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6.0 ENGINEERED SAFETY FEATURES

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 environmental conditions encountered during normal operation and any postulated accident. Their compatibility with core and containment spray solutions has been considered and the effects of radiolytic decomposition products have been evaluated.

Coatings used on exterior surfaces within the primary containment are suitable for the environmental conditions expected. Non-metallic thermal insulation employed is required to have the proper ratio of leachable sodium plus silicate ions to leachable chloride plus fluoride ions to minimize the possibility of stress corrosion cracking.

6.1.1 METALLIC MATERIALS

6.1.1.1 Materials Selection and Fabrication

6.1.1.1.1 Material Specifications

Principal pressure retaining materials and the appropriate material specifications for the reactor coolant pressure boundary components are listed in Table 5.2-5. Table 6.1-1 lists the principal pressure retaining materials and the appropriate material specifications for the engineered safety features of the plant. All materials have been provided with ASME Section III material tests as required by the applicable component safety classifications. In addition, all Safety Class 2 carbon steel piping and valves installed in the main steam or feedwater systems meet the fracture toughness requirements specified in Subsection NB-2300, Section III of the ASME Code.

6.1.1.1.2 Engineered Safety Features Construction Material

Section 5.2.3 discusses compatibility of the reactor coolant with materials of construction exposed to the reactor coolant. These same materials of construction are found in the engineered safety feature components.

All ESF construction materials are resistant to stress corrosion in the BWR coolant and containment sprays. Conservative corrosion allowance are provided for all exposed surfaces of carbon steel. General corrosion on all other materials is negligible. Demineralized water, with no additives, is used 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, all of the materials listed in Table 6.1-1 are compatible.

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

Conformance with Regulatory Guides 1.44 and 1.31 is discussed in Section 1.8, and Section 5.2.3. The following controls were used to avoid severe sensitization of balance-of-plant (BOP) piping and to comply with the intent of Regulatory Guide 1.44 and NUREG-0313:

a. Corrosion Resistant Material

All safety related types 304 and 316L stainless steel material used in the Perry BWR coolant pressure boundary and ESF systems obtained in the solution annealed condition. Piping subject to hot bending is solution heat treated with all cold straightening limited to the two percent strain rule as specified by the ASME Section III Code. All BOP piping subject to the reactor coolant uses socket seal welded fittings with controlled heat flux and the welding interpass temperatures limited to 350°F. Both the design of the weld and the weld procedure reduce the susceptability of the material to crack sensitization.

b. Other Methods

The methods employed include:

1. Piping subject to the BWR coolant pressure boundary within the scope of BOP piping is included in four systems: reactor recirculation, nuclear boiler, standby liquid control and control rod drive. The largest size piping used in these systems for BOP design is 1-1/2 inch diameter schedule 40 or thicker; over 99 percent are one inch diameter or less and employ socket welded fittings. The design of socket fittings, using fillet seal welds, limits the heat flux into the pipe. When combined with a limited voltage, amperage and weld feed control, this prevents sensitization of the type 304 austinetic stainless steel piping used. The gas tungsten arc welds now being used in accordance with strict QA approved procedures result in a maximum of 45,000 joules per inch; shielded metal arc welds result in 56,000 joules per inch for all socket welded stainless steel pipe. This limited heat input control, when combined with the insulation effect of a socket seal weld connection design, provides a maximum protection from sensitization of the metal adjacent to the seal weld, since the weld is not exposed to the reactor coolant.

2. Using socket seals welds to prevent the welded portion of pipe from being exposed to the reactor coolant. This also eliminates the necessity of interior grinding since the interior surface of the pipe is not disturbed.

3. Using weld heat input control to limit the material heat flux to a value that avoids the conditions that cause excessive sensitization.

4. Limiting weld interpass temperatures to 350° and the weld weave pattern to four times the core wire diameter to control the heat buildup that contributes to excessive sensitization.

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.

Exposure to contaminants capable of causing stress corrosion cracking of austenitic stainless steel components was avoided by carefully controlling all cleaning and processing materials which contact the stainless steel during manufacture and construction. Special care was exercised to ensure removal of surface contaminants prior to any heating operations. Water quality for cleaning, rinsing, flushing, and testing was controlled and monitored. Suitable packaging and protection was provided for components to maintain cleanliness during shipping and storage.

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 engineered safety features systems.

6.1.1.1.3.4 Nonmetallic Insulation

Nonmetallic thermal insulation materials in ESF systems are in accordance with the staff positions of Regulatory Guide 1.36. They have the proper ratio of leachable sodium plus silicate ions, to leachable chloride plus fluoride ions. A detailed discussion of the nonmetallic thermal insulation used inside containment is presented in Section 6.1.2.

6.1.1.1.4 Weld Fabrication and Assembly of Stainless Steel ESF Components

All ESF system components and piping have been constructed in accordance with the staff positions of Regulatory Guide 1.31 or the interim positions specified in NRC Branch Technical Position MTEB 5-1, "Control of Stainless Steel Welding." General compliance or alternate approach assessment for Regulatory Guide 1.31 may also be found in Sections 1.8 and 5.2.3.

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 (see Section 6.2.5).

No soluble acids or bases are stored within containment, except for the 5,150-gallon capacity sodium pentaborate (13 percent by weight) storage tank. This volume of sodium pentaborate will be injected into the reactor only if a failure of the CRD system occurs.

Water used in the engineered safety feature systems will be controlled to provide assurance against stress corrosion cracking of unstabilized austenitic stainless steel components. Water used for emergency core cooling systems and spray systems will be controlled to ensure the following limits:

a. Conductivity = 3 to < 10 μmhos/cm at 25°C

b. Chloride (Cl^-) < 0.50 ppm

c. pH = 5.3 to 8.6 at 25°C

Water used in the ESF systems is stored in the suppression pool and condensate storage tank. Water quality is maintained by filter demineralizers.

The coating systems used inside containment comply with the staff positions of Regulatory Guide 1.54 and have undergone a qualification program to verify integrity following a LOCA. All coating materials (exceptions are noted in Section 6.1.2) used inside containment have been successfully tested at Oak Ridge National Laboratory for irradiation decontamination and DBA in accordance with application specifications[1,2,3].

The nonmetallic insulating system used inside containment (Owens-Corning "Nu'k'on" fiberglass blanket insulation) has also undergone a qualification program[4] to verify its performance following a LOCA.

6.1.2 ORGANIC MATERIALS

Many protective coatings that are common in industrial use can deteriorate in a post accident environment and contribute substantial quantities of foreign solids and residue to the reactor building sump. Therefore, protective coatings to be used inside the reactor building have been demonstrated to withstand the post accident conditions by satisfying all the criteria listed in ANSI N101.2. Excluded from this qualification are trace amounts of epoxy calking material which is used to seal weld discontinuities, such as porosity and laminations prior to final application of the coating system.

The suitability of reactor building coating systems to withstand the DBA has been evaluated. Coatings have been applied in accordance with manufacturer's recommendations. In addition, the guidance of Regulatory Guide 1.54 is followed.

Organic coating materials for inside the reactor building are listed in Table 6.1-2. Stainless steels will not be placed in contact with organic coatings or cleaning materials that could contribute to stress corrosion cracking. These materials are compounds containing unacceptable levels of leachable chlorides, fluorides, lead, zinc, copper, sulfur or mercury.

Various nonmetallic materials may be used in bearings: ethylene propylene, silicone or butyl rubber for O-rings; wire wound asbestos for gaskets; cross linked polyethylene or ethylene propylene rubber for cable insulation; neoprene or chlorosulfonated polyethylene for cable jacketing; and lubricants with less than 200 ppm leachable chlorides. Any plastics or elastomers used in a high radiation area will be evaluated to determine service deterioration in accordance with ANSI N4.1.

Penetrants used in liquid penetrant testing will contain not more than 1 percent total sulfur and not more than 1 percent total halogens.

The only significant organic materials on equipment supplied by General Electric are the protective coatings used on some carbon steel components. These coatings are specified to meet the requirements of Regulatory Guide 1.54 and are qualified using the standard ANSI tests. However, because of the impracticability of using these special coatings on all equipment, certain exemptions are taken. These exemptions are restricted to small size equipment where, in case of a LOCA, the paint debris would in no way be a safety hazard. Exemptions are for such items as electronic/electrical trim, covers, face plates, valve handles, etc.

Insulation used in containment (Owens Corning "Nu'K'on") is 95-100 percent inorganic. Exterior cloth and fiberglass insulating wool are the major components of the insulation. Together they represent over 95 percent of the total mass of the insulation.

The insulation is comprised of a quilted, light density, semi-rigid fiberous glass (pad) material, encapsulated in woven glass (cloth) to form a composite blanket. The blankets will use stainless steel Velcro hooks and Nomex nylon hooks for ease of installation and removal.

Insulation blankets outside guard pipes are encapsulated with rolled and formed 26 gauge (304) stainless steel jacketing, combining quick release latches and closure handles.

6.1.3 REFERENCES FOR SECTION 6.1

1. Bechtel Corporation, "Standard Specification Coatings for Nuclear Power Plants," Spec. Nos. CP-951, CP-952, CP-956.

2. American National Standards Institute, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," ANSI N101.2, 1972.

3. American National Standards Institute, "Protective Coatings (Paints) for the Nuclear Industry," ANSI N5.12, 1974.

4. Topical Report OCF-1, "Nuclear Containment Insulation System," August 1977.

TABLE 6.1-1

PRINCIPAL ENGINEERED SAFETY FEATURES COMPONENT
PRESSURE RETAINING MATERIALS

Principal Component	Form	Material	ASME Specification
RHR Heat Exchanger:			
Shell, head and channel	Plate	Carbon steel	SA-516, GR 70
Tube sheet	Plate	Carbon steel	SA-516, GR 70
Nozzles	Forging	Carbon steel	SA-105
Flanges	Forging	Carbon steel	SA-105
Tubes	Tubing	Stainless steel	SA-249, Type 304L
Bolts	Bar	Low alloy steel	SA-193, GR B7
Nuts	Forging	Low alloy steel	SA-194, GR 7
RHR, HPCS and LPCS Pumps:			
Bowl assembly	Casting	Cast steel	A-216, GR WCB (ASTM)
Discharge head shell	Plate	Carbon steel	SA-516, GR 70
Discharge head cover	Forging	Carbon steel	SA-105
Suction barrel shell and dished head	Plate	Carbon steel	SA-516, GR 70
Flanges	Forging	Carbon steel	SA-105
Pipe	Plate	Carbon steel	SA-516, GR 70
	Pipe	Carbon steel	SA-106, GR B
Shaft	Bar	Stainless steel	A-276, Type 410 (ASTM)
Impeller	Casting	Stainless steel	A-351, GR CA6NM (ASTM)
Studs	Bolting	Alloy steel	SA-193, GR B7
Nuts	Nut	Low alloy steel	SA-194, GR 7
Cyclone separator body and cover	Bar	Stainless steel	SA-479
HPCS Valves:			
Body, bonnet and disc	Casting	Cast steel	SA-216, WCB
Stem	Bar	Stainless steel	A-479, Type 410 (ASTM)
Studs	Bar	Alloy steel	SA-193, GR B7
Nuts	Bar	Steel	SA-194, GR 2H

TABLE 6.1-1 (Continued)

Principal Component	Form	Material	ASME Specification
Standby Liquid Control Pump:			
Fluid cylinder	Forging	Stainless steel	SA-182, F304
Cylinder head, valve, cover, and stuf.'ng box flange plate	Plate	Stainless steel	SA-240, Type 304
Cylinder head extension, valve stop, and stuffing box	Bar	Stainless steel	SA-479, Type 304
Stuffing box gland and plungers	Forging	Nickel alloy	SA-564, Type 630
Studs	Bar	Alloy steel	SA-193, GR B7
Nuts	Forging	Alloy steel	SA-194, GR 7
Standby Liquid Storage Tank:			
Tank	Plate	Stainless steel	SA-240, Type 304
Fittings	Forgings	Stainless steel	SA-182, Type F304
Pipe	Pipe	Stainless steel	SA-312, Type 304
Welds	Electrodes	Stainless steel	SFA 5.4 and 5.9, Types 308, 308L, 316, 316L
Control Rod Velocity Limiter	Casting	Stainless steel	A-351, GR CF8 (ASTM)
<u>Other Components</u>			
Piping:			
	Pipe	Stainless steel	SA-312, Type 304
		Stainless steel	SA-312, Type 316L
		Stainless steel	SA-358, Type 304, Cl-2
		Stainless steel	SA-376, Type 304
		Stainless steel	SA-403, GR WP304
		Stainless steel	SA-403, GR WP304H
		Carbon steel	SA-155, GR KCF70, Cl-2
		Carbon steel	SA-155, GRKCF70, Cl-1
		Carbon steel	SA-234, GR WPB
		Carbon steel	SA-106, GR B
		Alloy steel	SA-335, GR P12
		Alloy steel	SA-335, GR P22
		Alloy steel	SB-464
	Forgings	Stainless steel	SA-182, GR F304
		Stainless steel	SA-182, GR F316
		Carbon steel	SA-105
		Alloy steel	SA-182, GR F12
		Alloy steel	SA-182, GR F22

TABLE 6.1-1 (Continued)

Other Components	Form	Material	ASME Specification
	Plate	Stainless steel	SA-240, Type 304
	Bolting	Alloy steel	SA-193, GR B7
	Nuts	Carbon steel	SA-194, GR 2H
Valves:			
	Castings	Stainless steel	SA-351, GR CF8M
		Stainless steel	SA-351, GR CF8
		Stainless steel	SA-487, GR CA6NM
		Carbon steel	SA-216, GR WCB
		Carbon steel	SA-351, GR CN7M
		Stainless steel	SA-351, GR CF3M
		Alloy steel	SA-217, GR WC9
	Forgings	Stainless steel	SA-182, GR F316
		Stainless steel	SA-182, GR F304
		Alloy steel	SA-182, GR F11
		Alloy steel	SA-182, GR F12
		Alloy steel	SB-462
		Carbon steel	SA-105
		Carbon steel	SA-350, GR LF1
		Alloy steel	SA-182, GR F22
	Plate	Carbon steel	SA-516, GR 60
		Carbon steel	SA-516, GR 65
		Carbon steel	SA-516, GR 70
	Bolts	Stainless steel	SA-193, GR B8
		Carbon steel	SA-193, GR B8
	Nuts	Stainless steel	SA-194, GR B8
		Carbon steel	SA-194, GR 2H
	Bar	Stainless steel	SA-479, Type 316L
		Stainless steel	SA-564, Type 630
		(per Code Case 1773)	
Pumps:			
	Castings	Stainless steel	SA-351, GR CF8M
		Carbon steel	SA-216, GR WCB
	Plate	Stainless steel	SA-240, Type 304
		Carbon steel	SA-515, GR 70
	Pipe	Carbon steel	SA-106, GR B
		Carbon steel	SA-155, GR C55
	Bolts	Alloy steel	SA-193, GR B7
		Alloy steel	SA-193, GR B8
Vessels:			
	Plate	Stainless steel	SA-240, Type 304L
		Carbon steel	SA-283, GR C
	Pipe	Stainless steel	SA-312, Type 304L

TABLE 6.1-1 (Continued)

Other Components	Form	Material	ASME Specification
Heat Exchangers:			
	Plate	Stainless steel	SA-240, GR 304L
		Carbon steel	SA-285, GR C
			SA-306, GR 60
			SA-515, GR 70
			SA-516, GR 70
	Pipe	Carbon steel	SA-53, GR B
	Forgings	Carbon steel	SA-181, GR I
	Extrusions	Stainless steel	SA-249, GR 304L
	(tubes)	Copper	SB-359
	Bolts	Alloy steel	SA-193, GR B7
	Nuts	Carbon steel	SA-194, GR 2H

TABLE 6.1-2

ORGANIC COATING MATERIALS INSIDE REACTOR BUILDING

Surface	Area (ft^2)	DFT_{max} (mils)	Materials Type	Material Weight (oz./mil-ft)	Total Weight (lbs)
Steel(1)	210,000	8	Polyamide - cured epoxy	.15	15,800
Concrete	45,000	20	Polyamide - cured epoxy	.15	8,500
				Total	24,300

NOTE:

1. Includes pipe, structural steel, plate and equipment.

6.2 CONTAINMENT SYSTEMS

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Containment Structure

6.2.1.1.1 Design Bases

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

a. The containment and drywell have the capability to maintain functional integrity during and following 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 temperature) and is further postulated to occure simultaneously with loss of offsite power and a safe shutdown earthquake (SSE). A detailed discussion of LOCA events is presented in Section 6.2.1.1.3.3. A detailed discussion of mass and energy released is presented in Section 6.2.1.3.

b. The containment, in combination with other accident mitigation systems, limits fission product leakage during and following the postulated design basis accident to values less than leakage rates that would result in offsite doses greater than those stated in 10 CFR 100.

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

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

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

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

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

6.2.1.1.2 Design Features

General layout drawings of the containment structure are provided by Figures 1.2-3 through 1.2-11 and 1.2-13.

Design provisions for protection of the containment structure against internally and externally generated missiles are discussed in Section 3.5. Protection against pipe rupture is discussed in Section 3.6.

Codes, standards, and guides applicable to the design of the containment and internal structures are addressed in Sections 3.8.2 and 3.8.3.

The tests that demonstrate the functional capability of structural systems and components are discussed in Section 6.2.1.6.

The functional capability and frequency of operation of systems which maintain containment and subcompartment atmospheric conditions within limits during normal plant operation are discussed in Section 9.4.6.

Design provisions for protection of the containment structure against loss of integrity under external pressure loading conditions resulting from inadvertent operation of heat removal systems that could result in significant external structural loadings are described in Section 3.8.2.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Summary Evaluation

Key design parameters and the maximum calculated accident parameters for the pressure suppression containment are presented by Table 6.2-1. These 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.

It is assumed for analytical purposes that the primary system and containment are initially at the maximum normal operating conditions. References 1 through 4 describe relevant experimental verification of analytical models used to evaluate the containment system response.

6.2.1.1.3.2 Containment Design Parameters

Table 6.2-2 provides a listing of key design parameters for the primary containment system, including the design characteristics of the drywell, suppression pool, and pressure suppression vent system.

Table 6.2-3 provides a listing of performance parameters for the related engineered safety feature systems which supplement the design conditions presented by Table 6.2-2 for containment cooling purposes during post blowdown, long term accident operation. Performance parameters listed 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 consideration of several postulated accident conditions resulting in release of reactor coolant to containment. These accidents include the following:

a. Instantaneous guillotine rupture of a recirculation line.

b. Instantaneous guillotine rupture of a main steam line.

c. Rupture of an intermediate size liquid line.

d. Rupture of a small size steam line.

Energy release resulting from these accidents is addressed in Section 6.2.1.3.

6.2.1.1.3.3.1 Recirculation Line Break

Immediately following rupture of a recirculation line, flow from both sides of the break is the maximum value limited by critical flow considerations. The total effective flow area is shown by Figure 6.2-1. On the side of the break adjacent to the suction nozzle, flow corresponds to critical flow in the pipe cross section. On the side adjacent to the injection nozzle, flow corresponds to critical flow at the ten jet pump nozzles associated with the broken loop. In addition, the cleanup line crosstie adds to the critical flow area. Table 6.2-4 summarizes 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. Initial conditions for the recirculation line break accident are such that system energy is maximized and system mass is minimized. These conditions are as follows:

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

   2. Service water temperature is the maximum normal.

   3. Suppression pool mass is at the low water level.

4. Suppression pool temperature is the maximum normal.

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

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

d. Reactor pressure vessel depressurization flow rates are calculated using Moody's critical flow model(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 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 reactor pressure vessel discharge flow rates. Further, Moody's critical flow model, which assumes annular, isentropic flow, thermodynamic phase equilibrium, and maximized slip ratio, accurately predicts reactor pressure vessel outflows through small orifices. Actual rates through larger flow areas, however, are less than the model indicates because of the effects of a nearly homogeneous two phase flow pattern and phase nonequilibrium. These effects are conservatively neglected in the analysis.

e. Core decay heat and sensible heat released in cooling the fuel to initial average coolant temperature are included in the reactor pressure vessel depressurization calculation. The rate of energy release is calculated using a conservately high heat transfer coefficient throughout the depressurization period. The resulting high energy release rate causes the reactor pressure vessel to maintain nearly rated pressure for approximately 20 seconds. The high reactor pressure vessel pressure increases the calculated blowdown flow rates. This, again, is

conservative for analytical purposes. The sensible energy of the fuel stored at temperatures below the initial average coolant temperature is released to the reactor pressure vessel fluid along with the stored energy in the vessel and internals as vessel fluid temperatures decrease during the remainder of the transient calculation.

f. The main steam isolation valves start closing at 0.5 seconds after the accident. These valves are fully closed in the shortest possible time of three seconds following closure initiation. Actually, the closure signal for the main steam isolation valves occurs as a result of low reactor water level. Therefore, the valves do not receive a signal to close for more than four seconds and the closing time may be as long as five seconds. By assuming rapid closure of the main steam isolation valves, the reactor pressure vessel is maintained at a high pressure which maximizes the calculated discharge of high energy water in the drywell.

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

6.2.1.1.3.3.1.1.2 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 assumes complete mixing.

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

c. 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 containment. Actually, condensation of some steam on the drywell surfaces would occur.

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:

a. The low pressure core injection (LPCI) pumps are used to flood the core prior to 600 seconds after the accident. The high pressure core spray (HPCS) is available for the entire accident.

b. The effects on suppression pool temperature decay energy, stored energy, sensible energy, energy added by ECCS pumps, and energy from the zirconium water reaction are considered.

c. The suppression pool is the only heat sink available in the containment system. After 1,800 seconds, makeup water from the upper containment pool is included.

d. After approximately 1,800 seconds, the residual heat removal (RHR) heat exchangers are activated to remove energy from the containment by means of recirculation cooling of the suppression pool with the RHR service water systems. It is conservatively assumed that containment spray is not used.

Performance of the ECCS equipment during the long term cooling period is evaluated for each of the following cases of interest:

a. Case A, offsite power available, all ECCS equipment operating.

b. Case B, loss of offsite power, minimum diesel power available for ECCS.

6.2.1.1.3.3.1.4 Initial Conditions for Accident Analysis

Table 6.2-5 presents the initial reactor coolant system and containment conditions used in all the accident response evaluations. This tabulation includes paramters for the reactor, drywell, and containment.

Table 6.2-4 provides the initial conditions and numerical values assumed for the recirculation line break accident, as well as the sources of energy considered prior to the postulated pipe rupture. The assumed conditions for the reactor blowdown are also provided.

Mass and energy release sources and rates for the containment response analyses are addressed in Section 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 by Figures 6.2-2 and 6.2-3, respectively. Following the break, 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, drywell pressure decreases as break flow decreases.

The containment is pressurized early in the transient by the carryover of noncondensibles 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 containment pressure to increase. At the end of the blowdown, drywell pressure stabilizes at a slightly higher pressure than the containment, the difference being equal to the hydrostatic head of vent submergence. During the reactor pressure vessel depressurization phase most of the noncondensible gases initially in the drywell are forced into containment. However, following depressurization the noncondensibles are

redistributed between the drywell and containment through the vacuum breaker system. This redistribution occurs as steam in the drywell is condensed by the relatively cool ECCS water which begins to cascade from the break causing drywell pressure to decrease.

The ECCS supplies sufficient core cooling water to control core heatup and limit metal-water reaction to less than one percent. After the reactor pressure vessel 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 reactor pressure vessel through the broken recirculation line in the form of hot water. This hot water flows into the suppression pool through the drywell to suppression pool vent system.

Table 6.2-6 lists the peak pressure, temperature, and time parameters for the recirculation line break as predicted for the conditions presented by Tables 6.2-4 and 6.2-5 and corresponds with Figures 6.2-2 and 6.2-3. Figure 6.2-4 illustrates 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 6.2-5 provides the mass flow through the vent system versus time relationship for this accident.

6.2.1.1.3.3.1.6 Long Term Accident Responses

To assess the adequacy of the containment following the initial blowdown transient, an analysis of the long term temperature and pressure response following the accident was performed. The assumptions used in this analysis are those discussed in Section 6.2.1.1.3.3.1.3 for the two cases of interest.

a. Case A; All ECCS Equipment Operating

This case assumes that offsite a-c power is available to operate all cooling systems. During the first 1,800 seconds following the pipe break HPCS, low pressure core spray (LPCS), and all LPCI pumps are assumed to be operating. All flow is injected directly into the reactor vessel.

After 1,800 seconds both RHR heat exchangers are activated to remove energy from the containment. In this mode of operation LPCI flow is routed through both RHR heat exchangers where the fluid is cooled before being returned to the suppression pocl.

The containment pressure response under this set of conditions is illustrated by the solid line of Figure 6.2-6. Corresponding drywell and suppression pool temperature responses are shown by Figures 6.2-7 and 6.2-8. After the initial blowdown and subsequent depressurization, core decay heat results in a gradual pressure and temperature rise in containment. When the energy removal rate of the RHRS equals the energy addition rate from decay heat, containment pressure and temperature reach a second peak value and then decrease gradually. Table 6.2-7 summarizes equipment operation, the peak long term containment pressure, and the peak suppression pool temperature.

b. Case B; Loss of Offsite Power, Minimum ECCS Equipment Operating

This case assumes that no offsite power is available following the accident and that only minimum diesel generator power is available. After 1800 seconds LPCI flow through one RHR heat exchanger is returned to the suppression pool. The containment pressure response under this set of conditions is illustrated by the dashed line of Figure 6.2-6. Corresponding drywell and suppression pool temperature responses are shown by Figures 6.2-7 and 6.2-8. A summary for this case is presented by Table 6.2-7.

Figure 6.2-9 shows the rate at which the RHR heat exchanger removes heat from the suppression pool following a LOCA (Section 6.2.2 describes the containment cooling mode of RHRS operation). The heat removal rate is shown by both Case A and Case B. The first case assumes that all ECCS equipment is available, including both RHR heat exchangers and the associated emergency service water pumps. The second case assumes the very degraded minimum cooling condition that limits heat removal capacity to one heat exchanger. For both cases it is conservatively assumed that all the time of the accident the RHR service water is at the maximum design temperature as defined by Table 6.2-3.

6.2.1.1.3.3.1.7 Energy Balance during Accident

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

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. Rate of removal of heat from the suppression pool (see Figure 6.2-9).

f. Metal-water reaction heat rate.

A further discussion of Items a. through d. and f. above, is provided in Section 6.2.1.3.

6.2.1.1.3.3.1.8 Chronology of Accident Events

A complete description of the containment response to the recirculation line break is presented by Sections 6.2.1.1.3.3.1.5 through 6.2.1.1.3.3.1.7. Results for this accident are illustrated by Figures 6.2-2 through 6.2-9.

6.2.1.1.3.3.2 Main Steam Line Break

The postulated sudden rupture of a main steam line between the reactor pressure vessel and the flow limiter results in the maximum rate of primary system fluid flow and energy to transfer to the drywell. This, in turn, results in the maximum drywell differential pressure. Steam flow immediately following rupture of a main steam line between the reactor pressure vessel and the break accelerates to the maximum allowed by the critical flow considerations. On the side adjacent to the reactor pressure vessel the flow corresponds to critical flow in the main steam line break area. Blowdown through the other side of the break occurs because the main steam lines are all interconnected by the bypass header at a point upstream of the turbine. This interconnection allows primary system fluid to flow from the three unbroken steam lines through the header back into the drywell through the broken line. Flow is limited by critical flow in the steam line flow restrictor. The total effective flow area is given by Figure 6.2-10.

6.2.1.1.3.3.2.1 Assumptions for Reactor Blowdown

The response of the reactor coolant system during the blowdown period of the accident is analyzed using the assumptions listed in Section 6.2.1.1.3.3.1.1 for the recirculation line break, with the following exceptions:

a. Reactor pressure vessel depressurization flow rates are calculated using Moody's critical flow model[3]. During the first second of blowdown the flow consists of saturated steam.

   Immediately following the break the total steam flow rate leaving the reactor pressure vessel exceeds the rate of steam generation in the core. This causes an initial depressurization of the reactor pressure vessel. Void formation in the water within the reactor pressure vessel causes a

rapid rise in vessel water level. It is conservatively assumed that 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. After one second, a two-phase mixture is discharged from the break.

b. The main steam isolation valves start to close at 0.5 seconds after the accident and are fully closed in the maximum time of five seconds after initiation of closure. By assuming slow closure of these valves, a large effective break area is maintained for a longer period of time. Peak drywell pressure occurs before the reduction in effective break area and is, therefore, insensitive to any additional delay in closure of the main steam isolation valves.

6.2.1.1.3.3.2.2 Assumptions for Containment Pressurization

The pressure response of the containment during the blowdown period of the accident is analyzed using the assumptions listed in Section 6.2.1.1.3.3.1.2.

6.2.1.1.3.3.2.3 Assumptions for Long Term Cooling

The containment pressure and temperature response during the period following blowdown is analyzed using the assumptions listed in Section 6.2.1.1.3.3.1.3.

6.2.1.1.3.3.2.4 Initial Conditions for Accident Analyses

Table 6.2-5 lists the initial reactor coolant system and containment conditions used in all the accident response evaluations. This tabulation includes parameters for the reactor, drywell, and containment.

Table 6.2-4 lists the initial conditions and numerical values assumed for the main steam line break accident, as well as the sources of energy considered prior to the postulated pipe rupture. Assumed conditions for the reactor blowdown are also provided.

Mass and energy release sources and rates for the containment response analyses are presented in Section 6.2.1.3.

6.2.1.1.3.3.2.5 Short Term Accident Response

Figure 6.2-11 and 6.2-12 show the pressure and temperature responses of the drywell and suppression pool during the primary system blowdown phase of the main steam line break accident. Figure 6.2-13 shows the response of the drywell differential pressure and Figure 6.2-14 shows the vent mass flow versus time.

The drywell atmosphere temperature approaches a peak after approximately one second of primary system blowdown. At that time, water level in the reactor pressure vessel reaches the steam line nozzle elevation and the blowdown flow changes 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 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 pool begin to decrease.

Table 6.2-6 presents the peak pressures, peak temperatures, and times of this accident in comparison with similar parameters for the recirculation line break.

After the primary system pressure has decreased to the drywell pressure, the blowdown is over. At this time the drywell contains saturated steam and drywell and containment pressures stabilize. The pressure difference corresponds to the hydrostatic pressure of vent submergence.

The drywell and suppression pool remain in this equilibrium condition until the reactor pressure vessel is reflooded. During this period the ECCS pumps inject cooling water from the suppression pool into the reactor. This injection of water eventually floods the reactor vessel to the level of the

steam line nozzles. At this point the ECCS flow spills into the drywell. The water spillage condenses the steam in the drywell, reducing drywell pressure. As soon as drywell pressure drops below containment pressure, the drywell vacuum breakers open and noncondensible gases from containment flow into the drywell until pressures in the two regions are equalized.

6.2.1.1.3.3.2.6 Long Term Accident Responses

The long term containment pressure and temperature responses following the accident are identical to those described in Section 6.2.1.1.3.1.6 for the recirculation line break. The results are shown by Figures 6.2-6 through 6.2-9. Table 6.2-7 summarizes cooling equipment operation, peak long term containment pressure, and peak suppression pool temperature.

6.2.1.1.3.3.2.7 Energy Balance during Accident

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

a. Blowdown energy release rates.

b. Decay heat and fuel relaxation sensible energy.

c. Sensible heat rate (reactor pressure vessel and intervals).

d. Pump heat rate.

e. Rate of removal of heat from the suppression pool (see Figure 6.2-9).

f. Metal-water reaction heat rate.

A further discussion of Items a. through d. and f. above, is provided in Section 6.2.1.3. A complete energy balance for the main steam line break accident is provided by Table 6.2-8 for the reactor system, containment, and

containment cooling systems at time zero, time of peak drywell pressure, time of end of reactor blowdown, and time of long term peak pressure in containment.

6.2.1.1.3.3.2.8 Chronology of Accident Events

A complete description of the containment response to the main steam line break is presented in Sections 6.2.1.1.3.3.2.5 through 6.2.1.1.3.3.2.7. Results for this accident analysis are shown by Figures 6.2-6 through 6.2-14. A chronological sequence of events for this accident from time zero is provided by Table 6.2-9.

6.2.1.1.3.3.3 Hot Standby Accident Analysis

Both the short term and long term response of the containment system have been evaluated, assuming that the reactor has been operating in the hot standby mode prior to the LOCA.

The peak drywell pressure following a main steam line break is dependent upon the rise time of the reactor pressure vessel water level since this determines the time at which two phase blowdown begins. A level rise time of one second is a conservative bounding condition for a main steam line break at a reduced reactor power level. However, since a one second level rise time was conservatively assumed for the LOCA at 102 percent of rated power, the peak drywell pressure following a blowdown at hot standby will be no higher than shown by Figure 6.2-11.

In the event of a recirculation line break, the short term blowdown flow rate is essentially independent of 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 result in lower blowdown flow rates and in peak drywell pressures lower than the value presented by Figure 6.2-2. The short term drywell response to either a main steam line or recirculation line break is insensitive to suppression pool water temperature. This insensitivity is due to domination of the transient by the rate at which

energy is transferred to the drywell and the rate at which vent clearing can be accomplished. Neither is sensitive to suppression pool water temperature.

The long term suppression pool and containment transient is only affected very slightly by a period of hot standby operation prior to blowdown. Figure 6.2-15 presents a comparison of suppression pool temperature transients following a blowdown under the following conditions:

a. Maximum normal suppression pool water temperature and 102 percent of rated power.

b. Approximately 1/2 hour of hot standby operation.

In both cases containment cooling (RHRS) is initiated 30 minutes after the LOCA.

A blowdown at 1/2 hour after an isolation results in the highest peak long term temperature because it is assumed that no heat is rejected from the system for 1/2 hour after the start of an isolation event. Thus, from the results presented by Figure 6.2-15, the long term consequences of a LOCA occurring after a period of hot standby operation are no more severe than for a LOCA occurring at 102 percent of rated steam flow.

6.2.1.1.3.3.4 Intermediate Size Breaks

The classification, intermediate size breaks, includes those breaks, the blowdown from which results in reactor depressurization and operation of the ECCS. This section describes the consequences to the containment of a 0.68 ft^2 break below the reactor pressure vessel water level. This break was chosen as being representative of the intermediate size break range. Such breaks can involve either reactor steam or liquid blowdown.

Following the occurrence of the 0.68 ft^2 break, drywell pressure increases at approximately one psi/sec. This transient is sufficiently slow that the dynamic effect of the water in the vents is negligible and the vents clear

when the drywell to containment differential pressure is equal to the vent submergence hydrostatic pressure.

Figures 6.2-16 and 6.2-17 show the drywell and containment pressure and temperature response, respectively. The ECCS response is discussed in Section 6.3. Approximately five seconds after the 0.68 ft^2 break occurs, air, steam, and water start to flow from the drywell to the suppression pool. The steam is condensed and the air enters the containment free space. The continual purging of drywell air to the containment results in a gradual pressurization of both containment and drywell. Containment pressure continues to gradually increase due to the long term suppression pool heatup.

The ECCS is initiated as a result of the 0.68 ft^2 and provides emergency cooling of the core. Operation of the ECCS is such that the reactor is depressurized in approximately 600 seconds, terminating the blowdown phase of the transient.

In addition, the suppression pool temperature at the end of blowdown is the same as that of the main steam line break because essentially the same amount of primary system energy is released during the blowdown. After reactor pressure vessel depressurization and reflood, water from the ECCS begins to flow out the break. This flow condenses the drywell steam and eventually causes the drywell and containment pressures to equalize in the same manner as described for a main steam line break.

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

6.2.1.1.3.3.5 Small Size Breaks

6.2.1.1.3.3.5.1 Reactor System Blowdown Considerations

Ths section discusses the containment transient associated with small primary system blowdowns. The sizes of primary system ruptures in this category are those blowdowns that do not result in reactor pressure vessel depressurization

due either to loss of reactor coolant or automatic operation of ECCS equipment. Following the occurrence of a break of this size, it is assumed that the reactor operators initiate an orderly plant shutdown and depressurization of the reactor system. The thermodynamic process associated with blowdown of primary system fluid is one of constant enthalpy. If the primary system break is below the water level, blowdown flow consists of reactor water. Blowdown from reactor pressure to drywell pressure results in flashing of approximately one-third of the blowdown water to steam. Two-thirds of the water remain liquid. Both phases are 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 a temperature of 212°F.

If the primary system rupture is so located that the blowdown flow consists only of reactor steam, the resultant steam temperature in containment is significantly higher than the temperature associated with liquid blowdown. This is because the constant enthalpy depressurization of high pressure, saturated steam results in superheated conditions. For example, decompression of saturated steam at 1,000 psia to atmospheric pressure results in superheated steam at 298°F (86°F of superheat).

A small reactor steam leak resulting in superheated steam imposes the most severe temperature conditions on the drywell structures and on 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 is less for the larger break. This is a result of the more rapid depressurization of the reactor pressure vessel through the larger breaks. Depressurization is slower for the orderly shutdown 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 under normal maximum conditions, a small break occurs that allows blowdown of reactor steam to the

drywell. The resulting pressure increase in the drywell leads to a high drywell pressure signal that scrams the reactor and activates the containment isolation system. Drywell pressure continues to increase at a rate dependent upon the size of the steam leak. The pressure increase lowers the water level in the annulus until the level begins to clear the vents. At this time, air and water start to enter the suppression pool. The steam is condensed and the air carries over to the containment free space. The air carryover results in a gradual pressurization of the containment at a rate dependent upon the size of the steam leak. Once all of the drywell air is carried over into the containment, short term containment pressurization ceases and the system reaches an equlibrium condition. The drywell contains only superheated steam and continued blowdown of reactor steam is condensed in the suppression pool. Suppression pool temperature continues to rise until the RHR heat exchanger heat removal rate equals the decay heat release rate.

6.2.1.1.3.3.5.3 Recovery Operations

The reactor operators are alerted to the small size break incident by the high drywell pressure signal and reactor scram. For purposes of evaluating the duration of the superheat condition in the drywell, it is assumed that the response of the operators is to shut down the reactor in an orderly manner, using the main condenser, while limiting the reactor cooldown rate to 100°F/hr. This results in depressurization of the primary system within six hours. At this time blowdown flow to the drywell ceases and the superheat condition is terminated. If the operators elect to cool down and depressurize the primary system more rapidly than at 100°F/hr, the duration of the drywell superheat condition is 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. The

maximum drywell steam temperature occurs when the primary system is at approximately 450 psig and the drywell pressure is maximum. Thus, for design purposes, it is assumed that the drywell is at 15 psig. This results in temperatures of 330°F for the first three hours of the cooldown period, and 310°F for the next three hours.

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 GE to evaluate the containment response during the reactor pressure vessel blowdown phase of a LOCA are described in References 1 and 2.

6.2.1.1.3.4.2 Long Term Cooling Model

Once the reactor pressure vessel blowdown phase of the LOCA is over, a fairly simple model of the drywell and containment is used. During the long-term post-blowdown transient, the RHR containment cooling system flow path is a closed system and the suppression pool mass is constant. The cooling loop model used for analysis is schematically illustrated by Figure 6.2-18.

The analytical models, assumptions, and methods used by GE to evaluate the containment response during the long term cooling phase of a LOCA are described in Reference 2.

6.2.1.1.3.5 High Energy Line Rupture Inside Containment

Some primary system pipes are routed from the drywell through the containment to the auxiliary building (main steam lines for example). If such pipes were unguarded, rupture within containment would result in 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 the potential for overpressurizing containment, all reactor coolant pressure boundary pipes of a size which would result in containment overpressurization and which pass through the containment except LPCI, HPCS, and LPCS pipes, are provided with guard pipes that vent to the drywell. Thus, in the event of rupture of a reactor coolant pressure boundary pipe, flow passes through the suppression pool vent system and the steam is condensed.

The LPCI, HPCS, and LPCS pipes have check valves inboard of the drywell penetration that prevent blowdown to the containment.

The traversing incore probe, control rod drive insert and withdraw, and instrument lines could discharge primary coolant to the containment in the event of a rupture. The unisolatable instrument line rupture results in the maximum discharge of primary coolant to containment. This accident is discussed in Chapter 15. Each instrument line includes a 1/4 inch diameter flow restricting orifice to limit the containment pressure increase to values well below the design pressure.

The major components of the reactor water cleanup system are located within containment and system piping could also discharge primary coolant to the containment in the event of rupture. The system suction line penetrates the drywell and is provided with a guard pipe. System components located inside containment are provided with break detection and isolation systems that limit the total blowdown fluid flow to containment to acceptable values.

6.2.1.1.4 Negative Pressure Design Evaluation

6.2.1.1.4.1 Evaluation of Drywell Negative Differential Pressure

Following the blowdown phase of a LOCA, air initially contained in the drywell has been purged to the containment and the drywell is full of steam. During this period the ECCS is injecting cooling water from the suppression pool into the reactor pressure vessel. When the reactor pressure vessel is flooded to the level of the break, water begins spilling into the drywell, condensing the steam and causing rapid depressurization of the drywell. A bounding

calculation of the peak drywell negative differential pressure is based upon the following conservative assumptions:

a. All air has been purged out of the drywell.

b. Drywell vacuum breakers do not open.

c. The suppression pool is at peak short term (post blowdown) temperature, as determined from Figure 6.2-12.

d. The containment is at suppression pool temperature and 100 percent relative humidity.

e. Steam in the drywell is cooled to suppression pool temperature.

Using the above assumptions, the final drywell pressure is equal to saturation pressure at 184°F or:

$$P_d = 8.2 \text{ psia}$$

Based upon the initial conditions listed in Table 6.2-5, the initial air masses in the drywell and containment are:

$$M_d = 17{,}044 \text{ lbm}$$

$$M_c = 80{,}162 \text{ lbm}$$

Using the assumptions in Items a. through e., above, the final containment pressure for the purposes of determining the drywell negative differential pressure is calculated as the summation of the partial pressures of air and vapor:

$$P_c = 28.58 \text{ psia}$$

Thus, the bounding negative pressure load across the drywell wall is:

$$\Delta P_d = P_d - P_c$$

$$\Delta P_d = -20.38 \text{ psid}$$

6.2.1.1.4.2 Evaluation of Containment Negative Pressure

If the containment spray system is activated during any period of time other than when it is designed to be operated, it is possible that a vacuum could be created inside the containment vessel. If the containment spray system is accidently activated, an excessive vacuum is prevented from developing by means of vacuum breakers provided for this purpose.

Containment vacuum relief capability is necessary only to maintain containment integrity should the containment spray system be operated incorrectly in such a way as to tend to create a vacuum inside containment. Although the containment spray system is adequately protected against inadvertent, unintentional, or incorrect operation by interlocks and administrative procedures (Section 6.2.2), two hypothetical situations are considered, assuming these protective measures are bypassed in some manner and the spray is started at the wrong time:

a. For the first situation, pressure and temperature conditions for the containment atmosphere are based on the following sequence of events:

   1. The atmosphere inside containment is at normal pressure and temperature.

   2. A 6-inch reactor water cleanup (RWCU) line break occurs inside containment.

   3. Isolation of the RWCU line is complete at 40 seconds after the accident. At this time, the containment pressure is 5 psig, temperature is 157°F, and the containment has been isolated.

4. The vacuum breakers between the containment and drywell (Section 3.8.3) open to equalize the pressure of the containment and drywell. During this pressure equalization period, a portion of the containment air is swept into the drywell through the drywell vacuum breakers and remains there when the vacuum breakers close.

The maximum amount of air drawn into the drywell from containment is simply the difference between the amount of air in containment during normal operation and the amount of air in containment after the RWCU line isolation, assuming a slightly conservative relative humidity of 100 percent.

	Normal Operating Conditions	RWCU Line Isolation
Pressure (psig)	0.0	5.0
Temperature (°F)	90.0	157.0
Relative Humidity (%)	50.0	100.0
Mass of air (lbm)	82,200.0	78,100.0

5. The containment spray system is activated (due to operator error) at a maximum flow rate of 10,500 gpm and a temperature of 60°F (minimum suppression pool temperature).

6. The containment is depressurized as a result of steam being condensed by the containment spray; the spray droplets are assumed to have an efficiency of 100 percent. Three cases are considered in sizing the containment vacuum breaks:

   (a) Condensation rate including heat transfer structures with initial temperature of 80°F.

   (b) Condensation rate including heat transfer structures with initial temperature of 90°F.

(c) The effects of the internal surfaces on the condensation rate are not considered. This is the limiting case.

The resulting pressure-temperature history within containment is calculated using the digital computer code CONTEMPT[5].

7. Figures 6.2-19 and 6.2-20 present the results of the analyses for Cases a and b, respectively. Curves are plotted on these figures showing the containment vapor pressure and temperature, the total vapor mass, and the surface temperature of the internal concrete and steel liner as a function of time after RWCU isolation.

   Figure 6.2-21 presents the results for Case c.

   As indicated by comparing these three figures the net effect of considering the internal surfaces is a lesser vacuum condition than when the effects of the internal surfaces are not considered. The peak vacuum calculated is 0.70 psig.

b. For the second case it is assumed that the containment depressurization is a result of accidental initiation of the containment spray system during normal plant operation. The conditions present in the containment at the time of spray initiation are chosen to provide the most conservative results:

   1. Maximum temperature in containment during normal operation - 105°F

   2. Minimum relative humidity in containment during normal operation -30 percent.

   3. Minimum spray water temperature - 60°F.

   The source for the containment spray system water is the suppression pool. The normal water temperature in the pool is 90°F or equal to the normal operating temperature in the containment vessel outside the drywell. The minimum temperature of 60°F for the suppression pool is

based on the minimum ambient air temperature (60°F) in the drywell and containment vessel which could occur only under shutdown conditions. As described in Section 9.4.6, the reactor building ventilation system is designed to assure that the temperature of the containment atmosphere never falls below 60°F.

4. Spray system flow rate - 10,500 gpm

5. During the evaporative cooling phase of the transient, the water drops sprayed into the containment absorb heat from the containment atmosphere and evaporate to contribute to saturating the containment atmosphere. This process is generally very rapid for spray rates typical of containment spray systems, and therefore, the time to complete the evaporative cooling process is important to compare to the vacuum breaker response time. In the calculations presented here the following assumptions are made:

   (a) Spray efficiency is 100 percent.

   (b) All of the spray water entering the containment is immediately vaporized and forms a homogeneous mixture with the containment atmosphere. Because of this conservative assumption, no detailed analytical heat/mass transfer modeling of the spray droplets is required.

   (c) No heat is transferred back into the containment atmosphere from the structures during the transient.

   (d) The mass flow through two 20-inch diameter containment vacuum relief lines as a function of pressure differential is shown on Figure 6.2-22.

The equations used in the analyses are derived from the conservation of mass and energy and the equations of state of water and air. Utilizing the above assumptions the equations can be written as:

(a) Conservation of mass:

$$\frac{dm_g}{dt} = \dot{m}fg$$

$$\frac{dm_f}{dt} = \dot{m}s - \dot{m}fg$$

The assumption of instantaneous evaporation of the spray water defines the following additional relationship:

$$\dot{m}_{fg} = \dot{m}_s$$

and therefore,

$$\frac{dmf}{dt} = \dot{m}s - \dot{m}fg = 0$$

(b) Conservation of energy:

From these equations it can be seen that the equation for the conservation-of-energy includes the effect of evaporative cooling. This equation is given as:

$$\frac{d}{dt} [m_a u_a + m_g u_g + m_f u_f] = \dot{m}_s h_f = \dot{m}_{fg} h_f$$

For any addition of low enthalpy spray water, the heat required for evaporation lowers the total energy (temperature) of the vapor region, thereby lowering the partial pressure of the air (constant mass with decreasing temperature) while increasing the partial pressure of the vapor (result of increasing mass of vapor being more dominant than decreasing temperature).

(c) Equation of state:

$$p_a V = m_a R_a T$$

$$p_g V = m_g R_g T$$

where:

m_a = mass of air, lbm

m_f = mass of liquid water, lbm

m_g = mass of vapor, lbm

$\dot{m}_s$ = rate of spray water, lbm/sec

$\dot{m}_{fg}$ = rate of evaporation, lbm/sec

u_a = internal energy of air, Btu/lbm

u_f = internal energy of liquid water, Btu/lbm

u_g = internal energy of vapor, Btu/lbm

h_f = enthalpy of spray water, Btu/lbm

p_a = partial pressure of air, psi

p_g = partial pressure of vapor, psi

R_a = gas constant of air, ft-lb_f/°R-lbm

R_g = gas constant of vapor, ft-lb_f/°R-lbm

T = temperature of the containment atmosphere, °R

V = volume of the containment, ft^3

The Hamming's modified predictor - corrector method is used to obtain an approximate solution of the equations listed above.(6)

6. After the evaporative cooling phase of the analyses is complete, the pressure - temperature history of the containment in the saturated condition is calculated utilizing the digital computer code CONTEMPT.(5)

Figure 6.2-23 shows the pressure and temperature inside containment as a function of time after start of the containment spray system. As indicated on this curve the resulting peak vacuum calculated is 0.72 psig.

In addition, Figure 6.2-24 shows a curve of initial containment temperature versus relative humidity which results in a peak calculated vacuum of approximately 0.7 psig. This curve is used in establishing plant technical specifications.

As a result of these analyses, a value of 0.8 psi is selected as the design negative pressure differential between the outside atmosphere and containment atmosphere (acting inward on the containment vessel).

The containment vacuum relief system is available for any postulated situation requiring relief of a vacuum inside containment. This would include the rupture of a RWCU line. For this event, the containment vacuum relief isolation valves would initially be closed by high drywell pressure. After initiation of the spray system (due to operator error), differential pressure switches in the containment override the containment isolation signal and open the vacuum relief isolation valves when the pressure in containment has decreased to 0.0 psig. Section 7.3.1 gives details of the instrumentation and logic for this system.

6.2.1.1.4.2.1 Vacuum Breaker Design

Two 24-inch nominal diameter vacuum relief lines are provided to obtain the vacuum relief cross-sectional area required to prevent the negative pressure inside containment from exceeding the design value of 0.8 psi during the hypothetical situations presented in this section. Two additional 24-inch nominal diameter vacuum relief lines are provided for redundancy.

Each vacuum relief line has a 24-inch nominal diameter, free swinging, simple check valve inside containment. This check valve serves as both the vacuum breaker device and the inner isolation valve for the vacuum relief line. Outside containment, each vacuum relief line has a 24-inch nominal diameter motor operated butterfly valve to serve as the outer isolation valve.

A combination of any two vacuum relief lines provides a 10 percent margin between the maximum calculated negative pressure and the design negative pressure. If all four vacuum relief lines are assumed operable (i.e., no failures) this margin is increased to 80 percent. These margins are considered satisfactory for the following reasons:

a. When a design negative pressure differential is selected and an $A/\sqrt{k}$ ratio is calculated, sizing of the vacuum breakers depends entirely upon

the k value used. Precise, tested, k values are available from vacuum relief valve manufacturers. In addition, a 10 percent margin on friction losses is standard in sizing piping systems.

b. The hypothetical situations used in the analyses are very conservative in that they assume during each of the occurrences that the suppression pool is at its minimum design temperature while the containment atmosphere is at its peak temperature.

6.2.1.1.4.2.2 Testing and Inspection

Periodically, each check valve is exercised to ensure that it is in proper working condition. For this purpose, each check valve has an air cylinder for power operated exercising. Testing and inspection of the containment isolation function of the check valves and the outer isolation valves are discussed in Sections 6.2.4.4 and 6.2.1.6.

6.2.1.1.4.2.3 Instrumentation Applications

The vacuum breaker check valves are normally closed. They begin to open under a pressure differential of 0.1 psid and close by gravity. The motor operated outer isolation valves are controlled remote manually from the control room or automatically, as discussed in Section 6.2.4 and Section 7.3.1 and are open during normal plant operation. Position indicators on the vacuum breaker check valves annunciate in the control room if any of these check valves stick open during normal plant operation. If this occurs, the outer isolation valves are closed manually from the control room.

6.2.1.1.5 Steam Bypass of the Suppression Pool

6.2.1.1.5.1 Introduction

The concept of the pressure suppression reactor containment is that any steam released from the primary system is condensed by the suppression pool and does 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 steam released from the primary system to be condensed in the suppression pool. Should a leakage path exist between the drywell and containment, the leaking steam would result in pressurization of the containment. To mitigate the consequences of any steam bypassing the suppression pool, a high containment pressure signal automatically initiates the containment spray system any time after LOCA plus ten minutes. Realignment logic and interlocks affecting operation of containment spray are discussed in Section 7.3.

Sections 6.2.1.1.5.2 through 6.2.1.1.5.5 present 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. In calculating this value, a stratified atmosphere model is used to ensure conservatism.

6.2.1.1.5.3 Analysis

The allowable drywell leakage capacity has been evaluated for the complete spectrum of credible primary system rupture areas. This leakage capacity is expressed in terms of the parameter:

$$A/\sqrt{K}$$

Where:

A = Flow area of leakage path, ft^2.

K = Geometric and friction loss coefficient.

The parameter $A/\sqrt{K}$ is dependent only upon 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, incompressible fluid flow theory to be applicable to the leakage flow, the pressure loss between the drywell and containment can be written as follows:

$$P_d - P_c = K \cdot \frac{V^2}{2g_c} \cdot \frac{1}{144v}$$

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, 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 $\dot{m}$ lbm/sec and the flow area is A ft^2, the above equation can be rewritten to give:

$$\dot{m} = \frac{A}{\sqrt{K}} \sqrt{2g_c \; (P_d - P_c) \left(\frac{144}{v}\right)}$$

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

6.2.1.1.5.4 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 spray and containment heat sinks as means for mitigating the effects of bypass leakage.

The flow rate of one containment spray loop is 5,250 gpm. This flow is assumed to start not sooner than ten minutes after the accident. The suppression pool water passes through the RHR heat exchanger and is injected into the upper containment region. The spray rapidly condenses the stratified steam and, therefore, creates a homogeneous air steam mixture in containment. The available containment heat sinks, listed in Table 6.2-10, were considered with variable convective heat transfer coefficients, based upon the local instantaneous air-steam ratio. The cooldown rate was assumed to be 100°F/hr and the maximum design service water temperature (see Table 6.2-3) was used. The cooldown rate corresponds to the maximum rate which does not thermally cycle the reactor pressure vessel. This analysis results in an allowable drywell leakage capability of $A/\sqrt{K}$ of 1.68 ft^2. The corresponding pressure transient is illustrated by Figure 6.2-25.

Assumptions for allowable bybass calculations using heat sinks are as follows:

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

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

c. Air in containment is compressed by incoming steam.

d. Containment spray is activated 180 seconds after containment pressure reaches 9 psig or at LOCA plus 13 minutes, whichever occurs later.

e. Efficiency of containment spray is based upon the local steam to air ratio.

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

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

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

The following analysis provides an illustration of the methods used to calculate steam condensing capability under typical post LOCA conditions. The condensation capability is calculated using the following equation:

$$\dot{M}_c = \dot{M}_s \left[\frac{N_s(T_c - T_s)}{H_{fg}} \right] C_p$$

Where:

$\dot{M}_c$ = Steam condensation rate, lbm/sec.

$\dot{M}_S$ = Spray flow rate, lbm/sec (degraded flow of one RHR pump).

N_s = Spray efficiency.

T_c = Containment temperature, °F.

T_s = Spray temperature at the nozzles, °F.

H_{fg} = Latent heat of vaporization, Btu/lbm

C_p = Constant pressure specific heat of water, Btu/°F-lbm.

The spray water temperature is calculated from:

$$T_s = T_p - \frac{KHX}{\dot{M}_s} \quad \frac{T_p - T_{sw}}{C_p}$$

Where:

T_p = Suppression pool temperature, °F.
KHX = Heat exchange effectiveness, Btu/sec - °F (degraded).
T_{sw} = Service water temperature, °F.

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

A study of potential cracking of the reinforced concrete drywell due to shrinkage, thermal gradients, seismic events, small breaks and LOCA, and combinations of these has been performed. Reference 4, a report of this study, indicates no significant cracking of the drywell walls. In addition, a 1/4 inch thick inherently leak-tight steel liner is provided on the inside face of the drywell wall (see Section 3.8.3 for further discussion). Also, the Perry drywell is steel - plate lined, assuring negligible bypass leakage through the drywell concrete to the containment.

6.2.1.1.6 Suppression Pool Dynamic Loads

Following a design basis LOCA in the drywell, the drywell atmosphere is rapidly compressed due to blowdown mass and energy addition to the drywell volume. This compression is transmitted to the water in the weir annulus in the form of a compressive wave which propagates through the horizontal vent system into the suppression pool.

Upon pressurization of the drywell, water in the weir annulus is depressed and forced out through the horizontal vent system into the suppression pool. This movement of pool water can result in a vent clearing reaction force on the weir wall and a water jet impingement force on the containment wall.

Following vent clearing, the air-steam-water mixture flows from the drywell through the vents and is injected into the suppression pool. A vent flow reaction load is imparted to the weir wall and a vent flow differential pressure loads the drywell wall.

During vent flow the steam component of the flow mixture condenses in the suppression pool while the air, since it is noncondensible, is released to the suppression pool in the form of high pressure air bubbles. Initial air bubble loads are experienced by all suppression pool retaining and submerged structures.

The continued addition and expansion of air within the suppression pool causes pool volume to swell resulting in acceleration of the pool surface vertically upward. This response of the suppression pool is referred to as bulk pool swell since the air is confined beneath the pool and is driving a solid ligament of water. Bulk pool swell air bubble and flow drag loads are imparted to the drywell and containment walls and to structures, components, etc., which may be located at low elevations above the normal pool surface. Bulk pool swell impact loads also result for low elevation structures and components.

Due to the effects of buoyancy, air bubbles rise faster than the suppression pool water mass and eventually break through the swollen surface and relieve the driving force beneath the pool. This breakup of the water ligament leads to the upward expulsion of a two-phase mixture of air and water and is referred to as pool swell in the froth mode. Structures which are located at higher elevations above the initial pool surface, i.e., the hydraulic control unit (HCU) floors, experience a pool swell froth impingment load due to impact of two phase flow.

In the annular region between the drywell and containment walls where pool swell occurs, a flow restriction exists at the HCU floor level, 27'-2" above the normal pool surface. The volume between the normal suppression pool surface and the HCU level is referred to as the wetwell. During pool swell in the froth mode, passage of the air-water mixture through this restriction generates a two-phase flow pressure drop and produces a wetwell pressurization load on the HCU floors. Froth flow continues until the fluid kinetic energy is expended, followed by fallback of the water to the initial suppression pool level. Water fallback loads are experienced by all previously mentioned structures and equipment in the wetwell.

Following the initial pool swell event, the suppression system settles into a generally coherent phase during which vent flow rates are maintained from the drywell to the suppression pool. A resultant effect is the occurrence of vent flow steam condensation loads on pool retaining structures. As the reactor coolant system inventory of mass and energy is depleted near the end of blowdown, venting rates to the suppression pool diminish, allowing recovering of each row of horizontal vents. During phases of low vent mass flux, the suppression system behaves in an oscillatory manner, referred to as chugging. This periodic clearing and subsequent recovering of vents occurs since the vent flow cannot sustain bulk steam condensation at the vent exit. The resultant local fluctuations in pressure and water level generate chugging oscillation loads, predominantly on the drywell and weir wall.

Pool dynamic loading associated with relief valve operations has been identified in addition to loading associated with the design basis LOCA. Pressure waves are generated within the suppression pool when, upon first opening, relief valves discharge air and steam into the pool water. This phenomenon yields steam vent clearing loads which are imparted to pool retaining and submerged structures. The design basis loads for the containment system due to pool swell and safety/relief valve actuation discussed in Appendix 3A.

6.2.1.1.7 Containment Environment Control

The functional capability of the normal containment ventilation system to maintain the temperature, pressure, and humidity in the containment and subcompartments within prescribed limits (maximum allowable containment conditions) are discussed in Section 9.4.6.

6.2.1.1.8 Post Accident Monitoring

The containment atmosphere monitoring system provides highly reliable instrumentation for detecting and possibly predicting abnormal occurrences in containment and for monitoring following postulated accidents. Temperature and pressure sensors are furnished throughout the containment and drywell and are equipped with adjustable alarm features. Instrumentation channels are of high quality and accuracy so that precise monitoring information is available to the operator. The suppression pool is similarly instrumented for purposes of temperature monitoring.

Monitoring system components are considered to be safety related and are qualified in accordance with IEEE Standards 323(7) and 344(8). Redundant channels are provided and independence is maintained in accordance with the criteria of IEEE Standards 279(9) and 384(10). Redundant Train A and Train B components are used.

Precision trip/calibration units continuously monitor each channel to ensure accurate alarming and inplace calibration at any time.

Recording of all containment atmosphere monitoring safety related channels is accomplished at the post accident monitoring panel in the control room.

Further details concerning the containment atmosphere monitoring system are presented in Section 7.6.

6.2.1.2 Containment Subcompartments

6.2.1.2.1 Design Bases

An analysis of the containment subcompartments containing high energy piping in which breaks are postulated to occur has been performed. The breaks selected for a pressurization analysis are those which release the most energy into the subcompartments.

All of the breaks were assumed to be circumferential in nature. Appropriate restraints were used where applicable to limit the mass release while still producing conservative results.

A margin of 40 percent was added to the maximum calculated pressure differential for use in the structural design of the subcompartment walls and equipment supports.

6.2.1.2.2 Design Features

6.2.1.2.2.1 Analyses Performed

a. Reactor Annulus Pressurization

The reactor annulus was analyzed for a recirculation suction line break and for a feedwater line break. Obstructions considered included feedwater piping, recirculation piping, instrument lines, and inservice inspection pins.

b. Drywell Head Region Pressurization

A six inch reactor core isolation cooling (RCIC) spray line enters the head region of the drywell and is attached to the top of the reactor pressure vessel (see Figure 6.2-26). When this line breaks, the reactor pressure vessel blows down into the head region which is vented to the drywell through six 26 inch holes in the bulkhead member. The six inch RCIC line is not assumed to discharge any liquid since the valve at the reactor pressure vessel head is closed.

c. Reactor Water Cleanup Rooms Pressurization

Four reactor water cleanup rooms, listed below, were analyzed:

1. Heat exchanger room.

2. Filter demineralizer valve room.

3. Filter demineralizer room.

4. Drain valve nest room.

Plan and elevation drawings of the above rooms are provided by Figure 6.2-27.

Blowout panels are incorporated into the design of each of these rooms. Characteristics of these blowout panels are listed in Table 6.2-11. The blowout panels each consist of segmented vertical units 10 inches wide. The weight per unit area was selected so that the effect on the dynamic pressurization of the compartment is minimized. The specified blowout pressure was also chosen to minimize the effect on pressurization time history.

None of the segments constituting the blowout panels become missiles which could jeopardize the safety of significant components since retaining cables are attached to each segment and are securely anchored to the adjacent structure. To assure that the presence of the segments does not retard the depressurization of the rooms by blocking the vent flow path, all anchor cables are attached at the bottoms of the openings.

d. Steam Tunnel Pressurization

The steam tunnel was analyzed for the same break as were the reactor water cleanup rooms. This break was used since the main steam lines are enclosed in guard pipes inside containment. Plan and elevation drawings showing the steam tunnel and the break location are provided by Figure 6.2-27.

6.2.1.2.2.2 Subcompartment Volumes

Volumes of the subcompartments are discussed in Section 6.2.1.2.3.

6.2.1.2.2.3 Vent Areas

Vent areas are discussed in Section 6.2.1.2.3.

6.2.1.2.3 Design Evaluation

The computer code COMPARE[11] was used in all subcompartment analyses, except for the analysis of the reactor annulus. The computer code RELAP4/MOD3[12] was used in the analysis of the reactor annulus.

Initial conditions, along with modal volumes, calculated peak pressure differentials and design pressure differentials, are presented by Tables 6.2-12 through 6.2-16.

Description and justification of flow models using the COMPARE computer code are provided in Reference 11. The reactor annulus description and justification is the compressible flow model as described in Reference 12.

Descriptions of break locations are presented in Section 3.6 and below:

a. Reactor Annulus

   Two breaks were considered as follows:

   1. The recirculation suction line break is assumed to occur at the nozzle of the reactor pressure vessel. A flow diverter is constructed around the recirculation line as shown by Figure 6.2-28. This limits the amount of fluid discharged from the nozzle into the reactor annulus.

2. The feedwater line break is a guillotine break which occurs in the reactor annulus area.

b. Drywell Head Region

The break in the six inch RCIC spray line is at the top of the reactor pressure vessel where the line enters the vessel.

c. Reactor Water Cleanup Rooms

All four reactor water cleanup rooms were conservatively analyzed using the blowdown flow for the same break. The six inch to four inch junction in the RWCU line is the assumed rupture point.

d. Steam Tunnel

The break used in the steam tunnel analysis is the same as that used for the reactor water cleanup rooms.

Nodalization information is as follows:

a. Reactor Annulus

1. A diagram for the recirculation suction line break is provided by Figure 6.2-29. Node 25 is the blowdown node; node 50, containment.

2. Figure 6.2-30 presents a diagram for the feedwater line break. Node 29 is the blowdown node; node 50, containment.

b. Drywell Head Region

The drywell head region model is a two node model. Node 1 is the head region and node 2 is the drywell.

c. Reactor Water Cleanup Rooms

Four reactor water cleanup rooms are modeled as follows:

1. The heat exchanger room is modeled using three nodes: the heat exchanger room, corridor and containment.

2. The filter demineralizer valve room is modeled using three nodes: the filter demineralizer valve room, corridor and containment.

3. The filter demineralizer room model is a two node model: the filter demineralizer room and containment.

4. The drain valve nest room is modeled using three nodes: the drain valve nest room, corridor and containment.

d. Steam Tunnel

The steam tunnel model is a two node model: node 1 is the steam tunnel, node 2 is the containment.

Graphs of pressure differential with respect to time are provided for the subcompartments by the figures indicated:

a. Reactor annulus:

1. Recirculation suction line break, Figures 6.2-31 through 6.2-37.

2. Feedwater line break, Figures 6.2-38 through 6.2-45.

b. Drywell head region, Figure 6.2-46.

c. Reactor water cleanup r oms, Figures 6.2-47 through 6.2-50.

d. Steam tunnel, Figure 6.2-51.

Mass and energy releases used in the analyses are presented in the tables indicated or as stated below:

a. Reactor annulus:

   1. Recirculation suction line break, Table 6.2-17.

   2. Feedwater line break, Table 6.2-18.

b. Drywell head region: flow rate, 390 lb/sec; enthalpy, 1190 Btu/lb.

c. Reactor water cleanup rooms, Table 6.2-19.

d. Steam tunnel: flow rate, 390 lb/sec; enthalpy, 1190 Btu/lb.

Vent loss coefficients for critical flow for the reactor annulus used a factor of 0.6. The K factor was calculated by methods described in Reference 3. Vent loss coefficients for the drywell head region, reactor water cleanup rooms, and steam tunnel were calculated using the computer code COMPARE. Head and friction losses were calculated by methods described in Reference 3.

Tables 6.2-20 through 6.2-24 provide flow path information.

6.2.1.3 Mass and Energy Release Analyses for Postulated Loss of Coolant Accident

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 have been applied to maximize the release.

6.2.1.3.1 Mass and Energy Release Data

Table 6.2-25 provides the mass and enthalpy release data for the recirculation line break. Blowdown steam and liquid flow rates approach zero in approximately 391 seconds and do not change significantly during the remainder of the 24-hour period following the accident. Figure 6.2-52 shows the blowdown flow rates for the recirculation line break. These data were used in the containment pressure-temperature transient analyses discussed in Section 6.2.1.1.3.3.1.

Table 6.2-26 provides the mass and enthalpy release data for the main steam line break. Blowdown steam and liquid flow rates approach zero in approximately 417 seconds and do not change significantly during the remainder of the 24-hour period following the accident. Figure 6.2-53 shows the reactor pressure vessel blowdown flow rates for the main steam line break as a function of time after the postulated rupture. This information was used in the containment response analyses discussed in Section 6.2.1.1.3.3.2.

6.2.1.3.2 Energy Sources

Reactor coolant system conditions prior to the line break are listed in Tables 6.2-4 and 6.2-5. Reactor blowdown calculations for containment response analyses are based upon these conditions during a LOCA.

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

a. Stored energy in the reactor system.

b. Energy generated by fission product decay.

c. Energy from fuel relaxation.

d. Sensible energy stored in reactor structures.

e. Energy being added by the ECCS pumps.

f. Metal-water reaction energy.

All of the above energies, except pump heat energy, are discussed or referenced in this section. The pump heat rate used in evaluating the containment response to the LOCA is selected as an input of 5,267 Btu/sec to the system with all ECCS equipment operating and 3,393 Btu/sec for minimum ECCS equipment operating. 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 is released. The rate of release of core decay heat for the evaluation of the containment response to a LOCA is presented by Table 6.2-27 as a function of time after accident initiation.

Following a LOCA, the sensible energy stored in the reactor primary system metal is transferred to the recirculating ECCS water, and thus, contributes to suppression pool and containment heatup. Figure 6.2-54 shows the variation of the sensible heat content of the reactor pressure vessel and internal structures during a main steam 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 using the model described in Reference 1.

6.2.1.3.4 Effects of Metal-Water Reaction

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

of the generation of hydrogen within containment by metal-water reaction. In evaluating the containment response, 13,439 Btu/sec of heat from metal-water reaction is included for the first 120 seconds. The containment response is insensitive to the reaction time, even for the extremely conservative case where all the energy is included prior to the occurence of peak drywell pressure.

6.2.1.3.5 Thermal Hydraulic Data for Reactor Analysis

Sufficient data to perform thermodynamic evaluations of the containment have been provided in Section 6.2.1.1.3.3 and associated tables, in particular Table 6.2-5.

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

This section is not applicable to PNPP.

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

This section is not applicable to PNPP.

6.2.1.6 Testing and Inspection

Containment testing and inspection requirements are discussed in Sections 3.8.1, 3.8.2, 3.8.3 and 6.2.6. No other special tests of either the drywell or containment structure are planned. Testing and inspection of other engineered safety features inside containment that interface with the containment structures are discussed in those sections which address the specific systems.

6.2.1.7 Instrumentation Requirements

The containment atmosphere monitoring system provides the operator with precise alarming, indicating, and recording of the drywell and containment atmospheric conditions and suppression pool temperature before, during, and after a design basis accident. Additional details concerning the containment atmosphere monitoring system are provided in Section 7.6.

The drywell and containment vacuum relief system continuously monitors the drywell/containment and containment/atmosphere differential pressures and initiates automatic valve actuation as required. Redundant instrumentation is provided. Additional details concerning this system are presented in Section 7.3.

The combustible gas control system provides redundant hydrogen analyzers to monitor post accident containment hydrogen concentration. Additional details concerning the hydrogen analyzers are provided in Sections 6.2.5 and 7.3.

The plant and area radiation monitoring system provides indication of containment ventilation exhaust and area radiation levels. Alarms are also provided. Details concerning radiation monitoring are provided in Sections 11.5 and 12.3.4.

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 suppression pool cooling system meets the following safety design bases:

a. The system limits the long term bulk temperature of the suppression pool to 185°F without spray operation when considering the energy additions to the containment following a LOCA. These energy additions, as a function of time, are provided in Section 6.2.1.3.

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 maintains 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 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. The return flow penetrates containment through 18 inch lines at elevation 603'-6" which is 10'-2" above normal water level. After penetrating containment, the return line descends vertically to elevation 588'-6" where it turns and discharges horizontally into the pool. Physical model testing of the suction and discharge arrangement was performed to assure adequate mixing of the return water with the total suppression pool inventory. Plan and section views are shown on Figures 6.2.-55 and 6.2-56.

Water from the emergency 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 discussed in Section 5.4.7.

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 (Section 6.2.1); the RHR pumps are operating.

Containment cooling is initiated in loop A or B by manually starting the emergency service water pump, closing the heat exchanger bypass valve, opening the service water valve at the heat exchangers, closing the LPCI injection valve and opening the pool return valve.

If a single failure 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 close the LPCI injection valves and open the spray valves. The containment spray mode is also initiated automatically on high containment pressure, with an interlock to delay initiation until ten minutes after a high drywell pressure signal. Automatic initiation is provided to protect the containment in the event of suppression pool bypass leakage as is described in Section 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 containment spray header. A sample of the nozzles are bench tested for flow rate versus pressure drop to evaluate the original hydraulic calculations. Finally, the headers are tested by air and visually inspected to verify that all nozzles are clear. Refer to Section 5.4.7.4 for further discussion of preoperational testing.

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.

The suction piping strainers from the suppression pool are specified with 0.070 inch mesh openings capable of screening all foreign particles which are of sufficient size to clog the containment spray nozzles, which have 3/8 inch orifices. The total strainer area is selected so that in the event the strainer becomes 50 percent plugged, the minimum required NPSH is still provided to the RHR pumps during LPCI and suppression pool cooling modes. The large strainer area also results in low approach velocity to the strainer of approximately 1.0 ft/sec at a design rated flow of 8,500 gpm.

The strainers are conically shaped and are constructed from stainless steel plate with 0.070 inch openings. With the horizontal orientation of the strainers, the centerline distance from the strainer to the suppression pool floor is approximately 3'-9".

The mechanism for transport of any insulation from the drywell into the containment suppression pool following an accident involves a series of unlikely 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.

b. Metal-jacketed fiberglass blanket (Nu"K"on) for all hot piping and equipment.

Metal-reflective insulation is installed in sections with overlapping edges and quick release latches with keepers.

Metallic jacketed fiberglass blanket insulation is installed in two-foot sections with VELCRO fasteners on the longitudinal seam for ease of installation and removal. The blanket is jacketed with a separate stainless steel sheath combining quick release latches and closure handles.

If a postulated pipe break (LOCA) occurs, some insulation in the immediate vicinity of the break could possibly be removed by direct jet impingement. Only sections in the immediate vicinity of the break would likely be affected. The metal jacket minimizes the possibility of the non-metallic insulation breaking up and becoming transportable debris. Any metal components removed would likely fall to the drywell floor or weir annulus floor and remain there throughout the accident.

If any insulation breaks away from the piping or equipment, the insulation would most probably fall to the drywell floor. The surface area of the weir annulus is very small when compared to the area of the drywell and only a small percentage,

if any, of the insulation would enter the weir annulus. If any insulation that falls to the drywell floor floats when the water level rises in the lower drywell region, the weir wall will act as a skim to prevent the insulation from entering the weir annulus. Entrance of insulation into the weir annulus is also partially restricted by the main steam relief valve discharge piping (uninsulated) in the vicinity.

The velocity of water down through the weir annulus and out through the horizontal vents is less than 0.2 ft/sec. Therefore, most of the metal jacketed insulation that might enter the weir annulus will sink to the floor of the annulus and remain there throughout the accident. If any part of the insulation entering the annulus were to float, it is very unlikely that the insulation would be drawn downward and out through the vents by the ECCS suction lines.

As previously outlined, the probability of transporting insulation into the suppression pool is extremely low. If any insulation were to become entrained in the flow through the horizontal vents (at a flow velocity of less than 0.2 ft/sec), the insulation would float to the surface of the pool or sink to the floor of the pool as the insulation exits from the vents. The insulation would not be close to the suction strainers since the ECCS suction strainers are located about 19 to 20 feet out from the drywell wall, about 10 feet below the post LOCA pool level, and about 4 feet above the suppression pool floor. Since the inlet design velocity through the strainer is only 1.0 ft/sec, the possibility for any insulation to migrate toward the strainers and cause clogging is virtually nonexistent.

A complete DBA analysis of the interaction of the Nu"K"on insulation with the ECCS systems is presented in Owens-Corning Topical Report OCF-1.

6.2.2.3 Design Evaluation

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 45°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.

To evaluate the adequacy of the RHR system, the following sequence of events is assumed to occur:

a. The reactor initially operating at 102 percent of rated 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 item b., above.

d. After 30 minutes 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.

NPSH requirements of Regulatory Guide 1.1 are found in Section 6.3.2.2.

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 emergency 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 Section 6.2.1.1.3.3.1 and is shown in Figures 6.2-7 and 6.2-8. Even with the degraded conditions outlined above, the maximum temperature is only 174°F, which is below the design limit specified in Section 6.2.2.1.

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 Section 6.2.1.3. Figure 6.2-9 shows the actual heat removal rate of the RHR heat exchanger.

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

6.2.2.4 Tests and Inspections

The preoperational test program of the containment cooling system is described in Section 6.2.2.2. Operational testing is discussed in Section 5.4.7.4.

6.2.2.5 Instrumentation Requirements

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

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

6.2.3.1 Design Bases

The secondary containment system includes the shield building and the annulus exhaust gas treatment system (AEGTS). Details of the AEGTS are given in Section 6.5.3. The following are the design bases for the shield building:

a. The shield building is designed to collect the fission product leakage during and following a postulated design basis accident from the primary containment and delay it until it can be released to the environs after processing through the annulus exhaust gas treatment system such that the resultant offsite doses are less than the values set forth in 10 CFR 100 and 10 CFR 50, General Design Criterion 19.

b. The shield building is designed to withstand the peak transient pressures and temperatures which could occur due to the postulated design basis accident.

c. The shield building is designed as a Seismic Category I structure.

d. The shield building is maintained at a slight negative pressure relative to atmospheric pressure (approximately 0.40 inch water gage) so any leakage through the shield building or the containment vessel is into this space.

e. The design loads on the shield building are discussed in Section 3.8.1.

f. The leak tightness of the shield building is continually verified by maintaining the annulus at a vacuum of 0.40 inch water gage. This constitutes a continuous testing program. Inspection of the secondary containment structure will not be necessary as long as a vacuum can be maintained through normal operation of plant equipment.

6.2.3.2 System Design

The shield building is a cylindrical reinforced concrete structure with a spherical dome enclosing the containment vessel. The internal diameter is 130 feet and the outside diameter is 136 feet. There is an annulus width of five feet between the containment vessel and the inside of the shield building. Figures 3.8-53 through 3.8-63 show plan and elevation views of the shield building.

There are two doors allowing access to the annulus area, both of which are normally locked. They are provided with position indicators and alarms which annunciate in the control room.

A tabulation of the design and performance data for the shield building is provided in Table 6.2-28.

The performance objective of the shield building is to collect and retain any fission product leakage from the containment vessel during and following a design basis accident and in conjunction with the annulus exhaust gas treatment system process and release the fission products to the environs in a controlled manner. This release is accomplished such that the resultant offsite doses to the general public are within the values given in 10 CFR 100 and the doses to the control room operators are within the values given in 10 CFR 50, General Design Criterion 19.

The principal construction codes, standards, and guides used in the design of the shield building are described in Section 3.8.1.

In order to minimize the amount of radioactive material that leaks to the secondary containment following a design basis accident, all primary containment penetrations are provided with redundant, ASME Code, Section III, Class 2, Seismic Category I isolation valves, one inside of the primary containment and one outside of the shield building. The section of pipe between the two containment isolation valves is also ASME Code, Section III, Class 2. This isolation valve arrangement functions to prevent "through-line" leakage because in the event of any single failure, no through-line leakage beyond the AEGTS is possible. The containment isolation system is discussed in Section 6.2.4. The containment and reactor vessel isolation control system is discussed in Section 7.3.1.

The containment boundary and all penetrations except for penetrations with guard pipes terminate in the annulus. Therefore, containment shell leakage and penetration leakage are considered to be totally directed to the annulus. The sources listed in Table 6.2-33 are a summary of potential leakage paths that could bypass the AEGTS. The containment design basis accident leakage is 0.2 percent by weight of the contained atmosphere in 24 hours. The maximum test leakage rate permitted from the sources listed in Table 6.2-33 is 3 percent of the total containment leakage. This value will be the technical specification commitment for leakage bypassing the AEGTS as listed in technical specifications. In order to verify that the total amount of potential bypass leakage will be within this limit, a testing and evaluation program will be conducted on isolation valves, personnel airlocks and guard pipes as described in Section 6.2.4.3.1.

6.2.3.3 Design Evaluation

All high energy lines which penetrate the containment wall and the shield wall are protected by guard pipes, with the exception of the control rod drive hydraulic supply. See Table 6.2-33. The CRD supply is a 2-1/2 inch water line with a normal operating pressure of 1,850 psi.

The justifying logic allowing postulation of pipe rupture locations in other high energy lines penetrating the containment which require guard pipe protection does not apply to this line. Guard pipes are used where the energy release rate of the postulated accident is such that the resulting pressurization must be confined to the drywell rather than allowed to pressurize the containment volume directly. The energy release rate of an 1,850 psi fluid at a maximum of 140°F does not require that it be diverted from either the containment volume or from the annulus volume. Release of such a fluid within the containment volume will not prevent the AEGTS from performing its function, since pressurization of the volume does not result.

In the case of high energy lines whose postulated rupture would jeopardize containment design pressure capacity, the pipe break location criteria in MEB 3-1 were suspended and additional breaks postulated which could pose a hazard. Since the consequences of a 2-1/2 inch CRD line rupture are not significant with respect to hazard, the criteria of MEB 3-1 apply and no rupture is postulated to occur within the penetration. Due to line size being under 4 inches nominal, no longitudinal splits are considered to occur but circumferential ruptures only.

The postulation of a rupture in the 2-1/2 inch line at either end of the penetration will not jeopardize the integrity of the penetration. A break inside the containment structure will only load the penetration axially. Any break outside of the shield building will not load the penetration at all since no flow issues from the containment side of such a rupture, but from the pump side only.

An analysis of the pressure response profile in the shield building annulus following the design basis was performed using a modified version of the CONTEMPT[5] Computer Code.

The following methods and assumptions were used in calculating the pressure response:

a. During a LOCA, the containment vessel will expand. It is included in the analysis by assuming that the volume expansion takes place linearly as a function of time until it reaches the maximum value corresponding to the time of the maximum containment temperature during the accident as shown in Figure 6.2-8.

b. The annulus exhaust fan is conservatively assumed to purge at a rate of 600 cfm to the environment.

c. The containment vessel and shield building were the only heat conducting structures considered in the analysis. Conservative valves are summarized as follows:

Description	Material	Surface Area (ft^2)	Thickness (ft)
Containment Vessel	Carbon Steel	73,000	0.0833
Shield Building	Concrete	73,000	3.00

d. The total heat transfer coefficient was assumed to be the same on both faces of the containment vessel and is given as the sum of the convective film coefficient and the radiation coefficient.

In the case of the inside film coefficient, it was conservatively assumed that the containment atmosphere temperature is as given in Figure 6.2-8 and the containment vessel temperature was 90°F. For the outside film coefficient it was conservatively assumed that the containment vessel

temperature equals the containment atmosphere temperature and the annulus air temperature was 90°F. These assumptions result in the maximum coefficients in both cases.

The convective film coefficient is given by (Reference 13):

$$h_c = 0.3 \sqrt[4]{\Delta T}$$

where:

h_c = convective film coefficient, Btu/hr/ft^2/°F

and ΔT = temperature difference, °F

The resultant convective film coefficients are given in Table 6.2-29.

The radiation coefficient is given by (Reference 13):

$$h_r = \varepsilon_1 \varepsilon_2 \, S \, \theta \, \frac{T_1^4 - T_2^4}{T_1 - T_2}$$

where:

h_r = radiation coefficient, Btu/hr/ft^2/°F

ε_1 = emissivity of steel = 0.7

ε_2 = emissivity of air = 1.0

θ = Stephan-Boltzman constant, .174 x 10^{-8} Btu/hr/ft^2/°R^4

T_1 = higher temperature, °F

T_2 = lower temperature, °F

S = shape factor = 1.0

The radiation coefficients are given in Table 6.2-30 and assume the same relative temperatures used in calculating the convective film coefficient.

The overall heat transfer coefficient as a function of time is shown in Table 6.2-31.

For the purposes of calculating the annulus pressure response, a heat transfer coefficient of 2.0 Btu/hr/ft^2/°F was conservatively assumed for the duration of the accident.

e. A schematic diagram of the model input into CONTEMPT is presented in Figure 6.2-57.

The results of the annulus pressure response are presented in Figures 6.2-58 and 6.2-59. As shown on these figures the annulus exhaust fans are more than adequate to maintain negative pressure in the annulus following a DBA-LOCA.

6.2.3.4 Tests and Inspections

The program for test and inspection of the containment isolation system is described in detail in Sections 6.2.4 and 6.2.6. The program for the annulus exhaust gas treatment system is described in Section 6.5.3.

6.2.3.5 Instrumentation Requirements

Design details and logic of the instrumentation for the AEGTS are given in Section 7.3.1.

6.2.4 CONTAINMENT ISOLATION SYSTEM

6.2.4.1 Design Bases

The design objective for the containment isolation systems is to allow normal or emergency passage of fluids through the containment boundary while preserving the ability of the boundary to prevent or limit the escape of fission products that

may result from postulated accidents so that site boundary dose guidelines specified by 10 CFR 100 are not exceeded. This objective is achieved by provisions for automatic isolation of appropriate lines that penetrate the containment boundary.

The containment isolation systems are automatically actuated by the following signals:

a. Low reactor pressure vessel water level (two setpoints).
b. High drywell pressure.
c. High main steam line space temperature.
d. High radiation in steam line.
e. High main steam line flow.
f. Low main steam line pressure at turbine inlet.
g. High reactor building ventilation exhaust radiation.

The containment isolation systems can also be manually actuated from the control room. After initiation of containment isolation, either automatically or manually, the function goes to completion.

Upon receipt of signals indicating low reactor pressure vessel water level or high drywell pressure, all containment isolation valves in systems not required for emergency shutdown are closed. These signals also activate systems associated with emergency core cooling.

Those fluid penetrations that support systems not required for emergency operation are closed by the containment isolation systems. Fluid penetrations that support engineered safety feature (ESF) systems have remotely operated isolation valves that may be closed from the control room if required.

The isolation criteria for determination of quantity, type, and location of containment isolation valves for a particular system generally conform to the requirements of General Design Criteria (GDC) 54, 55, 56, and 57 and comply with the recommendations of Regulatory Guide 1.11.

Redundancy and physical separation are required in the electrical and mechanical design of the systems to ensure that no single failure in the containment isolation systems prevents performance of the intended functions. Protection of system components from missiles and from the effects of postulated high and moderate energy line breaks is also a design consideration.

Instrument lines that penetrate the containment boundary conform to the requirements of GDC 55 and 56 and comply with the recommendations of Regulatory Guide 1.11.

Containment isolation valves and associated piping and penetrations satisfy the requirements of the ASME Code, Section III, Class 1 or Class 2, as applicable. These components are also Seismic Category I. Classification of systems and equipment is presented by Table 3.2-1.

Upon loss of instrument air, air operated containment isolation valves fail in the position required for containment isolation. Closure times and leak tightness of containment isolation valves are sufficient to ensure that site boundary dose guidelines specified by 10 CFR 100 are not exceeded following a postulated accident. A capability for rapid closure of all lines provides a containment barrier within the lines that is sufficient to maintain leakage within permissible limits.

6.2.4.2 System Design

6.2.4.2.1 General

A summary of containment isolation valves is presented by Table 6.2-32. Each valve is described, including penetration number, applicable GDC or regulatory guide, fluid system, fluid, line size, valve arrangement, location, valve type, actuation mode, valve position, initiating signal, power source, etc. Figure 6.2-60 illustrates the various containment isolation valve arrangements.

Justification for containment isolation provisions which differ from the requirements of GDCs is presented in Section 6.2.4.2.2.

Containment isolation valve closure times (see Table 6.2-32) are established to prevent radiological effects from exceeding the guidelines specified by 10 CFR 100. A discussion of valve closure times, for those valves through which a direct path from containment to the environment could exist is provided in Chapter 15. Containment isolation for such lines is accomplished in accordance with NRC Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations." Additional discussion of Branch Technical Position CSB 6-4 is presented in Section 6.2.4.2.3.

Instrument lines which penetrate containment comply with the recommendations of Regulatory Guide 1.11. A power operated remotely controlled isolation valve is provided just outside containment. Instrument lines which penetrate both containment and drywell have a similar arrangement. A motor operated isolation valve is provided just outside containment. Details of these arrangements are illustrated by Figure 6.2-60.

Inside containment each instrument line is either sized to adequately restrict flow or is provided with a 0.25 inch orifice as close to the beginning of the line as possible. In some cases a power operated valve is provided inside containment in lieu of a flow restriction.

Quality standards for containment isolation systems follow the recommendations of Regulatory Guide 1.26. Additional discussion of Regulatory Guide 1.26 is presented in Section 3.2.2. Seismic classification is in accordance with the recommendations of Regulatory Guide 1.29. Additional discussion of Regulatory Guide 1.29 is presented in Section 3.2.1. Table 3.2-1 addresses classification of specific systems and equipment.

Containment isolation valve, actuators, and controls are protected against damage from missiles, jet impingement, and pipe whip. Potential sources of missiles and jet forces and locations of postulated pipe breaks are evaluated. Where potential hazards exist, protection is provided by physical separation, missile or jet shields, etc. These valves are located either inside containment or inside the auxiliary building. Both of these structures are designed to satisfy Seismic Category I requirements and the turbine missile design criteria stated in

Section 3.5. To prevent debris from entering lines and obstructing valve closure, screens are provided on the open ends of lines through which a direct path from containment to the environment could exist.

Isolation valves are designed to be operable under the most adverse environmental conditions, such as maximum differential pressures, extreme seismic occurrences, steam laden atmosphere, high temperature, and high relative humidity. Normal and accident environmental conditions, for which the containment isolation valves and associated electrical equipment are designed, are discussed in Section 3.11. Also, where necessary, a dynamic system analysis to determine the effects of rapid valve closure under operating conditions is required by the design specifications for piping systems associated with containment isolation valves. The valve operability assurance program for active, safety related valves is discussed in Section 3.9.

Electrical redundancy is provided for power operated valves. Power for the operation of two isolation valves in a line (inside and outside containment) is supplied from two redundant, independent power sources without cross ties. In general, isolation valves outside containment are powered from the Division 1 power supply while isolation valves within containment are powered from the Division 2 power supply. Both Division 1 and Division 2 valves are generally powered from a-c power sources. Loss of power to each motor operated valve is annunciated.

Provisions for detecting leakage from remote manually controlled systems are discussed in Section 5.2.5. Detection of leakage from containment is discussed in Section 6.2.6. Section 6.7 describes the main steam isolation valve leakage control system.

The fraction of total containment leakage following a design basis accident/ LOCA that could bypass the containment annulus exhaust gas treatment system is limited to the leakage from sources which constitute open systems or nonsafety related systems. Safety class systems which are open systems are considered. For example, it is assumed, for nonsafety related systems, that the only portion of such a system remaining following a seismic occurrence would be the containment

isolation valves and the piping between these valves. Additional leakage sources considered are the personnel airlocks and containment penetrations with guard pipes.

The containment boundary is surrounded by the annulus. Containment penetrations, except those with guard pipes, terminate in the annulus. Therefore, containment shell leakage and penetration leakage are totally directed into the annulus.

Containment design basis accident leakage is 0.2 percent, by weight, of the contained atmosphere in 24 hours. The maximum permitted leakage rate from potential sources listed in Table 6.2-33 is 4 percent of the total containment leakage. The maximum allowable combined test leakage rate from potential sources listed in Table 6.2-33 is 3 percent (0.75 times 4 percent) of the total containment leakage. This value is the technical specification commitment for leakage bypassing the containment annulus exhaust gas treatment system.

To verify that the total amount of potential bypass leakage is within the established limit, the following test and evaluation program will be conducted:

a. Isolation Valves

   Since it is assumed that nonsafety related systems outside the containment isolation valves will not remain intact following a seismic occurrence, containment atmosphere must terminate at the outer containment isolation valve seat. The same effect is possible for open ended safety class systems. To assure that this potential source of leakage is checked, isolation valves listed in Table 6.2-33 are included in the periodic "Type C" test program discussed in Section 6.2.6. Basically, the test method requires application of containment design pressure to the reactor side of the isolation valve seat being tested while the valve is fully closed and the outer side of the valve is vented. By measuring the time related pressure decay or by directly measuring the leakage flow rate, each valve is quantitatively evaluated for leak tightness.

b. Guard Pipes

The basic configuration for guard pipes is to have one end open to the drywell and the other end welded closed to the process pipe outside the shield building. The primary potential leakage path is at the outer end closure welds. Secondary leakage paths may exist through discontinuities in the guard pipe material. Leakage testing is performed concurrently with the initial containment integrated leak rate test. Guard pipe leakage is detected by application of a soap bubble solution to 100 percent of the exposed guard pipe surface outside the shield building, including all weld connections. Any leak detected as a result of bubble formation will be eliminated (i.e., no detectable leakage) by performing the appropriate repair procedure. This test will be repeated each time a "Type A" test (containment integrated leak rate test) is performed (see Section 6.2.6).

c. Personnel Airlocks

Containment atmosphere could potentially bypass the annulus exhaust gas treatment system by leaking past the double seals on each door of the personnel airlocks. Verification that this leakage does not exceed established limits is obtained periodically by the performance of "Type B" leak tests (see Section 6.2.6). In addition, a test of the leak tightness of the volume between the double seals is performed after each use of an airlock, except when the airlock is being used for multiple entries, then at least once per 72 hours. By using the pressure decay method or leakage flow rate method, the actual leakage rate through the seals can be determined.

Results of "Type B" and "Type C" testing are used to determine whether the 3 percent limit has been met.

Tests or analyses are also performed to demonstrate that the purge isolation valves function as specified. These are as follows:

a. Necessary prototype tests and/or analyses to satisfy the recommendations of Regulatory Guide 1.48 relative to demonstrating the operability of the equipment under the specified loading combination.

b. Hydrostatic test of the valve body in accordance with the ASME Code, Section III.

c. Leak test of the valve assembly at maximum operating pressure in accordance with applicable requirements of Appendix J to 10 CFR 50.

d. Valve operator performance test for closure speed under maximum operating pressure.

All systems penetrating containment can be isolated by remote manual action from the control room if necessary. Discussions of individual system isolation are presented in the sections which address the specific systems.

In the event of valve power failure, motor operated containment isolation valves remain "as is". Air operated valves (except air testable check valves) close upon loss of air.

Main steam line isolation valves are spring loaded, pneumatic, piston operated globe valves, designed to fail closed upon loss of air pressure or loss of power to the solenoid operated pilot valves. Each main steam isolation valve is served by two independent pilot valves, each of which is powered from an independent source. In addition, each main steam isolation valve is equipped with an air accumulator to assist in valve closure in the event of loss of air, loss of electrical power to the pilot valves, and/or failure of the valve spring. The separate and independent action of either air pressure or spring force is capable of closing a main steam isolation valve.

Both pneumatic and motor operated containment isolation valves have two sets of status lights to indicate open or closed position. One set of lights is at the control switch in the control room. The other set is on the control room isolation status panel. Position of manual isolation valves is maintained by means of locking devices and/or administrative controls.

The containment isolation valves are designed in accordance with the requirements of Section III of the ASME Code.

6.2.4.2.2 Justification of Differences from General Design Criteria

The GDCs were not established specifically for BWR plants; rather, these criteria are intended to guide the design of all water cooled nuclear power plants. As a result, the GDCs are generic in nature and subject to a variety of interpretations. For this reason some cases exist where there is no "one-to-one" correspondence between the applicability of an individual GDC and plant design. In such cases, GE has developed a design that meets the intent of the criteria.

The isolation criteria within the GDCs contain clauses, such as, "unless it can be demonstrated ... on some other defined bases", which allows for an alternate design with reliability and performance capabilities that reflect the importance to safety of isolating the piping systems.

Such alternates are described in Sections 6.2.4.2.2.1 through 6.2.4.2.2.3. The final measure by which GE is assured that the BWR design is in agreement with the GDCs is receipt of the Advisory Committee on Reactor Safeguards (ACRS) letters permitting construction and operation of previous plants with comparable valving arrangements.

6.2.4.2.2.1 Justification with Respect to General Design Criterion 55

The reactor coolant pressure boundary, as defined in 10 CFR 50, Section 50.2 (v), consists of the following: reactor pressure vessel; pressure retaining appurtenances attached to the vessel; valves, and pipes which extend from the reactor pressure vessel to, and including, the outermost isolation valve. The lines of the reactor coolant pressure boundary which penetrate containment are capable of isolating the containment, thereby precluding any significant release of radioactivity. Similarly, for lines which do not penetrate containment, but which do comprise a portion of the reactor coolant pressure boundary, the design ensures that isolation of the reactor coolant pressure boundary can be achieved. Items a, b, and c, below, address influent lines, effluent lines, and conclusions with respect to GDC 55, respectively.

a. Influent Lines

Influent lines which penetrate containment and the drywell directly to the reactor coolant pressure boundary are equipped with at least two isolation valves. One valve is inside the drywell; the second, as close as possible to the external side of containment. These isolation valves protect the environment. Where needed, protection of the containment in the event of pipe rupture outside the drywell but within containment is further insured by extension of the drywell by use of guard pipes. These guard pipes, together with the isolation valves, assure protection in the event of an active failure between drywell and containment. Table 6.2-34 lists those influent lines that comprise part of the reactor coolant pressure boundary and penetrate containment. The purpose of this table is to summarize the design of each line with respect to the requirements of GDC 55. Items 1 through 8, below, demonstrate that, although a word for word comparison with GDC 55 is not always practical, it is possible to demonstrate adequate isolation provisions on some other defined basis.

1. Feedwater Lines

Feedwater lines are part of the reactor coolant pressure boundary since they penetrate both the containment and drywell and connect to the reactor pressure vessel. Each line includes three isolation valves and is enclosed in a guard pipe.

The isolation valve inside the drywell is a check valve. The other two isolation valves are outside containment. An air operated check valve is located as close as possible to the outside containment wall. The outermost valve is a motor operated gate valve.

Extension of the drywell by means of the guard pipe protects the containment from overpressurization in the event of a feedwater line break between the drywell and containment walls. The internal design temperature and pressure for the guard pipes which enclose the feedwater lines are the same as the design valves specified for the enclosed feedwater lines.

Should a break occur in a feedwater line, the inside check valve prevents significant loss of reactor coolant inventory and provides immediate isolation. The outermost motor operated valve does not close automatically upon occurrence of a protection system signal since, during a LOCA accident, maintenance of reactor coolant makeup from all sources is desirable. This valve, however, can be remotely closed from the control room to provide long term leakage protection when, in the judgement of the operator, continued makeup from the feedwater system is no longer necessary.

2. High Pressure Core Spray Line

The high pressure core spray line penetrates both the containment and the drywell and connects to the reactor pressure vessel. Isolation is provided by an air testable check valve inside the drywell and a motor operated block valve as close as possible to the outside of the containment wall. This block valve maintains long term leakage control. Position indication for the air testable check valve is provided in the control room. The block valve is automatically and remote manually operated. A guard pipe is not necessary since influent high pressure core spray fluid is at such a low energy level during system operation that containment overpressurization cannot result should the line break between the containment and the drywell.

3. Low Pressure Core Spray and Low Pressure Coolant Injection Lines

Isolation of the low pressure core spray and low pressure coolant injection system lines is accomplished by use of an air testable check valve and a motor operated block valve. The check valve is located as close as possible to the reactor vessel and is normally closed. This valve protects against containment overpressurization in the event of a line break between the check valve and the containment wall by preventing high energy reactor coolant from entering containment. The block valve located outside containment is automatically and remote manually operated and is also normally closed. The block valve is

automatically opened at the appropriate time to assure that acceptable fuel design limits are not exceeded during LOCA. A guard pipe is not necessary since system fluid energy during operation is sufficiently low to preclude the possibility of containment overpressurization should a break occur.

4. Control Rod Drive System Lines

The control rod drive system, located between the reactor pressure vessel and containment, includes two types of influent lines: the supply line that penetrates containment; and the insert and withdraw lines that penetrate the drywell.

Isolation of the supply line is accomplished by a check valve inside containment and a remote manually actuated motor operated block valve as close as possible to the outside of the containment wall.

The insert and withdraw lines are not part of the reactor coolant pressure boundary since these lines do not communicate directly to reactor coolant. The basis upon which these lines are designed is commensurate with the importance to safety of maintaining the pressure integrity of these lines. The classification of these lines is Quality Group B and they are designed in accordance with the ASME Code, Section III, Class 2.

In the design of the control rod drive system, it has been accepted practice to omit automatic valves for isolation purposes since inclusion of such a valve would introduce a possible failure mechanism into the shutdown (scram) function. Manual shutoff valves are provided for isolation. In the event of a break in these lines, the manual valves provide isolation capability. In addition, a ball check valve 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 contaiment since these lines contain small volumes of fluids, resulting in relatively small blowdown masses.

5. Residual Heat Removal Head Spray and Reactor Core Isolation Cooling Lines

The residual heat removal head spray and reactor core isolation cooling lines join outside containment to form a common line which penetrates both the containment and the drywell and connects to the reactor pressure vessel. An air testable check valve is provided inside the drywell as close as possible to the reactor pressure vessel. Two valves, a check valve and a remote manually actuated, motor operated block valve, are located outside containment in each line. The line is also enclosed in a guard pipe.

The air testable check valve inside the drywell is normally closed. The check valves outside containment assure immediate containment isolation in the event of a line break. The block valve in each line is manually actuated to provide long term leakage control.

The guard pipe provides protection against containment overpressurization in the event of a line break between the drywell and containment walls. Should the check valve inside the drywell fail coincident with a line break, the guard pipe would direct the released fluid into the drywell.

Position indication lights are provided in the control room for each of the air testable check valves inside the drywell.

6. Standby Liquid Control Line

The standby liquid control system is located between the containment and the drywell. The standby liquid control line penetrates the drywell and connects to the reactor pressure vessel. Isolation is provided by a check valve inside the drywell and a check valve and explosive valve outside the drywell. The explosive 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. Since the standby liquid control line is

normally an isolated, nonflowing line, rupture is extremely improbable. However, should a break occur subsequent to actuation of the explosive valve, the check valves ensure isolation.

7. Residual Heat Removal Shutdown Cooling Return Lines

The residual heat removal shutdown cooling return lines discharge into the feedwater line between the air operated check valve and the motor operated block valve outside of containment. A check valve and a normally closed, motor operated, remote manually actuated gate valve provide for isolation of the residual heat removal shutdown cooling return lines.

8. Reactor Water Cleanup System Line

The discharge line from the reactor water cleanup pumps penetrates containment and serves the reactor water cleanup regenerative heat exchangers inside containment. Automatically actuated motor operated block valves, one inside, one outside containment, provide for isolation.

b. Effluent Lines

Effluent lines that form part of the reactor coolant pressure boundary and penetrate containment and/or the drywell are equipped with at least two isolation valves. One valve is inside the drywell, the other outside, but as close as possible to, the containment. Where needed, the containment is protected, in the event of a pipe rupture outside of the drywell but inside containment, by guard pipes which enclose the process lines, forming an extension of the drywell. This combination of isolation valves and guard pipes assures protection in the event of a failure between drywell and containment walls.

Table 6.2-35 lists those effluent lines that comprise part of the reactor coolant pressure boundary and that penetrate containment and/or the drywell. Items 1 through 4, below, address specifics of these lines.

1. Steam Lines

Steam lines include main steam, main steam drain, residual heat removal, and reactor core isolation cooling steam lines.

The main steam lines from the reactor pressure vessel to the turbine penetrate both drywell and containment. Main steam line drains (one for each main steam line) in the drywell are headered together to form one line which penetrates both drywell and containment. Isolation for the main steam lines and main steam drain line is provided by automatically actuated block valves, one inside the drywell and one outside containment.

The residual heat removal steam supply and reactor core isolation cooling turbine steam line branches from the main steam line inside the drywell. Isolation for this line is provided by normally open, remote, manually actuated, motor operated block valves, one inside the drywell, one outside containment.

Use of guard pipes to enclose these steam lines prevents containment overpressurization in the event of line break between the drywell and containment walls. The internal design temperature and pressure for the guard pipes which enclose these steam lines are the same as the design values specified for the enclosed lines.

2. Reactor Water Cleanup Lines

The reactor water cleanup pumps are located outside containment; the heat exchangers and filter demineralizers, inside containment, but outside the drywell. The reactor water cleanup pump suction line from the reactor recirculation system lines and the reactor bottom head penetrates the drywell and containment. Two automatically actuated, motor operated valves provide for isolation of this line. One valve is just inside the drywell; the other, outside containment. A guard pipe encloses the line between the drywell and containment walls.

The reactor water cleanup pump discharge line to the heat exchangers and filter demineralizers penetrates containment. Two automatically actuated, motor operated valves (one inside and one outside containment) provide for isolation of this line.

A blowdown line from the filter demineralizers penetrates containment and divides to form separate lines to the condenser and radwaste system. Automatically actuated, motor operated block valves, one inside and one outside containment, provide for isolation of this line.

The return line from the filter demineralizers penetrates containment and connects to the feedwater line between the containment wall and the air operated (feedwater) check valve. Two automatically, actuated, motor operated block valves provide for isolation of this line. One valve is inside, the other outside of containment.

3. Residual Heat Removal Shutdown Cooling Line

The residual heat removal shutdown cooling line branches from the B reactor recirculation loop and penetrates both the drywell and containment. Normally closed, remote manually actuated, motor operated valves, one inside the drywell, one outside containment, provide for isolation of this line. A guard pipe encloses this line from the drywell wall to the containment wall to protect against containment overpressurization in the event of a line break.

4. Recirculation System Sample Line

A sample line from the recirculation system penetrates the drywell. This line is 3/4 inches in diameter and is designed in accordance with the requirements of the ASME Code, Section III, Class 2. A sample probe with a 1/8 inch diameter hole is located inside one recirculation discharge line within the drywell. In the event of a line break, this probe acts as a restricting orifice and limits escaping fluid flow. Two air operated valves which fail closed are provided for isolation of this line. One valve is inside containment; the other, outside.

c. Conclusions Concerning General Design Criterion 55

To assure protection against the consequences of accidents involving the release of radioactive material, piping which forms portions of the reactor coolant pressure boundary has been shown to provide adequate isolation capability on a case by case basis. In all cases, a minimum of two barriers is shown to protect against release of radioactive materials. Where necessary to protect the containment against overpressure, guard pipes are provided which enclose the process pipes between the drywell and containment walls.

In addition to satisfying the requirements of GDC 55, the pressure retaining components which comprise the reactor coolant pressure boundary are designed to satisfy other appropriate requirements which minimize the probability or consequences of an accident rupture. Quality requirements for these components ensure that they are designed, fabricated, and tested to the highest reactor plant component standards. The classification of components which comprise the reactor coolant pressure boundary is Quality Group A and such components are designed in accordance with the ASME Code, Section III, Class 1. Additional information concerning classification is presented by Table 3.2-1. The containment and reactor vessel isolation control system is addressed in Section 7.3.

6.2.4.2.2.2 Justification with Respect to General Design Criterion 56

GDC 56 requires that lines that penetrate containment and communicate with the containment interior must have two isolation valves, one valve inside containment, the other outside, unless it can be demonstrated that the containment isolation provisions for a specific class of lines are acceptable on some other basis.

Table 6.2-36 lists those lines that penetrate primary containment and connect to the drywell and suppression chamber. The purpose of this table is to summarize the design of each listed line with respect to the requirements of GDC 56. Although a word for word comparison with GDC 56 is, in some cases, not practical,

it is possible to demonstrate adequate isolation provisions on some other defined basis. It should be noted that this criterion does not reflect consideration of the BWR suppression pool design, in that those lines which connect to the suppression pool would require placement of inside containment isolation valve underwater. All of the lines which connect to the suppression pool are to or from the individual watertight ECCS pump rooms. Items a, b, c, and d, below, address influent lines to the suppression pool, effluent lines from the suppression pool, influent and effluent lines from the drywell and suppression pool free volume, and conclusions with respect to GDC 56, respectively.

a. Influent Lines to the Suppression Pool

1. Low Pressure Core Spray, High Pressure Core Spray, and Residual Heat Removal Test and Pump Minimum Flow Bypass Lines, and Residual Heat Removal Steam Condensing Mode Bypass Line

The low pressure core spray, high pressure core spray and residual heat removal test lines have isolation capability commensurate with the importance to safety of isolating these lines. Each line has a normally closed, motor operated valve located outside containment. Containment isolation requirements are satisfied 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 one of these lines result in no significant effect on safety. All of these lines terminate below the minimum suppression pool drawdown level.

The test return lines are also used for suppression pool return flow during other modes of operation. This reduces the number of penetrations, 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 and a restricting orifice is provided downstream of the valves.

2. Reactor Core Isolation Cooling Pump Minimum Flow Bypass, Turbine Exhaust, and Turbine Exhaust Vacuum Relief

The reactor core isolation cooling pump minimum flow bypass, turbine exhaust, and turbine exhaust vacuum relief lines penetrate containment and discharge to the suppression pool. The minimum flow bypass and turbine exhaust lines are each equipped with a motor operated, remote manually actuated gate valve outside and as close to containment as possible. A check valve upstream of the gate valve provides for immediate isolation in the event of a break upstream of the check valve. The turbine exhaust vacuum relief line has two automatic and remote manually actuated isolation valves located outside containment. The motor operated gate valve in the minimum flow bypass line is normally closed. The turbine exhaust line motor operated gate valve is designed to be locked open in the control room and is interlocked to preclude opening of the reactor core isolation cooling pump turbine steam inlet valve if the turbine exhaust valve is not fully open. The turbine exhaust vacuum relief line valves are normally open.

3. Residual Heat Removal Heat Exchanger Vent and Relief Valve Discharge Lines

Residual heat removal heat exchanger vent lines discharge to the suppression chamber. Two normally closed, remote manually actuated, motor operated valves outside containment and a check valve, located between containment and the drywell, provide isolation.

Relief valve discharge lines from the residual heat removal heat exchangers and various emergency core cooling system suction and discharge lines discharge to the suppression pool. These vent lines are isolated by the relief valves. The addition of block valves would defeat the purpose of the relief valves. The relief valves set pressure is greater than 1.5 times containment design pressure.

b. Effluent Lines from the Suppression Pool

The low pressure core spray, high pressure core spray, reactor core isolation cooling, and residual heat removal suction lines are equipped with remote manually actuated, motor operated gate valves outside containment. These valves provide the ability to isolate in the event of a line break and also provide long term leakage control. The high pressure core spray and reactor core isolation cooling pump suction lines also include check valves.

In addition, suction piping from the suppression pool is considered an extension of containment since this piping must be available for long term use following a design basis LOCA. Therefore, this piping 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 water-tight ECCS pump rooms. Also, the emergency core cooling system discharge line fill system (emergency core cooling system waterleg pumps) takes suction from the respective emergency core cooling system pump effluent line from the suppression pool downstream of the isolation valve. The emergency core cooling system discharge line fill system suction line includes a manual valve, provided for operational purposes. This system is isolated from containment by the respective emergency core cooling system pump suction valve from the suppression pool (see Table 6.2-32).

c. Influent and Effluent Lines from Drywell and Suppression Pool Free Volume

1. Combustible Gas Control and Post LOCA Atmosphere Sampling Lines

The combustible gas control system line which penetrates containment includes two normally closed, remote manually actuated valves, one inside and one outside containment. The post LOCA sampling system lines which penetrate containment and connect to the drywell and suppression chamber air volume are equipped with two normally closed, solenoid operated isolation valves in series. These valves are located outside containment and provide assurance of isolation of these lines

in the event of a line break and also provide long term leakage control. In addition, the piping is considered an extension of containment since it must be available for long term use following a design basis LOCA. Therefore, it is designed to the same quality standards as containment.

2. Containment Purge and Exhaust Lines

The containment purge and exhaust lines are equipped with three automatically actuated isolation valves. One valve is outside containment and one valve is in each of the two branch lines inside containment.

d. Conclusions Concerning General Design Criterion 56

To assure protection against the consequences of accidents involving the release of significant amounts of radioactive material, piping that penetrates containment has been shown to provide adequate isolation capability on a case by case basis in accordance with GDC 56.

In addition to satisfying the isolation requirements specified by GDC 56, the pressure retaining components of these systems are designed, fabricated, and tested in accordance with the requirements of the ASME Code, Section III. In some cases, provision of a high quality system obviates the need for isolation valves due to the diminished probability of a rupture in such a system. Additional information concerning classification is presented by Table 3.2-1. The containment and reactor vessel isolation control system is addressed in Section 7.3.

6.2.4.2.2.3 Justification with Respect to General Design Criterion 57

Lines that penetrate containment and for which neither GDC 55 nor GDC 56 are governing comprise the closed system isolation valve group. Influent lines are equipped with a motor operated valve outside containment and a check valve inside containment. Effluent lines are equipped with motor operated valves both outside

and inside containment. In all cases, the isolation valves are located as close to containment wall as possible. System lines within this group include the following:

a. Nuclear closed cooling water supply and return.

b. Fuel pool cooling influent and effluent.

c. Condensate makeup influent and effluent.

d. Containment chilled water supply and return.

e. Plant service air.

f. Instrument air.

g. Demineralized water.

h. Equipment drain sump to radwaste.

i. Fire protection carbon dioxide.

j. Floor drain effluent to radwaste.

k. Reactor water sample.

l. Backwash receiving tank to radwaste.

m. Nitrogen supply.

n. Safety related instrument air.

6.2.4.2.3 Consideration of NRC Branch Technical Position CSB 6-4, "Containment Purging during Normal Operation"

The containment purge system is designed to achieve the objectives stated in Branch Technical Position CSB 6-4. Purge system containment isolation valves are capable of isolating containment within 5 seconds. The containment purge system is described in Section 6.5.1.

Radiological consequences due to the occurrence of a postulated LOCA when the containment is being purged during normal operation have been examined to determine compliance with the dose criteria set forth in Branch Technical Position CSB 6-4. The calculated site boundary doses are 0.45 Rem to the thyroid and 81 mRem whole body. These doses are a small fraction of the 10 CFR 100 guideline values.

Major assumptions used in the dose analysis are as follows:

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

b. Purge system isolation valve closure will isolate containment within five seconds (includes valve closure time of four seconds and an additional maximum time of one second for conservatism). During this period reactor coolant blowdown was conservatively estimated to be 109,766 pounds (see Table 6.2-25).

c. Forty percent of the blowdown was assumed to flash to steam. It was conservatively assumed that the entire iodine activity in the flashed fraction of the total blowdown was instantaneously released to the containment atmosphere at the instant the accident occurred. Plate out of iodine was ignored. Retention of iodines in the suppression pool was also ignored although, actually, the flashed activity would first be dumped into the suppression pool and would then slowly evolve into containment.

d. Specific activity in the reactor coolant was conservatively assumed to be 6.56 µCi/g of I-131 and 34.9 µCi/g of Xe-133, with other isotopes in proportionate quantities. This corresponds to spike conditions.

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

f. Containment air was assumed to be released through an 18 inch purge line for five seconds. Constant flow rates through the open purge lines corresponding to the maximum containment pressure of approximately 3.0 psig during the release period (see Figure 6.2-2) were used to determine a total flow to the environment of 510 pounds. This value is conservative since it ignores lower flow rates due to lower containment pressures and partial closure of the purge isolation valves at times prior to five seconds.

g. No credit was allowed for iodine removal by the 99 percent efficient charcoal adsorbers in the containment purge exhaust lines.

h. Site boundary χ/Q of 6.7×10^{-4} sec/m^3 (see Table 15.6-12) was used in the dose calculation.

6.2.4.3 Design Evaluation

6.2.4.3.1 General Evaluation

To ensure the accomplishment of the design objective stated in Section 6.2.4.1, redundancy is provided in all design aspects of the containment isolation systems. Mechanical components are redundant and each isolation valve is protected, by separation and/or adequate barriers, against the consequences of potential missiles. Also, system design specifications require each containment isolation valve to be operable under the most severe operating conditions to which it may be exposed. A program of testing is planned to ensure valve operability and leak tightness. Isolation valve arrangements provide backup in the event of accident and satisfy the requirements of GDC 54, 55, 56, and 57, and follow the recommendations of Regulatory Guide 1.11. Electrical redundancy is provided by valve arrangements which eliminate dependence upon one power source to achieve isolation. Electrical cables for isolation valves in the same line are routed separately. Cables are selected with consideration of the specific environmental conditions to which they may be subjected, such as magnetic fields, high radiation, high temperature, and high relative humidity. The containment isolation valve arrangements, with appropriate instrumentation, are illustrated by Figure 6.2-60. Modes of valve actuation are also redundant. The primary mode is automatic; the secondary mode, remote manual. No active failure of a single valve or other component can prevent containment isolation.

All nonpowered isolation valves are administratively controlled and/or locked to ensure that position is known and maintained. The position of all power operated isolation valves is indicated in the control room. Instrumentation and controls associated with the containment isolation systems are discussed in Chapter 7.

6.2.4.3.2 Failure Mode and Effects Analyses

A single failure can be defined as a failure of some component in any safety system which results in a loss or degradation of the capability of the system to perform the safety function. Active components are defined as components that must perform a mechanical motion in the process of accomplishing a system safety function. Appendix A to 10 CFR 50 requires that electrical systems also be designed against passive single failures, as well as active single failures. Chapter 3 describes the implementation of these requirements, as well as GDCs 17, 21, 35, 41, 44, 54, 55, and 56.

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

Electrical systems, as well as mechanical systems, are designed to satisfy the single failure criterion for both mechanical active and passive fluid system components that are required to perform a safety action.

6.2.4.4 Tests and Inspections

The containment isolation systems are scheduled to undergo periodic testing during reactor operation. Functional capabilities of power operated isolation valves are tested remote manually from the control room. By observing position indicators and changes in the operation of the affected system, the operability of a particular isolation valve is verified.

Air testable check valves are used in certain systems, such as in the low pressure core spray, high pressure core spray, and residual heat removal influent lines. These valves, located inside containment, are tested from the control room to ensure functional capability when required to operate.

Leakage testing is addressed in Sections 6.2.4.2.1 and 6.2.6.

Instrument isolation valves inside and outside containment can be exercised from the control room and can be locally tested.

An inservice inspection program for valves forming parts of the reactor coolant pressure boundary is described in Section 5.2.4.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

The control of combustible gas following a LOCA will be accomplished by mixing volumes of relatively high combustible gas concentration with those of low concentration. Prior to the time when the amount of combustible gas reaches critical mixture, electrical hydrogen recombiners will be placed in operation. This will control any additional gas produced and subsequently reduce the hydrogen gas inventory. As a backup means of control, the containment atmosphere can be purged through the annulus exhaust gas treatment system.

6.2.5.1 Design Bases

6.2.5.1.1 Safety Design Bases

The safety design bases are:

a. To evaluate the hydrogen concentration as a function of time following the hypothetical LOCA, the hydrogen generation from the metal-water reaction and core and sump radiolysis is based on parameters found in Regulatory Guide 1.7.

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. In addition, the initiation of the containment sprays will create turbulence in the containment and enhance mixing.

c. The system design complies with all applicable requirements of 10 CFR 50, Appendix A, Criterion 41 and Regulatory Guide 1.7.

d. The system is capable of sampling and measuring the hydrogen concentration in both the drywell and containment vessel and provide remote indication and alarms in the control room.

e. The system is capable of mixing areas of high hydrogen concentration with areas of low hydrogen concentration in order to control combustible gas concentration in the drywell and containment vessel without reliance on purging.

f. To control the long-term buildup of hydrogen in the containment, recombiners are provided. There are two 100 percent capacity recombiners per unit, and therefore no sharing of recombiners between units is required.

g. Capability to purge the containment vessel and drywell atmospheres through a fission product removal system is provided as backup to the electric hydrogen recombiners.

h. The mixing subsystem and the electrical hydrogen recombiners will meet the quality assurance, redundant instrumentation and power availability requirements assigned to an engineered safety feature system (refer to Table 3.2-1).

i. All components in the mixing 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).

j. 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 6.2-37.

k. Since operation of only one of the two independent combustible gas control systems is required, a single failure will not prevent the system from fullfilling its design function. The combustible gas control system failure analysis is presented in Table 6.2-38.

l. The capability to periodically inspect and test systems and system components is discussed in Section 6.2.5.4.

m. 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.

n. In accordance with Regulatory Guide 1.7, the concentration of hydrogen will be the controlling factor for the combustible gas control system since the oxygen concentration is greater than five percent by volume.

o. The combustible gas control system will be placed in operation prior to the drywell hydrogen concentration reaching four percent by volume.

6.2.5.2 System Design

A tabulation of the design and performance data for each system component is located in Table 6.2-39. A detailed discussion of instrumentation features is provided in Section 7.3.

6.2.5.2.1 Hydrogen Analysis Subsystem

The hydrogen analyzer is a thermal conductivity device that measures the percentage of hydrogen by volume by detecting changes in thermal conductivity. These changes are found by first measuring the thermal conductivity of a sample. The sample is then passed through a catalytic reactor which causes the hydrogen to react and be removed as water. The conductivity of the sample is measured again. The difference between the first and second conductivity measurement is the amount of hydrogen initially present in the sample. These analyses are

designed to provide an accuracy of +10 percent to -1 percent of atomic hydrogen concentration. Tests have been conducted to qualify the analyzer in accordance with IEEE 323[9], 334[14] and 344[8]. Refer to Sections 3.10 and 3.11.

Since hydrogen is much lighter than air it diffuses rapidly and tends to form a uniform mixture. Because of this, it is unlikely that areas of higher concentrations could form. Any such concentrations would tend to form first at the high points but only if the hydrogen release point were near the ceiling of an enclosed area and no circulation of atmosphere were to occur[15]. These conditions will not be present after the LOCA since pressure and temperature transients due to the release of steam to the containment and drywell, as well as operation of the ECCS systems, will cause considerable turbulance throughout the area.

Since this turbulance will result in a relatively homogeneous mixture of hydrogen, the hydrogen sample locations are representative of the containment and drywell atmosphere. Redundant sample lines from the space between the reactor vessel head and the drywell dome, the top of the drywell area, and the containment dome are connected to redundant hydrogen analyzers.

Piping and instrumentation for the hydrogen analysis subsystem is presented in Section 7.3. Design of the subsystem is Safety Class 2, Seismic Category I.

The analyzer panels are located in the auxiliary building at elevation 620'-0" and the intermediate building at elevation 654'-6". (Figures 1.2-5 and Figure 1.2-7) The hydrogen analysis subsystem operates independently of any other subsystem in the containment combustible gas control system. Provisions exist for grab samples in the hydrogen analyzer sample system at each of the two analyzer stations. Shielding and remotely operated valves are provided for the sample station to limit radiation exposure of plant personnel. The two redundant hydrogen analyzers and sample systems ensure that no single failure will prevent continuous monitoring of the hydrogen concentrations in the drywell and containment following a LOCA.

The analyzers and sample systems are manually initiated by the operator from the control room following a LOCA. The required presence of the operator in the control room and the relatively slow buildup of hydrogen concentrations in containment make delayed startup of these analyzers acceptable. Delaying initiation 15 minutes to 1 hour after a LOCA also subjects the analyzer to less severe sample conditions than the maximum LOCA conditions, for which they are designed, thereby increasing the probability of their successful operation. Figure 6.2-61 indicates that hydrogen concentrations approach 3 percent in approximately 18 hours after a LOCA, providing more than sufficient time to initiate manual action.

6.2.5.2.2 Hydrogen Mixing Subsystem

Initial control of the hydrogen concentration following a LOCA will be accomplished by mixing volumes of potentially high and low hydrogen concentrations. Mixing is accomplished by means of redundant, 500 scfm, centrifugal air compressors which take suction from the containment volume above the service floor and discharge into the drywell. This pressurizes the drywell sufficiently to uncover the upper row of suppression pool vents. Adequate mixing is obtained by this method due to the fact that the drywell volume is dispersed to the containment uniformly from around the entire circumference of the drywell at the lowest possible point, while the return to the drywell is from a single point in the dome of the containment. This arrangement precludes any possibility of short circuiting the mix ng subsystem.

Piping and instrumentation from the mixing subsystem are shown in Figure 6.2-62. Locations of the mixing compressors are shown in Figure 3.8-58.

Physical separation of components in the hydrogen mixing system assures proper operation despite pipe whip, missiles and jet impingement. There are two systems supplying air to the drywell. Supply piping and compressors are located on adjacent quadrants outside the drywell. Hence, no single pipe break, missile or jet can disable both systems. This arrangement meets the criteria of Regulatory Guide 1.46. The piping is designed for the maximum differential pressure loads

and is seismically supported. No ductwork is used in the system. This subsystem is designed as Safety Class 2, Seismic Category I. 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 Section 3.9 and environmental qualification described in Section 3.11.

6.2.5.2.3 Hydrogen Recombination System

The hydrogen control system is fully redundant and consists of two 100 percent capacity hydrogen recombiners for each unit. Therefore, no sharing is required between the two nuclear units. Figure 6.2-61 depicts hydrogen concentration in the drywell and containment as a function of time.

a. Each recombiner subsystem consists of a control panel and a power supply cabinet located in the control complex. The recombiner is located on the operating floor of the containment. Air flows by natural convection through the unit. The recombiner is a completely passive device.

b. The power supply cabinet contains an isolation transformer plus a controller to regulate the power to the recombiner. The controls for the power supply are located in the separate control panel 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 five 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 support 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^{o}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 cooled with containment atmosphere before the gases 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 16 and 17 and production unit test results are given in References 18 and 19. There are no differences between the recombiner system on which the qualification tests were conducted and the recombiner system which was supplied for Perry. For environmental qualification see Section 3.11. The system is designed to Safety Class 2, Seismic Category I requirements. The system is shown on Figure 6.2-63.

6.2.5.2.4 Purge Subsystem

A purge subsystem is provided as a backup means of combustible gas control. Purging will be initiated manually from the control room, if required purging is accomplished through the annulus exhaust gas treatment system to the outside atmosphere. Makeup air is drawn into the containments through the containment vacuum relief valves. This will cause the containment air to be diluted with air of a low hydrogen concentration. Those portions of the backup purge associated with containment isolation are designed to meet Safety Class 2, Seismic Category I requirements. The system is shown on Figure 6.2-62.

6.2.5.3 Design Evaluation

The design evaluation of the combustible gas control system follows the guidelines of NRC Branch Technical Position CSB 6-2, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," and is as follows:

a. The production of hydrogen from the corrosion of zinc and aluminum is zero. This is due to the noncorrosive solution that is used for the containment spray system.

b. The mass of the Zircaloy fuel cladding to a depth of .23 mills as specified in Regulatory Guide 1.7 is 574 pounds.

ne integrated production of hydrogen for the containment and drywell due to adiolysis of water is shown in Figure 6.2-64.

gligible hydrogen and oxygen is contained in the reactor coolant system h respect to the other components of hydrogen generation following a CA.

e. The total fission product decay power as a fraction of operating power rsus time is given in Table 6.2-27.

f. The fission product distribution model is discussed in Section 12.2.

g. The integrated production of hydrogen in the drywell due to the zirconium-water reaction is 12.6 lb-moles for the first two minutes. There is no zirconium-water reaction after this time.

h. The hydrogen concentration in containment plotted as a function of time is shown in Figure 6.2-61.

i. Three methods of hydrogen control are used. They are the containment atmospheric dilution system, hydrogen recombiner, and containment purge. The purge is used only if the recombiners are not functional at the time they are required to operate. Table 6.2-39 shows the design and operating parameters.

j. Since hydrogen is much lighter than air, it diffuses rapidly, tending to form a uniform mixture. Because of this, it is unlikely that areas of higher concentrations could form; however, any such concentrations would tend to form at the high points of containment, where the containment spray lines and mixing system suction lines are located. The initiation of these systems would create turbulance and enhance mixing.

k. The hydrogen mixing system piping is designed for the maximum differential pressure loads and is seismically supported. No ductwork is used in the system.

6.2.5.4 Testing and Inspection

Except for piping located inside the drywell, the entire system is visually inspected periodically during normal plant operation. Compressors are tested by turning them on from the control room and measuring discharge pressure. Isolation and control valves are exercised periodically and position checked on indicators in the control room.

Testing of the hydrogen analyzers is done periodically by injecting a calibration gas into the sample lines and comparing the known concentration with the analyzer readout.

The hydrogen recombiners are tested once a year to check the calibration of the unit and proper operation of the heaters by energizing the unit and allowing temperatures to stabilize at the operating conditions.

Preoperational tests of the combustible gas control system are conducted during the final stages of plant construction prior to initial startup (see Section 14.2). These tests ensure correct functioning of all controls, instrumentation, compressors, recombiners, piping, and valves. System reference characteristics, such as pressure differentials and flow rates, are documented during the preoperational tests and are used as base points for measurements in subsequent operational tests.

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 Requirements

Operation of the combustible gas control system is performed manually. On-off status of compressors and position of valves are indicated in the control room. Hydrogen concentration recorders and alarms, flow recorders, low flow, system bypassed alarms and control switches are located in the control room.

Within the first hour after a LOCA both hydrogen analyzers are started manually from the control room. Controls on the recorder switch station located in the control room on panel H13-P800 allow the hydrogen analyzers to be placed in either an automatic sequencing mode, in which samples are sequentially taken from the four areas of high hydrogen concentration previously discussed, or a manual mode in which the operator selects one of the four areas to sample. Both hydrogen analyzers alarm high hydrogen concentration at 3 percent hydrogen by volume. This is below the four percent limit in Regulatory Guide 1.7 and thus

provides ample time for the operator to initiate the mixing subsystem (Figure 6.2-64). The operator is alerted again by another annunciator alarm at 3.5 percent hydrogen by volume. The second alarm serves as a backup and still provides time for the operator to initiate the mixing systems before hydrogen concentrations exceed the limits of Regulatory Guide 1.7.

Absence of this second alarm after starting the mixing subsystem is a confirmation of the effectiveness of the mixing subsystem. These setpoints have been conservatively selected considering all instrument errors and accuracies.

On high hydrogen concentration signal from the hydrogen analyzers, the mixing subsystem is manually started. Prior to starting the mixing compressors, the pressure in the drywell and containment is equalized by automatic opening of the drywell vacuum relief valves. See Section 3.8.3 for further details of the DVR system. The mixing subsystem will be operated manually from the control room because mixing will not be required for a number of hours after the LOCA. The discharge control valve for each mixing compressor is normally closed, opens automatically when the compressor starts, and closes automatically when the compressor is stopped. The operation of the mixing system is electrically locked out whenever a LOCA signal is present.

Days after the LOCA, the mixing system becomes ineffective in maintaining the hydrogen concentration below the combustible limit. At this time, if the hydrogen analyzer indicates that the concentration has increased to approximately 3.5 volume percent, the hydrogen recombiner subsystem is manually started from the control room. In the unlikely event that the redundant hydrogen recombiners fail to maintain the hydrogen concentration below 4 volume percent, the containment will be purged after operator initiation from the control room, as discussed in Section 6.2.5.2.4. Instrumentation for the purge subsystem consists of a flow controller for the purge line to the annulus exhaust filters. A high flow alarm on the purge line alerts the operator to the high flow condition.

All lines in the system that connect the drywell with the containment vessel have isolation valves which close automatically on LOCA signal. Manual initiation and test operation is overridden by the LOCA signal. During normal plant operation, these isolation valves are closed. 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 complex for convenience in test and periodic checkout of the recombiner. A controller is operated from the control complex to regulate the power supply to the recombiner. Proper recombiners operation after an accident is determined by monitoring a watt-meter in the control complex.

Design details of the combustible gas control system instrumentation and controls are discussed in Section 7.3.

6.2.6 CONTAINMENT LEAKAGE 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 and ANSI/ANS-56.8[20]. Testing requirements for piping penetration barriers and valves have been established using the intent of Appendix J to 10 CFR 50. Exceptions taken to Appendix J for Type A, B, or C tests are described and justified in Tables 6.2-40 and 6.2-41. This section also presents the testing program for determination of the drywell integrated leakage rate. The integrated leak rate test system is shown in Figure 6.2-65.

Periodic Type A, B, and C tests are performed to assure that leakage through the primary reactor containment and systems and components that penetrate the primary containment do not exceed allowable leakage rate values as specified in technical specifications. These periodic tests also assure that proper maintenance and repairs are performed during the service life of the plant.

6.2.6.1 Primary Reactor Containment Integrated Leakage Rate Test

During the construction phase localized leakage testing is employed as described in Section 3.8 to detect leaks which may affect containment integrity or the results of the initial integrated leak rate test.

Structural integrity tests of the containment structure and the drywell substructure, described in Sections 3.8.1 and 3.8.3, must be satisfactorily completed prior to performance of the preoperational integrated leakage rate tests.

On completion of construction of the primary reactor containment including installation of all portions of mechanical, fluid, electrical and instrumentation systems penetrating containment or associated with containment integrity .d 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 integrated leakage rate tests are performed at the design basis accident pressure (P_a) to determine the measured leakage rate (L_{am}).

The leakage rate, L_{am}, at test pressure, P_a, shall be less than 0.75 of L_a. Other pertinent test data, including test pressures, test duration and definition of terms are presented in Table 6.2-41.

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.

However, during the period between the initiation of the containment inspection and the performance of a periodic Type A test, no repairs other than structural repairs or adjustments are made so that the primary reactor containment can be tested for leakage in as close to the "as is" condition as practical.

The Type A test is conducted using the Absolute Method as described in Reference 20. Primary containment atmosphere drybulb temperature, dewpoint temperature (water vapor pressure) and 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 reported in accordance with the requirements of technical specifications.

The quantity and types of sensors associated with the primary containment integrated leakage rate instrumentation are listed in Table 6.2-42.

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 containment atmosphere is considered stabilized when the average rate of change of air temperature (weighted average) over the last hour does not deviate by more than 0.5 °F/hr from the average rate of change of air temperature over the last three hours.

c. Those portions of fluid systems that are part of the reactor coolant pressure boundary and are therefore 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 a LOCA are vented to the containment atmosphere.

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 required to maintain the plant in a safe condition during the Type A test and 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 6.2-40 for the systems in this category.

g. Systems that are normally filled with water and operating under post-accident conditions are not vented. All systems will be vented for the Type A test except those identified as "non-vented" in Table 6.2-40.

Upon completion of the Type A test, a verification test is performed to confirm the accuracy of the integrated leakage rate instrumentation. The verification test is accomplished by imposing a known leak on the containment through a calibrated flow measurement device. The difference between the composite test

leakage rate, L_c, and the imposed leakage rate, L_o, is compared with the original leakage rate. Complete descriptive details are found in appendix C of ANSI N 45.4[21]. Verification test acceptance criteria is given in technical specifications.

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 an integrated leakage rate in excess of the acceptance criteria, 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 tne repairs and/or adjustments documented in the final report.

If any Type A test fails to meet the acceptance criteria, the test schedule applicable to subsequent Type A tests will be modified as described in technical specifications.

6.2.6.2 Containment Penetration Leakage Rate Test

Containment penetrations whose design incorporates resilient seals, gaskets, or sealant compounds; air locks and lock door seals; equipment and access hatch seals; and electrical penetrations receive preoperational and periodic Type B leakage rate tests in accordance with 10 CFR 50, Appendix J. A list of all containment penetrations subject to Type B tests is provided in Table 6.2-40.

All Type B tests are performed at containment design basis accident pressure, P_a, as defined in Table 6.2-41. The acceptance criteria is given in technical specifications. Test methods are described in Section 6.2.6.3.

For the containment personnel locks, the lock design incorporates provisions for testing between the door seals and between the doors (refer to Figure 6.2-66). The provisions are:

a. Testing of Annulus between Seals

An automatic leak rate monitor is connected to the seal test point on the inner door and outer door of each air lock. The monitors are supplied with instrument air and upon activation of the door interlock switch, the test

cycle begins by pressurizing the cavity between the door seals to the preset pressure. At the preset pressure the automatic sequence will proceed to the test mode and indicate a pass or fail condition. This result is remotely displayed as an alarm in the control room. After the test cycle the monitor automatically shuts down and resets for the next test.

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 leakage monitored to calculate the overall lock leakage.

Both tests are run at a pressure of P_a. Four test bars are provided to keep the inner door sealed during the overall lock test.

6.2.6.3 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 6.2-40.

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 more 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 indicated flow rate is the isolation valve (or Type B test) leakage rate.

All isolation valve seats which are exposed to containment atmosphere subsequent to a LOCA are tested with air or nitrogen at containment peak accident pressure, P_a, as defined in Table 6.2-41.

Those valves which are in lines designed to remain filled with a liquid for at least 30 days subsequent to a LOCA are leakage rate tested with that liquid. The measured liquid leakage is not converted to equivalent air leakage nor added to the Type B and C test total. However, if the liquid contains radioactive contaminants that may become airborne, then a factor shall be applied to the liquid leakage to determine the airborne fraction. That fraction is added to the Type B and C test total. Isolation valves tested with liquid are identified in Table 6.2-40.

The acceptance criteria for leakage through all penetrations and isolation valves subject to Type B and C tests are given in 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 given in technical specifications.

Type B and C tests may be conducted at any time during normal plant operations or during shutdown periods as long as the time interval between tests for any individual Type B or C test does not exceed the maximum allowable interval specified in technical specifications. 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 are submitted to the NRC after each test.

6.2.6.5 Special Testing Requirements

6.2.6.5.1 Drywell Leakage Rate Test

Following the drywell structural integrity test described in Section 3.8.3, a preoperational drywell leakage rate test is performed at drywell design pressure. Subsequently, periodic drywell leakage rate tests are performed at a reduced pressure as defined in technical specifications. The reduced pressure tests verify that drywell to containment leakage does not exceed the allowable suppression pool bypass limits specified in technical specifications. The combination of the design pressure and reduced pressure leakage rate tests also

verifies that the drywell will perform adequately for the full range of postulated primary system break sizes. The allowable drywell leakage rate, L_d, is 10 percent of the allowable bypass leakage for the small break accident with containment spray (10% of $\surd/\sqrt{K}$ = .10(1.68) = .168).

Drywell leakage rate tests are performed with the drywell isolation valves and system lineups in their post accident position. Any paths for equalizing drywell and containment pressure open during the Type A test are isolated. The containment air space external to the drywell is vented to atmosphere or to the annulus.

Preoperational drywell tests are performed as late as is practical in the construction sequence, but prior to initial operation. For these tests the upper containment pool is filled to normal water level; the suppression pool is left dry so the horizontal vents can be plugged as required to achieve design pressure.

After preoperational testing is satisfactorily completed, the drywell vent plugs can be removed and the suppression pool filled. All subsequent periodic tests are conducted at a reduced pressure (less than that required to bubble drywell air through the top row of vents).

For all of the above tests the drywell atmosphere is allowed to stabilize for one hour after attaining test pressure. When the steady state conditions are achieved the drywell leakage rate is determined by metering the makeup air flow required to maintain the constant test pressure. Test pressure, duration and acceptance criteria are specified in technical specifications. Periodic drywell leakage rate tests are performed at the intervals specified in technical specifications.

The maximum allowable leakage rate into the annulus and the means to verify that the rate has not been exceeded and the bypass leakage rate is discussed in Section 6.2.4.

6.2.7 SUPPRESSION POOL MAKEUP SYSTEM

Following a LOCA, the suppression pool makeup system provides water from the upper containment pool to the suppression pool by gravity flow. 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 Bases

The following criteria were used in the design of the suppression pool make-up system:

a. The system is redundant with two 100 percent capacity lines. The redundant lines are physically separated and all electrical power and control is separated into two divisions in accordance with IEEE Standard 279.

b. The system is Safety Class 2, Seismic Category I.

c. The minimum long term postaccident suppression pool water coverage over the top of the top drywell vent is two feet.

d. The minimum normal operation low water level (LWL) suppression pool height above the top drywell vent center line is seven feet.

e. The maximum normal operation high water level (HWL) suppression pool height above the top drywell vent center line is 7'-3-1/2".

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 postaccident entrapment volumes for suppression pool water, and keep the suppression pool at an acceptable water level.

g. The postaccident 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 postaccident complete fill of the vessel including 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 hold up on equipment and structural surfaces.

h. No credit for feedwater or HPCS injection from condensate storage is taken in calculating minimum postaccident 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 without flooding into the drywell over the weir wall in case of an inadvertant dump of the upper pool.

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 shall consist 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 postaccident from the upper containment pool.

l. The system gravity dump time through one of the two redundant lines is less than or equal to the minimum pump time; pump time is determined by dividing pumping volume (upper pool makeup volume plus volume in the suppression pool stored between LLWL and minimum top vent coverage) by the total maximum runout flow rate from all five ECCS pumps.

6.2.7.2 System Design

The piping system consists of two lines which penetrate the separator storage section of the upper containment pool through the side walls. One line is located on either side of the separator pool. From there, each line is 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 insures that no excessive drywell flooding over the weir wall will occur for inadvertant opening of the valves on the suppression pool make-up lines.

The volume of the upper containment pool, which is available for suppression pool makeup, is equivalent to the volume of an 8.33 foot thick slice across the entire upper pool surface area plus the separator pool volume between the top of the separator wall and the make-up system penetration to the upper pool. This requires that the refueling gate leading to the dryer storage/fuel transfer pool be removed during power operation.

Each suppression pool makeup line has two normally closed valves in series. The valves on one line are on the same electrical division. Valves on the other line are on a different electrical division. All valves are powered from an on-site emergency power source which has divisional separation and redundancy.

The upper pool is dumped by gravity flow after opening the two normally closed series valves in each line. The valves on both lines receive divisionally separate but simultaneous 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. There is also a series permissive signal permitting valve opening only when the LOCA signal exists. This LOCA signal is the same signal which actuates the ECCS pumps. This combination provides high reliability that the upper containment pool will be dumped when required but not dumped inadvertantly by spurious signals.

The dump of the upper pool on low-low suppression pool level ensures adequate water volume to keep the suppression pool vents covered for all break sizes. In addition to the suppression pool level dump signal, the upper pool will also be dumped automatically from a timer set for LOCA + 30 minutes. This upper pool dump at 30 minutes postaccident insures that adequate heat sink is available long term regardless of break size or energy dump sequence.

The suppression pool makeup system will always operate following a DBA-LOCA as long as only one simultaneous equipment failure or operator error is postulated to occur. The suppression pool makeup system is specifically designed with redundant piping, valves, and instrumentation to preclude failure to operate given a DBA-LOCA and any single equipment failure or operator error (see Figure 6.2-67). Each of the two dump systems is independent and safety class.

The two series valves on each of two makeup system dump lines are located above the top of the drywell and outside the range of pool swell effect. The end of the pipe will terminate at approximately elevation 605'-4" which provides an unobstructed free fall to the suppression pool. Pool level transmitters are located in the auxiliary building, protected from suppression pool dynamic effects.

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 Section 6.2.7.2). The low-low level signal is 18 inches below the normal LWL. Since maximum ECCS pump flow lowers the suppression pool at a rate of approximately .88 feet per minute, there is a minimum 1-1/2 minute delay between start of ECCS flow and dumping of the upper pool. The delay is actually 1-2 minutes longer than this because vessel inventory mass is added to the suppression pool during blowdown steam condensation. This built-in volume integrated delay assures 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 signalled to open by a LOCA signal in series with a 30 minute timer where the timer itself is started by the LOCA signal. This path of initiation logic is independent of suppression pool level 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 minutes.

A pool dump initiated from the LOCA + 30 minute timer could result in higher vent submergence than the initial maximum of 7'-3-1/2". 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 would persist out to 30 minutes. Note that action of the drywell vacuum breakers which might reintroduce air into the drywell prior to 30 minutes postaccident 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 would also have no effect on peak drywell pressure since the high submergence would only occur 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 less than 8.67 minutes through one of two lines. The valves on the suppression pool makeup lines are fully open within 30 seconds of opening signal application.

6.2.7.3.3 Inadvertent Dump

The design of the opening signal circuitry for the suppression pool make-up valves assures high probability that no inadvertant dump will occur. The suppression pool level signal (LLWL) to open the valves is in series with a permissive which only allows the open signal to pass through when a LOCA signal

exists on that division. Only a simultaneous signal of either suppression pool LLWL combined with LOCA, or LOCA with a 30 minute time delay will open both valves to allow gravity drain of the upper pool to the suppression pool. Even manual action is incapable of opening both series valves unless the plant is in the shutdown mode or a LOCA permissive signal exists. The LOCA signal plus the timer signal after 30 minutes would 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 (see Figure 6.2-68) and a double failure is required to give a spurious LOCA signal.

There are four level sensors indicating suppression pool water level with two sensors per electrical division. The two level sensors in one division are paralleled so that either sensor 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 sensors. Level sensors on one electrical division cannot initiate flow from the makeup line where valves are in a separate electrical division.

There is a remote possibility that a single failure of a suppression pool level sensor and a concurrent LOCA event could initiate suppression pool makeup flow from one line such that the makeup flow started at the instant of LOCA. The flow from one makeup line will raise the suppression pool level at a rate of .75 feet per minute following full opening of the valves which normally prevent flow.

For a large break DBA, the peak drywell pressure occurs at about 1 second after the break with the pressure being reduced to the steady flow submergence of the top vent by about 30 seconds. Any pool swell associated loading would occur during the first few seconds while drywell air purge is taking place. Thus, the structural loading which would occur following a DBA would occur prior to any significant flow of water from a makeup line which was erroneously signalled 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 one minute 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 upper pool makeup volume on top of the normal suppression pool HWL without flooding over the weir wall into the drywell. The dumped upper pool makeup volume can be transferred back to the upper pool through the RHR pumps with a 20 minute pumping time, thus restoring the initial suppression pool water level.

No fuel is stored in the upper pool during plant operation, therefore shielding is no issue for this case. Fuel can be temporarily stored in one end of the upper pool during fuel transfer as part of the refueling operation. This temporary storage pool has sufficient depth that adequate shielding is maintained over the fuel even following inadvertant dump of the upper pool makeup volume to the suppression pool. The separator storage wall limits the water height drop over the temporary storage pool to an 8.33 foot change. This would leave approximately 20 feet of shielding over the top of active fuel temporarily stored even after inadvertant dump.

The only inadvertant 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. An 8.33 foot upper pool level drop with one bundle in the highest position leaves less than one foot of water shielding over top of active fuel. This is adequate for bundle cooling. Radiation alarms at the top of the upper pool would warn plant operating personnel to evacuate from the edge of the pool if a radiation problem occurs. Several minutes would be available for personnel to step to a safe shielding area out of line of sight of the suspended fuel bundle which is nine feet below the operating floor. The valve initiation logic is designed with interlocks so that neither automatic nor manual action can open the suppression pool make-up valves while the plant is in the refueling mode.

6.2.7.4 Tests and Inspections

The suppression pool makeup valves will be manually tested periodically, 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. Also, instruments will be periodically tested and inspected.

Preoperational testing will include a complete flow test of the system including a timed dump of the required makeup volume. Similar flow testing could be performed at any plant shutdown outage; however, the need for such testing occurs only a few times in the plant lifetime.

6.2.7.5 Instrumentation Requirements

Suppression pool water level sensors provide a signal to open the suppression pool makeup system valves. Four level instruments, two in each division, are provided. These instruments are the same analog instruments which measure normal water level variation with an extended range for LLWL. (See Section 7.3.1.)

A level indication for the upper pool is also provided to alert the 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 constant during plant power operation.

The upper pool and suppression pool temperature are monitored to ensure 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.

Administrative procedures ensure that the fuel transfer gate is not in place while the reactor is in the RUN mode. This gate is left open during plant operation where suppression pool make-up from the upper pool might be required.

A functional control diagram for the suppression pool makeup system is presented in Section 7.3.

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TABLE 6.2-1

KEY DESIGN AND MAXIMUM ACCIDENT PARAMETERS FOR PRESSURE SUPPRESSION CONTAINMENT

Parameter	Design Value	Maximum Calculated Accident Value
Containment Pressure, psig	15	12.0
Containment Temperature, °F	185	184.6
Drywell Pressure, psig	30	22.1
Drywell Temperature, °F	330	330

TABLE 6.2-2

CONTAINMENT DESIGN PARAMETERS

	Drywell	Containment
Drywell and Containment		
Negative Design Pressure, psig	-21.0	-0.8
Positive Design Pressure, psig	30	15
Design Temperature, °F	330	185
Net Free Volume, ft^3	277,685	1,141,014
Design Leak Rate	100%/6hrs@3psig	0.2%/day
Maximum Allowable Leak Rate	100%/6hrs@3psig	0.2%/day
Suppression Pool Water Volume, ft^3		
Low Level	11,155	105,950
High Level	11,395	108,750
Suppression Pool Surface Area, ft^2	482	5,900
Suppression Pool Depth, ft		
Low Level	18.0	18.0
High Level	18.5	18.5
Upper Pool Makeup Volume, ft^3	-	32,830

TABLE 6.2-2 (Continued)

	Containment
Vent System	
Number of Vents	120
Nominal Vent Diameter, ft	2.29
Total Vent Area, ft^2	495
Vent Centerline Submergence (low level), ft	
Top Row	7
Middle Row	11.5
Bottom Row	16
Vent Loss Coefficient (varies with number of vents open)	2.5-3.5

TABLE 6.2-3

ENGINEERED SAFETY FEATURE SYSTEMS
PERFORMANCE PARAMETERS FOR CONTAINMENT RESPONSE ANALYSES

	Full Capacity	Containment Analysis Value Case A	Case B
Containment Spray			
Number of RHR Pumps	2	0	0
Number of Lines	2	0	0
Number of Heaters	2	0	0
Flow Rate, gpm/pump	5250	0	0
Containment Cooling System			
Number of RHR Pumps	2	2	1
Pump Capacity, gpm/pump	7100	7100	7100
RHR Heat Exchangers			
Type	Inverted U-tube, single pass shell, multipress tube, vertical mounting		
Number	2	2	1
Heat Transfer Area, ft^2/unit	14,850	-	-
Overall Heat Transfer Coefficient, Btu/hr-ft^2-°F/unit	200	-	-
Service Water Flow Rate, gpm/unit	7300	7300	7300
Service Water Temperature, °F			
Minimum Design	32	-	-
Maximum Design	80	80	80
Containment Heat Removal Capability (using 80°F service water and 185° pool temperature) Btu/hr/unit	166.4×10^6	-	-

TABLE 6.2-4

ACCIDENT ASSUMPTIONS AND INITIAL CONDITIONS FOR CONTAINMENT RESPONSE ANALYSES

Components of Effective Break Area (recirculation line break), ft^2	
Recirculation Line	2.127
Cleanup Line	0.062
Jet Pumps	0.461
Primary Steam Energy Distribution[(1)], 10^6 Btu	
Steam Energy	25.59
Liquid Energy	722.3
Sensible Energy	
Reactor Vessel	98.25
Reactor Internals (less core)	40.49
Primary System Piping	45.40
Fuel[(2)]	7.2
Other Assumptions Used in Analysis	
Main Steam Closure Time, sec	
Recirculation Break	3.5
Main Steam Line Break	5.5
Scram Time, sec	<1

NOTES:

1. All energy values, except fuel, are based upon a 32°F datum.
2. Fuel energy is based upon a datum of 285°F.

TABLE 6.2-5

INITIAL CONDITIONS EMPLOYED IN CONTAINMENT RESPONSE ANALYSES

Reactor Coolant System[(1)]

Reactor Power Level, MWt	3,651
Average Coolant Pressure, psia	1,040
Average Coolant Temperature, °F	549
Mass of Reactor Coolant System Liquid, lbm	544,540
Mass of Reactor Coolant System Steam, lbm	21,530
Volume of Liquid in Reactor Pressure Vessel, ft^3	11,838.3
Volume of Steam in Reactor Pressure Vessel, ft^3	9,189.2
Volume of Liquid in Recirculation Loops, ft^3	742
Volume of Steam in Steam Lines, ft^3	1,454
Volume of Liquid in Feedwater System, ft^3	24,303
Volume of Liquid in Miscellaneous Lines, ft^3	84

Drywell and Containment

	Drywell	Containment
Pressure, psig	0	0
Air Temperature, °F	135	90
Relative Humidity, %	40	50
Suppression Pool Water Temperature, °F	90	90
Suppression Pool Water Volume, ft^3	8,680	105,950
Top Row Vent Centerline, ft	7.0	7.0

TABLE 6.2-5 (Continued)

Drywell and Containment (Cont'd)

	Drywell	Containment
Upper Pool Water Temperature, °F	-	100
Upper Pool Makeup Water Volume, ft^3	-	32,830

NOTE:

1. Reactor coolant system at 102 percent of rated power and normal liquid levels.

TABLE 6.2-6

SUMMARY OF SHORT TERM CONTAINMENT RESPONSES TO RECIRCULATION LINE AND MAIN STEAM LINE BREAKS (MINIMUM ECCS)

	Recirculation Line Break	Main Steam Line Break
Peak Drywell Pressure, psig	21.26	22.1
Peak Drywell Differential Pressure, psid	20.26	21.05
Time of Peak Pressure, sec	1.89	1.8
Peak Drywell Temperature, °F	248.8	324
Peak Wetwell Pressure, psig	9.82	10.36
Time of Peak Wetwell Pressure, sec	462.5	691.6
Peak Suppression Pool Temperature during Blowdown, °F	155.8	157.8
Calculated Drywell Margin, %	29	26.33
Energy Released to Containment at Time of Peak Pressure, 10^6 Btu	9.0	9.0
Energy Absorbed by Passive Heat Sinks at Time of Peak Pressure, 10^6 Btu	0	0

TABLE 6.2-7

SUMMARY OF LONG TERM CONTAINMENT RESPONSES TO RECIRCULATION LINE OR MAIN STEAM LINE BREAK

	Case A	Case B
Peak Containment Pressure, psig	8.58	11.31
Time of Peak Containment Pressure, sec	4,167	11,128
Peak Suppression Pool Temperature, °F	170.5	184.6
Calculated Containment Margin, %	42.8	24.6
HPCS Flow Rate, gpm	6,000	6,000
LPCS Flow Rate, gpm	7,100	7,100
RHRS Flow Rate, gpm	14,200	7,100

TABLE 6.2-8

ENERGY BALANCE FOR
MAIN STEAM LINE BREAK ACCIDENT

	Energy			
	Initial (time zero)	Drywell Peak Pressure	End of Blowdown	Long Term Peak Wetwell Pressure
Reactor Coolant	7.5+8	7.3+8	7.5+7	2.0+8
Fuel and Cladding				
Fuel	7.2+6	7.2+6	0	0
Cladding	3.4+6	3.4+6	1.7+6	1.7+6
Core Internals	1.0+8	1.0+8	8.7+7	3.4+7
Reactor Vessel Metal	9.1+7	9.1+7	7.7+7	3.1+7
Reactor Coolant System Piping, Pumps, and Valves	Included in "Core Internals", above.			
Blowdown Enthalpy				
Liquid	0	9.1+5	9.2+8	9.2+8
Steam	0	9.0+6	1.4+8	1.4+8
Decay Heat	0	2.8+6	8.0+7	7.4+8
Metal-Water Reaction Heat	0	1.4+4	1.6+6	1.6+6
Drywell Structures	0	0	0	0
Drywell Air	1.8+6	2.1+6	1.2+0	1.3+6
Drywell Steam	8.4+5	1.0+7	2.1+7	9.0+6
Containment Air	7.6+6	7.7+6	1.0+7	9.5+6
Containment Steam	1.3+6	2.5+6	1.5+7	2.6+7
Suppression Pool Water	5.6+8	5.6+8	1.2+9	1.2+9
Energy Transferred by Heat Exchangers	0	0	0	3.9+8
Passive Heat Sinks	0	0	0	0

TABLE 6.2-9

ACCIDENT CHRONOLOGY FOR MAIN STEAM LINE BREAK ACCIDENT

Event	Time (sec) All ECCS in Operation	Time (sec) Minimum ECCS Available
First Row Vent Cleared	0.897	0.897
Second Row Vent Cleared	1.104	1.104
Third Row Vent Cleared	1.511	1.511
Drywell Reaches Peak Pressure	1.8	1.8
Maximum Positive Differential Pressure Occurs	1.8	1.8
Initiation of ECCS Operation	30	30
Third Row Vent Recovered	32	32
Second Row Vent Recovered	53	53
End of Blowdown	322	416
Reactor Pressure Vessel Reflooded	309	696
First Row Vent Recovered	730	730
Initiation of RHR Heat Exchanger Operation	1,980	1,980
Containment Peak Pressure Reached	4,167	11,128

TABLE 6.2-10

AVAILABLE CONTAINMENT HEAT SINKS

Item	Volume (ft^3)	Surface Area (ft^2)	Material
Drywell Structures	71,769	4,268	Concrete
Containment Shell	8,317	66,539	Steel
Miscellaneous Steel Structures and Equipment	2,337	126,641	Steel
Miscellaneous Concrete Structures	153,898	30,870	Concrete

TABLE 6.2-11

BLOWOUT PANEL CHARACTERISTICS
USED IN REACTOR WATER CLEANUP ROOMS ANALYSES

Blowout Panels for Heat Exchanger Room, Filter Demineralizer Valve Room, and Filter Demineralizer Valve Nest Room

Maximum Relief Area, ft^2	16.25
Weight/Area, lb/ft^2	3.33
Blowout Pressure, psi	0.2083
Height, inches	78
Width, inches	30
Drag Coefficient	2.67

Blowout Panel for Filter Demineralizer Room

Maximum Relief Area, ft^2	17.7
Weight/Area, lb/ft^2	3.33
Blowout Pressure, psi	0.2083
Height, ft	10
Width, ft	5
Drag Coefficient	2.67

TABLE 6.2-12

REACTOR ANNULUS
RECIRCULATION SUCTION LINE BREAK WITH FLOW DIVERTER
SUBCOOLED LIQUID BLOWDOWN

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elevation (ft)	Initial Conditions Temperature (°F)	Pressure (psia)	Quality	Calculated Peak ΔP[1] (psid)
1	Volume 1 - Level 1	5.81	91.56	16.80	6.83	212.0	14.696	0.926	22.43
2	Volume 2 - Level 1	8.71	138.46	16.80	6.83	212.0	14.696	0.926	16.17
3	Volume 3 - Level 1	8.71	142.96	16.80	6.83	212.0	14.696	0.926	15.61
4	Volume 4 - Level 1	8.71	205.13	25.20	6.83	212.0	14.696	0.926	17.64
5	Volume 5 - Level 1	8.71	212.77	25.20	6.83	212.0	14.696	0.926	17.49
6	Volume 6 - Level 2	5.81	82.56	16.80	18.44	212.0	14.696	0.926	19.69
7	Volume 7 - Level 2	8.71	128.13	16.80	15.54	212.0	14.696	0.926	17.10
8	Volume 8 - Level 2	8.71	132.63	16.80	15.54	212.0	14.696	0.926	16.76
9	Volume 9 - Level 2	8.71	195.00	25.20	15.54	212.0	14.696	0.926	17.18
10	Volume 10 - Level 2	8.71	210.31	25.20	15.54	212.0	14.696	0.926	17.39
11	Volume 11 - Level 3	6.875	100.64	16.80	24.25	212.0	14.696	0.926	16.41
12	Volume 12 - Level 3	6.875	112.45	16.80	24.25	212.0	14.696	0.926	16.21
13	Volume 13 - Level 3	6.875	112.45	16.80	24.25	212.0	14.696	0.926	15.67
14	Volume 14 - Level 3	6.875	166.72	25.20	24.25	212.0	14.696	0.926	16.74
15	Volume 15 - Level 3	6.875	174.59	25.20	24.25	212.0	14.696	0.926	16.87
16	Volume 16 Level 4	6.925	147.00	25.20	31.125	212.0	14.696	0.926	18.83
17	Volume 17 - Level 4	6.925	158.88	25.20	31.125	212.0	14.696	0.926	15.82
18	Volume 18 - Level 4	6.925	166.76	25.20	31.125	212.0	14.696	0.926	16.05
19	Volume 19 - Level 4	6.925	174.57	25.20	31.125	212.0	14.696	0.926	15.67
20	Volume 20 - Level 4	13.66	297.69	25.20	38.05	212.0	14.696	0.926	15.16
21	Volume 21 - Level 4	13.66	325.41	25.20	38.05	212.0	14.696	0.926	15.04
22	Volume 22 - Level 4	13.66	316.20	25.20	38.05	212.0	14.696	0.926	14.89
23	Volume 23 - Level 4	13.66	344.37	25.20	38.05	212.0	14.696	0.926	14.78
24	Volume 24 - Drywell	90.00	139,000.0	1544.0	0.0	212.0	14.696	0.52	-
25	Volume 25 - Blowdown Node	5.80	71.48	16.80	12.64	212.0	14.696	0.926	29.26
26	Volume 26 - Level 5	6.50	188.25	25.20	51.71	212.0	14.696	0.926	15.11
27	Volume 27 - Level 5	6.50	178.42	25.20	51.71	212.0	14.696	0.926	14.99
28	Volume 28 - Level 5	6.50	178.42	25.20	51.71	212.0	14.696	0.926	14.76
29	Volume 29 - Level 5	6.50	188.25	25.20	51.75	212.0	14.696	0.926	14.72

NOTE:

1. With respect to drywell.

TABLE 6.2-13

REACTOR ANNULUS
FEEDWATER LINE BREAK

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elevation (ft)	Initial Conditions Temperature (°F)	Initial Conditions Pressure (psia)	Initial Conditions Quality	Calculated Peak ΔP[1] (psid)	Design Pressure (psid)
1	Volume 1 - Level 1	9.44	137.31	16.93	5.5	212.0	14.696	0.926	22.01	
2	Volume 2 - Level 1	9.44	205.27	25.39	5.5	212.0	14.696	0.926	21.85	
3	Volume 3 - Level 1	9.44	272.93	33.86	5.5	212.0	14.696	0.926	21.52	
4	Volume 4 - Level 1	9.44	280.55	33.86	5.5	212.0	14.696	0.926	20.58	
5	Volume 5 - Level 1	9.44	284.02	33.86	5.5	212.0	14.696	0.926	20.92	
6	Volume 6 - Level 1	9.44	282.10	33.86	5.5	212.0	14.696	0.926	21.92	
7	Volume 7 - Level 1	9.44	179.28	25.39	5.5	212.0	14.696	0.926	22.10	
8	Volume 8 - Level 2	9.44	121.97	16.93	14.94	212.0	14.696	0.926	23.49	
9	Volume 9 - Level 2	9.44	200.65	25.39	14.94	212.0	14.696	0.926	21.56	
10	Volume 10 - Level 2	9.44	272.93	33.86	14.94	212.0	14.696	0.926	19.74	
11	Volume 11 - Level 2	9.44	293.93	33.86	14.94	212.0	14.696	0.926	19.32	
12	Volume 12 - Level 2	9.44	292.15	33.86	14.94	212.0	14.696	0.926	19.66	
13	Volume 13 - Level 2	9.44	266.93	33.86	14.94	212.0	14.696	0.926	20.12	
14	Volume 14 - Level 2	9.	189.49	25.39	14.94	212.0	14.696	0.926	22.80	
15	Volume 15 - Level 3	6.50	94.81	16.93	24.38	212.0	14.696	0.926	22.65	
16	Volume 16 - Level 3	6.50	149.73	25.39	24.38	212.0	14.696	0.926	21.64	
17	Volume 17 - Level 3	6.50	207.92	33.86	24.38	212.0	14.696	0.926	18.91	
18	Volume 18 - Level 3	6.50	219.97	33.86	24.38	212.0	14.696	0.926	18.21	
19	Volume 19 - Level 3	6.50	219.63	33.86	24.38	212.0	14.696	0.926	18.12	
20	Volume 20 - Level 3	6.50	201.92	33.86	24.38	212.0	14.696	0.926	20.19	
21	Volume 21 - Level 3	6.50	146.89	25.39	24.38	212.0	14.696	0.926	22.31	
22	Volume 22 - Level 4	6.50	99.81	16.83	30.88	212.0	14.696	0.926	21.21	
23	Volume 23 - Level 4	6.50	149.87	25.39	25.39	212.0	14.696	0.926	20.95	
24	Volume 24 - Level 4	6.50	202.63	33.86	30.88	212.0	14.696	0.926	17.89	
25	Volume 25 - Level 4	6.50	220.09	33.86	30.88	212.0	14.696	0.926	16.37	
26	Volume 26 - Level 4	6.50	220.09	33.86	30.88	212.0	14.696	0.926	17.99	
27	Volume 27 - Level 4	6.50	220.63	33.86	30.88	212.0	14.696	0.926	21.14	
28	Volume 28 - Level 4	6.50	154.83	35.39	30.88	212.0	14.696	0.926	18.90	
29	Volume 29 - Level 5	6.50	93.88	17.33	37.38	212.0	14.696	0.926	69.75	
30	Volume 30 - Level 5	6.50	120.07	17.33	37.38	212.0	14.696	0.926	163.86	
31	Volume 31 - Level 5	6.50	194.00	17.33	37.38	212.0	14.696	0.926	18.65	
32	Volume 32 - Level 5	6.50	211.46	17.33	37.38	212.0	14.696	0.926	15.25	
33	Volume 33 - Level 5	6.50	209.67	17.33	37.38	212.0	14.696	0.926	14.18	
34	Volume 34 - Level 5	6.50	182.96	17.33	37.38	212.0	14.696	0.926	23.42	
35	Volume 35 - Level 5	6.50	134.20	17.33	37.38	212.0	14.696	0.926	22.00	
36	Volume 36 - Level 6	6.50	102.43	17.33	43.88	212.0	14.696	0.926	15.51	
37	Volume 37 - Level 6	6.50	137.45	17.33	43.88	212.0	14.696	0.926	12.95	
38	Volume 38 - Level 6	6.50	212.51	17.33	43.88	212.0	14.696	0.926	13.43	
39	Volume 39 - Level 6	6.50	220.01	17.33	43.88	212.0	14.696	0.926	14.87	
40	Volume 40 - Level 6	6.50	219.86	17.33	43.88	212.0	14.696	0.926	12.10	

TABLE 6.2-13 (Continued)

Control Volume No.	Description	Height (ft)	Volume (ft^3)	Volume Flow Area (ft^2)	Bottom Elevation (ft)	Initial Conditions Temperature (°F)	Pressure (psia)	Quality	Calculated Peak ΔP[1] (psid)	Design Pressure (psid)
41	Volume 41 - Level 6	6.50	212.51	17.33	43.88	212.0	14.696	0.926	16.47	
42	Volume 42 - Level 6	6.50	155.98	17.33	43.88	212.0	14.696	0.926	22.37	
43	Volume 43 - Level 7	6.50	102.43	16.93	50.38	212.0	14.696	0.926	14.11	
44	Volume 44 - Level 7	6.50	147.39	25.39	50.38	212.0	14.696	0.926	14.10	
45	Volume 45 - Level 7	6.50	204.82	33.86	50.38	212.0	14.696	0.926	13.80	
46	Volume 46 - Level 7	6.50	212.32	33.86	50.38	212.0	14.696	0.926	14.66	
47	Volume 47 - Level 7	6.50	219.86	33.86	50.38	212.0	14.696	0.926	14.05	
48	Volume 48 - Level 7	6.50	186.82	33.86	50.38	212.0	14.696	0.926	14.95	
49	Volume 49 - Level 7	6.50	148.79	25.39	50.38	212.0	14.696	0.926	14.87	
50	Volume 50 - Drywell	90.0	278,000	3089.0	0.0	212.0	14.696	0.52	-	

NOTE:

1. With respect to drywell.

TABLE 6.2-14

DRYWELL HEAD REGION ANALYSIS

Control Volume No.	Description	Volume (ft^3)	Initial Conditions: Temperature (°F)	Initial Conditions: Pressure (psia)	Initial Conditions: Rel. Hum. (%)	Calculated Peak ΔP[1] (psid)	Design Pressure (psid)
1	Drywell Head	7610	150	14.696	100	6.6	9.2
2	Drywell	2.70+5	150	14.696	0	-	-

NOTE:

1. Calculated peak pressure differentials are with respect to containment.

TABLE 6.2-15

STEAM TUNNEL

Control Volume No.	Description	Volume (ft^3)	Initial Conditions Temperature (°F)	Initial Conditions Pressure (psia)	Initial Conditions Rel. Hum. (%)	Calculated Peak ΔP(1) (psid)	Design Pressure (psid)
1	Steam Tunnel Inside Containment	8950	125	14.696	100	1.15	1.6
2	Containment	1.17+6	104	14.696	0	-	-

NOTE:

1. Calculated peak pressure differentials are with respect to containment.

TABLE 6.2-16

REACTOR WATER CLEANUP ROOMS ANALYSIS

Control Volume No.	Description	Volume (ft^3)	Initial Conditions: Temperature (°F)	Pressure (psia)	Rel. Hum. (%)	Calculated Peak ΔP[1] (psid)	Design Pressure (psid)
1	RWCU Heat Exchanger Room	12,600	120	14.696	100.0	7.75	10.9
2	Corridor	412	120	14.696	0.0	-	-
3	Containment	1.17+6	120	14.696	0.0	-	-
1	RWCU Filter Demineralizer Valve Room	6,580	120	14.696	100.0	6.65	9.3
2	Corridor	302	120	14.696	0.0	-	-
3	Containment	1.17+6	120	14.696	0.0	-	-
1	RWCU Filter Demineralizer Room	3[illegible]	120	14.696	100.0	4.52	6.3
2	Containment	1.[illegible]	120	14.696	0.0	-	-
1	RWCU Drain Valve Nest Room	2,915	120	14.696	100.0	7.70	10.8
2	Corridor	179	120	14.696	0.0	-	-
3	Containment	1.17+6	120	14.696	0.0	-	-

NOTE:

1. Calculated peak pressure differentials are with respect to containment.

TABLE 6.2-17

MASS FLOW FROM RECIRCULATION SUCTION LINE BREAK WITH ONE INCH FLOW DIVERTER

Time (sec)	Into Annulus (lb/sec)	Into Drywell (lb/sec)
0	3039.0	1805.8
3.0	3039.0	1802.8
6.042	3035.1	1803.5

TABLE 6.2-18

MASS FLOW INTO REACTOR ANNULUS DUE TO FEEDWATER BREAK USED FOR ANALYSIS

Time (sec)	Mass (lb/sec)
0.0	5787.5
0.00875	4525.0
0.0521	6210.9
0.1001	6711.7
0.04941	6798.4
0.7376	6940.0
1.00	6620.0

TABLE 6.2-19

REACTOR WATER CLEANUP SYSTEM

DOUBLE ENDED PIPE BREAK[1]

(Liquid Blowdown)

Time (sec)	Total Flow Rate (lbs/sec)	Enthalpy (Btu/lbm)
0	1000	550
5	1000	550
10	1000	550
14	1000	550
15	980	550
16	970	550
18	940	400
20	880	400
22	810	400
24	720	400
26	600	400
28	450	400
30	220	400
32	0	-

NOTE:

1. Suction line pipe size is 6 inch schedule 80; discharge line pipe size is 4 inch schedule 80.

TABLE 6.2-20

REACTOR ANNULUS
RECIRCULATION SUCTION LINE BREAK WITH FLOW DIVERTER
SUBCOOLED LIQUID BLOWDOWN

Junction No.	From CV	To CV	Elevation (ft)	Minimum Flow Area (ft^2)	Inertia (L/A) (ft^{-1})	Head Loss, K Bends	Friction (fL/D)	Expansion	Contraction	Total(1)
1	1	2	9.74	12.03	0.585	0.15	0.0235	-	-	0.20
2	1	25	12.64	14.23	0.544	-	0.0226	-	-	0.05
3	2	3	11.19	20.45	0.324	0.15	0.0235	-	-	0.20
4	2	7	15.59	0.10	0.639	-	0.0226	-	-	0.05
5	2	25	14.09	0.01	0.820	0.15	0.0235	-	-	0.20
6	3	4	11.19	14.89	0.580	0.15	0.0235	-	-	0.20
7	3	8	15.54	3.57	0.592	-	0.0226	-	-	0.05
8	4	5	11.19	18.09	0.461	0.15	0.0235	-	-	0.20
9	4	9	15.54	0.10	0.457	-	0.0226	-	-	0.05
10	5	10	15.54	19.64	0.343	-	0.0226	-	-	0.05
11	6	7	21.35	9.88	0.629	0.15	0.0235	-	-	0.20
12	6	11	24.25	11.64	0.710	-	0.0226	-	-	0.05
13	6	25	18.44	11.64	0.706	-	0.0226	-	-	0.05
14	7	8	19.90	7.54	0.392	0.15	0.0235	-	-	0.20
15	7	12	24.25	14.38	0.685	-	0.0226	-	-	0.05
16	7	25	16.99	0.01	0.820	0.15	0.0235	-	-	0.20
17	8	9	19.90	9.52	0.673	0.15	0.0235	-	-	0.20
18	8	13	24.25	14.38	0.695	-	0.0226	-	-	0.05
19	9	10	19.90	10.74	0.925	0.15	0.0235	-	-	0.20
20	9	14	24.25	20.30	0.485	-	0.0226	-	-	0.05
21	10	15	24.25	24.79	0.307	-	0.0226	-	-	0.05
22	11	12	27.69	15.03	0.518	0.15	0.0235	-	-	0.20
23	11	16	31.125	3.14	0.588	-	0.0226	-	-	0.05
24	12	13	27.69	11.74	0.427	0.15	0.0235	-	-	0.20
25	12	16	31.125	5.41	0.406	-	0.0226	-	-	0.05
26	12	17	31.125	0.62	0.390	-	0.0226	-	-	0.05
27	13	14	27.69	15.03	0.776	0.15	0.0235	-	-	0.20
28	13	17	31.125	12.14	0.390	-	0.0226	-	-	0.05
29	14	15	27.69	15.33	0.519	0.15	0.0235	-	-	0.20
30	14	18	31.125	15.81	0.310	-	0.0226	-	-	0.05

TABLE 6.2-20 (Continued)

Junction No.	From CV	To CV	Elevation (ft)	Minimum Flow Area (ft^2)	Inertia (L/A) (ft^{-1})	Head Loss, K				
						Bends	Friction (fL/D)	Expansion	Contraction	Total(1)
31	15	19	31.125	24.35	0.339	-	0.0226	-	-	0.05
32	16	17	34.59	3.04	0.618	0.15	0.0235	-	-	0.20
33	16	20	38.05	0.10	1.328	-	0.0226	-	-	0.05
34	17	18	34.59	17.42	0.774	0.15	0.0235	-	-	0.20
35	17	21	38.05	12.24	0.882	-	0.0226	-	-	0.05
36	18	19	34.59	14.53	0.580	0.15	0.0235	-	-	0.20
37	18	22	38.05	8.58	0.970	-	0.0226	-	-	0.05
38	19	23	38.05	20.06	0.933	-	0.0226	-	-	0.05
39	20	21	44.885	19.71	0.494	0.15	0.0235	-	-	0.20
40	20	26	51.71	6.73	0.397	-	0.0226	-	-	0.05
41	21	22	44.885	16.73	0.454	0.15	0.0235	-	-	0.20
42	21	27	51.71	12.39	0.565	-	0.0226	-	-	0.05
43	22	23	44.885	26.29	0.473	0.15	0.0235	-	-	0.20
44	22	28	51.71	5.36	0.565	-	0.0226	-	-	0.05
45	23	29	51.71	15.80	0.397	-	0.0226	-	-	0.05
46	26	27	54.96	17.33	0.549	0.15	0.0235	-	-	0.20
47	26	24	54.96	70.41	0.036	-	-	1.0	-	1.00
48	27	28	54.96	5.77	1.209	0.15	0.0235	-	-	0.20
49	27	24	54.96	66.72	0.037	-	-	1.0	-	1.00
50	28	29	54.96	17.33	0.549	0.15	0.0235	-	-	0.20
51	28	24	54.96	66.72	0.037	-	-	1.0	-	1.00
52	29	24	54.96	70.41	0.036	-	-	1.0	-	1.00
53	0	25	15.44	1.00	0.0	-	-	-	-	0.0
54	0	24	15.54	1.00	0.0	-	-	-	-	0.0

NOTE:

1. All horizontal flow paths are assumed to have a conservative K of 0.20; all vertical flow paths are assumed to have a conservative K of 0.05.

TABLE 6.2-21

REACTOR ANNULUS
FEEDWATER LINE BREAK

Junction No.	From CV	To CV	Elevation	Minimum Flow Area (ft^2)	Inertia (L/A) (ft^{-1})	Head Loss, K Bends	Friction (fL/D)	Expansion	Contraction	Total(1)
1	1	2	10.22	18.43	0.701	0.084	0.019	-	-	0.20
2	1	7	10.22	13.94	0.777	0.084	0.019	-	-	0.20
3	1	8	14.94	0.01	2.125	-	0.0244	-	-	0.05
4	2	3	10.22	16.01	0.875	0.112	0.026	-	-	0.20
5	2	9	14.94	0.01	0.820	-	0.0199	-	-	0.05
6	3	4	10.22	14.49	1.732	0.112	0.029	-	-	0.20
7	3	10	14.94	0.01	0.583	-	0.0173	-	-	0.05
8	4	5	10.22	19.97	1.258	0.112	0.029	-	-	0.20
9	4	11	14.94	12.26	0.592	-	0.0173	-	-	0.05
10	5	6	10.22	19.67	1.387	0.112	0.029	-	-	0.20
11	5	12	14.94	14.43	0.675	-	0.0173	-	-	0.05
12	6	7	10.22	14.50	1.132	0.112	0.026	-	-	0.20
13	6	13	14.94	0.01	0.597	-	0.0173	-	-	0.05
14	7	14	14.94	0.01	1.086	-	0.0199	-	-	0.05
15	8	9	19.66	8.01	0.968	0.084	0.019	-	-	0.20
16	8	14	19.66	7.36	0.875	0.084	0.019	-	-	0.20
17	8	15	24.38	13.27	0.471	-	0.0206	-	-	0.05
18	9	10	19.66	8.68	1.241	0.112	0.026	-	-	0.20
19	9	16	24.38	22.39	0.341	-	0.0168	-	-	0.05
20	10	11	19.66	8.68	1.870	0.112	0.029	-	-	0.20
21	10	17	24.38	30.86	0.271	-	0.0146	-	-	0.05
22	11	12	19.66	18.02	1.628	0.112	0.029	-	-	0.20
23	11	18	24.38	33.53	0.235	-	0.0146	-	-	0.05
24	12	13	19.66	8.01	2.248	0.112	0.029	-	-	0.20
25	12	19	24.38	33.20	0.235	-	0.0146	-	-	0.05
26	13	14	19.66	7.35	1.581	0.112	0.026	-	-	0.20

TABLE 6.2-21 (Continued)

Junction No.	From CV	To CV	Elevation	Minimum Flow Area (ft^2)	Inertia (L/A) (ft^{-1})	Head Loss, K Bends	Friction (fL/D)	Expansion	Contraction	Total(1)
27	13	20	24.38	25.85	0.255	-	0.0146	-	-	0.05
28	14	21	24.38	16.72	0.374	-	0.0168	-	-	0.05
29	15	16	27.63	5.93	0.679	0.084	0.023	-	-	0.20
30	15	21	27.63	9.02	0.511	0.084	0.023	-	-	0.20
31	15	22	30.88	7.92	0.689	-	0.0168	-	-	0.05
32	16	17	27.63	5.93	1.310	0.112	0.031	-	-	0.20
33	16	23	30.88	11.98	0.614	-	0.0137	-	-	0.05
34	17	18	27.63	9.35	3.144	0.112	0.035	-	-	0.20
35	17	24	30.88	21.08	0.253	-	0.0119	-	-	0.05
36	18	19	27.63	15.89	1.553	0.112	0.035	-	-	0.20
37	18	25	30.88	33.19	0.243	-	0.0119	-	-	0.05
38	19	20	27.63	7.91	10.548	0.112	0.035	-	-	0.20
39	19	26	30.88	31.64	0.355	-	0.0119	-	-	0.05
40	20	21	27.63	0.71	7.449	0.112	0.031	-	-	0.20
41	20	27	30.88	22.74	0.260	-	0.0119	-	-	0.05
42	21	28	30.88	16.65	0.358	-	0.0137	-	-	0.05
43	22	23	34.13	11.50	0.941	0.084	0.023	-	-	0.20
44	22	28	34.13	6.64	0.666	0.084	0.023	-	-	0.20
45	22	29	37.38	8.59	0.828	-	0.0168	-	-	0.05
46	23	24	34.13	6.71	2.192	0.112	0.031	-	-	0.20
47	23	30	37.38	0.01	0.655	-	0.0137	-	-	0.05
48	24	25	34.13	12.55	0.796	0.112	0.035	-	-	0.20
49	24	31	37.38	14.70	0.660	-	0.0119	-	-	0.05
50	25	26	34.13	17.33	0.796	0.112	0.035	-	-	0.20
51	25	32	37.38	28.41	0.493	-	0.0119	-	-	0.05
52	26	27	34.13	7.77	1.259	0.112	0.035	-	-	0.20
53	26	33	37.38	27.41	0.565	-	0.0119	-	-	0.05
54	27	28	34.13	17.33	0.703	0.112	0.031	-	-	0.20
55	27	34	37.38	11.97	0.703	-	0.0119	-	-	0.05
56	28	35	37.38	11.48	0.782	-	0.0137	-	-	0.05
57	29	30	40.63	5.87	0.701	0.084	0.023	-	-	0.20
58	29	35	40.63	12.55	0.943	0.084	0.023	-	-	0.20
59	29	36	43.88	13.37	0.459	-	0.0168	-	-	0.05
60	30	31	40.63	0.01	1.382	0.112	0.031	-	-	0.20

TABLE 6.2-21 (Continued)

Junction No.	From CV	To CV	Elevation	Minimum Flow Area (ft^2)	Inertia (L/A) (ft^{-1})	Head Loss, K: Bends	Friction (fL/D)	Expansion	Contraction	Total (1)
61	30	37	43.88	1.34	0.406	-	0.0137	-	-	0.05
62	31	32	40.63	4.00	1.793	0.112	0.035	-	-	0.20
63	31	38	43.88	21.49	0.422	-	0.0119	-	-	0.05
64	32	33	40.63	13.00	1.623	0.112	0.035	-	-	0.20
65	32	39	43.88	28.41	0.422	-	0.0119	-	-	0.05
66	33	34	40.63	2.33	2.052	0.112	0.035	-	-	0.20
67	33	40	43.88	27.85	0.482	-	0.0119	-	-	0.05
68	34	35	40.63	0.99	1.602	0.112	0.031	-	-	0.20
69	34	41	43.88	18.76	0.433	-	0.0119	-	-	0.05
70	35	42	43.88	15.88	0.419	-	0.0137	-	-	0.05
71	36	37	47.13	11.90	0.663	0.084	0.023	-	-	0.20
72	36	42	47.13	15.44	0.511	0.084	0.023	-	-	0.20
73	36	43	50.38	10.53	0.479	-	0.0168	-	-	0.05
74	37	38	47.13	11.90	1.198	0.112	0.031	-	-	0.20
75	37	44	50.38	8.31	0.549	-	0.0137	-	-	0.05
76	38	39	47.13	13.33	1.149	0.112	0.035	-	-	0.20
77	38	45	50.38	23.75	0.234	-	0.0119	-	-	0.05
78	39	40	47.13	16.67	1.543	0.112	0.035	-	-	0.20
79	39	46	50.38	30.41	0.338	-	0.0119	-	-	0.05
80	40	41	47.13	15.00	1.641	0.112	0.035	-	-	0.20
81	40	47	50.38	31.19	0.312	-	0.0119	-	-	0.05
82	41	42	47.13	13.55	1.056	0.112	0.031	-	-	0.20
83	41	48	50.38	19.75	1.222	-	0.0119	-	-	0.05
84	42	49	50.38	15.06	0.322	-	0.0137	-	-	0.05
85	43	44	53.63	1.66	1.345	0.084	0.023	-	-	0.20
86	43	49	53.63	11.37	0.511	0.084	0.023	-	-	0.20
87	43	50	53.63	38.17	0.054	-	-	1.00	-	1.00
88	44	45	53.63	1.66	1.172	0.112	0.031	-	-	0.20
89	44	50	53.63	53.54	0.043	-	-	1.00	-	1.00
90	45	46	53.63	2.62	2.036	0.112	0.035	-	-	0.20
91	45	50	53.63	83.11	0.033	-	-	1.00	-	1.00
92	46	47	53.63	14.11	1.543	0.112	0.035	-	-	0.20
93	46	50	53.63	88.59	0.032	-	-	1.00	-	1.00
94	47	48	53.63	10.92	2.386	0.112	0.035	-	-	0.20

TABLE 6.2-21 (Continued)

Junction No.	From CV	To CV	Elevation	Minimum Flow Area (ft^2)	Inertia (L/A) (ft^{-1})	Head Loss, K				
						Bends	Friction (fL/D)	Expansion	Contraction	Total(1)
95	47	50	53.63	91.34	0.031	-	-	1.00	-	1.00
96	48	49	53.63	0.01	3.555	0.112	0.031	-	-	0.20
97	48	50	53.63	72.09	0.035	-	-	1.00	-	1.00
98	49	50	53.63	56.70	0.041	-	-	1.00	-	1.00
99	0	29	40.69	1.00	0.0	-	-	-	-	0.0

NOTE:

1. All horizontal flow paths are assumed to have a conservative K of 0.20.
   All vertical flow paths are assumed to have a conservative K of 0.05.

TABLE 6.2-22

DRYWELL HEAD FLOW PATH DATA

Junction No.	From CV	To CV	Minimum Flow Area (ft^2)	Inertia L/A (ft^{-1})	Entrance Head Losses, K(1): Bends	Friction (f L/D)	Expansion	Contraction	Total	Exit Head Losses, K(1): Bends	Friction (f L/D)	Expansion	Contraction	Total
1	1	2	13.1	0.77	-	-	-	0.5	0.5	-	-	1.0	-	1.02

NOTE:

1. Head loss terms are with respect to minimum flow area.

TABLE 6.2-23

REACTOR WATER CLEANUP ROOMS FLOW PATH DATA

Junction No.	From CV	To CV	Minimum Flow Area (ft^2)	Inertia L/A (ft^{-1})	Entrance Head Losses, K(2) Bends	Entrance Friction (f L/D)	Entrance Expansion	Entrance Contraction	Entrance Total	Exit Head Losses, K(2) Bends	Exit Friction (f L/D)	Exit Expansion	Exit Contraction	Exit Total
1(1)	1	2	16.25	0.444	0.000	0.000	0.000	0.500	0.500	0.497	0.021	0.051	0.000	0.569
2	2	3	16.93	0.356	1.683	0.026	0.000	0.195	0.901	0.000	0.000	1.000	0.000	1.000
1(1)	1	2	16.25	0.247	0.000	0.000	0.000	0.500	0.500	0.390	0.007	0.120	0.000	0.517
2	2	3	24.43	0.175	0.000	0.016	0.000	0.000	0.016	0.882	0.000	1.000	0.150	2.032
1(1)	1	2	17.7	0.258	0.300	0.029	0.000	0.500	0.829	0.000	0.000	1.000	0.000	1.000
1	1	2	16.93	0.717	0.780	0.025	0.000	0.189	0.994	0.000	0.012	0.000	0.195	0.207
2(1)	2	3	16.25	0.191	0.719	0.012	0.000	0.000	0.731	0.000	0.000	1.000	0.051	1.051

NOTES:

1. Junction contains blowout panel with the following properties:

   Weight/Area = 2.5 lb/ft^2
   Set Point Pressure = 30 lb/ft^2
   Drag Coefficient = 2.0

2. Head loss terms are with respect to minimum flow area.

TABLE 6.2-24

STEAM TUNNEL FLOW PATH DATA

Junction No.	From CV	To CV	Minimum Flow Area (ft^2)	Inertia L/A (ft^{-1})	Entrance Head Losses, K(1)					Exit Head Losses, K(1)				
					Bends	Friction (f L/D)	Expansion	Contraction	Total	Bends	Friction (f L/D)	Expansion	Contraction	Total
1	1	2	16.76	0.92	1.53	0.06	-	0.51	2.1	-	-	1.0	-	1.0
2	1	2	25.8	0.24	-	-	-	0.5	0.5	-	0.16	1.0	-	1.16

NOTE:

1. Head loss terms are with respect to minimum flow area.

TABLE 6.2-25

REACTOR BLOWDOWN DATA FOR RECIRCULATION SUCTION LINE BREAK

Time (sec)	Reactor Vessel Pressure (psia)	Liquid Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Steam Flow (lbm/sec)	Steam Enthalpy (Btu/lbm)
0	1040	18870	549	0.	-
1.0	1025	27850	546	0.	-
2.04	1010	20960	544	0.	-
2.60	1005	20910	543	0.	-
3.05	1003	20900	543	0.	-
4.05	1007	20930	543	0.	-
6.05	1016	21010	544.5	0.	-
8.05	1020	21050	545	0.	-
10.80	1014	21000	545	0.	-
19.30	922	20090	530	0.	-
24.60	926	8886	514	2618	1198
26.08	709	8364	499	2374	1200
30.70	543	7078	459	1753	1204
35.70	382	6229	419	1205	1204
40.08	287	5697	390.6	878.8	1202
50.45	163	4929	338	444.4	1195
60.45	102	4675	300	220.5	1187
70.45	76	4534	278	126.8	1182
100.45	59	4528	261	57.64	1177
149.9	56	4673	256	30.91	1176
200.9	57	4830	259	20.95	1176
302.7	62	5075	263	12.24	1178
390.7	39	3886	236	10.47	1170
400.	-	-	-	-	-

TABLE 6.2-26

REACTOR BLOWDOWN DATA FOR MAIN STEAM LINE BREAK
(Minimum ECCS)

Time (sec)	Reactor Vessel Pressure (psia)	Liquid Flow (lbm/sec)	Liquid Enthalpy (Btu/lbm)	Steam Flow (lbm/sec)	Steam Enthalpy (Btu/lbm)
0	1040	0.0	-	9655	1191.4
0.05	1036	0.0	-	11220	1191.5
0.21	1024	0.0	-	8072	1194.0
0.995	976	0.0	-	7676	1194.1
1.01	975	26660	538	988	1194.2
2.05	954	26100	535	1065	1194.5
3.05	941	25630	533	1146	1195.1
4.05	934	23960	532.5	1171	1195.2
6.05	927	19290	532	1096	1195.5
8.05	916	18720	530	1218	1195.9
10.05	897	18080	527	1319	1196.5
15.05	816	16170	512	1490	1199.0
20.05	701	14020	492	1511	1201.8
25.05	580	12010	468	1413	1204.0
30.05	468	10170	449	1260	1204.8
50.05	171	6071	341	485.5	1196.0
70.05	78	5065	279	152.9	1182
90.05	60	4938	262.2	83.11	1178
101.05	57	4959	258	68.19	1176
120.05	55	5028	256	53.46	1176
140.05	54	5094	255	43.45	1175
200.05	56	5302	255	28.53	1175
300.71	62	5666	264	20.14	1178
350.7	46	4866	245	19.36	1173
416.7	30	446.8	217	1.33	1163

TABLE 6.2-27

CORE DECAY HEAT FOLLOWING LOSS OF COOLANT ACCIDENT FOR CONTAINMENT ANALYSIS

Time (sec)	Normalized Core Heat(1)
0	1.084
2.0	0.5574
6.0	0.5491
10.0	0.3856
20.0	0.125
60.0	0.04692
100.0	0.0426
120.0	0.041
200.0	0.0358
800.0	0.026
1,000.0	0.0245
8,000.0	0.013
20,000.0	0.0101
60,000.0	0.00739
200,000.0	0.00512
600,000.0	0.0036
2,000,000.0	0.00237

NOTE:

1. Normalized to 3651 MWt; includes fuel relaxation energy.

TABLE 6.2-28

ADDITIONAL INFORMATION TO BE PROVIDED FOR DUAL CONTAINMENT PLANTS

I.	Secondary Containment Design	
	A. Free volume, ft^3	438,040
	B. Pressure, inches of water gauge	
	1. Normal operation	-0.4
	2. Postaccident	-0.4 inch to -0.25
	C. Leak rate at postaccident pressure, %/day	100
	D. Exhaust fans	
	1. Number	2
	2. Type	Centrifugal
	E. Filters	
	1. Number	2
	2. Type Charcoal filter train consisting of a demister, roughing filter, electric heating coil, HEPA filters, charcoal filters (4 inches deep), and HEPA filter.	
II.	Transient Analysis	
	A. Initial conditions	
	1. Pressure, psia	14.682
	2. Temperature, °F	90
	3. Outside air temperature, °F	90
	4. Thickness of secondary containment wall, inches	36
	5. Thickness of primary containment wall, inches	1.5

TABLE 6.2-28 (Continued)

B. Thermal characteristics

1. Primary containment wall

a. Coefficient of linear expansion, inch per inch-°F (if applicable)	N/A
b. Modulus of elasticity, psi (if applicable)	N/A
c. Thermal conductivity, Btu/hr/ft/°F	25
d. Thermal capacitance, Btu/ft^3/°F	56

2. Secondary containment wall

a. Thermal conductivity, Btu/hr/ft/°F	1
b. Thermal capacitance, Btu/ft^3/°F	28

3. Heat transfer coefficients

a. Primary containment atmosphere to primary containment wall, Btu/hr/ft^2/°F	2.0
b. Primary containment to secondary containment atmosphere, Btu/hr/ft^2/°F	2.0
c. Secondary containment wall to secondary containment atmosphere, Btu/hr/ft^2/°F	2.0

TABLE 6.2-29

CONVECTIVE FILM COEFFICIENTS

Time (hours)	Film Coefficient Btu/hr/ft^2/°F
0	0
2.778-4	0
2.778-3	.629
2.220-2	.759
2.778-2	.750
2.778-1	.842
2.000+0	.911
2.400+1	.764

TABLE 6.2-30

RADIATION COEFFICIENTS

Time (hours)	Radiation Coefficient $Btu/hr/ft^2/°F$
0	0
2.778-4	0
2.778-3	0.841
2.22-2	0.892
2.778-2	0.888
2.778-1	0.944
2.0+0	1.003
2.4+1	0.895

TABLE 6.2-31

OVERALL HEAT TRANSFER COEFFICIENTS AS A FUNCTION OF TIME

Time (hours)	h_C Btu/hr/ft^2/°F	h_F Btu/hr/ft^2/°F	h_T Btu/hr/ft^2/°F
0	0	0	0
2.778-4	0	0	0
2.778-3	0.629	0.841	1.470
2.220-2	0.759	0.892	1.651
2.778-2	0.750	0.888	1.638
2.779-1	0.842	0.944	1.786
2.000+0	0.911	1.003	1.914
2.400+1	0.764	0.895	1.659

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CONTAINMENT IS

Penetration Number(3) Unit 1	Unit 2	GDC/ Reg. Guide	System Name	Fluid	Line Size (in)	ESF Sys(4)	Fig. 6.2-60 Arr. No.	Sys. and Valve Number	L
P101	P101	GDC56	RCIC Pump Suction	Water	6	Yes	21	E51F031	
P102	P102	GDC56,	RHR A Pump Suction	Water	24	Yes	13	E12F004A	
		RG1.11	Suppression Pool Makeup	Water	3/4	Yes	55	G43F050A	
P103	P103	GDC56	LPCS Pump Suction	Water	24	Yes	6	E21F001	
P104	P107	GDC56	RCIC Pump Discharge	Water	2	Yes	18	E51F019	
			Min. Flow to Sup. Pool	Water	2	Yes	18	E51F021	
P105	P106	GDC56	RHR A Min. Flow & Test;	Water	18	Yes	15	E12F024A	
			LPCS Pump Min. Flow & Test;	Water	6	Yes	15	E12F046A	
			RHR Steam Cond. Mode	Water	4	Yes	15	E12F011A	
			Bypass Lines	Water	12	Yes	15	E21F012	
				Water	4	Yes	15	E21F011	
				Water	6	Yes	15	E12F064A	
P106	P108	GDC56	RCIC Turbine Exhaust	Steam	12	Yes	10(b)	E51F068	
				Steam	12	Yes	10(b)	E51F040	
P107	P109	GDC56	RHR A Loop Relief Line	Water	6	Yes	37	E12F055A	
			to Sup. Pool	Water	2	Yes	37	E12F025A	
				Water	1-1/2	Yes	37	E12F103A	
				Water	2	Yes	37	E21F018	
P108	P424	GDC56	Condensate Supply	Cond.	12	No	27(a)	P11-F060	
					12	No	27(a)	P11-F545	
P109	P428	GDC56	Containment Leak Rate	Cont. Atmos.	8	No	35(b)	Spect. Flange	
			Test Connection Blowdown Line	Cont. Atmos.	8	No	35(b)	Spect. Flange	
P111	P426	GDC56	Condensate Return	Water	10	No	27(b)	P11F080	
			(Containment Pool Drain Line)	Water	10	No	27(b)	P11F090	
P112	P113	GDC55	LPCS Pump Discharge to	Water	12	Yes	7	E21F005	
			Reactor Pressure Vessel	Water	12	Yes	7	E21F006	
P113	P114	GDC55	LPCI A to Reactor and RHR	Water	12	Yes	11	E12F027A	
			to Containment Spray and	Water	12	Yes	11	E12F042A	
			Containment Pool Cooling	Water	12	Yes	11	E12F041A	
					12	Yes	11	E12F037A	
					12	Yes	11	E12F028A	
P114	P121	GDC56	Containment Vacuum	Cont. Atmos.	24	Yes	19	M17F015	
			Relief	Cont. Atmos.	24	Yes	19	M17F010	
P115	P111	GDC56	RCIC Turbine Exhaust	Cont. Atmos.	2	No	10(a)	E51F078	
			Vacuum Relief	Cont. Atmos.	2	No	10(a)	E51F077	

BLE 6.2-32

LATION VALVE SUMMARY (1)(2)

c.(5)	Type C Test	Pipe Length(6)	Valve Type	Valve Oper	Actuation Mode Pri.	Actuation Mode Sec.	Valve Position Norm	Valve Position Shut down	Valve Position Post Acc.	Valve Position Pwr. Fail(7)	Isolation Signal (8)	Closure Time(sec)(9)	Pwr Source 1E Bus(10)	Norm. Flow Dir.
0	No	20'-8"	Gate	EM	E	M	CL	OP	OP or CL	AI	RM_s,T,J,K,M,F	30	1	Out
0	No	18'-4"	Gate	EM	E	M	OP	CL	OP	AI	RM_s	Std.	1	Out
0	Yes	< 10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	< 0.25	1	-
0	No	14'-7"	Gate	EM	E	M	OP	OP	OP	AI	RM_c	Std.	1	Out
0	No	NA	Globe	EM	E	M	CL	OP	OP or CL	AI	RM_s	5	1	In
0	No	19'-0"	Chk	P	P	-	CL	CL	OP or CL	-	Rev. Flow	-	-	In
0	No	15'-9"	Gate	EM	E	M	CL	CL	CL or CL	AI	C,G,RM_s	90	1	In
0	No	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
0	No	18'-9"	Globe	EM	E	M	CL	CL	CL	AI	C,G,RM_s	Std.	1	In
0	No	21'-9"	Globe	EM	E	M	CL	CL	CL	AI	C,G,RM_c	Std.	1	In
0	No	24'-0"	Gate	EM	E	M	OP	OP	OP	AI	RM_c	Std.	1	In
0	No	77'-7"	Gate	EM	E	M	OP	OP	OP	AI	RM_s	< 8	1	In
0	No	NA	Gate	EM	E	M	OP	OP	OP	AI	RM_s	30	1	In
0	No	27'-10"	Chk	P	P	-	OP	CL	CL	-	Rev. Flow	-	-	In
0	No	77'-3"	Rel	P	P	-	CL	CL	CL	-	-	-	-	In
0	No	29'-6"	Rel	P	P	-	CL	CL	CL	-	-	-	-	In
0	No	42'-3"	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
0	No	37'-0"	Rel	P	P	-	CL	CL	CL	-	-	-	-	In
0	Yes	10'-9"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	1	In
I	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
0	Yes	-	-	-	-	-	-	-	-	-	-	-	-	Out
I	Yes	-	-	-	-	-	-	-	-	-	-	-	-	Out
0	Yes	12'-0"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	1	Out
I	Yes	NA	B'fly	EM	E	M	CL	CL	CL	AI	B,G,RM_c	30	2	Out
0	No	29'-0"	Gate	EM	E	M	CL	CL	OP	AI	RM_c	27	1	In
I	No	NA	Chk	P	(11)	-	CL	CL	OP	-	Rev. Flow	-	-	In
0	No	25'-9"	Gate	EM	E	M	OP	OP	OP	AI	RM_s	Std.	1	In
I	No	NA	Gate	EM	E	M	CL	CL	OP	AI	RM_s	27	1	In
I	No	NA	Chk	P	(11)	-	CL	CL	OP	-	Rev. Flow	-	-	In
I	No	NA	Globe	EM	E	M	CL	OP	OP or CL	AI	A,U,M,RM_s	Std.	1	In
I	No	NA	Gate	EM	E	M	CL	CL	OP	AI	RM_s	60	1	In
0	Yes	2'-6"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,X,RM_c	5	1	In
I	Yes	NA	Chk	P	V	-	CL	CL	CL	-	Rev. Flow	-	-	In
0	Yes	NA	Globe	EM	E	M	OP	OP	OP	AI	G & J, RM_s	Std.	1	Out
0	Yes	27'-3"	Globe	EM	E	M	OP	OP	OP	AI	G & J, RM_s	7.5	2	Out

TABL

Penetration Number(3) Unit 1	Unit 2	GDC/ Reg. Guide	System Name	Fluid	Line Size (in)	ESF Sys (4)	Fig. 6.2-60 Arr. No.	Sys. and Valve Number	Lo
P116	P125	GDC57	Air Supply to ADS	Air	1	Yes	33	P57F020A	
			Accumulator	Air	1	Yes	33	P57F015A	
P117	P123	GDC57	Nitrogen Supply to	Nitrogen	2	No	41	P86F002	
			Control Rod Drive	Nitrogen	2	No	41	P86F528	
P118	P133	GDC56	RHR Heat Exchanger Vent	Noncondens.	1	Yes	45	E12F073A	
			to Suppression Pool						
				Noncondens.	1	Yes	45	E12F558A	
P119	P110	GDC56	Containment Leak Rate	Cont. Atmos.	1/2	No	35	Spect. Flange	
			Test PI	Cont. Atmos.	1/2	No	35	Spect. Flange	
P120	P427	GDC56	Containment Leak Rate -	Air	8	No	35(b)	Spect. Flange	
			Pressurization Line	Air	8	No	35(b)	Spect. Flange	
P121	P112	GDC55	Feedwater A, RHR, and	Water	20	Yes	2	B21F065A	
			RCIC Return to Reactor	Water	20	Yes	2	B21F032A	
			Pressure Vessel	Water	20	Yes	2	N27F559A	
				Water	12	Yes	2	E12F050A	
				Water	12	Yes	2	E12F053A	
				Water	6	Yes	2	G33F052A	
				Water	6	Yes	2	G33F039	
P122	P115	GDC55	Main Steam Line C	Steam	26	Yes	1(a)	B21F028C	
				Steam	26	Yes	1(a)	B21F022C	
				Steam	1-1/2	No	1(a)	B21F067C	
				Steam	1-1/2	No	1(a)	E32F001J	
P123	P117	GDC55	RCIC Pump Discharge and	Water	6	Yes	5	E51F066	
			RHR Head Spray	Water	6	Yes	5	E51F065	
				Water	6	Yes	5	E51F013	
				Water	6	Yes	5	E12F023	
				Water	6	Yes	5	E12F019	
P124	P116	GDC55	Main Steam Line A	Steam	26	Yes	1(a)	B21F028A	
				Steam	26	Yes	1(a)	B21F022A	
				Steam	1-1/2	No	1(a)	B21F067A	
				Steam	1-1/2	No	1(a)	E32F001A	
P131	P132	GDC55	RWCU Pump Suction	Water	6	Yes	49	G33F001	
				Water	6	Yes	49	G33F004	
P132	P408	GDC55	RWCU Line from Regenerative	Water	6	Yes	44	G33F040	
			Heat Exchanger to Feedwater	Water	6	Yes	44	G33F039	

6.2-32 (Continued)

. (5)	Type C Test	Pipe Length(6)	Valve Type	Valve Oper	Actuation Mode Pri.	Actuation Mode Sec.	Valve Position Norm	Valve Position Shut down	Valve Position Post Acc.	Valve Position Pwr. Fail(7)	Isolation Signal(8)	Closure Time(sec)(9)	Pwr Source 1E Bus(10)	Norm. Flow Dir.
I	Yes	NA	Globe	EM	E	M	OP	OP	CL	AI	RM_c	Std.	1	In
O	Yes	16'-9"	Globe	EM	E	M	OP	OP	CL	AI	RM_c	Std.	1	In
O	Yes	< 20'	Globe	EM	E	M	CL	CL	CL	AI	B,G,RM_c	Std.	1	In
I	Yes	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
O	No	12'-9"	Globe	EM	E	M	[illegible]	CL	CL	AI	RM_c	Std.	1	In
I	No	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
O	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	Out
I	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	Out
O	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	In
I	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	In
O	Yes	38'-5-3/4"	Gate	EM	E	M	OP	CL	OP or CL	AI	RM_c	Std.	1	In
O	Yes	NA	Chk	P	A(12)	P	OP	CL	OP or CL	FC	RM_c	-	-	In
I	Yes	NA	Chk	P	P	-	OP	CL	CL	-	Rev. Flow	-	-	In
O	Yes	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
O	Yes	81'-11-3/4"	Globe	EM	E	M	CL	CL	CL	AI	A,U,M,RM_s	Std.	1	In
O	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
O	Yes	19'-11-3/4"	Gate	EM	E	M	OP	OP	CL	AI	B,F,H,W,Y,RM_c	15	1	In
O	Yes	17'-2-3/4"	Globe	A	A	SP	OP	CL	CL	FC	C,D,E,F,S,N,P,RM_c	(13)	-	Out
I	Yes	NA	Globe	A	A	SP	OP	CL	CL	FC	C,D,E,F,S,N,P,RM_c	(13)	-	Out
O	Yes	25'-2-3/4"	Globe	EM	E	M	OP	CL	CL	AI	C,D,E,F,S,N,P,RM_c	Std.	1	Out
O	Yes	21'-2-3/4"	Gate	EM	E	M	CL	CL	CL	AI	RM_c*,U	Std.	1	Out
I	Yes	NA	Chk	P	(11)	-	CL	CL	OP or CL	-	Rev. Flow	-	-	In
O	Yes	NA	Chk	P	(11)	-	CL	CL	OP or CL	-	Rev. Flow	-	-	In
O	Yes	43'-6"	Gate	EM	E	M	CL	CL	OP or CL	AI	RM_s	15	1	In
O	Yes	50'-5"	Globe	EM	E	M	CL	CL	OP or CL	AI	A,M,V,RM_s	Std.	1	In
O	Yes	NA	Chk	P	P	-	CL	CL	OP or CL	-	Rev. Flow	-	-	In
O	Yes	16'-5-7/8"	Globe	A	A	SP	OP	CL	CL	FC	C,D,E,F,S,N,P,RM_c	(13)	-	Out
I	Yes	NA	Globe	A	A	SP	OP	CL	CL	FC	C,D,E,F,S,N,P,RM_c	(13)	-	Out
O	Yes	23'-5-7/8"	Globe	EM	E	M	OP	CL	CL	AI	C,D,E,F,S,N,P,RM_c	Std.	1	Out
O	Yes	20'-5-7/8"	Gate	EM	E	M	CL	CL	CL	AI	RM_c*,U	Std.	1	Out
I	Yes	NA	Gate	EM	E	M	OP	OP	CL	AI	B,F,H,W,Y,RM_c	15	2	Out
O	Yes	14'-0"	Gate	EM	E	M	OP	OP	CL	AI	B,F,H,W,Y,RM_c	15	1	Out
I	Yes	NA	Gate	EM	E	M	OP	OP	CL	AI	B,F,H,W,Y,RM_c	15	2	Out
O	Yes	10'-9"	Gate	EM	E	M	OP	OP	CL	AI	B,F,H,L,W,Y,RM_c	15	1	Out

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Penetration Number(3) Unit 1	Unit 2	GDC Reg. Guide	System Name	Fluid	Line Size (in)	ESF Sys (4)	Fig. 6.2-60 Arr. No.	Sys. and Valve Number
P201	P218	GDC56	Drywell Atmosphere	Drywell Atm.	1	No	52	D17F079A
			Radiation Monitor Line	Drywell Atm.	1	No	52	D17F079B
				Drywell Atm.	1	No	52	D17F071A
				Drywell Atm.	1	No	52	D17F071B
P203	P301	GDC56	Fuel Pool Cooling Supply	Water	8	No	26(a)	G41F100
				Water	8	No	26(a)	G41F522
P204	P302	GDC55	Control Rod Drive to Reactor	Condensate	2-1/2	Yes	3	C11F083
			Pressure Vessel	Condensate	2-1/2	Yes	3	C11F122
P205	P304	GDC56	Fuel Transfer Tube (15)	Water	36	No	36	F42F004
				Water	36	No	36	F42F002
P208	P122	GDC56	Containment Vacuum	Cont. Atmos.	24	Yes	19	M17F025
			Relief	Cont. Atmos.	24	Yes	19	M17F020
P210	P206	GDC57	Carbon Dioxide to Fire	CO_2	4	No	42	P54F340
			Protection System	CO_2	4	No	42	P54F395
P301	P222	GDC56	Fuel Pool Cooling	Water	10	No	26(b)	G41F145
			Return	Water	10	No	26(b)	G41F140
P302	P211	GDC56	Backup Hydrogen	Drywell Atm.	2	Yes	39(b)	M51F110
			Purge System	Drywell Atm.	2	Yes	39(b)	M51F090
P304	P303	GDC57	Air Supply to ADS	Air	1	Yes	33	P57F015B
			Accumulators	Air	1	Yes	33	P57F020B
P305	P205	GDC56	Instrument Air	Air	3/4	Yes	56	P53F030
				Air	3/4	Yes	56	P53F035
				Air	3/4	Yes	56	P53F050
				Air	3/4	Yes	56	P53F055
				Air	3/4	Yes		P52F160
P306	P204	GDC57	Instrument Air	Air	2	Yes	34	P52F200
				Air	2	Yes	34	P52F550
P308	P203	GDC57	Service Air	Air	2-1/2	No	32	P51F150
				Air	2-1/2	No	32	P51F530

LE 6.2-32 (Continued)

Loc.(5)	Type C Test	Pipe Length (6)	Valve Type	Valve Oper	Actuation Mode Pri.	Actuation Mode Sec.	Valve Position Norm	Valve Position Shut down	Valve Position Post Acc.	Valve Position Pwr. Fail(7)	Isolation Signal (8)	Closure Time(sec)(9)	Pwr. Source 1E Bus(10)	Norm. Flow Dir.
0	Yes	$<$ 10'	Globe	S	E	-	OP	OP	CL	CL	B,G,RM_c	$<$ 0.25	1	In
I	Yes	$<$ 10'	Globe	S	E	-	OP	OP	CL	CL	B,G,RM_c	$<$ 0.25	2	In
0	Yes	$<$ 10'	Ball	EH	E	M	OP	OP	CL	AI	B,G,RM_c	$\leq$ 1.0	1	Out
I	Yes	$<$ 10'	Ball	EH	E	M	OP	OP	CL	AI	B,G,RM_c	$\leq$ 1.0	2	Out
0	Yes	10'-9"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	1	In
I	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
0	Yes	18'-0"	Gate	EM	E	M	OP	OP	CL	AI	RM_c	Std.	1	In
I	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
0	No	54'-0"	Gate	H	H	M	CL	OP or CL	CL	NA	-	$<$ 60	-	In or Out
I	No	NA	Gate	M	M	-	CL	OP or CL	CL	NA	-	-	-	In or Out
0	Yes	2'-6"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,X,RM_c	5	[illegible]	In
I	Yes	NA	Chk	P	V	-	CL	CL	CL	-	Rev. Flow	-	-	In
0	Yes	12'-6"	Gate	EM	E	M	CL	CL	CL	AI	B,G,RM_c	20	1	In
I	Yes	NA	Gate	EM	E	M	CL	CL	CL	AI	B,G,RM_c	20	1	In
0	Yes	13'-0"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	1	Out
I	Yes	NA	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	2	Out
0	Yes	18'-0"	Globe	EM	E	M	CL	OP or CL	CL	AI	RM_c	Std.	1	Out
I	Yes	NA	Globe	EM	E	M	CL	OP or CL	CL	AI	RM_c	Std.	2	Out
0	Yes	14'-6"	Globe	EM	E	M	OP	OP	CL	AI	RM_c	Std.	2	In
I	Yes	NA	Globe	EM	E	M	OP	OP	CL	AI	RM_c	Std.	2	In
0	Yes	$<$ 10'	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	$<$ 0.25	1	In
0	Yes	$<$ 10'	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	$<$ 0.25	1	In
I(14)	Yes	NA	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	$<$ 0.25	1	In
I(14)	Yes	NA	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	$<$ 0.25	1	In
0	Yes		Globe	S	E	-	OP	OP	CL	AI	B.G,RM_c			In
0	Yes	24'-6"	Globe	EM	E	M	OP	OP	CL	AI	B,G,RM_c	Std.	1	In
I	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
0	Yes	11'-3"	Globe	A	A	M	OP	OP	CL	FC	B,G,RM_c	15	1	In
I	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In

TABL

Penetration Number(3) Unit 1	Unit 2	GDC/ Reg. Guide	System Name	Fluid	Line Size (in)	ESF Sys(4)	Fig. 6.2-60 Arr. No.	Sys. and Valve Number	Lo
P309	P207	GDC57	Demineralized Water	Demin. Wtr.	3	No	29	P22F010	
				Demin. Wtr.	3	No	29	P22F577	
P310	P201	GDC57	Nuclear Closed Cooling Water Supply	Water	12	No	25(a)	P43F055	
				Water	12	No	25(a)	P43F721	
P311	P202	GDC57	Nuclear Closed Cooling Water Return	Water	12	No	25(b)	P43F140	
				Water	12	No	25(b)	P43F215	
P312	P215	GDC56	Instrument Air	Air	3/4	Yes	56	P53F040	
				Air	3/4	Yes	56	P53F045	
				Air	3/4	Yes	56	P53F060	
				Air	3/4	Yes	56	P53F065	
				Air	3/4	No		P52F170	
V313	V216	GDC56	Containment Purge Supply	Cont. Atmos.	42	No	30(a)	M14F040	
				Cont. Atmos.	42	No	30(a)	M14F045	
				Cont. Atmos.	18	No	30(a)	M14F190	
V314	V214	GDC56	Containment Purge Exhaust	Cont. Atmos.	42	No	30(b)	M14F090	
				Cont. Atmos.	42	No	30(b)	M14F085	
				Cont. Atmos.	18	No	30(b)	M14F200	
P317	P217	GDC56	Containment Atmosphere Radiation Monitor Line	Cont. Atmos.	1	No	54	D17F089A	
				Cont. Atmos.	1	No	54	D17F089B	
				Cont. Atmos.	1	No	54	D17F081A	
				Cont. Atmos.	1	No	54	D17F081B	
		GDC56	Containment Leak Rate	Cont. Atmos.	1/2	No	35	Spect. Flange	
				Cont. Atmos.	1/2	No	35	Flange	
		GDC56	Containment Leak Rate	Cont. Atmos.	3/4	No	35	Spect. Flange	
				Cont. Atmos.	3/4	No	35	Flange	
P318	P422, P423	RG1.11	Combustible Gas Control Post Accident Hydrogen Analyzer	Cont. Atmos.	1/2	Yes	58(a)	M51F210B	
				Drywell Atm.	1/2	Yes	58(a)	M51F220B	
				Drywell Atm.	1/2	Yes	58(a)	M51F230B	
				Cont. Atmos.	1/2	Yes	58(a)	M51F240B	
				Water	1/2	Yes	58(a)	M51F250B	
P319	P422	RG1.11	Containment Pressure	Cont. Atmos.	3/4	Yes	38(b)	D23F030B	
		RG1.11	Drywell Pressure	Cont. Atmos.	3/4	Yes	38(a)	D23F040B	
		GDC56	Containment Leak Rate	Cont. Atmos.	3/4	No	35	Spect. Flange	
				Cont. Atmos.	3/4	No	35	E61F551	
		GDC56	Containment Leak Rate	Cont. Atmos.	1/2	No	35	Spect. Flange	
				Cont. Atmos.	1/2	No	35	E61F552	
P320	P423	RG1.11	Containment Vacuum Relief	Cont. Atmos.	3/4	Yes	59	M17F065	
		RG1.11	Containment Pressure	Cont. Atmos.	3/4	Yes	38(b)	D23F020B	
		RG1.11	Suppression Pool Level Reference Leg	Cont. Atmos.	3/4	Yes	38(b)	D23F010B	

6.2-32 (Continued)

(5)	Type C Test	Pipe Length(6)	Valve Type	Valve Oper	Actuation Mode Pri	Actuation Mode Sec.	Valve Position Norm	Valve Position Shut down	Valve Position Post Acc.	Valve Position Pwr. Fail(7)	Isolation Signal(8)	Closure Time(sec)(9)	Pwr Source 1E Bus(10)	Norm. Flow Dir.
	Yes	17'-3"	Gate	EM	E	M	OP	OP	CL	AI	B,G,RM_c	Std.	1	In
	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
	Yes	8'-6"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	1	In
	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
	Yes	8'-6"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	1	Out
	Yes	NA	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	2	Out
	Yes	<10'	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	<0.25	2	In
	Yes	<10'	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	<0.25	2	In
(14)	Yes	<10'	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	<0.25	2	In
(14)	Yes	<10'	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	<0.25	2	In
	Yes		Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c			
	Yes	2'-0"	B'fly	A	A	M	OP	OP	CL	FC	B,G,RM_c,Z	4	NA	In
	Yes	NA	B'fly	A	A	M	CL	OP	CL	FC	B,G,RM_c,Z	4	NA	In
	Yes	NA	B'fly	A	A	M	OP	OP	CL	FC	B,G,RM_c,Z	4	NA	In
	Yes	2'-0"	B'fly	A	A	M	OP	OP	CL	FC	B,G,RM_c,Z	4	NA	Out
	Yes	NA	B'fly	A	A	M	CL	OP	CL	FC	B,G,RM_c,Z	4	NA	Out
	Yes	NA	B'fly	A	A	M	OP	OP	CL	FC	B,G,RM_c,Z	4	NA	Out
	Yes	<10'	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	<0.25	1	In
	Yes	NA	Globe	S	E	-	OP	OP	CL	AI	B,G,RM_c	<0.25	2	In
	Yes	<10'	Ball	EH	E	M	OP	OP	CL	CL	B,G,RM_c	<1.0	1	Out
	Yes	NA	Ball	EH	E	M	OP	OP	CL	CL	B,G,RM_c	<1.0	2	Out
	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	Out
	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	Out
	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	Out
	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	2	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	2	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	2	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	2	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	2	In
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	2	-
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	2	-
	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	Out
	Yes	NA	Globe	M	M	-	CL	CL or OP	CL	-	-	-	-	Out
	Yes	NA	-	-	-	-	-	-	-	-	-	-	-	Out
	Yes	NA	Globe	M	M	-	CL	CL or OP	CL	-	-	-	-	Out
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	2	-
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	2	-
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	2	-

TA

Penetration Number(3) Unit 1	Unit 2	GDC/ Reg. Guide	System Name	Fluid	Line Size (in)	ESF Sys(4)	Fig. 6.2-60 Arr. No.	Sys. and Valve Number
P401	P401	GDC56	HPCS Pump Suction	Water	24	Yes	8	E22F015
		RG1.11	Suppression Pool Makeup	Water	3/4	Yes	55	G43F060
P402	P402	GDC56	RHR B Pump Suction	Water	24	Yes	13	E12F004B
		RG1.11	Suppression Pool Makeup	Water	3/4	Yes	55	G43F050B
P403	P403	GDC56	RHR C Pump Suction	Supp. Pool Wtr.	24	Yes	13	E12F105
P404	P104	GDC57	Chilled Water Supply	Water	6	Yes	28(a)	P50F060
				Water	6	Yes	28(a)	P50F539
P405	P105	GDC57	Chilled Water Return	Water	6	Yes	28(b)	P50F150
				Water	6	Yes	28(b)	P50F140
P406	P208	GDC57	Fire Protection Water	Water	4	No	51	P54F726
				Water	4	No	51	P54F727
P407	P404	GDC56	RHR B Test and Pump	Water	18	Yes	17	E12F024B
			Minimum Flow Line, RHR	Water	6	Yes	17	E12F046B
			Steam Condensing Mode	Water	4	Yes	17	E12F011B
			Bypass Line	Water	6	Yes	17	E12F064B
P408	P405	GDC56	RHR C Test and Pump	Water	18	Yes	23	E12F021
			Minimum Flow Line	Water	6	Yes	22	E12F064C
				Water	6	Yes	22	E12F046C
P409	P409	GDC56	HPCS Minimum Flow	Water	12	Yes	24	E22F023
			Line and Test Line to	Water	12	Yes	24	E22F012
			Suppression Pool					
P410	P411	GDC55	HPCS to Reactor	Water	12	Yes	9	E22F004
			Pressure Vessel	Water	12	Yes	9	E22F005
P411	P417	GDC55	LPCI C to Reactor	Water	12	Yes	12	E12F042C
				Water	12	Yes	12	E12F041C
P412	P418	GDC55	LPCI B to Reactor and	Water	12	Yes	11	E12F027B
			RHR to Containment	Water	12	Yes	11	E12F042B
			Spray and Containment	Water	12	Yes	11	E12F041B
			Pool Cooling	Water	12	Yes	11	E12F037B
					12	Yes	11	E12F028B
P414	P410	GDC55	Feedwater B, RHR and	Water	20	Yes	2	B21F065B
			RCIC Return to Reactor	Water	20	Yes	2	B21F032B
			Pressure Vessel	Water	20	Yes	2	N27F559B
				Water	12	Yes	2	E12F050B
				Water	12	Yes	2	E12F053B
				Water	6	Yes	2	G33F052B
				Water	6	Yes	2	G33F039

LE 6.2-32 (Continued)

oc.(5)	Type C Test	Pipe Length(6)	Valve Type	Valve Oper	Actuation Mode Pri	Actuation Mode Sec.	Valve Position Norm	Valve Position Shut down	Valve Position Post Acc.	Valve Position Pwr. Fail(7)	solation Signal(8)	Closure Time(sec)(9)	Pwr Source 1E Bus(10)	Norm. Flow Dir.
0	No	18'-3"	Gate	EM	E	M	CL	CL	OP or CL	AI	RM_c	24	3	Out
0	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	3	-
0	No	17'-8'/16"	Gate	EM	E	M	OP	CL	OP	AI	RM_c	Std.	2	Out
0	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	2	-
0	No	20'-11'/16"	Gate	EM	E	M	OP	CL	OP	AI	RM_c	Std.	1	Out
0	No	9'-6"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	1	In
I	No	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
0	No	10'-3"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	1	Out
I	No	NA	B'fly	EM	E	M	OP	OP	CL	AI	B,G,RM_c	30	2	Out
0	Yes	13'-3"	Gate	M	M	-	LC	LC	LC	-	-	-	-	In
I	Yes	NA	Gate	M	M	-	LC	LC	LC	-	-	-	-	In
0	No	20'-3"	Gate	EM	E	M	CL	CL	CL	AI	C,G,RM_c	90	2	In
0	No	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
0	No	15'-9"	Globe	EM	E	M	CL	CL	CL	AI	C,G,RM_c	Std.	2	In
0	No	78'-0"	Gate	EM	E	M	OP	OP	OP	AI	RM_c	<8	2	In
0	No	18'-7-1/2"	Globe	EM	E	M	CL	CL	CL	AI	C,G,RM_c	90	2	In
0	No	97'-0"	Gate	EM	E	M	OP	OP	OP	AI	RM_c	<8	2	In
0	No	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
0	No	27'-9"	Globe	EM	E	M	CL	CL	CL	AI	B,G,RM_c	Std.	3	In
0	No	17'-0"	Gate	EM	E	M	OP	OP	OP	AI	RM_c	5	3	In
0	No	22'-0"	Gate	EM	E	M	CL	CL	OP	AI	RM_c	27	3	In
I	No	NA	Chk	P	(11)	-	CL	CL	OP	-	Rev. Flow	-	-	In
0	No	22'-9"	Gate	EM	E	-	CL	CL	OP	AI	RM_c	27	2	In
I	No	NA	Chk	P	(11)	-	CL	CL	OP	AI	Rev. Flow	-	-	In
0	No	19'-3"	Gate	EM	E	M	OP	OP	OP	AI	RM_c	Std.	2	In
I	No	NA	Gate	EM	E	M	CL	CL	OP	AI	RM_c	27	2	In
I	No	NA	Chk	P	(11)	-	CL	CL	OP	-	Rev. Flow	-	-	In
I	No	NA	Globe	EM	E	M	CL	OP	OP or CL	AI	A,M,U,RM_c	Std.	2	In
I	No	NA	Gate	EM	E	M	CL	CL	OP	AI	RM_c	60	2	In
0	Yes	36'-6-1/4"	Gate	EM	E	M	OP	CL	OP or CL	AI	RM_c	Std.	1	In
0	Yes	NA	Chk	P	A(12)	-	OP	CL	OP or CL	FC	RM_c	-	-	In
I	Yes	NA	Chk	P	P	-	OP	CL	OP or CL	-	Rev. Flow	-	-	In
0	Yes	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
0	Yes	102'-9-1/4"	Globe	EM	E	M	CL	CL	CL	AI	A,M,U,RM_c	Std.	2	In
0	Yes	NA	Chk	P	P	-	OP	OP	CL	-	Rev. Flow	-	-	In
0	Yes	18'-1/4"	Gate	EM	E	M	OP	OP	CL	AI	B,F,H,L,W,Y,RM-	15	1	In

TABLE

Penetration Number (3) Unit 1	Unit 2	GDC/ Reg. Guide	System Name	Fluid	Line Size (in)	ESF Sys(4)	Fig. 6.2-60 Arr. No.	Sys. and Valve Number	Loc
P415	P415	GDC55	Main Steam Line D	Steam	26	Yes	1(a)	B21F028D	O
				Steam	26	Yes	1(a)	B21F022D	I
				Steam	1-1/2	No	1(a)	B21F067D	O
				Steam	1-1/2	No	1(a)	E32F001N	O
P416	P414	GDC55	Main Steam Line B	Steam	26	Yes	1(a)	B21F028B	O
				Steam	26	Yes	1(a)	B21F022B	I
				Steam	1-1/2	No	1(a)	B21F067B	O
				Steam	1-1/2	No	1(a)	E32F001E	O
P417	P128	GDC56	Drywell and Containment Equipment Drain Sump to Radwaste	Water	3	No	40	G61F080	O
				Water	3	No	40	G61F075	I
P418	P127	GDC56	Drywell and Containment Floor Drain Sump to Radwaste	Water	3	No	43	G61F170	O
				Water	3	No	43	G61F165	I
P419	P432	GDC55	RWCU Pump Discharge	Water	4	No	48	G33F054	O
				Water	4	No	48	G33F053	I
P420	P412	GDC55	RWCU Backwash Transfer Pump to Radwaste	Water	4	No	46	G50F277	O
				Water	4	No	46	G50F272	I
P421	P406	GDC55	RHR Reactor Shutdown Cooling Suction	Water	20	Yes	20	E12F008	O
				Water	20	Yes	20	E12F009	I
				Water	3/4	Yes	20	E12F550	I
P422	P407	GDC55	RHR and RCIC Steam Supply	Steam	10	Yes	1(c)	E51F063	I
				Steam	10	Yes	1(c)	E51F064	O
				Steam	1	Yes	1(c)	E51F076	I
P423	P129	GDC55	Main Steam Line Drain	Water	3	No	1(b)	B21F019	O
				Water	3	No	1(b)	B21F016	I
P424	P420	GDC55	RWCU to Main Condenser and Radwaste	Water	4	No	14	G33F034	O
				Water	4	No	14	G33F028	I
P425	P219	RG1.11	Combustible Gas Control Post Accident Hydrogen Analyzer	Cont. Atmos.	1/2	Yes	58(b)	M51F210A	O
				Drywell Atm.	1/2	Yes	58(b)	M51F220A	O
				Cont. Atmos.	1/2	Yes	58(b)	M51F230A	O
				Cont. Atmos.	1/2	Yes	58(b)	M51F240A	O
				Water	1/2	Yes	58(b)	M51F250A	O
			Suppression Pool Level	Cont. Atmos.	3/4	Yes	38(b)	D23F050	O
P428	P309	GDC56	Containment Vacuum Relief	Cont. Atmos.	24	Yes	19	M17F035	O
				Cont. Atmos.	24	Yes	19	M17F030	I
P429	P419	GDC56	RHR Relief Line to Suppression Pool	Water	2	Yes	57	E12F025B	O
				Water	2	Yes	57	E12F025C	O
				Water	6	Yes	57	E12F055B	O
				Water	1-1/2	Yes	57	E12F103B	O
				Water	1-1/2	Yes	57	E12F005	O

6.2-32 (Continued)

(5)	Type C Test	Pipe Length(6)	Valve Type	Valve Oper	Actuation Mode Pri	Actuation Mode Sec.	Valve Position Norm	Valve Position Shut down	Valve Position Post Acc.	Valve Position Pwr. Fail(7)	Isolation Signal(8)	Closure Time(sec)(9)	Pwr Source 1E Bus(10)	Norm. Flow Dir.
	Yes	16'-5-7/8"	Globe	A	A	SP	OP	CL	CL	FC	C,D,E,F,S,N,P,RM_c	(13)	-	Out
	Yes	NA	Globe	A	A	SP	OP	CL	CL	FC	C,D,E,F,S,N,P,RM_c	(13)	-	Out
	Yes	23'-5-7/8"	Globe	EM	E	M	OP	CL	CL	AI	C,D,E,F,S,N,P,RM_c	Std.	1	Out
	Yes	20'-5-7/8"	Gate	EM	E	M	CL	CL	CL	AI	RM_c*,U	Std.	1	Out
	Yes	17'-4-3/4"	Globe	A	A	SP	OP	CL	CL	FC	C,D,E,F,S,N,P,RM_c	(13)	-	Out
	Yes	NA	Globe	A	A	SP	OP	CL	CL	FC	C,D,E,F,S,N,P,RM_c	(13)	-	Out
	Yes	24'-4-3/4"	Globe	EM	E	M	OP	CL	CL	AI	C,D,E,F,S,N,P,RM_c	Std.	1	Out
	Yes	21'-4-3/4"	Gate	EM	E	M	CL	CL	CL	AI	RM_c*,U	Std.	1	Out
	Yes	26'-6"	Gate	EM	E	M	OP	OP	CL	AI	B,G,RM_c	Std.	1	Out
	Yes	NA	Gate	EM	E	M	OP	OP	CL	AI	B,G,RM_c	Std.	2	Out
	Yes	28'-3"	Gate	EM	E	M	OP	OP	CL	AI	B,G,RM_c	Std.	1	Out
	Yes	NA	Gate	EM	E	M	OP	OP	CL	AI	B,G,RM_c	Std.	2	Out
	Yes	10'-6"	Gate	EM	E	M	OP	OP	CL	AI	B,F,H,W,Y,RM_c	15	1	In
	Yes	NA	Gate	EM	E	M	OP	OP	CL	AI	B,F,H,W,Y,RM_c	15	2	In
	Yes	12'-0"	Gate	EM	E	M	OP	OP	CL	AI	B,G,RM_c	Std.	1	Out
	Yes	NA	Gate	EM	E	M	OP	OP	CL	AI	B,G,RM_c	Std.	2	Out
	Yes	14'-0"	Gate	EM	E	M	CL	OP	CL	AI	A,M,V,RM_s	<33	1	Out
	Yes	NA	Gate	EM	E	M	CL	OP	CL	AI	A,M,V,RM_s	<33	2	Out
	Yes	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	Out
	Yes	NA	Gate	EM	E	M	CL	OP	Op or CL	AI	J,F,K,M,T,RM_s	10	2	Out
	Yes	13'-2"	Gate	EM	E	M	OP	OP	OP or CL	AI	J,F,K,M,T,RM_s	10	1	Out
	Yes	NA	Globe	EM	E	M	OP	CL	OP or CL	AI	J,F,K,M,T,RM_s	Std.	2	Out
	Yes	13'-0"	Gate	EM	E	M	OP	CL	CL	AI	C,D,E,F,S,N,P,RM_c	Std.	1	Out
	Yes	NA	Gate	EM	E	M	OP	CL	CL	AI	C,D,E,F,S,N,P,RM_c	Std.	2	Out
	Yes	8'-6"	Gate	EM	E	M	CL	CL	CL	AI	B,F,H,W,Y,RM_c	15	1	Out
	Yes	NA	Gate	EM	E	M	CL	CL	CL	AI	B,F,H,W,Y,RM_c	15	2	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	1	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	1	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	1	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	1	Out
	Yes	<10'	Globe	S	E	-	CL	CL	OP	AI	RM_c	<0.25	1	In
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	3	-
	Yes	2'-6"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,X,RM_c	5	2	In
	Yes	NA	Chk	P	V	-	CL	CL	CL	-	Rev. Flow	-	-	In
	No	45'-6"	Rel	P	P	-	CL	CL	CL	-	-	-	-	In
	No	39'-6"	Rel	P	P	-	CL	CL	CL	-	-	-	-	In
	No	92'6"	Rel	P	P	-	CL	CL	CL	-	-	-	-	In
	No	57'-9"	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
	No	91'-9"	Rel	P	P	-	CL	CL	CL	-	-	-	-	In

Penetration Number(3) Unit 1	Unit 2	GDC/ Reg. Guide	System Name	Fluid	Line Size (in)	ESF Sys(4)	Fig. 6.2-60 Arr. No.	Sys. and Valve Number	Loc.
P431	P421	GDC56	RHR Heat Exchanger Vent to Suppression Pool	Noncondens.	1	Yes	45	E12F073B	0
				Noncondens.	1	Yes	45	E12F0558B	I
P433	P220	RG1.11	Containment/Drywell Pressure	Cont. Atmos.	3/4	Yes	38(b)	D23F030A	0
				Cont. Atmos.	3/4	Yes	38(a)	D23F040A	0
P434	P221	RG1.11	Suppression Pool Level Reference Leg	Cont. Atmos.	3/4	Yes	38(b)	D23F010A	0
			Containment Pressure	Cont. Atmos.	3/4	Yes	38(b)	D23F020A	0
			Containment Vacuum Relief	Cont. Atmos.	3/4	Yes	59	M17F055	0
P436	P416	GDC56	Containment Vacuum Relief	Cont. Atmos.	24	Yes	19	M17F045	0
				Cont. Atmos.	24	Yes	19	M17F040	I

.2-32 (Continued)

5)	Type C Test	Pipe Length(6)	Valve Type	Valve Oper	Actuation Mode Pri	Actuation Mode Sec.	Valve Position Norm	Valve Position Shut down	Valve Position Post Acc.	Valve Position Pwr. Fail(7)	Isolation Signal(8)	Closure Time(sec)(9)	Pwr Source 1E Bus(10)	Norm. Flow Dir.
	No	12'-9"	Globe	EM	E	M	CL	CL	CL	AI	RM_c	Std.	2	In
	No	NA	Chk	P	P	-	CL	CL	CL	-	Rev. Flow	-	-	In
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	1	-
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	1	-
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	1	-
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	1	-
	Yes	<10'	Globe	S	E	-	OP	OP	OP	AI	RM_c	<0.25	1	-
	Yes	2'-6"	B'fly	EM	E	M	OP	OP	CL	AI	B,G,X,RM_c	5	2	In
	Yes	NA	Chk	P	V	-	CL	CL	CL	NA	Rev. Flow	-	-	In

TABLE 6.2-32 (Continued)

NOTES:

1. Through line leakage classification is discussed in Section 6.2.3.

2. Abbreviations used are as follows:

   A - Air
   ADS - Automatic depressurization system
   AI - As is
   B'fly - Butterfly valve
   Chk - Check valve
   CL - Closed
   E - Electric
   EH - Electrohydraulic
   EM - Electric motor
   FC - Fail Closed
   H - Hydraulic
   HPCS - High pressure core spray system
   LC - Locked closed
   LPCI - Low pressure coolant injection system
   LPCS - Low pressure core spray system
   M - Manual
   NA - Not applicable
   OP - Open
   P - Process fluid
   RCIC - Reactor core isolation cooling system
   Rel - Relief valve
   RHR - Residual heat removal system
   RWCU - Reactor water cleanup system
   S - Solenoid
   SP - Spring
   V - Vacuum in containment

3. Penetrations not listed are spares and are capped, except penetrations P202 (Unit 1)/P306 (Unit 2), P305/P205, and P311/P215, which are the equipment hatch and personnel airlocks.

4. Engineered safety feature system includes support systems required for shutdown.

5. Location inside (I) or outside (O) of containment.

6. Length of pipe from containment to outermost isolation valve.

7. All motor operated isolation valves remain in last position upon failure of valve power. All air operated valves close upon loss of motive air, except as indicated by Note 12, below.

8. Remote manual (RM) valves can be opened or closed by remote manual switch operation during any mode of reactor operation, except when an automatic signal is present. Remote manual valves have two sets of position indicator lights, one set at the remote manual switch, the other set at the control room isolation status panel. Isolation signals are defined as follows:

TABLE 6.2-32 (Continued)

NOTES (Cont'd)

Signal	Description
A	Reactor vessel low water level - level 3. (A scram occurs at this level. 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 reactor core isolation cooling and high pressure core spray systems are activated at this level.)
C	Reactor vessel low water level - level 1. (This is the lowest of the three water level signals. Main steam line isolation occurs at this level. The low pressure core spray and low pressure coolant injection systems are also activated at this level.)
D	High radiation - main steam line.
E	Line break - main steam line (steam line high steam flow).
F	Line break - main steam line (steam line high space temperature).
G	High drywell pressure.
H	Line break in reactor water cleanup system (high space temperature).
J	Line break in reactor core isolation cooling system steam line to turbine (low steam line pressure).
K	Line break in reactor core isolation cooling system steam line to turbine (high steam line space temperature, or high steam flow).
L	High differential flow in the reactor water cleanup system.
M	Line break in residual heat removal shutdown and head cooling (high space temperature).
N	Low main condenser vacuum.
P	Low main steam line pressure at inlet to turbine (RUN mode, only).
S	High main steam line temperature, turbine building.

TABLE 6.2-32 (Continued)

NOTES (Cont'd)

Signal	Description
T	High pressure reactor isolation cooling turbine exhaust diaphragm.
U	High reactor vessel pressure - close residual heat removal - shutdown cooling valves and head cooling valves.
V	Low reactor vessel pressure.
W	High temperature at outlet of cleanup system nonregenerative heat exchanger.
X	Containment to atmosphere differential pressure greater than 0.0 psid.
Y	Standby liquid control system actuated.
Z	High radiation, containment and drywell ventilation exhaust.
RM_c	Remote manual switch from control room. (All automatically actuated containment isolation valves are capable of remote operation from the control room.)
RM_c*	Valve does not have an individual valve remote manual control switch, but uses a "system initiate" remote control switch which controls the valve as well as other functions.
RM_s	Remote manual switch from shutdown panel. (Provided in addition to RM_c, noted above, on selected valves as indicated.)

9. Standard (Std.) closure time, based upon nominal pipe diameter, is approximately 12 inches/min for gate valves and approximately 4 inches/min for globe valves. The standard closure time for butterfly valves is 30 to 60 seconds.

10. A-C motor operated valves required for isolation functions are powered from the a-c standby power buses. D-C operated isolation valves are powered from the batteries.

11. Testable check valves are designed for remote opening with zero differential pressure across the valve seat. The valves close under reverse flow conditions, even if the test switch is positioned to open. The valves open when pump pressure exceeds reactor pressure, even if the test switch is positioned to close.

12. Air operated check valves are only air closed. These valves act as simple check valves upon loss of air.

TABLE 6.2-32 (Continued)

NOTES (Cont'd)

13. Main steam line isolation valves require that both solenoid pilots be de-energized to close. Accumulator air pressure plus spring act to close valves when both pilots are de-energized. Voltage failure at only one pilot does not cause valve closure. These valves are designed to close fully in 3 to 5 seconds (see Section 5.4.5.3).

14. Inside personnel airlock.

15. During reactor operation, a blind flange is installed on the outboard end of the transfer tube as the containment boundary.

TABLE 6.2-33

POTENTIAL SECONDARY CONTAINMENT BYPASS LEAKAGE PATHS

Primary Containment Penetration(1)(2)	Size of Line Penetrating Primary Containment	Termination Region	Bypass Leakage Barrier(3)
Lines Penetrating Primary Containment			
Condensate Makeup Supply	12"	Environment	27(a)
Condensate Makeup Return (Containment Pool Drain Line)	10"	Environment	27(b)
Containment Vacuum Relief	24"	Environment	19
Nitrogen Supply to Control Rod Drive	2"	Environment	41
Feedwater	20"	Environment	2
Drywell Atmosphere Radiation Monitor Line	1"	Environment	52
Control Rod Drive to Reactor Pressure Vessel	2-1/2"	Environment	3
Carbon Dioxide to Fire Protection System	4"	Environment	42
Backup Hydrogen Purge System	2"	Environment	39(b)
Instrument Air (Non Safety)	2"	Environment	34
Instrument Air to Personnel Airlock	3/4"	Environment	56
Service Air	2-1/2"	Environment	32
Demineralized Water	3"	Environment	29
Nuclear Closed Cooling Water Supply	12"	Environment	25(a)
Nuclear Closed Cooling Water Return	12"	Environment	25(b)
Containment Purge Supply	42"	Environment	30(a)
Containment Purge Exhaust	42"	Environment	30(b)
Containment Radiation Monitoring Supply and Return	1"	Environment	54
Combustible Gas Control Hydrogen Analyzer Lines	1/2"	Environment	58(a)&(b)
Containment Pressure	3/4"	Environment	38(b)
Drywell Pressure	3/4"	Environment	38(a)
Suppression Pool Level Reference Leg	3/4"	Environment	38(b)
Chilled Water Supply	6"	Environment	28(a)
Chilled Water Return	6"	Environment	28(b)
Fire Protection Water	4"	Environment	51

TABLE 6.2-33 (Continued)

Primary Containment Penetration[1][2]	Size of Line Penetrating Primary Containment	Termination Region	Bypass Leakage Barrier[3]
Drywell and Containment Equipment Drain Sump to Radwaste	3"	Environment	40
Drywell and Containment Floor Drain Sump to Radwaste	3"	Environment	43
RWCU Backwash Transfer Pump to Radwaste	4"	Environment	46
Main Steam Line Drain	3"	Environment	1(b)
Reactor Water Cleanup to Main Condenser and Radwaste	4"	Environment	14
Lines Enclosed by Guard Pipes			
Main Steam	38"	Environment	Welded Conn.
Main Steam Drains	14"	Environment	Welded Conn.
Feedwater	32"	Environment	Welded Conn.
Residual Heat Removal and Reactor Core Isolation Cooling Steam Supply	22"	Environment	Welded Conn.
Reactor Core Isolation Cooling Pump Discharge and Residual Heat Removal Head Spray	18"	Environment	Welded Conn.
Reactor Water Cleanup Pump Suction	18"	Environment	Welded Conn.
Low Pressure Core Spray Pump Suction from Suppression Pool	36"	Environment	Welded Conn.
High Pressure Core Spray Pump Suction from Suppression Pool	36"	Environment	Welded Conn.
Residual Heat Removal A, B, and C Suction from Suppression Pool	36"	Environment	Welded Conn.
Reactor Core Isolation Cooling Suction from Suppression Pool	18"	Environment	Welded Conn.
Residual Heat Removal Shutdown Supply Suction	32"	Environment	Welded Conn.
Reactor Water Cleanup Pump Discharge	16"	Environment	Welded Conn.
Reactor Water Cleanup from Regenerative Heat Exchanger to Feedwater	16"	Environment	Welded Conn.
Personnel Airlocks	9'-7"	Environment	Resilent Seals

TABLE 6.2-33 (Continued)

NOTES:

1. A technical specification commitment of 3 percent of total design containment leakage is made for the maximum test leakage rate bypassing the containment annulus exhaust gas treatment system (for leakage sources in lines penetrating primary containment and personnel airlocks).

2. Leakage sources from components that circulate core cooling water following LOCA:

   a. Pumps - total leakage of 5 gal/day from residual heat removal, high pressure spray, and low pressure core spray pumps.

   b. Valves - total valve stem leakage of 300 cc/hr from systems handling reactor fluid outside containment.

3. Bypass leakage barrier arrangement is shown on designated detail of Figure 6.2-64.

TABLE 6.2-34

REACTOR COOLANT PRESSURE BOUNDARY
INFLUENT LINES THAT PENETRATE CONTAINMENT/DRYWELL

Influent Line	Isolation Device(s)(1) Inside Drywell	Isolation Device(s)(1) Between Drywell and Containment	Isolation Device(s)(1) Outside Containment	Reference FSAR Section
Feedwater Lines	CV	GP	AOCV, MOV	6.2.4.2.2.1.a.1
High Pressure Core Spray Line	TCV	-	MOV	6.2.4.2.2.1.a.2
Low Pressure Core Spray and Low Pressure Coolant Injection C Lines	TCV	-	MOV	6.2.4.2.2.1.a.3
Low Pressure Coolant Injection A and B Lines	TCV	MOV	MOV	6.2.4.2.2.1.a.3
Control Rod Drive Supply Line	-	CV	MOV	6.2.4.2.2.1.a.4
Reactor Core Isolation Cooling Return and Residual Heat Removal Head Spray Lines	TCV	GP	TCV, MOV	6.2.4.2.2.1.a.5
Standby Liquid Control Lines(2)	CV	EV	-	6.2.4.2.2.1.a.6
Residual Heat Removal Shutdown Cooling Return Lines	-	-	CV, MOV	6.2.4.2.2.1.a.7
Reactor Water Cleanup Discharge to Heat Exchangers	-	MOV	MOV	6.2.4.2.2.1.a.8

NOTES:

1. Isolation devices:

   AOCV - air operated check valve.
   CV - check valve.
   EV - explosive valve.
   GP - Guard pipe.
   MOV - Motor Operated Valve
   TCV - Testable Check Valve

2. These lines do not penetrate containment.

TABLE 6.2-35

REACTOR COOLANT PRESSURE BOUNDARY
EFFLUENT LINES THAT PENETRATE CONTAINMENT/DRYWELL

	Isolation Device(s)[1]			
Effluent Line	Inside Drywell	Between Drywell and Containment	Outside Containment	Reference FSAR Section
Main Steam Lines	AOV	GP	AOV	6.2.4.2.2.1.b.1
Main Steam Drains	MOV	GP	MOV	6.2.4.2.2.1.b.1
Residual Heat Removal and Reactor Core Isolation Cooling Steam Supply	MOV	GP	MOV	6.2.4.2.2.1.b.1
Reactor Water Cleanup to Pumps	MOV	GP	MOV	6.2.4.2.2.1.b.2
Reactor Water Cleanup to Condenser and Radwaste	-	MOV	MOV	6.2.4.2.2.1.b.2
Reactor Water Cleanup from Regenerative Heat Exchangers to Feedwater	-	MOV	MOV	6.2.4.2.2.1.b.2
Residual Heat Removal Shutdown Cooling Line	MOV	GP	MOV	6.2.4.2.2.1.b.3
Recirculation System Sample Line	AOV	AOV	-	6.2.4.2.2.1.b.4

NOTE:

1. Isolation devices:

   AOV - air operated valve.
   GP - guard pipe
   MOV - motor operated valve.

TABLE 6.2-36

PRIMARY CONTAINMENT ISOLATION FOR
LINES THAT PENETRATE CONTAINMENT AND
CONNECT TO THE SUPPRESSION POOL

Line	Isolation Device(s)[1] Outside Containment	Reference FSAR Section
Influent Lines		
Low Pressure Core Spray Minimum Flow Line	MOV	6.2.4.2.2.2.a.1
Low Pressure Core Spray Test Line	MOV	6.2.4.2.2.2.a.1
High Pressure Core Spray Minimum Flow Line	MOV	6.2.4.2.2.2.a.1
High Pressure Core Spray Test Line	MOV	6.2.4.2.2.2.a.1
Residual Heat Removal Suppression Pool Cooling and Test Line	MOV	6.2.4.2.2.2.a.1
Residual Heat Removal Steam Condensing Mode Bypass Line	MOV	6.2.4.2.2.2.a.1
Residual Heat Removal Minimum Flow Line	MOV, CV	6.2.4.2.2.2.a.1
Reactor Core Isolation Cooling Minimum Flow Line	MOV, CV	6.2.4.2.2.2.a.2
Reactor Core Isolation Cooling Turbine Exhaust	MOV, CV	6.2.4.2.2.2.a.2
Reactor Core Isolation Cooling Turbine Exhaust Vacuum Relief	MOV	6.2.4.2.2.2.a.2
Residual Heat Removal Heat Exchanger Vent to Suppression Pool	MOV, CV	6.2.4.2.2.2.a.3
Relief Valve Discharge Lines	RV	6.2.4.2.2.2.a.3
Effluent Lines		
Low Pressure Core Spray Suction Line	MOV	6.2.4.2.2.2.b
High Pressure Core Spray Alternate Suction Line	MOV	6.2.4.2.2.2.b
Reactor Core Isolation Cooling System Alternate Suction Line	MOV	6.2.4.2.2.2.b
Residual Heat Removal Suction Line	MOV	6.2.4.2.2.2.b

TABLE 6.2-36 (Continued)

NOTE:

1. Isolation devices:

   CV - check valve.
   MOV - motor operated valve.
   RV - relief valve.

TABLE 6.2-37

COMBUSTIBLE GAS CONTROL SYSTEM
EQUIPMENT DESIGN AND PERFORMANCE DATA

a. Combustible Gas Purging Units (Mixing)

1.	Compressor	Centrifugal
	Max inlet pressure, psia	23.3
	Max discharge pressure, psia	29.13
	Max inlet temperature, °F	185
	Max discharge temperature, °F	238
	Relative humidity (inlet), %	100
	Capacity, scfm	546
	Power requirement, BHP	41
2.	Heat Exchanger	
	Design Pressure (tube side), psig	500
	Air Temperature in/out, °F	238/190
	Cooling Water Temp. in/out, °F	140/170
3.	Material	
	Compressor	
	Casing	cast steel
	Shroud	aluminum
	impeller	174 PH S.S.
	Heat Exchanger	
	Tube	304 S.S.

TABLE 6.2-37 (Continued)

4. Manufacturer	Turbonetics
b. Isolation Valves	
Type	globe
Body	Bronze
Stem	Bronze
Disc	Hardened 304 S.S.
Disc Type	Swivel plug
Seats	Renewable hardened 304 S.S.
c. Hydrogen Recombiner	
1. Material	
Outer Structure	Type 300 series S.S.
Inner Structure	Inconel 600
Heater Element Sheath	Inconel 800
Base Skid	Carbon Steel, painted
2. Power	
Maximum, kW	75
Nominal, kW	50
3. Capacity, scfm	100 to 120 at 1 atm
4. Temperatures	
Gas in, °F	150
Outlet of heater section, °F	1,150 to 1,400
Exhaust, °F	50 above ambient

TABLE 6.2-37 (Continued)

5. Heaters	
Number	5 banks
Max. heat flux, watts/in^2	5.8
Max. sheath temperature, °F	1,550
6. Manufacturer	Westinghouse
d. Piping	
Material	Carbon Steel

TABLE 6.2-38

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 valves	Should valve control power fail, valves will remain shut: redundant subsystem will maintain system capabilities.
Hydrogen recombiner	Failure of recombiner to operate resulting in loss of hydrogen removal capability	Should recombiner fail, redundant recombiner will maintain system capabilities.
Hydrogen analyzer	Failure of analyzer or sample system	Should the analyzer or sample system fail, redundant analysis or sample system will maintain system capabilities.

TABLE 6.2-39

DESIGN AND OPERATING PARAMETERS FOR HYDROGEN CONTROL

System	Turn-On Time	System Design	System Used For Analysis
Containment Atmospheric Dilution	18 hr.	Two-500 scfm compressors	One-500 scfm compressor
Hydrogen Recombiner	287 hr.	Two-100 scfm recombiner	One-100 scfm recombiner
Containment Purge	287 hr.	One-50 scfm purge line	One-50 scfm purge

TABLE 6.2-40

PRIMARY REACTOR CONTAINMENT PENETRATION AND CONTAINMENT ISOLATION VALVE LEAKAGE RATE TEST LIST

Item No.	Description	Type Test	Inboard Isolation Barrier Barrier Description/ Valve No.	Notes	Outboard Isolation Barrier Barrier Description/ Valve No.	Notes
1	Equipment hatch	B	Double O-ring	1	-	-
2	Personnel lock					
	Inner door	B	Double gasket	1	-	-
	Outer door	B	-	-	Double gasket	1
	Barrel	B	Inner door	2	Outer door	2
3	Personnel lock					
	Inner door	B	Double gasket	1	-	-
	Outer door	B	-	-	Double gasket	1
	Barrel	B	Inner door	2	Outer door	2
4	Fuel transfer tube	B	Double gasket	1,12	-	-
5	Main steam line A	B,C	B21F022A	3,4,12	B21F028A	4
		C			B21F067A	-
		C			E32F001A	-
6	Main steam line B	B,C	B21F022B	3,4,12	B21F028B	4
		C			B21F067B	-
		C			E32F001E	-
7	Main steam line C	B,C	B21F022C	3,4,12	B21F028C	4
		C			B21F067C	-
		C			E32F001J	-
8	Main steam line D	B,C	B21F022D	3,4,12	B21F028D	4
		C			B21F067D	-
		C			E32F001N	-
9	Feedwater A	B,C	N27F559A	6,12,13	B21F032A	6,13
		C	-	-	B21F065A	4,6,7,13
		C			E12F050A	6,7,13
		C			E12F053A	6,7,13
		C			G33F052A	-
		C			G33F039	-
10	Feedwater B	B,C	N27F559B	6,12,13	B21F032B	6,13
		C	-	-	B21F065B	4,6,7,13
		C			E12F050B	6,7,13
		C			E12F053B	6,7,13
		C			G33F052B	-
		C			G33F039	-

TABLE 6.2-40 (Continued)

Item No.	Description	Type Test	Inboard Isolation Barrier Barrier Description/ Valve No.	Notes	Outboard Isolation Barrier Barrier Description/ Valve No.	Notes
11	RHR pump A suction	-	E12F004A	6,13	Closed system	6,7,13
		-	E12F017A	6,8,13	Closed system	6,7,13
12	RHR pump B suction	-	E12F004B	6,13	Closed system	6,7,13
		-	E12F017B	6,8,13	Closed system	6,7,13
13	RHR pump C suction	-	E12F105	6,13	Closed system	6,7,13
		-	E12F017C	6,8,13	Closed system	6,7,13
14	RHR shutdown suction	B,C	E12F009	12	E12F008	-
			E12F550	-		-
15	RHR A pump test line to suppression pool	-	E12F011A	9	Closed system	7,9
		-	E12F046A	9	Closed system	
		-	E12F024A	9	Closed system	
		-	E21F501	9	Closed System	
16	RHR pump B test line to suppression pool	-	E12F011B	9	Closed System	7,9
		-	E12F046B	9	Closed System	-
		-	E12F024B	9	Closed System	-
17	RHR C pump test line to suppression pool	-	E12F046C	9	Closed System	7,9
		-	E12F021	9	Closed System	
18	RHR A relief valve discharge to suppression pool	-	E12F103A	9	Closed System	7,9
		-	E12F025A	9	Closed System	-
		-	E12F055A	6,8		-
19	RHR B relief valve discharge to suppression pool	-	E12F103B	9	Closed System	-
		-	E12F025B	9	Closed System	-
		-	E12F025C	6,9,13	Closed System	-
		-	E12F055B	6,8,13	Closed System	-
20	Steam supply to RCIC turbine @ RHR heat exchanger	B,C	E51F063	5,12	E51F064	-
		B,C	E51F076	3,12		-
21	RHR heat exchanger vents	-	E12F558A	9	E12F073A	9
22	RHR heat exchanger vents	-	E12F558B	9	E12F073B	9

TABLE 6.2-40 (Continued)

Item No.	Description	Type Test	Inboard Isolation Barrier Barrier Description/ Valve No.	Notes	Outboard Isolation Barrier Barrier Description/ Valve No.	Notes
23	RCIC and RHR to RPV head spray	B,C	E51F066	12	E51F065	-
				-	E51F013	-
				-	E12F023	-
				-	E12F019	-
24	LPCI A to Reactor	C	E12F042A	-	E12F027A	-
25	LPCI B to Reactor	C	E12F042B	-	E12F027B	-
26	LPCI C to Reactor	C	E12F041C	-	E12F042C	-
27	RCIC pump minimum flow line	-	E51F019	9	Closed System	7,9
28	RCIC pump suction	-	E51F031	9	Closed System	7,9
29	RCIC turbine exhaust	-	E51F068	9	E51F040	9
30	RCIC pump turbine exhaust vacuum relief	C	E51F078	3	E51F077	-
31	HPCS pump suction	-	E22F015	6,13	Closed System	6,7,13
32	HPCS pump discharge to RPV	-	E22F005	6,13	E22F004	6,13
33	HPCS min. flow and test line to suppression pool	-	E22F023	9	Closed System	7,9
		-	E22F035	8,9	Closed System	
		-	E22F012	9	Closed System	
34	LPCS pump suction	-	E21F001	6,13	Closed System	6,7,13
35	LPCS pump discharge to RPV	-	E21F006	6,13	E21F005	6,13
36	Main steam line drain	B,C	B21F016	12	B21F019	-
37	RWCU pump suction	B,C	G33F001	12	G33F004	-
38	RWCU pump discharge	C	G33F053	-	G33F054	-
39	RWCU return to feedwater	C	G33F040	-	G33F039	-
40	RWCU to main condenser and radwaste	C	G33F028	-	G33F034	-

TABLE 6.2-40 (Continued)

Item No.	Description	Type Test	Inboard Isolation Barrier Barrier Description/ Valve No.	Notes	Outboard Isolation Barrier Barrier Description/ Valve No.	Notes
41	Fuel pool cooling and cleanup supply	C	G41F522	-	G41F100	-
42	Fuel pool cooling and cleanup system return	C	G41F140	-	G41F145	-
43	Containment purge supply	C	M14F045 M14F190	10	M14F040	-
44	Containment purge exhaust	C	M14F200 M14F085	10	M14F090	-
45	Chilled water supply	C	P50F539	-	P50F060	-
46	Chilled water return	C	P50F140	-	P50F150	-
47	Drywell and containment equipment drain sump pump discharge	C	G61F075	-	G61F080	-
48	Drywell and containment floor drain sump pump discharge	C	G61F165	-	G61F170	-
49	Demineralized water supply to containment	C	P22F577	-	P22F010	-
50	RWCU backwash transfer pump discharge	C	G50F272	-	G50F277	-
51	Nuclear closed cooling water supply	C	P43F721	-	P43F055	-
52	Nuclear closed cooling water return	C	P43F215	-	P43F140	-
53	Condensate supply	C	P11F545	-	P11F060	-
54	Condensate return	C	P11F090	-	P11F080	-
55	Air supply to ADS accumulators	C	P57F020A	-	P57F015A	-
56	Air supply to ADS accumulators	C	P57F020B	-	P57F015B	-

TABLE 6.2-40 (Continued)

Item No.	Description	Type Test	Inboard Isolation Barrier Barrier Description/ Valve No.	Notes	Outboard Isolation Barrier Barrier Description/ Valve No.	Notes
57	Service air	C	P51F530	-	P51F150	-
58	Instrument Air	C	P52F550	-	P52F200	-
59	Containment Vacuum Relief	C	M17F010	-	M17F015	-
60	Containment Vacuum Relief	C	M17F020	-	M17F025	-
61	Containment Vacuum Relief	C	M17F030	-	M17F035	-
62	Containment Vacuum Relief	C	M17F040	-	M17F045	-
63	Containment Vacuum Relief	C	M17F501A	-	M17F055	-
64	Containment Vacuum Relief	C	M17F501B	-	M17F065	-
65	Fire Protection Water	C	P54F727	-	P54F726	-
66	CO_2 to Fire Protection	C	P54F395	-	P54F340	
67	Backup H_2 Purge	C	M51F090	-	M51F110	-
68	Post LOCA H_2 Analyzer (Containment)	C	M51F210A	14		-
69	Post LOCA H_2 Analyzer (Drywell)	C	M51F220A	14		-
70	Post LOCA H_2 Analyzer (Drywell)	C	M51F230A	14		-
71	Post LOCA H_2 Analyzer (Containment)	C	M51F240A	14		-

TABLE 6.2-40 (Continued)

Item No.	Description	Type Test	Inboard Isolation Barrier Barrier Description/ Valve No.	Notes	Outboard Isolation Barrier Barrier Description/ Valve No.	Notes
72	Post LOCA H_2 Analyzer (Containment)	C	M51F250A	14		-
73	Post LOCA H_2 Analyzer (Containment)	C	M51F210B	14		-
74	Post LOCA H_2 Analyzer (Drywell)	C	M51F220B	14		-
75	Post LOCA H_2 Analyzer (Drywell)	C	M51F230B	14		-
76	Post LOCA H_2 Analyzer (Containment)	C	M51F240B	14		-
77	Post LOCA H_2 Analyzer (Containment)	C	M51F250B	14		-
78	ILRT Air Supply	C	E61D016 and blind flange	-	E61D001	-
79	ILRT Blowdown	C	E61D017 and blind flange	-	E61D003	-
80	Drywell Pressure	C	E61D014	-	E61D015	-
81	ILRT Instrumentation	C	E61F549 and blind flange	-	E61D007	13
82	ILRT Instrumentation	C	E61F550 and blind flange	-	E61D006	13
83	ILRT Instrumentation	C	E61F551 and blind flange	-	E61D005	13
84	ILRT Instrumentation	C	E61F552 and blind flange	-	E61D004	13
85	N_2 Supply	C	P86F528	-	P86F002	-
86	CRD to Reactor	C	C11F122	-	C11F083	-
87	Drywell Atmosphere Radiation Monitor	C	D17F071B	-	D17F071A	-
88	Drywell Atmosphere Radiation Monitor	C	D17F079B	-	D17F079A	-

TABLE 6.2-40 (Continued)

Item No.	Description	Type Test	Inboard Isolation Barrier Barrier Description/ Valve No.	Notes	Outboard Isolation Barrier Barrier Description/ Valve No.	Notes
89	Containment Atmosphere Radiation Monitor	C	D17F081B	-	D17F081A	-
90	Containment Atmosphere Radiation Monitor	C	D17F089B	-	D17F089A	-
91	Containment Pressure	C,A	D23F030A	14		-
92	Containment Pressure	C,A	D23F030B	14		-
93	Drywell Pressure	C,A	D23F040A	14		-
94	Drywell Pressure	C,A	D23F040B	14		-
95	Containment Pressure	C,A	D23F020A	14		-
96	Containment Pressure	C,A	D23F020B	14		-
97	Suppression Pool Level Reference Leg	C,A	D23F010A	14		-
98	Suppression Pool Level Reference Leg	C,A	D23F050B	14		-
99	Suppression Pool Level Reference Leg	C,A	D23F050	14		-
100	Suppression Pool Level	C	G43F502A	3,9	G43F050A	-
101	Suppression Pool Level	C	G43F502B	3,9	G43F050B	-
102	Suppression Pool Level	C	G43F503	3,9	G43F060	-
Various	Spares	-	Capped	-	-	-
Various	Electrical	B	Double O-rings	11	-	-

TABLE 6.2-40 (Continued)

NOTES:

1. Penetration is sealed by a blind flange or door with double O-ring or double gasket seals. The gaskets or O-rings are leak checked by pressurizing the space between them.

2. Personnel air lock volume is pressurized to pressure (P_a) as given in Chapter 16. During the air lock test, tie downs are installed on the inner door since it is not designed to withstand the full differential pressure across the door in the reverse direction. Pressurizing the lock barrel also tests the lock mechanical and electrical penetrations.

3. Globe valve tested in reverse direction. Conservative test; test pressure tends to unseat disc.

4. MSIV seat leakage rate shall not exceed 25 scfh for any valve. FWIV seat leakage rate shall not exceed 2cc/hr./inch of seat diameter when tested with water.

5. Gate valve tested in reverse direction. Leakage characteristics are the same in both directions.

6. System remains water filled post-LOCA. Isolation valve tested with water. Isolation valve leakage not included in 0.60 La Type B and C test totals.

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. 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. Closed system integrity is maintained and verified during periodic Type A test and during system operational tests.

TABLE 6.2-40 (Continued)

8. Relief valve not locally testable. Tested in correct direction during Type A test.

9. System is sealed from the primary containment atmosphere because its line terminated below the water level of the suppression pool. Leakage is not included in 0.60 L_a Type B and C test totals.

10. Butterfly valve tested in reverse direction; leakage characteristics same in both directions.

11. Modular type electrical penetration with header plate bolted to penetration nozzle. Double O-ring seals with test connection is provided at interface.

12. Penetration design utilizes a double bellows for containment isolation. The bellows is leak checked by pressurizing the space between the inner and outer bellows. The fuel transfer tube bellows is sealed on both ends with double gasketed flange joints. These joints are leak checked by pressurizing the space between the double gaskets.

13. System is not vented and drained for Type A test.

14. Isolation valving for instrument lines which penetrate the containment conform to the requirements of Regulatory Guide 1.11. The ISI program will provide assurance of the operability and integrity of the isolation provisions. Type "C" testing will not be performed on the instrument line isolation valves. The instrument lines will be within the boundaries of the Type "A" test, open to the media (containment atmosphere or suppression pool water) to which they will be exposed under postulated accident conditions.

TABLE 6.2-41

CONTAINMENT LEAK RATE TEST DATA

Type A Test Definitions

A.	Peak Test Pressure The calculated peak containment internal pressure related to the design basis accident.	P_a = 12 ± 0.1 psig
B.	Maximum Allowable Leakage Rate at P_a	L_a = .2% by weight of the contained atmosphere in 24 hrs.
C.	Measured Leakage Rate at P_a The total measured containment leakage rate at pressure P_a 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.	L_{am}
D.	Imposed Leakage Rate The known leakage rate superimposed on the containment during the verification test.	L_o
E.	Composite Test Leakage Rate The composite leakage rate measured using the ILRT instruments after L_o is superimposed.	L_c

TABLE 6.2-41 (Continued)

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.

2. A Type A test shall last a minimum of eight hours after stabilization and shall have a total of not less than 20 sets of data points at approximately equal time intervals.

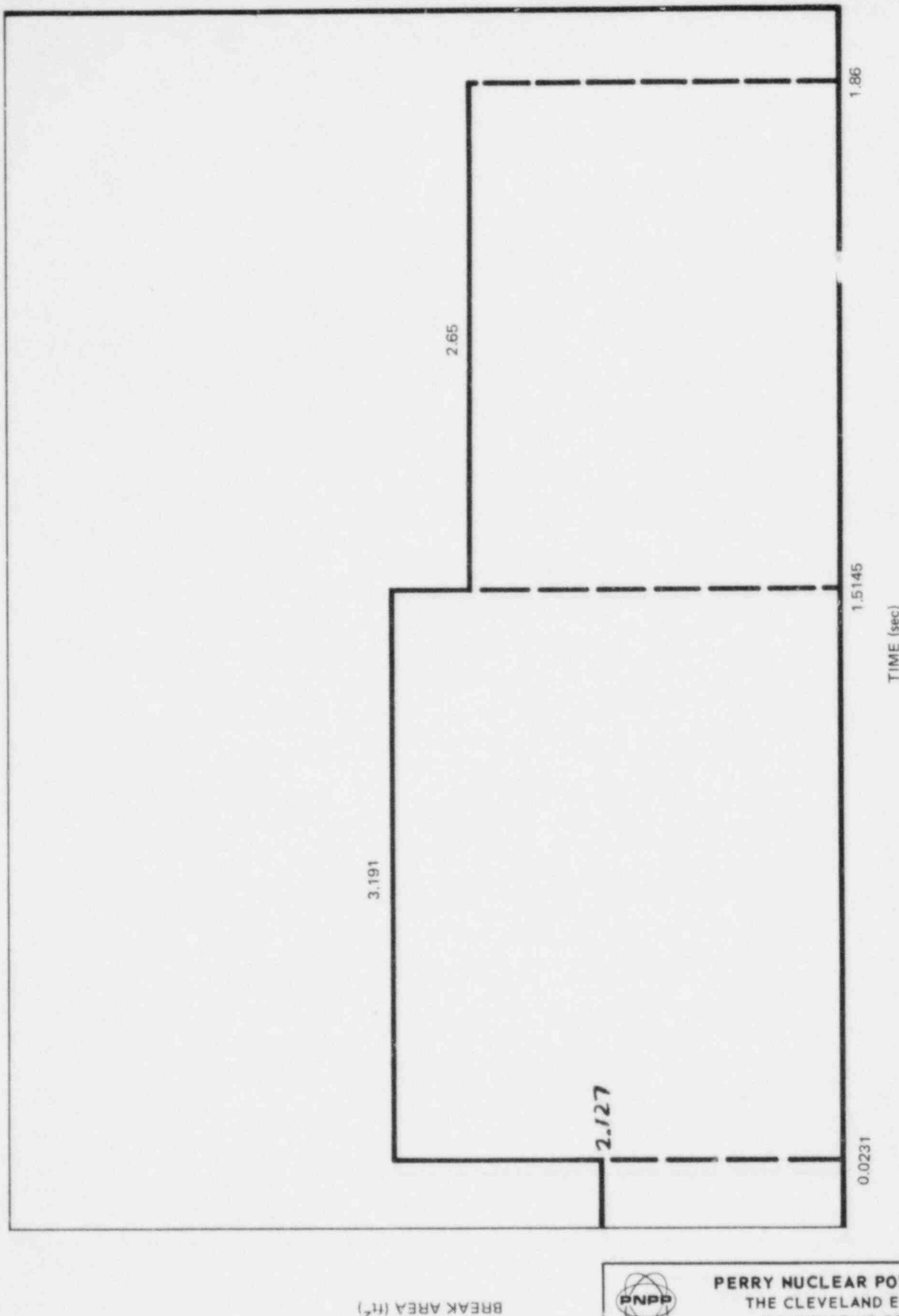
3. A Type A test cannot be successfully terminated until the acceptance criteria of Chapter 16 are met.

G.	Containment Atmosphere Temperature Limits During Type A Test	40-120° F
H.	Containment Free Air Volume	1,165,400 ft^3 (includes drywell free air volume)
I.	Drywell Free Air Volume	276,500 ft^3

TABLE 6.2-42

PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE INSTRUMENTATION

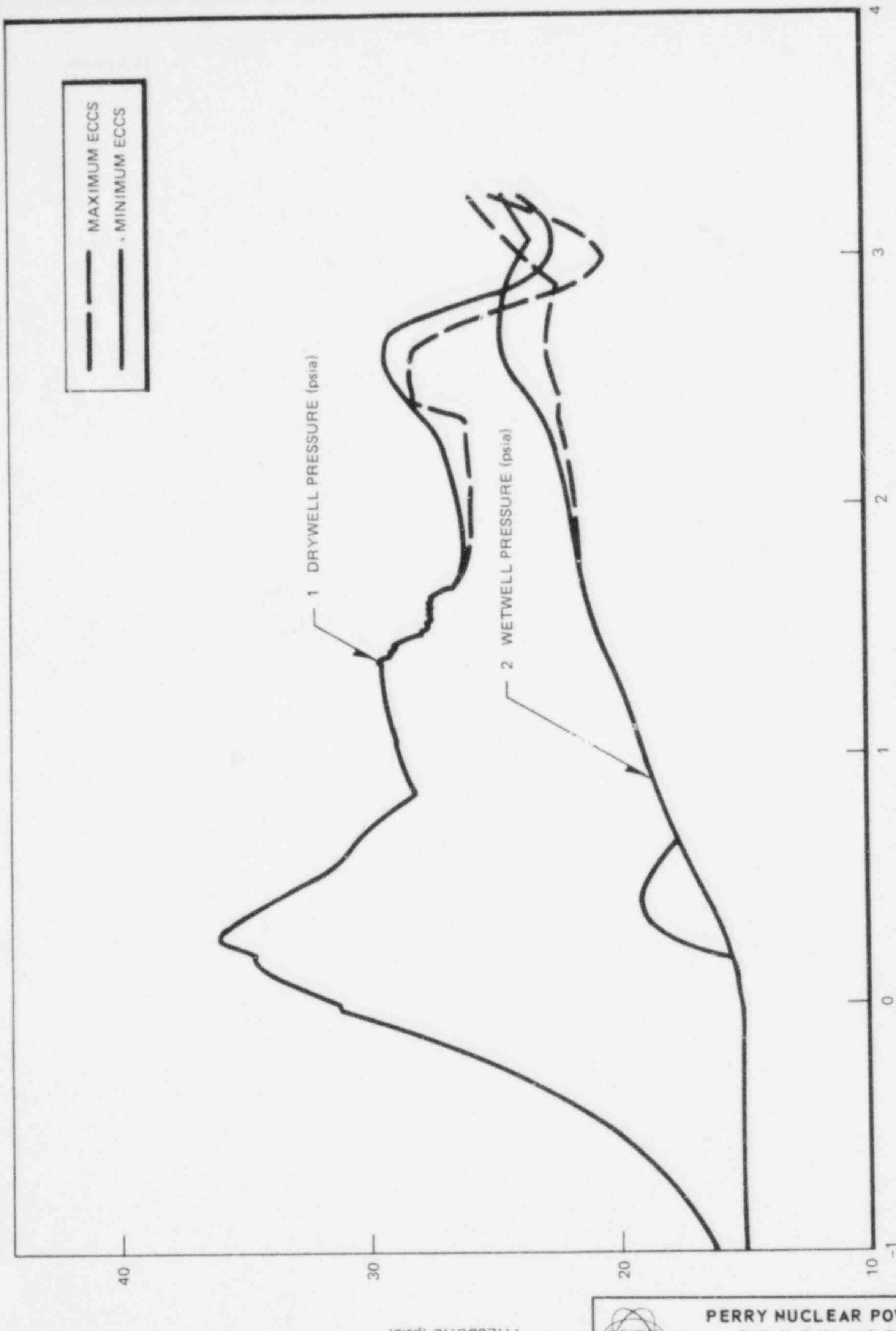
Item	No. Required	Description
PIT-N120	2	Precision pressure gauge with BCD (8421) shaft encoder kit
PIT-N121		Range: 0-100 psia Accuracy: 0.010% of reading ± .002% of full scale or better Repeatability: 0.002% of full scale
TE-N001 through TE-N034	34	Resistance temperature detectors Usable Range: -100 to 250° F Accuracy: ± 0.1° F or better Repeatability: ± .05° F
ME-N080 through ME-N092	13	Dewpoint temperature detectors Range: 0-100° F Accuracy: ± 0.5° F or better Repeatability: ± 5° F over the range of 40 to 120° F
FT-N130 FT-N131	2	Mass flow transmitter Range: 0-10 scfm Accuracy: ± 1% full scale including linearity Repeatability: ± 0.2% full scale
R-133	1	Pressure Indicator Range: 0-50 psig Accuracy: Combined linearity and hysteresis within ± 0.1% full scale



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Effective Blowdown Area
for Recirculation Line Break

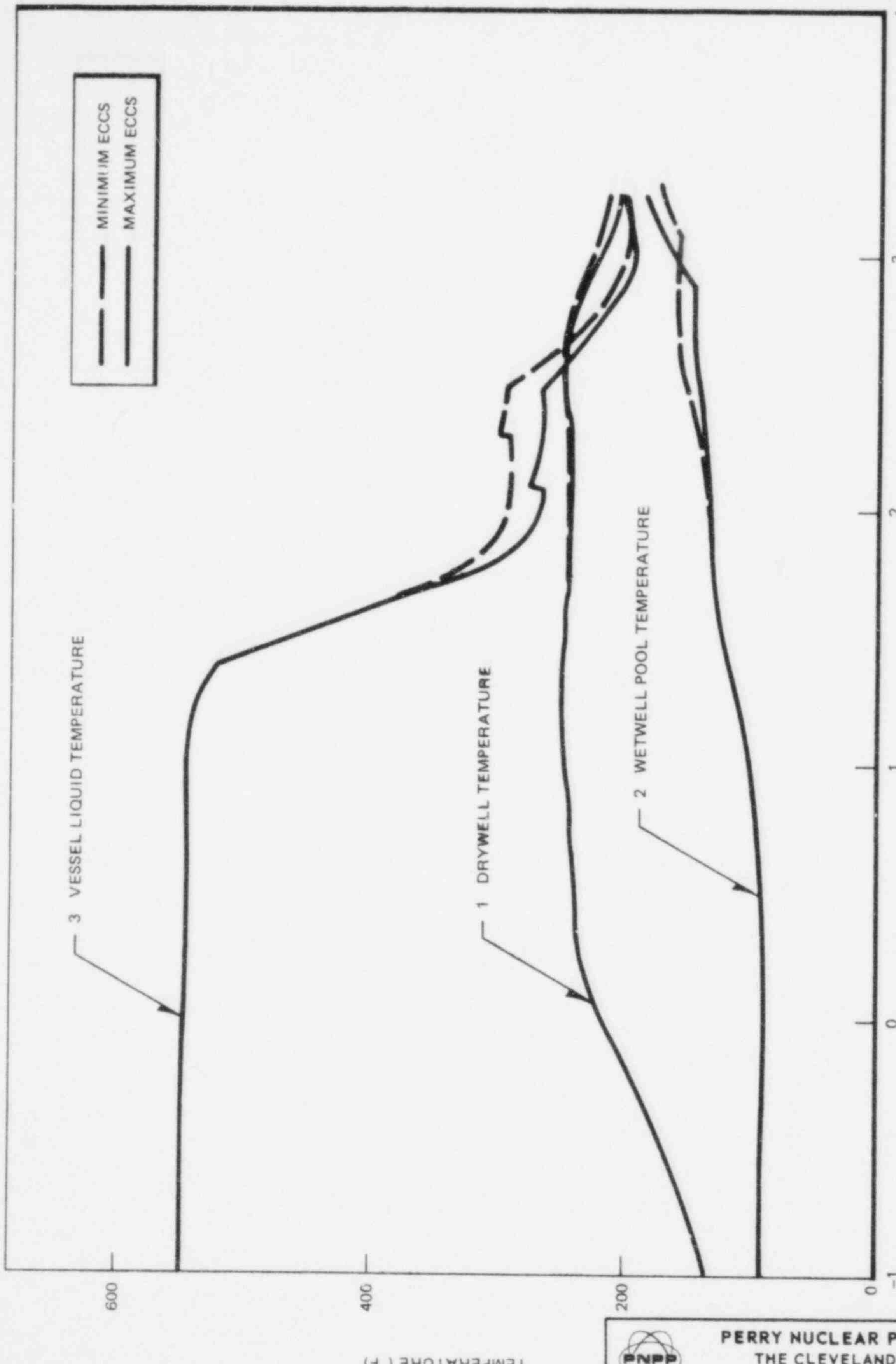
Figure 6.2-1



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Short Term Pressure Response
Following a Recirculation
Line Break

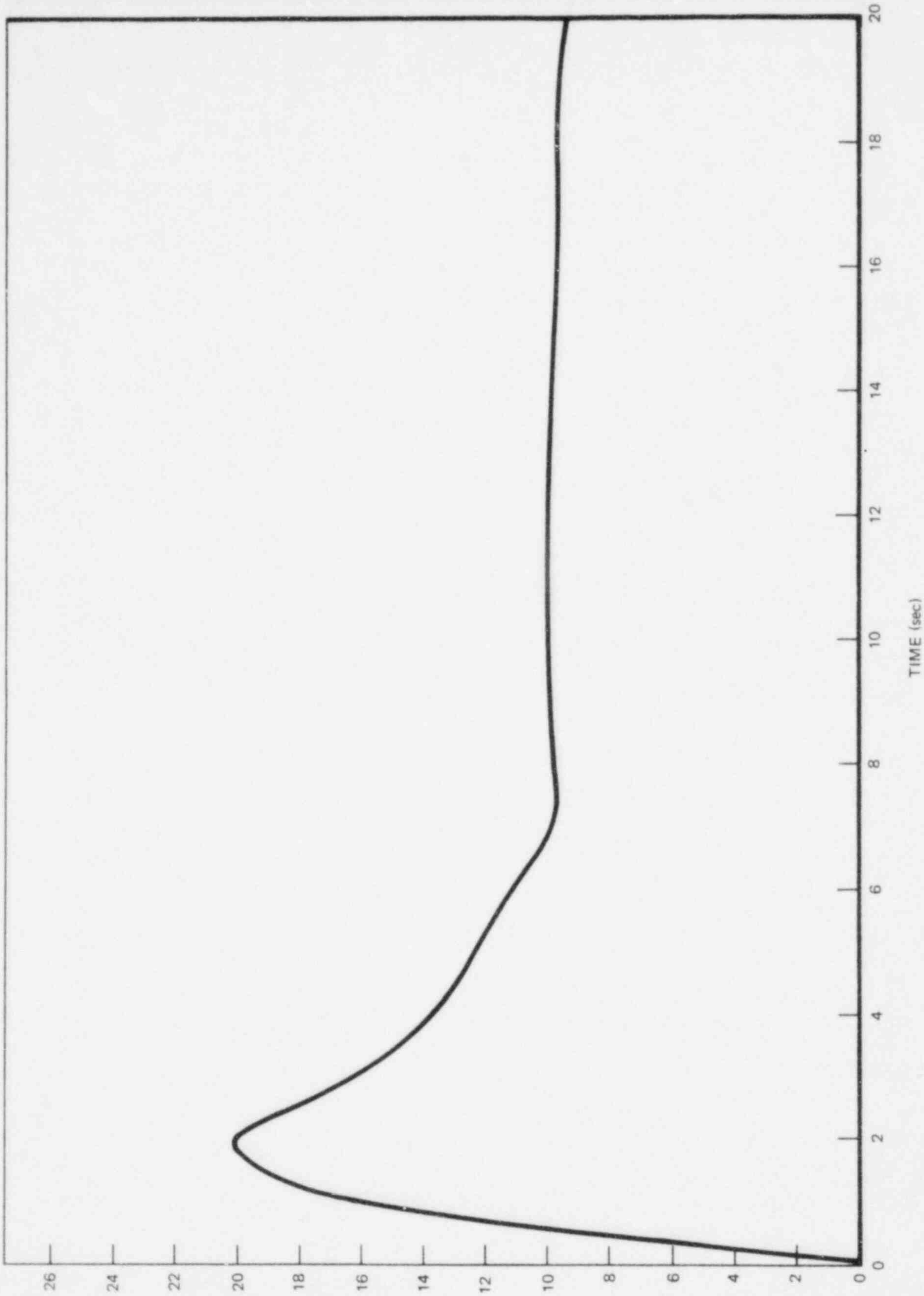
Figure 6.2-2



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Short Term Temperature Response Following a Recirculation Line Break

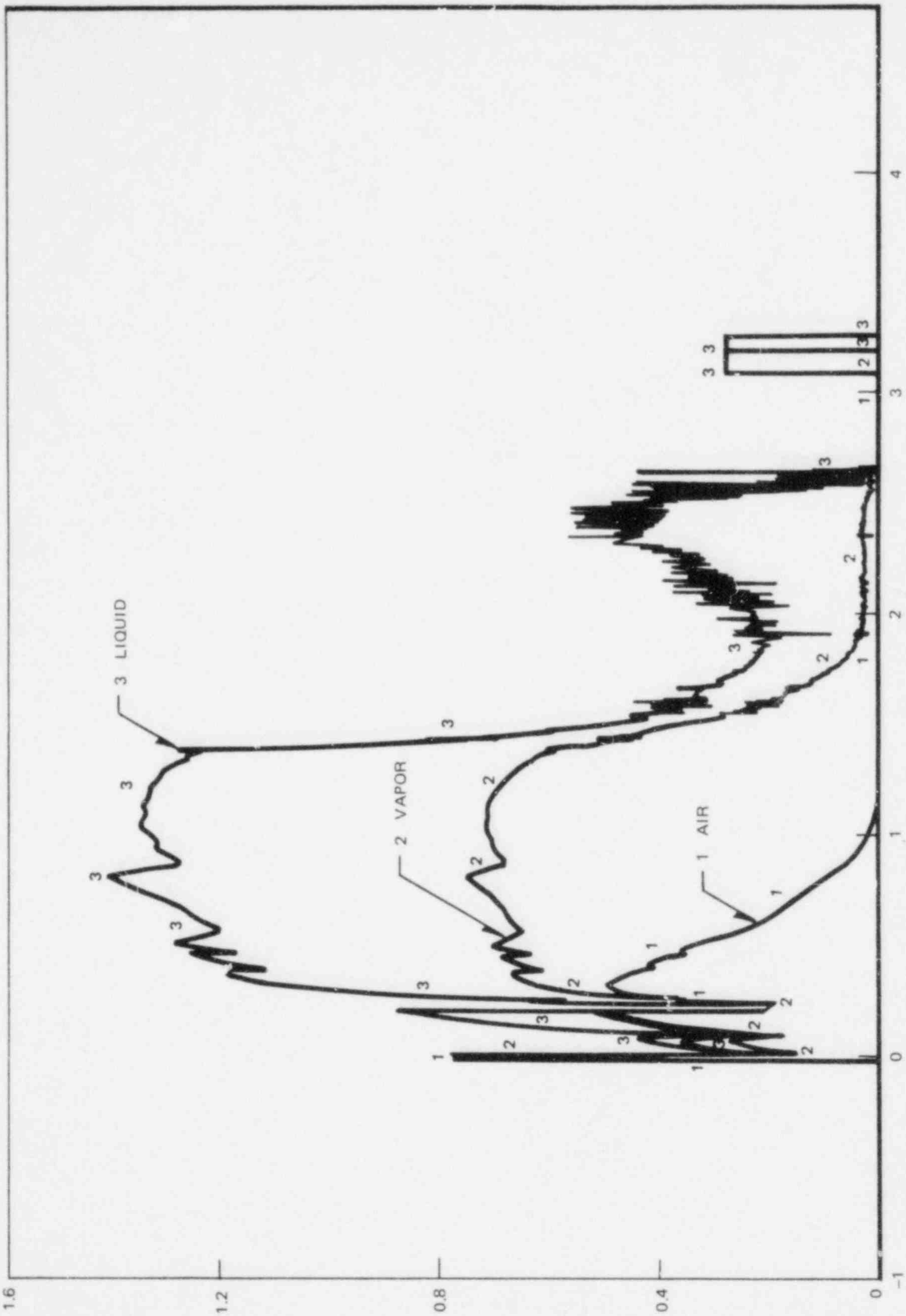
Figure 6.2-3



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Short Term Drywell Differential
Pressure Following a
Recirculation Line Break

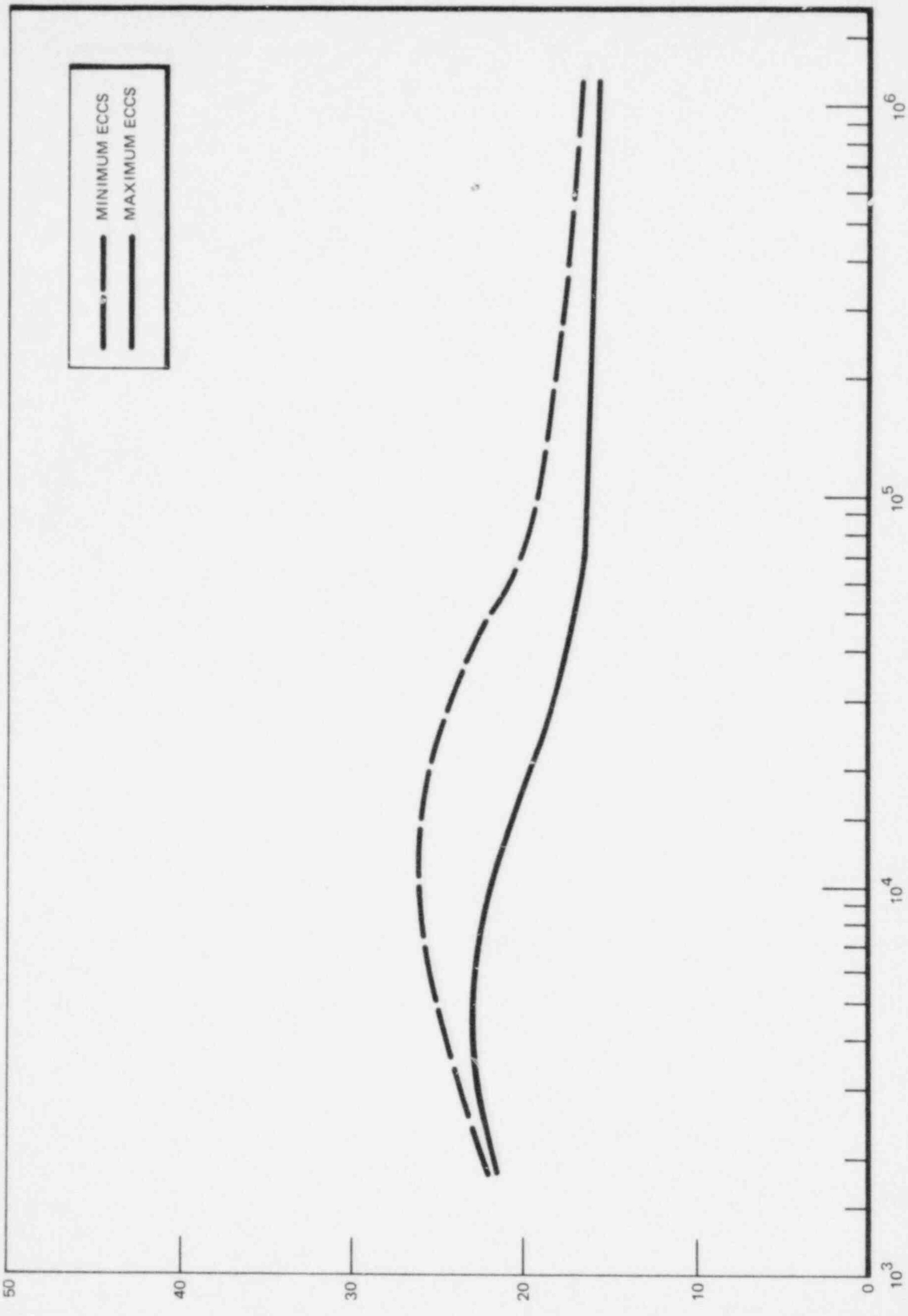
Figure 6.2-4



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Short Term Vent Flow
Following a Recirculation Line
Break (Min. ECCS)

Figure 6.2-5



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

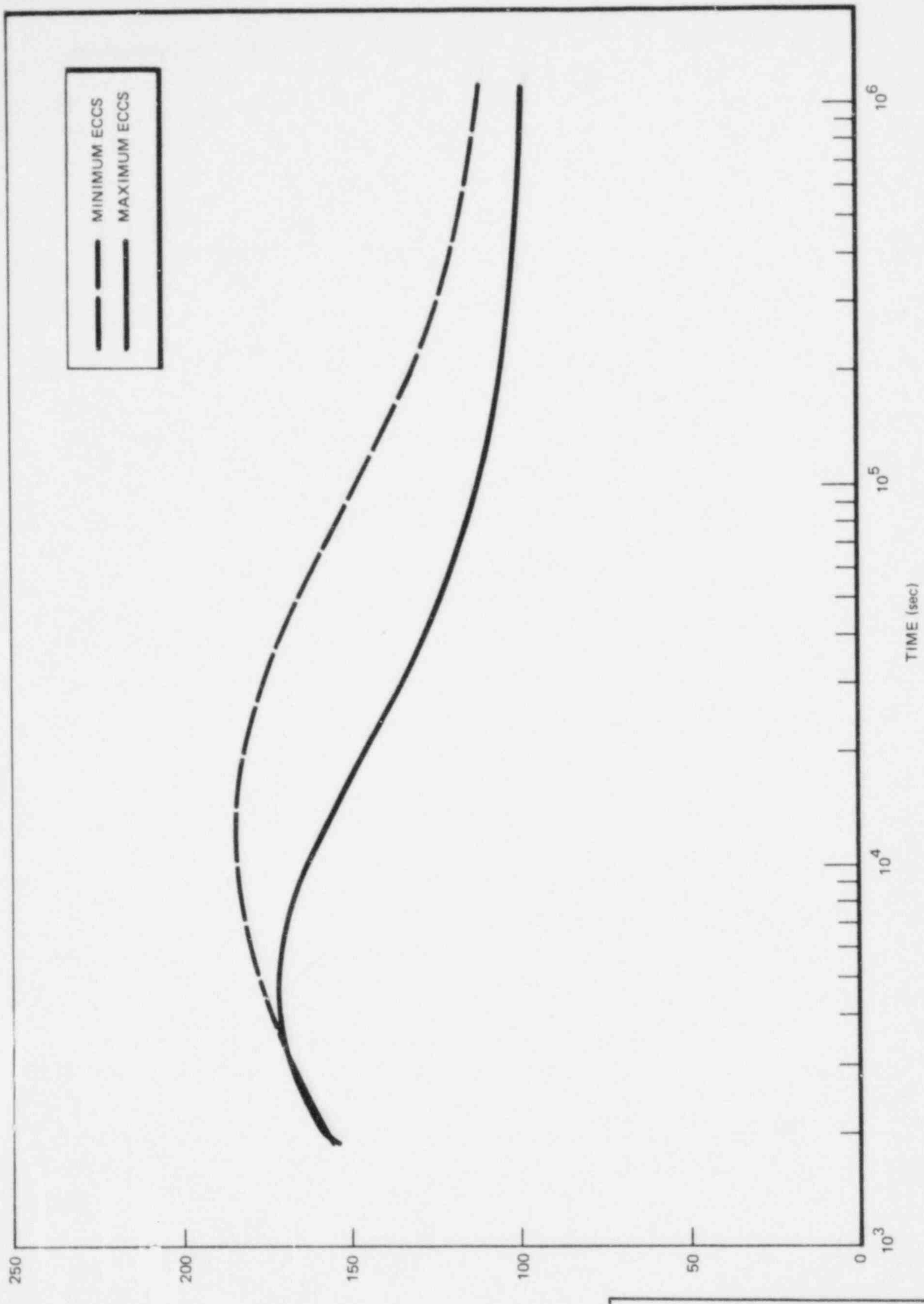
Long Term Pressure Response
Following a Main Steam Line
Break

Figure 6.2-6

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Long Term Drywell Temperature Response Following a Main Steam Line Break

Figure 6.2-7



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

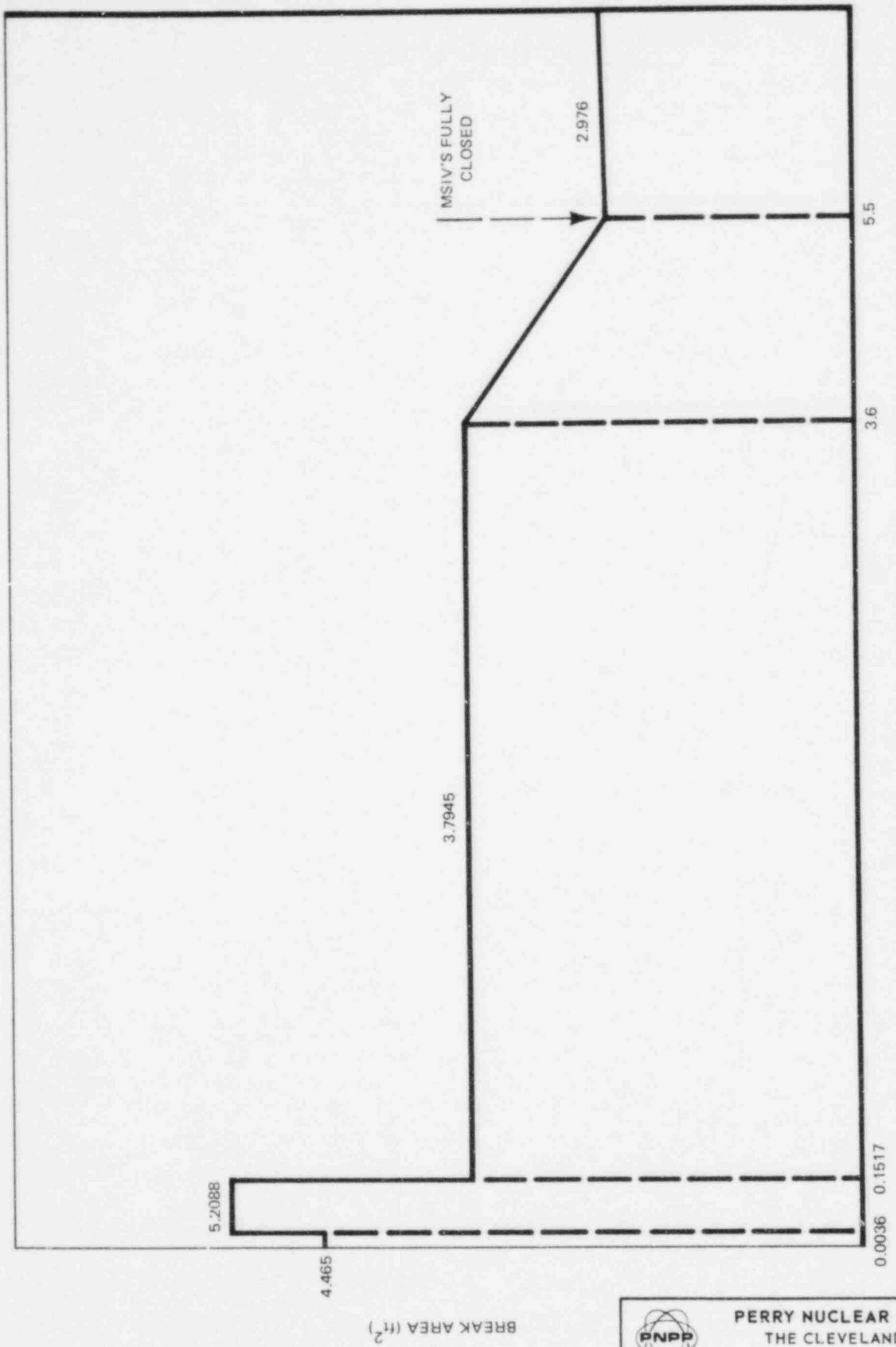
Long Term Suppression Pool
Temperature Response Following a
Main Steam Line Break

Figure 6.2-8

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

RHR Heat Removal Rate Following
a Main Steam Line Break

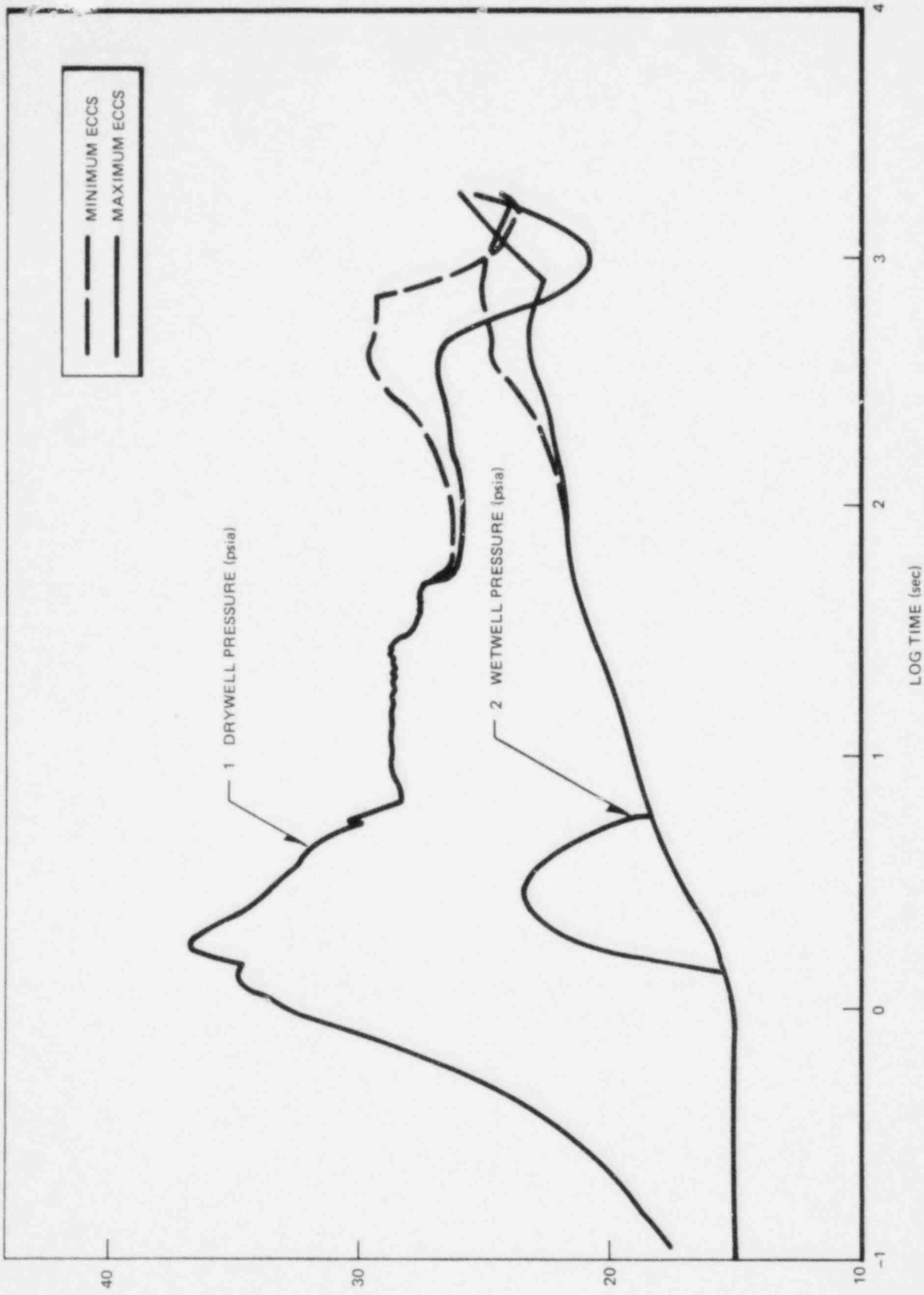
Figure 6.2-9



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Effective Blowdown Area for Main Steam Line Break

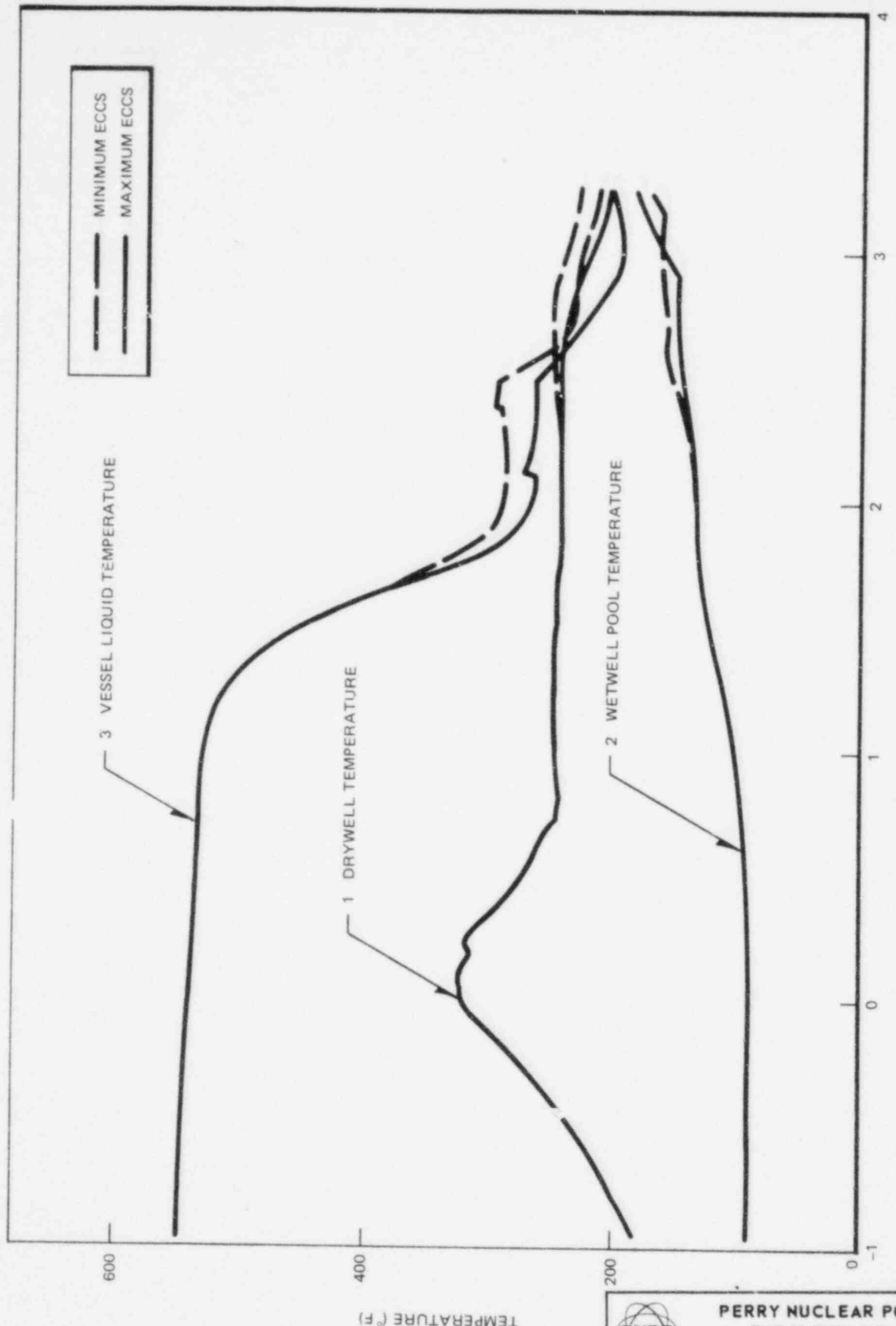
Figure 6.2-10



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Short Term Pressure Response
Following a Main Steam
Line Break

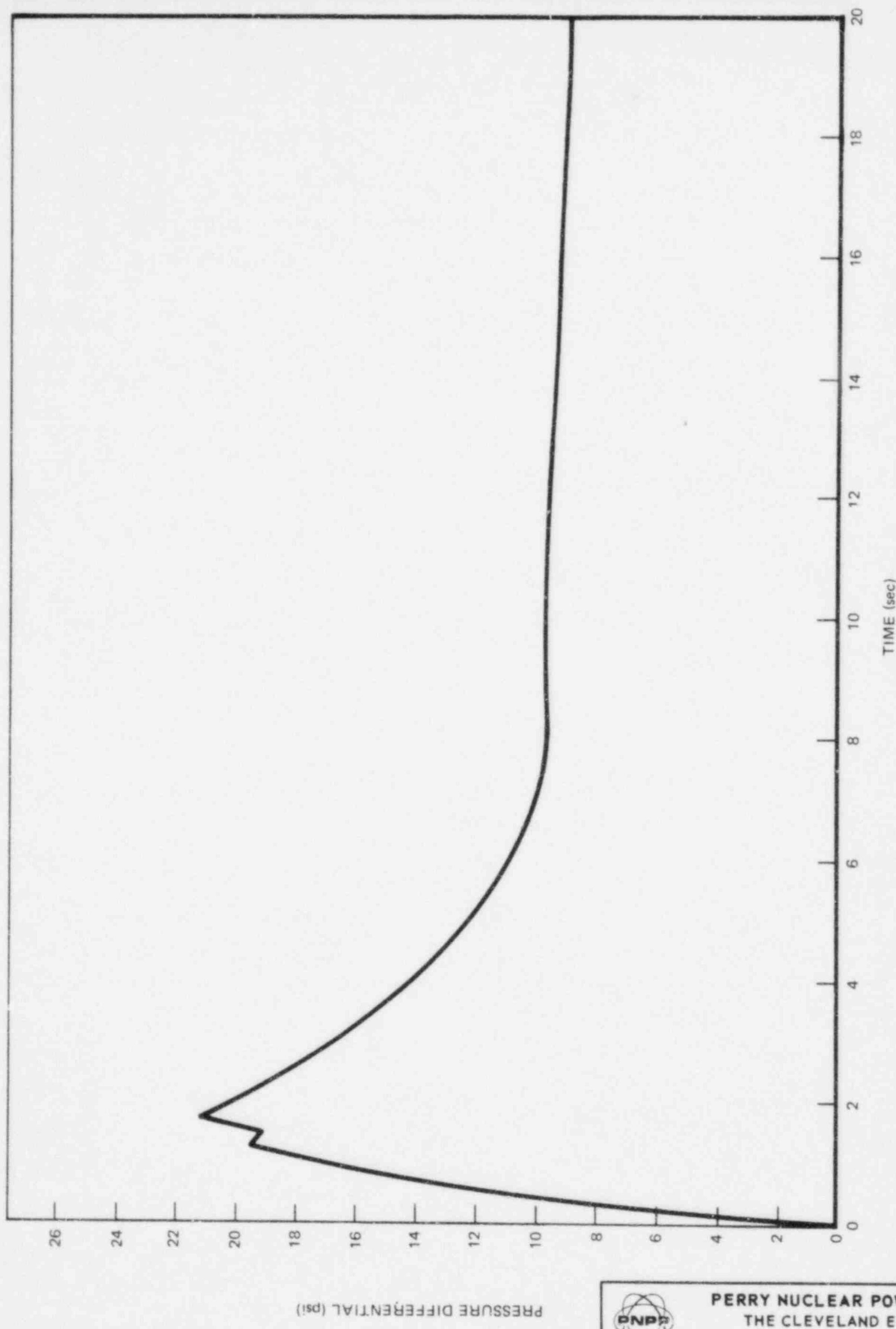
Figure 6.2-11



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Short Term Temperature Response
Following a Main Steam Line Break

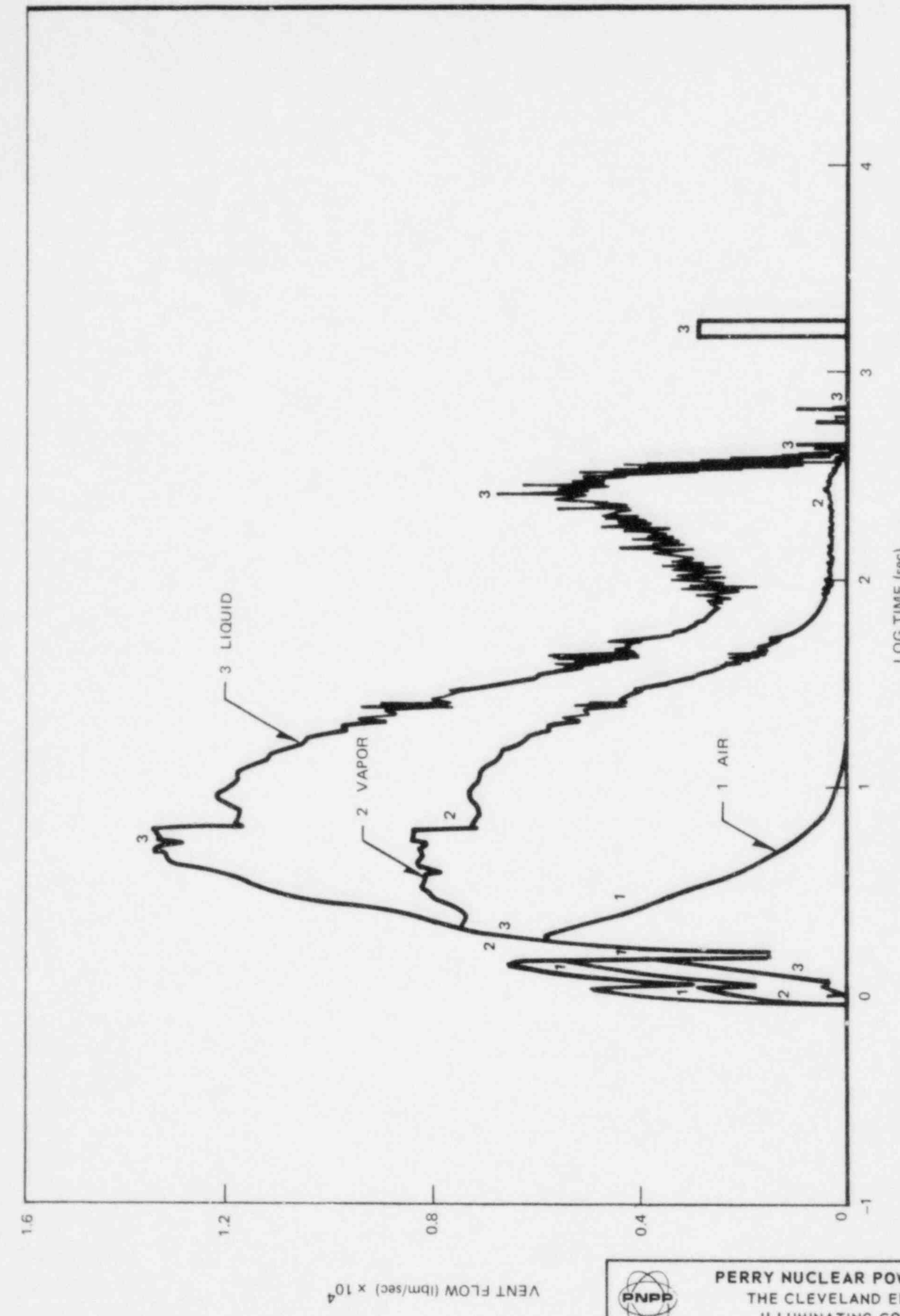
Figure 6.2-12



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Short Term Drywell Differential
Pressure Following a Main Steam
Line Break

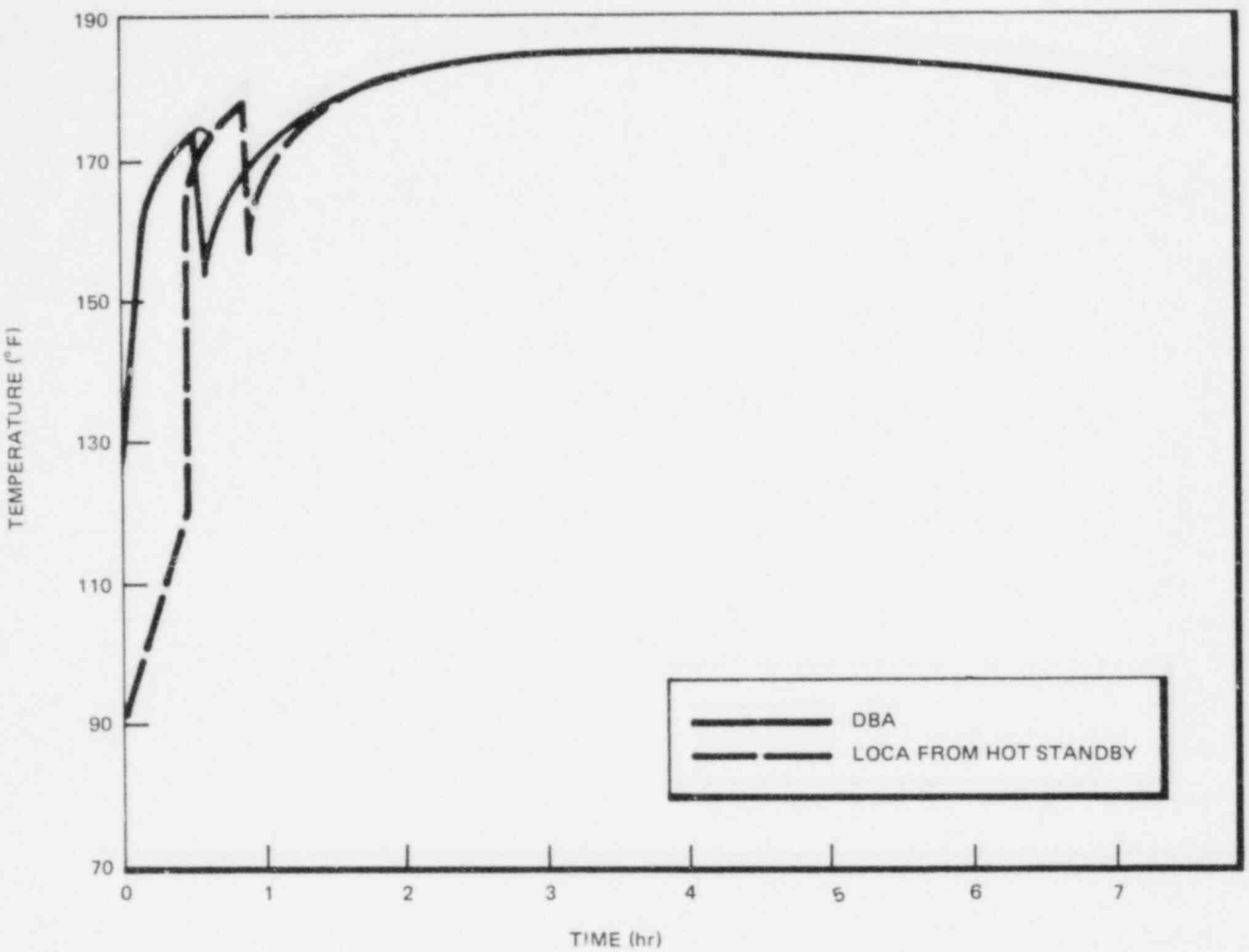
Figure 6.2-13



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Short Term Vent Flow
Following a Main Steam Line
Break (Minimum ECCS)

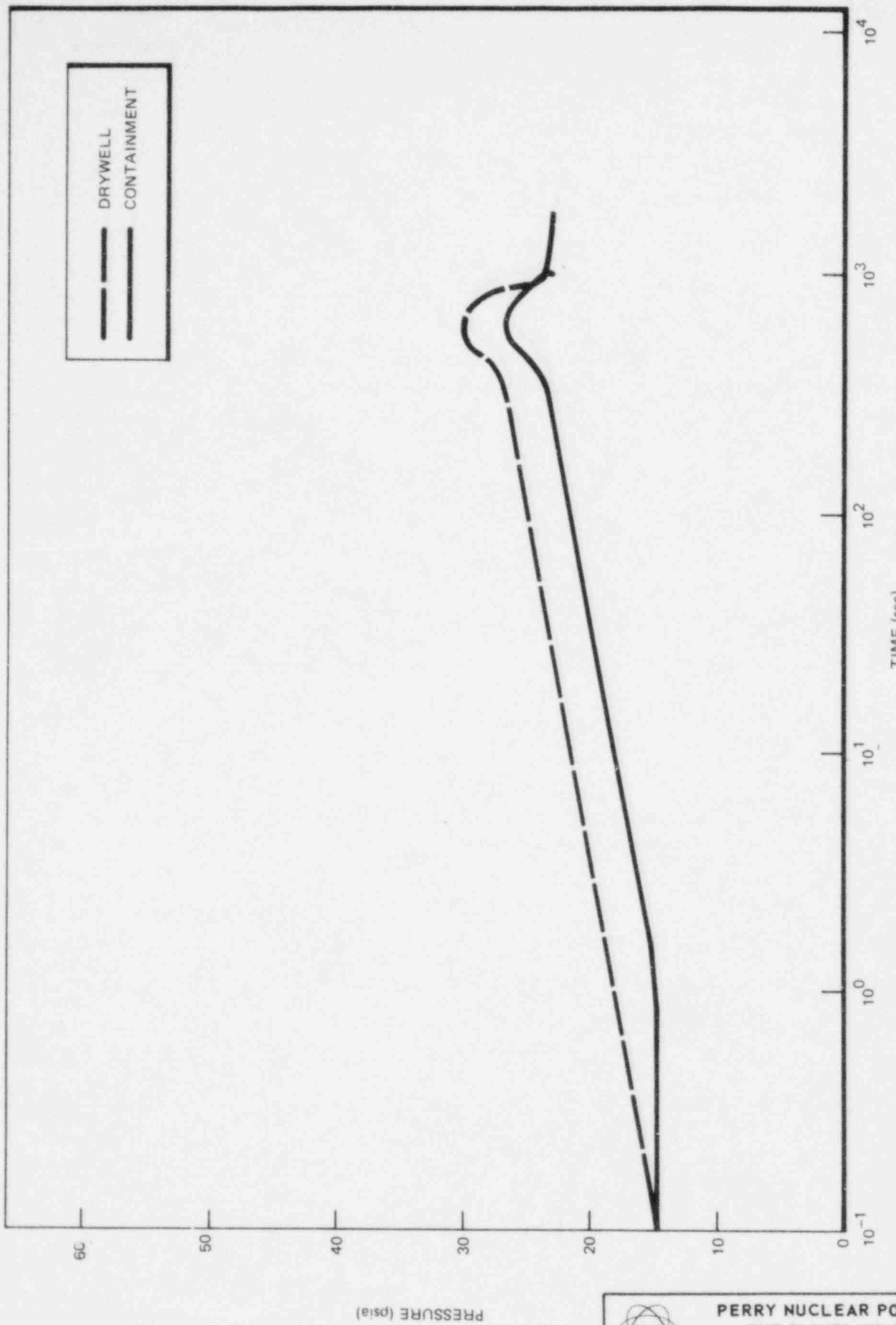
Figure 6.2-14



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Suppression Pool Temperature
Response Following Blowdown
During Hot Standby Operation

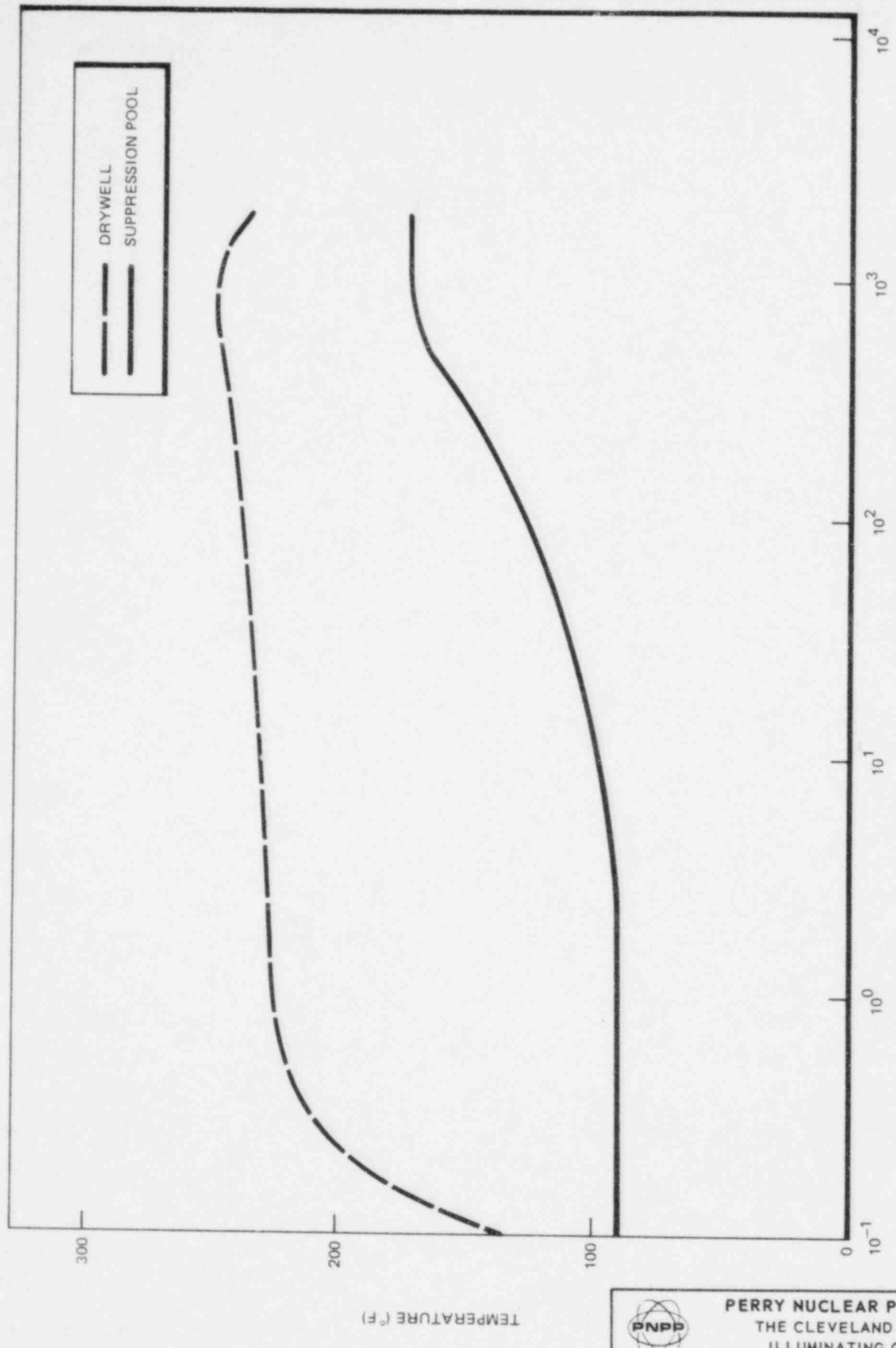
Figure 6.2-15



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Short Term Pressure Response
Following an Intermediate Size
Break (IBA = 0.68 ft^2)

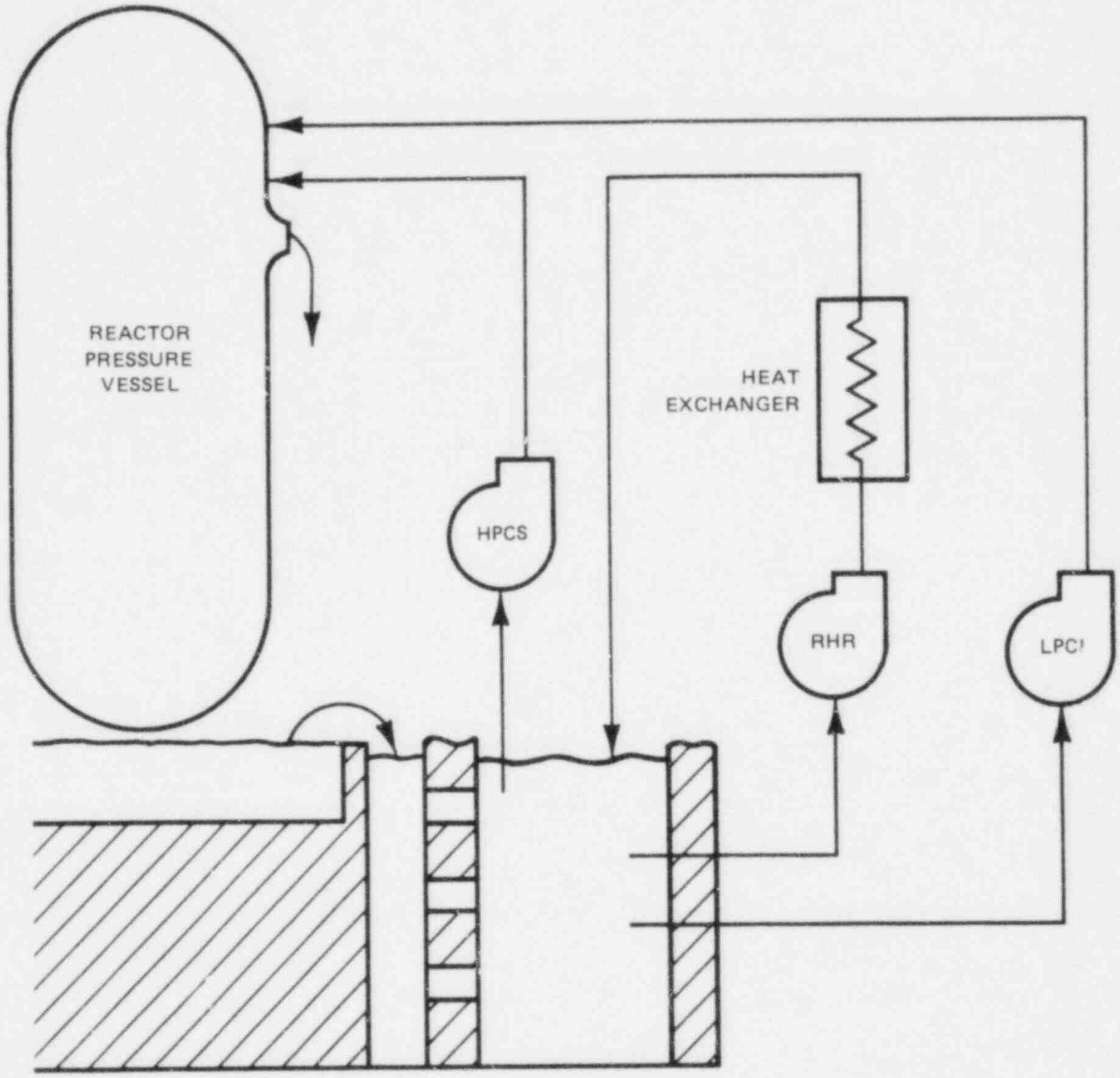
Figure 6.2-16



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Short Term Temperature Response Following an Intermediate Size Break (IBA = 0.68 ft^2)

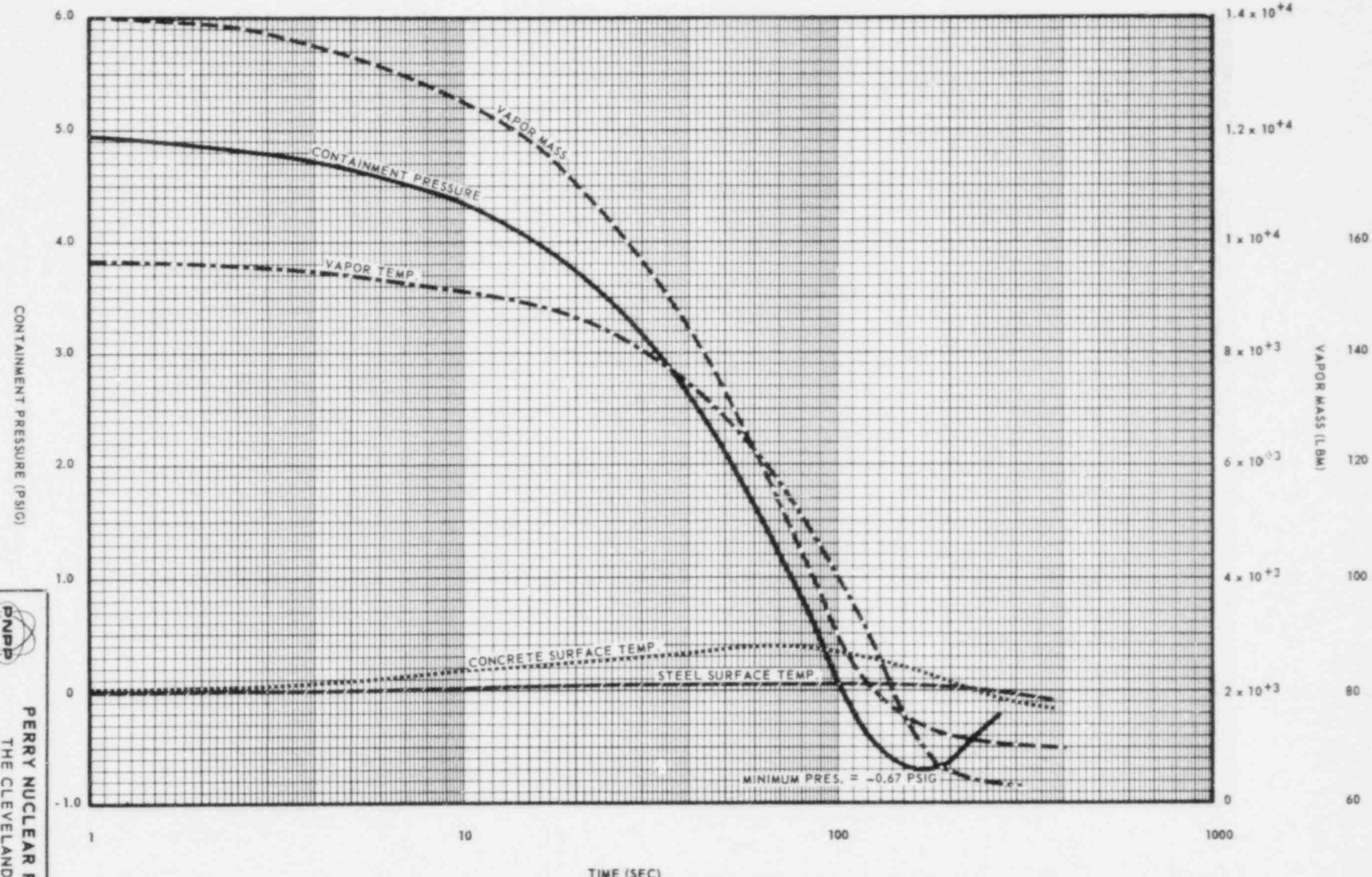
Figure 6.2-17



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Schematic of the RHR Containment Cooling System Analytical Model (Min. ECCS)

Figure 6.2-18



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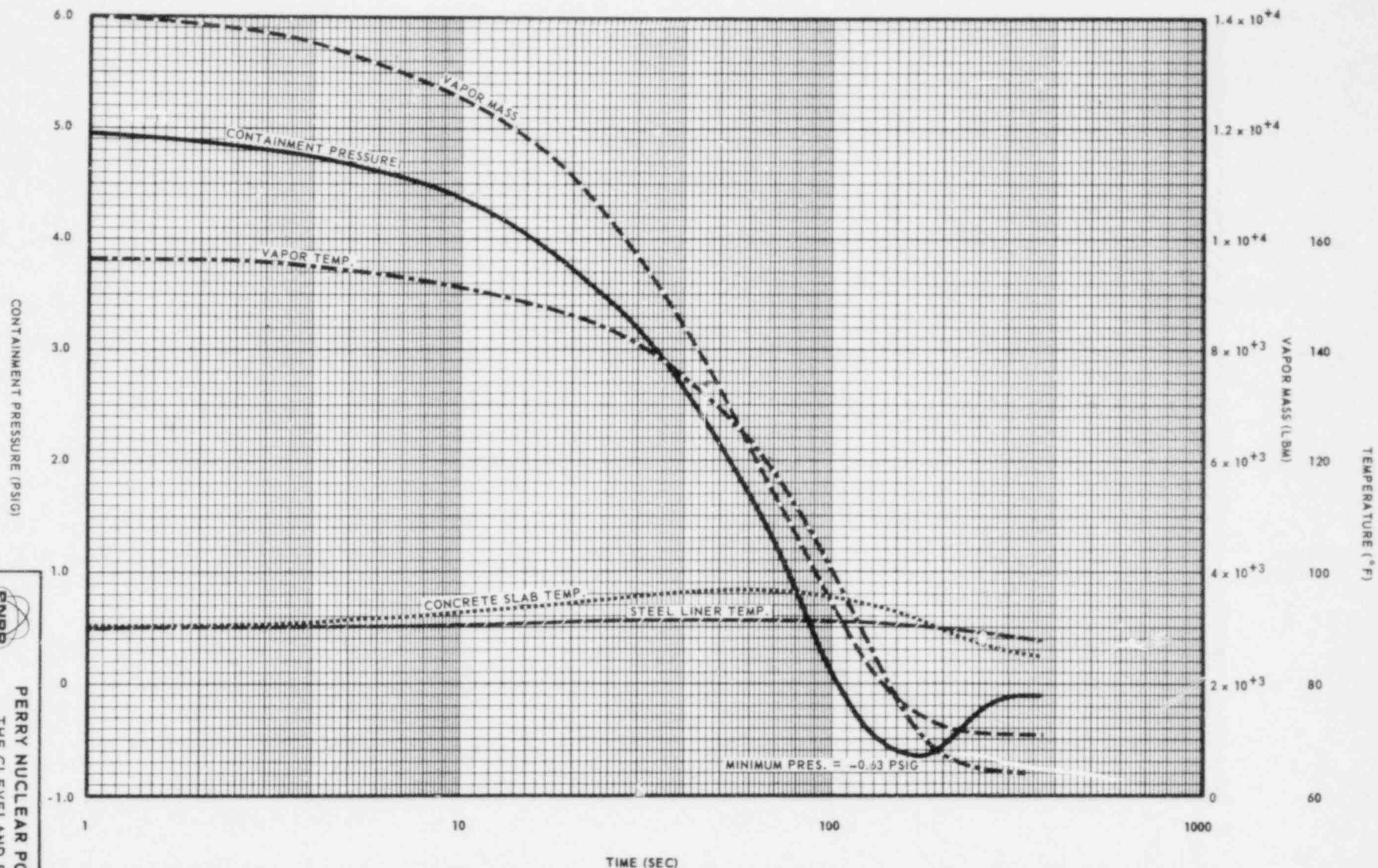
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Containment Vacuum Breaker
Analysis with Initial Internal
Surface Temp. 80°F

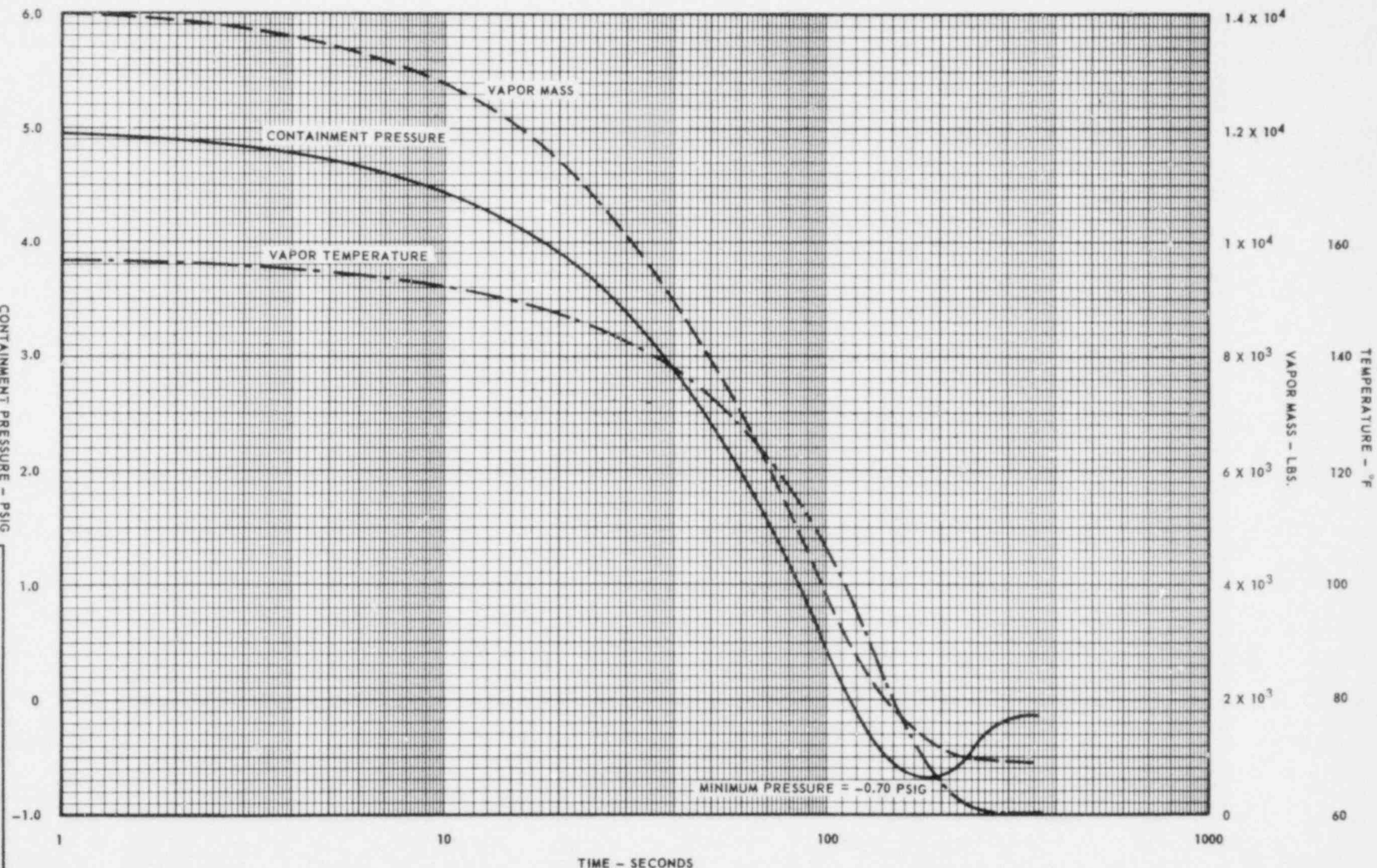
Figure 6.2-19



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

PNPP

Containment Vacuum Breaker
Analysis with Initial Internal
Surface Temp. 90°F
Figure 6.2-20



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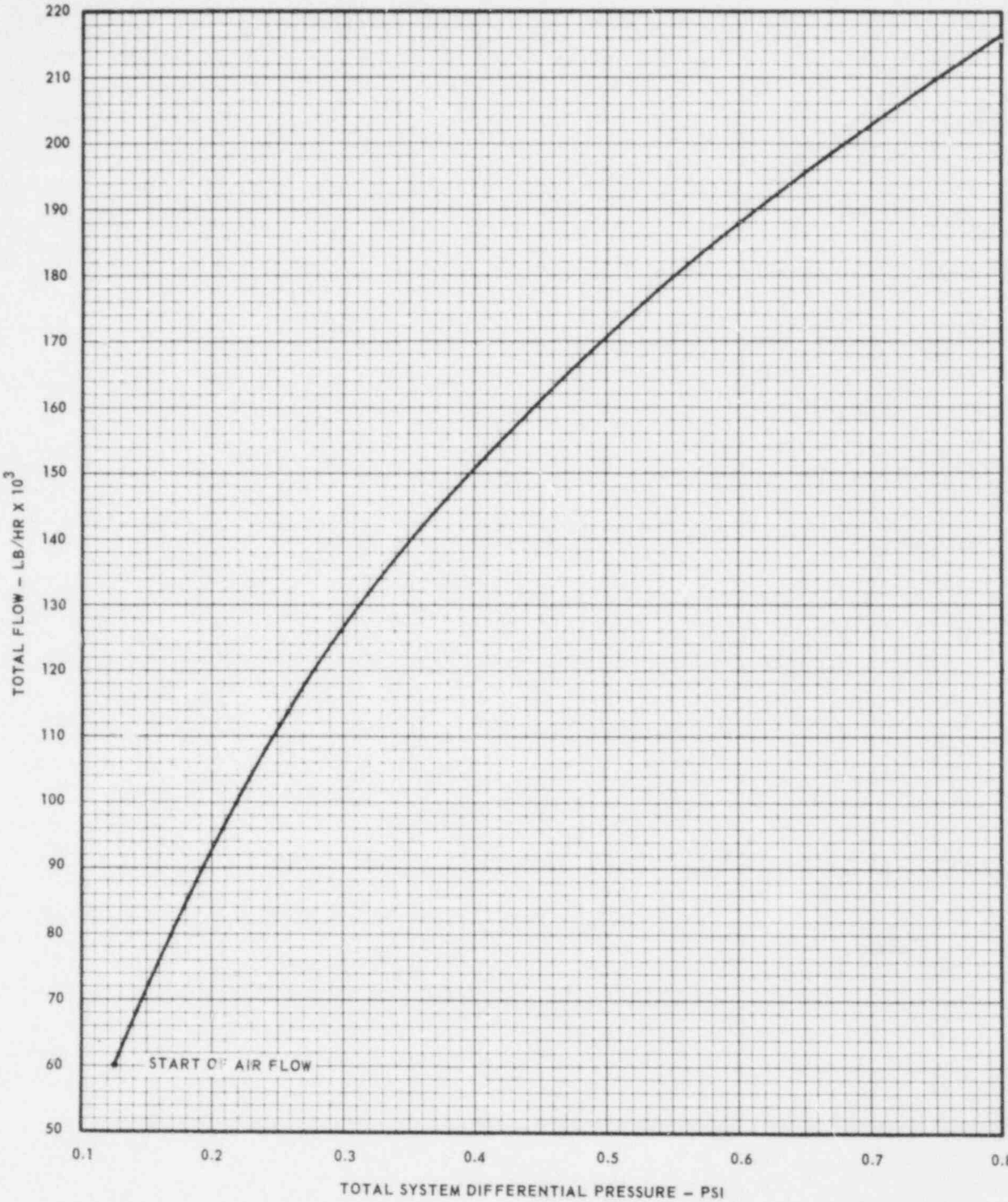
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Containment Pressure Versus
Time - Small Line Break

Figure 6.2-21



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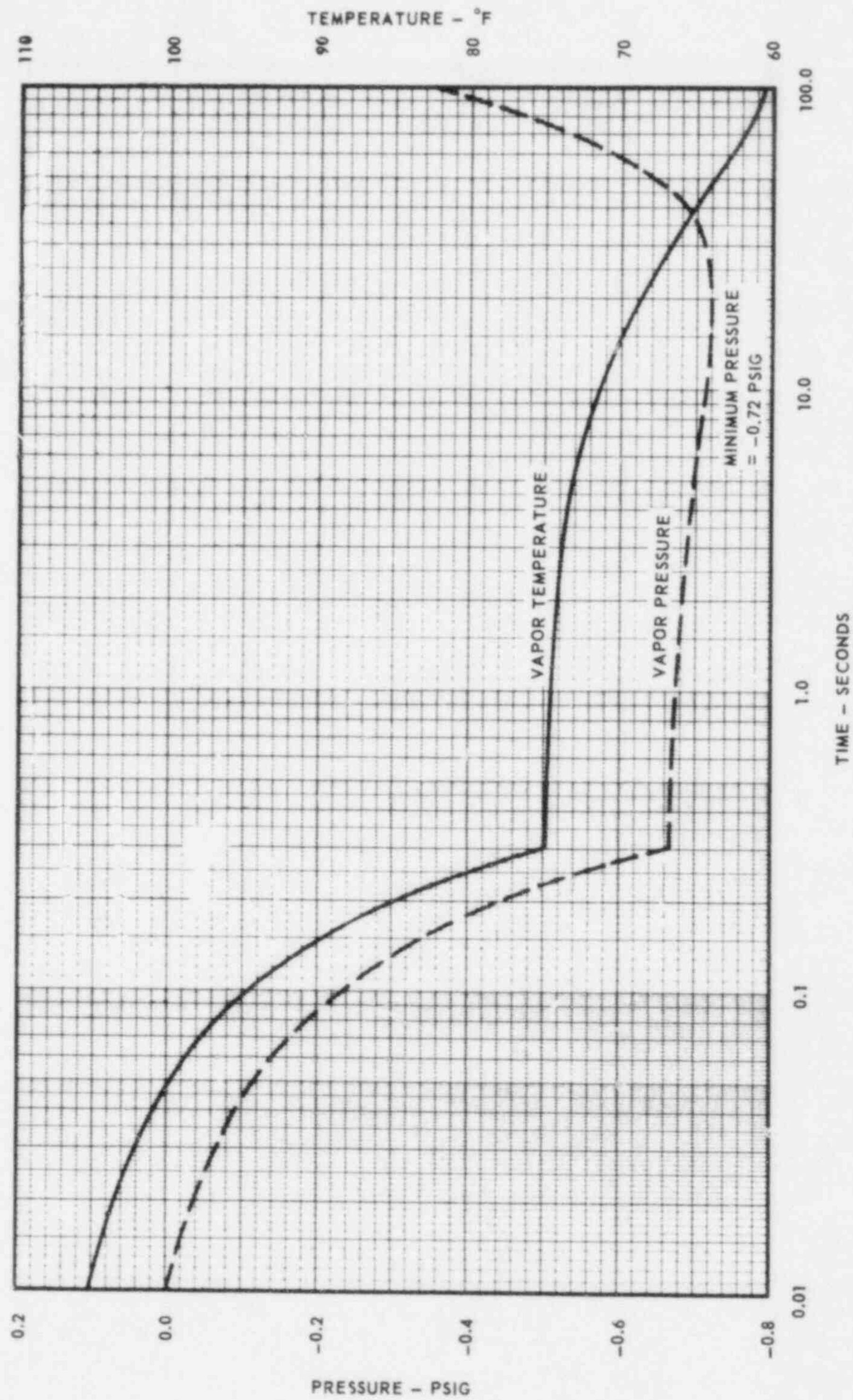
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Total Flow Through Two 24 - Inch Diameter CVR lines Versus Total System Differential Pressure

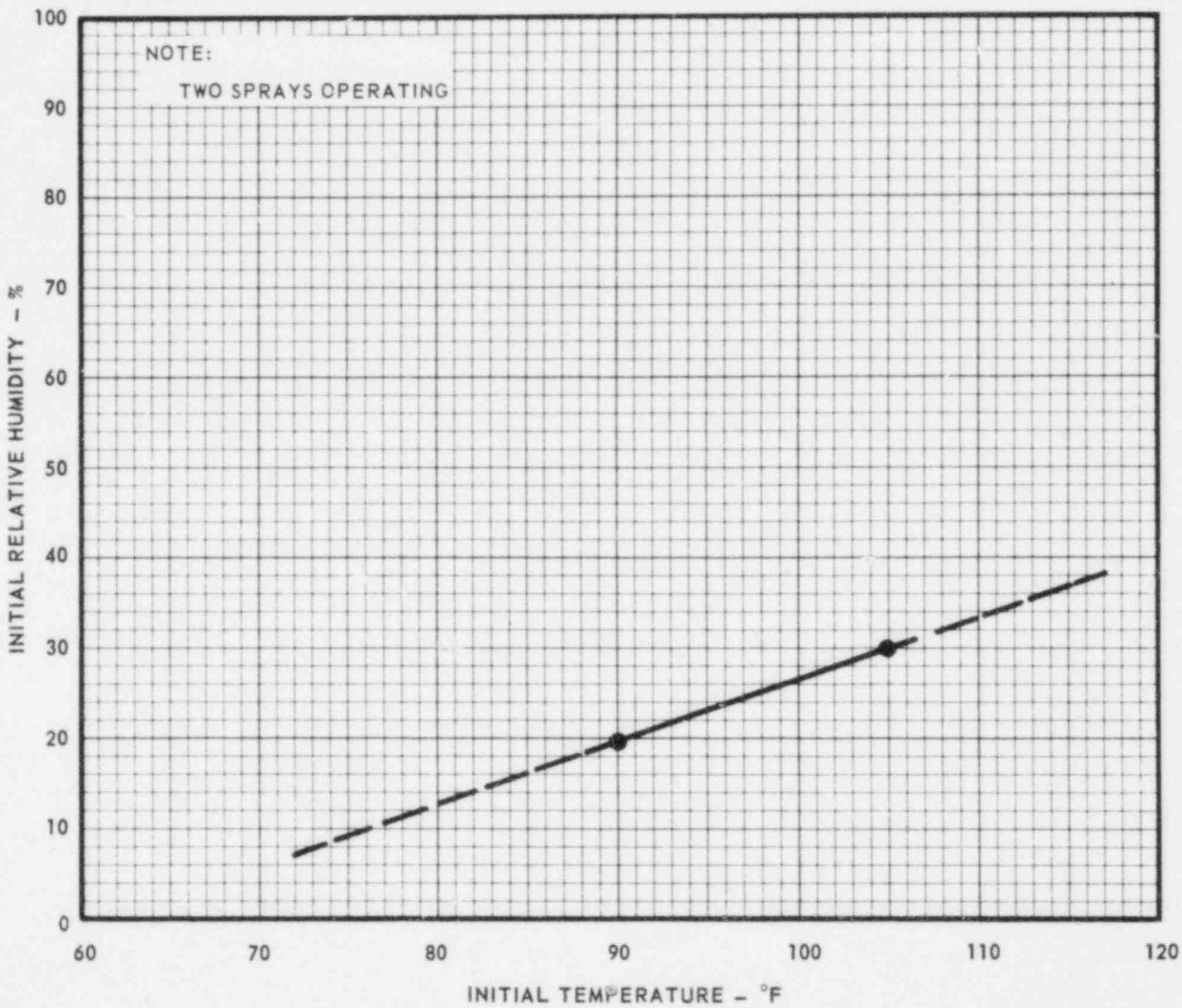
Figure 6.2-22



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Containment Pressure Versus Time
Inadvertent Spray Operation -
Normal Operation

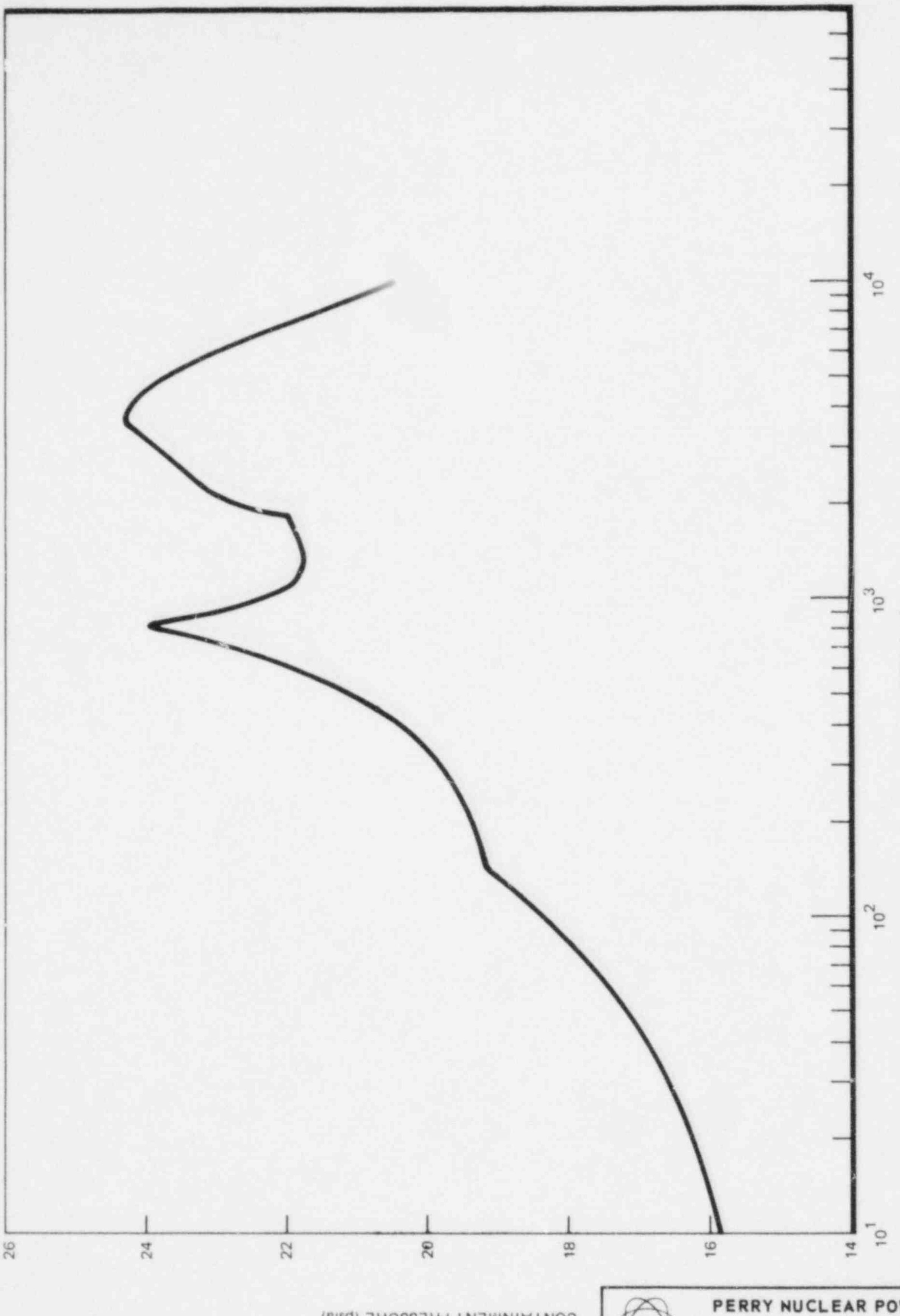
Figure 6.2-23



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Initial Relative Humidity Versus Initial Temperature for Inadvertent Spray Operation to Maintain Peak Vacuum $\leq$ 0.72 PSI

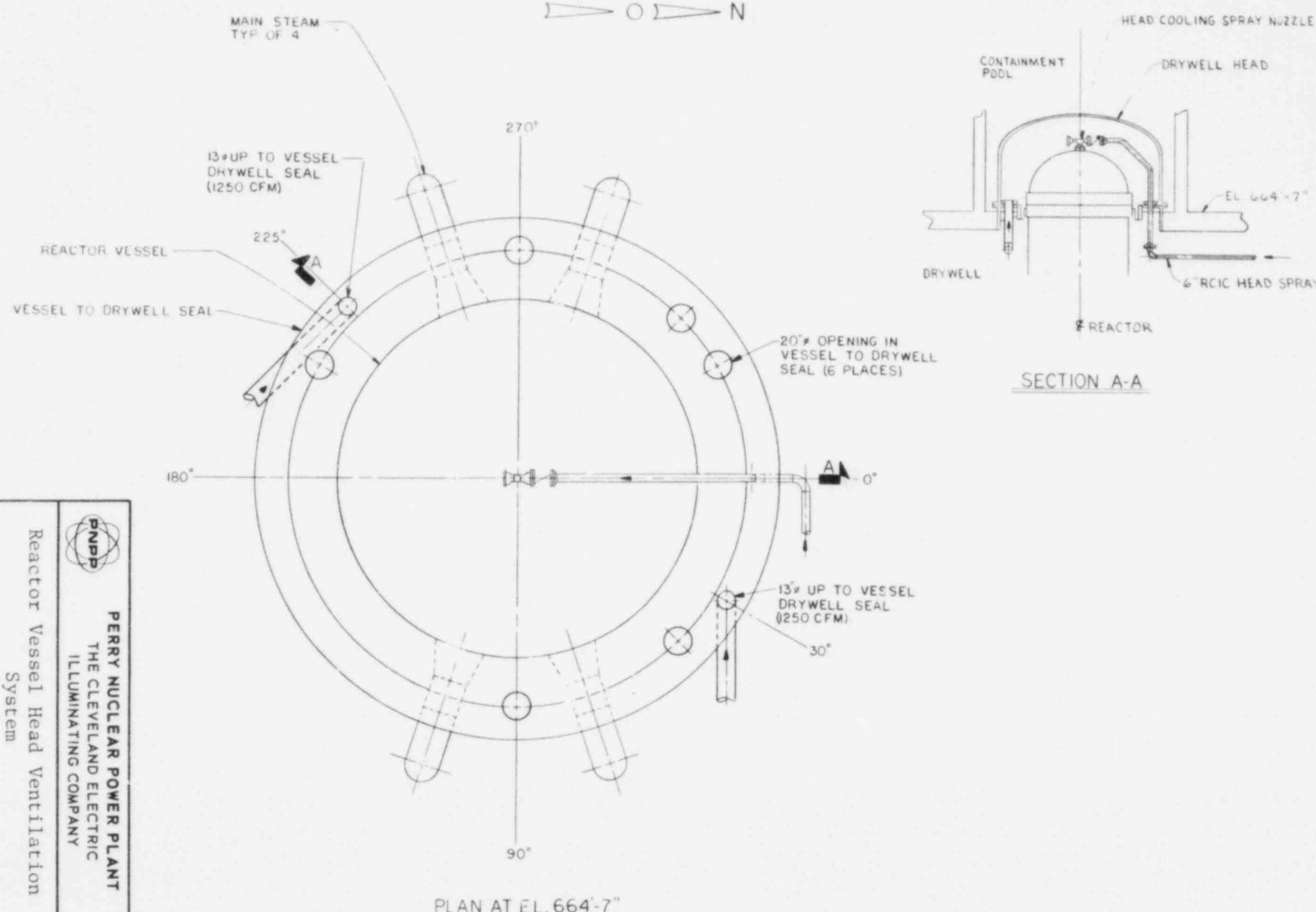
Figure 6.2-24



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Containment Pressure Following a Small Break with Steam Bypass (With Containment Spray and Heat Sinks)

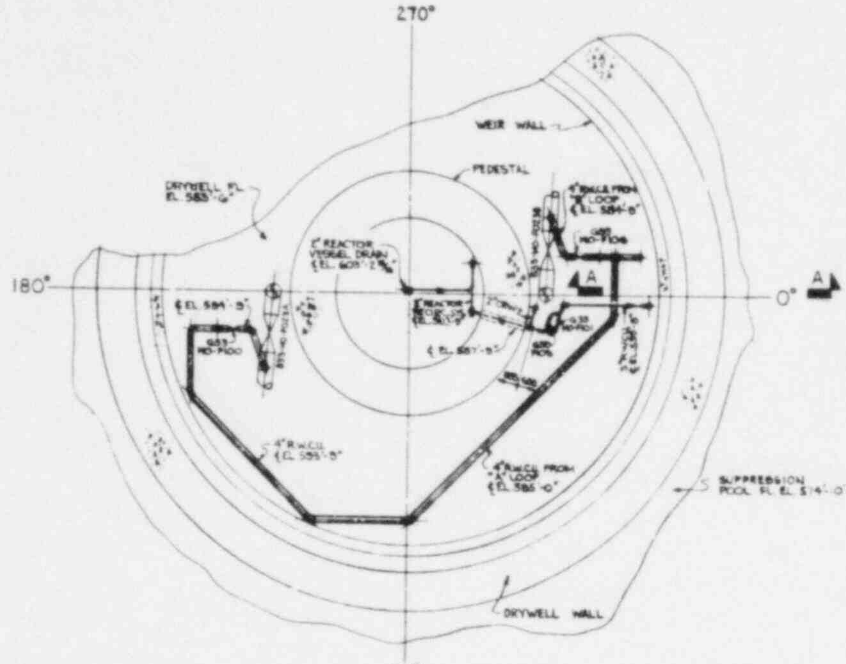
Figure 6.2-25



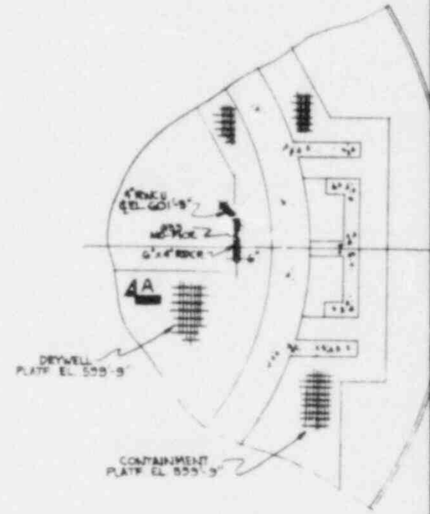
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Vessel Head Ventilation System

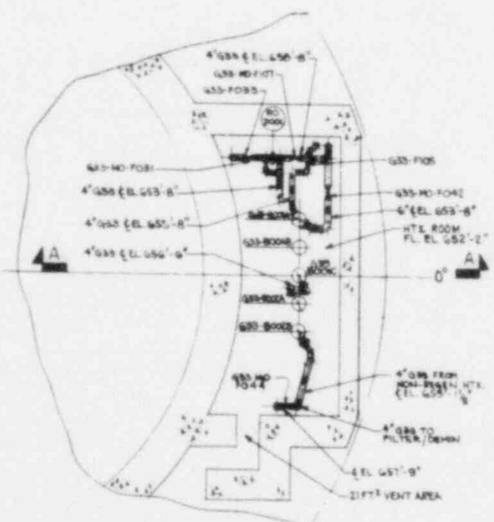
Figure 6.2-26



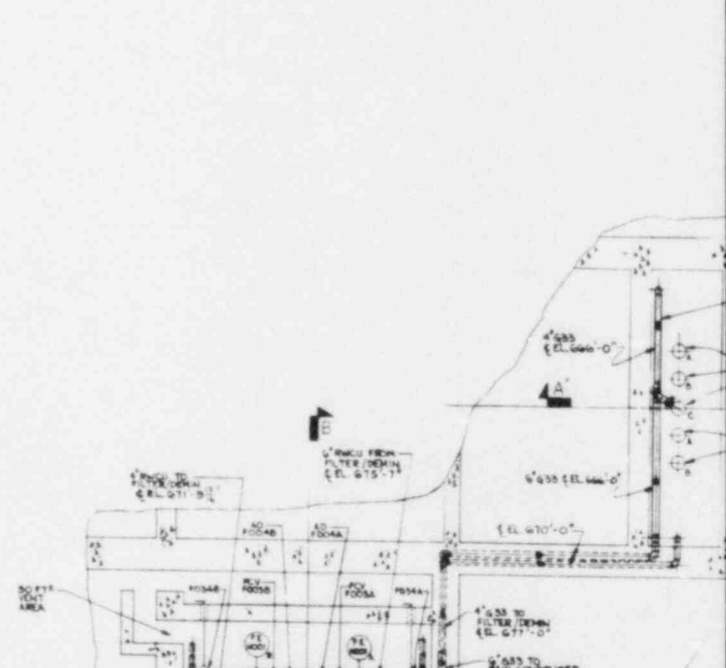
PLAN AT EL. 583'-6"
INSIDE DRYWELL



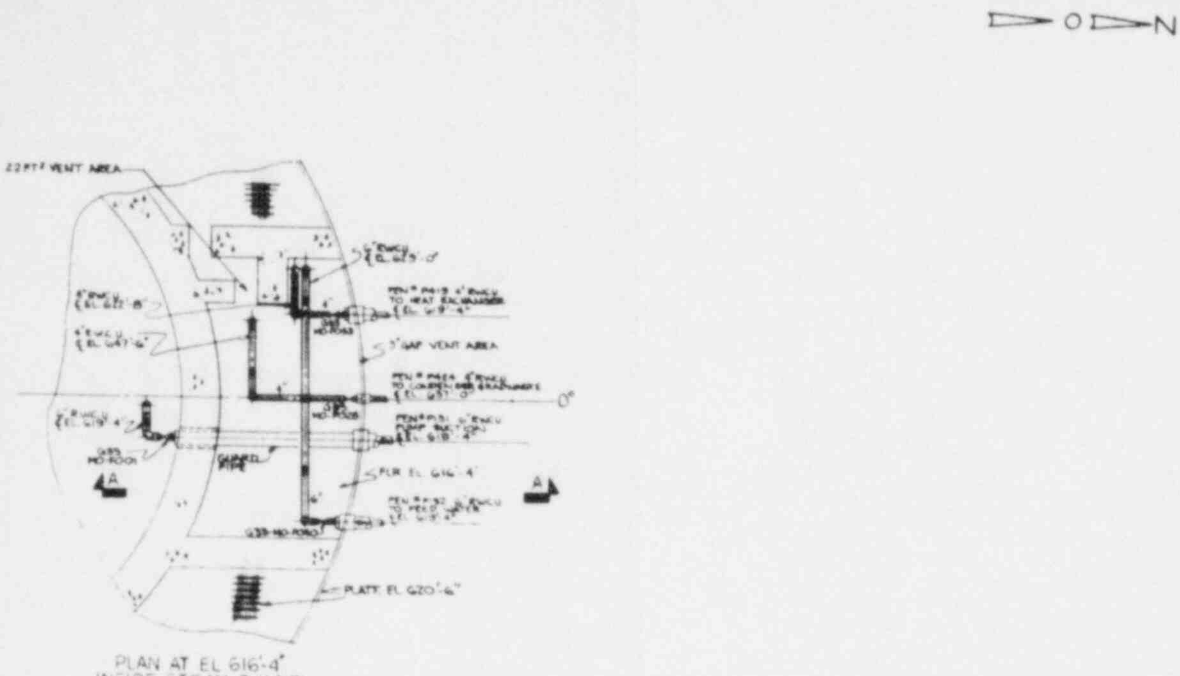
PLAN AT EL 599'-9"



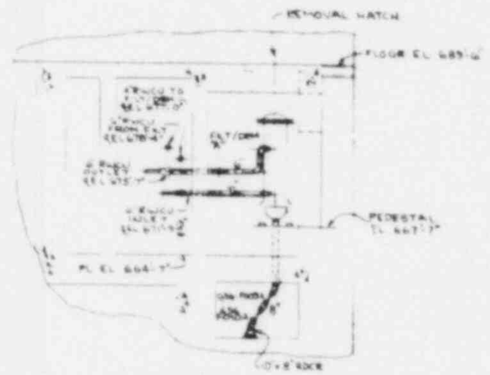
PLAN AT EL. 652'-2"
INSIDE HTX. ROOM



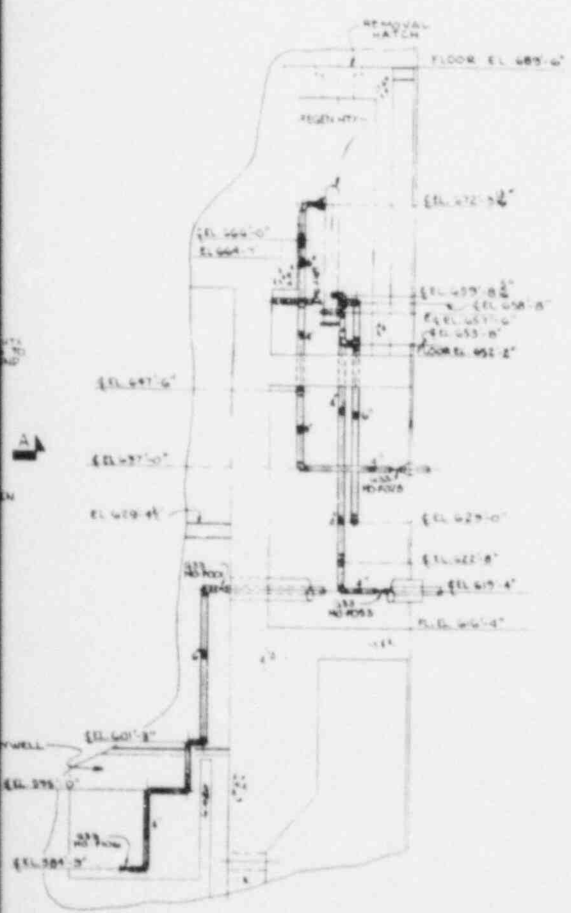
PLAN AT EL 664'-7"
INSIDE HTX. ROOM
& FILTER DEMIN ROOM



PLAN AT EL 616'-4"
INSIDE STEAM TUNNEL



SECTION "B-B"

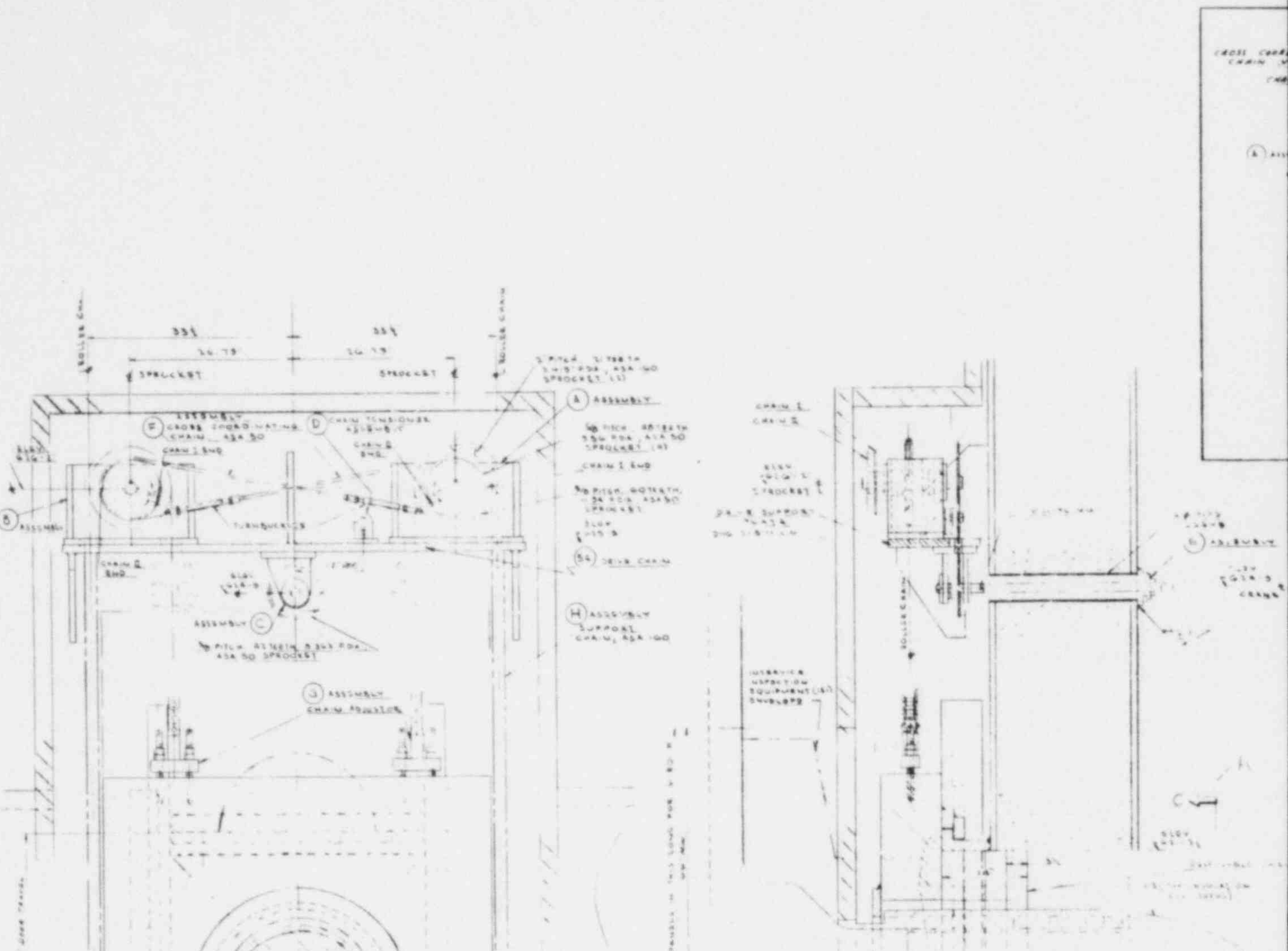


SECTION "A-A"

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

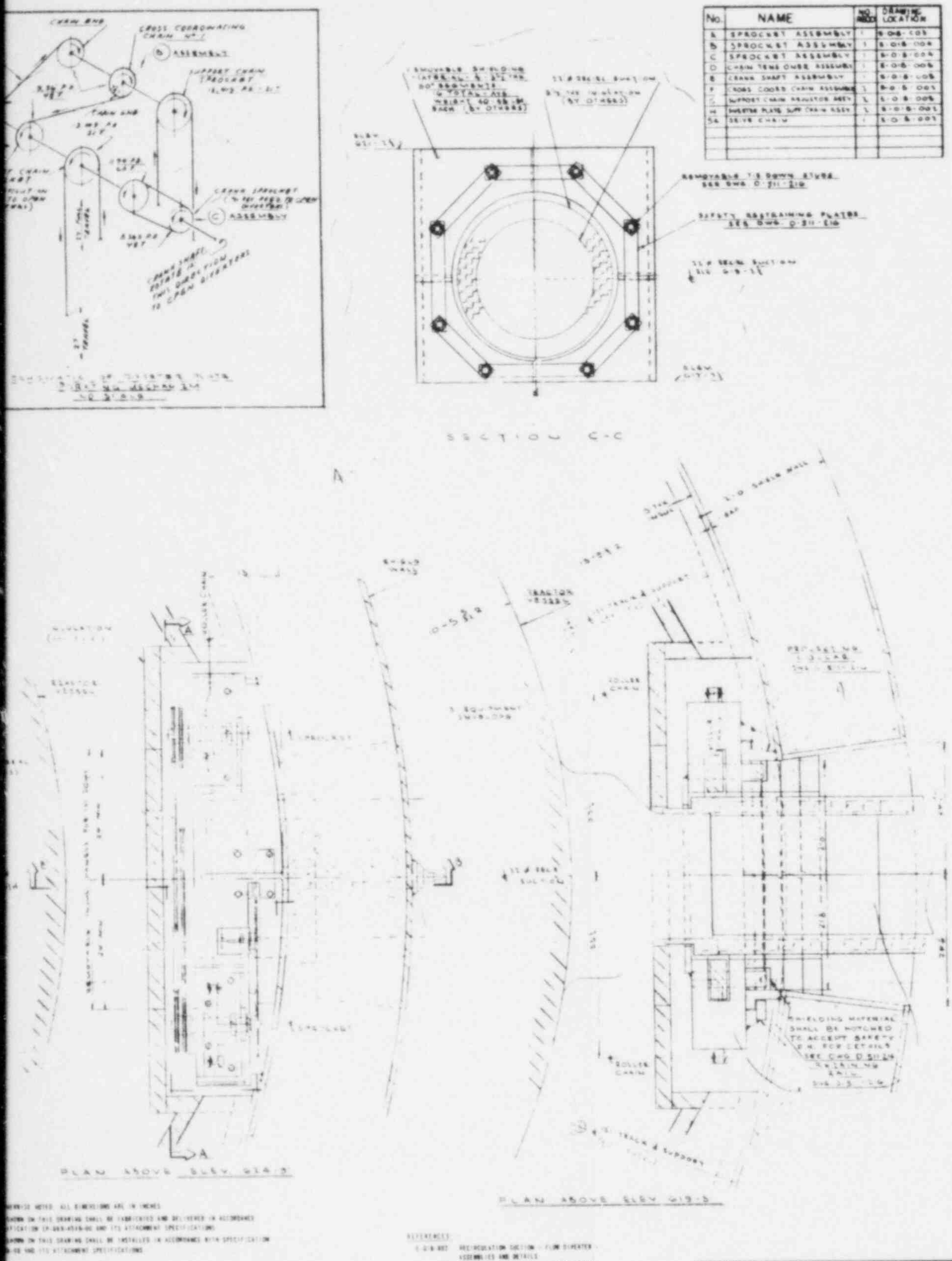
RWCU Main Flow Piping Inside
Containment and Drywell

Figure 6.2-27
(GAI Dwg. E-300-705)



ELEVATION A-A

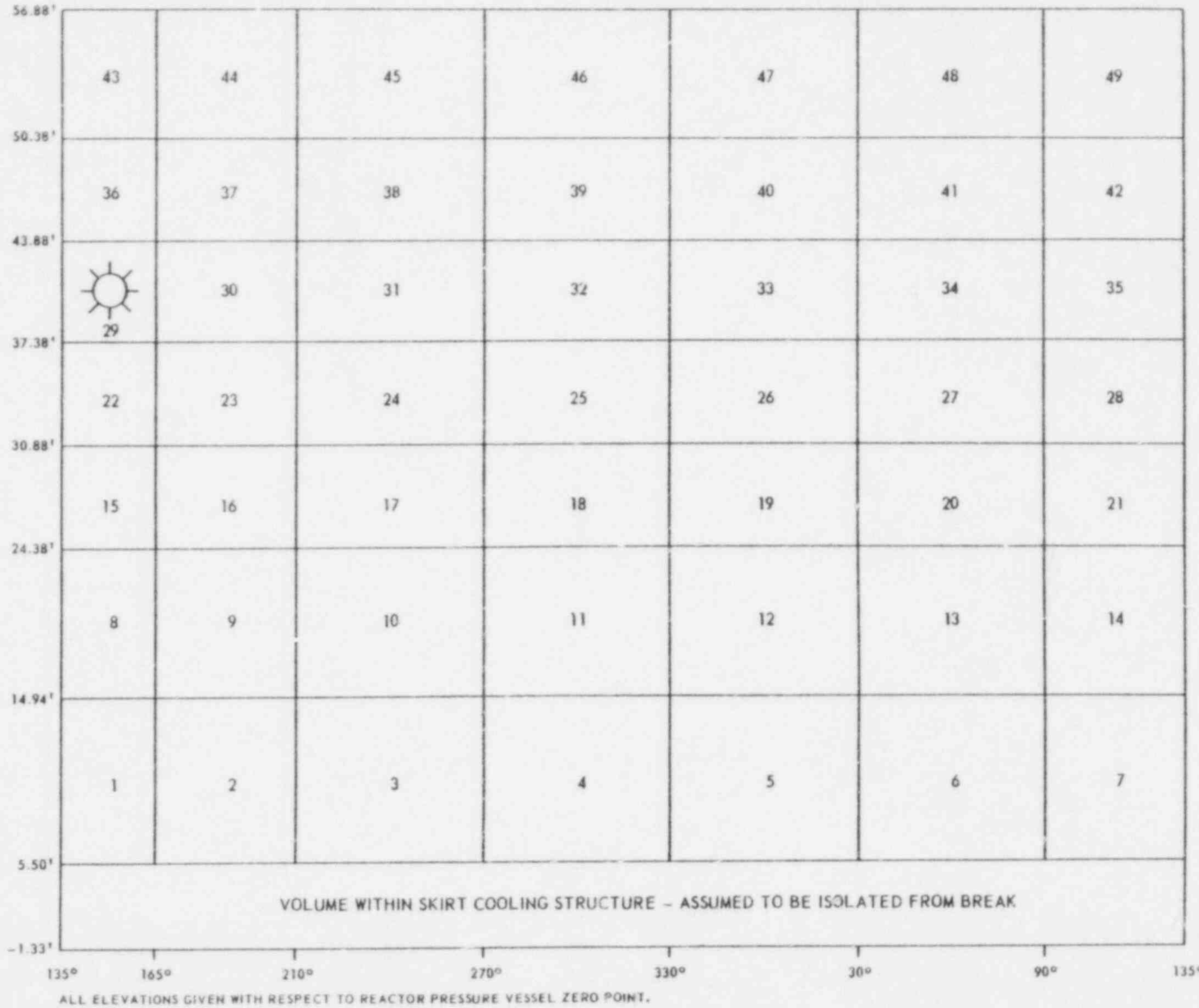
ELEVATION B-B



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Recirculation Suction Flow
Diverter Arrangement

Figure 6.2-28
(GAI Dwg. E-018-001)



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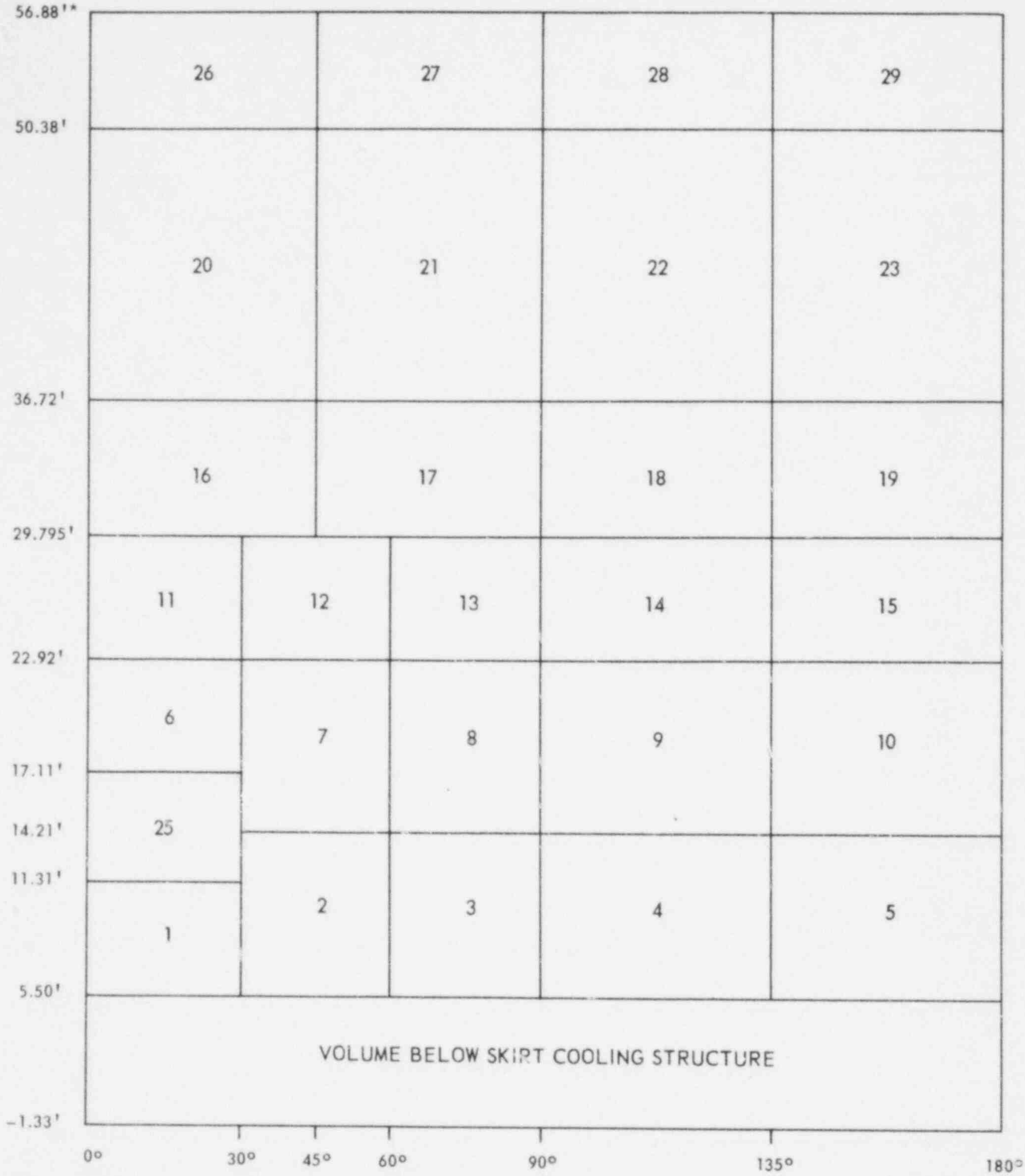
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Nodalization
- Recirculation Suction Line Break

Figure 6.2-29



ELEVATIONS GIVEN WITH RESPECT TO REACTOR PRESSURE VESSEL ZERO POINT.

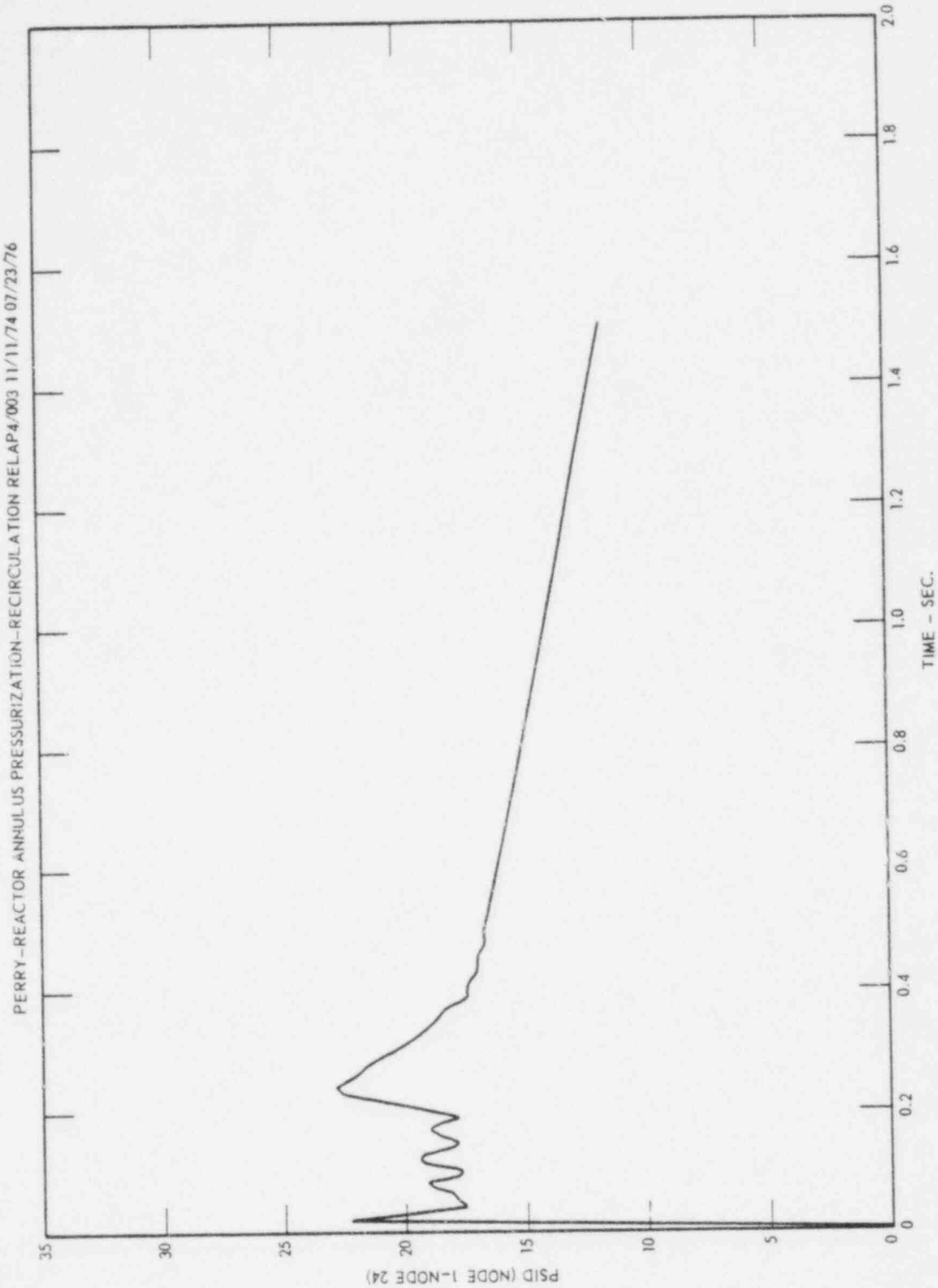
* VOLUME BETWEEN ELEVATIONS 50.38' TO 56.88' REPRESENT THAT VOLUME BELOW THE REFUELING BELLOWS & ABOVE THE BIOLOGICAL SHIELD & STILL ISOLATED FROM THE DRYWELL.

PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Nodalization - Feedwater Line Break

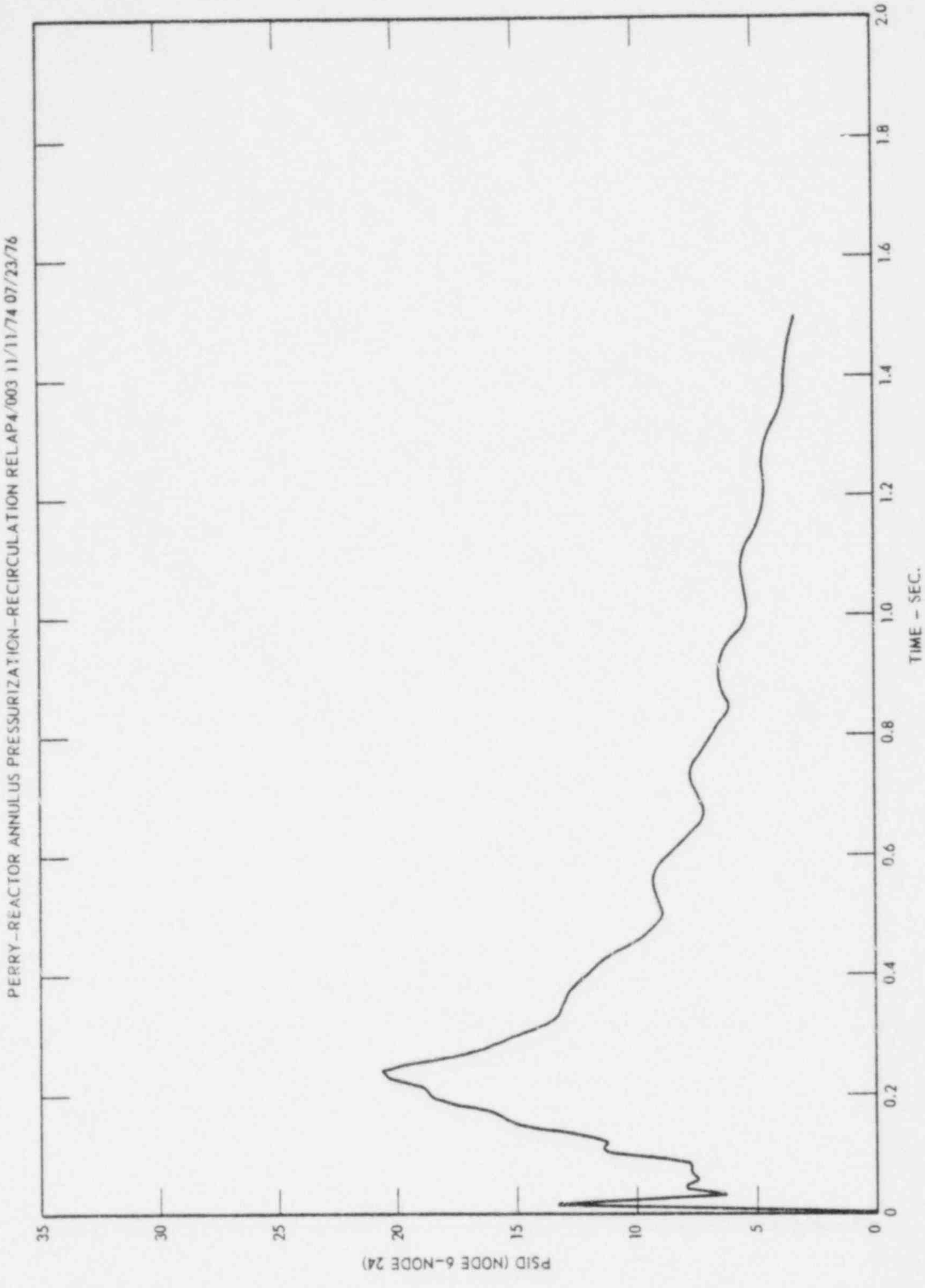
Figure 6.2-30



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 1 - 24)

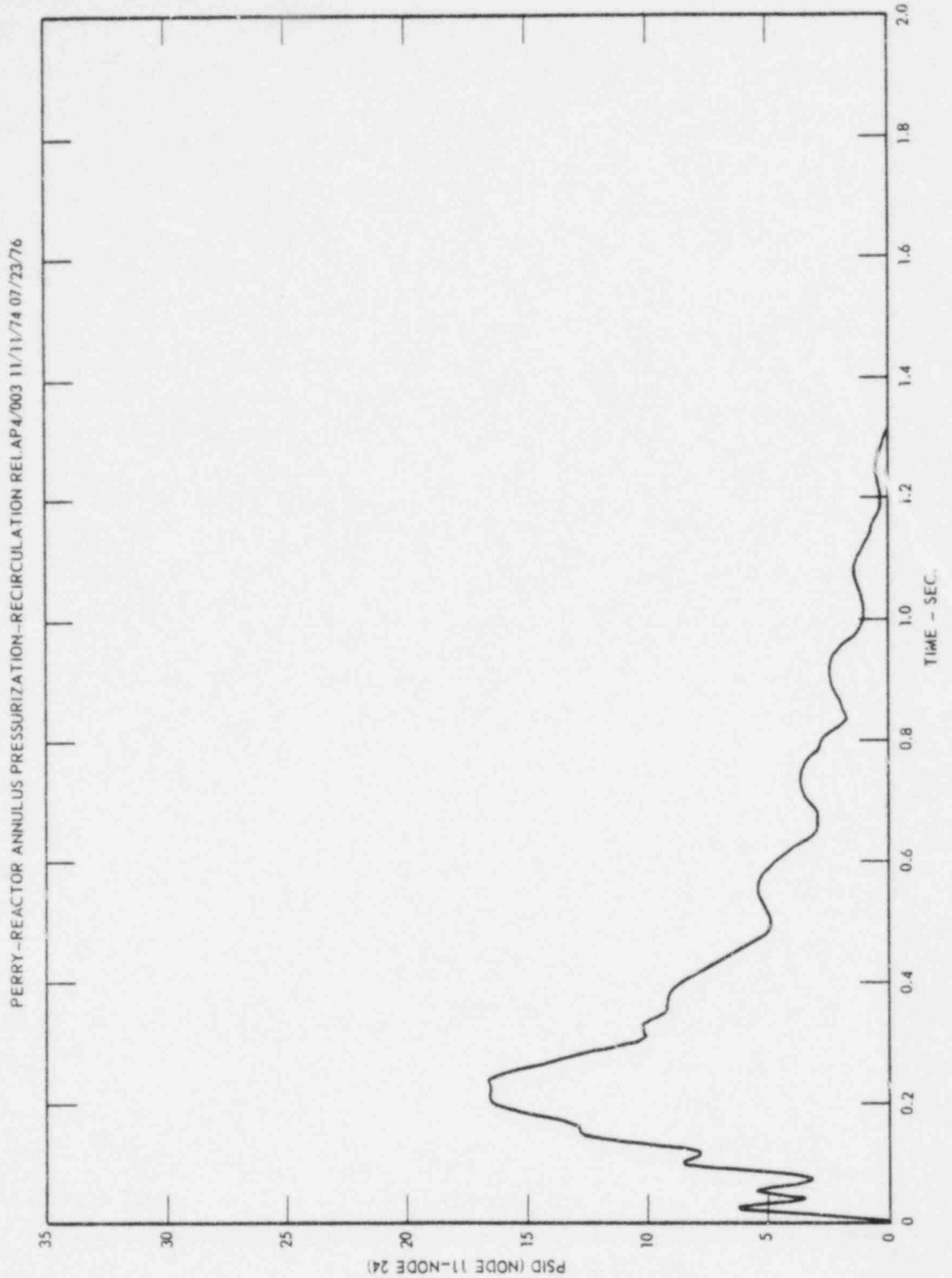
Figure 6.2-31



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 6 - 24)

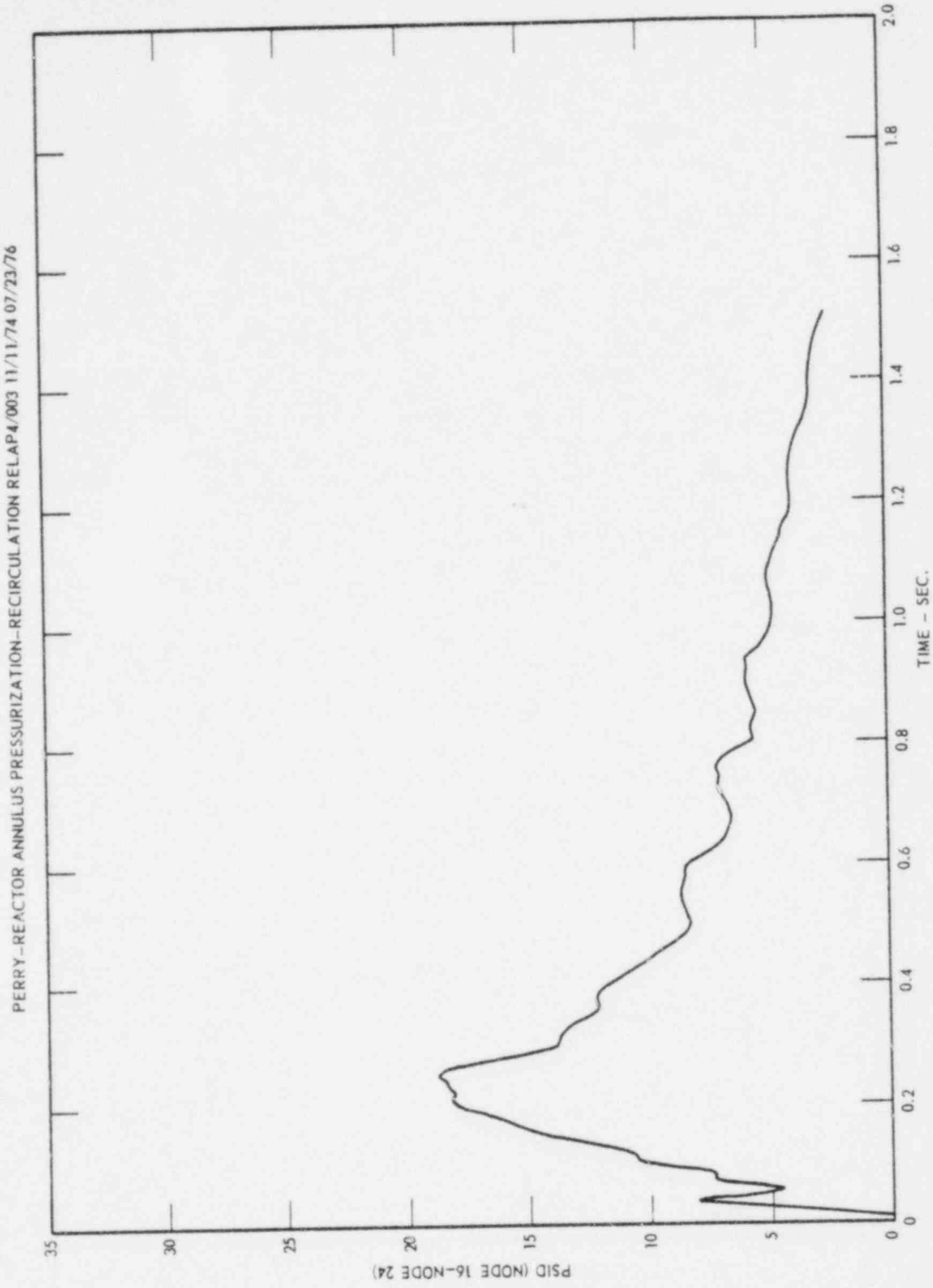
Figure 6.2-32



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 11 - 24)

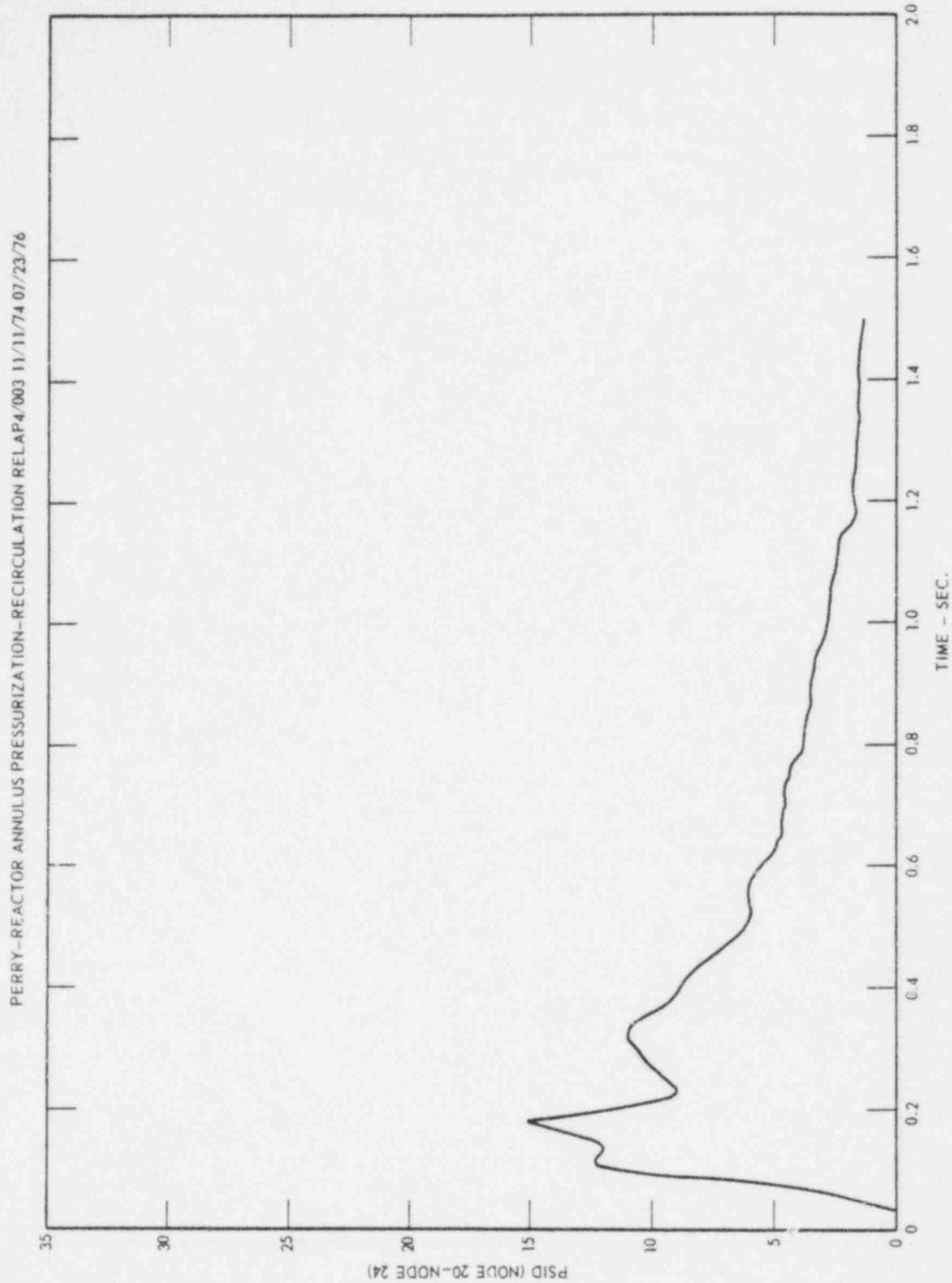
Figure 6.2-33



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 16 - 24)

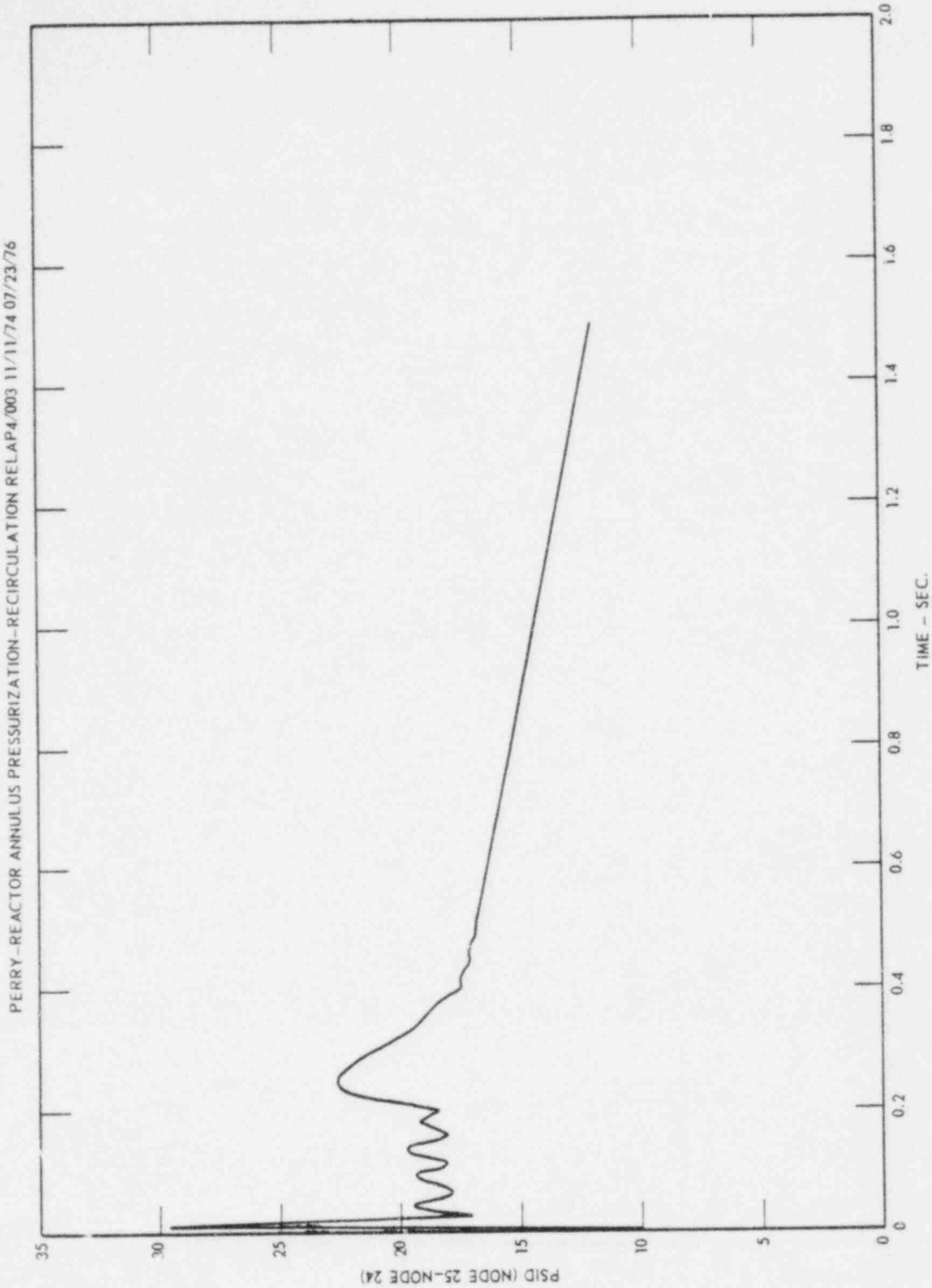
Figure 6.2-34



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 20 - 24)

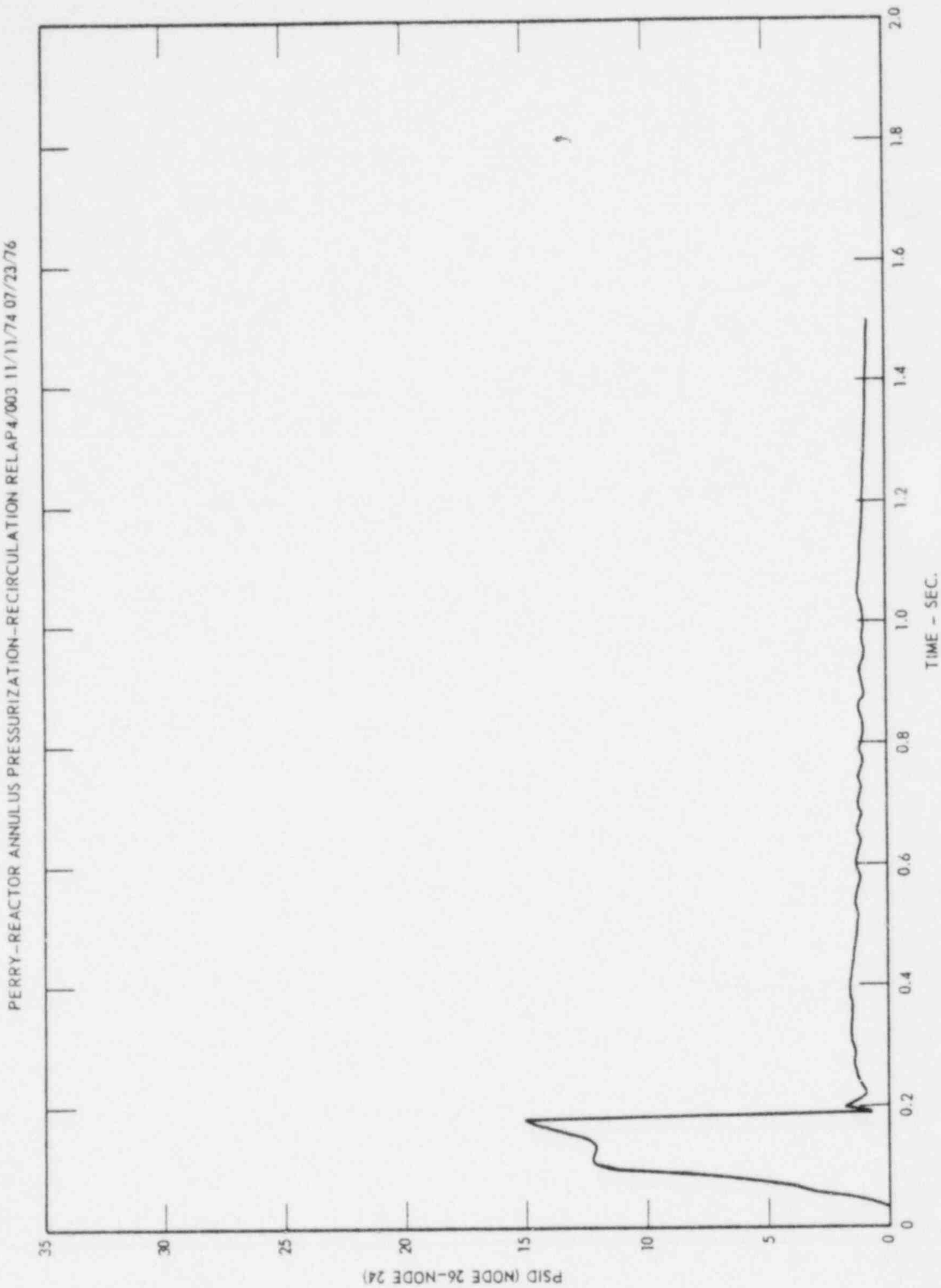
Figure 6.2-35



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 25 - 24)

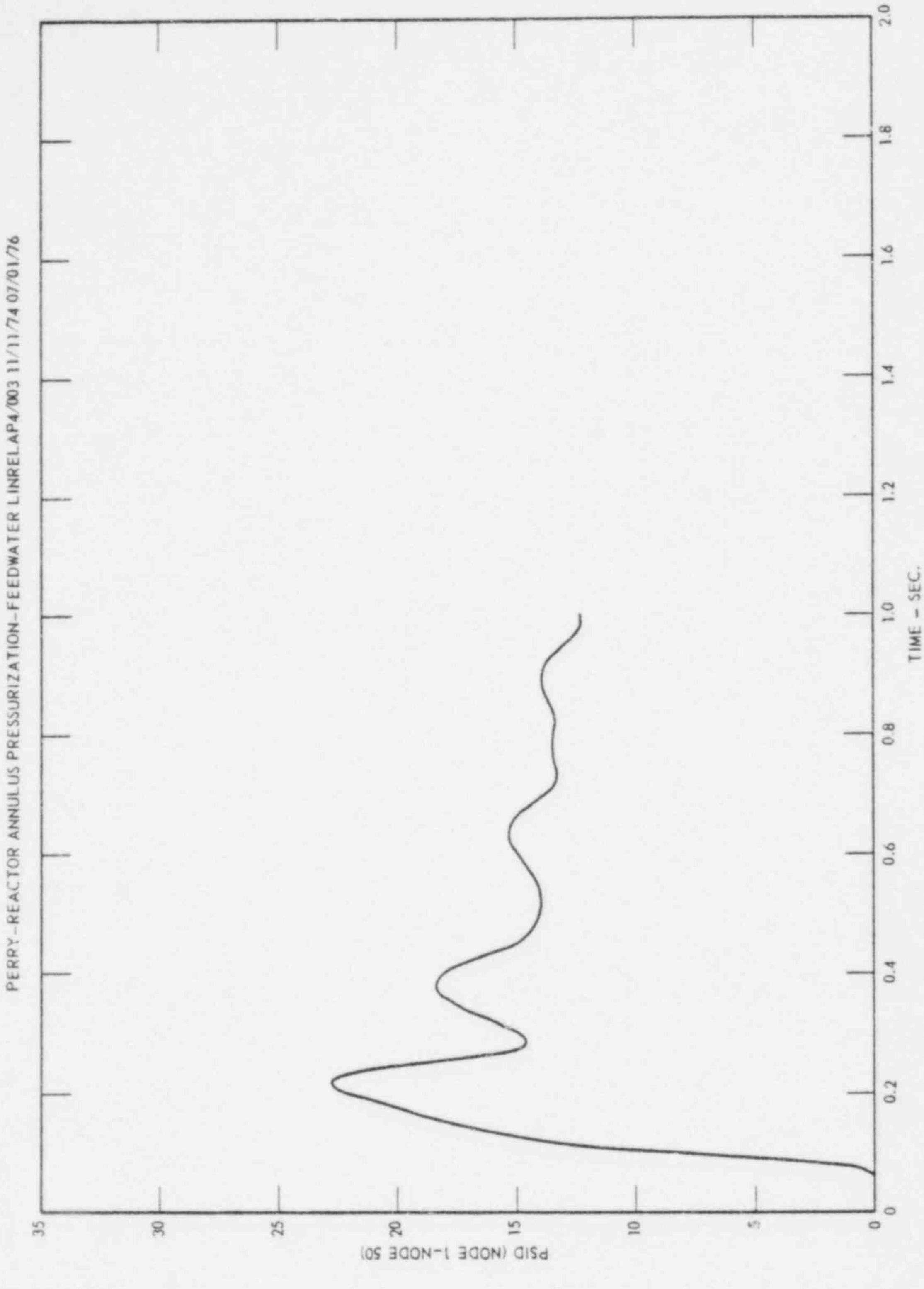
Figure 6.2-36



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 26 - 24)

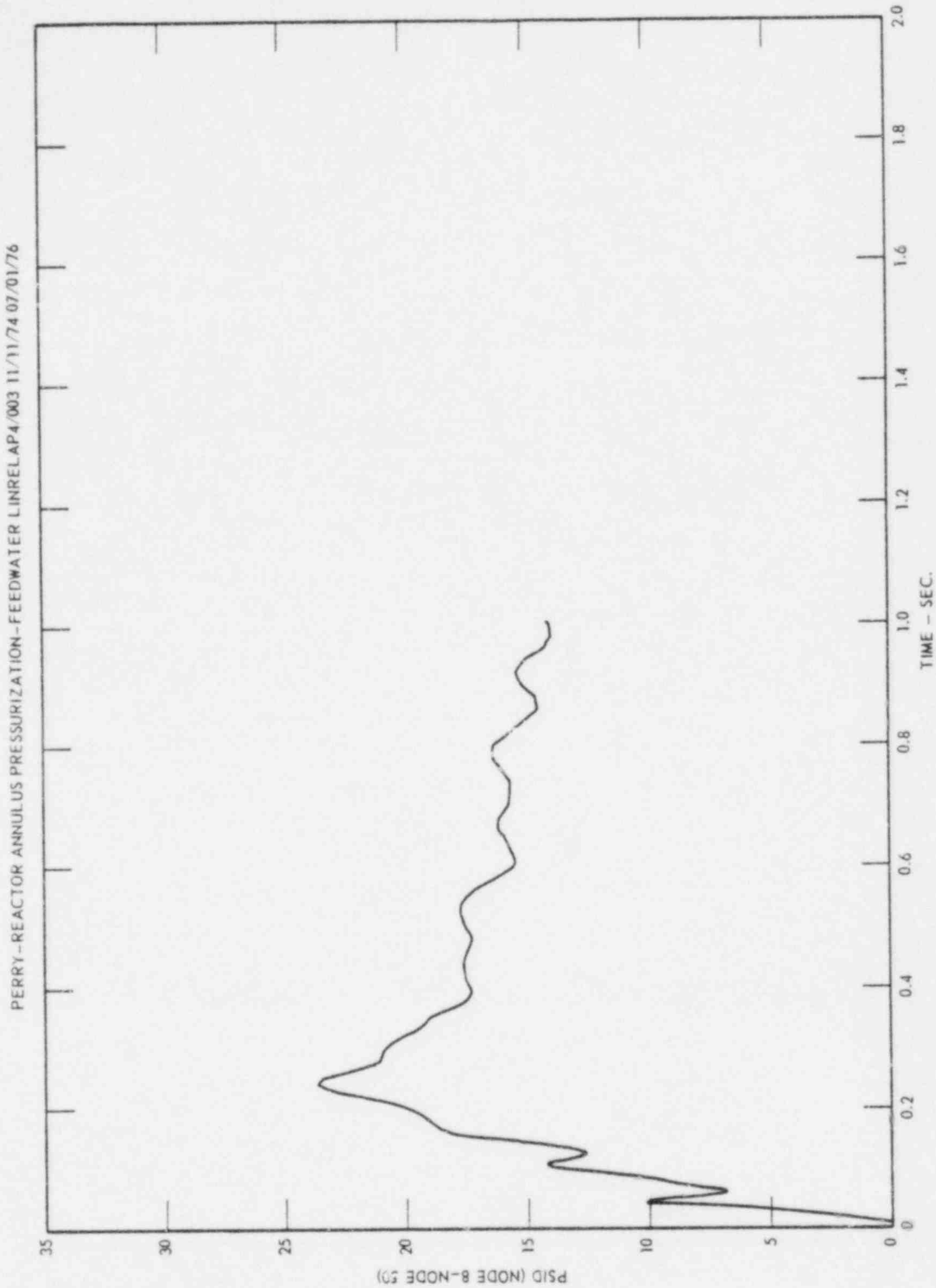
Figure 6.2-37



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 1 - 50)

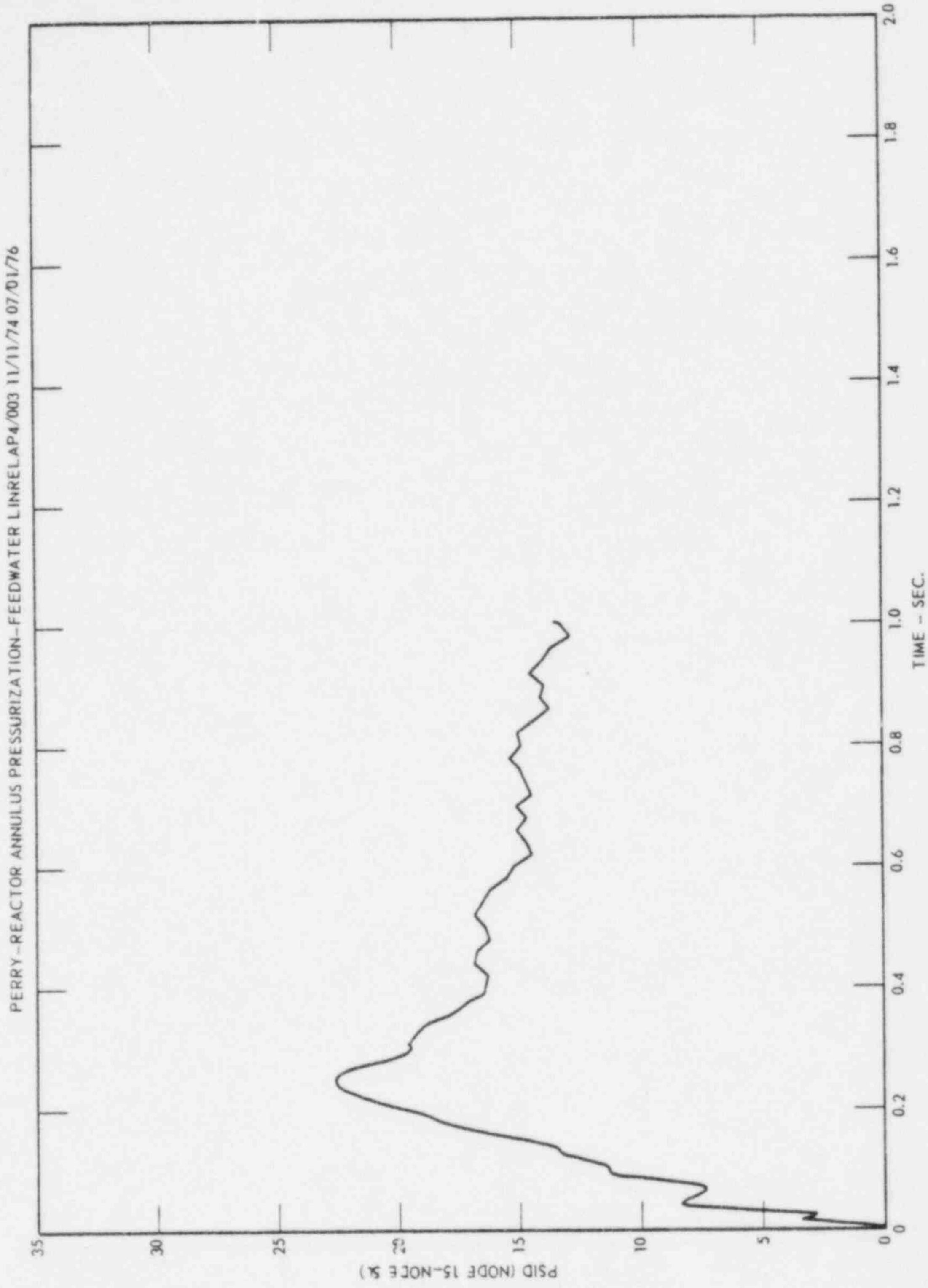
Figure 6.2-38



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 8 - 50)

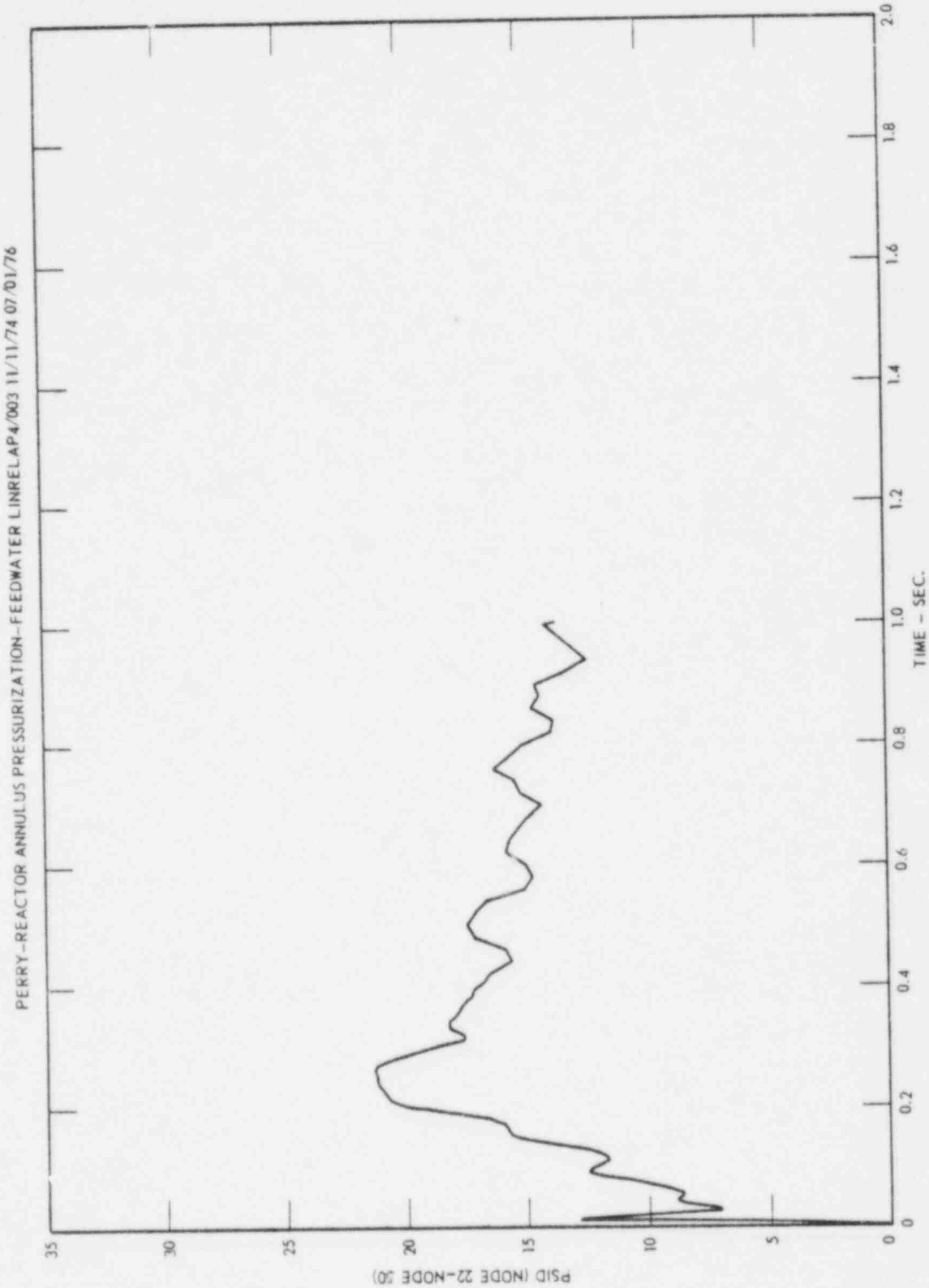
Figure 6.2-39



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 15 - 50)

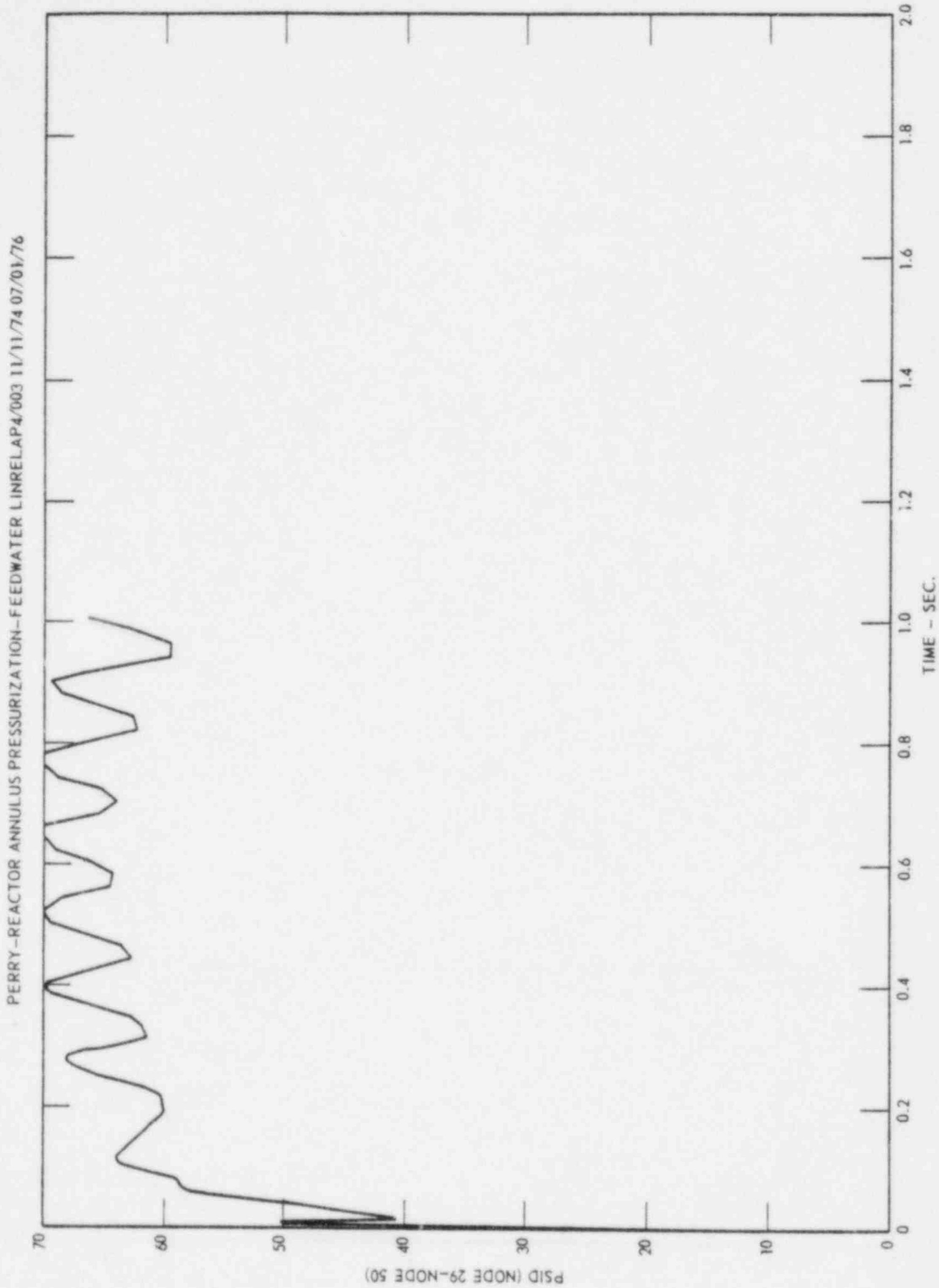
Figure 6.2-40



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 22 - 50)

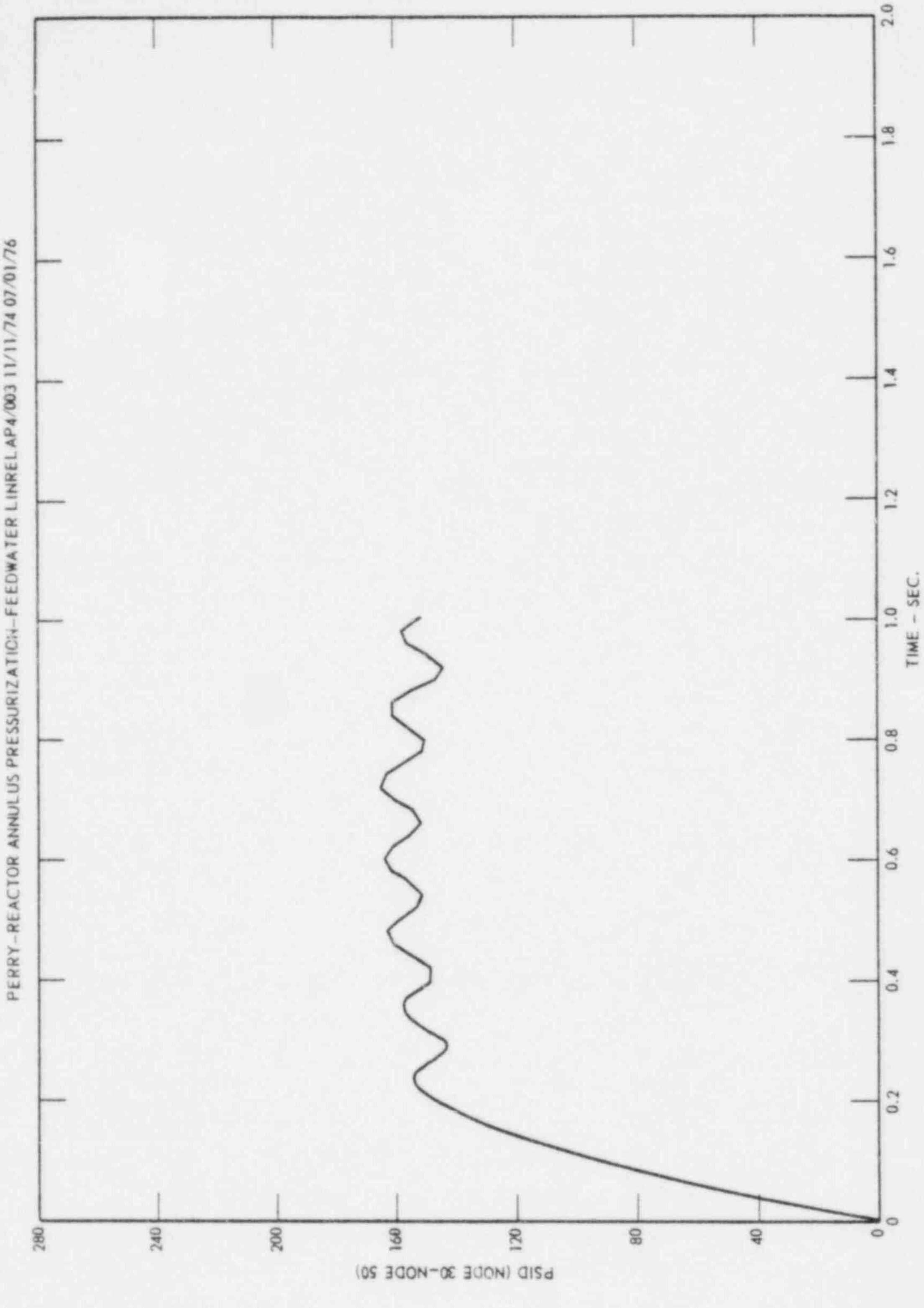
Figure 6.2-41



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 29 - 50)

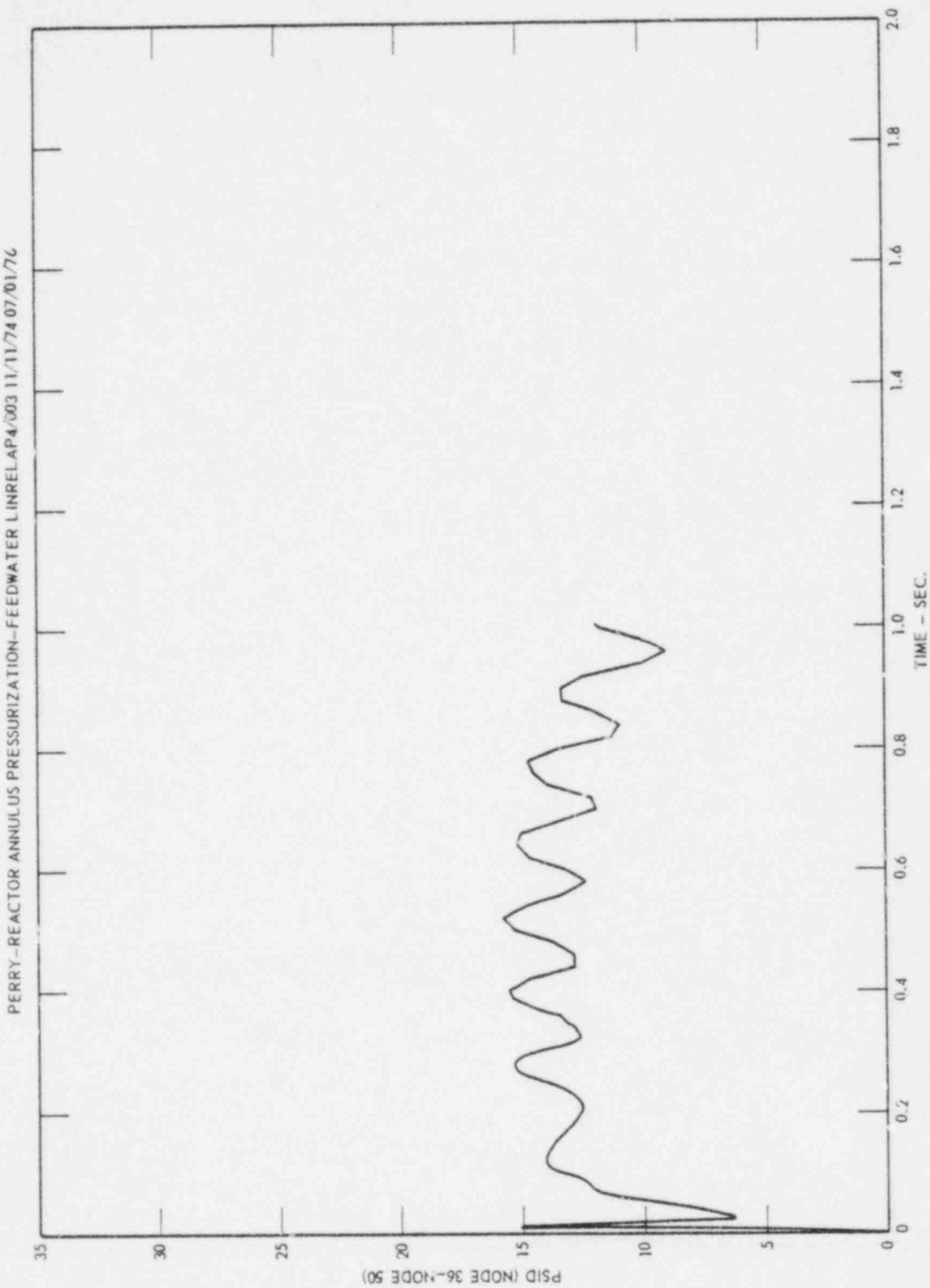
Figure 6.2-42



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 30 - 50)

Figure 6.2-43



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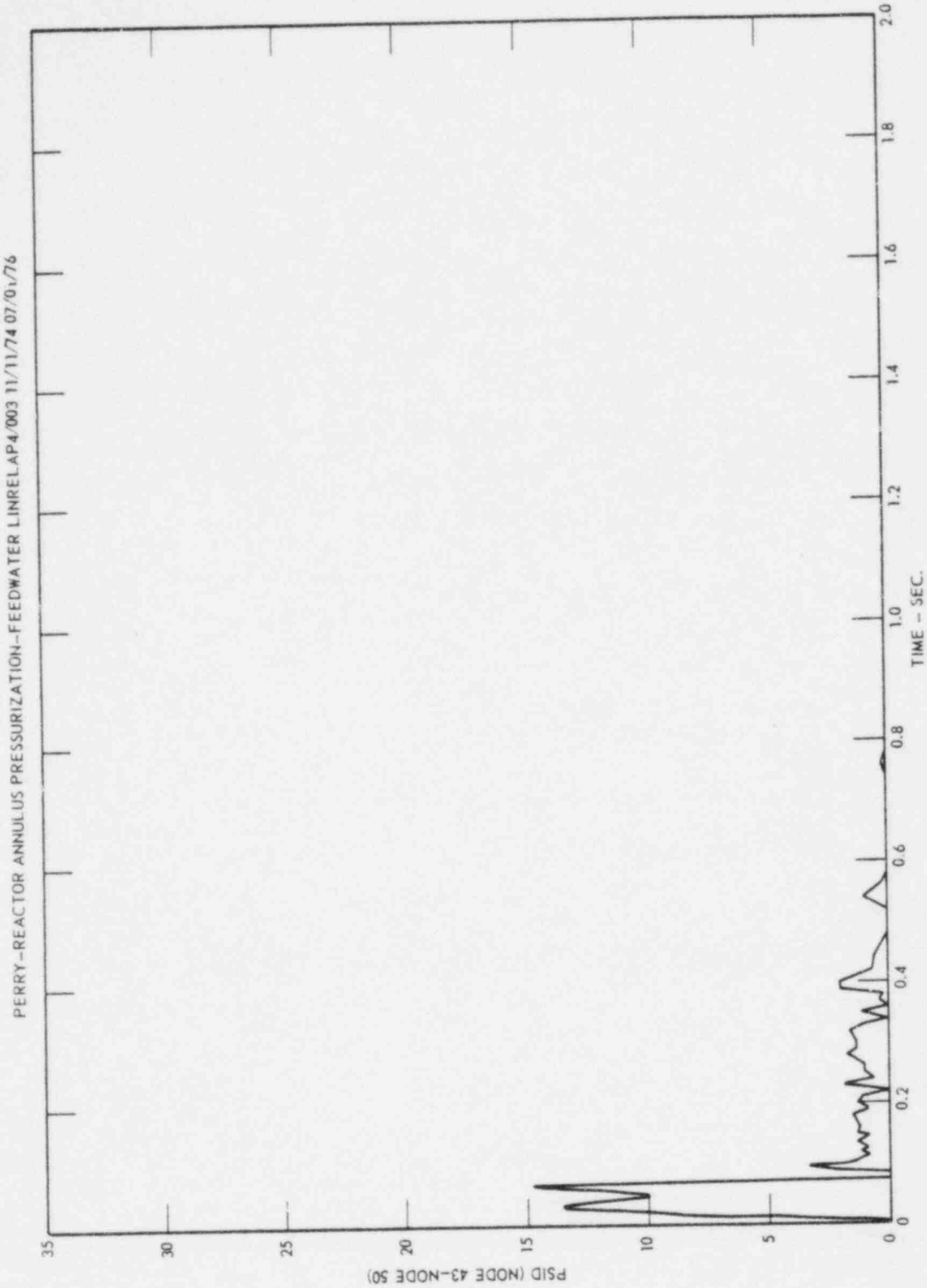
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 36 - 50)

Figure 6.2-44



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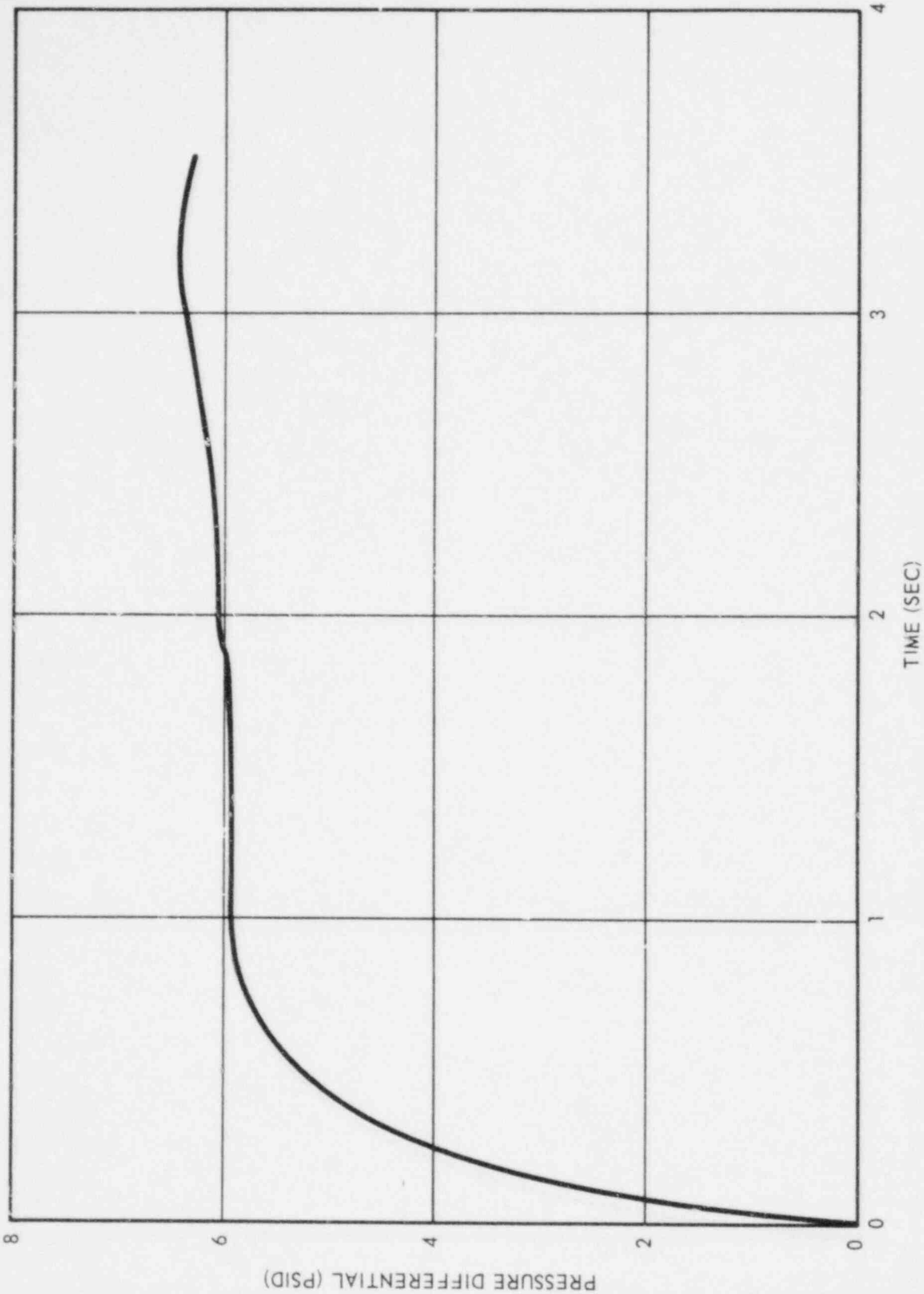
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Annulus Pressure
Differentials (Nodes 34 - 50)

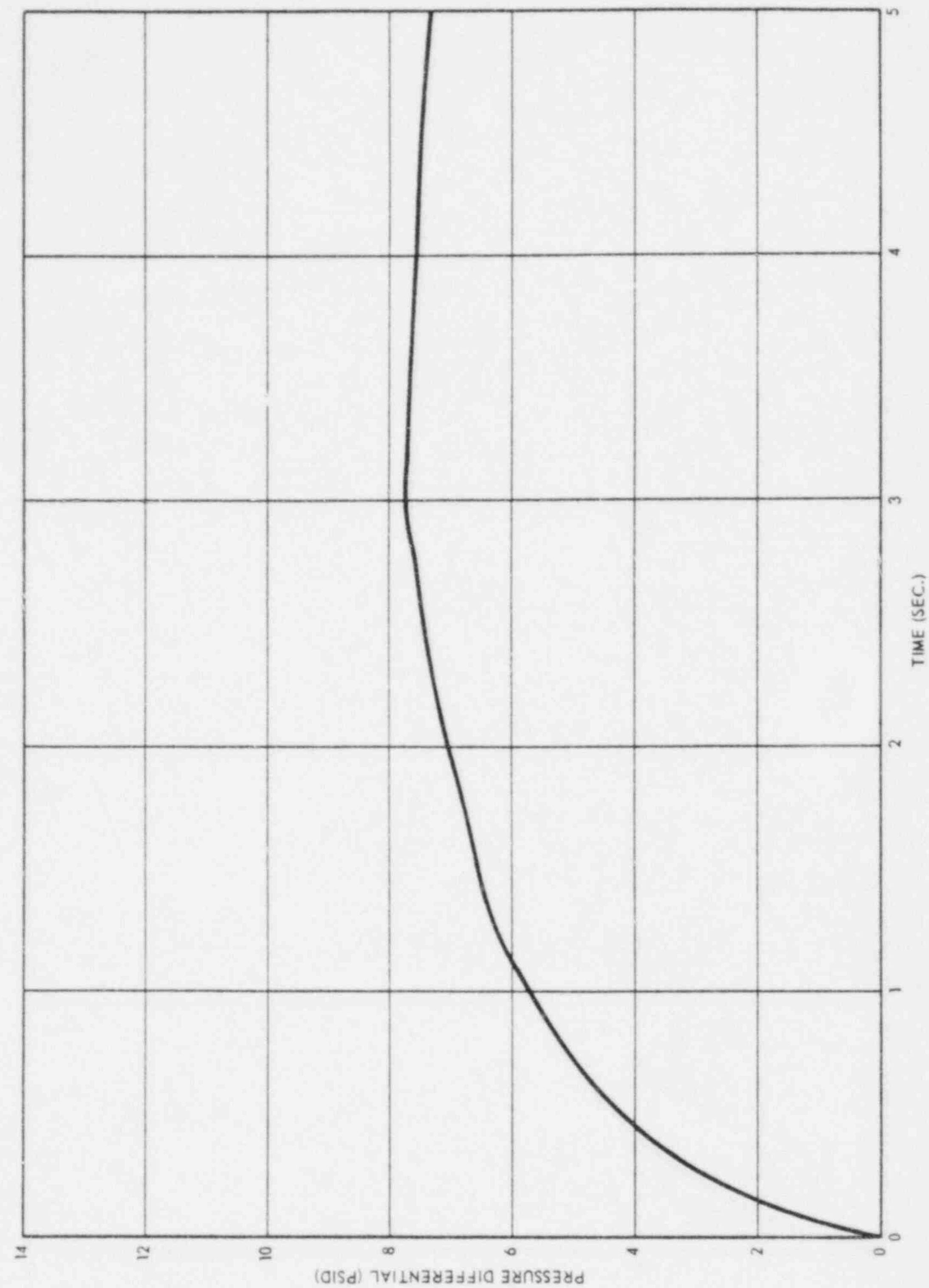
Figure 6.2-45



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Drywell Head Pressure
Differential

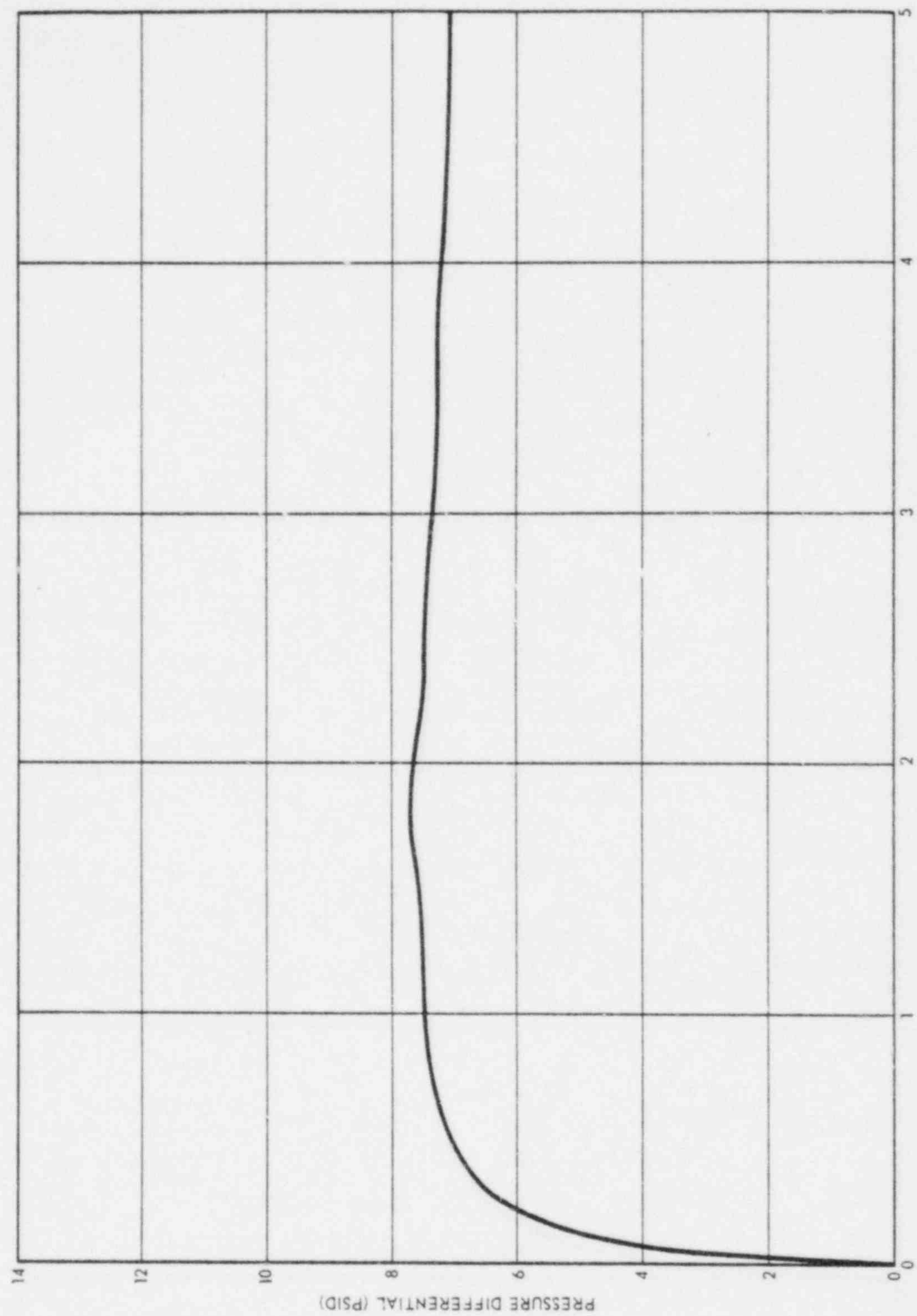
Figure 6.2-46



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

RWCU Heat Exchanger
Pressure Differential

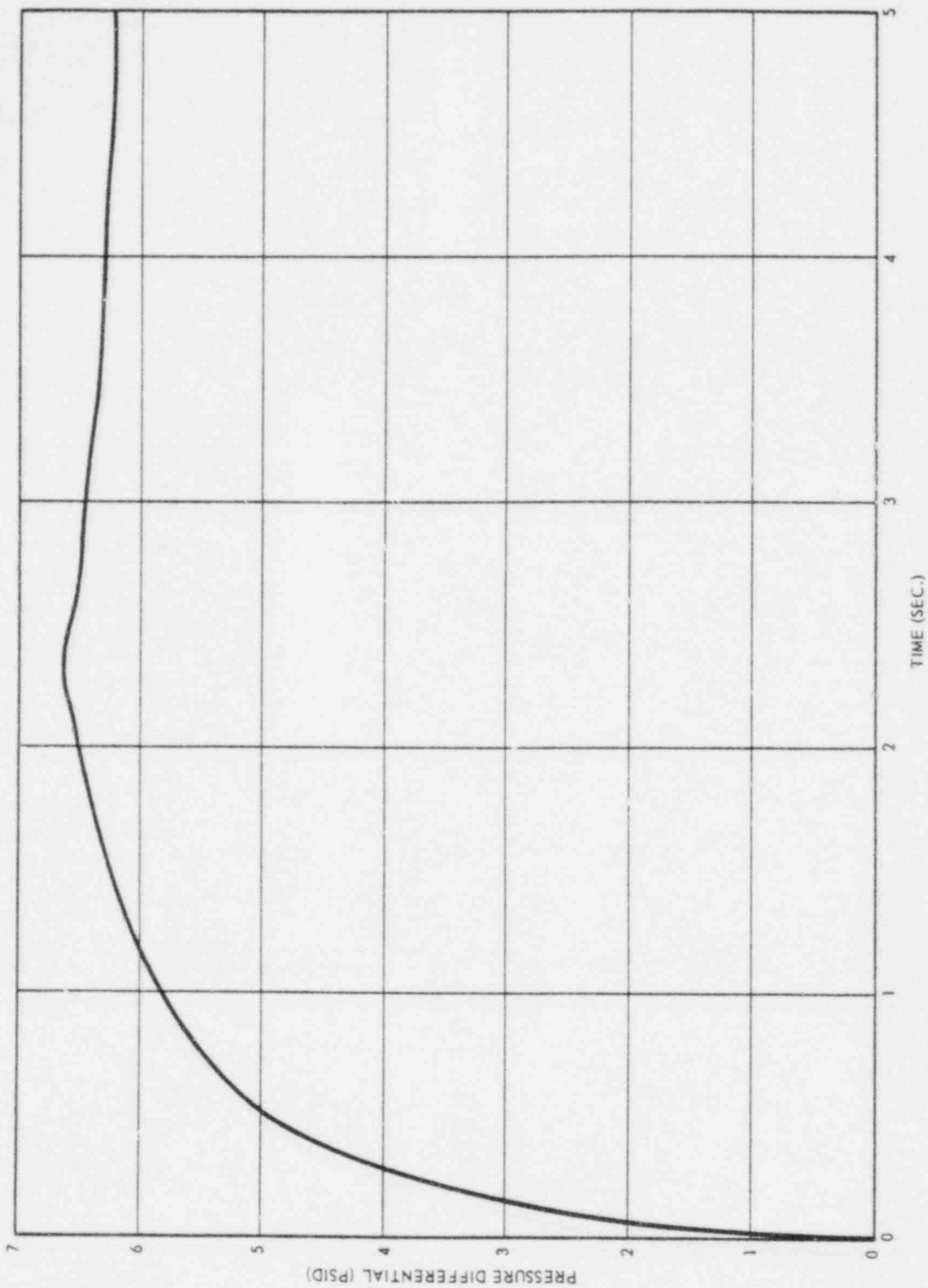
Figure 6.2-47



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

RWCU Filter Demineralizer
Drain Valve Nest Room Pressure
Differential

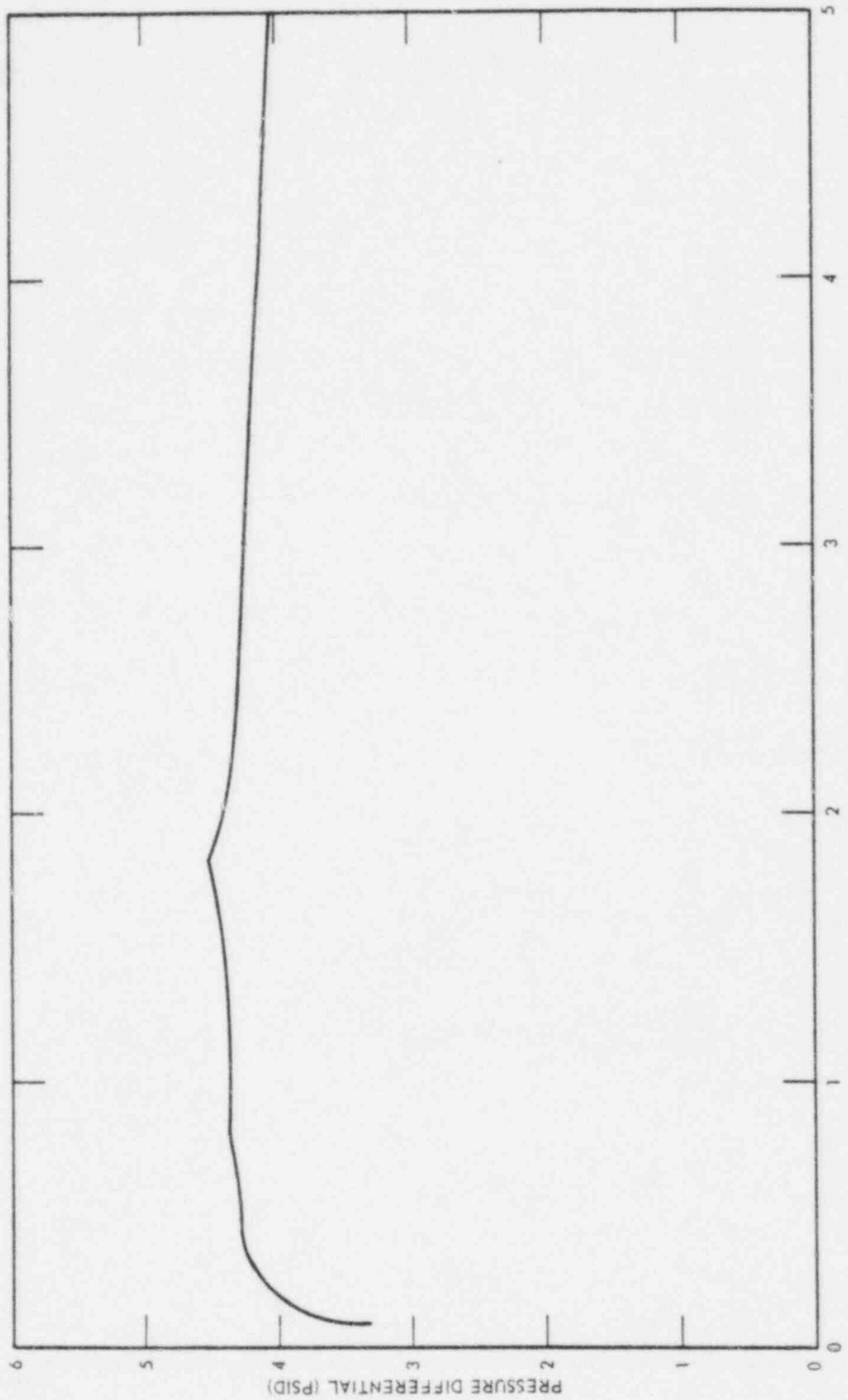
Figure 6.2-48



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

RWCU Filter Demineralizer
Valve Room Pressure Differential

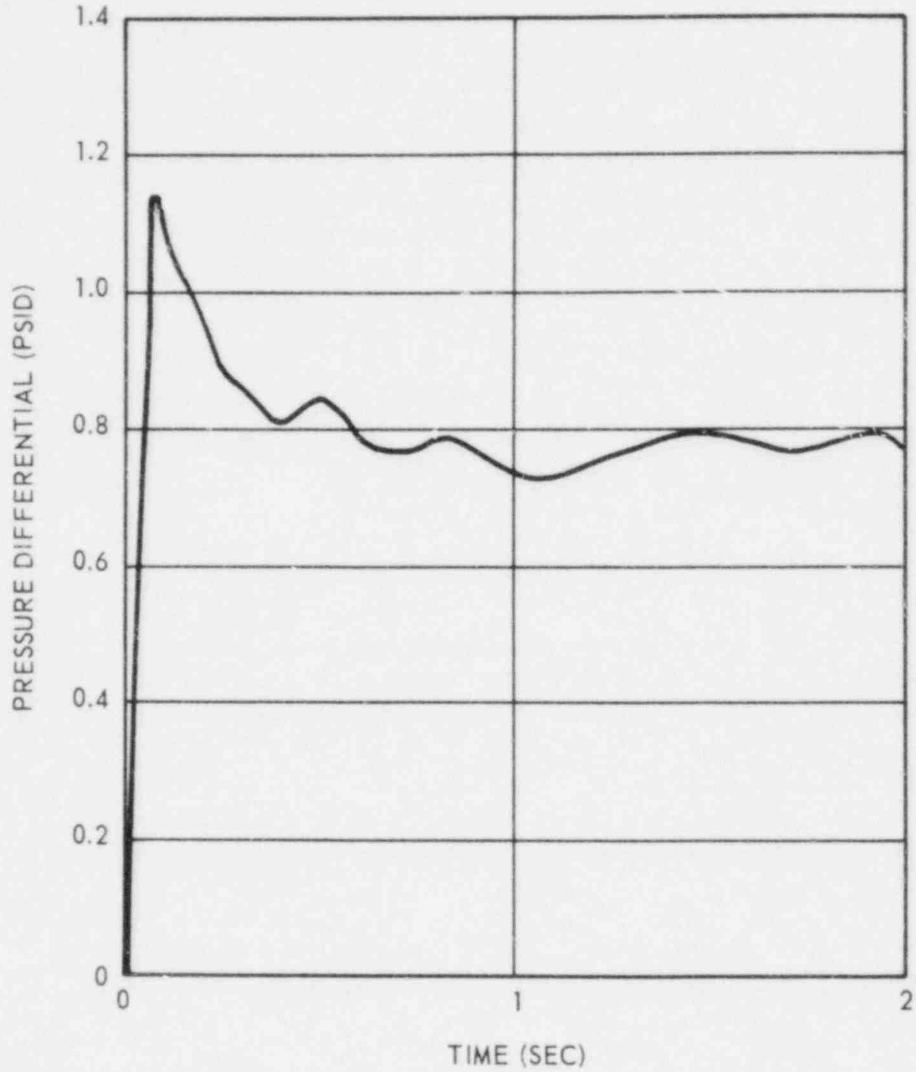
Figure 6.2-49



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

RWCU Filter Demineralizer Room
Pressure Differential

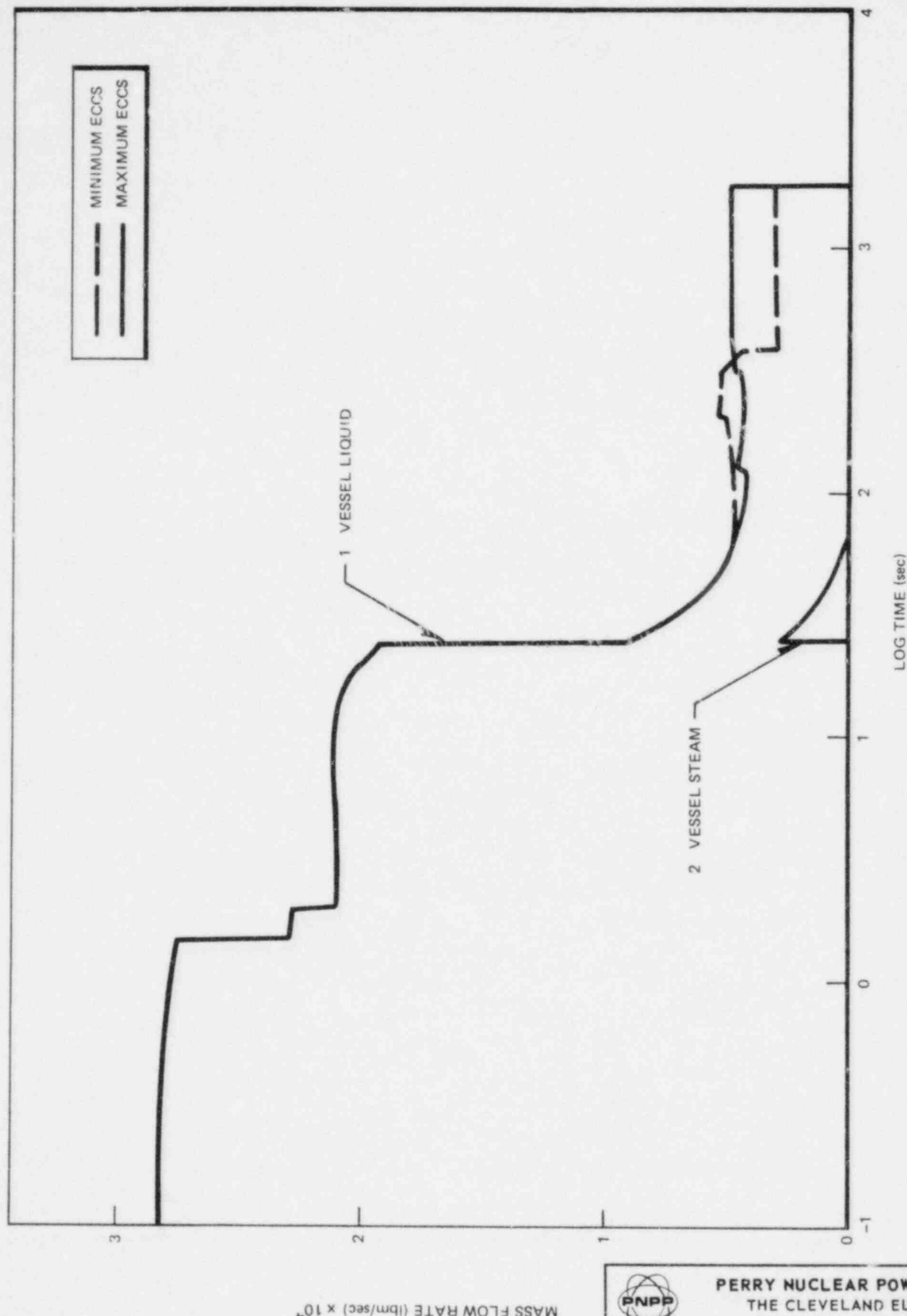
Figure 6.2-50



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Steam Tunnel
Pressure Differential

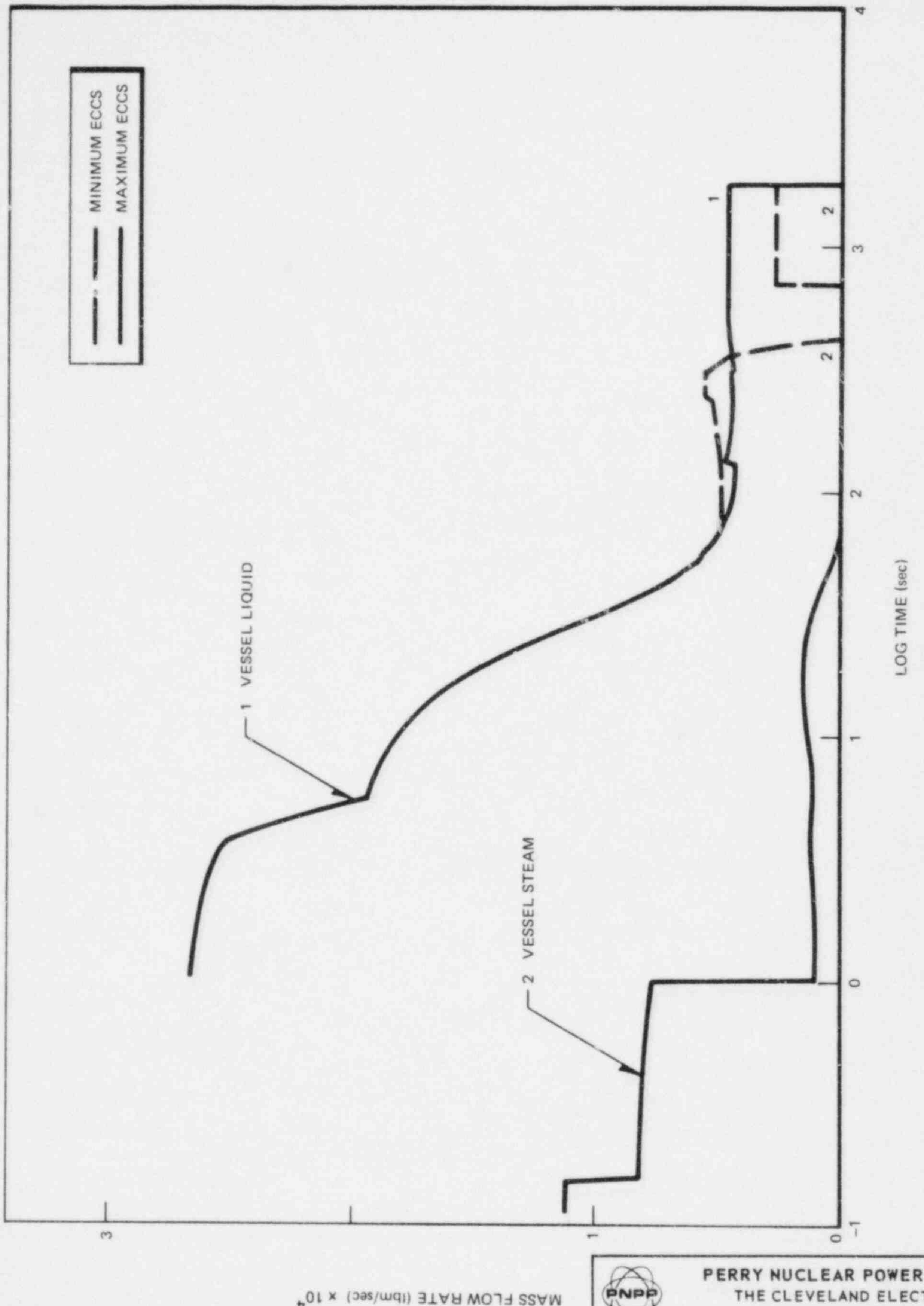
Figure 6.2-51



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Vessel Blowdown Flow Rates
Following a Recirculation
Line Break

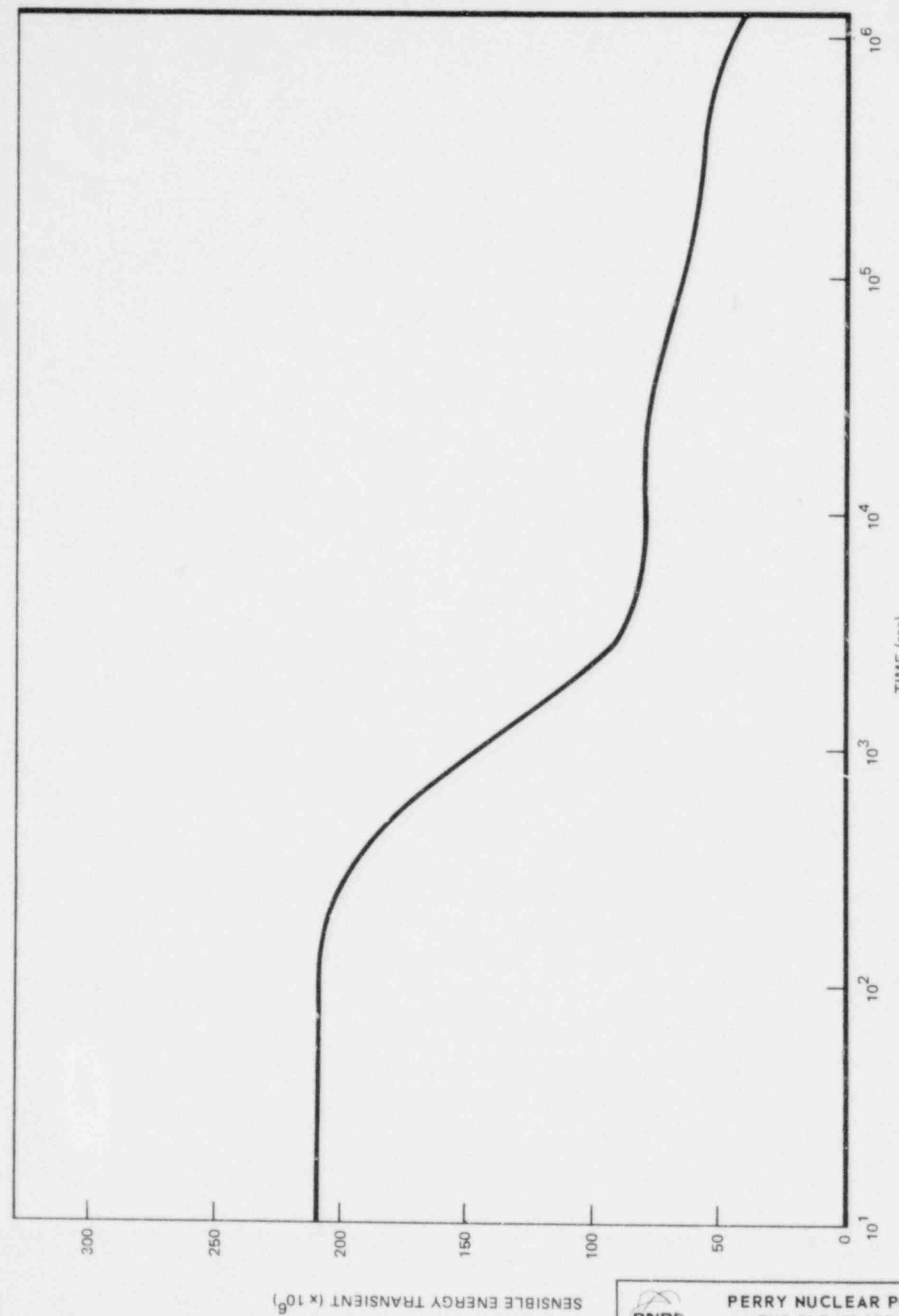
Figure 6.2-52



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Vessel Blowdown Flow Rates
Following a Main Steam
Line Break

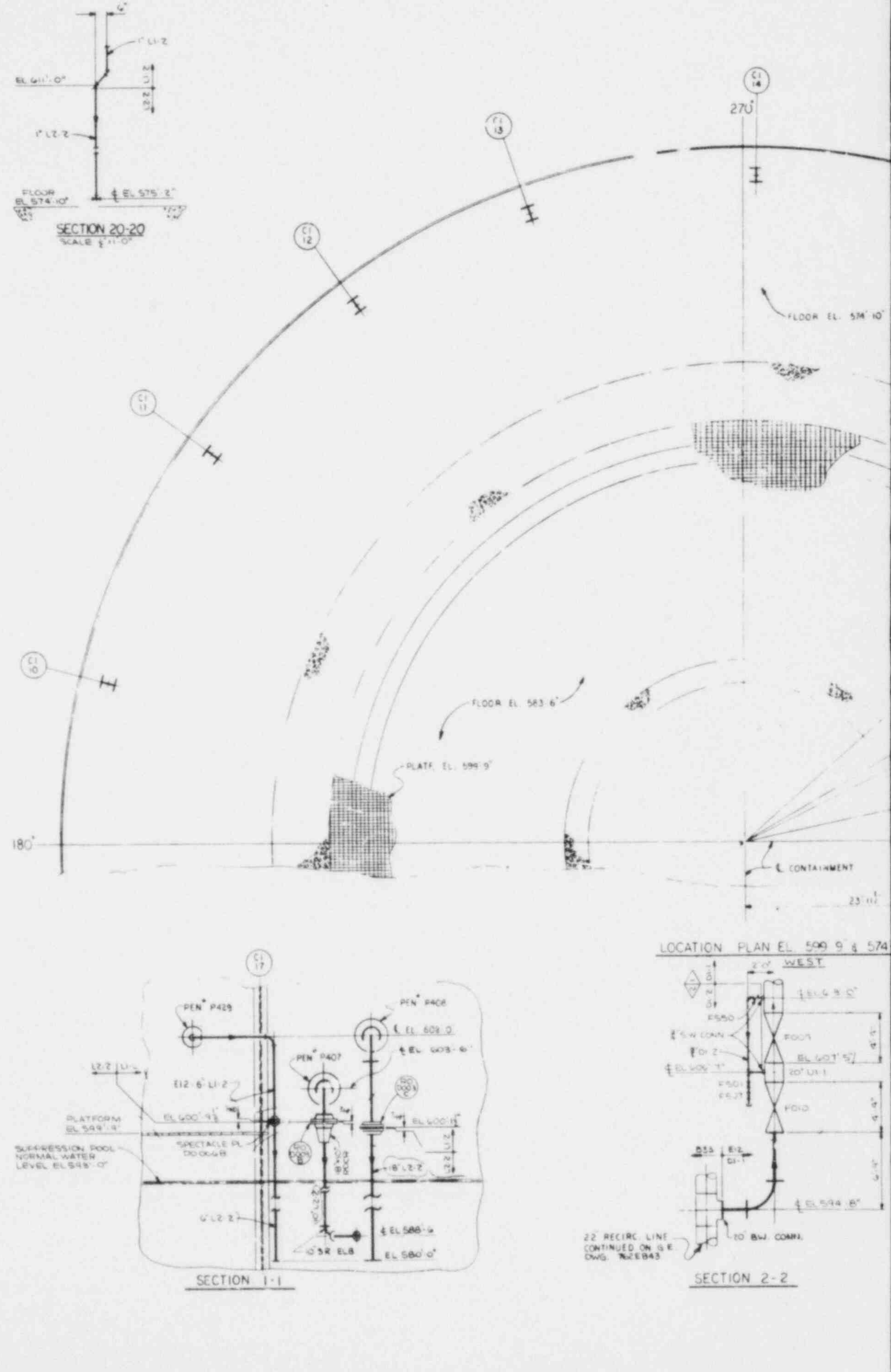
Figure 6.2-53

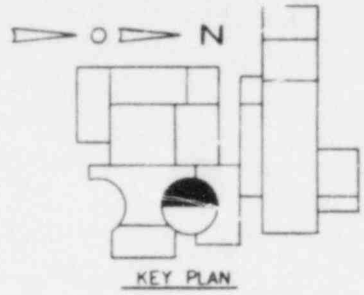


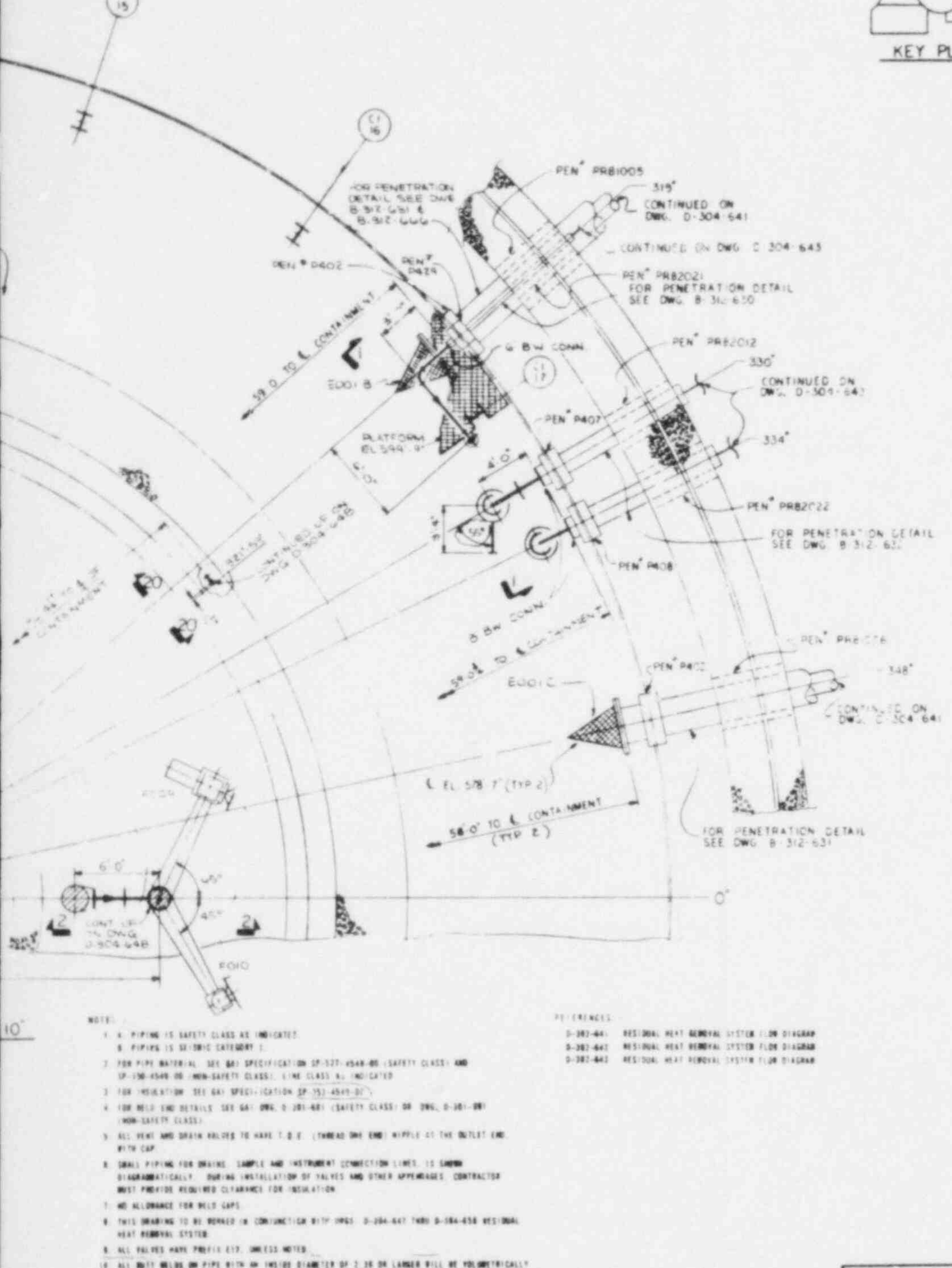
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Sensible Energy in the Reactor Pressure Vessel and Internal Metals Following a Main Steam Line Break

Figure 6.2-54


SECTION 20-20
SCALE ½"=1'-0"
FLOOR EL 574'-10"
1" L1-2
1" L2-2
C1 10
C1 11
C1 12
C1 13
C1 14
270°
180°
FLOOR EL. 574'-10"
FLOOR EL. 583'-6"
PLATF. EL. 599'-9"
℄ CONTAINMENT
LOCATION PLAN EL. 599'-9" & 574
C1 17
PEN P429
PEN P408
PEN P407
PLATFORM EL 599'-9"
SUPPRESSION POOL NORMAL WATER LEVEL EL 598'-0"
SPECTACLE PL
10" SR ELB
EL 580'-0"
SECTION 1-1
WEST
F550
F007
F010
20" L1-1
22" RECIRC. LINE CONTINUED ON G.E. DWG.
20" BW. CONN.
SECTION 2-2

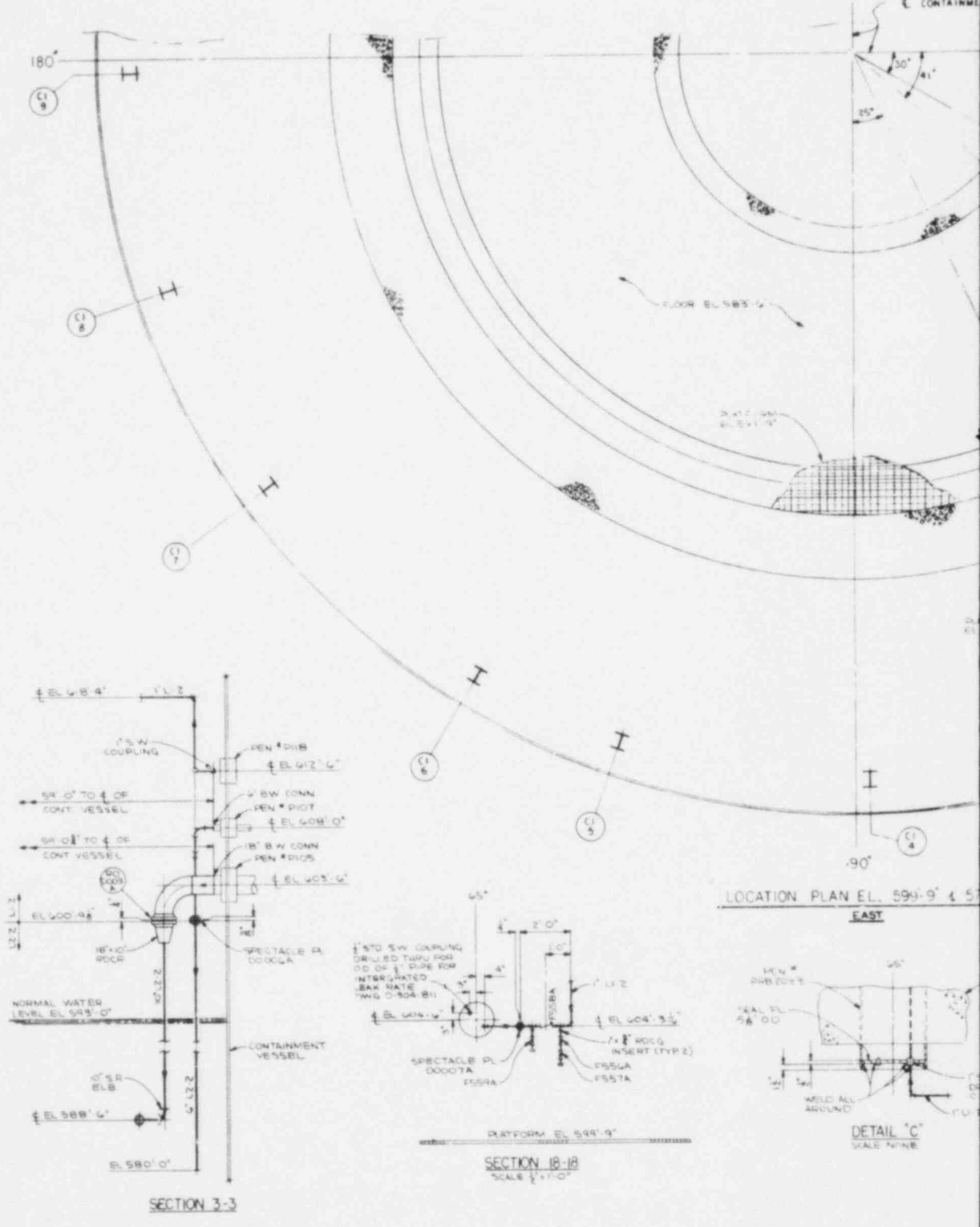




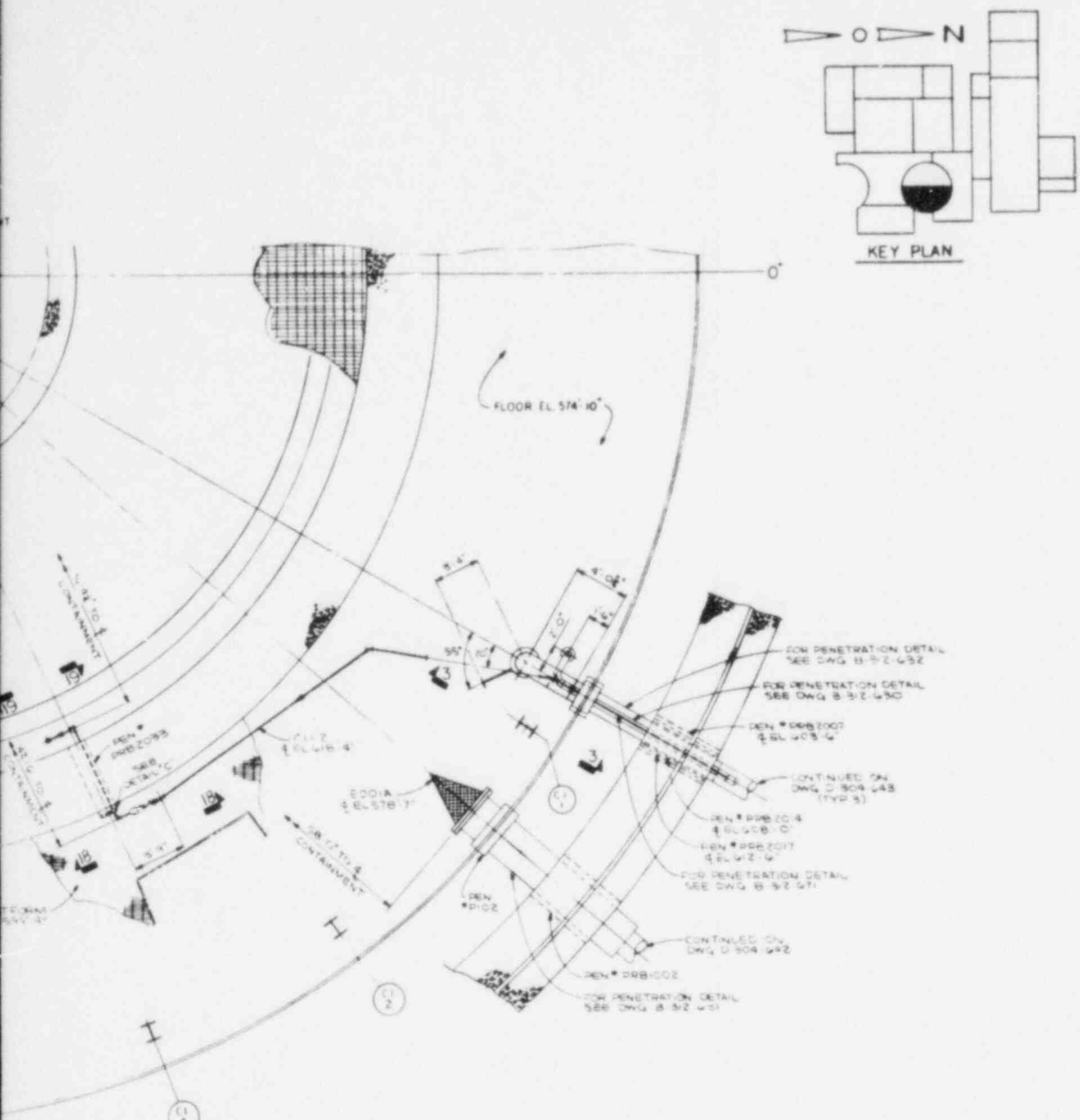
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

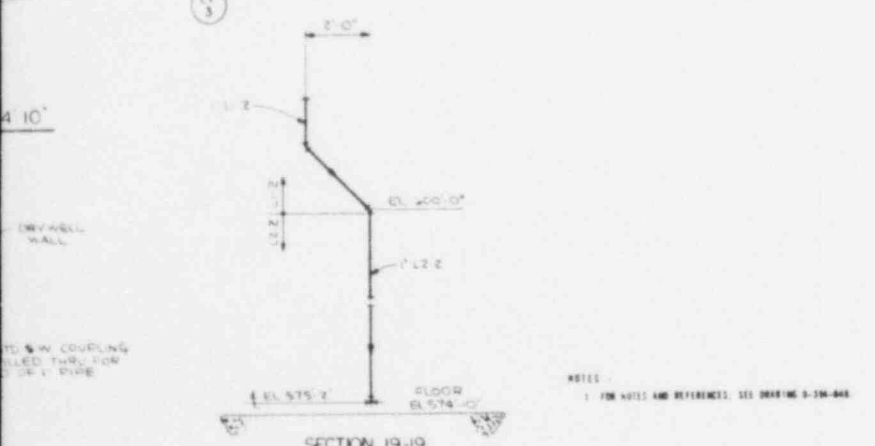
Residual Heat Removal System
Plan and Section - West

Figure 6.2-55
(GAI Dwg. D-304-646)



180°
90°
FLOOR EL 583'-6"
LOCATION PLAN EL. 599'-9"
EAST
NORMAL WATER LEVEL EL 595'-0"
CONTAINMENT VESSEL
SPECTACLE PL
PLATFORM EL 599'-9"
SECTION 3-3
SECTION 18-18
DETAIL "C"

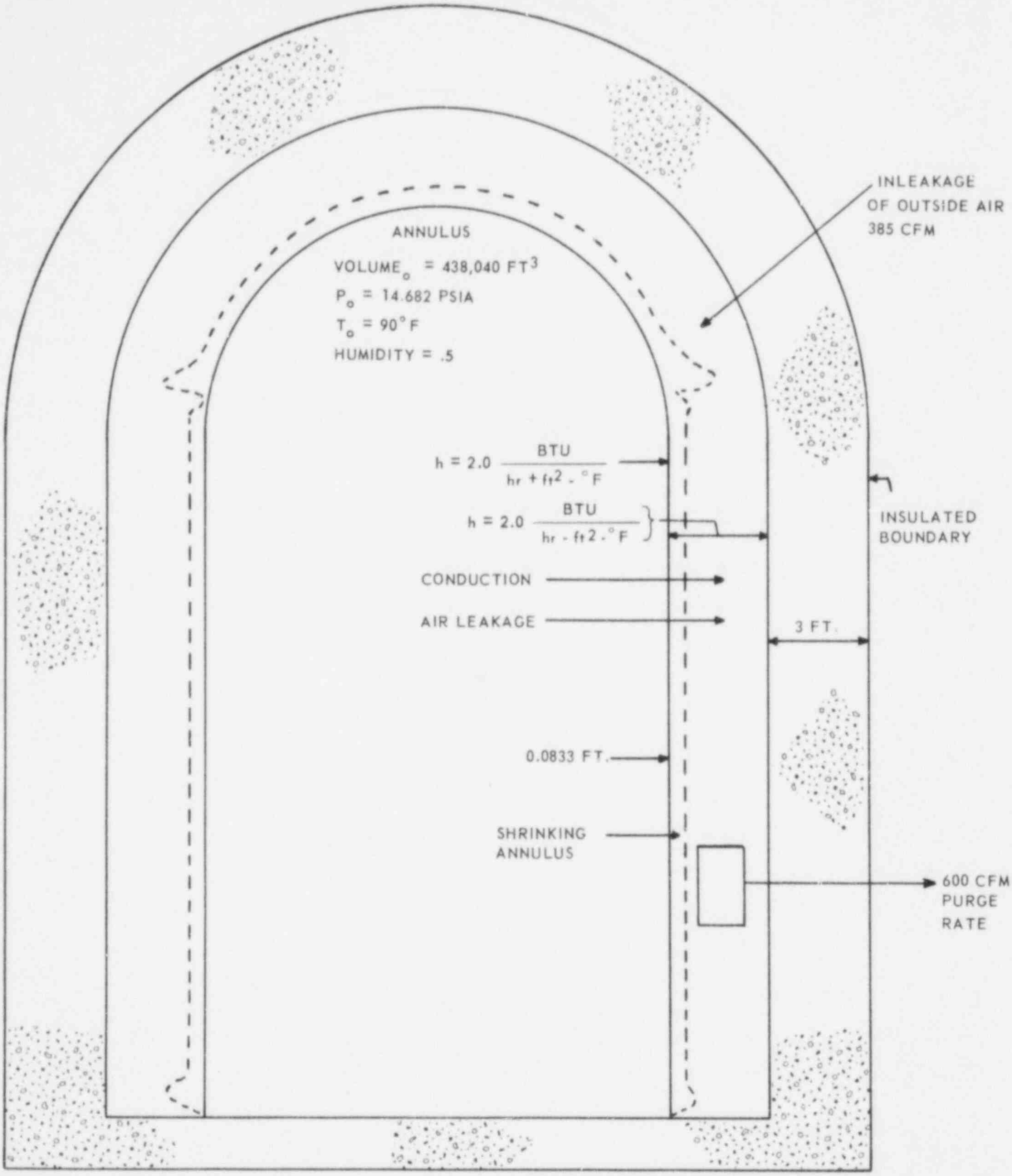




PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Residual Heat Removal System
Plan and Section - East

Figure 6.2-56
(GAI Dwg. D-304-647)

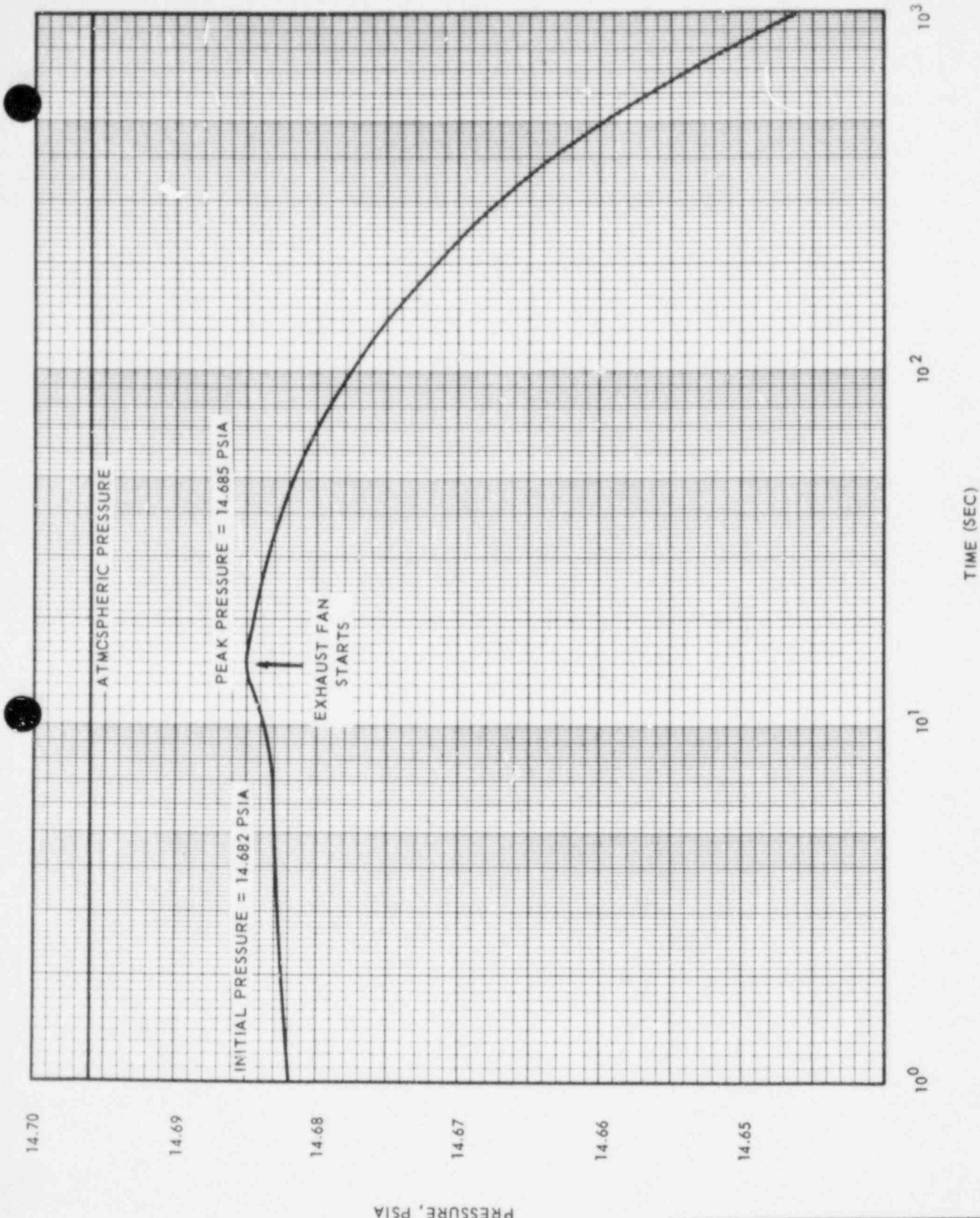


PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Model Used In CONTEMPT

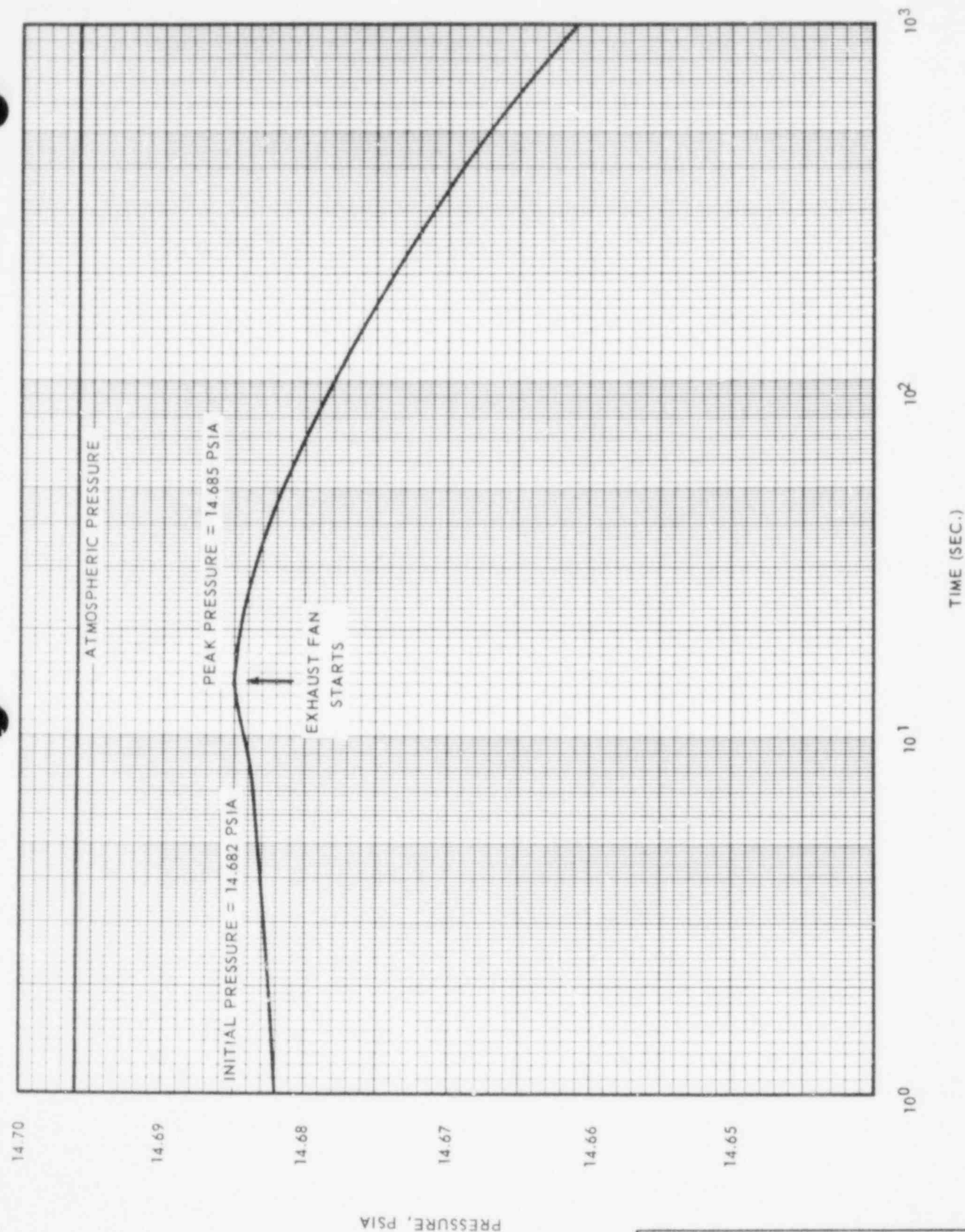
Figure 6.2-57



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Annulus Pressure Following
DBA LOCA Versus Time

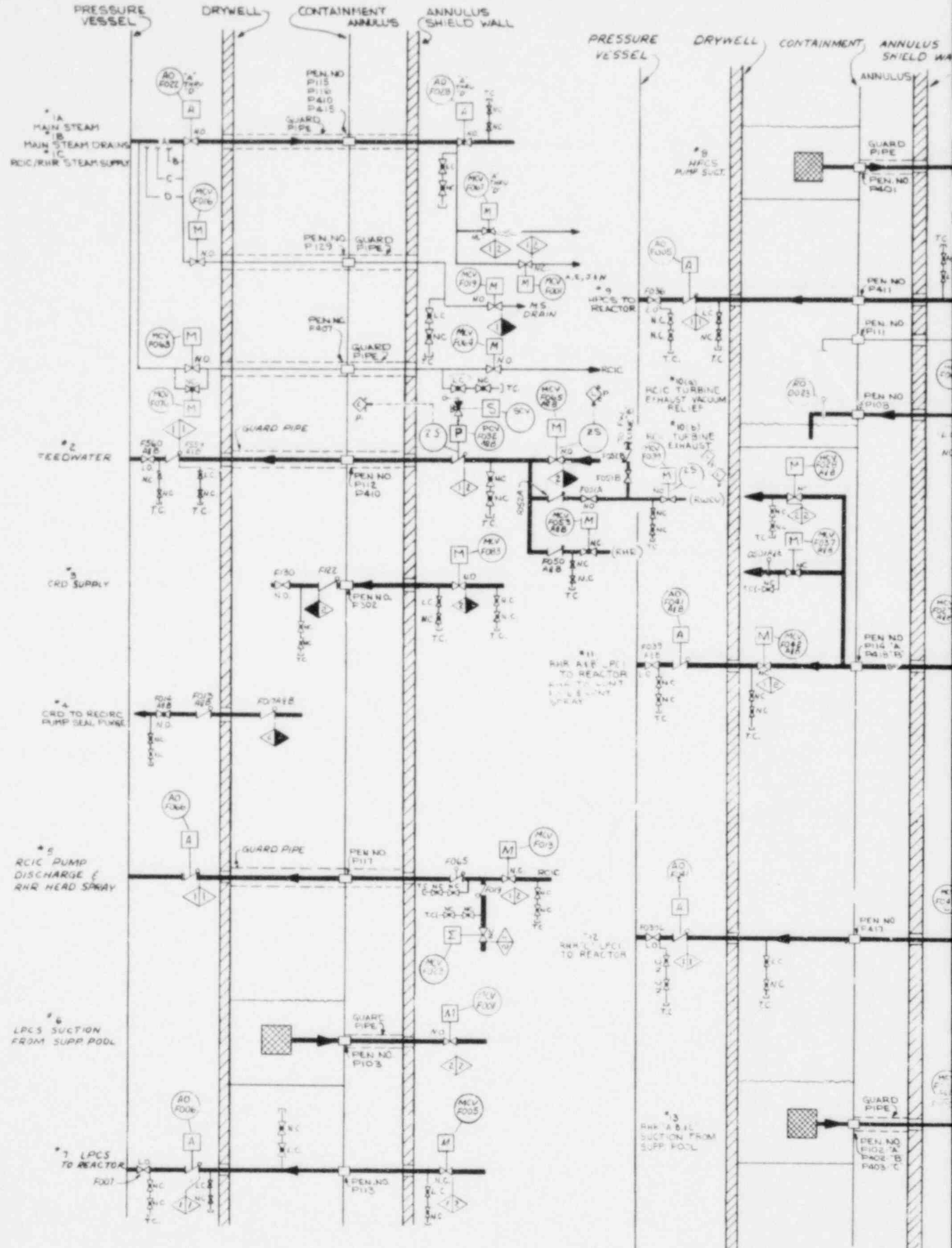
Figure 6.2-58



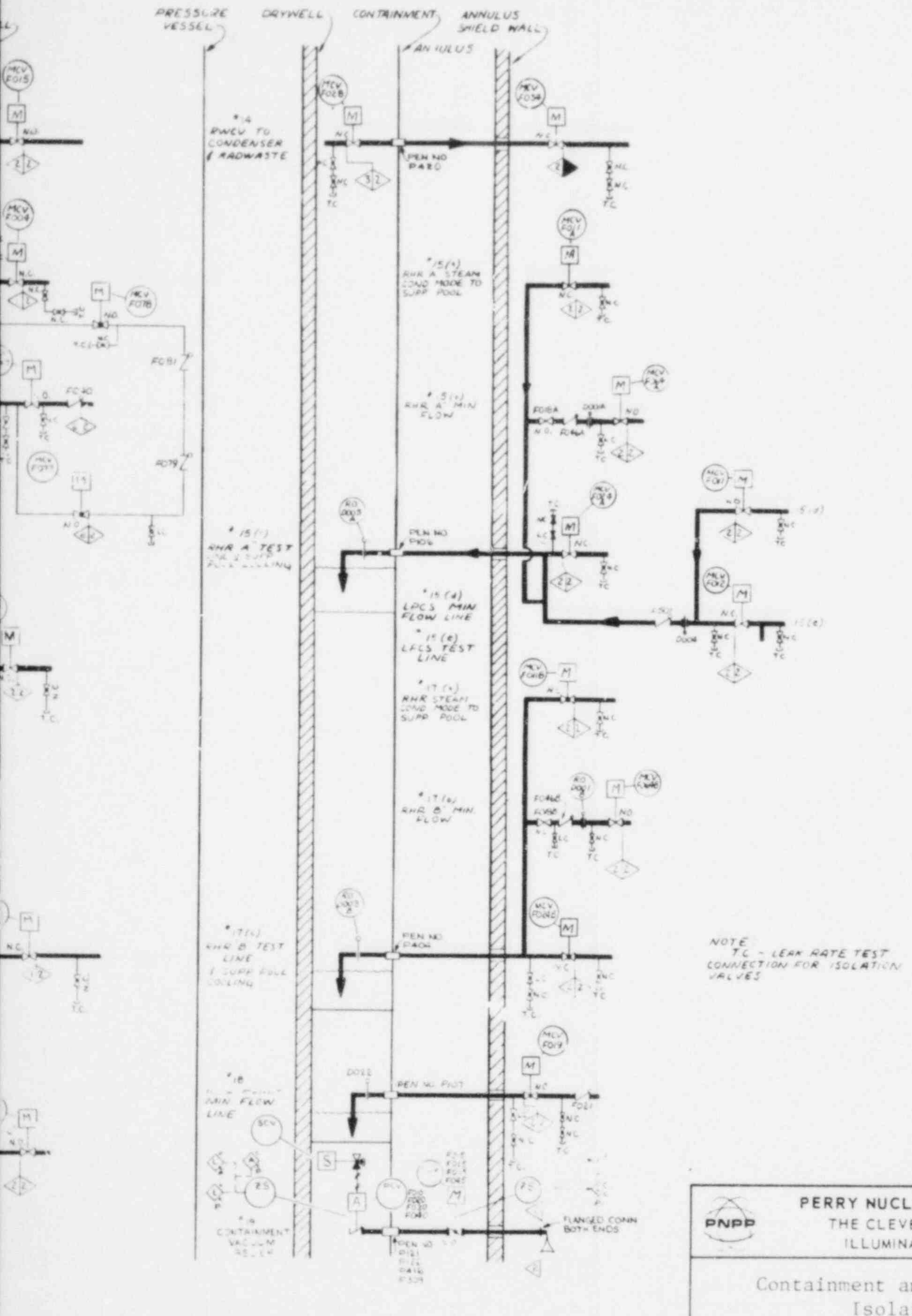
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Annulus Pressure Following
Recirculation Line Break

Figure 6.2-59



PRESSURE VESSEL
DRYWELL
CONTAINMENT ANNULUS
ANNULUS SHIELD WALL
*1A MAIN STEAM
*1B MAIN STEAM DRAINS
*1C RCIC/RHR STEAM SUPPLY
GUARD PIPE
PEN NO. P115 P116 P410 P415
PEN NO. P129
PEN NO. P407
M.S. DRAIN
RCIC
*2 FEEDWATER
PEN NO. P112 P410
(RWCU)
(RHR)
*3 CRD SUPPLY
PEN NO. P302
*4 CRD TO RECIRC PUMP SEAL PURGE
*5 RCIC PUMP DISCHARGE & RHR HEAD SPRAY
PEN NO. P117
*6 LPCS SUCTION FROM SUPP. POOL
PEN NO. P103
*7 LPCS TO REACTOR
PEN NO. P113
*8 HPCS PUMP SUCT.
PEN NO. P401
*9 HPCS TO REACTOR
PEN NO. P411
*10(a) RCIC TURBINE EXHAUST VACUUM RELIEF
*10(b) RCIC TURBINE EXHAUST
*11 RHR A&B LPCI TO REACTOR
*12 RHR "C" LPCI TO REACTOR
*13 RHR "A,B&C" SUCTION FROM SUPP. POOL
PEN NO. P102 "A" P402 "B" P403 "C"



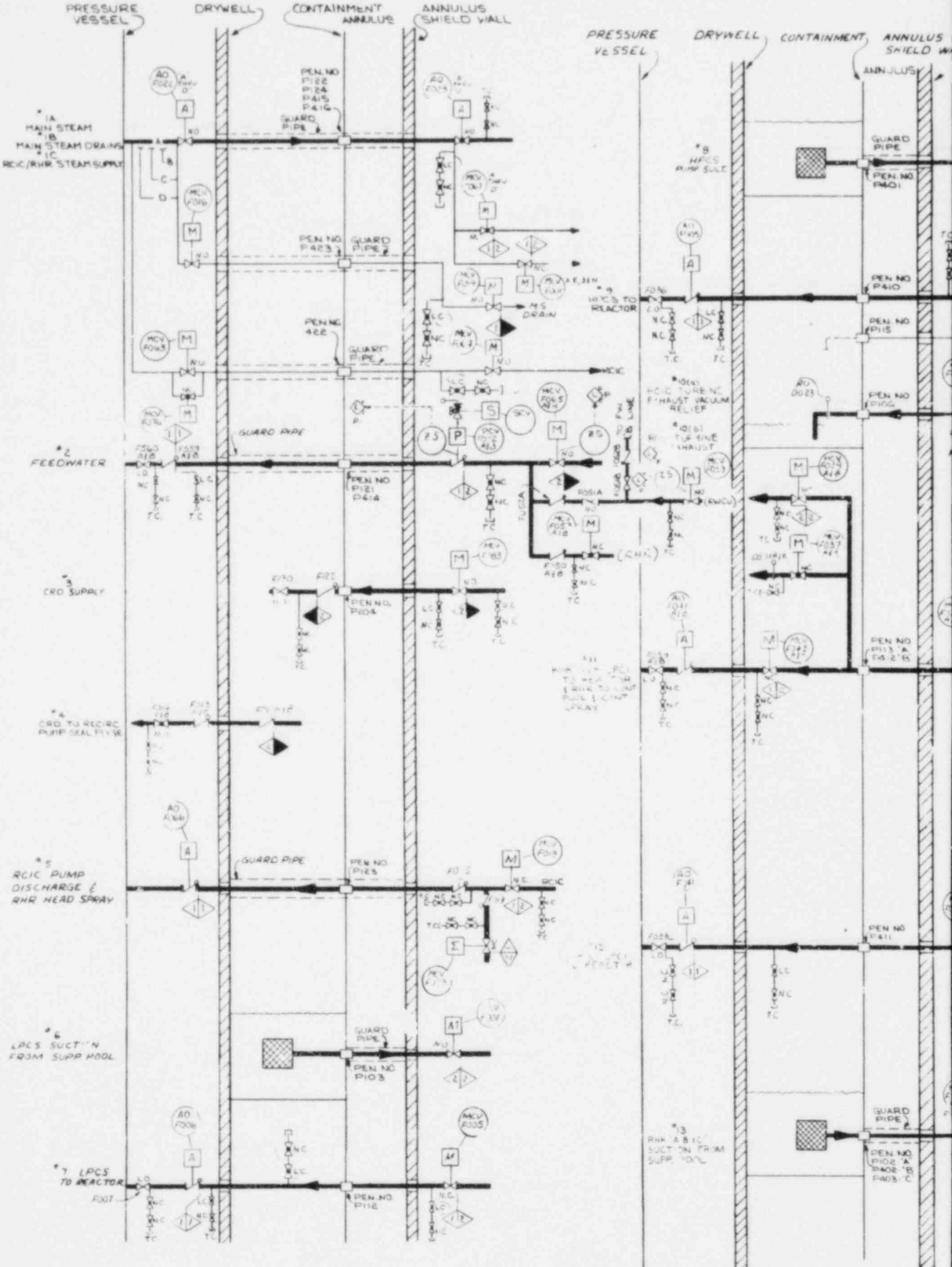
PERRY NUCLEAR POWER PLANT

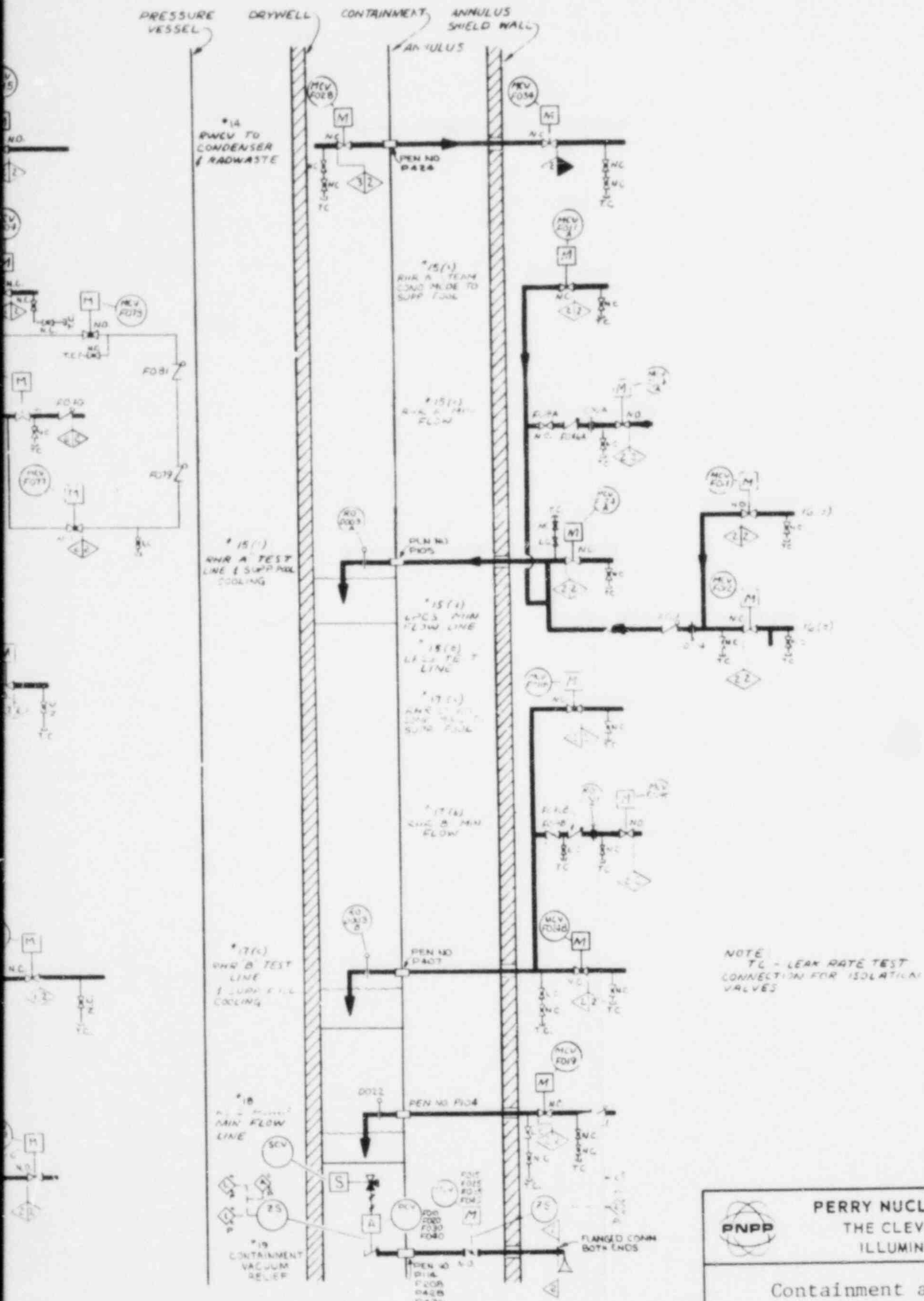
PNPP

THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Containment and Drywell Isolation

Figure 6.2-60 (Sheet 1 of 8)
(GAI Dwg. D-300-761)

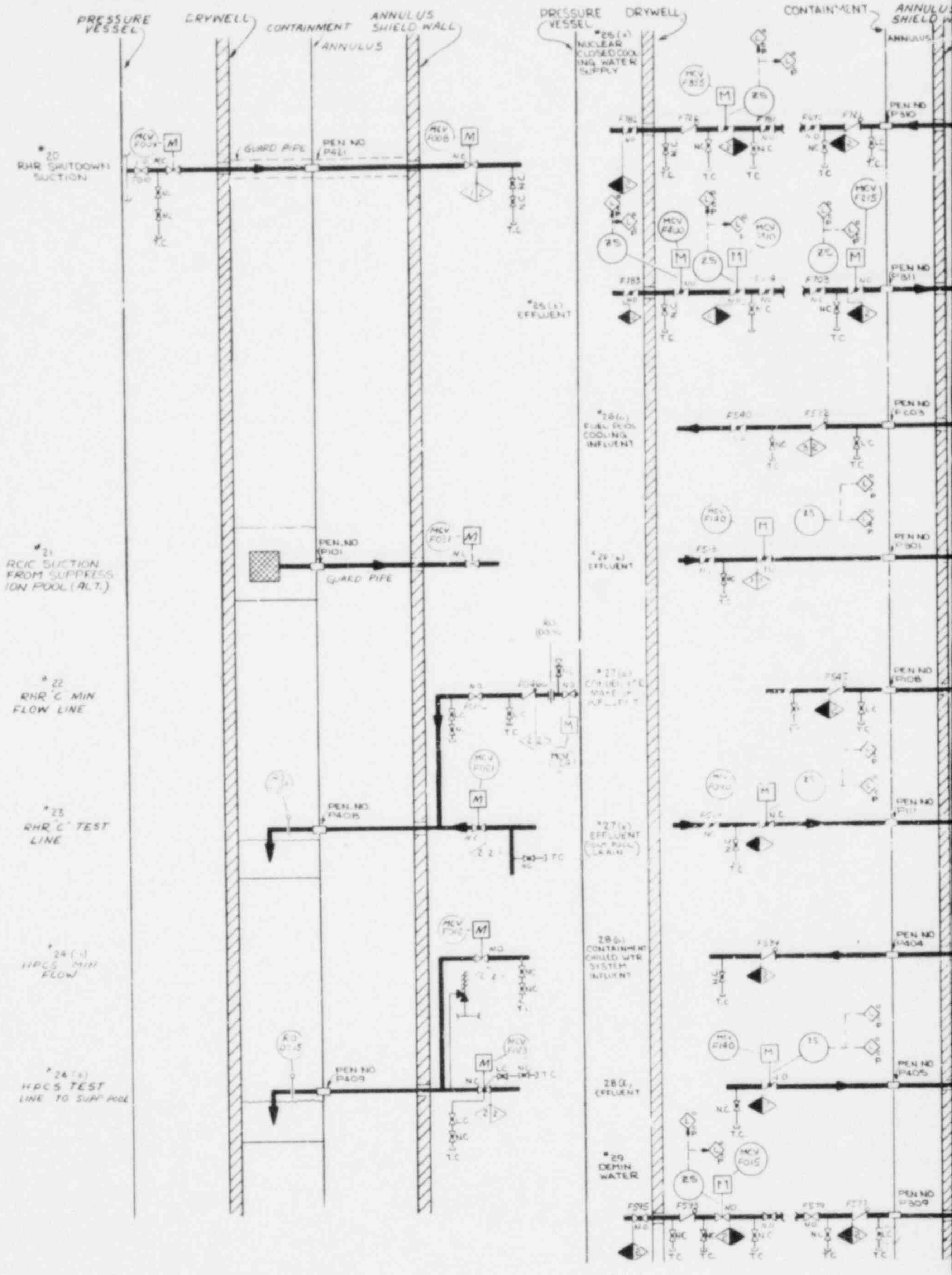

PRESSURE VESSEL
DRYWELL
CONTAINMENT ANNULUS
ANNULUS SHIELD WALL
*1A MAIN STEAM
*1B MAIN STEAM DRAINS
*1C RCIC/RHR STEAM SUPPLY
GUARD PIPE
PEN. NO. P122 P124 P415 P416
PEN. NO. P423
PEN. NO. 422
M.S. DRAIN
RCIC
*2 FEEDWATER
PEN. NO. P121 P414
(RWCU)
(RHR)
*3 CRD SUPPLY
PEN. NO. P204
*4 CRD TO RECIRC PUMP SEAL PURGE
*5 RCIC PUMP DISCHARGE & RHR HEAD SPRAY
PEN. NO. P123
*6 LPCS SUCTION FROM SUPP POOL
PEN. NO. P103
*7 LPCS TO REACTOR
PEN. NO. P112
*8 HPCS PUMP SUCT.
PEN. NO. P401
*9 HPCS TO REACTOR
PEN. NO. P410
PEN. NO. P115
*10(A) RCIC TURBINE EXHAUST VACUUM RELIEF
PEN. NO. P116
PEN. NO. P113 'A' P412 'B'
PEN. NO. P411
*13 RHR 'A B C' SUCTION FROM SUPP. POOL
PEN. NO. P102 'A' P402 'B' P403 'C'

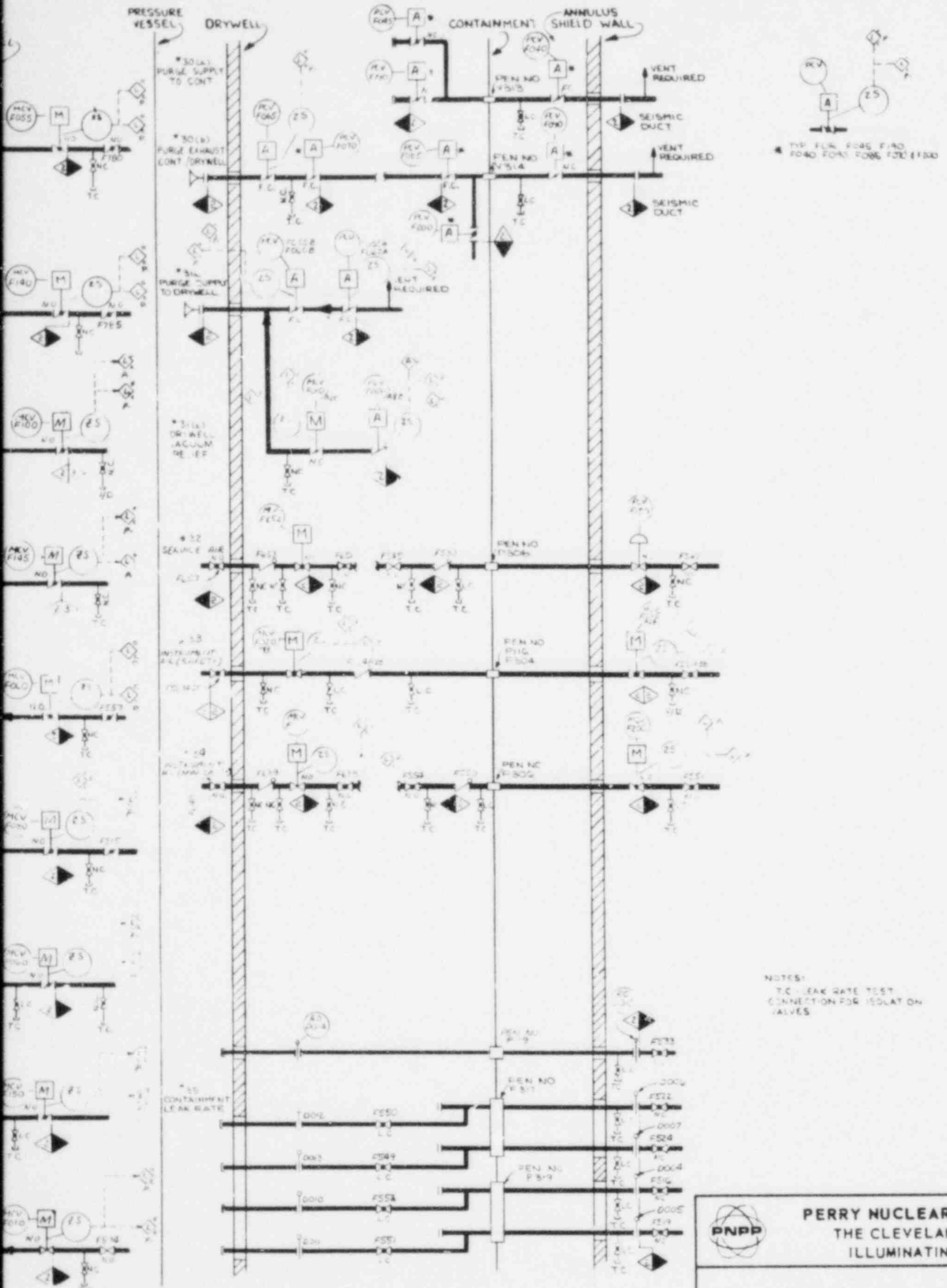


PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Containment and Drywell Isolation

Figure 6.2-60 (Sheet 2 of 8)
(GAI Dwg. D-350-761)

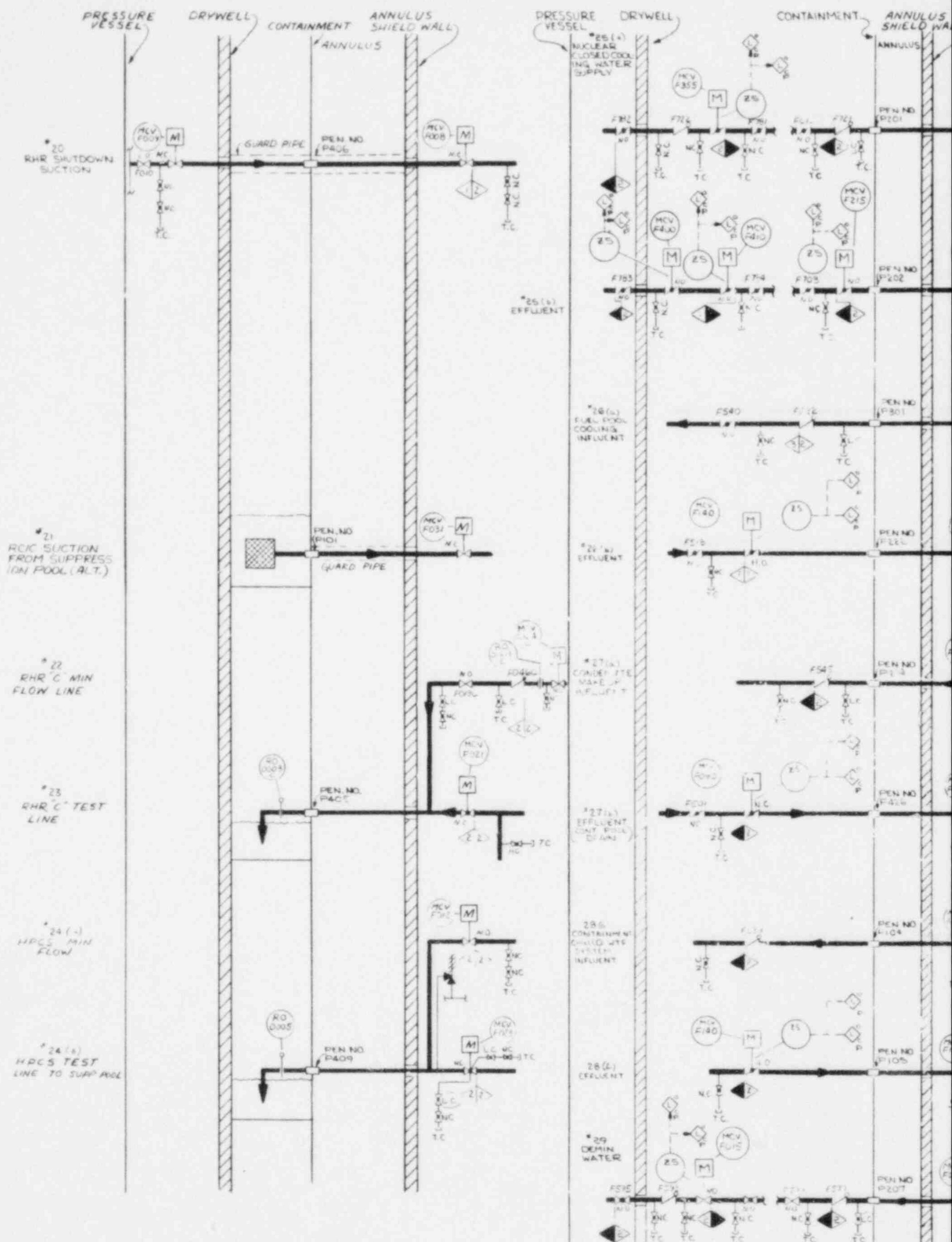

PRESSURE VESSEL
DRYWELL
CONTAINMENT
ANNULUS
ANNULUS SHIELD WALL
#20 RHR SHUTDOWN SUCTION
GUARD PIPE
PEN NO P421
#21 RCIC SUCTION FROM SUPPRESSION POOL (ALT.)
PEN. NO P101
#22 RHR 'C' MIN FLOW LINE
#23 RHR 'C' TEST LINE
PEN. NO. P408
#24 HPCS MIN FLOW
#24 HPCS TEST LINE TO SUPP POOL
PEN NO P409
NUCLEAR CLOSED COOLING WATER SUPPLY
PEN NO P310
EFFLUENT
PEN NO P811
FUEL POOL COOLING INFLUENT
PEN NO P203
PEN NO P801
PEN NO P108
PEN NO P404
CONTAINMENT CHILLED WTR SYSTEM INFLUENT
PEN NO P405
#29 DEMIN WATER
PEN NO P309

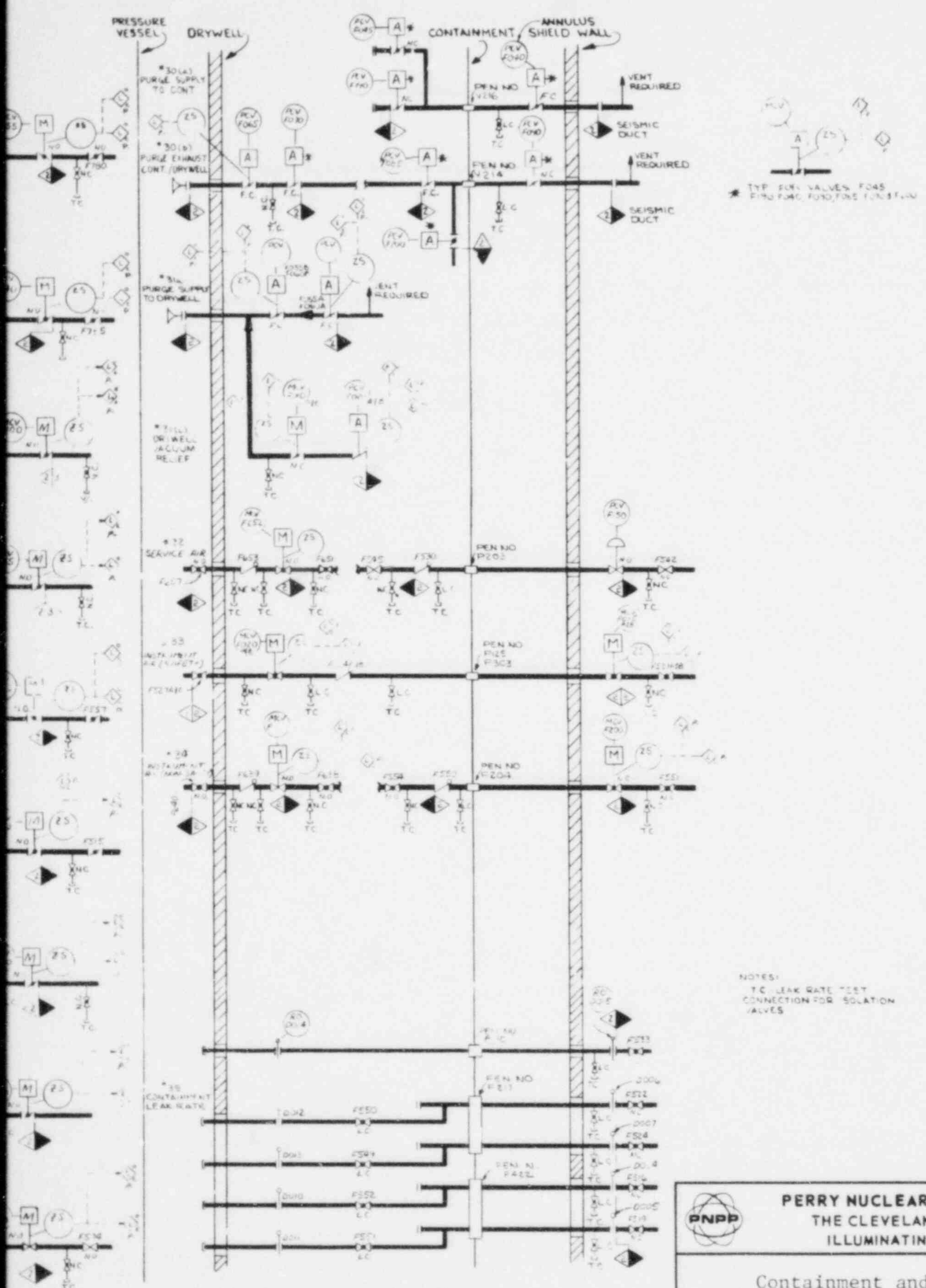


PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Containment and Drywell Isolation

Figure 6.2-60 (Sheet 3 of 8)
(GAI Dwg. D-300-762)

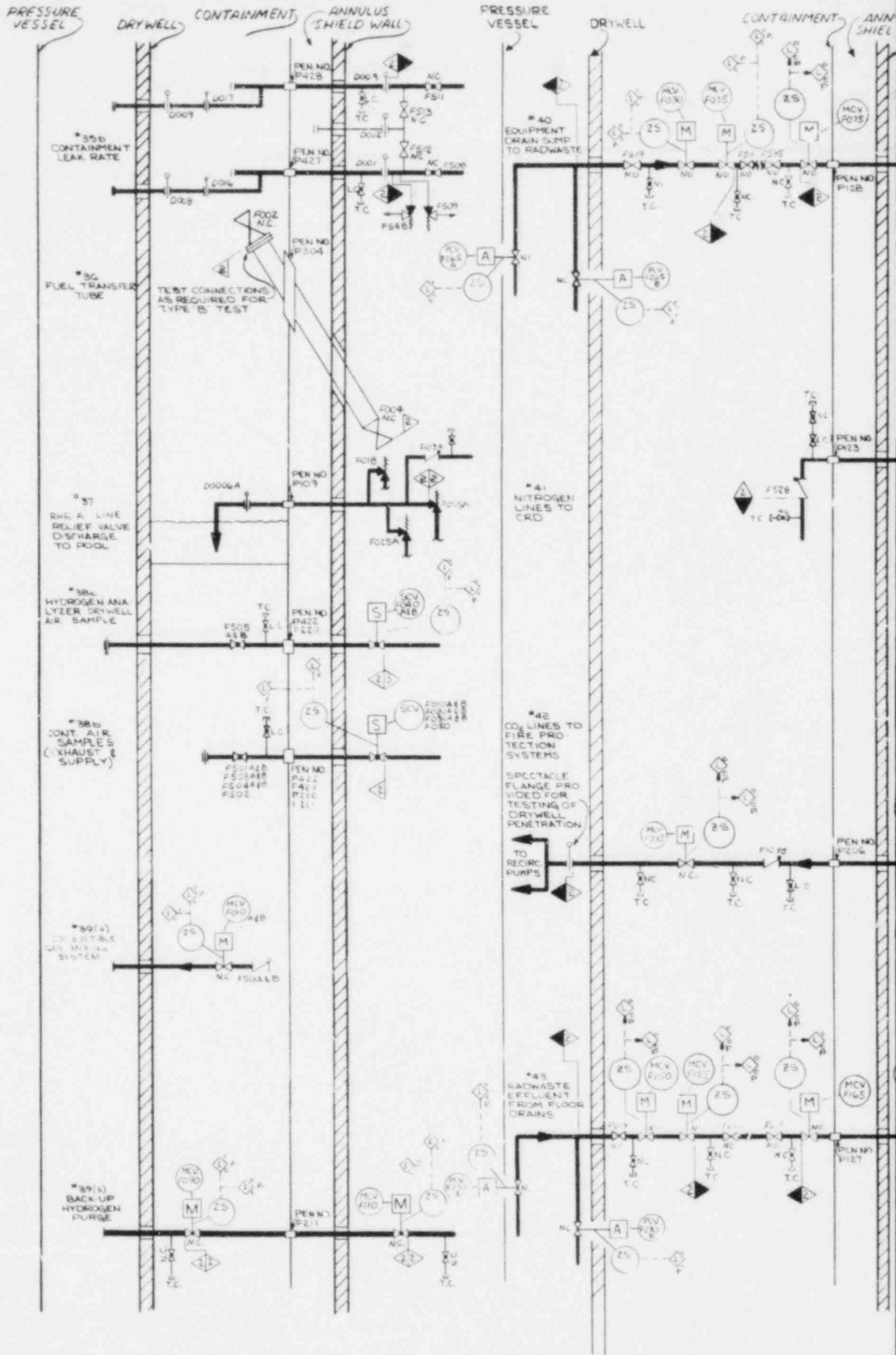

PRESSURE VESSEL
DRYWELL
CONTAINMENT
ANNULUS
ANNULUS SHIELD WALL
*20 RHR SHUTDOWN SUCTION
GUARD PIPE
PEN. NO. P406
*21 RCIC SUCTION FROM SUPPRESSION POOL (ALT.)
PEN. NO. P101
GUARD PIPE
*22 RHR "C" MIN FLOW LINE
*23 RHR "C" TEST LINE
PEN. NO. P405
*24 (-) HPCS MIN FLOW
*24 (-) HPCS TEST LINE TO SUPP POOL
PEN. NO. P409
*25 (-) NUCLEAR CLOSED COOLING WATER SUPPLY
PEN NO P201
*25 (-) EFFLUENT
PEN NO P202
*26 (-) FUEL POOL COOLING INFLUENT
PEN NO P301
*26 (-) EFFLUENT
*27 (-) CONDENSATE MAKE UP INFLUENT
*27 (-) EFFLUENT CONT. POOL DRAIN
28 (-) CONTAINMENT SHIELD WTR SYSTEM INFLUENT
28 (-) EFFLUENT
PEN NO P105
*29 DEMIN WATER
PEN NO P207

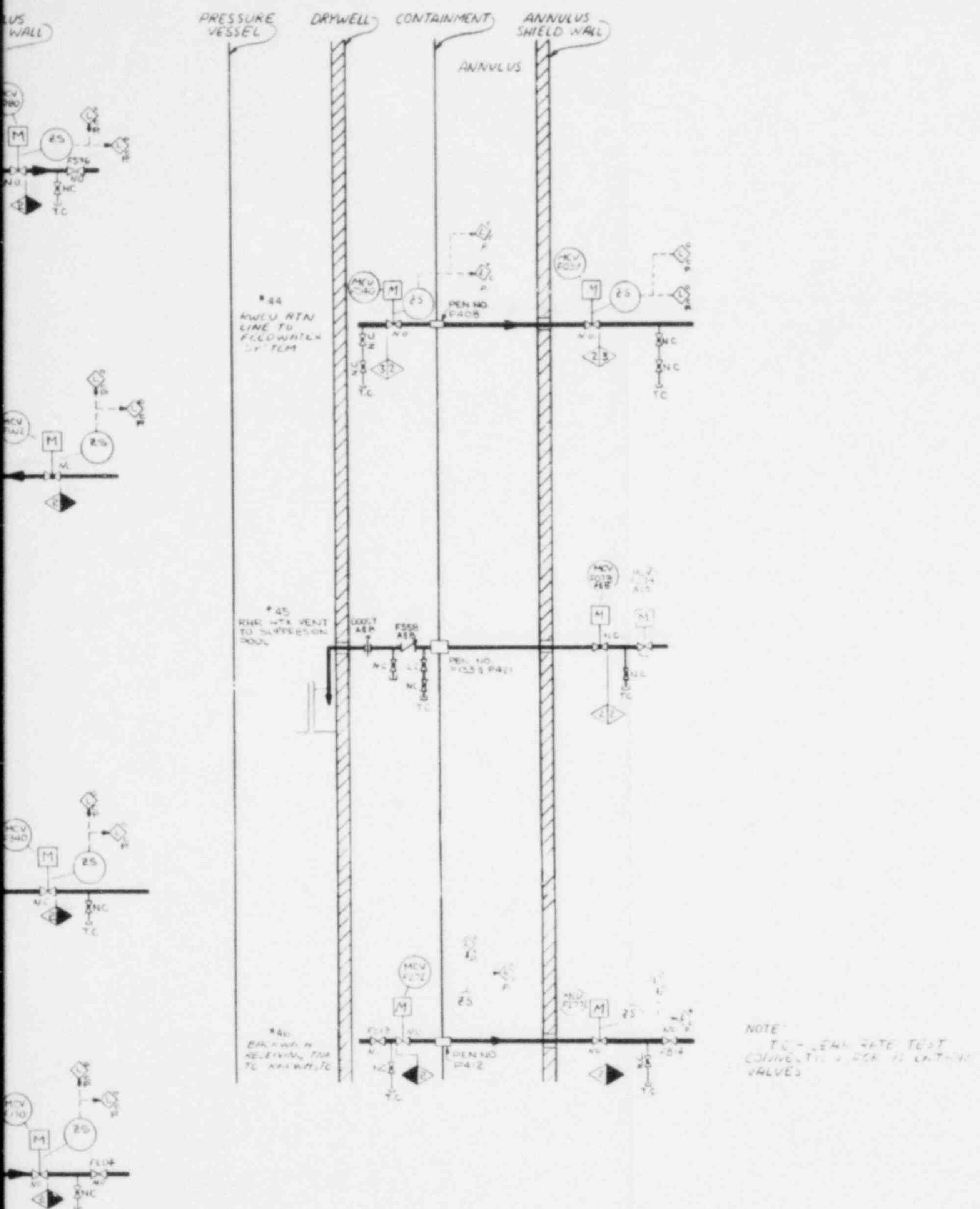


PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Containment and Drywell Isolation

Figure 6.2-60 (Sheet 4 of 8)
(GAI Dwg. D-350-762)

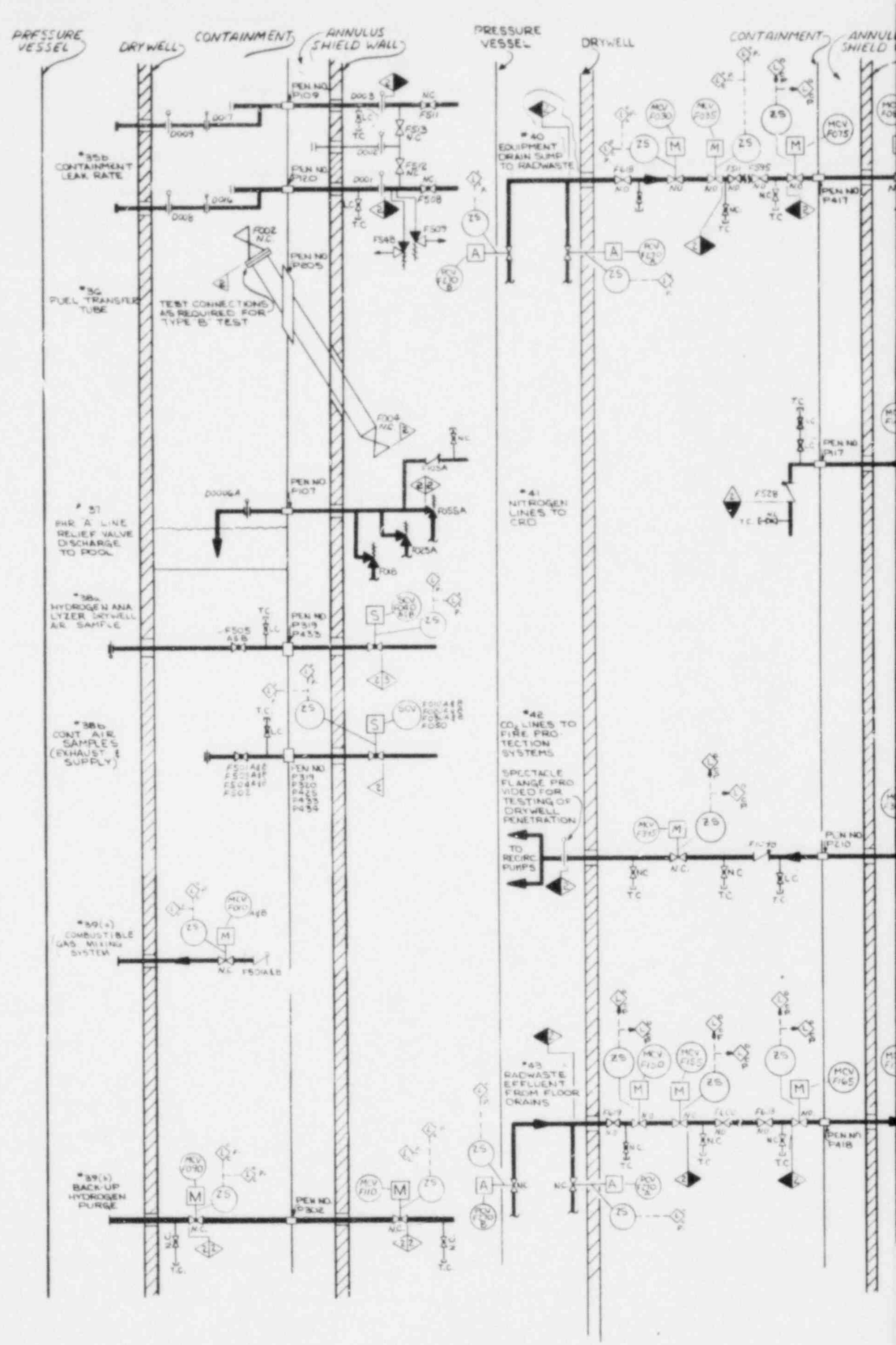

PRESSURE VESSEL
DRYWELL
CONTAINMENT
ANNULUS SHIELD WALL
PRESSURE VESSEL
DRYWELL
CONTAINMENT
#35b CONTAINMENT LEAK RATE
PEN NO. P428
PEN NO. P427
#36 FUEL TRANSFER TUBE
PEN NO. P304
TEST CONNECTIONS AS REQUIRED FOR TYPE 'B' TEST
#37 RHR 'A' LINE RELIEF VALVE DISCHARGE TO POOL
PEN NO. P109
#38a HYDROGEN ANALYZER DRYWELL AIR SAMPLE
PEN NO. P422
#38b CONT. AIR SAMPLES (EXHAUST & SUPPLY)
#39(a) COMBUSTIBLE GAS MIXING SYSTEM
#39(b) BACK-UP HYDROGEN PURGE
PEN NO. P211
#40 EQUIPMENT DRAIN SUMP TO RADWASTE
PEN NO. P128
#41 NITROGEN LINES TO CRD
PEN NO. P123
#42 CO2 LINES TO FIRE PROTECTION SYSTEMS
SPECTACLE FLANGE PROVIDED FOR TESTING OF DRYWELL PENETRATION
TO RECIRC. PUMPS
PEN NO. P206
#43 RADWASTE EFFLUENT FROM FLOOR DRAINS
PEN NO. P127

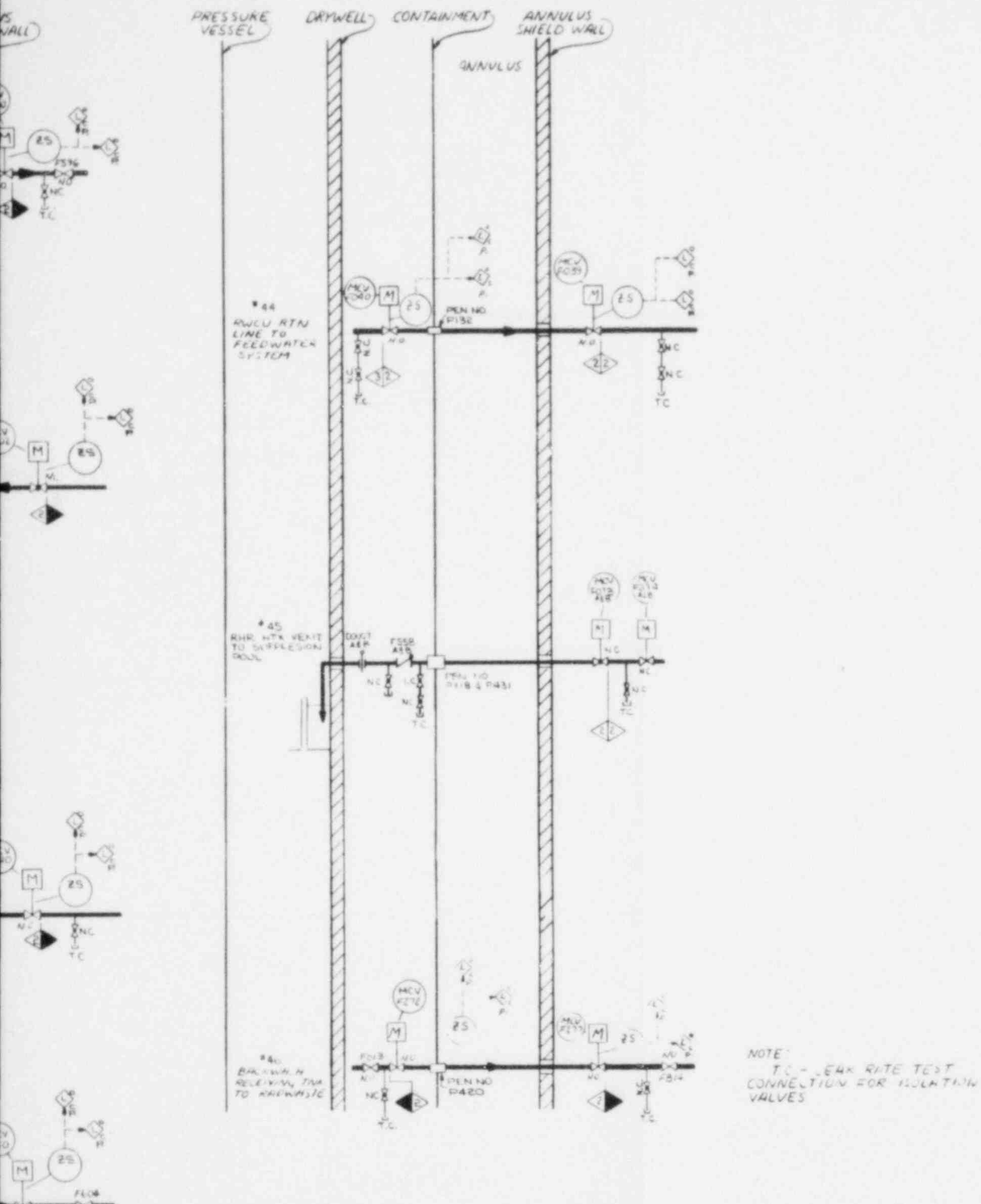


PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Containment and Drywell Isolation

Figure 6.2-60 (Sheet 5 of 8)
(GAI Dwg. D-300-763)

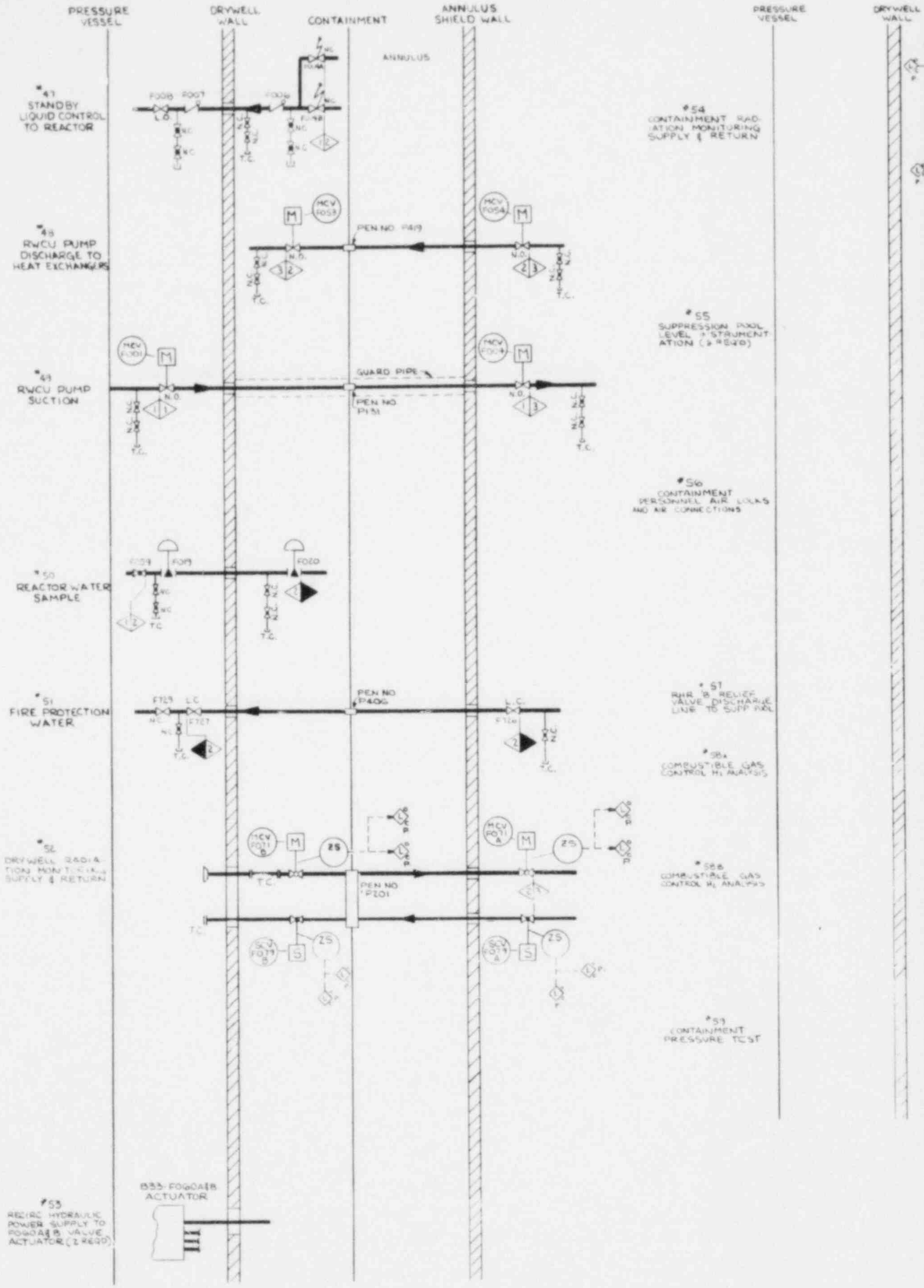

PRESSURE VESSEL
DRYWELL
CONTAINMENT
ANNULUS SHIELD WALL
*35b CONTAINMENT LEAK RATE
*36 FUEL TRANSFER TUBE
TEST CONNECTIONS AS REQUIRED FOR TYPE 'B' TEST
*37 RHR 'A' LINE RELIEF VALVE DISCHARGE TO POOL
*38a HYDROGEN ANALYZER DRYWELL AIR SAMPLE
*38b CONT. AIR SAMPLES (EXHAUST & SUPPLY)
*39(a) COMBUSTIBLE GAS MIXING SYSTEM
*39(b) BACK-UP HYDROGEN PURGE
*40 EQUIPMENT DRAIN SUMP TO RADWASTE
*41 NITROGEN LINES TO CRD
*42 CO_2 LINES TO FIRE PROTECTION SYSTEMS
SPECTACLE FLANGE PROVIDED FOR TESTING OF DRYWELL PENETRATION
TO RECIRC PUMPS
*43 RADWASTE EFFLUENT FROM FLOOR DRAINS
PEN NO. P109
PEN NO. P120
PEN NO. P205
PEN NO. P107
PEN NO. P319 P433
PEN NO. P302
PEN NO. P417
PEN NO. P117
PEN NO. P210
PEN NO. P418

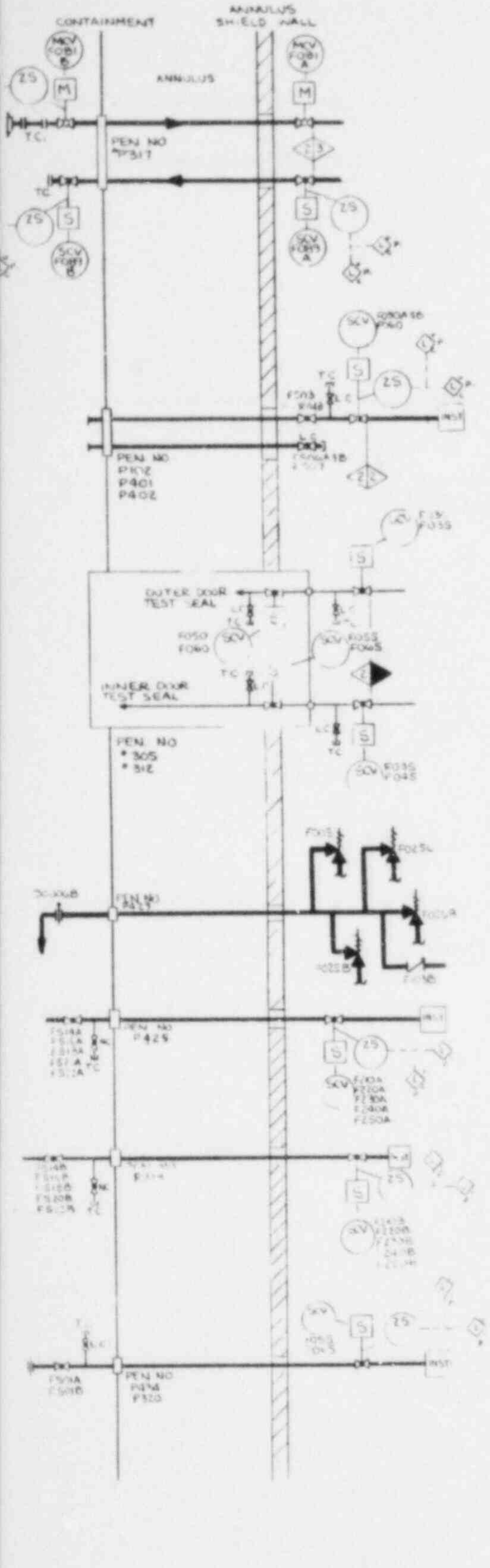


PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Containment and Drywell Isolation

Figure 6.2-60 (Sheet 6 of 8)
(GAI Dwg. D-350-763)


PRESSURE VESSEL
DRYWELL WALL
CONTAINMENT
ANNULUS SHIELD WALL
PRESSURE VESSEL
DRYWELL WALL
ANNULUS
#47 STANDBY LIQUID CONTROL TO REACTOR
#48 RWCU PUMP DISCHARGE TO HEAT EXCHANGERS
PEN NO. P419
#49 RWCU PUMP SUCTION
GUARD PIPE
PEN NO. P131
#50 REACTOR WATER SAMPLE
#51 FIRE PROTECTION WATER
PEN NO. P406
#52 DRYWELL RADIATION MONITORING SUPPLY & RETURN
PEN NO. P201
#53 RECIRC HYDRAULIC POWER SUPPLY TO F060A&B VALVE ACTUATOR (2 REQD)
B33-F060A&B ACTUATOR
#54 CONTAINMENT RADIATION MONITORING SUPPLY & RETURN
#55 SUPPRESSION POOL LEVEL INSTRUMENTATION
#56 CONTAINMENT PERSONNEL AIR LOCKS AND AIR CONNECTIONS
#57 RHR 'B' RELIEF VALVE DISCHARGE LINE TO SUPP POOL
#58A COMBUSTIBLE GAS CONTROL H2 ANALYSIS
#58B COMBUSTIBLE GAS CONTROL H2 ANALYSIS
#59 CONTAINMENT PRESSURE TEST



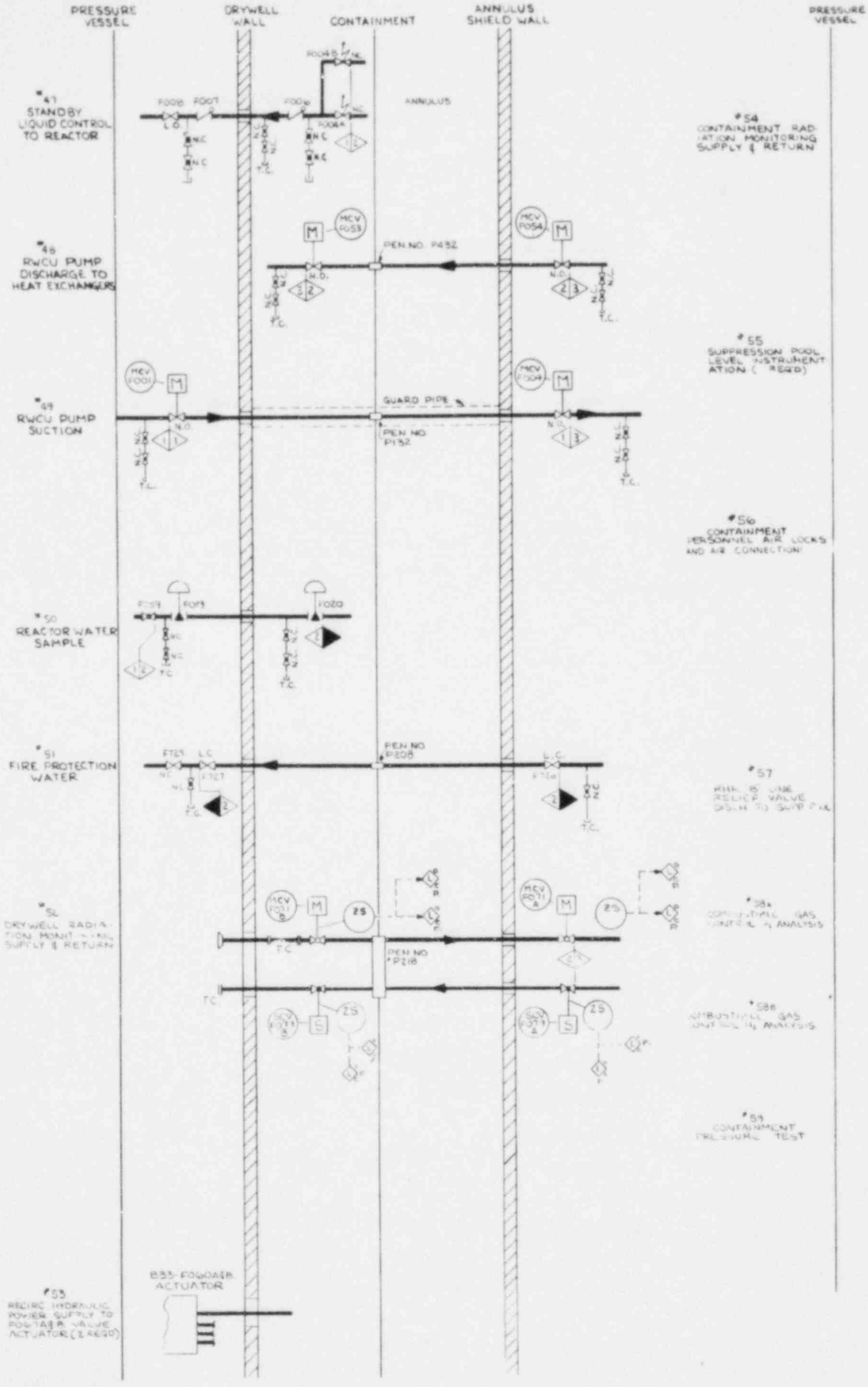
NOTES

1. T.C. - LEAK RATE TEST CONNECTION FOR ISOLATION VALVES

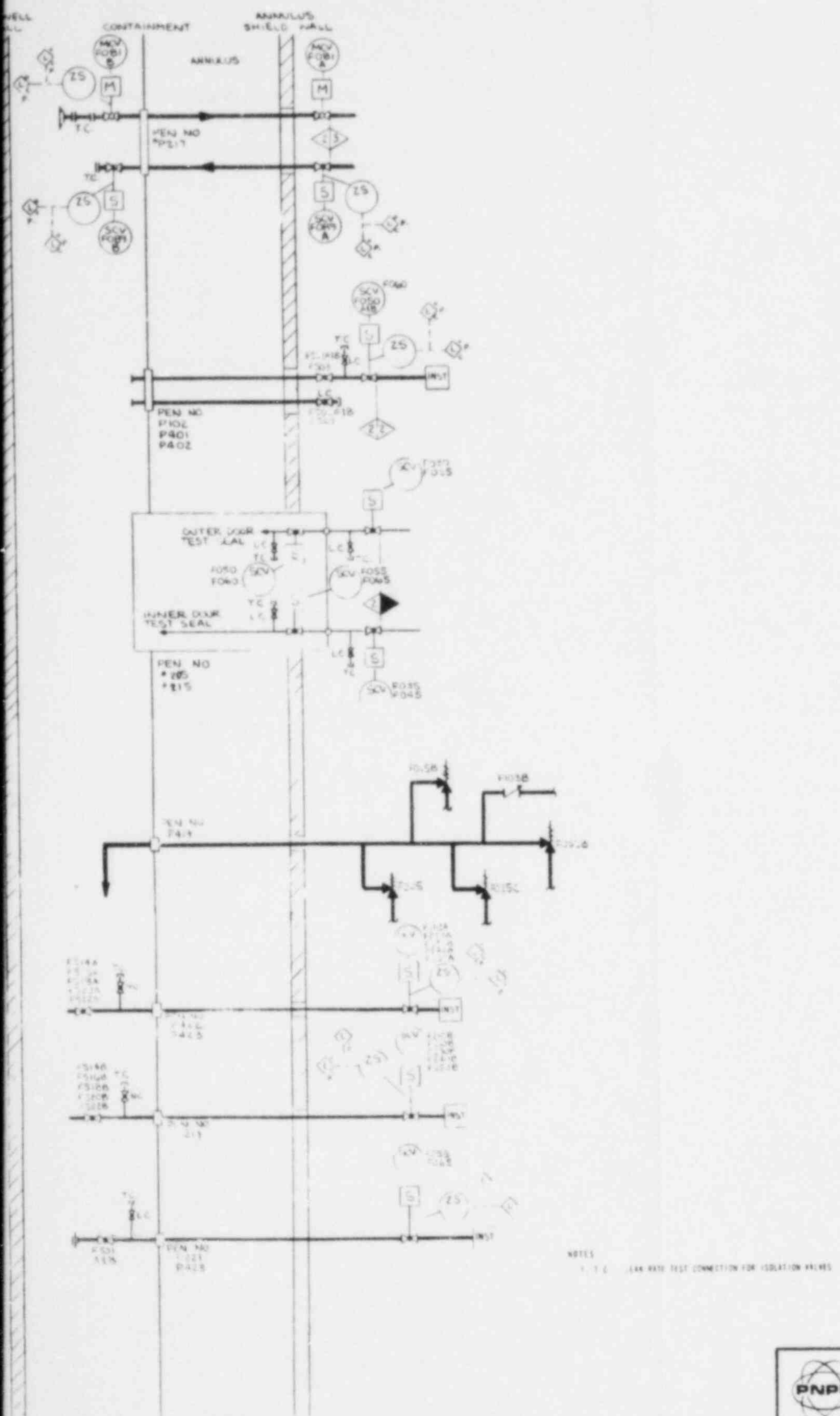
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Containment and Drywell
Isolation

Figure 6.2-60 (Sheet 7 of 8)
(GAI Dwg. D-300-764)



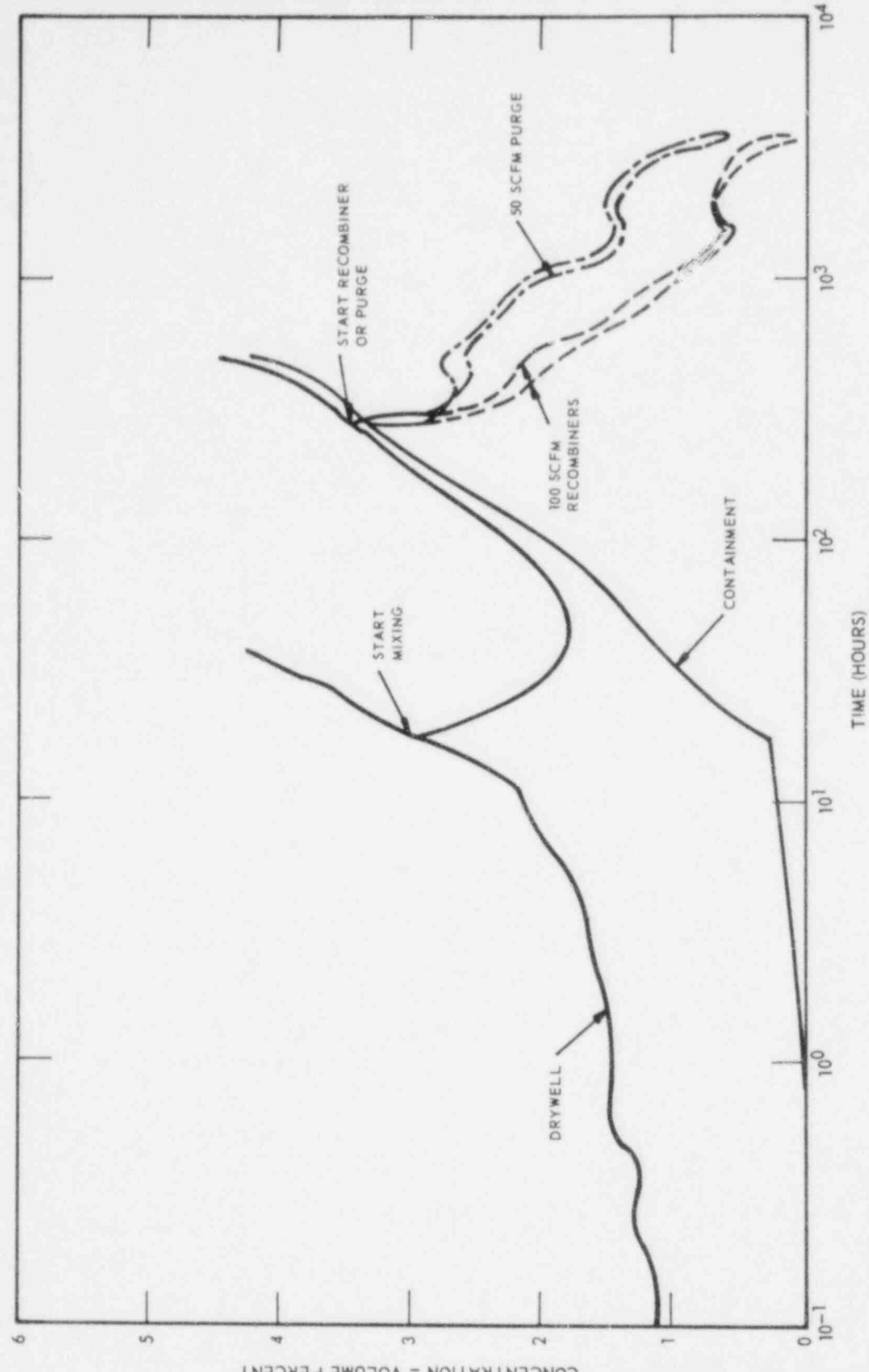
PRESSURE VESSEL
DRYWELL WALL
CONTAINMENT
ANNULUS SHIELD WALL
PRESSURE VESSEL
#47 STANDBY LIQUID CONTROL TO REACTOR
F008
F007
F006
F004B
F004A
ANNULUS
#48 RWCU PUMP DISCHARGE TO HEAT EXCHANGERS
MCV F053
MCV F054
PEN. NO. P432
#49 RWCU PUMP SUCTION
MCV F001
MCV F004
GUARD PIPE
PEN NO P132
#50 REACTOR WATER SAMPLE
F019
F020
#51 FIRE PROTECTION WATER
PEN NO P208
#52 DRYWELL RADIATION MONIT... SUPPLY & RETURN
PEN NO P218
#53 RECIRC HYDRAULIC POWER SUPPLY TO F0G7A & B VALVE ACTUATOR (2 REQD)
B33-F060A&B ACTUATOR
#54 CONTAINMENT RADIATION MONITORING SUPPLY & RETURN
#55 SUPPRESSION POOL LEVEL INSTRUMENTATION (2 REQD)
#56 CONTAINMENT PERSONNEL AIR LOCKS AND AIR CONNECTION
#57
#58A
#58B
#59 CONTAINMENT PRESSURE TEST



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Containment and Drywell
Isolation

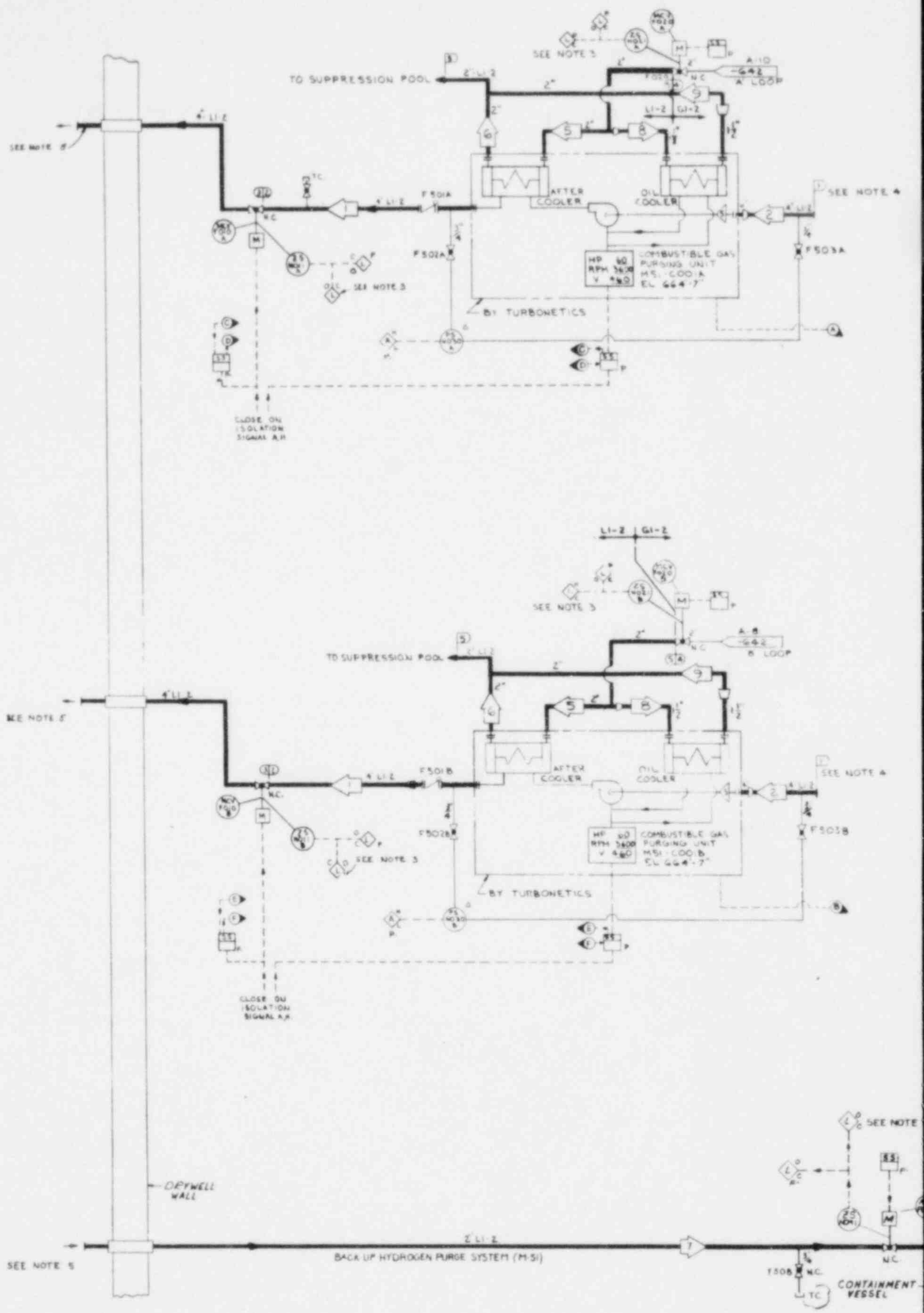
Figure 6.2-60 (Sheet 8 of 8)
(GAI Dwg. D-350-764)



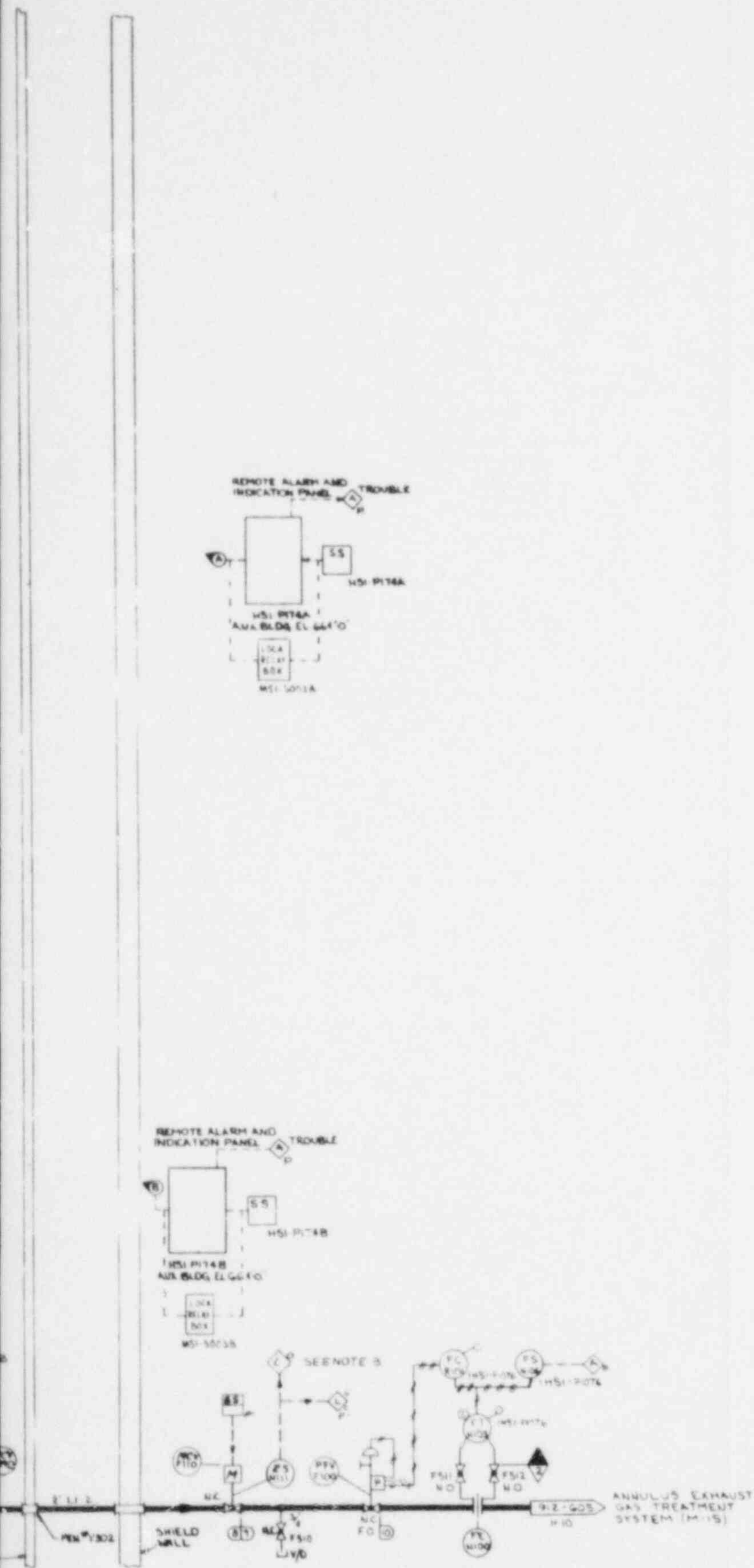
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Hydrogen Concentration Versus Time

Figure 6.2-61



TO SUPPRESSION POOL
SEE NOTE 3
SEE NOTE 5
SEE NOTE 4
AFTER COOLER
OIL COOLER
COMBUSTIBLE GAS PURGING UNIT M51-C001A EL 664'-7"
HP 60 RPM 3600 V 460
BY TURBONETICS
F501A
F502A
F503A
'A' LOOP
CLOSE ON ISOLATION SIGNAL A,H
L1-2 G1-2
B LOOP
F501B
F502B
F503B
COMBUSTIBLE GAS PURGING UNIT M51-C001B EL 664'-7"
DRYWELL WALL
BACK UP HYDROGEN PURGE SYSTEM (M-51)
CONTAINMENT VESSEL
F508



OPERATING CONDITIONS

		INCHES H_2O	SCFM	°F	BY	REMARKS
AIR	1	760	560	185	[illegible]	[illegible]
	2	650	560	190	[illegible]	
	7	665	50	185	[illegible]	
		PSIG	GPM	°F	BY	REMARKS
WATER	5	160	80	140	[illegible]	[illegible]
	6	158	80	145	[illegible]	
	8	160	40	140	[illegible]	
	9	155	40	145	[illegible]	

TEST CONDITIONS

	INCHES H_2O	SCFM	°F	BY	REMARKS
1	776	500	151	[illegible]	[illegible]
2	614	500	90	[illegible]	

DESIGN DATA

P#	NORMAL IN H_2O	NORMAL °F	UPSET IN H_2O	UPSET °F	UPSET			REMARKS
1	407	90	665	185	LOCA	[illegible]	[illegible]	
2	177	140	1030	330	LOCA	[illegible]	[illegible]	
3	77	145	1030	330	LOCA	[illegible]	[illegible]	
8	77	90	1030	330	LOCA	[illegible]	[illegible]	
9	407	90	665	185	LOCA	[illegible]	[illegible]	
10	407	90	665	185	LOCA	[illegible]	[illegible]	
	PSIG	°F	PSIG	°F	TIME			
4	120	145	125	212		[illegible]	[illegible]	PUMP SEAL
5	110	145	125	212		[illegible]	[illegible]	PUMP SEAL

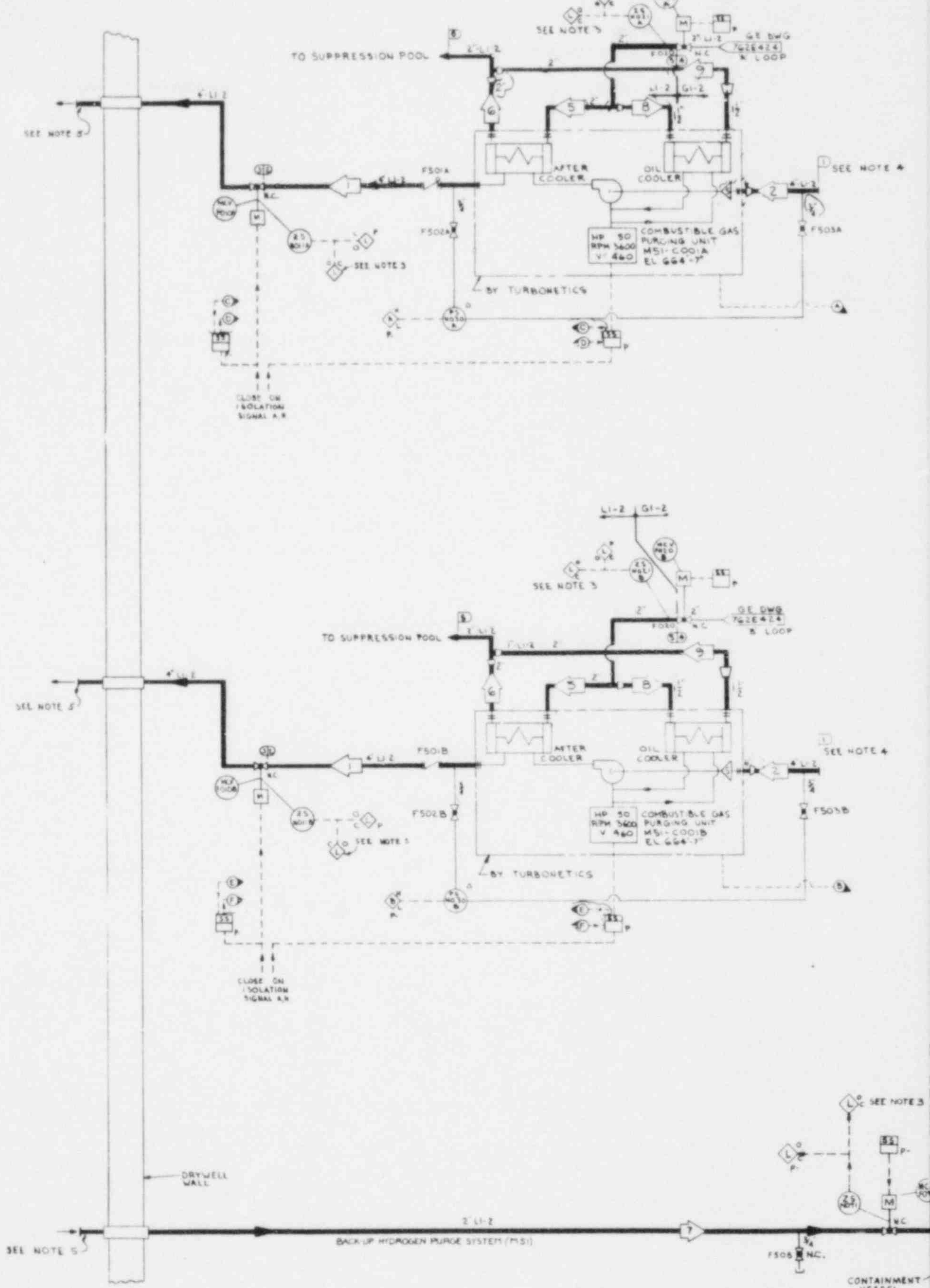
REFERENCES:
[illegible] RESIDUAL HEAT REMOVAL (E-12)
D-912-605 REACTOR BLDG. ANNULUS EXHAUST GAS TREATMENT SYS.

NOTES:
1. THIS SYSTEM IS SAFETY CLASS 2.
2. ALL CONTROL SWITCHES, STATUS LIGHTS, VALVE POSITION LIGHTS AND ALARMS ON MAIN CONTROL BOARD ARE LOCATED ON PANEL H13-P800, EXCEPT WHERE NOTED.
3. THESE LIGHTS ARE LOCATED ON THE CONTAINMENT/DRYWELL ISOLATION STATUS PANEL H13-P801.
4. SUCTION WILL BE TAKEN FROM CONTAINMENT DOME.
5. PROVIDE BLIND FLANGE FOR LEAK TEST.

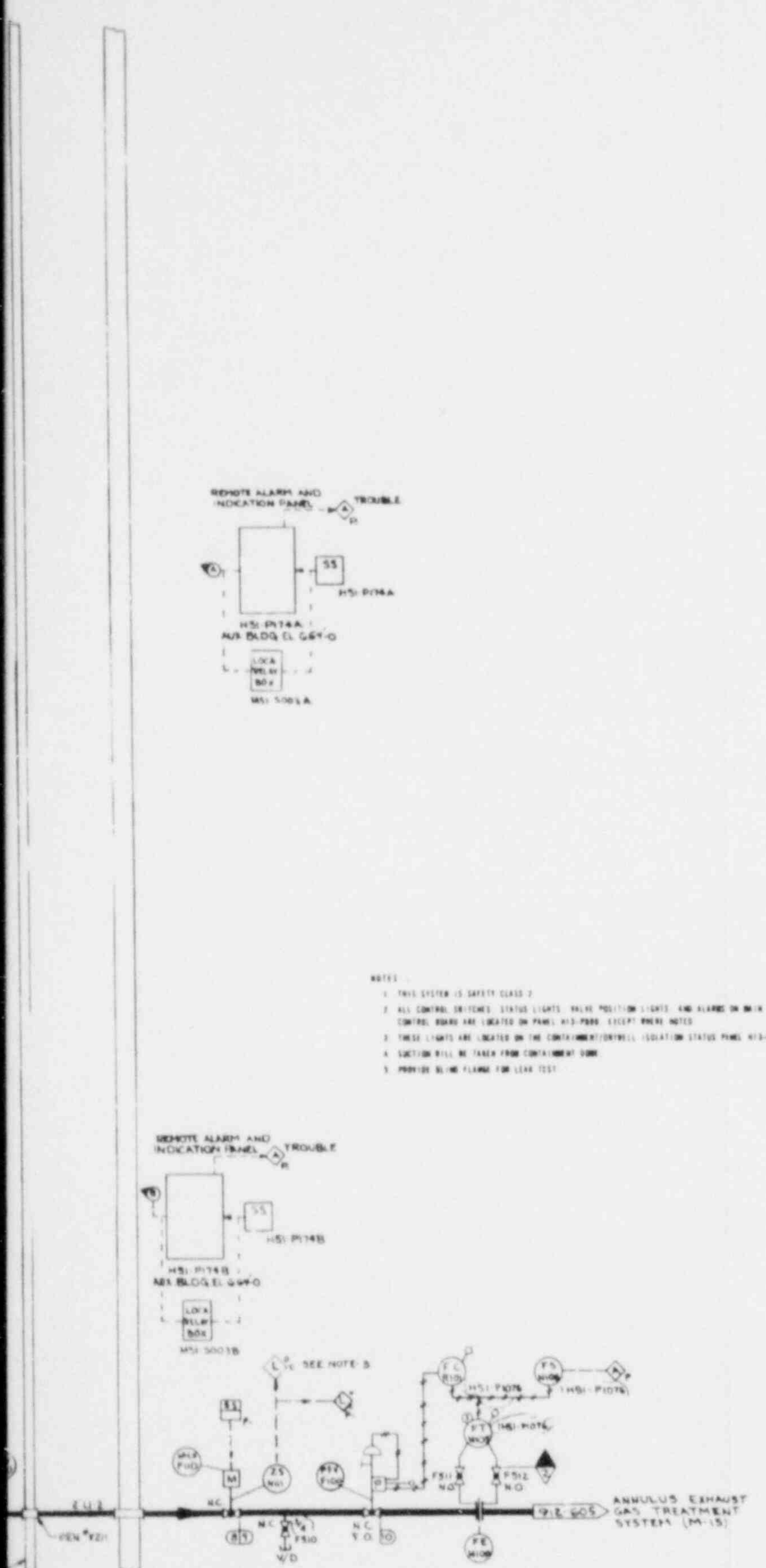
PNPP
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Combustible Gas Control System

Figure 6.2-62 (Sheet 1 of 2)
(GAI Dwg. D-302-831)



TO SUPPRESSION POOL
SEE NOTE 3
SEE NOTE 5
G.E. DWG 762E424 A LOOP
AFTER COOLER
OIL COOLER
SEE NOTE 4
F501A
F502A
F503A
HP 50
RPM 3600
V 460
COMBUSTIBLE GAS PURGING UNIT MS1-C001A
EL 664'-7"
BY TURBONETICS
CLOSE ON ISOLATION SIGNAL A,R
TO SUPPRESSION POOL
SEE NOTE 3
G.E. DWG 762E424 B LOOP
AFTER COOLER
OIL COOLER
SEE NOTE 4
F501B
F502B
F503B
HP 50
RPM 3600
V 460
COMBUSTIBLE GAS PURGING UNIT MS1-C001B
EL 664'-7"
BY TURBONETICS
CLOSE ON ISOLATION SIGNAL A,H
DRYWELL WALL
2" L1-2
BACK-UP HYDROGEN PURGE SYSTEM (MS1)
SEE NOTE 5
F506
N.C.
CONTAINMENT VESSEL



OPERATING CONDITIONS

	#	INCHES H_2O	SCFM	°F	BY	REMARKS
AIR	1	765	560	155	CTO	[illegible]
	2	650	560	150	[illegible]	
	3	665	50	185	[illegible]	
		PSIG	GPM	°F	BY	REMARKS
WATER	5	160	80	[illegible]	CTO	[illegible]
	6	158	80	148	CTO	
	8	160	40	140	CTO	
	9	155	40	148	CTO	

TEST CONDITIONS

	INCHES H_2O	SCFM	°F	BY	REMARKS
1	771	500	51	CTO	[illegible]
2	614	500	90	[illegible]	

DESIGN DATA

#	NORMAL IN H_2O	°F	UPSET IN H_2O	°F	TIME			REMARKS
1	407	90	665	185	LOCA	[illegible]	[illegible]	
2	348	140	1050	150	LOCA	[illegible]	[illegible]	
3	545	140	1030	150	LOCA	[illegible]	[illegible]	
8	407	90	1030	130	LOCA	[illegible]	[illegible]	
9	407	90	665	185	LOCA	[illegible]	[illegible]	
10	407	90	665	185	LOCA	[illegible]	[illegible]	
	PSIG	°F	PSIG	°F	TIME			
4	10	145	25	212		CTO	[illegible]	PUMP SCH
5	10	75	[illegible]	212		CTO	[illegible]	PUMP SCH

NOTES:

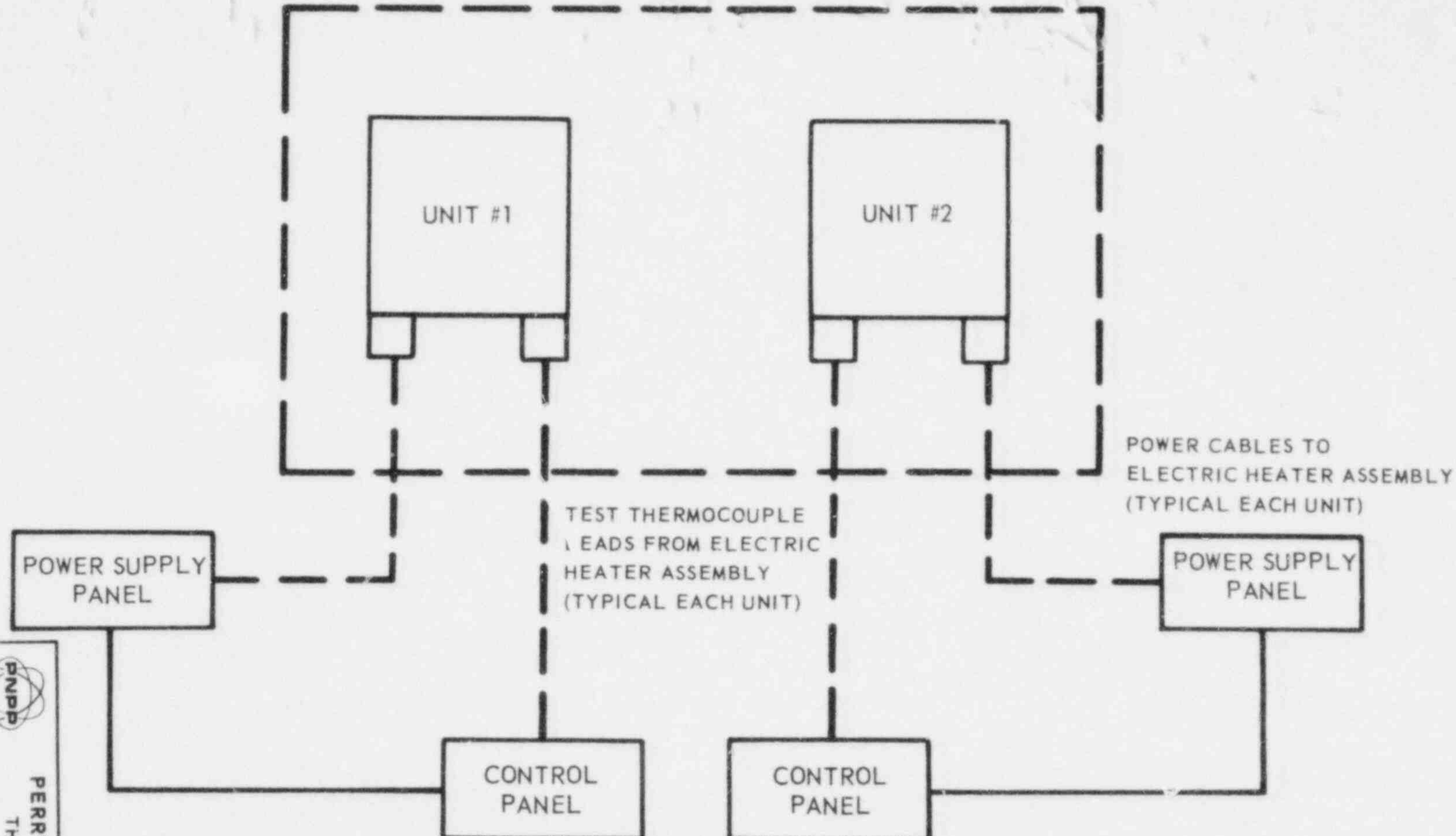
1. THIS SYSTEM IS SAFETY CLASS 2
2. ALL CONTROL SWITCHES, STATUS LIGHTS, VALVE POSITION LIGHTS, AND ALARMS ON MAIN CONTROL BOARD ARE LOCATED ON PANEL H13-P800, EXCEPT WHERE NOTED.
3. THESE LIGHTS ARE LOCATED ON THE CONTAINMENT/DRYWELL ISOLATION STATUS PANEL H13-P801
4. SUCTION WILL BE TAKEN FROM CONTAINMENT DOME
5. PROVIDE BLIND FLANGE FOR LEAK TEST

PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Combustible Gas Control System

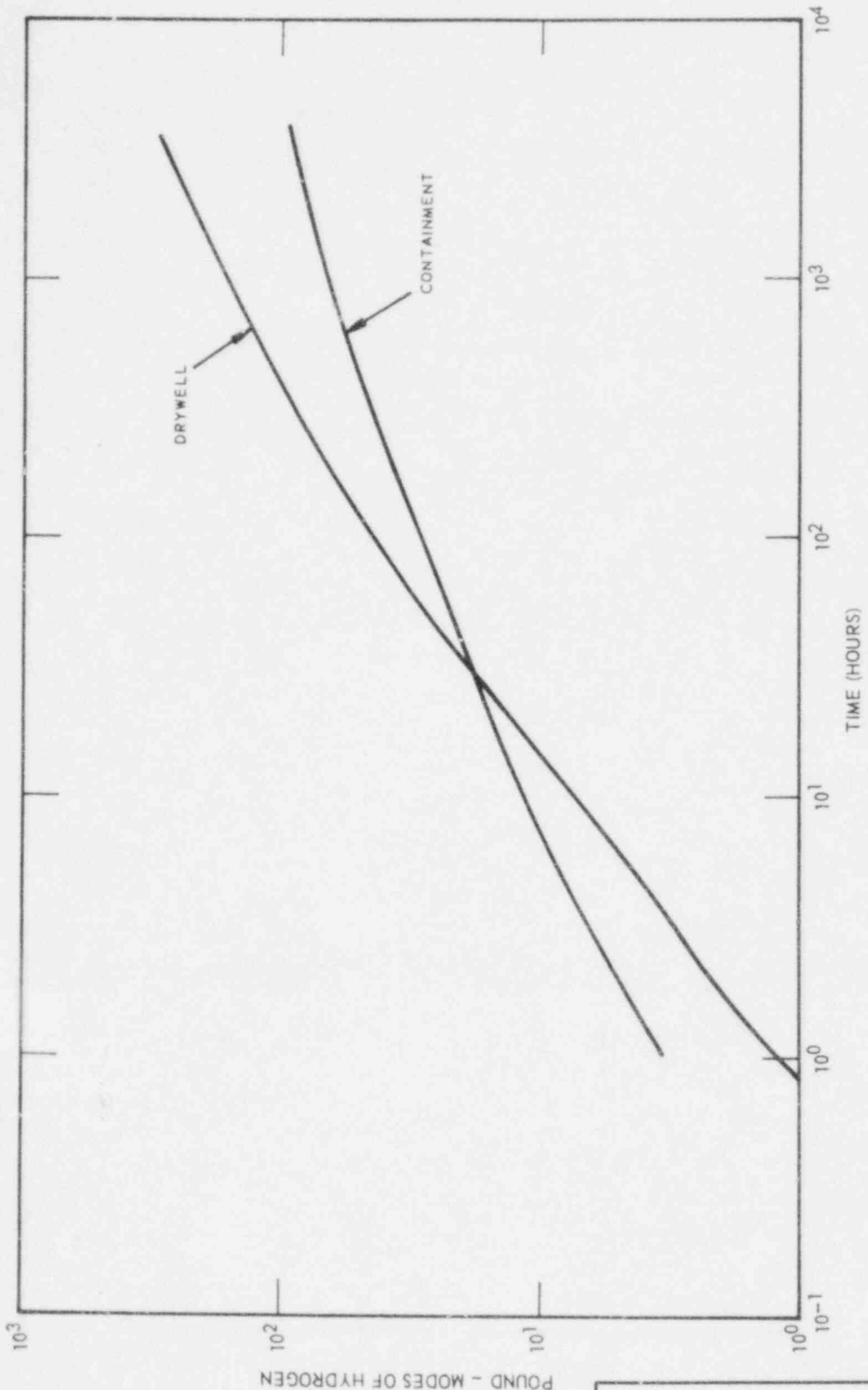
Figure 6.2-62 (Sheet 2 of 2)
(GAI Dwg. D-352-831)



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Hydrogen Recombiner System

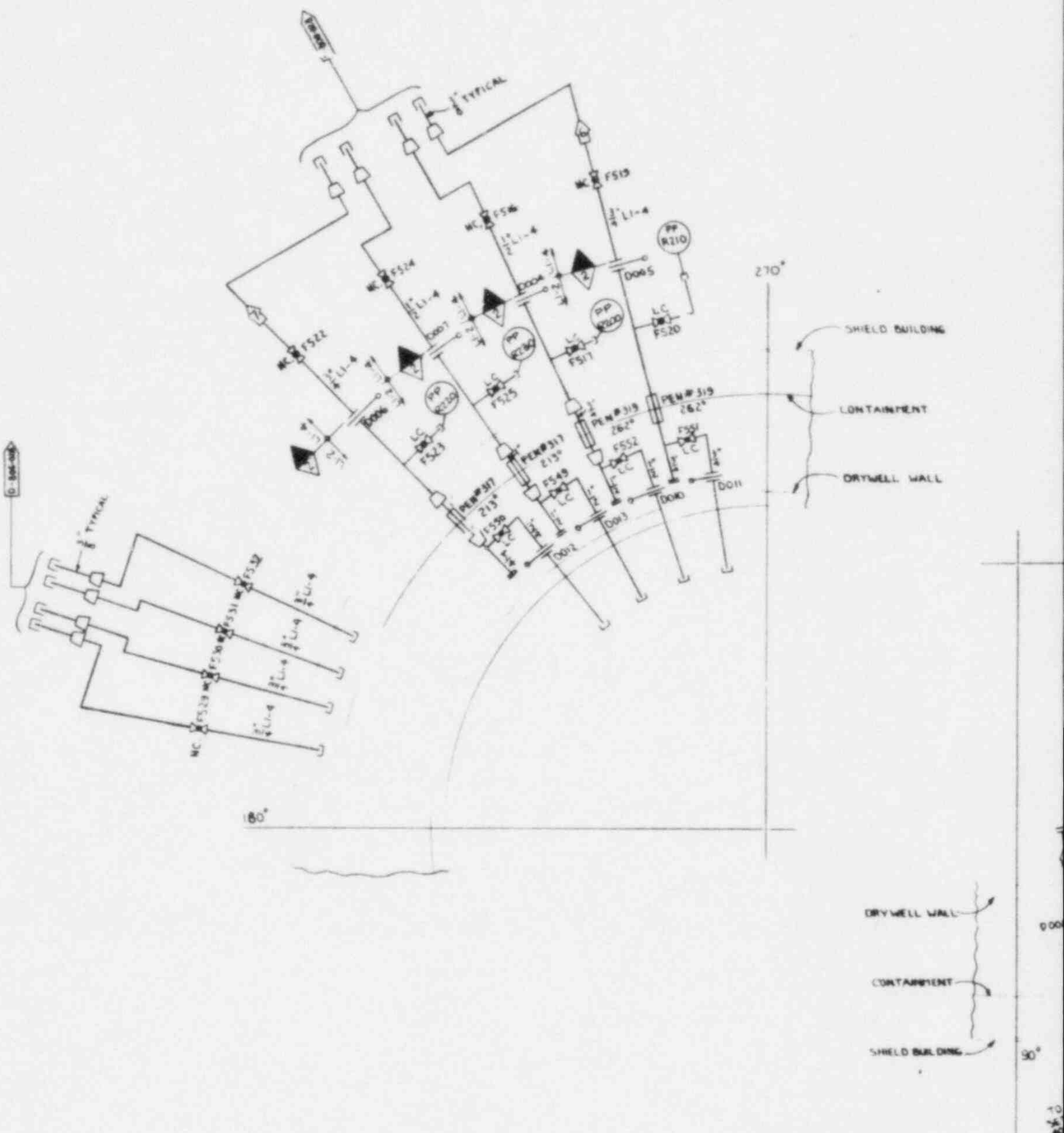
Figure 6.2-63



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Hydrogen Production Versus Time

Figure 6.2-64



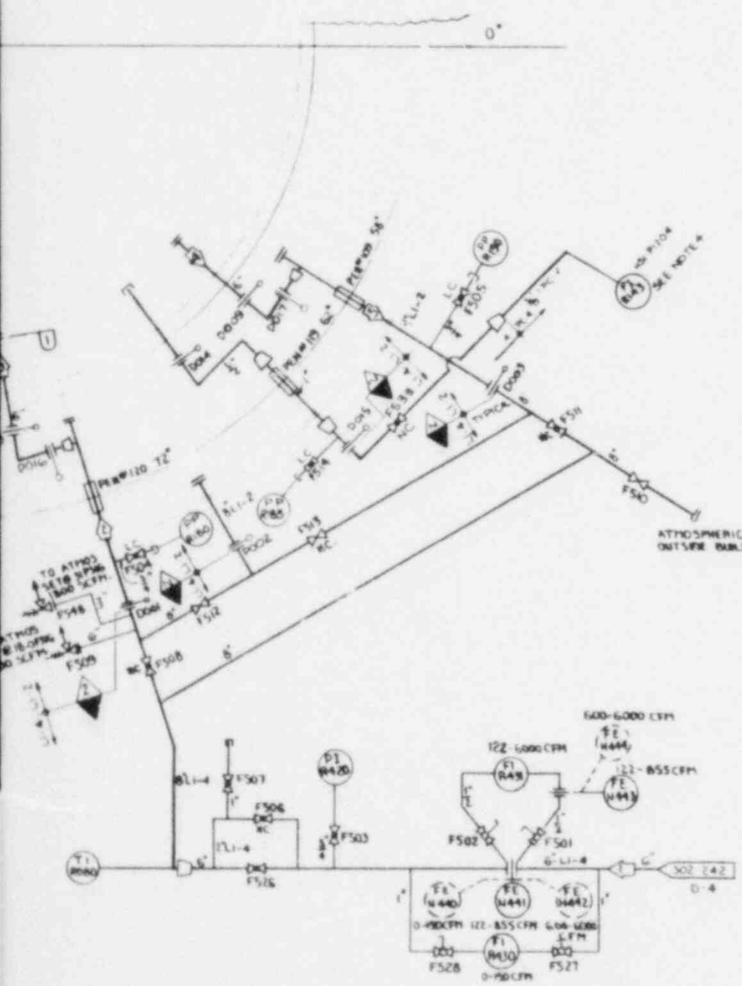
TYPICAL
FS19
FS16
FS24
FS22
L1-4
PP R210
PP R200
PP R190
PP R220
D005
D004
D007
D006
LC
FS20
FS17
FS25
FS23
PEN#319
262°
PEN#317
213°
FS52
FS51
FS49
FS50
D013
D010
D011
D012
270°
180°
90°
SHIELD BUILDING
CONTAINMENT
DRYWELL WALL
FS32
FS31
FS30
FS29
NC

OPERATING DATA CONTAINMENT TEST						
#	PSIG	CFM*	F	BY	REMARKS	
1	100	160	100	DAK		
2	0	4250	90	DAK	MIN.	
					↕	
2	15	2100	90	DAK	MAX.	
3		0		DAK		
4		0		AEH		
5				AEH	[illegible]	
6	15	.5	90	AEH	FLOW [illegible]	
7	15	.5	90	AEH	FLOW [illegible]	

* CFM IS ACTUAL

OPERATING DATA DRYWELL TEST						
#	PSIG	CFM*	F	BY	REMARKS	
1	100	250	100	DAK		
2	—	—	—			
3	0	1900	90	DAK	MIN	
					↕	
3	30	625	90	DAK	MAX	
4				AEH	3 PSI/HR [illegible]	
5				AEH	3 PSI/HR [illegible]	
6		0		AEH		
7		0		AEH		

DESIGN DATA								
	NORMAL		UPSET					
#	PSIG	F	PSIG	F	TIME	BY	[illegible]	REMARKS
1	150	110	—	—	—	[illegible]		



NOTES:

1. PRIOR TO REACTOR OPERATION
   A. SPECTACLE FLANGES SHALL BE CLOSED ON ALL DRYWELL TEST LINES AND OUTBOARD SIDE OF ALL CONTAINMENT PENETRATIONS
   B. BLIND FLANGES SHALL BE INSTALLED ON INBOARD SIDE OF CONTAINMENT PENETRATIONS
2. WHEN THE LEAK RATE TEST SYSTEM IS USED TO PERFORM DRYWELL PRESSURIZATION THE LINES PENETRATING CONTAINMENT WILL BE CLOSED WITH BLIND FLANGES ON THE INTERIOR SIDE OF THE CONTAINMENT
3. FOR CONTINUATION OF THIS SYSTEM, REFER TO D-302-811 (CONTAINMENT INTEGRATED LEAK RATE TEST SYSTEM - UNIT 2)
4. PI R143 TO BE WALL MOUNTED NEAR [illegible] AND F520

REFERENCES:

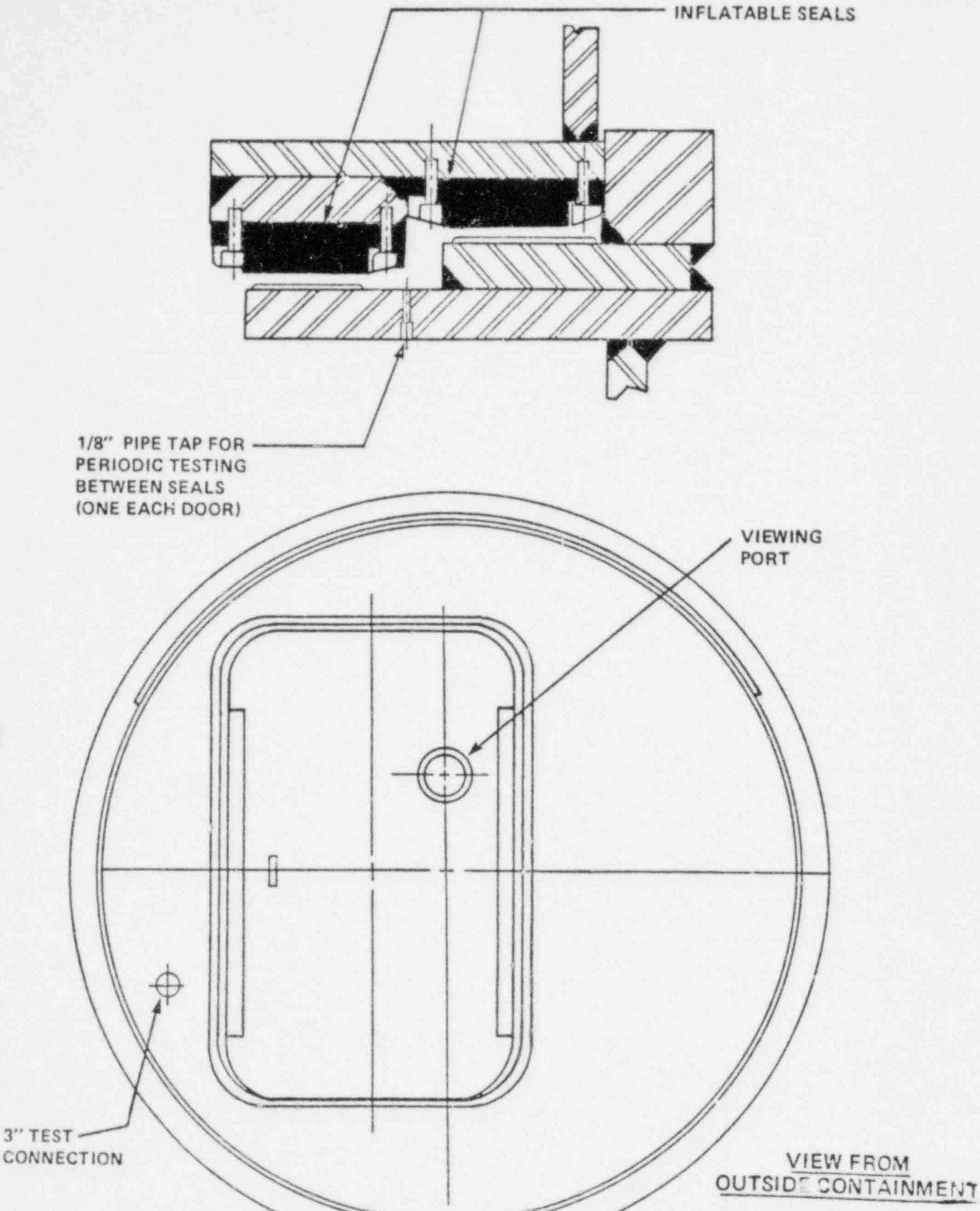
D-302-242 SERVICE AND INSTRUMENT AIR SUPPLY P51 AND P52
[illegible] INTEGRATED LEAK RATE TEST INSTRUMENTATION

PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Containment Integrated Leak Rate Testing System

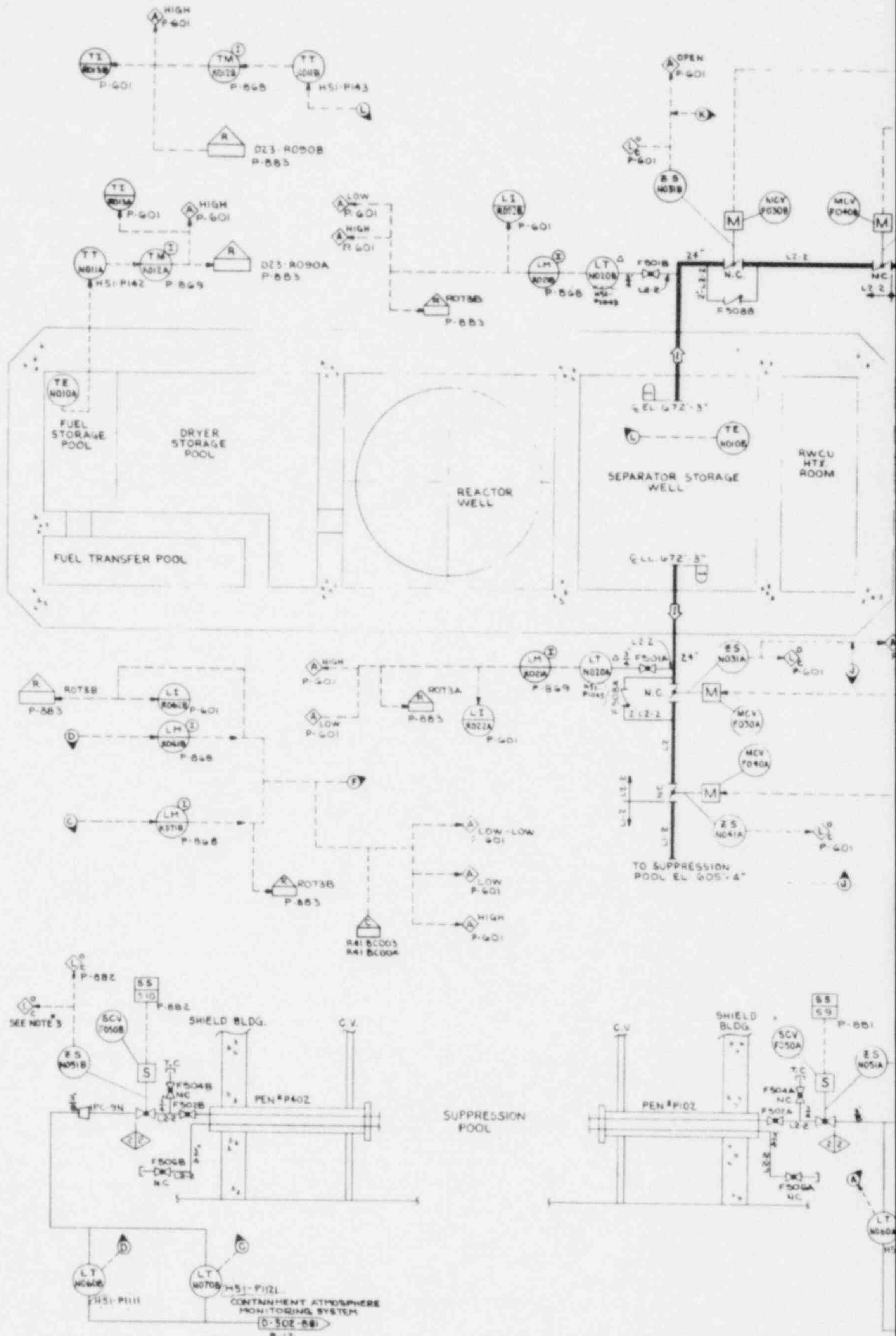
Figure 6.2-65
(GAI Dwg. D-302-811)



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Details of Personnel Lock
for Periodic Testing

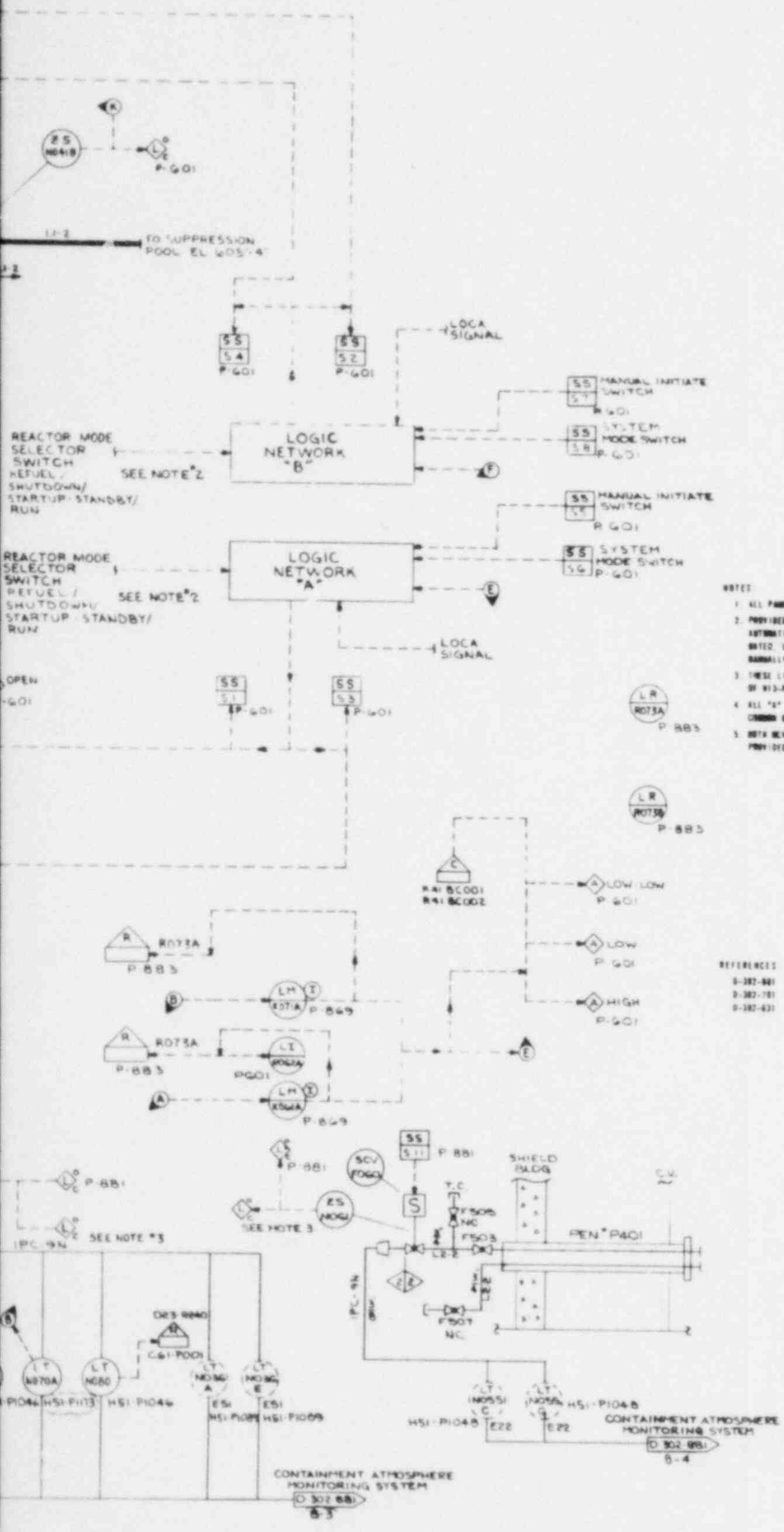
Figure 6.2-66



FUEL STORAGE POOL
DRYER STORAGE POOL
REACTOR WELL
SEPARATOR STORAGE WELL
RWCU HTX ROOM
FUEL TRANSFER POOL
TO SUPPRESSION POOL EL 605'-4"
SHIELD BLDG.
C.V.
PEN# P402
SUPPRESSION POOL
PEN# P102
SEE NOTE 3
CONTAINMENT ATMOSPHERE MONITORING SYSTEM
D-302-881
B-12
D23-R090B
P-883
D23-R090A
P-601
P-868
P-869
P-882
P-881

OPERATING DATA						
	GPM	PSIG	°F	BY	REMARKS	
1	35600	50	185	[illegible]		1

DESIGN DATA									
	NORMAL		UPSET						
	PSIG	°F	PSIG	°F	TIME	BY		REMARKS	
1	30	150	30	185		[illegible]			



NOTES:

1. ALL PANELS CARRY PREFIX 1H13 UNLESS NOTED OTHERWISE
2. PROVIDED APPLICABLE PERMISSIVE SIGNALS ARE PRESENT, BOTH SCV'S ARE OPENED AUTOMATICALLY UPON RECEIPT OF THE FOLLOWING: (1) SUPPRESSION POOL LOW LOW WATER LEVEL SIGNAL FROM EITHER LEVEL SENSOR SIGNAL WITH A LOCA (OR ECCS MANUALLY ACTUATED) SIGNAL. (2) LOCA SIGNAL PLUS 30 MINUTES TIME DELAY.
3. THESE LIGHTS ARE LOCATED ON THE CONTAINMENT/DRYWELL ISOLATION STATUS SECTION OF H13-P601
4. ALL "A" TRAIN CHANNELS HAVE A COMMON FAILURE ALARM (COMPUTER POINT) AND A COMMON OUT OF LIMITS ALARM (COMPUTER POINT). "B" TRAIN CHANNELS ARE IDENTICAL
5. BOTH SCV'S CAN BE OPENED REMOTE MANUALLY WITH THE MANUAL INITIATE SWITCH PROVIDED A LOCA SIGNAL IS PRESENT, OR ECCS HAS BEEN MANUALLY ACTIVATED

REFERENCES

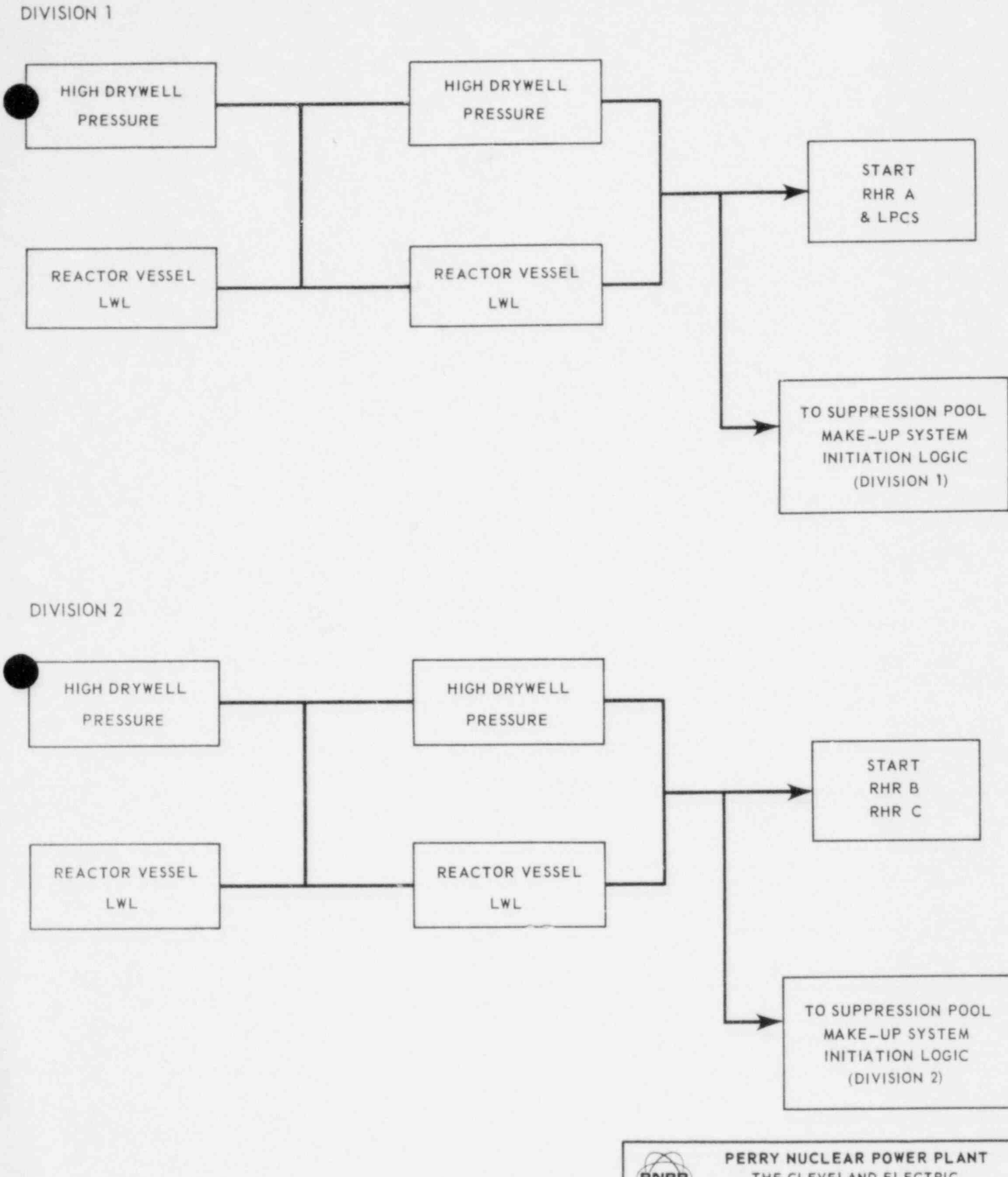
D-302-881 CONTAINMENT ATMOSPHERE MONITORING SYSTEM (D23)
D-302-701 HIGH PRESSURE CORE SPRAY SYSTEM (E22)
D-302-631 REACTOR CORE ISOLATION COOLING SYSTEM (E51)

PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Suppression Pool Makeup System

Figure 6.2-67
(GAI Dwg. D-302-686)



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

LOCA Signal Used in Initiation Logic of Suppression Pool Makeup System

Figure 6.2-68

#12

PERRY NUCLEAR POWER PLANT
UNITS 1 & 2

FINAL
SAFETY
ANALYSIS
REPORT

THE CLEVELAND ELECTRIC ILLUMINATING CO.

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MASTER TABLE OF CONTENTS (Continued)

6.3 EMERGENCY CORE COOLING SYSTEMS

6.3.1 DESIGN BASES AND SUMMARY DESCRIPTION

Section 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 Section 6.3.2 and the performance analysis provided in Section 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 6.3-1 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 Section 6.3.3.2. In addition, the ECCS is designed to meet the following requirements:

a. Protection is provided for any primary system 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 any normal mode of reactor operation.

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 must conform 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 shall have built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. As a minimum, the following equipment shall make up the ECCS:

    1. 1 High Pressure Core Spray (HPCS)

    2. 1 Low Pressure Core Spray (LPCS)

    3. 3 Low Pressure Coolant Injection (LPCI) Loops

    4. 1 Automatic Depressurization System (ADS)

c. The system shall be designed so that a single active or passive component failure, including power buses, electrical and mechanical parts, cabinets, and wiring will not disable the ADS.

d. In the event of a break in a pipe that is not 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. 3 LPCI loops, the LPCS and the ADS (i.e., HPCS failure); or

2. 2 LPCI loops, the HPCS and the ADS (i.e., failure of diesel generator supplying LPCS/LPCI); or

3. 1 LPCI loop, the LPCS, the HPCS and ADS (i.e., "diesel generator" failure).

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. 2 LPCI loops and the ADS; or

2. 1 LPCI loop, the LPCS and the ADS; or

3. 1 LPCI loop, the HPCS and the ADS; or

4. The LPCS, the HPCS and ADS.

These are the minimum ECCS combinations which result after assuming any failure (from 4 above) and assuming that the ECCS line break disables the affected system.

f. Long term (10 minutes after initiation signal) cooling requirements call for the removal of decay heat via the service water system. In addition to the break which initiated the loss of coolant event, the system must be able to sustain one failure, either active or passive and still have

at least one low pressure ECCS pump (LPCI, HPCS or LPCS) operating with a heat exchanger and 100 percent service water flow.

g. Offsite power is the preferred source of power for the ECCS network and every reasonable precaution must be made to assure its high availability. However, onsite emergency power shall be provided with sufficient diversity and capacity so that all the above requirements can be met even if off-site power is not available.

h. The on-site diesel fuel reserve shall be in accordance with IEEE Standard 308-1974 criteria.

i. Diesel-load configuration shall be as follows:

   1. 1 LPCI loop (with heat exchanger) and the LPCS connected to a single diesel generator.

   2. 2 additional LPCI loops (1 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 shall be 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 offsite AC power is not available.

l. No more than one storage battery shall be connectable to a d-c power bus.

m. Each system of the ECCS including flow rate and sensing networks must be capable of being tested during shutdown. All active components shall be 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) shall be installed in such a manner that they are an integral and nonseparable 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 (SSE).

The ECCS is protected against the effects of pipe whip, which might result from piping failures up to and including the design basis event LOCA. This protection is provided by separation, pipe whip restraints, or energy absorbing materials if required. One of these three methods will be 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.

The ECCS piping and components located outside the reactor building 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 when required 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% service water and heat exchanger

3. 2 LPCI pumps + 100% service water and heat exchanger

b. The equipment in each group shall be separated from that in the other two groups. In addition, the HPCS and RCIC (which is not part of the ECCS) shall be separated.

c. Separation barriers shall be 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 shall be 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

Each emergency core cooling system, and the RCIC system, has a safety related injection/isolation testable check valve located in piping within the drywell. In addition, the RCIC system has an isolation valve in the drywell portion of its steam supply piping. All valves are located above the highest water level expected in the drywell during any accident. The valves are qualified for the following environmental conditions:

a. Normal and upset plant operating ambient temperatures, relative humidities and pressures for each area of the drywell.

b. Envelope-of-accident conditions for temperature, relative humidity and pressure within the drywell for various time periods following the accident.

c. Normal and envelope-of-accident radiation environment (gamma and neutron).

The portions of ECCS and RCIC piping and equipment located outside the drywell and within the secondary containment are qualified for the following environmental conditions:

a. Normal and upset plant operating ambient temperatures, relative humidities and pressures.

b. Envelope-of-accident conditions for temperature, relative humidity and pressure for various time periods following the accident.

c. Normal and envelope-of-accident radiation environment (gamma and neutron).

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 (RHR) System. These systems are briefly described here as an introduction to the more detailed system design descriptions provided in Section 6.3.2. The automatic depressurization system (ADS) which assists the injection network under certain conditions is also briefly described. 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 core uncovery is calculated.

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. Following ADS initiation, LPCI provides inventory makeup following a small break.

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 penetrations to provide inventory makeup following large pipe breaks. Following ADS initiation, LPCI provides inventory makeup following a small break.

6.3.1.2.4 Automatic Depressurization System

The ADS uses a number of the reactor safety relief valves to reduce reactor pressure during such 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 Sections 6.3.2.1 through 6.3.2.4. 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 piping and instrumentation diagrams (P&IDs) for the ECCS are identified in Section 6.3.2.2. The process diagrams which identify the various operating modes of each system are also identified in Section 6.3.2.2.

6.3.2.2 Equipment and Component Descriptions

The 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 6.3-2.

Electric power for operation of the ECCS is from regular a-c power sources. Upon loss of the regular power, operation is from onsite standby a-c power sources. Standby sources have sufficient diversity and capacity so that all ECCS requirements are satisfied. The HPCS is powered from one a-c supply bus. The LPCS and one LPCI loop are powered from a second a-c supply bus and the two remaining LPCI loops are powered from a third and separate a-c supply bus. The HPCS has its own diesel generator as its alternate power supply. The LPCS and one LPCI loops switch to one site backup power supply and the other two LPCI loops switch to a second site backup power supply. Section 8.3 contains a more detailed description of the power supplies for the ECCS.

a. Regulatory Guide 1.1

General Compliance or Alternate Approach Assessment

This guide prohibits design reliance on pressure and/or temperature transients expected during a LOCA for assuring adequate NPSH. The guidelines of this Regulatory Guide are applicable to the HPCS, LPCS, and LPCI pumps.

The BWR design conservatively assumes 0 psig containment pressure and maximum expected temperatures of the pumped fluids. Thus no reliance is placed on pressure and/or temperature transients to assure adequate NPSH.

Requirements for NPSH are available at the centerline of the pump suction nozzles for each pump and are given in Figures 6.3-1 (HPCS), 6.3-2 (LPCS), 6.3-3 (LPCI). Pump characteristic curves are given in Figures 6.3-4 (HPCS), 6.3-5 (LPCS), and 6.3-6 (LPCI).

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 a standby diesel generator supply if offsite power is not available. The piping and instrumentation diagram, Figure 6.3-7 for the HPCS, shows the system components and their arrangement. The HPCS system process diagram, Figure 6.3-1, shows the design operating modes of the system. A simplified system flow diagram showing system injection into the reactor vessel is included in Figure 6.3-1.

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 as 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 condensate storage tank reserves water just for use by the HPCS and RCIC.

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 pressure across the valve expected for any system operating mode including HPCS pump shutoff head. The valve opens within 12 seconds following receipt of a signal to open. 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 main control room. The controls and instrumentation of the HPCS system are described, illustrated, and evaluated in detail in Chapter 7.

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. The system can also be placed in operation manually.

The HPCS system is capable of delivery rated flow into the reactor vessel within 27 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 drywell pressure signal exists. If a high drywell pressure signal exists in conjunction with a high reactor water level signal, 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.

The HPCS pump head flow characteristic used in LOCA analyses is shown in Figure 6.3-4. 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 (differential pressure between the reactor vessel and the suction source) the system r ches rated core spray flow. The HPCS motor size is based on peak horsepower requirements.

The elevation of the HPCS pump is sufficiently below the water level of both the condensate storage tank and the suppression pool to provide a flooded pump suction and to meet pump NPSH requirements with the containment at atmospheric pressure, and the suction strainer 50 percent plugged.

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 6.3-4.

The design pressure and temperature of the system components are established based on the ASME Section III Boiler and Pressure Vessel Code. The design pressures and temperatures, at various points in the system can be obtained from the miscellaneous information blocks on the HPCS process diagram, Figure 6.3-1.

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 Section 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 process diagram, Figure 6.3-1.

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 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 to relieve at 1560 psig, 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 of <10 gpm - 10% accumulation. A third relief valve is located between the two isolation valves of the test line to the condensate storage tank and is set at 15 psid (pressure in the line between the isolation valves above the pressure upstream of the first isolation valve in the test line to condensate storage tank) to relieve thermally expanded fluid.

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 will 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 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 Section 5.2.2. The operation of the ADS is discussed in Section 7.3.1.

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 a-c 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 6.3-8, the LPCS system P&ID presents the system components and their arrangement. The LPCS system process diagram, Figure 6.3-2, shows the design operating modes of the system. Figure 6.3-2 includes a simplified system flow diagram showing injection into the reactor vessel by the LPCS 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 LOCA analyses is shown in Figure 6.3-5.

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.

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. The valve is capable of opening within 40 seconds following a maximum recirculation line break accident. 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 Section 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-operation test of the system to limit system flow to acceptable values as described on the LPCS System Process Diagram.

The LPCS pump (pump performance test results) characteristics, head, flow, horsepower, and required NPSH are shown in Figure 6.3-5.

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 suppression pool, a closed loop is established for the spray water escaping from the break.

The design pressure and temperature of the system components are established based on the ASME Section III boiler and pressure vessel code. The design pressures and temperatures at various points in the system can be obtained from the miscellaneous information blocks on the LPCS process diagram Figure 6.3-2.

The LPCS pump is located in the auxiliary building sufficiently below the water level in the suppression pool to assure a flooded pump suction and to meet pump NPSH requirements are met with the containment at atmospheric pressure and the suction strainers 50 percent plugged. A pressure gage is provided to indicate the suction head. The LPCS pump characteristics are shown in Figure 6.3-5.

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 600 psig with capacity of 100 gpm - 10% accumulation. The second relief valve is located on the suction side of the pump and is set for 100 psig at a capacity of 10 gpm - 10% accumulation.

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 will 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) System

The low pressure coolant injection subsystem is an operating mode of the RHR system. The LPCI system 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 to deliver flooding water on 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 then 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. The head flow characteristics assumed in the LOCA analyses for the LPCI pumps are shown in Figure 6.3-6.

Figure 6.3-3 shows a process diagram and process data for the RHR system, including LPCI. The RHR pumps receive power from a-c power buses having standby power source backup supply. Two RHR pump motors and the associated automatic motor-operated valves receive a-c 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.

Each 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 close 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 valve will open within 40 seconds following an accident signal, including time to start emergency power sources.

The process diagram (Figure 6.3-3) and P&ID (Figure 5.4-13) 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.

A check valve in the pump discharge line is used together with a discharge line fill system (see Section 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, 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.

The design 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 LPCI process diagram, Figure 6.3-3.

LPCI pumps and equipment are described in detail in Section 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 Section 6.2.2. 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 LPCI pump characteristics are shown in Figure 6.3-6.

The 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.

Provisions are included in the 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.

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 a-c 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 water leg pump is provided for each of the three ECCS divisions. The power supply to

these pumps is classified as essential when the main ECCS pumps are deactivated. Indication is provided in the control room as to whether these pumps are operating, and alarms indicate low discharge line pressure.

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 Section 3.2, 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 Material 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 failures are shown in Table 6.3-3.

6.3.2.6 Protection Provisions

Protection provisions are included in the design of the ECCS. Protection is afforded against missiles, pipe whip, and flooding. Also accounted for in the design are thermal stresses, loadings from a LOCA and seismic effects.

The ECCS piping and components located outside the drywell 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 as discussed in Section 3.4.1.

The ECCS is protected against the effects of pipe whip, which might result from piping failures up to and including the design basis event 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 Section 5.4.14. The methods used to provide assurance that thermal stresses do not cause damage to the ECCS are described in Section 3.9.

6.3.2.7 Provisions for Performance Testing

Periodic system and component testing provisions for the ECCS are described in Section 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 longterm cooling period (after 10 minutes), the operator will take action as specified in Section 6.2.2 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, temperature and radiation levels 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, 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 Section 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 Chapter 5 and Section 7.3.

6.3.3 PERFORMANCE EVALUATION

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 (Reference 1), "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. 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 1.

The ECCS performance is evaluated for the entire spectrum of break sizes for postulated LOCA's. The accidents, as listed in Chapter 15, for which ECCS operation is required are:

a. Feedwater line break

b. Steam system piping break outside of containment

c. 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 calculated in this performance analysis provide the basis for technical specifications designed to ensure conformance with the acceptance criteria of 10 CFR 50.46. Minimum ECCS functional requirements are specified in Sections 6.3.3.4 and 6.3.3.5, and testing requirements are discussed in Section 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 Section 6.3.3 where conformance is demonstrated are indicated. A detailed description of the methods used to show compliance are shown in Reference 1.

Criterion 1, Peak Cladding Temperature

"The calculated maximum fuel element cladding temperature shall not exceed 2200°F Conformance to Criterion 1", is shown in Sections 6.3.3.7.3, 6.3.3.7.4, 6.3.3.7.5, 6.3.3.7.6 and specifically in Table 6.3-4 (maximum average planar linear heat generation rate, maximum local oxidation, and peak cladding temperature versus exposure).

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 Figure 6.3-9 (break spectrum plot), in Table 6.3-4 (local oxidation versus exposure) and in Table 6.3-5 (break spectrum summary).

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 Table 6.3-4.

Criterion 4, Coolable Geometry

"Calculated changes in core geometry shall be such that the core remains amenable to cooling." As described in Reference 2, Section III, conformance to Criterion 4 is demonstrated by conformance to Criteria 1 and 2.

Criterion 5, Long-Term Cooling

"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 Reference 1, 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 and/or by steam generated in the covered part of the core.

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 Section 6.3.2. There it was shown that all potential single failures are no more severe than one of the single failures identified in Table 6.3-3.

It is therefore only necessary to consider each of these single failures in the emergency core cooling system performance analyses. For large breaks, failure of one of the diesel standby generators is in general the most severe failure. For small breaks, the HPCS is the most severe failure.

A single failure in the ADS (one ADS valve) has no effect in large breaks. Therefore, as a matter of calculational convenience, it is assumed in all calculations that one ADS valve fails to operate in addition to the identified single failure. This assumption reduces the number of calculations required in the performance analysis and bounds the effects of one ADS valve failure and HPCS failure by themselves. The only effect of the assumed ADS valve failure on the calculations is a small increase (on the order of 100°F) in the calculated temperatures following small breaks.

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), and

c. the ECCS flow entering the vessel.

Key ECCS actuation set points and time delays for all the ECC systems are provided in Table 6.3-1. 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-generat rs and pumps. The delay time due to valve motion in the case of high pressure system provides a suitably conservative allowance for valves available for this application. 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 Section 6.3.3 can be determined from the head-flow curves in Figures 6.3-4, 6.3-5, and 6.3-6 of Section 6.3.2 and the pressure versus time plots discussed in Section 6.3.3.7. Simplified piping and instrumentation and functional control diagrams for the ECCS are provided in Section 6.3.2. The operational sequence of ECCS for the DBA is presented in Table 6.3-2.

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 as specified in Section 6.2.2 to place the containment cooling system into operation.

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, shutdown cooling, or steam condensing. Immediately following a LOCA, the RHR system is directed to the LPCI mode.

6.3.3.6 Limits on ECCS System Parameters

The limits on the ECC system parameters are discussed in Section 6.3.3.1 and Section 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. The maximum allowable out of service time is a function of the level of redundance and the specified test intervals as generally discussed in Section 15.A.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 Reference 1. These procedures were used in the calculations documented in Section 6.3.3. 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 1. 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 1.

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 1.

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 uncovery 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 1.

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 1.

The significant input variables used by the LOCA codes are listed in Table 6.3-1 and shown graphically in Figure 6.3-10.

6.3.3.7.2 Accident Description

A detailed description of the LOCA calculation is provided in Reference 1. 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 6.3-11) 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 6.3-12) 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 coastdown 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 plane until shortly after jet pump uncovery. Boiling transition follows shortly after the core flow loss that results from jet pump uncovery. 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 6.3-15) decreases 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.

6.3.3.7.3 Break Spectrum Calculations

The analysis results presented in this section were obtained from a typical LOCA analysis which is representative of this plant size and product line. A plant specific LOCA analysis will be submitted as an FSAR amendment later in the SAR review cycle.

A complete spectrum of postulated break sizes and locations is considered in the evaluation of ECCS performance. 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 presented in Section 6.3.3 is shown in Table 6.3-6.

A summary of the results of the break spectrum calculations is shown in tabular form in Table 6.3-5 and graphically in Figure 6.3-9. Conformance to the acceptance criteria (PCT of 2200°F, local oxidation of 17 percent and core wide metal-water reaction of 1 percent) is demonstrated. Details of calculations for specific breaks are included in subsequent paragraphs.

6.3.3.7.4 Large Recirculation Line Break Calculations

Important variables from the analyses of the DBA are shown in Figures 6.3-11 through 6.3-20. 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.

j. PCT rod internal pressure as a function of time from CHASTE.

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 6.3-3.

Important variables in two other large break calculations (break size = 0.80 x DBA break size, 0.60 x DBA break size) are shown in Figures 6.3-21 through 6.3-36.

6.3.3.7.5 Transition Recirculation Line Break Calculations

Important variables from the analysis of the transition (1.0 ft^2) break are shown in Figures 6.3-37 through 6.3-48. 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. Fuel Rod 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.

6.3.3.7.6 Small Recirculation Line Break Calculations

Important variables from the analysis of the small break yielding the highest cladding temperature are shown in Figures 6.3-49 through 6.3-52. 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. Peak 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 6.3-53 through 6.3-56.

6.3.3.7.7 Calculations for Other Break Locations

Reactor water level and vessel pressure from SAFE/REFLOOD and peak cladding temperature and fuel rod convective heat transfer coefficients from REFLOOD are shown in Figures 6.3-57 through 6.3-60 for the core spray line break, Figures 6.3-61 through 6.3-64 for the feedwater line break, and in Figures 6.3-65 and 6.3-66 for the main steam line break inside the containment.

An analysis was also done for the main steam line break outside the containment. Reactor water level and vessel pressure from SAFE/REFLOOD and peak cladding temperature and fuel rod convective heat transfer coefficients from REFLOOD are shown in Figures 6.3-67 through 6.3-70.

6.3.3.8 <u>LOCA Analysis Conclusions</u>

Having shown compliance with the applicable acceptance criteria of Section 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 6.3-3.

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 <u>ECCS Performance Tests</u>

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 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 2.

All of the active components of the HPCS system, LPCS system, and 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 during racking out of the injection valve breaker, each ECCS loop can be tested for response time.

All of the active components of the ADS system except the safety/relief valves and their associated solenoid valves are designed so that they may be tested during normal plant operation. The safety/relief valves and associated solenoid valves are all tested at least once each 18 months during plant start-up following a refueling outage. Safety/relief valves and their associated solenoid valves which have been overhauled during a plant outage are tested during the start-up following that outage.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3.1. The emergency power system, which supplies electrical power to the ECCS in the event that offsite power is unavailable, is tested as described in Section 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.

6.3.4.2.1 HPCS Testing

The HPCS can be tested at full flow with condensate storage tank water at any time during plant operation except when the reactor vessel water level is low, or when the condensate level in the condensate storage tank is below the reserve level, or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the HPCS is being tested, the system returns automatically to the operating mode. The two motor-operated valves in the test line to the condensate storage system are interlocked closed when the suction valve from the suppression pool is open.

A design flow functional test of the HPCS over the operating pressure and flow range is performed by pumping water from the condensate storage tank and back through the full flow test return line to the condensate storage tank.

The suction valve from the suppression pool and the discharge valve to the reactor remain closed. These two valves are tested separately to ensure their operability.

The HPCS test conditions are tabulated on the HPCS process flow diagram, Figure 6.3-1.

6.3.4.2.2 ADS Testing

The ADS valves are fully tested during the time when the reactor is at reduced pressure prior to or following a refueling outage. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence. Each individual ADS valve is manually actuated.

During plant operation the ADS system can be checked as discussed in Section 7.3.1.

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 process diagram, Figure 6.3-2.

6.3.4.2.4 LPCI Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated in Figure 6.3-3. 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. 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 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 the instruments in the control room.

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 Section 7.3.

All instrumentation required for automatic and manual initiation of the HPCS, LPCS, LPCI and ADS is discussed in Chapter 7 and is designed to meet the requirements of IEEE Standard 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 6.3-4 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 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 1160 psid (psid - differential pressure between RPV and pump suction source) to 0 psid.

6.3.6 REFERENCES FOR SECTION 6.3

1. 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.

2. H. M. Hirsch, "Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems," January 1973 (NEDO-10739).

TABLE 6.3-1

SIGNIFICANT INPUT VARIABLES USED IN THE LOSS-OF-COOLANT ACCIDENT ANALYSIS

Variable	Units	Valve
A. PLANT PARAMETERS		
Core thermal power	MWt	3729
Vessel steam output	lbm/hr	16.17×10^6
Corresponding percent of rated steam flow	%	105
Vessel steam dome pressure	psia	1060
B. EMERGENCY CORE COOLING SYSTEM PARAMETERS		
B.1 Low Pressure Coolant Injection System		
Vessel pressure at which flow may commence	psid (vessel to drywell)	225
Minimum rated flow at vessel pressure	GPM psid (vessel to drywell)	19500 20
Initiating Signals		
low water level	ft. above top of active fuel	≤ 1.0
or		
high drywell pressure	psig	≥ 2.0
Maximum allowable time delay from initiating signal to pumps at rated speed	sec	27
Injection valve fully open	sec. after maximum suction break	40

TABLE 6.3-1 (continued)

Variable	Units	Valve
B.2 Low Pressure Core Spray System		
Vessel pressure at which flow may commence	psid (vessel to drywell)	289
Minimum rated flow at vessel pressure	gpm psid (vessel to drywell)	6000 122
Initiating Signals		
low water level or high drywell pressure	ft. above top of active fuel psig	1.0 2.0
Maximum allowed (runout) flow	gpm	7800
Maximum allowed delay time from initiating signal to pump at rated speed	sec	27.0
Injection valve fully open	sec. after maximum break	40
B.3 High Pressure Core Spray		
Vessel pressure at which flow may commence	psid	1177
Minimum rated flow available at vessel pressure	gpm psid (vessel to pump suction)	517 6000 1177 200
Initiating Signals		
low water level or high drywell pressure	ft. above top of active fuel psig	10.9 2.0
Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	sec	27.0

TABLE 6.3-1 (continued)

Variable	Units	Valve
B.4 Automatic Depressurization System		
Total number of valves installed		8
Number of valves used in analysis		7
Minimum flow capacity of valves at pressure	lb/hr psig (vessel to suppression pool)	6.4×10^6 1125
Initiating Signals		
low water level and high drywell pressure	ft. above top of active fuel psig	≤ 1.0 ≥ 2.0
Delay time from all initiating signals completed to the time valves are open	sec	120
C. FUEL PARAMETERS		
Fuel type		Initial core
Fuel bundle geometry		8 x 8
Lattice		C
Number of fueled rods/assembly		62
Peak technical specification linear heat generation rate	kW/ft	13.4
Initial minimum critical power ratio		1.2
Design axial peaking factor		1.4

TABLE 6.3-2

OPERATIONAL SEQUENCE OF EMERGENCY CORE COOLING SYSTEMS FOR DESIGN BASIS ACCIDENT[1]

Time (sec)	Events
0	Design basis loss-of-coolant accident assumed to start; normal auxiliary power assumed to be lost.
0	Drywell high pressure and reactor low water level reached. All diesel generators signaled to start; scram; HPCS, LPCS, LPCI signaled to start on high drywell pressure.
3	Reactor low-low water level reached. HPCS receives second signal to start.
7	Reactor low-low-low water level reached. Second signal to start LPCI and LPCS; auto-depressurization sequence begins; main steam isolation valve signaled to close.
10	All diesel generators ready to load; energize HPCS pump motor; open HPCS injection valve: begin energizing LPCI and LPCS pump motors.
27	HPCS injection valve open and pump at design flow, which completes HPCS startup.
40	LPCI and LPCS pumps at rated flow, LPCI and LPCS injection valves open, which completes the LPCI and LPCS startups.
See Figure 6.3-15	Core effectively reflooded assuming worst single failure; heatup terminated.
10 min	Operator shifts to containment cooling.

NOTE:

1. 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 Sections 6.3.2.5 and 6.3.3.3).

TABLE 6.3-3

SINGLE FAILURE EVALUATION[1]

Assumed Failure	Suction Break Systems Remaining
LPCI Emergency Diesel Generator (D/G)	All ADS, HPCS, LPCS, 1 LPCI
LPCS Emergency D/G	All ADS, HPCS, 2 LPCI
HPCS Emergency D/G	All ADS, LPCS, 3 LPCI
One ADS Valve	All ADS minus one, LPCS, HPCS, 3 LPCI

NOTE:

1. Single, active failures are considered in the ECCS performance evaluation. Other postulated failures are not specially considered because they all result in at least as much ECCS capacity as one of the above designed failures.

TABLE 6.3-4

MAPLHGR, MAXIMUM LOCAL OXIDATION, AND PEAK CLAD TEMPERATURE VERSUS EXPOSURE

Core Wide Metal-Water Reactor % = 0.11

Exposure MWD/T	MAPLHGR KW/FT	P.C.T. DEG-F	Oxide Frac.
High Enrichment Fuel			
200.0	11.9	1996.	0.014
1000.0	12.0	1987.	0.013
5000.0	12.1	1977.	0.012
10000.0	12.2	1977.	0.012
15000.0	12.3	2003.	0.014
20000.0	12.1	2005.	0.014
25000.0	11.6	1950.	0.011
30000.0	11.3	1916.	0.010
Medium Enrichment Fuel			
200.0	12.0	1990.	0.014
1000.0	12.2	1988.	0.013
5000.0	12.7	2024.	0.015
10000.0	12.9	2038.	0.015
15000.0	12.9	2066.	0.017
20000.0	12.6	2043.	0.015
25000.0	11.7	1922.	0.010
30000.0	10.8	1802.	0.007

TABLE 6.3-4 (continued)

Exposure MWD/T	MAPLHGR KW/FT	P.C.T. DEG-F	Oxide Frac.
Low Enrichment Fuel			
200.0	11.58	1906.	0.010
1000.0	11.42	1866.	0.008
5000.0	11.38	1838.	0.007
10000.0	11.55	1830.	0.007
15000.0	11.54	1836.	0.007
20000.0	11.02	1784.	0.006
25000.0	10.40	1711.	0.004

TABLE 6.3-5

SUMMARY OF RESULTS OF LOCA ANALYSIS

Break Spectrum Analysis	PCT(°F)	Peak Local Oxidation
Break Size - 2.2 ft^2 (DBA) Location - Recirc. Suction Single Failure - LPCS D/G	2066[1]	1.7%
Break Size - 1.0 ft^2 Location - Recirc. Suction Single Failure - LPCI D/G	2027[1] 1848[2]	1.4% <1%
Break Size - 0.07 ft^2 Location - Recirc. Suction Single Failure - HPCS D/G	1652[2]	<1%

NOTES:

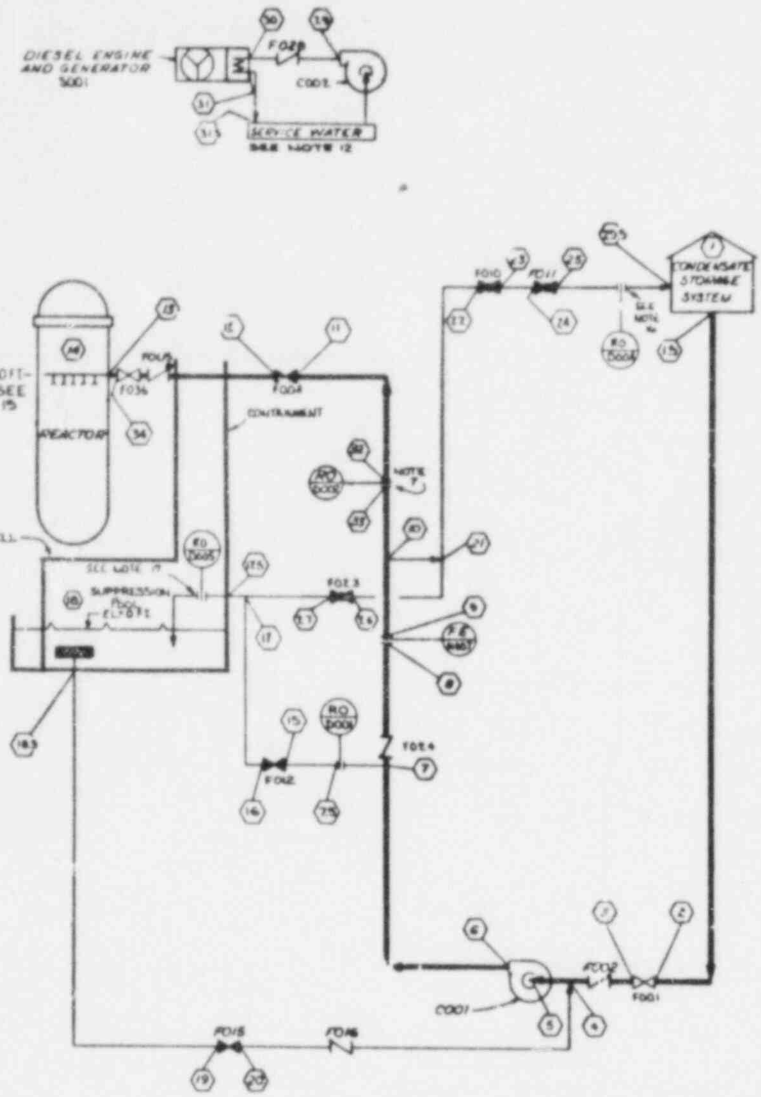
1. CHASTE - large break methods

2. Non-DBA reflood - small break methods

TABLE 6.3-6

KEY TO FIGURES

		Large Break Method			Small Break Method						
	DBA	0.80 DBA	0.60 DBA	1.0 ft^2 Large Break Methods	1.0 ft^2 Small Break Methods	Worst Small Break 0.1 ft^2	Less Limiting Small Break	Core Spray Line	Feedwater Line	Main Steam Line Inside Containment	Main Steam Line Outside Containment
Core Average Pressure	11	21	29	37	NA	NA	NA	NA	NA	NA	NA
Core Average Inlet Flow	12	22	30	38	NA	NA	NA	NA	NA	NA	NA
Core Inlet Enthalpy	16	23	31	39	NA	NA	NA	NA	NA	NA	NA
Minimum Critical Power Ratio	17	24	32	40	NA	NA	NA	NA	NA	NA	NA
Water Level Inside Shroud	14	25	33	41	45	49	53	57	61	65	67
Reactor Vessel Pressure	18	26	34	42	46	50	54	58	62	66	68
Convective Heat Transfer Coefficient	13	27	35	43	47	51	55	59	63	NA	69
Peak Cladding Temperature	15	28	36	44	48	52	56	60	64	NA	70
Average Fuel Temperature	19										
PCT Rod Internal Pressure	20										
Peak Cladding Temperature and Peak Local Oxidation Versus Break Area	9	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA



PRIMARY

TABLE I
VALVE POSITION TABLE

VALVE	F001	F004	F010	F011	F012	F015	F023	F036
MODE A	O	O	C	C	C	C	C	O
MODE B	C	O	C	C	C	O	C	
MODE C	C	O	C	C	C	O	C	
MODE CC	C	O	C	C	O	O	C	
MODE E	O	O	C	C	C	C	C	
MODE F	C	O	C	C	C	O	C	
MODE G	C	C	C	C	C	O	O	
MODE H	O	C	O	O	C	C	C	
MODE J	O	C	C	C	O	C	C	
MODE S	O	C	C	C	C	C	C	O

O - VALVE OPEN
C - VALVE CLOSED

MODE J PUMP OPERATING ON BYPASS, SUCTION FROM CONDENSATE STORAGE

POSITION ○	1	2	3	4	5	6	7	15	16	17	18
FLOW GPM	N/A	600	←					SEE NOTE 8		600	N/A
PRESS. PSIA	14.7										14.7
TEMP. °F	AMB	140/40	←						→	140/40	AMB
MAX. PRESSURE DIFFERENCE FT					← 1450 →			← 18 →			

MODE S SYSTEM ON STANDBY DUTY

POSITION ○	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM	N/A	0	←										→ 0	N/A
PRESS. PSIA	14.7													1035
TEMP	AMB	140/40	←						→	140/40	AMB	←	→	AMB
MAX. PRESS. DIFFERENCE FT					← 0 →									

MODE A ACCIDENT OR RCIC BACKUP REACTOR AT HIGH PRESSURE SUCTION FROM

POSITION ○	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM	N/A	1550	←										→ 1550	N/A
PRESS PSIA	14.7													1162
TEMP °F	AMB	140/40	←										→ 140/40	AMB
MAX. PRESS. DIFFERENCE FT SEE NOTE 18					← 2815 →									

MODE B ACCIDENT, REACTOR AT HIGH PRESSURE, SUCTION FROM SUPPR

POSITION ○	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM	1550	←								→ 1550	N/A	1550	1550	N/A
PRESS PSIA											1162			14.7
TEMP °F	140/40	←								→ 140/40	AMB	140/40	140/40	AMB
MAX. PRESS. DIFFERENCE FT SEE NOTE 18		← 2815 →												

MODE C ACCIDENT, SYSTEM INJECTION AT RATED CORE SPRAY, SUCTION FROM SUP

POSITION ○	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM NOTE 7	610	←								→ 610	N/A	610	610	N/A
PRESS PSIA											315			14.7
TEMP °F	212/40	←								→ 212/40	AMB	212/40	212/40	AMB
MAX. PRESS. DIFFERENCE FT		← 900 →			← 21 →			← 1.4 →		← 223 →		← 27 →		

MODE CC ACCIDENT OR RCIC BACK UP, REACTOR AT HIGH PRESSURE (SEE NOTE 19) SUCTION FROM SUPPR

POSITION ○	18	19	20	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM	N/A	1117	←			→	1117	517	←				→ 517	N/A
PRESS PSIA	14.7													1192
TEMP °F	AMB	120/40	←										→ 120/40	AMB
MAX. PRESS. DIFFERENCE FT SEE NOTE 19					← 2811 →									

MODE E ACCIDENT, SYSTEM INJECTION AT RATED CORE SPRAY, SUCTION FROM CO

POSITION ○	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM NOTE 7	N/A	610	←										→ 610	N/A
PRESS PSIA	14.7	NOTE 6			NOTE 9									219
TEMP °F	AMB	140/40	←										→ 140/40	AMB
MAX. PRESS. DIFFERENCE FT		← 4 →			← 900 →			← 21 →			← 1.4 →		← 223 →	

MODE F ACCIDENT, SYSTEM OPERATING AT RUNOUT, SUCTION FROM SUPPRESSIO

POSITION ○	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM NOTE 7	7800	←								→ 7800	N/A	7800	7800	N/A
PRESS PSIA		SEE NOTE 5									14.7			14.7
TEMP °F	212/40	←								→ 212/40	AMB	212/40	212/40	AMB
MAX. PRESS. DIFFERENCE FT		← 564 →										← 3 →		

MODE G SYSTEM TEST SUCTION FROM SUPPRESSION POOL

POSITION ○	4	5	6	7	8	9	10	11	26	27	17	19	20	18
FLOW GPM	7800	←											→ 7800	N/A
PRESS. PSIA														14.7
TEMP °F	170/40	←											→ 170/40	AMB
MAX. PRESS. DIFFERENCE FT		← 564 →							← 48 → SEE NOTE 8					

MODE H SYSTEM TEST, SUCTION FROM CONDENSATE STORAGE

POSITION ○	1	2	3	4	5	6	7	8	9	10	21	22	23	24
FLOW GPM	N/A	610	←											→
PRESS PSIA	14.7													
TEMP °F	AMB	170/40	←											→
MAX. PRESS. DIFFERENCE FT					← 900 →							← [illegible] → NOTE 8		← [illegible] NOTE

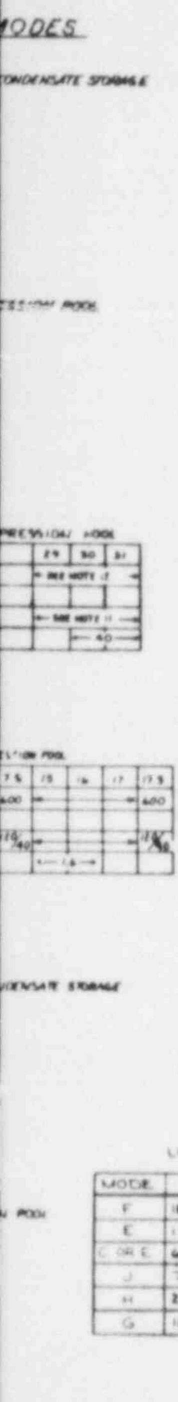


TABLE II
LIMITING LINE LOSS

MODE	FLOW PATH	COMMENT
F	18.5-18-20-4-5	SEE NOTE 5
E	1.5-2-3-4	SEE NOTE 6
C OR E	6-7-8-9-10-11-12-13	
J	7-15-16-17	
H	21-22-23-24-25-25.5	
G	10-21-26-27-17-13.5	

MISCELLANEOUS INFORMATION
(SEE NOTE 10)

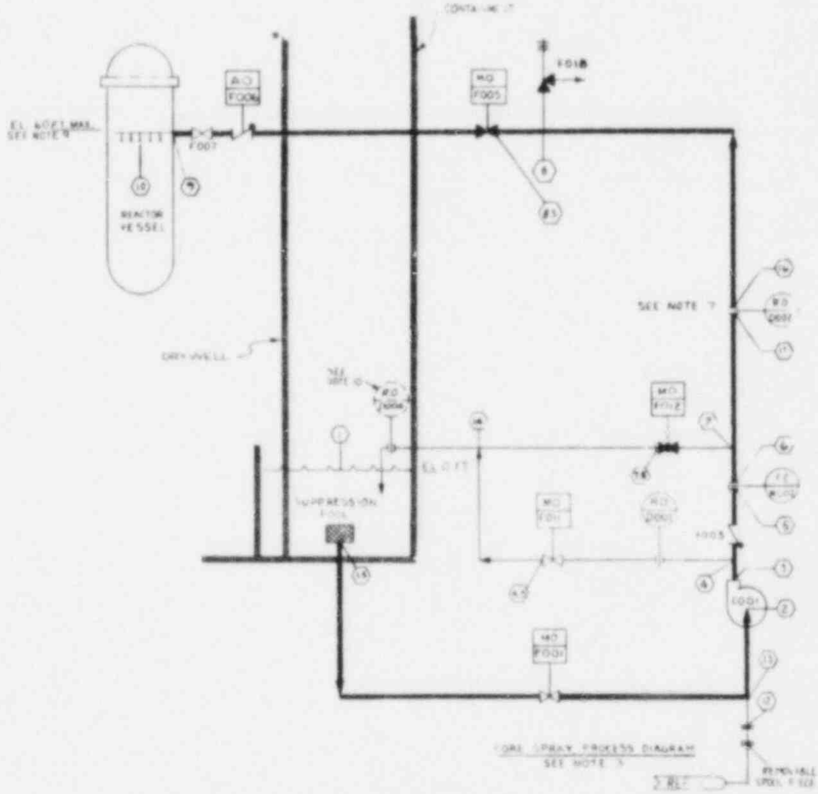
LINE	LOCATION	DESIGN TEMP (°F)	DESIGN PRESS (PSIG)	ESTIMATED LINE SIZE (IN.)
CONDENSATE STG. SUCTION	1.5 2 4	140 / 212	100	16
SUPPRESS. POOL SUCTION	18.5 4 5	212	100	24
MAIN HPCS LINE TO REACTOR	6 11 12 34 13	212 / 575 / * / 575	1575 / 1575 / * / 1250	16 / 12 / 12 / 12
BY PASS LINE	7 15 17	212	1575 / 100	4
SUPPRESS. POOL TEST LINE	10 27 17.5	212	1575 / 100	12
CONDENSATE STORAGE TEST RETURN LINE	21 25 25.5	212 / 140	1575 / 100	10
DIESEL COOL WATER LINE	29 30 31 31.5	100 / [illegible] / 150	100 / 100	3 / 3

* DUAL DESIGN CONDITIONS
1250 PSI @ 575 °F AND
1575 PSI @ 140 °F

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

High Pressure Core Spray System
Process Diagram

Figure 6.3-1



CORE SPRAY PROCESS DIAGRAM
SEE NOTE 3

MISCELLANEOUS INFORMATION SEE NOTE 6

LOCATION ○	1.5	2	3 4 5 6 7 8		8.5	9	4 A4		7 7.5		12 13
DESIGN TEMP (°F)	212	PUMP	← 212 →	500	575		← 212 →		← 212 →		← 212 →
DESIGN PRESS (PSIG)	100		← 600 →		1250		600 | 100		600 | 100		← 100 →
ESTIMATED LINE SIZES (IN.)	24"		← 14" →		12"		← 4" →		← 12" →		← 16 →
	MAIN CORE SPRAY LINE TO REACTOR						BYPASS LINE		TEST LINE		RHR LINE

LOCAT
FLOW
PRESS
TEMP
MAX P DIFFER

LOCAT
FLOW
PRESS
TEMP
MAX P DIFFER
SEE NOT

LOCAT
FLOW
PRESS
TEMP
MAX DIFFER

LOCAT
FLOW
PRESS
TEMP
MAX P DIFFER
SEE NO

LOCAT
FLOW
PRES
TEMP
MAX P DIFFER
SEE NO

LOCA
FLOW
PRES
TEMP
MAX DIFFER

MPL NO. E21-1050

TABLE II
LIMITING LINE LOSS

MODE	FLOW PATH	COMMENTS
F	15 13 2	SEE NOTE 5
D	3 4 5 6 15 6 8 6 5 9 10	
A	7 3 5 4	
C	4 4 5 4	
B	12 13	SEE NOTE 6

SYSTEM TEST, SUCTION FROM SUPPRESSION POOL

[illegible]	1	2	3	4	5	6	7	8	9	10		12	13	14
[illegible]	N/A	7800					7800	0	0	0		0	0	7800
[illegible]	14.7													
[illegible]	120/40						120/40	AMB					AMB	120/40
[illegible] FEET		645												

SYSTEM TEST, SUCTION FROM RESIDUAL HEAT REMOVAL SYSTEM

[illegible]	1	2	3	4	5	6	7	8	9	10		12	13	14
[illegible]	N/A	8160								8160		8160	8160	0
[illegible]	14.7									14.7				
[illegible]	N/A	125/40								125/40		125/40	125/40	AMB
[illegible] FEET		619												

PUMP OPERATION, SUCTION FROM SUPPRESSION POOL

[illegible]	1	2	3	4	5	6	7	8	9	10		12	13	14
[illegible]	N/A	1200	1200	1200	0	0	0	0	0	0		0	0	1200
[illegible]	14.7													
[illegible]	212/40			212/40	AMB								AMB	212/40
[illegible] FEET		235/180												

[illegible] (SUB MAX)

[illegible]	1	2	3	4	5	6	7	8	9	10
[illegible]	N/A	6110								6110
[illegible]	14.7									14.7
[illegible]	170									170
[illegible] FEET		730			221					223

VALVE POSITIONS

[illegible]						
MODE A						
MODE B						
MODE						
MODE D						
MODE F	C					
MODE S	C					

P - PARTIALLY OPEN
C - FULLY CLOSED
O - FULLY OPEN

SYSTEM IN STANDBY DUTY

[illegible]	1	2	3	4	5	6	7	8	9	10		12	13	14
GPM	N/A	0												0
PSIA	14.7									[illegible]				
°F	125/40						125/40	AMB	AMB	AMB		125/40	125/40	125/40
[illegible] FEET		[illegible]												

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Low Pressure Core Spray System
Process Diagram

Figure 6.3-2

MODE A-1 (SEE NOTES 3 & 23)

POSITION	1	2	3	4	5	6	$7_{A,B}$	$8_{A,B}$	9	10	46	11	29
FLOW GPM	—	7100										7100	—
PRESSURE PSIA	29.7 / 14.7												53.3 / 38.7
TEMPERATURE °F	—	170 / 40										170 / 40	—
MAX PRESSURE DROP FEET						TDH = 275				ΔH = 20		ΔH = 35	

LOOP A & B — LOOP — SEE NOTE 7 TYP. ALL TABLES

MODE A-2 SEE NOTE 13

POSITION	1	2	3	4
FLOW GPM	—	8520		
PRESSURE PSIA	14.7			
TEMPERATURE °F	—	180 / 50		
MAX PRESSURE DROP FEET				

LOOP A & B

MODE B-1 SEE NOTE 23

POSITION	1	2_B	3_B	4_B	5_B	6_B	18_B	19_B	9_B	10_B	12_B	53_B	44_B	43_B	24_B	1		60_B	61_B
FLOW GPM	—	7100													7100	—		7300	7300
PRESSURE PSIA	29.7 / 14.7															29.7 / 14.7			
TEMPERATURE °F	—	185					185	138.1							138.1	—		80	125.6
MAX PRESSURE DROP FEET						TDH = 275													

HEAT REMOVAL CAPABILITY PER HX LOOP 166.4 x 10^6 BTU/HR (1 HX OPERATING)

MODE B-2

POSITION	1	2_B	3_B	4_B	5_B	6_B	18_B	19_B	9_B	10_B	16_B	47_B	48_B	49_B	1			60_B	61_B
FLOW GPM	—	5250												[illegible]	—			7300	[illegible]
PRESSURE PSIA	29.7 / 14.7														29.7 / 14.7				
TEMPERATURE °F	—	195					195	131.7						131.7	—			80	118.3
MAX PRESSURE DROP FEET						TDH = 310													

HEAT REMOVAL CAPABILITY PER HX LOOP 151 x [illegible] BTU/HR (1 HX OPERATING)

MODE C-1 RX PRESSURE 1000 PSIG

POSITION		29	35	$36_{A,B}$	$37_{A,B}$	$17_{A,B}$	$18_{A,B}$	$19_{A,B}$	$20_{A,B}$	$38_{A,B}$	$39_{A,B}$	$40_{A,B}$	41	42	$40\text{-}2_{A,B}$	$44_{A,B}$	$24_{A,B}$	1		$60_{A,B}$	$61_{A,B}$
FLOW - SEE NOTE 14		—	193	96.5			96.5	193				193	386	386	193	193	193	—		7300	7300
PRESSURE PSIA		1040			215									50				14.7			
TEMPERATURE °F		—	548	548	387.7	387.7	387.7	140									140	—		80	108.7
PRESSURE DROP - PSI		ΔP = 821								ΔP = 200 / ΔP = 175											

COND. TO RCIC — COND. TO POOL

HEAT REMOVAL CAPABILITY PER HX LOOP 104.8 x 10^6 BTU/HR (2 HX'S OPERATING)

MODE C-2 RX PRESSURE 1000 PSIG

POSITION			29	35	36_A	37_A	17_A	18_A	19_A	20_A	38_A	39_A	40_A	41	42			60_A	61_A
FLOW - SEE NOTE 14			—	138.6				138.6	277						277			7300	7300
PRESSURE PSIA			1040			215									60				
TEMPERATURE °F			—	548	548	387.7	387.7	387.7	140						140			80	121.2
PRESSURE DROP - PSI			ΔP = 825								ΔP = 155								

HEAT REMOVAL CAPABILITY PER STEAM CONDENSING HX LOOP 150.4 x 10^6 BTU/HR (1 HX STEAM CONDENSING)

MODE C-2 CONT'D SEE NOTE 13 SEE NOTE 23

POSITION	1	2_B	3_B	4_B	5_B	6_B	18_B	19_B	9_B	10_B	12_B	53_B	44_B	43_B	24_B	1		60_B	61_B
FLOW GPM	—	7100													7100	—		7300	7300
PRESSURE PSIA	14.7															14.7			
TEMPERATURE °F	—	120					120	102.1							102.1	—		80	97.4
MAX PRESSURE DROP FEET						TDH = 275													

HEAT REMOVAL CAPABILITY PER POOL COOLING HX LOOP 53.8 x 10^6 BTU/HR (1 HX OPERATING)

MODE C-3 RX PRESSURE 135 PSIG

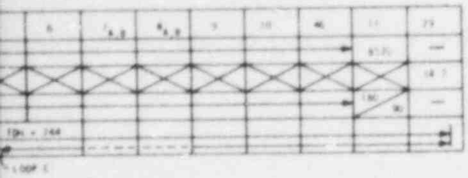
POSITION			29	35	$36_{A,B}$	$37_{A,B}$	$17_{A,B}$	$18_{A,B}$	$19_{A,B}$	$20_{A,B}$	$38_{A,B}$	$39_{A,B}$	$40_{A,B}$	41	42			$60_{A,B}$	$61_{A,B}$
FLOW - SEE NOTE 14			—	116.6	58.3			58.3	116				116	132	132			7300	7300
PRESSURE PSIA			150												60 / 11				
TEMPERATURE °F			—	358.4				358.4	140						140			80	97.3
PRESSURE DROP - PSI								ΔP = 90 / 135											

HEAT REMOVAL CAPABILITY PER STEAM CONDENSING HX LOOP 63.3 x 10^6 BTU/HR (2 HX'S STEAM CONDENSING)

MODE C-4 RX PRESSURE 135 PSIG

POSITION			29	35	36_A	37_A	17_A	18_A	19_A	20_A	38_A	39_A	40_A	41	42			60_A	61_A
FLOW - SEE NOTE 14			—	98				98	196						196			7300	7300
PRESSURE PSIA			150												60 / 11				
TEMPERATURE °F			—	358.4				358.4	140						140			80	109.1
PRESSURE DROP - PSI								ΔP = 90 / 135											

HEAT REMOVAL CAPABILITY PER STEAM CONDENSING HX LOOP 106.4 x 10^6 BTU/HR (1 HX STEAM CONDENSING)



MODES

A-1 LOW PRESSURE COOLANT INJECTION (LPCI) RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMPS OPERATING. ONE STRAINER 50% PLUGGED

A-2 LOW PRESSURE COOLANT INJECTION (LPCI) RECIRCULATION LINE BREAK IN EITHER SIDE AND THREE PUMPS OPERATING. ONE STRAINER 50% PLUGGED VESSEL PRESSURE

B-1 POST ACCIDENT SUPPRESSION POOL COOLING WITH ONE PUMP OPERATION AND STRAINER 50% PLUGGED. (PEAK SUPPRESSION POOL TEMPERATURE

B-2 POST ACCIDENT CONTAINMENT SPRAY WITH HEAT REJECTION WITH ONE PUMP OPERATION AND STRAINER 50% PLUGGED

C-1 REACTOR STEAM CONDENSING - 2HX STEAM CONDENSING (AT HOUR)

C-2 REACTOR STEAM CONDENSING - 1HX STEAM CONDENSING (AT HOURS) AND 1HX POOL COOLING

C-3 REACTOR STEAM CONDENSING - 2HX STEAM CONDENSING

C-4 REACTOR STEAM CONDENSING - 1HX STEAM CONDENSING (AT 8 HOURS)

D-1 INITIATION OF SHUTDOWN COOLING AFTER BLOWDOWN TO MAIN CONDENSER AT 4 HOURS

D-2 CONTINUATION OF SHUTDOWN COOLING AT HOURS

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Residual Heat Removal System
Process Diagram

Figure 6.3-3 (Sheet 1 of 3)

MODE [illegible] RX PRESSURE [illegible] PSIG SEE NOTE 20

POSITION	29	25	26	5_{AB}	6_{AB}	18_{AB}	19_{AB}	16_{AB}	50_{B}	50_{A}	27_{A}	28_{A}	14	30	31	46	32	23	27_{B}	28_{B}	29
FLOW GPM	—	14200	14200	7100	7100	≤ 7100	≤ 7100	7100	7100	7100 / 6700	7100 / 6700	7100 / 6700	[illegible]				[illegible]	—	7100	7100	—
PRESSURE PSIA	125																	125			125
TEMPERATURE °F	—	344				344	304.1										304.1	—	304.1	304.1	—
MAX PRESSURE DROP FEET				70																	

LOOP B — LOOP A WITH HEAD SPRAY — LOOP A WITHOUT HEAD SPRAY — SEE NOTE [illegible]

HEAT REMOVAL CAPABILITY PER HX LOOP [illegible] x 10^6 BTU/HR (2 HX'S OPERATING)

MODE [illegible] RX PRESSURE 0 PSIG SEE NOTE 20

POSITION	29+	25	26	5_{AB}	6_{AB}	18_{AB}	19_{AB}	16_{AB}	50_{AB}	27_{AB}	28_{AB}	29
FLOW GPM	—	14200	14200	7100							7100	—
PRESSURE PSIA	14.7											14.7
TEMPERATURE °F	—	125				125	100.4				100.4	—
MAX PRESSURE DROP FEET				70								

HEAT REMOVAL CAPABILITY PER HX LOOP [illegible] x 10^6 BTU/HR (2 HX'S OPERATING)

[illegible]

LOOPS A & B ONLY

LOOP C TEST — DOES NOT INCLUDE INTERCONNECTING PIPING — LOOP A & B TEST

HEAT REMOVAL CAPABILITY PER HX LOOP [illegible] x 10^6 BTU/HR (2 HX'S OPERATING)

MODE [illegible] RX PRESSURE 0 PSIG SEE NOTE 20 & 21

POSITION	[illegible]	2	3	56	56	[illegible]	[illegible]	6	5_{AB}	18_{AB}	19_{AB}	6_{AB}	9	10	11	47_{AB}	28_{AB}	11	29
FLOW GPM	—	[illegible]	[illegible]	7100	7100	7100											[illegible]	[illegible]	—
PRESSURE PSIA	14.7																		14.7
TEMPERATURE °F	—	≤ [illegible]							≤ 99	[illegible]						[illegible]	—	—	
MAX PRESSURE DROP FEET																			

LOOPS A & C ONLY

MODE [illegible] SEE NOTE [illegible]

SEE NOTE [illegible]

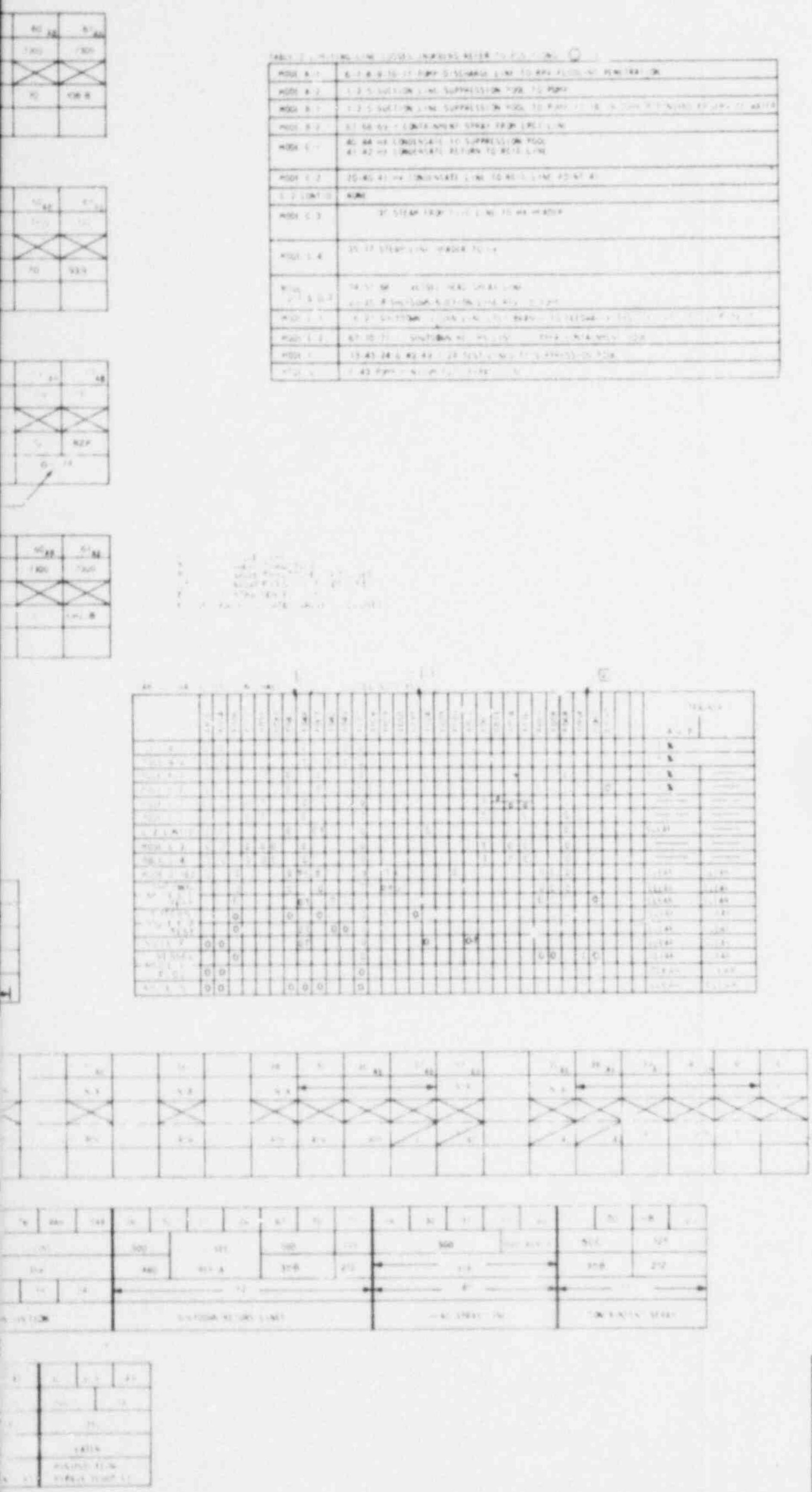
MODE [illegible]

DESIGN PRESSURE AND TEMPERATURE TABLE SEE NOTE [illegible]

POSITION	[illegible]
DESIGN PRESSURE PSIG	500 / 500 / 500 / 550
DESIGN TEMP °F	358 / 480 / 358 / 212 / 480
EXTENDED LINE SIZE	[illegible]
	LPCI LINE (LOOP A & B) (LESS FOR HX BYPASS) — HEAT EXCHANGER LINE — LPCI LINE LOOP C (DIRECT TO REACTOR)

DESIGN PRESSURE AND TEMPERATURE TABLE SEE NOTE [illegible]

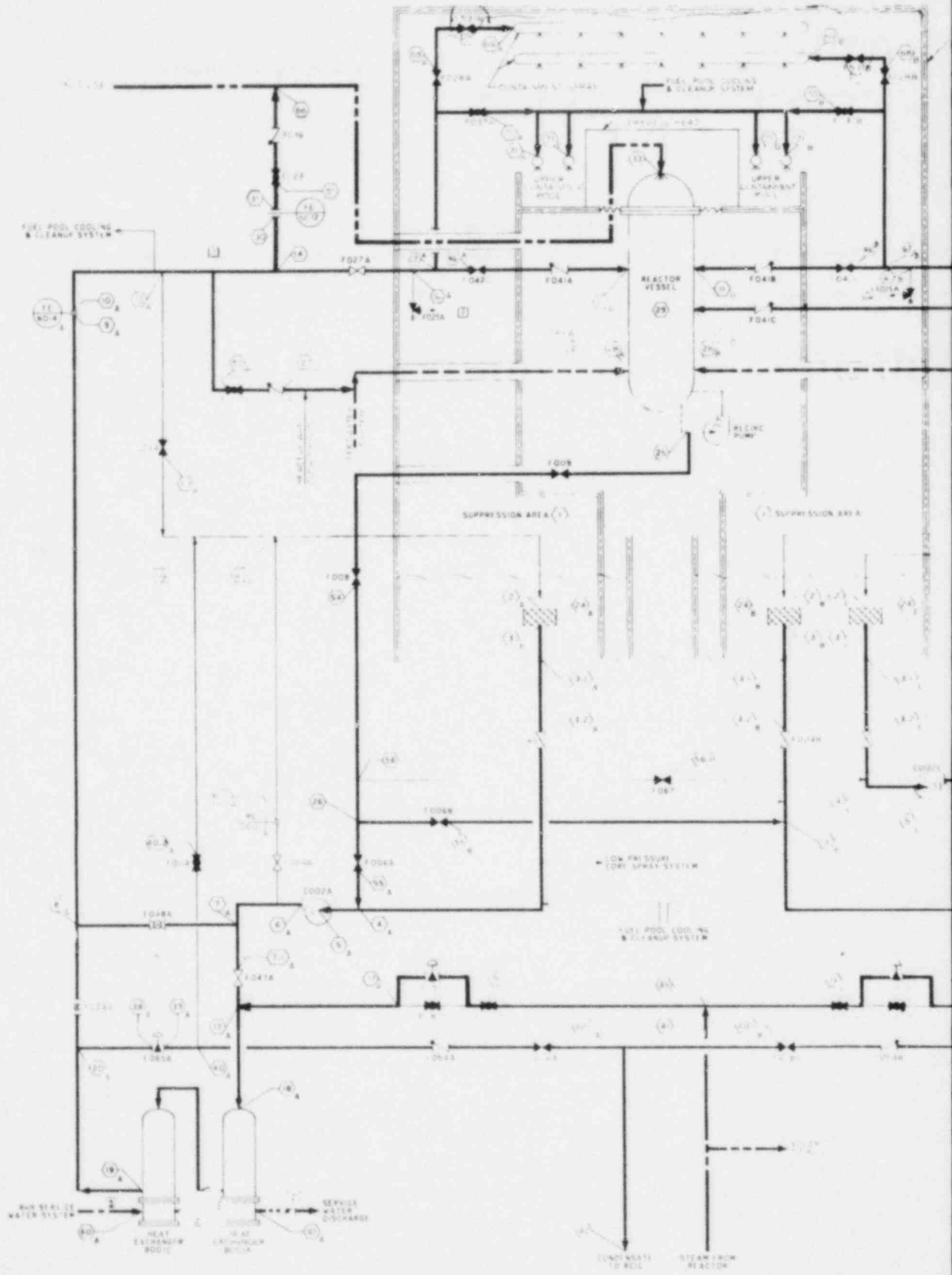
POSITION	[illegible]
DESIGN PRESSURE PSIG	500 / [illegible]
DESIGN TEMP °F	480 / 358 / 358 / 212
EXTENDED LINE SIZE	4 / [illegible]
	STEAM TO HX — CONDENSATE FROM HX — CONDENSATE TO POOL — SYSTEM TEST LINE (LOOP A & B) — SYSTEM TEST SUCTION LINE (LOOP C) — SYSTEM TEST LINE (LOOP C)



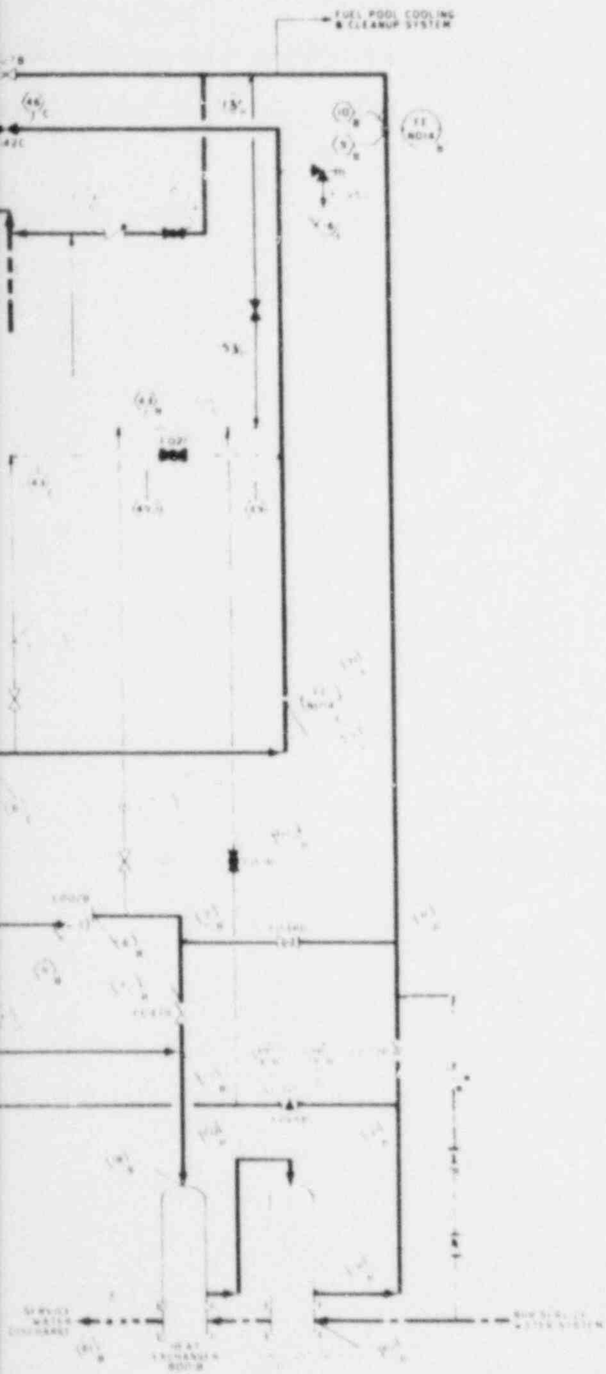
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Residual Heat Removal System
Process Diagram

Figure 6.3-3 (Sheet 2 of 3)



FUEL POOL COOLING & CLEANUP SYSTEM
REACTOR VESSEL
F027A
F042
F041A
F041B
F041C
F009
F008
F006B
F006A
F048A
F047A
F065A
E002A
SUPPRESSION AREA
LOW PRESSURE CORE SPRAY SYSTEM
RCIC PUMP
RHR SERVICE WATER SYSTEM
SERVICE WATER DISCHARGE
HEAT EXCHANGER
CONDENSATE TO RCIC
STEAM FROM REACTOR



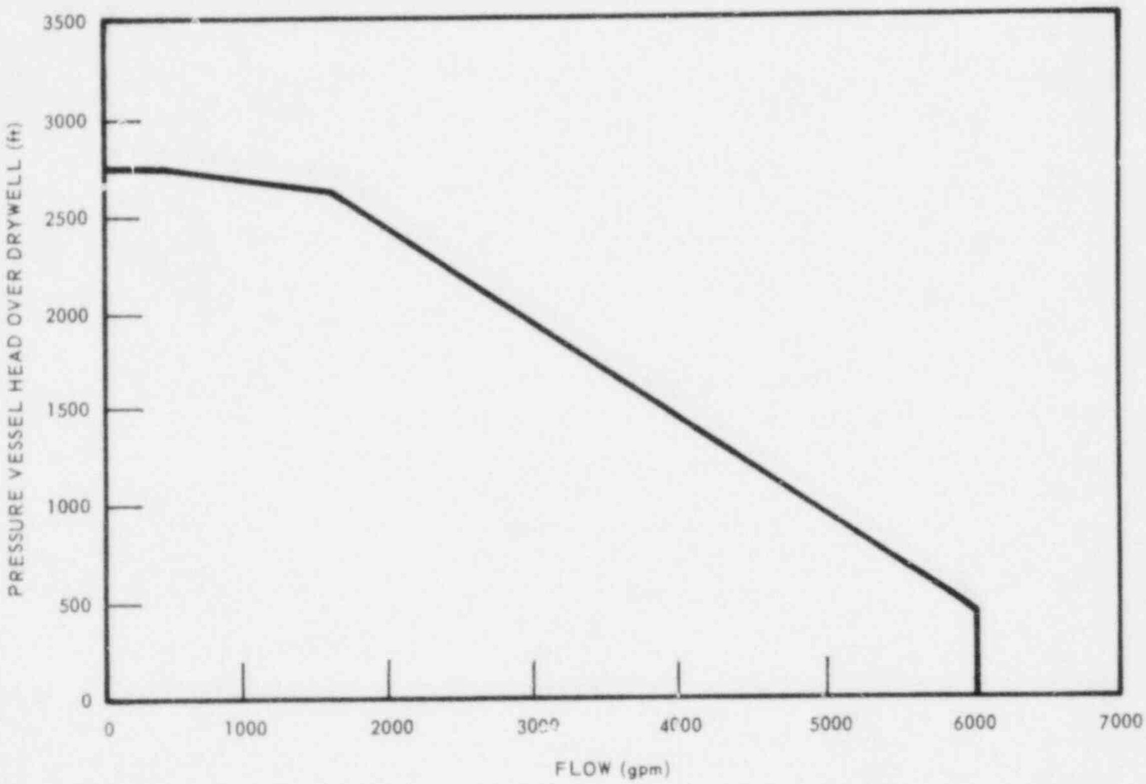
PNPP

PERRY NUCLEAR POWER PLANT

THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Residual Heat Removal System
Process Diagram

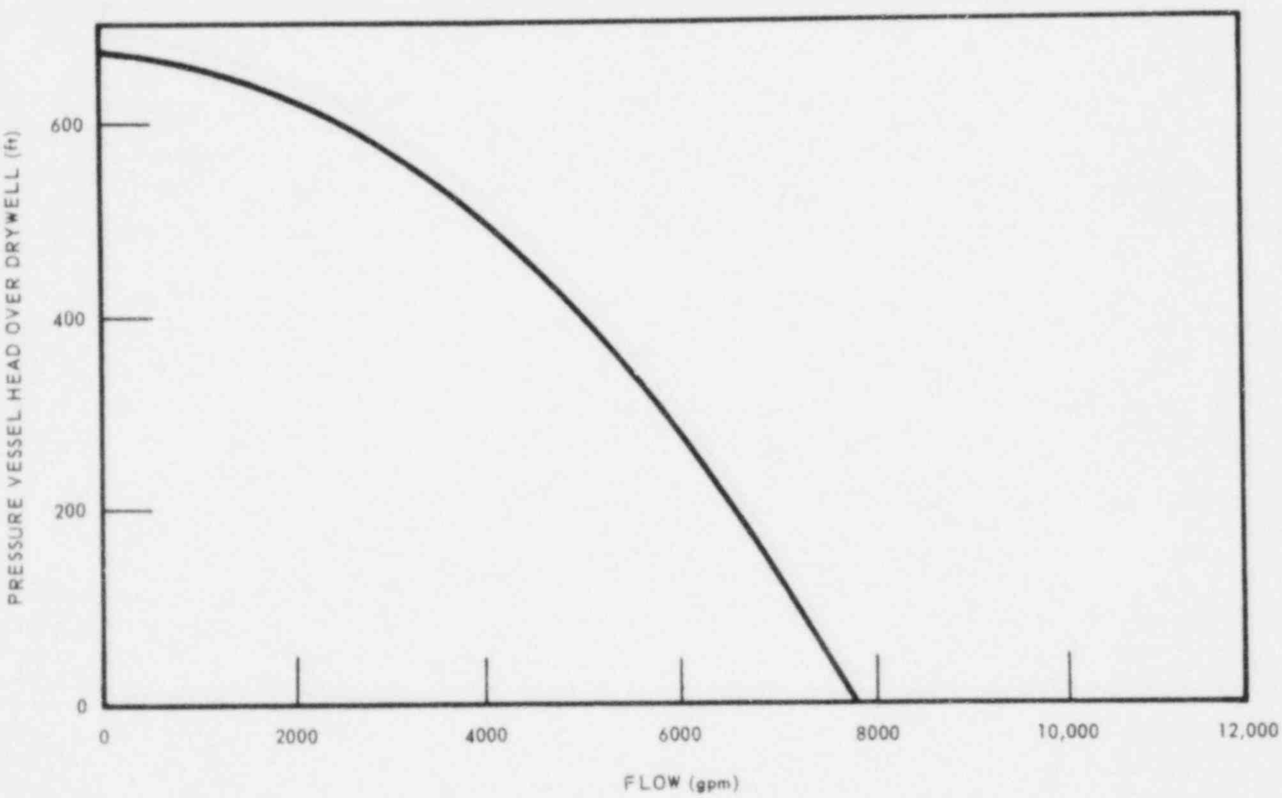
Figure 6.3-3 (Sheet 3 of 3)



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Head Versus High Pressure Core Spray Flow Used in LOCA Analysis

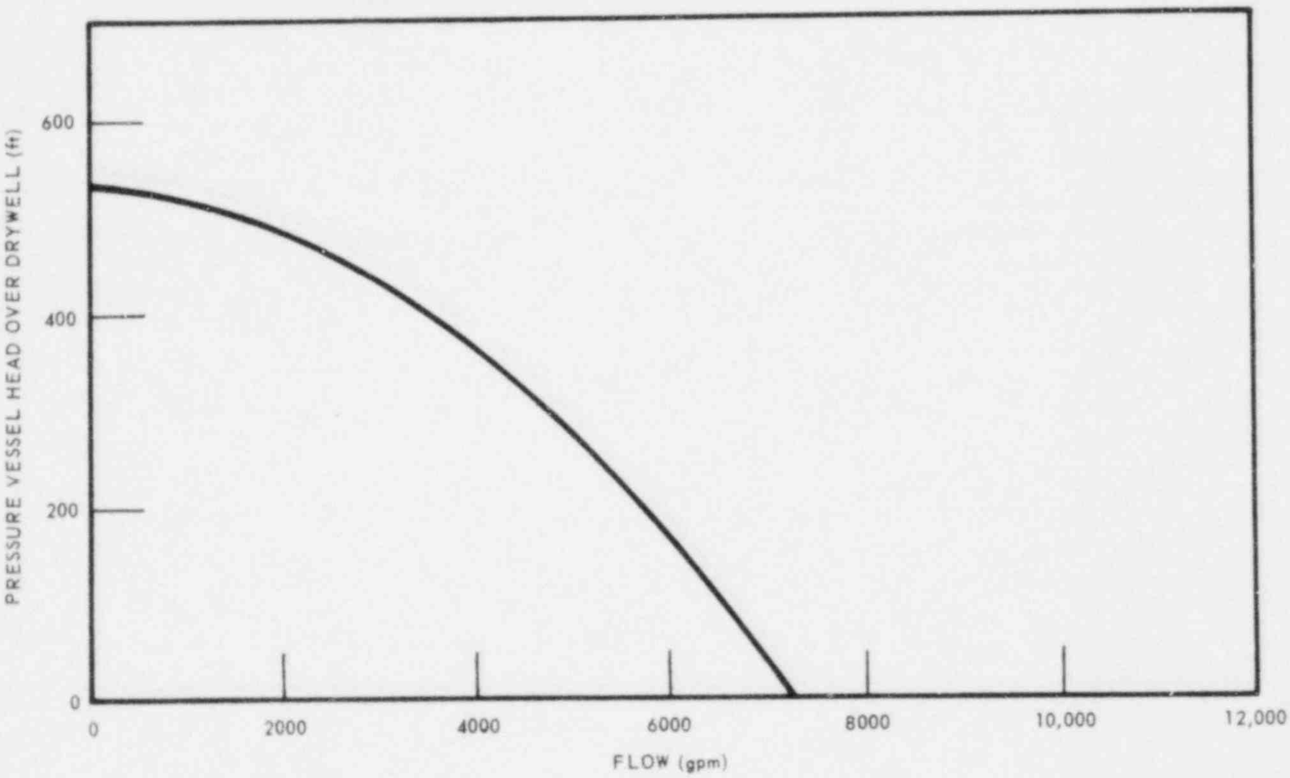
Figure 6.3-4



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Head Versus Low Pressure Core Spray Flow Used in LOCA Analysis

Figure 6.3-5



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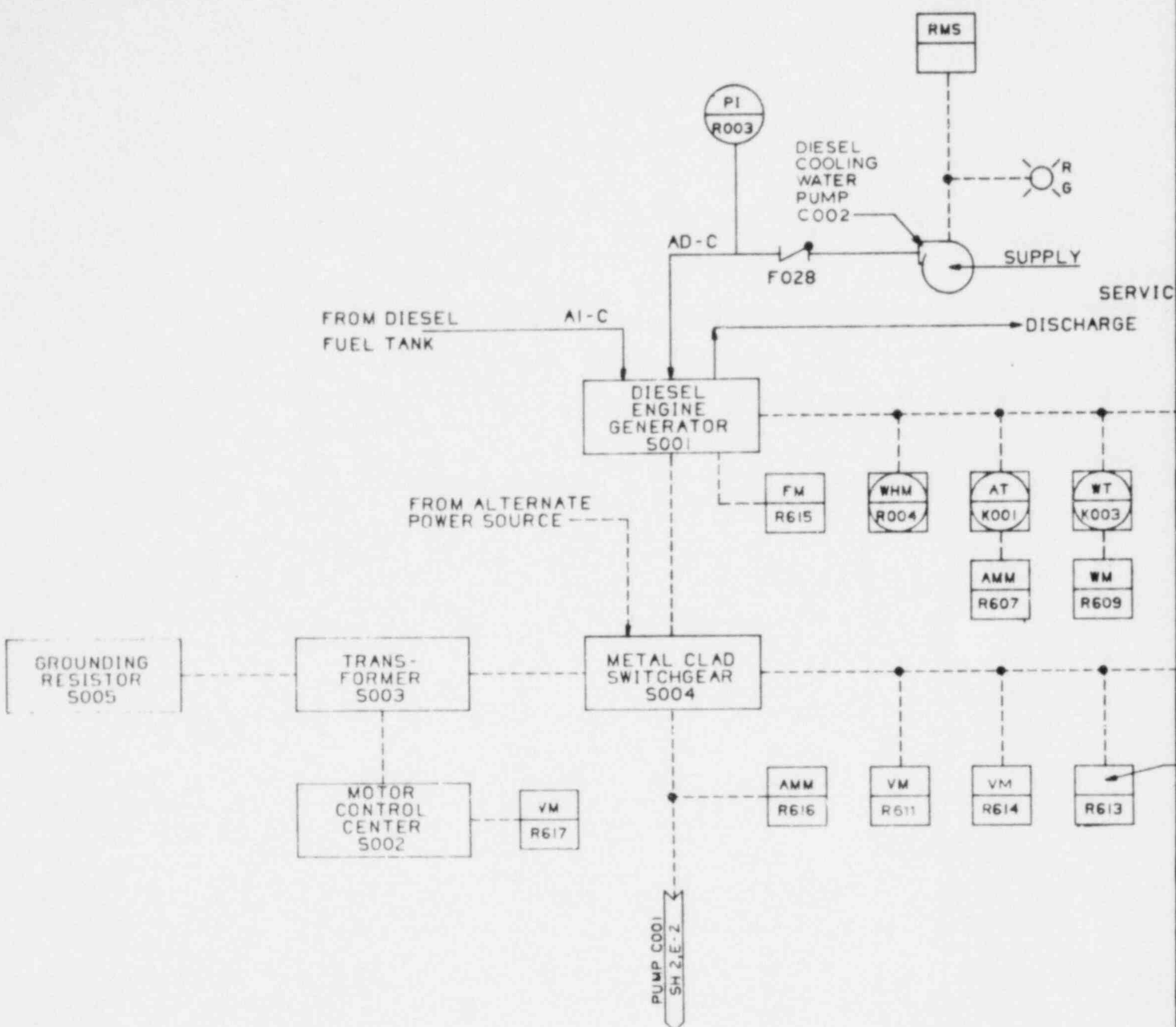
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

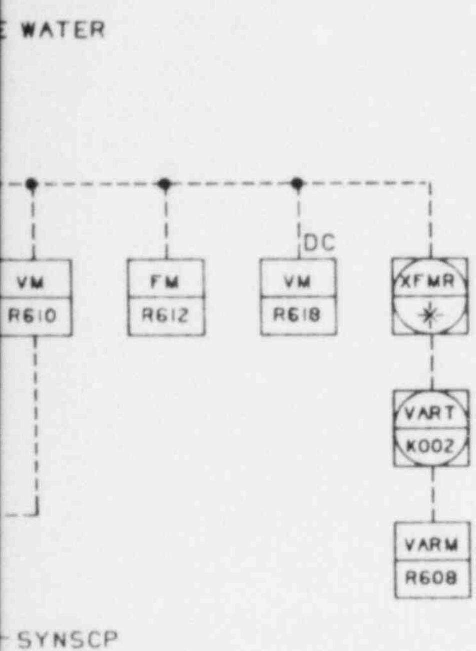
Head Versus Low Pressure Coolant Injection Flow Used in LOCA Analysis

Figure 6.3-6



RMS
PI
R003
DIESEL
COOLING
WATER
PUMP
C002
R
G
AD-C
F028
SUPPLY
SERVIC
FROM DIESEL
FUEL TANK
AI-C
DISCHARGE
DIESEL
ENGINE
GENERATOR
S001
FM
R615
WHM
R004
AT
K001
WT
K003
AMM
R607
WM
R609
FROM ALTERNATE
POWER SOURCE
GROUNDING
RESISTOR
S005
TRANS-
FORMER
S003
METAL CLAD
SWITCHGEAR
S004
MOTOR
CONTROL
CENTER
S002
VM
R617
AMM
R616
VM
R611
VM
R614
R613
PUMP C001
SH 2,E-2

MPL NO: E22-1010



NOTES:

1. EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY SYSTEM NUMBER E22 UNLESS OTHERWISE SPECIFIED.
2. PIPING HIGH POINT VENTS AND LOW POINT DRAINS ARE TO BE ADDED AS NECESSARY. ADDITIONAL TEST CONNECTIONS, BARRIERS, DRAINS, VENTS, AND OTHER PIPING DETAILS, AS WELL AS SPECIFIC VALVE CHARACTERISTICS, MAY BE REQUIRED IN ORDER TO COMPLY WITH 10CFR50 APPENDIX J TYPE C LEAK RATE TESTING REQUIREMENTS.
3. CHEMICAL CLEANING CONNECTIONS, (VALVES, ETC.), IF REQUIRED, ARE TO BE PROVIDED AS NECESSARY.
4. INSTRUMENT LINE DESIGN AND VALVING SHALL BE IN ACCORDANCE WITH INSTRUMENTATION SPECIFICATION REF 5.
5. THE METHOD OF MOUNTING LOCAL INSTRUMENTS IS TO BE DETERMINED BY PIPING DESIGNER.
6. VALVE F023 SHALL BE INSTALLED WITH THE PACKING GLAND ON THE UPSTREAM SIDE OF THE VALVE DISC.
7. VALVE F010 SHALL BE LOCATED AS CLOSE AS PRACTICAL TO VALVE F011.
8. FOR ADDITIONAL CONTROL ROOM LIGHTS, SYSTEM ALARMS AND REMOTE MANUAL SWITCHES, SEE HPCS SYSTEM FCD AND ELECTRICAL ONE LINE DIAGRAM.
9. PROVISION FOR ISOLATION SHALL BE IN ACCORDANCE WITH CURRENT LICENSING REQUIREMENTS.
10. THIS LINE MAY BE CLASS "B" IF IT IS 3/4 INCH OR LESS IN DIAMETER. IF LARGER THAN 3/4 INCH THE LINE SHALL BE CLASS "A".
11. THE PIPE DESIGN SHALL PROVIDE ADEQUATE PIPE SURFACE AREA FROM THE DISCHARGE TO INLET NOZZLE OF C003 TO ASSURE SUFFICIENT CONVECTION COOLING OF C003 BYPASS.
12. VALVE F024 SHALL BE LOCATED AT AN ELEVATION LOWER THAN THE SUPPRESSION POOL MINIMUM WATER LEVEL AND CONDENSATE SYSTEM MINIMUM WATER LEVEL.
13. FLUSHING WATER CONNECTIONS ARE LOCATED AS CLOSE AS PRACTICAL TO F004 AND F015.
14. FOR LOCATION AND IDENTIFICATION OF INSTRUMENTS SEE THE HPCS SYSTEM INSTRUMENT DATA SHEET.
15. EXCEPT AT POINTS CONNECTING WITH G.E. SUPPLIED EQUIPMENT OR PIPING, THE PIPING DESIGNER SHALL SIZE PIPES IN CONFORMANCE WITH THE SYSTEM DESIGN SPEC AND PROCESS DIAGRAM.
16. FLUSHING CONNECTIONS SHALL BE PROVIDED IN ACCORDANCE WITH REF 6. TEMPORARY STRAINER SCREENS SHALL BE PROVIDED ON THE SUCTION SIDE OF ALL PUMPS IN ACCORDANCE WITH REF 6.
17. VALVE F036 IS RECOMMENDED FOR MAINTENANCE AND/OR LEAK RATE TESTING PER 10CFR50 APPENDIX J, TYPE C. G.E. SHALL BE ADVISED IF VALVE WILL NOT BE INSTALLED.
18. CHECK VALVE F005 SHALL BE LOCATED AS CLOSE AS PRACTICAL TO THE HIGH PRESSURE CORE SPRAY REACTOR VESSEL NOZZLE.
19. VALVES F012 AND F023 SHALL BE LOCATED AS CLOSE AS PRACTIC/ TO THE CONTAINMENT PENETRATION OF THE RETURN LINE TO THE SUPPRESSION POOL.
20. COOLING WATER FOR E22-C001 BEARINGS AND SEALS, IF REQUIRED, IS SPECIFIED IN REF 4.
21. OPTIONAL ORIFICE MAY BE REQUIRED TO PREVENT EXCESSIVE PUMP FLOW. FOR SIZING SEE HPCS SYSTEM PROCESS DIAGRAMS NOTES 16 AND 17.
22. ALL MOTOR OPERATED VALVES ARE AC OPERATED UNLESS OTHERWISE NOTED.

SUPPLEMENTAL DOCUMENTS	MPL ITEM NO
1. RHR SYSTEM P&ID	E12-1010
2. PROCESS COMPUTER SYSTEM INPUT/OUTPUT LIST	C91-4030
3. LEAK DETECTION SYSTEM IED	E31-1010
4. EMERGENCY EQUIP COOLING WATER	A62-4230
5. PROCESS INSTRUMENTATION	A62-4070
6. CLEANING OF PIPING & EQUIPMENT	A62-4140
7. PRESSURE INTEGRITY OF NUCLEAR COMPONENTS	A62-4030
8. PIPING & INSTRUMENT SYMBOLS	A42-1010

LEGEND

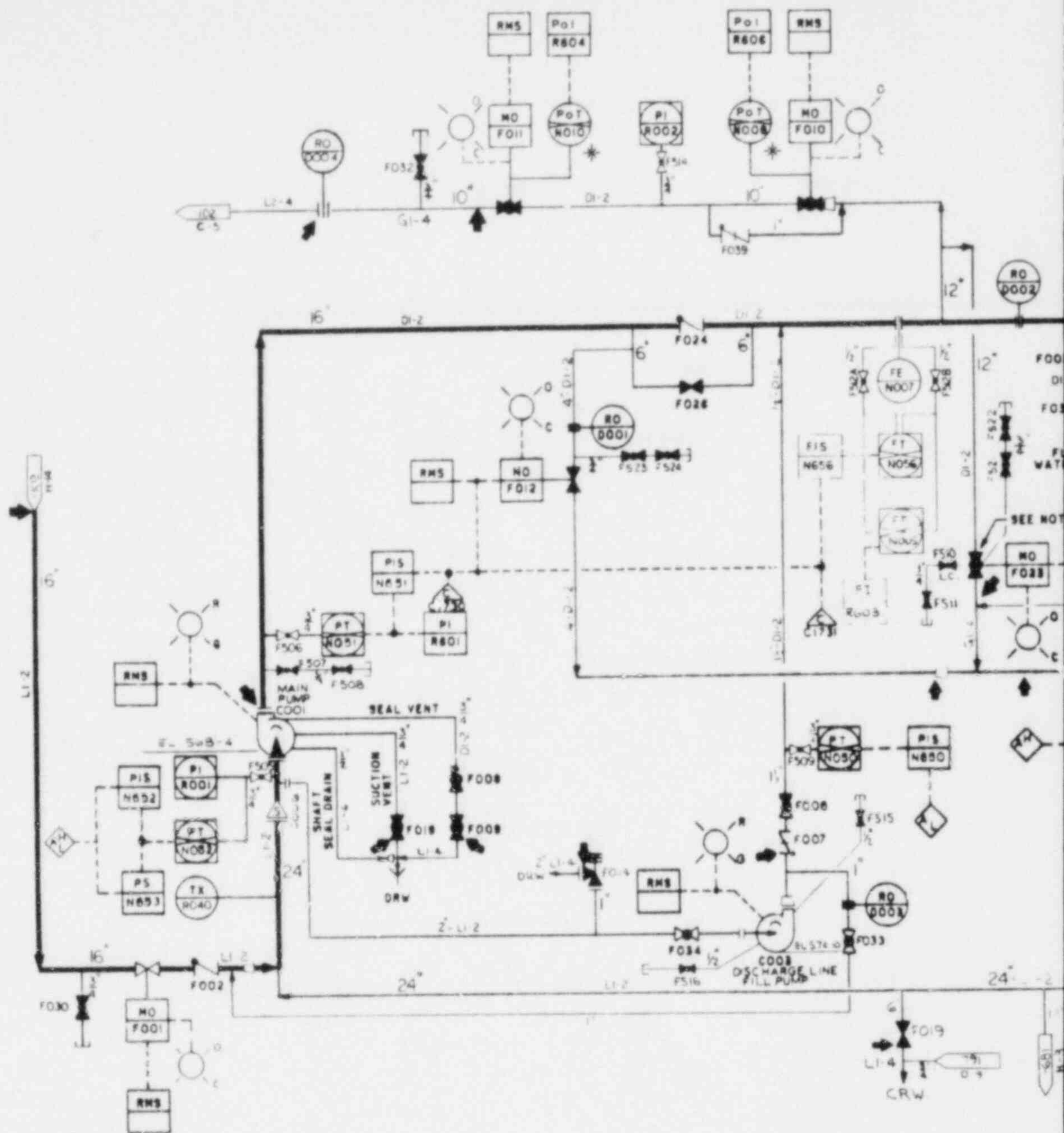
AMM	AMMETER
AT	CURRENT TRANSDUCER
FM	FREQUENCY METER
SYNSCP	SYNCHROSCOPE
VARM	VARMETER
VART	VARTRANSDUCER
VM	VOLTMETER
WHM	WATTHOUR METER
WM	WATTMETER
WT	WATT TRANSDUCER
XFMR	TRANSFORMER

PNPP

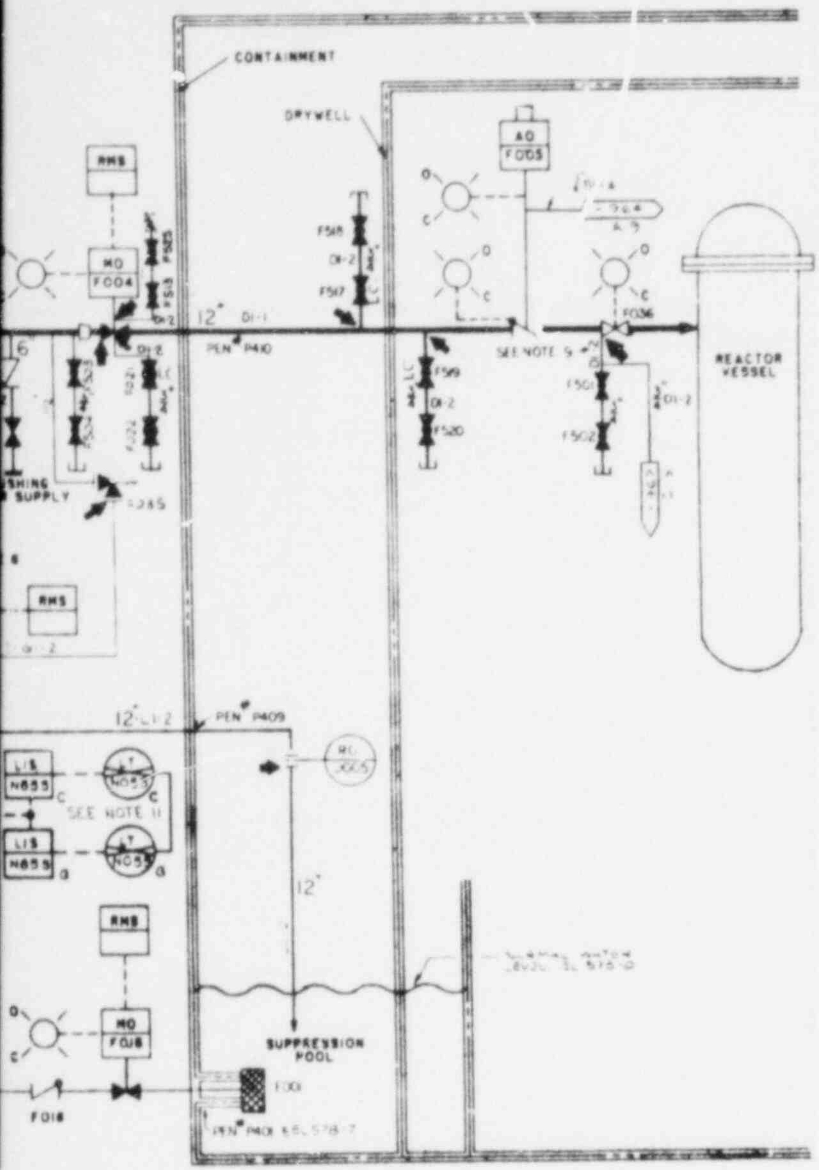
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

High Pressure Core Spray System P & ID

Figure 6.3-7 (Sheet 1 of 2)



RMS
PoI
R604
PoI
R606
RMS
MO
F011
PoT
N010
PI
R002
PoT
MO
F010
RO
D004
F032
10"
D1-2
10"
F039
G1-4
C-5
12"
RO
D002
16"
D1-2
F024
6"
6"
F026
12"
FE
N007
RO
D001
RMS
MO
F012
F523
F524
FIS
N656
FT
N056
SEE NOT
MO
F023
PIS
N651
PI
R601
F510
F511
6"
RMS
MAIN
PUMP
C001
SEAL VENT
F506
F507
F508
PT
N051
PIS
N652
PI
R001
PT
N082
PS
N653
TX
R040
SHAFT
SEAL DRAIN
SUCTION
VENT
F009
F008
F018
DRW
24"
PT
N052
PIS
N650
F509
F006
F007
F515
RMS
RO
D003
F033
F034
F516
C003
DISCHARGE LINE
FILL PUMP
16"
F002
F030
MO
F001
RMS
24"
24"
F019
L1-4
CRW



NOTES:

1. EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY SYSTEM NUMBER E22 UNLESS OTHERWISE NOTED
2. DELETED
3. CHEMICAL CLEANING CONNECTIONS (VALVES, ETC.) IF REQUIRED, ARE TO BE PROVIDED AS NECESSARY
4. INSTRUMENT LINE DESIGN AND VALVING SHALL BE IN ACCORDANCE WITH INSTRUMENTATION SPECIFICATION 482-4878
5.
6. VALVE F023 SHALL BE INSTALLED WITH THE PACKING GLAND ON THE UPSTREAM SIDE OF THE VALVE DISCHARGE
7. DELETED
8. FOR ADDITIONAL CONTROL ROOM LIGHTS, SYSTEM ALARMS AND REMOTE MANUAL SWITCHES, SEE HPCS SYSTEM FCD AND ELECTRICAL ONE LINE DIAGRAM
9. PROVISION FOR ISOLATION SHALL BE IN ACCORDANCE WITH CURRENT LICENSING REQUIREMENTS
10. E22 LEVEL INSTRUMENTATION (LT-N054G, LIS-N054C, LIS-N054G) FOR THE CONDENSATE STORAGE TANK IS SHOWN ON DWG. D-302-102
11. E22 LEVEL INSTRUMENTATION (LT-N055C, LT-N055G, LIS-N055C, LIS-N055G) IMPULSE LINES FOR THE SUPPRESSION POOL ARE SHOWN ON DWG. D-302-895 (AREA I-5)
12. DELETED
13. DELETED
14. DELETED
15. EXCEPT AT POINTS CONNECTING WITH G.E. SUPPLIED EQUIPMENT OR PIPING THE PIPING DESIGNER SHALL SIZE PIPES IN CONFORMANCE WITH THE SYSTEM DESIGN SPECIFICATION AND PROCESS DIAGRAM
16. FLUSHING CONNECTIONS SHALL BE PROVIDED IN ACCORDANCE WITH 482-4148. TEMPORARY STRAINER SCREENS SHALL BE PROVIDED ON THE SUCTION SIDE OF ALL PUMPS IN ACCORDANCE WITH 482-4148
17. DELETED
18. DELETED
19. DELETED
20. ALL MOTOR OPERATED VALVES ARE AC OPERATED UNLESS OTHERWISE NOTED
21. THIS SYSTEM DIAGRAM IS A PHOTOGRAPHIC REPRODUCTION OF G.E. DWG. 105D5075 SHEET 2. SPECIFIC REVISION IS SHOWN BENEATH GAI TITLE BLOCK
22. ALL LIGHTS, ALARMS, SWITCHES, AND INDICATORS ARE LOCATED ON H13-P601 UNLESS OTHERWISE NOTED
23. ALL INSTRUMENT LOCATIONS ARE IDENTIFIED ON THE INSTRUMENT INDEX

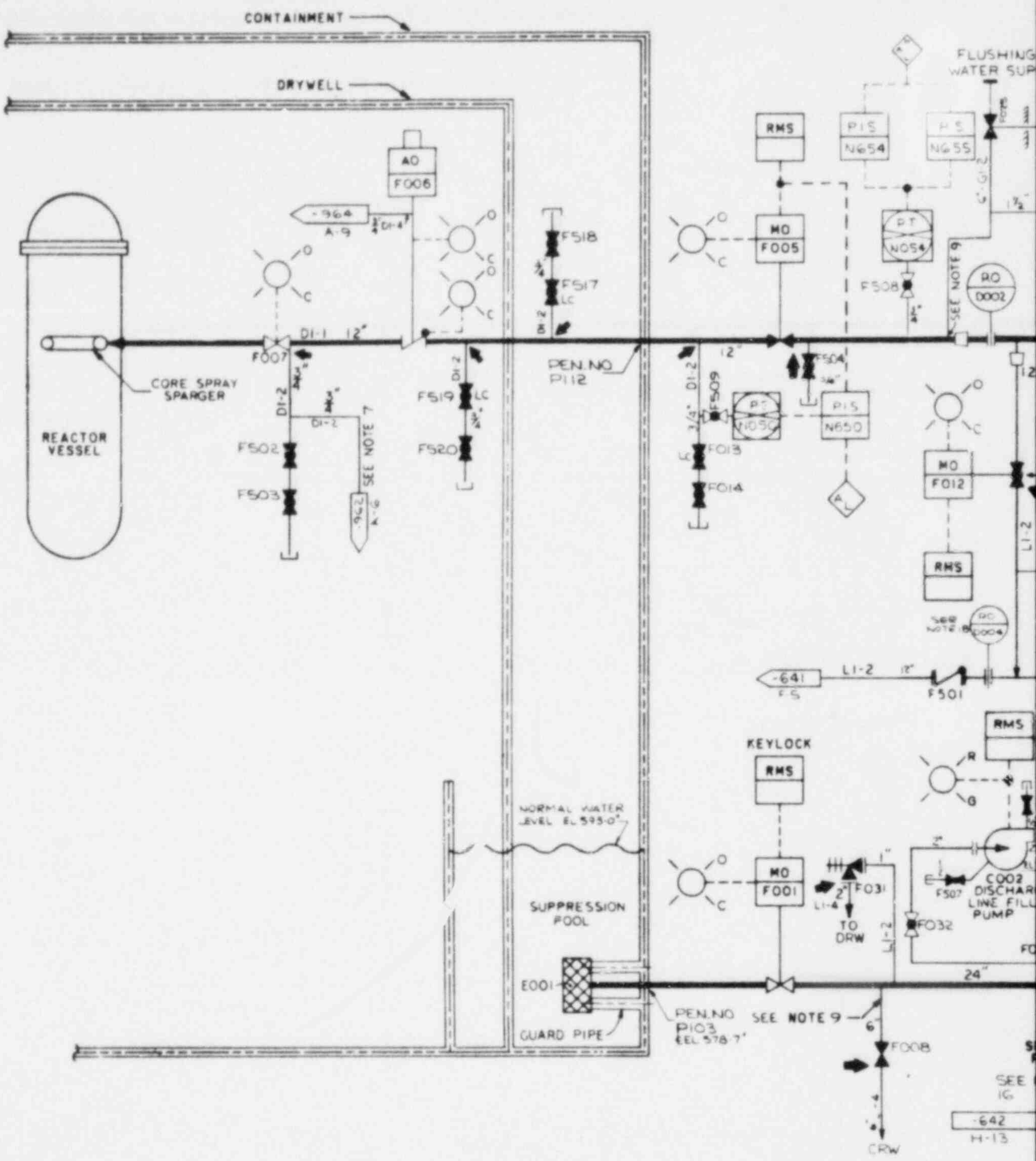
REFERENCE DRAWINGS:

D-302-661	SUPPRESSION POOL CLEANUP GAI
D-302-102	CONDENSATE TRANSFER P&ID
D-302-862	LEAK DETECTION SYSTEM EDI
D-302-864	LEAK DETECTION SYSTEM EDI
E91-4838	INPUT OUTPUT LIST
E22-1020	HIGH PRESSURE CORE SPRAY PROCESS DIAGRAM
D-302-791	EMERGENCY SERVICE WATER SYSTEM

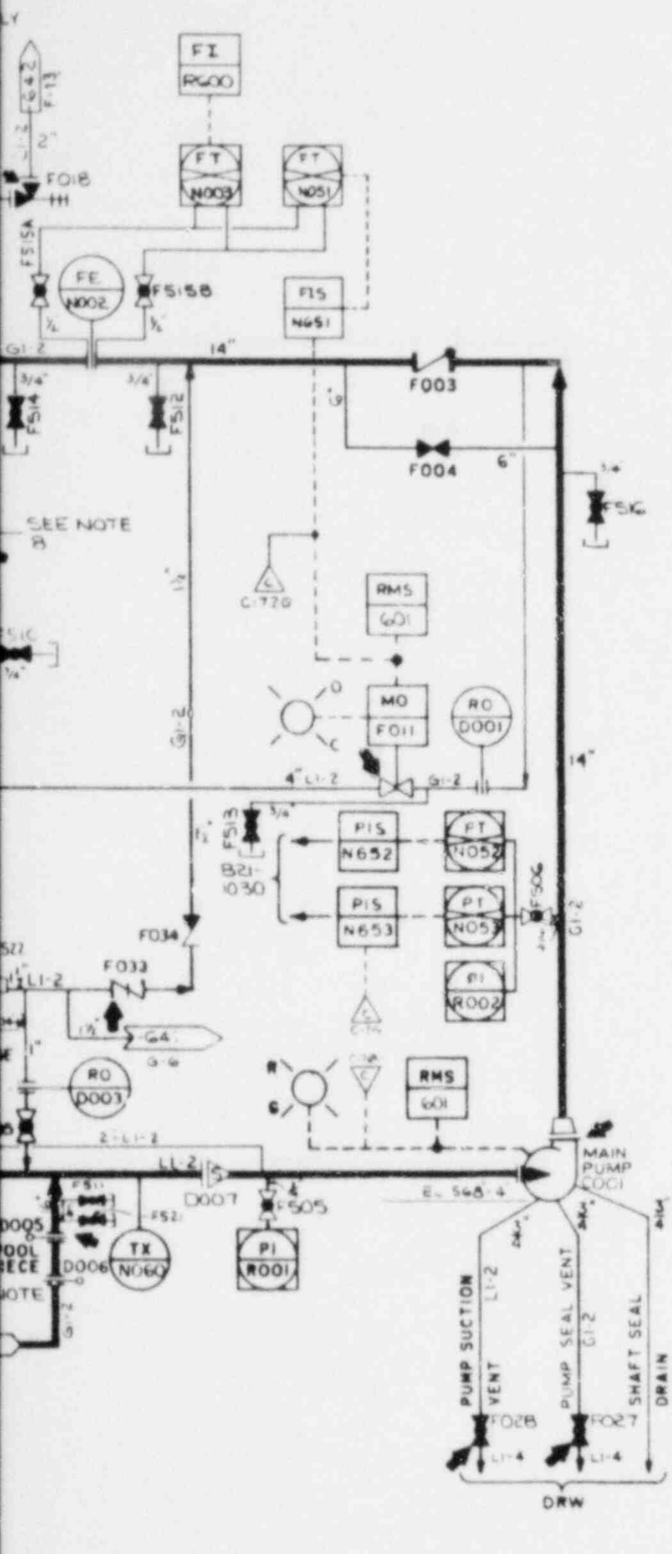
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

High Pressure Core Spray System P & ID

Figure 6.3-7 (Sheet 2 of 2)
(GAI Dwg. D-302-701)



CONTAINMENT
DRYWELL
FLUSHING
WATER SUP
RMS
PIS
N654
HS
N655
AO
F006
-964
A-9
MO
F005
PT
N054
F518
F517
LC
F508
SEE NOTE 9
RO
D002
CORE SPRAY
SPARGER
REACTOR
VESSEL
F007
D1-1
12"
PEN. NO
P112
F504
F509
PI
N050
PIS
N650
F013
F014
MO
F012
D1-2
SEE NOTE 7
F502
F503
F519
F520
-942
A-10
L1-2
RMS
SEE
NOTE 18
RO
D004
-641
F-5
F501
RMS
KEYLOCK
RMS
NORMAL WATER
LEVEL EL 593-0"
MO
F001
F031
TO
DRW
F032
C002
DISCHAR
LINE FILL
PUMP
F507
SUPPRESSION
POOL
E001
PEN. NO
P103
EL 578-7"
GUARD PIPE
SEE NOTE 9
F008
24"
CRW
-642
H-13
SEE
16



NOTES -

1. DELETED
2. CHEMICAL CLEANING CONNECTIONS (I.E. VALVES, ETC.) IF REQUIRED ARE TO BE PROVIDED AS NECESSARY
3. INSTRUMENT LINE DESIGN AND VALVING SHALL BE IN ACCORDANCE WITH INSTRUMENT PIPING SPECIFICATION 4A2-4819
4. DELETED
5. DELETED
6. FOR ADDITIONAL CONTROL ROOM LIGHTS, SYSTEM ALARMS & REMOTE MANUAL SWITCHES, SEE THE LPCS SYSTEM FUNCTIONAL CONTROL DIAGRAM
7. PROVISIONS FOR CONTAINMENT ISOLATION SHALL BE IN ACCORDANCE WITH CURRENT LICENSING REQUIREMENTS
8. THE PACKING GLAND OF VALVE F012 SHALL BE LOCATED ON THE UPSTREAM SIDE OF THE VALVE DISC
9. FLUSHING WATER CONNECTIONS ARE LOCATED AS CLOSE AS PRACTICAL TO VALVES F001 & F006. FLUSHING CONNECTIONS SHALL BE PROVIDED IN ACCORDANCE WITH 4A2-4140. TEMPORARY STRAINER SCREENS SHALL BE PROVIDED ON THE SUCTION SIDE OF ALL PUMPS IN ACCORDANCE WITH 4A2-4140
10. EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY SYSTEM NUMBER (E21) UNLESS OTHERWISE NOTED
11. DELETED
12. DELETED
13. EXCEPT AT POINTS OF CONNECTION WITH THE G.E. SUPPLIED EQUIPMENT OR PIPING, THE PIPING DESIGNER SHALL SIZE PIPES IN CONFORMANCE WITH THE SYSTEM DESIGN SPECIFICATION AND PROCESS DIAGRAM
14. DELETED
15. DELETED
16. SPECTACLE PORTION OF [illegible] TO BE INSTALLED ONLY DURING REFUELING SHUTDOWN
17. DELETED
18. OPTIONAL ORIFICE MAY BE REQUIRED TO PREVENT EXCESSIVE PUMP FLOW. FOR SIZING SEE LPCS SYSTEM PROCESS DIAGRAM
19. ALL MOTOR OPERATED VALVES ARE AC OPERATED UNLESS OTHERWISE NOTED
20. THIS SYSTEM DIAGRAM IS A PHOTOGRAPHIC REPRODUCTION OF GE DRAWING [illegible]. SPECIFIC REVISION IS SHOWN BENEATH GAI TITLE BLOCK.
21. ALL REMOTE MANUAL SWITCHES, ALARMS & INDICATING LIGHTS ARE LOCATED ON H13P601 UNLESS OTHERWISE NOTED
22. FOR CONTROL ROOM, LOCAL OR REMOTE PANEL & RACK I.D. NUMBERS FOR INSTRUMENTS SEE INSTRUMENT INDEX

REFERENCES

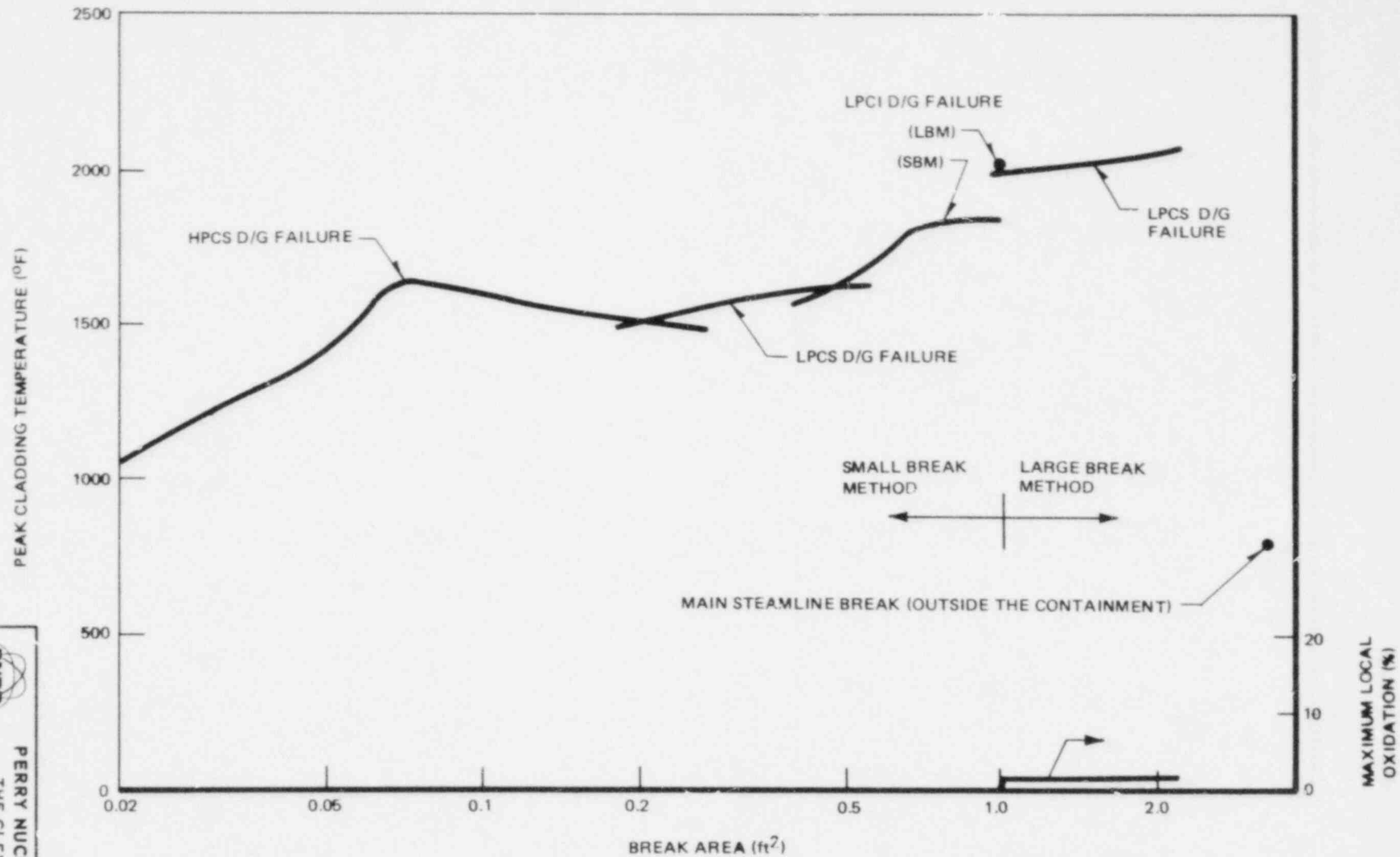
D-302-641	RHR SYSTEM E12
D-302-642	RHR SYSTEM E12
C91-4830	PROCESS COMPUTER SYSTEM INPUT OUTPUT LIST
D-302-867	LEAK DETECTION SYSTEM E31
D-302-864	LEAK DETECTION SYSTEM E31
B21-1030	NUCLEAR BOILER SYSTEM FCD
4A2-4730	EMERGENCY EQUIPMENT COOLING WATER
E21-1020	LOW PRESSURE CORE SPRAY PROCESS DIAGRAM

PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Low Pressure Core Spray System P & ID

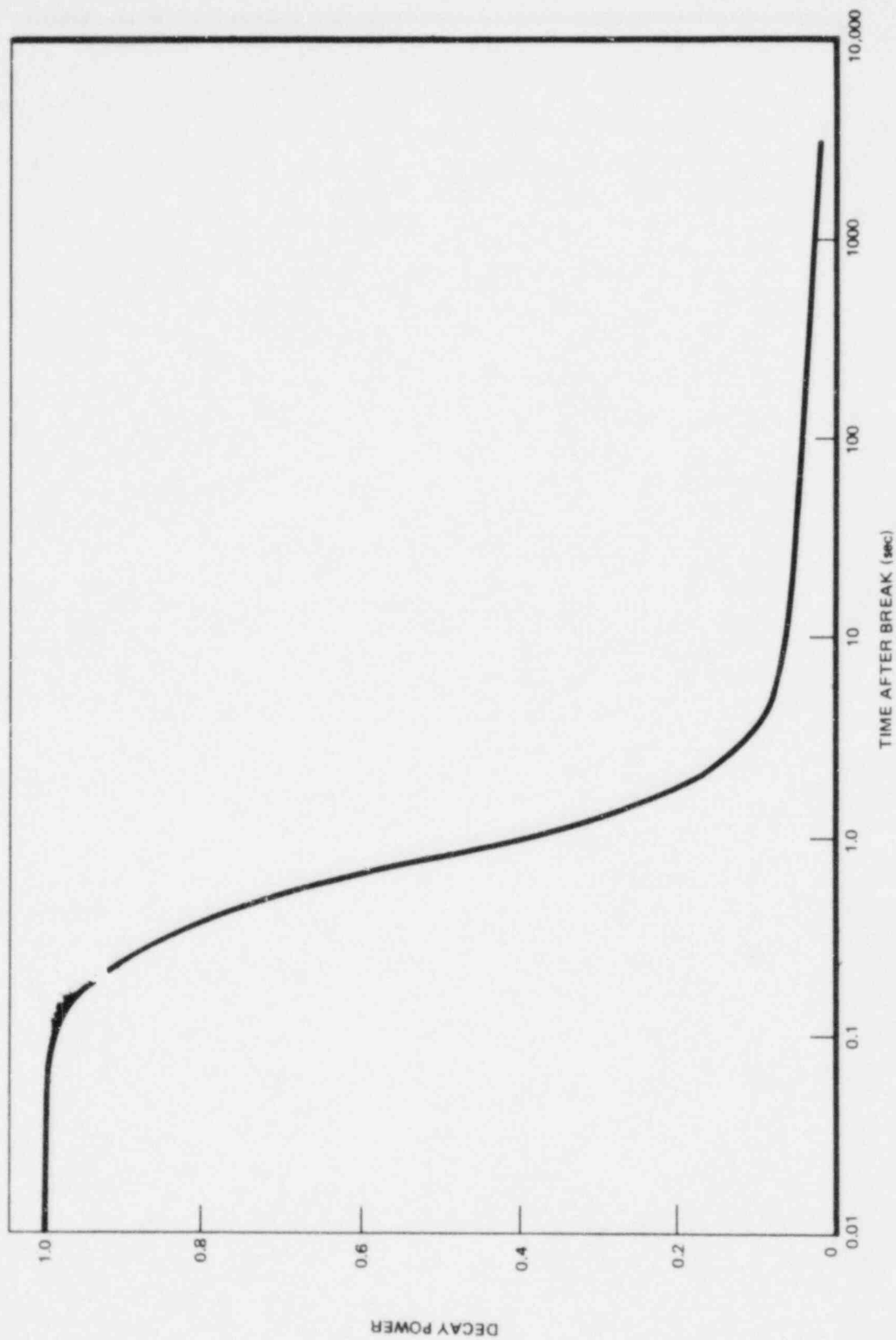
Figure 6.3-8
(GAI Dwg. D-302-705)



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Peak Cladding Temperature and Maximum Local Oxidation Versus Break Area

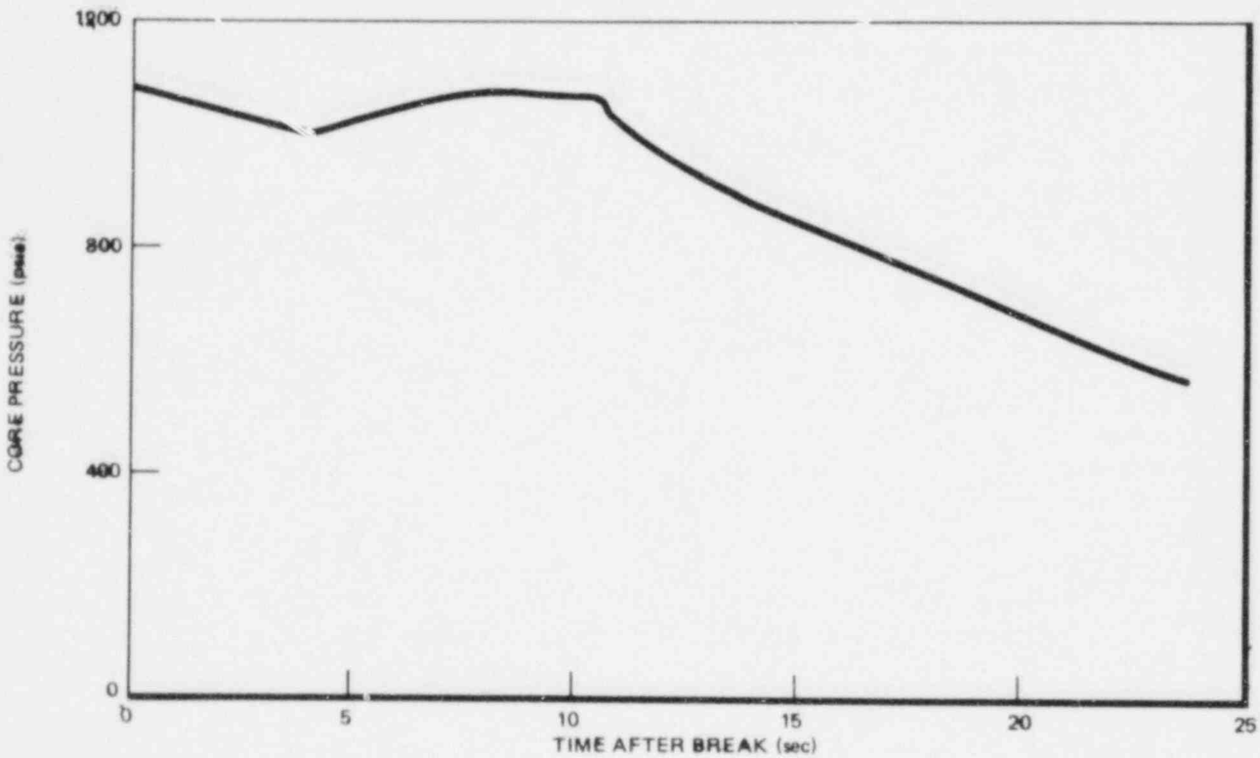
Figure 6.3-9



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Normalized Power Versus Time

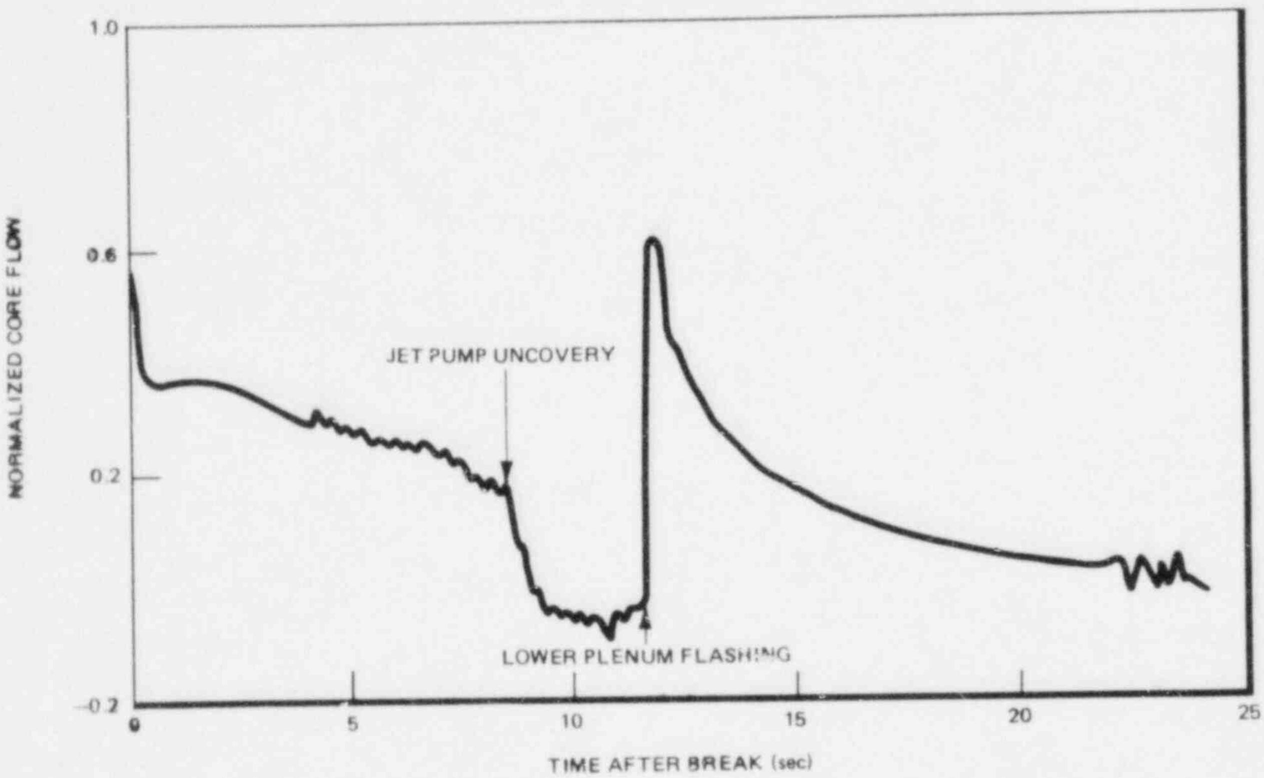
Figu-e 6.3-10



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Core Average Pressure Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

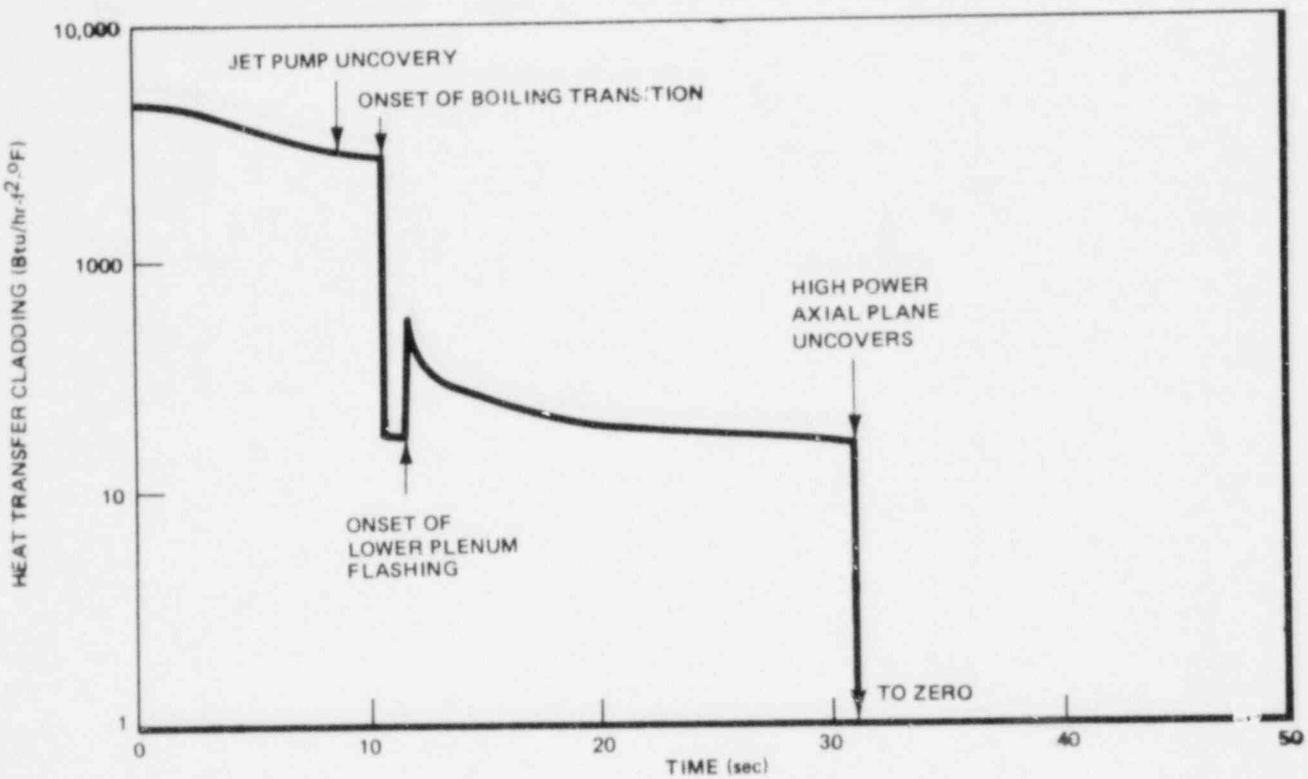
Figure 6.3-11



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Normalized Core Average Inlet Flow Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

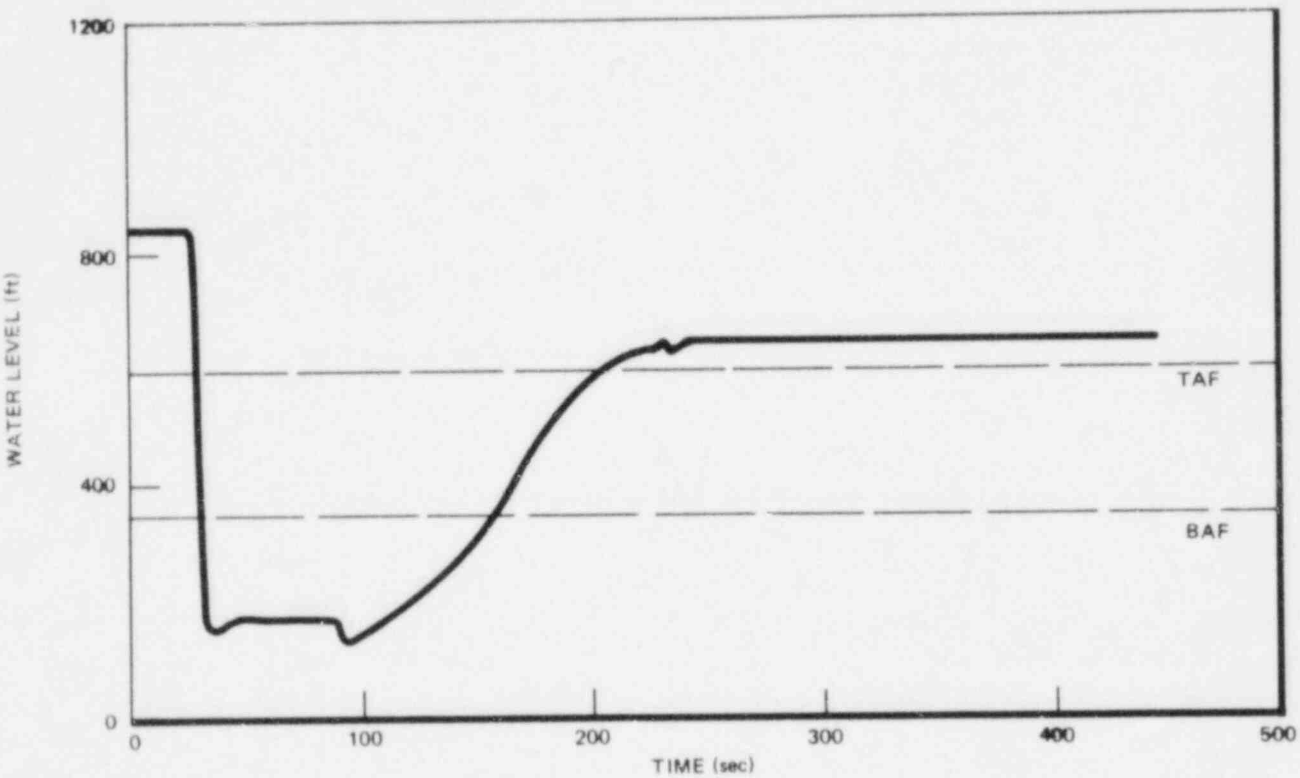
Figure 6.3-12



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Fuel Rod Convective Heat Transfer Coef. Vs. Time After Break (Large Break Model) DBA, Recirc. Suction Break, LPCS D-G Failure

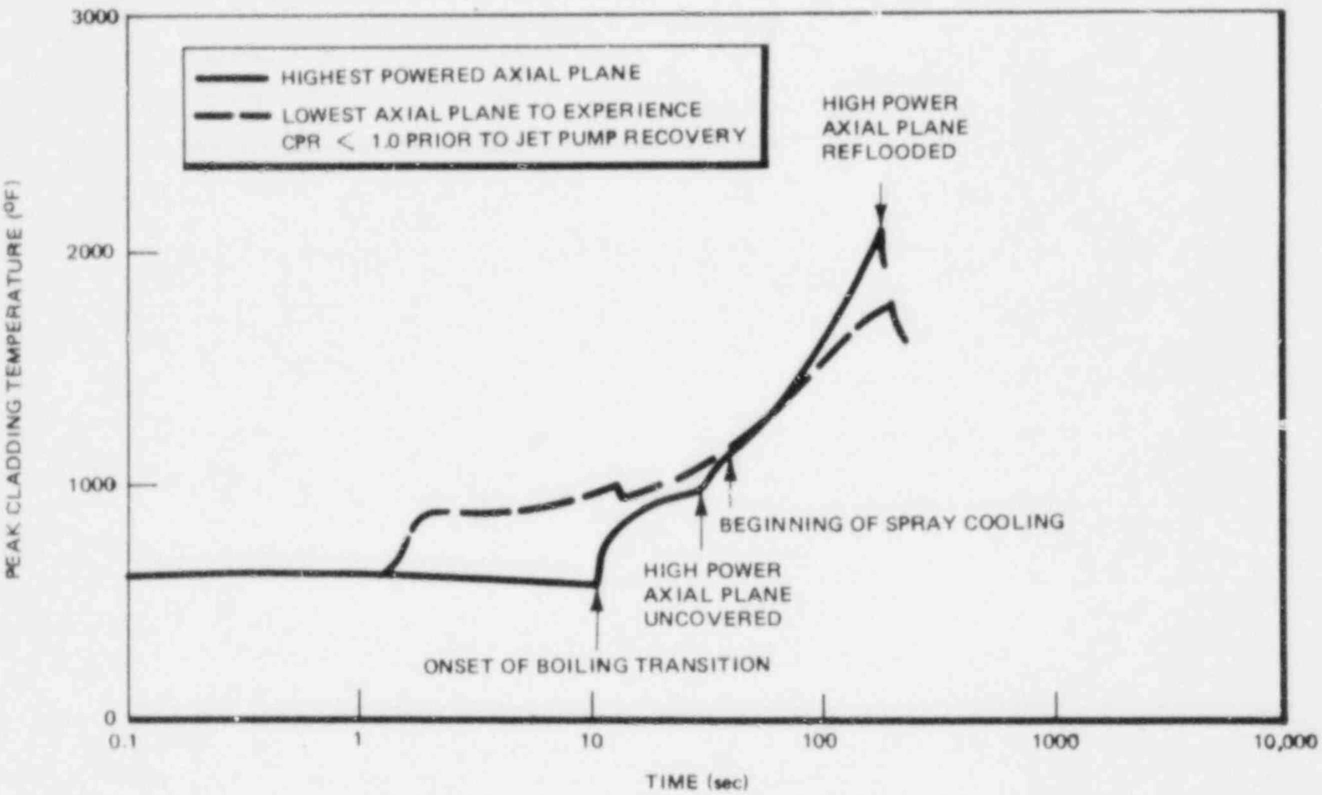
Figure 6.3-13



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

Figure 6.3-14



PERRY NUCLEAR POWER PLANT
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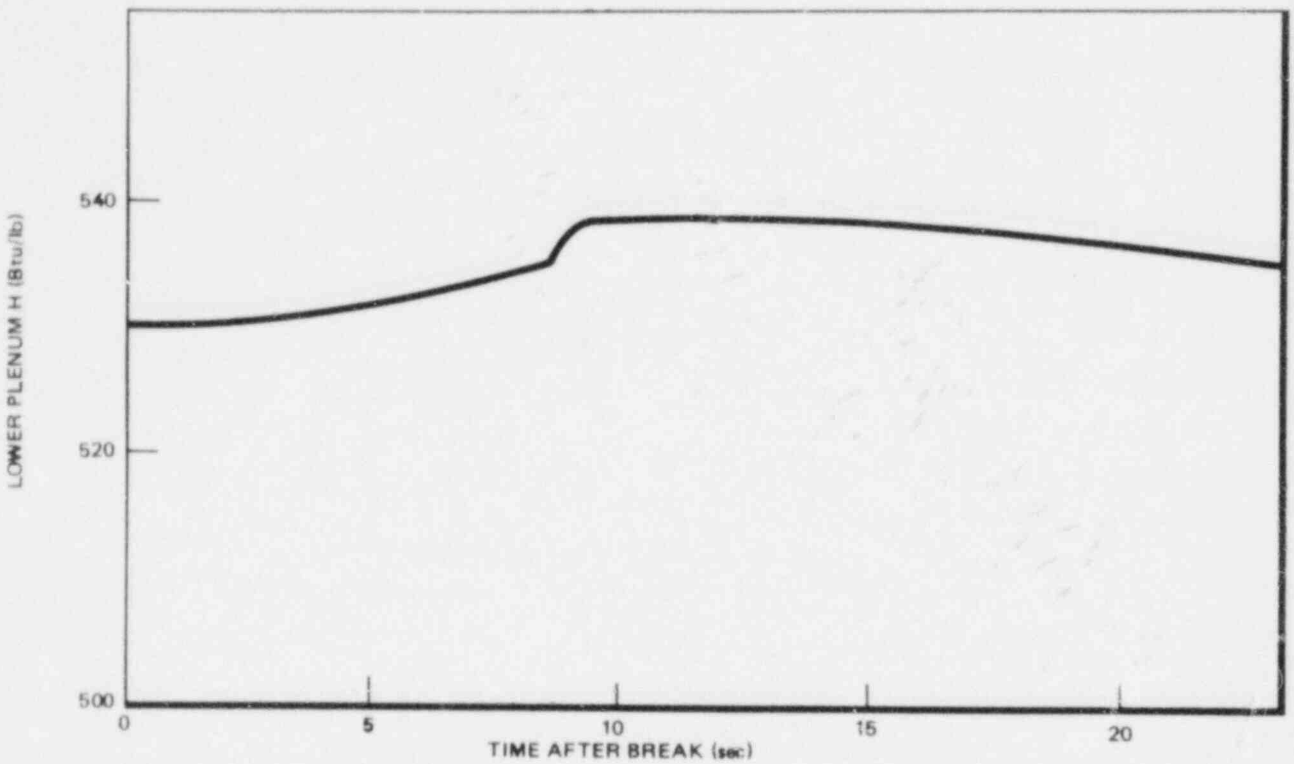
Peak Cladding Temperature Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

Figure 6.3-15



PERRY NUCLEAR POWER PLANT
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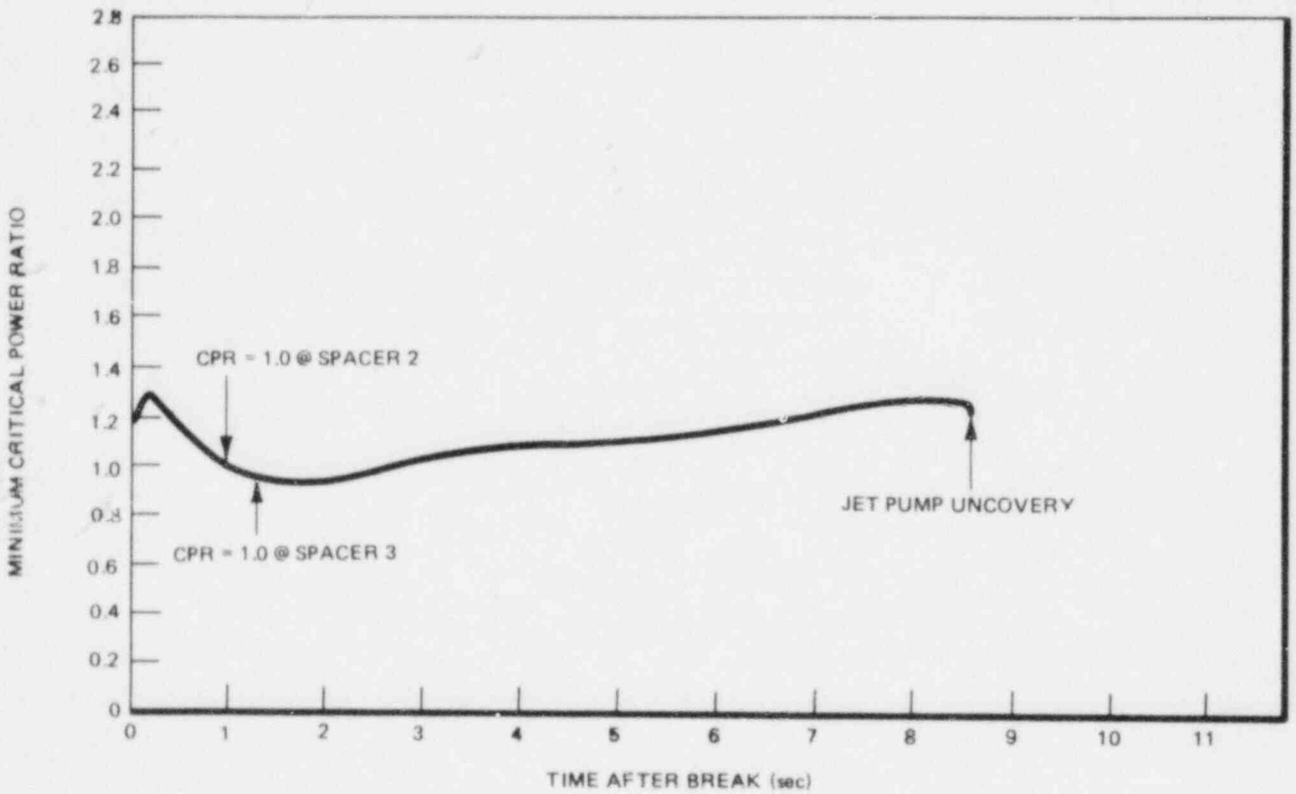
ILLUMINATING COMPANY

Core Inlet Enthalpy Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

Figure 6.3-16



PERRY NUCLEAR POWER PLANT
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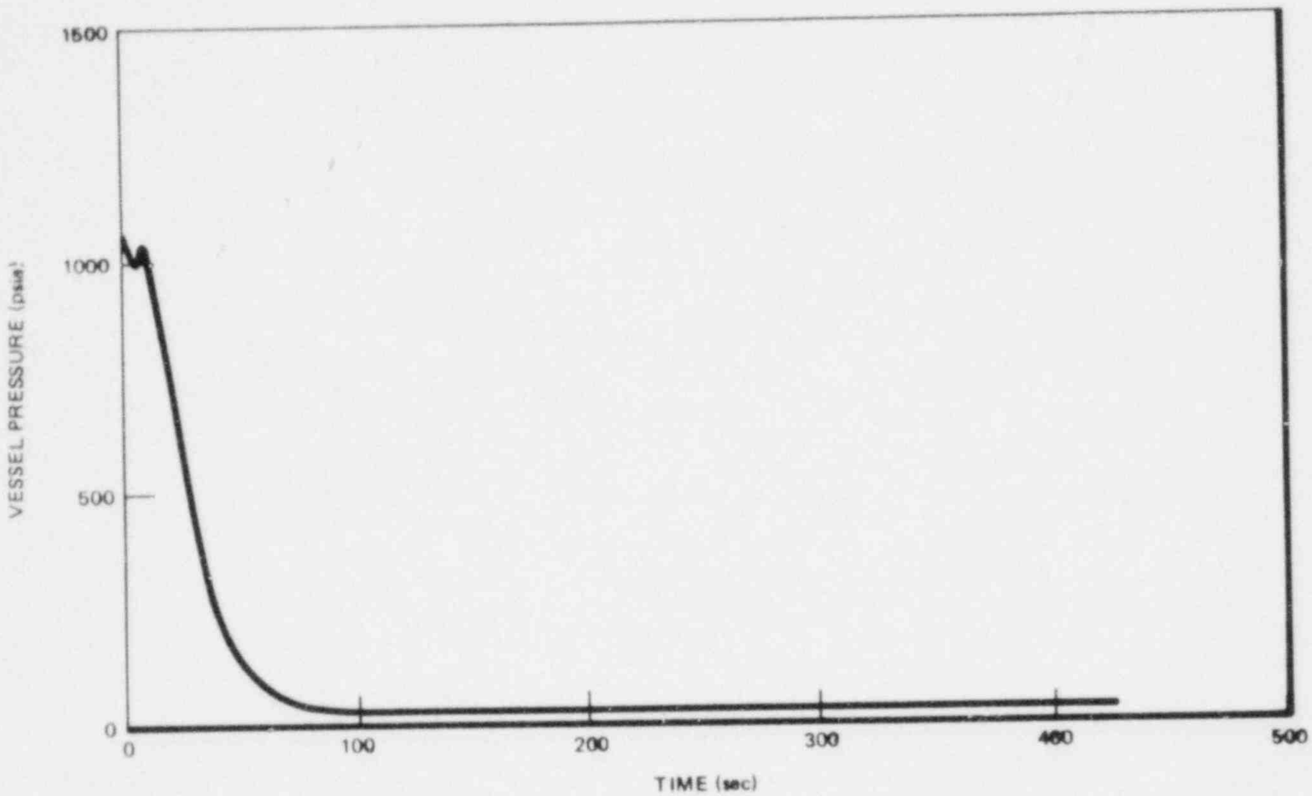
ILLUMINATING COMPANY

Minimum Critical Power Ratio Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

Figure 6.3-17



PERRY NUCLEAR POWER PLANT
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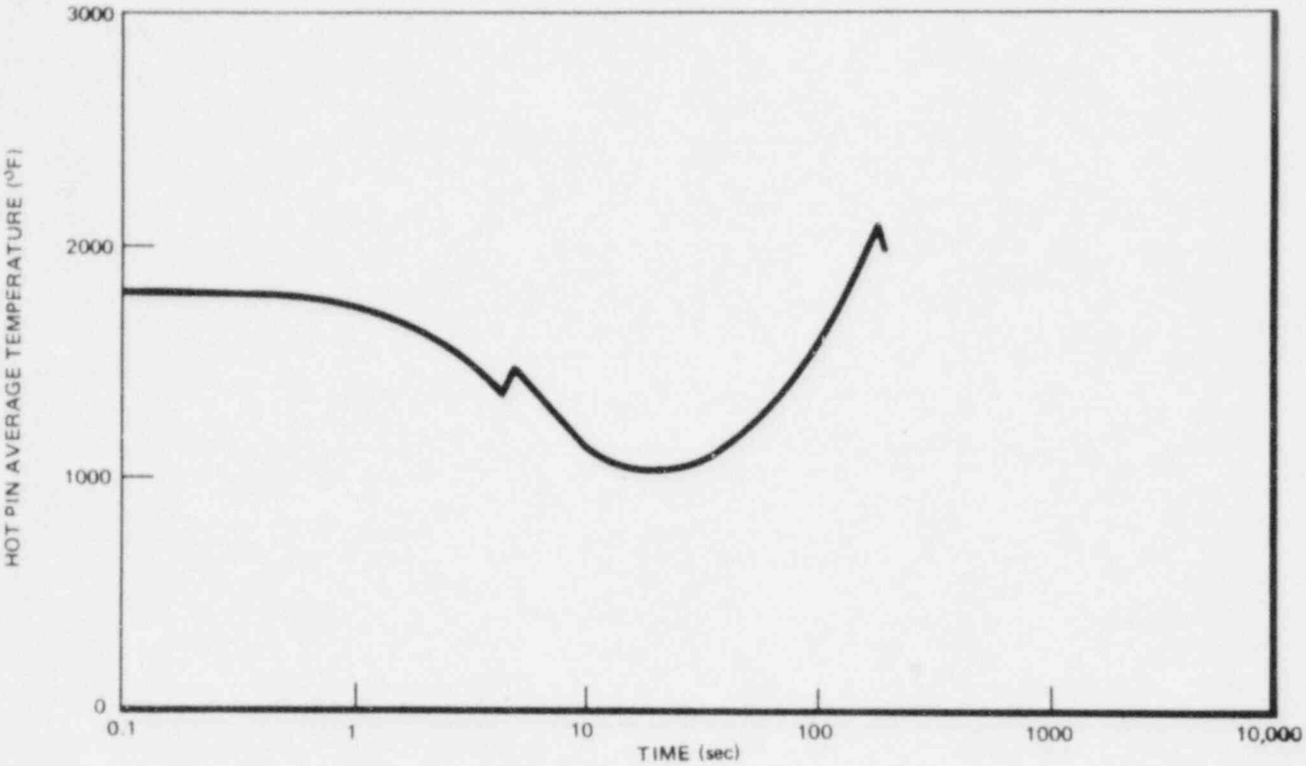
ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

Figure 6.3-18



PERRY NUCLEAR POWER PLANT
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Hot Pin Fuel Average Temperature Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

Figure 6.3-19

PERRY NUCLEAR POWER PLANT
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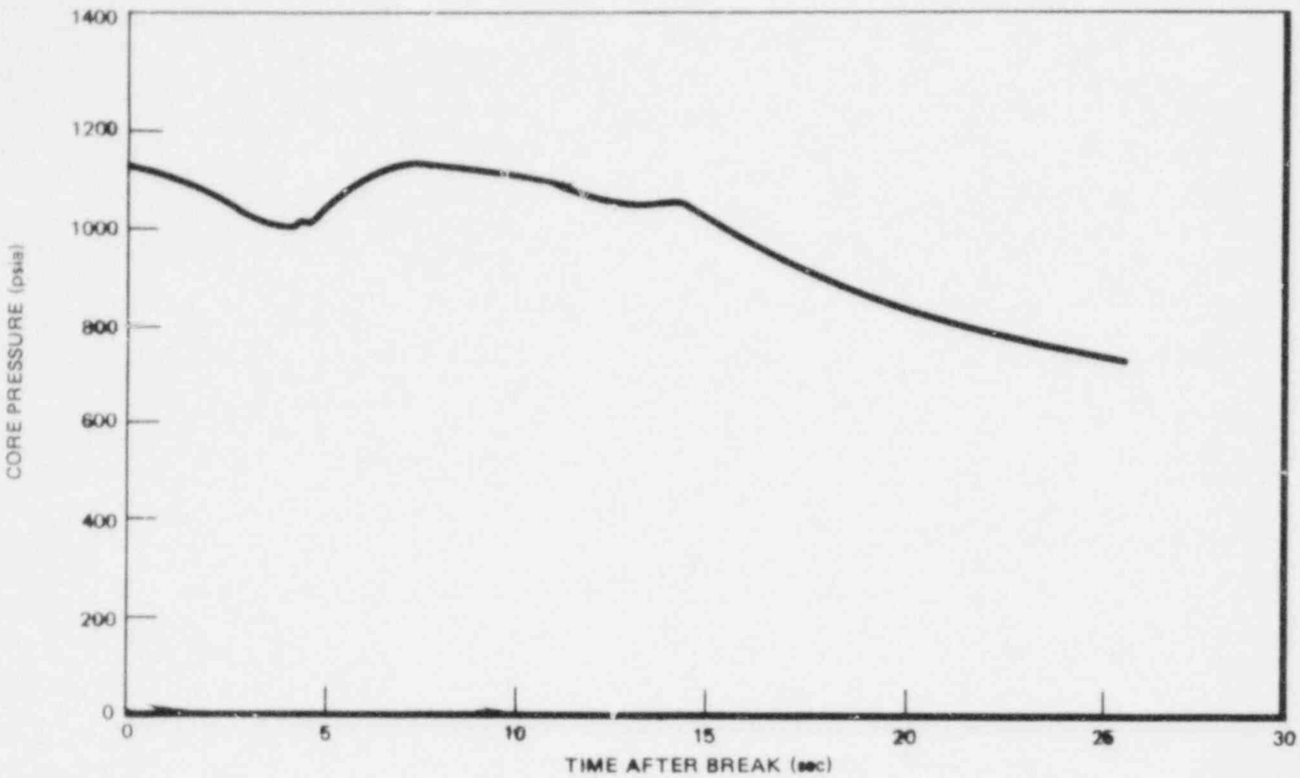
Hot Pin Pressure Vs. Time After Break (Design Basis Accident, Recirculation Suction Break, LPCS Diesel-Generator Failure)

Figure 6.3-20



PERRY NUCLEAR POWER PLANT
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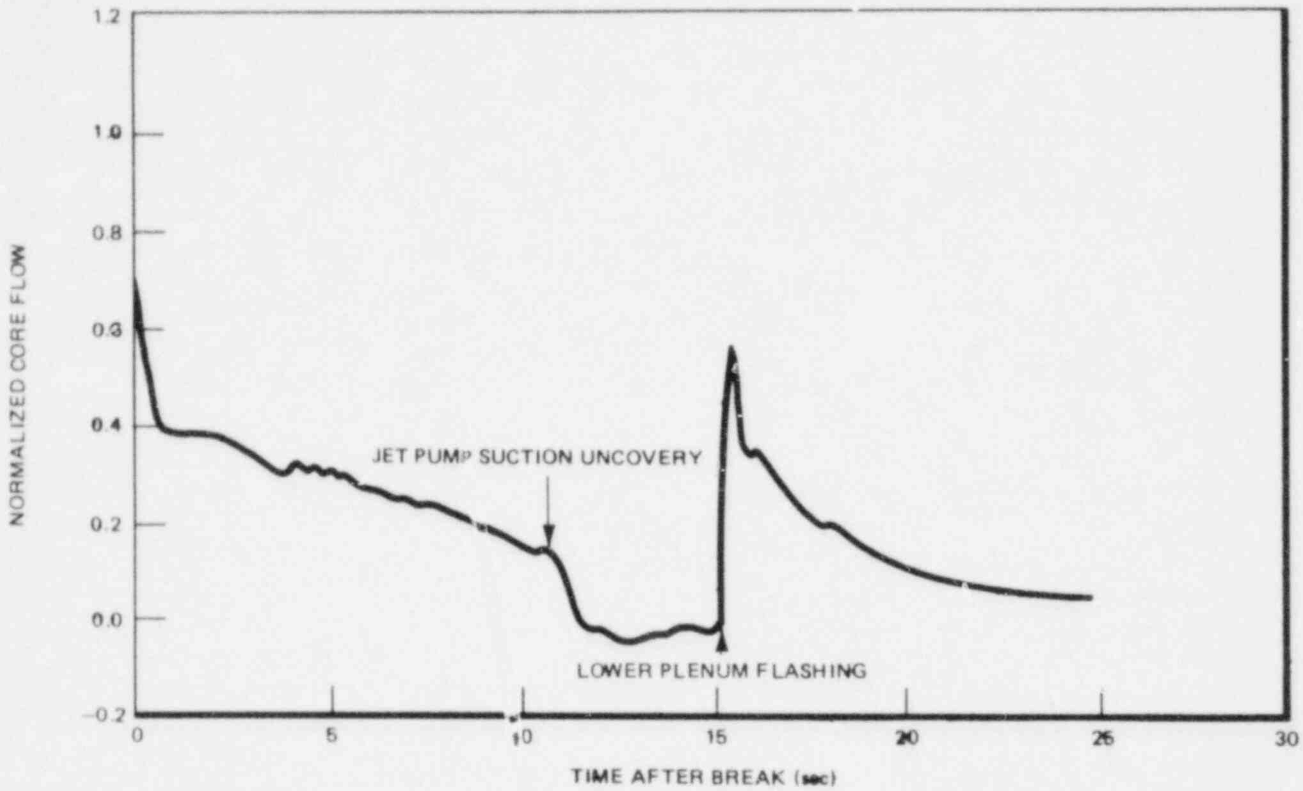
ILLUMINATING COMPANY

Core Average Pressure Vs. Time After Break (80% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

Figure 6.3-21



PERRY NUCLEAR POWER PLANT
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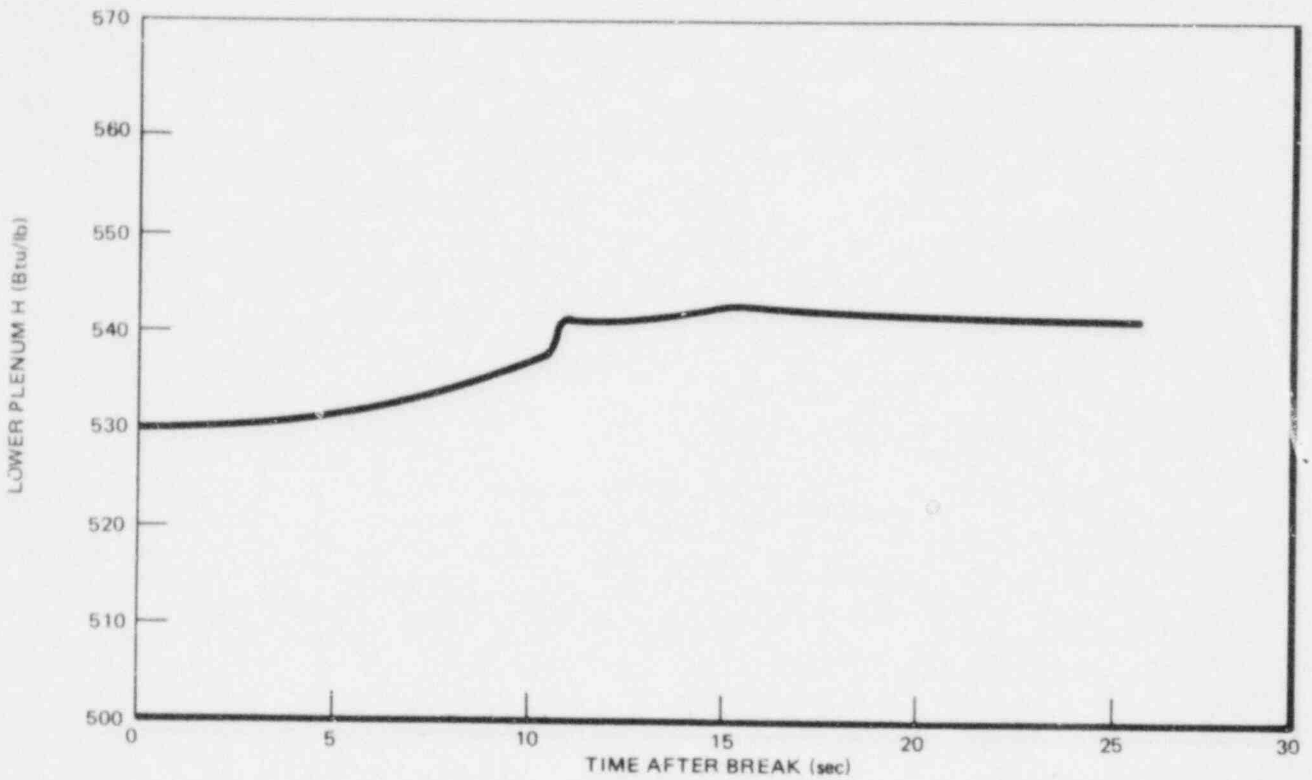
ILLUMINATING COMPANY

Normalized Core Average Inlet Flow Vs. Time After Break (80% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

Figure 6.3-22



PERRY NUCLEAR POWER PLANT
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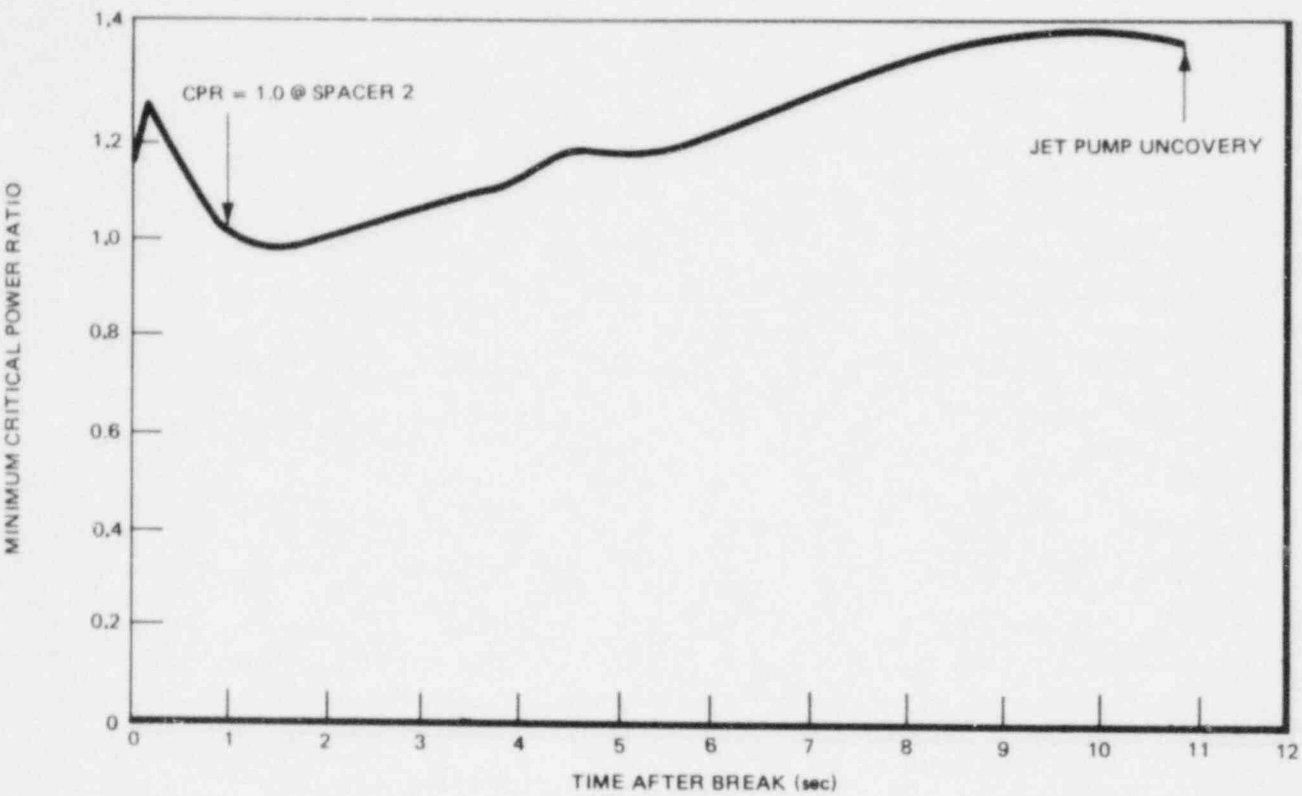
ILLUMINATING COMPANY

Core Inlet Enthalpy Vs. Time After Break (80% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

Figure 6.3-23



PERRY NUCLEAR POWER PLANT
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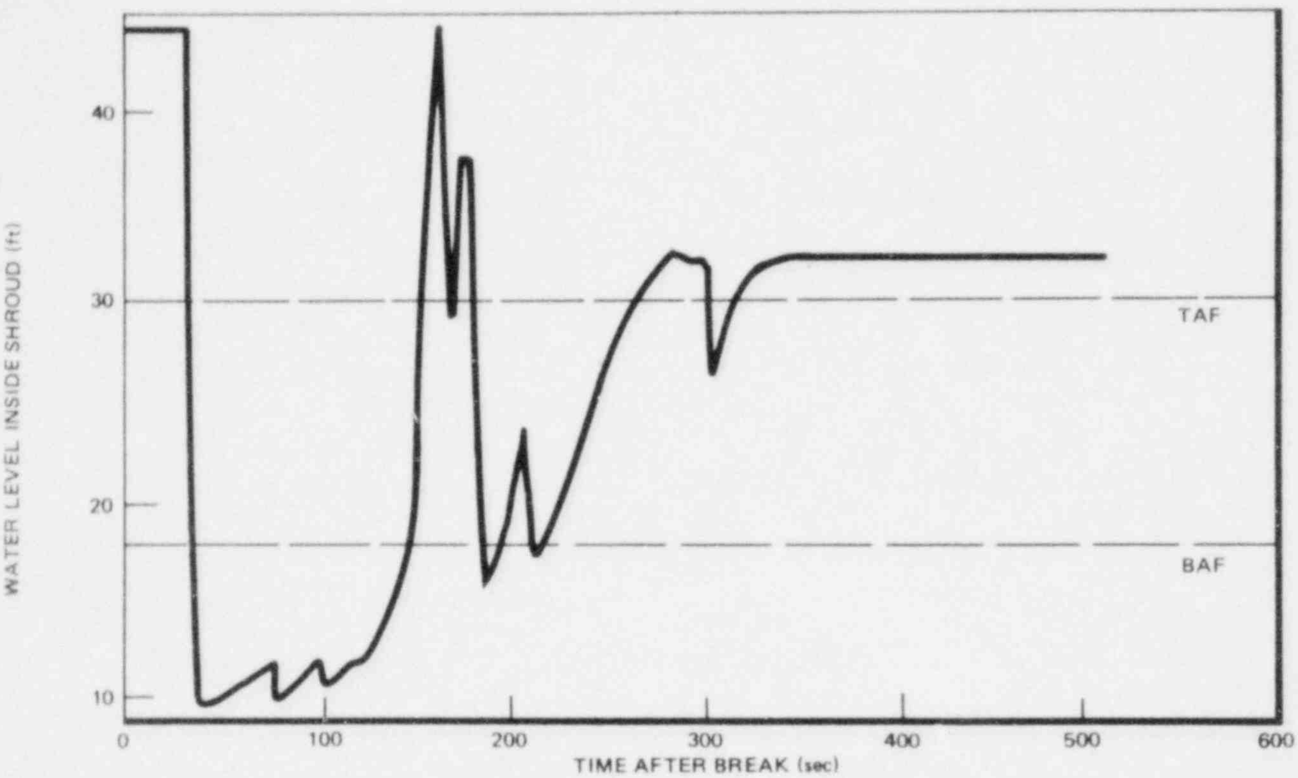
Minimum Critical Power Ratio Vs. Time After Break (80% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

Figure 6.3-24



PERRY NUCLEAR POWER PLANT
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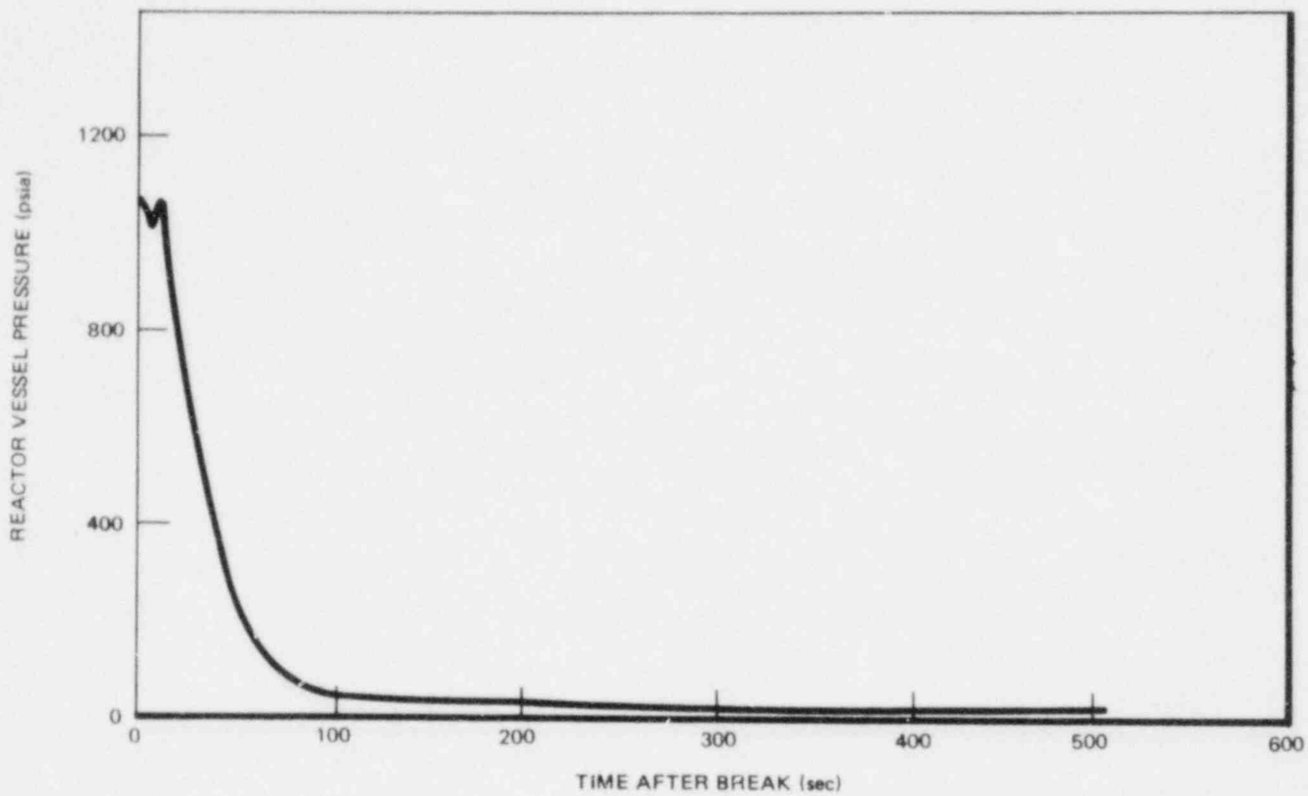
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs.
Time After Break (60% Design Basis
Accident, Recirculation
Suction Break, LPCI
Diesel-Generator Failure)

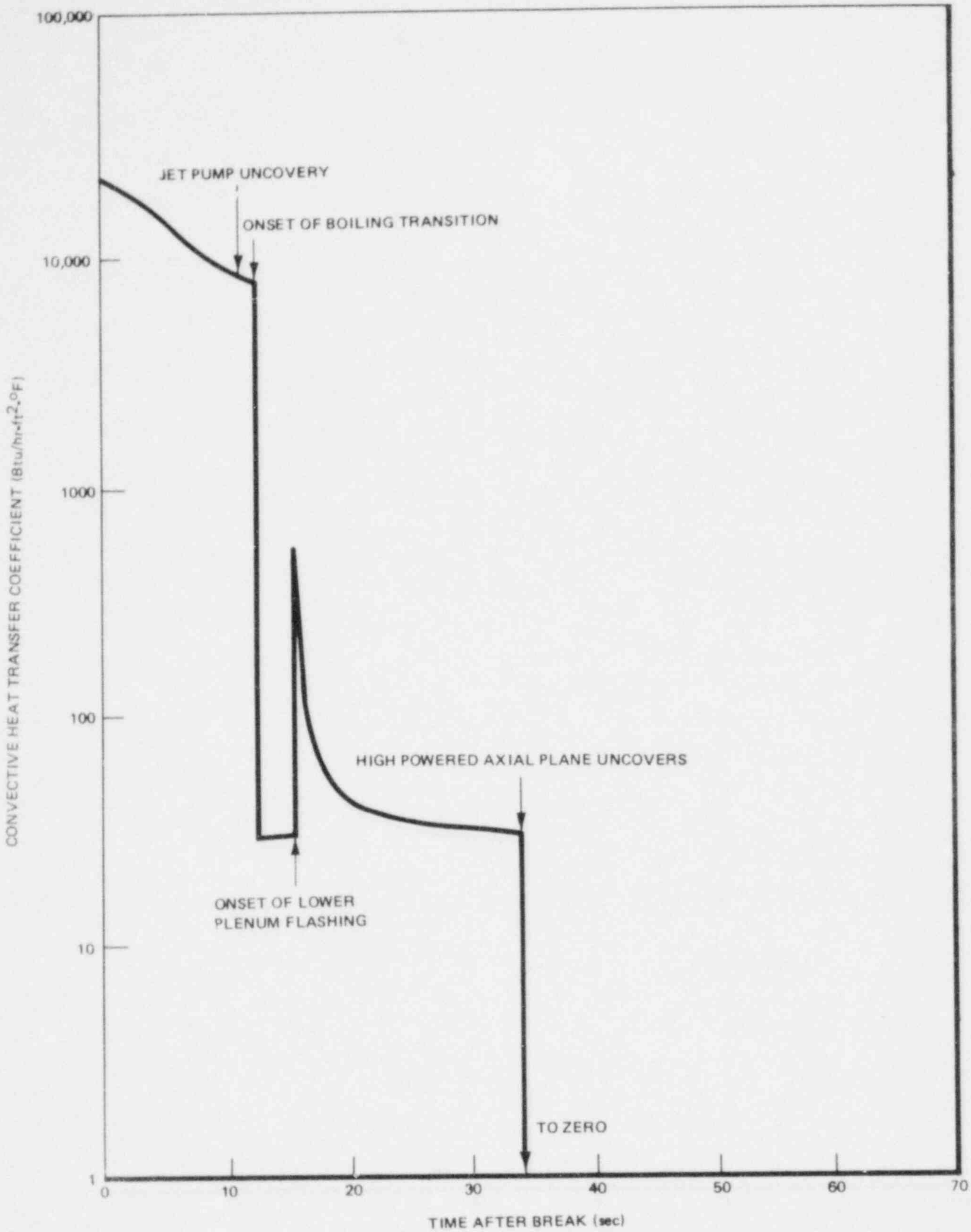
Figure 6.3-25



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break (60% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

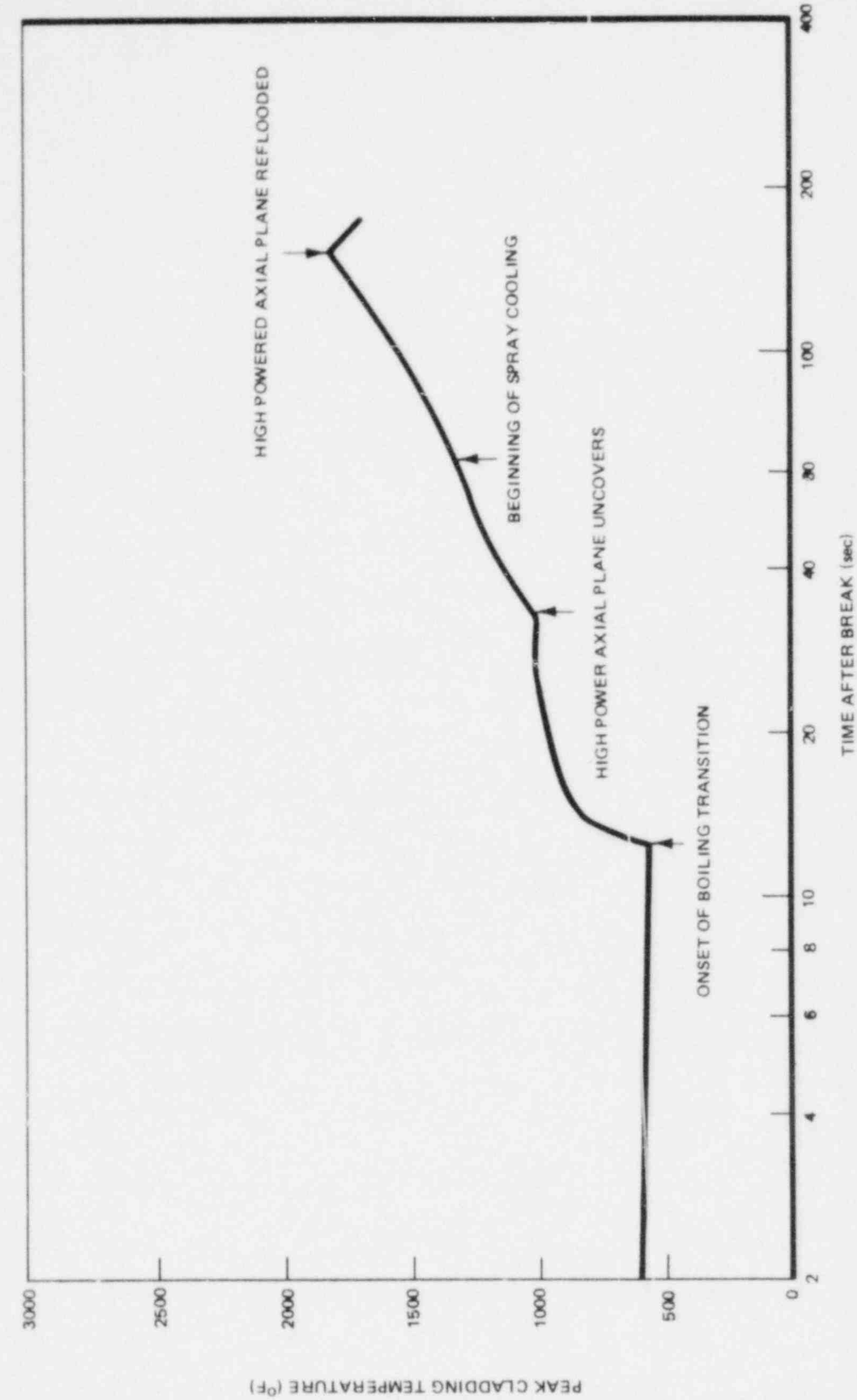
Figure 6.3-26



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Fuel Rod Convective Heat Transfer Coef. Vs. Time After Break (Large Break Model) [80% DBA, Recirc. Suction Break, LPCI D-G Failure]

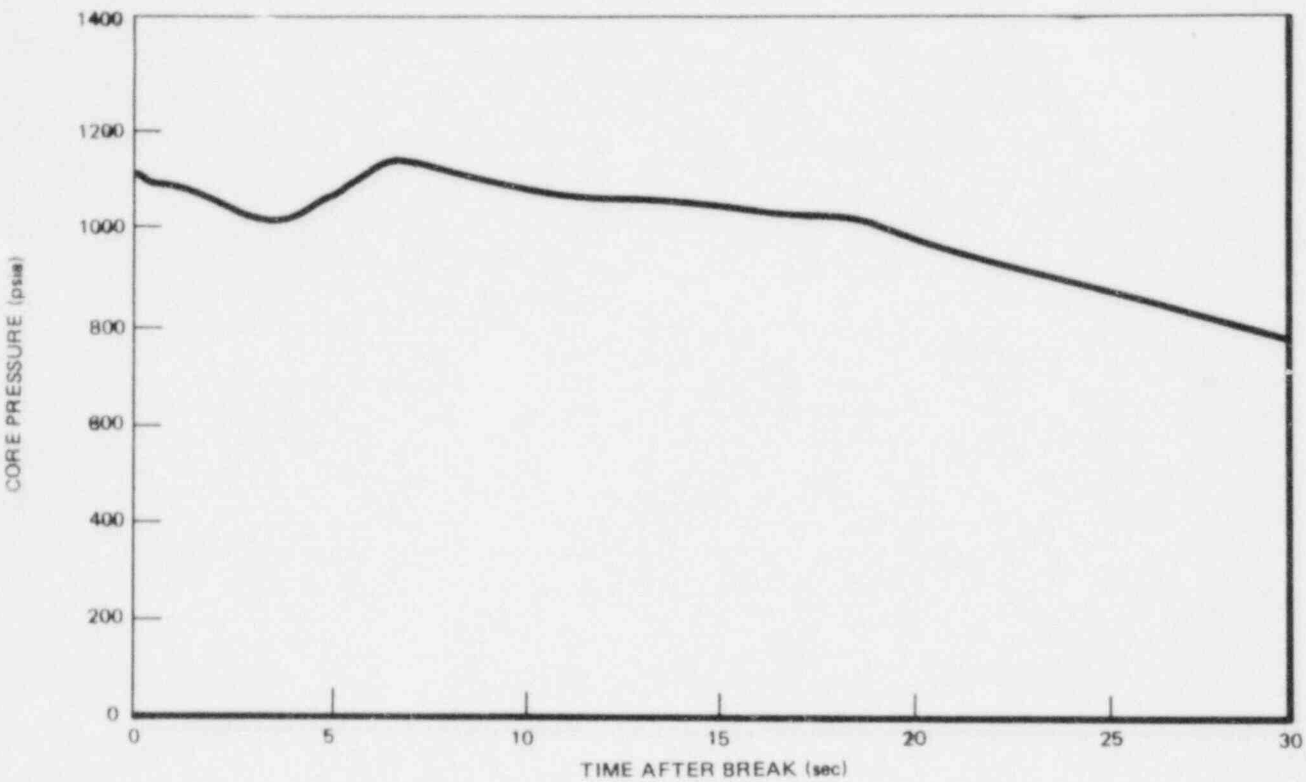
Figure 6.3-27



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Peak Cladding Temperature Vs.
Time After Break (80% Design Basis
Accident, Recirculation
Suction Break, LPCI
Diesel-Generator Failure)

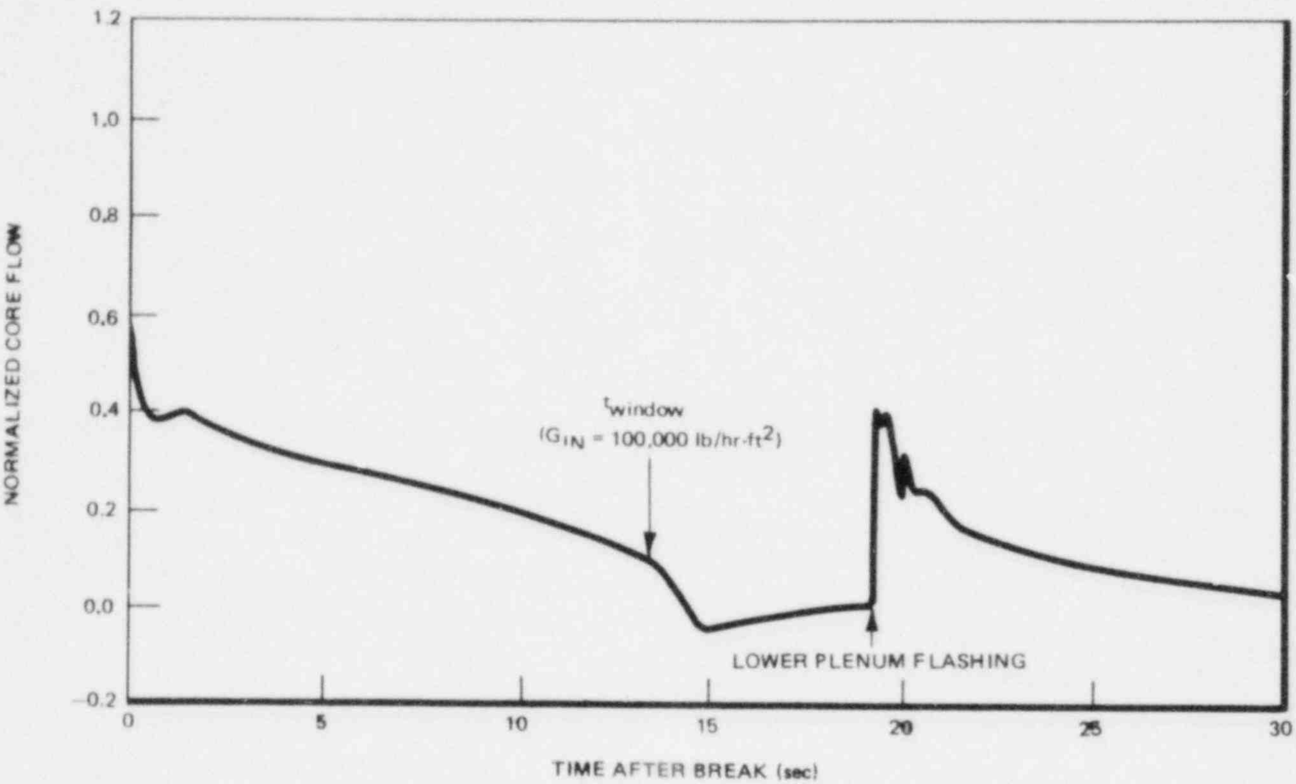
Figure 6.3-28



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Core Average Pressure Vs. Time After Break (60% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

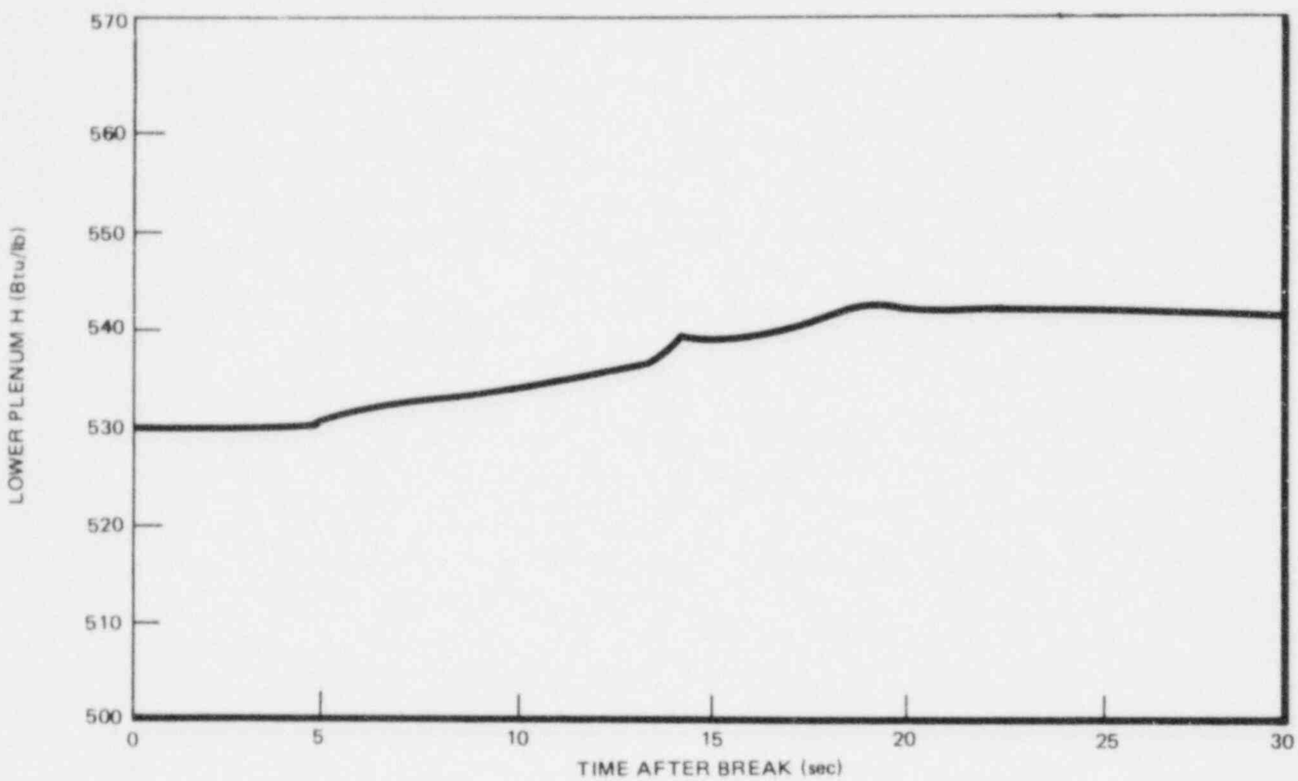
Figure 6.3-29



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Normalized Core Average Inlet Flow Vs. Time After Break (60% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

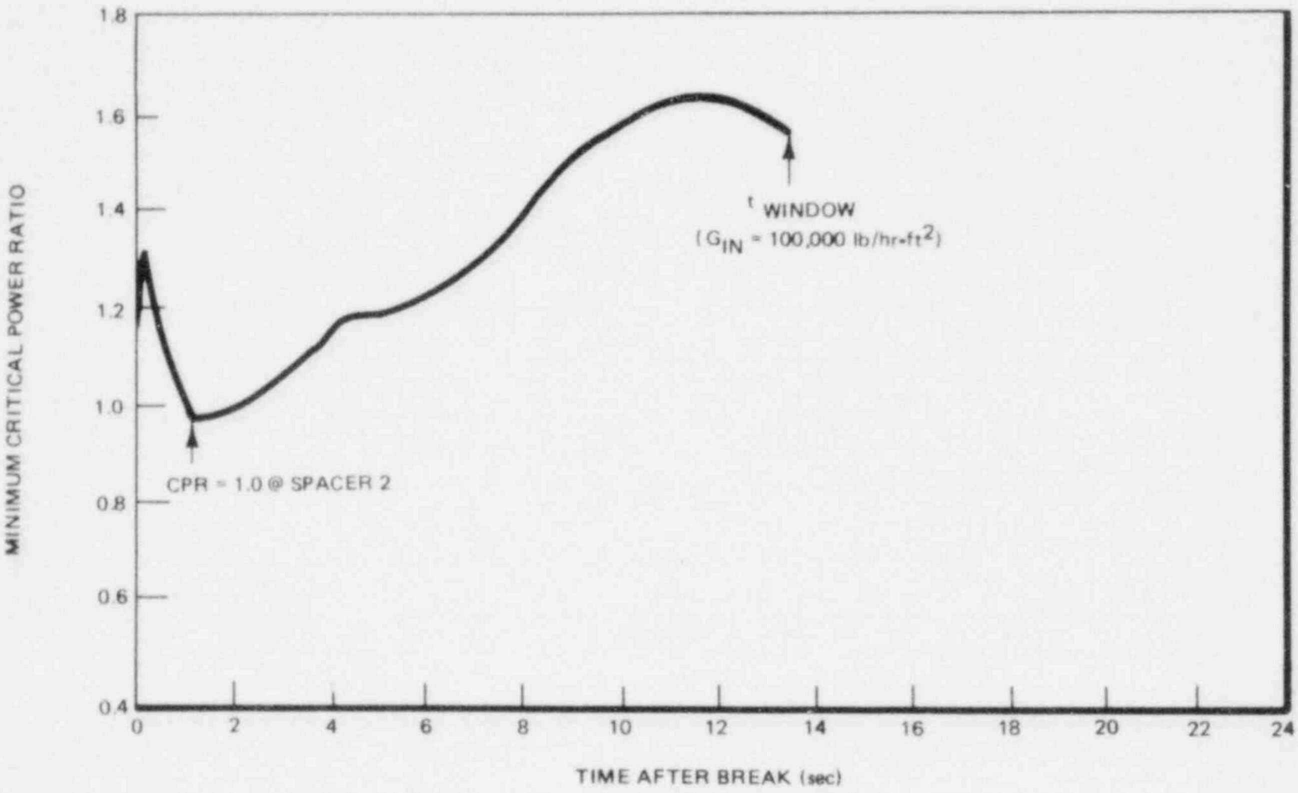
Figure 6.3-30



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Core Inlet Enthalpy Vs. Time After Break (60% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

Figure 6.3-31



PERRY NUCLEAR POWER PLANT
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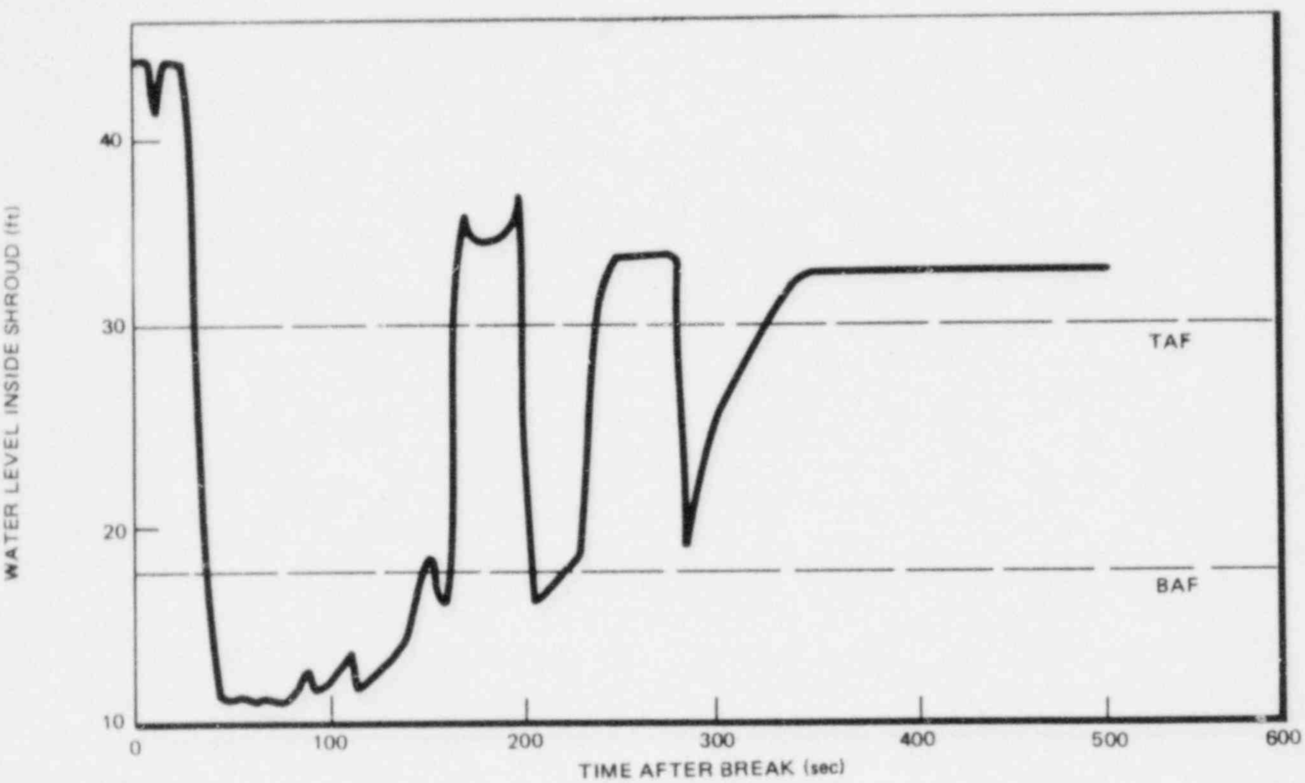
ILLUMINATING COMPANY

Minimum Critical Power Ratio Vs. Time After Break (60% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

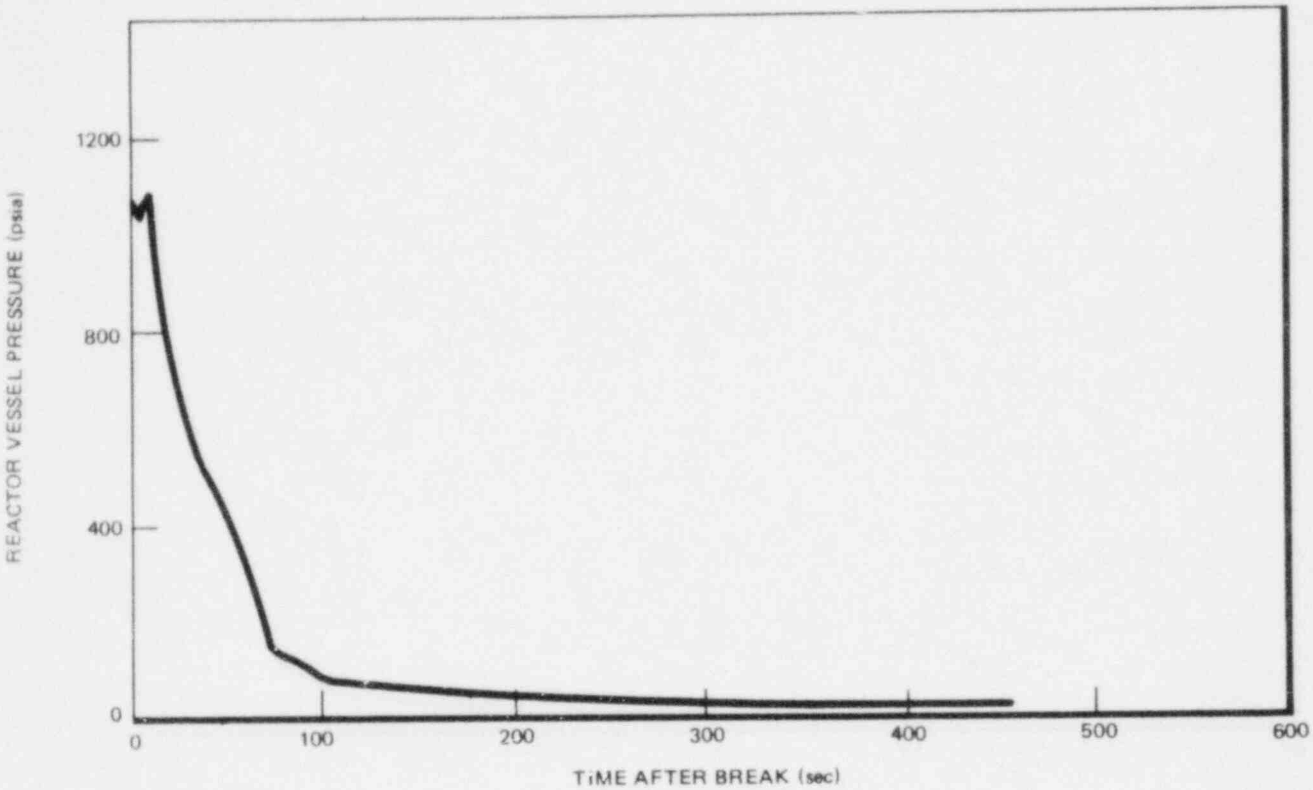
Figure 6.3-32



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break (60% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

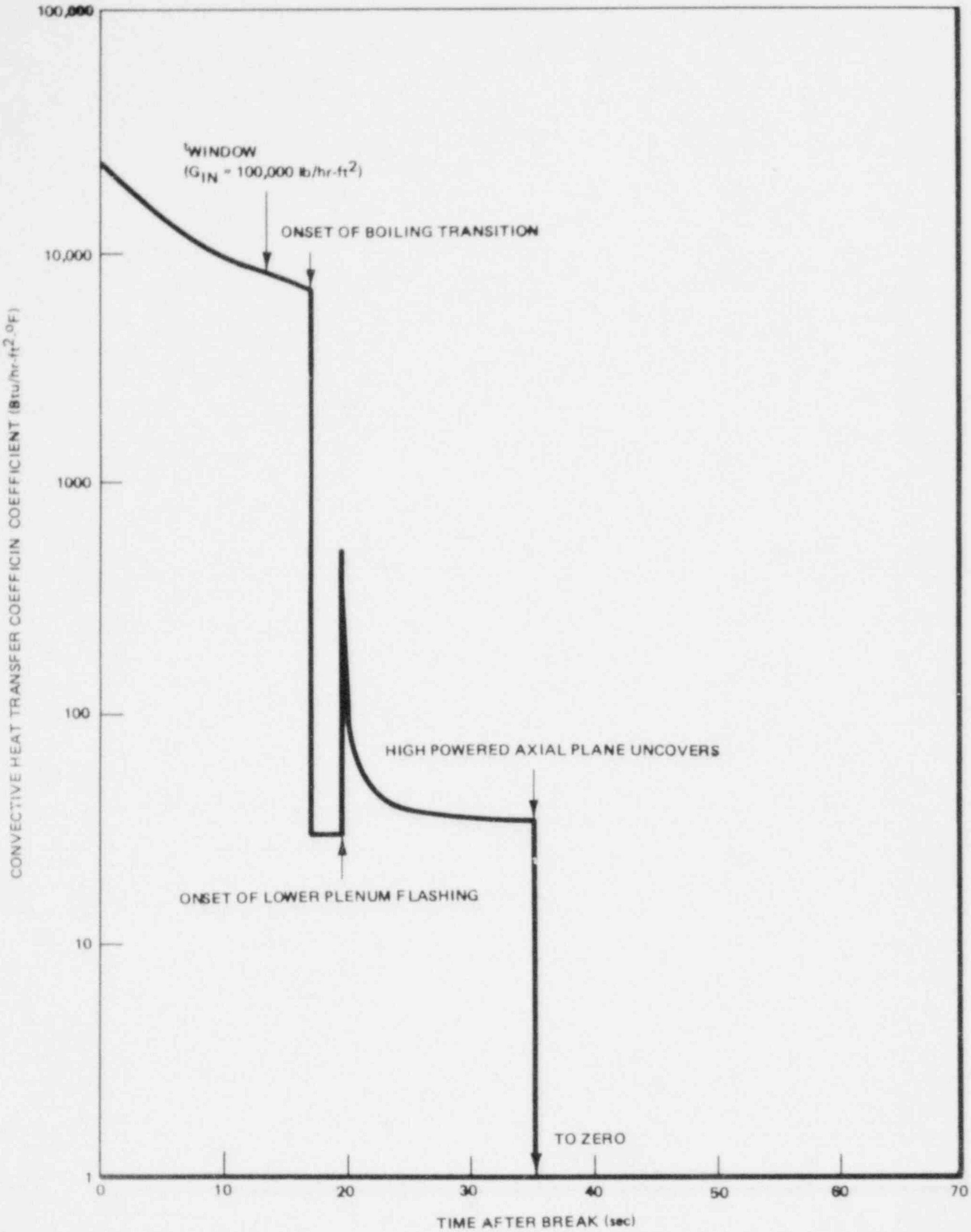
Figure 6.3-33



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break (60% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

Figure 6.3-34



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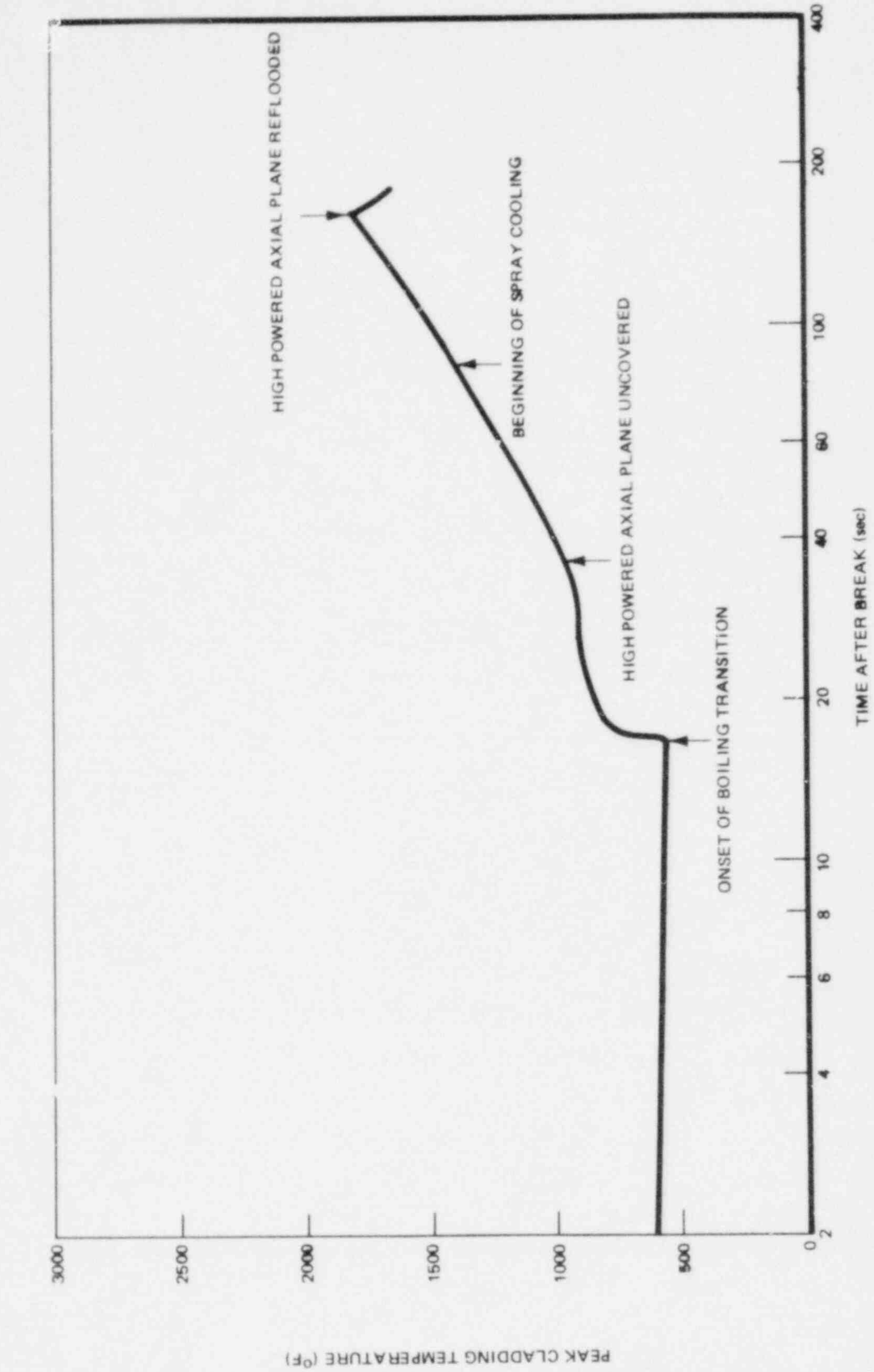
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Fuel Rod Convective Heat Transfer Coef. Vs. Time After Break (Large Break Model) [60% DBA, Recirc. Suction Break, LPCI D-G Failure]

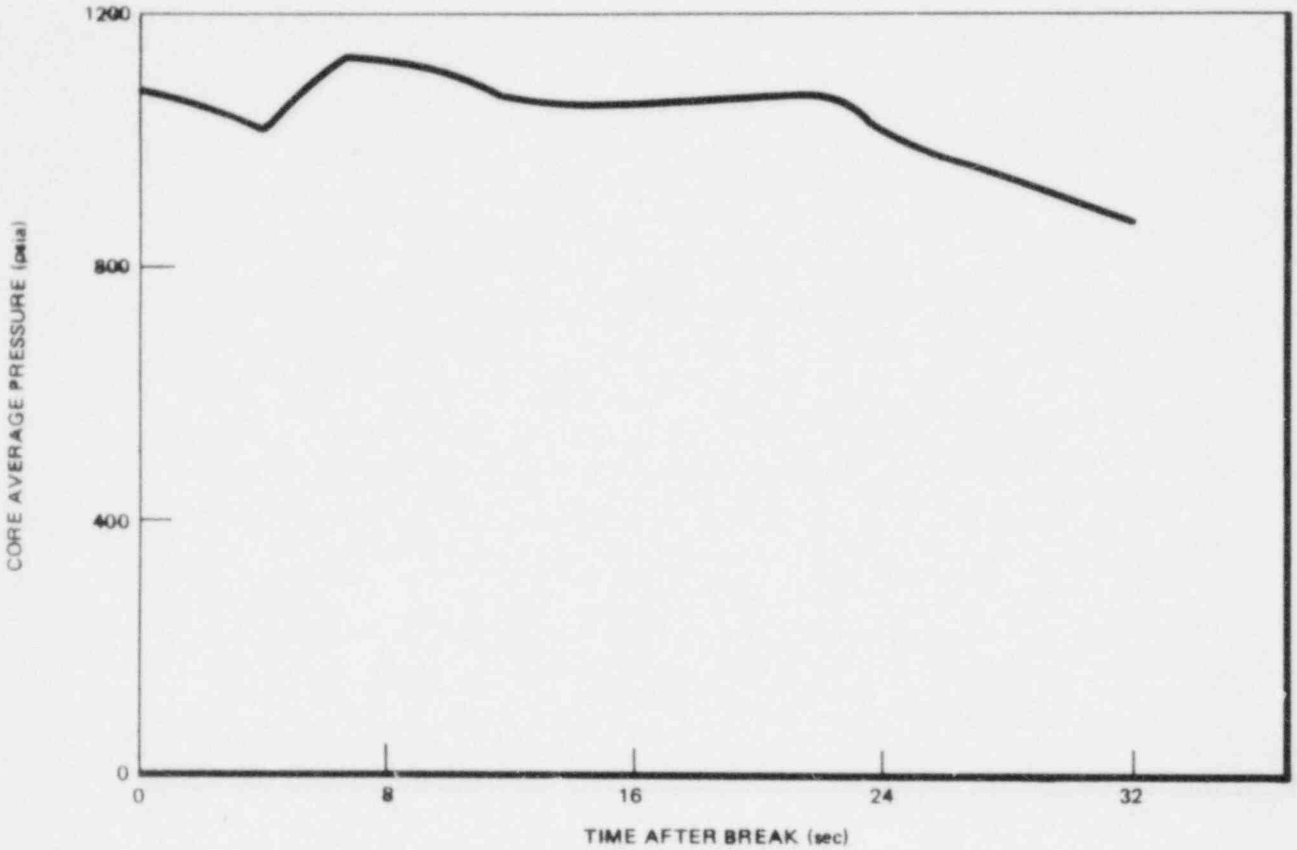
Figure 6.3-35



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Peak Cladding Temperature Vs. Time After Break (60% Design Basis Accident, Recirculation Suction Break, LPCI Diesel-Generator Failure)

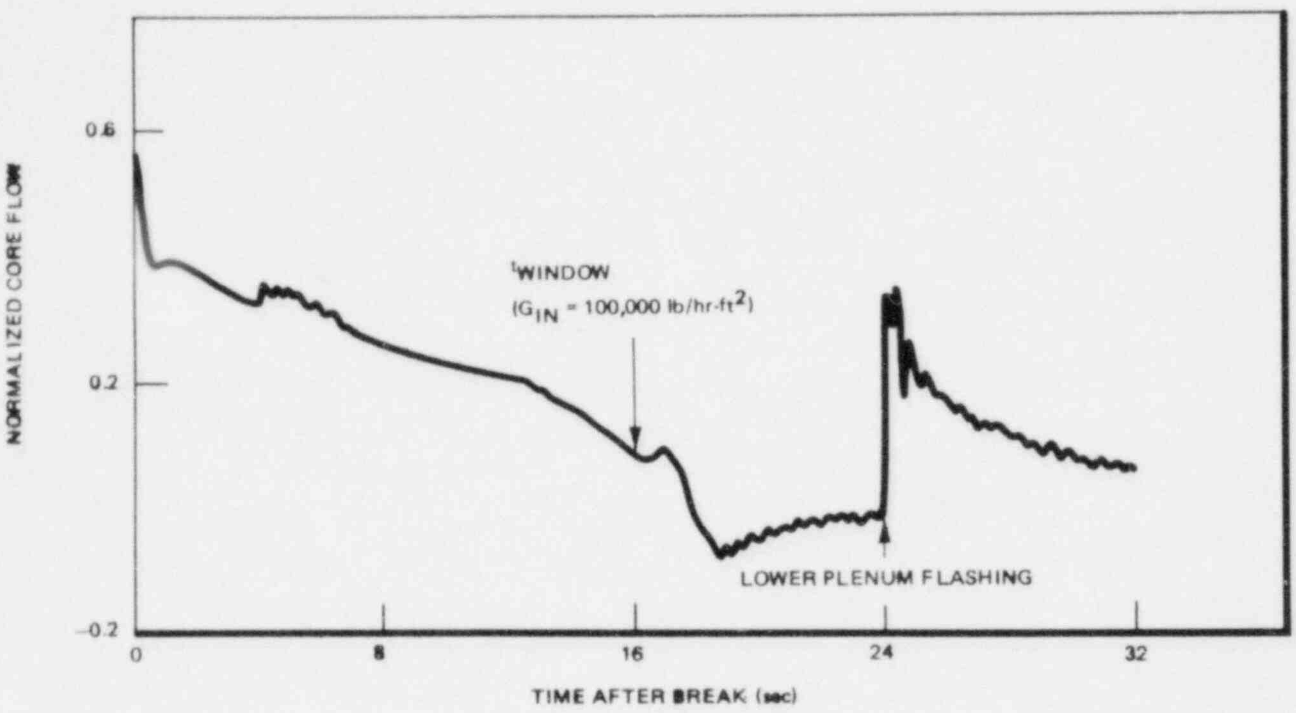
Figure 6.3-36



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Core Average Pressure Vs. Time After Break (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

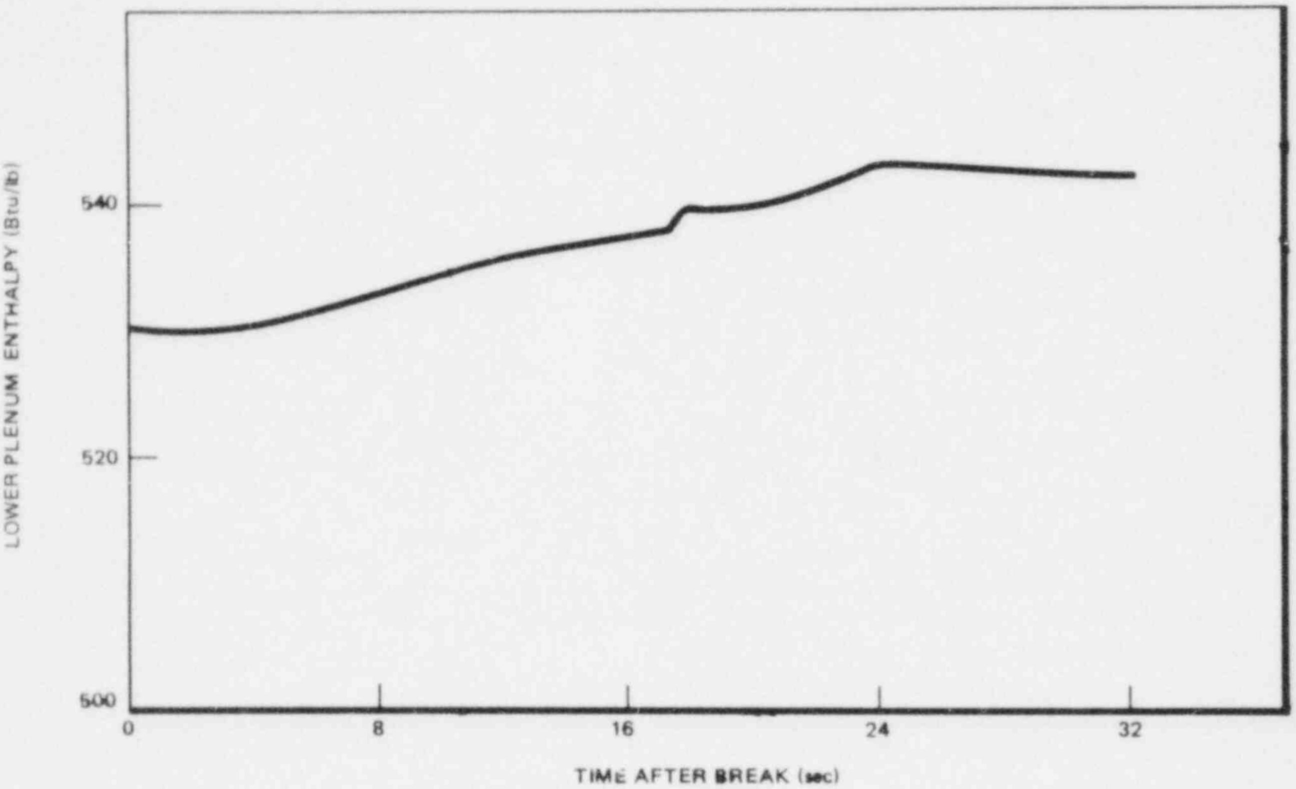
Figure 6.3-37



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Normalized Core Average Inlet Flow Vs. Time After Break (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

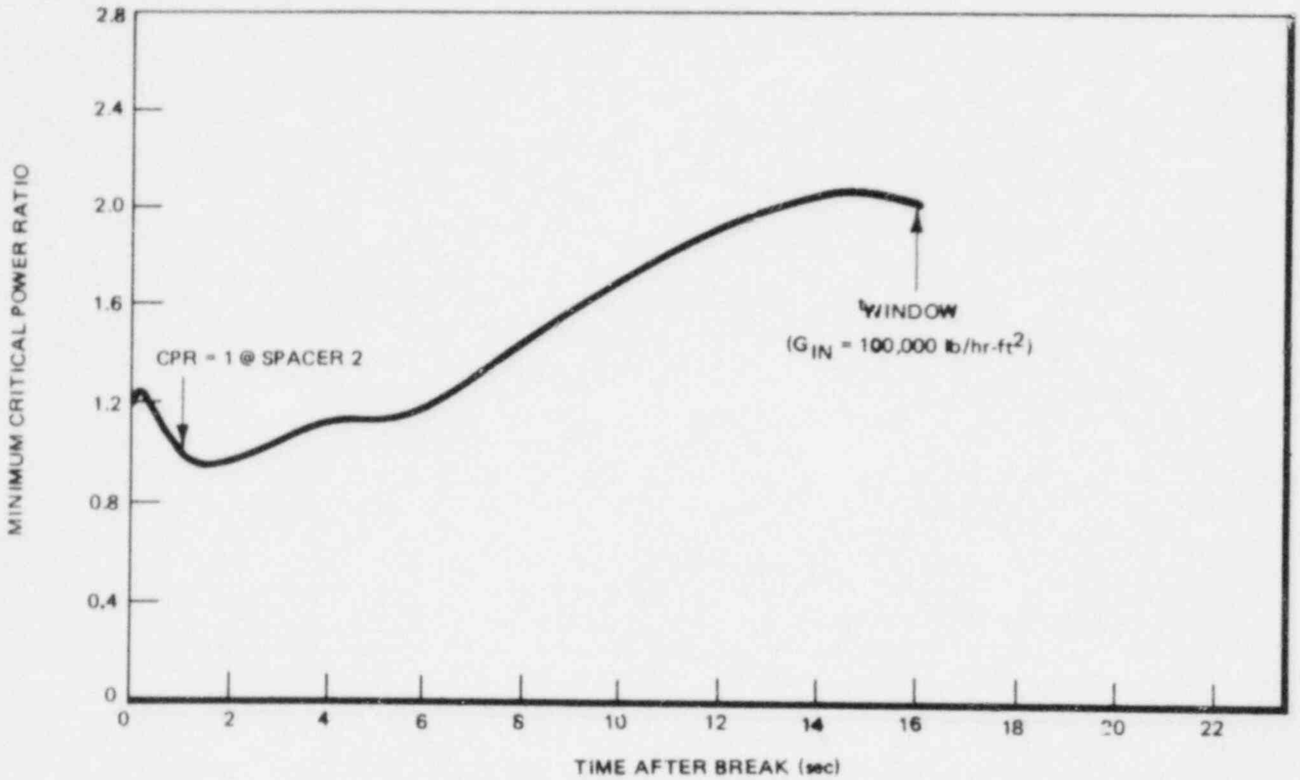
Figure 6.3-38



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Core Inlet Enthalpy Vs. Time After Break (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

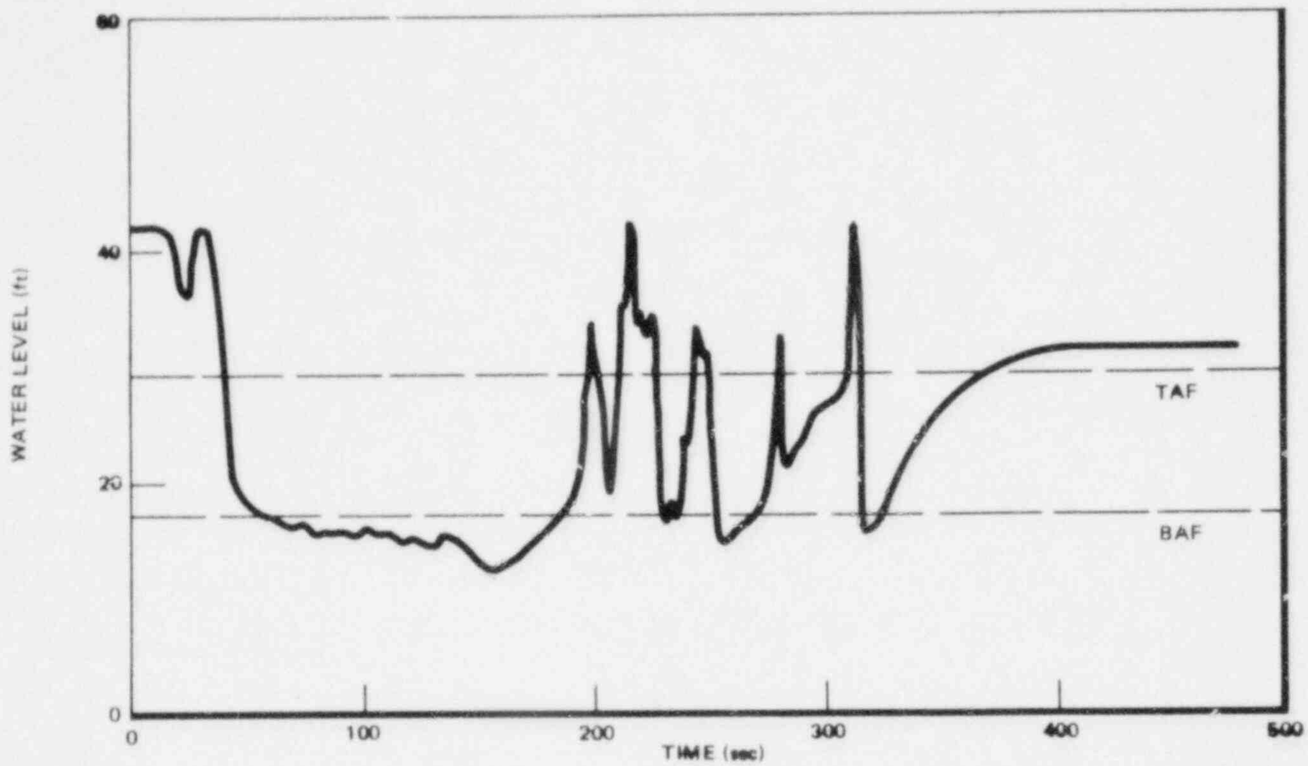
Figure 6.3-39



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Minimum Critical Power Ratio Vs. Time After Break (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

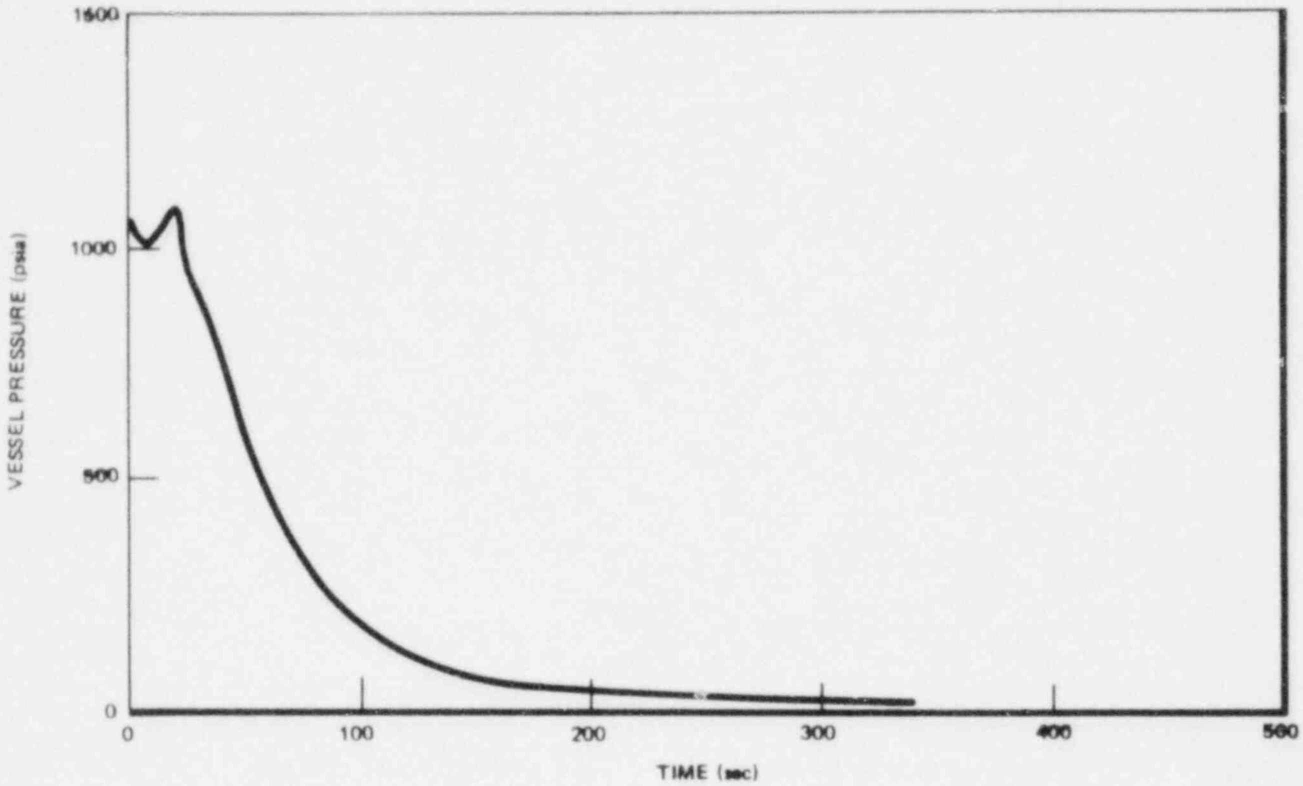
Figure 6.3-40



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break, Large Break Model (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

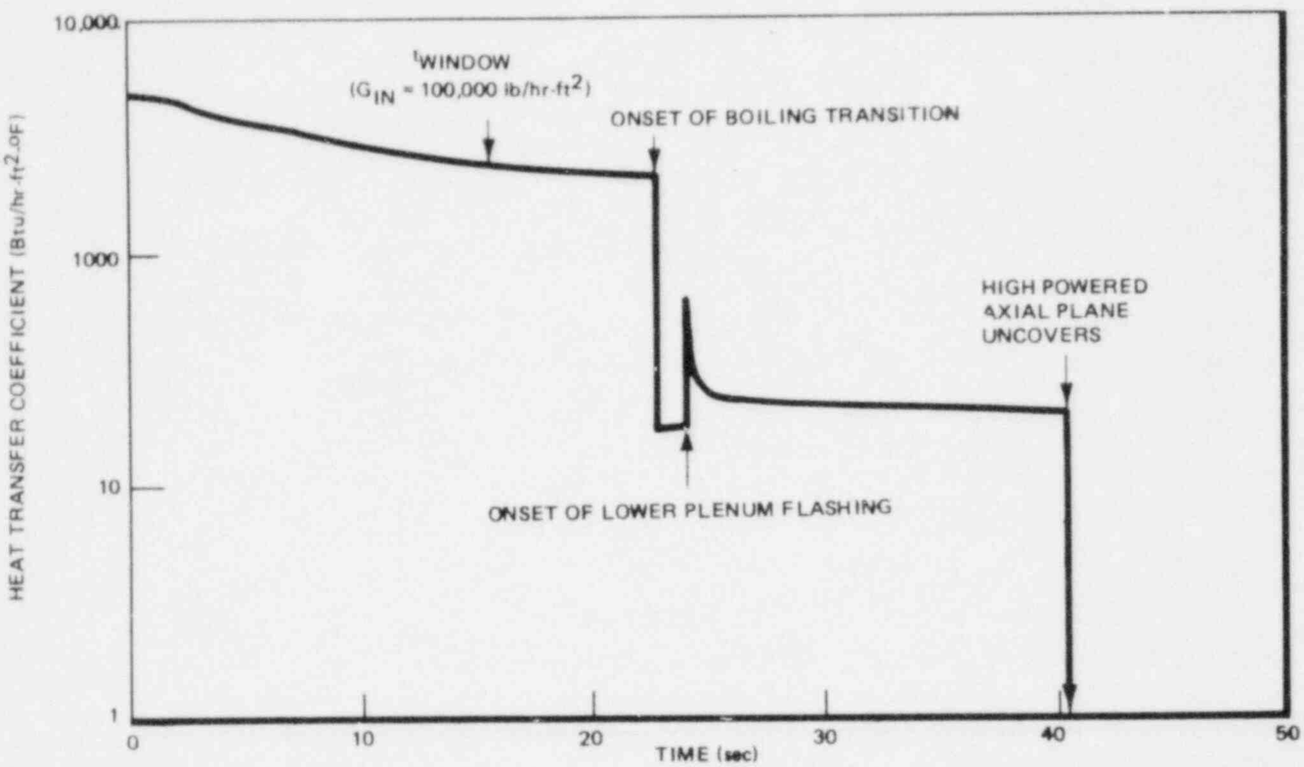
Figure 6.3-41



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break, Large Break Model ($1.0\ ft^2$ Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

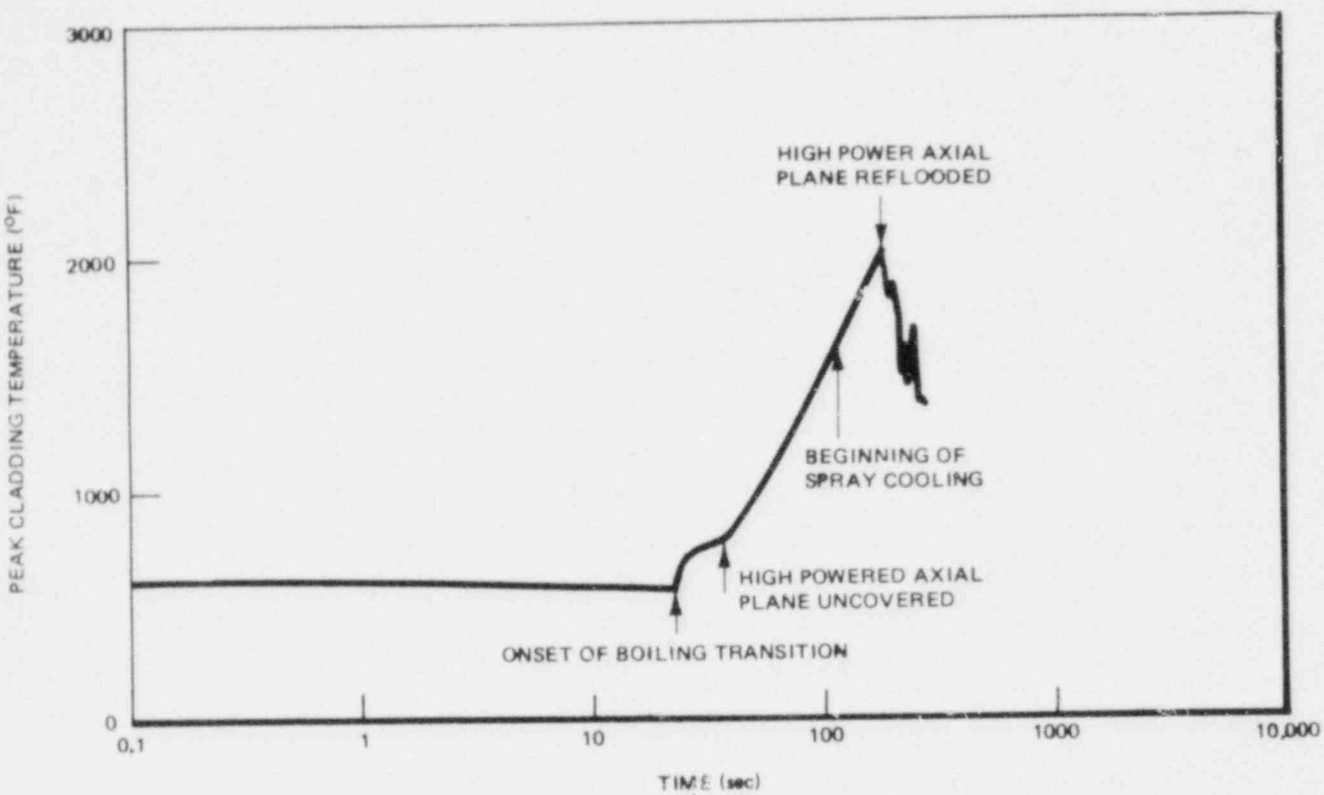
Figure 6.3-42



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Fuel Rod Convective Heat Transfer Coefficient Vs. Time After Break, Large Break Model (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

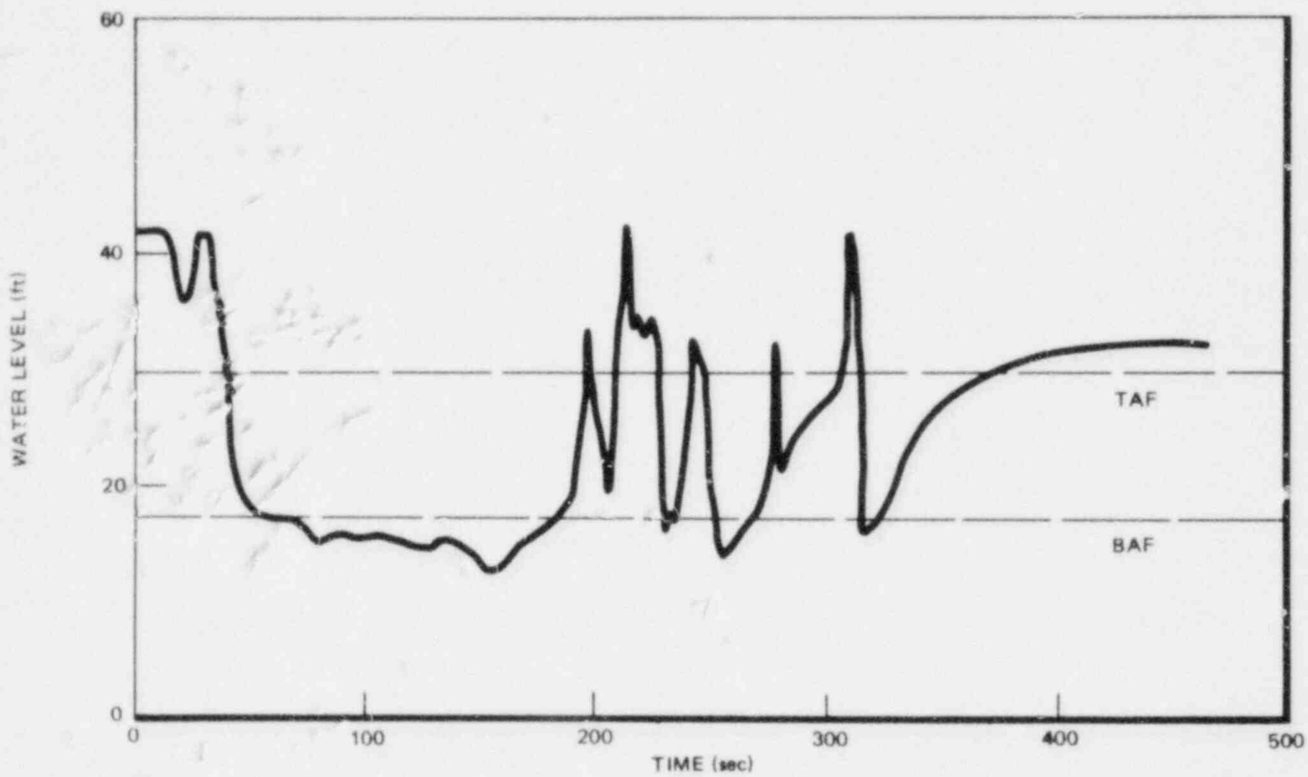
Figure 6.3-43



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Peak Cladding Temperature Vs. Time After Break, Large Break Model (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

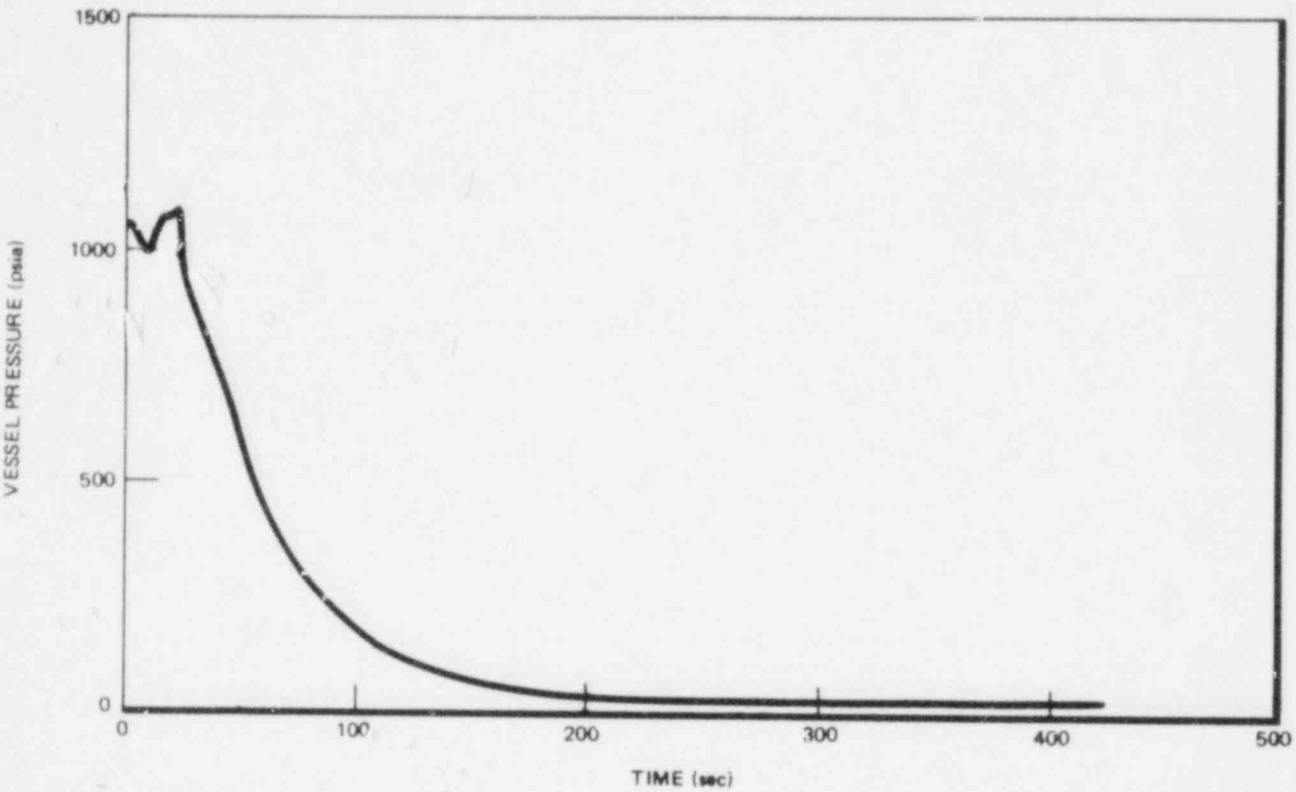
Figure 6.3-44



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break, Small Break Model ($1.0\ ft^2$ Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

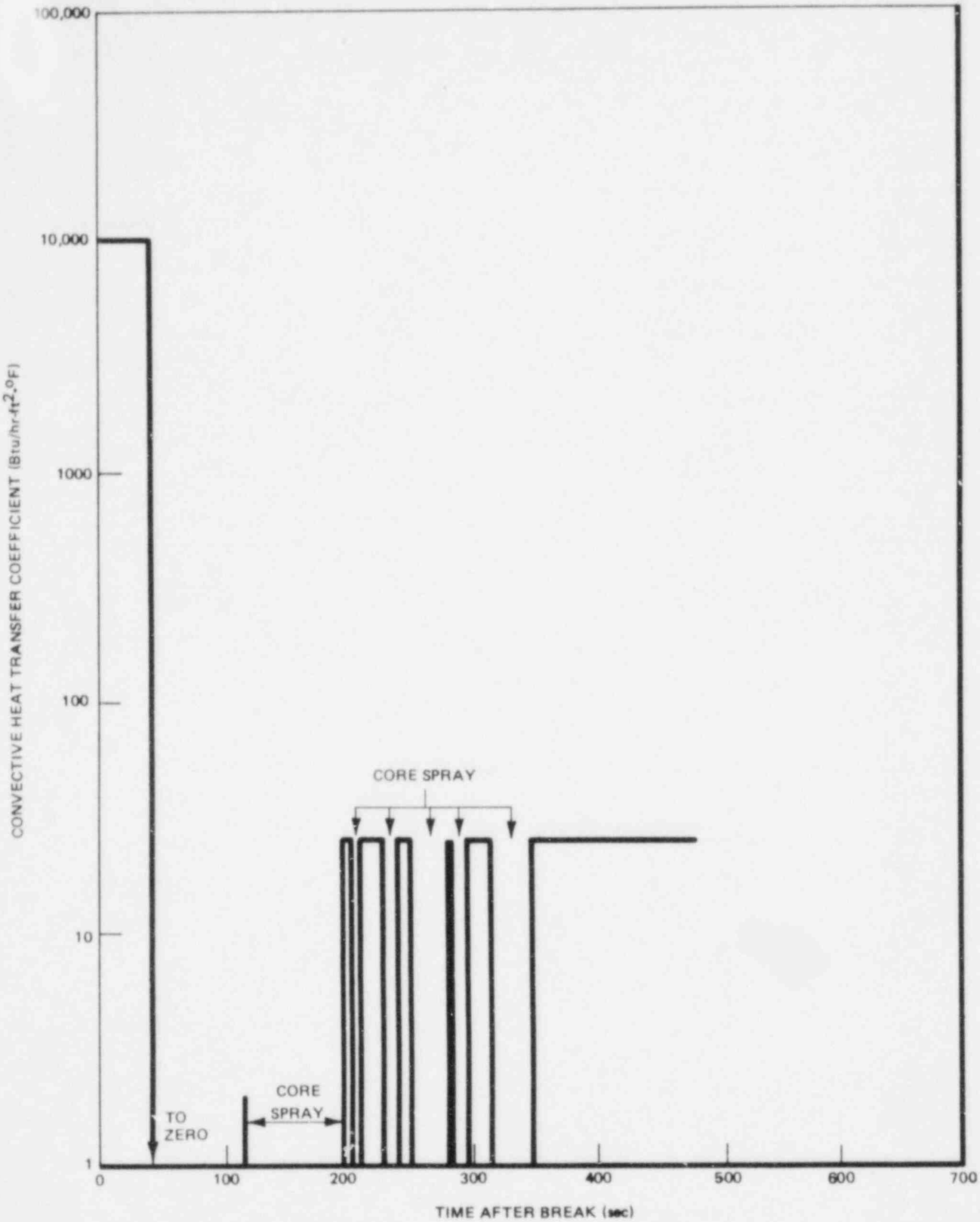
Figure 6.3-45



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break, Small Break Model ($1.0\ ft^2$ Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

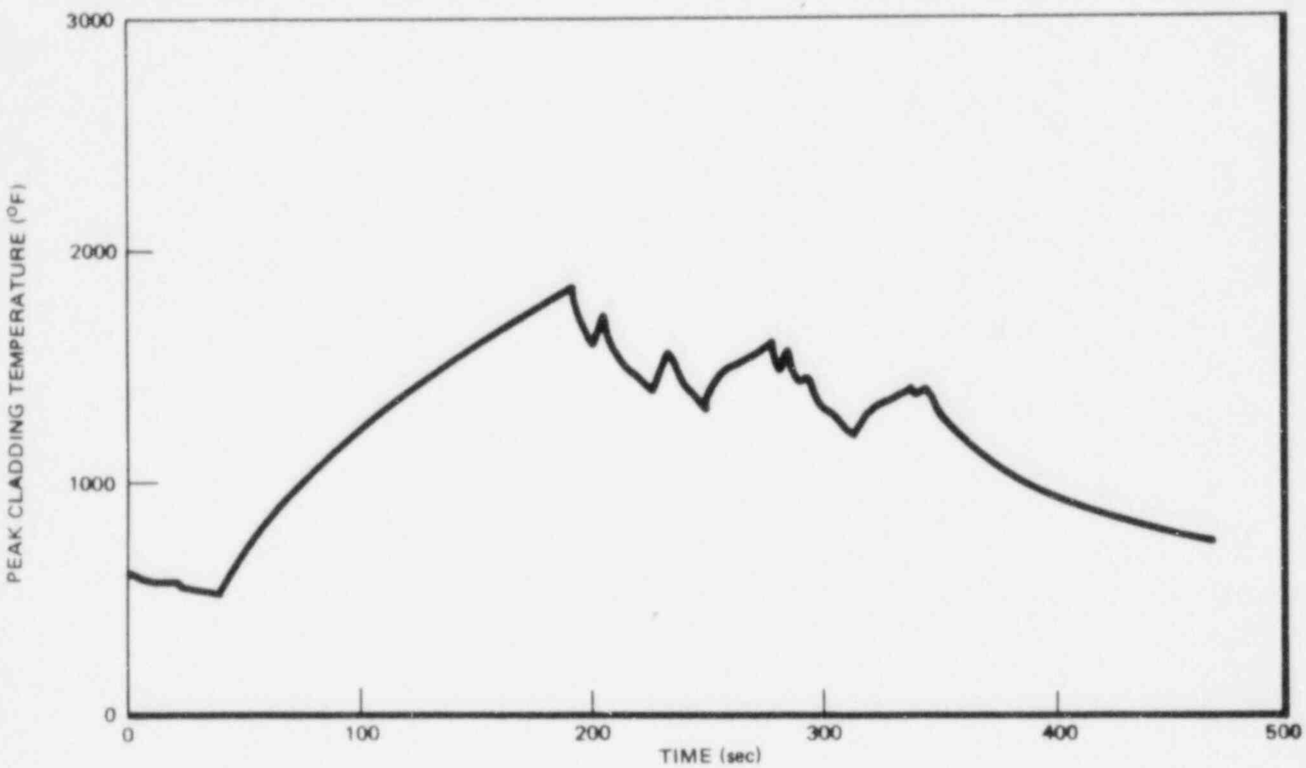
Figure 6.3-46



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Fuel Rod Convective Heat Transfer Coefficient Vs. Time After Break, Small Break Model (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

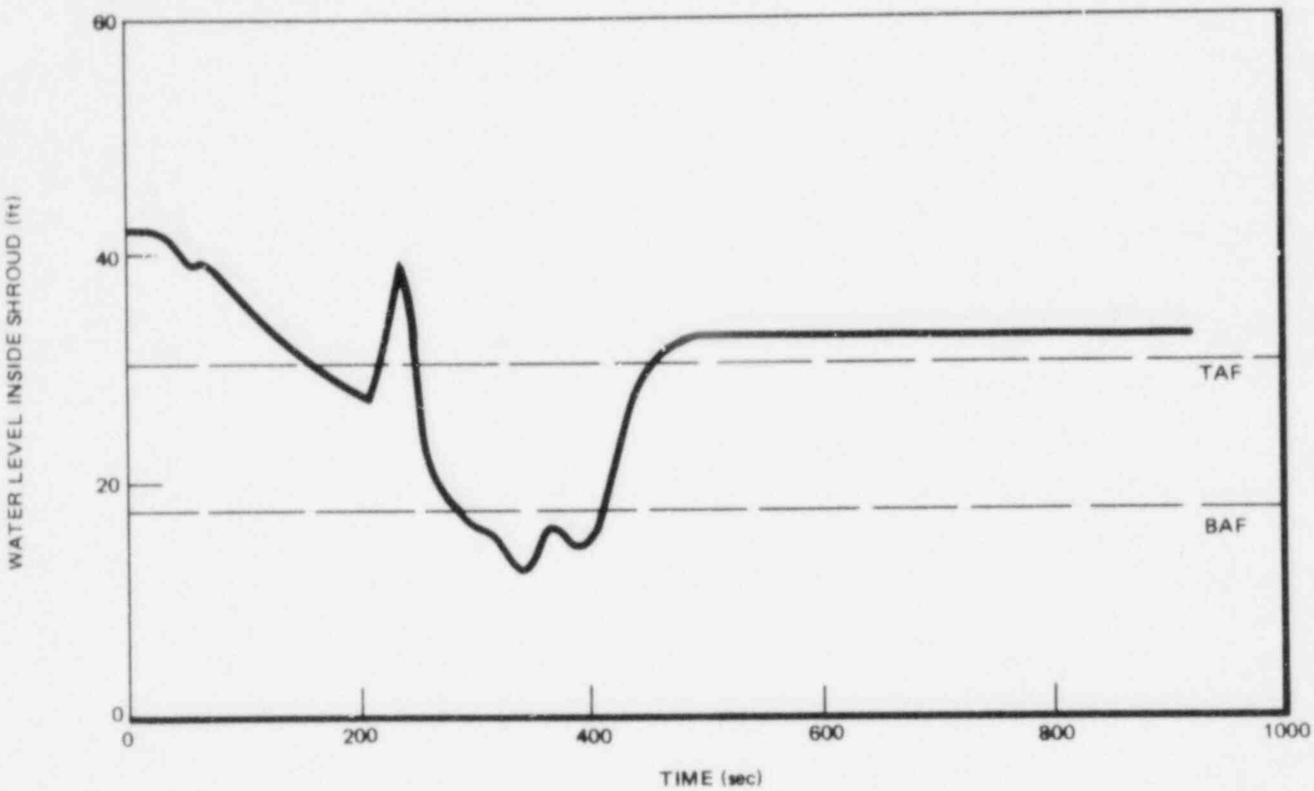
Figure 6.3-47



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Peak Cladding Temperature Vs. Time After Break, Small Break Model (1.0 ft^2 Break, Recirculation Suction Break, LPCI Diesel-Generator Failure)

Figure 6.3-48



PERRY NUCLEAR POWER PLANT
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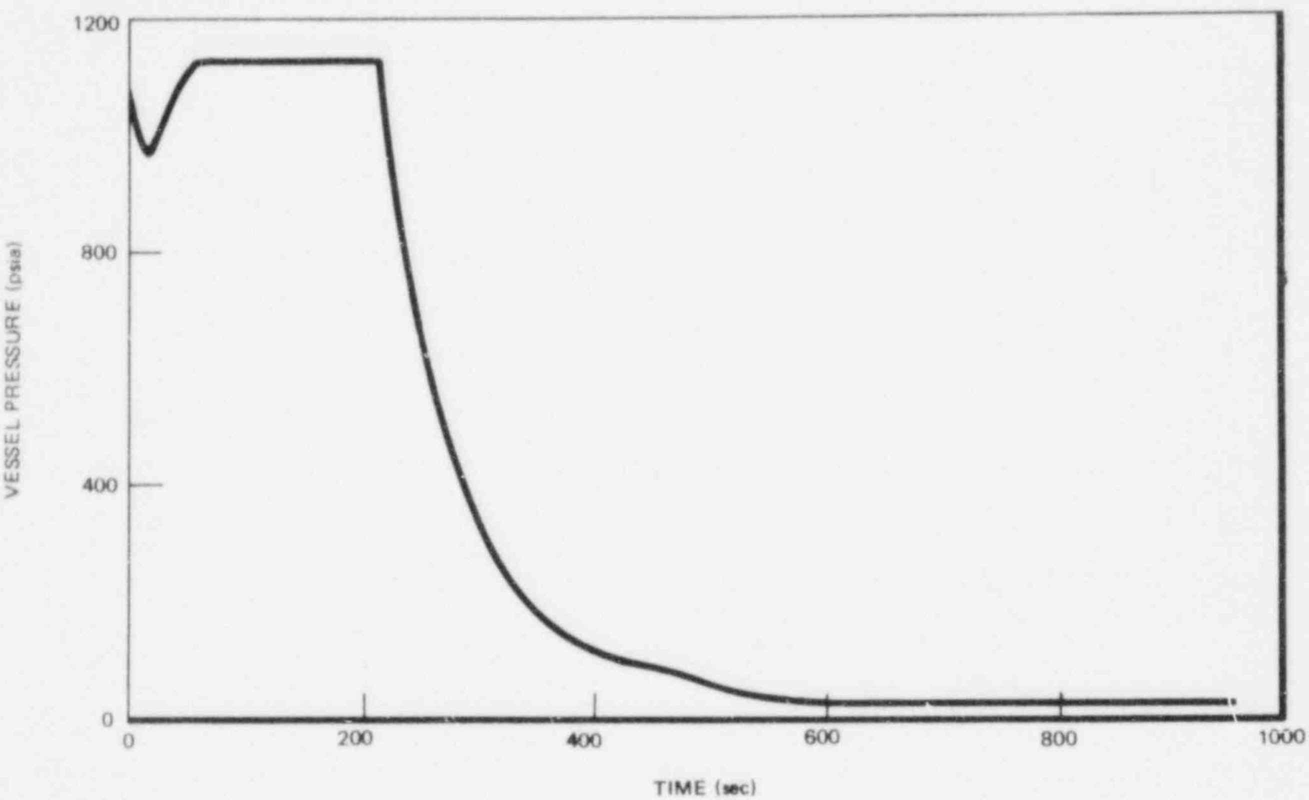
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break, Small Break Model (0.07 ft^2 Break (Highest Temperature Small Break), Recirculation Suction Break, HPCS Diesel-Generator Failure)

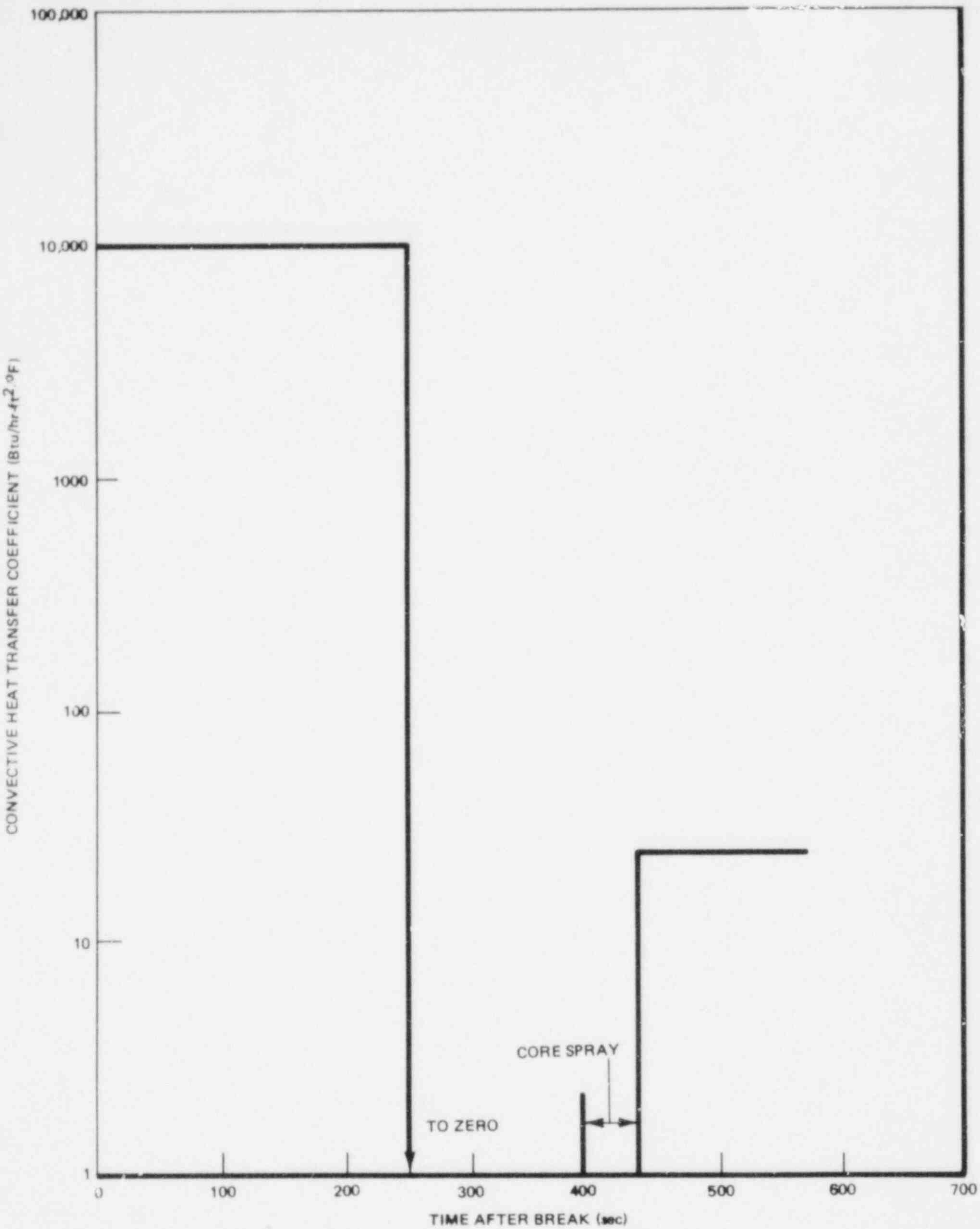
Figure 6.3-49



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

RV Pressure Vs. Time After Break, Small Break Model (0.07 ft^2 Break, Highest Temp. Small Break, Recirc. Suction Break, HPCS Diesel-Generator Failure)

Figure 6.3-50



PERRY NUCLEAR POWER PLANT
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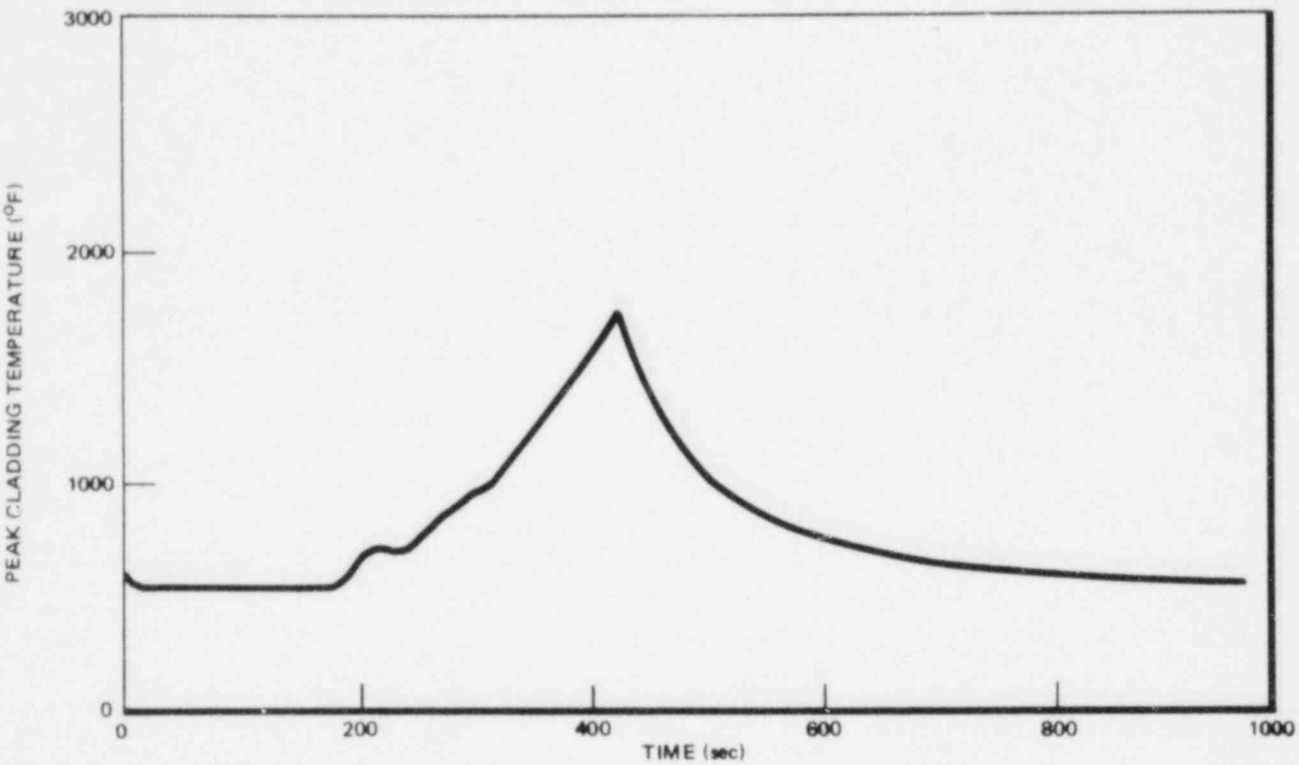
Fuel Rod Convective Heat Transfer Coef. Vs. Time After Break, Small Break Model (0.07 ft^2 Break, Highest Temp. Small Break, Recirc. Suction Break, HPCS D-G Failure)

Figure 6.3-51



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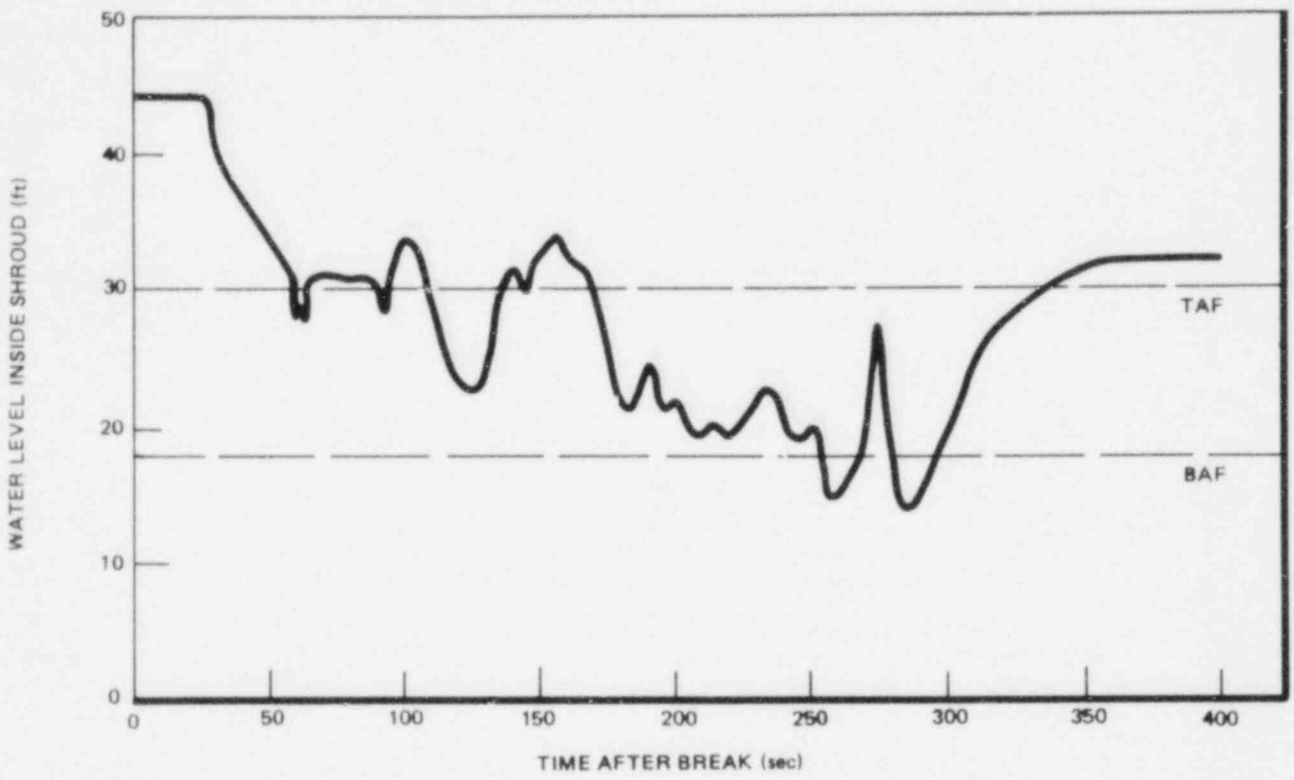
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Peak Cladding Temp. Vs. Time After Break, Small Break Model ($0.07\ ft^2$ Break, Highest Temp. Small Break, Recirc. Suction Break, HPCS D-G Failure)

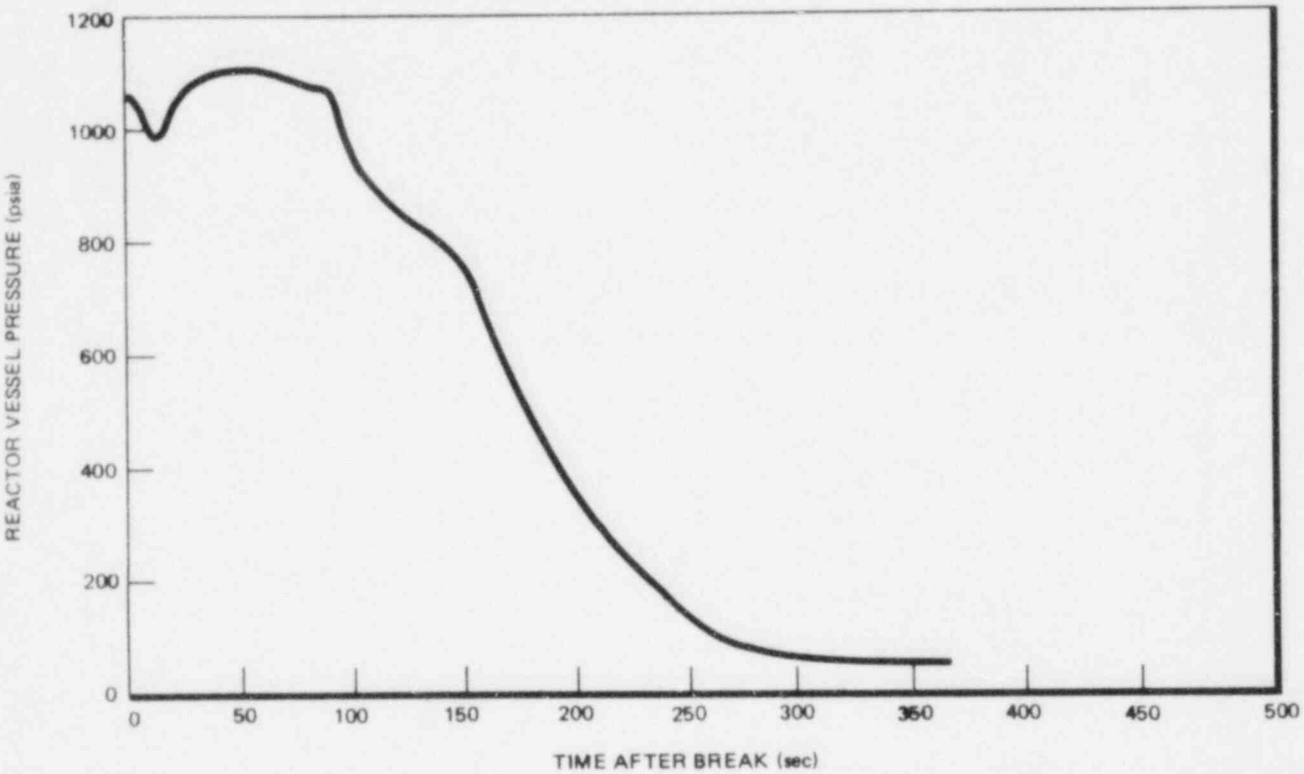
Figure 6.3-52



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break, Small Break Model ($0.30\ ft^2$ Break, Additional Small Break, Recirc. Suction Break, LPCS D-G Failure)

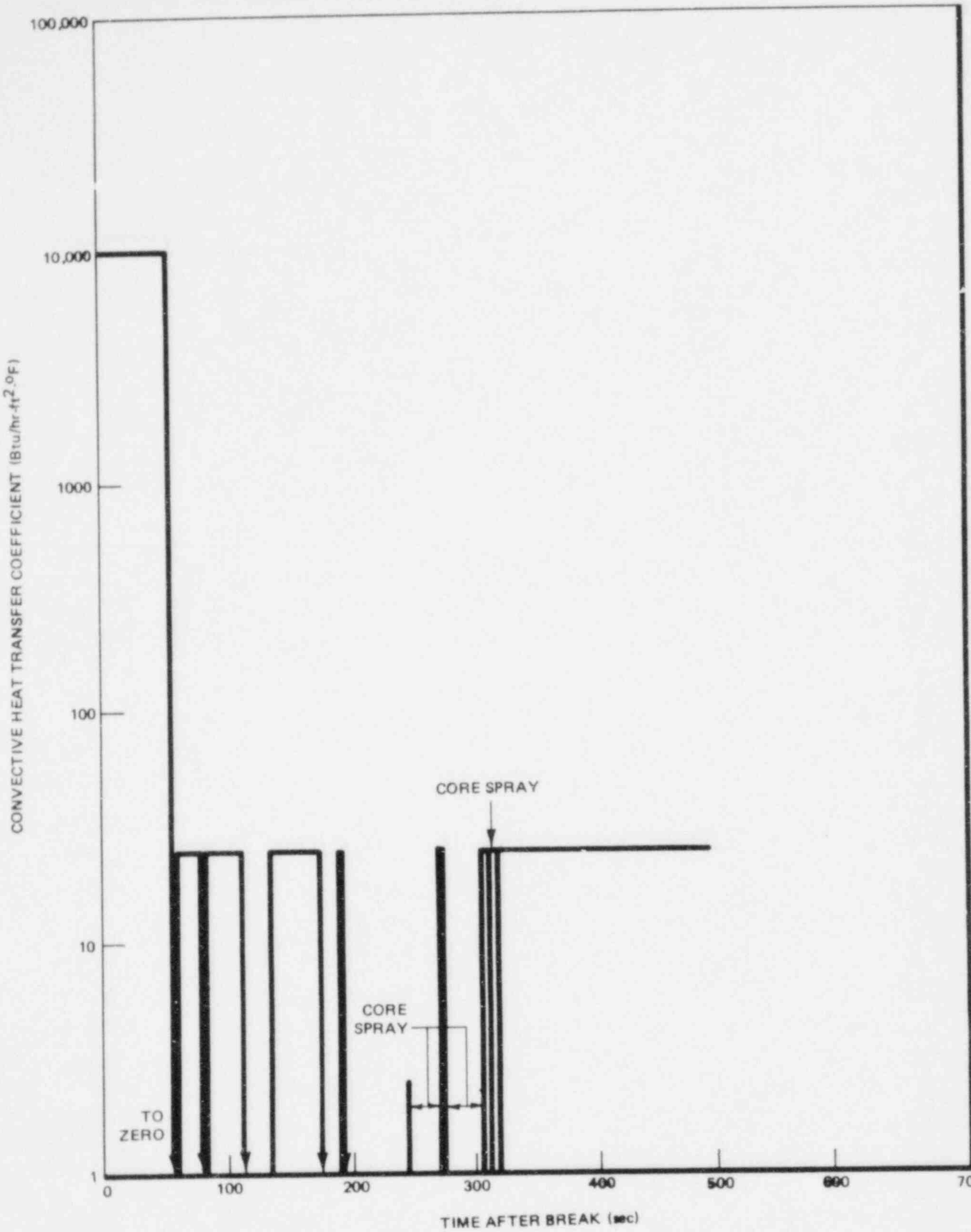
Figure 6.3-53



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break, Small Break Model ($0.30\ ft^2$ Break, Additional Small Break, Recirc. Suction Break, LPCS D-G Failure)

Figure 6.3-54



PERRY NUCLEAR POWER PLANT
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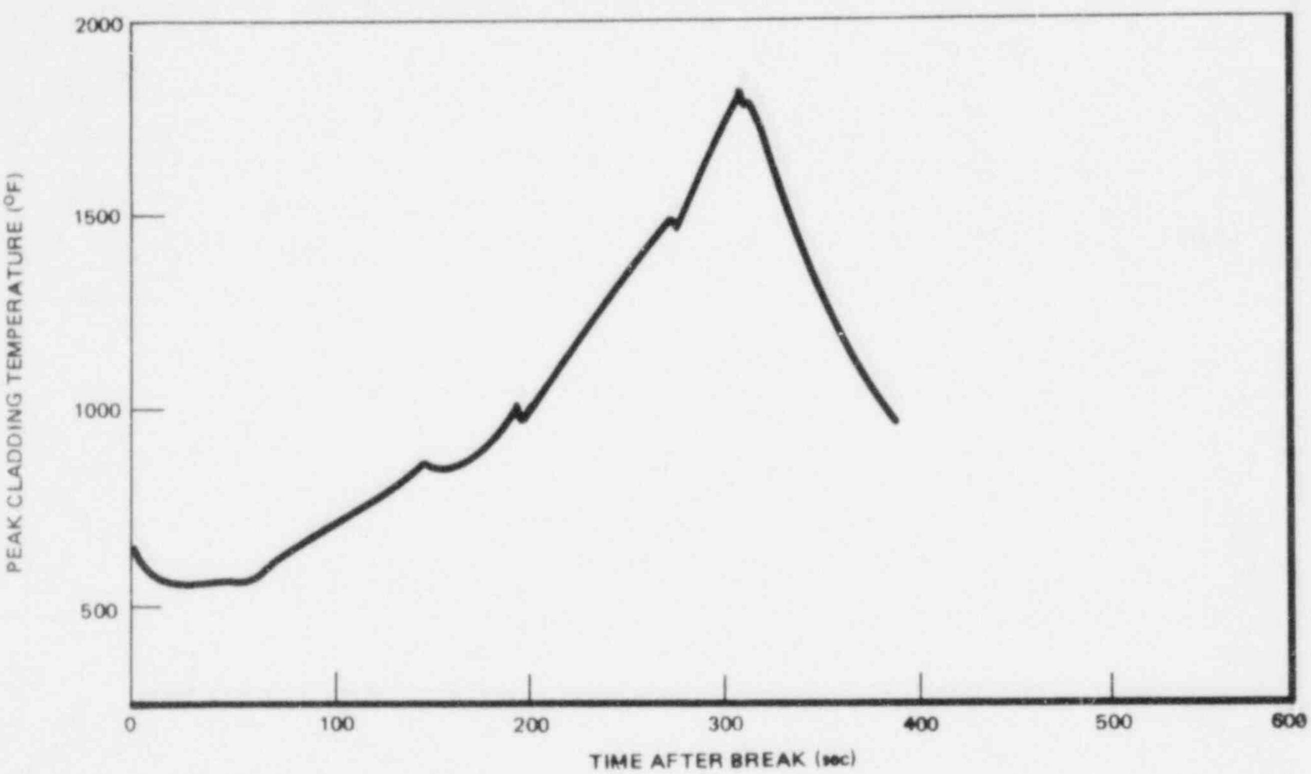
Fuel Rod Convective Heat Transfer Coef. Vs. Time After Break, Small Break Model, (0.30 ft^2 Break, Additional Small Break, Recirc. Suction Break, LPCS D-G Failure)

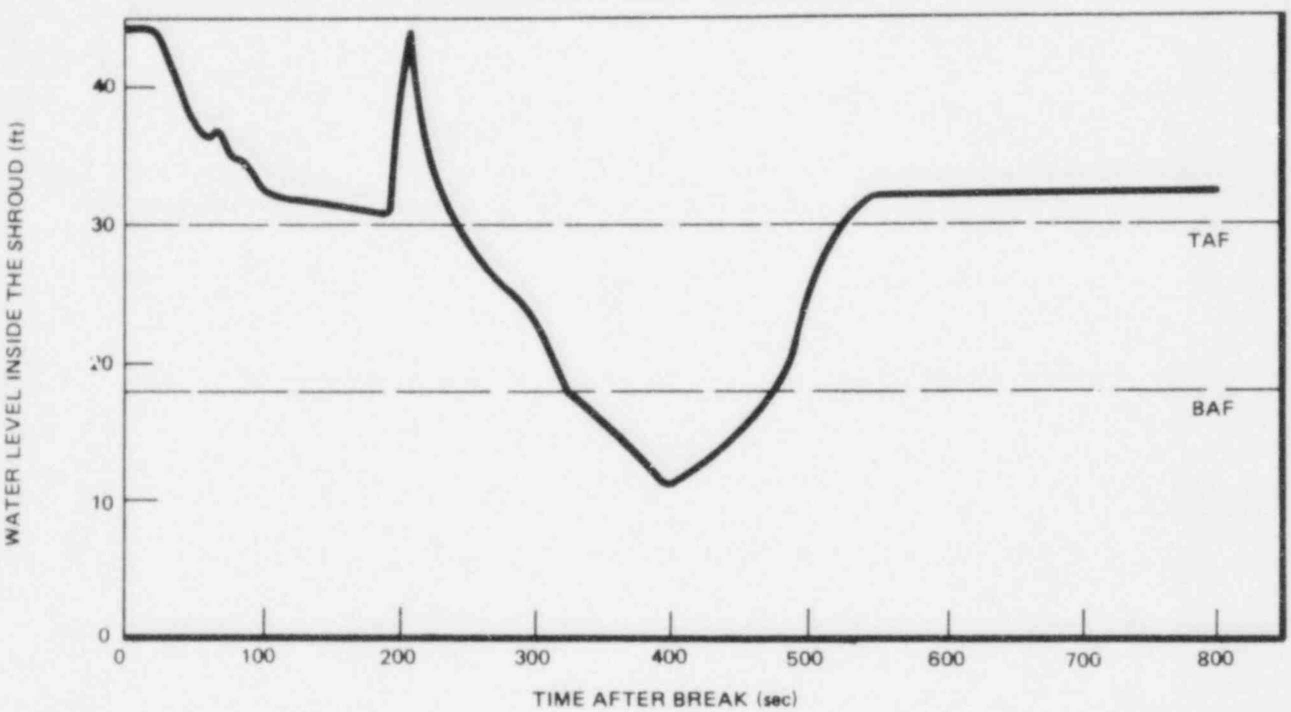
Figure 6.3-55



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Peak Cladding Temp. Vs. Time After Break (Small Break Model) [0.30 ft^2 Break (Additional Small Break), Recirc. Suction Break, LPCS D-G Failure]

Figure 6.3-56



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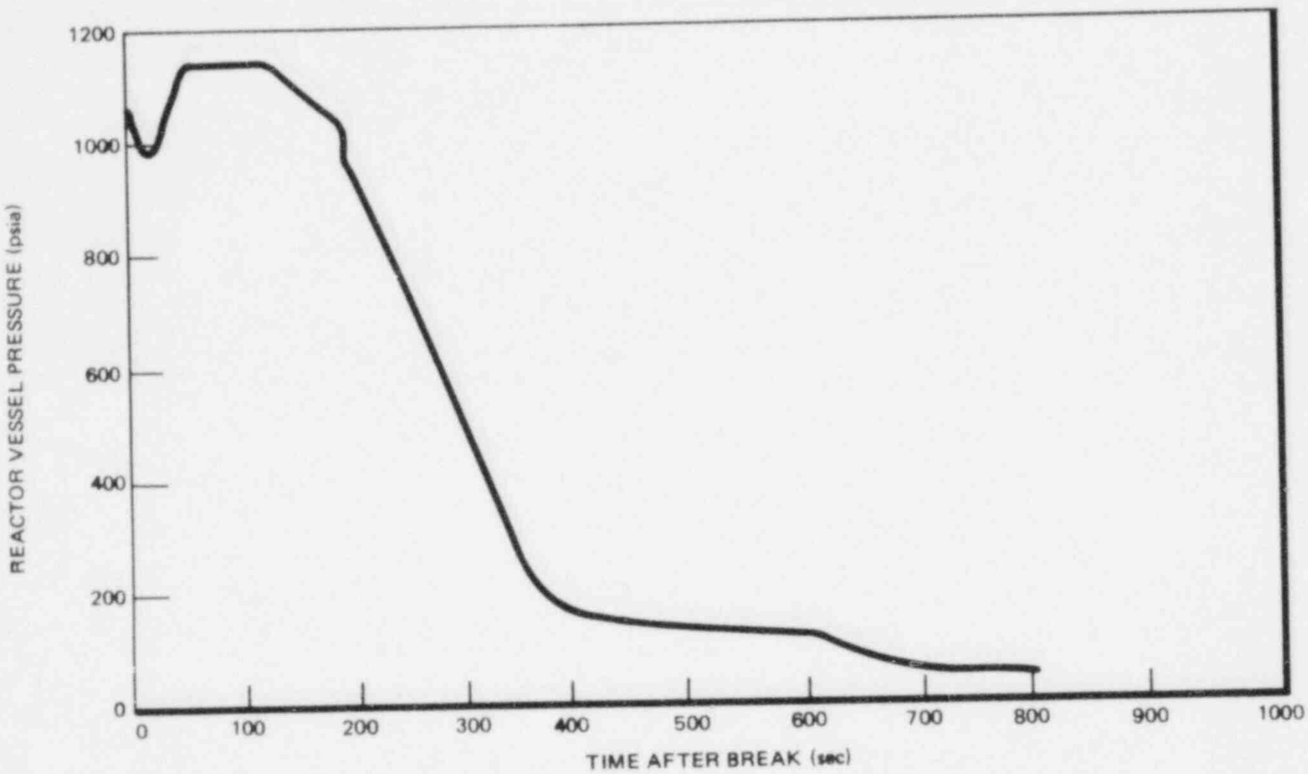
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break (Small Break Model), HPCS Line Break ($0.128\ ft^2$), LPCS D-G Failure

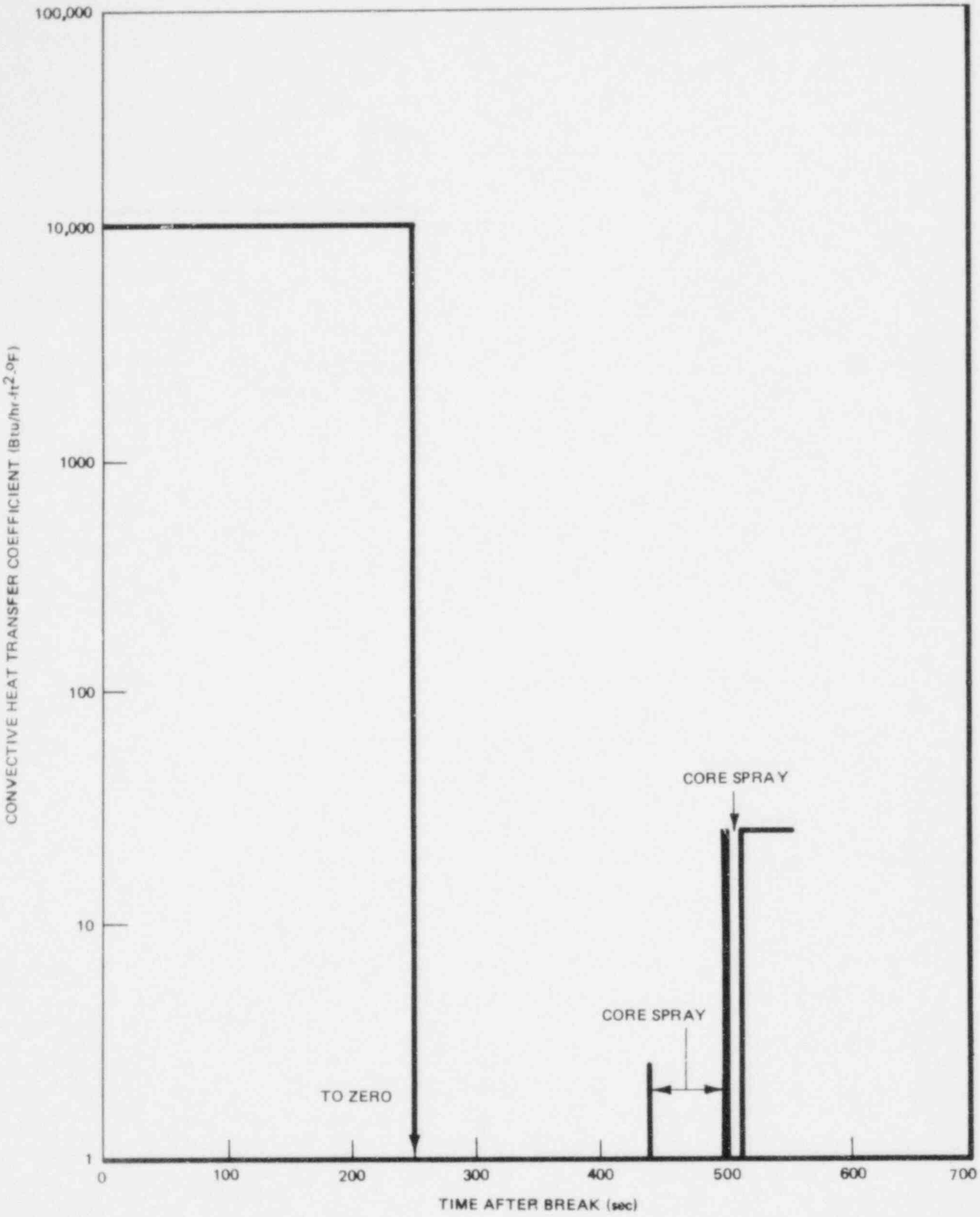
Figure 6.3-57



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break (Small Break Model) HPCS Line Break ($0.128\ ft^2$), LPCS D-G Failure

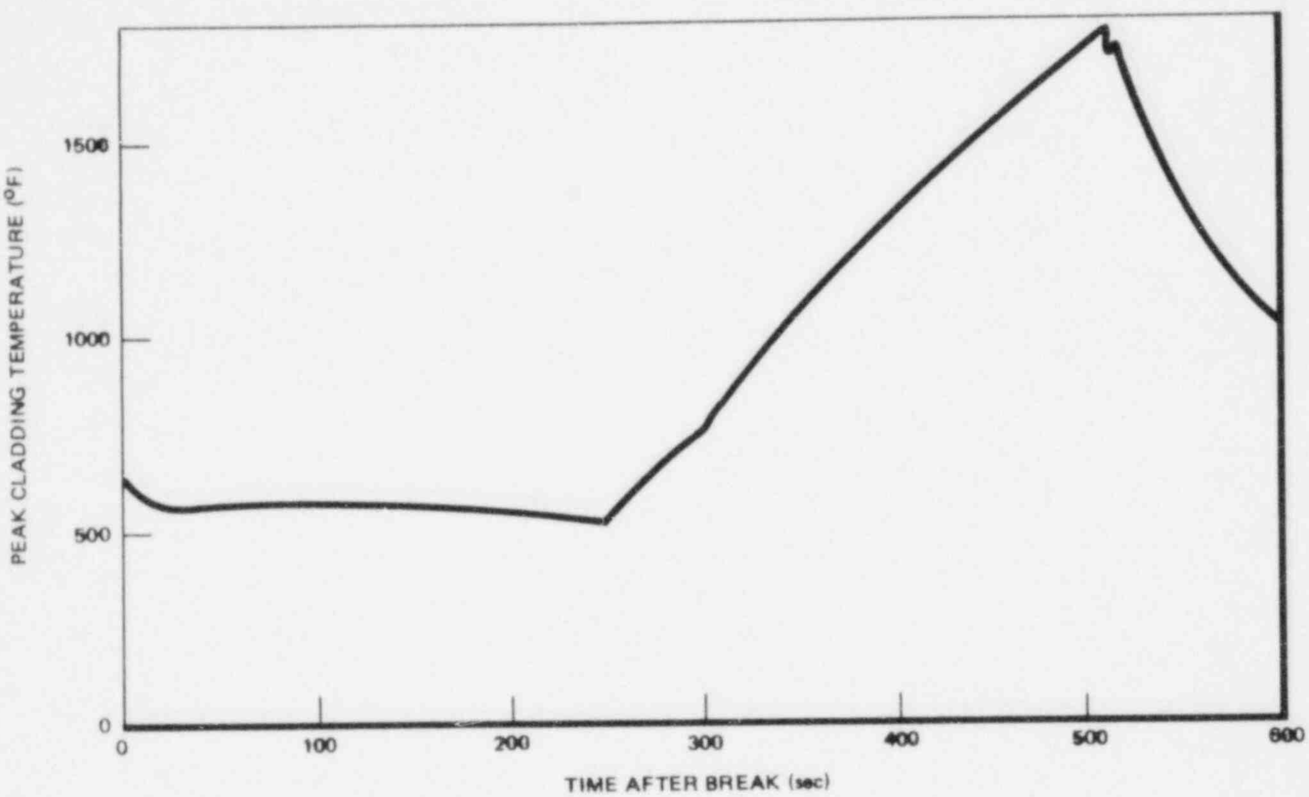
Figure 6.3-58



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Fuel Rod Convective Heat Transfer Coef. Vs. Time After Break (Small Break Model) HPCS Line Break (0.126 ft^2), LPCS D-G Failure

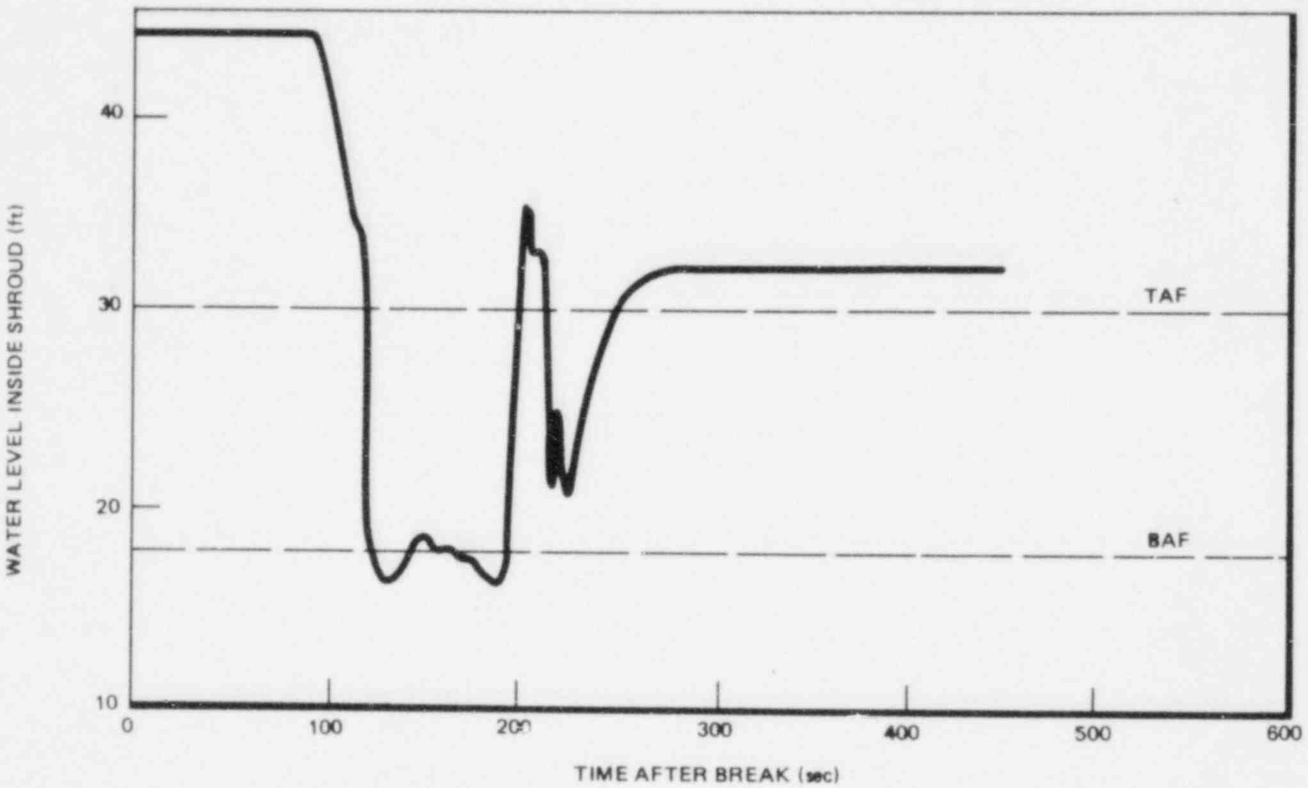
Figure 6.3-59



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Peak Cladding Temperature Vs. Time After Break (Small Break Model) HPCS Line Break ($0.126\ ft^2$), LPCS Diesel-Generator Failure

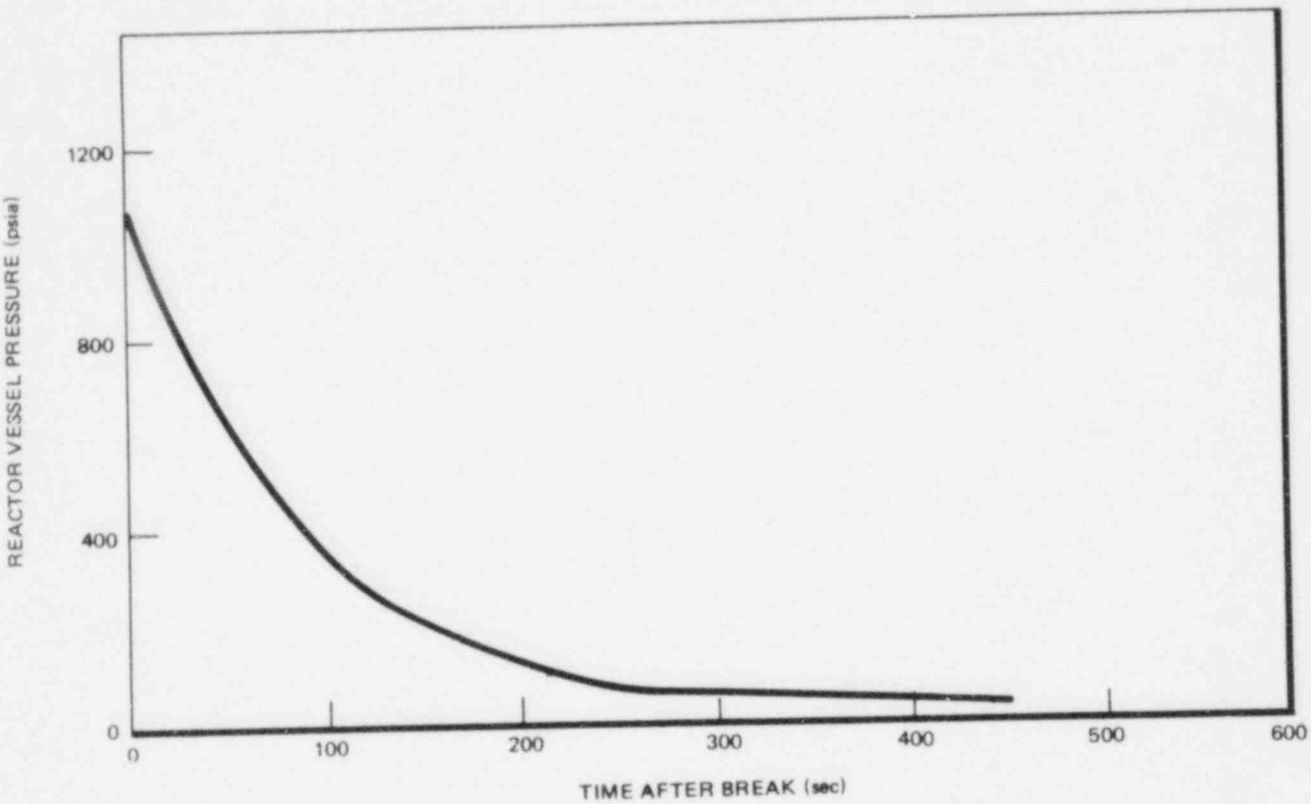
Figure 6.3-60



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break (Small Break Model) [Feedwater Line Break ($1.086\ ft^2$), HPCS Diesel-Generator Failure]

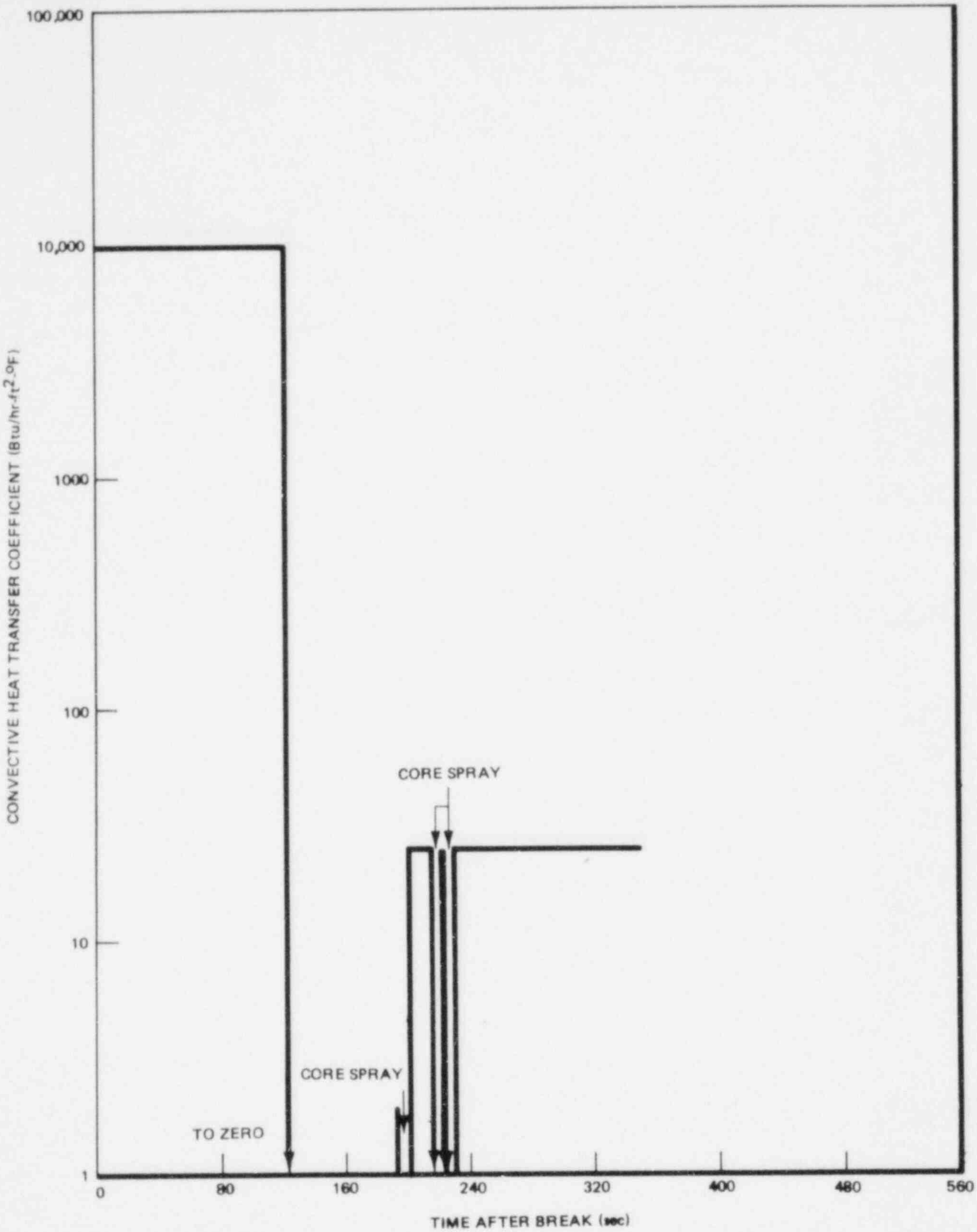
Figure 6.3-61



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break (Small Break Model) Feedwater Line Break (1.086 ft^2), HPCS D-G Failure

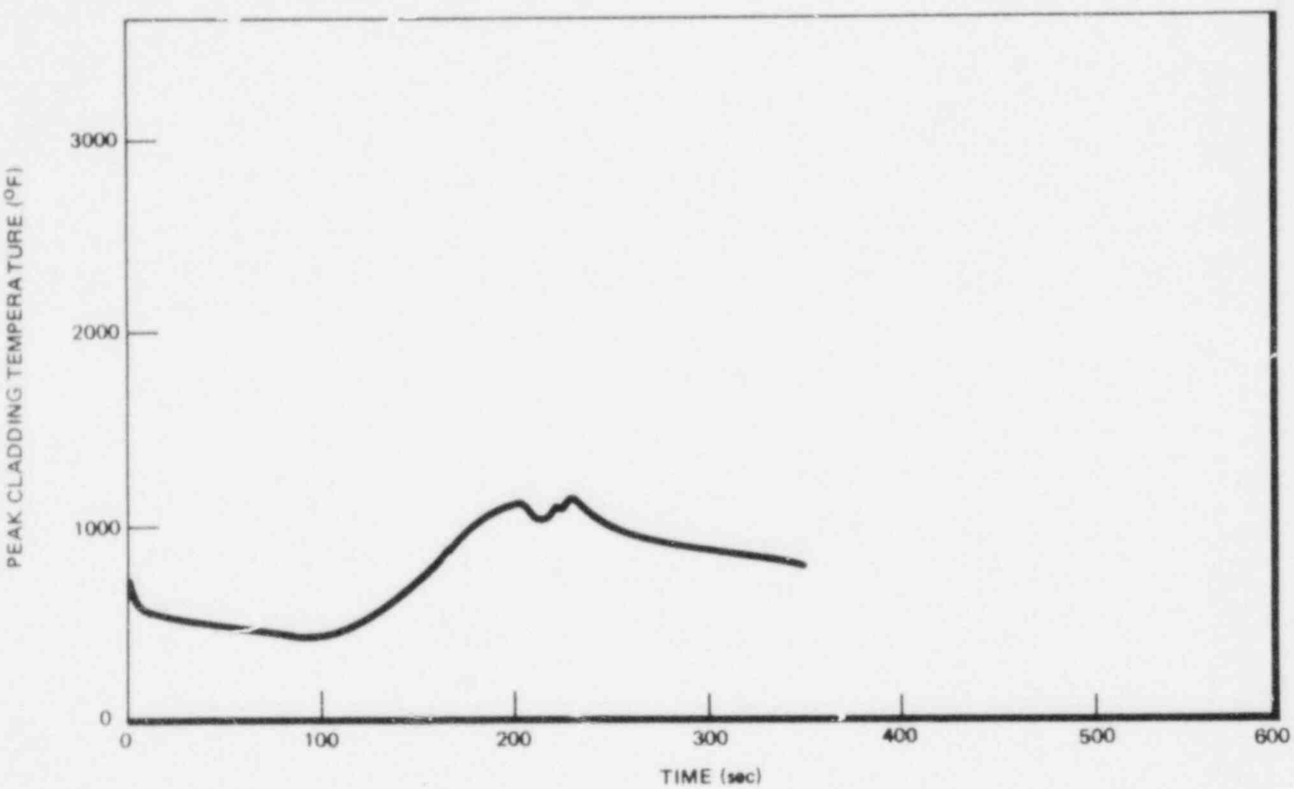
Figure 6.3-62



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Fuel Rod Convective Heat Transfer Coefficient Vs. Time After Break (Small Break Model) [Feedwater Line Break (1.086 ft^2), HPCS Diesel-Generator Failure]

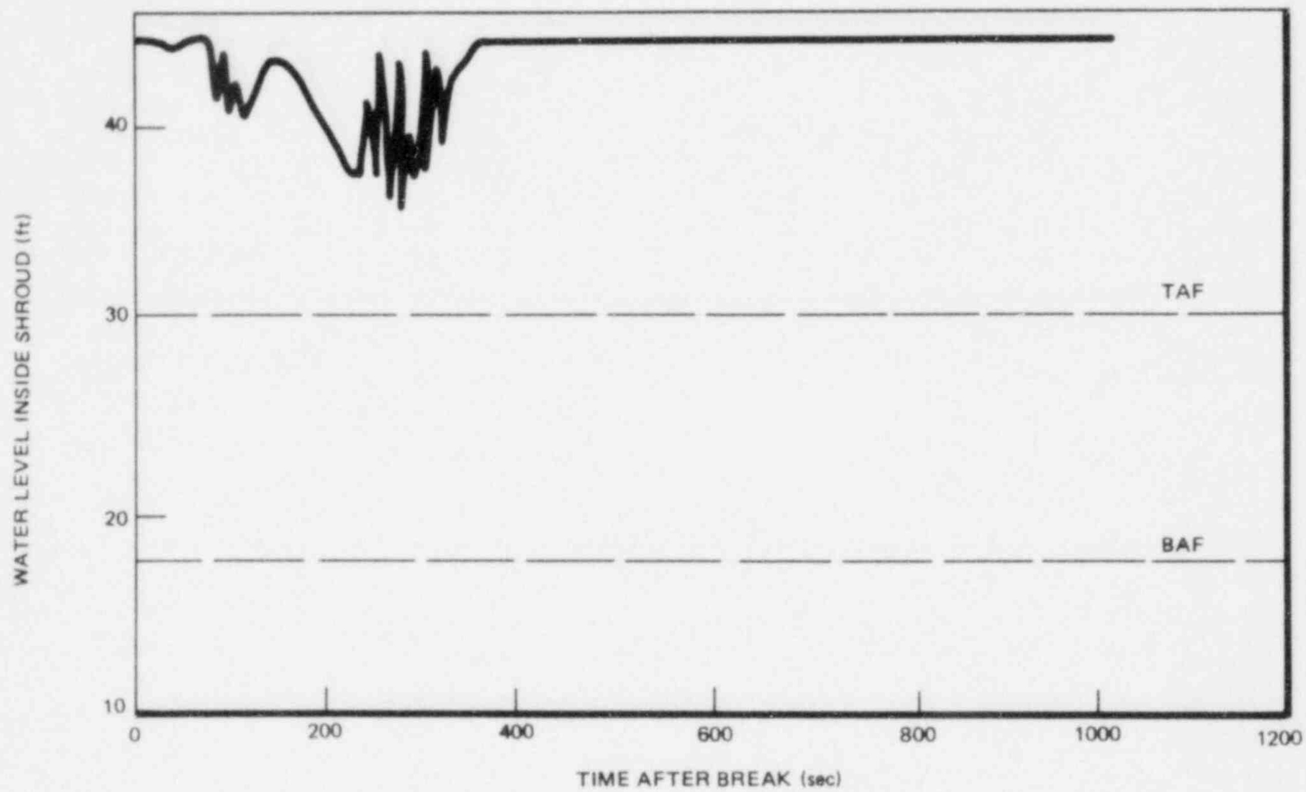
Figure 6.3-63



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Peak Cladding Temperature Vs. Time After Break (Small Break Model) [Feedwater Line Break (1.086 ft^2), HPCS Diesel-Generator Failure]

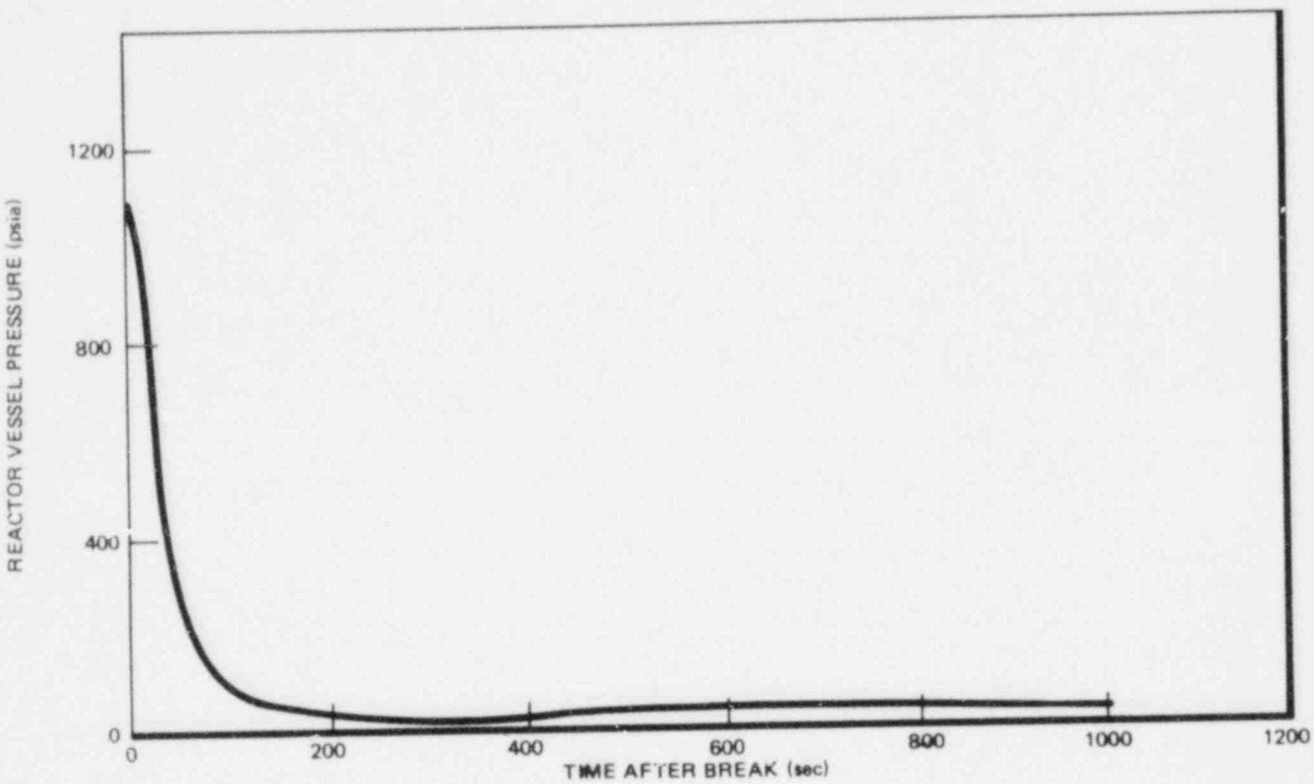
Figure 6.3-64



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break [Main Steamline Break (3.050 ft^2), Inside the Containment, LPCS D-G Failure]

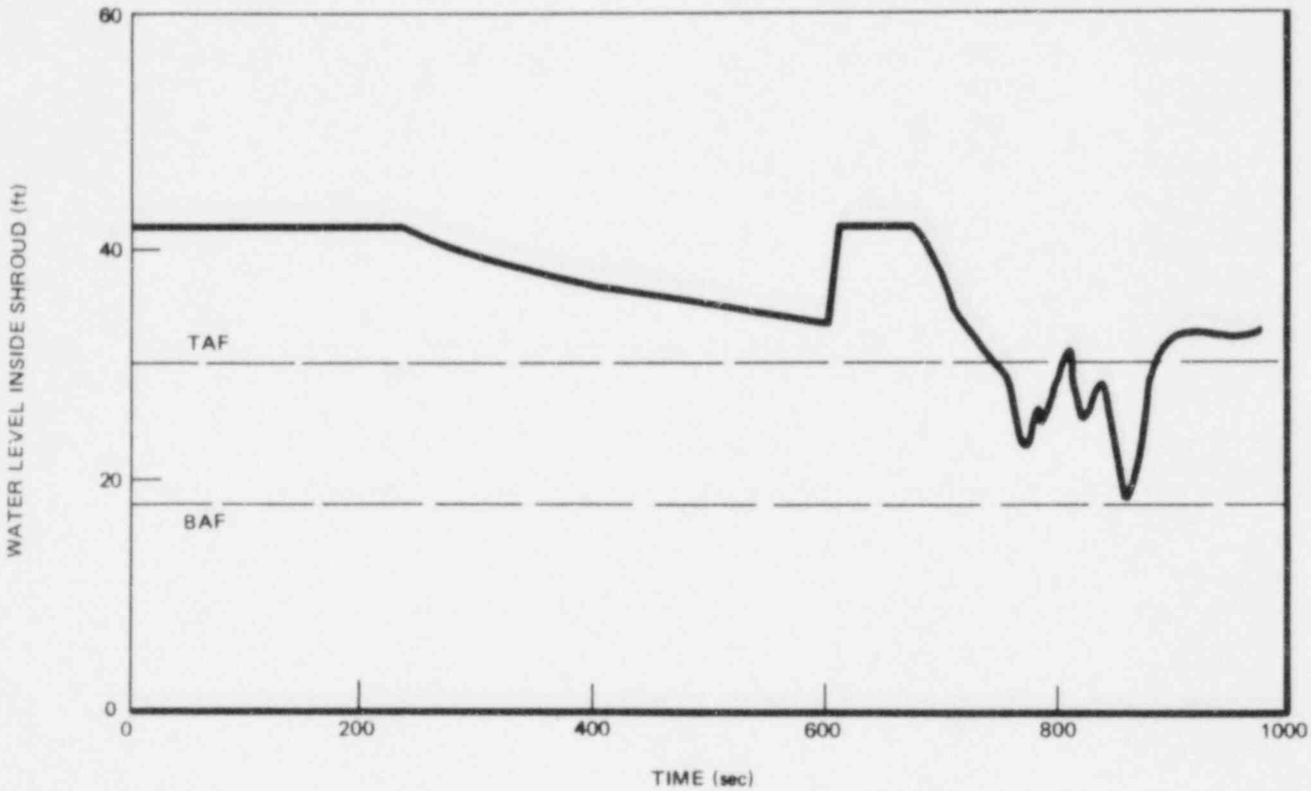
Figure 6.3-65



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break [Main Steamline Break ($3.050\ ft^2$), Inside the Containment, LPCI D-G Failure]

Figure 6.3-66



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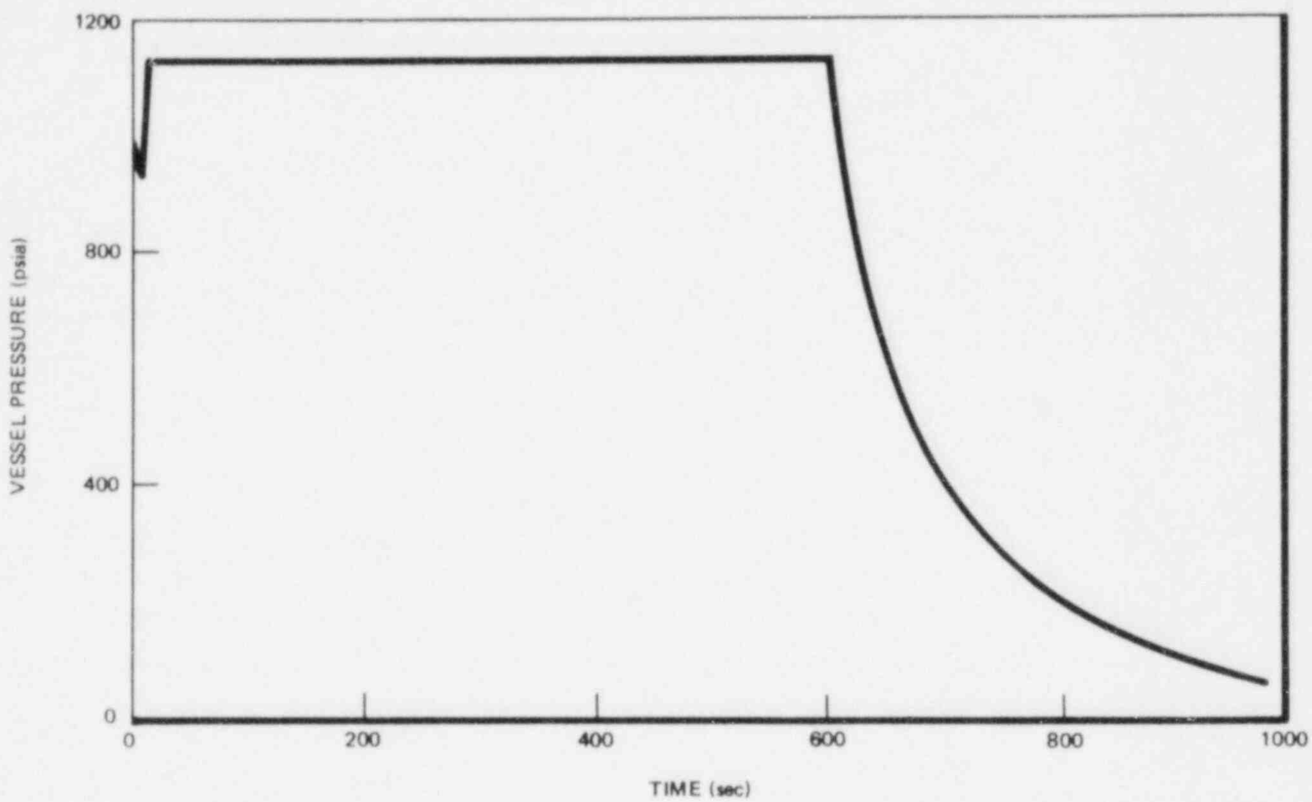
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Water Level Inside the Shroud Vs. Time After Break [Main Steamline Break (3.292 ft^2), Outside the Containment, HPCS D-G Failure]

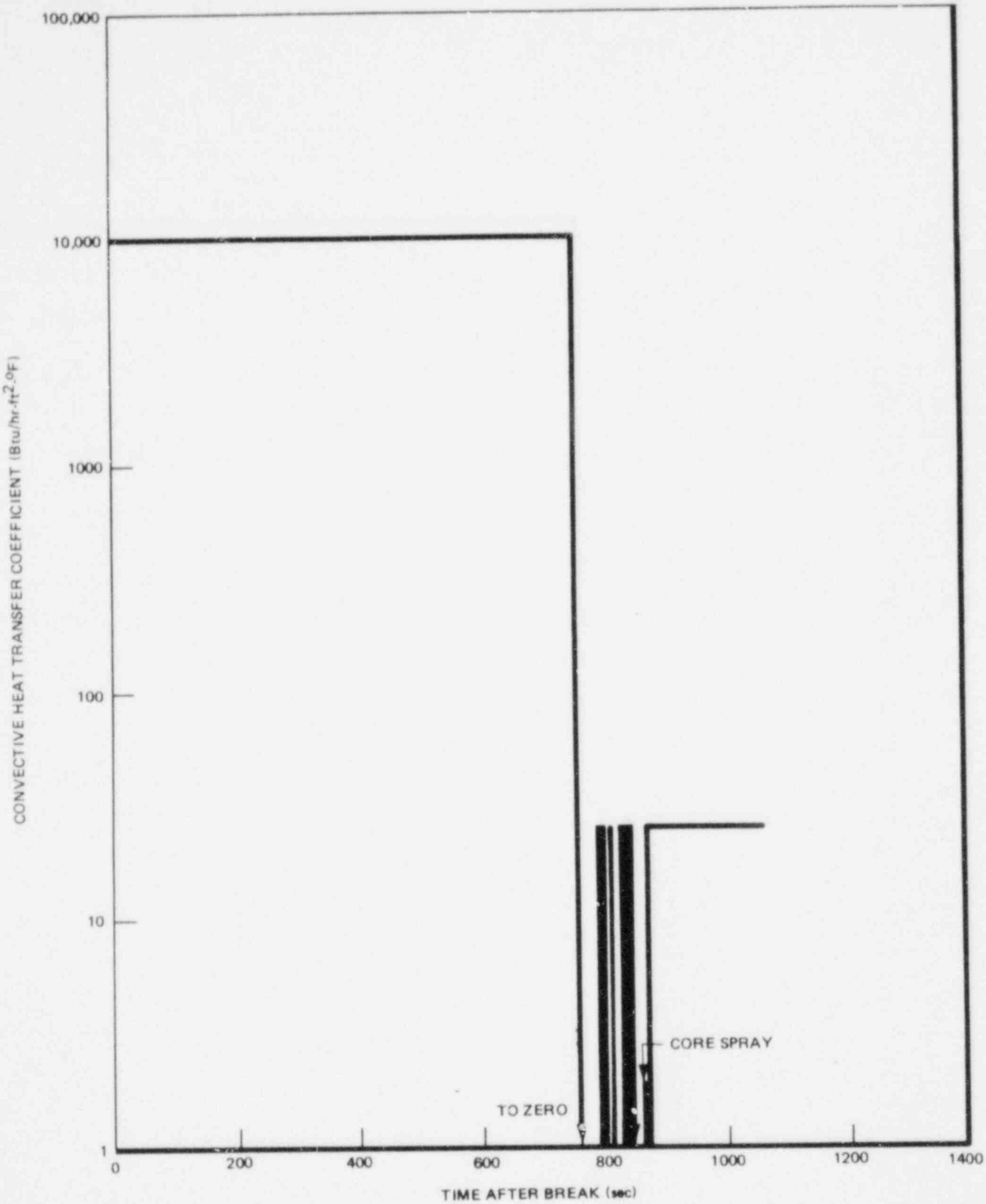
Figure 6.3-67



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Reactor Vessel Pressure Vs. Time After Break [Main Steamline Break (3.292 ft^2), Outside the Containment, HPCS D-G Failure]

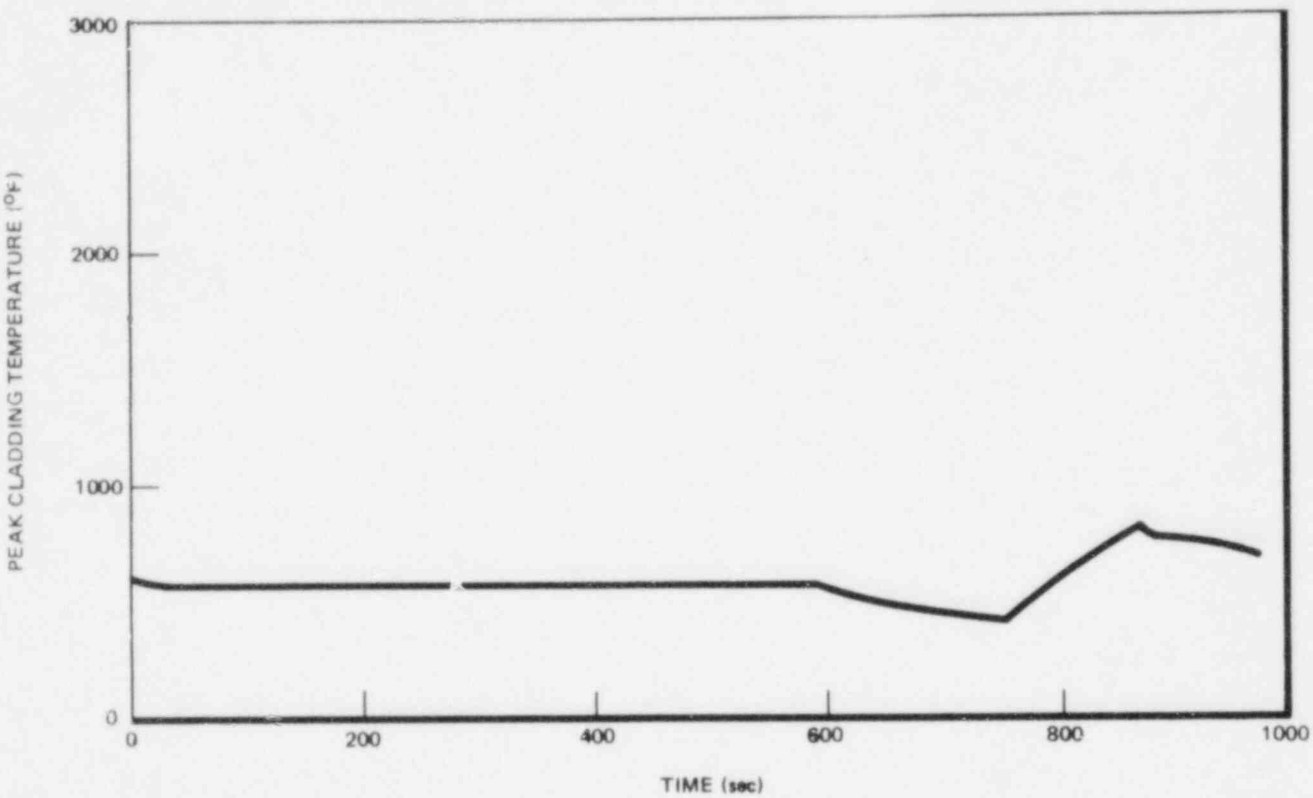
Figure 6.3-68



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Fuel Rod Convective Heat Transfer Coefficient Vs. Time After Break [Main Steamline Break (3.292 ft^2), Outside the Containment, HPCS Diesel-Generator Failure]

Figure 6.3-69



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Peak Cladding Temperature Vs. Time After Break [Main Steamline Break (3.292 ft^2), Outside the Containment, HPCS Diesel-Generator Failure]

Figure 6.3-70

6.4 HABITABILITY SYSTEMS

Control room systems are designed in accordance with the design bases described in Section 6.4.1 so that habitability of the control room can be maintained under normal and accident conditions. The general guidance contained in General Design Criterion 19 of 10CFR50, Appendix A, and the specific guidance contained in Regulatory Guide 1.78 is reflected throughout this section.

6.4.1 DESIGN BASES

The design bases for control room habitability systems are as follows:

a. Control Room Envelope

The control room envelope includes all areas located on elevation 654'-6" of the control complex. Housed within this control room envelope are the monitoring equipment, instrumentation and control panels required for safe operation and shutdown of the plant. The control room envelope is provided with fire protection equipment, adequate lighting, communications equipment and kitchen, sanitary, administrative and storage facilities and spaces necessary for normal plant operation and required to maintain the plant in a safe condition following an accident. The control room envelope ambient atomosphere is normally maintained at 75°F ± 2°F, drybulb and 50 percent relative humidity.

b. Period of Habitability

The control room envelope is equipped to sustain seven people for a period of seven days following an accident.

c. Capacity

The normal occupancy level of the control room is six people.

d. Food, Water, Medical Supplies and Sanitary Facilities

First aid equipment, food and water are provided to sustain seven people for seven days following an accident. Chemical toilet facilities are provided for use in the event that normal sanitary facilities become inoperative.

e. Radiation Protection

Radiation protection, as required by 10 CFR 50, Appendix A, Criterion 19, is provided by shield walls on the four exposures, shield slabs at floor and ceiling, radiation monitoring equipment and emergency filtering systems. The control room atmosphere is monitored for radiation. When required, the control room atmosphere can be recirculated through the emergency filter system to remove contaminants. This filter system consists of roughing, high efficiency particulate arrestor (HEPA) and charcoal filters. Assumptions and analyses regarding sources and amounts of radioactivity which may surround or leak into the control room and related shielding requirements are discussed in Chapters 12 and 15. The radiation monitoring system is discussed in Section 12.3.4.

f. Noxious Gas Protection

Smoke detectors located in the control room air supply duct and in the emergency filter system discharge duct actuate alarms to indicate the presence of smoke in these locations. Additionally, the control room can be purged with outside air if required. Conformance with the guidelines given in Regulatory Guide 1.78 is discussed in Section 2.2.3.

g. Respiratory, Eye and Facial Protection for Emergencies

Breathing and eye protection apparatus are provided for control room occupants. Breathable air is provided by the safety related instrument air system compressors located in the auxiliary building at elevation 620'-6". This air system supplies a breathable air station for face masks located in each control room. Scott Air Packs (Model 11A) are provided for control room occupants. A charging station for the Scott Air Packs,

located outside the control room, is also served by the safety related instrument air system. The capacity of the safety related air system and purifier cartridge is sufficient to supply seven men for approximately 140 hours.

h. Habitability System Operation during Emergencies

Operation of the habitability system during emergencies is discussed in Section 6.4.3.

i. Emergency Monitors and Control Equipment

Emergency monitors and control equipment are discussed in Section 13.3.

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of Control Room Envelope

The control room envelope comprises those areas to which the control room operator could require access during an emergency. It includes the following:

a. Control room main control board and monitoring panel area - continuous occupancy required.

b. Chart and storage room - infrequent access required.

c. Shift supervisor's office - infrequent access required.

d. Kitchen facility - infrequent access required.

e. Toilet room - infrequent access required.

The equipment to which the control room operator could require access during an emergency is listed in Table 6.4-1.

6.4.2.2 Ventilation System Design

The heating, ventilating and air conditioning (HVAC) and the emergency filtration systems for the control room are shown schematically in Figure 6.4-1. This figure illustrates components, ducts, dampers, instrumentation and normal and emergency air flow rates, and consists of the following:

a. Control room HVAC system

b. Control room emergency recirculation system

The components are not subject to the effects of floods, catastrophic weather, internal or external missiles, pipe whip or jet impingement.

Figure 6.4-2 presents a layout drawing of the control room, indicating doors, corridors, stairwells and shielded walls.

The location of potential radioactive gas releases and their effect upon control room operation and the monitoring instrumentation and controls located therein are discussed in Chapter 11.

6.4.2.2.1 Control Room HVAC System

The function of this system is to provide cooling, heating, ventilation, and, when required, smoke removal of the control room equipment areas and office during normal plant operation, plant shutdown, loss of offsite power and during periods of emergency (loss-of-coolant-accident or high radiation conditions).

This system operates continously to supply 45,000 cfm of conditioned air, including 6,000 cfm outside air for ventilation, to the control room to dissipate the internal heat load generated and maintain the control room ambient air at approximately 75°F and 50 percent relative humidity year round.

During normal plant operation, the system supply (M25-C001A or B) and return fans (M25-C002A or B) run continuously, the outside air intake dampers (M25-F010A or B, M25-F020B or A), and the return damper (M25-F110A or B) are open, and the exhaust air damper (M25-F130A or B) is closed. Either the "A" set or the "B" set of supply and return components is in operation with the idle redundant equipment as backup. The emergency recirculation system is idle and closed off from the HVAC system by its closed discharge (M26-F040A or B) damper; see Section 6.4.2.2.2 for further details on the operation of this system. Normally, 4,900 cfm is assumed to exfiltrate from the control room through normal openings, thereby ensuring a positive pressure inside the room.

Electric heating coils (with SCR controllers) in the branch supply ducts to the various zones in the control room are provided to control the final ambient air temperature in each zone. An electronic thermostat in each zone is used to provide a signal to the SCR controller which will control the heating coil, depending upon final room temperature.

Humidification during the winter is also provided by the control and computer rooms humidification system. An electronic humidity controller, with local indication, is located in the general area of the control room to modulate the electric motor operated valve on the humidifier (M29-B002A, B). For further details in the operation of the humidification system, see Section 9.4.12.

The instrument air system which supplies control air to the pneumatic dampers is not connected to the emergency bus. In the event of loss of offsite power (without LOCA, coupled with subsequent loss of control air), the pneumatic dampers assume their failed position. This places the system in the recirculation mode with return flow prevented by check damper (M25-F551A, B). At this time the operator will manually place the system in the emergency recirculation mode through the system mode selector switch.

In the event of high smoke condition, the smoke can be purged by manually setting the mode selector switch in the smoke clear mode.

The main components of this system are located in the control complex at elevation 679'-6" and consist of two redundant supply plenums (M25-B001A and B001B), two redundant supply fans (M25-C001A, C001B) and two redundant return fans (M25-C002A, C002B), each rated at 100 percent of the total required capacity.

Each supply plenum includes roughing filters and chilled water coils. Each outside air intake duct is provided with redundant dampers (M25-F010A or F010B and M25-F020A or F020B) in series to reduce the outside air inleakage when the system is in the emergency recirculation mode. A check damper (M25-F510A or F510B) is provided in the discharge duct of each supply fan. In addition, manually operated balancing dampers for balancing, and fire dampers for fire protection, are provided.

Each return unit consists of a centrifugal fan (M25-C002A or C002B), an exhaust air isolation damper (M25-F130A or F130B), a return air isolation damper (M25-F110A or F110B), manually operated balancing dampers and fire dampers. The exhaust isolation damper (M25-F130A or F130B) is normally closed and the return isolation damper (M25-F110A or F110B) is normally open.

The fans, filter elements, coils, and dampers are of standard industrial design manufactured in accordance with the Quality Assurance (QA) requirements of Safety Class 3, Seismic Category I items. The filter racks and plenums are specially designed to satisfy system space requirements and also meet the above QA requirements. However, the electric heating coils and the humidifiers are non-safety related items. Design information for the major components in this system is listed in Table 6.4-2.

6.4.2.2.2 Control Room Emergency Recirculation System

This system provides the necessary supplementary particulate and halogen filtration of the air supplied to the control room areas and offices during emergency periods and other abnormal conditions for personnel protection.

This system is automatically activated by an emergency signal, such as LOCA or high radiation, or by manually setting the mode selector switch to the emergency recirculation mode. In addition, the receipt of the emergency signal causes dampers in the control room HVAC system to be automatically positioned to the emergency recirculation mode of operation (see Note 4 of Figure 6.4-1a for the damper positions). The vortex damper operator (M25-F260A, B) of the supply fan (M25-C001A, B) is then automatically deenergized allowing the operator spring to partially close the variable inlet vanes to reduce the supply air flow to 30,000 cfm. This flow reduction is required so that the supply fan and recirculation fan flow rates are compatible. Return fan (M25-C002A or B) is also deactivated and the electric heating coil in the charcoal filter train is automatically energized upon receipt of an emergency signal.

The emergency recirculation system causes the supply air to be filtered through the charcoal filter train (M26-D001A, B) before being distributed to the control room. This system is idle during normal plant operation. During periods of loss of offsite power, emergency power will be supplied by the standby diesel generators.

The degree to which the reccommentations of Regulatory Guide 1.52 are followed is given in Table 6.5-1.

The main components of this system are located in the control complex at elevation 679'-6" and consist of two 100 percent capacity filter trains. Each filter train includes the following sequential components: demisters, roughing filters, HEPA prefilters, charcoal filters, HEPA after filters, centrifugal fan isolation damper and check damper.

The fans, filter elements and dampers are of standard industrial design, manufactured in accordance with Quality Assurance (QA) requirements of Safety Class 3, Seismic Category I items. The filter racks, frames and housing are specially designed to satisfy the system space requirements and also meet the above QA requirements.

Design information for the major components in this system is listed in Table 6.4-3.

6.4.2.3 <u>Leak Tightness</u>

The control room system is designed so that, when operating in a normal mode (admitting outside air), the system automatically maintains a positive differential pressure between the control room and the outside and thus, between the control room and adjacent spaces. During an emergency, when the system operates in the recirculation mode (no designed admittance of outside air), no attempt is made to pressurize the control room. In the recirculation mode, the potential paths of air infiltration to the control room include (1) outside air dampers and relief air dampers, (2) openings around supply and return ducts in the control room walls and in duct chase floors, (3) openings for electrical conduit and cables in the control room and chase walls and floors, (4) doors, and (5) piping.

A review of these paths, summarized as follows, indicates that infiltration through these paths during the recirculation mode is minimal:

a. The outside air is sealed from the control room by two 40 inch wide by 48 inch high dampers in series, both gasketed and arranged to close in the recirculation mode and to fail closed upon loss of control air or power. The maximum leakage is 29 cfm through a single 42 inch by 48 inch outside air damper in the recirculation mode, at an estimated pressure differential across the damper of 0.25 inches of water. Maximum leakage through two closed dampers in series is approximately 20 cfm. This estimate conservatively assumes no pressurization in the control room. If the control room were pressurized, the pressure differential across the dampers would decrease. The duct pressure loss calculations for the control room system indicate that, during operation in the recirculation mode and with control room ambient pressure assumed to be 0 psig, the pressure at the inside of the outside air inlet damper would be 0.25 inches of water.

b. The exhaust isolation dampers are similar in arrangement and the potential infiltration quantity is similar to that discussed in item a, above.

c. Openings around supply and return ducts in the walls and floors of the control room and chases are sealed with expanded silicone foam with a fire resistance rating of three hours. These openings are air tight.

d. Openings for electrical conduit and cables in the walls and floors of the control room and chases are sealed in the same manner as the openings noted in item c, above.

e. Doors from the control room to the chase area and stairwells are three hour fire rated doors with closures. The maximum anticipated total air gap around each door is 0.27 ft^2.

f. Piping to plumbing fixtures, drains and potable water leaving the control room are sealed in the manner noted in item c, above.

None of the control room doors lead directly to the outside. All doors lead to closed chase spaces, closed stairwells or closed corridor space. Thus, neither outside wind conditions nor other ventilation system cause infiltration or leakage into the control room.

6.4.2.4 Interaction With Other Zones and Pressure Containing Equipment

The control room ventilation system does not communicate with other building areas where potential for radioactivity exists. The system does communicate with the chart room which is flooded with carbon dioxide in the event of a fire emergency in this area. The supply is automatically sealed with smoke dampers to prevent the escape of carbon dioxide to control room areas, should the carbon dioxide system be used. There are no pressure containing pipes or equipment containing hazardous chemicals in the control room chases.

The normal operating mode of the control room ventilation system maintains a positive pressure differential between the control room and adjacent spaces. The likelihood of infiltration is therefore further reduced. A radiation monitor sensing control room atmospheric radioactivity immediately causes the ventilation system to shift into the recirculation mode upon detection of high

gaseous activity. Thus, the potential for entry of outside airborne material into the control room is reduced. The control room ventilation system can also be manually controlled to purge the control room with outside air. The outside air purge rate is variable up to 100 percent of the system flow rate.

6.4.2.5 Shielding Design

The control room shielding design is discussed in Section 12.1.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

The control room is served by redundant normal and redundant emergency HVAC systems. The emergency systems provide for operation in the recirculation mode, the smoke clearing mode, during loss of offsite power, and for activation of the carbon dioxide fire protection system and charcoal water spray system.

The normal control room HVAC system operates continuously to provide heating, ventilating and cooling to various equipment and personnel areas in the control room.

The control room emergency recirculation system is idle except when activated by an emergency signal or when the mode selector switch is manually set to "EMER. RECIRC.". During periods of emergency, such as a LOCA or high ra[illegible]ion, the dampers automatically are positioned for the recirculation [illegible] Also, following this type of emergency the return fan (M25-C002A or B) [illegible], both emergency recirculation fans (M26-C001A & B) and the control room [illegible]upply fans (M25-C001A & B) start simultaneously, and subsequently, one [illegible]n is manually stopped.

[illegible]trol room has a smoke removal mode of operation used to purge the control room with outside air when smoke is detected. This is accomplished by remote-manually positioning the mode selector switch located on panel H13-P904

to "SMOKE-CLEAR." Operation of this switch positions the related dampers to the purge mode and automatically positions the variable inlet vanes of the supply and return fans at 30,000 cfm flow.

The position of system dampers during the normal, emergency-recirculation and smoke clearing mode is indicated under Note 4 of Figure 6.4-1a.

If loss of offsite power occurs (without LOCA), emergency power is provided by the standby diesel generators and the system operates with dampers in the normal mode until control air is lost. At this time, the operator manually places the system in the emergency recirculation mode by setting the mode selector switch to "EMER. RECIRC.".

If fire occurs in the chart room, the carbon dioxide system for this room activates. At the same time, a signal is given to melt the electro-thermal link of the fire dampers allowing the dampers to close, thus isolating the chart room. After the fire has been controlled, the room may be purged using a portable blower.

If excess temperature occurs in emergency filter plenums (as indicated by a high-high temperature alarm), the fire protection water spray system in the filter plenum activates. This is accomplished by activating the spray deluge valve remote-manually from the control room. This action also energizes the solenoid valve (M26-F081A or B) and opens the drain valve (M26-F080A or B). Deactivating the spray deluge valve deenergizes the solenoid valve (M26-F081A or B); however, the drain valve remains open until it is manually closed by a manual override lever.

6.4.4 DESIGN EVALUATION

Each of the operating systems which ensures control room habitability is discussed in detail in other sections. These systems, and the section in which they are discussed, are as follows:

a. Control room ventilation system, Section 6.4.2.

b. Fire protection system, Section 9.5.1.

c. Communications system, Section 9.5.2.

d. Lighting system, Section 9.5.3.

e. Offsite power system, Section 8.2.

f. Onsite power system, Section 8.3.

g. Radiation monitoring system, Section 12.3.4.

A summary evaluation of control room habitability based on selected considerations is presented in Sections 6.4.4.1 through 6.4.4.6.

6.4.4.1 Radiological Protection

The evaluation of radiological exposures to control room operators for postulated accident conditions is presented in Section 15.4.

6.4.4.2 Toxic Gas Protection

No toxic materials which could interfere with control room occupancy are stored in the plant. Sodium hypo-chlorite, rather than chlorine, is used as a biocide. No chlorine is stored on site. The potential effects of offsite and onsite hazardous materials are discussed in Sections 2.2.2 and 2.2.3.

6.4.4.3 Control Room Emergency Recirculation System

The general arrangement and control of the control room emergency recirculation system is as described in Section 6.4.2.2.2. Detailed information concerning the emergency filter is presented in Section 6.5.1. The equipment is shielded, housed in a Seismic Category I structure,

separated, redundant and powered from the Class 1E electrical system. It is equipped with filters designed in accordance with the requirements of Regulatory Guide 1.52 (see Section 6.5.1).

No single failure results in loss of system function.

In case of loss of offsite power, redundant emergency power will be provided by the standby diesel generators and the fans will be automatically started.

The electric heating coils for the emergency recirculation system are connected to the standby diesel generators to allow operation of the coils during loss of offsite power. The power supply to each filter train heating coil is from a separate safety division bus.

Single component failure analysis of the control room emergency filter system is discussed in Table 6.4-4.

Implementation of scheduled field testing, inspection, and maintenance programs ensure that each filtering system performs in accordance with design requirements.

6.4.4.4 Control of the Control Room Thermal Environment

The control room air handling system operates during normal and emergency periods to maintain an environment suitable for personnel and equipment. The conditions maintained and general system description are presented in Section 6.4.2.2.1. The system satisfies the single failure criteria by providing redundant, separated and shielded air handling and cooling water systems (see Section 9.4.9 for details on the cooling water system). Thus, the integrity and operability of this system during normal and emergency periods is ensured.

Each portion of the system is sized for its maximum anticipated internal cooling load, considering outdoor summer design conditions expected for no more than 2.5 percent of the year. Additional margin is provided in equipment selection to allow for degradation of coil surfaces, films and changes in system air flow during operation. Scheduled maintenance procedures assure that each system performs in accordance with design requirements.

6.4.4.5 Fire Protection

Protection against fire hazards is provided by fire hose cabinets, CO_2 extinguishers and dry chemicals in the control room and adjacent areas. These fire supression devices are provided in accordance with requirements of the National Fire Codes of the National Fire Protection Association (NFPA), the requirements of American Nuclear Insurers (ANI), the applicable regulations of the state of Ohio, and the requirements of the Occupational Safety and Health Administration (OSHA). The state of readiness of the fire protection system is maintained by enforcing a program of listing, inspection and maintenance. Further evaluation of the fire protection system is presented in Section 9.5.1.

6.4.4.6 Food, Water and Sanitation

A seven day supply of food is provided in the control room for emergency use. If the emergency requires confinement for periods longer than seven days, additional food will be brought onsite in protected containers. Site accessability will be determined by the plant health physicist.

Potable water is normally available from the potable water system described in Section 9.2.4. Should this system become unavailable during an emergency period, stored, bottled water is available in an area immediately adjacent to the control room. Additional bottled water could be brought into the control room, if required.

Normal sanitation facilities are available as described in Section 9.2.4. Chemical toilets are also available in these areas for use in the event that the normal facilities become inoperative following an emergency.

6.4.5 TESTING AND INSPECTION

The equipment which maintains control room habitability includes the emergency filter system, the control room air handling system and the chilled water system.

Components of these systems are subjected to documented preoperational test procedures to verify proper wiring, system integrity and leak tightness, proper function of system components and control devices under normal and emergency conditions and to establish system air and water balance in accordance with design requirements. Those not in accordance with design requirements are returned to construction for repair/replacement prior to final acceptance.

The main components of the control room HVAC system, control room emergency recirculation system and the control complex chilled water system are readily accessible for inspection, testing and maintenance during normal plant operation or shutdown. Redundancy in the system enables inspection, maintenance and testing to be performed without interrupting the normal operation of the systems.

Periodic tests will be performed on the control room emergency filter system. These tests will include measurement of differential pressure across the filter units and determination of filter efficiency to demonstrate that aging, weathering, or poisoning of the filters has not significantly degraded the adsorption material in the charcoal and HEPA filters.

After system startup, test and balance procedures have been completed, the system is periodically and routinely tested, checked and/or inspected as follows:

a. Inspections are made for signs of corrosion, metal fatigue, excess vibration, belt wear and tightness of isolation dampers.

b. Filter pressure drops are checked and recorded.

c. Water and air flow rates in main pipes or main ducts are checked and verified against the design flow rates.

d. Functions of dampers, valves or control devices necessary for component isolation or changeover from normal to emergency mode are verified.

e. Charcoal filter canisters are laboratory tested in accordance with the recommendations of Regulatory Guide 1.52.

f. Bearings are lubricated.

g. The redundant components of the system are switched from the standby mode to the operating mode.

6.4.6 INSTRUMENTATION REQUIREMENTS

Habitability systems instrumentation and control equipment provides for control and monitoring of performance and status during system operation and testing. The instrumentation and control provisions for each of the systems used to ensure control room habitability are discussed in other sections. A list of these systems and the sections in which they are discussed is presented in Section 6.4.4. A summary discussion is presented in Sections 6.4.6.1 through 6.4.6.4.

6.4.6.1 Control Room HVAC System

Operation of this system is initiated manually from the control room, such that either the "A" or the "B" set of supply and return components is operating, with the redundant set of components idle as backup.

The control room HVAC system (exclusive of the emergency recirculation fans, ducts and filters) is provided with controls for temperature, flow and humidity. This system is provided with alarms, status lights and indicators in the control room and at appropriate locations to ensure that the operator can determine the status and operation of the system from the control room. The system is also equipped with sensors and detectors to detect, alarm, and monitor smoke and radiation. The details of the instrumentation and controls for this system are presented in Section 7.3.1.

6.4.6.2 Control Room Emergency Recirculation System

Operation of this system is initiated automatically upon receipt of an emergency signal. During emergency recirculation mode of operation, one of the two fans (the one related to the active control room HVAC system) operates continuously.

The control room emergency recirculation system is provided with controls for automatic or manual initiation. This system has sensors, instruments and indicators to monitor flow, pressure drop across filters, humidity and charcoal filter temperature. Alarms, status lights and indicators located in the control room provide the operator sufficient information to determine system status and operation. The system instrumentation is designed essentially to conform with Regulatory Guide 1.52. No recorders are provided since this system is intended for infrequent use (periodic testing and emergency periods only), and operability and reliability difficulties become a factor for recorders that are infrequently used. Complete details of the system instrumentation and controls are presented in Section 7.3.1.

6.4.6.3 Lighting System

Actuation of the control room emergency d-c lighting system occurs automatically if the a-c lighting system power is lost.

6.4.6.4 Offsite and Onsite Power Systems

Operator control and monitoring of the status of onsite power, as well as offsite power feeds, are performed from control panels in the control room. Automatic actuation of each onsite a-c emergency diesel generator occurs when an undervoltage condition is sensed on the associated bus.

TABLE 6.4-1

EQUIPMENT WHICH COULD REQUIRE CONTROL ROOM OPERATOR ACCESS DURING AN EMERGENCY

Item or Equipment	Location Within Control Room Envelope
Control and Monitoring Panels	Identified on Figures 6.4-2 and 6.4-3
Portable Radiation Measuring Instruments	Store room
Emergency Procedures, Manuals and Drawings	Operator's work station
Self-Contained Breathing Apparatus	Store room
Communications Equipment	Operator's work station
Fire Extinguishing Equipment	Identified on Figure 6.4-3
Food Supplies	Kitchen

TABLE 6.4-2

CONTROL ROOM HVAC SYSTEM MAJOR COMPONENTS

A. PLENUMS

No. of plenums	2 for Units 1 & 2 (each 100%)
Manufacturer	AAF

B. SUPPLY FAN

No. of fans	2 for Units 1 & 2 (each 100%)
Manufacturer	Westinghouse
Fan type	Centrifugal, SWSI
Fan size (wheel diameter), in.	49
Arrangement	No. 3
Discharge position	Upblast
Air quantity required, cfm	45,000 per fan
Static pressure required, in WG.	5 per fan
Motor horsepower, hp	60 per fan
Motor location	Direct driven
Motor speed, rpm	1170
Motor electrical characteristics	460 V, 3 phase, 60 hertz

C. RETURN FAN

No. of fans	2 for Units 1 & 2 (each 100%)
Manufacturer	Westinghouse
Fan type	Centrifugal, SWSI
Fan size (wheel diameter), in.	49
Arrangement	No. 3
Discharge position	Upblast
Air quantity required, cfm	39,000 per fan
Static pressure required, in. WG.	3 per fan

TABLE 6.4-2 (Continued)

Motor horsepower, hp	60 per fan
Motor location	Direct Driven
Motor speed, rpm	900
Motor electrical characteristics	460 V, 3 phase, 60 hertz

D. COOLING COILS

No. of coil bank	1 per plenum
Type of coil	Horizontal finned tubes air-water counter flow
Cooling capacity, tons	155 per coil bank
Entering water temperature, °F	45
Leaving water temperature, °F	54.30
Chilled water flow rate (max), gpm	400 per coil bank
Max. coil face velocity, fpm	600 per coil bank

E. DUCT REHEAT COILS

No. of coils	9 for Units 1 & 2
Type	Electric
Type of Controller	SCR
Quantity and kw rating required	2 - 1 kw 1 - 3 kw 2 - 15 kw 2 - 25 kw 2 - 30 kw
Electrical characteristics	480 V, 3 phase, 60 hertz

TABLE 6.4-2 (Continued)

F. ROUGHING FILTERS

No. of filter banks	1 per plenum
Manufacturer and Model	AAF, Varicel 9-2424-12
Material	Glass fiber with aluminum separators
No. of cells per bank	25
Rated flow per cell, cfm	2000
Efficiency, %	85-90 (per ASHRAE 52-68)
Max resistance, in. WG.	0.55 (clean)

TABLE 6.4-3

CONTROL ROOM EMERGENCY RECIRCULATION SYSTEM

MAJOR COMPONENTS

A. PLENUMS

No. of plenums	2 for Units 1 & 2 (each 100%)
Manufacturer	CVI

B. FAN

No. of fans	1 - 100% capacity per plenum
Manufacturer	Westinghouse
Fan type	Centrifugal, SWSI
Fan size (wheel diameter), in.	36-1/2
Arrangement	No. 8
Discharge position	Upblast
Motor location	Direct Driven
Motor speed, rpm	1200
Air quantity required, cfm	30,000 per fan
Static pressure required, in. WG	8 per fan
Motor horsepower, hp	100 per fan
Motor electrical characteristics	460 V, 3 phase, 60 hertz

C. FILTERS

1. Demisters

Manufacturer and Model	ACS #-01-55
No. of demister bank	1 per plenum
No. of cells/bank	21
Rated flow per cell, cfm	1600
Max. resistance at rated flow, in. WG	0.97 (clean)

TABLE 6.4-3 (Continued)

2. Roughing Filters

No. of filter banks	1 per plenum
Manufacturer and Model	Flanders, A083-L
No. of cells/bank	21
Rated flow per cell, cfm	2000
Material	Glass fiber without separators
Efficiency, %	85-90 (per ASHRAE 52-68)
Max. resistance at rated flow, in. WG.	0.52 (clean)

3. HEPA Prefilters and Afterfilters

No. of filter banks	2 per plenum
Manufacturer and Model	Flanders, 7083-NL
No. of cells per bank	21
Rated flow per cell, cfm	1500
Material	Continuous pleated web of glass fiber without separators
Efficiency, %	99.97 for particles 0.3 microns and larger
Max. resistance at rated flow, in. WG.	1.0 (clean)

TABLE 6.4-3 (Continued)

4. Charcoal Filters

Manufacturer and Model	CVI, HECA Module
No. of filter banks/plenum	1
No. of beds per banks	15 - 2" thick beds
Rated flow per bed, cfm	2000
Material	Activated coconut charcoal impregnated with KI
Efficiency, %	99.9 on elemental iodine 95 on methyl iodide
Max. resistance at rated flow, in. WG.	1.3 (clean)
Iodine desorption temperature range, °F	250-300
Charcoal ignition temperature range, °F	662-752

5. Electric Heating Coil

No. of coil bank	1 per plenum
Heating capacity, kw	100
Electrical characteristics	480 V, 3 phase, 60 hertz

TABLE 6.4-4

CONTROL ROOM EMERGENCY FILTER SYSTEM

SINGLE FAILURE ANALYSIS

Component	Malfunction	Comments
Fan	Failure of operating fan resulting in loss of air flow	Two 100% capacity fans are provided. If the operating fan fails, resultant loss of air flow in the duct actuates the alarm in the control room and the standby fan will be started manually by the operator.
HEPA filters	Release of DOP resulting in contamination of charcoal filters	After initial installation of the HEPA filters and periodically thereafter, the filter bank leak integrity will be determined by using DOP. On the basis of testing each HEPA filter element individually, a maximum of approximately 2.82 micrograms of DOP will be retained in each HEPA filter element. The Control Room Emergency filter system has one HEPA filter element upstream of the charcoal filter and one HEPA filter element downstream of the charcoal filter. It is possible that the DOP can be released from the HEPA filter as the filter temperature increases. However, the charcoal adsorber being a poor particulate filter would retain a negligible quantity of DOP released in this manner.

TABLE 6.4-4 (Continued)

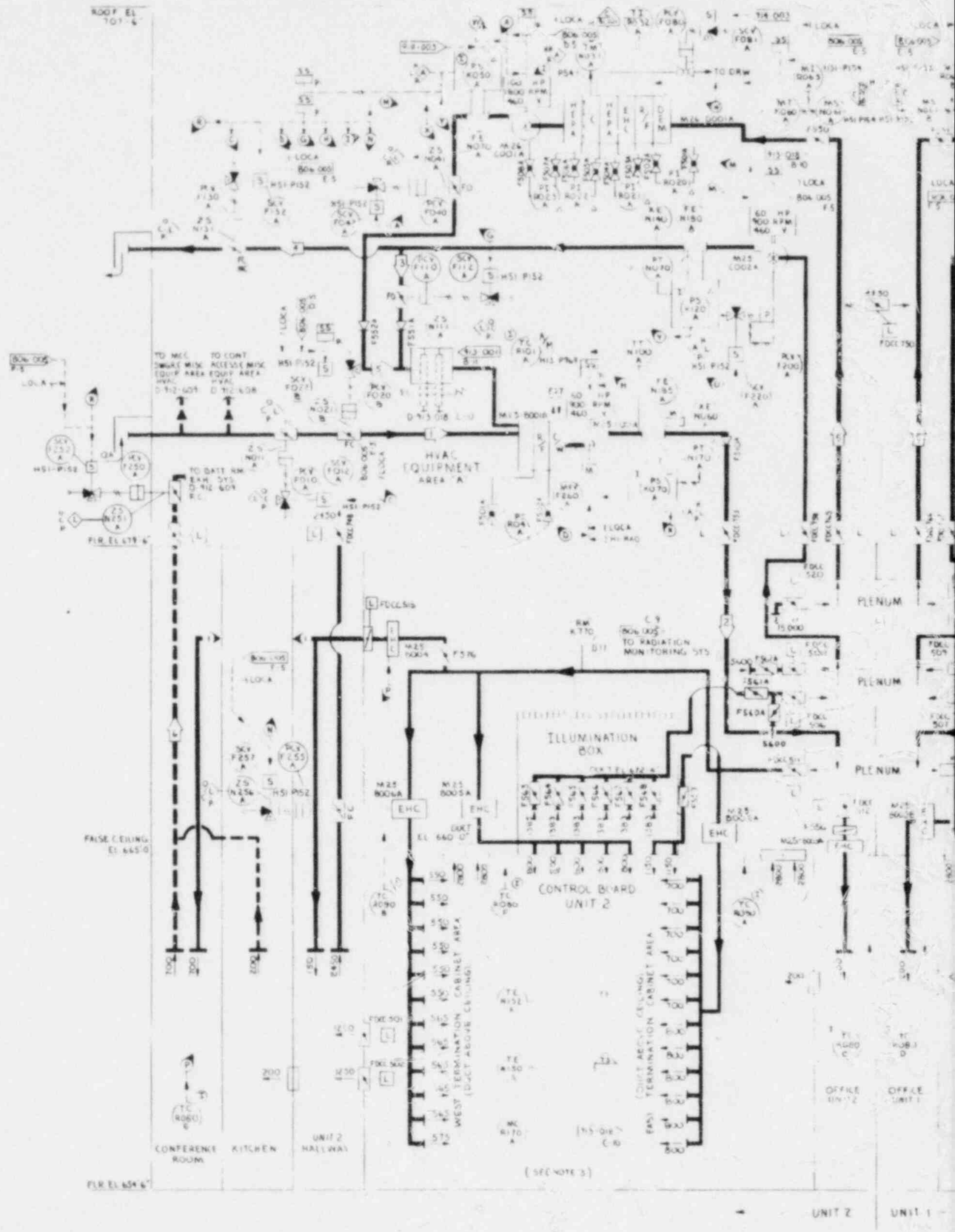
Component	Malfunction	Comments
		Combining I-131 with the retained DOP in the HEPA filter results in an insignificant amount of methyl iodine formed. The system has enough charcoal capacity to absorb the maximum loading of both radioactive and non-radioactive isotopes of iodine and bromine. Also, the temperature of this system is substantially below the 410°F flash point of DOP.
Charcoal filters	High temperature in the charcoal beds	Two 100 percent capacity filter trains are provided in this system. In addition, temperature indicators and switches are provided in each charcoal cell bed to alarm in the control room and give an indication (readout) on rising charcoal temperature. Also, since the air flowing through the charcoal is at a low temperature (75-80°F), this air will keep the charcoal filter temperature from rising to the critical value (250-300°F desorption temperature). However, should the temperature reach 250°F, an alarm is set in the control room to signal the operator to activate the charcoal water spray system and prevent the charcoal beds from desorbing. Also at this time, the standby charcoal

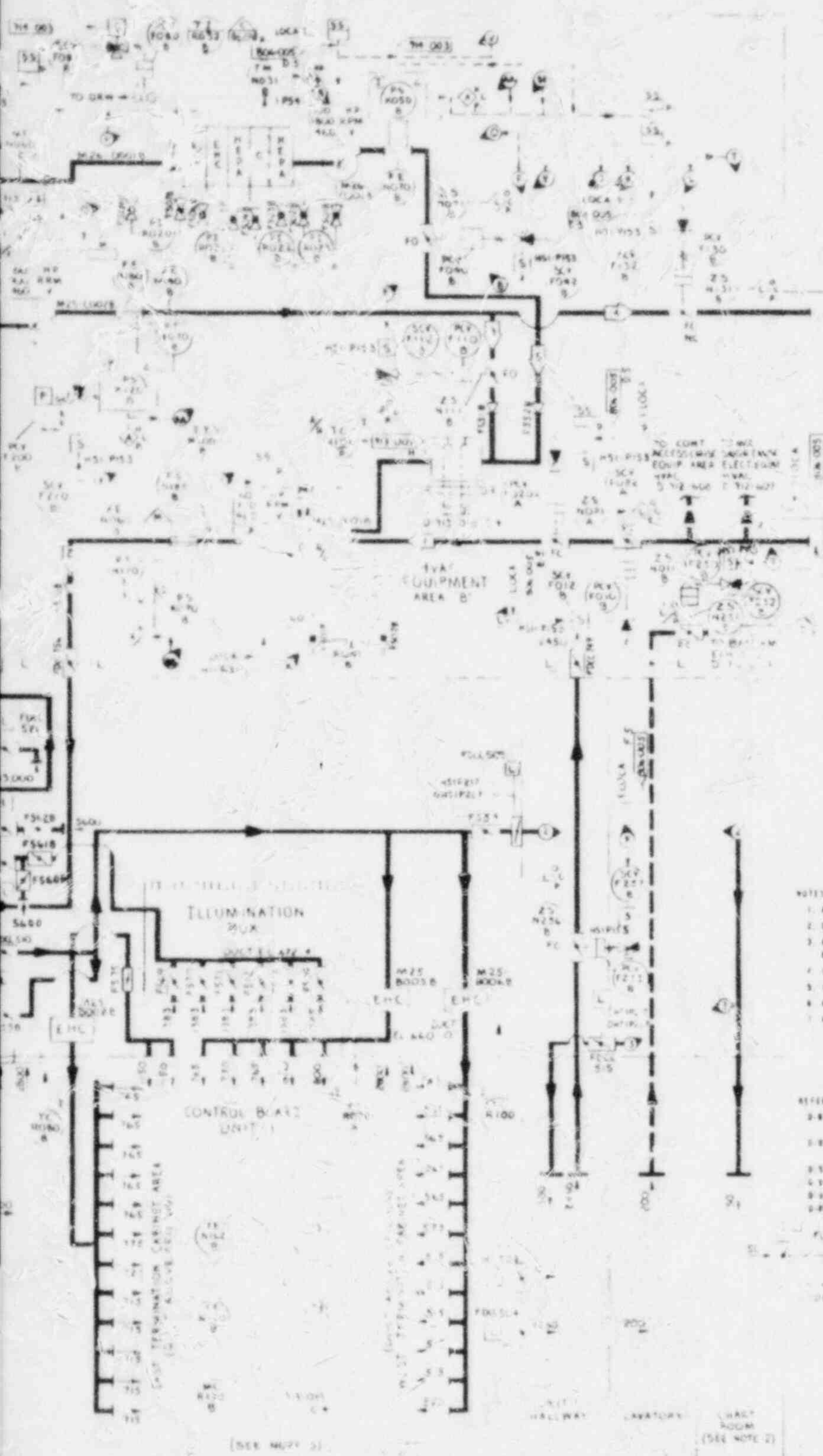
TABLE 6.4-4 (Continued)

Component	Malfunction	Comments
		filter train will be activated so that operation of the emergency recirculation system is not interrpputed.
Filter train	Failure resulting in high differential pressures across HEPA or charcoal filters	High differential pressure across filters results in low air flow which is alarmed in the control room. Operator may switch to the redundant train.
	Failure resulting in high temperatures in the charcoal bed	High temperature is annunciated in the control room. High-high temperature is alarmed in the control room to signal operator to initiate the deluge system. Initiation of the deluge system is indicated in the control room and the operator may switch to the redundant train.
Dampers	Loss of control air	The dampers are spring assisted to position them in the safety or emergency mode of operation on loss of control air.
Ducting	Duct failure	This system is designed with separate and redundant ducting and dampers.

TABLE 6.4-4 (Continued)

Component	Malfunction	Comments
		filter train will be activated so that operation of the emergency recirculation system is not interrputed.
Filter train	Failure resulting in high differential pressures across HEPA or charcoal filters	High differential pressure across filters results in low air flow which is alarmed in the control room. Operator may switch to the redundant train.
	Failure resulting in high temperatures in the charcoal bed	High temperature is annunciated in the control room. High-high temperature is alarmed in the control room to signal operator to initiate the deluge system. Initiation of the deluge system is indicated in the control room and the operator may switch to the redundant train.
Dampers	Loss of control air	The dampers are spring assisted to position them in the safety or emergency mode of operation on loss of control air.
Ducting	Duct failure	This system is designed with separate and redundant ducting and dampers.


ROOF EL 707'-6"
HVAC EQUIPMENT AREA "A"
TO RADIATION MONITORING SYS
ILLUMINATION BOX
CONTROL BOARD UNIT 2
PLENUM
PLENUM
PLENUM
FALSE CEILING EL 665'0"
WEST TERMINATION CABINET AREA (DUCT ABOVE CEILING)
(DUCT ABOVE CEILING) TERMINATION CABINET AREA
CONFERENCE ROOM
KITCHEN
UNIT 2 HALLWAY
OFFICE UNIT 2
OFFICE UNIT 1
(SEE NOTE 3)
FLR EL 654'-6"
UNIT 2
UNIT 1



DESIGN DATA (NORMAL)			
	CFM	BY	REMARKS
	6 000		
2	45 000		
3	39 000		
4	0		
5	0		
6	900		

DESIGN DATA (EMERGENCY)			
	CFM	BY	REMARKS
1	0		
2	30 000		
3	0		
4	0		
5	30 000		
6	0		

DESIGN DATA (SMOKE CLEAR)			
	CFM	BY	REMARKS
1	30 000		
2	30 000		
3	0		
4	30 000		
5	0		
6	0		

NOTES:

1. ALL FANS, SUPPLY PLENUMS AND EXHAUST PLENUMS ARE [illegible]
2. CHART ROOM VENTS 50 CFM TO UNIT 1 HALLWAY
3. ALL DUCTING SHOWN IN THIS AREA ACTUALLY IN [illegible] CEILING WITH REGISTERS DOWN TO [illegible]
4. ILLUMINATION BOXES CONTAIN LIGHTING FOR AREA [illegible]
5. INLET VANES FOR FANS [illegible] ARE MANUALLY OPERATED
6. ALL AIR QUANTITIES ARE IN CFM
7. ADDITIONAL NOTES AND OPERATING DATA ARE SHOWN ON DWG. [illegible]

REFERENCES

D-912-600 CONTROLLED ACCESS AND MISCELLANEOUS EQUIPMENT AREAS HVAC SYSTEMS [illegible]

[illegible]

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Control Room HVAC and Emergency Recirculation System

Figure 6.4-1
(GAI Dwg. D-912-610)

CONTROL ROOM HVAC AND EMERGENCY RECIRCULATION SYSTEM
NOTES AND OPERATING DATA
(D-912-610)

NOTES -

1. ALL DIFFERENTIAL PRESSURE SWITCH ALARMS ARE INTERLOCKED WITH THE FAN MOTOR STARTER AND PROVIDED WITH TIME DELAY RELAY.
2. ALL CONTROL SWITCHES, STATUS LIGHTS, ALARMS AND TEMPERATURE INDICATORS ARE LOCATED ON THE COMMON HVAC PANEL (H13-P904) IN CONTROL ROOM #1.
3. ALL ALARMS FROM THIS SYSTEM ARE ANNUNCIATED AS "COMMON HVAC TROUBLE" ON PANEL H13-P680 IN BOTH CONTROL ROOMS.
4. THE 3 - POSITION SELECTOR SWITCH WILL POSITION THE DAMPERS AND START AND STOP FANS AS INDICATED IN THE TABLE BELOW.

ITEM		SMOKE CLEAR	NORMAL		EMER RECIRC
F130A (B)		O	C		C
F110A (B)		C	O		C
F010A (B)		O	O		C
F250A (B)		C	O		C
F255A (B)		C	O		C
SCV-F220A (B)		E	DE		E
M26-C001A (B)		S	S		R
M25-C001A (B)		R	R		R
M25-C002A (B)		R	R		S
M25-F260A (B)		DE	E		DE

R = RUN
S = STOP
C = CLOSED
O = OPEN
E = ENERGIZE
DE = DEENERGIZE

5. DAMPERS, EXCEPT F110, F250, AND F255 ARE POSITIONED AND FANS ARE OPERATED ACCORDING TO THE SELECTOR SWITCH POSITION ONLY WHEN THE ASSOCIATED FAN TRAIN INITIATE SWITCH IS IN "ON" POSITION, OTHERWISE THE DAMPERS ARE IN THE FAIL SAFE POSITION. SEE NOTE 11.
6. LOSS OF FAN OPERATION (LOW FLOW OR FAN TRIP) ON ANY OF THE OPERATING FAN TRAIN (A OR B) WILL TRIP THE REMAINING FANS. THE STAND BY FAN TRAIN (A OR B) IS MANUALLY STARTED AND WILL OPERATE ACCORDING TO THE SELECTOR SWITCH POSITION (SEE NOTE 4).
7. LOCA (FROM EITHER REACTOR) OR HIGH RADIATION WILL OVERRIDE THE SELECTOR SWITCH AND OPERATE THE SYSTEM IN THE EMERGENCY RECIRCULATION MODE.
8. SMOKE CLEARING MODE POSITION OF THE SELECTOR SWITCH WILL GIVE A SIGNAL TO ENERGIZE THE SOLENOID VALVE (SCV-F220A, B) TO VENT ACTUATORS (PCV-F200A, B) AND POSITION THE VARIABLE INLET VANES OF FANS (M25-C002A, B) TO REDUCE THE AIR FLOW TO 30,000 CFM.
9. SMOKE CLEARING MODE POSITION OF THE SELECTOR SWITCH WILL GIVE A SIGNAL TO DEENERGIZE THE ACTUATOR (MCV-F260A, B) AND POSITION THE VARIABLE INLET VANES OF FANS (M25-C001A, B) TO REDUCE THE AIR FLOW TO 30,000 CFM.
10. BYPASS AND INOPERABLE STATUS INDICATION IS REQUIRED IN THE CONTROL ROOM.
11. DAMPER M25-F255A, F255B, F250A AND F250B ARE NORMALLY IN THE "OPEN" POSITION. THESE DAMPERS CLOSE ONLY ON LOCA (FROM EITHER REACTOR), HIGH RADIATION, OR WHEN THE ASSOCIATED THREE-POSITION SELECTOR SWITCH (TRAIN MODE SWITCH) IS NOT IN THE "NORMAL" POSITION.
12. FOR PROPER SYSTEM OPERATION, BOTH A AND B TRAIN MODE SWITCHES SHOULD BE ADMINISTRATIVELY KEPT IN THE SAME POSITION.

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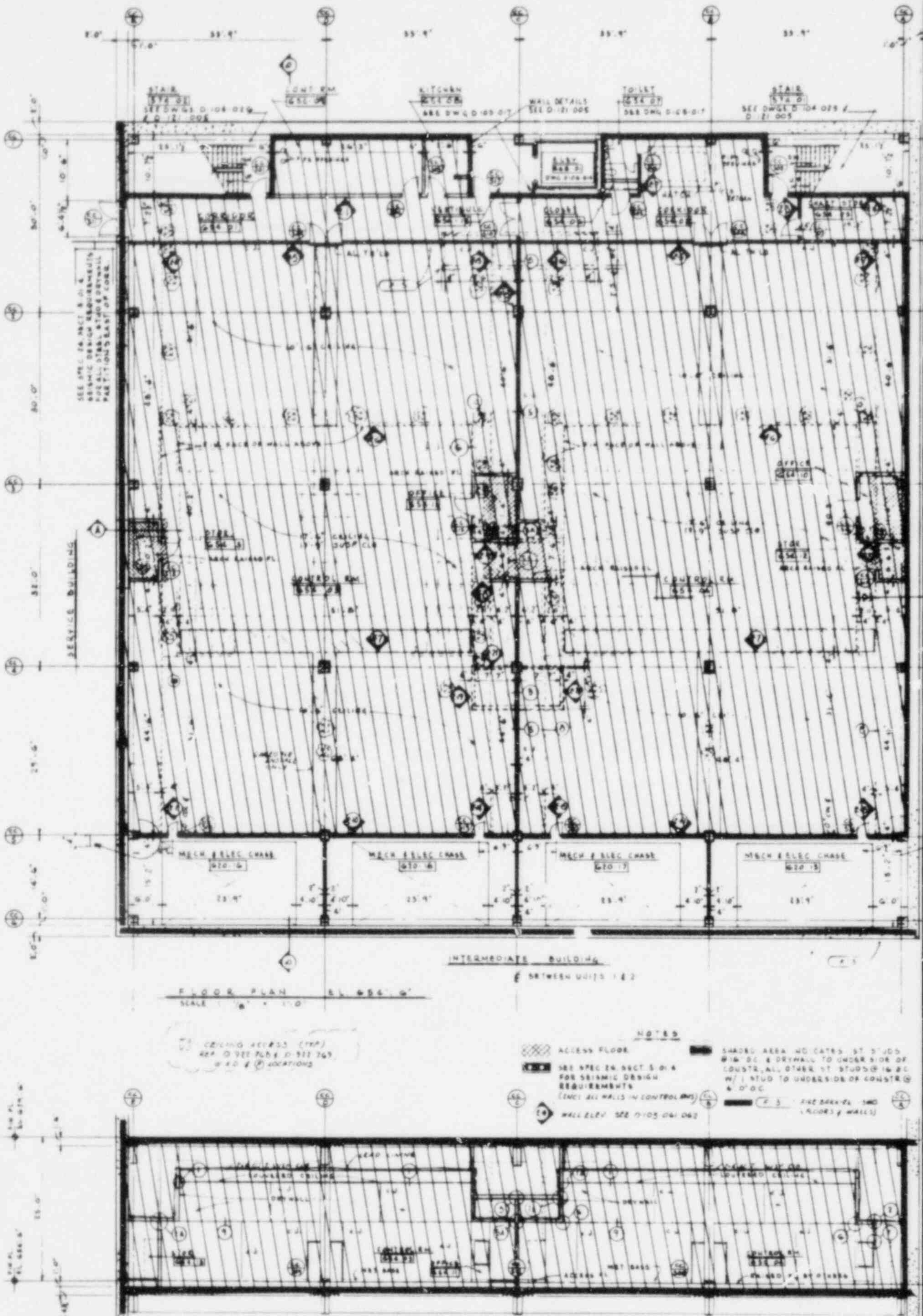
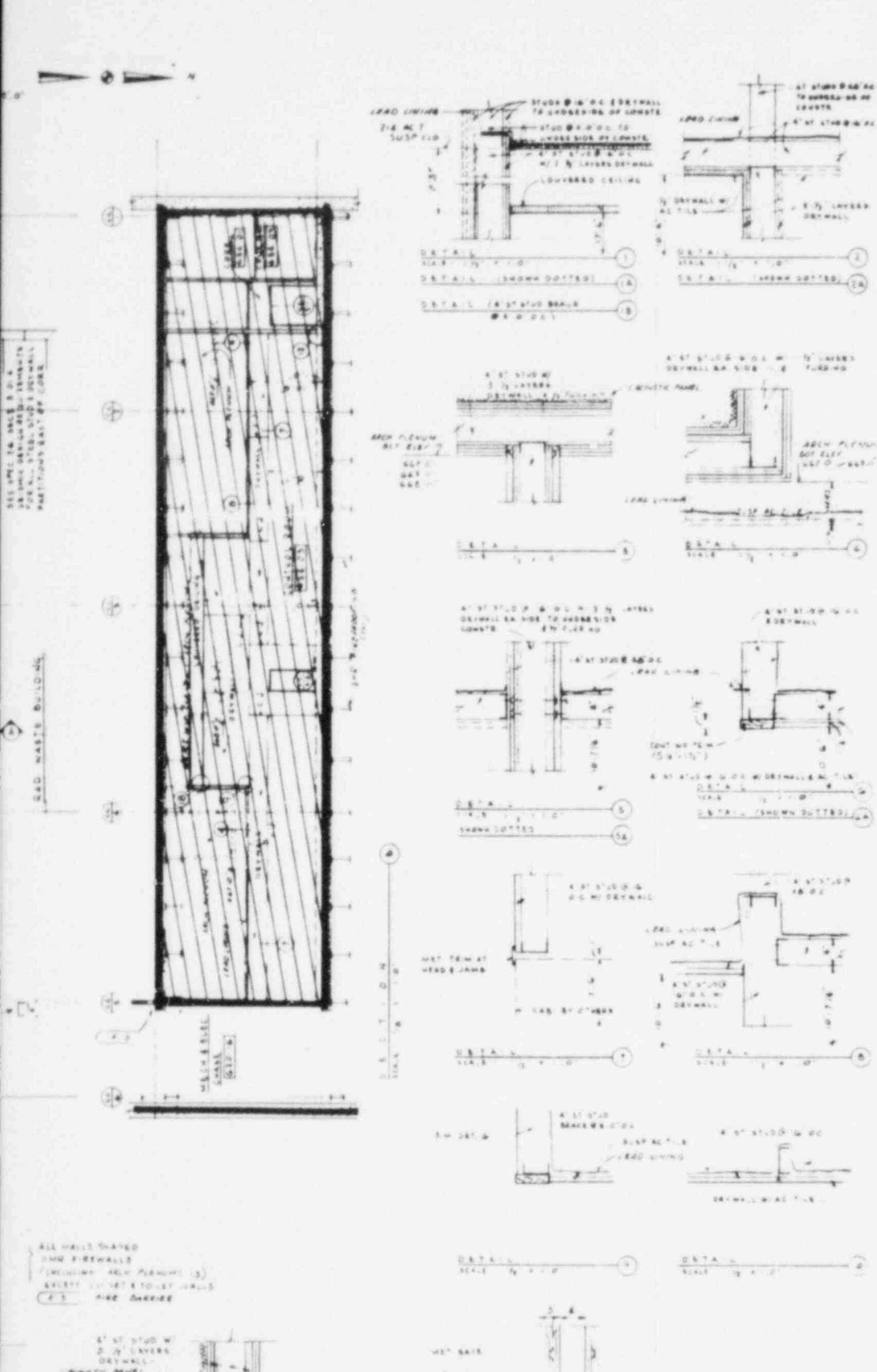
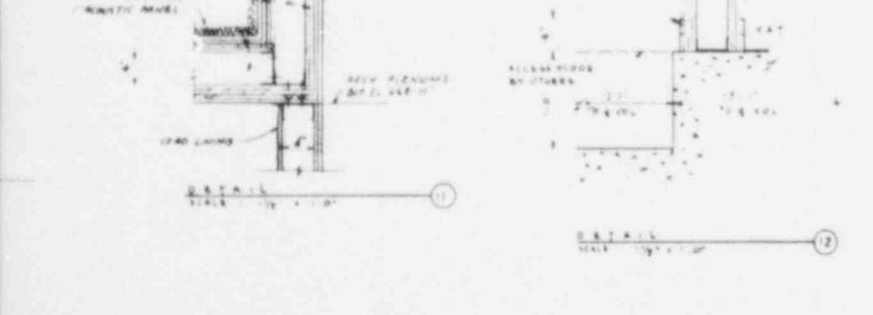
Notes and Operating Data for Figure 6.4-1

Figure 6.4-1a


STAIR
CONT RM
KITCHEN
WALL DETAILS SEE D-121-005
TOILET
STAIR
SEE SPEC 2A SECT 5.01.6 SEISMIC DESIGN REQUIREMENTS FOR ALL STEEL STUDS & DRYWALL PARTITIONS EAST OF CORR.
SERVICE BUILDING
OFFICE
CONTROL RM
MECH & ELEC CHASE
INTERMEDIATE BUILDING
℄ BETWEEN UNITS 1 & 2
FLOOR PLAN EL 656'-0"
SCALE 1/8" = 1'-0"
CEILING ACCESS (TYP)
NOTES
ACCESS FLOOR
SEE SPEC 2A SECT 5.01.6 FOR SEISMIC DESIGN REQUIREMENTS (INCL ALL WALLS IN CONTROL RMS)
WALL ELEV SEE D-103-061-062
SHADED AREA INDICATES ST STUDS @16" OC & DRYWALL TO UNDERSIDE OF CONSTR, ALL OTHER ST STUDS @ 16" OC W/ 1 STUD TO UNDERSIDE OF CONSTR @ 4'-0" OC
FIRE BARRIER (FLOORS & WALLS)
DRYWALL
SECTION
SCALE 1/8" = 1'-0"





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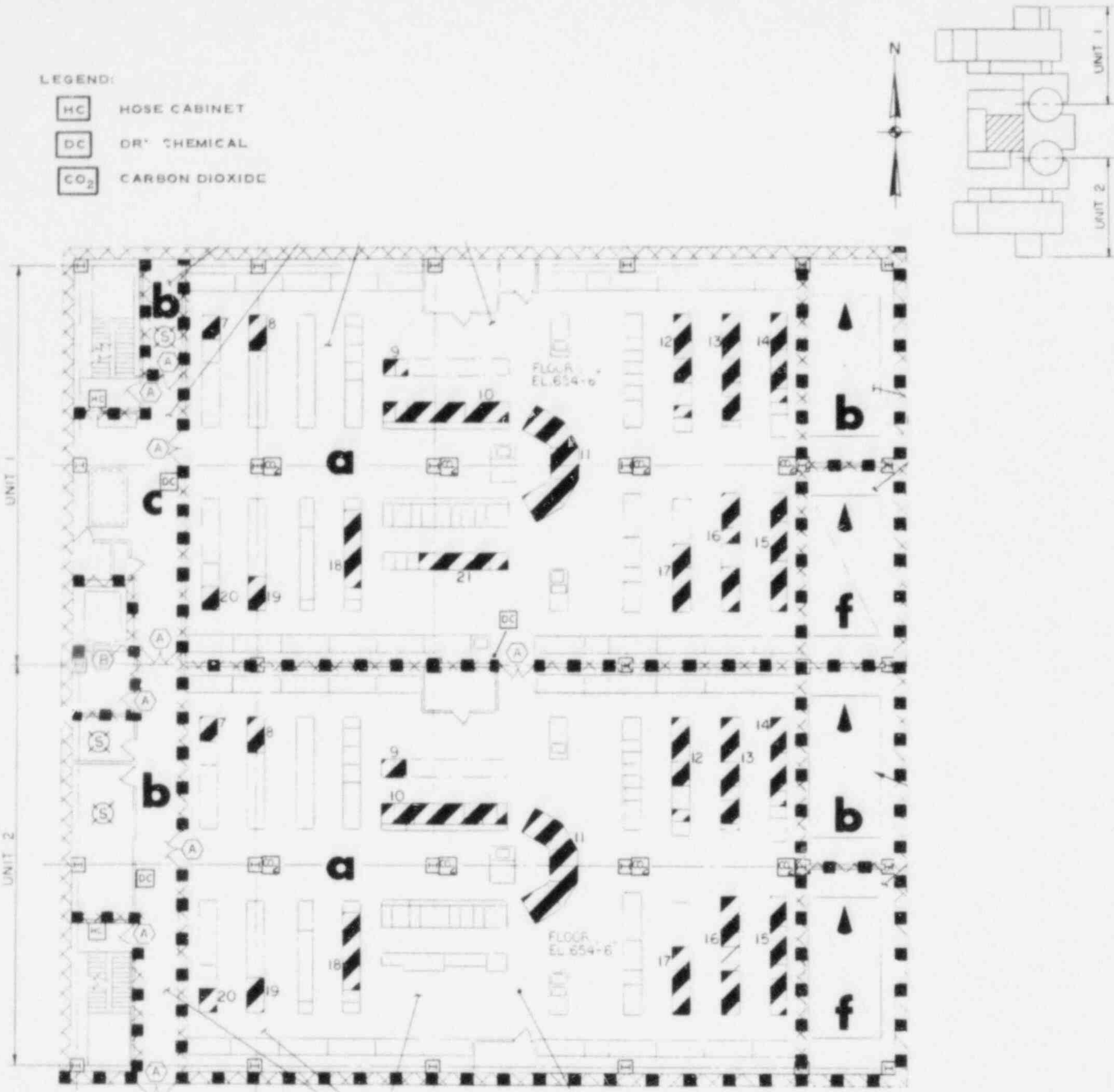
Control Room Envelope

Figure 6.4-2
(GAI Dwg. D-105-015)



ITEM NO	PANEL NUMBER	DESCRIPTION
7	P668	ANALOG LOOP DIVISION 2 INSTRUMENTATION PANEL
8	P871	DIVISION 2 AUXILIARY RELAY PANEL
9	P881	DIVISION 1 CONTAINMENT AND DRYWELL ISOLATION VALVE CONTROL PANEL
	P882	DIVISION 2 CONTAINMENT AND DRYWELL ISOLATION VALVE CONTROL PANEL
10	P281	DIESEL GENERATOR BENCHBOARD
	P601	EMERGENCY CORE COOLING SYSTEMS BENCHBOARD
11	P680	UNIT CONTROL CONSOLE
12	P671	DIVISION 3 NEUTRON POWER AND RADIATION INSTRUMENTATION PANEL
	P693	DIVISION 3 REACTOR PROTECTION SYSTEM INSTRUMENTATION AND AUXILIARY RELAY PANEL
	P613	DIVISION 3 AUXILIARY RELAY PANEL
13	P670	DIVISION 2 NEUTRON POWER AND RADIATION INSTRUMENTATION PANEL
	P692	DIVISION 2 REACTOR PROTECTION SYSTEM INSTRUMENTATION AND AUXILIARY RELAY PANEL
	P622	DIVISION 2 AUXILIARY RELAY PANEL (INBOARD VALVES)
	P642	DIVISION 2 LEAK DETECTION MONITORING PANEL
14	P618	DIVISION 2 AUXILIARY RELAY PANEL (RHR B AND C)
	P631	DIVISION 2 AUXILIARY RELAY PANEL (ADS CHANNEL "B")
	P654	DIVISION 2 AUXILIARY RELAY PANEL (MSIV LEAK CONTROL SYSTEM)
	P657	CONTROL ROD POSITION PANEL
15	P651	CONTROL ROD POSITION PANEL
	P653	CONTROL ROD DRIVE CONTROL INSTRUMENTATION PANEL
	P655	DIVISION 1 AUXILIARY RELAY PANEL (MSIV LEAK CONTROL SYSTEM)
	P628	DIVISION 1 AUXILIARY RELAY PANEL (ADS CHANNEL "A")
	P621	DIVISION 1 AUXILIARY RELAY PANEL (RCIC)
	P629	DIVISION 1 AUXILIARY RELAY PANEL (LPCI AND RHR "A")
16	P632	DIVISION 1 LEAK DETECTION MONITORING PANEL
	P623	DIVISION 1 AUXILIARY RELAY PANEL (OUTBOARD VALVES)
	P669	DIVISION 1 NEUTRON POWER AND RADIATION INSTRUMENTATION PANEL
17	P694	DIVISION 4 REACTOR PROTECTION SYSTEM INSTRUMENTATION AND AUXILIARY RELAY PANEL
	P672	DIVISION 4 NEUTRON POWER AND RADIATION INSTRUMENTATION PANEL
18	P800	HEATING, VENTILATION AND AIR CONDITIONING CONTROL PANEL
19	P817	DIVISION 1 AUXILIARY RELAY PANEL
20	P669	ANALOG LOOP DIVISION 1 INSTRUMENTATION PANEL
21	P665	COMMON ANALOG LOOP INSTRUMENTATION AND AUXILIARY RELAY PANEL
	P904	COMMON HEATING, VENTILATION AND AIR CONDITIONING CONTROL PANEL
	P970	COMMON LONG RESPONSE CONTROL PANEL

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Locations of Panels and Fire Extinguishing Equipment

Figure 6.4-3

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 ENGINEERED SAFETY FEATURES (ESF) FILTER SYSTEMS

The control room emergency recirculation system (CRERS), the fuel handling area charcoal exhaust system (FHACES), and the annulus exhaust gas treatment system (AEGTS) are the ESF filter systems that reduce the concentration of airborne radioactive contaminants following a design basis accident (DBA).

6.5.1.1 Design Bases

Design bases for the charcoal adsorber plenums of the CRERS, FHACES and the AEGTS are as follows:

a. Design Criteria

The CRERS, FHACES and AEGTS are safety related. System design conforms with the requirements of General Design Criteria (GDC) 1, 2, 3, 4, 19, 60 and 61 of Appendix A to 10 CFR 50. To satisfy the requirements of these GDCs, the guidance presented in Regulatory Guides 1.3, 1.13, 1.26, 1.29, 1.47 and 1.52 has been considered in the design of these systems.

b. Need for Filtration

The remote possibility of airborne radioactive contaminants entering the control room following a LOCA and the requirements of GDC 19 establish the need for the CRERS for filtration of control room air. GDC 19 requires, in part, that adequate radiation protection be provided to permit access to, and occupancy of, the control room under accident conditions for the duration of the accident without radiation exposure to personnel in excess of 5 Rem, whole body.

The remote possibility of release or airborne radioactive contaminants due to a fuel handling accident, the requirements of GDC 61 and the recommendations of Regulatory Guides 1.13 and 1.25 establish the need for the FHACES to accomplish fuel pool area air filtration. GDC 61 requires, in part, that fuel storage and handling, and radioactive waste and other systems that may contain radioactivity be designed to ensure adequate safety under normal and postulated accident conditions and that appropriate filtering systems be provided.

The remote possibility of release of airborne radioactive contaminants due to a LOCA, and the requirements of 10 CFR 100 to limit the offsite radiation exposure for individual members of the public, establish the need for the AEGTS for annulus exhaust air filtration. Also, the AEGTS is designed to maintain a negative pressure in the annulus relative to the outside to minimize ground level release of airborne radioactivity due to containment exfiltration during normal and post-accident conditions.

c. Component System Sizing

Two 100 percent capacity filter units are provided for the CRERS. Air flow rate for the CRERS is 30,000 cfm per plenum. Based on this air flow rate and the assumed charcoal adsorber efficiencies and factors discussed in Section 15.6, the overall dose to the operators following an accident has been shown to satisfy the requirements of GDC 19.

Three 50 percent capacity filter units are provided for the FHACES. Air flow for the FHACES, including exhaust flow from the fuel handling area, the fuel pool cooling equipment rooms and the control rod drive pump areas, is 30,000 cfm. Of this quantity, 23,400 cfm is exhausted directly from the fuel pool area. This air flow rate is based on the air velocities and flow patterns required to entrain contaminants escaping from the fuel pool area.

Two 100 percent capacity AEGTS filter units are provided for each reactor unit. Air flow rate for the AEGTS is 2,000 cfm per plenum. Based on this flow rate, the negative pressure in the annulus is maintained at -0.40 in WG continuously, and the requirements of 10 CFR 100 are satisfied.

Components of these filter systems have been sized to handle system air flow based on the recommendations of Regulatory Guide 1.52, ERDA 76-21 and general engineering practice.

d. Fission Product Removal Capability

The fission product removal capability of the activated charcoal adsorber material used in the CRERS, FHACES and AEGTS is based on the recommendations of Regulatory Guide 1.52.

The decontamination efficiency of the AEGTS charcoal adsorber is 99 percent for both elemental iodine and organic species of iodine. The AEGTS charcoal adsorber bed is 4 inches deep with annulus exhaust air maintained at less than 70 percent relative humidity.

The decontamination efficiencies used for the CRERS and FHACES charcoal adsorbers are 99 percent for elemental iodine and 95 percent for organic species of iodine. The CRERS and FHACES charcoal adsorber beds are 2 inches deep; exhaust air for both plenums is maintained at less than 70 percent.

The HEPA filter efficiency used for all the plenums is 99.97 percent on particles 0.3 microns and larger.

Additional bases for the design of the CRERS, FHACES and AEGTS are presented in Sections 6.4, 9.4.2 and 6.5.3, respectively.

6.5.1.2 System Design

The design features of the CRERS, FHACES and AEGTS are compared to the recommendations of Regulatory Guide 1.52 in Tables 6.5-1, 6.5-2 and 6.5-3, respectively.

Design of the activated charcoal adsorber plenums used in the CRERS, FHACES and AEGTS follows the guidelines of Regulatory Guide 1.52 and ERDA 76-21.

Each charcoal adsorber plenum contains the following:

a. Demisters to remove large particles and water droplets (about 1 micron diameter).

b. Roughing filters to remove large particles (about 1 micron).

c. HEPA filters to remove small particles (0.3 to 1 micron).

d. Electric heater coils to maintain the relative humidity of the exhaust air at 70 percent or less.

e. Gasketless activated charcoal adsorber beds to remove gaseous elemental and organic iodines.

f. HEPA filters downstream of the charcoal beds to remove charcoal particles that may be entrained in the air stream.

g. A fan external to the plenum.

h. Instrumentation.

i. Test ports.

j. Water deluge system for fire protection.

Plenum housings and filter support frames are shop fabricated. Potential leakage and bypass paths are closed by seal welding. No caulking or sealant is used. Housings are fabricated of carbon steel sheet. Filter support frames are of unpainted stainless steel.

Roughing and HEPA filters are mounted in frames in accordance with the recommendations of ERDA 76-21.

The activated charcoal adsorber is bulk loaded into the permanently installed, gasketless adsorber section which is seal welded to the housing and support frames of the plenum. Tray type activated charcoal adsorber units are not used.

Spent charcoal adsorber material is vacuumed from the bottom of the plenum and is loaded into 55 gallon drums for shipment off site. New charcoal adsorber material is added at the top of the adsorber section. Personnel are not directly exposed to potentially contaminated adsorber material during the changing procedure.

Roughing and HEPA filters are replaced when pressure drop across a filter exceeds the technical specification value. Pressure drop is measured by permanently installed differential pressure indicators. Charcoal adsorber material is changed when laboratory test results from representative samples indicate failure of the adsorber material to satisfy the testing recommendations listed in Table 2 of Regulatory Guide 1.52.

6.5.1.3 Design Evaluation

Design and safety evaluations of the CRERS, FHACES and AEGTS are presented in Sections 6.4, 9.4.2 and 6.5.3, respectively.

The charcoal adsorber plenums are not exposed to conditions that can impair plenum efficiency. The exhaust air flowing through the charcoal plenums is maintained at 70 percent relative humidity by continuous operation of the electric heating coils during abnormal conditions.

The FHACES and AEGTS are operated continuously during plant normal operation. The CRERS is operated for at least 10 hours each month as recommended by Regulatory Guide 1.52; during this operation of CRERS, the exhaust air is free of radioactive contaminants. Air exhausted or circulated through the charcoal adsorber plenums is not expected to contain enough radioactive contaminants following a DBA to develop decay heat that could ignite the charcoal adsorber material.

The charcoal adsorber plenums are redundant, physically separated and powered from separate Class 1E electrical system Division 4.

In the event smoke from a fire is exhausted through any charcoal filter, the filter will be tested for any degradation in charcoal performance as a result of the smoke. This testing will be performed within a period determined in the technical specifications. If the testing indicates that degradation has occurred beyond acceptable limits, the charcoal will be replaced. For charcoal filters in systems needed to mitigate the consequences of a LOCA, namely the annulus exhaust gas treatment system (AEGTS), the filters will be tested and the charcoal replaced, if required, within a period specified in the technical specifications.

6.5.1.4 Tests and Inspections

Tests and inspections of the CRERS, FHACES, and AEGTS charcoal adsorber plenums are performed prior to startup and on a periodic basis thereafter. Other tests and inspections of these filter systems are discussed in Sections 6.4, 9.4.2 and 6.5.3, respectively.

6.5.1.4.1 Filter and Charcoal Adsorber Tests

HEPA filters are individually tested by an appropriate filter test facility at 100 percent and 20 percent of rated flow, in accordance with the recommendation of Regulatory Guide 1.52. Original or replacement HEPA filters used in the CRERS, FHACES, and AEGTS are tested as indicated above.

Each batch of charcoal adsorber material satisfies the "acceptable results" recommended by Regulatory Guide 1.52. Since the charcoal adsorber material is expected to be replaced several times during the 40 year life of the plant, test methods used may change. Therefore, only "acceptable results" of the tests are specified.

6.5.1.4.2 Inplace Testing

After all the activated charcoal adsorber plenums for CRERS, FHACES, and AEGTS are installed, the following preoperational and inplace tests are performed:

a. Distribution of air flow to HEPA filters and charcoal adsorber beds is tested as recommended by Position C.5.b of Regulatory Guide 1.52. This test is performed initially and following each HEPA filter change. HEPA filters are changed when filter pressure drop exceeds twice the maximum clean resistance at rated flow.

b. Dioctylphthalate (DOP) smoke tests of the HEPA filter sections are performed initially, and periodically thereafter, in accordance with ANSI N510.

c. Leak tests of the charcoal adsorber section of the charcoal filter plenums are performed initially, and periodically thereafter, in accordance with the schedule recommended by Regulatory Guide 1.52 (also whenever the HEPA filters are tested). Testing uses gaseous halogenated hydrocarbon refrigerant in accordance with the recommendations of Regulatory Guide 1.52.

d. Test cannisters containing representative samples of the charcoal adsorber material are removed from the charcoal filter plenums for laboratory testing in accordance with the schedule recommended by Regulatory Guide 1.52. Laboratory tests determine the iodine removal efficiency of the charcoal adsorber material in accordance with the recommendations of Position C.6.b of Regulatory Guide 1.52.

6.5.1.4.3 Operation

In addition to regular test and inspection, the normally idle units (CRERS) are operated for at least 10 hours each month to reduce the buildup of moisture on the HEPA filters and charcoal adsorber material. During system operation, pressure drop across the filter banks is manually checked and recorded.

6.5.1.5 Instrumentation Requirements

Instrumentation and actuation requirements for the CRERS, FHACES and AEGTS are discussed in Sections 6.4.6, 9.4.1 and 6.5.3, respectively.

Each of the activated charcoal adsorber plenums has locally mounted differential pressure indicators to show the pressure drop across each filter bank in a plenum. These indicators permit the operator to determine when prefilters and HEPA filters should be changed.

Each charcoal adsorber bed is provided with a permanently installed temperature sensing device and temperature switches which actuate alarms upon detection of a bed temperature of 225°F and 250°F. The water deluge fire protection system is manually actuated when the higher temperature is reached.

6.5.1.6 Materials

Estimated quantities of materials used in the activated charcoal adsorber plenums for CRERS, FHACES and AEGTS are listed in Tables 6.5-4, 6.5-5 and 6.5-6, respectively. The governing specifications for the various materials are also listed and provide information regarding chemical composition of materials used.

There are no radiolytic or pyrolytic decomposition products from the ESF filter systems. Actuation of the activated charcoal adsorber plenum water deluge fire protection systems will extinguish a charcoal fire before pyrolytic decomposition products are formed. None of these systems are located in areas where gamma radiation sources are sufficiently strong to cause radiolytic decomposition products. Therefore, decomposition products do not affect any engineered safety features.

6.5.2 CONTAINMENT SPRAY SYSTEM

Containment overpressurization protection following a LOCA is provided by the suppression pool which condenses any steam released in the drywell before it reaches the outer containment. The containment spray system provides additional overpressurization protection if any steam is bypassed directly to the outer containment as a result of leakage around piping penetrations in the drywell wall. This function of the containment spray system is discussed in detail in Section 6.2.2. The containment spray system is not designed for fission product removal.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

6.5.3.1 Primary Containment

The primary containment vessel is a hybrid pressure retaining structure composed of a steel cylinder and ellipsoidal dome secured to a steel lined reinforced concrete foundation mat. The containment vessel is designed to contain radioactive material that might be released during an accident and to ensure leak tightness during normal operating and accident conditions. Details of the primary containment vessel design are discussed in Section 3.8, and a section layout of containment vessel is shown on Figure 3.8-1. The primary containment pressure suppression concept uses the General Electric Mark III design.

The primary containment vessel steel shell, mechanical penetrations, isolation valves, hatches, and locks will limit release of radioactive materials (subsequent to postulated accidents) such that the resulting offsite doses are less than the guideline values of 10 CFR 100. Primary containment parameters affecting fission product release accident analyses are given in Table 6.5-7.

Long term primary containment pressure response to the design basis accident is discussed in Section 6.2.1.

Redundant, safety-related hydrogen recombiners are provided in the primary containment as the primary means of controlling post-accident hydrogen concentrations. A hydrogen purge system is provided for backup hydrogen control. Details of the post-accident hydrogen control system are discussed in Section 6.2.5.

During normal operation, the primary containment is continuously vented through a charcoal filter train. 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) and high radiation signals.

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. Section 9.4.6 presents a detailed discussion of the containment purge system.

6.5.3.2 Secondary Containment

The secondary containment (shield building) is a reinforced concrete structure consisting of a flat foundation mat, a cylindrical wall and a shallow dome. The secondary containment boundary consists of the volume between the shield building and the primary containment vessel steel shell. Details of the shield building structural design are discussed in Section 3.8 and the boundary region is shown in Figure 3.8-1.

The annulus exhaust gas treatment system (AEGTS) processes the ambient air in the annular space between the shield building and the primary containment vessel in order to limit the release to the environment of radioisotopes which may leak from the primary containment under accident conditions. The AEGTS is a recirculation type system with split flow. Some of the filtered air extracted from the annulus space is recirculated and some is discharged to the unit vent. An analysis indicating the effectiveness of this system in controlling contamination releases is presented in Section 15.6.5.

6.5.3.2.1 Design Bases

Design bases for the annulus exhaust gas treatment system are as follows:

a. The AEGTS is classified as Safety Class 2, Seismic Category I. The design of this system complies with the requirements of General Design Criteria (GDC) 1, 2, 3, 4, and 5 of 10 CFR 50 Appendix A, 10 CFR 50 Appendix B, and 10 CFR 100 concerning ground level accident releases. The recommendations of Regulatory Guides 1.26, 1.29, 1.47, 1.52, 1.53 and 3.2, National Fire Protection Association (NFPA) 90A, and Branch Technical Position APCSB 9.5-1 have also been considered in the system design and equipment procurement.

b. The AEGTS is:

   1. Required to function during normal, shutdown and refueling operations, loss of offsite power periods and following a LOCA.

   2. Started manually from the control room with the redundant system started automatically when low system air flow is indicated.

   3. Designed to continuously maintain a negative pressure differential of 0.40 inches of water gauge between the containment vessel annulus ambient and the outside. The design parameters of this system include the leakage through the shield building (100 percent of the annulus volume per day), leakage from the containment vessel following an accident (0.2 percent of the containment volume per day), increased annulus temperature following an accident, increased annulus air pressure resulting from the containment vessel expansion following an accident and the discharge from the hydrogen purge subsystem.

   4. Designed to direct the exhaust flow from the annulus through a charcoal filter plenum to ensure that the release of radioactivity to the environment is below permissible discharge limits.

5. Designed so that the exhaust inlet points from the annulus are remotely located from the return air to the annulus, thus promoting mixing of the annulus air.

6. Continuously monitored in the control room to indicate system operating status, system malfunction, high radiation in fan discharges, high smoke in fan discharges, temperatures in the charcoal plenums and annulus to outside ambient pressure differential.

7. Provided with redundant and separated equipment, control and power supplies so that a single active component failure will not prevent satisfactory system operation.

8. Designed with system operating components located in equipment areas not affected by internally generated missiles, pipe whip or jet impingement resulting from breaks in high or moderate energy piping.

6.5.3.2.2 System Description

The AEGTS is shown on Figure 6.5-1. This system functions continuously during normal, shutdown and refueling operations during loss of offsite power periods, and following a LOCA to maintain a negative pressure differential between the containment vessel annulus ambient and the outside.

The system includes two 100 percent capacity filter plenums (M15-D001A, B), two 100 percent capacity centrifugal fans (M15-C001A, B), and redundant supply, recirculation and exhaust ductwork systems for Unit 1 and Unit 2. The plenums and fans are located in the intermediate building at elevation 620'-6". Each unit is provided with "A" equipment and "B" equipment, located in separate rooms. The duct distribution systems in the annulus are arranged so that the annulus ambient air is continuously circulated and mixed throughout the annulus space and then directed to the charcoal filter plenum. Air is extracted at one location and returned at another remote location to ensure adequate mixing of the recirculated air with the annulus volume. Also, adequate distribution ductwork is provided. The main exhaust header draws air

from various regions of the annulus and the recirculation header returns the recirculated air at a different region. The exhaust header and the recirculation headers are located at appropriate distance from each other to assure that adequate mixing occurs in the annulus (See Figure 6.5-2). A portion of this filtered air is then discharged to the unit vent and the remaining portion is returned to the annulus. The continuous circulation and mixing ensures that any inleakage to the annulus ambient will be mixed with this ambient before being filtered and discharged. The amount of air discharged to the plant vent and the amount returned to the annulus is automatically controlled so that the negative differential pressure is maintained.

The total extraction rate from the annulus is 2,000 cfm and the design maximum discharge rate to the atmosphere is 2,000 cfm. During normal operation the expected discharge to the unit vent is 400 cfm, based on a postulated leakage through the shield building into the annulus (100 percent of annulus volume per day) at a negative pressure differential of 0.40 inches of water gage. During an accident, the maximum expected discharge rate is 650 cfm. This takes into consideration a postulated leakage from the containment vessel to the annulus of 1.6 cfm (equivalent to 0.2 percent of containment volume per day at a containment pressure of 15 psi), the air expansion due to increase in temperature during the accident, increase in annulus air pressure due to the expansion of the containment steel shell and the discharge from the hydrogen purge subsystem of 50 scfm and the MSIVLCS. However, the discharge and recirculation dampers will modulate to vary the discharge flow from the expected maximum (650 cfm) to the design maximum (2,000 cfm), as required, to achieve and maintain a negative pressure differential of 0.40 inches of water gage between the annulus and the atmosphere.

Two pressure differential transmitters, each located 180° apart, are provided for each filter plenum and fan. These transmitters are used to monitor the negative pressure differential in the annulus and send appropriate signals to the differential pressure controllers and recorders located in the control room. The differential pressure controller will modulate the discharge and recirculation dampers accordingly.

Regular a-c offsite power sources are provided for this system. If loss of offsite power occurs during a LOCA, redundant emergency power is available from the diesel generators. Inactive circulating and filtering components are isolated from the annulus space and the unit vent by check dampers, and by automatically controlled duct dampers. The redundant system automatically starts upon indication of low air flow from the operating system.

Design information for the annulus exhaust gas treatment system components is listed in Table 6.5-8.

6.5.3.2.3 Safety Evaluation

The AEGTS maintains a negative pressure differential between the containment vessel annulus and the outside so that leakage from the containment vessel will be detained in the annular space, mixed with the annulus space air, diluted with air leakage into the annular space and filtered before release to the unit vent.

The mixing and dilution of the annulus air is ensured by the supply and exhaust duct arrangement which includes distribution ducts with multiple supply and exhaust outlets along the entire circumference of the annulus space. The supply distribution ducts are at elevation 590'-0" and the exhaust distribution ducts are at elevation 742'-0". The annulus width is five feet. This resultant volume is the space in which containment vessel leakage is mixed with annulus space air before being directed to the filter plenum.

The maximum exhaust flow rate from the annulus space directed to the filter is 2,000 cfm and the maximum expected amount of the filtered air released to the unit vent is 650 cfm. The remaining 1,350 cfm is circulated back to the annulus space for subsequent refiltering. This arrangement of duct systems, and the high proportion of recirculated and refiltered air, assures maximum mixing of leakage and maximum filtering before release to the unit vent.

Minimum release of contamination after filtering is further assured by the filter plenum components which include an electric heating coil for lowering of relative humidity, HEPA prefilters, 4-inch deep charcoal filters and HEPA after-filters. When the system is operating at normal meteorological conditions (wind velocity up to 30 mph), the annulus is maintained at a negative pressure differential of 0.4 inches water gage relative to the outside by modulating the exhaust and recirculation dampers.

Operation of the system is monitored with alarms in the control room for system malfunctions including high temperature in ducts and plenums, high smoke, high radiation, loss of negative differential pressure and high relative humidity of the exhaust air.

Malfunctioning system components are automatically stopped and isolated, and redundant components are automatically placed in service. This assures maintenance of the negative differential pressure in the annulus at all times.

The main components of the system are located in separate rooms. No unguarded high energy lines pass through the annulus space or in the AEGTS equipment areas.

Redundancy in this system provides capability to maintain a negative differential pressure and to remove contaminants when considering failure of an active or passive component.

If decay heat in the charcoal filter section raised the charcoal temperature to 250°F, a control room alarm would alert the operator so that the charcoal filter deluge system could be manually activated.

6.5.3.2.4 Inspection and Testing Requirements

The various components of the AEGTS are accessible for inspection and testing during normal plant operation. The ability to isolate an idle redundant component enables inspection maintenance and testing to be performed while the system is in normal operation. Periodic tests, as recommended by Regulatory

Guide 1.52, will be performed on the systems. These tests will include measurement of differential pressure across the filter banks, and field and laboratory determination of filter leakage and efficiency. This will demonstrate that aging, weathering, or poisoning of the filters has not significantly degraded the filter mounting or absorptive material in the charcoal banks.

These tests will also include verification of the functional performance of fans, dampers, controls and other safety devices to ensure that these components perform their function reliably.

6.5.3.2.5 Instruments, Controls and Protective Devices

Operation of the AEGTS is initiated by manually starting (from the control room) one of the two exhaust fans which then operates continuously. The details of the instrumentations and controls for this system are discussed in Section 7.3.1.

6.5.4 ICE CONDENSER AS A FISSION PRODUCT CLEANUP SYSTEM

This section is not applicable to WPP.

TABLE 6.5-1

COMPARISON OF CONTROL ROOM EMERGENCY RECIRCULATION SYSTEM WITH REGULATORY GUIDE 1.52 POSITIONS

Regulatory Position	System Design Feature
1.a	The design conforms with this position.
1.b	The design conforms with this position.
1.c	The design conforms with this position.
1.d	The design conforms with this position.
1.e	The design conforms with this position.
2.a	The design conforms with this position.
2.b	The design conforms with this position.
2.c	The design conforms with this position.
2.d	The filter units are not exposed to pressure surges from the postulated DBA.
2.e	The design conforms with this position.
2.f	The design conforms with this position.
2.g	The pertinent data which are instrumented to signal, alarm or record in the control room are discussed in Section 7.3.1.

TABLE 6.5-1 (Continued)

Regulatory Position	System Design Feature
2.h	The design conforms with this position.
2.i	The design conforms with this position.
2.j	The design conforms with the intent of this position. See Section 12.1 for a discussion of conformance with Regulatory Guide 8.8.
2.k	The design conforms with this position.
2.l	The design conforms with this position.
3.a	The design conforms with this position.
3.b	The design conforms with this position.
3.c	The design conforms with this position.
3.d	The design conforms with this position.
3.e	The design conforms with this position.
3.f	The design conforms with this position.
3.g	The design conforms with this position.
3.h	The design conforms with the intent of the recommendations of Section 4.5.8 of ERDA 76-21.
3.i	The design conforms with this position.
3.j	The design conforms with this position.
3.k	The design of the charcoal adsorber section considers possible radioactivity-induced fires. Water spray deluge fire protection system is provided.
3.l	The design conforms with the intent of the recommendations of Sections 5.7 and 5.8 of ANSI N509-1976.
3.m	The design conforms with this position.
3.n	The design conforms with the recommendations of Section 5.10 of ANSI N509-1976.
3.o	The design conforms with this position.
3.p	The design conforms with the intent of the recommendations of Section 5.9 of ANSI N509-1976.

TABLE 6.5-1 (Continued)

Regulatory Position	System Design Feature
4.a	The design conforms with the intent of the recommendations of Section 2.3.8 of ERDA 76-21 and Section 4.7 of ANSI N509-1976.
4.b	The maximum length of component plus 2'-6" is provided due to space limitation imposed by equipment room size. It was determined that this is adequate for the replacement of the roughing and HEPA filters and is consistent with the manufacturer's recommendations.
4.c	The design conforms with this position.
4.d	Operating procedures will conform with this position.
4.e	The design conforms with this position.
5.a	Testing procedures will conform with this position.
5.b	Testing procedures will conform with this position.
5.c	Testing procedures will conform with this position.
5.d	Testing procedures will conform with this position.
6.a	Testing procedures will conform with this position.
6.b	Design procedures do, and testing procedures will conform with this position.

TABLE 6.5-2

COMPARISON OF FUEL HANDLING AREA CHARCOAL EXHAUST SYSTEM WITH REGULATORY GUIDE 1.52 POSITIONS

Regulatory Position	System Design Feature
1.a	The design conforms with this position.
1.b	The design conforms with this position.
1.c	The design conforms with this position.
1.d	The design conforms with this position.
1.e	The design conforms with this position.
2.a	The design conforms with this position.
2.b	The design conforms with this position.
2.c	The design conforms with this position.
2.d	The filter units are not exposed to pressure surges from the postulated DBA.
2.e	The design conforms with this position.
2.f	The design conforms with this position.
2.g	The pertinent data which are instrumented to signal, alarm or record in the control room are discussed in Section 7.3.1.

TABLE 6.5-2 (Continued)

Regulatory Position	System Design Feature
2.h	The design conforms with this position.
2.i	The design conforms with this position.
2.j	The design conforms with the intent of this position. See Section 12.1 for a discussion of conformance with Regulatory Guide 8.8.
2.k	The design conforms with this position.
2.l	The design conforms with this position.
3.a	The design conforms with this position.
3.b	The design conforms with this position.
3.c	The design conforms with this position.
3.d	The design conforms with this position.
3.e	The design conforms with this position.
3.f	The design conforms with this position.
3.g	The design conforms with this position.
3.h	The design conforms with the intent of the recommendations of Section 4.5.8 of ERDA 76-21.
3.i	The design conforms with this position.
3.j	The design conforms with this position.
3.k	The design of the charcoal adsorber section considers possible radioactivity-induced fires. Water spray deluge fire protection system is provided.
3.l	The design conforms with the intent of the recommendations of Sections 5.7 and 5.8 of ANSI N509-1976.
3.m	The design conforms with this position.
3.n	The design conforms with the recommendations of Section 5.10 of ANSI N509-1976.
3.o	The design conforms with this position.
3.p	The design conforms with the intent of the recommendations of Section 5.9 of ANSI N509-1976.

TABLE 6.5-2 (Continued)

Regulatory Position	System Design Feature
4.a	The design conforms with the intent of the recommendations of Section 2.3.8 of ERDA 76-21 and Section 4.7 of ANSI N509-1976.
4.b	The maximum length of component plus 2'-6" is provided due to space limitation imposed by equipment room size. It was determined that this is adequate for the replacement of the roughing and HEPA filters.
4.c	The design conforms with this position and is consistent with the manufacturer's recommendations.
4.d	Operating procedures will conform with this position.
4.e	The design conforms with this position.
5.a	Testing procedures will conform with this position.
5.b	Testing procedures will conform with this position.
5.c	Testing procedures will conform with this position.
5.d	Testing procedures will conform with this position.
6.a	Testing procedures will conform with this position.
6.b	Design procedures do, and testing procedures will conform with this position.

TABLE 6.5-3

COMPARISON OF ANNULUS EXHAUST GAS TREATMENT SYSTEM WITH REGULATORY GUIDE 1.52 POSITIONS

Regulatory Position	System Design Feature
1.a	The design conforms with this position.
1.b	The design conforms with this position.
1.c	The design conforms with this position.
1.d	The design conforms with this position.
1.e	The design conforms with this position.
2.a	The design conforms with this position.
2.b	The design conforms with this position.
2.c	The design conforms with this position.
2.d	The filter units are not exposed to pressure surges from the postulated DBA.
2.e	The design conforms with this position.
2.f	The design conforms with this position.
2.g	The pertinent data which are instrumented to signal, alarm or record in the control room are discussed in Section 7.3.1.

TABLE 6.5-3 (Continued)

Regulatory Position	System Design Feature
2.h	The design conforms with this position.
2.i	The design conforms with this position.
2.j	The design conforms with the intent of this position. See Section 12.1 for a discussion of conformance with Regulatory Guide 8.8.
2.k	The design conforms with this position.
2.l	The design conforms with this position.
3.a	The design conforms with this position.
3.b	The design conforms with this position.
3.c	The design conforms with this position.
3.d	The design conforms with this position.
3.e	The design conforms with this position.
3.f	The design conforms with this position.
3.g	The design conforms with this position.
3.h	The design conforms with the intent of the recommendations of Section 4.5.8 of ERDA 76-21.
3.i	The design conforms with this position.
3.j	The design conforms with this position.
3.k	The design of the charcoal adsorber section considers possible radioactivity-induced fires. Water spray deluge fire protection system is provided.
3.l	The design conforms with the intent of the recommendations of Sections 5.7 and 5.8 of ANSI N509-1976.
3.m	The design conforms with this position.
3.n	The design conforms with the recommendations of Section 5.10 of ANSI N509-1976.
3.o	The design conforms with this position.
3.p	The design conforms with the intent of the recommendations of Section 5.9 of ANSI N509-1976.

TABLE 6.5-3 (Continued)

Regulatory Position	System Design Feature
4.a	The design conforms with the intent of the recommendations of Section 2.3.8 of ERDA 76-21 and Section 4.7 of ANSI N509-1976.
4.b	The maximum length of component plus 2'-6" is provided due to space limitation imposed by equipment room size. It was determined that this is adequate for the replacement of the roughing and HEPA filters and is consistent with the manufacturer's recommendations.
4.c	The design conforms with this position.
4.d	Operating procedures will conform with this position.
4.e	The design conforms with this position.
5.a	Testing procedures will conform with this position.
5.b	Testing procedures will conform with this position.
5.c	Testing procedures will conform with this position.
5.d	Testing procedures will conform with this position.
6.a	Testing procedures will conform with this position.
6.b	Design procedures do, and testing procedures will conform with this position.

TABLE 6.5-4

CONTROL ROOM EMERGENCY RECIRCULATION SYSTEM

MATERIALS LIST

Filter Unit Housing	
Number of filter units	2 for Units 1 & 2
Manufacturer	CVI-Pennwalt
Filter holding frame	Stainless steel, ASTM A 479, Type 304
Demisters	
Number, per filter unit	21
Manufacturer & model no.	ACS, #101-55
General standards	MSAR-71-45
Frame Material	Stainless steel, ASTM A 479, Type 304
Media	Stainless steel and fiberglass woven mesh
Roughing Filters	
Number, per filter unit	21
Manufacturer	Flanders
Model number	A083-L
General standards	MIL-F-51068D; UL 900 Class 1; UL 586
Frame material	14 gauge chromized steel (MIL-F-46055)
Filter material	95 percent boron silicate fiberglass, 5 percent organic material (MIL-F-51079B)
Adhesives	Fire retardant polyurethane and rubber based adhesives
Gaskets	Sponge Neoprene (SCE-43) (ASTM D1056)

TABLE 6.5-4 (Continued)

Weight, per filter, lbs.	
Steel, approx.	25
Glass and Miscellaneous Material, approx.	10
Total	35
HEPA Filters Upstream and Downstream	
Number, per filter unit	42
Manufacturer	Flanders
Model number	7083-NL
General standards	MIL-F-51068D; UL 900 Class 1; UL 586
Frame material	14 gauge chromized steel (MIL-F-46055)
Filter material	95 percent boron silicate fiberglass, 5 percent organic material (MIL-F-51079)
Adhesives	Fire retardant polyurethane and rubber based adhesives
Gaskets	Sponge Neoprene (SCE-43) (ASTM D1056)
Weight, per filter, lb.	
Steel, approx.	25
Glass and miscellaneous material, approx.	15
Total	40
Activated Charcoal Adsorber	
Manufacturer	CVI-Pennwalt
Type of media	New, activated coconut shell charcoal
Impregnant	Potassium iodide (KI) and elemental iodine type

TABLE 6.5-4 (Continued)

Weight of carbon, lb.	5700
Adsorber enclosure	Stainless steel, ASTM A240, Type 304
<u>Electric Heating Coil</u>	
Manufacturer	CVI-Pennwalt
Frame material	Stainless steel
Heating element	Inconel steel sheathed elements

TABLE 6.5-5

FUEL HANDLING AREA CHARCOAL EXHAUST SYSTEM

MATERIALS LIST

Filter Unit Housing	
Number of filter units	3 for Units 1 & 2
Manufacturer	CVI-Pennwalt
Filter holding frame	Stainless steel, ASTM A479, Type 304
Demisters	
Number per filter unit	12
Manufacturer & model no.	ACS, #101-55
General standards	MSAR-71-45
Frame material	Stainless steel, ASTM A479, Type 304
Media	Stainless steel and fiberglass woven mesh
Roughing Filters	
Number, per filter unit	12
Manufacturer	Flanders
Model number	A083-L
General standards	MIL-F-51068D; UL 900 Class 1; UL 586
Frame material	14 gauge chromized steel (MIL-F-46055)
Filter material	95 percent boron silicate fiberglass, 5 percent organic material (MIL-F-51079B)
Adhesives	Fire retardant polyurethane and rubber based adhesives
Gaskets	Sponge Neoprene (SCE-43) (ASTM D1056)

TABLE 6.5-5 (Continued)

Weight, per filter, lbs.	
Steel, approx.	25
Glass and miscellaneous material, approx.	10
Total	35
HEPA Filters Upstream and Downstream	
Number, per filter unit	24
Manufacturer	Flanders
Model number	7083-NL
General standards	MIL-F-51068D; UL 900 Class 1; UL 586
Frame material	14 gauge chromized steel (MIL-F-46055)
Filter material	95 percent boron silicate fiberglass, 5 percent organic material (MIL-F-51079)
Adhesives	Fire retardant polyurethane and rubber based adhesives
Gaskets	Sponge Neoprene (SCE-43) (ASTM D1056)
Weight, per filter, lb.	
Steel, approx.	25
Glass and miscellaneous material, approx.	15
Total	40
Activated Charcoal Adsorber	
Manufacturer	CVI-Pennwalt
Type of media	New, activated coconut shell charcoal
Impregnant	Potassium iodide (KI) and elemental iodine type

TABLE 6.5-5 (Continued)

Weight of carbon, lb.	3040
Adsorber enclosure	Stainless steel, ASTM A240, Type 304
Electric Heating Coil	
Manufacturer	CVI-Pennwalt
Frame material	Stainless steel
Heating element	Inconel steel sheathed elements

TABLE 6.5-6

ANNULUS EXHAUST GAS TREATMENT SYSTEM

MATERIALS LIST

Filter Unit Housing	
Number of filter units	2 for Unit 1 2 for Unit 2
Manufacturer	CVI-Pennwalt
Filter holding frame	Stainless steel, ASTM A479, Type 304
Demisters	
Number, per filter unit	2
Manufacturer & model no.	ACS, #101-55
General standards	MSAR-71-45
Frame material	Stainless steel, ASTM A479, Type 304
Media	Stainless steel and fiberglass woven mesh
Roughing Filters	
Number, per filter unit	2
Manufacturer	Flanders
Model number	A083-L
General standards	MIL-F-51068D; UL 900 Class 1; UL 586
Frame material	14 gauge chromized steel (MIL-F-46055)
Filter material	95 percent boron silicate fiberglass, 5 percent organic material (MIL-F-51079B)
Adhesives	Fire retardant polyurethane and rubber based adhesives
Gaskets	Spone Neoprene (SCE-43)

TABLE 6.5-6 (Continued)

Weight, per filter, lbs.	
Steel, approx.	25
Glass and miscellaneous material, approx.	10
Total	35
<u>HEPA Filters Upstream and Downstream</u>	
Number, per filter unit	4
Manufacturer	Flanders
Model number	7083-NL
General standards	MIL-F-51068D; UL 900 Class 1; UL 586
Frame material	14 gauge chromized steel (MIL-F-46055)
Filter material	95 percent boron silicate fiberglass, 5 percent organic material (MIL-F-51079)
Adhesives	Fire retardant polyurethane and rubber based adhesives
Gaskets	Sponge Neoprene (SCE-43) (ASTM D1056)
Weight, per filter, lb.	
Steel, approx.	25
Glass and miscellaneous material, approx.	15
Total	40
<u>Activated Charcoal Adsorber</u>	
Manufacturer	CVI-Pennwalt
Type of Media	New, activated coconut shell charcoal
Impregnant	Potassium iodide (KI) and elemental iodine type

TABLE 6.5-6 (Continued)

Weight of carbon, lb.	804
Ads‹rber enclosure	Stainless steel, ASTM A240, Type 304
<u>Electric Heating Coil</u>	
Manufacturer	CVI-Pennwalt
Frame material	Stainless steel
Heating element	Inconel steel sheathed elements

TABLE 6.5-7

PRIMARY CONTAINMENT OPERATION FOLLOWING A DESIGN BASIS ACCIDENT

Type of structure	Steel cylinder with ellopsoidal dome secured to a steel lined reinforced concrete foundation mat.
Internal fission product removal systems	None
Free volume of primary containment, ft^3	1.2×10^6 (excluding drywell)
Hydrogen purge system operation	See Section 6.2.5
Containment leakage rate, Vol%/day	0.20
Effectiveness of internal fission product removal systems	Not applicable

TABLE 6.5-8

ANNULUS EXHAUST GAS TREATMENT SYSTEM COMPONENTS

Plenums (M15-D001A, 1B)

No. of plenums	2 for Unit 1
	2 for Unit 2
Manufacturer	CVI Corporation

Demisters

Manufacturer and model	ACS, 101-55
No. of banks per plenum	1
No. of cells per bank	2
Material	Stainless steel mesh
Rated flow per cell, cfm	1,600
Max. resistance at rated flow, in. W.G.	0.97 (clean)

Roughing Filters

Manufacturer and model	Flanders, A083-L
No. of filter banks per plenum	1
No. of cells per bank	2
Rated flow per cell, cfm	2,000
Material	Glass fiber without separators
Efficiency, %	85-90 (per ASHRAE 52-68)
Max. resistance at rated flow, in. W.G.	0.52 (clean)

HEPA Filters

Manufacturer and model	Flanders, 7083-NL
No. of filter banks per plenum	2
No. of cells per bank	2
Rated flow per cell, cfm	1,500

Table 6.5-8 (Continued)

Material	Glass fiber without separators
Efficiency, %	99.97 (on particles 0.3 micron or larger)
Max. resistance at rated flow, in W.G.	1.0 (clean)

Charcoal Filters

Manufacturer and Model	CVI, HECA module
No. of charcoal beds per plenum	2 (4 inches thick)
Rated flow per bed, cfm	1,000
Material	Activated coconut charcoal impregnated with KI
Efficiency, %	99.9 on elemental iodine 95 on methyl iodide
Maximum resistance at rated flow, in W.G.	2.3 (clean)

Heating Coil

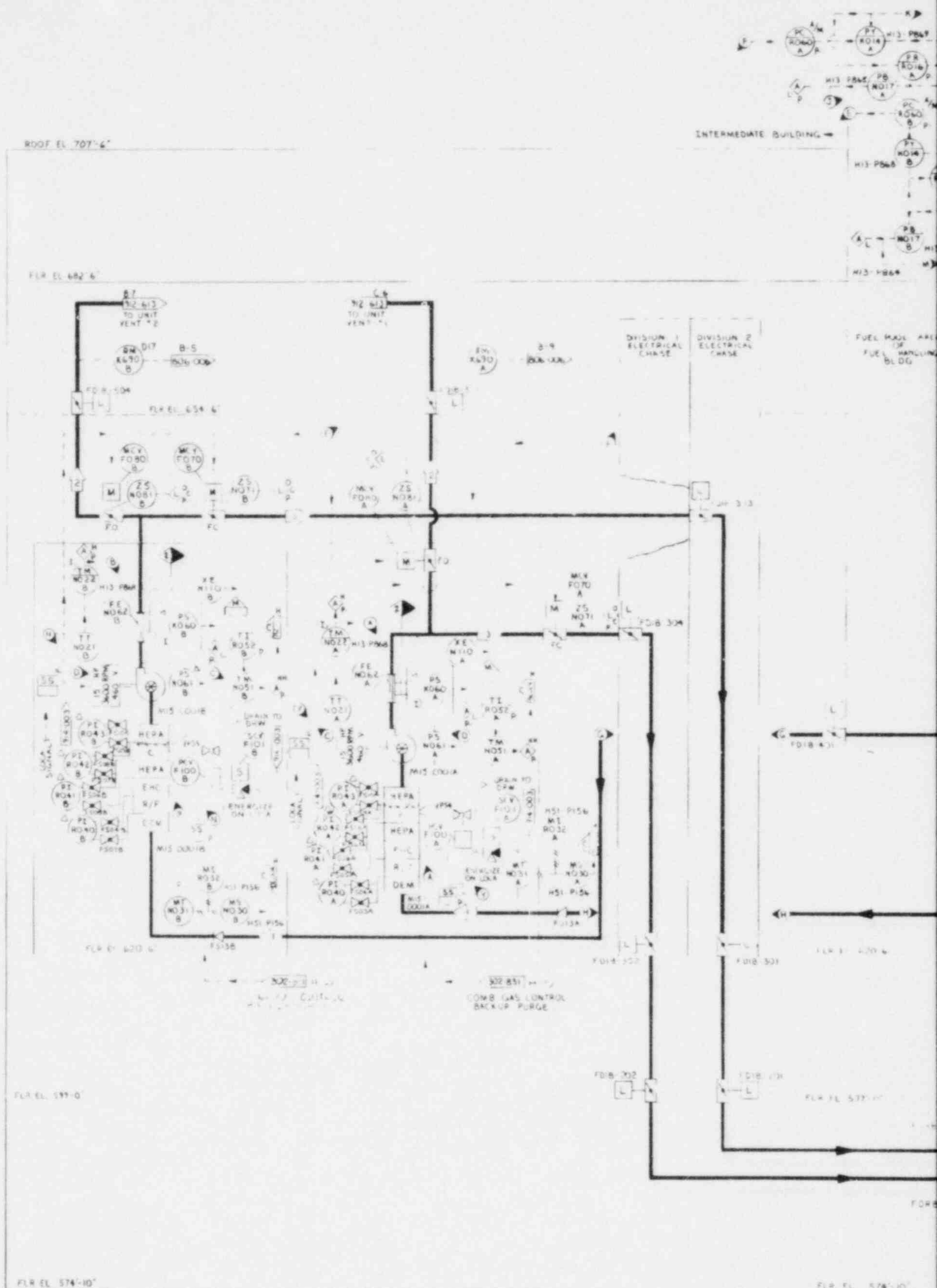
Manufacturer	CVI-Pennwalt
No. of coils per plenum	1
Heating capacity per coil, KW	15
Electrical characteristics	480 volt, 3 phase, 60 hertz

Fans (M15-C001A, 1B)

No. required	2 for Unit 1 2 for Unit 2
Manufacturer	Westinghouse
Fan type	Centrifugal SISW
Fan size (wheel diameter), in.	25-3/8
Arrangement	No. 4
Discharge position	Upblast

Table 6.5-8 (Continued)

Air quantity required per fan, cfm	2,000
Static pressure required, in W.G.	12
Fan motor horsepower	15
Motor electrical characteristics	460V, 3 phase, 60 hertz



ROOF EL 707'-6"
INTERMEDIATE BUILDING
FLR EL 682'-6"
TO UNIT VENT #2
DIVISION 1 ELECTRICAL CHASE
DIVISION 2 ELECTRICAL CHASE
FLR EL 654'-6"
HEPA
EHC
DEM
COMB GAS CONTROL BACKUP PURGE
FLR EL 620'-6"
FLR EL 599'-0"
FLR EL 574'-10"

DESIGN DATA						
#		CFM		BY	REMARKS	
1		2000				
2		400				
3		1600				
1		2000				
2		700				
3		1300				

NOTES:

1. ALL DIFFERENTIAL PRESSURE [illegible] ALARMS ARE INTERLOCKED WITH FAN MOTOR STARTER AND PROVIDED WITH TIME DELAY RELAY.
2. ALL CONTROL SWITCHES, STATUS LIGHTS, RECORDER, TEMPERATURE INDICATORS AND ALARMS ARE LOCATED ON THE HVAC PANEL (H13-P800) IN THE CONTROL ROOM, EXCEPT WHERE NOTED.
3. LOSS OF FAN OPERATION (FAN TRIP OR LOW FLOW) OF THE OPERATING FAN AUTOMATICALLY STARTS THE STAND BY FAN.
4. BYPASS AND INOPERABLE SYSTEM STATUS INDICATION IS PROVIDED IN THE CONTROL ROOM.
5. ALL ALARMS FROM THIS SYSTEM WILL BE ANNUNCIATED AS "HVAC TROUBLE" ON THE PANEL (H13-P680) IN THE CONTROL ROOM.
6. HCV-F008A (B) WILL MODULATE TOWARD FULL CLOSE ONLY WHEN DAMPER HCV-F070A (B) IS FULL OPEN.
7. ALL AIR QUANTITIES ARE IN CFM.

REFERENCES:

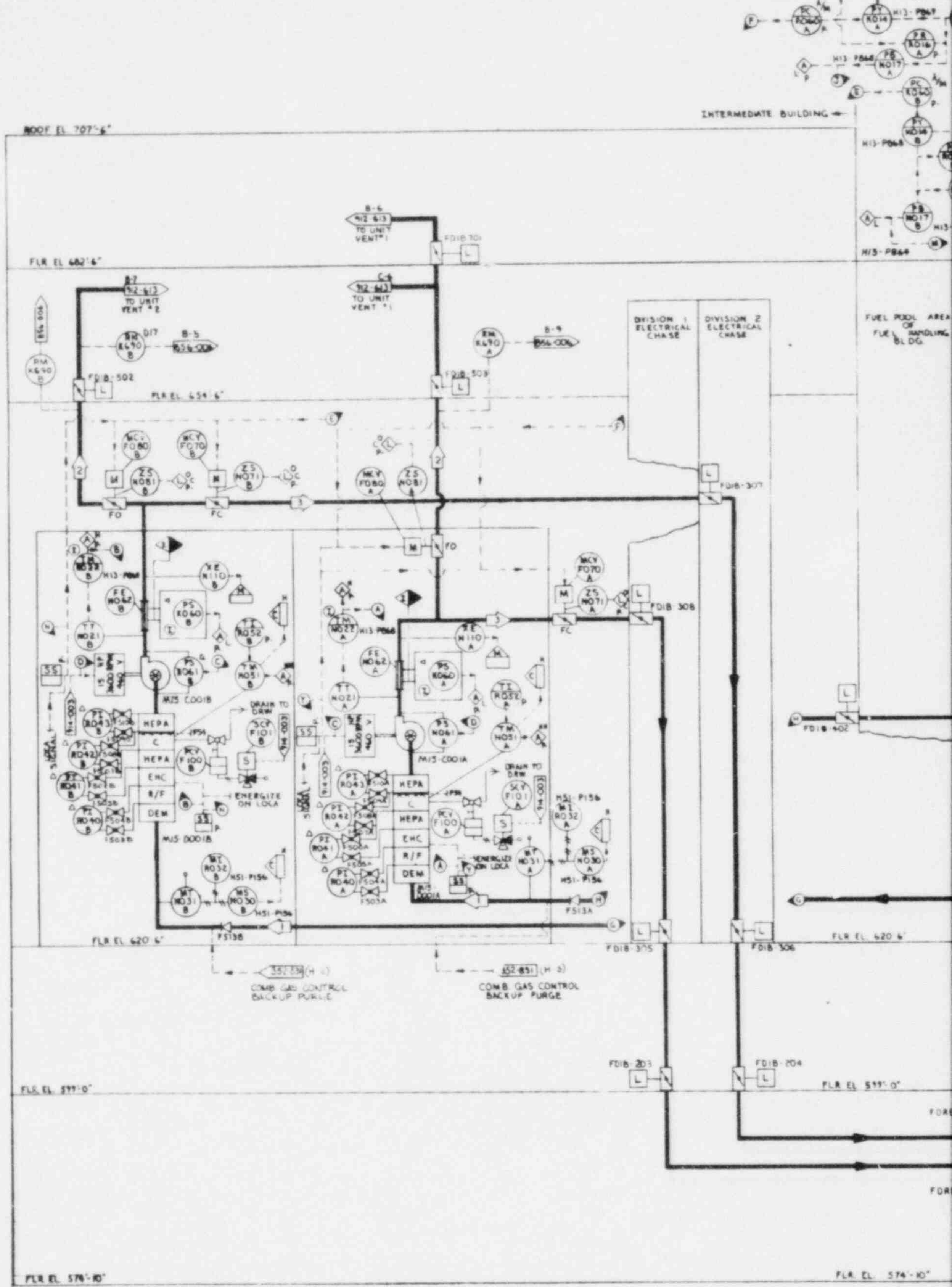
D-302-831 COMBUSTIBLE GAS CONTROL SYSTEM M51
D-814-803 FIRE SERVICE WATER SYSTEM P54
D-806-806 RADIATION MONITORING SYSTEM D17

PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Annulus Exhaust Gas Treatment System

Figure 6.5-1 (Sheet 1 of 2)
(GAI Dwg. D-912-605)



INTERMEDIATE BUILDING
ROOF EL 707'-6"
FLR EL 682'-6"
TO UNIT VENT #2
TO UNIT VENT #1
FLR EL 654'-6"
DIVISION 1 ELECTRICAL CHASE
DIVISION 2 ELECTRICAL CHASE
FUEL POOL AREA OF FUEL HANDLING BLDG
HEPA
C
HEPA
EHC
R/F
DEM
DRAIN TO DRW
ENERGIZE ON LOCA
FLR EL 620'-6"
COMB GAS CONTROL BACKUP PURGE
COMB GAS CONTROL BACKUP PURGE
FLR EL 599'-0"
FLR EL 574'-10"

DESIGN DATA						
		CFM		BY	REMARKS	
(NORMAL) 1		2000				
2		400				
3		1600				
(LOCA) 1		2000				
2		700				
3		1800				

NOTES:-

1. ALL DIFFERENTIAL PRESSURE SWITCH ALARMS ARE INTERLOCKED WITH FAN MOTOR STARTER AND PROVIDED WITH TIME DELAY RELAY.
2. ALL CONTROL SWITCHES, STATUS LIGHTS, RECORDERS, TEMPERATURE INDICATORS AND ALARMS ARE LOCATED ON THE HVAC PANEL (H13-P800) IN THE CONTROL ROOM, EXCEPT WHERE NOTED.
3. LOSS OF FAN OPERATION (FAN TRIP OR LOW FLOW) OF THE OPERATING FAN AUTOMATICALLY STARTS THE STAND BY FAN.
4. BYPASS AND INOPERABLE SYSTEM STATUS INDICATION IS PROVIDED IN THE CONTROL ROOM.
5. ALL ALARMS FROM THIS SYSTEM WILL BE ANNUNCIATED AS "HVAC TROUBLE" ON THE PANEL (H13-P800) IN THE CONTROL ROOM.
6. [illegible] (B) WILL MODULATE TOWARD FULL CLOSE ONLY WHEN DAMPER [illegible] (B) IS FULL OPEN
7. ALL AIR QUANTITIES ARE IN CFM

REFERENCES:-

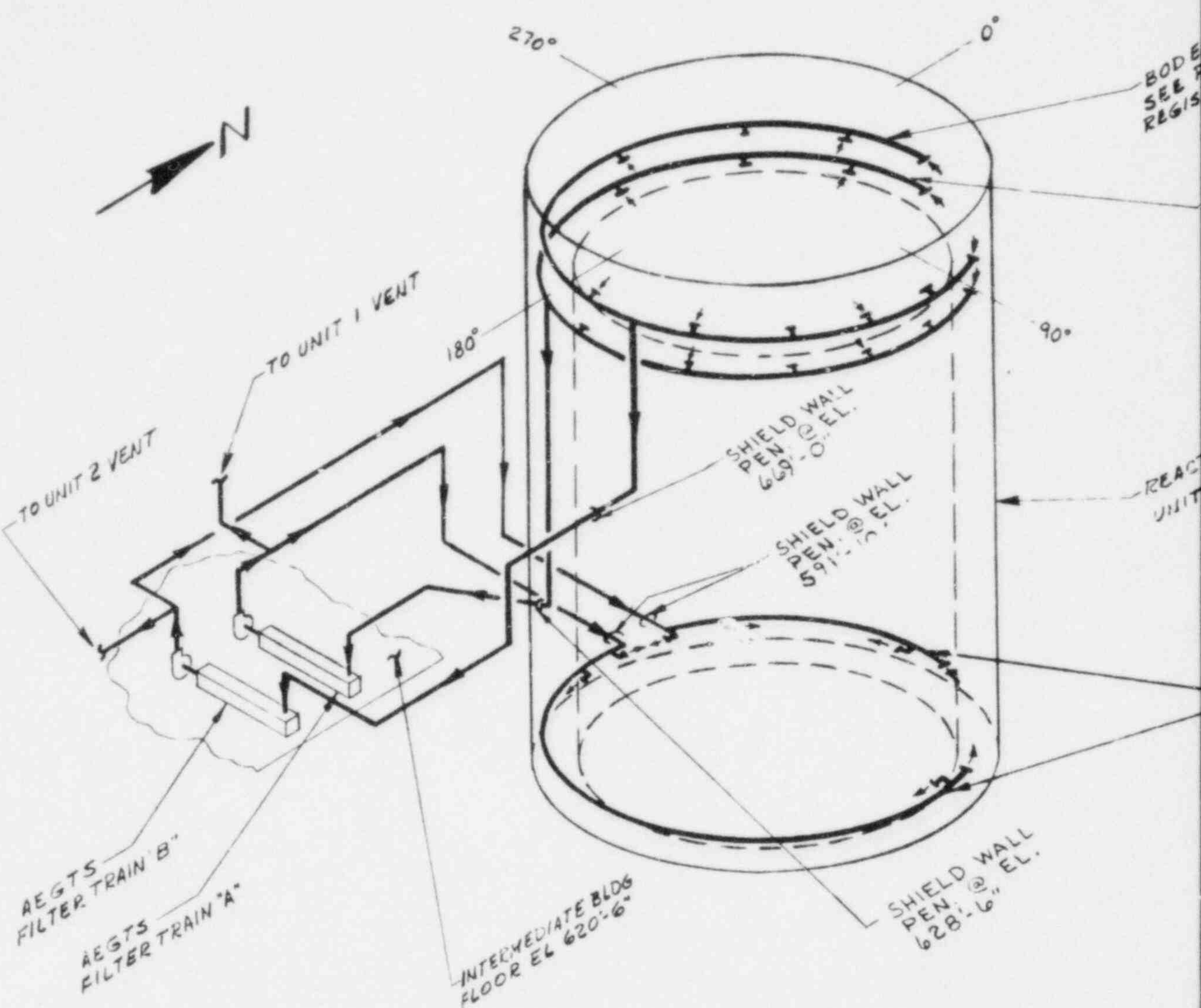
D-852-631 COMBUSTIBLE GAS CONTROL SYSTEM M51
D-814-[illegible] FIRE SERVICE WATER SYSTEM P54
D-[illegible] RADIATION MONITORING SYSTEM D17

PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

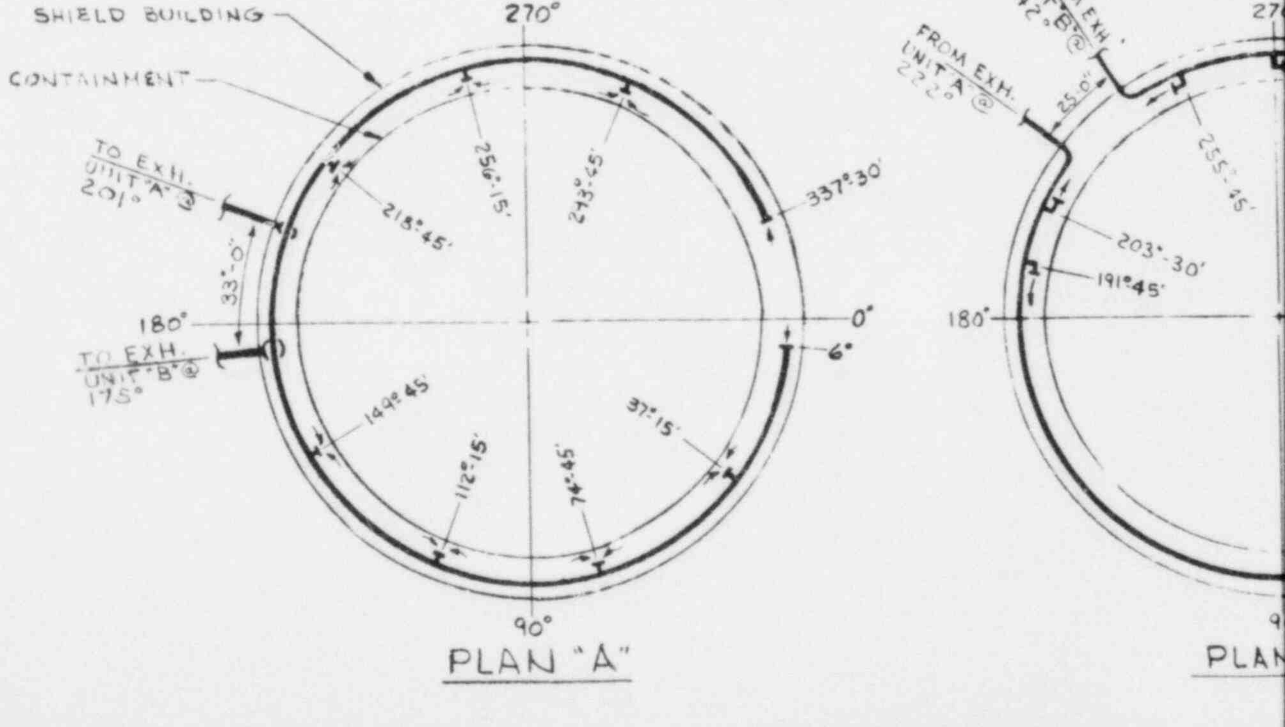
Annulus Exhaust Gas Treatment System

Figure 6.5-1 (Sheet 2 of 2)
(GAI Dwg. D-962-605)



ANNULUS EXHAUST GAS TREATMENT SYSTEM

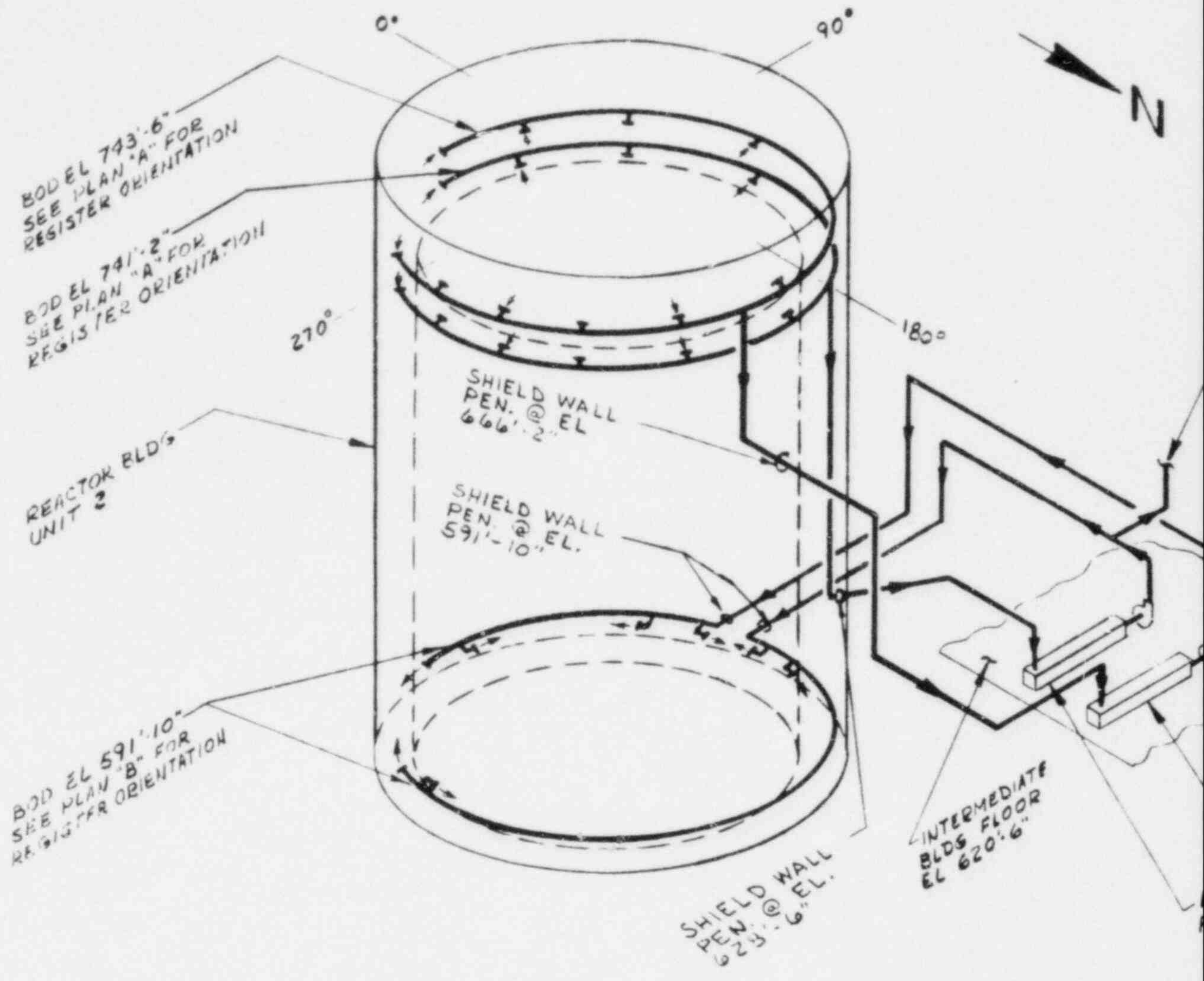
UNIT 1



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

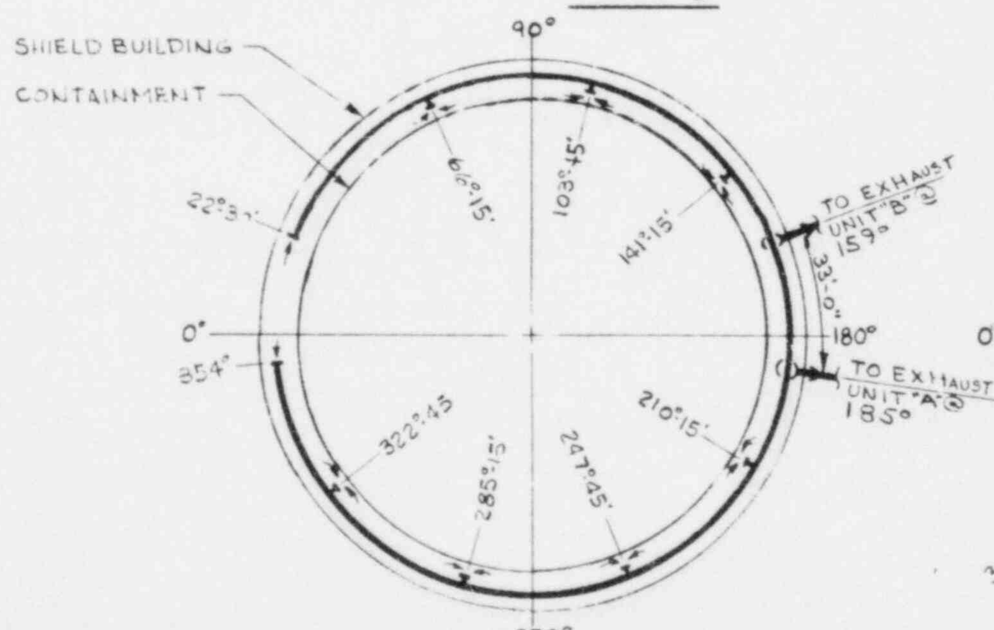
Annulus Exhaust Gas Treatment System Distribution Ductwork

Figure 6.5-2 (Sheet 1 of 2)
(GAI Dwg. B-2674)

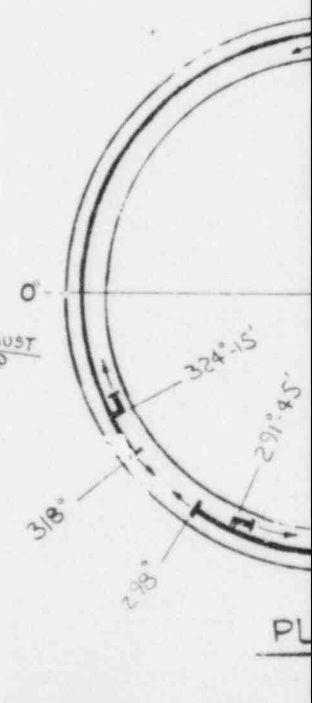


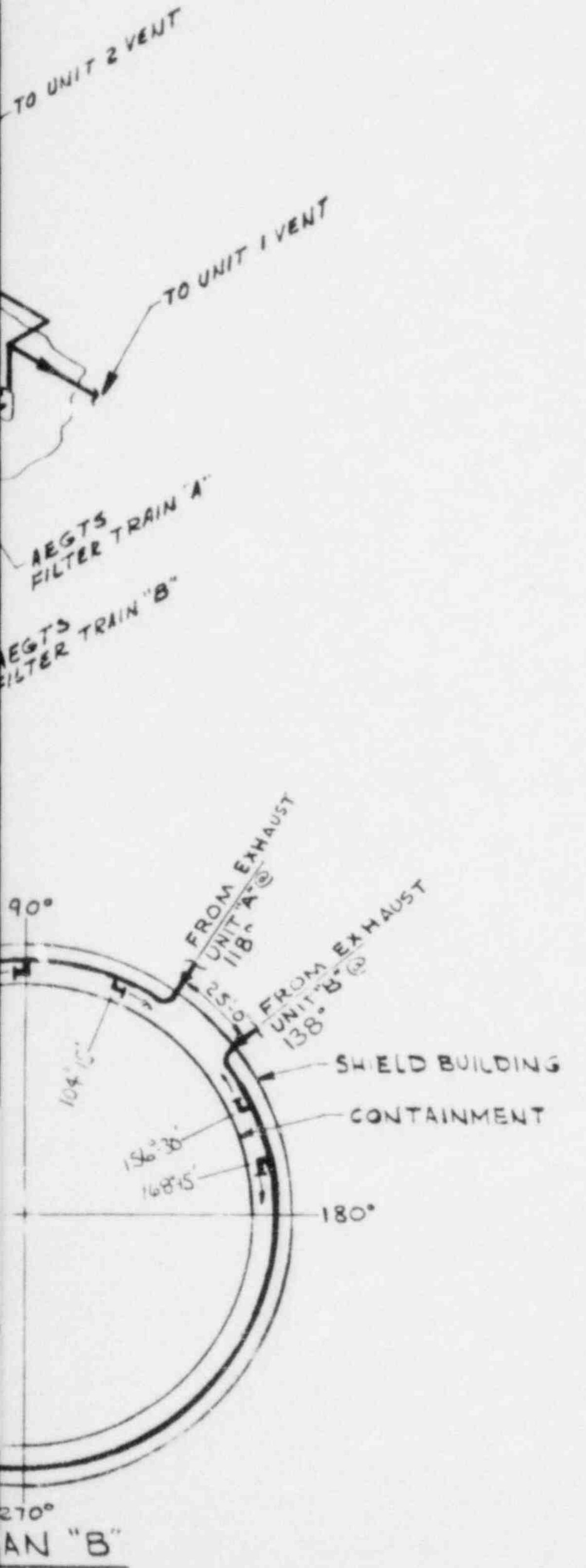
ANNULUS EXHAUST GAS TREATMENT SYSTEM

UNIT 2



PLAN "A"





PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Annulus Exhaust Gas Treatment
System Distribution Ductwork

Figure 6.5-2 (Sheet 2 of 2)
(GAI Dwg. B-2774)

6.6 INSERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS

6.6.1 COMPONENTS SUBJECT TO EXAMINATION

All Quality Group B pipewelds in the residual heat removal systems, emergency core cooling systems, and containment heat removal systems will be examined in accordance with the Summer 1975 Addenda of Section XI of the ASME Code (as required by 10 CFR 50.55a at this time).

All other components in Quality Group B and Quality Group C components will be examined in accordance with the Summer 1978 Addenda of Section XI of the ASME Code.

The Inservice Inspection (ISI) Program Plan covers Class 2 and 3 systems and components as described in Section XI. Exceptions for those portions of systems that cannot be examined to fully meet the requirements of Section XI, if any, are fully identified and the reasons for the exceptions given in the ISI Program Plan. The Plan also defines a schedule for examinations.

6.6.2 ACCESSIBILITY

The design and arrangement of Class 2 system components provide adequate clearances to conduct the required examinations at the code-required inspection interval, and the design and arrangement of Class 3 system components also provides adequate clearances.

6.6.3 EXAMINATION TECHNIQUES AND PROCEDURES

The Inservice Inspection Program Book describes the scope of the examinations and includes isometric drawings and component sketches. The drawings show weld locations in the various piping systems and on components. Boundary diagrams and classification tables are incorporated into the Program Plan to delineate systems boundaries. The Plan specifies the type of examinations to be performed and the total extent of the examination coverage for each system component.

Detailed procedures for volumetric (ultrasonic), surface penetrant and visual examinations are included in the Plan. Accompanying drawings include diagrams of calibration blocks and unique designations for each block to be used in the examination procedure.

6.6.4 INSPECTION INTERVALS

An inspection schedule for Class 2 system components is developed in accordance with the guidance of Section XI, Subarticle IWC-2400, and a schedule for Class 3 system components is developed according to Subarticle IWD-2400.

6.6.5 EXAMINATION CATEGORIES AND REQUIREMENTS

The inservice inspection categories and requirements for Class 2 components are in agreement with Section XI, Subarticles IWC-2520 and IWC-2600. Inservice inspection categories and requirements for Class 3 components are in agreement with Section XI, Subarticle IWD-2600.

6.6.6 EVALUATION OF EXAMINATION RESULTS

The evaluation of Class 2 component examination results will comply with the requirements of Article IWC-3000 of Section XI. The method to be used in the evaluation of examination results for Class 3 components will comply with the requirements of Article IWD-3000 of Section XI. The repair procedures for Class 2 components will comply with the requirements of Article IWC-4000 of Section XI. The procedures to be utilized for repair of Class 3 components will be in agreement with Article IWD-4000 of Section XI.

6.6.7 SYSTEM PRESSURE TESTS

The program for Class 2 system pressure testing will comply with the criteria of Code Section XI, Article IWC-5000. The program for Class 3 system pressure tests will comply with the criteria of Article IWD-5000.

6.6.8 AUGMENTED INSERVICE INSPECTION TO PROTECT AGAINST POSTULATED PIPING FAILURES

A separate Program Plan covers the Augmented Inservice Inspection Program for high-energy fluid system piping. This program plan book follows the same general outline as the Inservice Inspection Program Book and includes areas subject to examination, method of examination, and extent and frequency of examinations.

6.7 MAIN STEAM LINE ISOLATION VALVE LEAKAGE CONTROL SYSTEM

The main steam line isolation valve leakage control system (MSIVLCS) 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 the shield building annulus which is served by the annulus exhaust gas treatment system (AEGTS).

6.7.1 DESIGN BASES

6.7.1.1 Safety Criteria

The following criteria represent system design, safety and performance requirements imposed upon the MSIVLCS:

a. The MSIVLCS 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 shall not result in an offsite dose which exceeds the guidelines of 10 CFR 100.

b. The MSIVLCS shall conform to Seismic Category I requirements.

c. The MSIVLCS shall be capable of performing its safety function, when necessary, considering effects resulting from a LOCA, including (1) missiles that may result from equipment failures, (2) dynamic effects associated with pipe whip and jet forces, and (3) normal operating and accident caused local environmental conditions consistent with the design basis event. Further, any portion of the MSIVLCS which is Quality Group A, and is located outside the primary containment structure, shall be protected from missiles, pipe whip, and jet force effects originating outside the containment so containment integrity is maintained.

d. The MSIVLCS shall be capable of performing its safety function following a LOCA and an assumed single active failure (including failure of any one of the main steam isolation valves to close).

e. The MSIVLCS shall be designed so that effects resulting from a single active component failure shall not affect the integrity or operability of the main steam lines or main steam isolation valves.

f. The MSIVLCS shall be capable of performing its safety function following a loss of all offsite power coincident with a postulated design basis LOCA.

g. The MSIVLCS shall be designed to prevent leakage from the main steam lines consistent with maintaining containment integrity for up to 100 days.

h. The MSIVLCS shall be manually actuated, and shall be designed to permit actuation within about 20 minutes after a postulated design basis LOCA. This time period is consistent with loading requirements of the emergency electrical busses and with reasonable times for operator action.

i. The MSIVLCS, including instrumentation and circuits necessary for the functioning of the system, shall be designed in accordance with standards applicable to an engineered safety feature.

j. The MSIVLCS controls include interlocks to prevent inadvertent operation of the system. In particular, interlocks are provided to prevent multiple valve openings which could result in blowing high pressure steam to the building volume whenever the pressure in the connecting main steam piping exceeds MSIVLCS initiating pressure. All such controls and interlocks are activated from appropriately designed safety systems or circuits.

k. The subsystem connected between fast closing MSIVs shall have an interlock which shall preclude operating of the bleed valves on a main steam line if the inboard MSIV in that steam line is not closed.

l. The plant shall be designed to permit testing of the operability of MSIVLCS controls and actuating devices during power operation, to the extent practical, and testing of the complete functioning of the system during plant shutdowns.

6.7.1.2 Regulatory Acceptance Criteria

The piping and components of the MSIVLCS upstream from 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 upstream MSIVLCS are Quality Group B. The piping and components of the MSIVLCS 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 upstream system is connected to the main steam lines outside of the primary containment between the fast closing inboard and outboard MSIVs. The downstream system 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 MSIVLCS comply with the applicable codes, addenda, code cases, and errata in effect at the time the equipment was procured. The overall system design conforms to the recommendations of Regulatory Guide 1.96. Conformance with applicable regulatory guides and GDCs is discussed in Sections 1.8 and 3.1, respectively. Conformance with Branch Technical Positions ASB 3-1 and MEB 3-1, as related to breaks in high and moderate energy piping systems, is discussed in Sections 3.6.1 and 3.6.2. Conformance with Branch Technical Position RSB 3-2, as related to the classification of main steam and feedwater components, is discussed in Table 3.2-1.

The MSIVLCS is designed to permit testing of controls and actuating devices during power operation (where practical) and testing of the complete system during plant shutdown.

6.7.1.3 Leakage Rate Requirements

The design features employed with this system are established to reduce the dose rate of radioactive materials released to the environment following the postulated LOCA. Leakage control requirements are imposed upon the MSIVLCS 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 (once a year at shutdown).

The design and operational requirements imposed on the MSIVLCS relative to the foregoing criteria are established to:

a. Allow MSIV leakage rates up to 100 scfh for each MSIV in each line.

b. Allow MSIV leakage rate verification testing frequency compatible with the requirements of plant operating technical specifications.

c. Assure and restrict total plant dose impacts below 10 CFR 100 guidelines.

6.7.2 SYSTEM DESCRIPTION

6.7.2.1 General Description

The MSIVLCS is designed to minimize the release of fission products which could bypass the annulus exhaust gas treatment system after the postulated LOCA. This is accomplished by directing the leakage through the closed main steam isolation valves (MSIVs) to bleed lines which pass the leakage flow into the annulus area served by the AEGTS. By directing the MSIV leakage flow into the annulus, rather than directly into the AEGTS piping, mixing with the air in the annulus can occur, thereby reducing the offsite dose rates. Credit is taken for this mixing in the accident analyzed in Section 15.6.5. The flow is effected by a blower which maintains a slightly negative pressure in the steam lines with respect to atmosphere, thus assuring that the MSIV leakage will pass through the blower and on into the AEGTS prior to release to the atmosphere.

P&ID and system piping drawings are shown in Figures 6.7-1 and 6.7-2, respectively. As indicated on Figure 6.7-1, two independent systems (one downstream from the outboard MSIV and the other upstream) are provided to accomplish the leakage control function. The upstream MSIVLCS receives power from one electrical division and the downstream MSIVLCS from the other electrical division of the emergency power supply.

6.7.2.1.1 Downstream System

The downstream system is connected to the segments of the main steam lines between fast closing MSIVs outside containment and the downstream shutoff valves. The bleed line from each main steam line connects to a bleed header. The 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 is provided which are automatically opened following depressurization to connect the blower suction to the steam lines. 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; this will prevent

valve actuation when MSL pressure is greater than 1 psig. Pressure indicators are provided for monitoring the pressure in the main steam lines between the fast closing MSIVs outside containment and the downstream shutoff valves. The major flow to the blower suction is dilution air from the auxiliary building. This dilution air reduces the temperature of the MSIV leakage to approximately 190°F as it passes thr ugh the blower. The dilution air to leakage ratio is 5:1. A dilution air flow indicator using 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 the shield building annulus, which is served and processed by the AEGTS while depressurizing the steam lines (without adversely affecting equipment). The blower discharge line is also terminated in the shield building annulus such that the discharge flow will be processed by the AEGTS.

Manual switches are provided for functional testing of the bleed valves. These valves will not be tested during operation. This will preclude inadvertent dumping of steam due to equipment malfunction or operator error.

6.7.2.1.2 Upstream System

The upstream system is connected to the segments of the main steam lines between the inboard and outboard MSIVs. An individually controlled bleed line is provided for each main steam line. For each bleed line, two motor operated bleed valves are connected in series followed by a flow meter and a motor operated bypass valve. Flow through the four flow elements passes to a common blower which discharges to the shield building annulus and is served by the AEGTS. Discharge through the flow meter bypass (depressurization) valve is similarly routed to the AEGTS. Pressure sensors are used for interlock control to prevent any accidental actuation of the system as described for the downstream system. An added safety feature is that the bleed valves on each

of the bleed 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 bleed valves if 5 psig is not achieved in about 1 minute after the upstream system is activated. Another timer, together with a high flow limiter, is used to monitor and reclose the bleed valves if the total leakages through both MSIVs exceed a high flow set point. Electric heaters are used, one at the low point of each bleed line, to boil off any condensate and pass it through the flow limiter.

A differential pressure sensor is provided to monitor dilution air flow, which is an indication of a blower in operation. The bleed valves are interlocked to remain closed upon actuation of the upstream system until flow is established. A low differential pressure indicates that the blower is not running and the system valves will remain closed to assure that the low pressure manifold will always be maintained at a negative pressure whenever the bleed valves are open. Bleed valve reclosure is also initiated whenever dilution air flow is lower than a preset value.

The bleed line depressurization branches are discharged to the shield building annulus, which is served and processed by the AEGTS, without affecting any equipment. The blower discharge line is also terminated at a location in the annulus so that the discharge flow will be processed by the AEGTS.

Manual switches are provided for testing the bleed valves. These valves will not be tested during operation to preclude inadvertent dumping of steam due to equipment malfunction or operator error.

6.7.2.2 System Operation

The upstream and downstream MSIVLCS are actuated manually with initiate switches by the operator (from the control room) after it has been determined that a design basis LOCA has occurred, i.e., high drywell pressure and low reactor water level. System operation will start, provided that the steam

line and reactor vessel pressures are below the pressure permissive interlock set point, inboard MSIV position switch interlock is cleared and differential pressure in the dilution air line is established (unique to the upstream system only).

In the downstream system, the valves in the depressurization branch line open to permit the steam lines beyond the fast closing MSIVs outside containment to depressurize. The blowers are started coincident with the system initiating switch actuation. 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 volume served by the AEGTS.

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 a system component failure. The system would then be manually secured by the operator.

Upstream system actuation automatically depressurizes the main steam lines through the flow limiter bypass valves which reclose automatically to route the flow through the flow limiter. The electric heaters are turned on from the system actuation signal. The blower also starts from the system actuation signal and establishes a subatmospheric pressure in the main steam lines after the flow limiter bypass valves reclose. MSIV leakage is routed to annulus exhaust gas treatment during depressurization and exhaust stages of operation.

The upstream system is designed to automatically reclose if excessive MSIV leakage occurs. Automatic reclosure capability is provided on the bleed system for each individual steam line. Each steam line has its own bleed valves, electric heater, flow limiter, flow limiter bypass valve, timers and pressure instrumentation.

6.7.2.3 Equipment Required

The following equipment components are provided to facilitate system operation:

a. Piping

Process piping is carbon steel pipe 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 MSIVLCS isolation valve is designed and constructed to ASME III, Class 1. The remainder is designed and constructed to ASME III, Class 2 codes. The components and piping installation is designed to withstand Seismic Category I loads.

b. Valves

Motor operated gate valve to provide about 12 in./min. (nominal) opening and closing speed and constructed to the ASME III code class appropriate to the piping in which they are installed.

c. Blower

Rated at 100 scfm at -60 in. H_2O suction pressure.

d. Drain lines

Drain lines with loop seals and check valves are located in both the upstream and downstream systems. If, during system blowdown, water should accumulate in the loop seals upstream of the check valve, the loop seals will overflow and the check valves will open when the water head reaches seven feet and permit drainage to radwaste. Water will stop flowing through the loop seal and the check valve will reseat when the level decreases to below seven feet. The blower design and capacity are such

that it will not actuate the check valve to open during expected operational conditions. A heater is used in the upstream system to further assure that any condensate is boiled off prior to entering the low pressure manifold. The open drain is located in the annulus which is served by the AEGTS.

e. Annulus exhaust gas treatment system

The MSIVLCS will add about 50 scfm of load to the AEGTS during the exhaust phase. This is a small portion of the rated capacity of the AEGTS (Section 6.5.3) and will be conditioned to be compatible with the system temperature and verify humidity operating limits.

The MSIVLCS will add approximately 100 lbs of steam to the building volume served by the AEGTS during steam line depressurization, where it will be diluted before entering the system.

6.7.3 SYSTEM EVALUATION

An evaluation of the capability of the MSIVLCS to prevent or control the release of radioactivity from the main steam lines during and following a LOCA has been conducted. The sections that follow discuss the results of this evaluation.

6.7.3.1 Functional Protection Features

The upstream and downstream systems are physically separated. The equipment is designed to operate under the expected environmental conditions appropriate to the equipment location.

The MSIVLCS equipment is arranged to minimize the exposure of the system components to missiles, pipe deformations and jet forces. This is accomplished by locating the MSIVLCS outside the containment such that the design basis recirculation line break inside the containment will not affect the MSIVLCS. 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. The inboard and outboard systems are physically separated. 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; erefore, pipe whip protection is not required.

The use of the engineered safeguard power source to power the components of the system assures system operation during loss of offsite power.

6.7.3.2 Effects of Single Active Failures

The MSIVLCS functions following an active component failure (including failure of any one MSIV to close) by virtue of two redundant systems. The systems 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 will affect the integrity of the main steam lines.

The effects of other failure modes are evaluated in Table 6.7-1.

6.7.3.3 Effects of Seismic Induced Failures

The MSIVLCS is designed to operate during and following the application of Seismic Category I design loads in conjunction with LOCA induced loads.

6.7.3.4 Isolation Provisions

The MSIVLCS valves are expected to 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 setpoints are satisfied, the system isolation valves remain in a closed position. Two isolation valves are provided with one out of two valves satisfying isolation

requirements. In addition, the valve electrical circuit cannot be activated unless the initiating keylocked remote manual switch is in the "operate" position.

6.7.3.5 Leakage Protection Evaluation

The MSIVLCS is designed to limit the release of radioactive materials to the environment following a postulated LOCA. The system accomplishes this function through the use of the equipment described in Section 6.7.2.3. Excessive MSIV leakage originating from the primary containment is prevented by automatic closure of the bleed system on each steam line.

The manual initiation of the system could be carried out 20 minutes following the accident provided that the setpoint of the steam line pressure interlock is satisfied. Due to MSIV closure sequence, it is possible to have high pressure between the inboard and outboard MSIVs. If such pressure existed, it would remain above vessel pressure for more than one hour based on a leakage rate of 11.5 scfh per MSIV. There would be no need to actuate any portion of the MSIVLCS when the pressure between valves is higher than containment pressure, since clean steam (trapped between the valves when they closed) would be leaking toward the containment.

Once the pressure between the MSIVs has decayed, the bleed system is ac ivated to effect leakage control. The performance of the bleed system for possible conditions of operation has been evaluated.

Figure 6.7-3 shows the steam line pressure decay curves with the bleedoff line equivalent to 100, 200, 300 and 400 feet of 1-1/2 inch Schedule 160 pipe. For illustration purposes, assume the bleedoff line is 100 feet. If such pressure exists, the steam line pressure between the two MSIVs at one minute after system initiation will be approximately 20 psia.

The first timer bypasses a trip unit permitting the process valves to remain open for one minute after system initiation. If the steam line pressure exceeds 5 psig when the timer times out, the system valves will reclose. Otherwise, the valves will remain open and steam line depressurization

continues. At the setpoint of a second timer, about 2 minutes after system initiation, the flow limiter bypass valve is activated to reclose. A third timer is set at approximately 2-1/2 minutes after system initiation and bypasses the flow limiter high flow trip. This will allow the space between MSIVs to drop to subatmospheric pressure and for the flow to settle down to a steady value reflecting MSIV leakage flow. If the measured flow is lower than the preset value the bleedoff flow will continue. Each of the four flow limiters on the inboard system can be set to automatically reclose the bleed system from its associated steam line at any flow rate from 11.5 to 100 scfh. Final set point is selected based on the limits established in each individual plant technical specification.

The effects on the pressure decay are shown in Figure 6.7-4.

The outboard MSIV packing leakage is piped to an area served by the AEGTS. Piping and equipment associated with the leakoff line conforms to Seismic Category I requirements up to and including the packing leakoff valve. This valve and the open drain to radwaste are located in an area that is accessible during normal operation, allowing the operator to observe packing leakage. 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 MSIVLCS is evaluated in Section 15.6.5. Thus, the system will detect high steam line pressure and prevent system actuation, and also detect high leakage and prevent excessive release of leakage to the volume served by the AEGTS.

6.7.3.6 Failure Mode and Effects Analysis

The consequences of component malfunctions are shown in Table 6.7-1.

6.7.3.7 Influence on Other Safety Features

The MSIVLCS is powered from the engineered safeguard power sources. The load is estimated to be about 40 kW.

The MSIVLCS will add no more than 100 pounds of steam to the building volume served by the annulus exhaust gas treatment system during steam line depressurization. The steam will be diluted before entering the AEGTS.

The initial discharge will have no significant effect on building pressure buildup. The continuous flow is considered negligible compared to the AEGTS rated flow stated in Section 6.5.3. The MSIVLCS conditions the exhaust temperature and humidity to the requirements of the annulus exhaust gas treatment system prior to delivery to the AEGTS inlet.

In addition, by exhausting leakage steam and gases, the MSIVLCS does not introduce or expose the steam piping or valves to thermal or mass loadings different from those experienced in normal isolation valve service; therefore, this system cannot affect or degrade the sealing ability of the MSIVs.

6.7.3.8 Radiological Evaluation

Section 15.6.5 discusses the activity released to the environment by way of the annulus exhaust gas treatment system and the resulting offsite dose consequences.

6.7.4 INSTRUMENTATION REQUIREMENTS

The instrumentation necessary for control and status indication of the MSIVLCS is classified as essential and is designed and qualified in accordance with applicable IEEE Standards. This instrumentation will function to Seismic Category I requirements and LOCA environmental loading conditions appropriate to their installation, with control circuits designed to satisfy the mechanical and electrical separation criteria. Refer to Section 7.3 for a further discussion.

6.7.5 INSPECTION AND TESTING

Preoperational tests for the MSIVLCS are discussed in Chapter 14. 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. Complete system testing, including isolation valve testing, is 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 specification. Valves are capable of eing exercised periodically during normal operation.

Operation of the isolation valves and complete system testing or isolation valve leak testing are performed only during reactor shutdown to preclude inadvertent steam discharge.

TABLE 6.7-1

SINGLE FAILURE ANALYSIS OF MSIVLCS

	Component/Equipment	Malfunction	Effect
1.	Inboard MSIV	Any one valve fails to close	The upstream subsystem associated with the failed MSIV will remain deactivated by virtue of an interlock signal from MSIV position switch signifying an open valve. Three of four upstream subsystems function to collect leakage although not required. The downstream system is adequate to control leakage.
2.	Outboard MSIV	Any one valve fails to close	The upstream subsystem associated with the failed MSIV will isolate on either high pressure or high flow. The downstream system continues to function and control leakage.
3.	Block valve (2nd outboard main steamline valve)	Any one valve fails to close	The downstream system functions but its capacity is insufficient to establish a subatmospheric pressure in the steam lines. The upstream system functions to control leakage.
4.	Upstream subsystem bleed valve	(a) Fails to open	The flow limiter bypass valve associated with the failed bleed valve cycles to open coincident with the bleed valve trip signal but will reclose on the two-minute timer setpoint.

TABLE 6.7-1 (Continued)

Component/Equipment	Malfunction	Effect
		The heater will trip on but will trip off automatically due to high pressure in the steam line.
		The downstream system and three upstream subsystems remain functional.
	(b) Fails to close when tripped	One out of two valves satisfy isolation by virtue of single active component failure criteria.
		The downstream system and upstream subsystems remain functional.
5. Upstream subsystem flow limiter bypass valve	(a) Fails to open	One main steam line between MSIVs will not depressurize in time. The bleed valves will trip to reclose due to high steam line pressure (greater than 5 psig) or due to excessive flow if pressure permissive is satisfied.
		The downstream system and three upstream subsystems remain functional.
	(b) Fails to reclose at timer setpoint	The associated upstream subsystem will isolate due to excessive flow through the flow limiter caused by back flow from the open bypass valve.
		The downstream system and three upstream subsystems remain functional.

TABLE 6.7-1 (Continued)

	Component/Equipment	Malfunction	Effect
6.	Flow limiter	Malfunction to detect excessive flow	With the instrument as the single active failure, the rest of the leakage control system equipment or components should function as required and the design parameters are within the system capability. The upstream system remains functional.
7.	Heater	Fails to operate or failure to evaporate condensation.	The condensate will ultimately fill up the associated subsystem process line acting as a seal. A subatmospheric pressure will not be established in the steam line. The downstream system and three upstream subsystems remain functional.
8.	Blower	Fails to operate	The upstream system remains inoperative because dilution air flow, used as an interlock, will not be established. Downstream system functions to control leakage.
9.	Vessel pressure interlock	(a) Instrument failure following a LOCA	Each upstream subsystem initiating RMS remains inactive. The upstream system becomes inoperative and the downstream system functions to control leakage.

TABLE 6.7-1 (Continued)

	Component/Equipment	Malfunction	Effect
		(b) Instrument failure to become active during normal power operation	MSIV position switches and steam line pressure interlocks will act to keep the upstream system equipment and components activated. Also, each subsystem initiating RMS is keylocked; therefore, the probability of inadvertent system operation is remote.
10.	Steam line pressure interlock	(a) Instrument failure to clear permissive interlock following a LOCA	The associated upstream subsystem will not function to control leakage. The downstream system and three upstream subsystems remain functional.
		(b) Instrument failure following a LOCA	The associated upstream subsystem remains inactive because of two other interlocks not permissive. Inadvertent subsystem operation is remote.
11.	One-minute timer	Instrument failure	If the timer cycles earlier than setpoint and steam line pressure greater than 5 psig, subsystem valves trip to reclose. If the line pressure satisfies the pressure switch setpoint, leakage control remains in effect.
12.	Steam line pressure switch	Instrument failure	If the steam line pressure is greater than 5 psig when the one-minute timer has timed out, isolation trip signal to the subsystem valves is not established. The consequences in item 6 apply.

TABLE 6.7-1 (Continued)

	Component/Equipment	Malfunction	Effect
13.	Two-minute timer	Instrument failure	The flow limiter bypass valve remains open. Same consequences as in item 5(b).
14.	Three-minute timer	Instrument failure	Same consequences as in item 6.
15.	Dilution air flow sensor	Instrument failure	Same consequences as in item 6.
16.	Check valve	Stuck open	The blower will operate at semi runoff capacity due to recirculated gas through the open check valve. Failure to establish the required ΔP on the dilution air line provides the trip signal for the upstream system to isolate. The downstream system remains functional to control leakage.
	OUTBOARD SYSTEM(1)		
17.	Depressurization valves	(a) Fail to open	Steam line will not depressurize and the downstream system remains inoperative.
		(b) Fail to close with the reclosure trip signal	Bleed valves remain closed and subatmospheric pressure will not be established in the steam lines. An alarm is annunciated at the duration of a timer which will alert the operator to secure the system in a safe shutdown condition.
18.	Bleed valves	Fail to open	Same consequences as in item 17(b).

TABLE 6.7-1 (Continued)

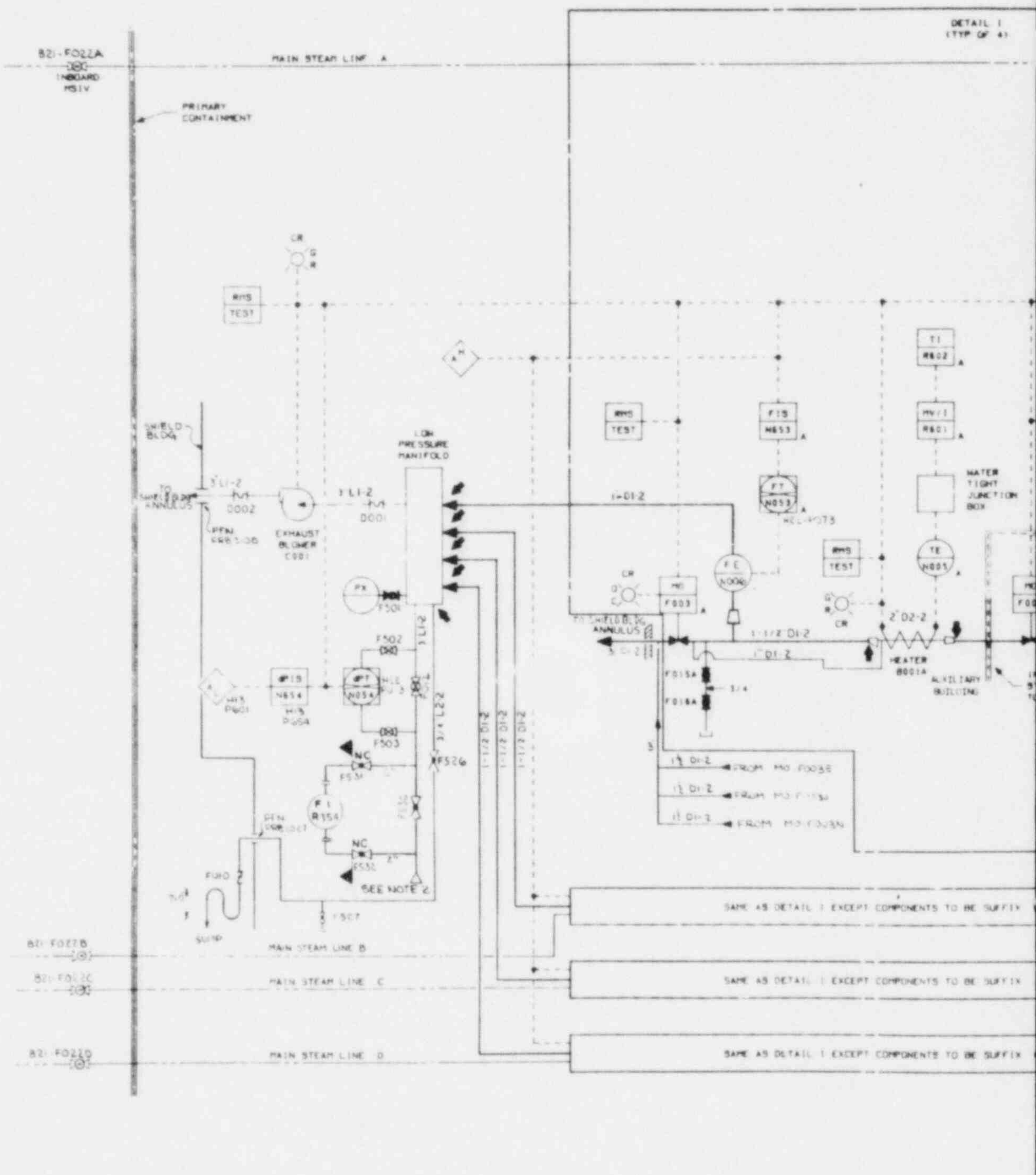
	Component/Equipment	Malfunction	Effect
19.	Vessel and steam line pressure interlocks	Instrument failure following a LOCA	The downstream system remains inoperative.
20.	Six-minute timer or pressure switch	Instrument failure	The alarm fails to annunciate if the steam line pressure is not subatmospheric. The system remains functional.
21.	Dilution air flow sensor	Instrument failure	Dilution air flow will not be monitored and since this is the single active failure, the rest of the system equipment or components should function as required and the design parameters are within the system capability. The downstream system remains functional.
22.	Blower	Fails to operate	Dilution air flow will not be established causing an alarm to annunciate. Also, when the timer has timed out, another alarm is annunciated which is an indication that the system failed to establish the required vacuum in the steam lines. On the basis of the available information the operator will then initiate the necessary action to secure the system to safe shutdown condition.

TABLE 6.7-1 (Continued)

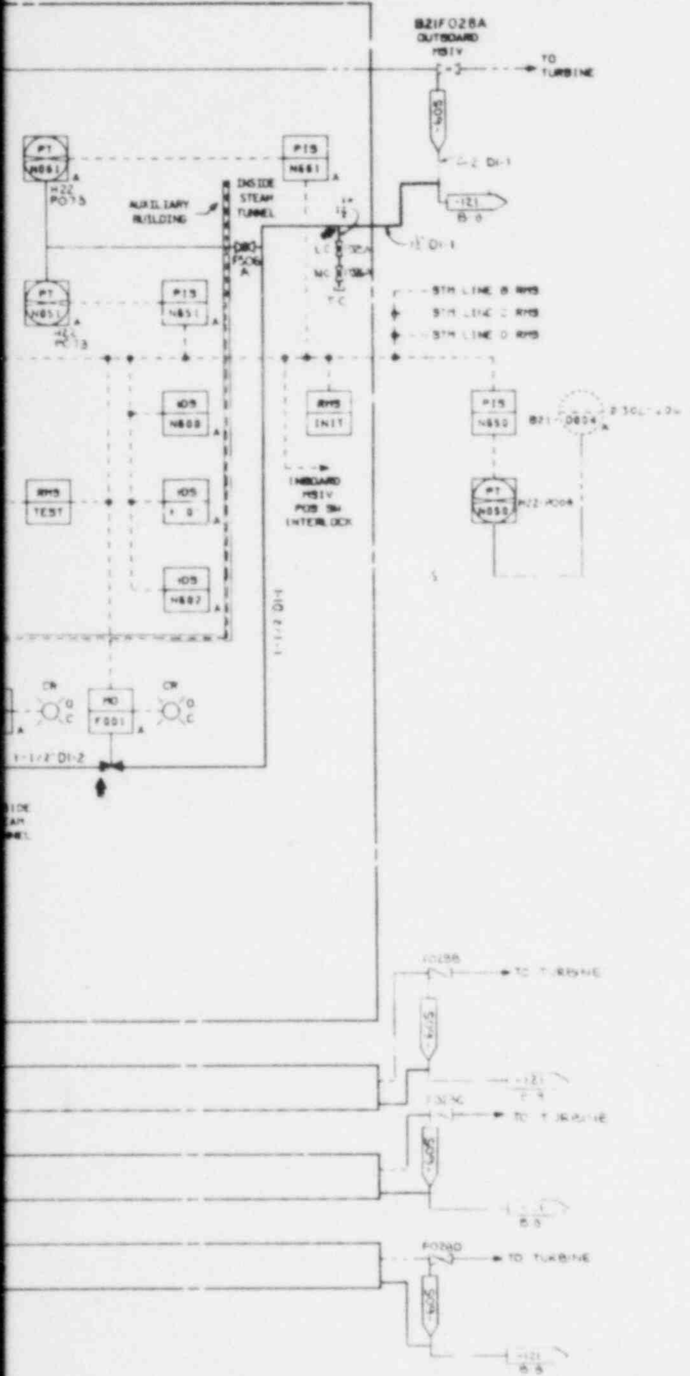
	Component/Equipment	Malfunction	Effect
23.	Steam line pressure switch	Instrument failure to transfer mode of operation from depressurization to bleedoff.	Same consequences as in item 17(b).
24.	Check valve	Stuck open	Same consequences as in item 16.

NOTE:

1. If any situation occurs wherein the downstream system does not function due to an active component failure, the upstream system will function to control leakage.



B21-F022A
INBOARD MSIV
MAIN STEAM LINE A
PRIMARY CONTAINMENT
DETAIL 1 (TYP OF 4)
RMS TEST
SHIELD BLDG
LOW PRESSURE MANIFOLD
EXHAUST BLOWER C001
D002
D001
FIS N653
FT N053
TI R602
MV/I R601
WATER TIGHT JUNCTION BOX
TE N005
FE N006
F003
HEATER B001A
AUXILIARY BUILDING
F015A
F016A
FROM MO F003B
FROM MO F003C
FROM MO F003D
F502
F503
F526
F531
F532
F501
SEE NOTE 2
F507
SUMP
MAIN STEAM LINE B
B21-F022B
B21-F022C
MAIN STEAM LINE C
B21-F022D
MAIN STEAM LINE D
SAME AS DETAIL 1 EXCEPT COMPONENTS TO BE SUFFIX



NOTES

1. ALL EQUIPMENT AND INSTRUMENTS ARE PREFIXED BY NUMBER E32 UNLESS OTHERWISE NOTED.
2. DILUTION AIR SHALL ORIGINATE FROM THE AUXILIARY BUILDING.
3. ALL REMOTE MANUAL SWITCHES, INDICATING LIGHTS, AND INSTRUMENTS ON PANEL H13-P800 UNLESS OTHERWISE NOTED.
4. THE INBOARD SYSTEM POWER SUPPLY SHALL BE THE SAME AS THE POWER SUPPLY TO THE OUTBOARD MSIV'S (DIVISION 1). THE OUTBOARD SYSTEM POWER SUPPLY SHALL BE THE SAME AS THE POWER SUPPLY TO THE INBOARD MSIV'S (DIVISION 2).
5. FOR INTERLOCK REQUIREMENTS AND VALVE ACTUATION, SEE SYSTEM FCD E32-1030.
6. THIS SYSTEM DIAGRAM IS A PHOTOGRAPHIC REPRODUCTION OF G.E. DWG. 762E750, SHEET 1 SPEC FAC BUILD IRC ARE SHOWN BENEATH ON TITLE BLOCK.
7. PERMANENTLY INSTALLED ROTOMETERS ARE PROVIDED TO ESTABLISH THE ALLOWABLE FLOW RATE DURING SYSTEM PREOP AND SUBSEQUENT SURVEILLANCE TESTING.

REFERENCES

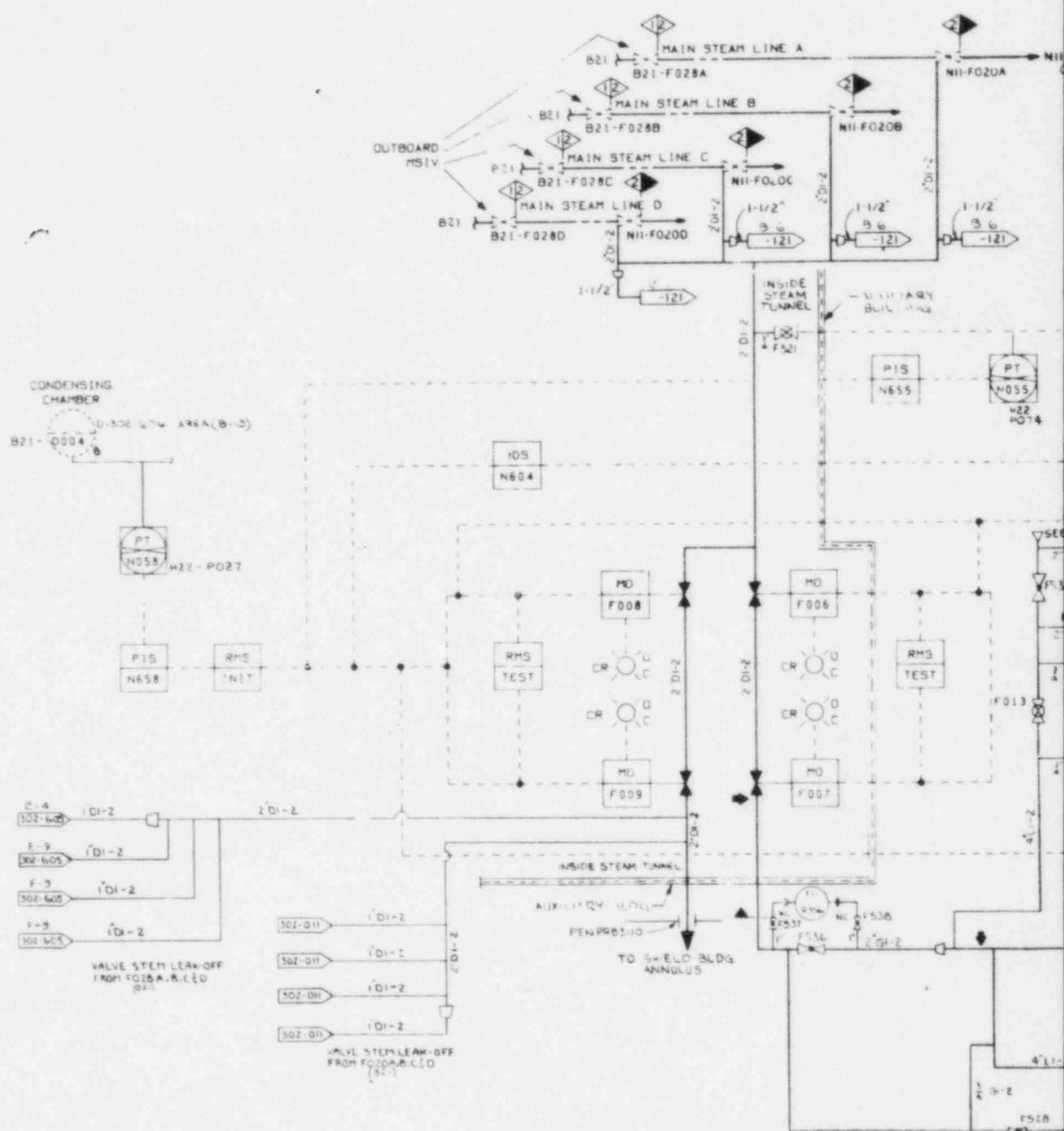
D-302-605	NUCLEAR BOILER SYSTEM
D-302-606	NUCLEAR BOILER SYSTEM
D-302-607	NUCLEAR BOILER SYSTEM
462-4070	G.E. - PROCESS INSTRUMENTATION
462-1010	G.E. - PIPING AND INSTRUMENT SYMBOLS
462-4030	G.E. - PRESSURE INTEGRITY OF PIPING AND EQUIPMENT PRESSURE PARTS
E32-1030	G.E. - INTERLOCK REQUIREMENTS AND VALVE ACTUATION
E32-1020	G.E. - MSIV LEAKAGE CONTROL PROCESS CONTROL DIAGRAM
D-302-121	R.R.C. AND MISCELLANEOUS DRAINS

PNPP

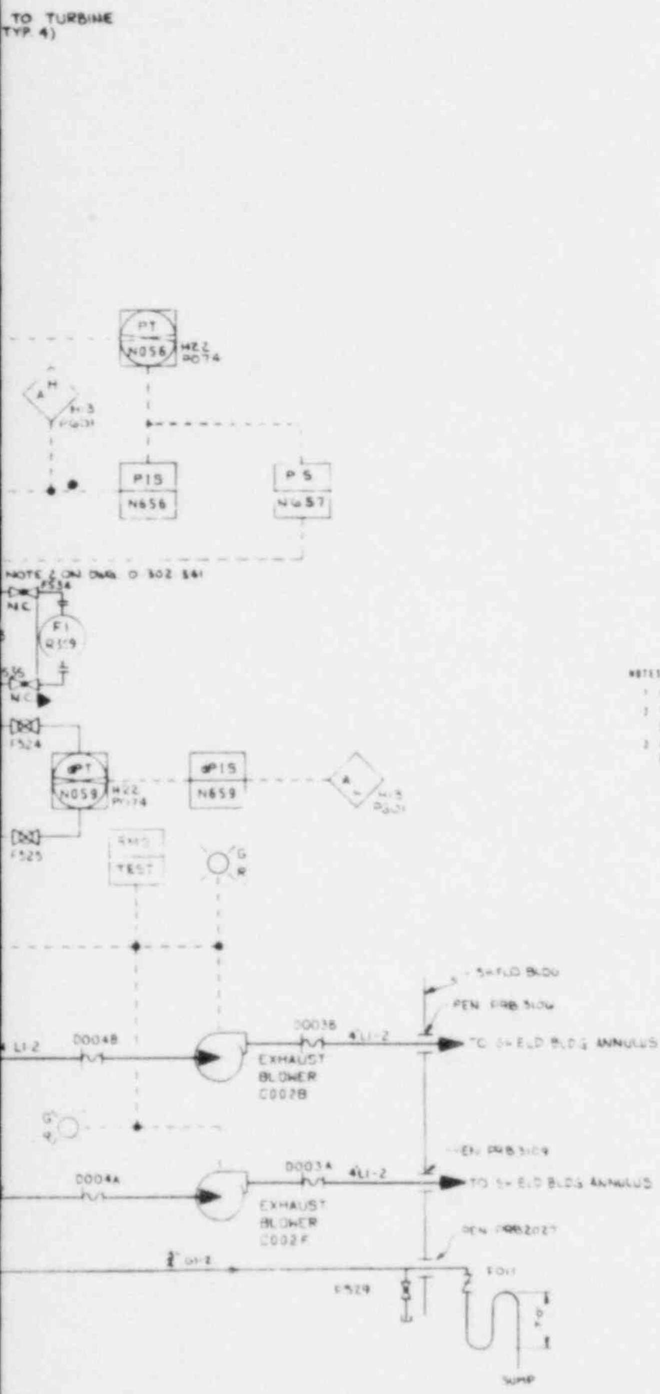
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Main Steam Line Isolation Valve Leakage Control System

Figure 6.7-1 (Sheet 1 of 2)
(GAI Dwg. D-302-341)



MAIN STEAM LINE A
MAIN STEAM LINE B
MAIN STEAM LINE C
MAIN STEAM LINE D
B21-F028A
B21-F028B
B21-F028C
B21-F028D
N11-F020A
N11-F020B
N11-F020D
OUTBOARD MSIV
INSIDE STEAM TUNNEL
CONDENSING CHAMBER
B21-D004
PT N058
H22-P027
PIS N658
RMS INIT
IDS N604
PIS N655
PT N055
MO F008
MO F006
MO F009
MO F007
RMS TEST
TO SHIELD BLDG ANNULUS
VALVE STEM LEAK-OFF FROM F028A,B,C,&D
VALVE STEM LEAK-OFF FROM F020A,B,C,D
F521
F013
F528
F534
F537
F538



NOTES

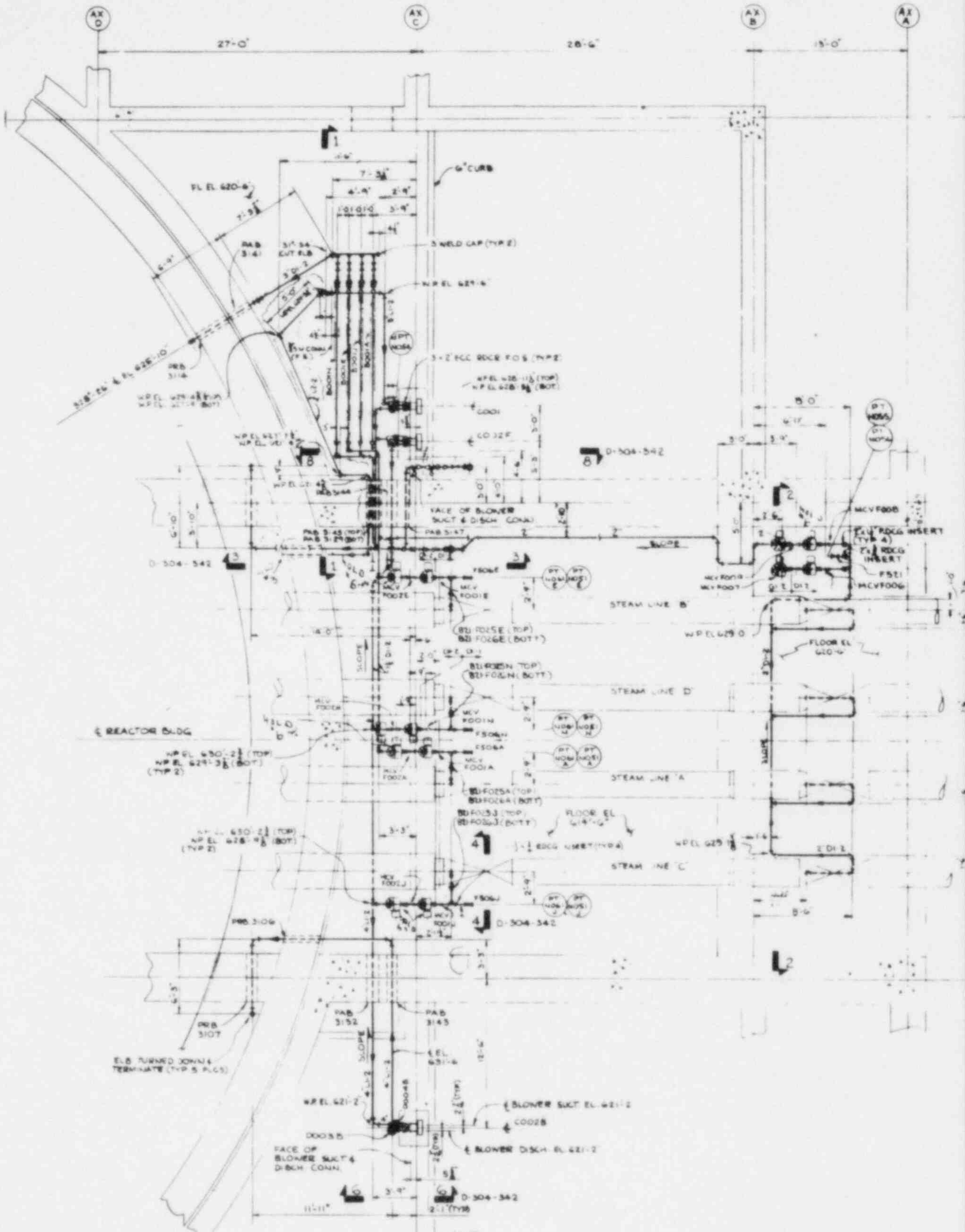
1. FOR NOTES AND REFERENCES SEE DWG D-302-341
2. THIS SYSTEM DIAGRAM IS A PHOTOGRAPHIC REPRODUCTION OF G.E. DWG [illegible] SHEET 2. SPECIFIC REVISIONS ARE SHOWN BENEATH GAI TITLE BLOCK
3. ALL REMOTE MANUAL SWITCHES, INDICATING LIGHTS AND INSTRUMENTS ON THIS DRAWING ARE ON H13-P845 UNLESS OTHERWISE NOTED

PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

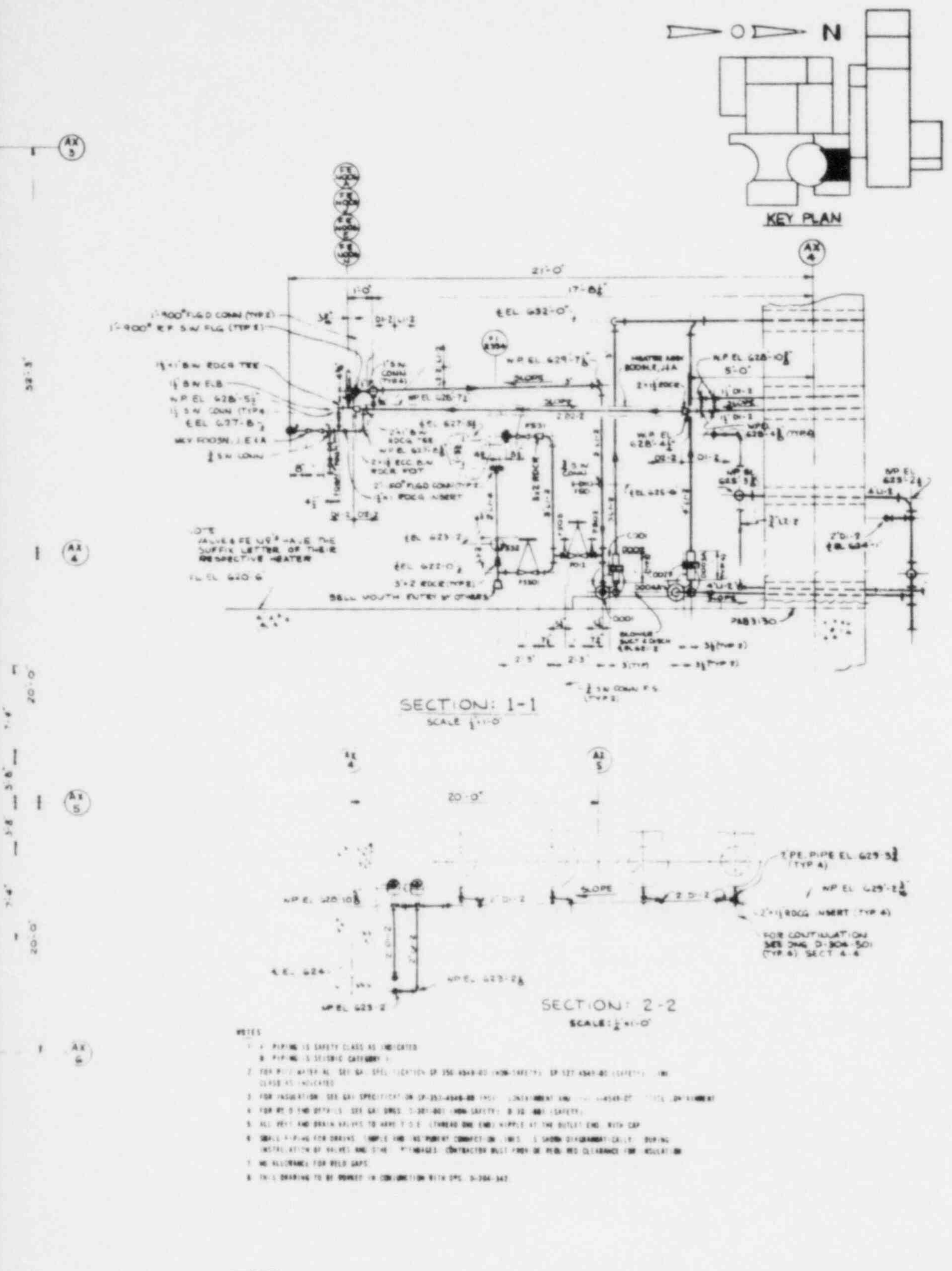
Main Steam Line Isolation Valve
Leakage Control System

Figure 6.7-1 (Sheet 2 of 2)
(GAI Dwg. D-302-342)



PLAN ABOVE EL. 620'-6" & 614'-6"

SCALE ¼"=1'-0"

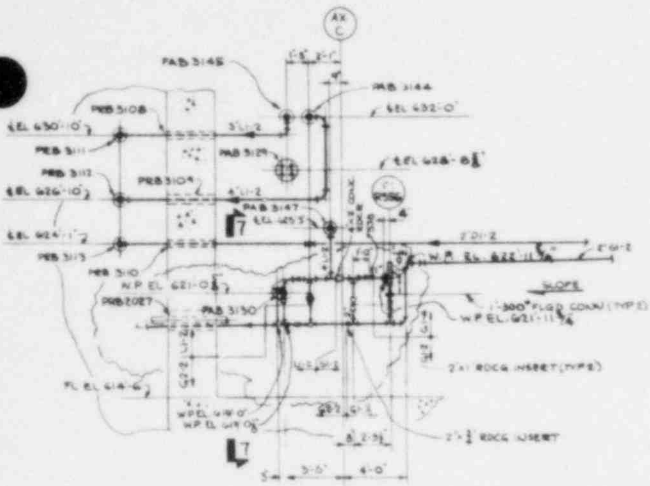


VALVES M&&F006, 007, 008, 009
" B21F001 A,B,N,J
" B21F002 A,B,N,J

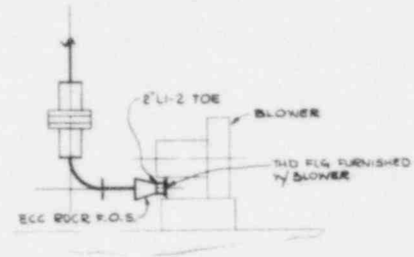
PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Main Steam Line Isolation Valve Leakage Control System Piping

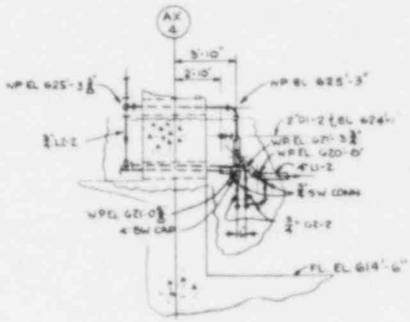
Figure 6.7-2 (Sheet 1 of 2)
(GAI Dwg. D-304-341)



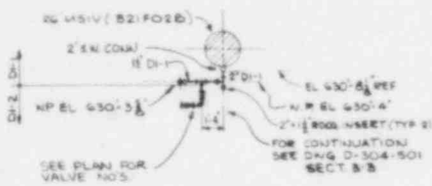
SECTION: 3-3
SCALE: 1/4"=1'-0"
D-304-341



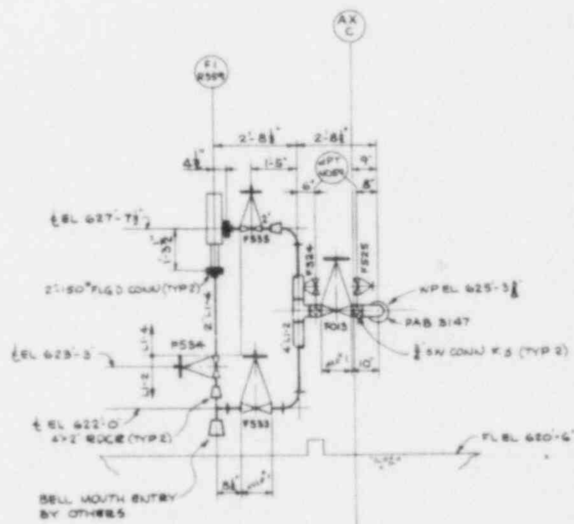
SECTION: 6-6
VIEW AT BLOWER SUCT-DISCH. (SIMILAR 6 PLCS)
SCALE: NONE
D-304-341



SECTION: 7-7
SCALE: 1/4"=1'-0"



SECTION: 4-4
TYPICAL (4) MAIN STEAM LINES
SCALE: 1/4"=1'-0"
D-304-341



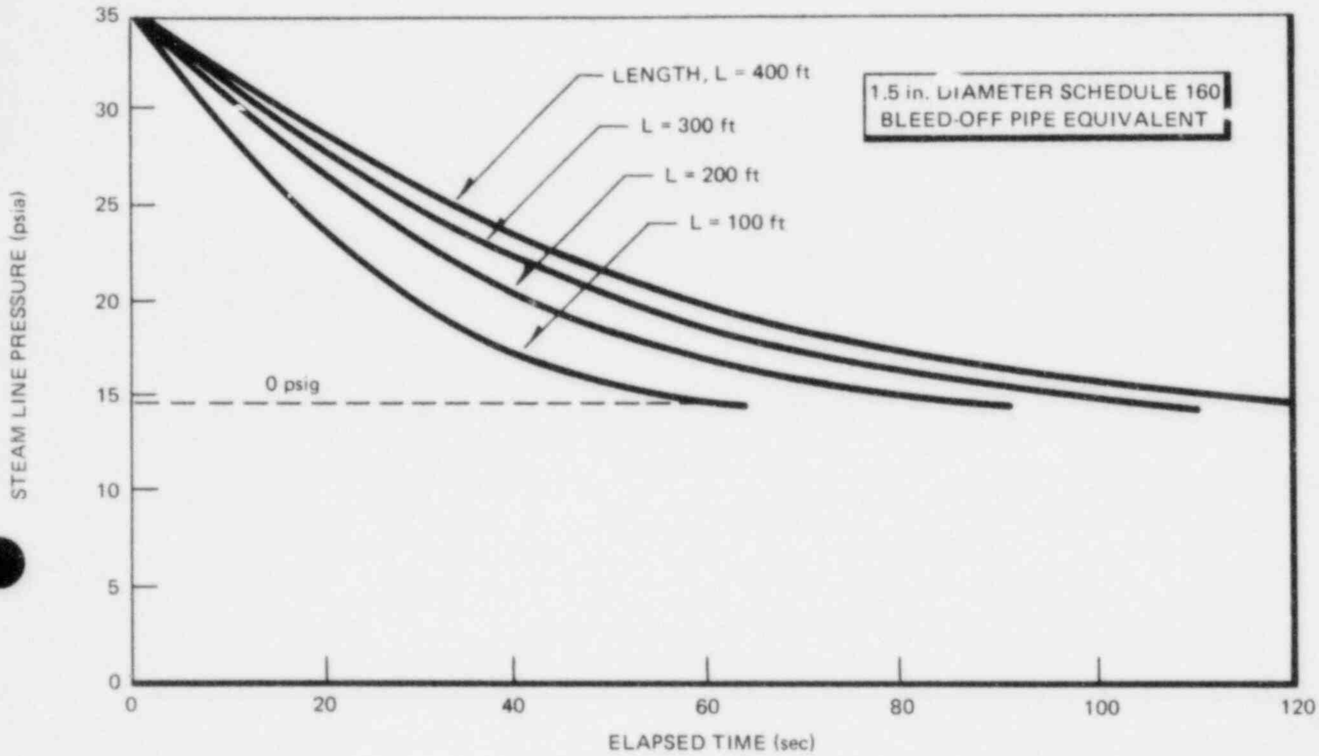
SECTION: 8-8
SCALE: 1/4"=1'-0"
D-304-341

NOTES:-
1. FOR NOTES AND REFERENCES, SEE DWG D-304-341

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Main Steam Line Isolation Valve
Leakage Control System Piping

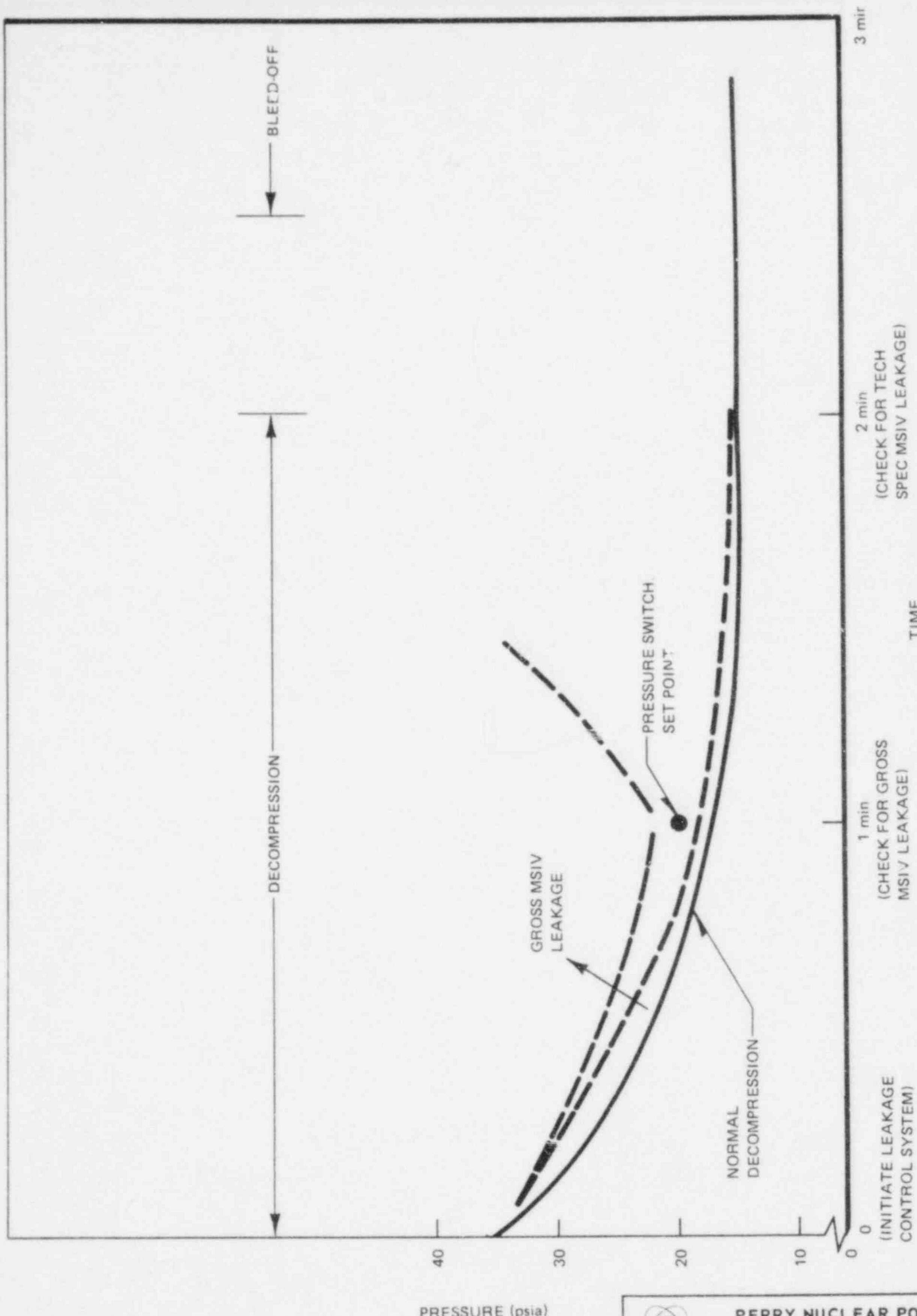
Figure 6.7-2 (Sheet 2 of 2)
(GAI Dwg. D-304-342)



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Main Steam Line Between
Isolation Valve-Decompression
Versus Elapsed Time

Figure 6.7-3



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Steam Line Pressure Between MSIV During Decompression and Bleed-off

Figure 6.7-4

6.8 SAFETY RELATED INSTRUMENT AIR SYSTEM

6.8.1 DESIGN BASES

The function of the safety related instrument air system is to continuously supply clean, dry, oil-free air for the initial charge and recharging of the automatic depressurization system (ADS) safety relief valve accumulators when the depressurization function of the safety relief valves is used. Air receiver tanks are sized by volume to provide a sufficient quantity of air for recharging the ADS accumulators under accident conditions. In addition, the tanks contain a sufficient volume of air to provide makeup for system leakage for a period of 14 days after an accident occurs. After this initial 14-day period, the system can be recharged with the air compressors or commercially available compressed air bottles.

6.8.2 SYSTEM DESIGN

The safety related instrument air system is shown on Figure 6.8-1. The system is designed to provide clean, dry air continuously at 150 psig to the ADS relief valve accumulators. The system stores air at 2,500 psig in receiver tanks downstream of the 2,500 psig compressor purifier package. A pressure reducing valve downstream of the air receiver tanks is used to reduce air pressure from 2,500 psig to 150 psig by sensing the downstream pressure.

One reciprocating type air compressor purifier package is provided for each unit. The compressors supply 15 scfm at 2,500 psig and are automatically operated by a pressure switch on the compressor. The compressor automatically starts at 2250 psig and stops at 2500 psig. They are sized to initially charge the two receiver tanks for each unit in eight hours. Recharging from the normal low pressure switch set point of 2,250 psig will require 12 minutes. The compressor unloads automatically after it shuts off.

The system has a connection for recharging Scott air packs. This connection can be used for recharging in emergency and normal situations. The purifier portion of the compressor purifier package filters, dries and treats the air to make it breathable for Scott air pack use.

One air receiver tank is provided in each supply line for the ADS accumulators. The tanks are of welded steel construction and are designed in accordance with ASME Section III of the Boiler and Pressure Vessel Code.

Air receiver tank pressure is sensed and transmitted to the control room. An alarm is sounded in the control room if the receiver tank pressure decreases to 2,000 psig.

Each tank is of the vertical, cylindrical type, measuring 18 inches in diameter and six feet in height. The tanks are equipped with relief and drain valves. The relief valves are set to relieve at 110 percent (2,750 psig) of the operating pressure.

Motor operated containment and drywell isolation valves are also provided for the safety related instrument air system.

6.8.3 DESIGN EVALUATION

The air system is Safety Class 2 and 3, except for the section between the air compressors and the dual isolation check valves upstream of the air receiver tanks, which is non-safety (see Figure 6.8-1).

Each unit has one compressor for supplying air to the air receiver tanks, which in turn supply air to the ADS accumulators.

Physically separate air lines are employed to distribute air at 150 psig to the ADS accumulators. Each of the two physically separate air line supplies four ADS accumulators. Check valves are provided between each receiver tank and the compressor to assure no backflow from the receiver tank to the compressor.

The storage capacity (10.5 cubic feet water volume) of each receiver tank is based on the requirements established by the General Electric Company for the operation of the safety relief valves.

The selection of piping and valves is based on a design pressure of 2,800 psig for the section of pipe between the compressor and the pressure regulating valves. The selection of pipe and valves downstream of the pressure regulating valves is based on a design pressure of 200 psig. Relief valves are provided on the air receiver tanks, downstream of the pressure regulating valves and the air compressors, to ensure that the system does not exceed the design pressure. The valves are set to relieve at 110 percent of the required operating pressures.

6.8.4 TESTS AND INSPECTIONS

Operator action during normal operation consists of periodically checking that system pressure is maintained within the correct range, and servicing the compressor purifier package and drain valves as necessary. This includes checking the purifier visual indicator which signals when purifier cartridge replacement is necessary. When the alarm in the control room indicates low receiver tank pressure, the air compressor is manually operated and runs until the system pressure is returned to the operating range.

Scheduled checks will be made to assure that the air receiver tanks have retained their pressure integrity and that the pressure regulating valves operate.

A scheduled program of testing and inspection will be maintained to ensure that all system components and their control systems are in good working condition.

All instrumentation, control and alarm devices will be tested and calibrated at regular intervals. Manufacturer recommendations will be observed for inspection, and preventive and inservice maintenance.

6.8.5 INSTRUMENTATION REQUIREMENTS

Instrumentation provided on the compressor purifier package inc udes a low oil level switch, high air temperature switch, photo-conductivity monitor and a discharge pressure switch; also included are gauges showing discharge pressure at each compressor stage and final discharge air pressure.

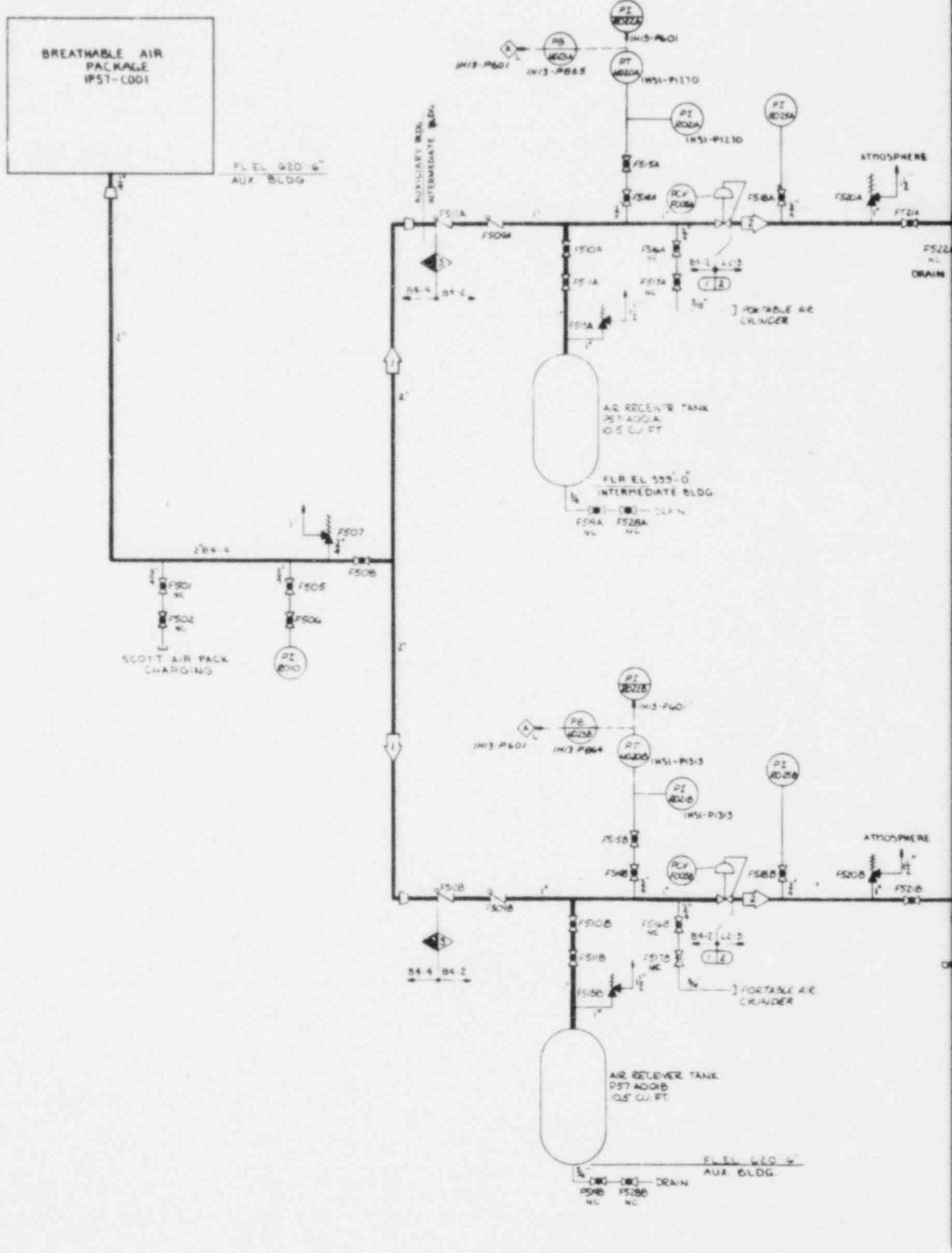
Instrumentation is provided on the compressor purifier package to shut down the compressor if any of the following conditions occur:

a. Expiration of the purifier cartridge usable life
b. Failure of the automatic condensate drain
c. High discharge air temperature
d. Low oil level
e. Motor overload

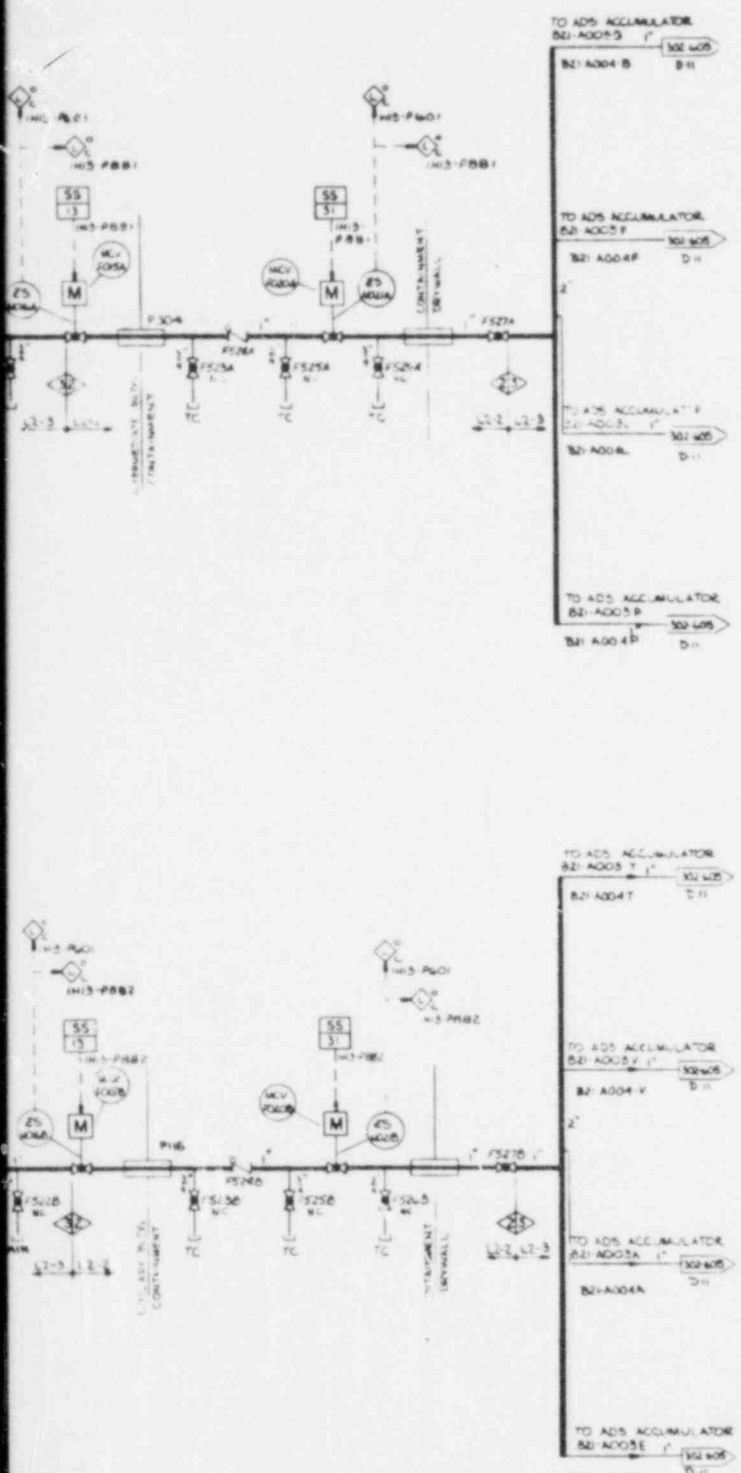
Pressure indication is provided locally and in the control room for the high pressure portion of the system. An alarm is sounded in the control room when the receiver tank pressure decreases to 2,000 psig. Local pressure indication is provided downstream of the pressure regulating valves.

Manual switches with status lights are provided in the control room for closing motor operated containment and drywell isolation valves if a LOCA condition occurs. No automatic closure signal is provided.

Relief valves are provided upstream of the double check valves, downstream of the pressure reducing valves and on the air receiver tanks to ensure that the system does not exceed the design pressure. The valves are set to relieve at 110 percent of required operating pressures.



BREATHABLE AIR PACKAGE 1P57-C001
FL EL 620'-6" AUX BLDG
AUXILIARY BLDG.
INTERMEDIATE BLDG.
ATMOSPHERE
DRAIN
PORTABLE AIR CYLINDER
AIR RECEIVER TANK P57-A001A 10.5 CU. FT.
FLR EL 599'-0" INTERMEDIATE BLDG
SCOTT AIR PACK CHARGING
AIR RECEIVER TANK P57-A001B 10.5 CU. FT.
FL EL 620'-6" AUX. BLDG.
DRAIN



OPERATING DATA						
#	PSIG	SCFM	°F	BY	REMARKS	REV
1	2520	15	150	[illegible]		
2	150	300	90	[illegible]		

DESIGN DATA									
#	NORMAL		UPSET			BY	CKD	REMARKS	REV
	PSIG	°F	PSIG	°F	TIME				
1	2800	50	—	—	—	[illegible]	[illegible]		
2	200	90	—	—	—	[illegible]	[illegible]		

REFERENCES

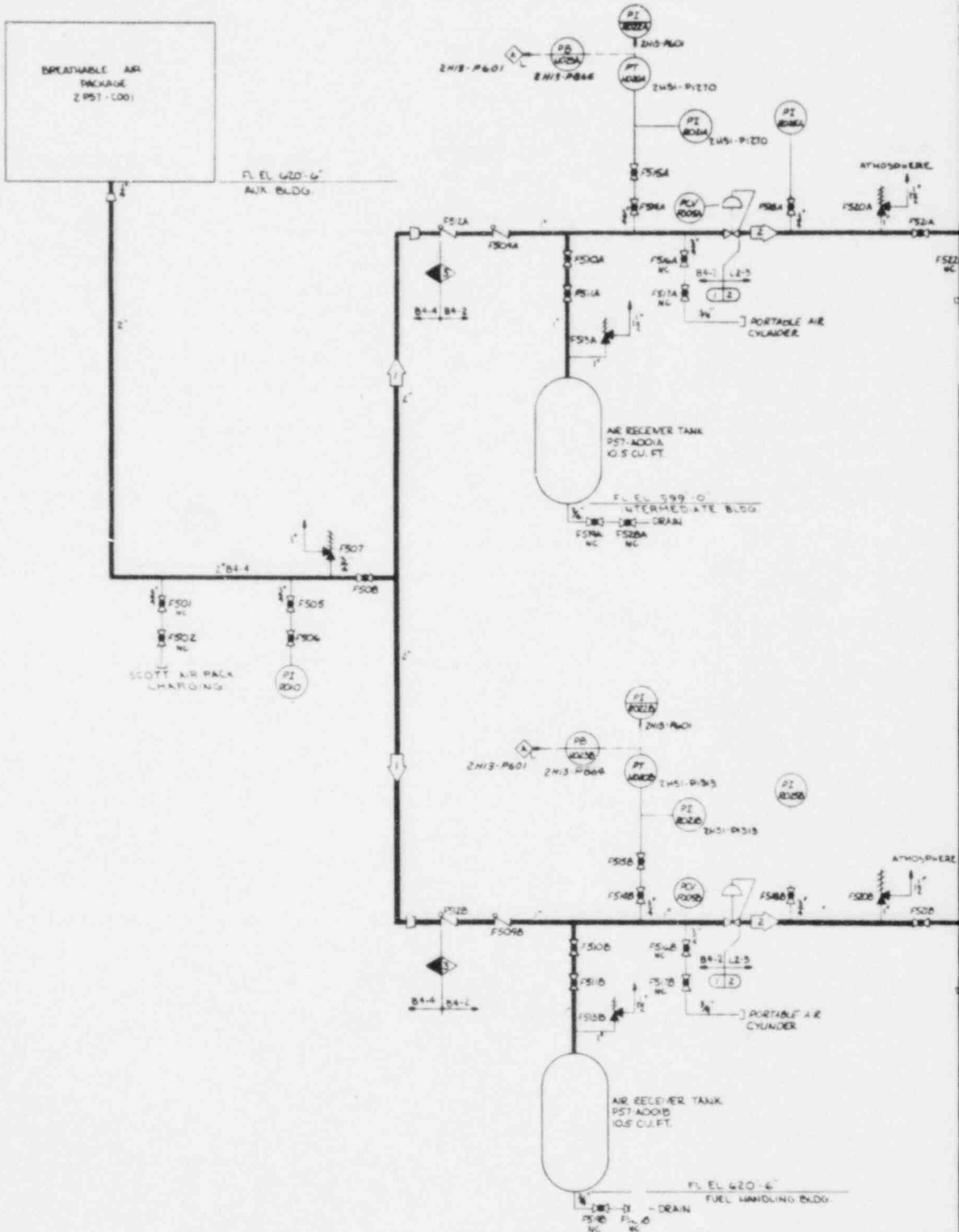
[illegible]

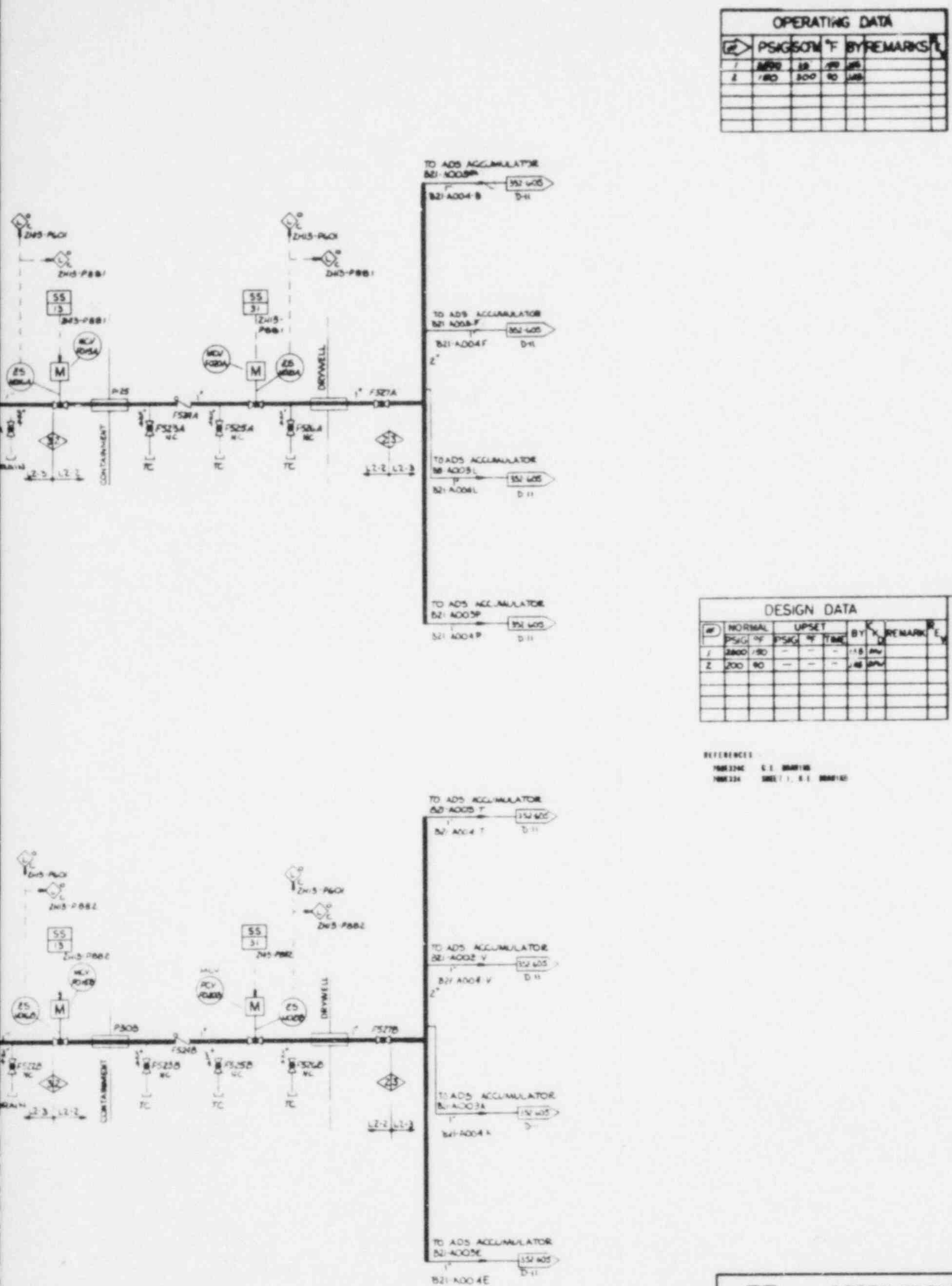
PNPP

PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

Safety Related Instrument Air System

Figure 6.8-1 (Sheet 1 of 2)
(GAI Dwg. D-302-271)


BREATHABLE AIR PACKAGE
FL EL 620'-6"
AUX BLDG.
ATMOSPHERE
PORTABLE AIR CYLINDER
AIR RECEIVER TANK
10.5 CU. FT.
INTERMEDIATE BLDG.
DRAIN
SCOTT AIR PACK CHARGING
2H13-P601
PORTABLE AIR CYLINDER
AIR RECEIVER TANK
10.5 CU. FT.
FL EL 620'-6"
FUEL HANDLING BLDG
DRAIN



PERRY NUCLEAR POWER PLANT
THE CLEVELAND ELECTRIC
ILLUMINATING COMPANY

Safety Related Instrument
Air System

Figure 6.8-1 (Sheet 2 of 2)
(GAI Dwg. D-352-271)