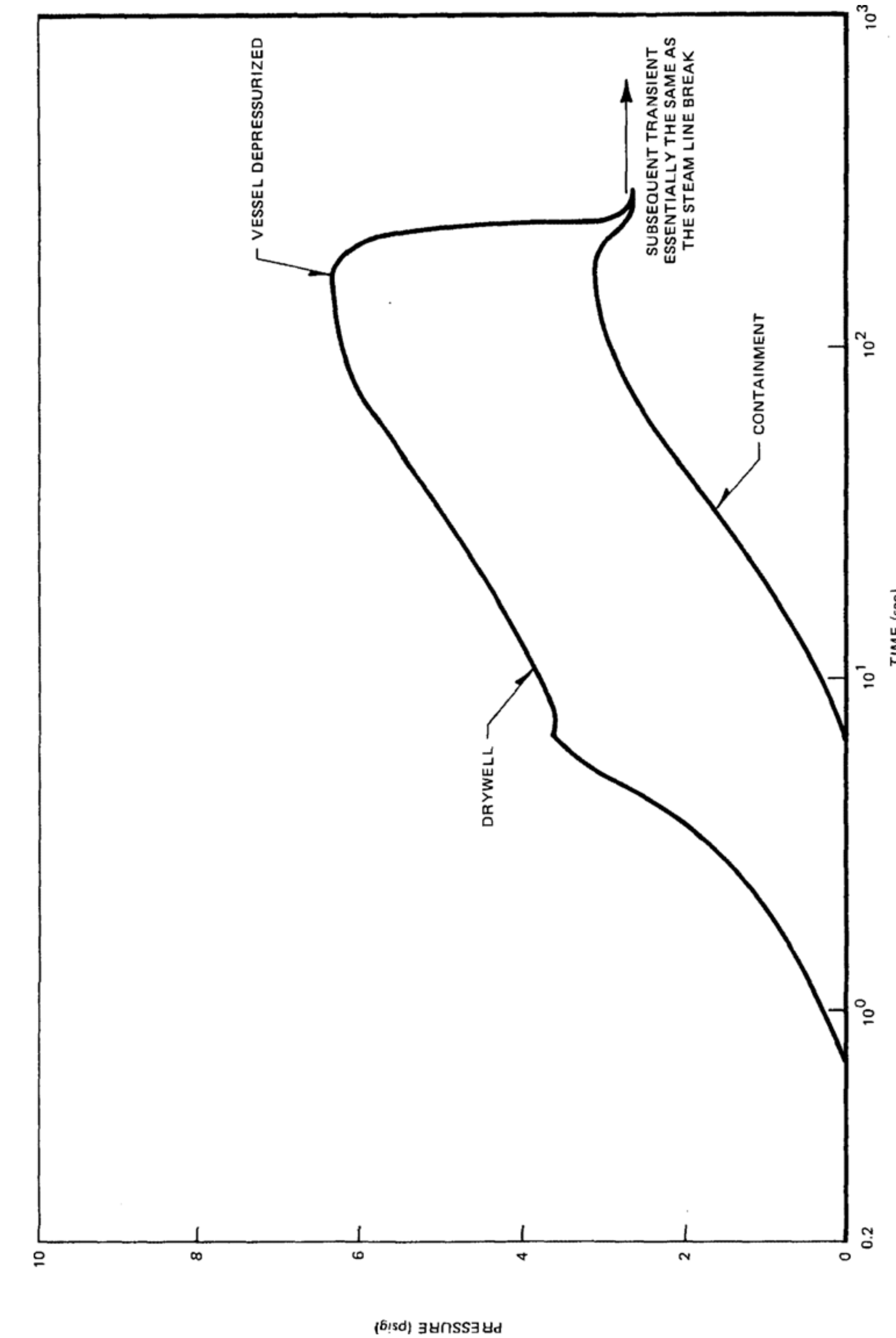
TEMPERATURE RESPONSE TO
A STEAMLINE BREAK
FIGURE 6.2-11



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	SUPRESSION POOL TEMPERATURE TRANSIENT FOLLOWING BLOWDOWN [HISTORICAL INFORMATION] FIGURE 6.2-12



[HISTORICAL INFORMATION]

PRESSURE RESPONSE TO
AN INTERMEDIATE SIZE BREAK
FIGURE 6.2-13

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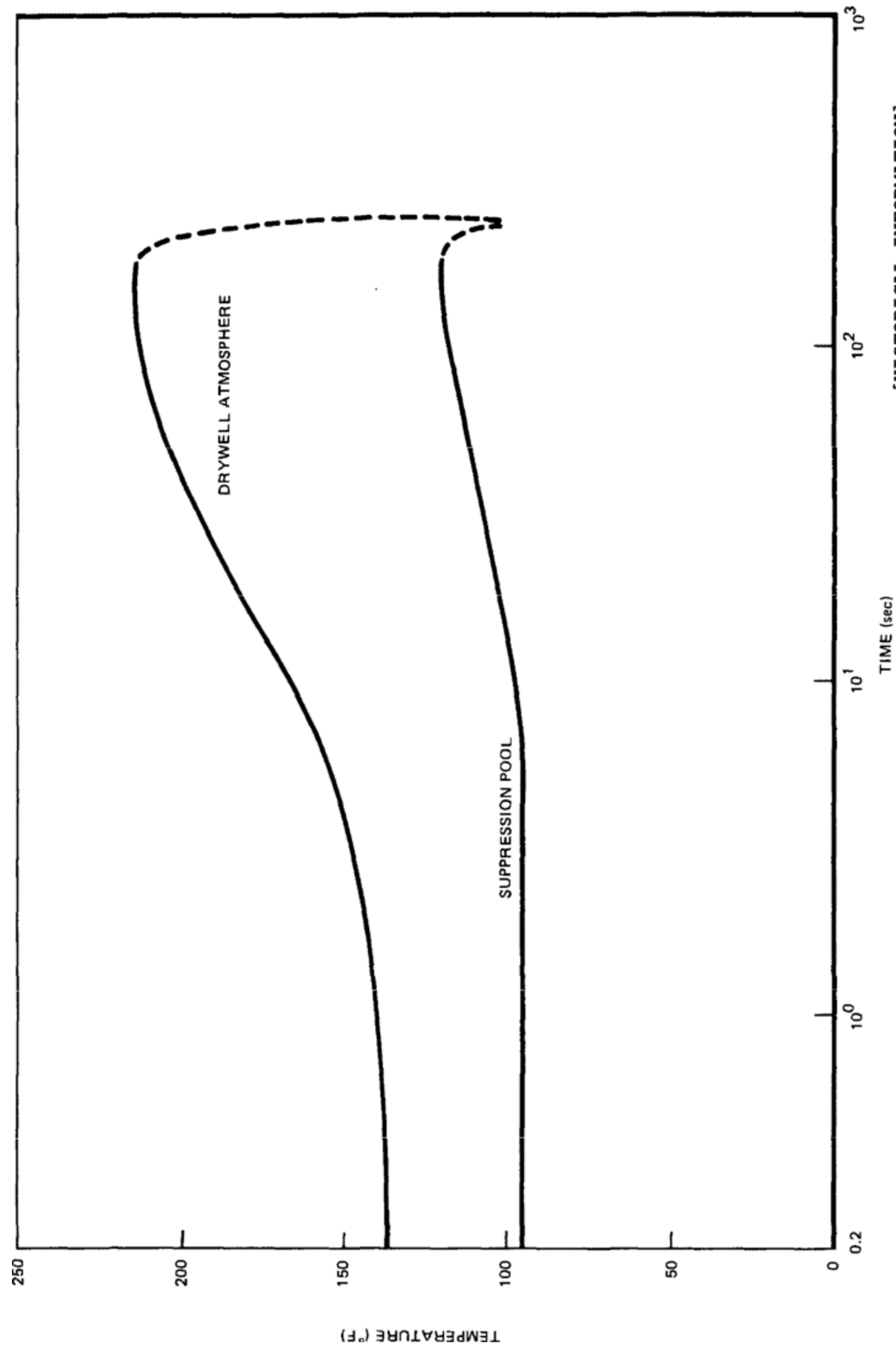

[HISTORICAL INFORMATION]

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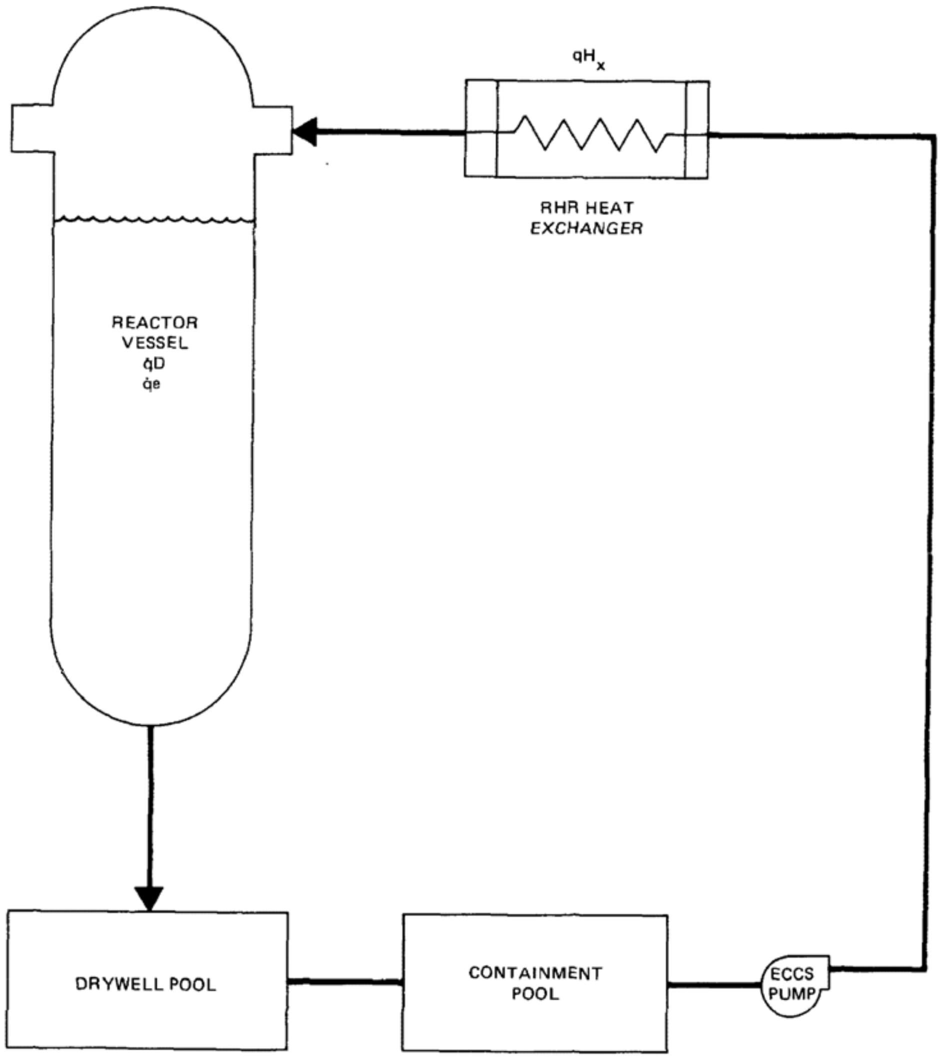
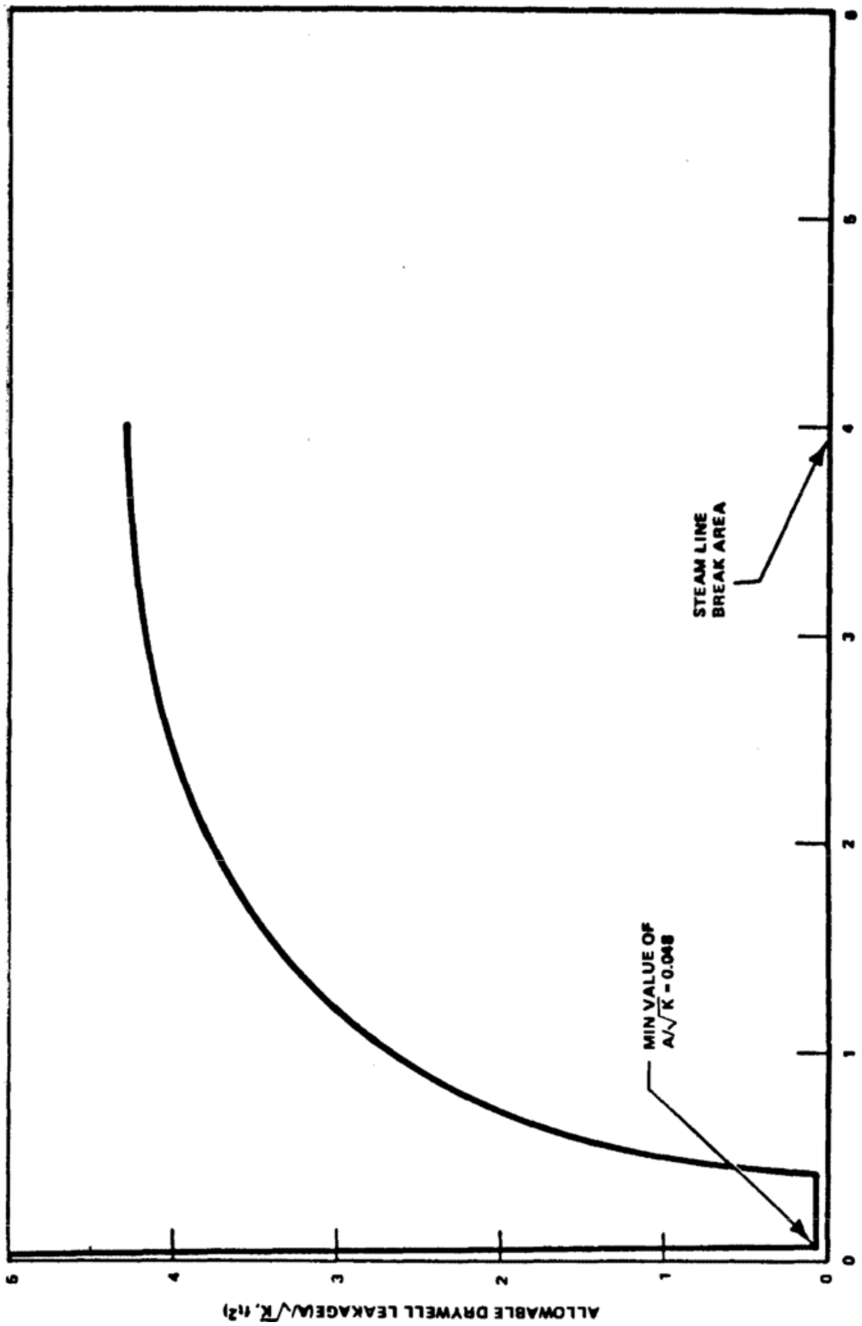
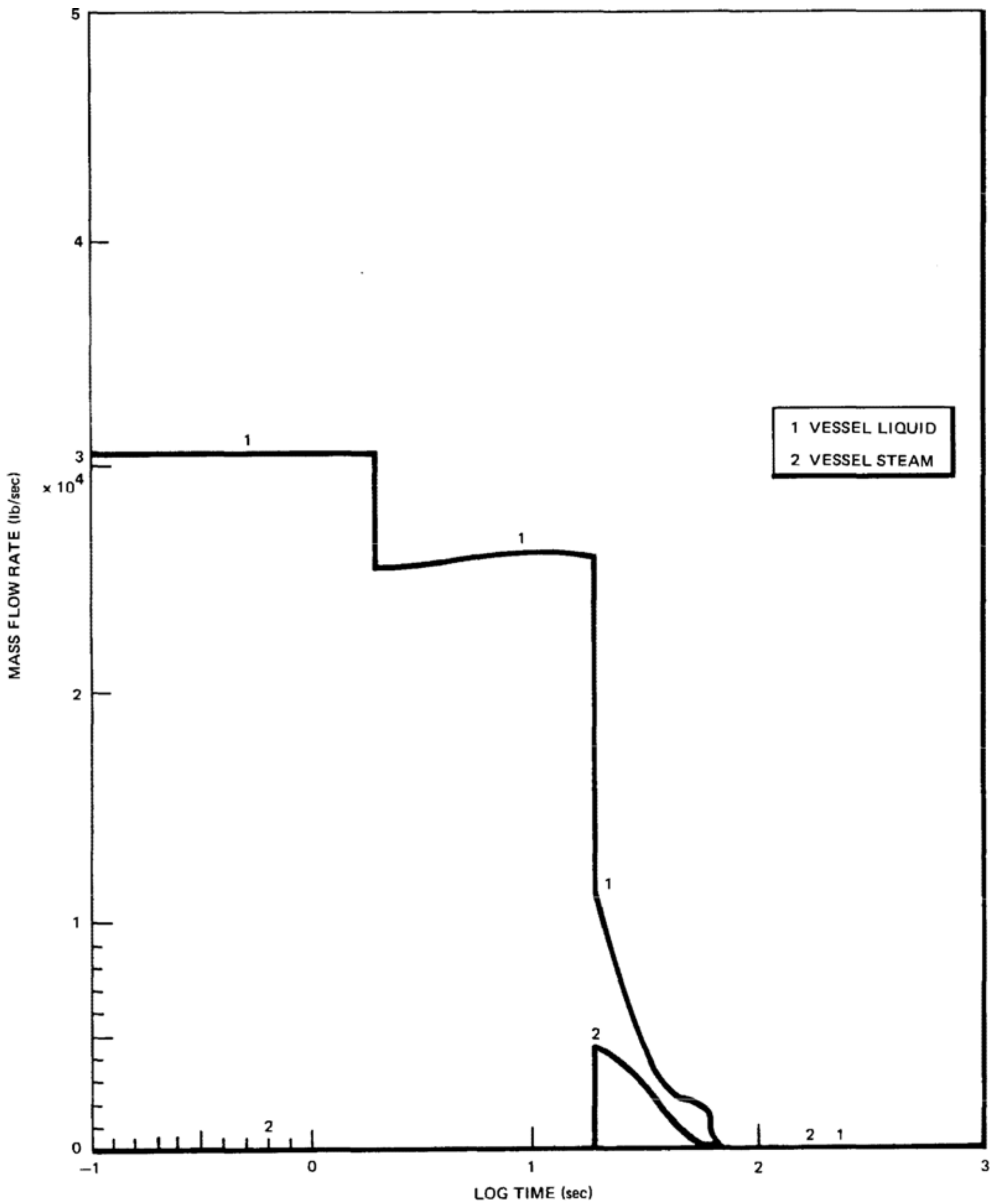
TEMPERATURE RESPONSE TO
AN INTERMEDIATE SIZE BREAK
FIGURE 6.2-14



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	SCHEMATIC OF ECCS LOOP [HISTORICAL INFORMATION] FIGURE 6.2-15



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	ALLOWABLE LEAKAGE CAPACITY [HISTORICAL INFORMATION] FIGURE 6.2-16



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	VESSEL STEAM AND LIQUID BLOWDOWN RATES FOR RECIRCULATION BREAK FIGURE 6.2-17

Figure 6.2-18
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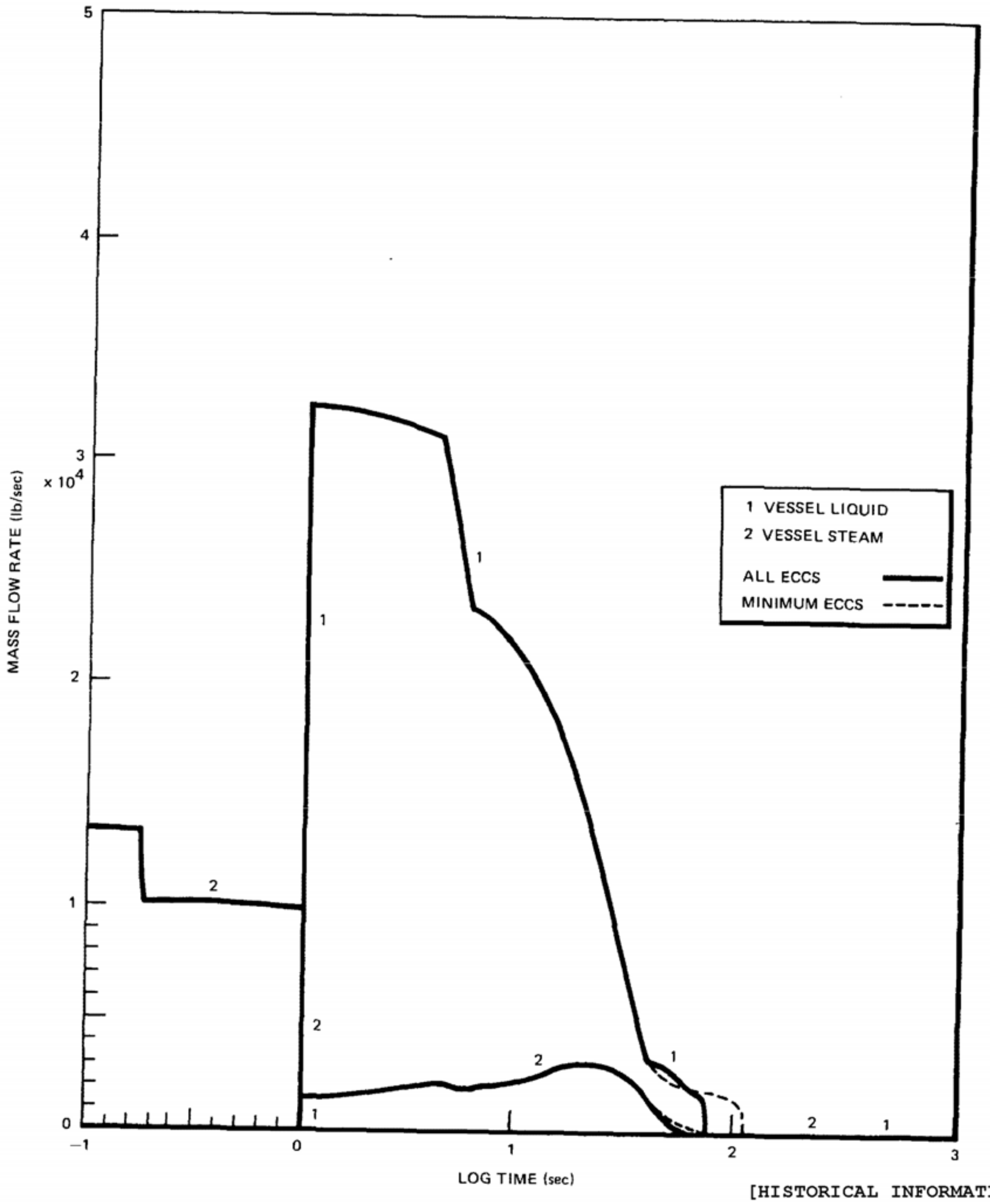
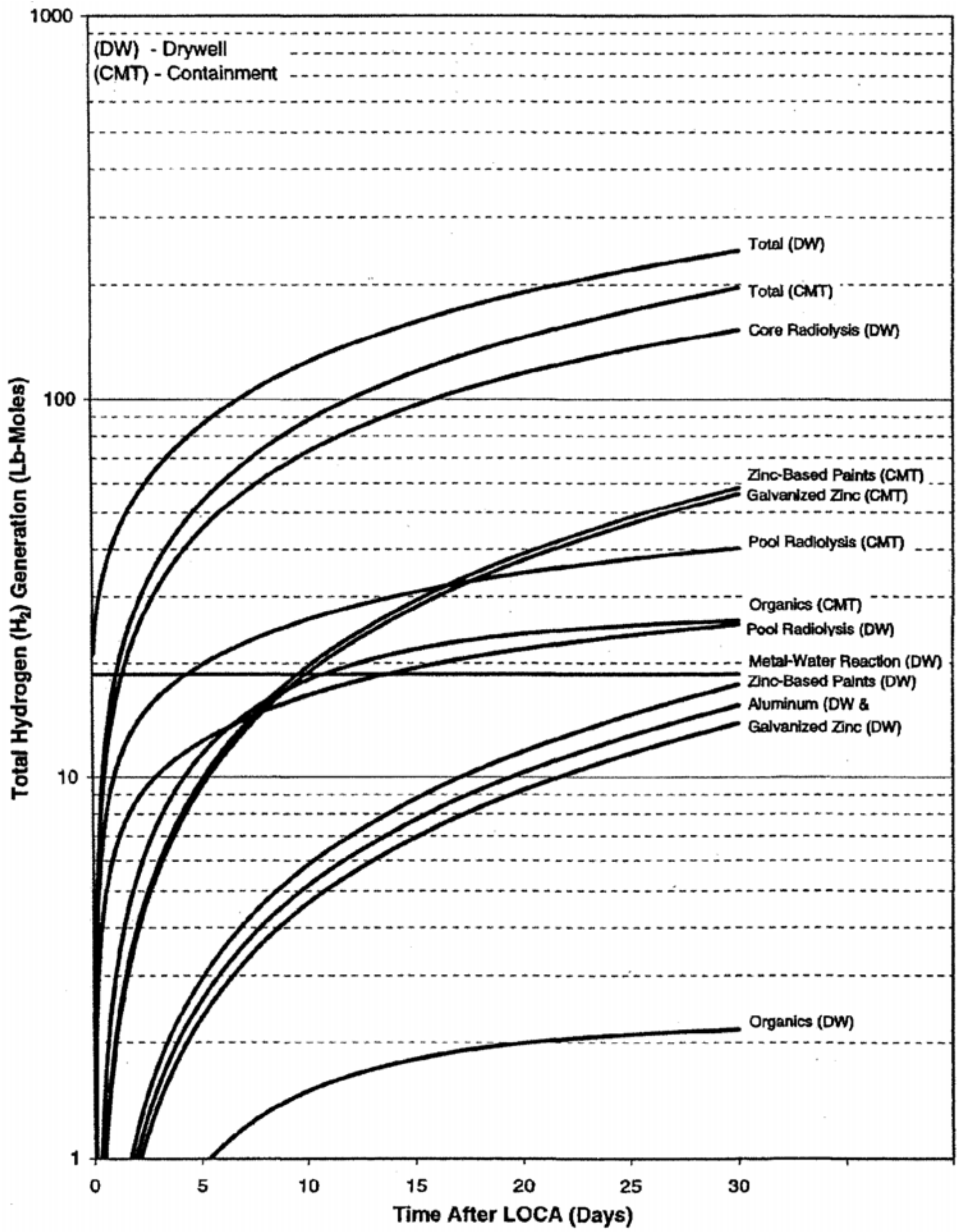


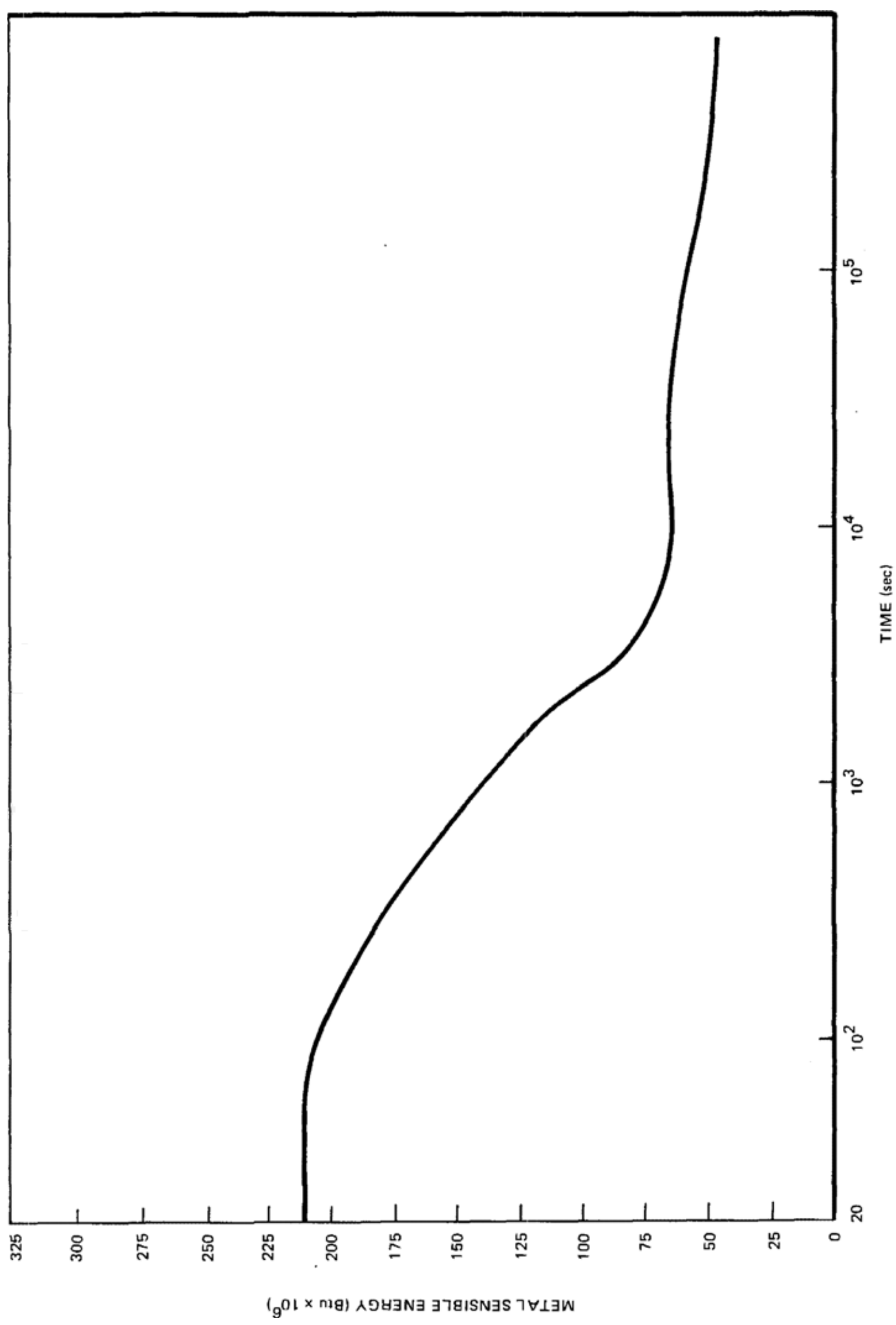
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	VESSEL STEAM AND LIQUID BLOWDOWN RATES FOR MAIN STEAM LINE BREAK FIGURE 6.2-19



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	HYDROGEN GENERATION FROM ALL SOURCES VERSUS TIME AFTER LOCA FIGURE 6.2-20



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UNITS 1 & 2
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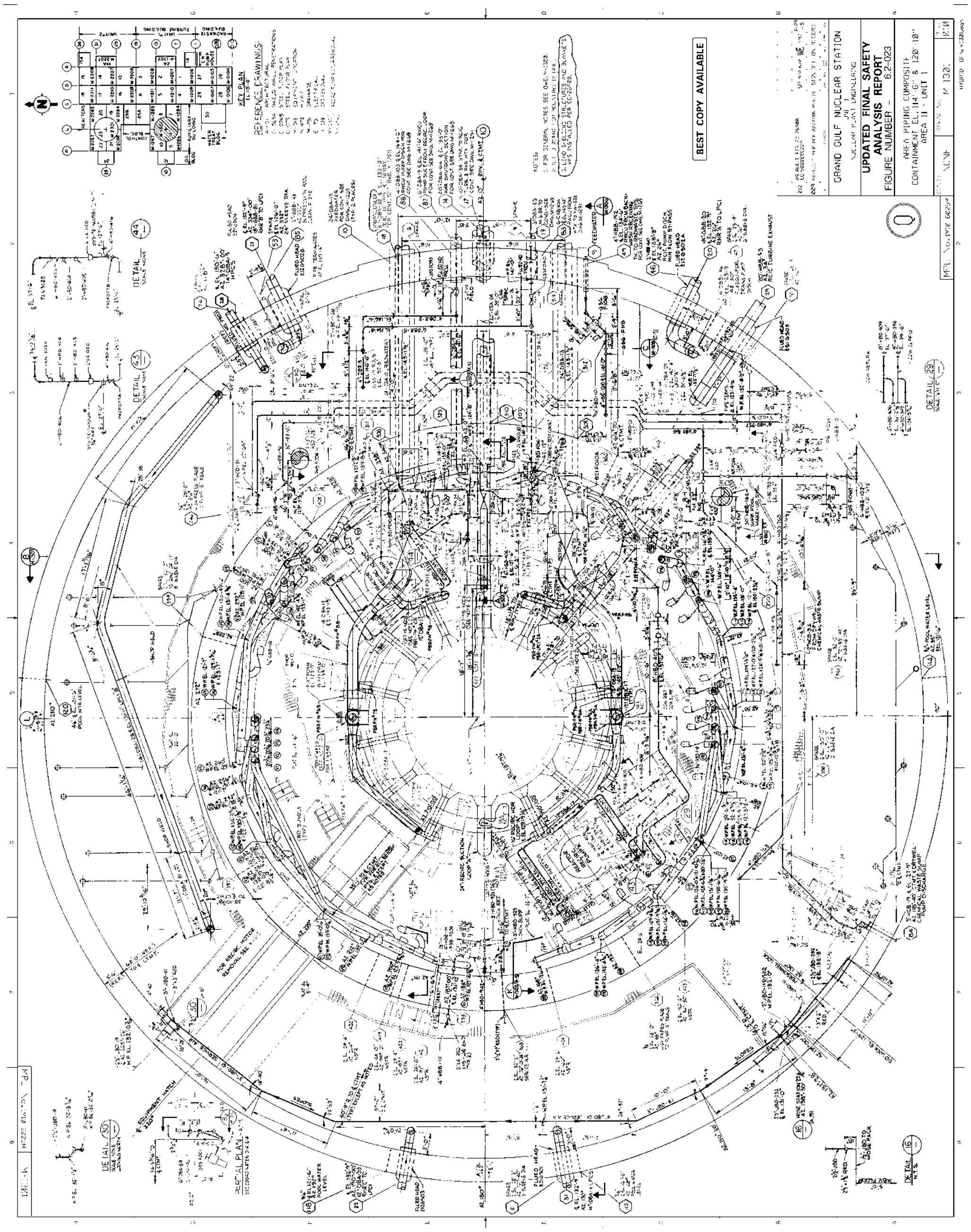
SENSIBLE ENERGY TRANSIENT IN THE REACTOR VESSEL AND INTERNALS METAL
[HISTORICAL INFORMATION]
FIGURE 6.2-21

[redacted]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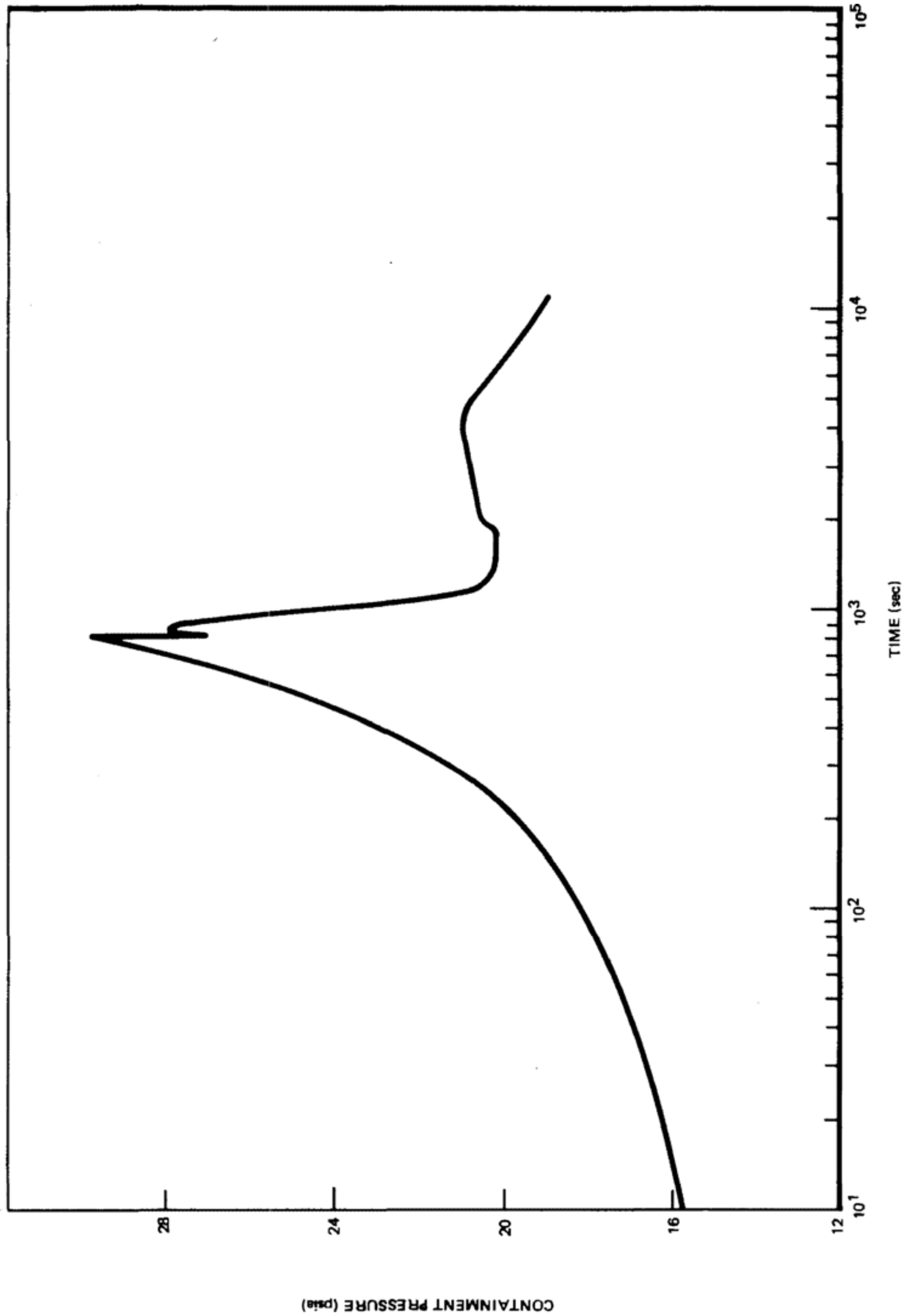
GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 6.2-023



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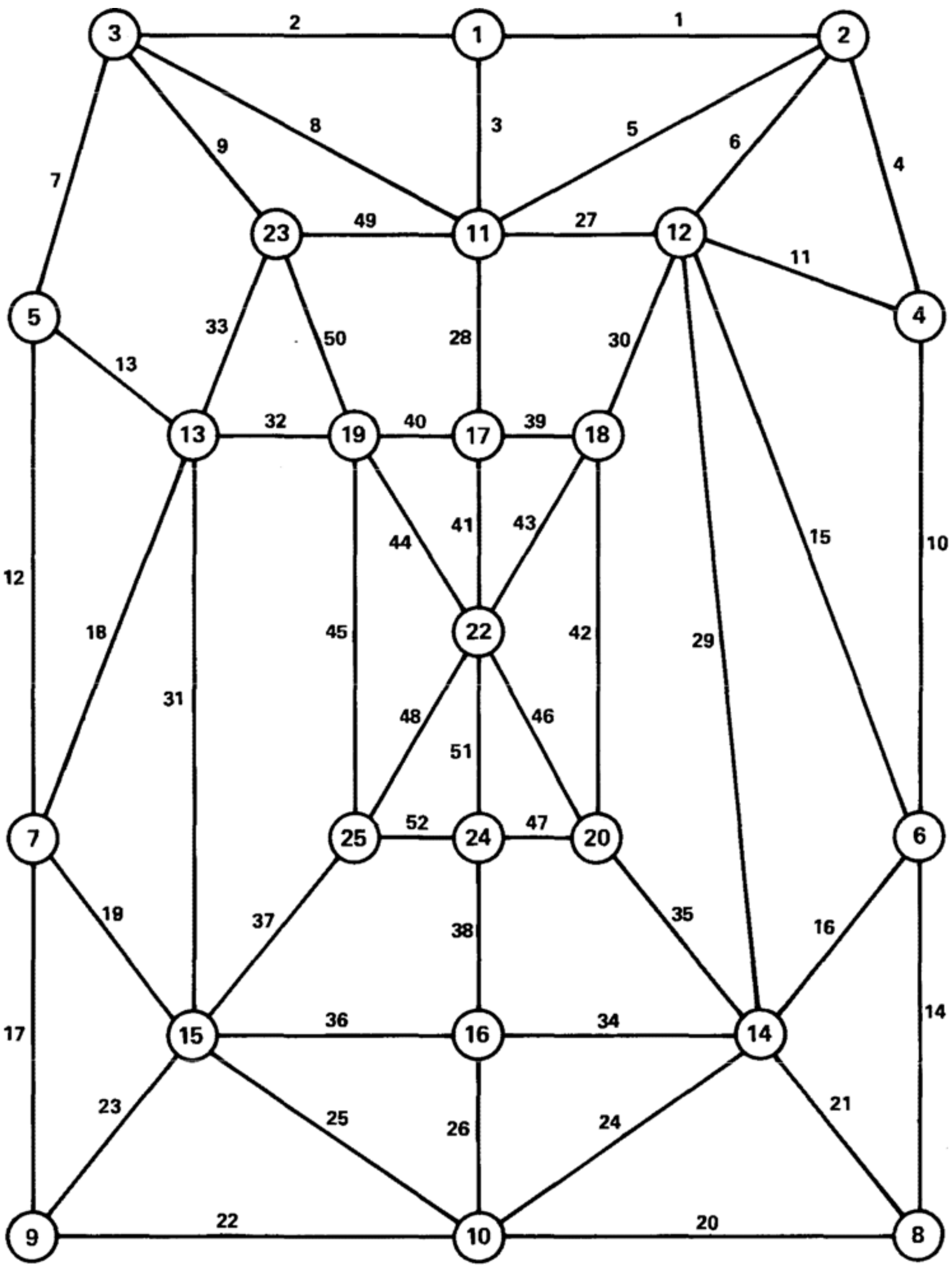
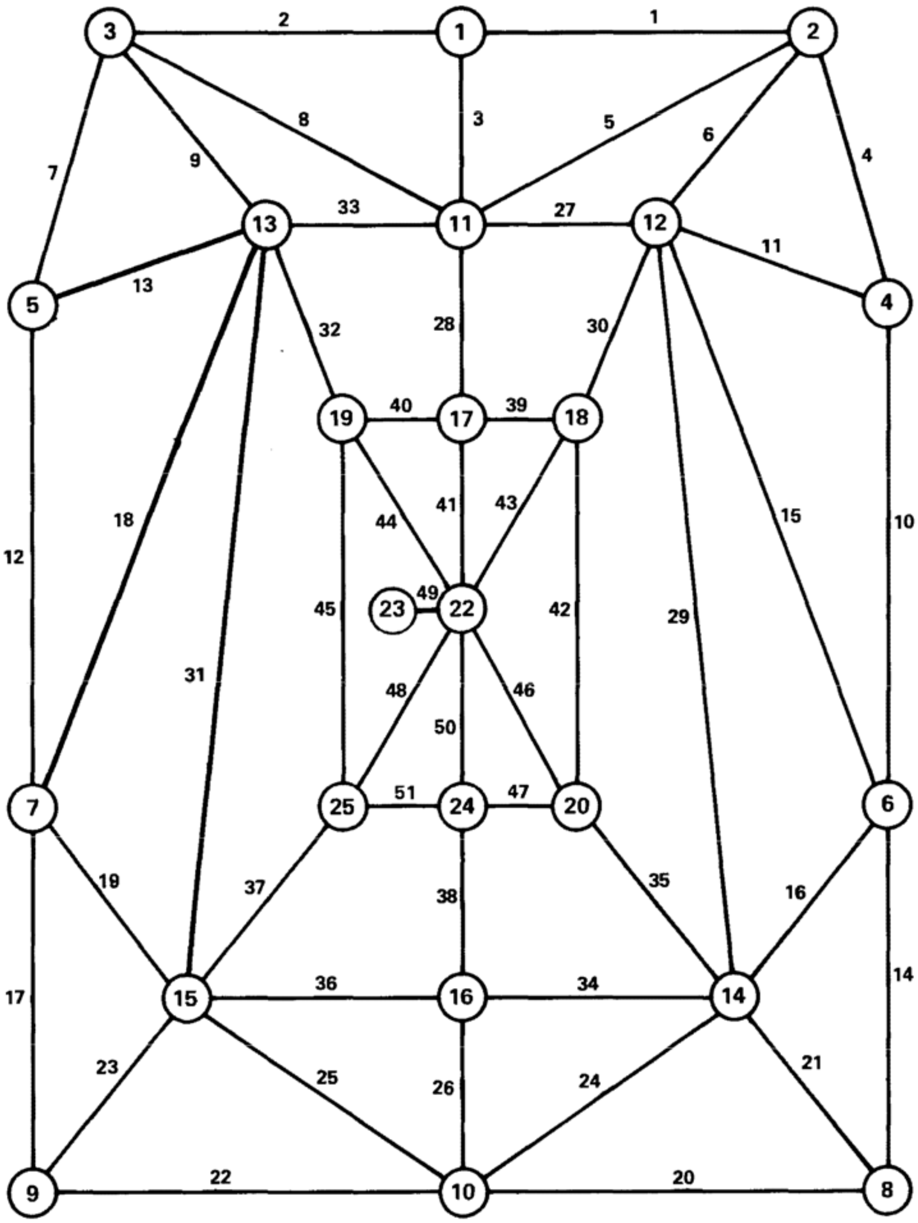
CONTAINMENT PRESSURE VERSUS TIME

[HISTORICAL INFORMATION]

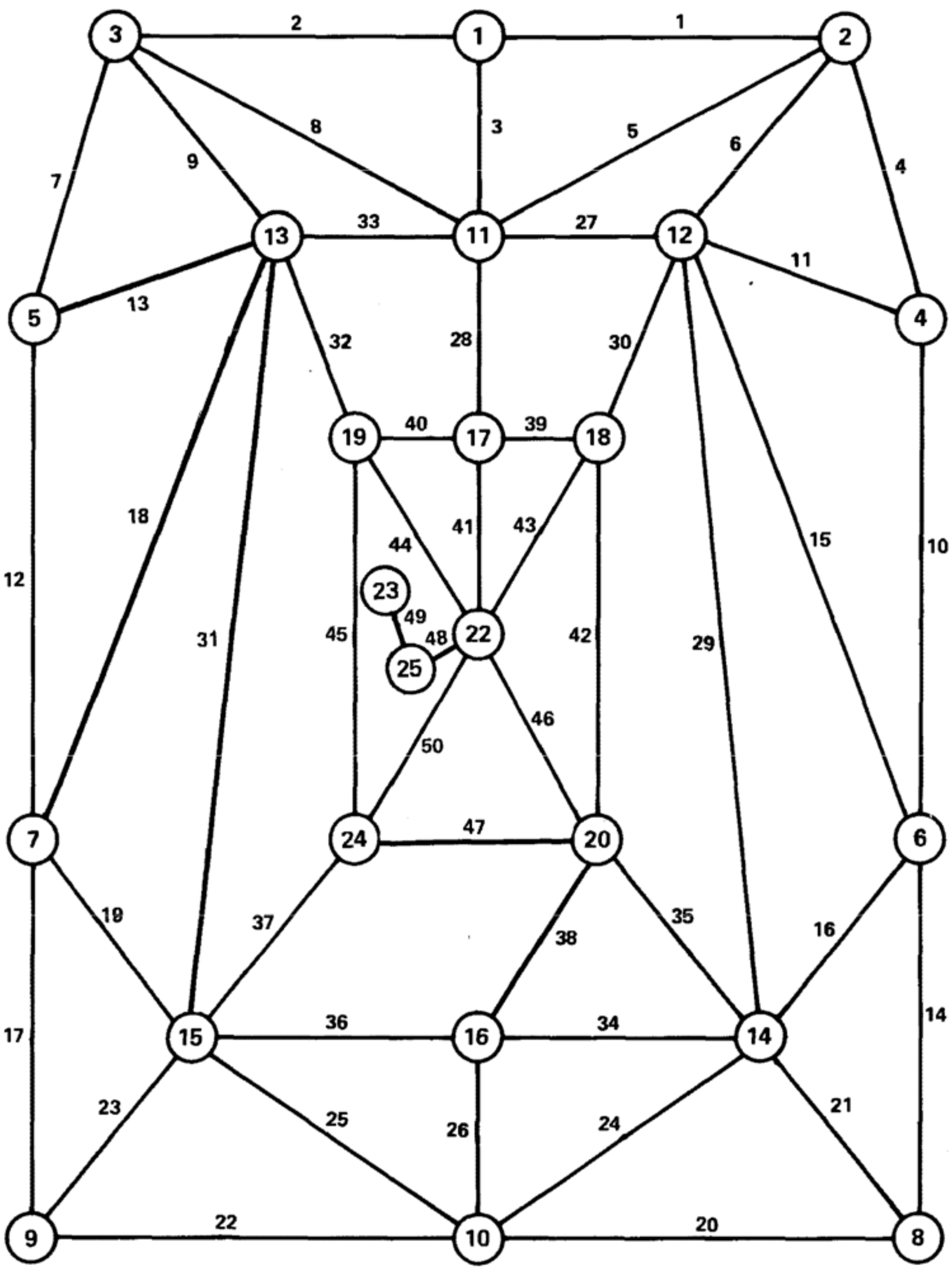
FIGURE 6.2-24



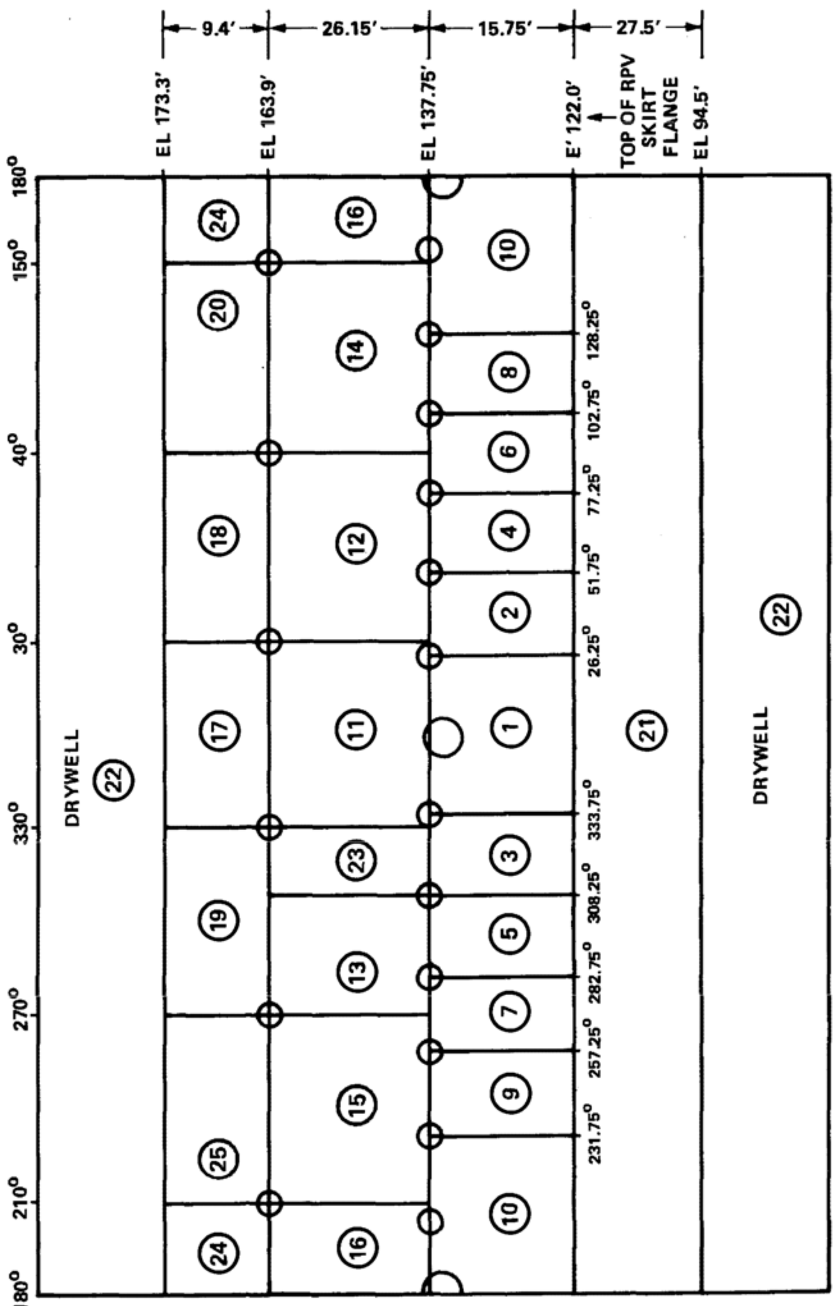
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRCULATION INLET LINE BREAK SCHEMATIC FLOW DIAGRAM [HISTORICAL INFORMATION] FIGURE 6.2 – 25a



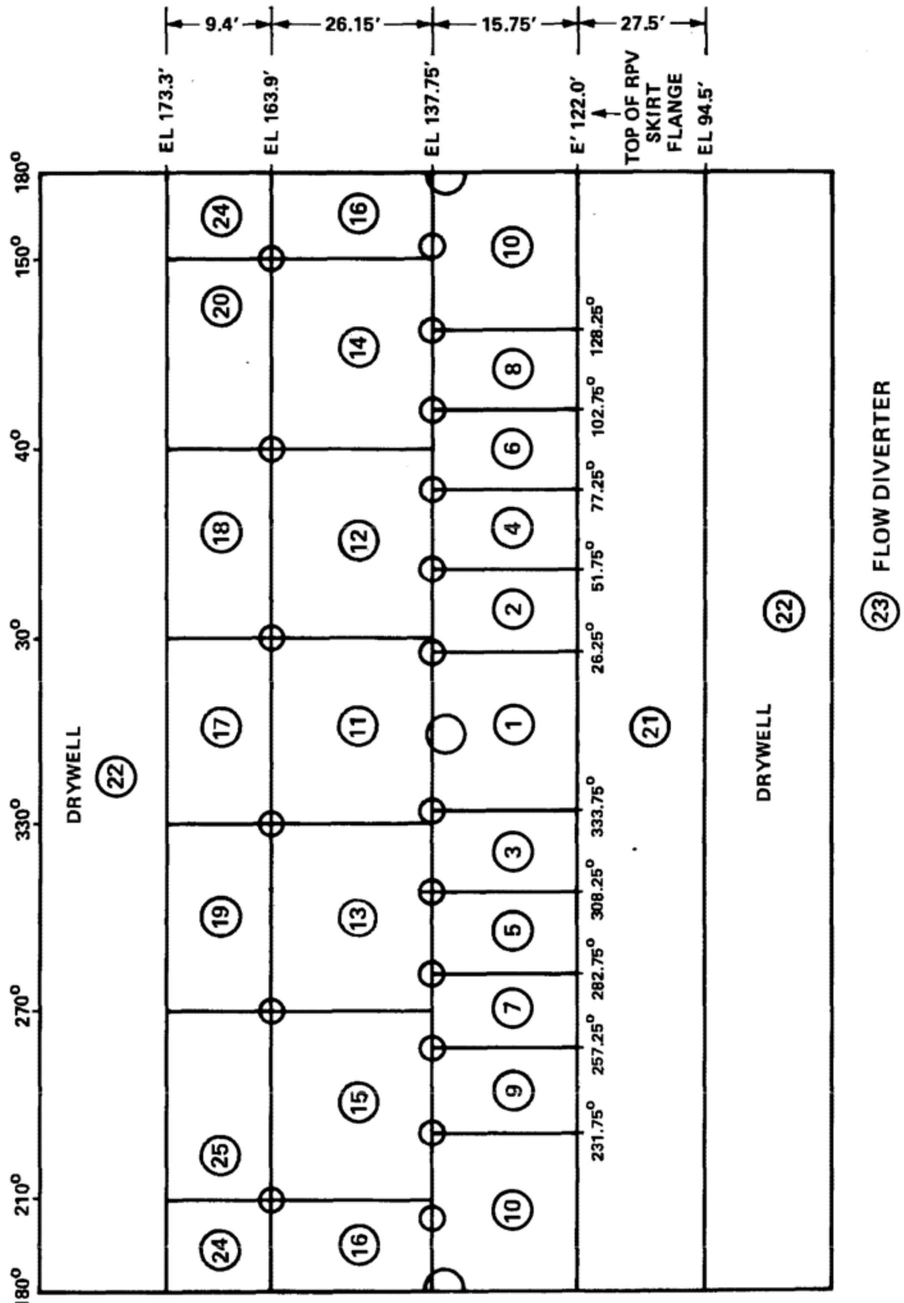
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRCULATION SUCTION LINE BREAK SCHEMATIC FLOW DIAGRAM [HISTORICAL INFORMATION] FIGURE 6.2 – 25b



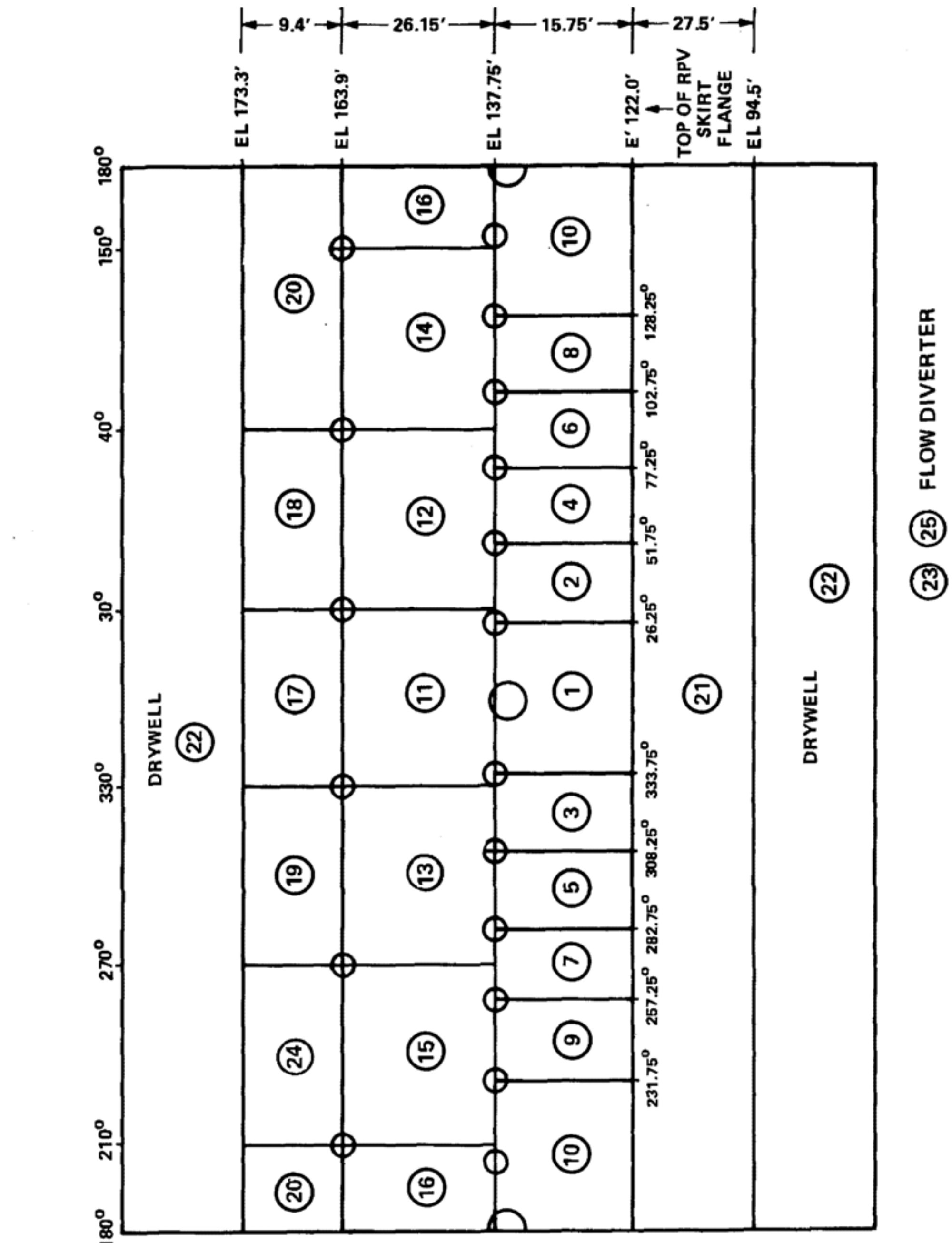
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK SCHEMATIC FLOW DIAGRAM [HISTORICAL INFORMATION] FIGURE 6.2 – 25c



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	NODAL MODEL FOR RECIRCULATION INLET LINE BREAK [HISTORICAL INFORMATION] FIGURE 6.2 – 26a



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	NODAL MODEL FOR RECIRCULATION SUCTION LINE BREAK [HISTORICAL INFORMATION] FIGURE 6.2 – 26b



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	NODAL MODEL FOR FEEDWATER LINE BREAK [HISTORICAL INFORMATION] FIGURE 6.2-26c

Figure 6.2-27
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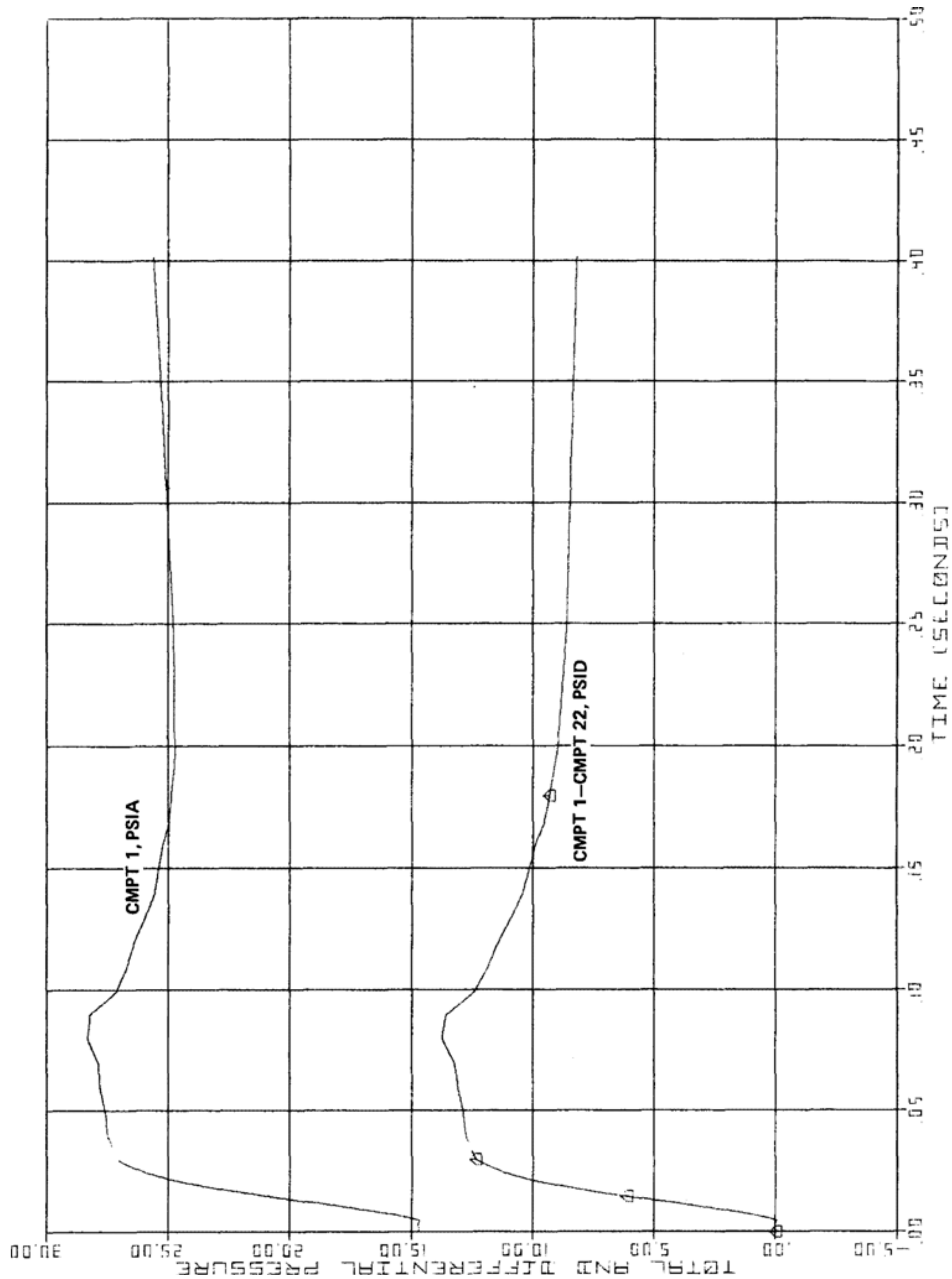

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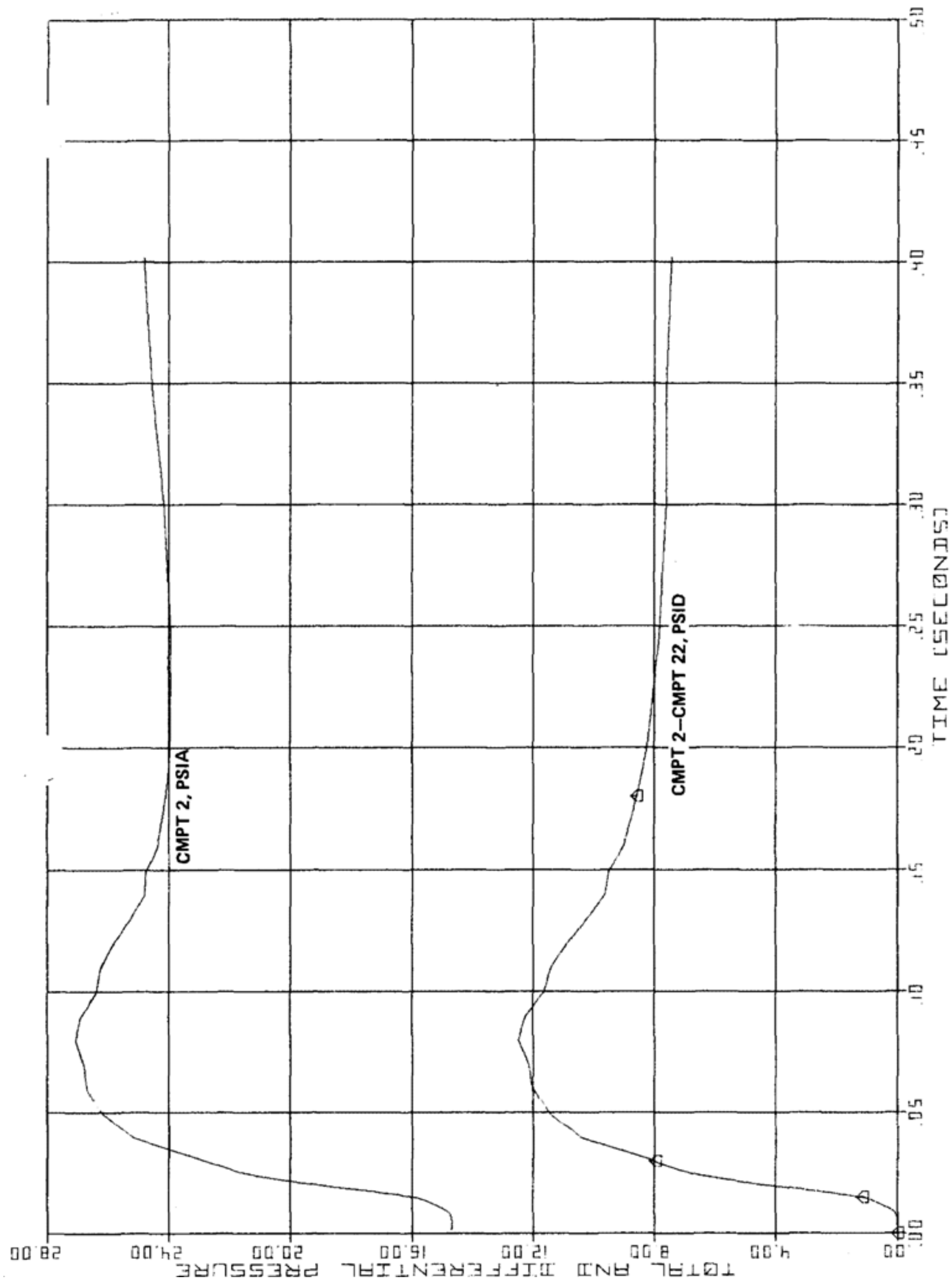
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 1, PSIA; CMPT 1-CMPT 22, PSID
[HISTORICAL INFORMATION]
FIGURE 6.2 – 27aa



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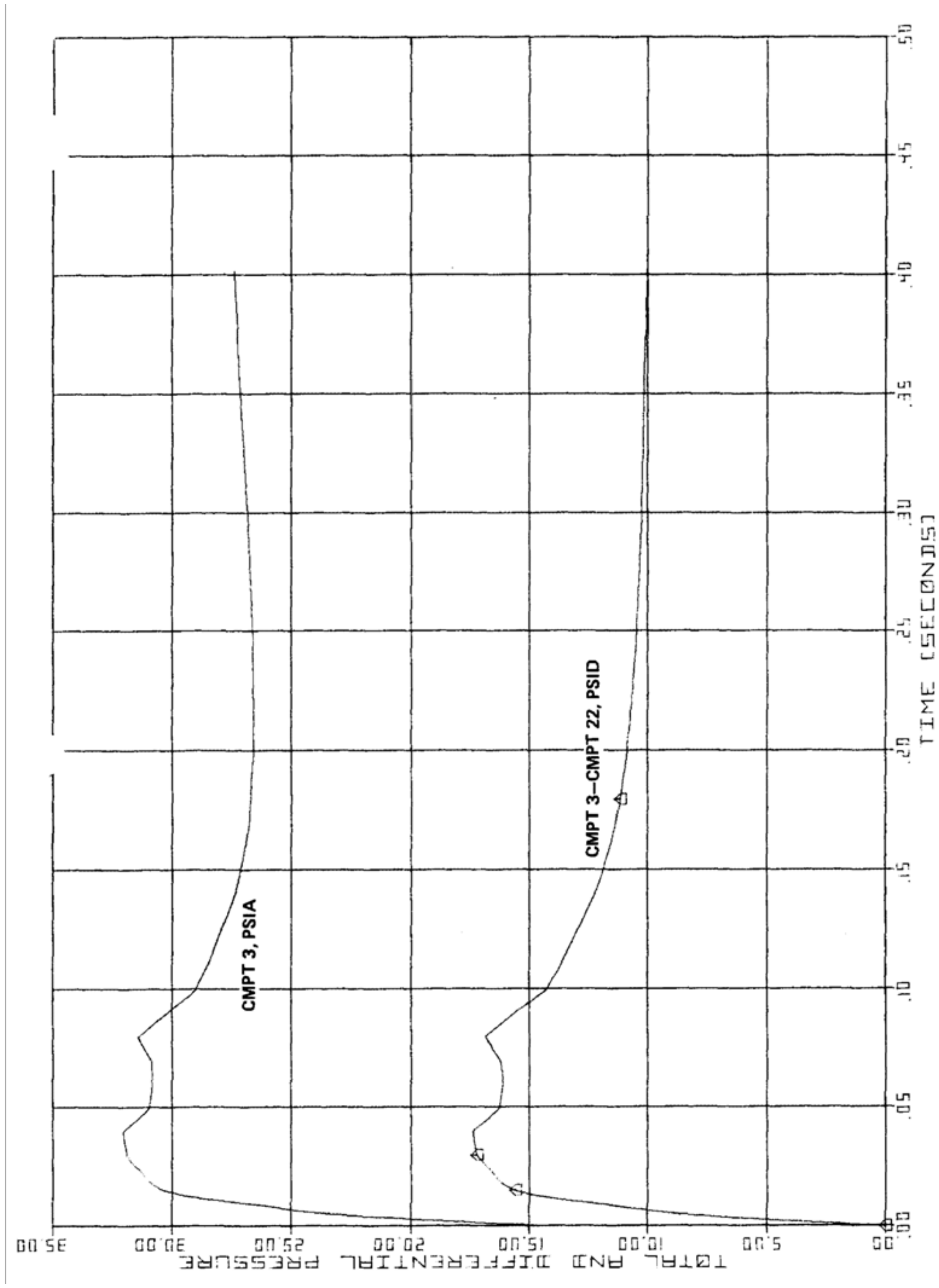
PRESSURE RESPONSES FOR RECIRC RETURN LINE BREAK CMPT 2, PSIA; CMPT 2-CMPT 22, PSID [HISTORICAL INFORMATION]
FIGURE 6.2 – 27ab



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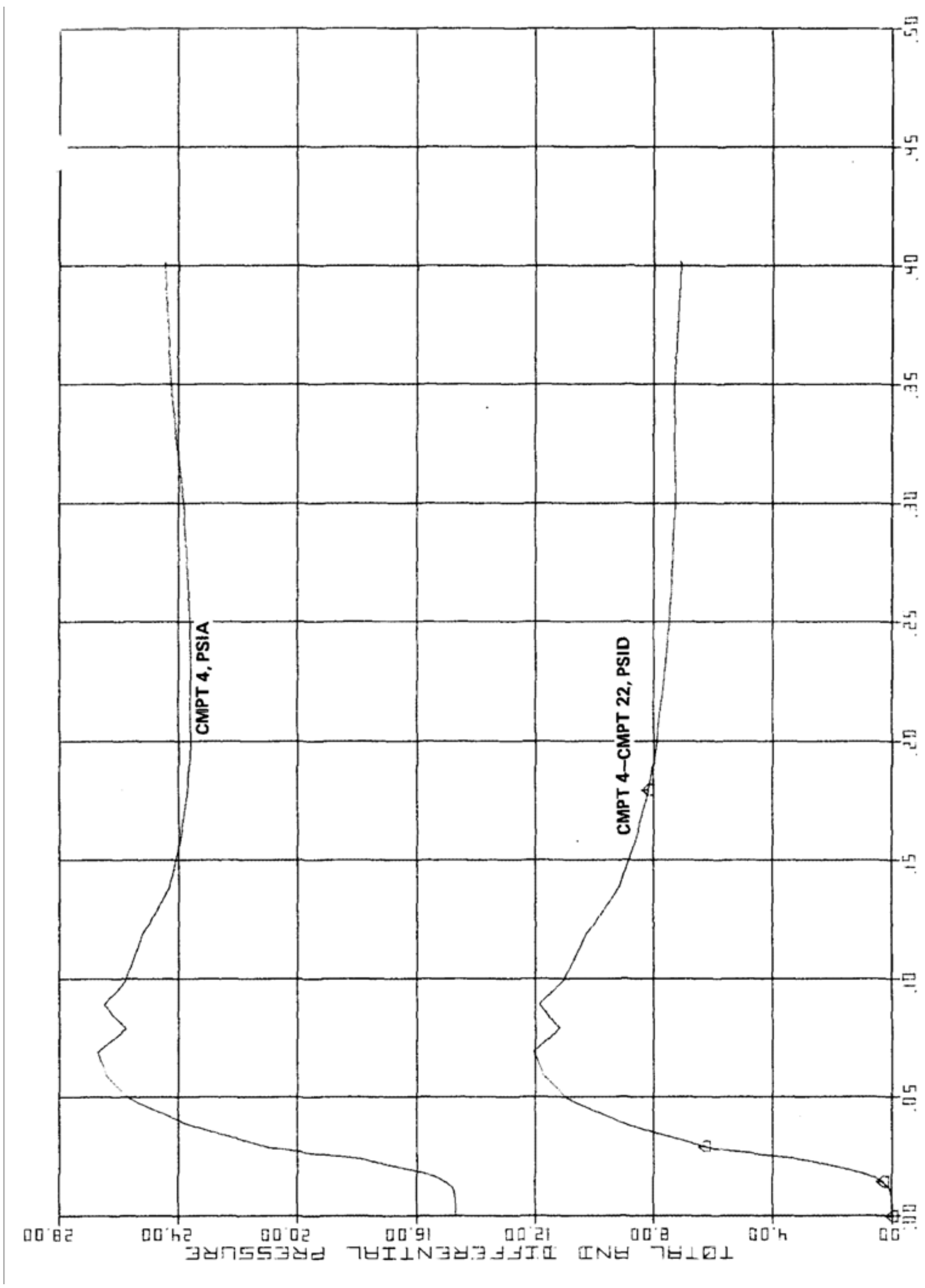
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 3, PSIA; CMPT 3-CMPT 22, PSID
[HISTORICAL INFORMATION]
FIGURE 6.2 – 27ac



[HISTORICAL INFORMATION]

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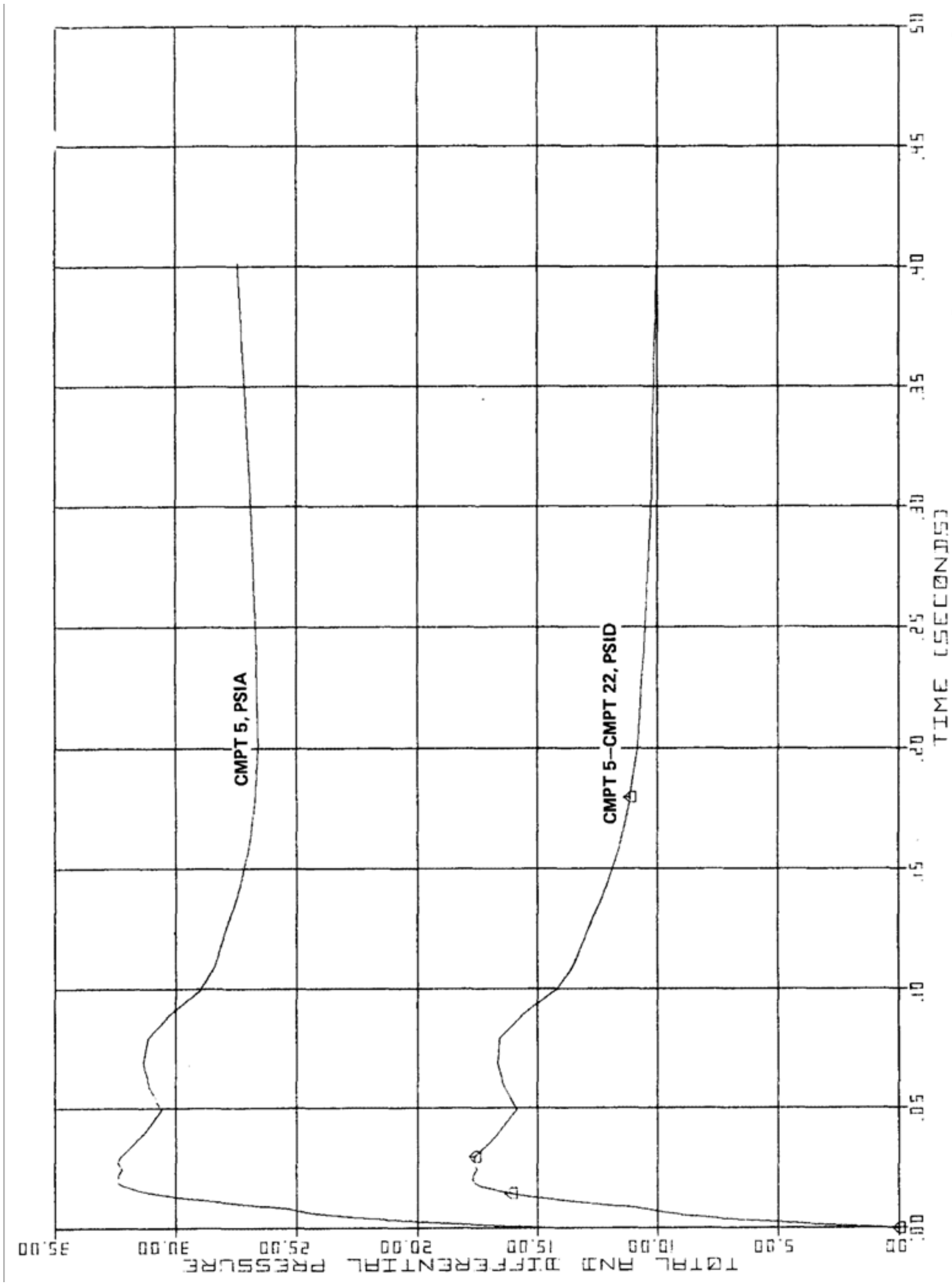
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 4, PSIA; CMPT 4-CMPT 22, PSID

FIGURE 6.2 – 27ad



[HISTORICAL INFORMATION]

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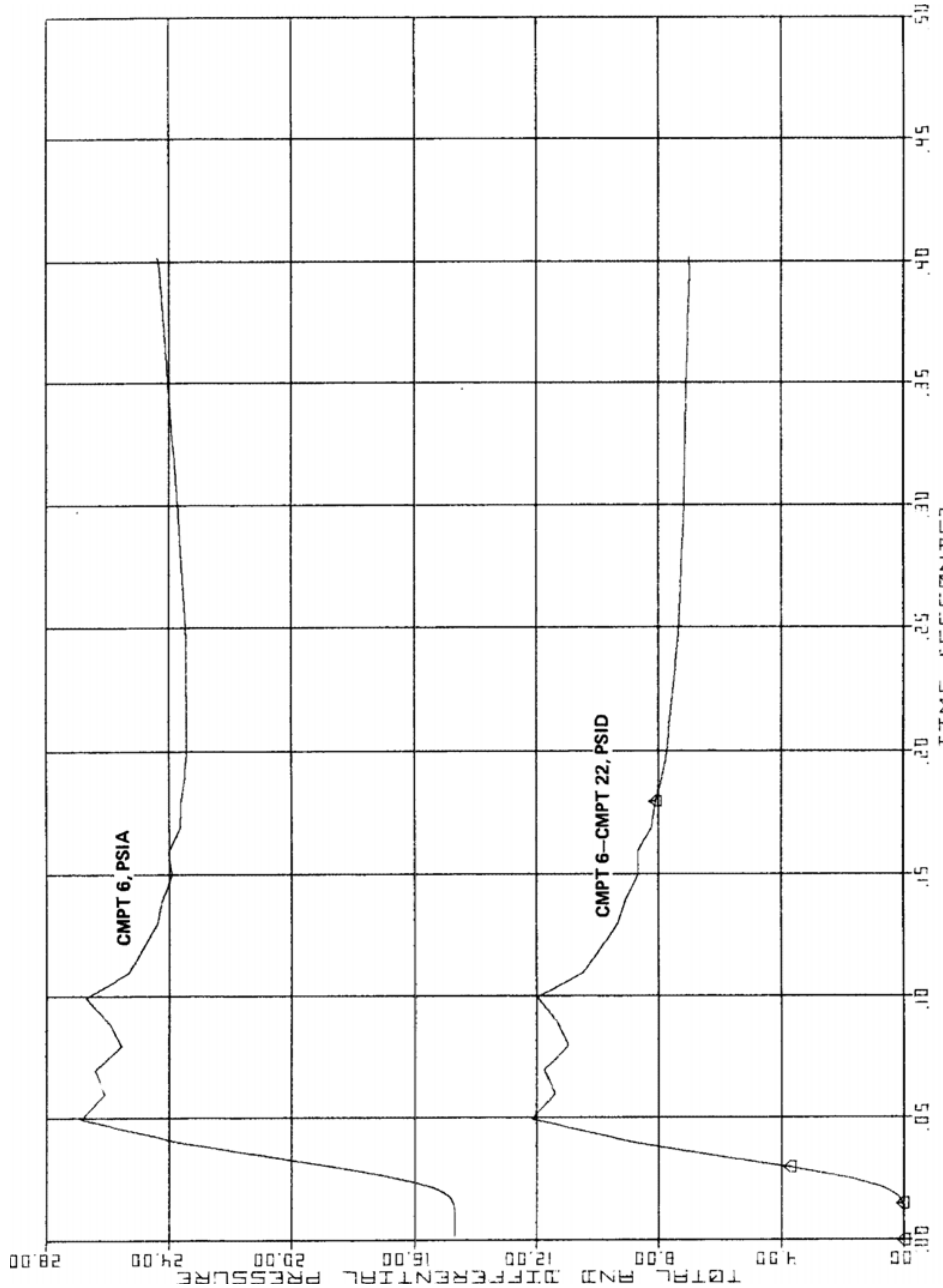
PRESSURE RESPONSES FOR RECIRC RETURN LINE BREAK CMPT 5, PSIA; CMPT 5-CMPT 22, PSID

FIGURE 6.2 – 27ae



[HISTORICAL INFORMATION]

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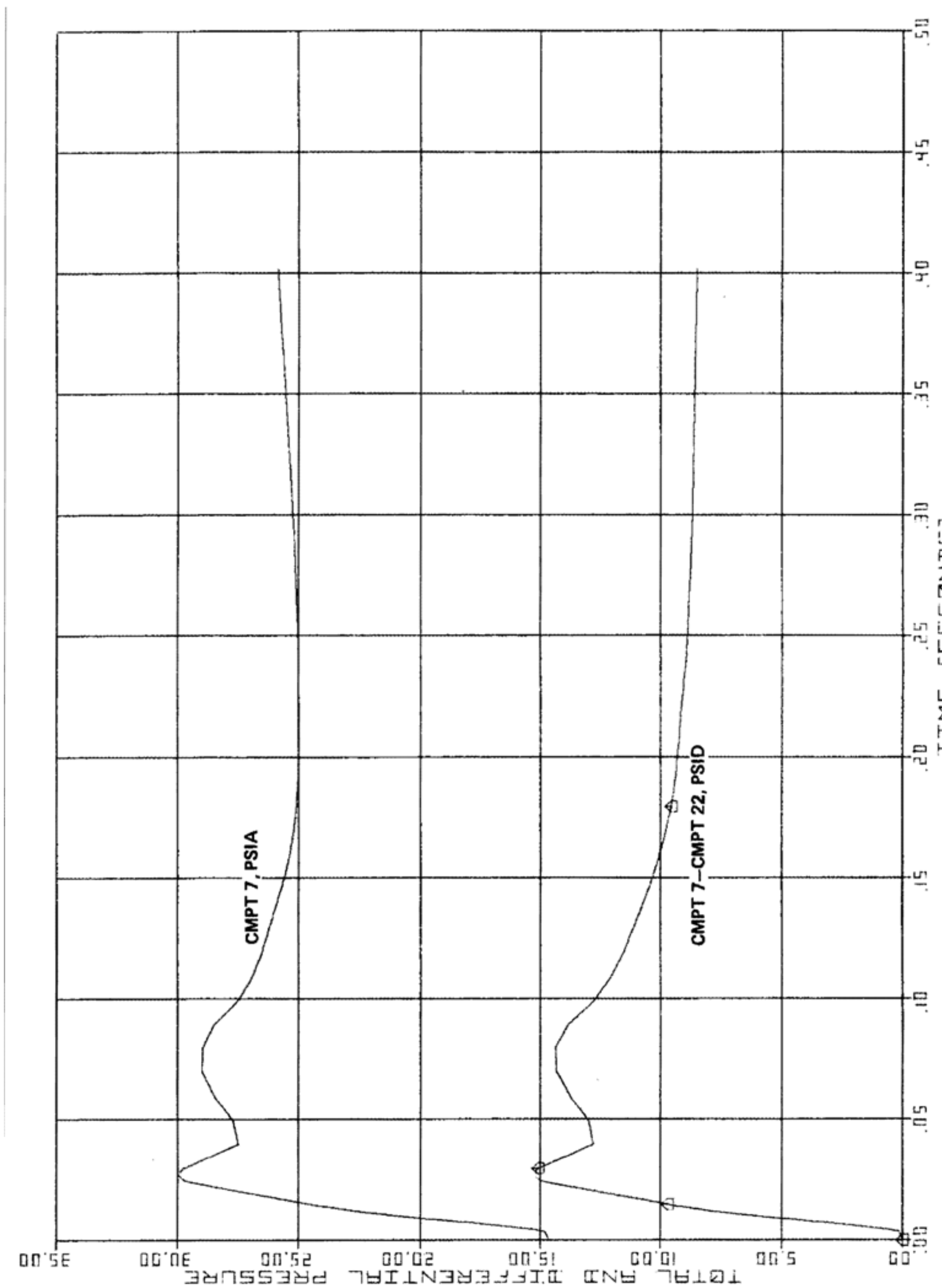
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 6, PSIA; CMPT 6-CMPT 22, PSID

FIGURE 6.2 – 27af



[HISTORICAL INFORMATION]

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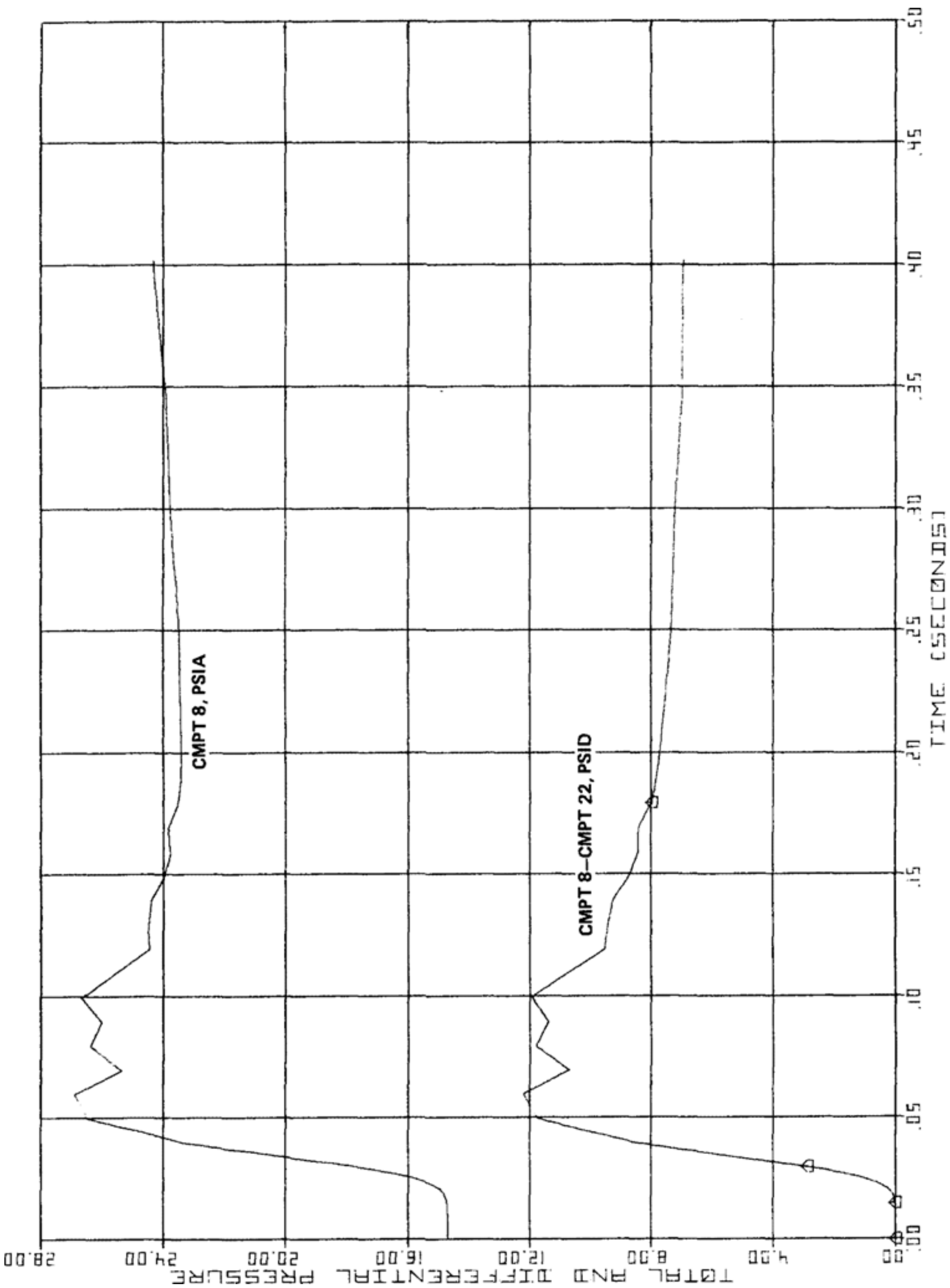
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 7, PSIA; CMPT 7-CMPT 22, PSID

FIGURE 6.2 – 27ag



[HISTORICAL INFORMATION]

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GRAND GULF NUCLEAR STATION
UNITS 1 & 2
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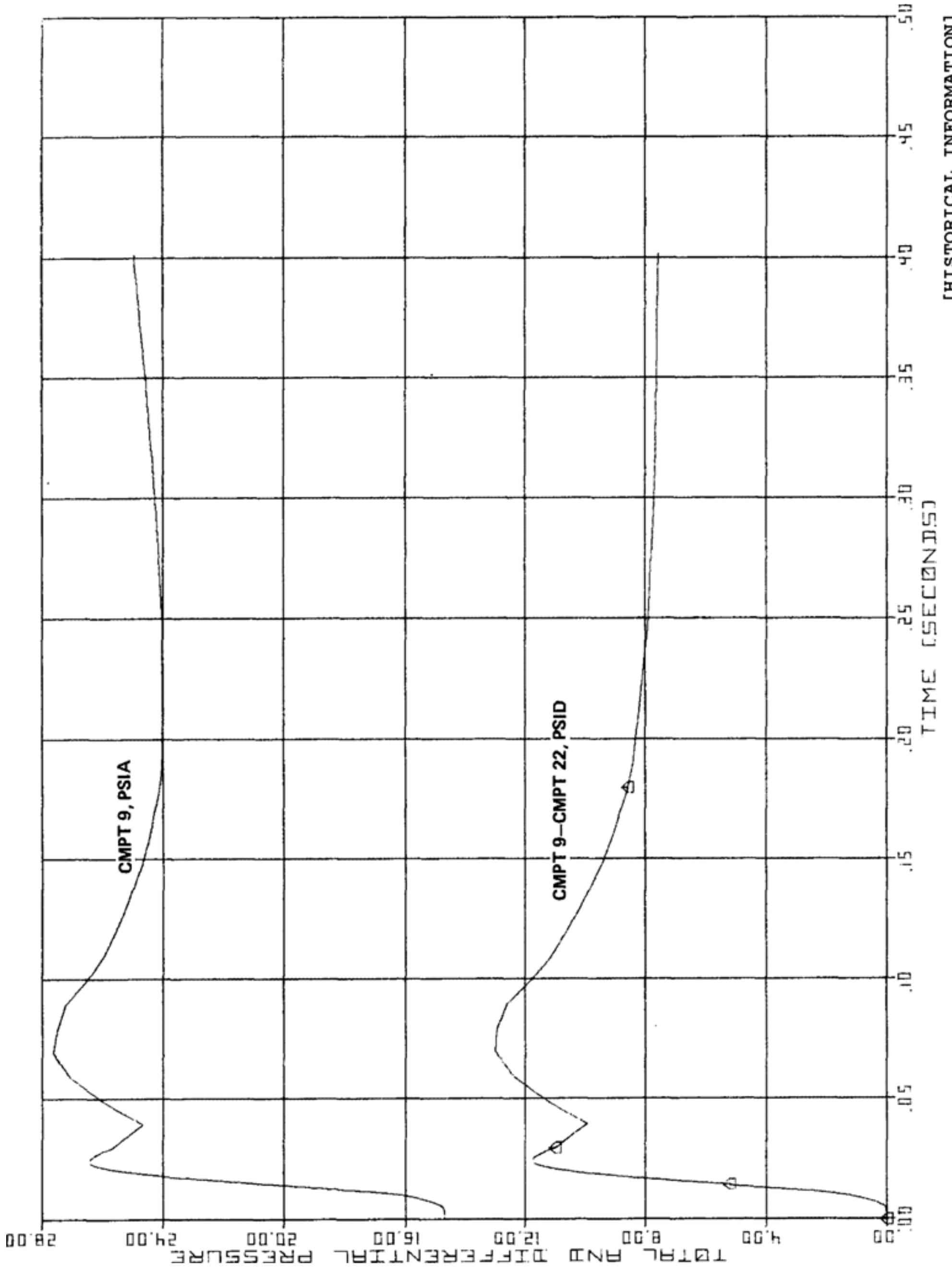
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 8, PSIA; CMPT 8-CMPT 22, PSID

FIGURE 6.2 – 27ah



[HISTORICAL INFORMATION]

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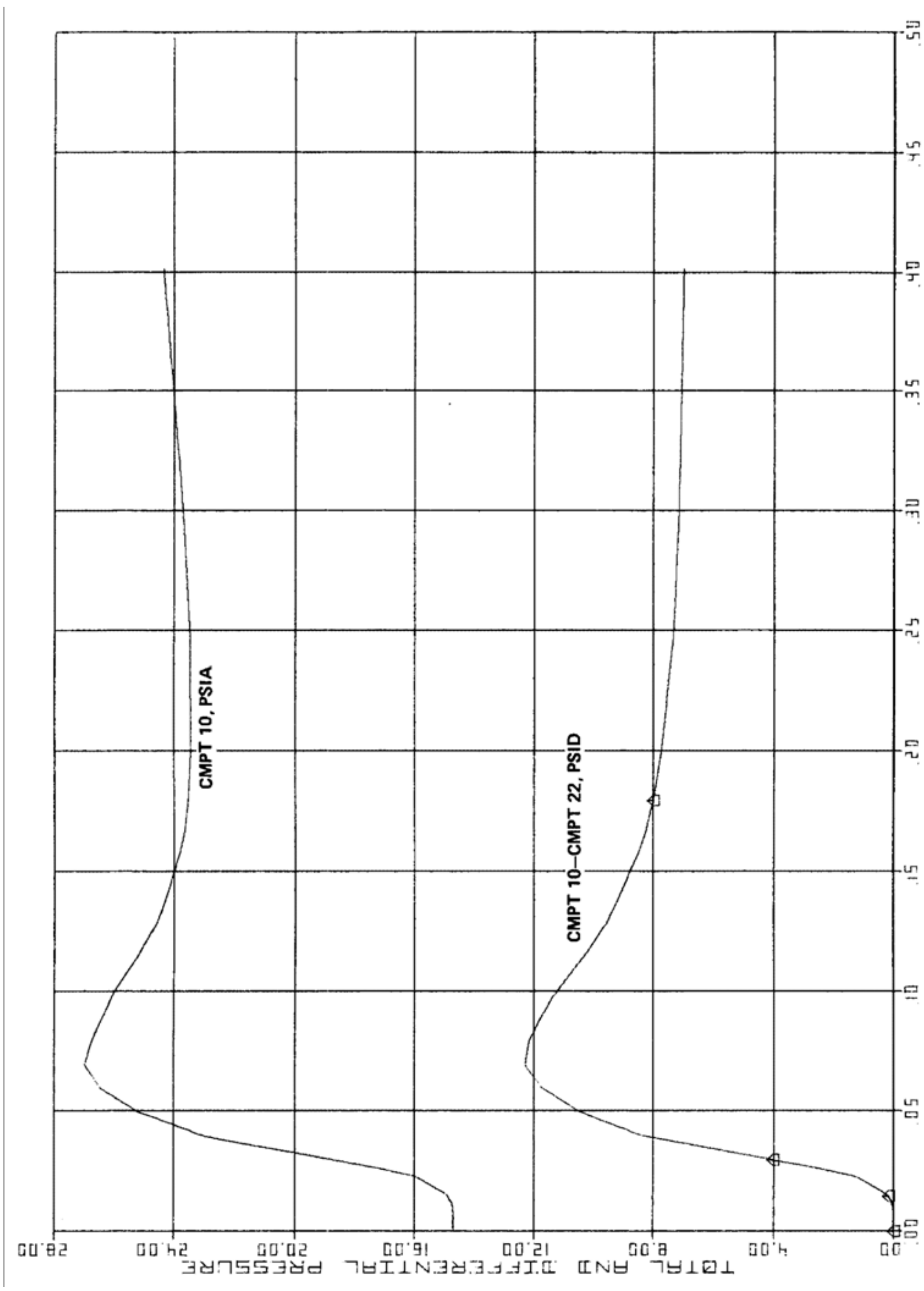
UPDATED FINAL SAFETY ANALYSIS REPORT

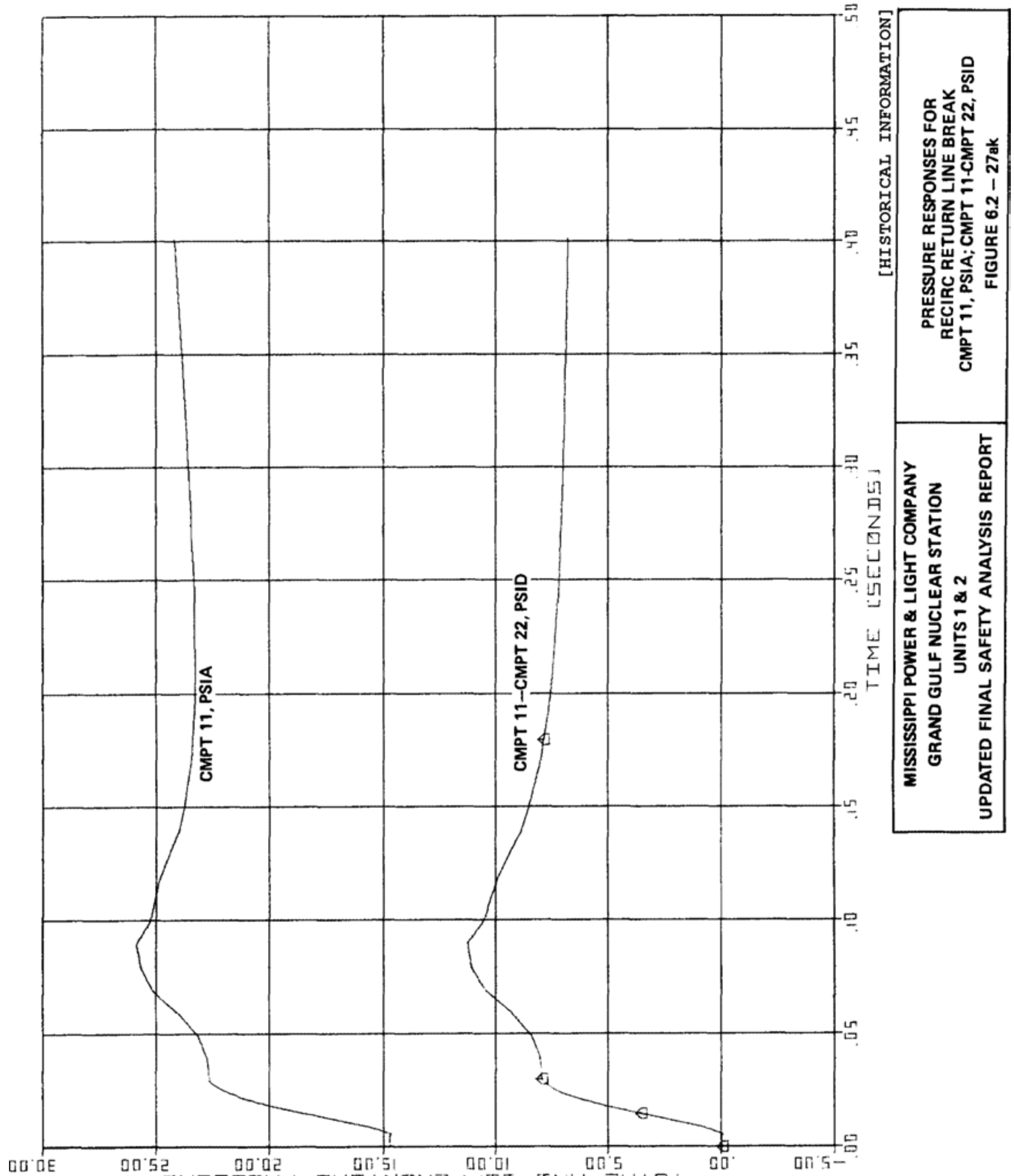
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 9, PSIA; CMPT 9-CMPT 22, PSID
FIGURE 6.2 – 27ai

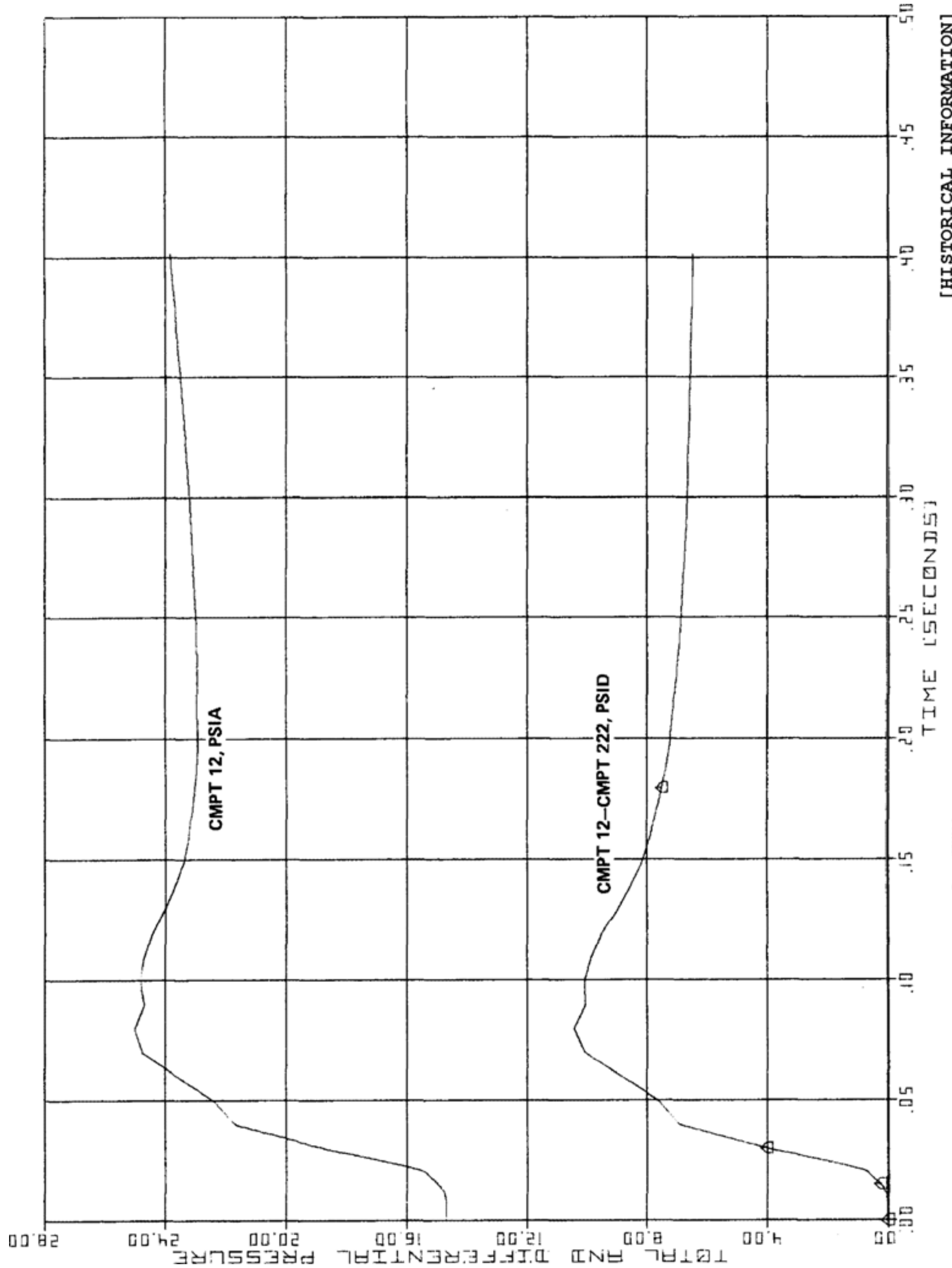


[HISTORICAL INFORMATION]

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 10, PSIA; CMPT 10-CMPT 22, PSID
FIGURE 6.2 – 27aj

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT


CMPT 11, PSIA
CMPT 11—CMPT 22, PSID
TIME (SECONDS)
TOTAL AND DIFFERENTIAL PRESSURE
.00
.05
.10
.15
.20
.25
.30
.35
.40
.45
.50
-5.00
.00
5.00
10.00
15.00
20.00
25.00
30.00
[HISTORICAL INFORMATION]
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 11, PSIA; CMPT 11-CMPT 22, PSID
FIGURE 6.2 — 27ak

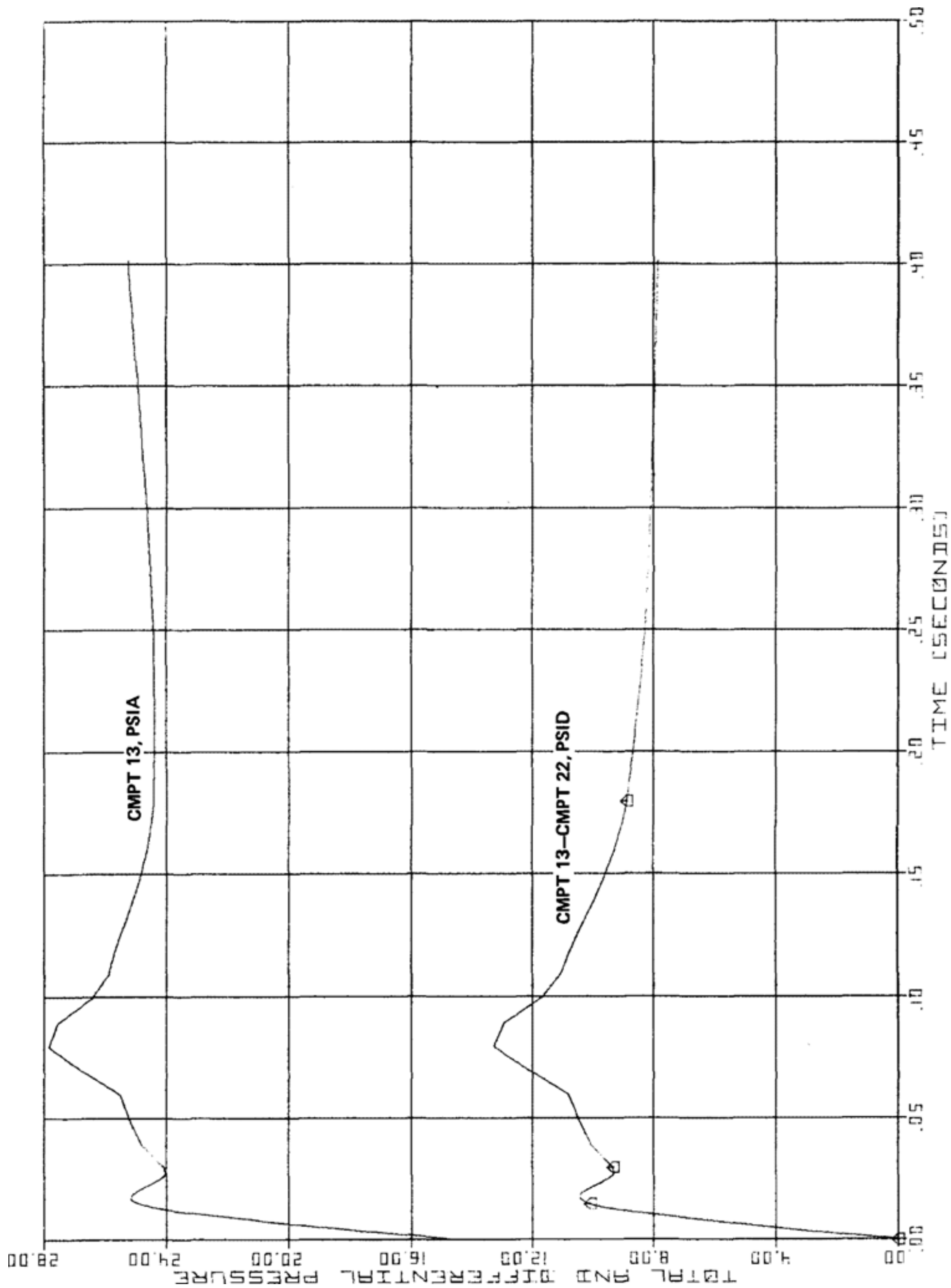


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 12, PSIA; CMPT 12-CMPT 22, PSID

FIGURE 6.2 – 27al

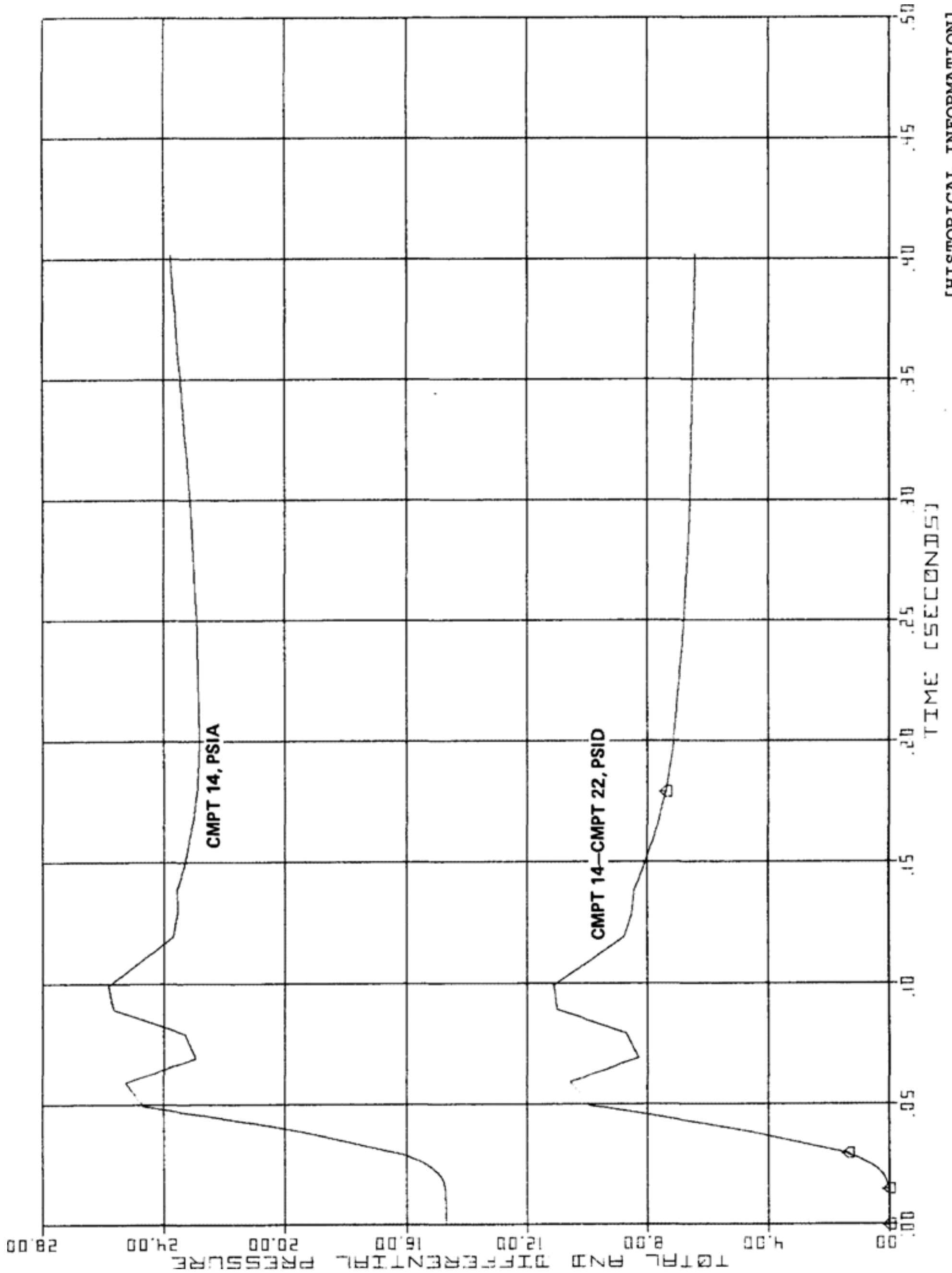


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 13, PSIA; CMPT 13-CMPT 22, PSID

FIGURE 6.2 – 27am

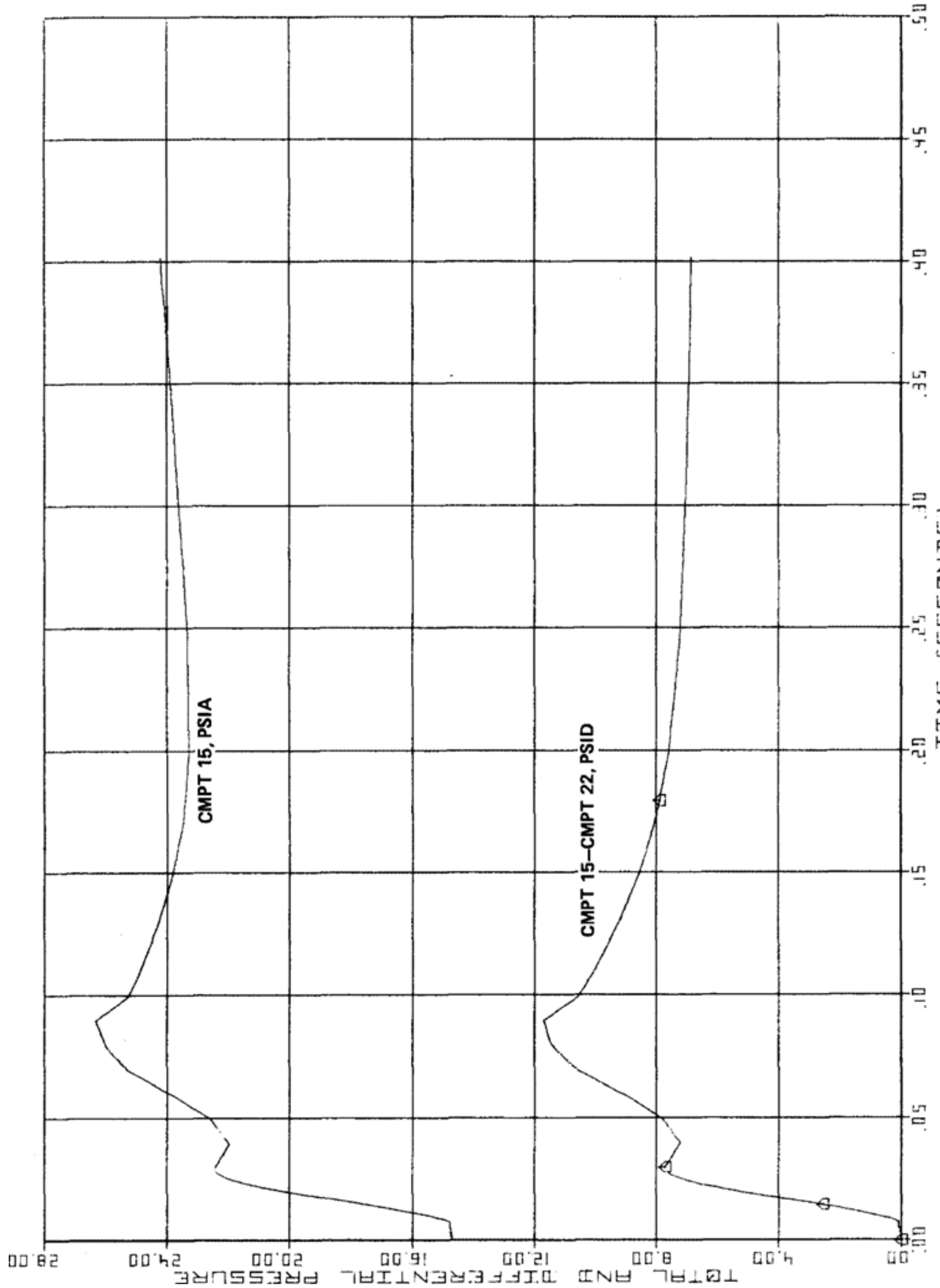


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 14, PSIA; CMPT 14-CMPT 22, PSID

FIGURE 6.2 – 27an



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

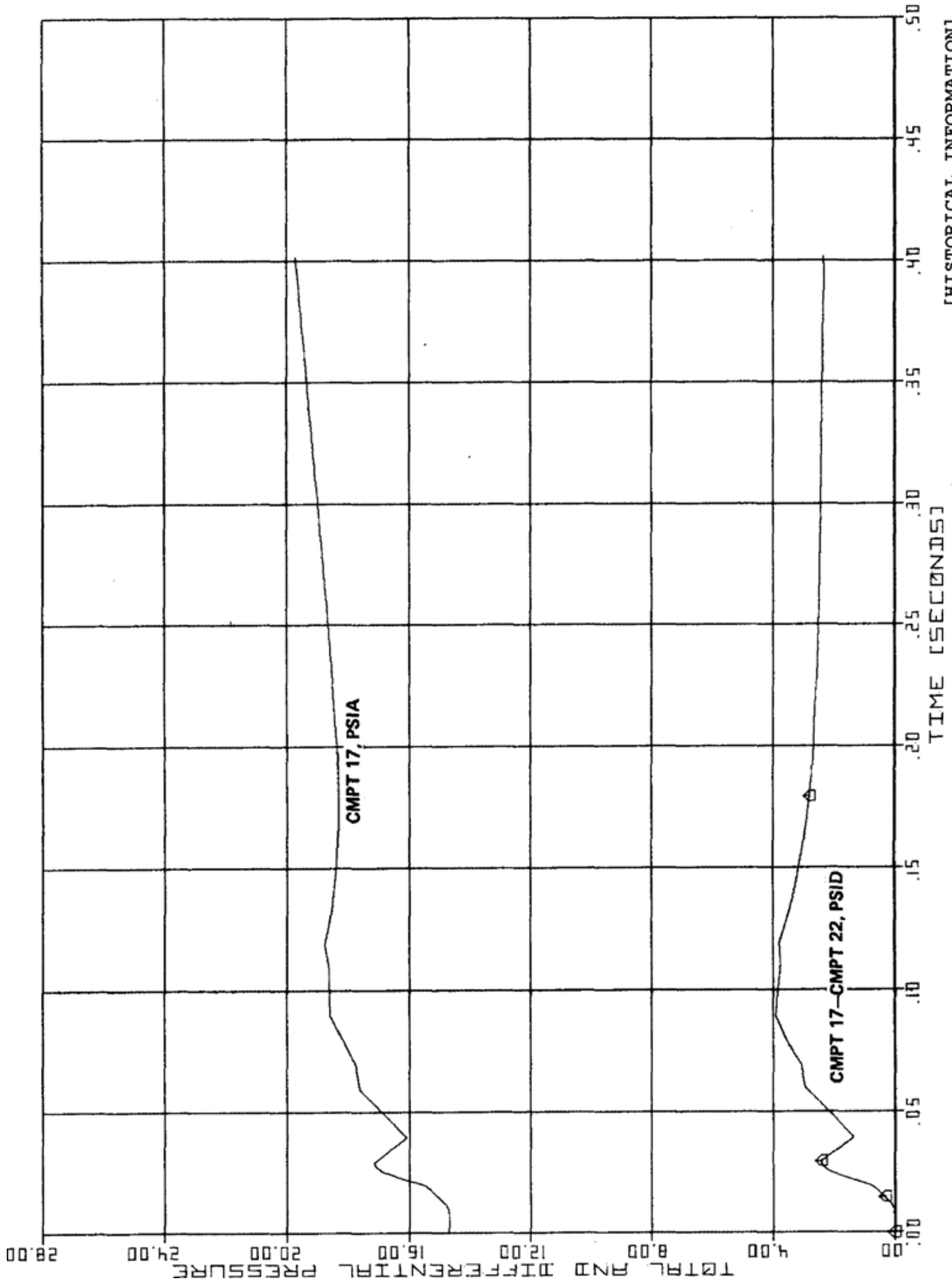
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 15, PSIA; CMPT 15-CMPT 22, PSID
FIGURE 6.2 — 27ao

[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 16, PSIA; CMPT 16-CMPT 22, PSID

FIGURE 6.2 – 27ap

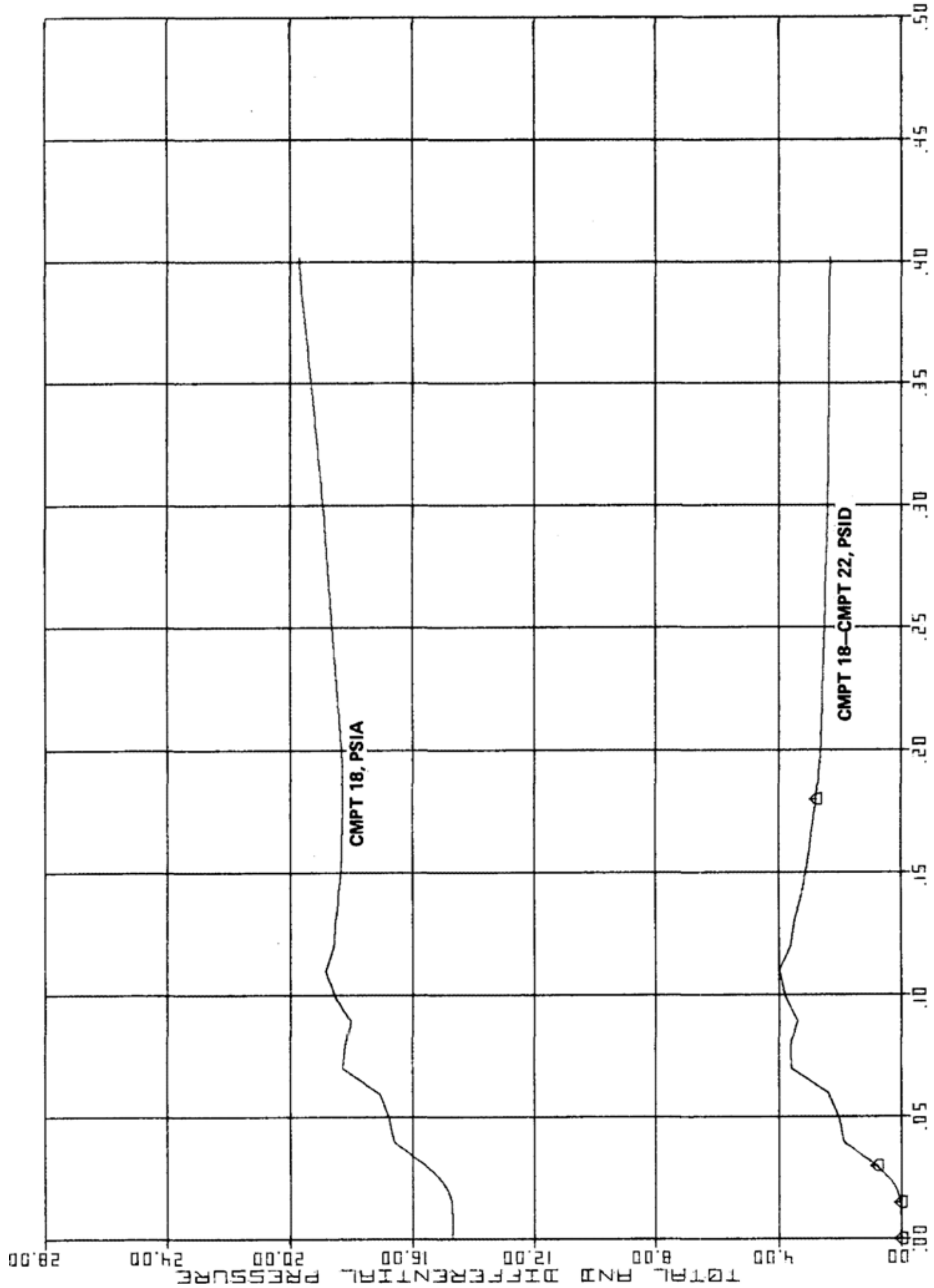


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 17, PSIA; CMPT 17-CMPT 22, PSID

FIGURE 6.2 – 27aq



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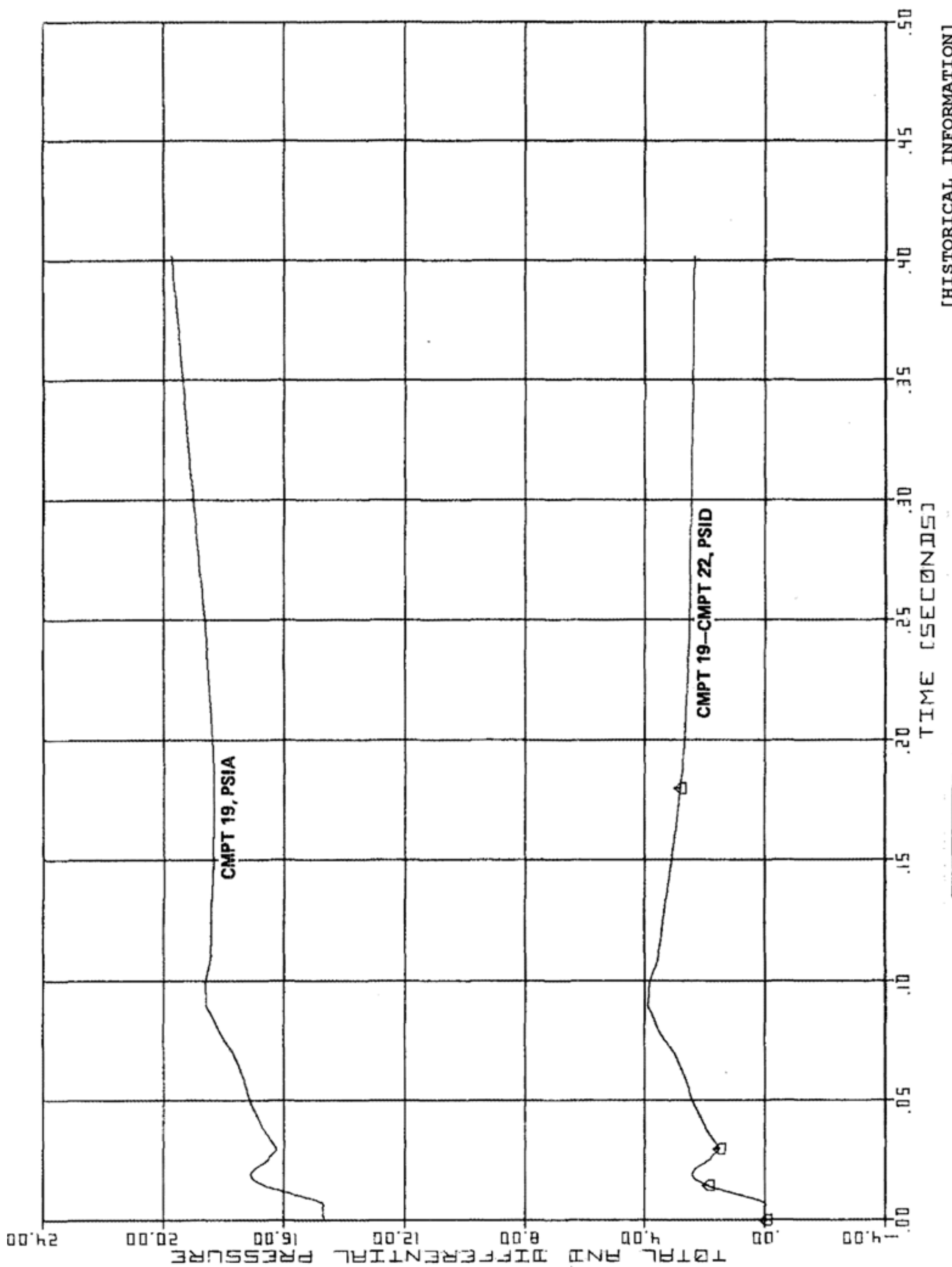
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 18, PSIA; CMPT 18-CMPT 22, PSID

FIGURE 6.2 – 27ar



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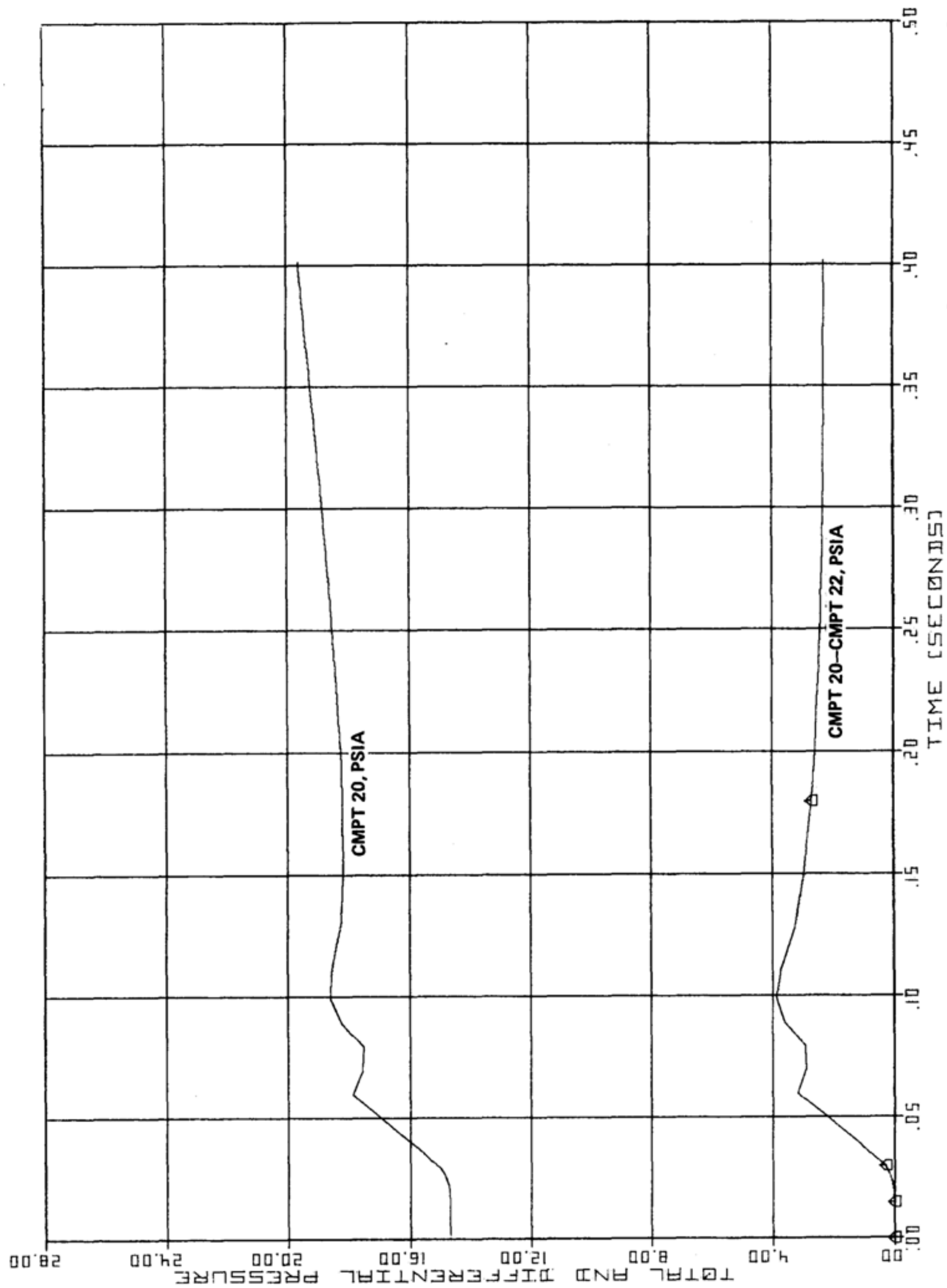
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 19, PSIA; CMPT 19-CMPT 22, PSID

FIGURE 6.2 – 27as

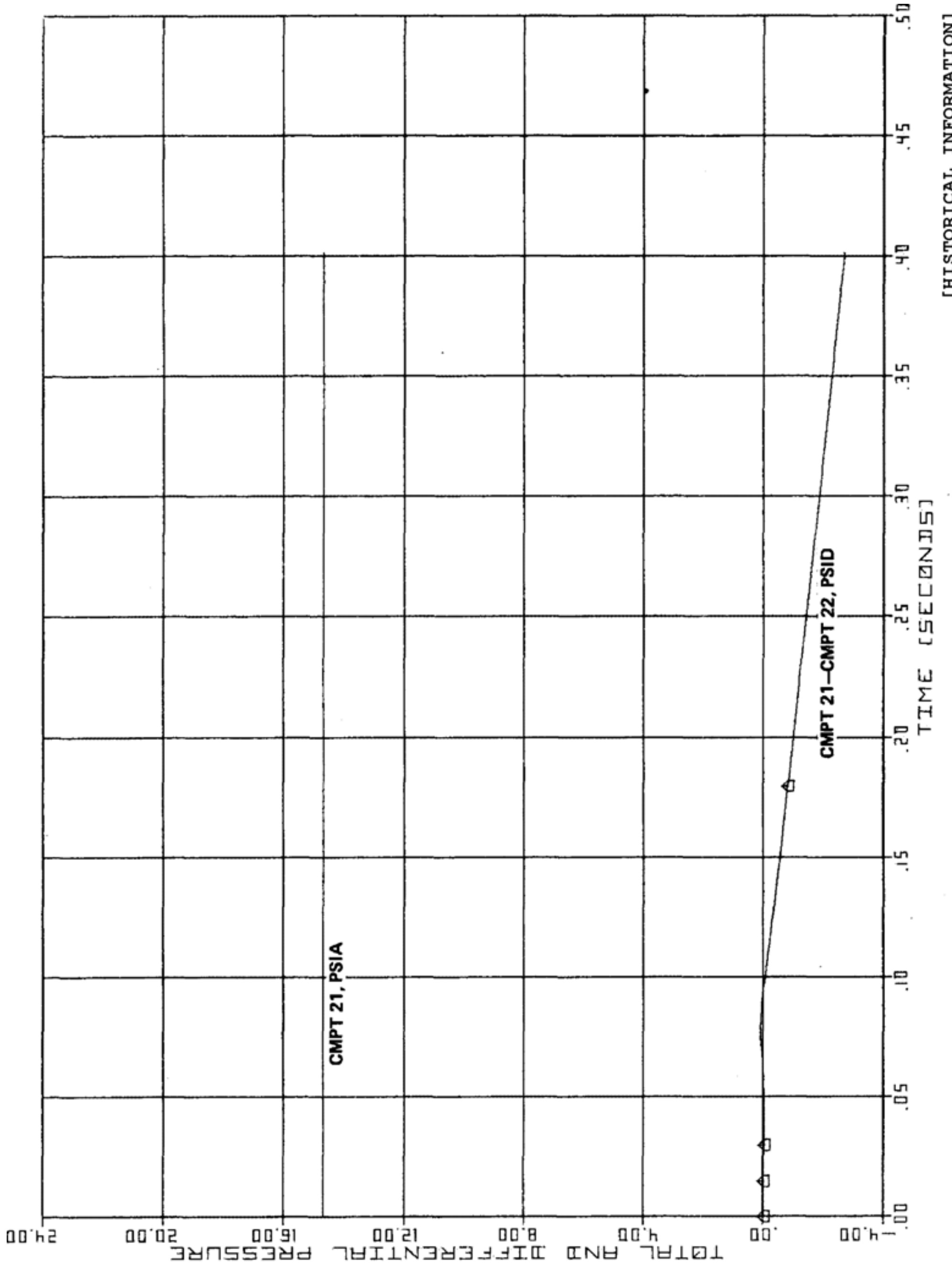


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 20, PSIA; CMPT 20-CMPT 22, PSID

FIGURE 6.2 — 27at

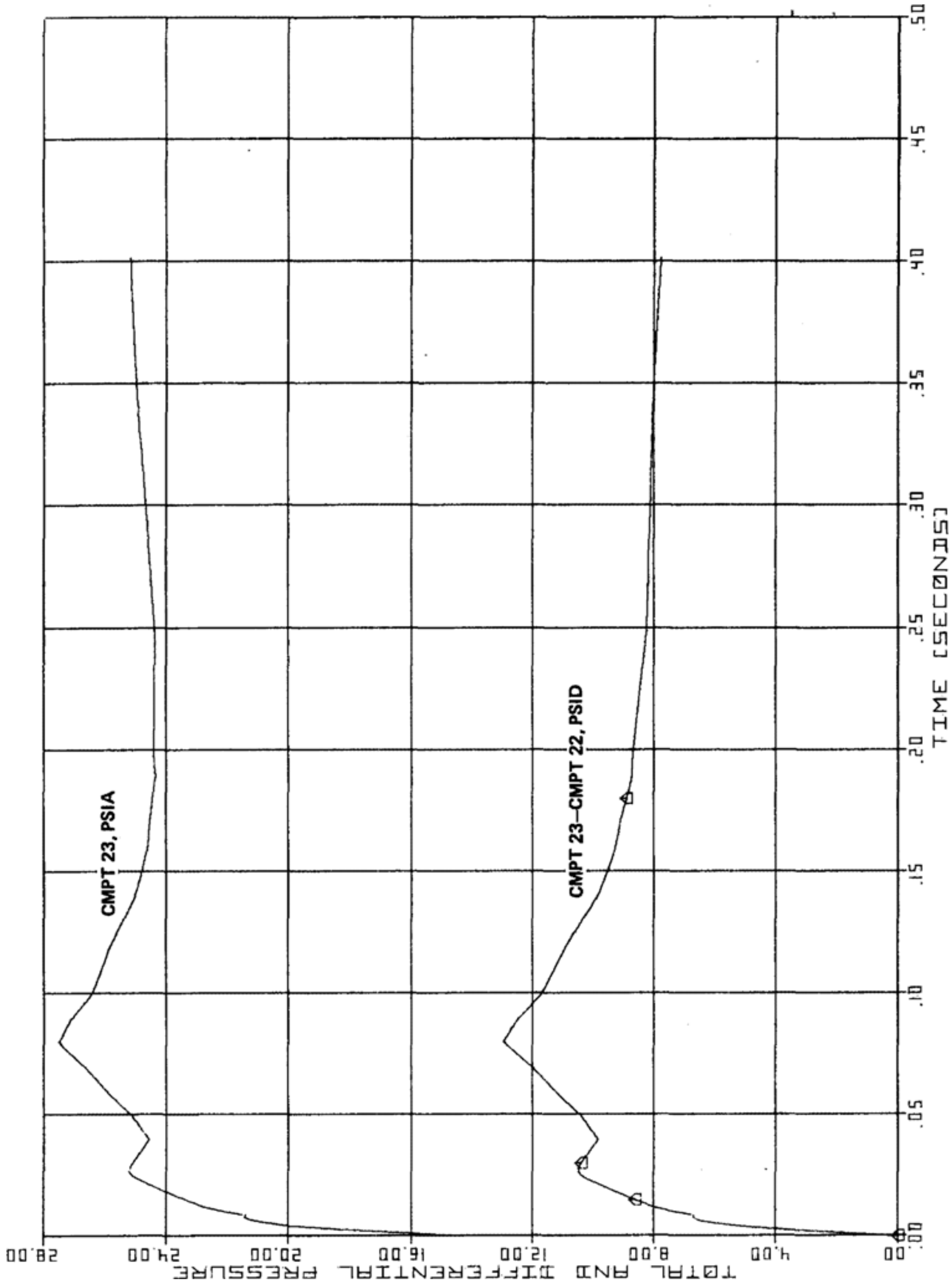


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 21, PSIA; CMPT 21-CMPT 22, PSID

FIGURE 6.2 — 27au

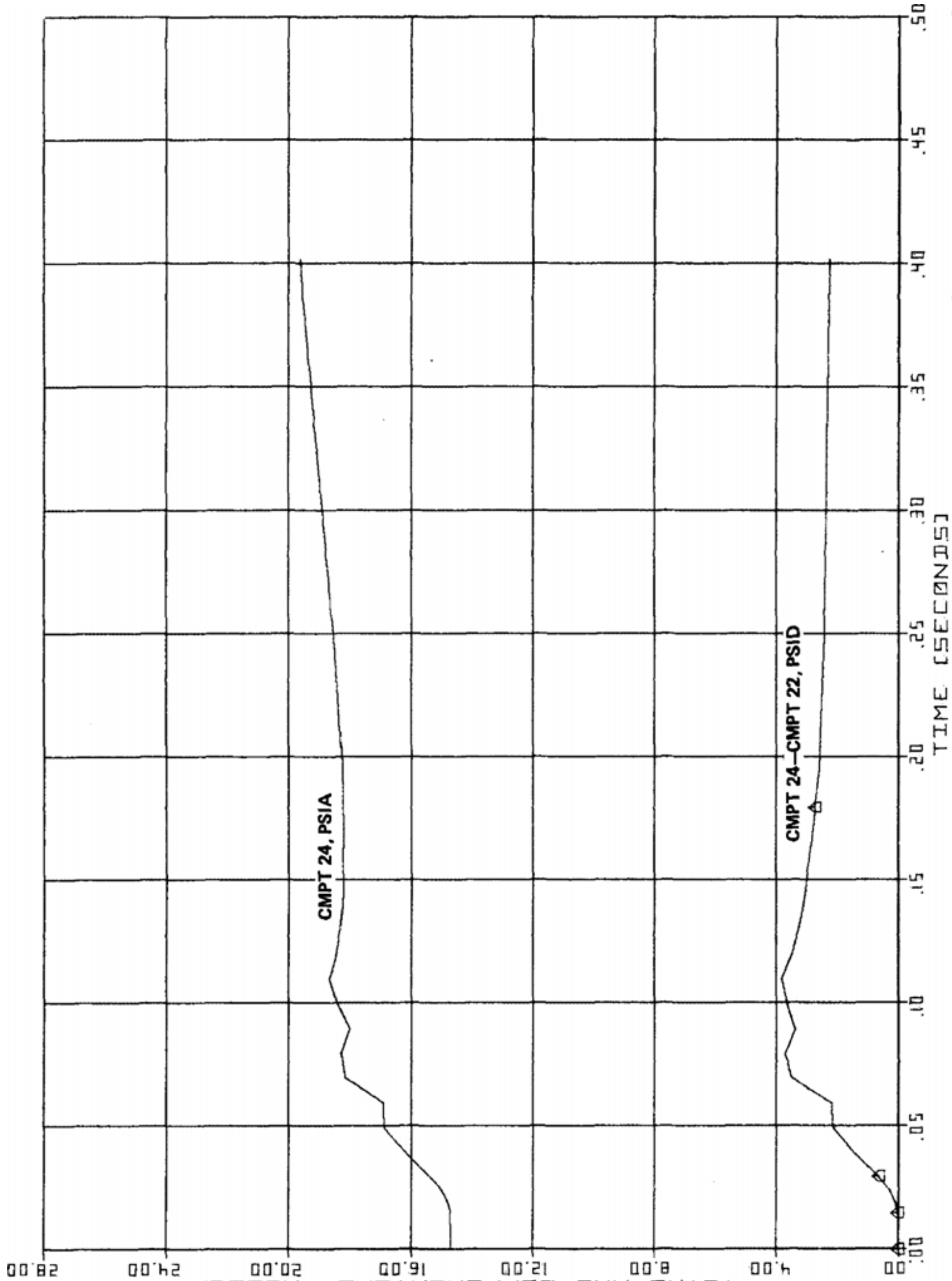


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 23, PSIA; CMPT 23-CMPT 22, PSID

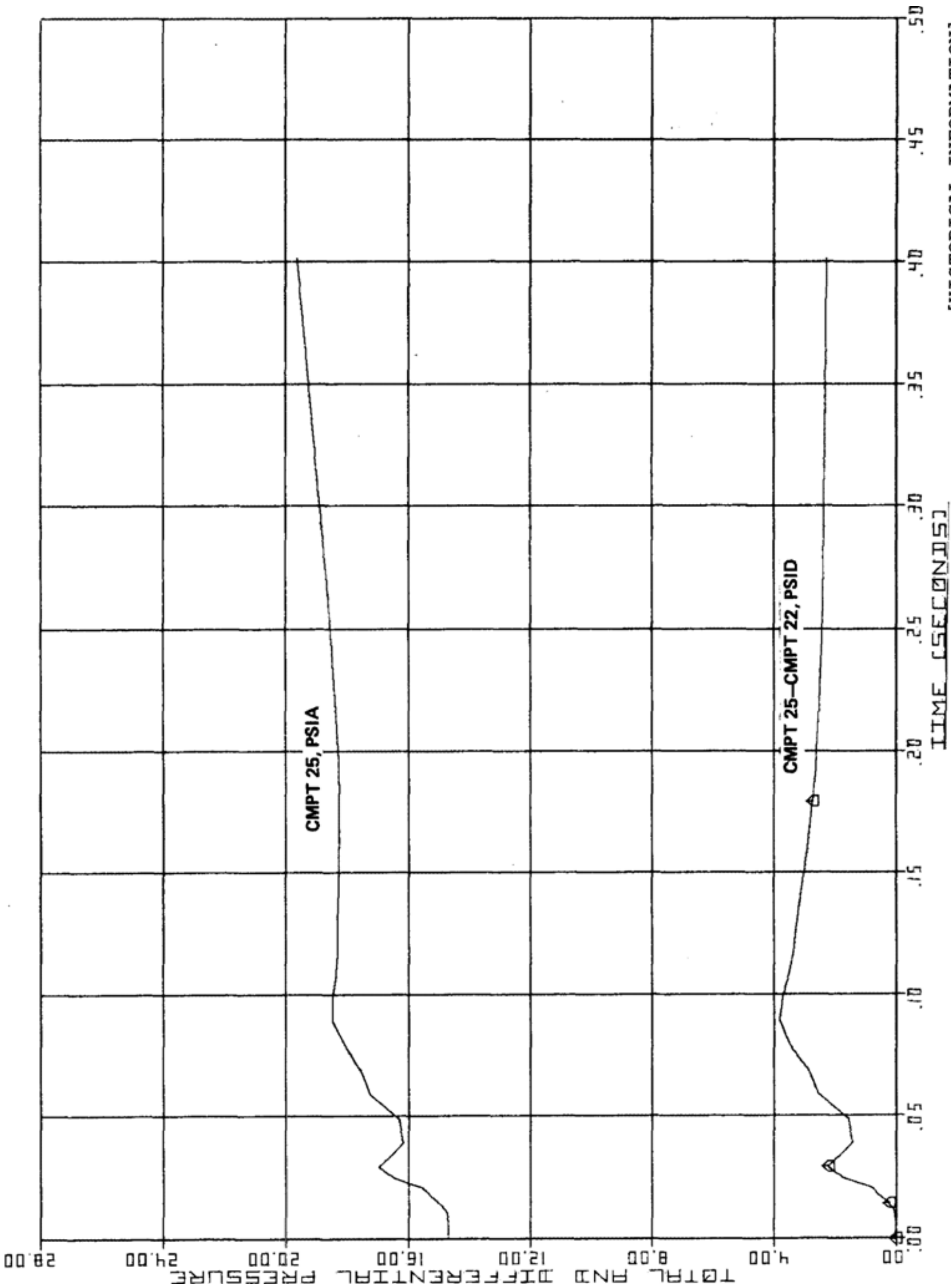
FIGURE 6.2 – 27av



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE RESONSES FOR
RECIRC RETURN LINE BREAK
CMPT 24, PSIA; CMPT 24-CMPT 22, PSID
FIGURE 6.2 — 27aw



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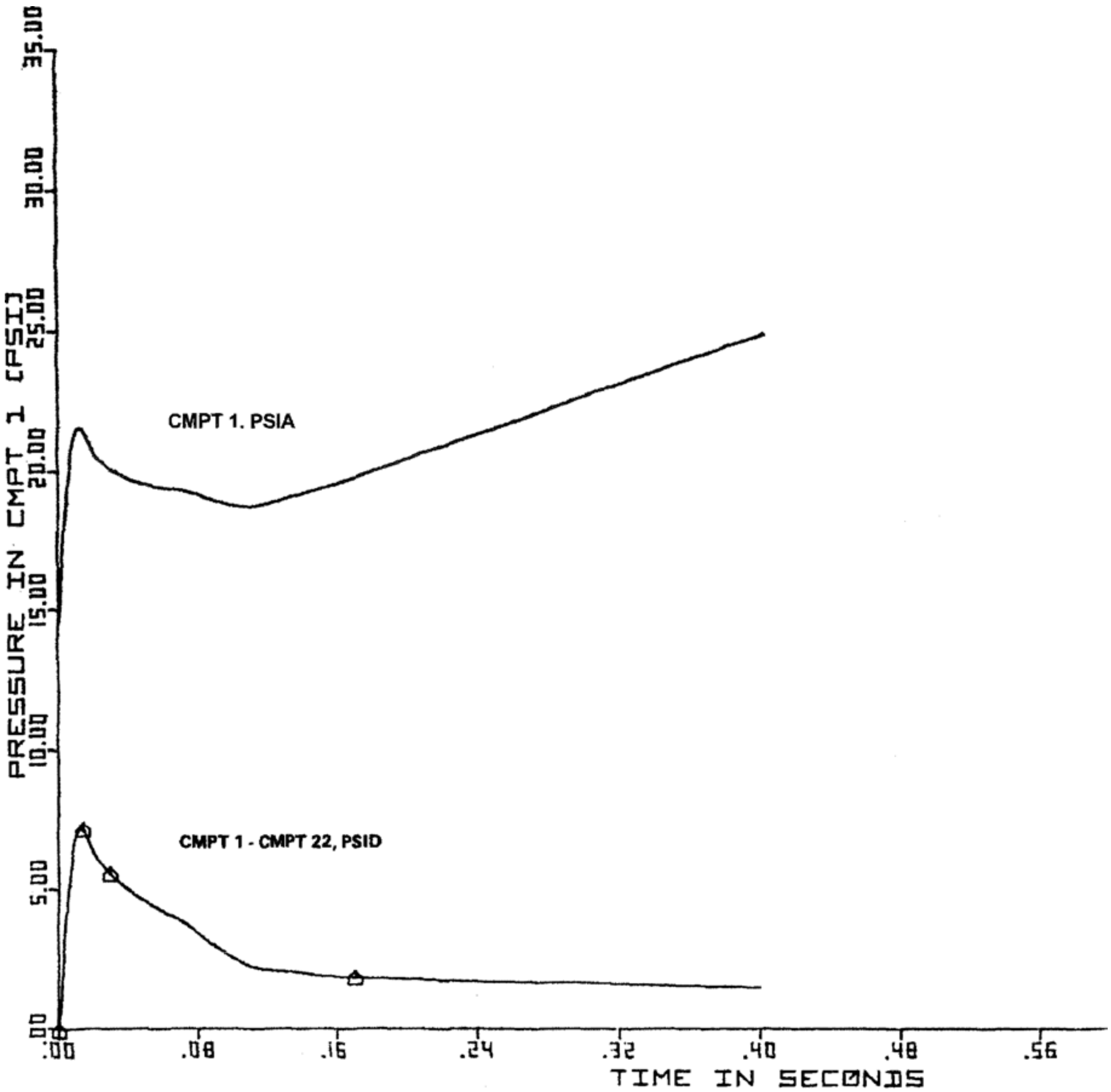
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

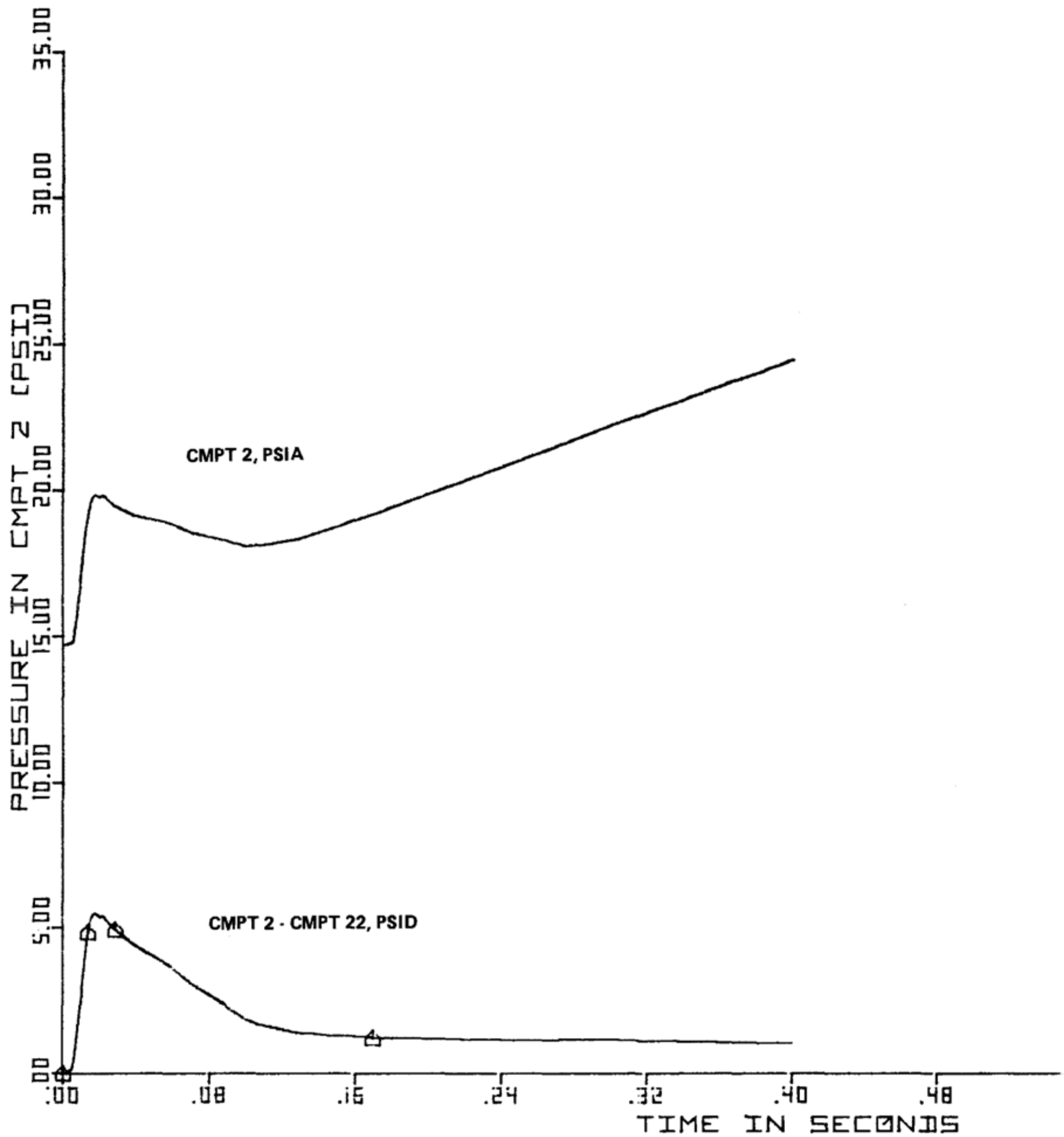
PRESSURE RESPONSES FOR
RECIRC RETURN LINE BREAK
CMPT 25, PSIA; CMPT 25-CMPT 22, PSID

FIGURE 6.2 – 27ax



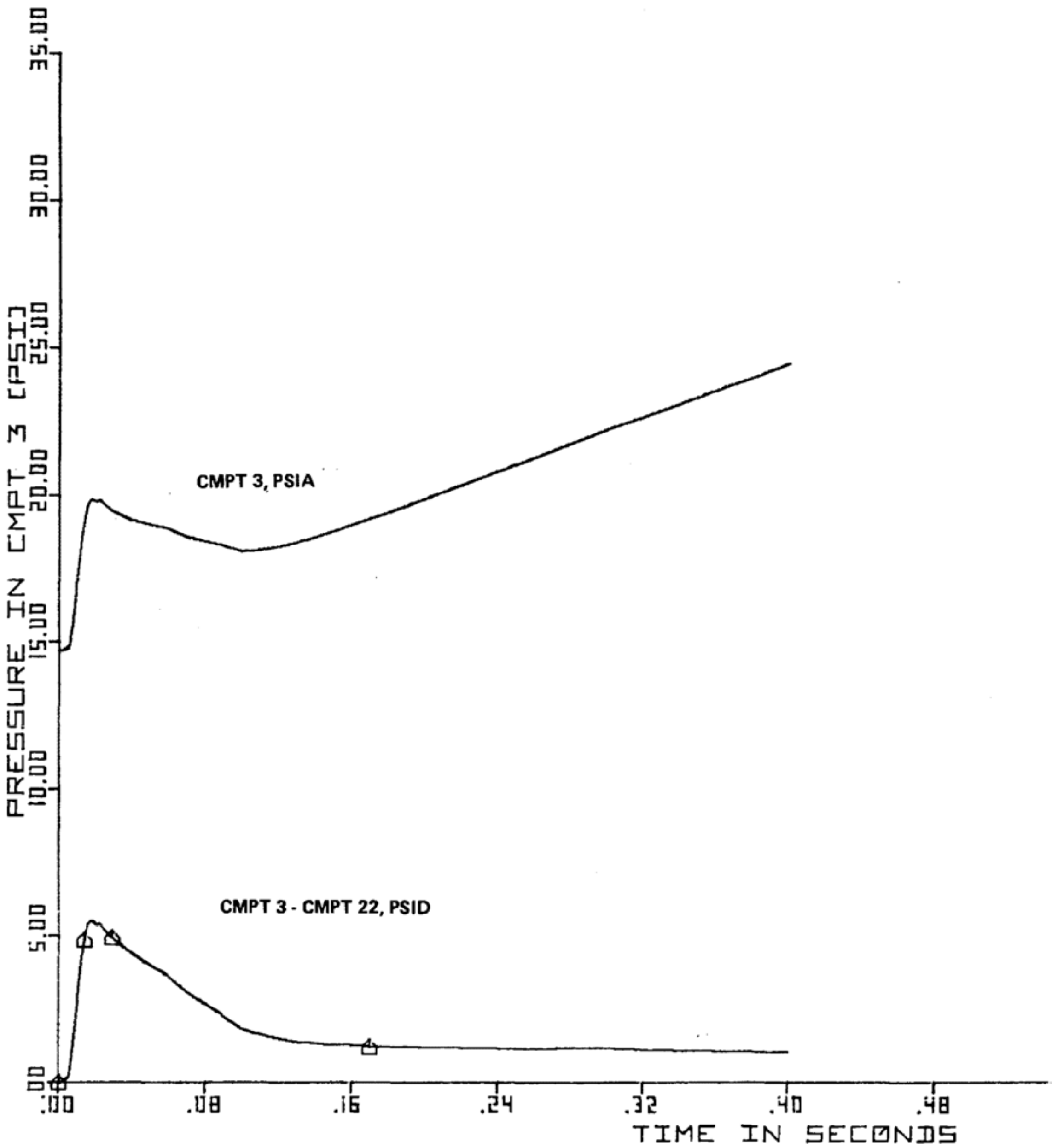
[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 1, PSIA; CMPT 1-CMPT 22, PSID FIGURE 6.2 – 27ba



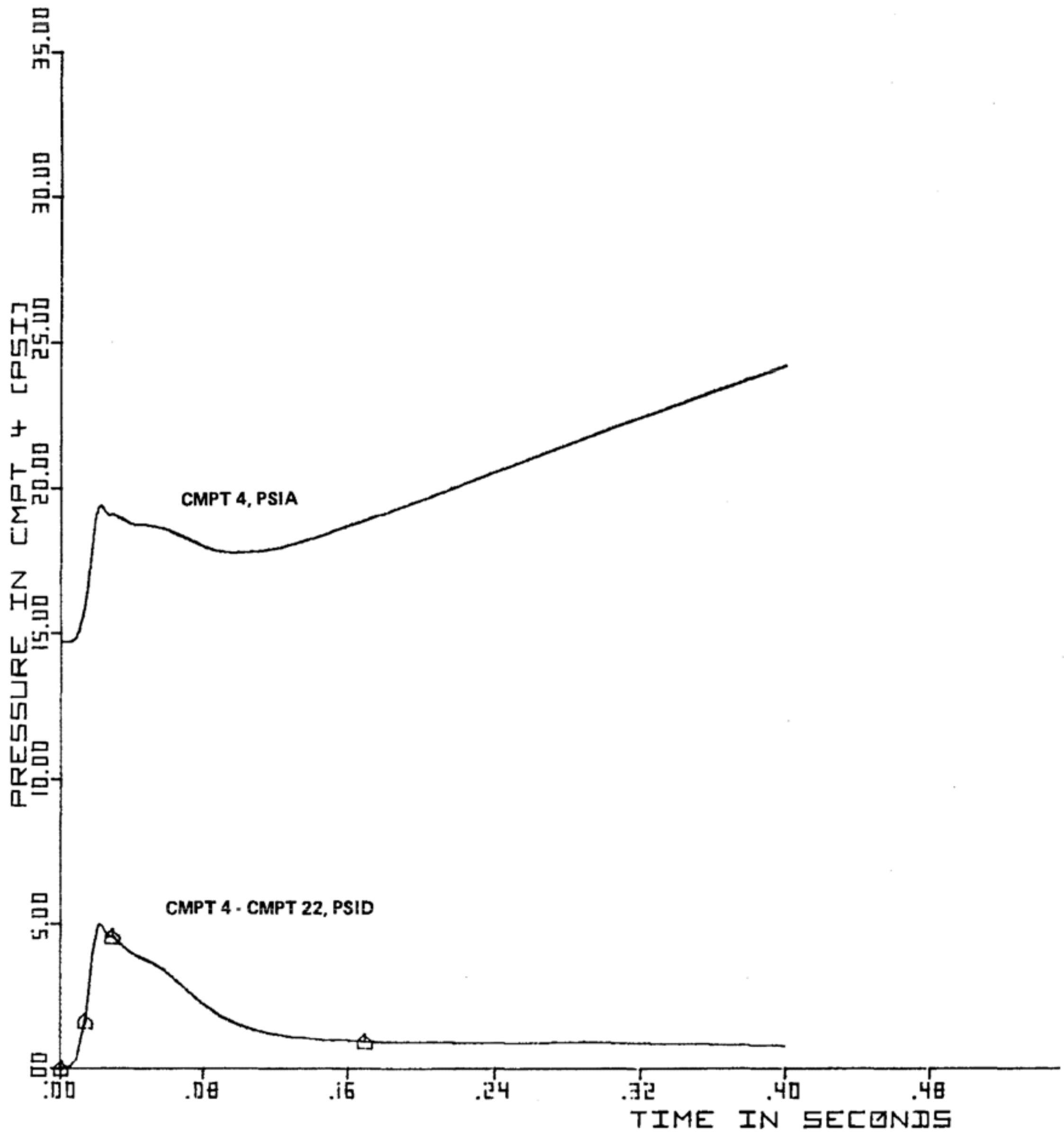
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 2, PSIA; CMPT 2-CMPT 22, PSID FIGURE 6.2 – 27bb



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 3, PSIA; CMPT 3-CMPT 22, PSID FIGURE 6.2 – 27bc



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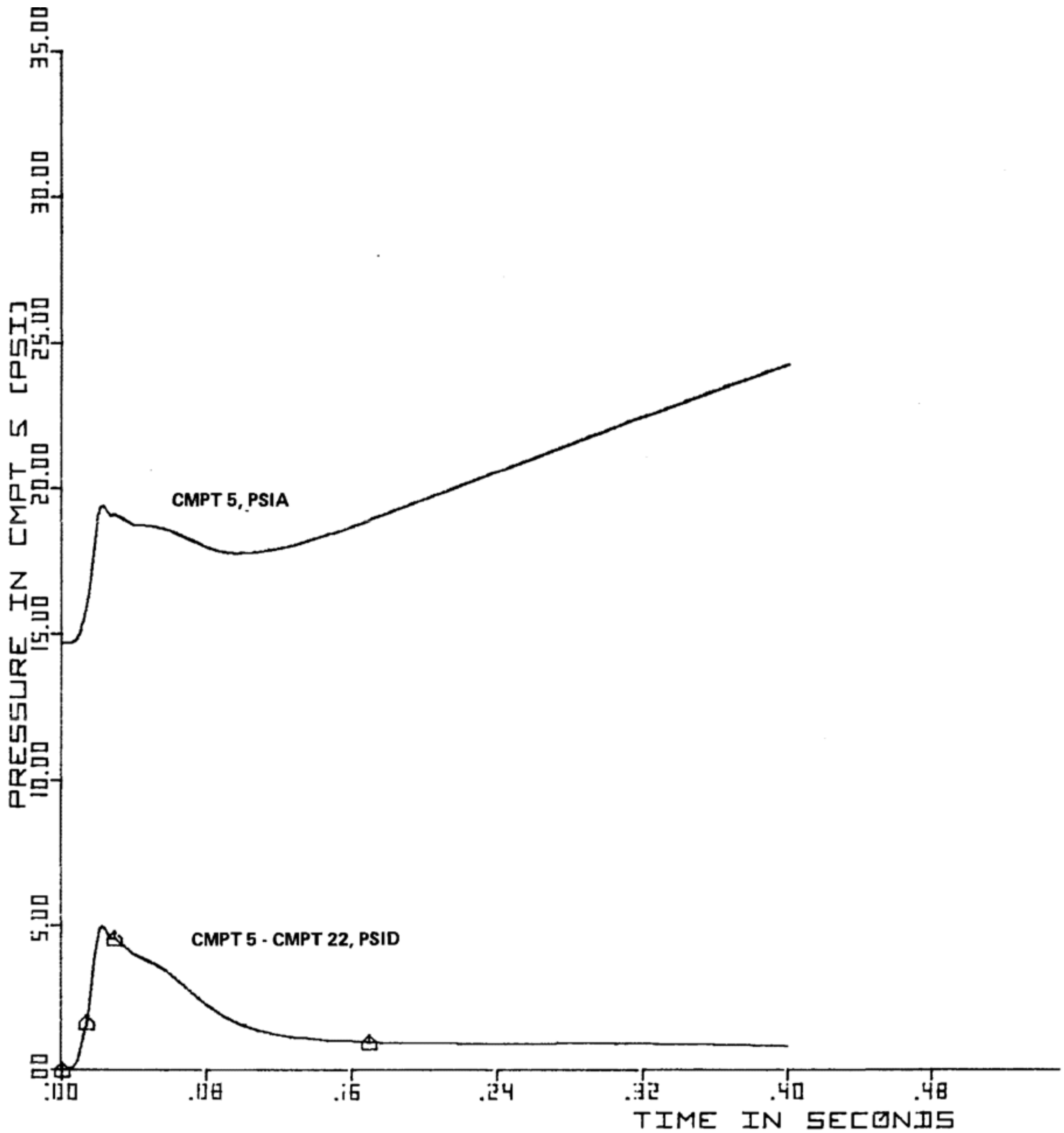
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 4, PSIA; CMPT 4-CMPT 22, PSID FIGURE 6.2 — 27bd



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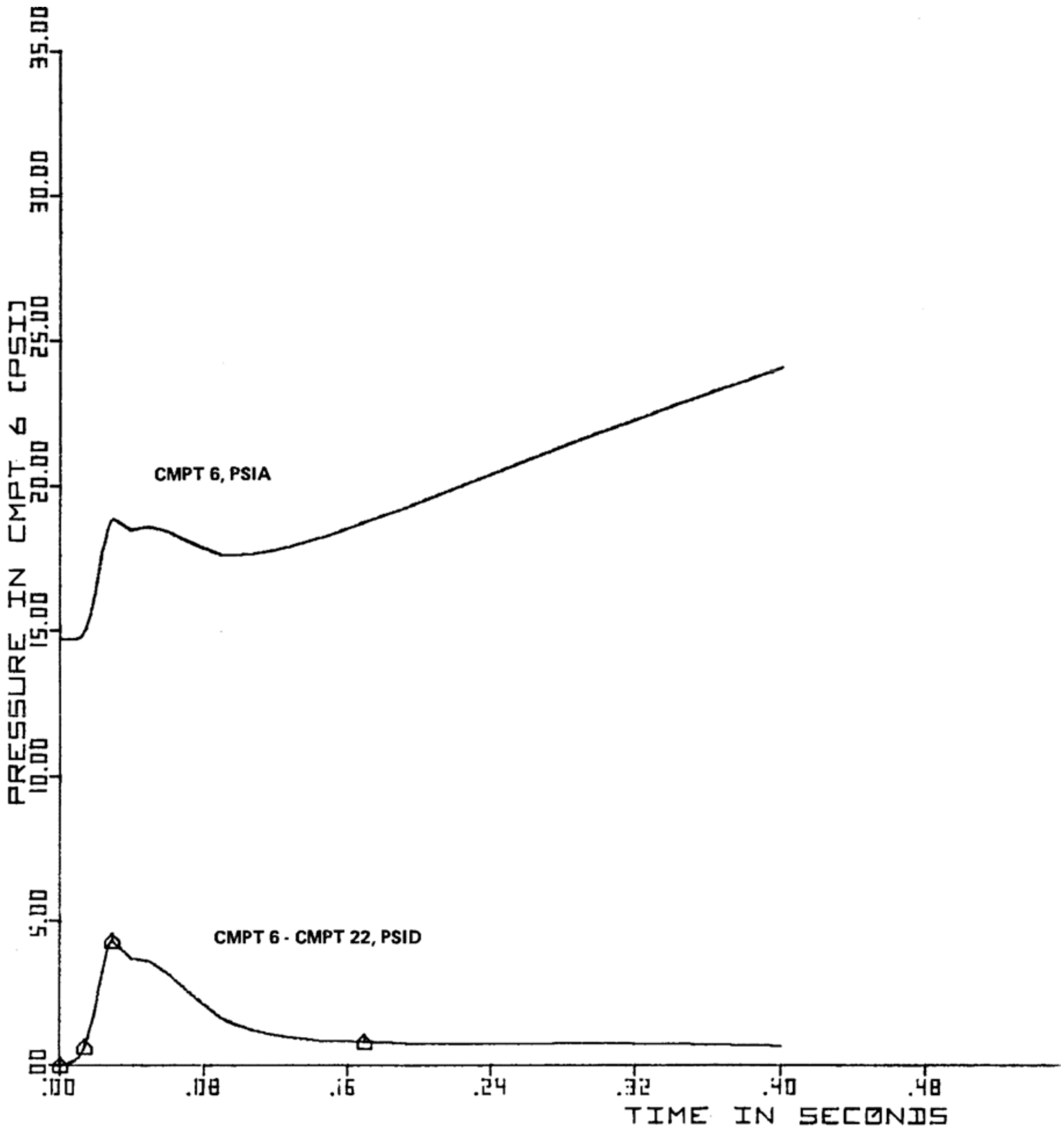
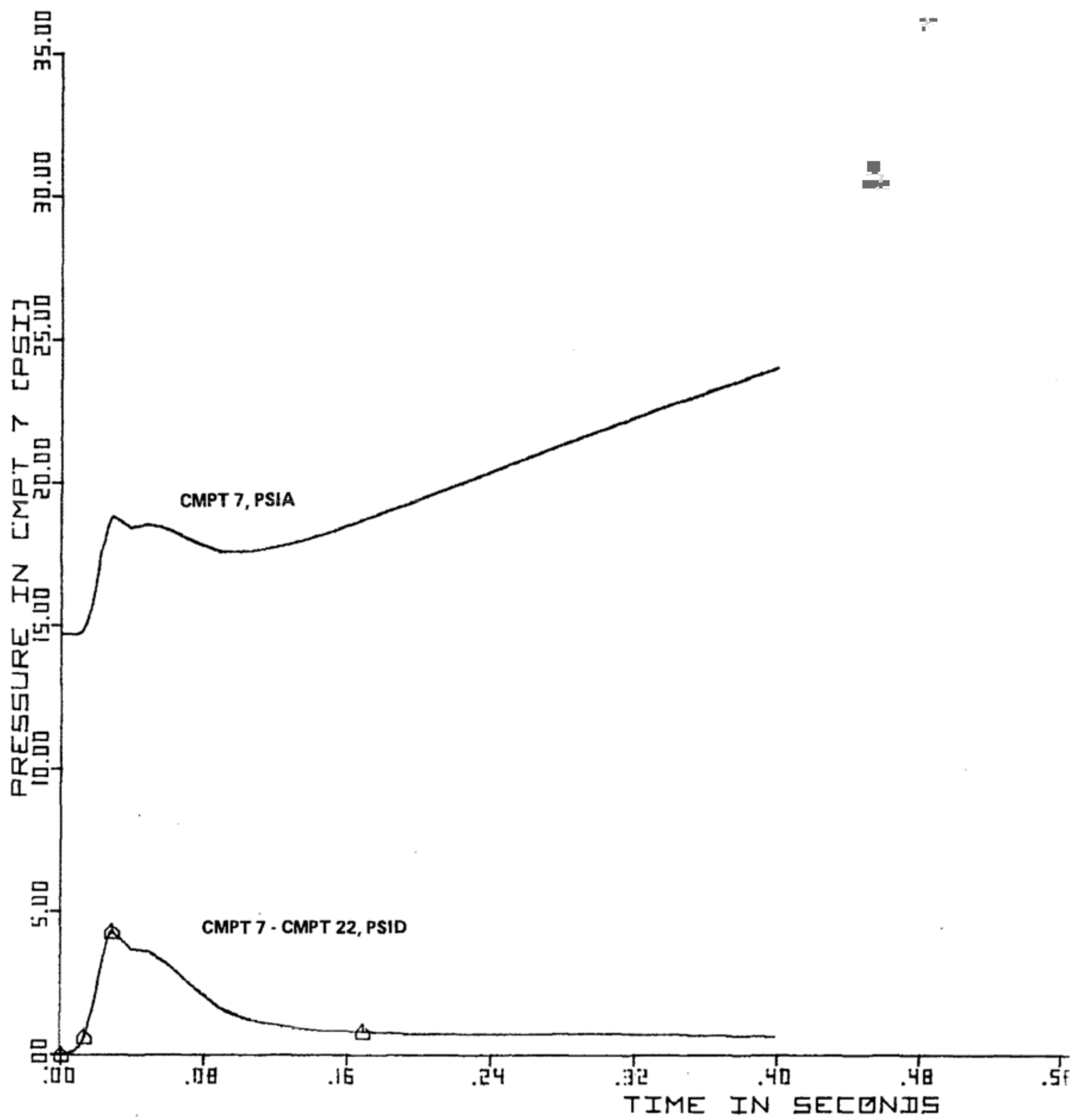
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 5, PSIA; CMPT 5-CMPT 22, PSID FIGURE 6.2 –27be



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 6, PSIA; CMPT 6-CMPT 22, PSID FIGURE 6.2 – 27bf



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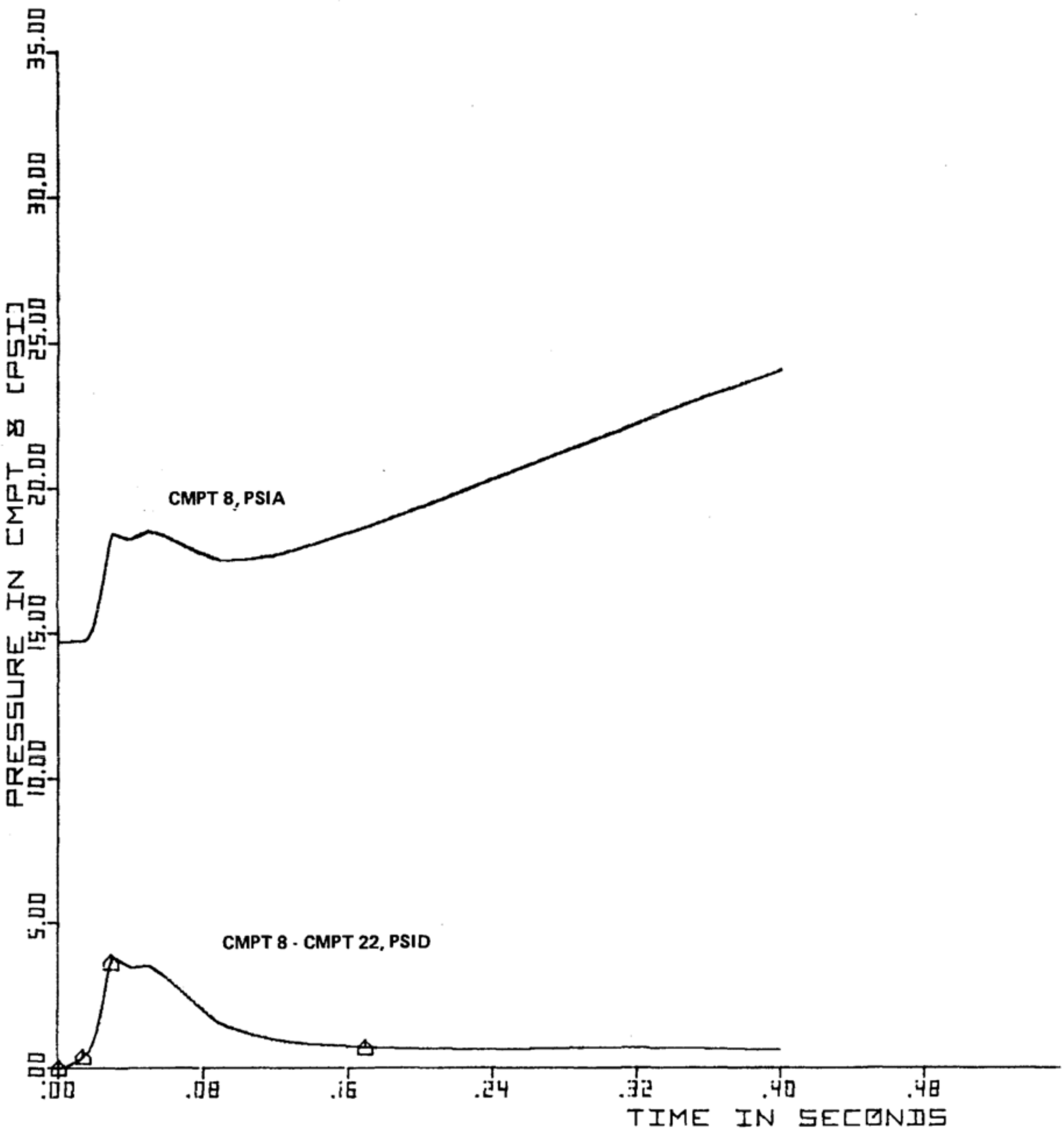
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 7, PSIA; CMPT 7-CMPT 22, PSID FIGURE 6.2 – 27bg



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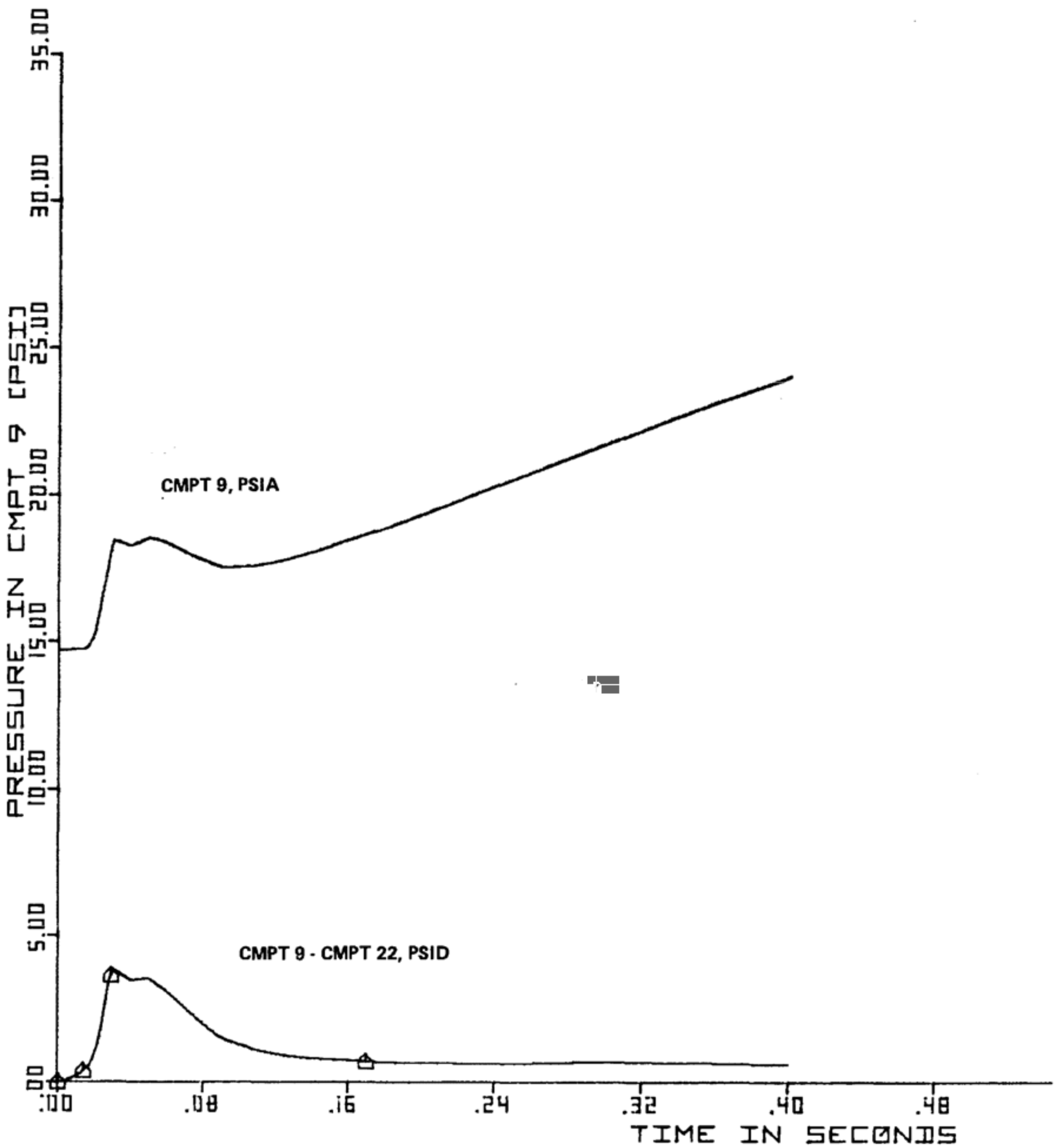
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 8, PSIA; CMPT 8-CMPT 22, PSID FIGURE 6.2 — 27bh



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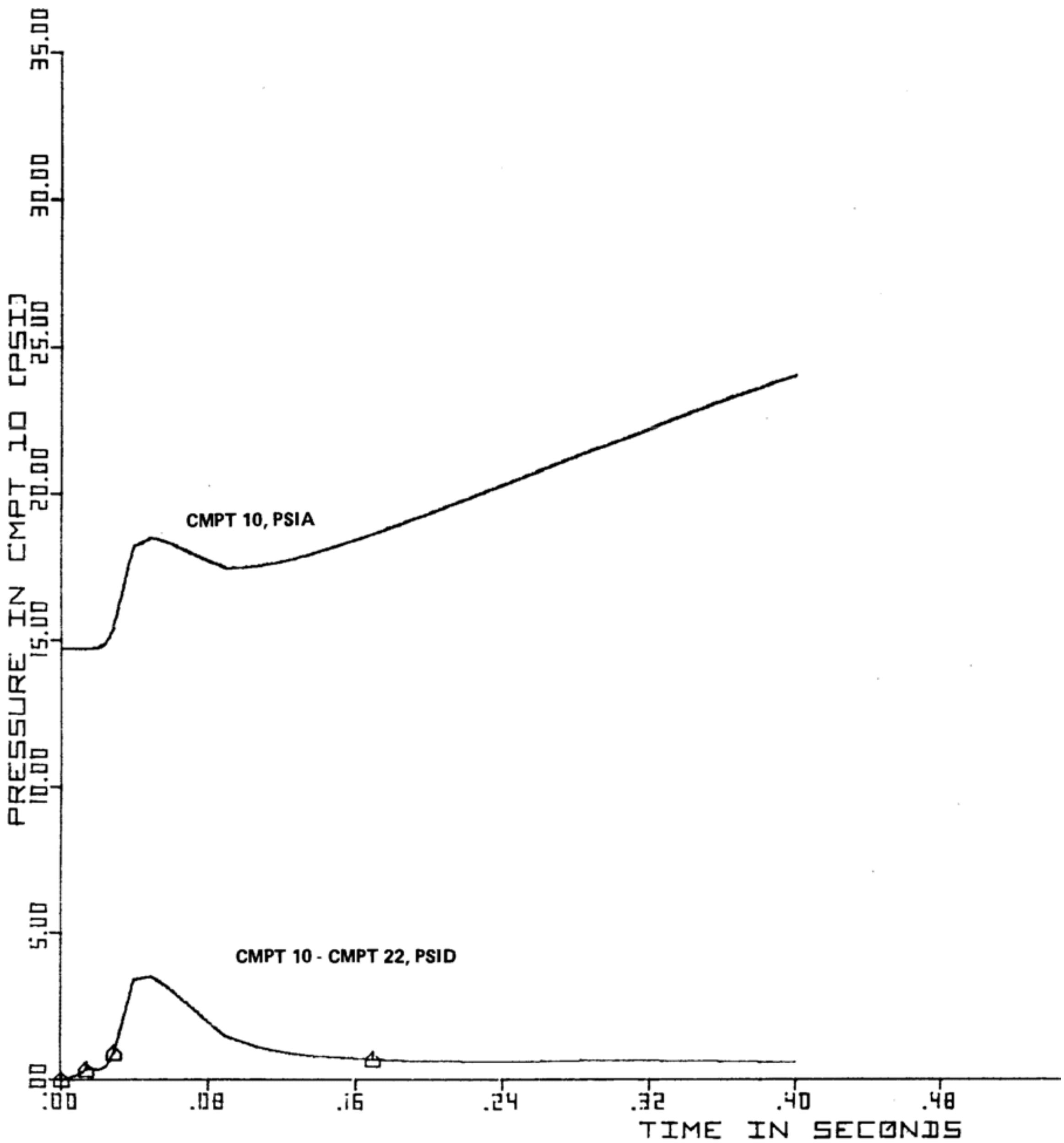
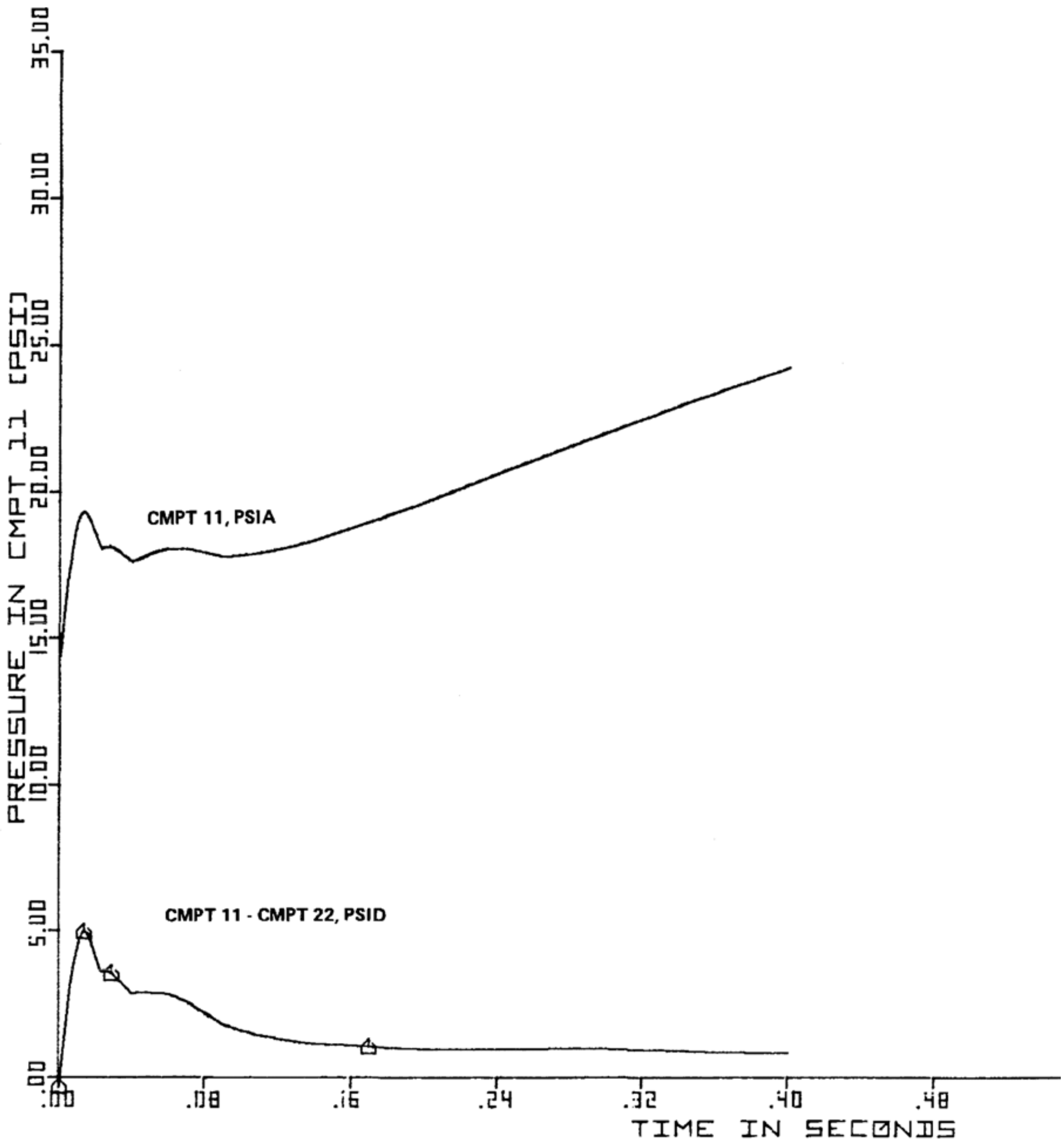
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 9, PSIA; CMPT 9-CMPT 22, PSID FIGURE 6.2 – 27bi



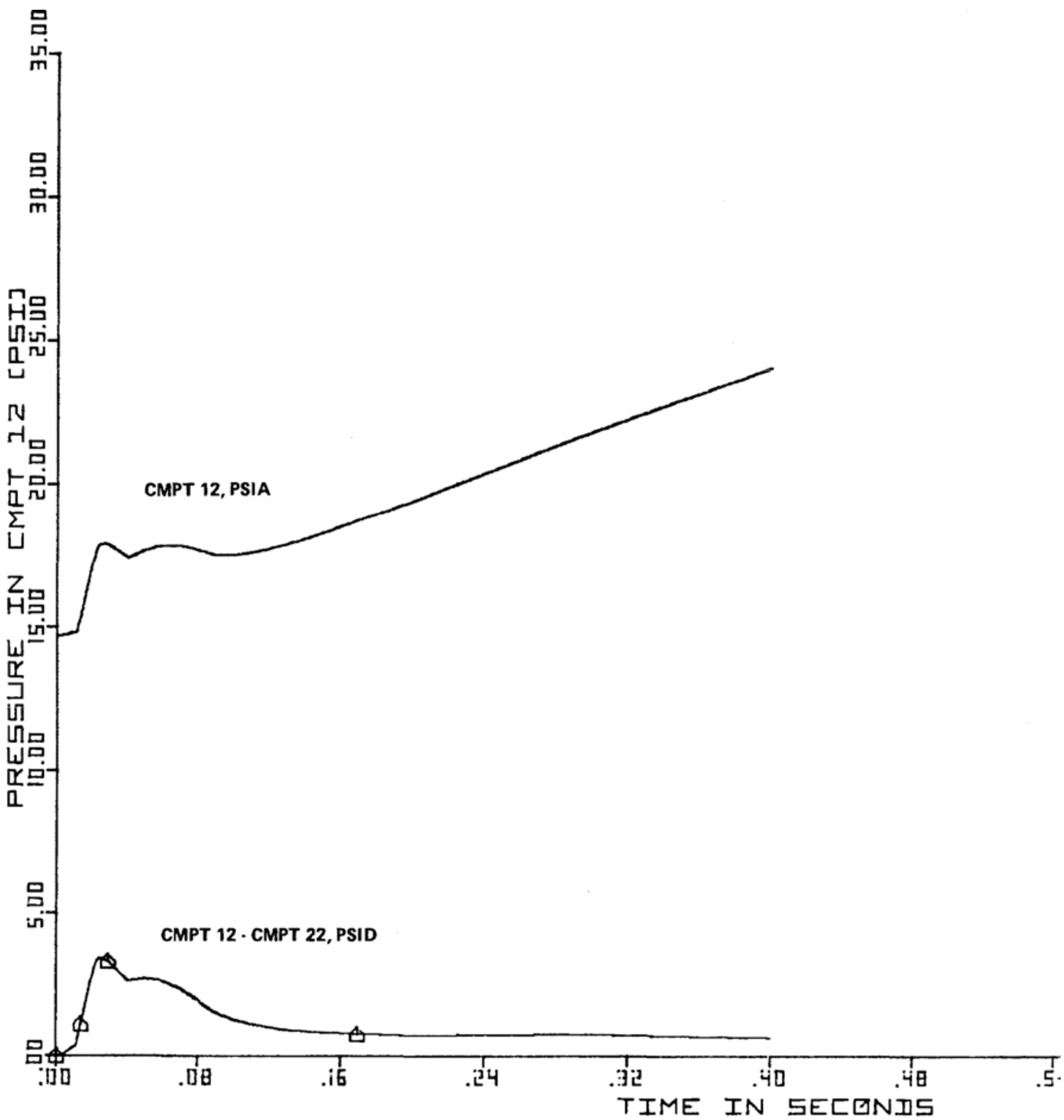
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 10, PSIA; CMPT 10-CMPT 22, PSID FIGURE 6.2 — 27 bj



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 11, PSIA; CMPT 11-CMPT 22, PSID FIGURE 6.2 – 27bk



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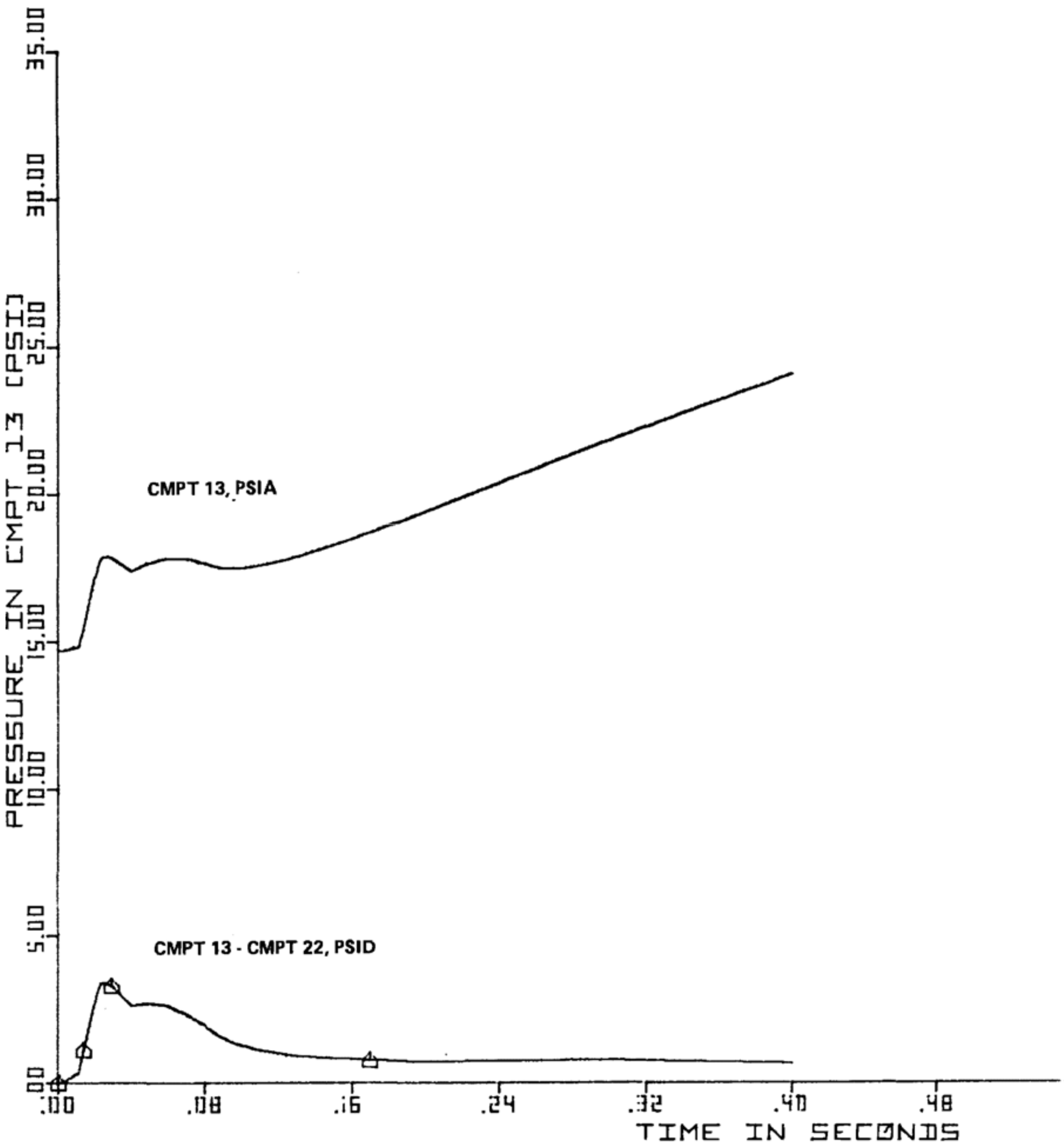
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 12, PSIA; CMPT 12-CMPT 22, PSID FIGURE 6.2 – 27bl



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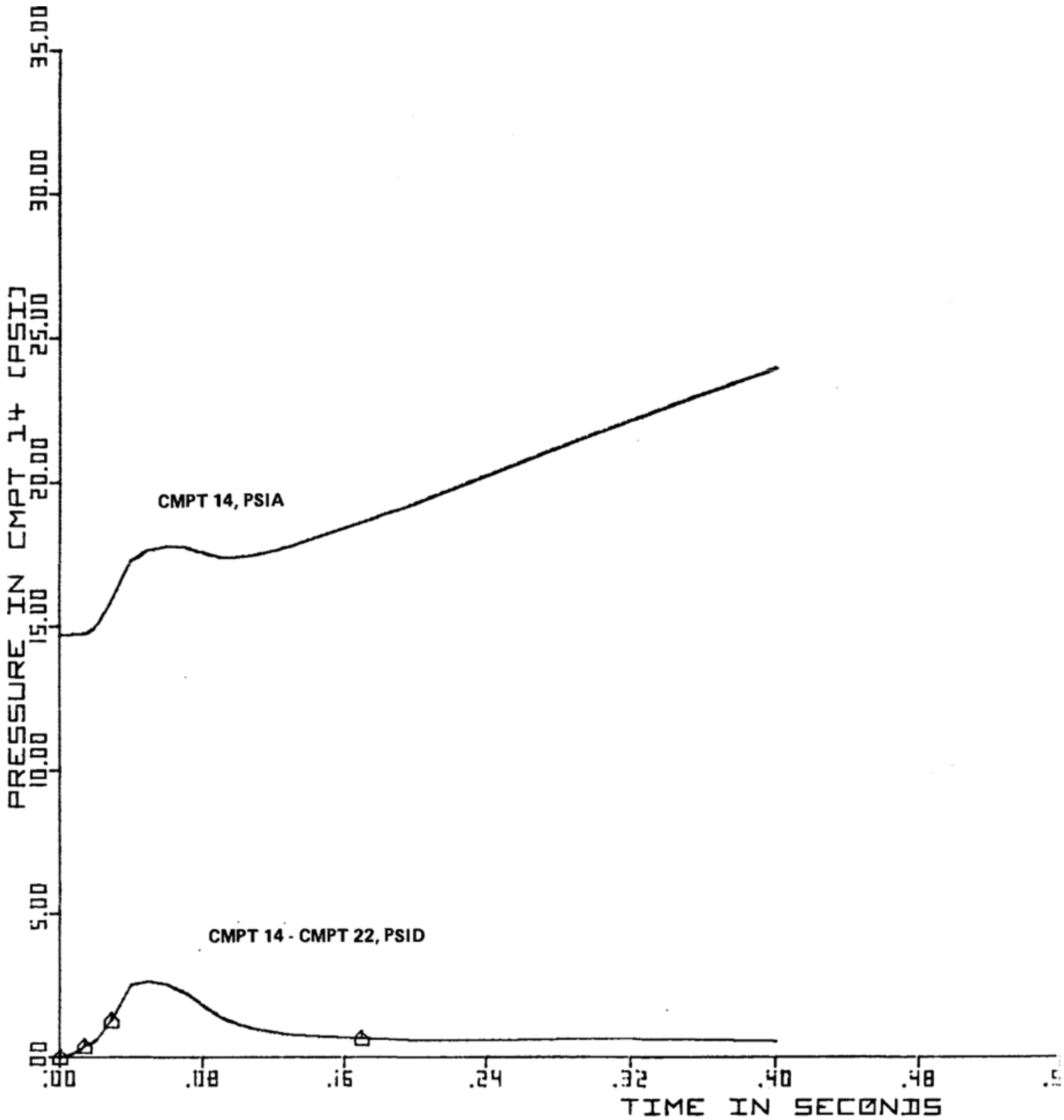
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 13, PSIA; CMPT 13-CMPT 22, PSID FIGURE 6.2 – 27bm



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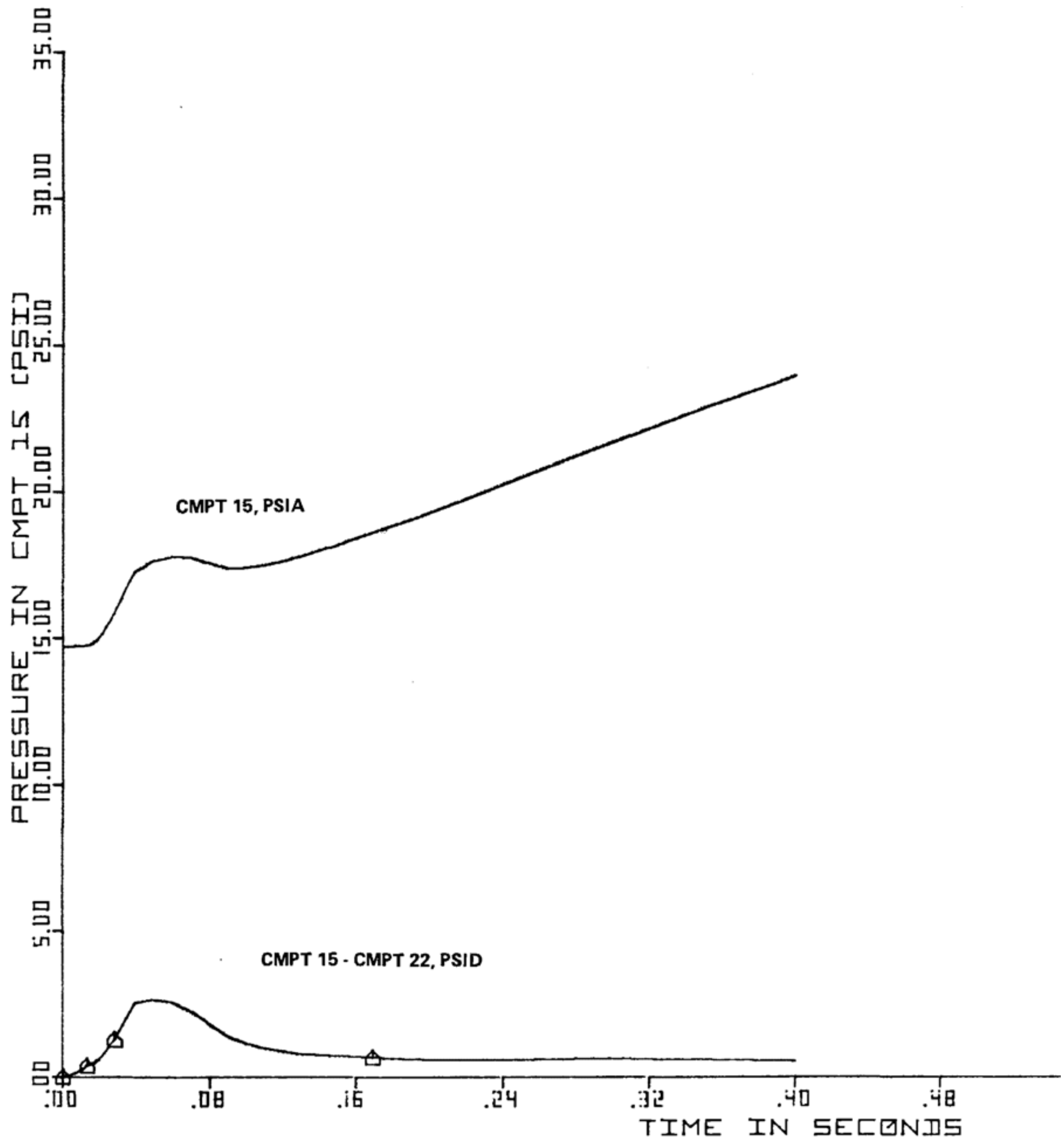
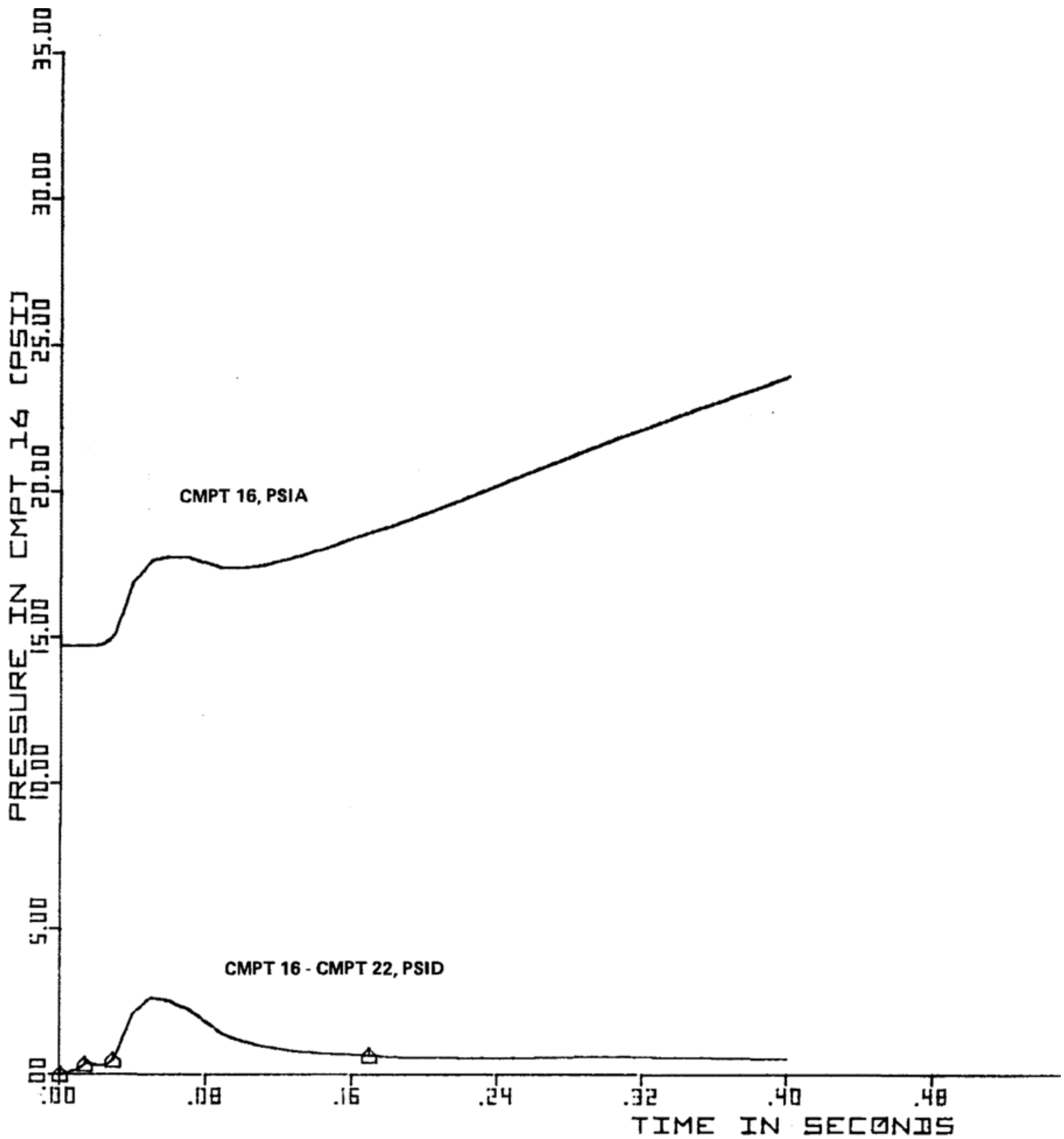
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 14, PSIA; CMPT 14-CMPT 22, PSID FIGURE 6.2 – 27bn



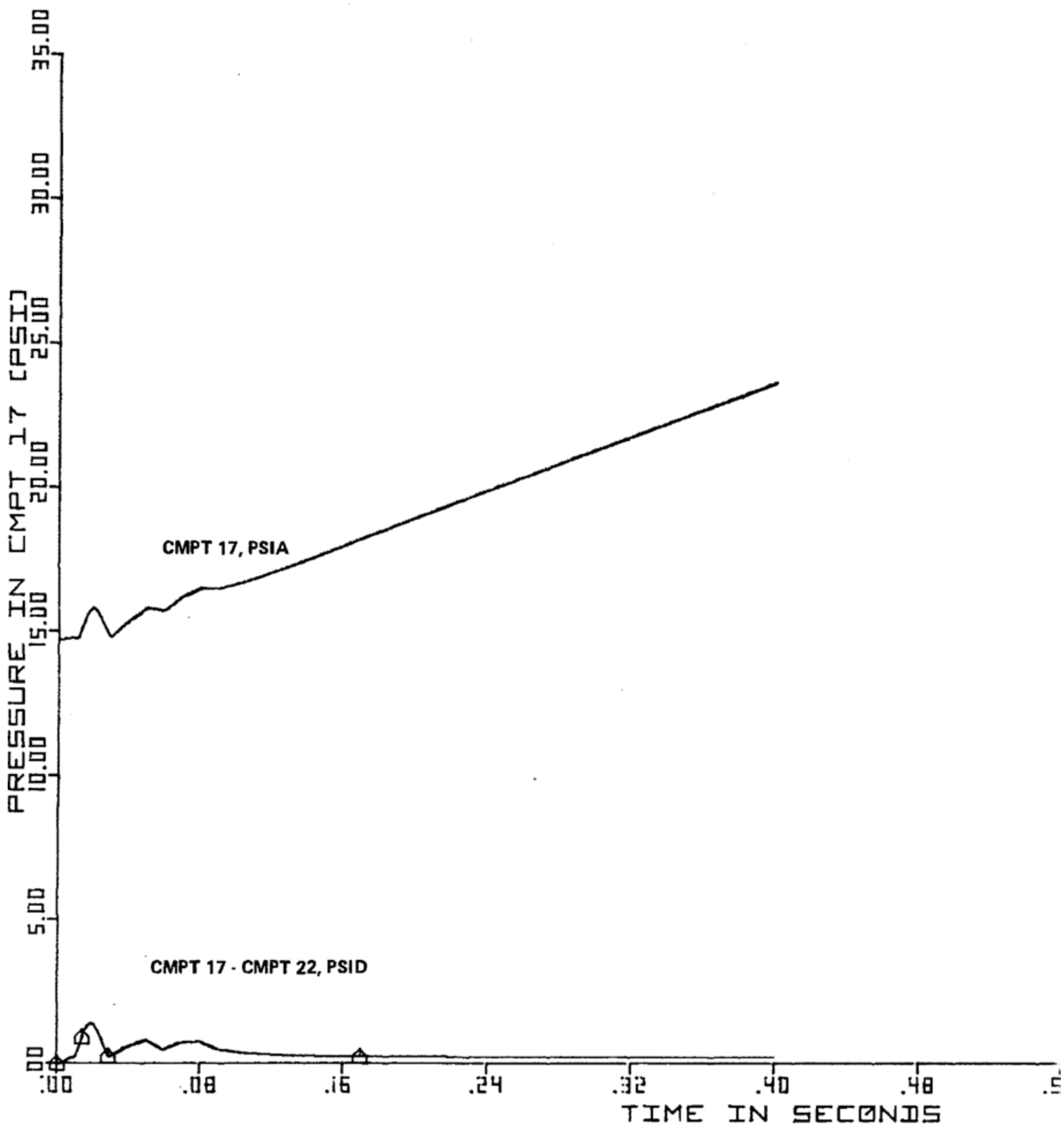
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 15, PSIA; CMPT 15-CMPT 22, PSID FIGURE 6.2 – 27bo



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 16, PSIA; CMPT 16-CMPT 22, PSID FIGURE 6.2 — 27bp



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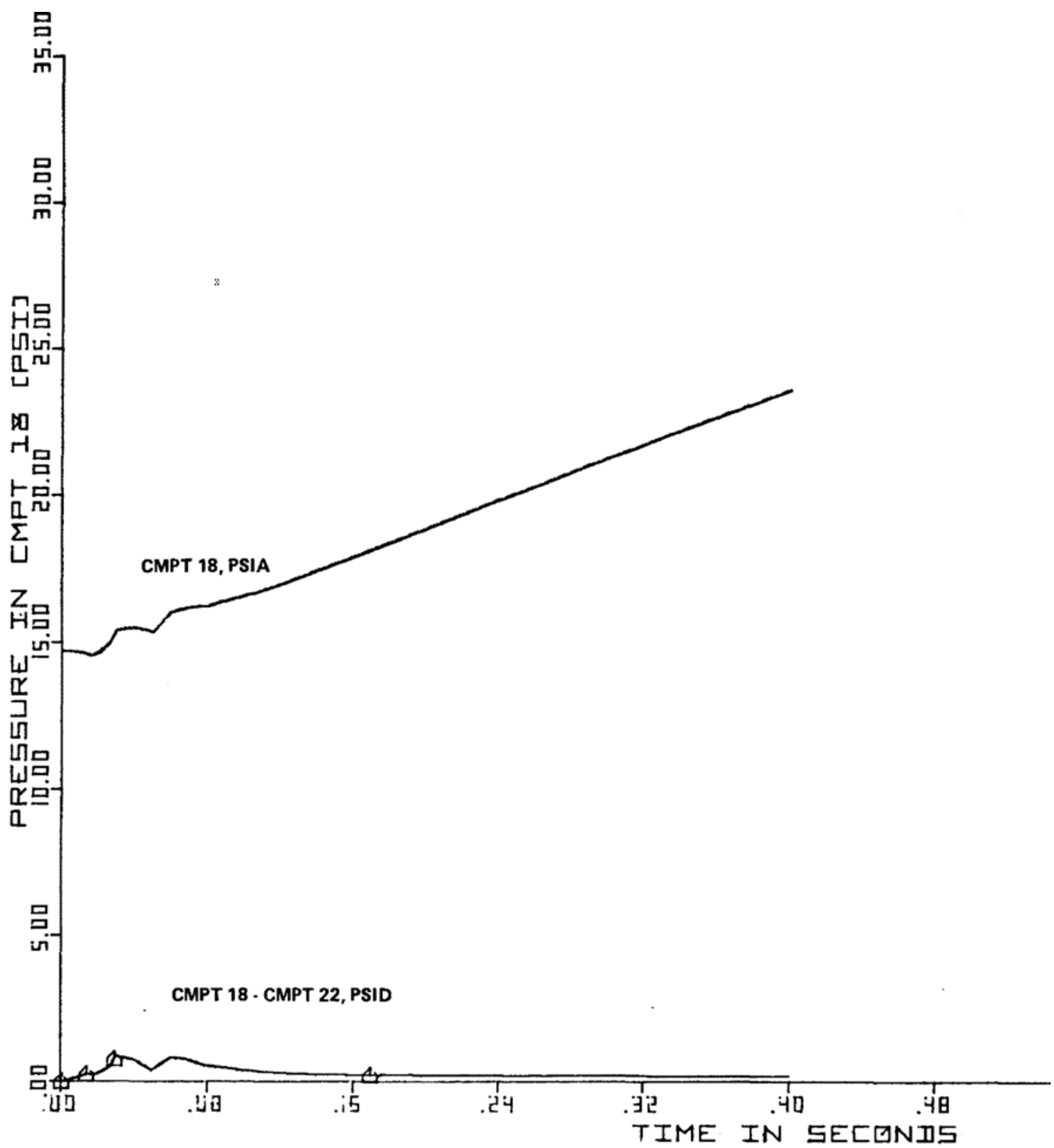
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 17, PSIA; CMPT 17-CMPT 22, PSID FIGURE 6.2 – 27bq



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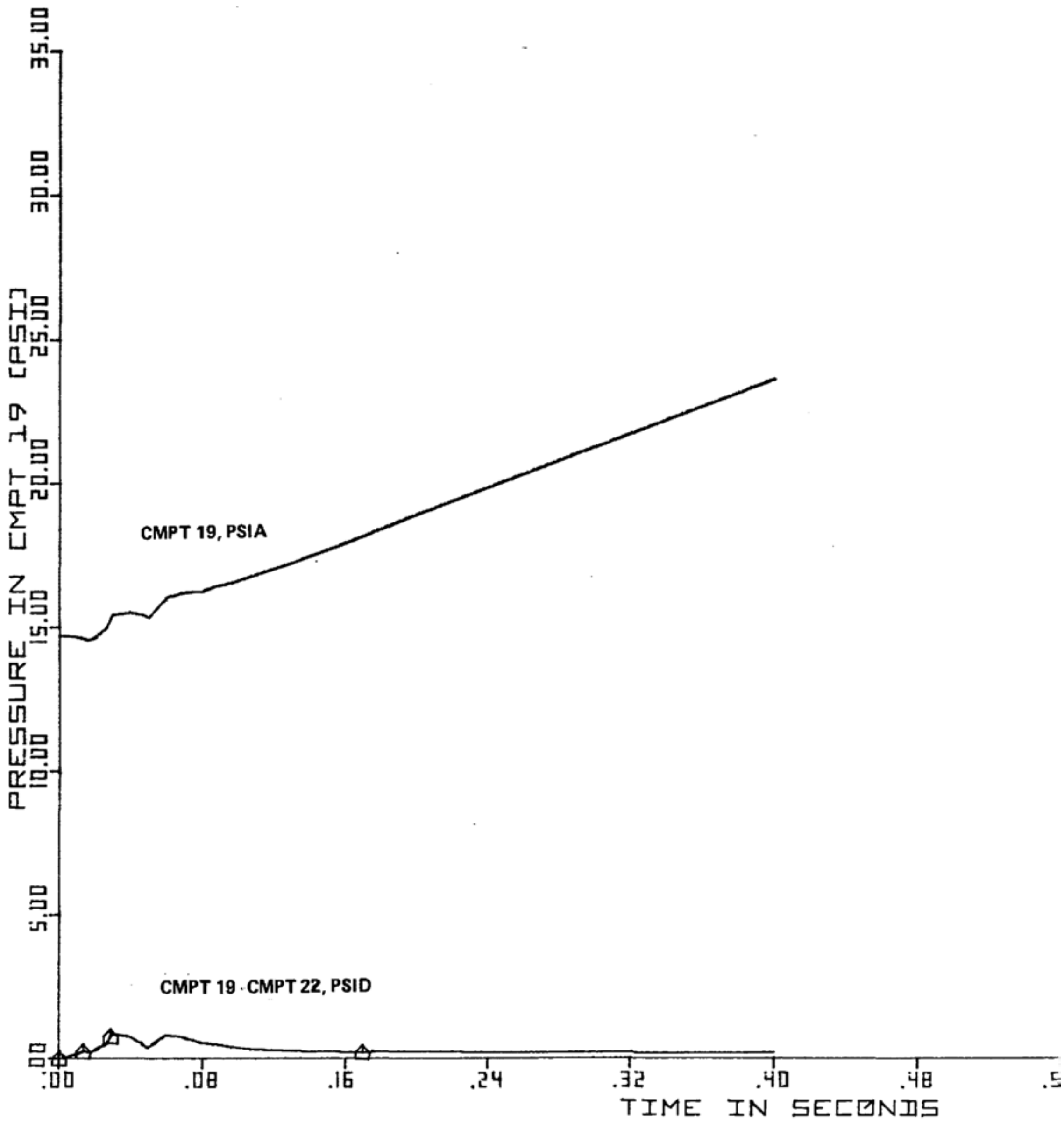
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 18, PSIA; CMPT 18-CMPT 22, PSID FIGURE 6.2 — 27br



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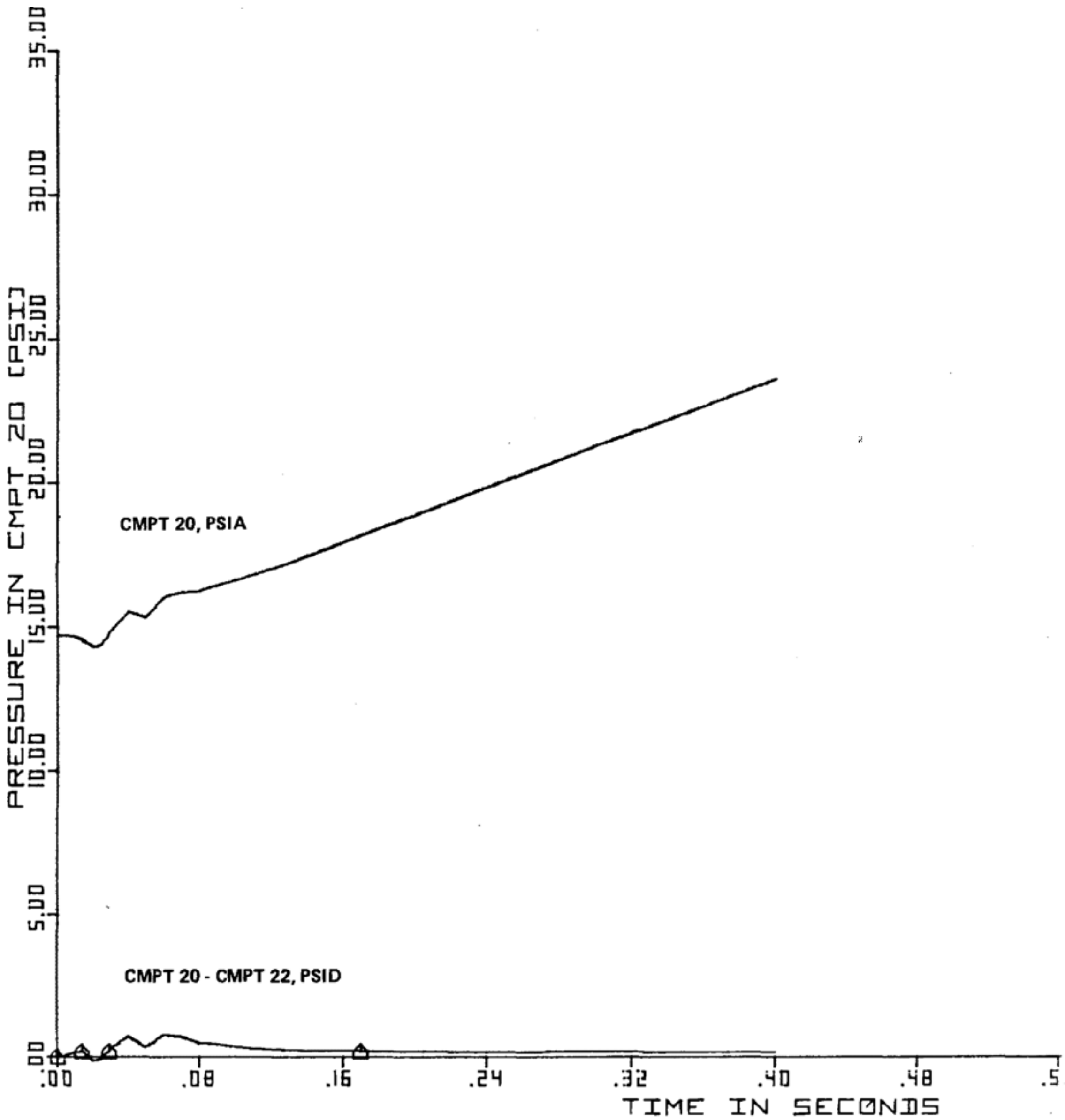
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 19, PSIA; CMPT 19-CMPT 22, PSID FIGURE 6.2 – 27bs



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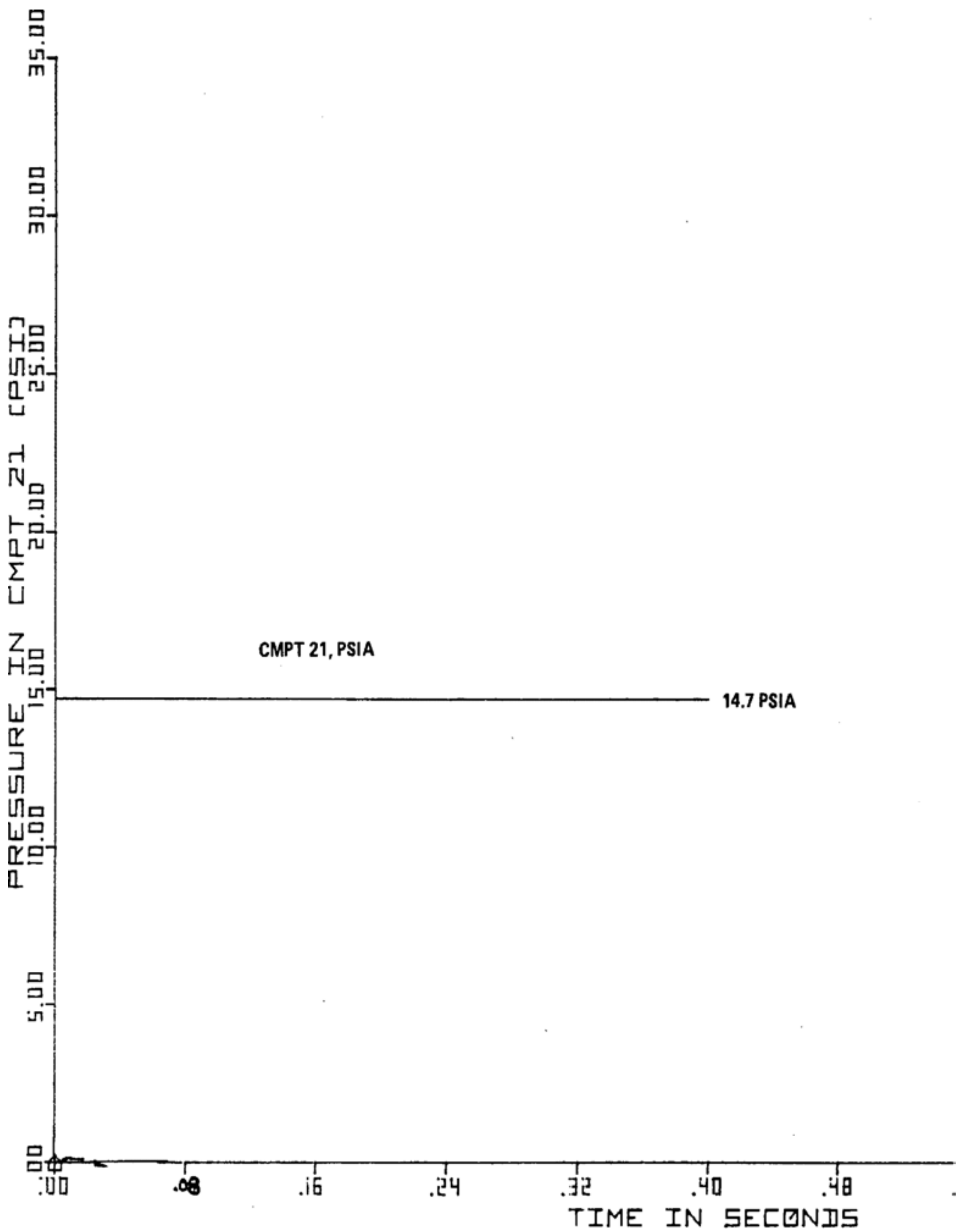
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 20, PSIA; CMPT 20-CMPT 22, PSID FIGURE 6.2 – 27bt



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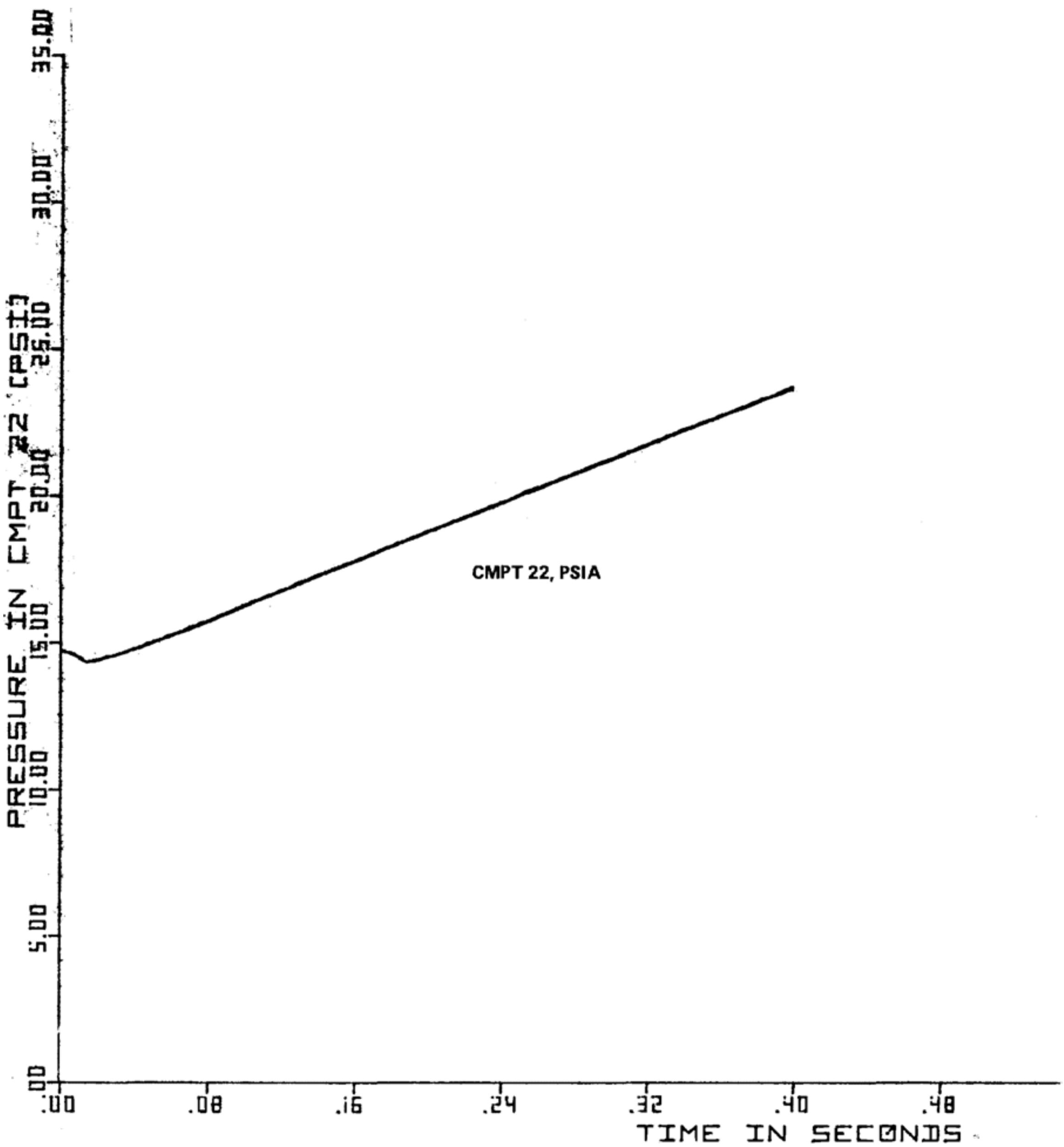
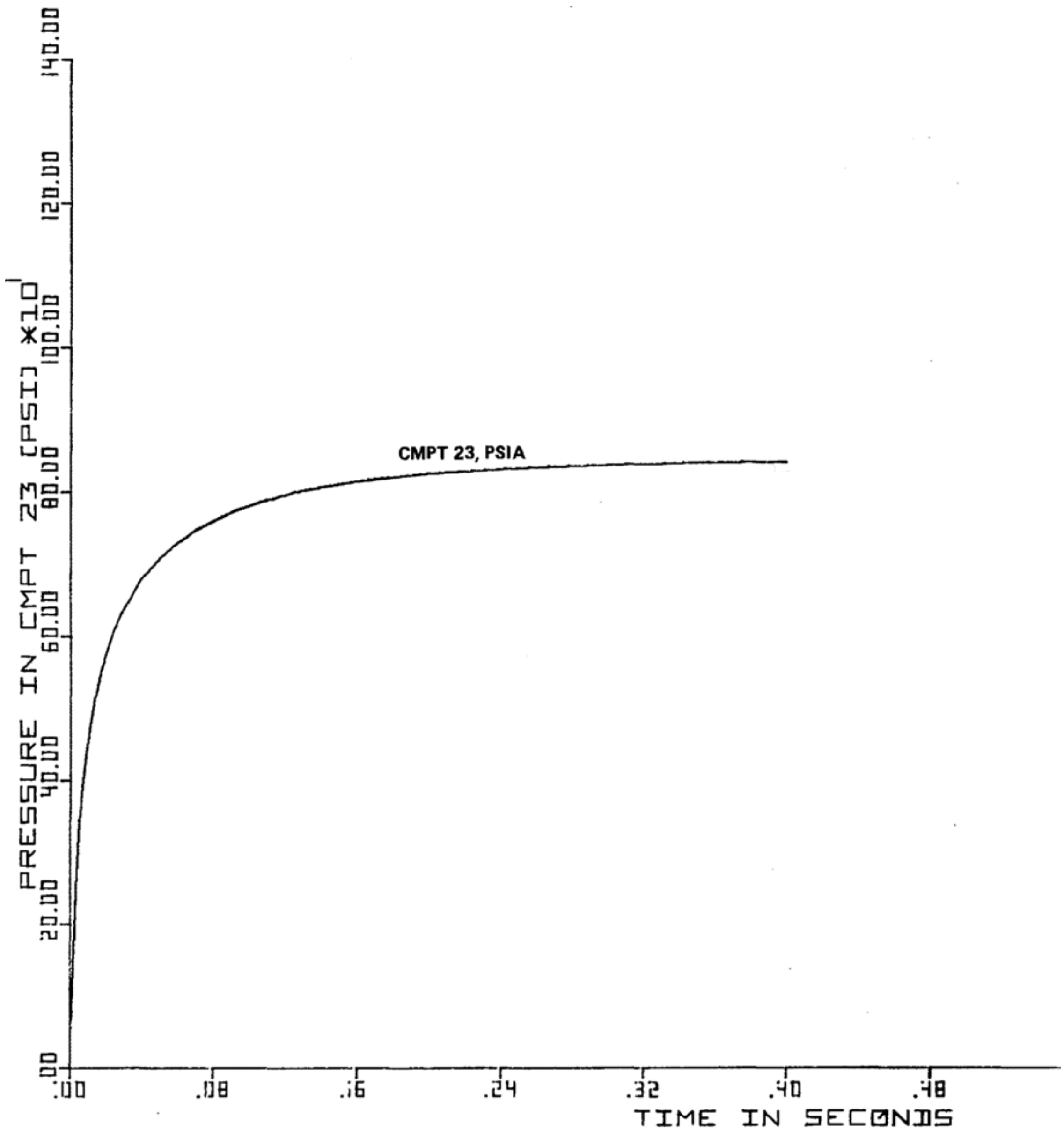
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 21, PSIA FIGURE 6.2 – 27bu



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 22, PSIA FIGURE 6.2 – 27bv



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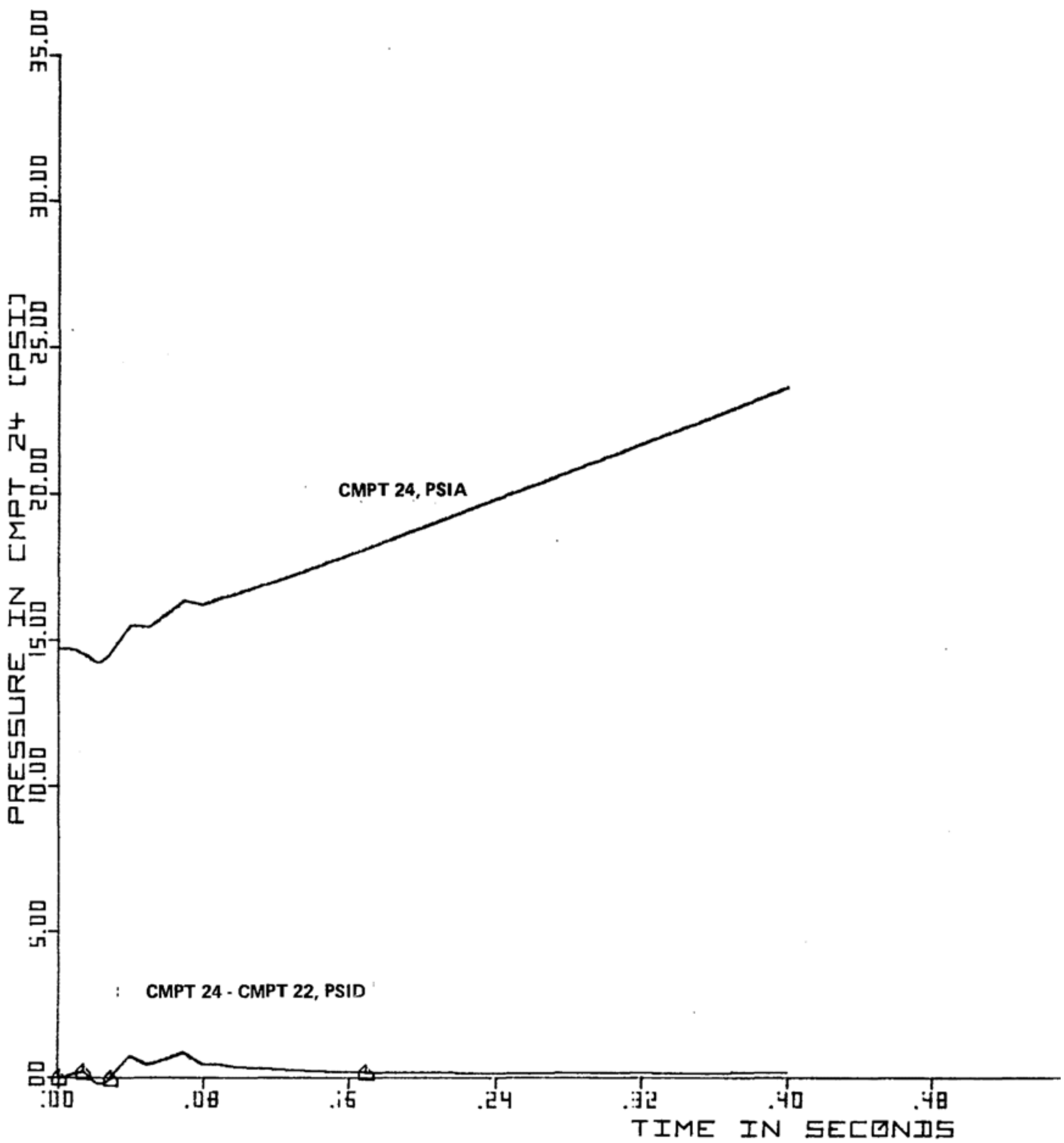
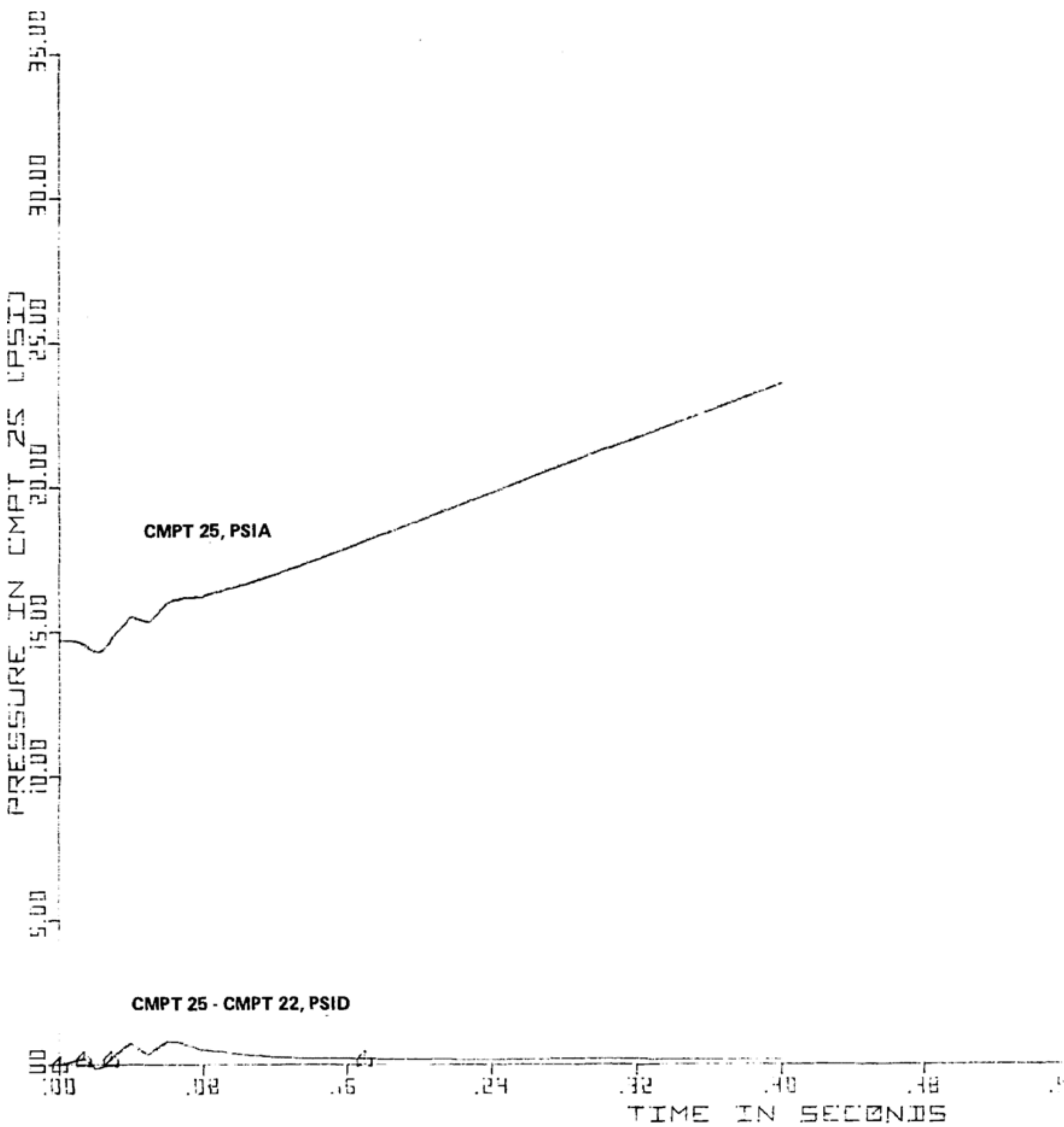
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 23, PSIA FIGURE 6.2 – 27bw



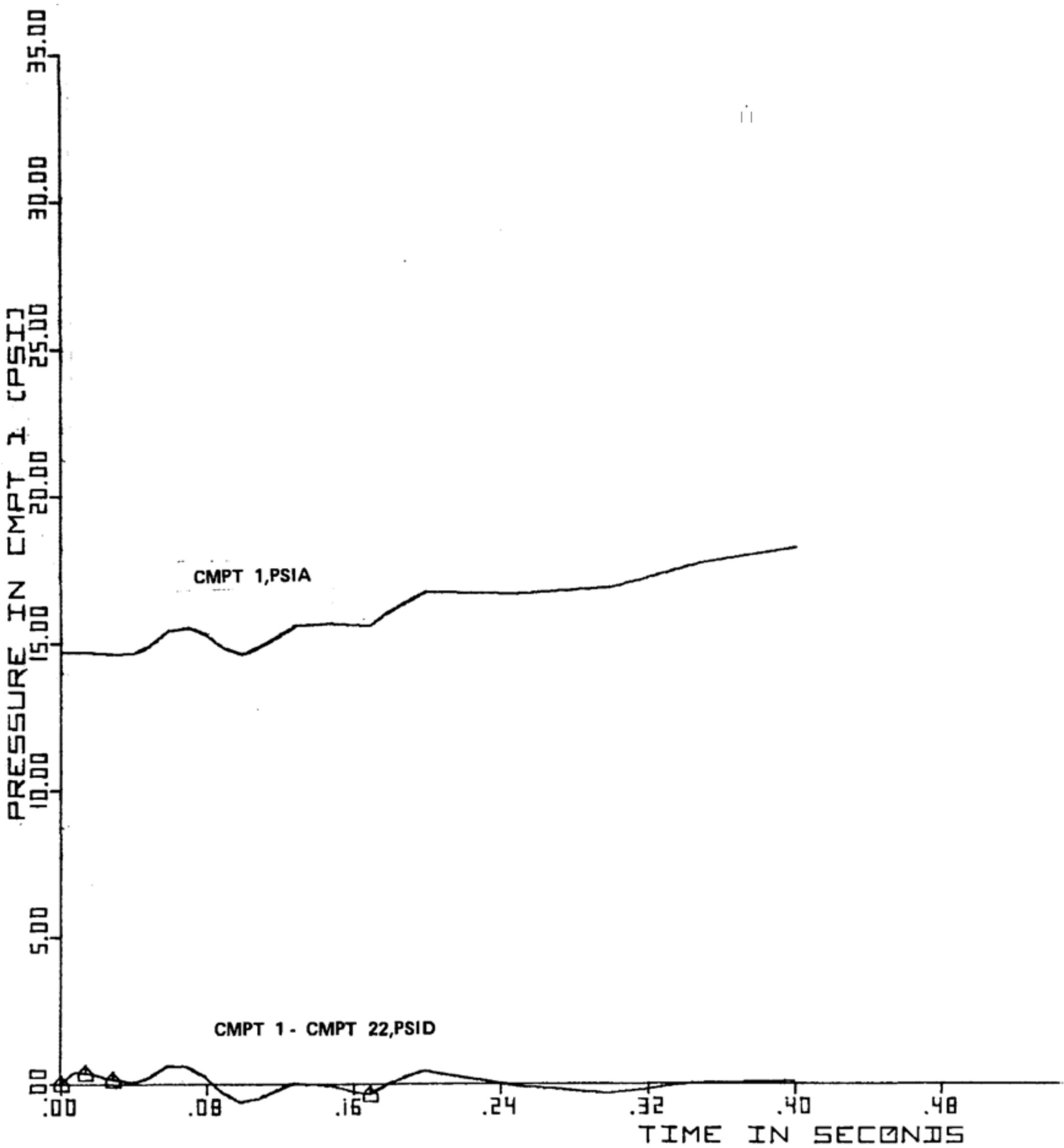
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 24, PSIA; CMPT 24-CMPT 22, PSID FIGURE 6.2 — 27bx



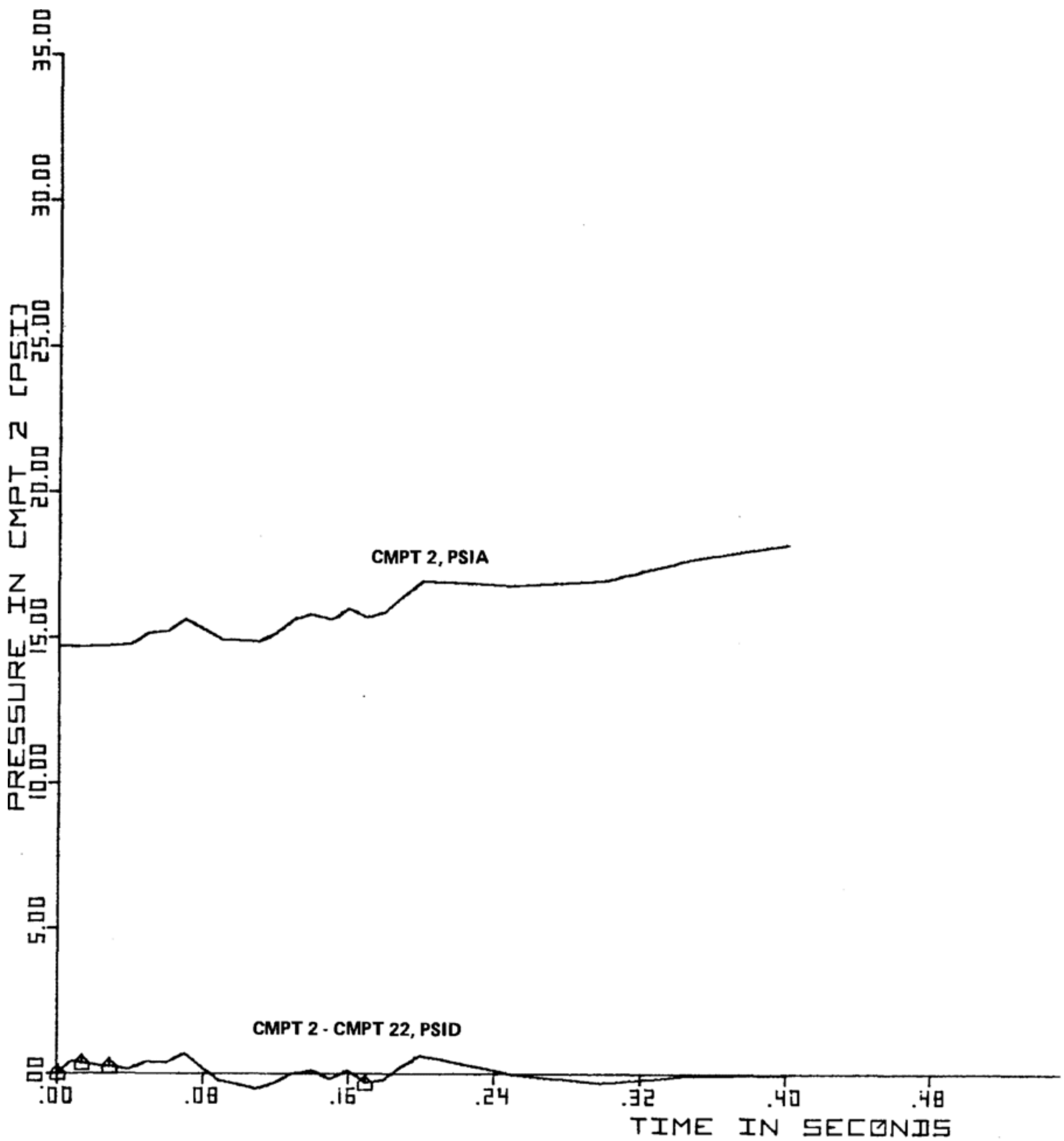
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR RECIRC SUCTION LINE BREAK CMPT 25 PSIA; CMPT 25-CMPT 22, PSID FIGURE 6.2 – 27by



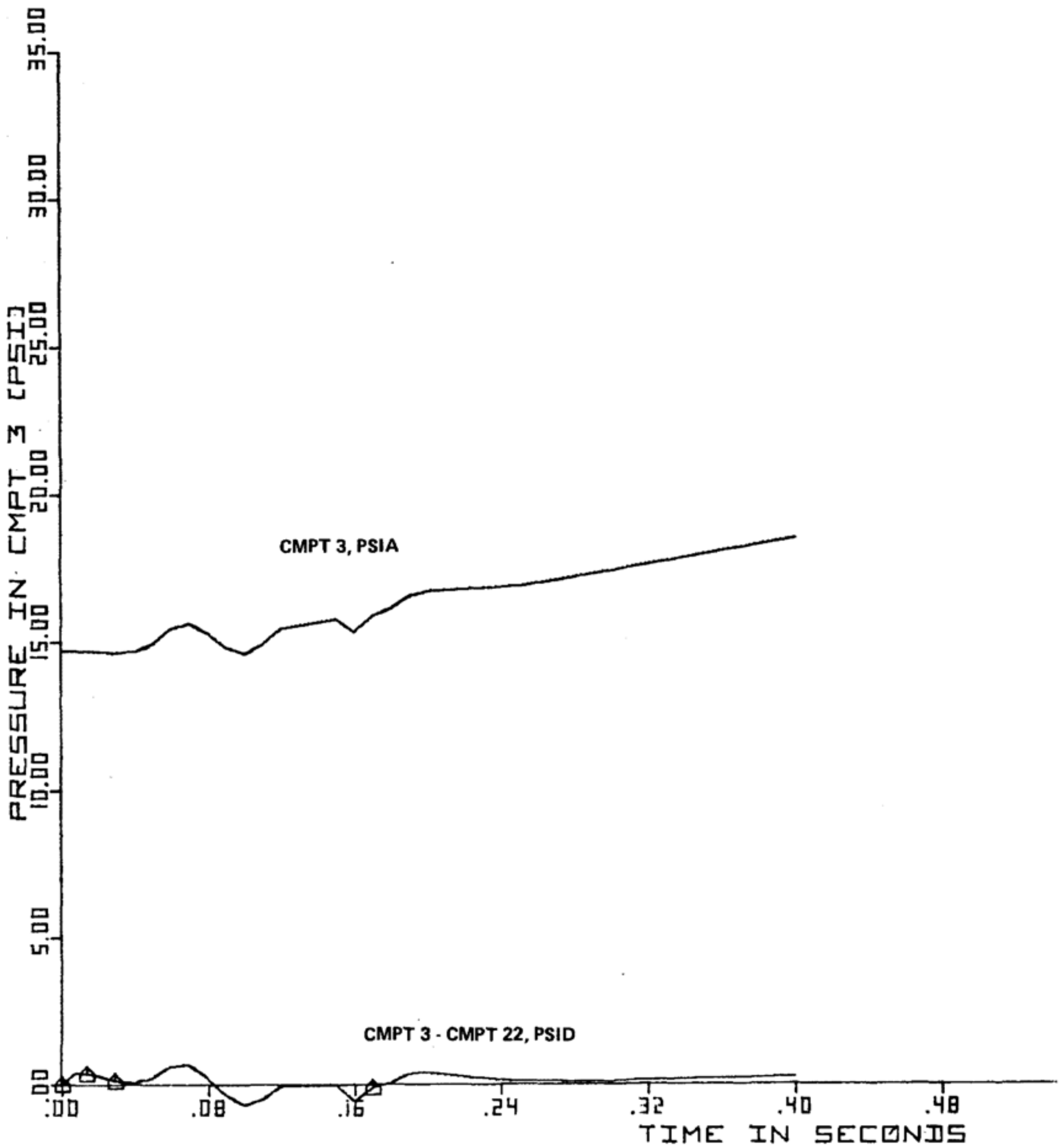
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 1 PSIA; CMPT 1-CMPT 22, PSID FIGURE 6.2 – 27ca



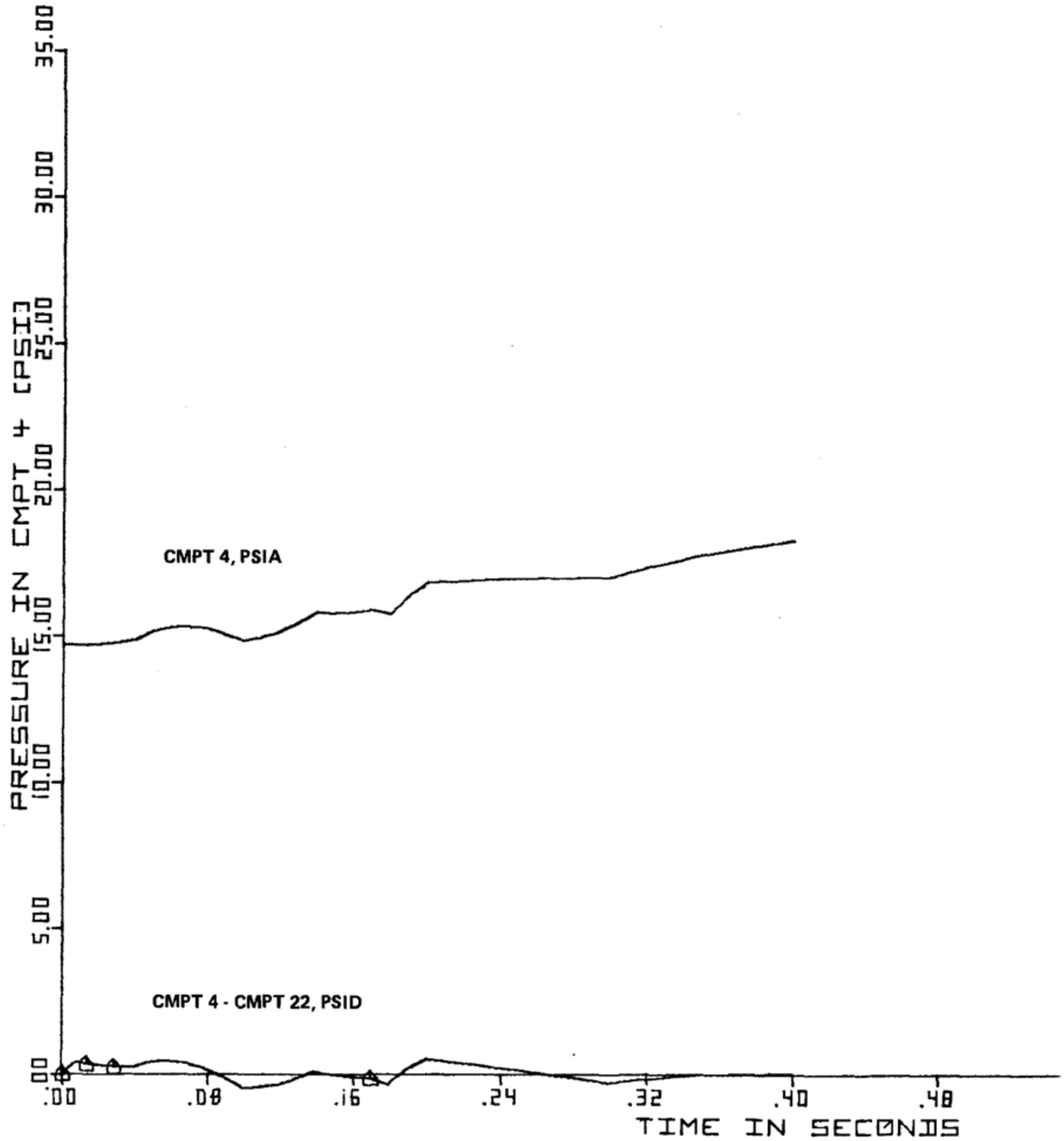
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 2, PSIA; CMPT 2-CMPT 22, PSID FIGURE 6.2 — 27cb



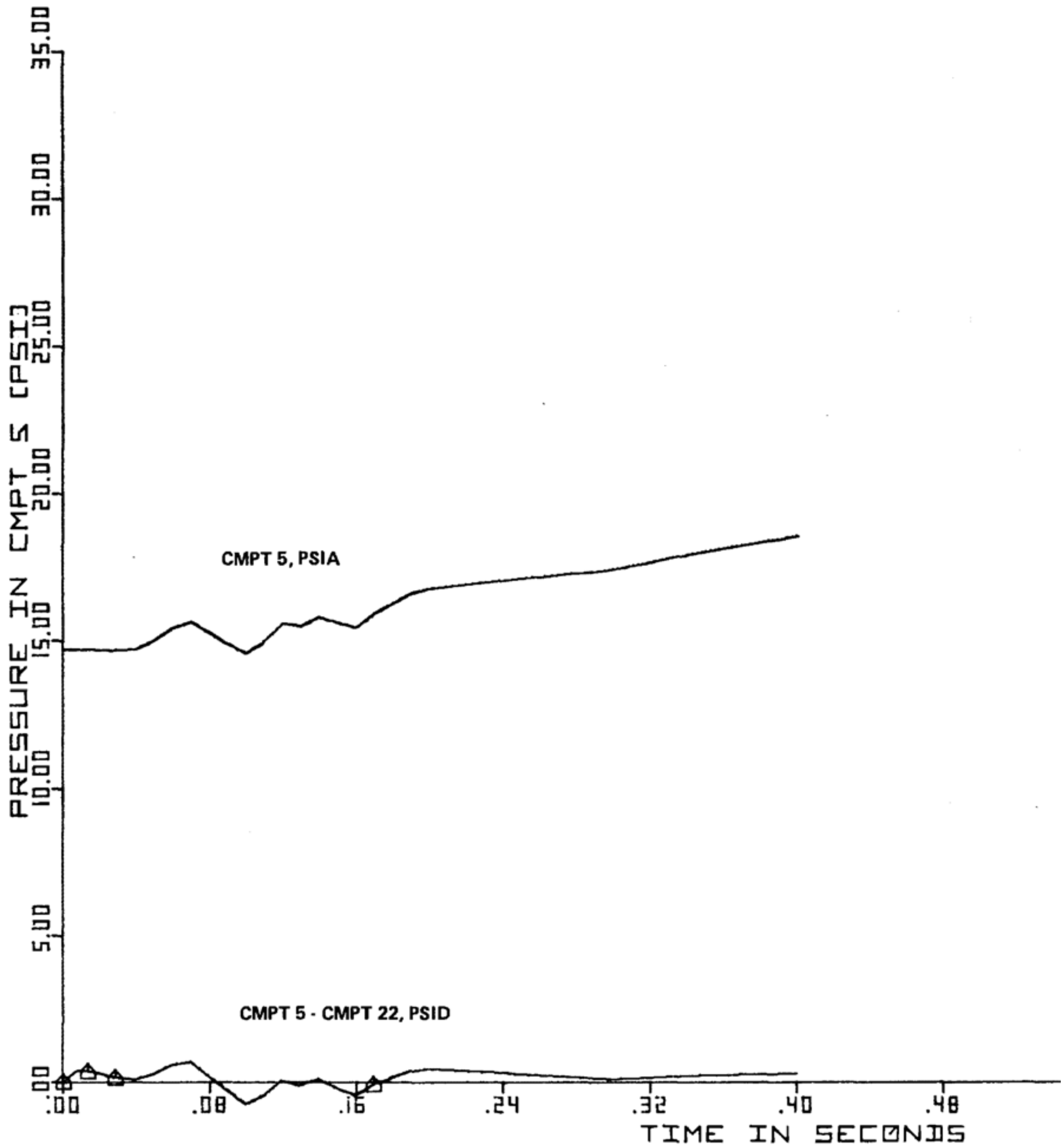
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 3, PSIA; CMPT 3-CMPT 22, PSID FIGURE 6.2 – 27cc



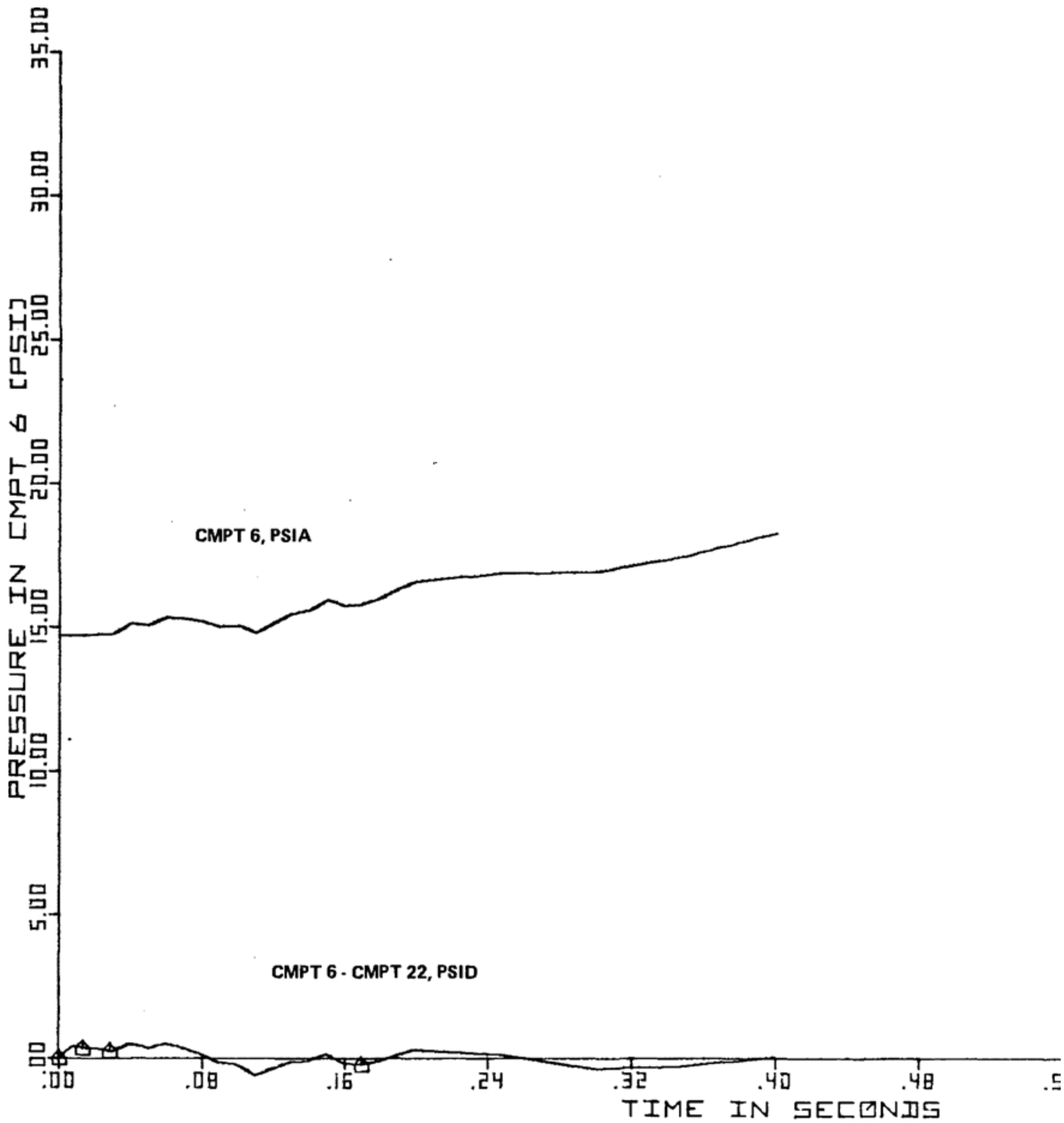
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 4, PSIA; CMPT 4-CMPT 22, PSID FIGURE 6.2 – 27cd



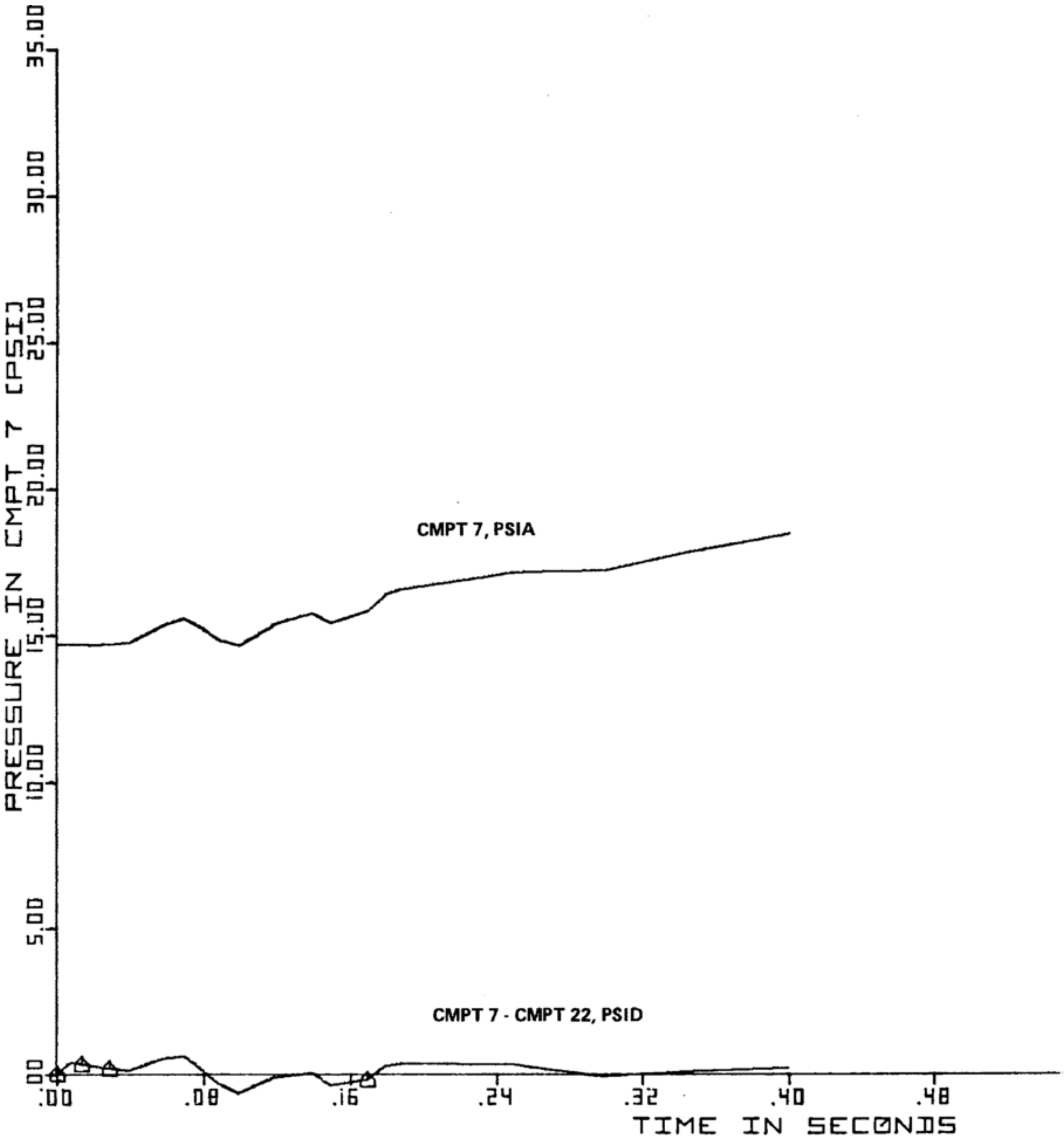
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 5, PSIA; CMPT 5-CMPT 22, PSID FIGURE 6.2 — 27ce



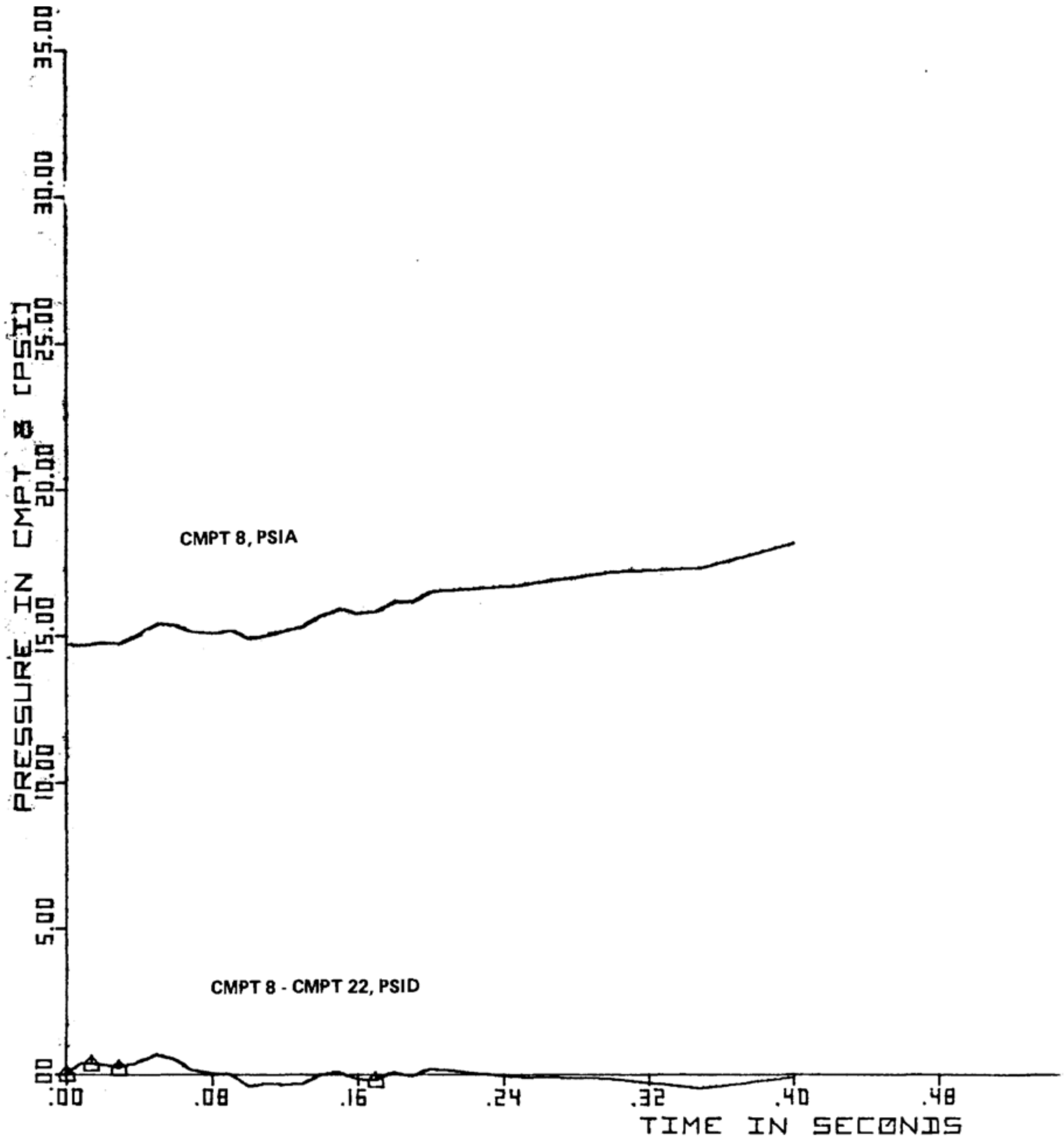
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 6, PSIA; CMPT 6-CMPT 22, PSID FIGURE 6.2 – 27cf



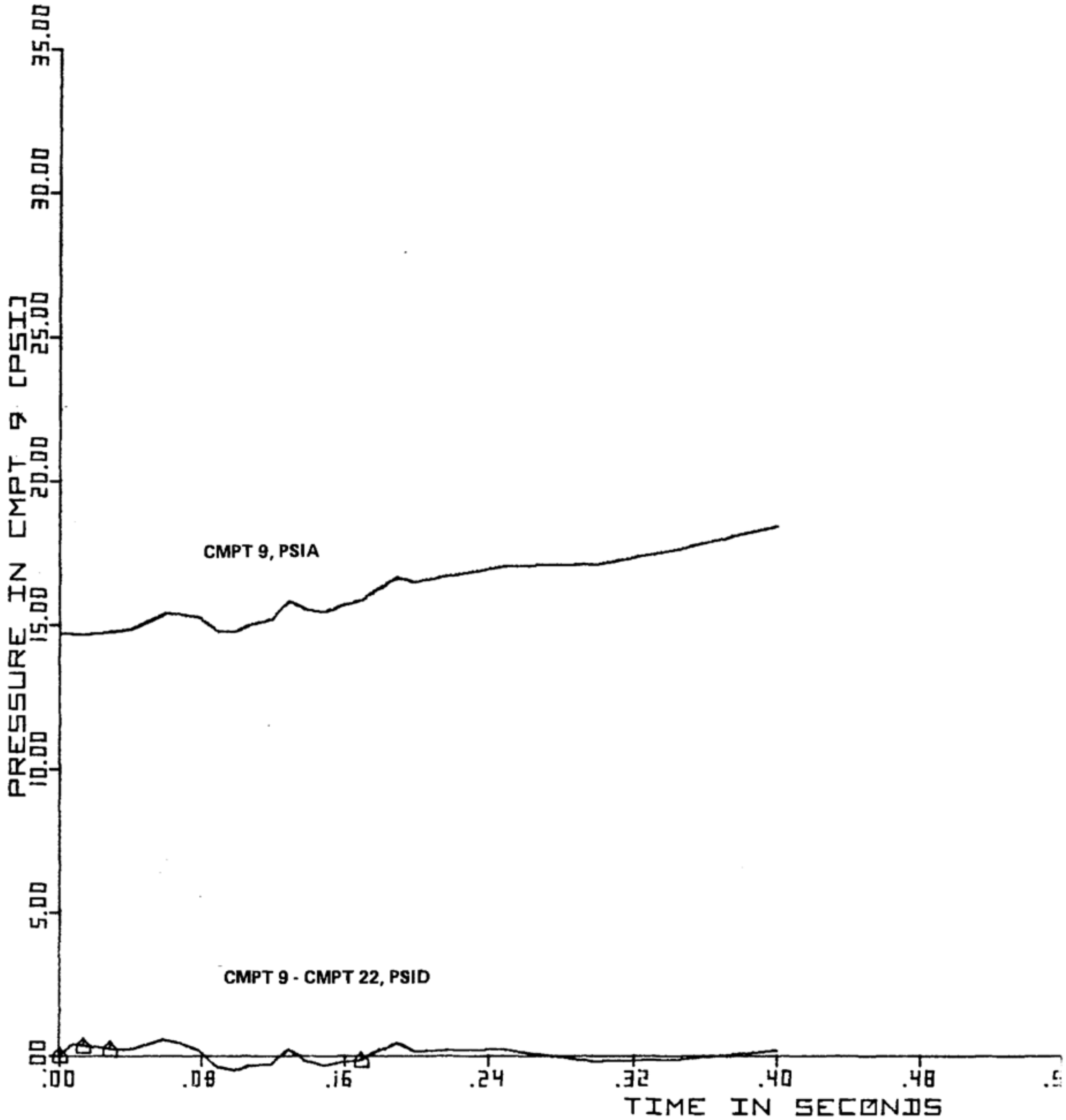
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 7, PSIA; CMPT 7- CMPT 22, PSID FIGURE 6.2 — 27cg



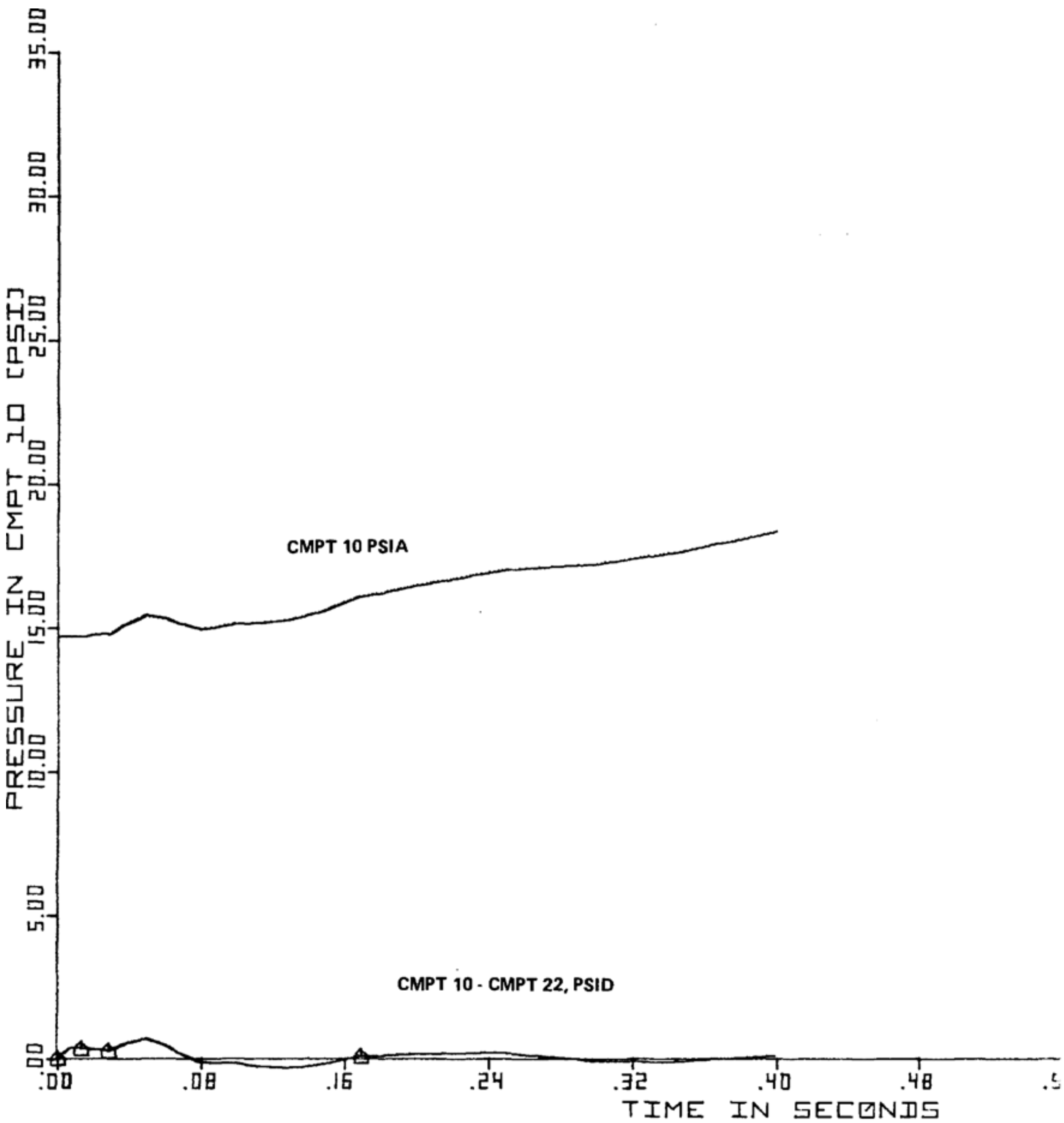
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 8, PSIA; CMPT 8-CMPT 22, PSID FIGURE 6.2 – 27ch



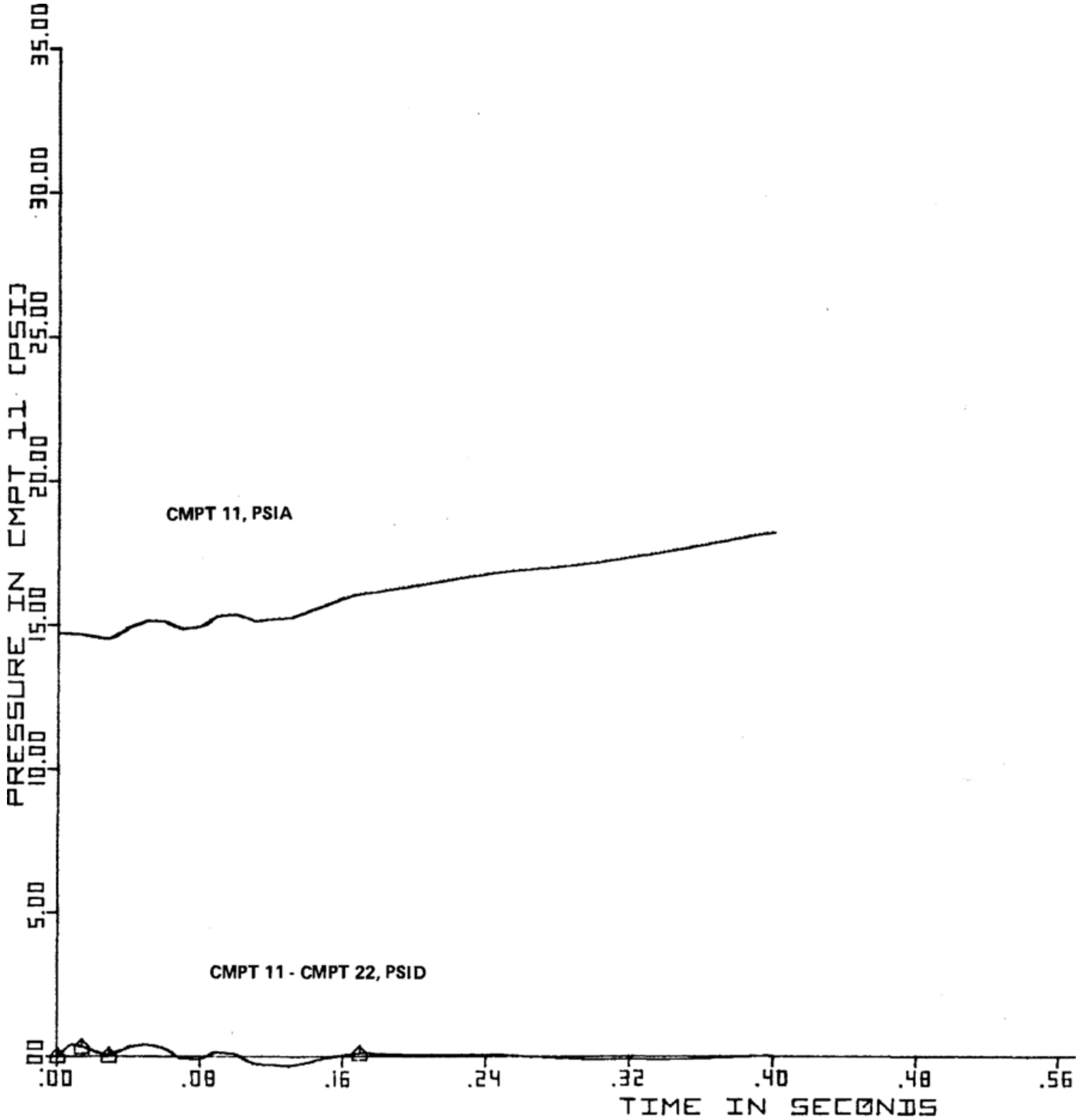
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 9, PSIA; CMPT 9-CMPT 22, PSID FIGURE 6.2 — 27ci



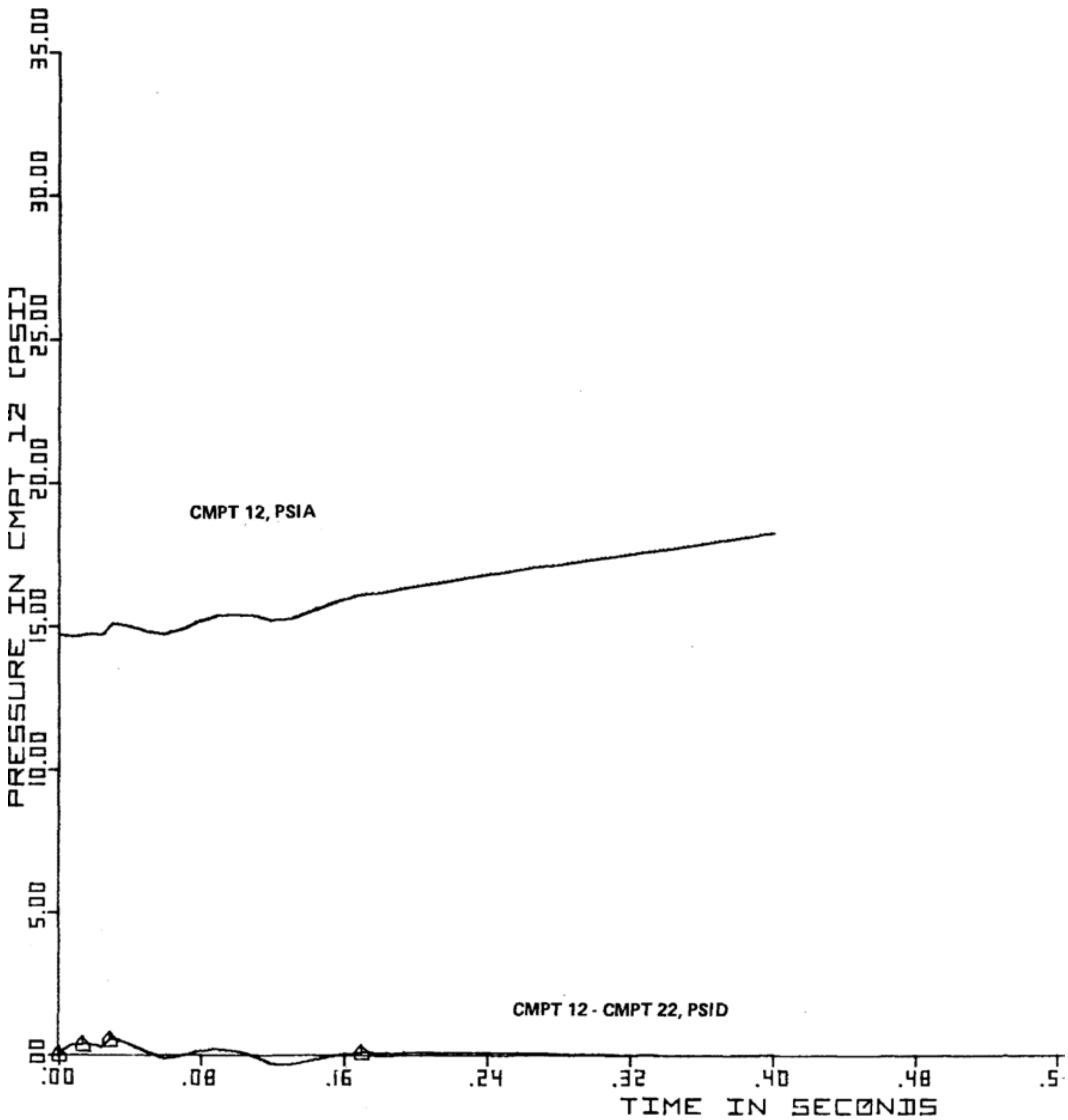
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 10, PSIA; CMPT 10-CMPT 22, PSID FIGURE 6.2 – 27cj



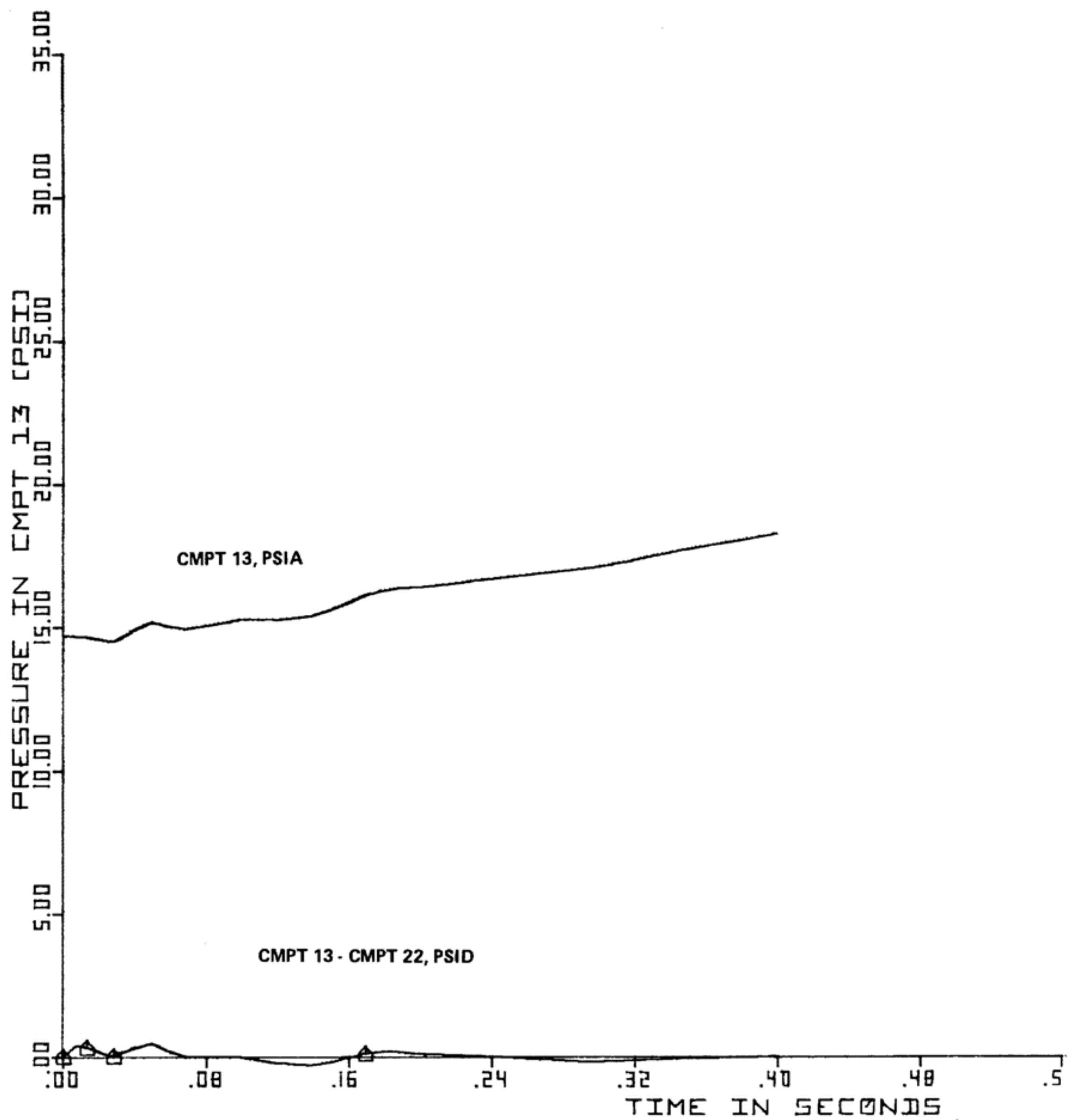
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 11, PSIA; CMPT 11-CMPT 22, PSID FIGURE 6.2 – 27ck



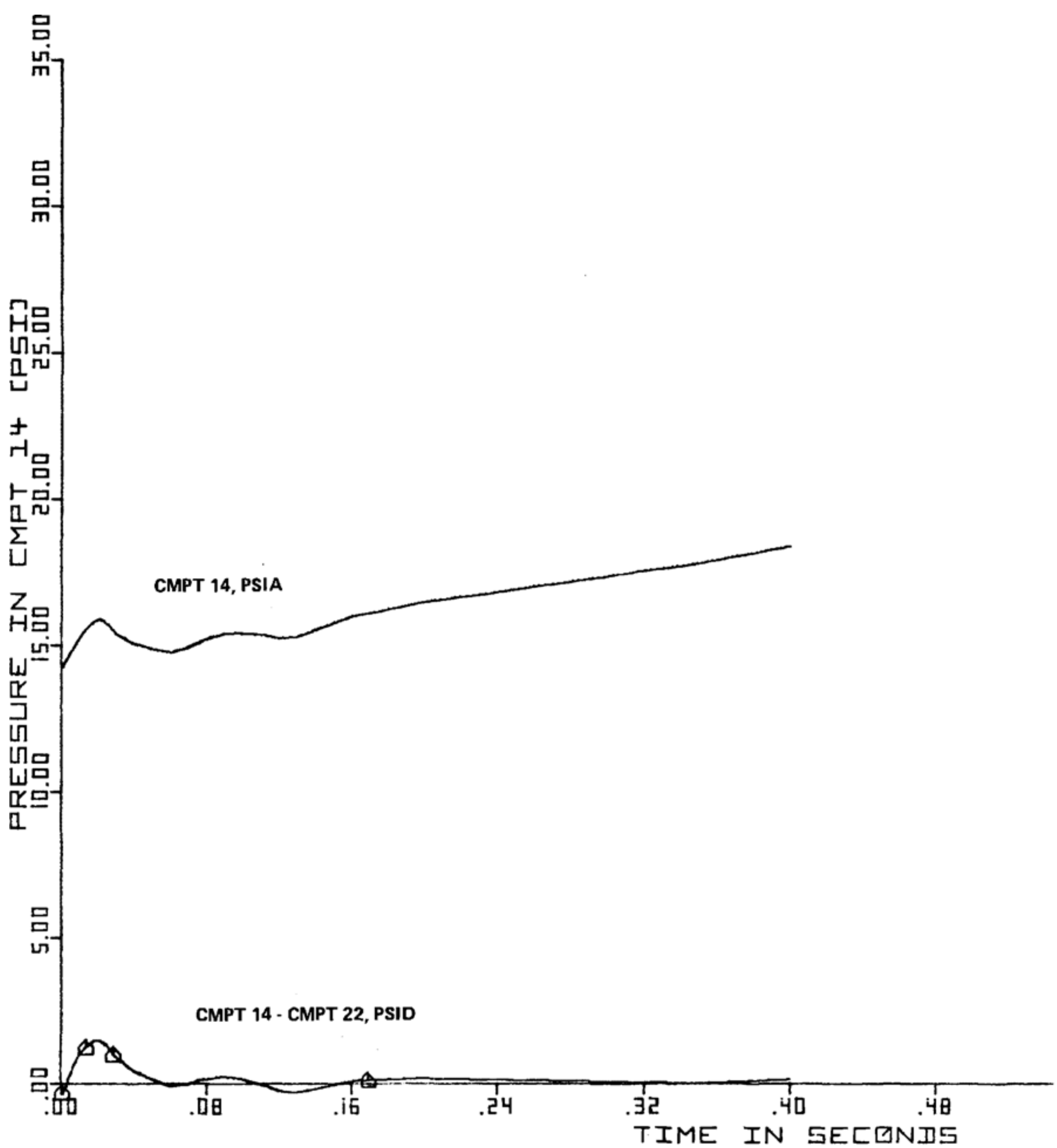
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 12, PSIA; CMPT 12-CMPT 22, PSID FIGURE 6.2 – 27cl



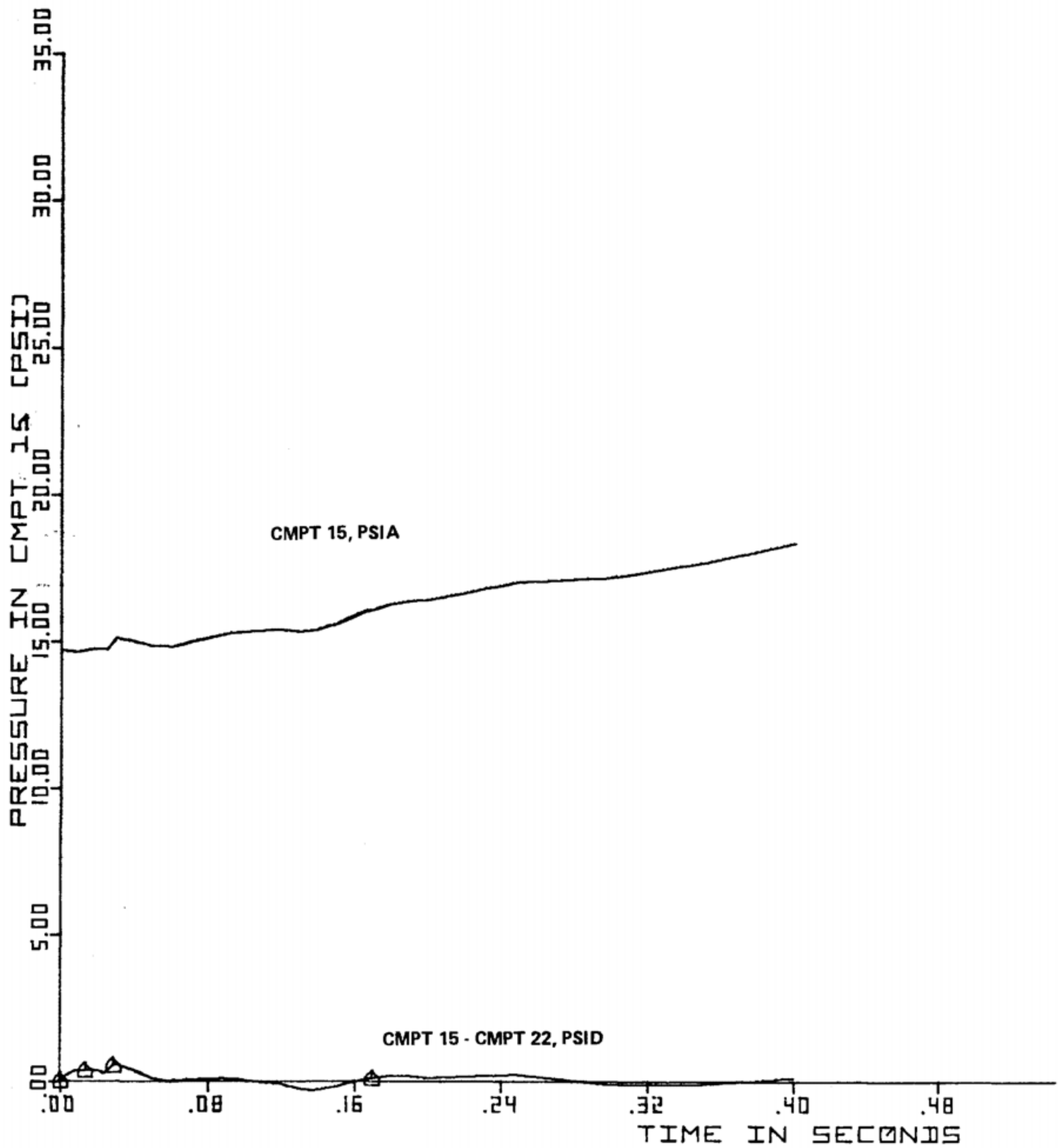
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 13, PSIA; CMPT 13-CMPT 22, PSID FIGURE 6.2 — 27cm



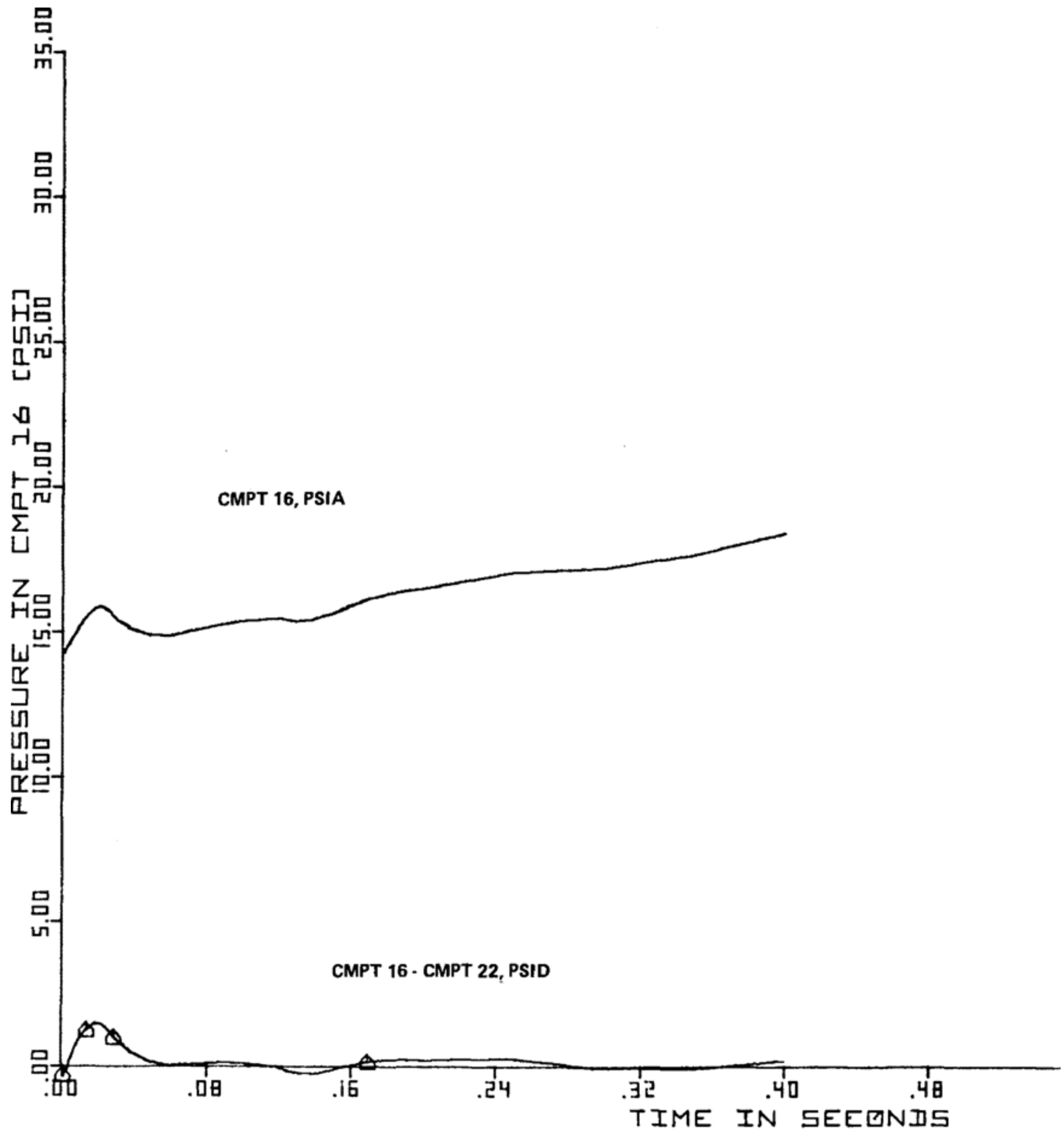
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 14, PSIA; CMPT 14-CMPT 22, PSID FIGURE 6.2 — 27cn



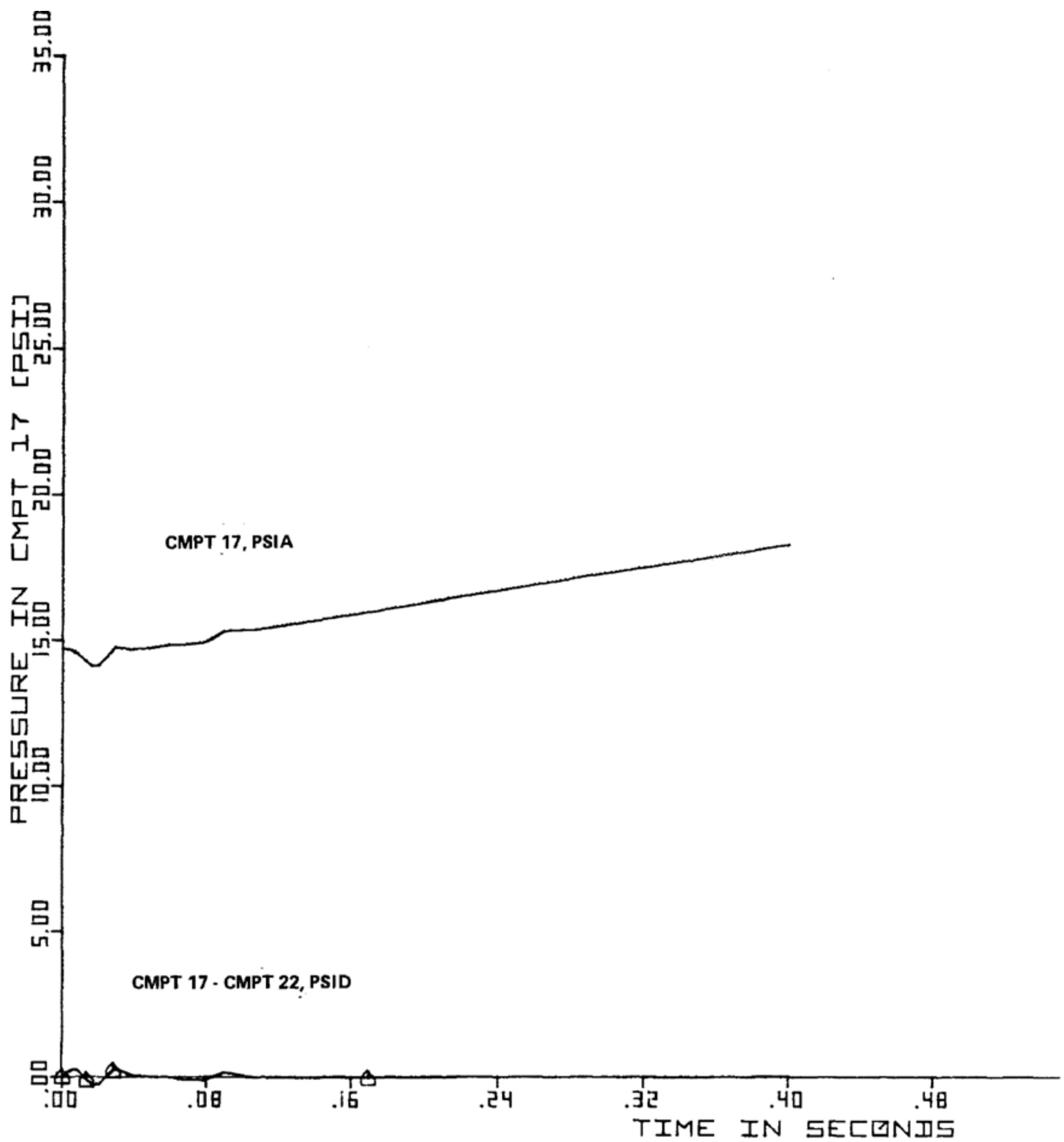
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 15, PSIA; CMPT 15-CMPT 22, PSID FIGURE 6.2 — 27co



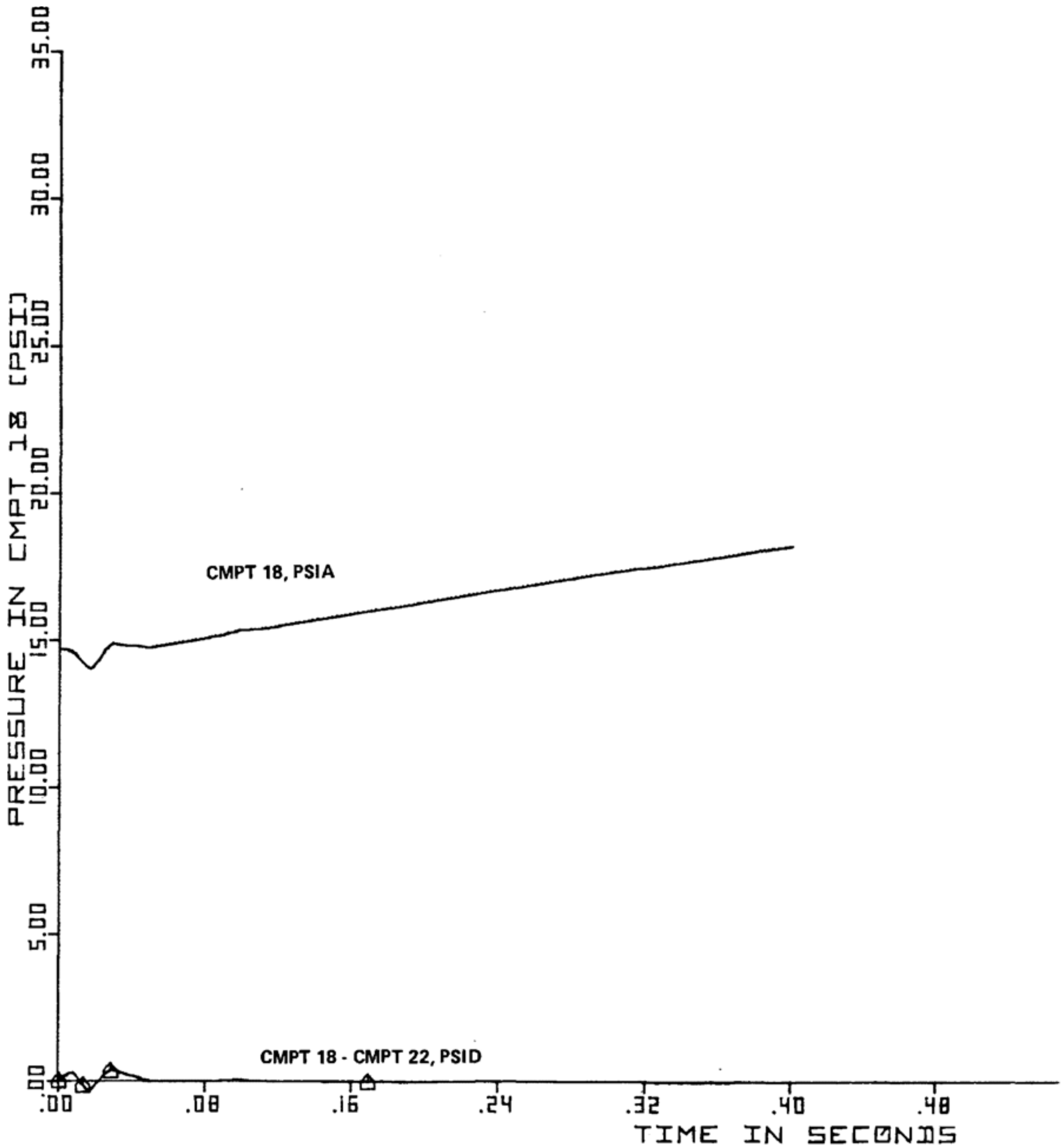
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 16, PSIA; CMPT 16-CMPT 22, PSID FIGURE 6.2 – 27cp



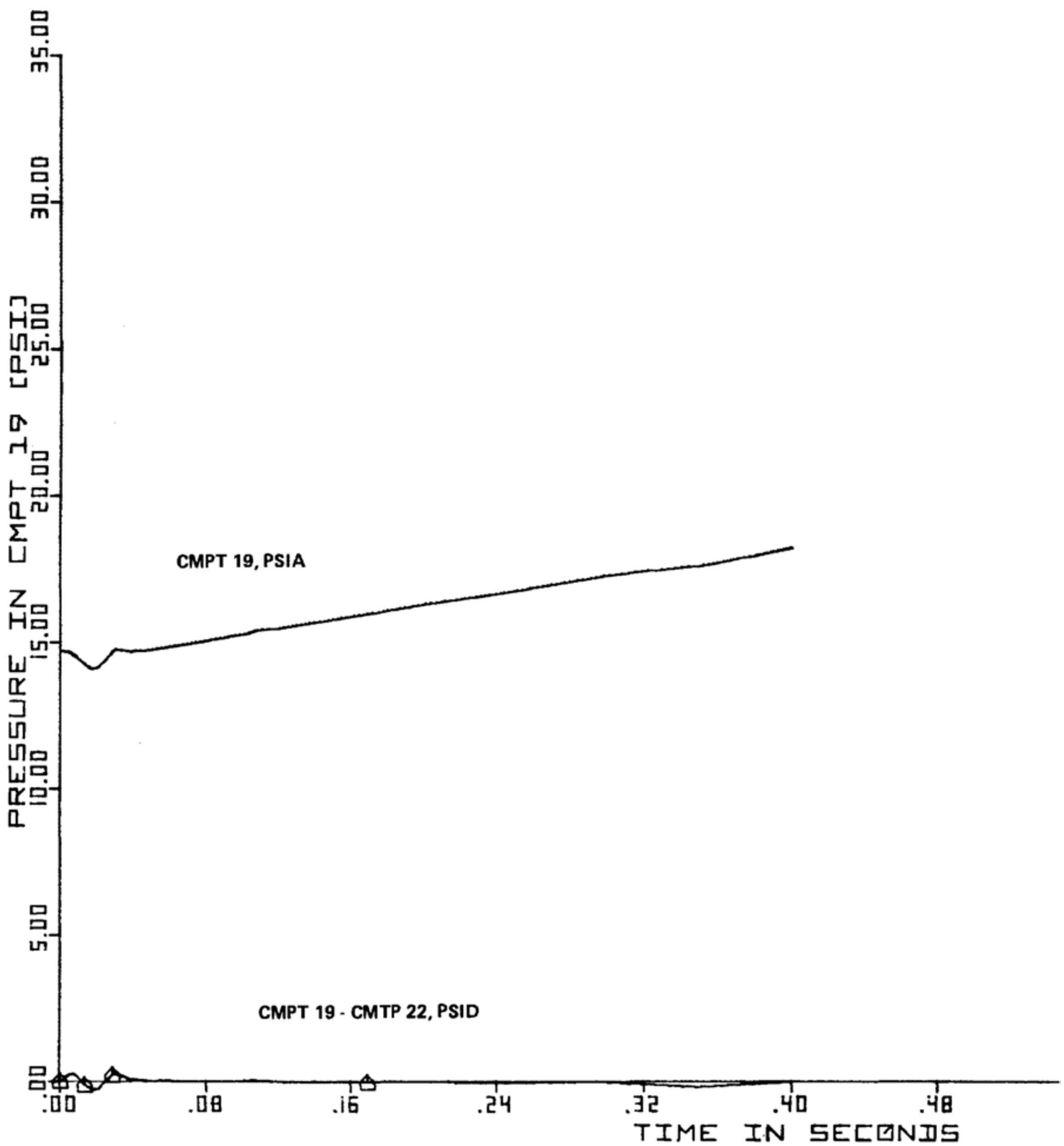
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 17, PSIA; CMPT 17-CMPT 22, PSID FIGURE 6.2 – 27cq



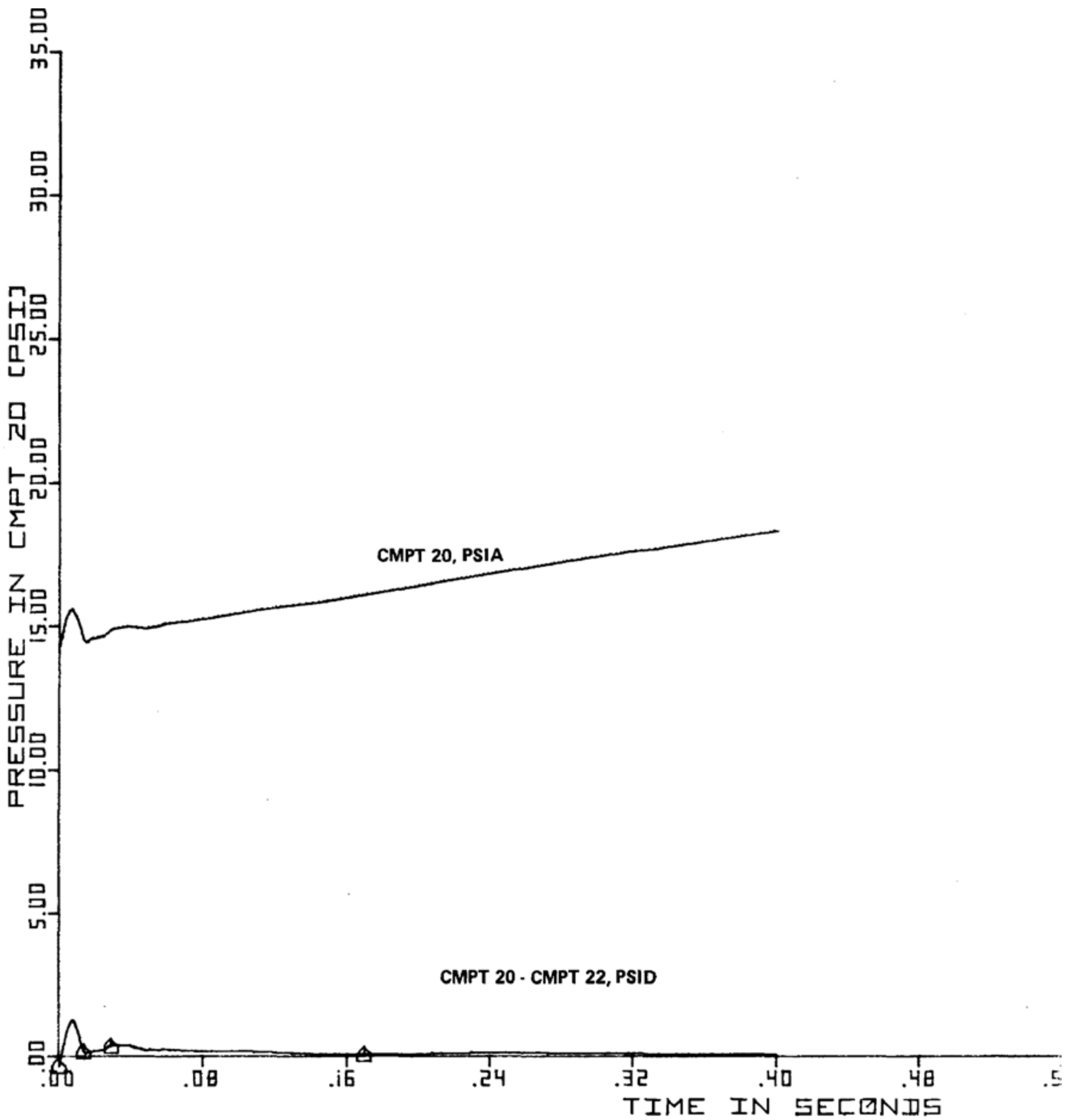
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 18, PSIA; CMPT 18-CMPT 22, PSID FIGURE 6.2 – 27cr



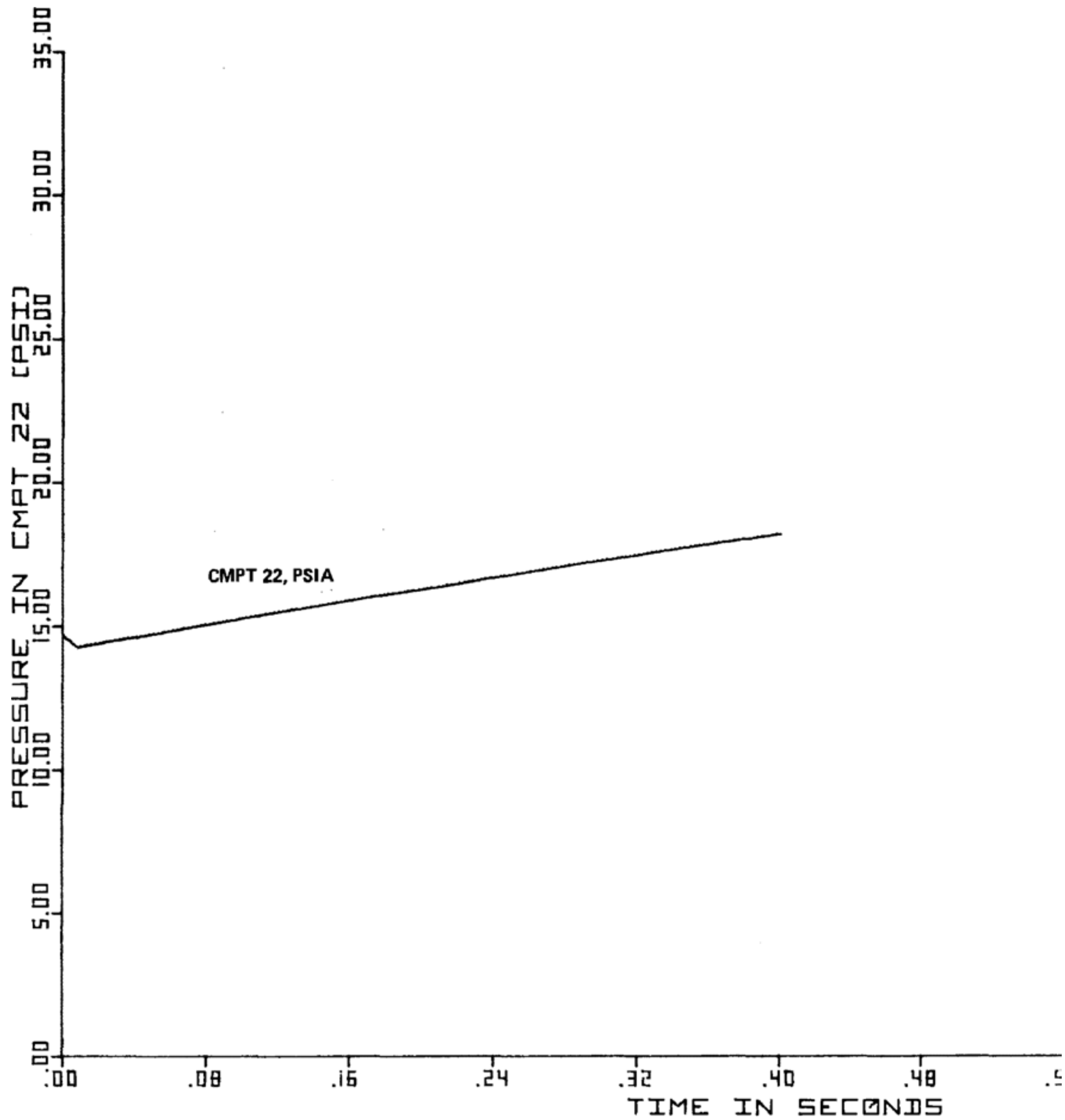
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 19, PSIA; CMPT 19-CMPT 22, PSID FIGURE 6.2 – 27cs



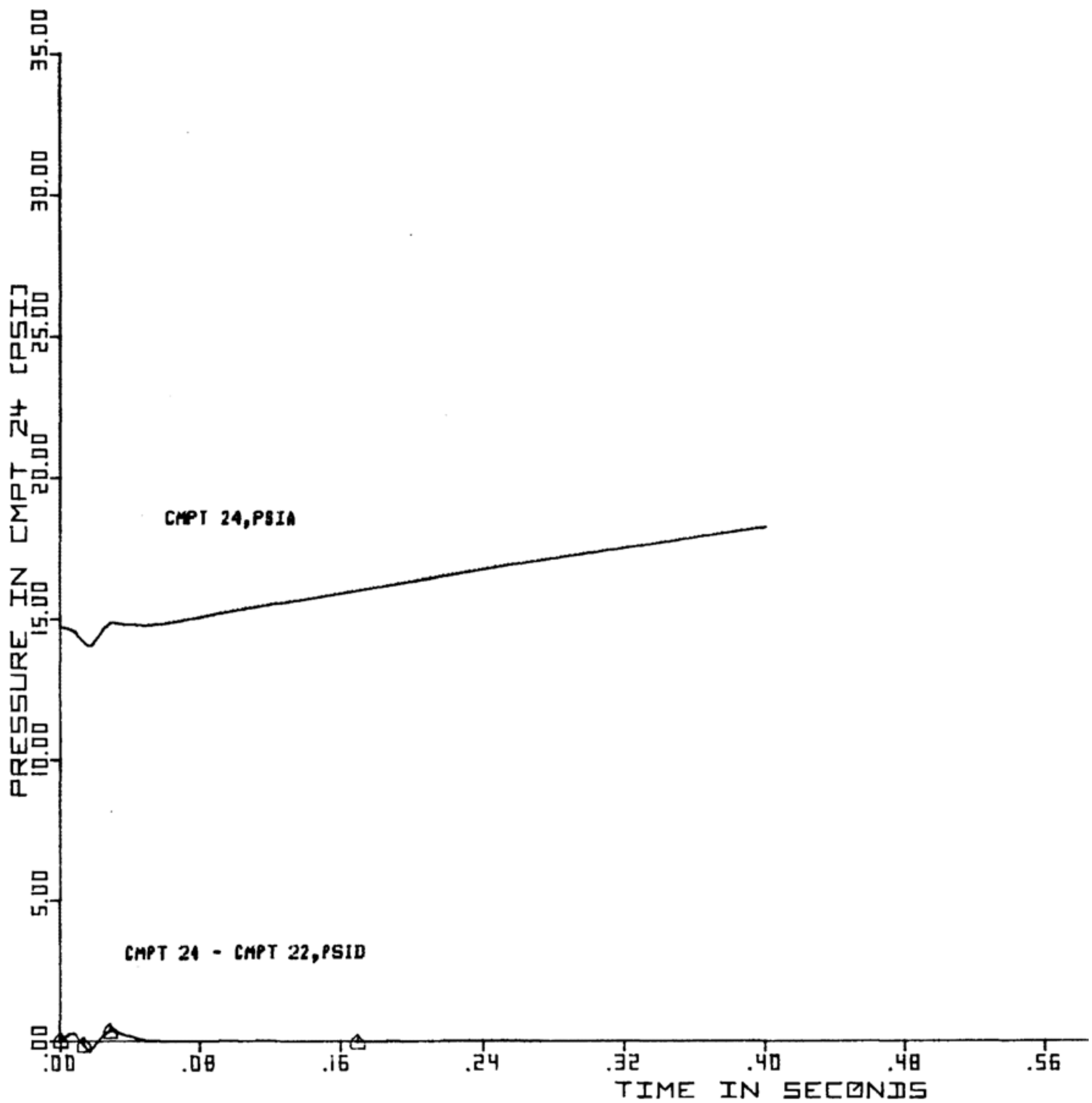
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 20, PSIA; CMPT 20-CMPT 22, PSID FIGURE 6.2 – 27ct



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 22, PSIA FIGURE 6.2 – 27cu



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	PRESSURE RESPONSE FOR FEEDWATER LINE BREAK CMPT 24, PSIA; CMPT 24-CMPT 22, PSID FIGURE 6.2 – 27cv

Figure 6.2-28
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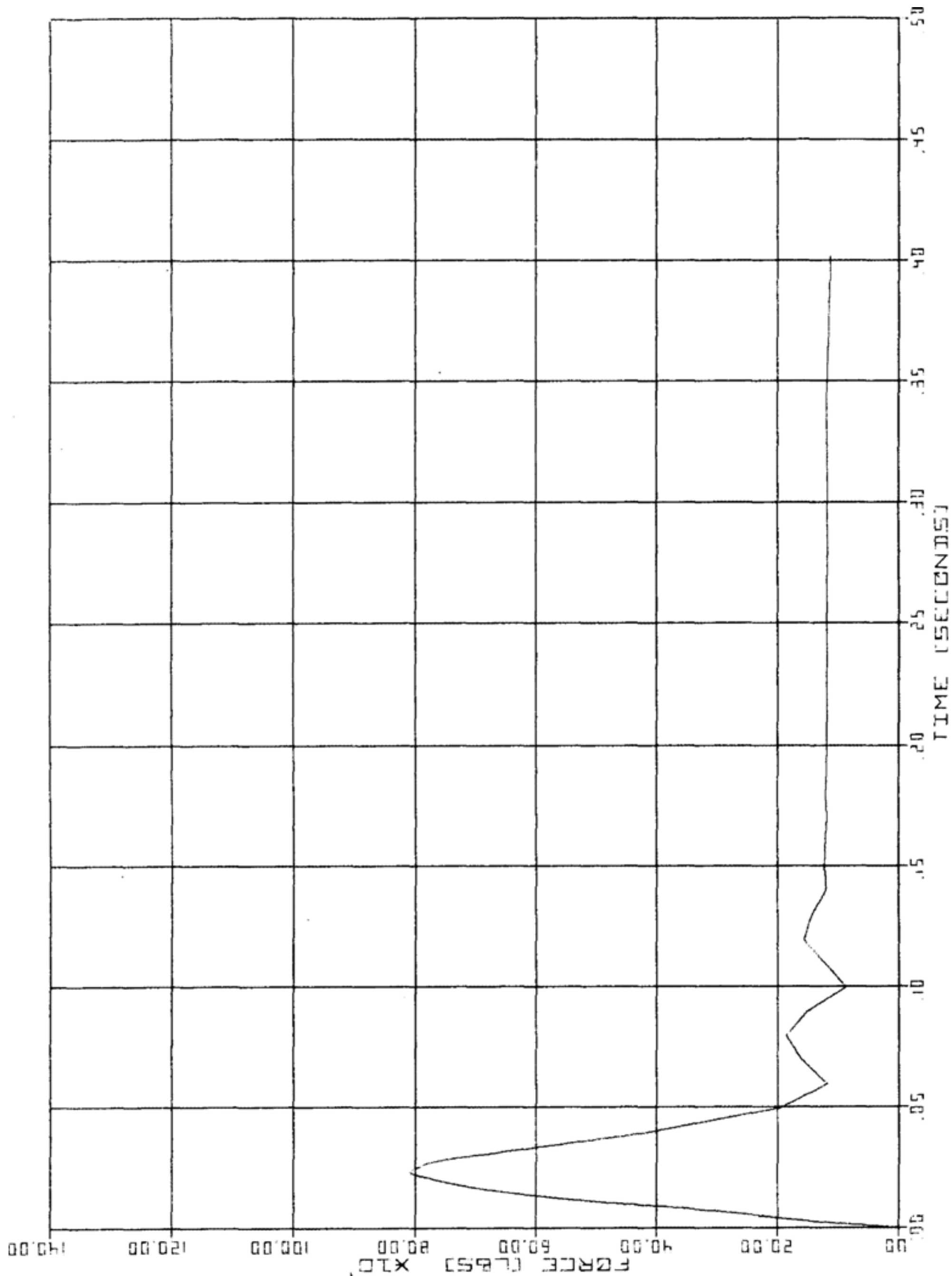
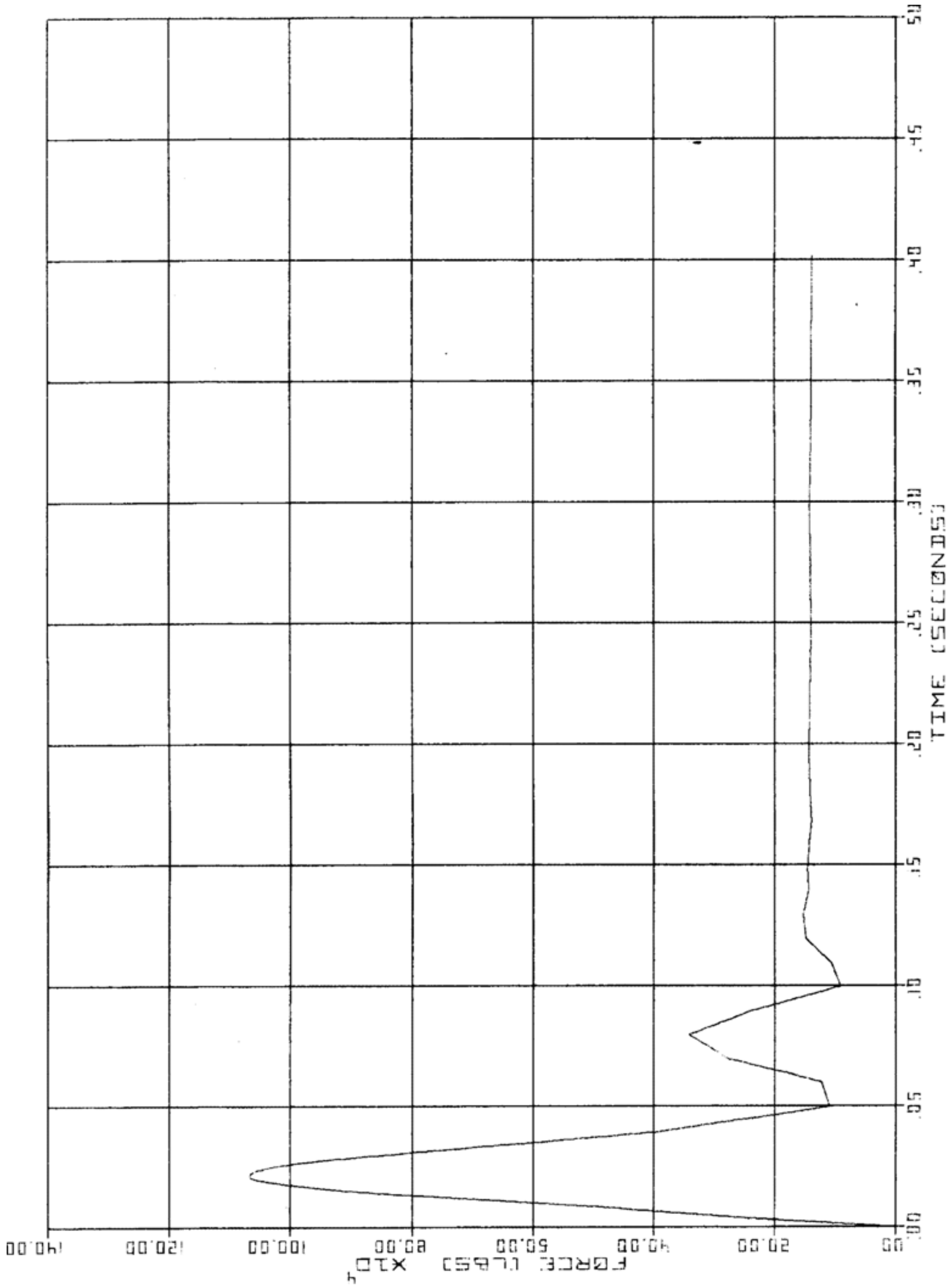


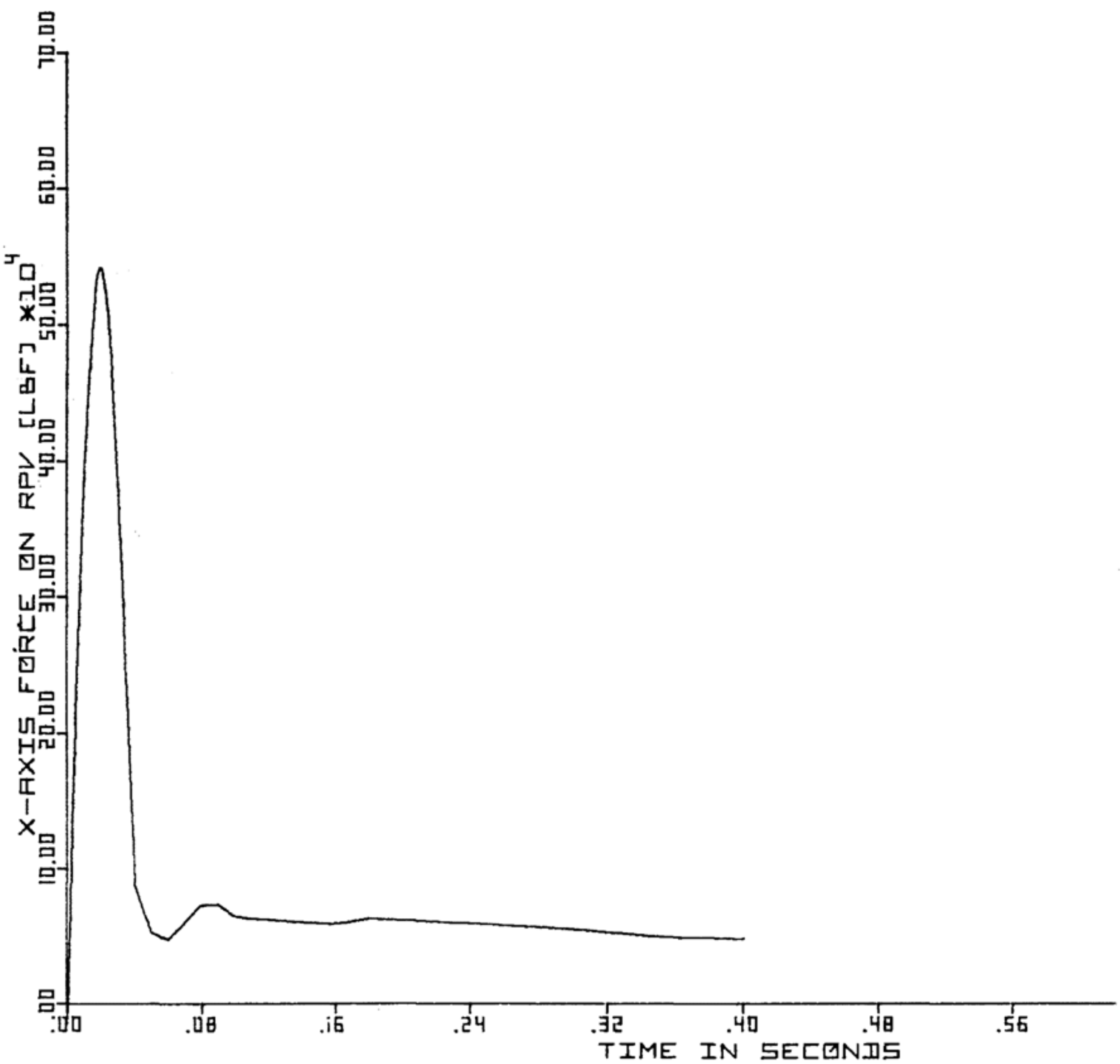
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRC RETURN LINE BREAK
FORCE X ON THE RPV
[HISTORICAL INFORMATION]
FIGURE 6.2 — 28aa

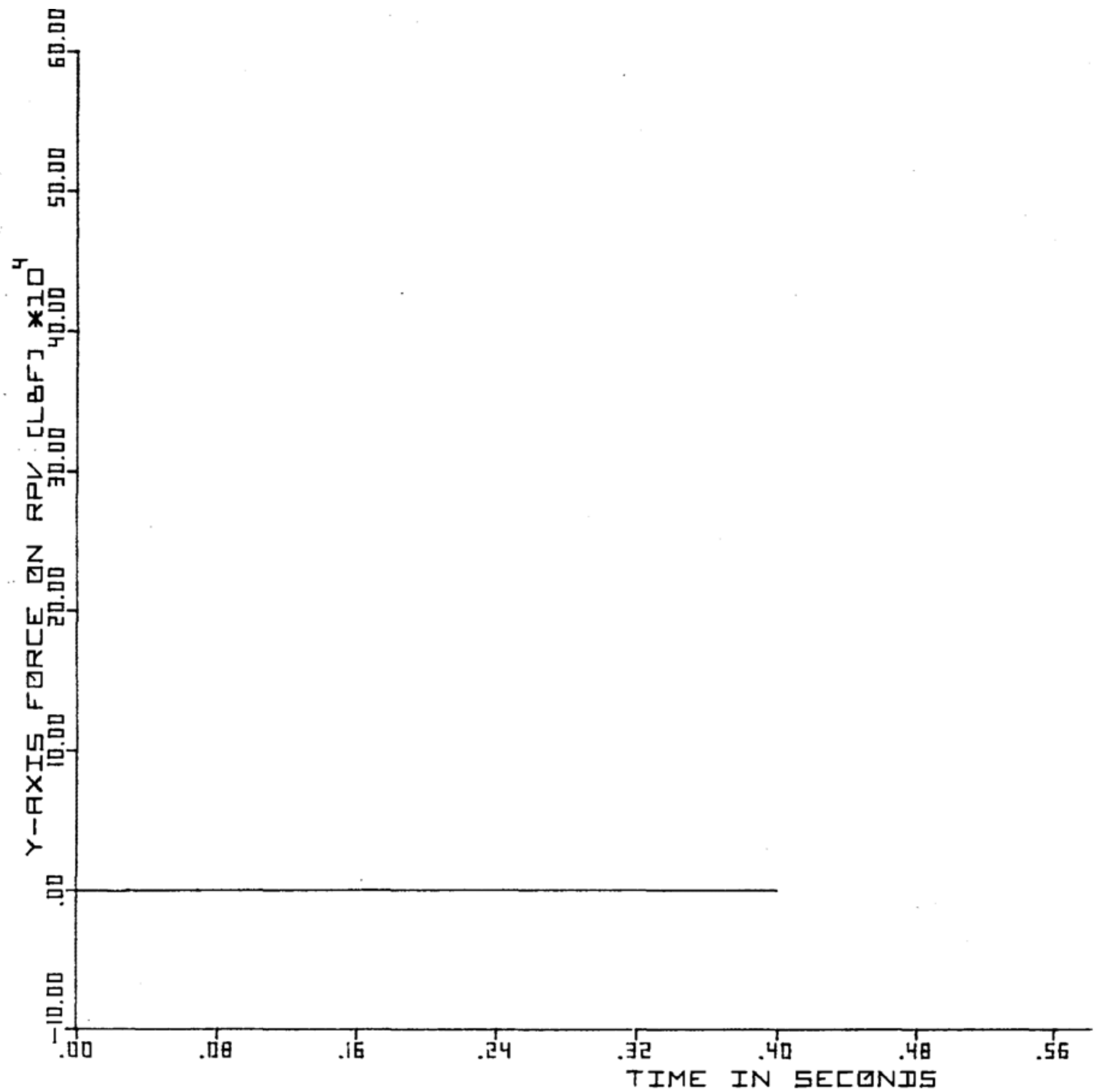


RECIRC RETURN LINE BREAK
FORCE Y ON THE RPV
[HISTORICAL INFORMATION]
FIGURE 6.2 – 28ab

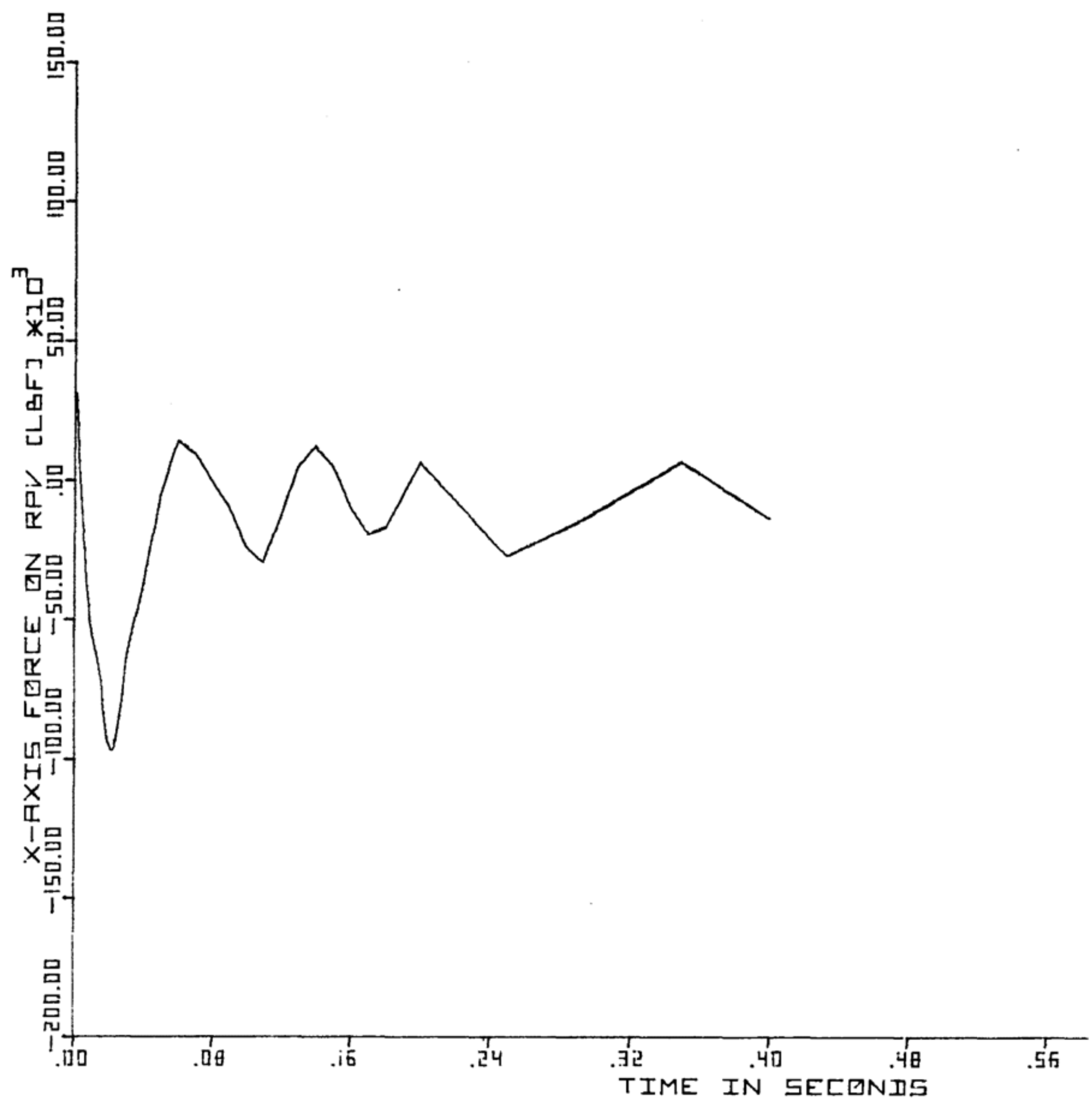
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT



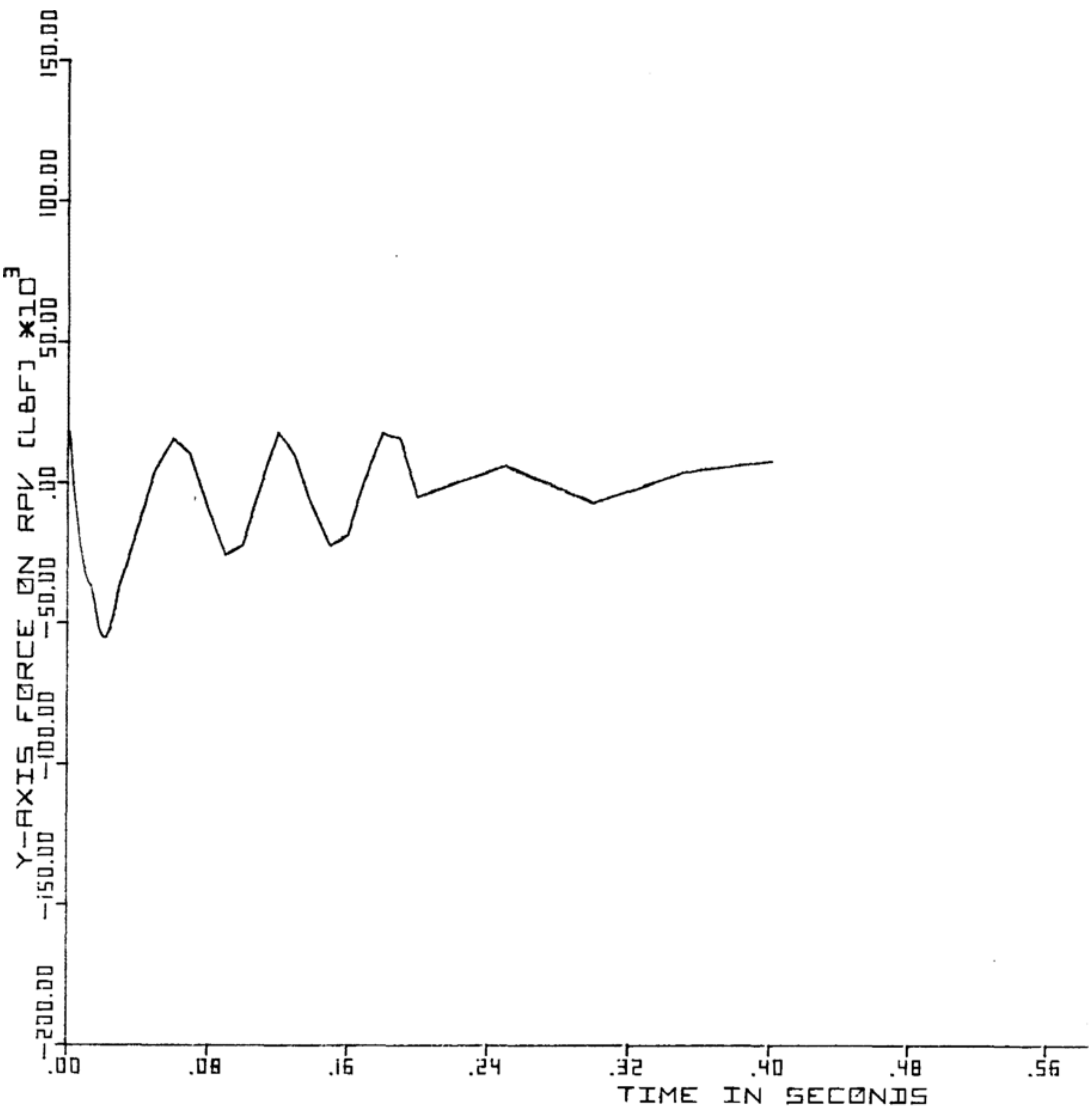
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRC SUCTION LINE BREAK FORCE X ON RPV [HISTORICAL INFORMATION] FIGURE 6.2 – 28ba



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRC SUCTION LINE BREAK FORCE Y ON RPV [HISTORICAL INFORMATION] FIGURE 6.2 – 28bb



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK FORCE X ON THE RPV [HISTORICAL INFORMATION] FIGURE 6.2 – 28ca



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK FORCE Y ON THE RPV [HISTORICAL INFORMATION] FIGURE 6.2 – 28cb

Figure 6.2-29
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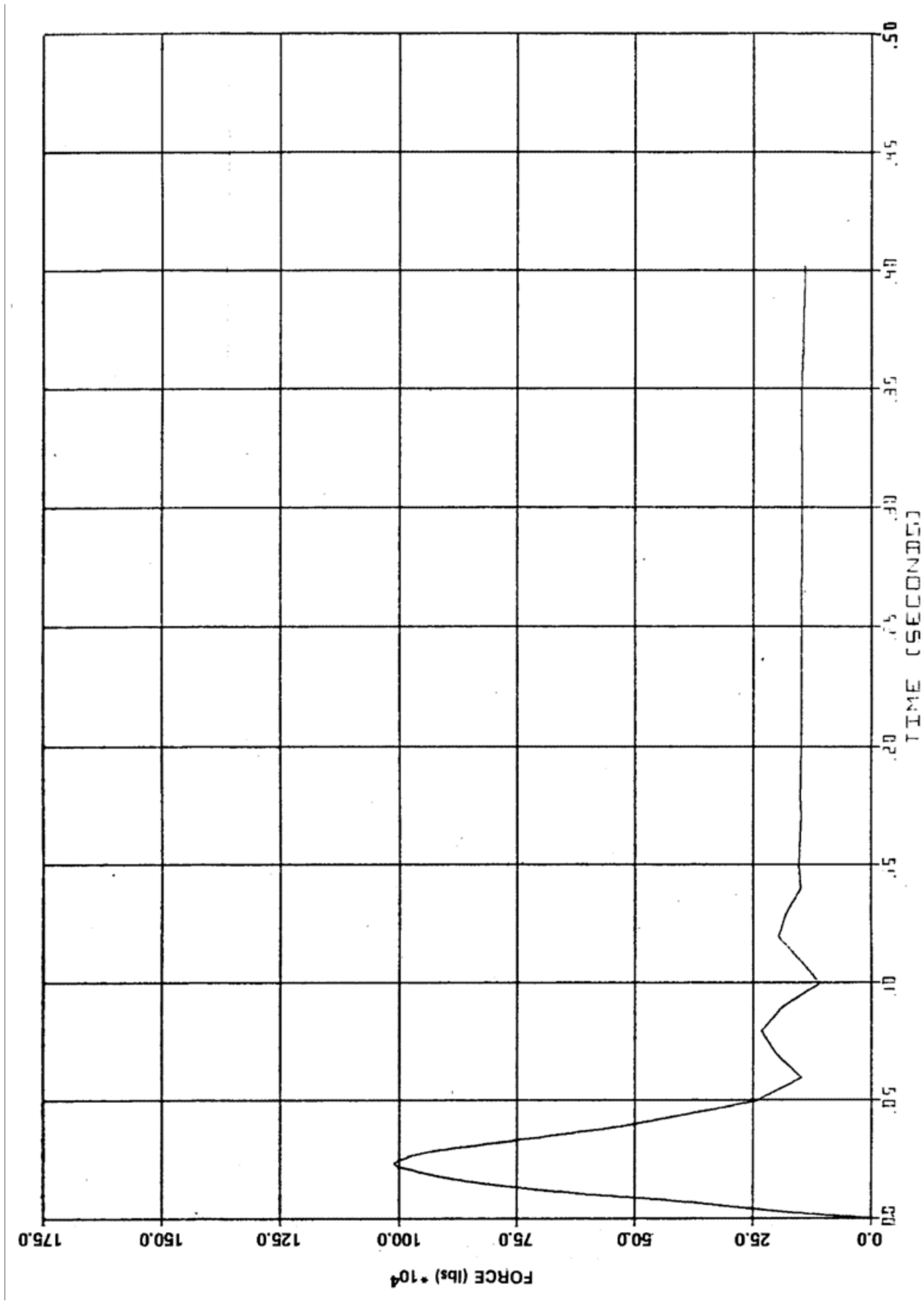
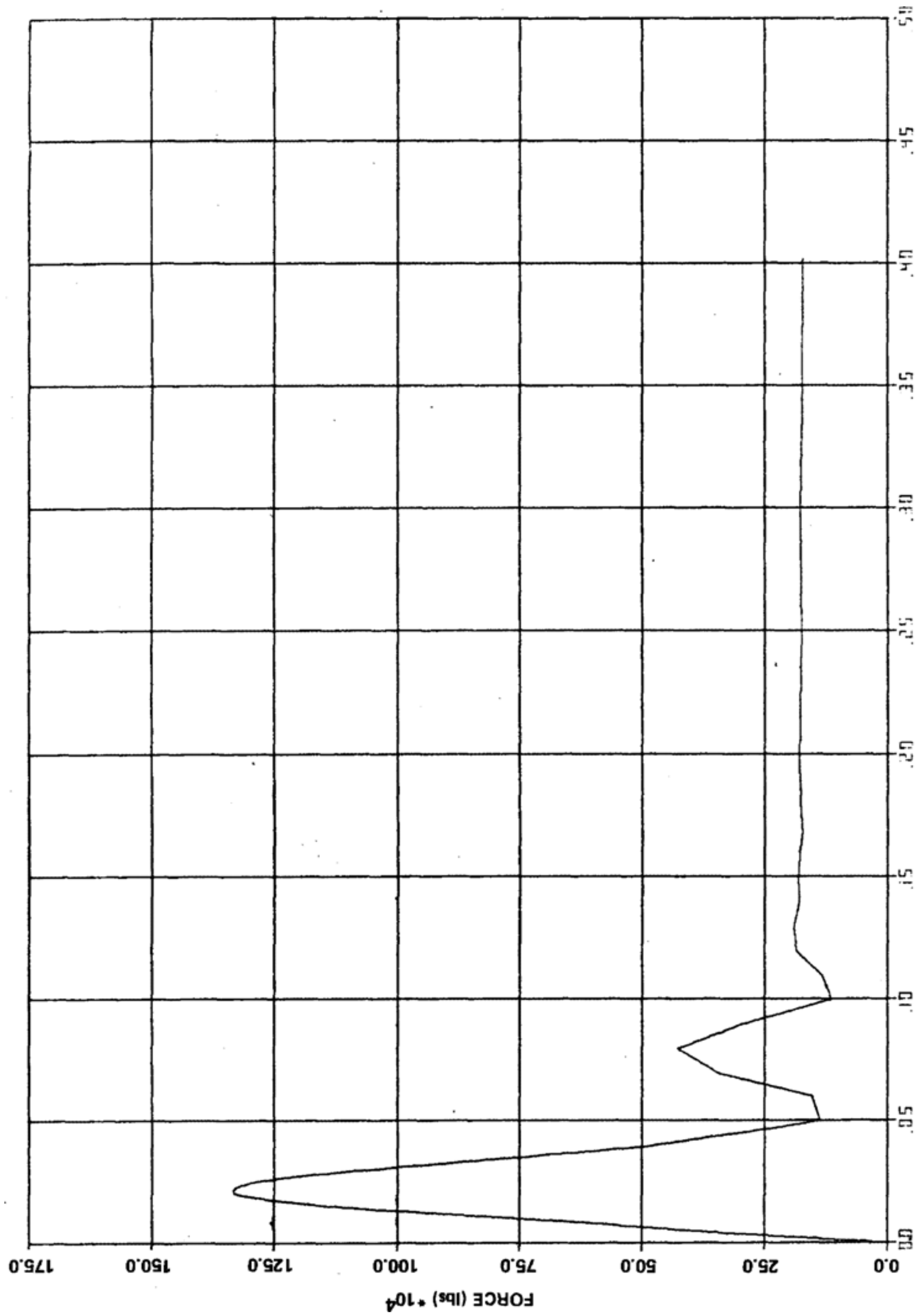


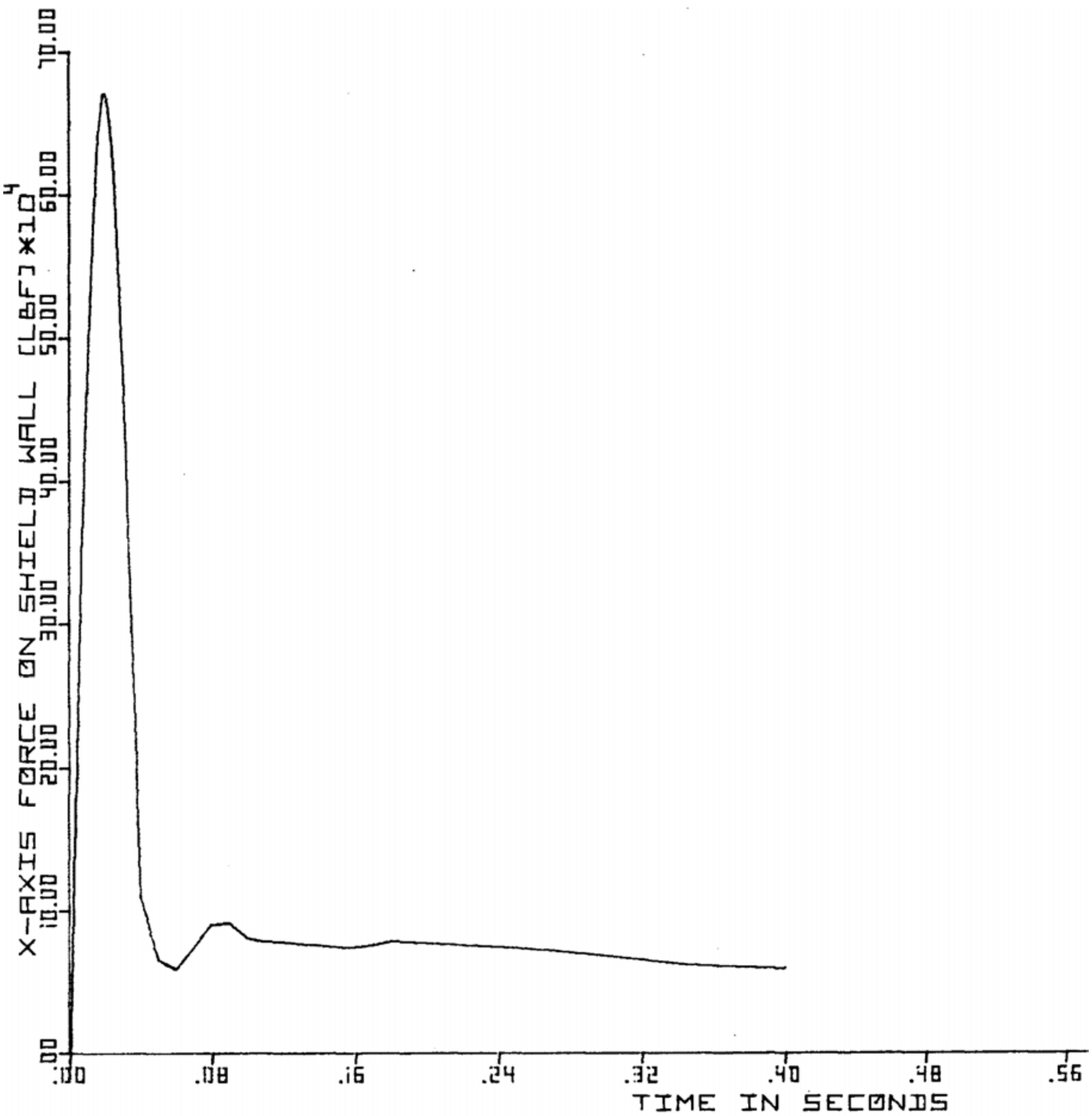
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRC RETURN LINE BREAK
FORCE X ON SHIELD WALL
[HISTORICAL INFORMATION]
FIGURE 6.2 – 29aa

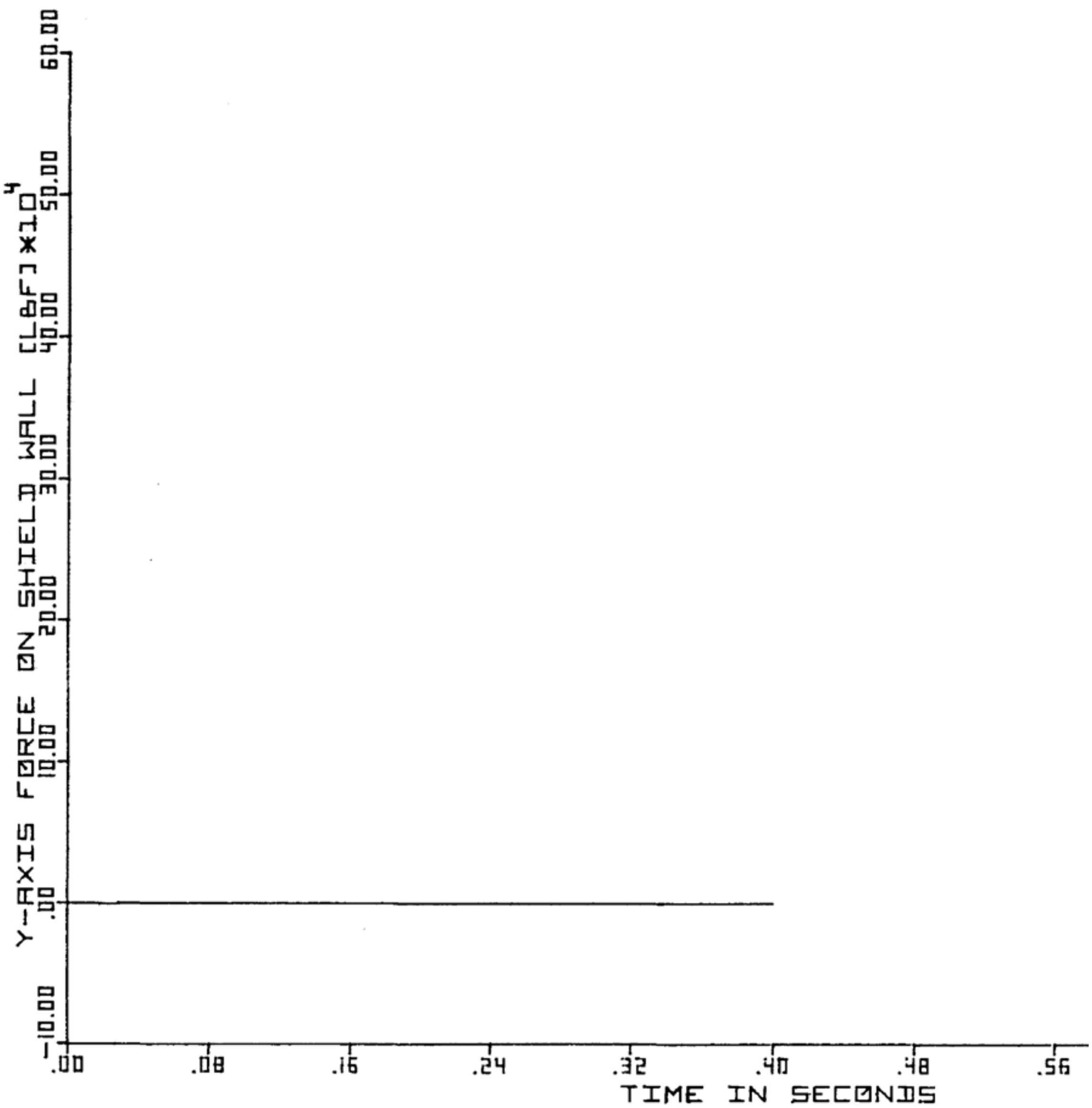


RECIRC RETURN LINE BREAK
FORCE Y ON SHIELD WALL
[HISTORICAL INFORMATION]
FIGURE 6.2 – 29ab

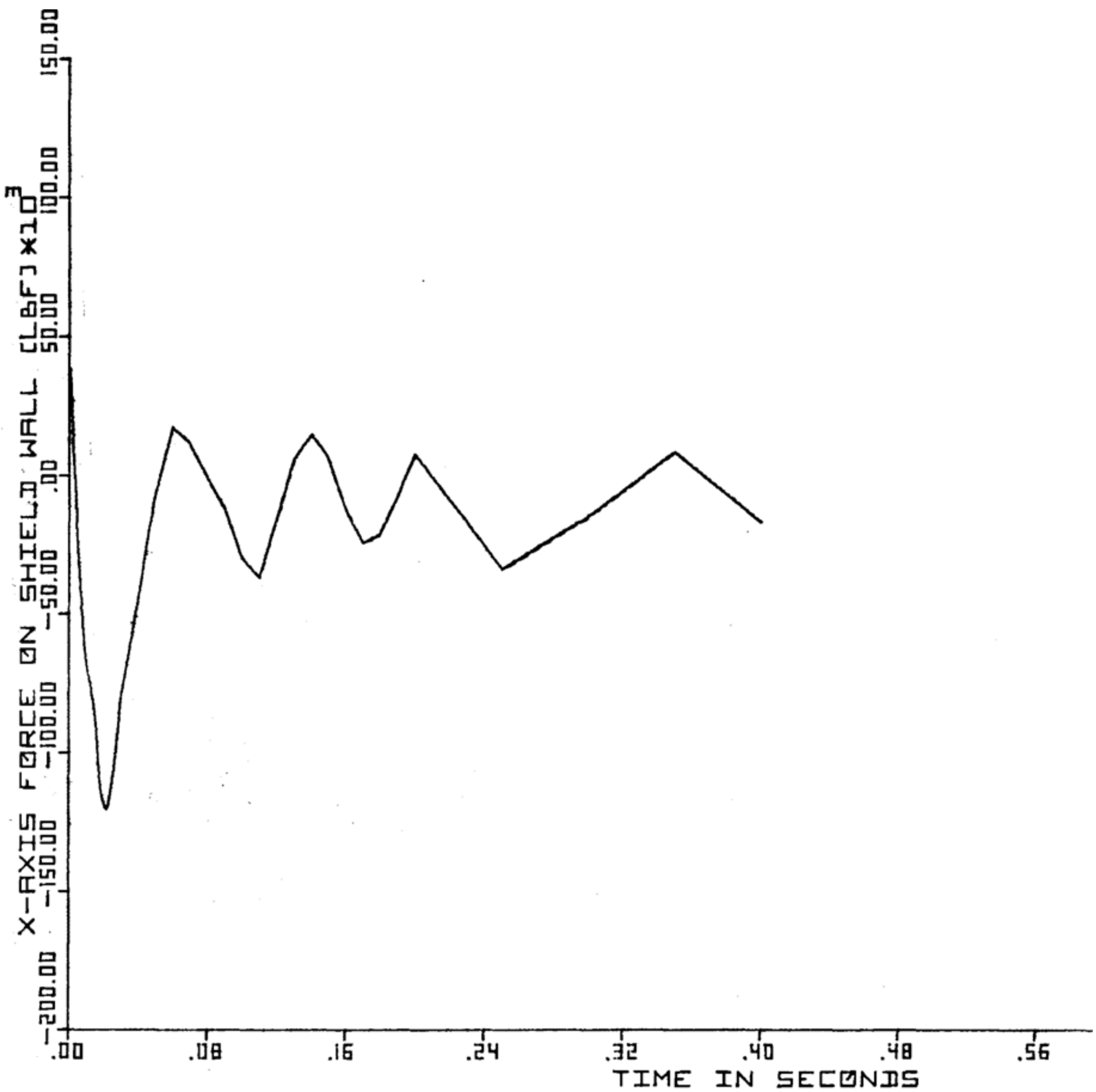
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT



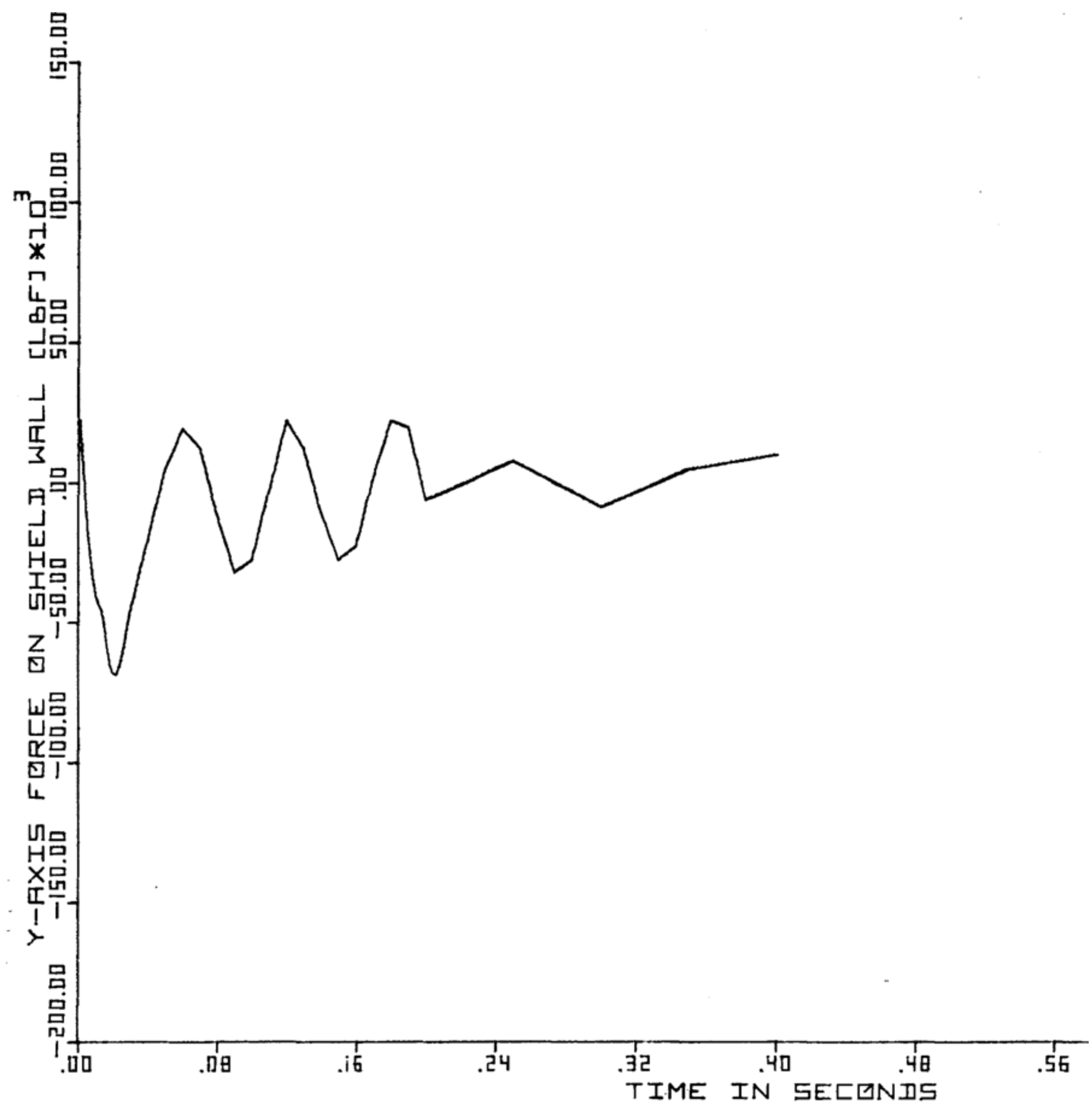
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRC SUCTION LINE BREAK FORCE X ON SHIELD WALL [HISTORICAL INFORMATION] FIGURE 6.2 – 29ba



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRC SUCTION LINE BREAK FORCE Y ON SHIELD WALL [HISTORICAL INFORMATION] FIGURE 6.2 – 29bb

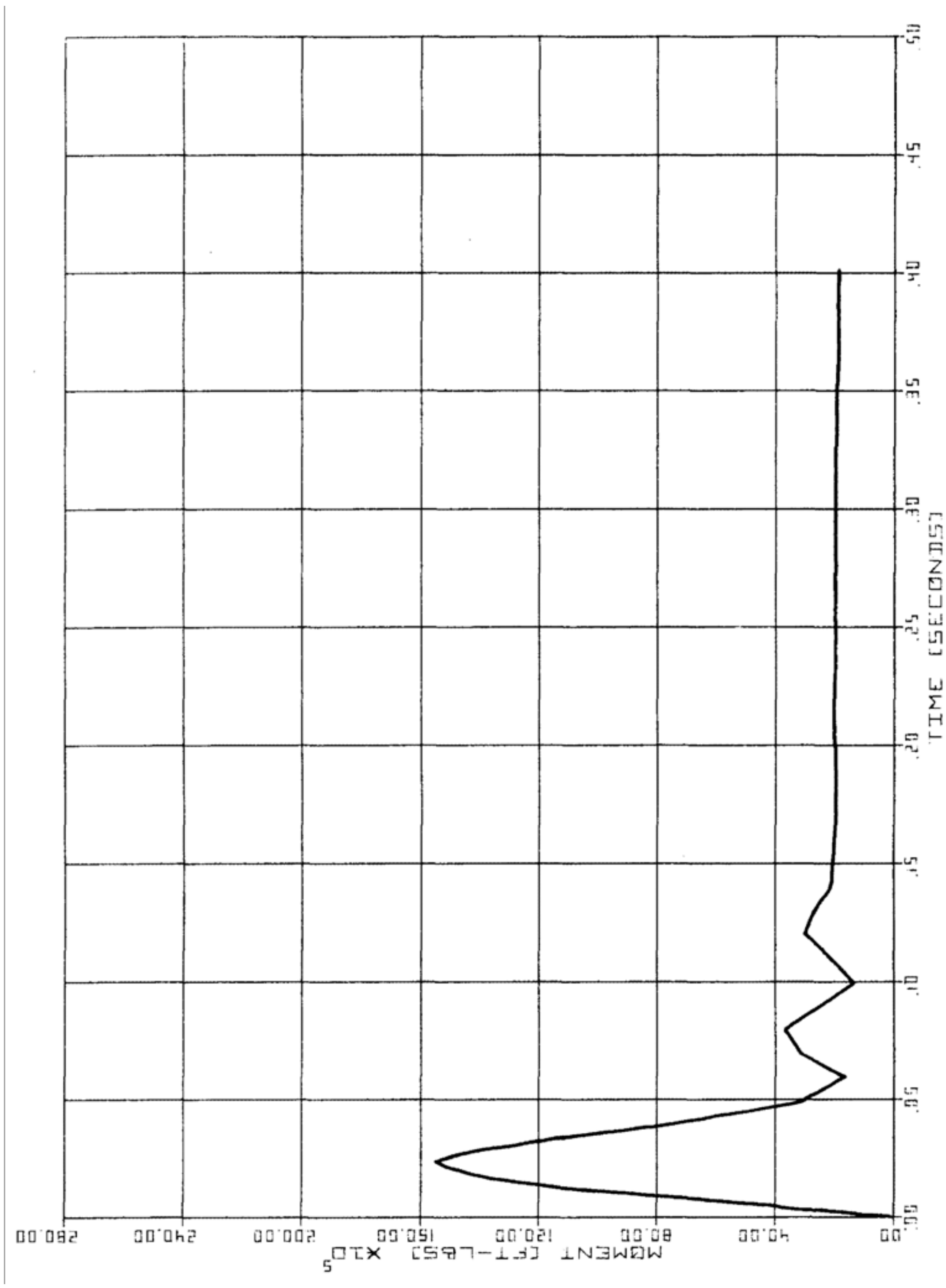


MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK FORCE X ON SHIELD WALL [HISTORICAL INFORMATION] FIGURE 6.2 – 29ca



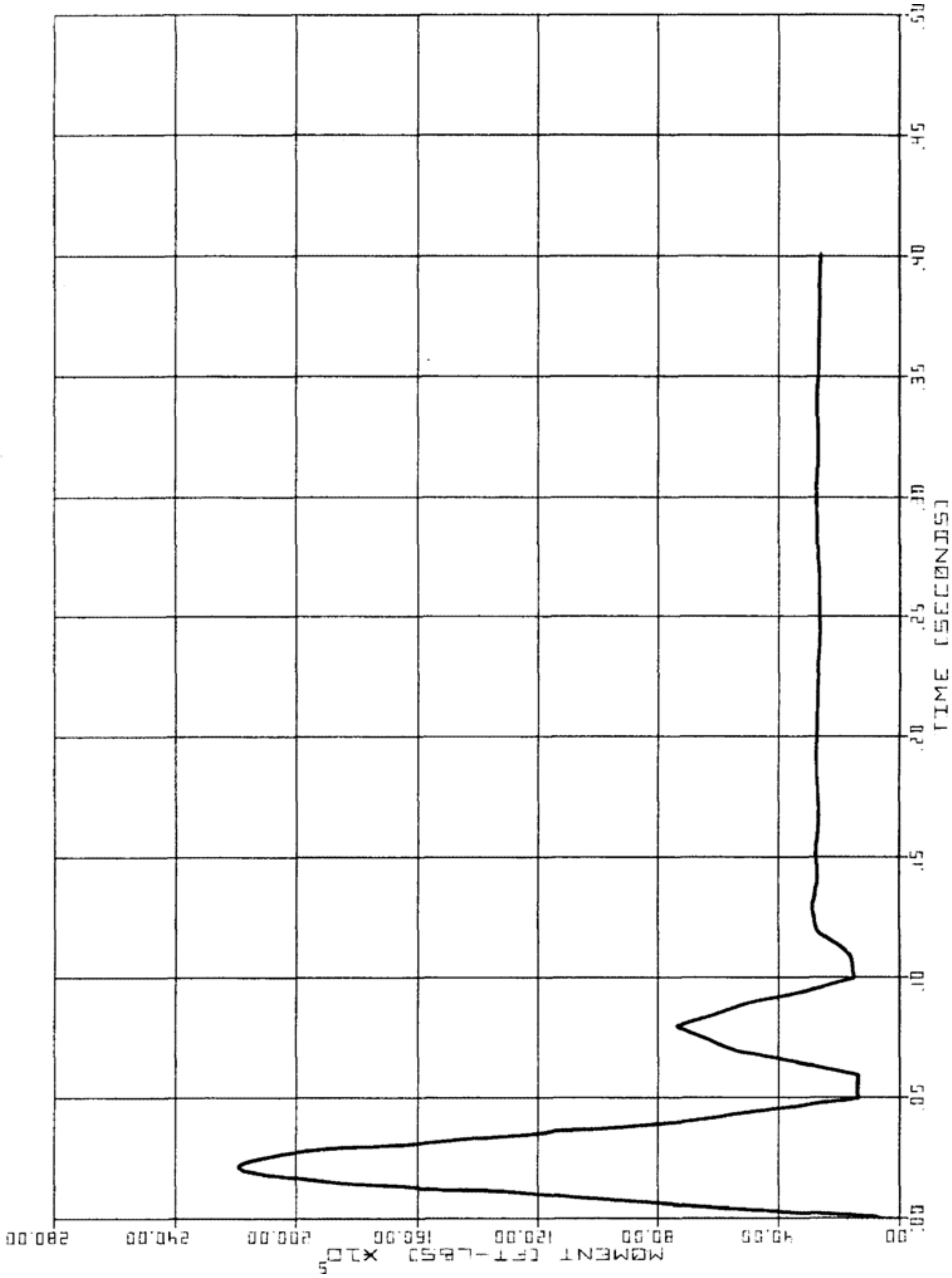
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK FORCE Y ON SHIELD WALL FIGURE 6.2 – 29cb



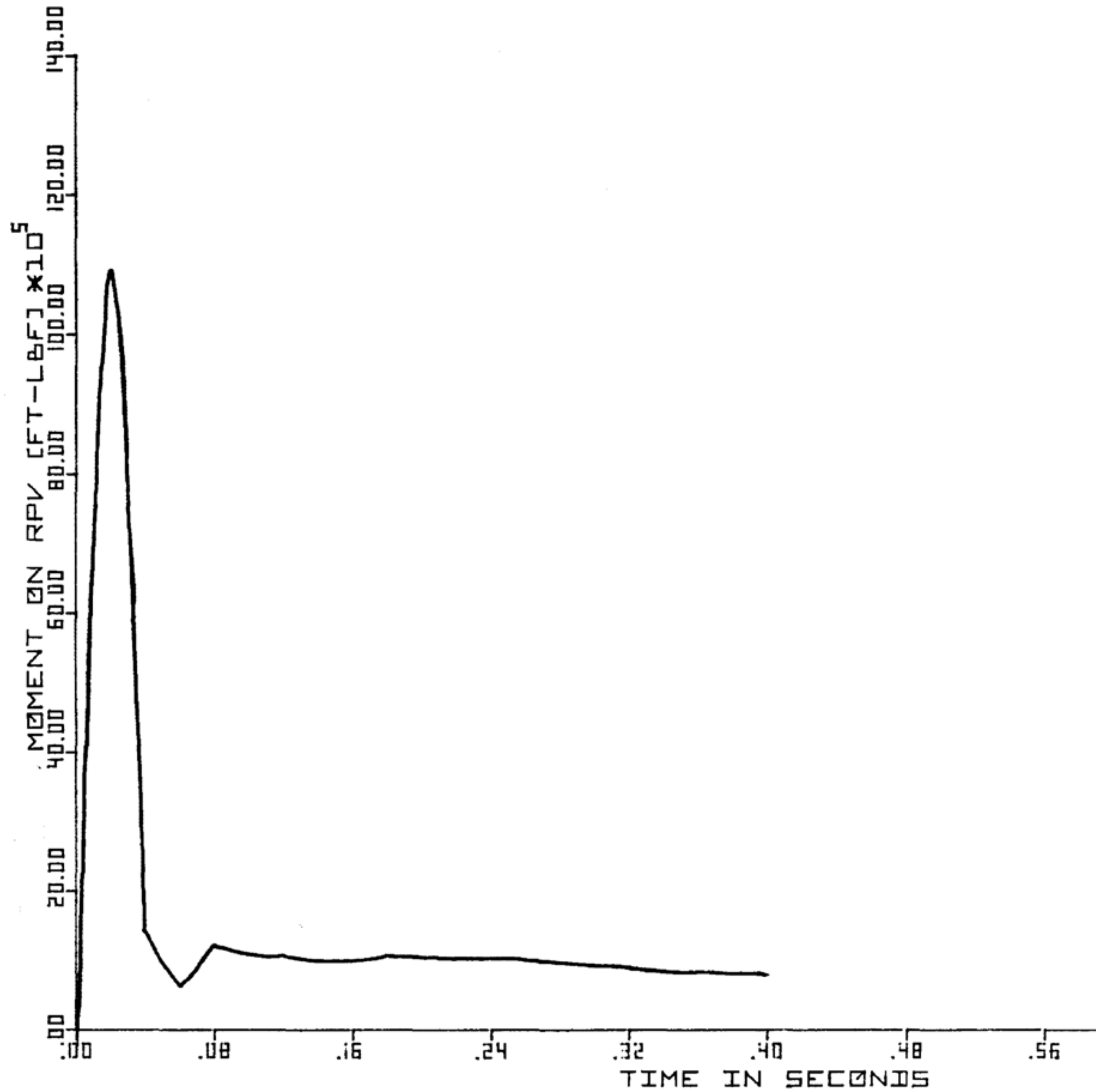
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RECIRC RETURN LINE BREAK
MOMENT X ON THE RPV
[HISTORICAL INFORMATION]
FIGURE 6.2 – 30aa

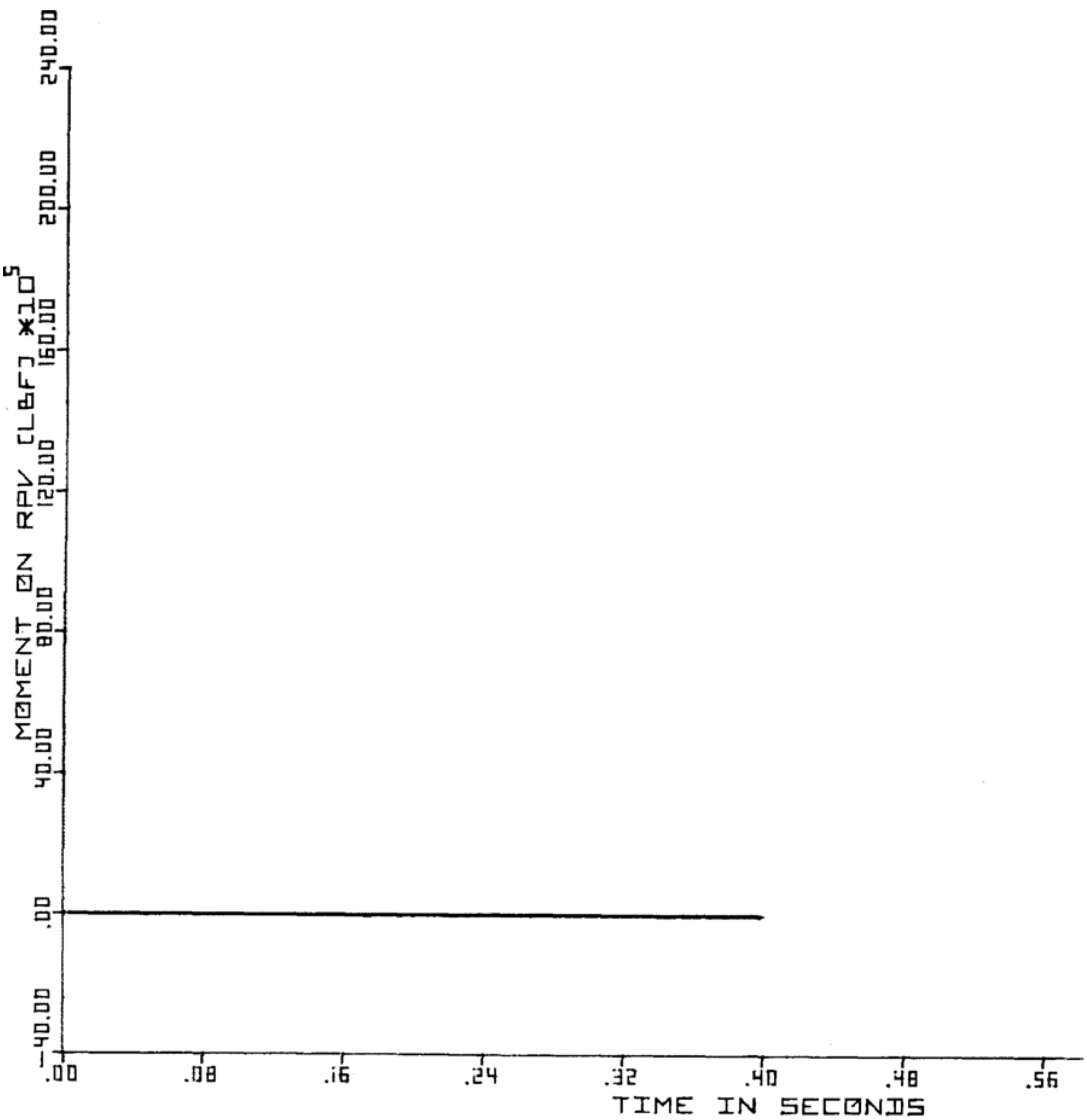


MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

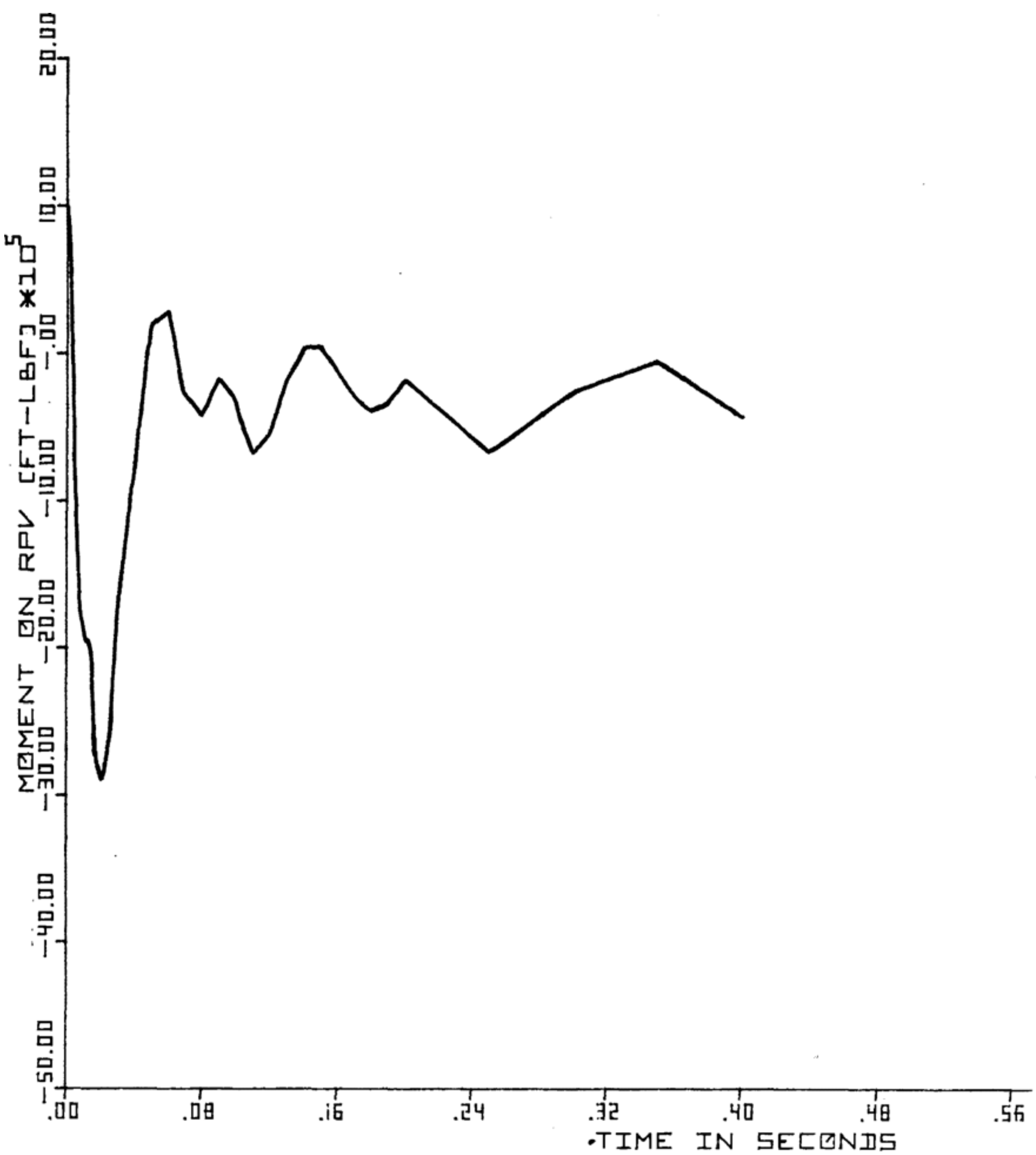
RECIRC RETURN LINE BREAK
MOMENT Y ON THE RPV
[HISTORICAL INFORMATION]
FIGURE 6.2 – 30ab



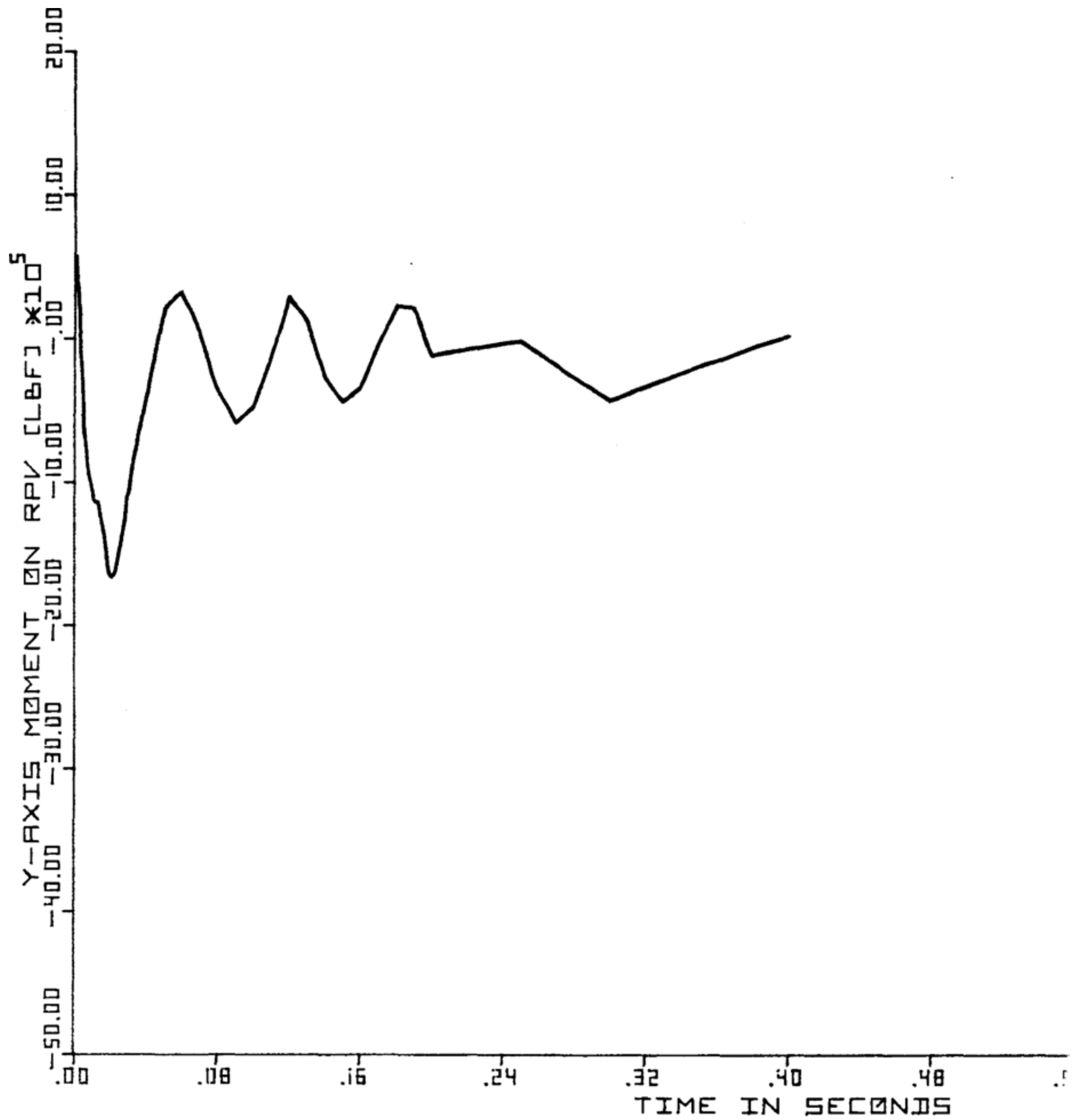
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRC SUCTION LINE BREAK MOMENT X ON THE RPV [HISTORICAL INFORMATION] FIGURE 6.2 – 30ba



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRC SUCTION LINE BREAK MOMENT Y ON THE RPV [HISTORICAL INFORMATION] FIGURE 6.2 – 30bb



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK MOMENT X ON THE RPV [HISTORICAL INFORMATION] FIGURE 6.2 – 30ca



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK MOMENT Y ON THE RPV [HISTORICAL INFORMATION] FIGURE 6.2 – 30cb

Figure 6.2-31
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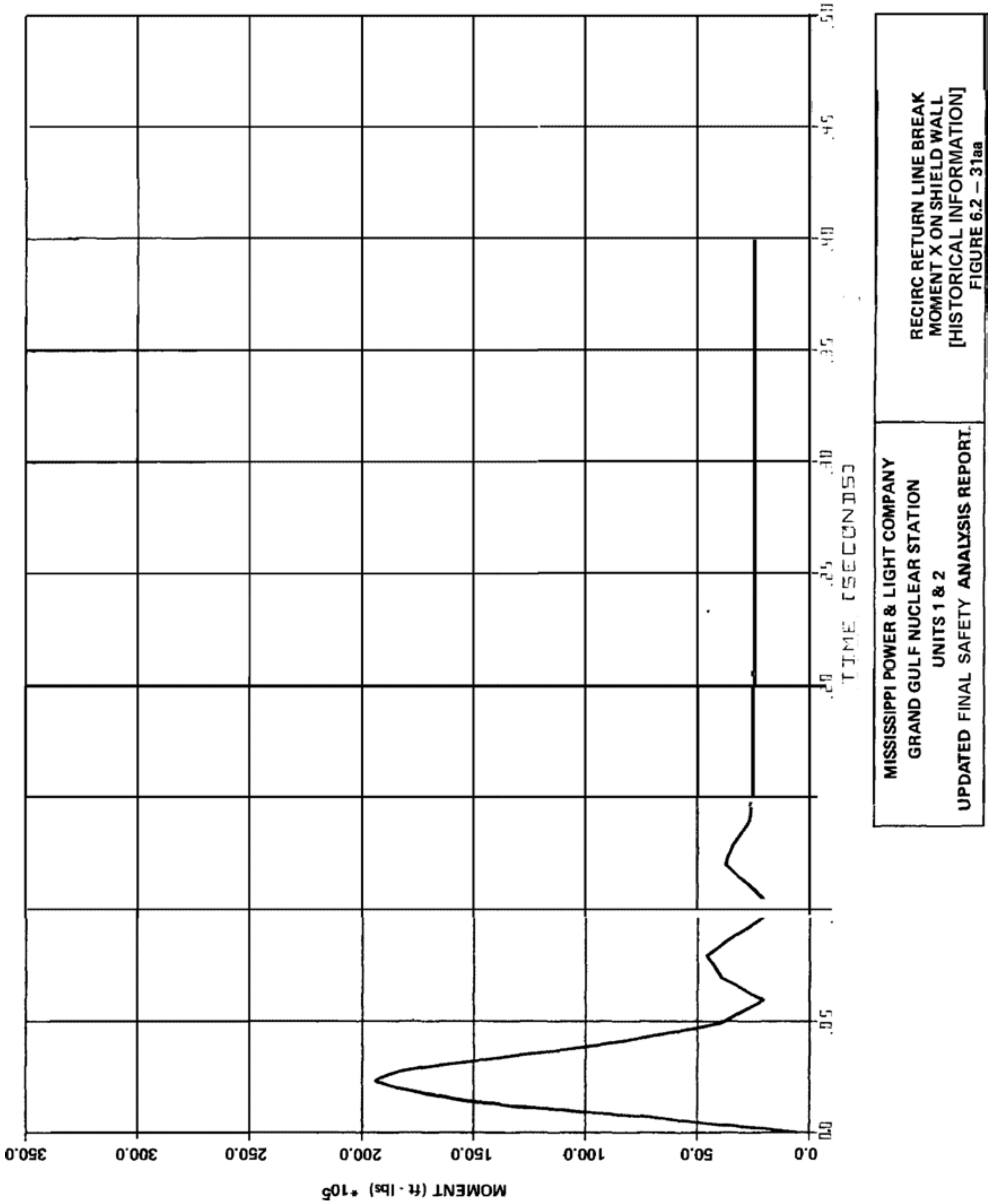
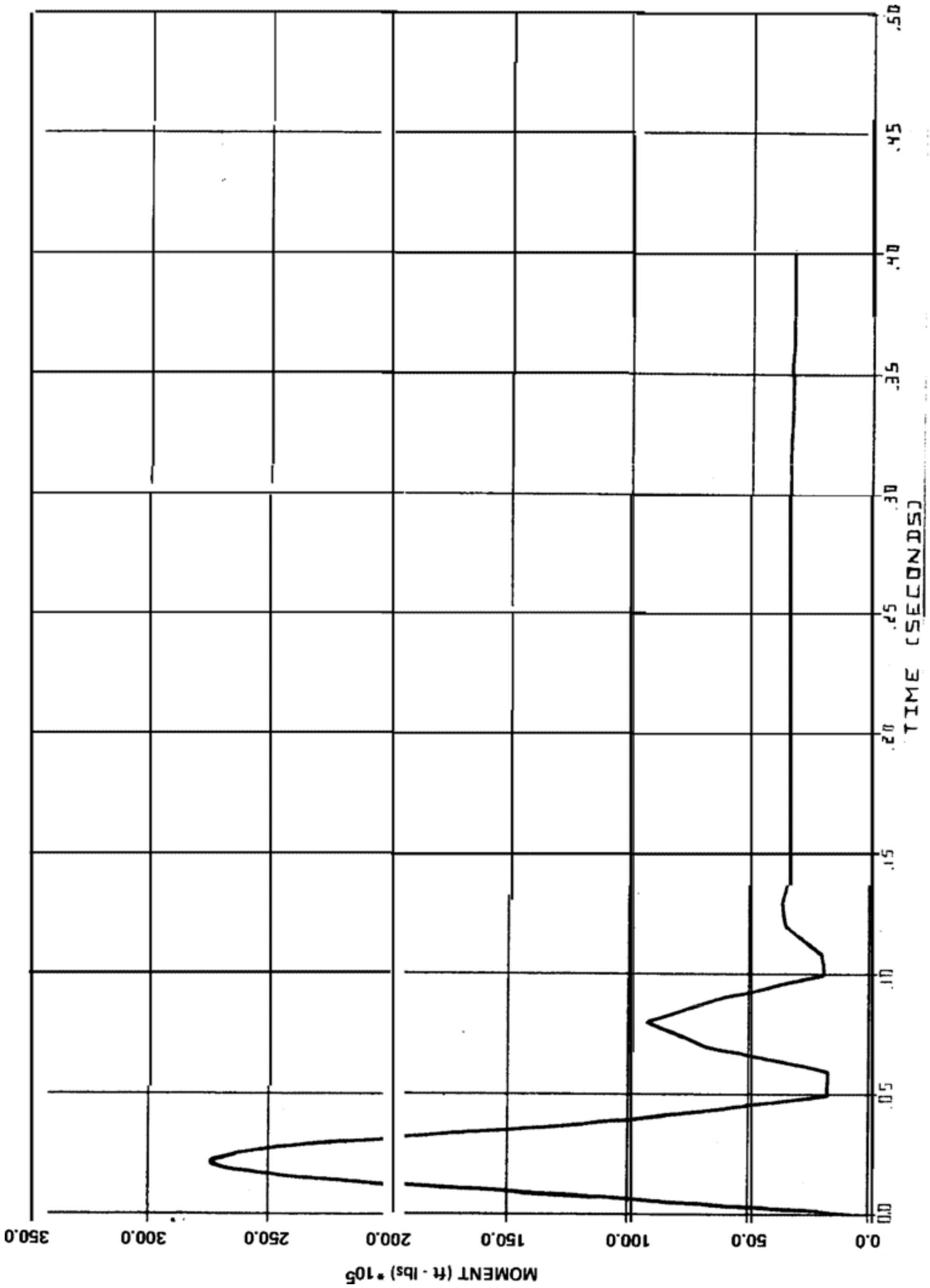
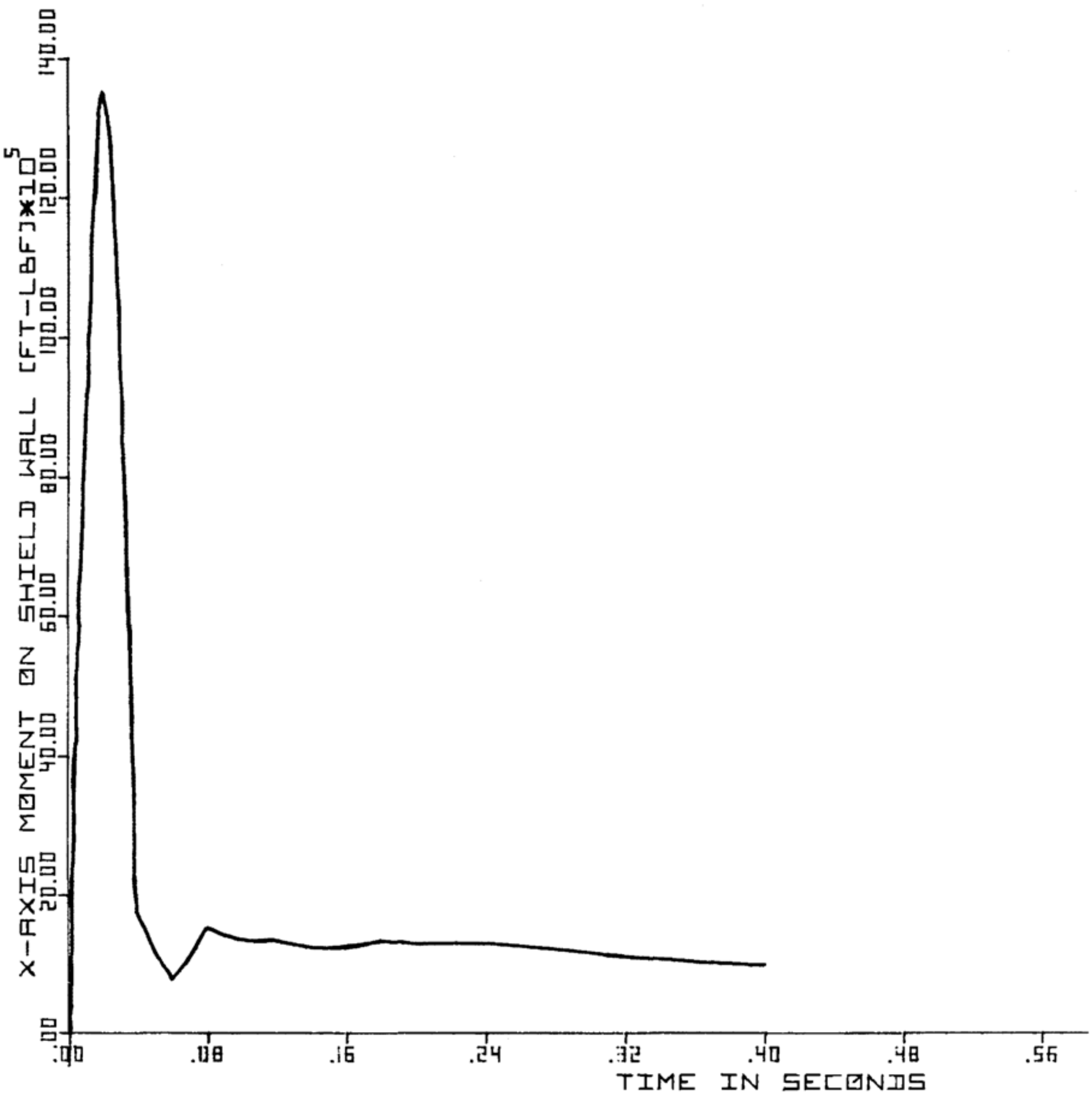


MOMENT (ft - lbs) *10^5
0.0
50.0
100.0
150.0
200.0
250.0
300.0
350.0
TIME (SECONDS)
RECIRC RETURN LINE BREAK
MOMENT X ON SHIELD WALL
[HISTORICAL INFORMATION]
FIGURE 6.2 – 31aa
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

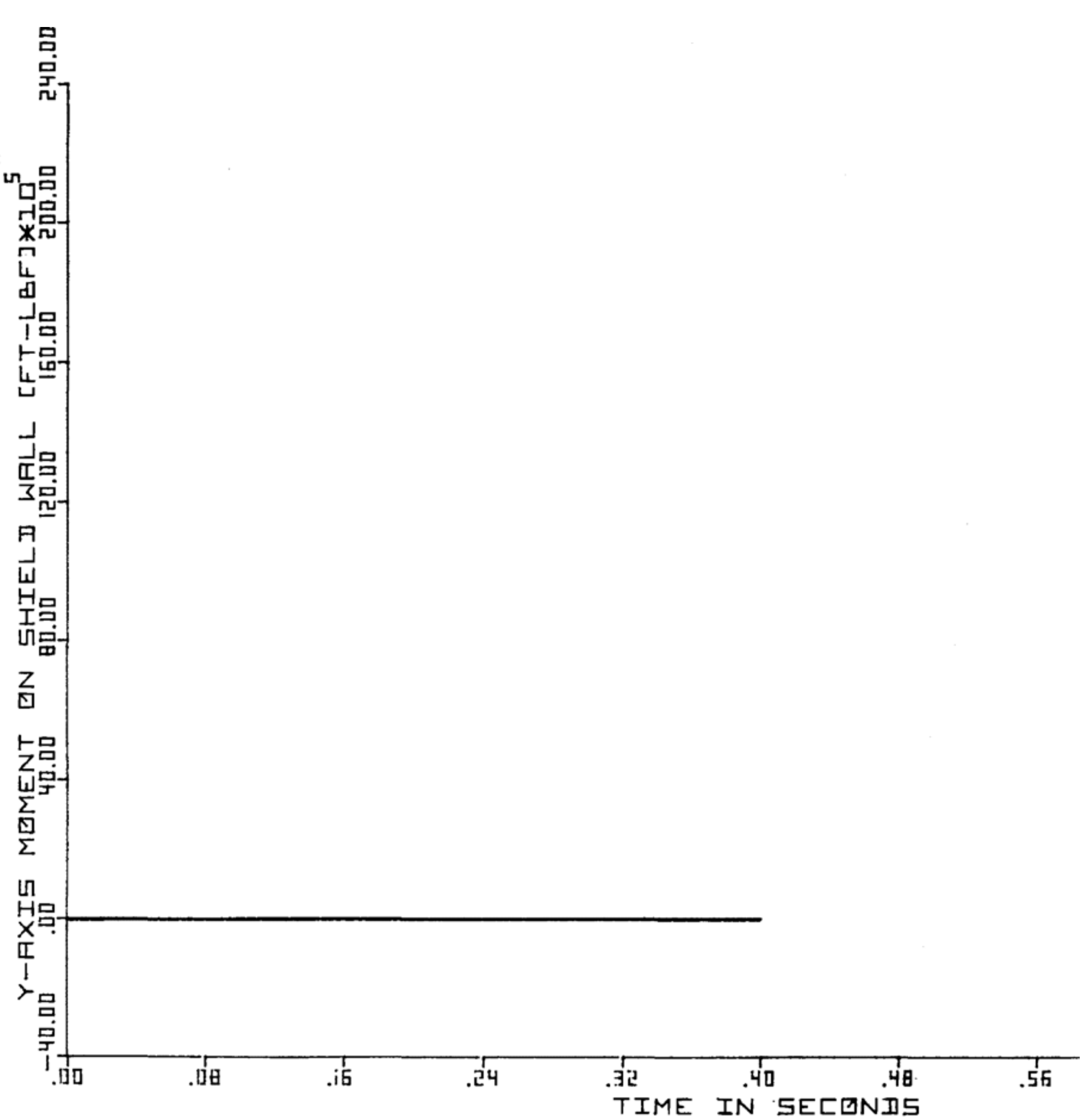


RECIRC RETURN LINE BREAK
MOMENT Y ON SHIELD WALL
[HISTORICAL INFORMATION]
FIGURE 6.2 — 31ab

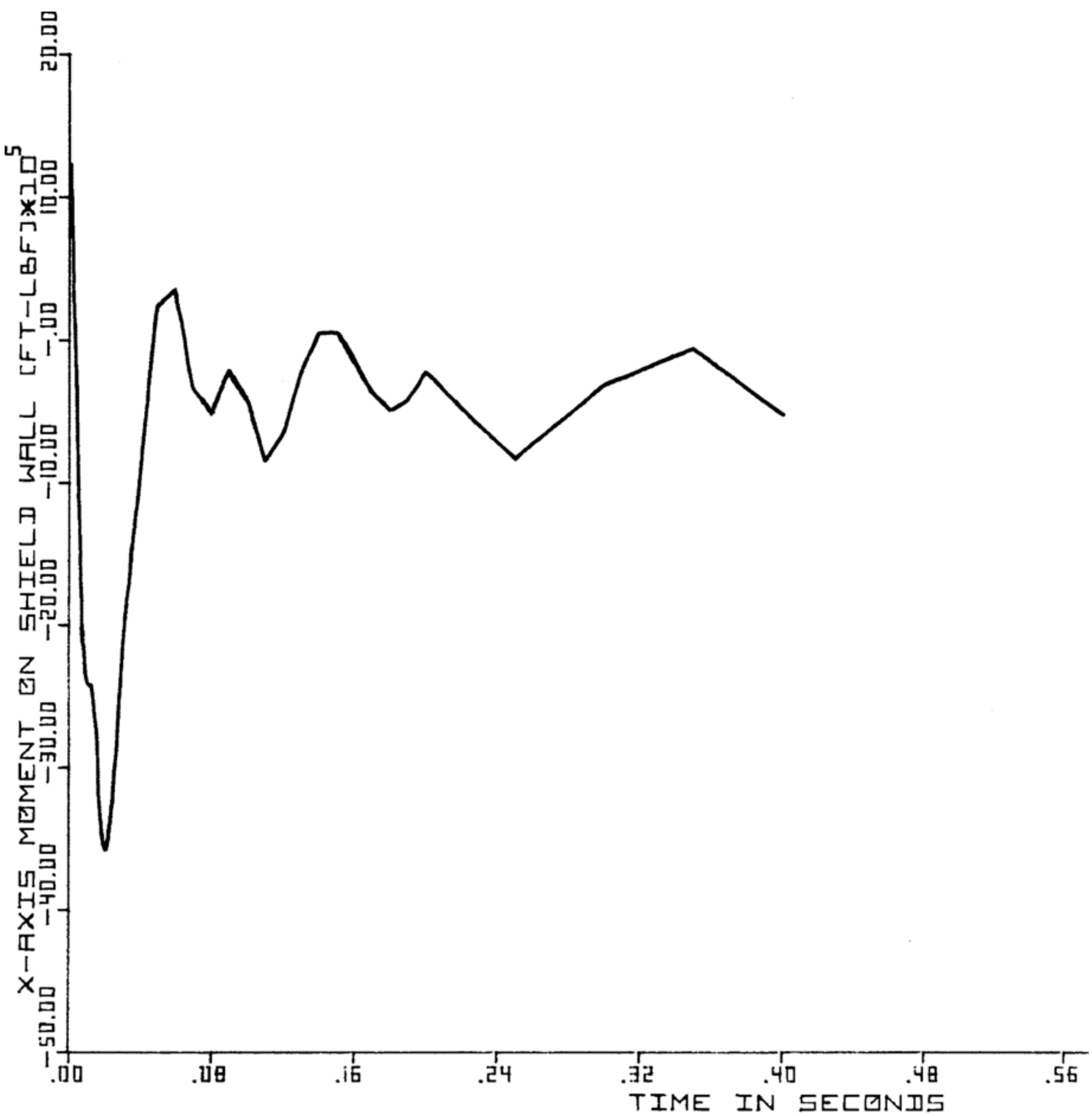
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT



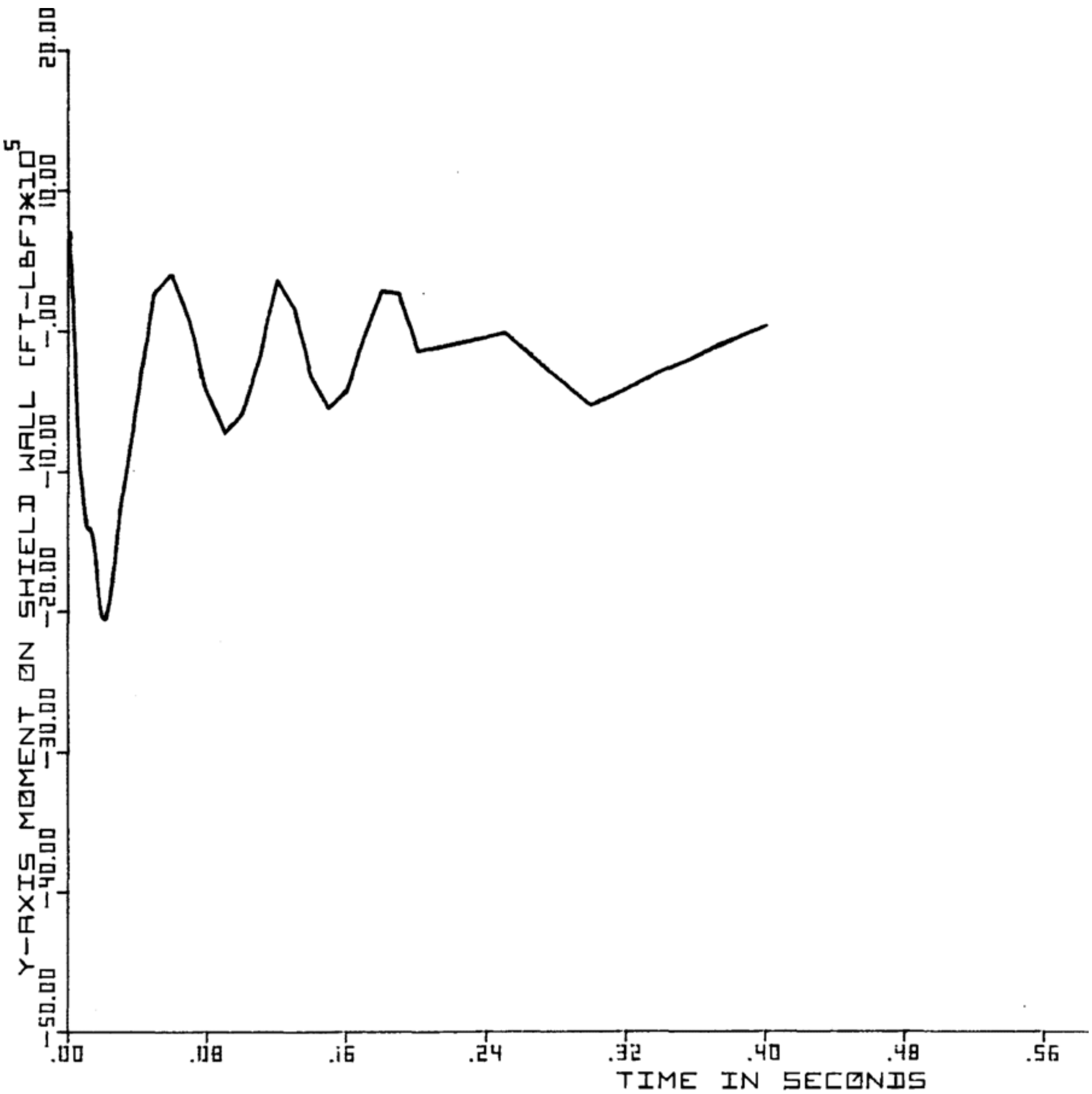
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRC SUCTION LINE BREAK MOMENT X ON SHIELD WALL [HISTORICAL INFORMATION] FIGURE 6.2 – 31ba



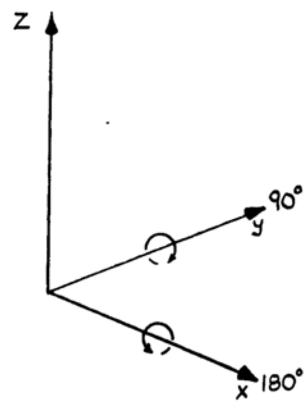
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	RECIRC SUCTION LINE BREAK MOMENT Y ON SHIELD WALL [HISTORICAL INFORMATION] FIGURE 6.2 – 31bb



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK MOMENT X ON SHIELD WALL [HISTORICAL INFORMATION] FIGURE 6.2 – 31ca



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	FEEDWATER LINE BREAK MOMENT Y ON SHIELD WALL [HISTORICAL INFORMATION] FIGURE 6.2 – 31cb

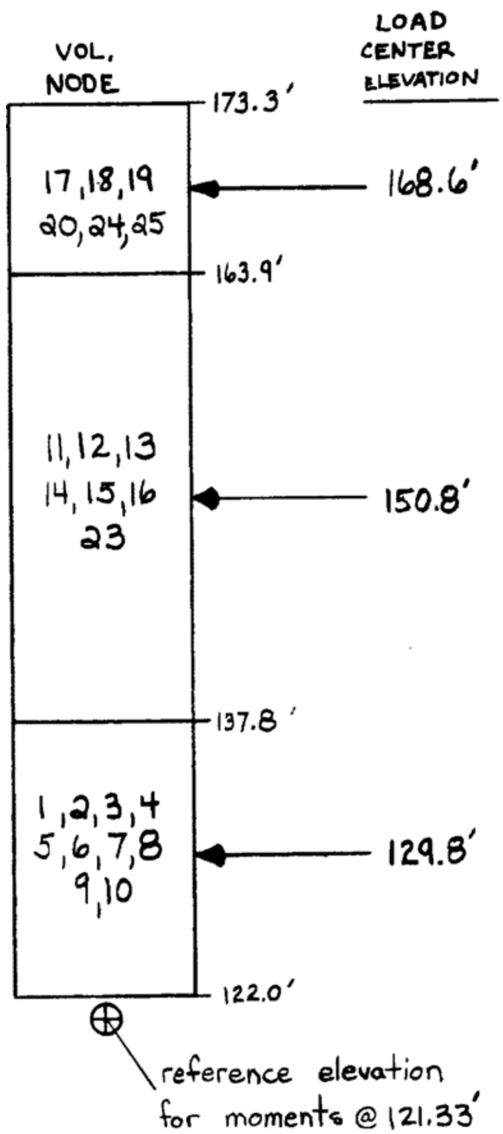


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RIGHT-HAND COORDINATE SYSTEM UTILIZED FOR RECIRCULATION INLET, RECIRCULATION SUCTION, AND FEEDWATER LINE BREAKS FORCES AND MOMENTS

FIGURE 6.2 - 32

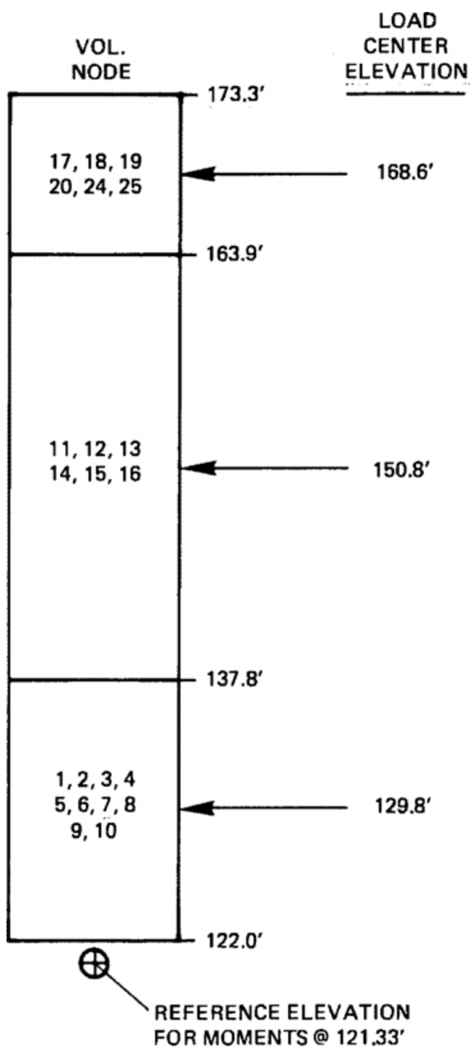


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LOAD CENTER ELEVATION
UTILIZED FOR RECIRCULATION
INLET LINE BREAK
FORCES AND MOMENTS

FIGURE 6.2 – 33a

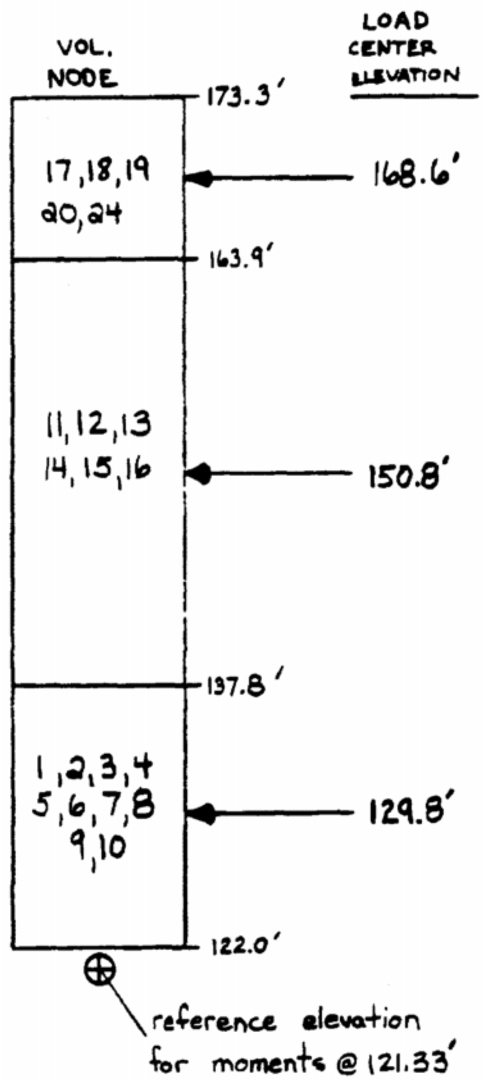


[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LOAD CENTER ELEVATION
UTILIZED FOR RECIRCULATION SUCTION
LINE BREAK FORCES AND MOMENTS

FIGURE 6.2 – 33b



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LOAD CENTER ELEVATION
UTILIZED FOR FEEDWATER
LINE BREAK FORCES AND MOMENTS

FIGURE 6.2 – 33c

Figures 6.2-34 through 6.2-46
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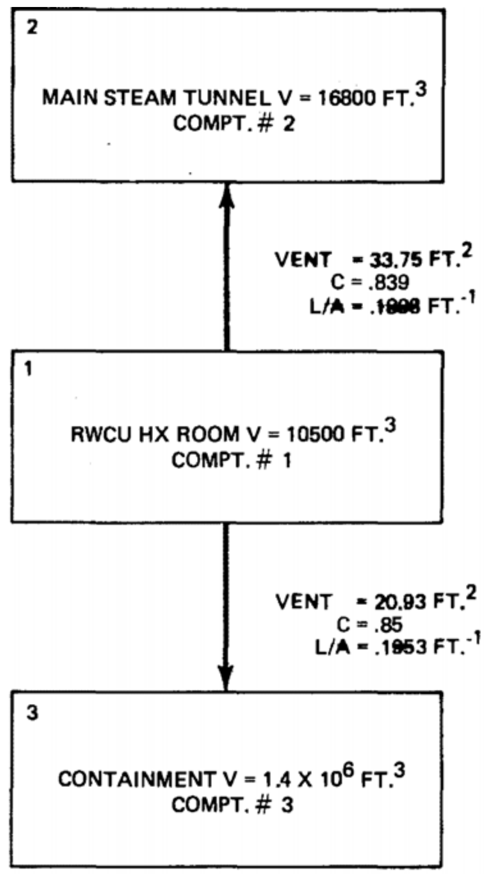
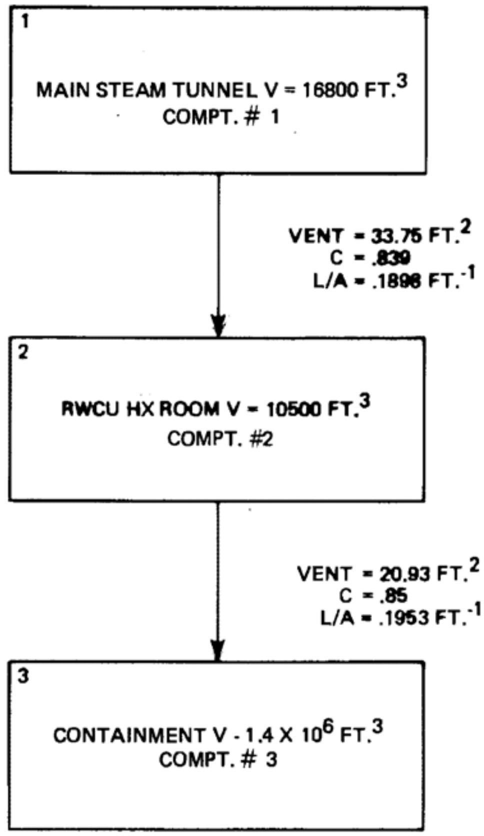
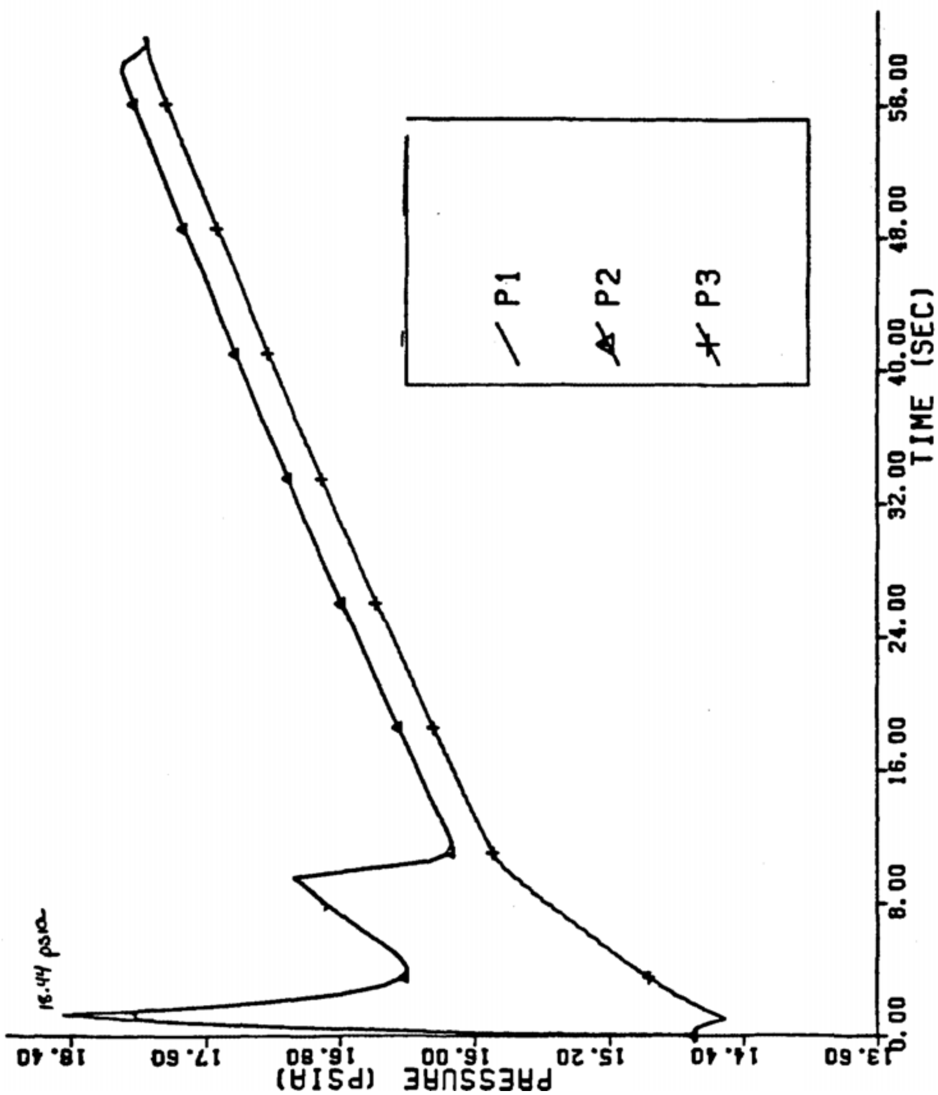


MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	VENT FLOW PATH FOR RWCU LINE BREAK HEAT EXCHANGER ROOM [HISTORICAL INFORMATION] FIGURE 6.2-47



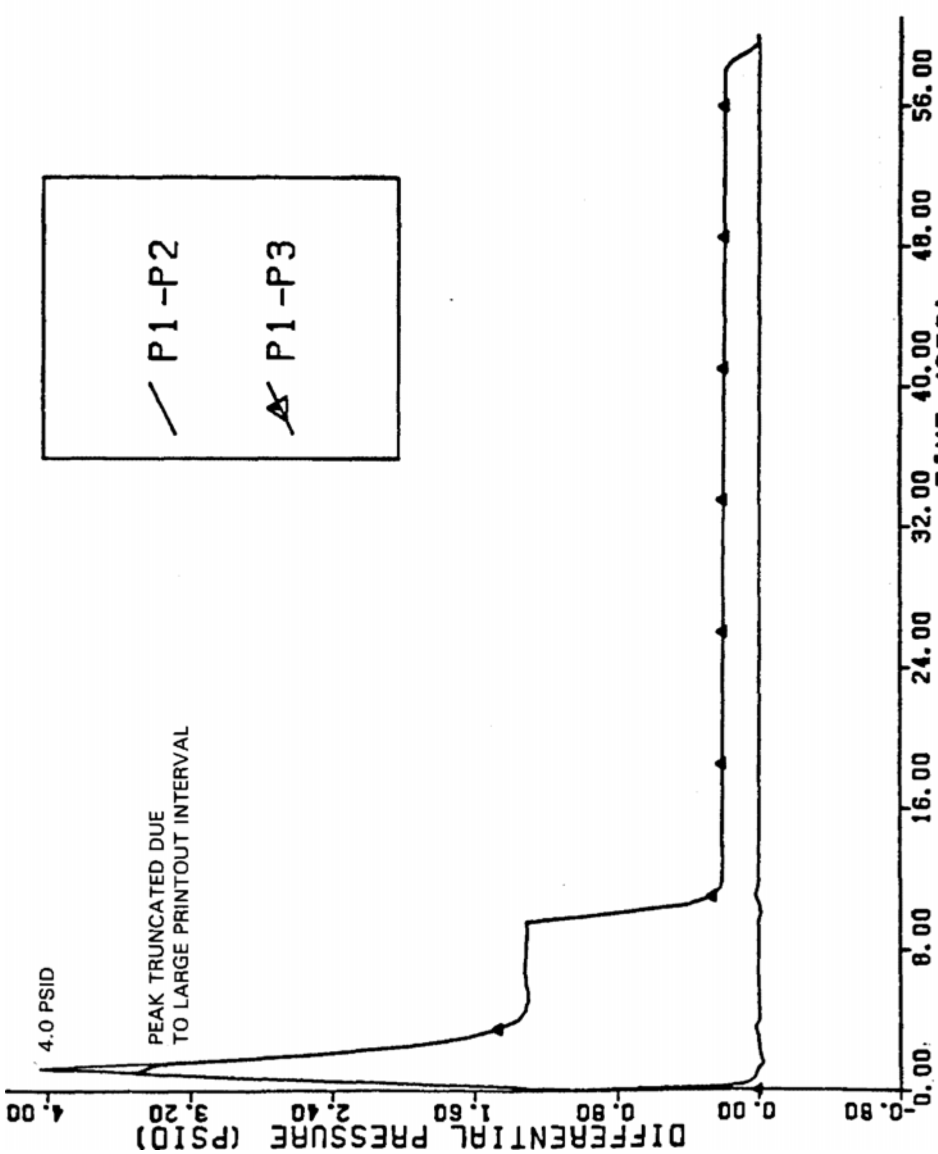
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	VENT FLOW PATH FOR RWCU LINE BREAK IN MAIN STEAM TUNNEL FIGURE 6.2-48



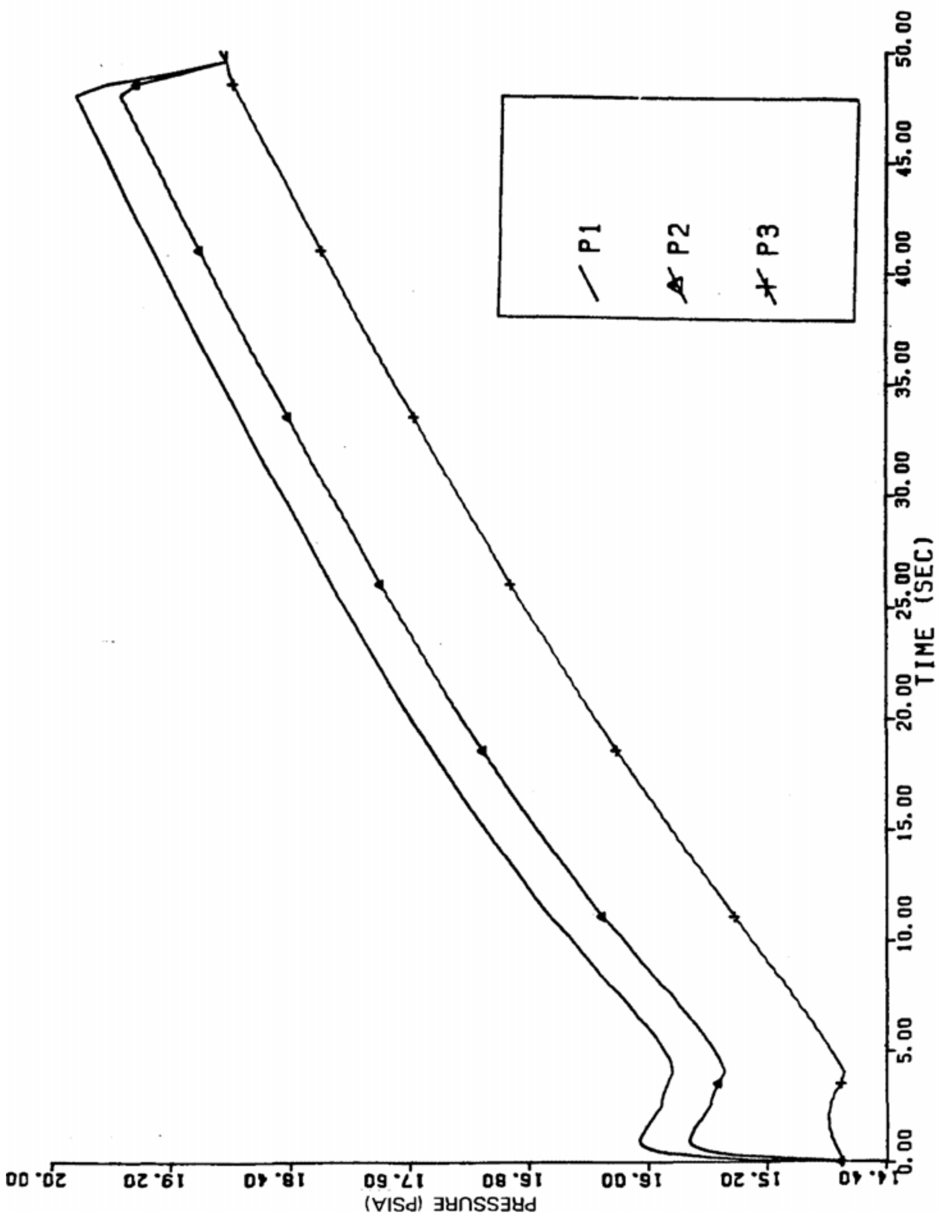
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

ABSOLUTE PRESSURES
RWCU HEAT EXCH. ROOM BREAK
[HISTORICAL INFORMATION]
FIGURE 6.2-49



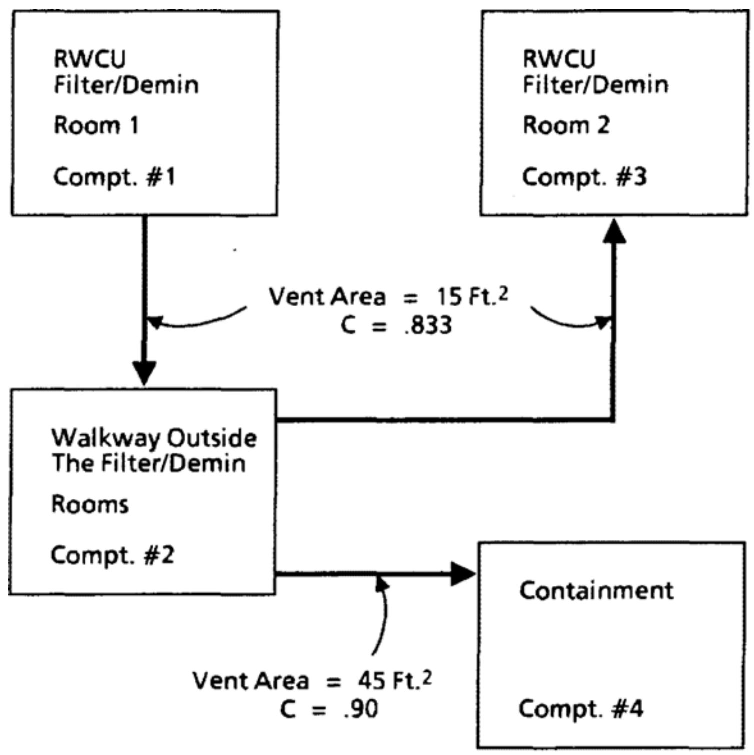
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DIFFERENTIAL PRESSURES
RWCU HEAT EXCH. ROOM BREAK
[HISTORICAL INFORMATION]
FIGURE 6.2-50



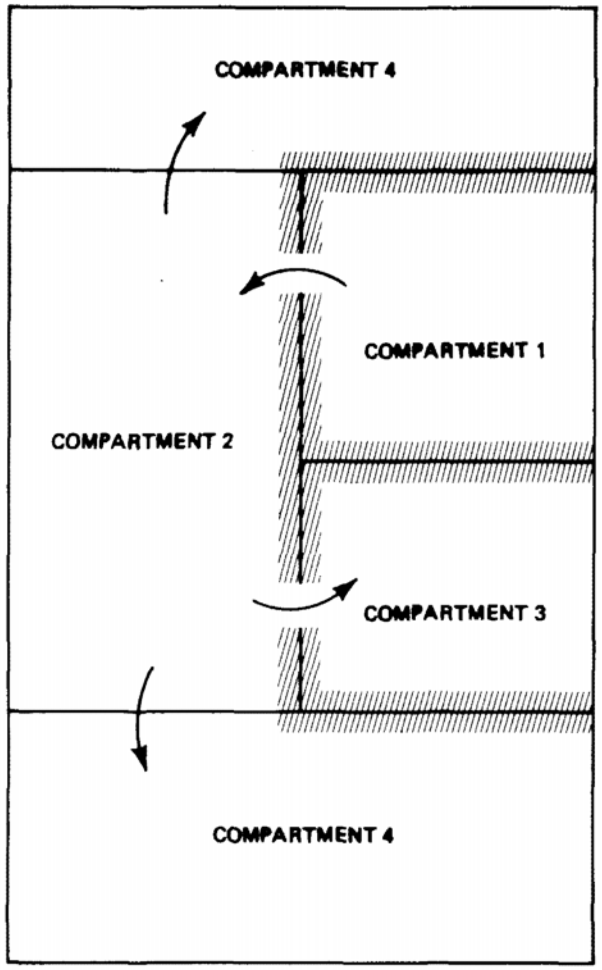
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RWCU LINE BREAK AT
MAIN STEAM TUNNEL (CMPTS 1, 2, 3)
[HISTORICAL INFORMATION]
FIGURE 6.2-51



SYSTEM ENERGY RESOURCES, INC.
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

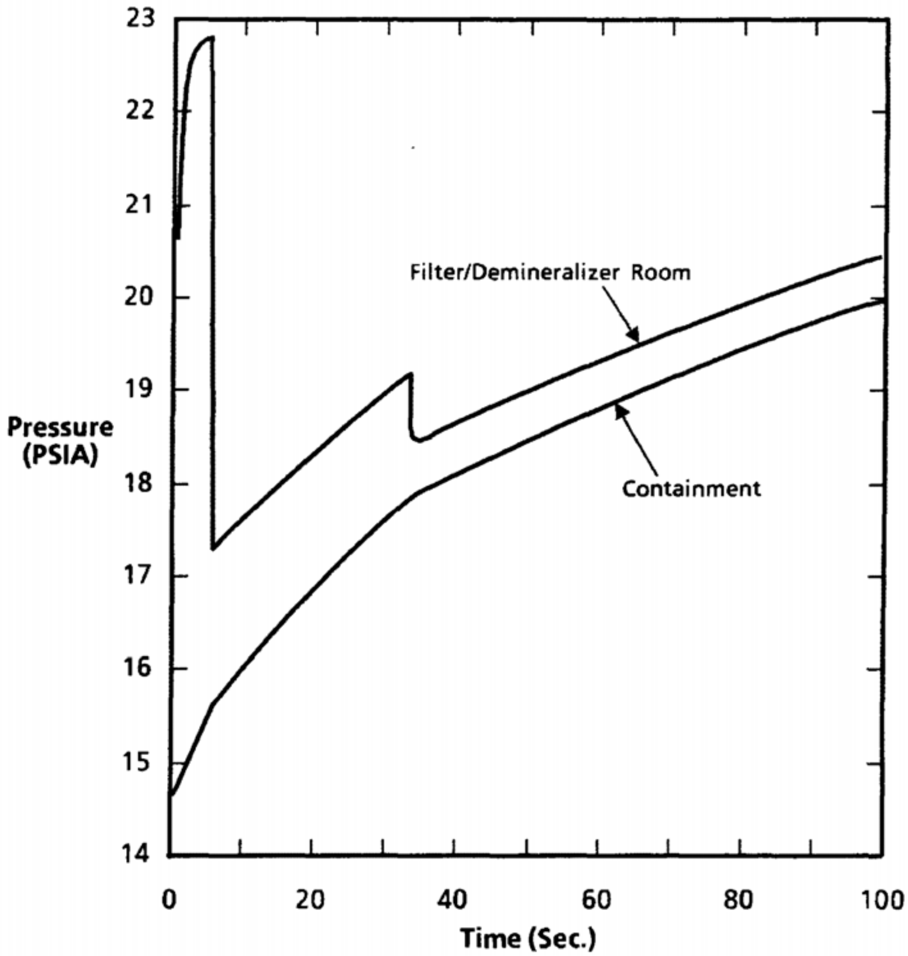
VENT FLOW PATH FOR
RWCU BREAK IN
FILTER/DEMINERALIZER ROOM
[HISTORICAL INFORMATION]
Figure 6.2-52



[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	NODAL MODEL FOR RWCU BREAK IN FILTER/DEMINERALIZER ROOM FIGURE 6.2-53

GRAND GULF FILTER DEMINERALIZER ROOM
PRESSURE VS TIME



SYSTEM ENERGY RESOURCES, INC. GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	ABSOLUTE PRESSURES RWCU FILTER/DEMINERALIZER BREAK [HISTORICAL INFORMATION] Figure 6.2-54

Figure 6.2-55
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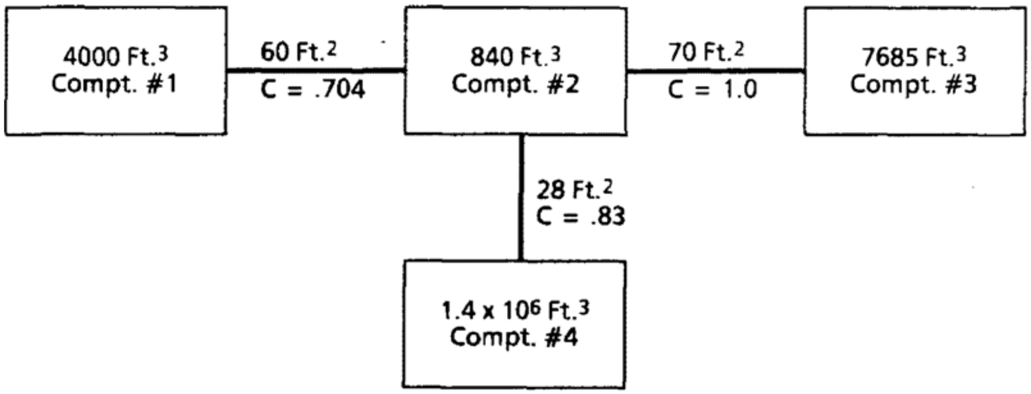
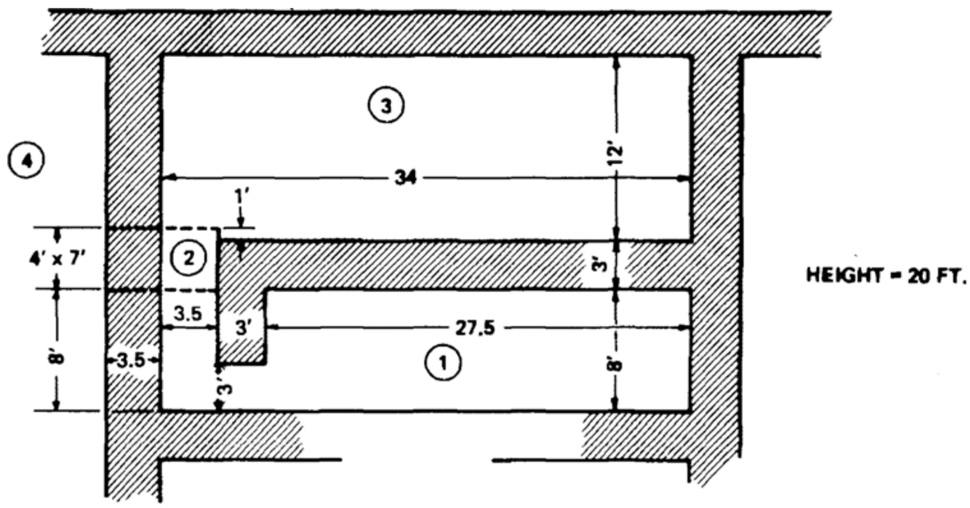
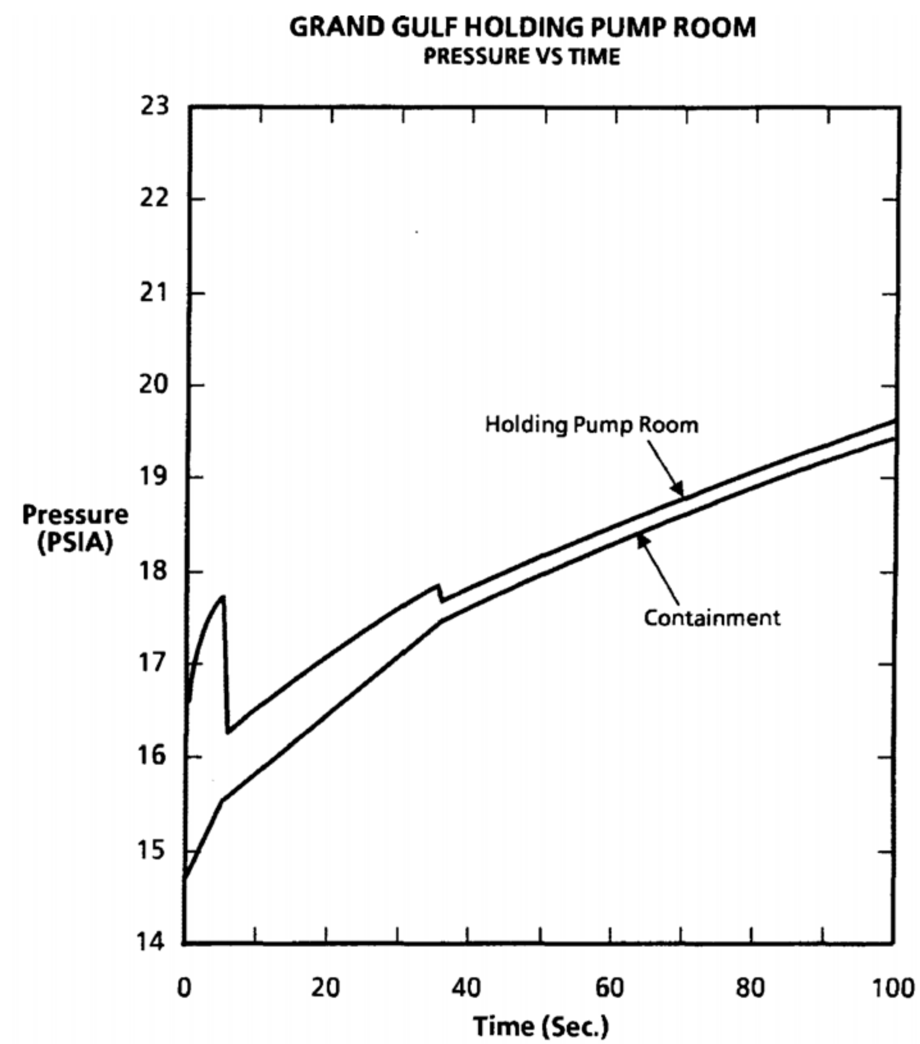


SYSTEM ENERGY RESOURCES, INC.
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VENT FLOW PATH FOR
RWCU BREAK IN
HOLDING PUMP ROOM
[HISTORICAL INFORMATION]
Figure 6.2-56



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	LAYOUT DRAWING RWCU HOLDING PUMP ROOM [HISTORICAL INFORMATION] FIGURE 6.2-57



SYSTEM ENERGY RESOURCES, INC. GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	ABSOLUTE PRESSURES RWCU HOLDING PUMP ROOM BREAK [HISTORICAL INFORMATION] Figure 6.2-58

FIGURE 6.2-59
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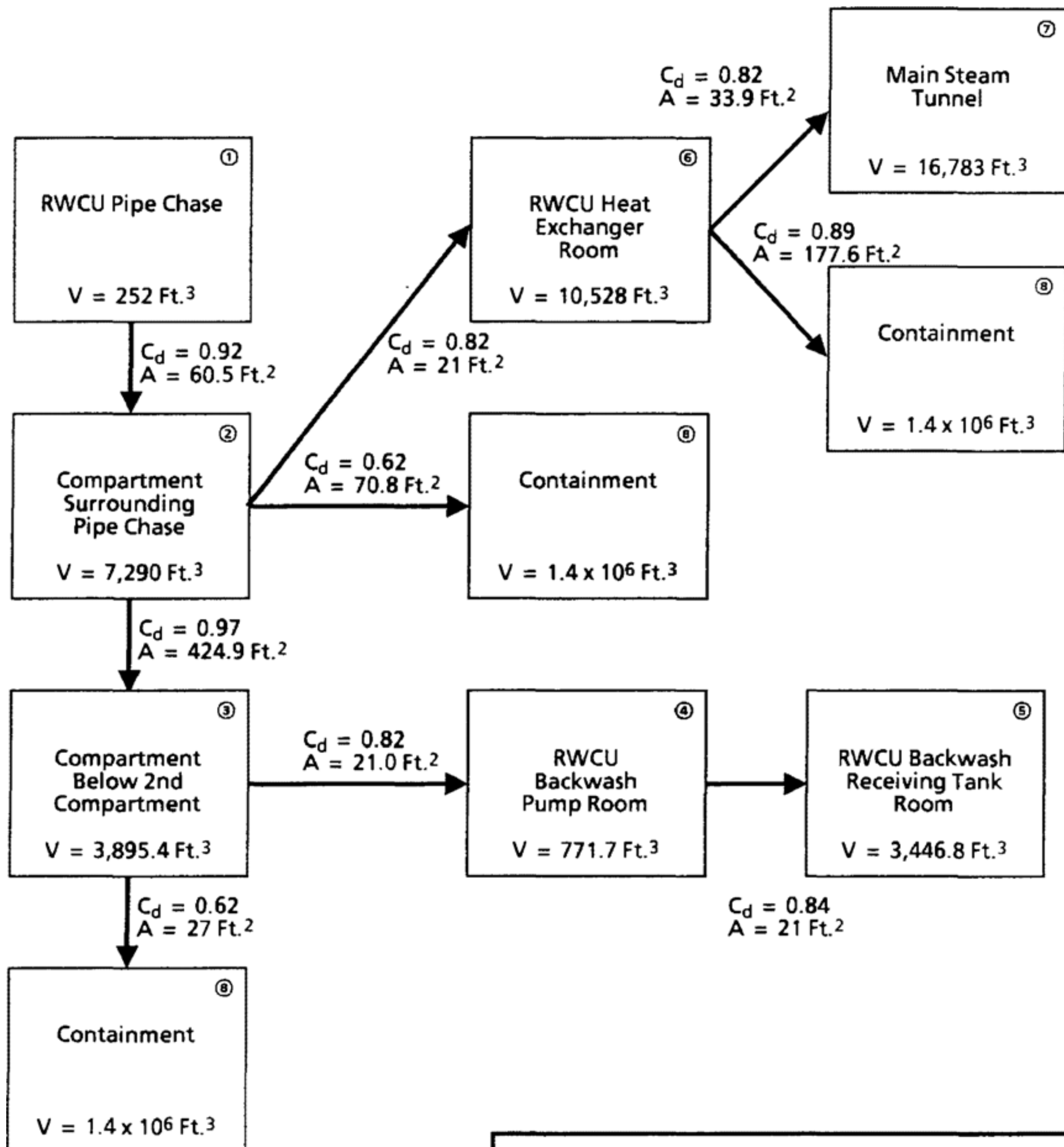
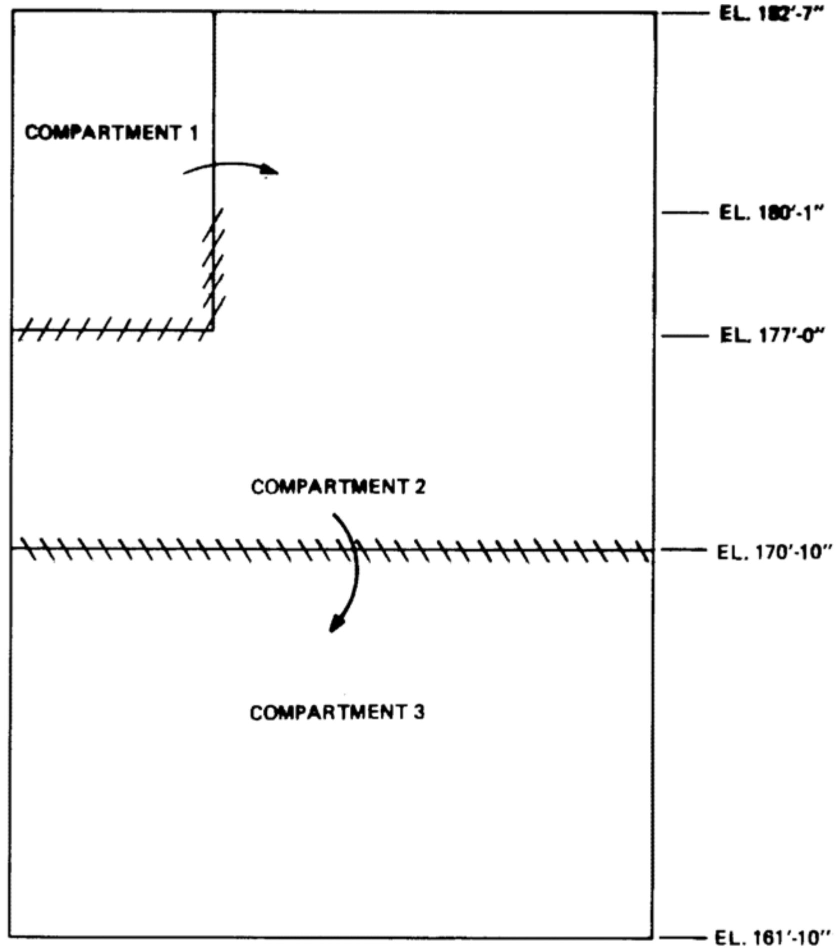


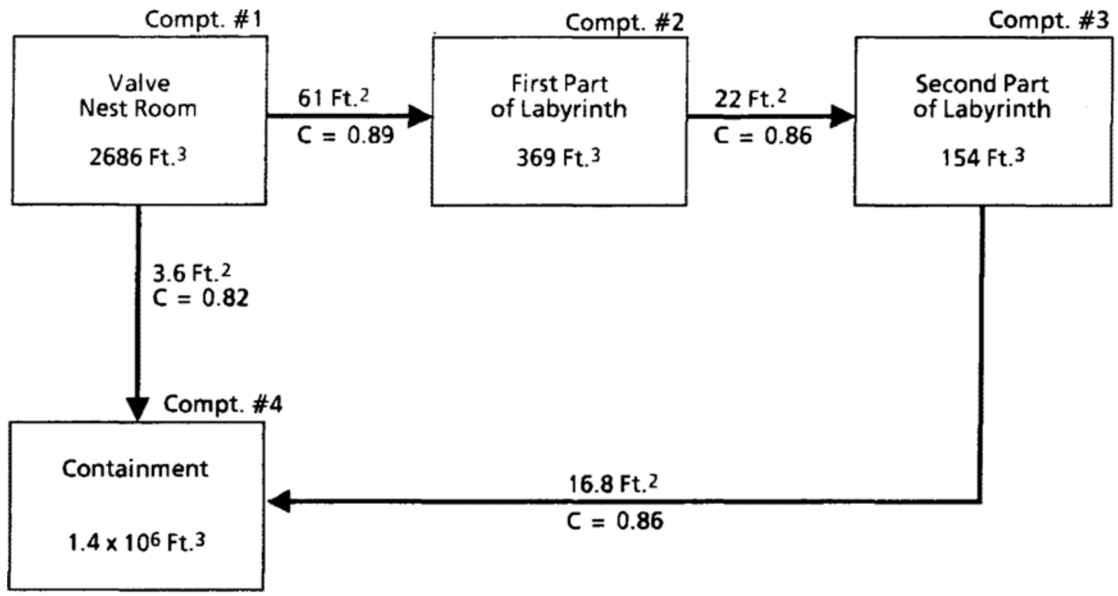
SYSTEM ENERGY RESOURCES, INC.
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VENT FLOW PATH FOR
RWCU LINE BREAK IN
PIPE CHASE
[HISTORICAL INFORMATION]
Figure 6.2-60



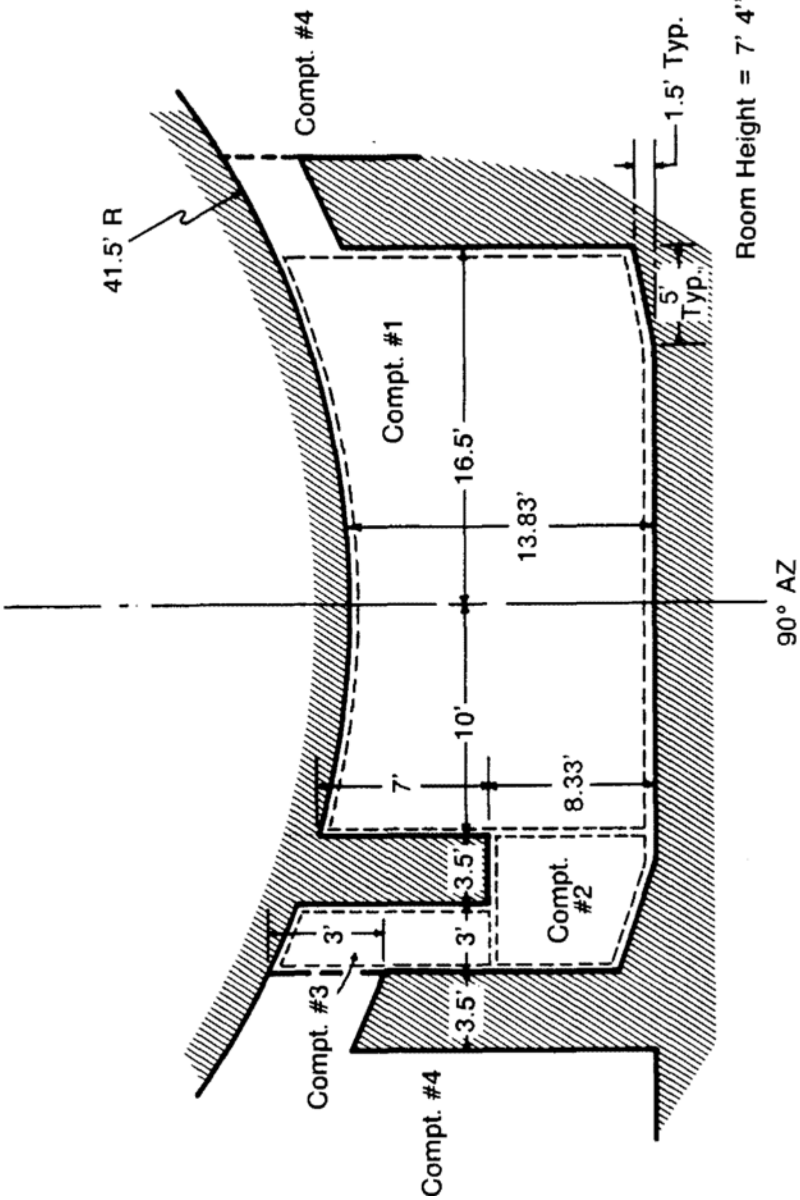
[HISTORICAL INFORMATION]

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	NODAL MODEL 6" RWCU LINE BREAK IN PIPE CHASE FIGURE 6.2-61



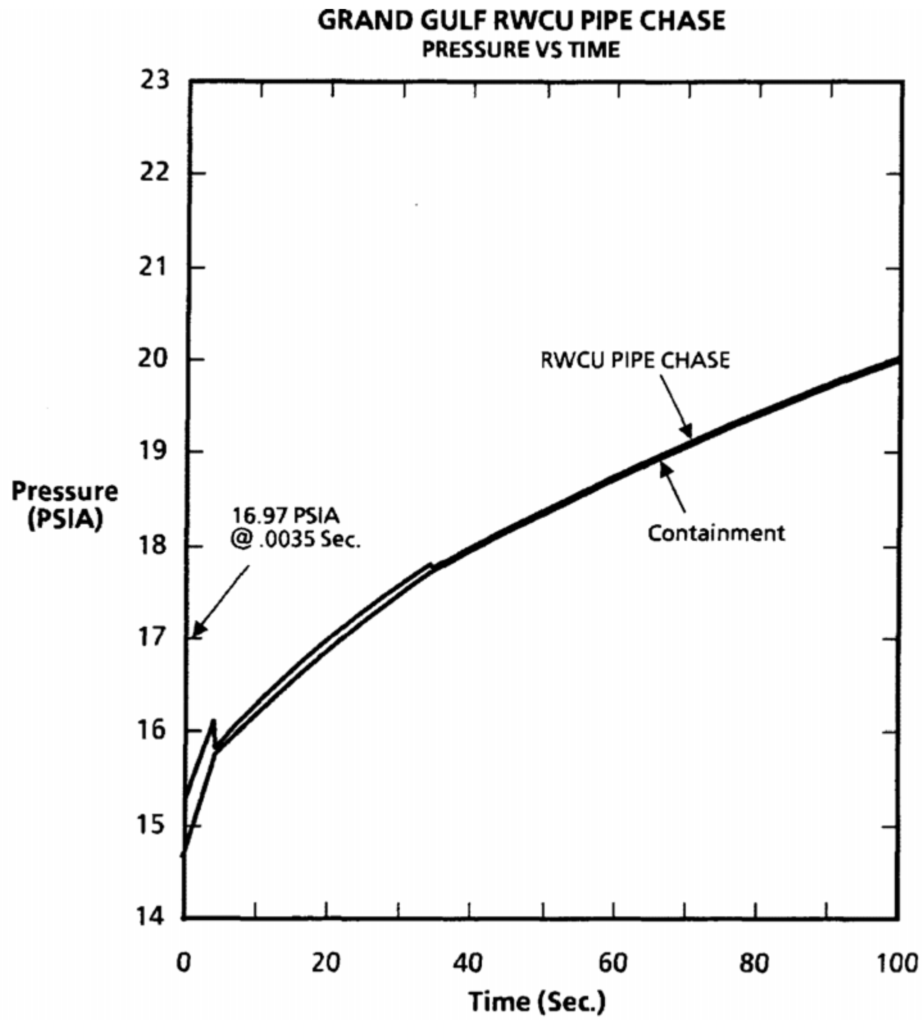
SYSTEM ENERGY RESOURCES, INC.
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VENT FLOW PATH FOR
RWCU LINE BREAK IN
VALVE NEST ROOM
[HISTORICAL INFORMATION]
Figure 6.2-62



SYSTEM ENERGY RESOURCES, INC.
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

6" RWCU LINE BREAK
VALVE NEST ROOM LAYOUT
[HISTORICAL INFORMATION]
Figure 6.2-63



SYSTEM ENERGY RESOURCES, INC. GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	6" EBZ-2 HELB IN RWCU PIPE CHASE TOTAL PRESSURE [HISTORICAL INFORMATION] Figure 6.2-64

FIGURE 6.2-65
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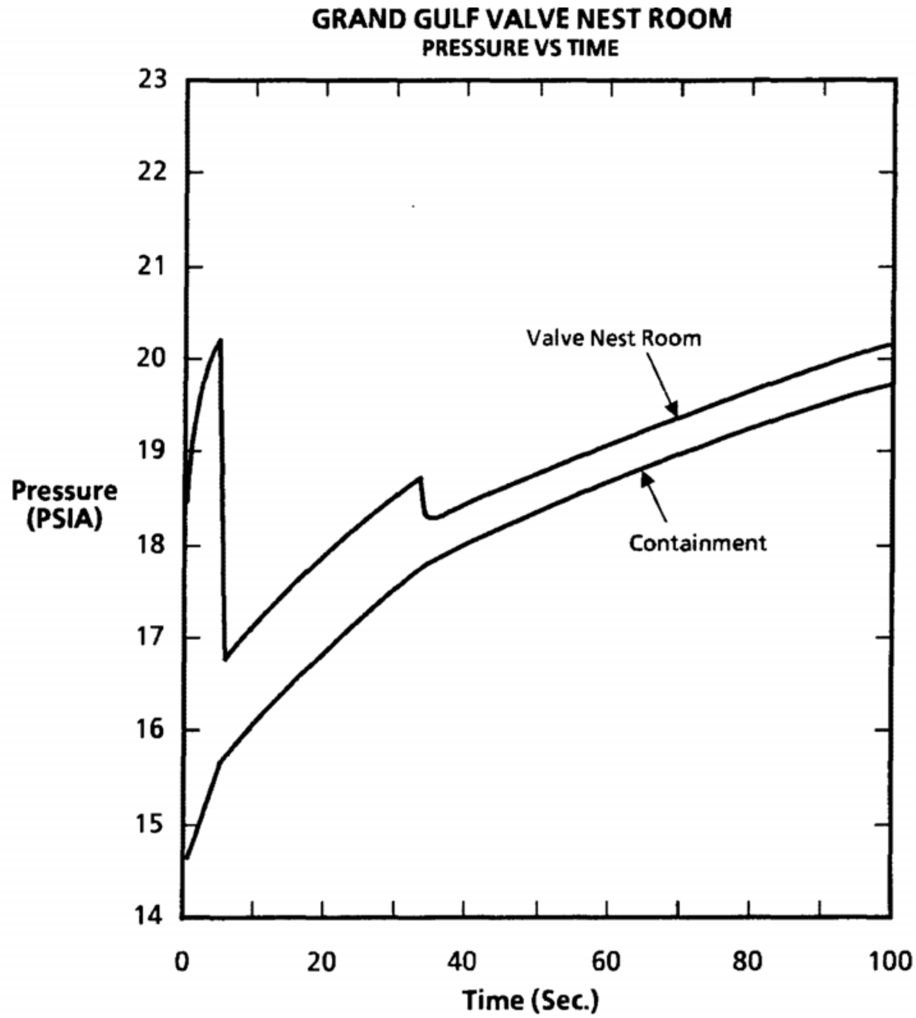

SYSTEM ENERGY RESOURCES, INC. GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	ABSOLUTE PRESSURES 6" RWCU LINE BREAK IN VALVE NEST ROOM [HISTORICAL INFORMATION] Figure 6.2-66

FIGURE 6.2-67
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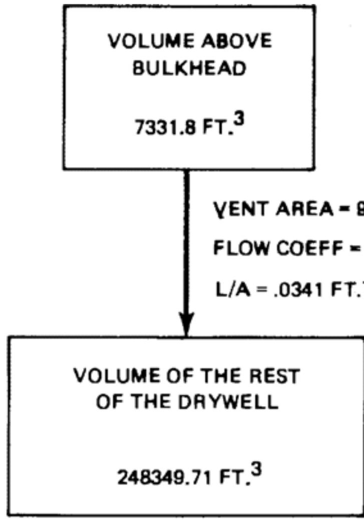
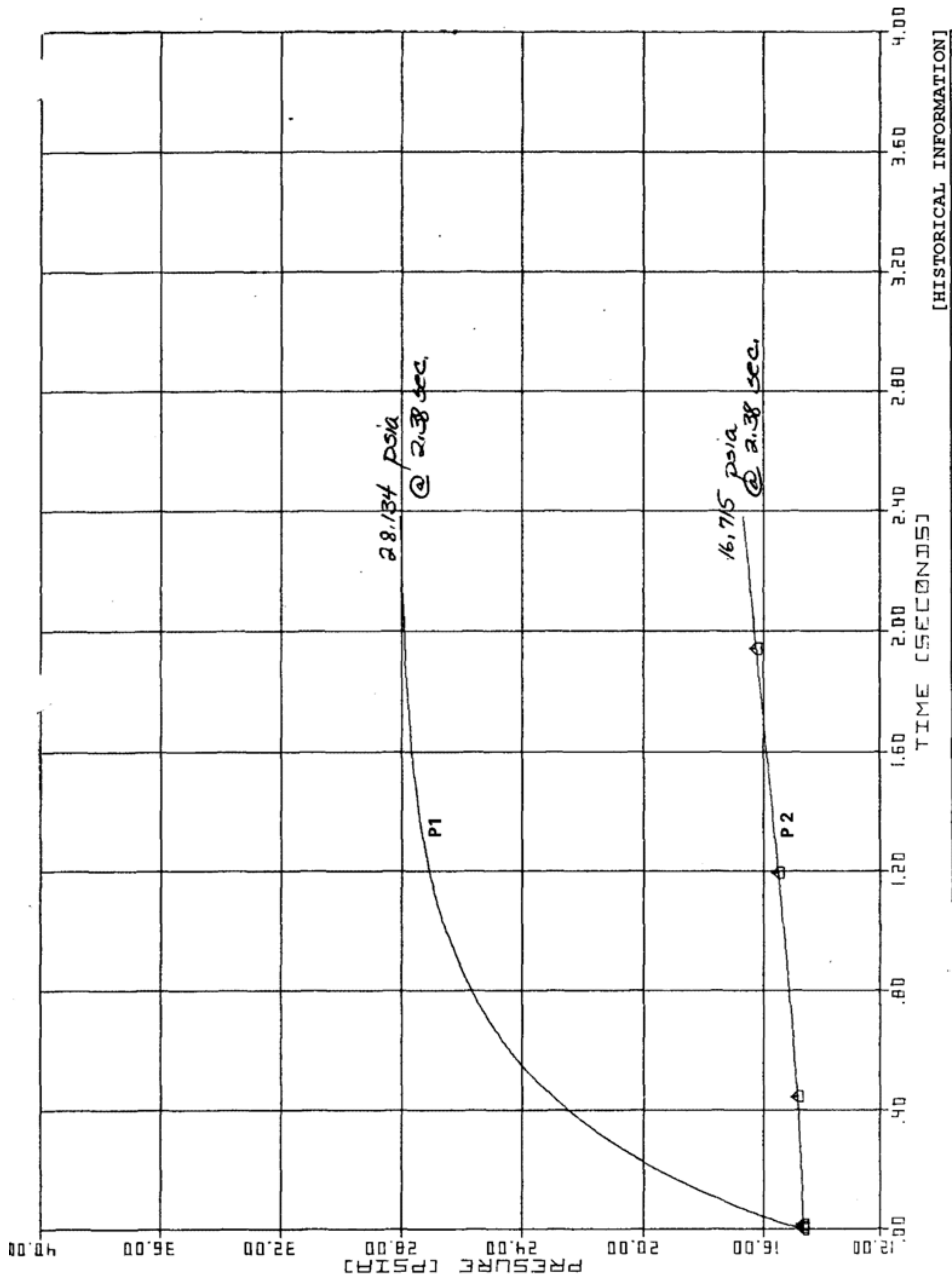


[HISTORICAL INFORMATION]

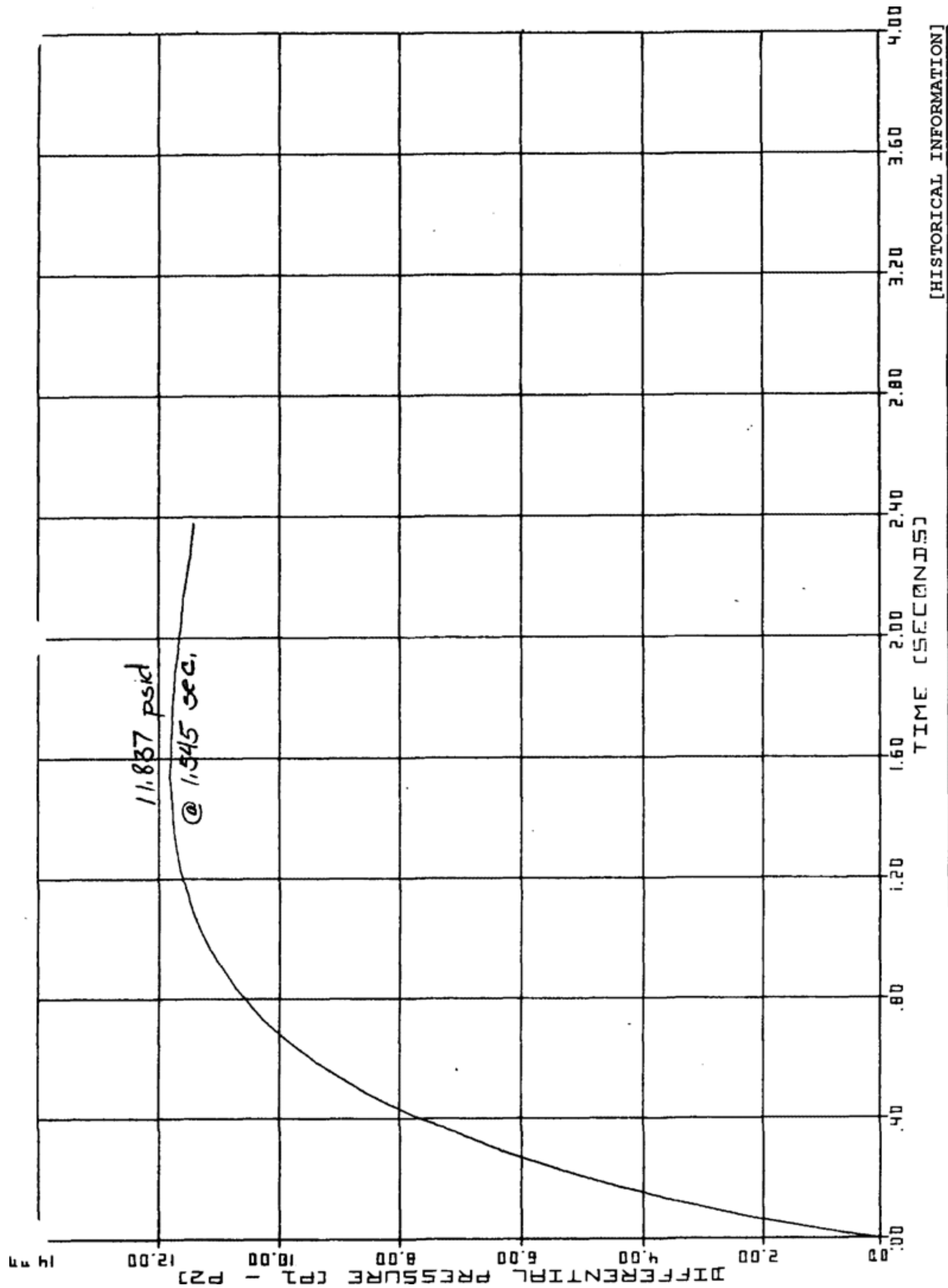
MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	VENT FLOW PATH FOR RCIC LINE BREAK IN DRYWELL HEAD AREA FIGURE 6.2 - 68



[HISTORICAL INFORMATION]

ABSOLUTE PRESSURES
RCIC LINE BREAK IN
DRYWELL HEAD REGION
FIGURE 6.2-69

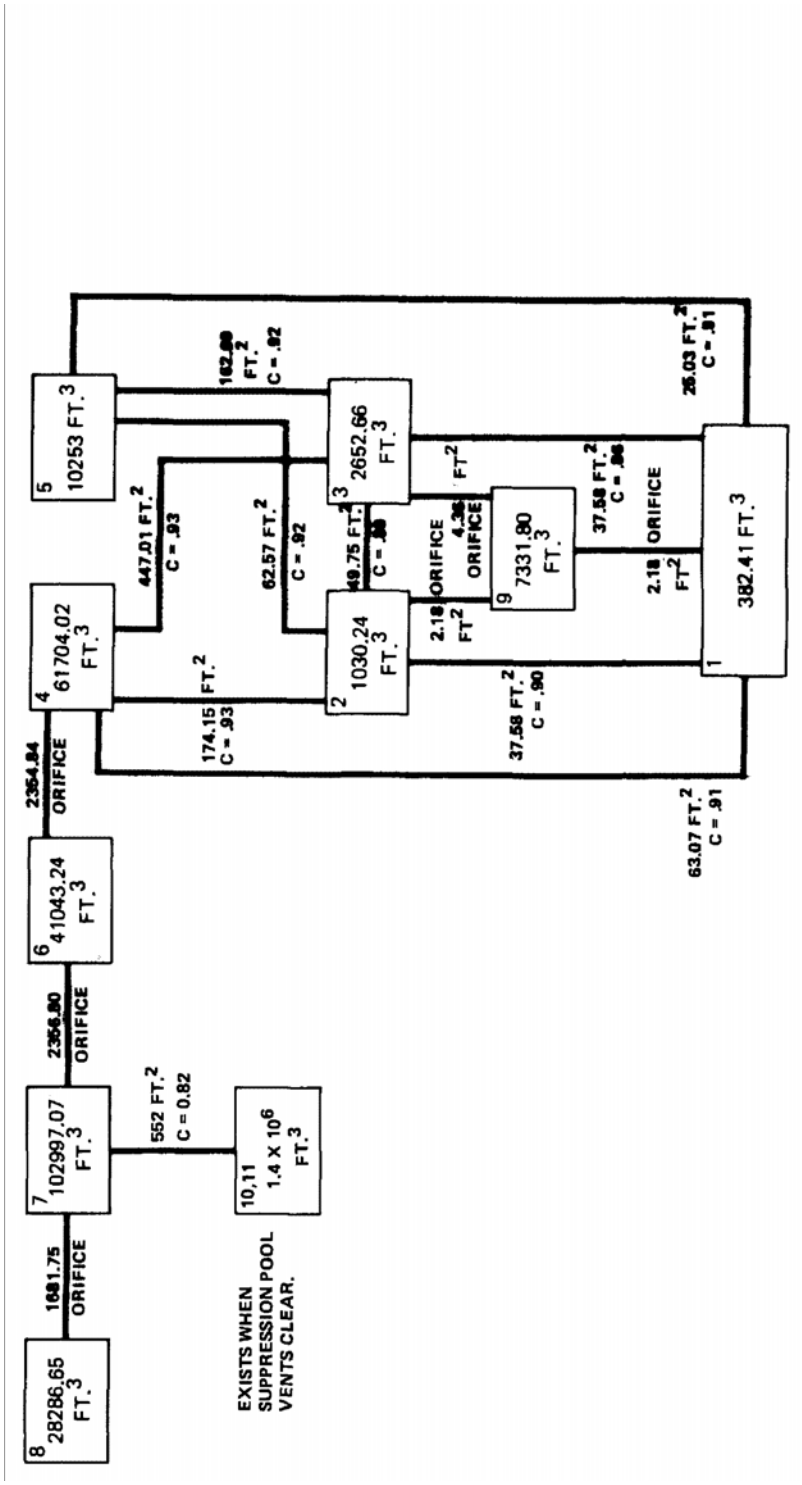
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT



[HISTORICAL INFORMATION]

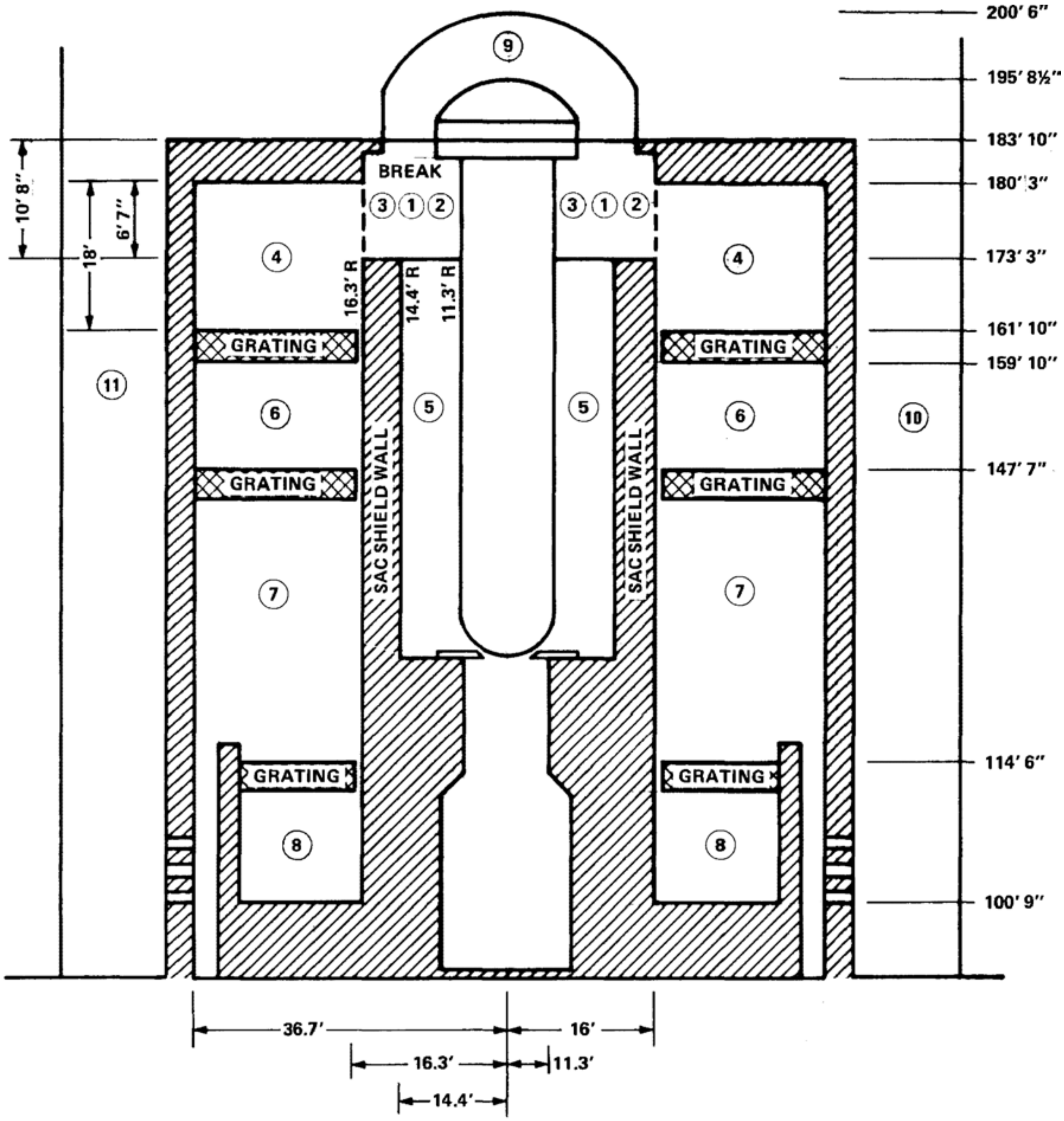
DIFFERENTIAL PRESSURES
CMPT 1-CMPT 2
RCIC LINE BREAK IN
DRYWELL HEAD REGION
FIGURE 6.2-70

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT



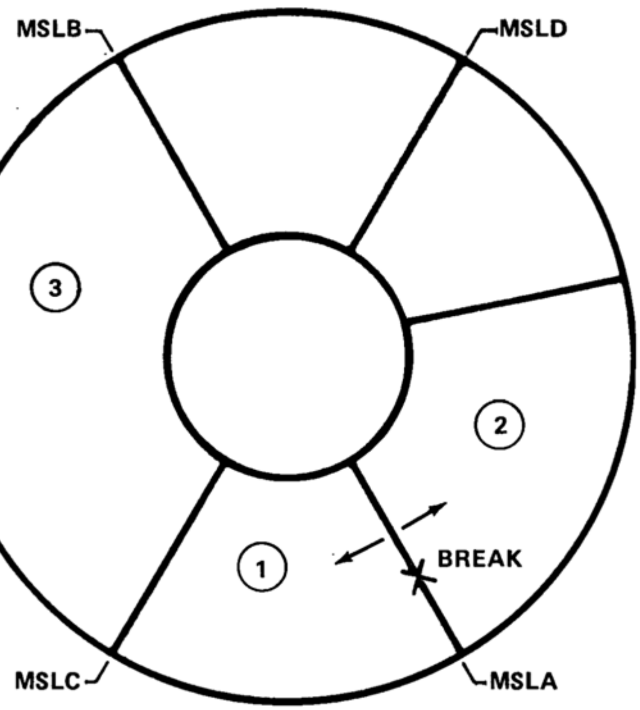
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

VENT FLOW PATH FOR MAIN STEAM LINE BREAK IN DRYWELL HEAD AREA
[HISTORICAL INFORMATION]
FIGURE 6.2-71



SECTION VIEW OF THE NODALIZATION SCHEME

MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	MSLB - DRYWELL HEAD ANALYSIS [HISTORICAL INFORMATION] FIGURE 6.2-72a



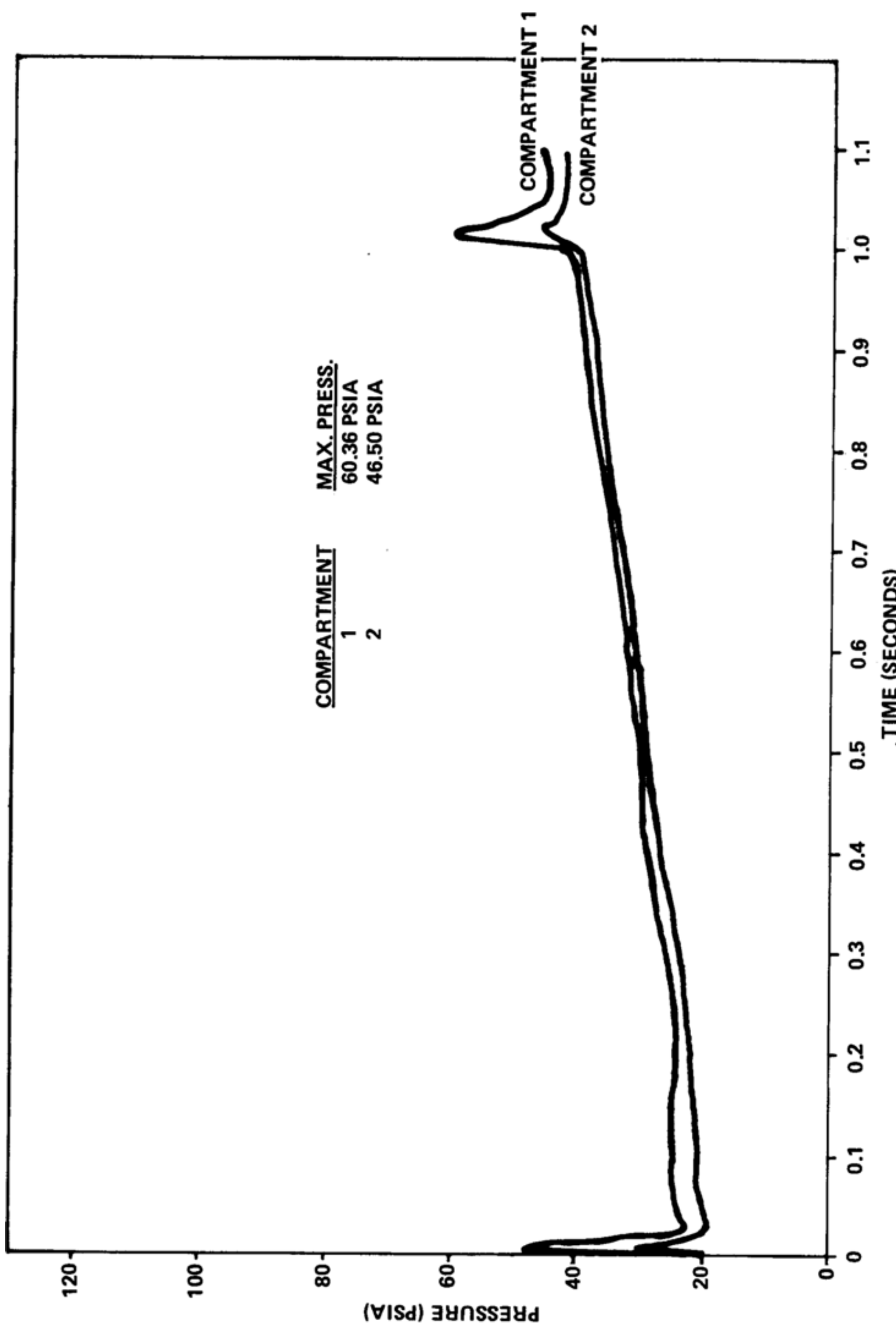
PLAN VIEW OF THE UPPER NODALIZATION SCHEME. THE CONTAINMENT WAS DIVIDED INTO TWO HALF CYLINDERS, NODES 10 AND 11.

MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MSLB - DRYWELL HEAD ANALYSIS

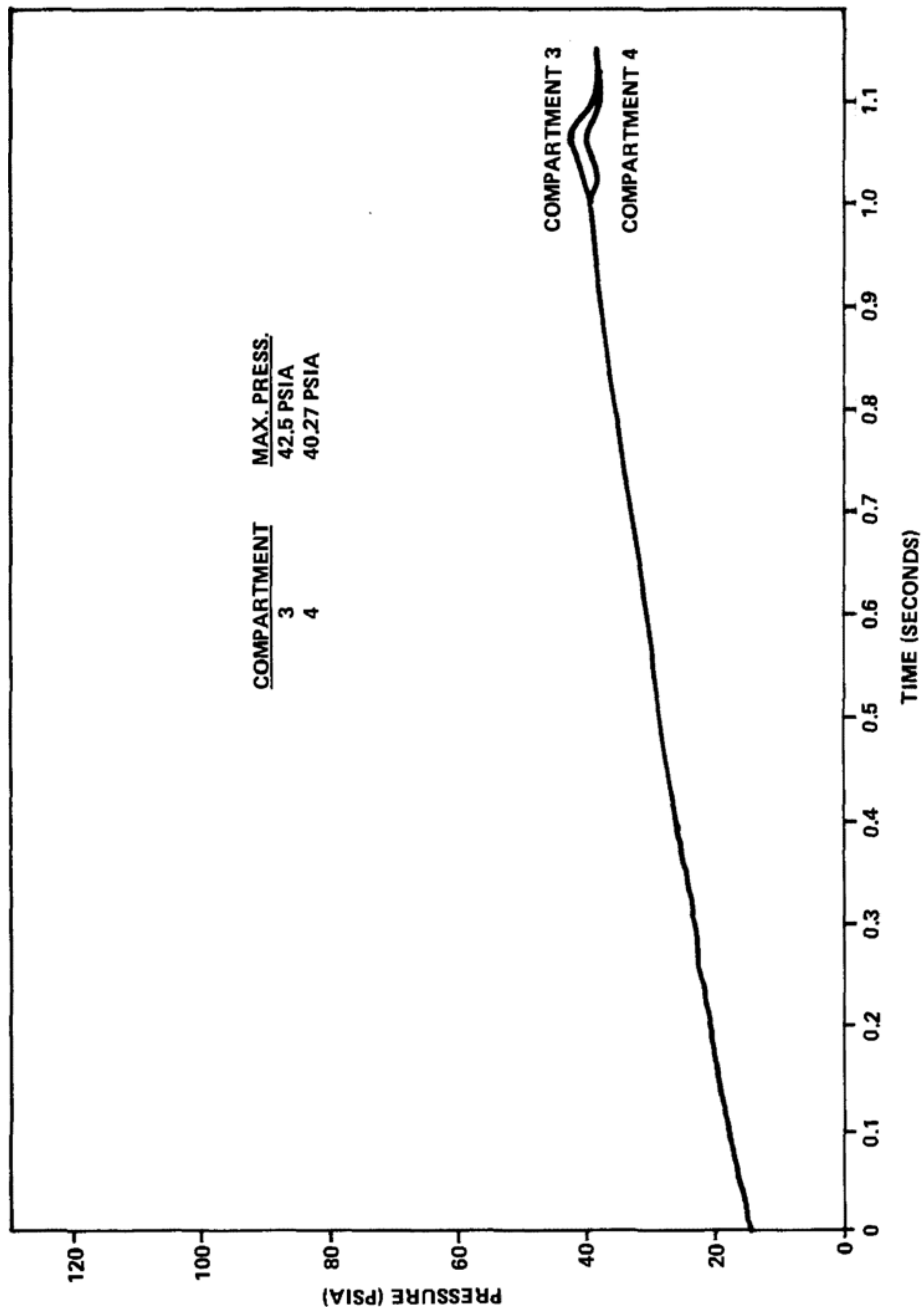
[HISTORICAL INFORMATION]

FIGURE 6.2-72b



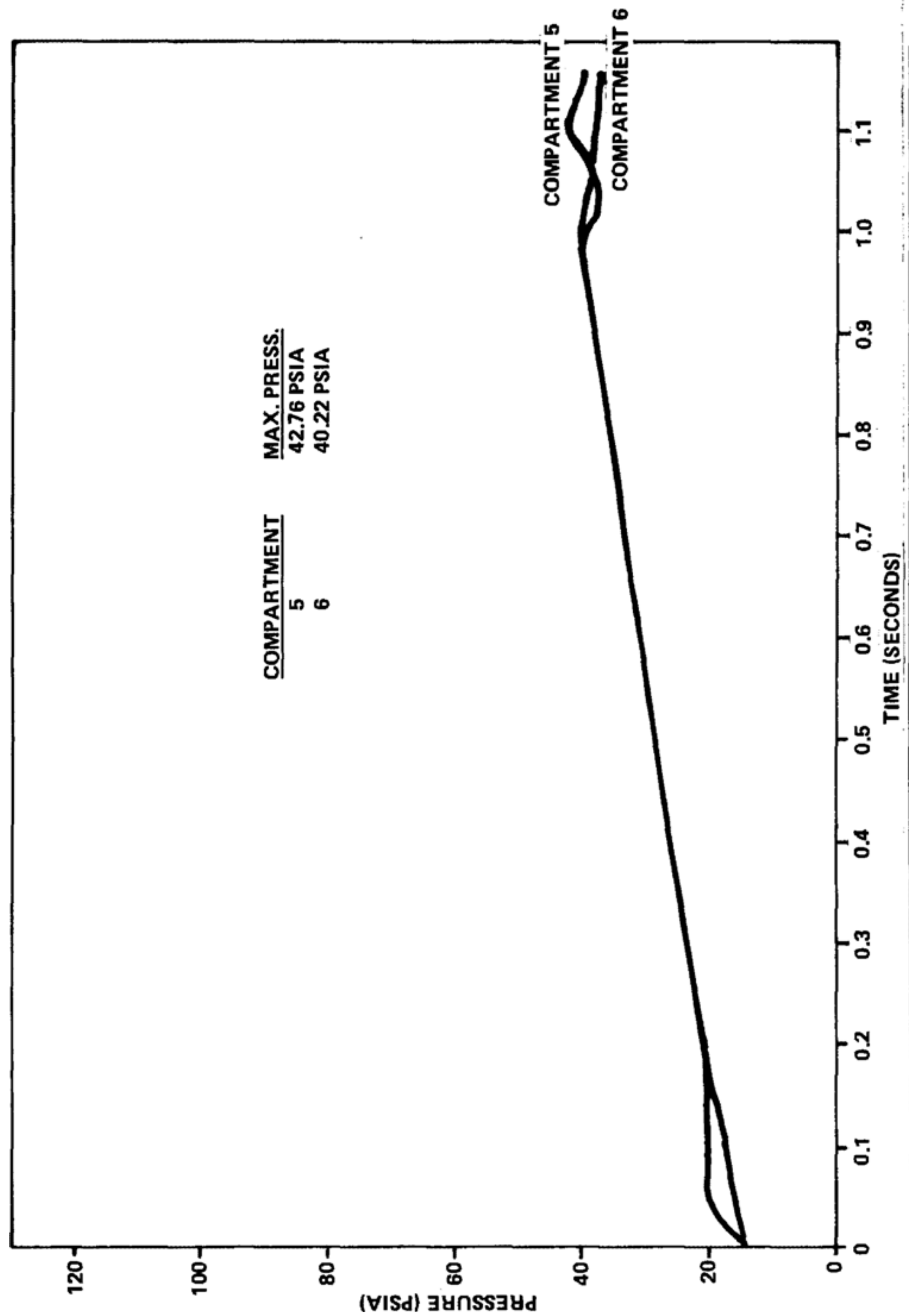
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MSLB - DRYWELL HEAD ANALYSIS
[HISTORICAL INFORMATION]
FIGURE 6.2-73a



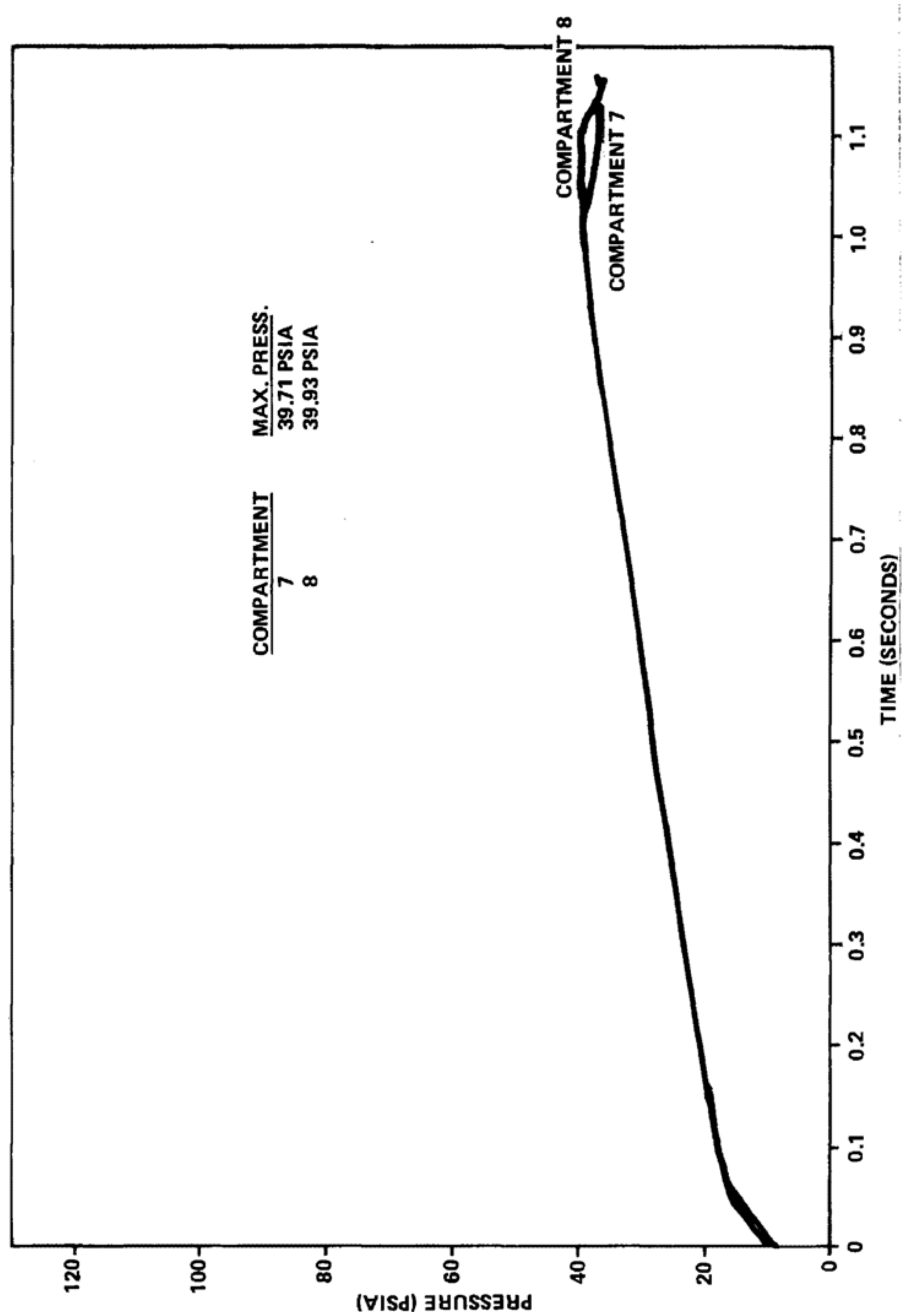
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MSLB - DRYWELL HEAD ANALYSIS
[HISTORICAL INFORMATION]
FIGURE 6.2-73b



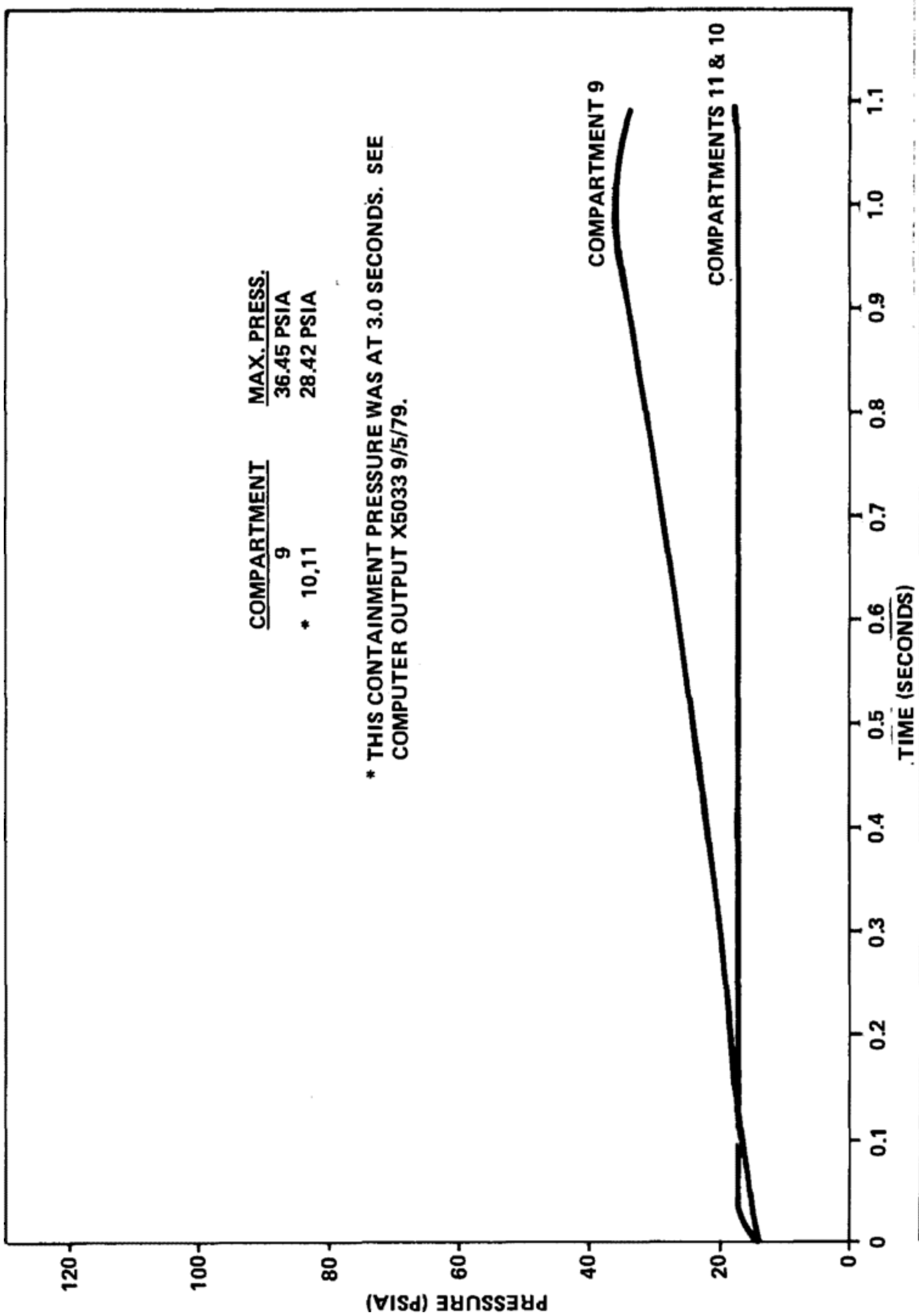
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MSLB - DRYWELL HEAD ANALYSIS
[HISTORICAL INFORMATION]
FIGURE 6.2-74a



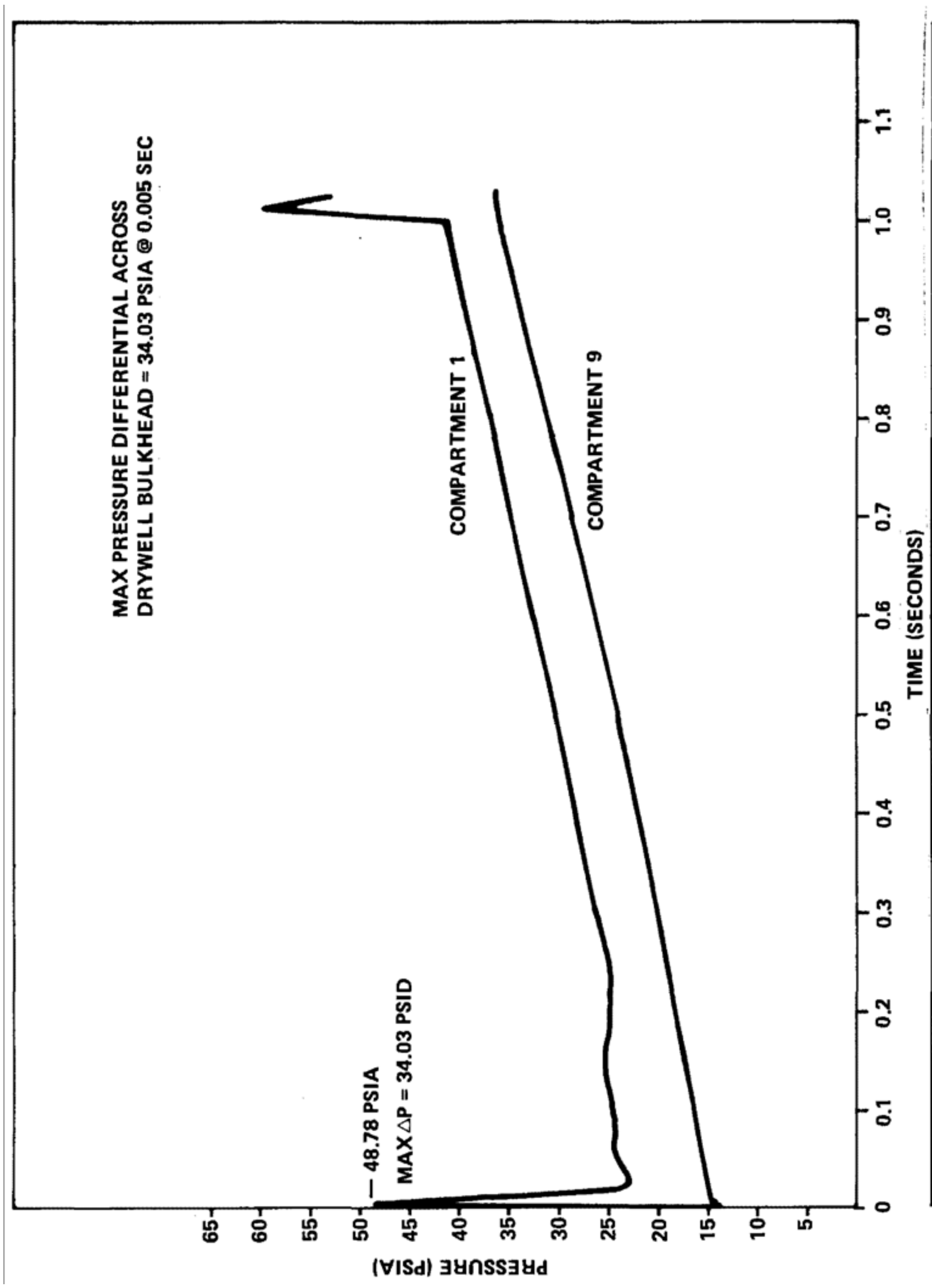
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MSLB - DRYWELL HEAD ANALYSIS
[HISTORICAL INFORMATION]
FIGURE 6.2-74b



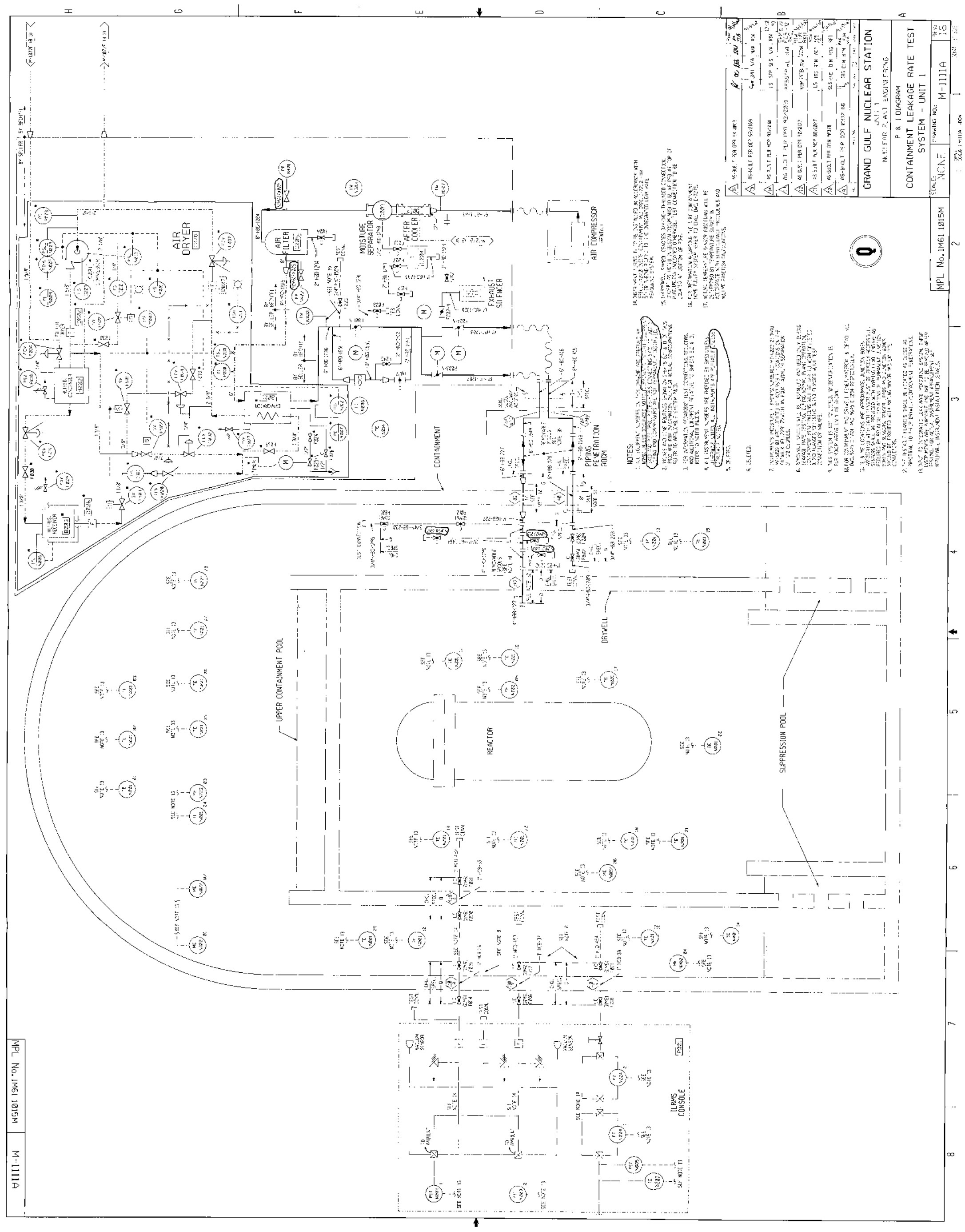
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

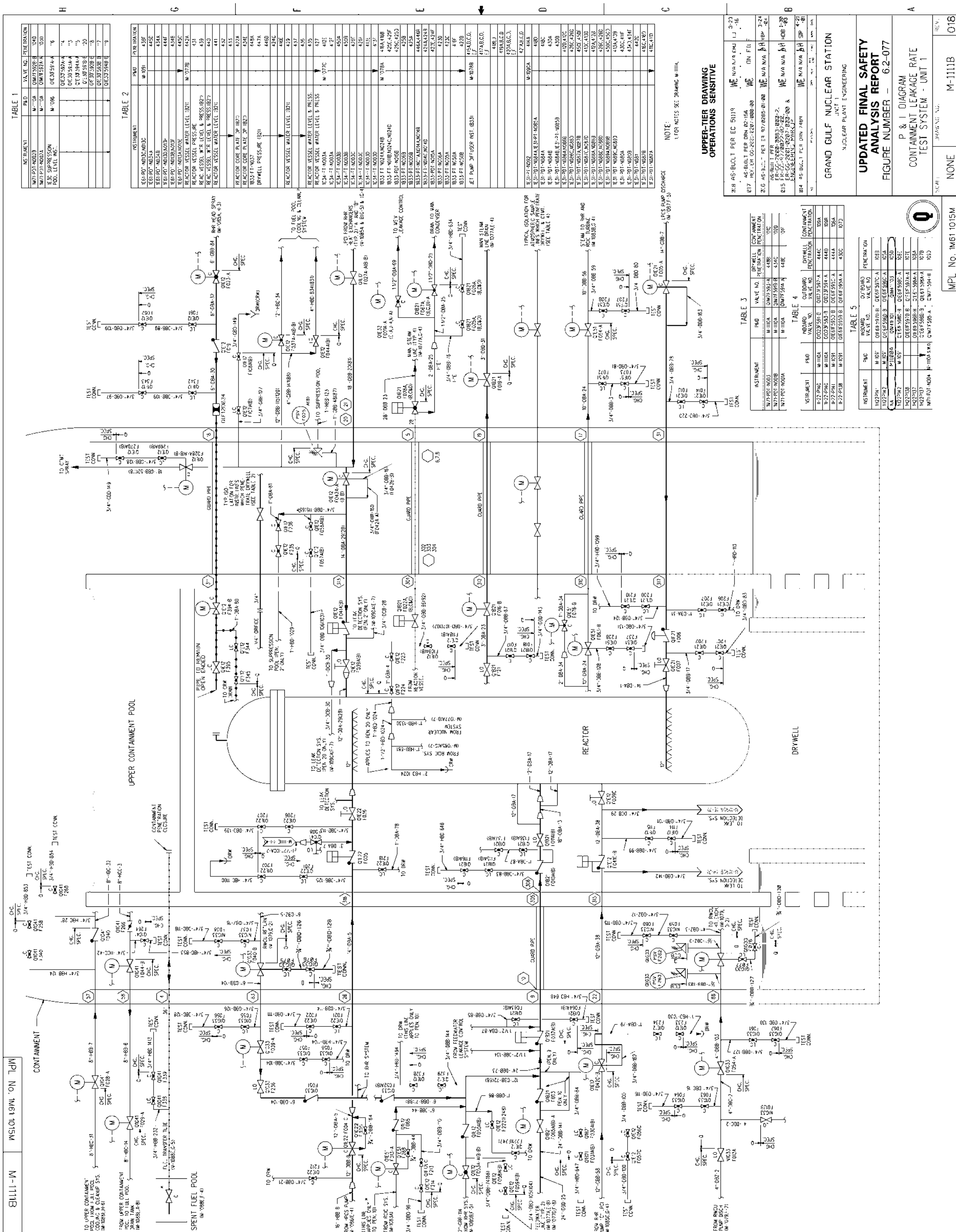
MSLB - DRYWELL HEAD ANALYSIS
[HISTORICAL INFORMATION]
FIGURE 6.2-74c

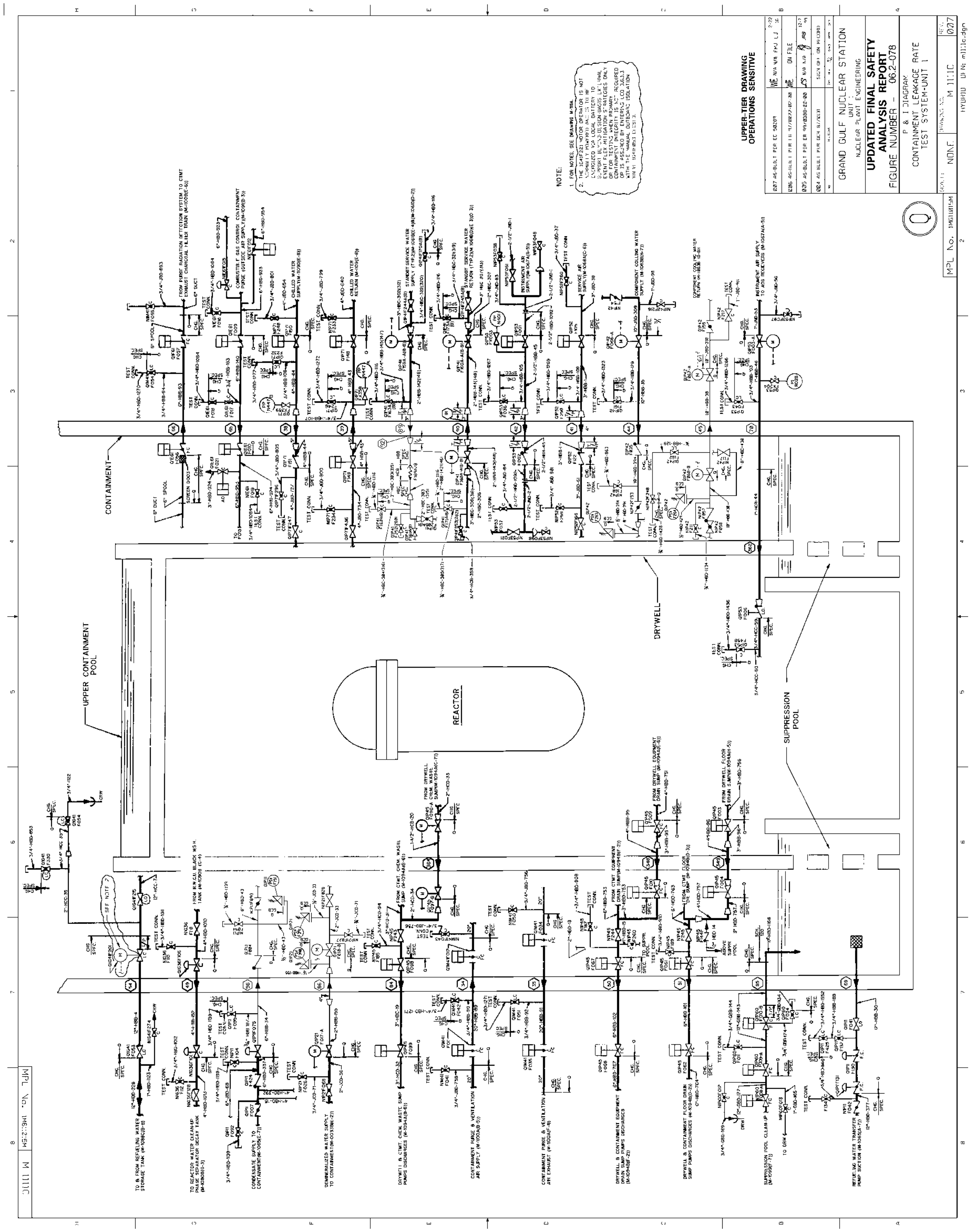


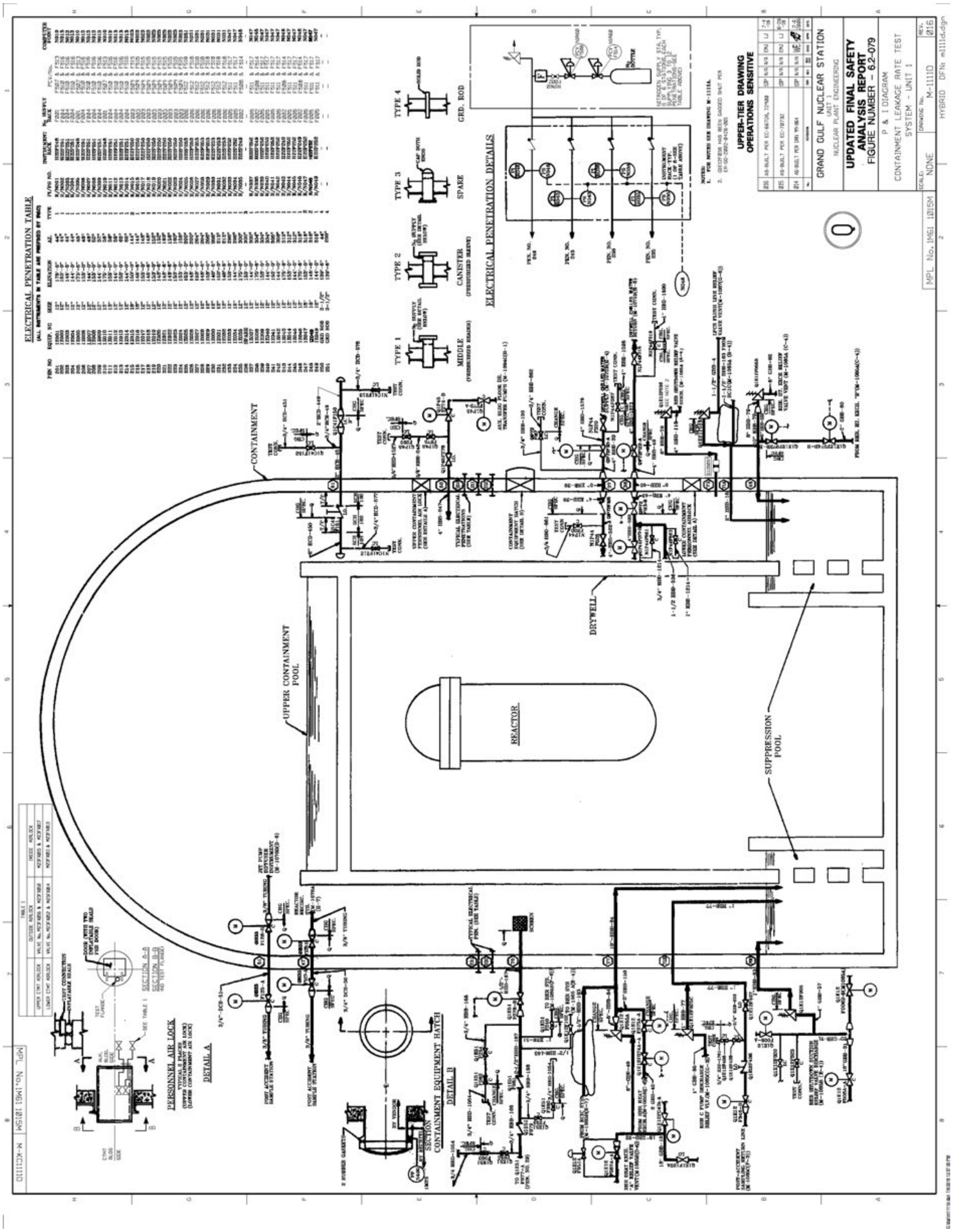
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MSLB - DRYWELL HEAD ANALYSIS
[HISTORICAL INFORMATION]
FIGURE 6.2-75

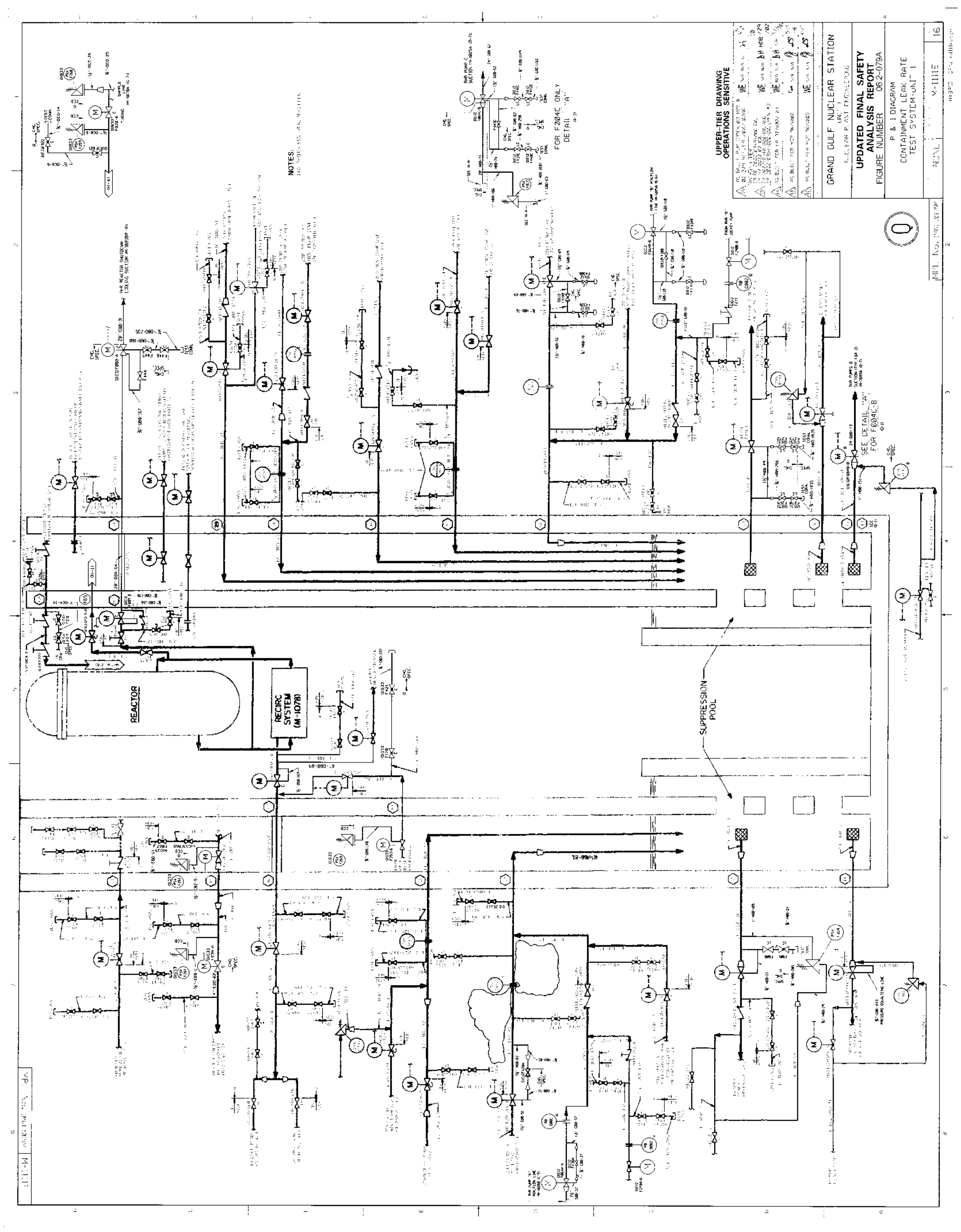

GRAND GULF NUCLEAR STATION
P & I DIAGRAM
CONTAINMENT LEAKAGE RATE TEST SYSTEM - UNIT 1
M-1111A
MPL No.1M61 1015M
AIR DRYER
AIR FILTER
MOISTURE SEPARATOR
AFTER COOLER
AIR COMPRESSOR
CONTAINMENT
PIPING PENETRATION ROOM
NOTES:
DRYWELL
UPPER CONTAINMENT POOL
REACTOR
SUPPRESSION POOL

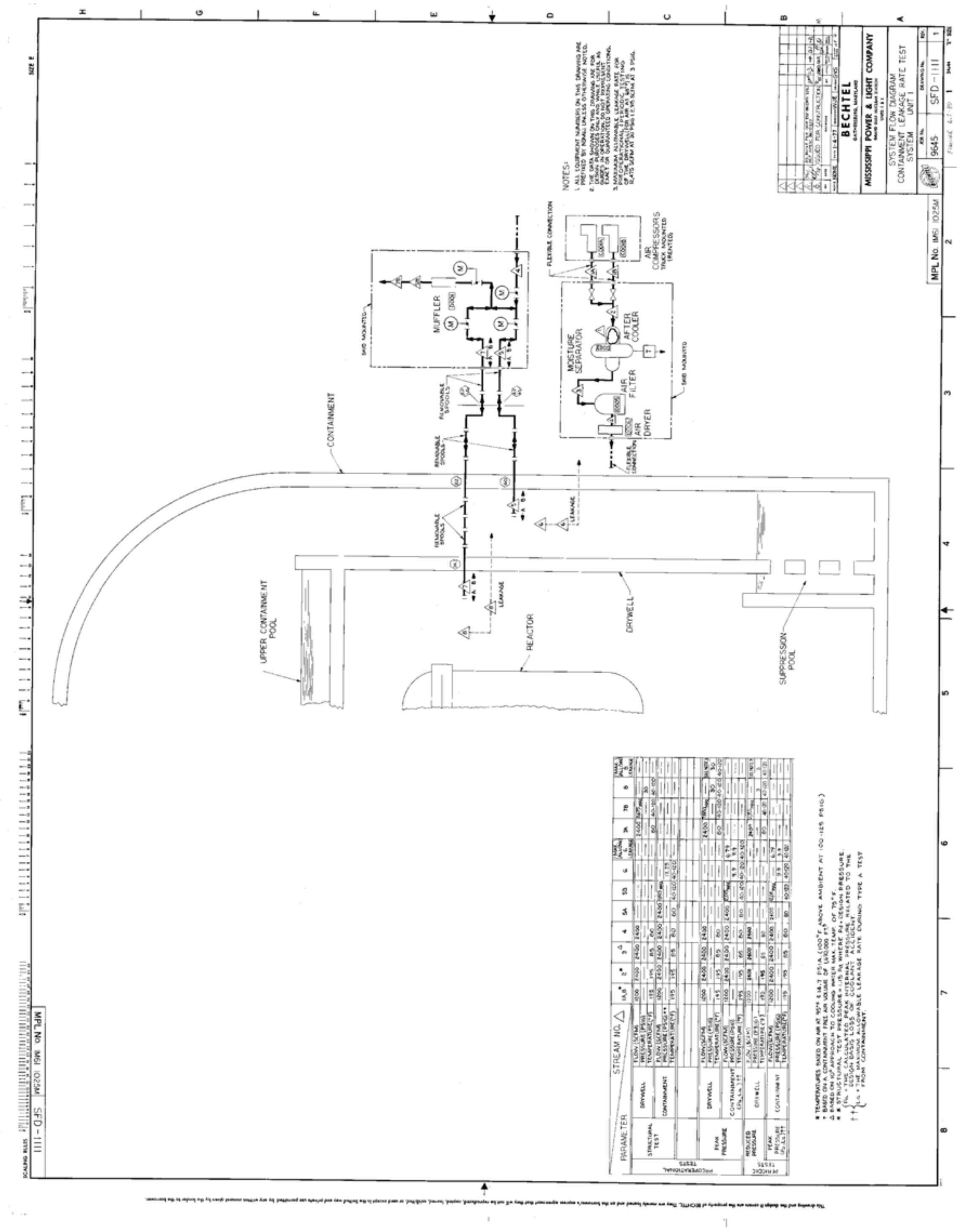

GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER — 6.2-077
P & I DIAGRAM
CONTAINMENT LEAKAGE RATE TEST SYSTEM - UNIT 1
M-1111B
UPPER-TIER DRAWING OPERATIONS SENSITIVE
TABLE 1
TABLE 2
TABLE 3
TABLE 4
TABLE 5
REACTOR
DRYWELL
UPPER CONTAINMENT POOL
CONTAINMENT
SPENT FUEL POOL
MPL No. 1M61 1015M


UPPER-TIER DRAWING
OPERATIONS SENSITIVE
GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER - 06.2-078
P & I DIAGRAM
CONTAINMENT LEAKAGE RATE
TEST SYSTEM-UNIT 1
CONTAINMENT
UPPER CONTAINMENT
POOL
REACTOR
DRYWELL
SUPPRESSION
POOL

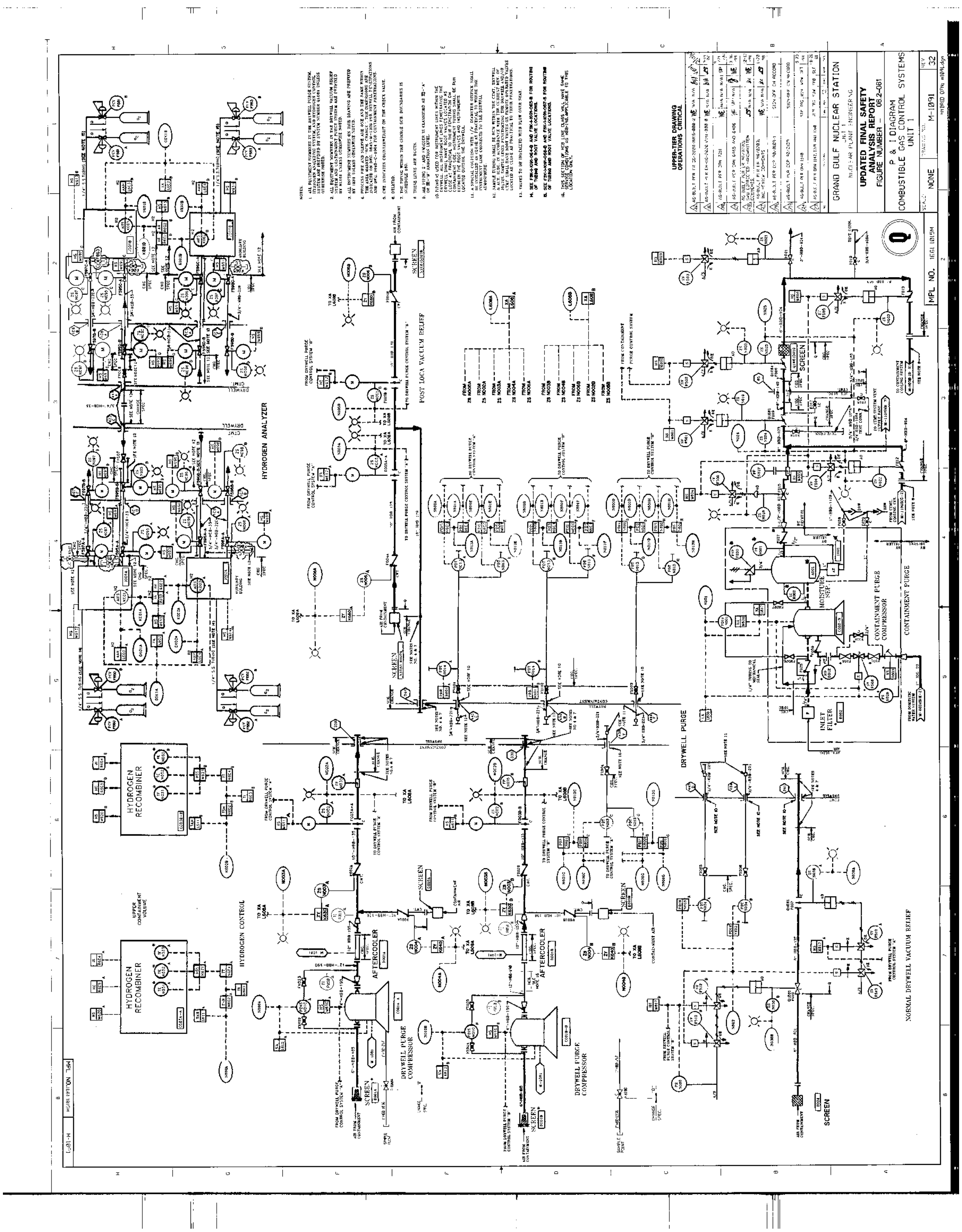


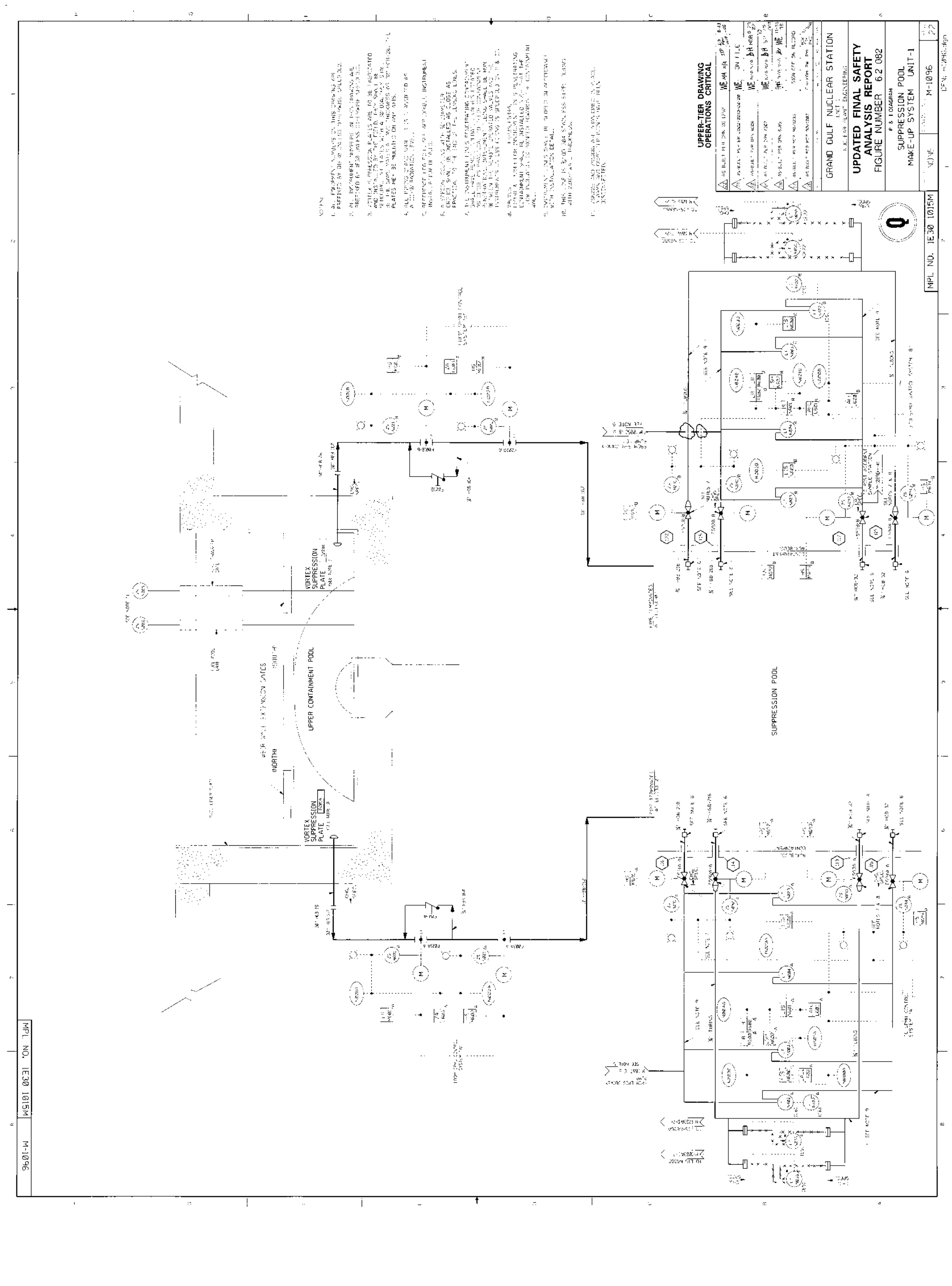
LBDCR 2017-057
LBDCR 2017-059
LBDCR 2016-261

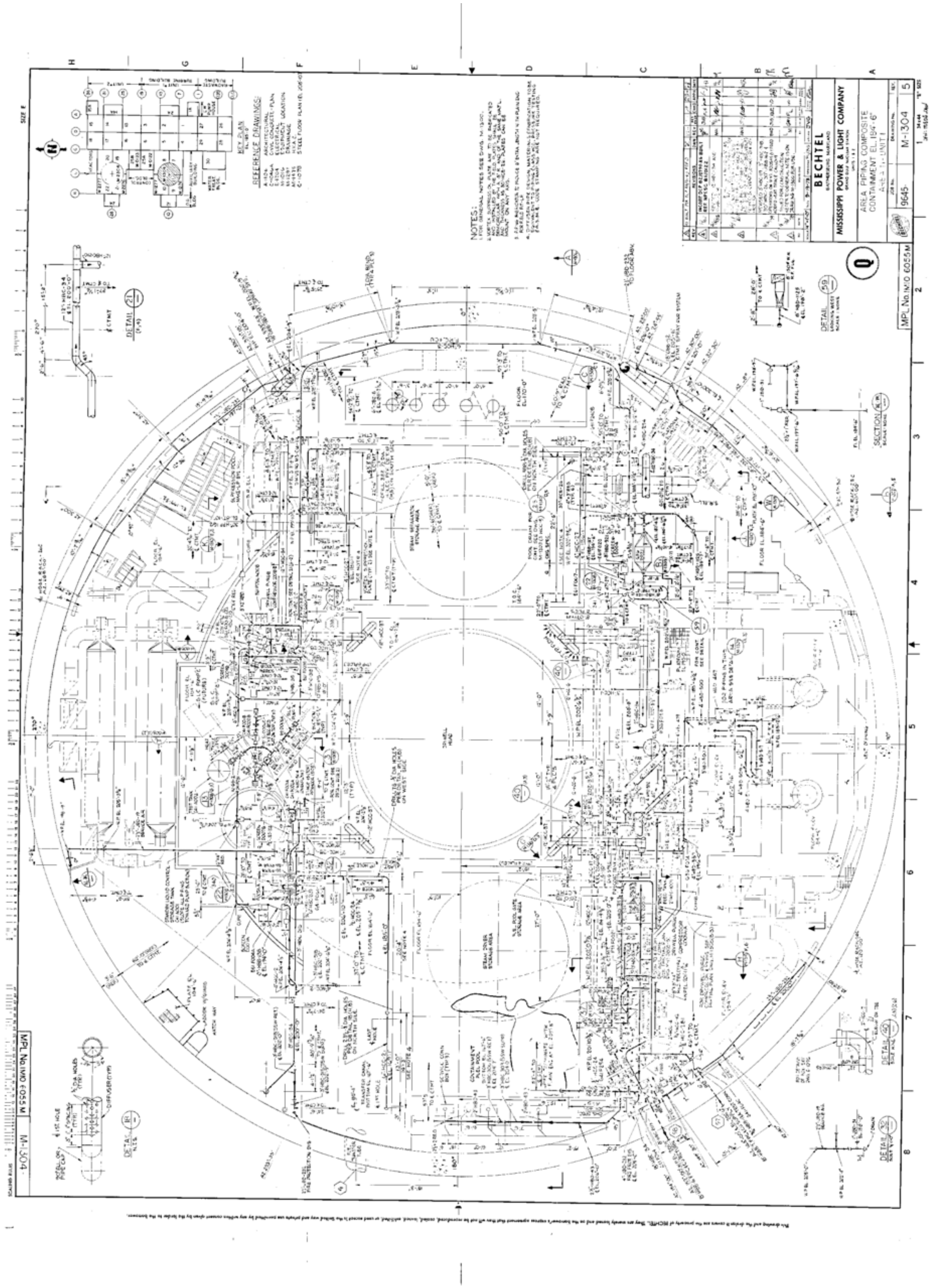

UPPER-TIER DRAWING
OPERATIONS SENSITIVE
GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER 06.2-079A
P & I DIAGRAM
CONTAINMENT LEAK RATE
TEST SYSTEM-UNIT 1
16
REACTOR
RECIRC SYSTEM (M-1078)
SUPPRESSION POOL
NOTES:
FOR F204C ONLY
DETAIL "A"
SEE DETAIL "A"
FOR F004C, B

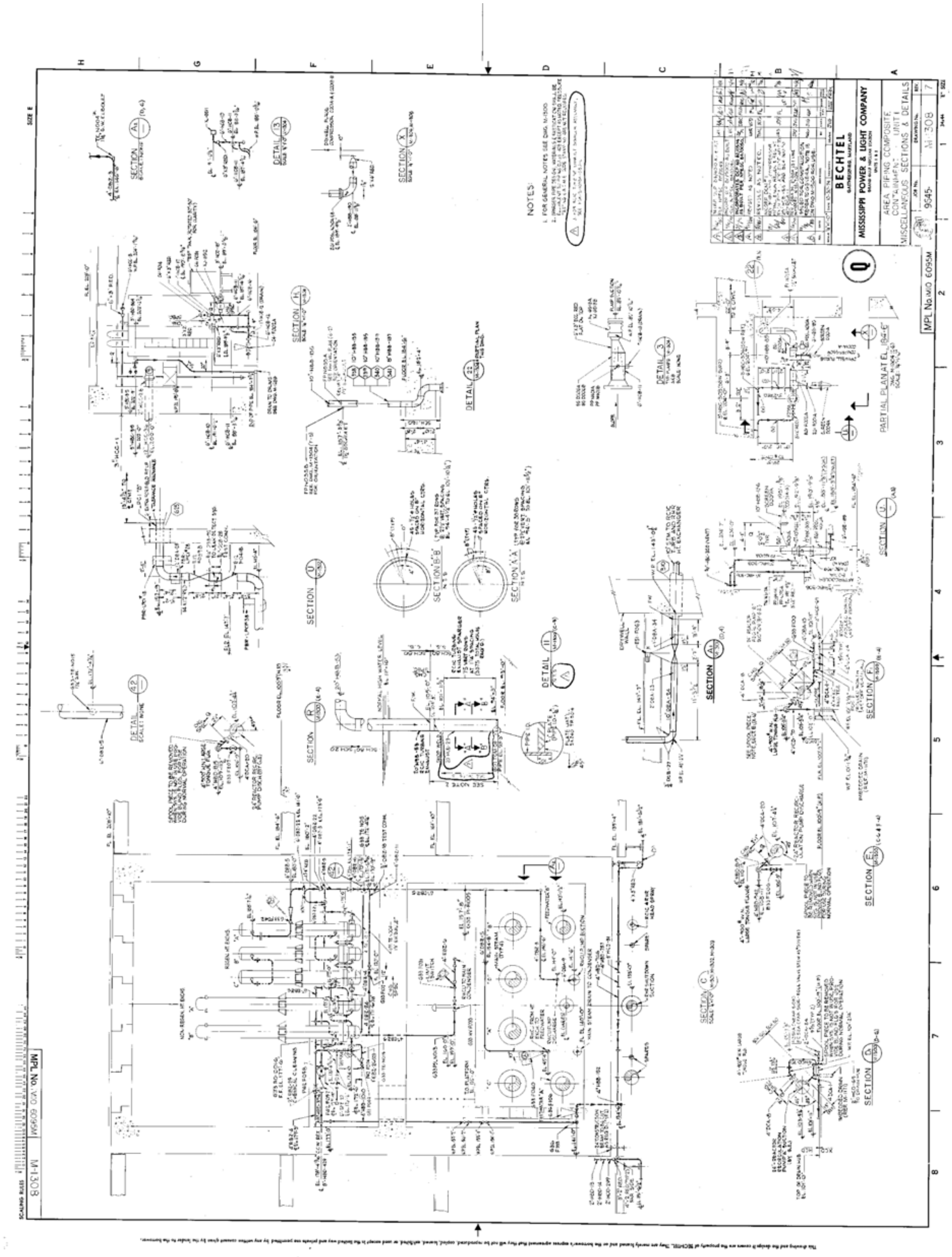


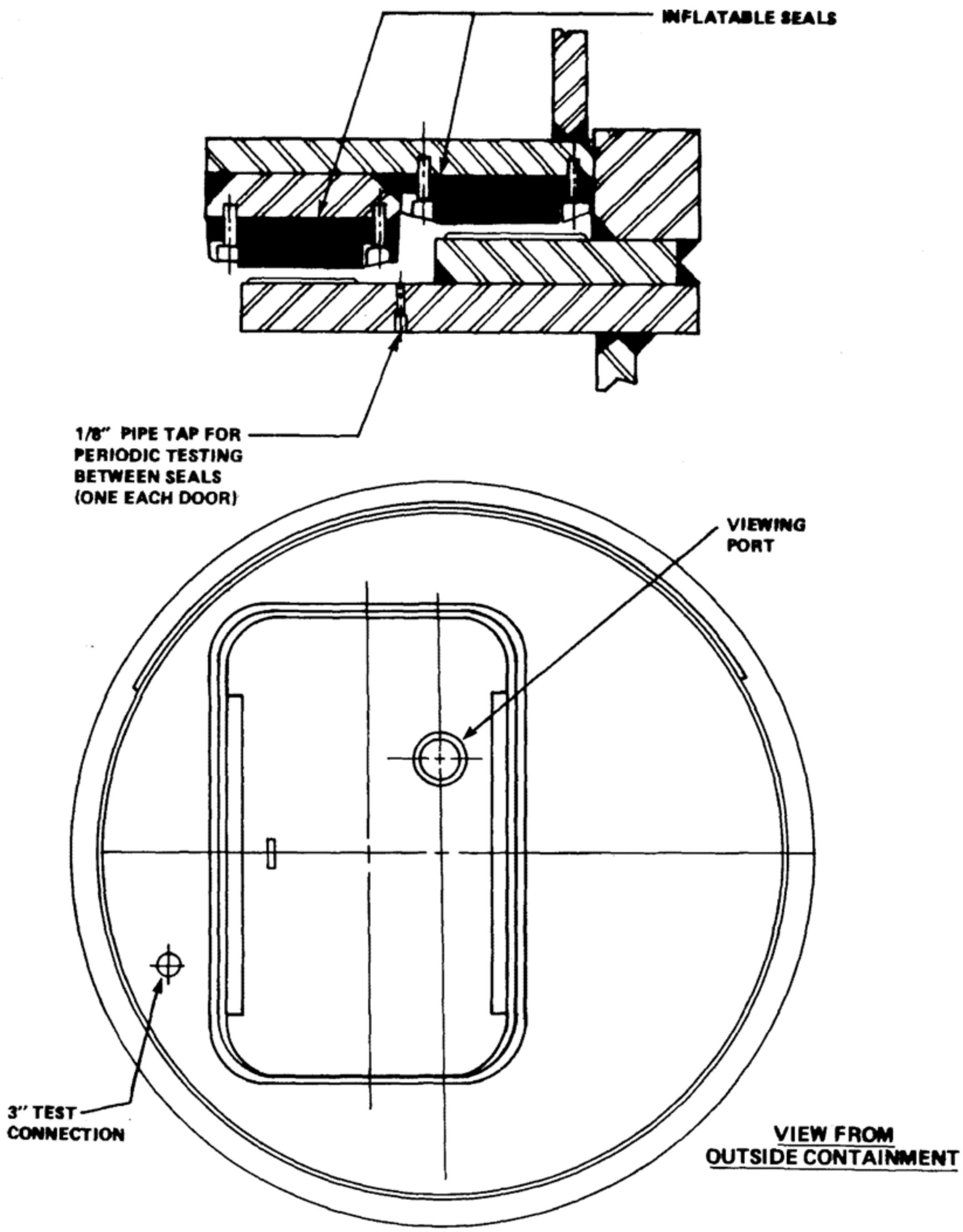
UFSAR Figure 6.2-080


GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
P & I DIAGRAM
COMBUSTIBLE GAS CONTROL SYSTEMS
UNIT 1
M-1091
HYDROGEN ANALYZER
HYDROGEN RECOMBINER
HYDROGEN CONTROL
POST LOCA VACUUM RELIEF
DRYWELL PURGE
DRYWELL PURGE COMPRESSOR
AFTERCOOLER
CONTAINMENT PURGE COMPRESSOR
MOISTURE SEP
INLET FILTER
NORMAL DRYWELL VACUUM RELIEF
SCREEN

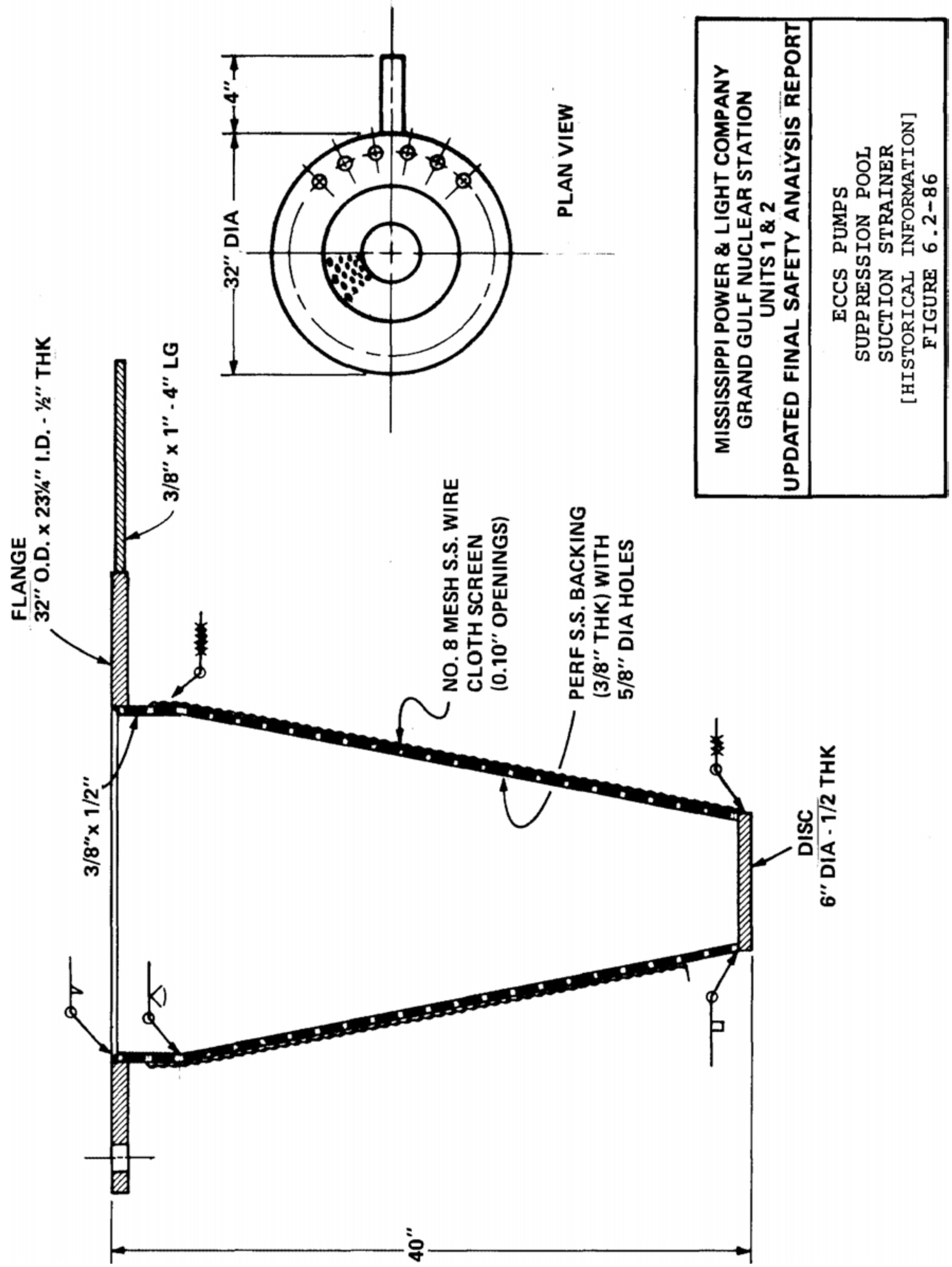

UPPER-TIER DRAWING
OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER 6.2 082
P & I DIAGRAM
SUPPRESSION POOL
MAKE-UP SYSTEM UNIT-1
M-1096
MPL NO. 1E30 1015M
SUPPRESSION POOL
UPPER CONTAINMENT POOL
VORTEX SUPPRESSION PLATE

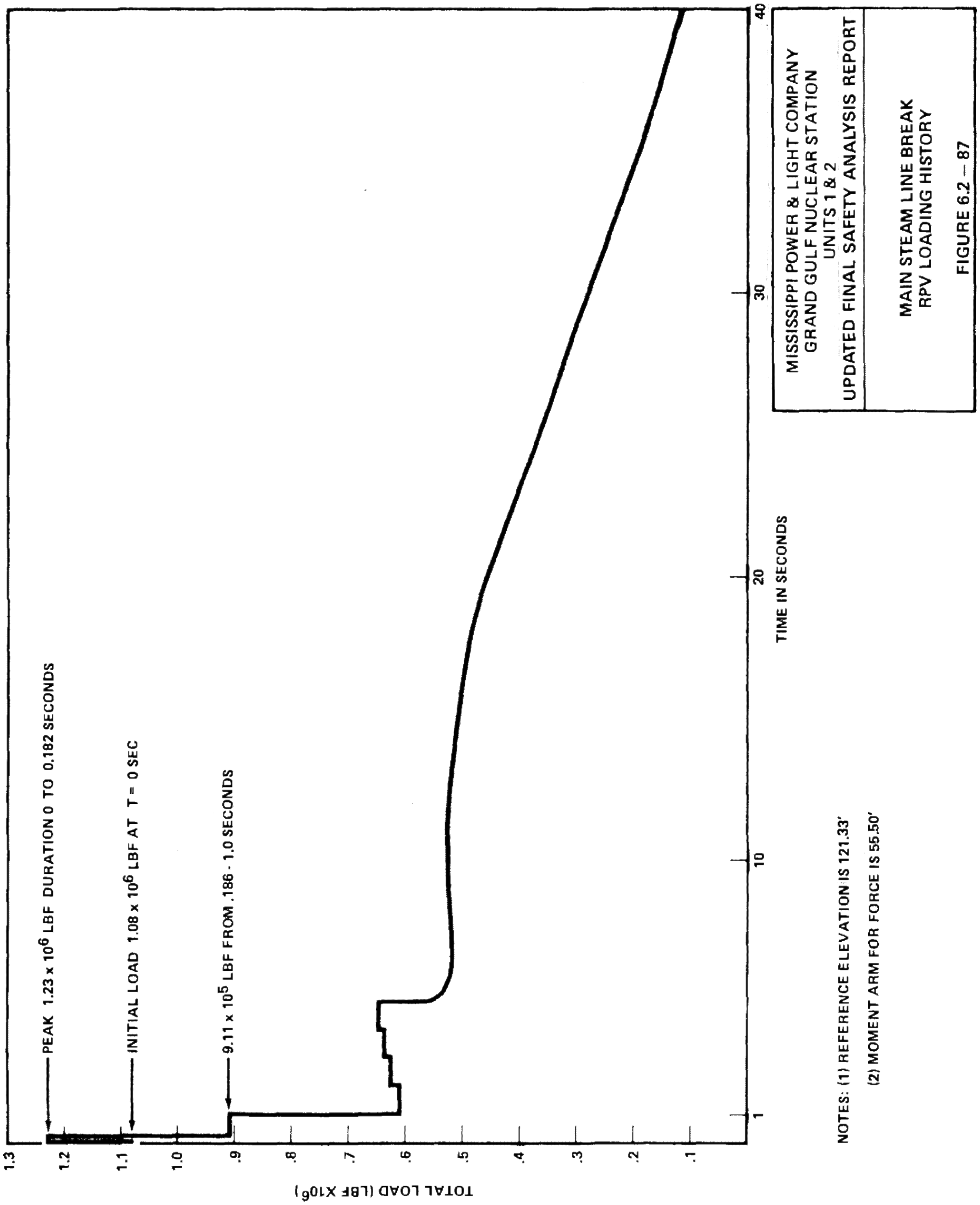

BECHTEL
MISSISSIPPI POWER & LIGHT COMPANY
M-1304
DETAIL
NOTES:
REFERENCE DRAWINGS:


BECHTEL
MISSISSIPPI POWER & LIGHT COMPANY
NOTES:
M-1308



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	DETAILS OF PERSONNEL LOCK FOR PERIODIC TESTING [HISTORICAL INFORMATION] FIGURE 6.2-85

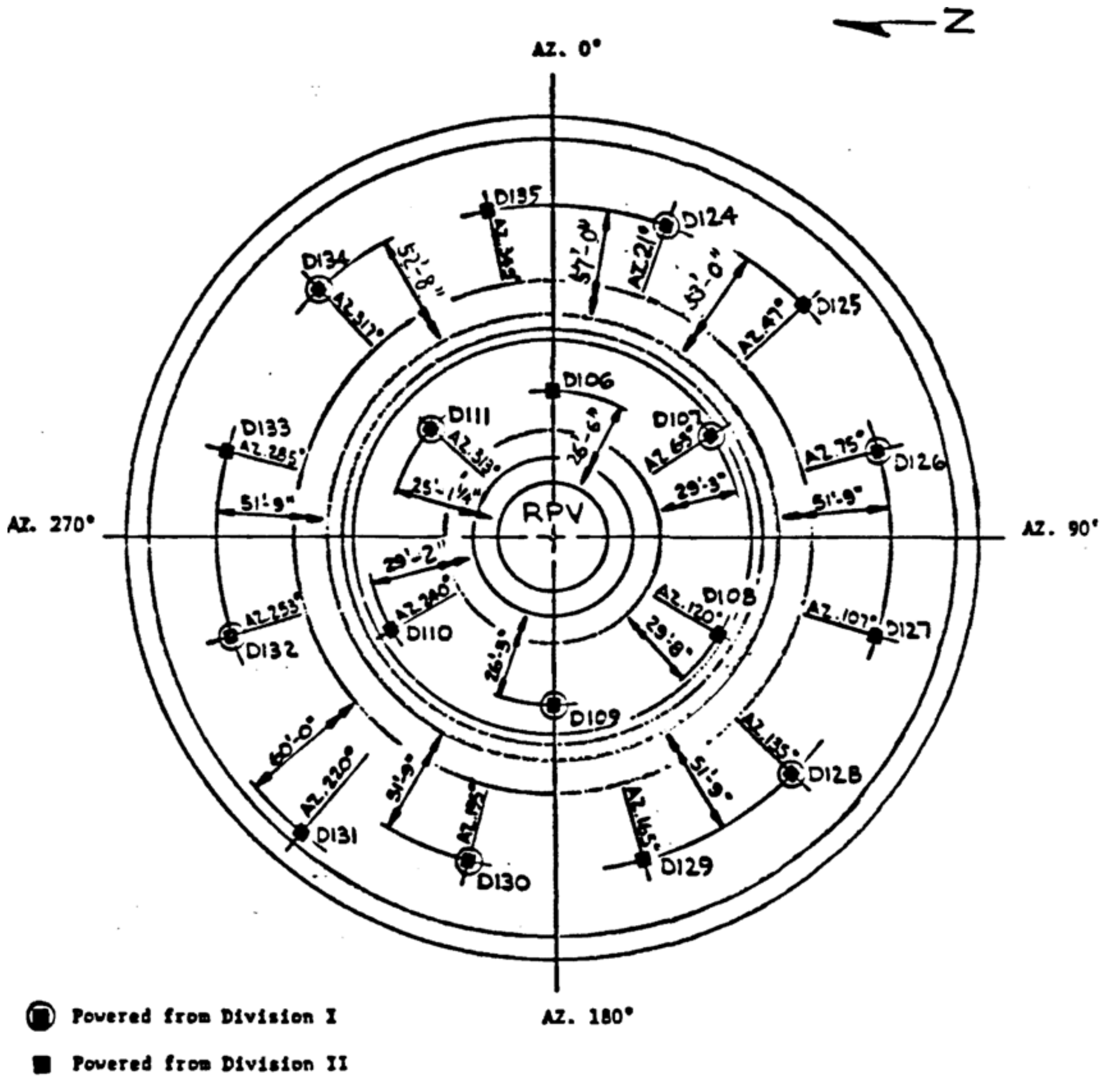

FLANGE
32" O.D. x 23¼" I.D. - ½" THK
3/8" x 1" - 4" LG
NO. 8 MESH S.S. WIRE
CLOTH SCREEN
(0.10" OPENINGS)
PERF S.S. BACKING
(3/8" THK) WITH
5/8" DIA HOLES
3/8" x 1/2"
DISC
6" DIA - 1/2 THK
40"
4"
32" DIA
PLAN VIEW
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT
ECCS PUMPS
SUPPRESSION POOL
SUCTION STRAINER
[HISTORICAL INFORMATION]
FIGURE 6.2-86



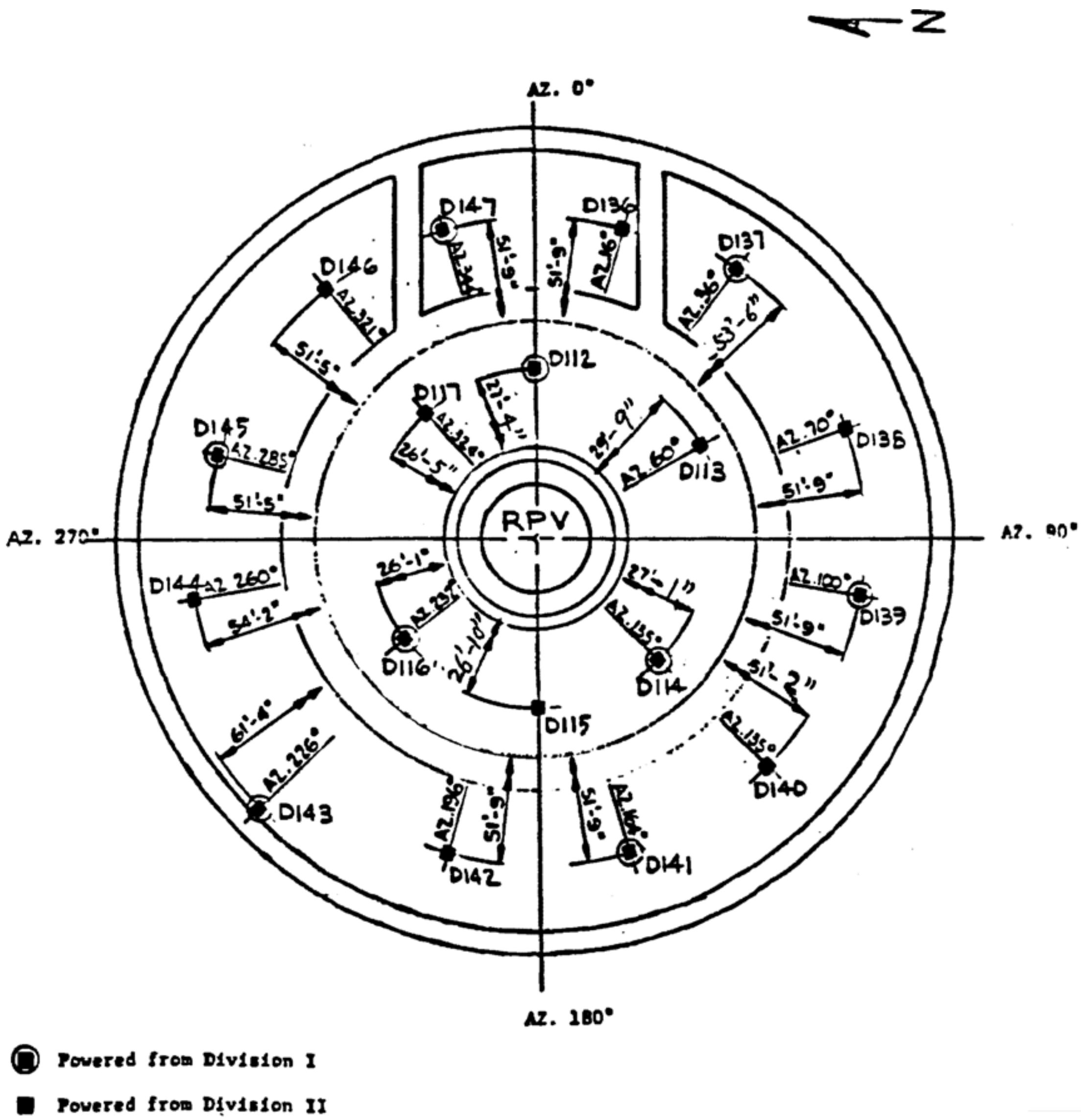
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MAIN STEAM LINE BREAK
RPV LOADING HISTORY

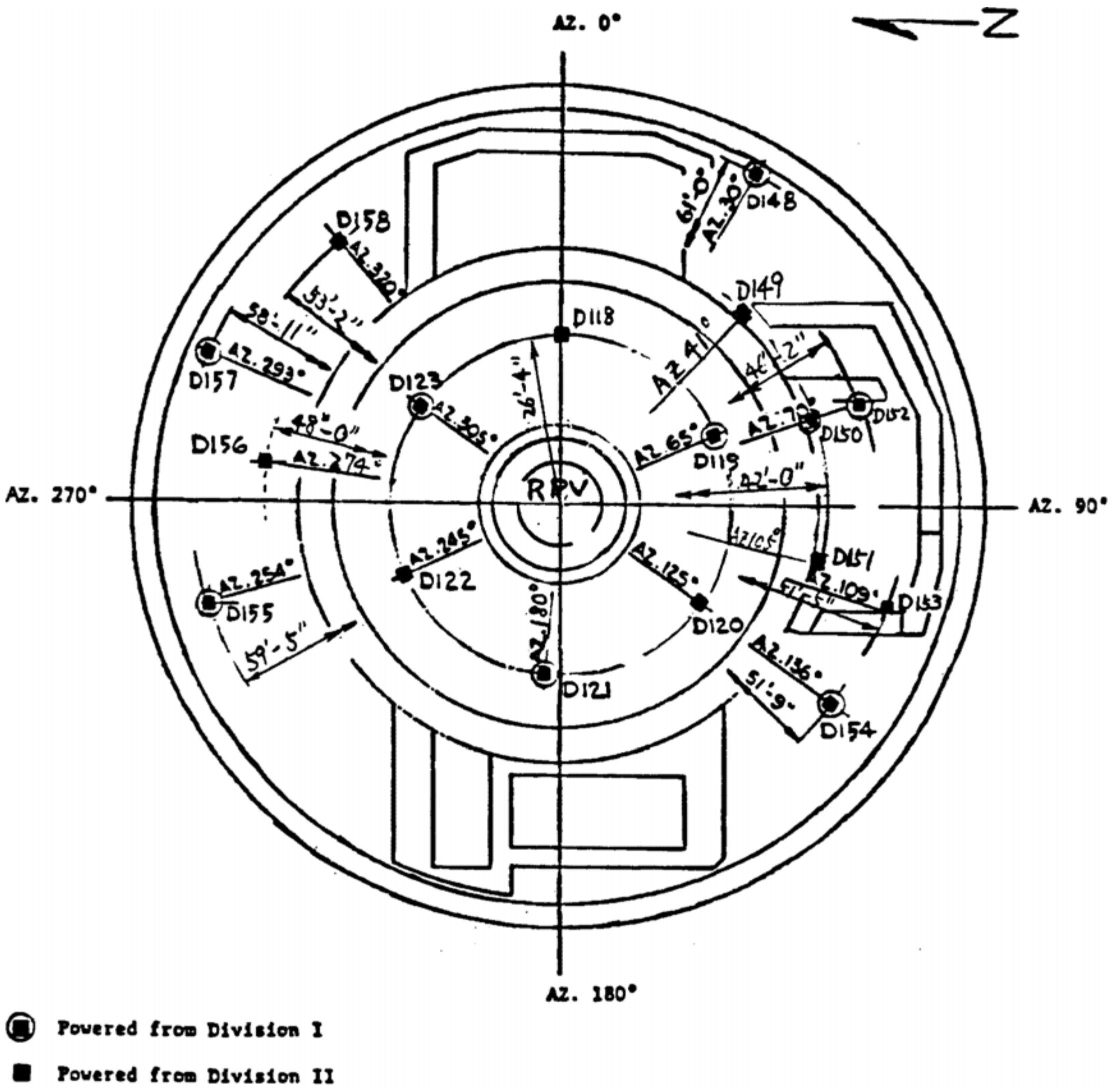
FIGURE 6.2 – 87



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT
HYDROGEN IGNITER LOCATIONS EL. 120'10" AND 114'6" [HISTORICAL INFORMATION] FIGURE 6.2-88a



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT
HYDROGEN IGNITER LOCATIONS EL. 135'-4" AND 147'-7" [HISTORICAL INFORMATION] FIGURE 6.2-88b

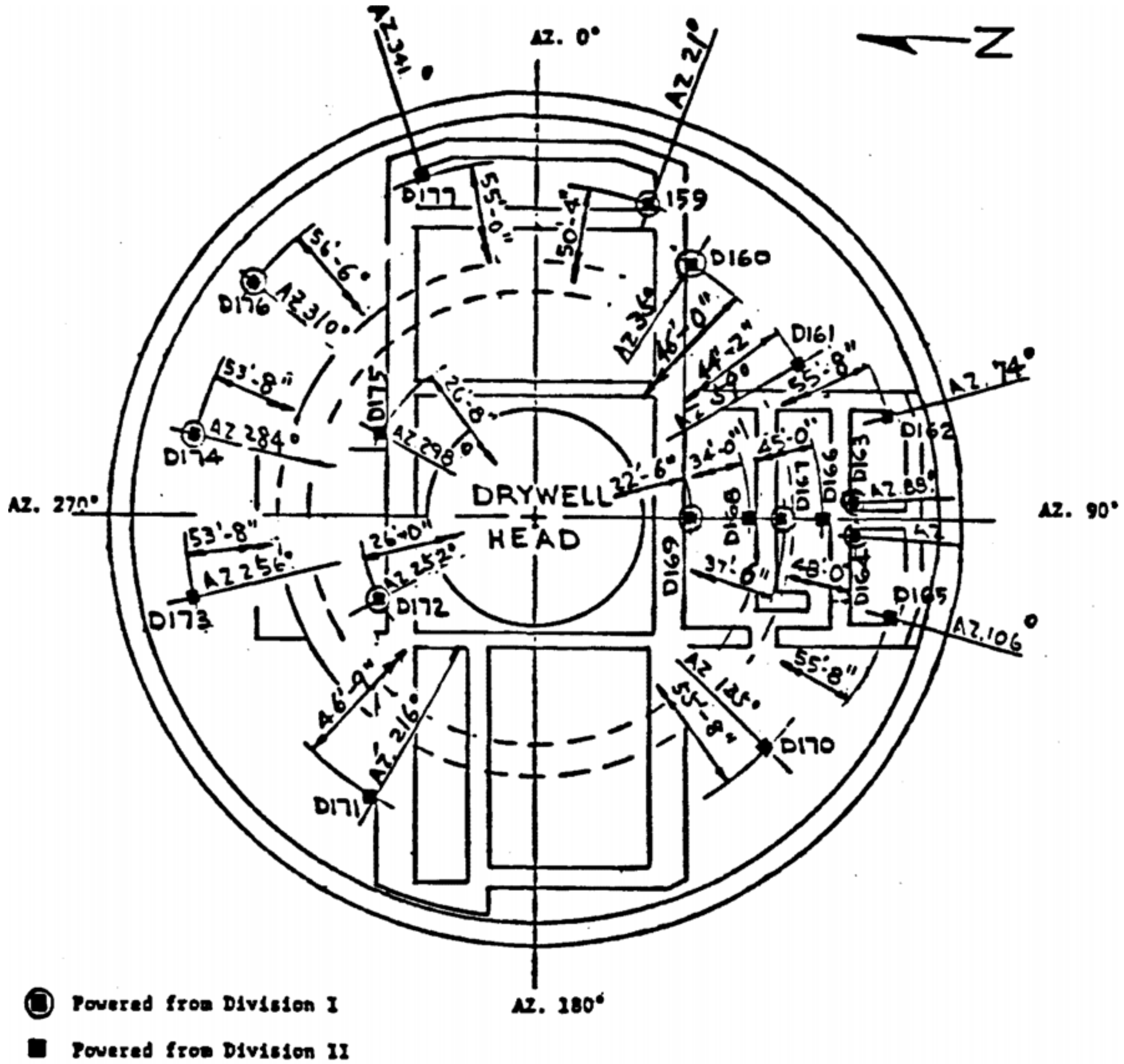


MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HYDROGEN IGNITER LOCATIONS
EL. 161'-10"

[HISTORICAL INFORMATION]

FIGURE 6.2-88c

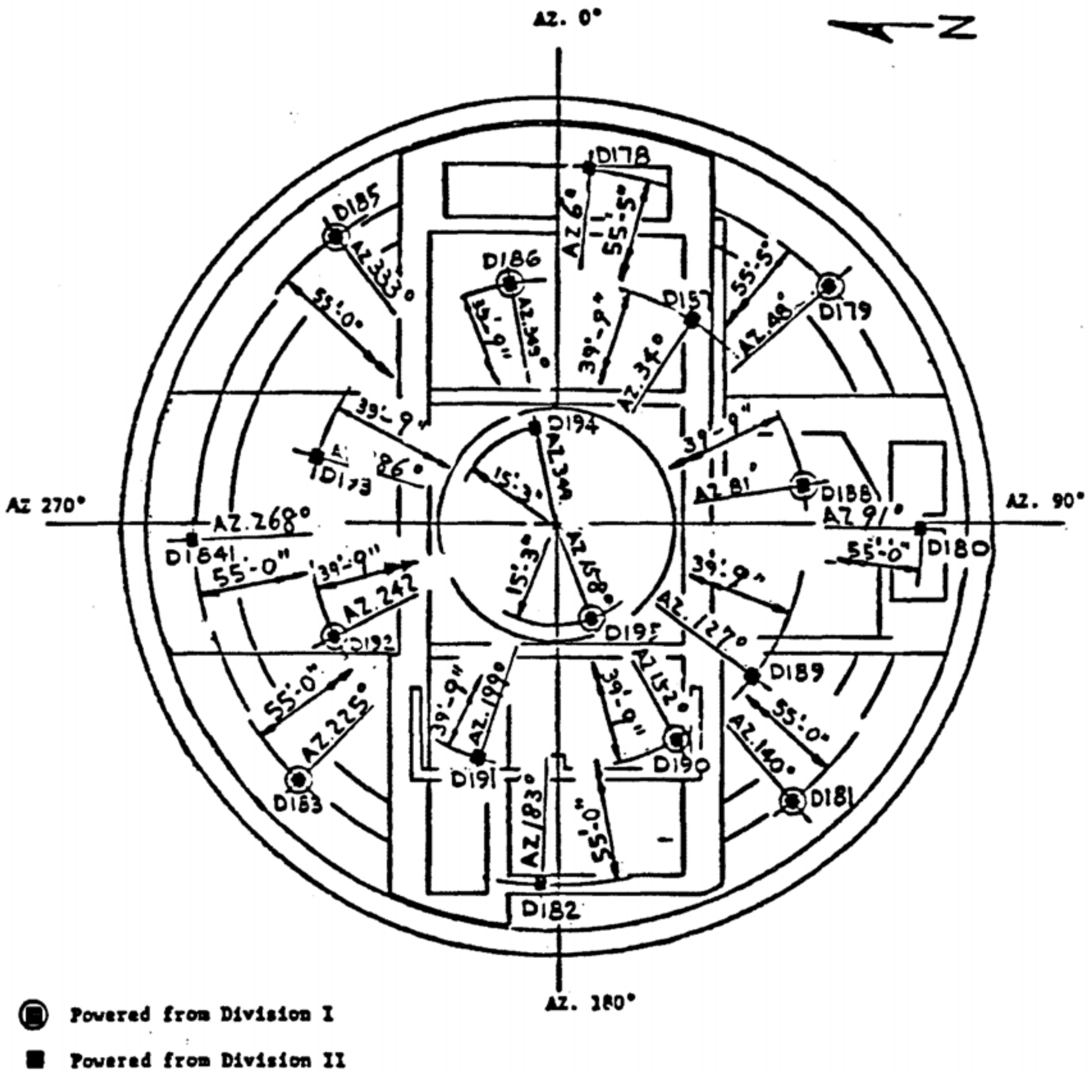


MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HYDROGEN IGNITER LOCATIONS
EL. 184'-6"

[HISTORICAL INFORMATION]

FIGURE 6.2-88d



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
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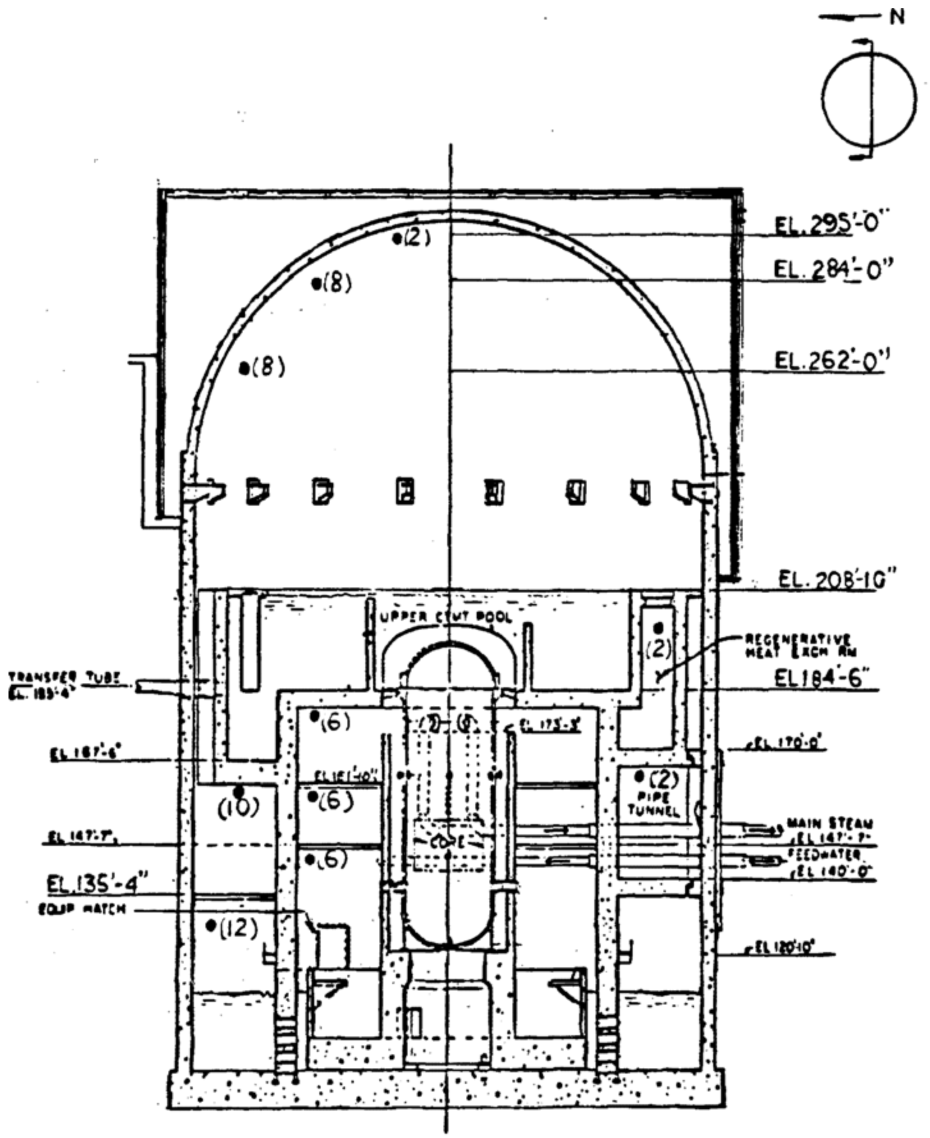
HYDROGEN IGNITER LOCATIONS
EL. 208'-0"

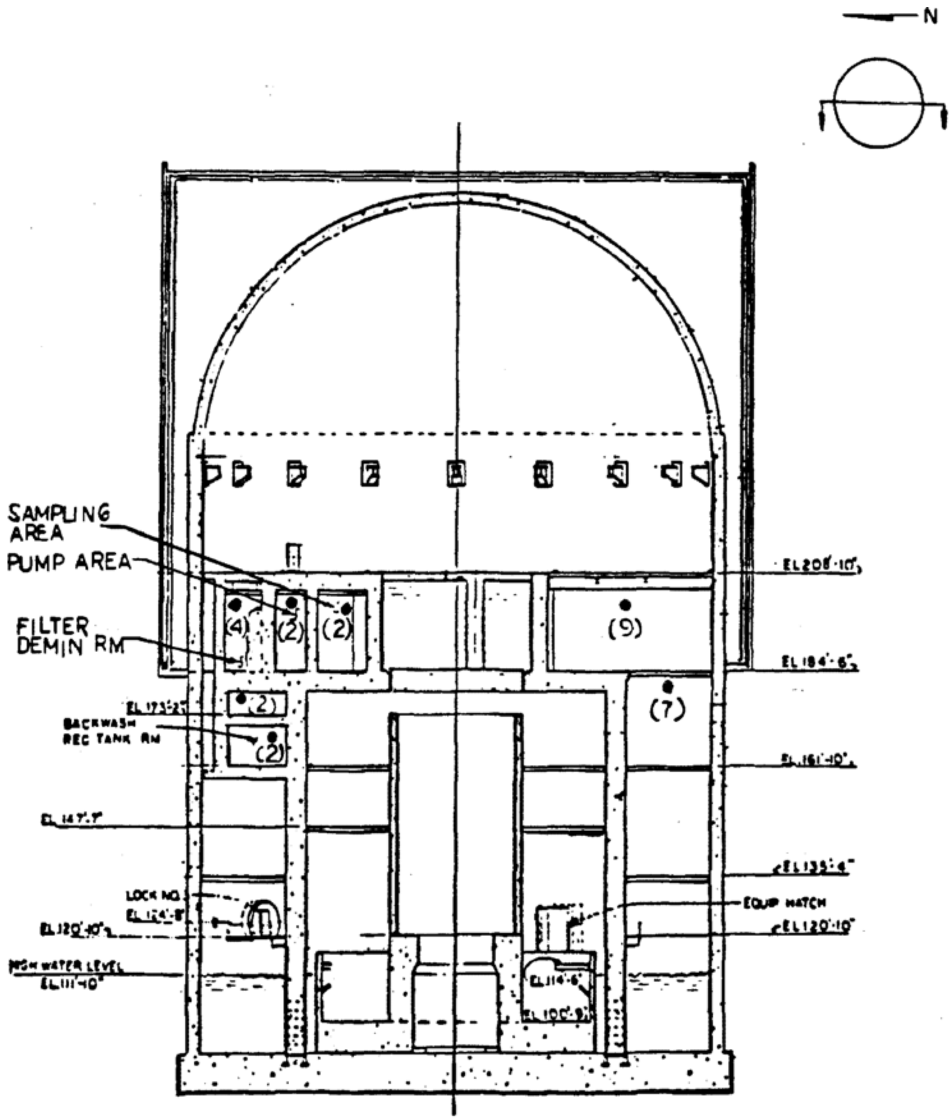
[HISTORICAL INFORMATION]

FIGURE 6.2-88e



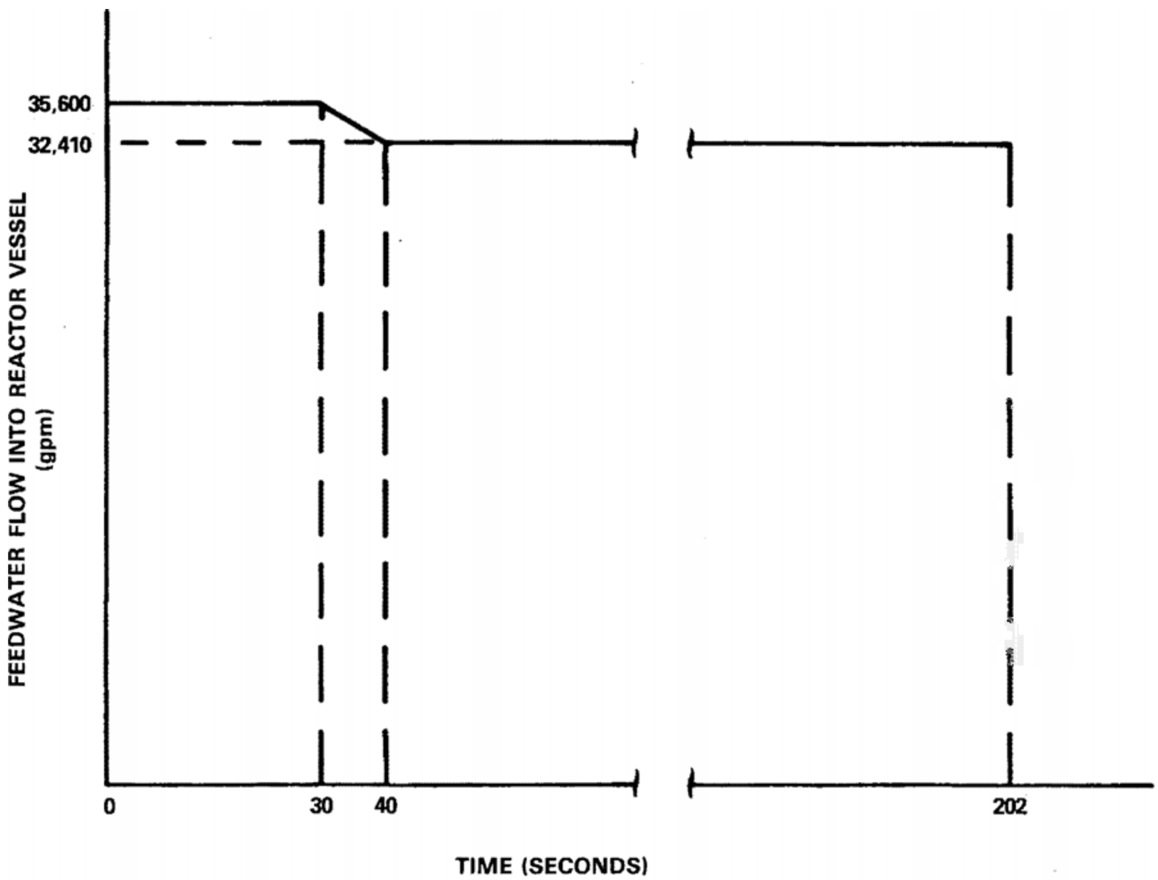
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HYDROGEN IGNITER LOCATIONS
ELEVATION VIEW, LOOKING NORTH
(SHOW APPROXIMATE ELEVATION)
[HISTORICAL INFORMATION]
FIGURE 6.2-88f



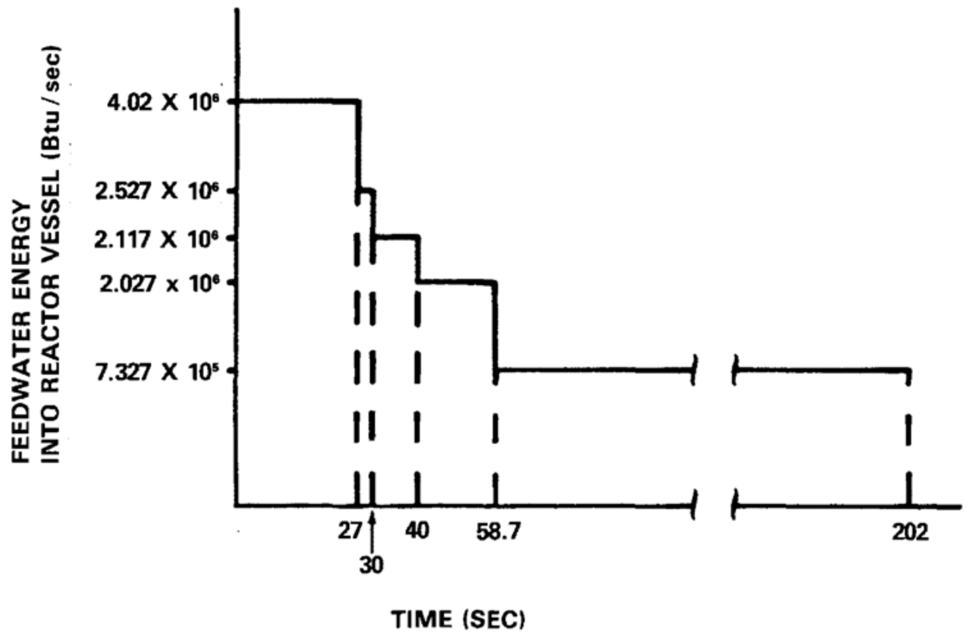
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HYDROGEN IGNITER LOCATIONS
ELEVATION VIEW, LOOKING WEST
(SHOW APPROXIMATE ELEVATION)
[HISTORICAL INFORMATION]
FIGURE 6.2-88g



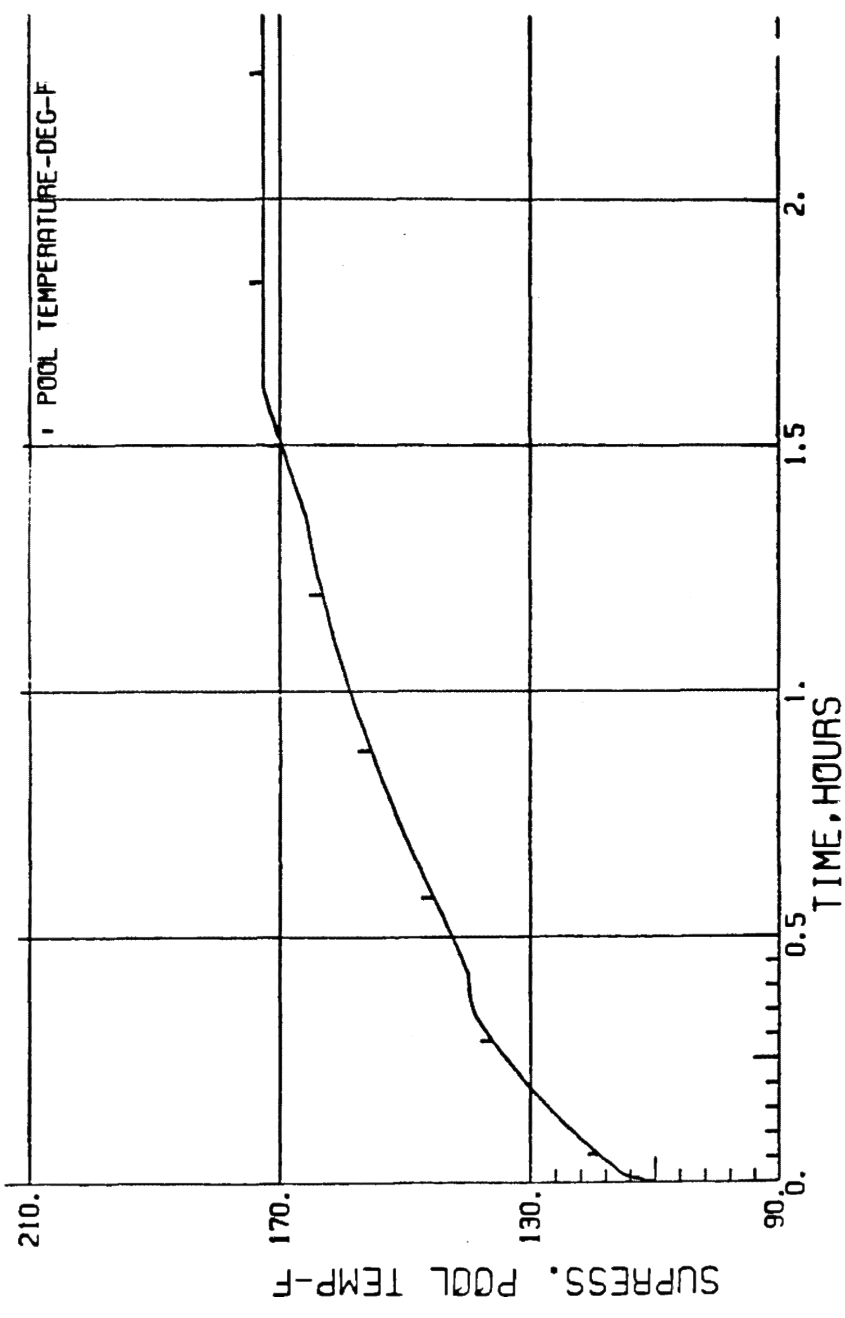
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

FEEDWATER FLOW INTO RPV
FOLLOWING RECIRCULATION LINE
BREAK
[HISTORICAL INFORMATION]
FIGURE 6.2-89



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

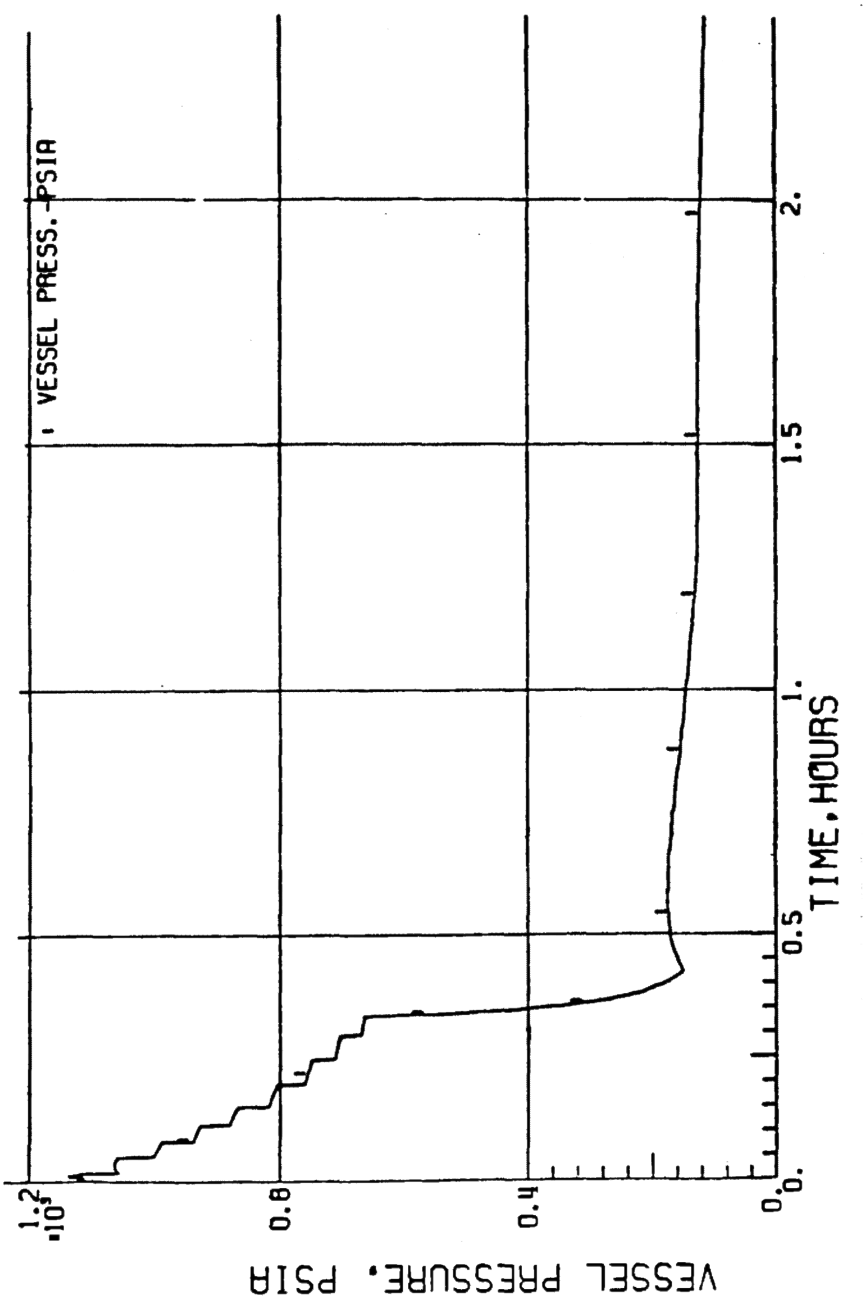
FEEDWATER ENERGY INTO RPV
FOLLOWING RECIRCULATION LINE
BREAK
[HISTORICAL INFORMATION]
FIGURE 6.2-90



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

STUCK OPEN RV CASE (1 RHR)
EVENT 1(a)

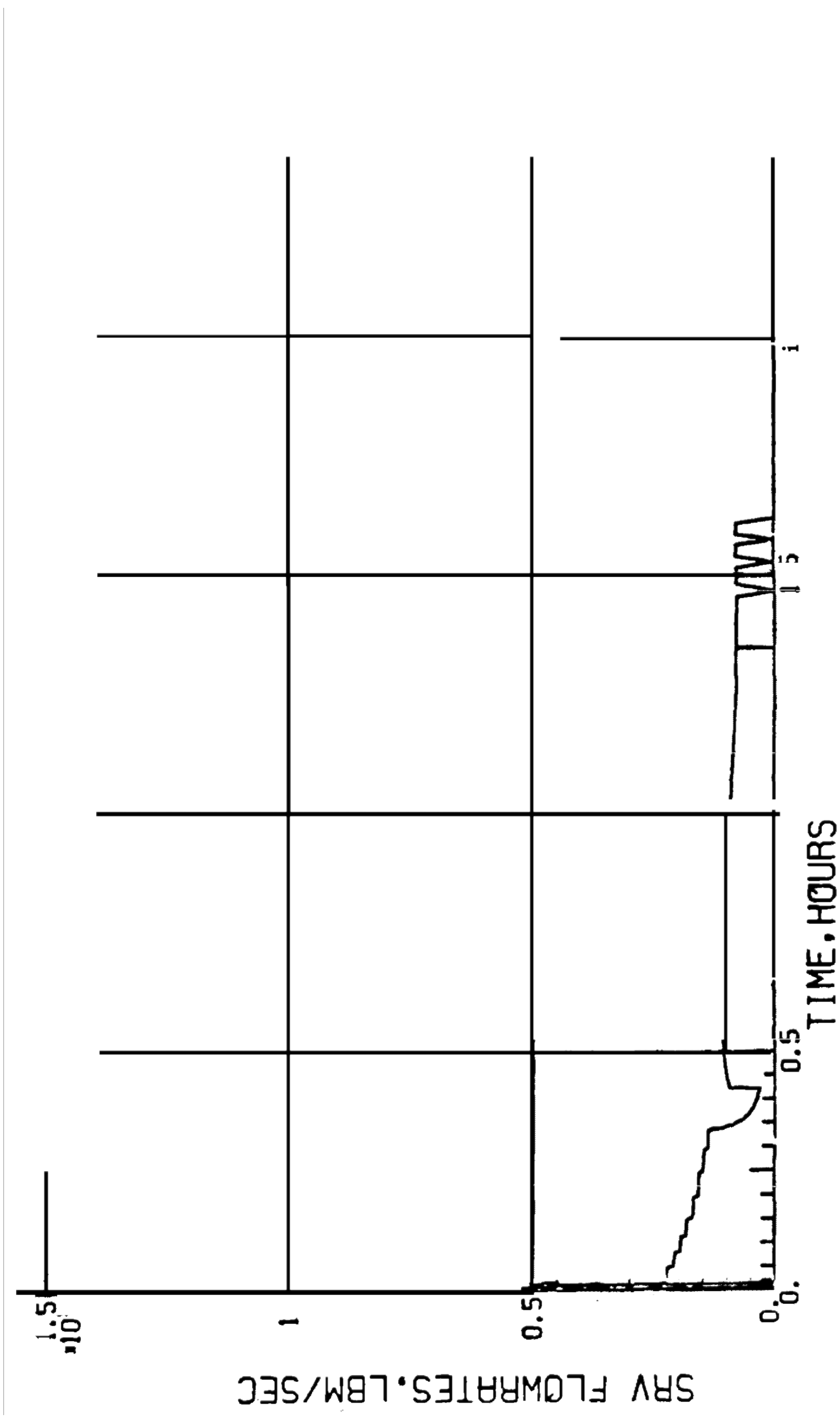
FIGURE 6.2-91



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

STUCK OPEN RV CASE (1 RHR)
EVENT 1(a)

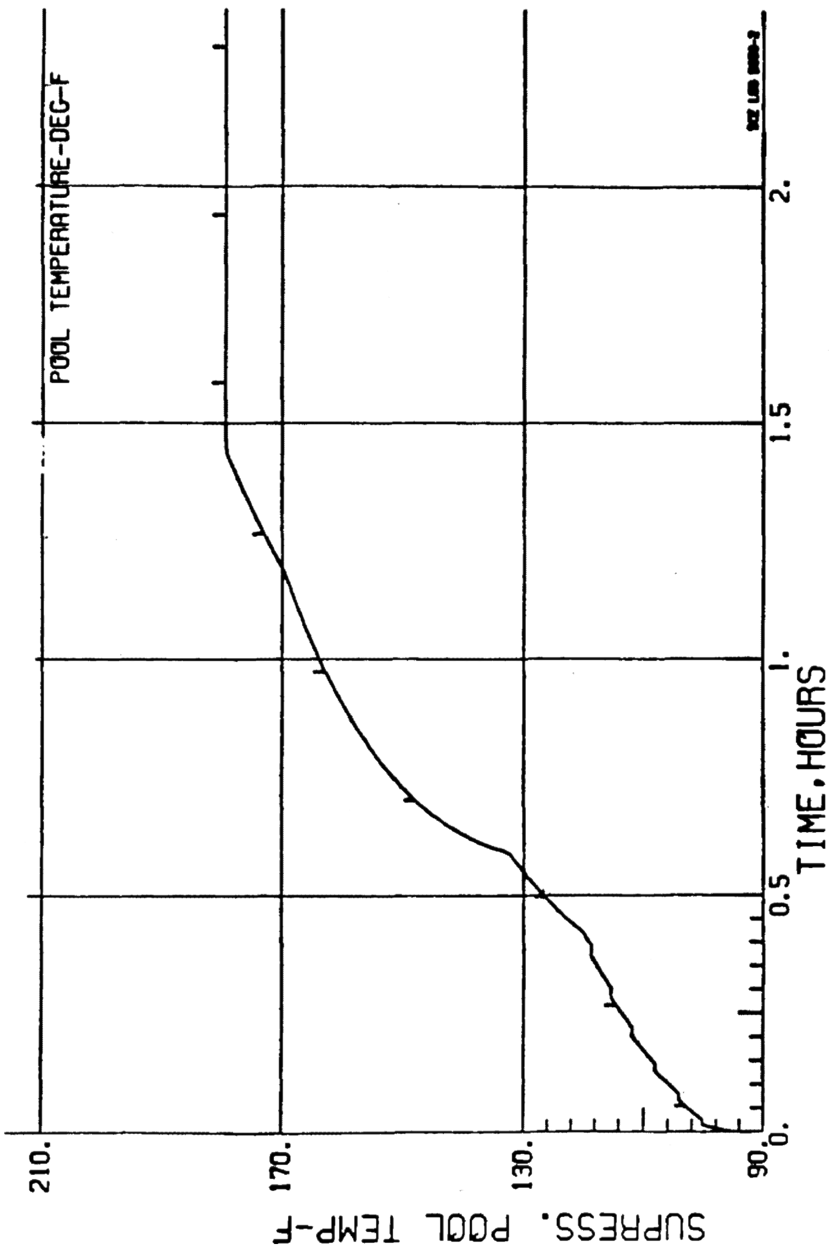
FIGURE 6.2-92



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

STUCK OPEN RV CASE (1RHR)
EVENT 1(a)

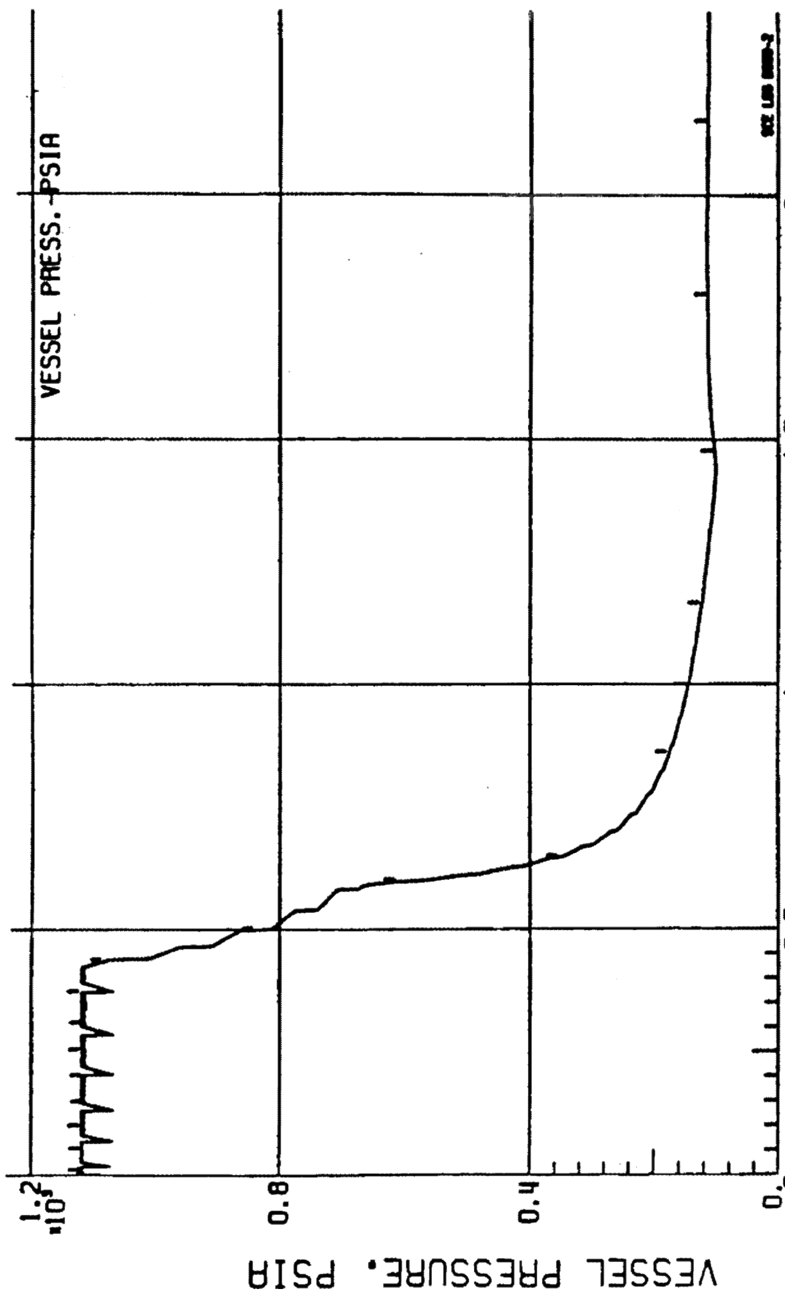
FIGURE 6.2-93



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DEPRESSURIZATION FROM ISOLATION (1 RHR)
EVENT 2(a)

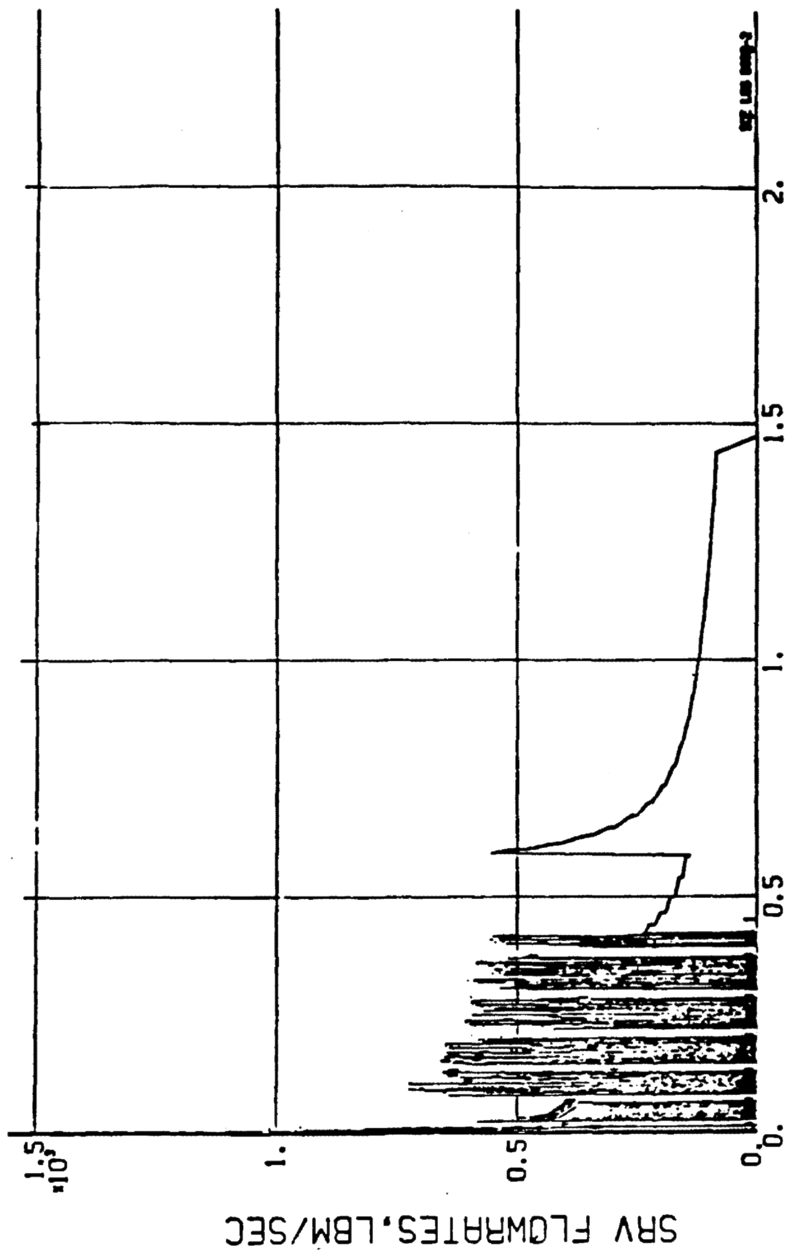
FIGURE 6.2-94



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DEPRESSURIZATION FROM ISOLATION (1 RHR)
EVENT 2(a)

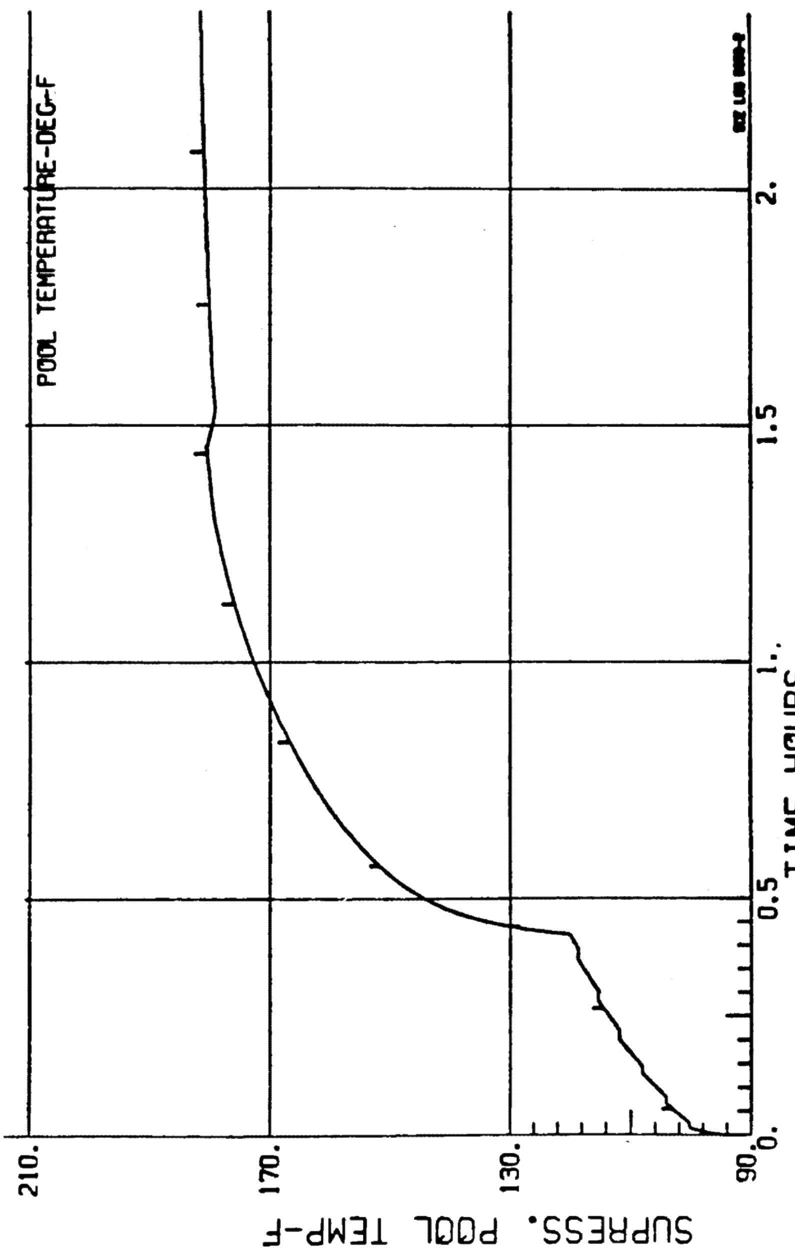
FIGURE 6.2-95



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DEPRESSURIZATION FROM ISOLATION (1 RHR)
EVENT 2(a)

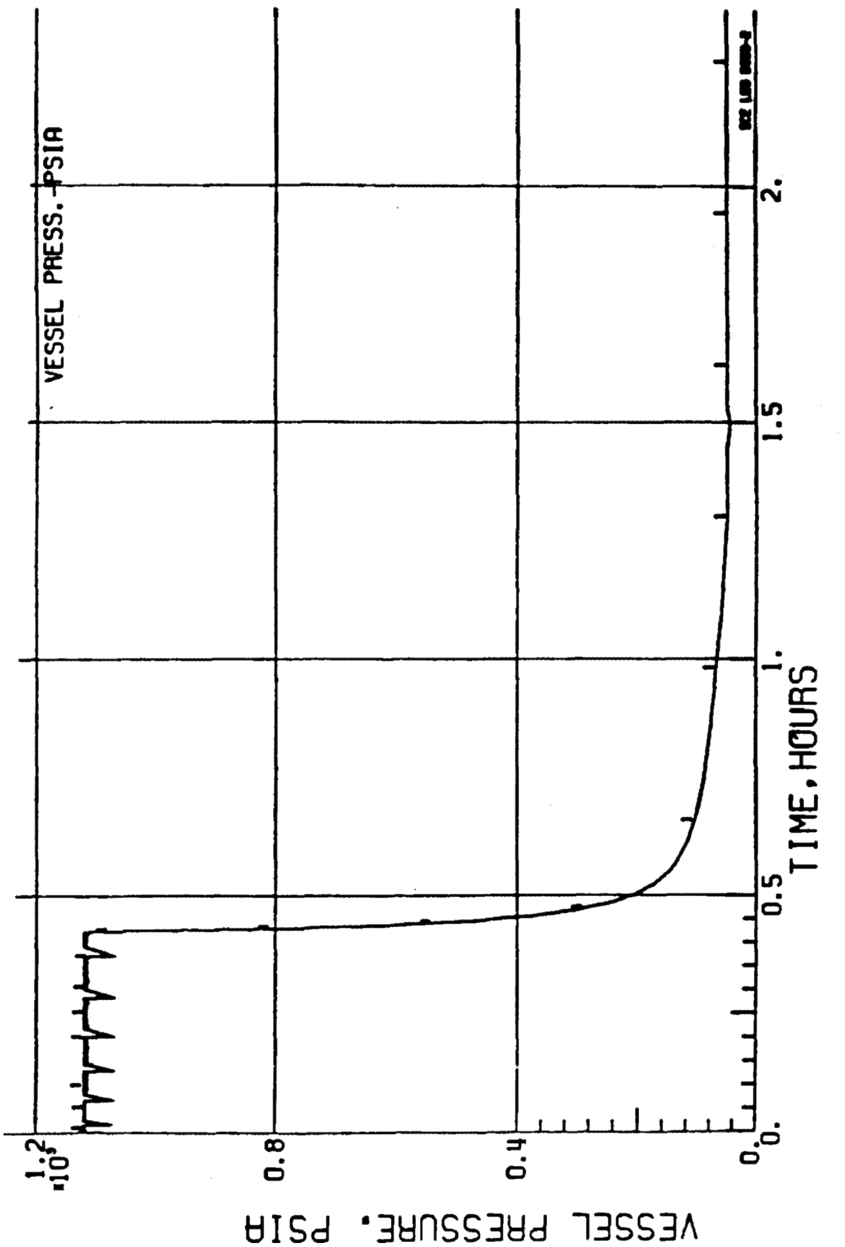
FIGURE 6.2-96



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SMALL BREAK ACCIDENT (1 RHR)
EVENT 3(a)

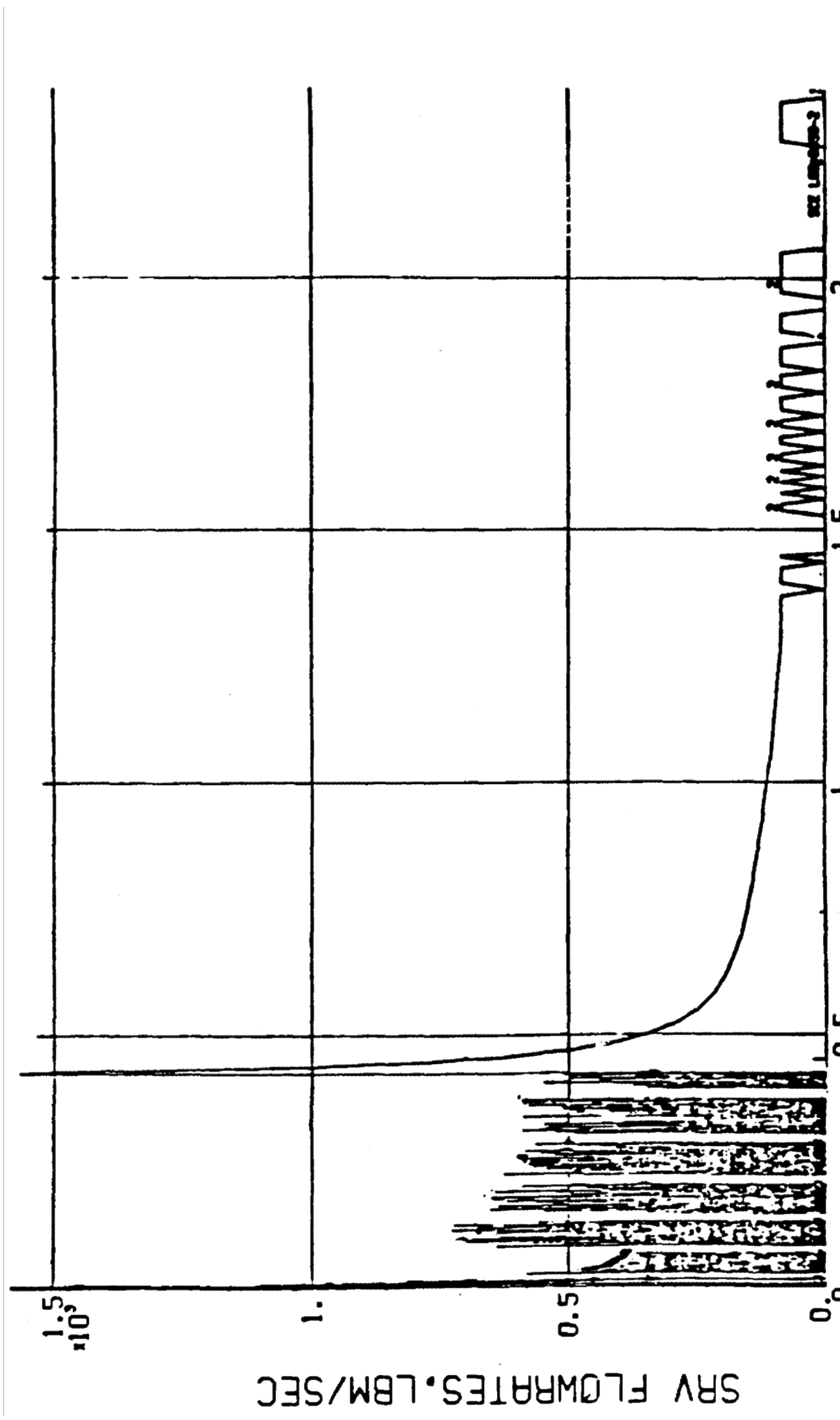
FIGURE 6.2-97



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SMALL BREAK ACCIDENT (1 RHR)
EVENT 3(a)

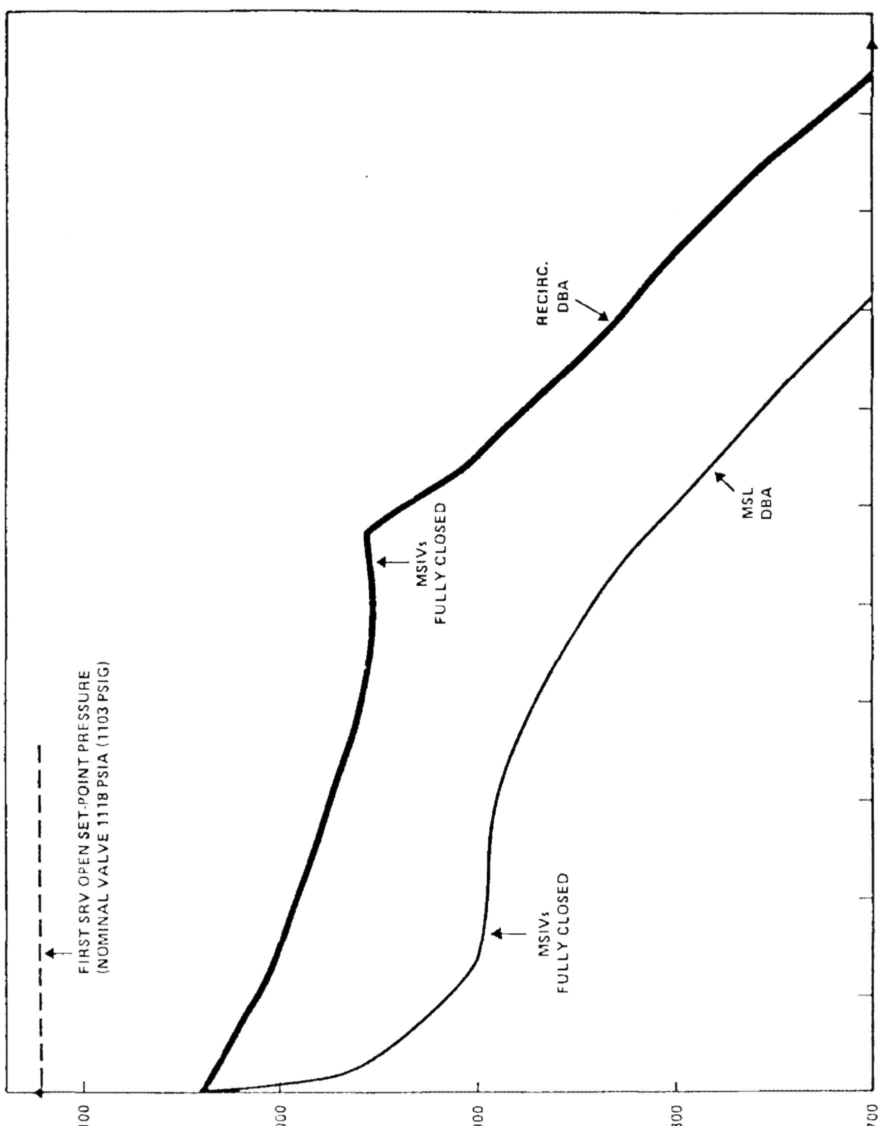
FIGURE 6.2-98



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SMALL BREAK ACCIDENT (1 RHR)
EVENT 3(a)

FIGURE 6.2-99



SYSTEM ENERGY RESOURCES, INC.
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE VS TIME-DBA

FIGURE 6.2-100

6.3 EMERGENCY CORE COOLING SYSTEMS

6.3.1 Design Bases and Summary Description

Subsection 6.3.1 provides the design bases for the emergency core cooling system (ECCS) and a summary description of the several systems as an introduction to the more detailed design descriptions provided in subsection 6.3.2 and the performance analysis provided in subsection 6.3.3.

6.3.1.1 Design Bases

6.3.1.1.1 Performance and Functional Requirements

The ECCS is designed to provide protection against postulated loss-of-coolant accidents (LOCA) caused by ruptures in primary system piping. The functional requirements (for example, coolant delivery rates) specified in detail in Table 6.3-2 are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of Paragraph 50.46, Acceptance Criteria for Emergency Core Cooling System for Light Water Cooled Nuclear Power Reactors, of 10 CFR 50. These requirements, the most important of which is that the post-LOCA peak cladding temperature be limited to 2200 F, are summarized in subsection 6.3.3.2. In addition, the ECCS is designed to meet the following requirements:

a. Protection is provided for any primary steam line break up to and including the double-ended break of the largest line.

b. Two independent phenomenological cooling methods (flooding and spraying) are provided to cool the core.

c. One high-pressure cooling system is provided which is capable of maintaining water level above the top of the core and preventing ADS actuation for breaks of lines less than 1 inch nominal diameter.

d. No operator action is required until 10 minutes after an accident to allow for operator assessment and decision.

e. The ECCS is designed to satisfy all criteria specified in Section 6.3 for reactor operation in modes 1, 2, and 3.

f. A sufficient water source and the necessary piping, pumps and other hardware are provided so that the containment and reactor core can be flooded for possible core heat removal following a loss-of-coolant accident.

6.3.1.1.2 Reliability Requirements

The following reliability requirements apply:

a. The ECCS conforms to all licensing requirements, and good design practices of isolation, separation, and common mode failure considerations.

b. In order to meet the above requirements, the ECCS network has built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. As a minimum, the following equipment makes up the ECCS:

   One high-pressure core spray (HPCS)

   One low-pressure core spray (LPCS)

   Three low-pressure coolant injection (LPCI) loops

   One automatic depressurization system (ADS)

c. The system is designed so that a single active or passive component failure, including power buses, electrical and mechanical parts, cabinets, and/or wiring will not disable the ADS.

d. In the event of a break in a pipe that is part of the reactor coolant pressure boundary, no single active component failure in the ECCS shall prevent automatic initiation and successful operation of less than the following combination of ECCS equipment:

   1. Three LPCI loops, the LPCS and the ADS (i.e., HPCS failure)

   2. Two LPCI loops, the HPCS and the ADS (i.e., “LPCS diesel generator” failure)

   3. One LPCI loop, the LPCS, the HPCS and ADS (i.e., “LPCI diesel generator” failure)

During Operation in Mode 3 below the RHR cut in permissive pressure a reduced complement of ECCS subsystems provide the required core cooling thereby allowing alignment of one LPCI for decay heat removal.

e. In the event of a break in a pipe that is a part of the ECCS, no single active component failure in the ECCS shall prevent automatic initiation and successful operation of less than the following combination of ECCS equipment:

   1. Two LPCI loops and the ADS

   2. One LPCI loop, the LPCS and the ADS

   3. One LPCI loop, the HPCS and the ADS

   4. The LPCS, the HPCS and ADS

   These are the minimum ECCS combinations which result after assuming any failure (from d. above) and assuming that the ECCS line break disables the affected system.

f. Long-term (once level has been recovered and PCT has dropped significantly) cooling requirements call for the removal of decay heat via the standby service water system. In addition to the break which initiated the loss-of-coolant event, the system is able to sustain one failure, either active or passive and still have at least one low-pressure ECCS pump (RHR (LPCI)) operating with a heat exchanger and 100 percent standby service water flow.

g. Offsite power is the preferred source of power for the ECCS network and every reasonable precaution is made to assure its high availability. However, onsite emergency power is provided with sufficient diversity and capacity so that all the above requirements can be met even if offsite power is not available.

h. The onsite diesel fuel reserve is in accordance with IEEE-308 1971 criteria.

i. Diesel-load configuration is as follows:

   1. One LPCI loop (with heat exchanger) and the LPCS connected to a single diesel generator

2. Two additional LPCI loops (one loop with heat exchanger) connected to a single diesel generator

3. The HPCS connected to a single diesel generator

j. Systems which interface with, but are not part of, the ECCS, are designed and operated such that failure(s) in the interfacing systems shall not propagate to and/or affect the performance of the ECCS.

k. Non-ECCS systems interfacing with the ECCS buses shall automatically be shed from and/or be inhibited from the ECCS buses when a LOCA signal exists and off-site ac power is not available.

l. No more than one storage battery is connectible to a dc power bus.

m. Each system of the ECCS including flow rate and sensing networks, is capable of being tested during shutdown. All active components are capable of being tested during plant operation, including logic required to automatically initiate component action.

n. Provisions for testing the ECCS network components (electronic, mechanical, hydraulic, and pneumatic, as applicable) are installed in such a manner that they are an integral and non-separable part of the design.

6.3.1.1.3 ECCS Requirements for Protection from Physical Damage

The emergency core cooling system piping and components are protected against damage from movement, from thermal stresses, from the effects of the LOCA and the safe shutdown earthquake.

The ECCS is protected against the effects of pipe whip, which might result from piping failures that can cause a LOCA. This protection is provided by separation, pipe whip restraints, or energy absorbing materials if required. One of these three methods is applied to provide protection against damage to piping and components of the ECCS which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level. (See Section 3.6.)

The ECCS piping and components located outside the containment are protected from internally and externally generated missiles by the reinforced concrete structure of the auxiliary building ECCS pump rooms. In addition, the watertight construction of the ECCS pump rooms protects against mass flooding of redundant ECCS pumps.

Mechanical separation outside the drywell is achieved as follows:

a. The ECCS shall be separated into three functional groups:

   1. HPCS

   2. LPCS + 1 LPCI + 100 percent standby service water and heat exchanger

   3. 2 (RHR LPCI) pumps + 100 percent standby service water and heat exchanger

b. The equipment in each group is separated from that in the other two groups. In addition, the HPCS and RCIC (which is not part of the ECCS) are separated.

c. Separation barriers are constructed between the functional groups as required to assure that environmental disturbances such as fire, pipe rupture, falling objects, etc., affecting one functional group will not affect the remaining groups. In addition, separation barriers are provided as required to assure that such disturbances do not affect both the RCIC and the HPCS.

6.3.1.1.4 ECCS Environmental Design Basis

The systems of the ECCS have testable check valves in the drywell portions of their respective piping runs. These safety-related, injection/isolation valves are qualified for the abnormal environmental requirements specified in Table 3.11-3. These ECCS valves are installed above the expected flood level in the drywell.

The following ECCS valves in the containment and drywell may be sprayed for periods of less than 5 seconds by the spray associated with pool swell following a DBA; both valves are in the RHR system:

Subsystem	Valve	Elevation	Azimuth
LPCI "A"	F042A	143'-9"	39°
LPCI "B"	F042B	137'-10"	328°

These valves have been provided with a NEMA 4 enclosure for the valve operator and for the position switches. No adverse conditions will exist as a result of the spraying event.

No other ECCS valves in the drywell or containment will experience spraying or submergence following a LOCA.

The outboard isolation valves of the ECCS systems are qualified for the abnormal requirements specified in the EQ files.

The RCIC turbine and the balance of the ECCS equipment (e.g., pumps, motors) are qualified for abnormal environmental requirements specified in the EQ files.

6.3.1.2 Summary Descriptions of ECCS

The ECCS injection network comprises a high-pressure core spray (HPCS) system, a low-pressure core spray (LPCS) system and the low-pressure coolant injection (LPCI) mode of the residual heat removal system. These systems are briefly described here as an introduction to the more detailed system design descriptions provided in subsection 6.3.2. The automatic depressurization system (ADS) which assists the injection network under certain conditions is also briefly described. [HISTORICAL INFORMATION] [Boiling water reactors which employ the same ECCS design are listed in Table 1.3-3.]

6.3.1.2.1 High-Pressure Core Spray

The HPCS pumps water through a peripheral ring spray sparger mounted above the reactor core. Coolant is supplied over the entire range of system operation pressures. The primary purpose of HPCS is to maintain reactor vessel inventory after small breaks which do not depressurize the reactor vessel. HPCS also provides spray cooling heat transfer during breaks in which the core is calculated to uncover.

6.3.1.2.2 Low-Pressure Core Spray

The LPCS is an independent loop similar to the HPCS, the primary difference being the LPCS delivers water over the core at relatively low reactor pressures. The primary purpose of the LPCS is to provide inventory makeup and spray cooling during large breaks in which the core is calculated to uncover. LPCS also provides inventory makeup for small breaks.

6.3.1.2.3 Low-Pressure Coolant Injection

LPCI is an operating mode of the residual heat removal system. Three pumps deliver water from the suppression pool to the bypass region inside the shroud through three separate reactor vessel nozzles. The primary purpose of the LPCI is to provide inventory makeup following large pipe breaks. LPCI also provides inventory makeup for small breaks.

6.3.1.2.4 Automatic Depressurization System

The ADS utilizes a number of the reactor safety/relief valves to reduce reactor pressure during small breaks in the event of HPCS failure. When the vessel pressure is reduced to within the capacity of the low-pressure system (LPCS and LPCI), these systems provide inventory makeup so that acceptable post accident temperatures are maintained.

6.3.2 System Design

A more detailed description of the individual systems, including individual design characteristics of the systems, are covered in detail in subsections 6.3.2.1 through 6.3.2.4. Table 6.3-8 provides a list of significant ECCS design parameters along with their design bases. The following discussion will provide details of the combined systems; in particular, those design features and characteristics which are common to all systems.

6.3.2.1 Schematic Piping and Instrumentation Diagrams

The P&IDs for the ECCS are specified in subsection 6.3.2.2. The flow diagram which identifies the various operating modes of each system is specified in subsection 6.3.2.2. Instrumentation is discussed in detail in Section 7.3. Detailed instrumentation drawings and logic drawings submitted separately to the NRC are listed in Section 1.7.

6.3.2.2 Equipment and Component Descriptions

The diverse starting signal for the ECCS comes from at least two independent and redundant sensors of drywell pressure and low reactor water level. The ECCS is actuated automatically and requires no operator action during the first 10 minutes following the accident. A time sequence for starting of the systems is provided in Table 6.3-1.

Electric power for operation of the ECCS is from normal ac power sources. Upon loss of the normal power, operation is from onsite standby ac power sources. Standby sources have sufficient redundancy and capacity so that all ECCS requirements are satisfied. The HPCS is powered from one ac supply bus. The LPCS and one LPCI are powered from a second ac supply bus and the two remaining LPCIs are powered from a third and separate ac supply bus. The HPCS has its own diesel generator as its alternate power supply. The LPCS and one LPCI loops switch to diesel generator No. 1 and the other two LPCI loops switch to diesel generator No. 2. Section 8.3 contains a more detailed description of the power supplies for the ECCS.

a. Regulatory Guide 1.82, Water Sources for Long-Term Recirculation Cooling Following a Loss-Of-Coolant Accident.

   General Compliance or Alternate Approach Assessment

   The design of the large toroidal passive ECCS/RCIC suction strainer was evaluated against the regulatory positions contained in Reg. Guide 1.82, Rev. 2.

   The ECCS/RCIC suction strainer is designed to preclude the potential for loss of NPSH caused by debris blockage during the period that the ECCS is required to maintain long-term cooling. The large toroidal passive ECCS/RCIC suction strainer results in a very low approach velocity for water entering the strainer. Debris collected on the strainer surface is not expected to compact significantly (due to the very low approach velocity), resulting in minimal head loss. A ¼-scale model of the ECCS/RCIC suction strainer design was tested to confirm the performance of the strainer and the behavior of the postulated debris bed as a function of time after the postulated LOCA. Because the debris bed will not be significantly compacted, flow will continue to pass

through the debris (and the strainer) and thus the overall differential pressure will remain low. Maintaining a low differential pressure will ensure adequate NPSH for the ECCS pumps.

The size of the openings in the ECCS/RCIC suppression pool suction strainer material has been chosen based on the minimum restrictions found in systems served by the suppression pool.

The ECCS pump suctions are designed to prevent degradation of pump performance through air ingestion and other adverse hydraulic effects. All of the suction piping remains below the surface of the suppression pool, and due to the very low approach velocity design of the ECCS/RCIC suction strainer and the depth of the strainer in the pool, vortexing will not be present. The strainer is located at the bottom of the suppression pool, below the elevation of the S/RV quencher arms. Because of the physical size of the strainer, minimal encroachment into the recommended exclusion zone around the quenchers occurs. The ECCS/RCIC suction strainer design is such that any air that may enter the stainer will be released through the strainer mesh before traveling to the pump suction plenums; that is, air entrainment in the strainer will be minimized.

Analyses show that S/RV air bubble contact will not occur even in the worst case second pop event using methodology for determining bubble size and location provided in GE document 22A7000, Rev. 2 (GESSAR II, Appendix 3B; Grand Gulf FSAR, Appendix 6D) and Grand Gulf specific parameters. Therefore, given the design and arrangement of the ECCS/RCIC suction strainer, air ingestion into the strainer and piping system will not occur.

The ECCS/RCIC suction strainer does not involve any modification in the arrangement of drains from upper floors in the containment. In addition, there are no floor or equipment drains from the containment that drain directly into the suppression pool. In addition, the ECCS/RCIC suction strainer is located at the bottom of the suppression pool such that it is highly unlikely that any debris from drains from the upper regions of the containment could impinge directly on the ECCS/RCIC

suction strainer. The Suppression Pool Makeup dump lines discharge upper containment pool water into the suppression pool following a LOCA. The upper containment pools are maintained in a clean condition by operation of the Fuel Pool Cleanup system and through the foreign material exclusion program. Therefore, debris from these lines will be limited to any corrosion products present in the dump lines carried along by the dump flow.

The ECCS/RCIC suction strainer is designed such that its support structure will protect it from the effects of large debris. The ECCS/RCIC suction strainer is designed so that it is capable of withstanding LOCA-induced hydrodynamic loads. GGNS utilizes GE document 22A7000, Rev. 2 (GESSAR II, Appendix 3B; Grand Gulf FSAR, Appendix 6D) methods combined with acoustic methodology which demonstrates that the strainer can withstand the LOCA-induced hydrodynamic loads. Missile protection was evaluated and determined to be of no concern based on the location of the strainer and the postulated missile sources for GGNS.

The ECCS/RCIC suction strainer was evaluated and shown to be able to withstand loads associated with design basis seismic events without loss of structural integrity. In addition, the design incorporates provisions so that bolts do not lose torque during any vibratory motion, and incorporates restraints to preclude radial movement of the strainer.

ASTM Type 304 stainless steel is used as the primary material for the ECCS/RCIC suction strainer to prevent corrosive degradation during periods of inactivity and normal operation.

GGNS has established a containment cleanliness program for the control of foreign materials, and other programs to minimize the potential for strainer fouling from operations generated debris.

GGNS takes no credit for LOCA generated debris hold up in the drywell, and the design does not include debris interceptors of any kind.

The ECCS/RCIC suction strainer design requires no operator actions in response to debris accumulations or to otherwise assure availability of adequate NPSH for the ECCS pumps. Accordingly, no additional safety-related instrumentation is required.

The design of the ECCS/RCIC suction strainer is passive.

GGNS conducts inspections during refueling outages to evaluate the cleanliness of the suppression pool. The ECCS/RCIC suction strainer is periodically monitored by visual inspection for evidence of structural degradation or debris fouling. The frequency of suppression pool inspection and cleaning activities is determined based on plant specific debris collection data.

The large toroidal passive ECCS/RCIC suction strainer does not require operator actions to prevent the accumulation of debris on the strainer or to mitigate the consequences of debris accumulation. The design of the strainer provides sufficient area to accommodate the maximum quantity of debris that is expected to be produced following a design basis LOCA combined with postulated in-situ debris quantities. The Emergency Procedures contain guidance to the operator on the use of alternate water sources to provide a diverse means of providing long-term cooling to the core.

See UFSAR Section 6.2.2.2 for a discussion of the ECCS/RCIC suction strainer compliance with Reg. Guide 1.82 as it pertains to debris generation and transport.

NPSH available to the ECCS pumps has been determined in accordance with Reg. Guide 1.1. Pressure drop across the ECCS/RCIC suction strainer is based on results from testing and conservative analysis. The vapor pressure for suppression pool water used in NPSH calculations for events where significant debris generation is expected is based on a suppression pool bulk water temperature of 194°F provides 5°F of design margin to the highest calculated debris-generating event suppression pool temperature of 189°F. For events in which no significant debris generation is expected, NPSHA is evaluated for

212°F suppression pool water temperature. Containment pressure is assumed to be atmospheric in accordance with Reg. Guide 1.1 requirements.

Tests have quantified head loss caused by debris blockage on the ECCS/RCIC suction strainer. Head loss measured during the testing accounts for the filtration of particulates by the debris bed. Tests were conducted to determine the performance characteristics of the passive strainer for the quantities and types of debris predicted following postulated accidents.

6.3.2.2.1 High-Pressure Core Spray (HPCS) System

The high-pressure core spray (HPCS) system consists of a single motor driven centrifugal pump located outside the primary containment, a spray sparger in the reactor vessel located above the core (separate from the LPCS sparger), and associated system piping, valves, controls, and instrumentation. The system is designed to operate from normal offsite auxiliary power or from its diesel generator supply if offsite power is not available. The piping and instrumentation diagram, Figure 6.3-1 for the HPCS, shows the system components and their arrangement. The HPCS system flow diagram, Figure 6.3-2, shows the design operating modes of the system and injection into the reactor vessel.

The principal active HPCS equipment is located outside the primary containment. Suction piping is provided from the condensate storage tank and the suppression pool. Such an arrangement provides the capability to use reactor grade water from the condensate storage tank when the HPCS system functions to backup the RCIC system. In the event that the condensate storage water supply becomes exhausted or is not available, automatic switchover to the suppression pool water source will assure a closed cooling water supply for continuous operation of the HPCS system. HPCS pump suction is also automatically transferred to the suppression pool if the suppression pool water level exceeds a prescribed value. The CST level is normally maintained above 25 ft and has a low level alarm at 22 ft. Standpipes inside the CST ensure that the non-safety systems cannot draw the CST below an 18.9 ft indicated level. The remainder of the CST volume is reserved specifically for RCIC and HPCS.

After the HPCS injection piping enters the vessel, it divides and enters the shroud at two points near the top of the shroud. A semicircular sparger is attached to each outlet. Nozzles are spaced around the spargers to spray the water radially over the core and into the fuel assemblies.

The HPCS discharge line to the reactor is provided with two isolation valves. One of these valves is an air testable check valve located inside the drywell as close as practical to the reactor vessel. HPCS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during LOCA). If the HPCS line should break outside the containment, the check valve in the line inside the drywell will prevent loss of reactor water outside the containment. The other isolation valve (which is also referred to as the HPCS injection valve) is a motor-operated gate valve located outside the primary containment as close as practical to HPCS discharge line penetration into the containment. This valve is capable of opening with the maximum differential across the valve expected for any system operating mode including HPCS pump shutoff head. This valve is normally closed to back up the inside testable check valve for containment integrity purposes. A drain line is provided between the two valves. The test connection line is normally closed with two valves to assure containment integrity.

Remote controls for operating the motor-operated components and diesel generator are provided in the plant control room. The controls and instrumentation of the HPCS system are described, illustrated, and evaluated in detail in Chapter 7, Control and Instrumentation.

The location and type of the manual valves in the HPCS system are detailed in Table 6.3-9 (see also Figure 6.3-1). Design considerations have been given to protect the system's safety functions from an undetected, incorrect positioning of any of these manual valves. Administrative controls likewise serve to minimize the possibility of such errors. These design/operations features are outlined in the table (see also subsection 6.3.2.8).

The position of each manually operated valve will be identified in a valve lineup sheet. System operating instructions will require that the valve lineup be completed before the system can be considered operable. For safety-related systems/components, this

lineup will have independent verification. Where appropriate, valves will be locked in the designated position to prevent inadvertent repositioning.

If valve positions are to be changed for surveillance purposes, the surveillance procedure will have steps requiring return to normal valve lineup prior to completion. Start and completion status of surveillance procedures will be available to control room personnel and will be maintained by the operator at the controls or by the Control Room Supervisor.

If maintenance is performed on a safety-related system that requires any valve position to be changed from that specified in the valve lineup, the following sequence will occur:

a. The request for the valve position change will be approved by the Control Room Supervisor before it is implemented.

   o The Control Room Supervisor will assure that Technical Specifications are met before approving the change.

b. A list of valves and/or boundaries of valves so changed will be kept in a file or logbook accessible to all Control Room Supervisors.

   o The change in status of any safety-related system from operable to inoperable or vice versa will be logged in a logbook that will be reviewed by each oncoming operator at the controls and by the Control Room Supervisor.

c. When work has been completed, the order to return all valves to their previous position will be approved by the Control Room Supervisor.

d. The Control Room Supervisor will not consider the system operable until all valves identified within the boundaries of the maintenance activities have been returned to the position specified in the valve lineup and written evidence to this effect has been presented to him.

If valve position in the ECCS are changed for operational purposes (venting, filling, rotation of equipment, etc.), these changes will be made in accordance with procedures having similar adequate administrative controls to assure that:

a. Valves will be returned to the valve lineup position before the operational activity has been completed, or

b. Valve positions not in accordance with the valve lineup are known by the Control Room Supervisor.

The system is designed to pump water into the reactor vessel over a wide range of pressures. For small breaks that do not result in rapid reactor depressurization, the system maintains reactor water level and depressurizes the vessel. For large breaks the HPCS system cools the core by a spray.

If a loss-of-coolant accident should occur, a low water level signal or a high drywell pressure signal initiates the HPCS and its support equipment. However, the LOCA analyses conservatively credit only the low water level signal for HPCS initiation. The system can also be placed in operation manually. When at low reactor pressure (at or below 600 psig) an artificially high-water level (Level 8) trip may result in the closing of the HPCS injection valve thus causing HPCS isolation when the actual vessel level is below the high-water level setpoint. This condition results in the high drywell pressure and manual initiation signals to the HPCS injection valve being inhibited. The isolation logic may be manually reset once the indicated vessel level drops below the high-water level setpoint or it will reset automatically when the indicated vessel level reaches the low-water level (Level 2). At this level the HPCS initiation logic is actuated.

The HPCS system is capable of delivering rated flow into the reactor vessel within 32 seconds following receipt of an automatic initiation signal.

When a high-water level in the reactor vessel is signaled, the HPCS is automatically stopped by a signal to the injection valve to close. Unless a high reactor water level signal exists, HPCS injection will continue until manually stopped. The HPCS system also serves as a backup to the RCIC system in the event the reactor becomes isolated from the main condenser during operation and feedwater flow is lost.

If normal auxiliary power is not available, the HPCS pump motor is driven by its own onsite power source. The HPCS standby power source is discussed in Section 8.3.

[HISTORICAL INFORMATION] [The HPCS system head flow characteristic assumed in the initial cycle LOCA analyses is shown in Figure 6.3-3.] The current LOCA analyses use a more conservative flow characteristic curve (Ref. 11, Ref. 13). When the system is started, initial flow rate is established by primary system pressure. As vessel pressure decreases, flow will increase. When vessel pressure reaches 200 psid*, the system reaches rated core spray flow. The HPCS motor size is based on peak horsepower requirements.

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*psid = differential pressure between the reactor vessel and the suction source

The elevation of the HPCS pump is below the water level of both the condensate storage tank and the suppression pool. This assures a flooded pump suction. When the system senses a low water level in the condensate storage tank (setpoint of 5.0 ft), the HPCS pump suction automatically transfers from this tank to the suppression pool. The actual water level in the tank at this point, however, is considerably greater than 5.0 ft due to system piping losses between the CST and the level transmitter which initiates suction transfer. At the time immediately preceding switchover, the available NPSH is approximately 46 feet (conservatively ignoring higher transfer due to piping losses). The required NPSH for the HPCS pump, as shown on Figure 6.3-67, is 2 feet. Air entrainment in the condensate storage tank suction is precluded by a 4'X 4' horizontal plate vortex breaker at the suction inlet and by maintaining at least 5.33 feet actual submergence over the inlet in the design basis scenario throughout the suction transfer transient.

Pump NPSH requirements are met by providing adequate suction head and suction line size. The available NPSH, calculated in accordance with Regulatory Guide 1.1, is based on the following design conditions:

a. Pump design maximum runout flow of 8175 gpm

b. Atmospheric containment pressure

c. Maximum suppression pool water temperature of 194°F

d. Suppression pool minimum design water level at El. 107'-6"

e. HPCS pump suction piping arrangement, as shown on Figure 6.3-68

f. Suction strainer fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials) (refer to subsection 6.2.2.2 for strainer pressure drop)

The minimum NPSH requirement is, as specified by the manufacturer, to be evaluated at a point 3 feet above the top of the pump mounting flange (this reference point is 4.75 inches above the pump suction nozzle center line). The calculated minimum available NPSH for the HPCS pump is 6.1 feet (6.5 feet at pump suction nozzle) which exceeds the required NPSH of 2 feet. The HPCS pump characteristics are shown on Figure 6.3-67. During cold shutdown and refueling modes, the Technical Specifications allow the suppression pool water level to be lowered to 105'-8" elevation. NPSH calculations for this condition, assuming a fluid temperature of 125 F, maximum pump flow rate, minimum containment pressure (atmospheric), suction line losses, and the maximum pressure drop across the suction strainers, corresponding to the strainers fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials), determined the available NPSH at the manufacturer's reference point to be 23 feet. The available NPSH exceeds the required NPSH of 2 feet. Detailed NPSH calculations are provided in Appendix 6E.

A motor-operated valve is provided in the suction line from the suppression pool. The valve is located as close to the suppression pool penetration as practical. This valve is used to isolate the suppression pool water source when HPCS system suction is from the condensate storage system and to isolate the system from the suppression pool in the event a leak develops in the HPCS system.

The HPCS pump characteristics, head, flow, horsepower, and required NPSH are shown in Figure 6.3-67.

The design pressure and temperature of the system components are established based on the ASME Section III Boiler and Pressure Vessel Code.

A check valve, flow element and restricting orifice are provided in the HPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve

can be maintained full of water by the discharge line fill system (see subsection 6.3.2.2.5). The flow element is provided to measure system flow rate during LOCA and test conditions and for automatic control of the minimum low-flow bypass gate valve. The measured flow is indicated in the main control room. The restricting orifice is sized during pre-operational test of the system to limit system flow to acceptable values as described on the HPCS system flow diagram.

A low-flow bypass line with a motor-operated gate valve connects to the HPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage due to overheating when other discharge line valves are closed. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

To assure continuous core cooling, signals to isolate the containment do not operate any HPCS valves.

The HPCS system incorporates relief valves to protect the components and piping from inadvertent overpressure conditions. One relief valve, set at 1560 psig with a required capacity of 10 gpm, is located on the discharge side of the pump downstream of the check valve to relieve thermally expanded fluid. A second relief valve is located on the suction side of the pump and is set at 100 psig with a capacity equal to 10 gpm - 10 percent accumulation. The basis for the HPCS discharge line relief valve sizing is thermal expansion since the pipe design pressure is higher than that for the primary system. The suction relief valve is sized to provide protection from backleakage (as in LPCS). The rated capacity and maximum set point pressure for each valve are given in Table 6.3-9a.

The Standby Liquid Control System (SLCS) injects into the HPCS discharge line downstream of the HPCS injection check valve. This injection point provides for a lower system pressure drop than the injection via the SLCS sparger and allows adequate mixing of the sodium pentaborate solution during SLCS injection.

The HPCS components and piping are positioned to avoid damage from the physical effects of design-basis accidents, such as pipe whip, missiles, high temperature, pressure, and humidity.

The HPCS equipment and support structures are designed in accordance with seismic Category I criteria (see Chapter 3). The system is assumed to be filled with water for seismic analysis.

Provisions are included in the HPCS system which permit the HPCS system to be tested. These provisions are:

a. All active HPCS components are testable during normal plant operation.

b. A full-flow test line is provided to route water from and to the condensate storage tank without entering the reactor pressure vessel. The suction line from the condensate tank also provides reactor grade water to fully test the HPCS including injection into the RPV during shutdown.

c. A full-flow test line is provided to route water from and to the suppression pool without entering the reactor pressure vessel.

d. Instrumentation is provided to indicate system performance during normal test operations.

e. All motor-operated valves are capable of either local or remote manual operation for test purposes.

f. System relief valves are removable for bench-testing during plant shutdown.

6.3.2.2.2 Automatic Depressurization System (ADS)

If the RCIC and HPCS cannot maintain the reactor water level, the automatic depressurization system, which is independent of any other ECCS, reduces the reactor pressure so that flow from LPCI and LPCS systems enters the reactor vessel in time to cool the core and limit fuel cladding temperature.

The ADS actuation logic includes a timer actuated bypass of the high drywell pressure trip. (See Subsections 18.1.30.6 and 7.3.1.1 for description and discussion.) This logic provides for automatic ADS initiation for pipe breaks outside containment and eliminates the requirement for operator action. For such breaks, the LOCA analysis assumptions take no credit for the feedwater system or the RCIC system, and the HPCS system is assumed to fail (worst single failure). Following a delay period which allows the

timers to run out, the ADS will automatically depressurize the vessel below the shutoff head of the low-pressure ECC systems, allowing these systems to terminate the transient.

The automatic depressurization system employs nuclear system pressure relief valves to relieve high-pressure steam to the suppression pool. The design, number, location, description, operational characteristics, and evaluation of the pressure relief valves are discussed in detail in subsection 5.2.2. The operation of the ADS is discussed in subsection 7.3.1.1.1.4.

6.3.2.2.3 Low Pressure Core Spray (LPCS) System

The low-pressure core spray system consists of: a centrifugal pump that can be powered by normal auxiliary power or the standby ac power system; a spray sparger in the reactor vessel above the core (separate from the HPCS sparger); piping and valves to convey water from the suppression pool to the sparger; and associated controls and instrumentation. Figure 6.3-4, the LPCS system P&ID, presents the system components and their arrangement. The LPCS system flow diagram, Figure 6.3-5, shows the design operating modes of the system.

When low-water level in the reactor vessel or high-pressure in the drywell is sensed, and with reactor vessel pressure low enough, the low-pressure core spray system automatically starts and sprays water into the top of the fuel assemblies to cool the core. The LPCS injection piping enters the vessel, divides, and enters the core shroud at two points near the top of the shroud. A semicircular sparger is attached to each outlet. Nozzles are spaced around the sparger to spray the water radially over the core and into the fuel assemblies.

The LPCS is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCS operates in conjunction with the ADS, then the effective core cooling capability of the LPCS is extended to all break sizes because the ADS will rapidly reduce the reactor vessel pressure to the LPCS operating range. The system head flow characteristic assumed for the initial cycle LOCA analyses is shown in Figure 6.3-6. The current LOCA analyses use a more conservative flow characteristic curve (Ref. 11, Ref. 13).

The low-pressure core spray pump and all motor-operated valves can be operated individually by manual switches located in the control room. Operating indication is provided in the control room by a flowmeter and valve indicator lights.

The location and type of the manual valves in the LPCS system are detailed in Table 6.3-10 (see also Figure 6.3-4). Design considerations have been given to protect the system's safety functions from an undetected, incorrect positioning of any of these manual valves. Administrative controls likewise serve to minimize the possibility of such errors. These design/operations features are outlined in the Table (see also subsections 6.3.2.2.1 and 6.3.2.8).

To assure continuity of core cooling, signals to isolate the containment do not operate any low-pressure core spray system valves.

The LPCS discharge line to the reactor is provided with two isolation valves. One of these valves is an air testable check valve located inside the drywell as close as practical to the reactor vessel. LPCS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during LOCA). If the LPCS line should break outside the containment the check valve in the line inside the drywell will prevent loss of reactor water outside the containment.

The other isolation valve (which is also referred to as the LPCS injection valve) is a motor-operated gate valve located outside the primary containment as close as practical to LPCS discharge line penetration into the containment. This valve is capable of opening with the maximum differential across the valve expected for any system operating mode. The valve is capable of opening against a differential pressure equal to normal reactor pressure minus the minimum LPCS system shutoff pressure. This valve is normally closed to back up the inside testable check valve for containment integrity purposes. A drain line is provided between the two valves. The test connection line is normally closed with two valves to assure containment integrity.

The LPCS system components and piping are arranged to avoid unacceptable damage from the physical effect of design-basis accidents, such as pipe whip, missiles, high temperature, pressure, and humidity.

All principal active LPCS equipment is located outside the primary containment.

A check valve, flow element and restricting orifice are provided in the LPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system (see subsection 6.3.2.2.5). The flow element is provided to measure system flow rate during LOCA and test conditions and for automatic control of the minimum low-flow bypass gate valve. The measured flow is indicated in the control room. The restricting orifice is sized during pre-operation test of the system to limit system flow to acceptable values as described on the LPCS system flow diagram.

The LPCS pump (pump performance test results) characteristics, head, flow, horsepower, and required NPSH are shown in Figure 6.3-69.

A low-flow bypass line with a motor-operated gate valve connects to the LPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage due to overheating when other discharge line valves are closed or reactor pressure is greater than the LPCS system discharge pressure following system initiation. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

LPCS flow passes through a motor-operated pump suction valve that is normally open. This valve can be closed by a remote manual switch (located in the control room) to isolate the LPCS system from the suppression pool should a leak develop in the system. This valve is located in the core spray pump suction line as close to the suppression pool penetration as practical. Because the LPCS conveys water from the suppression pool, a closed loop is established for the spray water escaping from the break. Volume in the suppression pool during accident conditions is discussed in subsection 6.2.1.1.

The design pressure and temperature of the system components are established based on the ASME Section III Boiler and Pressure Vessel Code.

The LPCS pump is located in the auxiliary building below the water level in the suppression pool to assure positive pump suction. Pump NPSH requirements are met with the containment at atmospheric pressure. A pressure gauge is provided to indicate the suction head.

The available NPSH, calculated in accordance with Regulatory Guide 1.1, is based on the following design conditions:

a. Pump design maximum runout flow of 9100 gpm

b. Atmospheric containment pressure

c. Maximum suppression pool water temperature of 194 F

d. Suppression pool minimum design water level at El. 107'6"

e. LPCS pump suction piping arrangement, as shown on Figure 6.3-70

f. Suction strainer fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials) (refer to subsection 6.2.2.2 for strainer pressure drop)

The minimum NPSH requirement is, as specified by the manufacturer, to be evaluated at the center-line of the pump suction nozzle. The calculated minimum available NPSH for the LPCS pump is 4.49 feet which exceeds the required NPSH of 2 feet. The LPCS pump characteristics are shown on Figure 6.3-69. During cold shutdown and refueling modes, the Technical Specifications allow the suppression pool water level to be lowered to 105'-8" elevation. NPSH calculations for this condition, assuming a fluid temperature of 125 F, maximum pump flow rate, minimum containment pressure (atmospheric), suction line losses and the maximum pressure drop across the suction strainers, corresponding to the strainers fully loaded (i.e., conservatively specified debris loading resulting from LOCA-generated and pre-LOCA debris materials), determined the available NPSH to be 22.3 feet at the pump suction nozzle which exceeds the required NPSH of 2 feet. Detailed NPSH calculations are provided in Appendix 6E.

The LPCS system incorporates relief valves to prevent the components and piping from inadvertent overpressure conditions. One relief valve, located on the pump discharge, is set at 584 psig with capacity of 100 gpm - 10 percent accumulation. The

second relief valve is located on the suction side of the pump and is set for 100 psig at a capacity equal to 10 gpm - 10 percent accumulation. The basis for the LPCS discharge line relief valve sizing is protection of the low pressure line due to leakage from the reactor.

The basis for the sizing of the LPCS suction relief valve is backleakage from the reactor past several closed gate and check valves when the suction line is isolated and the minimum flow valve is closed. The rated capacity and maximum set point pressure for each valve are given in Table 6.3-9a.

The LPCS system piping and support structures are designed in accordance with seismic Category I criteria (see Chapter 3). The system is assumed to be filled with water for seismic analysis.

Provisions are included in the LPCS system which permit the LPCS system to be tested. These provisions are:

a. All active LPCS components are testable during normal plant operation.

b. A full-flow test line is provided to route water from and to the suppression pool without entering the reactor pressure vessel.

c. A suction test line supplying reactor grade water is provided to test pump discharge into the reactor pressure vessel during normal plant shutdown.

d. Instrumentation is provided to indicate system performance during normal and test operations.

e. All motor-operated valves and check valves are capable of operation for test purposes.

f. Relief valves are removable for bench-testing during plant shutdown.

6.3.2.2.4 Low-Pressure Coolant Injection (LPCI) Subsystem

The low-pressure coolant injection subsystem is one of three independent operating subsystems of the RHR system. The LPCI subsystem is automatically actuated by low water level in the reactor or high pressure in the drywell and uses the three RHR motor-driven pumps to draw suction from the suppression pool and

inject cooling water flow into the reactor core and accomplish cooling of the core by flooding. Each loop has its own suction and discharge piping and separate vessel nozzle which connects with the core shroud through the LPCI couplings to deliver flooding water near the top of the core. The system is a high-volume core flooding system.

The LPCI system, like the LPCS system, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCI operates in conjunction with the ADS, the effective core cooling capability of the LPCI is extended to all break sizes because the ADS will rapidly reduce the reactor vessel pressure to the LPCI operating range. [HISTORICAL INFORMATION] [The head flow characteristics assumed in the initial cycle LOCA analyses for the LPCI pumps are shown in Figure 6.3-7.] The current LOCA analyses use a more conservative flow characteristic curve (Ref. 11, Ref. 13).

Figures 5.4-18 and 5.4-19 show a flow diagram (and flow data) of the RHR system. The LPCI subsystem flowpath is presented in these figures. The RHR pumps receive power from ac power buses having standby power source backup supply. Two RHR pump motors and the associated automatic motor-operated valves receive ac power from one bus, while the LPCS pump and the other RHR pump motor and valves receive power from another bus (see Section 8.3).

The pump, piping, controls, and instrumentation of the LPCI loops are separated and protected so that any single physical event, or missiles generated by rupture of any pipe in any system within the drywell, cannot make all loops inoperable.

To assure continuity of core cooling, signals to isolate the primary containment do not operate any RHR system valves which interfere with the LPCI mode of operation.

The LPCI discharge line to the reactor is provided with two isolation valves. The valve inside the drywell is a testable check valve and the valve outside the drywell is a motor-operated gate valve. No power is required to operate the check valve inside of the drywell; rather, it opens as a result of LPCI injection flow. If a break were to occur outboard of the check valve, it would shuttle closed to isolate the reactor from the line break.

The motor-operated valve outside of the drywell is called the LPCI injection valve and is located as close as practical to the drywell wall. It is capable of opening against the maximum differential expected for the LPCI modes; i.e., normal reactor pressure minus the upstream pressure with the RHR pump running at minimum flow.

The flow diagram, Figures 5.4-18 and 5.4-19, and the P&ID, Figures 5.4-16 and 5.4-17, indicate a great many flow paths are available other than the LPCI injection line. However, the low water level or high drywell pressure signals which automatically initiate the LPCI mode are also used to isolate all other modes of operation and revert other system valves to the LPCI lineup. Inlet and outlet valves from the heat exchangers receive no automatic signals as the system is designed to provide rated flow to the vessel whether they are open or not.

Design considerations have been given to protect the LPCI mode safety functions from an undetected, incorrect positioning of the manual valves in the system. Administrative controls likewise serve to minimize the possibility of such errors. The location and type of these valves as well as the design/operations features are outlined in Table 6.3-11 (see also subsections 6.3.2.2.1 and 6.3.2.8).

A check valve in the pump discharge line is used together with a discharge line fill system (see subsection 6.3.2.2.5) to prevent water hammer resulting from pump start against a potential shutoff condition. A flow element in the pump discharge line is used to provide a measure of system flow and to originate automatic signals for control of the pump minimum flow valve. The minimum flow valve permits a small flow to the suppression pool in the event no discharge valve is open; or, in the case of a LOCA, when vessel pressure is higher than pump shutoff head.

Using the suppression pool as the source of water for the LPCI establishes a closed loop for recirculation of LPCI water escaping from the break.

Approximate pressures and temperatures at various points in the system during each of the several modes of operation of the RHR subsystems, can be obtained from the miscellaneous information blocks on the flow diagram, Figures 5.4-18 and 5.4-19.

RHR (LPCI) pumps and equipment are described in detail in subsection 5.4.7 which also describes the other functions served by the same pumps if not needed for the LPCI function. The RHR heat exchangers are not associated with the emergency core cooling function. The heat exchangers are discussed in subsection 6.2.2, containment heat removal system. The portions of the RHR required for accident protection including support structures are designed in accordance with seismic Category I criteria (see Chapter 3). The available NPSH was calculated in accordance with Regulatory Guide 1.1 (refer to subsection 5.4.7.2.2). The RHR pump characteristics are shown in Figure 5.4-20.

The RHR (LPCI) system incorporates a relief valve on each of the pump discharge lines which protects the components and piping from inadvertent overpressure conditions. These valves are set to relieve pressure at 500 psig.

The following relief valves have discharge lines terminating below the surface of the suppression pool: E12F055A, E12F055B, E12F036.

For these valves, the dynamic loads such as thrust and momentum caused by the relief valve opening are calculated for the discharge piping and include such effects as backpressure caused by submergence of the discharge piping in the suppression pool.

The dynamic loadings have been included in the piping stress analysis. Supports have been located in such a manner that the ASME Section III stress allowables as well as functional requirements have been met.

Supports have been designed to ensure that they are capable of withstanding the normal plus dynamic loading resulting from the relief valve opening.

Provisions are included in the RHR (LPCI) system to permit testing of the system. These provisions are:

a. All active LPCI components are designed to be testable during normal plant operation.

b. A discharge test line is provided for the three pump loops to route suppression pool water back to the suppression pool without entering the reactor pressure vessel.

c. A suction test line, supplying reactor grade water, is provided to test loop C discharge into the reactor pressure vessel during normal plant shutdown.

d. Instrumentation is provided to indicate system performance during normal and test operations.

e. All motor-operated valves, air-operated valves, and check valves are capable of manual operation for test purposes.

f. Shutdown lines taking suction from the recirculation system are provided for loops A and B to test pump discharge into the reactor pressure vessel after normal plant shutdown and to provide for shutdown cooling.

g. All relief valves are removable for bench-testing during plant shutdown.

h. The LPCI pumps are located in the auxiliary building below the water level in the suppression pool to assure positive pump suction. Pump NPSH requirements are met with containment at atmospheric pressure. A pressure gage is provided to indicate the suction head.

6.3.2.2.5 ECCS Discharge Line Fill System

A requirement of the core cooling systems is that cooling water flow to the reactor vessel be initiated rapidly when the system is called on to perform its function. This quick-start system characteristic is provided by quick-opening valves, quick-start pumps, and standby ac power source. The lag between the signal to start the pump and the initiation of flow into the RPV can be minimized by keeping the core cooling pump discharge lines full. Additionally, if these lines were empty when the systems were called for, the large momentum forces associated with accelerating fluid into a dry pipe could cause physical damage to the piping. Therefore, the ECCS discharge line fill system is designed to maintain the pump discharge lines in a filled condition.

Since the ECCS discharge lines are elevated above the suppression pool, check or stop-check valves are provided near the pumps to prevent back flow from emptying the lines into the suppression pool. Past experience has shown that these valves will leak slightly, producing a small back flow that will eventually empty

the discharge piping. To ensure that this leakage from the discharge lines is replaced and the lines are always kept filled, a fill system is provided for each of the five ECCS loops.

The fill system, typical in principle and operation for each ECCS loop, consists of a jockey pump that takes suction from its corresponding ECCS pump suction line from the suppression pool and discharges downstream of the check valve on the ECCS pump discharge line. The piping and instrumentation diagrams for the fill systems are shown on Figures 5.4-16, 5.4-17, 6.3-1, and 6.3-4.

The RHR (LPCI) jockey pumps are rated at a differential pressure of 50 psi at a flow of 40 gpm to ensure that the discharge piping up to the LPCI injection valve (E12-F042A, B, or C) and the containment spray header isolation valve (E12-F028A or B) remain full even with the maximum expected leakage rate through each boundary valve of the filled piping system of 2 cc/hr per inch of valve seat diameter. The HPCS and LPCS jockey pumps are rated at a differential pressure of 45 psi at a flow of 40 gpm to ensure that the discharge piping to the injection valves (E22-F004 and E21-F005) remains full assuming a similar leakage rate through the valves in these systems. Typical performance curves for the RHR jockey pumps and for the HPCS and LPCS jockey pumps are given in Figures 5.4-35 and 5.4-36, respectively. The maximum expected leakage rate for each filled ECCS train is much less than 1 gpm. The large difference between this rate and the jockey pump ratings provides adequate margin to meet unexpected leakage rates due to equipment deterioration, etc. The highest point in the discharge piping to be filled by any of the RHR jockey pumps is approximately 75 feet above the pump. For HPCS and LPCS, the maximum static head is approximately 68 feet. To prevent overheating of the jockey pump if the discharge line valves do not leak, a low-flow bypass line is provided to continuously circulate water back to the ECCS pump suction lines or suppression pool. Initial complete filling of the piping systems is accomplished using the combination of jockey pumps, condensate water supply lines (located a minimum distance from filled system boundary valves), and maintenance drains, vents, and test connections available as shown on the piping and instrumentation diagrams noted above. Maintenance of the filled status of the system is ensured by continuous indication of pump operation and pump discharge pressure. In accordance with monthly surveillance procedures, the uppermost vent lines in the filled system are opened and checked for flow to eliminate the possibility of the

formation of air pockets (see Note 19 on Figure 5.4-16, Note 11 on Figure 6.3-1, and Note 13 on Figure 6.3-4 for testing provisions in the system design). Pressure instrumentation provided on the jockey pump discharge line initiates an alarm in the main control room when pressure in the discharge line is less than the hydrostatic head required to maintain the line full of water up to the injection valves. Calibration and functional testing of the pressure switches and associated alarms will be performed at a frequency consistent with other similar devices in the ECCS. The power supply to the jockey pumps is classified as essential when the main ECCS pumps are not in operation or in support of the feedwater leakage control system (see subsection 6.7.2).

6.3.2.3 Applicable Codes and Classifications

The applicable codes and classification of the ECCS are specified in Section 3.2. All piping systems and components (pumps, valves, etc.) for the ECCS comply with applicable codes, addenda, code cases, and errata in effect at the time the equipment is procured. The piping and components of each ECCS within the containment and out to and including the pressure retaining injection valve are Safety Class 1. The remaining piping and components are Safety Class 2, 3, or non-code as indicated in Table 3.2-1, and as indicated on the individual system P&ID. The equipment and piping of the ECCS are designed to the requirements of seismic Category I. This seismic designation applies to all structures and equipments essential to the core cooling function. IEEE codes applicable to the controls and power supplies are specified in Section 7.1.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in Sections 6.1 and 3.2. Nonmetallic materials such as lubricants, seals, packings, paints and primers, insulation, as well as metallic materials, etc., are selected as a result of an engineering review and evaluation for compatibility with other materials in the system and the surroundings with concern for chemical, radiolytic, mechanical, and nuclear effects. Materials used are reviewed and evaluated with regard to radiolytic and pyrolytic decomposition and attendant effects on safe operation of the ECCS.

6.3.2.5 System Reliability

A single failure analysis shows that no single failure prevents the starting of the ECCS when required, or the delivery of coolant to the reactor vessel. No individual system of the ECCS is single failure proof with the exception of the ADS, hence it is expected that single failures will disable individual systems of the ECCS. The most severe effects of single failures with respect to loss of equipment occur if the loss-of-coolant accident occurs in combination with an ECCS pipe break coincident with a loss of offsite power. The consequences of the most severe single failure are shown in Table 6.3-7.

6.3.2.6 Protection Provisions

Protection provisions are included in the design of the ECCS. Protection is afforded against missiles, and pipe whip when failure of these systems prevents the ability of the plant to be safely shutdown (see Sections 3.5 and 3.6). Also accounted for in the design are thermal stresses, loadings from a LOCA, and seismic effects.

The ECCS piping and components located outside the containment are protected from internally and externally generated missiles by the reinforced concrete structure of the ECCS pump rooms. The water tight construction of these ECCS pump rooms also protects the equipment against flooding. The pump rooms layout and protection is covered in subsection 6.2.3.

The minimum suppression pool drawdown level, the low entrance velocities at the suction line tee and the design of the suction strainers are all factors in the prevention of a vortex. The pool water depth and bulk act to minimize and suppress the formation of eddies, swirls, and rotational flows. The possible sources of such flow characteristics, the RHR A and B lines that return to the suppression pool for suppression pool cooling, are, as shown in Figure 6.2-22, located as far from the ECCS suction tees as possible. LPCS and RHR C test return lines discharge in the vicinity of their respective system strainers. However, these lines are used only during normal plant operation when the suppression pool water is at its normal level. The low entrance velocities at the suction lines tend to prevent the formation of similar turbulence near the suction lines. The suction strainers (see Figure 6.2-86) act to smooth and straighten flows to the volume immediately outside of the suction pipe entrance, the most

critical area. The strainers are effective vortex breakers. A vortex, should one form, would not penetrate the strainer due to the small openings. Thus the possibility of an increase in entrance losses in the suction piping due to a flow reducing vortex or the entrainment of air in the suction line flows by formation of an air-entraining vortex is prevented. See subsection 6.3.2.2.a for additional discussion of vortex formation and air entrainment.

The sensitivity of each system for detection of unidentified leakage is provided in subsection 7.6.2.4.2.1. The leak detection capability for the ECCS is discussed in subsections 5.2.5 and 9.3.3. Loss of any one train of an ECCS will not negate the function of the ECCS. Flooding of one ECCS pump room cannot cause flooding of a redundant ECCS pump room.

Each ECCS pump is located in its own leaktight room with its own sump. A leak in any of these rooms would be identified by a high sump level alarm sounded in the control room. A leak in any ECCS train outside these rooms would be detected by the leak detection methods described in subsections 5.2.5 and 7.6.1.4. Any ECCS train which is found to have excessive leakage can be isolated and a redundant train initiated.

All leakage in the ECCS rooms is pumped to the auxiliary building floor drain transfer tank (refer to Figures 9.3-10 and 9.3-11). From here the leakage is processed through the floor drain processing subsystem (Refer to Figure 11.2-2). For the operation of the floor and equipment drainage system and the floor drain processing subsystems, refer to Sections 9.3.3 and 11.2.

The ECCS is capable of withstanding the passive failure of valve stem packings and pump seals following a LOCA. The maximum leakage due to a failure of this nature could be 23 gpm or less from an HPCS, LPCS, or RHR pump seal failure. Valve stem leakage would be significantly less than this.

The maximum allowable time for operator action is the time required to drain the suppression pool to a level below that required to maintain the design minimum suppression pool water coverage of 2 feet over the top of the top drywell vent. The suppression pool water level margin available is 1 inch or 4,500 gallons. Based on a postulated seal failure for one of the ECCS pumps at a rate of 23 gpm, the leakage would be detected within 35 minutes upon receipt of an alarm in the control room from the

leakage detection system (see subsection 9.3.3.2.3.d.). Following detection of the leakage, operator action to isolate the faulted ECCS loop would be required within approximately 2-1/2 hours to limit the total leakage volume to less than the 4,500 gallons.

There is little likelihood that failure will occur in the ECCS suction lines (between the suppression pool and the pumps), as the lines are safety/containment grade (extension of containment) and experience only containment pressure plus the gravity head from the pool. Likewise, postulated thermal transients are relatively small, less than 200 F, and are moderated by the very large suppression pool water volume. Should leakage and subsequent minimal flooding occur, provisions have been incorporated to pump the collected leakage back to the suppression pool. See also the response to Item III.D.1.1 of NUREG-0737 provided in subsection 18.1.34.

If suppression pool water level falls below the preset minimum vent cover, the upper pool dump system will be automatically activated to supplement the suppression pool water volume.

The standards met by the leak detection system are described in subsection 7.6.2.4.2.1 and 7.6.2.4.2.3.

The capability of the leak detection system to detect passive failures such as pump seals, valve seals, and measurement devices is also described in subsections 5.2.5 and 7.6.2.4.1.

The ECCS is protected against the effects of pipe whip, which might result from piping failures causing a LOCA. This protection is provided by separation, pipe whip restraints, and energy absorbing materials. These three methods are applied to provide protection against damage to piping and components of the ECCS which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level. See Section 3.6 for criteria on pipe whip.

The component supports which protect against damage from movement and from seismic events are discussed in subsection 5.4.14. The methods used to provide assurance that thermal stresses do not cause damage to the ECCS are described in subsection 3.9.3.

6.3.2.7 Provisions for Performance Testing

Periodic system and component testing provisions for the ECCS are described in subsection 6.3.2.2 as part of the individual system descriptions.

6.3.2.8 Manual Actions

The ECCS is actuated automatically and requires no operator action during the first 10 minutes following the accident. During the long-term cooling period (after 10 minutes), the operator will take action as specified in subsection 6.2.2.2 to place the containment cooling system into operation. Placing the containment cooling system into operation is the only manual action that the operator needs to accomplish during the course of the LOCA.

The operator has multiple instrumentation available in the control room to assist him in assessing the post-LOCA conditions. This instrumentation provides reactor vessel pressures, water levels, containment pressure, and temperature as well as indicating the operation of the ECCS. ECC system flow indication is the primary parameter available to assess proper operation of the system. Other indications such as position of valves, status of circuit breakers, status (initiated/not initiated) of the ADS timers, and essential power bus voltage are also available to assist him in determining system operating status. The electrical and instrumentation complement to the ECCS is discussed in detail in Chapter 7.3. Other available instrumentation is listed in the P&IDs for the individual systems. Much of the monitoring instrumentation available to the operator is discussed in more detail in Chapters 5 and 6.2.

6.3.3 ECCS Performance Evaluation

[HISTORICAL INFORMATION] [The baseline analyses to verify the adequacy of ECCS design were performed by the NSSS vendor for the initial core, which was a GE 8x8 fueled core. The adequacy of ECCS design was verified subsequently for Single Loop Operation (Appendix 15C) and operation in the Maximum Extended Operating Domain (Appendix 15D). These analyses considered a variety of single failures and a spectrum of postulated break sizes and locations. The NSSS vendor's analysis established the large break with failure of the LPCI diesel generator as the limiting (design

basis) event. The NSSS vendor's analysis is described in subsection 6.3.3.9. A more complete description is provided in Reference 2.

Starting with Cycle 20, the GGNS core contains only the GNF2 fuel type. The reload fuel vendor has performed ECCS analyses for this fuel type. The analyses show that the large break with failure of the HPCS diesel generator is limiting.]

A summary description of the initial cycle design basis LOCA and the reload vendor's analysis methods is provided in this section. For a complete description of the current cycle design basis LOCA event, see References 11 and 13.

The performance of the ECCS is determined utilizing analysis methods in compliance with the requirements of 10 CFR 50 Appendix K and then showing conformance to the acceptance criteria of 10 CFR 50.46. These methods were used to analyze the full LOCA break spectrum, including small, intermediate, and large size breaks. The NSSS vendor's analysis established the large break as the limiting design basis break. The current cycle analyses were performed for the entire break spectrum using the methods described in Reference 13. The NSSS vendor's analysis described in subsection 6.3.3.9 provides the baseline comparison for the full LOCA break spectrum. The current cycle analyses provide the ECCS performance evaluation for the design basis LOCA and the analyses methods are summarized herein. A summary description of the loss-of-coolant accidents is also provided herein. For a complete description of the LOCA events see References 2, 11 and 13.

The ECCS performance was evaluated for the entire spectrum of break sizes for postulated LOCAs by the NSSS vendor. The accidents, as listed in Chapter 15, for which ECCS operation is required are:

15.2.8 Feedwater piping break

15.6.4 Spectrum of BWR steam system piping failures outside of containment

15.6.5 Loss-of-coolant accidents

Chapter 15 provides the radiological consequences of the above listed events.

6.3.3.1 ECCS Bases for Technical Specifications

The maximum average planar linear heat generation rates (MAPLHGR) calculated in this performance analysis provide the basis designed to ensure conformance with the acceptance criteria of 10 CFR 50.46. The MAPLHGR limits used in the Reference 13 GNF2 LOCA analysis are bounding values. Minimum ECCS functional requirements are specified in subsections 6.3.3.4 and 6.3.3.5, and testing requirements are discussed in subsection 6.3.4. Limits on minimum suppression pool water level are discussed in Section 6.2.

6.3.3.2 Acceptance Criteria for ECCS Performance

The applicable acceptance criteria, extracted from 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water-cooled nuclear power reactors," are listed, and, for each criterion, applicable parts of subsection 6.3.3 where conformance is demonstrated are indicated. The GEH methods used to show compliance are described in Reference 13.

Criterion 1, Peak Cladding Temperature

"The calculated maximum fuel element cladding temperature shall not exceed 2200 F." Conformance to Criterion 1 is shown in subsections 6.3.3.7.3 (Break Spectrum), 6.3.3.7.4 (Design Basis Accident), 6.3.3.7.5 (Transition Break), 6.3.3.7.6 (Small Break), and specifically in Table 6.3-3 and References 11 and 13.

Criterion 2, Maximum Cladding Oxidation

"The calculated total local oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation." Conformance to Criterion 2 is shown in Table 6.3-6 (local oxidation), Table 6.3-3 (break spectrum summary), and Reference 13.

Criterion 3, Maximum Hydrogen Generation

"The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinder surrounding the fuel, excluding the cladding

surrounding the plenum volume, were to react." Conformance to Criterion 3 is shown in Tables 6.3-3 and 6.3-6 and References 11 and 13.

<u>Criterion 4, Coolable Geometry</u>

"Calculated changes in core geometry shall be such that the core remains amenable to cooling." As described in Reference 2, Section III and References 11 and 13 conformance to Criterion 4 is demonstrated by conformance to Criteria 1 and 2.

<u>Criterion 5, Long-Term Cooling</u>

"After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core." Conformance to Criterion 5 is demonstrated generically for General Electric BWRs in References 2 and 10, Section III.A. Briefly summarized, the core remains covered to at least the jet pump suction elevation and the uncovered region is cooled by spray cooling.

6.3.3.3 Single Failure Considerations

The functional consequences of potential operator errors and single failures, (including those which might cause any manually controlled electrically operated valve in the ECCS to move to a position which could adversely affect the ECCS) and the potential for submergence of valve motors in the ECCS are discussed in subsection 6.3.2. There it was shown that all potential single failures can be identified as no more severe than one of the following:

a. Low-pressure coolant injection (LPCI) emergency diesel generator, which powers two RHR (LPCI) pumps. For example, failure of one LPCI pump or one RHR (LPCI) injection valve is less severe than the diesel generator failure which disables two RHR (LPCI) pumps.

b. Low-pressure core spray (LPCS) emergency diesel generator, which powers one RHR (LPCI) pump and one LPCS pump.

c. High-pressure core spray (HPCS).

d. One automatic depressurization system (ADS) valve.

It is therefore only necessary to consider each of the above single failures in the emergency core cooling system performance analyses. For large breaks, failure of one of the diesel generators is in general the most severe failure. Substantial amounts of initial vessel inventory are lost through the break during the blowdown. With fewer systems available, there is less ECCS flow available for reflooding the core and the core will reflood later. The later reflooding results in higher peak cladding temperatures. The systems of the ECCS which remain operational after these failures are shown in Table 6.3-7.

6.3.3.4 System Performance During the Accident

In general, the system response to an accident can be described as:

a. Receiving an initiation signal

b. A small lag time (to open all valves and have the pumps up to rated speed)

c. Finally the ECCS flow entering the vessel

Key ECCS actuation set points and time delays for all the ECC systems are provided in Table 6.3-2. Actual values used in the LOCA analyses may be more conservative than those listed in Table 6.3-2. See Reference 13 for actual values used. The minimization of the delay from the receipt of signal until the ECCS pumps have reached rated speed is limited by the physical constraints on accelerating the diesel generators and pumps. The delay time due to valve motion in the case of high-pressure system provides a suitably conservative allowance for valves in the system. In the case of the low-pressure system, the time delay for valve motion is such that the pumps are at rated speed prior to the time the vessel pressure reaches the pump shutoff pressure.

The flow delivery rates analyzed in subsection 6.3.3 can be determined from the head-flow curves in Figures 6.3-3, 6.3-6, and 6.3-7 of subsection 6.3.2 and the pressure versus time plots discussed in subsection 6.3.3.7. Piping and instrumentation and functional control diagrams for the ECCS are provided in subsection 6.3.2. The operational sequence of ECCS for the DBA is shown in Table 6.3-1.

Operator action is not required, except as a monitoring function, during the short-term cooling period following the LOCA. During the long-term cooling period, the operator will take action when specified in the Plant-Specific Emergency Operating Procedures to place the containment cooling system into operation.

The Grand Gulf equipment for long-term cooling following a postulated LOCA includes two complete core spray systems (a high pressure system and a low pressure system) and three RHR systems. These systems consist of a total of five pumps capable of providing water to the reactor pressure vessel. The piping and instrumentation diagrams of these systems are shown in Figures 5.4-16, 5.4-17, 6.3-1, and 6.3-4. Long-term cooling water can be provided to the core by any one of these five pumps, while heat can be rejected to the ultimate heat sink via either of the two passive RHR heat exchangers using one of two RHR pumps. Thus a maximum of two pumps would be required for post-LOCA core cooling. All of these components are designed to remain operable during and following a LOCA, and the redundancy provided is such that maintenance is not expected to be required during the long-term core cooling period following a LOCA. However, the RHR, HPCS, and LPCS systems are designed with provisions for flushing as shown in Figures 5.4-16, 5.4-17, 6.3-1, and 6.3-4.

During long-term cooling following a small LOCA, no operator actions are required to control system pressure to preclude overpressurizing the pressure vessel after it has been cooled off. The system is always protected by relief valves more than adequate to handle decay heat energy generation. If a small LOCA caused reactor vessel water level to drop to Level 3 or drywell pressurization, then the plant would scram. If water level drops to Level 2, then HPCS (and RCIC) automatically start, reestablish water level for the postulated small LOCA, and automatically control water level between Levels 2 and 8. If a small LOCA caused high drywell pressure and water level dropped to Level 1, then all ECCS would automatically start to reestablish water level and ADS would automatically initiate to depressurize the vessel. Once actuated, the ADS valves stay open and are designed to remain open for 100 days following a LOCA, thereby precluding any significant repressurizing of the reactor vessel. If the pressure vessel were cooled off following the hypothetical small LOCA, then the ADS valves would be open and would prevent repressurizing the pressure vessel.

6.3.3.5 Use of Dual Function Components for ECCS

With the exception of the LPCI system, the systems of the ECCS are designed to accomplish only one function: to cool the reactor core following a loss-of-reactor coolant. To this extent, components or portions of these systems (except for pressure relief) are not required for operation of other systems which have emergency core cooling functions, or vice versa. Because either the ADS initiating signal or the overpressure signal opens the safety/ relief valve, no conflict exists.

The LPCI subsystem, however, uses the RHR pumps and some of the RHR valves and piping. When the reactor water level is low, the LPCI subsystem has priority through the valve control logic over the other RHR subsystems for containment cooling or shutdown cooling. Immediately following a LOCA, the RHR system is directed to the LPCI mode.

6.3.3.6 Limits on ECC System Parameters

The limits on the ECC system parameters are discussed in subsections 6.3.3.1 and 6.3.3.7.1.

Any number of components in any given system may be out of service, up to and including the entire system for periods of time discussed in the Technical Specifications. The maximum allowable out of service time is a function of the level of redundancy as discussed in subsection 15A.5.

6.3.3.7 ECCS Analyses for LOCA

6.3.3.7.1 LOCA Analysis Procedures and Input Variables

The procedures approved for LOCA analysis conformance calculations are described in detail in References 2 for the initial cycle, and in Reference 13 for GNF2 fuel. These procedures were used in the calculations documented in subsection 6.3.3.

The Reference 13 GNF2 LOCA evaluation utilizes the SAFER/GESTR-LOCA evaluation model described by References 10, 14-20. The computer codes utilized by these analyses are:

<u>Short Term Thermal Hydraulic Model (LAMB)</u>

The LAMB model analyzes the short term blowdown phenomena for postulated large pipe breaks in which nucleate boiling is lost before the water level drops sufficiently to uncover the active fuel. The LAMB output (most importantly, core flow as a function of time) is used in the SCAT/TASC model for calculating blowdown heat transfer and fuel dryout time.

Transient Critical Power Model (TASC)

The TASC model completes the transient short term thermal hydraulic calculation for large recirculation line breaks. The time and location of boiling transition are predicted during the period of recirculation pump coastdown. When the core inlet flow is low, TASC also predicts the resulting bundle dryout time and location. The calculated fuel dryout time is an input to the long term thermal hydraulic transient model, SAFER. TASC is also used to predict the time and location of boiling transition and dryout time. This model explicitly models the axially varying flow areas and heat transfer surface resulting from the part length fuel rods, and incorporates the fuel’s critical power correlation.

Thermal Mechanical Model (GESTR LOCA)

The GESTR LOCA model provides the parameters to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA for input to SAFER. GESTR LOCA also establishes the initial transient pellet cladding gap conductance for input to both SAFER and TASC.

Long Term Thermal Hydraulic Model (SAFER)

The SAFER model calculates the long term system response of the reactor over a complete spectrum of hypothetical break sizes and locations. SAFER is compatible with the GESTR LOCA fuel rod model for gap conductance and fission gas release. SAFER calculates the core and vessel water levels, system pressure response, ECCS performance, and other primary thermal hydraulic phenomena occurring in the reactor as a function of time. SAFER realistically models all regimes of heat transfer that occur inside the core, and provides the PCT and the heat transfer coefficients (which determine the severity of the temperature change) as a function of time. Part length fuel rods are modeled as full length rods, which conservatively overestimates the hot bundle power. Both top peaked and mid peaked axial power shapes are considered.

The significant input parameters are listed in Table 6.3-2. The actual values for these parameters used in the current LOCA analyses may be more conservative than those listed in Table 6.3-2. These values are given in Reference 13.

6.3.3.7.2 Accident Description

The design basis LOCA applicable to the maximum extended operating domain for reload cores is addressed in References 11 and 13.

6.3.3.7.3 Break Spectrum Calculations

Current cycle analyses included evaluations of the entire break spectrum; the analyses are provided in References 11 and 13.

A summary of the results of the break spectrum calculations are shown in Table 6.3-3. Conformance to the acceptance criteria (PCT ≤ 2200°F, local oxidation ≤ 17 percent and core wide metal-water reaction ≤ 1 percent) is demonstrated.

6.3.3.7.4 Large Recirculation Line Break Calculations

The characteristics that determine which is the most limiting large break are:

a. the calculated hot node reflooding time,

b. the calculated hot node uncovery time, and

c. the time of calculated boiling transition

The time of calculated boiling transition increases with decreasing break size, since jet pump suction uncovery (which leads to boiling transition) is determined primarily by the break size for a particular plant. The calculated hot node uncovery time also generally increases with decreasing break size, as it is primarily determined by the inventory loss during the blowdown.

The hot node reflooding time is determined by a number of interacting phenomena such as depressurization rate, counter current flow limiting and the combination of available ECCS.

The period between hot node uncovery and reflooding is the period when the hot node has the lowest heat transfer. Hence, the break that results in the longest period during which the hot node remains uncovered results in the highest calculated PCT. If two

breaks have similar times during which the hot node remains uncovered, then the larger of the two breaks will be limiting as it would have an earlier boiling transition time.

The most limiting large break for reload cores is the recirculation line break, as determined by the break spectrum analyses for the current cycle.

For the GNF2 fuel, the important variables for the DBA are shown in Figures 6.3-18A through 6.3-18E. The MAPLHGRS, PCTs, and maximum local oxidation percentages for all fuel types are shown in Table 6.3-6. Reference 13 reports the results for other parameters and breaks.

The analysis of the large break accident for Single Loop Operation is addressed in References 11 and 13. The applicable acceptance criteria are satisfied, as shown in Table 6.3-6.

6.3.3.7.5 Transition Recirculation Line Break Calculations

The large break accident results in more severe conditions than the transition break accident; this finding is valid for SLO and for operation in the MEOD.

6.3.3.7.6 Small Recirculation Line Break Calculations

The GNF2 large break accidents result in more severe conditions than the corresponding GNF2 small break accidents. Figures 6.3-18P through 6.3-18T display the important variables for the GNF2 small break. Reference 13 reports the results for the small breaks.

6.3.3.7.7 Calculations for Other Break Locations

The NSSS vendor has shown that the large break in the recirculation line results in the most severe conditions. See the discussion in subsection 6.3.3.9. This finding also applies to reload cores.

6.3.3.7.8 ADS Valve Out of Service Calculations

The NSSS vendor performed an analysis to quantify the effect on the LOCA calculations of an ADS valve out of service. See the discussion in subsection 6.3.3.9. The analysis also applies to reload cores, in view of the fact that the large break is still the limiting break.

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6.3.3.8 LOCA Analysis Conclusions

Having shown compliance with the applicable acceptance criteria of subsection 6.3.3.2, it is concluded that the ECCS will perform its function in an acceptable manner and meet all of the 10 CFR 50.46 Acceptance Criteria, given operation at or below the maximum average planar linear heat generation rates in Table 6.3-6.

6.3.3.9 ECCS Performance Evaluation (Initial Cycle)

[HISTORICAL INFORMATION] [Analyses supporting GGNS Single Loop Operation (SLO) and operation in the Maximum Extended Operating Domain (MEOD) are detailed in Appendix 15C and Appendix 15D, respectively. The analyses summarized below are the baseline analyses performed in support of GGNS operation. Analyses performed subsequently beyond the original baseline analyses are described above in subsection 6.3.3.

The performance of the ECCS is determined through application of the 10 CFR 50 Appendix K evaluation models and then showing conformance to the acceptance criteria of 10 CFR 50.46.

NEDO-20566 (Ref. 2), "General Electric Company Analytical Model for Loss-of-Coolant Analysis In Accordance with 10 CFR 50 Appendix K," provides a complete description of the methods used to perform the calculations for the initial fuel cycle. These methods are summarized herein. A summary description of the loss-of-coolant accidents is also provided herein. For a complete description of the LOCA events see Reference 2.

The ECCS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs by the NSSS vendor for the initial cycle. The accidents, as listed in Chapter 15, for which ECCS operation is required are:

15.2.8 Feedwater piping break

15.6.4 Spectrum of BWR steam system piping failures outside of containment

15.6.5 Loss-of-coolant accidents

Chapter 15 provides the radiological consequences of the above listed events.]

6.3.3.9.1 Acceptance Criteria for ECCS Performance (Initial Cycle)

[HISTORICAL INFORMATION] [The applicable acceptance criteria, extracted from 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water-cooled nuclear power reactors," are listed in subsection 6.3.3.2.

6.3.3.9.2 Single Failure Considerations (Initial Cycle)

See subsection 6.3.3.3. They were the same for the initial cycle.

6.3.3.9.3 System Performance During the Accident (Initial Cycle)

[HISTORICAL INFORMATION] [In general, the system response to an accident can be described as:

a. Receiving an initiation signal.

b. A small lag time (to open all valves and have the pumps up to rated speed).

c. Finally the ECCS flow entering the vessel.

Key ECCS actuation set points and time delays for all the ECC systems are provided in Table 6.3-2a.

The flow delivery rates analyzed in subsection 6.3.3.9 can be determined from the head-flow curves in Figures 6.3-3, 6.3-6, and 6.3-7 and the pressure versus time plots. Piping and instrumentation and functional control diagrams for the ECCS are provided in subsection 6.3.2. The operational sequence of ECCS for the DBA is shown in Table 6.3-1a.]

6.3.3.9.4 Use of Dual Function Components for ECCS (Initial Cycle)

Same as current cycle.

6.3.3.9.5 Limits on ECC System Parameters (Initial Cycle)

The limits on the ECC system parameters are discussed in subsection 6.3.3.1 and 6.3.3.7.1.

6.3.3.9.6 ECCS Analyses for LOCA (Initial Cycle)

6.3.3.9.6.1 LOCA Analysis Procedures and Input Variables (Initial Cycle)

[HISTORICAL INFORMATION] [The procedures approved for LOCA analysis conformance calculations are described in detail in Reference 2. These procedures were used in the initial cycle calculations documented in subsection 6.3.3.9.

For convenience, the four computer codes are briefly described below. The interfaces between the codes are shown schematically in Figures II-2a, II-2b, and II-2c in the "Documentation of Evaluation Models" Section II.A of Reference 2. The major interfaces are briefly noted below.

SHORT-TERM THERMAL HYDRAULIC MODEL (LAMB)

The LAMB code is a model which is used to analyze the short-term thermodynamic and thermal-hydraulic behavior of the coolant in the vessel during a postulated LOCA. In particular, LAMB predicts the core flow, core inlet enthalpy and core pressure during the early stages of the reactor vessel blowdown. For a detailed description of the model and a discussion regarding sources of input to the model refer to the "LAMB Code Documentation" Section II.A.3 of Reference 2.

TRANSIENT CRITICAL POWER MODEL (SCAT)

The SCAT code is used to evaluate the short-term thermal-hydraulic response of the coolant in the core during a postulated LOCA. SCAT receives input from LAMB and analyzes the convective heat transfer process in the thermally limiting fuel bundle. For a detailed description of the model and a discussion regarding sources of input to the model refer to the "SCAT Code Documentation" Section II.A.4 of Reference 2.

LONG-TERM THERMAL HYDRAULIC MODEL AND REFILL/REFLOOD MODEL (SAFE/REFLOOD)

The SAFE/REFLOOD code is a model which is used to analyze the long-term thermodynamic behavior of the coolant in the vessel. The SAFE/REFLOOD code calculates the uncovering and reflooding of the core and the duration of spray cooling and (for small breaks) the peak cladding temperature.

For a detailed description of the model and a discussion regarding sources of input to the model refer to the "SAFE code and REFLOOD code documentation" Sections II.A.1 and II.A.2 of Reference 2, and References 5 and 21.

CORE HEATUP MODEL (CHASTE)

The CHASTE code solves the transient heat transfer equations for specific axial planes of each fuel bundle type, for large breaks. CHASTE receives input from, SCAT, SAFE, and REFLOOD and calculates cladding temperatures and local cladding oxidation during the entire LOCA transient. For a detailed description of the CHASTE model and a discussion regarding sources of input, refer to the "CHASTE code documentation" Section II.A.5 of Reference 2, and References 5 and 6.

The significant input variables used by the LOCA codes are listed in Table 6.3-2a and Figure 6.3-72.]

6.3.3.9.6.2 Accident Description (Initial Cycle)

[HISTORICAL INFORMATION] [A detailed description of the LOCA calculation is provided in Reference 2. For convenience, a short description of the major events during the design basis accident (DBA) is included here.

Immediately after the postulated double-ended recirculation line break, vessel pressure and core flow begin to decrease. The initial pressure response (Figure 6.3-15) is governed by the closure of the main steam isolation valves and the relative values of energy added to the system by decay heat and energy removed from the system by the initial blowdown of fluid from the downcomer. The initial core flow decrease (Figure 6.3-9) is rapid because the recirculation pump in the broken loop ceases to pump almost immediately because it has lost suction. The pump in the intact loop coasts down relatively slowly. This pump coast-down governs the core flow response for the next several seconds. When the jet pump suctions uncover, calculated core flow decreases to near zero. When the recirculation pump suction nozzle uncovers, the energy release rate from the break increases significantly and the pressure begins to decay more rapidly. As a result of the increased rate of vessel pressure loss, the initially subcooled water in the lower plenum saturates and flashes up through the core, increasing the core flow. This lower plenum flashing continues at a reduced rate for the next several seconds.

Heat transfer rates on the fuel cladding (Figure 6.3-13) during the early stages of the blowdown are governed primarily by the core flow response. Nucleate boiling continues in the high power plant until shortly after jet pump uncovering. Boiling transition follows shortly after the core flow loss that results from jet pump uncovering. Film boiling heat transfer rates then apply, with increasing heat transfer resulting from the core flow increase during the lower plenum flashing period. Heat transfer then slowly decreases until the high power axial plane uncovers. At that time, convective heat transfer is assumed to cease.

Water level inside the shroud (Figure 6.3-14) remains high during the early stages of the blowdown because of flashing of the water in the core. After a short time, the level inside the shroud has decreased to uncover the core. Several seconds later the ECCS is actuated. As a result the vessel water level begins to increase. Some time later, the lower plenum is filled, and the core is subsequently rapidly recovered.

The cladding temperature at the high-power plane (Figure 6.3-16) decrease initially because nucleate boiling is maintained, the heat input decreases and the sink temperature decreases. A rapid, short duration cladding heatup follows the time of boiling transition when film boiling occurs and the cladding temperature approaches that of the fuel. The subsequent heatup is slower, being governed by decay heat and core spray heat transfer. Finally the heatup is terminated when the core is recovered by the accumulation of ECCS water.

Supplemental calculations were performed to evaluate the effect of clad swelling and rupture parameters on the fuel heatup. The analysis used the material models of NUREG-0630 as applicable to the Grand Gulf design. The results show only a small sensitivity to the effects of the clad swelling and rupture model and is reported in a letter from R. H. Buchholz (G.E.) to L. S. Rubenstein (NRC), "General Electric Fuel Clad Swelling and Rupture Model," Dated May 15, 1981.]

6.3.3.9.6.3 Break Spectrum Calculations (Initial Cycle)

[HISTORICAL INFORMATION] [A complete spectrum of postulated break sizes and locations was considered in the evaluation of ECCS performance. The maximum recirculation break area of 3.112 ft^2 consists of the following areas: recirculation safe end area (2.521 ft^2), total jet pump nozzle area of one recirculation loop

(0.511 ft^2), and the minimum flow area of the reactor water cleanup system piping connecting the two loops (0.0798 ft^2). The maximum steam line break inside the containment is based on the steam line safe end area (3.477 ft^2). The maximum outside containment steam line break area (3.542 ft^2) is based on the minimum flow limiter area for each steam line (0.886 ft^2). The feedwater line break area (0.362 ft^2) is based on the inside area of the feedwater sparger pipe (0.181 ft^2). The maximum core spray line break area is based on the limiting area of the core spray line tee/reducer connection inside the vessel (0.2819 ft^2). The general analytical procedures for conducting break spectrum calculations are discussed in Section III.B of Reference 2. For ease of reference, a summary of all figures and tables presented in subsection 6.3.3.9 is shown in Table 6.3-4. A summary of the results of the break spectrum calculations is shown in tabular form in Table 6.3-3a and graphically in Figure 6.3-8. Conformance to the acceptance criteria (PCT ≤ 2200°F, local oxidation ≤ 17 percent and core wide metal-water reaction ≤1 percent) is demonstrated. Details of calculations for specific breaks are included in subsequent paragraphs.]

6.3.3.9.6.4 Large Recirculation Line Break Calculations (Initial Cycle)

[HISTORICAL INFORMATION] [The characteristics that determine which is the most limiting large break are:

a. the calculated hot node reflooding time,

b. the calculated hot node uncovery time, and

c. the time of calculated boiling transition

The time of calculated boiling transition increases with decreasing break size, since jet pump suction uncovery (which leads to boiling transition) is determined primarily by the break size for a particular plant. The calculated hot node uncovery time also generally increases with decreasing break size, as it is primarily determined by the inventory loss during the blowdown.

The hot node reflooding time is determined by a number of interacting phenomena such as depressurization rate, counter current flow limiting and a combination of available ECCS.

The period between hot node uncovery and reflooding is the period when the hot node has the lowest heat transfer. Hence, the break that results in the longest period during which the hot node remains uncovered results in the highest calculated PCT. If two breaks have similar times during which the hot node remains uncovered, then the larger of the two breaks will be limiting as it would have an earlier boiling transition time (i.e., the larger break would have a more severe LAMB/SCAT blowdown heat transfer analysis).

Figure 6.3-71 shows the variation with break size of the calculated time the hot node remains uncovered. Based on these calculations, the DBA was determined to be the break that results in the highest calculated PCT in the 1.0 ft^2 to DBA region. Confirmation that this is the most limiting break over the entire break spectrum is shown in Figure 6.3-8.

Important variables from the analyses of the DBA for the initial cycle are shown in Figures 6.3-9 through 6.3-18. These variables are:

a. Core average pressure as a function of time from LAMB

b. Core flow as a function of time from LAMB

c. Core inlet enthalpy as a function of time from LAMB

d. Minimum critical power ratio as a function of time from SCAT

e. Water level as a function of time from SAFE/REFLOOD

f. Pressure as a function of time from SAFE/REFLOOD

g. Fuel rod convective heat transfer coefficient as a function of time from CHASTE

h. Peak cladding temperature as a function of time from CHASTE

i. Average fuel temperature as a function of time from CHASTE (from a generic analysis for this product line)

j. PCT rod internal pressure as a function of time from CHASTE (from a generic analysis for this product line)

The maximum average planar linear heat generation rate, maximum local oxidation, and peak cladding temperature as a function of exposure from the CHASTE analysis of the DBA are shown in Table 6.3-6a.]

6.3.3.9.6.5 Transition Recirculation Line Break Calculations (Initial Cycle)

[HISTORICAL INFORMATION] [Important variables from the analysis of the transition (1.0 ft^2) break are shown in Figures 6.3-35 through 6.3-46. These variables are:

a. Core average pressure (large break methods) as a function of time from LAMB

b. Core flow (large break methods) as a function of time from LAMB

c. Core inlet enthalpy (large break methods) as a function of time from LAMB

d. Minimum critical power ratio (large break methods) as a function of time from SCAT

e. Water level (large break methods) as a function of time from SAFE/REFLOOD

f. Pressure (large break methods) as a function of time from SAFE/REFLOOD

g. Fuel rod convective heat transfer coefficient (large break methods) as a function of time from CHASTE

h. Peak cladding temperature (large break methods) as a function of time from CHASTE

i. Water Level (small break methods) as a function of time from SAFE/REFLOOD

j. Pressure (small breaks methods) as a function of time from SAFE/REFLOOD

k. Convective heat transfer coefficients (small break methods) as a function of time from REFLOOD

l. Peaking cladding temperature (small break methods) as a function of time from REFLOOD]

6.3.3.9.6.6 Small Recirculation Line Break Calculations (Initial Cycle)

[HISTORICAL INFORMATION] [Important variables from the analysis of the small break yielding the highest cladding temperature are shown in Figures 6.3-47 through 6.3-50. These variables are:

a. Water level as a function of time from SAFE/REFLOOD

b. Pressure as a function of time from SAFE/REFLOOD

c. Convective heat transfer coefficients as a function of time from REFLOOD

d. Peaking cladding temperature as a function of time from REFLOOD

The same variables resulting from the analysis of a less limiting small break are shown in Figures 6.3-51 through 6.3-54.]

6.3.3.9.6.7 Calculations for Other Break Locations (Initial Cycle)

[HISTORICAL INFORMATION] [Reactor water level and vessel pressure from SAFE/REFLOOD and peak cladding temperature and convective heat transfer coefficients from REFLOOD are shown in Figures 6.3-55 through 6.3-58 for the HPCS line break, Figures 6.3-59 through 6.3-62 for the feedwater line break, and in Figures 6.3-63 through 6.3-66 for the main steam line break inside the containment. The main steam line break inside the containment analysis assumes the starting of ECC systems on low-water level only as does the other ECCS analyses. For this case, the LPCS D/G was found to be the most limiting failure with a calculated PCT of 1322 F.

An analysis was done for the main steam line break outside the containment. Reactor water level and vessel pressure from SAFE/REFLOOD and peak cladding temperature and convective heat transfer coefficients from REFLOOD are shown in Figures 6.3-73 through 6.3-76.]

6.3.3.9.6.8 ADS Valve Out of Service Calculations (Initial Cycle)

[HISTORICAL INFORMATION] [The purpose of this section is to quantify the effect on the LOCA calculations of an ADS valve out of service.

As demonstrated in the previous sections, for small breaks, the unavailability of the HPCS system (as a result of the break or an assumed single failure) will result in the highest calculated peak cladding temperature (PCT). For these cases the emergency core cooling systems remaining include the Automatic Depressurization System (ADS) and some low pressure ECCS. Here the ADS is required to rapidly depressurize the vessel below the shutoff head of the low pressure ECCS.

If an ADS valve is out of service in addition to the assumed worst single failure, the ADS will depressurize the vessel slower. This will result in a delay of low pressure ECCS and, in general, a corresponding delay in reflooding time and increase in the PCT. However, the significance of the ADS decreases as larger break sizes are considered, because of the increasing depressurization due to mass loss through the break. Therefore, the maximum impact on the PCT due to an ADS valve out of service will be determined by the recalculation of the small break spectrum.

Figure 6.3-77 is a comparison between the two break spectrum calculations for recirculation line breaks. The increase in PCT for an ADS valve out of service is shown to be about 115°F, with a maximum PCT of 1477°F occurring at a break size of 0.09 ft^2. Reactor water level, vessel pressure, heat transfer coefficients, and peak cladding temperature versus time for this limiting case are shown in Figures 6.3-78 through 6.3-81.

The maximum core spray line break with an LPCS diesel generator failure was also reevaluated with an ADS valve out of service. For this case, reactor water level, vessel pressure, heat transfer coefficients, and peak cladding temperature versus time are shown in Figures 6.3-82 through 6.3-85. The increase in PCT for an ADS valve out of service is shown to be 95°F, yielding a PCT for this case of 1784°F.

For the analysis presented in subsection 6.3.3.7.9, the effect of an ADS valve out of service was quantified and is presented in Section F5 of Appendix 6F.]

6.3.3.9.6.9 Diversion of ECCS to Containment Cooling Calculations (Initial Cycle)

[HISTORICAL INFORMATION] [An analysis was performed to investigate the effect of diverting low pressure coolant injection (LPCI) pumps to the containment spray mode ten minutes

after a LOCA initiation. Details of the analysis are presented in Appendix 6F. The results and actions taken as a result of the analysis are summarized below.

The results show that the worst single failure/break type combination is an HPCS line break of approximately 0.01 ft^2 assuming the failure of the LPCS diesel generator which powers one LPCS pump and one LPCI pump (see Figure 6.3-86). This single failure/break type combination yields the highest peak cladding temperature (approximately 1824 F) of all the cases affected by LPCI diversion at 10 minutes. The peak cladding temperatures experienced by the cases affected by LPCI diversion are below the limits established in 10 CFR 50.46 (2200°F). The maximum cladding oxidation is less than 0.8 percent, well below the 17 percent limit. The maximum hydrogen generation is less than 0.07 percent, well below the 1 percent limit (see Figure 6.3-86).

Grand Gulf symptom-based emergency procedures have been constructed to caution the operator against premature diversion unless adequate core cooling is assured. These procedures clearly identify LPCI diversion as secondary to the core cooling requirements except in those instances, outside the plant design envelope, which involve multiple failures and for which maintenance of containment integrity is required to minimize risk to the environment.]

6.3.3.9.7 LOCA Analysis Conclusions

Same as current cycle. See subsection 6.3.3.8.

6.3.4 Tests and Inspections

6.3.4.1 ECCS Performance Tests

All systems of the ECCS are tested for their operational ECCS function during the pre-operational and/or startup test program. Each component is tested for power source, range, direction of rotation, set point, limit switch setting, torque switch setting, etc. Each pump is tested for flow capacity for comparison with vendor data. (This test is also used to verify flow measuring capability.) The flow tests involve the same suction and discharge source; i.e., suppression pool or condensate storage tank.

All logic elements are tested individually and then as a system to verify complete system response to emergency signals including the ability of valves to revert to the ECCS alignment from other positions.

Finally the entire system is tested for response time and flow capacity taking suction from its normal source and delivering flow into the reactor vessel. This last series of tests is performed with power supplied from both offsite power and onsite emergency power.

See Chapter 14 for a thorough discussion of pre-operational testing for these systems.

6.3.4.2 Reliability Tests and Inspections

The expected service life of the RHR, LPCS, and HPCS pumps, by design, is the life of the plant (40 years). The maximum expected accumulated operating time for the ECCS pumps during the life of the plant was estimated using the following criteria:

a. In-shop tests including (1) hydrostatic tests of pressure retaining parts of 150 percent times the design pressure, (2) performance tests while the pump is operated with flow to determine the total developed head at zero flow and design flow, and (3) net positive suction head (NPSH) requirements.

b. After the pump is installed in the plant, it undergoes the (1) system hydro tests, (2) functional tests, and (3) the required periodic in-service inspection of once a month for an hour during normal plant operation and one month of operation each year for shutdown (RHR pumps only).

c. The pumps are designed for a postulated single operation of 4368 hours per design specification for one accident during the unit's 40-year life. To show compliance to meet design operational requirements, the following has been performed. Analytical design calculations, in conjunction with the performance tests, are performed. A 50-hour test on the River Bend Unit 2 LPCS and a 150-hour test on the TVA 18 HPCS were performed. Tests were performed, under NRC surveillance, for diesel generator start capabilities on the La Salle HPCS pump. Finally, operating experience of similar pumps is used in conjunction with the above, to validate design operational lifetimes.

d. Table 6.3-12 shows the maximum expected accumulated operating time for the life of the plant (40 years).

The average reliability of a standby (non-operating) safety system is a function of the duration of the interval between periodic functional tests. The factors considered in determining the periodic test interval of the ECCS are: the desired system availability (average reliability), the number of redundant functional system success paths, the failure rates of the individual components in the system, and the schedule of periodic tests (simultaneous versus uniformly staggered versus randomly staggered). For the ECCS the above factors were used to determine safe test intervals utilizing the methods described in Reference 1.

All of the active components of the HPCS system, ADS, LPCS, and RHR (LPCI) systems are designed so that they may be tested during normal plant operation. Full flow test capability is provided by a test line back to the suction source. The full flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed in the power generation mode. In addition, each individual valve may be tested during normal plant operation. Input jacks are provided such that racking out the injection valve breaker, each ECCS loop can be tested for response time.

All valves performing an isolation function to protect the low-pressure portions of the ECCS from full reactor pressure will be leak rate tested to the requirements of the ASME OM Code for Operation and Maintenance of Nuclear Power Plants. These valves are categorized as Category A valves as defined in ASME OM Code.

Check valves performing a pressure isolation function are categorized as Category A and C valves as defined in ASME/ANSI OMa-1988, Part 10, Paragraph 1.4. The ECCS check valves which are categorized as Category A and C valves are as follows:

System	Valve Identification	FSAR Figure
RHR (LPCI)	F041A, B, C	5.4-16 & 5.4-17
LPCS	F006	6.3-4

The necessary test provisions to leak test each valve have been incorporated into the piping system design.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in subsection 7.3.1.1.1. The emergency power system, which supplies electrical power to the ECCS in the event that offsite power is unavailable, is tested as described in subsection 8.3.1. The frequency of testing is specified in Technical Specifications. Visual inspections of all the ECCS components located outside the drywell can be made at any time during power operation. Components inside the drywell can be visually inspected only during periods of access to the drywell. When the reactor vessel is open, the spargers and other internals can be inspected.

Inservice inspection of these systems is discussed in subsection 5.2.4 and Section 6.6. Inservice testing is discussed in subsection 3.9.6.

6.3.4.2.1 HPCS Testing

HPCS can be tested at full flow in any operational condition with condensate storage tank water except when condensate level in the condensate storage tank is below the reserve level or HPCS is automatically actuated for emergency service. HPCS also can be tested in any operational condition using suppression pool water provided that the suppression pool level is above the minimum level for adequate HPCS net positive suction head and HPCS is not actuated for emergency service. If an automatic initiation signal occurs while HPCS is being tested, the system returns automatically to the operating mode.

The discharge valve to the reactor remains closed during periodic HPCS pump testing. The two motor-operated valves in the test return line to the condensate storage tank are interlocked closed when the suction valve from the suppression pool is open. HPCS valves are also tested periodically to ensure operability. HPCS test conditions are tabulated on the HPCS flow diagram, Figure 6.3-2.

[HISTORICAL INFORMATION] [A design flow functional test of HPCS over the operating pressure and flow range was performed as part of the pre-operational test program by pumping water from the condensate storage tank and back through the full flow test return line to the condensate storage tank. The suppression pool flow path also was required to be pre-op tested as described in Section 14.2.12.1.8.]

6.3.4.2.2 ADS Testing

The ADS valves are fully tested in accordance with the Technical Specifications. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence, but excludes actual valve actuation. Each individual ADS valve is manually actuated.

During plant operation the ADS system can be checked as discussed in subsection 7.3.1.1.1.4.

6.3.4.2.3 LPCS Testing

The LPCS pump and valves are tested periodically during reactor operation. With the injection valve closed and the return line open to the suppression pool, full flowing pump capability is demonstrated. The injection valve and the check valve are tested in a manner similar to that used for the LPCI valves. The system test conditions during reactor shutdown are shown on the LPCS system flow diagram, Figure 6.3-5.

6.3.4.2.4 LPCI Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated in Figures 5.4-18 and 5.4-19. During plant operation, this test does not inject cold water into the reactor because the injection line check valve is held closed by vessel pressure, which is higher than the pump pressure. Also, injection line isolation valve is closed. The injection line portion is tested with reactor water when the reactor is shut down and when a closed system loop is created. This prevents unnecessary thermal stresses.

To test an RHR (LPCI) pump at rated flow, the test line valve to the suppression pool is opened, the pump suction valve from the suppression pool is opened (this valve is normally open), and the pumps are started using the remote/manual switches in the control room. Correct operation is determined by observing instruments in the control room and locally.

If an initiation signal occurs during the test, the LPCI system returns to the operating mode. The valves in the test bypass lines are closed automatically to assure that the LPCI pump discharge is correctly routed to the vessel.

6.3.5 Instrumentation Requirements

Design details including redundancy and logic of the ECCS instrumentation are discussed in Chapter 7, Section 7.3.1.1.1.

All instrumentation required for automatic and manual initiation of the HPCS, LPCS, LPCI, and ADS is discussed in Chapter 7, subsection 7.3.2.1 and is designed to meet the requirements of IEEE 279 and other applicable regulatory requirements. The HPCS, LPCS, LPCI, and ADS can be manually initiated from the control room.

The HPCS, LPCS, and LPCI are automatically initiated on low reactor water level or high drywell pressure. (See Table 6.3-2 for specific initiation levels for each system.) The ADS is automatically actuated by sensed variables for reactor vessel low water level and drywell high pressure plus indication that at least one RHR (LPCI), or LPCS pump is operating. The HPCS, LPCS, and LPCI automatically return from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. The LPCS and LPCI system injection into the RPV begin when reactor pressure decreases to system discharge shutoff pressure.

HPCS injection begins as soon as the HPCS pump is up to speed and the injection valve is open since the HPCS is capable of injecting water into the RPV over a pressure range from 1177 psid* to 0 psid*.

6.3.6 Generic Letter 08-01 Response

Generic Letter (GL 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems,” (Reference 7) requested licensees to take actions to ensure that gas accumulation in the ECCS, the Shutdown Cooling System and the Containment Spray System is managed such that operability of these systems is not challenged and that appropriate action is taken when conditions that could impact system operability are identified. The NRC requested in the generic letter that licensees perform evaluations and submit information regarding gas management activities. As part of Grand Gulf’s response to the letter, the susceptibility of plant systems to gas accumulation was evaluated, fill and vent procedures were reviewed, acceptance criteria for allowable gas

* psid – differential pressure between RPV and pump suction source

systems to gas accumulation was evaluated, fill and vent procedures were reviewed, acceptance criteria for allowable gas volumes was developed, and procedures and administrative controls were developed for periodic monitoring and trending of gas accumulation (References 8 and 9). These actions provide assurance that systems are kept sufficiently filled with water to ensure system operability.

6.3.7 References

1. Hirsch, H. M., "Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems," January 1973 (NEDO-10739).

2. "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50 Appendix K, "NEDO-20566 submitted August 1974, and "General Electric Refill Reflood Calculation," (Supplement to Safe Code Description) transmitted to US NRC by letter, G. L. Gyorey to Victor Stello, Jr., dated December 20, 1974.

3. GESSAR-238, Nuclear Island Standard Design (Section 6.3), docket number STN 50-447.

4. Compliance with Acceptance Criteria of 10 CFR 50.46 Letter G. L. Gyorey to V. Stello, May 12, 1975.

5. "Safety Evaluation for General Electric ECCS Evaluation Model Modifications," letter from K. R. Goller (NRC) to G. G. Sherwood (GE), dated April 12, 1977.

6. "General Electric (GE) Loss-of-Coolant (LOCA) Analysis Model Revisions - Core Heating Code CHASTE05," letter from A. J. Levine (GE) to D. F. Ross (NRC), dated January 27, 1977.

7. NRC Generic Letter (GL 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray System", January 11, 2008

8. Letter from Mike Krupa (EOI) to NRC, GNRO 2008/00066, "Nine-Month Response to NRC Generic Letter 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems" dated October 13, 2008.

9. Letter from Mike Krupa (EOI) to NRC, GNRO 2008/00066, "Nine-Month Supplemental Response to NRC Generic Letter 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems" dated November 20, 2008.

10. NEDO-20566-P-A, "General Electric Co. Analytical Model for Loss of Coolant Analysis in Accordance with 10CFR50 Appendix K," September 1986.

11. GGNS-SA-09-00002, Rev. 1, "Grand Gulf Nuclear Station GNF2 ECCS-LOCA Evaluation," GE Hitachi Nuclear Energy 0000-0100-8822, Revision 1, December 2009.

12. Deleted.

13. GGNS-NE-09-0018, Rev. 2, "GGNS EPU ECCS-LOCA SAFER/GESTR,"GE Hitachi Nuclear Energy 0000-0107-6093-R1, Revision 1, January 2010.

14. GE Nuclear Energy, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 1, GESTR-LOCA-A Model for the Prediction of Fuel Rod Thermal Performance," NEDE-23785-1-PA, Revision 1, October 1984.

15. GE Nuclear Energy, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 2, SAFER - Long Term Inventory Model for BWR Loss-of-Coolant Analysis," NEDE-23785-1-PA, Revision 1, October 1984.

16. GE Nuclear Energy, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 3, SAFER/ GESTR Application Methodology," NEDE-23785-1-PA, Revision 1, October 1984.

17. GE Nuclear Energy, "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 3 Supplement 1, Additional Information for Upper Bound PCT Calculation," NEDE-23785P-A, Revision 1, March 2002.

18. GE Nuclear Energy, "TASC-03A A Computer Program for Transient Analysis of a Single Channel," NEDC-32084P-A, Revision 2, July 2002.

19. GE Nuclear Energy, "SAFER Model for Evaluation of Loss-of-Coolant Accidents for Jet Pump and Non-Jet Pump Plants," NEDE-30996P-A, October 1997.

20. GE Nuclear Energy, “Compilation of Improvements to GENE’s SAFER ECCS-LOCA Evaluation Model,” NEDE-32950P Revision 1, July 2007.

21. “Request for Approval for Use of Loss-of-Coolant Accident LOCA Evaluation Model Code REFLOODS,” letter from A. J. Levine (GE) to D.B. Vassallo (NRC), dated March 14, 1977.

22. DELETED

23. GNR02012/00148, "Report of Changes and Errors to 10CFR 50.46," dated December 6, 2012.

TABLE 6.3-1: OPERATIONAL SEQUENCE OF EMERGENCY CORE COOLING SYSTEMS FOR DESIGN BASIS ACCIDENT (DBA)[(1)]

GNF2 Analysis for Two-Loop Operation[(2)]

Event Occurrences	Time(sec)
LOCA Occurs	0.00
Initiate Scram (on Level 3)[(3)]	0.01
Low-low-Low (Level 1) Level	4.36
Jet Pump Uncovers	5.03
Feedwater Flow Reaches Zero	5.00
TCVs Fully Closed	5.00
Lower Plenum Flashes	8.26
LPCS Valve Pressure Permissive	23.35
LPCI Valve Pressure Permissive	25.35
LPCS Injection Occurs	70.36
LPCI Injection Occurs	70.36
ADS Valves Open	124.37
PCT Occurs	150.43

(1) DBA is a HPCS-DG failure; therefore, no HPCS injection shown.

(2) Peak cladding temperature (PCT) for single loop operation (SLO) is bounded by PCT for two loop operation.

(3) The initial water level is conservatively assumed to be at L3.

TABLE 6.3-1A: HISTORICAL INFORMATION
OPERATIONAL SEQUENCE OF EMERGENCY CORE COOLING SYSTEMS FOR DESIGN BASIS ACCIDENT (DBA)
(INITIAL CYCLE)

Time (sec)	Events
0	Design basis loss-of-coolant accident assumed to start; normal auxiliary power assumed to be lost.
~0	High drywell pressure and reactor low water level (level 3) are reached. All diesel generators, HPCS, LPCS, LPCI signaled to start on high drywell pressure*. Scram initiated on level 3.
~3	Reactor low-low water level (level 2) reached. HPCS receives second signal to start.
~6	Reactor low-low-low water level (level 1) reached. Second signal to start LPCI and LPCS; main steam isolation valves close. Auto-depressurization sequence begins.
~13	All diesel generators ready to load; energize HPCS pump motor; open HPCS injection valve: begin energizing LPCI and LPCS pump motors.
~28	Pressure permissive for LPCI & LPCS injection valve reached.
~30	HPCS injection valve open and pump at design flow, which completes HPCS startup.
~33	LPCI & LPCS pumps at rated speed.
~58	LPCI and LPCS pumps at rated flow, LPCI and LPCS injection valves open, which completes the LPCI and LPCS startups.

TABLE 6.3-1A: HISTORICAL INFORMATION
OPERATIONAL SEQUENCE OF EMERGENCY CORE COOLING SYSTEMS FOR DESIGN BASIS ACCIDENT (DBA)
(INITIAL CYCLE) (Continued)

Time (sec)	Events
See Figure 6.3-14	Core effectively reflooded assuming worst single failure; heatup terminated.
>10 min	Operator shifts to containment (suppression pool) cooling.

* No credit taken in LOCA analysis for ECC system start on high drywell pressure signal.

NOTE: For the purpose of all but the next to last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures (see subsections 6.3.2.5 and 6.3.3.3).

TABLE 6.3-2: PLANT PARAMETERS USED IN GGNS GNF2 LOCA ANALYSIS

Plant Parameters	Value
Core Thermal Power[1] (Mwt)	4496.2
Corresponding Power (% of 4408 Mwt)[2]	102
Vessel Steam Output (lbm/hr)	19.6×10^6
Rated Core Flow (lbm/hr)[2]	112.5×10^6
Vessel Steam Dome Pressure (psia)[3]	1100
Maximum Recirculation Line [4] Break Area (ft^2)	3.112

(1) The Appendix K core thermal power corresponds to 102% of the current licensed value of 4408 MWt.

(2) Results bound increased core flow operation at 118.125 Mlbm/hr.

(3) Same for two loop and single loop operation.

(4) The recirculation line break area includes the vessel nozzle on the suction side of the pump and the recirculation piping which feeds the jet pump drive lines.

TABLE 6.3-2: PLANT PARAMETERS USED IN GGNS GNF2 LOCA ANALYSIS (Continued)

1. **Low Pressure Coolant Injection (LPCI) System**

	Variable	Units	Value
a.	Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	225
b.	Minimum rated flow from three pumps at vessel pressure	gpm psid (vessel to drywell)	22000 20
c.	Initiating Signals		
	Low Water level (L1)	in. above vessel zero (AVZ)	378.3
	Or		
	High drywell pressure	psig	2[5]
d.	Maximum allowable time delay from initiating signal to pumps at rated speed (including DG start time)	sec	27
e.	Pressure at which LPCI injection valve may open	psia	450
f.	LPCI injection valve (IV) stroke time	sec	30

2. **Low Pressure Core Spray (LPCS) System**

	Variable	Units	Value
a.	Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	289
b.	Minimum rated flow at vessel pressure	psid (vessel to drywell)	7000 122
c.	Initiating Signals		

TABLE 6.3-2: PLANT PARAMETERS USED IN GGNS GNF2 LOCA ANALYSIS (Continued)

	Variable	Units	Value
	Low water level (L1)	in. AVZ	378.3
	or		
	High drywell pressure	psig	2(5)
d.	Maximum allowable time delay from initiating signal to LPCS pumps at rated speed (including DG start time)	sec	27
e.	Pressure at which LPCS injection valve may open	psia	450
f.	LPCS injection valve (IV) stroke time	sec	30
g.	Maximum allowed runout flow	gpm	9100
3.	**High Pressure Core Spray (HPCS) System**		
a.	Vessel pressure at which flow pumps can inject flow	psid (vessel to source of suction)	1177
b.	Minimum rated flow at vessel pressure	gpm/psid (vessel to source of suction)	550/1177 1650/1147 7000/200 7000/0
c.	Initiating Signals		
	Low water level (L2)	in. AVZ	487.0
	or		
	High drywell pressure	psig	2(5)
d.	Maximum allowable time delay from initiating signal to rated flow available and injection valve wide open	Sec	32

TABLE 6.3-2: PLANT PARAMETERS USED IN GGNS GNF2 LOCA ANALYSIS (Continued)

	Variable	Units	Value
e.	Maximum allowed runout flow	gpm	8175
4.	**Automatic Depressurization System (ADS)**		
a.	Total number of valves installed	-	8
b.	Number of valves used in analysis	-	7[6]
c.	Minimum flow capacity of 6 valves at vessel pressure	1bm/hr psg	5.550×10^6 1241
d.	Initiating signals		
	Low water level (Ll) and	in. above vessel zero	378.3
	High drywell pressure	psig	2
	or		
	Low water level (L1) and High drywell pressure bypass timer timed out	in. above vessel zero	378.3
e.	High drywell pressure bypass timer	Sec	600
	Initiating signal:		
	low water level (L1)	in. above vessel zero	378.3
f.	Delay time from all initiating signals completed to the time valves are open with confirmation that LPCI or LPCS pump is running	Sec	120

[5] No credit is taken for the initiation signal on high drywell pressure.

(6) The ECCS-LOCA evaluation assumes a single ADS valve is unavailable. A single failure consisting of an additional unavailable ADS valve (six operable valves) is not limiting thus eliminating the need to evaluate the single failure of an ADS valve (SF-ADS) as a separate failure.

TABLE 6.3-2A: HISTORICAL INFORMATION SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANAYLSIS (INITIAL CYCLE)

Plant Parameters

o Core Thermal Power	MWt	3993
o Vessel Steam Output	LBm/hr	17.3×10^6
o Corresponding percent of rated steam flow	percent	105
o Vessel Steam Dome Pressure	psia	1060
o Maximum Recirculation Line Break Area	ft^2	3.1

Emergency Core Cooling System Parameters

Low-Pressure Coolant Injection System

o Vessel Pressure at which flow may commence	psid (vessel to drywell)	225
o Minimum Rated Flow at Vessel Pressure	GPM psid (vessel to drywell)	22000 20

Initiating signals

o low-low-low water level	inches above top of active fuel	16.4
or		
high drywell pressure	psig	2.0
o Maximum allowable time delay from initiating signal to pumps at rated speed	sec	27.0

TABLE 6.3-2A: HISTORICAL INFORMATION
SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANAYLSIS (INITIAL CYCLE)

o Injection valve fully open	sec after low pressure permissive	30.0
o Pressure at which injection valve may open	psia	450
Low-Pressure Core Spray System		
o Vessel pressure at which flow may commence	psid (vessel to drywell)	289
o Minimum rated flow at Vessel Pressure	GPM psid (vessel to drywell)	7000 122
o **Initiating signals**		
low-low-low water level	inches above top of active fuel	16.4
or		
high drywell pressure	psig	2.0
o Maximum allowed (runout) flow	GPM	9100
o Maximum allowed delay time from initiating signal to pump at rated speed	sec	27
o Injection valve fully open	sec after low pressure permissive	30
o Pressure at which injection valve may open	psia	450

**TABLE 6.3-2A: HISTORICAL INFORMATION
SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANAYLSIS (INITIAL CYCLE)**

High-Pressure Core Spray		
o Vessel pressure at which flow may commence	psid	1177
o Minimum flow available at vessel to pump suction head		See Figure 6.3-3
o **Initiating signals**		
low-low water level	ft. above top of active fuel	10.06
or		
high drywell pressure	psig	2.0
o Maximum allowed (runout) flow	GPM	9100
o Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	sec	27.0
Automatic Depressurization System		
o Total number of valves installed		8
o Number of valves used in analysis		8(1)
o Minimum Flow Capacity of 8 valves at vessel pressure	lb/hr psid (vessel suppression pool)	6.4×10^6 1125
ADS TIMER		
o Initiating Signals:		

TABLE 6.3-2A: HISTORICAL INFORMATION
SIGNIFICANT INPUT PARAMETERS TO THE LOSS-OF-COOLANT ACCIDENT ANAYLSIS (INITIAL CYCLE)

a.	low water level	inches above top	16.4
	and	of active fuel	
	high drywell pressure	psig	2.0
	or		
b.	low water level	ft. above top of active fuel	1.0
	and		
	high drywell pressure bypass timer timed out	delay time (seconds)	600
	Delay time from all initiating signals completed (with high drywell pressure signal or bypass, as applicable) to the time valves are open	sec	120

FUEL PARAMETERS

o Fuel type	--	Initial Core
o Fuel Bundle Geometry	--	P 8 x 8 R
o Lattice		C
o Number of fueled rods		62
o Peak Linear Heat Generation Rate	kw/ft	13.4
o Initial Minimum Critical Power Ratio	--	1.17

(1) Additional LOCA analyses in Section 6.3.3.7.8 with seven ADS valves justify one ADS valve out of service for an extended period of time.

TABLE 6.3-3: BREAK SPECTRUM SUMMARY OF RESULTS OF LOCA ANALYSIS (CURRENT CYCLE)

Break Size (Appendix K)[1,2]	Single Failure	GNF2 PCT (°F)
DBA	HPCS-DG	1676
DBA	LPCS-DG	1483
DBA	LPCI-DG	1420

Current Licensing Basis PCT: < 1730°F[3]

Notes: (1) Peak Local Oxidation is <3% for all cases and core-wide metal-water reaction is <0.1% for all cases.

(2) DBA is defined as the break size and break type that produces the highest PCT for a given single failure. A detailed listing of the PCT for various break sizes and types is given in References 11 and 13. The current Licensing Basis PCT is reported in Reference 20.

(3) Based on the 2016 Supplemental Reload Licensing Report for GGNS Cycle 21, the License Basis PCT was updated to 1730 °F, for MELLLA+ operation (Ref. GNRO-2016/00058).

TABLE 6.3-3A: HISTORICAL INFORMATION
SUMMARY OF RESULTS OF LOCA ANALYSIS
(INITIAL CYCLE)

Break Spectrum Analysis		PCT (F)	Peak Local Oxidation % of Initial Cladding Thickness
Break Size Location Single Failure			
3.1 ft^2 (DBA) Recirc. Suction LPCI D/G		2098 (1, 3)	2.01
2.5 ft^2 (80% DBA) Recirc. Suction LPCI D/G		1973 (1)	1.23
1.9 ft^2 (60% DBA) Recirc. Suction LPCI D/G		1791 (1)	<1.0
1.0 ft^2 Recirc. Suction LPCI D/G	Large Break Method	1990 (1)	1.71
	Small Break Methods	1718 (2)	<1.0
.09 ft^2 Recirc. Suction HPCS		1404 (2)	<1.0

NOTES:

(1) CHASTE - large break method

(2) Non-DBA reflood

(3) The impact of the LPCI and LPCS injection valve pressure interlock is estimated to be a 51°F increase in PCT (which includes a less than 10°F increase resulting from a recirculation pump coastdown time of 3 seconds as reported in AECM-85/0138) and a 0.004 increase in oxidation fraction. Consistent with the estimated increase in PCT, the CWMWR would be 0.16%.

The corewide metal-water reaction for the subject plant has been calculated using method 1 described in Reference 2. The value is as follows:

Corewide Metal-Water Reaction % = .13

TABLE 6.3-4: HISTORICAL INFORMATION
KEY TO FIGURES
(INITIAL CYCLE ANALYSES)

		Large Break Method			Small Break Method						
	DBA	80% DBA 2.5 ft² Larger Break Methods	60% DBA 1.9 ft² Large break methods	1.0 ft² Large Break Methods	1.0 ft² Small Break Methods	Worst Small Break 0.09 ft²	Additional Small Break	Core Spray Line	Main Feedwater Line	Main Steamline Inside Containment	Main Steamline Outside Containment
Core Average Inlet Flow	6.3-9	6.3-19	6.3-27	6.3-35	NA	NA	NA	NA	NA	NA	NA
Core Inlet Enthalpy	6.3-10	6.3-20	6.3-28	6.3-36	NA	NA	NA	NA	NA	NA	NA
Core Average Pressure	6.3-11	6.3-21	6.3-29	6.3-37	NA	NA	NA	NA	NA	NA	NA
Minimum Critical Power Ratio	6.3-12	6.3-22	6.3-30	6.3-38	NA	NA	NA	NA	NA	NA	NA
Convective Heat Transfer Coefficient	6.3-13	6.3-23	6.3-31	6.3-39	6.3-43	6.3-47	6.3-51	6.3-55	6.3-59	6.3-63	6.3-73
Water Level Inside Shroud	6.3-14	6.3-24	6.3-32	6.3-40	6.3-44	6.3-48	6.3-52	6.3-56	6.3-60	6.3-64	6.3-74
Reactor Vessel Pressure	6.3-15	6.3-25	6.3-33	6.3-41	6.3-45	6.3-49	6.3-53	6.3-57	6.3-61	6.3-65	6.3-75
Peak Cladding Temperature	6.3-16	6.3-26	6.3-34	6.3-42	6.3-46	6.3-50	6.3-54	6.3-58	6.3-62	6.3-66	6.3-76
		Large Break Method			Small Break Method						

TABLE 6.3-4: HISTORICAL INFORMATION
KEY TO FIGURES
(INITIAL CYCLE ANALYSES)

	DBA	80% DBA 2.5 ft^2 Larger Break Methods	60% DBA 1.9 ft^2 Large break methods	1.0 ft^2 Large Break Methods	1.0 ft^2 Small Break Methods	Worst Small Break 0.09 ft^2	Additional Small Break	Core Spray Line	Main Feedwater Line	Main Steamline Inside Containment	Main Steamline Outside Containment
Peak Cladding Temperature and Peak Local Oxidation vs. Break Area	6.3-8	6.3-8	6.3-8	6.3-8	6.3-8	6.3-8	6.3-8	6.3-8	6.3-8	6.3-8	6.3-8
Hot Pin Fuel Average Temperature	6.3-17	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hot Pin Internal Pressure	6.3-18	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Total Time for Which Highest Powered Node Remains Uncovered Vs. Break Area	6.3-71	6.3-71	6.3-71	6.3-71	NA	NA	NA	NA	NA	NA	NA
Normalized Decay Power vs. Time	6.3-72	6.3-72	6.3-72	6.3-72	6.3-72	6.3-72	6.3-72	6.3-72	6.3-72	6.3-72	6.3-72

TABLE 6.3-5: DELETED

TABLE 6.3-6: MAPLHGR, MAXIMUM LOCAL OXIDATION, AND PEAK CLAD TEMPERATURE FOR RELOAD CORES

	Fuel Type	MAPLHGR (kW/ft)	Maximum Oxidation[1] Percentage	Appendix K PCT (°F)
Two Loop Operation[2]	GNF2	13.78	≤2	1676
Single Loop Operation[3]	GNF2	11.44	≤1	1372

(1) The core wide metal-water reaction is ≤0.1% for all cases.

(2) The two loop operation Appendix K PCT values are calculated at the limiting MEOD power / flow point.

(3) MAPLHGR for SLO is the two loop operation MAPLHGR multiplied by 0.83.

**TABLE 6.3-6A: HISTORICAL INFORMATION
MAPLHGR, MAXIMUM LOCAL OXIDATION, AND
PEAK CLAD TEMPERATURE VERSUS EXPOSURE
(INITIAL CYCLE)**

High Enrichment Fuel

Exposure MWD/T	MAPLHGR KW/FT	P. C. T. DEG = F	OXID FRAC
200.0	12.0	2098*	0.0201*
1,000.0	12.0	2087	0.0193
5,000.0	12.4	2069	0.0178
10,000.0	12.6	2071	0.0177
15,000.0	12.6	2083	0.0184
20,000.0	12.6	2085	0.0186
25,000.0	12.1	2014	0.0147
30,000.0	11.1	1885	0.0093
35,000.0	10.2	1764	0.0060
40,000.0	9.6	1692	0.0045

Medium Enrichment Fuel

Exposure MWD/T	MAPLHGR KW/FT	P. C. T. DEG = F	OXID FRAC
200.0	11.7	2016	0.0152
1,000.0	11.8	2019	0.0152
5,000.0	12.4	2027	0.0154
10,000.0	12.4	2018	0.0150
15,000.0	12.4	2026	0.0154
20,000.0	12.1	1986	0.0135
25,000.0	11.2	1869	0.0090
30,000.0	10.4	1760	0.0060
35,000.0	9.6	1672	0.0042
40,000.0	9	1609	0.0031

**TABLE 6.3-6A: HISTORICAL INFORMATION
MAPLHGR, MAXIMUM LOCAL OXIDATION, AND
PEAK CLAD TEMPERATURE VERSUS EXPOSURE
(INITIAL CYCLE)**

Low Enrichment Fuel

Exposure MWD/T	MAPLHGR KW/FT	P. C. T. DEG = F	OXID FRAC
200.0	11.5	1960	0.0125
1,000.0	11.4	1929	0.0112
5,000.0	11.3	1886	0.0095
10,000.0	11.5	1881	0.0092
15,000.0	11.5	1878	0.0091
20,000.0	11.0	1818	0.0073
25,000.0	10.4	1743	0.0055
30,000.0	9.7	1666	0.0040
35,000.0	9.0	1596	0.0029

* The impact of the LPCI and LPCS injection valve pressure interlock is estimated to be a 51°F increase in PCT and a 0.004 increase in oxidation fraction.

TABLE 6.3-7: SINGLE FAILURE EVALUATION

The following table shows the single, active failures considered in the ECCS performance evaluation.

Assumed Failure	**Suction Break Systems Remaining**
LPCI Emergency Diesel Generator (D/G)	All ADS[(1)], HPCS, LPCS, 1 LPCI
LPCS Emergency D/G	All ADS[(1)], HPCS, 2 LPCI
HPCS Emergency D/G	All ADS[(1)], LPCS, 3 LPCI
One ADS Valve[(1)]	All ADS minus one, LPCS, HPCS, 3 LPCI

Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above designed failures.

(1) The ECCS performance evaluations assume one ADS valve is inoperable to eliminate the need to evaluate the single failure of an ADS valve (SF-ADS) as a separate single failure.

TABLE 6.3-8: ECCS DESIGN PARAMETERS

System	Parameter	Design Value	Basis
LPCS	Pool suction line design pressure	100 psig	Nominal value, suction from RPV (shutdown test)
RHR	Pool suction line design pressure	100 psig	Nominal value, suction from RPV (shutdown test)
HPCS	Design pressure for suction from condensate storage	100 psig	Nominal value, suction from condensate tank
RHR	Shutdown suction line pressure	200 psig	Max vessel cut in pressure + max vessel water level above pump
LPCS	Pump discharge line pressure	600 psig	Shutoff head + max suction pressure
RHR (LPCI)	Pump discharge line pressure	500 psig	Shutoff head + max suction pressure
HPCS	Pump discharge line pressure	1575 psig	Shutoff head + max suction pressure
LPCS	Pump suction & discharge temp.	*212°F	Saturation at 1 atmosphere (Reg. Guide 1.1)
HPCS	Pump suction & discharge temp.	*212°F	Saturation at 1 atmosphere (Reg. Guide 1.1)
RHR (LPCI)	Pool suction temp.	*212°F	Saturation at 1 atmosphere (Reg. Guide 1.1)
RHR	Shutdown line temperature	358°F	Max shutdown suction temperature (saturation @ 135 psig)

TABLE 6.3-8: ECCS DESIGN PARAMETERS (Continued)

System	Parameter	Design Value	Basis
LPCS	Rated flow	7115 gpm @ 128 psid	FSAR Table 6.3-2
RHR (LPCI)	Rated flow	@ 24 psid	7450 gpm/loop - 3 loops, FSAR Table 6.3-2
HPCS	Rated flow	7115 gpm	FSAR Table 6.3-2 (values selected to provide adequate core cooling for all design basis events)
LPCS	RPV pressure at beginning flow	289 psid	FSAR Table 6.3-2 (values selected to provide adequate core cooling for all design basis events)
RHR (LPCI)	RPV pressure at beginning flow	225 psid	FSAR Table 6.3-2 (values selected to provide adequate core cooling for all design basis events)
HPCS	RPV pressure at beginning flow	1177 psid	FSAR Table 6.3-2 (values selected to provide adequate core cooling for all design basis events)
LPCS	Time to rated speed	27 sec	FSAR Table 6.3-2 (value selected to provide adequate core cooling for all design basis events)
RHR (LPCI) pump	Time to rated speed	27 sec	FSAR Table 6.3-2 (values selected to provide adequate core cooling for all design basis events)
HPCS Pump	Time to rated speed	32 sec	FSAR Table 6.3-2 (value selected to provide adequate core cooling for all design basis events)
LPCS	Injection valve fully open	30 sec	FSAR Table 6.3-2 (values selected to provide adequate core cooling for all design basis events)

TABLE 6.3-8: ECCS DESIGN PARAMETERS (Continued)

System	Parameter	Design Value	Basis
RHR (LPCI)	Injection valve fully open	30 sec	FSAR Table 6.3-2 (values selected to provide adequate core cooling for all design basis events)
HPCS	Injection valve fully open	32 sec	FSAR Table 6.3-2 (values selected to provide adequate core cooling for all design basis events)
LPCS	Rated flow pump head	735 feet	Rated vessel pressure + elevation difference from pool to vessel nozzle + frictional losses
HPCS	Rated flow pump head	910 feet	Rated vessel pressure + elevation difference from pool to vessel nozzle + frictional losses (suction from suppression pool)

* 212°F is the temperature used for design of system components. The maximum expected temperature of pumped fluid, 194°F (which provides 5°F of design margin to the highest calculated debris-generating event suppression pool temperature of 189°F) is used for NPSH calculations.

TABLE 6.3-9: MANUAL VALVES IN HPCS SYSTEM

Valve No. E22-	Type	Location	Service	Function	Methods for Minimizing Positioning Error (See Note 2)
F036	14"-Gate	Drywell	Main process line	Main process line block valve	Lo, position indicating light (control room mounted)
F026	4"-Gate	Aux bldg	Flushing	Backflush line by passing check valve (F024)	Lc, closed
F003	4"-Gate	Aux bldg	Flushing	Flushing water supply line to HPCS pump discharge	Lc, backed by check valve F224 and gate valve F031 (Lc)
F031	4"-Gate	Aux bldg	Flushing	Flushing water supply line to HPCS pump discharge	Lc, backed by check valve F224 and gate valve F003 (Lc)
F034	1-1/2"-Gate	Aux bldg	Jockey pump lines	Jockey pump suction isolation valve	Lo; during HPCS operation, position is not critical; closed
F033	1-1/2"-Globe	Aux bldg	Jockey pump lines	Jockey pump minimum flow line to HPCS pump suction	Open; during HPCS operation, position is not critical

TABLE 6.3-9: MANUAL VALVES IN HPCS SYSTEM (Continued)

Valve No. E22-	Type	Location	Service	Function	Methods for Minimizing Positioning Error (See Note 2)
F019	4"-Gate	Aux bldg	Jockey pump lines	Jockey pump discharge RHR system isolation valve	Lc; backed by RHR valves F072A & B,F071 A&B, and F070A all locked closed

1. Piping low point drains, high point vents, and test connections are all double valved.

2. Lo = Locked open under administrative control.

   Lc = Locked closed under administrative controls.

   Backed by . . . = Double valve arrangement precluding impact on system operation without two positioning errors and/or a non-manual valve failure.

   Closed = Indicates valve is in line that forms closed loop with piping that, without a double positioning error, would have no effect on system functioning.

TABLE 6.3-9A: HPCS AND LPCS RELIEF VALVE DATA

Pipe Class	Valve Number	Size (in.)	Max Set Point Pressure (psig)	Rated Capacity (Seller) gpm
LPCS SYSTEM (E 21) UNIT 1				
GBB	F018	1½	584	163
HBB	F031	3/4	100	17.9
HPCS SYSTEM (E 22) UNIT 1				
HBB	F014	3/4	100	17.5
DBB	F035	1	1560	102

TABLE 6.3-10: MANUAL VALVES IN LPCS SYSTEM

Valve No. EZl-	Type	Location	Service	Function	Methods for Minimizing Positioning Error (See Note 2)
F007	14"-Gate	Drywell	Main process line	Main process line block valve	Lo, position indicating light (control room mounted)
F025	4"-Gate	Aux Bldg	Flushing	Flushing water suzn.nClPvA to LPCS pump discharge piping to vessel	Lc, backed by several valves of condensate (Pll) system that fail closed and locked closed El2 F063C
F004	4"-Gate	Aux bldg	Flushing	Backflush line bypassing check valve F003	Lc, closed
F008	4"-Gate	Aux Bldg	Flushing, servicing	LPCS pump suction line drain to radwaste system	Lc; backed by E12F070B and E12F072C, both locked closed
F205	4"-Gate	Aux bldg	Min. flow SC test	Minimum flow & test return line to suppression pool	Lo; backed by motor-operated F011A
F036	18"-Gate	Aux bldg	System test	Fuel pool cool & cleanup input to LPCS suctions lines	Lc, backed by spectacle flange DO07 which is installed blind during plant operation

TABLE 6.3-10: MANUAL VALVES IN LPCS SYSTEM (Continued)

Valve No. EZ1-	Type	Location	Service	Function	Methods for Minimizing Positioning Error (See Note 2)
F032	1-1/2"-Globe	Aux bldg	Jockey pump lines	LPCS jockey pump suction isolation valve	Lo; LPCS operation would not be affected by this valve's position (closed)
F035	lit-Globe	Aux bldg	Jockey pump lines	Jockey pump minimum flow to LPCS suction lines	Open, LPCS operation would not be affected by this valve's position (closed)

NOTES: See Table 6.3-9

TABLE 6.3-11: MANUAL VALVES IN LPCI (RHR) SYSTEM

Valve No. E12-	Type	Location	Service	Function	Methods for Minimizing Positioning Error (See Note 2)
F029 A,B,C	18"-Gate	Aux bldg	Main process line	Block valves on RHR pumps discharge lines	Lo, See Note 3
F039 A,B,C	14"-Gate	Drywell	Main process line	Process line block valve for leak testing F041 A,B,C	Lo, position indicating light (control room mounted)
F120 A,B	18"-Gate	Aux bldg	Heat removal	RHR heat exchanger isolation valve	Lo
F130 A,B	18"-Gate	Aux bldg	Heat removal	RHR heat exchanger isolation valve	Lo
F066C	18"-Gate	Aux bldg	Pump test after shutdown	Inlet from spent fuel pool to RHR Pump C suction	LC, backed by normally closed valves G41F057 and G41F226
F099 A,B	14"-Gate	Aux bldg	Fuel pool cooling	Return to spent fuel after heat exchanger pass	Lc, backed by normally closed valve G41F035
F018 A,B,C	4"-Gate	Aux bldg	Minimum flow & standby	Minimum flow line to suppression pool from RHR pumps A,B,C discharges	Lo

TABLE 6.3-11: MANUAL VALVES IN LPCI (RHR) SYSTEM (Continued)

Valve No. E12-	Type	Location	Service	Function	Methods for Minimizing Positioning Error (See Note 2)
F063 A,C	4"-Gate	Aux bldg	Flushing	Flush line from RHR A,C pump discharges to radwaste system	Lc, backed by several valves of condensate (Pll) system that fail closed and locked closed E21F025
F086	4"-Gate	Aux bldg	Flushing	Flush water supply to RHR B pump discharge line	Lc, backed by check valve F266
F071 A,B	4"-Gate	Aux bldg	Flushing	RHR A,B pump suction line drains to radwaste system	Lc, backed by locked closed F070A and F072 A & B
F072 A,B	4"-Gate	Aux bldg	Flushing	RHR A,B pump discharge line drains to radwaste system	Lc, backed by locked closed F070A and F071 A SC B
F044 A,B	4"-Gate	Containment	Flushing	Flushing water supply to injection lines from RHR A,B pumps	Lc, backed by F265 A & B
F072C	4"-Gate	Aux bldg	Flushing	RHR C pump suction line drain to radwaste system	Lc, backed by locked closed F070B
F022	4"-Gate	Aux bldg	Flushing	Backflush line bypassing check valve F031C in RHR C pump discharge pipe	Lc, closed

TABLE 6.3-11: MANUAL VALVES IN LPCI (RHR) SYSTEM (Continued)

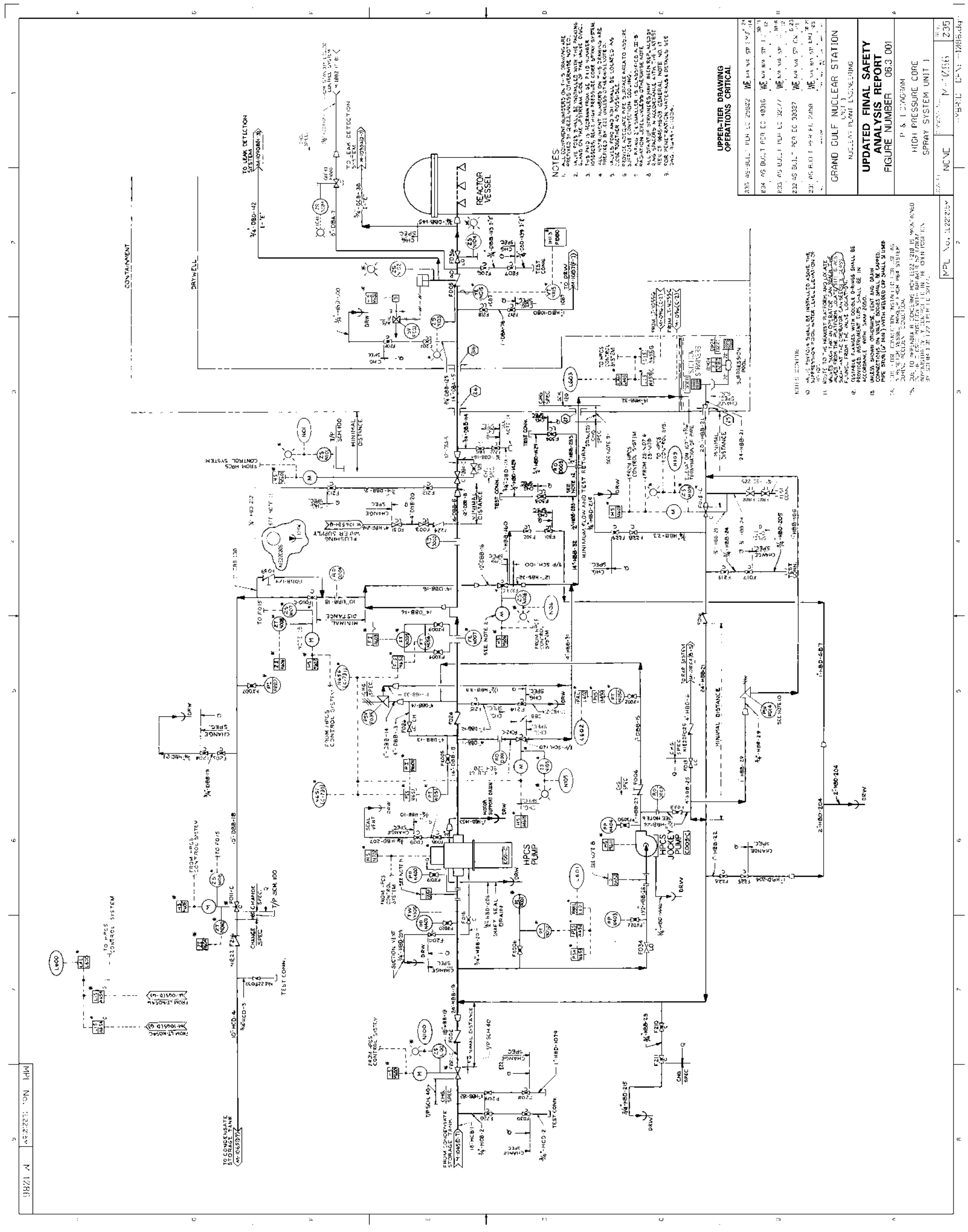
Valve No. E12-	Type	Location	Service	Function	Methods for Minimizing Positioning Error (See Note 2)
F082C	1 1/2" Globe	Aux bldg	Jockey pump lines	RHR loop C jockey pump suction isolation	Lo; during LPCI operation, position is not critical; closed

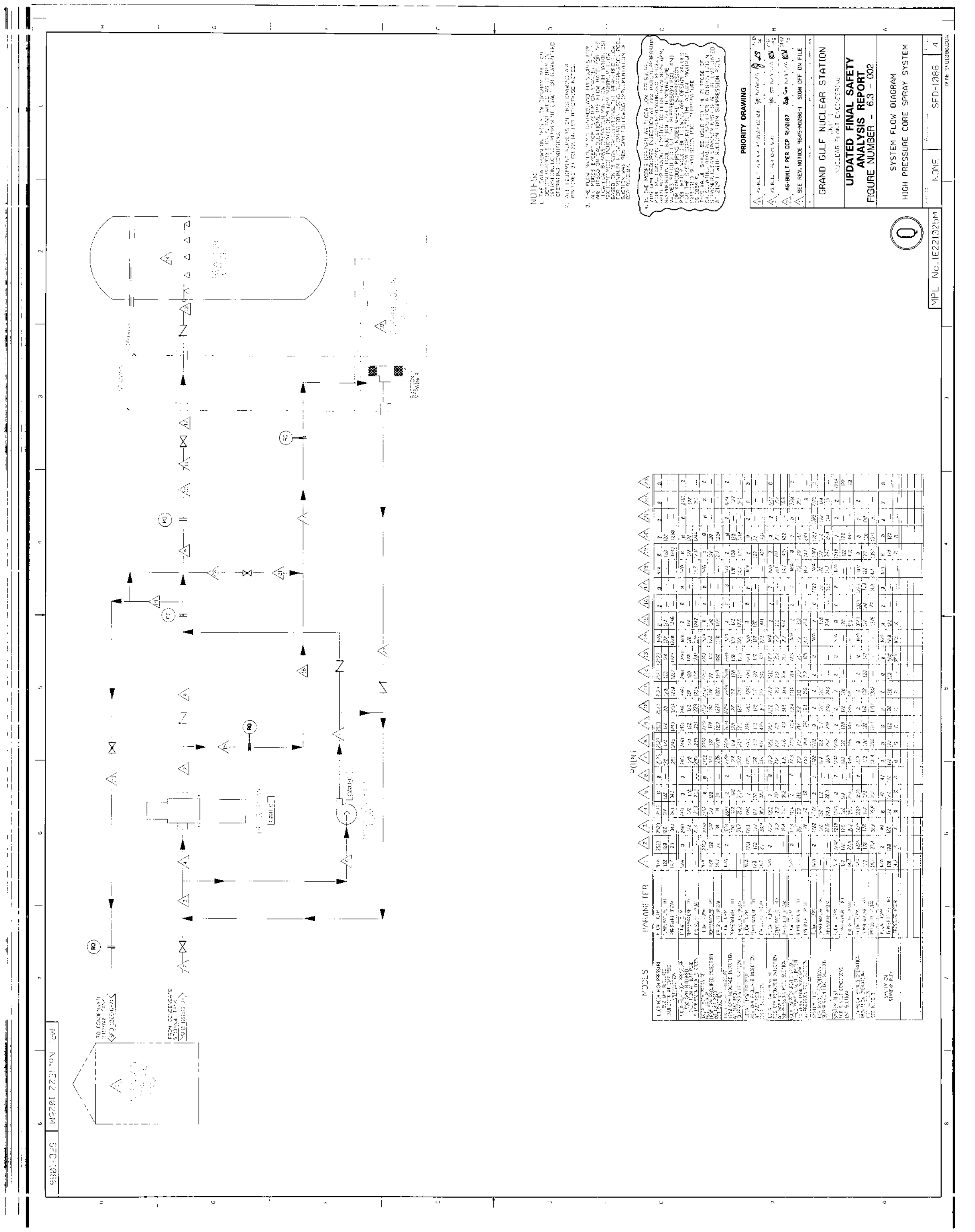
Notes: For Notes 1 and 2, see Table 6.3-9.

3. The incorrect positioning of F029 A, B, & C would also be detected during normal plant operation when LPCI flow capacity verification tests are periodically conducted.

TABLE 6.3-12: MAXIMUM EXPECTED ACCUMULATED OPERATING TIME FOR ECCS PUMPS

Mode of Operation	RHR (hr)	LPCS (hr)	LPCS (hr)
1. In-shop test	4	4	4
2. Preoperation	48	48	48
3. Monthly testing	120	480	480
4. Yearly testing	40	120	240
5. Post-LOCA	2400	2400	2400
6. Shutdown	28800	N/A	N/A
TOTAL	31412	3052	3172

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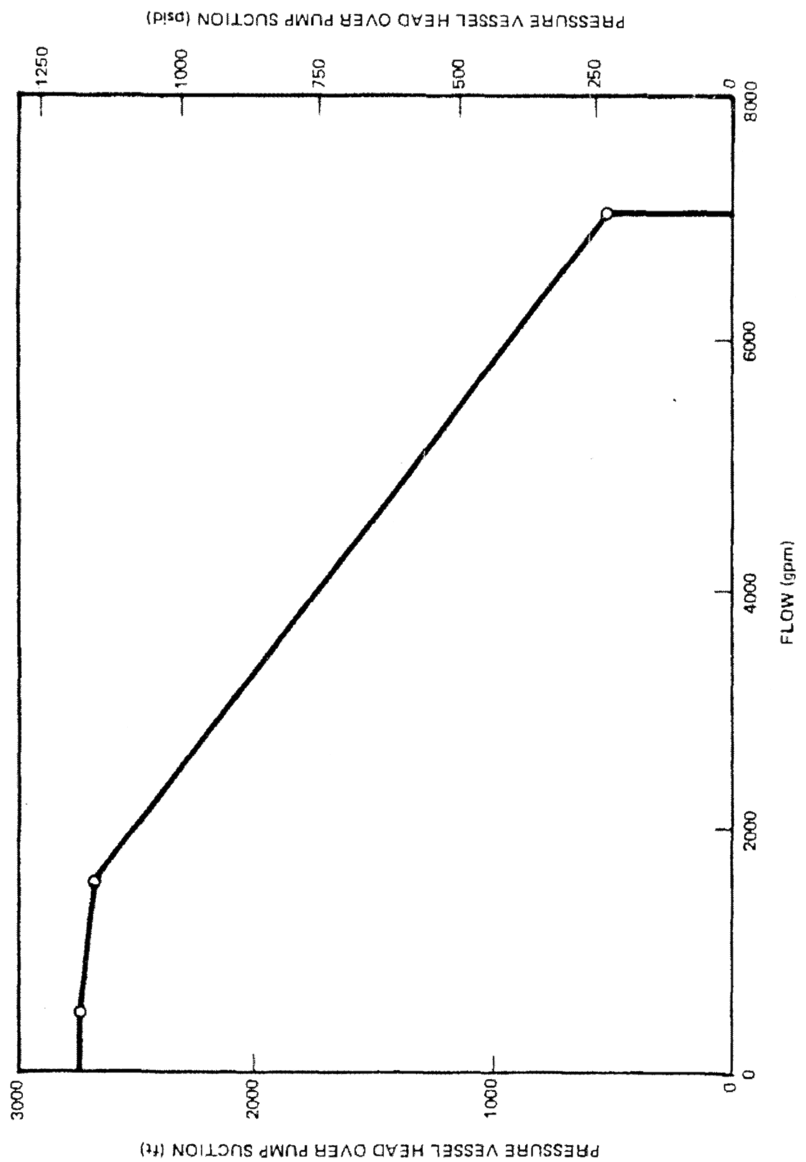
GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 6.3 - 002
SYSTEM FLOW DIAGRAM
HIGH PRESSURE CORE SPRAY SYSTEM
NOTES:
MODES
PARAMETER
POINT

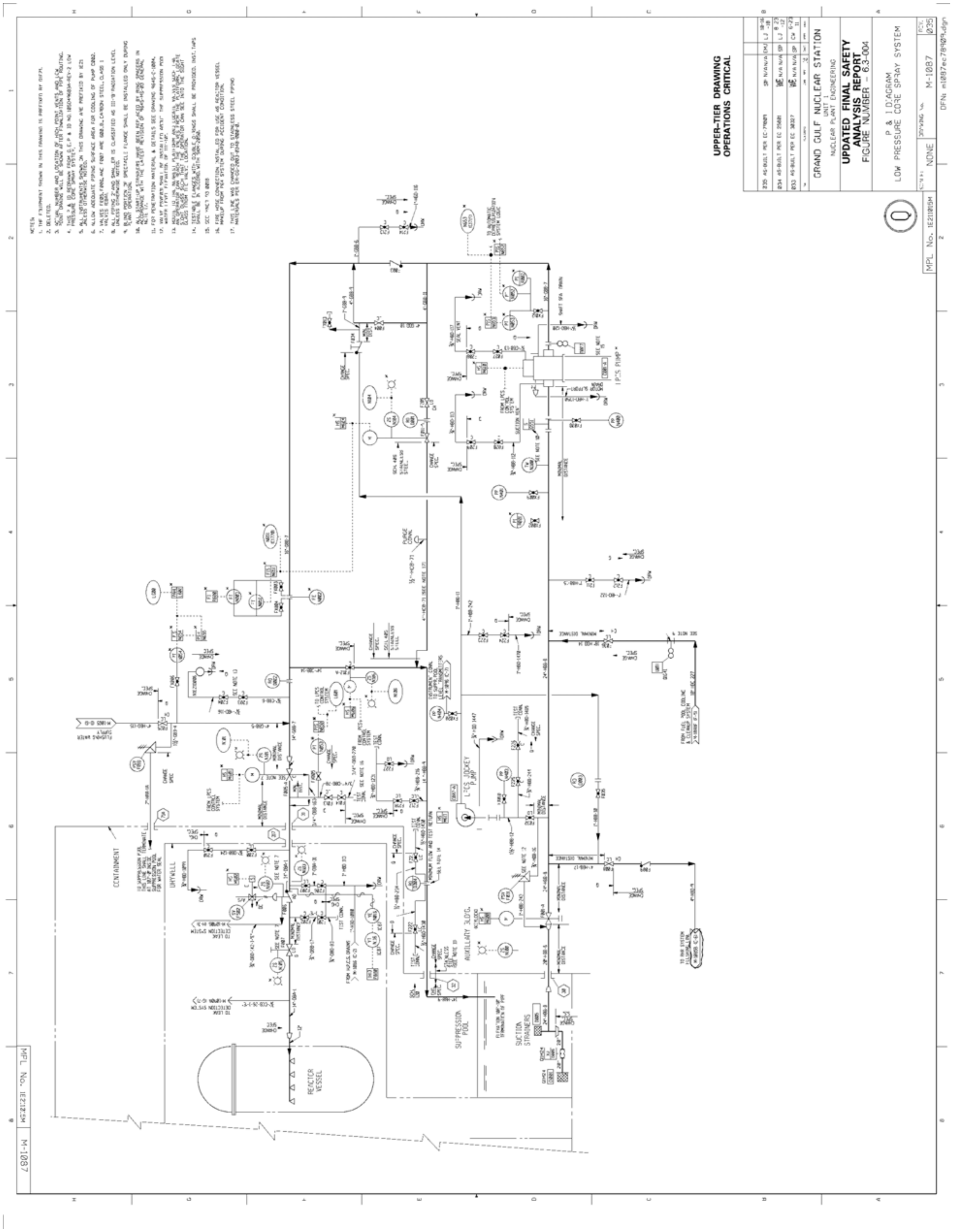


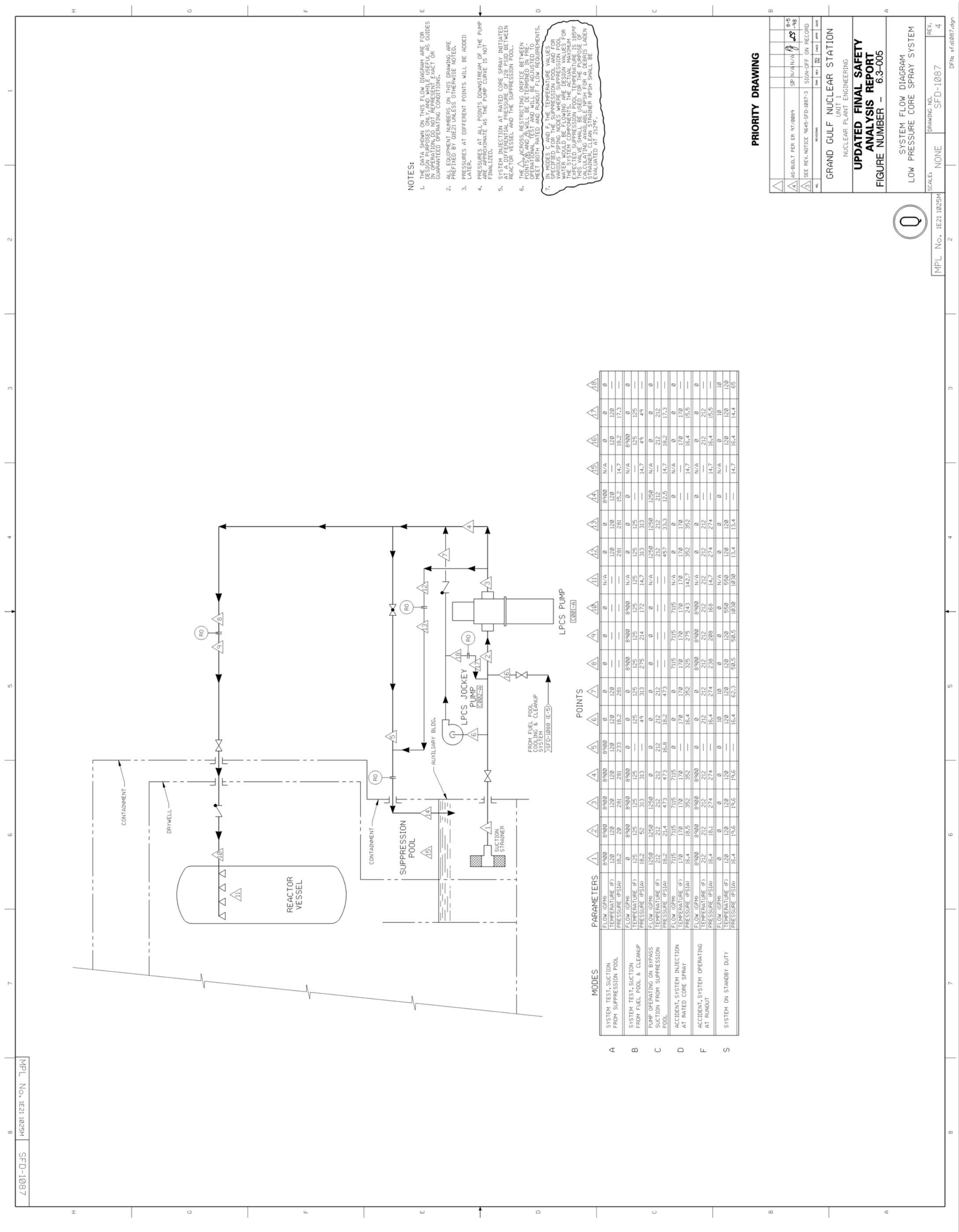
GRAND GULF NUCLEAR STATION
UNIT 1

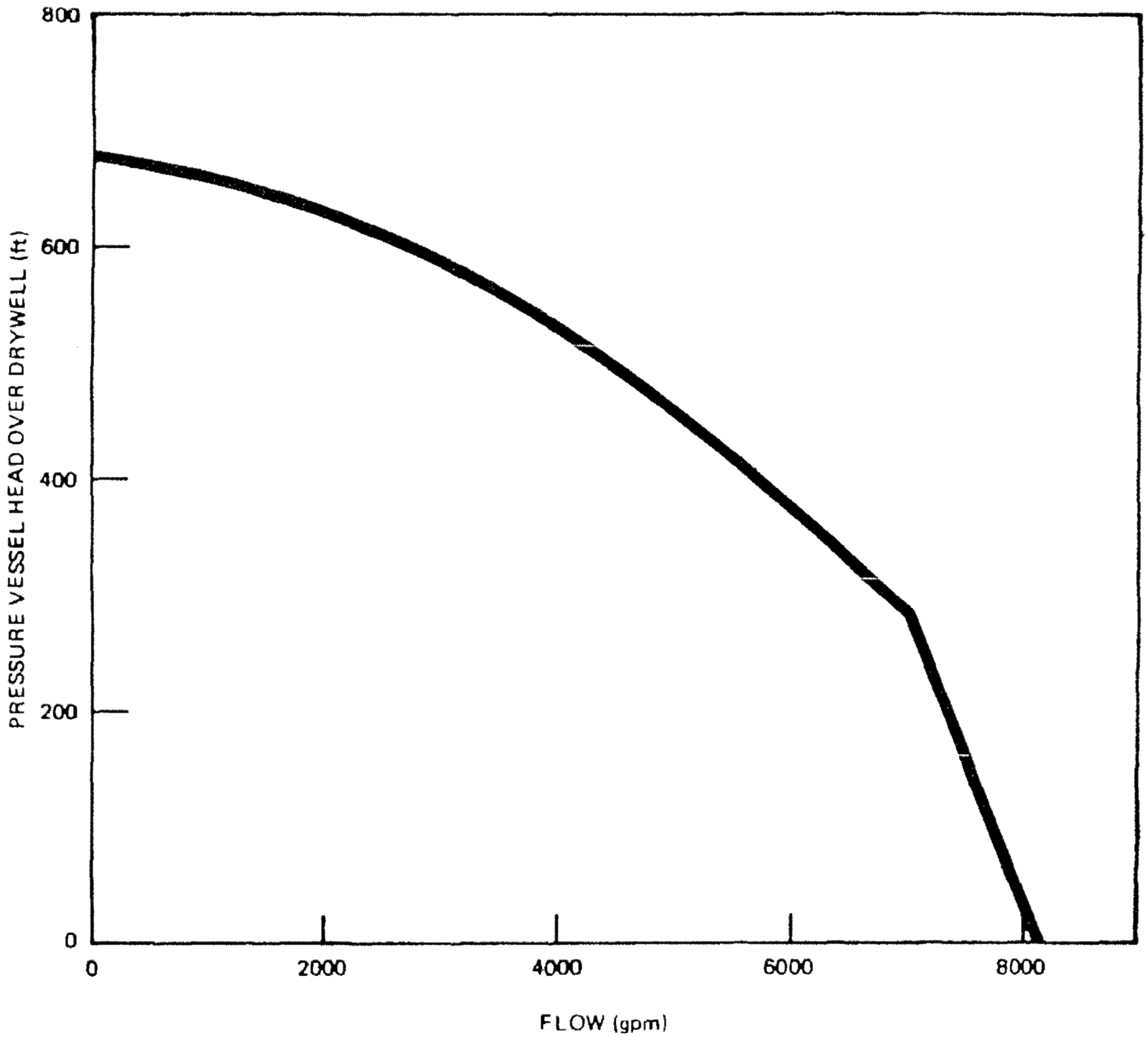
UPDATED FINAL SAFETY ANALYSIS REPORT

HEAD VERSUS HIGH PRESSURE CORE SPRAY FLOW USED IN THE INITIAL CYCLE LOCA ANALYSIS

FIGURE 6.3-3


UPPER-TIER DRAWING
OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 6.3-004
P & I DIAGRAM
LOW PRESSURE CORE SPRAY SYSTEM
M-1087


PRIORITY DRAWING
GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 6.3-005
SYSTEM FLOW DIAGRAM
LOW PRESSURE CORE SPRAY SYSTEM
SFD-1087
NOTES:
REACTOR VESSEL
SUPPRESSION POOL
CONTAINMENT
DRYWELL
LPCS PUMP
LPCS JOCKEY PUMP
SUCTION STRAINER
AUXILIARY BLDG.
MODES
PARAMETERS
POINTS

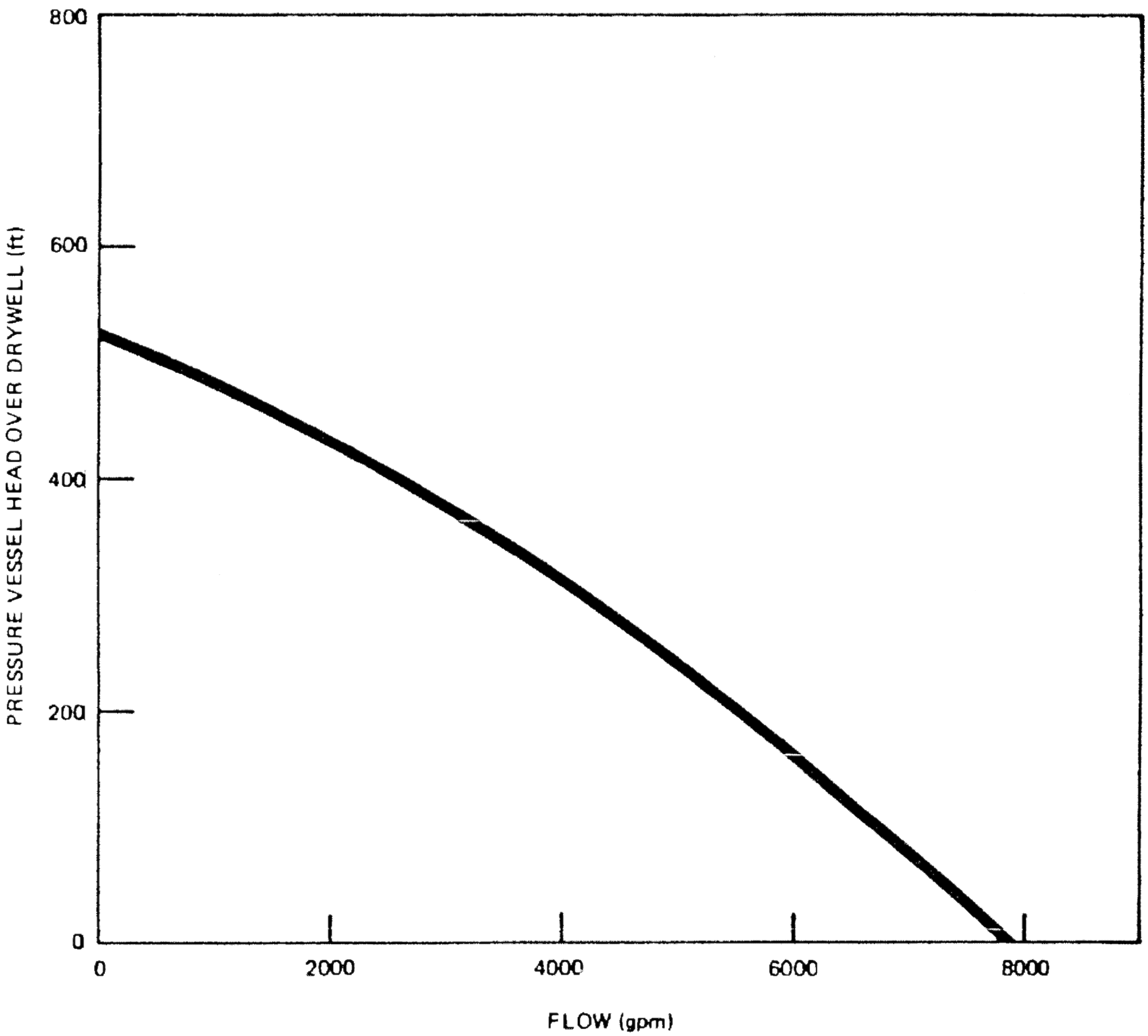


GRAND GULF NUCLEAR STATION
UNIT 1

UPDATED FINAL SAFETY ANALYSIS REPORT

HEAD VERSUS LOW PRESSURE CORE SPRAY FLOW USED IN THE INITIAL CYCLE LOCA ANALYSIS

FIGURE 6.3-6

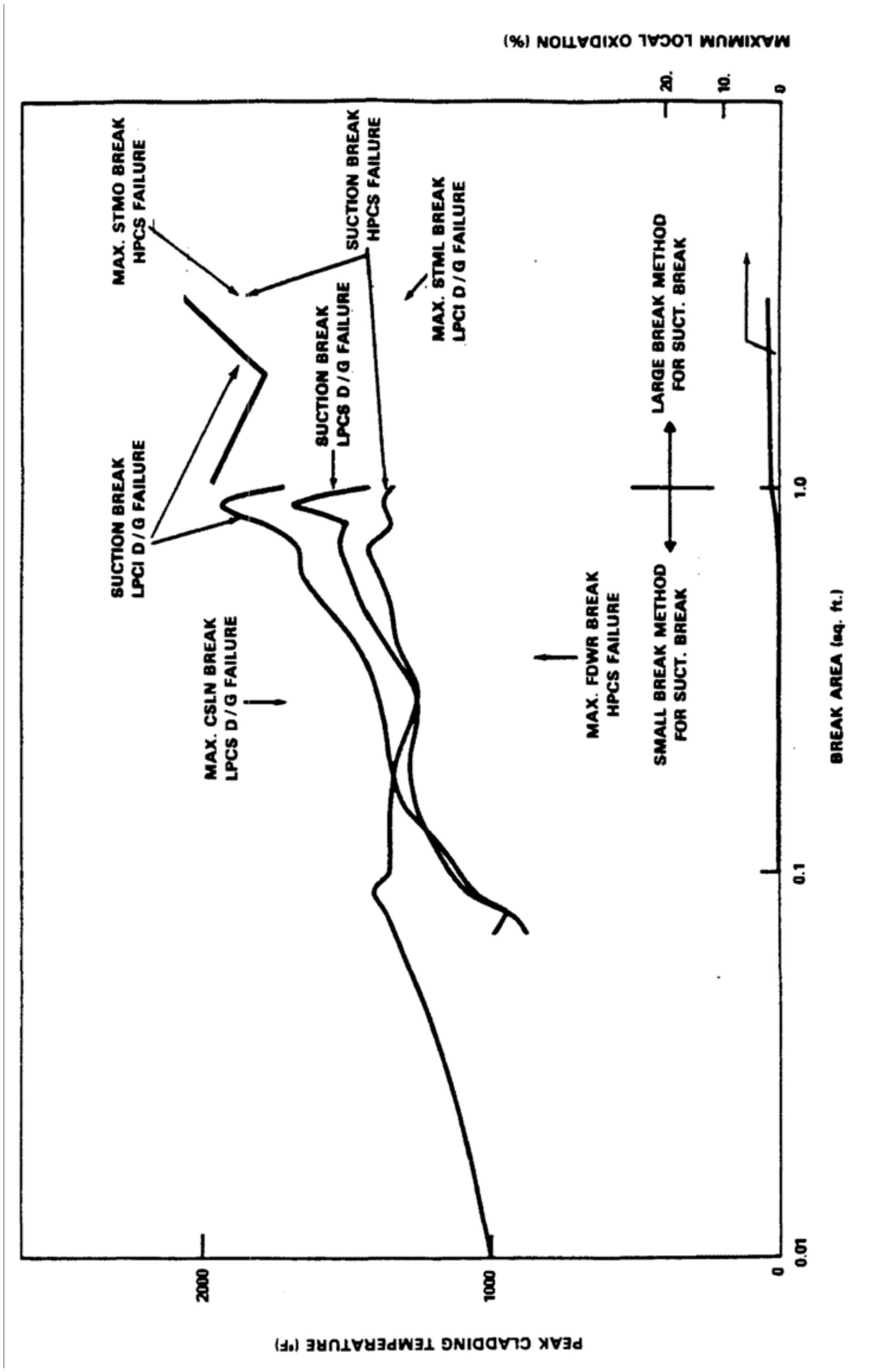


GRAND GULF NUCLEAR STATION
UNIT 1

UPDATED FINAL SAFETY ANALYSIS REPORT

HEAD VERSUS LOW PRESSURE COOLANT INJECTION FLOW USED IN THE INITIAL CYCLE LOCA ANALYSIS

FIGURE 6.3-7

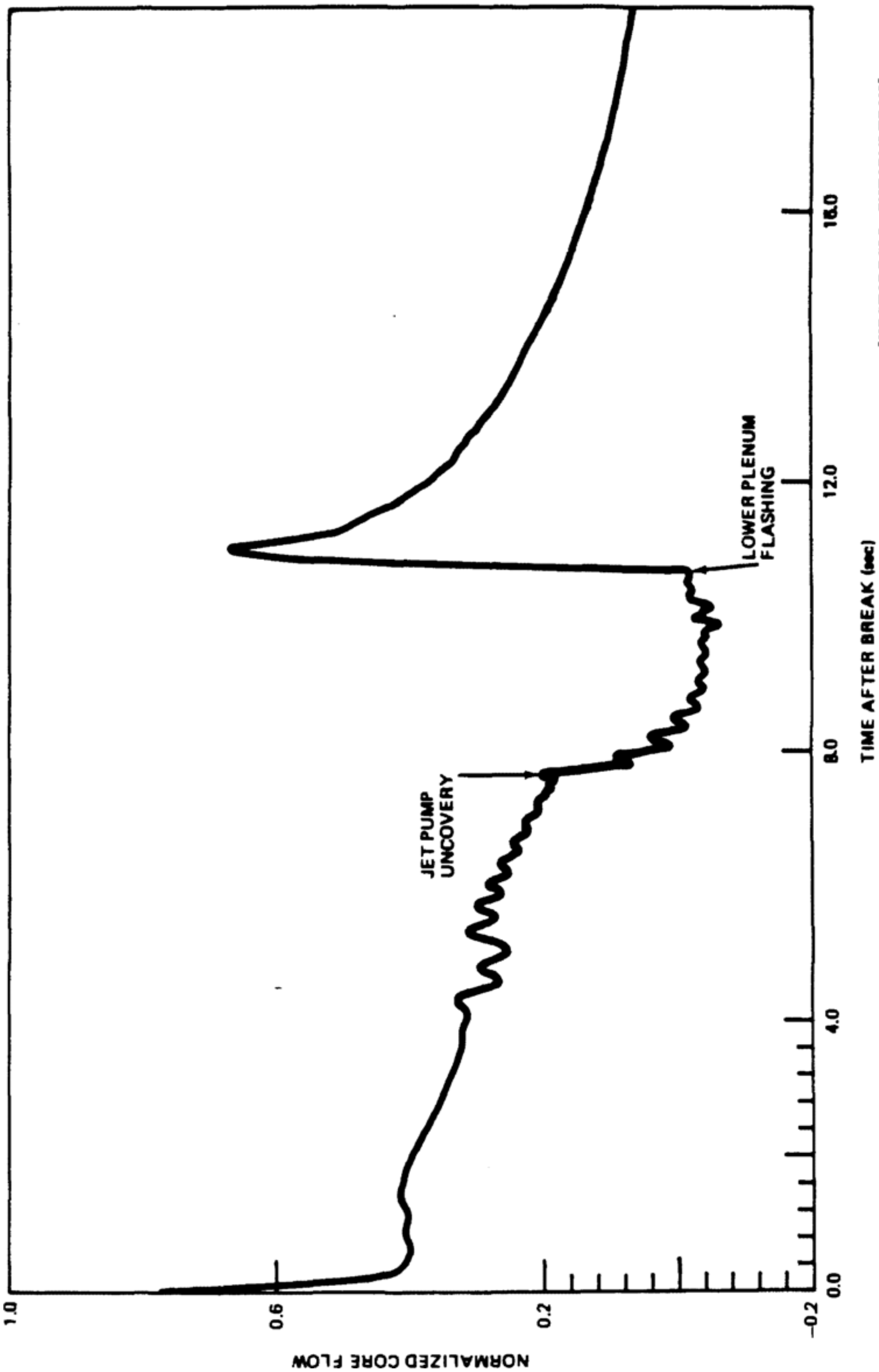


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

PEAK CLADDING TEMPERATURE AND
MAXIMUM LOCAL OXIDATION
VERSUS BREAK AREA
[INITIAL CYCLE]

FIGURE 6.3-8



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

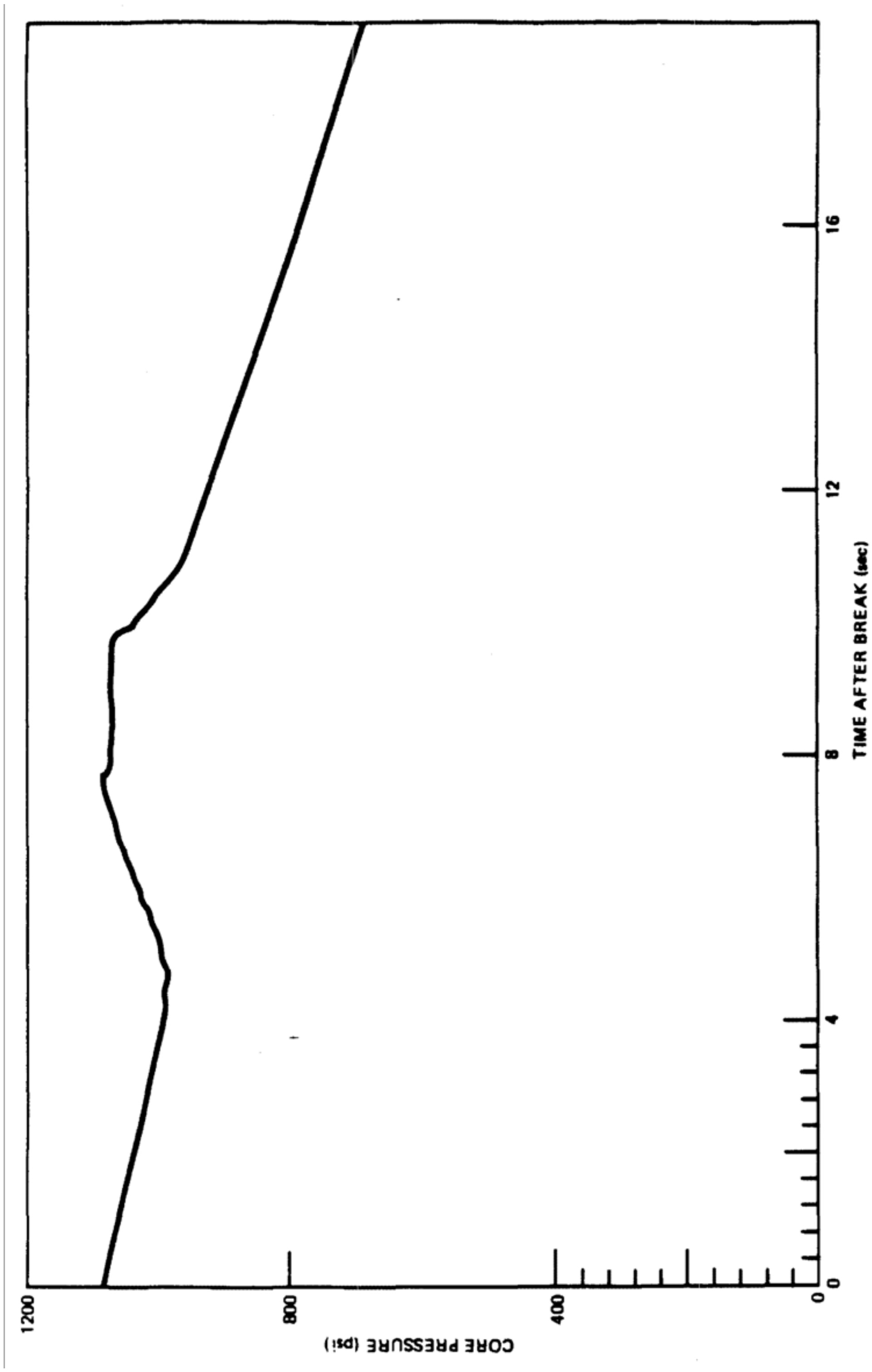
NORMALIZED CORE AVERAGE INLET FLOW
VERSUS TIME AFTER BREAK
(DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-9

[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CORE INLET ENTHALPY VERSUS TIME AFTER BREAK
(DESIGN BASIS ACCIDENT, RECIRCULATION SUCTION BREAK,
LPCI DIESEL GENERATOR FAILURE)
(INITIAL CYCLE)

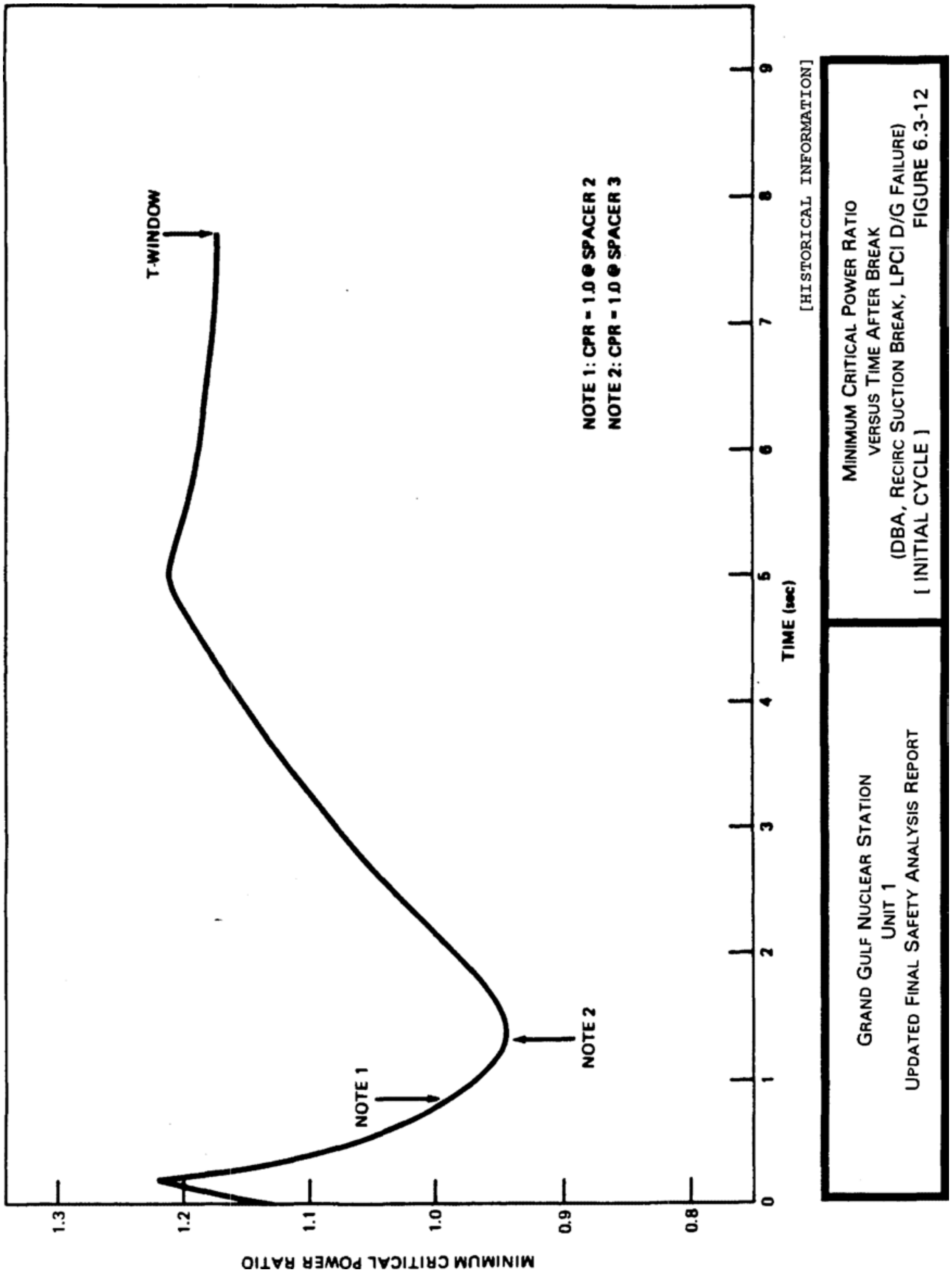
FIGURE 6.3-10



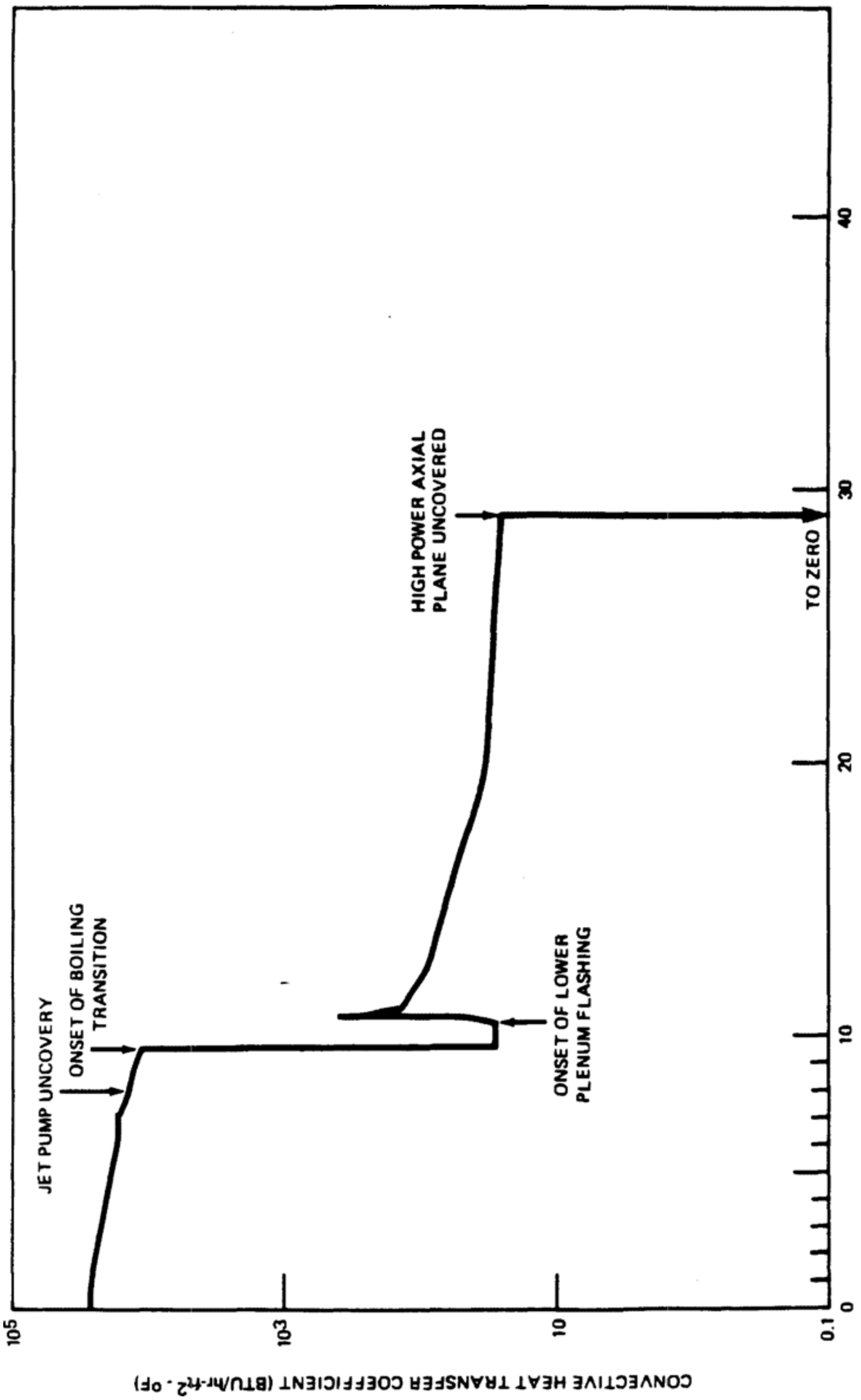
[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CORE AVERAGE PRESSURE
VERSUS TIME AFTER BREAK
(DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-11

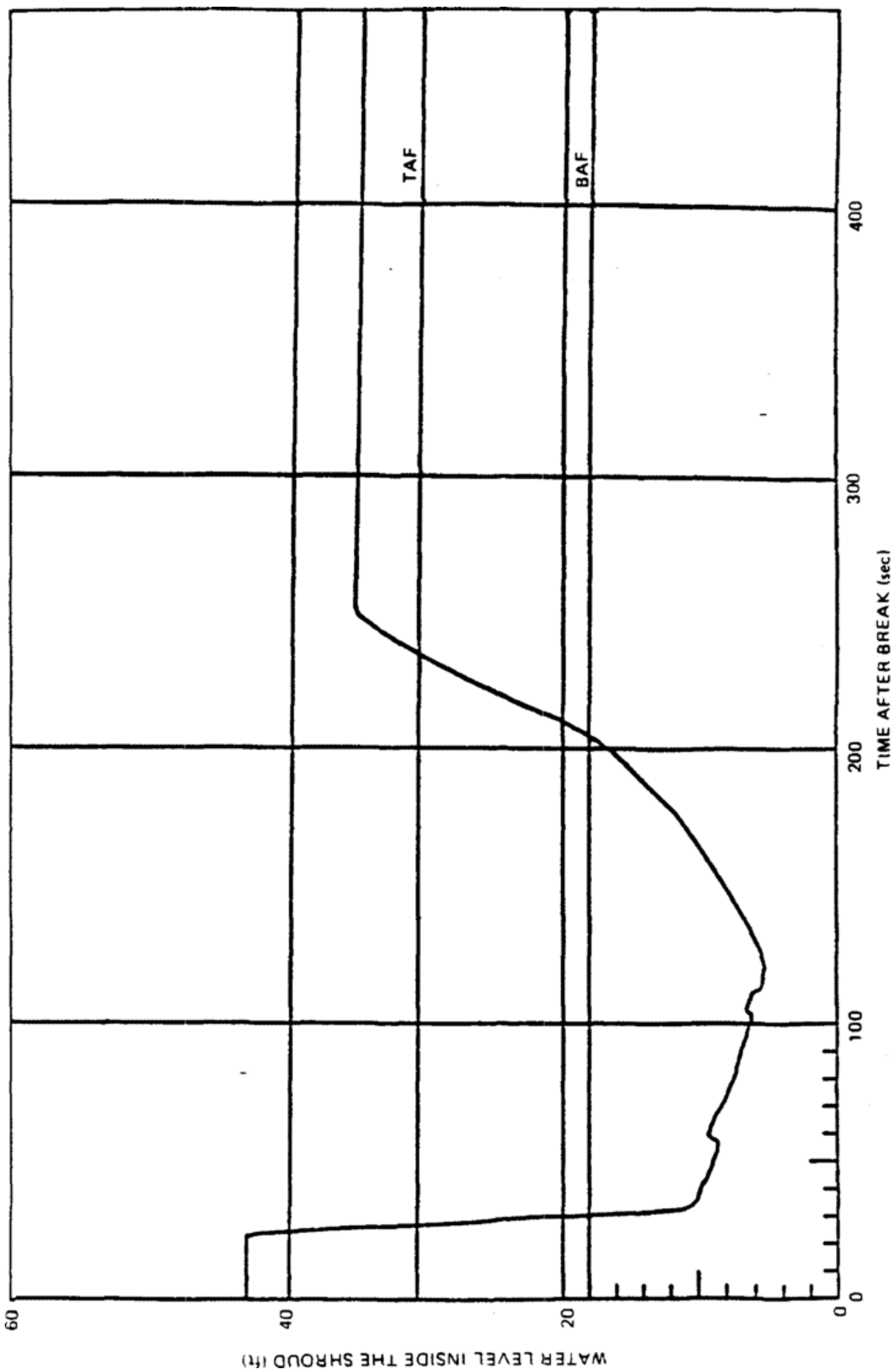


MINIMUM CRITICAL POWER RATIO
VERSUS TIME AFTER BREAK
(DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-12



[HISTORICAL INFORMATION]

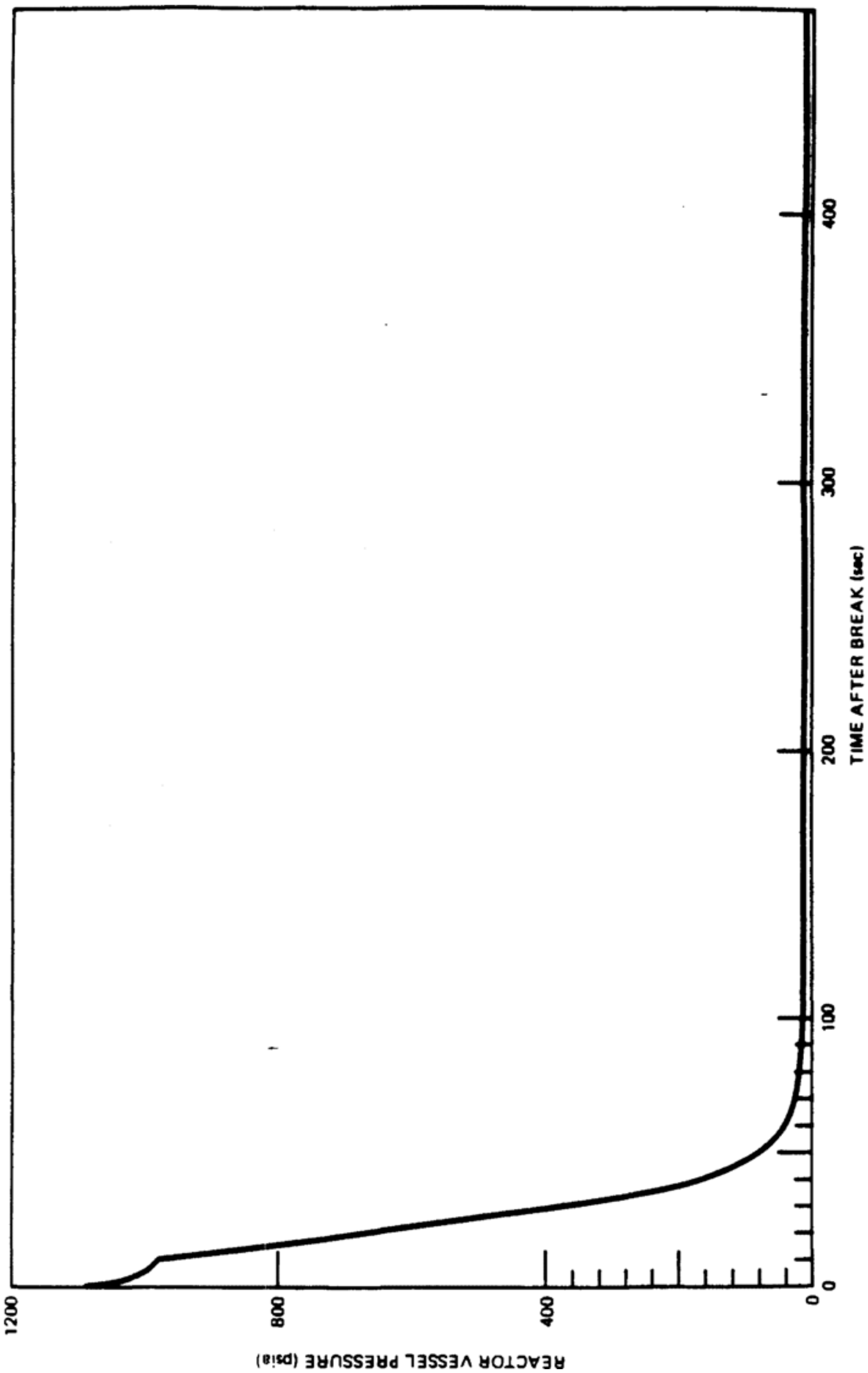
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	CONVECTIVE HEAT TRANSFER COEFFICIENT VERSUS TIME AFTER BREAK (DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE) [INITIAL CYCLE] FIGURE 6.3-13



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK
(DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-14

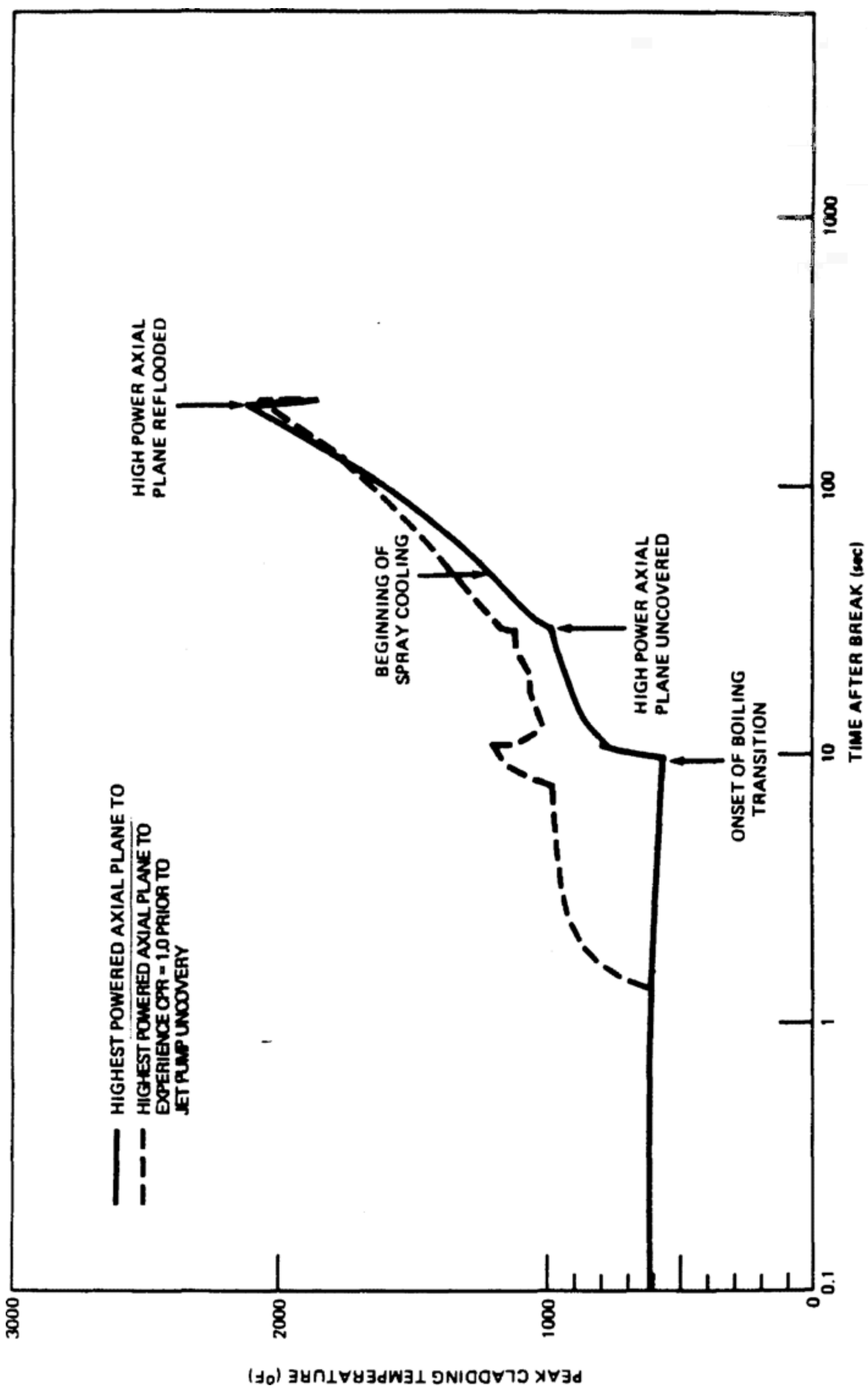


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK
(DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-15

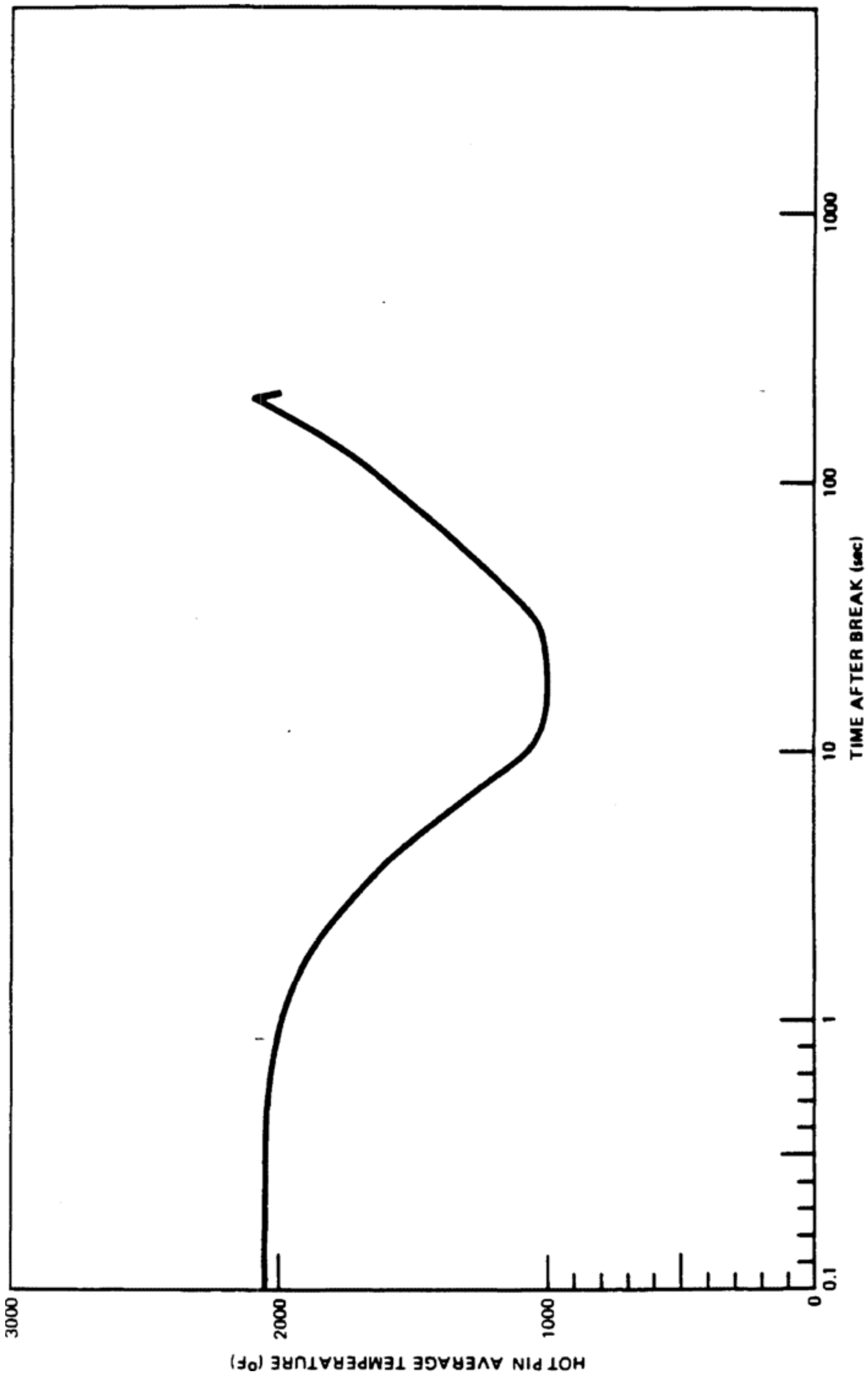


[HISTORICAL INFORMATION]

Grand Gulf Nuclear Station
Unit 1
Updated Final Safety Analysis Report

Peak Cladding Temperature
versus Time After Break
(DBA, Recirc Suction Break, LPCI D/G Failure)
[Initial Cycle]

FIGURE 6.3-16

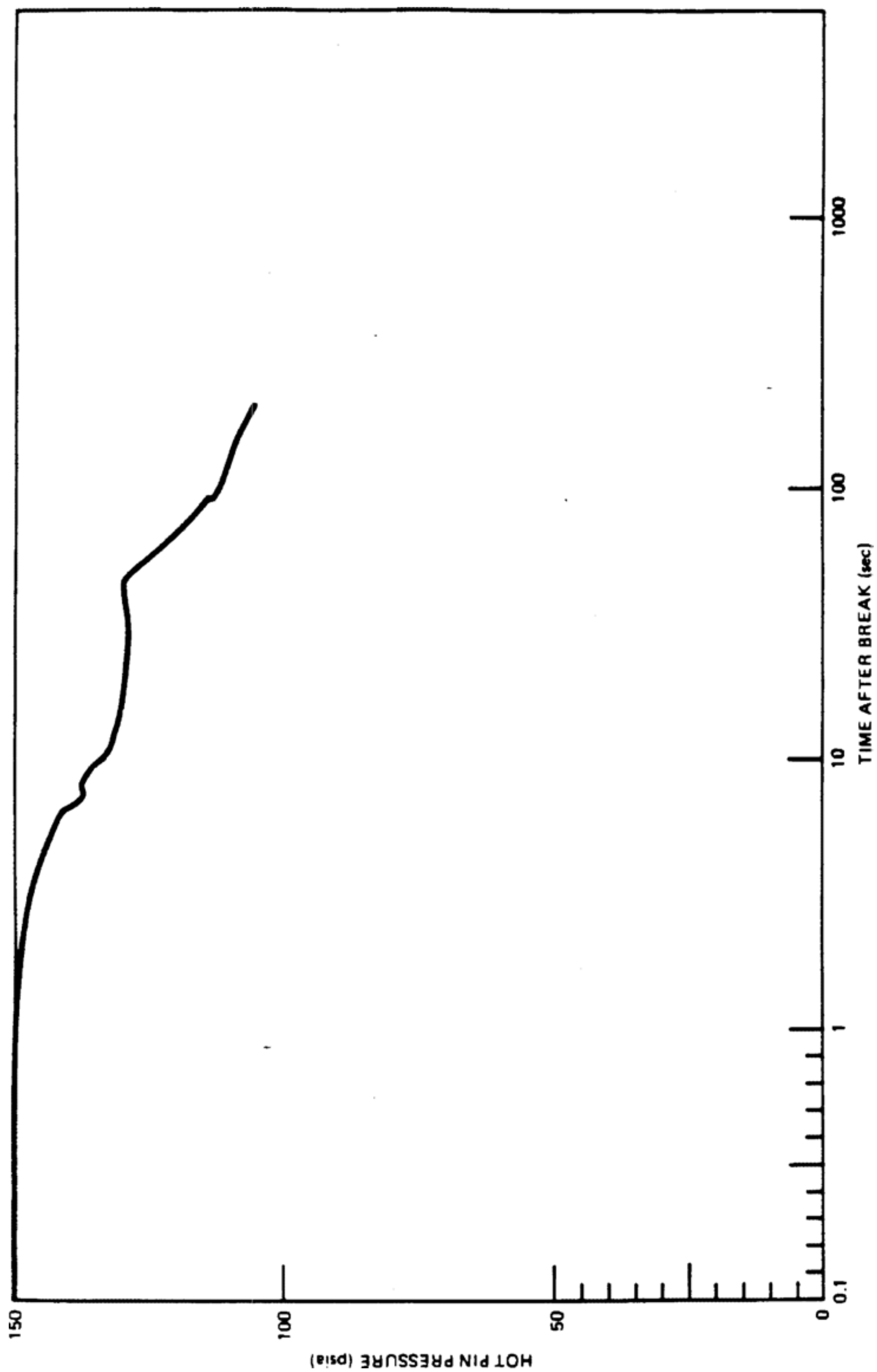


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

HOT PIN FUEL AVERAGE TEMPERATURE
VERSUS TIME AFTER BREAK
(DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-17



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

HOT PIN PRESSURE
VERSUS TIME AFTER BREAK
(DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-18

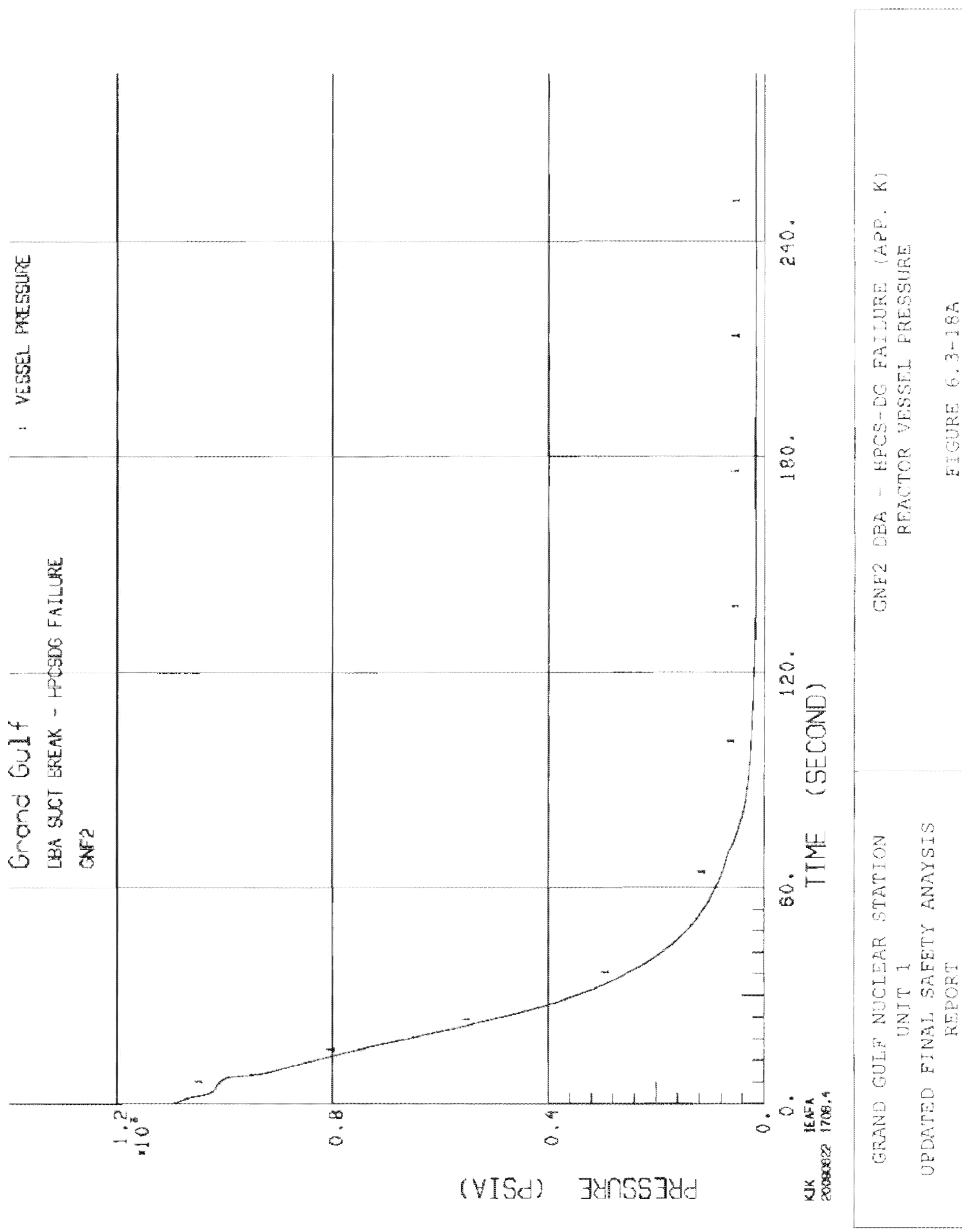
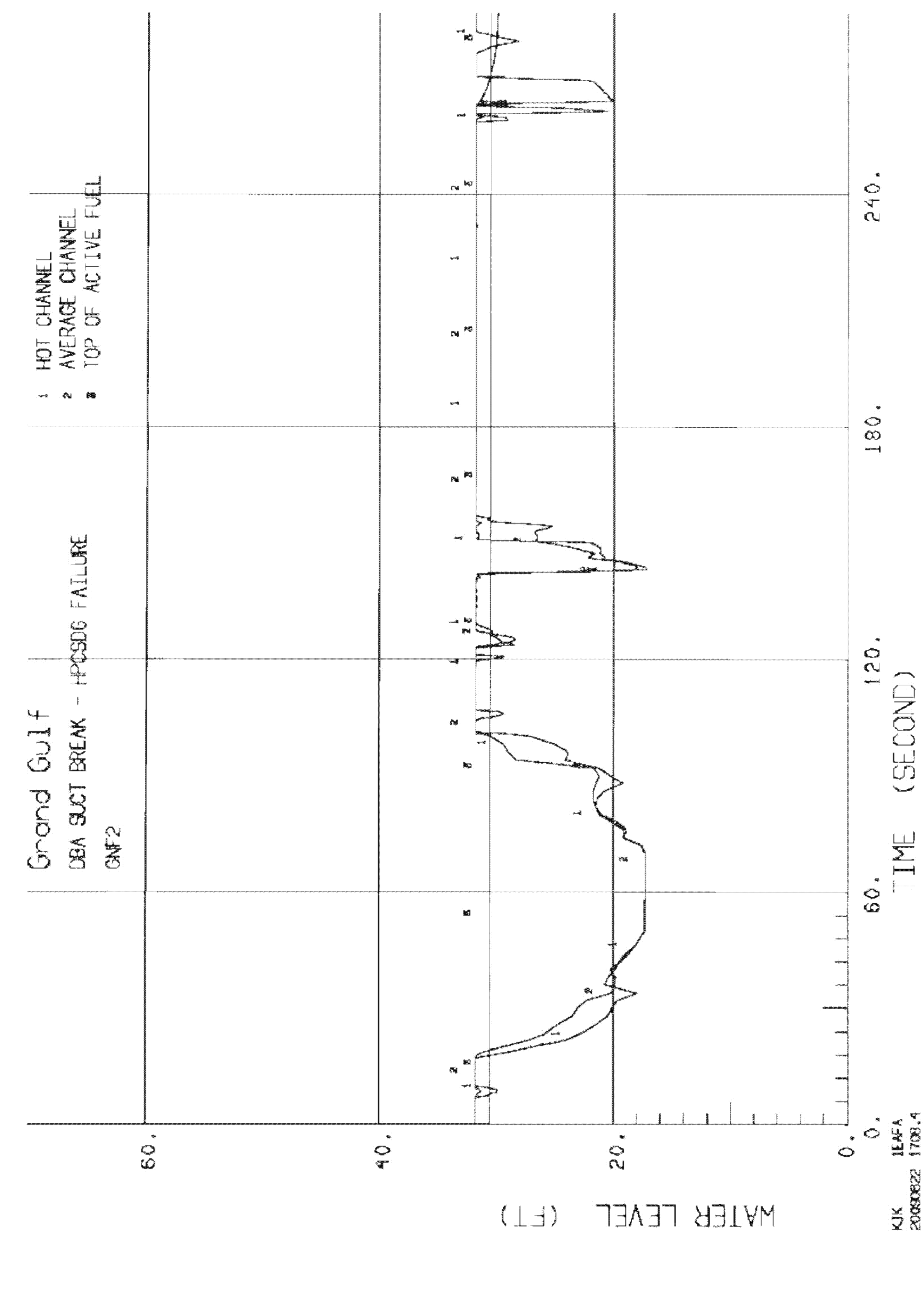


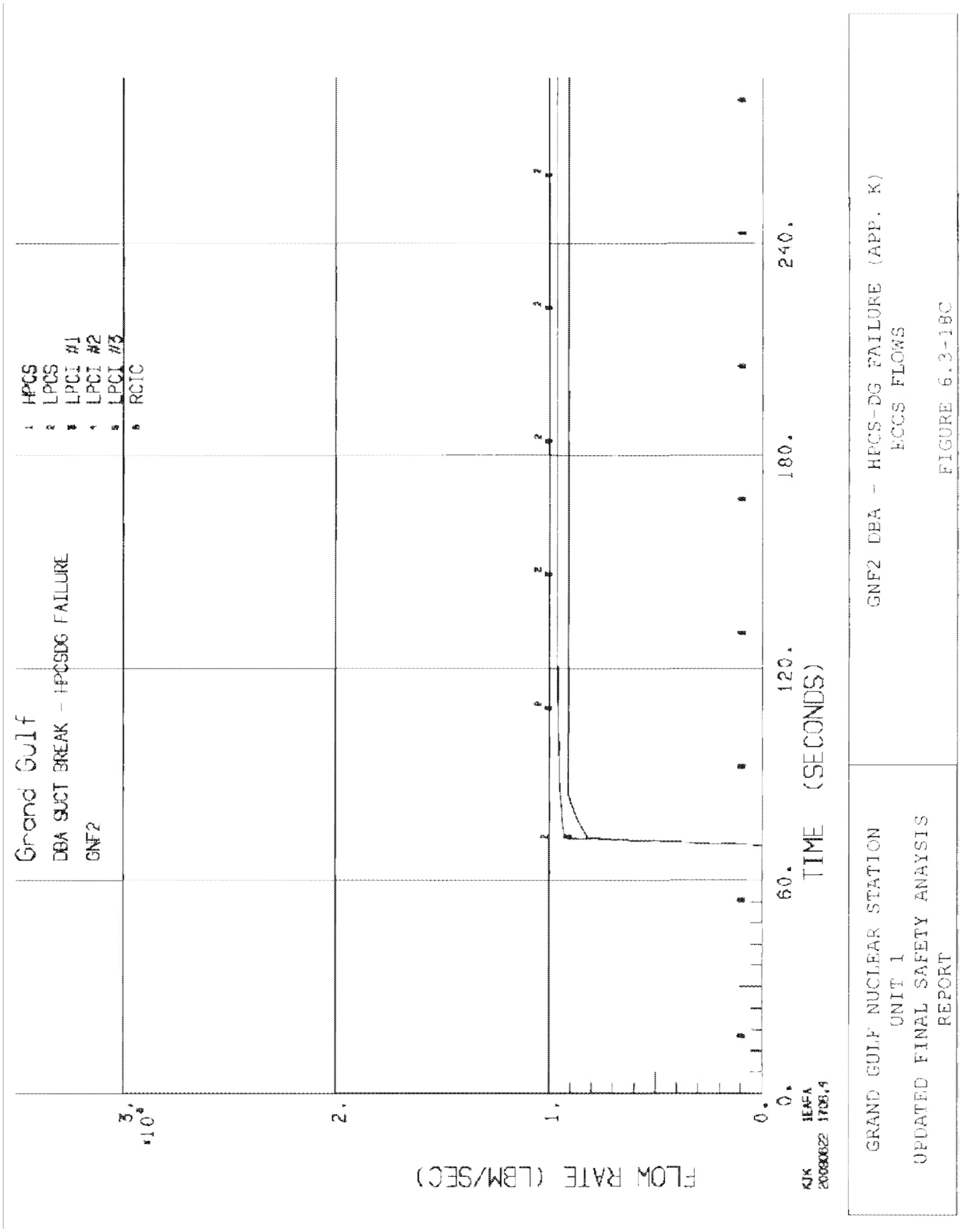
FIGURE 6.3-18A

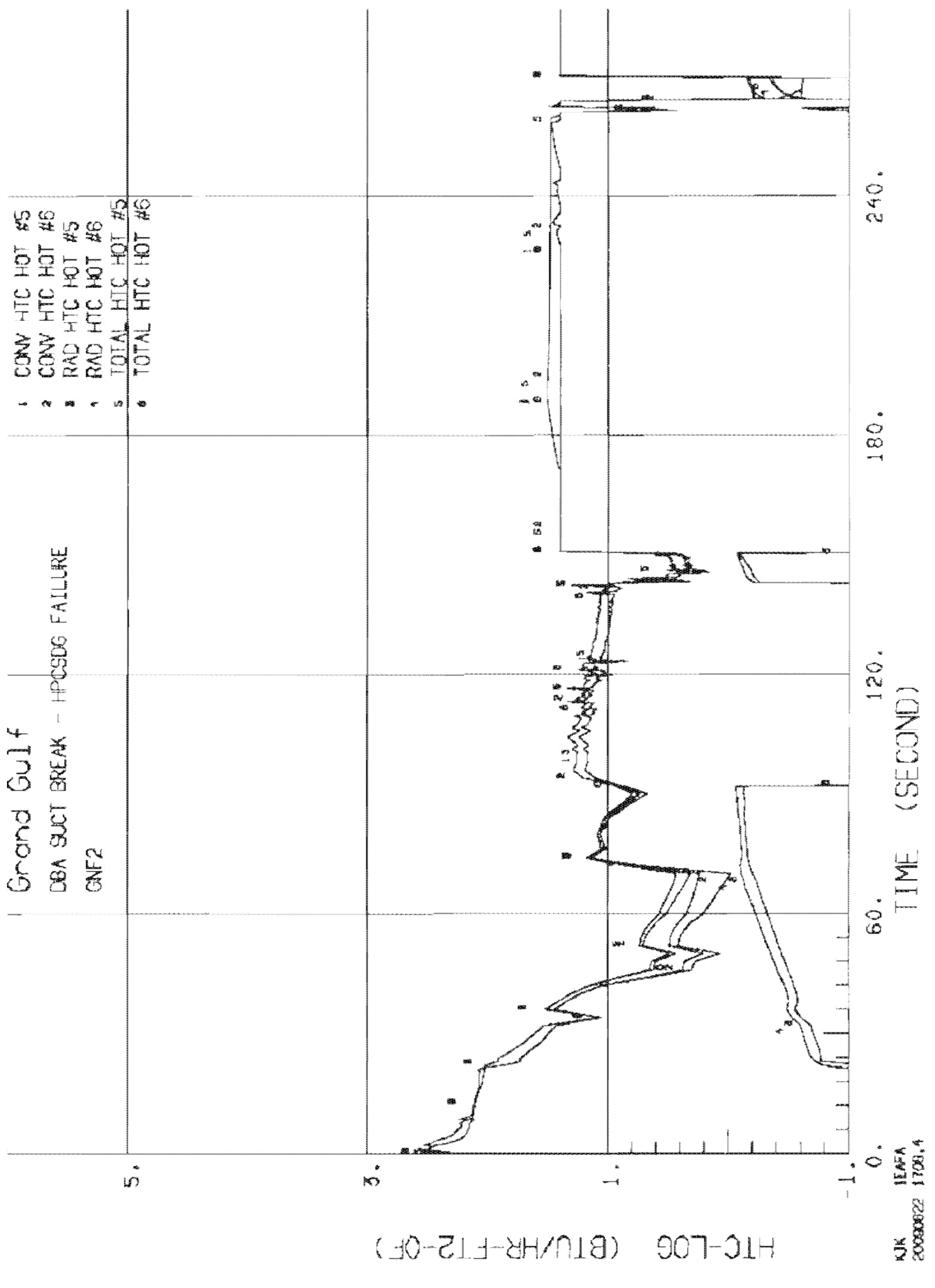


GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANAYSIS REPORT

GNF2 DBA - HPCS-DG FAILURE (APP. K)
HOT AND AVERAGE CHANNEL WATER LEVELS

FIGURE 6.3-18B

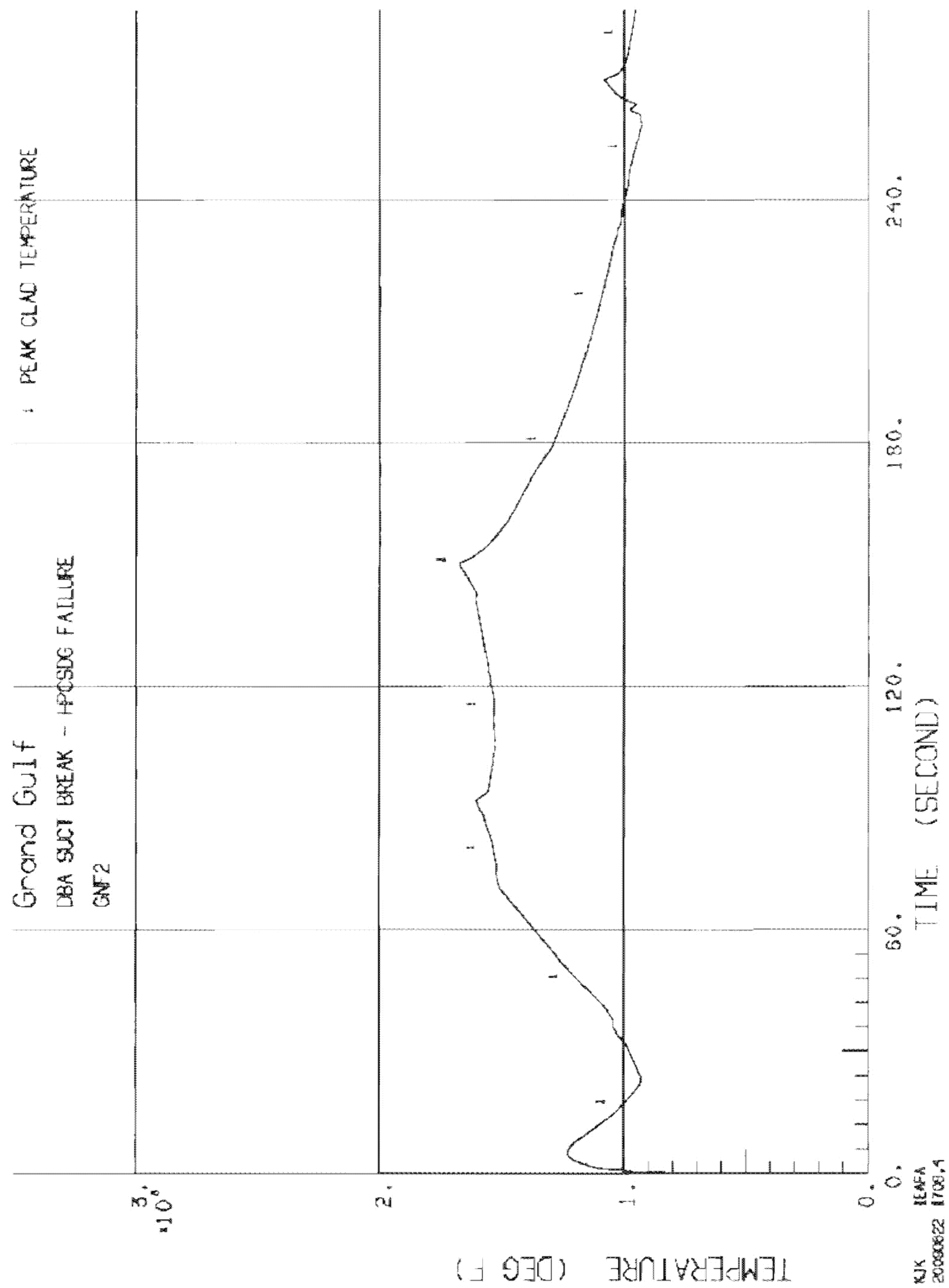

Grand Gulf
DBA SUCT BREAK - HPCSDG FAILURE
GNF2
1 HPCS
2 LPCS
3 LPCI #1
4 LPCI #2
5 LPCI #3
6 RCIC
FLOW RATE (LBM/SEC)
$\times 10^{4}$
0.
1.
2.
3.
TIME (SECONDS)
0.
60.
120.
180.
240.
GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANAYSIS
REPORT
GNF2 DBA - HPCS-DG FAILURE (APP. K)
ECCS FLOWS
FIGURE 6.3-18C



GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANAYSIS
REPORT

GNF2 DBA - HPCS-DG FAILURE (APP. K)
HEAT TRANSFER COEFFICIENTS

FIGURE 6.3-18D



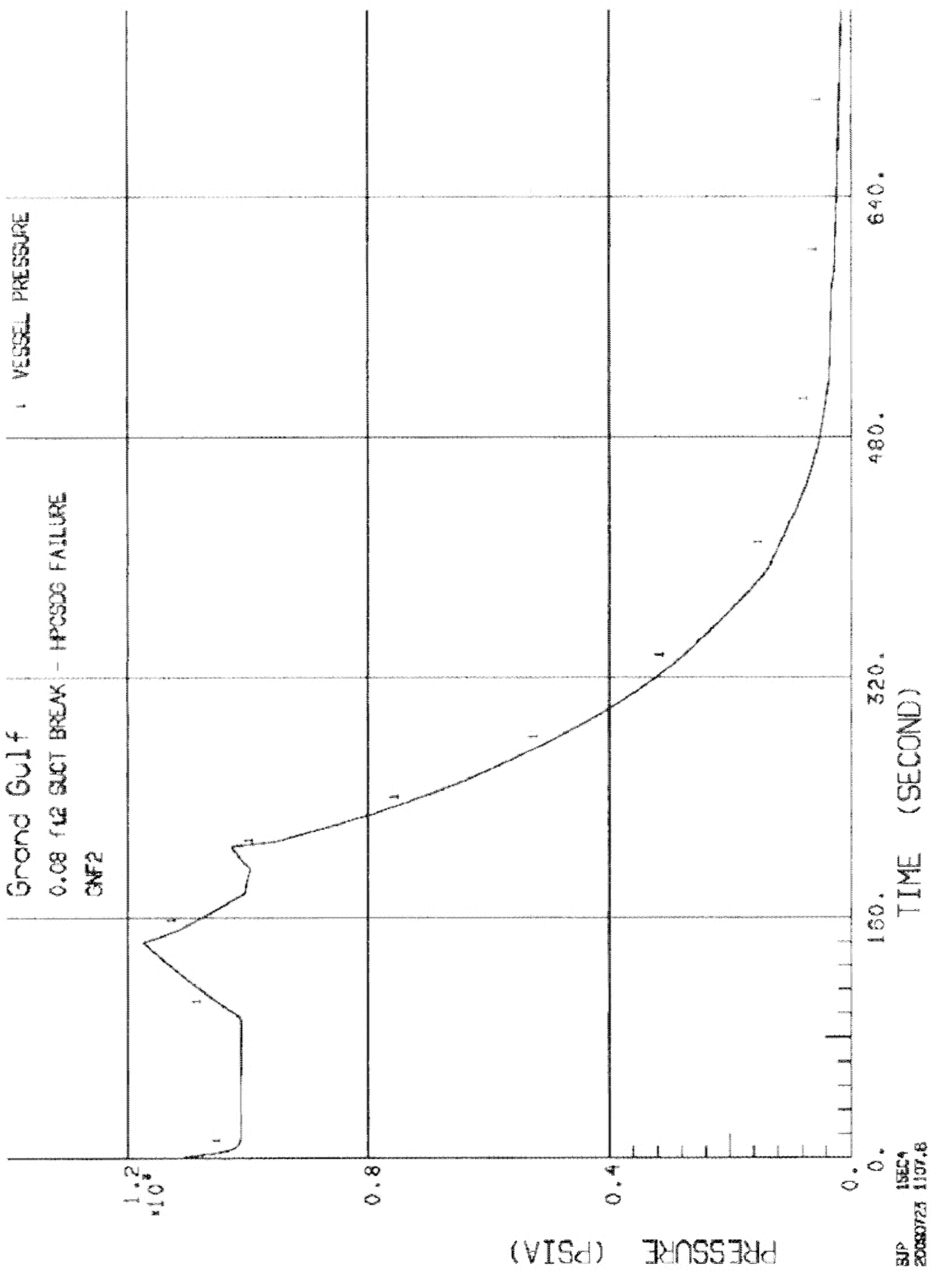
GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANAYSIS
REPORT

GNF2 DBA - HPCS-DG FAILURE (APP. K)
PEAK CLADDING TEMPERATURE

FIGURE 6.3-18E

FIGURE 6.3-18F thru 6.3-18J DELETED

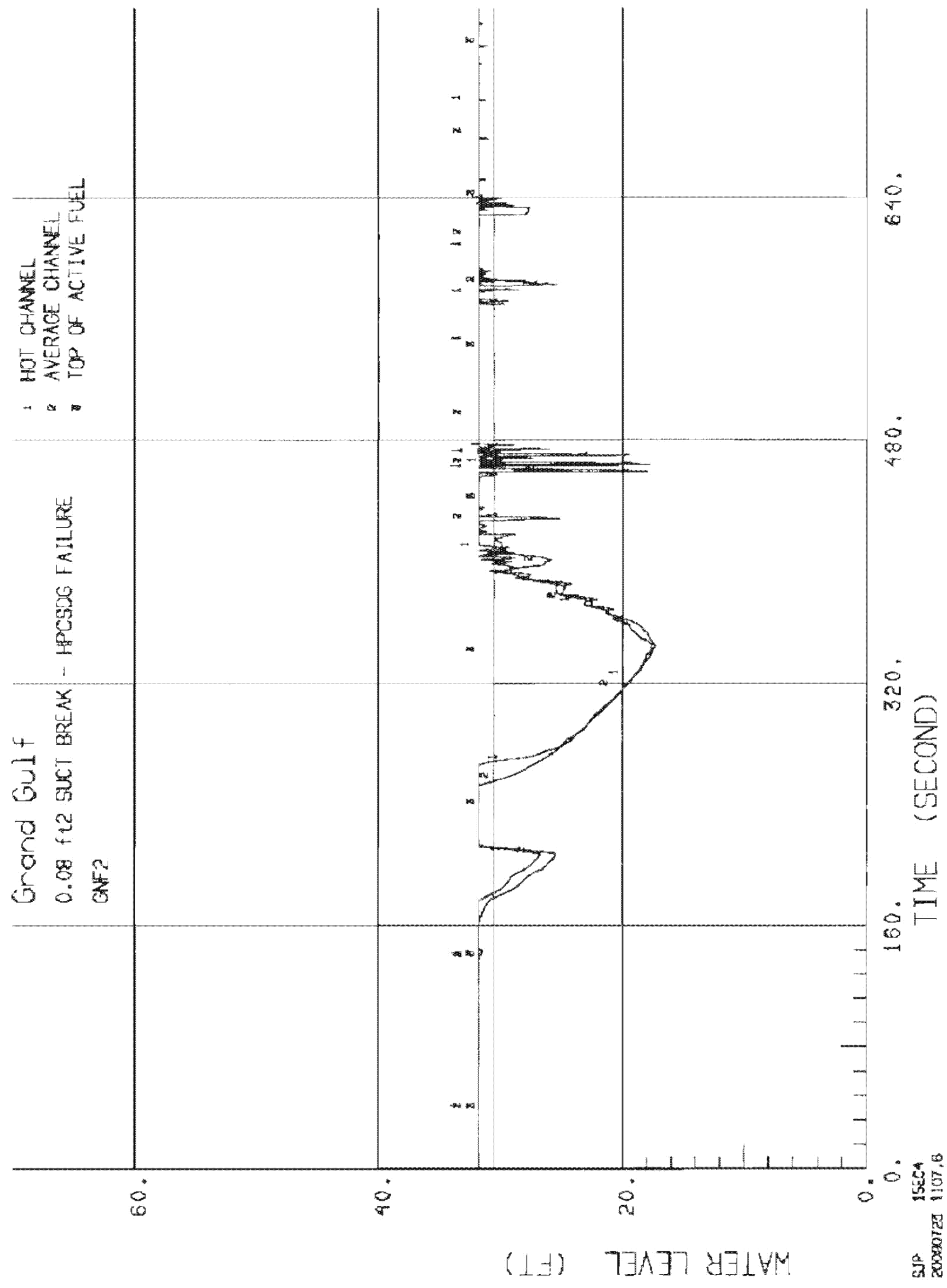
FIGURES 6.3-18K – 6.3-18O DELETED



GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANAYSIS
REPORT

GNF2 0.08 FT² SMALL BREAK - HPCS-DG FAILURE (APP. K)
REACTOR VESSEL PRESSURE

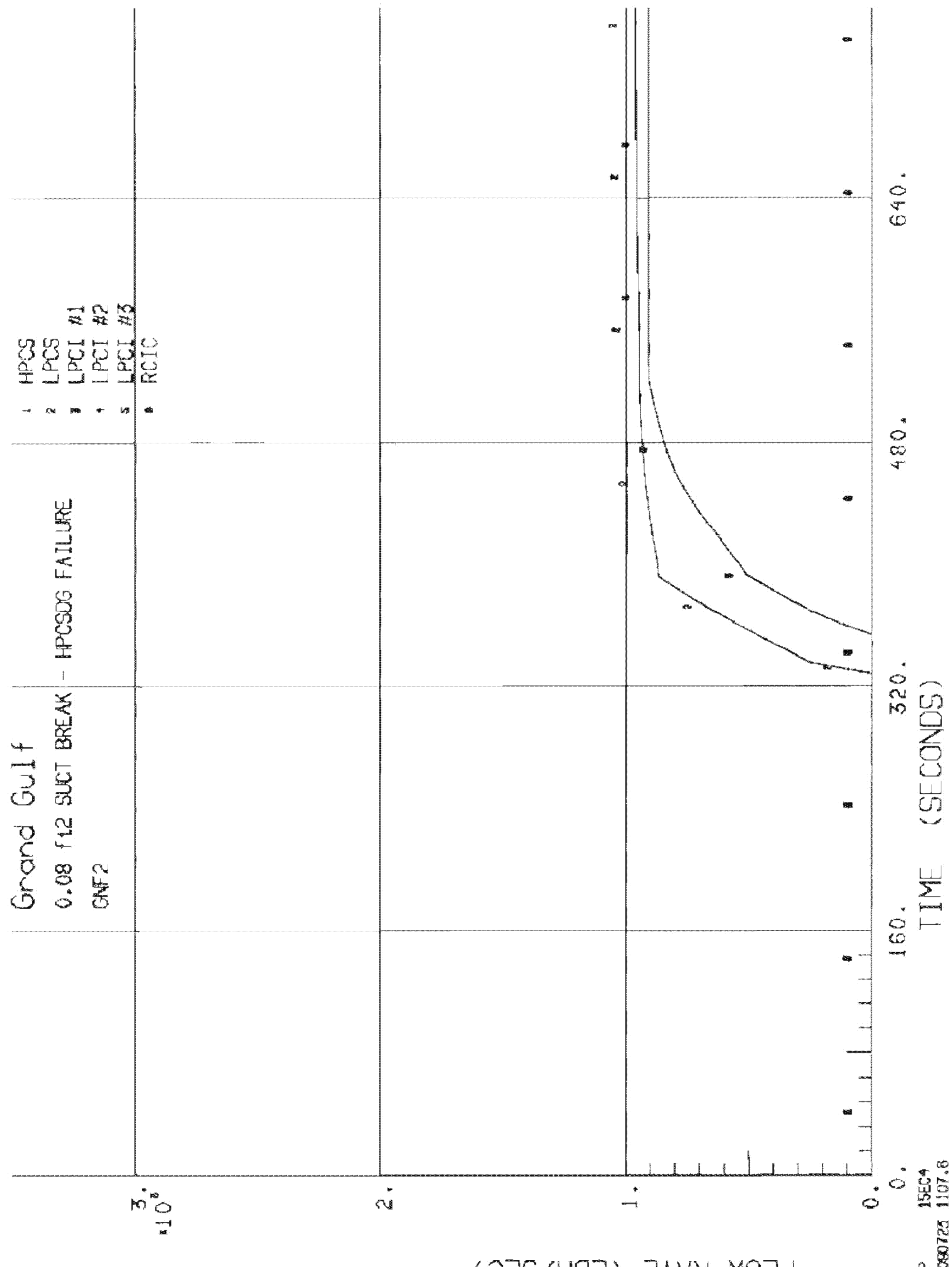
FIGURE 6.3-18P



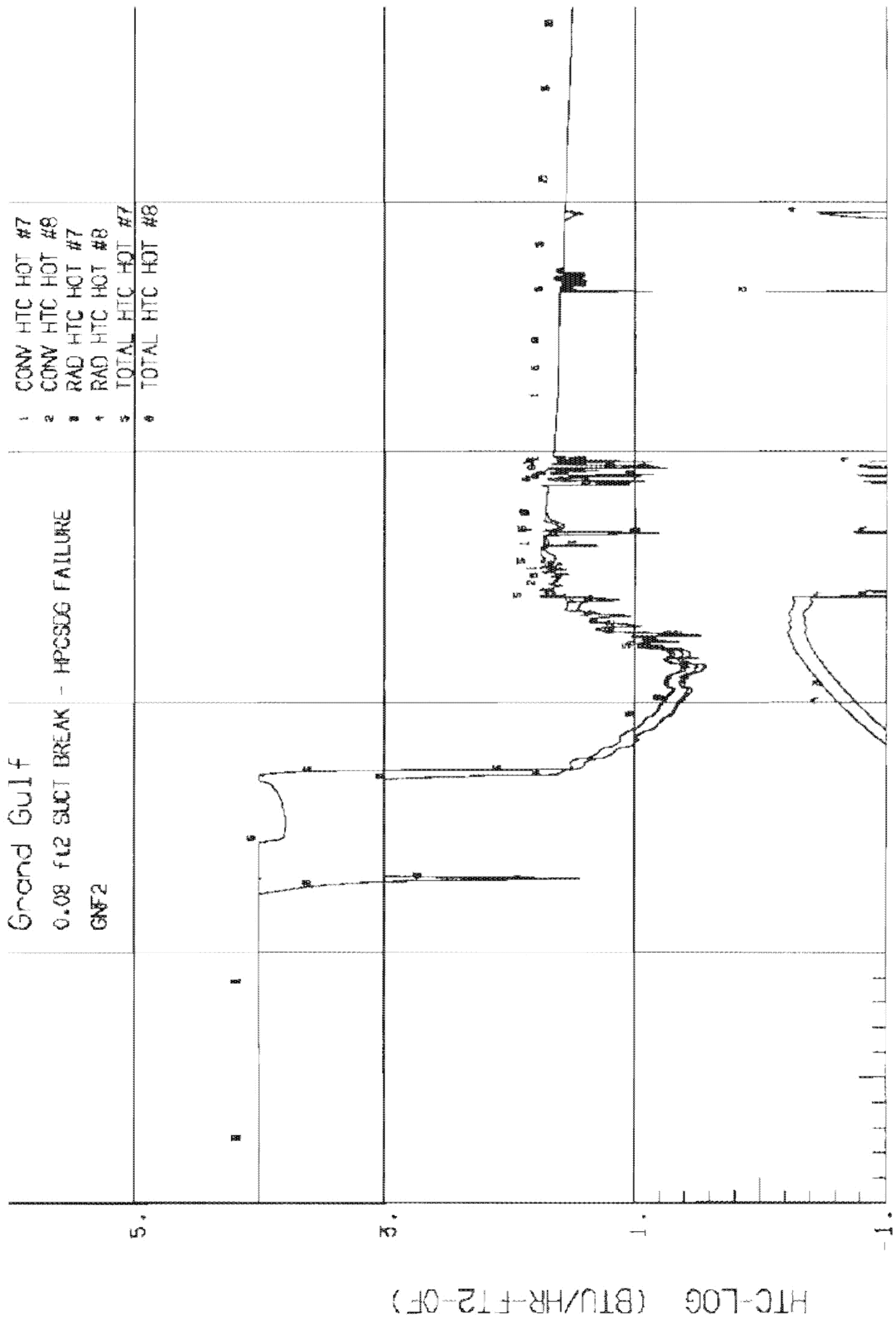
GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANAYSIS
REPORT

GNF2 0.08 FT^2 SMALL BREAK - HPCS-DG FAILURE (APP. K)
HOT AND AVERAGE CHANNEL WATER LEVELS

FIGURE 6.3-18Q



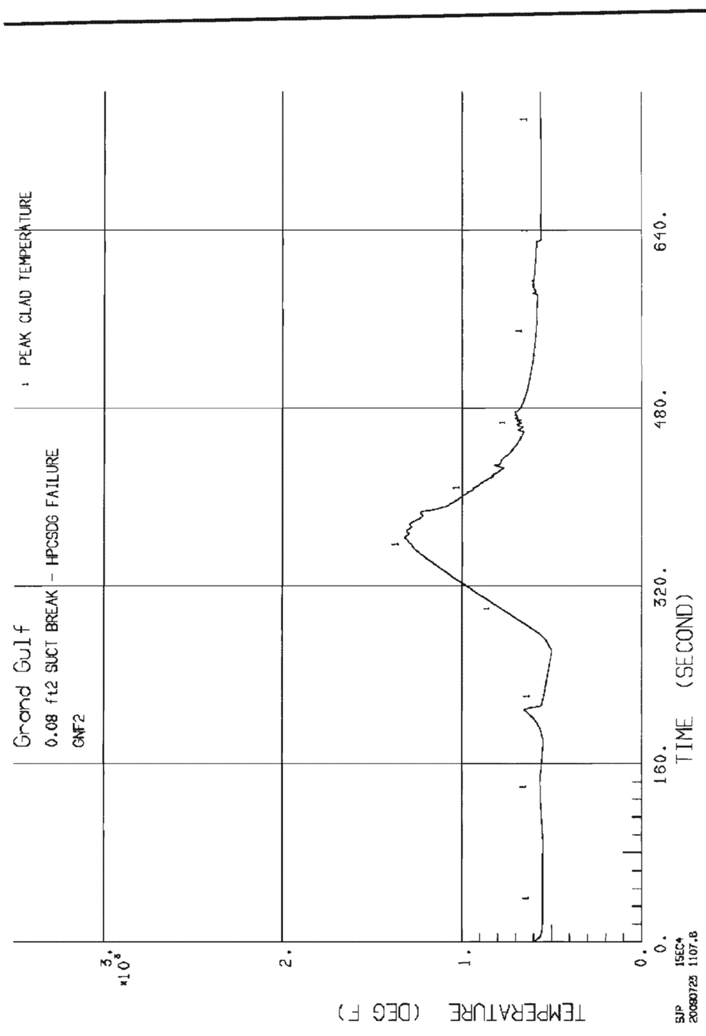
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANAYSIS REPORT	GNF2 0.08 FT^2 SMALL BREAK - HPCS-DG FAILURE (APP. K) ECCS FLOWS FIGURE 6.3-18R



GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANAYSIS
REPORT

GNF2 0.08 FT² SMALL BREAK - HPCS-DG FAILURE (APP. K)
HEAT TRANSFER COEFFICIENTS

FIGURE 6.3-18S



GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANAYSIS
REPORT

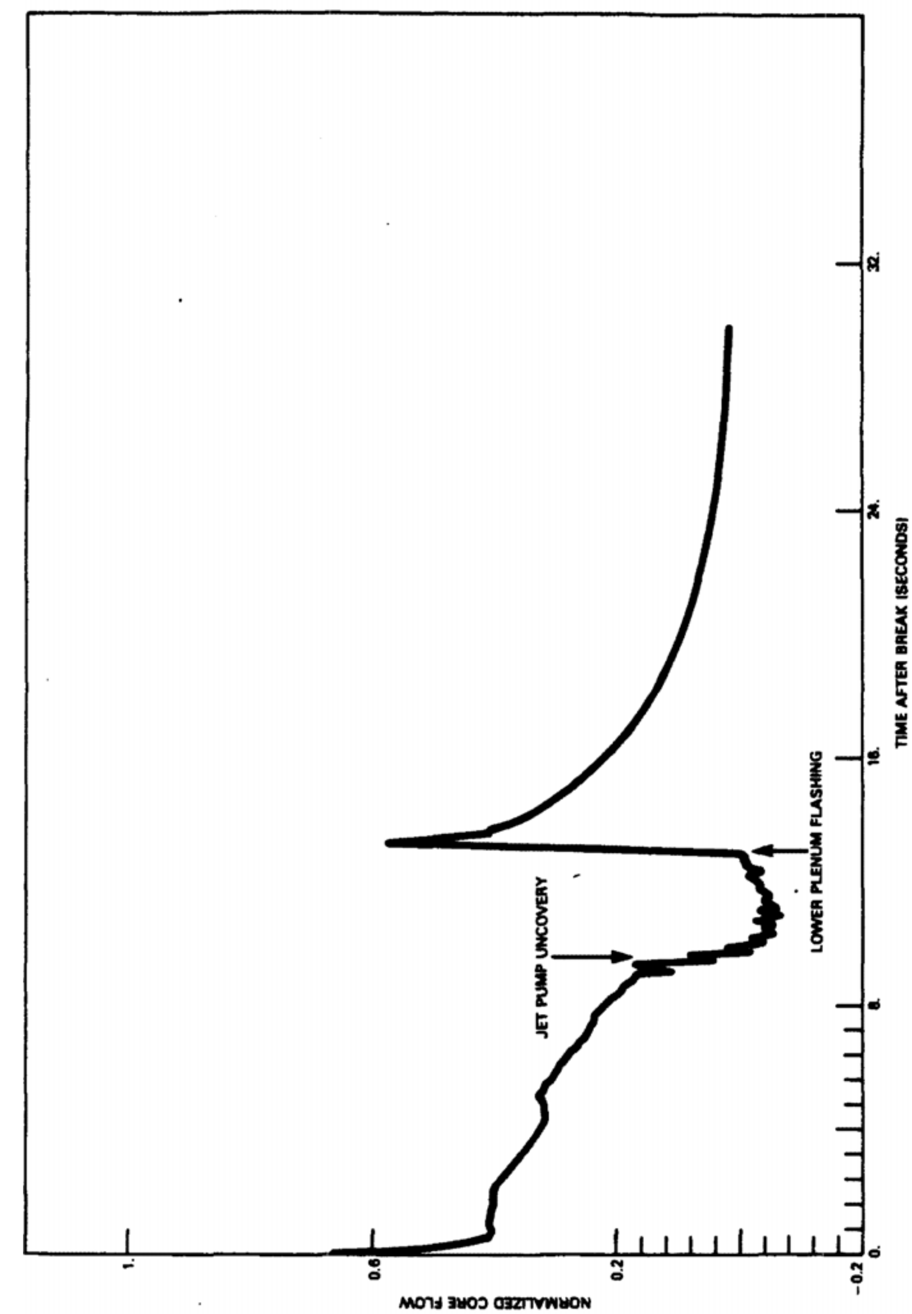
GNF2 0.08 FT² SMALL BREAK - HPCS-DG FAILURE (APP. K)
PEAK CLADDING TEMPERATURE

FIGURE 6.3-18T

LBDCR 10015

FIGURE 6.3-18U thru 6.3-18Y DELETED

FIGURES 6.3-18Z – 6.3-18AD DELETED

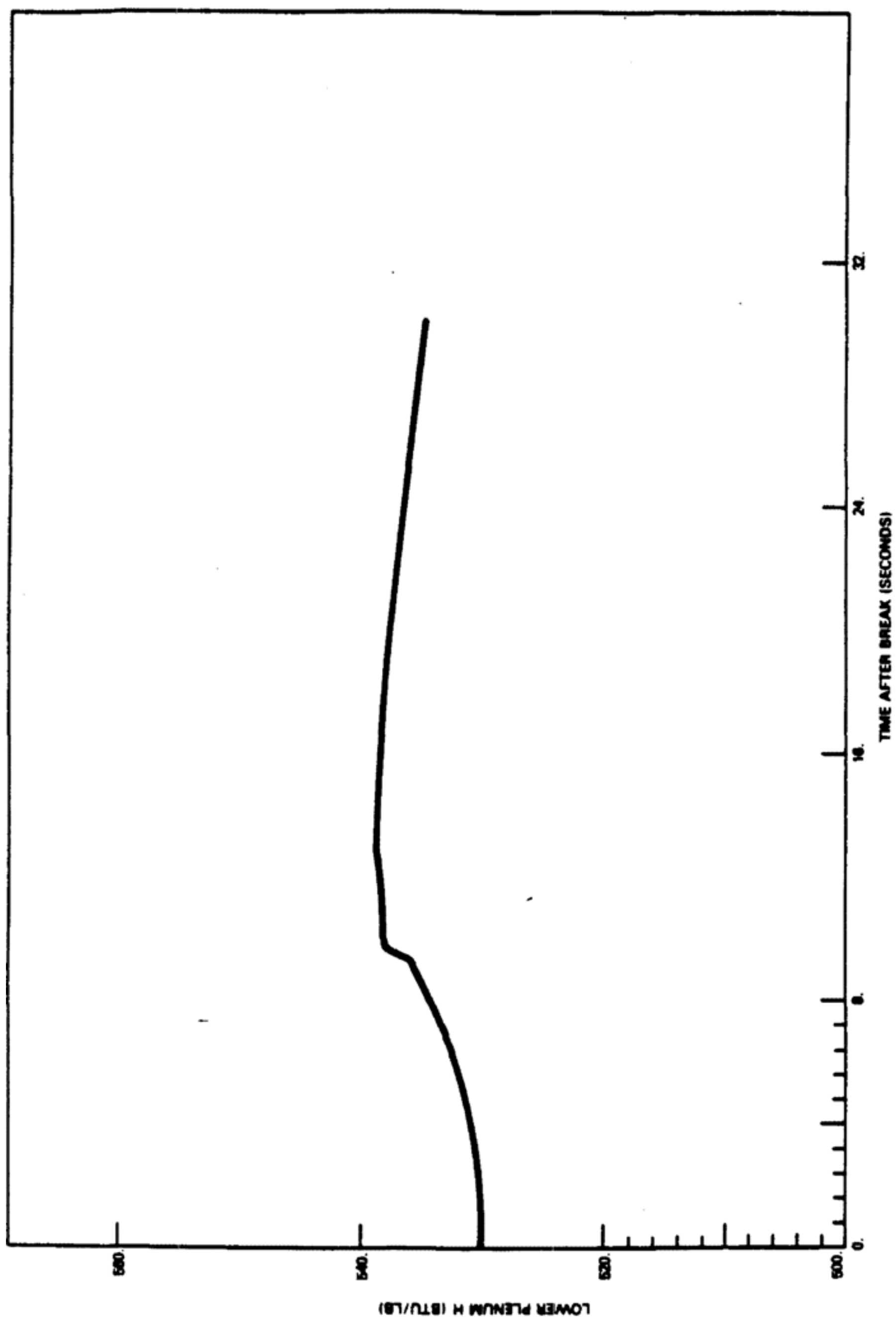


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

NORMALIZED CORE AVERAGE INLET FLOW
VERSUS TIME AFTER BREAK
(80% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-19

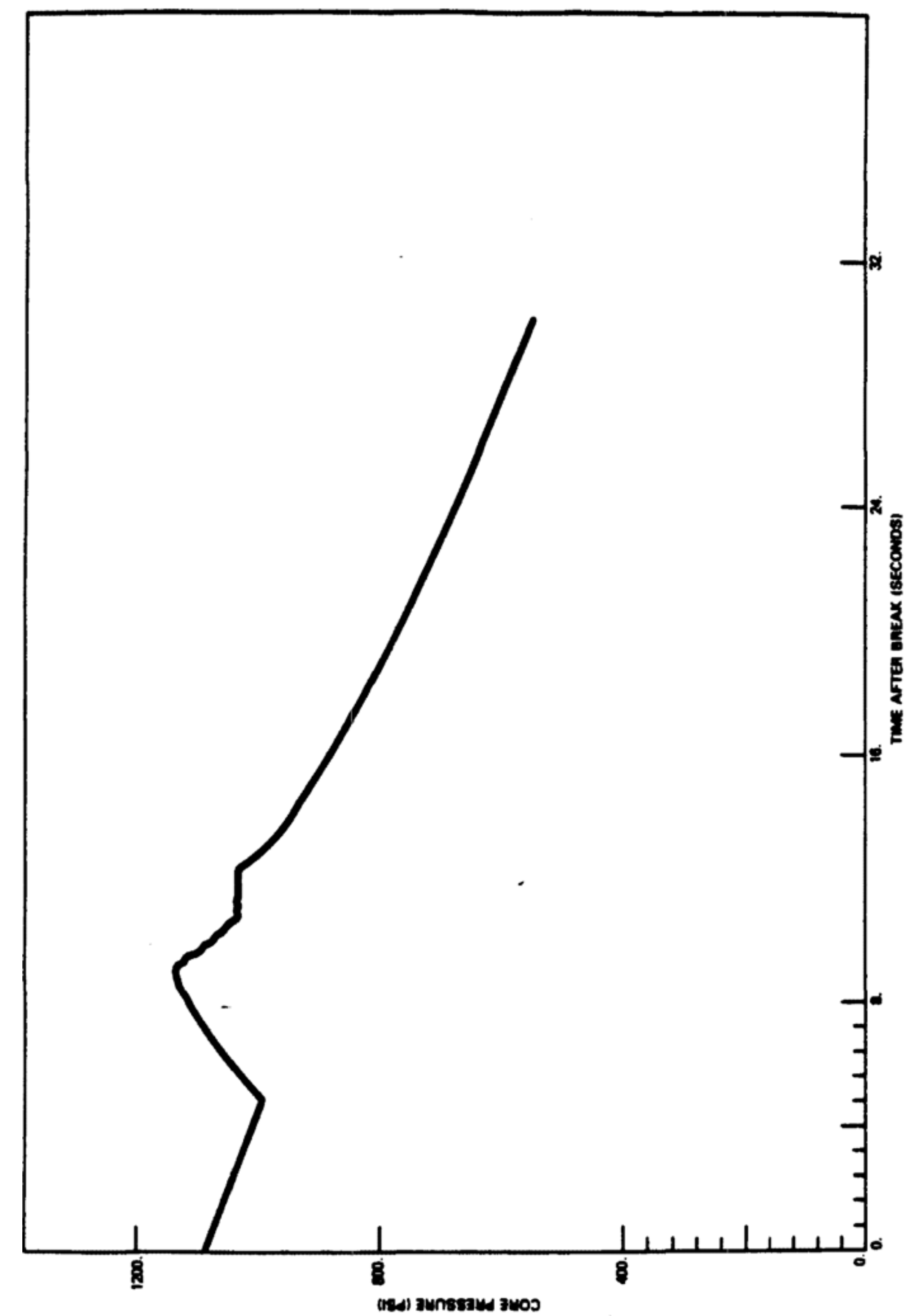


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CORE INLET ENTHALPY
VERSUS TIME AFTER BREAK
(80% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-20

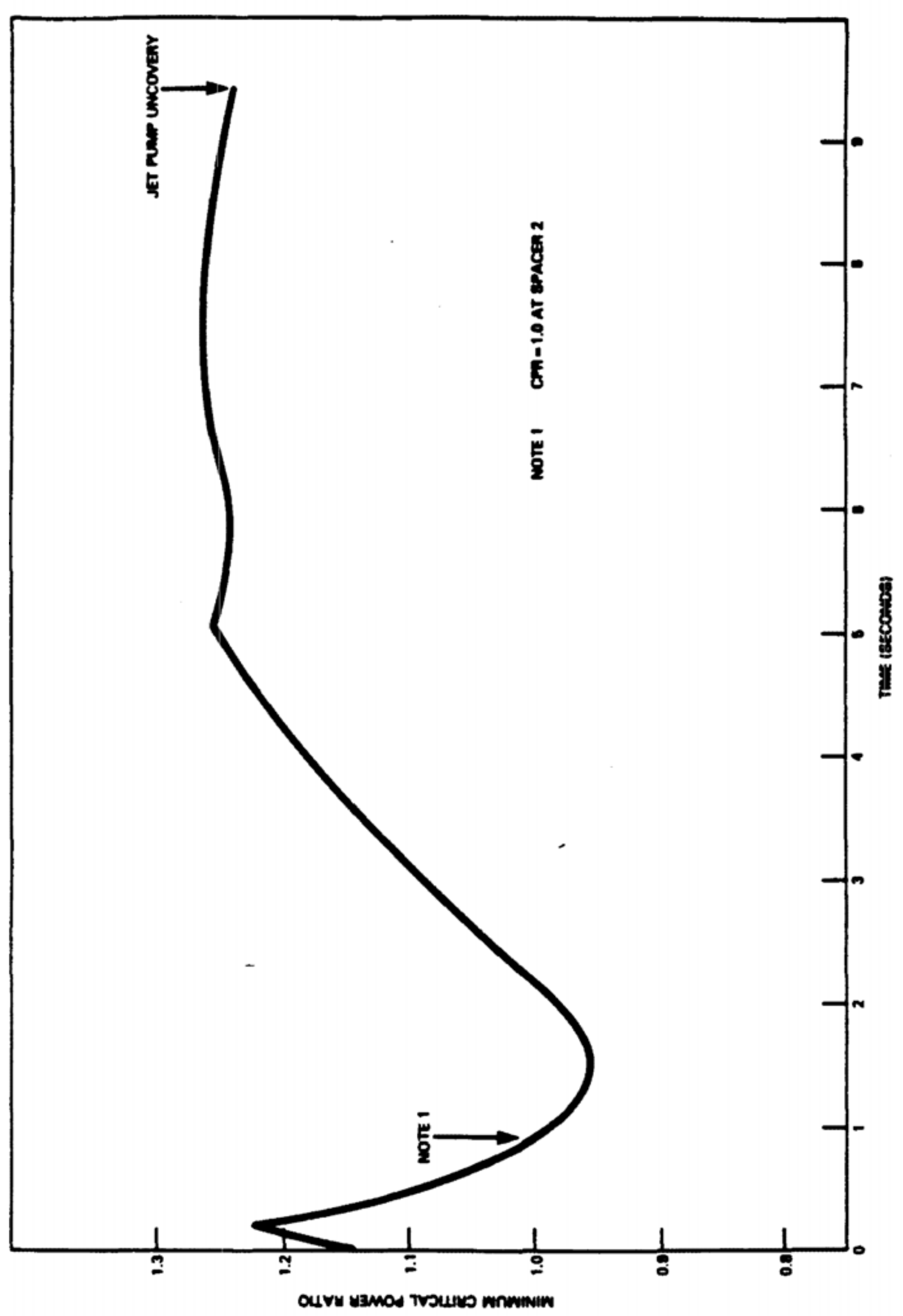


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CORE AVERAGE PRESSURE
VERSUS TIME AFTER BREAK
(80% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-21

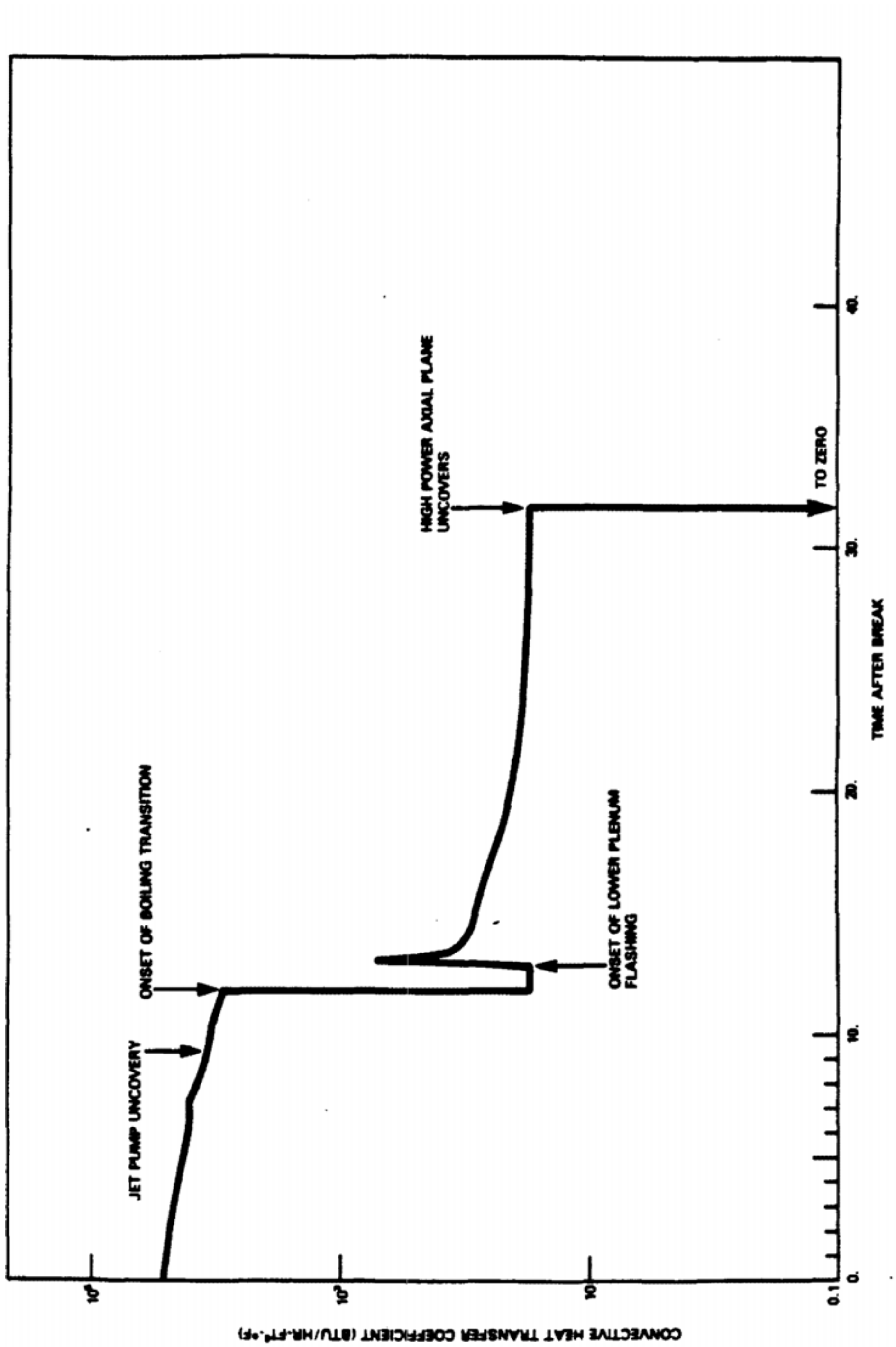


[HISTORICAL INFORMATION]

MINIMUM CRITICAL POWER RATIO
VERSUS TIME AFTER BREAK
(80% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-22

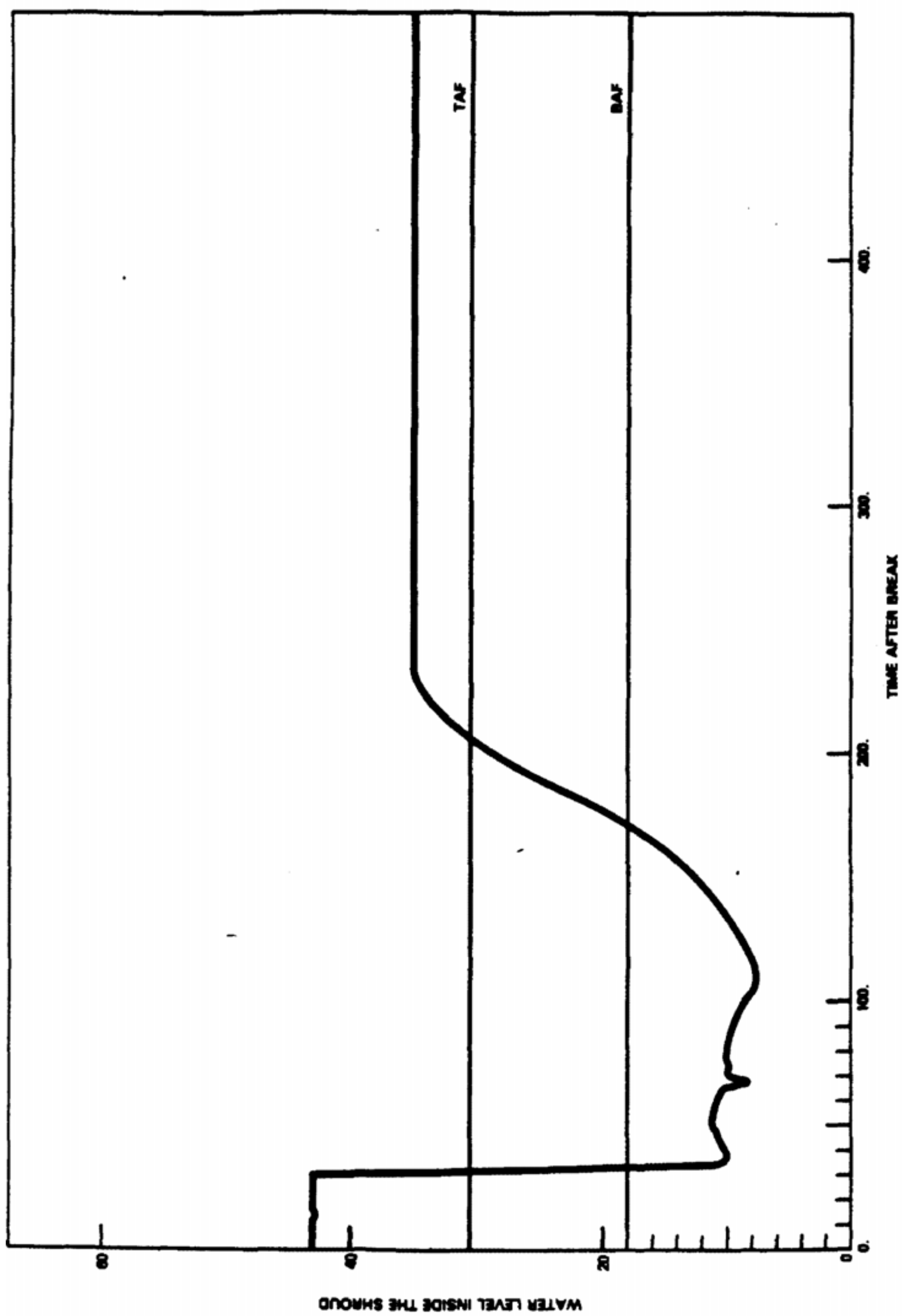
GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

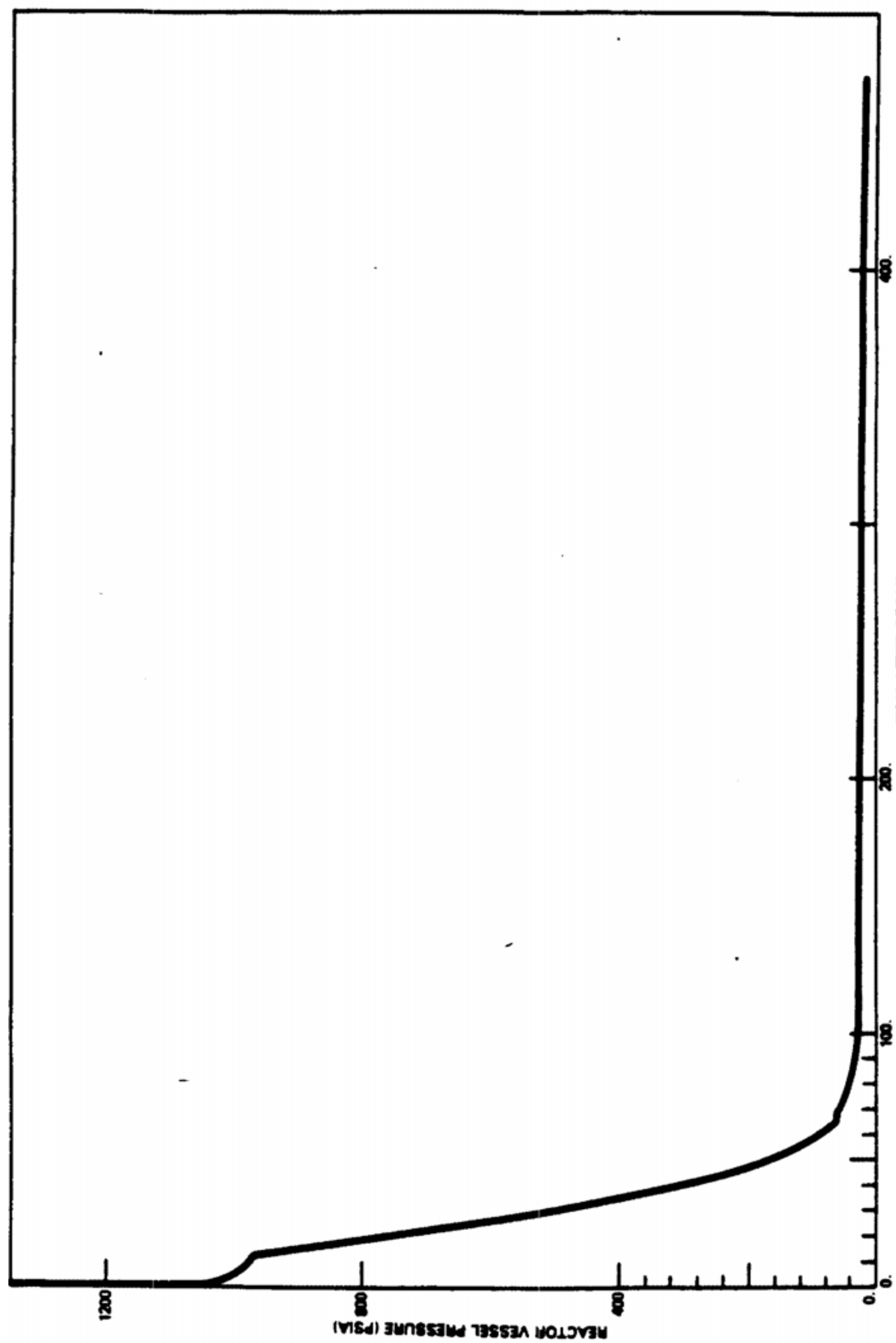
CONVECTIVE HEAT TRANSFER COEFFICIENT
VERSUS TIME AFTER BREAK
(80% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-23



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

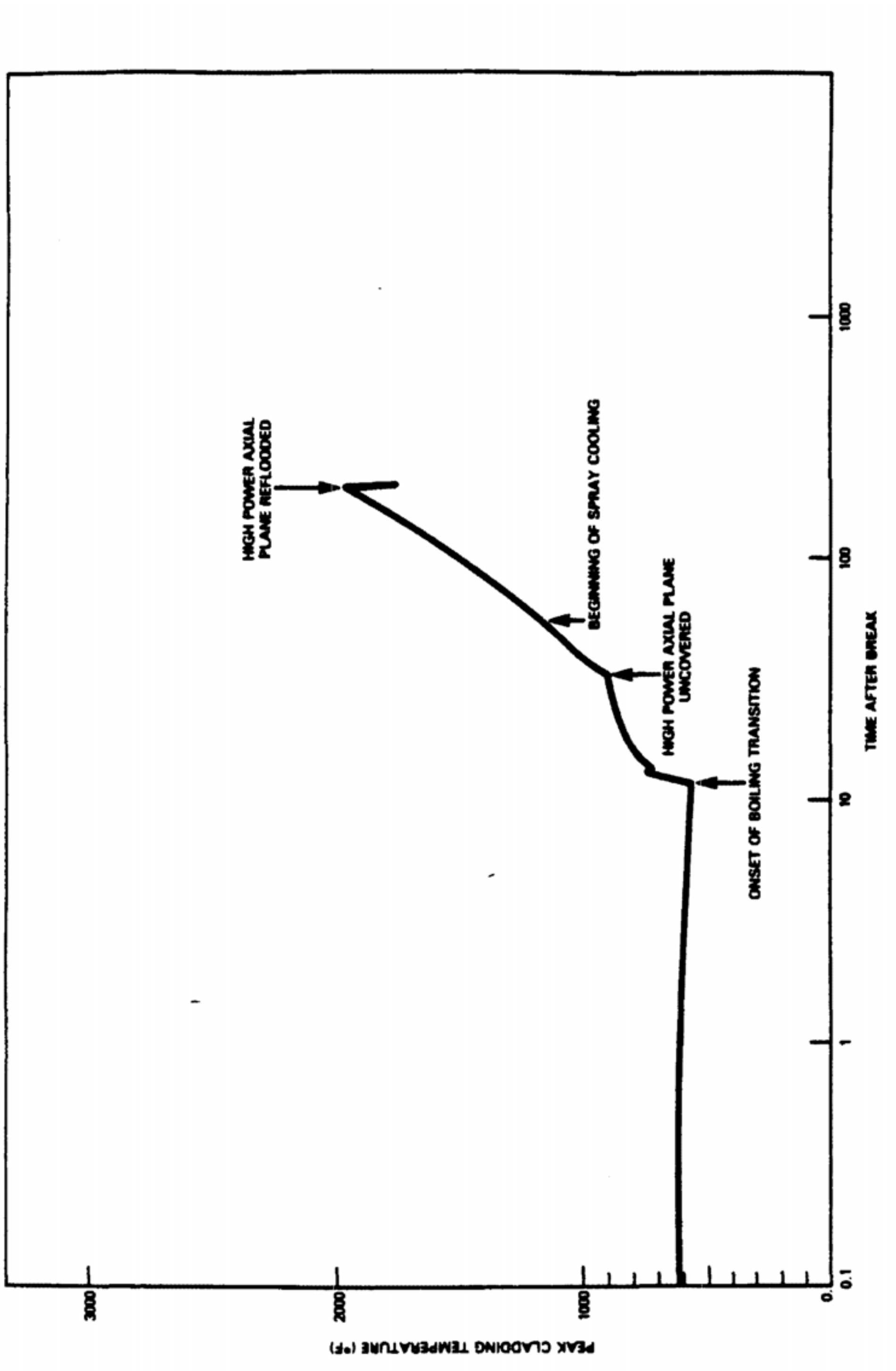
WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK
(80% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-24



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK
(80% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-25

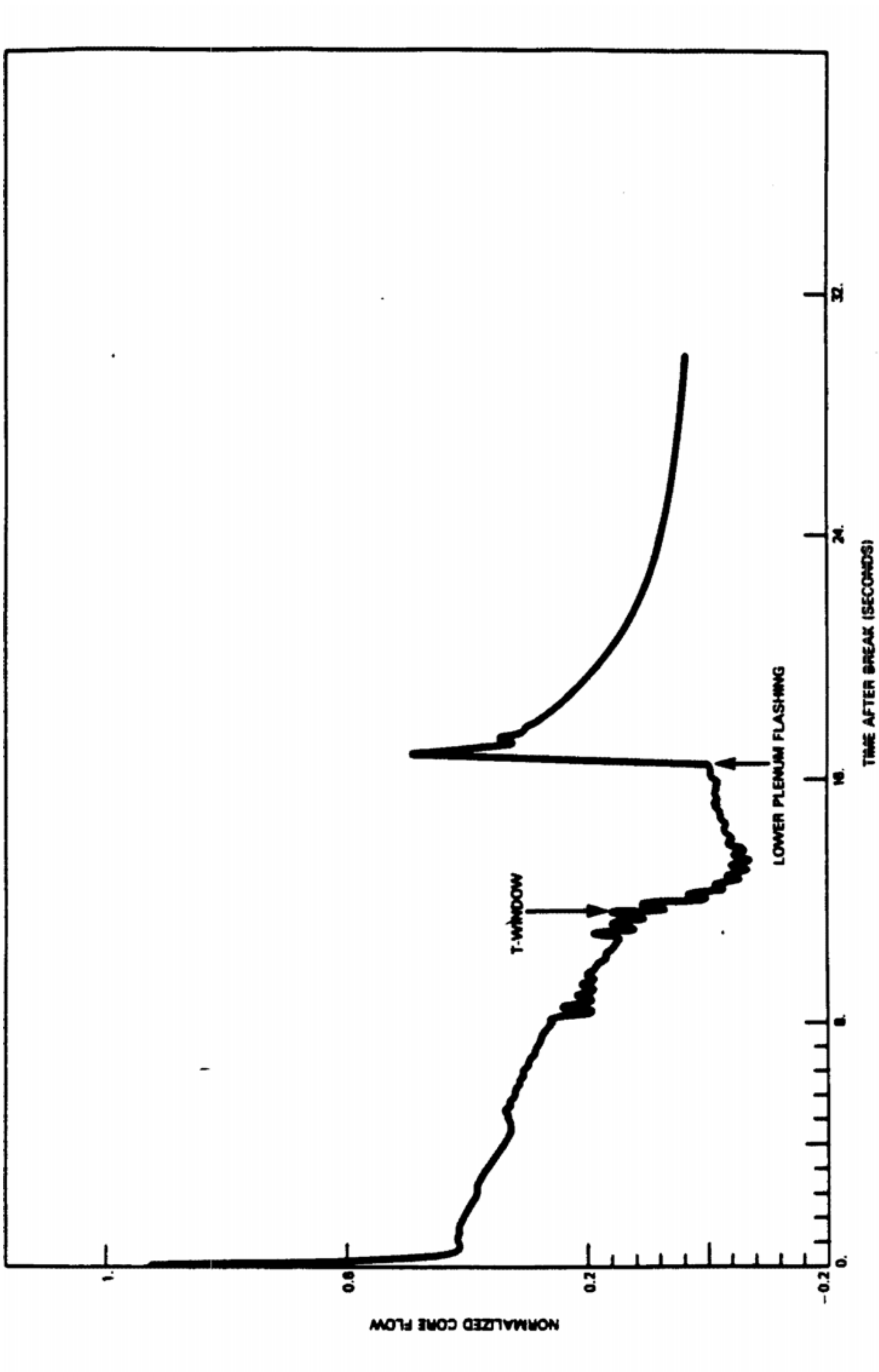


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

PEAK CLADDING TEMPERATURE
VERSUS TIME AFTER BREAK
(80% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

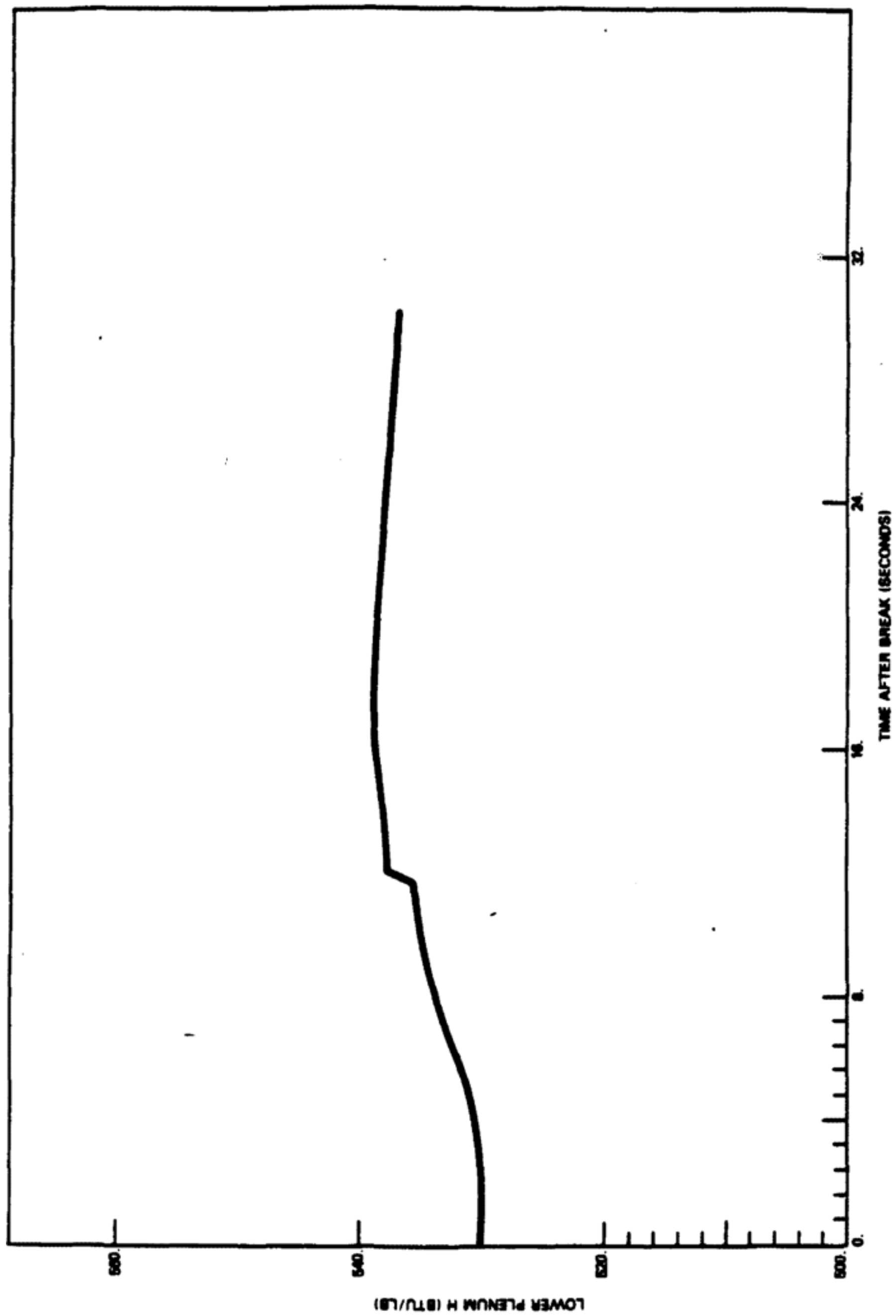
FIGURE 6.3-26



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

NORMALIZED CORE AVERAGE INLET FLOW
VERSUS TIME AFTER BREAK
(60% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-27

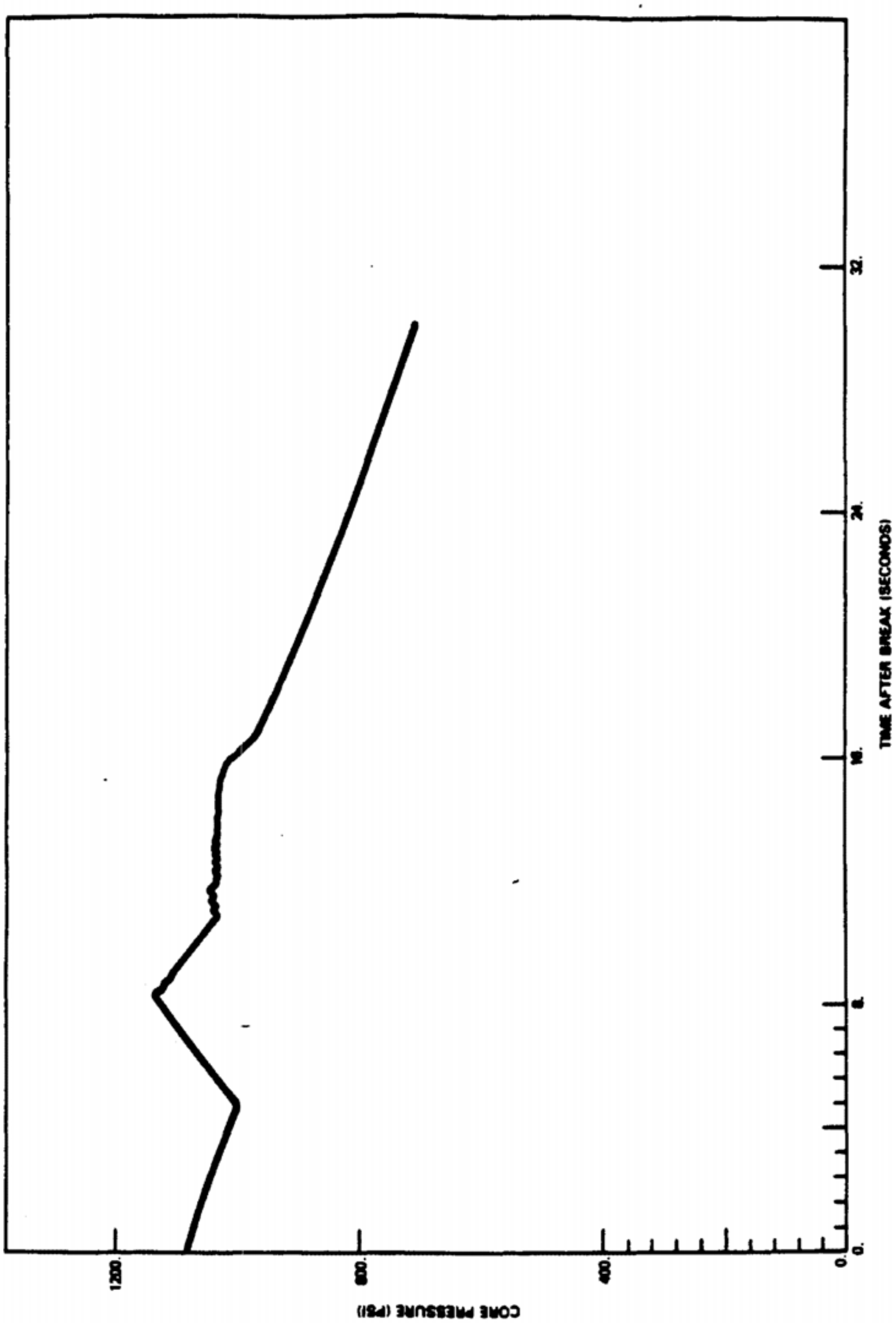


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CORE INLET ENTHALPY
VERSUS TIME AFTER BREAK
(60% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

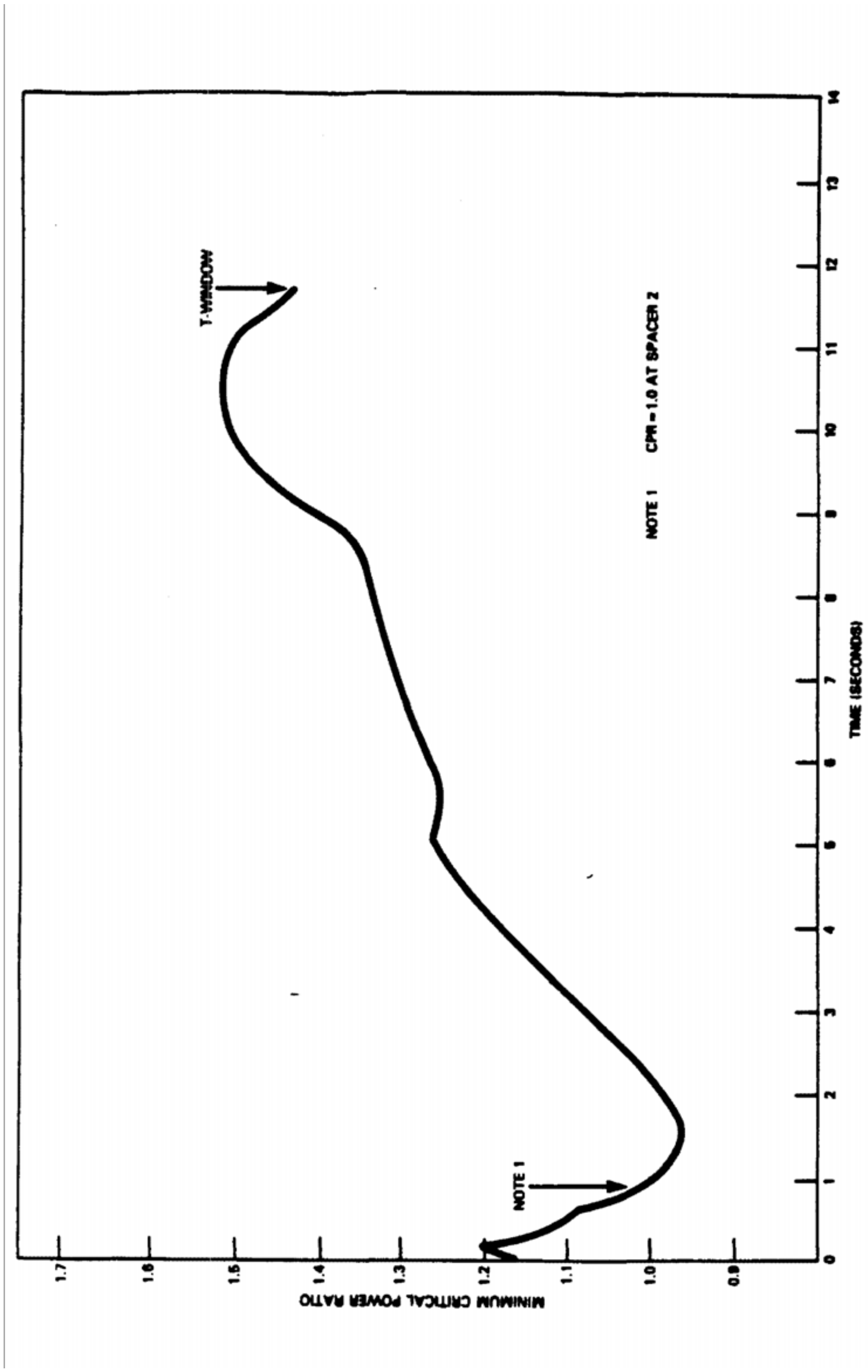
FIGURE 6.3-28



[HISTORICAL INFORMATION]

CORE AVERAGE PRESSURE
VERSUS TIME AFTER BREAK
(60% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-29

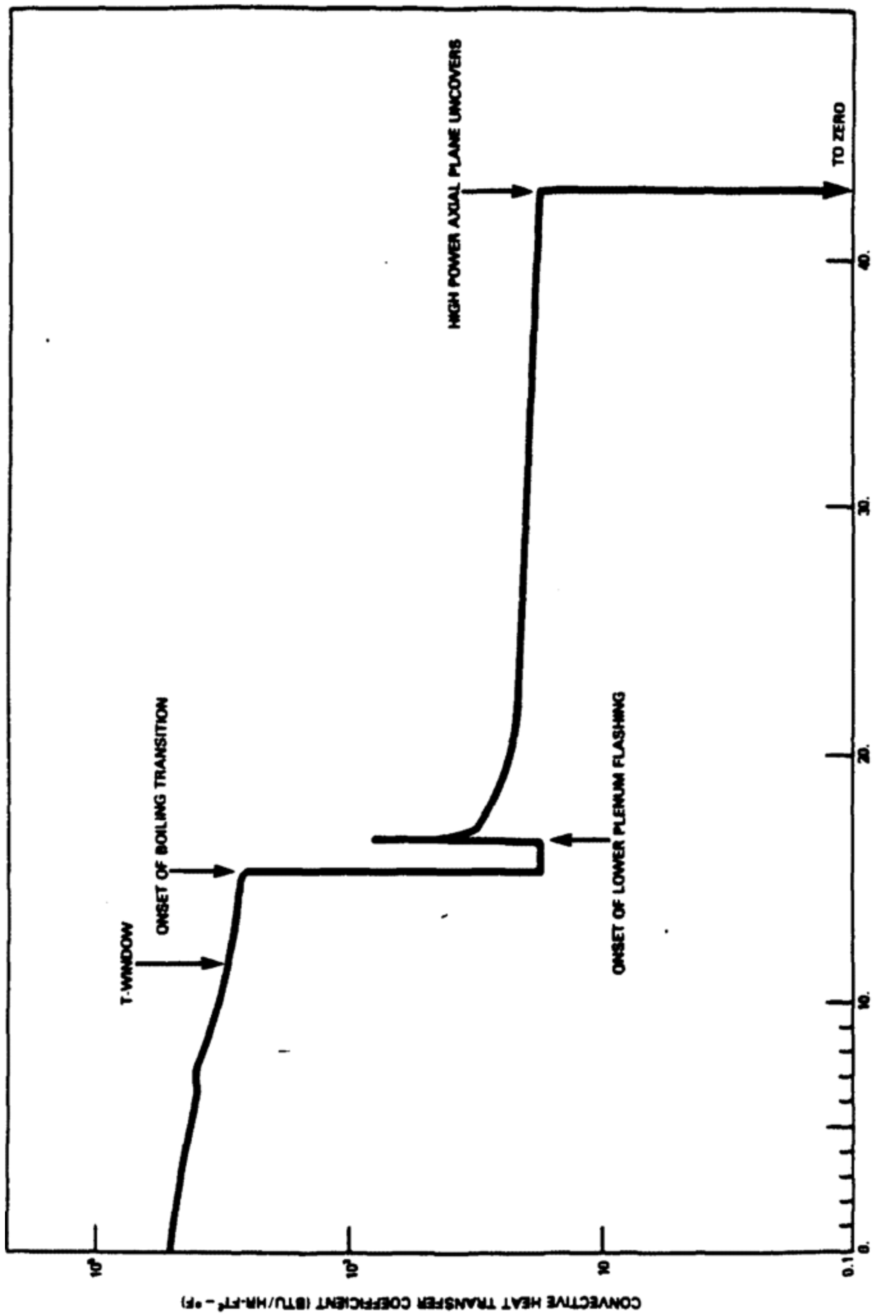
GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

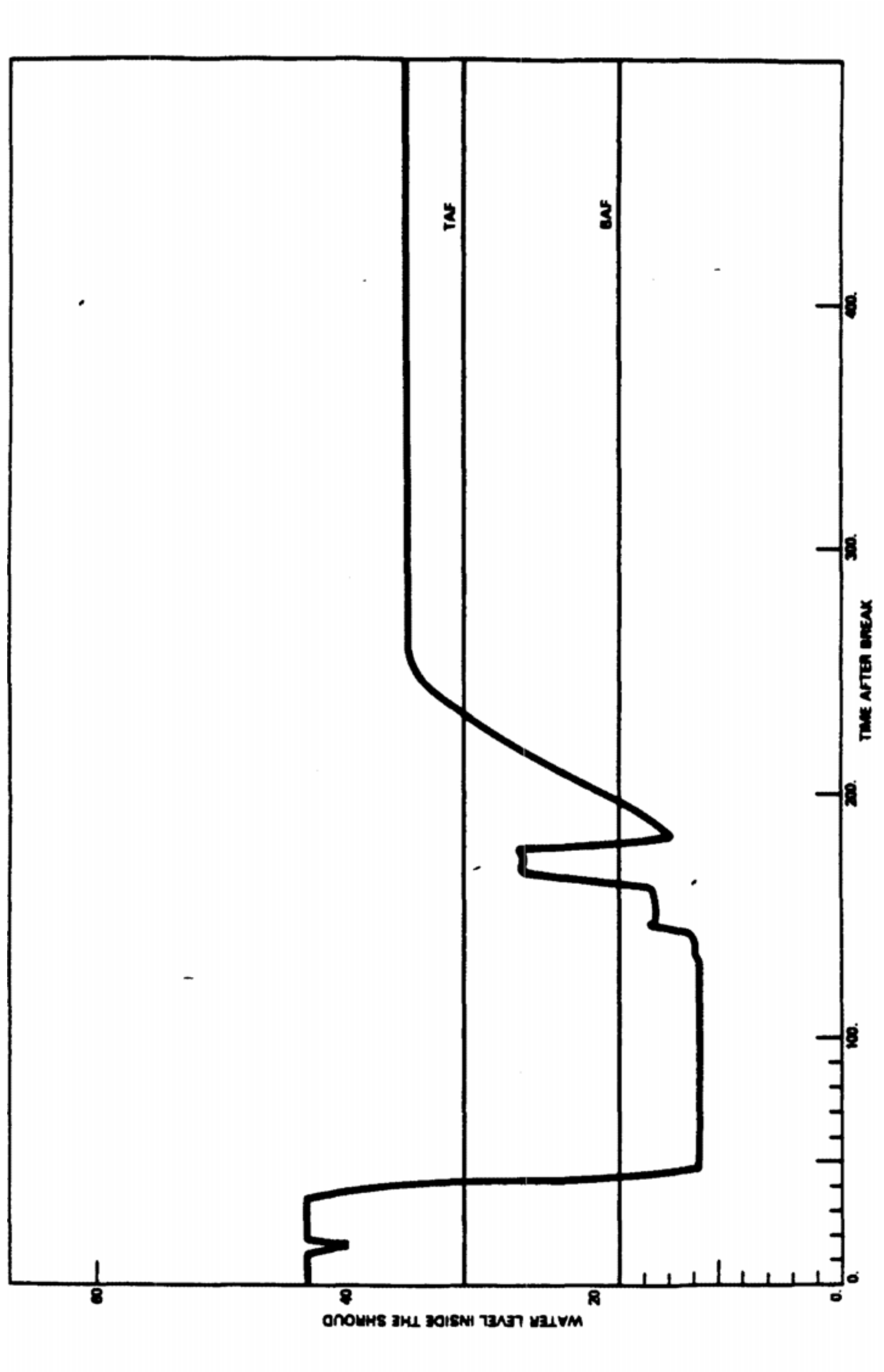
MINIMUM CRITICAL POWER RATIO
VERSUS TIME AFTER BREAK
(60% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-30



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CONVECTIVE HEAT TRANSFER COEFFICIENT
VERSUS TIME AFTER BREAK
(60% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-31

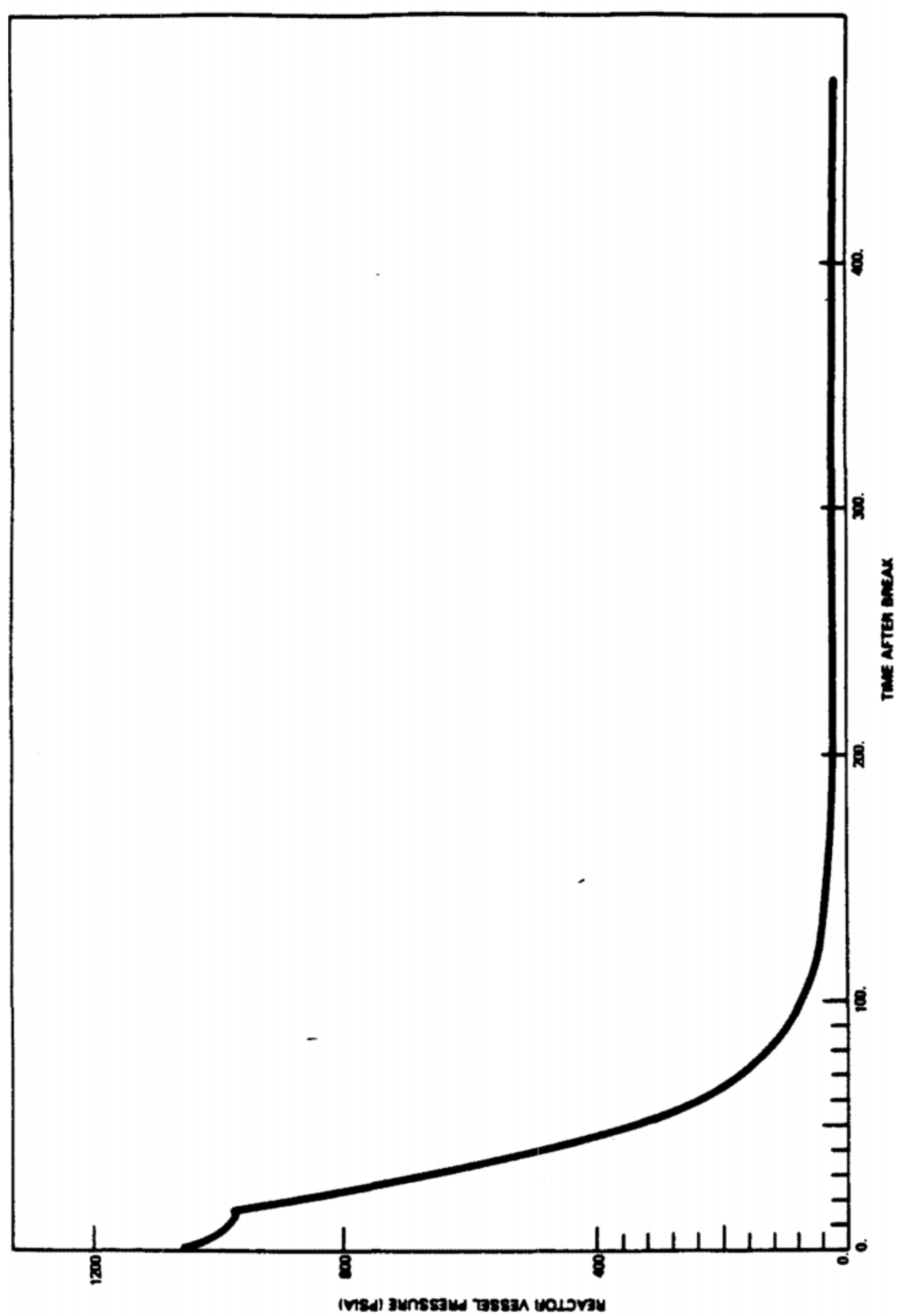


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK
(60% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-32

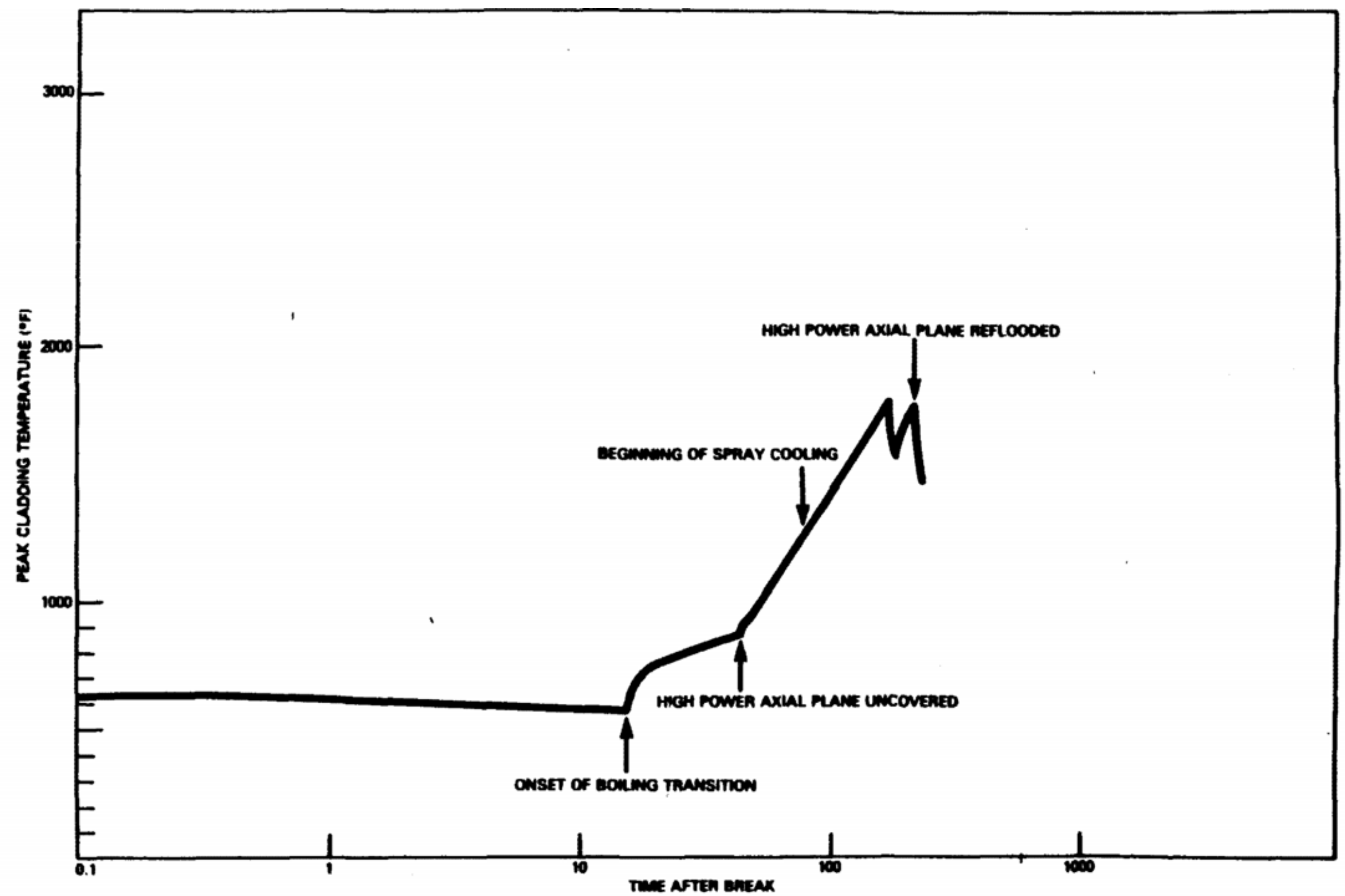


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

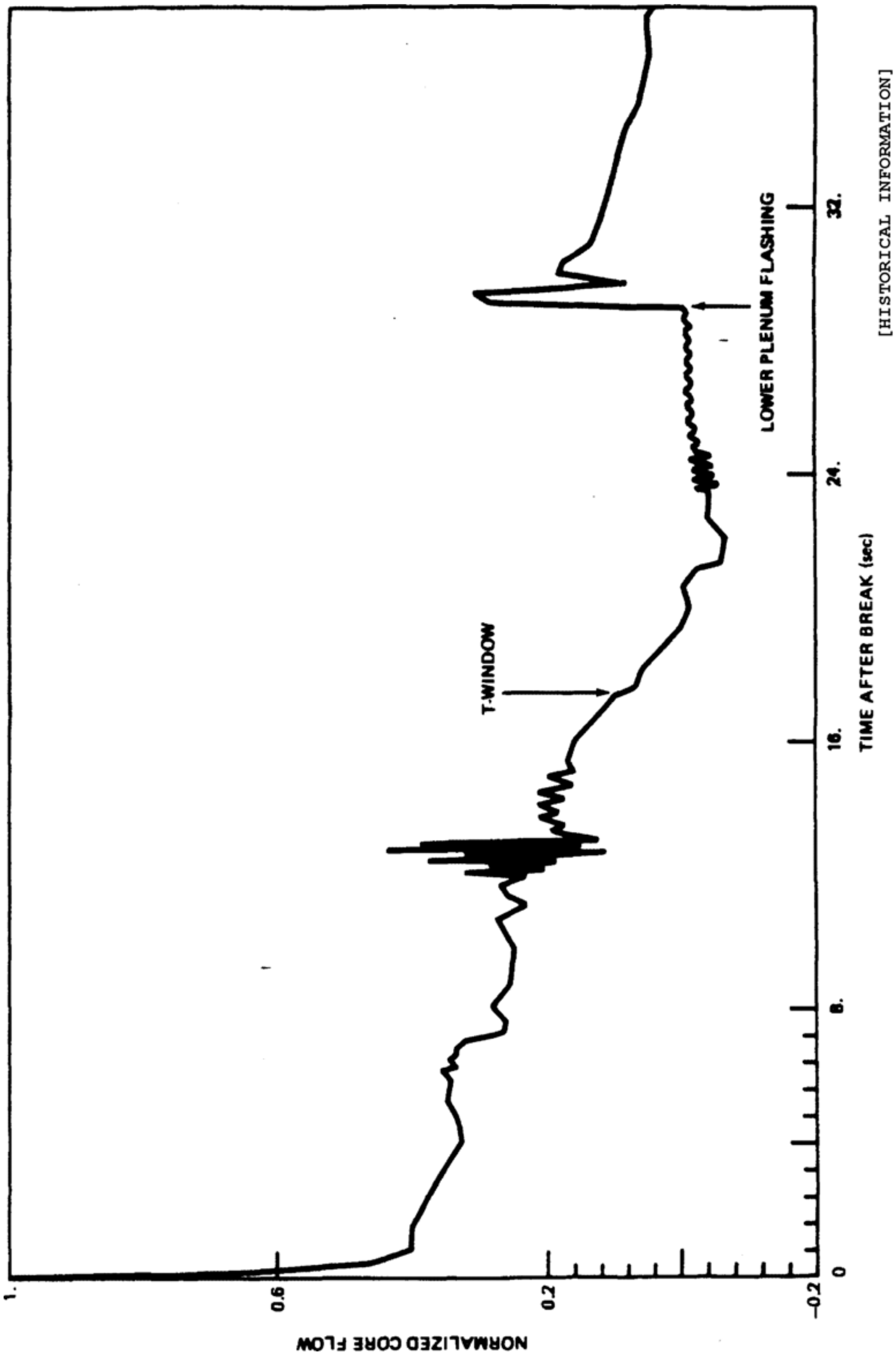
REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK
(60% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-33



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	PEAK CLADDING TEMPERATURE VERSUS TIME AFTER BREAK (60% DBA, RECIRC SUCTION BREAK, LPCI D/G FAILURE) [INITIAL CYCLE] FIGURE 6.3-34

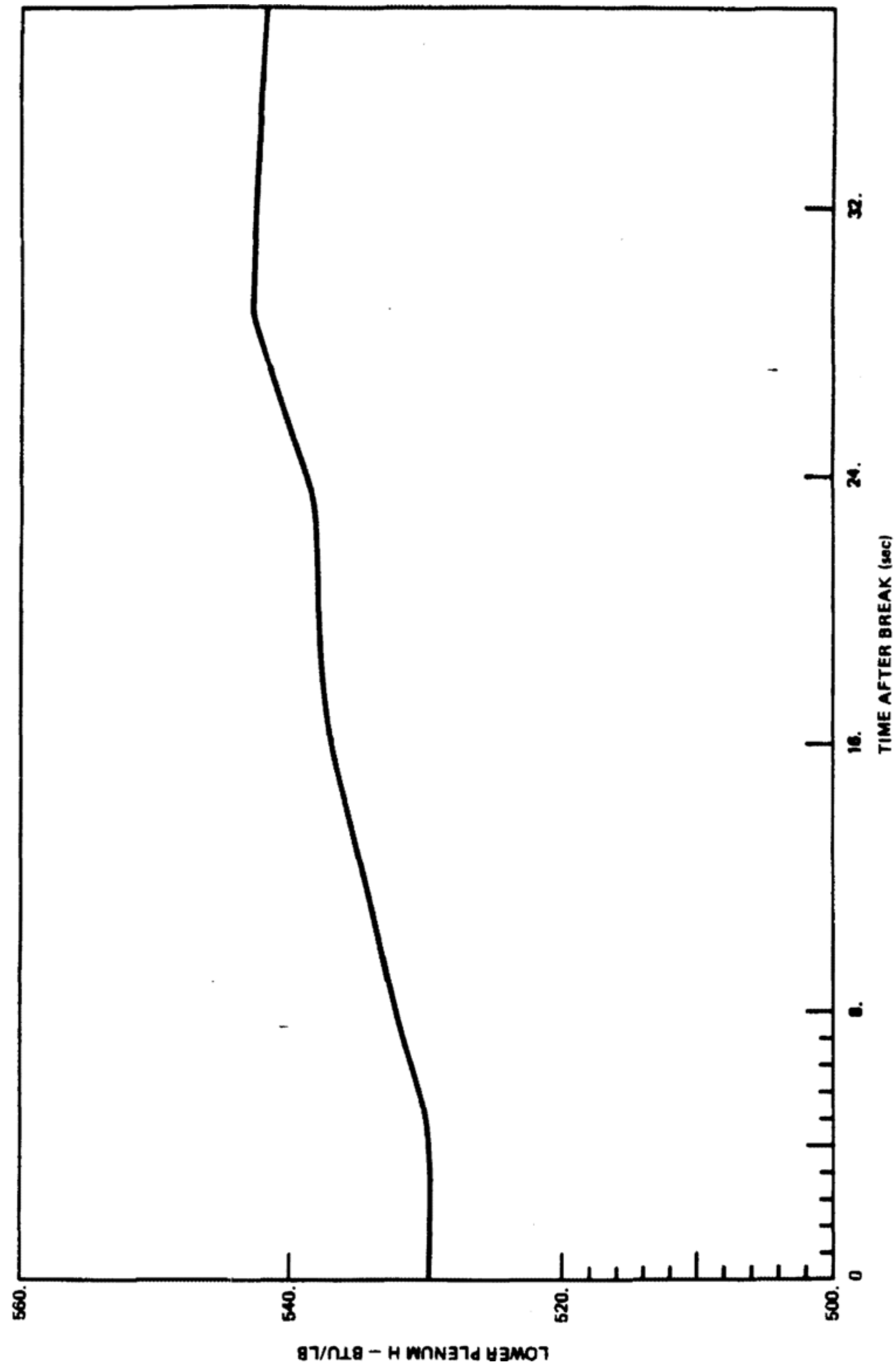


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

NORMALIZED CORE AVERAGE INLET FLOW VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK AREA, RECIRCULATION SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-35

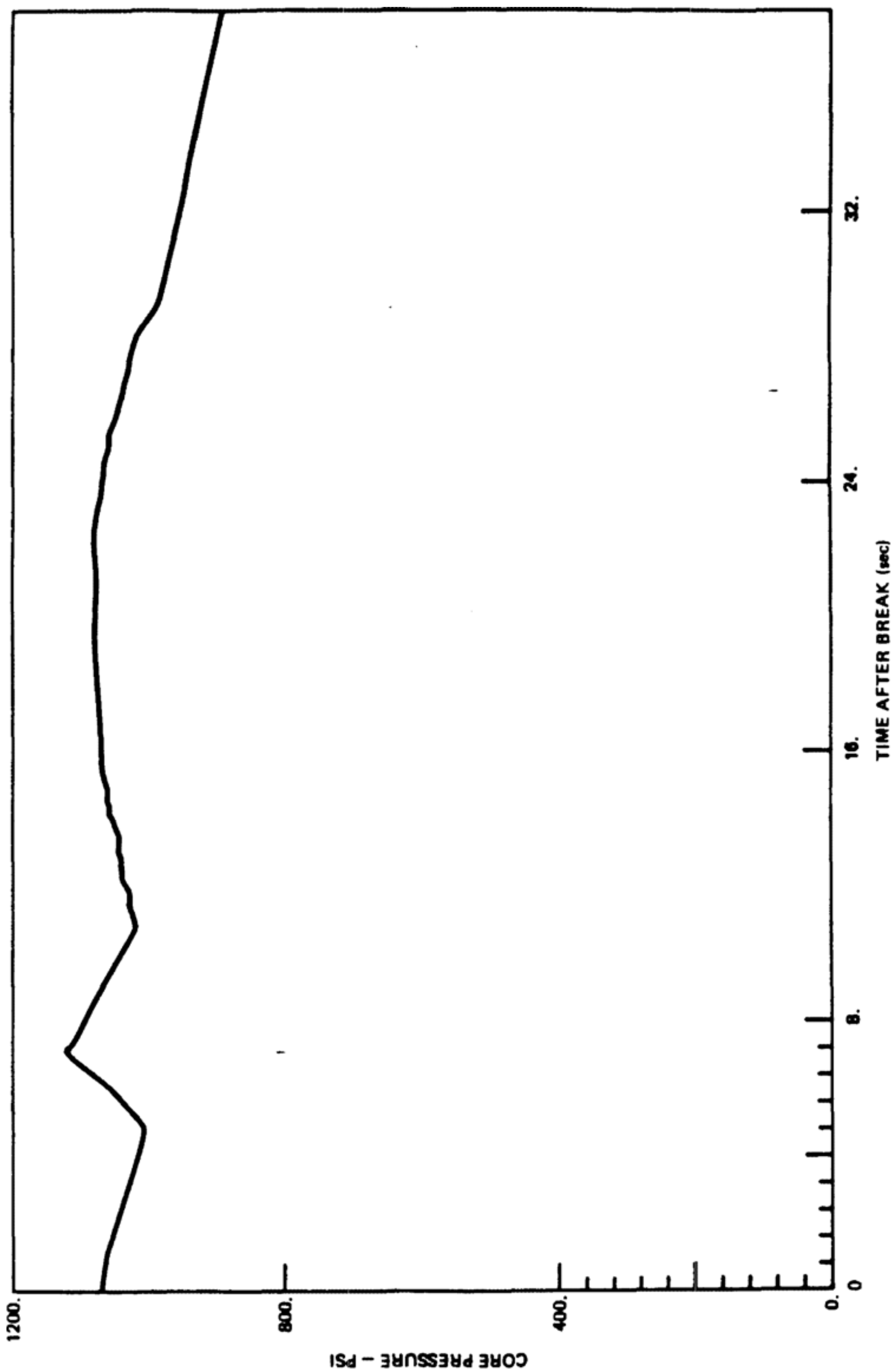


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

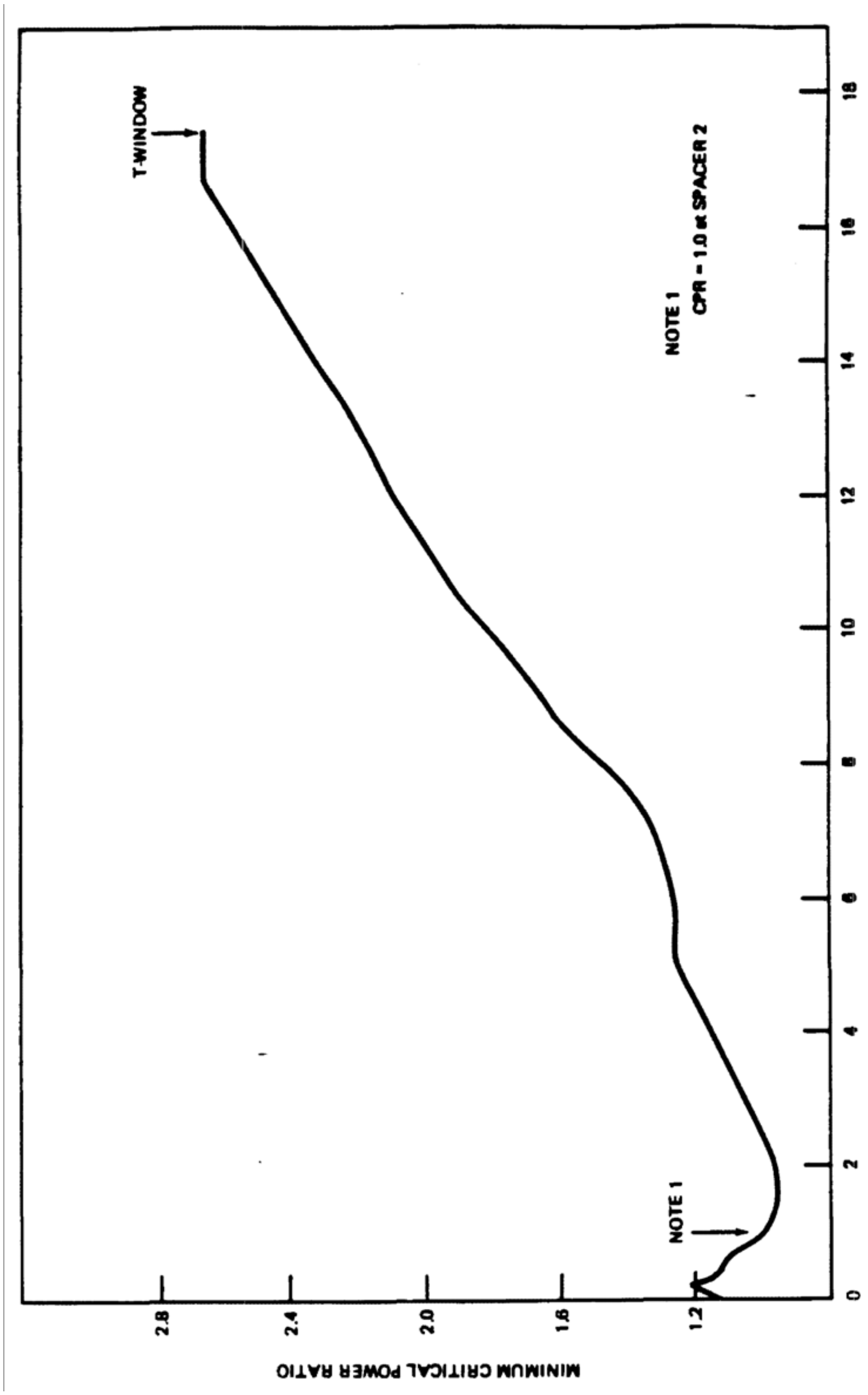
CORE INLET ENTHALPY
VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK AREA,
RECIRCULATION SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-36



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	CORE AVERAGE PRESSURE VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK AREA, RECIRCULATION SUCTION BREAK, LPCI D/G FAILURE) [INITIAL CYCLE] FIGURE 6.3-37

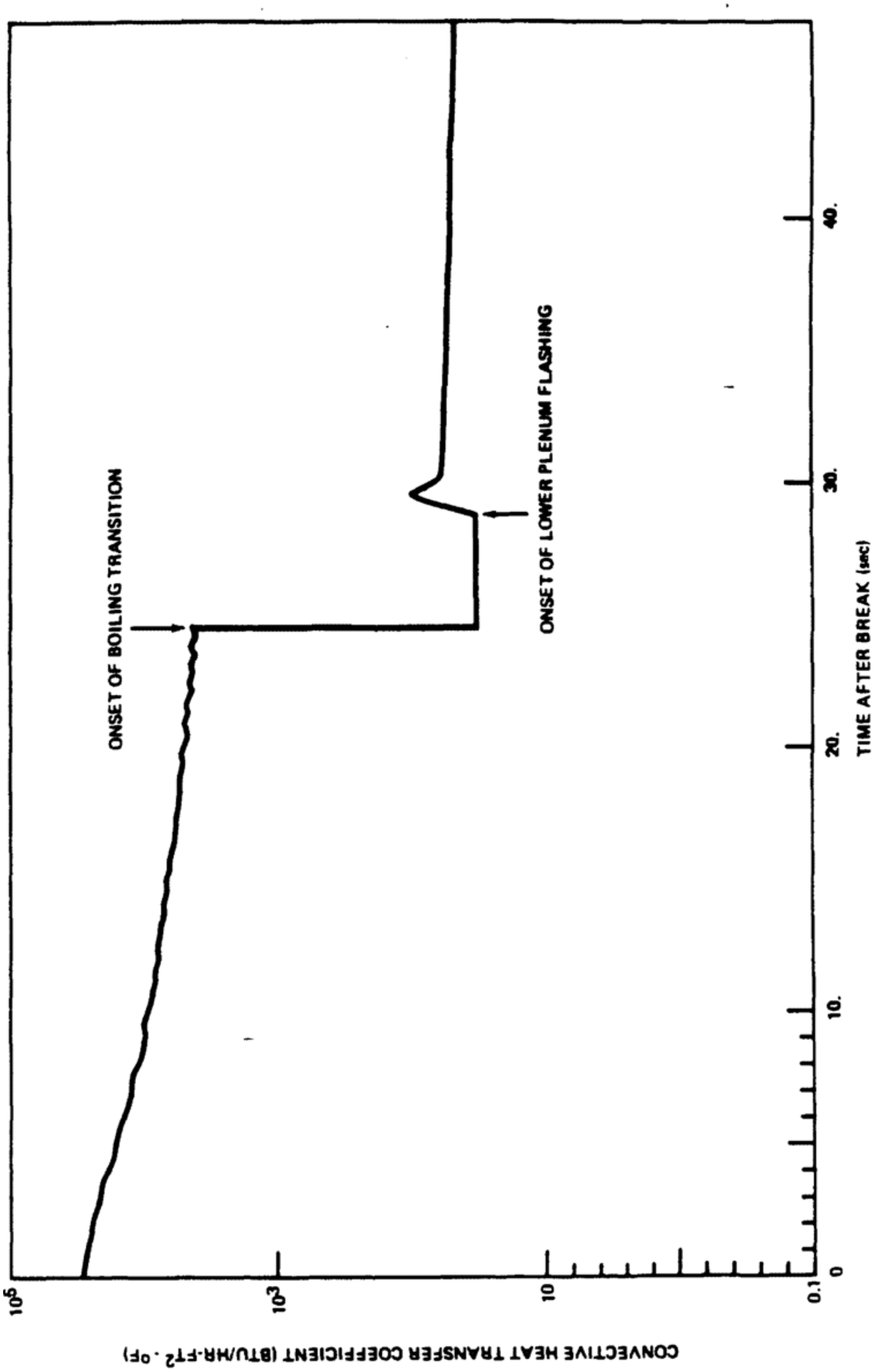


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

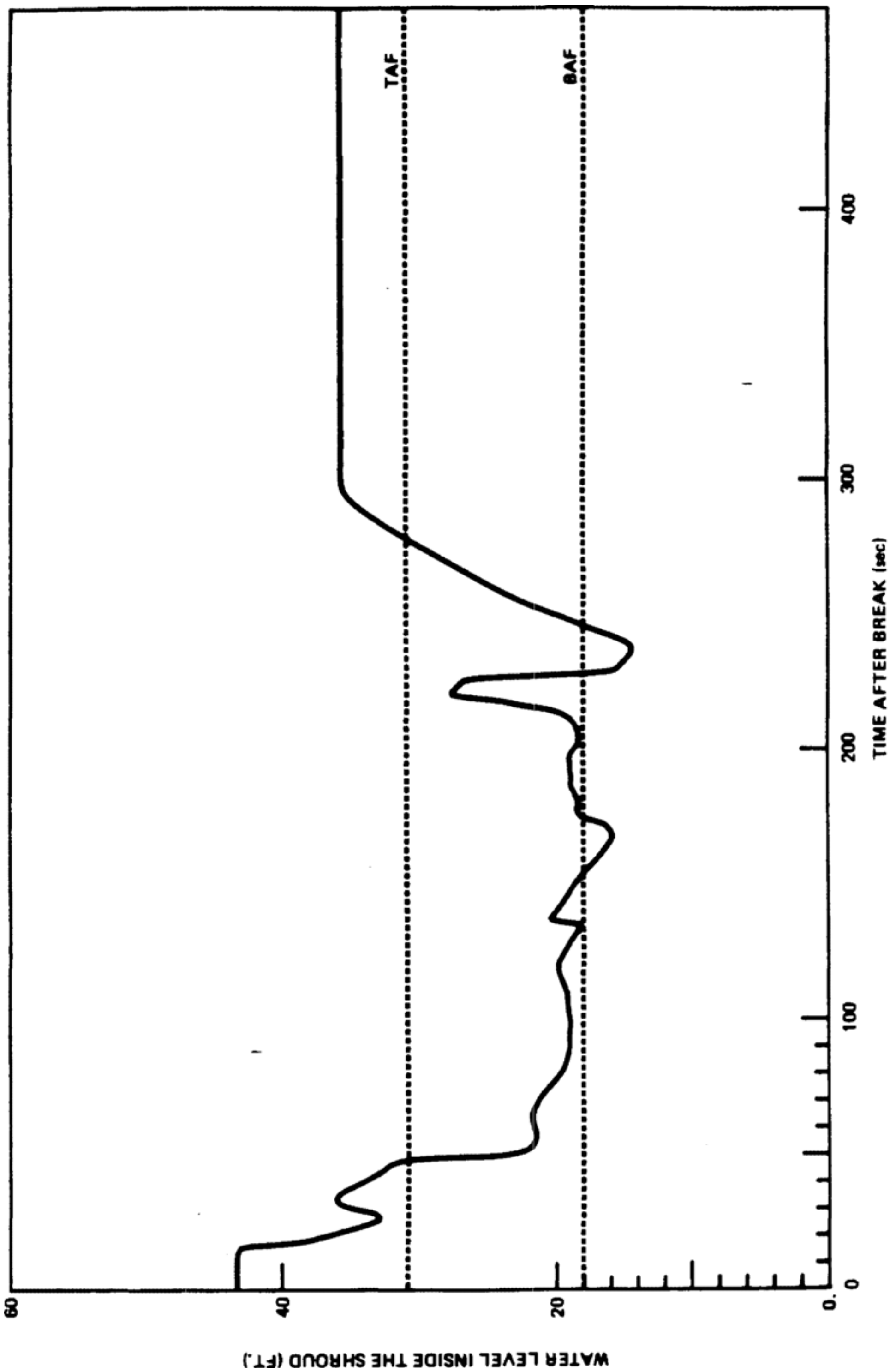
MINIMUM CRITICAL POWER RATIO
VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK AREA,
RECIRCULATION SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-38



[HISTORICAL INFORMATION]

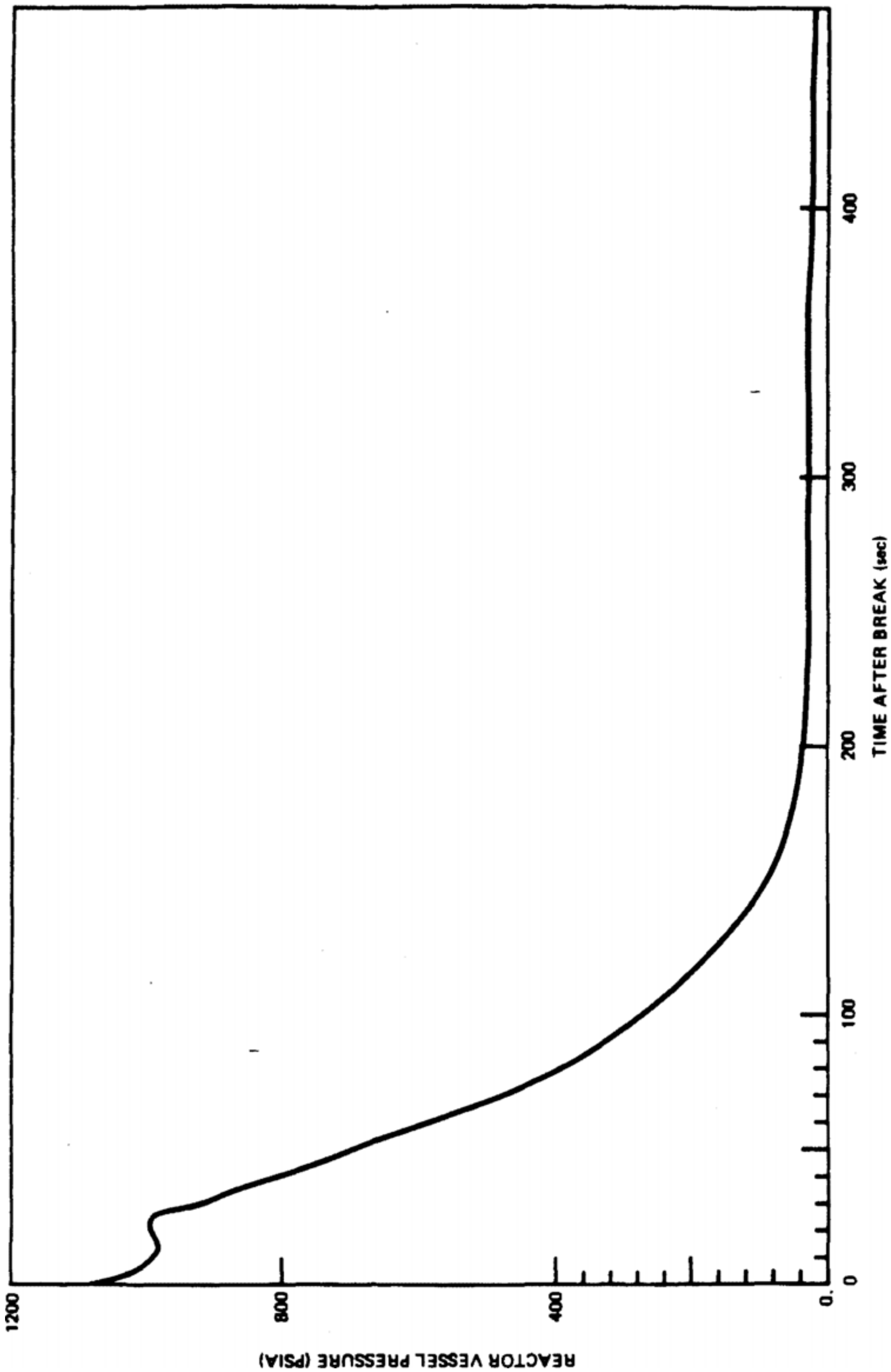
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	CONVECTIVE HEAT TRANSFER COEFFICIENT VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK, LARGE BREAK METHOD, RECIRC SUCTION BREAK, LPCI D/G FAILURE) [INITIAL CYCLE] FIGURE 6.3-39



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK, LARGE
BREAK METHOD, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-40

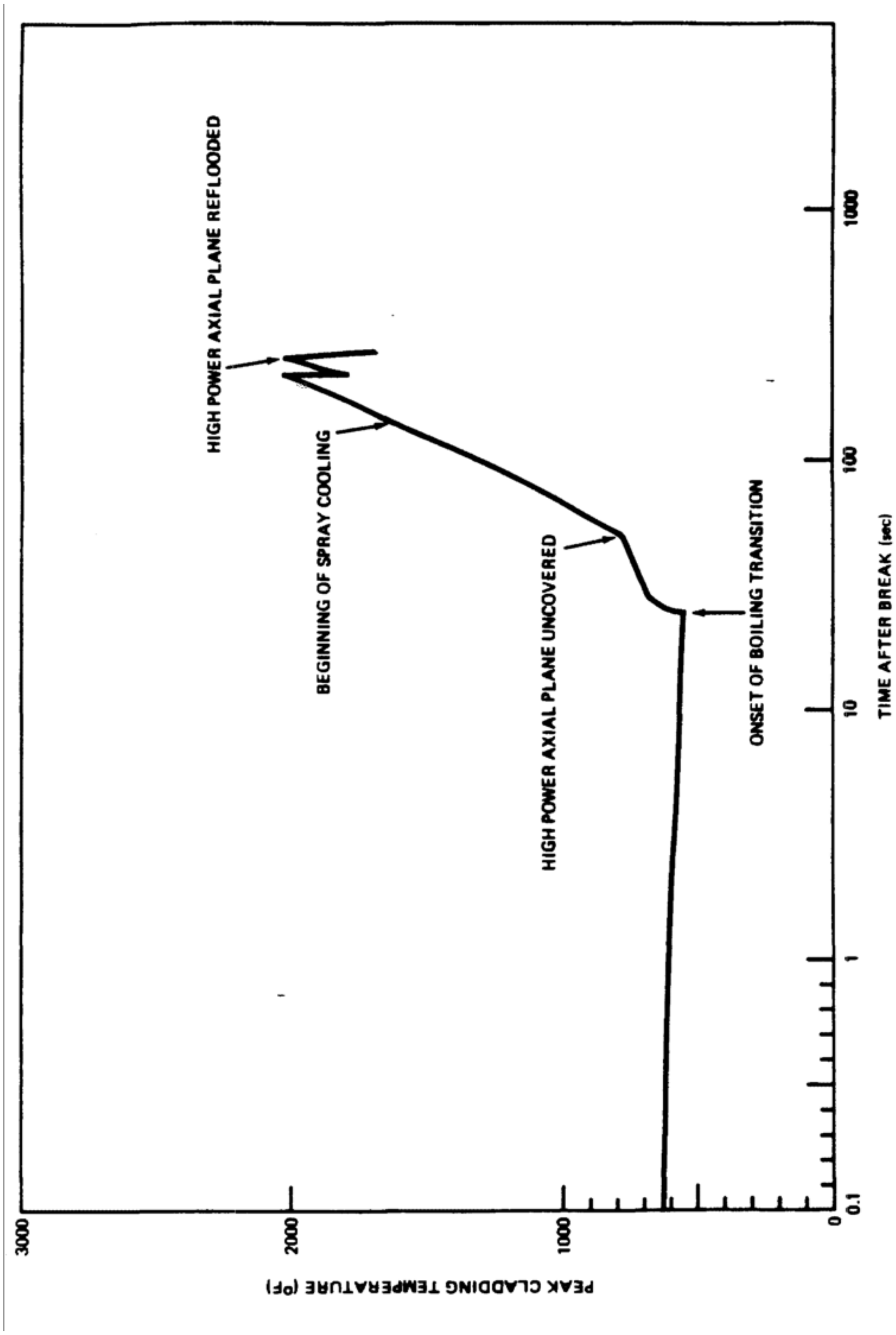


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK, LARGE
BREAK METHOD, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

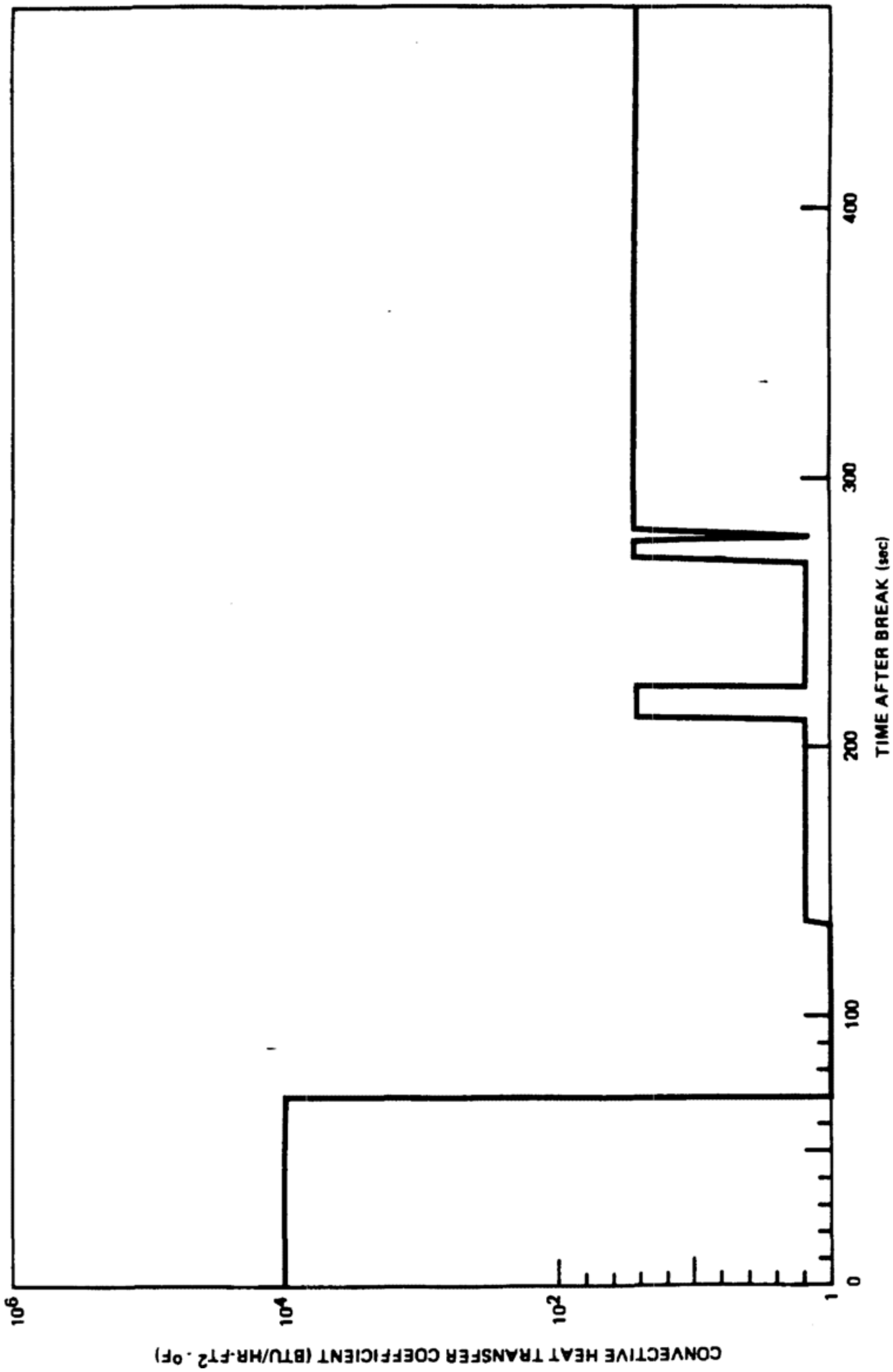
FIGURE 6.3-41



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

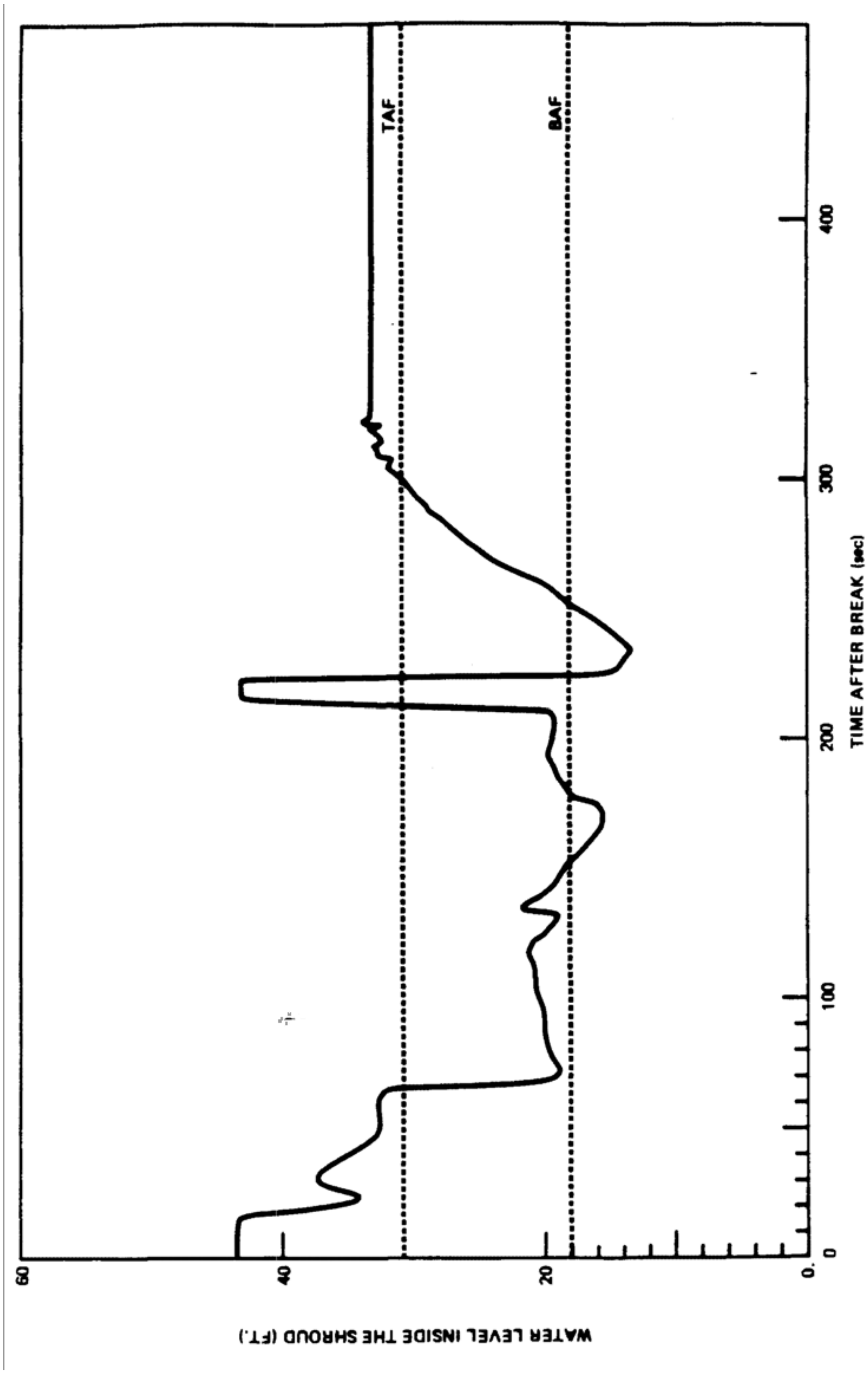
PEAK CLADDING TEMPERATURE
VERSUS TIME AFTER BREAK (1.0 FT² BREAK, LARGE
BREAK METHOD, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-42



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

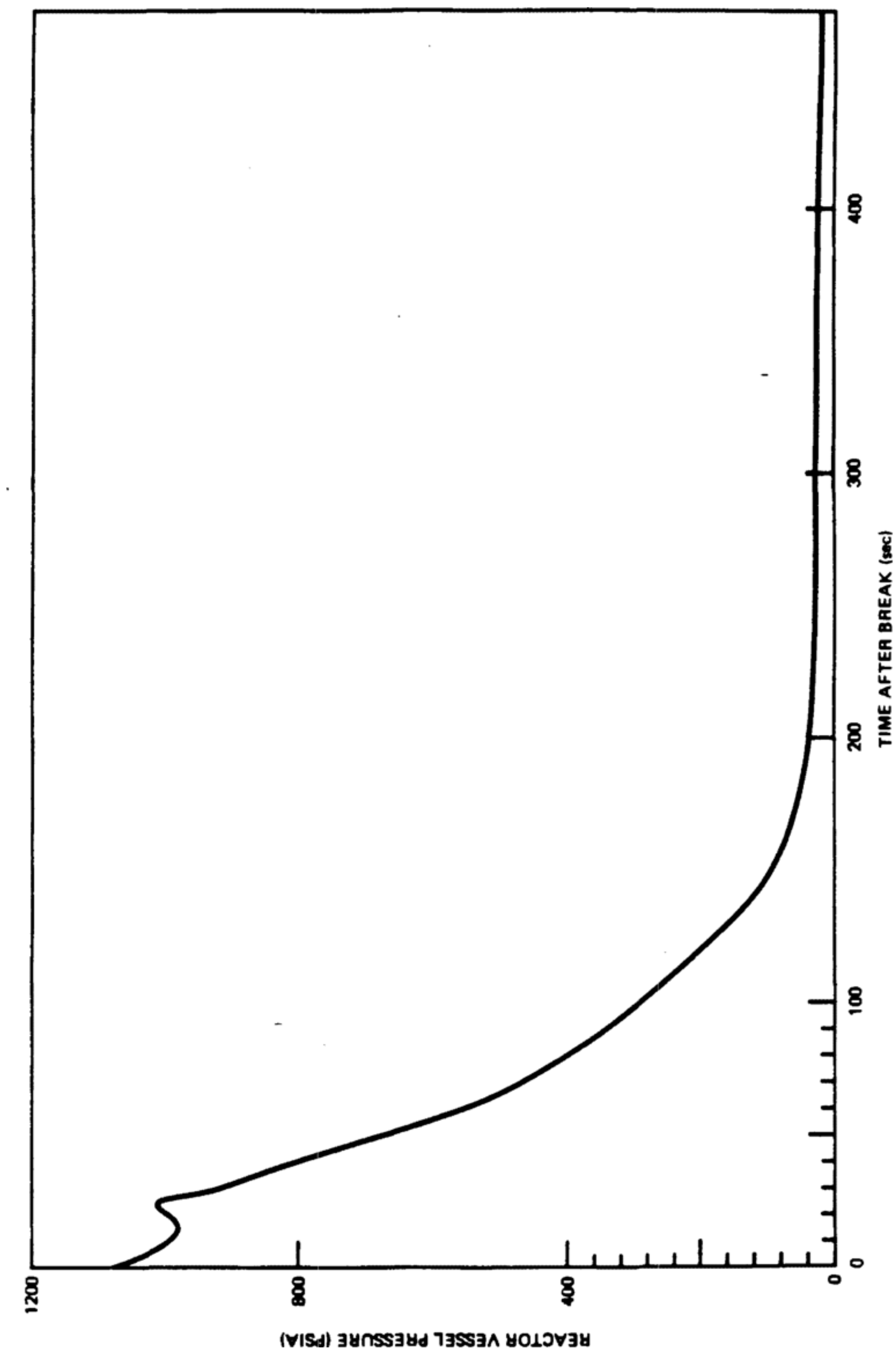
CONVECTIVE HEAT TRANSFER COEFFICIENT
VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK, SMALL
BREAK METHOD, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-43



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

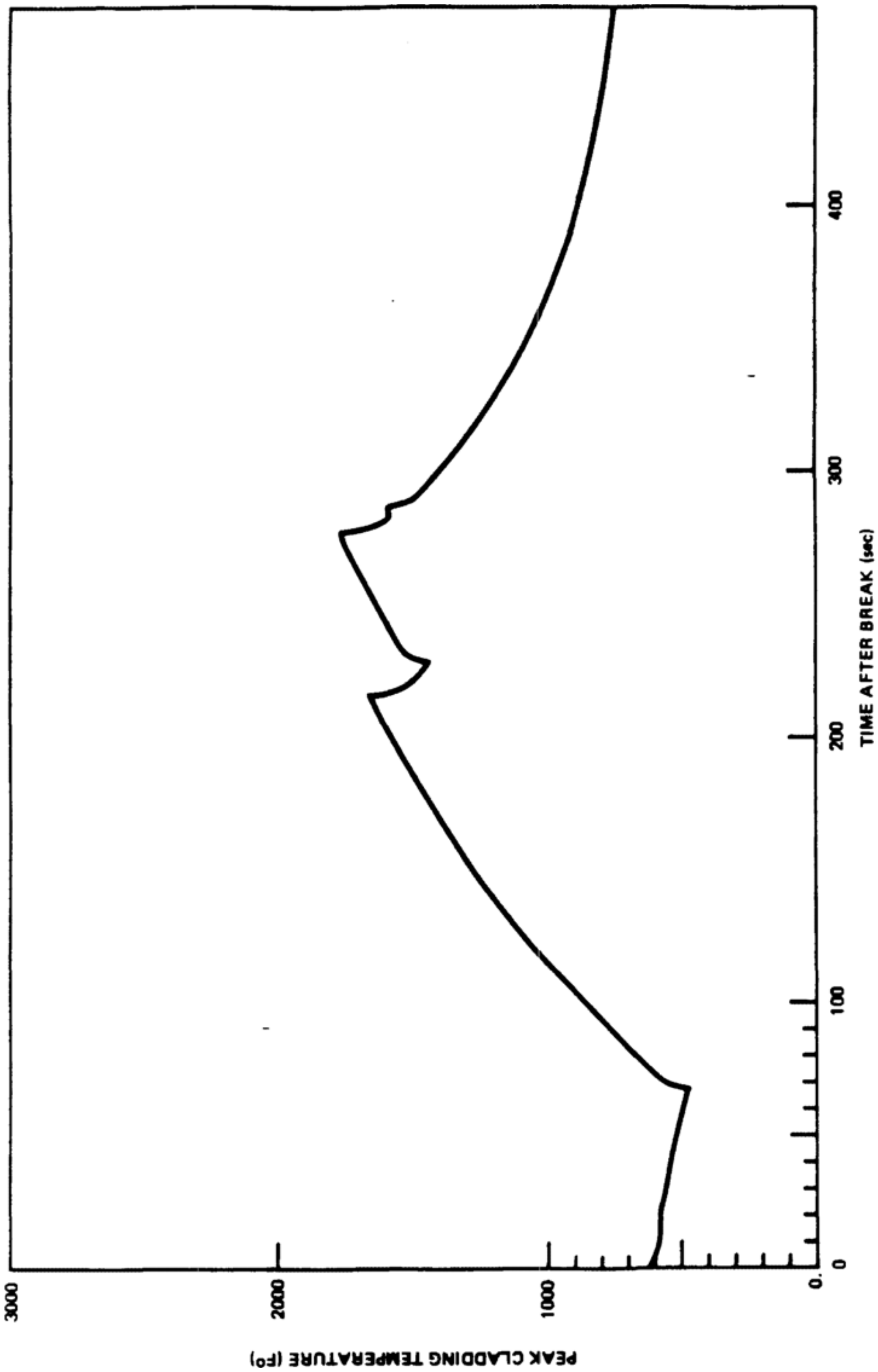
WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK, SMALL
BREAK METHOD, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-44



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK, SMALL
BREAK METHOD, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-45

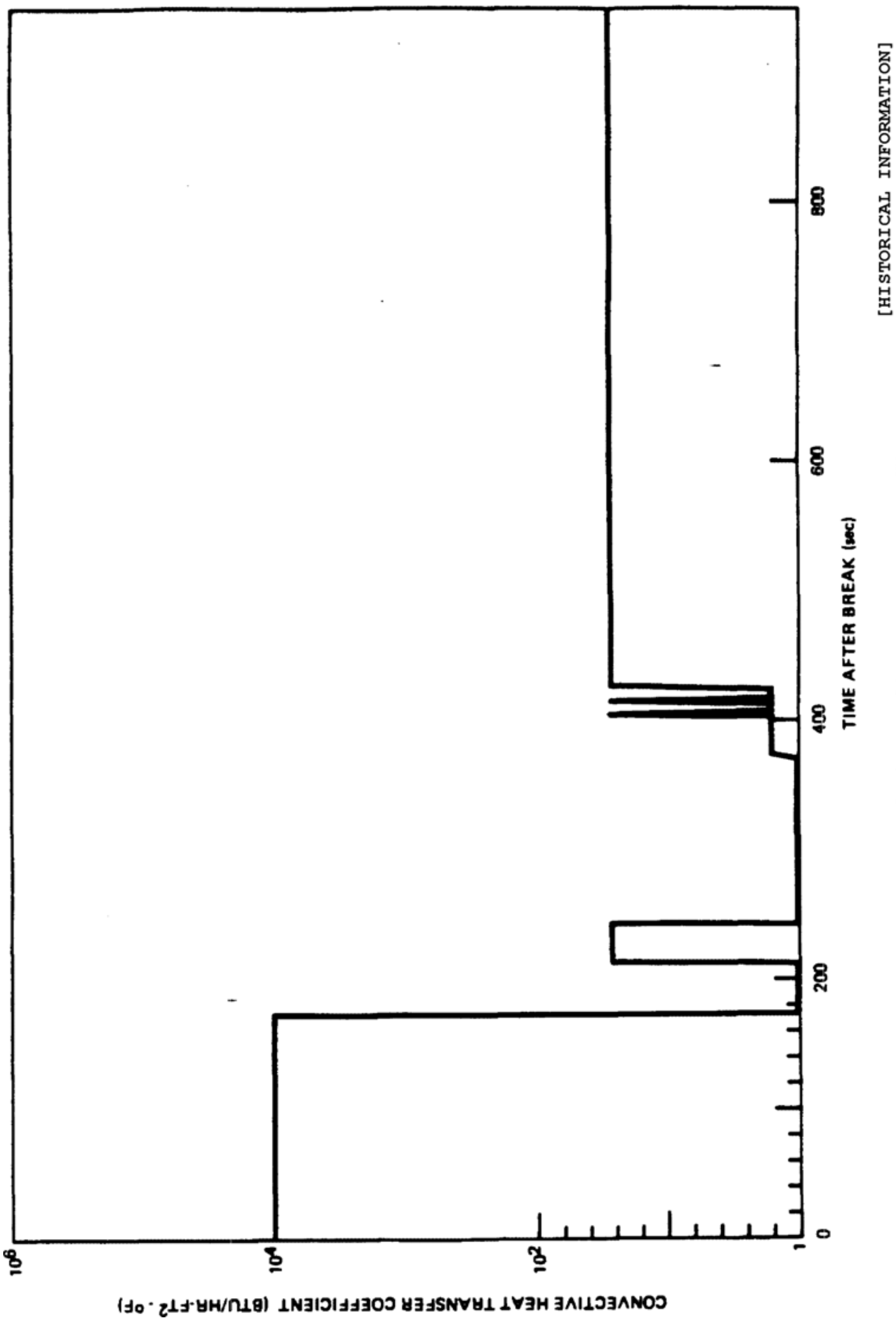


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

PEAK CLADDING TEMPERATURE
VERSUS TIME AFTER BREAK (1.0 FT^2 BREAK, SMALL
BREAK METHOD, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

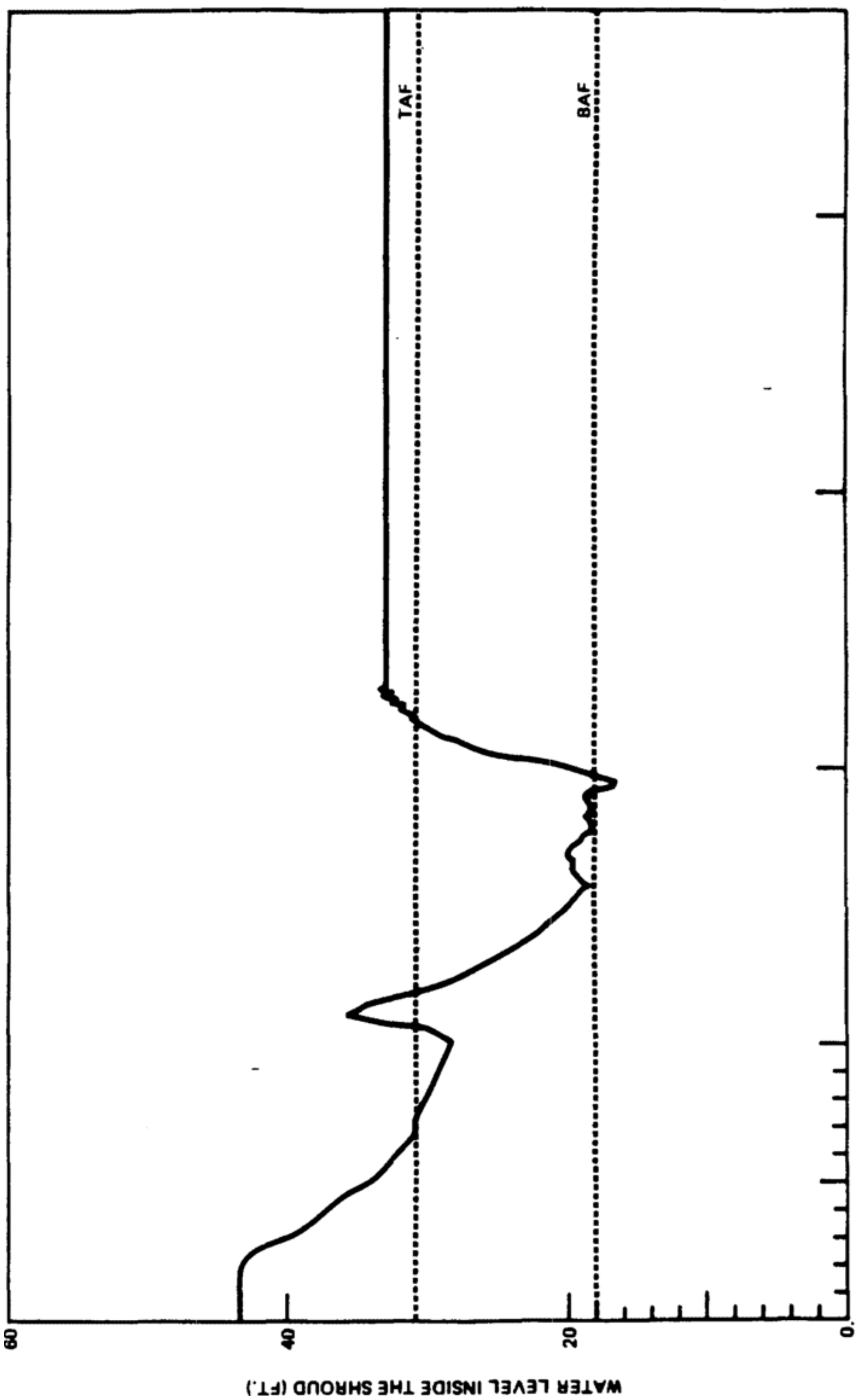
FIGURE 6.3-46



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CONVECTIVE HEAT TRANSFER COEFFICIENT
VERSUS TIME AFTER BREAK (0.9 FT^2 BREAK, HIGHEST TEMP.
SMALL BREAK, RECIRC SUCTION BREAK, HPCS FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-47

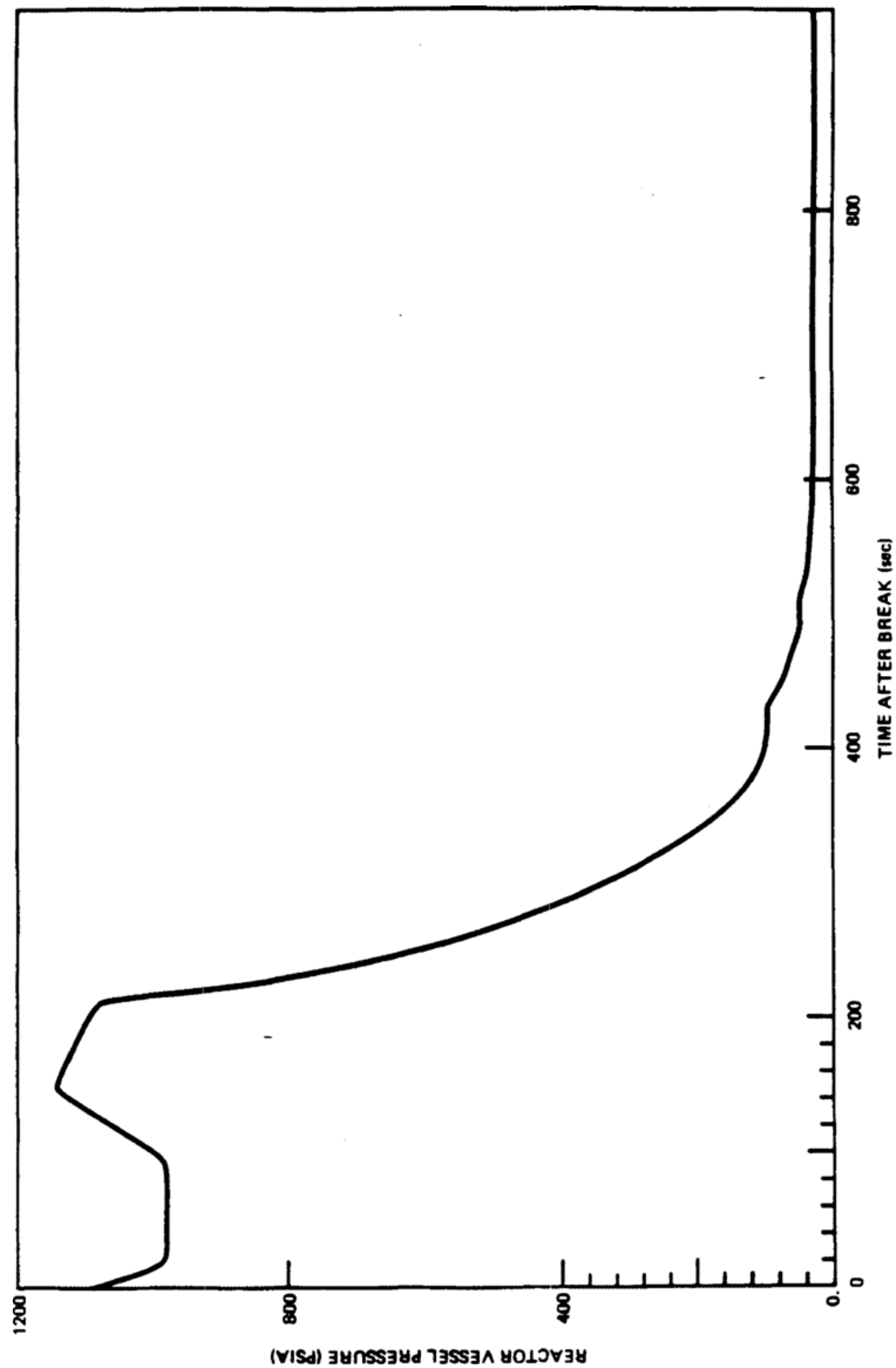


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK (0.9 FT^2 BREAK, HIGHEST TEMP.
SMALL BREAK, RECIRC SUCTION BREAK, HPCS FAILURE)
[INITIAL CYCLE]

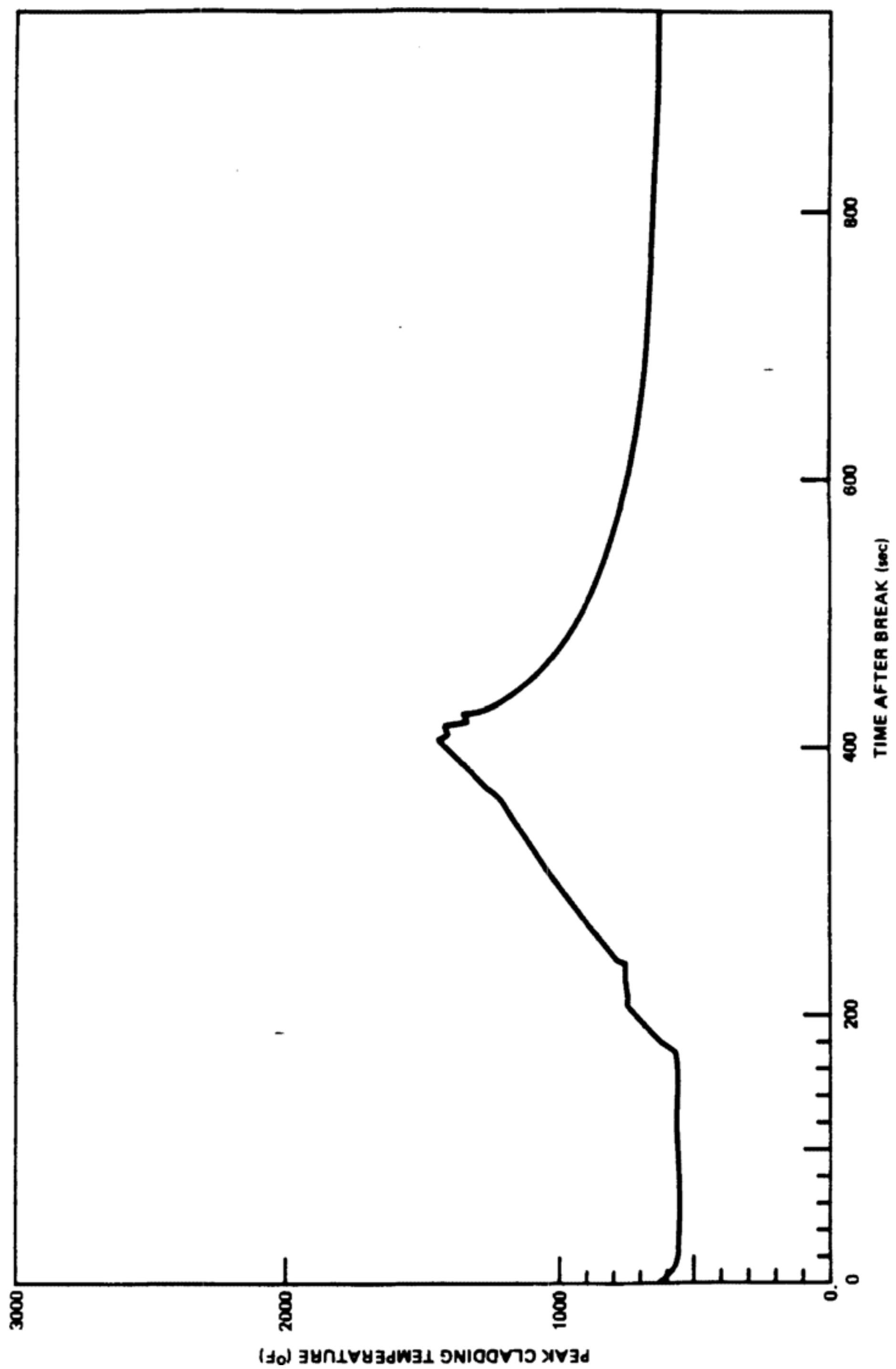
FIGURE 6.3-48



[HISTORICAL INFORMATION]

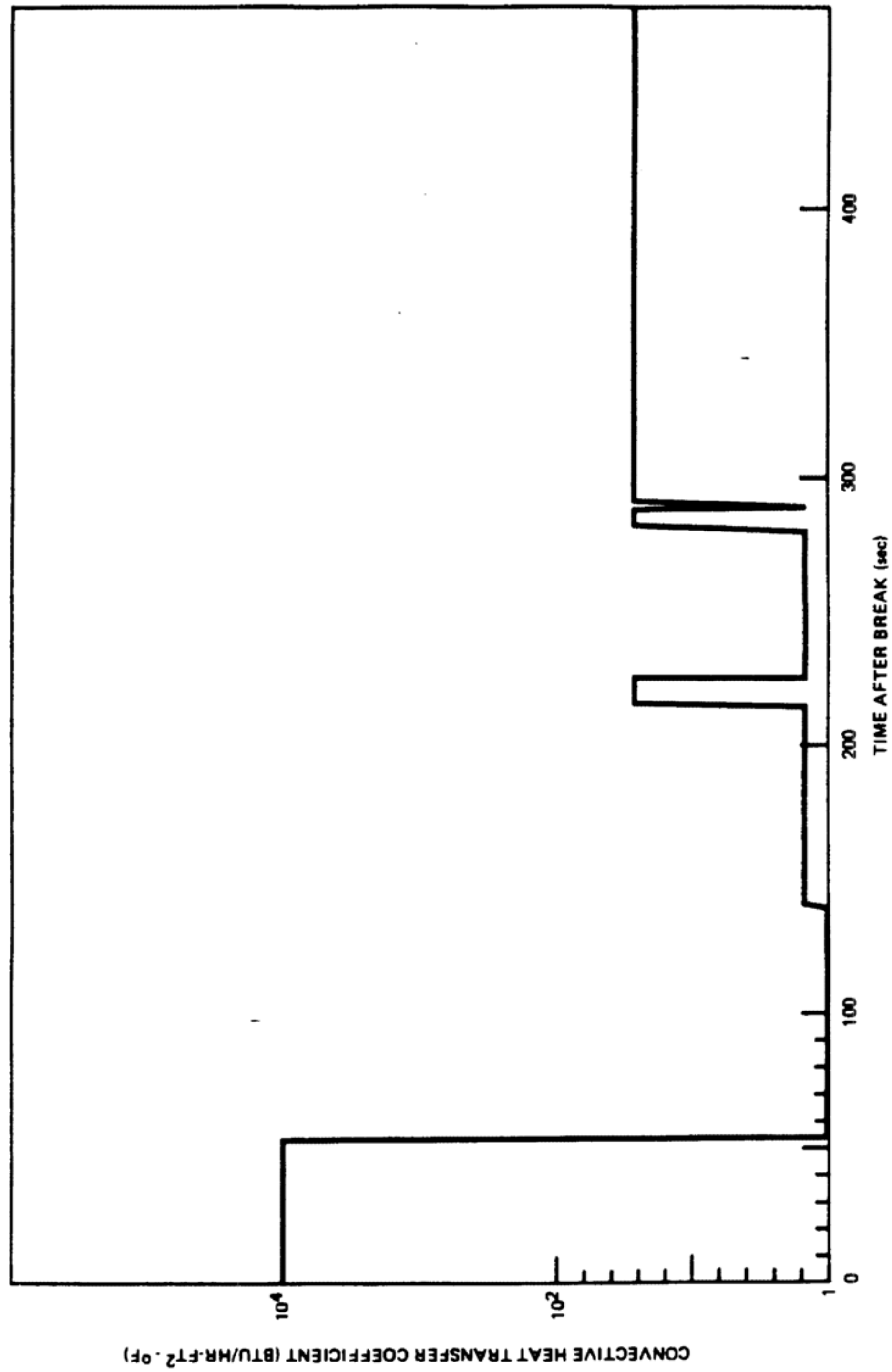
GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK (0.9 FT^2 BREAK, HIGHEST TEMP.
SMALL BREAK, RECIRC SUCTION BREAK, HPCS FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-49



[HISTORICAL INFORMATION]

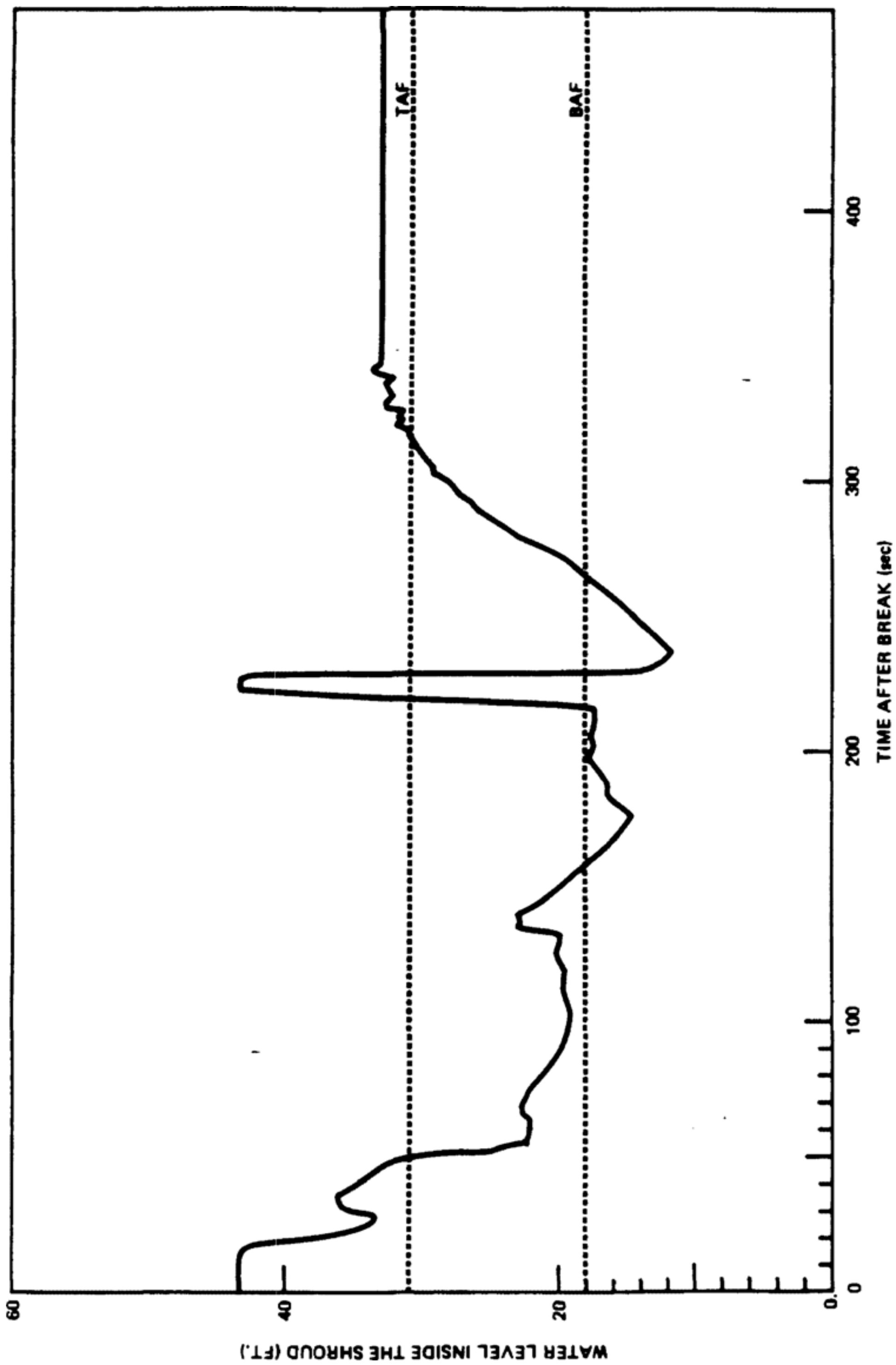
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	PEAK CLADDING TEMPERATURE VERSUS TIME AFTER BREAK (0.9 FT^2 BREAK, HIGHEST TEMP. SMALL BREAK, RECIRC SUCTION BREAK, HPCS FAILURE) [INITIAL CYCLE] FIGURE 6.3-50



[HISTORICAL INFORMATION]

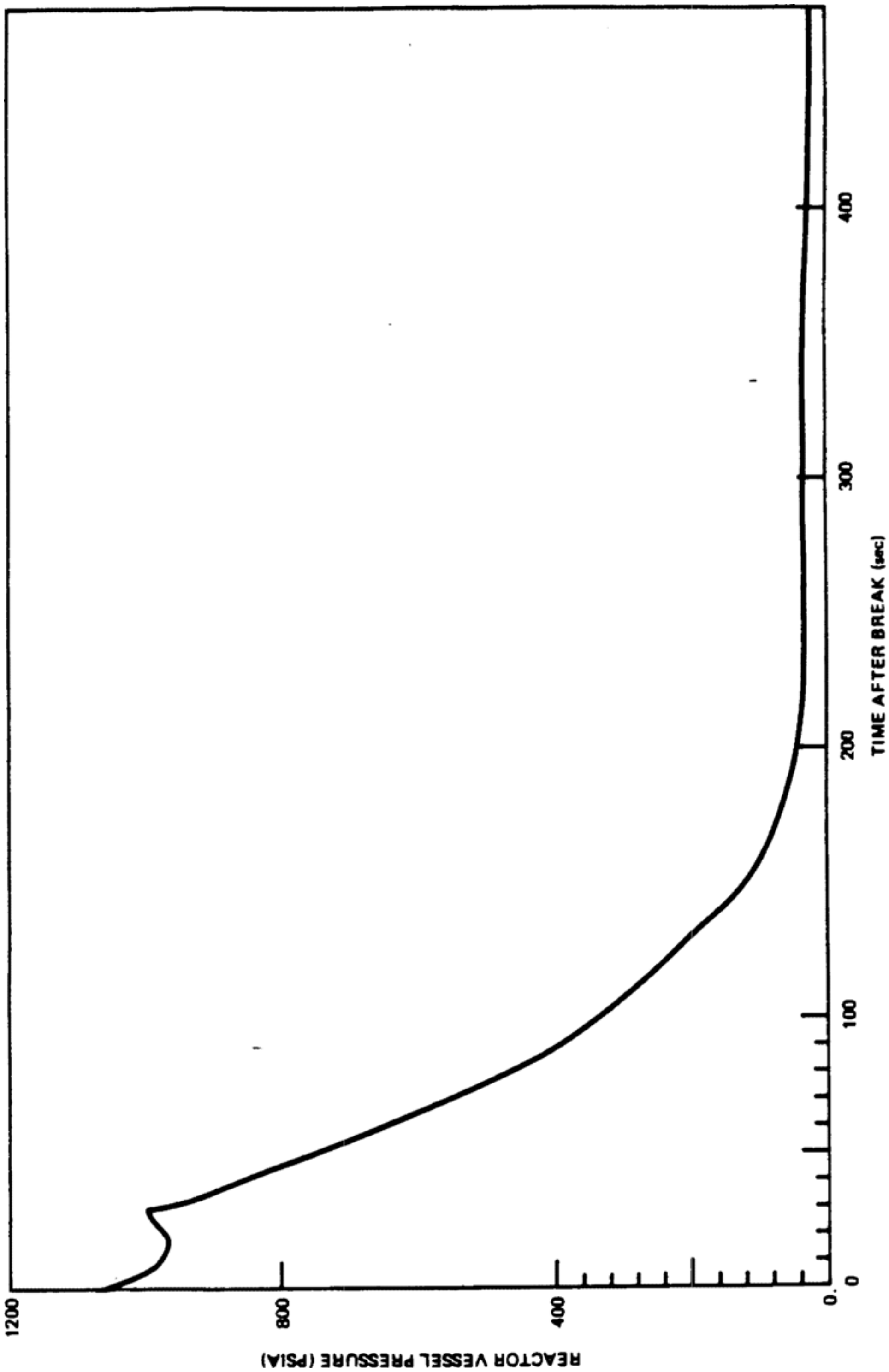
GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CONVECTIVE HEAT TRANSFER COEFFICIENT
VERSUS TIME AFTER BREAK (0.9 FT^2 BREAK, ADDITIONAL
SMALL BREAK, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-51



[HISTORICAL INFORMATION]

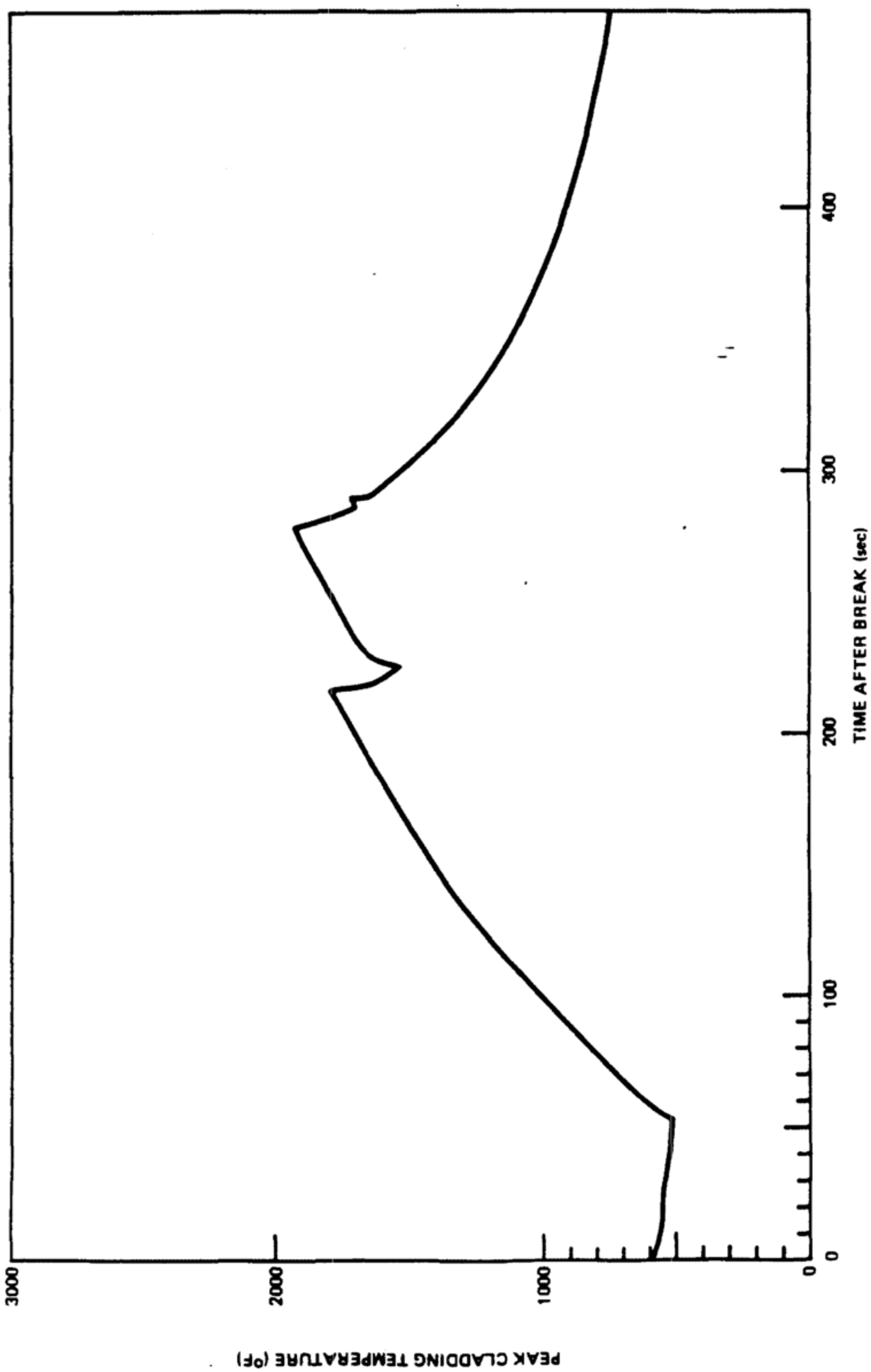
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	WATER LEVEL INSIDE THE SHROUD VERSUS TIME AFTER BREAK (0.9 FT^2 BREAK, ADDITIONAL SMALL BREAK, RECIRC SUCTION BREAK, LPCI D/G FAILURE) [INITIAL CYCLE] FIGURE 6.3-52



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK (0.9 FT^2 BREAK, ADDITIONAL
SMALL BREAK, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-53

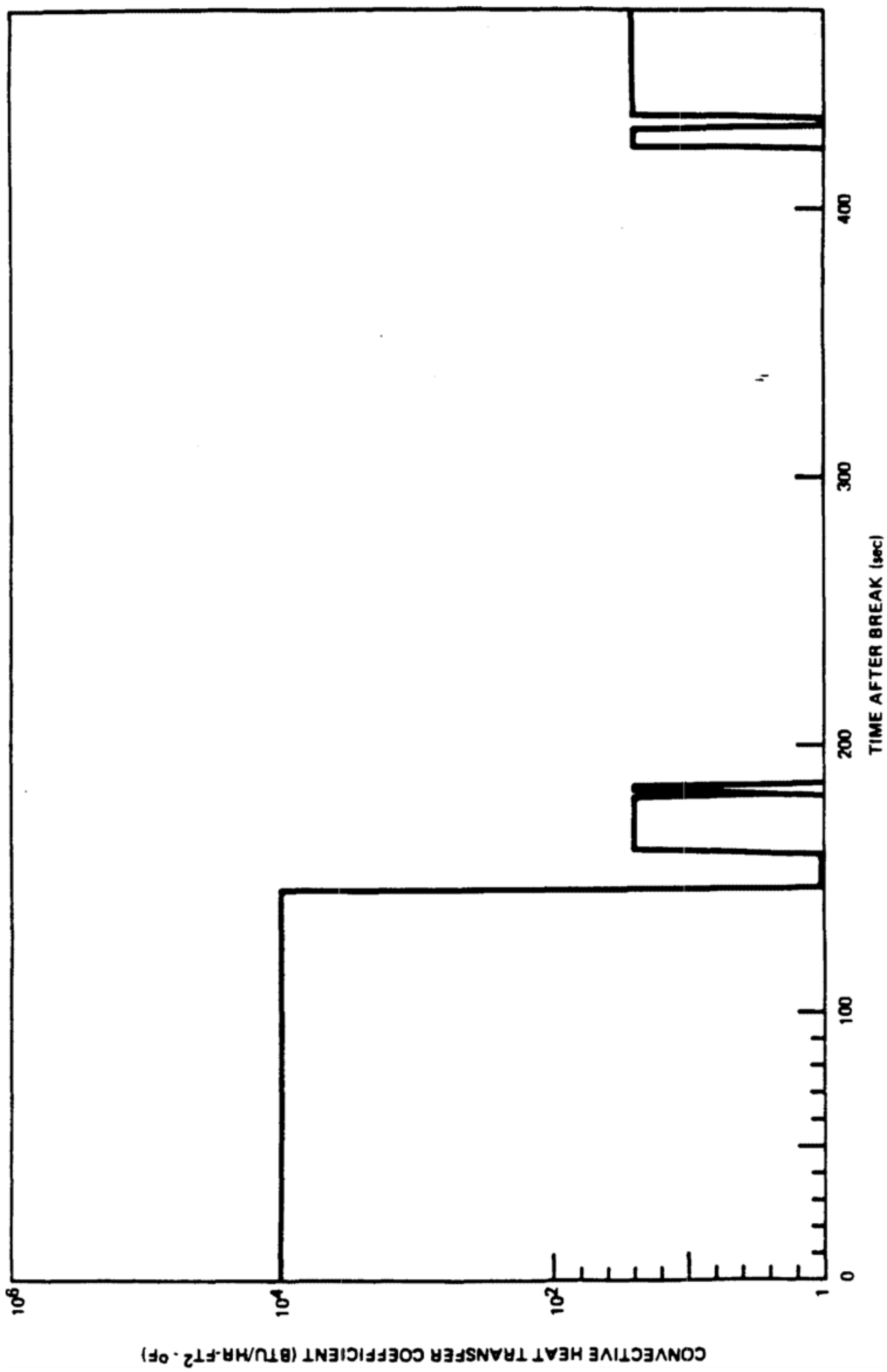


[HISTORICAL INFORMATION]

PEAK CLADDING TEMPERATURE
VERSUS TIME AFTER BREAK (0.9 FT^2 BREAK, ADDITIONAL
SMALL BREAK, RECIRC SUCTION BREAK, LPCI D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-54

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

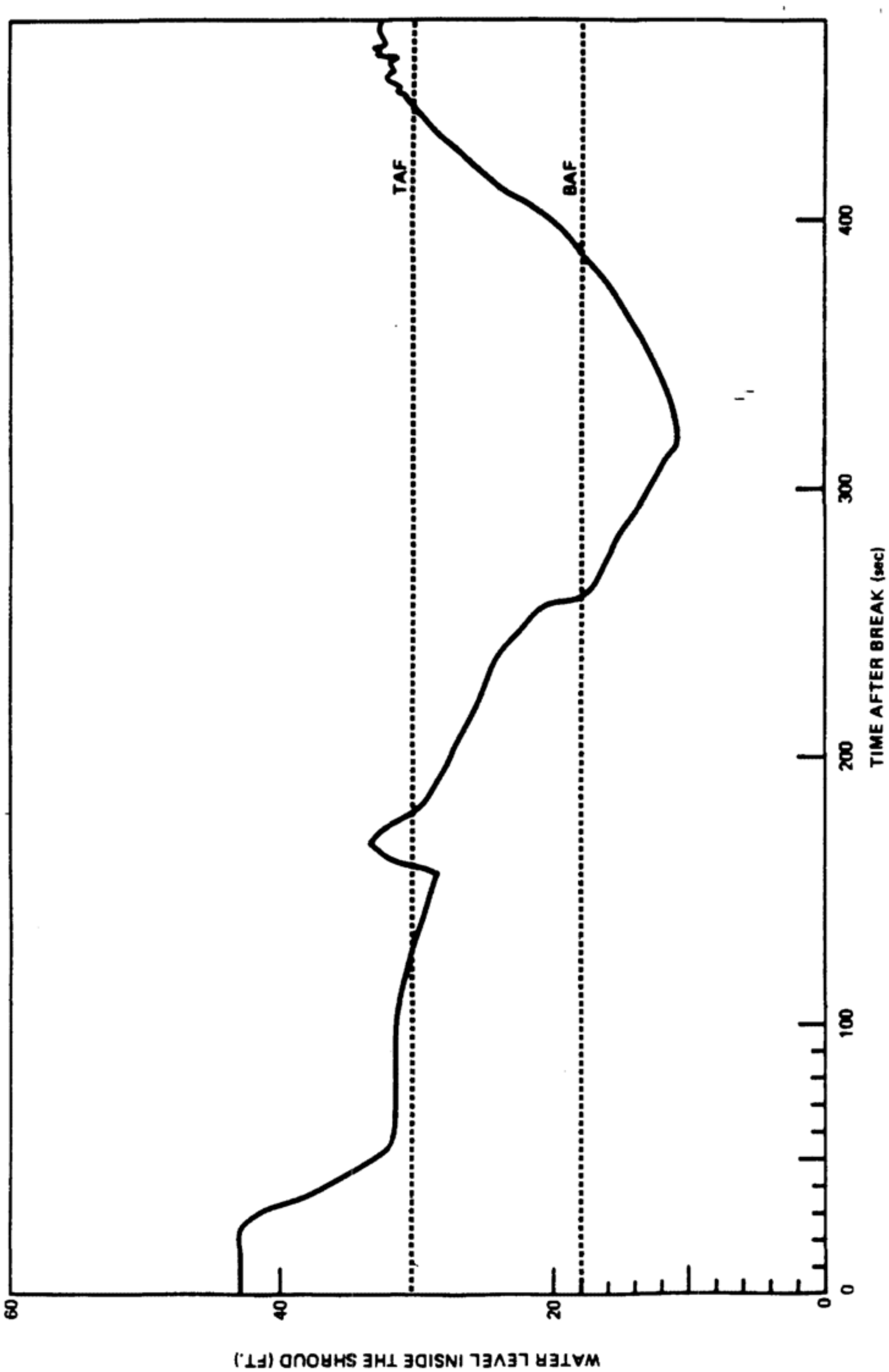


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CONVECTIVE HEAT TRANSFER COEFFICIENT
VERSUS TIME AFTER BREAK (CORE SPRAY LINE BREAK,
0.28 FT^2 BREAK, LPCS D/G FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-55

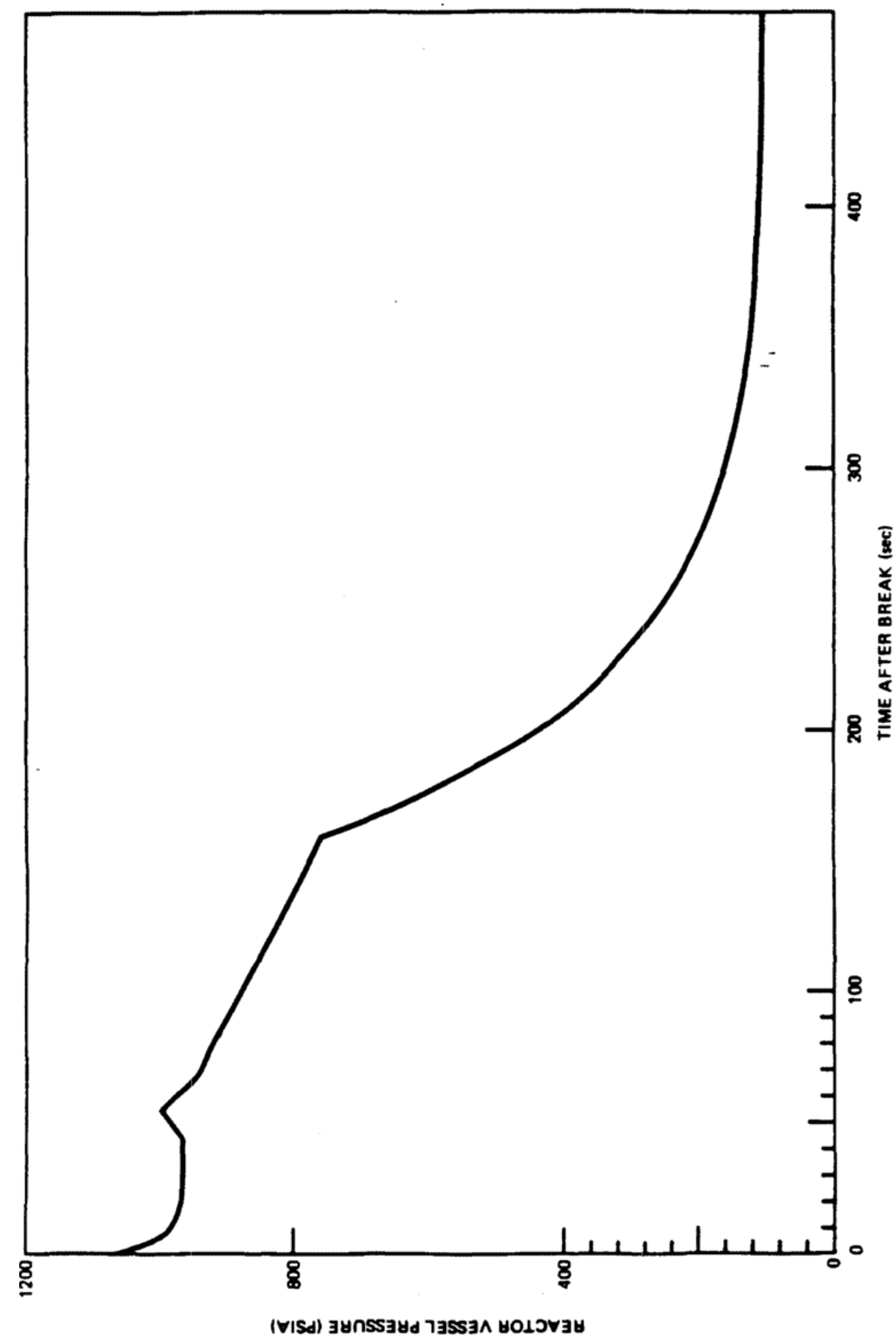


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK (CORE SPRAY LINE BREAK,
0.28 FT^2 BREAK, LPCS D/G FAILURE)
[INITIAL CYCLE]

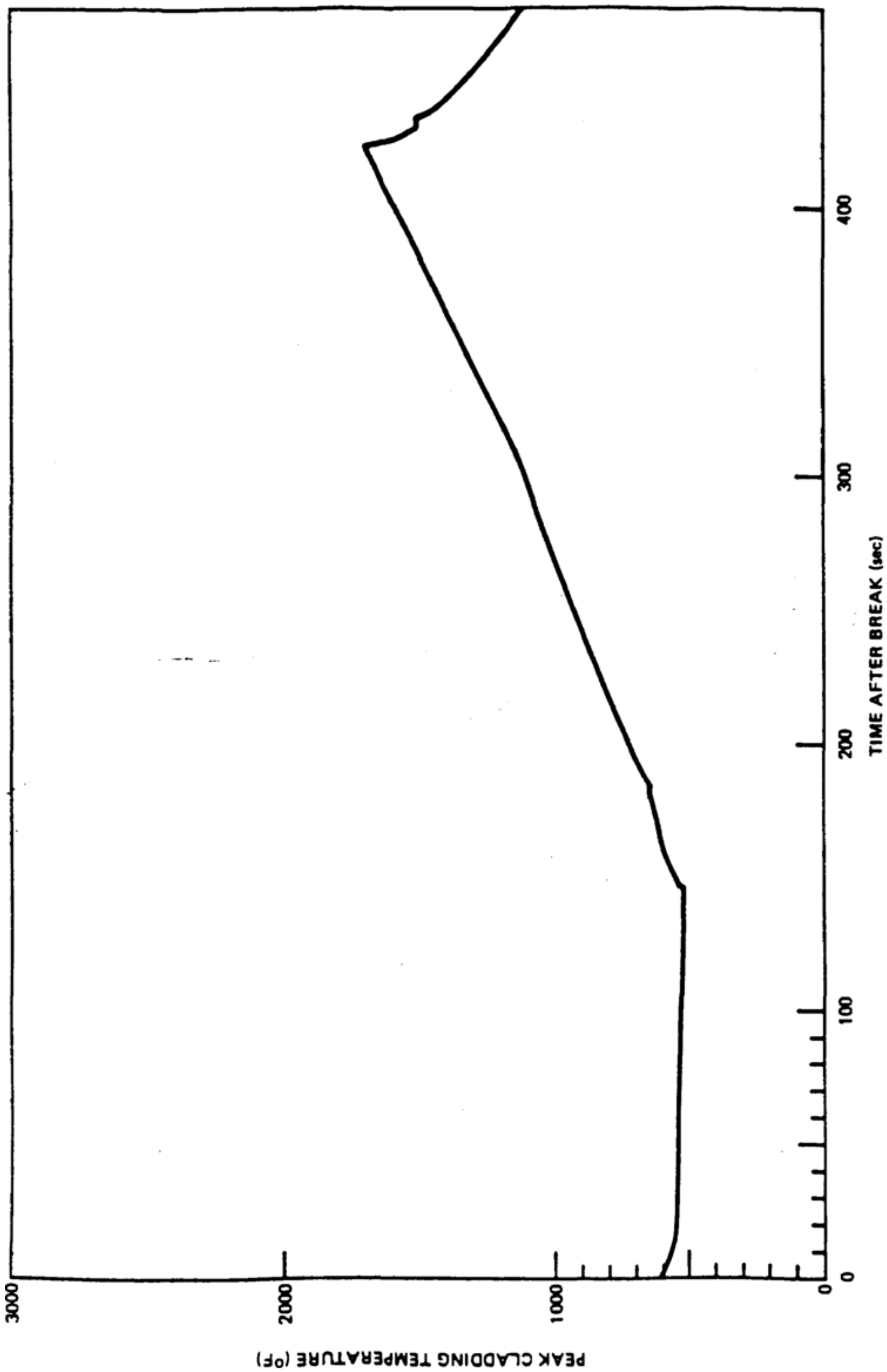
FIGURE 6.3-56



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK (CORE SPRAY LINE BREAK,
0.28 FT^2 BREAK, LPCS D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-57

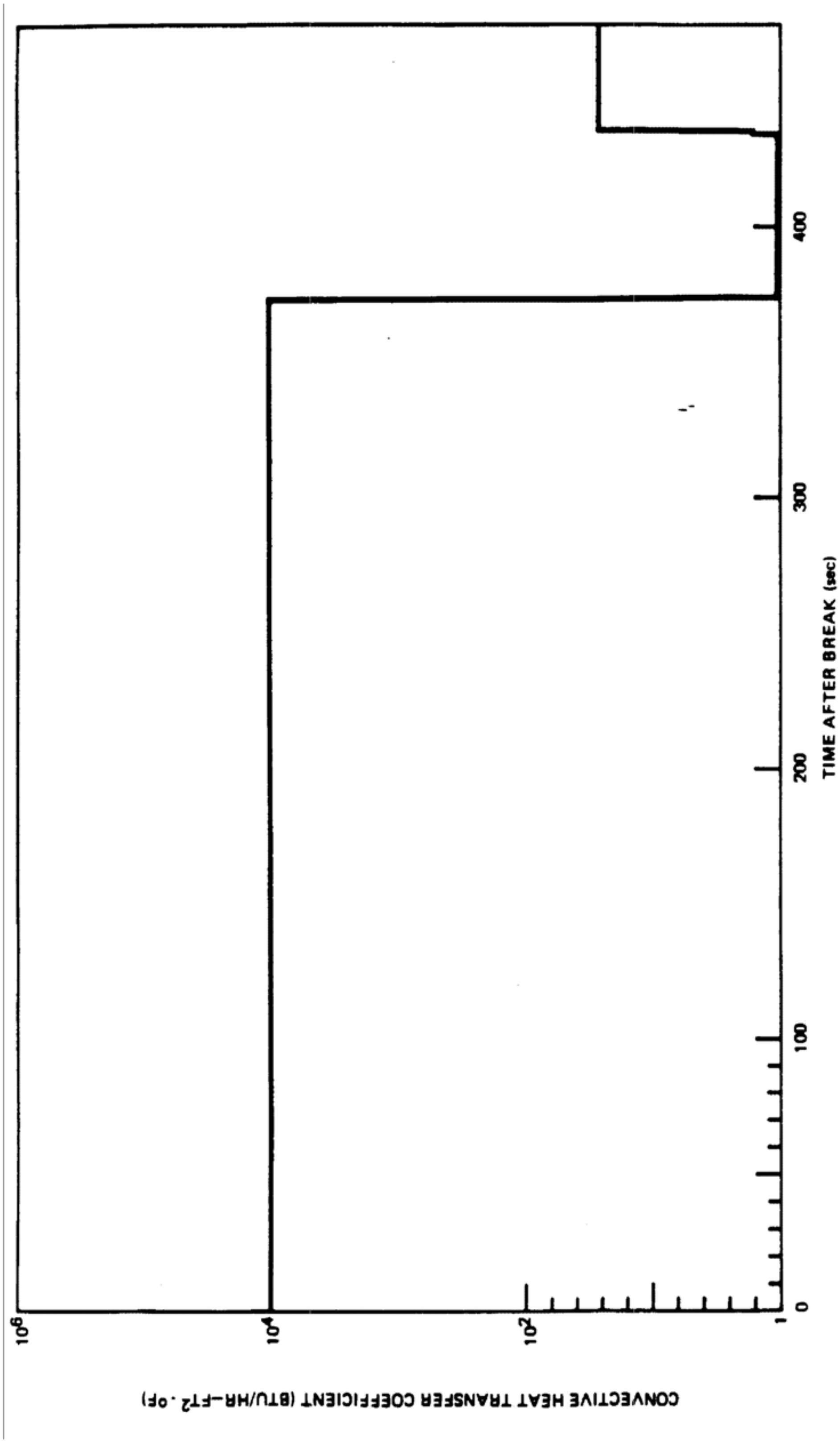


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

PEAK CLADDING TEMPERATURE
VERSUS TIME AFTER BREAK (CORE SPRAY LINE BREAK,
0.28 FT² BREAK, LPCS D/G FAILURE)
[INITIAL CYCLE]

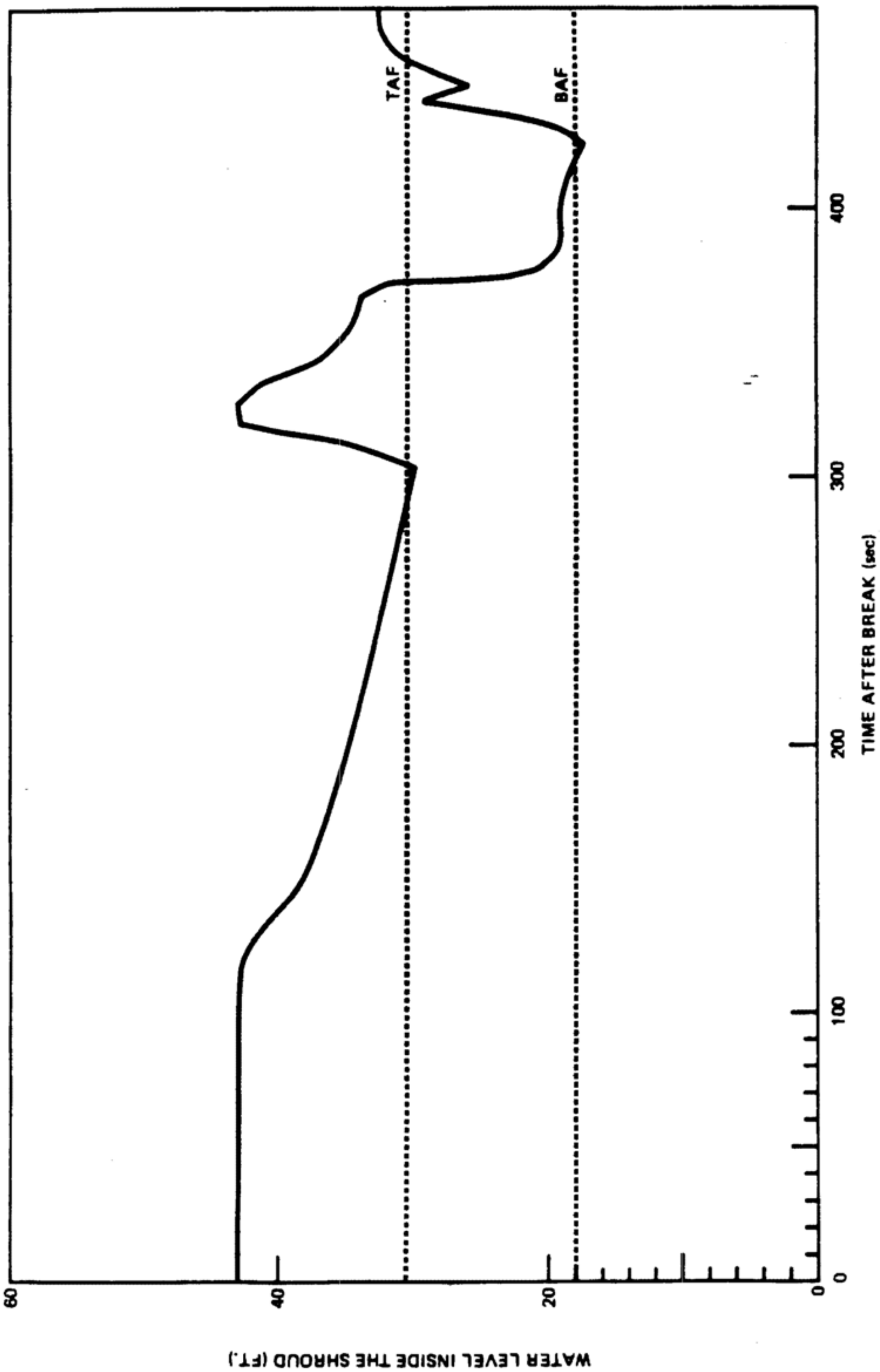
FIGURE 6.3-58



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

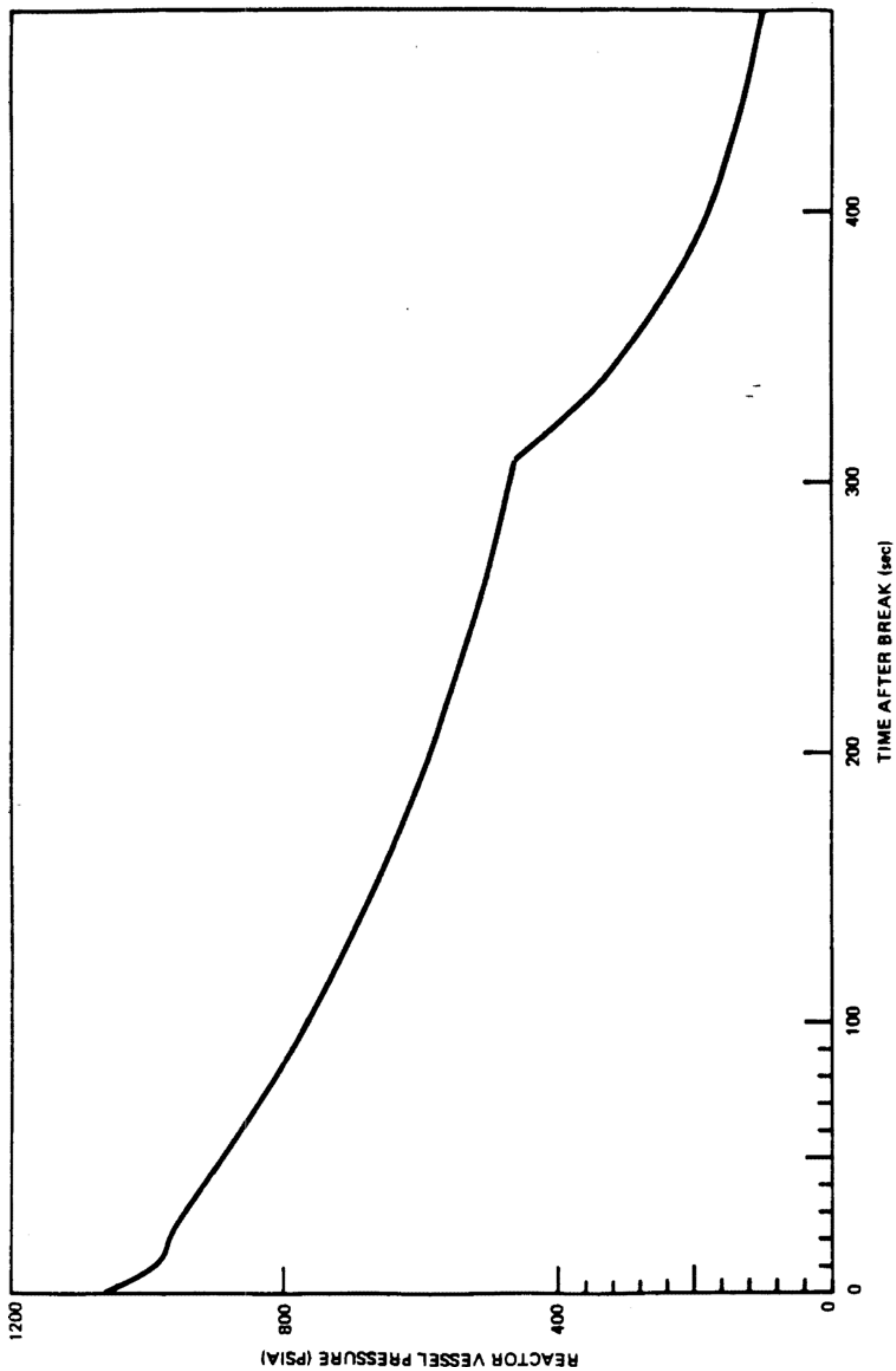
CONVECTIVE HEAT TRANSFER COEFFICIENT
VERSUS TIME AFTER BREAK
(FEEDWATER LINE BREAK, 0.36 FT^2 BREAK, HPCS FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-59



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

WATER LEVEL INSIE THE SHROUD
VERSUS TIME AFTER BREAK
(FEEDWATER LINE BREAK, 0.36 FT^2 BREAK, HPCS FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-60

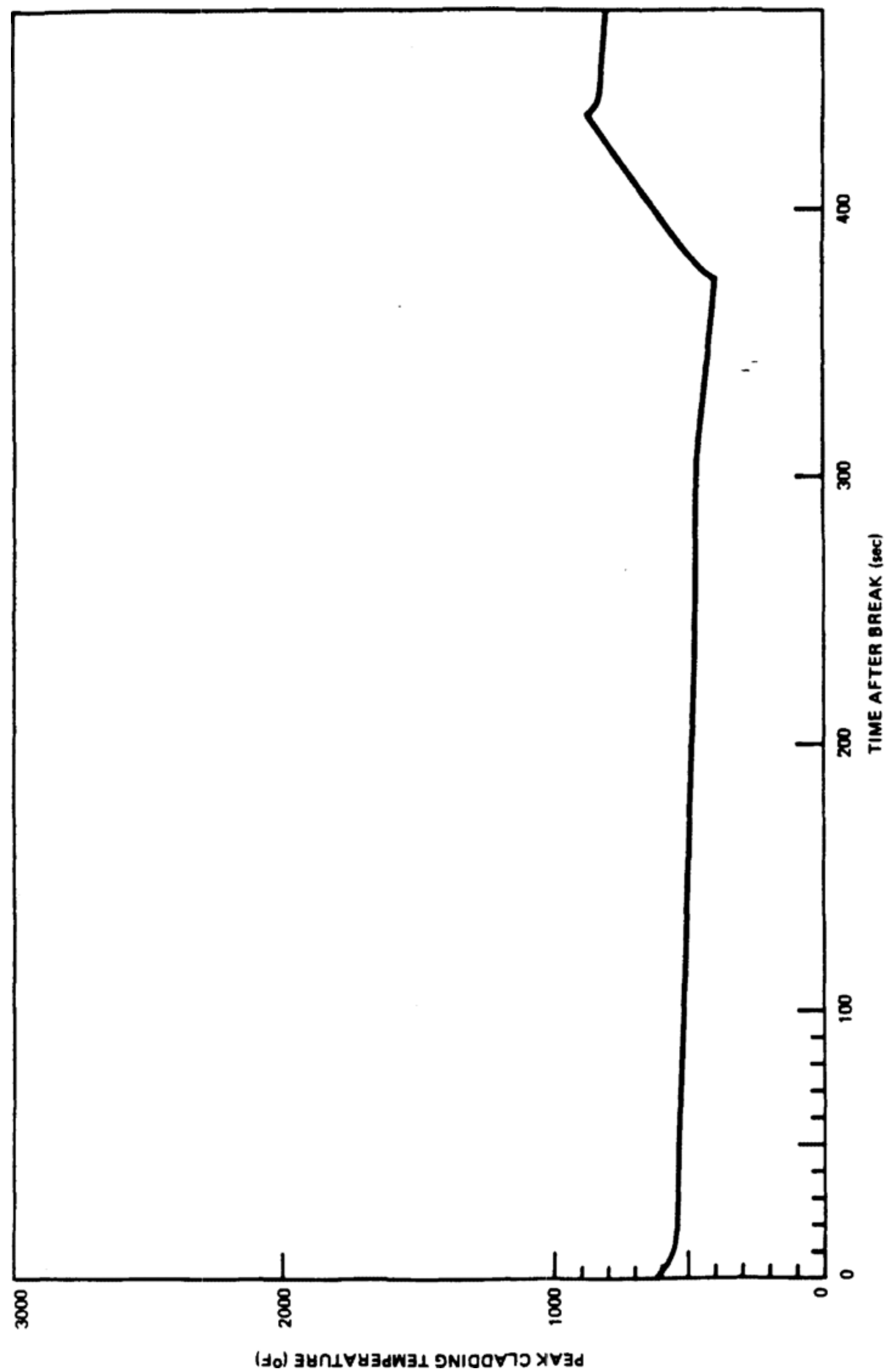


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

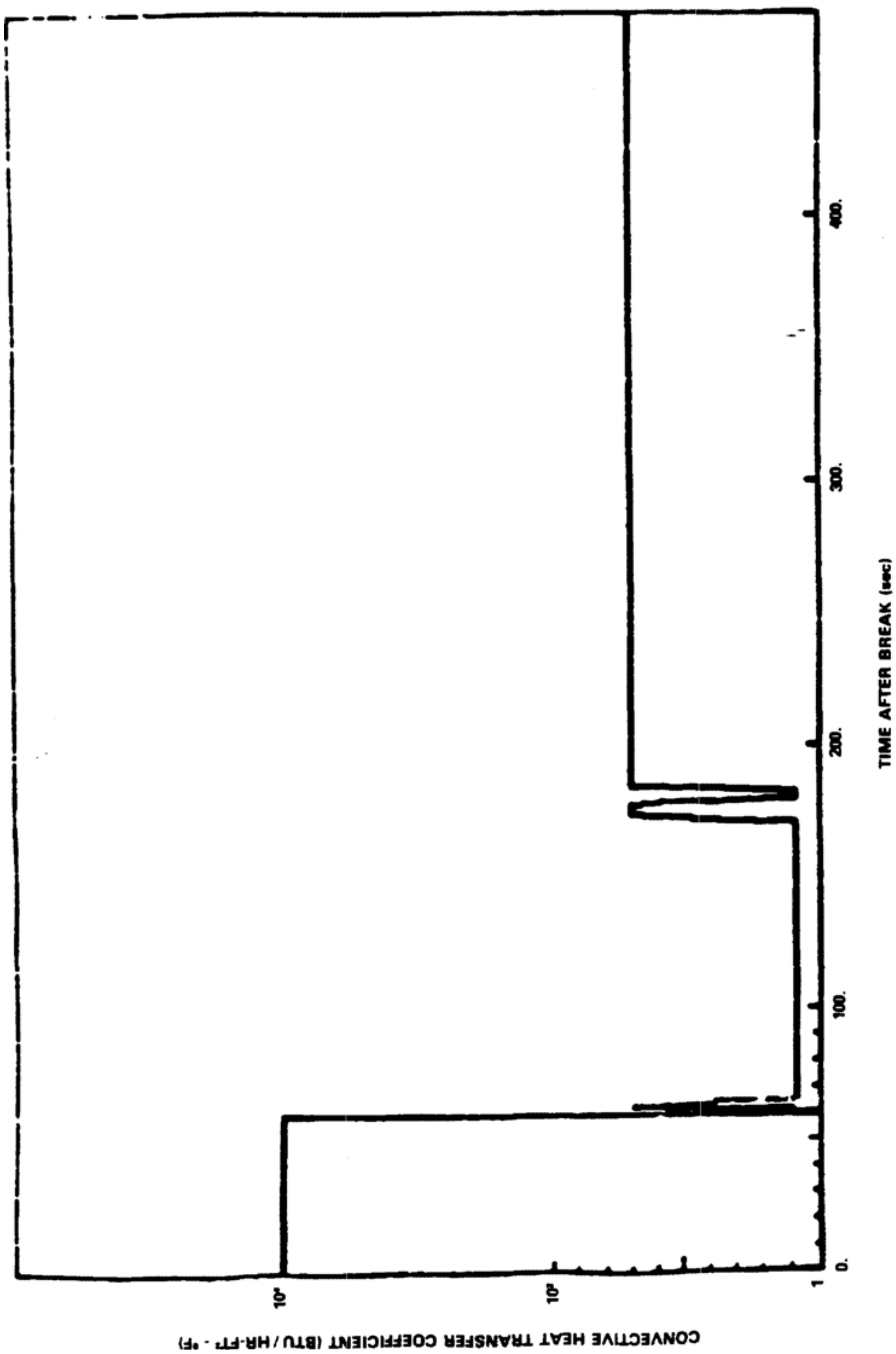
REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK
(FEEDWATER LINE BREAK, 0.36 FT^2 BREAK, HPCS FAILURE)
[INITIAL CYCLE]

FIGURE 6.3-61



[HISTORICAL INFORMATION]

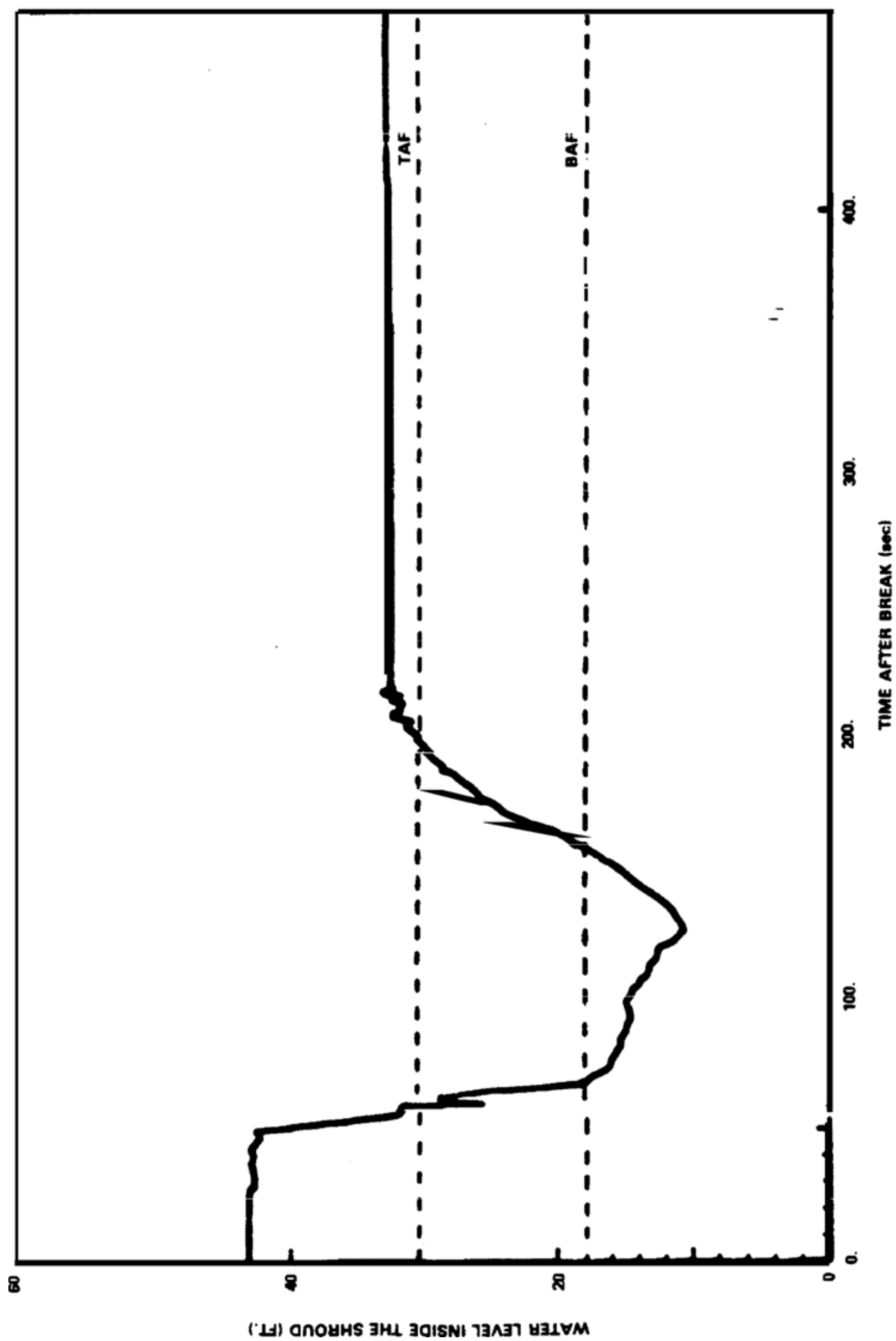
GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	PEAK CLADDING TEMPERATURE VERSUS TIME AFTER BREAK (FEEDWATER LINE BREAK, 0.36 FT^2 BREAK, HPCS FAILURE) [INITIAL CYCLE] FIGURE 6.3-62



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CONVECTIVE HEAT TRANSFER COEFFICIENT
VERSUS TIME AFTER BREAK (STEAMLINE BREAK, 3.5 FT^2,
INSIDE THE CONTAINMENT, LPCS D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-63

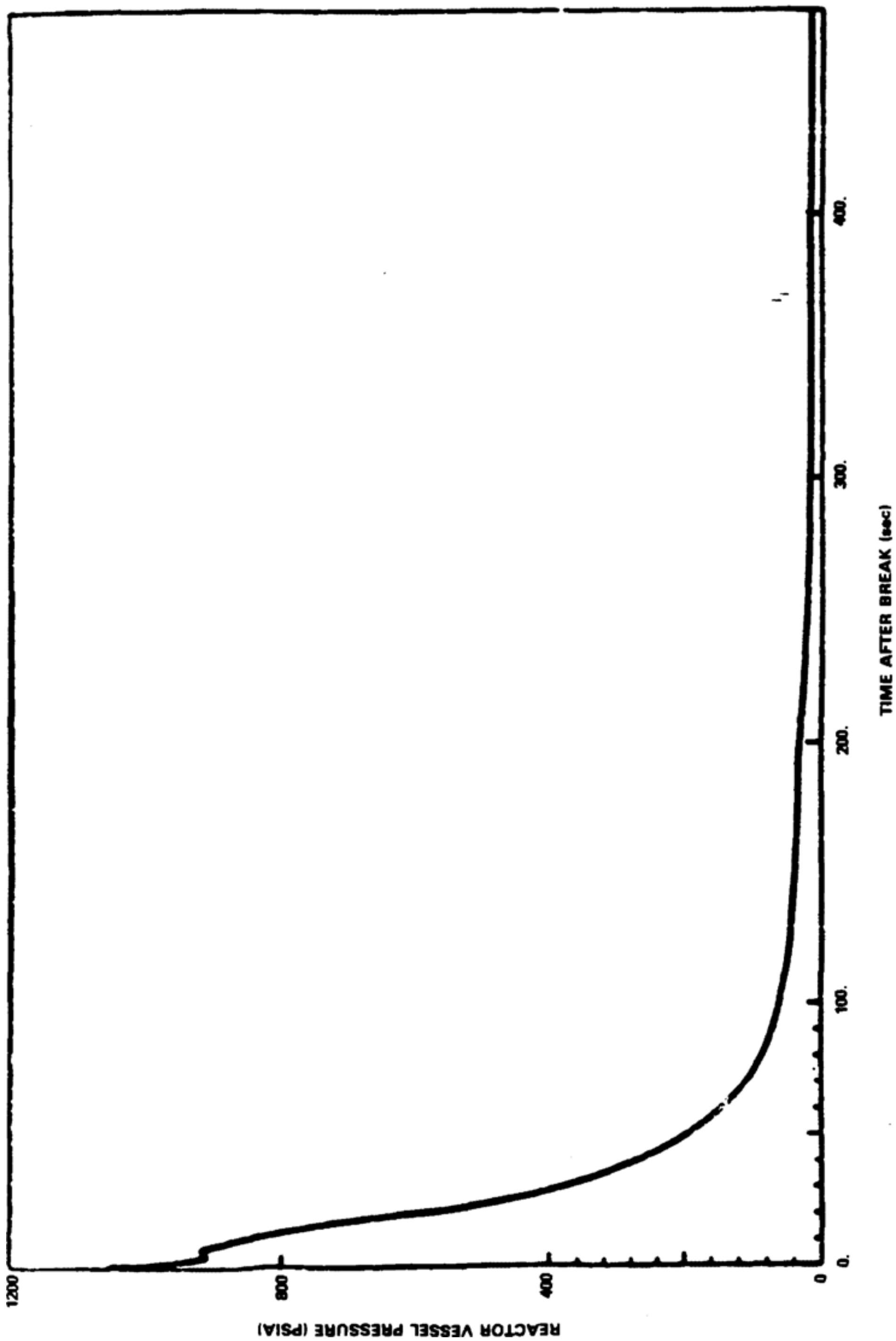


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK (STEAMLINE BREAK, 3.5 FT^2,
INSIDE THE CONTAINMENT, LPCS D/G FAILURE)
[INITIAL CYCLE]

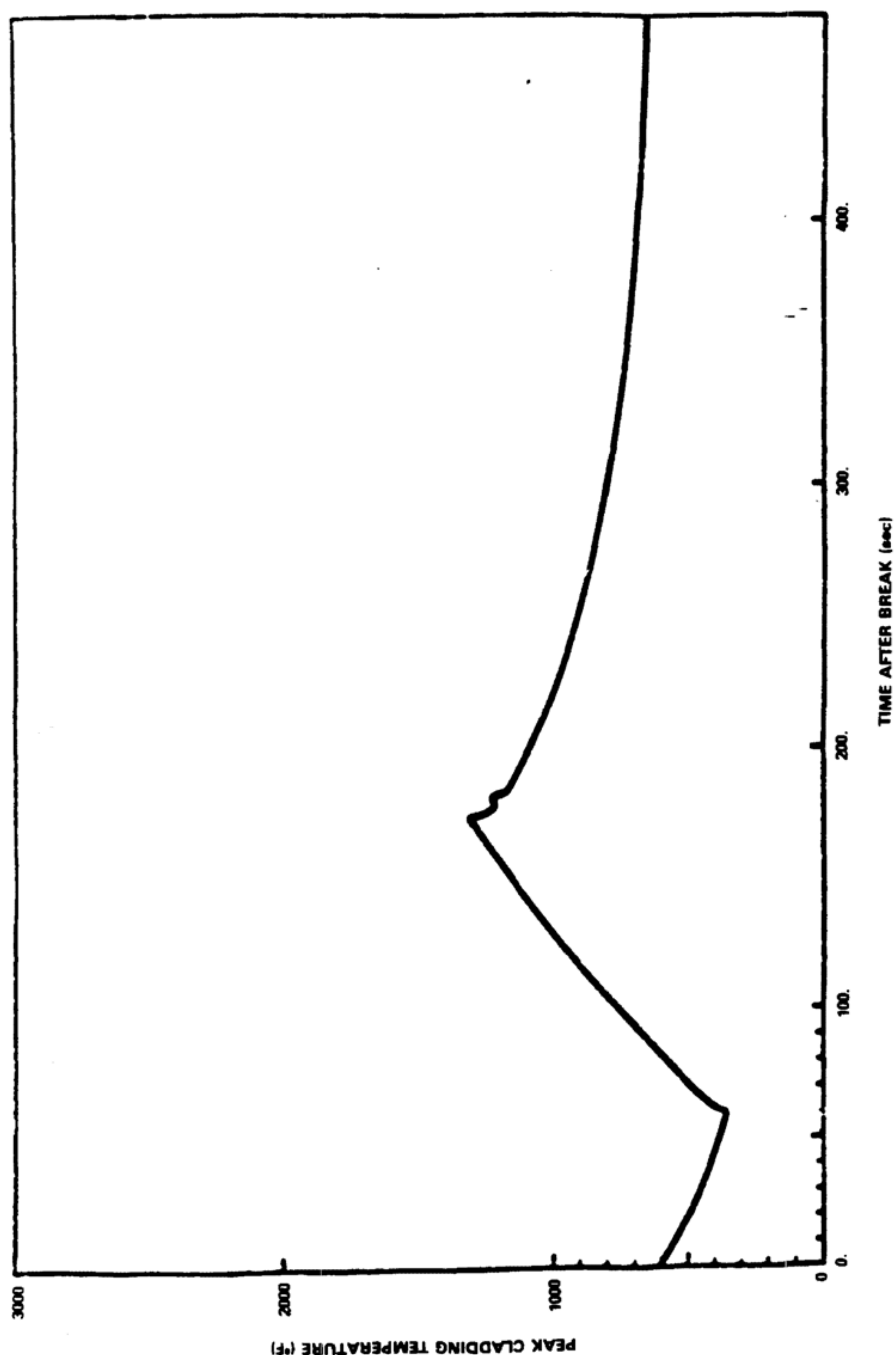
FIGURE 6.3-64



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

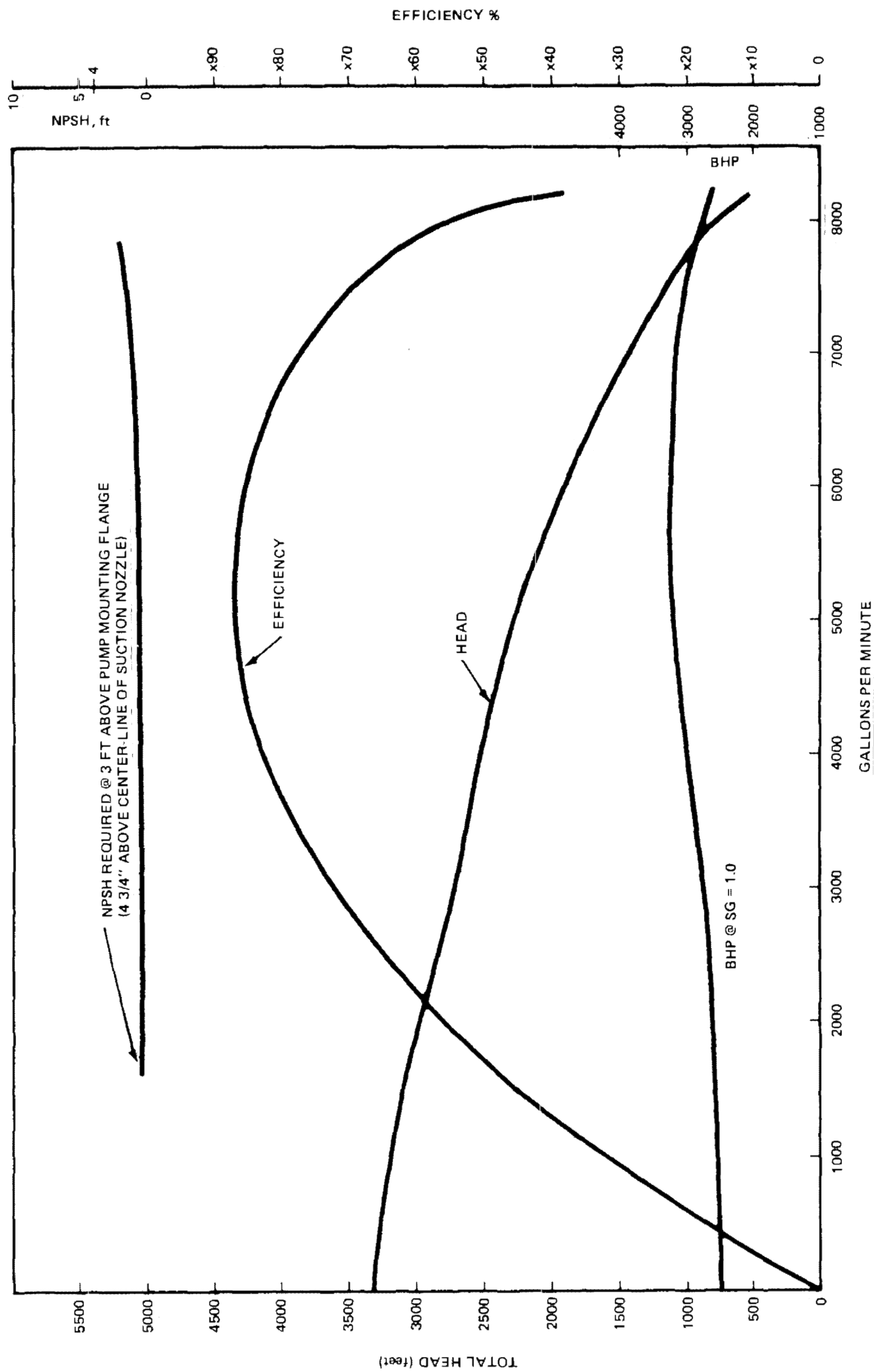
REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK (STEAMLINE BREAK, 3.5 FT^2,
INSIDE THE CONTAINMENT, LPCS D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-65



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

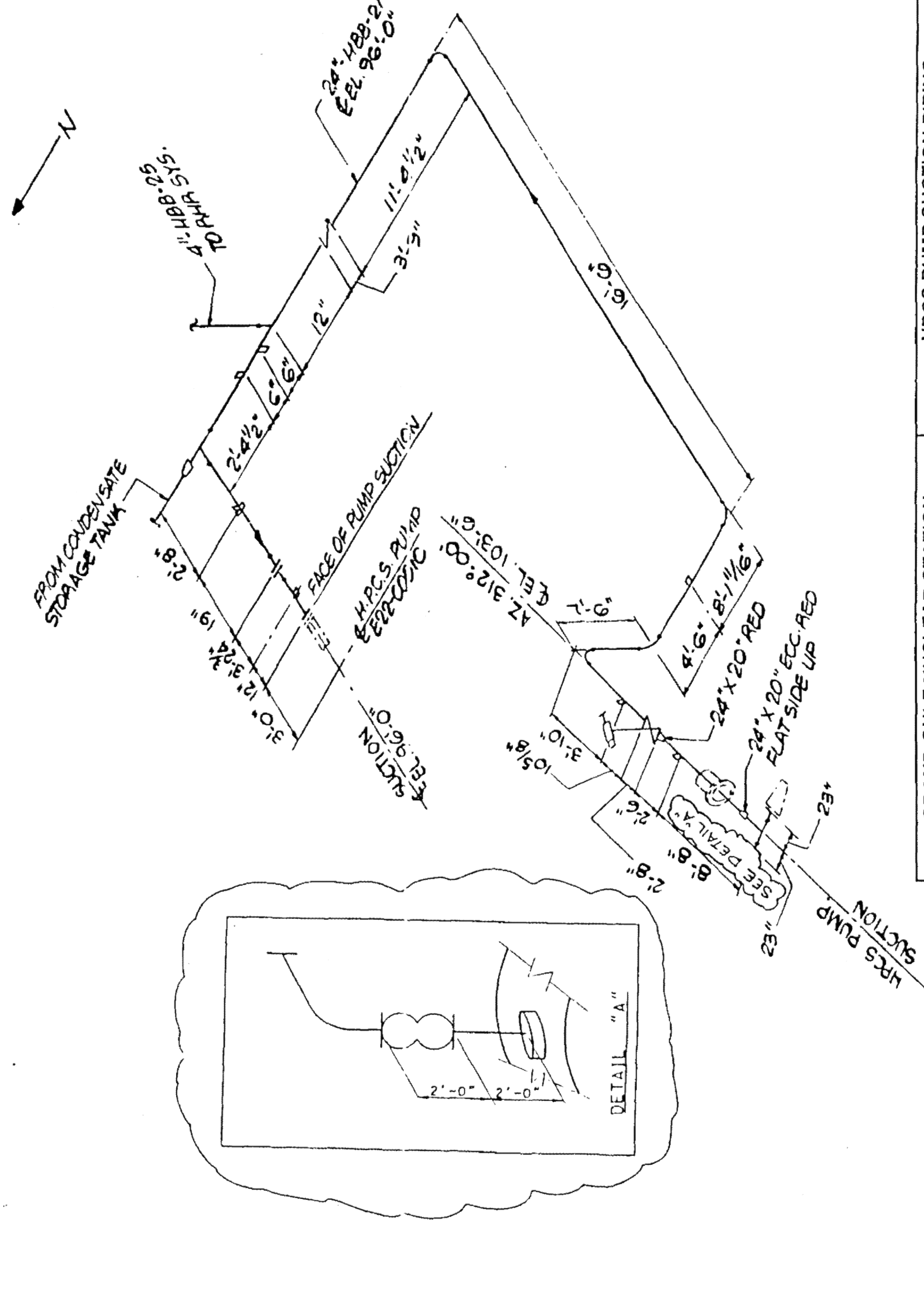
PEAK CLADDING TEMPERATURE
VERSUS TIME AFTER BREAK (STEAMLINE BREAK, 3.5 FT^2,
INSIDE THE CONTAINMENT, LPCS D/G FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-66



MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

HPCS PUMP
CHARACTERISTIC CURVE

FIGURE 6.3 - 67

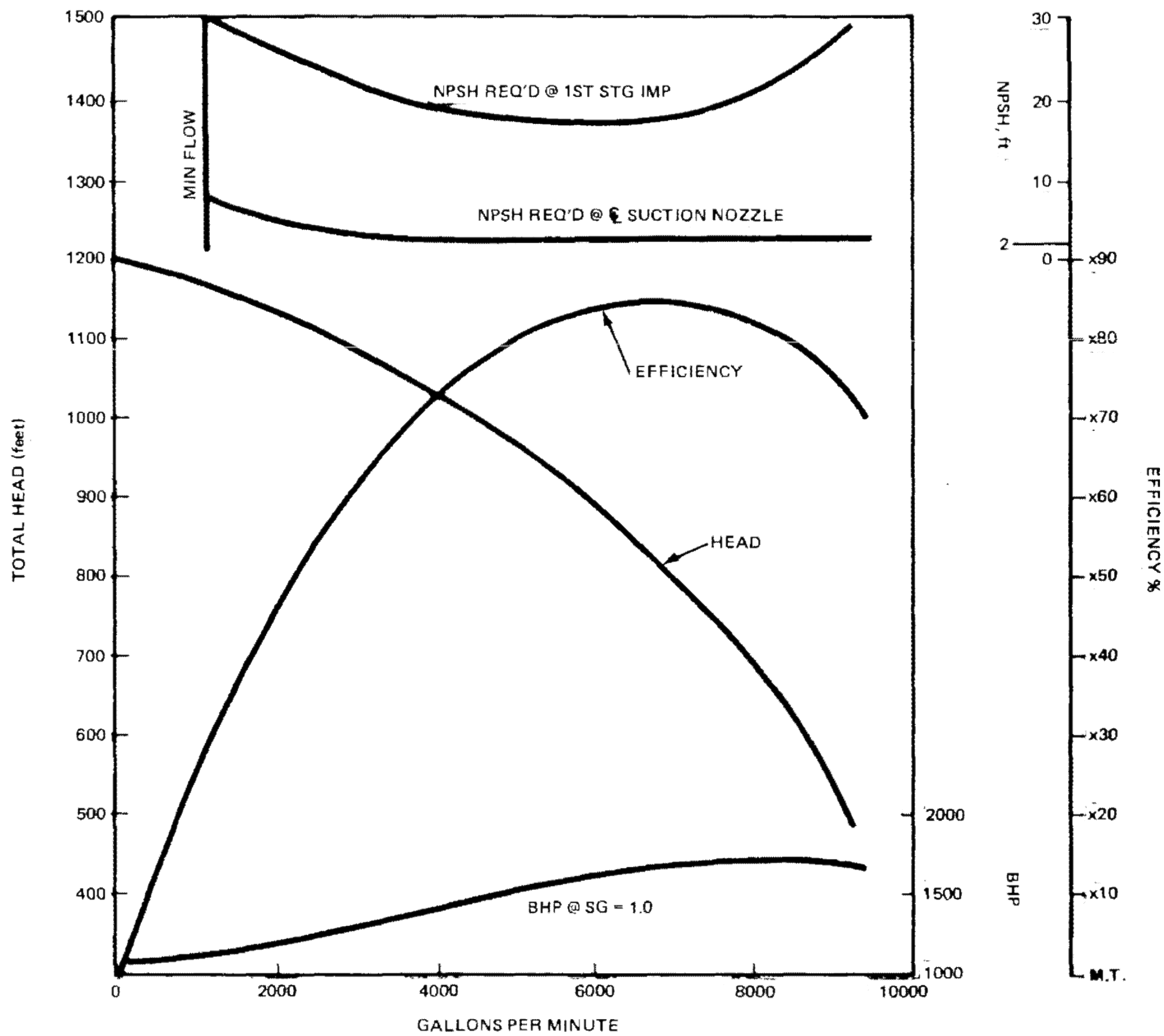


HPCS PUMP SUCTION PIPING ARRANGEMENT

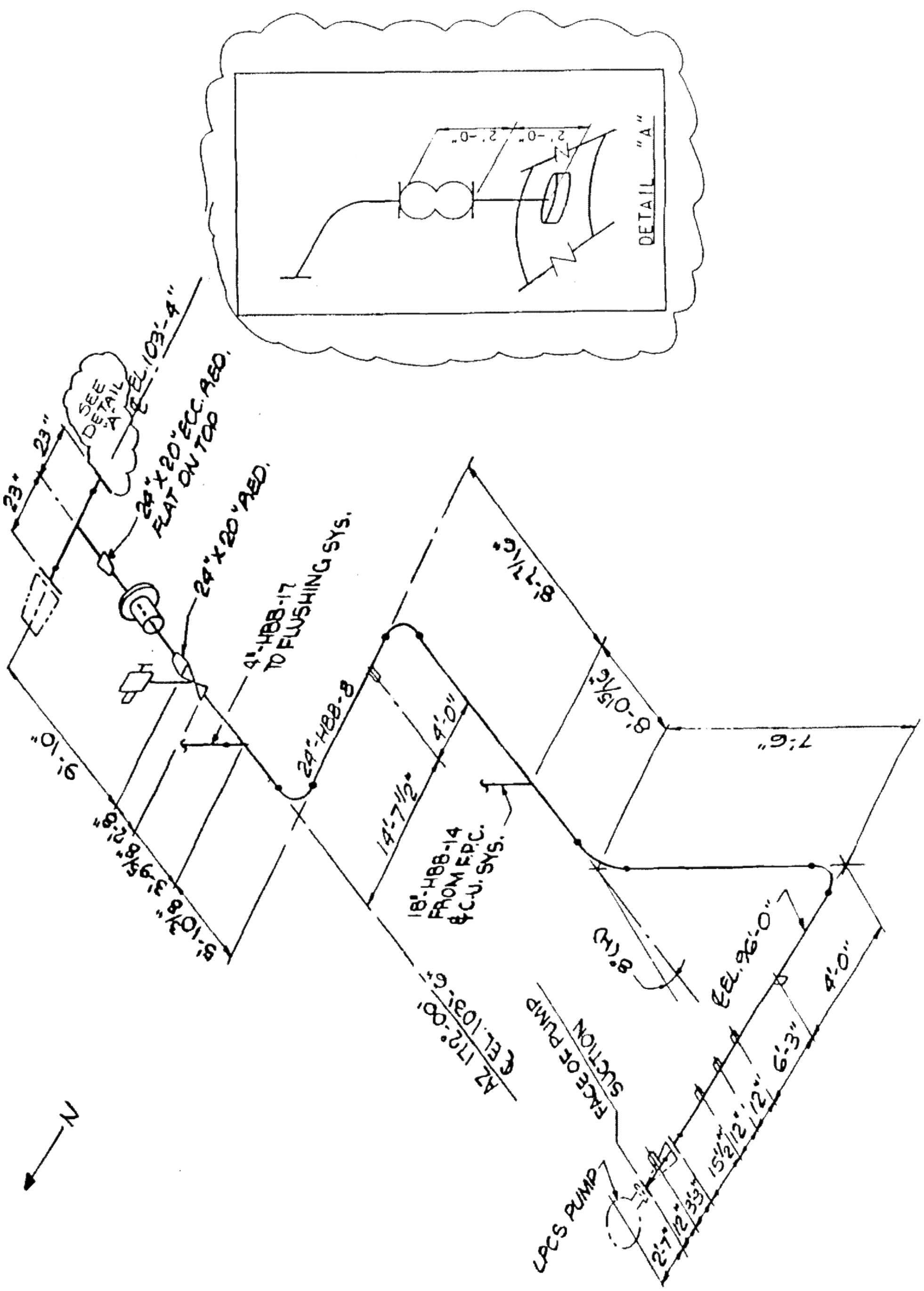
FIGURE 6.3-68

GRAND GULF NUCLEAR STATION UNIT 1

UPDATED FINAL SAFETY ANALYSIS REPORT



MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	LPCS PUMP CHARACTERISTIC CURVE FIGURE 6.3 - 69

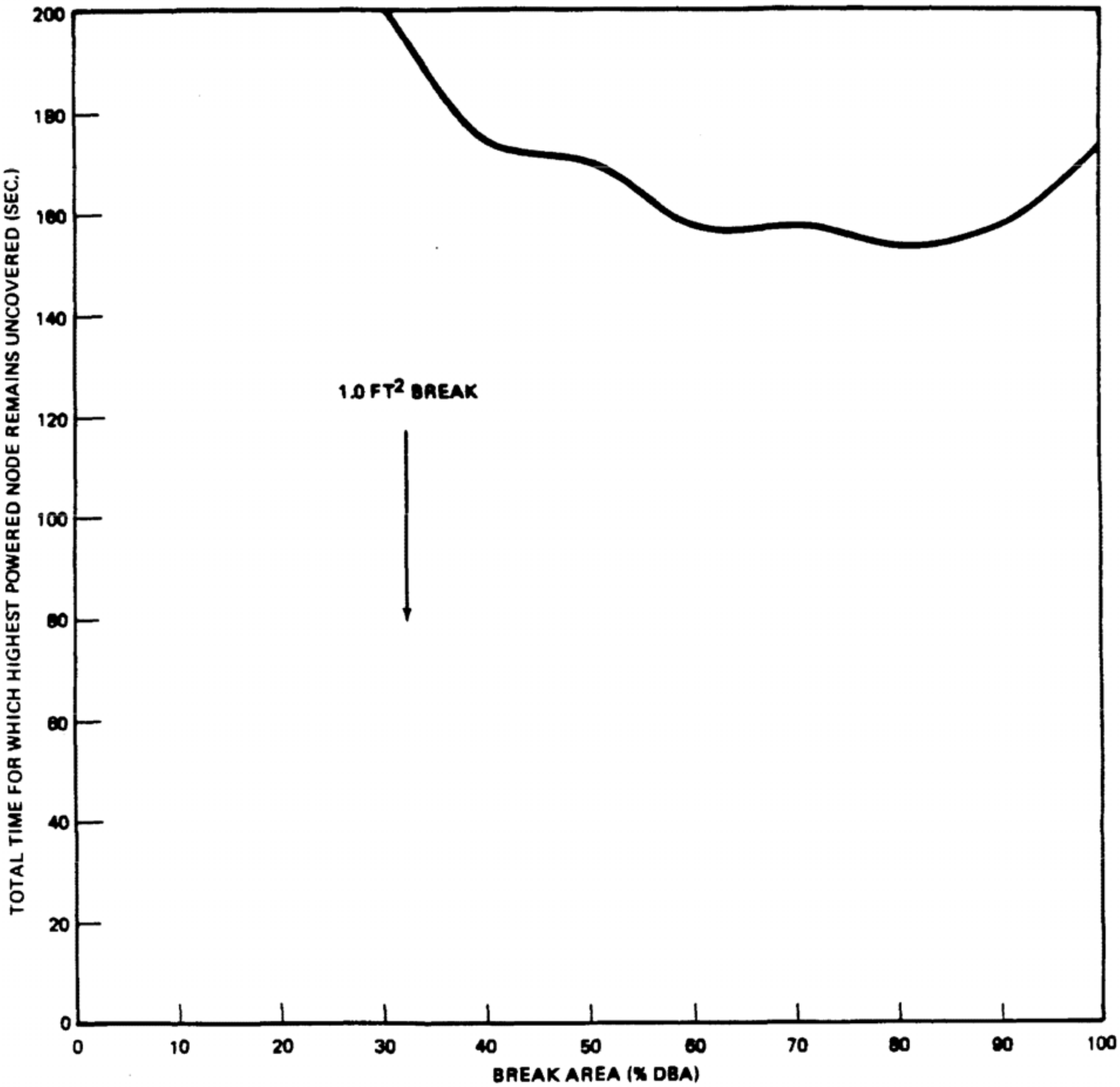


GRAND GULF NUCLEAR STATION
UNIT 1

UPDATED FINAL SAFETY ANALYSIS REPORT

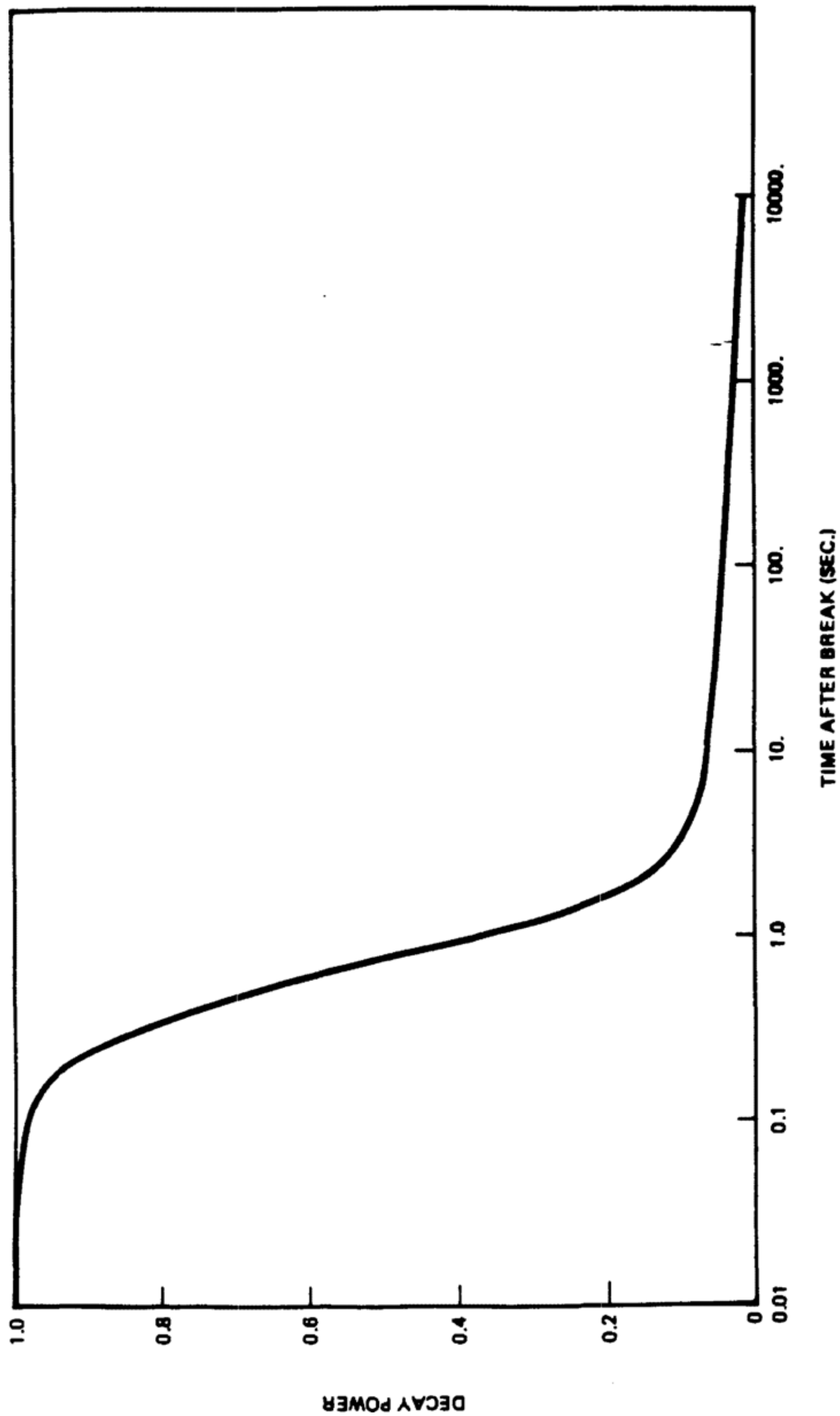
LPCS PUMP SUCTION PIPING ARRANGEMENT

FIGURE 6.3-70



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	TOTAL TIME FOR WHICH HIGHEST POWERED NODE REMAINS UNCOVERED VERSUS BREAK AREA [INITIAL CYCLE] FIGURE 6.3-71



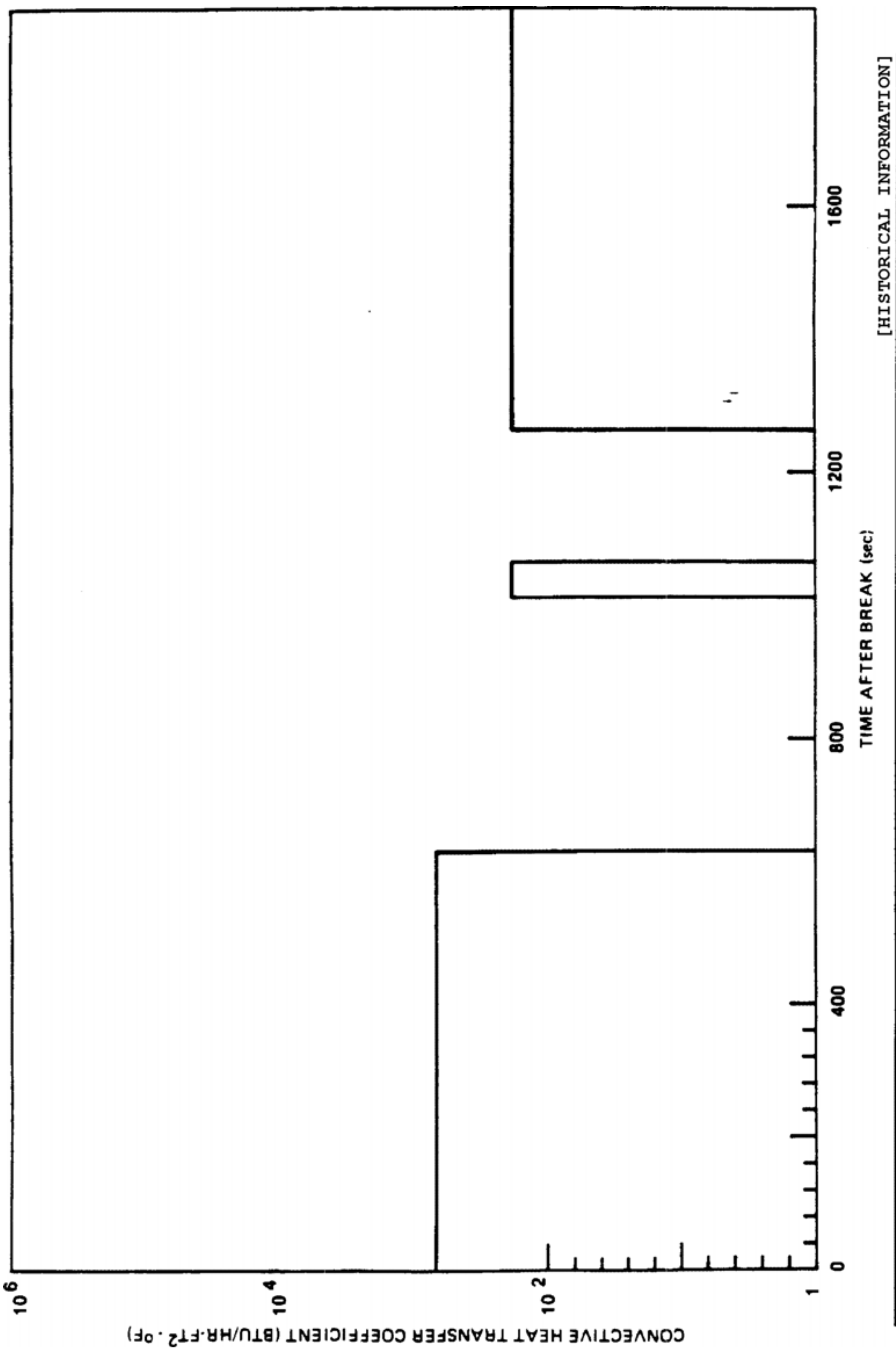
[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

NORMALIZED POWER
VERSUS TIME

[INITIAL CYCLE]

FIGURE 6.3-72

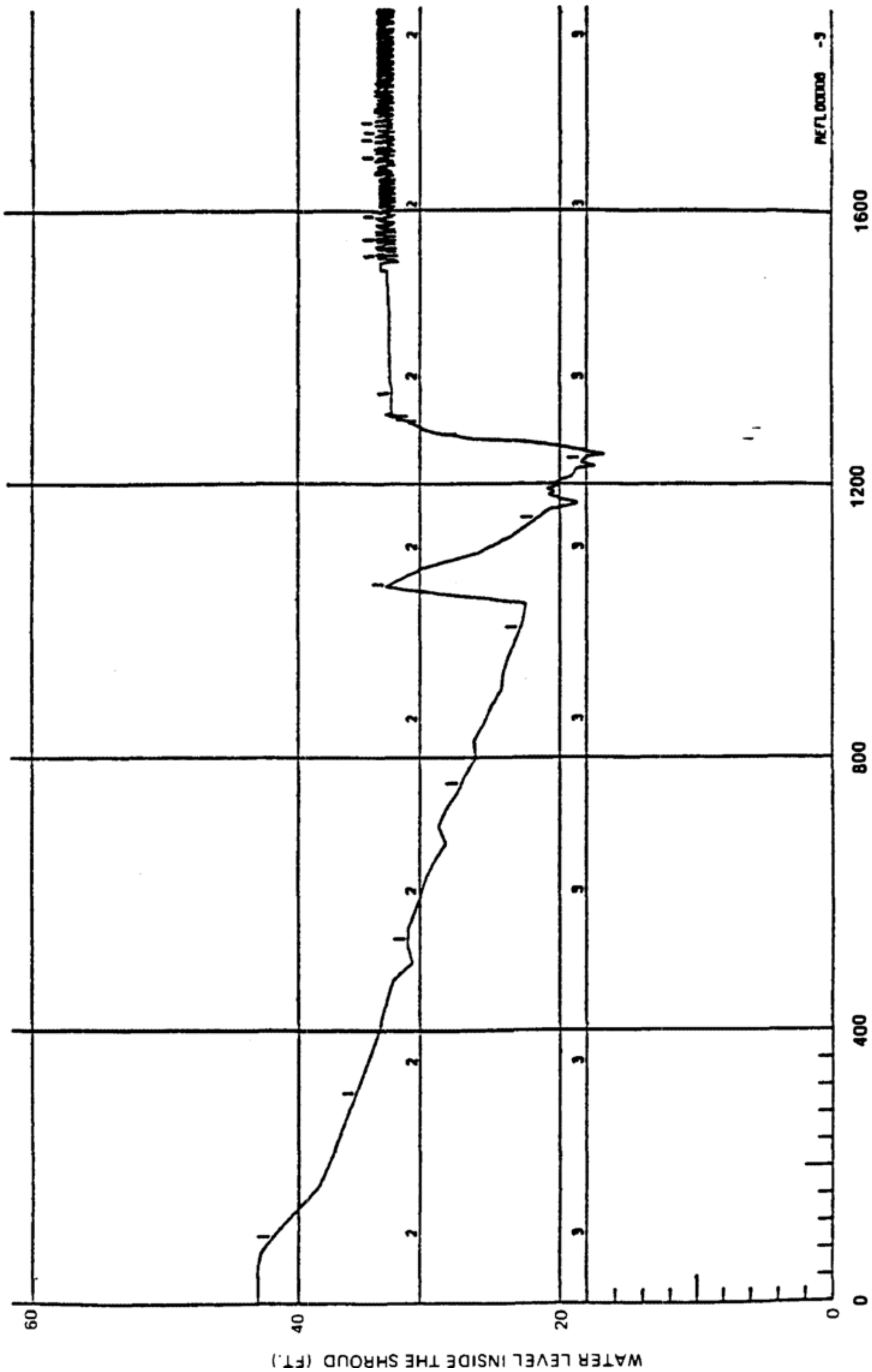


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CONVECTIVE HEAT TRANSFER COEFFICIENT VERSUS TIME AFTER BREAK (STEAMLINE BREAK, 3.5 FT^2, OUTSIDE THE CONTAINMENT, HPCS FAILURE)
[INITIAL CYCLE]

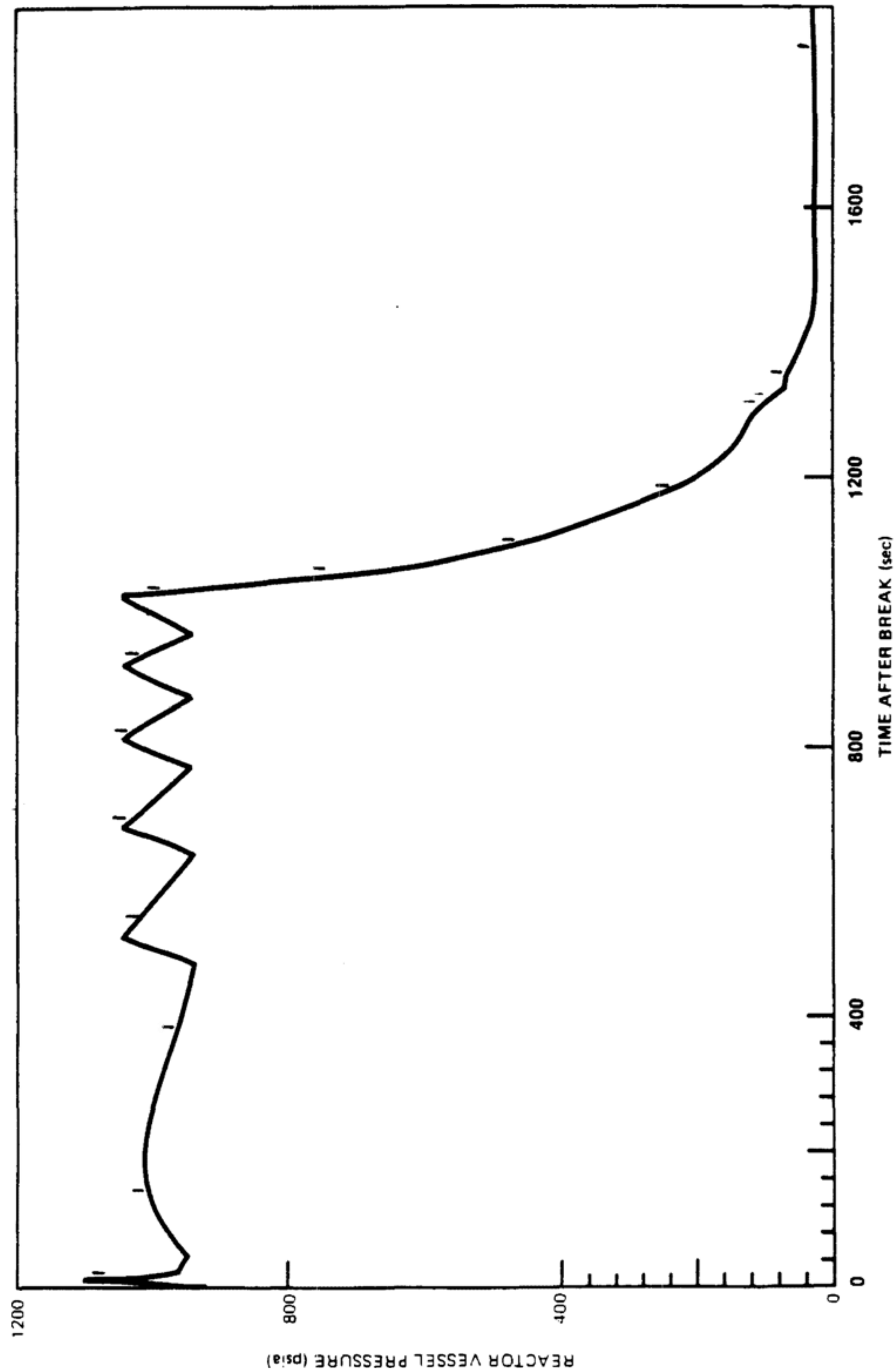
FIGURE 6.3-73



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

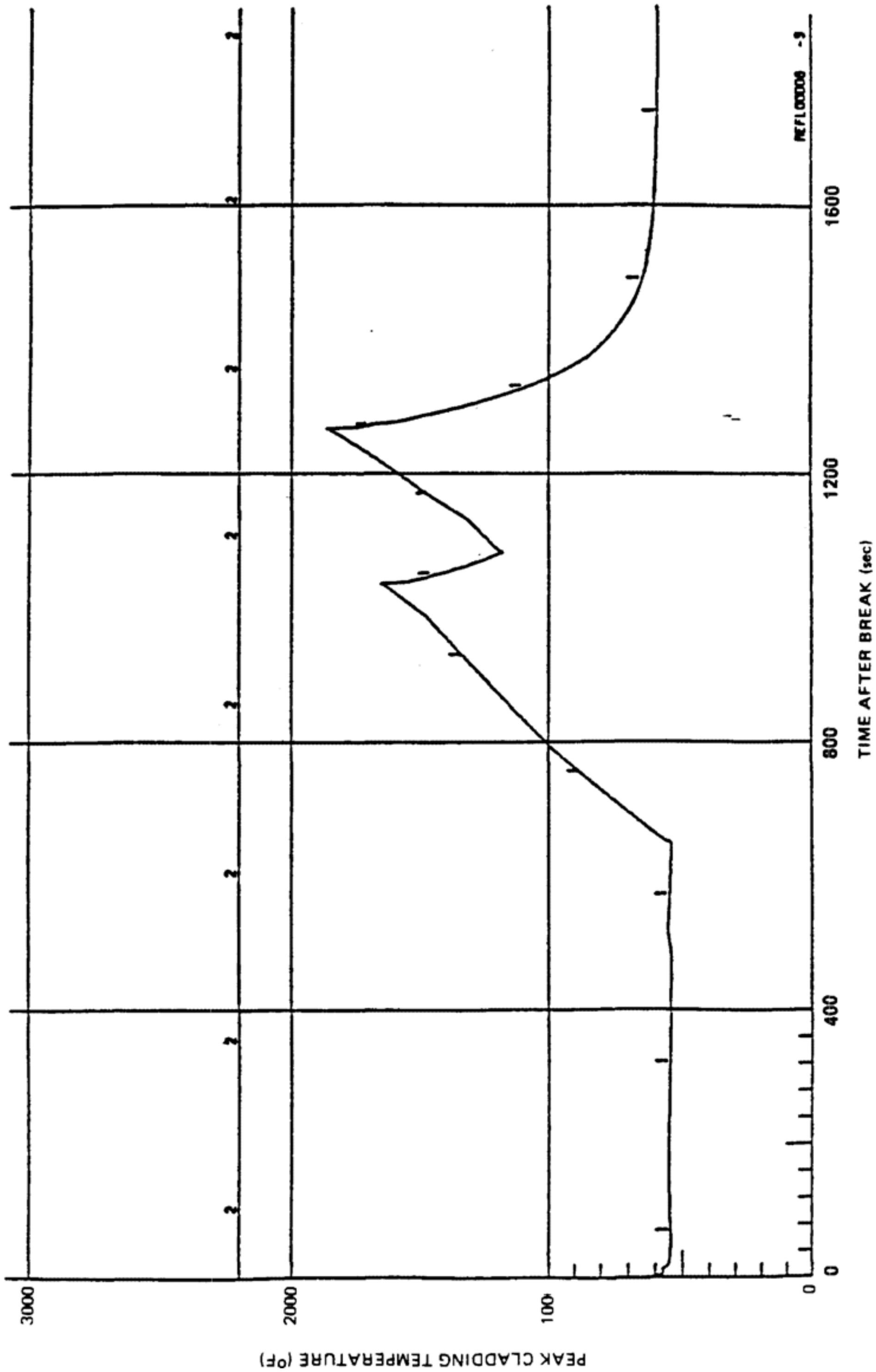
WATER LEVEL INSIDE THE SHROUD
VERSUS TIME AFTER BREAK (STEAMLINE BREAK, 3.5 FT^2,
OUTSIDE THE CONTAINMENT, HPCS FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-74



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

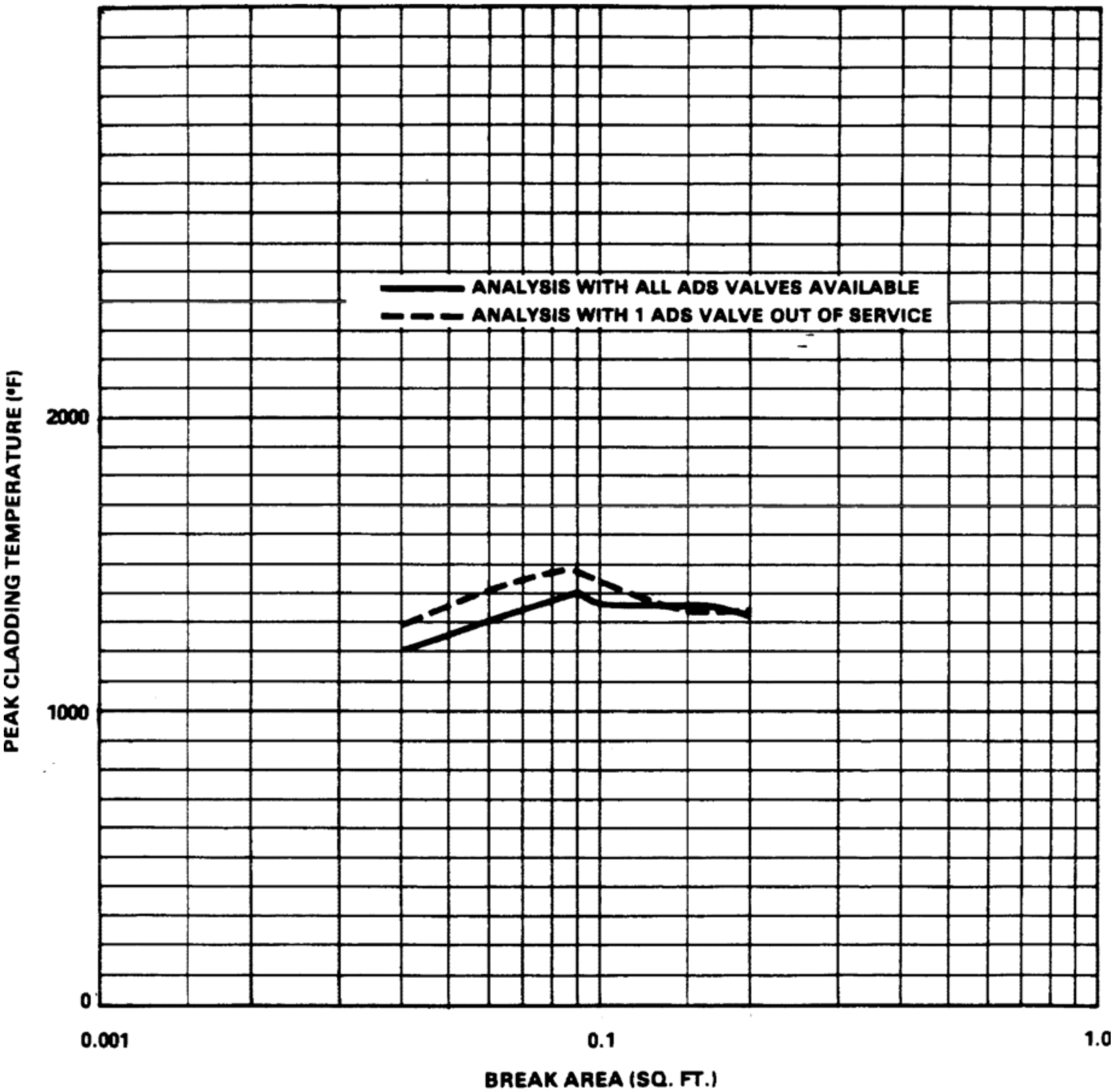
REACTOR VESSEL PRESSURE
VERSUS TIME AFTER BREAK (STEAMLINE BREAK, 3.5 FT^2,
OUTSIDE THE CONTAINMENT, HPCS FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-75



[HISTORICAL INFORMATION]

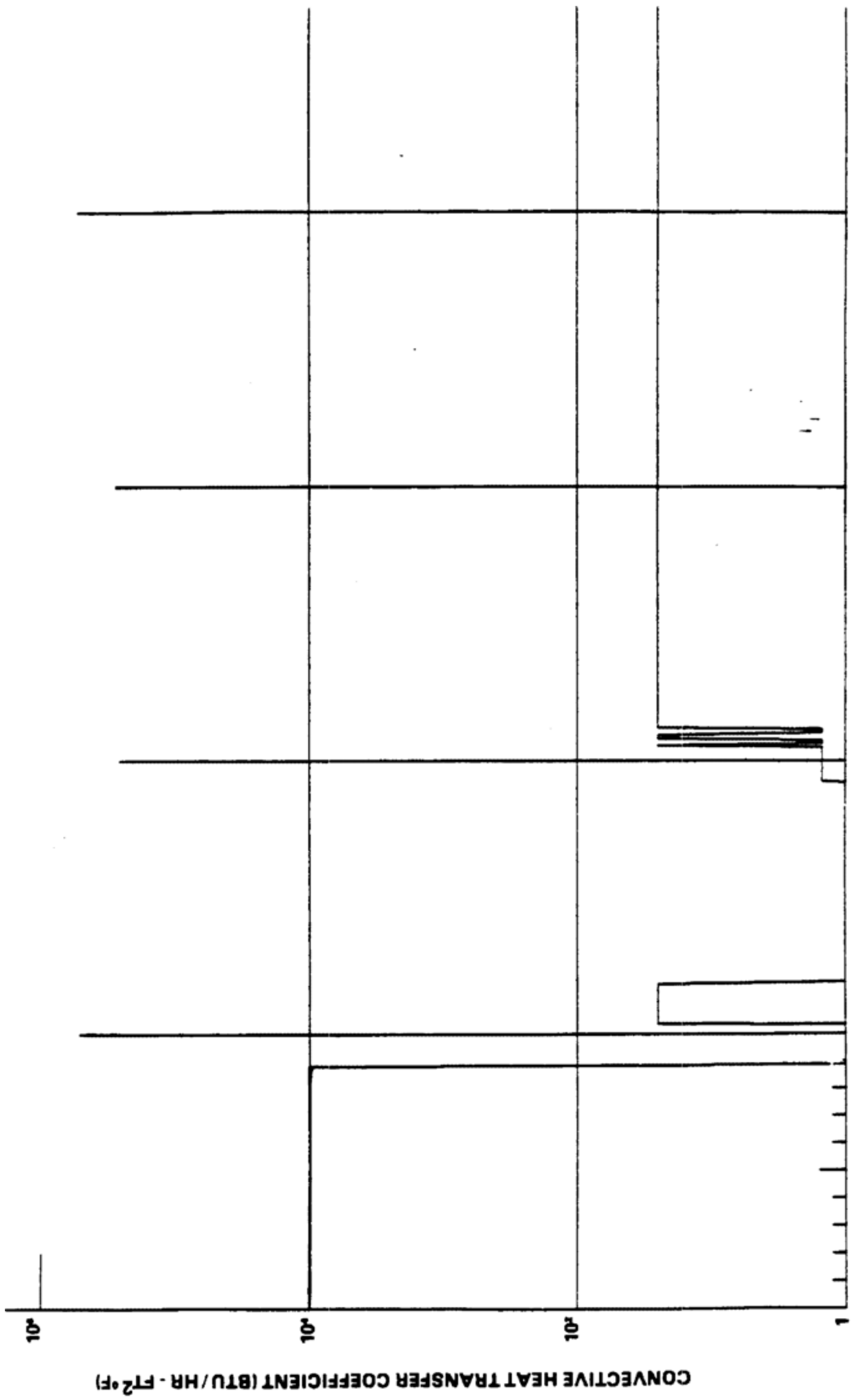
GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

PEAK CLADDING TEMPERATURE
VERSUS TIME AFTER BREAK (STEAMLINE BREAK, 3.5 FT^2,
OUTSIDE THE CONTAINMENT, HPCS FAILURE)
[INITIAL CYCLE]
FIGURE 6.3-76



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	PEAK CLADDING TEMPERATURE VERSUS BREAK AREA (RECIRC SUCTION SMALL BREAK, HPCS FAILURE) [INITIAL CYCLE] FIGURE 6.3-77

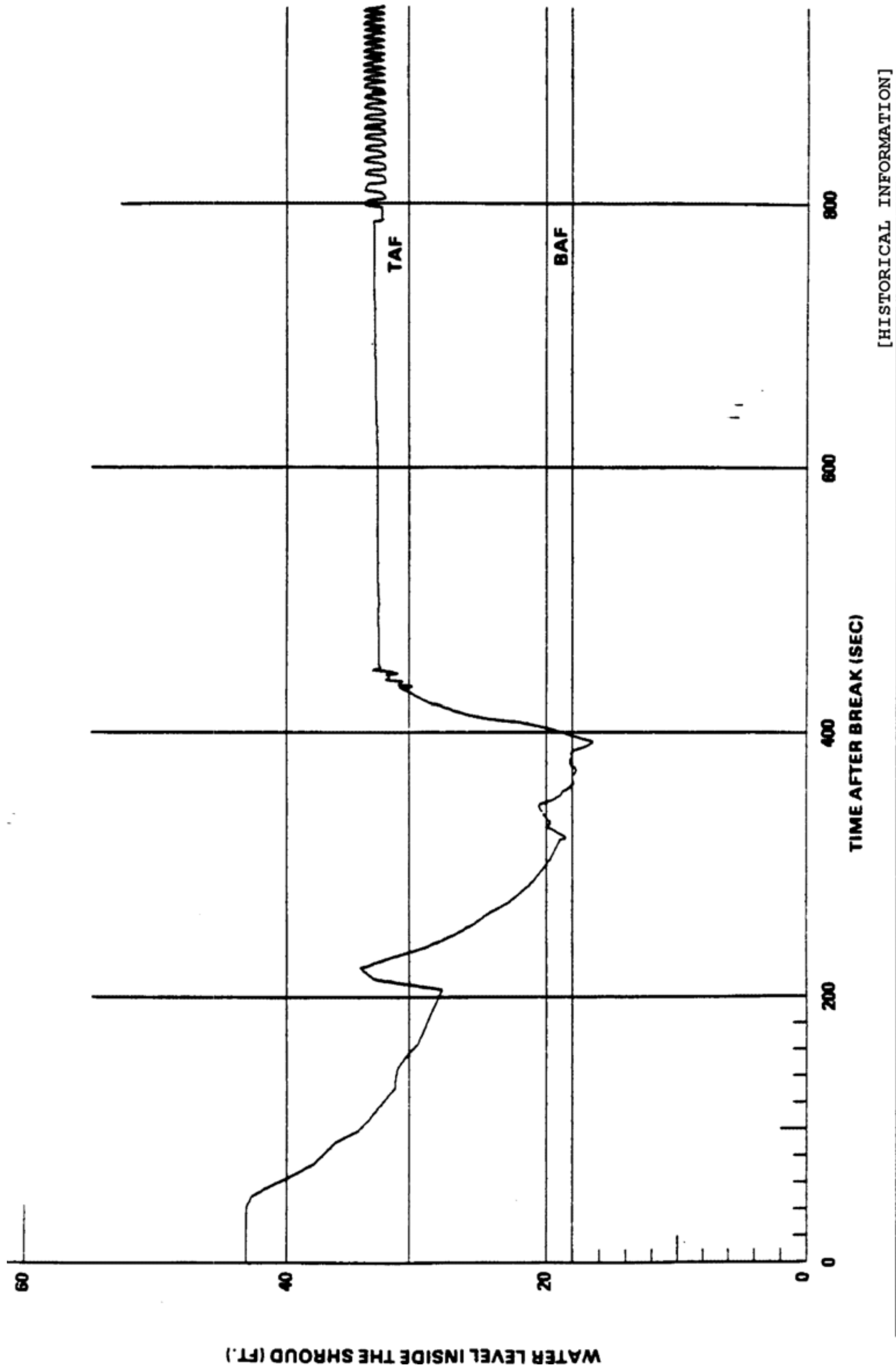


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

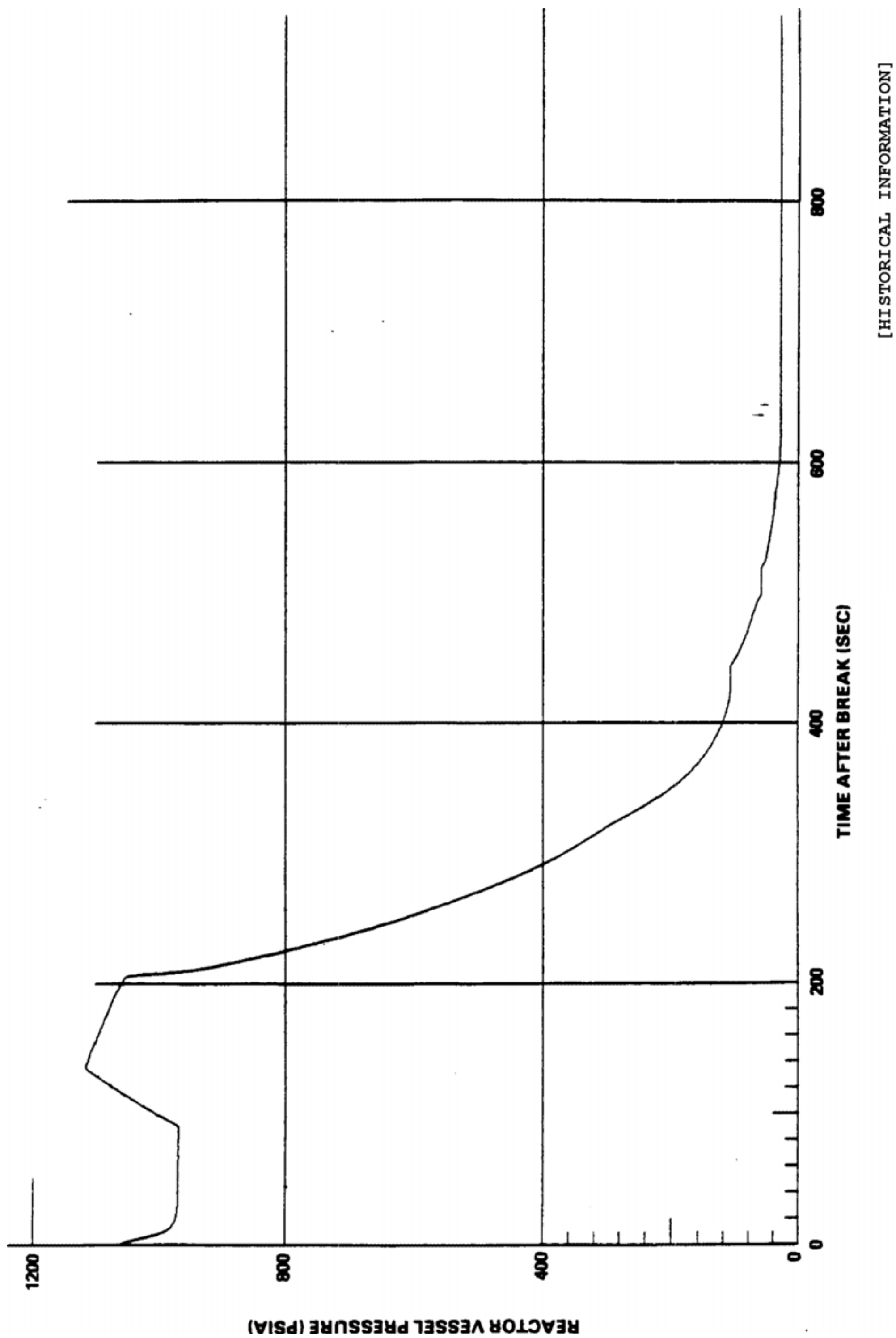
CONVECTIVE HEAT TRANSFER COEFFICIENT VERSUS TIME AFTER BREAK (0.09 FT^2 BREAK, HIGHEST TEMP. SMALL BREAK, RECIRC SUCTION BREAK, HPCS FAILURE, 1 ADS VALVE OOS)
[INITIAL CYCLE]

FIGURE 6.3-78



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION UNIT 1 UPDATED FINAL SAFETY ANALYSIS REPORT	WATER LEVEL INSIDE THE SHROUD VERSUS TIME AFTER BREAK (0.09 FT^2 BREAK, HIGHEST TEMP. SMALL BREAK, RECIRC SUCTION BREAK, HPCS FAILURE, 1 ADS VALVE OOS) [INITIAL CYCLE] FIGURE 6.3-79

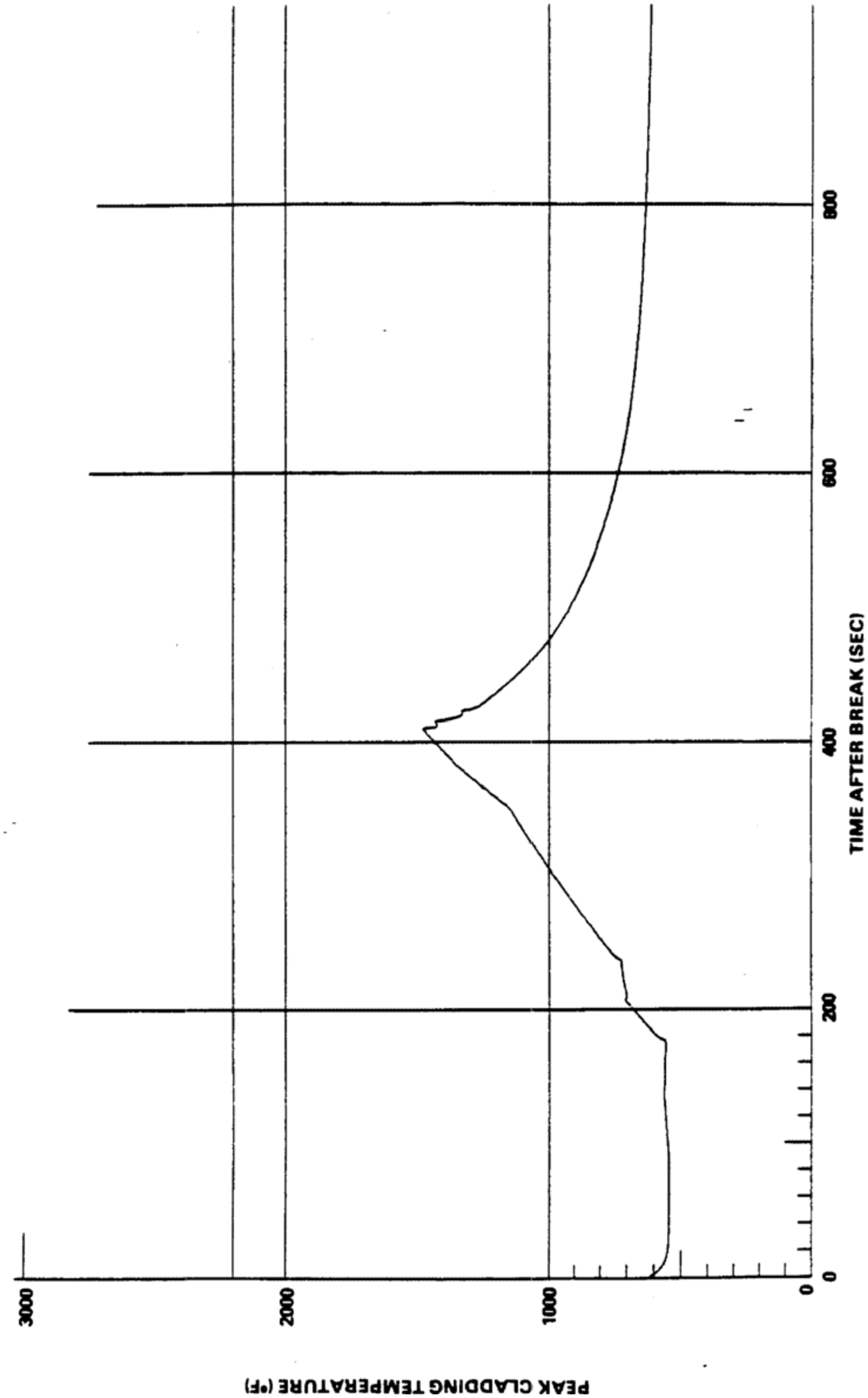


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE VERSUS TIME AFTER BREAK (0.09 FT^2 BREAK, HIGHEST TEMP. SMALL BREAK, RECIRC SUCTION BREAK, HPCS FAILURE, 1 ADS VALVE OOS)
[INITIAL CYCLE]

FIGURE 6.3-80

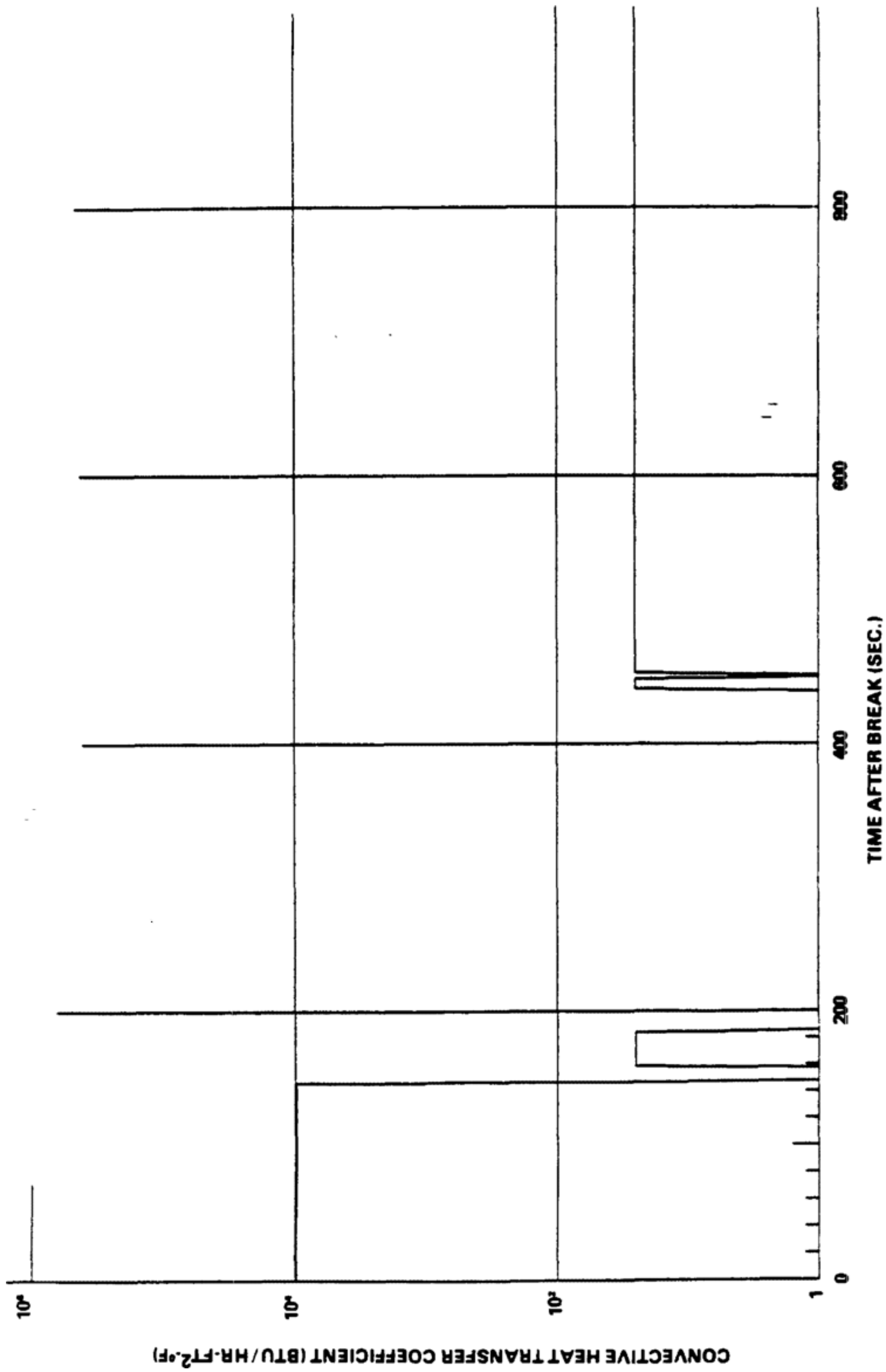


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

PEAK CLADDING TEMPERATURE VERSUS TIME AFTER BREAK (0.09 FT^2 BREAK, HIGHEST TEMP. SMALL BREAK, RECIRC SUCTION BREAK, HPCS FAILURE, 1 ADS VALVE OOS)
[INITIAL CYCLE]

FIGURE 6.3-81

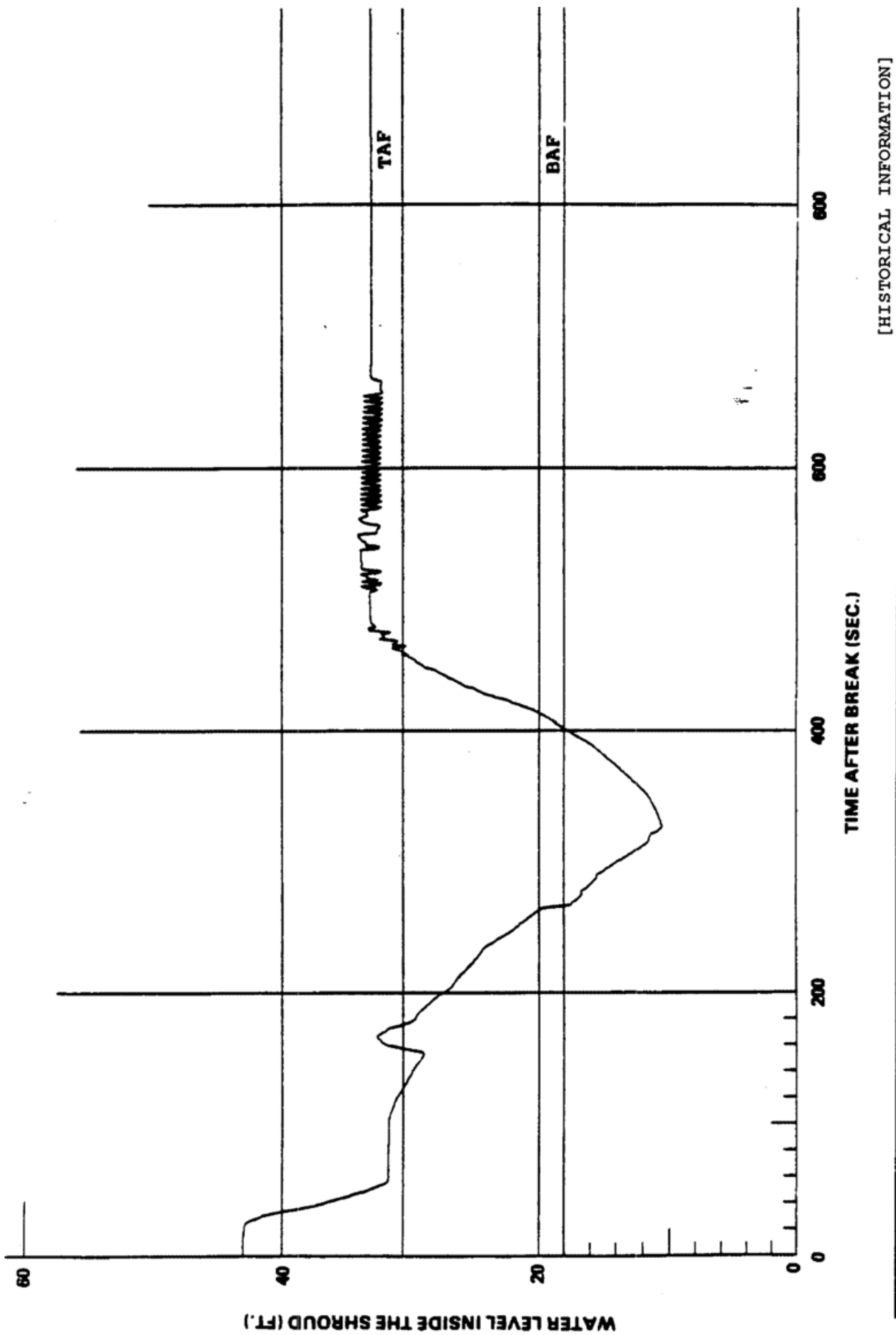


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

CONVECTIVE HEAT TRANSFER COEFFICIENT VERSUS TIME AFTER BREAK (CORE SPRAY LINE BREAK, 0.28 FT^2 BREAK, LPCS D/G FAILURE, 1 ADS VALVE OUT OF SERVICE)
[INITIAL CYCLE]

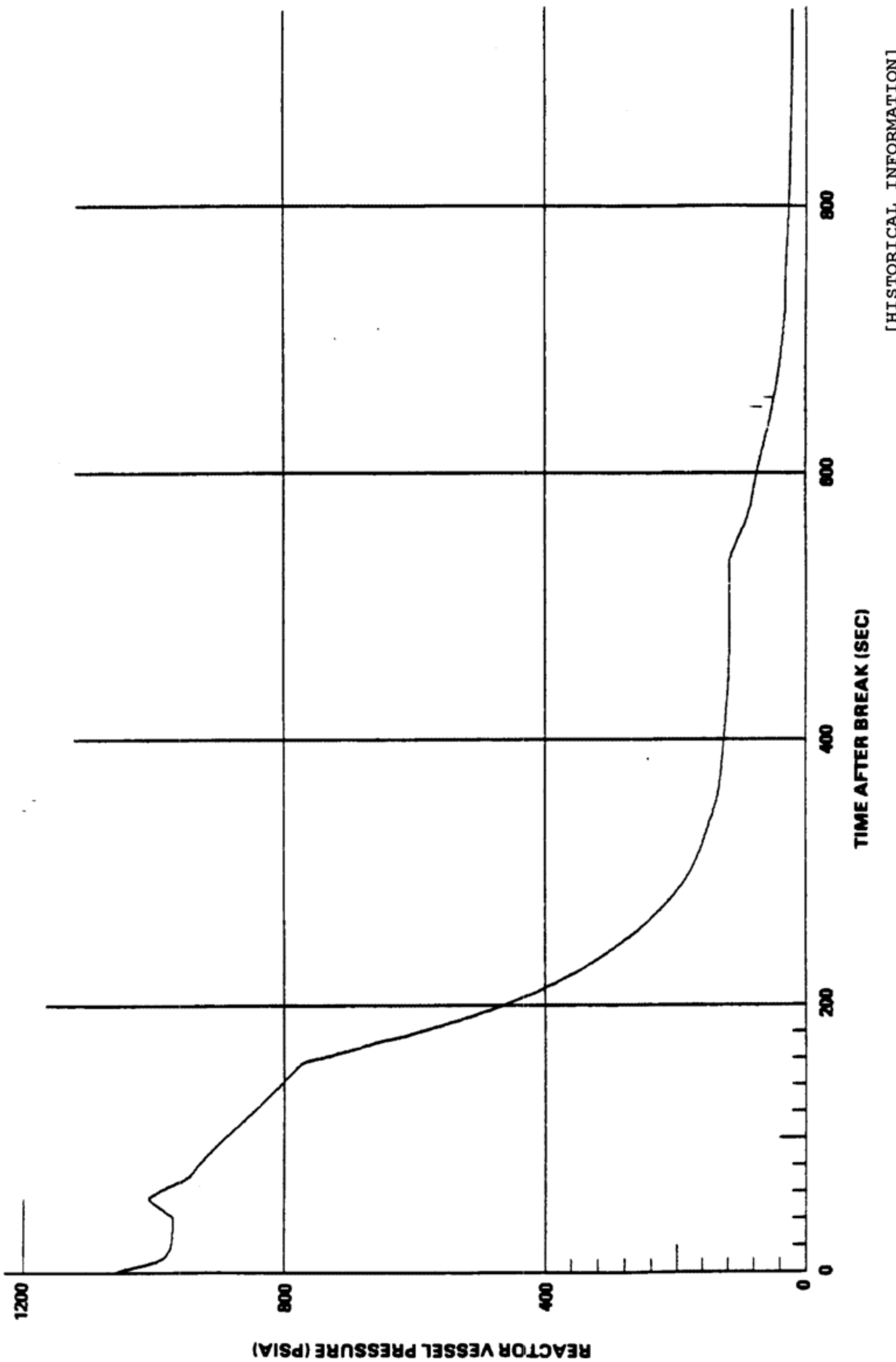
FIGURE 6.3-82



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

WATER LEVEL INSIDE THE SHROUD VERSUS TIME AFTER BREAK (CORE SPRAY LINE BREAK, 0.28 FT^2 BREAK, LPCS D/G FAILURE, 1 ADS VALVE OUT OF SERVICE)
[INITIAL CYCLE]
FIGURE 6.3-83

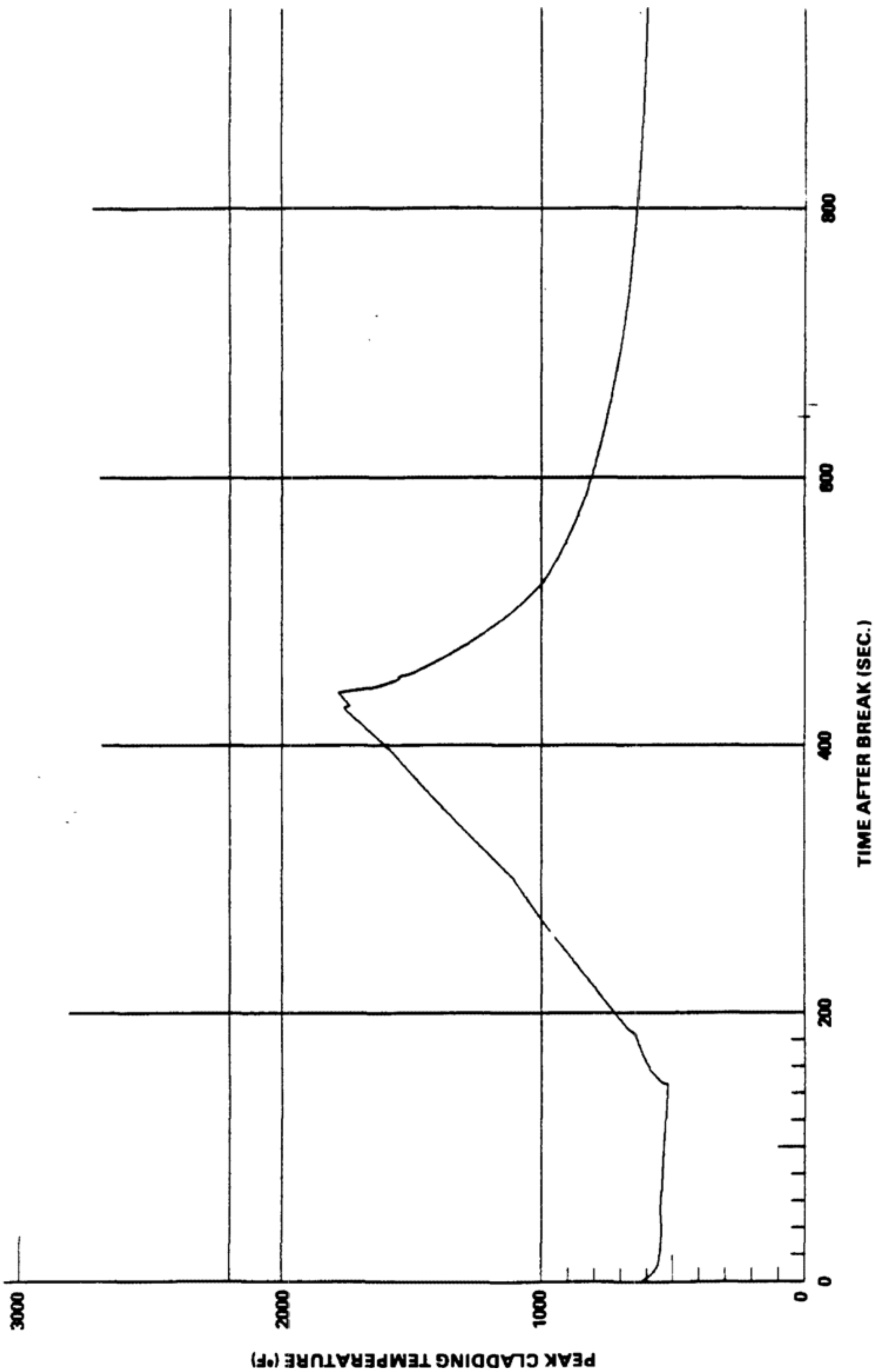


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL PRESSURE VERSUS TIME AFTER BREAK (CORE SPRAY LINE BREAK, 0.28 FT^2 BREAK, LPCS D/G FAILURE, 1 ADS VALVE OUT OF SERVICE)
[INITIAL CYCLE]

FIGURE 6.3-84

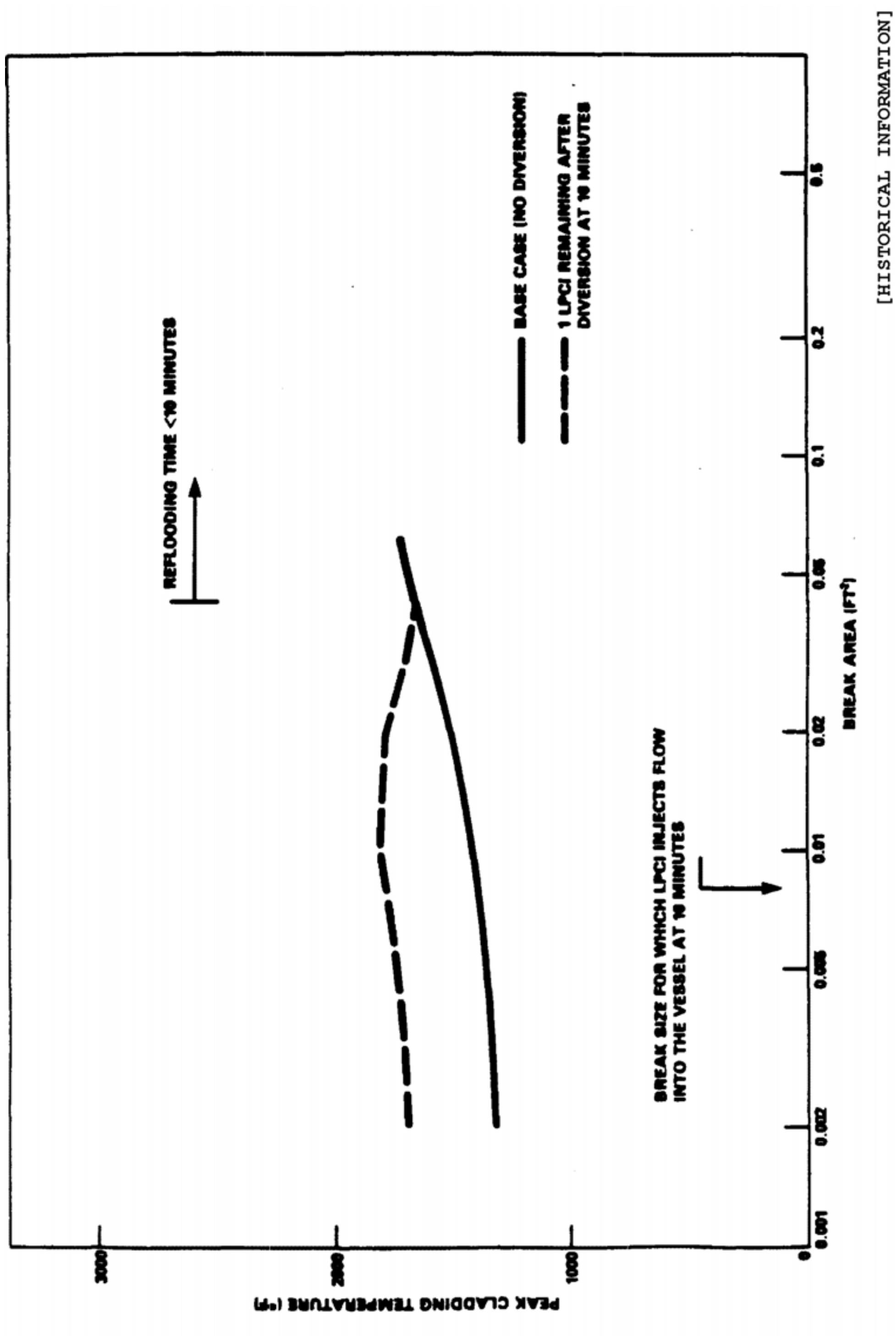


[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

PEAK CLADDING TEMPERATURE VERSUS TIME AFTER BREAK (CORE SPRAY LINE BREAK, 0.28 FT^2 BREAK, LPCS D/G FAILURE, 1 ADS VALVE OUT OF SERVICE) [INITIAL CYCLE]

FIGURE 6.3-85



[HISTORICAL INFORMATION]

GRAND GULF NUCLEAR STATION
UNIT 1
UPDATED FINAL SAFETY ANALYSIS REPORT

PEAK CLADDING TEMPERATURE VERSUS BREAK AREA FOR AN HPCS LINE BREAK ASSUMING AN LPCS D/G FAILURE
SYSTEMS REMAINING: 2 LPCI + ADS
[INITIAL CYCLE]

FIGURE 6.3-86

6.4 HABITABILITY SYSTEMS

The control room habitability systems include missile protection, radiation shielding, radiation monitoring, air filtration and ventilation systems, lighting, personnel and administrative support, and fire protection.

The habitability systems are provided to ensure that the control room operators can remain in the control room and take actions to operate the plant safely under normal conditions and to maintain it in a safe condition under all accident conditions.

The habitability systems are also essential for maintaining the Control Room as the backup Technical Support Center (TSC) (Ref. SER Section 2.7.1, PUSAR Section 2.7.1).

The detailed descriptions of the various habitability systems and provisions are discussed in the following sections:

o Conformance with NRC General Design Criterion 19	Section 3.1
o Wind and Tornado Protection	Section 3.3
o Flood Design	Section 3.4
o Missile Protection	Section 3.5
o Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
o Seismic Design of Electrical Components	Section 3.10
o Environmental Design of Mechanical and Electrical Equipment	Section 3.11
o Radiation Protection	Section 12.3 and Chapter 15.0
o Heating, Ventilating and Air Conditioning (HVAC)	Subsection 9.4.1

o	Fire Protection	Subsection 9.5.1
o	Lighting Systems	Subsection 9.5.3
o	Power Systems	Chapter 8
o	Radiation Instrumentation and Monitoring	Subsection 7.6.1.2 and 12.3.4, and Section 11.5
o	Control Room Isolation Instrumentation and Controls	Subsection 7.3.1.1.10

Equipment and systems are discussed in this section only as necessary to describe their connection with control room habitability. References to other sections are made where appropriate.

6.4.1 Design Basis

Criteria for the selection of design bases are found in subsection 1.2.1.2.

Protection of the habitability systems of the control room from wind and tornado effects, is discussed in Section 3.3. Flood design is discussed in Section 3.4. Missile protection is discussed in Section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is discussed in Section 3.6. Environmental design is discussed in Section 3.11. Seismic design of electrical components is discussed in Section 3.10.

6.4.1.1 Safety Design Basis

a. The control room envelope, or pressure boundary as shown in Figures 6.4-1 and 6.4-2, includes all instrumentation and controls necessary for safe shutdown of the plant, and is limited to those areas requiring operator access during and after a design basis accident (DBA).

b. Food, water, medical supplies, and sanitary facilities are provided for sustaining an emergency team of five persons for a period of 5 days.

c. The control room HVAC system during emergency mode maintains a suitable environment for sustained occupancy of 50 persons.

d. The radiation exposure of control room personnel through the duration of any one of the postulated design basis accidents discussed in Chapter 15.0 does not exceed the guidelines set by 10 CFR 50, Appendix A, General Design Criterion 19.

e. The habitability systems provide the capability to detect and limit the introduction of freon gas, radioactive material, and smoke into the control room.

f. Respiratory, eye, and skin protection is provided for emergency use within areas of the control room envelope.

g. Through the duration of any one of the postulated design basis accidents discussed in Chapter 15.0, the control room ventilation system maintains the control room atmosphere at temperatures suitable for prolonged occupancy.

h. The control room ventilation system is capable of automatic transfer from its normal operational mode to its emergency or isolation modes upon detection of conditions which could result in an accidental exposure of control room personnel to a high level of airborne radioactivity.

i. The system and components are located in a seismic Category I structure that is tornado-missile and flood protected.

j. Nonseismic pipe, ductwork, or components in the control room are evaluated to ensure that their physical collapse during an SSE will not adversely affect essential components.

k. The control room HVAC system is designed with sufficient redundancy to ensure operation under emergency conditions assuming the single failure of any one active component.

l. With the exception of the following components which are not required to be safety-related, the control room heating, ventilating, and air conditioning system is designed to seismic Category I requirements:

1. Control room utility exhaust fan and the associated ductwork extending from the second isolation valve to the exhaust louver

2. Control room purge exhaust ductwork extending from the second isolation valve to the exhaust louver

3. Control room freon detectors

4. Control room humidifiers, excluding the support structure and the steam distribution headers

   Note: The Control Room Humidifiers have been abandoned in place.

5. Safety-related panel area unit heaters

6. Pressure indicating controllers, pressure transmitters, and power supplies for Control Room HVAC flow control valves

m. The components of the control room HVAC system, except the components listed in item 1 above, are operable during the loss of offsite power.

6.4.2 System Design

6.4.2.1 Definition of Control Room Envelope

The control room envelope is shown in Figures 6.4-1 and 6.4-2, and consists of all rooms at the control room elevation of the control building. Included in the envelope, served by the control room HVAC system, are the control room, offices, the kitchen, the toilet, the emergency dormitory, the dining area, the safety-related panel room of the upper cable-spreading room, and several closets and storage rooms where access is required after a DBA. Airtight doors are provided at the access points and from the control room envelope.

6.4.2.2 Ventilation System Design

The design, construction, and operation of the control room HVAC system are described in detail in subsection 9.4.1. Figure 9.4-1, a diagram of the control room HVAC system, shows major components,

seismic classifications, and instrumentation. A description of the major component flow rates, capacities, and major design parameters is in subsection 9.4.1.

Figure 2.1-2 shows the plant layout, including the location of potential radiological release points with respect to the control room air intakes.

Elevation and plan drawings showing building dimensions and equipment locations are given in Figures 1.2-5 and 1.2-8. Potential sources of toxic gas release are identified in Section 2.2.

The volume of the zone served by the HVAC system in the emergency mode or the isolation mode is approximately 253,000 cubic feet.

Description of control room instrumentation for monitoring of radioactivity is given in subsections 7.6.1.2 and 12.3.4.

A description of the smoke detectors is in subsection 9.5.1.

A description of the control logic of the toxic gas monitors is in subsection 7.3.1.1.10.

Protection of the control room HVAC from internally generated missiles is discussed in subsection 3.5.1.2.

6.4.2.3 Leak Tightness

The control room boundary is designed with low leakage construction. All boundary penetrations are sealed. The access doors are of airtight design with self-closing devices which shut the doors automatically following the passage of personnel.

All potential leak paths in and from the control room boundary are tabulated and shown on Figures 9.4-1 through 9.4-5.

The control room inleakage analysis was performed using the methods and assumptions given in Conventional Building For Reactor Containment, Atomics International (NAA-SR-10100), and Regulatory Guide 1.78. The leakage rate is calculated using the following:

a. A 1/8 in. w.g. differential across surfaces and components exposed to direct effects of external winds

b. A 1/16 in. w.g. differential across surfaces and components protected from the effects of direct winds

c. Maximum design differential for closed dampers on the suction side of the supply fans

d. Equation:

$$q = AP + BP^{1/2} \qquad \text{Equation 6.4-1}$$

where:

q = leakage rate per unit leak path, cfm

A = empirical constant, cfm per unit leak path per inch of water pressure

B = empirical constant, cfm per unit leak path per inch$^{1/2}$ of water pressure

P = differential pressure (in. w.g.)

The leak paths considered were concrete walls and slabs, block walls, wall and slab joints, door frames, doors, electric cable penetrations, duct penetrations, and pipe penetrations. The empirical constants A and B for each leak path are taken from NAA-SR-10100.

Table 6.4-1 provides a listing of leakage data and total leakage for all leak paths. However, as shown on Table 15.6-13, a conservative air flow rate into the control room is used for dose calculations.

6.4.2.4 Interaction With Other Zones and Pressure-Containing Equipment

The control room air-conditioning system normal outside air intake duct is provided with radiation detectors which alarm on high activity and initiate automatic isolation of the control room. A freon detector at the discharge duct of each control room air conditioning unit detects the introduction of freon gas into the control room HVAC system. An area radiation monitor is also provided within the control room to monitor indoor ambient radiation levels. In addition, the control room is also isolated by the reactor vessel low water level and high drywell pressure signals (LOCA signals).

Once the control room isolation signal is activated, the following actions occur automatically:

a. All open outside air makeup isolation butterfly valves close.

b. The control room utility exhaust fan shuts down and the associated isolation butterfly valves close.

c. If the control room smoke and fume purge exhaust line isolation butterfly valves are open, they are closed; and a resulting signal shuts down the control building purge fan.

d. Both control room standby fresh air unit fans start and recirculate a portion of the room air through the standby fresh air units. One of the two control room standby fresh air units may be placed on standby by the operator with a key lock switch.

If a smoke detection signal is received during control room isolation, an alarm is given, but the air conditioning units continue to operate and the exhaust purge isolation butterfly valves remain closed. This prohibits possible spurious smoke detector signals from compromising system operation under emergency conditions. However, the filters of the control room fresh air unit partially remove smoke from the control room by recirculating a portion of the room air through the unit; portable respirators are also available for emergency needs.

6.4.2.5 Shielding Design

A perspective drawing illustrating the shielding provided to maintain the habitability of the control room envelope (as defined in subsection 6.4.2.1) is provided in Figure 6.4-6. Floor plans of the control room and upper levels are provided in Figures 6.4-1 and 6.4-2. Control room radiological considerations are discussed in Chapter 15.0.

Shielding is provided by the reinforced concrete floors and walls of the following thicknesses:

Structure	Envelope Boundary	Thickness
Walls	North and south exterior wall of control building from El. 166' to El. 206'.	3 ft-0 in.
	East and west exterior wall of control building from El. 166' to El. 206'.	2 ft-0 in.
	Interior walls enclosing the safety-related panel rooms of the upper cable spreading room from El. 186' to El. 206'.	0 ft-8 in.
Floor slabs	Control room floor, El. 166' (Envelops lower boundary)	ft-0 in (includes 3 in. corrugated steel decking)
	Control room/viewing gallery ceiling (upper cable spreading room floor, El. 189') (Envelops upper boundary except for safety-related panel rooms)	1 ft-3 in (includes 3 in. corrugated steel decking)
	Control building roof, El. 206' (Envelops upper boundary for safety-related panel rooms)	2 ft-4 1/2 in. (includes 4 1/2 in. corrugated steel decking)

1

6.4.2.6 Portable Self-Contained Air Breathing Units

Portable self-contained air breathing units are supplied for control room personnel. Five complete units and a minimum of ten charged spare cylinders are provided. Each complete unit and spare cylinder has a rated duration of at least 30 minutes. Onsite reserve air used to recharge spare cylinders is provided by a cascading air cylinder system and a breathing air compressor with associated air storage and delivery system.

The onsite supply of reserve air is available to provide a minimum of 6 hours of use per portable self-contained air breathing unit. In the event of a radiological accident, the cascading system shall be recharged offsite to preclude the use of potentially contaminated air.

The portable self-contained air breathing units, cascading system, and accessories are approved by the National Institute for Occupational Safety and Health. Use of portable self-contained air breathing units will protect control room operators from inhaling toxic gases or radioactive particulates or both.

6.4.3 System Operational Procedures

Normal and emergency operation of control room habitability systems is discussed in subsections 9.4.1, 9.5.1, 9.5.3, 12.3.4, 6.5.1, 7.3.1.1.10 and in Chapter 8.0.

6.4.4 Design Evaluations

6.4.4.1 Radiological Protection

Radiological protection of control room personnel is discussed in subsections 7.6.1.2 and 12.3.4, and in Chapter 15.0. Operation of the control room HVAC system in conjunction with radiological protection is discussed in subsection 9.4.1.

6.4.4.2 Toxic Gas Protection

As discussed and evaluated in subsection 9.5.1, the use of non-combustible construction and heat- and flame-resistant materials throughout the plant minimizes the likelihood of fire and consequential fouling of the control room atmosphere with smoke or noxious vapor introduced into the control room air. In the smoke removal mode, the flow of 5300 cfm through the control room is purged in order to sweep atmospheric contaminants out of the area.

To protect against high airborne radioactivity inside the control room, the control room HVAC system is automatically transferred from the normal mode to the isolation mode of operation upon receipt of any of the following actuation signals:

a. Loss-of-coolant accident

b. Control room outside air intake high airborne radiation signal

Transfer of the system to the isolation mode may also be initiated manually from the control room. Local, audible alarms warn the operators to shut the self-closing doors if for some reason they are held open after the receipt of a transfer signal. Isolation mode makeup air flow, required after approximately 72 hours of isolation (based on the buildup of carbon dioxide to one percent by volume in the space due to the respiration of 12 persons) must be initiated manually by the operator after tests with portable air analyzers indicate the need to do so. However, the operator is allowed to initiate manually the isolation mode makeup air flow after 10 minutes of isolation mode.

An evaluation of the resulting toxicity of freon release was performed and compared with the results in the Underwriters Laboratories, Inc., report on “The Comparative Life, Fire, and Explosion Hazards of Difluoromono Chloromethane (Freon-22)” (Miscellaneous Hazard No. 3134, September 26, 1940). Assuming that the entire gaseous volume of Freon-22 (R-22) is instantaneously released into the supply air, which is the worst case of refrigerant barrier failure, the resulting control room R-22 concentration is approximately 1.36 percent by volume. Based upon the evaluation, it is concluded that R-22 by either itself or decomposition products can not possibly present a hazard to the control room operators. However, a R-22 detector installed in the discharge ductwork of each air-conditioning unit is capable of sensing a 0.025 percent concentration of R-22 by volume in the discharge ductwork. Upon detection of refrigerant (R-22) leakage, the following actions occur simultaneously:

a. The operating air-conditioning unit shuts down.

b. The operating unit isolation dampers close.

c. The purge line isolation butterfly valves open.

d. The control building purge fan starts.

e. An alarm sounds in the control room.

Thus, any evaporation from the condenser/receiver into the airstream will be quickly isolated to prevent any further freon buildup into the control room. After isolation, the control room volume is purged at a rate of three air changes per hour. The

control room will also be equipped with self-contained breathing apparatus that can be used by the operators to preclude any potential discomfort resulting from the release of R-22.

Redundant components are provided where necessary to ensure that a single failure will not preclude adequate control room ventilation. A control room ventilation system failure analysis is presented in Table 9.4-2.

The control room HVAC system is designed in accordance with seismic Category I requirements as specified in Section 3.2. The components (and supporting structures) of any system, equipment, or structure which is not seismic Category I and whose collapse could result in loss of a required function of the control room HVAC system through either impact or flooding are analytically checked to determine that they will not collapse when subjected to seismic loading.

An analysis of hazardous chemicals, in accordance with Regulatory Guide 1.78, has been performed and is discussed in Section 2.2.

6.4.5 Testing and Inspection

Provisions are made for periodic tests of the emergency ventilation fans and filters. These tests include determinations of differential pressure across the filter and of filter efficiency. Connections for testing, such as injection and sampling connections, are located to provide adequate mixing of the injected fluid and representative sampling and monitoring so that test results are indicative of performance.

A leakage test was performed prior to initial plant operations to verify the leakage of the control room envelope. Control room envelope inleakage testing is performed in accordance with the Control Room Envelope Habitability Program.

The high-efficiency particulate air (HEPA) filters are tested periodically with dioctyl phthalate (DOP) smoke.

The balance of the system is proven operable by its use during normal plant operation. Portions of the system normally closed to flow can be tested to ensure operability and integrity of the system.

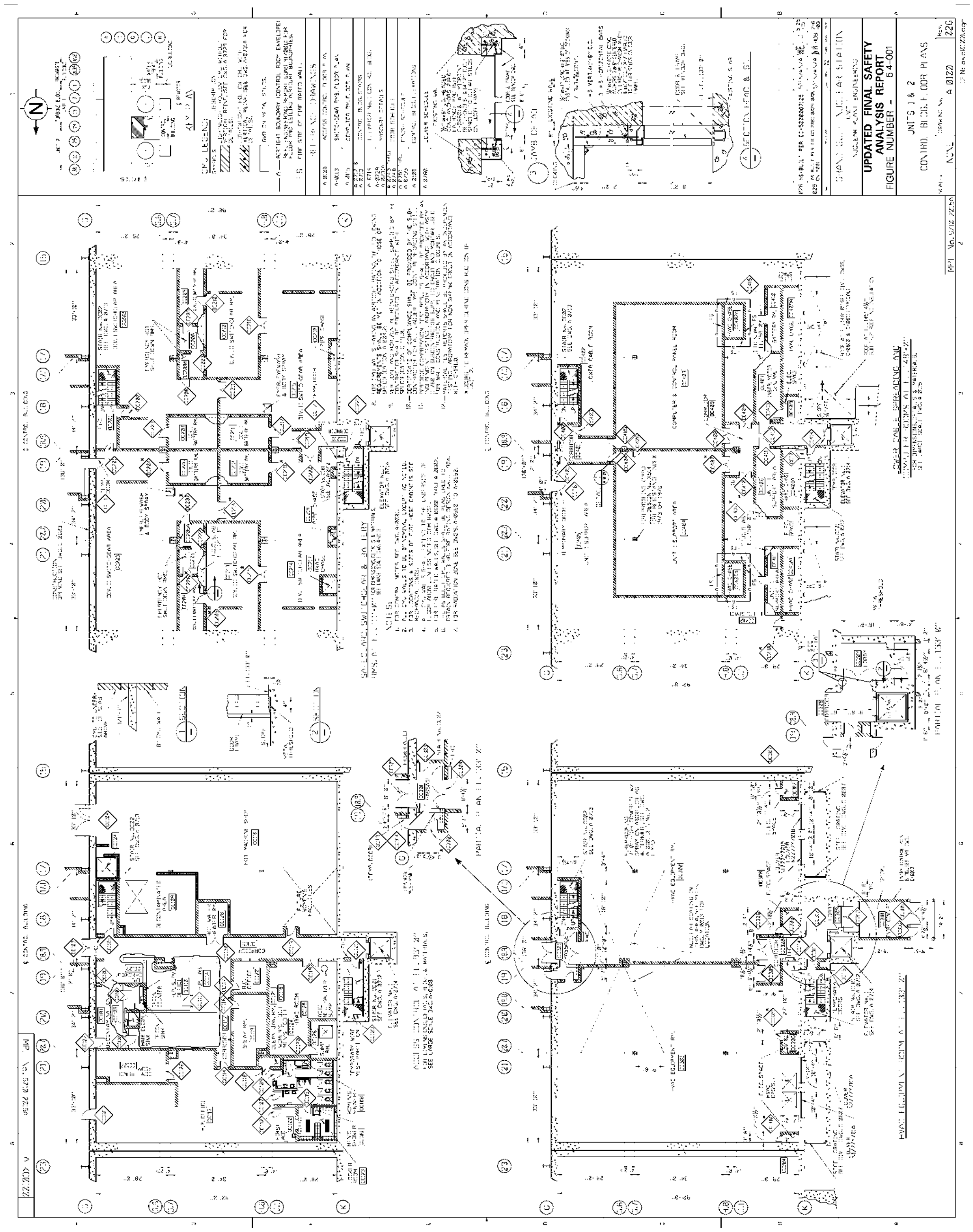
Fan ratings are in accordance with AMCA Standard Test Code 211A, "Certified Rating Program for Air Moving Devices." Testing of the Control Room Atmospheric Control and Isolation system controls is discussed in subsection 7.3.2.10.

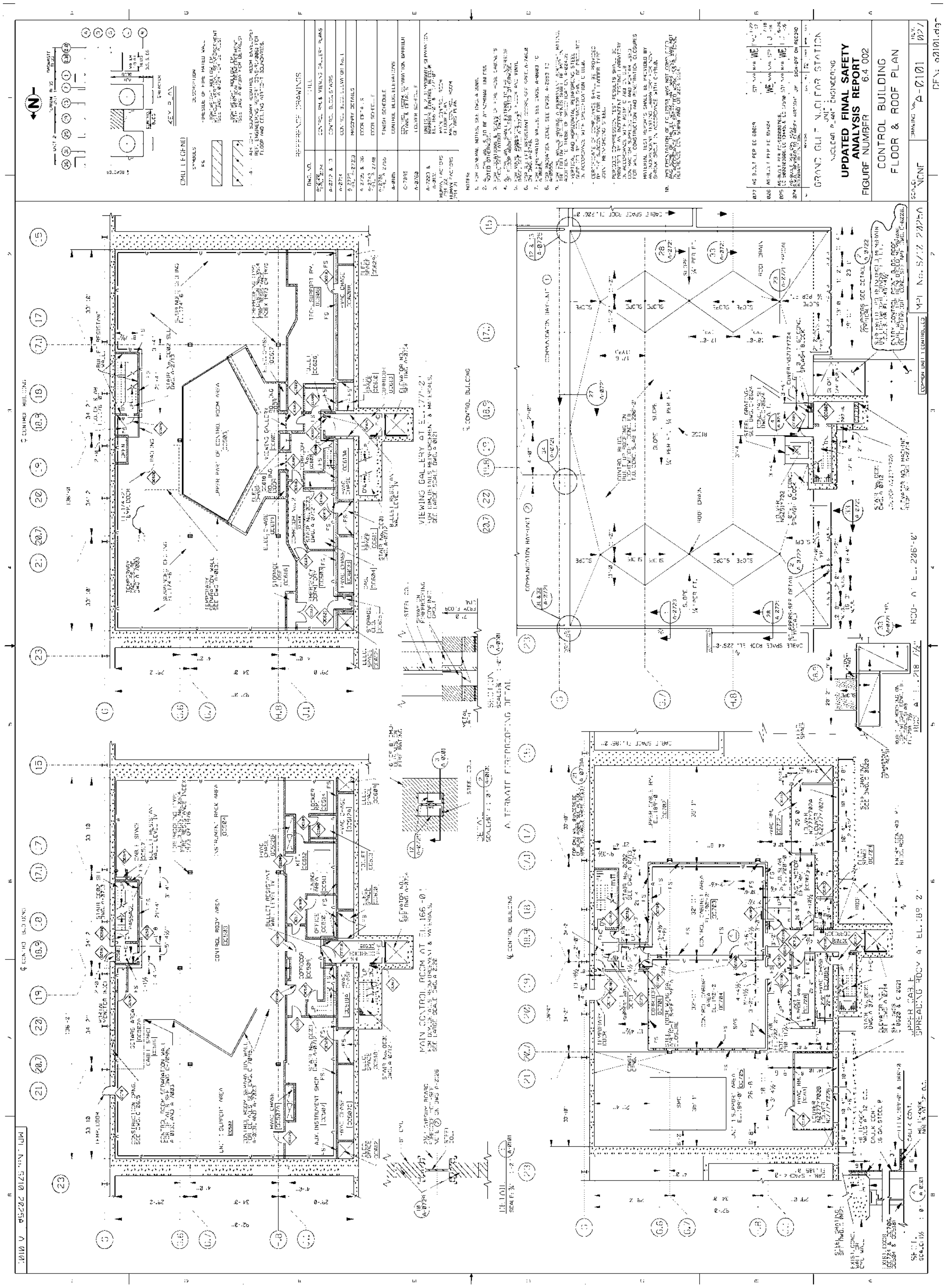
6.4.6 Instrumentation Requirement

Controls and instrumentation for the control room HVAC system are discussed in subsections 9.4.1.5, 7.3.1.1.10 and 7.3.2.10.

TABLE 6.4-1: CONTROL ROOM LEAKAGE ANALYSIS

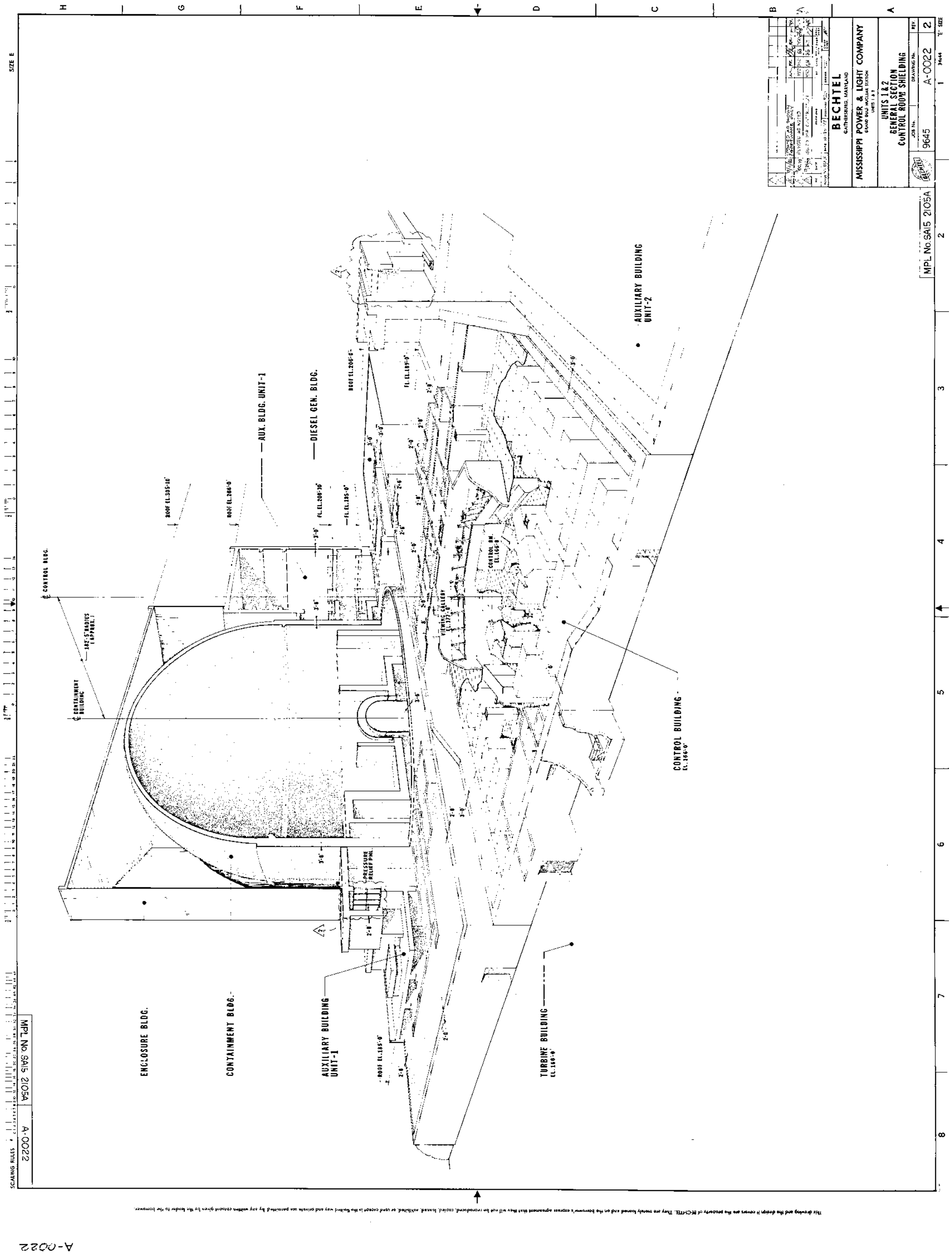
Leak Path	Differential Pressure (in.) w.g.	Leak Rate (cfm)
Doors	1/16	35.3
Butterfly valves	-	0
Roof	1/8	0.01734
Eave	1/16	0.00166
Eave	1/8	0.00153
Walls	1/16	0.00057
Walls	1/8	0.00054
Duct penetrations	1/8	0.000009
Electric cable penetrations	1/16	0.000015
Floor	1/16	0.000714
Footing joints	1/16	0.00022
Footing joints	1/8	0.0002
Corners	1/16	0.00024
Corners	1/8	0.00016
	Total (Approx.)	37


UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER – 6.4-001
UNITS 1 & 2
CONTROL BLDG. FLOOR PLANS
A 0122
226


GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER 6.4-002
CONTROL BUILDING
FLOOR & ROOF PLAN
MAIN CONTROL ROOM AT EL. 166'-0"
VIEWING GALLERY AT EL. 177'-0"

Figures 6.4-3 through 6.4-5

Deleted


BECHTEL
MISSISSIPPI POWER & LIGHT COMPANY
UNITS 1 & 2
GENERAL SECTION
CONTROL ROOM SHIELDING
9645
A-0022
MPL No. 9A15 2105A
AUXILIARY BUILDING UNIT-2
AUX. BLDG. UNIT-1
DIESEL GEN. BLDG.
CONTROL BUILDING
ENCLOSURE BLDG.
CONTAINMENT BLDG.
AUXILIARY BUILDING UNIT-1
TURBINE BUILDING
PRESSURE RELIEF PNL.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Feature (ESF) Filter Systems

The ESF filter systems consist of the control room standby fresh air system particulate filter and standby gas treatment system (SGTS) charcoal filter trains. The performance of the systems under postulated accident conditions is discussed in Chapter 15.

Nonsafety-related filter systems include the radwaste building exhaust air filter and tank vent charcoal filter trains discussed in subsection 9.4.3, containment cooling system and containment exhaust charcoal filter trains discussed in subsection 9.4.7, and the turbine building exhaust air charcoal filter train discussed in subsection 9.4.4.

6.5.1.1 Safety Design Bases

The filters for the control room standby fresh air system particulate filter trains and SGTS charcoal filter trains are designed to accomplish the following:

a. Control Room System Only

   Ensure that radiation exposures to operating personnel in the control room resulting from a maximum hypothetical accident, as discussed in Chapter 15, are within the guideline values of 10 CFR 50.67.

b. SGTS Only

   Ensure that the offsite radiation exposures (site boundary and low population zone) resulting from postulated accidents, as discussed in Chapter 15, are within the guideline values of 10 CFR 50.67

c. Ensure that failure of any component of the filtration trains, assuming loss of offsite power, cannot impair the ability of the system to perform its safety function

d. Remain intact and functional in the event of a safe shutdown earthquake (SSE)

e. Are consistent with the recommendations of NRC Regulatory Guide 1.52, subject to the exceptions discussed in Appendix 3A

The design bases employed for sizing the filters, fans, and ductwork of the control room standby fresh air system particulate filter trains are discussed in subsection 9.4.1. The design bases employed to size the filters, fans, and ductwork of the SGTS charcoal filter trains are discussed in subsection 6.5.3.

The fission product removal capabilities of the subject charcoal filter trains are derived from NRC Regulatory Guide 1.52, based on compliance with the applicable design requirements given in the Guide.

The work, equipment, and materials conform to the applicable requirements and recommendations of the guides, codes, and standards listed in Section 3.2.

6.5.1.2 System Design

6.5.1.2.1 General System Description

The control room standby fresh air system particulate filter trains are described in subsection 9.4.1. The SGTS charcoal filter trains are described in subsection 6.5.3. System and flow diagrams are shown in Figures 9.4-1 and 6.5-1 (control room HVAC) and 6.5-4 (SGTS).

6.5.1.2.2 Component Description

Each ESF filter train consists of a demister, electric heater, prefilter, high efficiency particulate air (HEPA) filter, a charcoal adsorber with fire detection temperature sensors (SGTS only), a downstream HEPA filter, and a fan. Specific component design parameters are given in Table 6.5-1. A comparison, in tabular form, of the design against the requirements of Regulatory Guide 1.52 is given in Appendix 3A.

The filter housing designs provide adequate space for filter maintenance and inspection. The housing is fitted with the necessary ports for inspection.

The charcoal adsorber portion of each filter train is provided with a high temperature detection and a water spray system to allow flooding of the charcoal bed in the unlikely event of high temperature in the charcoal, to preclude the possibility of iodine desorption.

6.5.1.3 Safety Evaluation

The following safety evaluation is written to correspond to the design bases of subsection 6.5.1.1.

a. The performance capability of the control room emergency filters is discussed in Section 6.4. The design of individual components, which ensure the capability to perform the safety function, is discussed in subsection 9.4.1. Control room doses resulting from postulated radiological accidents are given in Chapter 15. These doses are within the guideline values of 10 CFR 50.67.

b. Component descriptions and safety evaluations for the SGTS charcoal filter trains are provided in subsection 6.5.3. Dose analyses of postulated radiological releases involving the site boundary and low population zone are given in Chapter 15. Radiation exposure resulting from these occurrences are shown to be within the guideline values of 10 CFR 50.67.

c. The control room standby fresh air particulate filter trains and SGTS charcoal filter trains each consist of two independent and redundant filtration trains. Should any component in one train fail, filtration can be performed by the other train. The electrical devices of the respective trains are powered from separate Class IE electrical buses. Failure modes and effects analyses are presented in subsections 9.4.1 and 6.5.3.

d. The ESF filter systems are designed to seismic Category I requirements as specified in Section 3.2. The components and supporting structures of any system, equipment, or structure that is not seismic Category I, and whose collapse could result in loss of safety function of the ESF filters through either impact or flooding, are

analytically checked (and upgraded if necessary) to assure that they will not collapse when subjected to seismic loading.

e. The ESF filter systems are designed and constructed to be consistent with the recommendations of NRC Regulatory Guide 1.52, with the exceptions noted in Appendix 3A.

6.5.1.4 Tests and Inspections

6.5.1.4.1 Preoperational Testing

[HISTORICAL INFORMATION] [Charcoal filter train housings are shop pressure tested to demonstrate a leakage of less than 0.5 cfm per 1,000 cfm of system flow, at a differential pressure of 1 psig. This test pressure is in excess of the maximum operating differential pressure.

HEPA filters are shop tested prior to installation in accordance with MIL-STD-282 at 100 percent and at 20 percent of rated flow.

Impregnated activated carbon is tested prior to installation in accordance with the methods specified in RDT-M16-1T (October 1973) for apparent density, CCL4 activity, percent hardness, percent moisture, particle size distribution, and ash content. Surface area is determined in accordance with the BET Surface Area Method.

Elemental and methyl iodine removal and retention capabilities are measured at postulated accident conditions in accordance with RDT-M16-1T. Impregnant content, leachout, and charcoal ignition temperature are also determined.

HEPA filter banks are tested in place prior to operation to verify the efficiency of at least 99.97 percent with cold generated DOP (dioctyl phthalate).

The charcoal adsorber banks are freon leak tested prior to operation to verify less than 0.05 percent bypass. In addition, a laboratory test of a representative sample of the impregnated activated charcoal is performed to verify iodine removal efficiencies.]

Design and testing of ESF filtration systems is consistent with the recommendations of NRC Regulatory Guide 1.52, with the exceptions noted in Appendix 3A.

The program of preoperational testing performed on the ESF filtration systems is presented in Chapter 14.

6.5.1.4.2 Inservice Testing

Inservice testing of the ESF filtration systems is conducted in accordance with the surveillance requirements given in the plant Technical Specifications.

6.5.1.5 Instrumentation Requirements

Controls and instrumentation for the control room standby fresh air system and SGTS charcoal filter trains are discussed in Section 7.3. Each system is designed to function automatically upon receipt of an applicable ESF actuation signal. Fans can also be controlled from the control room.

The status of the ESF filter train equipment is displayed in the control room during both normal and accident operations. Monitoring instrumentation for ESF filter trains is discussed in Section 7.5.

Appendix 3A addresses the extent to which the recommendations of Regulatory Guide 1.52 are followed with respect to instrumentation.

6.5.1.6 Materials

The construction materials used in or on the filter systems are given in Table 6.5-2. Each of the materials is compatible with the normal and accident environments postulated for the area in which the equipment is located as well as the areas served by the return air duct work.

The ESF filter systems are not exposed to accident environments of extreme temperature or radiation that could potentially produce

pyrolytic or radiolytic decomposition of filter materials, and thus, filter system decomposition products will not be present.

A fire from external sources, which could cause pyrolytic decomposition of construction materials of the ESF filters, is not postulated to occur simultaneously with any other plant accident which could require the operation of the filters for radioiodine removal credit. Therefore, fire is not a credible event which could adversely affect the operation of the ESF filter trains. This position is consistent with Appendix A to NRC Branch Technical Position APCSB 9.5-1, Guidelines for Fire Protection for Nuclear Power Plants, docketed prior to July 1, 1976. See subsection 9.5.1.

Table 6.5-2 tabulates materials used in the filter trains, but for the above reasons, does not provide a detailed breakdown of quantity and composition.

6.5.2 Containment Spray System

6.5.2.1 Design Bases

a. The containment spray system (CSS) is a part of the residual heat removal (RHR) system.

b. The CSS provides containment cooling following a loss-of-coolant accident, in addition to being a fission product removal mechanism. (Refer to subsection 6.2.2 for the heat removal function of the CSS.)

c. The CSS consists of two completely redundant and independent trains.

d. The CSS is designed to remain operable in the containment accident environment, which is discussed in Section 3.11.

e. The CSS is designed such that a single failure of any active component will not degrade the ability of the system to fulfill design objectives. Each train of the CSS receives power from a separate emergency diesel generator, in the event that offsite power is unavailable during an accident. The two trains are physically separate from each

other, so that a failure in one train will not result in failure of the other train due to fire, flooding, pipe breaks or missiles.

f. The CSS is designed to seismic Category I requirements. System components as appropriate are designed to meet ASME Code Section III, Class 2 requirements.

g. The CSS is designed to permit periodic testing as described in subsections 6.2.2, and 6.5.2.4.

6.5.2.2 System Design

The source of water supply for the CSS during all phases of system operation is the suppression pool. The water is pumped by the RHR pumps through the RHR heat exchangers to the containment spray headers. The CSS is shown in Figures 5.4-16 and 5.4-17.

Each train of the containment spray system consists of three headers: the top header consists of 50 equally-spaced spray nozzles; the middle header consists of 115 equally-spaced spray nozzles; and the bottom header consists of 185 equally-spaced spray nozzles. The nozzle orientation for each spray header is shown in Figures 6.5-5 and 6.5-6. A plan view of each spray header is shown in Figure 6.5-7.

The spray nozzles used are Sprayco 1713A hollow-cone ramp bottom nozzles each of which is capable of a flow of 16 gpm with a pressure drop of 40 psid. These nozzles have an approximately 3/8-inch spray orifice and are not subject to clogging by particles less than 1/4-inch in maximum dimension. The nozzles produce a median diameter drop size of approximately 230 microns at rated service conditions. Each nozzle header is independently oriented to ensure efficient coverage of the containment volume. The water supply flow rate to the containment spray system is 5650 gpm.

There are no spray additives for the CSS. The CSS will automatically initiate after ≈10 minutes of a LOCA signal if containment pressure exceeds the high pressure setpoint (coincident with a high drywell pressure). The specific setpoints for the CSS timers, containment pressure, and drywell pressure setpoints for CSS initiation are provided in Technical

Requirements Manual (TRM). If containment pressure is less than the high pressure setpoint, the control room operator will actuate the system manually if containment conditions dictate, which will remove radioactive iodine in the containment atmosphere to support the accident analysis of section 15.6.

The sprayed and unsprayed volumes and regions of the containment, with their associated mixing rates, are shown in subsection 15.6.5.

The CSS takes no credit for ventilation.

6.5.2.3 Design Evaluation

The containment spray mode of the RHR system is safety-related and is designed to operate following the postulated design basis loss-of-coolant accident. A high degree of system reliability is maintained through system quality control, by general equipment arrangement to provide access for inspection and maintenance, and by periodic testing. A single failure analysis of the RHR system is given in subsection 6.2.2.

Because of the large surface area interface between the sprays and the containment atmosphere, the spray mode serves as a removal mechanism for fission products postulated to be dispersed in the containment atmosphere following an accident. Radioiodine in its various forms is the fission product of primary concern in the evaluation of a loss-of-coolant accident. The major benefit of the containment spray is its capacity to absorb molecular iodine from the containment atmosphere and thus reduce its release to the environment. Offsite and control room operator thyroid doses are a function of both the rate of removal and the final equilibrium decontamination factor.

6.5.2.3.1 Iodine Removal Performance Evaluation

The iodine removal analysis is based on the assumptions presented below and in Table 6.5-3.

The spray iodine removal analysis is based on the assumption that only one RHR pump is operating in the containment spray mode. The

containment spray directly sprays approximately 70.9 percent of the total containment free volume (excluding the drywell). The entire containment dome and all volumes under directly-sprayed gratings are assumed to be directly sprayed.

Of the remaining 29.1 percent of the containment free volume not directly sprayed, approximately 17 percent has good communication with the main spray while 12.1 percent has restricted communication with the main spray. Section 15.6.5 provides a summary of all unsprayed containment regions and the volumes of these regions.

The annular volumes between the drywell wall and the primary containment wall from El. 135'-4" (HCU floor) down to the surface of the suppression pool is considered to be unsprayed. This is based on the conservative assumption that significant obstructions to the main spray will result from equipment and structures above El. 135'-4".

The iodine removal rates for the containment sprays, calculated with the model described above and in subsection 6.5.2.3.2 are 6.9 hr^{-1} for the elemental iodine and 9.7 hr^{-1} for the particulate iodine.

It has been conservatively assumed in these evaluations of spray removal effectiveness that organic iodine forms are not removed by the sprays. Although the iodine removal capability is high, no credit is taken for elemental iodine removed after the decontamination factor (DF) of 200 is reached and particulate iodine removal is reduced by a factor of ten after the DF of 50 is reached.

6.5.2.3.2 Evaluation of Analytical Assumptions

6.5.2.3.2.1 Deleted

6.5.2.3.2.2 Elemental Iodine Removal Constant

The total elemental iodine removal coefficient is the sum of the wall removal coefficient and the spray removal coefficient. The wall removal coefficient was determined using the methodology

provided in Standard Review Plan 6.5.2 (Reference 2). Wall deposition may be estimated by:

$$\lambda_w = K_w \frac{A}{V}$$

Where:

λ_w is the first order removal coefficient by wall deposition,

A is the wetted surface area,

V is the containment building net free volume, and

K_w is the mass transfer coefficient (4.9 m/hr, SRP 6.5.2)

The spray removal coefficient was determined using a simplified spray removal model given in NUREG/CR-5966 (Reference 3). As stated in this NUREG, the fundamental rate equation for the removal of containment aerosols by sprays is

$$\frac{dM}{dt} = -\lambda M + \frac{ds}{dt} + \frac{drR}{dt}$$

Where:

M = mass of aerosols suspended in the containment atmosphere

$\frac{dS}{dt}$ = rate at which aerosols are injected into the containment atmosphere

$\frac{dR}{dt}$ = rate at which aerosols are removed from the atmosphere by process other than those brought on by sprays

λ = rate constant for aerosol removal by sprays

Since the removal rate by sprays is so much greater than the removal by other processes, the dR/dt term can be neglected. For

conditions in which there is no continuous source of aerosol injection into the containment, the term dS/dt is also negligible. As discussed in the NUREG, the spray removal rate constant is a complicated function of aerosol particle size distribution, the characteristics of the spray and the geometry of the containment. Based on a detailed model of the physical processes involved in decontamination by sprays, a Monte-Carlo uncertainty analysis of decontamination by sprays was conducted and the results analyzed using non-parametric order statistics. These analyses yield a quantitatively characterized uncertainty distribution for the decontamination that can be achieved by sprays in a volume with a specified height and water flow. These results for various heights and water flows were then used to develop simple expressions of the rate constant for aerosol removal.

Calculation parameters used in determination of the total elemental iodine removal coefficient can be found in Table 6.5-3.

6.5.2.3.2.3 Particulate Iodine Removal Constant

From Standard Review Plan 6.5.2 (Reference 2) the first order removal constant λ_p, for particulate iodine may be estimated by:

$$\lambda sp = \frac{3hEF_s}{2dV}$$

Where

λsp = removal rate constant for aerosol particles, hr^{-1}

h = drop fall height, ft

E/d = the ratio of a dimensionless collection efficiency to the average spray drop diameter, d. E/d is assumed to be 10 m^{-1} initially, changing to 1 m^{-1} after the aerosol has been depleted by a factor of 50.

F_s = spray flow rate, ft^3/hr

V = containment free volume, ft^3

The capture of particles by falling drops results from Brownian diffusion, diffusiophoresis, interception, and impaction. Early in the spray period particles are removed mainly by impaction. When the larger particles have been removed, the removal rate is controlled by diffusiophoresis, which is the collection of particulates by steam condensing on the spray drops.

A mean drop fall height of 65.64 ft was calculated by weighing the height of each spray ring (see Figures 6.5-5 and 6.5-6) above the operating floor at elevation 208'-10" by the associated spray flow rate, i.e.

$$h = \frac{h_1\, m_1 + h_2\, m_2 + h_3\, m_3}{m_1 + m_2 + m_3}$$

where

h_1 = 85.17 ft number of nozzles n_1 = 50
h_2 = 74.0 ft n_2 = 115

h_3 = 55.17 ft n_3 = 185

m_i = (number of nozzles n_i) x (flow rate per nozzle)
where i = 1, 2, 3...

Conservatively, no credit for drop fall height in the directly sprayed regions below the operating floor was taken. Based on these assumptions a conservative mean drop fall height of 65.64 ft was calculated.

6.5.2.4 Tests and Inspections

[HISTORICAL INFORMATION] [The CSS spray nozzles may be tested by connecting a smoke generator to a normally capped test connection on the spray header, or by attaching streamers to the nozzles and blowing air out the nozzles.] Further testing and inspection of the CSS is described in subsection 6.2.2.

6.5.2.5 Instrumentation Requirements

Instrumentation requirements for the CSS are discussed in subsection 7.3.1.1.4.

6.5.2.6 Materials

There are no spray additives used in the CSS.

6.5.3 Fission Product Control Systems

6.5.3.1 Primary Containment

The primary containment structure consists of a reinforced concrete cylinder and hemispherical dome, lined with welded steel plates, forming a continuous, leaktight, membrane. Details of the primary containment structural design are discussed in Section 3.8. The primary containment pressure suppression concept is the GE Mark III design. Layouts of the primary containment structure and the combustible gas control system are given in the general arrangement drawings of Section 1.2.

The primary containment walls, liner plate, mechanical penetrations, isolation valves, hatches, and locks function to limit release of radioactive materials, subsequent to postulated accidents, such that the resulting offsite doses are less than the guideline values of 10 CFR 50.67. Primary containment parameters affecting fission product release accident analyses are given in Table 6.5-6.

Long term primary containment pressure response to the design basis accident is discussed in subsection 6.2.1.

Redundant, safety-related hydrogen recombiners are provided in the primary containment as a backup means of controlling post-accident hydrogen concentrations. A hydrogen ignition system is provided to maintain the hydrogen concentration below its detonable limit during a degraded core accident. A hydrogen purge system is provided for backup hydrogen control. Details of the post-accident hydrogen control system are discussed in subsection 6.2.5.

During normal operation, the primary containment is vented as discussed in subsection 9.4.7.2.2. These normal primary containment ventilation supply and exhaust system penetrations are automatically isolated in response to LOCA signals (high drywell pressure and low reactor water level). The penetrations are provided with redundant, seismic Category I, air operated, fail-closed, ASME Code, Section III, Class 2 butterfly valves, which assure prompt and tight closure of the openings. In the event that the primary containment is being purged at a higher than normal rate through the containment cooling system charcoal filter trains, prompt and tight closure of these penetrations will also be assured by similar containment isolation valves. Refer to subsection 9.4.7 for a description of the containment ventilation system.

6.5.3.2 Secondary Containment

The secondary containment boundary region is as follows:

a. The volume enclosed by the exterior walls and roof of the auxiliary building, including the fuel handling area and the main steam tunnel

b. b.The volume enclosed by the metal siding enclosure building around the containment above the auxiliary building roofline

The boundary region is shown in the following figures:

Figure	Title
1.2-2	General Arrangement, Plan at El 93'-0" & 100'-9"
1.2-3	General Arrangement, Plan at El 113'-0", 111' 0", 119'-0", 120'-0", & 114'-6"
1.2-4	General Arrangement, Plan at 133'-0", 148'-0", 139-0", 135'-4" & 147'-7"
1.2-5	General Arrangement, Plan at El 166'-0" 161'-10", & 170'-0"

Main steam line isolation valve and feedwater line leakage control systems are provided and are discussed in subsections 6.7.1 and 6.7.2.

The standby gas treatment system (SGTS) limits release to the environment of radioisotopes which may leak from the primary containment, the fuel handling area, ECCS systems, main steam isolation valve leakage control system, and other potentially radioactive sources to the secondary containment region under accident conditions. The standby gas treatment system has the following safety design bases:

a. The standby gas treatment system is of seismic Category I design.

b. To meet single failure criteria, the SGTS, including ductwork, is completely redundant and missile protected (see Table 6.5-7).

c. The redundant equipment is connected to separate engineered safety features buses to allow uninterrupted operation of the system in the event of the loss of normal power.

d. The standby gas treatment system is designed to limit the thyroid and the whole body dose to within the guidelines of 10 CFR 50.67 at the site boundary (exclusion area boundary) and the low population zone outer boundary.

e. The standby gas treatment system meets the quality assurance requirements of an engineered safety features system.

f. The standby gas treatment system charcoal filter trains are designed in accordance with the intent and the interpretation of NRC Regulatory Guide 1.52 (see Appendix 3A and subsection 6.5.1).

g. The standby gas treatment system is classified as Quality Group B, Safety Class 2.

h. The standby gas treatment system is designed to maintain a 1/4 inch wg negative pressure in the SGTS boundary region and prevent exfiltration at wind speeds less than or equal to 10 mph.

i. The standby gas treatment system is designed to achieve the design negative pressure in the boundary region within 120 seconds after actuation.

j. The standby gas treatment system is designed to provide a minimum mixing ratio of enclosure building air to auxiliary building air of 3:1 for the design long-term operation flow rate of 4,000 cfm.

k. The standby gas treatment system is subject to a program of preoperational testing and post operational surveillance.

The standby gas treatment system is shown in Figures 6.5-2 and 6.5-3. System flow parameters are tabulated in Figure 6.5-4. Components are described in Table 6.5-8. The standby gas treatment system consists of the following:

a. Two, 100 percent capacity enclosure building recirculation fans

b. Two, 100 percent capacity charcoal filter trains, each consisting of:

   Demister
   Electric heater
   Prefilter
   High efficiency particulate air (HEPA) filter
   Charcoal adsorber
   HEPA filter
   Centrifugal fan with inlet flow control vanes

c. Two, fully redundant sets of ductwork, dampers, and controls

The standby gas treatment system charcoal filter trains are located in the auxiliary building at El. 139'-0" in an area

designated as radiation Zone B during normal plant operation. The enclosure building recirculation fans are located in the auxiliary building at El. 208'-10" in an area designated as radiation Zone B during normal plant operation.

The standby gas treatment system is designed to reduce the activity level at the SGTS boundary region release point following an accident which could result in abnormally high airborne activity in the region. The performance objective is to limit the thyroid and the whole body doses within the guidelines of 10 CFR 50.67 at the site boundary (exclusion area boundary) and the low population zone, outer boundary, and 10 CFR 50, General Design Criterion 19, for control room operator doses. The SGTS has been provided with a wide range of flow capabilities to ensure that secondary containment integrity is maintained under design conditions and to provide design margins for greater than design winds or infiltration. Doses have been analyzed for the full range of SGTS flow rates and have been verified to meet the referenced guidelines.

The system draws air from the Auxiliary Building, mixes this air with air from the Enclosure Building, and returns the mixed air to the Enclosure Building. A portion of the mixed air is exhausted via the charcoal filter assembly to maintain the SGTS boundary region at a negative pressure.

To ensure that adequate mixing is achieved by the recirculation fans, the following special considerations are given in the design:

a. Air velocities in the mixing portion of the system ductwork are sufficiently high to produce a Reynolds number well within the region of fully turbulent flow.

b. The recirculation fans mix a quantity of air from the enclosure building with the air drawn from the lower regions of the auxiliary building. At the maximum available flow of 4,000 cfm during the long term, the mixing ratio is greater than 3:1.

c. The system recirculates the enclosure building atmosphere at a rate equal to at least 1-1/2 enclosure building free volumes per hour.

d. Distribution and return ductwork in the enclosure building is designed to minimize the existence of stagnant areas. Exit velocities from distribution ducts are such that a significant amount of air is entrained by the discharge airstream.

e. Exhaust air to the charcoal filter trains is drawn from the downstream side of the recirculation fans to take advantage of additional mixing within the fan itself.

Because the system is designed to achieve mixing prior to exhausting, there is no requirement that mixing air be returned to the individual volumes of the SGTS boundary region. As long as the SGTS boundary region is isolated and under a negative pressure, there is no direct bypass of unmixed and unfiltered air to the environment. Refer to subsection 6.2.3 for a discussion of secondary containment bypass leakage. Similarly, air will not be directly exhausted from volumes such as penetration or ECCS pump rooms which are interior areas within the SGTS boundary region. Instead, the outer walls of the boundary region are the pressure interface, and isolated volumes which are adjacent to this outer boundary are individually exhausted.

Based on the above, 50 percent mixing is assumed in the enclosure building for dose calculations involving operation of the SGTS.

The sizing of the SGTS equipment and components is based on the results of an infiltration analysis as well as an exfiltration analysis of the auxiliary and enclosure building structures. The internal pressure of the SGTS boundary region is maintained at a negative pressure of 1/4 inch wg when the system is in operation, which represents the internal negative pressure required to ensure zero exfiltration of air from the building when exposed to a 10 mph wind blowing at an angle of 45 degrees to the building. [HISTORICAL INFORMATION] [According to Wind Tunnel Studies of Pressure Distribution on Elementary Building Forms, by Chien, et al (Ref. 11), for a similar building configuration and a specific wind direction, there are portions of the building which could be subjected to external negative pressures as high as a factor of five times the velocity pressure of the associated wind speed.] The negative 1/4 inch wg internal pressure, therefore, corresponds to the pressure required to prevent the external pressure from being below the internal pressure up to a wind speed of 10 mph.

The exhaust flow rate required to maintain the boundary region at 1/4 inch wg negative pressure has been calculated based on the leakage rate data presented in NRC Research and Development Report NAA-SR-10100, Conventional Buildings for Reactor Containment (Ref. 5). This flow rate corresponds to the long-term exhaust rate required for the SGTS charcoal filter train exhaust fans. The SGTS has the capability to operate at 4,000 cfm long term with 99 percent iodine removal efficiency. An exfiltration analysis was performed assuming that this maximum long-term exhaust rate was available.

As stated above, due to the amplification effects associated with the building geometry, exfiltration from the enclosure and the auxiliary buildings may occur at wind speeds in excess of 10 mph. A specific exfiltration analysis was performed for a windspeed at the elevation of the enclosure building roof to determine the impact of exfiltration on the site boundary dose. Exfiltration rates were calculated for the areas of the building where the resulting external pressure was below that in the building as generated by SGTS operation. A conservative factor of two was

applied to the exfiltration rate and the resulting rate was used in analyzing the consequences of this occurrence.
This analysis of exfiltration potential has shown that the expected exfiltration rate is less than 1 scfm.

An analysis of the dose effects of 1 scfm exfiltration using χ/Qs developed from the 15.9 mph windspeed and Pasquill E conditions has shown that the doses would be insignificant.

A leakage of even 100 scfm at the above conditions would result in a total 2-hour dose at the site boundary well within the guidelines of 10 CFR 50.67; therefore, the exfiltration contribution even at a rate much larger than the calculated value falls within acceptable guidelines.

The drawdown analysis takes into account the effects of internal heat gains due to lights, equipment, and piping and conservatively calculates the drawdown time. Assumptions and results of a drawdown analysis are given in subsection 6.2.3.

The drawdown rates and long-term exhaust rates have been individually determined for the several discrete volumes of the SGTS boundary, in order to account accurately for the differences in building construction, hence leaktightness of the structure. By properly apportioning the exhaust rates throughout the building, the entire boundary region is uniformly maintained at the design negative pressure.

The standby gas treatment system charcoal filter trains are designed in accordance with the intent and the interpretation of NRC Regulatory Guide 1.52 in order to obtain credit for 99 percent removal efficiency of elemental iodine and organic iodide. To account for unidentified leakage which could potentially bypass the Standby Gas Treatment System (SGTS), a bypass leakage (i.e. a leak from the secondary containment directly to the environment) of 1 scfm was incorporated into the Design Basis Accident (DBA) LOCA offsite dose analysis. The bypass leakage was assumed to coincide with the initiation of the SGTS and continue for the duration of the accident. It should by noted that the bypass leakage which was assumed in the DBA LOCA offsite dose analysis

does not apply exclusively to the SGTS effluent. The assumed bypass leakage envelopes all possible unfiltered leakage including the possible contribution from the SGTS effluent. The trains consist of the following sequential components:

Demister	Remove entrained water
Electric heater	Reduce relative humidity of entering airstream to less than 70 percent
Prefilter	Remove large particulate matter from entering airstream
HEPA filter	Remove fine particulate matter and protect the charcoal from fouling
Charcoal adsorber	Remove gaseous elemental iodine and organic iodides
HEPA filter	Collect any carbon fines exhausted from charcoal adsorber beds

Details of these components are provided in Table 6.5-8.

The demister and heater installed on each filter train function to remove entrained moisture and are sized to reduce the humidity of an incoming 4,000 cfm of air from 100 percent to 70 percent. The SGTS exhausts from corridor areas of the secondary containment. Locations of the SGTS exhaust headers are shown in Figure 2.1-2. Lines carrying high temperature fluids in the auxiliary building are located either in the RWCU pump rooms, the ECCS rooms, or in the steam tunnel. They are isolated from the corridor areas by normally closed doors and hatches. For small breaks or leakage in the ECCS rooms, the emergency room coolers in each room would assist in condensing ECCS system leakage from the room atmosphere before any air leakage from the isolated space is transported by the SGTS duct network. In the unlikely event that the operating filter train became excessively moisture laden, the performance degradation would be evident by high differential pressure alarms, radiation effluent alarms, and, if severe enough, by the start of the standby filter train, due to low flow, as described in subsection 7.3.1.1.8. The design and redundancy of the standby gas treatment system will ensure operability of the system for postulated releases of high temperature fluids into the secondary containment during the design basis loss-of-coolant accident.

For large breaks outside of primary containment, the fission product transport pathway analyzed is a direct unfiltered release to the environment, as explained in subsection 15.6.4.5.2, and no credit is taken for the operation of the SGTS.

The charcoal beds are of all-welded, gasketless construction, nominally 8 inches deep. Charcoal is impregnated coconut shell, 8 x 16 Tyler mesh, having chemical and physical properties which are rated, tested, and qualified in accordance with the requirements of NRC Regulatory Guide 1.52. Refer to subsection 6.5.1 for additional discussion of these items.

In consideration of the possibility of iodine desorption and charcoal ignition at elevated temperatures, a water spray system is provided for the charcoal adsorber section of the SGTS charcoal filter trains. In order to detect any abnormal temperature rise at the outlet of the charcoal adsorber, each charcoal bed is provided with temperature sensors. At the first set point there is an alarm in the control room which alerts the operator that an off-design temperature level exists. When the second set point is reached, another alarm sounds alerting the operator such that actions may be taken to manually shutdown the exhaust fan. Manual actuation of the deluge spray system can be accomplished locally. The water deluge system is of seismic Category I design.

A radiation monitoring system is also provided for SGTS A & B to monitor the effluent radioactivity releases to the environment. For a further discussion of this system, refer to subsection 11.5.2.2.9.

In addition to the instrumentation described above, the filter trains are instrumented to indicate differential pressure across each element of the filter train. Differential pressure is recorded and an alarm provided in the control room for the HEPA filters and the charcoal adsorber. The fan flow rate is recorded in the control room. A low flow switch automatically initiates the standby filter system. Refer to subsection 7.3.1.1.8 for further discussion of the instruments and controls of the SGTS.

6.5.3.3 SGTS Operation

During normal plant operation, the standby gas treatment system does not operate except for regularly scheduled testing prescribed by the Technical Specifications. Post-operational surveillance is as defined by the Technical Specifications and Regulatory Guide 1.52.

The standby gas treatment system automatically starts and operates in response to the following signals:

a. High pressure in the drywell

b. Low water level in the reactor vessel

c. High radiation in the fuel handling area ventilation system exhaust or the fuel pool sweep system exhaust

Following any of these standby gas treatment system actuation signals, both enclosure building recirculation fans, if available, and both charcoal filter train fans, if available, start. All ventilation penetrations through the auxiliary building walls, including fuel handling area penetrations, are automatically closed on a. or b. above. Closure of the fuel handling area ventilation penetration isolation valves actuates non-safety related limit switches and automatically shuts down the following equipment:

a. Fuel handling area supply fan

b. Fuel handling area exhaust fan

c. Fuel pool sweep supply fan (if operating)

d. Fuel pool sweep exhaust fan (if operating)

e. Fuel handling area fan coil units

f. Auxiliary building ventilation fans

The non-safety related shutdown feature is provided for non-safety related equipment protection and to limit the potential impact on the building's airflow patterns and pressure profiles. On the other hand, should the ventilation equipment continue to

operate, the function of the standby gas treatment system is not impacted. The building's airflow patterns and pressure profiles would be altered; however, the impact of their alteration is negligible and does not affect the function of the standby gas treatment system.

The SGTS is also capable of being manually initiated from the control room.

Standby gas treatment system flows are controlled by modulating inlet vanes installed on the charcoal filter train exhaust fans and two-position volume control dampers installed in branch ducts to individual regions of the secondary containment boundary. The volume control dampers are set to control the flow distribution from various areas within the secondary containment boundary.

To meet the 180-second drawdown time analyzed in Section 15.6, initially the full capacity of the exhaust fan is utilized. Upon receiving a start signal, the inlet vanes and volume control dampers assume the fully open position. As described in subsection 6.2.3.3, the design negative pressure will be established (single train operation assumed). After the region has been drawn down to the design negative pressure, motor-operated dampers located in the SGTS ductwork automatically throttle to their intermediate positions This ensures that the volume of air flowing from each discrete area of the boundary region is equal to the volume of air infiltrated when at the design negative pressure. After the system has operated at full fan capacity for 120 seconds, operation of the SGTS charcoal filter train exhaust fan is transferred to the flow controller where post-drawdown flow is maintained by modulating the motor-operated flow control vanes to a flow rate no greater than 4000 cfm. This flow rate corresponds to a 99 percent efficiency rating for the charcoal filters and has been analyzed for doses. Thus, significant conservatism has been designed into the system. An interlock causes these signals to be applied prior to the end of the 120 second period if the Enclosure Building Negative Pressure High alarm setpoint is reached.

If building negative pressure is lost during long-term operation, the pressure controller will also cycle the volume control dampers to the fully open position. A time delay for return to the intermediate position is utilized in the control circuit to avoid continuous cycling of the dampers. The time delay will limit damper operation to 25 percent duty, but will have no effect on the modulation of the fan inlet vanes.

When the design negative pressure is achieved in the SGTS boundary region, the operator is alerted that one recirculation fan and one exhaust fan (if both trains are operable) may be placed in a standby mode. Extensive information on the status of the SGTS is readily available to the control room operator. Position indications consisting of distinctively colored lights for each of the three damper positions, closed, intermediate, and open, is provided for each damper. An "out of service" annunciator warns of loss of control power to any motor-operated damper in the system, damper motor overload, loss of control power for the trip circuit, loss of instrument power when an SGTS system is placed in standby or when the trip units are in calibration or out of file. An "SGTS in operation" annunciator alerts the operator when SGTS is running. To receive the annunciator, the filter train inlet and outlet dampers and all 11 volume control dampers must be open; and the containment cooling system, auxiliary building HVAC, and fuel handling area isolation dampers must be closed. Without all of these conditions, the annunciator signal will not be generated. Additional alarms, indicators, and status lights are provided to monitor filter fan performance. Controls and instruments are described in detail in subsection 7.3.1.1.8. The operator will review the status of the systems prior to selecting the standby filter train. This operation must be performed manually.

A system which is in a standby mode automatically restarts in response to a low flow signal from the discharge of the operating enclosure building recirculation fan, a low flow signal from the discharge of the operating charcoal filter train exhaust fan, or low negative pressure. If one train is inoperative, the remaining train is adequate to achieve all design objectives.

6.5.3.4 SGTS Failure Modes and Effects Analysis

Primary protection against any postulated failure of the standby gas treatment system is provided by the completely redundant design of the system. Each train of the SGTS is independently capable of meeting the system design objectives and is provided with a 100 percent capacity filter train, recirculation fan, exhaust fan, ductwork, and associated instrumentation and controls. As described in subsection 6.5.3.3, any of the SGTS actuation signals automatically start both trains of the system. This action ensures that at least one system will start and draw down the secondary containment boundary to the design negative pressure within the 120 seconds analyzed. During long-term operation, one of the systems is manually placed in a standby mode. The filter train selected as the standby system will automatically start and will operate in the event of a major component failure, degradation of operating system performance due to exhaustion of the filter train, or upon a loss of power in the electrical division serving the operating system. Component malfunctions that result in operation of the standby SGTS train are summarized in Table 6.5-7.

In addition to the component malfunctions described in Table 6.5-7, component malfunctions that would not affect the SGTS operation severely enough to automatically start the standby filter train and recirculation fan have been reviewed. These malfunctions include perforation or deformation of the SGTS ductwork and failure of a volume control damper.

As shown by Figure 6.5-4, standby gas treatment system flow from the auxiliary building to the enclosure building is maintained by a 17,000 cfm capacity recirculation fan. The connecting ductwork from the various areas of the auxiliary building to the recirculation fan is sized for flows from each area that comprise the drawdown flow rate. To provide balanced flows and equalize pressures within the auxiliary building post-drawdown, when the design negative pressure can be maintained with a lower flow rate, motor-operated two-position volume control dampers are installed in each branch duct and in the main trunk to the recirculation fan. The normal (SGTS not operating) position of the volume

control dampers is closed. Upon system start, all dampers assume the fully open position until the design negative pressure is established. The dampers then assume the intermediate position, as required for long-term operation.

If necessary to maintain the negative pressure during the long term, the dampers will assume the full open position required for high system flows. However, the dampers will not return to the closed position unless the associated SGTS train is shut down or placed in the standby mode. Since the motor-operated dampers would fail as is, the failure position of the damper would be determined by the SGTS mode of operation at the time of failure.

For a volume control damper to fail in the closed position, an undetected failure would have to occur during system shutdown. Since both 100 percent capacity trains of the SGTS start automatically upon receipt of any of the system initiation signals described in subsection 6.5.3.3, failure of a volume control damper in the closed position would have no effect on initial drawdown. The failure of the damper would be evident to the operator by position indication and the lack of the associated "SGTS in operation" annunciator. After initial drawdown, one of the SGTS trains will be manually placed on standby. Prior to selecting the single filter train to operate during the long term, the operator will review the system status and the unaffected filter train will be selected for continued running. Therefore, a failed closed volume control damper will not affect the safety of the plant.

An auxiliary building volume control damper failed in the open position could affect the air flow balance of the SGTS and, consequently, pressure distribution in the secondary containment during system post-drawdown operation. Exhaust flow from the area served by the failed volume control damper would increase. It is anticipated that the maximum flow increase that could occur in any one area of the auxiliary building would be approximately equal to 20 percent of the total auxiliary building air flow to the enclosure building and 2 percent of the total capacity of the recirculation fan. The resultant decrease in exhaust flows from other areas of the secondary containment will be distributed

among all areas with dampers in the intermediate position until a flow distribution equilibrium is established due to flow-induced pressure losses.

The standby gas treatment system air flow is taken from corridors and general areas within the auxiliary building, rather than from specific rooms. These areas communicate through stairwells, an elevator shaft and the equipment hatches. Therefore, the effect of a stuck open volume control damper on the pressure distribution through areas of the auxiliary building will be minimized. The effect of a stuck open volume control damper on air flows within the enclosure building will be negligible.

Volume control dampers assume the intermediate position only after initial drawdown. Therefore, a damper failure in the intermediate position could not affect operation of the SGTS during drawdown. During long-term operation, the volume control dampers will maintain the intermediate position to provide the design flow, unless wind gusts in excess of 10 mph or unexpected leakages occur. If the design negative pressure cannot be maintained by increasing the opening of the fan inlet vanes, the system will automatically fully open the control dampers to reduce flow losses. If this demand for large air flows were generated, a damper stuck in the intermediate position would decrease exhaust flow from the affected area. Again, the effect on pressure distribution would be minimized by communication between the auxiliary building areas and by the conservative sizing of the recirculation fan. In any event, some negative pressure would exist in the affected area, and at worst, exfiltration results should not exceed those described in subsections 6.5.3.2 and 6.2.3.3.

Although an individual volume control damper that failed in a nonconforming position would have minimal effect on the overall operation of the system, the malfunction would be indicated and annunciated in the control room, and the operator would manually shift operation to the standby filter train.

Perforation or deformation of SGTS ductwork is unlikely, because the ductwork is seismic Category I and missile protected.

However, unless the failure is severe enough to start the standby filter train, as summarized in Table 6.5-7, the effect on SGTS operation would be similar to a damper stuck in a nonconforming position. The maximum effect would be a minimal change in pressure distribution if a perforation occurred between a volume control damper and the main duct. A perforation upstream of a volume control damper would have negligible effect.

6.5.4 Ice Condenser as a Fission Product Cleanup System

This Section is not applicable to GGNS.

6.5.5 Pressure Suppression Pool as a Fission Product Cleanup System

Standard Review Plan (SRP) 6.5.5, "Pressure Suppression Pool as a Fission Product Cleanup System" allows credit for the pressure suppression pool as a fission product cleanup system. The guidance in this SRP replaces the guidance provided in Regulatory Guide 1.3 Position C.1.f. In accordance with the guidance provided in this SRP, suppression pool scrubbing credit is allowed if:

a. The drywell and its penetrations are designed to ensure that, even with a single active failure, all releases from the reactor core must pass into the suppression pool, except for a small bypass fraction.

b. The bypass leakage assumed for purposes of evaluating fission product retention must be demonstrated in periodic tests by the licensee technical specifications.

c. For plants with a construction permit, the iodine retention calculated using SRP 6.5.5 must not be used to justify the removal of the standby gas treatment or other filtered exhaust system from status as an engineered safety feature.

d. Any change in plant design, proposed testing, surveillance or maintenance must be supported by considerations of lowered operator dose and other projected benefits.

e. Charcoal filters must be at least maintained to the minimum level of Table 2 of Regulatory Guide 1.52, Revision 2.

f. Acceptance criteria for containment leakage and engineered safety features atmospheric cleanup systems must be unchanged.

g. A decontamination factor (DF) of 10 for elemental and particulate iodine is allowed without additional calculational support for Mark III containments.

As noted above, SRP 6.5.5 allows a factor of 10 reduction in elemental and particulate iodine passing through the suppression pool without calculation provided certain design and operational conditions are met. GGNS meets these conditions as discussed below. The design of the GGNS drywell and its penetrations ensure all releases from the reactor core except for a small bypass fraction pass through the suppression pool even with the consideration of a single failure. This design complies with Criteria 1 of SRP 6.5.5. The allowable drywell bypass leakage is demonstrated by performance of periodic testing in accordance with GGNS Technical Specification. his testing complies with Criteria 2 of SRP 6.5.5.

Any credit taken for suppression pool scrubbing is discussed in the design basis analysis in Section 15.6.5.

6.5.6 References

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9. Regulatory Guide 1.52, "Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water Cooled Nuclear Power Plants," Revision 1, July 1976.

10. ORNL-NSIC-65, "Design, Construction, and Testing of High Efficiency Air Filtration Systems for Nuclear Application," Oak Ridge National Laboratory, January, 1970.

11. Chien, et al, "Wind Tunnel Studies of Pressure Distribution on Elementary Building Forms," Iowa Institute of Hydraulic Research, State University of Iowa, 1951.

12. ANSI N510-1975, “Testing of Nuclear Air-Cleaning Systems,” June, 1975.

13. ANSI N101.0-1972, “Efficiency Testing of Air Cleaning Systems Containing Devices for Removal of Particulates,” 1972.

14. USNRC Report DP-1082, “Standardized Non-Destructive Test of Carbon Beds for Reactor Confinement Application,” Savannah River Laboratory, July 1967.

15. Standard Review Plan (SRP) 6.5.5,”Pressure Suppression Pool as a Fission Product Cleanup System”, Revision 0, December 1988.

TABLE 6.5-1: ESF FILTER SYSTEM DESIGN PARAMETERS

Component	Units Installed	Unit Capacity	Units Required for Operation
Control Room Standby Fresh Air System Filter Trains			
Filter units	2		1
Fans, per filter unit:	1		1
capacity, ft^3/min		4,000	
total pressure, in. wg		12.6	
motor, hp.		20	
Prefilters, per filter unit:	4		4
capacity, ft^3/min.		1,000	
HEPA filters, per filter unit:	8		8
capacity, ft^3/min.		1,000	
Demisters, per filter unit:	4		4
capacity, ft^3/min.		1,000	
Electric heaters, per filter unit:	1		1
capacity, kW		20.7	
Unused Charcoal trays (2"), per unit:	12		12
capacity, ft^3/min		334	
Standby Gas Treatment System Charcoal Filter Trains			
Filter units	2		1
Fans, per filter unit:	1		1

TABLE 6.5-1: ESF FILTER SYSTEM DESIGN PARAMETERS (Continued)

Component	Units Installed	Unit Capacity	Units Required for Operation
capacity ft^3/min.,		>4000/	
drawdown/long term		4000 max.	
total pressure, in. wg		13.0	
motor, hp.		20	
Prefilters, per filter unit:	4		4
capacity, ft^3/min.		1,000	
HEPA filters, per unit:	8		8
capacity, ft^3/min		1,000	
Demisters, per filter unit:	4		4
capacity, ft^3/min.		1,000	
Electric heaters, per unit:	1		1
capacity, kW		48	
Charcoal (8") per filter unit, lbs.	2746		2746

TABLE 6.5-2: ESF FILTER SYSTEM MATERIAL

Component	Material	Quantity	Composition
Control Room Standby Fresh Air System			
Demister			
Media	Fiber glass	--	-
Casing	Hot dip galv	--	-
Spacer	302/304 SS	--	-
Heater			
Sheath	Chrome steel	--	
Prefilter			
Media	Fiber glass		
Casing	Galvanized steel	--	-
HEPA filters			
Media	Fiber glass (MIL-F51079)	--	-
Casing	Chromized Steel	--	-
Mounting frames	304 SS	--	-
Casing	Type 304 SS	--	-
Frame	Type 304 SS	--	-
Unit housing			
Shell	ASTM-A-569, 11 Ga	--	-
Interior coating	Mobil 89 Val-Chem Hi-build epoxy, 5-7 mils DFT; over Mobilzinc 7, 2-4 mils DFT	--	-
Exterior coating	Keeler & Long T-3-6280 Tri-Polar Enamel, 1.5-2.5	--	-

TABLE 6.5-2: ESF FILTER SYSTEM MATERIAL (Continued)

Component	Material	Quantity	Composition
	mils DFT; over Keeler and Long Tri-Polar No. 6000, 1-1.5 mils DFT		
Door gaskets	Neoprene	--	
Standby Gas Treatment System Filters			
Demister			
Media	Fiberglass	--	-
Casing	304 Stainless steel	--	-
Heater			
Sheath	Steel	--	-
Prefilter			
Media	Fiberglass	--	-
Casing	Chromized steel	--	-
Separators	Aluminum	--	-
HEPA filters			
Media	Fiberglass	--	-
Casing	Chromized steel	--	-
Face guard	Galvanized steel	--	-
Mounting frame	304 Stainless steel	--	-
Charcoal filters			
Media	Impregnated, activated coconut shell charcoal		
Casing	304 SS	--	-
Frame	304 SS	--	-

TABLE 6.5-2: ESF FILTER SYSTEM MATERIAL (Continued)

Component	Material	Quantity	Composition
Unit housing			
Shell	Carbon steel, A36	--	-
Interior coating	Mobil Val-Chem Hi-build epoxy, 89 Series, 5-7.0 mils DFT, over Mobilzinc 7, 1-3 mils DFT.	--	-
Exterior coating	Mobil Val-Chem Hi-build epoxy, series 89, 5-7 mils DFT, over Mobil 13-R-56, 1-3 mils DFT, underside coated with Koppers Bitumastic Black Solution or Gaco Neoprene Asphalt NA-62, by Gates Eng. Co.	--	-
Door Gaskets	Neoprene	--	-

TABLE 6.5-3: INPUT PARAMETERS FOR SPRAY IODINE REMOVAL ANALYSIS

Containment wall area above operating floor	$3.318 \times 10^4 ft^2$
Directly sprayed volume (above 208' 10")	$8.394 \times 10^5 ft^3$
Containment building net free volume	$1.4 \times 10^6 ft^3$
Spray fall height	65.64 ft.
Spray flow	5650 gpm

TABLE 6.5-4: Deleted

TABLE 6.5-5: Deleted

TABLE 6.5-6: PRIMARY CONTAINMENT OPERATION FOLLOWING A DESIGN BASIS ACCIDENT

General

Type of structure	Steel-lined, reinforced concrete cylinder and base with hemispherical dome
Internal fission product removal systems	Redundant containment water spray systems
Free volume of primary containment	1.4×10^6 ft^3 (excluding drywell) 1.67×10^6 ft^3 (including drywell)
Hydrogen purge system operation	See Subsection 6.2.5
Containment leakage rate:	
Vol%/day	0.35
Effectiveness of internal fission product removal systems	See Subsection 6.5.2

TABLE 6.5-7: SGTS FAILURE MODES AND EFFECTS ANALYSIS

Component	Malfunction	Comment
Enclosure building recirculation fan	Fan failure resulting in loss of airflow	Low flow switch will automatically shift to redundant train and fan
Filter train exhaust fan	Fan failure resulting in loss of airflow	Low flow switch will automatically shift to redundant train and fan
Electric heater	Heater failure resulting in overheating	Heater is equipped with thermal overload cutout switches
Filter train	Failure resulting in high differential pressure across HEPA or charcoal sections	High differential pressure is alarmed in control room. Operator may switch to redundant train
	Failure resulting in high temperature in charcoal bed	High temperature is alarmed in control room. Deluge system can be manually activated after a high ambient temperature is detected by fixed temperature sensors and alarmed on the security and fire protection system console. The operator may switch to redundant train.
Ductwork fan inlet vanes	Duct failure:	Redundant ductwork is provided
	Fail closed	Low airflow automatically starts redundant train

TABLE 6.5-7: SGTS FAILURE MODES AND EFFECTS ANALYSIS (Continued)

Component	Malfunction	Comment
	Fail open	High airflow causes excessive negative pressure in building which actuates an alarm. Upon alarm actuation, the control room operator can determine which system has failed (A or B) and remove it from service, allowing the other train to continue to operate.
Pressure sensor/ transmitter/ controller instruments	Instrument failure	Redundant instruments provided (see Table 7.3-27, SGTS FMEA)
Positioning Dampers	Fail closed	Redundant train achieves negative pressure. If second train is in standby mode when failure occurs, loss of airflow or low negative pressure starts redundant train.
	Fail open	Loss of low negative pressure signal opens filter train fan inlet vanes.

TABLE 6.5-8: SGTS CHARCOAL FILTER COMPONENT DESCRIPTION

1. Demister (each train)

Type	Woven mesh pads
Capacity, cfm	4000 per bank
Pressure drop, clean, in. wg.	0.5

2. Electric Heater (each train)

Type	Electric, finned tube
Quantity	One
Capacity, kW	48

3. Prefilters (each train)

Type	Dry
Quantity	One bank
Capacity, cfm	4000 per bank
Efficiency, %	90 ASHRAE 52
Pressure drop, clean, in. wg.	0.55

4. HEPA Filters (each train)

Type	High efficiency
Quantity	Two banks
Capacity, cfm	4000 per bank
Efficiency, %	99.97, DOP
Pressure drop, clean, in. wg.	1.0

5. Charcoal Adsorber (each train)

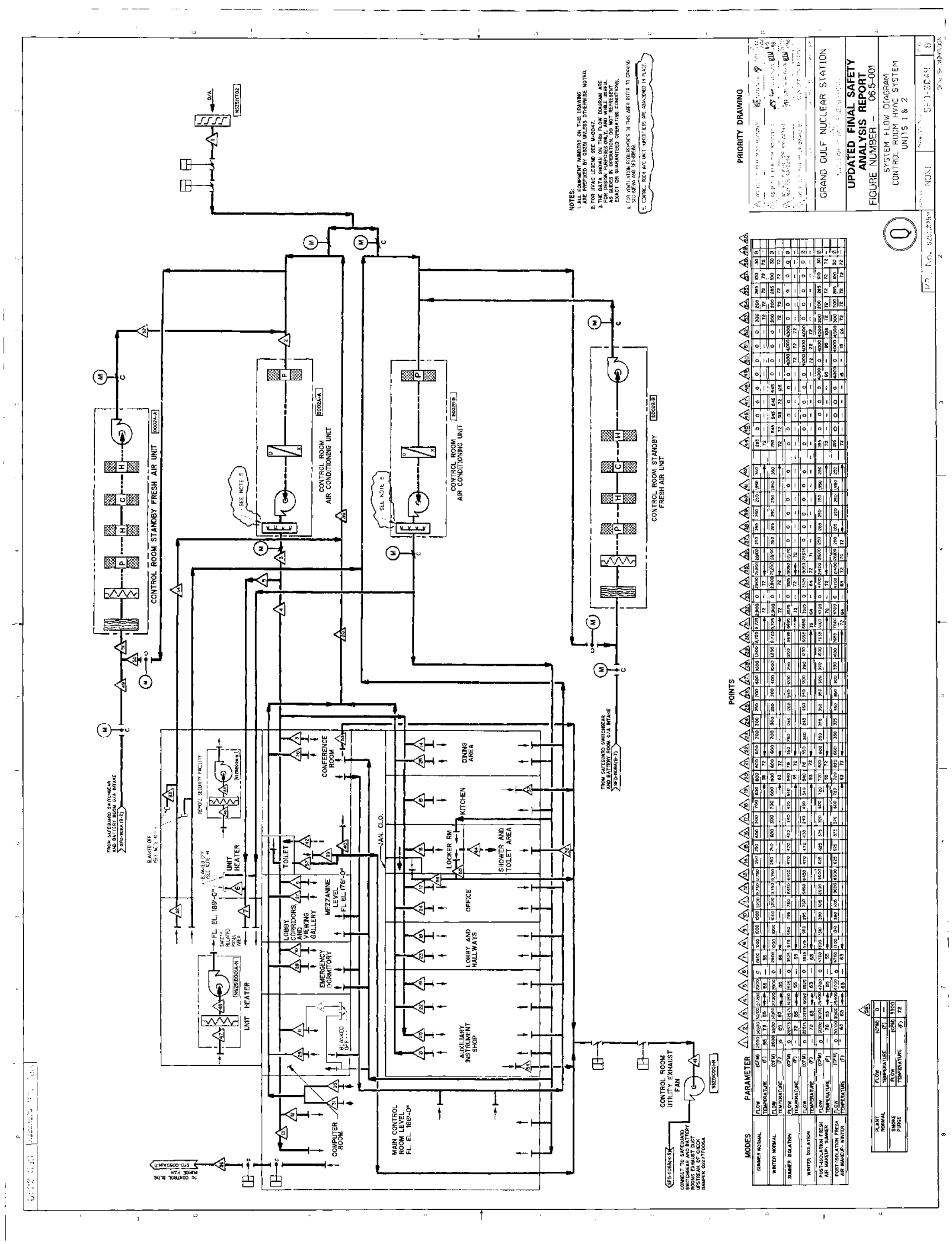
Type	Deep bed
Capacity, cfm	4000

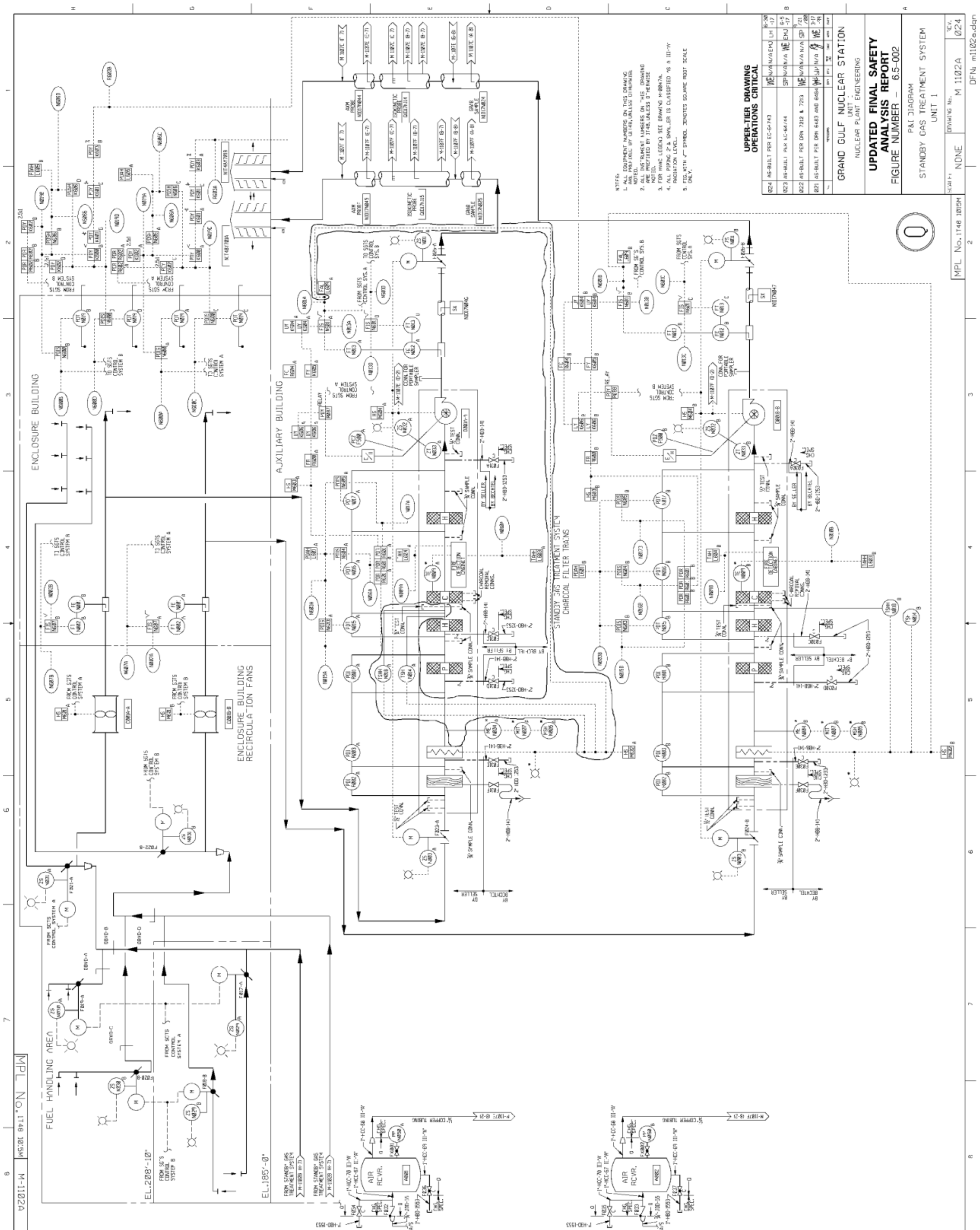
TABLE 6.5-8: SGTS CHARCOAL FILTER COMPONENT DESCRIPTION (Continued)

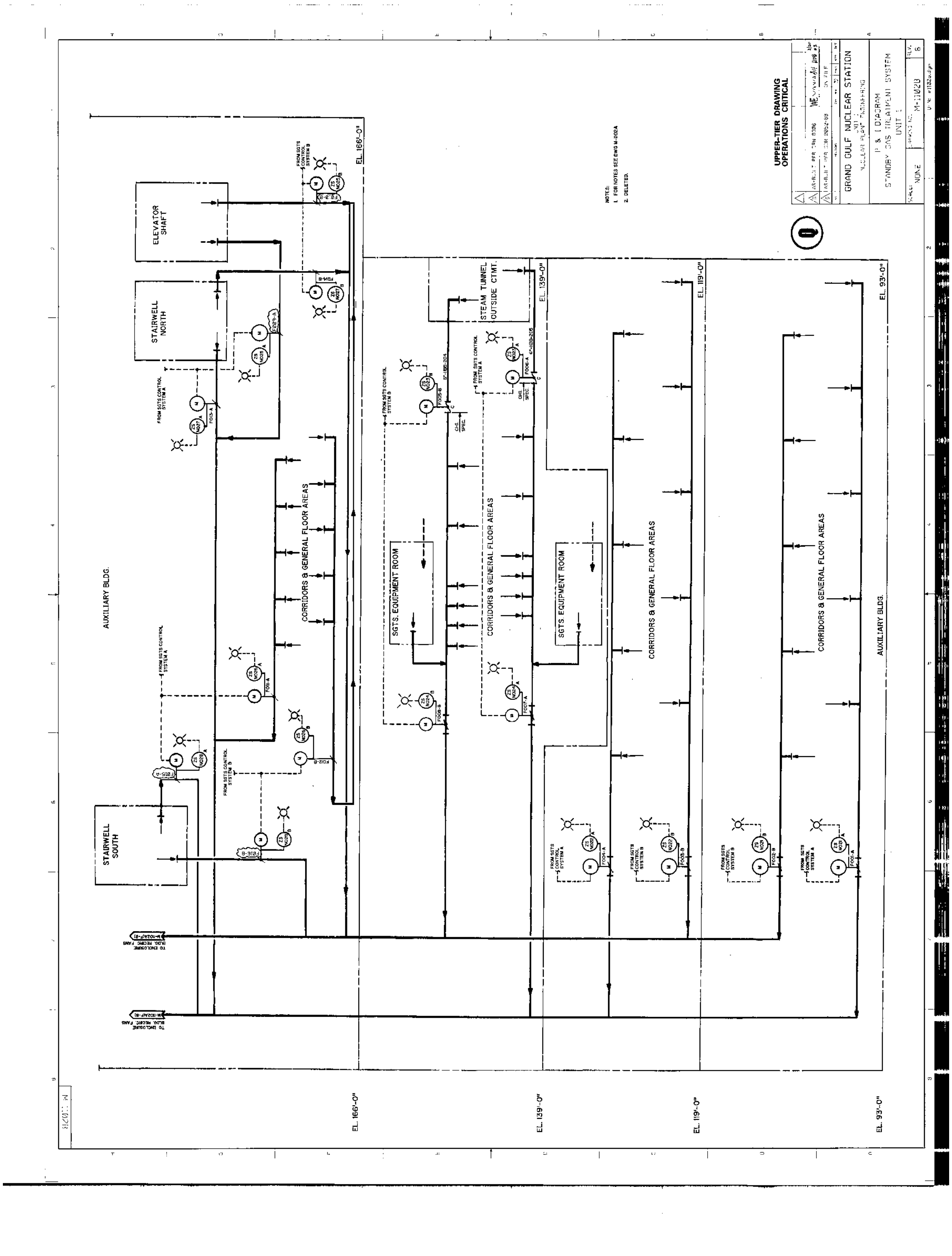
Media	Impregnated coconut shell
Efficiency credit, %	99, elemental iodine and organic iodide
Depth of bed, in.	8 nominal
Charcoal volume, ft^3	70.0 minimum
Face velocity, fpm	40
Residence time, sec.	1.0
Pressure drop, clean, in. wg.	4.4
Iodine desorption temp. range, F	250-300
Charcoal ignition temp., F	640 approx.
Charcoal density, gm/cc.	0.3 to 0.55
Impregnant content, % by weight	5 maximum
Charcoal size	8 x 16 Tyler mesh
distribution	nominal
Charcoal surface area, m/gm	1000 minimum
Charcoal moisture content efficiency, %	3 maximum
Charcoal ash content, %	6 maximum

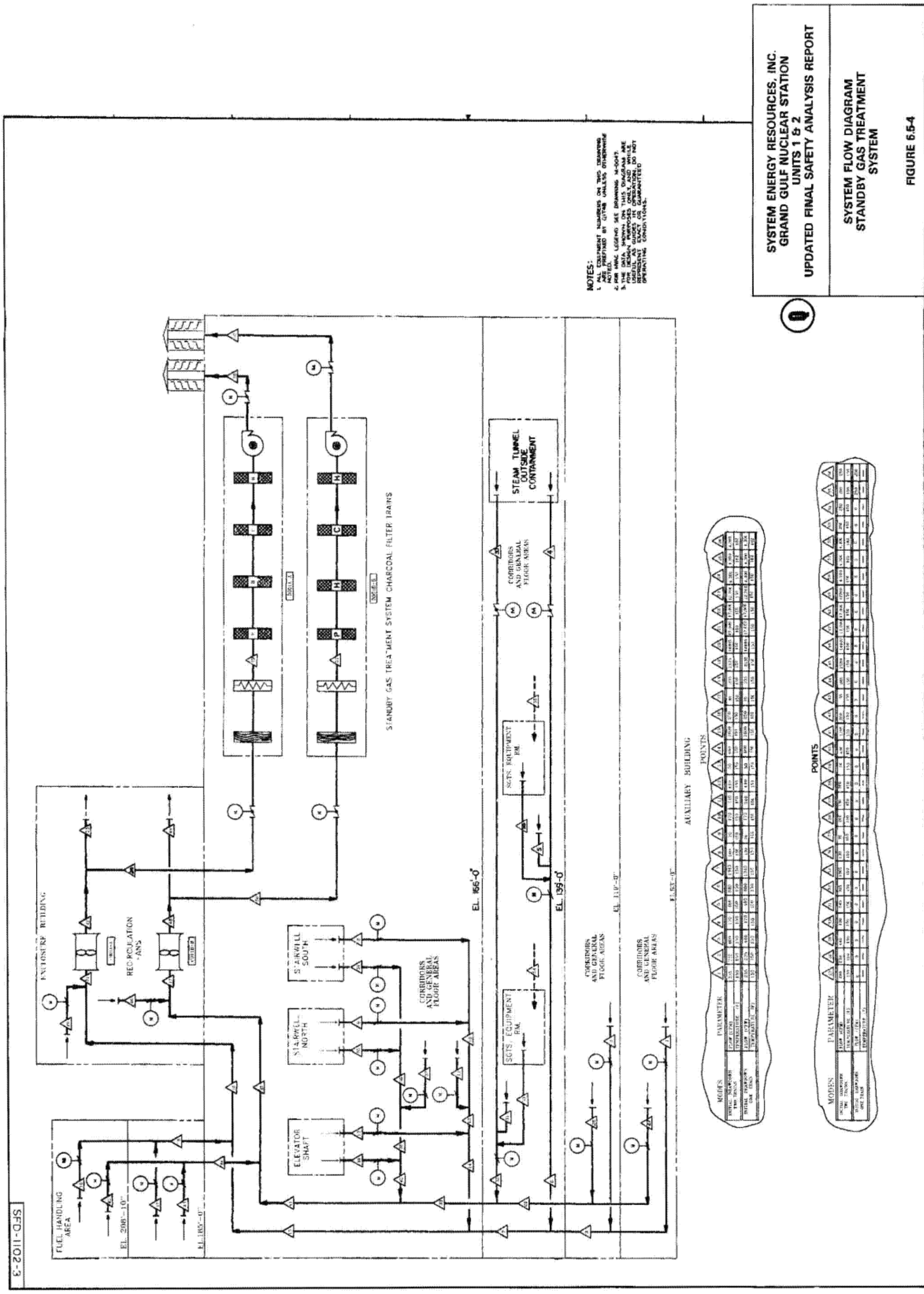
6. Exhaust Fan (each train)

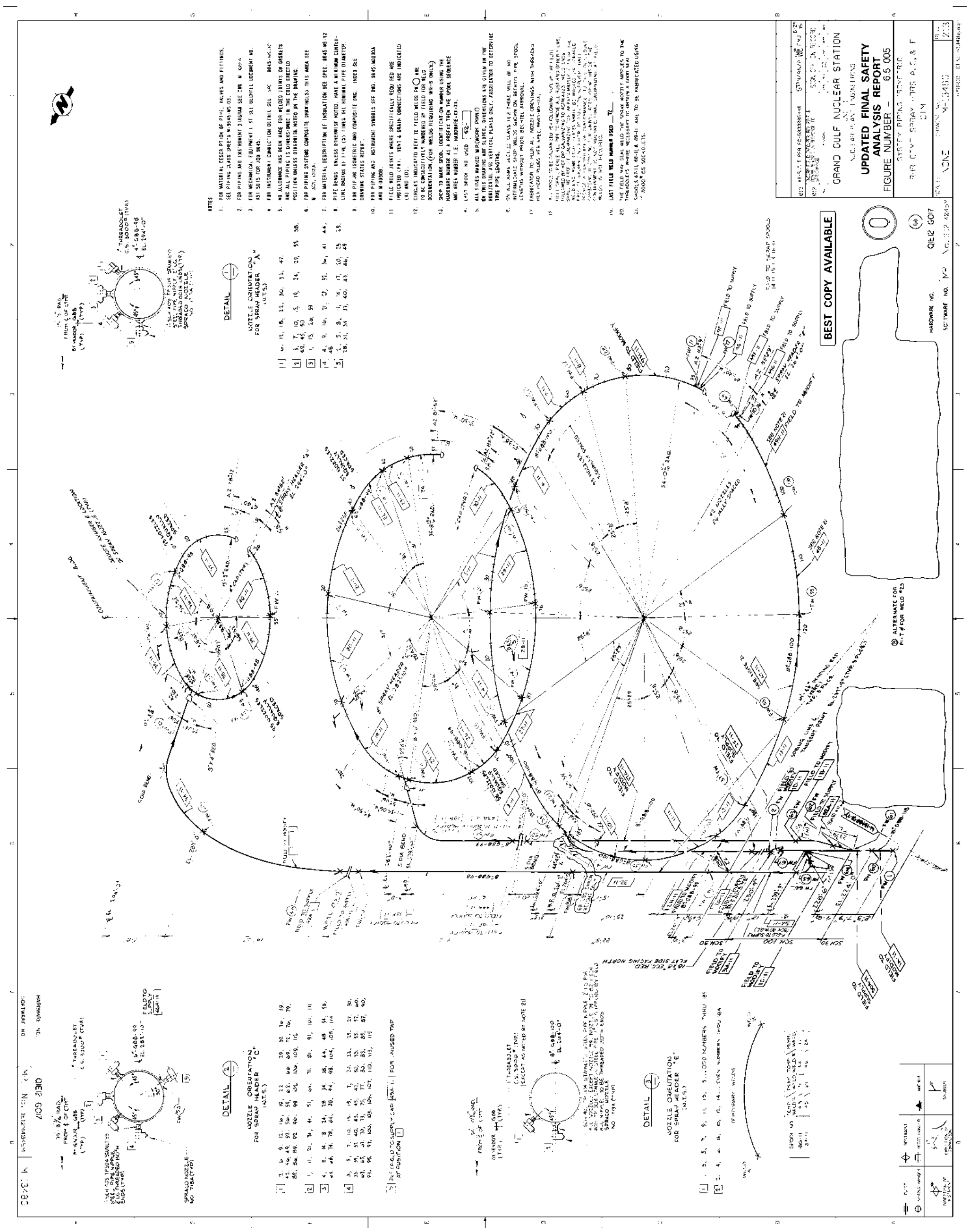
Type	Centrifugal SWSI
Quantity	One
Capacity, cfm, drawdown/long term	>4000/4000 max.

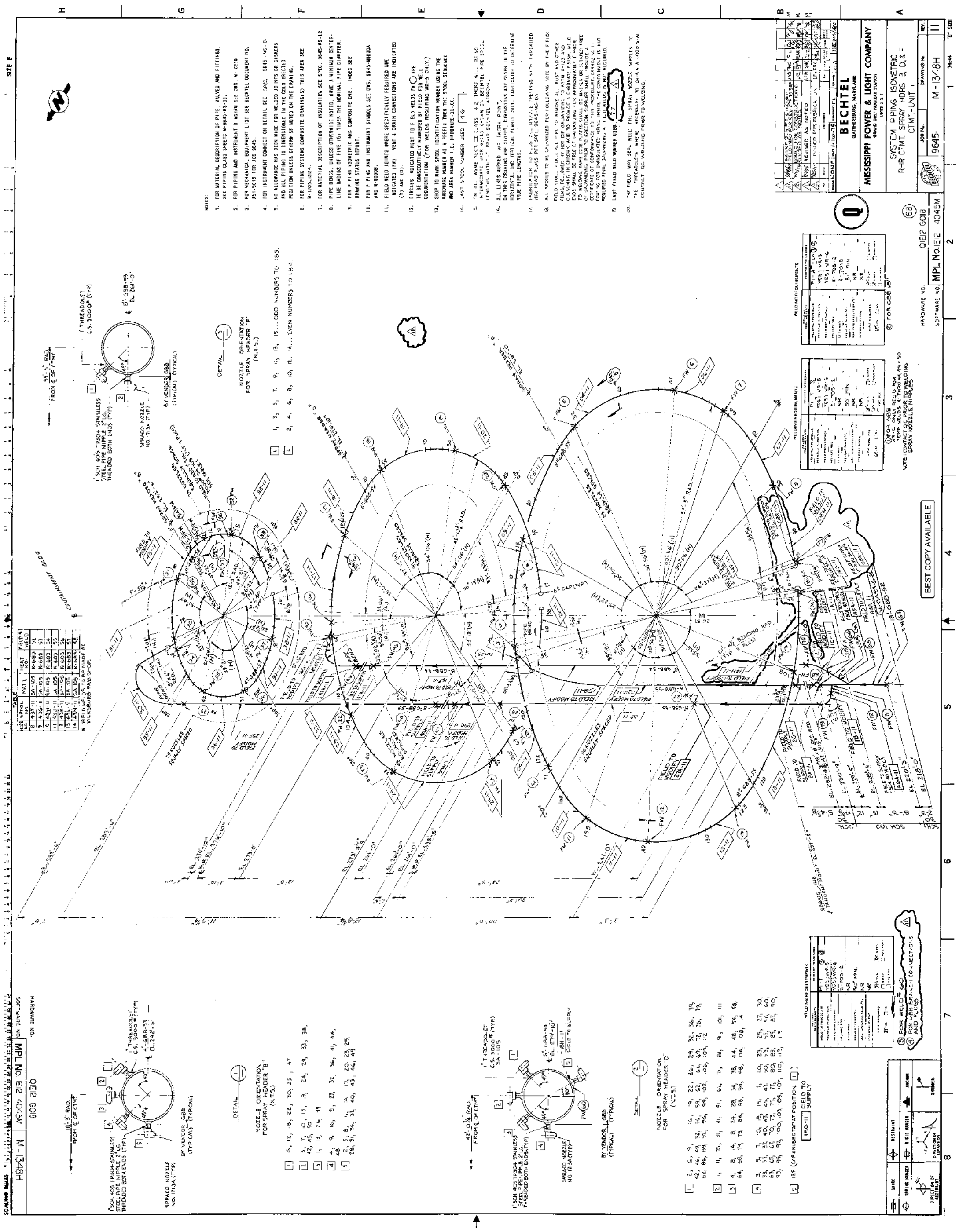

GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER – 06.5-001
SYSTEM FLOW DIAGRAM
CONTROL ROOM HVAC SYSTEM
UNITS 1 & 2
PRIORITY DRAWING
CONTROL ROOM STANDBY FRESH AIR UNIT
CONTROL ROOM AIR CONDITIONING UNIT
CONTROL ROOM STANDBY FRESH AIR UNIT
CONTROL ROOM UTILITY EXHAUST FAN
MAIN CONTROL ROOM LEVEL FL. EL. 166'-0"
COMPUTER ROOM
OFFICE
LOBBY AND HALLWAYS
LOCKER RM
KITCHEN
DINING AREA
CONFERENCE ROOM
SHOWER AND TOILET AREA
EMERGENCY DORMITORY
AUXILIARY INSTRUMENT SHOP
UNIT HEATER
MODES
PARAMETER
POINTS


UPPER-TIER DRAWING
OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 6.5-002
P&I DIAGRAM
STANDBY GAS TREATMENT SYSTEM
UNIT 1
M 1102A
ENCLOSURE BUILDING
AUXILIARY BUILDING
STANDBY GAS TREATMENT SYSTEM
CHARCOAL FILTER TRAINS
ENCLOSURE BUILDING
RECIRCULATION FANS
FUEL HANDLING AREA
EL.208'-10"
EL.185'-0"
AIR RCVR.


UPPER-TIER DRAWING
OPERATIONS CRITICAL
GRAND GULF NUCLEAR STATION
P & I DIAGRAM
ELEVATOR SHAFT
STAIRWELL NORTH
STAIRWELL SOUTH
AUXILIARY BLDG.
CORRIDORS & GENERAL FLOOR AREAS
SGTS. EQUIPMENT ROOM
STEAM TUNNEL OUTSIDE CTMT.
EL. 166'-0"
EL. 139'-0"
EL. 119'-0"
EL. 93'-0"


SYSTEM ENERGY RESOURCES, INC.
GRAND GULF NUCLEAR STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT
SYSTEM FLOW DIAGRAM
STANDBY GAS TREATMENT
SYSTEM
FIGURE 6.5-4
STANDBY GAS TREATMENT SYSTEM CHARCOAL FILTER TRAINS
STEAM TUNNEL OUTSIDE CONTAINMENT
AUXILIARY BUILDING
ENCLOSURE BUILDING
SFD-1102-3

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MISSISSIPPI POWER & LIGHT COMPANY
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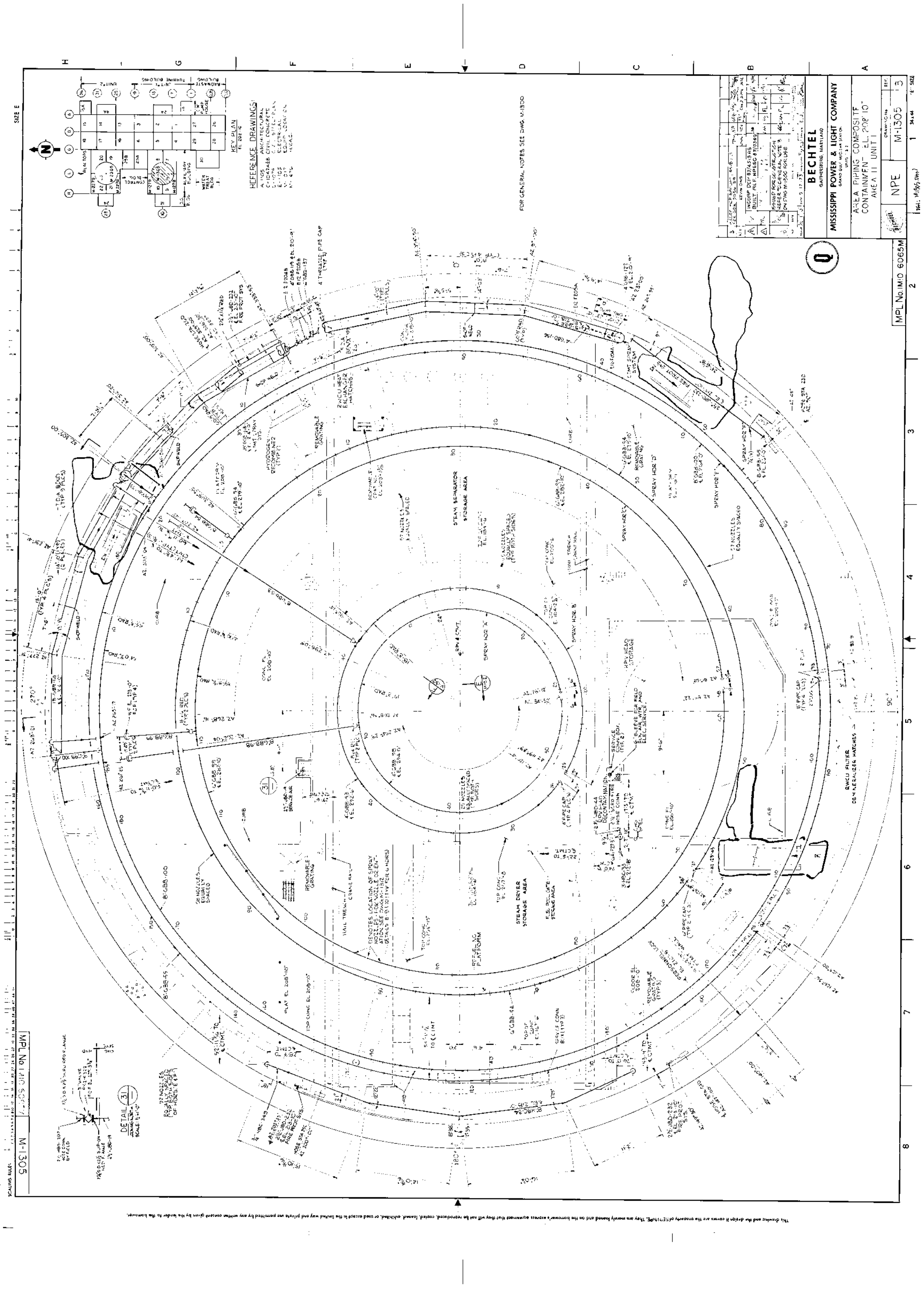
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MISSISSIPPI POWER & LIGHT COMPANY
M-1305

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"Figure 6.5-9 is Deleted"

6.6 INSERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS

6.6.1 Components Subject to Examination

[HISTORICAL INFORMATION] [The initial Preservice Inspection (PSI) of Unit 1 ASME Class 2 and 3 components has been performed in accordance with ASME Section XI, 1977 Edition, up to and including the Summer 1978 Addenda, and augmented examinations established by the Commission. PSI results have been submitted to the NRC.

Request for relief from ASME Section XI requirements identified during the initial PSI of Unit 1 were accepted by the NRC based on the considerations in Safety Evaluation Report Supplements 2 and 4, Appendix D, (NUREG-0831) and letter from the NRC dated October 16, 1985 (MAEC-85/0346).

Inservice inspection of Class 2 and 3 pressure retaining components such as vessels, piping, pumps, valves and bolting, and supports shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, including addenda per 10 CFR 50.55a(g), with certain exceptions whenever specific written relief is granted by the NRC per 10 CFR 50.55a(g)(6)i.

The inservice testing of Class 2 and 3 pumps and valves to requirements of the ASME OM Code for Operation and Maintenance of Nuclear Power Plants, is discussed in subsection 3.9.6.

The Inservice Inspections for the first 10-year inspection interval were in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, 1977 Edition, up to and including the Summer 1979 Addenda. Portions of the 1980 Edition, Winter 1980 Addenda were utilized for the first 10-year inspection interval.

Inservice Inspections for the second inspection interval were in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Edition and Addenda as specified in the Site ISI Plan GGNS-M-489.1.

Inservice Inspections for the third inspection interval will be in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, Div. I Inservice Inspection Program (CEP-ISI-102).

Details of the inspection program are contained in the Program Section for ASME Section XI, Div. I Inservice Inspection Program. This program plan defines the ASME Class 2 and 3 components, welds

and supports subject to inspection, including the method, extent and frequency of examination, exempt components and relief requests.]

6.6.2 Accessibility

The physical arrangement of components (such as piping, pumps and valves) and supports has been designed to allow personnel access to welds and components requiring inservice inspection. Removable insulation has been provided on those piping systems requiring volumetric and surface inspection. In addition, the placement of pipe hangers and supports with respect to those welds requiring inspection has been reviewed and modified, where necessary, to reduce the amount of plant support required in these areas during inspection. Where possible, working platforms have been provided in areas required to facilitate servicing of pumps and valves. When necessary, temporary platforms, scaffolding, and ladders will be provided to gain access to piping welds. Where volumetric inspection is required, the surface of welds within the inspection boundary has been prepared to permit effective ultrasonic examination.

[HISTORICAL INFORMATION] [An inservice inspection design review was undertaken to identify exceptions to the access requirements of the Code. Where access limitations preclude compliance with ASME Section XI requirements, relief requests have been submitted to the NRC. Applicable relief requests are included in the Program Section for ASME Section XI, Div. I Inservice Inspection Program.]

Additional exceptions due to modifications, design changes, or revisions to ASME Section XI may be identified and reported to the NRC after plant operation, as permitted in 10 CFR 50.55a(g)(5)(iv).

Space has been provided to handle and store insulation, structural members, shielding, and similar material related to the inspection. Suitable hoists and other handling equipment have also been provided. Lighting and sources of power for the inspection equipment are installed at appropriate locations.

6.6.3 Examination Techniques and Procedures

The visual, surface, and volumetric examination techniques and procedures, including any special techniques and procedures, are written in accordance with the requirements of ASME Code Section XI, subarticle IWA-2200.

[HISTORICAL INFORMATION] [The liquid penetrant or magnetic particle methods will be used for surface examinations and radiography or ultrasonic (U.T.) methods (manual, with the option for remote) for volumetric examinations.

When used, the remote ultrasonic scanning equipment for examination of welds will be supported and guided from tracks mounted on the piping or component. The examination equipment will provide radial and circumferential motion to the ultrasonic transducer while rotating about the weld. An electronic system with a receiver or data channel for each ultrasonic transducer will be used to acquire and store data when using remote automated examination equipment.

Reflected signals may be transmitted through an electronic distance amplitude correction device, gated, and multiplexed to initiate a digital recording. Scanning position will be indicated by encoders and subsequently logged by the data acquisition system. The key parameters of each reflector recorded includes location, maximum signal amplitude, depth below the scanning surface, and length of reflector. The data compilation format will be such as to provide for comparison of data from subsequent examinations to determine behavior of the reflector. However, similar or compatible systems of data acquisition may be utilized.

In areas where manual ultrasonic examination is performed, all reportable indications will be mapped and records made of maximum signal amplitude, depth below the scanning surface, and length of reflector. The data compilation format will be such as to provide for comparison of data from subsequent examinations.

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

6.6.4 Inspection Intervals

As defined in Paragraph IWA-2432 of ASME Code Section XI, the inspection interval will be 10 years. The interval may be extended by as much as one year to permit inspections to be concurrent with plant outages.

The inspection schedule shall be in accordance with IWC-2400 and IWD-2400 for Class 2 and 3 piping, respectively. It is intended that inservice examinations be performed during normal plant outages such as refueling shutdowns or maintenance shutdowns occurring during the inspection interval.

6.6.5 Examination Categories and Requirements

The extent of the examinations performed are in accordance with ASME Section XI, Table IWC-2500-1, and the methods used comply with Table IWC-2500-1 for Class 2 components and welds.

The examination requirements for Class 3 components comply with Table IWD-2500-1.

Further, preservice examinations for Class 2 and 3 components meet the requirements of IWC-2200 and IWD-2200, respectively.

6.6.6 Evaluation of Examination Results

Examination results will be evaluated to IWC-3000 for Class 2 components and IWD-3000 for Class 3 components with repairs based on the requirements of IWA-4000.

6.6.7 System Pressure Tests

System pressure tests will comply with IWC-5000 and IWD-5000 for Class 2 and 3 components, respectively.

6.6.8 Augmented Inservice Inspection to Protect against Postulated Piping Failure

All high-energy Class 2 piping between the required pipe break restraints located inside and outside the containment, beyond the isolation valves, is subject to the following additional inspection requirements:

Circumferential welds greater than 4 inch nominal pipe size (NPS) shall be volumetrically examined in accordance with the risk-informed methodology described in EPRI Report 1006937

incorporated through GGNS-PS-06-0002. All examinations shall be performed in accordance with ASME Section XI, except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g)(6)(i).

Further, accessibility, examination techniques and procedures, and evaluation of results shall be as discussed in subsections 6.6.2, 6.6.3, and 6.6.6, respectively.

Piping in these areas has been procured as seamless, thereby eliminating all longitudinal welds. Additionally, no Class 2 high-energy piping is located within guard pipe assemblies.

If pipe break restraints are not provided, the area between the containment isolation valves of high-energy pipe, including valve/pipe circumferential welds, will be subject to the augmented examinations.

6.7 CONTAINMENT ISOLATION VALVE LEAKAGE CONTROL SYSTEMS

6.7.1 Main Steam Isolation Valve Leakage Control System (MSIV-LCS)

The MSIV-LCS controls and minimizes the release of fission products which could leak through the closed main steam isolation valves (MSIVs) after a LOCA. The system provides this control by processing MSIV leakage prior to release to the atmosphere. This is accomplished by directing the leakage through a bleed line into an area served by the standby gas treatment system (SGTS).

6.7.1.1 Design Bases

6.7.1.1.1 Safety Criteria

The following criteria represent system design, safety, and performance requirements imposed upon the MSIV-LCS:

a. The MSIV-LCS is designed with sufficient capacity and capability to control the leakage from the main steam line isolation valves consistent with containment leakage limits imposed for the conditions associated with a postulated design-basis LOCA. Specifically, a complete severance of a recirculation line does not permit an offsite dose to exceed the guidelines of 10 CFR 100, or 10 CFR 50 General Design Criterion 19.

b. The MSIV-LCS is capable of performing its safety function during and subsequent to the postulated accident conditions and following a coincident loss of all offsite power.

c. The MSIV-LCS is designed in accordance with seismic Category I requirements.

d. The MSIV-LCS is protected from adverse conditions such as:

   1. Internally generated missiles within the containment

   2. The dynamic effects associated with pipe whip and jet forces

3. Normal operating and accident-caused containment environmental conditions consistent with the design-basis recirculation line break

e. The MSIV-LCS is capable of performing its intended function following any single active component failure (including failure of any one of the main steam line isolation valves to close). In addition, the MSIV-LCS is designed so that the effects resulting from a leakage control system single active component failure will not affect the integrity of the main lines or MSIVs.

f. Steam discharge from the MSIV-LCS is directed such that it does not affect functioning of structures, systems, or components important to safety. The MSIV-LCS does not prevent the SGTS from performing its safety functions.

1. The MSIV-LCS is manually initiated and controlled and is designed assuming actuation will occur in a time period no later than 20 minutes following the postulated design-basis LOCA. The required actuation time period is consistent with loading requirements on the emergency electrical buses and with reasonable times for operator information, decision, and action.

2. Instrumentation and controls necessary for the functioning of the MSIV-LCS are designed in accordance with standards applicable to nuclear plant safety-related instrumentation and control systems. The MSIV-LCS is designed to IEEE 279-1971 and IEEE 323-1971. [HISTORICAL INFORMATION] [The Grand Gulf initial design conforms to the requirements of IEEE 344-1971 as modified by EICSB Branch Technical Position 10. SQRT review was subsequently performed against IEEE 344-1975.] Qualification during the plant operating license stage is in accordance with IEEE 344-1975.

3. The MSIV-LCS controls are provided with interlocks actuated from appropriately designed safety systems or circuits to prevent inadvertent MSIV-LCS operation.

g. The MSIV-LCS is designed to permit testing of the operability of controls and actuating devices during power operation to the extent practical, and testing of the complete functioning of the system during plant shutdowns.

6.7.1.1.2 Regulatory Acceptance Criteria

The piping and components of the MSIV-LCS upstream of the outboard MSIV out through the first pressure retaining system valve are Quality Group A, as supplemented by Appendix A of Regulatory Guide 1.96; all other piping and components of the inboard MSIV-LCS are Quality Group B. The piping and components of the MSIV-LCS downstream of the outboard MSIV are classified as Quality Group B. The two pressure retaining valves and the remaining piping and components are Quality Group B.

The inboard subsystem is connected to the upstream nozzle of each outboard MSIV. The outboard subsystem connection is located downstream of the outboard MSIVs in a section of line where integrity is guaranteed by conformance with Regulatory Guides 1.26 and 1.29.

All piping systems and components for the MSIV-LCS comply with the applicable codes, addenda, code cases, and errata in effect at the time the equipment was procured. The overall system conforms to Regulatory Guide 1.96. The system is designed in accordance with the requirements of Table 3.2-1.

Inservice Inspection (ISI) is in accordance with ASME Code, Section XI.

6.7.1.1.3 Leakage Rate Requirements

The MSIV-LCS has been incorporated as an integral part of the BWR plant design. The design features employed with this system are established to eliminate the leakage rate of unfiltered radioactive materials to the environment during the postulated LOCA. Leakage control requirements are imposed upon the MSIV-LCS, in order to:

a. Eliminate the possibility of secondary containment bypass leakage of accident induced radioactive releases

b. Include all plant accident effluents in the filtered, elevated release dose calculations

c. Allow for realistically attainable MSIV leakage limits (limits which are operationally and statistically assured)

d. Assure reasonable leakage verification test frequencies

The design and operational requirements imposed upon the MSIV-LCS relative to the foregoing criteria are established to:

a. Accommodate MSIV leakage rates as defined by Technical Specifications

b. Allow a MSIV leakage rate verification testing frequency compatible with the requirements of the plant operating Technical Specifications and Technical Requirements Manual (TRM)

c. Assure and restrict total plant dose impacts below 10 CFR 50.67 and 10 CFR 50, General Design Criteria guidelines

6.7.1.2 System Description

[HISTORICAL INFORMATION] [In the past, following a loss-of-coolant accident (LOCA), two pathways for the release of radioactivity to the environment have been considered. One pathway was leakage from the containment with subsequent discharge to the environment following filtration by the standby gas treatment system. The other pathway was attributed to primary system/process containment system leakage which could bypass the secondary containment filtration system. This could possibly lead to direct leakage to the environment without the benefit of standby gas treatment system filtration. The significant portion of this potential bypass leakage was postulated to be via leakage through the MSIV. Therefore, very restrictive MSIV leakage limits were required of previous BWR plants. In addition to these limits (100 scfh per line and thus per valve), a rather restrictive leakage limit verification (frequency of testing) requirement was also imposed on recent operating BWR plants.] With the incorporation of the MSIV-LCS and the added assurance that all MSIV through-line leakage will be processed by the SGTS, the allowable MSIV leakage (per valve) has been raised to 250 scfh

without exceeding 10 CFR 50.67 dose limits.

6.7.1.2.1 General Description

The MSIV-LCS is designed to minimize the release of fission products which could bypass the standby gas treatment system after the postulated LOCA. This is accomplished by directing the leakage through the closed main steam isolation valves (MSIVs) to the outboard subsystem bleed lines which pass the leakage flow into an area served by the standby gas treatment system. The flow is affected by a blower which maintains the pressure in the steam lines slightly negative with respect to atmosphere, thus assuring that the MSIV leakage will pass through the blower and on into the area served by the standby gas treatment system prior to release to the atmosphere. The single leakage path per steam line of the inboard subsystem performs the same function.

The P&ID and system flow diagrams are shown in Figures 6.7-1 and 6.7-2, respectively. As indicated on the P&ID, two independent subsystems (one upstream of the outboard MSIV and the other downstream of the outboard MSIV) are provided to accomplish the leakage control function. The inboard MSIV-LCS receives power from one electrical division, and the outboard MSIV-LCS from the other electrical division of the emergency power supply.

The seismic, safety class, and quality group classifications for the main steam shutoff (block) valves have been clarified in subsection II of Table 3.2-1. The MSIV-LCS outboard system utilizes the integrity of the main steam line downstream of the second isolation valve to perform its safety function. In the event of a LOCA, the main steam block valves will be remotely closed from the control room to provide a closed volume from which MSIV-LCS suction can be taken. The block valves downstream of the fast-closing MSIVs are located as close as practicable to the auxiliary building wall. The valves are flexible wedge, high leaktight gate valves. These valves are within the SGTS boundary. The failure of one of the block valves is addressed in Table 6.7-1, Single Failure Analysis of MSIV-Leakage Control System. These valves operate from ESF power (including standby onsite AC).

6.7.1.2.1.1 Outboard Subsystem

The outboard subsystem is connected to the segments of the main steam lines, between the fast closing outboard MSIV and the downstream main steam shutoff valve. The bleed line from each main steam line connects to a bleed header. he bleed header outlet is provided with two valves in series which permit the main steam lines to be depressurized by venting following a LOCA. A parallel set of valves, which are automatically opened following depressurization to connect the blower suction to the steam lines, is provided. Pressure sensors, sensing steam line and vessel pressures, are used for depressurization interlock control to prevent accidental valve opening at pressures above 20 psig. Another pressure sensor is used for interlock control on the valves in the line to the blower suction to prevent valve actuation when MSL pressure is greater than 1 psig atmospheric. Pressure indicators are provided for monitoring the pressure in the main steam lines between the fast closing outboard MSIV and the downstream main steam shutoff valve. The major flow to the blower suction is dilution air from the auxiliary building served by the standby gas treatment system. This dilution air reduces the temperature of the MSIV leakage to approximately 196 F as it passes through the blower. The dilution air to leakage ratio is 5:1. A dilution air flow indicator utilizing a differential pressure sensor is provided to monitor blower flow rate. An alarm is annunciated if a predetermined differential pressure is not established. A timer is used to actuate a high steam line pressure alarm within a preset time period after system actuation if a subatmospheric main steam line pressure is not established.

A bleed line depressurization branch is discharged to a building volume served and processed by the standby gas treatment system while depressurizing the steam lines, without adversely affecting equipment. The blower discharge line is terminated at a location in a building volume such that the discharge flow is processed by the standby gas treatment system.

Manual switches are provided for functional testing of the bleed valves. These valves are not tested during operation. This

precludes inadvertent dumping of steam due to equipment malfunction or operator error.

The Outboard MSIV-LCS is the preferred division of MSIV-LCS operation. Establishing the Outboard MSIV-LCS as the preferred division provides greater assurance that leakage to the standby gas treatment system is minimized since there are two MSIV's prior to the outboard MSIV-LCS connection to the steam lines. In the event of a single failure of either an inboard or outboard MSIV to close, the redundant valve is functional and the outboard MSIV-LCS operation is unaffected.

6.7.1.2.1.2 Inboard Subsystem

The inboard subsystem is connected to the upstream nozzle of the outboard MSIV. An individually controlled process line is provided for each main steam line. For each process line, two isolation valves, which are the motor-operated-globe type, are connected in series. Flow through the four process lines discharges to a building volume and is processed by SGTS. Pressure sensors are used for interlock control to prevent any accidental actuation of the system as described for the outboard subsystem. An added safety feature is that the isolation valves on each of the process lines are interlocked to remain closed (when actuated in the operate mode), if the associated inboard MSIV failed to close following the reactor scram. Pressure indicators are provided for monitoring the pressure in the main steam lines between the fast closing MSIVs outside containment and those inside the containment. In case of gross leakage through an upstream MSIV, a delay timer and pressure sensor are used for reclosing the isolation valves if 5 psig is not achieved in about 1 minute after the inboard subsystem is activated.

The inboard subsystem process lines are discharged to a building volume served and processed by the standby gas treatment system without affecting any equipment.

Manual switches are provided for testing the isolation valves. These valves are not tested during operation. This precludes inadvertent dumping of steam due to equipment malfunction or operator error.

6.7.1.3 System Operation

The Outboard MSIV-LCS is the preferred division of MSIV-LCS operation. The Inboard MSIV-LCS is the back-up leakage control system to the outboard MSIV-LCS.

Both the inboard and outboard subsystems of the MSIV-LCS are actuated manually when directed by the site specific emergency operating procedure. The system is designed to be used when:

a. A design-basis LOCA has occurred

b. The steam lines and reactor vessel pressures are below the pressure permissive interlock set point; and inboard MSIV position switch interlock is cleared

c. All other main steam line valves are closed

In the outboard subsystem, the valves in the depressurization branch line open to permit the steam lines beyond the fast closing outboard MSIV to depressurize and the blower to start. When the steam lines have depressurized to approximately atmospheric pressure, the valves in the branch line to the blower open automatically and the valves in the depressurization branch close automatically. This establishes a subatmospheric pressure in the steam lines and the MSIV leakage is routed to the standby gas treatment system.

If a subatmospheric pressure is not established in the main steam lines within the estimated time required to depressurize, the timer will actuate the high-pressure alarm, indicating failure of a component required for the system to function. The system would then be manually secured by the operator.

Inboard subsystem actuation automatically depressurizes the main steam lines through the process lines. Flow is established into an area serviced by the standby gas treatment system.

The inboard subsystem is designed to automatically reclose in the event of excessive MSIV leakage. Automatic reclosure capability is provided for each individual steam line. Each steam line has its own isolation valves, electric timers, and pressure

instrumentation.

6.7.1.3.1 Equipment Required

The following equipment components are provided to facilitate system operation:

a. Piping - Process piping is carbon steel throughout except the system low point drain lines and heater sections which are stainless steel. That portion from the main steam piping between MSIVs up to the first MSIV-LCS isolation valve is designed and constructed to ASME Code, Section III, Class 1. The remainder is designed and constructed to ASME Code, Section III, Class 2. The components and piping are seismic Category I.

b. Valves - Valves are motor operated to provide maximum opening and closing stroke times of 15 seconds for the inboard subsystem valves and 30 seconds for the outboard subsystem valves. They are constructed to the ASME Code, Section III classification appropriate to the piping in which they are installed.

c. Blower - Rated at 100 scfm at -60 in. H_20 suction pressure.

d. Drain Lines - Drain lines with check valves are located in the outboard subsystem. If, during system blowdown, water should accumulate in the drain line piping upstream of the check valve, with the blower operating under design conditions, the check valve opens when the water head reaches 7 feet and permits drainage to the liquid radwaste system. The check valve reseats when the level decreases to below 7 feet. The blower design and its capacity are such that it does not actuate the check valve to open during expected operational conditions.

e. Standby gas treatment system - The MSIV-LCS adds about 50 scfm of load to the standby gas treatment system during the exhaust phase. This is a small portion of the rated capacity of the standby gas treatment system (see subsection 6.5.3) and is conditioned to be compatible with the SGTS temperature and humidity operating limits.

The MSIV-LCS adds approximately 100 lbs of steam to the

building volume served by the standby gas treatment system during steam line depressurization, where it is diluted before entering the standby gas treatment system.

6.7.1.4 System Evaluation

An evaluation of the capability of the MSIV-LCS to prevent or control the release of radioactivity from the main steam lines during and following a LOCA has been conducted. The results of this evaluation are presented in the following subsections.

6.7.1.4.1 Functional Protection Features

The two redundant subsystems (inboard and outboard) are physically separated. The equipment is designed to operate under the expected environmental conditions appropriate to the equipment location.

The MSIV-LCS equipment is arranged so as to minimize the exposure of the system components to missiles, pipe deformations and jet forces by locating the MSIV-LCS outside the containment such that the design basis recirculation line break inside the containment does not affect the MSIV-LCS. Where possible, equipment is located outside the steam tunnel and is removed and shielded from such effects by the concrete walls of the pipe tunnel. Since the system is not required for normal shutdown, it is only protected from hazards developed in a LOCA environment. The equipment is designed to operate under the expected LOCA environmental conditions appropriate to the equipment location. If a steam line breaks outside containment, this system is not needed for any safety function and therefore does not require pipe whip protection.

The use of the engineered safety features power source to power the components of the system assures system operation during the loss of offsite power.

System diversity is not deemed necessary due to present system reliability and redundancy relating to such an extremely low probability aspects as a TID-14944 source. Leakages from the system itself are accommodated by the standby gas treatment

system since the subject equipment is located within the structure served by the SGTS.

6.7.1.4.2 Effects of Single Active Failures

The MSIV-LCS functions following an active component failure (including failure of any one MSIV to close) by virtue of two redundant subsystems. The subsystems are independently powered from different divisions of the emergency power supply.

Double series isolation valves electrically and mechanically separated and operated by separate sensors and controls ensure that no single active failure affects the integrity of the main steam lines.

The effects of other failure modes are evaluated in subsection 6.7.1.4.6.

6.7.1.4.3 Effects of Seismic Induced Failures

The MSIV-LCS is designed to operate during and following the application of seismic Category I design loads in conjunction with operating loads associated with the LOCA.

6.7.1.4.4 Isolation Provisions

The MSIV-LCS system valves maintain containment integrity by virtue of a series of pressure interlocks obtained from two sources and in compliance with the electrical separation criteria. Unless the interlock set points are satisfied, the system isolation valves remain in a closed position. Two isolation valves are provided. One out of two valves satisfies isolation requirements. In addition, the valve electrical circuit cannot be activated unless the initiating keylocked remote manual switch is in the “operate” position. Isolation (separation) of electrical components is further discussed in subsection 7.3.1.1.3.

6.7.1.4.5 Leakage Protection Evaluation

The MSIV-LCS is designed to limit the release of radioactive materials to the environment during a postulated LOCA. The system

accomplishes this function through the use of the equipment described in subsection 6.7.1.3.1. Excessive MSIV leakage originating from the primary containment is prevented by automatic closure of the inboard subsystem on each steam line.

The manual initiation of the system could be carried out 20 minutes following the accident provided that the set point of the steam line pressure interlock is satisfied. It is possible, due to MSIV closure sequence, to have a high pressure between the inboard and outboard MSIVs. There would be no need to actuate any portion of the MSIV-LCS when the pressure between valves is higher than containment pressure since clean steam, trapped between the valves when they are closed, would be leaking toward the containment. Once the pressure between the MSIVs has decayed, the outboard MSIV-LCS system will be activated to effect leakage control.

If the outboard MSIV-LCS is unavailable, the inboard MSIV-LCS is initiated. A depressurization timer bypasses a pressure trip/ unit, permitting the process valves to remain open for 1 minute after system initiation. If the steam line pressure exceeds 5 psig when the timer times out, the system valves reclose. Otherwise, the valves remain open and steam line depressurization continues.

The outboard MSIV packing leakage is piped to the radwaste system. Piping and equipment associated with the leak-off line conform to seismic Category I up to and including the packing leakoff valve. If leakage is observed, the valve is manually closed and the outer stem packing of the MSIV is relied upon to prevent leakage.

The dose contribution from activity processed by the MSIV-LCS is evaluated in subsection 15.6.5.5.

The primary leakage control system (outboard MSIV-LCS) detects high steam line pressure and prevents system actuation. It also detects long term pressure above a atmospheric which prevents excessive release of leakage to the standby gas treatment system.

6.7.1.4.6 Failure Mode and Effects Analysis

The consequences of component malfunctions are shown in Table 6.7-1. System level qualitative type FMEA analysis is provided in Appendix A of Chapter 15.

6.7.1.4.7 Influence on Other Safety Features

The MSIV-LCS is powered from the engineered safeguard power sources.

The MSIV-LCS adds no more than 100 pounds of steam to the auxiliary building volume served by the standby gas treatment system during steam line depressurization, where it is diluted before entering the standby gas treatment system. The initial discharge has no significant effect on building pressure buildup. The continuous flow is considered negligible compared to the standby gas treatment system rated flow stated in subsection 6.5.3. In addition, this system, by exhausting leakage steam and gases, does not introduce or expose the steam piping or valves to thermal or mass loadings different from that experienced in normal isolation valve service and, therefore, cannot affect or degrade the sealing ability of the MSIVs.

6.7.1.4.8 Radiological Evaluation

Subsection 15.6.5 discusses the activity released to the environment by way of the MSIV-LCS and of the standby gas treatment system and the resulting offsite dose consequences.

6.7.1.5 Instrumentation Requirements

The instrumentation necessary for control and status indication of the MSIV-LCS are classified as essential and as such are designed and qualified in accordance with applicable IEEE standards, to function under seismic and LOCA environmental loading conditions appropriate to their installation. The control circuits are designed to satisfy the mechanical and electrical separation criteria. Refer to subsection 7.3.1.1.3 for a control and instrumentation description.

6.7.1.6 Inspection and Testing

Preoperational tests for the MSIV-LCS are discussed in Chapter 14.0. During plant operations, valves, piping, instrumentation, electrical circuits, and other components outside the steam tunnel can be inspected visually at any time. Components inside the tunnel can be inspected only during shutdown. Isolation valve testing and complete system testing are done during shutdown. Components downstream of the isolation valves may be tested at any time during operation. Test frequency is consistent with the requirements of the plant operation Technical Specifications and Technical Requirements Manual (TRM). Valves are capable of being exercised periodically during normal operation.

Operation of the isolation valves and complete system testing or isolation valve leak testing is performed only during reactor shutdown in order to preclude inadvertent steam discharge.

Since the MSIV-LCS routes any bypass leakage through the MSIVs back to standby gas treatment system filtration, it eliminates direct leakage to the environment. This allows for increased MSIV leak rates relative to the previous limits, yet results in reduced radiological impacts. The specific MSIV allowable leakage rate will be established within 10 CFR 50.67 radiological dose requirements. The MSIV allowable leakage rate verification test will be performed in accordance with Technical Specifications.

The MSIV-LCS with the established design operational objectives was designed to accommodate a significant increase in the MSIV allowable leakage rate and provide an improved (decreased) MSIV test frequency. The MSIV-LCS not only allows for increased plant availability and reliability, but also continues to assure the personal safety and health of the public.

6.7.2 Feedwater Leakage Control System

6.7.2.1 Safety Design Bases

a. The feedwater leakage control (FWLC) system is designed in accordance with seismic Category I and quality group classification requirements to comply with Regulatory

Guides 1.26 and 1.29. The system meets the intent of Regulatory Guide 1.96, where applicable. (See Table 3.2-1.)

b. The FWLC system is designed with sufficient redundancy, separation, reliability, and capacity as a safety-related system consistent with the need to maintain containment integrity for as long as postulated LOCA conditions require.

c. The FWLC system is capable of performing its intended safety function following a loss of all offsite power coincident with the postulated design basis LOCA.

d. The FWLC system is designed with sufficient capacity and capability to prevent leakage through the feedwater lines consistent with containment integrity under the conditions associated with the postulated design basis LOCA.

e. The FWLC system is provided with interlocks actuated from appropriately designed safety systems or circuits to prevent inadvertent system operation.

f. The FWLC system is designed to permit testing of the operability of controls and actuating devices as well as the complete functioning of the system during plant shutdowns.

g. The FWLC system is designed so that effects resulting from a system single active component failure will not affect the integrity of the feedwater lines or the operability of containment isolation valves.

h. The FWLC system is protected from the effects of internally generated missiles, pipe break failures, and adverse environments associated with a LOCA.

i. The FWLC system is manually initiated and controlled and is designed assuming actuation will occur in the postulated design-basis LOP/LOCA. The required actuation time period is consistent with loading requirements on the emergency electrical buses and with reasonable times for operator information, decision and action. If the feedwater pumps, condensate booster pumps or condensate pumps are running, then FWLC is not needed.

6.7.2.2 System Description

The FWLC system consists of piping, valves, and instrumentation as shown in Figure 6.7-5. The system components are designed to the requirements of Table 3.2-1, Item XLIV.

The FWLC system consists of two independent subsystems designed to eliminate through line leakage in the feedwater piping by providing a positive seal between the containment isolation check valves and outboard isolation valve. The outboard subsystem uses residual heat removal (RHR) jockey pump A and the inboard subsystem uses RHR jockey pump B to supply sealing water on the upstream and downstream sides of the outboard containment isolation check valve, respectively.

Following a LOCA, the FWLC system is manually initiated from the control room. The suppression pool sealing water from each jockey pump is routed to both feedwater lines. The sealing fluid from the RHR jockey pump B discharge line fills each feedwater line between the containment isolation check valves. The sealing water through the valve eventually fills the feedwater line up to the reactor vessel and finally the water returns to the suppression pool through the LOCA break. Since the source of sealing water is the suppression pool, 30 day water supply is assured. Operation of the FWLC system will not affect the function of the suppression pool since the seal water is eventually returned to the pool when the drywell is flooded back over the weir wall.

The sealing water from the RHR jockey pump A discharge line fills each feedwater line between the outboard containment isolation check valve and the feedwater shutoff gate valve.

6.7.2.3 Safety Evaluation

The FWLC system is designed to prevent the release of radioactivity through the feedwater line isolation valves by providing a continuous flow of water through the feedwater lines following a loss of all offsite power coincident with the postulated design basis loss-of-coolant accident. The two redundant subsystems are physically separated so as to minimize the exposure of the system components to missiles and to the

effects of pipe whip or jet impingement from high energy line breaks.

The FWLC system is seismic Category I and is capable of performing its intended function following an active component failure. Each independent subsystem is powered from a different division of the ESF power supply.

Double series isolation valves are provided to ensure that no single active failure will affect the integrity of the feedwater lines.

Nonseismic systems and components in the area of the FWLC system have been analyzed for the effects of their failure. Additional supports or protection by barriers is provided to assure the FWLC system is not jeopardized by nonseismic failures during an earthquake. A single failure analysis of the FWLC system is contained in Table 6.7-2.

6.7.2.4 Inspections and Tests

[HISTORICAL INFORMATION] [The FWLC system was hydrostatically tested prior to initial startup.] The complete functioning of the system, including operability of controls and actuating devices, can be tested during periods of plant shutdown.

6.7.2.5 Instrumentation Application

Each FWLC subsystem is manually initiated from the control room following a postulated LOCA. Independent pressure instrumentation is provided for each FWLC subsystem in order to prevent operation while the feedwater lines are pressurized. The motor operated valve on the outboard subsystem of the FWLC system is interlocked with each feedwater shutoff valve to preclude initiation of the subsystem of the FWLC system when the shutoff valve is not fully closed. Refer to subsection 7.3.1.1.6 for further details.

TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM

Component/ Equipment **Inboard Subsystem**	**Malfunction**	**Consequences**
1. Inboard MSIV	Any one valve fails to close	The inboard subsystem associated with the failed MSIV is deactivated by virtue of an interlock signal from MSIV position switch signifying an open valve. Three of four inboard subsystems are functional to collect leakage although not required. The inboard subsystem is not operational if the outboard subsystem is available. The outboard system is adequate to control leakage.
2. Outboard MSIV	Any one valve fails to close	The outboard subsystem (preferred) or inboard subsystem could be used. The inboard subsystem is not operational if the outboard subsystem is available. The outboard subsystem and the three remaining inboard subsystems remain functional and control leakage. The outboard system alone is adequate to control leakage.
3. Check Valve (F010)	a. Stuck open	a. No effect on inboard system operation

TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM (Continued)

Component/ Equipment Inboard Subsystem	Malfunction	Consequences
	b. Stuck closed	b. piping fills up with condensate until it overflows at abandoned inboard blower discharge. No effect on inboard system operation.
4. Inboard subsystem isolation valve (F001 or F002)	a. Fails to open	a. The remaining three inboard systems and the outboard system remain functional. The outboard subsystem alone is adequate to control leakage.
	b. Fails to close when tripped	b. One out of two valves satisfy isolation by virtue of single active component failure criteria. The outboard and inboard subsystems remain functional. The inboard subsystem is not operational if the outboard subsystem is available. The outboard subsystem alone is adequate to control leakage.

TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM (Continued)

Component/ Equipment Inboard Subsystem	Malfunction	Consequences
5. Vessel Pressure Interlock on Inboard System	a. Instrument failure following a LOCA	a. Each inboard subsystem initiating hand switch remains inactive. The inboard subsystem becomes inoperative and the outboard subsystem functions to control leakage.
	b. Instrument failure to become active during normal power operation.	b. MSIV position switches and steam line pressure interlocks act to keep the inboard subsystem equipment and components inactive. Also, each subsystem initiating hand switch is key locked; therefore, the probability of inadvertent system operation is remote. The inboard subsystem is not operational if the outboard subsystem is available. The outboard subsystem alone is adequate to control leakage.
6. Steam Line pressure interlock	a. Instrument failure to clear permissive interlock following LOCA	a. The associated inboard subsystem does not function to control leakage. The outboard subsystem and three inboard subsystems remain functional.

TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM (Continued)

Component/ Equipment Inboard Subsystem	Malfunction	Consequences
	b. Instrument failure following a LOCA	b. The associated inboard subsystem remains inactive because of two other interlocks not permissive. Inadvertent subsystem operation is remote. The inboard subsystem is not operational if the outboard subsystem is available. The outboard subsystem alone is adequate to control leakage.
7. Timer (Inboard)	Instrument failure	If the timer cycles earlier than the desired set point and if steam line pressure is greater than 5 psig, subsystem valves trip to reclose. If the line pressure satisfies the pressure switch set point, leakage control remains in effect. This failure has no effect on the outboard system. It will continue to be available for leakage control. The other three process lines will continue to function.

TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM (Continued)

Component/ Equipment Inboard Subsystem	**Malfunction**	**Consequences**
		The inboard subsystem is not operational if the outboard subsystem is available. The outboard subsystem alone is adequate to control leakage.
8. Steam Line pressure transmitter and trip unit. (Inboard)	Instrument failure	If the steam line pressure is greater than the setpoint when the timer has timed out, isolation trip signal to the subsystem valves would not be established. With the instrument as the single active failure, the rest of the leakage control system equipment or components will function as required and the design parameters are within the system capability. Note the outboard subsystem is the preferred leakage control system and would be initiated before the inboard system. Therefore, the outboard system would control leakage. The inboard subsystem is not operational if the outboard subsystem is available. The outboard subsystem remains functional and alone is adequate to control leakage.

TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM (Continued)

Component/ Equipment Outboard Subsystem	Malfunction	Consequences
OUTBOARD SUBSYSTEM		Note: At any situation wherein the outboard subsystem is not functional, due to active component failure, the inboard subsystem functions to control leakage.
9. Depressurization valves	a. Fail to open	a. Steam line does not depressurize and the outboard subsystem remains inoperative.
	b. Fail to close with the reclosure trip signal	b. Bleed valves remain closed and subatmospheric is not established in the steam lines. An alarm is annunciated at the duration of a timer which alerts the operator to secure the subsystem in a safe shutdown condition.
		The inboard subsystem is manually initiated to control leakage.
10. Bleed valves	Fail to open	Same consequences as in item 9(b)
11. Vessel and steam line pressure interlocks	Instrument failure following a LOCA	The outboard subsystem remains inoperative. The inboard subsystem permissive alarm indicates the inboard subsystem is available.

TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM (Continued)

Component/ Equipment Outboard Subsystem	**Malfunction**	**Consequences**
		The inboard subsystem is manually initiated to control leakage.
12. Six-minute timer or pressure switch	Instrument failure	The alarm fails to annunciate if the steam line pressure is not sub atmospheric. The outboard subsystem remains functional.
13. Dilution air flow sensor	Instrument failure	Although dilution air flow is monitored and since this is the single active failure, the rest of the subsystem equipment or components function as required and the design parameters are within the subsystem capacity. The outboard subsystem remains functional.
14. Blower	Fails to operate	If the other outboard MSIV-LCS blower is unable to drawdown, then dilution air flow is not established causing an alarm to annunciate. Also, when the timer has timed out, another alarm is annunciated which is an indication that the subsystem failed to establish required vacuum in the steam lines. On the basis of the available information, the operator will then initiate the necessary action to secure the subsystem to safe shutdown condition.

TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM (Continued)

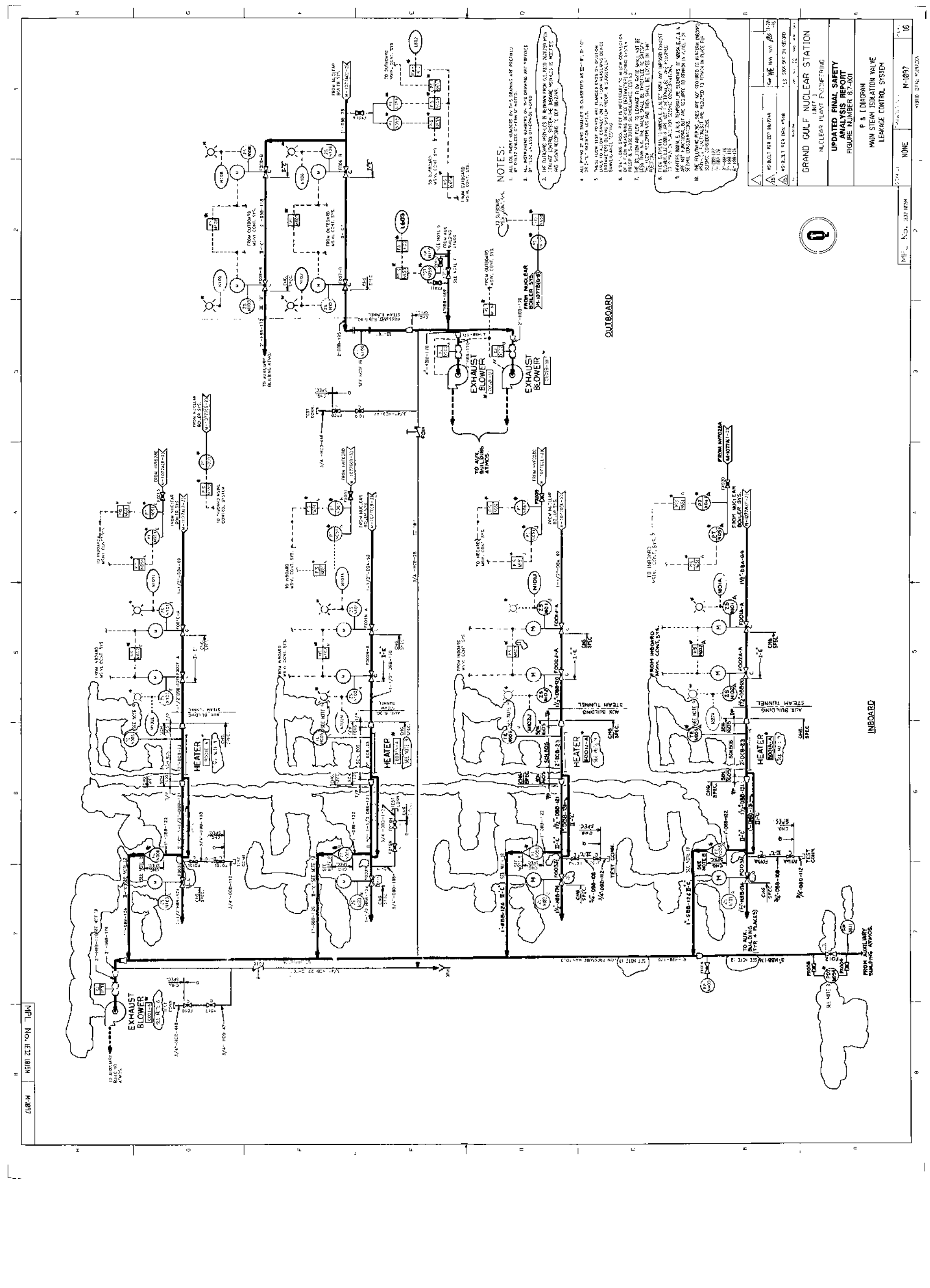
Component/ Equipment Outboard Subsystem	Malfunction	Consequences
		The inboard subsystem is manually initiated to control leakage.
15. Steam line pressure transmitter and trip unit	Instrument failure to transfer mode of operation from depressurization to bleed off.	Same consequences as in item 9(b) of outboard system.
16. Check valve (F011)	a. Stuck open	a. The blower operates at increased capacity due to some recirculation through the small bore drain line.
	b. Stuck closed	b. The failure of the drain check valve to open would result in water ingestion into the blower which would trip the outboard system.
		The inboard subsystem is manually initiated to control leakage.

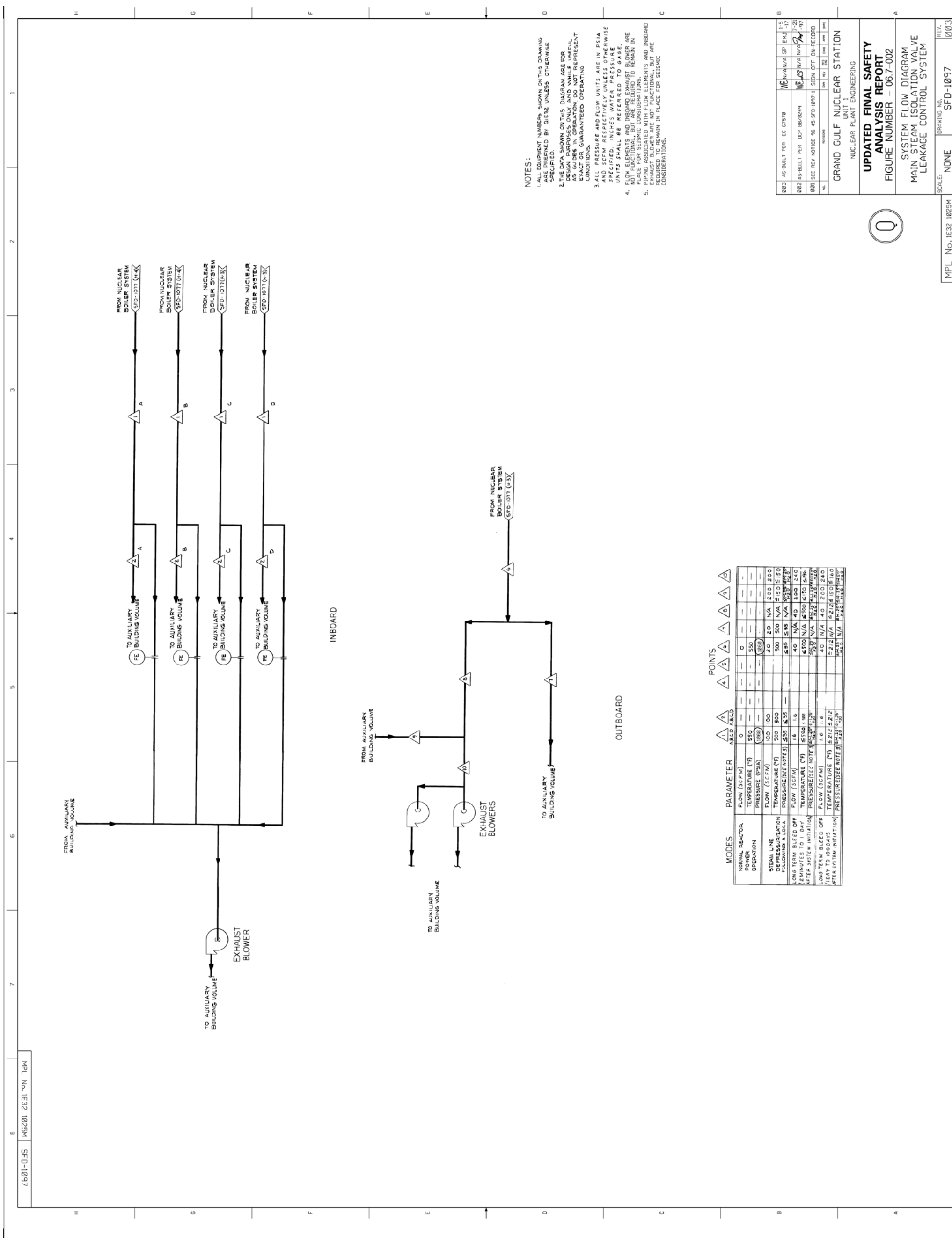
TABLE 6.7-1: SINGLE FAILURE ANALYSIS OF MSIV-LEAKAGE CONTROL SYSTEM (Continued)

Component/ Equipment Outboard Subsystem	**Malfunction**	**Consequences**
17. Shutoff valve (2nd outboard Main Steam Line Valve (F098s)	Any one valve fails to close	The Outboard subsystem functions to control steam line leakage, but its capacity is insufficient to establish a sub atmospheric pressure in the steam lines. If an alarm annunciates on high steam line pressure or inadequate dilution flow, the inboard subsystem is manually initiated. The inboard subsystem functions to control leakage.

TABLE 6.7-2: SINGLE FAILURE ANALYSIS OF FEEDWATER LEAKAGE CONTROL SYSTEM

Component/Equipment	Malfunction	Consequences
1. RHR jockey pump	Either A or B pump fails to operate	One subsystem is inoperative, system requirements met by redundant pump and associated subsystem
2. Motor-Operated valve on RHR jockey pump discharge line	Either A or B valve fails to open	One subsystem is inoperative, system requirements met by redundant subsystem
3. Feedwater Shutoff valve	Feedwater shutoff valve fails to close	The outboard subsystem associated with the failed valve remains deactivated by virtue of an interlock signal from shutoff valve position switch. The FWLC system requirements are met by the redundant inboard subsystem.


EXHAUST BLOWER
HEATER
OUTBOARD
INBOARD
NOTES:


GRAND GULF NUCLEAR STATION
UPDATED FINAL SAFETY ANALYSIS REPORT
FIGURE NUMBER - 06.7-002
SYSTEM FLOW DIAGRAM
MAIN STEAM ISOLATION VALVE
LEAKAGE CONTROL SYSTEM
SFD-1097
INBOARD
OUTBOARD
EXHAUST BLOWER
EXHAUST BLOWERS

Figures 6.7-3 and 6.7-4

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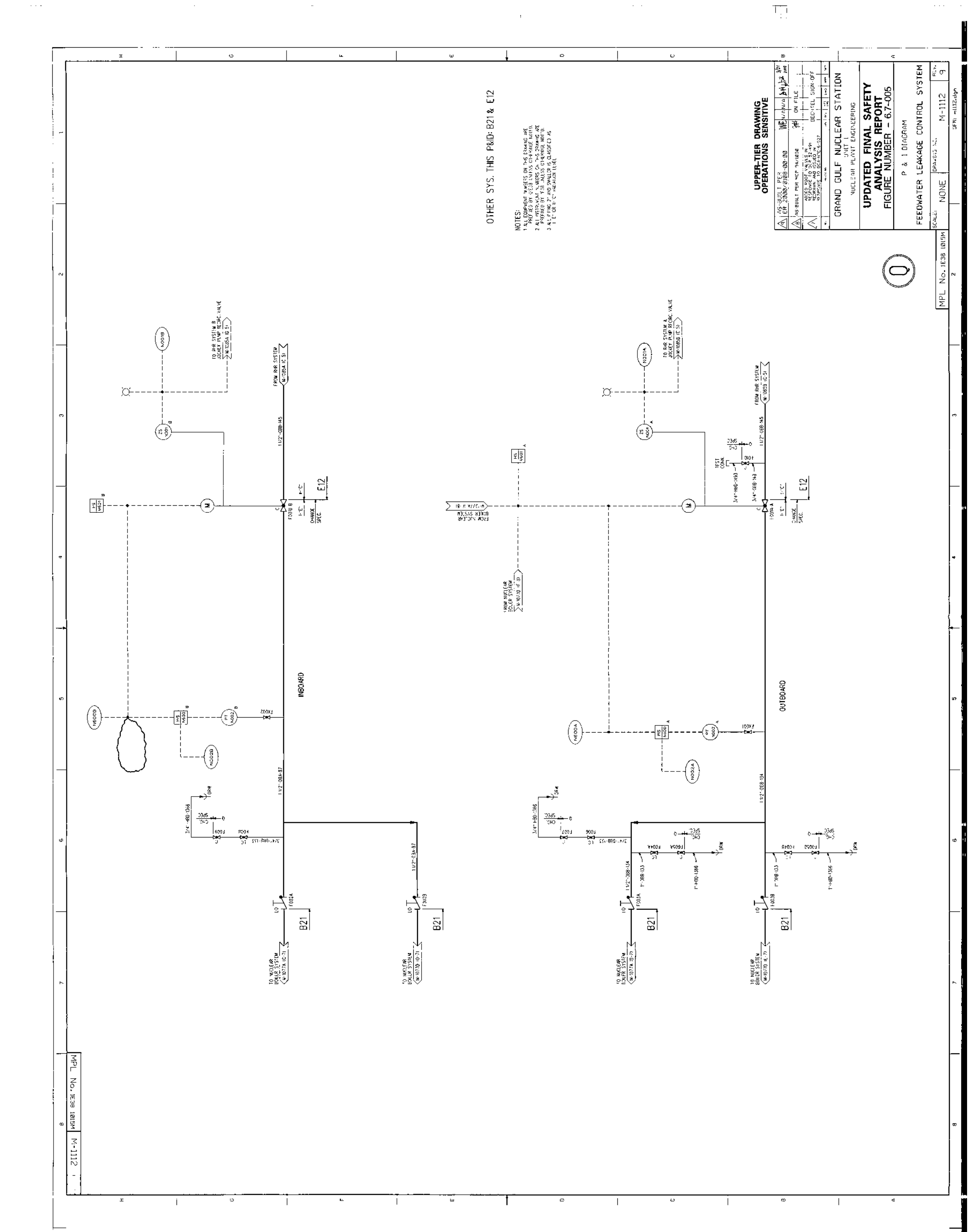
UPPER-TIER DRAWING
OPERATIONS SENSITIVE
GRAND GULF NUCLEAR STATION
NUCLEAR PLANT ENGINEERING
UPDATED FINAL SAFETY
ANALYSIS REPORT
FIGURE NUMBER - 6.7-005
P & I DIAGRAM
FEEDWATER LEAKAGE CONTROL SYSTEM
M-1112
OTHER SYS. THIS P&ID: B21 & E12
INBOARD
OUTBOARD
E12
B21

APPENDIX 6A GRAND GULF CONTAINMENT LOADS

Grand Gulf has utilized the parameters, methods, assumptions and concepts as described in Appendix 6D (GE document 22A7000, Rev. 2 (GESSAR II, Appendix 3B). The purpose of this Appendix is to supplement Appendix 6D by identifying the specific differences between the GEH Standard Plant and Grand Gulf and by identifying the corresponding application of generic Mark III containment load methodologies to Grand Gulf. The differences exist, for example, because Grand Gulf has a 251-inch-diameter reactor vessel with 800 fuel assemblies rated at 4408 MWt, 20 safety relief valves, and slightly different suppression pool dimensions. The GEH Standard Plant has a 238-inch-diameter reactor vessel rated at 3579 MWt and only 19 safety relief valves.

Grand Gulf has adhered to all the analytical techniques, assumptions, methodologies, and concepts for Mark III containment systems as described in Appendix 6D. Where Grand Gulf unique parameters or methodologies differ from those used for the GEH Standard Plant, Grand Gulf parameters or methodologies are used. For purposes of clarity, the figure and table numbers of Appendix 6D have been maintained throughout this Appendix, and therefore are not consecutively numbered. Those figures not repeated in this Appendix are assumed to be identical to those in Appendix 6D as applicable to a Mark III/BWR 6-251 arrangement. It is not intended that this Appendix be complete by itself; it must be accompanied by Appendix 6D for completeness.

APPENDIX 3B CONTAINMENT LOADS

3B.1 INTRODUCTION

The Grand Gulf containment is equivalent to the reactor building discussed in this subsection.

3B.1.1 Confirmatory Testing

No deviations.

3B.1.2 Definition of LOCA

No deviations.

3B.1.3 Design Margins

No deviations.

3B.2 REVIEW OF PHENOMENA

No deviations.

3B.2.1 Design Basis Accident (DBA)

Figures 3B-2 to 3B-6 are not applicable to Grand Gulf. See Figures 3.8-60, 3.8-66, 3.8-66a, and 3.8-67 for Grand Gulf.

3B.2.2 Intermediate Break Accident (IBA)

No deviations.

3B.2.3 Small Break Accident (SBA)

No deviations.

3B.2.4 Safety Relief Valve Actuation

The inadvertent opening of a single SRV is considered in combination with the SSE and DBA to demonstrate the additional structural capability of the containment and internal structures.

3B.2.5 Other Considerations

No deviations.

3B.3 DYNAMIC LOAD TABLE

No deviations.

3B.4 DRYWELL STRUCTURE

No deviations.

3B.4.1 Drywell Loads During a Large Break Accident

No deviations.

3B.4.1.1 Sonic Wave

No deviations.

3B.4.1.2 Drywell Pressure

Figure 3B-10 is not applicable to Grand Gulf. Figure 6.2-10 shows the Grand Gulf drywell pressure response to a main steam line break (DBA).

3B.4.1.3 Hydrostatic Pressure

No deviations.

3B.4.1.4 Loads on the Drywell Wall During Pool Swell

The peak drywell wall pressure for Grand Gulf in Figure 3B-11 is 22.0 psig. Figure 6.2-10 shows the Grand Gulf wetwell pressurization transient to a main steam line break. Figure 6.2-10a shows the predicted Grand Gulf wetwell pressurization relative to HCU floor percent open area.

3B.4.1.5 Condensation Oscillation Loads

A Grand Gulf unique condensation oscillation analysis for plant specific parameters shows that the GESSAR II, Appendix 3B condensation oscillation load specification, which has been used for the Grand Gulf design, conservatively bounds the plant unique specification. (See also letter AECM 81/401 dated October 9, 1981, Items 4a and 4b.)

3B.4.1.6 Fallback Loads

No deviations.

3B.4.1.7 Negative Load During ECCS Flooding

See Attachment G for deviations.

3B.4.1.8 Chugging

No deviations.

3B.4.1.9 Loads Due to Chugging

No deviations.

3B.4.1.9.1 Chugging Loads Applied to Top Vent

No deviations.

3B.4.1.9.2 Pool Boundary Chugging Loads

No deviations.

3B.4.2 Drywell Loads During Intermediate Break Accident

No deviations.

3B.4.3 Drywell During Small Break Accident

No deviations.

3B.4.3.1 Drywell Temperature

No deviations.

3B.4.3.2 Drywell Pressure

Air passing to the containment results in "...gradual pressurization of the containment...".

3B.4.3.3 Chugging

No deviations.

3B.4.4 Safety/Relief Valve Actuation

No deviations.

3B.4.5 Drywell Environmental Envelope

No deviations.

3B.4.6 Top Vent Temperature (Cycling) Profile During Chugging

No deviations.

3B.4.7 Drywell Multicell Effects

No deviations.

3B.5 WEIR WALL

No deviations.

3B.5.1 Weir Wall Loads During Design Basis Accident

No deviations.

3B.5.1.1 Sonic Wave

No deviations.

3B.5.1.2 Outward Load During Vent Clearing

No deviations.

3B.5.1.3 Outward Load Due to Vent Flow

No deviations.

3B.5.1.4 Chugging Loads

No deviations.

3B.5.1.5 Inward Load Due to Negative Drywell Pressure

See Attachment G for comments.

3B.5.1.6 Suppression Pool Fallback Loads

No deviations.

3B.5.1.7 Hydrostatic Pressure

No deviations.

3B.5.1.8 Safety/Relief Valve Actuation

No deviations.

3B.5.1.9 Condensation

No deviations.

3B.5.2 Weir Wall Loads During an Intermediate Break Accident

No deviations.

3B.5.3 Weir Wall Loads During a Small Break Accident

No deviations.

3B.5.4 Weir Wall Environmental Envelope

No deviations.

3B.5.5 Weir Annulus Multicell Effects

No deviations.

3B.6 CONTAINMENT

No deviations.

3B.6.1 Containment Loads During a Large Steamline Break (DBA)

Figures 3B-2 to 3B-6 are not applicable to Grand Gulf. See Figures 3.8-60, 3.8-66, 3.8-66a and 3.8-67 for Grand Gulf.

3B.6.1.1 Compressive Wave Loading

The Grand Gulf suppression pool is 20.5 feet wide (See Figure 3.8-1).

3B.6.1.2 Water Jet Loads

No deviations.

3B.6.1.3 Initial Bubble Pressure

No deviations.

3B.6.1.4 Hydrostatic Pressure

No deviations.

3B.6.1.5 Load Containment Loads Resulting from the Structures at or Near the Pool Surface

No deviations.

3B.6.1.6 Containment Load Due to Pool Swell at the HCU Floor (Wetwell Pressurization)

The Grand Gulf HCU floor is approximately 22-1/2 feet above the suppression pool surface. The peak calculated pressure differential for Grand Gulf is shown in Figure 6.2-10 and is equal to approximately 7.4 psid based upon a design open area ratio of 21 percent of the total HCU floor area. Figure 3B-58 is not applicable to Grand Gulf. Figure 6.2-10a shows the predicted Grand Gulf wetwell pressurization relative to HCU floor percent open area.

3B.6.1.7 Fallback Loads

No deviations.

3B.6.1.8 Post Pool-Swell Waves

No deviations.

3B.6.1.9 Condensation Oscillation Loads

No deviations. See also subsection 3B.4.1.5.

3B.6.1.10 Chugging

No deviations.

3B.6.1.11 Long-Term Transient

No deviations.

3B.6.1.12 Containment Environmental Envelope

No deviations.

3B.6.2 Containment Loads During an Intermediate Break Accident

No deviations.

3B.6.3 Containment Loads During a Small Break Accident

No deviations.

3B.6.4 Safety/Relief Valve Loads

No deviations.

3B.6.5 Suppression Pool Thermal Stratification

No deviations.

3B.6.6 Containment Wall Multicell Effects

No deviations.

3B.7 SUPPRESSION POOL BASEMAT LOADS

The suppression pool basemat pressure for Grand Gulf at the drywell wall associated with the initial air-bubble formation discussed in subsection 3B.6.1.3 is 22.0 psi.

3B.8 LOADS ON STRUCTURES IN THE SUPPRESSION POOL

No deviations.

3B.8.1 Design Basis Accident

No deviations.

3B.8.1.1 Vent Clearing Jet Load

In Question 021.1(2), Grand Gulf was asked to compare the methods used to determine the design loads on submerged structures to the loads generated using the methodology presented in NUREG-0487. These jet loads were considered using the procedures described in GE Topical Report NEDE-21472, September 1977. The LOCA water jets dissipate before reaching the containment wall. In the region between the horizontal vent outlet and point of dissipation, all piping and piping supports have been located to avoid impact by the LOCA water jets. The acceptance criteria in NUREG-0487 contains a number of constraints and modifications. It is our understanding that these will be modified to consider the spherical vortex model. We will demonstrate that the Grand Gulf design is conservative once the NUREG supplement has been issued.

3B.8.1.2 Drywell Bubble Pressure and Drag Loads Due to Pool Swell

In Item 021.1(2), Grand Gulf was asked to compare the design loads on submerged structures to the loads generated using the methodology presented in NUREG-0487.

For these loads, the vent discharge absolute bubble pressure was used to establish design loads for submerged piping and structures (including piping supports). The following is a comparison between the Grand Gulf design basis and the criteria contained in NUREG-0487. This sample case is a one-foot diameter pipe, two feet long that is located 4' from the drywell wall. The analysis shows that:

1. The Grand Gulf design basis yields 4980 lb_f.

2. The base method employed by the Mark II plants (from GE topical report NEDE-21471, September 1977) yields 1145 lb_f.

3. Adding 10% to the acceleration and velocity to estimate asymmetry per NUREG-0487 would result in a load of 1275 lb_f.

4. lncreasing the drag coefficient for standard drag by a factor of 3 would result in a design load of 1650 lb_f.

5. A comparison between the Grand Gulf design basis and the NUREG criteria for interference effects will be provided once the supplement to NUREG-0487 has been issued. It is our understanding that the supplement, will contain additional guidance concerning interference effects.

Table 3BL-5 specifies a resultant force of 1187.4 lbs for a nearly identical sample problem. Even when the factor of 2 was used resulting in a load of 2374.8 lbf, the Grand Gulf design loads are still more than twice the loads from the GE design methodology.

The design of the floor mounted portion of the ECCS suction strainers (i.e., ECCS/RCIC Suction Strainer, Q1M24D001) utilizes the GESSAR II load definition (method of images) for these loads.

3B.8.1.3 Fallback Loads

No deviations.

3B.8.1.4 Condensation Loads

The GE sample problem in Attachment L specifies a load of 0.73 psi (frequency range is 2 to 3.5 hz). The Grand Gulf design load, which is 2.0 psi with a frequency range of 3 to 8 Hz, is more conservative.

However, the design of the floor mounted portion of the ECCS suction strainers (i.e., ECCS/RCIC Suction Strainer, Q1M24D001) utilizes the load definition in Attachment L and not the Grand Gulf design load.

3B.8.1.5 Chugging

The GE sample problem in Attachment L specifies a load of 1.9 psi. The Grand Gulf design load of 2.0 psi is more conservative.

However, the design of the floor mounted portion of the ECCS suction strainers (i.e., ECCS/RCIC Suction Strainer, Q1M24D001) utilizes the acoustic wave methodology (References 1, 2, 3, and 4) in lieu of the Grand Gulf design load.

3B.8.1.6 Compressive Wave Loading

No deviations.

3B.8.1.7 Safety/Relief Valve Activation

No deviations.

3B.9 LOADS ON STRUCTURES AT THE POOL SURFACE

The maximum upward floor pressure specified for this design for Grand Gulf is equal to the maximum drywell pressure of 22.0 psid.

3B.10 LOADS ON STRUCTURES BETWEEN THE POOL SURFACE AND THE HCU FLOORS

No deviations.

3B.10.1 Impact Loads

No deviations. However, as a point of information, the GESSAR impact methodology is conservative for radial and circumferential beams and pipes up to an impact velocity of 60 ft/sec.

Grand Gulf has evaluated all piping within the pool swell zone and the results conclude that the current GESSAR pool swell impact load of 60 psi is conservative for Grand Gulf.

3B.10.2 Drag Loads

No deviations. However, as a point of clarification, the grating for the platforms above the suppression pool is designed to withstand dead, live, and seismic loads, and pool swell forces. [HISTORICAL INFORMATION] [The bulk pool swell drag load used for the design of the grating above the suppression pool and below the HCU floor is derived from an analytical method described in General Electric Interim Containment Loads Report (ICLR) No. 22A4365, Rev. 2, dated October 1978.] The present analytical method is shown in Figure 3B-72 of GESSAR II, Appendix 3B (Grand Gulf FSAR, Appendix 6D). The drag loads on gratings given in ICLR, Rev. 2, are identical to the drag loads determined by using the technique outlined in NUREG-0487. The load on the grating for the platforms above the suppression pool, based on an analytical technique described in NUREG-0487 and ICLR, Rev. 2, is well below the allowable load for the grating.

The drag load for grating above the suppression pool surface and below the HCU floor, based upon Figure 3B-72 of GESSAR II, Appendix 3B (Grand Gulf FSAR Appendix 6D), is also bounded by the drag loads used for design.

The grating design information is as follows:

Grating size	2-1/2" x 1/4" x 1-3/16" c/c
Percent open area	70 percent
Drag load on grating	
(per ICLR Rev. 2, Fig. 10.3)	9 psid
(per GESSAR II, App. 3B, Rev. 2, Fig. 3B-72)	6 psid
Dynamic amplification	
(per NUREG-0487, pp. III 30-33 and page D-2)	2
Effective equivalent static pressure	18 psid (approx 800 psf based on 30% solid area)

Initial design load	18 psid (approx 800 psf based on 30% solid area)
Grating capacity	1100 psf

In addition, all structures (piping and supports) within the region that is below the HCU floor and above the suppression pool have been evaluated for drag loads from either pool swell or froth with velocities in excess of 60 ft/sec. The results were found to be acceptable because pool swell impact loads or froth impact loads, where applicable, continue to be the bounding loads.

3B.10.3 Fallback Loads

No deviations.

3B.11 LOADS ON EXPANSIVE STRUCTURES AT THE HCU FLOOR

The peak calculated pressure differential for Grand Gulf is shown in Figure 6.2-10. Figure 6.2-10a shows the predicted Grand Gulf wetwell pressurization relative to HCU floor percent open area. The Grand Gulf methodology (proprietary) for application of the wetwell pressurization load to expansive structures at the HCU floor level has been provided in the letters from L. F. Dale, MP&L, to H. R. Denton, NRC, AECM-81/401, dated October 9, 1981, and from R. S. Trickovic, Bechtel Power Corporation, to H. R. Denton, NRC, VB-81/0577, dated November 10, 1981.

3B.12 LOADS ON SMALL STRUCTURES AT AND ABOVE THE HCU FLOOR ELEVATION

No deviations.

3B.13 REFERENCES

The following are Grand Gulf specific references:

1. "Mark II Containment Program Lead Plant Program Evaluation and Acceptance Criteria," Generic Technical Activity A-8, NUREG-0487, Supplement No. 2, U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Washington, D.C., February, 1981.

2. "Mark II Improved Chugging Methodology," NEDE-24822-P Class III General Electric Company, May 1980; This document was prepared for the Mark II Utility Owners' Group by Bechtel Power Corporation under contract with General Electric Company, (Proprietary).

3. "Mark II Containment Program Load Evaluation and Acceptance Criteria," Generic Technical Activity A-8, NUREG-0808, U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Washington, D.C., August, 1981.

4. "An Approach to Chugging, Assessment of RHR Steam Discharge Condensation Oscillation in Mark III Containments," Prepared for the Mark III Containment Issues Owners' Group, Job 16031, Bechtel Power Corporation, San Francisco Power Division, Nuclear Engineering Staff, March 1984, (Proprietary).

5. Letter, L.L. Kintner to O.D. Kingsley, Jr., "SER Relating to Humphrey Concerns," March 23, 1987, MAEC-87/0077.

ATTACHMENT A TO APPENDIX 3B
SAFETY/RELIEF VALVE LOADS (QUENCHER)

3BA.1 INTRODUCTION

No deviations.

3BA.2 SUMMARY AND CONCLUSIONS

Table 3BA-1 is not applicable to Grand Gulf. The enclosed Table A-1 lists the SRVDL information for Grand Gulf. Table 3BA-2 is not applicable to Grand Gulf. Table A-2 provides the results of the analysis to determine the maximum quencher bubble pressures for Grand Gulf. The SRVDL peak pressure is limited to 550 psid for Grand Gulf.

3BA.3 DESCRIPTION OF THE PHENOMENA

The SRVDL peak pressure is limited to 550 psid for Grand Gulf.

3BA.4 ARRANGEMENT

3BA.4.1 Distribution in Pool (Quencher Arrangement)

Figures 3BA-2 to 3BA-4 are not applicable to Grand Gulf. The enclosed Figures A-2, A-3, and A-4 show the elevation and plan views of the Grand Gulf quencher arrangement.

3BA.4.2 SRVDL Routing

Figure 3BA-7 is not applicable to Grand Gulf. Figure A-18 shows the SRVDL routing for Grand Gulf.

3BA.4.2.1 Line Lengths and Volume

Table 3BA-1 and Figure 3BA-7 are not applicable to Grand Gulf. Table A-1 shows Grand Gulf SRVDL line lengths and volumes based on the Grand Gulf SRVDL layout shown in Figure A-18.

3BA.4.2.2 Drywell Penetration Sleeve

The SRVDL drywell penetration sleeve for Grand Gulf is shown in Figure A-2.

3BA.4.2.3 SRVDL Vacuum Breaker

No deviations.

3BA.5 QUENCHER LOAD ON POOL BOUNDARY

3BA.5.1 Pressures on Drywell, Basemat, and Containment

Table 3BA-2 is not applicable to Grand Gulf. Table A-2 identifies the maximum and minimum bubble pressures for Grand Gulf.

3BA.5.1.1 Single SRV Loads

Table 3BA-6 and Figures 3BA-8, 3BA-9, and 3BA-10 are not applicable to Grand Gulf. Table A-3 and Figures A-5, A-6, and A-7 show the normalized dynamic peak pressure field and radial and circumferential peak values for Grand Gulf.

3BA.5.1.2 Two Adjacent SRV Loads

Table 3BA-7 and Figures 3BA-11, 3BA-12, and 3BA-13 are not applicable to Grand Gulf. Table A-4 and Figures A-8, A-9, and A-10 show the normalized dynamic peak pressure field and radial and circumferential peak values for the two adjacent SRVs V-8 and V-9 for Grand Gulf.

3BA.5.1.3 Eight SRV Loads (ADS)

Table 3BA-8 and Figures 3BA-14, 3BA-15, and 3BA-16 are not applicable to Grand Gulf. Table A-5 and Figures A-11, A-12, and A-13 show the normalized dynamic peak pressure field and radial and circumferential peak values for the eight ADS SRVs V-11, V-13, V-15, V-18, V-1, V-4, V-6 and V-8 for Grand Gulf.

3BA.5.1.4 All (19) SRV Loads

The Grand Gulf plant has twenty (20) SRVs. Table 3BA-9 and Figures 3BA-17, 3BA-18, and 3BA-19 are not applicable to Grand Gulf. Table A-6 and Figures A-14, A-15, and A-16 show the normalized dynamic peak pressure field and radial and circumferential peak values for all twenty SRVs V-1 to V-20 for Grand Gulf.

3BA.5.2 Load on Weir Wall

No deviations.

3BA.5.3 Loads on Submerged Structures

No deviations.

3BA.5.4 Normalized Pressure Time History (Theoretical Raleigh Bubble)

No deviations.

3BA.5.5 Representative Pressure Time History

No deviations.

3BA.5.6 Estimated Margins

3BA.5.6.1 Peak Bubble Pressures

Grand Gulf has specified design values for the four load cases described in subsection 3BA.12.5.1 and Table 3BA-11 that are equivalent to those specified for the GE238 standard design but are slightly different because of slightly different SRVDL volumes and routings. Grand Gulf's margins are equal to or greater than the margins shown in Table 3BA-11.

3BA.5.6.2 Bubble Pressure Amplitude

No deviations.

3BA.5.6.3 95% - 95% Confidence

No deviations.

3BA.5.6.4 Margin

Grand Gulf's margins are equal to or greater than the margins shown in Table 3BA-11.

3BA.6 OTHER LOADS ON STRUCTURES IN THE POOL

3BA.6.1 LOCA, Pool Swell, Condensation Oscillation, and Chugging

No deviations.

3BA.6.1.1 Forces on Pipes Due to Vent Clearing, Pool Swell and Fallback

The forces on piping and supports and the quenchers are calculated using the methods described in Attachment L (see also Table A-7). These loads have been included in the quencher anchor loads.

3BA.6.2 Thermal Expansion Loads

No deviations.

3BA.6.3 Seismic Loads

No deviations.

3BA.6.4 Seismic Slosh Loads

No deviations.

3BA.7 QUENCHER ANCHOR LOADS

Figures A-2, A-3 and A-4 show the general arrangement of the quencher in the pool. The quencher anchor loads are defined in Table A-9 and Figure A-17. Figures 3BA-2, 3BA-3, 3BA-5, 3BA-6 and 3BA-27 and Tables 3BA-13 and 3BA-14 are not applicable to Grand Gulf.

The Grand Gulf quencher rests in bearing on the containment basemat. A large cylindrical support arm extends from the quencher to the drywell wall. Moments and lateral and vertical-up forces are taken by this support arm. Vertical-down forces are taken by the support arm and the basemat.

3BA.7.1 Quencher Arm Loads and Quencher Loading Application

Table A-8 lists the maximum forces exerted on the quencher arms Table A-9 and Figure A-17 specify the design loads for the quencher. These loads are adjusted and incorporated into the design of the quencher-to-drywell interface.

3BA.7.2 Quencher Design Information

Figures A-2, A-3, and A-4 show the quencher side elevation, top elevation and angular locations in the suppression pool. Figures 3BA-2, 3BA-3 and 3BA-4 are not applicable to Grand Gulf.

3BA.7.2.1 Codes and Standards

No deviations.

3BA.7.2.2 Design Pressures, Temperatures, Loads, Configuration and Performance

3BA.7.2.2.1 Component Data for Safety/Relief Valve, Discharge Piping and Quencher

The maximum pressure and the design pressure for Grand Gulf is 550 psig.

3BA.7.2.2.2 SRVDL Geometry

No deviations.

3BA.7.2.2.3 Quencher Design Criteria

1.	Forces	See Tables A-8 and A-9 and Figure A-17
2.	Fatigue	18,000 cycles
3.	Cycles of operation	1,800

3BA.7.2.2.4 Quencher Configuration and Location

No comments except that the Grand Gulf design rating is 550 psig and the minimum centerline to centerline distance from the quencher to the ECCS strainers in 9 ft.

3BA.8 SRV VALVE LOAD COMBINATIONS

Figure 3BA-4 is not applicable to Grand Gulf. See Figure A-4 for the SRVDL discharge locations for Grand Gulf. Grand Gulf has a total of twenty SRVs.

3BA.8.1 Symmetric and Asymmetric Load Cases

Twenty valves actuated simultaneously are evaluated for the all valve case for Grand Gulf. Figures 3BA-10, 3BA-13, 3BA-16, and 3BA-19 are not applicable to Grand Gulf. See Figures A-7, A-10, A-13, and A-16, respectively for Grand Gulf.

3BA.8.2 SSE and OBE Considerations

No deviations.

3BA.8.3 LOCA Considerations

No deviations.

3BA.8.3.1 DBA With MS Line Break

No deviations.

3BA.8.3.2 DBA With Recirculation Line Break

No deviations.

3BA.8.3.3 Other SRV Conditions

No deviations.

3BA.8.3.3.1 Water Clearing Pressure Spike for SRV First Actuation, Normal Operating Conditions

No deviations.

3BA.8.3.3.2 SRV First Actuation With a Pressurized Containment

No deviations.

3BA.8.3.3.3 Water Clearing Pressure Spike for SRV, Second Actuation Normal Operating Conditions

No deviations.

3BA.8.3.3.4 Second Actuation of One SRV With a Pressurized Containment

No deviations.

3BA.8.3.3.5 First Actuation of One SRV, Leaking Valve Condition

No deviations.

3BA.8.3.3.6 SRV Steam Condensation

No deviations.

3BA.8.4 Design Load Summation

No deviations.

3BA.9 FATIGUE CYCLES

No deviations

3BA.10 CALCULATIONAL PROCEDURES FOR MARK III CONTAINMENT

Table 3BA-18 and Figure 3BA-86 are not applicable to Grand Gulf. Table A-10 illustrates the drywell and suppression pool geometry for Grand Gulf. Figure A-18 shows the arrangement of the Grand Gulf SRVDLs. Figure A-4 shows the location of the quenchers in the Grand Gulf suppression pool. The methodologies presented in this section have been used to calculate the Grand Gulf suppression pool loads for various combinations of SRV actuations. Grand Gulf unique parameters have been incorporated where required.

3BA.11 PARAMETRIC STUDIES

No deviations.

3BA.12 BASIS AND JUSTIFICATION FOR DEVELOPED QUENCHER LOADS

No deviations.

3BA.13 REFERENCES

No deviations.

ATTACHMENT B TO APPENDIX 3B
SCALING ANALYSES AND SMALL STRUCTURE POOL SWELL DYNAMIC LOADS

No deviations for the entire Attachment.

ATTACHMENT C TO APPENDIX 3B
WEIR ANNULUS BLOCKAGE

No deviations for the entire Attachment.

ATTACHMENT D TO APPENDIX 3B
DRYWELL PRESSURE DISTRIBUTION

No deviations for the entire Attachment.

ATTACHMENT E TO APPENDIX 3B
SUPPRESSION POOL SEISMIC-INDUCED LOADS

For suppression pool seismic-induced (sloshing) loads, the method described in Attachment E has been applied. For piping, the net increase in hydrostatic pressure caused by sloshing has been applied as an additional loading. The acceleration (a) of Attachment E is determined by using the horizontal and vertical acceleration of the pool water. This acceleration is taken from the required response spectra (RRS) for the particular pool elevation at the natural frequency of the pool mass. For example:

<u>Problem:</u> HPCS test return line, SSE, horizontal direction across the suppression pool (symbols are as described in Attachment B)

$a_h = 0.16$ g from RRS

W = 20.5 feet

$$\Delta P_H = \frac{\rho H}{144} + \frac{\rho W a_h}{144\ g}$$

Since the piping is completely surrounded by suppression pool water

$$\frac{\rho H}{144} = 0,$$

then

$$\Delta P_H = \frac{\rho W a_h}{144\ g}$$

$$\Delta P_H = \frac{\left(62.4 \frac{\text{lb}}{\text{ft}^3}\right)(20.5\ \text{feet})(0.16g)}{\left(144 \frac{\text{in}^2}{\text{ft}^2}\right) g}$$

$$\Delta P_H = 1.42\ \text{psid}$$

The load ΔP_H is uniformly applied to the projected cross sectional area of the piping. The load is combined with the inertial effects of the earthquake as well as other normal and accident loads.

ATTACHMENT F TO APPENDIX 3B
DIGITIZATION OF FORCING FUNCTION FOR CONDENSATION OSCILLATION

No deviations for the entire Attachment.

ATTACHMENT G TO APPENDIX 3B
DRYWELL NEGATIVE PRESSURE CALCULATION

Attachment G to Appendix 3B of GESSAR II (FSAR Appendix 6D) describes a very conservative bounding endpoint calculation that leads to the maximum theoretically possible negative pressure in the drywell. The maximum negative pressure is then used in the design of the drywell structure.

As shown in Grand Gulf FSAR Figure 6.2-10, the ECCS system will refill the reactor vessel. Once the vessel has been refilled to the elevation of the break, cool water will cascade from the break and start condensing steam in the drywell. This causes a depressurization of the drywell which will cause the suppression pool water to rise in the weir annulus and create a jet of water above the weir annulus. The jet front and steady state velocity profiles are shown in Figure A-19. The jet front velocity is used to calculate impact while the steady state velocity is used to calculate the drag loads. For cases where the component is below the top of the weir wall, the steady state velocity is as shown in Figure 3B-52 of Appendix 6D.

For items located above the top of the weir wall, impact loads are calculated using the following criteria:

a. Calculate the impulse using the equation:

$$I_p = \frac{M_H}{A} \times \frac{V}{(32.2)(144)}$$

Where I_p = Impulse per unit area, psi-sec

$\frac{M_H}{A}$ = Hydrodynamic mass per unit area, lbm/ft^2

V = Impact velocity, ft/sec

b. Determine the impulse duration (τ) based on the type of target and the test data reported in GE Topical Report NEDE-13426P, Class III, August 1975.

c. Calculate the loading using the equation:

$$P_{max} = \frac{2I_p}{\tau}$$

For drag loads above and below the top of the weir wall, the following equation is used:

$$F = \frac{C_D A \rho v^2}{2g_c}$$

F = Force

C_D = Drag coefficient

A = Area normal to flow

ρ = Density of water

g_c = Newton's constant

v = Velocity of fluid

ATTACHMENT H TO APPENDIX 3B
CONTAINMENT ASYMMETRIC LOADS

No deviations for the entire Attachment.

ATTACHMENT I TO APPENDIX 3B
SUPPRESSION POOL THERMAL STRATIFICATION

No deviations.

ATTACHMENT J TO APPENDIX 3B
WEIR WALL LOADS DURING DRYWELL DEPRESSURIZATION

No deviations for the entire Attachment.

ATTACHMENT K TO APPENDIX 3B
WETWELL ASYMMETRIC PRESSURES

No deviations to the entire Attachment.

ATTACHMENT L TO APPENDIX 3B
SUBMERGED STRUCTURE LOADS DUE TO LOCA AND SRV ACTUATIONS

3BL.1 Introduction

Drag loads on submerged structures (including piping) have been an issue on Mark III containments since 1976. In a letter from O.D. Parr to N. L. Stampley, July 1, 1976, the NRC position was that the absolute bubble pressure for the safety/relief (S/R) valve discharge or for the horizontal vent discharge during the LOCA should be the design basis for submerged structures. Our response was that we would follow the GESSAR resolution for this issue.

MP&L committed, in an August 15, 1979 meeting with the NRC, to provide a comparison between the acceptance criteria for Mark II containments (NUREG-0487, October 1978) and the Grand Gulf design basis. The purpose of the comparison is to demonstrate that the Grand Gulf design basis is conservative. The criteria contained in NUREG-0487 (including Supplement 1, September 1980; and Supplement 2, February 1981) were used as a guide for the comparison study.

a. LOCA Water Jet Loads. LOCA water jet loads were considered using the procedures described in GE topical report NEDE-21472, September 1977. The LOCA water jets dissipate before reaching the containment wall. In the region between the horizontal vent outlet and point of dissipation, all piping and piping supports have been located to avoid impact by the LOCA water jets. The acceptance criteria in NUREG 0487 contain a number of constraints and modifications. It is our understanding that these will be modified to consider the spherical vortex model. We will demonstrate that the Grand Gulf design is conservative once the NUREG supplement has been issued.

b. SRV Quencher Water Jet Loads. Grand Gulf uses the cross quencher (also known as the X quencher). Other than the quencher support, piping and supports have been located outside the sphere circumscribed about the quencher arms.

c. LOCA Air Bubble Loads. For these loads, the vent discharge absolute bubble pressure was used to establish design loads for submerged piping and structures (including piping supports). The following is a comparison between the Grand Gulf design basis and the criteria contained in NUREG-0487. This sample case is a 1-foot diameter pipe, 2 feet long that is located 4 feet from the drywell wall. The analysis shows that:

1. The Grand Gulf design basis yields 4980 lb_f.

2. The base method employed by the Mark II plants (from GE topical report NEDE-21471, September 1977) yields 1145 lb_f.

3. Adding 10% to the acceleration and velocity to estimate asymmetry per NUREG-0487 would result in a load of 1275 lb_f.

4. Increasing the drag coefficient for standard drag by a factor of 3 would result in a design load of 1650 lb_f.

5. Subsection II.C.2 of NUREG-0487 identifies the acceptance criteria for analysis of interference effects for computing drag loads on structures that are closer together than the equivalent diameter of the larger structure. Attachment 1.K of the Zimmer Nuclear Power Station FSAR, September 28, 1979, provides an alternative method for evaluating interference effects and has been accepted by the Staff as described in Supplement 1 of NUREG-0487. An arbitrary sample case was evaluated assuming that the 1-foot diameter line evaluated above was located within 4 inches of another 12-inch diameter line. The resultant loading for the sample case would be 2870 lbf which is less than 60 percent of the Grand Gulf design basis.

The design of the floor mounted portion of the ECCS suction strainers (i.e., ECCS/RCIC Suction Strainer, Q1M24D001) utilizes the GESSAR II load definition (method of images) for these loads.

d. SRV Air Bubble Loads. Supplement 1 of NUREG-0487, Subsection II.C.2 discusses acceptance criteria for SRV air bubble loads. The criteria accept application of the methodology contained in Attachment 1.K of the Zimmer Nuclear Power Station FSAR, September 28, 1979. For a pipe section that is 12 inches in diameter and 24 inches long, the loading based on the methodology would be 960 lb_f. Using the Grand Gulf design basis for the same situation, the loading would be 3915 lb_f.

   The design of the floor mounted portion of the ECCS suction strainers (i.e., ECCS/RCIC Suction Strainer, Q1M24D001) utilizes the GESSAR II load definition (method of images) for these loads.

e. Condensation Oscillation and Chugging Loads. Supplement 2 of NUREG-0487 addresses interim condensation oscillation and chugging loads based on the 4T CO tests. Because of the geometry of the Mark II vent system, it is not appropriate to apply the test results to the evaluation of submerged piping and structures in the Grand Gulf Mark III suppression pool. As demonstrated previously, the Grand Gulf design basis for submerged structures is very conservative.

   For Condensation oscillation loads, the design of the floor mounted portion of the ECCS suction strainers (i.e., ECCS/RCIC Suction Strainer, Q1M24D001) utilizes the GESSAR II load definition (method of images).

   For chugging loads, the design of the floor mounted portion of the ECCS suction strainers (i.e., ECCS/RCIC Suction Strainer, Q1M24D001) utilizes the acoustic wave methodology (References 1, 2, 3 and 4 of 3B.13).

In addition to the loads specified above, a dynamic load factor is applied for each load used in the design. The load factor depends upon the forcing function for the load and the natural frequency of the pipe or support.

Grand Gulf's design basis is more conservative than the Mark II acceptance criteria, and is more conservative than the criteria specified in Attachment L.

The load definition for the floor mounted portion of the ECCS suction strainers (i.e., ECCS/RCIC Suction Strainer, Q1M24D001) differs slightly from the Grand Gulf load definition in that the GESSAR II method of images is used for the SRV air bubble and condensation oscillation loads and the acoustic wave methodology is used for the LOCA vent chugging loads.

ATTACHMENT M TO APPENDIX 3B
POOL SWELL VELOCITY

No deviations for the entire Attachment.

All structures, piping, and supports within the region that is below the HCU floor and above the suppression pool surface have been evaluated for drag loads from bulk pool swell or pool swell froth for a bounding pool swell velocity of 60 ft/sec. The results were found to be acceptable because pool swell impact loads or froth impact loads, where applicable, are the controlling design loads.

ATTACHMENT N TO APPENDIX 3B
MULTIPLE SAFETY/RELIEF VALVE ACTUATION FORCING FUNCTION METHODS

3BN.1 INTRODUCTION

No deviations.

3BN.2 RANDOM PARAMETERS

3BN.2.1 Reactor Vessel Pressure Rise Rate (PRR)

No deviations.

3BN.2.2 Valve Setpoint Tolerance (VST)

Grand Gulf employs 20 SRVs with one pressure switch set at 1103 psi, ten with a pressure switch set at 1113 psi, and nine with a pressure switch set at 1123 psi. The SRV arrangement and pressure setpoints for Grand Gulf are shown in Figure A-4, Appendix 6A.

3BN.2.3 Valve Openinq Time (VOT)

No deviations.

3BN.2.4 Quencher Bubble Frequency Distribution (QBF)

No deviations.

3BN.3 MONTE CARLO TRIAL SIMULATIONS

No deviations.

3BN.4 FACTORS AFFECTING PRESSURE DISTRIBUTION ON THE SUPPRESSION POOL BOUNDARY

No deviations.

3BN.5 FORCING FUNCTIONS FOR NSSS EQUIPMENT

No deviations.

3BN.6 STRUCTURAL RESPONSE ANALYSIS

Resulting dynamic responses for the critical cases selected in subsection 3BN.5.4 are enveloped and used for both BOP and NSSS equipment and structural evaluations.

3BN.7 EXAMPLE OF TYPICAL TIME SEQUENCING APPLICATION

The use of Grand Gulf unique parameters and the procedures in this subsection result in Grand Gulf unique SRV forcing functions which have been used to determine the dynamic response necessary for NSSS and balance-of-plant equipment evaluation.

3BN.8 COMPARISON OF SELECTED TRIALS WITH THE FOURIER SPECTRA OF THE 59 MONTE CARLO SIMULATIONS

No deviations.

3BN.9 CONSERVATISM OF SRVA METHODOLOGY

No comments.

ATTACHMENT O TO APPENDIX 3B
APPENDIX 3B QUESTION AND RESPONSE GUIDE

No deviations from the entire attachment.

ATTACHMENT P TO APPENDIX 3B
DATA AND ANALYSES PERTAINING TO SRV ACTUATION RANDOM PARAMETERS

No deviations from the entire attachment.

TABLE 6A.1: SRVDL GRAND GULF

S/R Valve	Total Length	10" S/40^{5}	12" S/40S	14" S/30	Volume (Ft^{3})	Max (a) $f\ell/D$
V-1	94.42	60.29	27.71	--	57.98	2.56
		6.42*				
V-2	86.56	35.46	44.68	--	57.71	2.18
		6.42*				
V-3	73.40	29.46	--	37.52	55.26	1.69
		6.42*				
V-4	79.75	24.17	41.88	7.28	56.29	1.93
		6.42*				
V-5	78.18	19.74	39.84	12.18	56.96	1.93
		6.42*				
V-6	81.58	29.71	20.99	24.46	59.38	2.04
		6.42*				
V-7	71.44	27.70	--	37.32	54.11	1.89
		6.42*				
V-8	62.84	20.73	12.27	23.42+	53.89	1.68
		6.42*				
V-9	71.93	30.32	19.78	15.41+	54.88	1.73
		6.42*				
V-10	70.74	41.01	--	23.31+	55.22	1.99
		6.42*				

TABLE 6A.1: SRVDL GRAND GULF (CONTINUED)

S/R Valve	Total Length	10" S/40[5]	12" S/40S	14" S/30	Volume (Ft^3)	Max (a) $f\ell/D$
V-11	76.40	34.03	--	35.95	56.26	2.10
		6.42*				
V-12	78.84	34.50	--	37.92	58.40	1.90
		6.42*				
V-13	72.50	29.44	--	36.64	54.40	1.93
		6.42*				
V-14	74.49	18.76	40.23	9.08	53.78	1.83
		6.42*				
V-15	82.73	24.01	43.42	8.88	58.95	1.95
		6.42*				
V-16	82.89	25.79	50.68	--	57.13	2.21
		6.42*				
V-17	81.86	23.51	44.52	7.41	58.13	2.02
		6.42*				
V-18	79.68	23.97	38.87	10.42	56.84	1.77
		6.42*				
V-19	83.29	27.25	49.62	--	57.10	1.97
		6.42*				
V-20	88.87	35.72	46.73	--	59.46	2.13
		6.42*				

NOTES
1. * = SCH 80
2. f= 0.015
3. (a) is normalized to 10” schedule 40 pipe
4. + = 16” SCH 30
5. 10” S/40 length includes vacuum breaker piping within SRVDL boundary.

TABLE 6A.2: QUENCHER PRESSURE MARK III, GRAND GULF NUCLEAR STATION 95-95% CONFIDENCE LEVEL

	Design Value - Basemat Maximum Pressure (psid)		Containment Wall * Peak Pressure (psid)	
Case Description	P_B (+)	P_B (-)	P(+)	P(-)
Lowest set valve(s) <u>First Actuation</u>, at 100 F Pool Temperature	10.7	6.5	6.7	4.1
Lowest set valve(s) <u>Subsequent Actuation</u>, at 120 F Pool Temperature	19.0	7.9	12.0	4.9
Two Adjacent Valves <u>First Actuation</u> at 100 F Pool Temperature	10.7	6.5	8.6	5.2
All Valves <u>First Actuation</u>, at 100 F Pool Temperature	11.8	6.3	11.8	6.3
ADS Valves <u>First Actuation</u> at 120 F Pool Temperature	10.3	6.4	7.7	4.7

*Point 10 on Containment is Peak Pressure (Ref. NEDO-11314-08, June 18, 1976).

TABLE 6A.3: BUBBLE DYNAMIC PRESSURE FIELD FOR ONE S/R VALVE QUENCHER

S/R Valve Reference Point/Angle	V-10 0°	8°	16°	24°	32°	40°	48°	56°	64°	72°	80°	8°
13	-	-	-	-	-	-	-	-	-	-	-	-
12	0.541834	0.500145	0.416642	0.339797	0.281252	0.238190	0.206213	0.181974	0.163208	0.148406	0.136549	-
11	0.604545	0.548188	0.443213	0.353756	0.289015	0.242851	0.209214	0.184027	0.164684	0.149514	0.137410	-
10	0.628259	0.565684	0.452308	0.358329	0.291493	0.244315	0.210149	0.184661	0.165139	0.149854	0.137674	-
9	0.597806	0.543149	0.440537	0.352391	0.288269	0.242408	0.208931	0.183834	0.164546	0.149410	0.137330	-
8	0.845043	0.717408	0.529981	0.400941	0.318263	0.263115	0.224460	0.196200	0.174836	0.158259	0.145135	-
7	1.00000	0.975911	0.629752	0.449820	0.347839	0.283693	0.240134	0.208882	0.185540	0.167575	-	-
6	1.00000	1.00000	0.700740	0.486937	0.372389	0.302070	0.254914	0.221328	0.196356	-	-	-
5	1.00000	1.00000	0.689205	0.497119	0.386013	-	-	-	-	-	-	-
4	1.00000	1.00000	0.737100	0.514223	0.393859	-	-	-	-	-	-	-
3	1.00000	1.00000	0.69959	0.500975	0.387810	-	-	-	-	-	-	-
2	0.937727	0.807621	0.607096	0.463516	0.369633	-	-	-	-	-	-	-
1	-	-	-	-	-	-	-	-	-	-	-	-

NOTE: The pressure field is based on P(B max.) normalized to 1 psid.

TABLE 6A.4: BUBBLE DYNAMIC PRESSURE FIELD FOR TWO S/R VALVE QUENCHERS

S/R valve Reference Point/Angle	V-9 344°	352°	V-10 0°	8°	16°	24°	32°	40°	48°	56°	64°	72°	80°	88°
13	-	-	-	-	-	-	-		-	-	-	-	-	-
12	0.68283	0.70661	0.68283	0.60416	0.50240	0.41480	0.34865	0.29969	0.26294	0.23479	0.21277	0.14839	0.13653	-
11	0.74924	0.77488	0.74924	0.65216	0.52898	0.42902	0.35675	0.30467	0.26623	0.23709	0.21447	0.14950	0.13740	-
10	0.77416	0.80002	0.77416	0.66964	0.53810	0.43369	0.35935	0.30625	0.26727	0.23781	0.21500	0.14985	0.13767	-
9	0.74283	0.76837	0.74283	0.64762	0.52686	0.42776	0.35604	0.30424	0.26595	0.23690	0.21433	0.14941	0.13733	-
8	0.99813	1.00000	0.99813	0.82223	0.61835	0.47963	0.38948	0.32823	0.28453	0.25208	0.22723	0.15826	0.14513	-
7	1.00000	1.00000	1.00000	1.00000	0.71969	0.53190	0.42272	0.35232	0.30347	0.26780	0.18554	0.16758	-	-
6	1.00000	1.00000	1.00000	1.00000	0.79390	0.57314	0.45133	0.37450	0.32179	0.22134	0.19636	-	-	-
5	1.00000	1.00000	1.00000	1.00000	0.79028	0.49725	0.38607	-	-	-	-	-	-	-
4	1.00000	1.00000	1.00000	1.00000	0.83576	0.21423	0.39386	-	-	-	-	-	-	-
3	1.00000	1.00000	1.00000	1.00000	0.79936	0.50077	0.38771	-	-	-	-	-	-	-
2	1.00000	1.00000	1.00000	0.92920	0.70991	0.46312	0.36943	-	-	-	-	-	-	-
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-

NOTE: The pressure field is based on P(B max.) normalized to 1 psid.

S

TABLE 6A.5: BUBBLE DYNAMIC PRESSURE FIELD FOR EIGHT S/R VALVE QUENCHERS

S/R Valve Reference Point/Angle	0	8	V-11 16	24	32	40	V-13 48	56	64	72	80	V-15 88
13	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000
12	.563122	.532978	.660986	.651986	.637742	.655653	.669126	.635904	.594509	.590462	.623499	.663852
11	.588225	.675317	.717549	.697459	.673590	.701133	.725677	.679499	.622580	.618441	.666972	.700235
10	.596805	.690870	.739134	.713993	.685964	.717658	.747224	.695433	.632147	.627982	.682900	.721831
9	.585877	.671165	.711863	.693030	.670214	.696705	.719999	.675238	.61996	.615828	.662716	.694553
8	.676612	.834188	.944443	.863213	.794466	.866894	.952283	.840760	.719237	.714796	.828034	.927307
7	.776991	1.00000	1.00000	1.00000	.933774	1.00000	1.00000	1.00000	.827719	.823060	1.00000	1.00000
6	.833831	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.890950	.903521	1.00000	1.00000
5	.790289	1.00000	1.00000	1.00000	.975194	1.00000	1.00000	1.00000	.850156	.850156	1.00000	1.00000
4	.835753	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	.898771	.898771	1.00000	1.00000
3	.799599	1.00000	1.00000	1.00000	.988940	1.00000	1.00000	1.00000	.860154	.860154	1.00000	1.00000
2	.710388	.806695	1.00000	.930291	.858007	.930291	1.00000	.887311	.763396	.763396	.887311	.936279
1	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000

S/R Valve Reference Point/Angle	96	104	112	120	128	V-18 136	144	152	160	167	176	V-1 184
13	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000
12	.606474	.551653	.528666	.548838	.598668	.615074	.582889	.528394	.502846	.520779	.570345	.598182
11	.649592	.576743	.547453	.573900	.641923	.672884	.627044	.554082	.522097	.546597	.614981	.656779
10	.665447	.585331	.553653	.582482	.657843	.695022	.643275	.562875	.528451	.555438	.631393	.679227
9	.645359	.574394	.545737	.571553	.637675	.667058	.622711	.551677	.520338	.544179	.610600	.650872
8	.809909	.664779	.614199	.661805	.802535	.903327	.789301	.642603	.588787	.635164	.778180	.889190
7	1.00000	.749397	.683644	.761886	1.00000	1.00000	1.00000	.743228	.657982	.719694	1.00000	1.00000
6	1.00000	.824182	.716257	.817828	1.00000	1.00000	1.00000	.817828	.688814	.793904	1.00000	1.00000
5	1.00000	.790289	.703225	.790289	1.00000	1.00000	1.00000	.790289	.703225	.790289	1.00000	1.00000

TABLE 6A.5: BUBBLE DYNAMIC PRESSURE FIELD FOR EIGHT S/R VALVE QUENCHERS (CONTINUED)

S/R Valve Reference Point/Angle	96	104	112	120	128	V-18 136	144	152	160	167	176	V-1 184
4	1.00000	.835753	.727233	.835753	1.00000	1.00000	1.00000	.835753	.727233	.835753	1.00000	1.00000
3	1.00000	.799599	.708328	.799599	1.00000	1.00000	1.00000	.799599	.708328	.799599	1.00000	1.00000
2	.806695	.710388	.655264	.710388	.806695	.936279	.806695	.710388	.655264	.710388	.806695	.936279
1	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000

S/R Valve Reference Point/Angle	192	200	208	216	224	232	240	248	V-4 256	264	272	280
13	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000
12	.556480	.482939	.445646	.420086	.403037	.437085	.499112	.593235	.645297	.640796	.616507	.638637
11	.601111	.507300	.458386	.428629	.411835	.450274	.523451	.636649	.702469	.686634	.653149	.685006
10	.617563	.515712	.462575	.431359	.414646	.454604	.531837	.652632	.724301	.703306	.665790	.701838
9	.596722	.505006	.457225	.427866	.411049	.449074	.521162	.632384	.696719	.682168	.649700	.680494
8	.764412	.591711	.507260	.465475	.448469	.499697	.608227	.797580	.930931	.853056	.774988	.852325
7	1.00000	.689202	.536828	.479171	.485746	.551123	.705863	1.00000	1.00000	1.00000	.915154	1.00000
6	1.00000	.760999	.549748	.479563	.518208	.592634	.778171	1.00000	1.00000	1.00000	1.00000	1.00000
5	1.00000	.689566	.497255	.386077	.386077	.497255	.689566	1.00000	1.00000	1.00000	1.00000	1.00000
4	1.00000	.737126	.514232	.393863	.393863	.514232	.737126	1.00000	1.00000	1.00000	1.00000	1.00000
3	1.00000	.699286	.500863	.387758	.387758	.500863	.699286	1.00000	1.00000	1.00000	.988940	1.00000
2	.806695	.606703	.463342	.369545	.369545	.463342	.606703	.806695	1.00000	.930292	.858007	.930291
1	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000

S/R Valve Reference Point/Angle	V-6 288°	296°	304°	312°	320°	V-8 328°	336°	344°	352°
13	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000
12	.655046	.635904	.594509	.590462	.623499	.658171	.624366	.558848	.539051

TABLE 6A.5: BUBBLE DYNAMIC PRESSURE FIELD FOR EIGHT S/R VALVE QUENCHERS (CONTINUED)

11	.712549	.679500	.622580	.618441	.666972	.713590	.666576	.583842	.557867
10	.734432	.695433	.632147	.627982	.682900	.734843	.682112	.592392	.564070
9	.706780	.675239	.619960	.615828	.662716	.708000	.662430	.581503	.556149
8	.941157	.840761	.719237	.714796	.828034	.938597	.825227	.671890	.625052
7	1.000000	1.000000	.827719	.823060	1.000000	1.000000	1.000000	.772026	.694926
6	1.000000	1.000000	.890950	.903521	1.000000	1.000000	1.000000	.847251	.749677
5	1.000000	1.000000	.850156	.850156	1.000000	1.000000	1.000000	.790289	.703225
4	1.000000	1.000000	.898771	.898771	1.000000	1.000000	1.000000	.835753	.727233
3	1.000000	1.000000	.860154	.860154	1.000000	1.000000	1.000000	.799599	.708328
2	1.000000	.887311	.763396	.763396	.887311	.936279	.806695	.710388	.655264
1	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000

TABLE 6A.6: BUBBLE DYNAMIC PRESSURE FIELD FOR TWENTY S/R VALVE QUENCHERS

S/R Valve	V-10		V-11		V-12		V-13			V-14		V-15
Reference Point/Angle	0°	8°	16°	24°	32°	40°	48°	56°	64°	72°	80°	88°
13	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000
12	.963065	.970135	.960572	.964538	.958637	.945516	.927855	.904190	.904190	.927855	.945516	.958637
11	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	.987521	.954101	.954101	.987521	1.000000	1.000000
10	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	.971909	.971909	1.000000	1.000000	1.000000
9	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	.981643	.949301	.949301	.981643	1.000000	1.000000
8	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
7	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
6	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
5	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
4	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
3	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
2	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
1	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000

S/R Valve		V-16		V-17		V-18		V-19		V-20		V-1
Reference Point/Angle	96°	104°	112°	120°	128°	136°	144°	152°	160°	168°	176°	184°
13	.000000	.000000	.000000	.000000	1.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000
12	.964538	.970228	.971875	.975064	.975201	.967841	.965594	.963705	.958074	.953012	.942240	.928581
11	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	.993720
10	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
9	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	.999830	.987318
8	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
7	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
6	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
5	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
4	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000

TABLE 6A.6: BUBBLE DYNAMIC PRESSURE FIELD FOR TWENTY S/R VALVE QUENCHERS (CONTINUED)

S/R Valve		V-16		V-17		V-18		V-19		V-20		V-1
Reference Point/Angle	96°	104°	112°	120°	128°	136°	144°	152°	160°	168°	176°	184°
3	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
2	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
1	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000

S/R Valve		V-2					V-3		V-4		V-5	
Reference Point/Angle	192°	200°	208°	216°	224°	232°	240°	248°	256°	264°	272°	280°
13	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000
12	.902729	.863424	.802543	.753415	.740939	.800435	.849850	.897254	.910823	.929385	.923695	.926019
11	.964766	.921999	.844950	.780999	.768816	.842892	.909084	.959456	.976693	.993328	.989463	.988410
10	.987452	.943887	.860244	.790313	.778229	.858206	.931211	.982207	1.000000	1.000000	1.000000	1.000000
9	.958699	.916193	.840843	.778441	.766231	.838780	.903215	.953373	.970219	.987099	.983004	.982322
8	1.000000	1.000000	1.000000	.882037	.870013	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
7	1.000000	1.000000	1.000000	.982194	.982194	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
6	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
5	1.000000	1.000000	1.000000	.933713	.933713	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
4	1.000000	1.000000	1.000000	.981283	.981283	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
3	1.000000	1.000000	1.000000	.943516	.943516	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
2	1.000000	1.000000	1.000000	.848137	.848137	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
1	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000

S/R Valve	V-6			V-7		V-8		V-9	
Reference Point/Angle	288°	296°	304°	312°	320°	328°	336°	344°	352°
13	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000
12	.903126	.891929	.893821	.927856	.945516	.958637	.964538	.960572	.970135
11	.963948	.942314	.944155	.987521	1.000000	1.000000	1.000000	1.000000	1.000000
10	.986458	.960287	.962108	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000

TABLE 6A.6: BUBBLE DYNAMIC PRESSURE FIELD FOR TWENTY S/R VALVE QUENCHERS (CONTINUED)

S/R Valve Reference Point/Angle	V-6 288°	296°	304°	V-7 312°	320°	V-8 328°	336°	V-9 344°	352°
9	.957959	.937469	.939315	.981643	1.000000	1.000000	1.000000	1.000000	1.000000
8	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
7	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
6	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
5	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
4	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
3	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
2	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000	1.000000
1	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000	.000000

TABLE 6A.7: LOCA LOADS ON PIPES

Event	Time (sec)	F_p* Force On Quencher (lbf)	Water Velocity (ft/sec)	Reference
Water clearing	0.1 to 0.7		Refer to subsection 3B.6.1.2	
Pool swell	0.7 to 3		40	Sec. 3B.8.1.2
Fall back	3 to 6		35	Sec. 3B.8.1.3

$$*F_p = \frac{C_D \ \rho \ V^2}{2g(144)} \ A$$

TABLE 6A.8: GRAND GULF QUENCHER ARM LOADS

Load Description	
Air clearing - (lbs)	10,800
(Location F_a, any direction normal to arm centerline)	
Adjacent S/R - (lbs)	5,660
(Location F_b, horizontal direction)	
LOCA vent - (lbs)	10,250
(Location F_c, horizontal direction)	
Arm weight - (lbs)	350
(Location F_d, downward direction)	
Earthquake load, 1.25g - (lbs) at SSE	280
(Location F_e, vertical direction)	
Earthquake load, 1.0g - (lbs) at SSE	600
(Location F_f, horizontal direction)	

*Due to single valve subsequent actuation.

TABLE 6A.9: GRAND GULF QUENCHER ANCHOR LOADS

LOAD SUMMARY

Upset Plant Condition

Case 1 - Active

Symbol	Description		Water Clearing	Air Clearing
F_L	Lateral loads (lbf)		32,770	80,410
F_V	Vertical loads (lbf)	up	40,690	53,690
		down	202,430	70,950
M_L	Lateral moment (ft-lb)		89,570	173,460
M_V	Vertical moment (ft-lb)		36,390	101,430

Case 2 - Inactive

Symbol	Description		Water Clearing	Air Clearing
F_L	Lateral loads (lbf)		6,950	70,140
F_V	Vertical loads (lbf)	up	2,320	4,040
		down	8,930	10,640
M_L	Lateral moment (ft-lb)		12,950	36,750
M_V	Vertical moment (ft-lb)		0	27,780

LOAD SUMMARY

Faulted Plant Condition

Case 1 - Active

Symbol	Description		Water Clearing	Air Clearing
F_L	Lateral loads (lbf)		50,480	102,750
F_V	Vertical loads (lbf)	up	42,920	57,570
		down	204,660	74,830
M_L	Lateral moment (ft-lb)		141,000	246,240
M_V	Vertical moment (ft-lb)		40,360	116,540

TABLE 6A.9: GRAND GULF QUENCHER ANCHOR LOADS (CONTINUED)

	Case 2 - Inactive			
F_L	Lateral loads (lbf)		69,930	79,980
F_V	Vertical loads (lbf)	up	37,370	41,470
		down	18,620	22,710
M_L	Lateral moment (ft-lb)		260,280	306,660
M_V	Vertical moment (ft-lb)		23,480	51,120

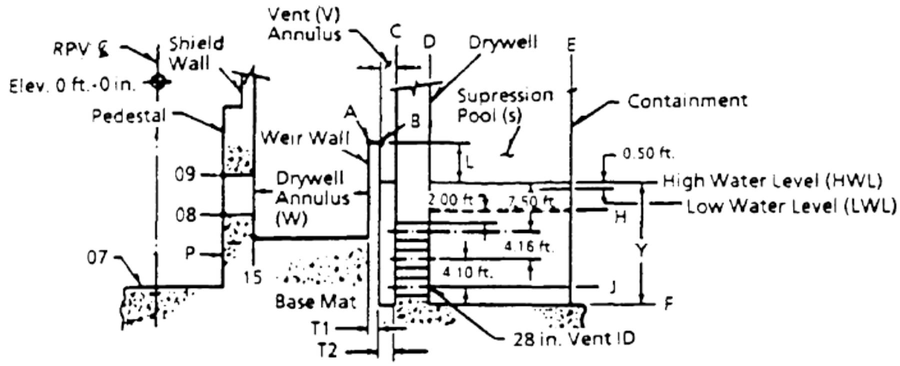

Table 1

PLT. SIZE/CNTMT-DIA. OR NO. OF FUEL BUNDLE					DESCRIPTIONS	
218/114 IN.	*218/120	*238	GG[1]	*251/864		
(-) 8.33	(-) 8.33	(-) 5.50	(-) 5.5	(-) 7.08	A	ELEV TOP OF WEIR WALL
455	455	482	553.7	570	V	VENT ANNULUS AREA (ft²)
5760	6863	6382	7219	8170	V + S	TOTAL AREA (ft²)
(-) 12.58	(-) 12.58	(-) 11.16	(-) 11.00	(-) 13.00	HWL	HIGH WATER LEVEL ELEV
4.25	4.25	5.67	5.5	5.92	L	MIN FREEBOARD (ft)
(-) 16.92	(-) 16.92	(-) 15.50	(-) 15.31	(-) 17.33	H	DRAWDOWN LEVEL ELEV
19.42	19.42	20.42	18.81	19.00	Y	POOL DEPTH (ft)
111.00	131.90	129.60	135.29	153.90		POOL VOL (1,000 FT³) AT LWL
21.80	17.31	34.15	36.16	30.03		DRAWDOWN MAKEUP VOL (1000 FT³)
(-) 29.08	(-) 29.08	(-) 27.67	(-) 28.81	(-) 29.50	J	℄ OF BOTTOM VENTS ELEV
(-) 32.00	(-) 32.00	(-) 31.58	(-) 29.81	(-) 32.00	F	ELEV TOP OF BASE MAT
102	102	120	135	135		NUMBER OF VENTS
34	34	40	45	45		VENT STATIONS
420	420	495	577	557		GROSS VENT AREA (ft²)
2100	2100	2475	2886.3	2785		VENT VOLUME (ft³)
16	16	19	20	22		NUMBER OF SAFETY RELIEF VALVE
6.38	6.38	5.75	5.10	5.25		CIRCUMFERENTIAL VENT SPC'G DW ID
2223	2223	2535	2486	2688	W	AREA (ft²)
27.84	27.84	39.29	41.13	38.75	W	VOLUME (1000 FT³)
267.6	267.60	301.10	351.88	351.90	P	AREA (ft²)
5525	5525	6948	8010.7[2]	7477	P	VOLUME (ft³)
(-) 28.98	(-) 28.98	(-) 28.58	(-) 28.33	(-) 28.33	07	RSO PT ELEV (REF)
(-) 19.35	(-) 19.35	(-) 19.46	(-) 18.75	(-) 19.21	08	RSO PT ELEV (REF)
(-) 12.35	(-) 12.35	(-) 12.46	(-) 11.75	(-) 12.21	09	RSO PT ELEV (REF)
(-) 20.85	(-) 20.85	(-) 20.98	(-) 22.08	(-) 21.90	15	RSO PT ELEV (REF)
118.00	118.00	145.50	165.6	(LTR)		110°F
					STD	REQD POOL VOL (1000 ft³) VS SVCE WATER TEMP
102.40	102.40	124.20	141.9	(LTR)	PLT	100°F
87.60	87.60	108.50	123.2	(LTR)		90°F

Notes: 1. GG as-built parameters.
2. Pedstel volume available to capture supression pool inventory including drywell sumps.

Table 2

PLT SIZE		08 (REF)	15 (REF)	A	B	C	D	E	T_1	T_2
218	DIA	18.42	29.83	61	64.67	69	79	114	1.83	2.17
	RAD	9.21	14.91	30.50	32.33	34.50	39.50	57		
218*	DIA	18.42	29.83	61	64.67	69	79	120	1.83	2.17
	RAD	9.21	14.91	30.50	32.33	34.50	39.50	60		
238*	DIA	19.58	31.58	65	68.67	73	83	120	1.83	2.17
	RAD	9.79	15.79	32.50	34.33	36.50	41.50	60		
251*/GG	DIA	21.17	32.66	65.0	68	73	83	124	1.50	2.50
	RAD	10.58	16.33	32.5	34	36.50	41.50	62		

Note: Plants identified with (*) asterisk are standard plants

Table A-10

DRYWELL AND SUPPRESSION POOL GEOMETRY

FIGURE 3BA-1 IS NOT APPLICABLE TO GRAND GULF. THE MAXIMUM PRESSURE IN THE SRVDL IS 550 PSIG. THE FACTOR $F \frac{l}{D}$ HAS BEEN LISTED IN TABLE A-1

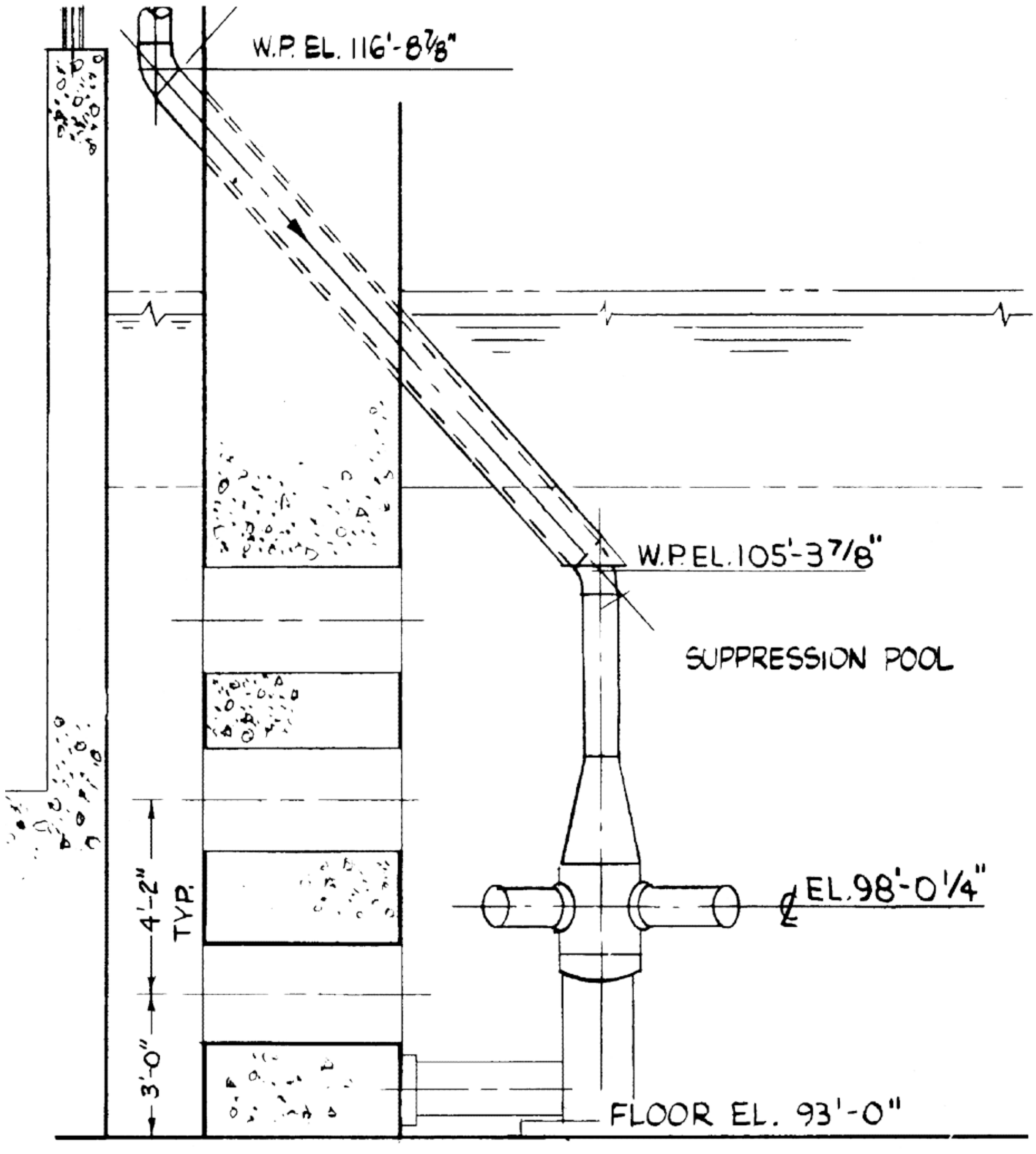

FIGURE A-2' GRAND GULF QUENCHER ARRANGEMENT

UPDATED FINAL SAFETY ANALYSIS REPORT

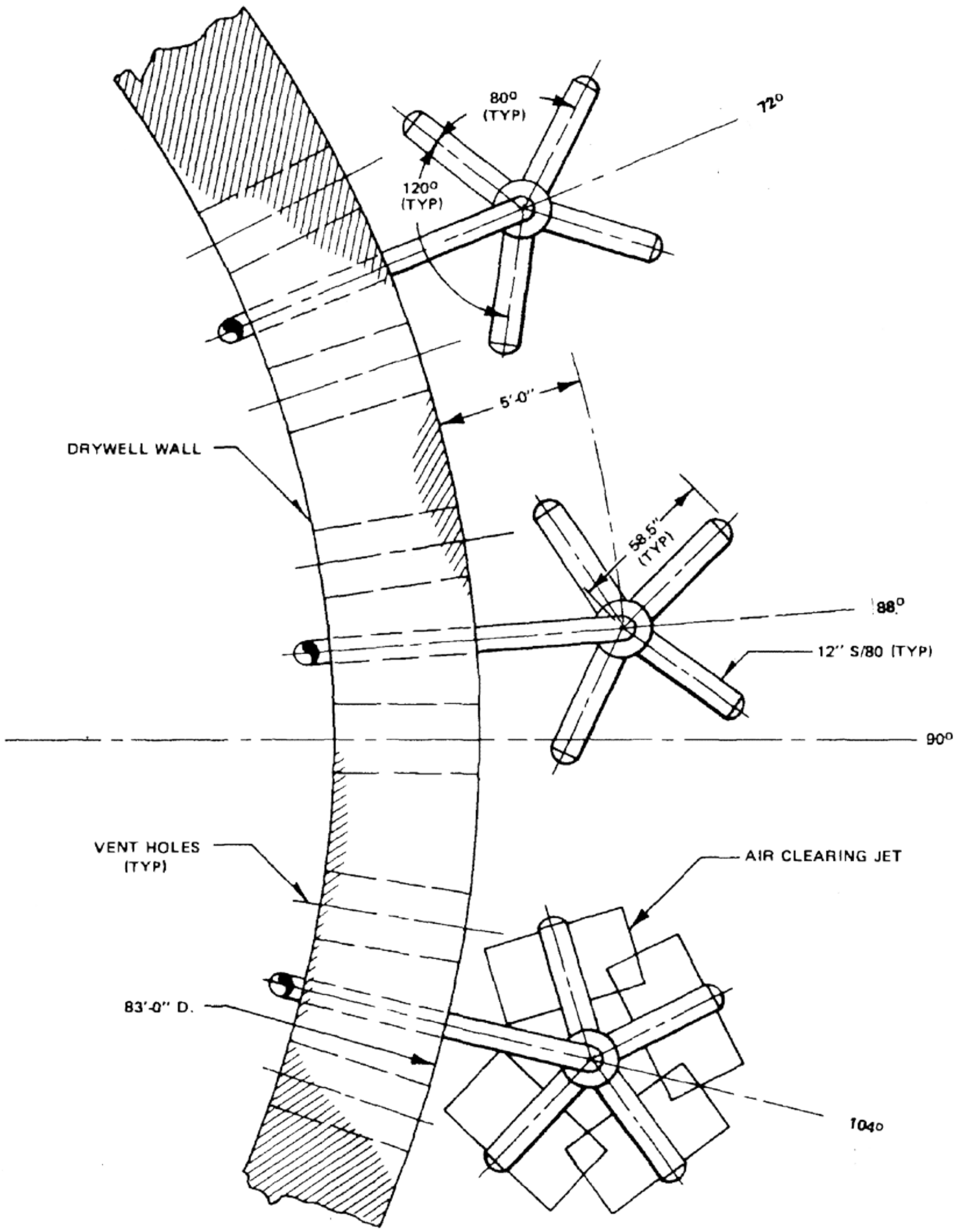

FIGURE A-3 GRAND GULF QUENCHER PLAN
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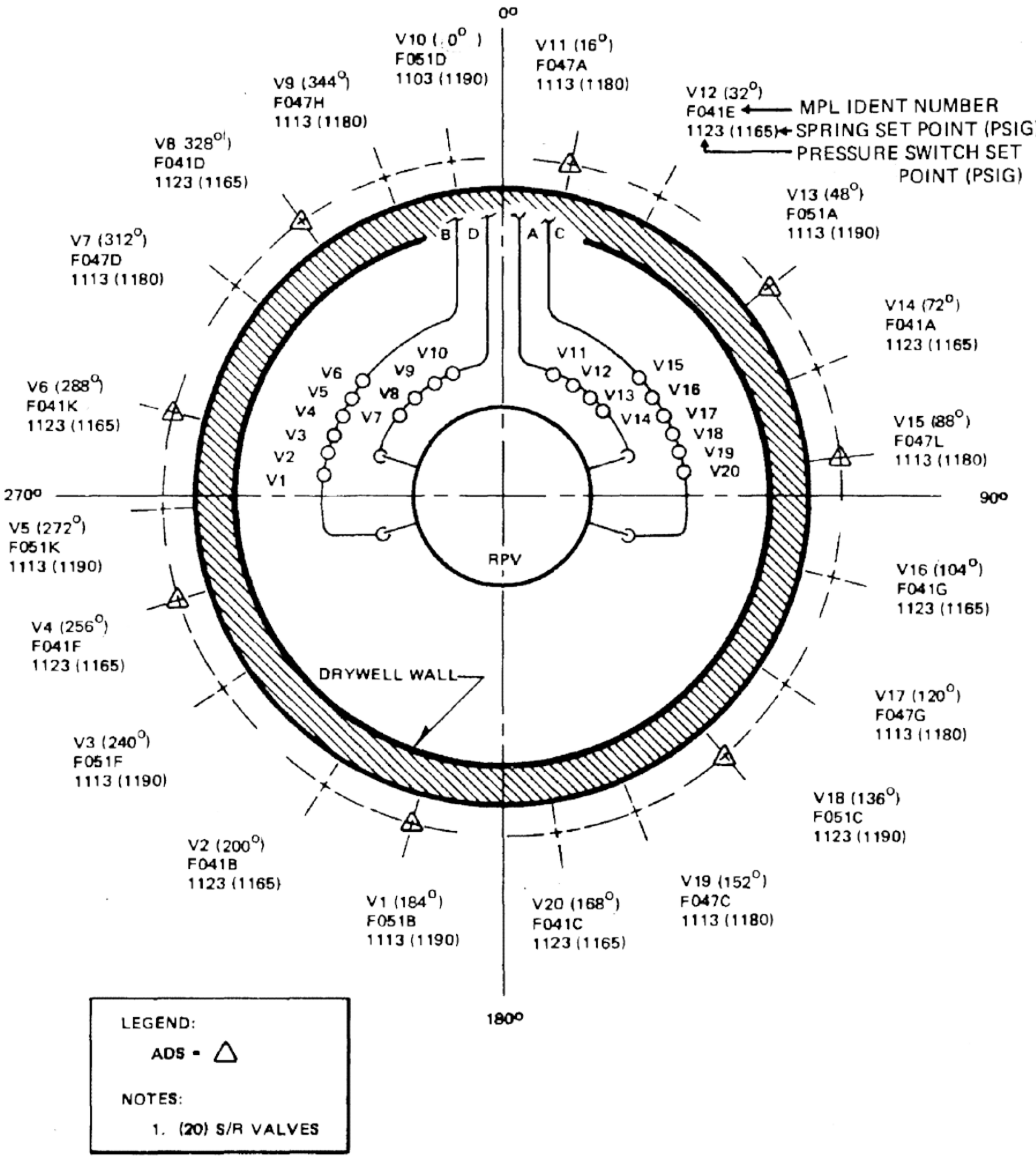


FIGURE A-4 VALVE DISCHARGE LOCATIONS FOR GRAND GULF
UPDATED FINAL SAFETY ANALYSIS REPORT

GG
FSAR

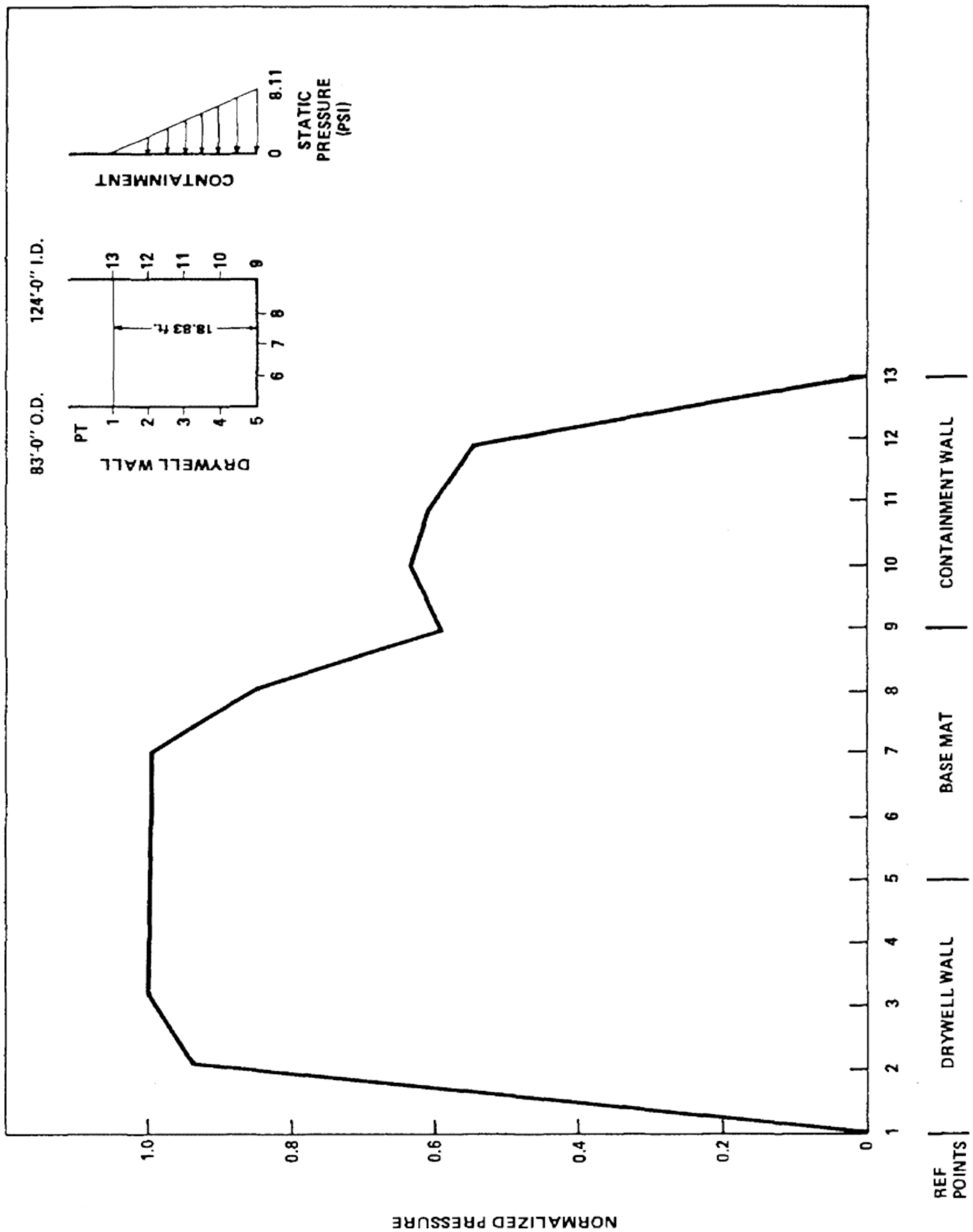


Figure A-5 Grand Gulf-Single S/R Valve Normalized Walls - Floor Pressure at 0°

UPDATED FINAL SAFETY ANALYSIS REPORT

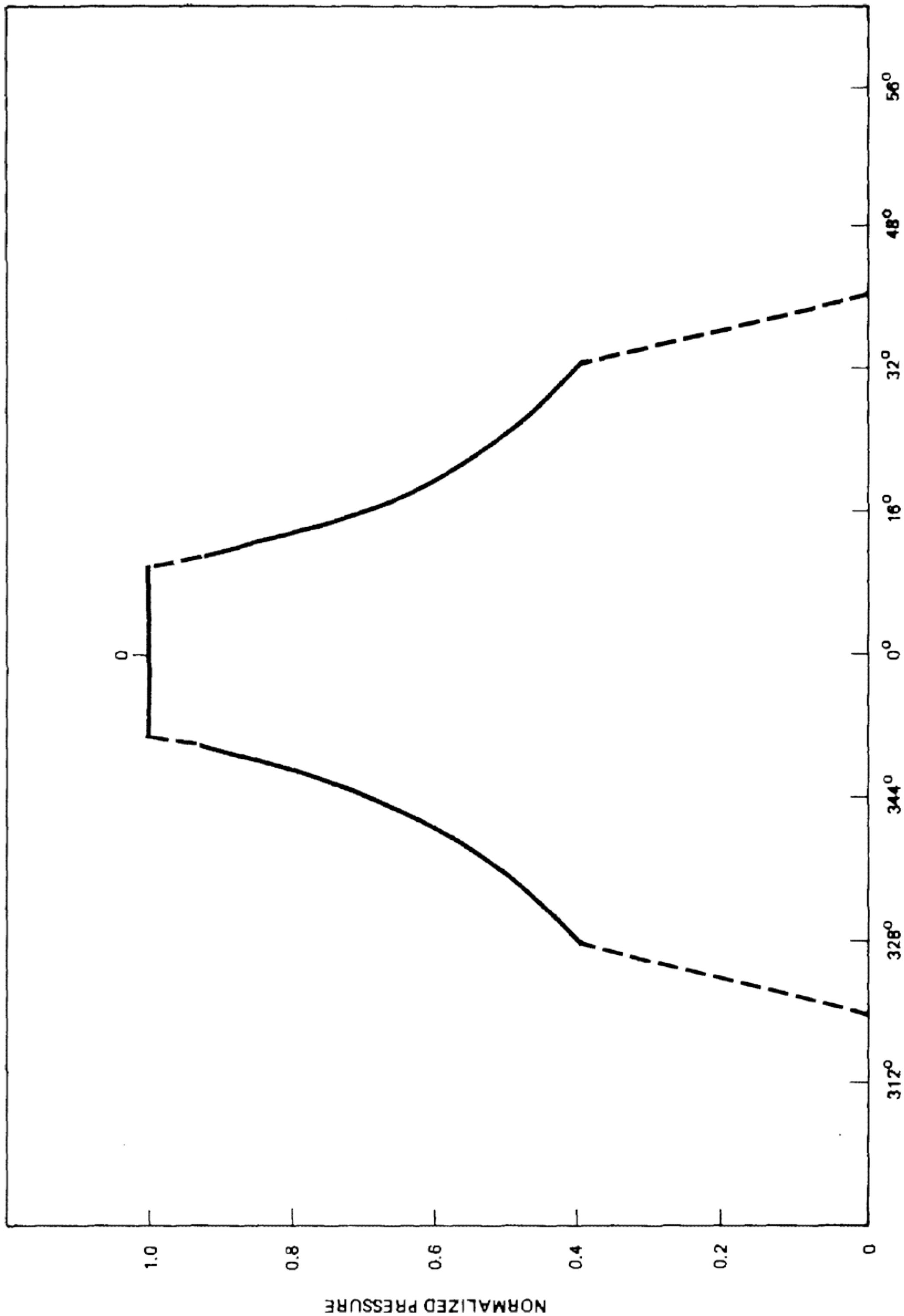


Figure A-6 Grand Gulf-Single S/R Valves Circumferential Pressure Distribution (Reference Point 4)

UPDATED FINAL SAFETY ANALYSIS REPORT

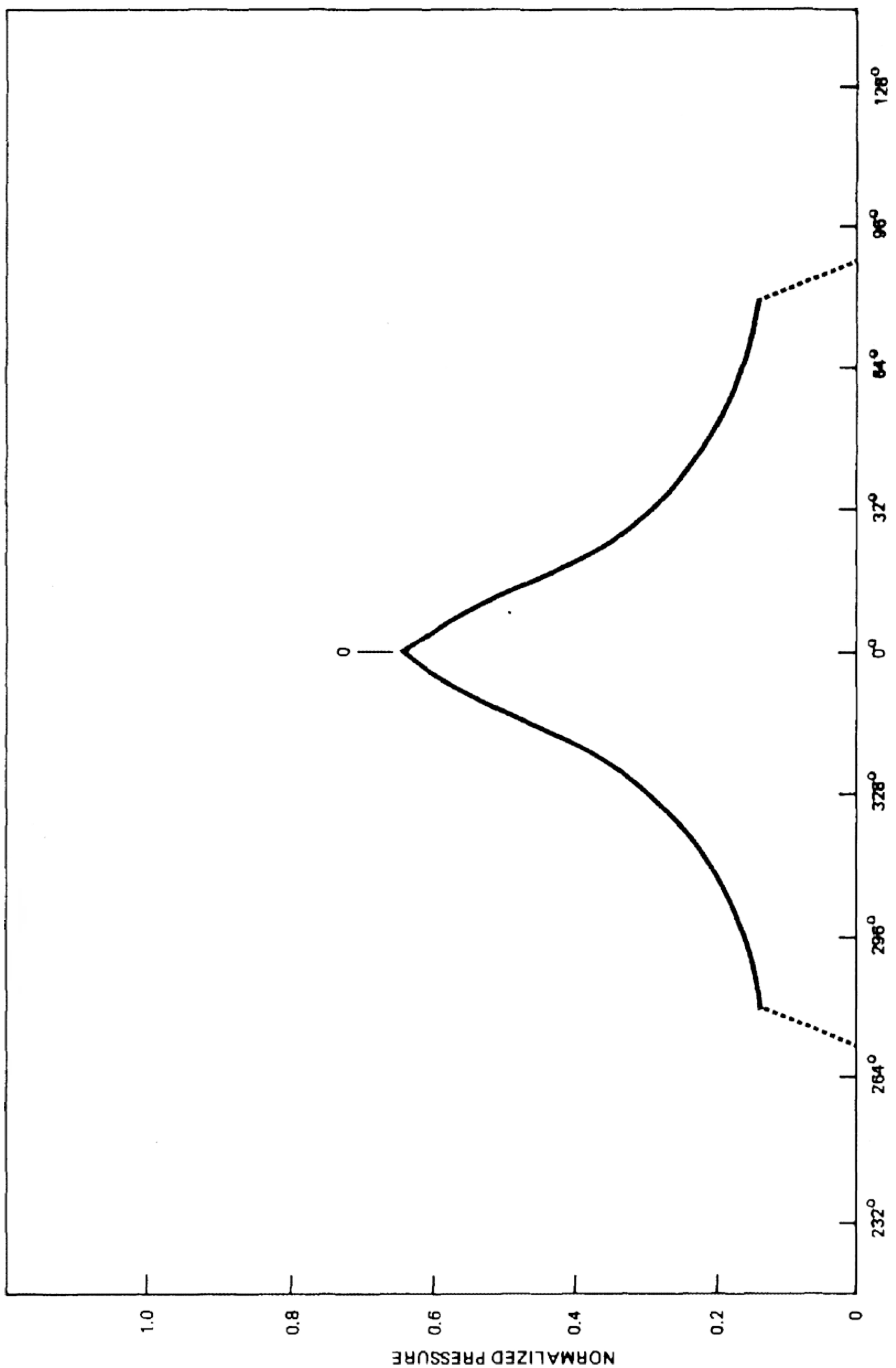


Figure A-7 Grand Gulf-Single S/R Valve Circumferential Pressure Distribution (Reference Point 10)

UPDATED FINAL SAFETY ANALYSIS REPORT

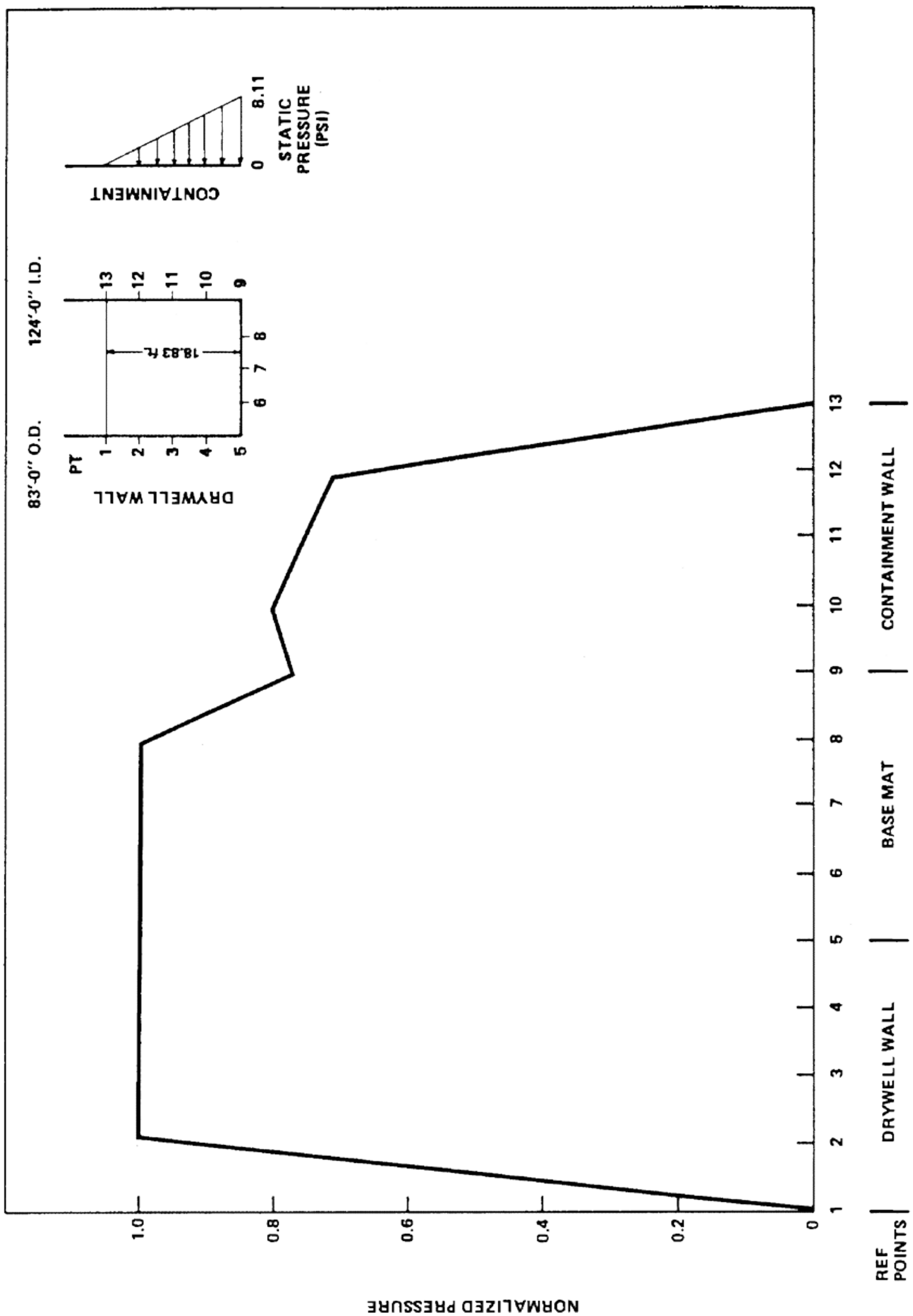


Figure A-8 Grand Gulf-Two S/R Valve Normalized Walls - Floor Pressure at 352°

UPDATED FINAL SAFETY ANALYSIS REPORT

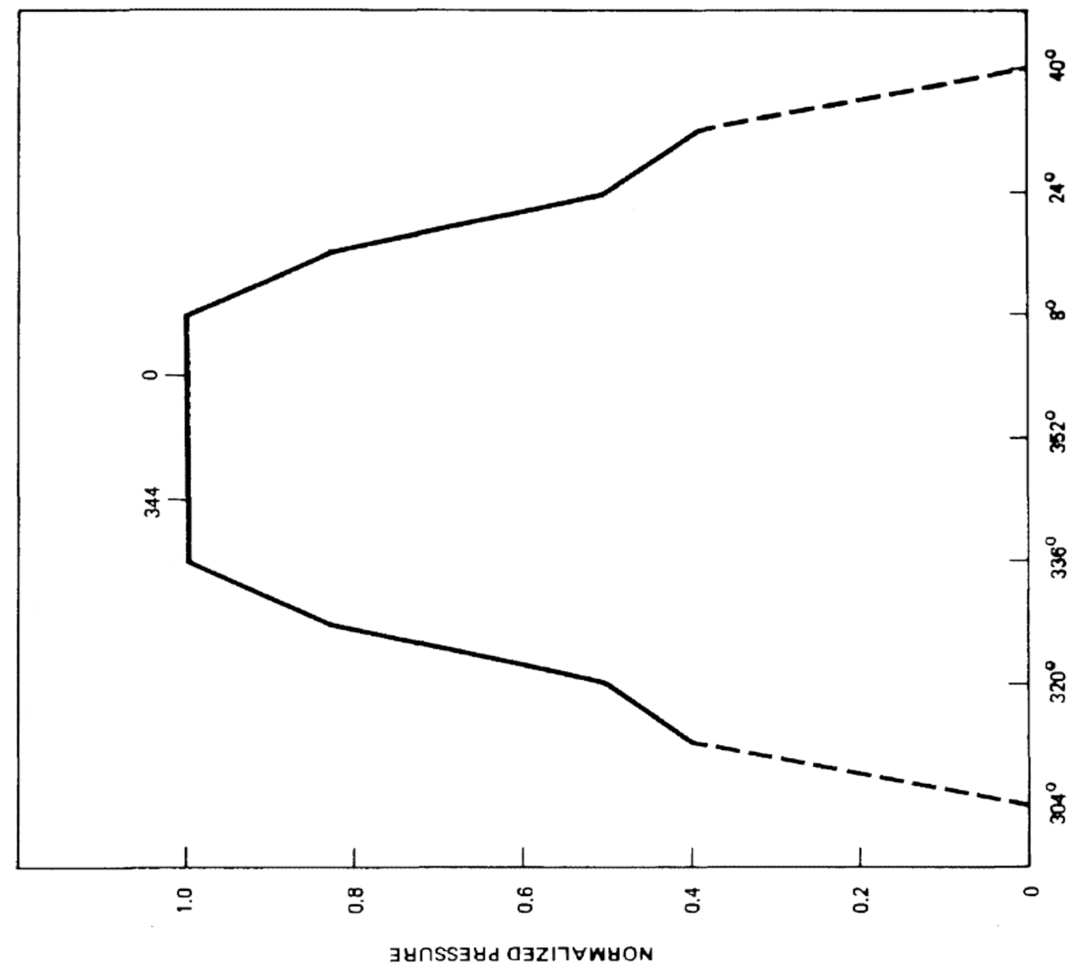


Figure A-9 Grand Gulf-Two S/R Valve Circumferential Pressure Distribution (Reference Point 4)

UPDATED FINAL SAFETY ANALYSIS REPORT

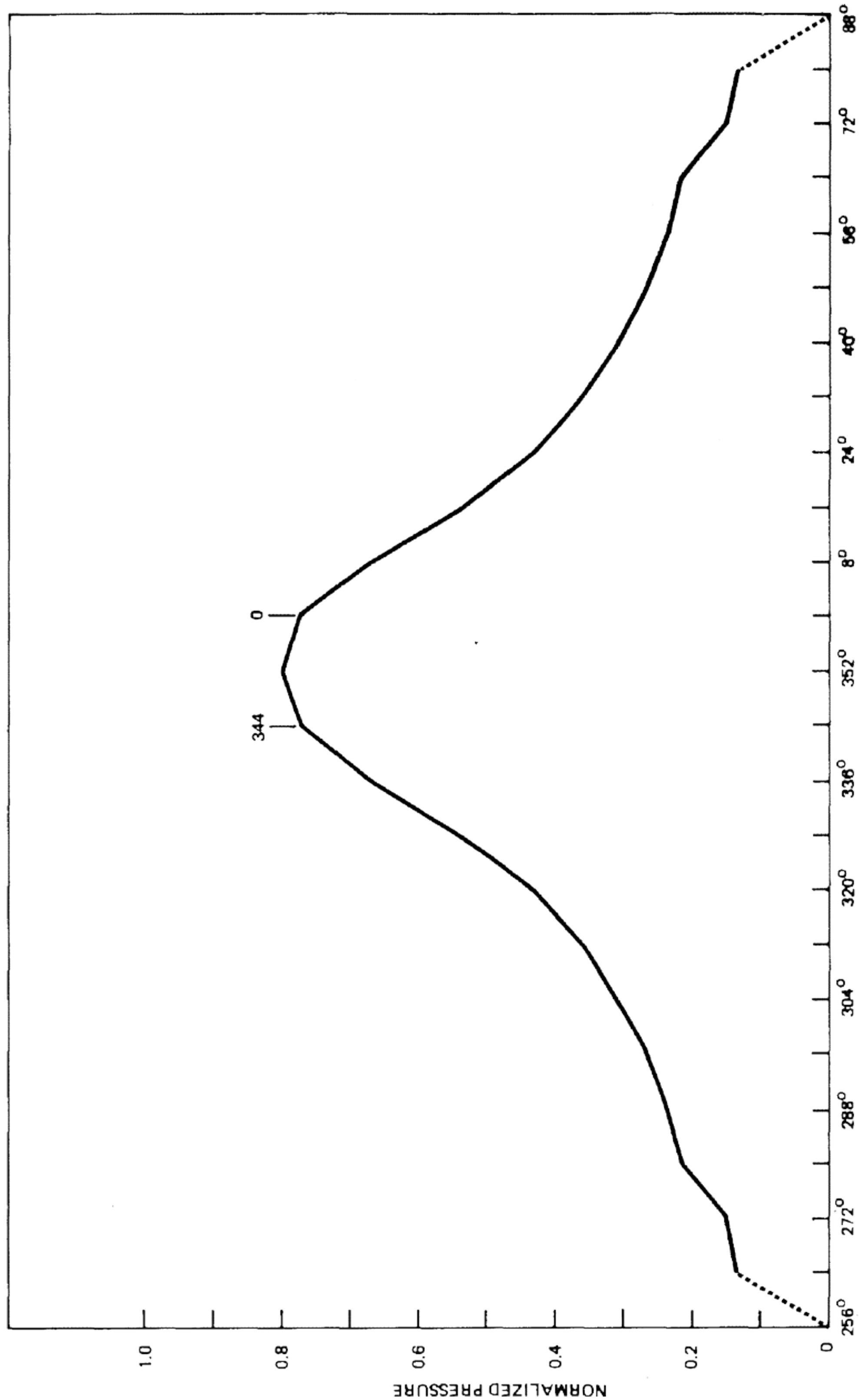


Figure A-10 Grand Gulf-Two S/R Valve Circumferential Pressure Distribution (Reference Point 10)

UPDATED FINAL SAFETY ANALYSIS REPORT

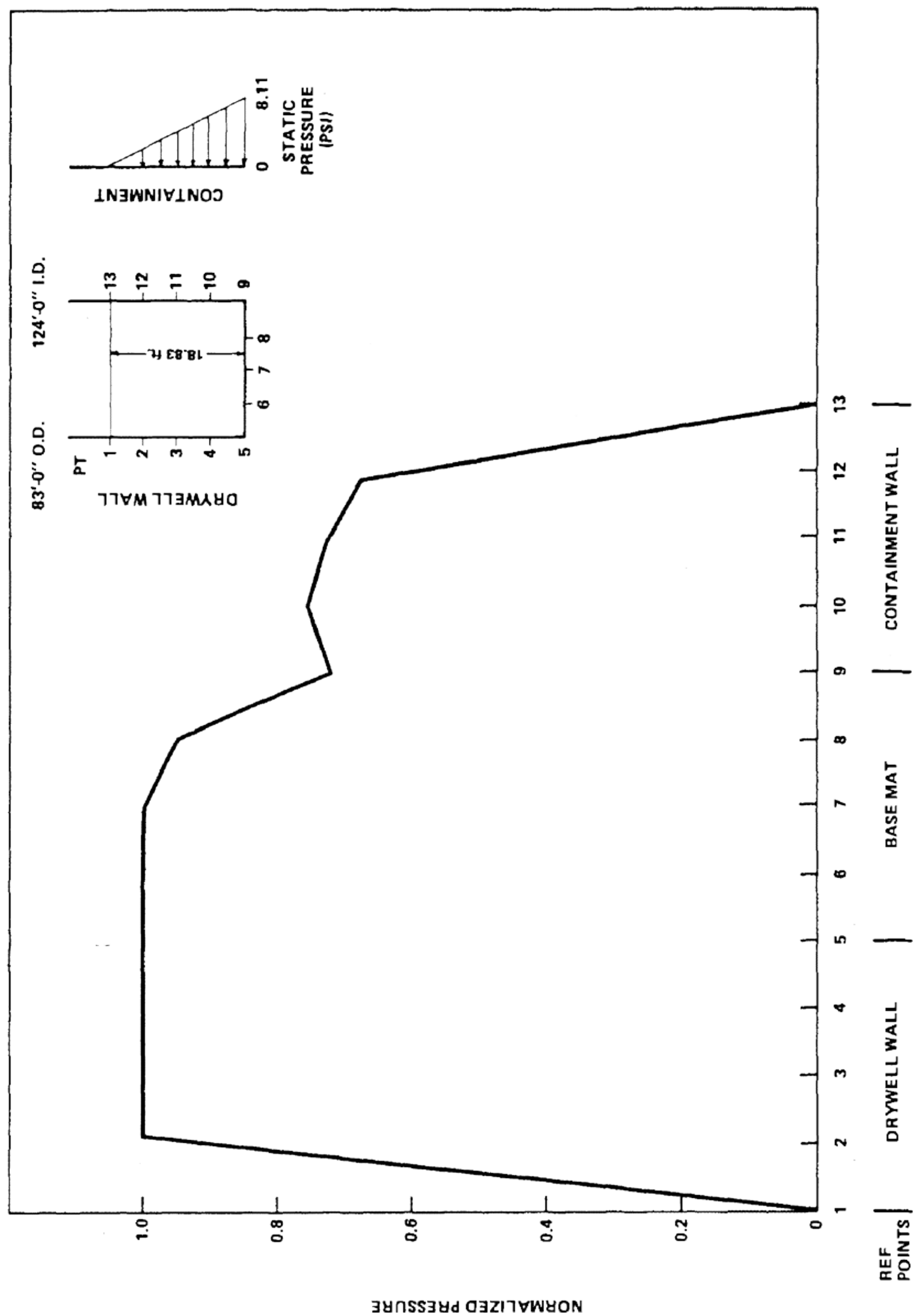


Figure A-11 Grand Gulf-Eight S/R Valve Normalized Walls - Floor Pressure at 48°

UPDATED FINAL SAFETY ANALYSIS REPORT

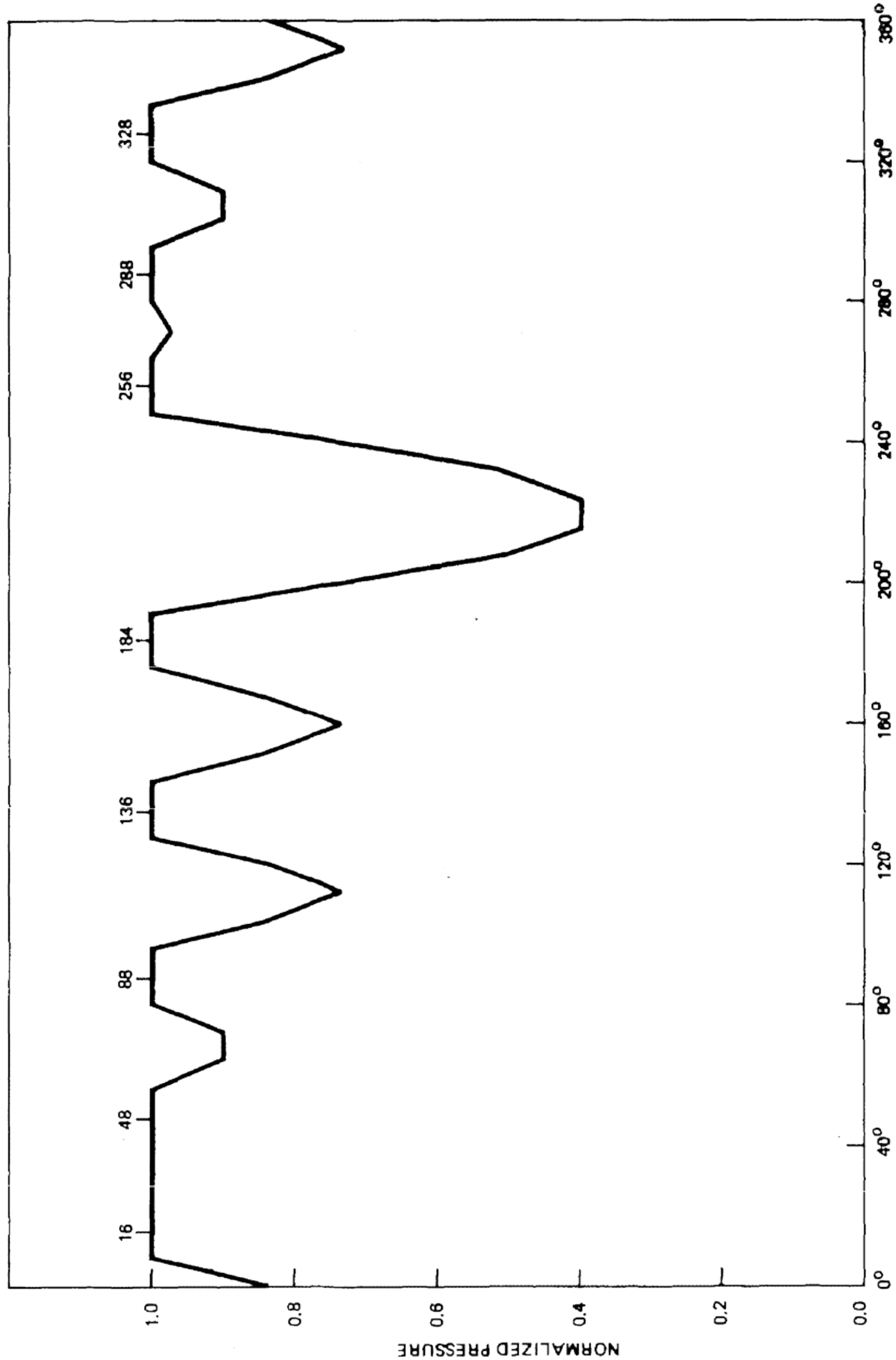


Figure A-12 Grand Gulf-Eight S/R Valves Circumferential Pressure Distribution (Reference Point 4)

UPDATED FINAL SAFETY ANALYSIS REPORT

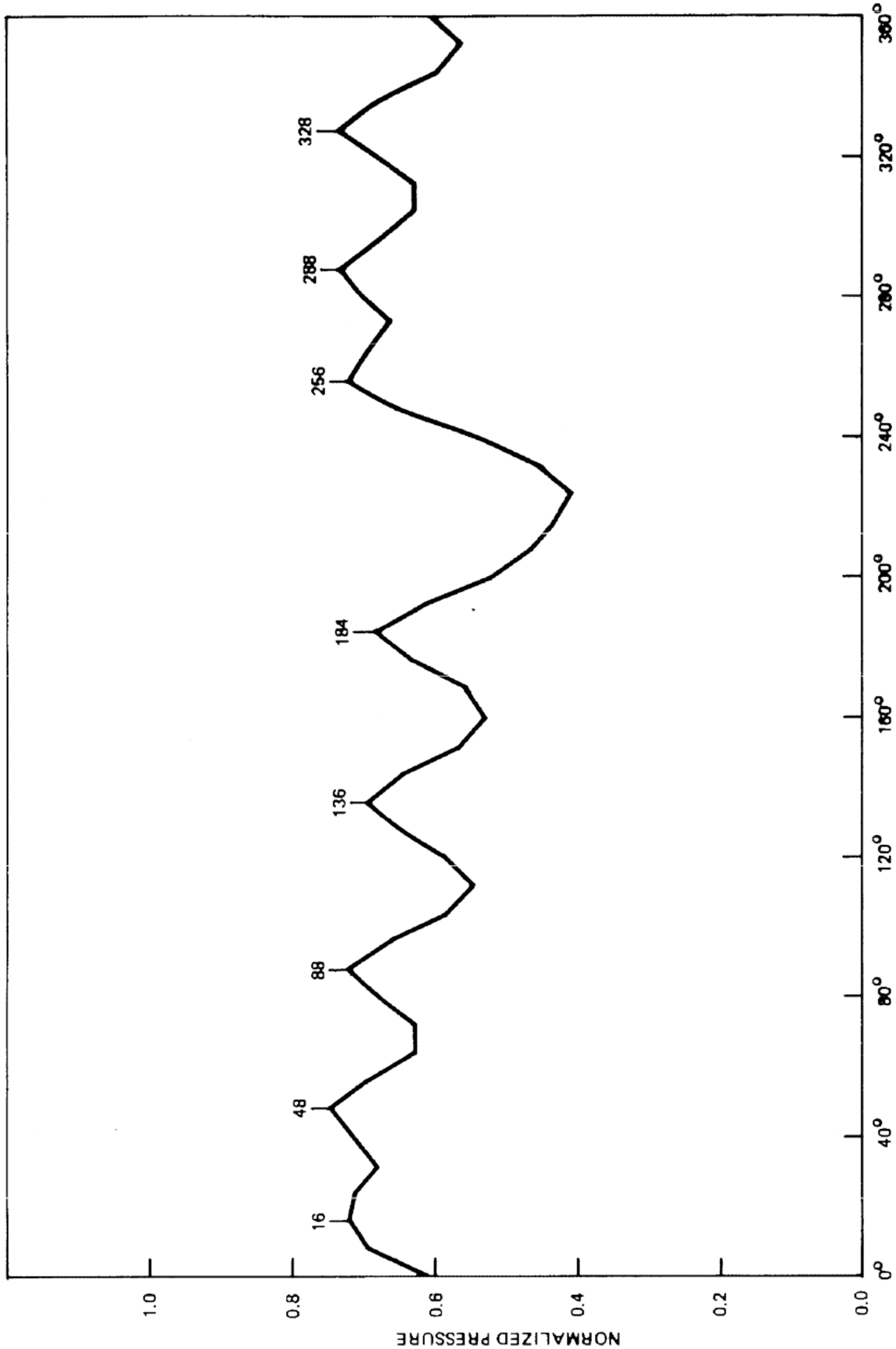


Figure A-13 Grand Gulf-Eight S/R Valves Circumferential Pressure Distribution (Reference Point 10)

UPDATED FINAL SAFETY ANALYSIS REPORT

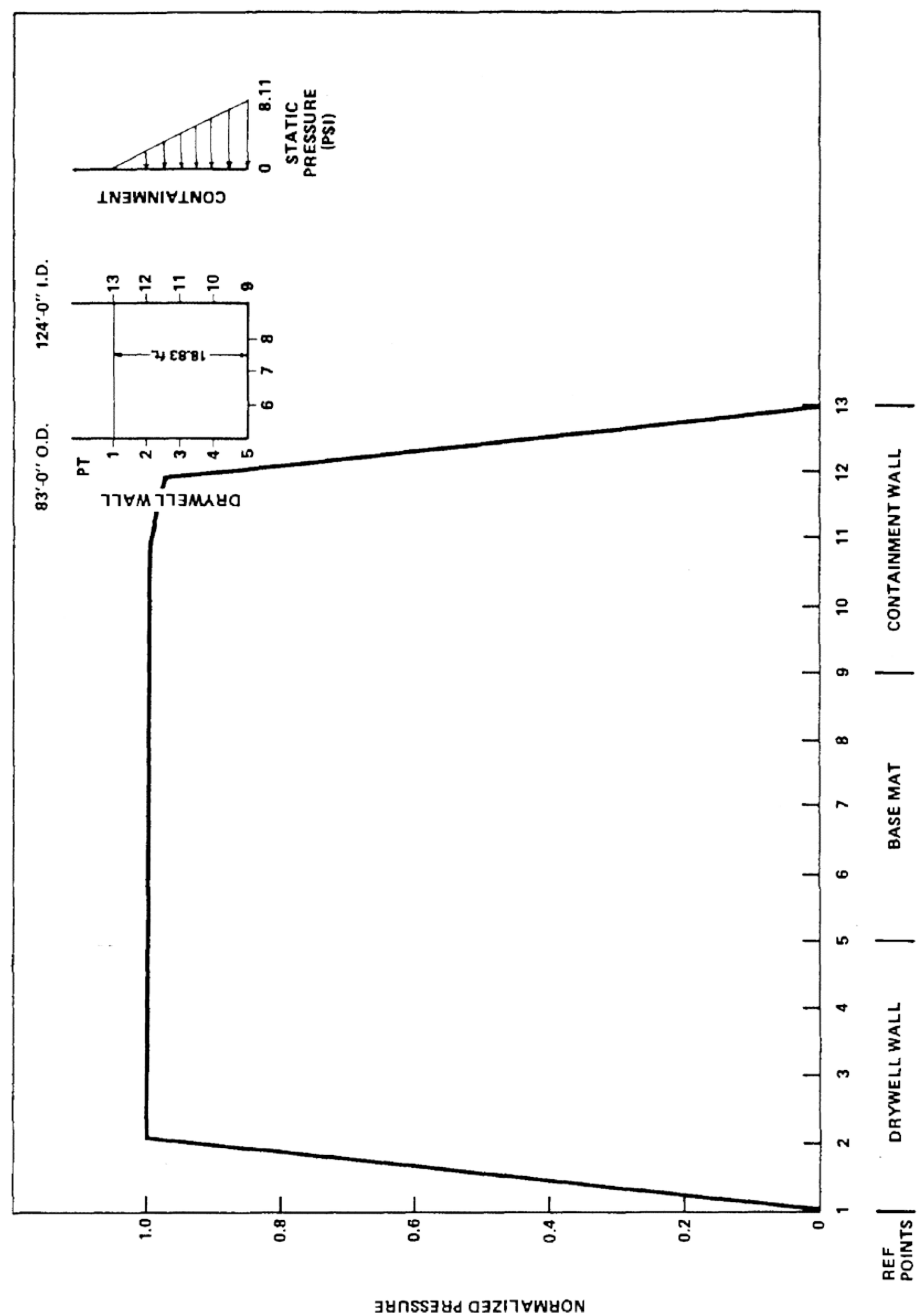


Figure A-14 Grand Gulf-Twenty S/R Valve Normalized Walls - Floor Pressure at 128°

UPDATED FINAL SAFETY ANALYSIS REPORT

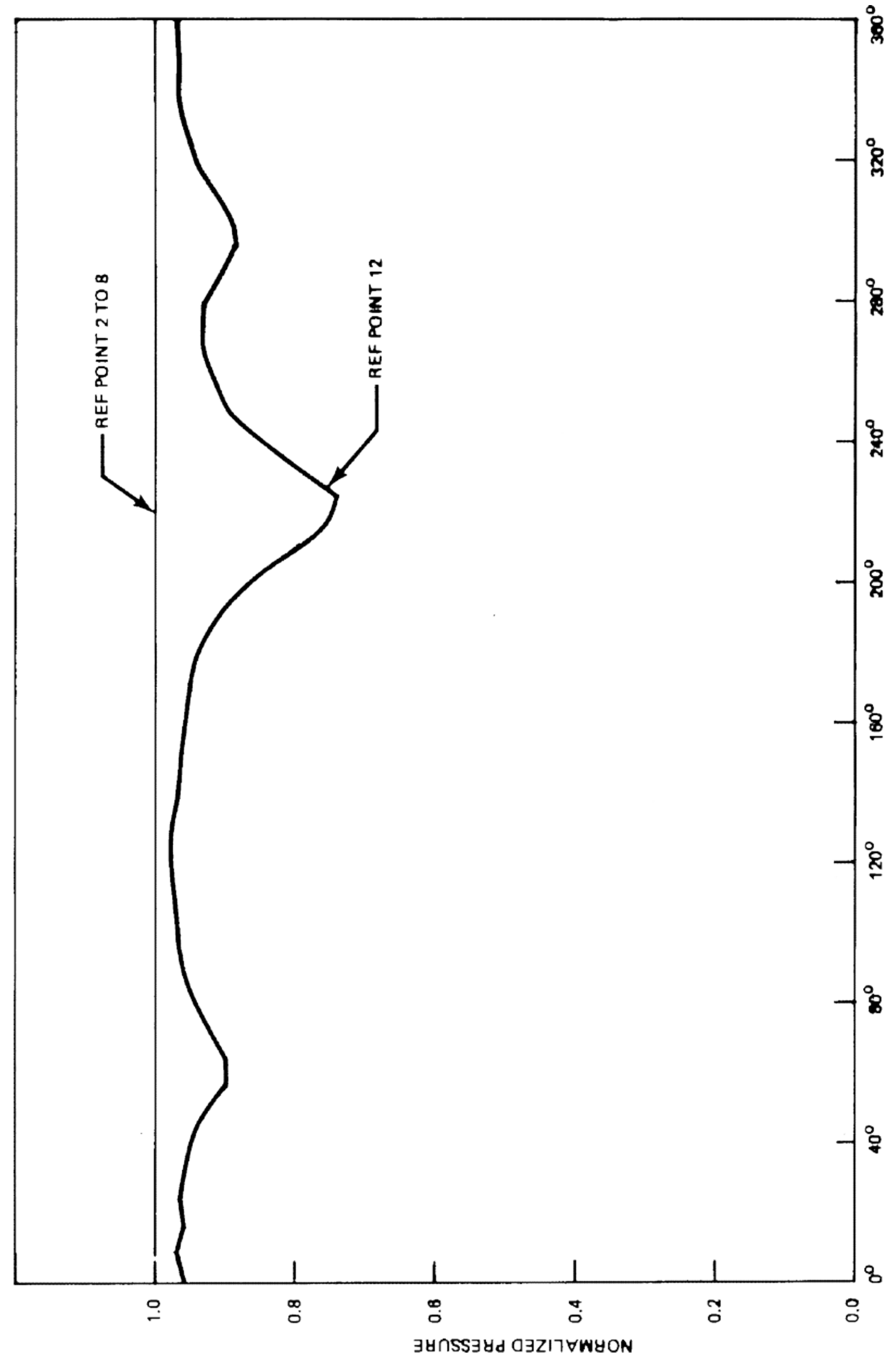


Figure A-15 Grand Gulf-Twenty S/R Valves Circumferential Pressure Distribution

UPDATED FINAL SAFETY ANALYSIS REPORT

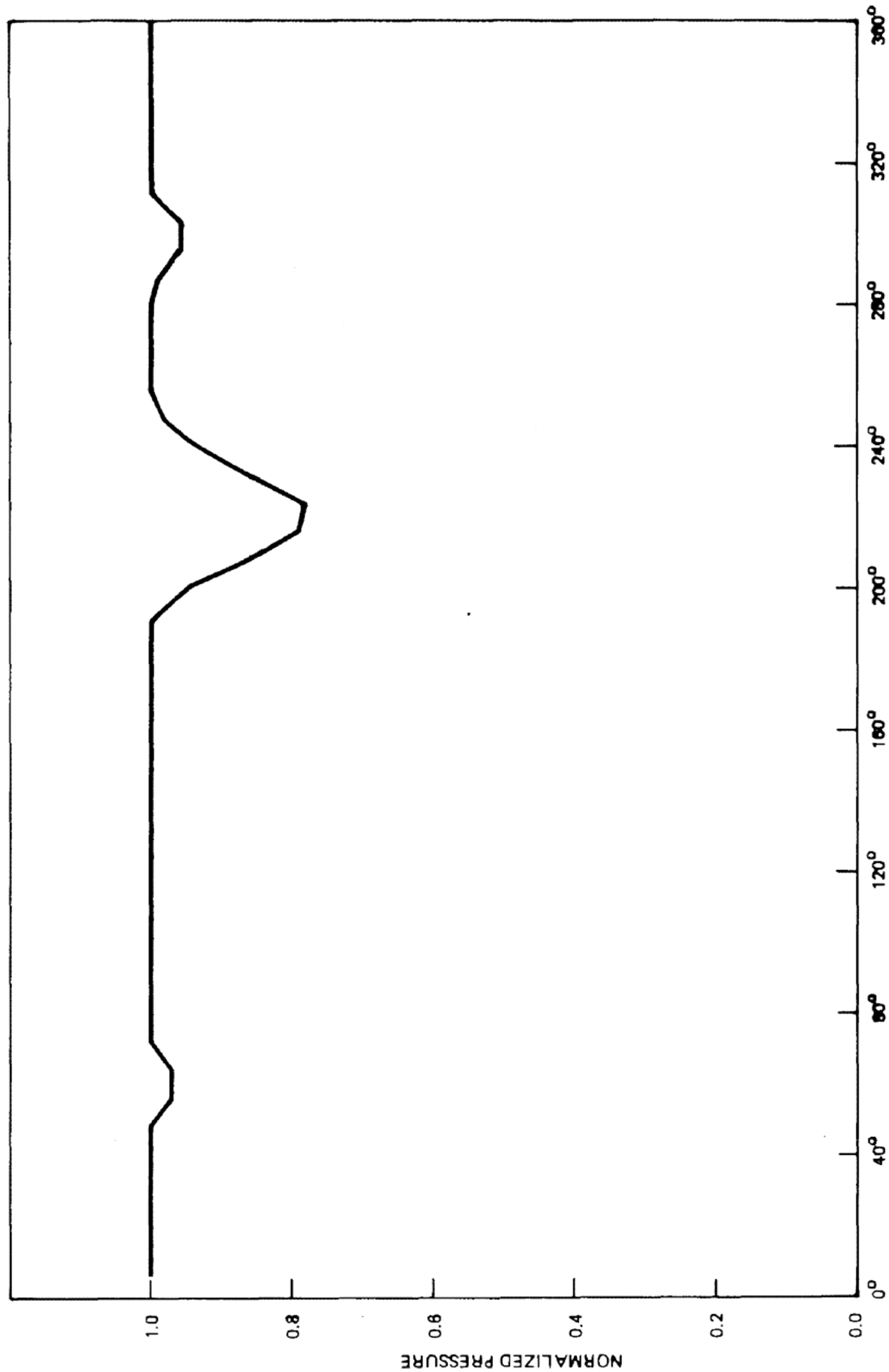


Figure A-16 Grand Gulf-Twenty S/R Valves Circumferential Pressure Distribution (Reference Point 10)

UPDATED FINAL SAFETY ANALYSIS REPORT

$F_X = \pm$ 20,000 lb

$F_Y = \pm$ 30,000 lb

$F_Z = \pm$ 20,000 lb

$M_X = \pm$ 50,000 ft-lb

$M_Y = \pm$ 25,000 ft-lb

$M_Z = \pm$ 35,000 ft-lb

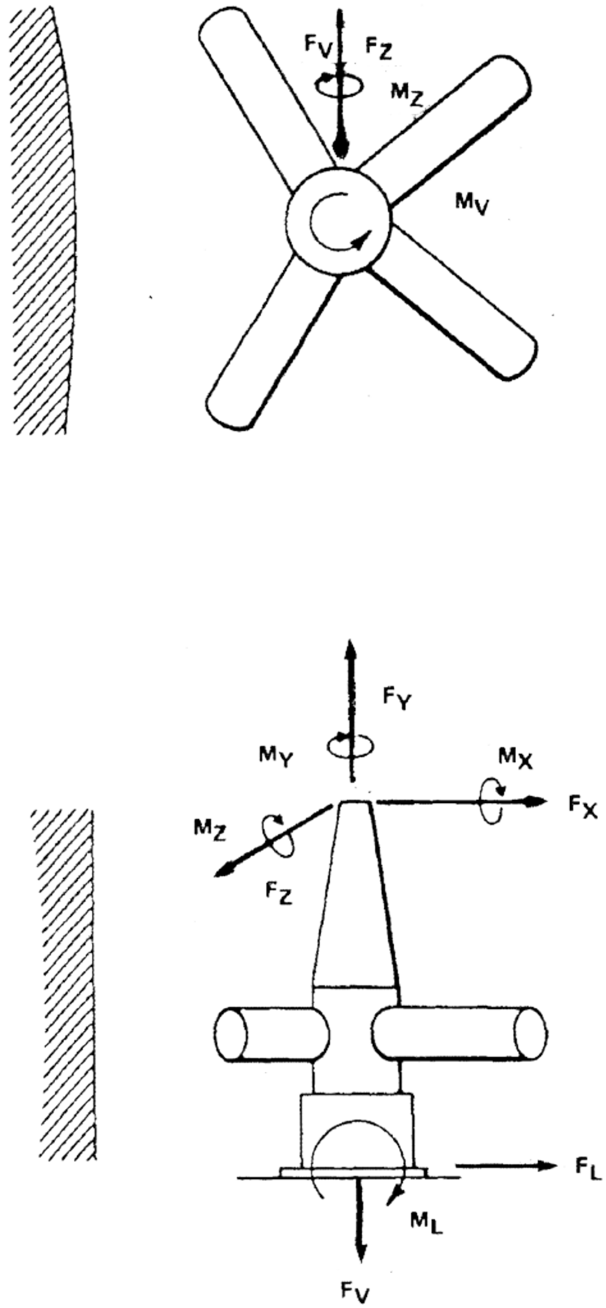
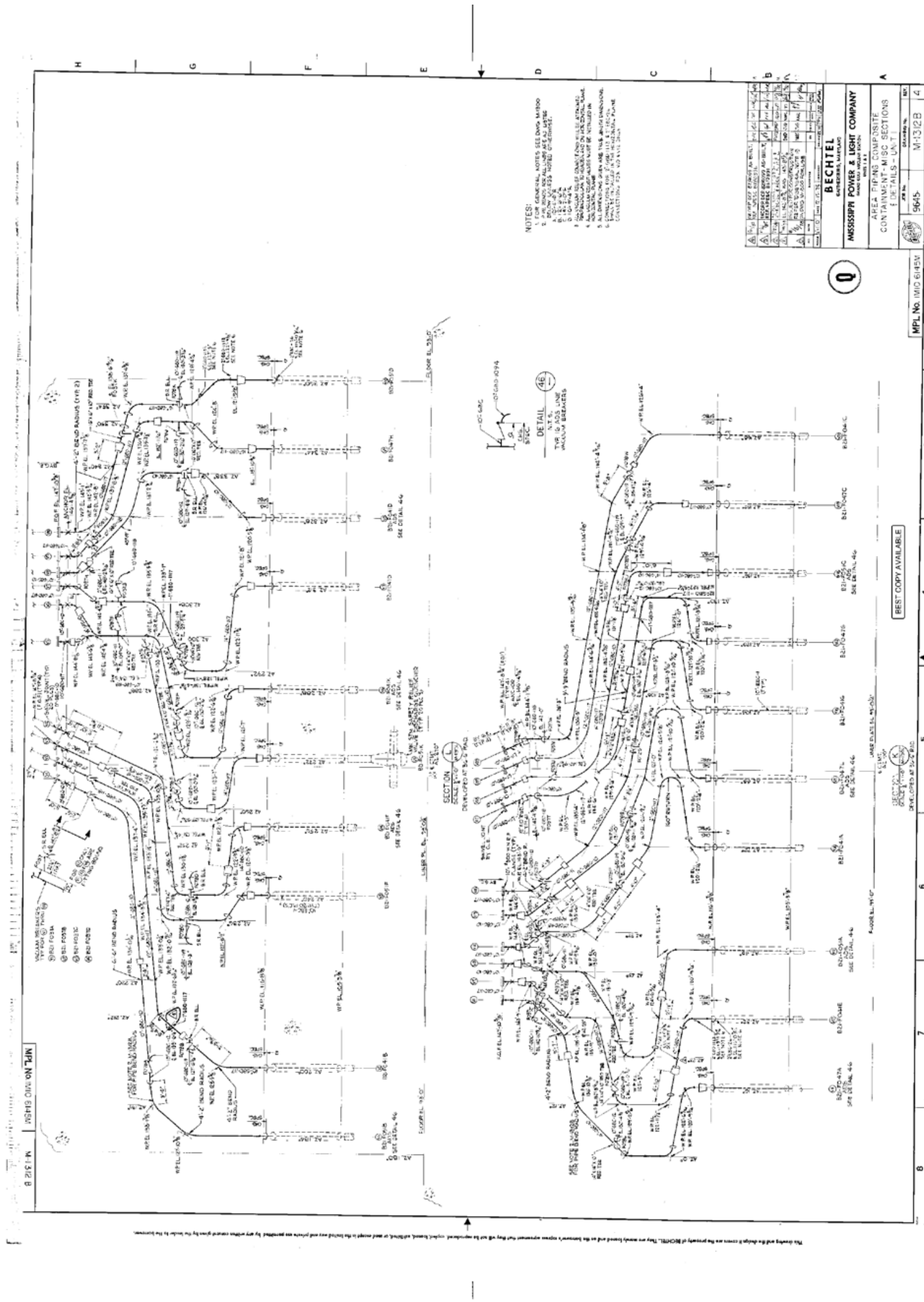


FIGURE A-17 GRAND GULF QUENCHER NOZZLE LOAD SUMMARY
UPDATED FINAL SAFETY ANALYSIS REPORT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MISSISSIPPI POWER & LIGHT COMPANY
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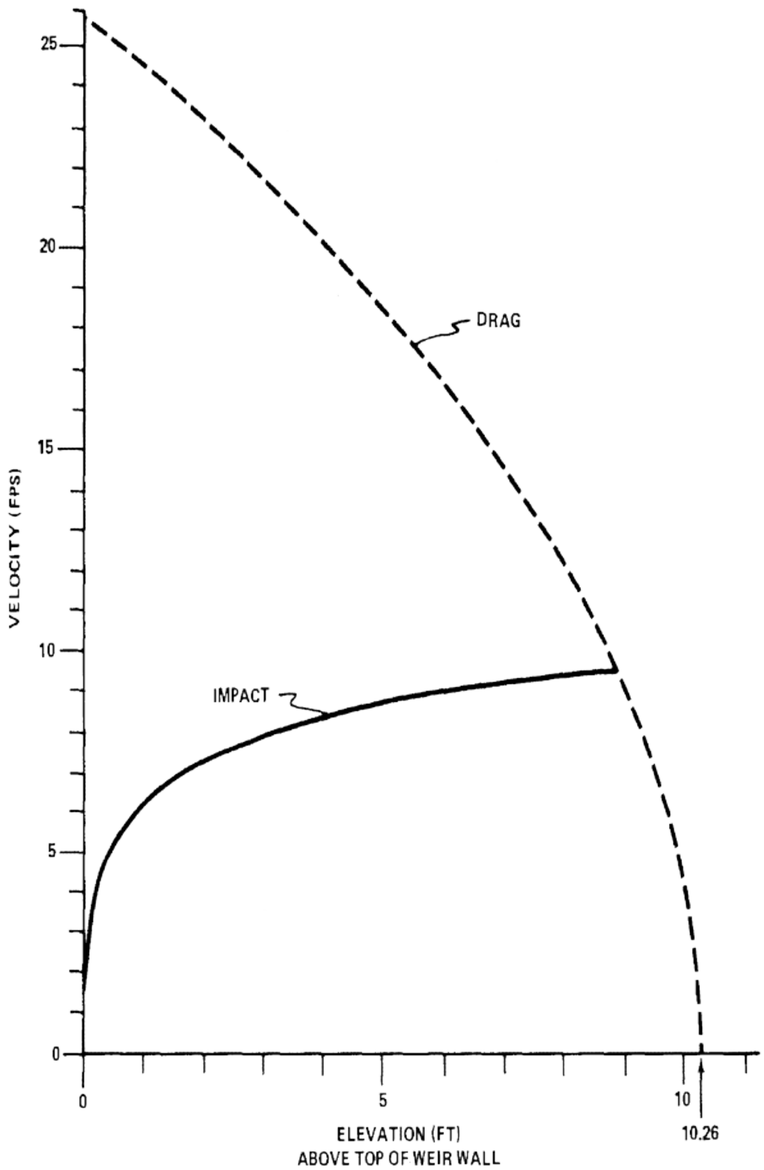


MISSISSIPPI POWER & LIGHT COMPANY GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT
WATER SLUG VELOCITY PROFILE DURING DRYWELL NEGATIVE PRESSURE TRANSIENT FIGURE A-19

APPENDIX 6B DESCRIPTION OF A CONFIRMATORY TEST PROGRAM FOR QUENCHERS IN A MARK III CONTAINMENT

1. OBJECTIVES

The primary objective of the confirmatory test program is to confirm the validity of the methods used to predict the pressure fields within the containment suppression pool caused by safety/relief valve air clearing loads. The secondary objectives of the confirmatory test program are to confirm that the piping located within the suppression pool has been adequately designed to withstand the air clearing loads, and to measure suppression pool temperature distribution during an extended SRV discharge.

2. INTRODUCTION

The confirmatory test program is a series of activities in which a select number of main steam safety/relief valves are actuated in a predetermined sequence for a prescribed duration. The test program is intended to simulate a variety of conditions and transients which are expected to occur during the life of the plant.

3. TEST PROGRAM

The test program is run with the plant operating at a power level of approximately 50 to 85 percent. The test will be a series of single valve first actuations, followed by a series of single valve subsequent actuations. The valve is opened for a specified time period with a specified time period between actuations. Then the testing will proceed with four valves being actuated simultaneously. The test sequence is described in Table 6B-1.

4. INSTRUMENTATION

Pressure sensors will be located on the containment and drywell walls, on the base mat at welded attachment points, and in the safety/relief valve (SRV) discharge piping of one of the valves. A pressure sensor will be located in the SRV discharge piping of one of the valves to monitor the water leg in the piping after the valve has closed. Table 6B-2 presents a description of the number and/or location of the instruments.

In addition, strain gauges will be located on the quencher support, on the RCIC turbine exhaust line, and on the RHR return line to monitor the loading on the piping.

The instrumentation such as sensors, amplifiers, recording equipment, etc., will be of sufficient capacity and resolution to produce the required information.

5. TEST SEQUENCE AND EVENTS

The test program consists of one shakedown test, three SVA/CVA tests and one MVA test as shown by Table 6B-1. Single actuation tests were conducted on the main test valve (V-12) as well as both backup valves (V-10 and V-11) with the MVA test performed on the 4 planned valves (V-2, V-7, V-12 and V-17).

6. SUMMARY OF RESULTS

Review of the data collected during the SRV tests clearly demonstrates that the objectives of the test program have been met. The major conclusions drawn from the test data are:

- The measured peak pressures for SVA, CVA and MVA are generally less than the predicted values and are well below the Grand Gulf design values.
- The pressure time history wave form compares favorably to the General Electric Company's GESSAR predicted wave form used for the Grand Gulf plant design. The initial high frequency portion of the wave form is not as pronounced as that measured at Kuosheng and has little effect on Grand Gulf structures, piping and/or equipment.
- The measured strains for the containment basemat and wall liners, the quencher support and submerged piping are less than half the predicted values.
- The peak measured zero period accelerations (zpa) are well below the predicted values at all locations. The peak measured piping and equipment accelerations are small compared to predicted values.
- The envelope spectra developed for the SVA, CVA and MVA cases are small compared to the design spectra for frequencies below 60 Hz. In three cases the test spectra exceed the design spectra at frequencies above 40 Hz. However, this does not result in significant strain response as shown by the small strain levels and low accelerations of the containment attached piping.

It is concluded that the GESSAR methodology used for the Grand Gulf plant design, reported in Appendix 6D of the Grand Gulf FSAR, provides a design which is conservative and has considerable margin for SRV discharge loads.

TABLE 6B-1: TEST MATRIX

			Initial Conditions					
Test No.	**Test Type**	Valve (1) Actuated	SRVDL Water Level	Pool Temp. (°F)	Power Level %	Discharge Time (Sec.)	Valve Closure Time Prior to CVA (Sec.)	Reactor Press. (psig
SD1	SVA	V-12	NWL	74	70.9	5	N/A	982.0
MT10	SVA	V-10	NWL	74	60.4	20	N/A	976.0
MT11	CVA	V-10	AWL			5	45	
MT20	SVA	V-11	NWL	74	68.0	20	N/A	983.6
MT21	CVA	V-11	AWL			5	45	
MT30	SVA	V-11	NWL	75	69.2	20	N/A	984.0
MT31	CVA	V-11	AWL			5	45	
MT70	MVA	V-2, V-7, V-12, V-17	NWL[2]	85.5	72.1	15, 25, 45, 35	N/A	1001.7

TABLE 6B-1 (Continued)

TEST MATRIX - DEFINITION OF ABBREVIATIONS AND FOOTNOTES

ABBREVIATIONS:

SD = Shakedown Test

MT = Matrix Test

SVA = Single Relief Valve First Actuation

CVA = Single Relief Valve Consecutive Actuation

MVA = Multivalve Simultaneous Actuation

NWL = Normal Water Level(3)

AWL = Actual Water Level(4)

NOTES:

(1) Control room switch designations: V-2 = F041B, V-7 = F047D, V-10 = F051D, V-11 = F047A, V-12 = F041E, V-17 = F047G.

(2) V-12 was leaking during this test and SRVDL had approximately 4 psi internal pressure at test, all other lines were NWL.

(3) NWL implies that the water surface within SRVDL is coincident with suppression pool.

(4) AWL implies that the water level is dependent on SRVDL internal pressure.

TABLE 6B-2: INSTRUMENTATION MATRIX

LOCATION

Type of Sensor	Drywell Wall	Base Mat	Containment Wall	Other
Pressure	X	X	X	SRV Pipe
Pressure (Low Range)	--	--	--	One SRV Discharge Pipe
Strain Gauge	--	X	X	On each of the following lines: 1. 4 on RCIC turbine exhaust 2. 6 on RHR A test return 3. 12 on a quencher base
Accelerometer				1. 14 on containment vessel 2. 5 sets of biaxial accelerometers on the drywell 3. 2 sets on the RPV pedestal 4. 2 biaxial sets in the Auxiliary Building 5. 8 sets of triaxial mounted on the polar crane, hydrogen recombiner, four valve actuators, and 1 snubber.

APPENDIX 6C SHORT-TERM MASS ENERGY RELEASE

6C.1 GENERAL

The purpose of this procedure is to document the method by which short-term mass release rates are calculated. The flow rates which could be produced by a primary system line break for the first 5 seconds include the effects of inventory and subcooling.

6C.2 ASSUMPTIONS

a. The initial velocity of the fluid in the pipe is zero. When considering both sides of the break, the effects of initial velocities would tend to cancel out.

b. Constant reservoir pressure.

c. Initially fluid conditions inside the pipe on both sides of the break are similar.

d. Wall thickness of the pipe is small compared to the diameter.

e. Subcompartment pressure ≈ 0.

f. Quasi-steady mass flux is calculated using the Moody Steady-Slip Flow Model with subcooling.

6C.3 NOMENCLATURE (see Figure C3.1)

A_{BR} = Break area

A_L = Minimum cross-sectional area between the vessel and the break. This is the sum of the areas of parallel flow paths.

c = Sonic speed in the fluid (see Figure C3.2)

D = Pipe inside diameter at the break location

F_I = Inventory flow multiplier
F_I = 0.75 for saturated steam
= F_I = 0.50 for liquid

g_c = Proportionality constant (= 32.17 lbm-ft/lbf-sec^2)

G = Mass flux

G_c = Maximum mass flux (see Figure C3.3)

h_o = Reservoir or vessel enthalpy

h_p = Initial enthalpy of the fluid in the pipe

L_I = Inventory length. The distance between the break and the nearest area increase or A_L, whichever distance is less.

$\dot{M}$ = Mass flow rate

$\dot{M}I$ = Mass flow rate during the inventory period

P_o = Reservoir or vessel pressure

P_{sat} = Saturation pressure for liquid with an enthalpy of h_p

t = Time

t_I = Length of the inventory period

v = Specific volume of the fluid initially in the pipe

V_I = Volume of the pipe between the break and A_L

X = Separation distance of the break

6C.4 INSTANTANEOUS GUILLOTINE BREAK

The following method should be applied to each side of the break and the results summed to determine the total flow.

6C.4.1 Inventory Period

Prior to a pipe break, the fluid in the pipe is moving at a relatively low velocity. After the break occurs, a finite time is required to accelerate the fluid to steady-state velocities. The length of this time period is conservatively estimated as follows:

a. If $A_L/A_{BR} > F_I$,

the discharge rate will increase from its initial value for each wave round trip from the break. Therefore, the minimum time for the initial discharge rate is obtained conservatively as

$$t_I = \frac{2L_I}{c}$$

b. If $A_L/A_{BR} < F_I$,

the discharge rate will decrease from its initial value. Therefore, it is conservative to permit the initial flow rate until the inventory pipe section is purged, or

$$t_I = \frac{V_I}{A_{BR} G F_I v}$$

where G is calculated as shown in Section 2.7(b) for a large separation distance and $t < t_I$

During this time period, the mass flow rate is calculated as

$$\dot{M}_I = G\ A_{BR}\ F_I$$

6C.4.2 Steady State Period

Following the inventory period, the flow is assumed to be choked at the limiting cross-sectional flow area.

For $t_I < t < 5.0$ seconds,

$$\dot{M} = A_L G$$

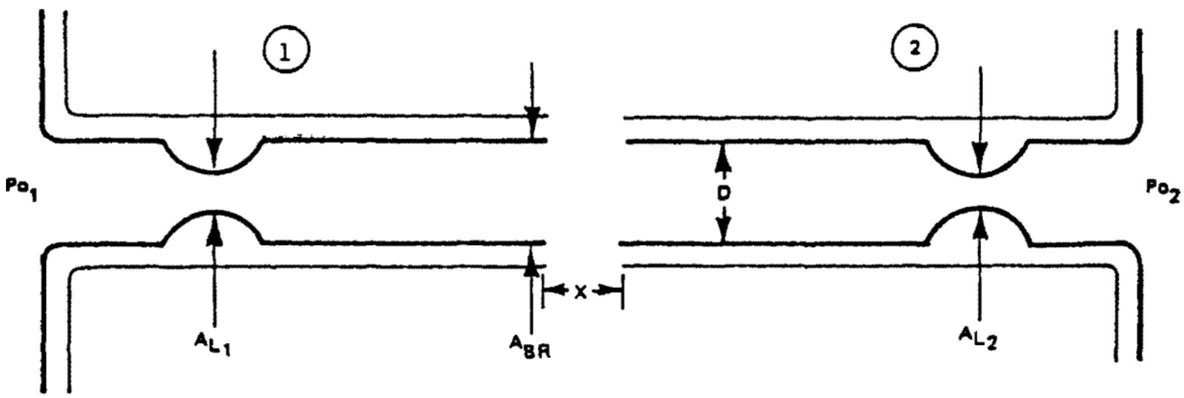


FIGURE C3.1 GEOMETRY

UPDATED FINAL SAFETY ANALYSIS REPORT

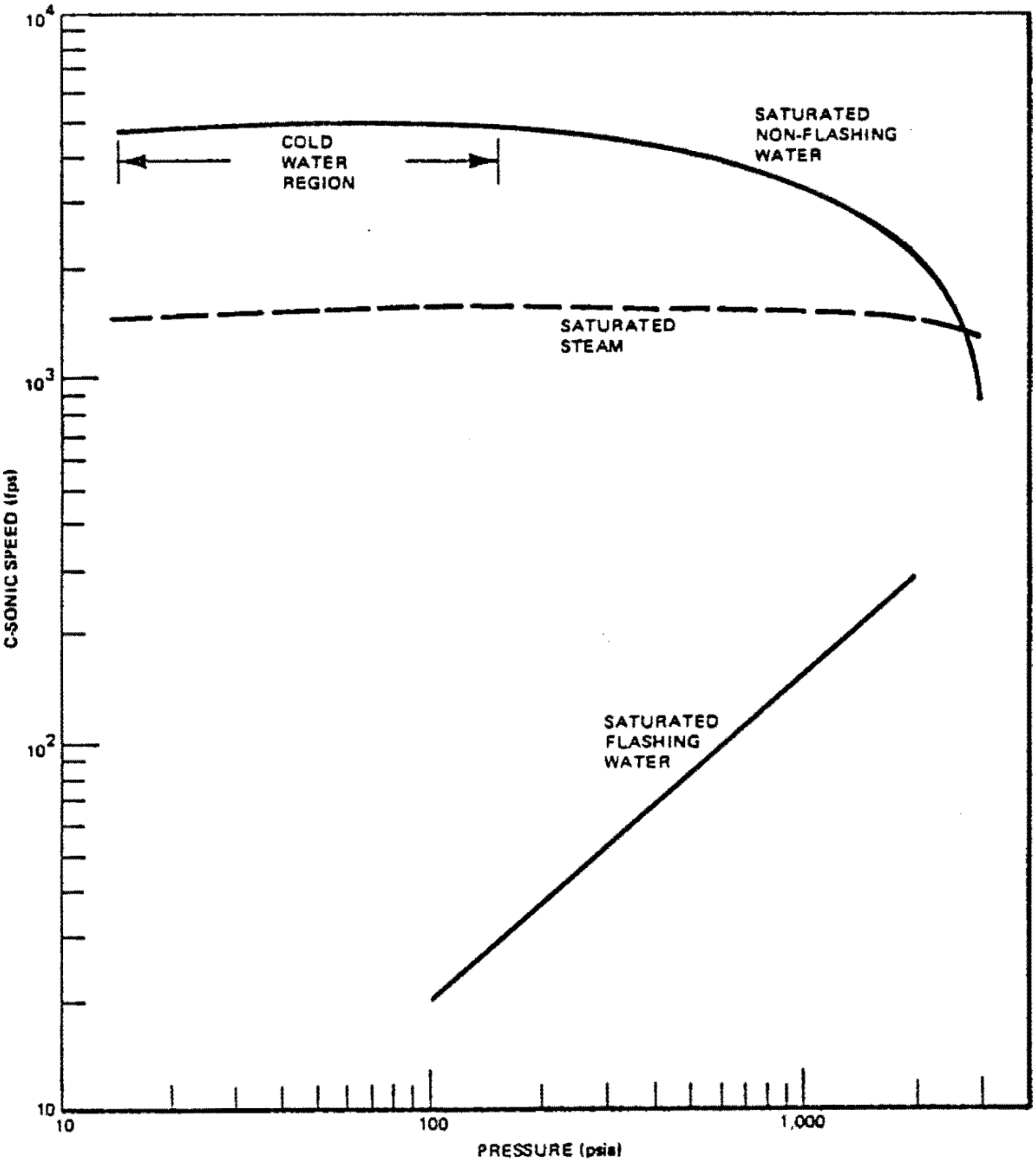


FIGURE C3.2 WAVE SPEED

UPDATED FINAL SAFETY ANALYSIS REPORT

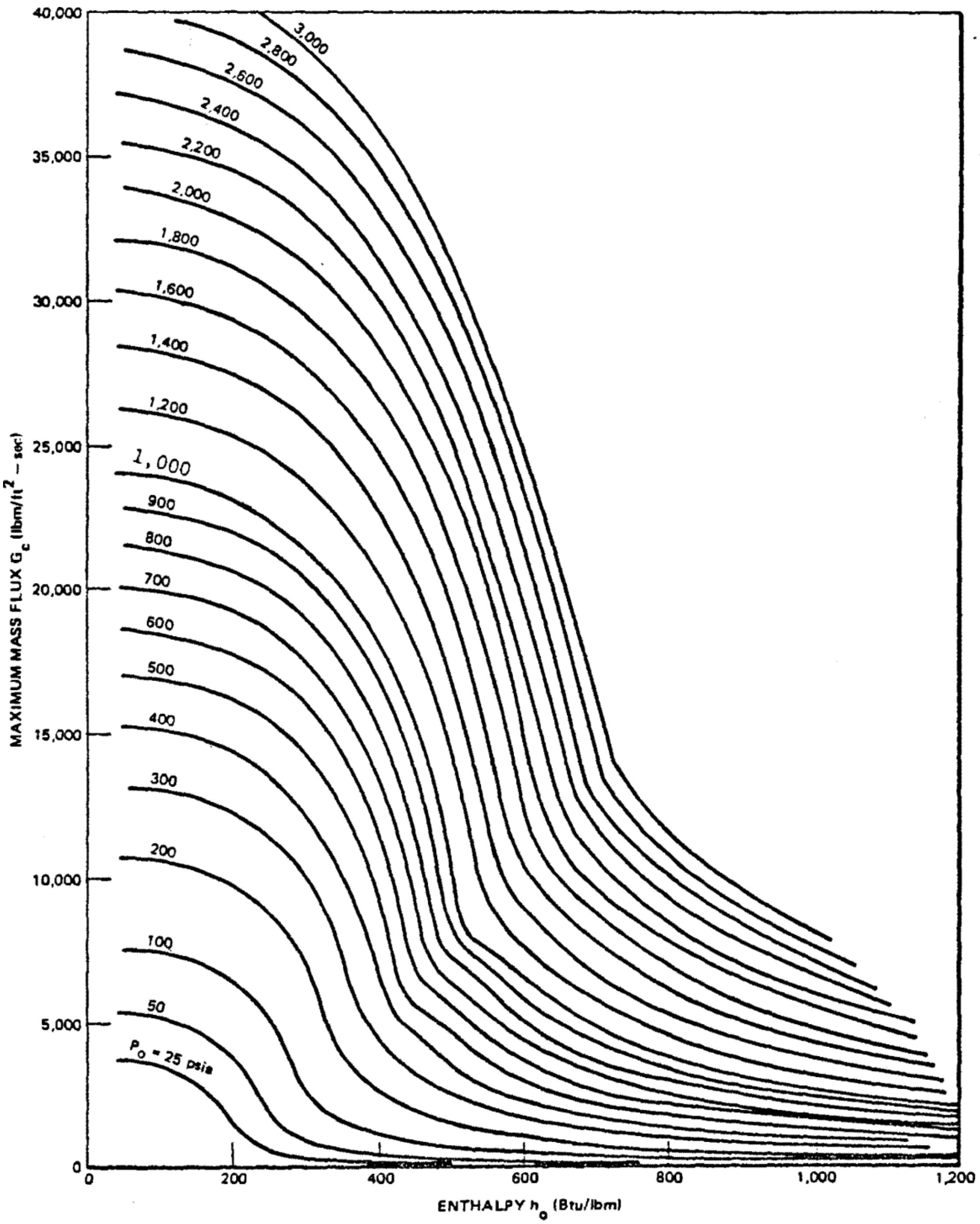


FIGURE C3.3 MASS FLUX, MOODY STEADY-SLIP FLOW

UPDATED FINAL SAFETY ANALYSIS REPORT

APPENDIX 6D MARK III CONTAINMENT LOADS

This appendix is Appendix 3B to GESSAR II; it is not reproduced here but it can be found in the FSAR, as revised through Amendment 59, January 1985. The application to Grand Gulf of the definitions, procedures, and techniques described in Appendix 3B of GESSAR II is discussed in Appendix 6A of the updated FSAR.

APPENDIX 6E NET POSITIVE SUCTION HEAD CALCULATIONS FOR ECCS PUMPS

c. RHR C Pump

d. NPSHA for a Maximum of 212°F Pool Water Temperature

3. Minimum NPSHA Calculations - Maximum Strainer Head Loss

a. RHR A Pump

b. RHR B Pump

c. RHR C Pump

d. NPSHA at Design Conditions

4. NPSHA for Cold Shutdown and Refueling Modes - Maximum Strainer Head Loss

a. RHR A Pump

b. RHR B Pump

c. RHR C Pump

d. NPSHA for a Maximum of 212°F Pool Water Temperature

B. LPCS and HPCS Pumps

1. Minimum NPSHA Calculations - Clean Strainers

a. LPCS Pump

b. HPCS Pump

2. NPSHA for Cold Shutdown and Refueling Modes - Clean Strainers

a. LPCS Pump

b. HPCS Pump

c. NPSHA for a Maximum of 212°F Pool Water Temperature

3. Minimum NPSHA Calculations - Maximum Strainer Head Loss

a. LPCS Pump

b. HPCS Pump

4. NPSHA for Cold Shutdown and Refueling Modes - Maximum Strainer Head Loss

a. LPCS Pump

b. HPCS Pump

c. NPSHA for a Maximum of 212°F Pool Water Temperature

6E.1 CALCULATION OF SUCTION PRESSURES - CLEAN STRAINER

For the ECCS suction strainer design, for those events where significant debris generation is expected, the temperature assumed for NPSH calculations is the maximum containment design temperature of 185°F. For those events where no significant debris generation (i.e., clean strainer) is expected (e.g., ATWS, SBO, etc.) NPSH will be conservatively evaluated at 212°F. Reference Subsection 6.3.2.2 for further discussion.

The following calculations determine the pressures at various locations along the ECCS pumps' suction piping. As concluded from the calculations, adequate pressures exist along the suction piping to preclude local flashing under the worst postulated conditions. That is, the pressure at each point exceeds the vapor pressure of the fluid. For the calculations, a suppression pool water temperature of 212°F with a corresponding vapor pressure of 14.7 psia was assumed. This is an extremely conservative assumption, since the maximum analyzed pool water temperature is 181°F as specified in Table 6.2-13. Since the vapor pressure for water at 181°F is 7.7 psia, more than adequate margin exists to preclude flashing in the suction piping.

Other conservative assumptions used for the calculations are:

a. Pump design maximum runout flow rate

b. Atmospheric containment pressure

c. Minimum suppression pool design water level

d. Maximum suction strainer pressure drop for the conditions assumed. For the condition where the strainers are clean, it will be assumed that the strainer head loss is equal to the head loss for the conical basket strainer that remains

on the suction tee, which is defined as 1.0 ft H_2O. This is conservative since flow will be preferentially taken through the path of least resistance, which in this case is the conical basket strainer; i.e., head loss for the toroidal strainer is greater than that for the conical basket strainer in a clean condition.

Calculations of pressures in ECCS Pumps Suction Piping

$$P_{(D.P.)} = P + H_s - \Delta P_L - \Delta P_s$$

where: $P_{(D.P.)}$ = absolute pressure at data points (i.e., P_1, P_2,...)

P = containment pressure (minimum pressure coincident with drawdown is 14.7 psia)

H_s = net static head from drawdown suppression pool level at elevation 107'-6" to data point elevation

ΔP_L = line losses at maximum pump flow

ΔP_s = suction strainer differential pressure

Note: Velocity head neglected for added conservatism.

A. RHR A Pump

Reference Figure 6E-1 (same as Figure 5.4-27 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - $H_s = (107.5' - 103.5')(59.8 \text{ lb/ft}^3)(\text{ft}^2/144 \text{ in.}^2)$
$= 1.66$ psi

D.P. 2 - $H_s = (107.5' - 103.5')(59.8 \text{ lb/ft}^3)(\text{ft}^2/144 \text{ in.}^2)$
$= 1.66$ psi

D.P. 3 - $H_s = (107.5' - 96')(59.8 \text{ lb/ft}^3)(\text{ft}^2/144 \text{ in.}^2)$
$= 4.77$ psi

D.P. 4 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 $in.^2$)
= 4.77 psi

D.P. 5 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 $in.^2$)
= 4.77 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 212°F

For 24" Schedule 20 pipe:

Re = 4.15×10^6

f = 0.012

ΔP/100 ft = 0.18 psi/100 ft

For 24" Schedule 30 pipe:

Re = 4.2×10^6

f = 0.012

ΔP/100 ft = 0.20 psi/100 ft

For 20" Schedule 20 pipe:

Re = 5.0×10^6

f = 0.012

ΔP/100 ft = 0.47 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" Schedule 20 pipe, fittings, and entrance) = 233 ft

L (equivalent length of 24" Schedule 30 pipe, valve, and fittings) = 101 ft

L (equivalent length of 20" Schedule 20 pipe and fittings) = 39 ft

ΔP_L = (233 x 0.18/100) + (101 x 0.20/100) + (39 x 0.47/100) = 0.80 psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 97.0 ft

ΔP_L = 97.0 x 0.20/100 = 0.19 psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 84.0 ft

ΔP_L = 84.0 x 0.20/100 = 0.17 psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 246.0 ft

ΔP_L = 246 x 0.20/100 = 0.49 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 10.0 ft

ΔP_L = 10.0 x 0.20/100 = 0.02 psi

Suppression pool strainer head loss

ΔP_s = 0.43 psi (from vendor flow tests for conical strainer)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.66 - 0.80 - 0.43 = 15.13 psia

@ D.P. 2 P_2 = 14.7 + 1.66 - 0.80 - 0.19 - 0.43 = 14.94 psia

@ D.P. 3 P_3 = 14.7 + 4.77 - 0.80 - 0.19 - 0.17 - 0.43 = 17.88 psia

@ D.P. 4 P_4 = 14.7 + 4.77 - 0.80 - 0.19 - 0.17 - 0.49 - 0.43 = 17.39 psia

@ D.P. 5 P_5 = 14.7 + 4.77 - 0.80 - 0.19 - 0.17 - 0.49 - 0.02 - 0.43 = 17.36 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at T = 212°F.

B. RHR B Pump

Reference Figure 6E-2 (same as Figure 5.4-28 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 2 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 3 – Hs = (107.5' - 96')(59.8 lb/ft3)(ft2/144 in.2)
= 4.77 psi

D.P. 4 – Hs = (107.5' - 96')(59.8 lb/ft3)(ft2/144 in.2)
= 4.77 psi

D.P. 5 – Hs = (107.5' - 96')(59.8 lb/ft3)(ft2/144 in.2)
= 4.77 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 212°F

For 24" Schedule 20 pipe:

Re = 4.15×10^6

f = 0.012

ΔP/100 ft = 0.18 psi/100 ft

For 24" Schedule 30 pipe:

Re = 4.2×10^6

f = 0.012

ΔP/100 ft = 0.20 psi/100 ft

For 20" Schedule 20 pipe:

Re = 5.0×10^6

$f = 0.012$

$\Delta P/100$ ft = 0.47 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" Schedule 20 pipe, fittings, and entrance) = 233 ft

L (equivalent length of 24" Schedule 30 pipe, valve, and fittings) = 101 ft

L (equivalent length of 20" Schedule 20 pipe and fittings) = 40 ft

$\Delta P_L = (233 \times 0.18/100) + (101 \times 0.20/100) + (40 \times 0.47/100) = 0.81$ psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 97.0 ft

$\Delta P_L = 97.0 \times 0.20/100 = 0.19$ psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 84.0 ft

$\Delta P_L = 84.0 \times 0.20/100 = 0.17$ psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 246 ft

$\Delta P_L = 246 \times 0.20/100 = 0.49$ psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 86.0 ft

$\Delta P_L = 86.0 \times 0.20/100 = 0.17$ psi

Suppression pool strainer head loss

$\Delta P_S = 0.43$ psi (from vendor flow tests for conical strainer)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.66 - 0.81 - 0.43 = 15.12 psia

@ D.P. 2 P_2 = 14.7 + 1.66 - 0.81 - 0.19 - 0.43 = 14.93 psia

@ D.P. 3 P_3 = 14.7 + 4.77 - 0.81 - 0.19 - 0.17 - 0.43
= 17.87 psia

@ D.P. 4 P_4 = 14.7 + 4.77 - 0.81 - 0.19 - 0.17 - 0.49 - 0.43
= 17.38 psia

@ D.P. 5 P_5 = 14.7 + 4.77 - 0.81 - 0.19 - 0.17 - 0.49 - 0.17
- 0.43 = 17.21 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at T = 212°F.

C. RHR C Pump

Reference Figure 6E-3 (same as Figure 5.4-29 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 2 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 3 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 4 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 4.77 psi

D.P. 5 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 4.77 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 212°F

For 24" Schedule 20 pipe:

Re = 4.15×10^6

f = 0.012

ΔP/100 ft = 0.18 psi/100 ft

For 24" Schedule 30 pipe:

Re = 4.2×10^6

f = 0.012

ΔP/100 ft = 0.20 psi/100 ft

For 20" Schedule 20 pipe:

Re = 5.0×10^6

f = 0.012

ΔP/100 ft = 0.47 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" Schedule 20 pipe, fittings, and entrance) = 233 ft

L (equivalent length of 24" Schedule 30 pipe, valve, and fittings) = 140 ft

L (equivalent length of 20" Schedule 20 pipe and fittings) = 42 ft

ΔP_L = (233 x 0.18/100) + (140 x 0.20/100) + (42 x 0.47/100) = 0.89 psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 57 ft

ΔP_L = 57 x 0.20/100 = 0.11 psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 93 ft

ΔP_L = 93.0 x 0.20/100 = 0.18 psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 84 ft

ΔP_L = 84 x 0.20/100 = 0.17 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 209 ft

ΔP_L = 209 x 0.20/100 = 0.42 psi

Suppression pool strainer head loss

ΔP_s = 0.43 psi (from vendor flow tests for conical strainer)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.66 - 0.89 - 0.43 = 15.04 psia

@ D.P. 2 P_2 = 14.7 + 1.66 - 0.89 - 0.43 - 0.11 = 14.93 psia

@ D.P. 3 P_3 = 14.7 + 1.66 - 0.89 - 0.11 - 0.18 - 0.43 = 14.75 psia

@ D.P. 4 P_4 = 14.7 + 4.77 - 0.89 - 0.11 - 0.18 - 0.17 - 0.43 = 17.69 psia

@ D.P. 5 P_5 = 14.7 + 4.77 - 0.89 - 0.11 - 0.18 - 0.43 - 0.17 - 0.42 = 17.27 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at T = 212°F.

D. LPCS Pump

Reference Figure 6E-4 (same as Figure 6.3-70 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 2 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 3 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 4 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 4.77 psi

D.P. 5 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 4.77 psi

Line losses (P_L) at maximum pump flow of 9100 gpm @ 212°F

For 24" Schedule 20 pipe:

Re = 4.4×10^6

f = 0.012

ΔP/100 ft = 0.205 psi/100 ft

For 20" Schedule 20 pipe:

Re = 5.3×10^6

f = 0.012

ΔP/100 ft = 0.53 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" pipe, valve, fittings, and entrance) = 275 ft

L (equivalent length of 20" pipe and fittings) = 36 ft

ΔP_L = (275 x 0.205/100) + (36 x 0.53/100) = 0.75 psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 57 ft

ΔP_L = 57 x 0.205/100 = 0.12 psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 55 ft

ΔP_L = 55 x 0.205/100 = 0.11 psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 85 ft

ΔP_L = 85 x 0.205/100 = 0.17 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 182 ft

ΔP_L = 182 x 0.205/100 = 0.37 psi

Suppression pool strainer head loss

P_S = 0.43 psi (from vendor flow tests for conical strainer)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.66 - 0.75 - 0.43 = 15.18 psia

@ D.P. 2 P_2 = 14.7 + 1.66 - 0.75 - 0.12 - 0.43 = 15.06 psia

@ D.P. 3 P_3 = 14.7 + 1.66 - 0.75 - 0.12 - 0.11 - 0.43 = 14.95 psia

@ D.P. 4 P_4 = 14.7 + 4.77 - 0.75 - 0.12 - 0.11 - 0.17 - 0.43 = 17.89 psia

@ D.P. 5 P_5 = 14.7 + 4.77 - 0.75 - 0.12 - 0.11 - 0.17 - 0.37 - 0.43 = 17.52 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at T = 212°F.

E. HPCS Pump

Reference Figure 6E-5 (same as Figure 6.3-68 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 212°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 1.66 psi

D.P. 2 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 4.77 psi

D.P. 3 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 4.77 psi

D.P. 4 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 4.77 psi

D.P. 5 - H_s = (107.5' - 96')(59.8 lb/ft^3)(ft^2/144 in.^{2})
= 4.77 psi

Line losses (P_L) at maximum pump flow of 8175 gpm @ 212°F

For 24" Schedule 20 pipe:

Re = 3.8×10^6

f = 0.012

ΔP/100 ft = 0.165 psi/100 ft

For 20" Schedule 20 pipe:

Re = 4.64×10^6

f = 0.012

ΔP/100 ft = 0.428 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" pipe, valve, fittings, and entrance) = 231 ft

L (equivalent length of 20" pipe and fittings) = 37 ft

ΔP_L = (37 x 0.428/100) + 231 (0.165/100) = 0.54 psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 85 ft

ΔP_L = 85 x 0.165/100 = 0.14 psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 51 ft

ΔP_L = 51 x 0.165/100 = 0.084 psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 55 ft

ΔP_L = 55 x 0.165/100 = 0.091 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 564 ft

ΔP_L = 564 x 0.165/100 = 0.93 psi

Suppression pool strainer head loss

ΔP_s = 0.43 psi (from vendor flow tests conical strainer)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.66 - 0.54 - 0.43 = 15.39 psia

@ D.P. 2 P_2 = 14.7 + 4.77 - 0.54 - 0.14 - 0.43 = 18.36 psia

@ D.P. 3 P_3 = 14.7 + 4.77 - 0.54 - 0.14 - 0.084 - 0.43 = 18.28 psia

@ D.P. 4 P_4 = 14.7 + 4.77 - 0.54 - 0.14 - 0.084 - 0.091 - 0.43 = 18.19 psia

@ D.P. 5 P_5 = 14.7 + 4.77 - 0.54 - 0.14 - 0.084 - 0.091 - 0.93 - 0.43 = 17.26 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (14.7 psia) at T = 212°F.

6E.1A. CALCULATION OF SUCTION PRESSURES - MAXIMUM STRAINER HEAD LOSS

The following calculations determine the pressures at various locations along the ECCS pumps' suction piping. As concluded from the calculations, adequate pressures exist along the suction piping to preclude local flashing under the worst postulated conditions. That is, the pressure at each point exceeds the vapor pressure of the fluid. For the calculations, a suppression pool water temperature of 185°F with a corresponding vapor pressure of 8.38 psia was assumed. This is a conservative assumption, since the maximum analyzed pool water temperature is 181°F as specified in Table 6.2-13. Since the vapor pressure for water at 181°F is 7.7 psia, more than adequate margin exists to preclude flashing in the suction piping. For the condition in which significant debris generation in the drywell is postulated, and assuming 100% transport of that debris to the suppression pool, a suppression pool water temperature of 185°F was assumed. This is conservative since the maximum analyzed suppression pool water temperature is 181°F as discussed above.

Other conservative assumptions used for the calculations are:

a. Pump design maximum runout flow rate

b. Atmospheric containment pressure

c. Minimum suppression pool design water level

d. Maximum suction strainer pressure drop for the conditions assumed. For the condition where the strainers are debris laden, it will be assumed that the strainer head loss is equal to the head loss for the toroidal strainer and that the conical basket strainer that remains on the suction tee is completely blocked. This is conservative since flow will be preferentially taken through the path of least resistance, which in this case is the toroidal strainer. Debris will initially be attracted to the conical basket strainer which will result in blockage of this strainer, increasing flow from the toroidal strainer, until such time as the conical strainer is fully blocked and all flow is from the toroidal strainer.

Calculations for pressures in ECCS Pumps Suction Piping

$$P_{(D.P.)} = P + H_S - \Delta P_L - \Delta P_S$$

where: $P_{(D.P.)}$ = absolute pressure at data points (i.e., P_1, P_2,...)

P = containment pressure (minimum pressure coincident with drawdown is 14.7 psia)

H_S = net static head from drawdown suppression pool level at elevation 107'-6" to data point elevation.

ΔP_L = line losses at maximum pump flow

ΔP_S = suction strainer maximum differential pressure

Note: Velocity head neglected for added conservatism.

A. RHR A Pump

Reference Figure 6E-1 (same as Figure 5.4-27 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 185°F) at each data point.

D.P. 1 - H_S = (107.5' - 103.5')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 1.68 psi

D.P. 2 - H_S = (107.5' - 103.5')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 1.68 psi

D.P. 3 - H_S = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.82 psi

D.P. 4 - H_S = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.82 psi

D.P. 5 - H_S = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.82 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 185°F

For 24" Schedule 20 pipe:

Re = 4.90×10^6

f = 0.012

ΔP/100 ft = 0.18 psi/100 ft

For 24" Schedule 30 pipe:

Re = 4.96×10^6

f = 0.012

ΔP/100 ft = 0.20 psi/100 ft

For 20" Schedule 20 pipe:

Re = 5.91×10^6

f = 0.012

ΔP/100 ft = 0.47 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" Schedule 20 pipe, fittings, and entrance) = 233 ft

L (equivalent length of 24" Schedule 30 pipe, valve, and fittings) = 101 ft

L (equivalent length of 20" Schedule 20 pipe and fittings) = 39 ft

ΔP_L = (233 x 0.18/100) + (101 x 0.20/100) + (39 x 0.47/100) = 0.80 psi

From D.P. 1 TO D.P. 2:

L (equivalent length of 24" pipe and fittings) = 97.0 ft

ΔP_L = 97.0 x 0.20/100 = 0.19 psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 84.0 ft

ΔP_L = 84.0 x 0.20/100 = 0.17 psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 246.0 ft

ΔP_L = 246 x 0.20/100 = 0.49 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 10.0 ft

ΔP_L = 10.0 x 0.20/100 = 0.02 psi

Suppression pool strainer head loss

ΔP_S = 4.86 psi (from calculation/tests)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.68 - 0.80 - 4.86 = 9.86 psia

@ D.P. 2 P_2 = 14.7 + 1.68 - 0.80 - 0.19 - 4.86 = 9.67 psia

@ D.P. 3 P_3 = 14.7 + 4.82 - 0.80 - 0.19 - 0.17 - 4.86 = 13.50 psia

@ D.P. 4 P_4 = 14.7 + 4.82 - 0.80 - 0.19 - 0.17 - 0.49 - 4.86 = 13.01 psia

@ D.P. 5 P_5 = 14.7 + 4.82 - 0.80 - 0.19 - 0.17 - 0.49 - 0.02 - 4.86 = 12.99 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (8.38 psia) at T = 185°F.

B. RHR B Pump

Reference Figure 6E-2 (same as Figure 5.4-28 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 185°F) at each data point.

D.P. 1 - H_s = $(107.5' - 103.5')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 1.68 psi

D.P. 2 - H_s = $(107.5' - 103.5')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 1.68 psi

D.P. 3 - H_s = $(107.5' - 96')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 4.82 psi

D.P. 4 - H_s = $(107.5' - 96')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 4.82 psi

D.P. 5 - H_s = $(107.5' - 96')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 4.82 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 185°F

For 24" Schedule 20 pipe:

Re = 4.90×10^6

f = 0.012

ΔP/100 ft = 0.18 psi/100 ft

For 24" Schedule 30 pipe:

Re = 4.96×10^6

f = 0.012

ΔP/100 ft = 0.20 psi/100 ft

For 20" Schedule 20 pipe:

Re = 5.91×10^6

f = 0.012

ΔP/100 ft = 0.47 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" Schedule 20 pipe, fittings, and entrance) = 233 ft

L (equivalent length of 24" Schedule 30 pipe, valve, and fittings) = 101 ft

L (equivalent length of 20" Schedule 20 pipe and fittings) = 40 ft

ΔP_L = (233 x 0.18/100) + (101 x 0.20/100) + (40 x 0.47/100) = 0.81 psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 97.0 ft

ΔP_L = 97.0 x 0.20/100 = 0.19 psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 84.0 ft

ΔP_L = 84.0 x 0.20/100 = 0.17 psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 246 ft

ΔP_L = 246 x 0.20/100 = 0.49 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 86.0 ft

ΔP_L = 86.0 x 0.20/100 = 0.17 psi

Suppression pool strainer head loss

ΔP_s = 4.81 psi (from calculation/tests)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.68 - 0.81 - 4.81 = 10.76 psia

@ D.P. 2 P_2 = 14.7 + 1.68 - 0.81 - 0.19 - 4.81 = 10.57 psia

@ D.P. 3 P_3 = 14.7 + 4.82 - 0.81 - 0.19 - 0.17 - 4.81
= 13.54 psia

@ D.P. 4 P_4 = 14.7 + 4.82 - 0.81 - 0.19 - 0.17 - 0.49 - 4.81
= 13.05 psia

@ D.P. 5 P_5 = 14.7 + 4.82 - 0.81 - 0.19 - 0.17 - 0.49 - 0.17 - 4.81 = 12.88 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (8.38 psia) at T = 185°F.

C. RHR C Pump

Reference Figure 6E-3 (same as Figure 5.4-29 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 185°F) at each data point.

D.P. 1 - H_s = $(107.5' - 103.5')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 1.68 psi

D.P. 2 - H_s = $(107.5' - 103.5')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 1.68 psi

D.P. 3 - H_s = $(107.5' - 103.5')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 1.68 psi

D.P. 4 - H_s = $(107.5' - 96')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 4.82 psi

D.P. 5 - H_s = $(107.5' - 96')(60.46\ lb/ft^3)(ft^2/144\ in.^2)$
= 4.82 psi

Line losses (ΔP_L) at maximum pump flow of 8940 gpm @ 185°F

For 24" Schedule 20 pipe:

Re = 4.90×10^6

f = 0.012

$\Delta P/100$ ft = 0.18 psi/100 ft

For 24" Schedule 30 pipe:

Re = 4.96×10^6

f = 0.012

$\Delta P/100$ ft = 0.20 psi/100 ft

For 20" Schedule 20 pipe:

Re = 5.91×10^6

f = 0.012

$\Delta P/100$ ft = 0.47 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" Schedule 20 pipe, fittings, and entrance) = 233 ft

L (equivalent length of 24" Schedule 30 pipe, valve, and fittings) = 140 ft

L (equivalent length of 20" Schedule 20 pipe and fittings) = 42 ft

$\Delta P_L = (233 \times 0.18/100) + (140 \times 0.20/100) + (42 \times 0.47/100) = 0.89$ psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 57 ft

$\Delta P_L = 57 \times 0.20/100 = 0.11$ psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 93 ft

$\Delta P_L = 93.0 \times 0.20/100 = 0.18$ psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 84 ft

ΔP_L = 84 x 0.20/100 = 0.17 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 209 ft

ΔP_L = 209 x 0.20/100 = 0.42 psi

Suppression pool strainer head loss

ΔP_s = 6.58 psi (from calculation/test)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.68 - 0.89 - 6.58 = 8.91 psia

@ D.P. 2 P_2 = 14.7 + 1.68 - 0.89 - 6.58 - 0.11 = 8.80 psia

@ D.P. 3 P_3 = 14.7 + 1.68 - 0.89 - 0.11 - 0.18 - 6.58
= 8.62 psia

@ D.P. 4 P_4 = 14.7 + 4.82 - 0.89 - 0.11 - 0.18 - 0.17 - 6.58
= 11.59 psia

@ D.P. 5 P_5 = 14.7 + 4.82 - 0.89 - 0.11 - 0.18 - 6.58 - 0.17
- 0.42 = 11.17 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (8.38 psia) at T = 185°F.

D. LPCS Pump

Reference Figure 6E-4 (same as Figure 6.3-70 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 185°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 1.68 psi

D.P. 2 - H_s = (107.5' - 103.5')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 1.68 psi

D.P. 3 - H_s = (107.5' - 103.5')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 1.68 psi

D.P. 4 - H_s = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.2)
= 4.82 psi

D.P. 5 - H_s = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.82 psi

Line losses (ΔP_L) at maximum pump flow of 9100 gpm @ 185°F

For 24" Schedule 20 pipe:

Re = 4.90×10^6

f = 0.012

ΔP/100 ft = 0.205 psi/100 ft

For 20" Schedule 20 pipe:

Re = 5.91×10^6

f = 0.012

ΔP/100 ft = 0.53 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" pipe, valve, fittings, and entrance) = 275 ft

L (equivalent length of 20" pipe and fittings) = 36 ft

ΔP_L = (275 x 0.205/100) + (36 x 0.53/100) = 0.75 psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 57 ft

ΔP_L = 57 x 0.205/100 = 0.12 psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 55 ft

ΔP_L = 55 x 0.205/100 = 0.11 psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 85 ft

ΔP_L = 85 x 0.205/100 = 0.17 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 182 ft

ΔP_L = 182 x 0.205/100 = 0.37 psi

Suppression pool strainer head loss

ΔP_S = 4.92 psi (from calculation/tests)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.68 - 0.75 - 4.92 = 10.71 psia

@ D.P. 2 P_2 = 14.7 + 1.68 - 0.75 - 0.12 - 4.92 = 10.59 psia

@ D.P. 3 P_3 = 14.7 + 1.68 - 0.75 - 0.12 - 0.11 - 4.92 = 10.48 psia

@ D.P. 4 P_4 = 14.7 + 4.82 - 0.75 - 0.12 - 0.11 - 0.17 - 4.92 = 13.45 psia

@ D.P. 5 P_5 = 14.7 + 4.82 - 0.75 - 0.12 - 0.11 - 0.17 - 0.37 - 4.92 = 13.08 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (8.38 psia) at T = 185°F.

E. HPCS Pump

Reference Figure 6E-5 (same as Figure 6.3-68 with the addition of data points) for suction line geometry.

Static head at minimum pool water density (ρ @ 185°F) at each data point.

D.P. 1 - H_s = (107.5' - 103.5')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 1.68 psi

D.P. 2 - H_s = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.82 psi

D.P. 3 - H_s = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.82 psi

D.P. 4 - H_s = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.82 psi

D.P. 5 - H_s = (107.5' - 96')(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.82 psi

Line losses (ΔP_L) at maximum pump flow of 8175 gpm @ 185°F

For 24" Schedule 20 pipe:

Re = 3.8×10^6

f = 0.012

ΔP/100 ft = 0.165 psi/100 ft

For 20" Schedule 20 pipe:

Re = 4.64×10^6

f = 0.012

ΔP/100 ft = 0.428 psi/100 ft

From strainer to D.P. 1:

L (equivalent length of 24" pipe, valve, fittings, and entrance) = 231 ft

L (equivalent length of 20" pipe and fittings) = 37 ft

ΔP_L = (37 x 0.428/100) + 231 (0.165/100) = 0.54 psi

From D.P. 1 to D.P. 2:

L (equivalent length of 24" pipe and fittings) = 85 ft

ΔP_L = 85 x 0.165/100 = 0.14 psi

From D.P. 2 to D.P. 3:

L (equivalent length of 24" pipe and fittings) = 51 ft

ΔP_L = 51 x 0.165/100 = 0.084 psi

From D.P. 3 to D.P. 4:

L (equivalent length of 24" pipe and fittings) = 55 ft

ΔP_L = 55 x 0.165/100 = 0.091 psi

From D.P. 4 to D.P. 5:

L (equivalent length of 24" pipe and fittings) = 564 ft

ΔP_L = 564 x 0.165/100 = 0.93 psi

Suppression pool strainer head loss

ΔP_S = 5.46 psi (from calculation/tests)

Pressure @ data points

@ D.P. 1 P_1 = 14.7 + 1.68 - 0.54 - 5.46 = 10.38 psia

@ D.P. 2 P_2 = 14.7 + 4.82 - 0.54 - 0.14 - 5.46 = 13.38 psia

@ D.P. 3 P_3 = 14.7 + 4.82 - 0.54 - 0.14 - 0.084 - 5.46
= 13.30 psia

@ D.P. 4 P_4 = 14.7 + 4.82 - 0.54 - 0.14 - 0.084 - 0.091 -
5.46 = 13.21 psia

@ D.P. 5 P_5 = 14.7 + 4.82 - 0.54 - 0.14 - 0.084 - 0.091 -
0.93 - 5.46 = 12.28 psia

Summary: The pressure at all points along the suction piping exceeds the vapor pressure (8.38 psia) at T = 185°F.

6E.2 NPSHA CALCULATIONS

A. RHR Pumps

1. Minimum NPSHA calculations - Clean Strainer

   a. NPSHA RHR A Pump

   Reference Figure 5.4-27 for suction line geometry. Reference Figure 3.6A-19 and Table 6.2-50 for suppression pool geometry (typical for all pumps)

   $NPSHA_{min} = P + H_s - \Delta P_L - \Delta P_s - P_v$

   where P = containment pressure, absolute

   H_s = net static head from drawdown suppression pool level at 107'-6" elevation to point 3 ft above top of pump mounting flange at 93'-4 3/4" elevation.

   ΔP_L = line losses at maximum pump flow (maximum), 8940 gpm

   ΔP_s = suction strainer ΔP (clean strainer) (Includes entrance loss)

   Note: For the condition where the strainers are clean, it will be assumed that the strainer head loss is equal to the head loss for the conical basket strainer that remains on the suction tee, which is defined as 1.0 ft H_2O. This is conservative since flow will be preferentially taken through the path of least resistance, which in this case is the conical basket strainer; i.e., head loss for the toroidal strainer is greater than that for the conical basket strainer in a clean condition.

   P_v = absolute vapor pressure above 212°F (hypothetical) suppression pool (maximum)

Note: minimum containment pressure coincident with drawdown is 0 psig (atmospheric); then P = 14.7 psia

then, evaluating static head at minimum pool water density (ρ at 212°F)

H_S = (107.5- 96.4 ft) (59.8 lb/ft^3) (ft^2/144 in^2) = 4.61 psi

line losses for the 24" Schedule 30 pipe (short length of 24"-0.375" nominal wall included) evaluated at flow conditions of 8940 gpm, 212°F

Re = 4.2×10^6

f = 0.0120

ΔP/100ft = 0.20 psi/100 ft

L (equiv. length of 24" piping and fittings) = 671 ft

then ΔP (24" piping)= (671 ft)(0.20 psi/100 ft) = 1.34 psi

line losses for 20" Schedule 20 are evaluated at 212°F, 8940 gpm

Re = 5.0×10^6

f = 0.012

ΔP/100 ft = 0.47 psi/100 ft

L (equiv. length of 20" Schedule 20 piping and fittings) = 39 ft

then ΔP (20" Schedule 20) = (39 ft) (0.47 psi/100 ft) = 0.19 psi

finally, ΔP_L = ΔP (24" piping) + ΔP (20" piping) = (1.34 + 0.19) psi

$\Delta P_L = 1.52$ psi

$\Delta P_s = 0.58$ psi(from vendor flow tests for conical strainer)

$P_v = 14.7$ psia

then $NPSHA_{min} = 14.7$ psia + 4.61 psi - 1.52 psi - 0.58 psi - 14.7 psia
= 2.5 psi

Converting this to feet at again, minimum density,

$NPSHA_{min} = 2.5\ psi(144\ in^2/ft^2)/(59.8\ lb/ft^2)$

$NPSHA_{min} = 6.0$ feet

b. NPSHA RHR B Pump

Reference Figure 5.4-28 for suction line geometry

By the same method and assumptions as for A, the following is calculated:

Static head = $H_s = 4.61$ psi

Line losses for 24" Schedule 30 suction piping (including 24" -0.375" wall piping)

$\Delta P/100$ ft = 0.20 psi/100 ft
L = 747 ft (equiv. length)

then ΔP (24" piping) = (747 ft) (0.20 psi/100 ft)
= 1.48 psi

Line losses for 20" Schedule 20 suction piping

$\Delta P/100$ ft = 0.47 psi/100 ft
L = 40 ft (equiv. length)

then ΔP (20" piping) = (40 ft) (0.47 psi/100 ft)
= 0.19 psi

finally, ΔP_L = (1.48 + 0.19) psi = 1.68 psi

ΔP_s = 0.58 psi

P_v = 14.7 psia

then $NPSHA_{min}$ = 14.7 psia + 4.61 psi - 1.68 psi- 0.58 psi - 14.7 psia
= 2.36 psi

in feet:

$NPSHA_{min}$ = 5.7 feet

c. NPSHA RHR C Pump

Reference Figure 5.4-29 for suction line geometry

By same method and assumptions as for A, the following is calculated:

Static head = H_s = 4.61 psi

Line losses for 24" Schedule 30 suction piping (including 24" - 0.375" wall piping)

ΔP/100 ft = 0.20 psi/100 ft

L = 716 ft (equiv. length)

then ΔP (24" piping) = (716 ft) (0.20 psi/100 ft)
= 1.43 psi

Line losses for 20" Schedule 20 suction piping

ΔP/100 ft = 0.47 psi/100 ft
L = 42 ft (equiv. length)

then ΔP (20" piping) = (42 ft) (0.47 psi/100 ft)
= 0.20 psi

finally, ΔP_L = (1.43 + 0.20) psi = 1.63 psi

ΔP_s = 0.58 psi

P_v = 14.7 psia

then $NPSHA_{min}$ = 14.7 psia + 4.61 psi - 1.63 psi - 0.58 psi - 14.7 psia
= 2.40 psi

in feet:

$NPSHA_{min}$ = 5.8 feet

d. NPSHA at Design Conditions

With all other conditions equal, RHR B pump NPSHA will be the least of the three due to the greatest equivalent length of suction piping and fittings. Accordingly, the calculation at maximum design conditions is presented for this pump only. The calculation method is the same.

Flow conditions:

Q (design flow) = 7450 gpm

T (temperature) = 185°F

Minimum containment pressure coincident with drawdown is 0 psig. The static head at drawdown level in the suppression pool with pool bulk temperature at 185°F

H_s = (107.5 - 96.4 ft)(60.46 lb/ft^3)(ft^2/144 in.^{2})
= 4.66 psi

Line losses for 24" Schedule 30 suction piping (including 24"-0.375" nom. wall piping)

Re = 3.1 x 10^6

f = 0.0122

ΔP/100 ft = 0.14 psi/100 ft

L (equiv. length) = 747 ft

then ΔP (24" piping) = (747 ft) (0.14 psi/100 ft) = 1.05 psi

Line losses for 20" Schedule 20 section suction piping

Re = 3.7×10^6

f = 0.0123

ΔP/100 ft = 0.34 psi/100 ft

L (equiv. length) = 40 ft

then ΔP (20" piping) = (40 ft) (0.34 psi/100 ft)
= 0.14 psi

finally, ΔP_L = P (24" piping) + ΔP (20" piping)
= (1.05 + 0.14) psi
= 1.19 psi

P_s = 0.58 psi (Strainer still assumed clean)

P_v (@ 185°F) = 8.38 psia

Then NPSHA = $P + H_s - \Delta P_L - \Delta P_s - P_v$
= (14.7 + 4.66 - 1.19 - 0.58 - 8.38) psi
= 9.2 psi

in feet:

NPSHA = 22 feet

In addition to revised Figure 5.4-20, the required NPSH for the RHR pump is also depicted on Figure 6E-6. This expanded scale performance curve shows that the NPSH is 2 feet for the range from 3000 to 8500 gpm. Note that the curve gives NPSH required at 3 feet above the mounting flange. The suction nozzle is 34.75 inches above the bottom of the mounting flange.

2. NPSHA for Cold Shutdown and Refueling Modes (Operational Conditions 4 and 5) - Clean Strainers

The Technical Specifications allow the suppression pool water level to be lowered to the 105'-8" elevation in the cold shutdown and refueling modes. A fluid

temperature of 125 F and all other conditions maximum as above are assumed. The calculative method is the same.

a. NPSHA RHR A Pump

Reference Figure 5.4-27 for suction line geometry.

NPSHA for the RHR A pump in operational conditions 4 and 5 is:

$$NPSHA = P + H_s - \Delta P_L - \Delta P_s - P_v$$

where P = containment pressure, absolute (14.7 psia)

H_s = net static head from suppression pool level at 105'-8" elevation (minimum level in operational conditions 4 and 5, 12'-8") to point 3 ft above top of pump mounting flange at 93'-4 3/4" elevation.

ΔP_L = line losses at maximum pump flow 8940 gpm

ΔP_s = suction strainer clean ΔP (includes entrance losses)

P_v = absolute vapor pressure at 125°F.

then, evaluating static head (ρ at 125°F)

$$H_s = (105.67 \text{ ft} - 96.4 \text{ ft})(61.63 \text{ lb/ft}^3)(\text{ft}^2/144 \text{ in.}^2) = 3.97 \text{ psi}$$

Line losses for the 24" schedule 30 pipe (short length of 24"-0.375" nominal wall included) evaluated at flow conditions of 8940 gpm, 125°F

Re = 2.3×10^6

f = 0.0123

ΔP/100 ft = 0.21 psi/100 ft

L (equiv. length of 24" piping and fittings) = 671 ft, then ΔP (24" piping) = (671 ft) (0.22 psi/100 ft) = 1.48 psi

line losses for 20" Schedule 20 are evaluated at 125°F, 8940 gpm

Re = 2.8×10^6

f = 0.0124

ΔP/100 ft = 0.50 psi/100 ft

L (equiv. length of 20" Schedule 20 piping and fittings) = 39 ft

then ΔP (20" Schedule 20) = (39 ft)(0.50 psi/100 ft) = 0.20 psi

finally, $\Delta P_L = \Delta P$ (24" piping) + ΔP (20" piping)
= (1.48 + 0.20) psi
ΔP_L = 1.68 psi

ΔP_s = 0.58 psi (from vendor flow tests for conical strainer)

P_v = 1.96 psia @ 125°F

then NPSHA = 14.7 psia + 3.97 psi - 1.68 psi - 0.58 psi - 1.96 psia
= 14.46 psi

Converting this to feet,

NPSHA = 14.46 psi (144 in.^{2}/ft^2)/(61.63 lb/ft^3)

NPSHA = 33.8 feet

b. NPSHA RHR B Pump

Reference Figure 5.4-28 for suction line geometry

By the same method and assumptions as for A, the following is calculated:

static head = H_S = 3.97 psi

Line losses for 24" Schedule 30 suction piping (including 24"-0.375" wall piping loss)

ΔP/100 ft = 0.22 psi/100 ft

L = 747 ft (equiv. length)

then ΔP (24" piping) = (747 ft) (0.22 psi/100 ft)
= 1.64 psi

Line losses for 20" Schedule 20 suction piping

ΔP/100 ft = 0.50 psi/100 ft
L = 40 ft (equiv. length)

then ΔP (20" piping) = (40 ft) (0.50 psi/100 ft)
= 0.20 psi

finally, ΔP_L = (1.64 + 0.20) psi = 1.84 psi

ΔP_S = 0.58 psi

P_V = 1.96 psi @ 125°F

then NPSHA = 14.7 psia + 3.97 psi - 1.84 psi - 0.58 psi - 1.96 psia
= 14.3 psi

in feet:

NPSHA = 33.4 feet

c. NPSHA RHR C Pump

Reference FSAR Figure 5.4-29 for suction line geometry

By same method and assumptions as for A, the following is calculated:

Static head = H_S = 3.97 psi

Line losses for 24" Schedule 30 suction piping (including 24" - 0.375" wall piping)

$\Delta P/100$ ft = 0.22 psi/100 ft
L = 716 ft (equiv. length)

then ΔP (24" piping) = (716 ft) (0.22 psi/100 ft)
= 1.58 psi

Line losses for 20" Schedule 20 suction piping

$\Delta P/100$ ft = 0.50 psi/100 ft

L = 42 ft (equiv. length)

then ΔP (20" piping) = (42 ft) (0.50 psi/100 ft)
= 0.21 psi

finally, ΔP_L = (1.58 + 0.21) psi
= 1.79 psi

ΔP_s = 0.43 psi

P_v = 1.96 psi @ 125°F

then, NPSHA = 14.7 psia + 3.97 psi - 1.79 psia - 0.58 psi - 1.96 psia = 14.36 psi

in feet:

NPSHA = 33.5 feet

d. Estimated NPSHA for a Maximum of 200°F Pool Water Temperature (Operational Conditions 4 and 5)

Assuming all data remains the same except absolute vapor pressure

P_v = 11.53 psia @ 200°F, ρ = 60.11 lb/ft^3

The difference between the vapor pressure at 200°F and 125°F is

ΔP_v = 11.53 psia - 1.96 psia

= 9.57 psia

in feet:

$$= 9.57 \text{ psia} \times \frac{144 \text{ in.}^2/\text{ft}^2}{60.11 \text{ lb/ft}^3}$$

= 22.93 ft

NPSHA for the RHR pumps at pool water temperature of 200°F are:

RHR A NPSHA = 33.79 ft - 22.93 ft = 10.86 ft

RHR B NPSHA = 33.41 ft - 22.93 ft = 10.48 ft

RHR C NPSHA = 33.55 ft - 22.93 ft = 10.62 ft

3. Minimum NPSHA calculations - Maximum Strainer Head Loss, Suppression Pool Temperature 185°F

a. NPSHA RHR A Pump

Reference Figure 5.4-27 for suction line geometry. Reference Figure 3.6A-19 and Table 6.2-50 for suppression pool geometry (typical for all pumps)

$NPSHA_{min} = P + H_s - \Delta P_L - \Delta P_s - P_v$

where P = containment pressure, absolute

H_s = net static head from drawdown suppression pool level at 107'-6" elevation to point 3 ft above top of pump mounting flange at 93'-4 3/4" elevation.

ΔP_L = line losses at maximum pump flow (maximum), 8940 gpm

ΔP_s = suction strainer ΔP (maximum) - includes entrance loss

Note: For the condition where the strainers are debris laden, it will be assumed that the strainer head loss is equal to the head loss

for the toroidal strainer and that the conical basket strainer that remains on the suction tee is completely blocked. This is conservative since flow will be preferentially taken through the path of least resistance, which in this case is the toroidal strainer. Debris will initially be attracted to the conical basket strainer which will result in blockage of this strainer, increasing flow from the toroidal strainer, until such time as the conical strainer is fully blocked and all flow is from the toroidal strainer.

P_v = absolute vapor pressure above 185°F suppression pool

Note: minimum containment pressure coincident with drawdown is 0 psig (atmospheric); then P = 14.7 psia

then, evaluating static head at minimum pool water density (ρ at 185°F)

$$H_s = (107.5 - 96.4 \text{ ft})\ (60.46 \text{ lb/ft}^3)\ (\text{ft}^2/144 \text{ in}^2) = 4.66 \text{ psi}$$

Line losses for the 24" Schedule 30 pipe (short length of 24"-0.375" nominal wall included) evaluated at flow conditions of 8940 gpm, 185°F

$Re = 4.2 \times 10^6$

$f = 0.0120$

$\Delta P/100 \text{ ft} = 0.20 \text{ psi}/100 \text{ ft}$

L (equiv. length of 24" piping and fittings) = 671 ft

then ΔP (24" piping) = (671 ft) (0.20 psi/100 ft) = 1.34 psi

Line losses for 20" Schedule 20 are evaluated at 185°F, 8940 gpm

Re = 5.0×10^6

f = 0.012

ΔP/100 ft = 0.47 psi/100 ft

L (equiv. length of 20" Schedule 20 piping and fittings) = 39 ft

then ΔP (20" Schedule 20) = (39 ft) (0.47 psi/100 ft)
= 0.19 psi

finally, ΔP_L = ΔP(24" piping) + ΔP (20" piping)
= (1.34 + 0.19) psi
ΔP_L = 1.52 psi

ΔP_s = 4.99 psi (maximum - calculation/tests)

P_v = 8.38 psia

then $NPSHA_{min}$ = 14.7 psia + 4.66 psi - 1.52 psi - 4.99 psi - 8.28 psia = 4.47 psi

Converting this to feet at again, minimum density,

$NPSHA_{min}$ = 4.47 psi (144 in^2/ft^2)/(60.46 lb/ft^2)

$NPSHA_{min}$ = 10.65 feet

b. NPSHA RHR B Pump

Reference Figure 5.4-28 for suction line geometry

By the same method and assumptions as for A, the following is calculated:

Static head = H_s = 4.66 psi

Line losses for 24" Schedule 30 suction piping (including 24" - 0.375" wall piping)

ΔP/100 ft = 0.20 psi/100 ft

L = 747 ft (equiv. length)

then ΔP (24" piping) = (747 ft) (0.20 psi/100 ft)
= 1.48 psi

Line losses for 20" Schedule 20 suction piping

ΔP/100 ft = 0.47 psi/100 ft

L = 40 ft (equiv. length)

then ΔP (20" piping) = (40 ft) (0.47 psi/100 ft)
= 0.19 psi

finally, ΔP_L = (1.48 + 0.19) psi = 1.68 psi

ΔP_s = 4.81 psi

P_v = 8.38 psia

then $NPSHA_{min}$ = 14.7 psia + 4.66 psi - 1.68 psi
- 4.81 psi = 8.38 psia
= 4.49 psi

in feet:

$NPSHA_{min}$ = 10.69 feet

c. NPSHA RHR C Pump

Reference Figure 5.4-29 for suction line geometry

By same method and assumptions as for A, the following is calculated:

Static head = H_s = 4.66 psi

Line losses for 24" Schedule 30 suction piping (including 24" - 0.375" wall piping and entrance losses)

ΔP/100 ft = 0.20 psi/100 ft

L = 716 ft (equiv. length)

then ΔP (24" piping) = (716 ft) (0.20 psi/100 ft)
= 1.43 psi

Line losses for 20" Schedule 20 suction piping

$\Delta P/100$ ft = 0.47 psi/100 ft

L = 42 ft (equiv. length)

then ΔP (20" piping) = (42 ft) (0.47 psi/100 ft)
= 0.20 psi

finally, ΔP_L = (1.43 + 0.20) psi = 1.63 psi

ΔP_s = 6.58 psi

P_v = 8.38 psia

then, $NPSHA_{min}$ = 14.7 psia + 4.66 psi - 1.63 psi - 6.58 psi - 8.38 psia = 2.77 psi

in feet:

$NPSHA_{min}$ = 6.6 feet

d. NPSHA at Design Conditions

With all other conditions equal, RHR C pump NPSHA will be the least of the three due to the greatest head loss due to debris.

Accordingly, the calculation at maximum design conditions is presented for this pump only. The calculation method is the same.

Flow conditions:

Q (design flow) = 7450 gpm

T (temperature) = 185°F

Minimum containment pressure coincident with drawdown is 0 psig. The static head at drawdown level in the suppression pool with pool bulk temperature at 185°F

H_s = (107.5 - 96.4 ft)(60.46 lb/ft^3) (ft^2/144 in.^{2}) = 4.66 psi

Line losses for 24" Schedule 30 suction piping (including 24" - 0.375" nom. wall piping)

Re = 3.1×10^6

f = 0.0122

ΔP/100 ft = 0.14 psi/100 ft

L (equiv. length) = 747 ft

then ΔP (24" piping) = (747 ft) (0.14 psi/100 ft)
= 1.05 psi

Line losses for 20" Schedule 20 section suction piping

Re = 3.7×10^6

f = 0.0123

ΔP/100 ft = 0.34 psi/100 ft

L (equiv. length) = 42 ft

then ΔP (20" piping) = (42 ft) (0.34 psi/100 ft)
= 0.14 psi

finally, ΔP_L = ΔP (24" piping) + ΔP (20" piping)
= (1.05 + 0.14) psi
= 1.19 psi

ΔPs = 6.58 psi (Strainer still assumed with debris)

P_v (@ 185°F) = 8.38 psia

then NPSHA = $P + Hs - \Delta P_L - \Delta P_s - P_v$
= (14.7 + 4.66 - 1.19 - 6.58 - 8.38)psi
= 3.21 psi

in feet:

NPSHA = 7.65 feet

In addition to revised Figure 5.4-20, the required NPSH for the RHR pump is also depicted on Figure 6E-6. This expanded scale performance curve shows that the NPSH is 2 feet for the range from 3000 to 8500 gpm. Note that the curve gives NPSH required at 3 feet above the mounting flange. The suction nozzle is 34.75 inches above the bottom of the mounting flange.

4. NPSHA for Cold Shutdown and Refueling Modes (Operational Conditions 4 and 5) - Maximum Strainer Head Loss

   The Technical Specifications allow the suppression pool water level to be lowered to the 105'-8" elevation in the cold shutdown and refueling modes. A fluid temperature of 125°F and all other conditions maximum as above are assumed. The calculative method is the same.

   a. NPSHA RHR A Pump

      Reference Figure 5.4-27 for suction line geometry.

      NPSHA for the RHR A pump in operational conditions 4 and 5 is:

      NPSHA = $P + H_s - \Delta P_L - \Delta P_s - P_v$

      where

P	=	containment pressure, absolute (14.7 psia)
H_s	=	net static head from suppression pool level at 105'-8" elevation (minimum level in operational conditions 4 and 5, 12'-8") to point 3 ft above top of pump mounting flange at 93'-4 3/4" elevation.
ΔP_L	=	line losses at maximum pump flow 8940 gpm
ΔP_s	=	suction strainer max ΔP - includes entrance loss
P_v	=	absolute vapor pressure at 125°F.

      then, evaluating static head (ρ at 125°F)

      H_s = $(105.67 \text{ ft} - 96.4 \text{ ft})\ (61.63 \text{ lb/ft}^3)\ (\text{ft}^2/144 \text{ in.}^2) = 3.97 \text{ psi}$

Line losses for the 24" schedule 30 pipe (short length of 24"-0.375" nominal wall included) evaluated at flow conditions of 8940 gpm, 125°F

Re = 2.3×10^6

f = 0.0123

ΔP/100 ft = 0.21 psi/100 ft

L (equiv. length of 24" piping and fittings)
= 671

then ΔP (24" piping) = (671 ft) (0.22 psi/100 ft)
= 1.48 psi

Line losses for 20" Schedule 20 are evaluated at 125°F, 8940 gpm

Re = 2.8×10^6

f = 0.0124

ΔP/100 ft = 0.50 psi/100 ft

L (equiv. length of 20" Schedule 20 piping and fittings) = 39 ft

then ΔP (20" Schedule 20) = (39 ft)(0.50 psi/100 ft) = 0.20 psi

finally, ΔP_L = ΔP (24" piping) + ΔP (20" piping)
= (1.48 + 0.20) psi
ΔP_L = 1.68 psi

ΔP_s = 4.99 psi

P_v = 1.96 psia @ 125°F

then NPSHA = 14.7 psia + 3.97 psi - 1.68 psi - 4.99 psi - 1.96 psia
= 10.04 psi

Converting this to feet,

NPSHA = 10.04 psi (144 $in.^2/ft^2$)/(61.63 lb/ft^3)

NPSHA = 23.46 feet

b. NPSHA RHR B pump

Reference Figure 5.4-28 for suction line geometry

By the same method and assumptions as for A, the following is calculated:

Static head = H_s = 3.97 psi

Line losses for 24" Schedule 30 suction piping (including 24" - 0.375" wall piping)

ΔP/100 ft = 0.22 psi/100 ft
L = 747 ft (equiv. length)

then ΔP (24" piping) = (747 ft) (0.22 psi/100 ft)
= 1.64 psi

Line losses for 20" Schedule 20 suction piping

ΔP/100 ft = 0.50 psi/100 ft
L = 40 ft (equiv. length)

then ΔP (20" piping) = (40 ft) (0.50 psi/100 ft)
= 0.20 psi

finally, ΔP_L = (1.64 + 0.20) psi
= 1.84 psi

ΔP_s = 4.81 psi

P_v = 1.96 psi @ 125°F

then NPSHA = 14.7 psia + 3.97 psi - 1.84 psi - 4.81 psi - 1.96 psia
= 10.06 psi

in feet:

NPSHA = 23.51 feet

c. NPSHA RHR C Pump

Reference FSAR Figure 5.4-29 for suction line geometry

By same method and assumptions as for A, the following is calculated:

Static head = H_S = 3.97 psi

Line losses for 24" Schedule 30 suction piping (including 24" - 0.375" wall piping)

ΔP/100 ft = 0.22 psi/100 ft
L = 716 ft (equiv. length)

then ΔP (24" piping) = (716 ft)(0.22 psi/100 ft)
= 1.58 psi

Line losses for 20" Schedule 20 suction piping

ΔP/100 ft = 0.50 psi/100 ft
L = 42 ft (equiv. length)

then ΔP (20" piping) = (42 ft) (0.50 psi/100 ft)
= 0.21 psi

finally, ΔP_L = (1.58 + 0.21) psi
= 1.79 psi

ΔP_S = 6.58 psi

P_V = 1.96 psi @ 125°F

then, NPSHA = 14.7 psia + 3.97 psia - 1.79 psia - 6.58 psi - 1.96 psia = 8.34 psi

in feet:

NPSHA = 19.49 feet

B. LPCS and HPCS Pumps

1. Minimum NPSHA Calculations - Clean Strainers

a. NPSHA - LPCS Pump

Reference Figure 6.3-70 for suction piping geometry. Reference Figure 3.6A-19 and Table 6.2-50 for suppression pool geometry (typical for both pumps).

$$NPSHA_{min} = (P_{atm} - P_{vap}) \times \frac{144\ in.^2/ft^2}{59.8\ lb/ft^3} + H_s - H_f - H_o$$

where:

P_{atm} = Atmosphere containment pressure

P_{vap} = Absolute vapor pressure above 212°F (hypothetical) suppression pool (maximum)

H_s = Net static head from drawdown suppression pool level at 107'-6" elevation to a point 3 feet above top of pump mounting flange at 93'-4 3/4" elevation

H_f = Frictional losses through pipe and fitting at maximum pump flow

H_o = Maximum head loss (ft) at 212°F

Note: For the condition where the strainers are clean, it will be assumed that the strainer head loss is equal to the head loss for the conical basket strainer that remains on the suction tee, which is defined as 1.0 ft H_2O. This is conservative since flow will be preferentially taken through the path of least resistance, which in this case is the conical basket strainer; i.e., head loss for the toroidal strainer is greater than that for the conical basket strainer in a clean condition.

Note: minimum containment pressure coincident with drawdown is 0 psig (atmospheric); therefore Patm = 14.7 psia

Then, evaluating the static head at minimum pool water density (ρ at 212°F)

H_s = (107.5 - 96.4) ft = 11.1 ft

Line losses for the 24"- HBB-8 piping (0.375" nominal wall thickness) are evaluated at the flow conditions of 9100 gpm, 212°F.

Re = 4.4×10^6

f = 0.012

therefore, ΔP/100 ft = 0.205 psi/100 ft

L (equiv. length of 24" piping and fittings) = 651 ft

$$\text{then } \Delta P(24\text{"piping}) = (651 \text{ ft}) \frac{(0.205 \text{ psi})}{100 \text{ ft}} = 1.33 \text{ psi}$$

Line losses for 20" HBB-8 (0.375" nominal wall thickness) are evaluated at the flow conditions of 9100 gpm, 212°F.

Re = 5.3×10^6

f = .012

therefore, ΔP/100 ft = 0.53 psi/100 ft

L (equiv. length of 20" piping and fittings) = 36 ft

then ΔP(20" piping) = (36 ft) (0.53 psi/100 ft)
= 0.19 psi

$$\text{Finally: } H_f = [\Delta P(24") + \Delta P(20")] \ (\frac{144}{59.8} \text{ ft/psi})$$

= [1.33 + .19]psi (2.408 ft/psi)
= 3.66 ft

Pressure drop through conical strainer

H_o = 1.0 ft (from vendor flow tests for conical strainer)

P_{vap} = 14.7 psia

$$\text{Then } NPSHA_{min} = (14.7 \text{ psia} - 14.7 \text{ psia})\left(\frac{144}{59.8} \text{ ft/psi}\right) + 11.1 \text{ ft} - 3.66 \text{ ft} - 1.0 \text{ ft} = 6.4 \text{ ft}$$

$$NPSHA_{min} = 6.4 \text{ ft}$$

b. NPSHA - HPCS Pump

Reference Figure 6.3-68 for suction piping geometry.

Methodology:

Net positive suction head available (NPSHA) is the total suction head in feet of liquid absolute corrected to datum less the vapor pressure of the pumped liquid in feet absolute. Therefore, NPSHA is the pressure or head available above vapor pressure to move and accelerate the fluid into the impeller inlet. Thus,

$NPSHA = h_{sa} - h_{vpa}$ where,

h_{sa} = total suction head in feet absolute, and since

$h_{sa} = h_p + h_{se} - h_f - h_o$

$NPSHA = h_p + h_{se} - h_f - h_o - h_{vpa}$ where,

h_p = Absolute pressure on the surface of the liquid where the pump takes suction expressed in feet of liquid,

h_{se} = Static elevation of liquid above the datum point of the pump expressed in feet. If the liquid level is below the pump datum, h_{se} has a negative value,

h_f = Friction, and entrance and exit head losses in the suction piping expressed in feet of liquid,

h_o = Head loss in the suction strainer expressed in feet of liquid, and

h_{vpa} = Vapor pressure of the liquid at the pumping temperature expressed in feet of liquid absolute.

The frictional head losses (h_f), in the suction piping are calculated using the Darcy equation,

$h_f = [(f)*(L)*(V)^2]/[(D)*(2g)]$

or in terms of the resistance coefficient (K),

$h_f = (K)*(V)^2/(2g)$ where K = (f)*(L)/(D) and

K = Resistance Coefficient,

f = Friction Factor in zone of complete turbulence,

L = Length of pipe in feet,

D = Internal diameter of pipe in feet,

V = Mean velocity of flow in feet per second

g = acceleration of gravity (32.2 feet per second per second)

The mean velocity of flow (V) in the suction piping is calculated using the continuity equation,

V = q/A where,

q = Rate of flow in cubic feet per second at flowing conditions (8175 gpm or 18.214 cfs), and

A = Internal transverse area of pipe in square feet.

Finally, the friction factor (f) is calculated based on the relative roughness of the pipe (e/D) and the Reynolds No. (Re), where

Re = 123.9*(d)*(V)*(rho)/(mu) where

e = Absolute roughness of pipe wall in feet,

d = Internal diameter of pipe in inches,

rho = fluid density in pounds per cubic foot, and

mu = absolute (dynamic) viscosity in centipoise.

Calculation:

Each head term in the NPSHA equation will be calculated starting with a determination of the suction piping frictional head loss (h_f) for the suction flow path from the suppression pool and maximum runout flow for the HPCS pump.

Calculating the mean velocity of flow (V) in the 24" and 20" suction piping from the suppression pool using the continuity equation,

V_{24} = (q)/(A) = {(18.214)]}/(2.9483) = 6.178 ft/sec,

and

V_{20} = (q)/(A) = {(18.214)]}/(2.0142) = 9.043 ft/sec.

Calculating the Reynolds No (Re) and relative roughness (e/D) for the 24" and 20" suction piping from the suppression pool,

Re_{24} = (123.9)*(23.25)*(6.178)*(59.81)/(0.278)
= 3.83E06,

e/D_{24} = (0.00015)/(1.9375) = 0.000077

and

Re_{20} = (123.9)*(19.25)*(9.043)*(59.81)/(0.278)
= 4.64E06

e/D_{20} = (0.00015)/(1.6042) = 0.000094

Therefore, for the 24" and 20" suction piping, the friction factor (f) is 0.012. Finally,

K_{24} = (0.012)*(71.4)/(1.9375) = 0.4422 and

K_{20} = (0.12)*(7.33)/(1.6042) = 0.0548

For the 24" and 20" suction fittings,

a. 24" Tee (flow thru branch) - Qty 2
$K_{24Tbrch} = (2)*(60)*(.012) = 1.44$

b. 24" Long Radius 90° El - Qty 4
$K_{2490} = (4)*(20)*(.012) = 0.96$

c. 24" Gate Valve (B = 1) - Qty 1
$K_{24Gtv} = (1)*(8)*(.012) = 0.096$

d. 24" Swing Check Valve - Qty 1
$K_{24Ckv} = (1)*(50)*(0.12) = 0.6$

e. 24" x 20" Diffuser - Qty 2
$K_{24Rd} = [0.026]*(2) = 0.052$

f. Pipe Entrance
$K_{Ent} = 0.5$

g. Pipe Exit
$K_{Ext} = 1.0$

Converting the resistance coefficient for the 20" piping to an equivalent resistance coefficient for the 24" piping,

$$K_{24'} = (K_{20})*(d_{24}/d_{20})^4 = (0.0548)*(23.25/19.25)^4 = 0.1166$$

and

$$K_{24Total} = K_{24} + K_{24Tbrch} + K_{2490} + K_{24Gtv} + K_{24Ckv} + K_{24Rd} + K_{Ent} + K_{Ext} + K_{24'}$$

$$K_{24Total} = 0.4422 + 1.44 + 0.96 + 0.096 + 0.6 + 0.052 + 0.5 + 1.0 + 0.1166$$

$$K_{24Total} = 5.2068$$

Finally, calculating the suction piping frictional head loss (h_f) for the suction flow path from the suppression pool and maximum runout flow for the HPCS pump,

$$h_f = (K_{24Total})*(V)^2/(2g) \text{ therefore,}$$

$$h_f = (5.2068)*(6.178)^2/(2*32.2) = 3.086 \text{ ft}$$

The next head term in the NPSHA equation to be calculated is the static elevation head (h_{se}) for the suction flow path from the suppression pool. The post drawdown suppression pool water level is 107'-6.25". Considering the 4" thick suction barrel flange and the sole plate elevation of 93'-1.25", the reference datum (i.e. 3' above the pump mounting flange) corresponds to an elevation of 96'-5.25". Therefore,

$$h_{se} = (107.5208 - 96.4375) = 11.0833$$

Substituting the remaining known data into the NPSHA equation,

$$NPSHA = h_p + h_{se} - h_f - h_o - h_{vpa}$$

$$NPSHA = (14.696\ psia) + (11.0833\ ft) - (3.086\ ft) - (1.0\ ft) - (14.696\ psia)$$

$$NPSHA = 6.9973\ ft$$

2. NPSHA for Cold Shutdown and Refueling Modes (Operational Conditions 4 and 5) - Clean Strainers

   The Technical Specifications allow the suppression pool water level to be lowered to the 105'-8" elevation in the cold shutdown and refueling modes. A fluid temperature of 125°F and all other conditions maximum as above are assumed. The calculative method is the same.

   a. NPSHA - LPCS Pump

      Reference Figure 6.3-70 for suction piping geometry.

      NPSHA for the LPCS pump in operational conditions 4 and 5 is:

$$NPSHA = (P_{atm} - P_{vap}) \times \frac{144(in.^2/ft^2)}{61.63\ lb/ft^3} + H_s - H_f - H_o$$

      where:

      P_{atm} = Atmosphere containment pressure, 14.7 psia
      P_{vap} = Absolute vapor pressure at 125°F

H_s = Net static head from suppression pool level at 105'-8" elevation (minimum level in operational conditions 4 and 5, 12'-8") to a point 3 feet above top of pump mounting flange at 93'-4 3/4" elevation.

H_f = Frictional losses through pipe and fittings at maximum pump flow

H_o = Maximum head loss (ft) for suction strainer, clean conditions

Then, elevating the static head (ρ at 125°F)

H_s = (105.67 - 96.4) ft = 9.27 ft.

Line losses for the 24"-HBB-8 piping (0.375" nominal wall thickness) are evaluated at the flow conditions of 9100 gpm, 125°F.

Re = 2.35×10^6

f = 0.0123

ΔP/100 ft = 0.20 psi/100 ft

L (equiv. length of 24" piping and fittings)
= 651 ft.

$$\text{then } \Delta P \text{ (24" piping)} = (651 \text{ ft}) \frac{(0.20 \text{ psi})}{100 \text{ ft}} = 1.30 \text{ psi}$$

Line losses for 20" HBB-8 (0.375" nominal wall thickness) are evaluated at the flow conditions of 9100 gpm, 125°F.

Re = 2.83×10^6

f = 0.0124

ΔP/100 ft = 0.52 psi/100 ft

L (equiv. length of 20" piping and fittings)
= 36 feet

then, ΔP (20" piping) = (36 ft) (0.52 psi/100 ft)
= 0.19 psi

$$\text{Finally: } H_f = [\Delta P\ (24") + \Delta P\ (20")] \frac{(144\ \text{in.}^2/\text{ft}^2)}{61.63\ \text{lb/ft}^3}$$

$$= [1.30 + .19]\ \text{psi}\ (2.337\ \frac{\text{ft}}{\text{psi}}) = 3.48\ \text{ft}$$

Pressure drop through 24" strainer

H_o = 1.0 ft. (from vendor flow tests for conical strainer)

P_{vap} = 1.96 psia @ 125°F

$$\text{Then NPSHA} = (14.7\ \text{psia} - 1.96\ \text{psia}) \frac{(144\ \text{in.}^2/\text{ft}^2)}{61.63\ \text{lb/ft}^3}$$

$$+ 9.27\ \text{ft} - 3.48\ \text{ft} - 1.0\ \text{ft}$$

$$= 34.56\ \text{ft}$$

b. NPSHA - HPCS Pump

Reference FSAR Figure 6.3-68 for suction piping geometry.

Methodology:

Net positive suction head available (NPSHA) is the total suction head in feet of liquid absolute corrected to datum less the vapor pressure of the pumped liquid in feet absolute. Therefore, NPSHA is the pressure or head available above vapor pressure to move and accelerate the fluid into the impeller inlet. Thus,

NPSHA = $h_{sa} - h_{vpa}$ where,

h_{sa} = total suction head in feet absolute, and since

$h_{sa} = h_p + h_{se} - h_f - h_o$

NPSHA = $h_p + h_{se} - h_f - h_o - h_{vpa}$ where,

h_p = Absolute pressure on the surface of the liquid where the pump takes suction expressed in feet of liquid,

h_{se} = Static elevation of liquid above the datum point of the pump expressed in feet. If the liquid level is below the pump datum, h_{se} has a negative value,

h_f = Friction and entrance and exit head losses in the suction piping expressed in feet of liquid,

h_o = Head loss in the suction strainer expressed in feet of liquid, and

h_{vpa} = Vapor pressure of the liquid at the pumping temperature expressed in feet of liquid absolute.

The frictional head losses (h_f) in the suction piping are calculated using the Darcy equation,

$h_f = [(f)*(L)*(V)^2]/[(D)*(2g)]$

or in terms of the resistance coefficient (K),

$h_f = (K)*(V)^2/(2g)$ where $K = (f)*(L)/(D)$ and

K = Resistance Coefficient,

f = Friction Factor in zone of complete turbulence,

L = Length of pipe in feet,

D = Internal diameter of pipe in feet,

V = Mean velocity of flow in feet per second

g = acceleration of gravity (32.2 feet per second per second)

The mean velocity of flow (V) in the suction piping is calculated using the continuity equation,

V = q/A where,

q = Rate of flow in cubic feet per second at flowing conditions, and

A = Internal transverse area of pipe in square feet.

Finally, the friction factor (f) is calculated based on the relative roughness of the pipe (e/D) and the Reynolds No. (Re), where

Re = 123.9*(d)*(V)*(rho)/(mu) where

e = Absolute roughness of pipe wall in feet,

d = Internal diameter of pipe in inches,

rho = fluid density in pounds per cubic foot, and

mu = absolute (dynamic) viscosity in centipoise.

Calculation:

Each head term in the NPSHA equation will be calculated starting with a determination of the suction piping frictional head loss (h_f) for the suction flow path from the suppression pool and maximum runout flow for the HPCS pump.

Calculating the mean velocity of flow (V) in the 24" and 20" suction piping from the suppression pool using the continuity equation,

V_{24} = (q)/(A) = {(18.214)]}/(2.9483) = 6.178 ft/sec,

and

V_{20} = (q)/(A) ={(18.214)]}/(2.0142) = 9.043 ft/sec.

Calculating the Reynolds No (Re) and relative roughness (e/D) for the 24" and 20" suction piping from the suppression pool,

Re_{24} = (123.9)*(23.25)*(6.178)*(61.63)/(0.52)
= 2.11E06,

e/D_{24} = (0.00015)/(1.9375) = 0.000077

and

Re_{20} = (123.9)*(19.25)*(9.043)*(61.63)/(0.52)
= 2.56E06

$e/_{D20}$ = (0.00015)/(1.6042) = 0.000094

Therefore, for the 24" and 20" suction piping, the friction factor (f) is 0.012. Finally,

K_{24} = (.012)*(71.4)/(1.9375) = 0.4422 and

K_{20} = (.012)*(7.33)/(1.6042) = 0.0548

For the 24" and 20" suction fittings,

a. 24" Tee (flow thru branch) - Qty 2

$K_{24Tbrch}$ = (2)*(60)*(.012) = 1.44

b. 24" Long Radius 90° El - Qty 4

K_{2490} = (4)*(20)*(.012) = 0.96

c. 24" Gate Valve (B = 1) - Qty 1

K_{24Gtv} = (1)*(8)*(.012) = 0.096

d. 24" Swing Check Valve - Qty 1

K_{24Ckv} = (1)*(50)*(.012) = 0.6

e. 24" x 20" Diffuser - Qty 2

K_{24Rd} = [0.026]*(2) = 0.052

f. Pipe Entrance

K_{Ent} = 0.5

g. Pipe Exit

K_{Ext} = 1.0

Converting the resistance coefficient for the 20" piping to an equivalent resistance coefficient for the 24" piping,

$$K_{24'} = (K_{20})*(d_{24}/d_{20})^4 = (0.0548)*(23.25/19.25)^4 = 0.1166$$

and

$$K_{24Total} = K_{24} + K_{24Tbrch} + K_{2490} + K_{24Gtv} + K_{24Ckv} + K_{24Rd} + K_{Ent} + K_{Ext} + K_{24'}$$

$$K_{24Total} = 0.4422 + 1.44 + 0.96 + 0.096 + 0.6 + 0.052 + 0.5 + 1.0 + 0.1166$$

$$K_{24Total} = 5.2068$$

Finally, calculating the suction piping frictional head loss (h_f) for the suction flow path from the suppression pool and maximum runout flow for the HPCS pump,

$h_f = (K_{24Total})*(V)^2/(2g)$ therefore,

$$h_f = (5.2068)*(6.178)^2/(2*32.2) = 3.086 \text{ ft}$$

The next head term in the NPSHA equation to be calculated is the static elevation head (h_{se}) for the suction flow path from the suppression pool. The mode 4/5 minimum suppression pool water level is 105' - 8". Considering the 4" thick suction barrel flange and the sole plate elevation of 93' - 1.25", the reference datum (i.e. 3' above the pump mounting flange) corresponds to an elevation of 96' - 5.25". Therefore,

$$h_{se} = (105.667 - 96.4375) = 9.230 \text{ ft}$$

Substituting the remaining known data into the NPSHA equation,

$$NPSHA = h_p + h_{se} - h_f - h_o - h_{vpa}$$

$$NPSHA = (14.696 \text{ psia}) + (9.230 \text{ ft}) - (3.086 \text{ ft}) - (1.0 \text{ ft}) - (1.96 \text{ psia})$$

NPSHA = 34.90 ft

c. Estimated NPSHA for a Maximum of 200°F Pool Water Temperature (Operational Conditions 4 and 5)

Assuming all data remains the same except absolute vapor pressure

P_V = 11.53 psia @ 200°F, ρ = 60.11 lb/ft^3

The difference between the vapor pressure at 200°F and 125°F is

ΔP_V = 11.53 psia - 1.96 psia

= 9.57 psia

in feet:

$$= 9.57 \text{ psia} \times \frac{144 \text{ in.}^2/\text{ft}^2}{60.11 \text{ lb/ft}^3}$$

= 22.93 ft

NPSHA for the LPCS and HPCS pumps at pool water temperature of 200°F are:

LPCS NPSHA = 34.56 ft - 22.93 ft = 11.63 ft

HPCS NPSHA = 34.92 ft - 22.93 ft = 11.99 ft

3. Minimum NPSHA Calculations - Maximum Strainer Head Loss, Suppression Pool Temperature 185°F

a. NPSHA - LPCS Pump

Reference Figure 6.3-70 for suction piping geometry. Reference Figure 3.6A-19 and Table 6.2-50 for suppression pool geometry (typical for both pumps).

$$NPSHA_{min} = (P_{atm} - P_{vap}) \times \frac{144 \text{ in.}^2/\text{ft}^2}{60.46 \text{ lb/ft}^3} + H_s - H_f - H_o$$

where:

P_{atm} = Atmosphere containment pressure

P_{vap} = Absolute vapor pressure above 185°F (hypothetical) suppression pool (maximum)

H_s = Net static head from drawdown suppression pool level at 107' - 6" elevation to a point 3 feet above top of pump mounting flange at 93'-4 3/4" elevation

H_f = Frictional Losses through pipe and fitting at maximum pump flow

H_o = Maximum head loss (ft) at 185°F

Note: minimum containment pressure coincident with drawdown is 0 psig (atmospheric); therefore P_{atm} = 14.7 psia

Then, evaluating the static head at minimum pool water density (ρ at 212°F)

H_s = (107.5 - 96.4) ft = 11.1 ft

Line losses for the 24"-HBB-8 piping (.375" nominal wall thickness) are evaluated at the flow conditions of 9100 gpm, 185°F.

Re = 4.4×10^6

f = 0.012

therefore, ΔP/100 ft = 0.20 psi/100 ft

L (equiv. length of 24" piping and fittings) = 651 ft

$$\text{then } \Delta P(24\text{" piping}) = (651 \text{ ft}) \frac{(0.20 \text{ psi})}{100 \text{ ft}} = 1.30 \text{ psi}$$

Line losses for 20" HBB-8 (.375" nominal wall thickness) are evaluated at the flow conditions of 9100 gpm, 185°F.

Re = 5.4×10^6

f = .012

therefore $\Delta P/100$ ft = 0.53 psi/100 ft

L (equiv. length of 20" piping and fittings)
= 36 ft

then ΔP (20" piping) = (36 ft) (0.53 psi/100 ft)
= 0.19 psi

$$\text{Finally: } H_f = [\Delta P(24'') + \Delta P(20'')]\left(\frac{144}{60.46}\text{ft/psi}\right)$$

= [1.33 + .19] psi (2.382 ft/psi)

= 3.55 ft

Pressure drop through 24" strainer

H_o = 13.66 ft (from calculation/tests)
P_{vap} = 8.38 psia

$$\text{Then } NPSHA_{min} = (14.7\text{ psia} - 8.38\text{ psia})\left(\frac{144}{60.46}\text{ft/psi}\right)$$

$$+ 11.1\text{ ft} - 3.55\text{ ft} - 13.66\text{ ft}$$

= 8.8 ft

$NPSHA_{min}$ = 8.8 ft

b. NPSHA - HPCS Pump

Reference Figure 6.3-68 for suction piping geometry.

Methodology:

Net positive suction head available (NPSHA) is the total suction head in feet of liquid absolute corrected to datum less the vapor pressure of the pumped liquid in feet absolute.

Therefore, NPSHA is the pressure or head available above vapor pressure to move and accelerate the fluid into the impeller inlet. Thus,

$NPSHA = h_{sa} - h_{vpa}$ where,

h_{sa} = total suction head in feet absolute, and since

$h_{sa} = h_p + h_{se} - h_f - h_o$

$NPSHA = h_p + h_{se} - h_f - h_o - h_{vpa}$ where,

h_p = Absolute pressure on the surface of the liquid where the pump takes suction expressed in feet of liquid = 14.696 psia = 35.00 ft @ 185°F

h_{se} = Static elevation of liquid above the datum point of the pump expressed in feet. If the liquid level is below the pump datum, h_{se} has a negative value,

h_f = Friction and entrance and exit head losses in the suction piping expressed in feet of liquid,

h_o = Head loss in the suction strainer expressed in feet of liquid, and

h_{vpa} = Vapor pressure of the liquid at the pumping temperature expressed in feet of liquid absolute = 8.384 psia = 19.97 ft @ 185°F

The frictional head losses (h_f) in the suction piping are calculated using the Darcy equation,

$h_f = [(f)*(L)*(V)^2]/[(D)*(2g)]$

or in terms of the resistance coefficient (K),

$h_f = (K)*(V)^2/(2g)$ where $K = (f)*(L)/(D)$ and

K = Resistance Coefficient,

f = Friction Factor in zone of complete turbulence,

L = Length of pipe in feet,

D = Internal diameter of pipe in feet,

V = Mean velocity of flow in feet per second

g = acceleration of gravity (32.2 feet per second per second)

The mean velocity of flow (V) in the suction piping is calculated using the continuity equation,

V = q/A where,

q = Rate of flow in cubic feet per second at flowing conditions (8175 gpm or 18.214 cfs), and

A = Internal transverse area of pipe in square feet.

Finally, the friction factor (f) is calculated based on the relative roughness of the pipe (e/D) and the Reynolds No. (Re), where

Re = 123.9*(d)*(V)*(rho)/(mu) where

e = Absolute roughness of pipe wall in feet,

d = Internal diameter of pipe in inches,

rho = fluid density in pounds per cubic foot, and

mu = absolute (dynamic) viscosity in centipoise.

Calculation:

Each head term in the NPSHA equation will be calculated starting with a determination for the suction piping frictional head loss (h_f) for the suction flow path from the suppression pool and maximum runout flow for the HPCS pump.

Calculating the mean velocity of flow (V) in the 24" and 20" suction piping from the suppression pool using the continuity equation,

V_{24} = (q)/(A) = {(18.214)]}/(2.9483) = 6.178 ft/sec,

and

V_{20} = (q)/(A) ={(18.214)]}/(2.0142) = 9.043 ft/sec.

Calculating the Reynolds No (Re) and relative roughness (e/D) for the 24" and 20" suction piping from the suppression pool,

Re_{24} = (123.9)*(23.25)*(6.178)*(60.46)/(0.326)
= 3.30E06,

e/D_{24} = (0.00015)/(1.9375) = 0.000077

and

Re_{20} = (123.9)*(19.25)*(9.043)*(60.46)/(0.326)
= 4.00E06

e/D_{20} = (0.00015)/(1.6042) = 0.000094

Therefore, for the 24" and 20" suction piping, the friction factor (f) is 0.012. Finally,

K_{24} = (.012)*(71.4)/(1.9375) = 0.4422 and

K_{20} = (.012)*(7.33)/(1.6042) = 0.0548

For the 24" and 20" suction fittings,

a. 24" Tee (flow thru branch) - Qty 2

$K_{24Tbrch}$ = (2)*(60)*(.012) = 1.44

b. 24" Long Radius 90° El - Qty 4

K_{2490} = (4)*(20)*(.012) = 0.96

c. 24" Gate Valve (B = 1) - Qty 1

K_{24Gtv} = (1)*(8)*(.012) = 0.096

d. 24" Swing Check Valve - Qty 1

K_{24Ckv} = (1)*(50)*(.012) = 0.6

e. 24" x 20" Diffuser - Qty 2

K_{24Rd} = [0.026]*(2) = 0.052

f. Pipe Entrance

$K_{Ent} = 0.5$

g. Pipe Exit

$K_{Ext} = 1.0$

Converting the resistance coefficient for the 20" piping to an equivalent resistance coefficient for the 24" piping,

$$K_{24'} = (K_{20})*(d_{24}/d_{20})^4 = (0.0548)*(23.25/19.25)^4$$
$$= 0.1166$$

and

$$K_{24Total} = K_{24} + K_{24Tbrch} + K_{2490} + K_{24Gtv} + K_{24Ckv} + K_{24Rd} + K_{Ent} + K_{Ext} + K_{24'}$$

$$K_{24Total} = 0.4422 + 1.44 + 0.96 + 0.096 + 0.6 + 0.052 + 0.5 + 1.0 + 0.1166$$

$$K_{24Total} = 5.2068$$

Finally, calculating the suction piping frictional head loss (h_f) for the suction flow path from the suppression pool and maximum runout flow for the HPCS pump,

$h_f = (K_{24Total})*(V)^2/(2g)$ therefore,

$h_f = (5.2068)*(6.178)^2/(2*32.2) = 3.086$ ft

The next head term in the NPSHA equation to be calculated is the static elevation head (h_{se}) for the suction flow path from the suppression pool. The post drawdown suppression pool water level is 107' - 6.25". Considering the 4" thick suction barrel flange and the sole plate elevation of 93' - 1.25", the reference datum (i.e. 3' above the pump mounting flange) corresponds to an elevation of 96' - 5.25". Therefore,

$h_{se} = (107.5208 - 96.4375) = 11.0833$ ft

Substituting the remaining known data into the NPSHA equation,

$$NPSHA = h_p + h_{se} - h_f - h_o - h_{vpa}$$

$$NPSHA = (35.00\ ft) + (11.0833\ ft) - (3.086\ ft) - (12.62\ ft) - (19.97\ ft)$$

$$NPSHA = 10.41\ ft$$

4. NPSHA for Cold Shutdown and Refueling Modes (Operational Conditions 4 and 5) - Maximum Strainer Head Loss

The Technical Specifications allow the suppression pool water level to be lowered to the 105' - 8" elevation in the cold shutdown and refueling modes. A fluid temperature of 125°F and all other conditions maximum as above are assumed. The calculative method is the same.

a. NPSHA - LPCS Pump

Reference Figure 6.3-70 for suction piping geometry.

NPSHA for the LPCS pump in operational conditions 4 and 5 is:

$$NPSHA = (P_{atm} - P_{vap}) \times \frac{144\ in.^2/ft^2}{61.63\ lb/ft^3} + H_s - H_f - H_o$$

where:

P_{atm} = Atmosphere containment pressure, 14.7 psia

P_{vap} = Absolute vapor pressure at 125°F

H_s = Net static head from suppression pool level at 105' - 8" elevation (minimum level operational conditions 4 and 5, 12' - 8") to a point 3 feet above top of pump mounting flange at 93'-4-3/4" elevation.

H_f = Frictional losses through pipe and fitting at maximum pump flow

H_o = Maximum head loss (ft) for suction strainer

Then, evaluating the static head (ρ at 125°F)

H_s = (105.67 - 96.4) ft = 9.27 ft.

Line losses for the 24"-HBB-8 piping (0.375" nominal wall thickness) are evaluated at the flow conditions of 9100 gpm, 125°F.

Re = 2.35×10^6

f = 0.0123

ΔP/100 ft = 0.20 psi/100 ft

L (equiv. length of 24" piping and fittings) = 651 ft

$$\text{then } \Delta P(24\text{" piping}) = (651 \text{ ft}) \frac{(0.20 \text{ psi})}{100 \text{ ft}} = 1.30 \text{ psi}$$

Line losses for 20" HBB-8 (0.375" nominal wall thickness) are evaluated at the flow conditions of 9100 gpm, 125°F.

Re = 2.83×10^6

f = 0.0124

ΔP/100 ft = 0.52 psi/100 ft

L (equiv. length of 20" piping and fittings) = 36 ft

then ΔP (20" piping) = (36 ft) (0.52 psi/100 ft)
= 0.19 psi

$$\text{Finally:} \quad H_f = [\Delta P\ (24") + \Delta P(20")] \frac{(144 \text{ in.}^2/\text{ft}^2)}{61.63 \text{ lb/ft}^3}$$

$$= [1.30 + .19] \text{ psi} \left(2.337 \frac{\text{ft}}{\text{psi}}\right) = 3.48 \text{ ft}$$

Pressure drop through 24" strainer

H_o = 13.66 ft

P_{vap} = 1.96 psia @ 125°F

$$\text{Then NPSHA} = (14.7\text{ psia} - 1.96\text{ psia})\frac{(144\text{ in.}^2/\text{ft}^2)}{61.63\text{ lb/ft}^3}$$
$$+ 9.27\text{ ft} - 3.48\text{ ft} - 13.66\text{ ft}$$
$$= 21.90\text{ ft}$$

b. NPSHA - HPCS Pump

Reference FSAR Figure 6.3-68 for suction piping geometry.

Methodology:

Net positive suction head available (NPSHA) is the total suction head in feet of liquid absolute corrected to datum less the vapor pressure of the pumped liquid in feet absolute.

Therefore, NPSHA is the pressure or head available above vapor pressure to move and accelerate the fluid into the impeller inlet. Thus,

NPSHA = $h_{sa} - h_{vpa}$ where,

h_{sa} = total suction head in feet absolute, and since

$h_{sa} = h_p + h_{se} - h_f - h_o$

NPSHA = $h_p + h_{se} - h_f - h_o - h_{vpa}$ where,

h_p = Absolute pressure on the surface of the liquid where the pump takes suction expressed in feet of liquid,

h_{se} = Static elevation of liquid above the datum point of the pump expressed in feet. If the liquid level is below the pump datum, h_{se} has a negative value,

h_f = Friction and entrance and exit head losses in the suction piping expressed in feet of liquid,

h_o = Head loss in the suction strainer expressed in feet of liquid, and

h_{vpa} = Vapor pressure of the liquid at the pumping temperature expressed in feet of liquid absolute.

The frictional head losses (h_f) in the suction piping are calculated using the Darcy equation,

h_f = $[(f)*(L)*(V)^2]/[(D)*(2g)]$

or in terms of the resistance coefficient (K),

h_f = $(K)*(V)^2/(2g)$ where $K = (f)*(L)/(D)$ and

K = Resistance Coefficient,

f = Friction Factor in zone of complete turbulence,

L = Length of pipe in feet,

D = Internal diameter of pipe in feet,

V = Mean velocity of flow in feet per second

g = acceleration of gravity (32.2 feet per second per second)

The mean velocity of flow (V) in the suction piping is calculated using the continuity equation,

$V = q/A$ where,

q = Rate of flow in cubic feet per second at flowing conditions, and

A = Internal transverse area of pipe in square feet.

Finally, the friction factor (f) is calculated based on the relative roughness of the pipe (e/D) and the Reynolds No. (Re), where

Re = 123.9*(d)*(V)*(rho)/(mu) where

e = Absolute roughness of pipe wall in feet,

d = Internal diameter of pipe in inches,

rho = fluid density in pounds per cubic foot, and

mu = absolute (dynamic) viscosity in centipoise.

Calculation:

Each head term in the NPSHA equation will be calculated starting with a determination of the suction piping frictional head loss (h_f) for the suction flow path from the suppression pool and maximum runout flow for the HPCS pump.

Calculating the mean velocity of flow (V) in the 24" and 20" suction piping from the suppression pool using the continuity equation,

V_{24} = (q)/(A) = {(18.214)]}/(2.9483) = 6.178 ft/sec,

and

V_{20} = (q)/(A) = {(18.214)]}/(2.0142) = 9.043 ft/sec.

Calculating the Reynolds No (Re) and relative roughness (e/D) for the 24" and 20" suction piping from the suppression pool,

Re_{24} = (123.9)*(23.25)*(6.178)*(61.63)/(0.278)
= 3.95E06,

e/D_{24} = (0.00015)/(1.9375) = 0.000077

and

Re_{20} = (123.9)*(19.25)*(9.043)*(61.63)/(0.278)
= 4.78E06

$e/D_{20} = (0.00015)/(1.6042) = 0.000094$

Therefore, for the 24" and 20" suction piping, the friction factor (f) is 0.012. Finally,

$K_{24} = (.012)*(71.4)/(1.9375) = 0.4422$ and

$K_{20} = (.012)*(7.33)/(1.6042) = 0.0548$

For the 24" and 20" suction fittings,

a. 24" Tee (flow thru branch) - Qty 2

$K_{24Tbrch} = (2)*(60)*(.012) = 1.44$

b. 24" Long Radius 90° El - Qty 4

$K_{2490} = (4)*(20)*(.012) = 0.96$

c. 24" Gate Valve (B = 1) - Qty 1

$K_{24Gtv} = (1)*(8)*(.012) = 0.096$

d. 24" Swing Check Valve - Qty 1

$K_{24Ckv} = (1)*(50)*(.012) = 0.6$

e. 24" x 20" Diffuser - Qty 2

$K_{24Rd} = [0.026]*(2) = 0.052$

f. Pipe Entrance

$K_{Ent} = 0.5$

g. Pipe Exit

$K_{Ext} = 1.0$

Converting the resistance coefficient for the 20" piping to an equivalent resistance coefficient for the 24" piping,

$$K_{24'} = (K_{20})*(d_{24}/d_{20})^4 = (0.0548)*(23.25/19.25)^4$$
$$= 0.1166$$

and

$K_{24Total}$ = K_{24} + $K_{24Tbrch}$ + K_{2490} + K_{24Gtv} + K_{24Ckv} + K_{24Rd} + K_{Ent} + K_{Ext} + $K_{24'}$

$K_{24Total}$ = 0.4422 + 1.44 + 0.96 + 0.096 + 0.6 + 0.052 + 0.5 + 1.0 + 0.1166

$K_{24Total}$ = 5.2068

Finally, calculating the suction piping frictional head loss (h_f) for the suction flow path from the suppression pool and maximum runout flow for the HPCS pump,

$h_f = (K_{24Total})*(V)^2/(2g)$ therefore,

$h_f = (5.2068)*(6.178)^2/(2*32.2) = 3.086$ ft

The next head term in the NPSHA equation to be calculated is the static elevation head (h_{se}) for the suction flow path from the suppression pool. The mode 4/5 minimum suppression pool water level is 105' - 8". Considering the 4" thick suction barrel flange and the sole plate elevation of 93' - 1.25", the reference datum (i.e. 3' above the pump mounting flange) corresponds to an elevation of 96' - 5.25". Therefore,

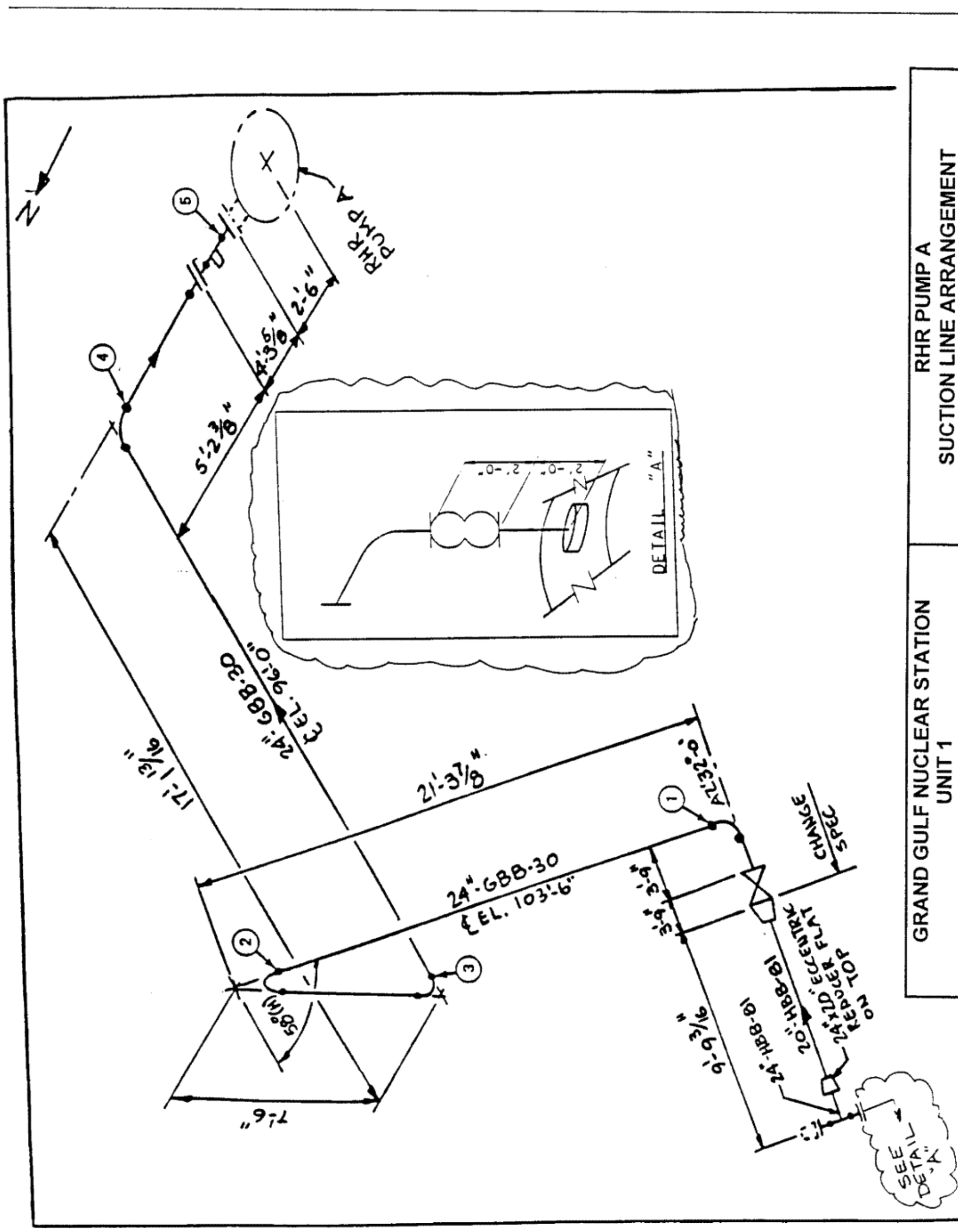
$h_{se} = (105.667 - 96.4375) = 9.230$ ft

Substituting the remaining known data into the NPSHA equation,

NPSHA = $h_p + h_{se} - h_f - h_o - h_{vpa}$

NPSHA = (14.696 psia) + (9.230 ft) - (3.086 ft) - (12.62 ft) - (1.96 psia)

NPSHA = 23.28 ft



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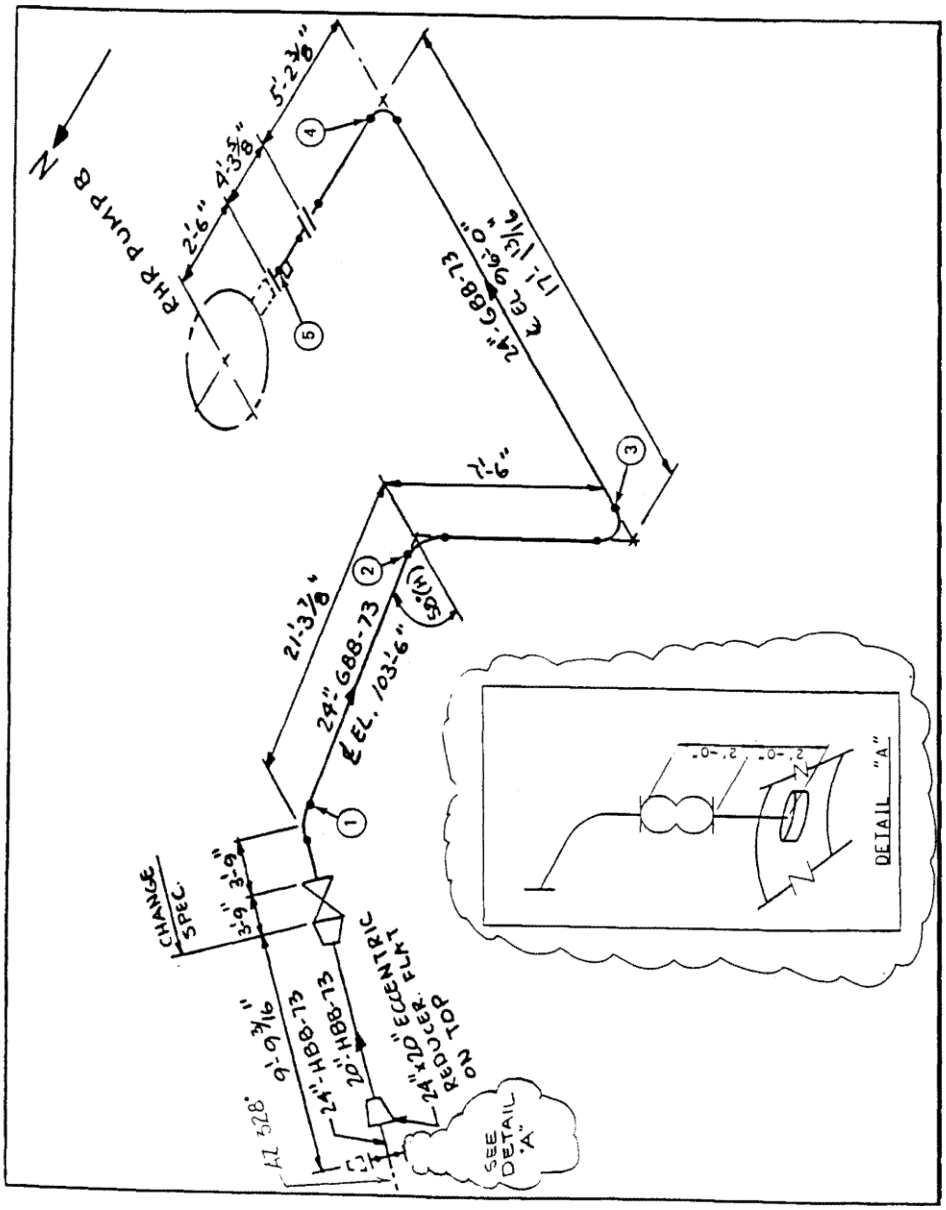
RHR PUMP A
SUCTION LINE ARRANGEMENT

FIGURE 6E-1



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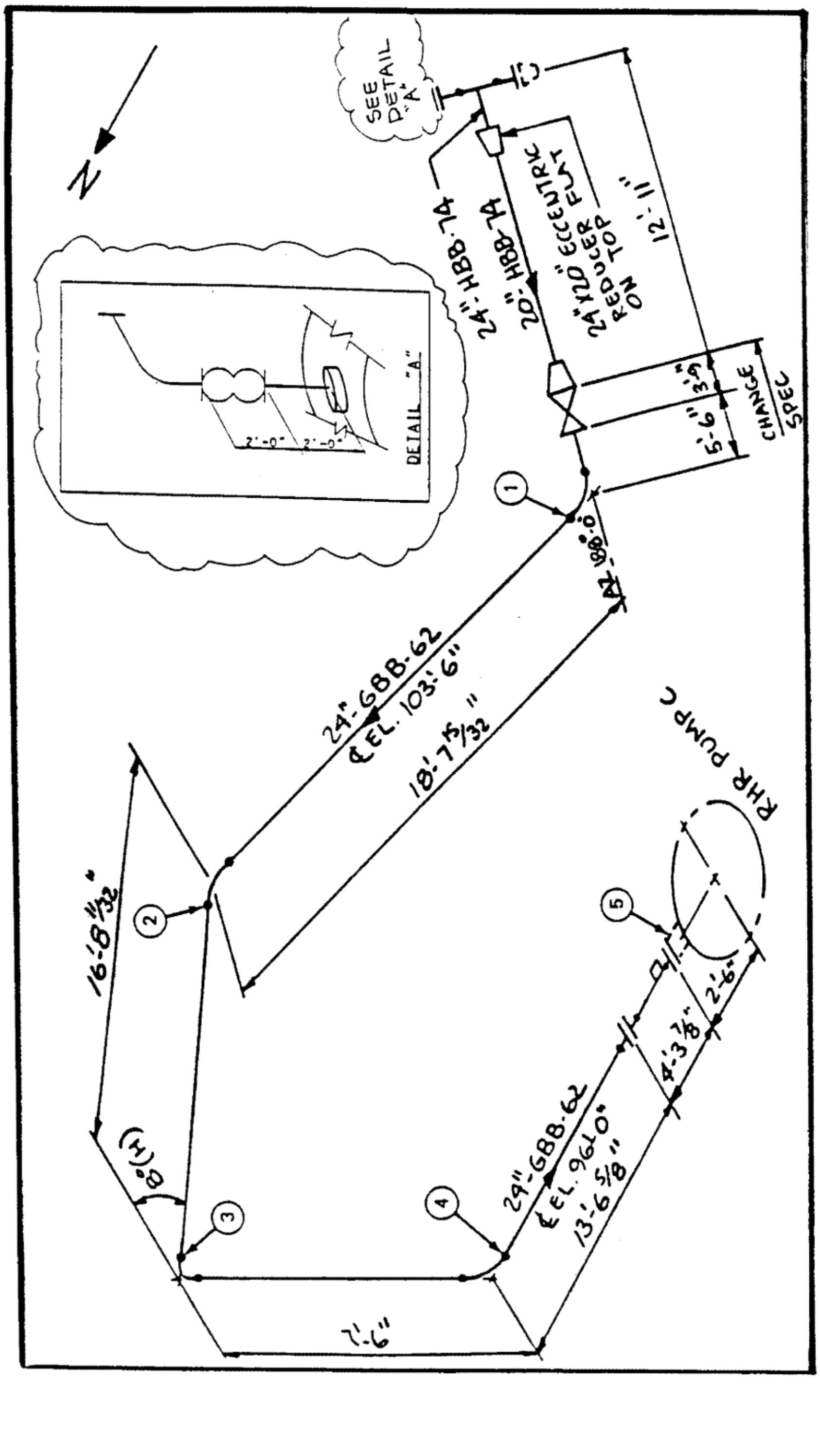
RHR PUMP B
SUCTION LINE ARRANGEMENT

FIGURE 6E-2

LDC 97074



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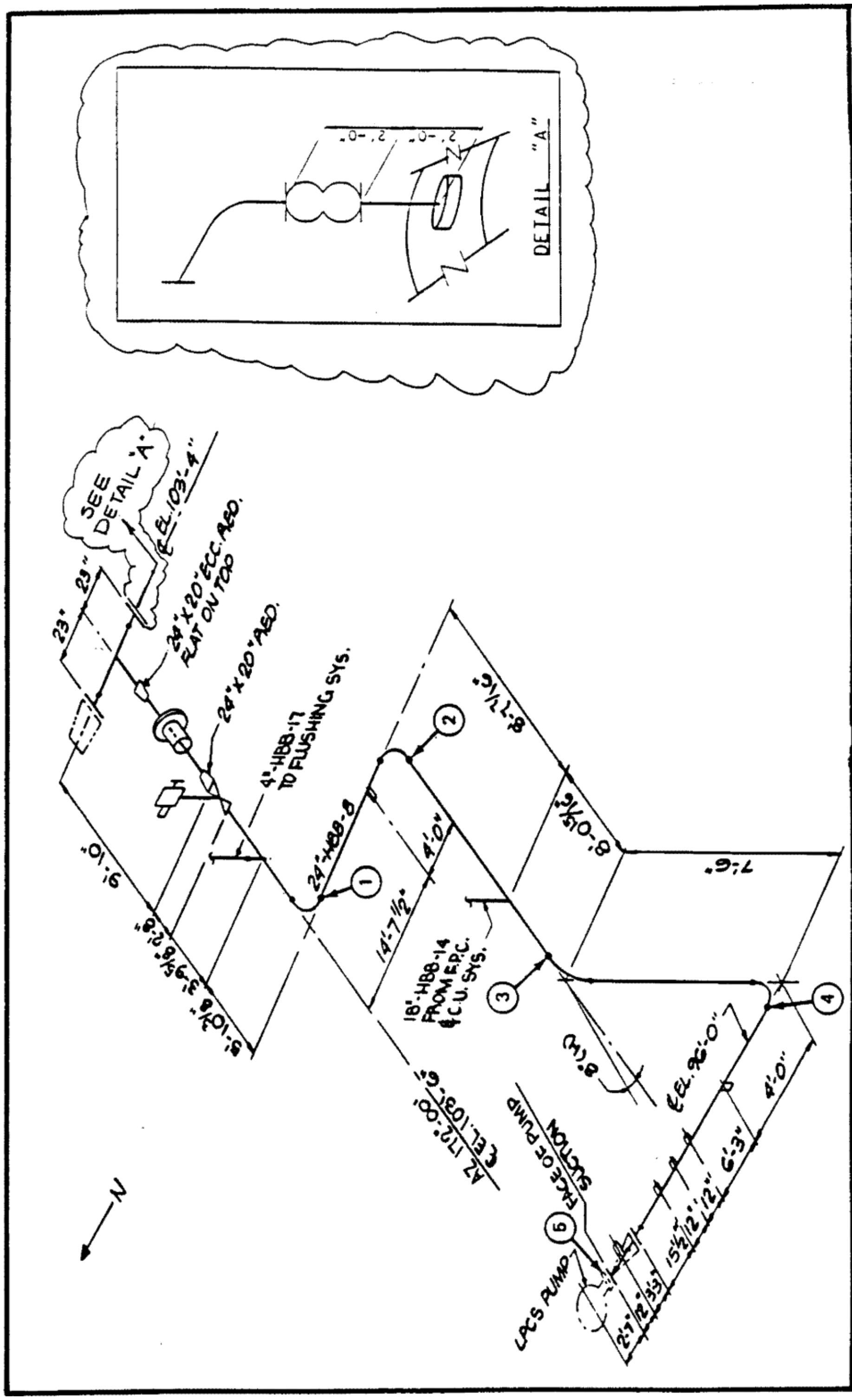
RHR PUMP C
SUCTION LINE ARRANGEMENT

FIGURE 6E-3

LDC 97074



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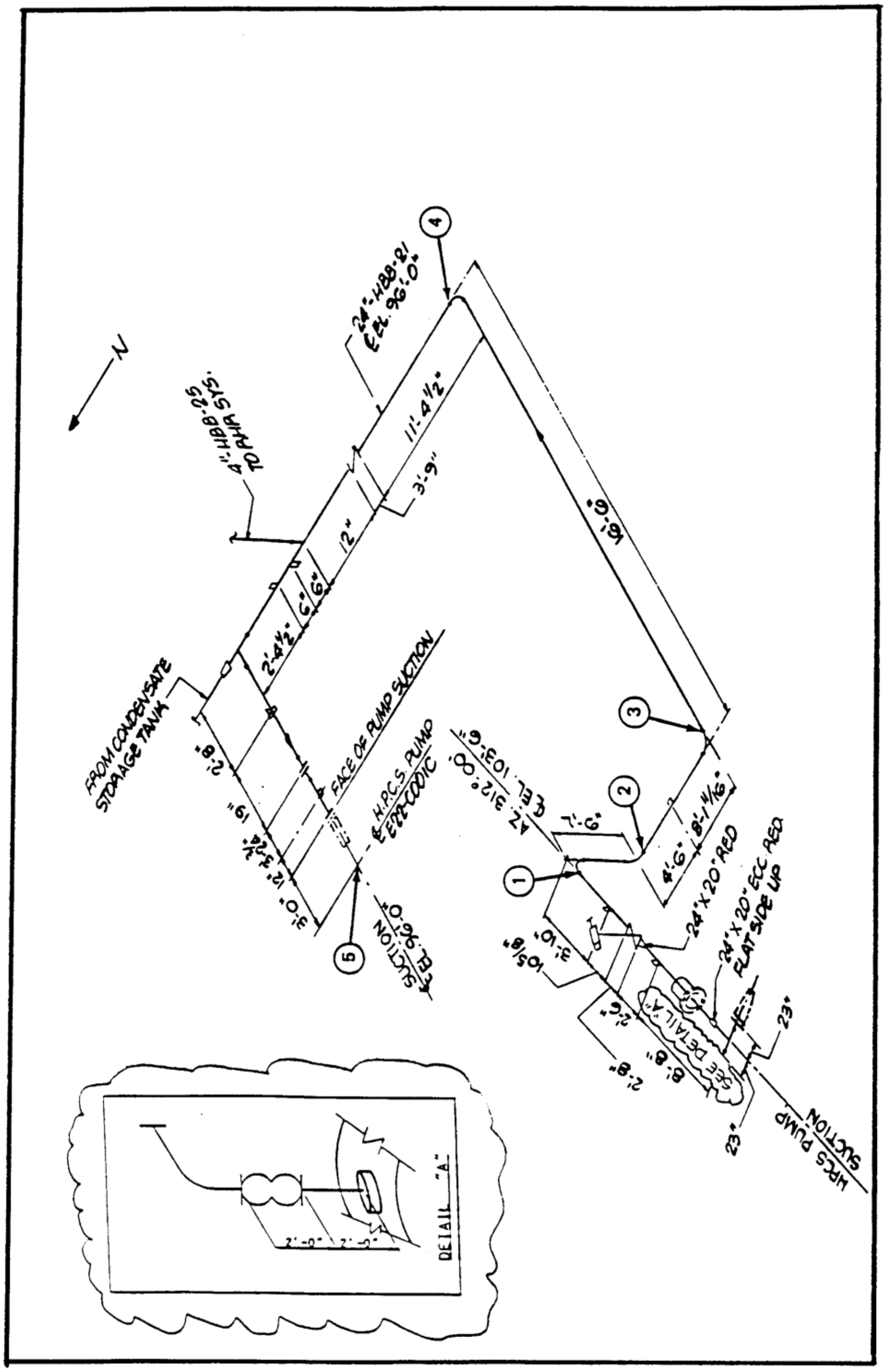
LPCS PUMP SUCTION PIPING ARRANGEMENT

FIGURE 6E-4

LDC 97074



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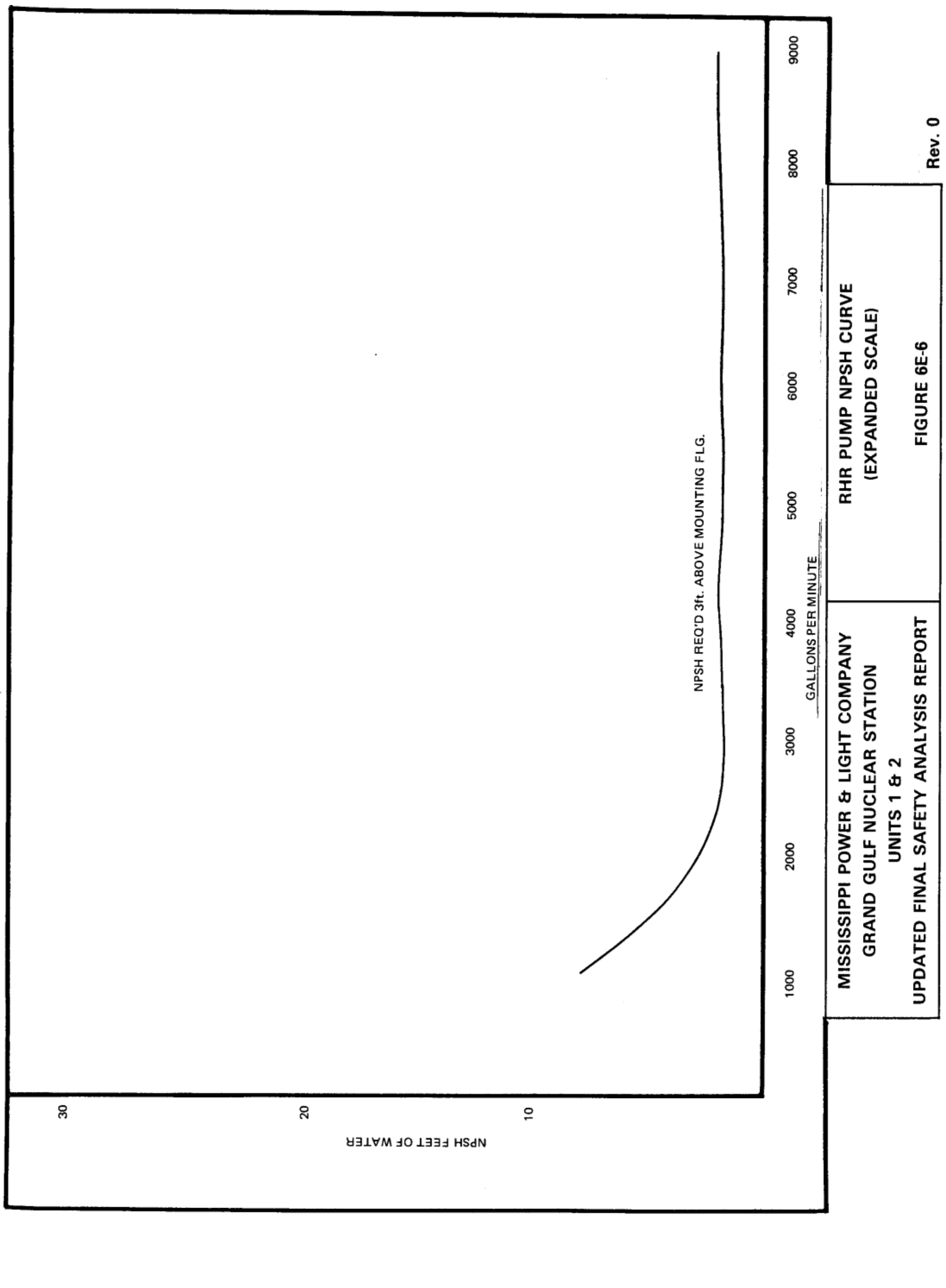
HPCS PUMP SUCTION PIPING ARRANGEMENT

FIGURE 6E-5

LDC 97074


NPSH FEET OF WATER
10
20
30
GALLONS PER MINUTE
1000
2000
3000
4000
5000
6000
7000
8000
9000
NPSH REQ'D 3ft. ABOVE MOUNTING FLG.
MISSISSIPPI POWER & LIGHT COMPANY
GRAND GULF NUCLEAR STATION
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RHR PUMP NPSH CURVE
(EXPANDED SCALE)
FIGURE 6E-6
Rev. 0

APPENDIX 6F DETERMINATION OF EFFECT ON ECCS ANALYSIS OF DIVERSION OF LPCI PUMPS TO CONTAINMENT SPRAY MODE 10 MINUTES AFTER LOCA INITIATION

6F.1 PURPOSE

An analysis was performed to investigate the effect on the ECCS analysis of diverting low pressure coolant injection (LPCI) pumps to the containment spray mode ten minutes after a loss-of-coolant accident (LOCA) initiation.

Automatic diversion of LPCI flow to containment spray was provided in response to an NRC requirement to assure containment integrity for postulated high steam flow bypassing the suppression pool. Such flow diversion would occur only if a high containment pressure signal is present after ten minutes. The assumption of sufficient bypassing to cause such a pressure has been shown to be extremely conservative and unrealistic[1]. The results of the drywell cracking study referenced in footnote 1 showed that for small breaks, which are of interest in this study, no through wall cracking of the drywell would occur where the structure has only minor prior cracking damage. Therefore, no bypass is expected to occur due to cracking of the drywell wall and the 9 psig containment pressure analytical limit will not be reached.

6F.2 ASSUMPTIONS

1. A maximum of two LPCI pumps (specifically LPCI "A" and LPCI "B") can be fully diverted at ten minutes to the containment spray mode. (NOTE: LPCI "A" shares an emergency diesel generator with the LPCS; LPCI "B" and "C" share an emergency diesel generator. The pump associated with LPCI "C" cannot be diverted to containment sprays).

2. Approved Appendix K analysis models were used, except that some LPCI flow to the reactor vessel was stopped ten minutes after the accident.

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1. NEDO-10977 Drywell Integrity Study: Investigation of Potential Cracking in BWR/6 Mark III Containment

6F.3 RESPONSE TO THE SPECIFIC NRC CONCERNS

Only those accident cases which are not reflooded to the hot mode before ten minutes are affected by the assumed LPCI diversion. Once the core has been reflooded, only one ECCS pump is necessary to keep the core covered. Thus, the breaks affected include small breaks less than approximately 0.04 ft^2 (depending on the break location) and outside steam line breaks (OSLB). The effect of the assumed LPCI diversion on the OSLB is small and is discussed in a later section of this report.

The following break locations were considered: a. core spray line; b. recirculation line; c. feedwater line; d. the steam line; and, e. LPCI line. A brief summary of each analysis is provided below.

a. Core Spray Line Break (HPCS Line) - It is conservatively assumed that no flow enters the vessel through the broken line independent of the break size. For this case, the failure of the diesel generator associated with LPCS and LPCI "A" is the worst single failure since all credit for core spray cooling is eliminated. The ECC systems remaining before diversions are 2 LPCI + ADS and 1 LPCI + ADS after diversion at ten minutes. Because in both cases the reflooding time is based on only subcooled LPCI flow reflooding the vessel, there is a longer reflooding time associated with the diverted case with reduced ECCS flow. The results of this investigation are shown in Figure 6.3-86. Because the temperature increase from the non-diverted case is a result of a loss of reflooding flow from 1 LPCI pump, intermediate cases (loss of part of the flow) will experience intermediate (lower) temperature increases.

   This particular failure/break type combination was the most adversely affected by the assumed LPCI diversion. However, the peak cladding temperatures are still below the limit of 2200 F.

b. Recirculation Line Break - Because this investigation is primarily concerned with small breaks, the failure of the HPCS, for non-core spray line breaks, is the worst single failure for this study. If the HPCS were operable, the break sizes being analyzed would reflood earlier than ten minutes with the very small break sizes never uncovering.

For a recirculation line break, the worst single failure is consequently the HPCS failure. The ECCS remaining before diversion are 3 LPCI + LPCS + ADS and, after diversion, 1 LPCI + LPCS + ADS. Since in the diverted case the remaining LPCI flow is not enough to significantly quench the voids in the lower plenum, the mixture in the lower plenum will reflood with a higher voided mixture. This higher void fraction for the diverted case more than offsets the reduction in ECCS flow entering the vessel due to this diversion of LPCI. Hence, there is a net reduction in PCT due to a shorter reflooding time and the recirculation line break without diversion which has already been reported is bounding relative to a line break with diversion. A representative break (0.005 ft^2) was analyzed which confirmed these results. The results of this investigation are shown in Table 6F-1. Intermediate cases (diversion of less than the full flow from two pumps) should result in smaller temperature decreases.

c.&d. Feedwater and Steam Line Breaks - For these breaks, the worst single failure is the HPCS failure, as described under item b. The ECCS remaining before diversion are 3 LPCI + LPCS + ADS and, after diversion, 1 LPCI + LPCS + ADS. For the diverted case, there will be a reduction in calculated PCT for the same reasons discussed for the recirculation line break. A representative break (i.e., 0.005 ft^2) was again analyzed which confirmed the anticipated results. The results of this investigation are shown in Table 6F-1. For both cases, insignificant decreases in calculated PCT result from LPCI diversion. The outside (isolated) steam line break was also considered with similar results.

e. LPCI Line Break - As in the case of the core spray line break, it is conservatively assumed that no flow enters the vessel through the broken line independent of the size. For the break, the worst single failure is the HPCS failure, as described previously. The ECCS remaining before diversion are 2 LPCI + LPCS + ADS and, after diversion, LPCS + ADS (if the break is in line "C") or LPCS + LPCI + ADS (if the break is in line "A"/or "B"). In either case there is insufficient LPCI flow to significantly quench the voids in the lower plenum. Therefore, the core will reflood with a voided mixture. This higher void fraction can more than offset the

reduction in ECCS flow entering the vessel due to diversion of LPCI. In these cases the calculated PCTs are extremely low, and changes in PCT in either direction would result in calculated PCTs which are still far below the limit. As above, the 0.005 ft^2 break was analyzed and the results of both diverted cases are shown in Table 6F-1.

6F.4 CONSIDERATION OF OPERATOR ACTION

No operator action, beyond verification, is required prior to 20 minutes.

The system provided for diversion of LPCI flow is a safety grade system. Consequently, it has a high reliability in performing its intended function. Postulation of a failure of this system to perform its function in combination with another single failure is not required under GDC 35 or 10 CFR 50.46.

As noted in items b, c, and d, for non-ECCS line breaks, there is a decrease in the PCT in going from the nondiverted to the diverted case. As noted in e, the PCT for the LPCI break is far below that for the limiting break. For LPCS line breaks, with the worst single failure of the HPCS, there are three LPCI pumps available before diversion and one LPCI available after diversion.

For the HPCS line break with failure of the LPCS/LPCI diesel, only two LPCIs are available before diversion and one LPCI is available after diversion. Consequently, the HPCS line break represents the most limiting break location when evaluating LOCA with diversion.

The diesel generator failure for the LPCS/LPCI is more limiting than the diesel generator failure for the two LPCIs because the LPCS, as opposed to the LPCI, will rapidly reflood the core with a voided mixture. With a voided mixture, the swollen level inside the lower plenum is higher and reflooding can occur sooner. The effect of LPCI flow is to quench voids in the lower plenum, therefore requiring more water to reflood the hot mode. Consequently, the reflooding time with just LPCI available is longer than that with LPCS available, and the loss of LPCS relative to LPCI would have a more adverse impact on reflooding capability. An analysis was performed for this limiting break, and a failure of the LPCI/LPCI diesel generator and the calculated PCTs were substantially below those for the assumed worst single failure. It should be noted that CCFL effects on LPCS which have

been included in this analysis are small for this break, and consequently, the LPCS diesel failure still represents the worst single failure.

Figure 6.3-86 is a plot of peak cladding temperature versus break area for an HPCS line break assuming an LPCS diesel generator failure. Both diverted and nondiverted cases are shown. The curve for flow diversion was generated using data points at break areas of 0.002, 0.005, 0.008, 0.009, 0.01, 0.015, 0.02, 0.03, 0.04, 0.05, and 0.06 ft^2.

Figures 6F-1 through 6F-5 are plots of water level inside the shroud, reactor vessel pressure, convective heat transfer coefficient, peak clad temperature, and LPCI flow versus time.

The maximum temperature for the assumed LPCI diversion case for any given break location occurs at approximately that break size where the LPCI system would normally inject flow into the vessel starting at 600 seconds (i.e., the assumed LPCI diversion time). Bigger breaks get some reflooding benefit from the LPCI pumps before diversion. Smaller breaks have the same ECC systems available as this maximum break, but the smaller break area has a lower calculated PCT. This follows from the fact that: 1) The core is uncovered for shorter periods for smaller breaks since less mass is lost through the break during the blowdown from the time the reactor water level trip set point is reached until the time ADS is actuated 120 seconds later, allowing the LPCI to operate, and 2) the decay heat is lower at the time of uncovery for smaller breaks. For breaks smaller than the critical break size of approximately 0.01 ft, the LPCI system would normally inject flow into the vessel at some time after 600 seconds. Therefore, a longer LPCI diversion time would have correspondingly smaller breaks where the maximum PCT would occur.

From the above argument two points arise: a) Maximum PCT from diversion will occur at a smaller break for longer diversion times, and b) the smaller the break the lower the calculated PCT as discussed previously. Consequently, diversion at times greater than 10 minutes will have less severe consequences than diversion of 10 minutes.

It should also be noted that the dotted line curve of Figure 6.3-86 is bounding for small breaks (<approximately 0.01 ft^2) since only one LPCI pump (the minimum possible since LPCI pump "C" does not divert) is assumed to operate for these breaks. Consequently,

if one assumed a new scenario whereby diversion occurred at times later than ten minutes, the Figure 6.3-86 curve would peak at a smaller break area, and the PCT at that peak would be the same as that on the dotted line curve for that break area.

6F.5 CONSIDERATION OF AN ADS VALVE OUT OF SERVICE

The purpose of this section is to quantify the effect of an ADS valve out of service on the above LOCA analysis.

The above analysis demonstrated that the HPCS line break with failure of the LPCS diesel generator results in the highest calculated peak cladding temperatures (PCT). For these cases, the emergency core cooling systems remaining are 2 LPCI plus the ADS. Here the ADS is required to rapidly depressurize the vessel below the shutoff head of the low pressure ECCS.

If an ADS valve is out of service and unavailable in addition to the assumed worst single failure, the ADS will depressurize the vessel slower. This will result in a delay of low pressure ECCS injection and, in general, a corresponding delay in reflooding time and increase in the PCT. However, the significance of the ADS decreases as larger break sizes are considered, because of the increasing depressurization due to mass loss through the break. Therefore, the maximum impact on the PCT due to an ADS valve out of service will be determined by the recalculation of the small break spectrum.

Figure 6F-6 shows the impact of an ADS valve out of service. The increase in PCT is shown to be about 270 F with a maximum PCT of 2064 F occurring at a break size of 0.015 sq ft. Reactor water level, vessel pressure, heat transfer coefficients, peak cladding temperature, and ECCS flow versus time for this limiting case are shown in Figures 6F-7 through 6F-11. Since the PCT for this limiting case is still below the 2200 F limit, no change in the operating MAPLHGR limit is required to meet the 10 CFR 50.46 licensing limits.

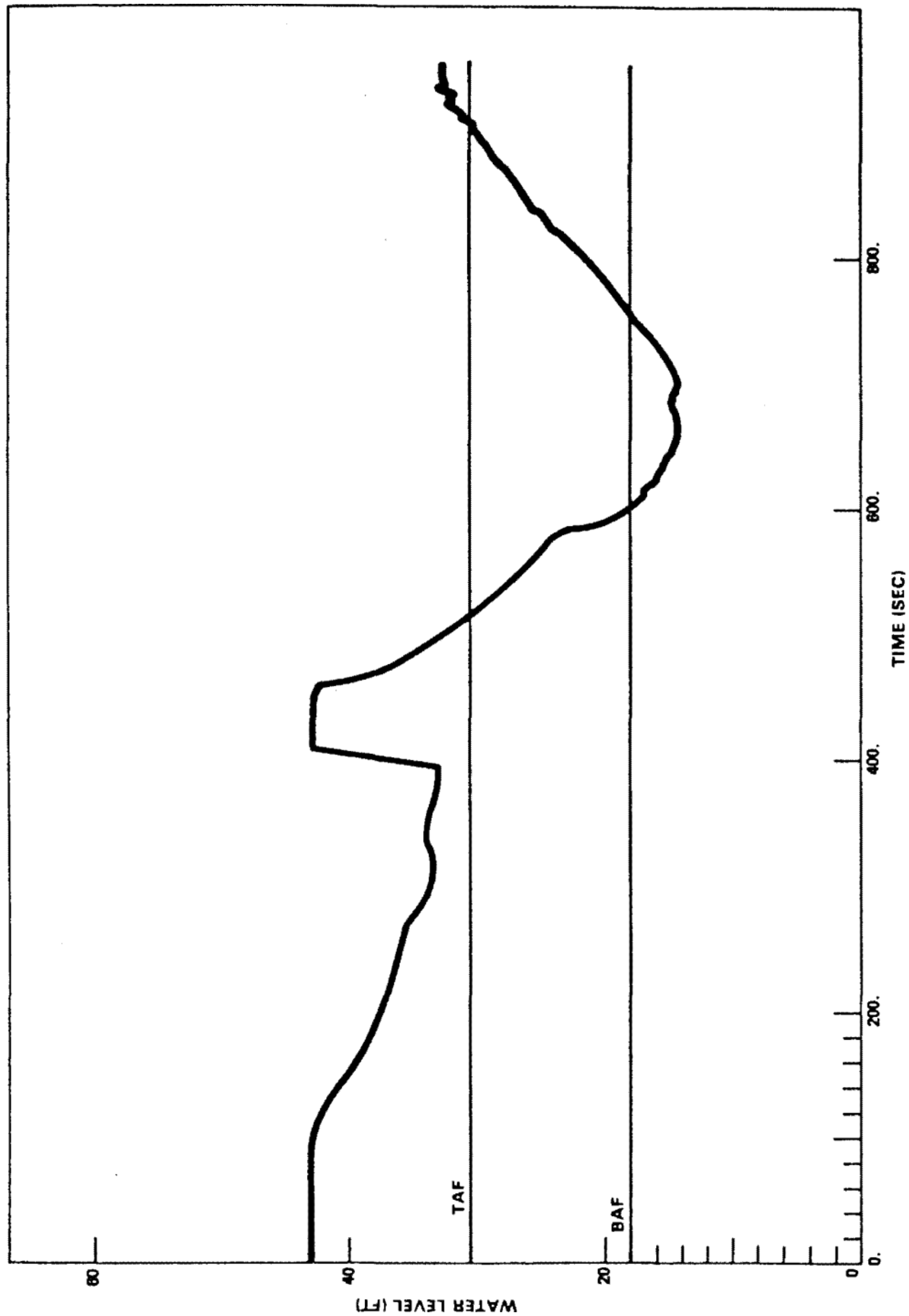
All peak cladding temperatures for the cases affected by an ADS valve out of service are still well below the PCT for the maximum recirculation line break which, as discussed earlier, is unaffected by the number of ADS valves available. Therefore based on the results of the LOCA analyses presented in this section, it is concluded that it is acceptable for an ADS valve to be out of

service for an extended period of time without changing the operating MAPLHGR limits to meet the 10 CFR 50.46 licensing limits.

TABLE 6F-1: THE EFFECT ON THE PCT OF DIVERTING LPCI FLOW AT 10 MINUTES FOR VARIOUS 0.005 FT^2 BREAK TYPES

BREAK TYPE	PCT NO DIVERSION	PCT WITH DIVERSION
Recirculation Line	942 F	783 F
Feedwater Line	969 F	714 F
Inside Steam Line	888 F	756 F
LPCI Line	777 F	766 F[1]
		713 F[2]

[1] PCT if break occurs in LPCI line "A" or "B"
[2] PCT if break occurs in LPCI line "C"



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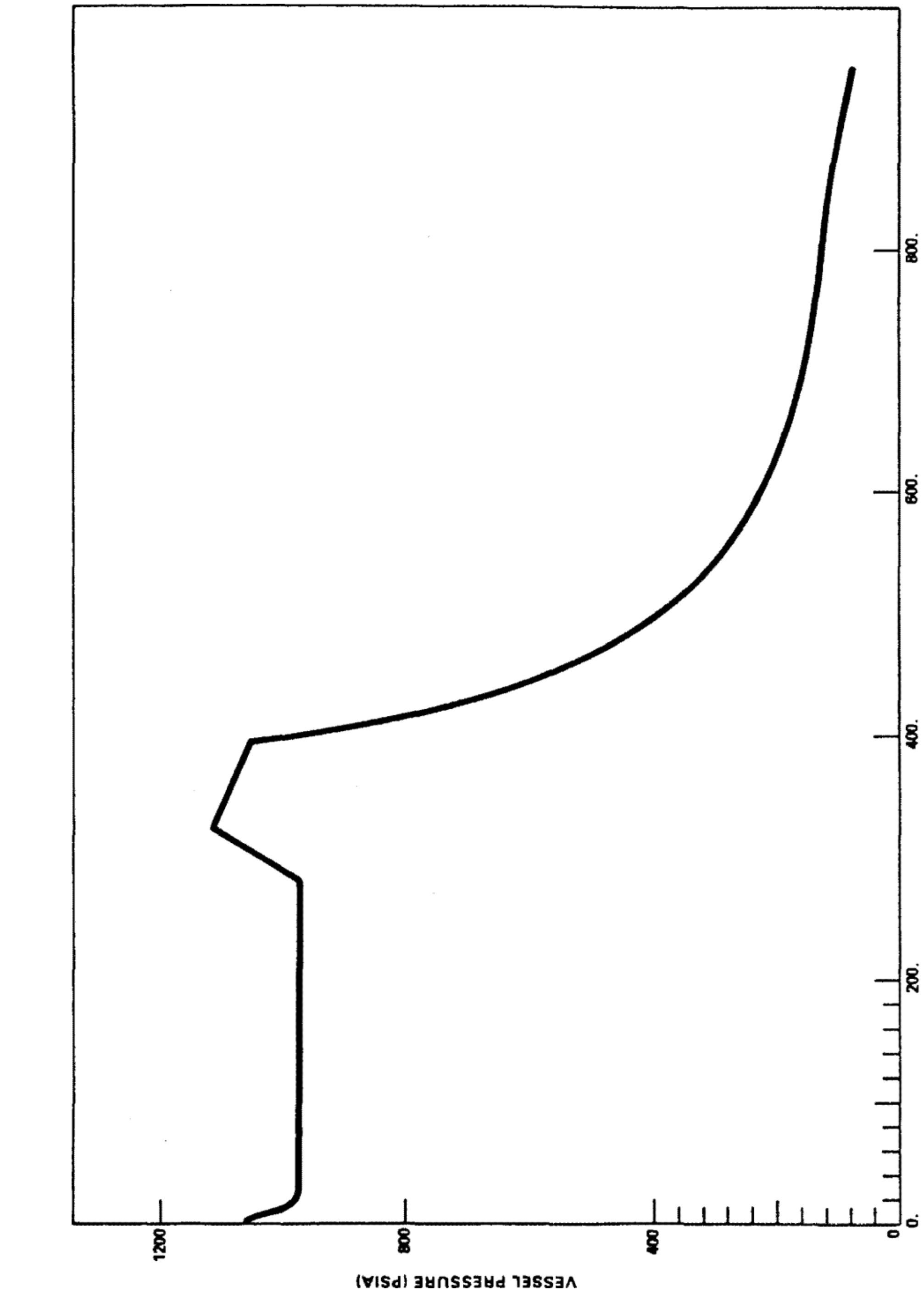
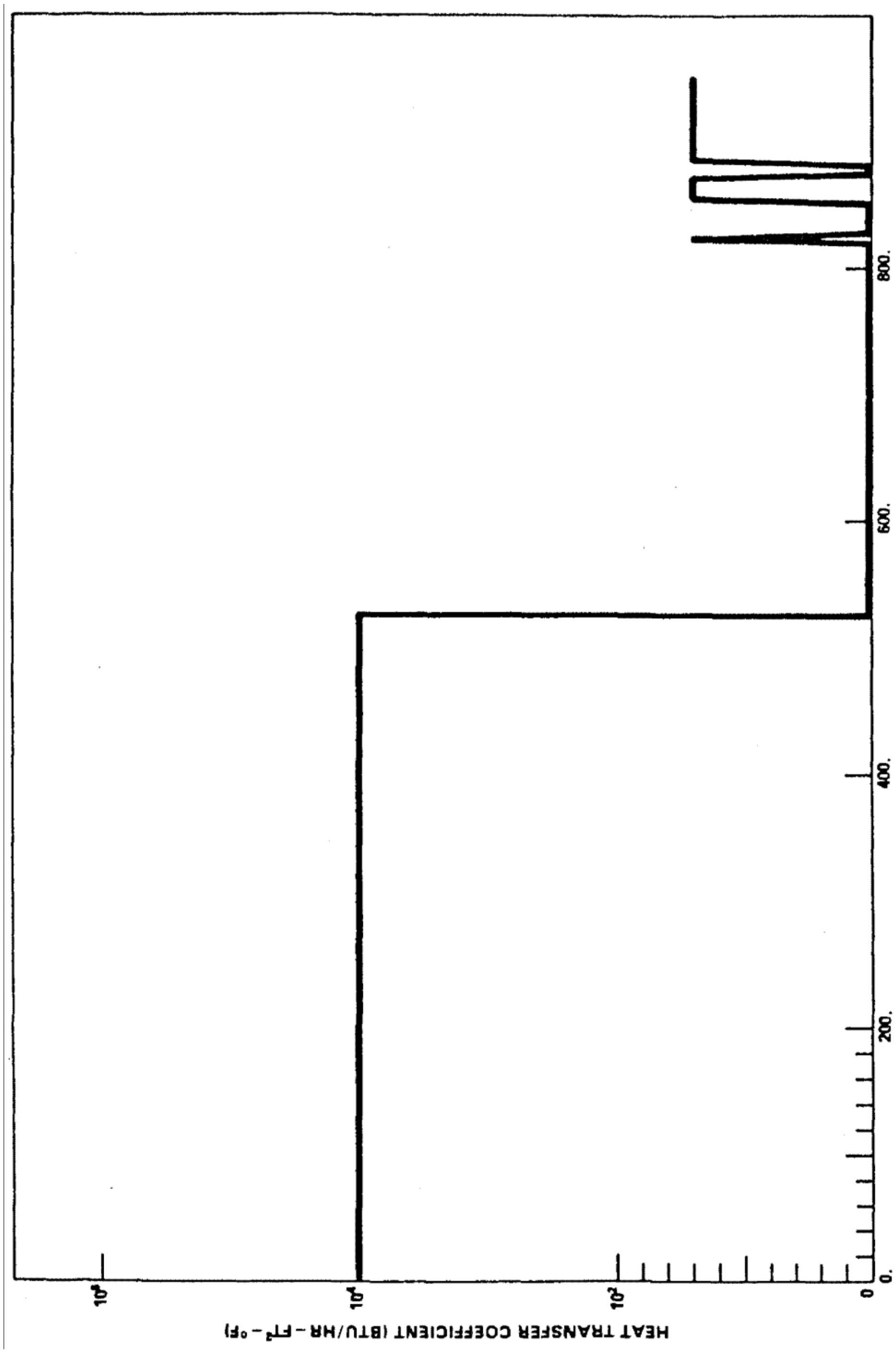
WATER LEVEL INSIDE THE SHROUD FOLLOWING
A HIGH PRESSURE CORE SPRAY LINE BREAK,
LPCS DG FAILURE BREAK AREA = 0.01 FT^2 (SBM)

FIGURE 6F-1



SYSTEM ENERGY RESOURCES, INC. GRAND GULF NUCLEAR STATION UNITS 1 & 2 UPDATED FINAL SAFETY ANALYSIS REPORT	REACTOR VESSEL PRESSURE FOLLOWING A HIGH PRESSURE CORE SPRAY LINE BREAK LPCS DG FAILURE BREAK AREA = 0.01 FT^2 (SBM) FIGURE 6F-2



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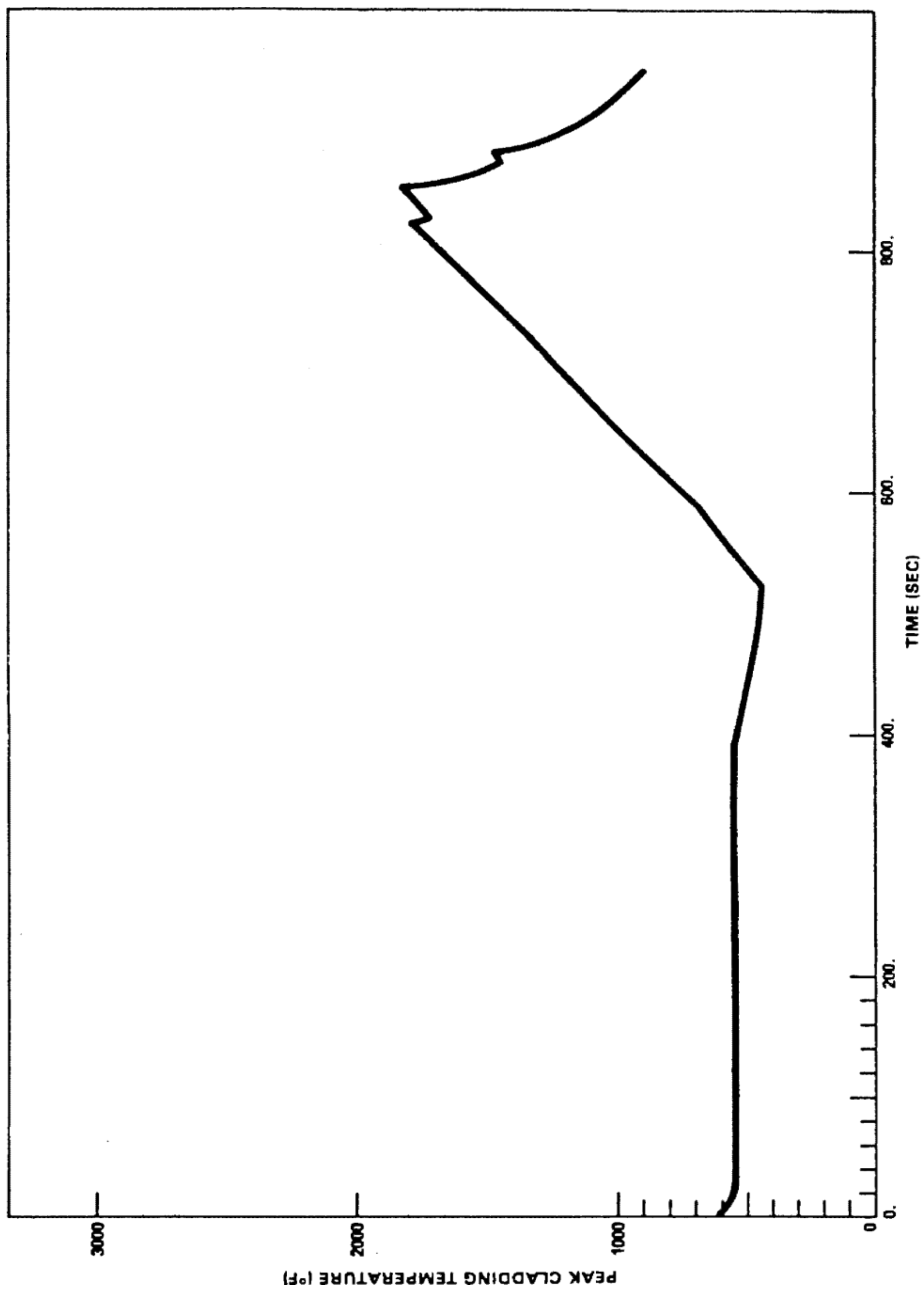
CONVECTIVE HEAT TRANSFER COEFFICIENT
FOLLOWING A HIGH PRESSURE CORE SPRAY
LINE BREAK LPCS DG FAILURE
BREAK AREA = 0.01 FT^2 (SBM)

FIGURE 6F-3



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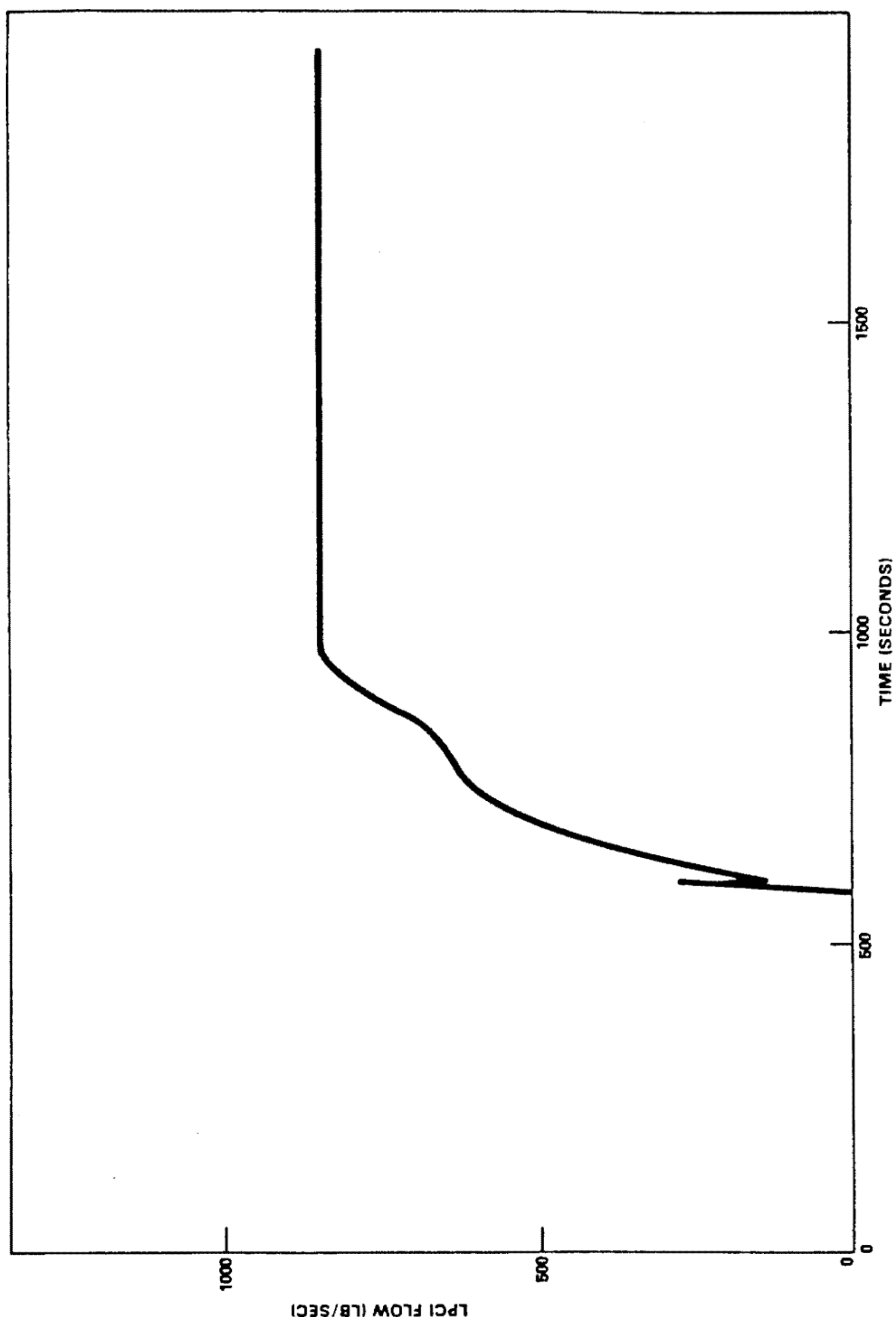
PEAK CLADDING TEMPERATURE FOLLOWING A HIGH PRESSURE CORE SPRAY LINE BREAK
LPCS DG FAILURE
BREAK AREA = 0.01 FT^2 (SBM)

FIGURE 6F-4



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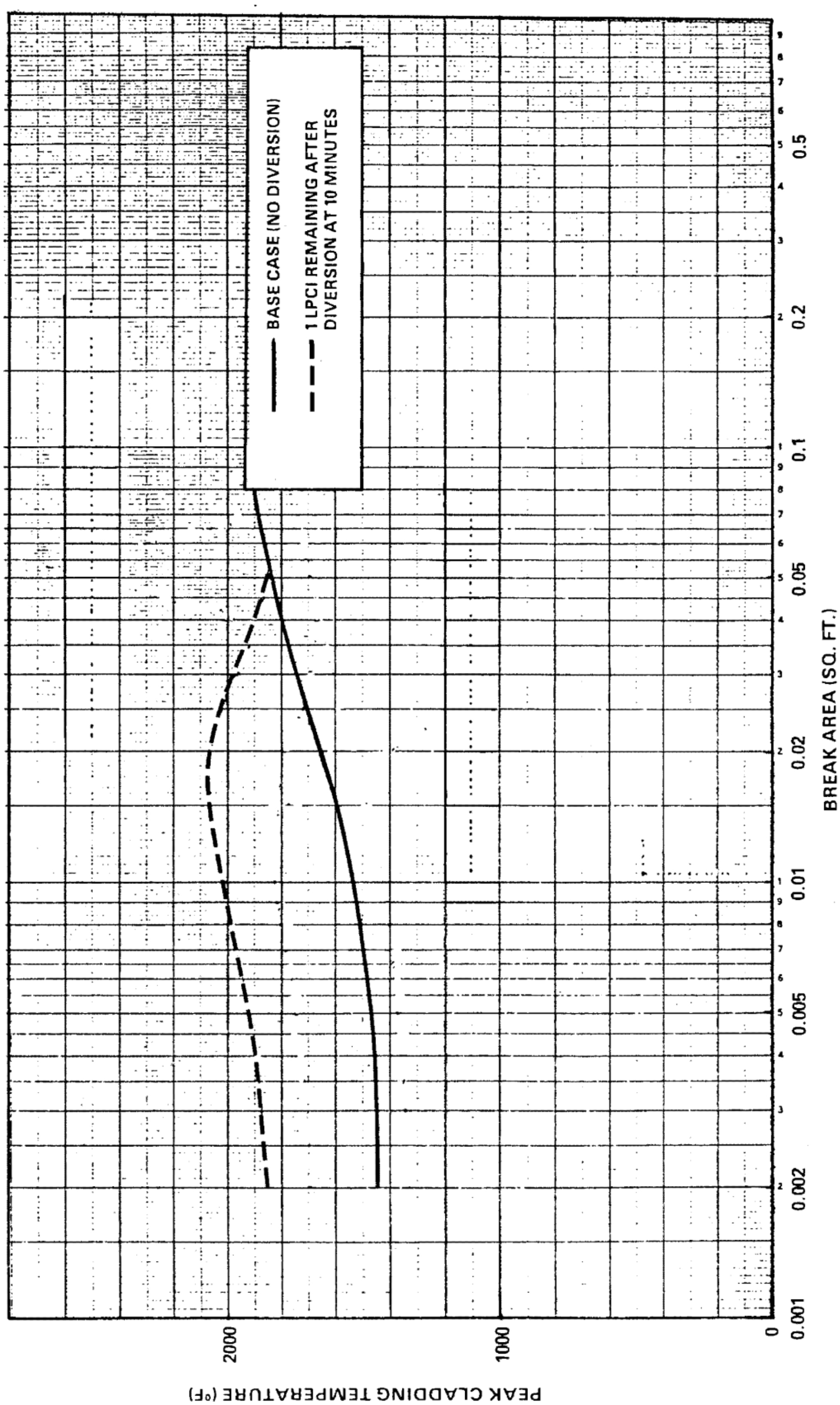
LPCI FLOW RATE FOLLOWING A HIGH PRESSURE CORE SPRAY LINE BREAK, LPCS DG FAILURE
BREAK AREA = 0.01 FT^2 (SBM)

FIGURE 6F-5



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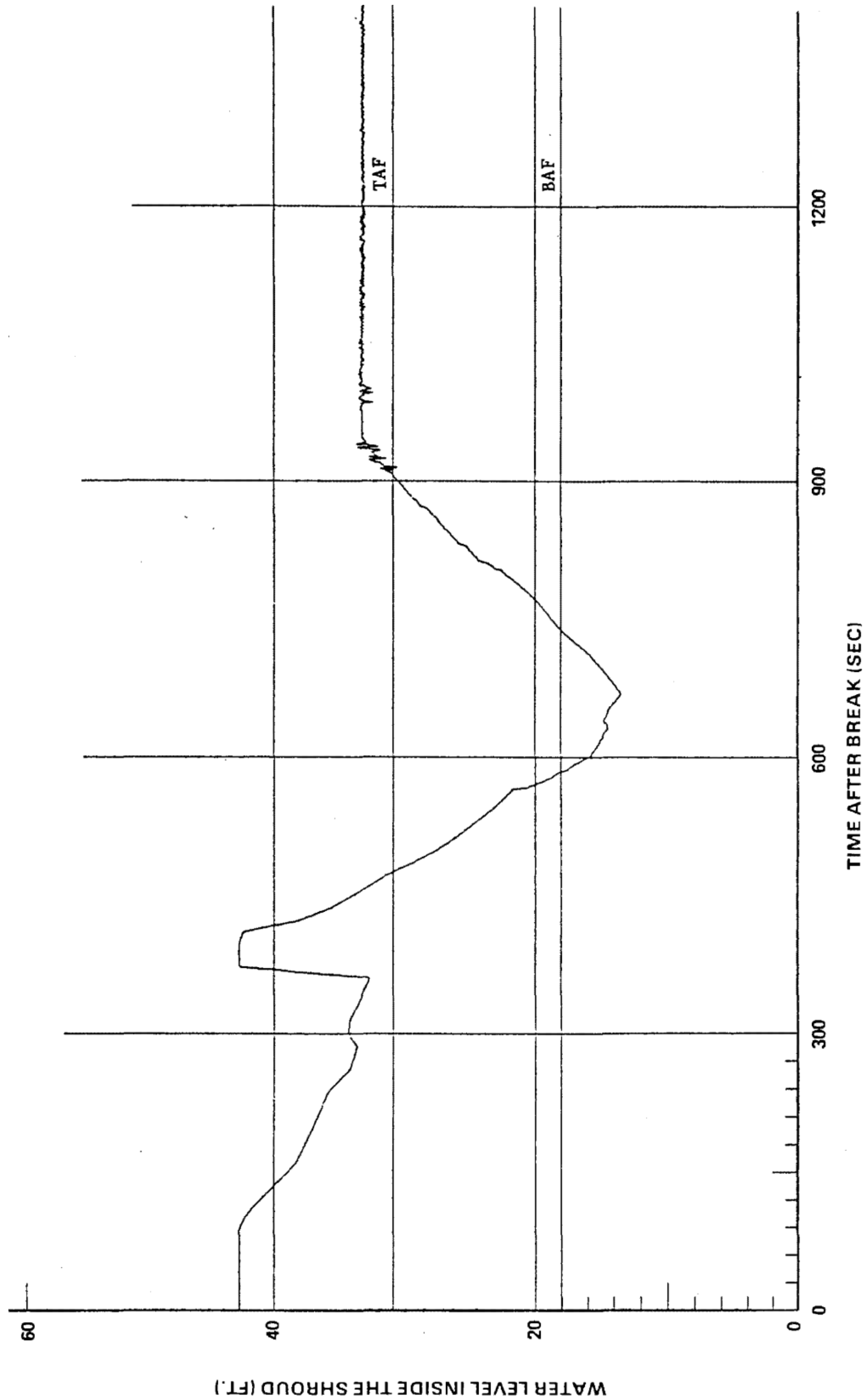
PEAK CLADDING TEMPERATURE VERSUS BREAK AREA FOR AN HPCS LINE BREAK ASSUMING AN LPCS DIESEL GENERATOR FAILURE SYSTEMS REMAINING: 2 LPCI + ADS 1 ADS VALVE OUT OF SERVICE

FIGURE 6F-6



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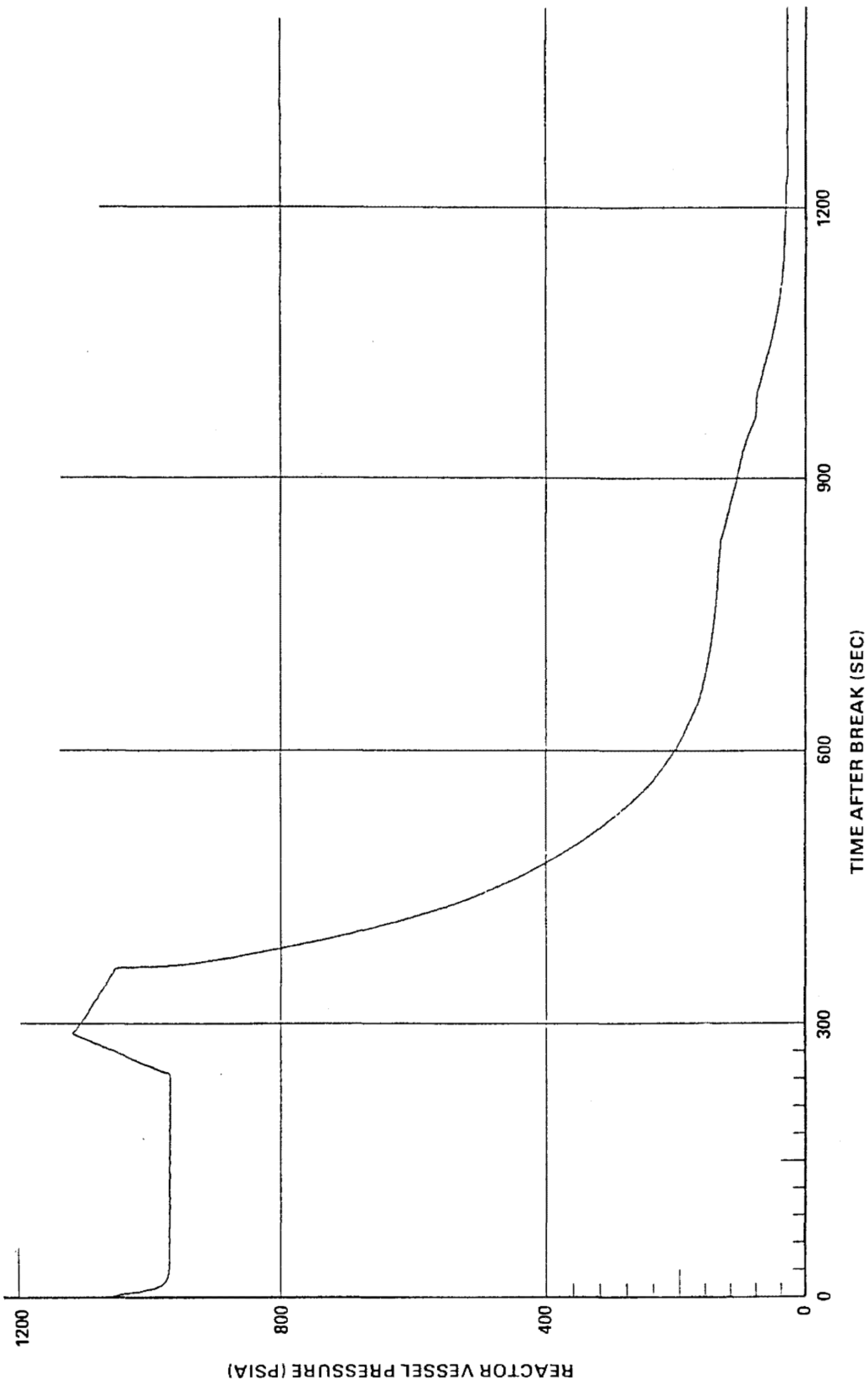
WATER LEVEL INSIDE THE SHROUD FOLLOWING A HIGH-PRESSURE CORE SPRAY LINE BREAK, LPCS DG FAILURE BREAK AREA = .015 FT² (SBM) 1 ADS VALVE OUT OF SERVICE

FIGURE 6F-7



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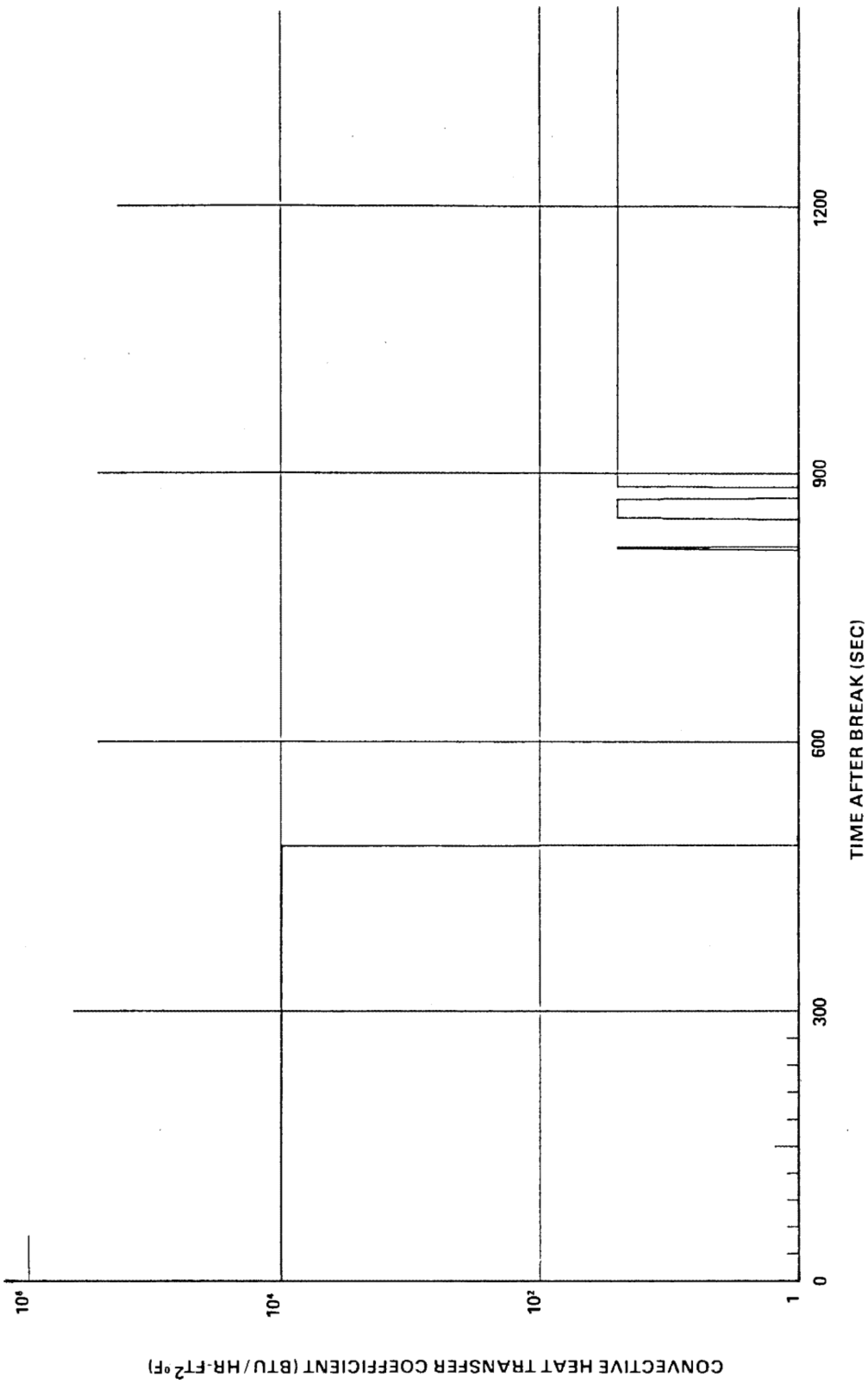
REACTOR VESSEL PRESSURE FOLLOWING A HIGH PRESSURE CORE SPRAY LINE BREAK, LPCS DG FAILURE BREAK AREA = 0.15 FT² (SBM) 1 ADS VALVE OUT OF SERVICE

FIGURE 6F-8



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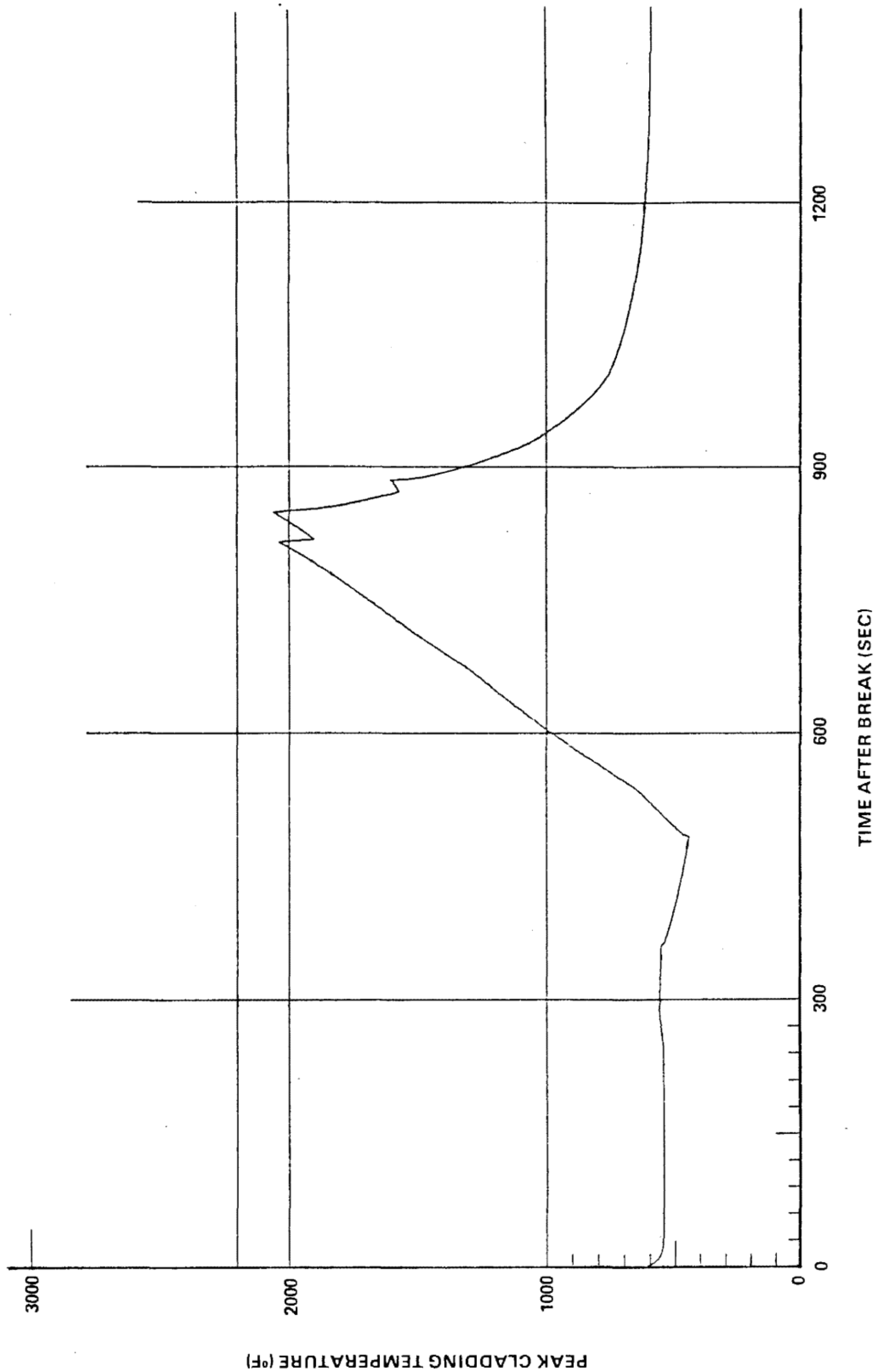
CONVECTIVE HEAT TRANSFER COEFFICIENT FOLLOWING A HIGH-PRESSURE CORE SPRAY LINE BREAK, LPCS DG FAILURE BREAK AREA = .015 FT² (SBM)
1 ADS VALVE OUT OF SERVICE

FIGURE 6F-9



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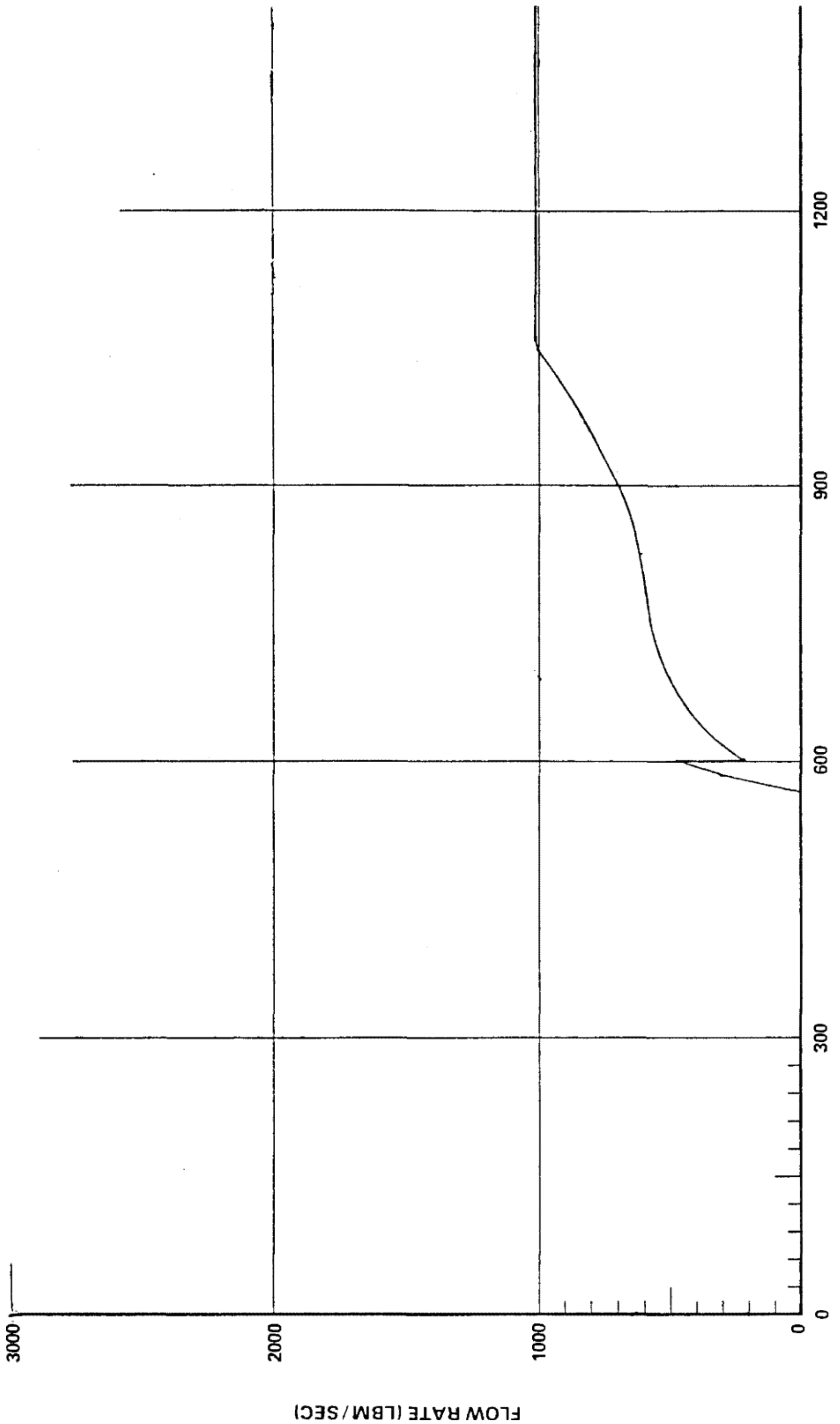
PEAK CLADDING TEMPERATURE FOLLOWING A HIGH-PRESSURE CORE SPRAY LINE BREAK, LPCS DG FAILURE BREAK AREA = .015 FT^2 (SBM) 1 ADS VALVE OUT OF SERVICE

FIGURE 6F-10



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LPCI FLOW RATE FOLLOWING A HIGH-PRESSURE CORE SPRAY LINE BREAK, LPCS DG FAILURE
BREAK AREA = .015 FT² (SBM)
1 ADS VALVE OUT OF SERVICE

FIGURE 6F-11