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CHAPTER 6 - ENGINEERED SAFETY FEATURES

6.0 INTRODUCTION

Engineered safety features are provided to mitigate the consequences of postulated serious accidents, even though these accidents are very unlikely. The following ESFs are discussed in this chapter:

a. Containment systems (Section 6.2)

1. Primary containment
2. Secondary containment
3. Containment heat removal system
4. Containment isolation system
5. Containment atmospheric control system

b. ECCS (Section 6.3)

1. HPCI system
2. ADS
3. Core spray system
4. LPCI system

c. Control room habitability system (Section 6.4)

d. Fission product removal and control systems (Section 6.5)

In addition to the ESFs discussed in this chapter, other ESF systems discussed elsewhere are provided to limit the consequences of postulated accidents. The ESF systems are described in the sections of Chapter 6 and those sections referenced in Table 6.1-1; therefore, no optional sections are required.

The information provided herein demonstrates the following:

a. The concepts on which the operation of each system is predicated have been proven by tests under simulated accident conditions and/or by conservative extrapolations from present knowledge and experience.

b. Component reliability, system interdependency, redundancy, and separation of components or portions of systems, etc., ensure that the ESF accomplishes its intended purpose and functions for the period required.

c. Provisions for testing, inspection, and surveillance are made to ensure that the ESF is dependable and effective on demand.

d. The material used can withstand the postulated accident environment, including radiation levels, and the radiolytic decomposition products that may occur cannot interfere with any ESF.

6.1 ENGINEERED SAFETY FEATURE MATERIALS

The materials used in the LGS ESF systems have been selected on the basis of an engineering review and evaluation for compatibility with:

a. The normal and accident service conditions of the ESF system

b. The normal and accident environmental conditions associated with the ESF system

c. The maximum expected normal and accident radiation levels to which the ESF system will be subjected

d. Other materials to preclude material interactions that could potentially impair the operation of the ESF systems

The materials selected for the ESF systems are expected to function satisfactorily in their intended service without adverse effects on the service, performance, or operation of any ESF.

6.1.1 METALLIC MATERIALS

In general, metallic materials used in ESF systems comply with the material specifications of ASME Section II. Pressure-retaining materials of the ESF systems comply with the quality requirements of their applicable quality group classification and ASME Section III classification. Adherence to these requirements ensures that materials for the ESF systems are of the highest quality. Where it is not possible to adhere to the ASME material specifications, metallic materials have been selected in compliance with other nationally recognized standards, e.g., ASTM, where practicable, or chosen in compliance with current industry practice.

6.1.1.1 Materials Selection and Fabrication

Metallic materials in ESF systems have been selected for a service life of 40 years, with due consideration of the effects of the service conditions on the properties of the material, as required by ASME Section III, Articles NB-2160, NC-2160, and ND-2160.

Pressure-retaining components are designed with appropriate corrosion allowances, considering the service conditions to which the material will be subjected, in accordance with the general requirements of ASME Section III, Articles NB-3120, NC-3120, and ND-3120.

6.1.1.1.1 NSSS Supplied Components

6.1.1.1.1.1 NSSS Material Specifications

Table 6.1-2 lists the principal pressure-retaining materials and the appropriate material specifications for the NSSS supplied ESF components.

6.1.1.1.1.2 Compatibility of NSSS Construction Materials with Core Cooling Water and Containment Sprays

Section 5.2.3.2.3 discusses compatibility of the reactor coolant with construction materials exposed to the reactor coolant. These same construction materials are found in other ESF components.

6.1.1.1.1.3 Controls for Austenitic Stainless Steel

a. Control of the use of sensitized stainless steel

   Where practicable, stainless steel with a carbon content of less than 0.02% is used.

   Controls to avoid severe sensitization are discussed in Section 5.2.3.4.1.1. Compliance with Regulatory Guide 1.44 is discussed in Section 5.2.3.4.

b. Process controls to minimize exposure to contaminants

   Process controls for austenitic stainless steel and compliance with Regulatory Guide 1.37 are discussed in Section 5.2.3.4.

c. Use of cold-worked austenitic stainless steel

   Cold-worked austenitic stainless steel with a yield strength greater than 90,000 psi is not used in ESF systems.

d. Avoidance of hot-cracking of stainless steel

   Process controls to avoid hot-cracking and compliance with Regulatory Guide 1.31 are discussed in Section 5.2.3.4.

6.1.1.1.2 Non-NSSS Supplied Components

6.1.1.1.2.1 Non-NSSS Material Specifications

Material specifications for the principal pressure-retaining ferritic, austenitic, and nonferrous metals for non-NSSS supplied components are listed in Table 6.1-3.

6.1.1.1.2.2 Compatibility of Non-NSSS Construction Materials with Core Cooling Water and Containment Sprays

Materials that would be exposed to the core cooling water and containment sprays if there is a LOCA are identified in Table 6.1-3. The metallic materials of the ESF systems have been evaluated for their compatibility with core cooling water and containment sprays. Demineralized water, with no additives, is employed for core cooling water and containment sprays. No radiolytic or pyrolytic decomposition of ESF material can occur during accident conditions, and the integrity of the containment or function of any other ESF cannot be affected by the action of core cooling water or containment spray systems.

6.1.1.1.3 Controls for Austenitic Stainless Steel

a. Control of the use of sensitized stainless steel

Design specifications call for ASME material, which is to be supplied in the solution annealed condition. Design specifications prohibit the use of materials that have been exposed to sensitizing temperatures in the range of 800°F to 1500°F unless they are subsequently solution annealed and water quenched or bright annealed. Where practicable, stainless steel with a carbon content of less than 0.02% is used. Compliance with Regulatory Guide 1.44 is discussed in Section 5.2.3.4.

b. Process controls to minimize exposure to contaminants

Design specifications for austenitic stainless steel components require that the material be cleaned using low halide cleaning solutions and that special care be exercised in the fabrication, shipment, storage, and construction to avoid contaminants. Conformance with Regulatory Guide 1.37 is discussed in Section 5.2.3.4.

c. Use of cold-worked austenitic stainless steel

Cold-worked austenitic stainless steels with yield strengths greater than 90,000 psi are not used in ESF systems. Therefore, there are no compatibility problems with core cooling water or the containment sprays.

d. Use of nonmetallic thermal insulation for austenitic stainless steel

Austenitic stainless steel piping inside the primary containment is insulated with nonmetallic thermal insulating materials. These nonmetallic insulating materials are either jacketed or encapsulated in stainless steel to protect against water entry. (Nukon insulation is not required to be jacketed or encapsulated since it meets all G.E. specifications requirements for leachable chlorides, fluorides, sodium and silicates without jacketing.) Leachable concentrations of chlorides, fluorides, sodium, and silicates for all nonmetallic insulation on austenitic stainless steel inside the primary containment meet the positions of Regulatory Guide 1.36. Conformance with Regulatory Guide 1.36 is discussed in Section 5.2.3.2.

e. Avoidance of hot-cracking of stainless steel

Process controls to avoid hot-cracking and compliance with Regulatory Guide 1.31 are discussed in Section 5.2.3.4.

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

The HPCI system is supplied from either the CST or the suppression pool. The core spray and LPCI are supplied from the suppression pool only. The containment spray mode of the RHR system, which uses the suppression pool as its source of supply, does not induce radiolytic or pyrolytic decomposition of ESF materials.

The Suppression Pool and CST water chemistry is normally maintained within the following guidelines:

a. pH: 5.3 to 8.6 at 25°C

b. Chloride: <0.5 ppm

c. Conductivity: <10 μmho/cm at 25°C

No corrosion inhibitors or other additives are present in either the CST water or the suppression pool water.

The makeup water for the SLCS (SLCS is not an ESF system but does have a safety-related function and is described in Section 9.3.5), is supplied from the demineralized water storage tank. The makeup water for the CST is supplied from both the demineralized water storage tank and treated liquid radwaste. The makeup water to the suppression pool can be supplied from either the CST or the Refueling Water Storage Tanks. Water supplied to the demineralized water storage tank and the CST is continuously monitored by conductivity measuring devices that initiate alarms and divert flow to waste on high conductivity. Treated liquid radwaste is sampled and analyzed prior to transfer to the CST. This ensures water quality.

Chloride concentration in the SLCS tank is controlled by specifications on the sodium penetaborate and the demineralized water that is added to the tank.

Water quality is maintained in the CST by using the "A" condensate filter/demineralizer to remove impurities from the water. CST water is processed from the CST with the refueling water transfer pump and refueling water transfer system. Water quality is maintained in the suppression pool by a bleed and feed method. Water is drained from the suppression pool with the suppression pool cleanup pump. This water goes to the hotwell for cleanup with the condensate cleanup system. Makeup water comes from the CST.

6.1.2 ORGANIC MATERIALS

Tables 6.1-4 and 6.1-5, respectively, list the significant organic materials and coatings that exist within the primary containment. These materials in ESF components have been evaluated with regard to the expected service conditions and have been found to have no adverse effects on service, performance, or operation.

6.1.2.1 NSSS Supplied Components

The only significant organic materials on NSSS equipment are the protective coatings used on carbon steel components. Most of the equipment is painted with a primer coat of inorganic zinc. The quality assurance requirements in Regulatory Guide 1.54 were not imposed on painting material and paint application, because most equipment was ordered before the issuance of the guide.

Equipment specifications in place at the time of ordering much of the LGS equipment specified a primer coat of inorganic zinc. These coatings are not considered qualified under the guide because the specifications did not require the near white blasted surface needed to meet nuclear qualification.

The total amount of unqualified paint in the containment on NSSS equipment is estimated to be less than 12 kg. Equipment tightly covered with thermal insulation is not included in this total because potential paint debris could not escape to the suppression pool during a LOCA.

6.1.2.2 Non-NSSS Supplied Components

The drywell liner is coated with modified phenolic epoxy, and exposed metal surfaces inside the drywell are coated with an inorganic zinc compound. These coatings have been qualified in accordance with ANSI N101.2. No radiolytic or pyrolytic decomposition or interaction with other ESF materials can occur.

The suppression pool liner is coated with an inorganic zinc compound that has been qualified in accordance with ANSI N101.2. Since the failure mode of inorganic zinc coatings is particulate rather then flaking in nature, this amount is not considered significant. No radiolytic or pyrolytic decomposition or interaction with other ESF materials can occur.

Non-NSSS coating practice and procedures are in conformance with ASTM D3843-93 as discussed in the Quality Assurance Topical Report (NO-AA-10).

6.1.2.3 Insoluble Debris

Insoluble debris formed under DBA conditions inside containment, from unqualified organic paint surfaces and from corrosion products from galvanized steel and zinc paints without qualified organic top coats, will not adversely affect the performance of the LGS RHR or the containment spray systems which take suction from the suppression pool.

a. The total amount of unqualified paint on both non-NSSS and NSSS supplied components has been reviewed and is summarized below. All coatings on non-NSSS equipment within the primary containment are qualified with the following exceptions:

    1. Unqualified primers and mill coats have been applied to pipe, inside the drywell, that has insulation covering the coating. The insulation will prevent any potential debris from entering the suppression pool.

NOTE: The information presented above regarding the quality of unqualified coatings in the primary containment is historical and is based on an original design estimate and does not represent the current unqualified coatings inventory. Unqualified coatings in the primary containment are administratively controlled to ensure that the design basis limits for debris are not exceeded.

    2. Heavy support steel in the drywell is coated with an inorganic zinc coating that passed DBA testing and is fully documented. Unqualified coatings on NSSS equipment have been reviewed and found to be less than 11.7 kg in total, as identified in Table 6.1-6. NSSS equipment has either 2-5 mils coating of inorganic zinc or 3-6 mils organic coating. The major equipment, the recirculation pump motors, have two coats of epoxy paint at 3-6 mils per coat.

b. The following discussion explains why insoluble debris from unqualified organic paints and corrosion products from galvanized steel and zinc paints without qualified organic top coat will not adversely affect the performance of the RHR or containment spray systems.

As discussed above, the only unqualified organic paints that could reach the suppression pool are on NSSS equipment. Due to the limited supply of NSSS unqualified paint noted in Table 6.1-6, it is not expected that the ECCS suction strainers would be sufficiently plugged so as to impair ECCS or containment spray performance. The redundant pair of suction strainers on each HPCI and RCIC suction line are sized to provide the design flow rate with each of the strainers 50% plugged and are centered approximately midway between the suppression pool surface and wetwell floor. The RHR and Core Spray strainers are designed based on debris loading and zone of influence of the worst case pipe location. The suction strainers are discussed in detail in Section 6.2.2.2.

Galvanized steel and zinc paints without qualified organic top coats were used for various applications in the primary containment. The demineralized suppression pool water, which is used for containment spray, is maintained near-neutral and the containment atmosphere is inerted during plant operating conditions to reduce the corrosion of exposed galvanized steel or zinc paints to the lowest possible rate. Typical zinc corrosion products produced in a neutral or near-neutral environment are zinc oxide and zinc carbonate. They are loosely adherent fluffy white substances. Because the zinc corrosion products are loosely adherent, they will not plug the ECCS suction strainers, containment spray nozzles, or ECCS pump seal flushing water circuits.

6.1.3 POST-ACCIDENT CHEMISTRY

This section is not applicable to BWR plants.

NOTE: The information presented above regarding the quality of unqualified coatings in the primary containment is historical and is based on an original design estimate and does not represent the current unqualified coatings inventory. Unqualified coatings in the primary containment are administratively controlled to ensure that the design basis limits for debris are not exceeded.

Table 6.1-1

ENGINEERED SAFETY FEATURES DISCUSSED IN
OTHER CHAPTERS OF THE UFSAR

ENGINEERED SAFETY FEATURE	UFSAR LOCATION
Chapter 4	
Control rod velocity limiter	4.6.2
Control rod drive housing supports	4.6
Chapter 5	
Overpressure protection	5.2.2
Main steam line flow restrictors	5.4.4
Main steam line isolation valves	5.4.5
Chapter 7	
Instrumentation and controls for ESF systems	7.3
Chapter 8	
Standby ac power system	8.3.1
Dc power system	8.3.2
Chapter 9	
ESW system	9.2.2
RHRSW system	9.2.3
UHS	9.2.6
CSCWS	9.2.10
Primary containment HVAC	9.4.5
Diesel generator enclosure HVAC	9.4.6
Spray pond pump structure HVAC	9.4.7
Diesel generator systems	9.5.4-9.5.8

Table 6.1-2

NSSS SUPPLIED ENGINEERED SAFETY FEATURES COMPONENT MATERIALS

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
RHR Heat Exchanger			
Shell, head, and channel	Plate	SA516, Grade 70	ASME
Tube sheet	Plate	SA516, Grade 70	ASME
Nozzles	Forging	SA105-II (Unit 2) SA105 (Unit 1)	ASME
Flanges	Forging	SA105-II (Unit 2) SA105 (Unit 1)	ASME
Tubes	Tube	SA249, Type 304L (Unit 2A) SB676, Type AL-6XN (Unit 1 and Unit 2B)	ASME
Bolts	Bar	SA193, Grade B7	ASME
Nuts	Forging	SA194, Grade 2H	ASME
RHR and CS Pumps			
Bowl	Casting	A536, Grade 65-45-12	ASTM
Discharge head shell	Plate	A516, Grade 70	ASTM
Discharge head cover	Plate	A516, Grade 70	ASTM
Suction barrel shell and dished head	Plate	A516, Grade 70	ASTM
Suction flange	Forging	A516, Grade 70	ASTM
Discharge flange	Forging	A350, LF1 or LF2	ASTM
Shaft	Bar	A276, Type 410	ASTM
Impeller	Forging	A296, CA15	ASTM
Studs	Bolting	A193, Grade B7	ASTM
Nuts	Nut	A194, Grade 7	ASTM
Cyclone separator body and cover		A351, Grade CF8M	ASTM

Table 6.1-2 (Cont'd)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
HPCI Pump			
Case	Casting	A216	ASTM
Bearing housing	Casting	A278	ASTM
Impeller	Casting	A276	ASTM
Shaft	Forging	A276	ASTM
Studs	Forging	A193	ASTM
SLCS Pump			
Fluid cylinder	Forging	A182, F304	ASTM
Cylinder head, valve cover, and stuffing box flange plate	Plate	A285, Grade C	ASTM
Cylinder head extension, valve stop, and stuffing box	Bar	A479, Type 304A	ASTM
Stuffing box gland and plungers	Bar	A564, Type 630	ASTM
Studs	Bar	A193, Grade B7	ASTM
Nuts	Forging	A194, Grade 7	ASTM
SLCS Tank			
Tank	Plate	SA240, Type 304	ASME
Fittings	Forging	SA782, Grade F304	ASME
Pipe	Pipe	SA312, Type 304	ASME
Welds	Electrodes	SFA5.4 & SFA5.9, Types 308,308L, 316,316L	ASME

Table 6.1-2 (Cont'd)

COMPONENT	FORM	MATERIAL	SPECIFICATION (ASTM/ASME)
Control Rod Velocity Limiter	Casting	A351, Grade CF8	ASTM

Table 6.1-3

PRINCIPAL PRESSURE-RETAINING MATERIALS FOR ESF COMPONENTS

SYSTEM/COMPONENT	MATERIAL
Containment Systems	
Primary containment:	
Containment walls	4000 psi concrete
Drywell and suppression chamber liner[1]	SA285, Grade A
Drywell head[1]	SA516, Grade 60
Penetrations[1]	SA333, Grade 1; A120
Equipment hatches[1]	SA516, Grade 60 or 70; SA537, Grade B
Personnel access hatches[1]	SA516, Grade 60 or 70; SA537, Grade B
Suppression vent downcomers[1]	SA333, Grade 6; SA516, Grade 60
Vacuum relief valve assemblies[1]	SA105
Pressure-retaining bolting[1]	SA194, Grade 4 or 7; SA320, Grade L43; SA540, Grade B23, Class 5
Flued heads	SA105; SA350, Grade LF2; SA182; Grade 316, 316L
Secondary containment:	
Ducts	A526, A527, A36
Dampers	A526, A157, A36

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Containment heat removal system:	
Equipment[1]	[2]
Piping[1]	SA106, Grade B; SA155, Grade KC-70, Class 1; SA155, Grade C55, Class 1; SA53, Grade B
Valves[1]	SA216, Grade WCB; SA105
Pressure-retaining bolting[1]	SA193, Grade B7; SA194, Grade 2H
Welding material[1]	E70-S2, E7018, E7016
Containment isolation system:	
Valves[1]	SA351, Grade CF8M; SA182, Grade F316; SA352, Grade LCB; SA350, Grade LF2; SA216, Grade WCB; SA182, Grade F316L; SA105
Pressure-retaining bolting[1]	SA193, Grade B7; SA194, Grade 2H
Welding material[1]	E70-S2, E7018, E7016, ER308, ER308L, ER316, E308-16, E308L-16, E316-16
Combustible gas control system:	
Piping	SA106, Grade B; SA155, Grade KC-70, Class 1; SA358, Type 304, Class 1; SA312, Type 304; SA376, Type 304
Valves	SA216, Grade WCB; SA105; SA351, Grade CF8M; SA182, Grade F316

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Recombiner	SA182, SA240, SA312 or SA376
Blower	SA234 WPB CS
Pressure-retaining bolting	SA193, Grade B7; SA194, Grade 2H
Welding material	E70-S2, E7018, E7016, ER308, ER308L, ER316, E308-16, E308L-16, E316-16
Emergency Core Cooling Systems	
HPCI:	
Equipment(1)	(2)
Piping(1)	SA106, Grade B; SA155, Grade KC-70, Class 1; SA106, Grade C; A155, Grade KC-70 or KC-65 Class II
Valves(1)	SA216, Grade WCB SA105; A216, Grade WCB; A105
Pressure-retaining bolting(1)	A193, Grade B7; SA193, Grade B7; SA194, Grade 2H; A194, Grade 2H
Welding materials(1)	E70-S2, E7018, E7016
Core spray:	
Equipment(1)	(2)
Piping(1)	SA106, Grade B; SA155, Grade KC-70, Class 1; SA106, Grade C; SA312, Type 316L; SA333, Grade 6; A358, Type 304, Class II; A376 or A312, Type 304 SA358, Type 316L, Class 1 with 0.02% C max

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Valves[1]	SA351, Grade CF8M; SA182, Grade F316; SA352, Grade LCB; SA350, Grade LF2; SA216, Grade WCB; SA105; A216, Grade WCB; A105
Pressure-retaining bolting[1]	SA193, Grade B7; SA194, Grade 2H
Welding materials[1]	E70-S2, E7018, E7016, ER308, ER308L, ER316, E308-16, E308L-16, E316-16
LPCI:	
Equipment[1]	[2]
Piping[1]	SA358, Type 316L, Class 1 with 0.02% C max.; SA358, Type 304, Class 1; SA312, Type 304; SA376, Type 304; SA333, Grade 6; SA106, Grade B; SA155, Grade KC-70, Class 1; SA155, Grade C55, Class 1; SA53, Grade B
Valves[1]	SA351, Grade CF8M; SA182, Grade F316; SA352, Grade LCB; SA350, Grade LF2, SA216, Grade WCB; SA105
Pressure-retaining bolting[1]	SA193, Grade B7; SA194, Grade 2H

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Welding materials(1)	E70-S2, E7018, E7016, ER308, ER308L, ER316, E308-16, E308L-16, E316-16
ADS:	
Piping(1)	SA106, Grade B
Pressure-retaining bolting(1)	SA193, Grade B7
Welding materials(1)	E70-S2, E7018, E7016
Control Room Habitability System	
Blowers	A283; B26 Alloy 356
Dampers	A36; A526; A527
Ducts	A526; A527; A36
Housing	A36
Fission Product Removal and Control Systems	
SGTS:	
Ducts	A526; A527; A36
Housing	A36
Valves	A36; A516, Type 304
Dampers	A526; A151, 1008/1018
Blowers	A283; A242
Pressure-retaining bolting	A307-74
Welding materials	E70-S3, E70-S6
CREFAS:	
Ducts	A526; A527; A36
Dampers	A526; A527; A36

Table 6.1-3 (Cont'd)

SYSTEM/COMPONENT	MATERIAL
Housing	A36; A240, Type 304; A193-87; A193-88; A276, Type 304; A312, Type 304; A182, Type 304
Blower	A283; B26 Alloy
RERS:	
Ducts	A526; A527; A36
Dampers	A526; A527, A36
Housing	A36; A240, Type 304; A193-87; A193-88; A276, Type 304; A312, Type 304; A182, Type 304
Blower	A283; B26 Alloy 356 A108, Grade 1040; A575; A510, Grade 1010; A569; B209 Alloy 6061; A307

(1) Material may be subjected to containment spray or core cooling water if there is a LOCA.
(2) See Table 6.1-2 for material designations.

Table 6.1-4

ORGANIC MATERIALS WITHIN THE PRIMARY CONTAINMENT

MATERIAL	USE	QUANTITY
Kerite Type FR-HT/ Kerite Type FR	Low voltage electrical power cable jacketing and insulation material	Throughout drywell
EPR/hypalon	Medium voltage electrical power cable jacketing and insulation material	Throughout drywell
XLPE	Instrumentation cable insulation/jacketing material	Throughout drywell
XLPE/neoprene	Instrumentation cable insulation/jacketing material	Throughout drywell
Cross-linked polyolefin/ alkaneimide polymer	Instrumentation coaxial and triaxial insulation/ jacketing material	Throughout drywell
Lube oil	Reactor recirculation pump motor (two motors per unit)	120 gal per unit
Gear lube	Valve motor operators	206 lbs per unit
Silicone rubber	Drywell duct-work and damper gaskets and seals	Throughout drywell
Cross-linked polyethylene/ chlorinated polyethylene	480VAC and 120VAC outage power cable insulation/ jacketing material	Throughout drywell (396 lbs per Unit)
Cross-linked polyethylene (XLPE) and polyvinyl chloride (PVC)	Armored coaxial cable for video signals from drywell video cameras, also armored multiconductor cable for drywell video camera control and audio signals. XLPE is used as insulating material, PVC as jacketing material.	Throughout drywell

Table 6.1-5

COATINGS USED INSIDE THE PRIMARY CONTAINMENT

		COATING TYPE				INITIAL APPLICATION			
CATEGORY	ITEM DESCRIPTION	Special Coating	Mfr Std Coating	Uncoated	GENERIC TYPE[1]	Total Film Thickness	Shop Applied	Field Applied	TOTAL COATING THICKNESS AFTER 40 YEARS
Carbon Steel Liner Plate	Containment dome	X			Modified phenolic epoxy	8-12 mils		X	8-12 mils
	Containment walls	X			Modified phenolic epoxy	8-12 mils		X	8-12 mils
	Containment floor	X			Modified phenolic epoxy	8-12 mils		X	8-12 mils
	Suppression chamber	X			Inorganic zinc	6-8 mils		X	6-8 mils
Structural Steel	Heavy support steel	X			Inorganic zinc	3-5 mils	X		3-5 mils
	Miscellaneous steel	X			Inorganic zinc	3-5 mils	X		3-5 mils
	Handrails and gratings			[3]					
	Exposed surface of steel inserts	X			Inorganic zinc	3-5 mils		X	3-5 mils
	Hatches (equipment and personnel)	X			Modified phenolic epoxy	8-10 mils	X or	X	8-10 mils
Steel Tubes	Downcomer caps	X			Modified phenolic epoxy	8-12 mils	X		8-12 mils
Carbon Steel Pipe	Uninsulated	X			Inorganic zinc silicate	3-5 mils	X		3-5 mils
Valve Operators	2 inches and smaller	X			Inorganic zinc silicate	3±0.5 mils	X		3±0.5 mils

Table 6.1-5 (Cont'd)

CATEGORY	ITEM DESCRIPTION	COATING TYPE: Special Coating	COATING TYPE: Mfr Std Coating	COATING TYPE: Uncoated	GENERIC TYPE[1]	INITIAL APPLICATION: Total Film Thickness	INITIAL APPLICATION: Shop Applied	INITIAL APPLICATION: Field Applied	TOTAL COATING THICKNESS AFTER 40 YEARS
	2½ inches and larger	X			Epoxy polyamide or modified epoxy phenolic inorganic zinc silicate	4.5 mils (total)	X		4.5 mils total
Valves[7]	2 inches and smaller	X			Inorganic zinc silicate	3-5 mils	X		3-5 mils
Pipe Hangers	2½ inches and larger	X			Inorganic zinc	3 mils	X		3 mils
	2 inches and smaller	X			Inorganic zinc	3 mils	X		3 mils
Mechanical Equipment	Reactor recirculation pump			[5]					
	Reactor recirculation pump motor	X			Modified phenolic epoxy	8-12 mils		X	16-20 mils
	Fan cabinet (carbon steel)		X		Epoxy polyamide or modified phenolic epoxy	7 mils (minimum)	X		7 mils (minimum)
	Fan housing		X		Primer: inorganic zinc; finish: Phenoline 305	7 mils		X	11 mils
	HVAC ducts			[3]					
Concrete[2] and Masonry	RPV concrete pedestal	X			Sand-filled epoxy surfacing	65-250 mils		X	65-250 mils

Table 6.1-5 (Cont'd)

CATEGORY	ITEM DESCRIPTION	COATING TYPE: Special Coating	COATING TYPE: Mfr Std Coating	COATING TYPE: Uncoated	GENERIC TYPE	INITIAL APPLICATION: Total Film Thickness	INITIAL APPLICATION: Shop Applied	INITIAL APPLICATION: Field Applied	TOTAL COATING THICKNESS AFTER 40 YEARS
Electrical Equipment	Terminal and junction boxes[8]				[4]				
	Cable trays			[4]					
	Conduits			[4]					
	Cables			[4]					

(1) Generic coating systems acceptable for containment use have been selected from suppliers who are prequalified to project standards and test criteria. Systems other than those listed are acceptable for specific units based on analysis of requirements.
(2) Concrete coating limited to minimum area required for decontamination purposes.
(3) No coating needed since material is galvanized.
(4) No coating needed since aluminum is used.
(5) No coating needed since material is stainless steel.
(6) Cables are insulated (EPR insulation and polyolefin insulation).
(7) Exterior coating system is identical to the pipe system in which the valve is installed.
(8) Bakelite is used inside terminal boxes.

Table 6.1-6

ESTIMATED WEIGHT OF UNQUALIFIED PAINT
ON NSSS CONTAINMENT EQUIPMENT

COMPONENT	WEIGHT (lbs)
Nuclear Boiler System	3.8
Reactor Recirculation System	6.9
CRD System	6.7
In-Vessel Service Equipment	<0.1
Under-Vessel Servicing Equipment	6.0
RWCU System	<0.4
RWCU Filter/Demineralizer System	1.9
TOTAL	25.8
	(11.7 kg)

NOTE: The information presented above regarding the quality of unqualified coatings in the primary containment is historical and is based on an original design estimate and does not present the current unqualified coatings inventory. Unqualified coatings in the primary containment are administratively controlled to ensure that the design basis limits for debris are not exceeded.

6.2 CONTAINMENT SYSTEMS

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Pressure-Suppression Containment

6.2.1.1.1 Design Bases

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

a. The containment has the capability to maintain its functional integrity during and following the peak transient pressures and temperatures which would occur following any postulated LOCA. The design basis LOCA includes the worst single active failure (which leads to maximum containment pressure and temperature) and is further postulated to occur simultaneously with LOOP and a SSE. A discussion of the LOCA events is contained in Section 6.2.1.1.3.3.

b. The containment, in combination with other accident mitigation systems, limits fission product leakage during and following the postulated DBA to values less than leakage rates that would result in offsite doses greater than those set forth in 10CFR50.67.

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

d. The containment is designed to accommodate flooding up to the refueling floor elevation to permit removal of fuel assemblies from the reactor core after the postulated LOCA.

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

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

g. The containment system is designed to allow for periodically conducted tests at the peak pressure calculated to result from the postulated DBA in order to confirm the leak-tight integrity of the containment and its penetrations.

h. The containment system is provided with pressure relief capability for use following a postulated accident accompanied by the loss of containment heat removal capability when high containment radiation levels do not exist.

6.2.1.1.2 Design Features

Section 3.8 describes the design features of the containment structure and internal structures. Figures 3.8-1 through 3.8-8 show the general arrangement of the containment and internal structures.

6.2.1.1.2.1 Protection from Dynamic Effects

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

6.2.1.1.2.2 Codes, Standards, and Guides

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

6.2.1.1.2.3 Functional Capability Tests

The functional capability of the containment structure is verified by:

a. Pressure testing the containment structure to 1.15 times the design pressure as required by Regulatory Guide 1.18 (Rev 1), and

b. Leak rate testing the containment structure to the design accident pressure as required by 10CFR50, Appendix J.

Refer to Sections 3.8.1.7, 3.8.2.7, 3.8.3.7, and 6.2.6 for a description of the structural integrity test and the integrated leak rate test.

6.2.1.1.2.4 External Pressure Loading Conditions

The containment structure is designed for an external to internal differential pressure of 5 psid.

6.2.1.1.2.5 Trapped Water that Cannot Return to Containment Sump

Not applicable to pressure-suppression containment.

6.2.1.1.2.6 Containment and Subcompartment Atmosphere

Sections 9.4.5 and 3.11 describe the pressure, temperature, and humidity limits within which all the Class 1E equipment located inside the containment structure is qualified to operate. Section 9.4.5 also describes the system that maintains these limits during normal plant operation.

6.2.1.1.3 Design Evaluation

The information presented in this section is historical and is based on the original design basis conditions and does not represent current plant conditions or current methodology used to analyze the containment response following a LOCA. The methods and results that bound current plant conditions are described in Section 6.2.1.8. Table 6.2-4A provides the plant conditions used for the current analysis. The results presented here, however, do provide the basis for determining which events are limiting. They also demonstrate the relationship of the containment response to different input assumptions.

The limiting cases were reanalyzed in Section 6.2.1.8 for the current plant conditions using the current analysis methodology. The current reactor power and RPV pressure have been increased over the original design basis conditions. The short-term containment pressure and pool swell load response is dependent on the initial reactor pressure. The double-ended guillotine recirculation line break was reanalyzed for the current plant conditions because this break results in the limiting peak containment pressures and pool swell loads. The long-term containment pool temperature

response is dependent on the initial reactor power. Case C (loss of offsite power with no containment spray) was reanalyzed for the current plant conditions because this case results in the highest suppression pool temperature. The intermediate and small line breaks result in the highest peak drywell temperature however, these breaks were not reanalyzed at the current operating conditions. As described in Section 6.2.1.1.3.3.5.4, the limiting drywell temperature response is determined by steam enthalpy properties and is not sensitive to the increase in reactor operating pressure or power level. The main steam line break was not reanalyzed for the current plant operating conditions. The containment pressure and pool swell load response for the main steam break is bounded by the recirculation line break results. The drywell temperature response for the main steam line break is bounded by the small and intermediate line break results.

6.2.1.1.3.1 Summary Evaluation

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

Parameter	Design Value	Calculated Accident Value
Drywell design pressure	55 psig	44.0 psig*
Drywell design temperature	340°F	340°F
Suppression chamber design pressure	55 psig	30.57 psig*
Suppression chamber design temperature	220°F	212.5°F*
Peak drywell deck downward differential pressure	30 psid	25.995 psid*

*NOTE: The calculated values presented in this table are based on the original design basis conditions. The calculated results for current plant conditions as shown in Table 6.2-5A.

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

A maximum drywell and suppression chamber pressure occurs near the end of the blowdown phase of a LOCA. Approximately the same peak pressure occurs for the break of either a recirculation line or a main steam line. Both accidents are evaluated.

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

All of the analyses assume that the primary system and containment are initially at the maximum normal operating conditions. References are provided that describe relevant experimental verification of the analytical models used to evaluate the containment system response.

6.2.1.1.3.2 Containment Design Parameters

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

A diagram showing the geometric configuration of the downcomer is shown in Figure 6.2-1.

As described in Section 9.4.5, vacuum relief valve assemblies are provided to limit the degree to which suppression chamber pressure can exceed drywell pressure, and to prevent the drywell design negative pressure from being exceeded as described in Section 6.2.1.1.4. There are four assemblies, each mounted on the side of a downcomer on the flanges shown in Figure 6.2-1. Each assembly consists of two vacuum relief valves mounted in series. A schematic diagram of a single vacuum relief valve is shown in Figure 9.4-6. The required number and size of the vacuum relief valve assemblies was determined as described in Section 6.2.1.1.3.3.1.5.

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

6.2.1.1.3.2.1 Downcomer Vent Flow Loss Coefficient

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

$$K = \frac{\Delta P}{\rho V^2 / 2g_c} \qquad \text{(EQ. 6.2-1)}$$

and is calculated from standard references (References 6.2-1 and 6.2-2). In the above equation ΔP is the total pressure drop across the downcomer, ρ is the fluid density, and V is the flow velocity.

The total downcomer flow loss coefficient is modeled as the sum of three contributors: an entrance loss (K_1), a length loss (K_2), and an exit loss (K_3). The entrance loss coefficient (K_1) is calculated from Reference 6.2-1 using a hooded duct entrance geometry that very nearly approximates the standoff jet deflector shield feature of the LGS downcomer and (K_1) is calculated to be 0.90. The length loss (K_2) is represented by a resistance coefficient (fL/D) loss with (f) calculated from Reference 6.2-2 and (K_2) calculated to be 0.33. The exit loss coefficient (K_3) is calculated to be 1.0 from Reference 6.2-2, which when combined with the above yields an overall loss coefficient value of K = 2.23.

6.2.1.1.3.3 Accident Response Analysis

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

a. An instantaneous guillotine rupture of a recirculation line

b. An instantaneous guillotine rupture of a main steam line

c. An intermediate size liquid line rupture

d. A small size steam line rupture

Energy release from these accidents is discussed in Section 6.2.1.3.

6.2.1.1.3.3.1 Recirculation Line Break

NOTE: The information presented in this section is historical and is based on the original design basis conditions. See the explanation at the beginning of Section 6.2.1.1.3.

Immediately following the rupture of the recirculation line, the flow out both sides of the break is limited to the maximum allowed by critical flow considerations. The total effective flow area is given in Figure 6.2-2. In the side adjacent to the suction nozzle, the flow corresponds to critical flow in the pipe cross-section. In the side adjacent to the injection nozzle, the flow corresponds to critical flow at the ten jet pump nozzles associated with the broken loop. Table 6.2-3 provides a summary of the break areas.

6.2.1.1.3.3.1.1 Assumptions for Reactor Blowdown

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

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

   1. The reactor is operating at 105% of rated steam flow. This maximizes the postaccident decay heat.

   2. The service water temperature is at the maximum normal value.

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

   4. The suppression pool temperature is at the maximum normal value.

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

c. Reactor power generation ceases at the time of accident initiation because of void formation in the core region. Scram occurs in less than one second from receipt of

the high drywell pressure signal. The difference in time between accident initiation and shutdown is negligible.

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

e. The core decay heat and the sensible heat released in cooling the fuel to initial average coolant temperature are included in the RPV depressurization calculation. The rate of energy release is calculated using a conservatively high heat transfer coefficient throughout the depressurization period. The resulting high energy release rate causes the RPV to maintain nearly rated pressure for approximately 20 seconds. The high RPV pressure increases the calculated blowdown flow rates, which is again conservative for analysis purposes. The sensible energy of the fuel stored at temperatures below the initial average coolant temperature is released to the 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 MSIVs start closing 0.5 seconds after the accident. They are fully closed in the shortest possible time of three seconds following closure initiation. In actuality, the closure signal for the MSIVs occurs from low-low-low reactor water level (level 1), so the valves do not receive a signal to close for greater than four seconds, and the closing time may be as long as five seconds. By assuming rapid closure of these valves, the RPV is maintained at a high pressure, which maximizes the calculated discharge of high energy water into the drywell.

g. Reactor feedwater flow is assumed to stop instantaneously at time t = zero. Since feedwater flow tends to depressurize the RPV, thereby reducing the discharge of steam and water into the drywell, this assumption is conservative for the short-term analysis.

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

6.2.1.1.3.3.1.2 Assumptions for Containment Pressurization

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

a. Thermodynamic equilibrium exists in the drywell and suppression chamber. The analysis assumes complete mixing and the error introduced by this assumption is negligible.

b. The fluid flowing through the downcomers is formed from a homogeneous mixture of the fluid in the drywell. The use of this assumption results in complete carryover of the drywell air and a higher positive flow rate of liquid droplets that conservatively minimizes downcomer pressure losses.

c. The fluid flow in the downcomers is compressible except for the liquid phase.

d. No heat loss occurs from the gases inside the primary 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 ECCS (discussed in Section 6.3) provides water for core flooding, containment spray, and long-term decay heat removal. The containment pressure and temperature responses during this period are analyzed using the following assumptions:

a. The RHR pumps are used to flood the core within 600 seconds after the accident (LPCI mode).

b. After 600 seconds, flow from one RHR pump can be diverted from the RPV to the containment cooling. This is a manual operation. Containment spray need not be actuated at all to keep the containment pressure below the containment design pressure. Analytically, no credit may be assumed for containment cooling earlier than 600 seconds after the accident and cooling is assumed to begin at 600 seconds. However, containment cooling will be initiated in accordance with plant emergency operating procedures based on plant conditions.

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

d. The suppression pool is the only heat sink available in the containment system prior to initiation of the RHRSW system.

e. After 600 seconds, the RHR heat exchangers are activated to remove energy from the containment via the RHR suppression pool cooling mode in conjunction with RHRSW system.

The performance of the ECCS equipment during the long-term cooling period is evaluated in Section 6.2.1.1.3.3.1.6 for each of the three cases of interest.

6.2.1.1.3.3.1.4 Initial Conditions for Accident Analyses

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

Table 6.2-3 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.

The mass and energy release sources and rates for the containment response analyses are given 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 in Figures 6.2-3 and 6.2-4, respectively.

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

In the early design phase of the plant, conservative hand calculations were performed to establish the minimum number of operating vacuum breaker assemblies required. Two cases leading to potentially rapid drywell depressurization were considered for wetwell-to-drywell vacuum breaker sizing:

a. The inadvertent actuation of one drywell spray train (10,000 gpm @ 90°F, assumed)

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

Each case was to determine the number of vacuum breaker valve assemblies required to ensure that the maximum differential pressure across the diaphragm slab in the upward direction does not exceed allowables. For the analyses, a conservatively low 3 psid across the diaphragm slab was used, well below the present design allowable of 20 psid upward.

In the analyses done for both cases, a. and b., it was conservatively assumed that all noncondensables have been removed to the wetwell vapor region prior to drywell depressurization. In addition to this, for the Case a. accident a 100% spray efficiency, together with a drywell temperature of 273°F, combine with the assumptions regarding spray rate and inlet temperature noted above, to render this analysis conservative. This results in a net drywell energy removal rate of approximately 321,000 Btu/sec.

The analysis for Case b. assumes a drywell saturation temperature of 262°F, an ECCS drop fall height of 42 feet, an average drop diameter of 1 inch (for calculating condensation heat transfer to the falling ECCS spillage), and an average heat transfer coefficient of 2300 Btu/hr-ft^2-°F (for calculating heat transfer from the drywell vapor region to the pool of ECCS spillage collected on the drywell floor). These considerations, combined with the assumptions regarding noncondensables and ECCS spillage rate and temperature, yield a net drywell energy removal rate of approximately 318,000 Btu/sec for an ECCS spillage spray effectiveness of 34%.

The two cases yield drywell energy removal rates of the same order of magnitude, with the inadvertent containment spray case being the larger, 321,000 Btu/sec. As such, this inadvertent spray actuation case controls the vacuum breaker sizing. The hand calculation established that three operable vacuum breaker valve assemblies each having a seat inner diameter of 18 inches, were required.

Subsequently, the inadvertent spray actuation (ISA) case was reanalyzed using a dynamic computer model, described in Section 6.2.1.1.4. This analysis was performed to verify that vacuum relief valve capacity is sufficient to prevent drywell depressurization below the design value of -5 psig. For purposes of vacuum relief valve sizing, primary containment negative pressure is more limiting than diaphragm slab differential pressure. The computer model conservatively approximated vacuum relief valve flow characteristics based on actual test data. Additional conservative assumptions were made to maximize the negative pressure in the drywell. The results confirmed that two operable vacuum relief valve assemblies were sufficient to prevent excessive drywell depressurization, as discussed in Section 6.2.1.1.4.

The ECCS supplies sufficient core cooling water to control core heatup and limit metal-water reaction to less than 1%. After the RPV is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow of water (steam flow is negligible), in the form of hot water which flows into the suppression chamber via the downcomers, transports the core decay heat out of the RPV through the broken recirculation line. This flow provides a heat sink for the drywell atmosphere, and thereby causes the drywell to depressurize.

Table 6.2-5 provides the peak pressure, temperature, and time parameters for the recirculation line break as predicted for the conditions of Table 6.2-4 and as correspond with Figures 6.2-3 and 6.2-4. Figure 6.2-5 shows the time-dependent response of the drywell floor (diaphragm slab) differential pressure.

During the blowdown period of the LOCA, the downcomers conduct 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 6.2-6 provides the mass flow versus time relationship through the downcomers for this accident.

6.2.1.1.3.3.1.6 Long-Term Accident Responses

NOTE: The information in this Section is based on the original design basis conditions. Only case C (Loss of Offsite Power with no Containment Spray) was reanalyzed for the current plant conditions because this case results in the highest suppression pool temperature. The methods and results that bound current plant conditions are described in Section 6.2.1.8.

In order to assess the adequacy of the containment following the initial blowdown transient, an analysis was made of the long-term temperature and pressure responses following the accident for each of three cases. The results of these analyses are described below. The analyses

assumptions for these cases are those discussed in Section 6.2.1.1.3.3.1.3. The initial pressure response of the containment (the first 600 seconds after the break) is the same for each case.

CASE A: All ECCS equipment operating - with containment spray

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

After 600 seconds, RHRSW pumps are started and both RHR heat exchangers are aligned to remove energy from the containment. During this mode of operation the flow from two RHR pumps is routed through their associated RHR heat exchanger where it is cooled before being discharged into the drywell and suppression chamber spray headers. The CS system continues operation during this mode with both loops injecting into the vessel.

The containment pressure response to this set of conditions is shown as curve A in Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as curve A in Figures 6.2-8 and 6.2-9. After the initial blowdown and subsequent depressurization due to CS and LPCI core flooding, energy addition due to core decay heat results in a gradual pressure and temperature rise in the containment.

When the energy removal rate of the RHR system equals the energy addition rate from the decay heat, the containment pressure and temperature reach a second peak value and decrease gradually. Table 6.2-6 summarizes the equipment operation, the peak long-term containment pressure following the initial blowdown peak, and the peak suppression pool temperature.

CASE B: LOOP - with containment spray

This case assumes that no offsite power is available following the accident with only minimum diesel power. The RHR system and the drywell and suppression chamber sprays are in operation after 600 seconds. During this mode of operation the RHR system flows through only one RHR heat exchanger and is directed to the spray headers while one LPCI pump and one CS loop continue to inject water into the vessel. The containment pressure response to this set of conditions is shown as curve B in Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as curve B in Figures 6.2-8 and 6.2-9. A summary of this case is given in Table 6.2-6.

CASE C: LOOP - no containment spray

This case assumes that no offsite power is available following the accident with only minimum diesel power. After 600 seconds the sprays may be manually activated to further reduce containment pressure if desired. This analysis assumes that the drywell and suppression chamber sprays are not activated.

After 600 seconds, the RHRSW system and one RHR heat exchanger are activated to remove energy from the containment. The flow from one RHR pump is cooled by the RHR heat exchanger before being discharged into the reactor vessel while another RHR pump and one CS loop inject directly into the vessel.

The containment pressure response to this set of conditions is shown as curve C in Figure 6.2-7. The corresponding drywell and suppression pool temperature responses are shown as curve C in Figures 6.2-8 and 6.2-9. A summary of this case is given in Table 6.2-6.

When comparing the "spray" case B with the "no spray" case C, the same RHR heat exchanger duty is obtained since the suppression pool temperature response is approximately the same, as shown in Figure 6.2-9. Thus, the same amount of energy is removed from the pool whether the exit flow from the RHR heat exchanger is injected into the reactor vessel, into the suppression pool, or into the drywell as spray. However, the peak containment pressure is higher for the "no spray" case, but the pressure is still much less than the containment design pressure.

Figure 6.2-10 shows the rate at which the RHR system heat exchanger removes heat from the suppression pool following a LOCA (Section 6.2.2 describes the containment cooling mode of the RHR system). The heat removal rate is shown for the three cases of interest (A, B and C). The first assumes that all the ECCS equipment is available, in addition to both RHR heat exchangers and their associated RHRSW pumps. The second and third cases are for the very degraded minimum cooling condition that limits the heat removal capacity to one heat exchanger. For all cases, it is conservatively assumed that at the time of the accident the RHRSW is at its maximum design temperature, as defined in Table 6.2-2.

6.2.1.1.3.3.1.7 Energy Balance During Accident

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

a. Blowdown energy release rates

b. Decay heat rate and fuel relaxation sensible energy

c. Sensible heat rate (vessel and internals)

d. Pump heat rate

e. Heat removal rate from suppression pool (Figure 6.2-10)

f. Metal-water reaction heat rate

Items a, b, c, d, and f are discussed in Section 6.2.1.3. A complete energy balance for the recirculation line break accident is given in Table 6.2-7 for the reactor system, the containment and the containment cooling systems at time zero, at the time of peak drywell pressure, at the end of reactor blowdown, and at the time of the long-term peak pressure in the containment.

6.2.1.1.3.3.1.8 Chronology of Accident Events

A complete description of the containment response to the recirculation line break has been given in Sections 6.2.1.1.3.3.1.5 through 6.2.1.1.3.3.1.7. Results for this accident are shown in Figures 6.2-3 through 6.2-10. A chronological sequence of events for this accident from time zero is provided in Table 6.2-8.

6.2.1.1.3.3.2 Main Steam Line Break

NOTE: The information in this section for the main steam line break is based on the original design basis conditions. See explanation at the beginning of Section 6.2.1.1.3. The main steam line break was not reanalyzed for current plant conditions. The containment pressure and pool swell load response for the main steam line break is bounded by the small and intermediate line break results and remains unchanged by the change in plant operating conditions. The information presented in this section reasonably represents the general characteristics of the main steam line break analysis.

The assumed sudden rupture of a main steam line between the reactor vessel and the flow restricting orifice results in the maximum flow rate of primary system fluid and energy to the drywell. This would in turn result in the maximum drywell differential pressure. The sequence of events immediately following the rupture of a main steam line between the reactor vessel and the flow restricting orifice has been determined. The flow on both sides of the break accelerates to the maximum allowed by the critical flow considerations. On the side adjacent to the reactor vessel, the flow corresponds to critical flow in the steam line break area. Blowdown through the other side of the break occurs because the steam lines are all interconnected at a point upstream of the turbine by the bypass header. This interconnection allows primary system fluid to flow from the three unbroken steam lines through the header and back into the drywell via the broken line. Flow is limited by critical flow in the steam line flow restricting orifice. The total effective flow area is given in Figure 6.2-11. The MSIVs are assumed to start closing at 0.5 seconds and are fully closed in the maximum time of 5 seconds following closure initiation. By assuming slow closure of these valves, a large effective break area is maintained for a longer period of time. The peak drywell floor differential pressure occurs before the reduction in effective break area and is therefore insensitive to any additional delay in closure of the isolation valves. An MSIV closure time longer than the 5 second maximum closure time would increase the break flow rate from the inventory side of the break (break to MSIV valve). However, this is offset by a lower flow rate from the vessel side of the break due to a decreasing vessel pressure. The net effect on the peak drywell pressure would be on the order of 1 psi. Section 6.2.1.3 provides the mass and energy release rates.

Immediately following the break, the total steam flow rate leaving the vessel exceeds the steam generation rate in the core, causing an initial depressurization of the RPV. Void formation in the reactor vessel water causes a rapid rise in the water level. It is conservatively assumed that the water level reaches the vessel steam nozzles one second after the break occurs. The water level rise time of one second is the minimum that can occur under any reactor operating condition. From that time on, a two-phase mixture is discharged from the break. During the first second of the blowdown, the blowdown flow consists of saturated steam. This steam enters the containment in a superheated condition at approximately 330°F.

Figures 6.2-12 and 6.2-13 show the pressure and temperature responses of the drywell and suppression chamber during the primary system blowdown phase of the steam line break accident.

Figure 6.2-13 shows that the drywell atmosphere temperature approaches a peak after approximately one second of primary system steam blowdown. At that time, the water level in the 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 and this results in reduced break flow rates. As a consequence, the flow rate in the downcomers and the differential pressure between the drywell and suppression chamber begin to decrease.

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

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

The drywell and suppression pool remain in this equilibrium condition until the reactor vessel refloods. 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 and the ECCS flow spills into the drywell. The water spillage condenses the steam in the drywell and thus reduces the drywell pressure. As soon as the drywell pressure drops below the suppression chamber pressure, the primary containment vacuum breakers open and noncondensable gases from the suppression chamber flow back into the drywell until the pressures in the two regions equalize.

6.2.1.1.3.3.3 Hot Standby Accident Analysis

This section is not applicable to BWR 4.

6.2.1.1.3.3.4 Intermediate Size Breaks

The information presented in this section for the intermediate size break is based on the original design basis conditions. As described in Section 6.2.1.1.3.5.4, the limiting drywell temperature response is determined by steam enthalpy properties and is not sensitive to the change in plant operating conditions. These breaks were not reanalyzed at the current operating conditions. The information presented in this section reasonably represents the general characteristics of the intermediate size break analysis. (See explanation at beginning of Section 6.2.1.1.3.)

An intermediate size break is analyzed as part of the containment performance evaluation to demonstrate that the consequences are no more severe than from a rupture of the largest primary system pipe. This classification covers those breaks for which the blowdown results in reactor depressurization and operation of the ECCS. This section describes the consequences to the containment of a 0.1 ft^2 break below the RPV water level. This break area is chosen as being representative of the intermediate size break area range. These breaks can involve either reactor steam or liquid blowdown.

The 0.1 ft^2 break was assumed to occur below the vessel water level to maximize the mass and energy release rates to the drywell. Based on the Moody slip flow model for the same-sized break, the total mass and energy release is greater for liquid break than for a steam break.

The initial reactor and containment conditions used in the analysis were the same as those used for the design basis accident as presented in Tables 6.2-1 and 6.2-4 and discussed in Section 6.2.1.1.3.3.1.

Following the 0.1 ft^2 break, the drywell pressure increases at approximately 1 psi/sec. This drywell pressure transient is sufficiently slow so that the dynamic effect of the water in the downcomers is negligible and the downcomers clear when the drywell-to-suppression chamber differential pressure is equal to the downcomer submergence hydrostatic pressure.

Figures 6.2-14 and 6.2-15 show the short-term drywell and suppression chamber pressure and temperature response, respectively. The ECCS response is discussed in Section 6.3. Approximately 5 seconds after the 0.1 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 suppression chamber free space. The continual purging of drywell air to the suppression chamber results in a gradual pressurization of both the wetwell and drywell. The containment continues to gradually increase in pressure due to the long-term pool heatup.

The ECCS is initiated as a result of the 0.1 ft^2 break as described in Section 7.3.1 and Table 6.3-2 and provides emergency cooling of the core. The operation of these systems is such that the reactor is depressurized in approximately 600 seconds. This terminates the blowdown phase of the transient.

In addition, the suppression pool temperature at the end of blowdown is the same as that of the recirculation line break because essentially the same amount of primary system energy is released during the blowdown. After reactor 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 suppression chamber pressures to equalize in the same manner as happens following a recirculation line break.

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

In comparison to the short-term drywell pressure and temperature responses for a large recirculation line break, it can be concluded that the consequences of an intermediate size break are less severe than those of a recirculation line break. The comparison of the short-term wetwell pressure and temperature responses shows that the intermediate size break is not significantly more severe than the large recirculation line break.

6.2.1.1.3.3.5 Small Size Breaks

The information presented in this section for the small size break is based on the original design basis conditions. As described in Section 6.2.1.1.3.3.5.4, the limiting drywell temperature response is determined by steam enthalpy properties and is not sensitive to the change in plant operating conditions. These breaks were not reanalyzed at the current operating conditions. The information presented in this section reasonably represents the general characteristics of the small size break analysis. (See explanation at beginning of Section 6.2.1.1.3.)

6.2.1.1.3.3.5.1 Reactor System Blowdown Considerations

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

the drywell is at atmospheric pressure (for example) the steam and liquid associated with the liquid blowdown would be at 212°F.

If the primary system rupture is located above the RPV water level so that the blowdown flow consists of reactor steam only, the resultant steam temperature in the containment is significantly higher than the temperature associated with liquid blowdown. This is because the constant enthalpy depressurization of high pressure, saturated steam results in superheated conditions.

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

6.2.1.1.3.3.5.2 Containment Response

For drywell design considerations, the following sequence of events is assumed to occur. With the reactor and containment operating at the maximum normal conditions, a small break occurs that allows blowdown of reactor steam to the drywell. The resulting pressure increase in the drywell leads to a high drywell pressure signal that scrams the reactor and activates the containment isolation system. The 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 downcomers until the level reaches the bottom of the downcomers. At this time, air and steam start to enter the suppression pool. The steam is condensed and the air carried over to the suppression chamber free space. The air carryover results in a gradual pressurization of the suppression chamber at a rate dependent upon the size of the steam leak. Once all the drywell air is carried over to the suppression chamber, short-term pressurization of the suppression chamber ceases and the system reaches an equilibrium condition. The drywell contains only superheated steam, and continued blowdown of reactor steam condenses in the suppression pool. The suppression pool temperature continues to increase until the RHR heat exchanger heat removal rate is equal to the decay heat release rate.

6.2.1.1.3.3.5.3 Recovery Operations

The reactor operators are alerted to the incident by the high drywell pressure signal and the reactor scram. For the purpose of evaluating the duration of the superheat condition in the drywell, it is assumed that their response is to shut the reactor down in an orderly manner using the main condenser while limiting the reactor cooldown rate to 100°F per hour. This results in the reactor primary system being depressurized within 6 hours. At this time, the blowdown flow to the drywell ceases and the superheat condition is terminated. If the plant operators elect to cool down and depressurize the reactor primary system more rapidly than at 100°F per hour, then the drywell superheat condition will be shorter.

6.2.1.1.3.3.5.4 Drywell Design Temperature Considerations

For drywell design purposes, it is assumed that there is a blowdown of reactor steam for the 6 hour cooldown period. The design temperature is determined by finding the combination of primary system pressure and drywell pressure that produces the maximum steam temperature. The maximum steam temperature occurs when the primary system is at approximately 450 psia and the drywell pressure is maximum. Thus, for design purposes, it is assumed that the drywell is at 35

psig; this results in a conservative temperature of 340°F for the first 3 hours. After the first 3 hours of blowdown of reactor steam, the primary system pressure is reduced to a level that results in a temperature which is conservatively bounded by 320°F for the remaining 3 hours.

6.2.1.1.3.4 Accident Analysis Models

NOTE: The information presented in this section for the accident analysis models is based on the original analysis models and does not represent the current methodology used to analyze the containment response following a LOCA. See explanation at the beginning of Section 6.2.1.1.3.

6.2.1.1.3.4.1 Short-Term Pressurization Model

The analytical models, assumptions, and methods used to evaluate the containment response during the reactor blowdown phase of a LOCA are described in References 6.2-4 and 6.2-5.

6.2.1.1.3.4.2 Long-Term Cooling Mode

Once the RPV blowdown phase of the LOCA is over, a fairly simple model of the drywell and suppression chamber may be used. During the long-term, postblowdown transient, the RHR containment cooling system flow path (Section 6.2.2.2) is a closed-loop and the suppression pool mass is constant. Schematically, the cooling loop mode used for analysis is shown in Figure 6.2-16. Since there is no change in mass storage in the system (the RPV is reflooded during the blowdown phase of the accident), the mass flow rates shown in the figure are equal, thus:

$$\dot{m}_{Do} = \dot{m}_{So} = \dot{m}_{eccs} \qquad \text{(EQ. 6.2-2)}$$

where:

$\dot{m}_{Do}$ = mass flow rate out of RPV, lb_m/sec

$\dot{m}_{So}$ = mass flow rate out of suppression pool, lb_m/sec

$\dot{m}_{eccs}$ = mass flow rate into RPV, lb_m/sec

6.2.1.1.3.4.3 Analytical Assumptions

The key assumptions employed in the model are as follows:

a. The drywell and suppression chamber atmospheres are both saturated (100% relative humidity).

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

c. The suppression chamber atmosphere temperature is equal to the suppression pool temperature or to the spray temperature if the sprays are activated.

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

6.2.1.1.3.4.4 Energy Balance Considerations

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

$$\frac{dE_p}{dt} = \frac{d}{dt}(M_{wS} \cdot u_S) = u_S \cdot \frac{dM_{wS}}{dt} + M_{wS}\frac{du_s}{dt} \qquad \text{(EQ. 6.2-3)}$$

where:

M_{wS} = mass of water in suppression pool, lb_m

u_S = internal energy of water in suppression pool, Btu/lb_m

Since $\frac{dM_{wS}}{dt} = 0$ (because there is no change in mass storage), and at the conditions existing in the containment:

$$\frac{du_S}{dt} = C_v \cdot \frac{dT_S}{dt} \qquad \text{(EQ. 6.2-4)}$$

where:

C_v = 1.0 for the constant volume specific heat of water, Btu/lb_m-°F

T_S = suppression pool temperature, °F

The pool energy balance yields:

$$M_{wS} \cdot C_v \cdot \frac{dT_S}{dt} = \dot{M}_{Do} \cdot h_D - \dot{M}_{So} \cdot h_S \qquad \text{(EQ. 6.2-5)}$$

where:

h_D = enthalpy of water leaving RPV, Btu/lb_m

h_S = enthalpy of water in suppression pool, Btu/lb_m

This equation can be rearranged to yield:

$$\frac{dT_S}{dt} = \frac{\dot{M}_{Do} \cdot h_D - \dot{M}_{So} \cdot h_s}{C_v \cdot M_{wS}} \qquad \text{(EQ. 6.2-6)}$$

An energy balance on the RHR heat exchanger yields:

$$h_c = h_s - \frac{\dot{q}_{HX}}{\dot{M}_{So}} \qquad \text{(EQ. 6.2-7)}$$

where:

h_c = enthalpy of water entering RPV, Btu/lb_m

q_{HX} = heat removal rate of heat exchanger, Btu/sec

Similarly, an energy balance on the RPV yields:

$$h_D = h_c + \frac{\dot{q}_D + \dot{q}_e}{\dot{M}_{eccs}} \qquad \text{(EQ. 6.2-8)}$$

where:

q_D = core decay and pump heat rate, Btu/sec

q_e = sensible energy release rate, Btu/sec

Combining Equations 6.2-2, 6.2-6, 6.2-7 and 6.2-8 gives:

$$\frac{dT_S}{dt} = \frac{\dot{q}_D + \dot{q}_e - \dot{q}_{HX}}{C_v M_{wS}} \qquad \text{(EQ. 6.2-9)}$$

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

6.2.1.1.3.4.5 Containment Thermodynamic Conditions

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

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

$$T_D = T_S + \frac{\dot{q}_D + \dot{q}_e - \dot{q}_{HX}}{C_p \dot{M}_{eccs}} \text{ and } T_W = T_S \qquad \text{(EQ. 6.2-10)}$$

where:

C_p = constant pressure specific heat of water, Btu/lb_m-°F

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

$$T_{sp} = T_S - \frac{\dot{q}_{HX}}{C_p \dot{M}_{eccs}} \text{ and } T_D = T_W = T_{sp} \qquad \text{(EQ. 6.2-11)}$$

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

$$P_D = P_{aD} + P_{vD} \qquad \text{(EQ. 6.2-12)}$$

$$P_S = P_{aS} + P_{vS} \qquad \text{(EQ. 6.2-13)}$$

where:

P_D = drywell total pressure, psia

P_{aD} = partial pressure of air in drywell, psia

P_{vD} = partial pressure of water vapor in drywell, psia

P_S = suppression chamber total pressure, psia

P_{aS} = partial pressure of air in the suppression chamber, psia

P_{vS} = partial pressure of water vapor in the suppression chamber, psia

and, from the Ideal Gas Law:

$$P_{aD} = \frac{M_{aD} \cdot RT_D}{V_D \cdot 144} \qquad \text{(EQ. 6.2-14)}$$

$$P_{aS} = \frac{M_{aS} \cdot RT_W}{V_S \cdot 144} \qquad \text{(EQ. 6.2-15)}$$

where:

M_{aD} = mass of air in the drywell, lb_m

M_{aS} = mass of air in the suppression chamber, lb_m

R = gas constant for air, $ft\text{-}lb_f/lb_m\text{-}°R$

V_D = drywell free volume, ft^3

V_S = suppression chamber free volume, ft^3

With known values of T_D and T_W Equations 6.2-12, 6.2-13, 6.2-14, and 6.2-15 can be solved by transient analysis and iteration. This iteration procedure is also used to calculate the unknown quantities M_{aD} and M_{aS}.

6.2.1.1.3.4.6 Solution of Equations

The transient analysis is based on successive time step integration of the suppression pool temperature. When this integration has been performed and the value of T_S at the end of a time step has been calculated, a pressure balance is made. Using values of M_{aD} and M_{aS} from the end of the previous time step and the updated values of T_D and T_S, a check is made to determine if P_S is greater than or equal to P_D using equations 6.2-12, 6.2-13, 6.2-14 and 6.2-15. If P_S is greater than or equal to P_D , then the two values are made equal. The vacuum breakers between the drywell and suppression chamber ensure that P_S cannot be greater than P_D.

Hence, with $P_D = P_S$ and knowing that:

$$M_{aD} + M_{aS} = \text{constant;} \qquad \text{(EQ. 6.2-16)}$$

where the constant is the known total initial mass of air in the suppression chamber and drywell prior to the accident, Equations 6.2-12, 6.2-13, 6.2-14, and 6.2-15 can be solved for M_{aS}, M_{aD}, and P_a. It is conservatively assumed that the total mass of air remains constant, which ignores any containment leakage that might occur during the transient.

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

$$P_S \le P_D \le P_S + \frac{H \cdot g}{V_W \cdot 144 \cdot g_c} \qquad \text{(EQ. 6.2-17)}$$

where:

g = acceleration of gravity, ft/sec^2

g_c = constant of proportionality $ft\text{-}lb_m/lb_f\text{-}sec^2$

H = submergence of downcomers, feet

V_W = specific volume of fluid in downcomer, ft^3/lb_m

then the pressure in the drywell is higher than the pressure in the suppression chamber but not sufficiently so to depress the water to the bottom of the downcomers and thus permit air to flow from the drywell to the suppression chamber. Under these circumstances, no air transfer is assumed to have occurred during the time step, and Equations 6.2-12, 6.2-13, 6.2-14, and 6.2-15 are solved during the time step, and Equations 6.2-12, 6.2-13, 6.2-14, and 6.2-15 are solved using the updated temperatures with the same M_{aS} and M_{aD} values from the previous time step.

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

$$P_D > P_S + \frac{H \cdot g}{V_W \cdot 144 \cdot g_c} \qquad \text{(EQ. 6.2-18)}$$

then the drywell pressure is set to the value:

$$P_D = P_S + \frac{H \cdot g}{V_W \cdot 144 \cdot g_c} \qquad \text{(EQ. 6.2-19)}$$

This requires that the drywell pressure can never exceed the suppression chamber pressure by more than the hydrostatic head associated with the submergence of the downcomers. To maintain this condition, some transfer of drywell air to the suppression chamber is required. The amount of air transfer is calculated by using Equation 6.2-16 and combining Equations 6.2-12, 6.2-13, 6.2-14, 6.2-15, and 6.2-19 to give:

$$P_{vD} + \frac{M_{aD} \cdot RT_D}{144V_D} = P_{vS} + \frac{M_{aS} \cdot RT_W}{144V_S} + \frac{H \cdot g}{144V_W g_c} \qquad \text{(EQ. 6.2-20)}$$

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

6.2.1.1.4 Negative Pressure Design Evaluation

The primary containment has been designed for a negative pressure of -5 psig. The worst case for this consideration results from actuation of the drywell sprays. During such a transient, cold spray water is passed through the drywell atmosphere resulting in a drop in vapor region temperature and a corresponding drop in vapor region pressure. This condition was analyzed for LGS and a peak negative pressure of -4.85 psig was obtained for actuation of one drywell spray network. With three operable vacuum relief valve assemblies (two operating and one redundant), a sensitivity study indicates that actuation of both drywell spray networks concurrently results in a pressure below -5 psig if the suppression pool temperature is below approximately 105°F, assuming worst case conditions for all other variables. Actuation of both drywell spray networks is administratively controlled whenever the suppression pool temperature is below 105°F.

Operation of the drywell sprays at LGS will be governed by appropriate EOPs, which will be written and revised to implement the BWROG EPGs. There will be no other procedural requirements or administrative directives that will cause drywell sprays to be used. In accordance with the EOPs, prior to initiating drywell sprays, the operators will be directed first to determine if the present combination of drywell temperature and drywell pressure fall below the drywell spray initiation limit. If the combination of parameters is below the limit, the operator is directed to initiate drywell spray with a flow rate as specified in the EOPs. The drywell spray initiation limit and minimum drywell spray flow rate are calculated in accordance with the BWROG EPGs. These limits prevent the generation of drywell negative pressures relative to secondary containment and suppression pool that could be damaging to the containment vessel.

The inadvertent actuation of both drywell spray trains is also prevented by the type and location of the control room switches. The outboard valves are normally closed and have key-locked switches that are approximately 8 feet apart.

To determine the temporal pressure and temperature of the primary containment the conservation equations of mass and energy, along with the state equations for steam and air (noncondensable), were written for the drywell and wetwell regions. A schematic of these two regions is presented in Figure 6.2-17. The various terms for the mass and energy transfer mechanisms are also presented in this figure. The systems of differential equations for each region are presented in the following sections (definition of nomenclature is provided below):

A_{cond} = suppression pool free surface area, ft^2

A_{VB} = vent area through vacuum breakers, ft^2

C_{VB} = vacuum breaker flow coefficient

C_P = specific heat at constant pressure for H_2O, 1 Btu/lb_m-°F

C_P^* = specific heat at constant pressure for N_2, O.247 Btu/lb_m-°R

C_V = specific heat at constant volume for H_2O, 1 Btu/lb_m-°F

C_v^* = specific heat at constant volume for N_2, 0.176 Btu/lb_m-°R

E = energy content, Btu

g_c = gravitational constant, 32.174 $ft\text{-}lb_m/lb_f\text{-}sec^2$

h = specific enthalpy, Btu/lb_m

k = ratio of specific heats

M = mass, lb_m

M_{nc} = noncondensable mass, lb_m

M_{cond} = condensate mass, lb_m

M_{drop} = dropout mass, lb_m

M_{evap} = evaporated steam mass, lb_m

M_{stm} = steam mass, lb_m

P = pressure, psi

R = gas constant, $lb_f\text{-}ft/lb_m$-°R

Q = transferred energy, Btu

T = temperature, °F

T^* = absolute temperature, °R

t = time, sec

U_{stm} = steam specific energy, Btu/lb_m

V = volume, ft^3

v = specific volume, ft^3/lb_m

Greek Symbols

ξ = heat exchanger effectiveness
ε = spray efficiency
ϕ = minimum heat exchanger flow rate, lb_m/sec
ρ = density, lb_m/ft^3

Subscripts

D - drywell region
f - final, saturated liquid
g - saturated vapor
S - suppression pool liquid region, sump
sat - saturated conditions
spray - spray
sv - suppression pool vapor region
VB - vacuum breaker

6.2.1.1.4.1 Drywell Region

As indicated in Figure 6.2-17, there are several mass transfer terms for the drywell region. These are: drywell spray rate ($\dot{m}_{spray}$), drywell vapor region condensation rate (or "rainout" due to dropping saturation temperature) ($\dot{m}_{cond}$), and wetwell-to-drywell vacuum breaker flow rate ($\dot{m}_{VB}$). A mass balance on the drywell vapor region yields:

$$\frac{dM_D}{dt} = \frac{dM_{nc}}{dt} + \frac{dM_{stm}}{dt} \qquad \text{(EQ. 6.2-21)}$$

$$= (\dot{M}_{VB} + \dot{M}_{spray})_{in} - (\dot{M}_{cond} + \dot{M}_{spray})_{out}$$

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

$$M_{stm} = \frac{V_D}{v_g(T_D)} \quad \text{or} \quad \frac{dM_{stm}}{dt} = -\frac{V_D}{v_g^2(T_D)} \cdot \frac{dv_g}{dT_D} \cdot \frac{dT_D}{dt} \qquad \text{(EQ. 6.2-22)}$$

The energy balance for this region is:

$$\frac{dE_D}{dt} = (\dot{M}_{spray} C_p (T_{out} - 32) + \dot{Q}_{VB})_{in} \qquad \text{(EQ. 6.2-23)}$$

$$-(\dot{M}_{spray} C_p (T_f - 32) + \dot{M}_{cond} h_f (T_f))_{out}$$

$$= \dot{M}_{spray} C_p (T_{out} - T_f) - \dot{M}_{cond} h_f (T_f) + \dot{Q}_{VB}$$

But,

$$\frac{dE_D}{dt} = \left[C_V^* T_D^* \frac{dM_{nc}}{dt} + u_g (T_D) \frac{dM_{stm}}{dt} \right] + \left[M_{nc} C_V^* + M_{stm} \frac{du_g}{dT_D} \right] \frac{dT_D}{dt} \quad \text{(EQ. 6.2-24)}$$

so,

$$\left[C_V^* T_D^* \frac{dM_{nc}}{dt} + u_g (T_D) \frac{dM_{stm}}{dt} \right] + \left[M_{nc} C_V^* + M_{stm} \frac{du_g}{dT_D} \right] \frac{dT_D}{dt} \quad \text{(EQ. 6.2-25)}$$

The spray efficiency, ε, is defined as follows:

$$\varepsilon = \frac{T_f - T_{out}}{T_D - T_{out}} = f\left(\frac{M_{stm}}{M_{nc}}\right) \quad \text{(EQ. 6.2-26)}$$

The functional relationship is determined in the work of Reference 6.2-4 and is illustrated in Figure 6.2-18.

6.2.1.1.4.2 Wetwell Region

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

$$\frac{dM_{sv}}{dt} = \frac{d(M_{nc})_{sv}}{dt} + \frac{d(M_{stm})_{sv}}{dt}$$

$$= (\dot{M}_{evap})_{in} - (\dot{M}_{VB} + \dot{M}_{cond})_{sv} + \dot{M}_{drop})_{out} \quad \text{(EQ. 6.2-27)}$$

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

$$(M_{stm})_{sv} = \frac{V_{sv}}{v_g(T_{sv})} \quad \text{or} \qquad \text{(EQ. 6.2-28)}$$

$$\frac{d(M_{stm})_{sv}}{dt} = \frac{1}{v_g(T_{sv})} \cdot \frac{dV_{sv}}{dt} - \frac{V_{sv}}{v^2 g(T_{sv})} \cdot \frac{dv_g}{dT_{sv}} \cdot \frac{dT_{sv}}{dt}$$

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

$$\frac{dV_{sv}}{dt} \sim 0 \qquad \text{(EQ. 6.2-29)}$$

The suppression pool represents a large surface for condensation and evaporation, thus resulting in a net mass transfer between the liquid and vapor subregions. This effect serves to maintain the wetwell vapor region in a saturated state and is therefore modeled with the terms $\dot{m}_{evap}$ and $\dot{m}_{drop}$. The kinetic theory of condensation (Reference 6.2-5) is used to determine these mass transfer rates. This results in the following expressions:

$$(\dot{M}_{cond})_{sv} = 144\ \Gamma\ A_{cond} \left(\frac{g_c}{2\pi R_{stm}} \right)^{1/2} \frac{(P_{stm})_{sv}}{(T_{sv})^{1/2}} \qquad \text{(EQ. 6.2-30)}$$

$$\dot{M}_{evap} = 144\ A_{cond} \left(\frac{g_c}{2\pi R_{stm}} \right)^{1/2} \cdot \frac{(P_{sat})_S}{(T_S^*)^{1/2}} \qquad \text{(EQ. 6.2-31)}$$

where:

$$\Gamma = -w\ (\pi)^{1/2}\ (1 + \text{erf}(w)) - e^{-w^2} \qquad \text{(EQ. 6.2-32)}$$

$$w = \frac{G_{net}}{G_{std}} = \frac{(\dot{M}_{evap} + (\dot{M}_{cond})_{sv})}{-A_{cond}\ \rho_{stm}\ (2g_c R_{stm} T^*_{sv})^{1/2}} \qquad \text{(EQ. 6.2-33)}$$

$$\text{erf}(w) = \frac{2}{(\pi)^{1/2}} \int_0^w e^{-z^2}\, dz \qquad \text{(EQ. 6.2-34)}$$

For the energy balance,

$$\frac{dE_{sv}}{dt} = C_v^* T_{sv}^* \frac{d(M_{nc})_{sv}}{dt} + (M_{nc})_{sv}\ C_v^* \frac{dT_{sv}^*}{dt} + u_g(T_{sv}) \frac{d(M_{nc})_{sv}}{dt} \qquad \text{(EQ. 6.2-35)}$$

$$= (M_{stm})_{sv} \frac{du_g}{dT_{sv}^*} \cdot \frac{dT_{sv}}{dt}$$

$$= (\dot{M}_{evap} h_g(T_S))_{in} - (\dot{Q}_{VB} + (\dot{M}_{cond})_{sv} h_f(T_{sv}) + \dot{M}_{drop} h_g(T_{sv}))_{out}$$

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

$$\frac{dM_s}{dt} = (\dot{M}_{drop} + \dot{M}_{cond} + (\dot{M}_{cond})_{sv})_{in} - (\dot{M}_{evap})_{out} \quad \text{(EQ. 6.2-36)}$$

$$\frac{dE_s}{dt} = C_v (T_s - 32) \frac{dM_s}{dt} + M_s C_v \frac{dT_s}{dt} \quad \text{(EQ. 6.2-37)}$$

$$= (\dot{M}_{cond} h_f(T_f) + (\dot{M}_{cond})_{sv} h_f(T_{sv}) + \dot{M}_{drop} h_f(T_{sv})$$

$$+ (\dot{M}_{spray} C_p (T_f - T_s))_{in} - (\dot{M}_{evap} h_g(T_s))_{out}$$

Two additional mass and energy transfer mechanisms need further definition. These are vacuum breaker flows and RHR heat exchangers, discussed in the next two sections.

6.2.1.1.4.3 Vacuum Breakers Flows

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

$$\dot{M}_{VB} = \begin{cases} C^*_{VB} A_{VB} \left(\frac{2 g_c K_{sv}}{K_{sv} - 1} \; r_{sv} P_{sv} \left(\left(\frac{P_D}{P_{sv}} \right)^{2/Ksv} - \left(\frac{P_D}{P_{sv}} \right)^{(Ksv+1)/Ksv} \right) \right)^{1/2} \\ \quad \text{For } \left(\frac{P_D}{P_{sv}} \right) > \left(\frac{2}{K_{sv}+1} \right)^{K_{sv}/(K_{sv}-1)} \\ C^*_{VB} \; A_{VB} \left(g_c K_{sv} P_{sv} r_{sv} \left(\frac{2}{K_{sv}+1} \right)^{(Ksv+1)/(Ksv-1)} \right)^{1/2} \\ \quad \text{For } \left(\frac{P_D}{P_{sv}} \right) \leq \left(\frac{2}{K_{sv}+1} \right)^{Ksv/(Ksv-1)} \end{cases} \quad \text{(EQ. 6.2-38)}$$

$$(\dot{M}_{VB})_{stm} = \left(\frac{M_{stm}}{M_{stm} + M_{nc}} \right)_{sv} \cdot \dot{M}_{VB} \quad \text{(EQ. 6.2-39)}$$

$$(\dot{M}_{VB})_{nc} = \left(\frac{M_{nc}}{M_{stm} + M_{nc}} \right)_{sv} \bullet \dot{M}_{VB} \quad \text{(EQ. 6.2-40)}$$

$$K_{sv} = \left(\frac{P_{NC}}{P_{tot}} \right)_{sv} \cdot K_{nc} + \left(\frac{P_{stm}}{P_{tot}} \right)_{sv} \cdot K_{stm} \quad \text{(EQ. 6.2-41)}$$

and,

$$\dot{Q}_{VB} = (\dot{M}_{VB})_{stm} h_g(T_{sv}) + (\dot{M}_{VB})_{nc} C_p^* T_{sv}^* \quad \text{(EQ. 6.2-42)}$$

6.2.1.1.4.4 RHR Heat Exchangers

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

$$\dot{Q}_{HX} = \dot{M}_{spray} C_p (T_S - T_{out}) = \phi \xi C_p (T_S - T_{sw}) \quad \text{(EQ. 6.2-43)}$$

where:

$$\phi = \min(\dot{M}_{spray}, \dot{M}_{sw}) \quad \text{(EQ. 6.2-44)}$$

Combining these yields,

$$T_{out} = T_S - \frac{\phi \xi}{\dot{M}_{spray}} (T_S - T_{sw}) \quad \text{(EQ. 6.2-45)}$$

6.2.1.1.4.5 Summary

The preceding equations, combined with the state equations for steam and air, yield a set of coupled equations which, when reduced and solved simultaneously, determine the dynamic response of the primary containment system to the postulated drywell spray accident.

The inherent conservatisms of this model are: to neglect transfer of sensible heat energy from equipment and structures to the drywell vapor region, to disallow re-evaporation of the condensed drywell steam, to maintain a large volume for the drywell region by transferring condensed steam mass directly to the suppression pool, and to require saturated conditions in the primary containment vapor regions.

In addition to the modeling conservatisms, initial conditions for the primary containment are also chosen to induce conservatism in the analysis. The presence of any noncondensables in the drywell tends to hold-up the depressurization rate of this region following spray actuation. Thus, a condition is postulated wherein a small break occurs within the drywell serving to pressurize this region and drive all the noncondensables from the drywell vapor space. This sets the initial

pressure distribution and, along with the assumptions regarding saturated conditions for the steam phase, the temperature distribution for all three regions - drywell, wetwell vapor region, and suppression pool. Normally the noncondensables are driven from the drywell to the wetwell. However, when evaluating the reduction from 4 operable vacuum breakers to 3 operable vacuum breakers, it was assumed for a worst case analysis that a small amount of noncondensables is discharged to the reactor enclosure, prior to purge valve closure, and the remainder are driven to the wetwell vapor space. These initial conditions are presented under the heading "t_o" in Table 6.2-9.

The results of this analysis are illustrated in Figures 6.2-19 and 6.2-20. These results indicate a maximum negative drywell pressure of -4.85 psig.

6.2.1.1.5 Steam Bypass of the Suppression Pool

NOTE: The information in this section for the steam bypass of the suppression pool is based on the original basis conditions. See explanation at the beginning of Section 6.2.1.1.3.

6.2.1.1.5.1 Protection Against Bypass Paths

The pressure boundary penetrations between drywell and suppression chamber include the downcomers, which are fabricated, erected, and inspected in accordance with ASME Section III, Subsection NC, 1971 Edition with the exception of the tees supporting the primary containment vacuum relief valves. This special construction, inspection, and quality control ensures the integrity of this boundary. The design pressure differential and temperature for this boundary are defined in Table 6.2-1. Actual peak accident differential pressure and temperature for this boundary are provided in Table 6.2-5.

All penetrations of this boundary are welded except the vacuum relief valves supported by four tees and the blinds closing 10 spare nozzles in the downcomers. All penetrations are available for periodic visual inspection.

All potential bypass leakage paths have been considered. Every path has at least two isolation valves in the potential leakage path. These valves are high quality leak-tight containment isolation valves that are all normally closed and receive an isolation signal to close. All AOVs in these paths are failed closed.

6.2.1.1.5.2 Reactor Blowdown Conditions and Operator Response

In the highly unlikely event of a primary system leak in the drywell accompanied by the existence of an open bypass path leakage between the drywell and suppression chamber, the suppression chamber is pressurized by the steam that enters through the leakage path (bypassing the suppression pool). For a given primary system break area, the maximum leakage that can be allowed is the amount that results in the containment pressure just reaching the design pressure at the end of reactor blowdown. The most limiting conditions, in terms of the smallest allowable leakage flow path area, occur for those primary system break sizes that do not cause rapid reactor depressurization, but do have a long leakage duration. This corresponds to break sizes less than approximately 0.4 ft^2, which require some operator action to terminate the reactor blowdown.

Immediately after the postulated conditions given for a small primary system break, there is a fairly rapid rise in containment pressure as the noncondensable gases in the drywell are carried over to the suppression chamber. During this portion of the transient, it is assumed that the plant operators are unaware that a leakage path exists. For the maximum allowable leakage

calculations, it is assumed that the plant operators become aware of a potential leakage only when the drywell pressure reaches 30 psig. For conservatism, an additional 30 minute delay is assumed to occur before any corrective action to terminate the transient takes effect. At that time, the drywell pressure would be equal to the design pressure if the allowable leakage had occurred. The operator will be alerted to the existence of significant steam bypass leakage by the attendant drywell pressure increase which the operator will be monitoring as part of the EOPs. The operator will initiate the wetwell spray in accordance with the EOPs which will be based on the BWROG EPGs. The BWROG EPGs explicitly consider the possibility of suppression pool bypass leakage in determining spray initiation points.

Termination of the wetwell (and drywell) pressure increase is assured by the operation of only one of the two wetwell sprays.

6.2.1.1.5.3 Analytical Assumptions

When calculating the allowable leakage capacities for a spectrum of break sizes, the following assumptions are made:

a. Flow through the postulated leakage path is pure steam. For a given leakage path, if the leakage flow consists of a mixture of liquid and vapor, the total leakage mass flow rate is higher but the steam flow rate is less than for the case of pure steam leakage. Since only the steam entering the suppression chamber free space results in the additional containment pressurization, this is a conservative assumption.

b. There is no condensation of the leakage flow on either the suppression pool surface or the containment and vent system structures. Since condensation acts to reduce the suppression chamber pressure, this is a conservative assumption. For an actual containment there is condensation, especially for the larger primary system break where vigorous agitation at the pool surface occurs during blowdown.

The following assumptions were made in performing the small break bypass leakage computations to demonstrate that operator action is not required for at least 30 minutes.

a. The steam that leaks into the wetwell air space does not mix with the air already there.

b. No portion of the steam that has leaked into the wetwell air space condenses.

c. Only steam leaks into the wetwell; any air moving from the drywell into the wetwell goes through the vents.

d. All of the air initially in the drywell is cleared into the wetwell before the moment when the operator is alerted.

e. The vents do not refill with water during the time span considered in this procedure.

f. The flow of steam through leakage paths is treated as being incompressible.

g. The pressure difference across the leakage path is assumed to be constant and equal to the vent submerged hydrostatic pressure difference.

h. The drywell pressure at which the operator is alerted is 30 psig.

i. The wetwell air temperature when the operator is alerted to the occurrence of bypass leakage is assumed to be equal to the initial wetwell temperature (95°F). Later, when the drywell pressure is reduced due to operator action, the wetwell air temperature is assumed to be 50°F greater than the initial wetwell temperature, i.e., 145°F.

j. Maximum allowable leakage area $A/(k)^{½} = 0.05\ ft^2$.

k. The wetwell air space is saturated at the time of spray initiation.

The initial conditions assumed were:

Drywell Temperature	135°F ①
Drywell Pressure	15.45 psia
Drywell Relative Humidity	20%
Wetwell Temperature	95°F
Wetwell Relative Humidity	100%
Drywell Volume	248390 ft^3 (HWL)*
Wetwell Volume	149425 ft^3 (HWL)*
Vent Submergence	12.25 ft (HWL)

Using the above assumptions and initial conditions, a small break LOCA in the drywell produces a constant drywell-to-wetwell pressure differential equivalent to the vent submergence static head (5.28 psid). The resulting bypass steam flow through the leakage path of $A/(k)^{½} = 0.05\ ft^2$ is 3.76 lb_m/sec. The operator becomes alerted to the existence of bypass leakage when the drywell pressure reaches 30 psig. For the drywell pressure to increase from 30 psig to 55 psig (design pressure), the corresponding wetwell pressure rise is from 24.72 to 49.72 psig. Therefore, based on the amount of bypassed steam needed to produce this pressure rise, the operator has about 31 minutes to complete an action that will terminate the pressure increase.

The following shows the minimum required spray efficiency as a function of spray temperature. Because the wetwell airspace is saturated when the spray is initiated (this conservative assumption maximizes pressurization at a given temperature), no net evaporation from hot downcomer surfaces will occur to counteract the spray depressurization effect. The mass flow rate of one spray system is 500 gpm. With two spray systems in operation, the required efficiency would be halved. The spray efficiency is typically on the order of 0.7 and, therefore, even with a single system is operation, the termination of the wetwell (and drywell) pressure increase is assured.

① The assumed initial condition for Drywell temperature of 135°F conservatively bounds an initial Drywell Temperature of 150°F.

* See Table 6.2-1 for final design volumes.

Spray Temperature	Required Efficiency of 1 Wetwell Spray System
70°F	0.22
90°F	0.24

120°F	0.28

6.2.1.1.5.4 Analytical Results

The containment has been analyzed to determine the allowable leakage between the drywell and suppression chamber. Figure 6.2-21 shows the allowable leakage capacity ($A/(k)^{1/2}$) as a function of the primary system break area. (A) is the area of the leakage flow path and (K) is the total geometric loss coefficient associated with the leakage flow path.

Figure 6.2-21 is a composite of two curves. If the break area is greater than approximately 0.4 ft^2, natural reactor depressurization rapidly terminates the transient and maximum allowable leakage is correspondingly high. For break areas less than approximately 0.4 ft^2, however, reactor blowdown is of long duration and the maximum allowable leakage is limited to small values. The smallest maximum allowable leakage capacity is at $A/(K)^{1/2}$ = .046 ft^2.

6.2.1.1.5.5 Tests and Inspections

A visual inspection will be conducted at each refueling outage to detect possible drywell-to-suppression bypass leakage paths. A visual inspection of each primary containment vacuum relief valve assembly will be conducted during each refueling outage to verify that it is clear of foreign matter.

Vacuum breakers will be tested for operability at an interval specified by the Technical Specifications. This surveillance testing will be in accordance with the Technical Specifications.

6.2.1.1.5.6 Instrumentation

The vacuum relief valve position indicator system has adequate sensitivity to detect a total valve opening, for all valves, that is less than the bypass capability for a small break. Outboard valve opening is detectable at a disk lift of 0.050 inch or greater off the valve seat. Inboard valve opening is detectable at a disk lift of 0.120 inch or greater off the valve seat. Even assuming that one outboard valve is in the fully open position and all other

valves are open to their minimum detectable position, the total $A/(k)^{1/2}$ is below 0.05 ft^2. Therefore, the valve leakage, which is based on the assumption that the valve opening is evenly divided among all the vacuum breakers assemblies with one outboard valve in the fully open position, is well within the limits of acceptable bypass leakage.

6.2.1.1.6 Suppression Pool Dynamic Loads

Hydrodynamic loads due to MSRV discharge and a LOCA are described in Appendix 3A.

6.2.1.1.7 Asymmetric Loading Conditions

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

6.2.1.1.8 Containment Environment Control

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

6.2.1.1.9 Postaccident Monitoring

A description of the postaccident monitoring systems is provided in Section 7.5.

6.2.1.2 Containment Subcompartments

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

6.2.1.3 Mass and Energy Release Analyses for Postulated LOCAs

The information presented in this section for the mass and energy release analyses for postulated LOCAs is based on the original design basis conditions. The information presented in this section reasonably represent the general characteristics for the mass and energy release following a postulated LOCA. (See explanation at beginning of Section 6.2.1.1.3.)

This section presents information concerning the transient energy release rates from the reactor primary system to the containment system following a LOCA. Where the ECCS enter into the determination of energy released to the containment, the single failure criterion has been applied in order to maximize the energy release to the containment following a LOCA. Long-term responses and single failure analyses are discussed in Section 6.2.1.1.3.3.1.6.

6.2.1.3.1 Mass and Energy Release Data

Table 6.2-10 provides the mass and enthalpy release data for the recirculation line break. Blowdown steam and liquid flow rates approach zero in approximately 40 seconds and do not change significantly during the remainder of the 24 hour period following the accident. Figures 6.2-22 and 6.2-23 show the blowdown flow rates for the recirculation line break graphically. These data were employed in the containment pressure-temperature transient analyses reported in Section 6.2.1.1.3.3.1.

Table 6.2-11 provides the mass and enthalpy release data for the main steam line break. Blowdown steam and liquid flow rates approach zero in approximately 60 seconds and do not change significantly during the remainder of the 24 hour period following the accident. Figure 6.2-24 shows the vessel blowdown flow rates for the main steam line break as a function of time after the postulated rupture. This information has been employed in the containment response analyses presented in Section 6.2.1.1.3.3.2.

6.2.1.3.2 Energy Sources

The RCS conditions prior to the line break are presented in Tables 6.2-3 and 6.2-4. Reactor blowdown calculations for containment response analyses are based on these conditions during a LOCA.

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

a. Energy stored in the reactor system

b. Energy generated by fission product decay

c. Energy from fuel relaxation

d. Sensible energy stored in the reactor structures

e. Energy being added by the ECCS pumps

f. Metal-water reaction energy

These energy additions are discussed or referenced in this section. The pump heat rate used in evaluating the containment response to the LOCA is conservatively selected as a constant input of $.00434 \times 10^6$ Btu/sec to the system. The pump heat rate is added to the decay heat rate for inclusion in the analysis.

Following each postulated accident event, the stored energy in the reactor system and the energy generated by fission product decay are released. The rate of release of core decay heat for the evaluation of the containment response to a LOCA is provided in Table 6.2-12 as a function of time after accident initiation.

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

Figure 6.2-25 shows the temperature transients of the various primary system structures that contribute to this sensible energy transfer. Figure 6.2-26 shows the variation of the sensible heat content of the reactor vessel and internal structures during a recirculation line break accident based on the temperature transient responses.

6.2.1.3.3 Reactor Blowdown Model Description

NOTE: The reactor blowdown model description provided below is for the original analysis models and do not represent the methods used to analyze current plant conditions. Refer to the explanation provided at the beginning of Section 6.2.1.1.3.

The reactor primary system blowdown flow rates are evaluated with the model described in References 6.2-4 and 6.2-5.

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 that may occur following a LOCA. The amount of metal-water reaction that can be accommodated is consistent with the performance objectives of the ECCS. Section 6.2.5.3 provides a discussion on the generation of hydrogen within the containment by metal-water reaction. In evaluating the containment response, 0.002077×10^6 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 of the energy is included prior to the occurrence of peak drywell pressure.

6.2.1.3.5 Thermal-Hydraulic Data for Reactor Analysis

Sufficient data to perform confirming thermodynamic evaluations of the containment are provided in Section 6.2.1.1.3.3 and associated tables, in particular, Table 6.2-4.

6.2.1.4 Pressurized Water Reactor - Not Applicable

6.2.1.5 Pressurized Water Reactor - Not Applicable

6.2.1.6 Testing and Inspection

Preoperational containment testing and inspection programs are described in Section 3.8 and Chapter 14. Operational containment leakage rate testing and inspection programs are described in Section 6.2.6. The requirements and bases for acceptability are described in Chapter 16.

6.2.1.7 Instrumentation Requirements

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

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

6.2.1.8 Containment System Performance at Power Rerate

The UFSAR provides the results of analyses of the containment response to various postulated accidents that constitute the design basis for the containment. Operation with power rerate changes some of the conditions for the containment analyses. For example, the short-term DBA-LOCA containment response during the blowdown is governed by the blowdown flow rate. This blowdown flow rate is dependent on the reactor initial thermal-hydraulic conditions, such as vessel dome pressure and the mass and energy of the vessel fluid inventory, which change slightly with power rerate. Also, the long-term heat up of the suppression pool following a LOCA or a transient is governed by the ability of the RHR to remove decay heat. Since the decay heat depends on the initial reactor power level, the long-term containment response is affected by power rerate. The LGS containment response has been conservatively re-analyzed to demonstrate the plant's capability to operate at 110% of the original rated power.

The analyses were performed in accordance with Regulatory Guide 1.49 and Reference 6.2-25 using GE codes and models. The M3CPT code was used to model the short-term containment pressure and temperature response. The modeling used in M3CPT is described in References 6.2-26 through 6.2-28. Reference 6.2-26 and 6.2-27 describe the basic containment analytical models used in GE codes. Reference 6.2-28 describes the more detailed RPV model used in the containment analyses for power rerate. The SHEX code was used to model the long-term containment pressure and temperature response. The key models in SHEX are based on models described in References 6.2-26 and 6.2-27. The GE models and methods have been reviewed by the NRC (Reference 6.2-29). The

NRC has approved the use of SHEX on a plant-specific basis, as described in Reference 6.2-30. The significant input parameters and initial conditions for the power rerate containment analyses are shown in the Table 6.2-4A.

The effects of power rerate on the containment dynamic loads due to a LOCA or SRV discharge have also been evaluated as described in Section 6.2.1.8.2. These loads were previously defined generically during the Mark II Containment Program as described in Reference 6.2-31 and accepted by the NRC in Reference 6.2-32 and 6.2-33. Plant-specific dynamic loads were also defined for the plant (Section 3A), which were accepted by the NRC in Reference 6.2-34. The evaluation of the LOCA containment dynamic loads is based primarily on the results of the short-term analysis described in Section 6.2.1.8.1.3. The SRV discharge load evaluation considers the change in the SRV opening setpoints with power rerate.

6.2.1.8.1 Containment Pressure and Temperature Response

The short-term analysis is directed primarily at determining the containment pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break inside the drywell. The long-term analysis is directed primarily at the pool temperature response, considering the decay heat addition to the pool. The impact of power rerate on the events which yield the limiting containment pressure and temperature response is provided below.

6.2.1.8.1.1 Long-Term Suppression Pool Temperature Response

6.2.1.8.1.1.1 Bulk Pool Temperature

The long-term bulk suppression pool temperature response for LGS with power rerate was evaluated for the DBA LOCA and includes the increased decay heat loads from SIL 636. The analysis was performed at 3528 MWt (Ref. 6.2-40, 6.2-41). Table 6.2-5A compares the calculated peak values for LOCA bulk pool temperature. The suppression pool temperature response is shown in Figure 6.2-9A. The peak bulk suppression pool temperature calculated is 203.4°F. This temperature is within the suppression pool water temperature structural design value (220°F), and does not exceed the low pressure ECCS pump limit of 212°F.

6.2.1.8.1.1.2 Steam Bypass Case

A concern during a LOCA event is steam bypass of the suppression pool due to leakage between the drywell and the wetwell airspace. Excess leakage could result in overpressurization of the primary containment. A steam bypass analysis was performed at 3694 MWt to ensure that there is sufficient time for a manual actuation of the containment spray to prevent the containment pressure from exceeding the design limit of 55 psig. The evaluation shows that power rerate has negligible impact on the suppression pool steam bypass effects. Reference 6.2-41 qualitatively equates the steam bypass event at 3458 MWt with the decay heat rates of SIL 636. At these conditions, it is expected that sufficient time for manual equation of containment spray is available to prevent containment pressure from exceeding 55 psig.

6.2.1.8.1.2 Containment Gas Temperature Response

The drywell design temperature (340°F) has been determined based on a bounding analysis of the superheated gas temperature which can be reached with blowdown of steam to the drywell during a LOCA. A small reactor steam leak (resulting in superheated steam) imposes the most severe temperature conditions on the drywell structures and the safety-related equipment in the drywell. For larger steam line breaks, the superheat temperature is nearly the same as for the small breaks, but the duration of the high temperature condition is less for the large break. This is because the larger breaks depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to be initiated for the small breaks. The changes in the reactor vessel conditions with power rerate will increase the calculated long-term peak drywell gas temperature during a small

break LOCA by a maximum of a few degrees. However, it has been evaluated that the small break drywell gas temperature response with power rerate will not exceed the drywell design value. The short-term drywell and wetwell gas temperature response is shown in Figure 6.2-4A. The long-term drywell gas temperature response is shown in Figure 6.2-8A.

The wetwell gas space peak temperature response is calculated assuming short-term thermal equilibrium between the pool and wetwell gas space. For the long term containment response, the heat and mass transfer between the suppression pool and the wetwell air space is mechanically calculated. Table 6.2-5A shows the peak bulk pool temperature is 203.4°F due to power rerate and SIL 636 (Reference 6.2-41). The peak wetwell gas space temperature is 210.7°F. These temperatures are well below the design temperature of 220°F.

6.2.1.8.1.3 Short-Term Containment Pressure Response

Short-term containment pressure response analyses were performed for the limiting DBA LOCA which assumes a double-ended guillotine break of a recirculation suction line to demonstrate that operation with power rerate will not result in exceeding the containment design limits. The short-term analysis covers the blowdown period during which the maximum drywell pressure, wetwell pressure, and differential pressure between the drywell and wetwell occur. This analysis was conservatively performed at 102% of 110% of original rated power. The results of this short-term analysis are summarized in Table 6.2-5A. The short-term containment pressure response for power rerate is shown in Figure 6.2-3A. The long-term containment pressure response is shown in Figure 6.2-7A. Table 6.2-5A also includes comparisons of the pressure values calculated with power rerate to the design pressures values from previous calculations reported in the UFSAR. As shown by these results, the peak pressure values are below the design values.

6.2.1.8.2 Containment Dynamic Loads

6.2.1.8.2.1 LOCA Containment Dynamic Loads

The LOCA containment dynamic loads analysis for power rerate is based primarily on the short-term LOCA analyses described in Section 6.2.1.8.1.3. These analyses provide calculated values for the controlling parameters for the dynamic loads throughout the blowdown. The key parameters are drywell and wetwell pressure, vent flow rate and suppression pool temperature. The LOCA dynamic loads which are considered in the power rerate evaluation include pool swell, condensation oscillation (CO), and chugging.

The short-term containment response conditions with power rerate are within the conditions used to define the pool swell loads. The initial drywell pressurization rate used to define the pool swell load is negligibly affected by rerated power. The short-term containment response conditions for vent flow rate and pool temperature with power rerate are negligibly affected by power rerate. In addition, the containment conditions with power rerate in which CO and chugging would occur are within the range of test conditions used to define the CO and chugging loads. Therefore, the LOCA dynamic loads are not affected by power rerate.

6.2.1.8.2.2 SRV Containment Dynamic Loads

Hydrodynamic loads generated by the actuation of Safety/Relief Valve (SRV) include both internal and external hydrodynamic loads. Internal loads include SRV discharge line loads and load on the quencher discharge device. External hydrodynamic loads include the suppression pool boundary pressure loads and the submerged structure loads. These loads are influenced by SRV opening

setpoint pressure, SRVDL geometry and submergence, initial air volume in SRVDL, quencher design and suppression pool geometry. The only parameter change introduced by power rerate which can affect SRV loads is the increase in SRV opening setpoint pressure which results in higher SRV flow rates and, therefore higher SRV loads.

The SRV analytical limits for setpoints show a 3.5% increase in the analytical values of the SRV opening pressure with power rerate. The increase in SRV setpoint pressure results in a corresponding 3.5% increase in flow rate and hydrodynamic loads. However, the original SRV external hydrodynamic load specification and the load specification on quenchers are defined based on a reference RPV pressure of 1276 psig. Comparison shows that the rerate increased SRV setpoint pressure and flow rate are still bounded by the referenced flow rate used to define the LGS T-quencher hydrodynamic loads (Reference 6.2-35). Therefore, the original containment dynamic and submerged structure loads remain bounding for power rerate. The same conclusion is also valid for the hydrodynamic loads on the quencher. The SRV discharge piping loads are included in the evaluation discussed in Appendix 3A and 3B.

6.2.1.8.2.3 Subcompartment Pressurization

The design loads on the shield wall due to a postulated pipe break in the annulus between this wall and the reactor vessel are acceptable for the higher reactor pressure at rerated conditions. The shield wall design remains adequate because the original analyzed loads were based on mass and energy releases which bound the rerated conditions. The subcompartment pressurization evaluations for power rerate are provided in Appendix 6A.

6.2.2 Containment Heat Removal System

6.2.2.1 Design Bases

The containment heat removal system (containment cooling system) prevents excessive containment temperatures following a LOCA so that containment integrity is maintained. To fulfill this purpose, the containment cooling system meets the following design bases:

a. The system is designed to limit the long-term bulk temperature of the suppression pool without spray operation when considering the energy additions to the containment following a LOCA (see Reference 6.2-4). These energy additions, as a function of time, are provided in Section 6.2.1.3.2.

b. The system is designed with sufficient capacity and redundancy so that a single failure of any active component, assuming a LOOP, cannot impair its capability to perform its safety-related function. The system is designed to remain operable following an SSE.

c. The system is designed to operate under any of the following conditions: LOOP, adverse natural phenomena (such as tornadoes, hurricanes, earthquakes, floods, etc.), and site related events (such as high and moderate energy pipe breaks, externally generated missiles, and transportation accidents).

d. Each active component of the system is testable during normal operation of the nuclear power plant.

6.2.2.2 System Design

The containment cooling system is an integral part of the RHR system as described in Section 5.4.7 and designed to seismic Category I requirements. The system is designed, fabricated, erected, and tested to quality Group B standards with the exception of the drywell and wetwell spray headers which were originally designed, fabricated, and erected to quality Group C standards but have been upgraded to quality Group B (Table 3.2-1). In the containment cooling mode, water is drawn from the suppression pool through redundant suction strainers, pumped through one or both RHR heat exchangers, and delivered to the vessel, the suppression pool, the drywell spray header, and/or the suppression pool vapor space spray header. Water from the RHRSW system is pumped through the heat exchanger tube side to remove heat from the suppression pool water. Two 100% capacity cooling loops are provided; each being mechanically and electrically separate from the other to achieve redundancy (Section 9.2.3). Power is supplied from the safeguard buses (Section 8.3). A P&ID and process diagram, including the process data, are provided in Section 5.4 for all design operating modes and conditions.

All ECCS and RCIC suction piping originating in the suppression pool is designed based on the following criteria:

a. The allowable pressure drop across the redundant pair of strainers for each RCIC and HPCI suction line is 2 psi maximum at the design flow rate with each of the strainers 50% plugged in order to exceed the minimum required NPSH provided to the associated pump.

b. The allowable dirty pressure drop across the redundant strainers for each of the RHR and Core Spray suction lines is 5 psi and 3.8 psi maximum, respectively, at the design flow rate in order to satisfy the minimum required NPSH provided to the associated pump. The dirty strainer pressure drop is based on the entire amount of fibrous debris generated in the drywell during a design basis LOCA (within the zone of influence of the worst case pipe break location) transported to the suppression pool and all fibrous debris is available to clog the strainer.

c. The strainer mesh openings are sized to allow foreign particles of no greater than 0.0625 inches to pass through in order to prevent plugging of the containment spray nozzles and pump seal flushing water circuits.

d. Each strainer is designed to withstand all seismic and hydrodynamic loads postulated to occur in the suppression pool. A dynamic loading analysis has been performed for the ECCS suction strainers that demonstrates their capability to adequately accommodate inertial loads (earthquake, SRV discharge, and LOCA condensation oscillation and chugging), operational loads (pressure and temperature), dead weight loads, and direct hydrodynamic loads. The latter loads are due to direct hydrodynamic SRV discharge (SRV air bubble loads) and downcomer discharges (LOCA air bubble, CO, chugging, water jet, and pool-swell loads). The mentioned loads are combined in accordance with Table 3A-20. Figure 3A-27 presents elevations, dimensions, and orientations of the piping systems inside containment that are associated with the ECCS suction strainers.

e. The RHR suction piping is arranged in the suppression pool considering the locations of the discharge piping, so that when operating in the suppression pool cooling mode the suppression pool is uniformly cooled.

Each pump suction line penetrates the vertical wall of the suppression pool, leading directly to a "T" arrangement. The "T"s for the RCIC line and HPCI line are oriented vertically. The remaining "T"s are horizontal. The centerline of this "T" is 23 inches maximum from the suppression pool wall and 11'-11" below the minimum Technical Specification suppression pool water level. Each arm of the "T" is the same nominal pipe size as the suction line. The strainers are bolted to the arms of each "T" except Core Spray strainers which are attached to one arm of each "T". Each of the two strainers for each suction line provides more than 100% of the cross-sectional area of the suction line. The design drawing for the RCIC and HPCI strainers is shown in Figure 6.2-51. The design drawings for the RHR and Core Spray strainers are shown in Figure 6.2-51.

In the unlikely event of a high energy pipe break within the primary containment, debris created might migrate to the suppression pool and build-up on the RCIC and HPCI pump suction strainers, impairing operation of these pumps. Such debris considerations are part of USI A-43, "Containment Emergency Sump Performance." The manufacturer has addressed this concern on a generic basis in a topical report which has been reviewed and accepted by the NRC (Reference 6.2-23). A plant specific review of this concern was made.

The only credible sources of LOCA generated debris inside the primary containment that have the potential to clog pump suction strainers are the thermal insulation materials on piping and equipment. There are four types of insulation materials used inside the primary containment:

a. Metallic reflective - used on reactor vessel.

b. Fiberglass (Nukon) - used on piping, valves, and pumps.

c. Fiberglass (antisweat) - used on chilled water piping.

d. Stainless steel encapsulated low conductivity insulation - used on piping at the pipe whip restraints.

Fiberglass insulation inside primary containment is protected with stainless steel jackets except where it is not practical (pipe hangers, supports) or where shapes are not suitable (some valves and reactor nozzles). Insulation added in the Unit 1 drywell during power ascension testing was installed without jackets to simplify installation.

Insulation debris can enter the suppression pool only through the wetwell downcomers (Figure 6.2-1). There are several physical barriers that will minimize the amount and size of debris that enters the downcomers, as described below:

a. Floor grating, walkways, stairs, structural steel, piping, etc., located above the drywell floor will trap the majority of dislodged insulation pieces before they can reach the drywell floor where the downcomers are located.

b. Covers over downcomer openings will prevent debris from falling directly into a downcomer.

c. Downcomer openings are above the floor. The downcomer pipes extend 18 inches above the drywell floor. This feature prevents entry of all heavier insulation debris due to the specific gravity of the debris and low velocity of the water converging on the downcomer rims. Floating debris, in most cases, will be partially submerged, which will prevent them from passing over the downcomer rim.

d. The clearances around the jet deflector assembly covering the downcomer openings are such that debris with dimensions larger than 10 inches will be blocked from entering the downcomer.

In the case of metallic reflective insulation, it will immediately sink to the bottom of the drywell floor pool, where the flow velocities are too low to transport this insulation over the downcomer rims into the suppression pool.

In the case of permanently installed antisweat insulation, the jacketing subjected to jet forces of a high energy line break is susceptible to being blown away along with the underlying fiberglass panels. The stainless steel jacketing is too dense to be transported to the wetwell. Loose fiberglass panels that fall to the floor float due to their low specific gravity and therefore could be carried over with the emergency core cooling water and be transported to the suppression pool. However, due to the minimal quantity of antisweat insulation provided on piping in the drywell, and the filtering effect of the physical barriers noted above, it is improbable that sufficient antisweat insulation materials would be available to plug the pump suction strainers.

In the case of stainless steel encapsulated low conductivity insulation, the steel jackets are welded around the low conductivity insulation and would therefore be expected to stay intact even if the entire assembly is blown away from the piping due to jet forces of a high energy line break. If the low conductivity insulation remained dry within the steel jackets, the assembly would have a lower specific gravity than water, thus allowing the assembly to float. However, vent holes are provided in each assembly for pressure equalization, so the low conductivity insulation would become wet, in which case the assembly would have a higher specific gravity than water and would sink. If the low conductivity insulation remained dry long enough to allow it to float to the downcomer openings, the size of most individual insulation assemblies would be too large to pass through the downcomer jet deflector assemblies. Also, the submergence of most smaller assemblies will be too deep to pass over the downcomer rims. Thus, due to the minimal quantity of low conductivity insulation provided on piping in the drywell, and the low probability of any dislodged insulation assemblies being transported to the suppression pool, it is improbable that these insulation materials would plug the pump suction strainers.

There is a potential for some quantity of fiberglass insulation to travel to the suppression pool. An evaluation was made to estimate the maximum quantity of fiberglass insulation debris that might be generated by a LOCA, the amount of such debris that might enter the suppression pool and cover the ECCS strainers, the attendant pressure losses and resulting effect on the ECCS pump NPSH margins.

In this review, no credit was taken for the protective effect of stainless steel jackets on the fiberglass insulation. The head loss due to 50% plugging of the suction strainers concurrent with minimum postaccident NPSH conditions does not cause the available NPSH to drop below that required by the RCIC and HPCI pumps. Using more realistic considerations, it has been determined that other transport mechanisms will significantly reduce the actual amount of fibrous insulation debris that could migrate to the suppression pool and cover the pump strainers.

Large capacity passive pump suction strainers have been installed on each RHR and Core Spray suction line in the suppression pool via plant modification, in response to NRC I.E. Bulletin 96-03, “Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors”. The assumptions used in sizing these new strainers are consistent with the guidance specified in Regulatory Guidance 1.82, Revision 2, “Water Sources for Long-Term Recirculation

Cooling Following a Loss-of Coolant Accident" and NUREG/CR-6224, "Parametric Study of the Potential for BWR ECCS Strainer Blockage Due to LOCA Generated Debris" as described in PECO Energy's letter from G. A. Hunger, Jr., Director Licensing, to USNRC, dated October 6, 1997, "Request for Licensing Amendment Associated with ECCS Pump Suction Strainer Plant Modification".

It has been determined that the amount of fiberglass insulation debris generated by a LOCA jet impinging on nearby insulation will not jeopardize ECCS pump operation at LGS Units 1 & 2.

The containment cooling system is designed to withstand operating loads and loads resulting from natural phenomena. Components required to operate can be tested during normal plant operation so that reliability can be ensured. Construction codes and standards are covered in Section 5.4.7.

The containment cooling system is started manually. There are no signals that automatically initiate the system. Rather, the LPCI mode of RHR operation is automatically initiated from ECCS signals. The RHR system is realigned for containment cooling by the plant operator after the reactor vessel water level has been restored (Section 6.2.1). The RHR pumps are already operating. Containment cooling is initiated in loop A or B by manually starting the RHRSW pump; closing the heat exchanger bypass valve; opening the service water valves at the heat exchanger; closing the LPCI injection valve; and opening the pool return valve, not necessarily in this order. If a single failure has occurred that prevents system initiation, the other totally redundant system is placed into operation by following the same initiation procedure. If the operator chooses to use the containment spray to reduce containment pressure, he must close the LPCI injection valve and open the spray valves. An interlock prevents the operator from opening the drywell spray valves unless a containment high pressure signal is present.

The containment cooling system equipment is located in the reactor enclosure and protected from both internal and external floods. The equipment is located in separate compartments, the walls and doors of which are steam-tight and water-tight so that flooding due to leakage from piping in an adjacent containment cooling system or other ECCS compartment does not affect the redundant containment cooling system equipment. Flood design of the reactor enclosure is discussed in Section 3.4.

6.2.2.3 Design Evaluation

If there is a postulated LOCA, the short-term energy release from the reactor primary system is dumped to the suppression pool. Subsequent to the accident, fission product decay heat results in a continuing energy input to the pool. The containment cooling system removes this energy that is input to the primary containment system, thus resulting in acceptable suppression pool temperatures and containment pressures.

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

a. With the reactor initially operating at 3528 MWt, a LOCA occurs.

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

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

d. No credit may be taken for manual actions within 10 minutes of a design basis accident. Analytically, it is assumed that containment heat removal begins at 10 minutes following a design basis LOCA. However, containment heat removal by activating an RHR heat exchanger for suppression pool cooling will be initiated in accordance with plant emergency operating procedures based on plant conditions. Once containment cooling has been established, no further operator actions are required.

When calculating the long-term post-LOCA pool temperature transient, it is assumed that the initial suppression pool temperature and the RHRSW 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. 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. 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.

Figure 6.2-10 shows the actual heat removal rate of the RHR heat exchanger. The resultant suppression pool temperature transient is described in Section 6.2.1.1.3.3.1 and is shown in Figure 6.2-9. Even with the degraded conditions outlined above, the maximum suppression pool temperature is maintained below the design limit of 220°F.

The conservative evaluation procedure described above clearly demonstrates that the RHR system in the containment cooling mode meets its design objective of limiting the post-LOCA containment temperature transients safely.

6.2.2.4 Tests and Inspections

The Suppression Pool floor and low pressure ECCS (RHR and Core Spray) suction strainers shall be visually inspected for sludge accumulation and foreign material. The visual inspection allows use of a remote camera in lieu of divers. The interval of these inspections shall be every other refueling outage.

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

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

A design flow functional test of the RHR pumps is performed for each pump during normal plant operation by taking suction from and returning to the suppression pool. The discharge valves to the reactor recirculation system loops remain closed during this test, and reactor operation is undisturbed.

An operational test of the discharge valves is performed by shutting the downstream valve after it has been satisfactorily tested, thereby establishing the RCPB at the downstream valve, and then operating the upstream valve. The discharge valves to the drywell spray headers are checked in a similar manner by operating the upstream and downstream valves individually. All these valves can be actuated from the control room by using remote manual switches. Control system design

provides automatic return from the test to the operating mode if LPCI initiation is required during testing.

The surveillance frequency for testing and inspection is discussed in Chapter 16.

6.2.2.5 Instrumentation Requirements

The containment spray and suppression pool cooling modes of the RHR system are manually initiated from the control room. Once initiated, containment cooling performance is monitored by suppression pool temperature, flow, and containment pressure instrumentation. Details of the instrumentation are provided in Section 7.3.1.

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

The secondary containment consists of three distinct isolatable zones. Zones I and II are the Unit 1 and Unit 2 reactor enclosures, respectively. Zone III is the common refueling area. Each zone has an independent normal ventilation system which is capable of providing secondary containment zone isolation as required.

Each reactor enclosure (Zones I or II) completely encloses and provides secondary containment for its corresponding primary containment and reactor auxiliary or service equipment, including the RCIC system, RWCU system, SLCS, CRD system equipment, the ECCS, and electrical equipment components.

The common refueling area (Zone III) completely encloses and provides secondary containment for the refueling servicing equipment and spent fuel storage facilities for Units 1 and 2.

When a unit's primary containment is open, as it is during the refueling period, the associated reactor enclosure and common refueling area provide primary containment for the unit being refueled.

The ability to procedurally combine each of the reactor enclosure secondary containment zones to the common refueling area secondary containment zone exists. The combining of the associated isolation zones is accomplished via an interlock switch located on the auxiliary equipment room panels. Table 6.2-29 identifies the associated secondary containment ventilation system automatic isolation valves that are required for the combined zone alignment.

6.2.3.1 Design Bases

a. The conditions that could exist following a LOCA or fuel handling accident require the establishment of a method of controlling any fission products that may leak into the secondary containment.

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

c. The seismic design, leak-tightness, and internal and external design pressures of the secondary containment structure are discussed in Section 6.2.3.2 and Chapter 3.

d. The surveillance requirements for periodic inspection and functional testing of the secondary containment structure is discussed in the Technical Specifications.

6.2.3.2 System Design

6.2.3.2.1 Secondary Containment Design

The secondary containment is designed and constructed in accordance with the design criteria outlined in Chapter 3. All of the major structural walls are constructed of reinforced concrete. All of the major structural floor slabs and roof slabs are constructed of reinforced concrete supported by structural steel framing.

The reactor enclosure secondary containment (Zones I and II) are designed to limit the inleakage to 200% of their zone free volume per day, and the refueling area secondary containment (Zone III) is designed to limit the inleakage to 50% of its zone free volume per day. These inleakage rates are based on a negative interior pressure of 0.25 in wg, while operating the SGTS. Following a LOCA the affected zone is maintained at this negative pressure by operation of the SGTS. The secondary containment zones are identified in Figures 6.2-27 through 6.2-35.

An analysis of the post-LOCA pressure transient in the Unit 1/2 reactor enclosure secondary containment was performed (Figure 6.2-52). The length of time following isolation signal initiation of the SGTS that the pressure in the secondary containment would exceed -0.25 in wg. is 15.5 minutes based on drawing down both reactor enclosures and the common refueling area simultaneously.

In addition to the pressure transient analysis, a detailed review has been performed to identify potential leakage paths from either the primary containment or the secondary containment to the common refueling area. This review resulted in the following changes which ensure that no leakage paths exits:

a. A vent path from the reactor well to the reactor enclosure was added. When blind flanges are attached, the vent path will be through the associated opened drain lines or through a 1.5 inch hole in the blind flange.

b. Normally closed valves on the reactor well skimmer drain lines were added.

c. Provisions have been made to ensure that there is no flow path through the drain system between the refueling area and the reactor enclosure secondary containment.

Periodic tests are performed in accordance with the plant Technical Specifications to verify that the reactor enclosure secondary containment inleakage is less than 200% of its free volume per day at a negative interior pressure of 0.25 in wg.

The time line of events for actuating the SGTS is as follows:

Event	Time (sec)
Start of accident	0
Signal to start diesel	3
Diesel ready to load	13

Apply power to 480 V block 1 load	16
SGTS fans at rated speed	18

A maximum SGTS flow rate of 2800 cfm from a single reactor enclosure zone was used for the drawdown analysis.

The guidelines stated in the SRP 6.2.3 have been followed in calculating the drawdown time as noted:

a.

1. The heat transfer coefficients found in BTP CSB 6-1 apply to an atmosphere with high-energy blowdown where condensation on the primary containment surface is expected. Because the drawdown analysis was only 15.5 minutes long, the primary containment heat load was calculated as the steady-state load during normal operation when there are no condensation effects. This is accurate because LOCA conditions inside the primary containment will not affect the exterior surface temperature of the 6 foot containment wall significantly in 15.5 minutes. For steady-state heat load a conservative value was assumed.

2. Steady-state conduction and convection was calculated.

3. Radiant heat transfer was considered.

b. Adiabatic boundary conditions were used.

c. There will be negligible expansion of the 6 foot thick primary containment concrete walls in 15.5 minutes.

d. Inleakage was considered.

e. No credit was taken for outleakage.

f. The analysis was based on the assumptions and delays indicated in the acceptance criteria.

g. Heat loads generated within the secondary containment were considered.

h. Fan performance characteristics were considered.

Information that demonstrates the external design pressure of the secondary containment structure ensures an adequate margin above the maximum expected external pressure for wind loadings, tornado loadings, and explosion loadings. This information is provided in Sections 3.3 and 2.2.3.

The openings provided for gaining access to the secondary containment are listed in Table 6.2-13, and are shown in Figures 6.2-27 through 6.2-33.

Personnel Access Doors:

At each secondary containment personnel access opening there are two doors, which are designated the inner door and the outer door. Each door is equipped with a door position switch to

provide monitoring. The monitoring circuitry consists of local indicating lights, local audible alarms, and control room annunciator lights and alarms. The monitoring operation is as follows:

a. Both doors closed - the blue indicating lights located on both sides above each door are de-energized

b. One door opened (either inner or outer) - the blue indicating lights above the door that is still closed are energized to warn against opening. The blue indicating lights above the opened door are still de-energized.

c. Both doors opened - the blue indicating lights above each door are energized; an instantaneous audible local alarm is energized; a time delay relay is energized and, after a preset time, it energizes a control room annunciator to identify that secondary containment access has been breached.

Closure of one of the doors returns the system condition to the same status as in paragraph B, above.

Equipment Access Doors:

All equipment access doors are kept locked. Each door is equipped with a door position switch to provide constant monitoring. The monitoring circuitry consists of a blue light indication on both sides of each door; instantaneous audible local alarm; and time delayed alarm in the main control room. The monitoring operation is the same as for the Personnel Access Doors described above.

Entrances to the reactor enclosure are provided with air locks for separation. Access doors between reactor enclosure ventilation zones are provided with airlocks.

The railroad access shaft, located between Unit 1 and Unit 2, is accessible through airlocks to the reactor enclosures and through the refueling floor ventilation duct-work and access hatch to the refueling floor. The railroad access door position is constantly monitored and alarmed (in the plant security system), under the requirements defined in the Physical Security Plan. Administrative procedures require that the access shaft outside door be closed and locked unless the access shaft is sealed closed from the refueling area and the ventilation duct-work is blocked whenever the refueling area secondary containment is required to be maintained.

Each door and section of the hatch is equipped with a position switch to provide constant monitoring. The monitoring circuitry consists of a blue light indication on both sides of the railroad access door and the top of the refueling floor access hatch; instantaneous audible local alarm; and time delayed alarm in the main control room. The monitoring operation is the same as for the Personnel Access Doors described above.

The boundaries of the secondary containment are shown in Figures 6.2-27 through 6.2-35.

The secondary containment design data are in Table 6.2-14.

6.2.3.2.2 Secondary Containment Isolation System

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

6.2.3.2.3 Containment Bypass Leakage

Upon receipt of a reactor enclosure isolation signal, the RERS and the SGTS are automatically activated and begin to process all air flow streams from the reactor enclosure ventilation system. Therefore, if a LOCA occurs, radioactivity that exfiltrates the steel-lined primary containment or piping systems containing radioactive fluids is collected and passed through the RERS and SGTS as described in Section 6.5.

The potential paths by which leakage from the primary containment can bypass the areas serviced by the SGTS have been evaluated. Table 6.2-15 identifies all primary containment penetrations, the termination region of all lines penetrating primary containment, and the bypass leakage barriers in each line. It has been determined that no potential bypass leakage paths exist except for the feedwater line following a feedwater line break inside containment and the TIP purge nitrogen supply line. No significant amounts of radioactivity will be released to the environment in either case, as discussed below.

Leakage through the containment isolation valves of the TIP purge line could be released from a break or equipment failure into the reactor enclosure, radwaste enclosure, or outdoors. Leakage into the reactor enclosure would not constitute a bypass leakage path because the reactor enclosure is serviced by the SGTS. Any leakage into the radwaste enclosure would not result in a significant release of radioactivity because of plateout, deposition, and transport delay within the TIP purge piping. The long lines within the reactor enclosure (>240 feet of 1 inch pipe and >220 feet of 6 inch pipe) and the presence of numerous valves in these lines (2 containment isolation valves, a ¼ inch check valve, a ¼ inch solenoid valve, a ¼ inch metering valve, a 1 inch check valve, and a 1 inch globe valve) provide a long and tortuous route between the primary containment and the radwaste enclosure. Any leakage through the reactor enclosure and radwaste enclosure piping would be into the liquid nitrogen facility (tanks, vaporizers, control valves, etc.) located adjacent to the radwaste enclosure. The liquid nitrogen facility maintains system pressure at 50 psig.

A water seal cannot be maintained in the broken feedwater line by the feedwater fill system (Section 6.2.3.2.3.2) for the case of a feedwater line break inside containment. For this case, containment leakage may travel past the broken feedwater line's containment isolation valves into the portion of the feedwater line located in the turbine enclosure. However, a water seal in this portion of the feedwater line would be maintained by water from the CST as discussed in Section 6.2.3.2.3.1.

When designating the termination region, if either the system line that penetrates primary containment or any branch lines connecting to it penetrate the reactor enclosure, the termination region is listed in Table 6.2-15 as outside reactor enclosure. The types of bypass leakage barriers employed by these lines are:

1. Redundant primary containment isolation valves

2. Closed piping system inside primary containment

3. A water seal maintained for 30 days following a LOCA

4. The line beyond the outboard primary containment isolation valve is vented to the reactor enclosure by use of a vent line located upstream of the two block valves.

5. A MSIV alternate drain pathway is provided.

6. The line contains a temporary spool piece that is removed during normal operation and replaced by blind flanges so that any leakage through the flange is into the reactor enclosure.

7. A closed seismic Category I piping system outside primary containment.

8. The line contains a spectacle flange with the blind side installed during normal operation. Any leakage through the flange will be into the reactor enclosure.

9. The line contains two spring loaded check valves and two manual stop valves.

Type 1 and Type 2 leakage barriers are considered to limit but not eliminate bypass leakage. Leakage barriers of Type 3 through Type 9 are considered to effectively eliminate any bypass leakage.

Leakage from those lines terminating in the reactor enclosure is collected during the LOCA because the reactor enclosure is restored to and maintained at subatmospheric pressure and all exhaust is processed by the RERS and SGTS during these modes (Section 6.5). Therefore, lines terminating within the reactor enclosure are not considered potential bypass leakage paths.

Lines penetrating primary containment are isolated following a LOCA as described in Section 6.2.4. All containment isolation valves and penetrations are designed to seismic Category I requirements.

The primary containment and penetration leakage is monitored during periodic tests as discussed in Section 6.2.6. Those penetrations for which credit is taken for water seals as a means of eliminating bypass leakage (Table 6.2-15) are preoperationally leak tested with water and Technical Specification leakage rates are given as water leak rates.

6.2.3.2.3.1 Water Seals

In each case where water seals are used to eliminate the potential of reactor enclosure bypass leakage, a 30 day water seal is assured because either a loop seal is present or the water for the seal is provided from a large reservoir. The water seals for all of these lines will be maintained at a pressure greater than the peak containment accident pressure. Each of the water seals listed in Table 6.2-15 is discussed below (some penetrations may be listed more than once due to the presence of multiple types of water seals).

a. Penetrations 9A, 9B, and 44:

The feedwater fill system (Section 6.2.3.2.3.2) is used to maintain a water seal in the lines downstream of these penetrations. The feedwater fill system cannot maintain a water seal in the feedwater lines (penetrations 9A and 9B) following a feedwater line break inside containment. However, for this case, a water seal will be maintained in the piping and equipment between the CST and the feedwater penetrations because:

1. The elevation of the primary containment penetrations is 287 ft.

2. The elevation of the minimum CST water level is 246 ft.

3. The low point of the makeup water line is at elevation 220 ft.

Therefore, the water seal will be maintained in that portion of the piping system below el 246'. This water seal will be able to withstand the containment pressure resulting from a feedwater line break as discussed below.

Immediately after the line break, when containment pressure will be at its peak, the feedwater line will still have a pressure greater than the pressure in primary containment. The feedwater will flash into steam at the break until the line pressure matches the containment pressure, thus preventing any containment atmosphere from entering the line during this period. In addition, there are several valves in the feedwater line between the primary containment and the water seal. A pressure decrease will occur across each valve, reducing the pressure that the water seal will encounter. Figures 6.2-3 and 6.2-7 show the primary containment pressure transient following a recirculation line break. These figures show that the maximum long-term pressure post-LOCA is approximately 17 psig. The difference in elevation between the lowest point of the water seal and the minimum CST water level indicates a head of 20 psig, which is greater than the pressure that the primary containment will exert on the water seal.

The piping and equipment that comprise this potential bypass leakage flow path is continuously inspected during normal operation when pressures are more than ten times greater than post-LOCA pressures. Even considering liquid leakage from the components in the water seal, the volume of water contained in the CST is sufficiently large to ensure that a water seal is maintained for at least 30 days.

b. Penetrations 204A, 204B, 207A, 207B, 208B, 210, 212, 215, 216, 217, 226A, 226B, 235, 236, 238, 239, and 240:

The lines associated with these penetrations all penetrate the wetwell above the suppression pool water level and terminate at least 4 feet below the minimum suppression pool water level. A 30 day water seal is therefore assured on the submerged portion of line.

c. Penetrations 13A, 13B, 16A, 16B, 17, 39A, 39B, 45A-D, 205A, and 205B:

Piping connected to these penetrations is normally full of water and will be kept full after a LOCA due to operation of the ECCS and/or safeguard piping fill system. The suppression pool is the water source for the ECCS and fill system, and therefore a 30 day water supply is assured.

d. Penetrations 203A-D, 206A-D, 209, 214, and 237:

The lines associated with these penetrations all penetrate the wetwell at least 11 feet below the minimum water level of the suppression pool, and therefore a 30 day water seal is assured.

e. Penetrations 231A and 231B:

The line to the containment isolation valves from the drywell floor drain sump is maintained full of water by an elevation difference between the sump and the valves. The line to the containment isolation valves from the drywell equipment drain tank is maintained full of water by an elevation difference between the tank and the valves.

f. Penetrations 10, 11, 12, 44, 228D, and 241:

Lines associated with these penetrations that pass through the secondary containment boundary and take credit for water seals are provided with loop seals inside secondary containment, which eliminates the possibility of bypass leakage. The HPCI and RCIC steam supply line connections to Auxiliary Steam contain spectacle flanges. After testing, the blind portion of the spectacle flange shall be installed. These spectacle flanges are shown on drawing M-55 (lines 4" GBD-137 and GBD-237) and on drawing M-50 (lines 3" GBD-136 and GBD-236).

g. Penetration 14:

The minimum piping height inside primary containment of the RWCU supply line that branches off the recirculation loop is at el 267'. The primary containment penetration is at el 297' and the RPV penetration is at el 280'. This elevation difference ensures that a water seal is maintained in the line from the RPV to the containment isolation valves. The RWCU supply branch line that connects to the bottom of the vessel is normally full of water, and the water will be maintained in this line because it connects directly to, and below, the vessel.

h. Penetrations 37A-D and 38A-D:

The CRD insert and withdraw lines are normally full of water. A water seal will be maintained in these lines after a LOCA due to the elevation difference between the

containment penetrations (el 265') and the connections to the control rod drives (el 215').

i. Penetrations 23, 24, 53, 54, 55, and 56:

Both the drywell chilled water system and the RECW system have a system vent in the refueling area. A 30 day water seal is provided between the system vent and the containment penetrations. These systems are normally full of water and are inspected during normal operation, when system pressure is greater than post-LOCA containment pressure, to ensure that leakage is minimized. These systems have an interconnecting line between them which decreases the possibility of depleting their water seals. The systems each contain a head tank with a water-retaining boundary qualified to LOCA (hydrodynamic) loads. These tanks increase the system water inventory and maintain the head of water in the system piping greater than the maximum containment pressure following a LOCA.

j. Penetration 61:

The recirculation pump seal purge lines are vented to secondary containment by use of vent lines located before two block valves and the secondary containment (drawings M-43 and M-46). The normally open block valves (HV127 and HV128) receive an automatic containment isolation signal to close, which is shown as Reference 18 on drawing M-46. It is not necessary for the containment isolation signal to also automatically open the (normally closed) vent valves. The seal lines are normally filled with water, which will spill into secondary containment when the vent valves open. To preclude the possibility of this happening in the event of a false LOCA, the vent valves will be manually actuated to open when the operator has verified that isolation and venting of these lines is required. The water in the lines will provide a temporary seal to prevent bypass leakage until the vent valves are opened.

6.2.3.2.3.2 Feedwater Fill System

The feedwater fill system prevents the release of fission products through the feedwater containment isolation valves after a LOCA by providing a water seal downstream of the valves.

6.2.3.2.3.2.1 Safety Design Bases

The feedwater fill system is designed with sufficient capacity and capability to prevent leakage through the feedwater lines under the conditions associated with the entire spectrum of LOCAs except for a feedwater line break inside containment.

The feedwater fill system conforms to seismic Category I requirements. Quality group classifications are shown in Table 3.2-1, Item XI.A. The system meets the intent of Regulatory Guide 1.96, where applicable.

The feedwater fill system is capable of performing its safety function considering the effects resulting from a LOCA, including missiles that may result from equipment failures, dynamic effects associated with pipe whip and jet forces, and normal operating and accident-caused local environmental conditions consistent with the design basis event. Furthermore, any portion of the feedwater fill system that is quality Group A and is located outside the primary containment

structure is protected from missiles, pipe whip, and jet force effects originating outside the containment so that containment integrity is maintained.

The feedwater fill system is capable of performing its safety function following a LOCA and an assumed single active failure.

The feedwater fill system is designed so that effects resulting from a single active component failure do not affect the integrity or operability of the feedwater lines or the feedwater containment isolation valves.

The feedwater fill system is capable of performing its safety function following a LOOP coincident with a postulated design basis LOCA.

The feedwater fill system is designed to prevent leakage from the feedwater lines consistent with maintaining containment integrity for up to 30 days.

The feedwater fill system is manually actuated and is not required to be actuated sooner than 30 minutes after a LOCA.

The feedwater fill system, including instrumentation and circuits necessary for the functioning of the system, is designed in accordance with standards applicable to an ESF.

The plant is designed to permit testing of the operability of the feedwater fill system controls and actuating devices during power operation, to the extent practicable, and to permit testing of the complete functioning of the system during plant shutdowns.

6.2.3.2.3.2.2 System Description

The feedwater fill system is a subsystem of the safeguard piping fill system. The safeguard piping fill pumps provide suppression pool water as the water seal source for the feedwater lines (Section 6.3.2.2.6 and drawing M-52). The feedwater fill system consists of two fill trains, one from each fill pump. Each train is routed to both feedwater lines (drawing M-41).

Following a LOCA, the feedwater fill system is manually initiated from the control room. A water seal is provided by the fill system in both feedwater lines for all line breaks other than a feedwater line break inside containment. For this case, the feedwater fill system can be isolated from the broken feedwater line so that a water seal can be maintained in the intact feedwater line. A water seal inside the broken feedwater line cannot be maintained by the fill system for the case of a feedwater line break inside containment because the water escapes out the broken pipe into primary containment.

The sealing water to the valves eventually fills the feedwater lines up to the reactor vessel, and the water returns to the suppression pool through the LOCA break. Because the source of sealing water is the suppression pool, a 30 day water supply is assured. Operation of the feedwater fill system will not affect the function of the suppression pool because the seal water is eventually returned to the pool when the drywell is flooded back through the downcomers.

6.2.3.2.3.2.3 Safety Evaluation

The feedwater fill system is designed to prevent the release of radioactivity through the feedwater line isolation valves by providing a continuous flow of water through the feedwater lines following a

LOOP coincident with the postulated design basis LOCA. The two redundant fill trains are physically separated, except where the lines are interconnected, to minimize the exposure to missiles and to the effects of pipe whip or jet impingement from high energy line breaks.

The feedwater fill system is seismic Category I and is capable of performing its intended function following an active component failure. Each fill train is powered from a different division of the Class 1E power supply. Double series isolation valves are provided to ensure that no single active failure will affect the integrity of the feedwater lines.

Feedwater line pressure is indicated in the control room so that the operator can determine if there has been a feedwater line break inside containment. If so, the operator can isolate the system from the broken line and still provide fill system water to the intact line.

6.2.3.2.3.2.4 Instrumentation and Controls

The instrumentation necessary for control and status indication of the feedwater fill system is classified as essential and, as such, is designed and qualified in accordance with applicable IEEE standards to function under seismic Category I and LOCA environmental loading conditions appropriate to its installation, with the control circuits designed to satisfy the mechanical and electrical separation criteria. Section 7.6 gives a control and instrumentation description.

6.2.3.2.3.2.5 Inspection and Testing

Preoperational tests for the safeguard piping fill system are discussed in Chapter 14. During plant operation, valves, piping, instrumentation, electrical circuits, and other components outside the steam tunnel can be inspected visually at any time. Complete system functional testing or isolation valve testing from fully closed-to-open and the return open-to-closed position is performed during reactor shutdown.

6.2.3.3 Design Evaluation

The design evaluation of the secondary containment ventilation systems are given in Sections 6.5.1 and 9.4.2. The high energy lines within the secondary containment are identified and pipe ruptures analyzed in Section 3.6. The leak-off system on the nitrogen purge lines has two outboard block valves in series downstream of the leak-off vent valves and the secondary containment boundary. The liquid nitrogen facility is located outside of secondary containment. Therefore, a failure of one of the outboard block valves does not prevent a negative pressure from being maintained in the secondary containment structure or result in leakage from the primary containment across the inboard valve to the environment.

6.2.3.4 Tests and Inspections

The program for initial performance testing is described in Chapter 14. The program for periodic functional testing of the secondary containment structures including SGTS drawdown time and the secondary containment isolation system and system components is described in Chapter 16. The leak rate testing program and provisions are discussed in Section 6.5.1, as part of the SGTS tests.

6.2.3.5 Instrumentation Requirements

The control systems to be employed for the actuation of the reactor enclosure ESF air handling systems are described in Section 7.3.

The control and monitoring instrumentation for the above systems is discussed in Sections 6.5.1 and 9.4.2. Design details and instrumentation logic are discussed in Section 7.3.

6.2.4 CONTAINMENT ISOLATION SYSTEM

The containment isolation system is designed to prevent or limit the release of radioactive materials that may result from postulated accidents. This is accomplished by providing isolation barriers in all fluid lines that penetrate primary containment.

6.2.4.1 Design Bases

a. The containment isolation system is designed to allow the normal or emergency passage of fluids through the containment boundary while preserving the ability of the boundary to prevent or limit the escape of radioactive materials that can result from postulated accidents.

b. The containment isolation system is designed to either automatically isolate fluid penetrations or provide the capability for remote manual isolation from the control room.

c. The arrangement of containment isolation valves for fluid systems that penetrate the primary containment conforms to GDC 54, 55, 56, and 57 to the greatest extent practicable.

d. Fluid instrument lines that penetrate primary containment conform to the isolation criteria of Regulatory Guide 1.11 to the greatest extent practicable.

e. Containment isolation provisions are designed to withstand the most severe natural phenomenon or site-related event (e.g., earthquake, tornado, wind, flood, or transportation accident) without impairing their functions.

f. The containment isolation system is designed with provisions for periodic operability and leak rate testing.

g. Valve closure times are selected to limit the release of containment atmosphere to the environs, to mitigate offsite radiological consequences, and to ensure that ECCS effectiveness is not degraded.

h. Design provisions are made to detect possible leakage from lines provided with remote manually controlled isolation valves.

i. Isolation valves, actuators, and controls are protected against loss of functional capability from missiles and accident environments for which they are designed.

j. Redundancy and physical separation are provided in the electrical and mechanical design to ensure that no single failure in the containment isolation system can prevent the system from performing its intended function (except as described in this section).

k. The design of the control systems for automatic containment isolation valves is such that resetting the isolation signal does not result in the automatic reopening of containment isolation valves (except as described in this section).

6.2.4.2 System Design

Table 6.2-17 lists the fluid system and instrument line containment penetrations and presents design information about each. Accompanying this table is Figure 6.2-36, which consists of diagrams for the various isolation valve arrangements. Cross references are provided between the diagrams and the table.

The plant protection signals and instrumentation that initiates containment isolation are discussed in Section 7.3.1.1.2.

Evaluation of the containment isolation system with respect to the following areas is discussed in separate sections as indicated:

a.	Code class and seismic design	Section 3.2
b.	Missile protection	Section 3.5
c.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
d.	Environmental design	Section 3.11

Debris transported to the suppression pool by the emergency core cooling water is prevented from entering the ECCS suction lines by suction strainers. The suction strainers are described in Section 6.2.2.

Assurance of the operability of valves and valve operators in the containment atmosphere under normal plant operating conditions and postulated accident conditions is discussed in Section 3.9.3.

Provisions for detecting leakage from systems connected to the RCPB which are provided with manual isolation valves are discussed in Section 5.2.5.

The design provisions for testing the operability of the isolation valves and the leakage rate of the containment isolation barriers are discussed in Section 6.2.6.

An alternate drain pathway is provided for the MSIVs, and is discussed in Section 6.7. A seismic Category I fill system provides a water seal for the feedwater lines, as discussed in Section 6.2.3.2.3.

Containment isolation valve closure times are selected to ensure rapid isolation of the containment following postulated accidents. The isolation valves, in lines that provide an open path from the containment to the environs, have closure times that limit the release of containment radioactivity to the environs to below 10CFR50.67 dose limits, mitigate the offsite radiological consequences, and ensure that ECCS effectiveness is not degraded. These valve closure times are identified with a double asterisk in Table 6.2-17. The isolation valves for lines in which HELBs can occur have

closure times that limit the resultant pressure and temperature transients as well as the radiological consequences. These valve closure times are identified with a single asterisk in Table 6.2-17.

All of the isolation valve closure times listed in Table 6.2-17 are the actual closure times that the isolation valves were purchased with, which in all cases are equal to or lower than the closure times necessary to meet the aforementioned design requirements. The given valve closure times are the maximum time it takes for a valve to move to its fully closed position after power has reached the operator assembly. Those closure times which are required to be met to satisfy isolation valve closure time design requirements are identified by a single or double asterisk in Table 6.2-17.

The essential/nonessential classification of containment isolation valves, as listed in Table 6.2-17, was based on the following: those systems identified as essential are regarded as indispensable or are backup systems in the event of an accident; nonessential systems have been judged to not be required after an accident. The classification of essential and nonessential systems is given in Table 6.2-27.

Isolation valves are designed to be operable under environmental conditions such as maximum differential pressures, seismic occurrences, steam atmosphere, high temperature, and high humidity. The normal and accident environmental conditions are described in Section 3.11.

Refer to Table 6.2-17 for isolation valve power supplies.

Motor-operated isolation valves remain in their last position upon failure of electrical power to the motor operator. Air operated containment isolation valves are spring-loaded to close upon loss of air or electrical power.

The design of the isolation valve system gives consideration to the possible adverse effects of sudden isolation valve closure when the plant systems are functioning under normal operation.

Reopening of the containment isolation valves requires deliberate operator action. The HPCI and RCIC steam line isolation valves are exceptions as discussed in Section 7.1.2.11. Control systems for the automatic containment isolation valves are discussed in Section 7.3.1.1.2.

The LGS containment purge valves have been designed to function if a LOCA should occur while the purge valves were open. The valve manufacturer has completed an extensive program of tests and analyses to demonstrate the operability of the valves in accordance with all published NRC guidelines and criteria. The following is a brief summary of the factors addressed in the valve operability qualification report (Reference 6.2-8):

a. Valves are supplied in accordance with ASME Section III, Class 2 requirements

b. Finite-element analyses have been used to determine valve component stress levels for limiting combinations of loads

c. The impact of dynamic loadings is addressed by analysis and static load testing

d. All valves are located outside containment, thus eliminating concern over the effects of containment pressure on pneumatic operator performance

e. Air operators are equipped with springs to facilitate valve closure; accumulators or other pneumatic systems are not used for valve closure or sealing

f. Valve dynamic torque coefficients have been determined by reduced-scale and full-scale testing

g. The effects of installation geometry and arrangement have been fully considered

h. Containment pressure has been conservatively assumed to be constant at its maximum pressure for all valve angles

i. Back pressure caused by flow through downstream piping has been conservatively neglected

j. Elastomeric materials are not used for valve seating surfaces

k. Valve operators and pilot solenoids have been qualified to IEEE 323 (1974) and NUREG-0588 Category I requirements

l. Motor operator performance has been demonstrated at minimum available voltage levels

m. Motor operators are equipped with hand wheels which automatically disengage upon electric activation

6.2.4.3 Design Evaluation

The main objective of the containment isolation system is to provide protection by limiting release to the environment of radioactive materials. This is accomplished by isolation of system lines penetrating the primary containment. Redundancy is provided so that the active failure of any single valve or component does not prevent containment isolation.

The arrangements of isolation valves are described in Table 6.2-17 and Figure 6.2-36. In general, isolation valves have redundancy in the mode of actuation as indicated in Table 6.2-17. A program of testing, described in Section 6.2.4.4, is maintained to ensure valve operability and leak-tightness.

The design specifications require each isolation valve to be operable under the most severe environmental conditions that it might experience. Protection from potential missiles is discussed in Section 3.5.

Provisions for administrative control of the proper position of all nonpowered isolation valves, including valves in test, vent, drain, and similar types of branch lines that serve as containment isolation barriers, are maintained. The test taps, vents, drains, and similar types of branch lines that constitute containment isolation barriers are equipped with manually closed isolation valves.

Administrative controls will ensure that the valves are locked closed after use.

All power-operated isolation valves have position indicators in the control room. Discussion of instrumentation and controls for the isolation valves is included in Chapter 7.

6.2.4.3.1 Evaluation Against General Design Criteria

6.2.4.3.1.1 Evaluation Against GDC 54

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

6.2.4.3.1.2 Evaluation Against GDC 55

GDC 55 requires that lines which penetrate the primary containment and form a part of the RCPB must have two isolation valves; one inside the containment and one outside, unless it can be demonstrated that the containment isolation provisions for a specific class of lines are acceptable on some other basis.

The RCPB, as defined in 10CFR50, Section 50.2 (v), consists of the RPV, pressure-retaining appurtenances attached to the vessel, and valves and pipes that extend from the RPV up to and including the outermost isolation valve.

6.2.4.3.1.2.1 Influent Lines

All influent lines that penetrate the primary containment and connect directly to the RCPB are equipped with at least two isolation valves, one inside the drywell, and the other outside the drywell and as close to the external side of the containment as practicable.

6.2.4.3.1.2.1.1 Feedwater Line

The feedwater lines are part of the RCPB as they penetrate the drywell to connect with the RPV. Each of the two feedwater penetrations is provided with a series arrangement of three isolation valves:

a. A check valve is provided inside the drywell as close to the containment wall as practicable. For a worst case break of a feedwater line inside containment, it would be impossible to ensure the operability of the inboard check valve due to pipe whip forces.

b. A spring assisted check valve is provided outside the drywell as close to the containment wall as practicable. The spring forces the valve flapper in the closed direction, thus providing added assurance of valve seating in the event of low pressure in the supply piping. The spring will not prevent flow in the downstream (toward the vessel) direction but does create some flow restriction. An air operator is provided with the check valve assembly. This air operator is normally pressurized, thus compressing the spring and reducing the flow restriction.

c. A third check valve is provided in the feedwater line outboard of the above described spring assisted check valve. The function of these valves is to:

    1. Prevent HPCI, RCIC, and RWCU water from flowing upstream in the feedwater line, thus ensuring flow into the reactor vessel.

    2. Provide isolation in the event of a feedwater line break upstream of this valve.

This third check valve includes a motor operator to seal the disc closed for long-term leakage control.

Additional isolation valves are provided on each of the lines connecting to the feedwater lines inboard of the check valve :

1. MOVs are provided on the HPCI, RCIC, and long path recirculation lines.

2. A spring assisted check valve is provided on the RWCU supply line. This valve is of a design similar to the outboard spring assisted feedwater check valves described above. This RWCU check valve is spring assisted to seal the disc closed for long-term leakage control.

In the Limerick SER Section 6.2.4, licensee committed to administrative procedures that will require isolation of the main feedwater, RWCU, RCIC, and HPCI system lines following an accident if these systems are not providing reactor coolant makeup. The NRC included this commitment in the SER to satisfy SRP 6.2.4.6.b criteria. Instead of using a leakage detection system in conjunction with a remote manual containment isolation valve, to satisfy SRP criteria, these valves would be procedurally controlled and remotely closed from the control room to provide long term leakage protection after a postulated LOCA to satisfy SRP criteria.

Plant procedures will require remote manual closure of the remote manual containment isolation valves in the main feedwater and RWCU systems, if reactor coolant makeup is no longer required. The containment isolation valves in the RCIC and HPCI system automatically reposition closed, if reactor coolant makeup is no longer required from these systems. Therefore, plant procedures will not be required to remote manually close the RCIC and HPCI containment isolation valves.

Limerick SER Section 6.2.4 also states that a remote-manual motor-operated valve upstream of the air-operated check valve on the RWCU branch line that can also be utilized to isolate this line. This non-safety related remote-manual motor-operated valve upstream of the air-operated check valve is not capable of, or required to support a safety related long-term leakage control function as described in the SER.

6.2.4.3.1.2.1.2 Core Spray (CS) Loop B

The CS loop B line penetrates the drywell to inject directly into the RPV. Isolation is provided by two valves in the CS line, a pneumatic testable check valve inside the containment, and a spring assisted check valve outside the containment, with positions of both indicated in the main control room. The core spray loop B line is also provided with a normally closed pneumatic operated globe valve which bypasses the inboard isolation valve for equalization during testing.

Although not a containment isolation valve, a MOV is provided outboard of the spring assisted check valve to provide isolation of this flow path for long-term leakage control.

One branch of the HPCI line connects to the CS loop B upstream of the outboard spring assisted check valve. Although not a containment isolation valve, the HPCI line also contains a MOV outboard of the spring assisted check valve to provide isolation of this flow path for long-term leakage control.

6.2.4.3.1.2.1.3 LPCI and CS Loop A

The LPCI lines and CS loop A line are provided with remote manually controlled gate valves outside and pneumatic testable check valves inside containment. Both types of valves are

normally closed with the gate valves receiving an automatic signal to open at the appropriate time. The check valves are located as close as practicable to the RPV. The normally closed check valves limit
containment pressurization if there is a pipe rupture between the check valve and containment wall. The core spray loop A line and the LPCI lines are also each provided with a normally closed pneumatic operated globe valve which bypasses the inboard isolation valve for testing purposes.

6.2.4.3.1.2.1.4 Deleted

6.2.4.3.1.2.1.5 Recirculation Pump Seal Purge Line

The recirculation pump seal purge line extends from the CRD supply line outside primary containment, penetrates primary containment through an excess flow check valve outside and a check valve inside containment, and connects to the recirculation pump seal housing. The 1 inch recirculation pump seal purge line is Quality Group Classification A from the pump up to and including the excess flow check valve outside containment. Should this line be postulated to fail and either one of the check valves is assumed to fail open, the flow rate through a broken line outside containment is calculated to be substantially less than that permitted for a broken instrument line. Therefore, the two check valves in series provide sufficient isolation capability for the postulated failure of this line.

6.2.4.3.1.2.1.6 Standby Liquid Control System Lines

The SLCS line penetrates the drywell and connects to the Core Spray loop B line. In addition to a simple check valve inside the drywell, a globe stop-check valve is located outside the drywell. Since the SLCS line is a normally closed, nonflowing line, rupture of this line is of extremely remote probability. The globe stop check includes a motor operator to seal the valve closed for long-term leakage control.

6.2.4.3.1.2.1.7 RWCU System

The RWCU pumps, heat exchangers, and filter/demineralizers are located outside the drywell. The return line branches into three separate lines outside the drywell. One line connects to the RCIC line that connects to the B feedwater line penetrating the drywell and injecting directly into the RPV. The second branch connects directly to the A feedwater line that penetrates the drywell and injects directly into the RPV.

Isolation of both these lines is provided by the feedwater system check valves inside and outside the containment and a spring assisted check valve in the connecting RWCU return line.

Following a LOCA, it is desirable to maintain reactor coolant makeup. For this reason, the above remote manual containment isolation valves are not provided with automatic isolation signals. However, plant procedures will require remote manual closure of the remote manual containment isolation valves, if reactor coolant makeup is no longer required.

The third line penetrates the drywell and then connects to the A feedwater line that injects directly into the RPV. This line is only used during outages. Isolation is provided by one locked closed globe valve inside containment and one locked closed globe valve outside containment. A 3/4 inch relief valve is provided outside containment between the two isolation valves for thermal relief.

6.2.4.3.1.2.1.8 RCIC Line

The RCIC line connects to the B feedwater line outside containment that penetrates the drywell to inject directly into the RPV. The feedwater line has a check valve both inside and outside the drywell. In addition to these two isolation valves, a motor- operated gate valve is located in the RCIC line that is normally closed and receives an automatic signal to open. Following a LOCA, plant procedures will require remote manual closure of this isolation valve unless RCIC is providing reactor coolant makeup.

6.2.4.3.1.2.1.9 RHR Shutdown Cooling Return

Each RHR shutdown cooling return line penetrates primary containment and discharges into a recirculation pump discharge line that injects directly into the RPV. Isolation is provided by an automatically actuated motor-operated globe valve outside containment and a pneumatic testable check valve and a spring-assist check valve inside containment. A normally closed pneumatic operated globe valve is provided which bypasses the inboard isolation testable check valve for equalization during testing. To increase the reliability of RHR shutdown cooling mode during refueling outages, the automatic isolation function of the RHR shutdown cooling mode return motor-operated valves is typically bypassed provided that automatic isolation is not required by the Technical Specifications or Technical Requirements Manual and the reactor cavity is flooded up. Manual isolation capability is retained.

6.2.4.3.1.2.2 Effluent Lines

Effluent lines that form part of the RCPB and penetrate containment are equipped with at least two isolation valves; one inside the drywell and the other outside, located as close to the containment as practicable or justified on an alternate basis.

6.2.4.3.1.2.2.1 Main Steam, RCIC and HPCI Steam Lines, and RHR Shutdown Cooling Supply Line

The main steam lines extend from the RPV to the main turbine and condenser system, and penetrate the primary containment. For these lines, isolation is provided by automatically actuated globe valves, one inside the containment and one just outside the containment. The MSIVs are spring-loaded, pneumatic, piston- operated globe valves designed to fail closed on loss of pneumatic pressure or loss of power to the solenoid-operated pilot valves. Each valve has two independent pilot valves supplied from independent power sources. Each MSIV has an accumulator to assist in its closure upon loss of normal supply. The springs and accumulator provide a local stored energy source dedicated to closure of an MSIV under all conditions which requires MSIV closure.

The main steam line drain connects to the main steam lines inside containment and extends through containment to the condenser. This line is provided with motor-operated gate valves inside and outside containment that receive an automatic isolation signal to close when the reactor water level drops below Level 1.

The RCIC turbine steam supply line from main steam line B is provided with two motor-operated, normally open globe valves, one inside and one outside the containment. These valves are closed on receipt of an RCIC isolation signal. The HPCI system turbine steam supply line from main steam line C is provided with motor-operated, normally open globe valves, one inside and one outside containment. These valves are closed on receipt of a HPCI isolation signal.

The RCIC and HPCI steam lines are each also provided with a normally closed motor-operated globe valve that bypasses the outboard isolation valve for steam supply line warmup purposes

only. The valve in the RCIC steam line is closed upon receipt of an RCIC isolation signal, and the HPCI steam line valve is closed upon receipt of an HPCI isolation signal. The isolation signals are considered adequate because there is no consequence if the valves open or leak while the system is in operation and appropriate isolation signals are provided to secure the line when system isolation is required.

The RHR shutdown cooling supply line is provided with motor- operated gate valves, one inside and one outside containment, that receive an automatic isolation signal when isolation is required. To increase the reliability of RHR shutdown cooling mode during refueling outages, the automatic isolation function of the RHR shutdown cooling mode supply motor-operated valves is typically bypassed provided that automatic isolation is not required by the Technical Specifications or Technical Requirements Manual and the reactor cavity is flooded up. Manual isolation capability is retained.

6.2.4.3.1.2.2.2 Main Steam and Recirculation System Sample Lines

Sample lines from the main steam and recirculation lines penetrate the primary containment. These lines are provided with air operated globe valves, one inside and one outside containment, that receive an automatic isolation signal if there is an accident, or fail closed on loss of air or electrical power.

6.2.4.3.1.2.3 CRD Lines

The CRD system has multiple lines, the insert and withdraw lines, that penetrate primary containment.

The classification of these lines is Quality Group B, and they are designed in accordance with ASME Section III, Class 2. The basis on which the CRD insert and withdraw lines are designed is commensurate with the safety importance of maintaining the pressure integrity of these lines.

The CRD insert and withdrawal lines are not provided with automatic containment isolation valves in order to maximize the reliability of the scram function. A ball check valve located in the CRD flange housing automatically seals the insert line in the event of a line break. The insert and withdrawal lines terminate in HCUs which contain multiple valves (manual, solenoid, air operated, and check valves) to control CRD movement, and limit leakage. The isolation function is provided by two redundant simple check valves outboard of the HCUs on each main water header (charging, cooling, drive and exhaust). All automatic valves in the HCUs are normally closed and are open only during rod movement. Because the scram valves in the HCU are normally open after a scram, the scram discharge volume is provided with redundant automatic vent and drain valves.

6.2.4.3.1.2.4 Conclusion on GDC 55

In order to ensure protection against the consequences of accidents involving the release of radioactive material, pipes that form the RCPB are shown to provide adequate isolation capabilities on a case-by-case basis. In all cases, a minimum of two barriers are shown to limit the release of radioactive materials.

The pressure-retaining components that comprise the RCPB are designed to meet other appropriate requirements that limit the probability or consequences of an accidental pipe rupture. The quality requirements for these components ensure that they are designed, fabricated, and tested to the highest quality standards of all reactor plant components. The classification of

components that comprise the RCPB are designed in accordance with ASME Section III, Class 1, with the exception of the CRD insert and withdrawal lines as discussed in Section 6.2.4.3.1.2.3 above.

It is therefore concluded that the design of piping systems that comprise the RCPB and penetrate containment either meet the explicit requirements of, or are acceptable alternatives to the explicit requirements of GDC 55.

6.2.4.3.1.3 Evaluation Against GDC 56

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

6.2.4.3.1.3.1 Influent and Effluent Lines to Suppression Pool

Typically, lines which connect directly to the suppression pool are provided with a single remote manual or automatic isolation valve. These valves are attached to lines which are an extension of the containment and are enclosed in a pump-room adjacent to the containment which has provisions for environmental control of any fluid leakage. The lines to the suppression pool are always submerged so no containment atmosphere can impinge upon the valves.

The systems which the lines from the suppression pool connect to outside containment are closed systems meeting the appropriate requirements of closed systems, except for the suppression pool cleanup line and the RCIC vacuum pump discharge line. Both of these lines have redundant containment isolation valves.

The valves provide a barrier outside containment to prevent loss of suppression pool water should a leak develop downstream of the valves in the lines from the suppression pool. (The valves are either remotely closed from the control room or automatically closed to accomplish this. Leak detection is provided for the lines outside containment so that the operator can determine which valve is to be closed.) Should a leak develop outside containment, the fluid will be contained within compartments that have provisions for the environmental control of any fluid leakage. The configuration of the connection of the lines to the suppression pool assures that the connections are always submerged, and prevents escape of containment atmosphere.

6.2.4.3.1.3.1.1 CS, HPCI, and RHR Test Lines and Minimum Flow Bypass Lines

The CS, HPCI, and RHR test and minimum flow bypass lines have isolation capabilities commensurate with the importance to safety of isolating these lines.

The RHR pump test lines connect to the associated minimum flow bypass lines outside primary containment and penetrate containment through normally open, remote manually controlled gate valves located directly on the containment. This reduces the number of penetrations through the primary containment, thus minimizing the potential pathways for radioactive material release.

The CS pump test lines have a normally closed, motor-operated globe valve located directly on the containment that receives an automatic isolation signal if there is an accident. The CS minimum flow bypass lines have a normally open motor-operated globe valve that receives an automatic isolation signal when adequate flow is established in the pump discharge lines.

The HPCI pump test line has a normally closed motor-operated gate valve located directly on the containment that receives an automatic isolation signal if there is an accident. The minimum flow bypass line has a normally closed motor-operated globe valve located directly on the containment that receives an automatic isolation signal when adequate flow is established in the pump discharge lines.

The CS, HPCI and RHR pump test and minimum flow bypass lines discharge below the surface of the suppression pool. Thus the lines are not directly open to the containment atmosphere.

6.2.4.3.1.3.1.2 RCIC Turbine Exhaust, Vacuum Pump Discharge, and RCIC Pump Minimum Flow Bypass Lines

The lines that penetrate the containment and discharge to the suppression pool are equipped with a remote manually actuated valve. The RCIC turbine exhaust isolation valve is a normally open motor-operated gate valve. The vacuum pump discharge isolation valve is a normally open globe stop-check valve. The RCIC pump minimum flow bypass isolation valve is a normally closed motor-operated globe valve. In addition, there is a check valve upstream of each valve that provides positive actuation for immediate isolation if there is a break upstream of this valve. The gate valve in the RCIC turbine exhaust is designed to be key-locked open in the control room and interlocked to preclude opening of the inlet steam valve to the turbine when the turbine exhaust valve is not in a fully open position. The RCIC vacuum pump discharge line is also normally key-locked open but has no requirement for interlocking with the steam inlet to the turbine. The RCIC vacuum pump discharge line is provided with a stop-check valve at the containment to automatically prevent flow out of the containment. This valve functions as both a check valve and a remote manually actuated globe valve. A remote manually actuated motor operator ensures the long-term positive closure of the stop-check valve. This arrangement ensures that the essential RCIC pump-turbine will be ready to operate in the event of a reactor vessel isolation occurrence accompanied by loss of feedwater flow. The RCIC pump minimum flow bypass line is isolated by a normally closed remote manually actuated valve that is automatically isolated when adequate flow is obtained in the pump discharge line, with a check valve installed upstream. These lines discharge below the surface of the suppression pool. Thus, the lines are not directly open to containment atmosphere.

6.2.4.3.1.3.1.3 RHR Heat Exchanger Vent Lines and Relief Valve Discharge Lines

The Unit 2 RHR heat exchanger vent lines discharge to the suppression chamber via relief valve discharge lines and are provided with two normally closed, remotely controlled motor-operated globe valves. The inboard valves receive an automatic isolation signal if there is a LOCA. The Unit 1 and Unit 2 relief valve discharge lines are isolated by the relief valves themselves in a fashion similar to a check valve, and the relief setting on these valves is more than 1.5 times the containment design pressure. The lines discharge below the surface of the suppression pool. Thus, the lines are not directly open to containment atmosphere.

6.2.4.3.1.3.1.4 HPCI Turbine Exhaust Line

The HPCI turbine exhaust line that penetrates the primary containment and discharges to the suppression pool is equipped with a remote manually operated gate valve located directly on the containment. In addition, there is a stop-check upstream of the gate valve that provides positive actuation for immediate isolation if there is a break upstream of this valve. The gate valve is designed to be key-locked open and interlocked to preclude opening of the inlet steam valve to the

turbine while the turbine exhaust valve is not fully open. This line discharges below the surface of the suppression pool. Thus, the line is not directly open to containment atmosphere.

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

The RHR, RCIC, CS, and HPCI suction lines contain motor-operated, remote manually actuated gate valves that provide assurance of isolating these lines if there is a break. These valves also provide long-term leakage control. In addition, the suction piping from the suppression chamber is considered an extension of containment since it must be available for long-term usage following a design basis LOCA, and as such, is designed to the same quality standards as the containment. System reliability is greater with only one isolation valve in the line because the ECCS pumps must have the capability to take suction from the suppression pool in order to mitigate the consequences of an accident. The RHR suction lines are also provided with a relief valve that discharges back into the suppression pool through the suction line penetration. The relief valve discharge lines are isolated by the relief valves themselves in a fashion similar to a check valve.

6.2.4.3.1.3.1.6 Suppression Pool Cleanup Line

The suppression pool cleanup line is isolated by two normally closed motor-operated gate valves that close on receipt of a containment isolation signal and a relief valve (PSV-52-127) whose setting is more than 1.5 times the containment design pressure.

6.2.4.3.1.3.2 Influent and Effluent Lines from Drywell and Suppression Pool Free Volume

6.2.4.3.1.3.2.1 Containment Atmosphere Sampling Lines

The sampling system lines that penetrate the containment and connect to the drywell and suppression chamber air volume are equipped with two normally open solenoid-operated isolation valves in series, located outside and as close to the containment as possible. These valves ensure isolation of these lines if there is a break; they also provide long-term leakage control. In addition, the piping is considered an extension of the containment boundary since it must be available for long-term usage following a design basis LOCA, and, as such, is designed to the same quality standards as the primary containment. The following containment atmosphere sampling isolation valves have ganged controls for reopening:

a. Inboard drywell sample and return isolation valves SV-132, SV-134, and SV-150 are ganged on HS-132

b. Inboard suppression pool sample and return valves SV-183 and SV-191 are ganged on HS-183

c. Outboard drywell sample and return isolation valves SV-141, SV-142, SV-143, SV-144, SV-145, and SV-159 are ganged on HS-153

d. Outboard suppression pool sample and return isolation valves SV-184, SV-185, SV-186, SV-190, and SV-195 are ganged on HS-187.

6.2.4.3.1.3.2.2 Drywell Equipment and Floor Drain Lines

The drywell equipment and floor drain lines are each provided with two air operated spring-closed valves located outside the primary containment. One of these valves is normally open and one

normally closed. The inner valve (normally open) is located directly on the containment. Both valves are automatically closed upon receipt of a containment isolation signal.

6.2.4.3.1.3.2.3 Containment Purge and Hydrogen Recombiner Lines

The high volume purge lines for the drywell and suppression chamber are each provided with two isolation valves located outside the primary containment. The inboard valve in each line is a normally closed, air operated butterfly valve located as close as practical to the primary containment penetration. The outboard valve in each line is a normally closed, motor-operated butterfly valve. A nonsafety-related north stack effluent high radiation isolation signal is also provided for the containment purge valves (HV-104, 109, 114, 115, 112, 121, 124, 123, 131, 135, 147). A description of the type and the arrangement of containment isolation valves used in the low volume purge exhaust lines is provided in Section 9.4.5.1.2. Each of these valves receives automatic isolation signals.

The hydrogen recombiner lines connect to the high volume purge lines between the containment penetration and the inboard isolation valve. Each of the recombiner lines is provided with two normally closed MOVs that can be manually actuated from the control room. These isolation valves each receive automatic isolation signals. For operation of the recombiners after a LOCA, the isolation signals to these valves are overridden by using key-locked bypass switches. All four isolation valves on each recombiner train are powered from the same channel of electrical power in order to minimize the impact on system reliability.

The ESF recombiner system (Section 6.2.5) is designed as a closed system outside containment in addition to the isolation valves described above. The containment isolation provisions for the recombiner lines meet all of the relevant design criteria in Regulatory Guide 1.141, ANSI N-271, and SRP 6.2.4, as described below:

a. The closed system does not communicate with either the secondary containment atmosphere or the environment.

b. The closed system has been designed, fabricated, installed, and stamped in accordance with ASME Section III, Class 2 requirements.

c. The closed system has a design temperature and pressure at least equal to the containment design conditions. The design temperatures and pressures are as follows:

    1. Nonoperating modes: 55 psig / 340°F for stainless steel and carbon steel components

    2. Operating conditions: stainless steel components (30 psig / 1400°F)

d. The closed system is designed as seismic Category I.

e. The system is designed to withstand the loads and environmental conditions accompanying a LOCA.

f. High energy and moderate energy pipe break effects will not affect hydrogen recombiner system continuity when the closed system is needed for containment isolation (Section 3.6.2).

g. The recombiner system is designed to be leak-tight and will be periodically leak tested at the containment peak accident pressure.

h. Any leakage from the system will be confined within the secondary containment and will be diluted and filtered prior to release.

i. The closed system is protected from missiles (Section 3.5).

The high volume purge lines are provided with debris screens located at the point where each purge line terminates inside the primary containment. The debris screens are designated as seismic Category I and are designed to withstand the maximum differential pressure across the screen that could result from a LOCA.

6.2.4.3.1.3.2.4 RCIC and HPCI Turbine Exhaust Vacuum Breaker Lines

These lines are provided with two normally open motor-operated remote manually actuated gate valves. The valves are automatically closed on receipt of an RCIC or HPCI isolation signal.

6.2.4.3.1.3.2.5 Traversing Incore Probe

The TIP system purge line is equipped with a normally open air operated globe valve outside containment and a check valve inside containment. The TIP system purge line air operated valve is normally open in order to provide a continuous supply of dry gas to the indexing mechanisms. Upon receipt of a containment isolation signal, the TIP system purge line AOV is automatically closed. TIP drive cables are normally retracted except during calibration of the power range neutron detectors or when an actual TIP mapping operation is in progress. Under normal operating conditions, the TIP system guide tubes do not communicate with the containment atmosphere because purge air supplied to the box surrounding the indexing mechanism effectively precludes such communication. However, following a LOCA or containment pressurizing event, a check valve on the box will open resulting in direct communication between the containment atmosphere and the TIP guide tubes. Because the TIP system lines can be considered instrument lines, the isolation provisions for the TIP system are described in the evaluation of compliance with Regulatory Guide 1.11, Section 6.2.4.3.1.5.

6.2.4.3.1.3.2.6 Containment Spray

The containment spray lines are provided with two normally closed, remote manually operated isolation valves outside the containment. The inner isolation valve is located directly on the containment.

6.2.4.3.1.3.2.7 Suppression Pool Spray

The suppression pool spray lines are provided with normally closed isolation valves outside containment, located directly on the containment. The valves automatically close upon receipt of an isolation signal. The external pipe, designed to Quality Group B and seismic Category I requirements, provides the second isolation barrier. Because of the desired use of this system after a LOCA, the system reliability is greater with only one isolation valve in the line.

6.2.4.3.1.3.2.8 Drywell Radiation Sampling Lines

The sampling system lines that penetrate the containment and connect to the drywell and suppression chamber air volume are equipped with two normally open solenoid-operated isolation valves in series, located outside and as close to the containment as possible. These valves ensure isolation of these lines if there should be a break; they also provide long-term leakage control.

In addition, the piping is considered an extension of the containment boundary and, as such, is designed to the same quality standards as the primary containment. The drywell radiation sampling isolation valves have ganged controls for reopening. Inboard sample and return isolation valves SV-190A and SV-190C are ganged on HS-190A. Outboard sample and return isolation valves SV-190B and SV-190D are ganged on HS-190B.

6.2.4.3.1.3.2.9 Primary Containment Instrument Gas

The influent lines are provided with a normally open power-operated globe valve outside the containment and a check valve inside the containment. MOVs are used on the influent lines that contain the ADS gas supply. These are essential lines that provide a long-term backup to the ADS accumulators inside containment. The valves on these essential lines are remote manually operated and automatically isolate only when flow out of containment through these lines would be possible (i.e., low differential pressure between the containment and the instrument gas line). The remaining influent lines are nonessential lines that use AOVs that are automatically closed on receipt of a containment isolation signal. The effluent line is provided with a normally open air operated globe valve outside and a motor-operated globe valve inside the containment that close automatically on receipt of a containment isolation signal.

6.2.4.3.1.3.2.10 Reactor Enclosure Cooling Water

Each influent and effluent line is provided with two gate valves located outside containment. The inboard valves are motor- operated. The outboard valves on the ESW intertie lines are locked closed and the motor operators are not connected to any power supply. The outboard valves on the RECW lines (HV-108 and HV-111) are motor-operated and their controls are ganged on HS-108. Each of the MOVs can be remote manually closed from the control room. Automatic, diverse isolation signals are also provided to these valves. In addition, the containment isolation signals to these valves can be overridden by using key-locked bypass switches.

6.2.4.3.1.3.2.11 Drywell Chilled Water

Each influent and effluent line is provided with two motor-operated gate valves located outside containment. The controls for these valves are ganged as follows:

a. Loop A inboard influent and effluent isolation valves HV-128 and HV-129 are ganged on HS-128.

b. Loop B inboard influent and effluent isolation valves HV-122 and HV-123 are ganged on HS-122.

c. Loop A outboard influent and effluent isolation valves HV-120A, 121A, 124A and 125A are ganged on HSS-121A.

d. Loop B outboard influent and effluent isolation valves HV-120B, 121B, 124B and 125B are ganged on HSS-121B.

The inboard valves are provided with automatic isolation signals as indicated in Table 6.2-17. The outboard isolation valves are normally aligned to the drywell chilled water system. Outboard valves HV-120A, HV-120B, HV-121A and HV-121B are provided with diverse, automatic isolation signals. In addition, the containment isolation signals to these valves can be overridden by using key-locked bypass switches. The other outboard isolation valves, HV-124A, HV-124B, HV-125A, and HV-125B are normally closed valves and do not receive an automatic isolation signal to close. These valves may be aligned to the RECW system only when containment isolation valves are not required to be operable or when the affected containment penetration is isolated as directed by the Technical Specifications and Technical Requirements Manual. These valves have administrative controls so that they are treated as locked closed valves.

6.2.4.3.1.3.3 Conclusion on GDC 56

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

In addition to meeting isolation requirements, the pressure- retaining components of these systems are designed to the same quality standards equivalent to those used for the primary containment.

6.2.4.3.1.4 Evaluation Against GDC 57

This GDC was not used in the design of containment penetrations for LGS.

6.2.4.3.1.5 Evaluation Against Regulatory Guide 1.11

Instrument lines that penetrate the containment from the RCPB conform to Regulatory Guide 1.11 in that they are equipped with a restricting orifice located inside the drywell and an EFCV located outside and as close as practicable to the containment. Should an instrument line that forms part of the reactor pressure boundary develop a leak outside the containment, a flow rate that results in a differential pressure across the valve of 3-10 psi causes the EFCV to close automatically. Should an EFCV fail to close when required, the main flow path through the valve has a resistance to flow at least equivalent to a sharp-edged orifice of 0.375 inch diameter. Valve position indication is provided in the reactor enclosure. Those instrument lines that do not connect to the RCPB conform to Regulatory Guide 1.11 in that they are either equipped with an EFCV or an isolation valve capable of remote operation from the control room, and are sized or orificed to meet the criteria outlined in Regulatory Guide 1.11. The drywell pressure, suppression pool level, suppression chamber pressure, and drywell sump level instrument lines are:

a. Provided with isolation valves capable of remote operation from the control room.

b. Q-listed, as discussed in Section 3.2.

c. Designed to seismic Category I standards.

d. Designed to withstand containment design pressure and temperature.

e. Terminate in the reactor enclosure, which is served by the SGTS.

The status of the isolation valves capable of remote operation from the control room is indicated in the control room.

The TIP system lines as shown in drawing M-59 and described below are considered instrument lines because:

a. they function as instrument lines or support the operation of instrument lines, and

b. they are small diameter lines.

TIP system isolation valves are provided on each guide tube immediately outside the containment. Dual barrier protection is provided by a solenoid-operated ball valve and an explosive actuated cable shearing valve. The ball valve is closed except when a TIP is inserted. These valves prevent loss of reactor coolant in the event that an incore guide tube ruptures inside the reactor vessel and prevents the escape of primary containment atmosphere.

The guide tube ball valve solenoid is normally de-energized and the valve is in the closed position. When the TIP starts forward, the valve solenoid is energized and the valve is held open against its spring. As the valve opens, it actuates a set of contacts which provide position indication at the TIP control panel and a permissive signal for TIP motion. Upon receipt of a containment isolation signal (reactor low water level or high drywell pressure), the TIP drive mechanism is signalled to retract the TIP. As the TIP is withdrawn into its shield chamber outside containment, a position switch signals the ball valve to close.

The shear valve is provided as a backup in the event that a TIP cannot be retracted or a ball valve sticks open when containment isolation is required. In this event, the shear valve would be operated from the control room to cut the cable and seal the guide tube. Continuity of the shear valve squib firing circuits is continuously monitored by front panel indicator lights in the control room.

The guidelines of Regulatory Guide 1.11, section 1.b are met for the TIP system as discussed below.

An analysis of the maximum leakage rate from the TIP system and the offsite radiological effects under normal reactor operating conditions was performed. The analysis conservatively assumed that all TIP system lines suffered guillotine breaks just outside the containment boundary. Specific activity inside the primary containment was assumed to be at the maximum Technical Specification limit for iodine in the primary coolant. (This is an extreme conservatism because a primary coolant rather than drywell atmosphere source term was assumed.) To characterize maximum flow through the TIP system lines, the drywell was assumed to be at its maximum normal pressure (2.0 psig) and normal temperature (135°F ①). It was also conservatively assumed that all TIP probes are fully retracted. Under these conditions, total flow from the TIP system lines would be only 0.105 lb_m/sec as compared to 2.2 lb_m/sec for an instrument line which penetrates the reactor primary coolant boundary. The corresponding 24 hour site boundary dose for this flow rate (using worst case average annual meteorology) would be less than 0.03 rem thyroid. The conservatively calculated leak rate is extremely low and the offsite dose is a small fraction of 10CFR50.67 limits.

The TIP guide tubes are equipped with dual isolation valves located as close to containment as practical; a solenoid-actuated ball valve and an explosively actuated shear valve acting in series. The ball valves are normally de-energized (in a closed position). Consequently, during normal operation, the containment isolation function for the TIP system is accomplished without the need

for any action. Therefore, requirement of Regulatory Guide 1.11, section 1.C.1 is met. In the unlikely event of a LOCA while the TIP system is in operation, containment isolation is automatically accomplished as follows. Upon receipt of a containment isolation signal (reactor low water level or high drywell pressure), the TIP drive mechanism is automatically signaled to retract the TIP. As the TIP is withdrawn into its shield chamber, a position switch signals the ball valve to close. All TIP line ball valves open against a spring and will close on loss of power. The cable shearing valves are equipped with redundant explosive actuating devices increasing the isolation reliability of the system and are remote manually operated from the control room. The ball and shear valves are instrumented to indicate position (i.e., open or closed).

Accidental closure of the TIP line isolation valves does not create a safety hazard, nor is the TIP system required to operate during an accident to mitigate the consequences of that accident. Therefore, the isolation provisions of the TIP system comply with the requirements of Regulatory Guide 1.11, section 1.C.2. When the TIP starts forward, the ball valve solenoid is energized and the valve is held open against its spring. This satisfies the requirement of section 1.C.3, and therefore satisfies all the requirements of Regulatory Guide 1.11, section 1.C.

The design of the TIP isolation system is commensurate with the importance to safety of isolating that system. It recognizes that the TIP system design is such that the TIP guide tube isolation ball valve is normally closed. Typically, a TIP scan requires insertion of the TIP probes into the reactor vessel for a period of approximately 4 hours per month. Over a one year period, this amounts to a total of 120 hours per year, or less than 2% of the time.

① This evaluation bounds the effects of operating at a normal temperature of 150°F, since total mass flow would be reduced.

Because of the normally closed state of the TIP ball valves, the probability of a release of radioactivity through the TIP guide tubes following a LOCA is extremely low. Even in the event of a LOCA, the TIP system design will reliably provide automatic isolation of any open TIP guide tubes by providing for automatic retraction of the TIP cable followed by automatic closure of the TIP ball valve. Should the ball valve fail to automatically close, that condition would be indicated to the operator in the control room. The operator could then manually actuate the shear valve in the control room to isolate that line.

The design of the TIP system isolation provisions is based on the low probability that the system will be called upon to isolate the containment following a significant fission product release to the containment atmosphere. Consequently, the power supplies and the controls for the TIP isolation valves are not safety-grade. However, the overall system reliability for isolation is high because: (1) the ball and shear valves are powered from separate power supplies, (2) the shear valves are powered from an onsite dc power source, (3) the ball, shear, and purge check valves, and the line from the containment to the outermost isolation valve are mechanically safety-grade, (4) upon loss of power the ball valves close, and (5) the TIP system receives automatic LOCA signals to retract and isolate.

In considering the potential magnitude of a fission product release through the TIP guide tubes as a result of a design basis LOCA event, it is appropriate to consider the event probability. There are several sequences of events which could lead to a fission product release through the TIP guide tubes. Any sequence which leads to a release must involve: (1) a design basis LOCA, and (2) a degraded core. The probability of this combination of events alone is on the order of 10^{-7} per reactor year. Additional failure(s) in the TIP isolation system have to be assumed for the release through the TIP guide tubes to occur. These failures would involve the ball and shear valves not

closing as designed for various reasons such as a hot short causing the ball valves to fail open and the shear valve not closing after the cable is retracted. The inclusion of the additional failures would lower the probability of occurrence of the event by several orders of magnitude below the 10^{-7} per reactor year figure discussed above. This analysis assumes the proper functioning of nonsafety-grade power supplies and circuits for the TIP isolation valves in determining overall system reliability. The low probability of a fission product release to the environment through the TIP guide tubes demonstrates the adequacy of the current TIP isolation system design basis.

Although the above discussion indicates an extremely low likelihood of a fission product release through the TIP guide tubes or purge lines, the consequence of that release has been evaluated for the most probable event. That event would involve the failure of all five TIP guide tubes to isolate following a degraded core event. In this instance, the TIP probe substantially reduces the flow area in the TIP guide tube which provides a pathway for fission product release unless some other unlikely event (i.e., earthquake) were to occur at the same time and cause further equipment failures. The pathway for an atmospheric fission product release would be through the check valve in the indexer box (open due to a positive internal containment pressure), down the long and narrow annulus between the TIP probe/cable assembly and the guide tube, and out through the end of the guide tube located in the reactor enclosure. The probe/cable assembly are never completely withdrawn from the guide tube, so the annular flow restriction is maintained. For the radiological analysis, Regulatory Guide 1.183 source terms and accident meteorology were assumed.

The results of the radiological evaluation show that the site boundary and low population zone doses for this limiting event using Regulatory Guide 1.183 assumptions are below 10CFR50.67 limits.

The low probability of fission product release and the results of the radiological evaluation satisfy the intent of Regulatory Guide 1.11, section 1.d.

6.2.4.3.1.6 Evaluation Against Regulatory Guide 1.141

The containment isolation system conforms to Regulatory Guide 1.141 except as discussed below:

> Section 3.6.4 Single Valve and Closed System Both Outside Containment...
>
> The single valve and piping between the containment and the valve shall be enclosed in a protective leak-tight or controlled leakage housing to prevent leakage to the atmosphere.

LGS Design:

For systems that fall into this category except for the ECCS pump suction lines, the single valve outside primary containment is not enclosed in a protective leak-tight or controlled leakage housing. Moderate energy lines that fall into this category do not connect to the RCPB and are not postulated to break concurrent with a LOCA. Therefore, neither reactor coolant nor post-LOCA containment atmosphere are released. However, any leakage is contained within the secondary containment and is diluted and filtered prior to release. The ECCS pump suction isolation valves are enclosed in pump rooms adjacent to the containment that have provisions for the environmental control of any fluid leakage.

The existing isolation provisions for the above lines meet the criteria set forth by ANSI N271 (1976). These isolation provisions consist of a line submerged in the suppression pool (except for

the suppression pool spray line) and a valve outside containment. In addition, a closed system is provided as another containment isolation barrier. For each of the lines, the closed system outside containment is protected from missiles, designed to seismic Category I standards, classified safety class 2, and is designed to the temperature and pressure conditions that the system will encounter after an accident. Justification for the design of the valve nearest containment and any piping between containment and the valve is provided in the following discussion.

> Section 3.6.5 Two Valves Outside Containment...
>
> The valve nearest the containment wall and piping between the containment and that valve shall be enclosed in a protective leak-tight or controlled leakage housing to prevent leakage to the atmosphere.

LGS Design:

The lines listed below, which have containment isolation provisions that consist of two valves in series located outside primary containment, are moderate energy lines that do not connect to the RCPB. These lines are not postulated to experience a guillotine break. Locating the valves on these lines outside the primary containment is more practical than locating the valves inside containment because of the adverse environment that is experienced when most of the valves may be needed (post-LOCA) and because this location allows inspections and maintenance to be performed on these valves during normal operation. The existing isolation provisions for all these lines meet the criteria set forth by ANSI N271 (1976).

The design of the valve nearest containment and any piping between the containment and the valve, for the following penetrations, is discussed below:

Penetration	Line	Valve
X-25	Drywell purge supply	122
X-26	Drywell purge exhaust	113
X-28A	Drywell $H_2/0_2$ sample	134, 132
X-28B	Drywell $H_2/0_2$ sample	133
X-39A,B	Containment Spray	F021A,B
X-35C-G	TIP Drive	140A-E, 141A-E
X-40G	ILRT data acquisition	1057, 1071
X-117B	Drywell radiation sampling	190A,B, 190C,D
X-62	$H_2/0_2$ sample return; drywell purge makeup	150
X-201A	Suppression pool purge supply	125
X-202	Suppression pool purge exhaust	103

X-203A,B,C,D	RHR pump suction	F004A,B,C,D
X-204A,B	RHR pump test and minimum flow	125A,B
X-205A,B	Suppression pool spray	F027A,B
X-206A,B,C,D	CS pump suction	F001A,B,C,D
X-207A,B	CS pump test and flush	F015A,B
X-208B	CS pump minimum flow	F031B
X-209	HPCI pump suction	F042
X-210	HPCI turbine exhaust	F072
X-212	HPCI pump test and flush	F071
X-214	RCIC pump suction	F031
X-215	RCIC turbine exhaust	F060
X-216	RCIC minimum flow	F019
X-217	RCIC vacuum pump discharge	F002
X-220A	$H_2/0_2$ sample return; wetwell purge makeup	190
X-221A	Wetwell $H_2/0_2$ sample	181
X-221B	Wetwell $H_2/0_2$ sample	183
X-226A,B	RHR minimum flow	105A,B
X-227	ILRT data acquisition	1073
X-228D	HPCI vacuum relief	F095
X-231A,B	Drywell sump drains	110, 130
X-235	CS pump minimum flow	F031A
X-236	HPCI pump minimum flow	F012
X-238	RHR relief valve discharge	106B
X-239	RHR relief valve discharge	106A
X-241	RCIC vacuum relief	F084

These moderate energy lines are not postulated to break concurrent with a LOCA. Therefore, neither reactor coolant nor post-LOCA containment atmosphere are released. Analyses have been performed to ensure that the effects of postulated moderate energy line breaks will not prevent the safe shutdown of the plant. The results of these analyses are provided in Section 3.6.1.2.

Section 4.4.2 Method of Valve Actuation...

It should not be possible for remote manual operation to override the automatic isolation signal until the sequence of automatic events following a isolation signal is completed...

LGS Design:

This guideline is met for all remote manually operable valves with the exception of valves in systems that must be operated after an accident and that have been provided with a key-locked override switch for this purpose.

Section 5.3.2 - Leakage Rate Testing

Provisions and Methods. Provisions shall be made for leakage rate testing of containment isolation valves.

LGS Design:

Individual leakage rate tests are performed for containment isolation valves as indicated in Table 6.2-25.

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 that results in a loss or degradation of the system's capability to perform its safety function. Active components are defined as components that must perform a mechanical motion during the course of accomplishing a system safety function. 10CFR50, Appendix A requires that electrical systems be designed against passive single failures as well as active single failures. Section 3.1 describes the implementation of these requirements as well as GDC 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.

6.2.4.4 Tests and Inspections

The containment isolation system undergoes periodic testing during reactor operation. The functional capabilities of power-operated isolation valves are remotely tested manually from the main control room. During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead zone", operator action is required to restart the valve. By observing position indicators and changes in the affected system operation, the closing ability of a particular isolation valve is demonstrated.

A discussion of testing and inspection pertaining to isolation valves is provided in Section 6.2.1.6 and in Chapter 16. Table 6.2-17 lists all isolation valves.

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

EFCVs are periodically tested to verify proper operation. As these valves are outside the containment and accessible, periodic visual inspection is performed in addition to the operational check.

Leak rate testing for the containment isolation system is discussed in Section 6.2.6.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

Limerick license amendment numbers 173/135 for Unit 1 and 2, respectively approved the removal of the hydrogen recombiner and hydrogen and oxygen monitoring controls from Technical Specifications. The following items were committed to as part of license amendment numbers 173/135.

1. Limerick will maintain the hydrogen monitors within the Emergency and Operating procedures and the Maintenance Program.

2. Limerick will maintain the oxygen monitors within the Emergency and Operating Procedures and the Maintenance Program.

The revised Technical Specifications are based on the NRC revision to 10CFR50.44 (Combustible gas control for nuclear power reactors), which eliminated the design basis LOCA hydrogen release based on risk significance; eliminated the requirements for hydrogen control systems to mitigate such releases; and maintained the requirements for containment inerting, containment atmosphere mixing, monitoring of oxygen to verify the status of the inert containment, and monitoring of hydrogen for diagnosing beyond design basis accidents. Based on the revised rule removing the design basis requirements for beyond design basis accidents, the hydrogen recombiners can be eliminated in the future and the H2/O2 analyzers are downgraded to non-safety related and non-redundant. However, the recombiners and analyzers are currently being maintained as described in the UFSAR, except for removal of the system requirements from the Technical Specifications. The analyzer system requirements removed from the Technical Specifications have been transferred to the Technical Requirements Manual (TRM).

Following a postulated LOCA, hydrogen gas may be generated within the primary containment as a result of the following processes:

a. Metal-water reaction involving the Zircaloy fuel cladding and the reactor coolant

b. Radiolytic decomposition of water in the reactor vessel and the suppression pool (oxygen also evolves in this process)

c. Corrosion of metals and paints in the primary containment

d. Release of free hydrogen already in the reactor coolant at the time of the LOCA.

To preclude the possibility of a combustible mixture of hydrogen and oxygen accumulating in the primary containment, the containment atmosphere is inerted with nitrogen gas during power operation of the reactor. The means provided for inerting the containment is described in Section 9.4.5.1. With the concentration of oxygen being controlled to below the lower flammability limit, the level of hydrogen buildup in the primary containment following a postulated LOCA is of no particular concern for combustible gas control.

To ensure that the oxygen concentration in the primary containment is maintained below the lower flammability limit, the following features are provided:

a. A containment hydrogen recombiner subsystem

b. A combustible gas analyzer subsystem

c. The capability to mix the primary containment atmosphere to prevent the local accumulation of hydrogen and oxygen (accomplished by the drywell air cooling system, which is discussed in Section 9.4.5.2)

d. The capability for a controlled purge of the primary containment following a LOCA (accomplished by the CAC system, which is discussed in Section 9.4.5.1)

Both the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are part of the CAC system, which is shown in drawing M-57.

6.2.5.1 Design Bases

a. The containment hydrogen recombiner subsystem is designed to maintain the oxygen concentration in the primary containment below the lower flammability limit of 5% by volume.

b. The combustible gas analyzer is designed to operate either in standby or continuous mode during normal operation. However, the combustible gas analyzer is required to continuously monitor hydrogen and oxygen concentrations in the primary containment following a LOCA.

c. Those lines that penetrate the primary containment and are associated with the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are provided with automatic isolation valves to ensure the integrity of the containment boundary during accident conditions. Two isolation valves in series are provided on the recombiner lines.

d. The controls for containment isolation valves on lines associated with post-LOCA combustible gas control and monitoring are designed so that the valves may be reopened by utilizing key-locked bypass switches to override the isolation signals.

e. The containment hydrogen recombiner subsystem and the safety-related portions of the drywell air cooling system are designed to remain functional after an SSE.

f. The containment hydrogen recombiner subsystem, the combustible gas analyzer subsystem, and the safety-related features of the drywell air cooling system are

designed so that a single failure of an active component, assuming a LOOP, cannot result in the loss of a safety function.

g. The CAC system is designed to permit a controlled purge of the primary containment atmosphere following a LOCA, as a backup means of combustible gas control and as an aid in cleanup.

h. The containment hydrogen recombiner subsystem, the combustible gas analyzer subsystem, and the portions of the CAC system that are related to post-LOCA purging are designed to facilitate periodic inspection and testing of safety-related features.

i. The containment hydrogen recombiner subsystem, the combustible gas analyzer subsystem, and the safety-related portions of the drywell air cooling system are designed to remain operable in the environments existing in their respective areas following a LOCA.

6.2.5.2 System Description

6.2.5.2.1 Containment Hydrogen Recombiner Subsystem

The containment hydrogen recombiner subsystem is part of the CAC system, which is discussed in Section 9.4.5.1 and shown schematically in drawing M-57. The recombiner subsystem consists of two redundant hydrogen recombiner packages, each of which has adequate processing capacity to control the quantity of oxygen postulated to be generated in the primary containment after a LOCA. The recombiners are of the thermal recombination type, manufactured by the Atomics International Division of Rockwell International. The recombiners are similar in design and construction to those described in Reference 6.2-9 and are identical to those described in Reference 6.2-10.

A schematic diagram of one recombiner package is shown in drawing M-58. Each hydrogen recombiner package consists of three modules: the recombiner skid assembly, the power cabinet, and the control cabinet. The recombiner skid assembly, which is shown in Figure 6.2-38, consists of the process components. The process components include valves, canned motor/blower assembly, gas heater pipe, reaction chamber, water spray cooler, and water separator. The gas heater pipe and the reaction chamber are located within an insulated enclosure that also contains electric heater elements. The recombiner skid assembly is located outside the primary containment in the reactor enclosure.

The power cabinet houses the power distribution components for the recombiner package. The cabinet is located adjacent to its associated recombiner skid assembly and contains the 480 V power supply, control transformer, blower motor starter, circuit breakers, control relays, and the silicon-controlled rectifiers that control electrical power to the heater elements.

The control cabinet contains all of the instrumentation, annunciators, lights, and switches necessary for operation of the recombiner package. The control cabinet is located in the control room.

Each recombiner package is designed to process 60 scfm of gas (inlet flow) containing 5% oxygen, or up to about 150 scfm of gas (inlet flow) containing 2% oxygen, with the balance consisting of unlimited amounts of hydrogen, nitrogen, and water vapor. Each recombiner package will also process up to about 150 scfm of air containing 4% hydrogen. As containment pressure decreases following an accident, recombiner flow may decrease below the 150 scfm nominal operating value,

as discussed in Section 6.2.5.3. The recombination process is accomplished by increasing the temperature of the process stream to approximately 1300°F, at which temperature the hydrogen and oxygen combine spontaneously to form water vapor by the reaction $2H_2 + O_2 \rightarrow 2H_2O$. Virtually complete recombination occurs, so that the concentration of the limiting gas in the effluent from the recombiner package is negligible.

During recombiner operation, gas from the drywell flows through the high volume purge piping of the CAC system to the gas inlet piping of the recombiner package. The effluent from the recombiner package flows through the gas outlet piping to the high volume purge piping associated with the suppression chamber, and then into the suppression chamber. By taking suction from the drywell and discharging to the suppression chamber, a differential pressure is created between these two volumes. This differential pressure is limited to 1.0 psid by the primary containment vacuum relief valve assemblies (described in Section 9.4.5.1), that open to allow air to flow from the suppression chamber back into the drywell.

The recombiner gas inlet and outlet lines are each provided with two normally closed valves for containment isolation. These valves can be operated by hand switches in the control room, and are automatically closed upon receipt of a containment isolation signal. The isolation signals can be overriden by using key-locked bypass switches. The recombiner outlet lines are each provided with pressure relief valves to protect the outlet piping from overpressurization in the event of recombiner cooling water line isolation valve leakage from the RHR system during recombiner isolation. Containment isolation is discussed further in Section 6.2.4.

Blank flanges will be installed on the outboard side of the isolation valves for pressure boundary maintenance.

The process stream entering the recombiner skid assembly flows first through a valve that is used to regulate the flow rate through the recombiner. Next along the process path is the blower, that provides sufficient head to overcome the system flow losses and also the 1.0 psid differential pressure between the drywell and the suppression chamber. From the blower, the gas flows through the gas heater pipe that spirals around the reaction chamber.

The gas is heated as it flows through the gas heater pipe, due to radiated heat from the electric heater elements and the reaction chamber. Next, the gas flows into the reaction chamber, where the exothermic recombination of hydrogen and oxygen occurs. The flow field in the reaction chamber is highly turbulent, with sufficient mixing to rapidly bring the inlet gas temperatures to a level where virtually complete recombination occurs. Reaction chamber temperature is not critical, and considerable deviation from the nominal operating temperature of 1300°F may be tolerated without seriously affecting recombiner performance. The geometric configuration and volume of the reaction chamber provide gas flow movement and transport times so that recombination is completed over a varied range of hydrogen-oxygen concentrations. Recombined gas flows from the reaction chamber to the water spray cooler where it is cooled to less than 250°F. The hot process gas is mixed with water spray in the throat region of a venturi, and the hot gas is cooled by vaporization of the water and by direct contact with the water droplets. The cooling water is supplied to the recombiners from the RHR system. Cooled gas flowing from the cooler is passed through a water separator that prevents any remaining water droplets from entering the gas recirculation line. The separated water drains down to the suppression pool through the recombiner gas outlet piping. Recirculation (dilution) gas is drawn from the top of the water separator and is routed to the recombiner gas inlet piping.

Operation of the hydrogen recombiner package is initiated manually from the control cabinet. When gas flow has been established and the water inlet valve is fully open, the heater elements are energized. Less than 2 hours are required for the system to reach operating temperature. As the temperature of the heated enclosure increases, the gas being circulated through the recombiner is heated. The recombination reaction begins to occur at the outlet of the gas heater pipe when the temperature at that location reaches approximately 1150°F. When the temperature at the gas heater pipe outlet reaches 1300°F, power to the heater elements is automatically turned off. When the gas heater pipe cools to the point at which it can no longer sustain the reaction, the reaction moves into the reaction chamber. When the temperature at the gas heater pipe outlet falls below 1300°F, an interlock is cleared and power is returned to the heater elements at a lower level than during startup. Temperatures in the gas heater pipe stay below those required for reaction, so the reaction stays in the reaction chamber. A temperature controller located in the control cabinet is used to maintain reaction chamber temperature at about 1300°F.

6.2.5.2.2 Combustible Gas Analyzer Subsystem

The combustible gas analyzer subsystem is part of the CAC system, which is discussed in Section 9.4.5.1 and shown schematically in drawing M-57. The combustible gas analyzer subsystem consists of two analyzer packages, each of which contains a hydrogen sensor and an oxygen sensor. The analyzer packages are provided with sufficient sample points so that both analyzer packages can take samples from either the drywell or the suppression chamber.

Each analyzer package consists of a sample cabinet located in the reactor enclosure and a remote control panel located in the control room. Sample points in the primary containment are located as follows:

a. Drywell

   1. el 291', azimuth 10°; 15' from containment centerline
   2. el 255', azimuth 215°; 25' from containment centerline
   3. el 242', azimuth 214°; 1.5' from inside wall of reactor pedestal.

b. Suppression chamber

   1. el 222', azimuth 70°; at inside of containment wall
   2. el 222', azimuth 250°; at inside of containment wall.

The sample suction and return lines are each provided with two normally open solenoid-operated valves for containment isolation. These valves are operated by hand switches in the control room, and are automatically closed upon receipt of a containment isolation signal. The isolation signals to the valves can be overridden by using key-locked bypass switches. Containment isolation is discussed further in Section 6.2.4.

Sample location is controlled by a touchscreen at remote control panel. Gases from the sample point thus selected are routed through a hydrogen sensor and an oxygen sensor located in the sample cabinet.

The operation of the hydrogen and oxygen sensors is based on the measurement of the partial pressure of the oxygen and/or hydrogen in the gas sample. The partial pressure sensors are

galvanic in nature and consist of two electrodes; a catalytic sensing electrode and metal oxide counter electrode for the hydrogen sensor and gold electrode and metal counter electrode for the oxygen sensor. The electrodes for the sensors are immersed in an electrolyte. The electrodes are externally connected by a resistive load. When the ambient atmosphere contains hydrogen and/or oxygen, the gas is ionized at the sensing electrode. The end result is an exchange of electrons through the resistive load connecting the electrodes that is in proportion to the amount of hydrogen (or oxygen). The voltage developed across the external resistance or load, is a mVDC signal, directly proportional to the partial pressure of hydrogen (or oxygen). Note that each sensor is designed to respond only to hydrogen or only to oxygen and is insensitive to other gasses. The total pressure is measured so the partial pressures can be converted to a concentration of hydrogen or oxygen.

The hydrogen sensor has a range of 0% to 10% (by volume) and the oxygen sensor has a range of 0% to 25% (by volume). The calibrated range of each analyzer is 0% to 7%. The sensors are capable of providing oxygen and hydrogen measurement under ambient pressure and up to 73 PSI for components exposed to containment sample under accident conditions. The hydrogen and oxygen concentrations are indicated at the remote control panel.

Sample gases are drawn through the sensors by a positive displacement pump located in the sample cabinet. Sample gases discharged from the pump are routed back to the primary containment.

6.2.5.2.3 Containment Atmosphere Mixing

The capability is provided to maintain the primary containment atmosphere in a thoroughly mixed condition following a LOCA in order to prevent nonuniform distributions of oxygen from occurring. This function is performed by the drywell air cooling system, which is discussed in Section 9.4.5.2. One fan in each of the unit coolers of the drywell air cooling system runs continuously during normal reactor operation and at least one fan in each of two of the safety-related coolers (1AV-212 or 1BV-212 and 1GV-212 or 1HV-212) continues to run after a LOCA to maintain containment in a thoroughly mixed condition.

The design of the primary containment is such that compartmentalization is minimized. The only regions of the drywell that are segregated to some extent from the remainder of the drywell are the drywell head area above the containment seal plate and the CRD area inside the reactor pedestal. Oxygen is prevented from accumulating in a concentration in excess of 5% (volume) in these areas during normal and post-LOCA operation by the operation of the drywell air cooling system.

Following a LOCA, containment oxygen would be mixed by several mechanisms in addition to the operation of the drywell air cooling system. Sprays and natural convective mixing would contribute significantly to maintaining all gases at nearly uniform concentrations (Reference 6.2-20). The boiling mechanism associated with the radiolysis responsible for the release of oxygen from irradiated water (Reference 6.2-21) would also create a significant amount of turbulent mixing, steam condensation effects, and a temperature gradient. These effects would cause oxygen to be well mixed with steam as it entered the drywell from the line break.

6.2.5.2.4 Post-LOCA Purging

The capability to purge the primary containment in order to control oxygen concentration and aid in cleanup after a LOCA is provided.

The BWROG EPGs make specific recommendations for Post-LOCA purging based on the hydrogen levels in containment. Post-LOCA purging using the low volume purge mode of CAC (discussed in section 9.4.5.1) is recommended when containment hydrogen levels are greater than a specific level in the BWROG EPGs, no deflagration can occur, and the containment can be purged without exceeding the normal release rate limits in the Technical Specifications or ODCM. Post-LOCA low volume purging continues until the containment hydrogen levels fall below the recommended value specified in the BWROG EPGs. Gases exhausted from the containment during post-LOCA purging are processed through the RERS and SGTS in order to remove radioactive particulate and halogen contaminants prior to release to the environment.

If containment hydrogen levels continue to increase a high volume purge of the containment can be performed using nitrogen, depending on the potential for the hydrogen and oxygen concentration to result in a deflagration. Depending on the plant conditions at the time of the high volume purge, RERS and SGTS may or may not be available. Depending on the specific concentrations of hydrogen in containment at the time, offsite release rates are limited to those in the Technical Specifications or ODCM. The high volume purge can be used in accordance with BWROG EPG recommendations to prevent containment failure due to a deflagration and to minimize the consequences of the accident. Post-LOCA high volume purging continues until the containment hydrogen levels fall below the recommended value specified in the BWROG EPGs. The BWROG EPG recommendations regarding purging of the containment are incorporated in the EOPs.

6.2.5.2.5 Venting of Combustible Gases from the Reactor Vessel

Combustible gases generated within the reactor vessel or its connected piping can accumulate in the steam space of the vessel following certain types of accidents. Several means are available to vent these gases from the reactor vessel into the primary containment, where they can be processed by the hydrogen recombiner subsystem.

Operation of either the HPCI or RCIC system provides one such means for combustible gas venting. Both of these systems utilize steam-driven turbines that take steam from the reactor vessel and discharge it to the suppression chamber. Any combustible gases present in the reactor vessel steam space are carried along in the steam driving the HPCI or RCIC turbines.

Combustible gases can also be vented from the reactor vessel through the use of the ADS. The ADS utilizes five of the MSRVs to discharge steam and any other gases present in the reactor vessel to the suppression chamber.

A third means that is available for combustible gas venting involves the RPV head vent line that runs from the top of the reactor vessel head to the drywell equipment drain sump. MOVs in this line can be opened to allow steam and other gases to be discharged to the drywell equipment drain sump. Any gases not condensed in the drain sump are released into the drywell through the drain sump's vent line.

6.2.5.3 Hydrogen and Oxygen Generation Analysis

In establishing the design and assessing the capability of the hydrogen recombiner subsystem and the post-LOCA purge, an analysis was performed to determine the hydrogen and oxygen concentrations in the primary containment (drywell and suppression chamber) as a function of time following a postulated LOCA. The assumptions and design parameters used in this analysis are listed in Tables 6.2-18 and 6.2-19, respectively. These assumptions are in accordance with Regulatory Guide 1.7 (Reference 6.2-12). The computer program used to conduct these primary containment hydrogen and oxygen analyses is the Bechtel in-house computer code, HYDROGEN, which incorporates the models from Regulatory Guide 1.7, SRP 6.2.5, and the NRC Code COGAP. The analysis considered the generation of hydrogen gas from the following sources:

a. Metal-water reaction involving the Zircaloy fuel cladding and the reactor coolant

b. Radiolytic decomposition of water in the reactor vessel and the suppression pool

c. Corrosion of metals and paints in the primary containment

d. Release of free hydrogen already in the reactor coolant at the time of the LOCA

Radiolytic decomposition of water is considered to be the only source of oxygen gas generation after a LOCA.

Metal-Water Reaction

As a result of a LOCA, fuel cladding temperatures rise beginning after blowdown and continuing until core reflood. Zirconium reacts with steam according to the following reaction (Reference 6.2-11):

$$Zr + 2H_2O \rightarrow ZrO_2 + 2H_2$$

Thus, for each mole of zirconium that reacts, 2 moles of free hydrogen are produced. The extent of the metal-water reaction and associated hydrogen generation depends strongly on the course of events assumed for the accident and on the effectiveness of emergency cooling systems, since the metal-water reaction is highly temperature-dependent. Regulatory Guide 1.7 (Reference 6.2-12) conservatively states that the amount of hydrogen assumed to be generated by metal-water reaction in determining the performance requirements for combustible gas control systems should be five times the maximum amount calculated in accordance with 10CFR50, Appendix K, but no less than the amount that would result from reaction of all the metal in the outside surfaces of the cladding cylinders surrounding the fuel (excluding the cladding surrounding the plenum volume) to a depth of 0.00023 inch.

In accordance with Appendix K, calculations have determined that the maximum core wide metal-water reaction is 0.09% (weight). Five times this calculated value is 0.45% (weight). Based on the fuel design, a reaction that results in a cladding penetration depth of 0.00023 inch is well in excess of the Appendix K value. Therefore, since the metal-water reaction based on 0.00023 inch penetration depth is greater than five times the value calculated in accordance with Appendix K, the value based on 0.00023 inch cladding penetration reaction is used as the basis for determining the amount of hydrogen generated by the metal-water reaction.

The analysis assumes that the hydrogen from the metal-water reaction is generated during the first 2 minutes after the beginning of the accident. The hydrogen thus evolved is assumed to mix homogeneously with the drywell atmosphere.

Radiolysis

Water is decomposed into free hydrogen and oxygen by the absorption of energy emitted by fission products contained in fuel and those mixed with the LOCA water. The quantities of hydrogen and oxygen that are produced by radiolysis are functions of both the energy of ionizing radiation absorbed by the LOCA water and the net hydrogen and oxygen radiolysis yields, $G(H_2)$ and $G(O_2)$, pertaining to the particular physical-chemical state of the irradiated water. As recommended in Regulatory Guide 1.7 (Reference 6.2-12), the net yields of hydrogen and oxygen from radiolysis of all LOCA water are conservatively assumed to be 0.5 molecule/100 eV for hydrogen and 0.25 molecule/100 eV for oxygen.

The total fission product decay power is taken from Reference 6.2-13, conservatively assuming a 730 day[1] reactor operating time for fission product buildup. The results are comparable to those of proposed Standard ANS 5.1. The fission product distribution after the accident and the fractions of fission product radiation energy assumed to be absorbed by the LOCA water are listed in Table 6.2-18. The rates of energy absorption by the LOCA water are shown in Figure 6.2-39 and the integrated energy absorption is shown in Figure 6.2-40.

Corrosion

The corrosion of zinc and aluminum located either in the drywell or the suppression chamber is evaluated as a potential source of hydrogen after a LOCA. One factor that affects the rate of corrosion of either of these metals is the pH of the water with which the metal is in contact. Since no chemicals are added to the containment spray water, the pH of water in the primary containment after a LOCA should be approximately 7 (neutral).

Zinc in the primary containment is in two forms: zinc-based paint and galvanized steel. The masses and exposed areas of zinc-based paint and galvanized steel are listed in Table 6.2-19.

Corrosion of zinc in contact with water at a nominal pH of 7 is caused by two processes:

1. A one time cycle length of 27 months for Unit 1 cycle 7 and Unit 2 cycle 5 was evaluated to have a negligible impact on total fission product decay power.

    a. $Zn + 2\ H_2O \rightarrow Zn(OH)_2 + H_2$

    b. $2\ Zn + 2\ H_2O + O_2 \rightarrow 2\ Zn(OH)_2$

Both reactions occur in the post-LOCA atmosphere of the containment, and the relative amount of corrosion due to reaction a. as compared to reaction b. depends on the availability of oxygen. Galvanized steel and zinc-based paint surfaces that are not submerged are in contact with atmospheric oxygen along with the spray water; therefore, reaction b. is a major contributor to the corrosion of zinc. For the submerged surfaces, the oxygen present depends on the solubility of oxygen, which decreases with increasing temperature. For this situation, reaction a. dominates zinc corrosion.

A search of the literature available on the subject of zinc corrosion at a pH of 7 gives data for corrosion as a weight loss of zinc (References 6.2-14, 6.2-15, and 6.2-16) and also as hydrogen evolved (References 6.2-17 and 6.2-18). Van Rooyen (Reference 6.2-19) surveyed the available literature and formulated a corrosion rate. The data given as weight loss of zinc should be viewed carefully to determine which corrosion reaction is involved.

Other data are available for corrosion in water at higher pH levels or in water with NaOH additives. However, these data are not applicable to a BWR.

Baylis (Reference 6.2-17) determined the hydrogen generated from a sample of zinc submerged in distilled water for different time periods. This study was performed for temperatures of 100°F and lower. Therefore, the lower temperature corrosion domain can be inferred from this data.

The Franklin Institute Research Laboratories (Reference 6.2-18) performed a study of hydrogen evolution from zinc under simulated LOCA conditions and gave corrosion data for 2 hour and 24 hour periods. These data show that corrosion is faster for the 2 hour period than for the 24 hour period for different temperatures, except at the high temperature end (260°F-300°F) where the corrosion rates are comparable. This effect is due to the buildup of a corrosion-resistant zinc hydroxide protective layer that inhibits corrosion after an extended period of time.

Burchell (Reference 6.2-15) and Cox (References 6.2-14 and 6.2-16) present corrosion as a weight loss of zinc. In both cases, the corrosion rate is higher at the lower temperature domain, peaking at approximately 110°F and then decreasing with increasing temperature. Since the solubility of oxygen decreases with increasing temperature, the decrease in the corrosion rates can be attributed to the depletion of oxygen available. Thus, these corrosion rates show that reaction b. is dominant in the oxygen-rich lower temperature water, and reaction a. becomes dominant with increasing temperature.

Van Rooyen (Reference 6.2-19) determined the corrosion rate of zinc from the available data, but did not differentiate whether the corrosion was due to reaction a. or b. Thus, Van Rooyen's calculated corrosion rate does not accurately present the hydrogen generated from the corrosion of zinc.

The data of References 6.2-17 and 6.2-18 on hydrogen generation from zinc corrosion are bounded by the following corrosion rate:

$$H\,(Zn) = 3.76 \times 10^{-9}\, e^{(0.0218T)} \text{ lb-moles/ft}^2\text{-hr} \qquad \text{(EQ. 6.2-46)}$$

where:

T = temperature in degrees Fahrenheit

This rate equation is used to calculate the hydrogen released due to zinc corrosion and corrosion of zinc paint by conservatively assuming that all corrosion is caused by reaction a.

Since containment spray water does not contain any chemical additives, the pH of the LOCA water is approximately 7. At this pH, the corrosion rate of aluminum is negligible even at high temperatures (References 6.2-14 and 6.2-15). Therefore, aluminum in the containment is not assumed to be the source of any hydrogen generation.

Hydrogen Existing in Reactor Coolant

During normal operation of the reactor, free hydrogen exists in the coolant water in concentrations of 10-50 scc/kg of coolant. Although it is unlikely, it is assumed that all of this hydrogen is stripped from the coolant at the time of the LOCA. The total amount added to the containment atmosphere (corresponding to a concentration of 30 scc/kg of coolant) is listed in Table 6.2-19.

Results

The curves of drywell pressure and temperature as a function of time after a LOCA, which are used in the analysis to adjust for the mass of steam in the drywell atmosphere, are shown in Figures 6.2-3, 6.2-4, 6.2-7, and 6.2-8.

Figure 6.2-41 shows the integrated production of hydrogen from all sources as a function of time after the postulated LOCA. The hydrogen concentrations in a noninerted containment over the short-term and long-term periods after a LOCA are shown in Figures 6.2-42 and 6.2-43, respectively. These figures show hydrogen concentrations for three cases: no hydrogen control, recombiner operation at 150 scfm, and a 150 scfm purge. The analysis shows that hydrogen concentration in the drywell reaches 4% (volume) at about 25 hours after the LOCA, if no control measures are taken. If operation of one recombiner package is started so that recombination begins when the hydrogen concentration reaches 3.5% (volume) (at 19 hours after the LOCA), the concentration peaks at 3.57% (volume) and then decreases as long as the recombiner remains in operation. This analysis assumes a flow rate of 150 scfm. As containment pressure decreases following an accident, recombiner flow may decrease below this value. Field tests show that the system resistance can limit flow to less than 150 scfm when the containment is at atmospheric pressure and normal temperature. Sensitivity calculations have been performed which demonstrate that the hydrogen concentration will not exceed 4 volume percent with a single recombiner operating at a flow rate as low as 95 scfm. Actual recombiner flow rates exceed this requirement by a significant margin. For a 150 scfm purge beginning at 19 hours, the hydrogen concentration continues to increase to a maximum of about 3.8% (volume), occurring at about 45 hours after the LOCA. The purge mode used as a basis for this calculation involves supply and exhaust evenly divided between the drywell and suppression chamber, without repressurization of the primary containment.

The oxygen concentrations in an inerted containment over the short-term and long-term periods after a LOCA are shown in Figures 6.2-44, 6.2-45, and 6.2-46. These figures show oxygen concentration for three cases: no oxygen control, recombiner operation at 60 scfm, and a 60 scfm purge. The oxygen concentration (volume percent) initially drops in both the drywell and suppression chamber because, following a LOCA, the blowdown and subsequent increases in containment temperature and pressure result in significant fractions of other gases, primarily steam. To account for the additional constituents, the volume percent of oxygen decreases. The analysis shows that oxygen concentration in the drywell reaches 5% (volume) at about 54 hours after the LOCA, if no control measures are taken. If operation of one recombiner package is started so that recombination begins when the oxygen concentration reaches 4.5% (volume) (at about 39 hours after the LOCA), the concentration will peak at 4.92% (volume) and will then decrease as long as the recombiner remains in operation. For a 60 scfm purge beginning at 39 hours, the oxygen concentration increases to a maximum of 4.61% (volume), occurring at about 54 hours after the LOCA. The purge mode used as a basis for this calculation involves supply and exhaust evenly divided between the drywell and suppression chamber, without repressurization of the primary containment.

6.2.5.4 Safety Evaluation

The containment hydrogen recombiner subsystem (including supporting structures) is designed to seismic Category I requirements as defined in Section 3.7. Except for tubing internal to the sample cabinets of the combustible gas analyzer subsystem, piping and tubing associated with both subsystems, except for some piping and the hydrogen cylinders of the gas analyzer subsystem, are designed, fabricated, inspected, and tested in accordance with the requirements of the ASME Section III, Class 2. All portions of the two subsystems are located within the reactor enclosure and control structure, which are designed to seismic Category I requirements as discussed in Section 3.8.4. H_2 span gas cylinders are seismically supported in a location outside the reactor enclosure (and other safety-related areas) as required by BTP CMEB 9.5-1. Evaluation with respect to the following areas is discussed in sections as indicated:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood design	Section 3.4
c.	Missile protection	Section 3.5
d.	Protection against dynamic effects associated with the postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11

The containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem both consist of two separate packages that are fully redundant and independent. The redundant packages are powered from different divisions of Class 1E power. A single failure in either subsystem would only render the affected package unavailable, with the redundant package fully capable of performing the required function at full capacity. Failure modes and effects analyses for the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are provided in Tables 6.2-20 and 6.2-21, respectively.

Each combustible gas analyzer sample line penetrating the primary containment is provided with redundant isolation valves powered from different divisions of Class 1E power. Since the isolation valves are of a type that fail closed upon loss of power, loss of power to any individual valve or to all valves powered from the same division does not disable the containment isolation function. In the event of a failure of any single valve to close when required, the redundant valve on the same line provides the isolation function. The bypass of an isolation signal to any valve is annunciated in the control room.

Containment isolation provisions for piping used in conjunction with hydrogen recombination and post-LOCA purging are discussed in Section 9.4.5.1.

The design pressures and temperatures for process components of the hydrogen recombiner packages are as follows:

a.	Nonoperating conditions: entire system	55 psig/340°F
b.	Operating conditions:	

Stainless steel components (gas heater pipe, reaction chamber, and water spray cooler)	30 psig/1400°F
Carbon steel components (inlet piping, water separator, and outlet piping)	55 psig/340°F

Since the post-LOCA primary containment pressure-temperature transient stays well below these design parameters for the time period greater than 6 hours after the LOCA (Section 6.2.1), no restrictions exist on recombiner operation after this 6 hour period.

As shown in Figures 6.2-44, 6.2-45, and 6.2-46, the operation of one hydrogen recombiner package is sufficient to maintain post-LOCA oxygen concentrations in the containment below 5% (volume). The analysis to determine post-LOCA oxygen concentrations assumes that hydrogen-oxygen recombination begins at 39 hours after the LOCA. Since the recombiner requires a maximum 2 hour heatup period (verified by surveillance testing) before complete recombination of oxygen in the process stream occurs, one recombiner package is activated at or prior to 37 hours after a LOCA.

In the extremely unlikely event that a LOCA occurs and both recombiner packages fail to function properly, purging may be utilized to control the oxygen concentration inside the containment. The oxygen generation analysis shows that the oxygen concentration reaches 4.5% (volume) at 39 hours after the LOCA, and that a 60 scfm purge initiated at that time ensures that the oxygen concentration remains below the 5% level. The effect of the purge on oxygen concentration is shown in Figures 6.2-44, 6.2-45, and 6.2-46.

The BWROG EPGs make specific recommendations for Post-LOCA purging based on the hydrogen levels in containment. Post-LOCA purging using the low volume purge mode of CAC (discussed in section 9.4.5.1) is recommended when containment hydrogen levels are greater than a specific level in the BWROG EPGs, no deflagration can occur, and the containment can be purged without exceeding the normal release rate limits in the Technical Specifications or ODCM. Post-LOCA low volume purging continues until the containment hydrogen levels fall below the recommended value specified in the BWROG EPGs. Gases exhausted from the containment during post-LOCA purging are processed through the RERS and SGTS in order to remove radioactive particulate and halogen contaminants prior to release to the environment.

If containment hydrogen levels continue to increase a high volume purge of the containment can be performed using nitrogen, or air depending on the potential for the hydrogen and oxygen concentration to result in a deflagration. Depending on the plant conditions at the time of the high volume purge, RERS and SGTS may or may not be available. Depending on the specific concentrations of hydrogen in containment at the time, offsite release rates are limited to those in the Technical Specifications or ODCM. The high volume purge can be used in accordance with BWROG EPG recommendations to prevent containment failure due to a deflagration and to minimize the consequences of the accident. Post-LOCA high volume purging continues until the containment hydrogen levels fall below the recommended value specified in the BWROG EPGs. The BWROG EPG recommendations regarding purging of the containment are incorporated in the EOPs.

6.2.5.5 Tests and Inspections

The containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of the maintenance program and the Technical Requirements Manual (TRM), respectively. Inservice inspection of the subsystems will be in accordance with the ASME Section XI, for ASME Section III, Class 2 components.

6.2.5.6 Instrumentation Applications

6.2.5.6.1 Containment Hydrogen Recombiner Subsystem

The control cabinet for each hydrogen recombiner package contains the following devices (on the front side of the cabinet) that control and monitor the operation of the recombiner:

a. Operate switch (HS-3)

b. Inlet valve flow control switch (HS-1)

c. Recirculation valve flow control switch (HS-2)

d. Reaction chamber temperature controller (TIC-7)

e. Flow/pressure recorder (XR-1)

f. Temperature recorders (TRS-2 and TRS-4)

g. Annunciator assembly

Also located on the control cabinet, but on the rear of the cabinet, are eight hand switches (HS-6 through HS-10 and HS-14 through HS-16).

The hydrogen recombiner packages have three basic modes of operation: standby, ready, and operate. The recombiner is kept in the "ready" mode when not being tested or otherwise operated. Initially, when the recombiner subsystem is first energized or during maintenance, the system is placed in the "standby" mode. The trickle heaters are energized in order to keep the insulated enclosure warm in the "standby" and "ready" modes. The temperature controller is set at the value that will be used during initial operation of the recombiner. The recombiner is placed in the "ready" mode by actuating the service disconnect switches (HS-6 through HS-9) to the "on" position. The recombiner is left in the "ready" mode for approximately one hour, to allow circuits to stabilize before proceeding to the "operate" mode. Since the recombiner is normally in the "ready" mode, the one hour stabilization time is not a concern prior to going to the "operate" mode. The recombiner is placed in the "operate" mode by actuating switch HS-3, at which time the blower starts and the water inlet valve opens. Interlocks are provided to prevent the heater elements from being energized until the water inlet valve is fully open and the blower inlet gas flow rate exceeds the low flow setpoint. Recombiner inlet flow control and recirculation flow control is achieved using hand switches HS-1 and HS-2 in conjunction with flow/pressure recorder XR-1.

While the recombiner is in the "operate" mode, the "startup" light is on while the reaction chamber gas temperature remains below 1150°F, and the "operate" light is on when this temperature has been exceeded.

The following process alarms are displayed on the annunciator:

a. Blower inlet gas pressure (high)

b. Blower inlet gas flow (low)

c. Blower inlet gas temperature (high)

d. Heater wall temperature (high)

e. Reaction chamber gas temperature (high and low)

f. Reaction chamber shell temperature (high)

g. Return gas temperature (high)

Automatic shutdown of the recombiners (interruption of power to the blower and the heater elements) results if setpoints are exceeded for variables a, c, d, f, and g as listed above. If the setpoint is exceeded for variable b or heater temperature two-thirds through heater (high), heater outlet temperature (high), or the water inlet control valve is not fully open, power to the heater elements is interrupted but the blower continues to run.

The recombiner process alarms listed above are annunciated by a general trouble alarm external to the recombiner control cabinet, as well as by the annunciator on each recombiner control cabinet. Failure of the recombiner trickle heat is also annunciated by this general trouble alarm.

The gas outlet piping from each recombiner package is provided with a level switch to detect (and annunciate in the control room) the accumulation of water in the outlet piping. Such an occurrence could result from leakage of the recombiner cooling water inlet valve while the recombiner is not in operation.

The following process variables are recorded on XR-1:

a. Blower inlet pressure

b. Recombiner inlet flow

c. Blower inlet flow

Separate modules provide alarm and trip outputs for variables a and c. These modules are mounted on an instrument rack located on the front side of the control cabinet.

The following process temperatures are recorded on TRS-2:

a. Blower inlet temperature

b. Reaction chamber shell temperature

c. Return gas temperature

The following process temperatures are recorded on TRS-4:

a. Heater temperature two-thirds through heater

b. Heater outlet temperature

c. Heater wall temperature

Process temperature alarm and trip outputs are provided by the temperature recorders.

The annunciator assembly is a backlighted legend plate, flasher, sequential type annunciator with a common horn. The annunciator, along with the TEST, ACKNOWLEDGE, and RESET push buttons are mounted on the front side of the control cabinet.

During normal conditions, the legend plate is dark and the horn is off. During abnormal conditions, the annunciator indicates an alarm by a fast flashing legend plate and by a horn. The operator can acknowledge the alarm by pressing the ACKNOWLEDGE push button. This causes the horn to stop sounding and the legend to stop flashing but remain lighted. When conditions return-to-normal, the legend changes from steady to slow flashing and the horn sounds. The operator can clear the alarm by pressing the RESET push button. This causes the window to become dark again.

The alarm sequence is different if the abnormal condition returns to normal before acknowledgement by the operator. In that case, pushing the ACKNOWLEDGE push button causes the legend to change from fast flashing to slow flashing. The horn remains on until the RESET push button is pressed.

The operator can functionally test the entire annunciator system by pressing the TEST push button. After testing, the operator returns the annunciator to the ready condition by pressing the ACKNOWLEDGE and RESET push buttons in sequence.

6.2.5.6.2 Combustible Gas Analyzer Subsystem

The combustible gas analyzer packages are designed to be operable from the remote control panel and includes hydrogen and oxygen concentration indicators. Also provided in the control room are annunciation of high oxygen concentration and high hydrogen concentration, and analyzer package malfunction. Those malfunctions that are annunciated include out of range signal from the partial or total pressure sensors, calibration errors, system configuration errors, low flow, over pressurization, and module hardware faults.

Instrumentation and controls for the containment hydrogen recombiner subsystem and the combustible gas analyzer subsystem are discussed further in Section 7.3.1.1.6.

6.2.6 PRIMARY REACTOR CONTAINMENT LEAKAGE RATE TESTING

This section presents the testing program for the primary reactor containment ILRTs (Type A tests), primary containment penetration leakage rate tests (Type B tests), and primary containment isolation valve leakage rate tests (Type C tests). This program complies with 10CFR50, Appendix A, General Design Criteria, and Performance Based Option B of 10CFR50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors", to the greatest extent practicable. The details of the program are defined in the Primary Containment Leak Rate Testing Program (PCLRTP) as identified in Chapter 16.

6.2.6.1 Primary Reactor Containment Integrated Leakage Rate Tests

Upon completion of construction of the primary reactor containment, including installation of all portions of the mechanical, fluid, electrical, and instrumentation systems penetrating the containment associated with containment integrity; and upon satisfactory completion of the structural integrity tests as described in Section 3.8, the preoperational containment ILRT was performed in accordance with the requirements of Chapter 14 to verify that the actual containment leakage rate did not exceed the design limit.

Type A tests are conducted at intervals as described in PCLRTP. A general inspection of the accessible interior and exterior surfaces of the primary containment structure and components is performed in accordance with the PCLRTP, to uncover any evidence of structural deterioration that could affect either the containment structural integrity or leak-tightness. If there is evidence of structural deterioration, corrective action is taken. The structural deterioration and corrective action are reported in accordance with 10CFR50, Appendix J. Repairs or adjustments made to the containment boundary prior to the conduct of the Type A test shall be accounted for in the determination of the As-Found Type A test.

The ILRT (Type A) is performed to determine that the total leakage from the containment does not exceed the maximum allowable leakage rate (La) at the design basis LOCA maximum peak containment pressure (Pa), as defined in Chapter 16. Typical piping and instrumentation are shown in drawing M-60. Acceptance criteria and frequency are defined in the PCLRTP.

The Type A test is conducted in accordance with 10 CFR 50, Appendix J, Option B and the PCLRTP.

A typical data acquisition system is shown in drawing M-60. Prior to commencement of any Type A test the pretest requirements of ANSI/ANS N56.8-1994 are met with specifics as follows:

a. Those portions of fluid systems that are part of the RCPB, and are open directly to the primary containment atmosphere under postaccident conditions and become an extension of the boundary of the primary containment, are opened or vented to the containment atmosphere prior to and during the Type A test, except as noted in Table 6.2-24. Portions of closed systems inside the containment that penetrate primary containment and can rupture as a result of a LOCA are vented to the containment atmosphere, except as noted in Table 6.2-24.

b. All systems not designed to remain water-filled post-LOCA are drained of water to the extent necessary to ensure exposure of the system primary containment isolation valves to containment air test pressure.

c. Those portions of fluid systems that penetrate the primary containment, that are external to the containment and are not designed to provide a containment isolation barrier, are vented to the outside atmosphere, as applicable, to ensure that full postaccident differential pressure is maintained across the containment isolation barrier.

d. Systems that are required to maintain the plant in a safe condition during the Type A test are operable in their normal mode and are not vented, as noted in Table 6.2-24.

e. Systems that are normally filled with water and operating under postaccident conditions are not vented. However, the measured leakage rates (Type C) for containment isolation valves in these systems identified in Table 6.2-24 are reported in the Type A test final report.

f. For planning and scheduling purposes, or ALARA considerations, pathways that are Type B or C tested within the previous 24 calendar months need not be vented or drained during the Type A test.

6.2.6.2 Primary Containment Penetration Leakage Rate Tests

Containment penetrations with designs incorporating resilient seals, gaskets or sealant compounds, air locks and lock door seals, equipment and access hatch seals, and electrical canisters receive preoperational and periodic Type B leakage rate tests in accordance with 10CFR50, Appendix J, Option B and the PCLRTP. A list of all containment penetrations subject to Type B tests is provided in Table 6.2-25.

All Type B tests are conducted at pressure (Pa) as defined in Chapter 16. The acceptance criteria are given in the PCLRTP. Test methods are described in Section 6.2.6.3 below.

Penetrations with threaded caps are provided in the air lock to permit pressure testing of the door seals and the entire lock.

Penetrations for equalizing valves as described in Section 3.8.2.1.2 are provided in the air lock. Figure 6.2-48 shows the locations of all mechanical and electrical penetrations in the air lock. Figure 6.2-49 shows details of the door seals and the pressure test connection.

The personnel air lock volume is pressurized to primary containment peak accident pressure and tested periodically as described in Chapter 16 and the PCLRTP. During the air lock test, tie-downs are installed from inside the lock on the inner door, since normal locking mechanisms are not designed to withstand a differential pressure across the door in the reverse direction in excess of 5 psig. See Figure 6.2-50 for details of the tie-downs for the inner door. The tie-downs are installed from within the air lock. The force exerted by the tie-downs on the inner door is not monitored. Pressurizing the lock barrel also tests the lock mechanical and electrical penetrations, and the door seals.

The door seals are periodically tested at Pa as indicated in Chapter 16. Additionally, the door seals are tested after each opening at 10 psig without installing tie-downs as indicated in Chapter 16 and the PCLRTP.

6.2.6.3 Primary Containment Isolation Valve Leakage Rate Tests

The containment isolation valves that are Type C tested are listed in Table 6.2-25.

Type B and C tests are performed by local pressurization, using either the pressure-decay or flowmeter method. For the majority of isolation valves, the test pressure is applied in the same direction that the valve would see when required to perform its safety function. There are a few exceptions where the test pressure is applied in the reverse direction. Further explanation is provided in Table 6.2-25. For the pressure decay method, the test volume is pressurized with air or nitrogen to at least Pa. The rate of decay of pressure of the known free air test volume is

monitored to calculate leakage rate. For the flowmeter method, pressure is maintained in the test volume by making up air, nitrogen, or water (if applicable) through a calibrated flowmeter. The flowmeter fluid flow rate is the isolation valve leakage rate.

All isolation valve seats that are exposed to containment atmosphere subsequent to a LOCA are tested with air or nitrogen at pressure (Pa) as defined in Chapter 16.

Those valves which are in lines designed to be, or remain, filled with a liquid for at least 30 days subsequent to a LOCA are leakage rate tested with that liquid. The liquid leakage measured is neither converted to equivalent air leakage nor added to the Type B and C test totals. Isolation valves tested with liquid are identified in Table 6.2-25 and designated under note (15).

The acceptance criteria for all penetrations and isolation valves subject to Type B and C tests are given in Chapter 16 and the PCLRTP.

6.2.6.4 Scheduling and Reporting of Periodic Tests

The periodic leakage rate test schedules for Types A, B and C tests are given in the PCLRTP.

Type B and C tests can be conducted at any time during normal plant operations or during shutdown periods, so long as the time interval between tests for any individual Type B or C test does not exceed the maximum allowable interval specified in the PCLRTP. Each time a Type B or C test is completed, the overall total leakage rate for all required Type B and C tests is corrected for any differences noted.

Provisions for reporting test results are given in the PCLRTP.

6.2.6.5 Special Testing Requirements

6.2.6.5.1 Drywell Steam Bypass Test

Following the drywell structural integrity test, described in Section 3.8.1.7, a preoperational drywell-to-wetwell leakage rate test is performed at the peak drywell-to-wetwell differential pressure. Table 14.2-4 gives the test descriptions. Also, drywell to wetwell leakage rate tests at a reduced differential pressure corresponding approximately to the submergence of the vents, defined in Chapter 16, are performed following the preoperational Type A test and periodically thereafter. These drywell leakage rate tests verify, over the design life of the plant, that no paths for gross leakage from the drywell to the suppression chamber air space bypassing the pressure-suppression feature exist. The combination of the design pressure and reduced pressure leakage rate tests also verifies that the drywell performs adequately for the full range of postulated primary system break sizes. The drywell leakage rate limits specified in Chapter 16 for the above tests are based on a value of 10% of the allowable bypass $A/(K)^{1/2}$ for small breaks that are described in Section 6.2.1.1.5.4.

Drywell leakage rate tests are performed with the drywell isolated from the suppression chamber. Valves and system lineups are the same as for the Type A test except any paths for equalizing drywell and suppression chamber pressure open during the Type A test are isolated. The drywell atmosphere is allowed to stabilize for a period of 1 hour after attaining test pressure. Leakage rate test calculations, using the wetwell pressure rise method on Unit 1 and the wetwell pressure rise method on Unit 2, commence after the stabilization period.

The pressure rise method (Unit 1) is based on containment atmosphere pressure and temperature observations and the known wetwell free air volume specified in Table 6.2-1. Leakage rate is calculated from the pressure and temperature data, wetwell free air volume, and elapsed time.

The pressure rise method (Unit 2) is based on containment atmosphere pressure and temperature observations and the known wetwell volume specified in Table 6.2-1. Leakage rate is calculated from the pressure and temperature data, wetwell free air volume, and elapsed time.

When the drywell leakage rate test described above is not performed, an alternate test is performed to verify that each set of downcomer vacuum breaker valves does not provide a path for gross leakage from the drywell to the suppression chamber.

The periodic drywell leakage rate test and downcomer vacuum breaker valve leakage rate test pressures, test duration, and acceptance criteria are specified in Chapter 16. Periodic drywell leakage rate tests and downcomer vacuum breaker valve leakage tests are performed at the intervals specified in Chapter 16. This surveillance testing will be in accordance with the Technical Specifications.

6.2.7 POSTACCIDENT SYSTEM ISOLATION

Following an accident in which significant fuel damage is postulated to occur, a number of plant systems whose piping penetrates the primary containment may contain highly radioactive fluids. Adequate system isolation features exist to ensure that the integrity of these systems will be maintained.

6.2.7.1 System Isolation Provisions

The boundaries of potentially contaminated systems are adequately isolated by one of the following:

a. Two normally closed manual valves

b. One normally closed manual valve (low pressure piping)

c. One or two normally closed manual valves and a cap

d. One SRV or one rupture disc

e. Two check valves

f. One remotely actuated valve and one check valve

g. Two remotely actuated valves

In cases where a remotely actuated valve is required to change position to provide system isolation, the valve receives an auto isolation signal. In some cases a system isolation valve does not receive a direct isolation signal but is interlocked to close when a containment isolation valve or other valve opens to permit fluid flow from the containment.

Table 6.2-26 lists remotely actuated system isolation valves, their normal and required accident positions and their actuation signals. Containment isolation valves that also provide postaccident system isolation are not included in this table but are listed in Table 6.2-17.

6.2.7.2 Potentially Contaminated Systems

The following systems whose piping penetrates primary containment may contain highly radioactive fluids after an accident. Other systems have been excluded from this list for the reasons discussed in Section 6.2.8.2.

a. RHR System (drawing M-51)

b. Core Spray System (drawing M-52)

c. HPCI System (drawing M-55)

d. RCIC System (drawing M-49)

e. CRD Hydraulic System (SDV, drawings M-46 and M-47).

f. Safeguard Piping Fill System (drawing M-52)

g. PASS (drawing M-30)

h. CAC System (drawing M-57)

6.2.8 LEAKAGE REDUCTION PROGRAM

To ensure that leakage from systems that may be expected to handle highly radioactive fluids during or after an accident is maintained as-low-as-practical, a leakage reduction program will be established. System isolation provisions have been reviewed in conjunction with this effort and are discussed in Section 6.2.7.

6.2.8.1 Systems to be Leak Tested

The following systems will be leak tested at 24-month intervals. The test conditions will simulate the expected operating conditions during an accident or transient:

a. RHR System

b. Core Spray System

c. HPCI System

d. RCIC System

e. CRD Scram Discharge System

f. Safeguard Piping Fill System

g. PASS (including portions of the Process Sampling System)

h. CAC System (recombiner and sample loops only)

6.2.8.2 Systems Excluded from the Program

The following systems are excluded from the leakage reduction program for the reasons given below:

a. Reactor Recirculation System - The interfaces between the recirculation system and the systems outside containment (other than RHR) are isolated by containment isolation valves.

b. RWCU - The RWCU system is isolated from the recirculation system by containment isolation valves.

c. Main Steam System - The main steam system is isolated by containment isolation valves.

d. Feedwater System - The feedwater system is isolated by containment isolation valves.

e. Process Sampling System - Sample lines from potentially contaminated sources inside the containment are isolated by containment isolation valves. Potentially contaminated sample lines from the RHR system, associated with postaccident sampling, will be leak tested with the postaccident sample system.

f. Suppression Pool Cleanup System - The suppression pool cleanup system is isolated by containment isolation valves.

g. RERS and SGTS - The reactor enclosure HVAC supply and exhaust valves will isolate the reactor enclosure upon receipt of high radiation isolation signal. The RERS and SGTS will then filter and exhaust air from the reactor enclosure and maintain a subatmospheric pressure. Because the source of radioactivity in these systems is airborne contamination resulting from previous leakage from the containment or contaminated systems, a leakage reduction program for the low pressure RERS/SGTS ducting would not significantly reduce the airborne radioactivity concentrations in the secondary containment. The recirculation and SGTS filters will be tested as described in Sections 6.5.1.3.4 and 6.5.1.1.4.

h. Containment Radiation Sampling System - The containment radiation sampling system, used to provide an indication of primary leakage during normal operation, is isolated by containment isolation valves.

6.2.8.3 Leak Testing Method

System leak test conditions will simulate the expected operating conditions during an accident. Each component in the system will be inspected for leakage. Water leakage will be collected and measured. Steam leakage will be estimated and converted to an equivalent water leak rate. Gas systems will be bubble leak tested with a zero leakage acceptance criteria or leakage will be quantified by means of a pressure decay or helium leak test.

Leakage rate goals will be established for each system based on baseline data from the first tests. Components whose leakage contributes significantly to the total leak rate or increases substantially between tests will be repaired to maintain total leakage as-low-as-practical.

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Table 6.2-1 (See Note)

CONTAINMENT DESIGN PARAMETERS*

DRYWELL AND SUPPRESSION CHAMBER	DRYWELL	SUPPRESSION CHAMBER
Internal design pressure, psig	55	55
External to internal design differential pressure, psid	5	5
Drywell deck design differential pressure, psid	30 downward	20 upward
Design temperature, °F	340	220
Drywell net free air volume, ft^3		
Low level[4]		243,580[1][2]
High level[4]		242,860[1][2]
Design leak rate, % by weight/day	0.5	0.5
Maximum allowable leak rate, % by weight/day	0.5	0.5
Suppression chamber free air volume, ft^3		
Low level[4]		159,540[2][3]
High level[4]		147,670[2][3]
Suppression pool water volume, ft^3		
Low level[4]		122,120[2][3]
High level[4]		134,600[2][3]
Suppression pool surface area, ft^2		
Outside pedestal		4974[2]
Inside pedestal		293
Suppression pool depth, ft		
Low level		22'
High level		24'-3"

Table 6.2-1 (Cont'd)

	DRYWELL	SUPPRESSION CHAMBER
VENT SYSTEM		
Number of downcomers		83(5)
Nominal downcomer diameter, ft		2
Total vent area, ft^2		244.7(5)
Downcomer submergence, ft		
Low water level		10'
High water level		12'-3"
Downcomer loss coefficient		2.23(2)

(1) Drywell volume includes downcomer air volume.
(2) These values vary slightly from those actually used in the analysis. The difference in analysis results is negligible.
(3) Including pedestal volume.
(4) Low level and high level refer to suppression pool water level.
(5) The original containment analysis included a total vent area of 256.5 square feet, equivalent to all 87 downcomers. Four of the downcomers have been capped. The impact of capping four downcomers on analysis results is negligable.

*NOTE: The information presented in this table was used for the original containment analysis and such should be considered historical. Refer to Table 6.2-4a for the parameters used in the current containment response analysis.

Table 6.2-2

ENGINEERED SAFETY FEATURE SYSTEMS INFORMATION
FOR CONTAINMENT RESPONSE ANALYSES*

	FULL CAPACITY	CONTAINMENT ANALYSIS VALUE CASE A	CASE B	CASE C
DRYWELL SPRAY				
Number of RHR pumps	2	2	1	0
Number of lines	2	2	1	0
Number of headers	2	2	1	0
Spray flow rate, gpm/pump	9,500	9,500	9,500	0
Spray thermal efficiency, %	See Section 6.2.1.1.3.4.3			
SUPPRESSION CHAMBER SPRAY				
Number of RHR pumps	2	2	1	0
Number of lines	2	2	1	0
Number of headers	1	1	1	0
Spray flow rate, gpm/pump	500	500	500	0
Spray thermal efficiency, %	See Section 6.2.1.1.3.4.3			
SUPPRESSION POOL COOLING SYSTEM				
Number of RHR pumps	2	2	1	1
Pump capacity, gpm/pump	10,000	10,000	10,000	10,000
RHR heat exchangers				
Type - Inverted U-tube, single pass shell, multipass tubes, vertical mounting	-	-	-	-
Number	2	2	1	1

Table 6.2-2 (Cont'd)

	FULL CAPACITY	CONTAINMENT ANALYSIS VALUE CASE A	CASE B	CASE C
Heat transfer area, ft^2/unit	6,281*	-	-	-
Overall heat transfer coefficient, Btu/hr-ft^2-°F/unit	228 *	-	-	-
RHRSW flow rate, gpm/unit	8000	5570	5570	5570
RHRSW temperature, °F	-	95	95	95
Minimum design	40	-	-	-
Maximum design	95	-	-	-
Containment heat removal capability per unit, using 95°F RHRSW and 212°F pool temperature, Btu/hr	128.5 $x10^6$	-	-	-
Peak Containment Heat removal rate Btu/hr at peak suppression pool temperature of 203.4°F	119.9 $x10^6$	-	-	-

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* Actual heat transfer surface area and heat transfer coefficient vary with the condition of the heat exchanger (e.g. plugged or fouled tubes). Acceptance criteria are administratively controlled by plant surveillance procedures to assure that the RHR heat exchangers can provide the required Peak Containment Heat Removal Rate at the peak suppression pool water temperature.

** For two-unit operation with one RHRSW loop in service, the RHRSW design minimum required flow rate under accident conditions is 8000 gpm to the LOCA unit and between 5570 and 8000 gpm to the unit under normal shutdown conditions. An evaluation has been performed, however, to confirm that a RHRSW flow rate as low as 5570 gpm is sufficient to meet the design heat removal requirements of the unit with the LOCA under certain conditions.

Table 6.2-3

ACCIDENT ASSUMPTIONS AND INITIAL CONDITIONS
FOR CONTAINMENT RESPONSE ANALYSES*

Components of effective break area (recirculation line break), ft^2	
Recirculation line	3.538
Jet pumps	0.537
Primary steam energy distribution(1), 10^6 Btu	
Steam energy	26.7
Liquid energy	365.0
Sensible energy	
Reactor vessel	93.97
Reactor internals (less core)	59.08
Primary system piping	23.2
Fuel(2)	6.299
Other assumptions used in analysis	
Feedwater valve closure time, sec	Instantaneous
MSIV closure time, sec	
Recirculation line break (includes 0.5 second delay)	3.0
Main steam line break (includes 0.5 second delay)	5.0
Scram time, sec	<1

(1) All energy values except fuel are based on a 32°F datum.
(2) Fuel energy is based on a datum of 285°F.

*NOTE: The information presented in this table was used for the original containment analysis and such should be considered historical. Refer to Table 6.2-4a for the parameters used in the current containment response analysis.

Table 6.2-4

INITIAL CONDITIONS FOR CONTAINMENT RESPONSE ANALYSES*

REACTOR COOLANT SYSTEM[1]		
Reactor power level, MWt		3,435
Average coolant pressure, psia		1,055
Average coolant temperature, °F		551.1
Mass of RCS liquid, lb		669,900
Mass of RCS steam, lb		24,100
Volume of liquid in vessel, ft^3		11,922.3
Volume of steam in vessel, ft^3		10,122
Volume of liquid in recirculation loops, ft^3		1,320.4
Volume of steam in steam lines, ft^3		1,218.0
Volume of liquid in feedwater line, ft^3		1,232.5
Volume of liquid in miscellaneous lines, ft^3		Insignificant
Total reactor coolant volume, ft^3		25,815.2
CONTAINMENT	DRYWELL	SUPPRESSION CHAMBER
Pressure, psig	0.75	0.75
Air temperature, °F	150	95
Relative humidity, %	20%	100%
Suppression pool water temperature, °F	-	95
Suppression pool water volume, ft^3	-	118,655
Vent submergence, ft	-	12'-3"

(1) 105% of rated steam flow and normal liquid levels

*NOTE: The information presented in this table was used for the original containment analysis and such should be considered historical. Refer to Table 6.2-4a for the parameters used in the current containment response analysis.

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

I. Short-Term Analysis

A. Drywell and Vent System

Variable	Units	Value Used for Analysis
Drywell Internal Design Pressure	psig	55
Drywell Internal Design Temperature	°F	340
Drywell Deck Design Differential Pressure	psid	30 (downward)
Drywell Free Volume (including vent system)	ft^3	243,580
Drywell Pressure	psia	15.45
Drywell Temperature	°F	150
Drywell Relative Humidity	%	20
Number of Downcomers		83 (1)
Downcomer Inside Diameter	ft	1.9375
Downcomer Length	ft	45.5
Downcomer Area (each)	ft^2	2.95
Total Downcomer Discharge Area	ft^2	244.7 (1)
Downcomer Submerge (HWL)	ft	12.25
Total Downcomer Flow Loss Coefficient (including exit loss)		2.23

B. Wetwell and Suppression Pool

Variable	Units	Value Used for Analysis
Wetwell Internal Design Pressure	psig	55
Wetwell Deck Design Differential Pressure	psid	20 (upward)
Wetwell Airspace Volume at high water level (including vent system)	ft^3	147,670
Suppression Pool Volume (HWL)	ft^3	134,600
Suppression Pool Surface Area (outside pedestal)	ft^2	4,974
Suppression Pool Surface Area (inside pedestal	ft^2	293
Wetwell Pressure	psia	15.45
Wetwell Airspace Temperature	°F	95
Suppression Pool Temperature	°F	95
Wetwell Relative Humidity	%	100

(1) The original containment analysis included a total vent area of 256.5 square feet, equivalent to all 87 downcomers. Four of the downcomers have been capped. The impact of capping four downcomers on analysis results is negligable.

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

I. Short-Term Analysis (cont'd)

C. Reactor Initial Conditions

Rerated Power*/Flow Operating Point	RPV Dome Pressure (psia)	Saturation Enthalpy (Btu/lbm)	Downcomer Enthalpy (Btu/lbm)	Downcomer Subcooling Btu/lbm
62RP/40F	1017	545.2	503.0	42.2
102RP/81F**	1068	552.8	526.1	26.7
102RP/87F	1068	552.8	527.7	25.1
102RP/100F	1068	552.8	531.3	21.5
102RP/110F	1068	552.8	533.4	19.4
62RP/40F - FFWTR	1009	543.9	487.9	56.0
102RP/81F - FFWTR**	1051	550.3	509.0	41.3
102RP/87F - FFWTR	1049	550.0	510.6	39.4
102RP/100F - FFWTR	1049	550.0	516.0	34.0
102RP/110F - FFWTR	1049	550.0	519.3	30.7

* RP (Rerate Power) is defined as 3458 MWt
** RP (Rerate Power) is defined here as 3622 MWt

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

II. Long-Term Analysis*

A. Reactor Coolant System

Variable	Units	Value Used for Analysis
Reactor Power	MWt	3528 (102% of 100%P)
Core Flow Rate	lbm/hr	100.0E6 (100%F)
RPV Dome Pressure	psia	1068
RPV Temperature	°F	552.5
Core Inlet Enthalpy	Btu/lbm	531.3
RPV Inlet Feedwater Enthalpy (upstream of RWCU inlet)	Btu/lbm	411.4
Initial Steam Flow	lbm/hr	15.451E6
Coolant System Total Free Volume	ft^3	23,492
Coolant System Liquid Volume	ft^3	13,108

B. Drywell and Vent System

Variable	Units	Value Used for Analysis
Drywell Free Volume (including vents)	ft^3	243,580
Drywell Pressure	psia	15.45
Drywell Temperature	°F	150
Drywell Relative Humidity	%	20
Number of Downcomers		83
Downcomers Inside Diameter (Nominal)	ft	1.9375
Total Vent Area	ft^2	244.7
Maximum Downcomer Submerge	ft	10.0
Total Downcomer Flow Loss Coefficient (including exit loss)		2.23

* The Long term containment analysis is performed for rerated conditions including the additional head load from SIL 636. (Reference 6.2-41)

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

II. Long-Term Analysis(cont'd)

C. Suppression Chamber and Suppression Pool

Variable	Units	Value Used for Analysis
Suppression Chamber Airspace Volume	ft^3	147,670 (HWL) 159,540 (LWL)
Suppression Pool Volume	ft^3	134,300 (HWL) 118,655 (LWL)
Suppression Pool Surface Area	ft^2	5267
Suppression Chamber Airspace Pressure	psia	15.45
Suppression Chamber Airspace Temperature	°F	95
Suppression Chamber Relative Humidity	%	100
Suppression Pool Temperature	°F	95

D. RHR System

Variable	Units	Value Used for Analysis
Service Water Temperature	°F	95
Heat Exchanger K-Factor	Btu/sec-°F	305
RHR Pump Heat per Pump	Hp	1250

Table 6.2-4A

THE LGS POWER RERATE CONTAINMENT ANALYSIS

II. Long-Term Analysis(cont'd)

E. ECCS

Variable	Units	Value Used for Analysis
HPCI		
Minimum Rated Flow at 0 to 200 psid	gpm	5600
LPCS		
Minimum Rated Flow at 105 psid (2 pumps)	gpm	6250
Pump Heat per pump	Hp	658
LPCI		
Minimum Rated Flow at 20 psid (per pump)	gpm	10000
Pump Heat per pump	Hp	1250

F. Containment Spray

Variable	Units	Value Used for Analysis
Drywell Spray		
Flow Rate Per Pump	gpm	9500
Pump Heat per Pump	Hp	1187.5
HX K-Factor	Btu/sec-°F	289.8
Wetwell Spray		
Flow Rate Per Pump	gpm	500
Pump Heat per Pump	Hp	62.5
HX K-Factor	Btu/sec-°F	15.2

Table 6.2-5

SUMMARY OF SHORT-TERM CONTAINMENT RESPONSES TO RECIRCULATION LINE AND MAIN STEAM LINE BREAKS

	RECIRCULATION LINE BREAK	MAIN STEAM LINE BREAK
Peak drywell pressure, psig	44.0	36.20
Peak drywell deck downward differential pressure, psid	25.995	19.5
Time of peak pressures, sec	13.66	20.12
Peak drywell temperature, °F	290.9	330
Peak suppression chamber pressure, psig	30.57	30.55
Time of peak suppression chamber pressure, sec	34.75	50
Peak suppression pool temperature during blowdown, °F	135.7	136
Calculated drywell pressure margin, %	20	34
Calculated suppression chamber pressure margin, %	44	44
Calculated deck differential pressure margin, %	13	35
Energy released to containment at time of peak pressure, 10^6 Btu	262.23	-
Energy absorbed by passive heat sinks at time of peak pressure, 10^6Btu	0	0

NOTE: The information presented in this table for the recirculation line break results is based on the original design basis conditions. Refer to Table 6.2-5A for the recirculation line break results for current plant conditions.

The information presented in this table for the main steam line break results is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results presented here reasonably represent the general characteristics of the main steam line break analysis results. See explanation at the beginning of Section 6.2.1.1.3.

Table 6.2-5A

CONTAINMENT LOCA RESPONSE AT RERATE POWER

Parameter	Analysis	Design Limit
Peak Drywell Pressure (psig)	42.1 (1)	55
Peak Wetwell Pressure (psig)	39.0 (2)	55
Peak Drywell-to-Wetwell Pressure Difference (psid)	28.5 (3)	30
Peak Bulk Pool Temperature (°F) (LOCA)	203.4 (4)	220* 212**

* Structural
** Low pressure ECCS pump NPSH @ 0 psig in the suppression chamber

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(1) Short Term Analysis performed for: Power=3694 MWt; Core Flow=110%; FWTR=105°F

(2) Short Term Analysis performed for: Power=3527 MWt; Core Flow=81%; FWTR=105°F

(3) Short Term Analysis performed for: Power=3694 MWt; Core Flow=100%; FWTR=0°F

(4) Long Term Analysis performed for: Power = 3528 MWt; Core Flow = 100%; FWTR = 0°F

(Initial Reactor pressure assumed to be 1053 psig)

Table 6.2-6

SUMMARY OF LONG-TERM CONTAINMENT RESPONSES TO RECIRCULATION LINE AND MAIN STEAM LINE BREAKS

	CASE A	CASE B	CASE C
Secondary peak suppression chamber pressure, psig	6.56	14.19	16.7
Peak suppression pool temperature, ^{o}F	173.6	211.3	212.5
HPCI flow rate, gpm		Not Used	
CS flow rate, gpm	12,500	6,250	6,250
RHR flow rate, gpm/pump	10,000	10,000	10,000

NOTE: The information presented in this table is based on the original design basis conditions. Refer to Table 6.2-5A for the Case C results for current plant conditions and methodology. The results for Cases A, B, and C shown is this table reasonably represent the general characteristics and relative differences between the three cases.

Table 6.2-7

ENERGY BALANCE FOR RECIRCULATION LINE BREAK ACCIDENT

	Energy, 10^6 Btu			
	INITIAL	DRYWELL PEAK PRESSURE	END OF BLOWDOWN	LONG-TERM PEAK PRESSURE
Reactor coolant	392.3	139.5	12.325	58.1
Fuel and cladding[1]	6.299	6.296	6.116	-
Core internals and primary primary system piping	82.29	82.99	82.26	28.097
Reactor vessel metal	93.97	93.97	93.97	32.56
Pump heat added	0	0	0.38045	185.3
Blowdown enthalpy[2]	0	262.23	409.6	409.6
Decay heat[3]	0	23.28	35.82	1,563.0
Metal-water reaction heat	0	0.02838	0.085	0.25
Drywell structures	0	0	0	0
Drywell air	[4]	[4]	[4]	1.98
Drywell steam	2.236	56.33	42.06	9.79
Suppression chamber air	1.005	2.622	2.7233	1.097
Suppression chamber steam	0.3849	0.7054	1.0749	5.6238
Suppression pool water	64.3	666.4	823.8	1,382.7
Energy transferred by heat exchangers	0	0	0	1,304.0
Passive heat sinks	0	0	0	0

(1) Does not include sensible energy in the fuel above initial reactor vessel saturation temperature (this energy is accounted for in decay heat as fuel relaxation energy)
(2) Blowdown is accounted for in drywell condition, and should not be used to sum the total energy
(3) Includes fuel relaxation energy
(4) Included in drywell steam

NOTE: The information presented in this table is based on the original design basis conditions. The current recirculations line break results are discussed in Section 6.2.1.8. The results presented here reasonably represent the general characteristics of the current recirculation line break analysis results.

Table 6.2-8

ACCIDENT CHRONOLOGY FOR
RECIRCULATION LINE BREAK ACCIDENT [1]

	TIME (SEC) ALL ECCS IN OPERATION	MINIMUM ECCS AVAILABLE
Vents cleared	0.733	0.733
Drywell reaches peak pressure	12.66	13.66
Maximum positive differential pressure occurs	0.85	0.85
Suppression chamber reaches pressure peak	33.72	34.75
Initiation of the ECCS	30	30
End of blowdown	36.35	37.69
Vessel reflooded	72.03	91.03
Initiation of RHR heat exchanger	600[2]	600[2]
Suppression chamber reaches secondary pressure peak	7,047	42,854

NOTE: (1) The information presented in this table is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonably represent the general characteristics of the current recirculation line break analysis results.

(2) Initiating time for analysis only. Containment heat removal will be initiated in accordance with emergency operating procedures based on plant conditions.

Table 6.2-9

INITIAL AND BOUNDARY CONDITIONS FOR
DRYWELL SPRAY ACTUATION ANALYSIS
(Used in Reference 6.2 - 24 Analysis)

TABLE A[5]

	t_{oo}[1]	t_o[2]
Drywell		
Volume[3], ft^3	242,860	242,860
Pressure, psia	13.7	35.61
Temperature, °F	135	260.3
Relative humidity, %	90	100
Spray rate, gpm/number of trains	0/0	9,500/1
Wetwell		
Volume - Vapor region[3], ft^3	137,132	137,132
- Suppression pool[3], ft^3	127,507	127,507
Pressure, psia	13.7	31.28
Temperature, °F	50	50
Relative humidity, %	100	100
Suppression pool free surface area, ft^2	4,974	4,974
Wetwell-to-Drywell Vacuum Breakers		
Number of valve assemblies operable (three required to operate and one redundant)	4 of 4	
Flow area per assembly, ft^2	2.05	
Flow coefficient[4]	0.495	
Vacuum breaker full open pressure[4] (psid)	4.48	
RHR System - Drywell Spray Mode		
Service water flow rate, gpm	9,000	
Service water temperature, °F	40	
Heat exchanger effectiveness	0.249	
Spray Temperature: (Initially)	47.6°F	
(at 300 seconds)	49.7°F	

Table 6.2-9

INITIAL AND BOUNDARY CONDITIONS FOR
DRYWELL SPRAY ACTUATION ANALYSIS
(Used in Reference 6.2 - 24 Analysis)

TABLE B[5]

	t_{oo}[1]	t_o[2]
Drywell		
Volume[3], ft^3	248,950	248,950
Pressure, psia	14.8	34.4
Temperature, °F	150	258.3
Relative humidity, %	100	100
Spray rate, gpm/number of trains	0/0	9,500/1
Wetwell		
Volume - Vapor region[3], ft^3	146,283	146,283
- Suppression pool[3], ft^3	127,507	127,507
Pressure, psia	14.8	29.1
Temperature, °F	50	50
Relative humidity, %	100	100
Suppression pool free surface area, ft^2	4,983	4,983
Wetwell-to-Drywell Vacuum Breakers		
Number of valve assemblies operable (two required to operate and one redundant)	3 of 4	
Flow area per assembly, ft^2	2.05	
Flow coefficient[4]	0.495	
Vacuum breaker full open pressure[4] (psid)	4.48	
RHR System - Drywell Spray Mode		
Service water flow rate, gpm	9,000	
Service water temperature, °F	40	
Heat exchanger effectiveness	0.249	
Spray Temperature: (Initially)	47.6°F	
(at 300 seconds)	49.7°F	

(1) Initial conditions prior to small break as discussed in Section 6.2.1.1.4.4
(2) Conditions after small break, preceding drywell spray actuation (see Section 6.2.1.1.4.5).
(3) High water level

Table 6.2-9

INITIAL AND BOUNDARY CONDITIONS FOR
DRYWELL SPRAY ACTUATION ANALYSIS
(Used in Reference 6.2 - 24 Analysis)

(4) Value given is for total flow path. Actual test results indicate that full open pressure differential across the vacuum breaker assembly only is 2.89 psid. For the ISA computer analysis, the following different pressures were used for opening the valves:

dp (across two valves) at which VB assembly starts to open equals 2.81 psid

dp (from wetwell to drywell) at which VB assembly is fully open equals 4.48 psid

(5) The initial conditions and parameters differ slightly from those indicated in UFSAR Table 6.2-1; however, the use of the conditions and assumptions such as the loss of noncondensables through the purge lines, which were used in the ISA Analysis (reference 6.2-24) produces a more severe transient for purposes of comparing the performance of two vs three operating vacuum breaker valve assemblies. Table A provides the initial conditions used in the original analysis which assumes that the purge valves are closed. The assumptions that are shown in Table B were used to created a worst case analysis to justify reducing the number of operable vacuum breakers from 4 to 3. This scenario assumes that the purge valves are open at the time of a small break LOCA.

Table 6.2-10

REACTOR BLOWDOWN DATA FOR RECIRCULATION LINE BREAK[1][2][3][4]

REACTOR VESSEL TEMPERATURE (°F)	TIME (sec)	REACTOR VESSEL PRESSURE (psia)	LIQUID FLOW (lb_m/sec)	LIQUID ENTHALPY (Btu/lb_m)	STEAM FLOW (lb_m/sec)	STEAM ENTHALPY (Btu/lb_m)
551.1	-	1055	47620	550.1	-	1190.3
550.4	0.733	1048	47620	549.4	-	1190.5
549.9	1.03	1045	47620	549.1	-	1190.6
549.3	1.53	1040	47620	549.0	-	1190.65
548.5	3.16	1032	32290	547.5	-	1191.0
549.3	4.16	1040	32380	549.0	-	1190.65
550.2	5.16	1047	32470	549.3	-	1190.5
550.1	6.16	1055	32560	550.1	-	1190.3
552.5	8.16	1067	32700	552.1	-	1189.9
553.3	10.16	1074	32790	553.5	-	1189.5
552.8	13.66	1069	32720	552.2	-	1189.9
542.0	15.16	979.2	14160	538.5	4895	1192.8
518.7	18.16	803.2	10480	509.2	4438	1199.4
500.7	20.16	685.5	8518	487.7	4054	1202.5
454.3	25.00	441.6	4788	435.8	2919	1205.6
403.4	30.00	257.0	2387	387.53	1851	1202.4
328	35.00	100.7	2673	298.76	609.2	1187.9
294.6	37.5	61.78	2505	263.8	265.8	1178.2
292.8	37.69	60.06	-	262.5	277.7	1178.1
282.6	38.6	51.26	-	252.2	121	1175.1
281.0	38.75	49.98	-	250.2	-	1174.4

(1) The volume of the primary system below the elevation of the recirculation line break is 4641 ft^3.

(2) The maximum diameter for the 251 sized vessel is 254 in corresponding to an inside cross-sectional vessel area of 352 ft^2. (The actual flow area is a function of elevation due to the varying amount of space occupied by the vessel internals).

(3) The surface area and maximum depth of the liquid pool formed on the drywell floor following a DBA LOCA and/or containment spray actuation are approximately 4800 ft^2 and 18 inches, respectively.

(4) The blowdown data provided includes the effect of ECCS additions prior to the end of blowdown. The amount of water in the vessel at the end of blowdown for the DBA is 1559 ft^3.

NOTE: The information presented in this table is histroical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8.

Table 6.2-11

REACTOR BLOWDOWN DATA FOR MAIN STEAM LINE BREAK[1][2][3]

REACTOR VESSEL TEMPERATURE (°F)	TIME (sec)	REACTOR VESSEL PRESSURE (psia)	LIQUID FLOW (lb_m/sec)	LIQUID ENTHALPY (Btu/lb_m)	STEAM FLOW (lb_m/sec)	STEAM ENTHALPY (Btu/lb_m)
551.1	-	1055	-	550.1	11650	1190.3
547.4	0.73	1023	-	546.1	8464.0	1191.6
546.5	1.0	1016	28250	544.2	1023.0	1191.3
547.0	1.499	1020	28120	545.7	1084.0	1191.7
547.2	2.06	1022	27950	545.7	1148.0	1191.7
547.3	2.56	1022	27730	545.7	1223.0	1191.7
547.3	3.06	1023	27600	545.7	1267.0	1191.7
547.3	4.06	1023	23960	545.7	1220.0	1191.7
547.8	5.18	1027	20710	546.8	1169.0	1191.6
548.2	8.18	1030	19880	546.0	1452.0	1191.5
547.2	10.1	1022	19190	545.7	1637.0	1191.7
540.7	15.1	968.8	16960	536.6	2069.0	1193.7
526.1	20.18	868.5	14130	518.0	2355.0	1197.5
509.0	25.18	737.7	11080	499.4	2431.0	1201.0
487.6	30.01	608.1	8285	473.0	2294.0	1203.4
460.7	35.03	470.2	5777	441.4	2046.0	1205.5
432.0	40.01	350.9	3695	410.5	1686.0	1204.4
395.3	45.18	234.4	2536	369.6	1164.0	1201.3
350.1	50.06	134.7	2570	321.8	604.9	1193.1
308.0	55.01	75.42	2442	278.0	237.9	1182.5
282.9	58.62	51.54	1126	252.28	58.74	1175.1
281.6	58.87	50.5	404.2	251.23	20.2	1174.7
280.5	59.12	49.56	-	249.18	-	1174.1

(1) The volume of the primary system below the elevation of the main steam line break is 16,148 ft^3.

(2) The maximum diameter for the 251 sized vessel is 254 in corresponding to an inside cross-sectional vessel area of 352 ft^2. (The actual flow area is a function of elevation due to the varying amount of space occupied by the vessel internals).

(3) The surface area and maximum depth of the liquid pool formed on the drywell floor following a DBA LOCA and/or containment spray actuation are approximately 4800 ft^2 and 18 inches, respectively.

NOTE: The information presented in this table is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break analysis results.

Table 6.2-12

CORE DECAY HEAT FOLLOWING LOCA
FOR CONTAINMENT ANALYSES

TIME (Sec)	NORMALIZED CORE HEAT(1)
0.0	1.00288
0.2	0.98188
0.6	0.74628
1.0	0.58218
2.0	0.54548
4.0	0.57113
6.0	0.53537
10.0	0.37232
20.0	0.11244
40.0	0.04215
60.0	0.03789
80.0	0.03575
100.0	0.03436
150.0	0.03197
220.0	0.02990
220.1	0.02702
300.0	0.02547
400.0	0.02408
600.0	0.02212
800.0	0.02069
1000.0	0.01956
2000.0	0.01599
3000.0	0.01400
$1x10^4$	0.01012
$2x10^4$	0.00850
$4x10^4$	0.00705
$1X10^5$	0.00546

(1) Normalized to include fuel relaxation energy, pump heat, and metal-water reaction

The information presented in this table is historical and was used in the original design basis for containment analysis. The current design basis analysis uses the decay heat model presented in ANSI/ANS 5.1-1979, as approved by the NRC (Ref. 6.2-30), including SIL 636 (Ref. 6.2-40)

Table 6.2-13

SECONDARY CONTAINMENT ACCESS OPENINGS

ACCESS OPENING ROOM NUMBER	ELEVATION (feet)	TYPE OF ACCESS OPENING
201	201	Personnel access air lock
282	201	Personnel access air lock
300	217	Personnel access air lock
310	217	Railroad access air lock
301	217	Equipment access air lock
303	217	Personnel access air lock
308	217	Personnel access air lock
366	217	Personnel access air lock
367	217	Equipment access air lock
369	217	Personnel access air lock
377	217	Personnel access air lock
402A	253	Personnel access air lock
408	269	Personnel access air lock
481	269	Personnel access air lock
608	313	Personnel access air lock
606	313	Personnel access air lock
614	331	Personnel access air lock
642	313	Personnel access air lock
635	313	Personnel access air lock
650	331	Personnel access air lock
655	352	Personnel access air lock
703	352	Personnel access air lock
707	352	Personnel access air lock
654	352	Personnel access air lock
591(1)	360	Personnel access air lock
711(1)	360	Personnel access air lock

(1) These are access openings to the refueling area containment rather than the secondary containment.

Table 6.2-14

SECONDARY CONTAINMENT
DESIGN DATA

REACTOR ENCLOSURE VENTILATION ZONES I AND II, AND
REFUELING AREA VENTILATION ZONE III

Free volume, ft^3:	Zones I and II	1,800,000 each
	Zone III	2,200,000

Pressure

Normal operation: Negative 0.25 in wg.

Postaccident: Negative 0.25 in wg.

Leak rate at postaccident pressure: 0.5 air change/day (Zone III)
2.0 air changes/day
(Zones I and II)

SGTS Exhaust fans - common

Number: 2

Type: centrifugal, single inlet single width

Secondary containment atmosphere filtration prior to release to outdoors via SGTS fans

Number: 2

Type:	Zone I and II	prefilter, HEPA, charcoal, HEPA in RERS followed by HEPA, charcoal, HEPA in SGTS
	Zone III	prefilter, HEPA, charcoal, HEPA in SGTS

TRANSIENT ANALYSIS

Initial Conditions

Pressure: negative 0.25 in wg.

Temperature: 104°F

Outside air temperature: 95°F

Thickness of secondary containment wall: 36 in

Thickness of primary containment wall: 72 in

Table 6.2-14 (Cont'd)

Thermal Characteristics

Primary containment wall

Thermal conductivity: 0.5 Btu/hr-ft-°F
Thermal capacitance: 25 Btu/ft^3-°F

Secondary containment wall

Thermal conductivity: 0.5 Btu/hr-ft-°F
Thermal capacitance: 25 Btu/ft^3-°F

Heat transfer coefficients

Primary containment atmosphere to primary containment wall: 1.46 Btu/hr-ft^2-°F

Primary containment wall to secondary containment atmosphere: 1.46 Btu/hr-ft^2-°F

Secondary containment wall to secondary containment atmosphere: 1.46 Btu/hr-ft^2-°F

Primary containment emissivity: 0.9 Btu/hr-ft^2-°F

Secondary containment emissivity: 0.9 Btu/hr-ft^2-°F

Table 6.2-15

EVALUATION OF POTENTIAL SECONDARY CONTAINMENT BYPASS LEAKAGE PATHS

CONTAINMENT PENETRATION	SYSTEM	TERMINATION REGION[1]	BYPASS LEAKAGE BARRIERS[2]	POTENTIAL BYPASS PATH
1	Equipment access door	IRE	Double O-Ring	No
2	Equipment access door and personnel lock	IRE	Double O-Ring	No
2	Service air supply to personnel lock	ORE	1,8	No
3A	Main steam line D flow instrumentation	IRE	-	No
3B	Instrument gas supply	ORE	1,4	No
3C	HPCI steam flow instrumentation	IRE	-	No
3D	Main steam line A flow instrumentation	IRE	-	No
3D	Instrument gas supply	ORE	1,4	No
4	Head access manhole	IRE	Double O-Ring	No
5	Spare	-	-	-
6	CRD removal hatch	IRE	Double O-Ring	No
7A-D	Primary steam	ORE	1,5	No
8	Primary steam line drain	ORE	1,4	No
9A&B	Feedwater	ORE	1,3	No[3][4]
10	Steam to RCIC turbine	ORE	1,3,8	No
11	Steam to HPCI turbine	ORE	1,3,8	No
12	RHR shutdown cooling supply	ORE	1,3	No
13A&B	RHR shutdown return	ORE	1,3	No
14	RWCU supply	ORE	1,3	No
15	Spare	-	-	-
16A&B	Core spray pump discharge	ORE	1,3	No
17	RPV head spray (Unit 1 only) (ABANDONED)	ORE	7	No
17	Spare (Unit 2 only)	-	-	-
18	Spare	-	-	-
19	Spare	-	-	-
20A	RPV level instrumentation	IRE	-	No
20A	LPCI ΔP instrumentation	IRE	-	No
20B	LPCI ΔP instrumentation	IRE	-	No
20B	RPV level instrumentation	IRE	-	No
21	Spare	-	-	-
22	Drywell pressure instrumentation	IRE	-	No
23	Closed cooling water supply	ORE	1,2,3	No
24	Closed cooling water return	ORE	1,2,3	No
25	Drywell purge supply	ORE	1,4,8	No
26	Drywell purge exhaust	IRE	-	No
27A	Instrument gas supply	ORE	1,4	No
27B	HPCI flow instrumentation	IRE	-	No
28A	Recirculation loop sample	IRE	-	No
28A	Drywell H_2/O_2	ORE	1,7	No
28B	LPCI ΔP instrumentation	IRE	-	No
28B	Drywell air sample	ORE	1,7	No
29A	RPV flange leakage instrumentation	IRE	-	No
29B	Core spray ΔP instrumentation	IRE	-	No
30A	Main steam line D flow instrumentation	IRE	-	No
30B	Drywell pressure instrumentation	IRE	-	No
30B	Main steam line C flow instrumentation	IRE	-	No
31A&B	Jet pump flow instrumentation	IRE	-	No
32A&B	Jet pump flow instrumentation	IRE	-	No
33A	Pressure above core plate instrumentation	IRE	-	No
33A	Pressure below core plate instrumentation	IRE	-	No

Table 6.2-15 (Cont'd)

CONTAINMENT PENETRATION	SYSTEM	TERMINATION REGION[1]	BYPASS LEAKAGE BARRIERS[2]	POTENTIAL BYPASS PATH
33B	RCIC steam flow instrumentation	IRE	-	No
34A	Main steam line C flow instrumentation	IRE	-	No
34B	Recirculation flow instrumentation	IRE	-	No
X-35A	Spare	-	-	-
35B	Instrumentation gas to TIP indexing mechanism	ORE	1	No[4]
35C-G	TIP drives	IRE	-	No
36	Spare	-	-	-
37A-D	CRD insert	ORE	1,3	No
38A-D	CRD withdraw	ORE	1,3	No
39A&B	Drywell spray	ORE	1,3	No
40A-C	Jet pump flow instrumentation	IRE	-	No
40D	Pressure below core plate instrumentation	IRE	-	No
40E	Drywell pressure instrumentation	IRE	-	No
40F	RCIC steam flow instrumentation	IRE	-	No
40F	Instrumentation gas suction	ORE	1,4	No
40G	ILRT data acquisition system (2 lines)	ORE	1,8	No
40H	Instrument gas supply	ORE	1,4	No
40H	Recirculation pump cooler flow instrumentation	IRE	-	No
41	LPCI ΔP instrumentation	IRE	-	No
41	RWCU flow instrumentation	IRE	-	No
42	SLCS	IRE	-	No
43A	Recirculation loop A ΔP instrumentation	IRE	-	No
43A	Recirculation pump seal pressure instrumentation	IRE	-	No
43B	Main steam sample	IRE	-	No
44	CRD/RWCU return	ORE	1,3	No
45A-D	LPCI	ORE	1,3	No
46	Spare	-	-	-
47	RWCU flow instrumentation	IRE	-	No
48A	RPV level instrumentation	IRE	-	No
48A	Core spray ΔP instrumentation	IRE	-	No
48B	RPV level instrumentation	IRE	-	No
49A&B	Main steam line A&B flow instrumentation	IRE	-	No
50A	Drywell pressure instrumentation	IRE	-	No
50A	Recirculation flow instrumentation	IRE	-	No
50B	Recirculation pump seal pressure instrumentation	IRE	-	No
50B	Recirculation pump cooler flow instrumentation	IRE	-	No
51A	Recirculation line flow instrumentation	IRE	-	No
51B	Jet pump flow instrumentation	IRE	-	No
52A	Main steam line B flow instrumentation	IRE	-	No
52B	Recirculation line flow instrumentation	IRE	-	No
53	Drywell chilled water supply	ORE	1,2,3	No
54	Drywell chilled water return	ORE	1,2,3	No
55	Drywell chilled water supply	ORE	1,2,3	No
56	Drywell chilled water return	ORE	1,2,3	No
57	RWCU flow instrumentation	IRE	-	No

Table 6.2-15 (Cont'd)

CONTAINMENT PENETRATION	SYSTEM	TERMINATION REGION[1]	BYPASS LEAKAGE BARRIERS[2]	POTENTIAL BYPASS PATH
58A	Recirc loop B ΔP instrumentation	IRE	-	No
58B	Spare	-	-	-
59A&B	Spare	-	-	-
60	Spare	-	-	-
61	Recirculation pump seal purge	ORE	1,4	No
62	H_2/O_2 sample return	ORE	1,4	No
63	Recirculation loop ΔP instrumentation; recirculation pump seal pressure instrumentation	IRE	-	No
64	Spare	-	-	-
65A&B	RPV pressure instrumentation	IRE	-	No
65A&B	RPV instrumentation reference leg backfill system	ORE	9	No
66A	RPV level instrumentation	IRE	-	No
66A	LPCI ΔP instrumentation	IRE	-	No
66B	RPV level instrumentation	IRE	-	No
66B	LPCI ΔP instrumentation	IRE	-	No
67A&B	RPV level and pressure instrumentation	IRE	-	No
67A&B	RPV instrumentation reference leg backfill system	ORE	9	No
100A-D	Neutron monitoring system	-	-	-
101A-D	Recirculation pump power	-	-	-
102A&B	Electrical spare	-	-	-
103A&B	Temperature and low level signals	-	-	-
104A-D	CRD position indicator	-	-	-
105A-E	Miscellaneous low voltage power	-	-	-
106A-C	Low voltage control	-	-	-
107	Electrical spare	-	-	-
108	Electrical spare	-	-	-
109	Electrical spare	-	-	-
110	Electrical spare	-	-	-
111	Electrical spare	-	-	-
112	Electrical spare	-	-	-
113	Electrical spare	-	-	-
114	Electrical spare	-	-	-
115	Electrical spare	-	-	-
116	SLCS	IRE	-	No
117A	Electrical spare	-	-	-
117B	Drywell radiation monitoring	IRE	-	No
118A&B	Electrical spare	-	-	-
200A&B	Access hatch	-	-	-
201A	Suppression pool purge supply	ORE	1,4,8	No
201A (Unit 2)	Hardened containment vent	ORE	1,11	No
	Argon purge supply	IRE	1,4	No
201B (Unit 1)	Hardened containment vent Unit 1	ORO	1,11	No
	Argon purge supply	IRE	1,4	No
201B (Unit 2)	Spare	-	-	-
202	Suppression pool purge exhaust	IRE	-	No
203A-D	RHR pump suction	ORE	3	No
204A&B	RHR pump test	ORE	3	
205A&B	Suppression pool spray	ORE	3	No
206A-D	CS pump suction	ORE	3	No
207A&B	CS pump test and flush	ORE	3	No
208A	Spare	-	-	-
208B	CS pump minimum recirculation	ORE	3	No
209	HPCI pump suction	ORE	3	No
210	HPCI turbine exhaust	ORE	3	No
211	Spare	-	-	-
212	HPCI pump test and flush	ORE	3	No
213	Spare	-	-	-
214	RCIC pump suction	ORE	3	No
215	RCIC turbine exhaust	ORE	3	No
216	RCIC minimum flow	ORE	3	No
217	RCIC vacuum pump discharge	ORE	3	No
218	Instrument gas to vacuum relief valves	ORE	1,4	No

Table 6.2-15 (Cont'd)

CONTAINMENT PENETRATION	SYSTEM	TERMINATION REGION[1]	BYPASS LEAKAGE BARRIERS[2]	POTENTIAL BYPASS PATH
219A&B	Suppression pool level instrumentation	IRE	-	No
220A	H_2/O_2 sample return	ORE	1,4	No
220B (Unit 1)	Suppression pool pressure instrumentation	IRE	-	No
220B (Unit 2)	Spare	-	-	-
221A	Wetwell H_2/O_2 sample	ORE	1,7	No
221B	Suppression pool air sample	ORE	1,7	No
222	Indication and control	-	-	-
223	Spare	-	-	-
224	Spare	-	-	-
225	Spare	-	-	-
226A&B	RHR minimum recirculation	ORE	3	No
227	ILRT data acquisition system	ORE	1,8	No
228A-C	Spare	-	-	-
228D	HPCI vacuum relief	ORE	1,3,8	No
229A (Unit 1)	Spare	-	-	-
229A (Unit 2)	Suppression pool pressure instrumentation	IRE	-	No
229B	Spare	-	-	-
230A	Strain gauge instrumentation	IRE	-	No
230B	Drywell sump level instrumentation	IRE	-	No
231A&B	Drywell sump drains	ORE	1,3	No
232A-S	MSRV discharge	-	-	-
235	CS pump minimum recirculation	ORE	3	No
236	HPCI pump minimum recirculation	ORE	3	No
237	Suppression pool cleanup pump suction	ORE	1,3	No
238	RHR relief valve discharge	ORE	3	No
239	RHR relief valve discharge	ORE	3	No
240	RHR relief valve discharge	ORE	3,10	No
241	RCIC vacuum relief	ORE	1,3,8	No

(1) The termination regions are: IRE - Inside reactor enclosure
ORE - Outside reactor enclosure

(2) The bypass leakage barriers are defined as follows (Section 6.2.3.3.3):

1. Redundant primary containment isolation valves.
2. Closed piping system inside containment.
3. A water seal maintained for 30 days following a LOCA.
4. The line beyond the outboard primary containment isolation valve is vented to the reactor enclosure by use of a vent line.
5. A MSIV alternate drain pathway (Section 6.7) is provided.
6. The line contains a temporary spool piece that is removed during normal operation and replaced by blind flanges so that any leakage through the flange is into the reactor enclosure.
7. Closed seismic Category I piping system outside containment.
8. The line contains a spectacle flange with the blind side installed during normal operation. Any leakage through the flange will be into the reactor enclosure.
9. The line contains two spring loaded check valves and two manual stop valves.
10. Blind flange permanently installed in line in the reactor enclosure.
11. Rupture disc installed downstream of primary containment isolation valves with burst pressure greater than maximum LOCA pressure.

(3) The feedwater fill system will provide a water seal in the feedwater lines for all line breaks other than a feedwater line break inside containment. For a feedwater line break inside containment, a water seal is maintained by the CST water supply as discussed in Section 6.2.3.2.3.1.a.

(4) No significant amounts of radioactivity will be released to the environment as discussed in Section 6.2.3.2.3.

Table 6.2-16

ACCIDENT CHRONOLOGY FOR MAIN STEAM LINE BREAK ACCIDENT

Time	Event
0	Break occurs
0	Scram assumed to occur
0	Isolation signal
0.5	MSIV start to close
1.0	Vessel water level reaches main steam line elevation
5.5	MSIV fully closed
30	ECCS flows start
59	End of blowdown
430	Vessel refloods

NOTE: The information presented in this table is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break analysis results.

Table 6.2-17

CONTAINMENT PENETRATION DATA

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-3A-1	Instrumentation - main steam line D flow	Water/ steam	1	55	-	-	F070D	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F073D	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-3A-2	Instrumentation - recirc pump seal pressure	Water	1	55	-	-	F003A	XFC	Outside	(40)	No	2'-3"	Flow	-	0	0	0	-	-	-	-	-	
X-3B	Instrument gas supply	Gas	1	56	No	No	1005B	CK	Inside	(22)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	
					No	No	129B	GB	Outside			6"	Comp air	Spring	0	0	C	C	C,H,S	Yes	4.4 sec	B	
X-3C-1	Instrumentation - HPCI steam flow	Steam	1	55	-	-	F024A	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-3C-2	Instrumentation - HPCI steam flow	Steam	1	55	-	-	F024C	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-3D-1	Instrumentation - main steam line A flow	Steam/ water	1	55	-	-	F070A	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F073A	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-3D-2	Instrument gas supply	Gas	1	56	No	Yes	1112	CK	Inside	(48)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	
					No	Yes	151B	GB	Outside			7"	AC motor	Manual	0	0	C	As is	M	NA	30 sec	D	
X-7A-D	Main steam	Steam	26	55	No	No	F022A-D	GB	Inside	(1)	Yes	-	Instr gas	Spring	0	C	C	C	C,D,E,F,P,Q	Yes	3-5*sec	A/W	
					No	No	F028A-D	GB	Outside			0"	Comp air	Spring	0	C	C	C	C,D,E,F,P,Q	Yes	3-5*sec	B/X	
X-8	Main steam drain	Steam/ water mix	3	55	No	No	F016	GT	Inside	(33)	Yes	-	AC motor	Manual	C	0	C	As is	C,D,E,F,P,Q	Yes	30 sec	A	
					No	No	F019	GT	Outside			0"	AC motor	Manual	C	0	C	As is	C,D,E,F,P,Q	Yes	Standard	B	
X-9A,B	Feedwater	Water	24	55	Yes	Yes	F010A	CK	Inside	(2)	Yes	-	Flow	-	0	C	0	-	-	-	-	-	
					No	Yes	F010B	CH	Inside			-	Flow	-	0	C	0	-	-	-	-	-	
					Yes	Yes	F074A	SLPACK	Outside			0"	Flow	Spring	0	C	0	-	-	-	-	D	
					No	Yes	F074B	SLPACK	Outside			0"	Flow	Spring	0	C	0	-	-	-	-	D	
					No	No	F032A,B	CK	Outside			22'-2"	Flow	AC motor	0	C	0	As is	-	-	-	D	
					No	No	109A,B	GT	Outside			31'-6"	AC motor	Manual	C	C	C	As is	RM	No	Standard	D	
					No	No	F039	SLPACK	Outside			29'-6"	Flow	Spring	0	C	C	-	-	-	-	N	
					No	Yes	F013	GT	Outside			20'-1"	DC motor	Manual	C	C	0	As is	LFCC	NA	23 sec	A	
					No	Yes	1036A,B	CK	Outside			2'-6"	Flow	-	C	C	0	-	-	-	-	-	
					No	Yes	130A,B	GB	Outside			124'-6"	AC motor	Manual	C	C	C	As is	RM	NA	30 sec	A,B	
					No	Yes	133A,B	GB	Outside			70'-1"	AC motor	Manual	C	C	0	As is	RM	NA	30 sec	A,B	
					No	No	1016	GB	Outside			83'-2"	Manual	-	C	C	C	C	-	-	-	-	
					Yes	Yes	F105	GT	Outside			22'-8"	DC motor	Manual	C	C	0	As is	RM	NA	30 sec	B	(19)
X-10	Steam to RCIC turbine	Steam	3	55	No	Yes	F007	GB	Inside	(3)	Yes	-	AC motor	Manual	0	C	0	As is	K,KA	NA	7.2* sec	C	
					No	Yes	F008	GB	Outside			0"	AC motor	Manual	0	C	0	As is	K,KA	NA	7.2* sec	A	(14)
					No	No	F076	GB	Outside			3'-3"	AC motor	Manual	C	C	C	As is	K,KA	No	30 sec	A	
X-11	Steam to HPCI turbine	Steam	10	55	No	Yes	F002	GB	Inside	(3)	Yes	-	AC motor	Manual	0	C	0	As is	L,LA	NA	12* sec	D	
					No	Yes	F003	GB	Outside			0"	AC motor	Manual	0	C	0	As is	L,LA	NA	12* sec	B	(14)
					No	No	F100	GB	Outside			6'-9"	AC motor	Manual	C	C	C	As is	L,LA	No	30 sec	B	
X-12	RHR shutdown cooling supply	Water	20	55	No	No	F009	GT	Inside	(21)	Yes	-	AC motor	Manual	C	0	C	As is	A,V	Yes	Standard	A	(15)
					No	No	F008	GT	Outside			17"	AC motor	Manual	C	0	C	As is	A,V	Yes	Standard	B	(15)
					No	-	155	PSV	Inside			-	Water	-	C	C	C	As is	-	-	-	-	
X-13A&B	RHR shutdown cooling return	Water	12	55	No	No	F050A,B	TCK	Inside	(11)	Yes	-	Flow	Inst gas	C	0	0	-	A,V	-	-	A,B	(15)
					No	No	151A,B	GB	Inside			-	Inst gas	Spring	C	C	C	C	A,V	Yes	20 sec	A	(15)
					No	No	F015A,B	GB	Outside			11"	AC motor	Manual	C	0	C	As is	A,V	Yes	29 sec	B	
					No	No	1200A, B	CK	Inside			-	Flow	Spring	C	C	C	C	-	-	-	-	
X-14	RWCU supply	Water	6	55	No	No	F001	GT	Inside	(20)	Yes	-	AC motor	Manual	0	0	C	As is	B,J,Y	Yes	10* sec	A	
					No	No	F004	GT	Outside			0"	AC motor	Manual	0	0	C	As is	B,J,Y	Yes	10* sec	B	
X-16A	CS discharge	Water	12	55	Yes	Yes	F006A	TCK	Inside	(11)	Yes	-	Flow	Inst gas	C	C	0	-	-	-	-	A	(9)
					Yes	Yes	F039A	GB	Inside			-	Inst gas	Spring	C	C	C	C	-	-	4.4 sec	A	
					Yes	Yes	F005	GT	Outside			0"	AC motor	Manual	C	C	0	As is	RM	NA	12 sec	A	
X-16B	CS discharge	Water	12	55	Yes	Yes	F006B	TCK	Inside	(11)	Yes	-	Flow	Inst gas	C	C	0	-	-	-	-	B	(9)
					Yes	Yes	F039B	GB	Inside			-	Inst gas	Spring	C	C	C	C	-	-	4.4 sec	B	
					Yes	Yes	108	SLPACK	Outside			0"	Flow	Spring	C	C	0	C	-	-	-	B	(9)
X-17	RPV head spray (Unit 1 only) (ABANDONED)				-	-	-	-	-	(21A)	-	-	-	-	-	-	-	-	-	-	-	-	
X-17	Spare (Unit 2 only)				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
X-20A-1	Instrumentation - RPV level	Water	1	55	-	-	F045B	XFC	Outside	(37)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-20A-2	Instrumentation - LPCI `B' dp	Water	1	55	-	-	102B	XFC	Outside	(40)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-20A-3	Instrumentation - LPCI `D' dp	Water	1	55	-	-	103B	XFC	Outside	(40)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-20B-1	Instrumentation - RPV level	Water	1	55	-	-	F045C	XFC	Outside	(37)	No	2'-2"	Flow	-	0	0	0	-	-	-	-	-	
X-20B-2	Instrumentation - LPCI `C' dp	Water	1	55	-	-	102C	XFC	Outside	(40)	No	13"	Flow	-	0	0	0	-	-	-	-	-	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-21	Service air	Gas	3	56	No	No	1140	GT	Inside	(8)	Yes	-	Manual	-	C	C	C	-	-	-	-	-	
	air				No	No	1139	GT	Outside			0"	Manual	-	C	C	C	-	-	-	-	-	
X-22	Instrumentation - drywell pressure	Gas	1	56	-	-	147C	GB	Outside	(41)	No	8"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	C	
X-23	Recirc pump	Water	4	56	No	No	106	GT	Outside	(13)	Yes	0"	AC motor	Manual	0	0	C	As is	C,H	Yes	Standard	C	
	cooling water				No	No	108	GT	Outside			3'-11"	AC motor	Manual	0	0	C	As is	C,H	Yes	Standard	D	
	supply				No	No	109	GT	Outside			5'-2"	Manual	-	C	C	C	-	-	-	-	-	
X-24	Recirc pump	Water	4	56	No	No	107	GT	Outside	(13)	Yes	0"	AC motor	Manual	0	0	C	As is	C,H	Yes	Standard	C	
	cooling water				No	No	111	GT	Outside			3'-8"	AC motor	Manual	0	0	C	As is	C,H	Yes	Standard	D	
	return				No	No	110	GT	Outside			5'-0"	Manual	-	C	C	C	-	-	-	- -		
X-25	Drywell purge	Gas	24	56	No	No	HV-57-135	BF	Outside	(5)	Yes	16'-7"	AC motor	Manual	C	0	C	As is	B,H,W,U,S,R,T	Yes	6** sec	B	(19)
	supply				Yes	Yes	HV-57-121	BF	Outside			3'-11"	Comp air	Spring	C	C	C	C	B,H,W,U,S,R,T	NA	5** sec	A	(23)
					No	No	HV-57-123	BF	Outside			3'-4"	Comp air	Spring	C	0	C	C	B,H,W,U,S,R,T	Yes	5** sec	A	
					Yes	Yes	HV-57-131	BF	Outside			60'-7"	Comp air	Spring	C	C	C	C	B,H,W,U,S,R,T	NA	5** sec	A	(19), (23)
					Yes	Yes	HV-57-163	BF	Outside			3'-8"	AC motor	Manual	C	C	0	As is	B,H,R,S	NA	6 sec	D	
					No	No	HV-57-109	BF	Outside			42'-2"	AC motor	Manual	C	C	C	As is	B,H,W,U,S,R,T	Yes	6** sec	B	(19)
					Yes	Yes	FV-DO-101B	GB	Outside			251-1"	AC motor	Manual	C	C	0	As is	B,H,R,S	NA	80 sec	D	(19)
X-26	Drywell purge	Gas	24	56	No	No	HV-57-115	BF	Outside	(27)	Yes	53'-7"	AC motor	Manual	C	0	C	As is	B,H,W,U,S,R,T	Yes	6** sec	A	(19)
	exhaust				Yes	Yes	SV-57-145	GB	Outside			66'-9"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	(19)
					No	No	HV-57-111	GB	Outside			6'-6"	AC motor	Manual	C	C	C	As is	B,H,U,S,R,T	Yes	15** sec	B	(20)
					No	No	HV-57-114	BF	Outside			49'-7"	Comp air	Spring	C	0	C	C	B,H,W,U,S,R,T	Yes	5** sec	B	(19)
					Yes	Yes	HV-57-161	BF	Outside			47'-11"	AC motor	Manual	C	C	0	As is	B,H,R,S	NA	6 sec	C	(19)
					No	No	HV-57-117	GB	Outside			60'-3"	Comp air	Spring	C	C	C	C	B,H,U,S,R,T	Yes	5** sec	A	(19)
					-	-	SV-57-139	GB	Outside		No	35'-5"	AC coil		0	0	0	C	RM	-	2 sec	A	(19)
					Yes	Yes	FV-DO-101A	GB	Outside			78'-3"	AC motor	Manual	C	C	0	As is	B,H,R,S	NA	80 sec	C	(19)
X-27A	Instrument gas	Gas	1	56	No	Yes	1128	CK	Inside	(48)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	
	supply				No	Yes	151A	GB	Outside			7"	AC motor	Manual	0	0	C	As is	M	NA	30 sec	C	
X-27B-1	Instrumentation - HPCI	Steam	1	55	-	-	F024B	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-27B-2	Instrumentation - HPCI flow	Steam	1	55	-	-	F024D	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-28A-1	Recirc loop	Water	3/4	55	No	No	F019	GB	Inside	(9)	Yes	-	Instr gas	Spring	C	C	C	C	B,D	Yes	7 sec	A	(14)
	sample				No	No	F020	GB	Outside			4'-3"	Comp air	Spring	C	C	C	C	B,D	Yes	7 sec	B	(14)
X-28A-2	Drywell H_2O_2	Gas	1	56	Yes	Yes	132	GB	Outside	(23)	Yes	20"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	B	
	sample				Yes	Yes	142	GB	Outside			3'-0"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
X-28A-3	Drywell H_2O_2	Gas	1	56	Yes	Yes	134	GB	Outside	(23)	Yes	20"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	B	
	sample				Yes	Yes	144	GB	Outside			3'-0"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
X-28B	Drywell H_2O_2	Gas	1	56	Yes	Yes	133	GB	Outside	(23)	Yes	17"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	A	
	sample				Yes	Yes	143	GB	Outside			2'-11"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
					Yes	Yes	195	GB	Outside			2'-11"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	C	
X-29A	Instrumentation - RPV flange leakage	Water	1	55	-	-	F009	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-29B	Instrumentation - CS WP	Water	1	55	-	-	F018A	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-30A	Instrumentation -	Water	1	55	-	-	F071D	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	main steam line D flow				-	-	F072D	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-30B-1	Instrumentation - drywell pressure	Gas	1	56	-	-	147A	GB	Outside	(41)	No	7"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	A	
X-30B-2	Instrumentation -	Water	1	55	-	-	F071C	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	main steam line C flow				-	-	F072C	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-31A,B	Instrumentation -	Water	1	55	-	-	F059B,F,H	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	jet pump flow				-	-	F059D	XFC	Outside			4'-7"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F051B	XFC	Outside			3'-4"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F053B	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-32A,B	Instrumentation -	Water	1	55	-	-	F059M,S,U	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	jet pump flow				-	-	F051D	XFC	Outside			3'-4"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F053D	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
					-	-	F059P	XFC	Outside			4'-6"	Flow	-	0	0	0	-	-	-	-	-	
X-33A-1	Instrumentation -	Water	1	55	-	-	F055	XFC	Outside	(37)	No	2'-5"	Flow	-	0	0	0	-	-	-	-	-	
	pressure above core plate				-	-	F076	XFC	Outside			4'-2"	Flow	-	0	0	0	-	-	-	-	-	
X-33A-2	Instrumentation - pressure below core plate	Water	1	55	-	-	F061	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-33B	Instrumentation - RCIC steam flow	Water	1	55	-	-	F044A,C	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-34A	Instrumentation -	Water	1	55	-	-	F070C	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
	main steam line C flow				-	-	F073C	XFC	Outside			12"	Flow	-	0	0	0	-	-	-	-	-	
X-34B-1	Instrumentation -	Water	1	55	-	-	F009C	XFC	Outside	(40)	No	18"	Flow	-	0	0	0	-	-	-	-	-	
	recirc flow				-	-	F010D	XFC	Outside			3'-6"	Flow	-	0	0	0	-	-	-	-	-	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-34B-2	Instrumentation - recirc flow	Water	1	55	- -	- -	F009D F010C	XFC XFC	Outside Outside	(40)	No	2'-9" 2'-9"	Flow Flow	-	0 0	0 0	0 0	- -	- -	-	-	-	-	
X-35B	TIP purge	Gas	1	56	No No	No No	131 1056	GB CK	Outside Inside	(46)	Yes	0" -	Comp air Flow	Spring -	0 0	C C	C C	C C	B,H,S -	Yes -	4.4 sec -	B -		
X-35C-G	TIP drives	Gas	3/8	56	No No	No No	140A-E 141A-E	XP BL	Outside Outside	(6)	Yes	16" 8"	Explosion AC coil	- Spring	0 C	0 C	0 C	As is C	RM B,H	- Yes	- -	N N	(10) (10)
X-37A-D	CRD insert	Water	1	55	Yes Yes	Yes Yes	- 46-1101 46-1102 46-1108 46-1109	BLCK CK	Inside Outside	(47) -	No Yes	- -	- Flow	- -	- 0	- 0	- C	- -	- -	- -	- -	- -	(11) (11)
X-38A-D	CRD withdraw	Water	3/4	55	Yes	Yes	46-1115 46-1116 46-1122 46-1123	CK	Outside	(47)	Yes	-	Flow	-	0	0	C	-	-	-	-	-	(11)
					Yes Yes Yes Yes	Yes Yes Yes Yes	F180 F181 F010 F011	GB GB GB GB	Outside Outside Outside Outside		Yes	Varies (input from 185 HCUs with max. of approx. 320')	Comp air Comp air Comp air Comp air	Spring Spring Spring Spring	0 0 0 0	0 0 0 0	C C C C	C C C C	- - - -	NA NA NA NA	30 30 25 25	N N N N	(11) (11) (11) (11)
X-39A,B	Containment spray	Water	16	56	Yes Yes	Yes Yes	F021A,B F016A,B	GT GT	Outside Outside	(25)	Yes	12" 8'-0"	AC motor AC motor	Manual Manual	C C	C C	C C	As is As is	RM RM	NA NA	Standard Standard	A,B A,B	
X-40A	Instrumentation - jet pump flow	Water	1	55	- -	- -	F059L,R F059N	XFC XFC	Outside Outside	(37)	No	12" 4'-7"	Flow Flow	- -	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-40B	Instrumentation - jet pump flow	Water	1	55	- - -	- - -	F059G F051A F053A	XFC XFC XFC	Outside Outside Outside	(37)	No	12" 3'-4" 12"	Flow Flow Flow	- - -	0 0 0	0 0 0	0 0 0	- - -	- - -	- - -	- - -	- - -	
X-40C	Instrumentation - jet pump flow	Water	1	55	- -	- -	F059A,E F059C	XFC XFC	Outside Outside	(37)	No	12" 4'-7"	Flow Flow	- -	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-40D-1	Instrumentation - pressure below core plate	Water	1	55	-	-	F057	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-40D-2	Instrumentation - RWCU flow	Water	1	55	- -	- -	170 171	XFC XFC	Outside Outside	(37)	No	1'-10" 1'-10"	Flow Flow	- -	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-40E	Instrumentation - drywell pressure	Gas	1	56	-	-	147D	GB	Outside	(41)	No	12"	AC motor	Manual	0	0	-	As is	RM	-	30 sec	D	
X-40F-1	Instrumentation - RCIC pressure	Steam	1	56	-	-	F044B,D	XFC	Outside	(40)	No	12"	Flow	Manual	0	0	0	-	-	-	-	D	
X-40F-2	Instrument gas suction	Gas	1	56	No No	No No	101 102	GB GB	Inside Outside	(4)	Yes	- 8"	AC motor Comp air	Manual Spring	0 0	0 0	C C	As is C	C,H,S C,H,S	Yes Yes	30 sec 4.4 sec	A B	
X-40G-1	ILRT data acquisition	Gas	3/4	56	No No	No No	1057 1058	GB GB	Outside Outside	(31)	Yes	7" 23"	Manual Manual	- -	C C	C C	C C	- -	- -	- -	- -	- -	
X-40G-2	ILRT data acquisition	Gas	3/4	56	No No	No No	1071 1070	GB GB	Outside Outside	(31)	Yes	7" 2'-10"	Manual Manual	- -	C C	C C	C C	- -	- -	- -	- -	- -	
X-40H-1	Instrument gas supply	Gas	1	56	No No	No No	1005A 129A	CK GB	Inside Outside	(22)	Yes	- 13"	Flow Comp air	- Spring	0 0	0 0	C C	- C	- C,H,S	- Yes	- 4.4 sec	- A	
X-40H-2	Instrumentation - recirc pump cooler	Water	1	56	- -	- -	156B 157B	XFC XFC	Outside Outside	(44)	No	12" 12"	Flow Flow	- -	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-41-1	Instrumentation - RWCU flow	Water	1	55	- -	- -	102A 102B	XFC XFC	Outside Outside	(40)	No	2'-5" 13"	Flow Flow	- -	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-41-2	Instrumentation - LPCI `A' dp	Water	1	55	-	-	103A	XFC	Outside	(40)	No	13"	Flow	-	0	0	0	-	-	-	-	-	
X-42	Standby liquid control	Sodium pentaborate solution	2	55 Yes	Yes Yes	Yes F006A	F007 SCK	CK Outside	Inside	(10)	Yes 8"	- Flow	Flow AC motor	- 0	C 0	C 0	C -	- RM	- NA	- Standard	- A	-	
X-43A	Instrumentation - recirc loop A WP	Water	1	55	-	-	F040A,C	XFC	Outside	(40)	No	2'-3"	Flow	-	0	0	0	-	-	-	-	-	
X-43B	Main steam sample	Steam	3/4	55	No No	No No	F084 F085	GB GB	Inside Outside	(9)	Yes	- 2'-6"	Inst gas Comp air	Spring Spring	C C	C C	C C	C C	B,D B,D	Yes Yes	7 sec 7 sec	A B	
X-44	Alternate RWCU return	Water	4	55	No No No	No No -	1017 1016 112	GB GB PSV	Inside Outside Outside	(14)	Yes	- 20" 7'-6"	Manual Manual Water pres	- - -	C C C	0 0 C	C C C	- - -	- - -	- - -	- - -	- - -	
X-45A-D	LPCI	Water	12	55	Yes Yes Yes	Yes Yes Yes	142A,B,C,D F041A,B,C,D F017A,B,C,D	GB TCK GT	Inside Inside Outside	(11)	Yes	- - 0"	Inst gas Flow AC motor	Spring Inst gas Manual	C C C	C C C	C 0 0	C - As is	- - RM	- - NA	4.4 sec - 24 sec	A,B,C,D A,B,C,D A,B,C,D	
X-47	Instrumentation - RWCU flow	Water	1	55	-	-	102D	XFC	Outside	(40)	No	11"	Flow	-	0	0	0	-	-	-	-	-	
X-48A-1	Instrumentation - RPV level	Water	1	55	- -	- -	F065B F047B	XFC XFC	Outside Outside	(37)	No	2'-6" 21"	Flow Flow	- -	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-48A-2	Instrumentation - core spray WP	Water	1	55	-	-	F018B	XFC	Outside	(40)	No	12"	Flow	-	0	0	0	-	-	-	-	-	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-48B	Instrumentation - RPV Level	Water	1	55	- -	- -	F065A F047A	XFC XFC	Outside Outside	(37)	No	21" 2'-6"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-49A,B	Instrumentation - main steam line A&B flow	Water/ steam	1	55	- -	- -	F071A,B F072A,B	XFC XFC	Outside Outside	(40)	No	12" 12"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-50A-1	Instrumentation - drywell pressure	Gas	1	56	-	-	147B	GB	Outside	(41)	No	7"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	B	
X-50A-2	Instrumentation - recirc flow	Water	1	55	- -	- -	F011A F012B	XFC XFC	Outside Outside	(40)	No	2'-9" 18"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-50A-3	Instrumentation - recirc flow	Water	1	55	- -	- -	F011B F012A	XFC XFC	Outside Outside	(40)	No	18" 2'-9"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-50B	Instrumentation - recirc pump seal pressure	Water	1	55	-	-	F004A	XFC	Outside	(45)	No	4'-11"	Flow	-	0	0	0	-	-	-	-	-	
X-50B	Instrumentation - recirc pump cooler flow	Water	1	56	- -	- -	156A 157A	XFC XFC	Outside Outside	(44)	No	22" 20"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-51A	Instrumentation - recirc line flow	Water	1	55	- -	- -	F009A,B F010A,B	XFC XFC	Outside Outside	(40)	No	18" 18"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-51B	Instrumentation - jet pump flow	Water	1	55	- - -	- - -	F059T F051C F053C	XFC XFC XFC	Outside Outside Outside	(37)	No	12" 3'-4" 12"	Flow Flow Flow	- - -	0 0 0	0 0 0	0 0 0	- - -	- - -	- - -	- - -	- - -	
X-52A	Instrumentation - main steam line B flow	Water	1	55	- -	- -	F070B F073B	XFC XFC	Outside Outside	(40)	No	12" 12"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-52B-1	Instrumentation - recirc line flow	Water	1	55	- -	- -	F011C F011D	XFC XFC	Outside Outside	(40)	No	2'-9" 18"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-52B-2	Instrumentation - recirc line flow	Water	1	55	- -	- -	F012C F012D	XFC XFC	Outside Outside	(40)	No	2'-3" 18"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-53	Chilled water supply A	Water	8	56 No	No No No	No No 125A	128 120A GT	GT GT Outside	Outside Outside	(13)	Yes 63'-10"	0" 63'-10" AC motor	AC motor AC motor Manual	Manual Manual C	0 0 C	0 0 C	C C As is	As is As is -	C,H C,H -	Yes Yes -	Standard Standard -	B A (21)	(19)
X-54	Chilled water return "A"	Water	8	56 No	No No No	No No 124A	129 121A GT	GT GT Outside	Outside Outside	(13)	Yes 67'-0"	0" 67'-0" AC motor	AC motor AC motor Manual	Manual Manual C	0 0 C	0 0 C	C C As is	As is As is -	C,H C,H -	Yes Yes -	Standard Standard -	B A (21)	(19)
X-55	Chilled water supply "B"	Water	8	56	No No No	No No No	122 120B 125B	GT GT GT	Outside Outside Outside	(13)	Yes	0" 46'-10" 46'-10"	AC motor AC motor AC motor	Manual Manual Manual	C 0 C	C 0 C	C C C	As is As is As is	C,H C,H -	Yes Yes -	Standard Standard -	B A -	(19) (21)
X-56	Chilled water return "B"	Water	8	56	No No No	No No No	123 121B 124B	GT GT GT	Outside Outside Outside	(13)	Yes	0" 37'-2" 37'-2"	AC motor AC motor AC motor	Manual Manual Manual	C 0 C	C 0 C	C C C	As is As is As is	C,H C,H -	Yes Yes -	Standard Standard -	B A -	(19) (21)
X-57	Instrumentation - RWCU flow	Water	1	55	-	-	102C	XFC	Outside	(40)	No	11"	Flow	-	0	0	0	-	-	-	-	-	
X-58A	Instrumentation - recirc loop B WP	Water	1	55	-	-	F040B	XFC	Outside	(40)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-61-1	Recirc pump seal purge	Water	1	55	No -	No -	1004A 103A	CK XFC	Inside Outside	(45)	Yes	- 20"	Flow Flow	-	0 0	C 0	C 0	-	-	-	-	-	
X-61-2	Recirc pump seal purge	Water	1	55	No -	No -	1004B 103B	CK XFC	Inside Outside	(45)	Yes	- 20"	Flow Flow	-	0 0	C 0	C 0	-	-	-	-	-	
X-62	H_2/O_2 sample return; drywell purge makeup	Gas	1	56	Yes No Yes Yes Yes	Yes No Yes Yes Yes	150 116 159 190 191	GB GB GB GB GB	Outside Outside Outside Outside Outside	(12)	Yes	3'-3" 6'-6" 15'-9" 255'-8" 253'-1"	AC coil AC motor AC coil AC coil AC coil	- Manual	0 C 0 0 0	0 C 0 0 0	0 C 0 0 0	C As is C C C	B,H,R,S B,H,R,S B,H,R,S B,H,R,S B,H,R,S	NA Yes NA NA NA	2 sec 30** sec 2 sec 2 sec 2 sec	B D D C A	(19)
X-63-1	Instrumentation - recirc loop "B" dp	Water	1	55	-	-	F040D	XFC	Outside	(40)	No	3'-4"	Flow	-	0	0	0	-	-	-	-	-	
X-63-2	Instrumentation - recirc pump seal pressure	Water	1	55	- -	- -	F004B F003B	XFC XFC	Outside Outside	(45)	No	12" 12"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-65A,B	Instrumentation - RPV pressure	Water	1	55	- -	- -	F043B F049A	XFC XFC	Outside Outside	(37)	No	14" 14"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-66A-1	Instrumentation - RPV level	Water	1	55	-	-	F045D	XFC	Outside	(37)	No	13"	Flow	-	0	0	0	-	-	-	-	-	
X-66A-2	Instrumentation - LPCI "B" dp	Water	1	55	- -	- -	102D 103D	XFC XFC	Outside Outside	(40)	No	13" 13"	Flow Flow	-	0 0	0 0	0 0	- -	- -	- -	- -	- -	
X-66B-1	Instrumentation - RPV level	Water	1	55	-	-	F045A	XFC	Outside	(37)	No	14"	Flow	-	0	0	0	-	-	-	-	-	
X-66B-2	Instrumentation - LPCI "A" dp	Water	1	55	-	-	102A	XFC	Outside	(37)	No	14"	Flow	-	0	0	0	-	-	-	-	-	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-67A	Instrumentation - RPV pressure	Water	1	55	-	-	F049B	XFC	Outside	(37)	No	13"	Flow	-	0	0	0	-	-	-	-	-	
X-67B-1	Instrumentation - RPV pressure	Water	1	55	-	-	F043A	XFC	Outside	(37)	No	12"	Flow	-	0	0	0	-	-	-	-	-	
X-67B-2	Instrumentation - RPV level	Water	1	55	-	-	F041	XFC	Outside	(37)	No	11"	Flow	-	0	0	0	-	-	-	-	-	
X-102A	Instrumentation - jet pump flow	Water	1	55	-	-	185A	XFC	Outside	(37)	No	18"	Flow	-	0	0	0	-	-	-	-	-	
X-107	Instrumentation - jet pump flow	Water	1	55	-	-	185B	XFC	Outside	(37)	No	18"	Flow	-	0	0	0	-	-	-	-	-	
X-116	Standby liquid control	Sodium pentaborate solution	2	55	Yes Yes	Yes Yes	F007 F006B	CK SCK	Inside Outside	(10)	Yes	- 16"	Flow Flow	- AC motor	C 0	C 0	C 0	- As is	- RM	- NA	- Standard	- B	
X-117B-1	Drywell radiation sample supply and return	Gas	1	56	No	No	190-A,B	GB	Outside	(23)	Yes	9'-4"	AC coil	-	0	C	C	C	B,H,R,S	Yes	2 sec	C,B	
X-117B-2	Drywell radiation sample supply and return	Gas	1	56	No	No	190-C,D	GB	Outside	(23)	Yes	10'-2"	AC coil	-	0	C	C	C	B,H,R,S	Yes	2 sec	C,B	(19)
X-201A	Suppression pool purge supply	Gas	20	56	No No No Yes Yes Yes Yes	No No No Yes Yes Yes Yes	HV-57-109 HV-57-147 HV-57-124 HV-57-131 HV-57-164 HV-57-121 HV-57-169	BF BF BF BF BF BF BF	Outside Outside Outside Outside Outside Outside Outside	(7)	Yes	42'-9" 17'-5" 13'-5" 7'-9" 8'-2" 69'-11" 9'-6"	AC motor AC motor Comp air Comp air AC motor Comp air AC motor	Manual Manual Spring Spring Manual Spring Manual	C C C C C C C	C 0 0 C C C C	C 0 C C 0 C 0	As is As is C C As is C As is	B,H,W,U,S,R,T B,H,W,U,S,R,T B,H,W,U,S,R,T B,H,W,U,S,R,T B,H,R,S B,H,W,U,S,R,T B,H,R,S	Yes Yes Yes NA NA NA NA	6** sec 6** sec 5** sec 5** sec 6 sec 5** sec 6 sec	B B A A D A D	(19) (19) (19) (23) (19), (23)
X-201A (Unit 2)	Hardened Containment Vent	Steam/ Non-Cond Gas	12	56	No	No	HV-57V-280	BF	Outside	(7)	Yes	13'-2"	Comp Air	Spring	C	C	C	C	-	NA	Standard**	N	(19), (21)
		Steam/ Non-Cond Gas	12	56	No	No	HV-57V-281	BF	Outside	(7)	Yes	22'-1"	Comp Air	Spring	C	C	C	C	-	NA	Standard**	N	(19), (21)
X-201B	Hardened Containment Vent	Steam/20 Non-Cond Gas	56	No	No	HV-57V-180	BF	Outside	(7)	Yes	16'-7"	Comp Air	Spring	C	C	C	C	-	NA	Standard**	N	(19), (21)	
		Steam/20 Non-Cond Gas	56	No	No	HV-57V-181	BF	Outside	(7)	Yes	23'-5"	Comp Air	Spring	C	C	C	C	-	NA	Standard**	N	(19), (21)	
X-202	Suppression pool purge exhaust	Gas	18	56	Yes Yes Yes No No No Yes	No Yes Yes No No No Yes	HV-57-112 HV-57-185 HV-57-162 HV-57-105 HV-57-104 HV-57-118 HV-57-166	BF GB BF GB BF BF BF	Outside Outside Outside Outside Outside Outside Outside	(15)	Yes	18'-6" 24'-6" 3'-10" 6'-10" 4'-0" 32'-11" 5'-9"	AC motor AC coil AC motor AC motor Comp air Comp air AC motor	Manual - Manual Manual Spring Spring Manual	C 0 C C C C C	0 0 C C 0 C C	0 0 0 C C C 0	As is C As is As is C C As is	B,H,W,U,S,R,T B,H,R,S B,H,R,S B,H,U,S,R,T B,H,W,U,S,R,T B,H,U,S,R,T B,H,R,S	NA NA NA Yes Yes Yes NA	6** sec 2 sec 6 sec 15** sec 5** sec 5** sec 6 sec	A C C B B A C	(19) (19) (20) (19)
X-203A-D	RHR pump suction	Water	24	56	Yes Yes Yes	Yes - -	F004A,B,C,D F030A,B F030C,D	GT PSV PSV	Outside Outside Outside	(16)	No	0" 46'-6" 35'-6"	AC motor Water pres Water pres	Manual - -	0 C C	0 C C	0 C C	As is - -	RM - -	NA - -	Standard - -	A,B,C,D - -	(22) (19) (19)
X-204A,B	RHR pump test and min flow	Water	6	56	Yes	Yes	125A,B	GT	Outside	(36)	No	0"	AC motor	Manual	0	0	0	As is	RM	NA	Standard	A,B	(22)
X-205A,B	Suppression pool spray	Water	6	56	Yes	Yes	F027A,B	GB	Outside	(43)	Yes	0"	AC motor	Manual	0	0	0	As is	C,G	NA	30 sec	A,B	
X-206A-D	CS pump suction	Water	16	56	Yes	Yes	F001A,B,C,D	GT	Outside	(42)	No	0"	AC motor	Manual	0	0	0	As is	RM	NA	Standard	A,B	(22)
X-207A,B	CS pump test and flush	Water	10	56	Yes	No	F015A,B	GB	Outside	(24)	No	0"	AC motor	Manual	C	C	C	As is	C,G	Yes	15 sec	A,B	(22)
X-208B	CS pump min flow	Water	4	56	Yes	Yes	F031B	GB	Outside	(24)	No	0"	AC motor	Manual	0	C	C	As is	LFCH	NA	30 sec	B	(22)
X-209	HPCI pump suction	Water	16	56	Yes	Yes	F042	GT	Outside	(42)	No	0"	DC motor	Manual	0	0	0	As is	L,LA	NA	Standard	B	(22)
X-210	HPCI turbine exhaust	Water	12	56	Yes	Yes	F072	GT	Outside	(24)	No	0"	DC motor	Manual	0	0	0	As is	RM	NA	Standard	B	(22)
X-212	HPCI pump test and flush	Water	4	56	Yes	No	F071	GT	Outside	(24)	No	0"	DC motor	Manual	C	C	C	As is	B,H	Yes	Standard	B	(22)
X-214	RCIC pump suction	Water	6	56	Yes	Yes	F031	GT	Outside	(42)	No	0"	DC motor	Manual	C	C	0	As is	RM	NA	Standard	A	(22)
X-215	RCIC turbine	Water exhaust	8	56	Yes	Yes	F060	GT	Outside	(24)	No	0"	DC motor	Manual	0	0	0	As is	RM	NA	Standard	A	(22)
X-216	RCIC min flow	Water	2	56	Yes	Yes	F019	GB	Outside	(24)	No	0"	DC motor	Manual	C	C	C	As is	LFRC	NA	8 sec	A	(22)
X-217	RCIC vacuum discharge (Unit 1)	Air	2	56	No No	No No	F002 F028	SCK CK	Outside Outside	(34)	No	11" 6'-2"	Flow Flow	DC motor -	0 C	0 C	0 C	- -	RM -	No -	Standard -	A -	(14)
X-217	RCIC vacuum discharge (Unit 2)	Air	2	56	No No	No No	F002 F028	SCK CK	Outside Outside	(34)	No	17" 6'-2"	Flow Flow	DC motor -	0 C	0 C	0 C	- -	RM -	No -	Standard -	A -	(14)
X-218	Instrument gas supply	Air	1	56	No No	No No	1001 135	CK GB	Inside Outside	(22)	Yes	-" 3"	Flow Comp air	- Manual	0 0	0 0	C C	- -	- C,H,S	- Yes	- 4.4 sec	- B	
X-219A,B	Instrumentation - suppression pool level	Water	2	56	- -	- -	120 121	GB GB	Outside Outside	(38)	No	0" 0"	AC motor AC motor	Manual Manual	0 0	0 0	0 0	As is As is	RM RM	- -	30 sec 30 sec	B B	

Table 6.2-17 (Cont'd)

CONTAINMENT PENETRATION NUMBER	LINE ISOLATED	FLUID	LINE SIZE (in)	NRC GENERAL DESIGN CRITERION	ESF SYSTEM	ESSENTIAL SYSTEM	VALVE NUMBER	VALVE TYPE (1)	VALVE LOCATION	VALVE ARRANGEMENT (2)	TYPE C TEST	LENGTH OF PIPE FROM CONT. TO OUTSIDE VALVES	PRIMARY METHOD OF ACTUATION (3)	SECONDARY METHOD OF ACTUATION	NORMAL VALVE POSITION (4)	SHUTDOWN VALVE POSITION	POST-ACCIDENT POSITION	POWER FAILURE VALVE POSITION	ISOLATION SIGNAL(5)	DIVERSE ISOLATION SIGNAL(12)	VALVE CLOSURE TIME(6)	POWER SOURCE (7)	REMARKS
X-220A	H_2/O_2 sample return; wet-well purge makeup	Air	2	56	Yes	Yes	190	GB	Outside	(12)	Yes	10'-5"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	C	(19)
					Yes	Yes	191	GB	Outside			8'-5"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	A	
					Yes	Yes	116	GB	Outside			14'-8"	AC motor	Manual	C	C	C	As is	B,H,R,S	NA	30** sec	D	
					Yes	Yes	150	GB	Outside			247'-9"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	B	
					Yes	Yes	159	GB	Outside			255'-3"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
X-220B	Instrumentation - suppression pool pressure (Unit 1 only)	Air	2	56	-	-	101	GB	Outside	(39)	No	0"	AC coil	-	0	0	0	C	RM	-	2 sec	A	
X-221A	Wetwell H_2/O_2 sample	Air	1	56	Yes	Yes	181	GB	Outside	(29)	Yes	2'-2"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	B	
					Yes	Yes	141	GB	Outside			3'-11"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	D	
					Yes	Yes	184	GB	Outside			3'-11"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	C	
X-221B	Wetwell H_2/O_2 sample	Air	1	56	Yes	Yes	183	GB	Outside	(23)	Yes	2'-5"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	A	
					Yes	Yes	186	GB	Outside			3'-5"	AC coil	-	0	0	0	C	B,H,R,S	NA	2 sec	C	
X-226A,B	RHR min flow	Water	4	56	Yes	Yes	105A,B	GT	Outside	(35)	No	0"	AC motor	Manual	0	0	0	As is	RM	NA	Standard	C,D	(22)
X-227	ILRT data acquisition	Air	3/4	56	No	No	1073	GB	Outside	(31)	Yes	18"	Manual	-	C	C	C	-	-	-	-	-	
					No	No	1074	GB	Outside			2'-9"	Manual	-	C	C	C	-	-	-	-	-	
X-228D	HPCI vacuum relief	Air	4	56	Yes	Yes	F095	GT	Outside	(17)	Yes	0"	AC motor	Manual	0	0	C	As is	H,LA	NA	Standard	D	(17)
					Yes	Yes	F093	GT	Outside			12'-6"	AC motor	Manual	0	0	C	As is	H,LA	NA	Standard	B	(17), (19)
X-229A	Instrumentation - suppression pool pressure (Unit 2 only)	Air	2	56	-	-	201	GB	Outside	(39)	No	0"	AC coil	-	0	0	0	C	RM	-	2 sec	A	
X-230B	Deactivated Instrumentation - drywell sumps	Water	1-1/2	56	-	-	102	GB	Outside	(32a)	No	3'-0"	AC motor	Manual	C	C	C	As is	-	-		A	(18)
					-	-	112	GB	Outside	(32)		4"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	A	
					-	-	132	GB	Outside			4"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	A	
X-231A,B	Drywell sump drains	Water	4	56	No	No	110	GT	Outside	(28)	No	0"	Comp air	Spring	0	C	C	C	B,H	Yes	20 sec	A	
					No	No	130	GT	Outside			0"	Comp air	Spring	0	C	C	C	B,H	Yes	20 sec	A	
					No	No	111	GT	Outside			3'-5"	Comp air	Spring	C	C	C	C	B,H	Yes	20 sec	B	
					No	No	131	GT	Outside			3'-5"	Comp air	Spring	C	C	C	C	B,H	Yes	20 sec	B	
X-235	CS pump min flow (Unit 1)	Water	4	56	Yes	Yes	F031A	GB	Outside	(24)	No	0"	AC motor	Manual	0	C	C	As is	LFCH	NA	30 sec	A	(22)
X-235	CS pump min flow (Unit 2)	Water	4	56	Yes	Yes	F031A	GB	Outside	(24)	No	6"	AC motor	Manual	0	C	C	As is	LFCH	NA	30 sec	A	
X-236	HPCI pump min flow	Water	4	56	Yes	Yes	F012	GB	Outside	(24)	No	0"	DC motor	Manual	C	C	C	As is	LFHP	NA	15 sec	B	(22)
X-237	Suppression pool clean-up pump suction; level instrumentation	Water	6	56	No	No	127	GT	Outside	(26)	No	(U1)12" (U2)18"	AC motor	Manual	C	C	C	As is	B,H	Yes	Standard	A	
					No	No	128	GT	Outside			(U1)15'-11" (U2)16'-5"	AC motor	Manual	C	C	C	As is	B,H	Yes	Standard	C	(19)
					No	-	127	PSV	Outside			(U1)4'-0" (U2)8'-3"	Water pres	-	C	C	C	-	-	-	-	-	
					-	-	HV-139	GB	Outside		No	(U1)4'-11" (U2)4'-11"	AC motor	Manual	0	0	0	As is	RM	-	30 sec	B	
					-	-	SV-139	GB	Outside		No	(U1)3'-7" (U2)2'-2"	AC coil	-	0	0	0	C	RM	-	4 sec	A	
X-238	RHR relief valve discharge (Unit 1)	Water	10	56	Yes	-	106B	PSV	Outside	(18)	No	38'-4"	Water pres	-	C	C	C	-	-	-	-	-	(19), (22)
					Yes	No	F104B	GB	Outside			34'-10"	Manual	-	C	C	C	-	-	-	-	-	(19), (22)
X-238	RHR relief valve discharge (Unit 2)	Water	10	56	Yes	-	206B	PSV	Outside	(18)	No	38'-4"	Water pres	-	C	C	C	-	-	-	-	-	(19), (22)
X-239	RHR relief valve discharge (Unit 1)	Water	10	56	Yes	-	106A	PSV	Outside	(18)	No	47'-0"	Water pres	-	C	C	C	-	-	-	-	-	(19), (22)
					Yes	No	F103A	GB	Outside			36'-3"	Manual	-	C	C	C	-	-	-	-	-	(19), (22)
X-239	RHR relief valve discharge (Unit 2)	Water	10	56	Yes	-	206A	PSV	Outside	(18)	No	47'-0"	Water pres	-	C	C	C	-	-	-	-	-	(19), (22)
					Yes	No	F203A	GB	Outside			36'-3"	AC motor	Manual	C	C	C	As is	C,G	Yes	12 sec	A	(19), (22)
X-241	RCIC vacuum relief	Water	3	56	Yes	Yes	F084	GT	Outside	(17)	Yes	0"	AC motor	Manual	0	0	C	As is	H,KA	NA	25 sec	A	(17)
					Yes	Yes	F080	GT	Outside			5'-6"	AC motor	Manual	0	0	C	As is	H,KA	NA	25 sec	B	(17)

Table 6.2-17 (Cont'd)

(1) Valve Type:

Ball	BL
Butterfly	BF
Check	Ck
Gate	GT
Globe	GB
Pressure relief	PSV
Stop-check	SCK
Testable check	TCK
Spring load piston-actuated check	SLPACK
Explosive (shear)	XP
Excessive flow check	XFC
Ball check	BLCK
Hydraulic control unit	HCU

(2) See Figure 6.2-36. Numbers in this column refer to details in the figure.

(3) Ac MOVs required for isolation functions are powered from the ac standby power buses. Dc operated isolation valves are powered from the station batteries.

(4) Normal valve position (open or closed) is the position during normal power operation of the reactor.

(5) Isolation Signal Codes

Signal	Description
A*	Reactor vessel level 3 trip (a scram occurs at this level also)
B*	Reactor vessel level 2 trip
C*	Reactor vessel level 1 trip (main steam line isolation occurs at this level)
D*	High radiation in main steam lines and vicinity
E*	Main steam line high flow
	Deleted
F*	High temperature in main steam tunnel or in vicinity of main steam lines in turbine enclosure

Table 6.2-17 (Cont'd)

Signal	Description
G*	High drywell pressure and low reactor vessel pressure
H*	High drywell pressure
J*	Line break in RWCU system (high differential flow, high temperature in RWCU compartments)
K*	Break in RCIC steam line (high temperature in pipe routing area, high temperature or high differential temperature in RCIC compartment, high steam flow), or high RCIC turbine exhaust diaphragm pressure
KA	Low RCIC steam supply pressure
L*	Break in HPCI steam line (high temperature in pipe routing area, high temperature or high differential temperature in HPCI compartment, or high steam flow), or high HPCI turbine exhaust diaphragm pressure
LA	Low HPCI steam supply pressure
LFHP	With HPCI pumps running, opens on low flow in associated pipe, closes when flow is above setpoint
LFRC	With RCIC pump running, opens on low flow in associated pipe, closes when flow is above setpoint
LFCH	With CS pump running, opens on low flow in associated pipe, closes when flow is above setpoint.
LFCC	Steam supply valve fully closed or RCIC turbine stop valve fully closed
M*	Low differential pressure between the instrument gas line and the primary containment
P*	Low main steam line pressure at inlet to turbine (RUN mode only)
Q*	Low condenser vacuum and turbine stop valve in bypass mode or more than 90% open

Table 6.2-17 (Cont'd)

Signal	Description
R*	High radioactivity in refueling floor ventilation exhaust ducts
S*	High radiation in the reactor enclosure
T	Low differential pressure between the outside atmosphere and the refueling area
U	Low differential pressure between the outside atmosphere and the reactor enclosure
V*	High reactor pressure (shutdown cooling mode only)
W*	North stack effluent high radiation
Y	SLCS actuated or RRCS actuated
RM*	Remote manual switch from control room (all power-operated isolation valves are capable of being operated remote manually from the control room)

* These are the isolation functions of the primary containment and reactor vessel isolation control system; other functions are given for information only.

(6) The standard closing rate for automatic isolation gate valves is based on a nominal line size of 12 inches. Using the standard closing rate, a 12 inch line is isolated in 60 seconds. Conversion to closing time can be made on this basis using the actual size of the line in which the gate valve is installed.

The closure times for isolation valves in lines in which HELBs could occur are identified with a single asterisk. The closure times for isolation valves in lines which provide an open path from the containment to the environs are identified with a double asterisk. Closure times for the valves identified by a single or double asterisk are considered maximum closure times. Closure times for all other valves are nominal times.

The closure time for F105 is a maximum closure time.

Table 6.2-17 (Cont'd)

(7) Power Source

Electrical Separation Source:

A - Class 1E electrical channel
B - Class 1E electrical channel
C - Class 1E electrical channel
D - Class 1E electrical channel
W - RPS electrical separation channel
X - RPS electrical separation channel
Y - RPS electrical separation channel
Z - RPS electrical separation channel
N - non-Class 1E

For explanation of electrical separation channels, refer to Section 8.1.

(8) Deleted

(9) The spring-loaded piston, which is actuated by an isolation signal or a loss of power, will not close this valve against normal flow on loss of power from the normal direction.

(10) The TIP drive guide tubes provide a path for the flexible drive cable of the TIP probes. The drive cable is automatically retracted on an isolation signal. When the drive cable is fully retracted, the ball valve closes. The shear valves is provided to isolate the guide tubes by cutting the cable if the drive cable cannot be withdrawn.

(11) The CRD insert and withdraw lines can be isolated outside containment. Upstream of the HCUs, two redundant simple check valves are provided on each main water header (i.e. charging, cooling, drive and exhaust). Air operated scram inlet and outlet valves are also provided. Leakage may occur through the scram outlet valves. A low leakage flowrate will be treated by the clean radwaste system. Excessive leakage will result in either automatic scram or operator initiated scram. When scram is complete, the SDV system is automatically isolated by the redundant vent and drain valves.

(12) Only nonessential systems require diverse signals for automatic isolation. Therefore, this column is not applicable, (NA), for essential systems.

Table 6.2-17 (Cont'd)

(13) These valves are sealed closed whenever the reactor is critical and reactor pressure is greater then 600 psig. The valves are expected to be opened only in the following instances:

a. Flushing of the condensate and feedwater systems during plant startup.

b. RPV hydrostatic testing, which is conducted following each refueling outage prior to commencing plant startup.

(14) Diverse isolation signals are not sensed as discussed in Section 6.2.4.3.1.

(15) These valves are normally closed, will be open only during reactor shutdown, are interlocked to open only on low reactor pressure, and connect to a closed system outside containment. Therefore, closure times less then 60 seconds are not required.

(16) Deleted

(17) Both isolation signals required for valve closure.

(18) Valve HV-61-102 is locked closed, the motor operator is normally de-energized and the valve position is controlled procedurally. The valve remains closed during 10 CFR50, Appendix J, Type A testing, and type C testing is not required. Valve HV-61-202 has been deleted from the Unit 2 design.

(19) All outside containment isolation valves have been located as close to containment as practical. Examples of containment isolation valve locations greater than 10 feet from containment are identified and justified below.

a. Deleted

b. Valves HV-F032A-B, HV-109A-B, HV-F039, HV-F013, HV-130A-B, HV-F105, HV-133A-B (Penetrations X-9A-B) provide a third isolation barrier for the feedwater lines. These valves are located at distances from the penetration dictated by equipment accessibility considerations.

c. Valve 1016 (penetrations X-9A-B, X-44) also provides a third isolation barrier for the feedwater lines and an outboard isolation barrier for the alternate RWCU return penetration (X-44). The valve is located in closer proximity to the latter penetration.

Table 6.2-17 (Cont'd)

d. Valves HV-121 & 131 (penetrations X-25, X-201A) are isolation valves for both drywell and wetwell penetrations. They have been located nearer to one penetration and therefore at some distance from the other.

e. Relief valves F030A-D (penetrations X-203A-D) are located as close to the RHR pumps as possible in order to perform their intended function of providing overpressure protection for the pumps. These valves are part of a closed system outside containment.

f. Relief valve 106B and globe valve F104B, (penetration X-238) have been located as close as practical to the RHR heat. Their location is dictated by functionality and pipe stress considerations. Valves 106A and F103A, (penetration X-239) are located similarly.

g. DELETED

h. Valves HV-114, HV-115 (penetration X-26) are restricted to their location because of necessary piping interties and for valve accessibility.

i. Valve 109 (penetration X-25, X-201A) provides the outboard barrier for both the drywell penetration and the wetwell penetration. Physical separation of the penetrations and the resulting piping arrangement prohibits a closer placement to either penetration.

j. Valves HV-57V-180 and HV-57V-181 (Unit 1 penetration X-201B) are associated with the hardened containment vent and located at distances from the penetration dictated by equipment located in the compartment. Valves HV-57V-280 and HV-57V-281 (Unit 2 penetration X-201A) are associated with the hardened containment vent and located at distances from the penetration dictated by equipment located in the compartment.

(20) Closure times of 6 seconds or less are provided for all isolation valves on the purge lines, with the exception of valves HV-57-105 and HV-57-111. Valves HV-57-105 and HV-57-111 are 2 inch MOVs in the low volume purge lines with closure times of 15 seconds or less. This closure time has been justified by an analysis of the radiological consequences of a LOCA that occurs during purging, as discussed in Section 9.4.5.1.2.

(21) 124A, 124B, 125A, and 125B (penetrations X-53, X-54, X-55 and X-56) do not receive an automatic isolation signal. Valves HV-57V-180 and HV-57V-181 associated with Unit 1 penetration X-201B also do not receive automatic isolation signals and are not normally powered. Valves HV-57V-280 and HV-57V-281 associated with penetration X-201A (Unit 2) also do not receive automatic isolation signals and are not normally powered.These valves are administratively controlled such that these valves are treated as locked closed valves. Therefore, these valves do not have a required closure time.

(22) These lines are below the minimum water level in the suppression pool, the system is a closed system outside primary containment, and will maintain a water seal following an accident. Therefore, 10CFR50 Appendix J, Type C testing is not required.

Table 6.2-17 (Cont'd)

(23) There are electrical interlocks between HV-057-121 and HV-057-131 and in between HV-057-221 and HV-057-231, which prevent both interlocked valves from being open at the same time. This interlock is consistent with requirements of UFSAR Section 9.4.5.1.2.2 to limit the number of high volume purge lines in use during the operational modes of startup, power operation and hot shutdown to one supply line and one exhaust line.

Table 6.2-18

ASSUMPTIONS USED IN EVALUATING THE PRODUCTION
OF COMBUSTIBLE GASES FOLLOWING A LOCA

PARAMETER	VALUE
Fraction of fission product radiation energy absorbed by the coolant:	
Betas from fission products in fuel rods	0.0
Betas from fission products mixed with coolant	1.0
Gammas from fission products in fuel rods	0.1
Gammas from fission products mixed with coolant	1.0
Hydrogen yield rate $G(H_2)$	0.5 molecule/100 eV
Oxygen yield rate $G(0_2)$	0.25 molecule/100 eV
Extent of initial core metal-water reaction involving cladding surrounding the fuel	0.00023 inch depth into original cladding
Evolution time of hydrogen produced from metal-water reaction	2 minutes
Corrosion rate for zinc and zinc paint	3.76×10^{-9} exp(0.0218T) lb-moles/ft^2-hr (where T = temperature in degrees Fahrenheit)
Fission product distribution model:	
Coolant water	1% of solids + 50% of halogens
Containment atmosphere	100% of noble gases
Fuel rods	All other fission products

Table 6.2-19

PARAMETERS USED IN EVALUATING THE PRODUCTION OF HYDROGEN FOLLOWING A LOCA

PARAMETER	VALUE
Reactor thermal power:	3,527 MWt (1)
Drywell free volume:	248,700 ft^3
Suppression chamber free volume:	149,000 ft^3
Zircaloy cladding surrounding active fuel:	
Mass	71,890 lb
Surface area	86,705 ft^2 (1)
Zinc (as galvanized steel) in drywell:	
Mass	1,850 lb
Surface area	32,055 ft^2
Zinc paint in drywell:	
Volume of paint	1.92 ft^3
Surface area	7,692 ft^2
Zinc content of zinc paint	87%
Zinc paint in suppression chamber:	
Volume of paint	39.67 ft^3
Surface area	68,000 ft^2
Zinc content of zinc paint	87%
Volume of free hydrogen normally in reactor coolant (at 60°F and atmospheric pressure):	195 ft^3

(1) Calculation 107 R2 accounts for GE14 fuel at 3527 MWT.

Table 6.2-20

CONTAINMENT HYDROGEN RECOMBINER SUBSYSTEM FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA)	Power supply	LOOP	Loss of both recombiner packages	Alarm in the control room	None. The recombiner packages are powered from the Class 1E buses. When standby power becomes available, the recombiner packages resume operation.
Emergency (LOCA or LOCA + LOOP)	Power supply	Loss of one Class 1E bus or the associated diesel generator	Loss of one recombiner package	Alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
Emergency (LOCA or LOCA + LOOP)	Containment isolation valve in one gas inlet or gas outlet line	Failure of valve to reopen after containment isolation signal is bypassed	No flow through recombiner package	Flow indication and low flow alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
Emergency (LOCA or LOCA + LOOP)	Blower in one recombiner package	Abnormally low blower speed or complete failure to operate	Insufficient flow through recombiner package	Flow indication and low flow alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
Emergency (LOCA or LOCA + LOOP)	Heater elements or SCRs in one recombiner package	Abnormally low heater output	Reaction chamber temperature too low for complete recombination	Alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.

Table 6.2-20 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA + LOOP)	Water inlet valve in one recombiner package	Failure to open fully	Abnormally high return gas temperature	Alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
Emergency (LOCA or LOCA + LOOP)	Gas inlet valve in one recombiner package	Case 1: Excessive valve opening	High flow through the recombiner package, with the possibility of excessive temperatures in the reaction chamber	Flow indication and high temperature alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.
		Case 2: Insufficient valve opening	Insufficient flow through the recombiner package	Flow indication and low flow alarm in the control room	None. The redundant recombiner package is unaffected and is activated manually by the operator.

Table 6.2-21

COMBUSTIBLE GAS ANALYZER SUBSYSTEM FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Normal or Emergency	Power supply	LOOP	Closure of containment isolation valves on all sample lines. Loss of both analyzer packages.	Alarm in the control room	None. The analyzer packages are powered from the Class 1E buses. When standby power becomes available, the containment isolation valves reopen and the analyzer packages resume operation.
Normal or Emergency	480V Fuses	Loss of one fuse.	A/B phase fuse failure would cause loss of one analyzer package. C phase fuse failure would cause pump not to start and analyzer package would not be able to perform function.	A/B phase fuse failure would cause alarm in the control room. C phase fuse failure would be detected upon use or during testing every month.	None. The redundant analyzer package is unaffected and continues to operate.
Emergency (LOCA or LOCA + LOOP)	Power supply	Loss of one Class 1E bus or the associated diesel Generator.	Loss of one analyzer package. Closure of containment isolation valves on associated sample lines.	Alarm in the control room	None. The redundant analyzer package is unaffected and continues to operate.
Emergency (LOCA or LOCA + LOOP)	Sample pump in one analyzer package.	Failure of the operating pump.	Loss of sample flow through the affected analyzer package.	Alarm in the control room	None. The redundant analyzer package is unaffected and continues to operate.
Emergency (LOCA or LOCA + LOOP)	Hydrogen analyzer cell in one analyzer package,	Analyzer cell failure.	Incorrect hydrogen concentration for the affected analyzer package.	Alarm in the control room	None. The redundant analyzer package is unaffected and continues to operate.
Emergency (LOCA or LOCA + LOOP)	Oxygen analyzer cell in one analyzer package.	Analyzer cell. failure.	Incorrect oxygen concentration for the affected analyzer package.	Alarm in the control room	None. The redundant analyzer package is unaffected and continues to operate.

Table 6.2-21 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA + LOOP)	Sample line containment isolation valves.	Failure of one valve to reopen when containment isolation signal is bypassed.	Case A, a sample suction line: inability to draw sample through affected line only.	Case A: alarm in the control room due to low flow when the affected line is selected.	None. The redundant analyzer package is unaffected and continues to operate.
			Case B, a sample return line: blockage of all flow through affected analyzer package.	Case **B**: alarm in the control room due to low flow Immediately.	
Emergency (LOCA or LOCA + LOOP)	Sample line containment isolation valves.	Failure of one valve to close when containment isolation signal is received.	Reduction in containment isolation barriers from two valves to one valve in the affected line.	Indicating lights in the control room.	None. The redundant valve provides isolation.
Normal or Emergency	Other electrical components and cables.	Open circuits and shorted circuits or loss of input / output due to various failure mechanisms or errors.	Loss of functions associated with failure of specific component (indication, alarms, controls, etc.	Depending on failed component alarm indication in control room or failure will be self-revealing.	None. The redundant analyzer package is unaffected and continues to operate.
Normal or Emergency	MCR Signal Conditioner and PLC Assembly	Failure to provide indication or control function.	Unable to obtain Combustible gas concentration readings.	Depending on failed component alarm indication in control room or failure will be self-revealing.	None. The redundant analyzer package is unaffected and continues to operate.

Table 6.2-22

The information in this table has been deleted

Table 6.2-23

The information in this table has been deleted

Table 6.2-24

SYSTEM VENTING AND DRAINING EXCEPTIONS FOR PRIMARY CONTAINMENT INTEGRATED LEAKAGE RATE TEST

I. The drywell chilled water system, located inside the primary containment, is required to maintain the plant in a stabilized condition during the Type A test and is not vented and operates in its normal mode.

II. Portions of systems that are normally filled with water and operating under post-LOCA conditions are not specifically vented to the containment atmosphere or to the outside atmosphere. They remain water-filled during the Type A test. These systems are listed below. (Note: Venting to the primary containment atmosphere does occur for these systems, since the reactor vessel is vented to the primary containment atmosphere and/or system penetrations are open to the suppression pool or containment atmospheres.)

III. For planning and scheduling purposes, or ALARA considerations, pathways that are Type B or C tested within the previous 24 calendar months need not be vented or drained during the Type A test.

System
RCIC
RHR
CS
HPCI

Table 6.2-25

CONTAINMENT PENETRATIONS
COMPLIANCE WITH 10CFR50, APPENDIX J

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
-	Drywell head flange	M-60	B	Double O-Ring	-	2
1	Equipment access door	M-60	B	Double O-Ring	-	2
2	Equipment access door and personnel lock	M-60	B	Double O-Ring	-	2
3A	Instrumentation - main steam line D flow	M-41	A	-	XFC-F070D XFC-F073D	1
3A	Instrumentation - recirculation pump seal pressure	M-43	A	-	XFC-F003A	1
3B	Instrument gas supply	M-59	C	CK-1005B	HV-129B	-
3C	Instrumentation - HPCI steam flow	M-55	A	-	XFC-F024A	1
3C	Instrumentation - HPCI steam flow	M-55	A	-	XFC-F024C	1
3D	Instrumentation - main steam line A flow	M-41	A	-	XFC-F070A XFC-F073A	1
3D	Instrument gas supply	M-59	C	CK-1112	MO-151B	-
4	Head access manhole	M-60	B	Double O-Ring	-	2
5	Spare	-	A	-	-	-
6	CRD removal hatch	M-60	B	Double O-Ring	-	2
7A-D	Primary steam	M-41	C	AO-F022A-D	AO-F028A-D	6
8	Primary steam line drain	M-41	C	MO-F016	MO-F019	4

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
9A,B	Feedwater	M-41	C	CK-F010A,B	CK-F074A,B CK-F032A,B MO-109A,B CK-F039 MO-F013 MO-F105 CK-1036A,B MO-130A,B MO-133A,B 1016	7(MO-F105 only), 18, 24
10	Steam to RCIC turbine	M-49	C	MO-F007	MO-F008 MO-F076	5
11	Steam to HPCI turbine	M-55	C	MO-F002	MO-F003 MO-F100	5
12	RHR shutdown cooling supply	M-51	C	MO-F008	Closed system	33
13A,B	RHR shutdown return	M-51	C	MO-F015A,B	Closed system	33
14	RWCU supply	M-44	C	MO-F001	MO-F004	-
15	Spare	-	A	-	-	-
16A	CS pump discharge	M-52	C	MO-F005	Closed system	33
16B	CS pump discharge	M-52	C	CK-108	Closed system	33
17	RPV head spray (Unit 1 only) (ABANDONED)	M-51	A		Welded Plate	-
17	Spare (Unit 2 only)	M-51	A	-	-	-
18	Spare	-	A	-	-	-
19	Spare	-	A	-	-	-

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
20A	Instrumentation - RPV level	M-42	A	-	XFC-F045B	1
20A	Instrumentation - LPCI ΔP	M-51	A	-	XFC-102B	1
20A	Instrumentation - LPCI ΔP	M-51	A	-	XFC-103B	1
20B	Instrumentation - RPV level	M-42	A	-	XFC-F045C	1
20B	Instrumentation - LPCI ΔP	M-51	A	-	XFC-102C	1
21	Service air	M-15	C	1140	1139	-
22	Instrumentation - drywell pressure	M-42	A	-	MO-147C	11
23	Closed cooling water supply	M-13	C	MO-106	MO-108 MO-109	12
24	Closed cooling water return	M-13	C	MO-107	MO-111 MO-110	12
25	Drywell purge supply	M-57	C B	AO-121 MO-163 AO-123 Double O-Ring Seal Assembly (3)	MO-109 FV-DO-101B AO-131 MO-135	3, 12, 25
26	Drywell purge exhaust	M-57	C B	SV-139 MO-161 MO-111 AO-114 Double O-Ring Seal Assembly (2)	SV-145 FV-DO-101A AO-117 MO-115	3, 1 (SV-139 only) 12, 25
27A	Instrument gas supply	M-59	C	CK-1128	MO-151A	-
27B	Instrumentation - HPCI flow	M-55	A	-	XFC-F024B	1
27B	Instrumentation - HPCI flow	M-55	A	-	XFC-FO24D	1
28A	Recirc loop sample	M-43	C	AO-F019	AO-F020	-

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
28A	Drywell H_2/O_2 sample	M-57	C	SV-134	SV-144	12
28A	Drywell H_2/O_2 sample	M-57	C	SV-132	SV-142	12
28B	Drywell H_2/O_2 sample	M-57	C	SV-133	SV-143 SV-195	12
28B	Spare	-	A	-	-	-
29A	Instrumentation - RPV flange leakage	M-41	A	-	XFC-F009	1, 28
29B	Instrumentation - CS ⩤P	M-52	A	-	XFC-F018A	1
30A	Instrumentation - main steam line D flow	M-41	A	-	XFC-F071D XFC-F072D	1
30B	Instrumentation - drywell pressure	M-42	A	-	MO-147A	11
30B	Instrumentation - main steam line C flow	M-41	A	-	XFC-F071C XFC-F072C	1
31 A,B	Instrumentation - jet pump flow	M-42	A	-	XFC-F059B,D,F,H XFC-F051B XFC-F053B	1
32 A,B	Instrumentation - jet pump flow	M-42	A	-	XFC-F059M,P,S,U XFC-F051D XFC-F053D	1
33A	Instrumentation - pressure above core plate	M-42	A	-	XFC-F055 XFC-F076	1
33A	Instrumentation - pressure below core plate	M-42	A	-	XFC-F061	1
33B	Instrumentation - RCIC steam flow	M-49	A	-	XFC-FO44A,C	1
34A	Instrumentation - main steam line C flow	M-41	A	-	XFC-F070C XFC-F073C	1

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
34B	Instrumentation - recirculation flow	M-43	A	-	XFC-F009C,D XFC-F010C,D	1
35A	Spare	-	A	-	-	-
35B	Instrument gas to TIP indexing mechanisms	M-59	C B	CK-1056 Double O-Ring Seal	AO-131	27
35C-G	TIP drives	M-59	C B	XV-141A-E Double O-Ring Seal (5)	XV-140A-E	12, 20, 27
36	Spare	-	A	-	-	-
37A-D	CRD insert	M-47	A C	Ball check -	- CK46-1101 CK46-1102 CK46-1108 CK46-1109	- 13,15
38A-D	CRD withdraw	M-47	C	-	CK46-1115 CK46-1116 CK46-1122 CK46-1123	13,15
			C		F010, F011 F180, F181	
39A,B	Drywell spray	M-51	C	MO-F021 A,B	Closed system	4, 12, 33
40A	Instrumentation - jet pump flow	M-42	A	-	XFC-F059L,N,R	1
40B	Instrumentation - jet pump flow	M-42	A	-	XFC-F059G XFC-F051A XFC-F053A	1
40C	Instrumentation - jet pump flow	M-42	A	-	XFC-F059A,C,E	1
40D	Instrumentation - pressure below core plate	M-42	A	-	XFC-F057	1
40D	Instrumentation - bottom drain flow	M-44	A	-	XFC-170 XFC-171	1
40E	Instrumentation - drywell pressure	M-42	A	-	MO-147D	11

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
40F	Instrumentation - RCIC steam flow	M-49	A	-	XFC-F044B,D	1
40F	Instrument gas suction	M-59	C	MO-101	AO-102	5
40G	ILRT data acquisition system	M-60	C	1057	1058	12, 30
40G	ILRT data acquisition system	M-60	C	1071	1070	12, 30
40H	Instrument gas supply	M-59	C	CK-1005A	AO-129A	-
40H	Instrumentation - recirculation pump cooler flow	M-87	A	-	XFC-156B XFC-157B	21
41	Instrumentation - RWCU flow	M-44	A	-	XFC-102A,B	1
41	Instrumentation - LPCI ⍁P	M-51	A	-	XFC-103A	1
42	SLCS	M-48	C	CK-F007	MO-F006A	-
43A	Instrumentation - recirculation loop A ⍁P;	M-43	A	-	XFC-F040A,C	1
43B	Main steam sample	M-41	C	AO-F084	AO-F085	-
44	RWCU alternate return	M-41	C	1017	1016 PSV-112	5, 24
45A-D	LPCI	M-51	C	MO-F017A-D	Closed system	33
46	Spare	-	A	-	-	-
47	Instrumentation - RWCU flow	M-44	A	-	XFC-102D	1
48A	Instrumentation - RPV level	M-42	A	-	XFC-F065B XFC-F047B	1
48A	Instrumentation - CS ⍁P	M-52	A	-	XFC-F018B	1

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
48B	Instrumentation - RPV level	M-42	A	-	XFC-F065A XFC-F047A	1
49A,B	Instrumentation - main steam line A & B flow	M-41	A	-	XFC-F071A,B XFC-F072A,B	1
50A	Instrumentation - drywell pressure	M-42	A	-	MO-147B	11
50A	Instrumentation - recirculation flow	M-43	A	-	XFC-F011A,B XFC-F012A,B	1
50B	Instrumentation - recirculation pump seal pressure	M-43	A	-	XFC-F004A	1
50B	Instrumentation - recirculation pump cooler flow	M-87	A	-	XFC-156A XFC-157A	21
51A	Instrumentation - recirculation line flow	M-43	A	-	XFC-F009A,B XFC-F010A,B	1
51B	Instrumentation - jet pump flow	M-42	A	-	XFC-F059T XFC-F051C XFC-F053C	1
52A	Instrumentation - main steam line B flow	M-41	A	-	XFC-F070B XFC-F073B	1
52B	Instrumentation - recirculation line flow	M-43	A	-	XFC-F011C,D XFC-F012C,D	1
53	Drywell chilled water supply	M-87	C	MO-128	MO120A, MO125A	12
54	Drywell chilled water return	M-87	C	MO-129	MO121A, MO124A	12
55	Drywell chilled water supply	M-87	C	MO-122	MO120B, MO125B	12
56	Drywell chilled water return	M-87	C	MO-123	MO121B, MO124B	12

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
57	Instrumentation - RWCU flow	M-44	A	-	XFC-102C	1
58A	Instrumentation - recirculation loop B ΔP	M-43	A	-	XFC-F040B	1
58B	Spare	-	A	-	-	-
59A,B	Spare	-	A	-	-	-
60	Spare	-	A	-	-	-
61	Recirculation pump seal purge	M-43	C	CK-1004A, B	XFC-103A,B	1, 19
62	H_2/O_2 sample return	M-57	C	SV-150	MO-116 SV-159 SV-190 SV-191	12
63	Instrumentation - recirculation loop ΔP; recirc pump Seal pressure	M-43	A	-	XFC-F003B XFC-F004B XFC-F040D	1
64	Spare	-	A	-	-	-
65A,B	Instrumentation - RPV pressure	M-42	A	-	XFC-F043B XFC-F049A	1
66A	Instrumentation - RPV level	M-42	A	-	XFC-F045D	1
66A	Instrumentation - LPCI ΔP	M-51	A	-	XFC-102D XFC-103D	1
66B	Instrumentation - RPV level	M-42	A	-	XFC-F045A	1
66B	Instrumentation - LPCI ΔP	M-51	A	-	XFC-102A XFC-103C	1
67A,B	Instrumentation - RPV level; RPV pressure	M-42	A	-	XFC-F041 XFC-F043A XFC-F049B	1

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
100 A-D	Neutron monitoring system	M-60	B	Canister	-	8
101 A-D	Recirculation pump power	M-60	B	Canister	-	8
102A	Instrumentation - Jet pump flow	M-42	A	-	XFC-185A	1
102B	Electrical spare	-	A	-	-	-
103A,B	Temperature and low level signals	M-60	B	Canister	-	8
104 A-D	CRD position indicator	M-60	B	Canister	-	8
105 A-E	Miscellaneous low voltage power	M-60	B	Canister	-	8
106 A-C	Low voltage control	M-60	B	Canister	-	8
107	Instrumentation - Jet pump flow	M-42	A	-	XFC-185B	1
108	Electrical spare	-	A	-	-	-
109	Electrical spare	-	A	-	-	-
110	Electrical spare	-	A	-	-	-
111	Electrical spare	-	A	-	-	-
112	Electrical spare	-	A	-	-	-
113	Electrical spare	-	A	-	-	-
114	Electrical spare	-	A	-	-	-
115	Electrical spare	-	A	-	-	-
116	SLCS	M-48	C	CK-F007	MO-F006B	-

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
117A	Electrical spare	-	A	-	-	-
117B	Drywell radiation monitoring supply and return	M-26	C	SV 190-A SV 190-C	SV 190-B SV 190-D	12
118 A,B	Electrical spare	-	A	-	-	-
200 A,B	Access hatch	M-60	B	Double O-Ring	-	2
201A	Suppression pool purge supply	M-57	C B	AO-131 MO-164 AO-124 Double O-Ring Seal Assembly (3)	AO-121 MO-169 MO-147 MO-109	3, 12, 25
201A	Hardened containment vent (Unit 2)	M-57	C B	AO-280 Double O-Ring Seal Assembly (3)	AO-281	3, 12, 25
201B	Hardened containment vent (Unit 1)	M-57	C B	AO-180 Double O-Ring Seal Assembly (2)	AO-181	3, 12, 25
202	Suppression pool purge Exhaust	M-57	C B	MO-162 MO-105 AO-104 Double O-Ring Seal Assembly (2)	MO-166 AO-118 SV-185 MO-112	3, 5 (MO-105) (Unit 1 only), 12, 25
203 A-D	RHR pump suction	M-51	A	Water seal	MO-F004A-D PSV-F030A-D	14
204 A,B	RHR pump test line and containment cooling	M-51	A	Water seal	MO-125A,B	14
205 A,B	Suppression pool spray	M-51	C	-	MO-F027A,B	10, 12
206 A-D	CS pump suction	M-52	A	Water seal	MO-F001A-D	14
207 A,B	CS pump test and flush	M-52	A	Water seal	MO-F015A,B	14

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
208A	Spare	-	A	-	-	-
208B	CS pump minimum recirc	M-52	A	Water seal	MO-F031B	14
209	HPCI pump suction	M-55	A	Water seal	MO-F042	14
210	HPCI turbine exhaust	M-55	A	Water seal	MO-F072	14
211	Spare	-	A	-	-	-
212	HPCI pump test and flush	M-55	A	Water seal	MO-F071	14
213	Spare	-	A	-	-	-
214	RCIC pump suction	M-49	A	Water seal	MO-F031	14
215	RCIC turbine exhaust	M-49	A	Water seal	MO-F060	14
216	RCIC minimum flow	M-49	A	Water seal	MO-F019	14
217	RCIC vacuum pump discharge	M-49	A	MO-F002	CK-F028	34
218	Instrument - gas to vacuum relief valves	M-59	C	CK-1001	AO-135	-
219 A,B	Instrumentation - suppression pool level	M-55	A	-	MO-120 MO-121 MO-126	11 31
220A	H_2/O_2 sample return	M-57	C	SV-191	SV-190 MO-116 SV-150 SV-159	12
220B	Instrumentation - suppression pool pressure; suppression pool level (Unit 1 only)	M-57	A	-	SV-101	11
220B	Spare (Unit 2 only)	-	A	-	-	-
221A	Wetwell H_2/O_2 sample	M-57	C	SV-181	SV-141 SV-184	12

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
221B	Wetwell H_2/O_2 sample	M-57	C	SV-183	SV-186	12
222	Indication and control	M-60	B	Canister	-	8
223	Spare	-	A	-	-	-
224	Spare	-	A	-	-	-
225	Spare	M-51	A	-	-	2 (Unit 2 Only)
226A,B	RHR minimum recirc	M-51	A	Water seal	MO-105A,B	14
227	ILRT data acquisition system	M-60	C	1073	1074	12
228A,B	Spare	-	A	-	-	-
228C	Spare	-	A	-	-	-
228D	HPCI vacuum relief	M-55	C	MO-F095	MO-F093	4, 12
229A	Spare (Unit 1 only)	-	A	-	-	-
229A	Instrumentation - suppression pool pressure; suppression pool level (Unit 2 only)	M-57	A	-	SV-201	11
229B	Spare	-	A	-	-	-
230A	Strain gauge instrumentation	-	B	Canister	-	8
230B	Instrumentation - drywell sump level	M-61	A	-	MO-102 MO-112 MO-132	29
231A	Drywell sump drains	M-61	A	AO-110	AO-111	12, 34
231B	Drywell sump drains	M-61	A	AO-130	AO-131	12, 34
232 A-S	MSRV discharge	M-41	-	-	-	16

Table 6.2-25 (Cont'd)

PENETRATION NUMBER	SYSTEM	DRAWING[17]	TEST TYPE	INBOARD ISOLATION BARRIER DESCRIPTION/ VALVE NUMBER	OUTBOARD ISOLATION BARRIER INSTRUMENT/ VALVE NUMBER	NOTE
235	CS pump minimum recirc	M-52	A	Water Seal	MO-F031A	14
236	HPCI pump minimum recirc	M-55	A	Water Seal	MO-F012	14
237	Suppression pool cleanup pump suction	M-52	A	MO-127	MO-128 PSV-127	12, 34
237	Level instrumentation	M-52	A	-	SV-139 MO-139	11
238	RHR relief valve discharge	M-51	A	Water Seal	PSV-106B MO-F104B Double O-ring Seal Assembly (4)	14, 23
239	RHR relief valve discharge	M-51	A	Water Seal	MO-F103A PSV-106A Double O-ring Seal Assembly (4)	14, 23
240	RHR relief valve discharge	M-51	A	Water Seal	Double O-ring Seal Assembly (3)	32
241	RCIC vacuum relief	M-49	C	MO-F084	MO-F080	4, 12

NOTES

1. Seismic Category I, Quality Group A instrument line with an orifice and excess flow check valve or remote manual isolation valve. The excess flow check valve is subjected to operability testing except as discussed in Note 28, but no Type C test is performed or required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leak-tightness of the line is verified during the integrated leak rate test (Type A test) by conducting the test with these valves open.

2. Penetration is sealed by a blind flange or door with double O-ring seals. These seals are leakage rate tested by pressurizing between the O-rings. For more detail, see Section 6.2.6.2.

3. Inboard butterfly valve installed such that testing in the reverse direction is equivalent to testing in the forward direction.

4. Inboard gate valve tested in the reverse direction. Valve seating forces are greater than unseating forces due to post-LOCA containment pressure by at least a factor of 3.

5. Inboard globe valve installed such that testing in the reverse direction is conservative.

6. The primary steam penetrations are tested by pressurizing between the valves. Testing of the inboard MSIV in the reverse direction tends to unseat the valve and is therefore conservative. The valves are Type C tested at a test pressure of 22 psig.

7. Gate valve tested in the reverse direction. Valve seating forces are greater than unseating forces due to post-LOCA containment pressure by at least a factor of 3.

8. Electrical penetrations are tested by pressurizing between the seals

Table 6.2-25 (Cont'd)

9. The isolation provisions for this penetration consist of two isolation valves and a closed system outside containment. Because a water seal is maintained in these lines by the safeguard piping fill system, the inboard valve may be tested with water. The outboard valve will be pneumatically tested.

10. The isolation provisions for this line consist of one isolation valve outside containment and a closed system outside containment. A single active failure can be accommodated. The closed system is missile-protected, seismic Category I, quality group B and designed to the temperature and pressure conditions that the system will encounter post-LOCA.

    System leakage will be minimized in accordance with NUREG-0737, Item III.D.1.1. Any leakage out of the closed system will be into the reactor enclosure, thus facilitating collection and treatment.

11. The valve does not receive an isolation signal but remains open to measure containment conditions post-LOCA. Leak-tightness of the penetration is verified during the Type A test by conducting the test with these valves open.

12. All isolation barriers are located outside containment.

13. Isolation provisions for the CRD insert and withdrawal lines are described in Section 6.2.4.3.1.2.3. The SDV vent and drain valves are Type C tested. Redundant check valves are provided on each main water header (i.e. charging, cooling, drive and exhaust). These valves are Type C tested with water.

14. The isolation provisions for this line consist of a suppression pool water seal, at least one isolation valve outside containment, and a closed system outside containment. The isolation valve is not exposed to the primary containment atmosphere because the line terminates below the minimum water level of the suppression pool. The closed system is missile-protected, seismic Category I, quality group B, and designed to the temperature and pressure conditions that the system will encounter post-LOCA. Because these valves will remain water covered following a LOCA, 10CFR50 Appendix J, Type C testing is not required. System leakage is minimized in accordance with NUREG-0737, Item III.D.1.1. Any leakage out of the closed system will be into the reactor enclosure, thus facilitating collection and treatment.

15. The isolation barrier remains water-filled post-LOCA and may be tested with water.

16. These lines penetrate the diaphragm slab and are not subject to Appendix J leakage rate testing.

17. Table 1.8-2 contains a cross-reference to figure numbers.

18. Feedwater penetrations will remain water-filled post-LOCA as described in Section 6.2.3.2.3.

19. Check valve used instead of flow orifice.

20. The ball valves (XV-141A-E) are Type C tested. It is not practical to leak test the shear valves (XV-140A-E) because squib detonation is required for closure; however, the following tests will be conducted to ensure that these valves will perform their intended function:

    a. The continuity of the explosive charge will be verified at least once per 31 days.

    b. One of the squib charges will be initiated at least once per 24 months. The replacement charge for the shear valve will be from the same manufacturing batch as the one fired, or from another batch that has been certified by having one sample from that batch successfully fired.

       In addition, all charges will be replaced at the manufacturer's recommended intervals. These requirements will be incorporated into the plant administrative procedures and surveillance test procedures.

21. Seismic Category I, Quality Group B instrument line with an excess flow check valve. Because the instrument line is connected to a closed cooling water system inside containment, no flow orifice is provided. The excess flow check valve is subject to operability testing, but no Type C test is performed or required. The line does not isolate during a LOCA and can leak only if the line or instrument should rupture. Leak-tightness of the line is verified during the integrated leak rate test (Type A test) by conducting the test with these valves open.

22. Deleted

Table 6.2-25 (Cont'd)

23. The RHR system safety pressure relief valves will be exempted from the initial LLRT. The relief valves in these lines will be exposed to containment pressure during the initial ILRT and all subsequent ILRTs. In addition, modifications will be performed at the first refueling to facilitate local testing or removal and bench testing of the relief valves during subsequent LLRTs. Justification for exclusion from separate testing of these valves as part of the initial LLRT program is based on the substantial containment isolation barriers provided by the design of the relief valves and the RHR system:

    a. The relief valves are maintained normally closed by their springs.

    b. The relief valves are oriented such that containment pressure would tend to seat the valve disc and enhance sealing.

    c. The relief valves are not exposed to the primary containment atmosphere because the lines terminate below the minimum water level of the suppression pool.

    d. The lines outside containment are part of a closed system which is missile-protected, Seismic Category I, quality group B, and designed to the temperature and pressure conditions that the system will encounter.

    e. System leakage will be minimized in accordance with NUREG-0737 Item III.D.1.1.

    f. Any leakage out of the system will be into the reactor enclosure, thus facilitating collection and treatment.

    g. Those relief valves that are flanged to facilitate removal will be equipped with double O-ring seal assemblies on the flange closest to primary containment.

24. Valve 41-1016 is an outboard isolation barrier for penetrations X-9A, B and X-44. Leakage through valve 41-1016 is included in the total for penetration X-44 only.

25. Butterfly valves are flanged. Those that serve as inboard isolation valves are equipped with double O-ring seal assemblies on the flange closest to primary containment. These seals are leak rate tested by pressurizing between the O-rings.

26. Relief valves PSV-51-1F030A, B, and C are flanged to facilitate removal and ISI testing. PSV-51-1F030D will be flanged prior to the end of the first refueling outage. In all cases, the flanges closest to primary containment will be equipped with double O-ring seal assemblies prior to the end of the first refueling outage. The seals will be leak rate tested by pressurizing between the O-rings. In the interim, the flanged valves are equipped with gasketed connections. The connections are exposed to suppression pool water and are tested during the integrated leak rate test. In addition, they are inspected as part of the system leakage reduction program (Section 6.2.8).

27. Penetration is sealed by a flange with double O-ring seals. Both the TIP purge supply (Penetration X-35B) and the TIP drive tubes (Penetration X-35C through G) are welded to their respective flanges. The seals are leak rate tested by pressurizing between the O-rings.

28. The reactor vessel head seal leak detection line (Penetration X-29A) excess flow check valve is not subject to operability testing. This valve will not be exposed to primary system pressure except under the unlikely conditions of a seal failure where it could be partially pressurized by reactor pressure. Any leakage path is restricted at the source; therefore, this valve need not be operability tested.

29. Valve HV-61-102 is locked closed, the motor operator is normally de-energized and the valve position is controlled procedurally. The valve remains closed during 10 CFR 50, Appendix J Type A testing, and Type C testing is not required. Valve HV-61-202 has been deleted from the Unit 2 design.

30. Inboard valve will be tested from the containment side using a temporary test connection at the open pipe end inside the drywell.

31. Valve HV-55-126 has been used for Unit 1 only.

32. The isolation provisions for this line consist of a suppression pool water seal, blind flange, and a closed system outside containment. The flange is not exposed to the primary containment atmosphere because the line terminates below the minimum water level in the suppression pool. The line is not used to support the system's functions. Because the line will maintain a water seal following a LOCA, 10 CFR 50 Appendix J, Type B testing is not required.

33. The isolation provisions for this line consist of one isolation valve outside containment and a closed system outside containment. A single active failure can be accommodated. The closed system does not communicate with the outside atmosphere, meets Seismic Category I and Safety Class 2 design requirements, designed to temperature and pressure conditions that the system will encounter post-LOCA, is protected from a HELB, is missile-protected, and is capable of being leak tested.

34. Type C testing of these valves is not required. A water seal for these lines will be maintained for 30 days.

Table 6.2-26

REMOTELY ACTUATED VALVES REQUIRED FOR POSTACCIDENT SYSTEM ISOLATION[1]

System	Boundary Valve	Location	Normal Valve Position[2]	Postaccident Position[3]	Actuation Signal[4]
HPCI	HV-F008	HPCI to CST (Test Bypass)	Closed	Closed	B, H
	HV-F011	HPCI/RCIC Test Return to CST	Closed	Closed	B, H, IA
	HV-F025	HPCI Vacuum Tank Drain	Open	Closed	IB
	HV-F026	HPCI Vacuum Tank Drain	Closed	Closed	IB
	HV-F028	HPCI Steam Line Drain	Open	Closed	IB
	HV-F029	HPCI Steam Line Drain	Open	Closed	IB
RCIC	HV-F004	RCIC Vacuum Tank Drain	Closed	Closed	IC
	HV-F005	RCIC Vacuum Tank Drain	Open	Closed	IC
	HV-F022	RCIC to CST (Test Bypass)	Closed	Closed	B, ID
	HV-F025	RCIC Steam Line Drain	Open	Closed	1C
	HV-F026	RCIC Steam Line Drain	Open	Closed	IC
RHR					
	HV-F040	RHR to Liquid Radwaste	Closed	Closed	H, A
	HV-F049	RHR to Liquid Radwaste	Closed	Closed	H, A

Table 6.2-26 (Cont'd)

System	Boundary Valve	Location	Normal Valve Position[2]	Postaccident Position[3]	Actuation Signal[4] [6]
RHR	HV-F079A, B	RHR Sample Isolation	Closed	Closed	H, A
	HV-F080A, B	RHR Sample Isolation	Closed	Closed	H, A
Containment Atmospheric Control	HV-116	Nitrogen Purge Supply	Closed	Closed	B, H
Reactor Enclosure HVAC	HV-030/031	Drywell Purge Exhaust	Closed	Closed	B, H, R, T
	HV-107/108	Reactor Enclosure Air Supply	Open	Closed	B, H, R, T
	HV-117/118	Refueling Floor Air Supply	Open	Closed	R, T
	HV-141/142	Reactor Enclosure Equipment Comp. Exhaust	Open	Closed	B, H, R, T
	HV-157/158	Reactor Enclosure Exhaust	Open	Closed	B, H, R, T
	HV-167/168	Refueling Floor Exhaust	Open	Closed	R, T
CRD Scram Discharge	XV-F010	Scram Discharge Piping Vent	Open	Closed	RPS
	XV-F180	Scram Discharge Piping Vent	Open	Closed	RPS
	XV-F011	Scram Discharge Piping Drain	Open	Closed	RPS
	XV-F181	Scram Discharge Piping Drain	Open	Closed	RPS

Table 6.2-26 (Cont'd)

(1) Closure of these valves establishes a redundant boundary for potentially contaminated systems. Containment isolation valves that also provide system isolation are not included in this table (see Table 6.2-17). Where Unit 1 valves are listed, the design is typical for Unit 2.

(2) Normal valve position (open or closed) is the position during normal power operation of the reactor.

(3) Postaccident position is the required position of the valve during DBA conditions.

(4) Actuation signal codes

Signal	Description
A	Reactor vessel level 3 trip (a scram occurs at this level also)
B	Reactor vessel level 2 trip
C	Reactor vessel level 1 trip (main steam line isolation occurs at this level)
G	High drywell pressure and low reactor vessel pressure
H	High drywell pressure
IA	Interlocked to close when any of the HPCI (F041) or RCIC suppression pool suction valves (HV49-F029 or HV49-F031) open
IB	Interlocked to close when the HPCI turbine steam supply isolation valve (F001) opens
IC	Interlocked to close when the RCIC turbine steam supply isolation valve (F045) opens
ID	Interlocked to close when the RCIC suppression pool suction valves (F029 or F031) open
R	High radioactivity in reactor enclosure or refueling floor ventilation exhaust ducts, as applicable
T	Low differential pressure between the outside atmosphere and either the secondary containment or refueling area, as applicable
RPS	Reactor Protection System Scram Signal

(5) DELETED

(6) With the Reactor Enclosure Secondary Containment Zones I or II interlocked with Refuel Area Secondary Containment Zone III, The Reactor Enclosure HVAC valve isolation signals are combined for all associated valves as follows: B, H, R, T. In addition, the same valves isolate on RE Vent. Exh. High Rad (S) and Outside Atmos. to RE - Low DP (U).

Table 6.2-27

ESSENTIAL/NONESSENTIAL SYSTEMS

	ESSENTIAL	COMMENTS
SLCS	Yes	Should be available as backup to CRD system.
LPCI	Yes	Safety System
HPCI	Yes	Safety System
Core Spray	Yes	Safety System
Service Water	No	Not required for shutdown.
CAC	Yes	Combustible gas control function necessary to monitor and control containment hydrogen/oxygen levels.
ADS	Yes	Safety System/control RPV pressure
SGTS	Yes	Necessary to control emissions to environment.
RECW	No	Not required for DBA, but necessary for the recirculation cleanup system operation and fuel pool heat exchangers.
RCIC	Yes	Necessary for core cooldown following isolation from the turbine condenser and feedwater makeup.
ESW	Yes	Necessary to remove heat following accident. Includes the UHS.
RHRSW	Yes	Necessary to remove heat following accident. Includes the UHS.
PCIG	No	Not required for shutdown.
Compressed Air	No	Not required for shutdown.
Main Steam	No	Not required for shutdown.
Feedwater Line	No	Not required for shutdown, except for the portion to which the RCIC and HPCI systems connects.
Sampling Systems	No	Not required for shutdown. Some sampling capability will be provided for postaccident assessment in accordance with NUREG-0737 Item II.B.3.

Table 6.2-27 (Cont'd)

	ESSENTIAL	COMMENTS
CRD System	Yes	Parts of system are necessary for reactor shutdown.
RWCU	No	Not required for shutdown.
Radwaste Collection	No	Not required for shutdown.
Recirculation System	No	Not required for shutdown.
RHR Heat Exchangers	Yes	Main heat sink during isolation.
RHR Shutdown Cooling	Yes	Not essential, but desirable to use if available. Not redundant, but safety-grade.
RHR Containment/Suppression Spray	Yes	Necessary to control pressure.
RHR - Suppression Pool Cooling	Yes	Main heat sink during isolation.
Drywell Chilled Water	No	Not required for shutdown, but desirable to keep running.
Clarified Water	No	Not required for shutdown.
Condensate	No	Not required for shutdown.
Fuel Pool Cooling	No	Not required for shutdown but continuous pool cooling is desired. Seismic Category I makeup line is provided.
Control Drywell Purge	Yes	Backup to hydrogen control.
MSIV Alternative Drain Pathway	Yes	Ensures that highly radioactive fluids are confined to the reactor building.
TIP System	No	Not required for shutdown.
Fire Protection System	Yes	Availability is essential for shutdown following a fire.
Makeup Demineralizer	No	Not required for shutdown.
ECCS Fill System	Yes	Required to ensure ECCS operability.
Feedwater Fill System	Yes	Required to mitigate radiological consequences.

Table 6.2-27 (Cont'd)

	ESSENTIAL	COMMENTS
Primary Containment Leak Test System	No	Not required for shutdown.
Suppression Pool Cleanup System	No	Not required for shutdown.
Long-Term ADS Gas Supply	Yes	Long-term backup to ADS accumulators inside containment.

Table 6.2-28

REACTOR ENCLOSURE AND REFUELING AREA SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION VALVES-SEPERATE ZONE SYSTEM ALIGNMENT

REACTOR ENCLOSURE (ZONE I) VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Reactor Enclosure Ventilation Supply Valve HV-76-107	5	B,H,S,U
2. Reactor Enclosure Ventilation Supply Valve HV-76-108	5	B,H,S,U
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-157	5	B,H,S,U
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-158	5	B,H,S,U
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-141	5	B,H,S,U
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-142	5	B,H,S,U
7. Drywell Purge Exhaust Valve HV-76-30	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-31	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-214 (Unit 2)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-215 (Unit 2)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-204 (Unit 2)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-212 (Unit 2)	6	B,H,S,U,W,R,T

TABLE 6.2-28 (Cont'd)

REACTOR ENCLOSURE (ZONE II)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Reactor Enclosure Ventilation Supply Valve HV-76-207	5	B,H,S,U
2. Reactor Enclosure Ventilation Supply Valve HV-76-208	5	B,H,S,U
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-257	5	B,H,S,U
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-258	5	B,H,S,U
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-241	5	B,H,S,U
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-242	5	B,H,S,U
7. Drywell Purge Exhaust Valve HV-76-30	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-31	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T

(a) See LGS Technical Specification 3.3.2, Table 3.3.2-1 for isolation signals that operate each automatic isolation valve.

Table 6.2-28 (Cont'd)

REFUELING AREA (ZONE III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Refueling Area Ventilation Supply Valve HV-76-117 (Unit 1)	5	R,T
2. Refueling Area Ventilation Supply Valve HV-76-118 (Unit 1)	5	R,T
3. Refueling Area Ventilation Exhaust Valve HV-76-167 (Unit 1)	5	R,T
4. Refueling Area Ventilation Exhaust Valve HV-76-168 (Unit 1)	5	R,T
5. Refueling Area Ventilation Supply Valve HV-76-217 (Unit 2)	5	R,T
6. Refueling Area Ventilation Supply Valve HV-76-218 (Unit 2)	5	R,T
7. Refueling Area Ventilation Exhaust Valve HV-76-267 (Unit 2)	5	R,T
8. Refueling Area Ventilation Exhaust Valve HV-76-268 (Unit 2)	5	R,T
9. Drywell Purge Exhaust Valve HV-76-030	5	B,H,S,U,R,T
10. Drywell Purge Exhaust Valve HV-76-031	5	B,H,S,U,R,T
11. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
12. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
13. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
14. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T
15. Drywell Purge Exhaust Inboard Valve HV-57-214 (Unit 2)	5	B,H,S,U,W,R,T
16. Drywell Purge Exhaust Outboard Valve HV-57-215 (Unit 2)	6	B,H,S,U,W,R,T
17. Suppression Pool Purge Exhaust Inboard Valve HV-57-204 (Unit 2)	5	B,H,S,U,W,R,T,
18. Suppression Pool Purge Exhaust Outboard Valve HV-57-212 (Unit 2)	6	B,H,S,U,W,R,T

(a) See UFSAR Table 6.2-17, note 5 for isolation signals that operate each automatic isolation valve.

Table 6.2-29

REACTOR ENCLOSURE AND REFUELING AREA SECONDARY CONTAINMENT VENTILATION SYSTEM AUTOMATIC ISOLATION VALVES-COMBINED ZONE SYSTEM ALIGNMENT

RX / REFUEL ENCL. (ZONE I & III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Reactor Enclosure Ventilation Supply Valve HV-76-107	5	B,H,S,U,R,T
2. Reactor Enclosure Ventilation Supply Valve HV-76-108	5	B,H,S,U,R,T
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-157	5	B,H,S,U,R,T
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-158	5	B,H,S,U,R,T
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-141	5	B,H,S,U,R,T
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-142	5	B,H,S,U,R,T
7. Drywell Purge Exhaust Valve HV-76-30	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-31	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-214 (Unit 2)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-215 (Unit 2)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-204 (Unit 2)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-212 (Unit 2)	6	B,H,S,U,W,R,T
13. Refueling Area Ventilation Supply Valve HV-76-117	5	B,H,S,U,R,T
14. Refueling Area Ventilation Supply Valve HV-76-118	5	B,H,S,U,R,T
15. Refueling Area Ventilation Exhaust Valve HV-76-167	5	B,H,S,U,R,T
16. Refueling Area Ventilation Exhaust Valve HV-76-168	5	B,H,S,U,R,T
17. Refueling Area Ventilation Supply Valve HV-76-217 (Unit 2)	5	B,H,S,U,R,T
18. Refueling Area Ventilation Supply Valve HV-76-218 (Unit 2)	5	B,H,S,U,R,T
19. Refueling Area Ventilation Exhaust Valve HV-76-267 (Unit 2)	5	B,H,S,U,R,T
20. Refueling Area Ventilation Exhaust Valve HV-76-268 (Unit 2)	5	B,H,S,U,R,T

TABLE 6.2-29 (Cont'd)

ZONE I & III (Cont'd)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
21. Drywell Purge Exhaust Inboard Valve HV-57-114	5	B,H,S,U,W,R,T
22. Drywell Purge Exhaust Outboard Valve HV-57-115	6	B,H,S,U,W,R,T
23. Suppression Pool Purge Exhaust Inboard Valve HV-57-104	5	B,H,S,U,W,R,T
24. Suppression Pool Purge Exhaust Outboard Valve HV-57-112	6	B,H,S,U,W,R,T

Table 6.2-29 (Cont'd)

RX / REFUEL ENCL.(ZONE II & III)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
1. Reactor Enclosure Ventilation Supply Valve HV-76-207	5	B,H,S,U,R,T
2. Reactor Enclosure Ventilation Supply Valve HV-76-208	5	B,H,S,U,R,T
3. Reactor Enclosure Ventilation Exhaust Valve HV-76-257	5	B,H,S,U,R,T
4. Reactor Enclosure Ventilation Exhaust Valve HV-76-258	5	B,H,S,U,R,T
5. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-241	5	B,H,S,U,R,T
6. Reactor Enclosure Equipment Compartment Exhaust Valve HV-76-242	5	B,H,S,U,R,T
7. Drywell Purge Exhaust Valve HV-76-30	5	B,H,S,U,R,T
8. Drywell Purge Exhaust Valve HV-76-31	5	B,H,S,U,R,T
9. Drywell Purge Exhaust Inboard Valve HV-57-114 (Unit 1)	5	B,H,S,U,W,R,T
10. Drywell Purge Exhaust Outboard Valve HV-57-115 (Unit 1)	6	B,H,S,U,W,R,T
11. Suppression Pool Purge Exhaust Inboard Valve HV-57-104 (Unit 1)	5	B,H,S,U,W,R,T
12. Suppression Pool Purge Exhaust Outboard Valve HV-57-112 (Unit 1)	6	B,H,S,U,W,R,T
13. Refueling Area Ventilation Supply Valve HV-76-117 (Unit 1)	5	B,H,S,U,R,T
14. Refueling Area Ventilation Supply Valve HV-76-118 (Unit 1)	5	B,H,S,U,R,T
15. Refueling Area Ventilation Exhaust Valve HV-76-167 (Unit 1)	5	B,H,S,U,R,T
16. Refueling Area Ventilation Exhaust Valve HV-76-168 (Unit 1)	5	B,H,S,U,R,T
17. Refueling Area Ventilation Supply Valve HV-76-217	5	B,H,S,U,R,T
18. Refueling Area Ventilation Supply Valve HV-76-218	5	B,H,S,U,R,T
19. Refueling Area Ventilation Exhaust Valve HV-76-267	5	B,H,S,U,R,T
20. Refueling Area Ventilation Exhaust Valve HV-76-268	5	B,H,S,U,R,T

Table 6.2-29 (Cont'd)

ZONE II & III (Cont'd)

VALVE FUNCTION	MAXIMUM ISOLATION TIME (Seconds)	ISOLATION SIGNALS [a]
21. Drywell Purge Exhaust Inboard Valve HV-57-214	5	B,H,S,U,W,R,T
22. Drywell Purge Exhaust Outboard Valve HV-57-215	6	B,H,S,U,W,R,T
23. Suppression Pool Purge Exhaust Inboard Valve HV-57-204	5	B,H,S,U,W,R,T
24. Suppression Pool Purge Exhaust Outboard Valve HV-57-212	6	B,H,S,U,W,R,T

(a) See UFSAR Table 6.2-17, note 5 for isolation signals that operate each automatic isolation valve.

6.3 EMERGENCY CORE COOLING SYSTEMS

6.3.1 DESIGN BASES AND SUMMARY DESCRIPTION

Section 6.3.1 provides the design basis for the Emergency Core Cooling System (ECCS) systems and a brief summary design description. Detailed system descriptions are provided in Section 6.3.2. Section 6.3.3 contains the results of the performance analysis.

The current ECCS-LOCA analysis was performed using the SAFER/GESTR-LOCA methodology described in References 6.3-5 and 6.3-7 and supplemented by the implementation of the PRIME methodology described in Reference 6.3-15. The SAFER/GESTR analysis was performed assuming a thermal power of 3622 MWt (which bounds the current plant conditions). The input parameters used for the current ECCS-LOCA analysis are listed in Table 6.3-1. Table 6.3-2 summarizes the revised operational sequence of ECCS for the design basis LOCA. The results of the original SAFER/GESTR-LOCA are provided in Reference 6.3-6.

This analysis addressed the fuel types that were in operation at the time. However, those 8x8 (e.g., GE9) and 9x9 (e.g., GE11/GE13) fuel designs are no longer in operation and therefore are not considered when evaluating the limiting peak cladding temperature.

An updated SAFER/GESTR-LOCA analysis was performed for the implementation of GE14 fuel (10x10 fuel design). The calculated licensing basis peak cladding temperature for GE14 fuel is 1670^{o}F (References 6.3-9 and 6.3-14). GE14 fuel is no longer in operation and therefore is not considered when evaluating the limiting peak cladding temperature. An updated SAFER/GESTR-LOCA analysis has been performed for the implementation of GNF2 fuel (10x10 fuel design). The calculated licensing basis peak cladding temperature for GNF2 fuel is 1880^{o}F (Reference 6.3-10). The licensing basis peak cladding temperature values for GNF2 fuel are provided in Table 6.3-5.

There exist changes or errors that affect the analysis of record PCT calculation. These changes or errors are documented via 10 CFR 50.46 reporting. After accounting for all changes or errors, the licensing basis PCT remains below the 2,200^{o}F limit. Refer to the docketed annual or thirty-day 10 CFR 50.46(a)(3) report for details.

The original ECCS-LOCA analysis was performed using the methodology described in reference 6.3-1. The input parameters used for the original ECCS-LOCA are listed in Table 6.3-1A. Table 6.3-2A contains the operational sequence of ECCS assumed in the original ECCS-LOCA analysis. Tables 6.3-1A and 6.3-2A are retained for historical purposes, because they provide the basis for most of the ECCS performance parameters specified in the current plant Technical Specifications.

6.3.1.1 Design Bases

6.3.1.1.1 Performance and Functional Requirements

The ECCS is designed to provide protection against postulated LOCA's caused by ruptures in primary system piping. The functional requirements (e.g., coolant delivery rates), specified in Table 6.3-1 for the current ECCS-LOCA analysis and in Table 6.3-1A for the original LOCA analysis, are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of 10CFR50.46, "Acceptance Criteria for Emergency Core Cooling System for Light-Water-Cooled Nuclear Power Reactors." These requirements 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 the water level above the top of the core and preventing Automatic Depressurization System (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 this section 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 LOCA.

6.3.1.1.2 Reliability Requirements

The following reliability requirements apply:

a. The ECCS conforms to all licensing requirements and to good design practices of isolation, separation, and common mode failure considerations.

b. In order to meet the above requirements, the ECCS network has built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. As a minimum, the following equipment makes up the ECCS:

1. One HPCI system
2. Two Core Spray (CS) loops
3. Four Low Pressure Coolant Injection (LPCI) loops
4. One ADS

c. The ECCS is designed so that a single active or passive component failure, including power buses, electrical and mechanical parts, cabinets, and wiring, cannot disable the ADS.

d. If there is a break in a pipe that is not a part of the ECCS, no single active component failure in the ECCS, including all common and support components, prevents automatic initiation and successful operation of less than one of the following combinations of ECCS equipment:

1. Three LPCI loops, one CS loop and the ADS and HPCI (i.e., single diesel generator failure). If the single failure occurs in a diesel generator that supplies power to an ESW pump, the diesel generator in the other unit is needed to support the other ESW pump that supplies that loop.

2. Four LPCI loops, two CS loops and the ADS (i.e., HPCI failure)

e. If there is a break in a pipe that is a part of the ECCS, no single active component failure in the ECCS, including all common and support components, prevents automatic initiation and successful operation of less than one of the following combinations of ECCS equipment:

1. Three LPCI loops and the ADS
2. Two LPCI loops, one CS loop, and the ADS and HPCI

These are the minimum ECCS combinations which result after assuming any failure (from d. above), and assuming that the ECCS line break disables the affected loop/system.

f. Long-term (later than10 minutes after initiation signal) cooling requirements call for the removal of decay heat via the RHRSW system. In addition to the break which initiated the loss-of-coolant event, the system can sustain one failure, either active or passive, and have at least one low pressure ECCS pump (LPCI or CS) operating for makeup, one RHR pump with a heat exchanger, and 100% RHRSW flow to the heat exchanger operating for heat removal.

g. Offsite ac power is the preferred source of ac power for the ECCS network, and every reasonable precaution is made to assure its high availability. However, onsite safeguard ac power has sufficient diversity and capacity to meet all the above requirements, even if offsite ac power is not available.

h. The onsite diesel fuel reserve is in accordance with IEEE 308 (1974) criteria.

i. The diesel load configuration is one LPCI pump and one CS pump, connected to a single diesel generator (4 sets per unit).

j. Electrical systems which interface with, but are not part of, the ECCS are designed and operated so that failure(s) in the interfacing systems do not propagate to, and/or affect the performance of, the ECCS.

k. 1. Nonsafety-related electrical systems in the accident unit interfacing with the Class 1E buses are automatically shed from the Class 1E buses when a LOCA signal exists.

2. Nonsafety-related electrical systems in the nonaccident unit will remain connected to the Class 1E buses when a LOCA signal exists in the other unit.

l. No more than one storage battery is connectable to a dc power bus.

m. Each fluid loop/system of the ECCS network, including flow rate and sensing networks, is capable of being tested during shutdown. All active components are capable of being tested during plant operation, including logic
required to automatically initiate component action.

n. Provisions for testing the ECCS network components (electronic, mechanical, hydraulic and pneumatic, as applicable) are installed in such a manner that they are an integral and nonseparable part of the design.

o. While a break in a non-ECCS or ECCS pipe concurrent with a single active component failure in an ECCS or support component will result in remaining combinations of ECCS as described in items d. and e. above, certain technical specification limiting conditions for operation (LCOs) are based on ECCS requirements as given in NEDO-24708A. This document, prepared in response to NRC questions arising from licensee responses to I. E. Bulletin 79-08 (Events relevant to boiling water power reactors identified during Three Mile Island incident), specifies the minimum ECCS system requirements to successfully terminate a transient or LOCA initiating event (with scram) assuming multiple failures with realistic conditions. For the postulated suction line breaks (including DBA), one low pressure ECCS (one LPCI pump or one CS loop) and ADS to depressurize thereby allowing the low-pressure ECCS to inject is adequate to reflood the vessel and maintain core cooling sufficient to preclude fuel damage. NEDC-30936P-A, specifically applicable to LGS, references NEDO-24708A and reaffirms that one low pressure ECCS will reflood the vessel and maintain core cooling. It adds the advisory that for a large break LOCA, following 2 hours of LPCI injection, an alternate cooling path may be necessary for long term core cooling. This is because LPCI injecting directly into the core shroud could possible keep the body of water around the core substantially subcooled, quenching any steam cooling effects.

6.3.1.1.3 ECCS Requirements for Protection from Physical Damage

The ECCS piping and components are protected against damage from the effects of movement, thermal-stresses, the effects of the LOCA, and the 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 is applied to provide protection against damage to piping and components of the ECCS, which otherwise could reduce ECCS effectiveness to an unacceptable level.

For the purpose of mechanical separation ECCS components are divided into two divisions. The Division 1 ECCS components include the following:

a. Core spray loop A

b. RHR loop A and RHR-LPCI loop C

c. ADS

The Division 2 ECCS components include the following:

a. Core spray loop B

b. RHR loop B and RHR-LPCI loop D

c. HPCI

With the exception of the RHR pumps, each of the ECCS pumps and its associated components are located in individual compartments within the reactor enclosure. The two RHR pumps in each division are located in a common compartment. This compartmentalization ensures that environmental disturbances such as fire, pipe rupture, flooding, etc., affecting one system do not affect the remaining systems. For ECCS mechanical components located outside the pump compartments, such as the outboard containment isolation valves, separation between the different divisions is provided by distance or by locating the components in different compartments.

Electrical separation is described in Sections 7.1 and 8.3.

6.3.1.1.4 ECCS Environmental Design Basis

Each loop/system of the ECCS injection network, except the HPCI system, has a safety-related injection/isolation testable check valve located in piping within the drywell. The HPCI system injects through one of the core spray spargers and through the feedwater sparger, and the (non-ECCS) RCIC system injects through the feedwater system. However, both systems have isolation valves in the drywell portion of their steam supply piping. No portion of the ECCS and RCIC piping is subject to drywell flooding, since water drains into the suppression chamber through the downcomers. The valves are qualified for the following environmental conditions:

a. Normal and upset plant operating ambient temperatures, relative humidities, and pressures as discussed for each area of the drywell in Section 3.11.

b. Envelope-of-accident conditions for temperature, relative humidity, and pressure within the drywell for various time periods following the accident as discussed in Section 3.11.

c. Normal and envelope-of-accident radiation environment (gamma and neutron) as discussed in Section 3.11.

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 as discussed in Section 3.11.

b. Envelope-of-accident conditions for temperature, relative humidity, and pressure for various time periods following the accident as discussed in Section 3.11.

c. Normal and envelope-of-accident radiation environment (gamma and neutron) as discussed in Section 3.11.

6.3.1.2 Summary Descriptions of ECCS

The ECCS injection network is comprised of a HPCI system, a low pressure CS system, and the LPCI mode of the 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 ADS, which assists the injection network under certain conditions, is also briefly described. BWRs with the same ECCS design are listed in Table 1.3-2.

6.3.1.2.1 High Pressure Coolant Injection System

The HPCI system pumps water into the reactor vessel through one of the CS spargers and through one of the feedwater sparger. The primary purpose of HPCI is to provide sufficient coolant to the reactor vessel following a small break LOCA until reactor pressure is below the pressure at which CS operation or LPCI mode of RHR system operation maintains core cooling. The HPCI system is also required to provide sufficient coolant to the reactor vessel to prevent the actuation of the ADS and maintain reactor level above the top of the reactor core in the event of a small pipe break with a break size of one-inch diameter or less.

6.3.1.2.2 Core Spray System

The two CS system loops pump water into peripheral ring spray spargers, mounted above the reactor core. The primary purposes of the CS loops are to provide inventory makeup and spray cooling during large breaks in which the core is calculated to uncover. Following ADS initiation, CS provides inventory makeup following a small break.

6.3.1.2.3 Low Pressure Coolant Injection Subsystem

LPCI is an operating mode of the RHR system. Four pumps deliver water from the suppression pool to separate vessel nozzles, which lead to direct discharge inside the core shroud region (four loops). The primary purpose of LPCI is to provide vessel 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 utilizes five of the reactor SRVs to reduce reactor pressure during small breaks or after containment isolation, in the event of HPCI failure. When the vessel pressure is reduced to within the design of the low pressure systems (CS and LPCI), these systems provide inventory makeup so that acceptable postaccident temperatures are maintained.

6.3.1.2.5 Management of Gas Accumulation in Fluid Systems

On January 11, 2008, the NRC issued Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray (Reference 6.3-12). Generic Letter 2008-01 requested licensees to evaluate the licensing basis, design, testing, and corrective action programs for the Emergency Core Cooling, Decay Heat Removal, and Containment Spray systems to ensure that gas accumulation is maintained less than the amount that challenges operability of these systems, and that appropriate action is taken when conditions adverse to quality are identified. As a consequence, Limerick performed in-depth system reviews for the RHR, HPCI, Cores Spray, and RCIC systems in accordance with the criteria of GL 2008-01, investigating whether the existing Licensing Basis, Design Basis, actual field configuration, system restoration processes, and operational procedures would introduce or allow the accumulation of a gas (air) void in system piping. Piping locations in each system that are susceptible to air accumulation are periodically monitored to ensure that the piping systems are maintained sufficiently filled with water. The piping systems addressed in the response to Generic Letter 2008-01 have the potential to develop voids and pockets of entrained gases. Maintaining the pump suction and discharge piping sufficiently full of water is necessary to ensure that the system will perform and will inject the flow assumed in the safety analyses into the Reactor Coolant System or containment upon demand. This will also prevent damage from pump cavitation or water hammer,

and pumping of unacceptable quantities on non-condensable gas (e.g., air, nitrogen, hydrogen) into the reactor vessel following an ECCS start signal or during shutdown cooling.

6.3.2 SYSTEM DESIGN

More detailed descriptions of the individual systems, including individual design characteristics of the systems, are covered in detail in Sections 6.3.2.2.1 through 6.3.2.2.4. The following discussion provides details of the combined systems, and in particular, those design features and characteristics which are common to all systems.

6.3.2.1 Piping and Instrumentation and Process Diagrams

The P&IDs for the ECCS and the process diagrams which identify the various operating modes of each system are 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 high drywell pressure and low reactor water level. The ECCS is actuated automatically, and is designed to require no operator action during the first l0 minutes following the accident. A time sequence for starting of the systems is provided in Table 6.3-2 for the current ECCS-LOCA analysis, and in Table 6.3-2A for the original ECCS-LOCA analysis.

Electric power for operating the ECCS (except the dc powered HPCI and ADS systems) is from the preferred offsite ac power supply.

Upon loss of the preferred source, operation is from the onsite standby diesel generators. Four diesel generators supplying individual ac buses in a unit have sufficient diversity and capacity so that any three units satisfy minimum ECCS requirements, which are stated in Section 6.3.1.1.2.b. One CS pump (2 loop) and one LPCI loop are powered by each ac bus. Section 8.3 contains a more detailed description of the power supplies for the ECCS.

Regulatory Guide 1.1

Regulatory Guide 1.1 prohibits design reliance on pressure and/or temperature transients expected during a LOCA for assuring adequate NPSH. The requirements of this guide are applicable to the HPCI, CS, 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 ensure adequate NPSH.

Requirements for NPSH at the centerline of the pump suction nozzles for each pump are given in drawings E41-1020-G-002 (HPCI), E21-1020-G-001 (CS), and E11-1020-G-002 (LPCI).

6.3.2.2.1 High Pressure Coolant Injection System

The HPCI system consists of a steam turbine-driven, constant flow pump assembly and associated system piping, valves, controls, and instrumentation. The P&IDs for the HPCI, drawings M-55 and

M-56, show the system components and their arrangement. The HPCI process diagram, drawing E41-1020-G-002, shows the design operating modes of the system.

The principal HPCI equipment is installed in the reactor enclosure. Suction piping comes from both the CST and the suppression pool. Injection water is piped to the reactor via the CS Loop B sparger pipe and through the Loop A feedwater sparger. The steam supply for the turbine is piped from a main steam line in the primary containment. This piping is provided with an isolation valve on each side of the primary containment. Remote controls for valve and turbine operation are provided in the main control room. The controls and instrumentation of the HPCI system are described, illustrated, and evaluated in detail in Section 7.3.

The HPCI system provides coolant to the reactor vessel following a small break LOCA until reactor vessel pressure is below the pressure at which CS operation or LPCI operation maintains core cooling. The HPCI system is also capable of providing sufficient coolant to the reactor vessel to prevent the actuation of the ADS and ensure that the reactor core remains covered in the event of a small pipe break with a break size of one-inch diameter or less. This permits the plant to be shut down, while maintaining sufficient reactor vessel inventory until the reactor is depressurized. For design basis events HPCI needs to operate for a maximum of six hours in order to fulfill its safety functions.

The HPCI system is designed to pump water into the reactor vessel for a wide range of pressures in the reactor vessel. The normal alignment of the HPCI system initially injects water from the CST instead of water from the suppression pool. An alternate alignment to the suppression pool is also available during periods whan the CST is not available. This provides reactor grade water to the reactor vessel. Water is pumped into the reactor vessel through a core spray sparger and a feedwater sparger; this flow split is provided by orificing.

The pump assembly is located below the water levels of the CST and the suppression pool, to ensure positive suction head to the pumps. Pump NPSH requirements are met by providing adequate suction head and adequate suction line size.

The HPCI turbine-pump assembly and piping are protected from the detrimental physical effects of pipe whip, flooding, and high temperature.

The HPCI turbine is driven by steam from the reactor vessel, generated by decay and residual heat. The steam is extracted from a main steam line upstream of the MSIVs. Inboard and outboard HPCI isolation valves in the steam line to the HPCI turbine are normally open. This keeps the piping to the turbine at an elevated temperature to permit rapid startup of the HPCI system. Signals from the HPCI control system open or close the turbine control valve adjacent to the turbine. The outboard isolation valve has a bypass line containing a normally closed valve. This bypass line permits pressure equalization and drainage around the isolation valve, and downstream line warmup prior to opening of the isolation valve.

A condensate drain pot is provided upstream of the turbine stop valve to prevent the HPCI steam supply line from filling with water. The drain pot normally routes the condensate to the main condenser, but upon receipt of a HPCI initiation signal and subsequent opening of the steam supply valve, or a loss of control air pressure signal, isolation valves on the condensate line automatically close.

The turbine power is controlled by a flow controller that senses pump discharge flow and provides a variable signal to the turbine governor to maintain constant pump discharge flow over the pressure range of operation. The turbine control system is capable of limiting speed overshoot to 15% of maximum operating speed on a quick start, while driving only the pump inertia load.

Limit switches are provided on the turbine control (governor) valves(s) to indicate fully open and closed positions. Both lights are "on" in midposition.

As reactor steam pressure decreases, the HPCI turbine throttle valves open further to pass the steam flow required to provide the necessary pump flow. The capacity of the system is selected to provide sufficient core cooling to prevent clad temperatures in excess of the limits (10CFR50.46) while the pressure in the reactor vessel is above the pressure at which CS and LPCI become effective.

Exhaust steam from the HPCI turbine is discharged to the suppression pool. A drain pot at the low point in the exhaust line collects moisture present in the steam. Collected moisture is discharged through an orifice to the barometric condenser.

The HPCI turbine gland seals are vented to the barometric condenser for cooling. Noncondensable gases from the barometric condenser are pumped to the reactor enclosure equipment compartment exhaust filter during normal plant operation and to the RERS during reactor enclosure isolation.

A redundant system of check valves and isolation valves is installed as a vacuum breaker line, which connects the air space in the suppression chamber with the HPCI turbine exhaust line. This eliminates any possibility of water from the suppression pool being drawn into the HPCI turbine exhaust line. The isolation valves in this vacuum breaker line automatically close via a combination of low HPCI steam supply pressure and high drywell pressure. Test connections are provided on either side of the two check valves.

Potential damage from water hammer in the HPCI turbine supply and exhaust lines is prevented by the use of design features such as exhaust line vacuum breakers, drain pots upstream and downstream of the turbine, and a sparger in the turbine exhaust line in the suppression pool. Further discussion of water hammer is provided in Section 1.12.3.

Startup of the HPCI system is completely independent of ac power. Only dc power from the station battery and steam extracted from the nuclear system are necessary.

The various operations of the HPCI components are summarized below.

The HPCI controls automatically start the system and bring it to design flow rate within 60 seconds from receipt of a RPV low water level signal, or a primary containment (drywell) high pressure signal. Refer to Chapter 15 for more analysis details.

The HPCI turbine is directly shut down by any of the following signals:

a. Turbine overspeed: this prevents damage to the turbine.

b. RPV high water level: this indicates that core cooling requirements are satisfied.

c. HPCI pump low suction pressure: this prevents damage to the pump due to loss of flow.

d. HPCI turbine exhaust high pressure: this indicates a turbine or turbine control malfunction.

e. Isolation of either inboard or outboard HPCI isolation valves.

f. Low steam supply pressure.

If an initiation signal is received after the turbine is shut down, the system restarts automatically, if no shutdown signal exists.

Because the steam supply line to the HPCI turbine is part of the RCPB, certain signals automatically isolate this line, causing shutdown of the HPCI turbine. Automatic shutoff of the steam supply is described in Section 7.3. However, automatic depressurization and the low pressure systems of the ECCS act as backup; and automatic shutoff of the steam supply does not negate the ability of the ECCS to satisfy the safety objective.

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

HPCI operation automatically actuates the following valves:

a. HPCI pump discharge shutoff valve, if closed (F007)

b. HPCI steam supply shutoff valve (F001)

c. HPCI turbine stop valve

d. HPCI turbine control valves

e. HPCI steam line drain isolation valve (F028, F029)

f. HPCI test valves, if open (F008, F011, F071)

g. Minimum flow bypass valve (F012)

h. HPCI pump discharge injection valves (F006, F105)

i. HPCI lube oil cooling water valve (F059)

j Condensate pump discharge isolation valves, if open (F025, F026)

Startup of the auxiliary oil pump and proper functioning of the hydraulic control system are required to open the turbine stop and control valves. Operation of the barometric condenser components is required to prevent out-leakage from the turbine shaft seals. Startup of the condenser equipment is automatic, but its failure does not prevent the HPCI system from fulfilling its core cooling objective. Prior to startup of the HPCI turbine, the turbine control system is set to maintain the turbine at the low speed design condition. Upon receipt of an initiation signal, a speed ramp generator module

automatically runs the control system toward its high speed design point, thereby controlling the transient acceleration of the turbine. The flow controller then automatically overrides the speed ramp generator, and when rated flow is established, the flow controller signal adjusts the setting of the turbine control so that rated flow is maintained as nuclear system pressure decreases.

A minimum flow bypass is provided for pump protection. The bypass valve automatically opens on low flow, provided pump discharge pressure is above a pressure permissive setpoint (indicates pump is running) and automatically closes on high flow, stop valve closure or steam supply valve closure. When the bypass is open, flow is directed to the suppression pool. A line used for system testing leads from the HPCI pump discharge line to the CST. The shutoff valves in this line are sequenced to close by the signal that actuates system operation, and valve F011 is interlocked closed when the F041 valve, suppression pool to pump suction valve, is open. All automatically operated valves are capable of remote manual operation.

The normal alignment of the HPCI system is to initially inject water from the CST. An alternate alignment to the suppression pool is also available when the CST is not available. When the water level in the tank falls below a predetermined level or the suppression pool level is high, the pump suction is automatically transferred to the suppression pool. A vortex breaker is located at the suction nozzle of the CST to prevent vortex formation. A calculation has been performed to demonstrate that air core vortex formation will not occur with the CST level at the transfer level, and with the HPCI pumps operating at 5600 gpm. This transfer may also be made from the main control room using remote controls. When the pump suction has been transferred to the suppression pool, a closed-loop is established for recirculation of water escaping from a break.

To ensure continuous core cooling, general containment isolation signals do not operate any HPCI valves. The HPCI system incorporates a relief valve in the pump suction line to protect the components and piping from inadvertent overpressure conditions.

Level instrumentation for the CST and the HPCI suction line are protected from the effects of cold weather. The HPCI suction line and the CST instrument sensing lines that are exposed to the outdoor environment are provided with heat tracing. Indication is provided in the control room if this heat tracing should become inoperative. The CST level instrumentation for control room monitoring is located in the reactor enclosure. The level instrumentation used to automatically transfer the HPCI pump suction from the CST to the suppression pool is located on the portion of the HPCI line in the reactor enclosure and is not subject to the effects of cold weather.

The HPCI pump and piping are designed and located to avoid damage from the physical effects of DBAs, such as pipe whip, missiles, temperature, pressure, and humidity.

The HPCI equipment and support structures are designed in accordance with seismic Category I criteria (Section 3.9). The system is assumed to be filled with water for seismic analysis.

Provisions are included in the HPCI system which permit the HPCI system to be tested. These provisions are:

a. A full flow test line is provided to route water from and to the CST, without entering the RPV.

b. A bypass flow test line is provided to route water from and to the suppression pool, without entering the RPV.

c. Instrumentation is provided to indicate system performance during normal test operations.

d. All MOVs are capable of manual operation for test purposes. During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead zone", operator action is required to restart the valve.

e. Drains are provided to leak test the major system valves.

Interlocks for the HPCI system are described in Chapter 7. The operating requirement parameters for the components of the HPCI system, listed below, are shown on the process diagram (drawing E41-1020-G-002).

a. One 100% capacity booster and main pump assembly with accessories

b. Piping, valves, and instrumentation for:

1. Steam supply to the turbine

2. Turbine exhaust to the suppression pool

3. Makeup supply from the CST to the pump suction

4. Makeup supply from the suppression pool to the pump suction including pump suction strainers described in Section 6.2.2.2.

5. Pump discharge to the core spray sparger and feedwater line, including a test line to the CST, a minimum flow bypass line to the suppression pool, and a coolant water supply to accessory equipment

The basis for the design conditions is the ASME Section III, "Nuclear Power Plant Components."

A design flow functional test of the HPCI is performed during plant operation by taking suction from the CST, and discharging through the full flow test return line back to the CST. The discharge valve to the core spray and feedwater lines remain closed during the test, and reactor operation is undisturbed. All components of the HPCI system are capable of individual functional testing during normal plant operation. Control system design provides automatic alignment from test to operating mode if system initiation is required. The three exceptions are as follows:

a. The auto/manual station is in "manual" on the flow controller. This feature is required for operator flexibility during system operation.

b. Steam inboard/outboard isolation valves: closure of either or both of these valves requires operator action to properly sequence their opening. An alarm sounds when either of these valves leaves the fully open position.

c. Parts of the system which are bypassed or deliberately rendered inoperable. This is automatically indicated in the control room.

Periodic inspection and maintenance of the turbine-pump unit are conducted in accordance with plant programs and procedures. Other than surveillances required by technical specifications, the types of inspection and maintenance are based on manufacturer's recommendations and industry guidelines and the frequency is based on industry and site specific experience. Valve position indications and instrumentation alarms are displayed in the control room.

6.3.2.2.1.1 NPSH Available with Suction from the CST

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data were used in the calculation:

a. Condensate water level is at el 191'- 7.25" at the bottom of the 34 inch section of pipe HCB-105. This level is approximately 27 ft below the static transfer level (i.e. 0 gpm HPCI flow), which is within the CST nozzle.

b. CST water is at 120°F.

c. Atmospheric pressure is assumed above the condensate water level.

d. $NPSH = h_s - h_{vp} - h_f + h_a$

where:

h_s	=	static head above pump suction nozzle centerline	
	=	191.6 ft to 182.25 ft	= 9.3 ft
h_f	=	friction head loss	= 4.0 ft
h_{vp}	=	vapor pressure (head loss)	= 3.9 ft
h_a	=	atmospheric head	= 34.3 ft
NPSH	=	35.7 ft	

6.3.2.2.1.2 NPSH Available with Suction from the Suppression Pool

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data were used in the calculation:

a. Suppression pool is at the minimum postaccident level reached while the pump is running of el 201'-5.64".

b. Suppression pool water is at its maximum temperature for the given operating mode, 170°F.

c. Atmospheric pressure is assumed over the suppression pool.

d. $NPSH = h_s - h_{vp} - h_f + h_a$

where:

h_s	=	static head above pump suction nozzle centerline	
	=	201.47 ft to 182.25 ft	= 19.2 ft
h_f	=	friction head loss (including 2 psi loss across suction strainers)	= 11.7 ft
h_{vp}	=	vapor pressure (head loss)	= 14.2 ft
h_a	=	atmospheric head	= 34.8 ft
NPSH	=	28.1 ft	

6.3.2.2.2 Automatic Depressurization System

If the RCIC system or the HPCI system cannot maintain the reactor water level, the ADS reduces the reactor pressure so that flow from LPCI and/or CS systems enters the reactor vessel in time to cool the core and limit fuel cladding temperature.

The ADS employs five of the nuclear system SRVs to relieve high pressure steam to the suppression pool. The design, number, location, description, operational characteristics, and evaluation of the SRVs and their pneumatic accumulators are discussed in detail in Section 5.2.2. The instrumentation and controls for the ADS are discussed in Section 7.3. Gas supplies for long term operation of ADS are described in Sections 9.3.1.3 and 7.6.

6.3.2.2.3 Core Spray System

Each of the two redundant CS system loops consists of: two 50% capacity centrifugal pumps powered from Class 1E buses; a spray sparger in the reactor vessel above the core (a separate sparger for each CS loop); piping and valves to convey water from the suppression pool to the sparger; and associated controls and instrumentation. A connection to the HPCI system is provided to allow HPCI injection through the CS Loop B vessel connection. The CS P&ID (drawing M-52) presents the system components and their arrangement. The CS process diagram (drawing E41-1020-G-001) shows the design operating modes of the system. A simplified system flow diagram showing system injection into the reactor vessel is included in drawing E41-1020-G-001.

When low water level in the reactor vessel and/or high pressure in the drywell is sensed, and if reactor vessel pressure is low enough, the CS system automatically starts and sprays water into the top of the fuel assemblies to cool the core. The time sequence assumed in the current ECCS-LOCA analysis for CS system operation is given in Table 6.3-2. The time sequence assumed in the original ECCS-LOCA analysis for CS system operation is given in Table 6.3-2A. The CS 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 CS 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 CS operates in conjunction with the ADS, the effective core cooling capability of CS is extended to all break sizes because the ADS rapidly reduces the reactor vessel pressure to the CS operating range.

The CS pumps and all MOVs 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 and pump indicator lights.

To assure continuity of core cooling, signals to isolate the containment do not operate any CS system valves. Suppression pool test return valves isolate on an automatic CS initiation signal.

Loop A and B injection lines are each provided with two isolation valves. One of these valves is a pneumatically-testable check valve located inside the drywell, as close as practical to the reactor vessel. CS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during the LOCA). If the CS line should break outside the containment, the check valve in the line inside the drywell prevents loss of reactor water.

The outer isolation valve on Loop A is a motor-operated gate valve, and the outer isolation valve on Loop B is a pneumatically-testable check valve. These valves are located as close as practicable to the CS discharge line containment penetration. The pneumatically-testable check valve is designed so that air failure will not close the valve against normal flow. Upstream of the HPCI injection connection on Loop B is a motor-operated gate valve which isolates CS Loop B upstream of the valve from HPCI injection pressure. This valve, and the Loop A outer isolation valve are also referred to as the CS injection valves. These valves are capable of opening with the maximum differential pressure across the valve expected for any system operating mode. These valves are normally closed. The containment isolation design of the CS system is discussed in detail in Section 6.2.4.

The CS system piping and components are designed and arranged to avoid unacceptable damage from the physical effect of pipe whip, missiles, high temperature, pressure or humidity. All principal active CS equipment is located outside the primary containment.

A check valve (one per CS pump), flow element, and restricting orifice are provided in the CS 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 that the piping downstream of the valve can be continuously filled with water by the condensate transfer or safeguard piping fill systems (Section 6.3.2.2.6). 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 valve. The flow rate is indicated in the main control room. The restricting orifice is sized during preoperational testing of the system to limit system flow to acceptable values, as described on the CS system process diagram.

A low flow bypass line with a motor-operated globe valve connects to the CS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool preventing pump damage when other discharge line valves are closed, or when reactor pressure is greater than the CS system discharge pressure following system initiation. The valve automatically closes when flow in the main discharge line is sufficient.

A normally open motor-operated pump suction valve is provided that can be remote-manually closed to isolate the CS system from the suppression pool should a leak develop in the system. This valve is located as close to the suppression pool penetration as practical. Because the CS system conveys water from the 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 based on ASME Section III. The design pressures and temperatures at various points in the system can be obtained from the miscellaneous information blocks on the CS process diagram (drawing E41-1020-G-001).

The CS pumps are located in the reactor enclosure below the water level in the suppression pool, assuring positive pump suction. Pump NPSH requirements are met with the containment at atmospheric pressure. Each CS Pump has a local pressure gauge to indicate the suction head. The pump suction strainers are described in Section 6.2.2.2.

The CS system incorporates relief valves to prevent the components and piping from inadvertent overpressure conditions.

For the CS “A” loop:

- One relief valve located on the pump discharge is set at 500 psig at a capacity of 16 gpm – 10% accumulation to 1340 psig at a capacity of 24 gpm – 10% accumulation.
- One relief valve is located on the suction side of each pump in the “A” loop and is set for 100 psig at a capacity of 10 gpm – 10% accumulation.

For the CS “B” loop:

- One relief valve located on the pump discharge is set at 500 psig at a capacity of 16 gpm – 10% accumulation to 1340 psig at a capacity of 24 gpm – 10% accumulation.
- One relief valve is located on the suction side of each pump in the “B” loop and is set for 100 psig at a capacity of 10 gpm – 10% accumulation.

The CS system piping and support structures are designed in accordance with seismic Category I criteria (Section 3.9). The system is assumed to be filled with water for seismic analysis. The CS system has the capability to be lined up to the CST, with the plant shutdown, to provide a clean water source for pipe flushes, cavity flood-up and as an alternate ECCS make-up volume.

Provisions are included in the design which permit the CS system to be tested. These provisions are:

a. All active CS components are testable during normal plant operation.

b. A full flow test line is provided in each loop of CS to route water to and from the suppression pool without entering the RPV.

c. A suction test line supplying water from the CST is provided to allow the capability to test pump discharge into the RPV during normal plant shutdown.

d. Instrumentation is provided to indicate system performance during normal and test operations.

e. All motor-operated and check valves are capable of operation for test purposes. During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead zone", operator action is required to restart the valve.

6.3.2.2.4 Low Pressure Coolant Injection Subsystem

The LPCI subsystem is an operating mode of the RHR system. The LPCI subsystem is automatically actuated by low water level in the reactor and/or high pressure in the drywell coincident with low reactor pressure. It uses four motor-driven RHR pumps to draw suction from the suppression pool and inject cooling water flow into the reactor core via separate vessel nozzles and core shroud penetrations.

The LPCI subsystem, like the CS 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 LPCI operates in conjunction with the ADS, the effective core cooling capability of LPCI is extended to all break sizes because the ADS rapidly reduces the reactor vessel pressure to the LPCI operating range.

Drawing E41-1020-G-002 shows a process diagram and process data for the RHR system, including the LPCI mode. The RHR system P&ID is shown in drawing M-51.

LPCI operation includes using associated valves, control, instrumentation, and pump accessories. LPCI is normally powered from the preferred ac power source, and from the standby ac power source upon a loss of preferred ac power.

If there is a LOCA, the four loops of the LPCI subsystem inject water into the reactor vessel. Separate power sources are provided for the LPCI injection valves, so that the failure of a single electrical division does not prevent the valves in other divisions from opening.

To ensure continuity of core cooling, signals to isolate the primary containment do not operate any RHR system valves which interfere with the LPCI mode of operation.

The process diagram (E11-1020-G-002) and the P&ID (drawing M-51) indicate that a great many flow paths are available other than the LPCI injection line. However, the low water level and/or high drywell pressure coincident with low reactor 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. Further discussion of valve logic is provided in Section 7.3.1.1.

A check valve in the pump discharge line is used, together with a discharge line fill system (Section 6.3.2.2.6), to prevent water hammer resulting from starting the pump with a partially drained discharge line.

Further discussion of water hammer is provided in Section 1.12.3.

A flow element in the pump discharge line originates automatic signals for control of the pump minimum flow valve. The minimum flow valve permits a small flow to the suppression pool if sufficient system flow is not available.

There is sufficient system resistance to preclude RHR pump damage due to pump run-out in the LPCI and containment spray operating modes. A combination of valve throttling and flow orifices prevents pump run-out during suppression pool cooling and test modes.

Using the suppression pool as the source of water for LPCI establishes a closed-loop for recirculation of water escaping from a pipe break inside containment.

The design pressures and temperatures at various points in the system, during each LPCI subsystem mode of operation can be obtained from the miscellaneous information blocks on the RHR process diagram (drawing E11-1020-G-002).

LPCI pumps and equipment are described in detail in Section 5.4.7, which also describes the other functions served by the same pumps in other modes of RHR system operation. The RHR heat exchangers are not associated with the emergency core cooling function. The heat exchangers are discussed in Section 5.4.7.2.2. Portions of the RHR system required for accident protection, including support structures, are designed in accordance with seismic Category I criteria (Section 3.9). The LPCI pump characteristic curves are shown in Figure 5.4-15.

The LPCI subsystem 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 as shown in Table 5.4-3.

Provisions are included in the LPCI subsystem to permit testing of the LPCI loops. 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 four pumps to route suppression pool water back to the suppression pool without entering the RPV.

c. Instrumentation is provided to indicate system performance during normal and test operations.

d. All MOVs, AOVs, and check valves are capable of manual operation for test purposes. During all modes of manual MOV operation using the handswitch from the main control room, a "dead zone" is present for a portion of the valve travel. The "dead zone" is present when the valve is not fully closed and green light only indication exists. If the valve is stopped in the "dead zone", operator action is required to restart the valve.

e. Shutdown cooling lines taking suction from the recirculation system permit testing of the pump discharge into the RPV after normal plant shutdown.

f. All relief valves are or will be removable for bench testing during plant shutdown.

6.3.2.2.4.1 NPSH for LPCI Mode

The available NPSH is calculated in accordance with Regulatory Guide 1.1. The following data are used for a typical NPSH calculation:

a. Suppression pool is at its minimum post accident depth, el 199'-11.5".

b. Centerline of pump suction is at el 174'-10.5".

c. Suppression pool water is at its maximum temperature for the given operating mode.

d. Pressure is atmospheric above the suppression pool.

e. Maximum suction strainer losses are 5.0 psi at 11,000 gpm.

$$NPSH = h_{ATM} + h_S - h_{VAP} - h_F$$

where:

h_{ATM} = atmospheric head

h_S = static head

h_{VAP} = vapor pressure head

h_F = frictional head

Operating modes and conditions are given on the process flow diagram (drawing E11-1020-G-002). NPSH requirements are given on the pump curve (Figure 5.4-15).

Case 1 LPCI Pump Run-out (Mode A-2)

Maximum suppression pool temperature is 180°F.

h_{ATM} = 34.94'

h_S = 25.08'

h_{VAP} = 17.85'

h_F = 4.61'

Strainer head loss = 11.85'

NPSH available = 34.94 + 25.08 - 17.85 - 4.61 - 11.85
= 25.71

Case 2 RHR Accident Mode B

Maximum suppression pool temperature assumed is 212°F

h_{ATM} = 35.4'

h_S = 25.08'

h_{VAP} = 35.4'

h_F = 3.8'

Strainer head loss at 10,000 gpm = 10.67'

NPSH available = 35.4 + 25.08 - 35.4 - 3.8' - 10.67'
= 10.61'

6.3.2.2.5 ECCS NPSH Margin and Vortex Formation

NPSH calculations for ECCS pumps, such as that in the previous section, have shown adequate margin to ensure capability of proper pump operation under accident conditions. This capability will be verified during preoperational testing by verifying expected pump operating parameters at specific operating conditions. The absence of air entrainment and vortex formation in the flow approaching the suction strainers in the suppression pool during ECCS pump operation will also be verified during preoperational testing. Pump performance and pump noise will be monitored during these tests to determine if pumps are sensitive to suction flow conditions in the suppression pool.

6.3.2.2.6 Safeguard Piping Fill System

A requirement of the core cooling systems is that cooling water flow to the RPV be initiated rapidly when the system is called upon to perform its function. This quick-start system capability is provided by quick-opening valves, quick-start pumps, and standby ac power sources. 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 are empty when the systems are called for, the large momentum forces associated with accelerating fluid into a dry pipe could cause physical damage to the piping. Therefore, the safeguard piping 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 backflow from emptying the lines into the suppression pool. Past experience shows that these valves may leak slightly, producing a small backflow that eventually empties the discharge piping. To ensure that the leakage from the discharge lines is replaced and the lines are always kept filled, suppression pool water is provided for each system of the ECCS by the safeguard piping fill system. There are two safeguard fill pump trains, as shown in drawing M-52. Each fill train and its associated ECCS lines are powered from separate Class 1E electrical divisions. Each fill train also provides water to both of the feedwater lines after a LOCA to prevent bypass leakage, as described in Section 6.2.3.2.3.

During normal plant operating conditions, the safeguard piping fill system (SPFS) is on standby and water from the condensate transfer system is used through different connections to keep the ECCS lines full.

The fill system is a safety-related system and is designed to seismic Category I criteria, as described in Section 3.7. Quality group classification is discussed in Section 3.2. A single failure of an active component in one fill system train will prevent that train from performing its intended function, but will not affect the operation of the other train. When the SPFS is in use, the fill pumps operate continuously, with recirculation back to the suppression pool via two core spray pump suction lines. The pumps are powered from the diesel generators during a LOOP. The pumps are operated from the control room and alarms in the control room indicate low fill pump discharge pressure.

As discussed in Section 5.4.7.1.1.5, all of the components comprising the steam condensing mode of the RHR system have either been abandoned in place or physically removed from the plant. Therefore, the mode is no longer functional.

6.3.2.3 Applicable Codes and Classification

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 equipment and piping of these systems are designed to the requirements of seismic Category I. This seismic designation applies to all structures and equipment essential to the core cooling function. IEEE standards applicable to the controls and power supplies are specified in Section 7.1.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in Section 6.1. Nonmetallic materials, such as lubricants, seals, packings, paints and primers, insulation, as well as metallic materials 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 and/or the delivery of coolant to the reactor vessel. The most severe effects of single failures with respect to loss of equipment occur if a LOCA occurs in an ECCS pipe coincident with a LOOP. The consequences of the most severe single failures are shown in Table 6.3-3.

Certain technical specification LCO periods are justified based on NEDO-24708A which states that for postulated LOCAs, one low pressure ECCS (one LPCI pump or one CS loop) and ADS to depressurize is adequate to reflood the vessel and maintain core cooling sufficient to preclude fuel damage. NEDC-30936P-A, specifically applicable to LGS references NEDO-24708A and reaffirms this conclusion, with the advisory regarding the possible necessity of an alternate cooling path following 2 hours of post large-break LOCA LPCI injection into the core shroud.

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 primary containment are protected from internally and externally generated missiles by the reinforced concrete structure of the ECCS pump rooms. The layout and protection of the pump rooms are covered in Section 6.2.3.

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 3.9.3.

The ECCS relief valves discharge lines that penetrate the primary containment and that have outlets below the surface of the suppression pool are designed to protect against the possibility of water hammer. RHR system valves in this category are: PSV-1(2)06A and PSV-1(2) 06B (Dwg. M-51). Each PSV discharge line connects to a 10 inch line which has been designed and installed with a continuous slope to the suppression pool to preclude water pockets from forming. These design features prevent the occurrence of excessive dynamic loads resulting from water hammer during relief valve actuation, and thereby preclude line cracking or rupture. The dynamic loadings have been included in the piping stress analysis. Supports are designed to ensure that they are capable of withstanding the normal plus dynamic loading resulting from the relief valve opening. Section 1.12.3 contains further discussion of water hammer.

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 is designed to require no operator action during the first 10 minutes following the accident. Only limited operator action is required before 20 minutes following a LOCA.

During the long-term cooling period (after 10 minutes), the operator takes action, as specified in Section 6.2.2.2, to place the containment cooling system into operation. This action will ensure that suppression pool temperature limits are not exceeded. This is the only manual action that the operator needs to accomplish for the ECCS 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 pressure and water level, and containment pressure, temperature, and radiation levels, as well as indicating the operation of the ECCS. ECCS 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 in determining system operating status.

All controls required to perform the above manual actions are located in the control room. If the RHRSW radiation monitors are inoperable either due to loss of power or component malfunction/failure, the RHRSW pump trip bypass can also be accomplished from the Control Room. The EOPs written in accordance with the BWROG EPGs have been incorporated into LGS training and procedures. The EOPs, with main sections on reactor control and containment control, specify operator actions based on the symptoms that are occurring. Implementation of these training and procedural measures will ensure that LGS operators are adequately equipped to deal with plant emergencies consistent with the design bases assumptions.

The instrumentation and controls for the ECCS are discussed in detail in Section 7.3. Monitoring instrumentation available to the operator is discussed in more detail in Chapter 5 and Section 6.2.

6.3.2.9 Correct Positioning of Manual Valves

Consideration has been given to the possibility that manual valves in the ECCS might be left in the wrong position when an accident occurs. Remote indication in the control room is not required for all critical ECCS manual valves unless they are located in primary containment and therefore are not accessible for survey during normal plant operation. (Critical ECCS manual valves are those that provide system isolation, other than vent, drain, or test connection valves, or are located in the main flow paths.) The positions of those critical valves that are not provided with remote position indication in the control room are administratively controlled and have the following additional protection features:

a. Manual valves in the main ECCS flow paths and manual system isolation valves for ECCS pump suction piping are physically locked in their normal position; access to the keys is controlled administratively.

b. All other manual ECCS isolation valves are redundant to provide double isolation.

The only manual valves in the RHR system that were evaluated are those associated with LPCI mode. The boundary of the LPCI mode piping also includes all piping associated with the suppression pool cooling mode.

Vent, drain, and test connection valves are valves which are not critical to the ECCS function, and administrative controls such as prestartup valve lineup checks suffice to reasonably ensure that such valves will not degrade ECCS performance. In addition, many of these valves are redundant or locked in position, and test connections are capped.

The position of each manually operated valve will be identified in a valve checkoff list. When verification of system operability is required, performance of the valve checkoff list in conjunction with the applicable lineup procedure is one method which may be used. When operability is verified in this manner, an independent verification of valve lineup will be accomplished by redundant performance of each valve checkoff list used. Use of a lineup procedure with its associated valve checkoff lists will not be the exclusive method available for verification of operability, but can be used in any circumstance and supersedes the other methods discussed below. If valve positions are to be changed for surveillance or maintenance purposes, the procedure or other administrative control will have steps requiring return-to-normal valve lineup prior to completion. The shift supervisor will not consider the system operable until all valves identified within the boundaries of the surveillance/maintenance activities have been returned to the position specified in the valve checkoff list. If valve positions in the ECCS are changed for

operational purposes, these changes will be made in accordance with procedures having similar administrative controls.

6.3.3 ECCS Performance Evaluation

The performance of the ECCS is determined through application of the 10CFR50, Appendix K evaluation models, and by conformance to the acceptance criteria of 10CFR50.46. The analytical models are documented in GESTAR II (Reference 4.1-1).

The ECCS performance is evaluated for the entire spectrum of break sizes for postulated LOCAs. The accidents, as listed in Chapter 15, for which ECCS operation is required are located in the following sections:

a.	Feedwater piping breaks outside primary containment	15.6.6
b.	Spectrum of BWR steam system piping failures outside of containment	15.6.4
c.	LOCAs inside primary containment	15.6.5

6.3.3.1 ECCS Bases for Technical Specifications

The maximum average planar linear heat generation rates calculated in this performance analysis provide the bases for Technical Specifications designed to ensure conformance with the acceptance criteria of 10CFR50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors." 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.

Certain technical specification LCO periods are justified based on the results of NEDO-24708A and NEDC-30936P-A which state that one low pressure ECCS (one LPCI pump or one CS loop) and ADS is adequate to reflood the vessel and maintain core cooling sufficient to preclude fuel damage following a suction line break (including DBA). NEDC-30936P-A adds an advisory about the possible necessity of an alternate cooling path following 2 hours of post large-break LOCA LPCI injection into the core shroud. The justification provided by these documents is required to provide a basis for the maximum period specified to restore equipment or systems declared inoperable to operable status.

6.3.3.2 Acceptance Criteria for ECCS Performance

The applicable acceptance criteria, extracted from 10CFR50.46, are listed below. For each criterion, applicable parts of Section 6.3.3 (where conformance is demonstrated) are indicated. A description of the methods used to show compliance is contained in GESTAR II (Reference 4.1-1).

Criterion 1, Peak Cladding Temperature:

"The calculated maximum fuel element cladding temperature shall not exceed 2200°F." Conformance to Criterion 1 is demonstrated in Table 6.3-5.

Criterion 2, Maximum Cladding Oxidation:

"The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation." Conformance to Criterion 2 is shown in Table 6.3-5.

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 References 6.3-6, 6.3-9, and 6.3-10.

Criterion 4, Coolable Geometry:

"Calculated changes in core geometry shall be such that the core remains amenable to cooling." As described in section III of Reference 6.3-6, 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 GE BWRs in section III.A of Reference 6.3-1 and confirmed in References 6.3-6, 6.3-9, and 6.3-10. Briefly summarized, the core remains covered to at least the jet pump suction elevation, and the uncovered region is cooled by spray cooling.

The LGS equipment for long-term cooling following a postulated LOCA includes two complete core spray systems and two RHR systems. System components required for long-term coolant recirculation and decay heat removal are designed to remain operable during and following a LOCA. The redundancy provided is such that maintenance is not expected to be required during the long-term core cooling period (180 days) following a LOCA. However, the RHR and core spray systems are designed with provisions for flushing as shown in drawings M-51 and M-52.

6.3.3.3 Single Failure Considerations

The functional consequences of single failures (including operator errors which might cause any manually controlled electrically operated valve in the ECCS to move to a position which could adversely affect the ECCS) are discussed in Section 6.3.2. 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 ECCS performance analyses. For the original Reference 6.3-1 methodology, failure of one of the diesel generators is, in general, the most severe failure for large break; and a loss of the HPCI system is the most severe failure for small break. For the ECCS analysis performed with SAFER/GESTR-LOCA method (References 6.3-5 and 6.3-7) the limiting failure for all breaks is the division 2 dc (battery) failure.

The worst failure of an ECCS pump seal or valve packing during the long-term cooling mode would produce a leak of less than 50 gpm. The ECCS equipment compartments, located on the lowest elevation of the reactor enclosure, are watertight and equipped with flood alarms. Any passive

failure including pump seal or valve packing failure occurring in an ECCS long-term cooling loop can be isolated by turning off the pump and shutting the suction isolation valve. If the packing of the suction isolation valve should fail, the leak could still be isolated because all of the suction isolation valves are gate valves.

6.3.3.4 System Performance During the Accident

In general, the system response to an accident can be described as the following:

a. Receiving an initiation signal

b. A small lag time (to open all valves and have the pumps up to rated speed)

c. Finally, the ECCS flow entering the vessel

Key ECCS actuation setpoints and time delays for all the ECCS are provided in Table 6.3-1 for the current ECCS-LOCA analysis and in Table 6.3-1A for the original ECCS-LOCA analysis. The minimization of the delay from the receipt of signal until the ECCS pumps have reached rated speed is limited by the physical constraints on accelerating the diesel generators and pumps. The delay time due to valve motion in the case of the 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 operational sequence of ECCS for the DBA is shown in Table 6.3-2 for the current ECCS-LOCA analysis and in Table 6.3-2A for the original ECCS-LOCA analysis.

Operator action is not required, except as a monitoring function, during the short-term cooling period following the LOCA. The HPCI system is designed to inject water into the reactor vessel for small breaks that do not depressurize the vessel.

If a small break occurs and the HPCI system does not function, the ADS will cause vessel blowdown, and the low pressure systems will then act to restore vessel water level. In either case, no operator action is required to restore reactor water level. To establish decay heat removal, the operator will realign the RHR system to the suppression pool cooling mode. The necessary operator actions are described in Section 6.2.2.2.

If a small break occurs and the HPCI system functions properly, reactor vessel water level will be maintained, and no automatic depressurization will occur. The operator must then manually depressurize the vessel, using a minimum number of ADS valves, and establish long-term cooling as above.

All control switches necessary for ADS operation and realignment of the RHR system are located in the control room. The instrumentation available to monitor RHR pressure and flow, reactor vessel pressure, level and temperature, suppression pool temperature, pump status and relevant valve positions are discussed in Chapter 7.

Direction for accomplishing the above actions are available to the operator in the EOPs and appropriate system operating procedures.

The preceding discussion of operator actions in response to a small break LOCA is applicable even when single active failures and LOOP are assumed.

The available NPSH for the pumps in the HPCI system has been calculated based on minimum postaccident suppression pool level, maximum suppression pool temperature, 50% plugged strainers, and no credit for wetwell pressurization. The available NPSH for the RHR and Core Spray pumps has been calculated based on the same assumptions used for the HPCI except for the criteria for the determination of the dirty strainer pressure drop. The dirty strainer pressure drop for these strainers is based on the entire amount of fibrous debris generated in the drywell during a design basis LOCA (within the zone of influence of the worst case pipe break location) transported to the suppression pool and all debris is available to clog the strainer. The results of these calculations show that available NPSH is greater than the required NPSH by a margin of at least 10 feet for RHR, at least 7 feet for Core Spray, and at least 4 feet for HPCI.

6.3.3.5 Use of Dual-Function Components for ECCS

With the exception of the LPCI and ADS systems, 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 the 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 SRV, 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 modes of operation. Immediately following a LOCA, the RHR system is aligned to the LPCI mode. Further discussion of valve logic is provided in Section 7.3.1.1.

6.3.3.6 Limits on ECCS System Parameters

Refer to GESTAR II (Reference 4.1-1).

6.3.3.7 ECCS Analyses for LOCA

6.3.3.7.1 LOCA Analysis Procedures and Input Variables

Refer to GESTAR II (Reference 4.1-1).

The significant input variables used by the LOCA codes are listed in Table 6.3-1 and Figure 6.3-11, for the current ECCS-LOCA. The significant input variables used for the original ECCS-LOCA analysis are shown in Table 6.3-1A and Figure 6.3-11A.

6.3.3.7.2 Accident Description

The original methodology for analysis of the LOCA is reflected in Reference 6.3-1. Reference 6.3-5 provides a detailed description of the current methodology for analysis of the LOCA. The results of the Reference 6.3-5 and 6.3-7 methods are detailed in References 6.3-6, 6.3-9, and 6.3-10.

6.3.3.7.3 Break Spectrum Calculations

A complete spectrum of postulated break sizes and locations is considered in the evaluation of ECCS performance.

A summary of the results of the break spectrum calculations is shown in tabular form in Table 6.3-5. Conformance to the acceptance criteria (PCT $\leq$2200°F, local oxidation <17%, and core-wide metal-water reaction <1%) is demonstrated in the above paragraphs. Details of calculations for specific breaks are included in subsequent paragraphs.

6.3.3.7.4 Large Recirculation Line Break Calculations

The characteristics that determine which is the most limiting large break are:

a. the calculated hot node reflooding time,

b. the calculated hot node uncovery time, and

c. the time of calculated boiling transition.

The time of calculated boiling transition increases with decreasing break size, since jet pump suction uncovery (which leads to boiling transition) is determined primarily by the break size for a particular plant. The calculated hot node uncovery time also generally increases with decreasing break size, as it is primarily determined by the inventory loss during the blowdown. The hot node reflooding time is determined by a number of interacting phenomena such as depressurization rate, counter current flow limiting, and a combination of available ECCS.

The period between hot node uncovery and reflooding is the period when the hot node has the lowest heat transfer. Hence, the break that results in the longest period during which the hot node remains uncovered results in the highest calculated PCT. If two breaks have similar times during which the hot node remains uncovered, then the larger of the two breaks will be limiting as it would have an earlier boiling transition time (i.e., the larger break would have a more severe LAMB/SCAT blowdown heat transfer analysis).

The DBA was determined to be the break that results in the highest calculated PCT in the 1.0 ft^2 to DBA region.

The component areas that comprise the suction and discharge break areas in the LOCA analysis are as follows:

a. Suction Break

Recirculation Suction Line Nozzle/Safe End	3.541 ft^2	
Jet Pump Discharge Nozzles - One Bank	0.548 ft^2	
Total		4.089 ft^2

b. Discharge Break

Recirculation Pump Minimum Area	1.736 ft^2	
Jet Pump Discharge Nozzles - One Bank	0.548 ft^2	
Total		2.284 ft^2

6.3.3.7.5 Steam Flow Induced Process Measurement Error

The impact on the ECCS-LOCA analysis of a Steam Flow Induced Error (SFIE) in the Level 3 scram has been evaluated. SFIE is a process measurement error in Reactor vessel level measurement induced by steam flowing in the annulus region between the dryer and vessel wall across the mouth of the instrument reference leg tap during a loss of coolant inventory event. For Limerick, SFIE can result in a level measurement error up to 4.67 inches at extended (20%) Power Uprate (3952 MWt). This error adversely impacts the timing of the Level 3 (L3) scram Analytical Limit (AL) for events resulting in a decrease in coolant inventory. Reference 6.3-13 provides an evaluation of this process error for ECCS-LOCA analysis.

For Limerick, the limiting LOCA analysis (and Licensing Basis PCT) is limited by large breaks. Therefore, the Limiting PCT is not affected by the reduction in the L3 analytical limit.

6.3.3.8 LOCA Analysis Conclusions

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 10CFR50.46 acceptance criteria.

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 ECCS Performance Tests

All systems of the ECCS are tested for their operational ECCS function during the preoperational and/or startup test program. Each component is tested for power source, range, direction of rotation, setpoint, limit switch setting, torque switch setting, etc., as applicable. Each pump is tested for flow capacity for a 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., the suppression pool or CST.

All logic elements are tested individually and 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 preoperational testing for these systems.

6.3.4.2 Reliability Tests and Inspections

The average reliability of a standby (nonoperating) 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 are used to determine safe test intervals, utilizing the methods described in Reference 6.3-2.

All of the active components of HPCI, CS, and LPCI are designed so that they may be tested during normal plant operation. Full flow test capability of each ECCS injection system is provided by test lines back to their suction sources. 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, and by racking out the injection valve breaker, each ECCS loop can be tested for response time.

The ADS logic is designed so that it may be tested during normal plant operation. The SRVs and associated solenoid valves are all tested at least once during the plant startup following each refueling outage. Those SRVs and their associated solenoid valves, which are overhauled during a plant outage, are tested during the startup following that outage.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3. The safeguard power system, which supplies electrical power to the ECCS if offsite power is unavailable, is tested as described in Section 8.3. Testing is specified in the Technical Specifications. Visual inspections of all the ECCS components located outside the primary containment can be made at any time during power operation. Components inside the primary containment can be visually inspected only during periods of access to the primary containment. When the reactor vessel is open, the spargers and other reactor vessel internals can be inspected.

6.3.4.2.1 HPCI Testing

The HPCI system can be tested at full flow with CST water at any time during plant operation, except when the reactor vessel water level is low, when the condensate level in the CST is below the reserve level, or when the HPCI F041 valve from the suppression pool to the pump are open. If an initiation signal occurs while the HPCI system is being tested, the system aligns automatically to the operating mode.

A design flow functional test of the HPCI system over the operating pressure and flow range is performed by pumping water from the CST and back through the full flow test return line to the CST. The HPCI system turbine-pump is driven at its rated output by steam from the reactor. The HPCI F041 valve, suction valve from the suppression pool, and the discharge valves to the core spray line remain closed. The HPCI F042 valve, suppression pool to pump suction PCIV remains open. These valves are tested separately to ensure their operability.

The HPCI test conditions are tabulated on the HPCI process flow diagram (drawing E41-1020-G-002).

6.3.4.2.2 ADS Testing

The ADS valves are tested once per fuel cycle. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence, but excludes actual valve actuation.

During plant operation the ADS system can be checked as discussed in Section 7.3.

6.3.4.2.3 CS Testing

The CS pumps and valves can be tested during reactor operation. The injection valve and injection line check valve for the A-loop and the outboard and inboard injection line check valves for the B-loop are normally tested with the reactor shutdown. The injection lines to the reactor can be tested when the reactor is shutdown and the CS suction is lined up to the CST. With the injection valve closed and the return line open to the suppression pool, full flow pump capability is demonstrated. The system test conditions during reactor shutdown are shown on the CS system process diagram (drawing E41-1020-G-001. The portion of the CS system outside the drywell may be inspected for leaks during tests.

If an initiation signal occurs during the test, the CS System aligns to the operating mode. The test return line valves close automatically to ensure that CS pump discharge is correctly routed to the RPV.

6.3.4.2.4 LPCI Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated in drawing E11-1020-G-002. 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 can be 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 a LPCI pump at rated flow, the test line valve to the suppression pool is opened, the pump suction valve from the suppression pool is opened (this valve is normally open), and the pumps are started using the remote manual switches in the control room. Correct operation is determined by observing instruments locally and in the control room.

If an initiation signal occurs during the test, the LPCI subsystem aligns to the operating mode. The valves in the test bypass lines close automatically to ensure that the LPCI pump discharge is correctly routed to the RPV.

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 HPCI, CS, LPCI, and ADS is discussed in Section 7.3.2, and is designed to meet the requirements of IEEE 279 and other applicable standards.

Long-term ADS gas supply instrumentation is addressed in Section 7.6.

The HPCI system is automatically initiated on low reactor water level and/or high drywell pressure. The CS and LPCI loops are automatically initiated on low reactor water level, and/or high drywell pressure (in combination with low reactor pressure). The ADS is automatically actuated by sensed variables for reactor vessel low water level and drywell high pressure plus the indication that at least one CS loop or LPCI pump is operating. HPCI, CS, and LPCI automatically realign from system flow test modes to the emergency core cooling mode of operation following receipt of an automatic initiation signal. The CS and LPCI injection into the RPV begins when reactor pressure decreases to loop discharge shutoff pressure.

HPCI injection begins as soon as the HPCI turbine-pump is up to speed and the injection valve is open, since the HPCI is capable of injecting water at full flow into the RPV at pressures up to the reactor pressure specified in Mode A of drawing E41-1020-G-002.

6.3.6 REFERENCES

6.3-1 "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50, Appendix K", NEDE-20566-P, (November 1975).

6.3-2 H.M. Hirsch, "Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems," NEDO-10739, (January 1973).

6.3-3 General Electric Company, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors", NEDO-24708A, Revision 1, (December 1980).

6.3-4 General Electric Company, "BWR Owner's Group Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Activation Instrumentation)", NEDC-30936P-A, (December 1988).

6.3-5 General Electric Company Analytical Model for Loss of Coolant Analysis in Accordance with 10CFR50, Appendix K, NEDO-20566A, General Electric Company, September 1986.

6.3-6 GE Nuclear Energy, Limerick Generating Station Units 1 and 2, SAFER/GESTR-LOCA, Rev. 2 Loss-of-Coolant Accident Analysis, NEDC-32170P, Rev. 2, May 1995

6.3-7 General Electric Company, "The GESTR-LOCA and SAFER models for the evaluation of the Loss-of-Coolant Accident, Volume III, SAFER/GESTR Application Methodology," NEDE-23785-1 PA, Rev. 1, (Oct 1984).

6.3-8 Deleted.

6.3-9 Limerick Generating Station Units 1 and 2 ECCS-LOCA Evaluation for GE-14, GE-NE-J1103793-09-01P, DFR J11-03793-09, March 2001.

6.3-10 GE-Hitachi Nuclear Energy, 0000-0111-9078-R0, “Limerick Generating Station Units 1 and 2 GNF2 ECCS-LOCA Evaluation,” February 2011.

6.3-11 Deleted.

6.3-12 Generic Letter 2008-01, “Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems,” dated January 11, 2008.

6.3-13 GE-Hitachi Nuclear Energy, 0000-0077-4603-R1, "BWR Owners Group Evaluation of Steam Flow Induced Error (SFIE) Impact on the L3 Setpoint Analytic Limit," October 2008.

6.3-14 Letter Report for Exelon, Summary of GEH Transient Anticipated Operational Occurrences (AOO) and Loss of Coolant Accident (LOCA) Analyses with Respect to ASD Modification in Limerick Generating Station Units 1 and 2, 0000-0129-8688-R1, Revision 1, May 2011.

6.3-15 GE Hitachi Nuclear Energy, "Implementation of PRIME Models and Data in Downstream Methods," NEDO-33173, Supplement 4-A, Revision 1, November 2012.

Table 6.3-1

SIGNIFICANT INPUT VARIABLES USED IN THE SAFER/GESTR-LOCA ANALYSIS

VARIABLE		VALUE	
A.	PLANT PARAMETERS	NOMINAL	APPENDIX K
	• Core thermal power	3622 MWt	3694 MWt
	• Vessel steam output	15.8×10^6 lbm/hr	16.2×10^6 lbm/hr
	• Vessel steam dome pressure	1060 psia	1063 psia
	• Maximum recirculation line break area	4.16 ft^2	4.16 ft^2
B.	ECCS PARAMETERS		
	B.1 LPCI System		
	• Vessel pressure at which flow may commence	<295 psid (vessel to drywell)	
	• Minimum rated flow at vessel pressure	32,000 gpm (4 pumps) 20 psid (vessel to drywell)	
	• Initiating signals		
	Low water level (level 1), or	≥366.5 inches above vessel zero	
	High drywell pressure	≤2.0 psig	
	• Maximum allowable time delay from initiating signal to power at injection valves	≤28 sec	
	• Maximum allowable time delay from initiating signal to injection valves full open	≤64 sec	
	B.2 Core Spray System		
	• Vessel pressure at which flow may commence	<289 psid (vessel to drywell)	
	• Minimum rated flow at vessel pressure	5000 gpm/loop 105 psid (vessel to drywell)	

Table 6.3-1 (Cont'd)

VARIABLE		VALUE
•	Initiating signals	
	Low water level (level 1), or	≥366.5 inches above vessel zero
	High drywell pressure	≤2.0 psig
•	Minimum allowed run-out flow	6250 gpm/loop
•	Maximum allowed delay time from initiating signal to power at injection valves	≤28.0 sec
•	Maximum allowed delay time from initiating signal to injection valve full open	48.0 sec
B.3	HPCI/Core Spray Flow Split Characteristics	
•	Minimum flow rate (independent of vessel pressure)	5400 gpm
•	Initiating signals	
	Low water level (level 2), or	≥457.5 inches above vessel zero
	High drywell pressure	≤2.0 psig
•	Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	≤60.0 sec
•	Maximum HPCI flow rate injected through core spray sparger	2890 gpm
B.4	Automatic Depressurization System	
•	Total number of relief valves with ADS function	5
•	Total minimum flow capacity at a vessel pressure	4.35×10^6 lbs/hr 1090 x 1.03 psig

Table 6.3-1 (Cont'd)

VARIABLE	VALUE
• Initiating signals	
a) Low water level (level 1), and	≥366.5 inches above vessel zero
High drywell pressure[1]	≤2.0 psig
b) Low water level (level 1), and	≥366.5 inches above vessel zero
High drywell pressure bypass timer timed out[2]	≤8 minutes
• Delay time from all initiating signals completed to the time valves are open	≤120 seconds

(1) Designed to actuate for breaks inside the drywell.

(2) Designed to actuate ADS when needed for events which do not result in drywell pressurization.

Table 6.3-1A

SIGNIFICANT INPUT VARIABLES USED IN THE LOCA ANALYSIS
BASED ON ORIGINAL REFERENCE 6.3-1 METHODOLOGY

VARIABLE		VALUE
A.	PLANT PARAMETERS	
•	Core thermal power	3430 MWt
•	Vessel steam output	14.86×10^6 lb_m/hr
•	Corresponding percent of rated steam flow	105%
•	Vessel steam dome pressure	1055 psia
•	Maximum recirculation line break area	4.1 ft^2
B.	ECCS PARAMETERS	
B.1	LPCI System	
•	Vessel pressure at which flow may commence	<295 psid (vessel to drywell)
•	Minimum rated flow at vessel pressure	40,000 gpm (4 pumps) 20 psid (vessel to drywell)
•	Initiating signals	
	Low water level (level 1), or	≥1.0 feet above top of active fuel
	High drywell pressure	≤2.0 psig
•	Maximum allowable time delay from initiating signal to pumps at rated speed	≤40 sec
B.2	Core Spray System	
•	Vessel pressure at which flow may commence	<289 psid (vessel to drywell)
•	Minimum rated flow at vessel pressure	6250 gpm/loop 105 psid (vessel to drywell)

Table 6.3-1A (Cont'd)

VARIABLE		VALUE
•	Initiating signals	
	Low water level (level 1), or	≥1.0 feet above top of active fuel
	High drywell pressure	≤2.0 psig
•	Minimum allowed run-out flow	7000 gpm/loop
•	Maximum allowed delay time from initiating signal to pump at rated speed	≤27.0 sec
B.3	HPCI/Core Spray Flow Split Characteristics	
•	Minimum flow rate (independent of vessel pressure)	5600 gpm
•	Initiating signals	
	Low water level (level 2), or	≥8.6 feet above top of active fuel
	High drywell pressure	≤2.0 psig
•	Maximum allowed delay time from initiating signal to rated flow available and injection valve wide open	≤30.0 sec
•	Maximum HPCI flow rate injected through core spray sparger	3000 gpm
B.4	Automatic Depressurization System	
•	Total number of relief valves with ADS function	5
•	Total minimum flow capacity at a vessel pressure of	4.0×10^6 lbs/hr 1125 psig

Table 6.3-1A (Cont'd)

VARIABLE		VALUE
•	Initiating signals	
	a) Low water level (level 1), and	≥1.0 feet above top of active fuel
	High drywell pressure[1]	≤2.0 psig
	b) Low water level (level 1), and	≥1.0 feet above top of active fuel
	High drywell pressure bypass timer timed out[2]	≤8 minutes
•	Delay time from all initiating signals completed to the time valves are open	≤120 seconds
C.	FUEL PARAMETERS	
•	Fuel type	Initial Core
•	Fuel bundle geometry	8x8
•	Lattice	C
•	Number of fueled rods per bundle	62
•	Peak Technical Specification LHGR	13.4 kW/ft
•	Initial minimum critical power ratio	1.2
•	Design axial peaking factor	1.4

(1) Designed to actuate for breaks inside the drywell.

(2) Designed to actuate ADS when needed for events which do not result in drywell pressurization.

Table 6.3-2

OPERATIONAL SEQUENCE OF ECCS FOR DESIGN BASIS LOCA[1]

TIME (sec)	EVENTS
0	Design basis LOCA is assumed to start; normal auxiliary power is assumed to be lost.
<1	Drywell high pressure is reached. Scram initiated; HPCI is signaled to start, and containment isolates, except for the MSIVs.
Approx 1	Reactor Low Water Level (Level 3) is reached [2]. The second scram initiation signal is received.
Approx 4	Reactor low-low water level (level 2) is reached. HPCI receives the second signal to start.
Approx 5	The reactor low-low-low water level (level 1) is reached; MSIVs are signaled to close; the signal to start LPCI and CS is given.
Approx 25	Reactor low pressure is reached. CS and LPCI receive the second signal to start. CS injection valve receives pressure permissive signal to open.
≤54	The CS pumps are at rated flow and the CS injection valves are open, which completes the CS system startup.
≤70	The LPCI pumps are at rated flow and the LPCI injection valves are open, which completes the LPCI system startup.
Approx 130	The core is effectively reflooded, assuming the worst single failure; heatup is terminated.
>10 min	The operator shifts to containment cooling.

(1) For the purpose of all but the next to the last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures (Sections 6.3.2.5 and 6.3.3.3).

(2) The Level 3 Analytical value in this table may be slightly different for various events due to a steam flow induced process measurement error. However, the impact of the change is not significant and the event descriptions or conclusions need not be modified (Section 6.3.3.7.5).

Table 6.3-2A

OPERATIONAL SEQUENCE OF ECCS FOR DESIGN BASIS LOCA [1]
BASED ON THE ORIGINAL REFERENCE 6.3-1 METHODOLOGY

TIME (sec)	EVENTS
0	Design basis LOCA is assumed to start; normal auxiliary power is assumed to be lost.
<1	Drywell high pressure [2] and reactor low water level (level 3) are reached [3]. All diesel generators are signaled to start; scram initiated; HPCI is signaled to start, and containment isolates, except for the MSIVs.
Approx 2	Reactor low-low water level (level 2) is reached [3]. HPCI receives the second signal to start.
Approx 5	The reactor low-low-low water level (level 1) is reached; MSIVs are signaled to close; the signal to start LPCI and CS is given.
Approx 22	Reactor low pressure is reached. CS and LPCI receive the second signal to start. CS injection valve receives pressure permissive signal to open.
Approx 26	LPCI injection valve receives ΔP permissive signal to open.
Approx 32	The HPCI injection valve opens and the pump is at design flow, which completes the HPCI startup.
≤34	The CS pumps are at rated flow and the CS injection valves are open, which completes the CS system startup.
≤50	The LPCI pumps are at rated flow and the LPCI injection valves are open, which completes the LPCI system startup.
Approx 165	The core is effectively reflooded, assuming the worst single failure; heatup is terminated.
>10 min	The operator shifts to containment cooling.

(1) For the purpose of all but the next to the last entry on this table, all ECCS equipment is assumed to function as designed. Performance analysis calculations consider the effects of single equipment failures (Sections 6.3.2.5 and 6.3.3.3).

(2) No credit taken in the DBA LOCA analysis for ECCS system initiation on the high drywell pressure signal.

(3) The Level 3 Analytical value in this table may be slightly different for various events due to a steam flow induced process measurement error. However, the impact of the change is not significant and the event descriptions or conclusions need not be modified (Section 6.3.3.7.5).

Table 6.3-3

SINGLE FAILURE EVALUATION[1][4]

No potential single failure has been identified as more severe than one of the following single failures:

ASSUMED FAILURE	SUCTION BREAK[2] SYSTEMS REMAINING
Division 2 dc source	1 CS loop + 3 LPCI + All ADS
Diesel generator[3]	1 CS loop + HPCI + 3 LPCI + All ADS
LPCI injection valve	2 CS loop + HPCI + 3 LPCI + All ADS
HPCI	2 CS loop + 4 LPCI + All ADS
One ADS valve	2 CS loop + 4 LPCI + HPCI + All ADS minus one

(1) Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above designated failures.

(2) Systems remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS system in which the break is assumed.

(3) If the single failure occurs in a diesel generator that supplies power to an ESW pump, the diesel generator in the other unit is needed to support the other ESW pump that supplies that loop.

(4) This table demonstrates the performance of safety systems under the single failure criteria. For the minimum system requirements to successfully terminate a transient or LOCA initiating event (with scram), assuming multiple failures with realistic conditions, refer to NEDO-24708.

Table 6.3-4 has been deleted

Table 6.3-5

SUMMARY OF RESULTS OF LOCA ANALYSIS
WITH SAFER/GESTR-LOCA USING TABLE 6.3-1 INPUTS

BREAK SIZE/ LOCATION/ SINGLE FAILURE	PCT (°F)	PEAK LOCAL OXIDATION(%)	FUEL
A. Deleted			
B. Deleted			
C. Deleted			
D. 4.174 ft^2 (DBA)[3] / Recirc suction/ Division 2 dc source	1880[1]	<3.0	GNF2
E. 0.07 ft^2 / Recirc suction/ Division 2 dc source	1538[2]	<3.0	GNF2

(1) Licensing basis PCT
(2) Appendix K PCT
(3) This includes the area of the bottom head drain line

Table 6.3-5A has been deleted

Table 6.3-6 has been deleted

Table 6.3-7 has been deleted

6.4 HABITABILITY SYSTEMS

The control room habitability systems are designed to provide safety and comfort for operating personnel during normal operations and during postulated accident conditions. These habitability systems for the control room include radiation shielding, charcoal filter systems, HVAC, storage for food and water, kitchen and sanitary facilities, and fire protection. The habitability systems are designed to meet GDC 19 of 10CFR50, Appendix A.

6.4.1 DESIGN BASES

The design bases of the habitability systems, upon which the functional design is established, are summarized as follows:

a. The control room environmental envelope is designed for continuous occupation on a year-round basis. The occupancy of the operating personnel is ensured for a minimum of 30 days after a DBA.

b. The habitability systems are designed to support 5 people during normal and abnormal station operating conditions. A 5 day emergency supply of food and water is provided within the control room habitability envelope. Supplies of potassium iodide adequate to protect 30 people are maintained onsite.

c. Kitchen and sanitary facilities and medical supplies for minor injuries are provided within the boundary of the control room habitability systems for the use of control room personnel during normal and accident conditions.

d. The radiological effects on the control room personnel that could exist as a consequence of the postulated DBAs described in Chapter 15 do not exceed the guidelines set by GDC 19 of 10CFR50, Appendix A, or the dose limits of 10CFR50.67.

e. The design includes provisions to preclude the effects of a chlorine release accident onsite or offsite from affecting the habitability of the control room.

f. The design includes provisions to preclude the effects of an offsite toxic chemical release from affecting the habitability of the control room.

g. Respiratory and skin protection and emergency breathing apparatus are provided within the control room envelope for control room operators.

h. The control room ventilation system is capable of automatic transfer from its normal operational mode to its accident or isolation mode upon detection of conditions which could result in the introduction of chlorine or airborne radioactivity into the control room.

i. The control room ventilation system is designed to remain functional during and after an OBE and an SSE.

j. The habitability systems are designed to remain functional following a failure of any one of the HVAC system components.

k. Radiation monitors, offsite toxic chemical detectors, and chlorine detectors continuously monitor the outside air at the control room envelope outside air intake. The detection of high radiation, chlorine or offsite toxic chemical release is alarmed in the control room, and related protection functions are simultaneously initiated.

l. The control room HVAC system design bases are discussed in Section 9.4.1.

m. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the habitability systems are discussed in Section 3.2.

n. The guidelines of Regulatory Guide 1.52, Regulatory Guide 1.78, and Regulatory Guide 1.95 apply to the design of habitability systems. Conformance for the analyses associated with Regulatory Guide 1.78 is discussed in Section 2.2.3. Conformance to design aspects of the guides is as follows:

    1. There is partial conformance with Regulatory Guide 1.52 as discussed in Section 6.5.1

    2. The habitability system design for offsite toxic chemical protection conforms with Regulatory Guide 1.78. Differences from the analytic models are discussed in Section 2.2.3.

    3. Regulatory Guide 1.95 (Rev 1), which discusses protection from accidental chlorine release, does not apply to LGS per its implementation section. Nevertheless, the LGS design is in conformance.

The design of the habitability systems with respect to the following areas is discussed in separate sections as indicated:

a.	Protection from wind and tornado effects	Section 3.3
b.	Flood Design	Section 3.4
c.	Missile Protection	Section 3.5
d.	Protection against dynamic effects associated with postulated rupture of piping	Section 3.6
e.	Environmental design	Section 3.11

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of Control Room Envelope

The control room envelope maintained under habitable conditions following an accident is shown on Figure 6.4-1. The envelope consists of the control room, peripheral offices at the west and east

ends, toilet room, and utility room; all on el 269'-0". Steam and air tight doors are provided for ingress and egress.

The volume of the emergency zone served by the HVAC system in the accident mode or the isolation mode is approximately 126,000 cubic feet.

6.4.2.2 Ventilation System Design

The control room HVAC system is discussed in detail in Section 9.4.1. The system is shown schematically in drawing M-78, and major system components are described in Table 9.4-1.

Figure 6.4-2 shows the plant layout, including the location of plant facilities, with respect to the control room outside air intake. The control room arrangement is shown in Figure 6.4-1. The seismic category and quality group classification of components, instrumentation, and ducts are listed in Section 3.2 and shown in drawing M-78.

The control room is common for Units 1 and 2. The principal equipment in the system includes:

a. Two 100% capacity air handling units which include cooling coils, and fans for use during normal plant operation and following a DBA, a chlorine accident, or an offsite toxic chemical accident. Electric humidifiers, electric heaters, and roll filters are provided for use during normal plant operation, during a chlorine accident, or during an offsite chemical accident.

b. Two 100% capacity return air fans for use during normal plant operation and following a DBA, chlorine or offsite toxic chemical accident.

c. Two banks of high efficiency air filtration units consisting of a prefilter, HEPA filter, an electric heating coil, a carbon adsorber, and a second HEPA filter for treatment of recirculated air or outside supply air following a DBA, chlorine, or offsite toxic chemical accident. Two filtration unit fans are provided; one for each filtration unit.

d. A single outside air intake for use during normal plant operation and following a DBA.

6.4.2.3 Leak-Tightness

Control room envelope construction joints and penetrations for cable, pipe, HVAC duct, HVAC equipment, dampers, and steam-tight doors have been designed specifically for leak-tightness. A list of potential leak paths to the control room is provided in Table 6.4-2, along with the type of material, joint, or penetration.

For the onsite chlorine storage discussed in Section 2.2.3, a control room design with a maximum allowable control room isolated air exchange rate of 0.25 air changes per hour is provided. The analysis discussed in Section 2.2.3.1.3 demonstrates that this air exchange rate allows the operators more than 2 minutes to put on their breathing masks.

6.4.2.4 Interaction with Other Zones and Pressure-Containing Equipment

a. Design of the control room envelope boundaries, duct-work and isolation valves minimizes interchange of exterior radioactive gases or toxic vapors into the control room envelope.

   The control room is surrounded by the turbine enclosure, the reactor enclosure, and the cable spreading room and auxiliary equipment room. Each of these areas is separated from the control room by shield walls, floors, and leak-tight doors and is served by the independent HVAC systems described in Section 9.4.

   The HVAC equipment room at el 304' is a part of the control structure. The negative pressure control room duct-work system in the HVAC equipment room is of welded construction and tested for leak-tightness. Dampers on the negative pressure duct-work are of gas-tight construction.

b. Steam lines and central carbon dioxide fire prevention system tanks are not located within the control room envelope.

6.4.2.5 Shielding Design

Control room shielding is discussed in Section 12.3. The shielding is designed for continuous occupancy during a DBA and meets GDC 19 and 10CFR50.67.

6.4.3 System Operational Procedures

6.4.3.1 Normal Operation

During normal operation, one of the two air handling units and one of the two return fans recirculate the control room air. Approximately 2100 cfm of fresh outside air is taken in at the control room ventilation system intake located on the north wall of the control enclosure. By balancing the exhaust and makeup flow rates, the control room is normally maintained at a slightly positive pressure with respect to the surrounding areas. The outside makeup air and recirculated air pass through a roll filter at the inlet of the air handling unit fans. The supply air is cooled or heated by the air handling units as required to maintain the desired temperature. Upon loss of supply or return air flow, the respective standby fans automatically start; the associated fan dampers reposition; and an alarm annunciates in the main control room. The start of standby equipment may also be manually initiated.

The control room is fully air conditioned and will be maintained between 65 and 78^{o}F and between 30 and 90% relative humidity. Control room temperature is sensed by a temperature transmitter which transmits a signal to a temperature indicating controller. The temperature controller maintains the proper temperature by controlling an electric heating coil or cooling coil valve as necessary. Control room minimum humidity is maintained by a return air duct moisture sensor and transmitter, which transmits a signal to the humidity controller which in turn controls an electric humidifier. Excessive humidity is precluded by the cooling coil which condenses excessive moisture.

6.4.3.2 Postaccident Operation

The control room HVAC system is designed to ensure habitability after any of the design basis radiological accidents or a chemical release accident. To provide adequate operator protection in the unlikely event of one of these accidents, three distinct accident modes of operation are

included. These modes are referred to as the chlorine isolation mode, the toxic chemical isolation mode, and the radiation isolation mode.

The mode of system operation after each of the individual accidents of concern with the control room HVAC system initially in the normal mode of operation is as follows:

Chlorine accident - Chlorine isolation mode

High radiation accident - Radiation isolation mode

Offsite toxic chemical accident - Toxic chemical isolation mode

In the event of a chlorine accident or radiation accident, the control room will be automatically isolated. In the event of an offsite toxic chemical accident, the control room will be remote manually isolated when the predetermined toxic chemical concentrations are detected in the control room air intake plenum and alarmed in the control room.

Note: the possibility exists for a chlorine accident to occur while the control room HVAC system is operating in the radiation isolation mode for testing purposes or as required by the Action statement of an associated Technical Specifications Limiting Condition of Operation, and likewise, a high radiation accident could occur while the control room HVAC system is operating in the chlorine isolation mode for the same purposes. The mode of system operation with the control room HVAC system in these initial system configurations is described in Sections 6.4.3.2.1 and 6.4.3.2.2 below.

The high radiation accident is discussed in detail in Chapter 15 and identification of design basis toxic chemicals including chlorine is discussed in Section 2.2.3.

6.4.3.2.1 Chlorine Isolation Mode

Upon receipt of a high chlorine concentration signal from the chlorine detectors in the control room outside air intake plenum, the following events occur (drawing M-78) to isolate the control room from the outside air when the control room HVAC system is initially in the normal mode of operation.

a. Redundant outside air intake isolation valves close in 3-5 seconds to prevent outside air from entering the control room supply air handling units.

b. For a chlorine accident only, outside air intake isolation valves to the charcoal filter inlets close, if open, in 8-12 seconds to provide isolation to the charcoal filter trains.

c. Control room exhaust isolation valves and control room toilet exhaust isolation valves close in 3-5 seconds.

d. The emergency fresh air charcoal filter recirculation inlet isolation valve opens in 8-12 seconds.

e. The emergency fresh air fan for charcoal filter train A or B starts to establish filtered recirculation of the control room environment.

f. High chlorine concentration is indicated and alarmed in the control room.

In the chlorine isolation mode approximately 3000 cfm of the control room atmosphere is recirculated through the charcoal filter train for cleanup.

The normal air handling units continue to recirculate approximately 26,200 cfm of the control room atmosphere, including the charcoal filter train discharge.

Once initiated, the system remains in the isolation mode until the high chlorine concentration condition is no longer present and the chlorine trip switch is manually reset.

If chlorine is detected with the control room HVAC system initially in the radiation isolation mode (as described in Section 6.4.3.2.2) because of testing or as required by the Action statement of the associated Technical Specifications Limiting Condition of Operation, the chlorine detectors would sense the presence of chlorine and initiate an automatic isolation of the control room outside air intakes, thus overriding the radiation isolation mode. However, the logic of the isolation signals with the control room HVAC system initially in the radiation isolation mode is such that a single failure of the chlorine detection system could allow the filtered outside air intake to remain open, and thus, the control room HVAC system would remain in the radiation isolation mode. Under these circumstances, once the chlorine has been detected and alarmed in the control room, manual action can be taken to realign the system to the chlorine isolation mode. Analysis of this event assumes that the system remains in the radiation isolation mode with 525 cfm of outside air being mixed with recirculated control room air for a total of 3,000 cfm being passed through the charcoal adsorber filter trains, and that the filter has no effect on removal of chlorine. The results of the analysis indicate that, with the control room HVAC system in the radiation isolation mode, the necessity for automatic chlorine isolation is not required to satisfy General Design Criterion (GDC) 19 of 10CFR50 of Appendix A, and that the control room operators would have sufficient time to don breathing apparatus after an alarm is sounded in the control room (as shown in Table 2.2-6).

The Chlorine Detection System consists of four separate channels in which the A&C Detectors and associated isolation logic constitutes one independent Chlorine Detection System Subsystem, and the B&D

Detectors with their associated isolation logic, the other. If an inoperable detector is placed in the “tripped” position the affected subsystem remains operable, provided the other instrument and isolation logic in the trip system is OPERABLE. Placing an INOP Detector in the “tripped” position would not prevent the subsystem from performing its safety related function. Placing an INOP detector in the “tripped” position would still provide an isolation regardless of a single active failure in the case of a real chlorine release. The condition in which two detectors (one per subsystem) were inoperable could result in both Detection System Subsystems logic being in a one-out-of-one once configuration. This configuration will still provide an isolation signal regardless of a single active failure and constitutes two independent Detection System Subsystems.

6.4.3.2.2 Radiation Isolation Mode

The radiation isolation mode of operation is intended to protect the control room operators if there are design basis radiological accidents.

Upon receipt of an initiating signal, the following automatic functions occur (drawing M-78) when the control room HVAC system is initially in the normal mode of operation:

a. The control room outside air exhaust is isolated.

b. The control room outside air intake, charcoal filter trains, and normal air handling units are aligned, so that all outside air must pass through the charcoal filter trains before it enters the control room.

c. The control room is maintained at a positive pressure (approximately 1/8 inch wg) with respect to the surrounding areas.

d. High radiation is alarmed in the control room.

The control room is now positively pressurized with respect to the surrounding areas. The quantity of outside air taken in at the normal ventilation intake on the north wall of the control structure is mixed with recirculated control room air, and a total of 3000 cfm is passed through the charcoal adsorber filter train for removal of airborne radioactivity.

If the control room HVAC system is initially in the chlorine isolation mode as described in Section 6.4.3.2.1 for any purpose, the system will remain in this mode of operation upon receipt of a high radiation signal, i.e., automatic transfer from the chlorine isolation mode to the radiation isolation mode will not occur. This design recognizes that the infiltration of chlorine into the main control room is a more immediate threat to the operations personnel.

If the control room HVAC system is initially in the chlorine isolation mode as result of maintenance or surveillance testing, the HVAC system can be manually switched to the radiation isolation mode once the operators determine that no chlorine is present.

6.4.3.2.3 Toxic Chemical Isolation Mode

The toxic chemical isolation mode is identical to the chlorine isolation mode as described in Section 6.4.3.2.1, with the exception that toxic chemical detection does not automatically initiate control room isolation.

Upon receipt of a high toxic chemical concentration alarm indicated by the toxic chemical detectors located in the control room outside air intake plenum, the operator manually initiates control room isolation utilizing controls available in the control room in accordance with plant procedures.

High toxic chemical concentration is indicated and alarmed in the control room and the system remains in the isolation mode until the high toxic chemical concentration condition is no longer present and the system is manually reset.

6.4.4 Design Evaluations

The control room habitability system is designed with redundancy and separation of active components to provide reliable operation under normal conditions and to ensure operation under accident conditions. A failure analysis of the system components is shown in Table 6.4-1.

6.4.4.1 Radiological Protection

A detailed discussion of the dose calculation model for control room operators following the postulated DBA is discussed in Section 15.10. The analysis considers both conditions in which the control room HVAC system is initially in the normal mode of operation and the chlorine isolation mode prior to the high radiation accident. The resulting calculated doses for control room ingress, egress, and occupancy (on a rotating shift basis) are less than 5 rem total effective dose equivalent (TEDE). These doses are within the dose limits specified in GDC 19 and 10CFR50.67. The analysis also assumes the installation of a MCR door seal, which ensures zero direct inleakage from the Turbine Enclosure through the MCR doors. Following the DBA LOCA, after the MSIV Leakage Alternate Drain Pathway has been aligned and when a Turbine Enclosure Area Radiation Monitor alarms, a temporary MCR door seal will be erected, to prevent the direct inleakage to the MCR. This action is necessary to prevent a relatively high calculated concentration of Iodine from entering the MCR directly from the Turbine Enclosure.

Control room shielding design, based on the most limiting radiological accident (design basis LOCA) is discussed in Section 12.3. The evaluations in Chapter 12 demonstrate that radiation exposures to control room personnel originate from containment shine, external cloud shine, and containment airborne radioactivity sources. Total exposures resulting from the worst radiological accident are below the dose limits specified by GDC 19 and 10CFR50.67; the portion contributed by containment shine and external cloud shine is reduced to a small fraction of the total by means of the walls which surround the control room.

Two radiation detector units are located in the control room fresh air inlet duct, and another two radiation detector units are located in the auxiliary equipment room HVAC system fresh air inlet duct. All four radiation detectors are situated in duct-work that is directly below the floor penetration level at el 332'. A description of the radiation detector units is provided in Section 7.1.2.1.11.

6.4.4.2 Toxic Gas Protection

The control room HVAC system is designed to satisfy the guidelines of Regulatory Guide 1.78 for toxic chemical protection, and Regulatory Guide 1.95 for chlorine protection (except as discussed in Section 6.4.1). Detection systems are provided for both offsite toxic chemical accidental release and onsite chlorine container accidental release.

Detector design criteria and descriptions and respiratory protection are discussed below.

6.4.4.2.1 Chlorine

Four chlorine detectors are provided to detect concentrations in the outside air intake, provide isolation signals, and annunciate in the main control room.

The outside air intake detectors are safety-grade, seismic Category I instruments.

An additional nonseismic detector is provided at the chlorination facility to alarm locally and on the main control room computer.

Details of operation, characteristics, etc. are discussed below:

a. Principle of Operation

The chlorine detectors utilize a probe element mounted in the air intake plenum.

The probe output signal and functional condition is monitored by a controller which in turn energize local and remote chlorine concentration indicators, and initiate local and remote trouble alarms and/or a remote high concentration alarm and ventilation system isolation trip.

The high chlorine concentration setpoint is adjustable from 1% to 99% of the instrument range.

The detectors are designed for fail-safe operation.

b. Testing and Maintenance

A calibration gas is used to calibrate the sensor. A simulated signal is used to test the chlorine detection channel functions and calibrate the channel components while the probe is disconnected.

c. Locations

The controllers, local indicators, and alarm relays are located at el 352'-0", above the control room ventilation supply plenum. The probes and transmitters are mounted in the plenum chamber at el 335'-0" (Area 08).

d. System Characteristics

Sensitivity:	Live measurement when reading zero chlorine.
Range:	0 ppm - 5 ppm gaseous chlorine.
Response Time:	Less than 5 second to reach setpoint and initiated trip signal after introduction of 5 ppm chlorine.

e. Seismic and Environmental Qualifications:

Refer to Sections 3.10 and 3.11 for seismic and environmental qualification criteria.

The chlorine release accident analysis is described in Section 2.2.3. The control room and isolation system are designed to meet the requirements of a control room that has a maximum allowable isolated air exchange rate of 0.25 air changes per hour.

The analysis considers both conditions in which the control room HVAC system is initially in the normal mode of operation and the radiation isolation mode prior to the chlorine accident.

6.4.4.2.2 Offsite Toxic Chemical System

Three toxic chemical detection systems are provided to detect the offsite toxic chemicals identified in Section 2.2.3, to provide annunciation in the control room, and identification of the chemical and concentration to a control room console.

Each toxic chemical detection system consists of a microcomputer built around a microprocessor and integrated with an infrared spectrometer and a multipoint sampling manifold. Each system is

designed to measure and record the concentration of toxic chemicals at one sample location. Each system, located in the control enclosure, monitors the control room outside air intake plenum.

The microcomputer controls the spectrometer, signal averages the infrared transmission measurements at each programmed wavelength, calculates absorbance, and uses a stored coefficient matrix to calculate the concentration of components in the air sample.

During factory calibration, each system is programmed to monitor the toxic gases listed in Table 2.2-6. Calibration coefficients for each gas are stored in the system hard drive.

The sampling program begins with a nitrogen zero gas cycle. Ambient air is collected from the air intake plenum and pumped into the sample cell of the analyzer. The analyzer passes an infrared beam through the sample and measures the amount of light absorbed at each of the analytical wavelengths of a programmed sequence. The computer uses the stored calibration coefficients to calculate the concentration of sample components.

If the concentration of any monitored gas should exceed the selected limits, alarms will be automatically triggered at the analyzer. The toxic chemical high concentration alarm in the control room will be energized when two-out-of-three analyzers alarm. In addition to the concentration alarms, the system will indicate any malfunction related to electronics, optical system, loss of flow by local indication, or a single toxic chemical high concentration alarm.

Three “Inop/Operate” selector switches are installed on the Relay Logic Panel 00-C734, one for each analyzer. Each selector switch allows the associated analyzer, when inoperable, to be placed in the tripped condition. The switch when placed in the "Inop" position bypasses the toxic analyzer trouble annunciator for the affected analyzer and interrupts the data sent to the remote computer and PMS. With one analyzer in the tripped condition, only one of the two operable analyzers are required to alarm to satisfy the two-out-of-three alarm criteria.

A computer display console in the control room can provide an indication of the toxic chemical and its concentration at any given time.

The equipment has built-in test features. A part of the self-test program is automatically performed each time the analyzer is zeroed.

This system has self calibrated features that are always running when the analyzers are in service to keep them within specification or to activate the control room “Trouble” annunciator if any critical parameter is outside its specified range.

Test points are provided on the Relay Logic Panel for each analyzer to facilitate testing of the toxic chemical high concentration alarm relays.

No special maintenance is required.

6.4.4.2.3 Respiratory Protection

Full-faced pressure demand self-contained breathing apparatus rated for 1 hour per cylinder and protective clothing are available for control room operators.

A 6 hour onsite bottled air supply is provided by charged cylinders maintained for backup fire protection and health physics use. Offsite replenishment is provided by compressors (fill capacity greater than 30 cylinders per hour) owned by an offsite vendor, fire company, or another offsite entity.

The number of respiratory devices shall, as a minimum, provide a 6 hour air supply for 6 individuals. Consistent with the provisions of Regulatory Guide 1.95, one extra respiratory device will be provided for every 3 devices needed to meet the minimum capacity.

See Section 13.2 for discussion on Respiratory Protection.

A program for periodic inspection of control room operator respiratory equipment will be established. The program will address inspection for defects, storage conditions, and, as found to be necessary, cleaning, disinfecting, and repairing. In addition, the equipment will be cleaned, disinfected, and inspected after each use. Replacements and repairs will be done only by trained personnel using parts designed for that equipment. The equipment will be stored to protect against dust, sunlight, extreme heat or cold, excessive moisture, and damaging chemicals.

6.4.5 TESTING AND INSPECTION

The control room HVAC emergency system filtration components are tested in a program consisting of the following classifications:

a. Predelivery tests and factory component qualification tests to ensure the quality of the manufactured product.

b. Preoperational tests in accordance with the requirements of Chapter 14.

c. Periodic tests in accordance with the requirements of Chapter 16.

The frequency of tests and inspections is selected to ensure the continued integrity of the system. Charcoal testing frequency is in accordance with Regulatory Guide 1.52 for the efficiency claimed and the bed depth specified. Except that in-place testing and laboratory testing is performed at least once per 24 months as discussed in Table 6.5-2.

Written test procedures establish minimum acceptable values for all tests. Test results are recorded as a matter of performance records, thus permitting early detection of faulty performance.

The predelivery and factory component qualification tests are in accordance with the recommendations and guidelines presented in section C-3 of Regulatory Guide 1.52. HEPA filters have a minimum efficiency of 99.97% when measured with a 0.3 micron DOP aerosol. Carbon lot testing is required and certified by a qualified testing agency to establish gas adsorption efficiency, uniformity of density, ignition temperature, hardness, and impregnate content.

Filter plenums are tested for leakage under positive pressure. Plenums are pressurized to the design pressure with soap bubble tests made at all welds. The maximum permissible leakage rate is 0.05% of the filter plenum rated flow in cubic feet per minute at 125% of the negative design plenum pressure.

Preoperational tests are conducted in accordance with the requirements of Chapter 14. In general, the tests include:

a. Visual inspection

b. Verification of ability to maintain control room pressurization without exceeding outside air makeup design flow rate

c. Airflow capacity verification test

d. Airflow distribution verification test

e. Air/aerosol uniformity test

f. Inplace HEPA test

g. Inplace adsorber test

h. Laboratory test of adsorbent

i. Electric heater test

Periodic tests of the makeup airflow to the control room HVAC system from the emergency fresh air intake are performed in accordance with the requirements of Chapter 16.

Periodic inplace testing of HEPA filters and charcoal adsorbers and laboratory testing of charcoal adsorbers are performed in accordance with the requirements of Chapter 16.

6.4.6 Instrumentation Requirement

Differential pressure indicators are provided locally to measure the pressure drop across each filter element. The overall pressure drop across each filter train is measured and indicated on the local panel and alarmed in the computer on high differential pressure.

Each charcoal adsorber is provided with three temperature switches that actuate alarms in the control room. The alarms provide information to allow the operator to discontinue operation in the event of fire or radioactivity release due to charcoal desorption. The temperature is also indicated in the control room.

The electric heating coils upstream of the filters are controlled by a minimum temperature control and a humidity control to maintain less than 70% relative humidity. In the recirculation mode, the filters are supplied with recirculated control room air at approximately 78°F dry-bulb, 50% relative humidity. Thus, in this mode, if the charcoal adsorber is subjected to less than 70% relative humidity, the heater does not operate, and no additional heat load is imposed upon the control room HVAC system.

Radiation, chlorine, and offsite toxic chemical monitors are provided in the outside air intake duct. Radiation monitors are also provided in the main control room. The monitors alarm in the control room upon detection of high radiation, high chlorine, or high toxic chemical conditions.

Differential pressure transmitters are provided which sense the differential pressure between the control room and the outside air and indicate positive pressure differential in the control room.

The hand switches for HVAC equipment required for control room habitability are located in the control room.

The flow of control room air recirculating through the emergency fresh air filter system is indicated in the control room.

Section 9.4 addresses instrumentation requirements for the control room supply and return air systems.

The instrumentation used to provide the initiating signals for control room pressurization are discussed in Sections 7.3 and 7.6.

Table 6.4-1

CONTROL ROOM EMERGENCY HVAC SYSTEM
FAILURE ANALYSIS

COMPONENT	MALFUNCTION	COMMENTS
Emergency fresh air fan	Failure of fan resulting in reduction of air flow	If the operating fan fails, the resultant reduction of air flow actuates an alarm in the control room, automatically starts the standby fan, and opens the standby filter train isolation valves.
Electric heating coil	Failure of coil control resulting in constant coil operation	Maximum capacity of the electric heating coil is not sufficient to cause damage.
	Failure of coil resulting in no heat	The heating coil is not required during emergency operation because the humidity will not exceed 70% relative humidity.
Filter train	Failure resulting in high differential pressure across the filter train	High differential pressure across the filter train is indicated on the local panel and automatically actuates an alarm in the computer. The defective filter train is manually isolated and the standby train is manually placed in service. If the high differential pressure results in low flow the standby fan and filter train will start.
	Failure resulting in high radiation at the discharge	The defective filter train is manually isolated and the redundant filter train is manually placed into operation upon receiving a high radiation signal.
Charcoal Adsorber	High temperature in charcoal bed	Temperature sensors are provided on the leaving air side of each charcoal bed to alarm in the control room

Table 6.4-1 (Cont'd)

COMPONENT	MALFUNCTION	COMMENTS
		on rising charcoal temperature. The charcoal temperature is also indicated in the control room. The deluge fire protection system is manually initiated if required.
Isolation Valve	Failure to close or failure to close completely	A series redundant isolation valve and a closed and capped test port connection provide the required isolation.
Operational Damper	Failure to open	Low flow switch actuates standby fan and filter train.
Air handling units and return air fans	All postulated failures	See Table 9.4-3.

Table 6.4-2

CONTROL ROOM POTENTIAL LEAK PATHS

	POTENTIAL LEAK PATHS	TYPE OF MATERIAL JOINT, OR PENETRATION
a.	Control room walls	3' thick reinforced concrete
b.	Control room ceiling	1½' thick reinforced concrete poured on 16 gauge galvanized steel metal decking
c.	Control room floor	1½' thick reinforced concrete poured on 16 gauge galvanized steel metal decking
d.	Control room construction joints - floor to wall, wall to wall, wall to ceiling, slab to slab	All are poured concrete cold joints
e.	Doors - personnel access	2 each - 3'x7' steam-tight metal doors with elastomer seals and sealing mechanism
f.	Electrical cable penetrations	Kaowool fiber and silicone expansion foam - 9" deep Dow-Corning 36548 RTV and Sylgard 170
g.	HVAC duct penetrations	Embedded metal sleeves through concrete walls - flanged and welded to ducts
h.	Control room HVAC ducts (negative pressure) exterior to control room	Welded galvanized steel
i.	Dampers (frames, shaft penetrations, flanges) in control room ducts (negative pressure) exterior to control room	Gas-tight construction maximum 0.1 cfm/damper from ambient into duct-work.
j.	HVAC isolation valves	Pneumatic or electrohydraulic butterfly valves - bubble-tight
k.	Piping penetrations	Bellows-type expansion joint

Table 6.4-2 (Cont'd)

	POTENTIAL LEAK PATHS	TYPE OF MATERIAL JOINT, OR PENETRATION
l.	Emergency fresh air supply system (filter assembly and fans)	Welded filter - leak tested; welded fan housing-bolted; and gasketed access doors; inlet and discharge connections
m.	Control room supply air fan cabinets	Welded cabinet construction; vaneaxial fan and coil connections - bolted; and gasketed inlet and discharge connections
n.	Test port connection and isolation valve	Capped test port connection and closed globe valve. Pneumatic or electrohydraulic butterfly valve - bubble-tight.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 ENGINEERED SAFETY FEATURE FILTER SYSTEMS

The following filtration systems, required to perform postaccident safety-related functions are provided:

a. SGTS: In its safety-related mode of operation, this system is used to reduce halogen and particulate concentrations in gases potentially present in the reactor enclosure following a LOCA, and gases present following a postulated fuel handling accident in the refueling area before the gases are discharged to the environment (Section 6.5.1.1). The system exhausts a controlled filtered flow to the atmosphere during isolation to restore and maintain a negative pressure in the affected secondary containment zone. In addition, this system performs the nonsafety-related function of reducing halogen and particulate concentrations in gases purged from the primary containment.

b. CREFAS filter units: This system is used to clean the outside air of halogens and particulates that are potentially present in the air following a postulated accident before introducing the air into the control room HVAC system (Section 6.5.1.2).

c. RERS filter units: This system is used to reduce halogen and particulate concentrations in gases in the reactor enclosures following a LOCA. The RERS is the initial cleanup system (the SGTS is the final cleanup system) before discharge of the gases from the reactor enclosures (Section 6.5.1.3).

6.5.1.1 Standby Gas Treatment System

6.5.1.1.1 Design Bases

As described in Section 9.4.2.1, the secondary containment consists of three ventilation zones. Zones I and II surround the primary containment of Units 1 and 2, respectively, below the floor at el 352'. Zone III consists of the common refueling area above the floor at el 352'.

The SGTS is designed to accomplish the following objectives:

a. Exhaust sufficient filtered air from the reactor enclosure and/or refueling area to maintain a negative pressure of about 0.25 inch wg. in the affected volumes during secondary containment isolation (see Section 9.4.2 for discussion of the secondary containment isolation signals)

b. Filter the air exhausted to remove radioactive particulates and both radioactive and nonradioactive forms of iodine from the following areas:

   1. Reactor enclosure (Zone I and Zone II)

   2. Refueling area (Zone III)

   3. Deleted

4. Primary containment during purging and ventilating

5. Discharge from the HPCI barometric condenser, following filtration by the RERS when the reactor enclosure is isolated

c. Ensure that the failure of any component of the filtration train, assuming LOOP, cannot impair the ability of the system to perform its safety function

d. Remain intact and functional in the event of a SSE

e. Automatically start in response to any one of the following signals:

1. LOCA signal as described in Section 9.4.2.

2. High radiation level in refueling area exhaust air

3. High radiation level in reactor enclosure (Zone I or Zone II) exhaust air

4. Low differential pressure in the reactor enclosure (Zone I or Zone II)

5. Low differential pressure in refueling area (Zone III)

(The SGTS fans can also be started manually in the control room by tripping the refueling area isolation system or the reactor enclosure isolation system.)

f. The design bases employed for sizing the filters, fans, and associated duct-work are as follows:

1. Each filter train is sized and specified for treating the incoming air-steam mixture at 11,000 cfm maximum and 135°F ① for drywell purge (drywell purge is discussed in Section 9.4.5). The SGTS fans are sized for 8400 cfm maximum flow at 20 inches wg. static pressure.

2. The system capacity is maintained with all filters fully loaded (dirty).

3. For HEPA filters, maximum free velocity does not exceed 300 fpm with maximum airflow resistance of 1 inch wg. when clean and minimum efficiency of 99.97% by DOP test method.

4. The charcoal adsorber is rated for 99.0% trapping of radioactive iodine as elemental iodine (I_2) and 99.0% trapping of radioactive iodine as methyl iodide (CH_3I) when passing through charcoal (8 inch bed depth) at 70% relative humidity. The air residence time in the 8 inch charcoal bed is 0.68 seconds considering a maximum total after drawdown leakage rate from Zones I, II, and III of 5764 cfm.

① This information is based on original design conditions. Further evaluation has validated this design for a drywell operating temperature of 150°F.

5. Relative humidity at the charcoal adsorber is limited to 70% by the appropriate heating of air.

6. The SGTS maximum fan capacity is based on the calculated inleakage into secondary containment with the secondary containment maintained at a negative pressure of 0.25 inches of water with reference to the outside atmosphere. The maximum capacity includes an allowance for thermal expansion of the secondary containment air volume due to equipment residual heat transfer to the air during SGTS operation.

6.5.1.1.2 System Description

The SGTS is common to both Units 1 and 2. Each of the two redundant SGTS filter trains consists of an electric air heater, two banks of HEPA filters (upstream and downstream of charcoal adsorber), a vertical 8 inch deep charcoal adsorber bed (with temperature detection sensors and a water flooding system for fire protection), and associated dampers, ducts, instruments, valves, and controls.

For its safety-related mode of operation (Section 6.5.1.a), two redundant 100% capacity SGTS fans are provided for use in conjunction with the SGTS filter trains. Each fan has a controllable capacity of 500 cfm to 8400 cfm, which is sufficient to restore and maintain both reactor enclosures and the common refueling area at the required negative pressure in relation to atmospheric pressure during secondary containment isolation. The air flow varies in response to secondary containment differential pressure controls, which modulate the fan inlet vanes and control dampers in the run-around bypass and discharge ducts provided for each fan. Slide gate dampers with position switches are closed to isolate the SGTS from any secondary containment zone which cannot be isolated and drawn down.

The SGTS is actuated automatically in its safety-related mode of operation. Both SGTS filter trains are maintained in the open position. Upon receipt of a secondary containment isolation signal (Section 6.5.1.1.1.e), both of the SGTS fans are started and the associated controls are activated to open or modulate appropriate dampers and valves so that the system function is accomplished. Following the initial fan start, the operators may elect to place one of the SGTS fans in the standby position.

For its nonsafety-related mode of operation (Section 6.5.1.a), two redundant 100% capacity drywell purge fans are provided for use in conjunction with the SGTS filter trains. Each fan has a capacity of 11,000 cfm which is sufficient for the drywell purge operation.

The SGTS is manually actuated for its nonsafety-related mode of operation.

If one of the SGTS filter train isolation valves fails closed during its safety-related mode of operation, the redundant filter train is automatically placed into service. If one of the SGTS fans fails to establish flow, because of either fan or fan damper failure, the standby SGTS fan automatically starts.

The SGTS is shown schematically on drawing M-76. Specific SGTS component design parameters are shown in Table 6.5-1.

The equipment and materials conform to the applicable requirements and recommendations of the guides, codes, and standards listed in Section 3.2. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2.

Components for each SGTS train are designed as discussed in the following paragraphs.

A prefilter is not included in the SGTS filter trains because the SGTS intake is downstream of the recirculation filter system fans so that the air is prefiltered before entering the SGTS filters after RERS start during reactor enclosure isolation. A prefilter is provided in the SGTS duct for air drawn from the refueling area during refueling area isolation. The drywell purge air supply is prefiltered by the reactor enclosure supply air system during the drywell purge mode.

The SGTS fan performance and motor selection are based on the maximum system pressure drop resulting from dirty SGTS filters. The SGTS filter banks are sized for 11,000 cfm drywell purge flow, (see Table 6.5-1 for filter pressure drops).

The charcoal adsorber is a gasketless, welded seam type filled with impregnated activated charcoal that meets the requirements in table 5-1 of ANSI N509 (1980) and Regulatory Guide 1.52 except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989. The bank holds a total of approximately 2400 pounds of charcoal having an ignition temperature of not less than 626°F. The charcoal adsorber is capable of removing not less than 99.0% of elemental iodine and 99.0% of methyl iodide at 70% relative humidity. The maximum loading is 2.5 milligrams of iodine per gram of activated charcoal.

A demister is not required for the SGTS filters. The absence of water droplets in the air stream entering the SGTS filters during post-LOCA isolation, refueling area isolation, and primary containment purging is assured based on the following:

a. The SGTS intake is downstream of the RERS filters and normally exhausts air which has been prefiltered by the RERS filters. However, prior to RERS fan operation (up to 3 minutes post-LOCA), the SGTS can draw air directly through a pressure relief vent located between the RERS and SGTS ducts. This vent is located in an access area on el 283' where there are no significant sources of humidity which can form water droplets. After the RERS fan starts, the vent is maintained at a slight positive pressure with air which has been prefiltered by the RERS filters. The absence of water droplets in the RERS air stream during reactor enclosure isolation is discussed in Section 6.5.1.3.2.

b. There are no sources of water droplets in the refueling area that could enter the duct connection to the SGTS. As discussed below, water droplets from condensation will not reach the SGTS filters during refueling area isolation because of the tortuous flow path and low velocities through the ducts, and low point drains in the ducts. The duct from the refueling area to the SGTS filters passes the Unit 1 reactor enclosure for approximately 260 feet and includes at least 20 bends and turns. If condensation does occur, the amount of condensation would be minor, based on the potential amount of water vapor in the air stream. One inch diameter low point drain is provided for the portion of duct-work in the reactor enclosure to ensure that any condensation will be drained from the duct. When refueling area drawdown begins, the flow rate could reach 2400 cfm or more for a short period of time. As water vapor accumulates in the refueling area, the flow rate will be decreasing. During the period when any significant condensation could occur in the

ducts, the flow rate in the duct will be no more than 800 cfm. The air velocity during this period varies from approximately 162 fpm to 325 fpm (1.8 mph to 3.7 mph) for the majority of the duct-work.

c. Water droplets will not reach the SGTS filters during drywell containment purging because of the reasons discussed below.

It is highly unlikely that water droplets will enter the purge lines during drywell purging. As discussed in Section 6.5.1.3.3, the licensee's preventive maintenance program will maintain normal plant leaks to low flow dripping type leakages. Any leakage with spraying water droplets (such as those due to failed seals in pumps and valves) will be identified and corrected as part of the maintenance program. It can be shown that any droplets formed will travel less than 20 feet. There are no potential sources of water droplets within 20 feet of the suppression chamber purge exhaust opening. There are no pumps, and only few valves, within 20 feet of the drywell purge exhaust opening. The closest valve is 8 feet away from the opening. Because the purge system is used during only a limited period of power operation (only open for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open), it is highly unlikely that a valve seal would fail and spray water into the drywell purge exhaust opening during purge system operation.

If water droplets are hypothetically assumed to enter the purge exhaust ducts, or if condensation within the duct-work occurs, the water droplets would not reach the SGTS filters because of the tortuous flow path, the insulated duct-work in the control structure, and the SGTS heaters. Purge air exhausted from the drywell flows approximately 215 feet in the reactor enclosure through three valves, two vertical upward turns, and four additional bends and turns with a flow rate of 11,000 cfm at a velocity of 2240 fpm (25.5 mph) in the duct, and 3731 fpm in the pipe. The purge air from the suppression chamber flows more than 160 feet in the reactor enclosure through valves and six bends and turns with a flow rate of 9750 cfm and a velocity of 1986 fpm (22.6 mph) in the duct, and 6008 fpm in the pipe. At these velocities, if condensation occurs within the duct-work, it is possible for some water droplets to be entrained in the air-steam. Condensation within the reactor enclosure duct-work could occur while purging the suppression chamber, but no significant condensation would occur while purging the drywell because the drywell is maintained at a low relative humidity by the drywell coolers. No significant condensation would occur in the control enclosure duct-work for either purge mode because it is insulated.

The environmental conditions within the reactor enclosure duct-work will be such that only surface type condensation could occur. Droplets will coalesce on the inside surface of the duct creating larger droplets, forming condensate flow on the bottom of the duct. Much of this flow will drain to low points in the duct-work and be removed via drains, and therefore never enters the air stream. Much of the condensate that does become entrained in the air stream is subsequently removed from the air stream due to the any bends and turns in the duct. Water droplets greater than 20 microns in size are removed by the bends and turns, including a square elbow with turning vanes, which act as course moisture separators (Reference 6.5-2). Water droplets less than 20 microns in size may reach the

SGTS heaters. However, analyses have been performed to demonstrate that the SGTS heaters can evaporate all water droplets less than 25 microns in size. Thus, no water droplets will reach the SGTS filters.

The effects of water droplets on the SGTS HEPA filters were evaluated, even though there is no credible way for water droplets to reach the HEPA filters. (Effects on the charcoal filters were not evaluated because the HEPA filters are upstream of the charcoal filters and would collect any water droplets postulated to be in the air stream). When HEPA filters are exposed to high concentrations of liquid, plugging could occur that would decrease air flow through them. Decreased efficiency in collecting particulate matter would not occur unless plugging is severe enough to rupture the HEPA filter. Based on Reference 6.5-2, if the maximum water delivery rate is kept below 0.18 gpm per 1000 cfm of air flow, plugging will not occur. Analyses have been performed to demonstrate that, even if all of the condensation that forms in the duct during the worst case condition of suppression pool purging is hypothetically assumed to reach the HEPA filters in the form of water droplets, the condensate loading is only 8.33×10^{-3} gpm/1000 cfm, which is well below 0.18 gpm/1000 cfm. Thus, plugging of the filters would not occur.

Analyses were performed to demonstrate that the SGTS heaters are capable of reducing the relative humidity of the air during suppression pool purging (9750 cfm for this mode) from 100% relative humidity, with entrained droplets, to less than 70% relative humidity, with no entrained droplets. The SGTS heaters are also capable of reducing the relative humidity of the air during drywell purging (11,000 cfm for this mode), from 100% relative humidity to less than 70% relative humidity.

A water flooding system within the charcoal bed is provided. The water system is connected to the station fire protection system. Valves are mounted outside the charcoal adsorber. Two continuous type thermistors are provided on the leaving air side of the charcoal bed. A rise in the charcoal bed area temperature results in the following:

a. The first temperature setpoint (200°F) actuates an alarm in the control room. The filter train is removed from service until the cause of the alarm has been determined. The operator shall investigate to determine if a fire has occurred and introduce the fire protection water to the charcoal plenum, if necessary, as listed in Item c.

b. The second temperature setpoint (250°F) also actuates an alarm in the control room. The operator shall continue to investigate to determine if a fire has occurred and introduce the fire protection water, if necessary, as listed in Item c. The SGTS charcoal temperature sensor system power trouble alarm is allied with this alarm window.

c. The third temperature setpoint (550°F) actuates an alarm in the control room. The operator shall investigate to determine if a fire has occurred and introduce the fire protection water to the charcoal plenum, if necessary, as follows: The operator manually opens the valves, thus introducing the fire protection water to the charcoal plenum. A drain valve is provided to drain the water from the filter plenum.

Four test canisters are provided for each charcoal adsorber. These canisters contain the same depth of the same charcoal that is in the adsorber. The canisters are mounted so that a parallel

flow path is created between each canister and the adsorber. Periodically one of the canisters can be removed and laboratory tested to verify the adsorbent efficiency. Alternate means of sampling (slotted-tube method) may also be used for obtaining representative samples of used activated charcoal per the requirements specified in ANSI N509-1980.

Permanently installed injection and sampling ports are provided for all ESF atmosphere cleanup systems to permit accurate testing in accordance with ANSI N510. Providing fewer charcoal test canisters on the ESF atmosphere cleanup systems than specified in ANSI N509 (1980) section 4.11 results in equal or more frequent replacement of activated carbon. Regulatory Guide 1.52 states that testing of representative samples should be performed (1) initially, (2) at least once per 18 months thereafter for systems in a standby status, or after 720 hours of system operation and (3) following painting, fire, or chemical release in any ventilation zone communicating with the system. However, representative samples of the SGTS are tested at least once per 24 months as discussed in Table 6.5-2. More frequent replacement may result because Regulatory Guide 1.52 further states that when no representative samples are available for testing, the activated carbon should be replaced with new activated carbon.

Access doors, with 30x68 inch openings, to each HEPA filter compartment are provided. An 18 inch access hatch is provided for the charcoal filter compartment.

The HEPA filter and charcoal filter housings are of all-welded construction.

Interior lights with external light switches are provided in the HEPA filter plenums to facilitate inspection, testing, and replacement of components.

The SGTS has been designed to continuously purge the filter plenums with dry instrument air when the filters are not in use. Any amount of dry air continuously purged through the adsorbers and HEPA filters will entrain moisture and maintain moisture levels at a minimum because the duct-work is gas-tight and there is no internal humidity source. (The periodic operation of the ESF atmosphere cleanup (SGTS) train could introduce additional moisture into the system and increase moisture levels above those normally maintained.)

The electric heater maintains the relative humidity below 70% for charcoal adsorber operation by maintaining a constant temperature rise of 15°F across the heater. An analysis of heater capabilities for various entering saturated air conditions up to 150°F (which exceeds any inlet conditions the SGTS system will experience) yields a peak heating requirement of 135,000 Btu/hr, at maximum 11,000 cfm airflow. A 55 kW heater is provided.

The automatic reset cutout (setpoint 260°F) is located inside the heater where the sensed temperature is higher than the actual air temperature downstream of the heater. This heater protection device that was selected and installed by the heater manufacturer. The automatic reset cutout (setpoint 180°F), which is located downstream of the heater, senses the actual temperature of air leaving the heater and causes an alarm signal in the control room when the air temperature exceeds 180°F. Because the SGTS electric heaters operate with a fixed temperature differential of 15°F between the inlet and outlet air temperatures and the maximum inlet temperature is 150°F, the maximum air temperature downstream of the heater should not exceed 165°F. In the event of a heater malfunction, the discharge air automatic reset cutout will shut off the heater when the downstream air temperature exceeds 180°F. The conservatively selected 180°F heater cutout temperature, and an alarm annunciation in the control room to notify the operator if this condition should occur are considered to be equivalent to the 225°F manual heater cutout required by section 5.5 of ANSI N509-76.

6.5.1.1.3 Design Evaluation

The SGTS is designed to preclude direct exfiltration of contaminated air from the secondary containment following a postulated accident or an abnormal occurrence which could result in abnormally high airborne radiation in the secondary containment. Equipment is powered from Class 1E buses, and all power circuits meet IEEE 279 and IEEE 308 requirements to ensure power availability from the standby diesel generator sets in the event of loss of normal offsite ac power. Redundant components are provided where necessary to ensure that a single failure does not impair or preclude system operation. The SGTS is designed to seismic Category I requirements as discussed in Section 3.7 to ensure that the system remains intact and functional in the event of an SSE. Components and materials of the SGTS system have been selected to assure availability of the system under postulated accident conditions. An SGTS failure mode and effect analysis is presented in Table 6.5-3.

6.5.1.1.4 Tests and Inspections

Except for Items D.2 and D.3 of Table 9.4-4, all tests and inspections described in the table apply to the SGTS. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2.

ESF atmosphere cleanup systems are accessible during normal operation and during anticipated transients. ESF atmosphere cleanup systems are designed to operate after an accident or during drywell purge. Periodic tests are performed during normal operation on all ESF atmosphere cleanup systems, to ensure that prefilters and HEPA filters are either changed on high pressure readings or checked on abnormal readings.

The system will be preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

6.5.1.1.5 Instrumentation

The SGTS can be actuated manually from the control room. Each SGTS train is designed to function automatically upon receipt of a secondary containment isolation signal. The status of system equipment, which is an indication of pertinent system temperatures and flow rates, is displayed in the control room during both normal and accident operation.

All instrumentation required during and after accident conditions is qualified to meet seismic Category I requirements. Instrumentation conformance with Regulatory Guide 1.52 is discussed in Tables 6.5-2 and 6.5-8.

The following alarms are annunciated in the control room:

a. Fan trouble

b. Heater failure (low temperature rise across the heater)

c. Charcoal filter high temperature alarms

d. Filter system trouble (including valve circuit trouble, charcoal temperature detection system trouble and electric heater trouble)

e. Low pressure differential, referenced to the outside ambient pressure, in the secondary containment ventilation zones being isolated

6.5.1.1.6 Materials

The materials of construction used in or on the SGTS are given in Table 6.5-4.

Materials used in or on the SGTS are selected to ensure that system operability is not affected by radiation, temperature, or other environmental effects. Environmental qualification of the SGTS is discussed in Section 3.11.

By being located in the control structure, the SGTS is protected from extremes of radiation and temperature that could potentially produce radiolytic or pyrolytic decomposition of filter materials. Thus, filter system decomposition products would not be generated.

6.5.1.2 Control Room Emergency Fresh Air Filter Units

6.5.1.2.1 Design Bases

The design bases for the control room emergency fresh air filter units are described in Sections 6.4 and 9.4.1 and as given below.

The design bases employed for sizing the filters, fans, and associated duct-work are as follows:

a. Each filter train is sized and specified for treating incoming air at 3000 cfm at design outdoor temperature.

b. The system capacity is maintained with all filters fully loaded (dirty).

c. For HEPA filters, maximum free velocity does not exceed 300 fpm with maximum airflow resistance of 1 inch wg. when clean and minimum efficiency of 99.97% by the DOP test method.

d. The charcoal adsorber is rated 95.0% for trapping of radioactive iodine as elemental iodine (I_2) and 95.0% trapping of radioactive iodine as methyl iodide (CH_3I) when passing through charcoal (2 inch bed depth) at 70% relative humidity. The air residence time in the 2 inch charcoal bed is not less than 0.25 seconds.

6.5.1.2.2 System Description

The control room emergency fresh air filter system is described in Sections 6.4 and 9.4.1. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2.

6.5.1.2.3 Design Evaluation

The control room emergency fresh air filter units work in conjunction with the control room HVAC system to maintain habitability in the control room. The design evaluation is given in Sections 6.4 and 9.4.1. Control room emergency fresh air filter system failure analysis is given in Section 6.4.

6.5.1.2.4 Tests and Inspections

Tests and inspections are described in Sections 6.4 and 9.4.1.

6.5.1.2.5 Instrumentation

Instrumentation requirements are discussed in Section 6.4. Conformance with Regulatory Guide 1.52 is discussed in Tables 6.5-2 and 6.5-8.

6.5.1.2.6 Materials

The materials of construction used in or on the control room emergency fresh air filter systems are given in Table 6.5-5.

Materials used in or on the emergency fresh air filter systems are selected to ensure that system operability is not affected by radiation, temperature, or other environmental effects. Environmental qualification of the system is discussed in Section 3.11.

By being located in the control structure, the emergency fresh air filter systems are protected from extremes of radiation and temperature that could potentially produce radiolytic or pyrolytic decomposition of filter materials. Thus, filter system decomposition products would not be generated.

6.5.1.3 Reactor Enclosure Recirculation System Filter Units

6.5.1.3.1 Design Bases

The RERS is designed to accomplish the following objectives:

a. Filter the air in the reactor enclosures following a LOCA to reduce the concentration of radioactive halogens and particulates potentially present in the reactor enclosures

b. Ensure that failure of any component of the filtration train, assuming loss of offsite power, cannot impair the ability of the system to perform its safety function

c. Remain intact and functional in the event of an SSE

d. Automatically start in response to any one of the following signals (the RERS fans can also be started manually in the control room by tripping the reactor enclosure isolation system):

    1. LOCA signal as described in Section 9.4.2

    2. High radiation level in the reactor enclosure (Zone I or Zone II) exhaust air of the respective unit

    3. Low differential pressure in the reactor enclosure (Zone I or Zone II)

e. The design bases employed for sizing the filters, fans, and associated duct-work are:

1. Each filter train is sized and specified for treating incoming air at 60,000 cfm and 150°F, which exceeds the accident temperature service requirements.

2. The system capacity is maintained with all filters fully loaded (dirty).

3. For HEPA filters, maximum free velocity does not exceed 375 fpm, with maximum airflow resistance of 1 inch wg. when clean and minimum efficiency of 99.97% by DOP test method.

4. The charcoal adsorber is rated for 95.0% trapping of radioactive iodine as elemental iodine (I_2) and 95.0% trapping of radioactive iodine as methyl iodide (CH_3I) when passing through charcoal (2 inch bed depth) at 70% relative humidity. The air residence time in the 2 inch charcoal bed is not less than 0.25 seconds.

6.5.1.3.2 System Description

There are two redundant RERS trains in each reactor enclosure. Each of the RERS trains consists of a bank of prefilters, two banks of HEPA filters (upstream and downstream of the charcoal adsorber), a vertical two inch deep charcoal adsorber bed (with fire detection temperature sensors and a water spray system for fire protection), and associated dampers, ducts, instruments, and controls. The RERS is shown schematically on drawing M-76. Specific RERS component design parameters are provided in Table 6.5-1.

The equipment and materials conform to the applicable requirements and recommendations of the guides, codes, and standards listed in Section 3.2. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2.

Each redundant RERS train has a constant capacity of 60,000 cfm, and each is capable of treating the required amount of air from the Unit 1 or Unit 2 reactor enclosure volume being recirculated. Components for each RERS are designed as discussed in the following paragraphs.

The fan performance and motor selection are based on maximum system pressure drop, that is, a pressure drop based on maximum pressure drops across the component filters (3 inches wg. for the first bank of HEPA filters and 4 inches wg. for the second bank). The air flow is maintained at a constant rate by flow control dampers.

The charcoal adsorber is a gasketless, welded seam type filled with impregnated activated charcoal that meets the requirements in table 5-1 of ANSI N509 (1980) and Regulatory Guide 1.52 except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989. The bank holds a total of approximately 13,000 pounds of charcoal having an ignition temperature of not less than 626°F. The charcoal adsorber is capable of removing not less than 95.0% of elemental iodine and 95.0% of methyl iodide at 70% relative humidity.

There are no demisters provided for the RERS. The absence of water droplets in the RERS air stream during reactor enclosure isolation is assured based on the following:

a. The reactor enclosure relative humidity will not exceed 77% during normal operation. This relative humidity will decrease to below 70% post-LOCA due to the increase in heat to the structure.

b. ESF system leakage will be held to a minimum because LGS will follow the guidelines of NUREG-0737 Item III.D.1.1, i.e., provide periodic surveillance tests to minimize system leakage.

c. The RERS is not required to mitigate the consequences of a HELB or a moderate energy line break. Therefore this line break is not considered a source of water that could enter the RERS air stream.

d. The RERS will not communicate with the refueling area during reactor enclosure isolation or refueling area isolation. Therefore humidity from the fuel pool is not considered a source of water that could enter the RERS air stream. As indicated in Table 6.5-2, the SGTS, which will drawdown the refueling area upon refueling area isolation, will be provided with a prefilter in accordance with Regulatory Guide 1.52.

A water spray system within the charcoal bed is provided. The spray system is connected to the fire protection system. A valve is mounted outside the charcoal adsorber. A continuous type thermistor is provided on the leaving air side of the charcoal bed. A rise in the charcoal bed area temperature results in the following:

a. The first temperature setpoint (200°F) actuates an alarm in the control room. The filter train is removed from service until the cause of the alarm has been determined. The operator shall investigate to determine if a fire has occurred and introduce the fire protection water to the charcoal plenum, if necessary, as listed in item c.

b. The second temperature setpoint (250°F) also actuates an alarm in the control room. The operator shall continue to investigate to determine if a fire has occurred and introduce the fire protection water, if necessary, as listed in item c. The RERS charcoal temperature sensor system power trouble alarm is allied with this alarm window.

c. The third temperature setpoint (550°F) actuates an alarm in the control room. The operator shall investigate to determine if a fire has occurred and introduce the fire protection water to the charcoal plenum, if necessary, as follows: The operator manually opens the valve, thus introducing the fire protection water to the charcoal plenum. A drain valve is provided to drain the water from the filter plenum.

Six test canisters are provided for each charcoal adsorber. These canisters contain the same depth of the same charcoal that is in the adsorber. The canisters are mounted so that a parallel flow path is created between each canister and the adsorber. Periodically one of the canisters can be removed and laboratory tested to verify the adsorbent efficiency. Alternate means of sampling (slotted-tube method) may also be used for obtaining representative samples of used activated charcoal per the requirements specified in ANSI N509-1980.

Access doors, with 20x50 inch openings, are provided in each filter compartment in the RERS plenum.

The RERS filter plenum housing is of all-welded construction.

Interior lights with external light switches are provided between all train components to facilitate inspection, testing, and replacement of components.

Each charcoal train is continuously purged with 1 cfm of dry instrument air; however, any amount of dry air continuously purged through the adsorbers and HEPA filters will entrain moisture and maintain moisture levels at a minimum because the duct-work is gas-tight and there is no internal humidity source. (The periodic operation of the ESF atmosphere cleanup train could introduce additional moisture into the system and increase moisture levels above those normally maintained.)

The RERS is actuated either automatically (safety-related mode) or manually for routine system operability testing (nonsafety-related mode). The automatic actuation is originated by the reactor enclosure isolation signal (Section 6.5.1.3.1.d).

During normal operation the RERS trains are maintained in a lead/lag mode of operation. Upon receipt of an automatic isolation signal the RERS train in lead will automatically start to accomplish the system functions. The RERS train in lag will remain in standby. In the event of a single active failure associated with the operating RERS train, the RERS train in standby will automatically start, following a time delay, to perform the system functions and will operate for the duration of the Design Bases Event.

6.5.1.3.3 Design Evaluation

The RERS is designed for filtration of contaminated air in the reactor enclosure following a postulated accident or abnormal occurrence which could result in abnormally high airborne radiation in the reactor enclosure. Equipment is powered from Class 1E buses and all power circuits meet IEEE 279 and IEEE 308 requirements to ensure uninterruptible operation in the event of loss of normal offsite ac power. Redundant components are provided where necessary to ensure that a single failure will not impair or preclude system operation. Operating the RERS trains in a lead/lag mode will assure compliance with the design bases since a single RERS train is sufficient to perform all of the required RERS safety functions and the time delay associated with the shutdown of the lead RERS train and standby start of the lag RERS train will have a negligible effect on the Reactor Enclosure differential pressure, the post-LOCA mixing function and the on-site/off-site dose analyses. The RERS is designed to seismic Category I requirements as discussed in Section 3.7 to ensure that the system remains intact and functional if there is an SSE. Components and materials of the RERS have been selected to assure availability of the system under postulated accident conditions. A RERS failure mode and effect analysis is presented in Table 6.5-6.

An analysis was conducted to calculate the maximum post-LOCA time period for which the relative humidity at the inlet of the RERS charcoal filters could exceed 70%. It was found that within 15 minutes after isolation of the reactor enclosure secondary containment, the relative humidity will decrease from an initial maximum condition of 76.2% to below 70%. The following conservative rationale was used for this analysis:

a. The reactor enclosure supply air system uses unconditioned outdoor air to provide once-through ventilation to cool the reactor enclosure during normal plant operation.

b. On a design basis summer day of 95°F (Db), the reactor enclosure ventilation system is designed to maintain the reactor enclosure at a nominal 104°F. The outdoor air is sensibly heated from 95°F to 104°F as it passes through the reactor enclosure supply fans and from internal reactor enclosure heat loads such as the primary containment, MCCs, load control centers, motors, lights, cable trays, and piping.

c. Assuming outdoor air conditions of 95°F (Db) and 95°F (Wb) (100% relative humidity) exist, the same air when heated to 104°F (Db) will have a relative humidity of 76.2%. This is the basis for the initial reactor enclosure relative humidity conditions when isolation occurs due to a LOCA.

d. Based on the ASHRAE 1981 Handbook of Fundamentals, less than 1% of the total hours during the months of June through September will exceed a 93°F (Db) or 77°F (Wb) in Philadelphia. Therefore the outdoor air conditions used in this analysis are improbable.

e. Other outdoor air conditions at lower dry-bulb and wet-bulb temperatures, which are more probable from a meteorological standpoint, can also result in an initial reactor enclosure relative humidity condition exceeding 70%. However, the initial relative humidity for these cases will be less than 76.2% because cooler air contains less moisture and the 9°F temperature rise from operating equipment has a greater effect on lowering the relative humidity.

f. After isolation occurs, an increase in the bulk reactor enclosure temperature from 104°F to 107°F will lower the relative humidity to 70% in accordance with basic psychrometric principles. At lower reactor enclosure temperatures, the initial relative humidity is closer to 70%, and a smaller temperature rise after isolation is needed to lower the relative humidity to 70%.

g. Only internal reactor enclosure heat loads that were determined to exist for the duration of the transient were considered to provide air heat-up. The heat load from seismic Category II motors was considered to decay instantly because loss of their internal motor ventilating fans would prevent efficient residual heat removal from the motor casings. The lighting load was also considered to decay to zero instantly because the small mass and therefore residual heat stored in this equipment would be small.

h. The heat loss of the air into the cooler exterior and interior walls and floor slabs of the reactor enclosure was calculated using a conservative heat transfer model.

i. The cooling effect of outdoor air inleakage into the reactor enclosure due to SGTS operation was considered.

j. Because the bulk reactor enclosure temperature 15 minutes post-LOCA will always exceed any outdoor air temperature by at least 12°F (107°F versus 95°F for worst case analysis), the relative humidity will not rise above 70% for the duration of RERS operation.

k. Internal sources of moisture resulting from operation of the ECCS pumps were evaluated. The additional moisture was found to be small and will not have a significant effect on relative humidity.

The RERS charcoal filter efficiency is not expected to be adversely affected by this temporary condition. Although the initial relative humidity of the reactor enclosure is 76.2% at the time of the LOCA, the RERS does not operate for the first 3 minutes. Therefore, the time period in which the relative humidity exceeds 70% and the RERS operates is between 3 minutes and 15 minutes when the average relative humidity will be approximately 73%. Reference 6.5-2 recommends a charcoal efficiency for methyl iodine removal of 95% for relative humidities of 85% and less as a conservative design basis. It also states that "Trapping of elemental radioiodine involves physical adsorption only, and the efficiency of nearly any good grade of activated carbon, impregnated or not, will be at least 99% (DF = 100) under any combination of temperature and humidity that would be encountered in a nuclear air cleaning system." Evidence that these efficiency values are realistic and conservative has been identified in the following sources:

a. The ANSI N509 (1980) activated carbon performance test requirements and acceptance values are more stringent than the recommended efficiency values of Reference 6.5-2. LGS RERS charcoal is being supplied in accordance with the ANSI N509 requirements.

b. Figure 4.6 of Reference 6.5-3 plots the test results of 65 different methyl iodine penetration tests as a function of relative humidity. In no cases was the penetration found to be greater than 4% when the relative humidity was less than 85%. Figure 4.7 of Reference 6.5-3, based on 7 different tests, indicates a generally low penetration (less than 1%) for elemental iodine for all relative humidity conditions.

It was also determined that demisters were not necessary for the RERS. This conclusion is based on the following analysis of a postulated situation in which water droplets are assumed to be formed from system leakage and the possible migration paths of this leakage to the RERS filters.

The estimated leakage from the drywell/suppression pool to the reactor enclosure is limited by several mechanisms. These are:

a. The limit of 0.5% per day air leakage imposed by the containment leak test Technical Specification, the periodic integrated leak rate test, and individual valve leak tests. The 0.5% per day leak rate corresponds to approximately 1.4 cfm, which dictates only pinhole-size leak paths. These small leak paths serve to condense moisture and preclude droplet formation.

b. The programs of preventive maintenance implemented by NUREG-0737, Item III.D.1.1 to minimize system leakage. This program includes helium leak detection for gaseous systems and liquid detection/inspection for liquid-containing systems.

c. The postulated passive failure of an RHR pump seal and resulting release of liquid. The licensee’s preventive maintenance program will maintain normal plant leaks to low flow dripping type leakages. Any leakages with spraying water droplets will be identified and corrected as part of the maintenance program. However, for the purpose of this discussion, a postulated passive failure of an RHR pump seal is assumed (SRP 15.6.5, Appendix B). This assumption results in a 5 gpm leak of

suppression water at less than 212°F (Figure 6.2-9) and may produce water spray into the air. Because the water is below the boiling point, the airborne water will fall to the floor and subsequently into the floor drains with little or no flashing.

If water should be sprayed from the passive failure, it can be shown that any droplets formed travel less than 20 feet, based on analyses of spray systems where the nozzles are designed to maximize the development of water droplets (Reference 6.5-1). These analyses have shown that 1000 micron droplets would travel no more than 20 feet in a horizontal direction with an initial velocity of 3000 ft/sec. The travel distance from the RHR pump seal to the local RERS exhaust vents is approximately 29 feet vertically and 10 feet horizontally. No droplets will reach the exhaust duct.

Another factor virtually eliminating the potential for water droplets to travel as far as 20 feet is the effect of the unit coolers in the ECCS rooms. These coolers have flow rates of 9000 cfm to 22,000 cfm. The major objective of the unit coolers is to ensure cool ambient air in the RHR room and to condense excess water vapor. The RHR pump rooms have unit coolers, each operating at 21,800 cfm. The unit cooler air flow competes with the 310 cfm RERS exhaust air flow. Over 95% of the moisture in the air will go through the unit coolers and not into the duct-work.

If it is hypothetically and nonmechanistically assumed that airborne droplets are available, those water droplets entering the exhaust duct must make an immediate 90° turn. A 155 fpm (1.8 mph) RERS exhaust air velocity is not sufficient to overcome the force of gravity to impart a vertical upward velocity to any water droplets. Over 400 feet of RERS ducting containing valves and dampers and numerous bends and turns (at least 15) exist between the exhaust and the prefilters. This tortuous path results in droplets either falling back or impacting on the walls of the ducting where it will evaporate due to the less than 100% humidity in the air flow.

Furthermore, any water droplets suspended in the small air flow (310 cfm) from the RHR room are diluted by 59,700 cfm entering the RERS from other parts of the reactor enclosure. Because the calculated maximum humidity is less than 76.2%, water droplets carried with the air stream would be evaporated.

Even if water droplets were to reach the RERS filters, the droplets must first pass through the prefilter and the HEPA filters before impacting the charcoal medium. Both of these filters are more efficient at removing water droplets from air than demisters. Water removed would be evaporated in the air due to the maximum humidity being less than 76.2%.

Given these physical conditions and the lack of a significant source of water droplets, there is no need to install a demister on the RERS.

These contributions to the DBA/LOCA are considered in the Section 15.6.5 analysis and in SRP 15.6.5, Appendices A and B.

d. Deleted

6.5.1.3.4 Tests and Inspections

Tests and inspections are described in the applicable items (2, 3, and 7 through 13) in Table 9.4-4. Conformance with Regulatory Guide 1.52 is discussed in Table 6.5-2. The system is preoperationally tested in accordance with the requirements of Chapter 14 and periodically tested in accordance with the requirements of Chapter 16.

6.5.1.3.5 Instrumentation

The RERS can be actuated manually from the control room by tripping the reactor enclosure isolation system. Each RERS train is designed to function automatically upon receipt of a reactor enclosure isolation signal. The status of system equipment, which is an indication of pertinent system pressure drops and temperatures, is displayed in the control room during both normal and accident operation.

All instrumentation required during and after accident conditions is designed to seismic Category I requirements. Instrumentation conformance with Regulatory Guide 1.52 is discussed in Tables 6.5-2 and 6.5-8.

The following alarms are annunciated in the control room:

a. Fan trouble (including valve circuit trouble and charcoal temperature detection system trouble)

b. Charcoal filter high temperature alarms

ESF atmosphere cleanup systems are accessible during normal operation and during anticipated transients. ESF atmosphere cleanup systems operate only after an accident or during drywell purge. This allows operation on all ESF atmosphere cleanup systems, which ensures that prefilters and HEPA filters are either changed on high pressure readings or checked on abnormal readings.

6.5.1.3.6 Materials

The materials of construction used in or on the RERS are given in Table 6.5-7.

Materials used in or on the RERS are selected to ensure that system operability is not affected by radiation, temperature, or other environmental effects. Environmental qualification of the RERS is discussed in Section 3.11.

Filter materials used will not decompose due to radiation during the specified useful life of the filter.

6.5.2 CONTAINMENT SPRAY SYSTEM

The containment spray cooling subsystem, which is one of the five modes of operation of the RHR system, is not designed to perform a fission product removal function following a DBA. The containment cooling subsystem is described in Section 6.2.2.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

6.5.3.1 Primary Containment

The primary containment structure is in the form of a truncated cone (the drywell) over a cylindrical section (the suppression chamber). Its pressure-suppression concept is the GE Mark II design. The primary containment is made of reinforced concrete, and it is lined with welded steel plate and provided with a steel domed head. The structural design of the primary containment is discussed in Section 3.8. Plan and elevation views of the primary containment are shown in Figures 3.8-1 through 3.8-8.

The primary containment walls, liner plate, mechanical penetrations, isolation valves, hatches, and locks function to limit release of radioactive materials, subsequent to postulated accidents, so that the resulting offsite doses are less than the dose limits of 10CFR50.67. Primary containment parameters affecting fission product release accident analyses are given in Section 6.2.1. Fission product removal systems are discussed in Section 6.5.1. Operation of the primary containment purge system during normal conditions is described in Section 9.4.5.1. This system isolates as described in Section 6.2.4. As discussed in Section 6.2.5, a low volume containment purge capability is provided as a backup to the containment hydrogen recombiner system. If placed into operation, the ESF filtration systems (RERS and SGTS) would process the low volume purge exhaust flow prior to its release.

6.5.3.2 Secondary Containment

The secondary containment completely encloses both primary containments and is provided to contain leakage from the primary containments so that any such leakage can be processed by filtration systems prior to release to the environment. The secondary containment boundary is formed by the exterior walls of the reactor enclosures and the refueling area, with the exception of the fan rooms on el 313' and el 331'. These fan rooms are not within the secondary containment, and the interior walls which separate them from the remainder of the reactor enclosure form a portion of the secondary containment boundary. The design of the secondary containment is discussed in Section 3.8.4, and plan and elevation views of the reactor enclosure are shown in drawings M-116, M-117, M-118, M-119, M-120, M-121, M-122, M-123, M-131, M-132, M-133, M-134, M-135, M-136, M-137, and M-138.

Two systems are provided for removal of fission products from reactor enclosure air following a DBA. These systems are the RERS and the SGTS, both of which are described in Section 6.5.1. Drawdown of the reactor enclosures by the SGTS following a postulated accident to establish a negative relative pressure with respect to the outside is discussed in Section 6.2.3.

The SGTS also provides for the drawdown of the refueling area to a negative relative pressure with respect to the outside following a fuel handling accident. As described in the LGS Technical Specifications, SGTS is only required to be aligned to the refueling area during handling of recently irradiated fuel and during operations with the potential for draining the reactor vessel.

Section 9.4.2.1.3 gives details of secondary containment isolation modes (REIS, RAIS) versus the various secondary containment isolation signal inputs.

6.5.4 ICE CONDENSER AS A FISSION PRODUCT CLEANUP SYSTEM

LGS does not have an ice condenser system.

6.5.5 REFERENCES

6.5-1 Sprayco Co., Catalog "1713A Nozzle for Nuclear Containment Vessels," Spray Engineering Co., Burlington, MA, includes: Article from Nuclear Technology Vol. 1, "Droplet Size Distribution and Spray Effectiveness," W.F. Pasedag and J.I. Gallagher, (April 10, 1971).

6.5-2 ERDA 76-21, "Nuclear Air Cleaning Handbook", pp. 64-65.

6.5-3 "American Air Filter Topical Report", AAF-TR-7102, (September 1, 1972).

Table 6.5-1

ENGINEERED SAFETY FEATURE FILTER SYSTEMS DESIGN PARAMETERS

ITEM	SGTS(1)	RERS(1)
Type	Built-up unit	Built-up unit
Number of units	2	2
Flow rate, each (cfm)	SGTS: 500 to 8400; Drywell purge: 11,000 max	60,000
COMPONENTS		
Fan	SGTS/Drywell purge	
Type	Centrifugal	Vaneaxial
Drive	Direct	Direct
No. of fans per unit	1/1	1
No. of running fans	1/1	1
Total pressure (in wg.)	20/28	15.3
Motor power each (hp)	40/100	200
Air Heater		
No. of coils per unit	1	-
Heating capacity (kW)	55	-
Prefilters	Refueling Area	
Quantity, per unit	4	40
Size, each (in)	24x24x12	24x24x12
Pressure drop (in wg.)		
Clean	0.17 @ 2400 cfm	0.55
Dirty	0.25 @ 2400 cfm	1
Efficiency (2)(%)	80	80
HEPA filter, upstream(3)	SGTS/Drywell Purge	
Size, each (in)	24x24x12	24x24x12
Pressure drop (in wg.)		
Clean	0.77/1.0	1.0
Dirty	1.53/2.0	3.0
Efficiency (4) %	99.97	99.97
Charcoal filter	SGTS/Drywell Purge	
Type	Vertical bed	Vertical bed
Depth (in)	8	2

Table 6.5-1 (Cont'd)

ITEM	SGTS(1)	RERS(1)
Filter media	Impregnated Activated charcoal	Impregnated activated charcoal
Pressure drop (in wg.)	6.0/10.5	1.2
Assigned efficiency(5), 70% relative humidity		
Removing elemental iodine (%)	99.0	95.0
Removing organic iodine (%)	99.0	95.0
Residence time (sec)	0.68 (when using SGTS fans at 3 zone maximum leakage rate of 5764 cfm)	0.25

(1) SGTS: Standby gas treatment system
RERS: Reactor enclosure recirculation system

(2) Dust spot test on atmospheric dust in accordance with ASHRAE 52-68

(3) All design parameters for the downstream HEPA filter are the same as the upstream HEPA filter, except in the drywell purge mode, the pressure drop when dirty is 4 in wg.

(4) By MIL Standards 282 DOP test method on 0.3 micron particles

(5) Efficiency designated by Regulatory Guide 1.52 for use in release analyses.

Table 6.5-2

**COMPLIANCE WITH REGULATORY GUIDE 1.52
OF LIGHT-WATER-COOLED NUCLEAR POWER PLANTS (REV 2)(1)**

REGULATORY POSITION		(SGTS)	(RERS)	CREFAS
C.1.	Environmental Design Criteria			
	Position a	Conforms	Conforms	Conforms
	Position b	Conforms The LGS system design is based on a total integrated dose over the 40 year plant life. The magnitude of the dose is dependent on location and includes the effect of a DBA. The design is more stringent than the regulatory guide guideline.	Conforms	Conforms
		Conforms with the shielding requirement: The system is shielded from other engineered safeguard features or components. There is no essential service located near the filters.	(Same as SGTS)	(Same as SGTS)
	Position c	Conforms	Conforms	Conforms
	Position d	Not applicable. There is no primary containment atmospheric cleanup system for LGS.	(Same as SGTS)	(Same as SGTS)
	Position e	Conforms	Conforms	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
C.2. System Design Criteria			
Position a	Partially conforms. Demisters are not included; there are no water droplets in the air stream. Air heaters are included to control humidity.	Partially conforms. Demisters are not included; there are no water droplets in the air stream. Air heaters are not included to control humidity.	Partially conforms. Demisters are not included; there are no water droplets in the air stream.
	Filter trains and fans are redundant, but duct-work is not: These systems are designed on a single active component failure basis.	(Same as SGTS)	(Same as SGTS)
Position b	Partially conforms. The filters are physically separated, but the fans are not: There will be no missiles from equipment failure or natural phenomenon.	(Same as SGTS)	Does not conform. There will be no missiles from equipment failure or natural phenomenon.
Position c	Conforms	Conforms	Conforms
Position d	Not applicable to systems outside the primary containment.	(Same as SGTS)	(Same as SGTS)
Position e	Conforms	Conforms	Conforms
Position f	Partially conforms. HEPA filters are arranged 3 wide by 4 high and are serviced by a stepladder. The plenum design provides easy access to the HEPA filters.	Does not conform. Due to space restrictions(1), recirculation system filter train is rated at 60,000 cfm. HEPA filters are arranged 8 wide by 5 high. Platforms are provided in the plenums to service the filters.	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
Position g	Partially conforms. Instruments are provided to indicate and alarm overall pressure drop across the entire filter train. Local pressure indicators are provided for each filter component. No recorders are provided, because the filters are able to be changed on high pressure readings.	(Same as SGTS)	(Same as SGTS)
	Flow rate is indicated in the control room.	Flow rate is indicated locally. Low flow activates alarm in control room.	Flow rate is indicated locally. Low flow activates alarm in control room.
Position h	Conforms	Conforms	Conforms
Position i	Conforms	Conforms	Conforms
Position j	Conforms	Partially conforms. Design meets intent of this paragraph. Because of space restrictions(1), filter plenum cannot be removed as a complete module or segmented sections.	Conforms
Position k	Not applicable. No outdoor air intake	Not applicable. No outdoor air intake	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
Position l	Does not conform. Allowable leak rate: (1) filter housing, 0.1% of rated flow at 125% negative pressure, which complies with the 1973 original version of Regulatory Guide 1.52; (2) fan discharge gas-tight duct-work, 0.1% scheduled air flow, multiplied by ratio of the volume of duct being tested to the total volume of the duct run; (3) fan suction duct, 1% of scheduled air flow, multiplied by ratio of the volume of duct being tested to the total volume of the duct run. The system is considered not to be in a high radiation zone.	Does not conform. Allowable leak rate: (1) filter housing, 0.05% of rated flow at 125% negative design pressure, which complies with the 1973 original version of Regulatory Guide 1.52; (2) gas-tight duct-work, 0.1% of scheduled air flow, multiplied by ratio of volume of duct being tested to the total volume of the duct run; (3) standard duct, 1% of scheduled air flow, multiplied by ratio of the volume of duct being tested to the total volume of the duct run. The system is considered not to be in a high radiation zone.	Does not conform. Allowable leak rate: (1) filter housing, 0.05% of rated flow at 125% negative pressure, which complies with the 1973 original version of Regulatory Guide 1.52; (2) duct-work, 0.1% of scheduled air flow, multiplied by ratio of the volume of duct being tested to the total volume of the duct run. The system is considered not to be in a high radiation zone.
C.3. Component Design Criteria and Qualification Testing			
Position a	Not applicable. Demisters are not included.	(Same as SGTS)	(Same as SGTS)
Position b	Partially conforms. Two automatic reset cut-outs set at 180°F and 260°F.	Not applicable. Heaters are not included.	Conforms
Position c	Conforms(3)	Conforms	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
Position d	Partially conforms. HEPA filters meet requirements in this paragraph. However, testing will not be performed in ERDA test facilities. Shop tests and field tests are considered adequate.	(Same as SGTS)	(Same as SGTS)
Position e	Conforms	Conforms	Conforms
Position f	Partially conforms. HEPA filters are arranged 3 wide by 4 high and are serviced by a stepladder.	Does not conform. Because of space restrictions(1), the system is rated at 60,000 cfm. HEPA filters are arranged 8 wide by 5 high. Platforms are provided in the plenum to service the filter.	Partially conforms. Filter arrangement meets general guideline, except that service aisles between filter banks are narrower than recommended.
Position g	Partially conforms. Housing design generally conforms with ANSI N509 (1976) section 5.6, except that view ports are not included.	(Same as SGTS)	(Same as SGTS)
Position h	Conforms	Conforms	Conforms
Position i	Partially Conforms(2) (5)	Conforms(2)	Conforms(2)
Position j	Conforms	Conforms	Conforms
Position k	Conforms	Conforms	Conforms
Position l	Conforms	Conforms	Conforms
Position m	Conforms	Conforms	Conforms

Table 6.5-2 (Cont'd)

REGULATORY POSITION	(SGTS)	(RERS)	CREFAS
Position n	Conforms	Conforms	Conforms
Position o	Conforms	Conforms	Conforms
Position p	Conforms	Conforms	Conforms
C.4. Maintenance			
Position a	Conforms	Conforms	Conforms
Position b	Conforms	Does not conform. Because of space restrictions(1), distance between filter banks is less than recommended.	(Same as RERS)
Position c	Partially conforms. There are 4 charcoal test canisters provided rather than 6.	Conforms	Conforms
Position d	Does not conform. SGTS trains continuously purged when the filters are not in use with dry instrument air to prevent build-up of moisture.	(Same as SGTS)	(Same as SGTS)
Position e	Conforms	Conforms	Conforms
C.5. In-Place Testing Criteria			
Position a	Conforms(4)	Conforms(4)	Conforms(4)
Position b	Conforms(4)	Conforms(4)	Conforms(4)
Position c	Partially conforms. (4) HEPA filters are tested to re-quirements of this paragraph. However, testing will be performed at least once per 24 months rather than 18 months.	(Same as SGTS)	(Same as SGTS)
Position d	Partially conforms.(4) Acti-vated carbon adsorber sections are tested to re-quirements of this paragraph. However, testing will be performed at least once per 24 months rather than 18 months.	(Same as SGTS)	(Same as SGTS)

Table 6.5-2 (Cont'd)

REGULATORY POSITION		(SGTS)	(RERS)	CREFAS
C.6.	Laboratory Testing Criteria for Activated Carbon[2]			
	Position a	Partially conforms. The Laboratory analysis of new and used carbon samples is performed in accordance with ASTM D3803-1989.	(Same as SGTS)	(Same as SGTS)
	Position b	Partially conforms. Activated carbon adsorber sections are tested to requirements of this paragraph. However, testing will be performed at least once per 24 months rather than 18 months. Additionally, the laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989.	(Same as SGTS)	(Same as SGTS)

(1) The LGS air filter systems were designed before the issuance of Regulatory Guide 1.52 in 1973. The filter design details have been studied in accordance with the regulatory guide and it was found that the filter performs satisfactorily although the design is not in strict conformance with the regulatory guide.

(2) Each original or replacement batch of impregnated activated charcoal used in the adsorber section meets the qualification and batch test results of ANSI N509 (1980). Laboratory tests of charcoal samples meeting the requirements of Position C.6 of Regulatory Guide 1.52 can be performed in accordance with ANSI N509 (1980) except that the laboratory analysis of carbpon samples is performed in accordance with ASTM D3803-1989.

(3) The prefilters in the RERS act as prefilters for the SGTS during reactor enclosure isolation. The prefilters in the SGTS duct from the refueling area act as prefilters for the SGTS during refueling area isolation.

(4) To ANSI/ASME N510 (1980) testing criteria.

(5) The air residence time in the 8 inch bed is 0.68 seconds considering a maximum total post inleakage rate from Zones I, II, and III of 5764 cfm.

Table 6.5-3

STANDBY GAS TREATMENT SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency	Power supply	Total LOOP	None. All units are powered from separate standby diesel generators.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Exhaust fans	Loss of one fan	The standby fan automatically starts.	Low flow indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Electric heaters	Loss of electric heater	Efficiency of of charcoal adsorber may decrease if the relative humidity is above 70%. The operator may manually switch to the standby train.	Temperature indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Upstream & downstream HEPA filters .	High differential pressure across the filter bank.	The fan recirculation dampers modulate in sequence to maintain airflow. However, if the system flow rate drops below the setting of the fan flow switch, the standby fan automatically starts and the filter train is manually switched to standby train	Low flow indication in the control room	No loss of safety function

Table 6.5-3 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA & LOOP)	Charcoal adsorbers	High-high-high temperature	At ignition temperature setting the fire protection system is manually actuated.	Temperature indication in the control room.	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	RERS to SGTS transfer valves	Valve fails to open	None. Valves are redundant and parallel. Normally closed valves fail open.	SGTS flow indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Fans inlet dampers	Damper fails closed	None. These dampers are redundant - standby unit will operate.	Flow indication and damper position indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Charcoal filter inlet valves and outlet valves	Valve fails closed	None. The valves are redundant - the standby unit will operate.	Flow indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Fans recirculation dampers	Dampers fail closed	None. These dampers are designed to fail closed. If the damper fails, this will increase a demand for more makeup air, and fans will attempt to deliver maximum flow.	Flow indication in the control room.	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Refueling Area to SGTS transfer valve	Valve fails open[1]	None. The refueling area is automatically isolated. The SGTS will drawdown both the reactor enclosure and refueling area.	Flow indication in the control room	No loss of safety function
Emergency (Fuel Handling Accident)	Refueling Area to SGTS transfer valve	Valve fails to open	None.Valves are redundant and parallel. Normally closed valves fail open.	SGTS flow indication in the control room	No loss of safety function

Table 6.5-3 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (Fuel Handling Accident)	RERS to SGTS transfer valve	Valve fails open[1]	None. The corresponding reactor enclosure is automatically The SGTS will drawdown the refueling area and that Unit's reactor enclosure.	Flow indication in the Control isolated.	No loss of safety function Room
Emergency (Unit LOCA or LOOP)	The other Unit RERS to SGTS transfer valve	Valve fails open[1]	None. The other Unit reactor enclosure is automatically isolated. The SGTS will drawdown both reactor enclosures.	Flow indication in the Control Room	No loss of safety function

Note: The SGTS is a common system.

(1) Any combination of valve failures which result in either a 2 or 3 zone isolation will not affect SGTS operation. The SGTS has a design flow of 8400 cfm which is adequate to restore and maintain the required pressure in both reactor enclosures and common refueling area.

Table 6.5-4

MATERIALS USED IN THE STANDBY GAS TREATMENT FILTER SYSTEM

COMPONENT	MATERIAL
Housing	
Structural steel	
Channel	CS ASTM A36
Plate	CS ASTM A36 SS ASTM A240 304 CS ASTM A36
Angle	CS ASTM A106 Grade B
Piping	CS ASTM A53 Grade B CS ASTM A105 Grade 1 or 2 CI ASTM A126 SS ASTM A312 TP304 CS ASTM A197
Internal structure	
Filter supports	
Plate	SS ASTM A240 304 CS ASTM A36
Angle	SS ASTM A276 304 CS ASTM A36
Fasteners	CS ASTM A307 CS ASTM A325 CS ASTM A449
Gaskets	ASTM D1056
Filter elements	
HEPA	
Frame	Cadmium Plated or Stainless Steel per ASME AG-1
Filter media	Glass Fiber per MIL-F-51079A or ASME AG-1
Electric heating coil	Nickel-chrome alloy wire with metal sheathing

Table 6.5-4 (Cont'd)

COMPONENT	MATERIAL
Carbon adsorber filter media	Activated impregnated coconut base charcoal per ANSI N509 (1980), table 5-1 and Regulatory Guide 1.52 except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989
Prefilter	(1)
Paint	
Interior Carboline CarboZinc 11 primer	with Carboline 3912 finish coat
Exterior	PPG 6-205 primer with PPG Lavax Machinery Enamel No. 23-61

(1) Prefilters for the refueling area to SGTS alignment are installed in the refueling area duct-work. The filter elements consist of galvanized carbon steel frames and fiberglass media. Each filter has a UL Class I flame retardant rating. Prefiltering for the reactor enclosure to SGTS alignment is provided by the RERS filter train.

Table 6.5-5

MATERIALS USED IN THE CONTROL ROOM
EMERGENCY FRESH AIR FILTER SYSTEM

COMPONENT	MATERIAL
Housing	
Structural steel	
Plate	CS ASTM A36
Angle	CS ASTM A36
Bar-stock	CS ASTM A36
Piping	CS ASTM A120 SS ASTM A312 TP304 CS ASTM A105 SS ASTM A182 F304
Internal structure	
Filter supports	
Plate	SS ASTM A240 304
Sheet	SS ASTM A240 304
Angle	SS ASTM A240 304
Bar-stock	SS ASTM A276 304
Studs	CS ASTM A108 SS AISI 166 304
Filter elements	
Prefilter	
Frame	Fire retardant particle board
Filter media	Glass fiber
HEPA	
Frame	Chromized or Stainless Steel per ASME AG-1
Filter media	Glass Fiber per MIL-F-51079A or ASME AG-1
Carbon adsorber filter media	Activated impregnated coconut base charcoal per table 5-1 of ANSI N509 (1980), and Regulatory Guide 1.52 except that laboratory analysis of carbon samples is performed in accordance with ASTM D3803-1989.

Table 6.5-5 (Cont'd)

COMPONENT	MATERIAL
Paint	
Interior	Carboline Carbo Zinc 11
Exterior	Mobil Val-Chem Zinc Chromate Primer, red base 13-R-56B with finish coat Mobil Val-Chem Hi-Build Epoxy 89 Series.

Table 6.5-6

REACTOR ENCLOSURE RECIRCULATION SYSTEM FAILURE MODES AND EFFECTS ANALYSIS
(Typical for Zone I or Zone II)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency	Power supply	Total LOOP	None; each of the redundant fans and associated dampers is powered from separate standby diesel generators.	Alarm in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Recirculation fans	Loss of one fan	The standby fan automatically starts.	Pressure differential indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Valves on duct from recirculation system to SGTS	One valve failed closed	None; the other valve installed in parallel remains open.	SGTS flow indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Valves on duct from reactor enclosure equipment compartment exhaust system to supply plenum of recirculation system	One valve failed closed	None; the other valve installed in parallel remains open.	Valve position indication on local panel C101	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Valves on duct from reactor enclosure exhaust system to supply plenum of recirculation	One valve failed at last position	None; the other valve installed in parallel remains open.	Valve position indication on local panel C101	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Valves on duct from discharge plenum of recirculation system to reactor enclosure supply system	One valve failed closed	None; the other valve installed remains open.	Valve position indication on local panel C101	No loss of safety function

Table 6.5-6 (Cont'd)

PLANT OPERATING MODE	SYSTEM COMPONENT	COMPONENT FAILURE MODE	EFFECT OF FAILURE ON THE SYSTEM	FAILURE MODE DETECTION	EFFECT OF FAILURE ON PLANT OPERATION
Emergency (LOCA or LOCA & LOOP)	Upstream & downstream HEPA filters	High differential pressure across the filter bank	None; the filter discharge flow control dampers will modulate to maintain constant airflow. However, if the pressure differential rises above a selected maximum value the operator may manually switch to the standby filter train.	Filter bank pressure differential indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Charcoal absorbers	High-high-high temperature	At ignition temperature setting the fire protection system is manually actuated.	Temperature indication in the control room	No loss of safety function
Emergency (LOCA or LOCA & LOOP)	Filter train inlet & outlet dampers	Damper fail close	Low flow on the flow switch will cause automatic switch-over to the standby train.	Filter differential pressure indication in the control room. Damper position indication in the control room	No loss of safety function

Table 6.5-7

MATERIALS USED IN THE REACTOR ENCLOSURE
RECIRCULATION FILTER SYSTEM

COMPONENT	MATERIAL
Housing	
Structural Steel	
Plate	CS ASTM A36
Angle	CS ASTM A36
I-Beams	CS ASTM A36
Bar-stock	CS ASTM A36
Piping	CS ASTM A105 SS ASTM A312 TP304 SS ASTM A182 F304
Internal Structure	
Filter Supports	
Plate	SS ASTM A240 304
Sheet	SS ASTM A240 304
Angle	SS ASTM A276 304
Studs	CS ASTM A193 B7 CS ASTM 193 B8
Filter elements	
Prefilter	
Frame	Fire retardant particle board
Filter media	Glass fiber
HEPA	
Frame	Chromized or Stainless Steel per ASME AG-1
Filter media	Glass Fiber per MIL-F-51079A or ASME AG-1
Carbon adsorber filter media	Activated impregnated coconut base charcoal per table 5-1 of ANSI N509 (1980), and Regulatory Guide 1.52

Table 6.5-7 (Cont'd)

COMPONENT	MATERIAL
Paint	
Interior	Carboline Carbo Zinc 11
Exterior	Mobil Val-Chem Zinc Chromate Primer, red base 13-R-56B with finish coat Mobil Val-Chem Hi-Build Epoxy 89 Series.

Table 6.5-8

INSTRUMENTATION FOR ESF ATMOSPHERE CLEANUP SYSTEMS

GUIDELINES PER SRP Table 6.5.1-1			INSTRUMENTATION PROVIDED IN LGS DESIGN[1]		
SENSING LOCATION	LOCAL READOUT/ALARM	CONTROL ROOM PANEL	SGTS	RERS	CREFAS
Unit inlet or outlet	Flow rate (indication)	-	Not provided[2]	Flow rate indication at outlet	Flow Rate indication at outlet
Unit inlet or outlet	-	Flow rate (recorded indication, high and low alarms	Flow indication at outlet Low flow alarm [2][3][4]	Low flow alarm[3][5]	Low flow alarm [3][6]
Electrical heater	Status indication	-	Status indication in the control room	N/A	Not provided (Trouble alarm in the control room)[7]
Space between heater and prefilter	Temperature (indication high and low alarm signals)	-	Indication only[8]	N/A	Indication only[8]
Space between heater and prefilter	-	Temperature (indication high and low alarms, trip alarm signals)	Provided	N/A	Not provided[9]
Prefilter	Pressure drop (indication, high alarm signal)	-	Indication only [8][10]	Indication only[8][10]	Indication only[8][10]
First HEPA	Pressure drop (indication, high alarm signal)	-	Indication only[8][10]	Same as SGTS[8][10]	Same as SGTS[8][10]
First HEPA	-	Pressure drop (recorded indication)	Not provided[10]	Not provided [10]	Not provided[10]
Space between adsorber and second HEPA	Temperature (two-stage high alarm signal)	-	Not provided[8]	Not provided [8]	Not provided[8]
Space between adsorber and second HEPA	-	Temperature (two-stage high alarm signal)	Three-stage high alarm and indication	Same as SGTS	Same as SGTS

Table 6.5-8 (Cont'd)

GUIDELINES PER SRP Table 6.5.1-1			INSTRUMENTATION PROVIDED IN LGS DESIGN[1]		
SENSING LOCATION	LOCAL READOUT/ALARM	CONTROL ROOM PANEL	SGTS	RERS	CREFAS
Second HEPA	Pressure drop (indication, high alarm signal)	-	Indication only [8][10]	Same as SGTS[8][10]	Same as SGTS[8][10]
Fan	(Optional hand switch and status indication)	-	Not provided	Not provided	Not provided
Fan	-	Hand switch, status indication	Provided	Provided	Provided
Valve/damper operator	(Optional status indication)	-	Not provided	Not provided	Not provided
Valve/damper	-	Status indication	Provided	Provided	Provided
Deluge valves	-	-	Manual valves Indication only	Same as SGTS	Same as SGTS
Deluge valves	-	-	Alarm[11]	Same as SGTS[11]	Same as SGTS[11]
System inlet to outlet	-	Summation of pressure drop across total system, high alarm signal.	Provided	Provided	Provided

(1) Regulatory Guide 1.52, ANSI-N509, and SRP Table 6.5.1-1 were originally issued after the LGS system design and therefore were not specifically considered in the design.

(2) The SGTS flow rate is variable to draw down and maintain the reactor enclosure/refueling area at a negative 0.25 in wg. Local flow indication does not provide meaningful information in terms of system operability. Flow indication is provided in the control room where this information, in addition to the reactor enclosure/refueling area pressure differential indicators, is available for operator evaluation of system performance.

(3) Low flow switch operates on loss of flow only.

Table 6.5-8 (Cont'd)

(4) Maximum SGTS flow occurs only during drawdown. As thermodynamic equilibrium is approached within the reactor enclosure and/or refueling area during isolation, the SGTS flow decreases to the design inleakage rate.

(5) The RERS does not operate during normal plant operation. The RERS flow is recirculated within the reactor enclosure during isolation and is not directly released to the environment.

(6) Outdoor air requirements are governed by the control room leak-tightness needed to maintain a positive pressure. High flow through the filtration system due to the failure of FD-C-78-011A in an open position will result in additional recirculation flow rather than additional unfiltered outdoor air. Control room pressure differential is indicated in the control room.

(7) Electric heater does not operate continuously during EFA system operation. Local temperature and humidity indicator controllers are provided to assess system operation.

(8) Local panels are not continuously manned to observe alarm signals.

(9) The Emergency Fresh Air system air is made up of approximately 90% recirculation air from the control room and 10% outdoor air to maintain the control room at a positive pressure. If the heater fails to operate, the temperature of the resultant air mixture will be similar to the control room even during winter conditions. Therefore, a low temperature alarm is not essential. The Emergency Fresh Air heaters are provided with automatic and manual high temperature cutouts to prevent overheating of the heater elements. Radiation monitors are provided downstream of the Emergency Fresh Air system filters and will alarm on high radiation in the event of unacceptable air quality.

(10) ESF systems do not operate continuously, and routine system testing will ensure that filter changeout requirements will be met.

(11) General trouble alarm for local panel OOC926 when any deluge valve is opened.

6.6 PRESERVICE/INSERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS

The construction permits for the LGS Units 1 and 2 were issued in June 1974. Based on this date, 10CFR50.55a required that the PSI program for the Class 2 and 3 components meet the examination requirements set forth in ASME Section XI, 1971 edition with addenda through Winter 1972 or alternatively, the examination requirements of the subsequent editions and addenda, subject to the limitations and modifications listed in 10CFR50.55a. The LGS PSI programs followed the alternative requirements.

Specifically, the Unit 1 Class 2 and 3 component PSI program (except operability testing of safety-related pumps and valves) meets the requirements of ASME Section XI, 1974 edition with addenda through Summer 1975, as modified by Appendix III of the Winter 1975 Addenda and paragraph IWA-2232 of the Summer 1976 Addenda.

At the time the LGS PSI program commenced, the latest edition of the code permissible for use was the Summer 1975 Addenda. In an effort to take advantage of improved UT methods, Appendix III of the Winter 1975 Addenda and paragraph IWA-2232 of the Summer 1976 were used. Although these items are not specifically referenced by 10CFR50.55a, they are equivalent to the comparable portions of the subsequently approved ASME Section XI of Summer 1978 Addenda as long as Section XI Appendix III indications greater than 50% DAC are recorded. The LGS ISI procedures do record such indications.

Supplement 7 of Appendix III permits the use of Appendix III for austenitic piping welds with certain modifications. It is our position, consistent with the PSI/ISI industry, that Appendix III (at 50% DAC recording) is more appropriate for austenitic piping weld examination than Article 5 of ASME Section V. Thus for austenitic piping welds:

a. All of the Supplement 7 modifications are being used.

b. Examination sensitivity is ensured through the calibration process.

c. Where one-sided access only occurs and penetrations cannot be confirmed, a one-sided access limitation is noted in the data package for that weld.

When using Section XI, Appendix III for either ferritic or austenitic piping welds, the following applies:

a. All indications showing signal amplitudes equal to or in excess of 20% of the reference response are evaluated to the extent that the level II or level III examiner can determine their true nature.

b. The owner evaluates and takes corrective action for the disposition of any indication investigated and found to be other than geometrical or metallurgical in nature.

The Unit 2 Class 2 and 3 component PSI program and Units 1 and 2 programs for the preservice testing of safety-related pumps and valves meet the requirements of the Section XI Code, 1980 edition with addenda through Winter 1981.

For certain ASME Section XI requirements that have been determined to be impractical in the course of inspecting the components, the licensee has submitted and will submit requests for relief from the requirements to the NRC in accordance with the provisions of 10CFR50.55a.

In accordance with 10CFR50.55a, throughout the service life, Class 2 and 3 components (including supports) will meet the ISI requirements, except design and access provisions and preservice examination requirements, set forth in the ASME Section XI edition and addenda that become effective, to the extent practical within the limitations of design, geometry, and materials of construction of the components. In accordance with 10CFR50.55a, inservice examinations of components, inservice tests to verify operational readiness of safety-related pumps and valves, and system pressure tests conducted during the initial 10 year inspection interval will comply with ASME Section XI edition and addenda in effect 12 months prior to the date of issuance of the operating license. In accordance with 10CFR50.55a, the initial 10 year inspection interval commences with commercial operation. The successive 10 year inspection intervals will comply with ASME Section XI edition and addenda in effect 12 months prior to the start of the 10 year inspection interval.

6.6.1 COMPONENTS SUBJECT TO EXAMINATION

LGS piping was originally designed to ANSI B31.7. For inservice inspection, ANSI B31.7 Classes II and III are considered equivalent to ASME Section III, Classes 2 and 3. The PSI/ISI program includes figures showing the systems or portions of systems within the scope of the Section XI Code. The applicable PSI/ISI programs are described in References 6.6-1 through 6.6-7. Any necessary requests for relief are addressed in these documents.

6.6.2 ACCESSIBILITY

a. Sufficient space is provided for personnel and equipment so that examinations of Class 2 and Class 3 piping and components can be performed, as required by the Code.

   1. Piping welds - The access provided for Class 2 system components depends on whether ultrasonic, surface, or visual examinations are performed.

   2. Pumps and valves - Space is provided to disassemble and reassemble the pump or valve. For visual examination, sufficient lighting and access space is provided to permit examination of the inner surface. For ultrasonic examination, access for equipment is provided, depending on the specific design of the weld.

   3. Supports - Access provisions for supports requiring examination are provided and depend on the specific type and design detail of the support.

   4. Pressure welds - Access is provided for the inspection of pressure-retaining welds, vessel supports, and pressure-retaining bolting.

b. Capability for the removal and temporary storage of structural members, shielding components, and insulation is provided.

c. Hoists and other handling machinery necessary to support ISI are provided.

d. Equipment and personnel for alternative examinations that may be required will be provided.

e. Repair and replacement operations are provided for system components and parts, where necessary.

6.6.3 EXAMINATION TECHNIQUES AND PROCEDURES

a. The techniques and procedures for surface, visual, and volumetric examinations are in compliance with IWA-2200 of the Section XI Code.

b. Alternate examination methods are acceptable, provided that the results are equal or superior to the methods of IWA-2200. The acceptance criteria for alternate examination methods are in accordance with IWA-3100 of the Section XI Code.

6.6.4 INSPECTION INTERVALS

The examinations required by IWC-2400 for Class 2 system components and by IWD-2400 for Class 3 system components will be performed on the basis of a 10 year interval, hereafter known as the inspection interval.

6.6.5 EXAMINATION CATEGORIES AND REQUIREMENTS

The PSI/ISI program provides a listing of the Class 2 and 3 components or parts including the Section XI Code item number, examination category, the required method of examination, and the extent and frequency of examination. The applicable PSI/ISI programs are identified in References 6.6-1 through 6.6-7.

6.6.6 EVALUATION OF EXAMINATION RESULTS

The standards for evaluation of results and repair procedures are in accordance with Articles IWB-3000 and IWA-4000. Where acceptance standards are still in preparation, IWA-3100 shall apply. The ISI program for the first and successive inspection intervals will use the articles in IWC and IWD as they are issued and approved. Summary reports for the RPV and piping PSI were submitted 90 days after commercial operation, in accordance with subarticle IWA-6220.

6.6.7 SYSTEM PRESSURE TESTS

The system pressure tests will be performed in accordance with the general requirements of IWA-5000 and the specific requirements of IWC-5000 and IWD-5000 for Class 2 and 3 components, respectively.

6.6.8 AUGMENTED INSERVICE INSPECTION TO PROTECT AGAINST POSTULATED PIPING FAILURES

Class 2 and 3 components will receive augmented inservice inspection in accordance with the documents listed below to the extent specified in the applicable PSI/ISI programs identified in References 6.6-1 through 6.6-7.

a. NUREG-0313, Revision 1, July 1980, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping" (see resolution of USI A-42, Section 1.12.2). Revision 1 of this NUREG is applicable prior to issuance of Generic Letter 88-01.

   In accordance with Generic Letter 88-01, the criteria of NUREG-0313, Revision 2, January 1988 are applicable for LGS Units 1 and 2. The ISI Program for weldments in piping shall be performed in accordance with the NRC staff positions and criteria addressed in Generic Letter 88-01 and BWRVIP-75-A, "BWR Vessel and Internals Project Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedule." Details for schedule, methods, personnel, and sample expansion shall be included as augmented inspection requirements. Response to the Generic Letter 88-01 was provided per letter from S.J. Kowalski (PECo) to F.J. Miraglia, Jr. (NRC), dated August 2, 1988. The ISI Program for weldments in piping shall be performed in accordance with the NRC staff positions and criteria addressed in Generic Letter 88-01. Details for schedule, methods, personnel, and sample expansion shall be included as augmented inspection requirements.

b. BTP MEB 3-1 (NUREG-0800) addresses high energy piping between containment isolation valves and first outboard restraint for which no breaks are postulated

In addition, high energy fluid system piping between containment isolation valves will receive an augmented examination as follows:

a. Protective measures and structures are located, to the greatest extent possible, so as not to prevent access for inservice inspections.

b. High energy fluid system piping between containment isolation valves is required to be either 100% volumetrically examined (both circumferential and longitudinal welds) during each examination interval or examined in accordance with the Risk Informed Inservice Inspection Program as applied to these welds.

c. High energy piping requiring ISI receives a baseline (preservice) examination to establish the integrity of the original condition of the welds.

d. Augmented examination for high energy piping is maintained out to outboard restraints.

e. Welds between outboard containment isolation valves and piping restraints will be included in the PSI and the ISI plans.

6.6.9 REFERENCES

6.6-1 Document 8031-M246AQA-59, Preservice Inspection Program Plan for the LGS Unit 1 Nuclear Piping Systems

6.6-2 Program Document ML-008, Limerick Generating Station Units 1 and 2, “IST Program Plan” and “IST Basis Document”

6.6-3 ER-LG-330-1001 through 1006, Limerick ISI Program Documents

6.6-4 Deleted

6.6-5 Document 8031-P-504, LGS Unit 2 Preservice Inspection Program

6.6-6 Document 8031-P-505, LGS Unit 2 Preservice Inspection Examination Plan for Nuclear Piping Systems

6.6-7 Document 8031-P-507, LGS Unit 2 Testing Plan for Safety-Related Pumps and Valves

6.7 MSIV LEAKAGE ALTERNATE DRAIN PATHWAY

The MSIV Leakage Alternate Drain Pathway prevents a direct release of fission products that could leak through the closed MSIVs after a LOCA. The pathway provides control by providing a hold-up volume for the MSIV leakage before release to the atmosphere. This is accomplished by directing the leakage through existing Main Steam Drain Lines to the High Pressure Shell of the Main Condenser.

6.7.1 DESIGN BASES

6.7.1.1 Safety Criteria

The following criteria represent pathway design, safety, and performance requirements imposed on the MSIV Leakage Alternate Drain Pathway.

a. The MSIV Leakage Alternate Drain Pathway is evaluated to have sufficient capacity and capability to control the leakage from the MSIVs, consistent with containment leakage limits imposed for the conditions associated with a postulated design basis LOCA. Specifically, a complete severance of a recirculation line does not permit an offsite dose to exceed the requirements of 10CFR50.67.

b. The MSIV Leakage Alternate Drain Pathway has been evaluated to demonstrate that the main system piping and equipment are seismically rugged and meet the requirements of 10CFR Part 100, Appendix A.

c. The MSIV Leakage Alternate Drain Pathway is capable of performing its safety function following a LOCA with Loss of Offsite Power. The Pathway is not single failure proof, but there are alternate unanalyzed pathways which will serve to direct any MSIV leakage to allow for reducing the offsite dose.

d. The MSIV Leakage Alternate Drain Pathway is manually actuated, and designed to permit actuation within about 20 minutes, but no earlier than 10 minutes, after a postulated design basis LOCA. This time period is considered to be consistent with loading requirements of the Class 1E electrical buses and with reasonable times for operator action.

6.7.1.2 Regulatory Acceptance Criteria

The piping and the components of the MSIV Leakage Alternate Drain Pathway have been evaluated to confirm the capability of the main steam piping and condenser to serve as an alternate leakage pathway. Seismic verification walkdowns have been performed to assure that the MSIV, the steam drain lines, the condenser and interconnecting piping and equipment that are not seismically analyzed fall within the bounds of the design characteristics of the seismic experience database as discussed in reference 1.

6.7.2 SYSTEM DESCRIPTION

The MSIV Leakage Alternate Drain Pathway is credited in the Radiological Dose Calculations for Limerick Generating Station. The pathway serves as a "hold-up" volume for processing of a potential release of fission products that could leak through the closed MSIV's during a Loss of Coolant Accident (LOCA). This pathway limits the calculated doses from the MSIV Leakage to within the requirements of 10CFR50.67 for offsite releases and GDC 19 for local area access. The

system has been evaluated to adequately handle the Technical Specification allowed MSIV leakage.

The design boundaries of the MSIV Leakage Alternate Drain Pathway are defined as follows. The designated boundary (block) valves (HV-1(2)08, HV-1(2)09, HV-1(2)11, HV-1(2)50, Main Turbine Stop Valves (MSTV), and Main Turbine Bypass Valves (MTBV)) will function to contain the MSIV leakage in the drain pathway. The boundary valves also identify the functional and design boundary of the "MSIV Leakage Alternate Drain Pathway." All other lines which interface with the designated drain pathway are shown in the applicable drawings and UFSAR Figures (drawings M-01, M-41, M-49, M-55, and Figure 10.4-4) will either be described below as a drain pathway, or lead back through Seismic Category I/IIA piping back into containment (primary or secondary) and as such do not represent potential leakage pathways.

There are three potential leakage pathways. These pathways are as follows:

1) Flow from all four Main Steam lines directly after the outboard MSIVs, through 2 inch EBB-1(2)05, into 3 inch EBB-1(2)05, into 3 inch EBD-1(2)08, into 4 inch EBD-1(2)08, discharging into the H.P. Condenser.

2) Flow from the above seat drain on the Main Stop Valves through 1 inch EBD-*, into 2 inch EBD-1(2)15, into 4 inch EBD-1(2)08, discharging into the H.P. Condenser.

3) Flow from all four Main Steam lines directly before the Main Stop Valves through 1 inch EBB-1(2)01(2,3,4), into 2 inch EBD-1(2)14, into 2 inch EBD-1(2)15, into 4 inch EBD-1(2)08, discharge into the H.P. Condenser.

Although all three drain pathways are capable of directing leakage to the H.P. Condenser the only credited drain line is item 1). This is based on the fact that the other drain lines are either not sized properly to ensure adequate flow or require the opening of non-class 1E valves. The primary drain pathway has one normally closed valve in the line (HV-041-1(2)F021). This valve is required to be opened to establish the drain pathway.

The remainder of the system shown in attachment 1 of reference 2, identifies the total scope of the potential pathways which was evaluated during a seismic walkdown, and was in a Design Analysis contained in reference 1 for "Seismic Ruggedness" specified in reference 2.

6.7.3 SYSTEM EVALUATION

An evaluation of the capability of the MSIV Leakage Alternate Drain Pathway to control the release of radioactivity from the MSIVs during and following a LOCA has been conducted. A summary of the evaluation is contained in reference 2. In addition, the results of the radiological evaluations are contained in section 15.6.5.

6.7.4 INSTRUMENTATION REQUIREMENTS

There are no specific instrumentation requirements for this pathway since there are no automatic actions required. The operational requirements of the pathway only require the capability to reposition one valve identified in section 6.7.2 .

6.7.5 Inspection And Testing

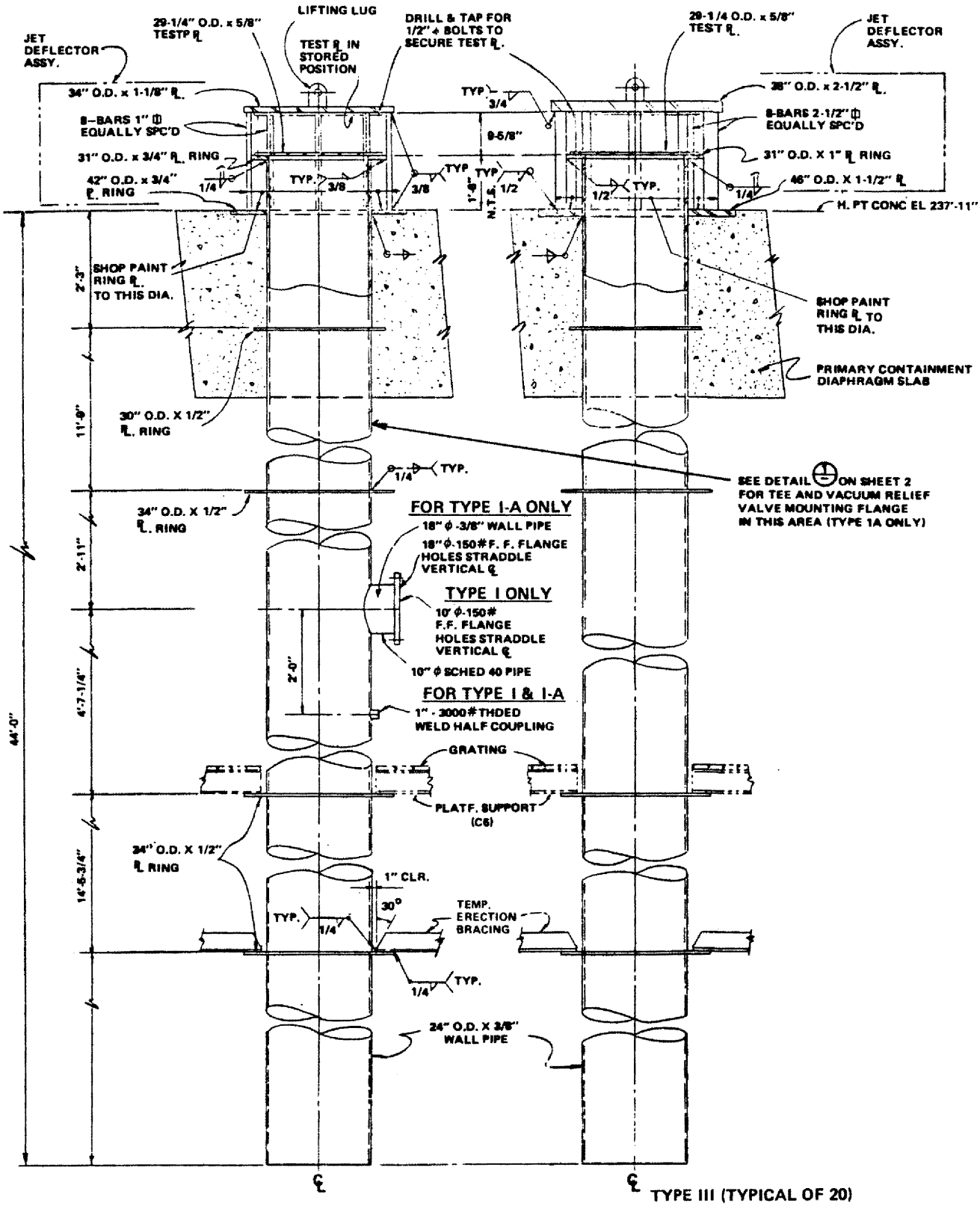
The valves required to be repositioned are tested in accordance with the requirements of the Inservice Testing Program.

6.7.6 REFERENCES

1. NEDC-31585P, Revision 2, BWROG Report for Increasing MSIV Leakage Rate Limits and Elimination of Leakage Control System, dated September 1993.

2. 10CFR50.90 Technical Specification Change Request 93-18-0, for removal of MSIV-LCS, dated January 14, 1994.

Table 6.7-1 has been deleted



TYPE I (TYPICAL OF 6)
TYPE IA (TYPICAL OF 4)
TYPE II (TYPICAL OF 57)

TYPE III (TYPICAL OF 20)

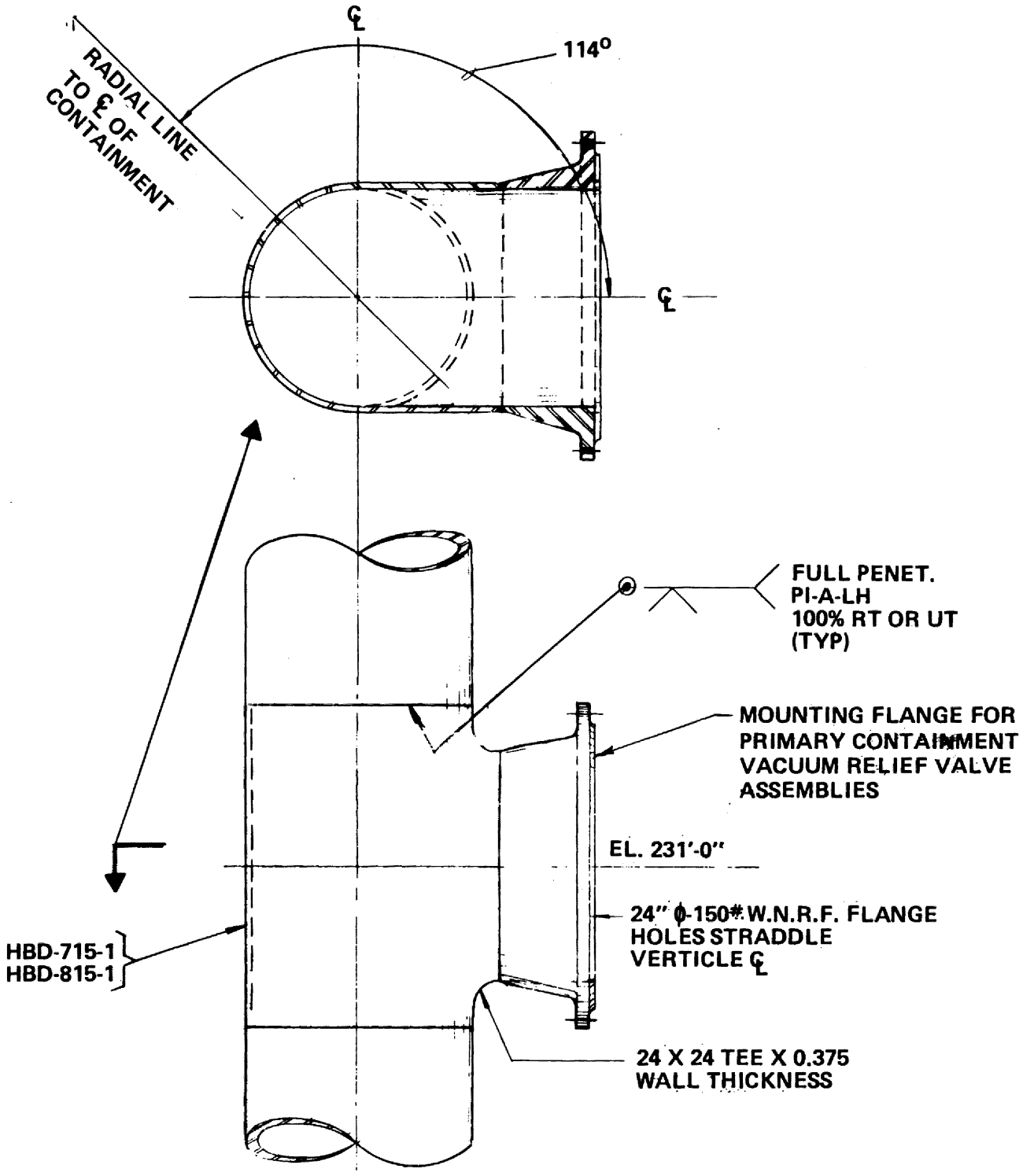
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-293.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DOWNCOMER DESIGN DETAILS
(SHEET 1 OF 2)

FIGURE 6.2-1



ELEVATION

FOR TYPE IA ONLY DETAIL (1/—)

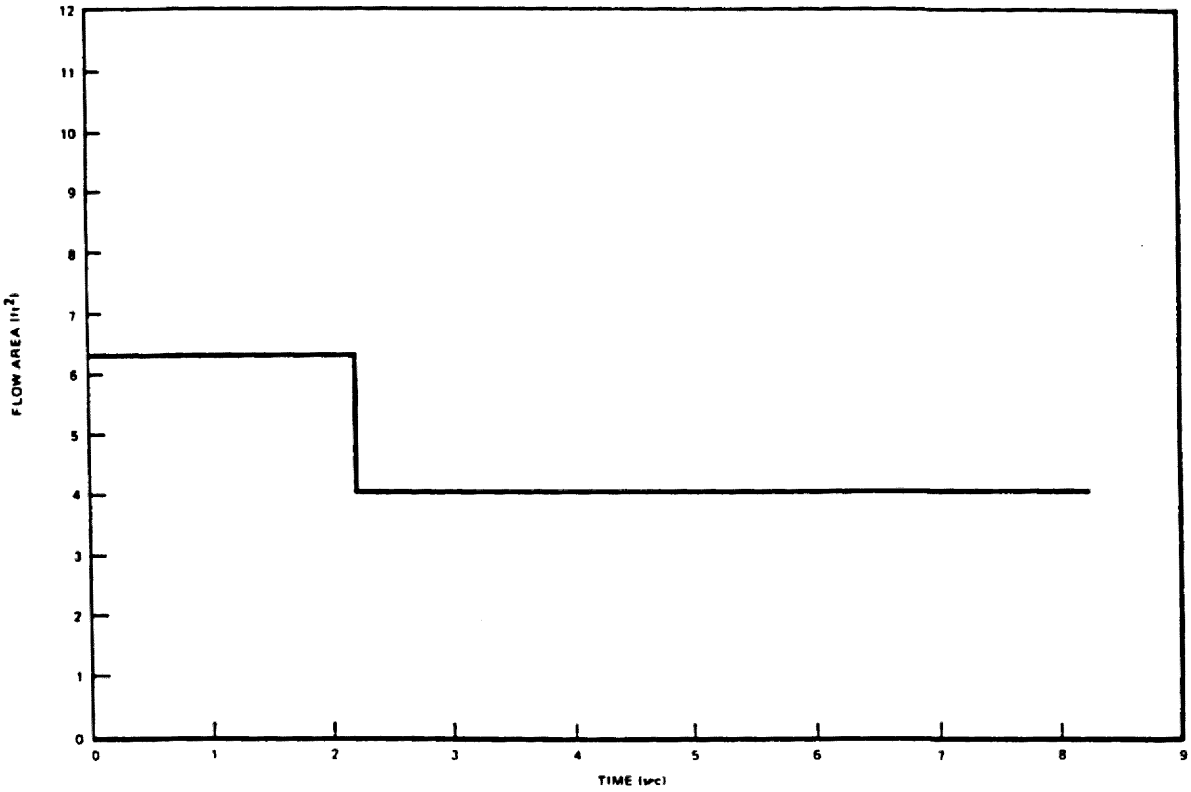
NOTE:

This UFSAR figure is provided to delineate the primary (typical) structural concepts, arrangements, and elements relied upon to perform the safety related functions of the subject structures. For detail design features, dimensions, and as-built condition of the structures, see design drawing number(s): 8031-C-293.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

DOWNCOMER DESIGN DETAILS
(SHEET 2 OF 2)

FIGURE 6.2-1



NOTE: The information presented in this figure is historical and is based on the original design basis conditions and does not represent current plant conditions or methodology used to analyze the containment response following a LOCA. Refer to Section 6.2.1.8 for the current analysis results and methodology.

LIMERICK GENERATING STATION
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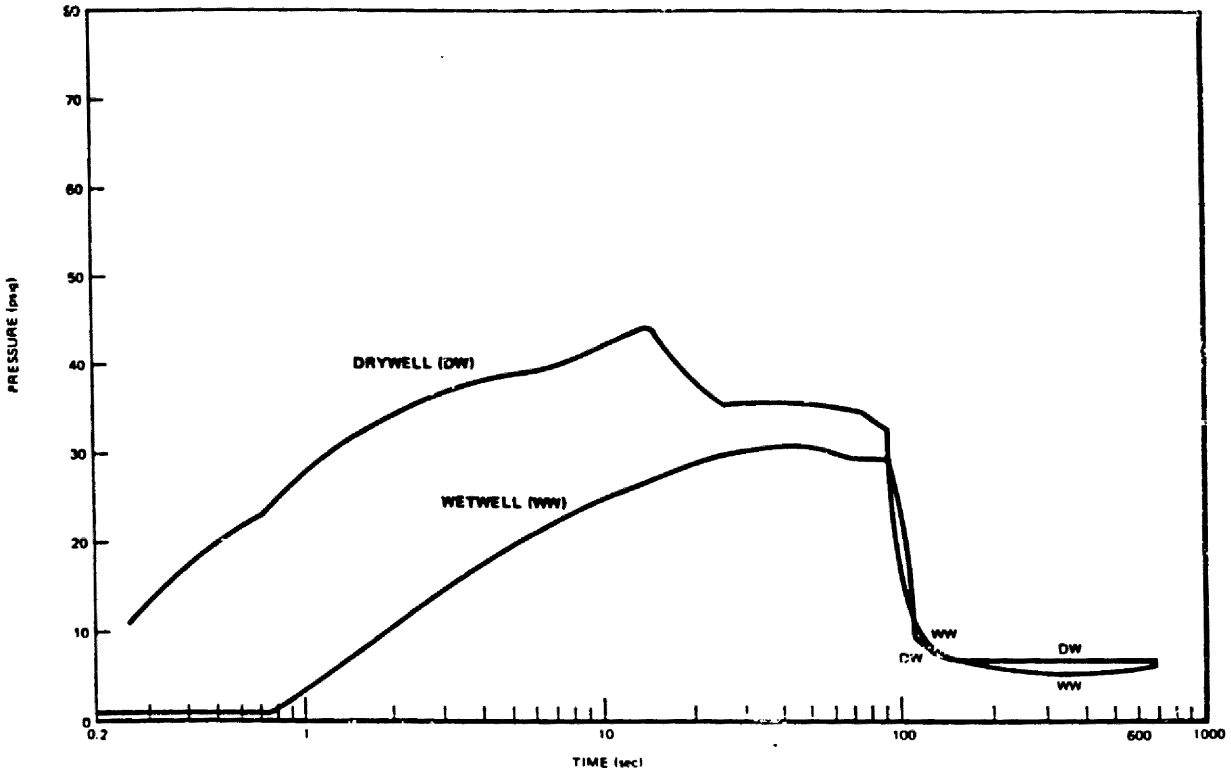
UPDATED FINAL SAFETY ANALYSIS REPORT

EFFECTIVE BLOWDOWN AREA FOR RECIRCULATION LINE BREAK

FIGURE 6.2-2

Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-3A for the recirculation line break results for current plant conditions.

LIMERICK GENERATING STATION
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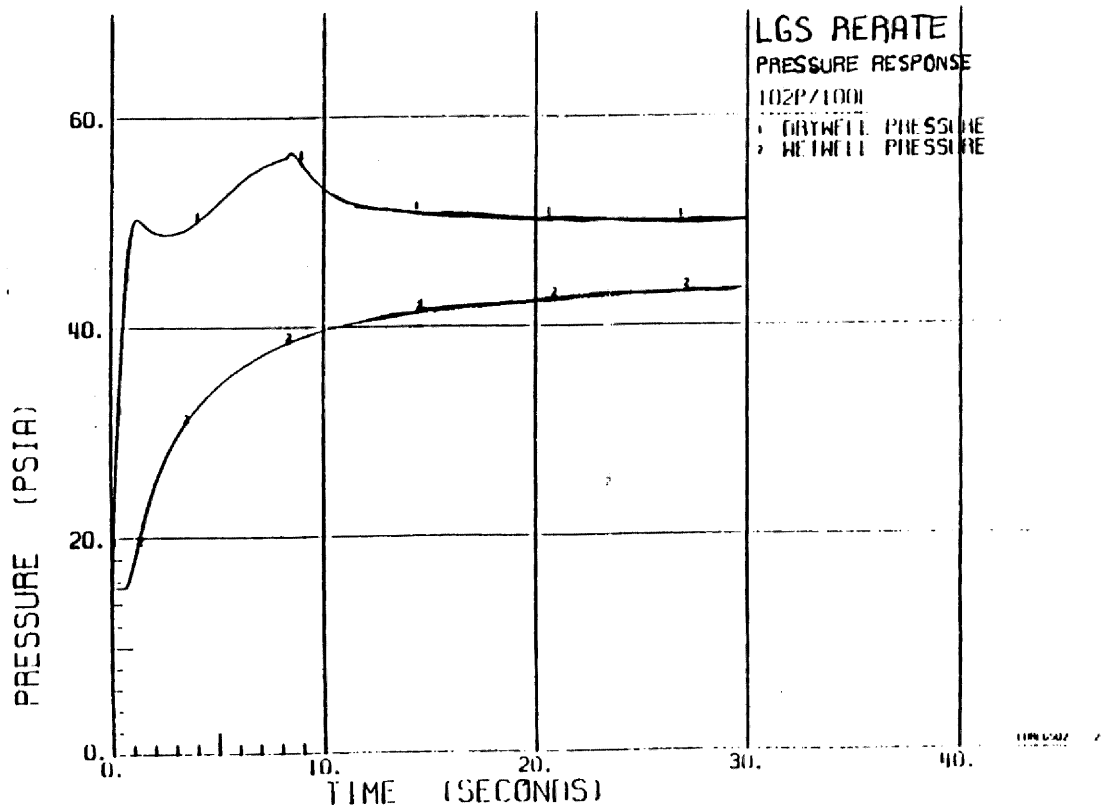
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK

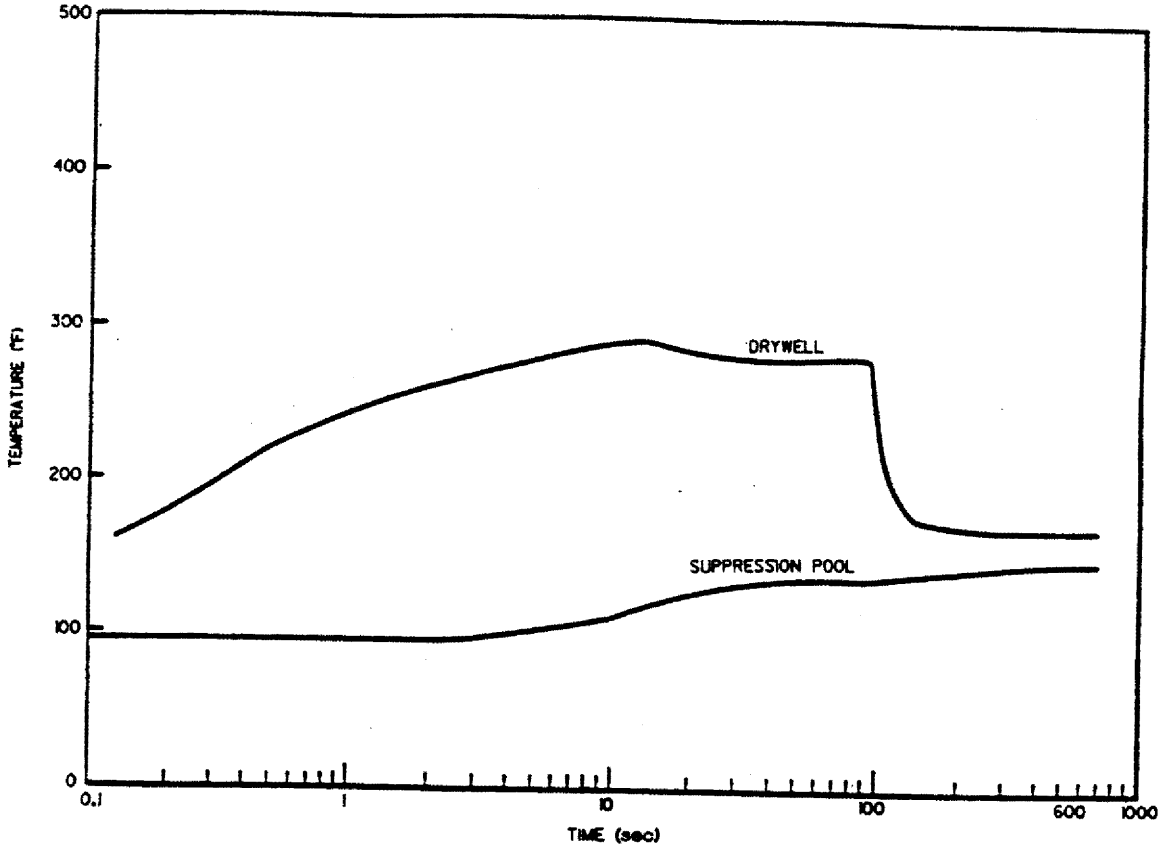
FIGURE 6.2-3 Rev. 5, 4/96



LIMERICK GENERATION STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PRESSURE RESPONSE AS A FUNCTION OF TIME

FIGURE 6.2-3A REV. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions and to analyze the containment response following a LOCA. Refer to Figure 6.2-4A for the recirculation line break results for current plant conditions.

LIMERICK GENERATING STATION
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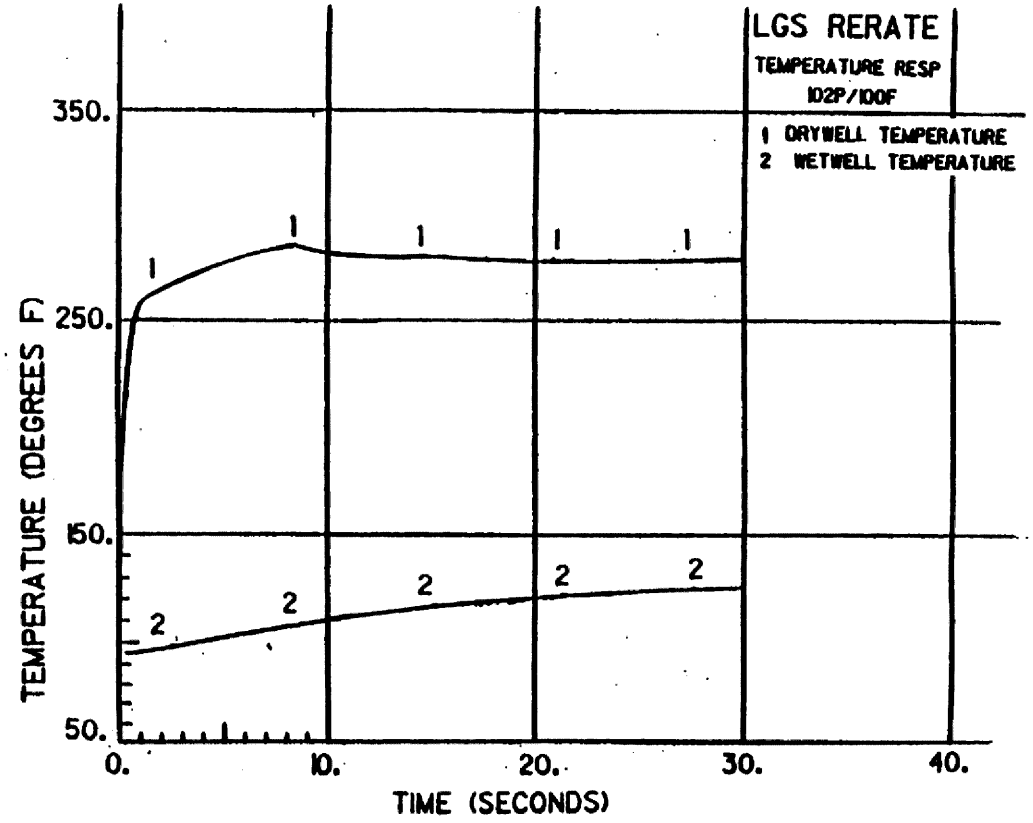
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK

FIG 6.2-4 Rev 08 11/98

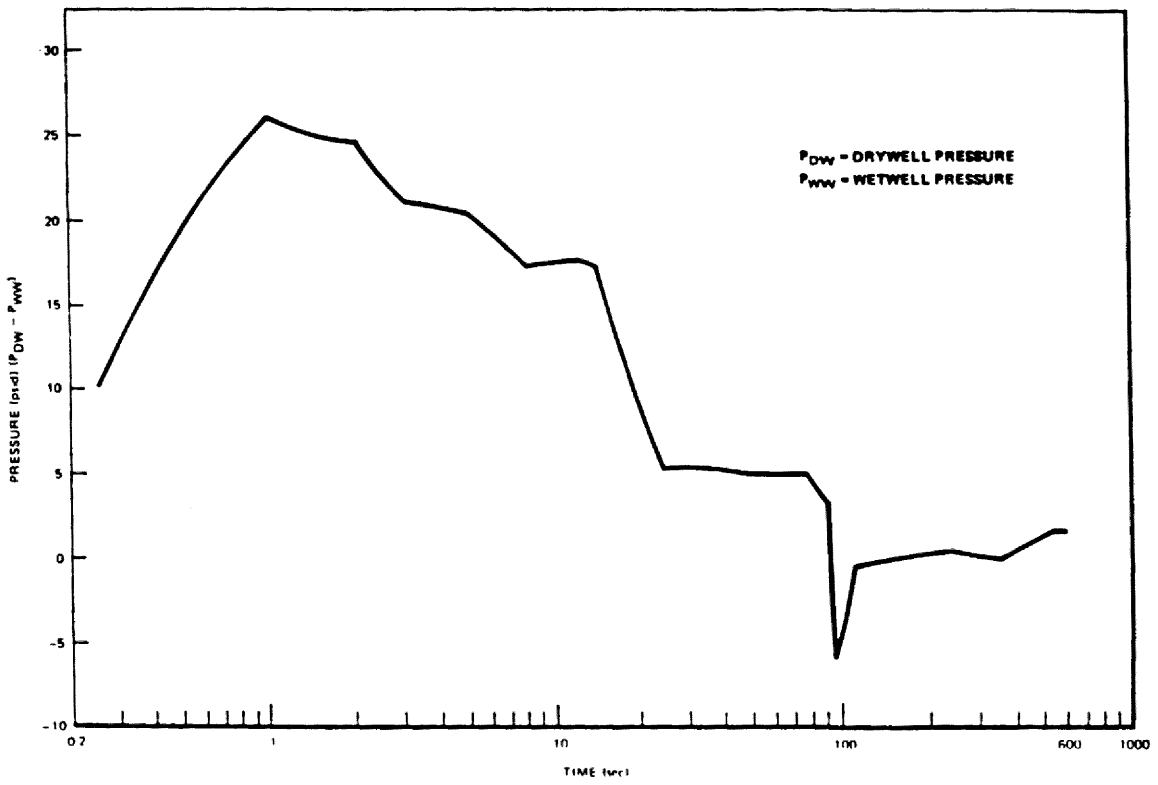


LIMERICK GENERATION STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

TEMPERATURE RESPONSE AS A
FUNCTION OF TIME
(at Rerate Power Conditions)

FIGURE 6.2-4A

Rev 08 11/98



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonably represent the general characteristics of the current recirculation line break analysis results.

LIMERICK GENERATING STATION
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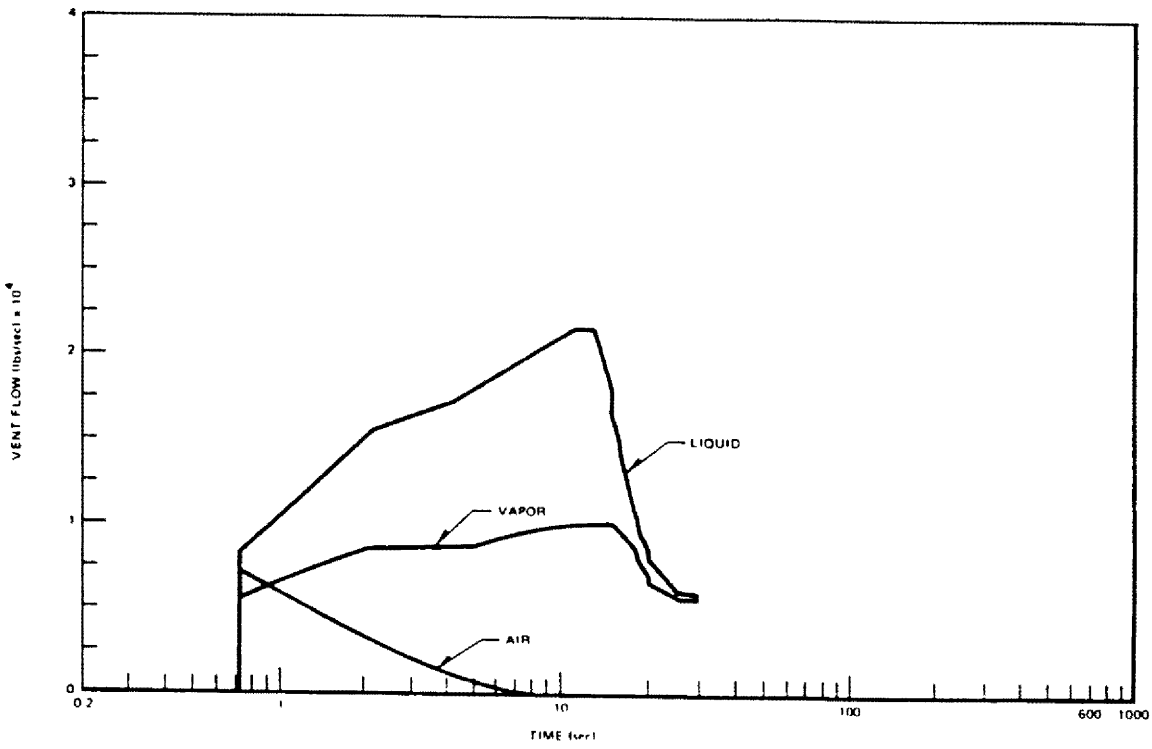
SHORT-TERM DIFFERENTIAL PRESSURE ACROSS DIAPHRAM SLAB FOLLOWING RECIRCULATION LINE BREAK

Rev. 5, 4/96

FIGURE 6.2-5



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonably represent the general characteristics of the current recirculation line break analysis results.

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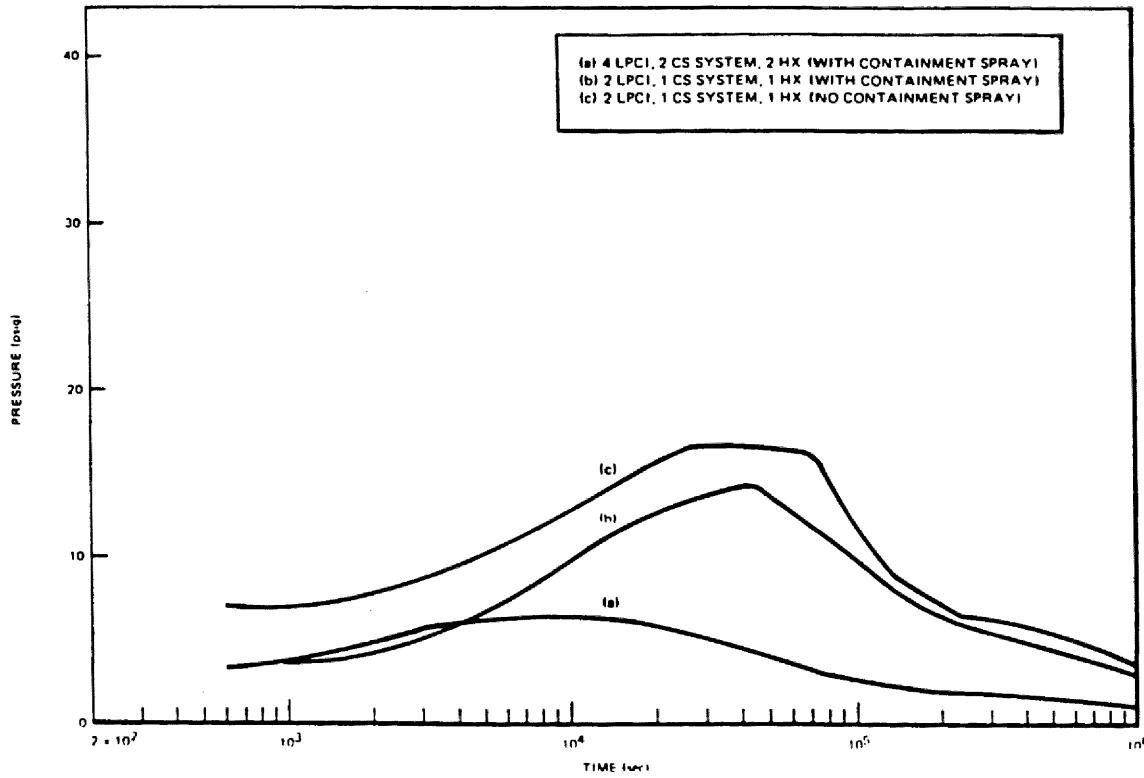
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM DOWNCOMER FLOW FOLLOWING RECIRCULATION LINE BREAK

Rev. 5, 4/96

FIGURE 6.2-6



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-7A for the Case C results for current plant conditions. The results for Cases A, B, and C shown in this figure do not reflect the current containment analysis, but reasonably represent the general characteristics and relative differences between the three cases.

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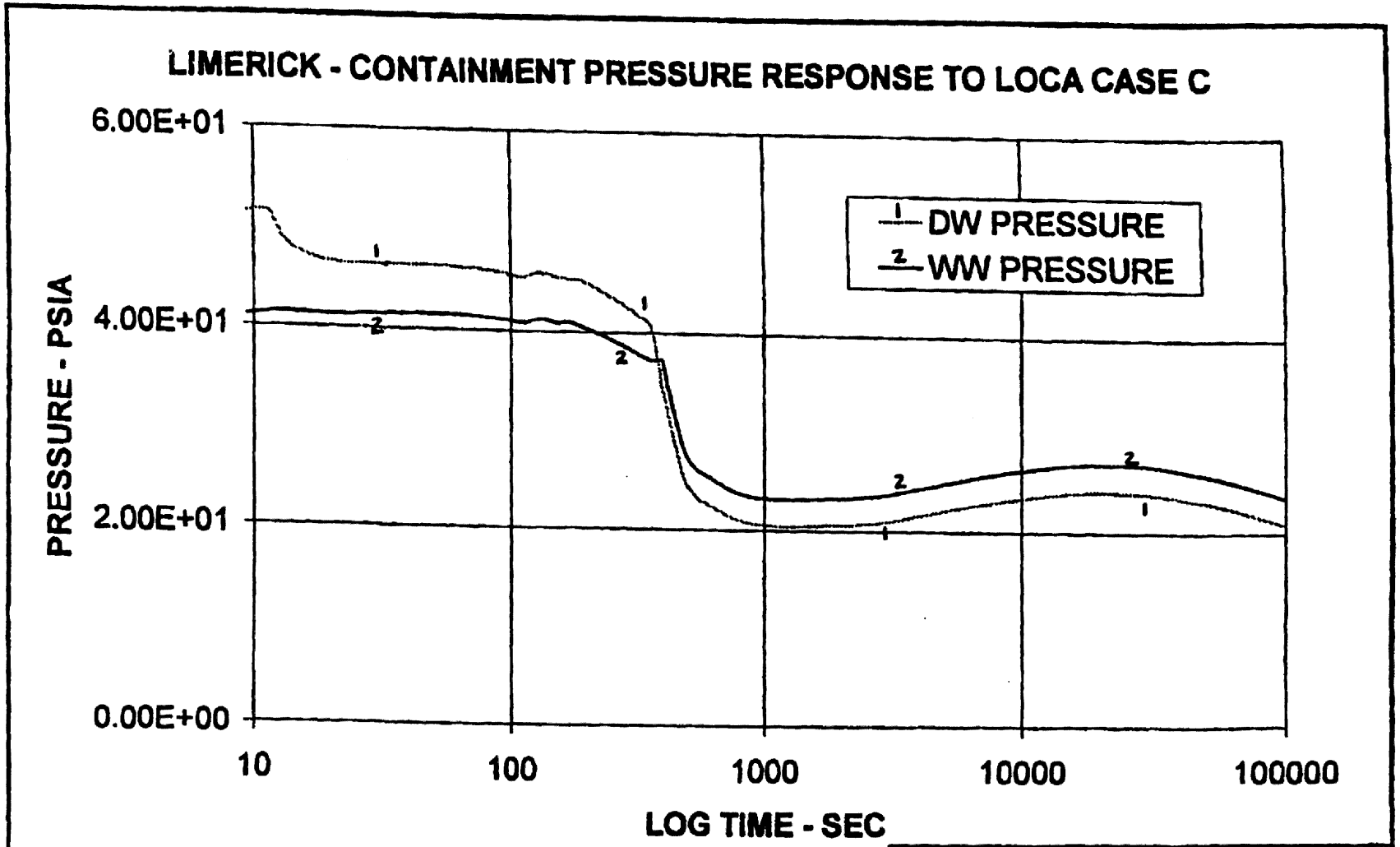
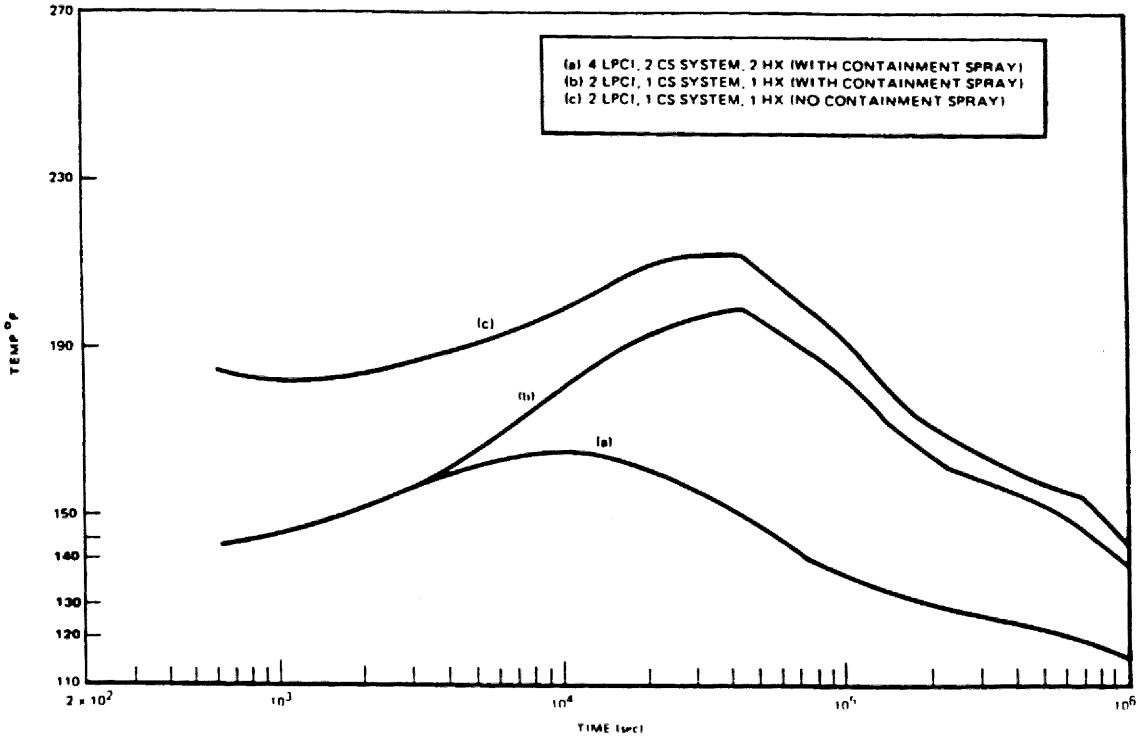
LONG-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING RECIRCULATION LINE OR MAIN STEAM LINE BREAK

FIGURE 6.2-7 Rev. 5, 4/96



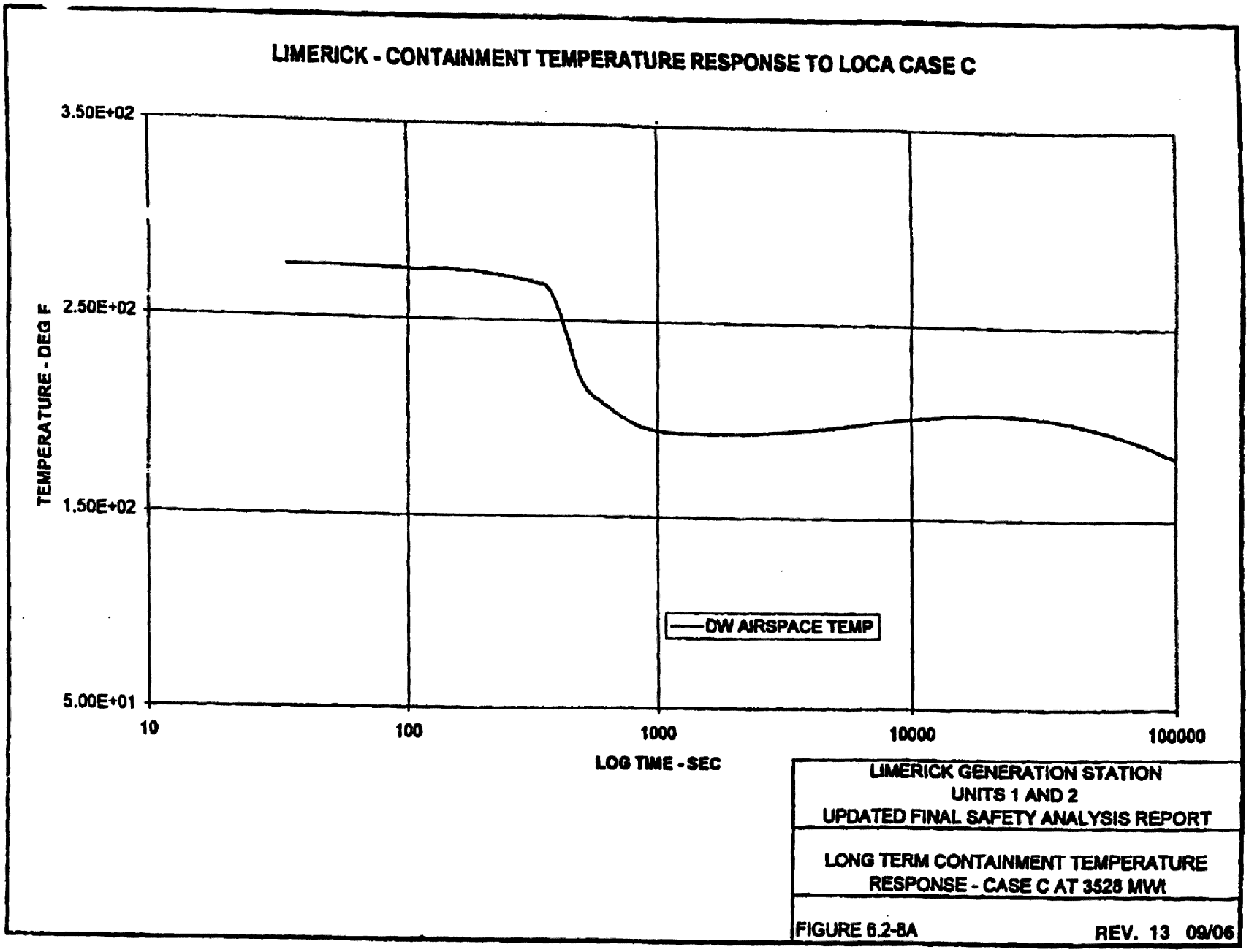
LIMERICK GENERATION STATION UNITS 1 AND 2 UPDATED FINAL SAFETY ANALYSIS REPORT
LONG TERM CONTAINMENT PRESSURE LOCA RESPONSE - CASE C AT 3528 MWt
FIGURE 6.2-7A REV. 13 09/06



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-8A for the Case C results for current plant conditions. The results for Cases A, B, and C shown in this figure do not reflect the current containment analysis, but reasonably represent the general characteristics and relative differences between the three cases.

LONG-TERM DRYWELL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE OR MAIN STEAM LINE BREAK

FIGURE 6.2-8 Rev. 5, 4/96


LIMERICK - CONTAINMENT TEMPERATURE RESPONSE TO LOCA CASE C
3.50E+02
2.50E+02
1.50E+02
5.00E+01
TEMPERATURE - DEG F
10
100
1000
10000
100000
LOG TIME - SEC
DW AIRSPACE TEMP
LIMERICK GENERATION STATION
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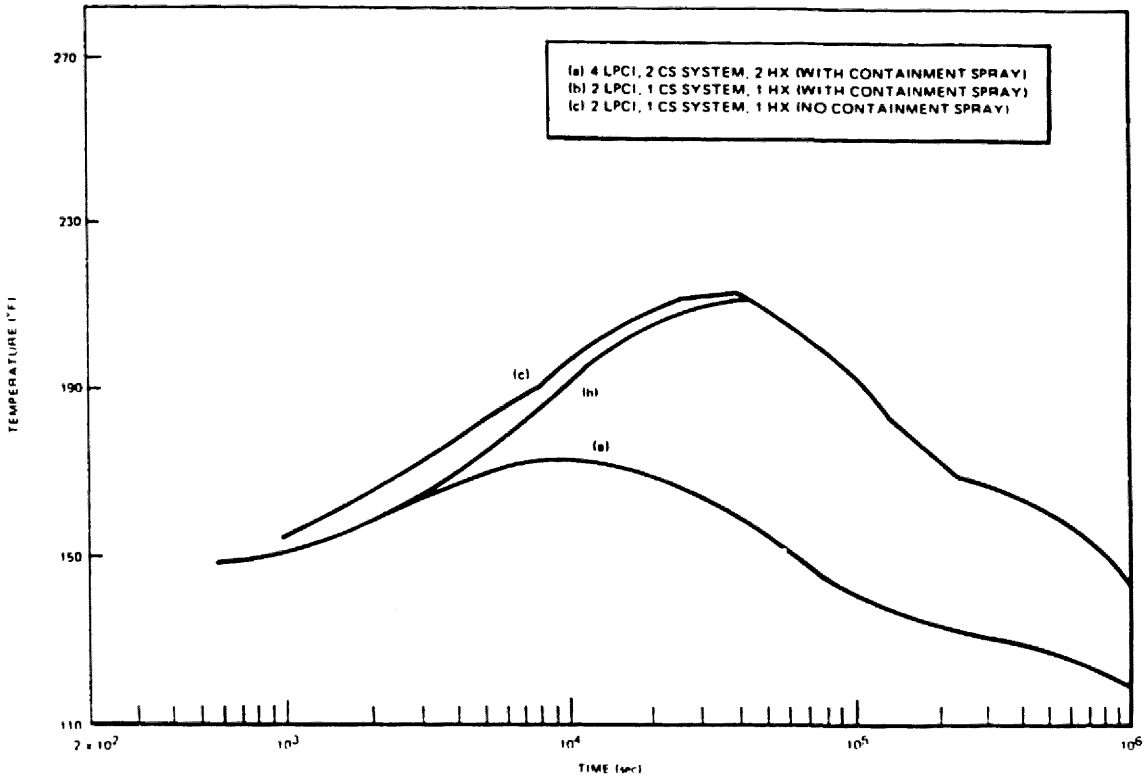
UPDATED FINAL SAFETY ANALYSIS REPORT
LONG TERM CONTAINMENT TEMPERATURE RESPONSE - CASE C AT 3528 MWt
FIGURE 6.2-8A
REV. 13 09/06



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Figure 6.2-9A for the Case C results for current plant conditions. The results for Cases A, B, and C shown in this figure do not reflect the current containment analysis, but reasonably represent the general characteristics and relative differences between the three cases.

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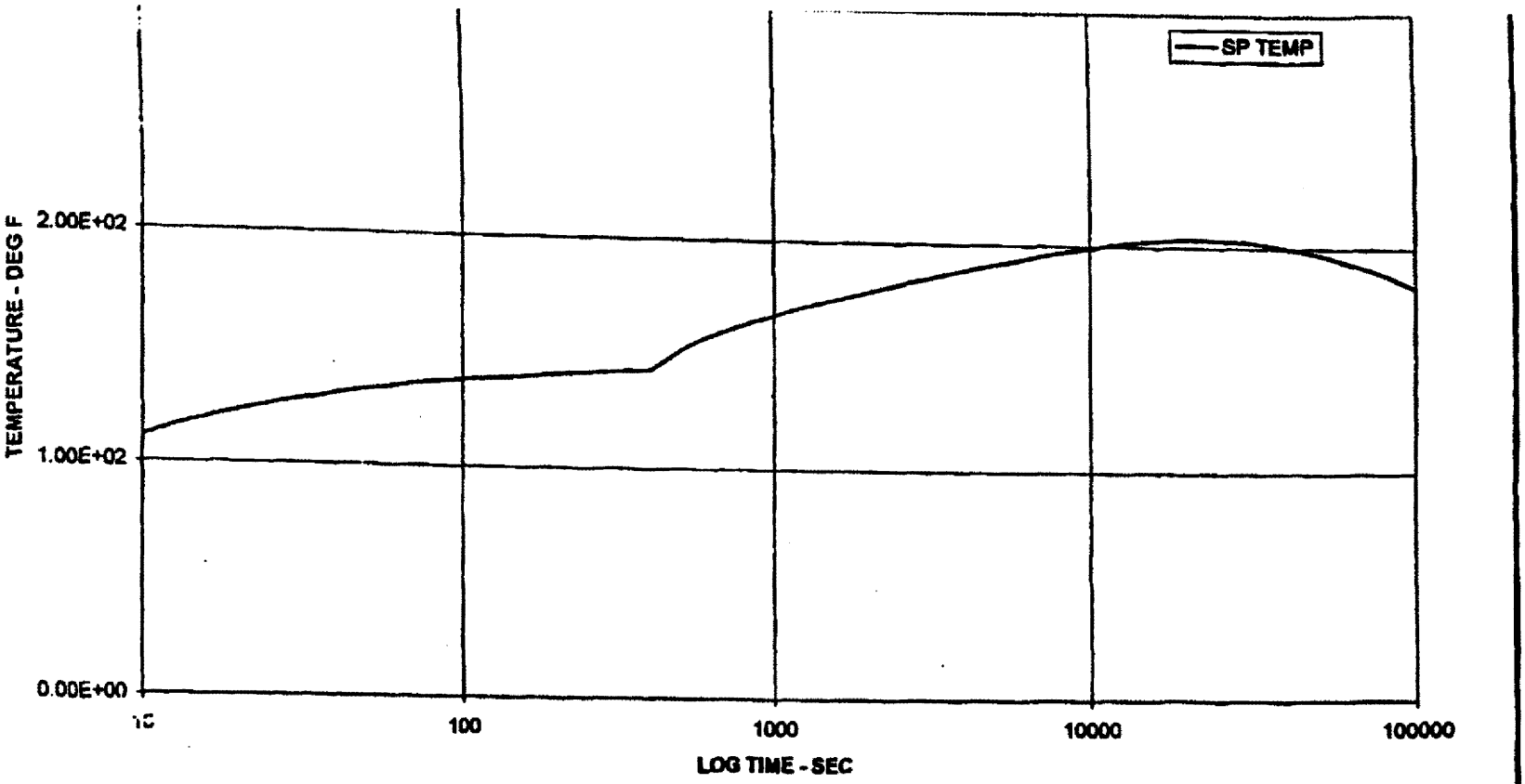
LONG-TERM SUPPRESSION POOL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE OR MAIN STEAM LINE BREAK

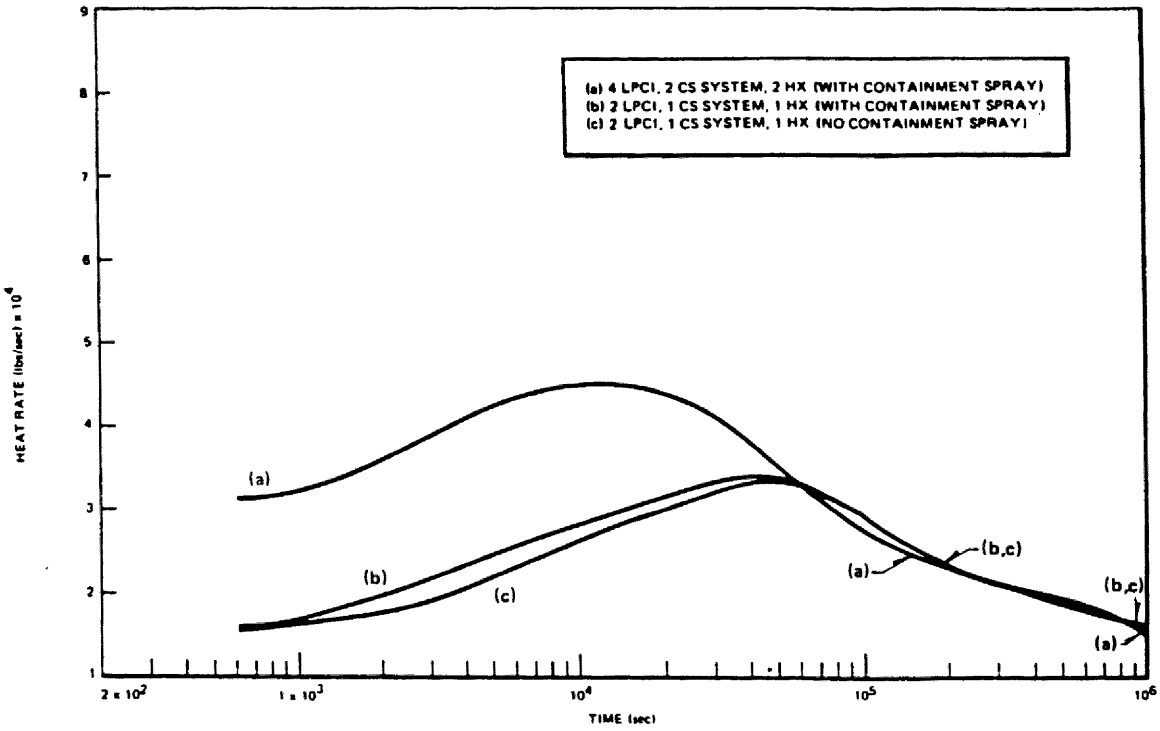
FIGURE 6.2-9 Rev. 5, 4/96



LIMERICK GENERATION STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LONG TERM SUPPRESSION POOL
TEMPERATURE RESPONSE - CASE C AT 3528 MWt

FIGURE 6.2-9A REV. 13 09/06



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 6.2.1.1.3, only Case C was reanalyzed for current plant conditions. The results for Cases A, B, and C shown in this figure do not reflect the current containment analysis, but reasonably represent the general characteristics and relative differences between the three cases.

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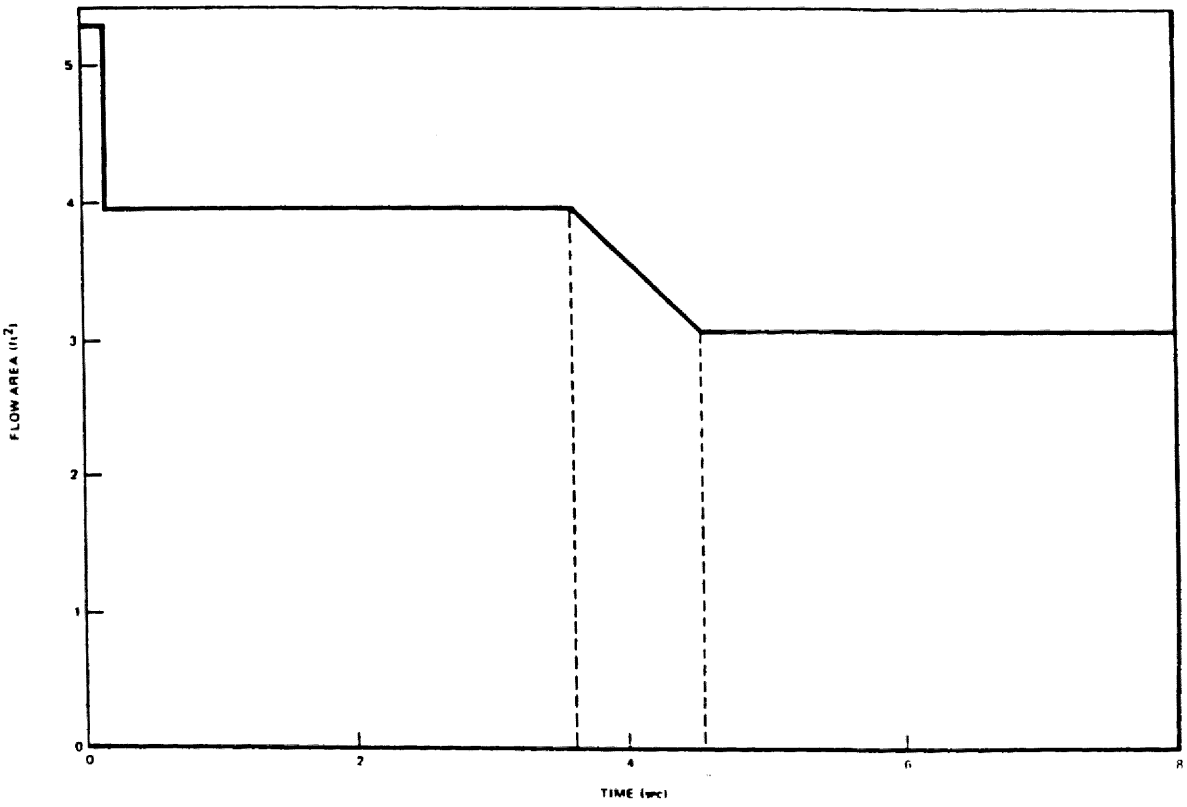
RHR HEAT REMOVAL RATE
FOLLOWING RECIRCULATION
LINE OR MAIN STEAM LINE BREAK

FIGURE 6.2-10 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. Refer to Section 6.2.1.8 for the current analysis results and methodology. The results shown here reasonably represent the general characteristics of the event.

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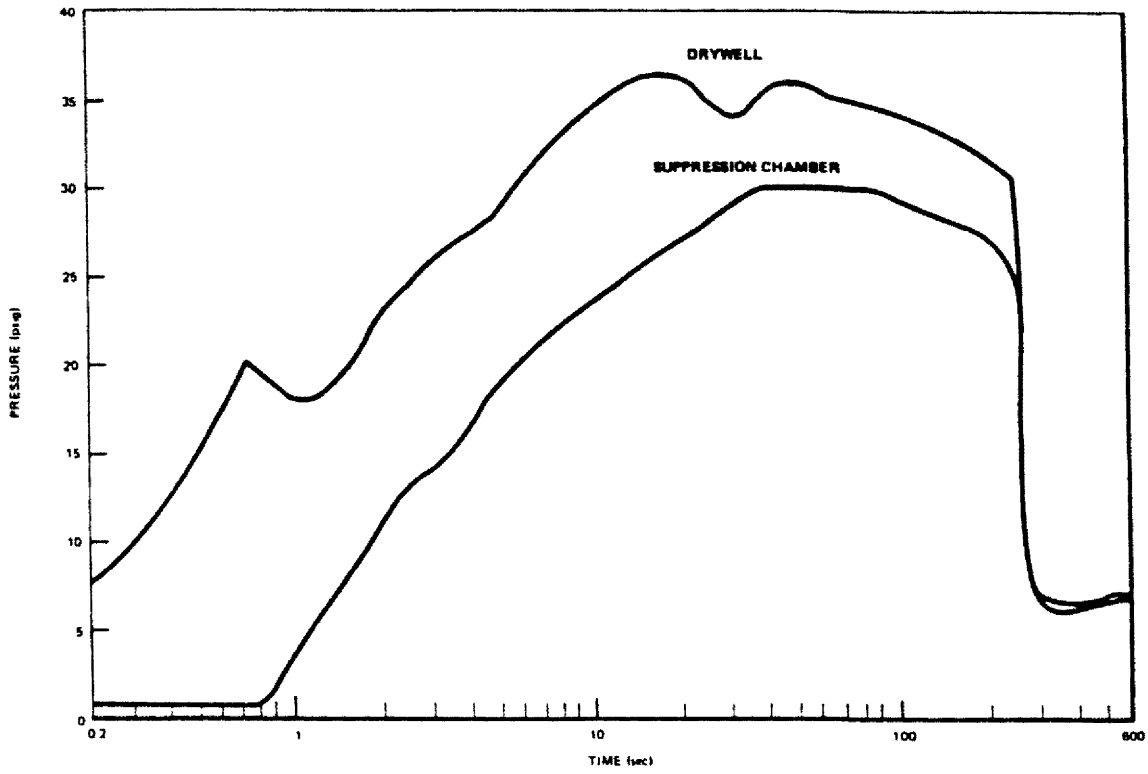
UPDATED FINAL SAFETY ANALYSIS REPORT

EFFECTIVE BLOWDOWN AREA
FOR MAIN STEAM LINE BREAK

FIGURE 6.2-11 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break.

LIMERICK GENERATING STATION
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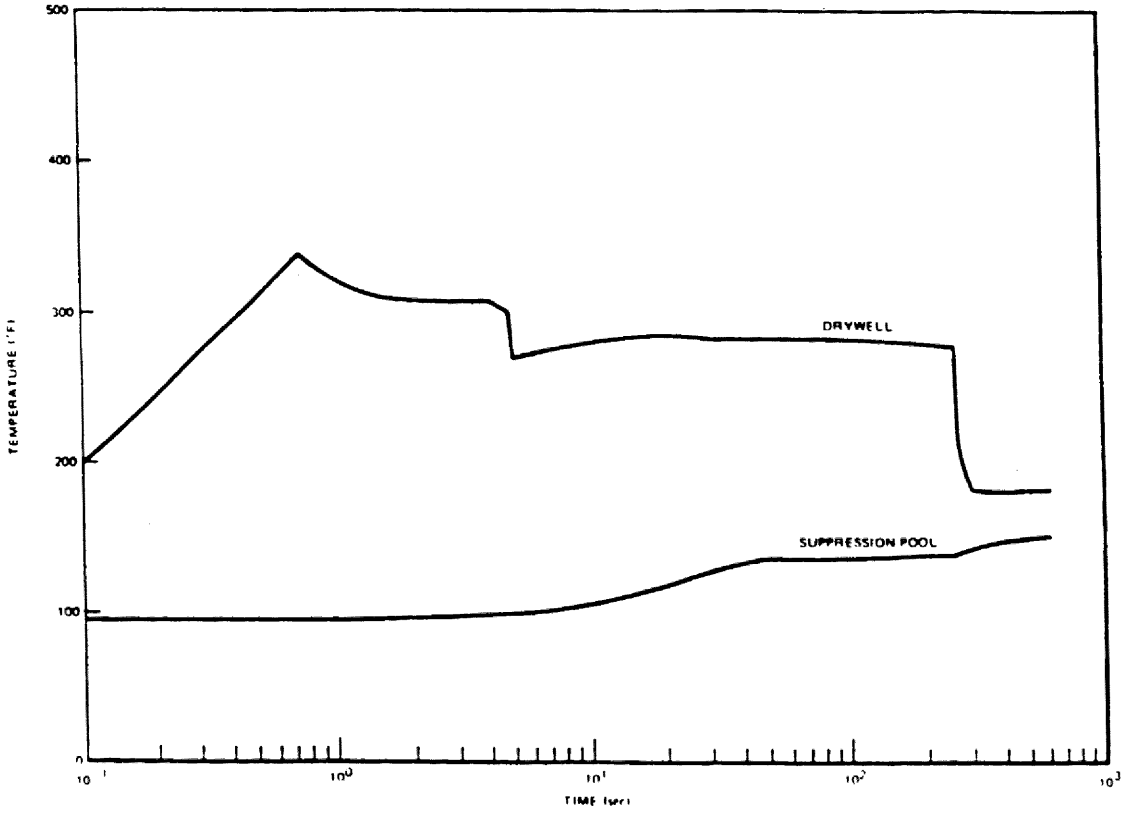
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING MAIN STEAM LINE BREAK

FIGURE 6.2-12

Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break.

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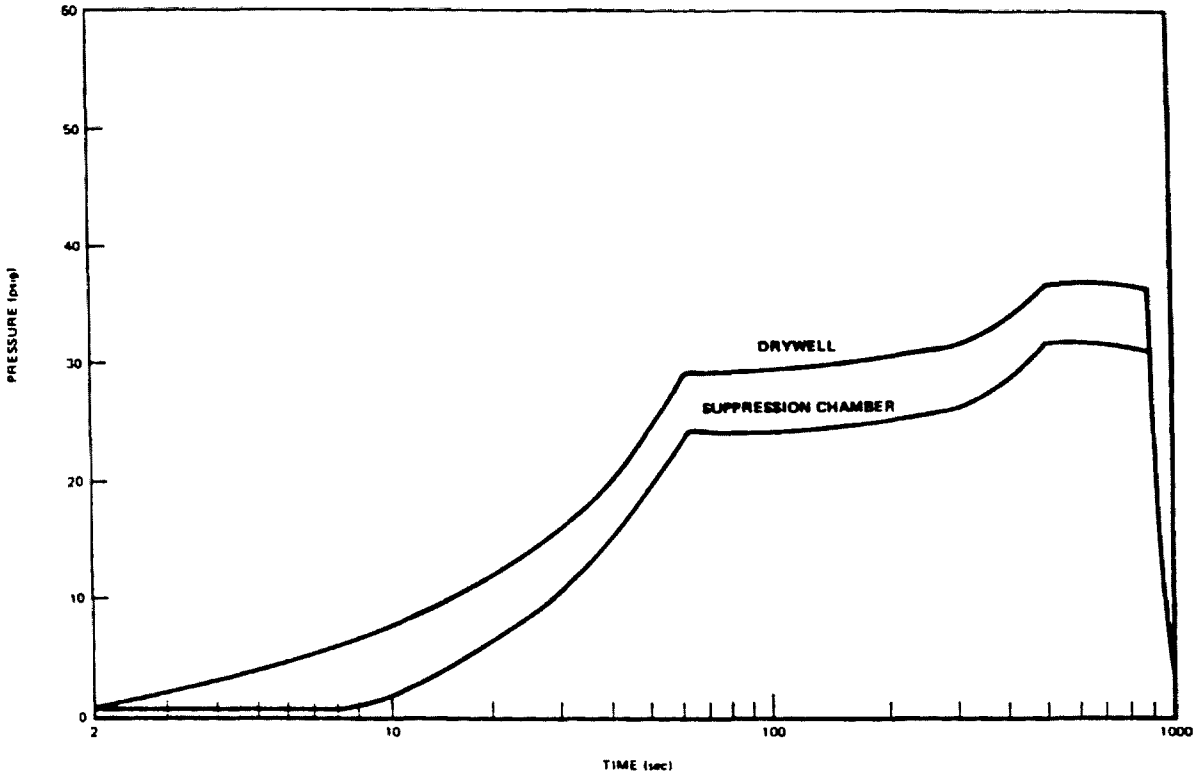
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING MAIN STEAM LINE BREAK

Rev. 5, 4/96

FIGURE 6.2-13



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the pipe break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the pipe break analysis results.

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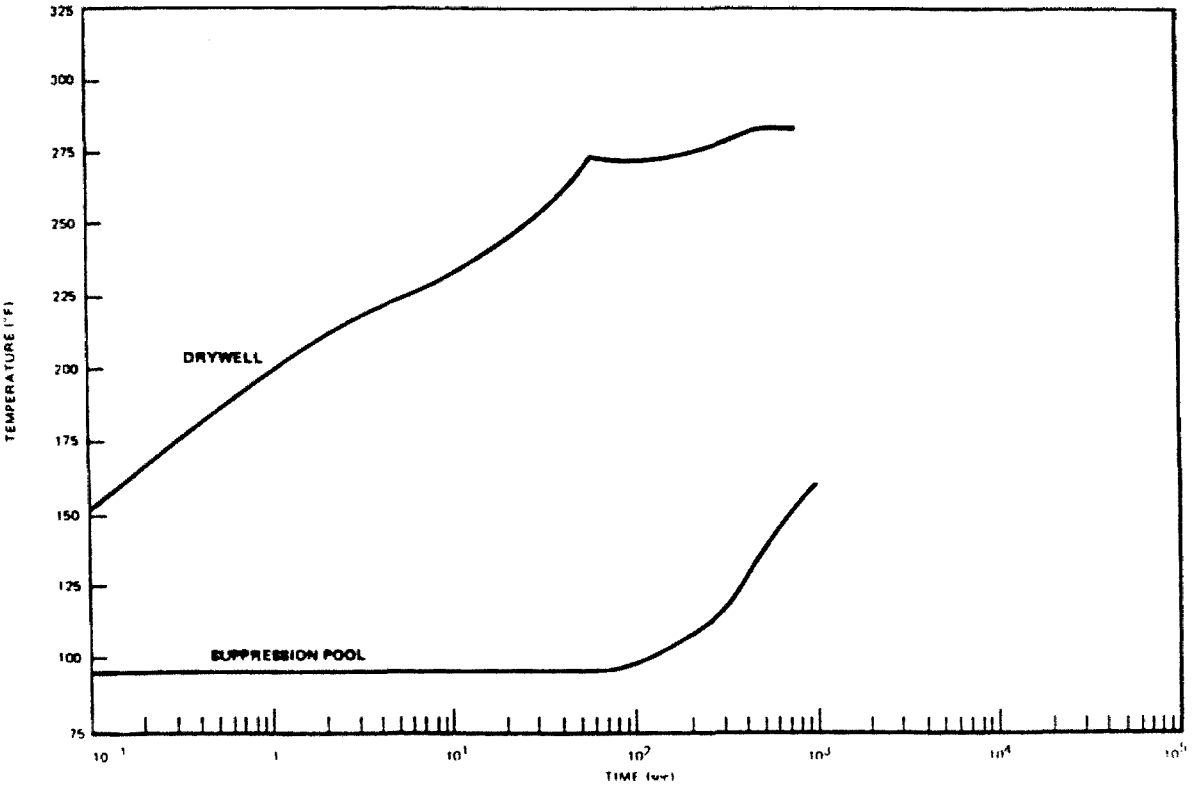
SHORT-TERM CONTAINMENT PRESSURE RESPONSE FOLLOWING AN INTERMEDIATE SIZE BREAK (0.1 ft^2 LIQUID BREAK)

Rev. 15, 09/10

FIGURE 6.2-14



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the pipe break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the pipe break analysis results.

LIMERICK GENERATING STATION
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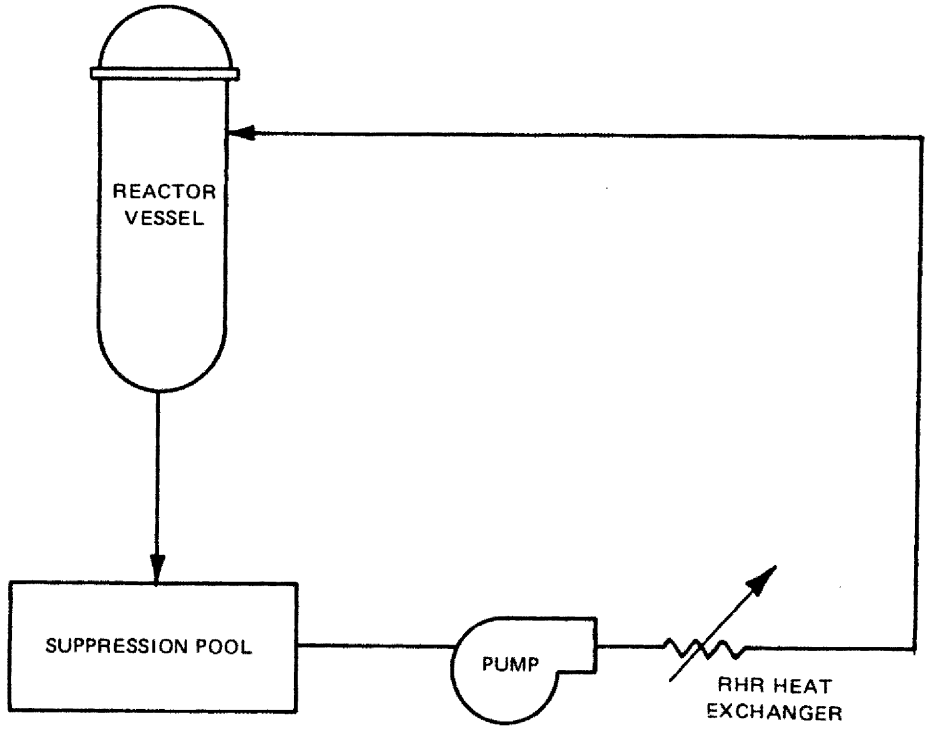
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE FOLLOWING AN INTERMEDIATE SIZE BREAK (0.1 ft^2 LIQUID BREAK)

FIGURE 6.2-15

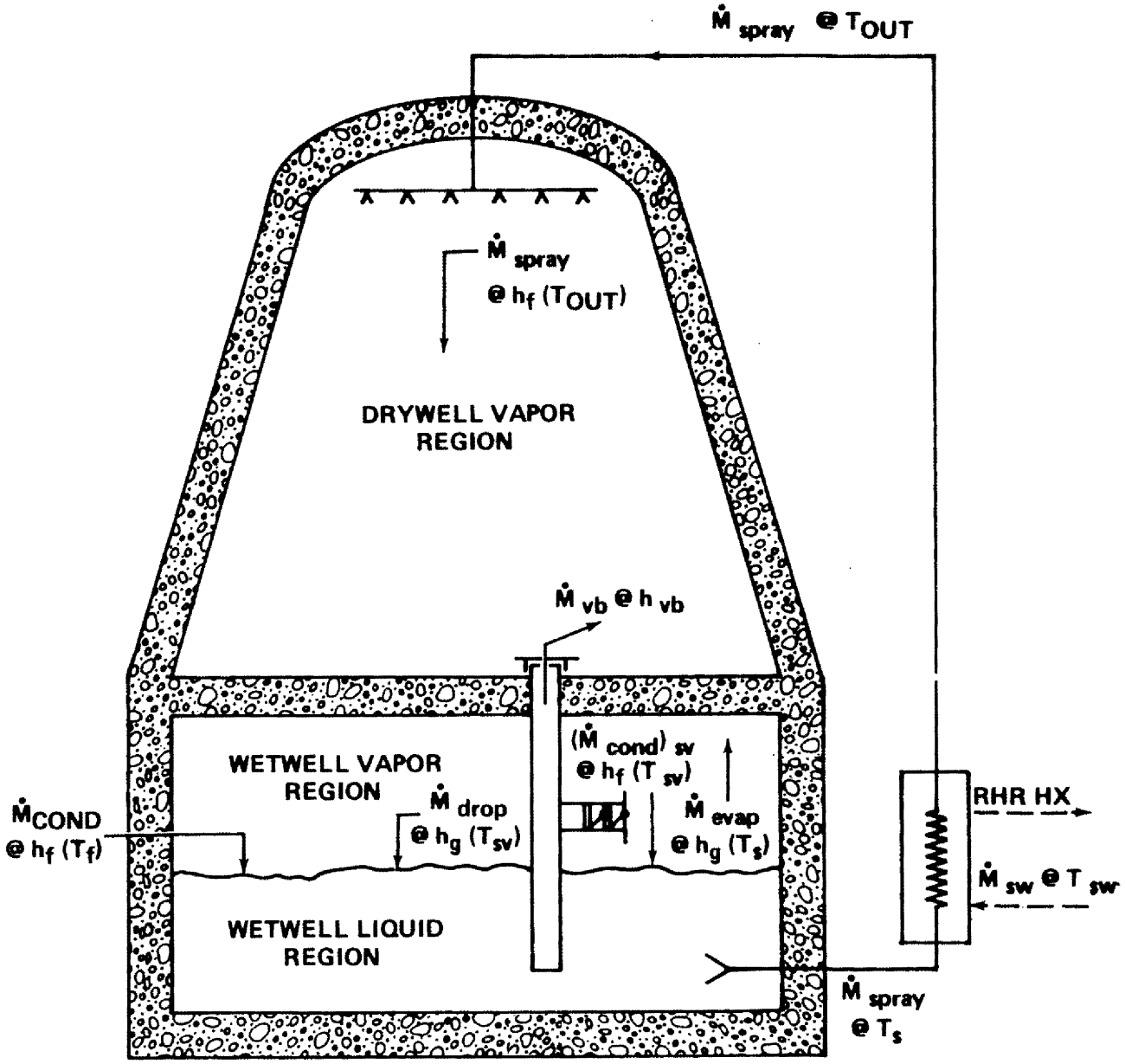
Rev. 15, 09/10



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SCHEMATIC OF ANALYTICAL MODEL FOR RHR CONTAINMENT COOLING SYSTEM

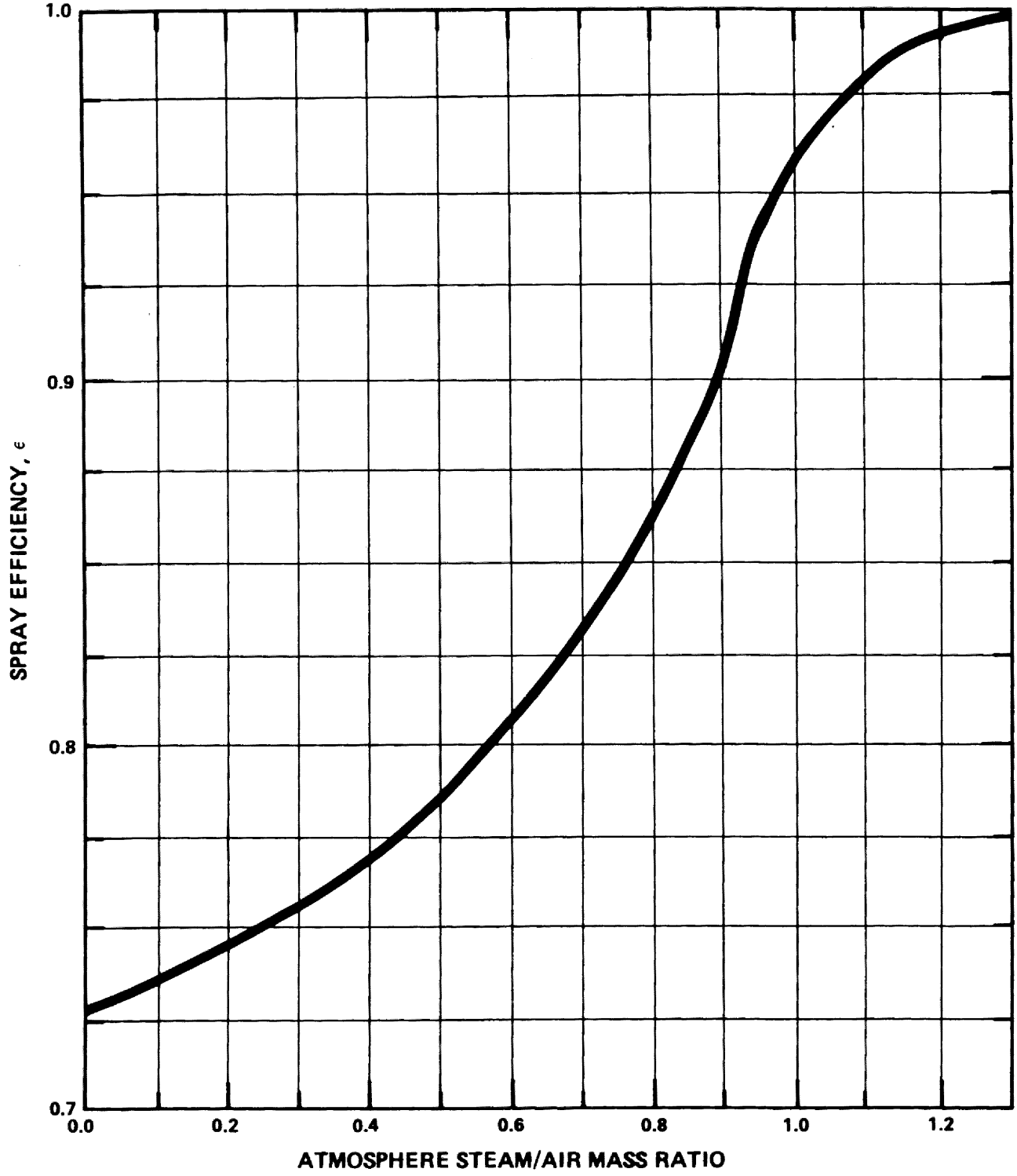
FIGURE 6.2-16



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

MODEL FOR ANALYSIS OF INADVERTANT DRYWELL SPRAY ACTUATION

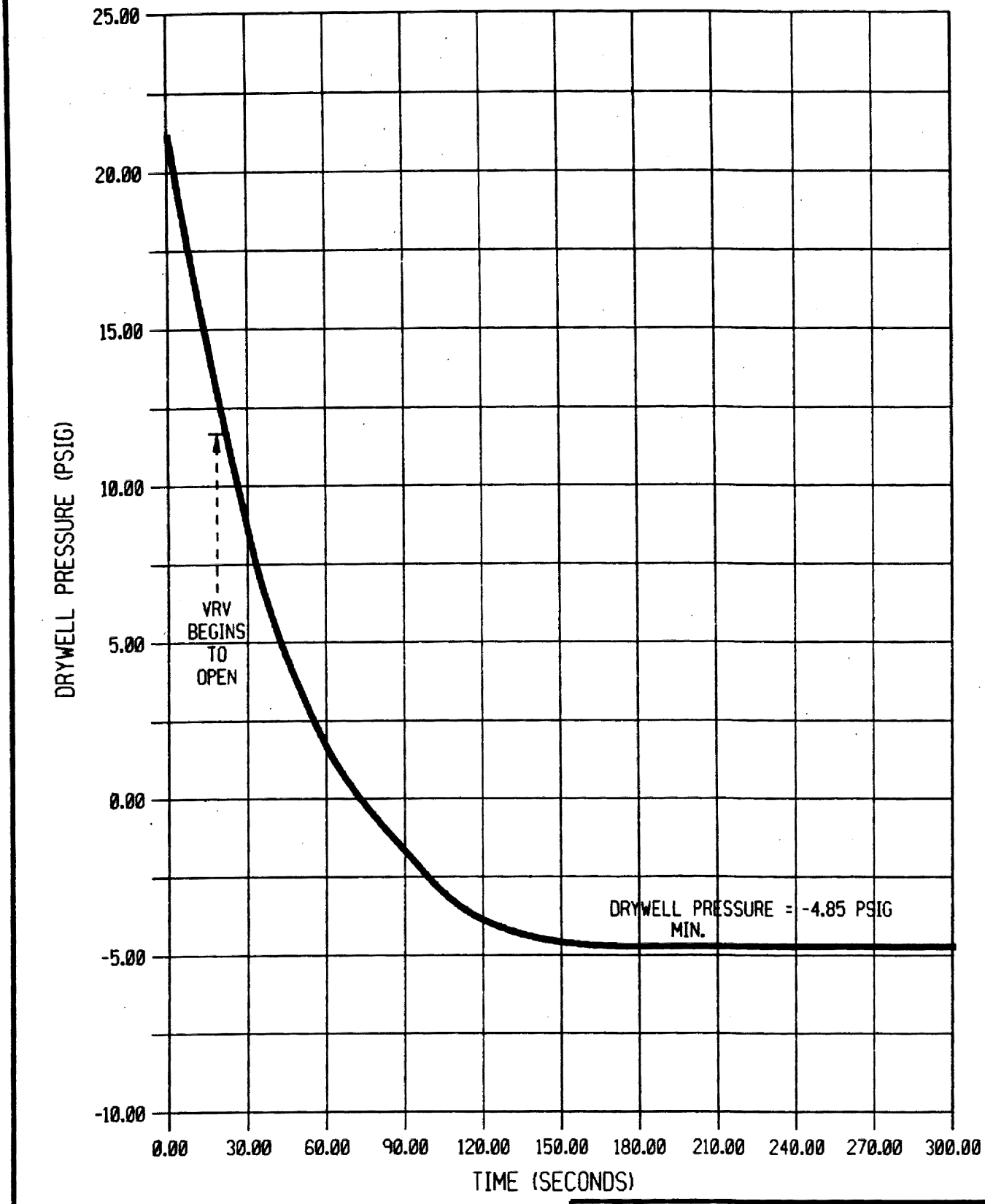
FIGURE 6.2-17



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

THERMAL HEAT
REMOVAL EFFICIENCY
OF DRYWELL SPRAY

FIGURE 6.2-18



LIMERICK GENERATING STATION
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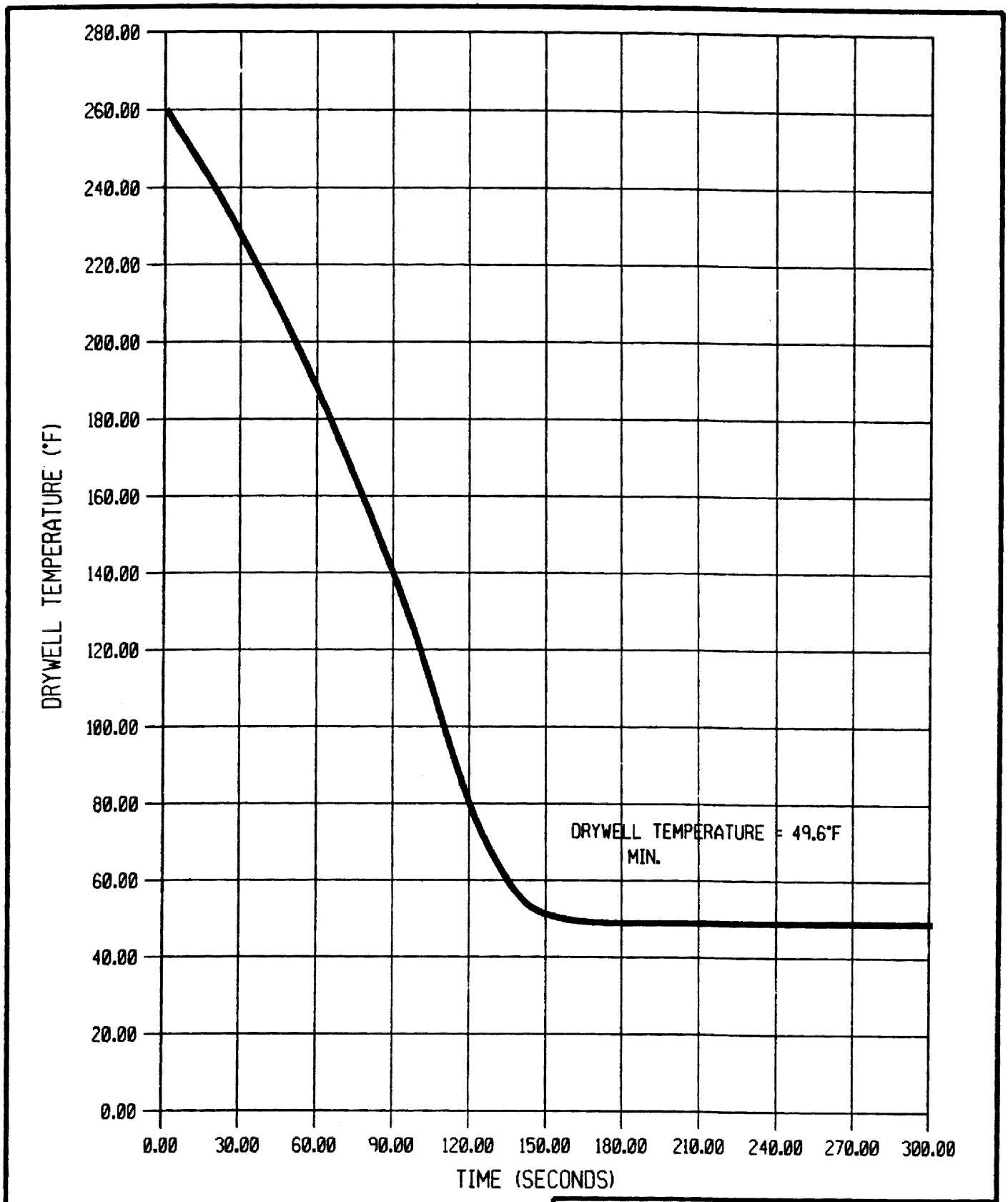
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL PRESSURE
RESPONSE TO
SPRAY ACTUATION

FIGURE 6.2-19 Rev. 1 July/91

7:\MECH\ 0602019.DGN



LIMERICK GENERATING STATION
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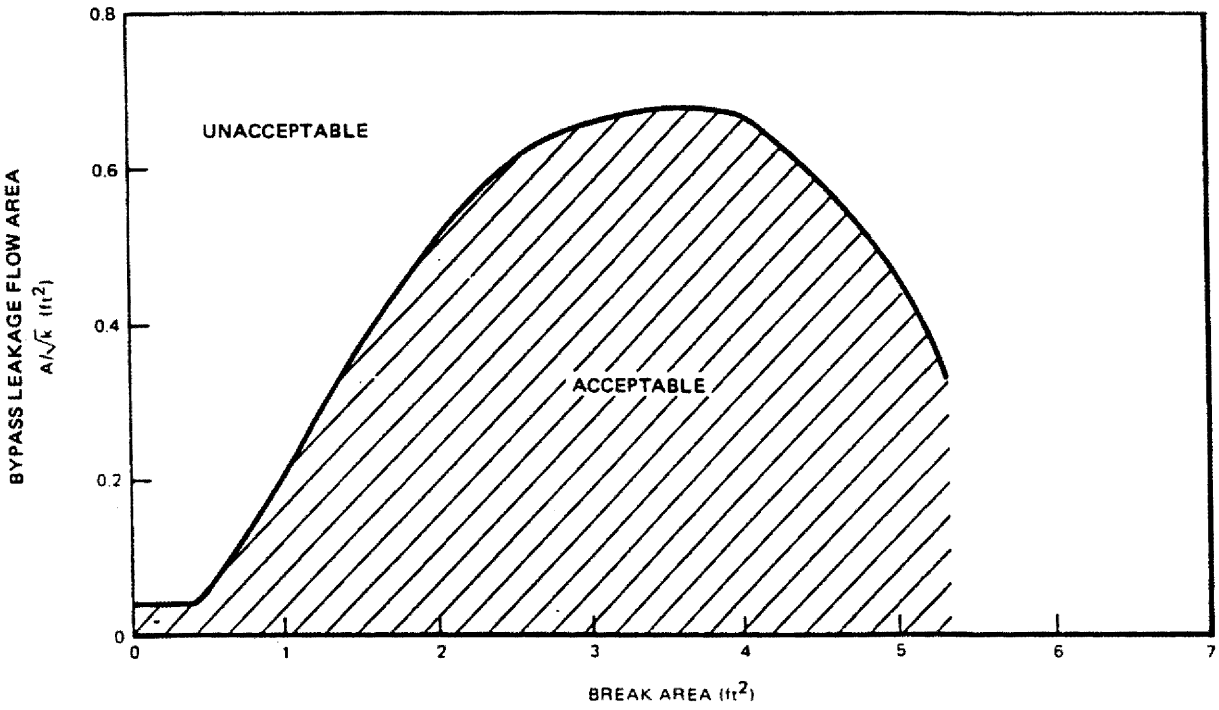
UPDATED FINAL SAFETY ANALYSIS REPORT

DRYWELL TEMPERATURE
RESPONSE TO
SPRAY ACTUATION

FIGURE 6.2-20 Rev. 1 July/91

Z:\MECH\ 0602020.DGN



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions; however, the results reasonably represent the general characteristics of the main steam line break analysis results.

LIMERICK GENERATING STATION
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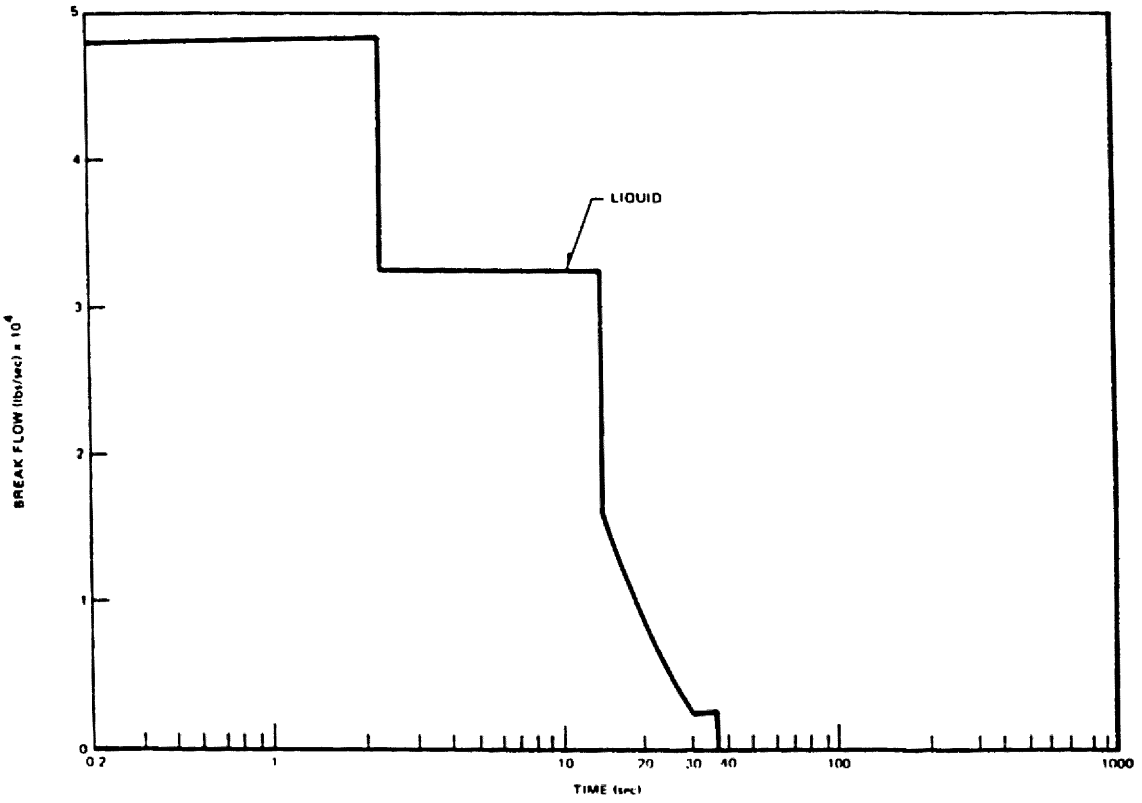
MAXIMUM ALLOWABLE STEAM
BYPASS LEAKAGE
FLOW AREA

FIGURE 6.2-21

Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions and does not represent current plant conditions or methodology used to analyze the containment response following a LOCA. Refer to Section 6.2.1.8 for the current analysis methodology.

LIMERICK GENERATING STATION
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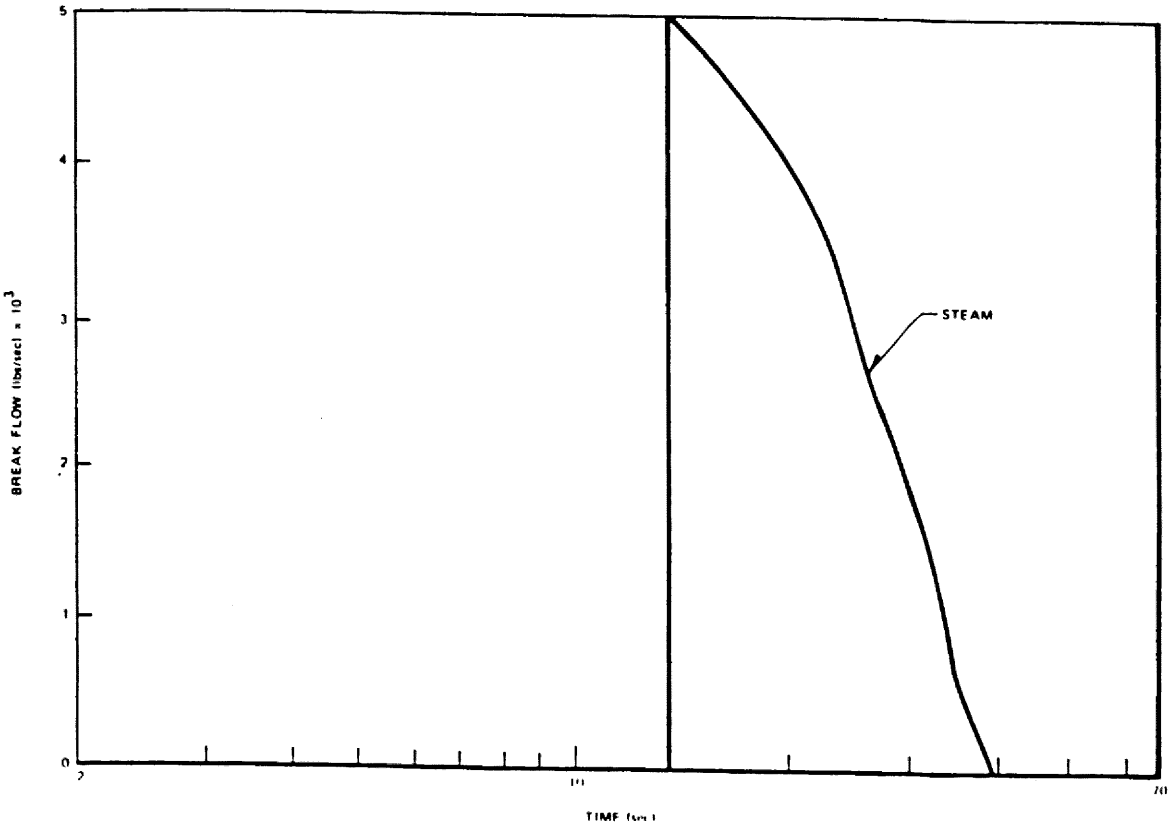
REACTOR VESSEL LIQUID BLOWDOWN FLOW RATE FOLLOWING RECIRCULATION LINE BREAK

FIGURE 6.2-22 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions and does not represent current plant conditions or methodology used to analyze the containment response following a LOCA. Refer to Section 6.2.1.8 for the current analysis methodology.

LIMERICK GENERATING STATION
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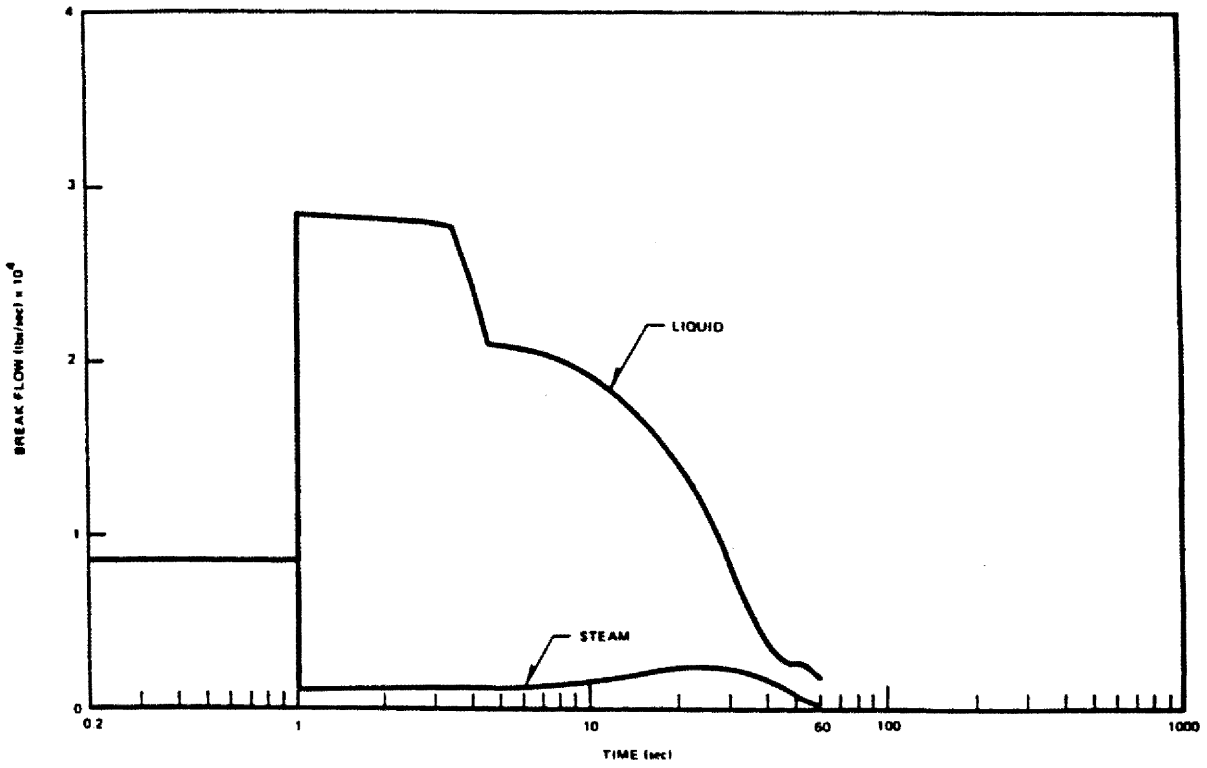
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL STEAM BLOWDOWN FLOW RATE FOLLOWING RECIRCULATION LINE BREAK

FIGURE 6.2-23 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and is based on the original design basis conditions. As described in Section 6.2.1.1.3, the main steam line break was not reanalyzed for the current conditions.

LIMERICK GENERATING STATION
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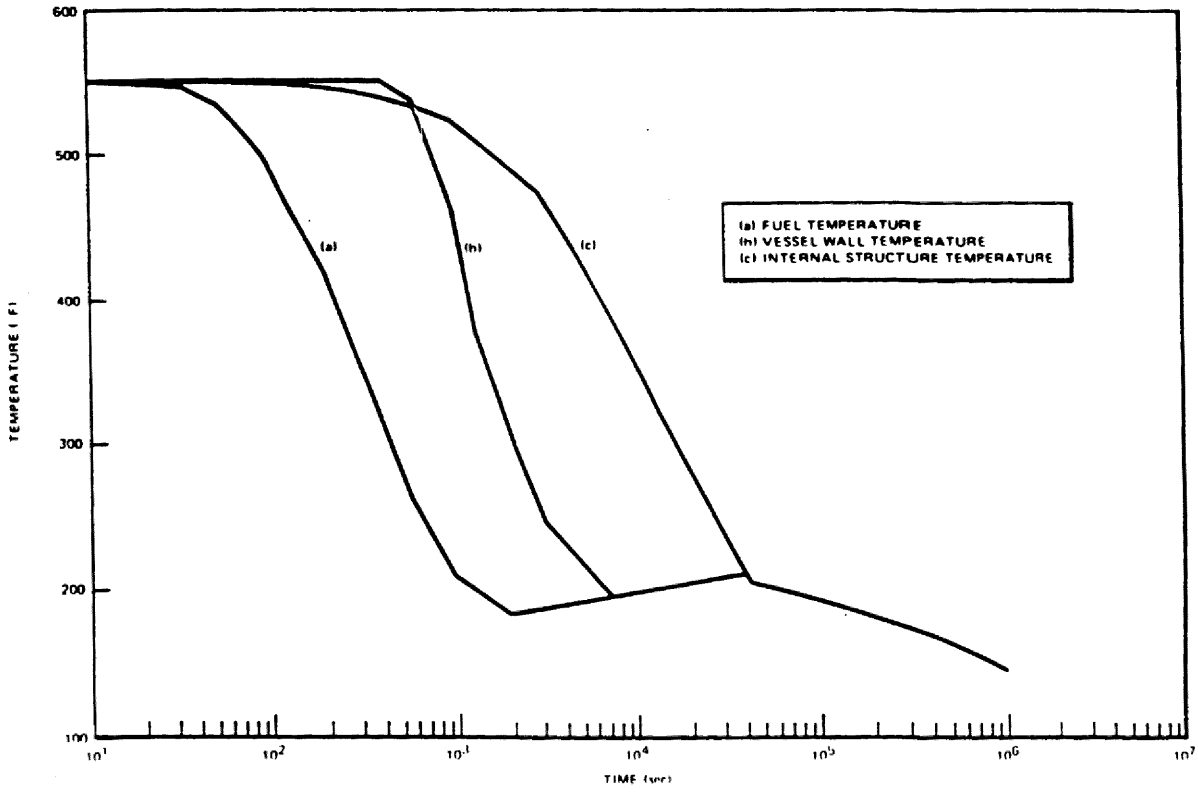
REACTOR VESSEL BLOWDOWN
FLOW RATE FOLLOWING
MAIN STEAM LINE BREAK

FIGURE 6.2-24 Rev. 5, 4/96



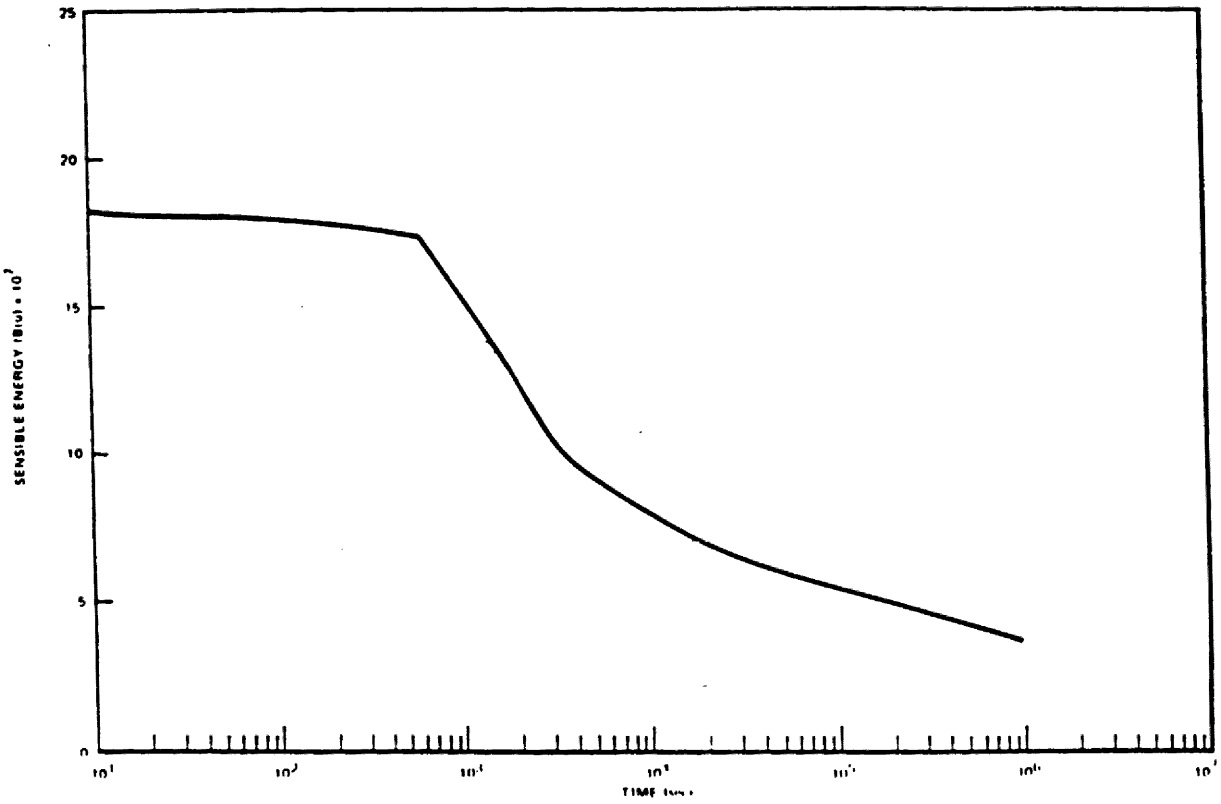
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonable represent the general characteristics of the current recirculation line break analysis results.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR VESSEL TEMPERATURE RESPONSE FOLLOWING RECIRCULATION LINE BREAK

FIGURE 6.2-25

Rev. 5, 4/96



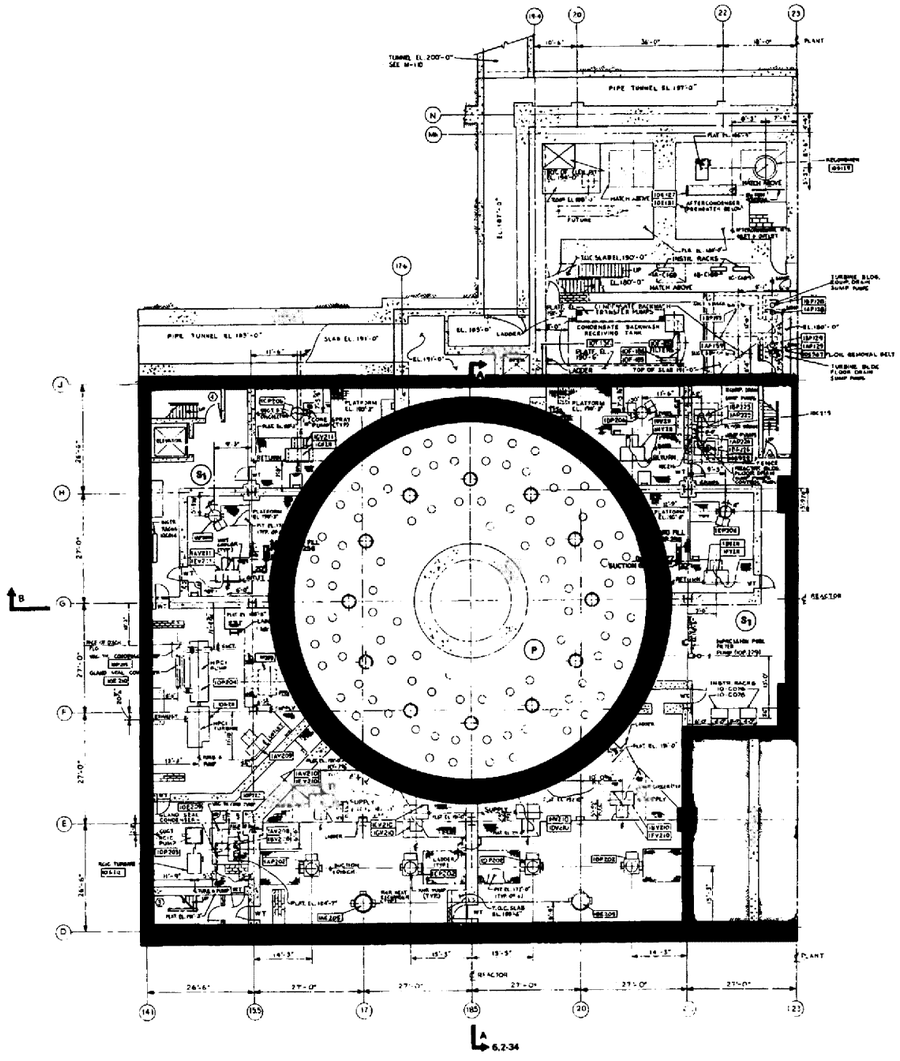
NOTE: The information presented in this figure is historical and is based on the original design basis conditions. The current recirculation line break results are discussed in Section 6.2.1.8. The results presented here reasonable represent the general characteristics of the current recirculation line break analysis results.

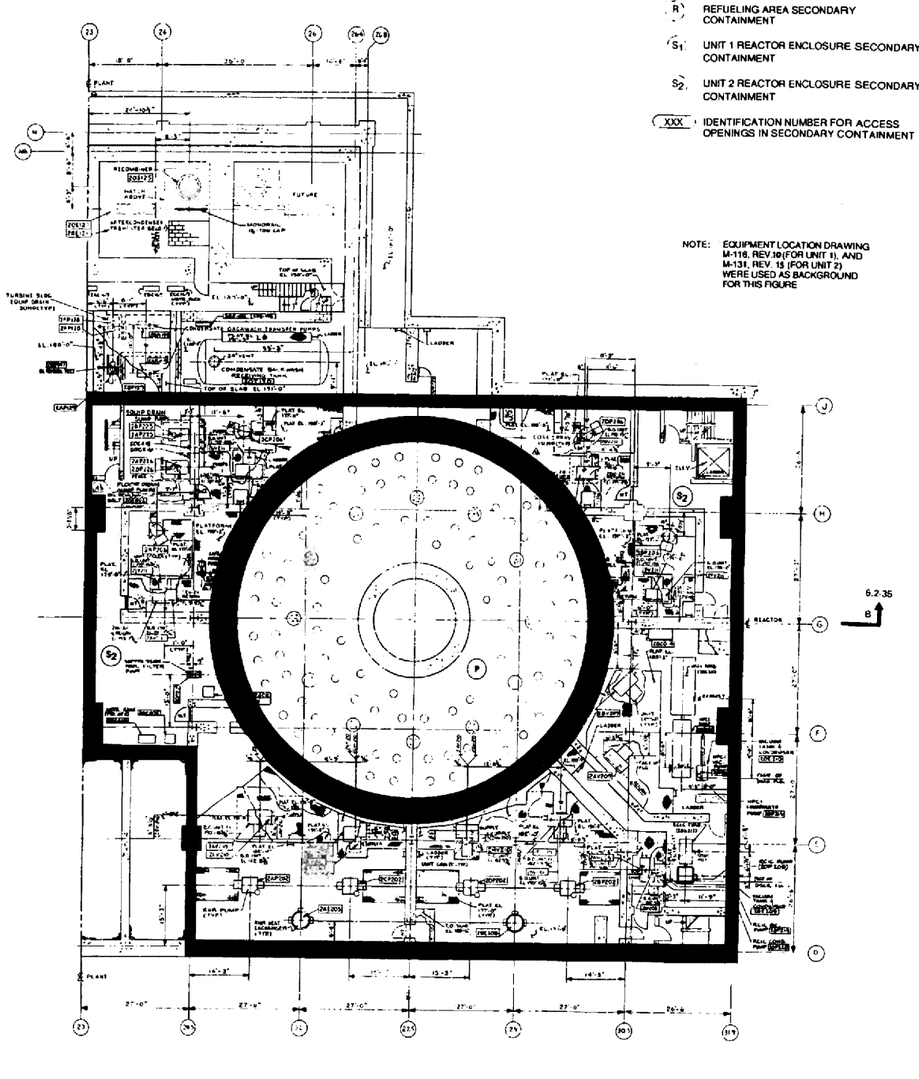
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SENSIBLE ENERGY IN REACTOR VESSEL AND INTERNAL STRUCTURE METALS FOLLOWING RECIRCULATION LINE BREAK

FIGURE 6.2-26

Rev. 5, 4/96





LEGEND

- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (XXX) IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT

NOTE: EQUIPMENT LOCATION DRAWING M-116, REV.19(FOR UNIT 1), AND M-131, REV. 18 (FOR UNIT 2) WERE USED AS BACKGROUND FOR THIS FIGURE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

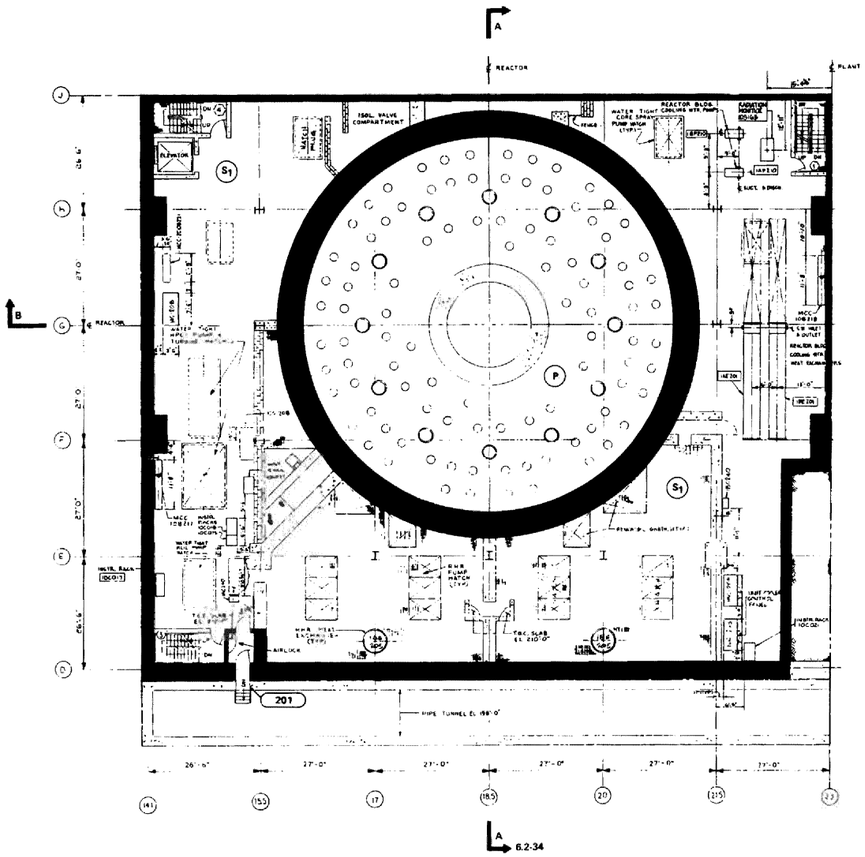
SECONDARY CONTAINMENT BOUNDARY OUTLINE, PLAN AT ELEV. 177 FEET

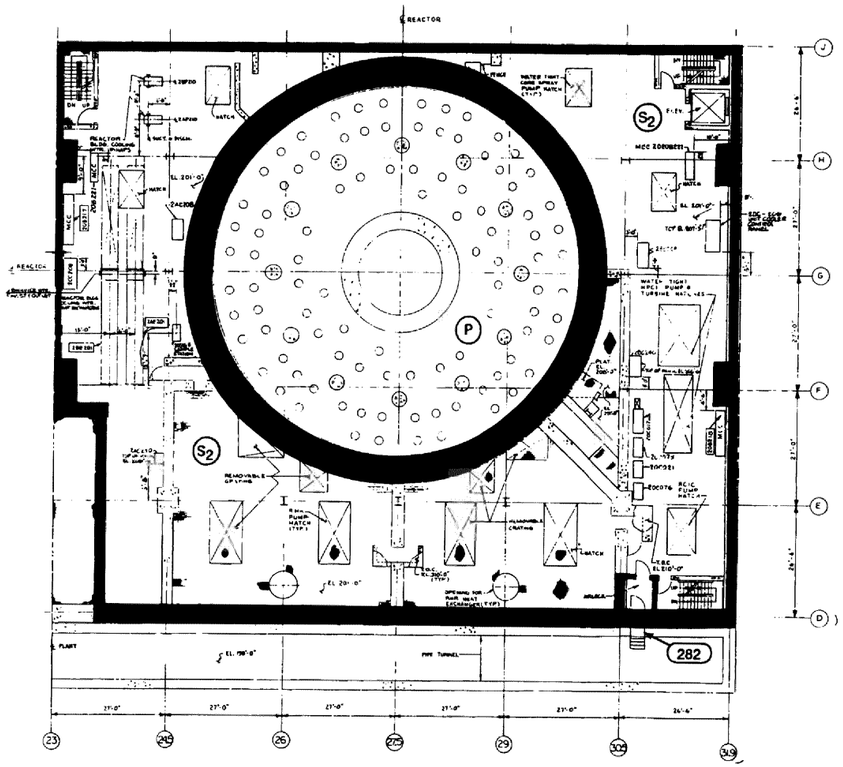
FIGURE 6.2-27

NOTE: EQUIPMENT LOCATION DRAWING M-117, REV. 9 (FOR UNIT 1), AND M-132, REV. 9 (FOR UNIT 2) WERE USED AS BACKGROUND FOR THIS FIGURE

LEGEND

- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- XXX IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT





LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

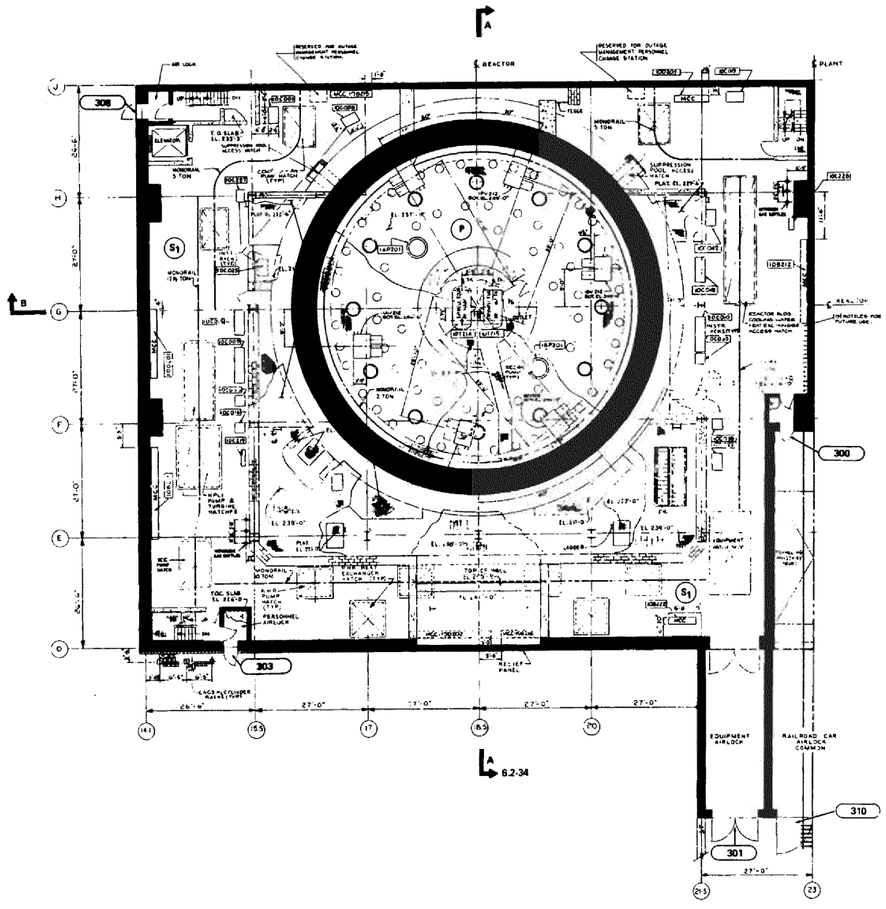
SECONDARY CONTAINMENT BOUNDARY OUTLINE, PLAN AT ELEV. 201 FEET

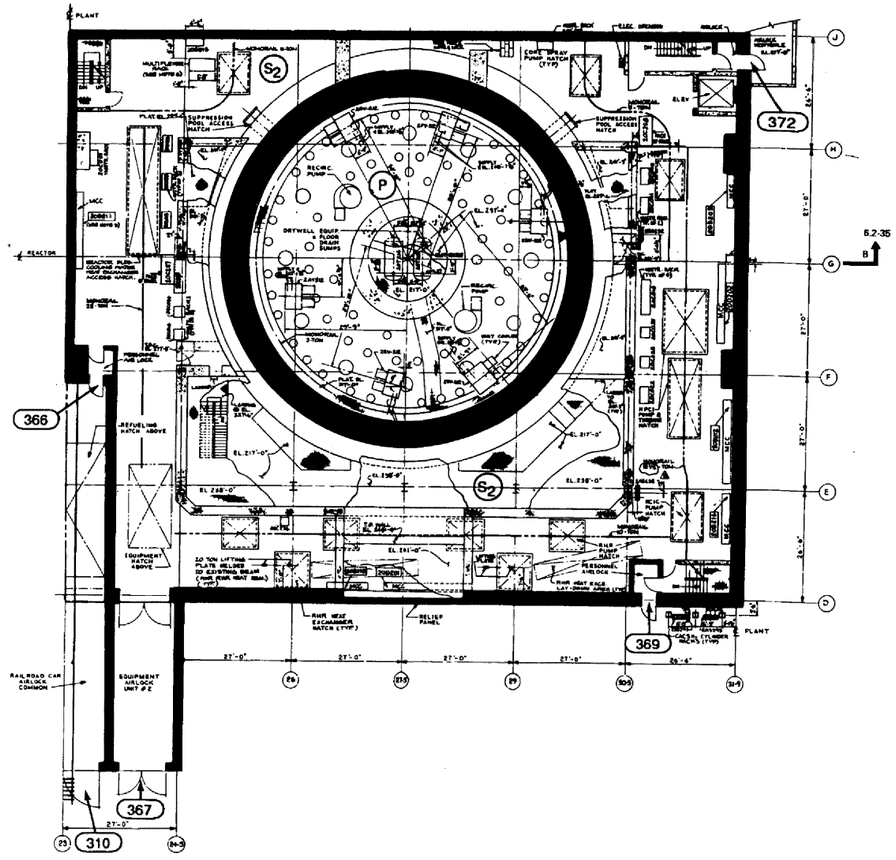
FIGURE 6.2-28

NOTE: EQUIPMENT LOCATION DRAWING M-118, REV. 17 (FOR UNIT 1), AND M-133, REV. 12 (FOR UNIT 2) WERE USED AS BACKGROUND FOR THIS FIGURE

LEGEND

- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (XXX) IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT





LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

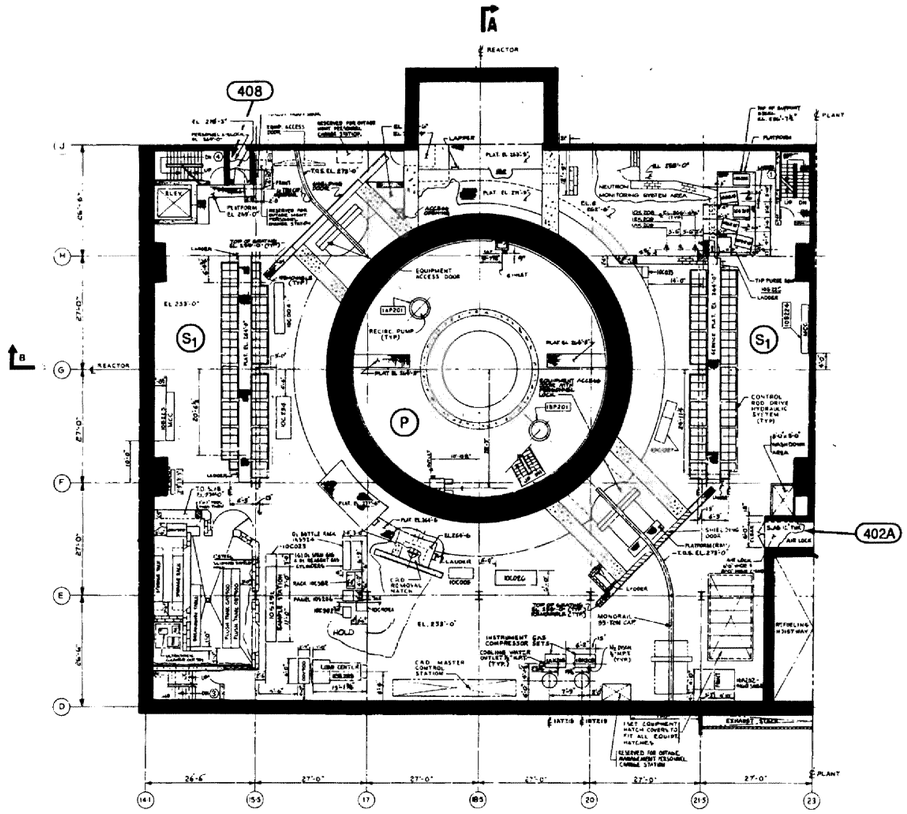
SECONDARY CONTAINMENT BOUNDARY OUTLINE, PLAN AT ELEV. 217 FEET

FIGURE 6.2-29

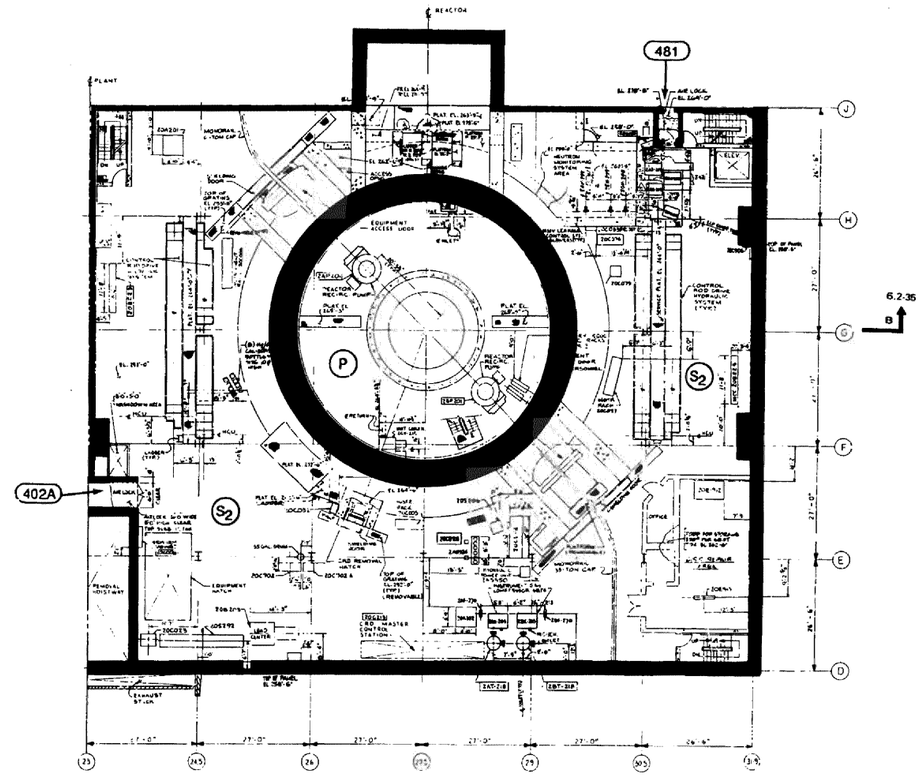
NOTE: EQUIPMENT LOCATION DRAWING M-119, REV. 24 (FOR UNIT 1), AND M-134, REV. 18 (FOR UNIT 2) WERE USED AS BACKGROUND FOR THIS FIGURE

LEGEND

- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (XXX) IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT



LA 6.2-34



6.2-35 B

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

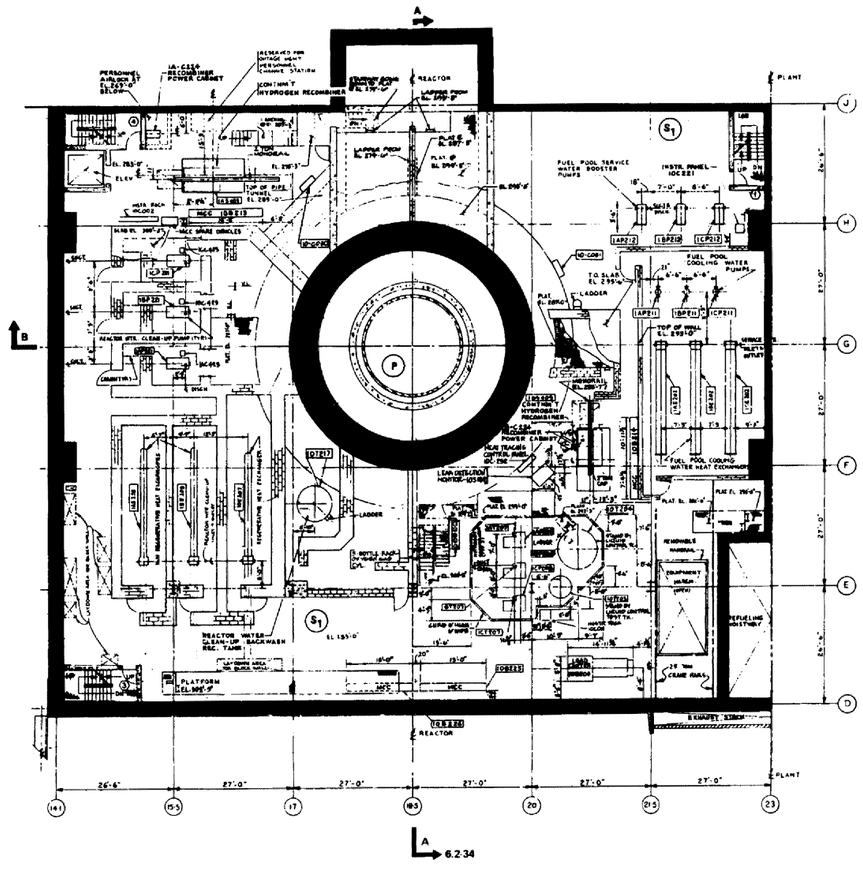
SECONDARY CONTAINMENT BOUNDARY OUTLINE, PLAN AT ELEV. 253 FEET

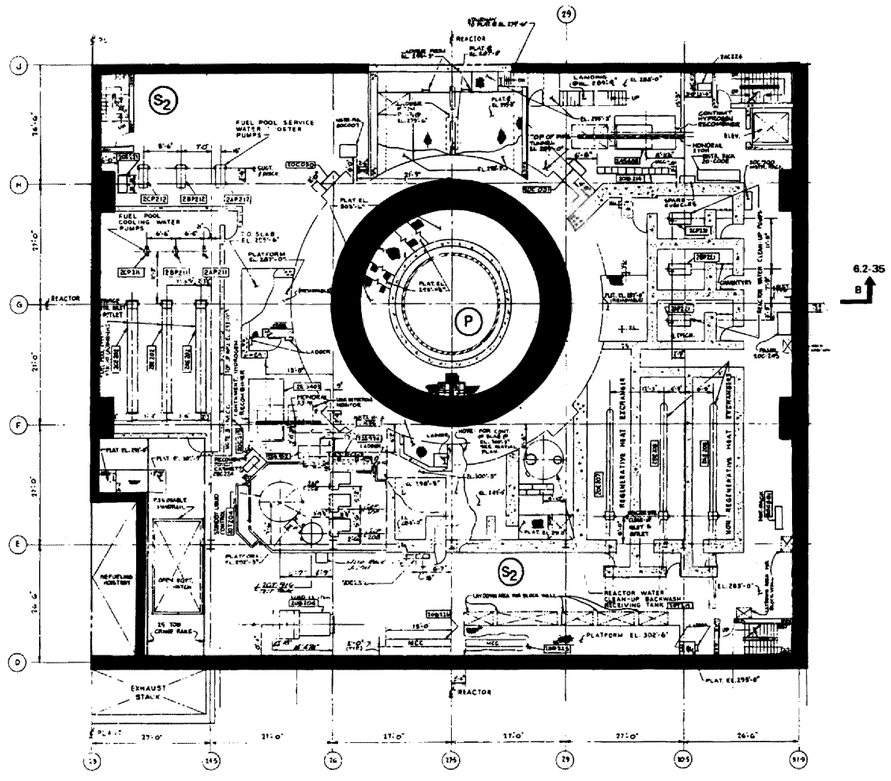
FIGURE 6.2-30

NOTE: EQUIPMENT LOCATION DRAWING M-120, REV. 22 (FOR UNIT 1), AND M-135, REV. 16 (FOR UNIT 2) WERE USED AS BACKGROUND FOR THIS FIGURE

LEGEND

- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (XXX) IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT



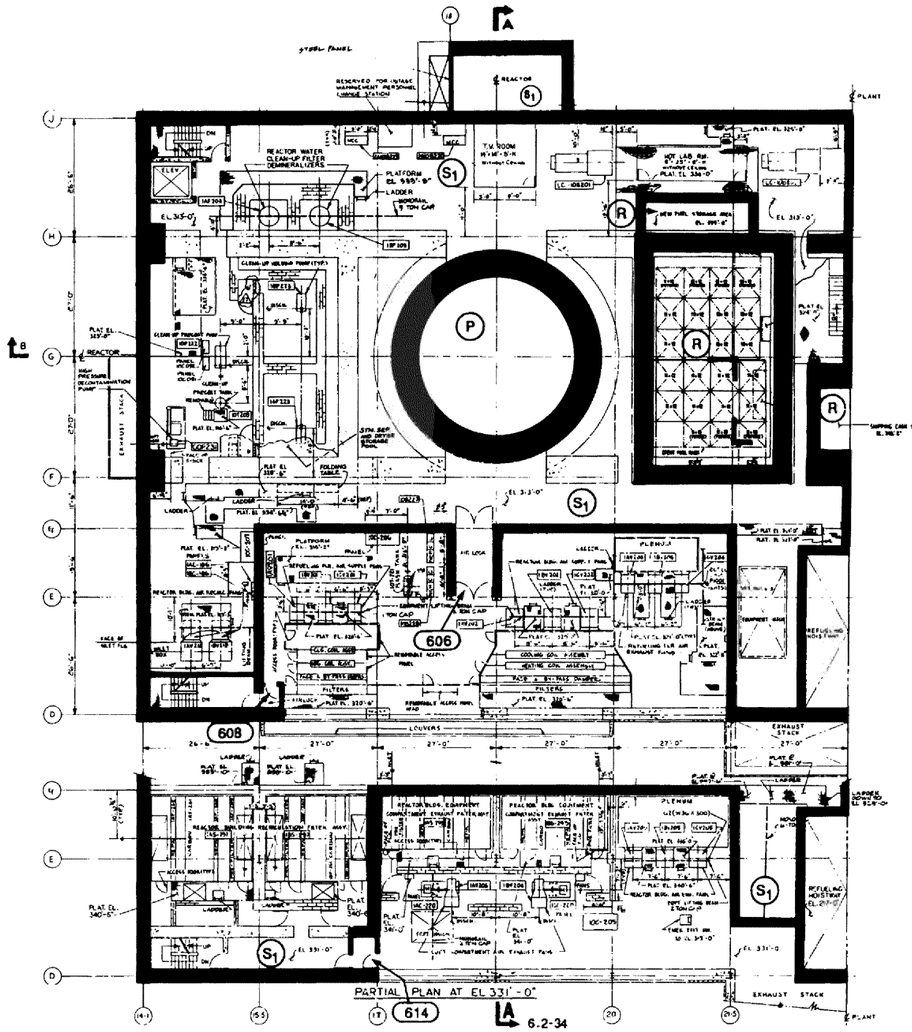


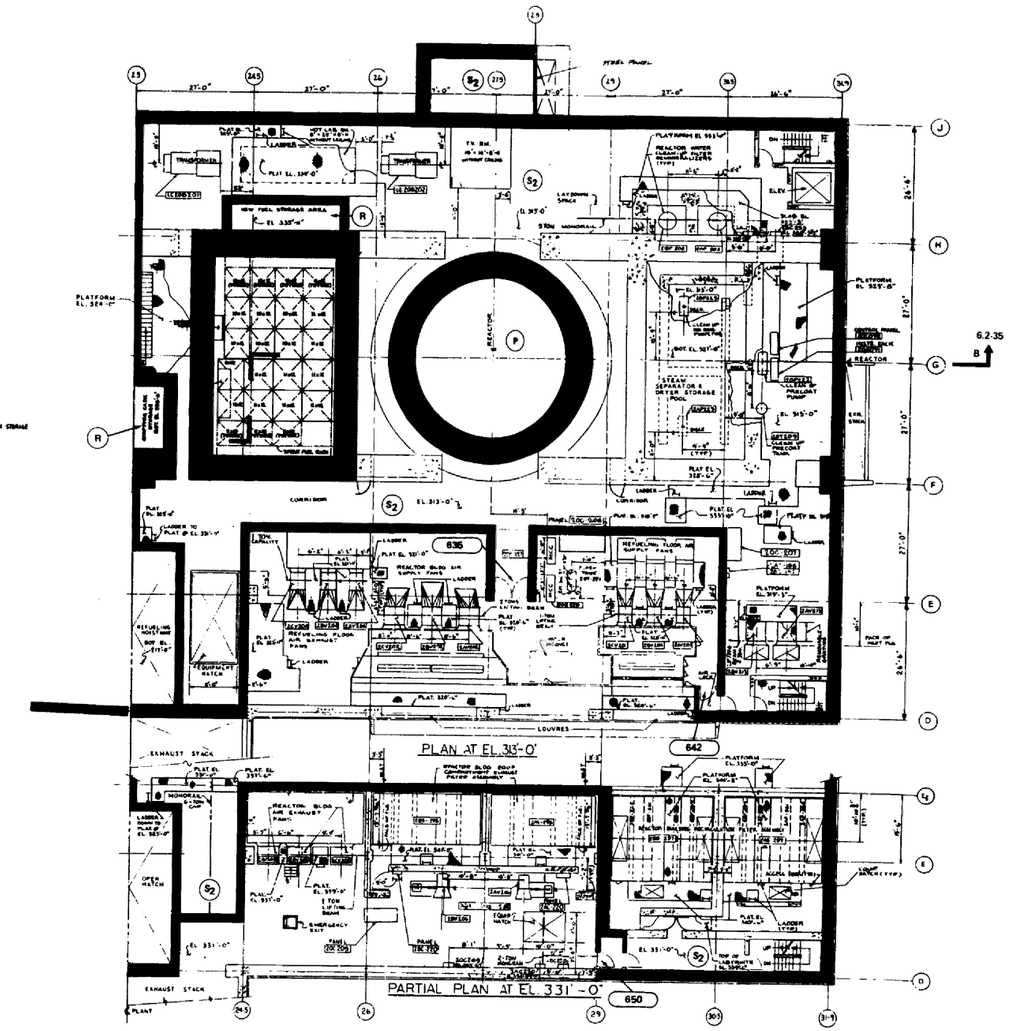
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT BOUNDARY OUTLINE, PLAN AT ELEV. 283 FEET

FIGURE 6.2-31

NOTE: EQUIPMENT LOCATION DRAWING M-121, REV. 17 (FOR UNIT 1), AND M-136, REV. 9 (FOR UNIT 2) WERE USED AS BACKGROUND FOR THIS FIGURE





LEGEND

- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- XXX IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

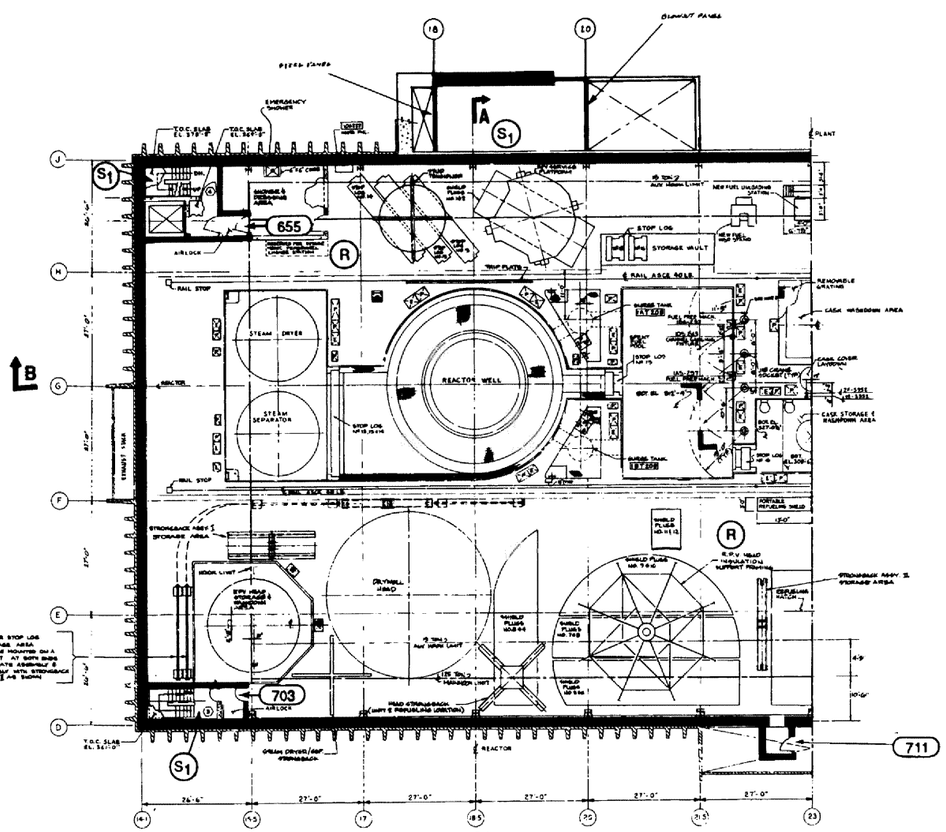
SECONDARY CONTAINMENT BOUNDARY OUTLINE, PLAN AT ELEV. 313 FEET

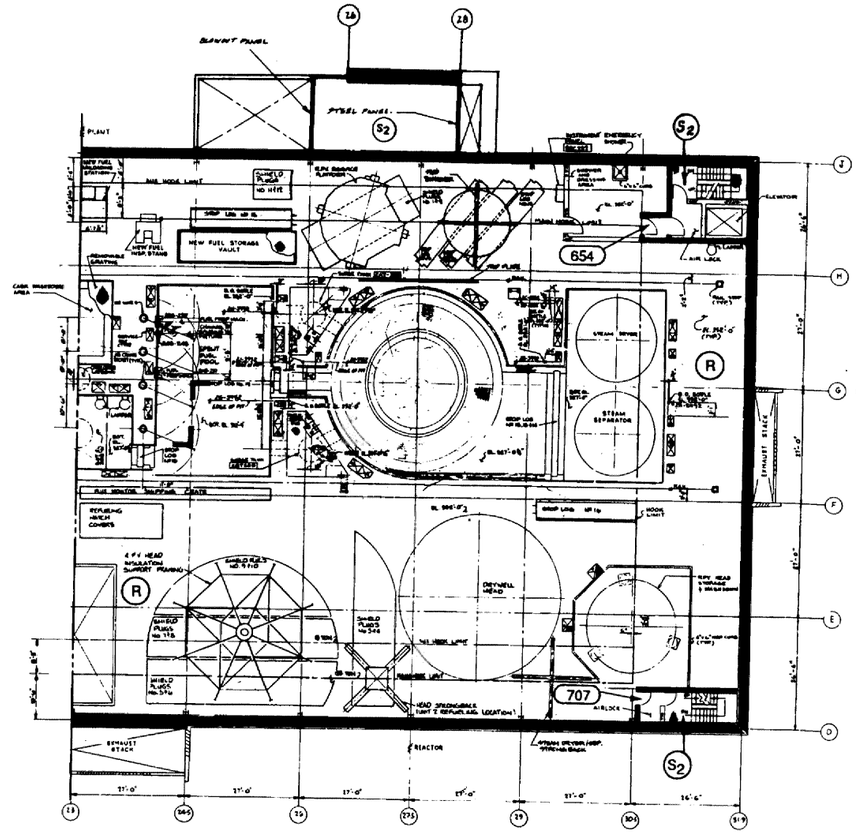
FIGURE 6.2-32

NOTE: EQUIPMENT LOCATION DRAWING M-122, REV. 14 (FOR UNIT 1), AND M-137, REV. 13 (FOR UNIT 2) WERE USED AS BACKGROUND FOR THIS FIGURE

LEGEND

- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (XXX) IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT

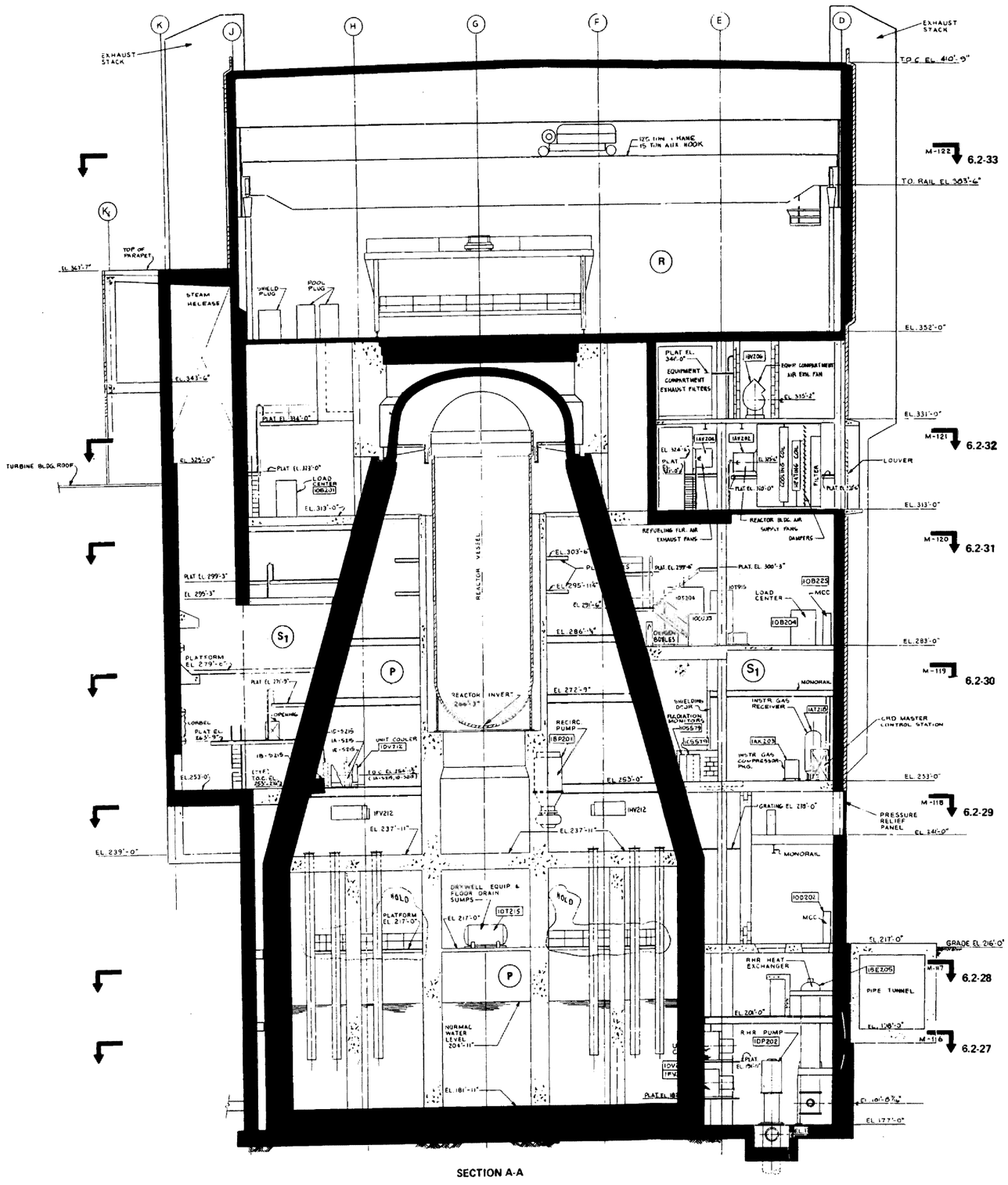




LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT BOUNDARY OUTLINE, PLAN AT ELEV. 352 FEET

FIGURE 6.2-33



SECTION A-A

LEGEND

- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (XXX) IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT

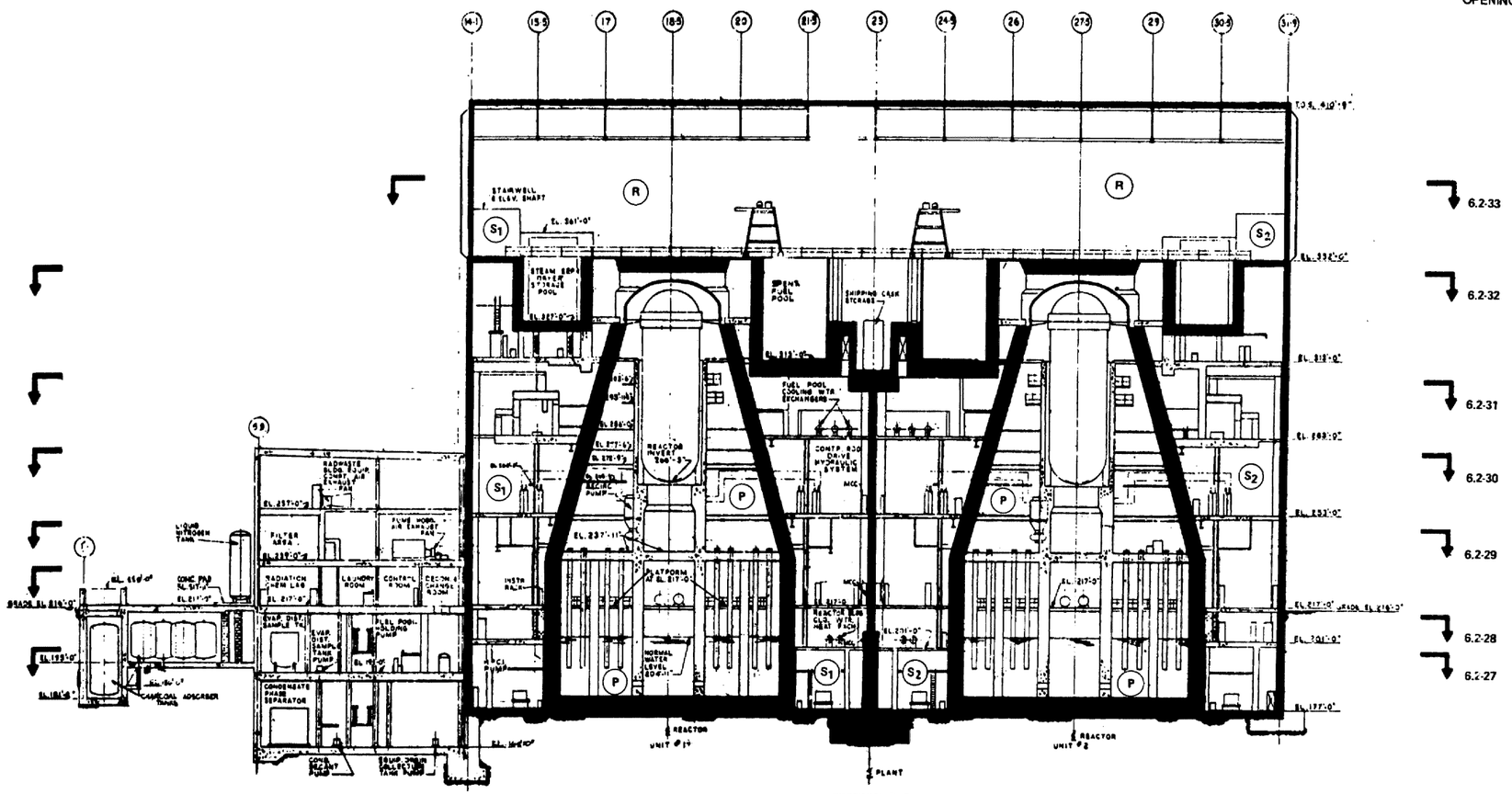
NOTE: EQUIPMENT LOCATION DRAWING M-123, REV. 6 WAS USED AS BACKGROUND FOR THIS FIGURE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT BOUNDARY OUTLINE NORTH-SOUTH SECTION VIEW (UNIT 1)

FIGURE 6.2-34

NOTE: EQUIPMENT LOCATION DRAWING M-108, REV. 5 WAS USED AS BACKGROUND FOR THIS FIGURE



SECTION B-B

LEGEND

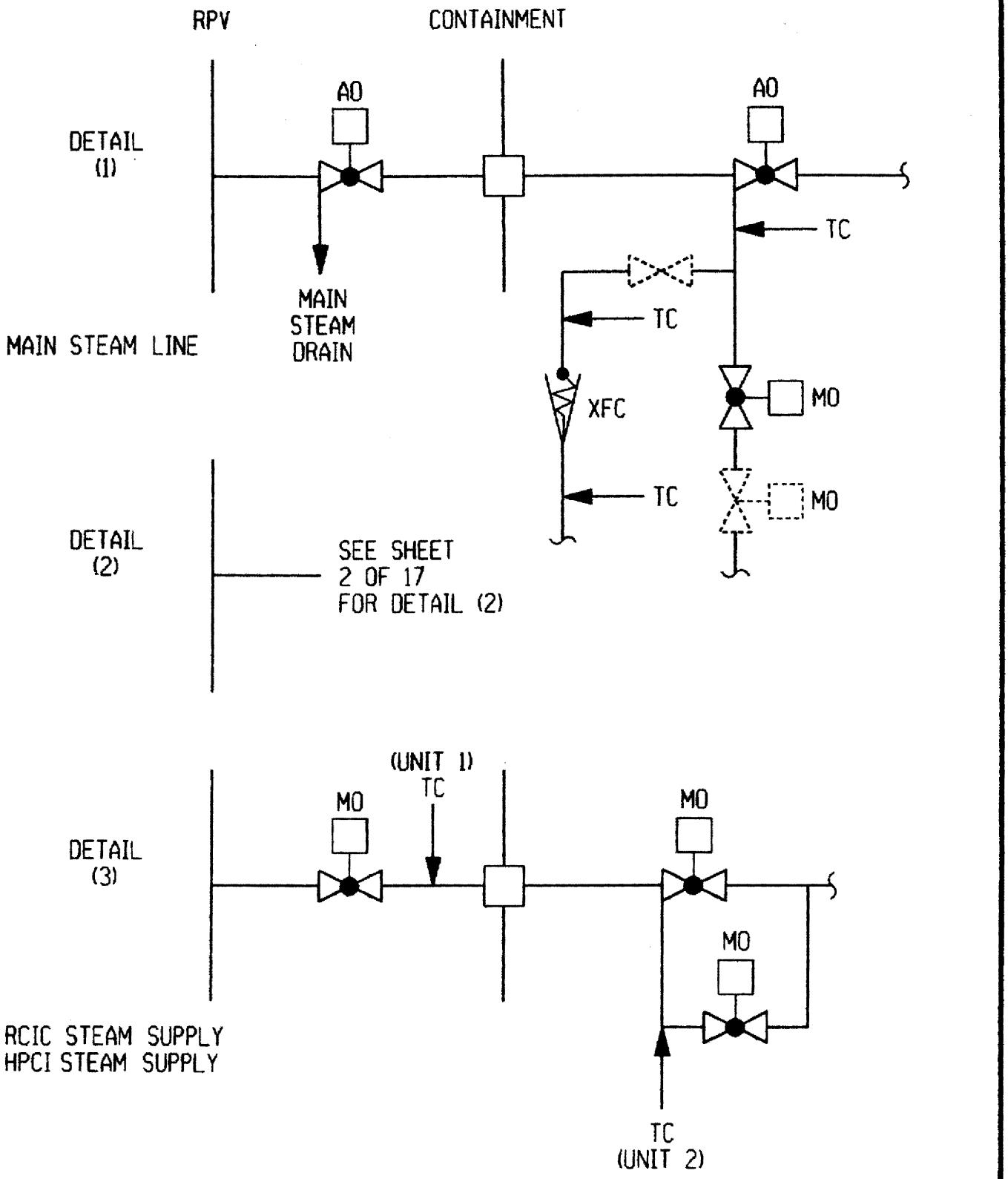
- (P) PRIMARY CONTAINMENT
- (R) REFUELING AREA SECONDARY CONTAINMENT
- (S_1) UNIT 1 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (S_2) UNIT 2 REACTOR ENCLOSURE SECONDARY CONTAINMENT
- (XXX) IDENTIFICATION NUMBER FOR ACCESS OPENINGS IN SECONDARY CONTAINMENT

6.2-33
6.2-32
6.2-31
6.2-30
6.2-29
6.2-28
6.2-27

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SECONDARY CONTAINMENT
BOUNDARY OUTLINE
EAST-WEST SECTION VIEW

FIGURE 6.2-35



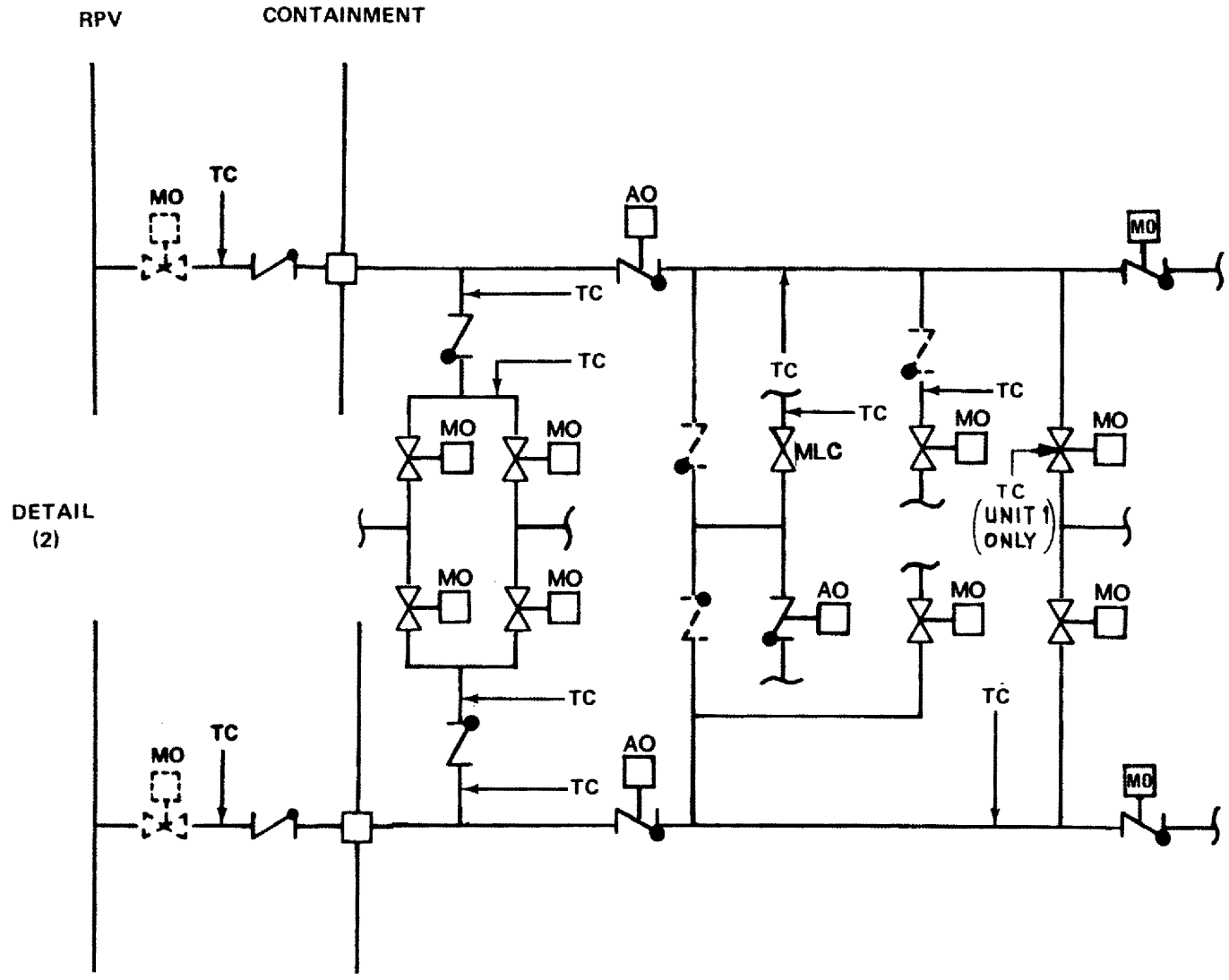
MO - MOTOR OPERATED
TC - TEST CONNECTION
AO - AIR OPERATED
XFC - EXCESS FLOW CHECK VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS (SHEET 1 OF 17)

FIGURE 6.2-36 Rev. 1 July/91

Z:\MECH\ 0602036.S1

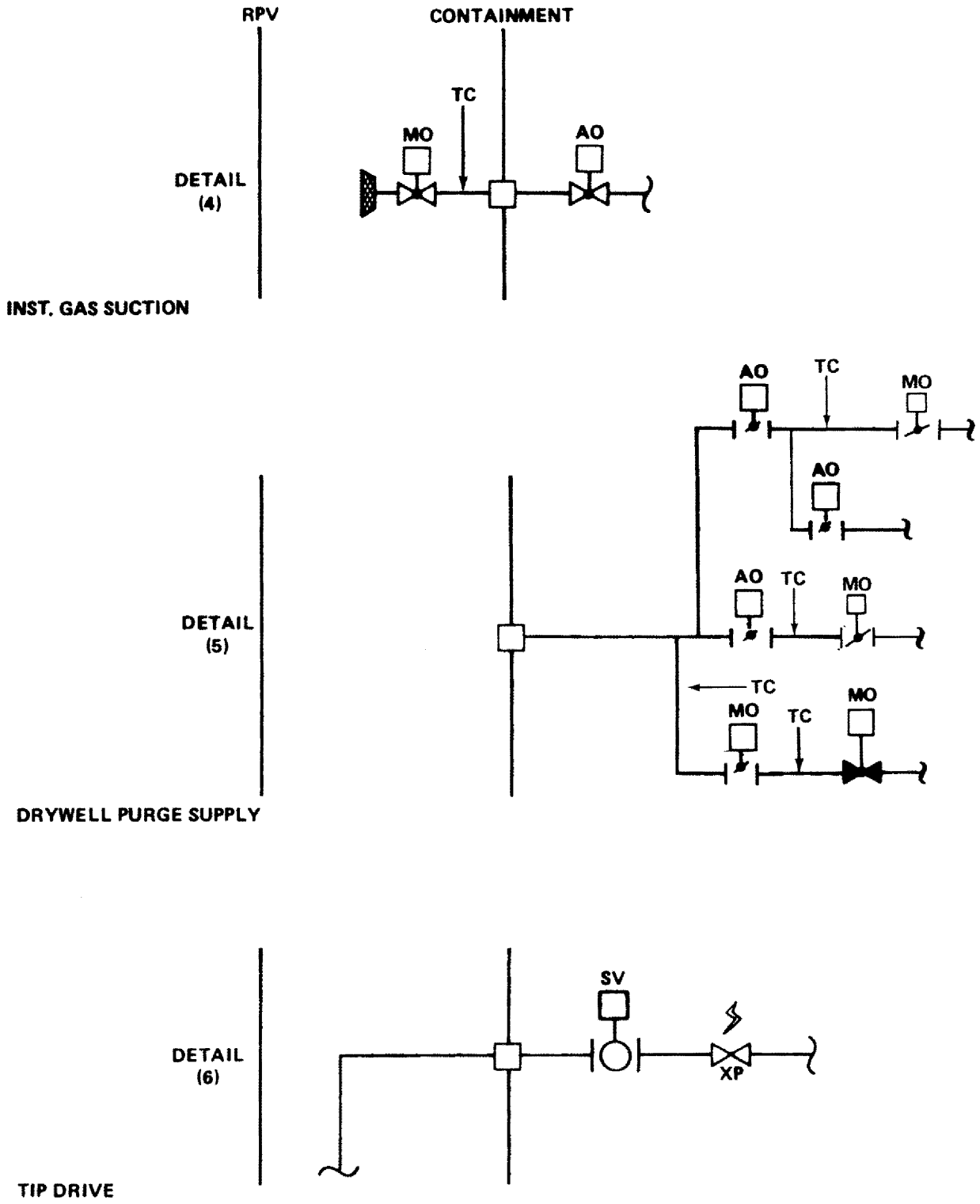


MO–MOTOR OPERATED
TC–TEST CONNECTION
AO–AIR OPERATED
XFC–EXCESS FLOW CHECK VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 2 OF 17)

FIGURE 6.2-36

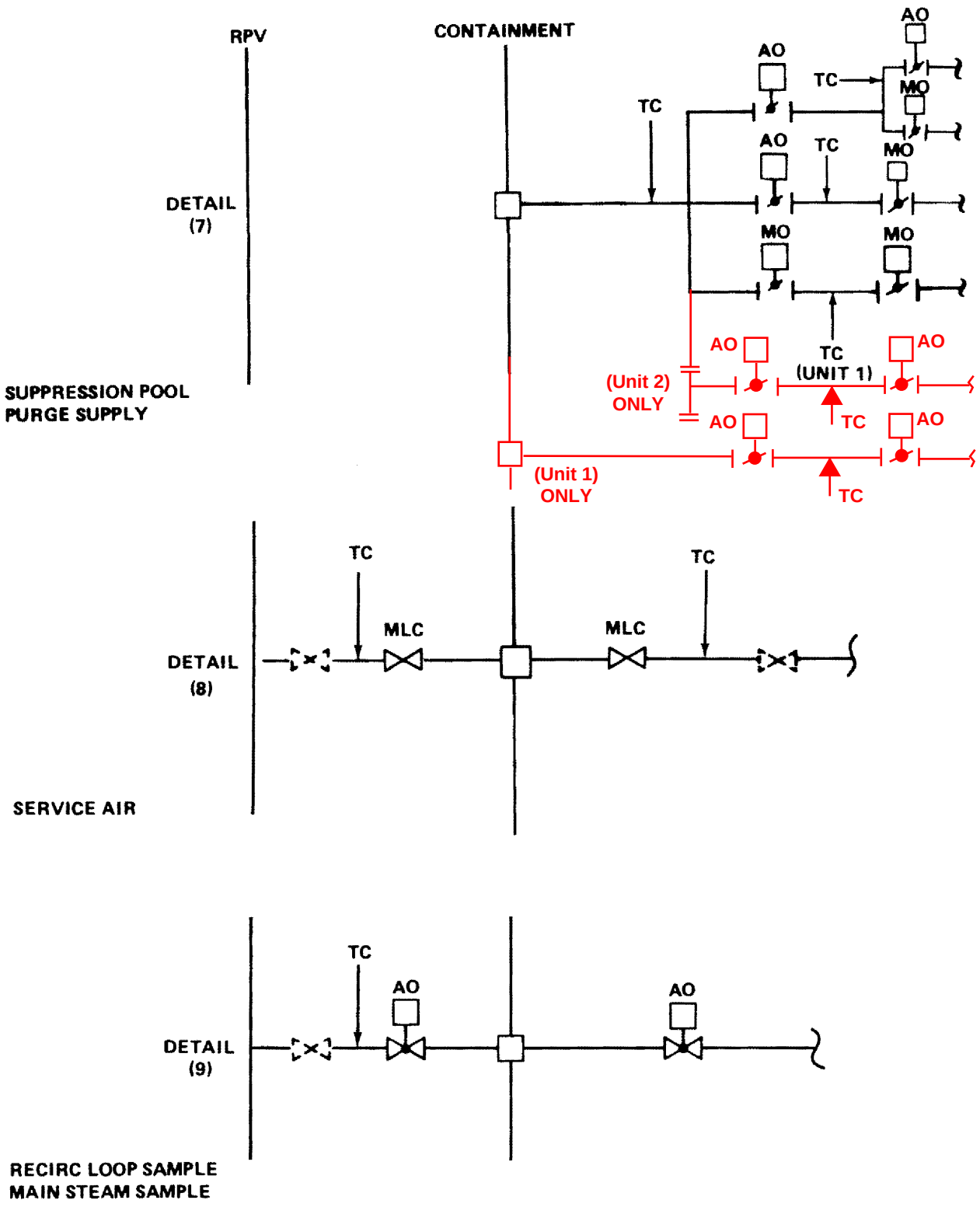


SV–SOLENOID VALVE
MO–MOTOR OPERATED
TC–TEST CONNECTION
AO–AIR OPERATED
XP–EXPLOSIVE (SHEAR) VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 3 OF 17)

FIGURE 6.2-36



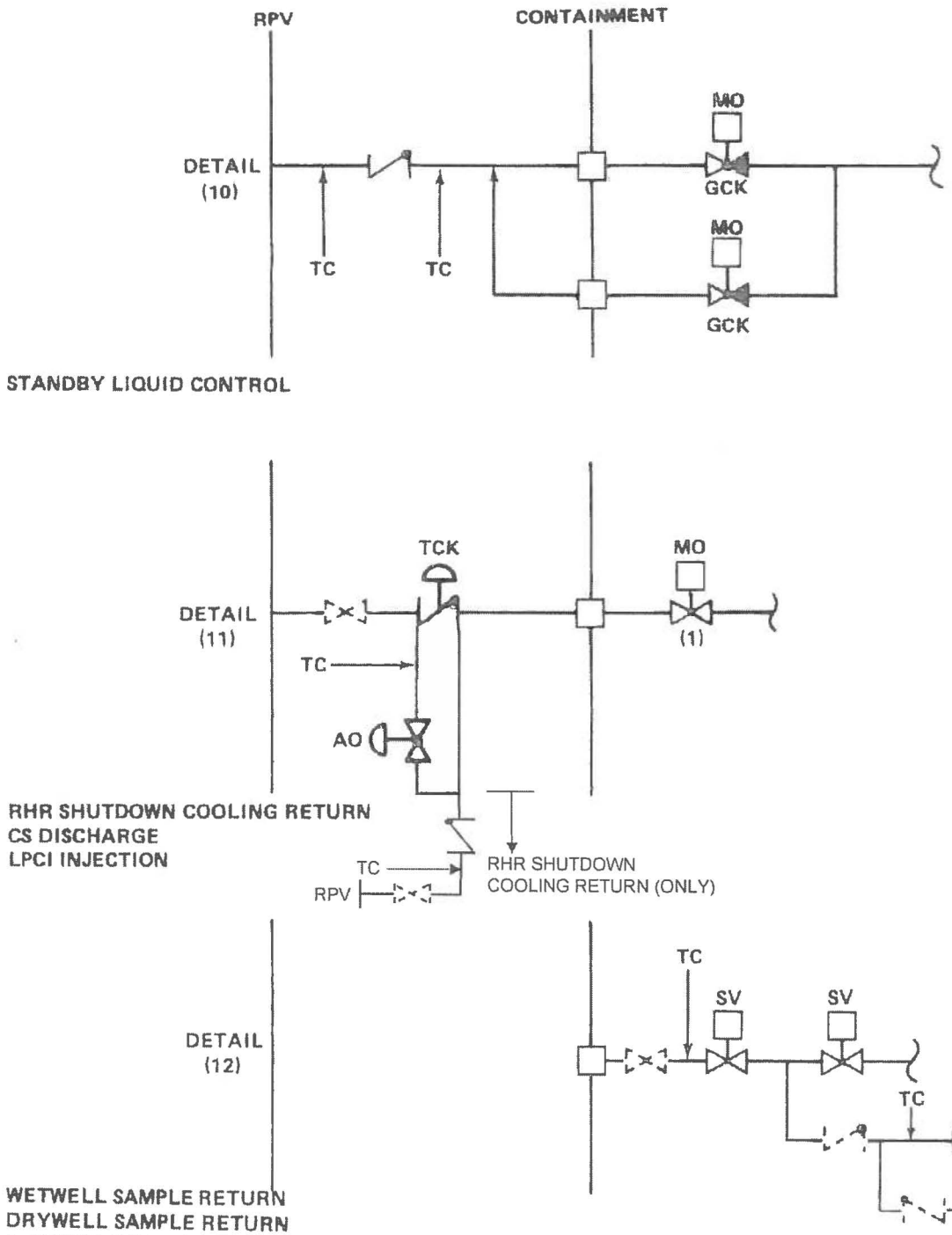
MO–MOTOR OPERATED
SV–SOLENOID VALVE
TC–TEST CONNECTION
AO–AIR OPERATED
TCK–TESTABLE CHECK VALVE
MLC–MANUAL LOCKED CLOSED

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 4 OF 17)

FIGURE 6.2-36

Rev. 19 09/18



MO–MOTOR OPERATED
SV–SOLENOID VALVE
TC–TEST CONNECTION
GCK–GLOBE STOP CHECK
TCK–TESTABLE CHECK VALVE
AO–AIR OPERATED

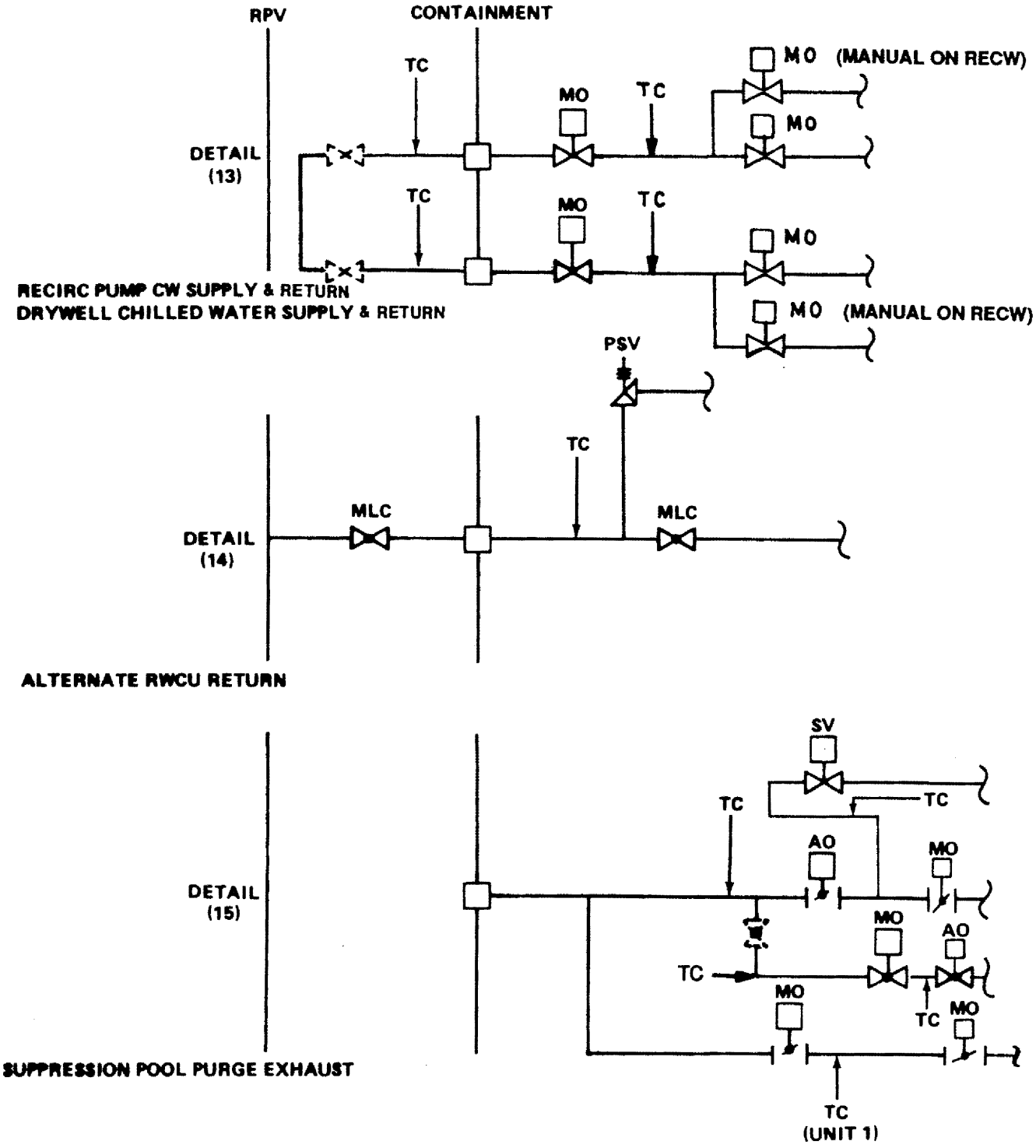
(1) THIS IS A GLOBE VALVE FOR RHR SHUTDOWN COOLING RETURN AND A SPRING LOADED PISTON ACTUATED CHECK VALVE FOR CS LOOP B.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 5 OF 17)

FIGURE 6.2-36

REV. 15, 09/10

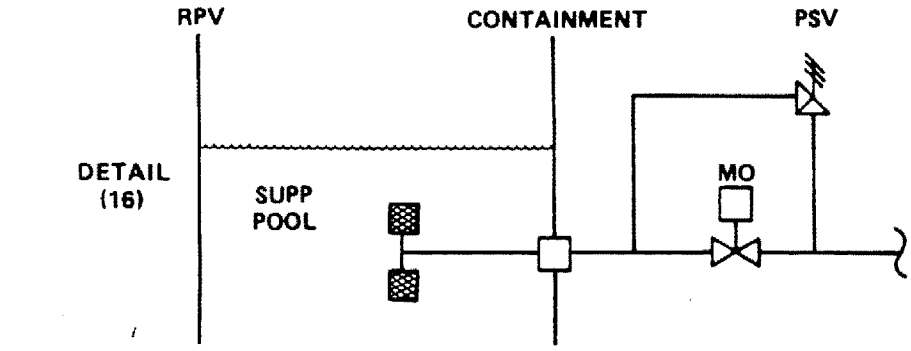


MO–MOTOR OPERATED
AO–AIR OPERATED
TC–TEST CONNECTION
MLC–MANUAL LOCKED CLOSED
SV–SOLENOID VALVE
PSV–PRESSURE SAFETY VALVE

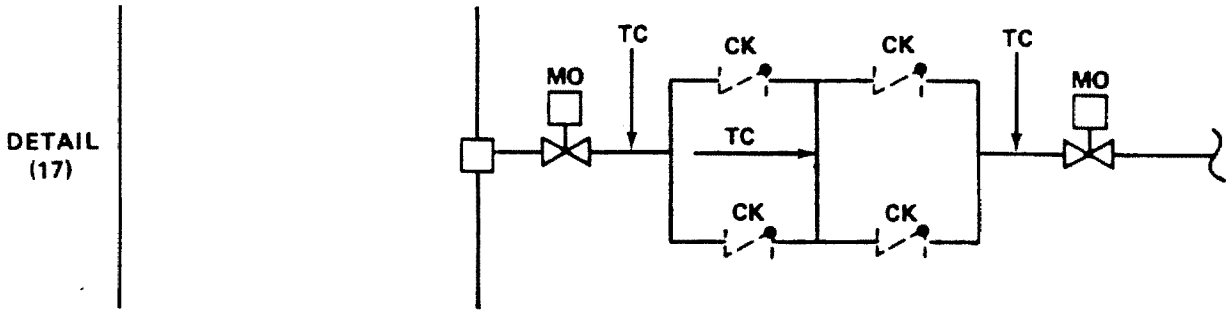
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 6 OF 17)

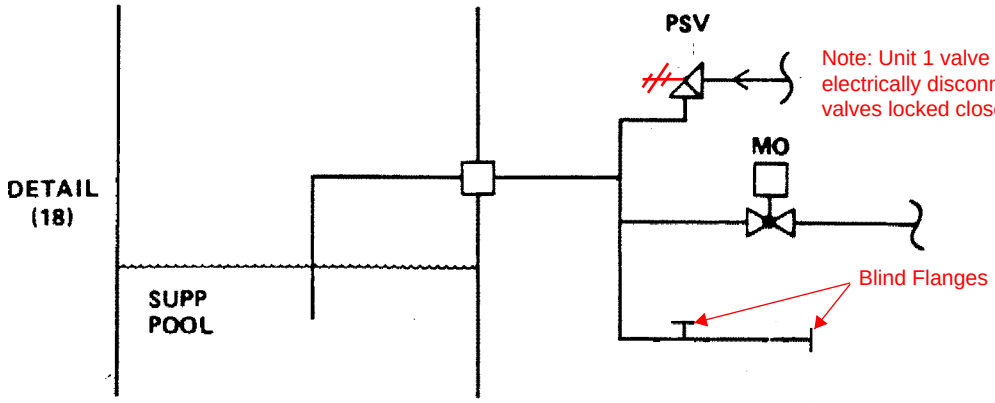
FIGURE 6.2-36



RHR PUMP SUCTION



HPCI VACUUM RELIEF
RCIC VACUUM RELIEF



RHR RELIEF VALVE DISCHARGE

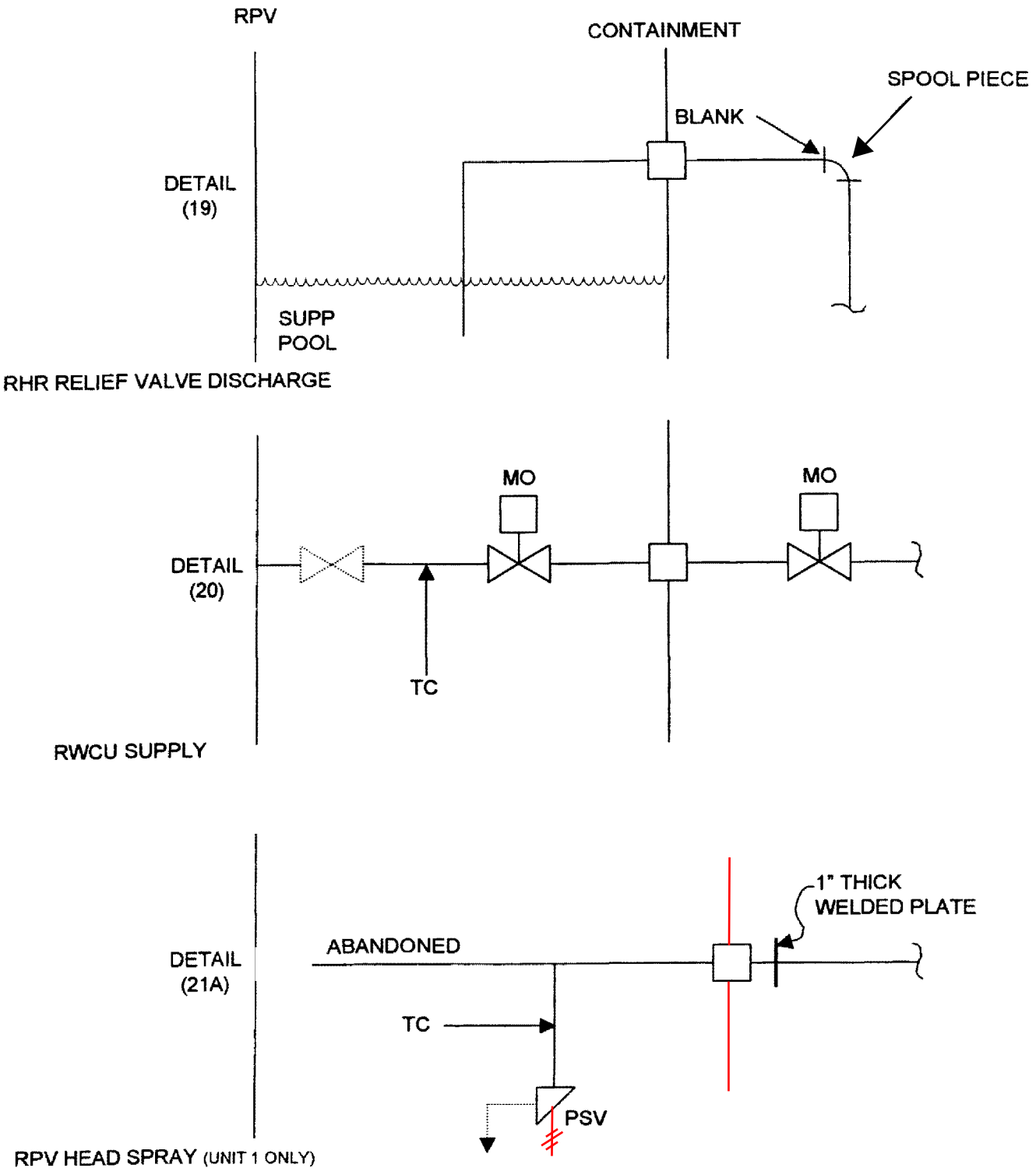
PSV–PRESSURE SAFETY VALVE
MO–MOTOR OPERATED
TC–TEST CONNECTION
CK–CHECK VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 7 OF 17)

FIGURE 6.2-36

Rev. 15, 09/10

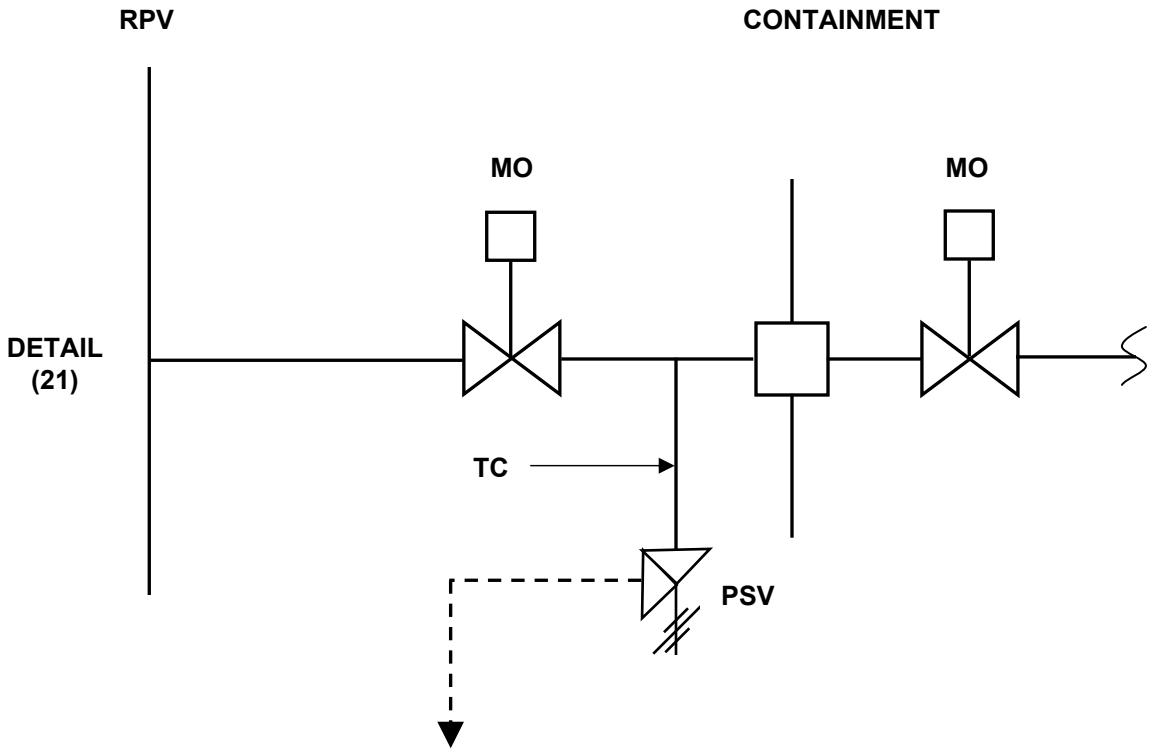


MO – MOTOR OPERATED
TC – TEST CONNECTION
PSV – PRESSURE SAFETY VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 8 of 17)

FIGURE 6.2-36 Rev. 15, 09/10



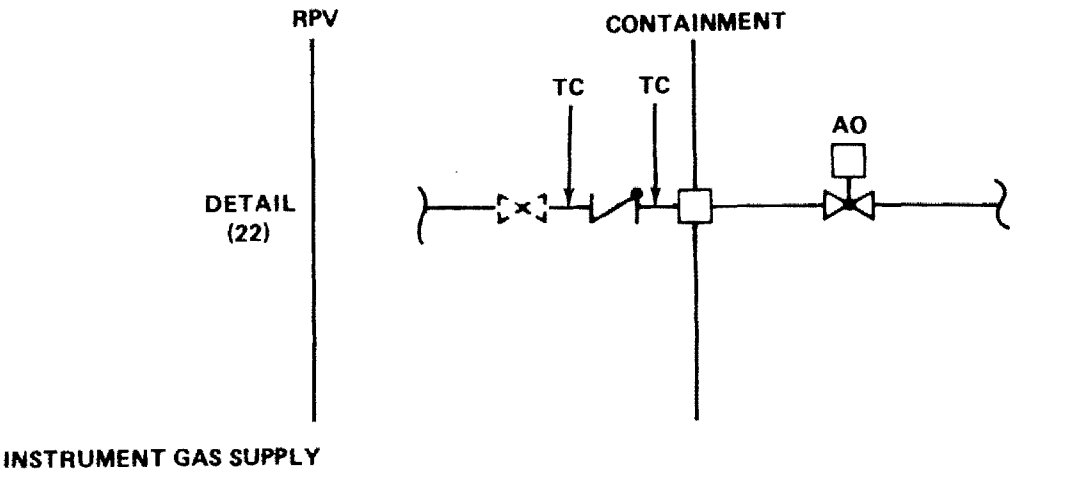
RHR SHUTDOWN COOLING SUPPLY

MO – MOTOR OPERATED
TC – TEST CONNECTION
PSV – PRESSURE SAFETY VALVE

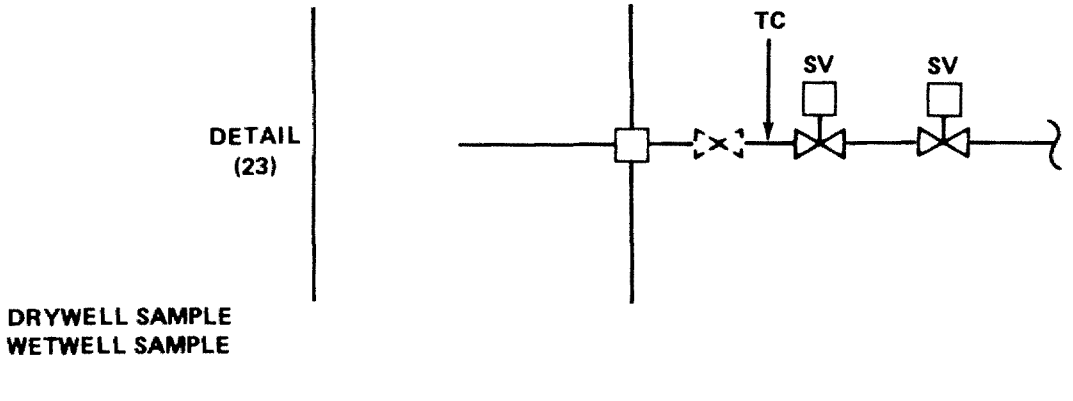
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(Sheet 8a of 17)

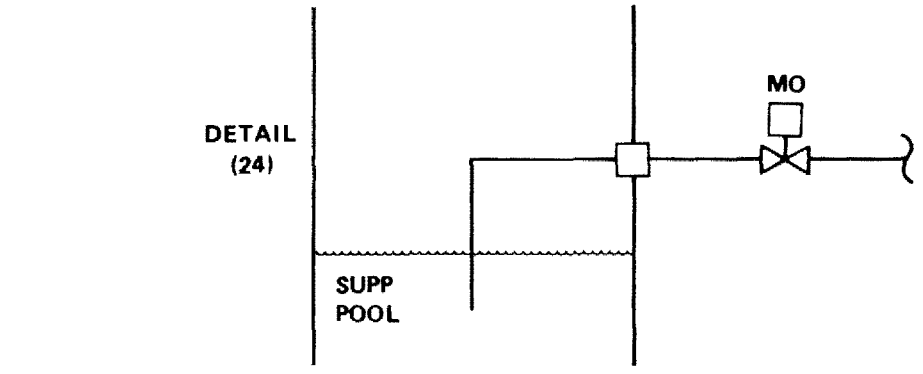
FIGURE 6.2-36 Rev. 15, 09/10



INSTRUMENT GAS SUPPLY



DRYWELL SAMPLE
WETWELL SAMPLE



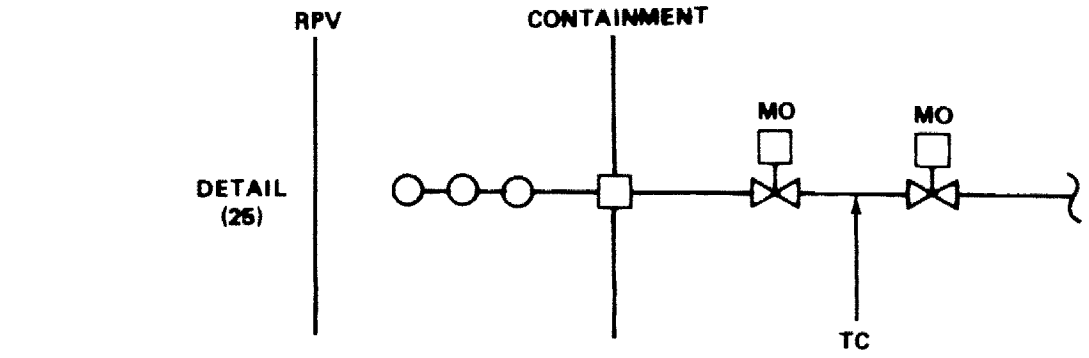
HPCI TURBINE EXHAUST
HPCI PUMP FLUSH
HPCI PUMP MIN FLOW
CS PUMP MIN FLOW
CS PUMP TEST & FLUSH
RCIC TURBINE EXHAUST
RCIC MIN FLOW
RHR PUMP MIN FLOW

AO–AIR OPERATED
MO–MOTOR OPERATED
SV–SOLENOID VALVE
TC–TEST CONNECTION

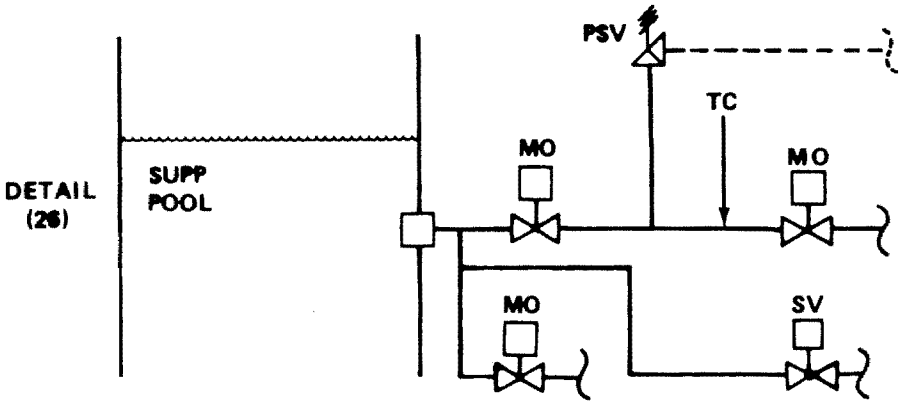
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 9 OF 17)

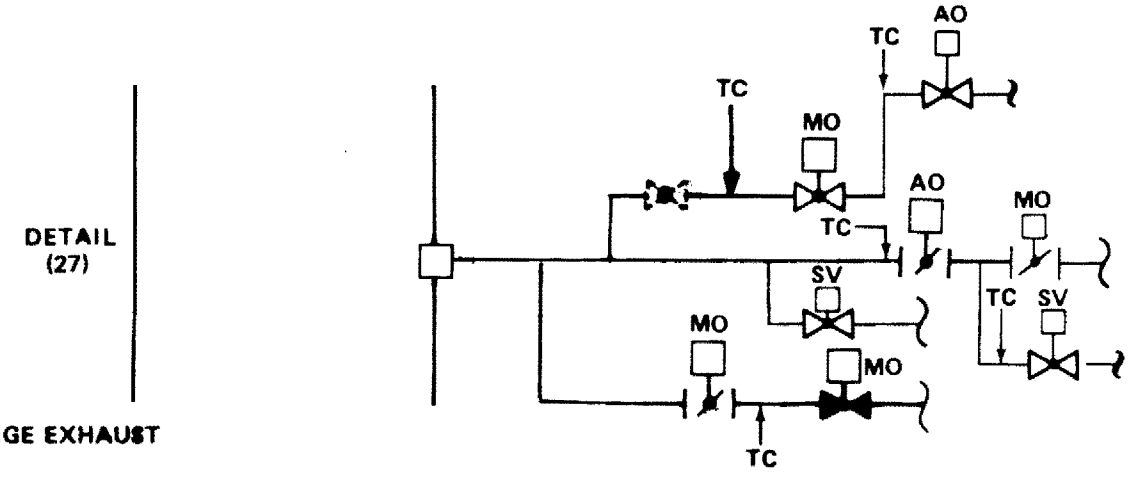
FIGURE 6.2-36



CONTAINMENT SPRAY



SUPPRESSION POOL
CLEANUP PUMP SUCTION
AND LEVEL
INSTRUMENTATION



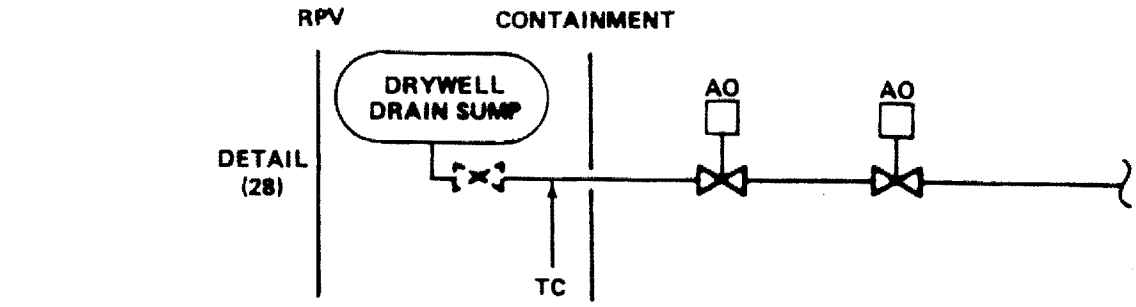
DRYWELL PURGE EXHAUST

MO–MOTOR OPERATED
AO–AIR OPERATED
TC–TEST CONNECTION
PSV–PRESSURE SAFETY VALVE
SV–SOLENOID VALVE

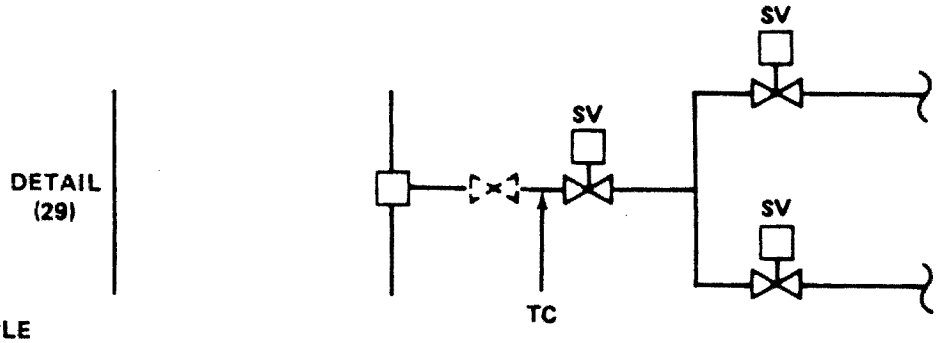
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(SHEET 10 OF 17)

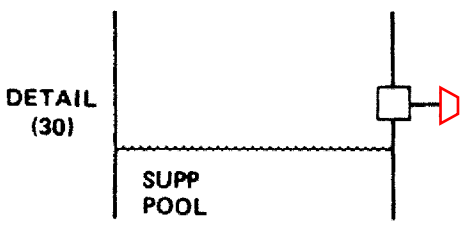
FIGURE 6.2-36



DRYWELL DRAIN SUMP DISCHARGE

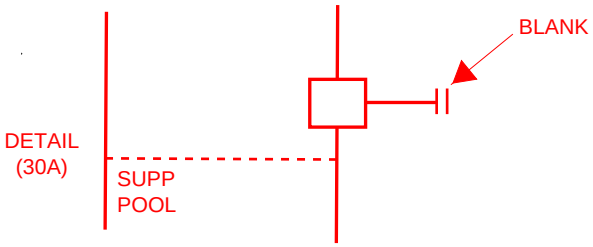


DRYWELL SAMPLE
WETWELL SAMPLE



RHR VACUUM RELIEF

UNIT 1 ONLY



UNIT 2 ONLY

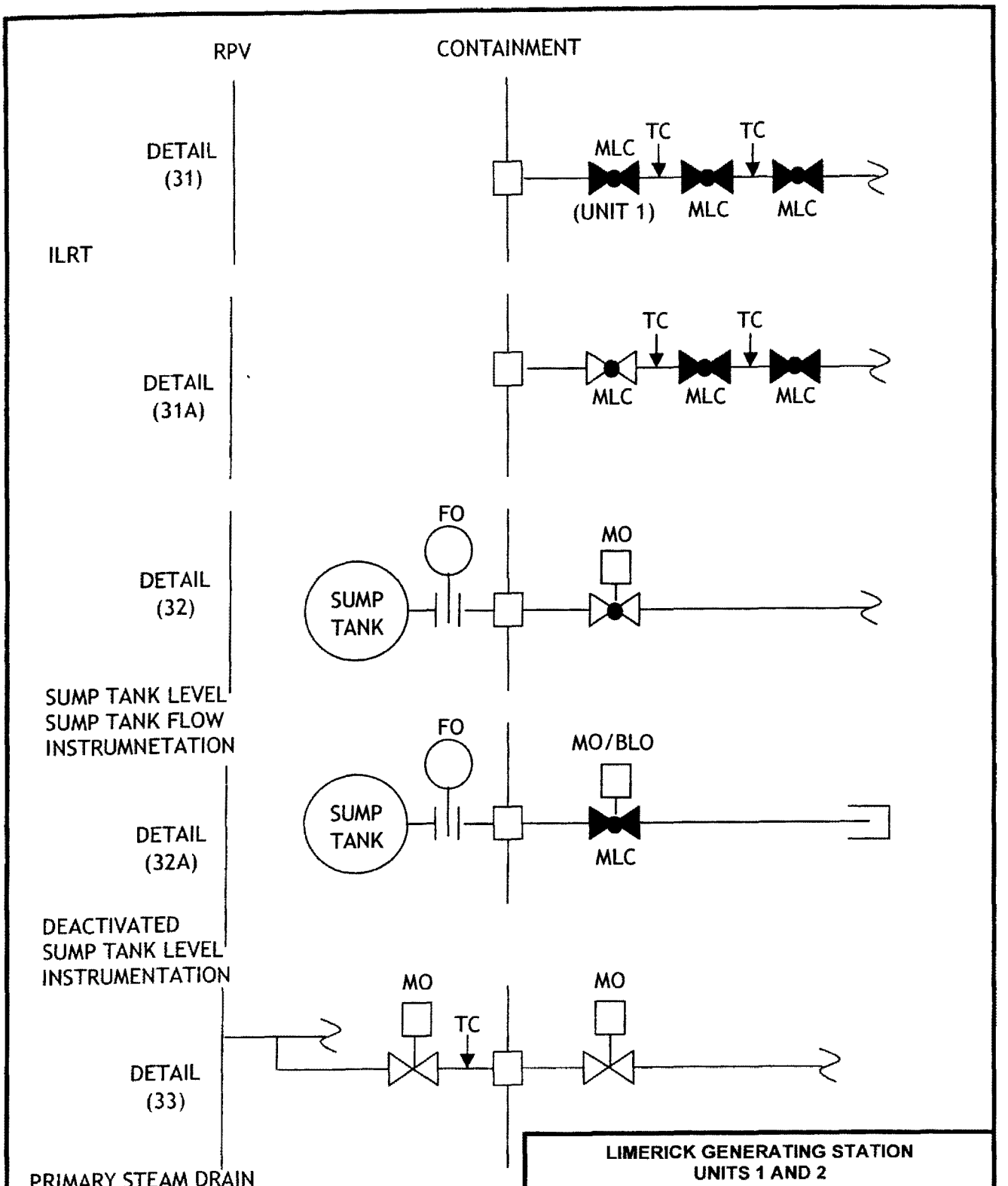
MO–MOTOR OPERATED
TC–TEST CONNECTION
SV–SOLENOID VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(SHEET 11 OF 17)

FIGURE 6.2-36

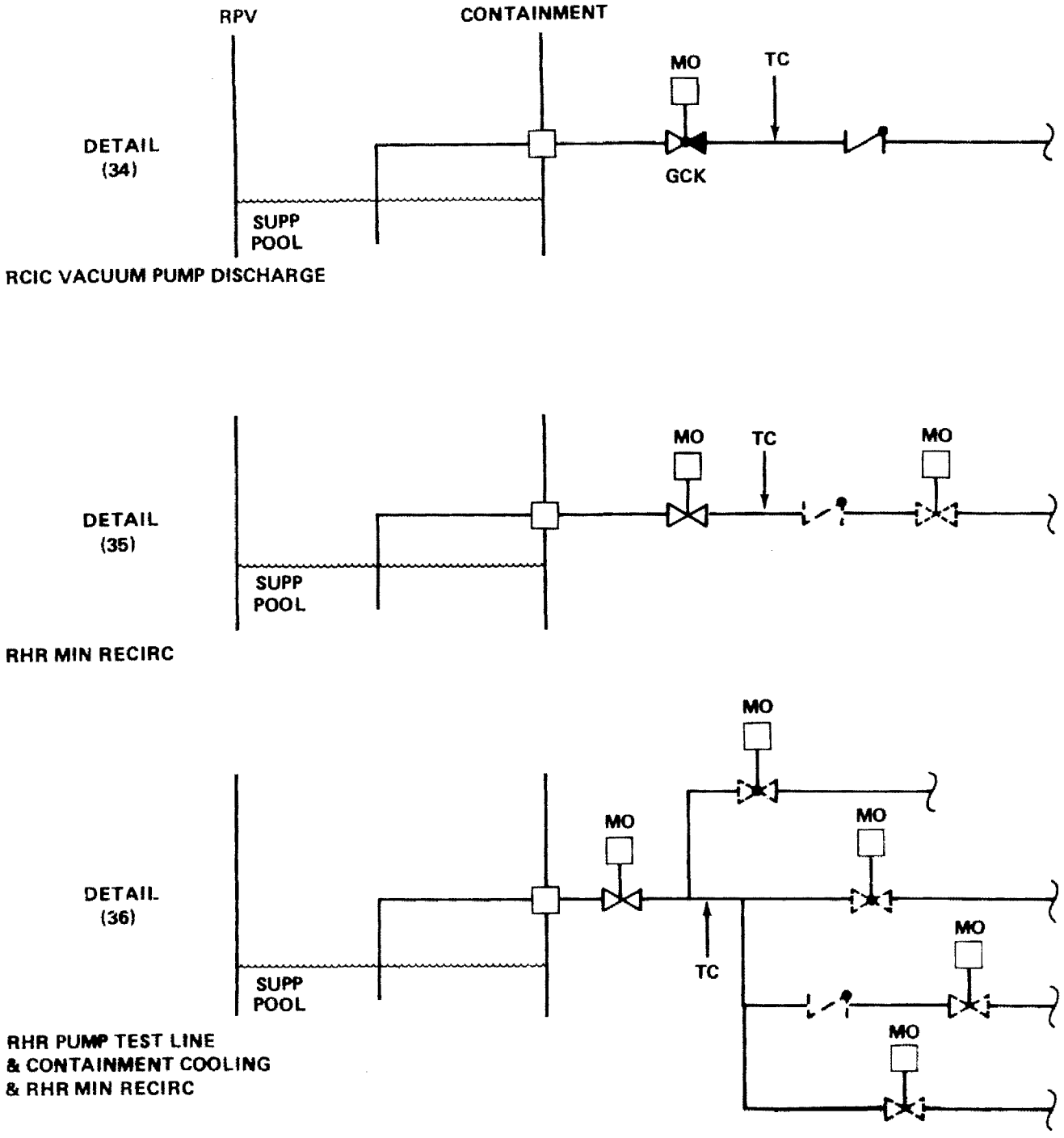
Rev. 15, 09/10



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 12 OF 17)

FIGURE 6.2-36 **Rev. 12 9/04**

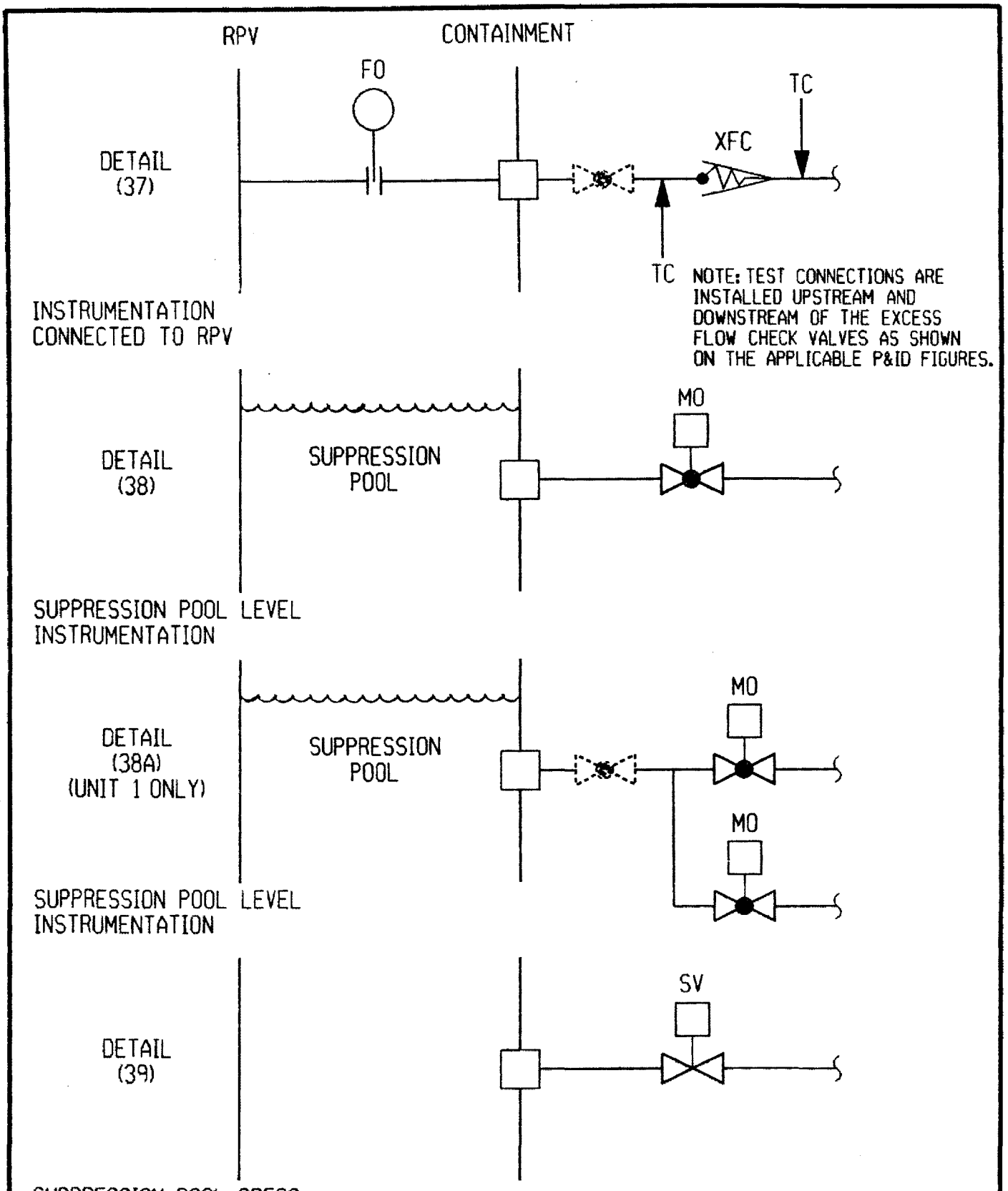


MO—MOTOR OPERATED
TC—TEST CONNECTION
GCK—GLOBE STOP CHECK

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(SHEET 13 OF 17)

FIGURE 6.2-36



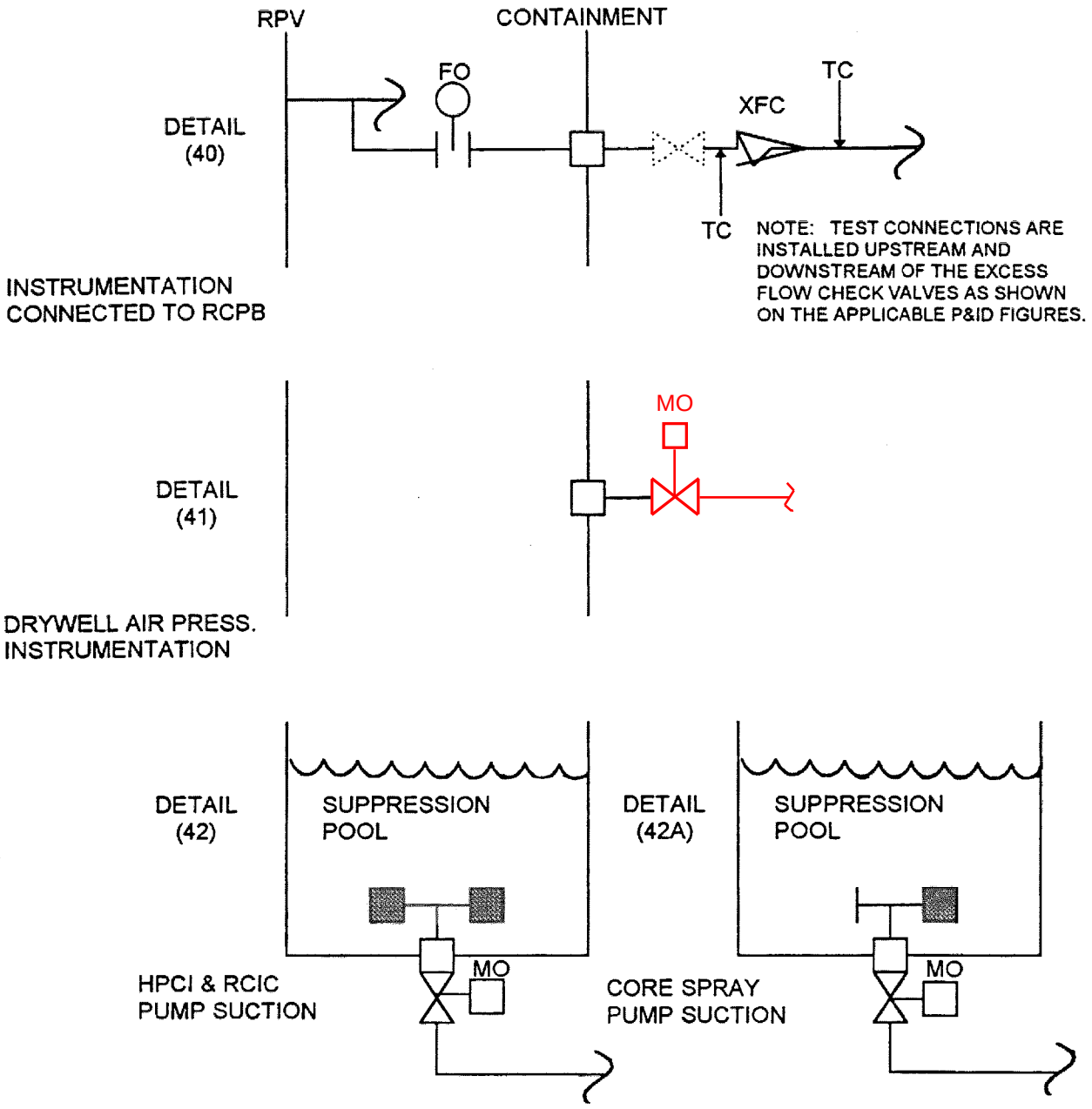
XFC - EXCESS FLOW CHECK VALVE
FO - FLOW ORIFICE
MO - MOTOR OPERATED
TC - TEST CONNECTION
SV - SOLENOID VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 14 OF 17)

FIGURE 6.2-36 Rev. 1 July/91

Z:\MECH\ 0602036.DGN



FO - FLOW ORIFICE
MO - MOTOR OPERATED
TC - TEST CONNECTION
XFC - EXCESS FLOW CHECK VALVE

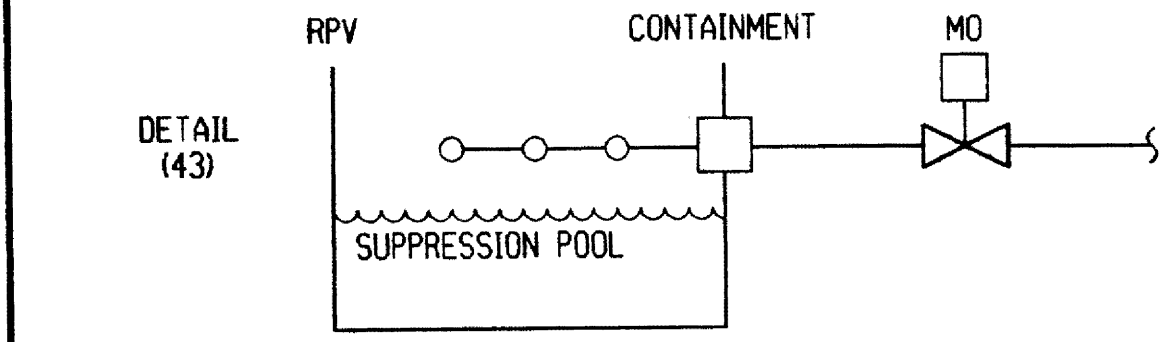
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS

(SHEET 15 OF 17)

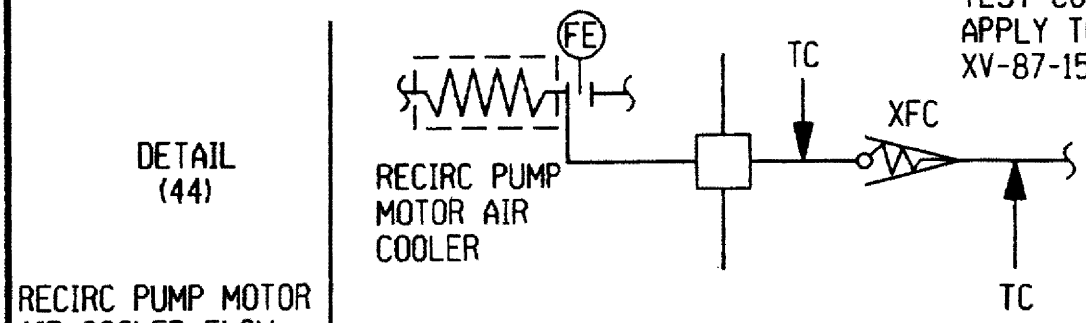
FIGURE 6.2-36

Rev. 15, 09/10

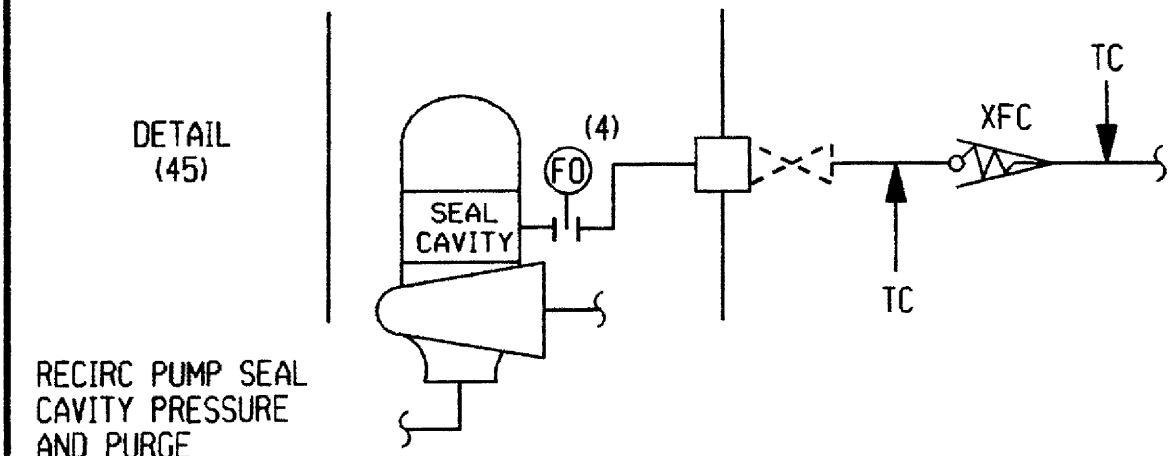


SUPPRESSION POOL SPRAY

NOTE:
TEST CONNECTIONS DO NOT APPLY TO UNIT 1 VALVES XV-87-156A AND XV-87-157A.



RECIRC PUMP MOTOR AIR COOLER FLOW INSTRUMENTATION



RECIRC PUMP SEAL CAVITY PRESSURE AND PURGE

XFC - EXCESS FLOW CHECK VALVE
FE - FLOW ELEMENT
TC - TEST CONNECTION
MO - MOTOR OPERATED
FO - FLOW ORIFICE

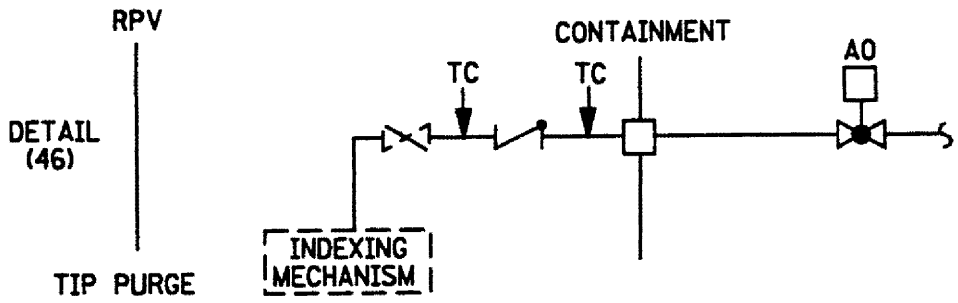
(3) DELETED

(4) CHECK VALVE INSTEAD OF FO FOR PURGE LINES

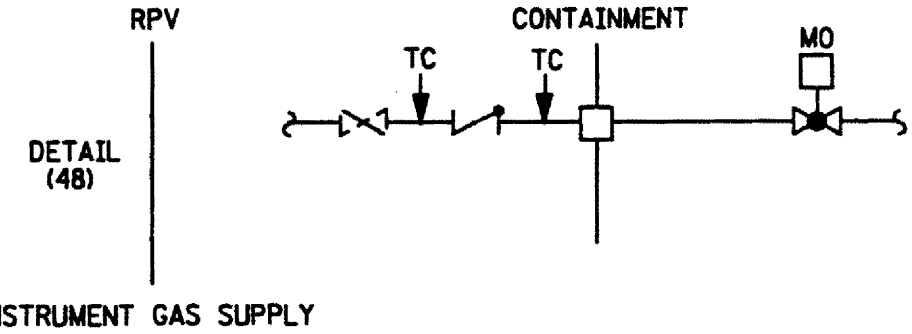
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 16 OF 17)

FIGURE 6.2-36 Rev. 1 July/91



CRD INSERT AND
WITHDRAWAL LINES



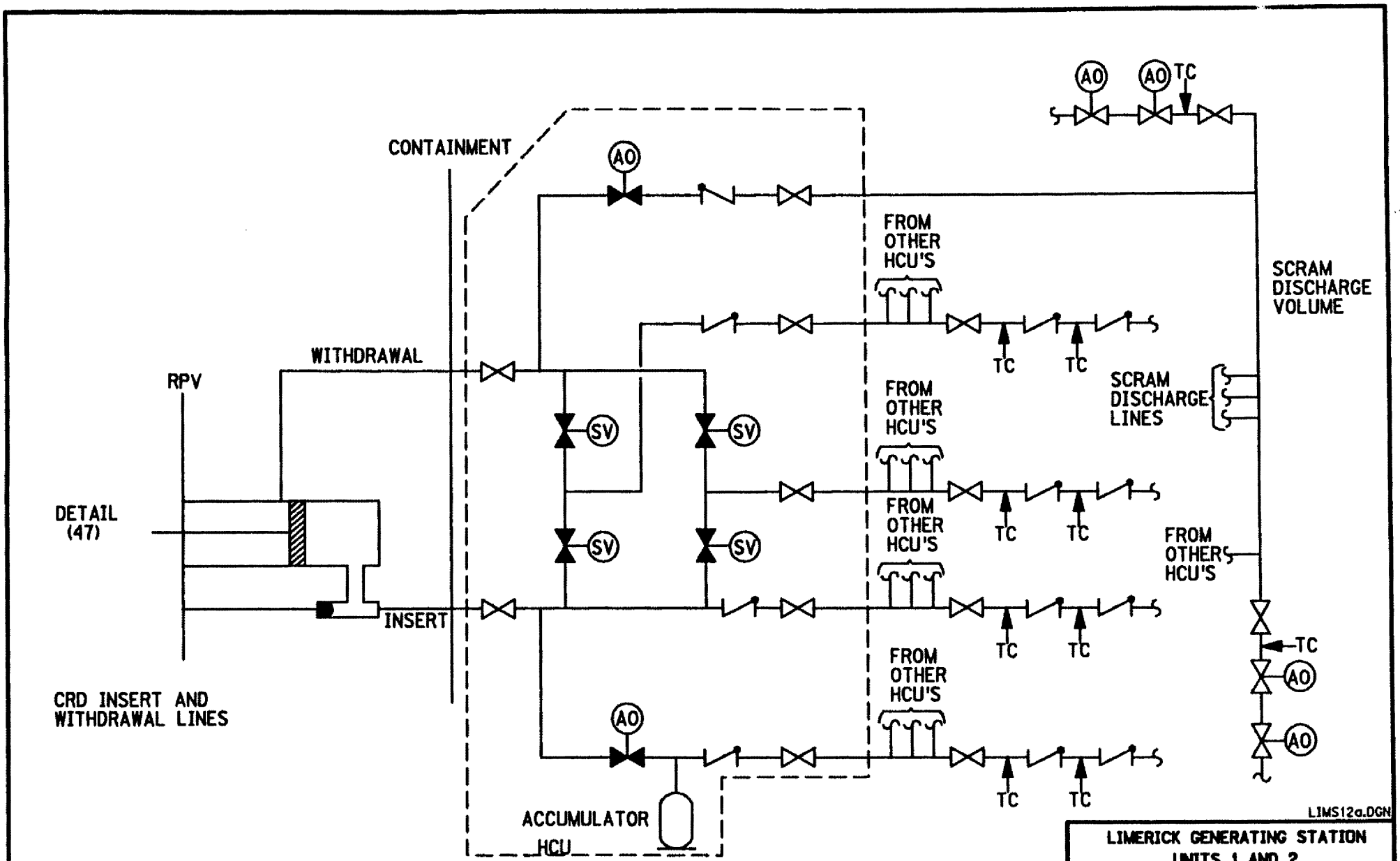
TC=TEST CONNECTION
MO= MOTOR OPERATED
AO= AIR OPERATED
SV=SOLENOID VALVE

LIMS12.DGN

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION
DETAILS
(SHEET 17 OF 17)

FIGURE 6.2-36 Rev. 3 Nov./93



TC=TEST CONNECTION
MO= MOTOR OPERATED
AO= AIR OPERATED
SV=SOLENOID VALVE

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PENETRATION DETAILS
(SHEET 17a OF 17)

FIGURE 6.2-36 Rev. 3 NOV./93

Figure 6.2-37

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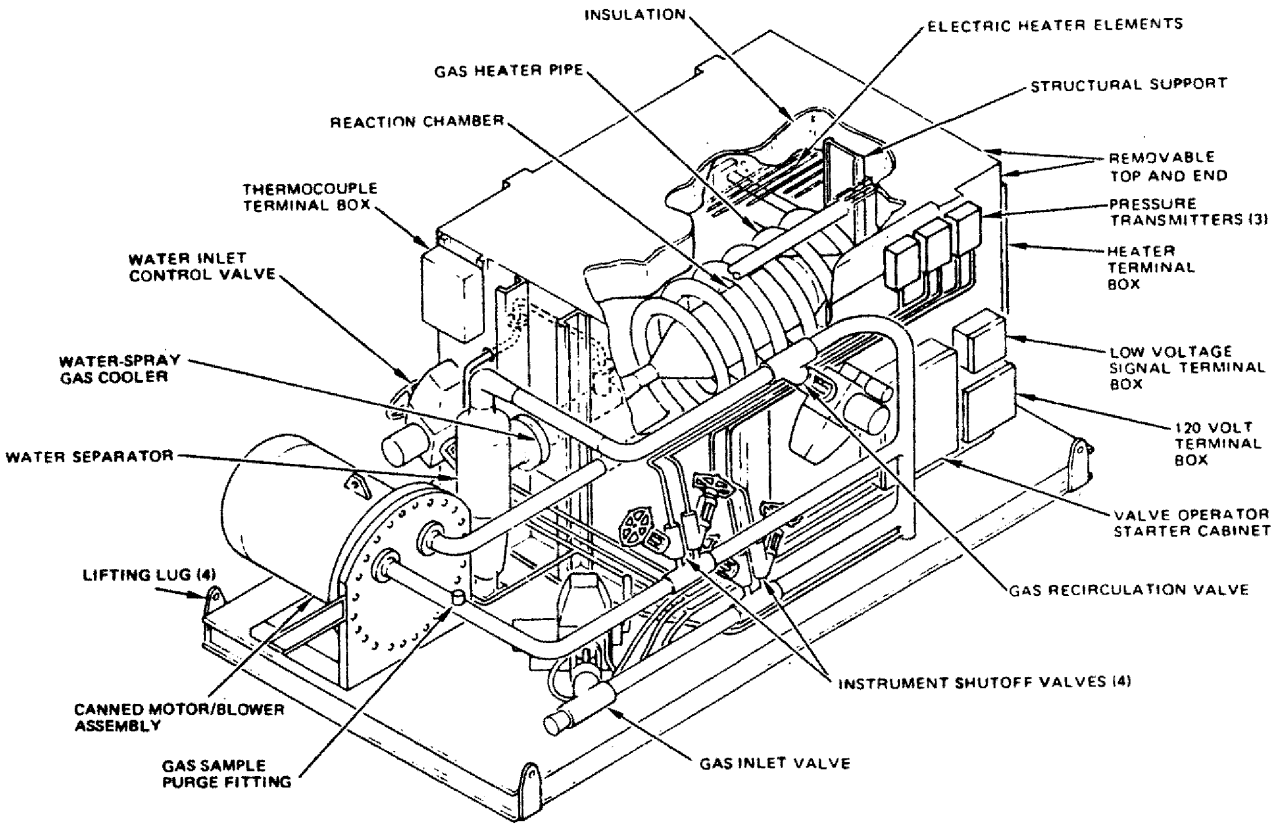
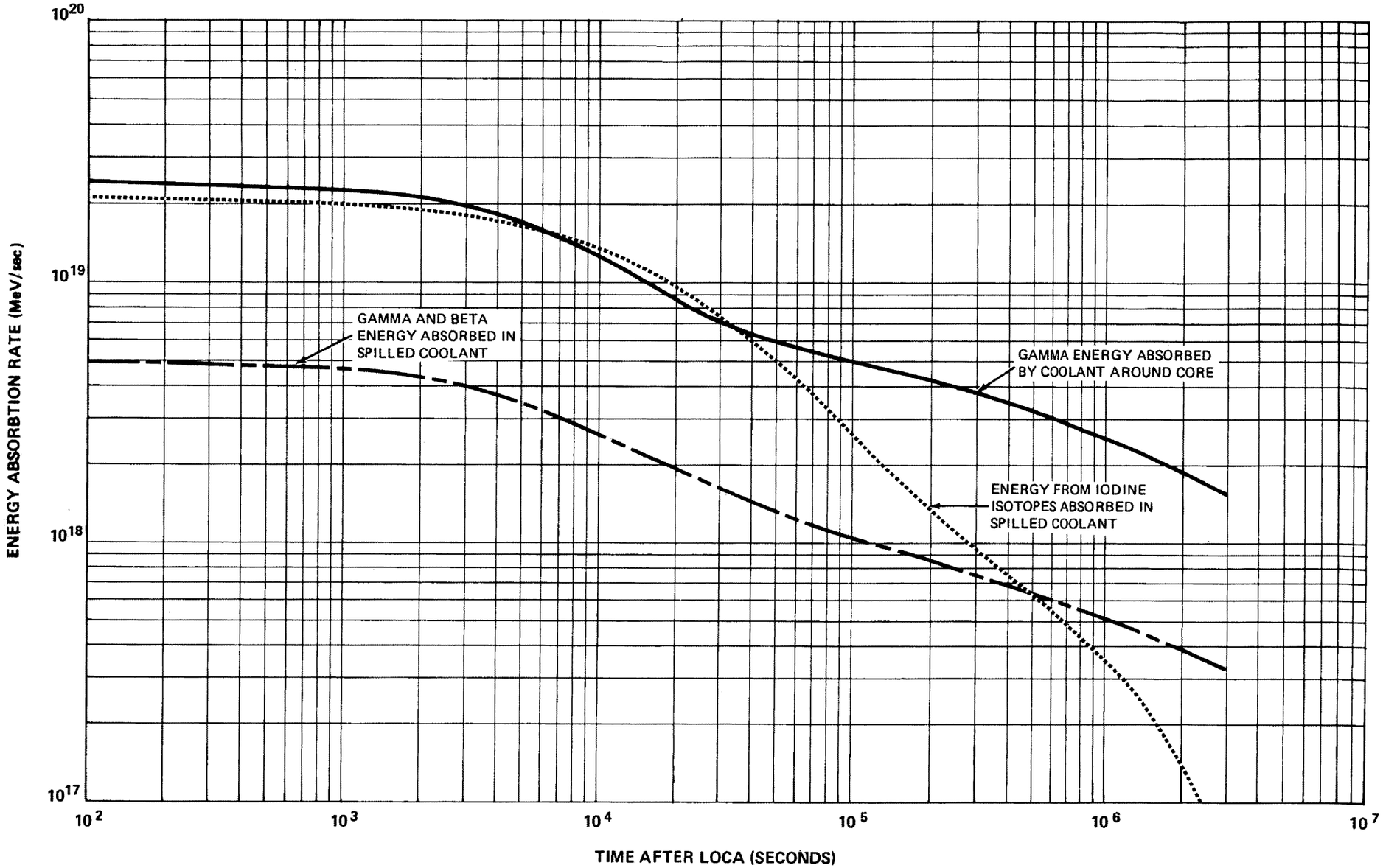


LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT HYDROGEN RECOMBINER SKID, CUTAWAY VIEW

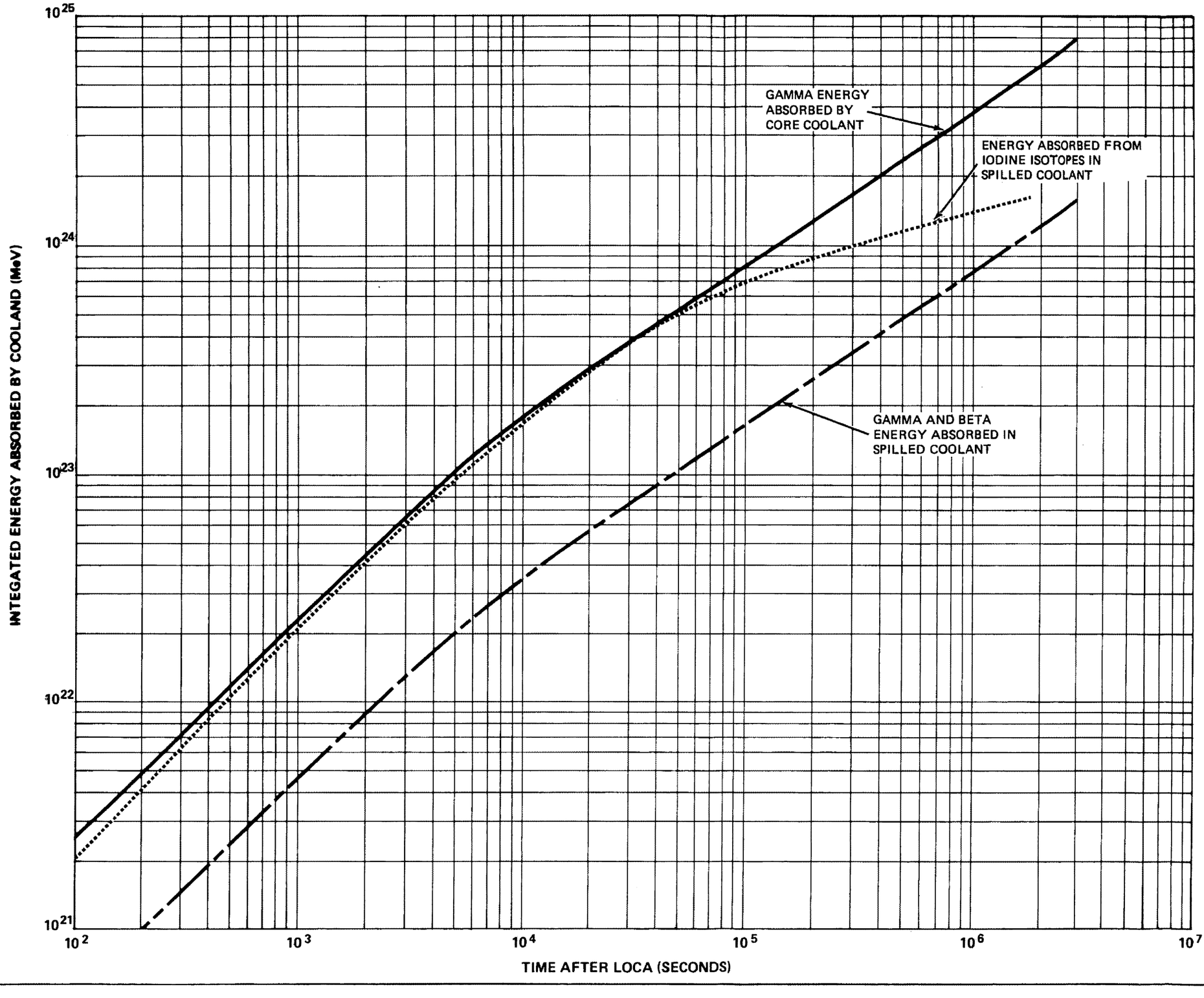
FIGURE 6.2-38



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

RATE OF ENERGY ABSORPTION BY LOCA WATER AS A FUNCTION OF TIME AFTER LOCA

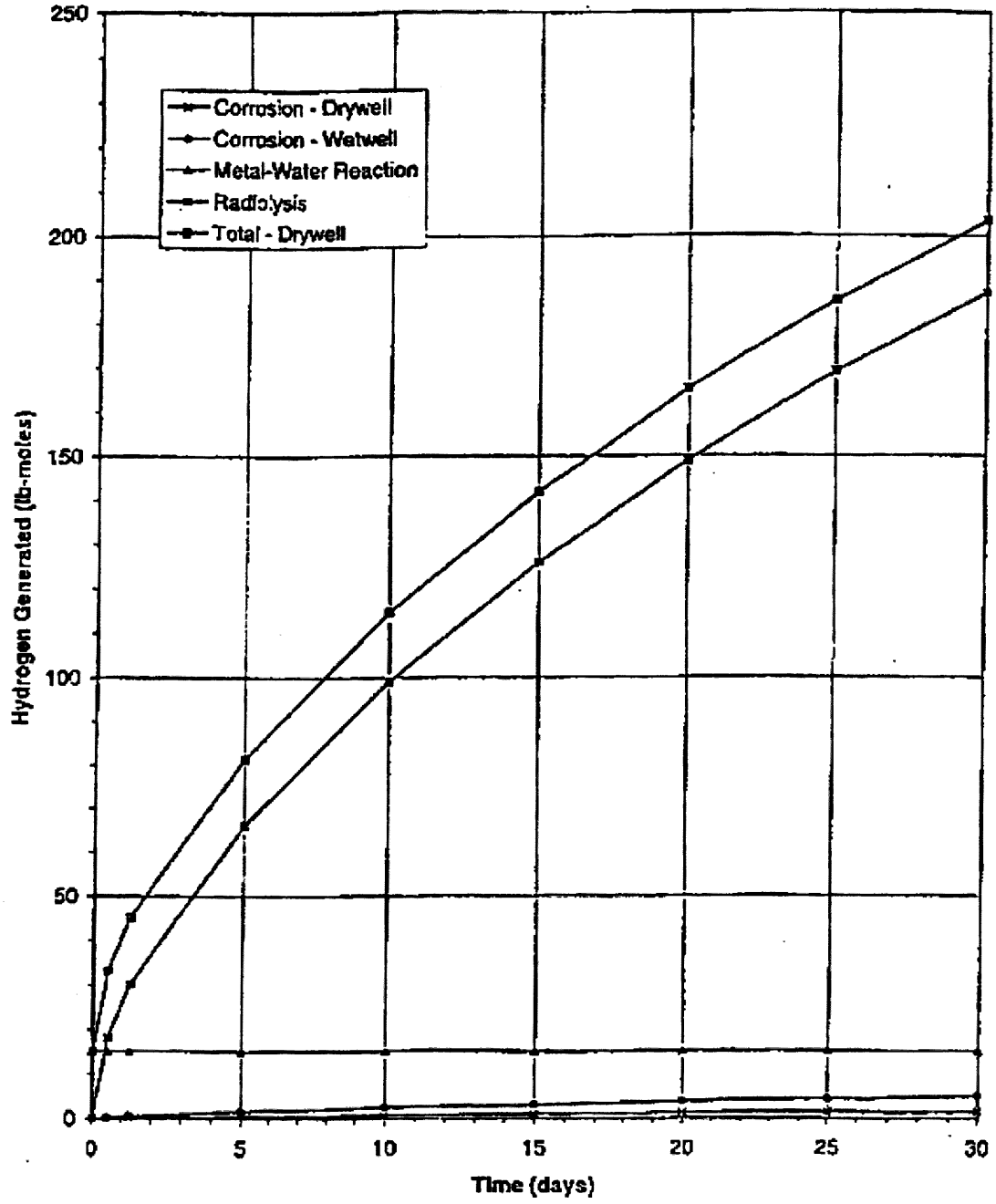
FIGURE 6.2-39



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTEGRATED ENERGY ABSORPTION BY LOCA WATER AS A FUNCTION OF TIME AFTER LOCA

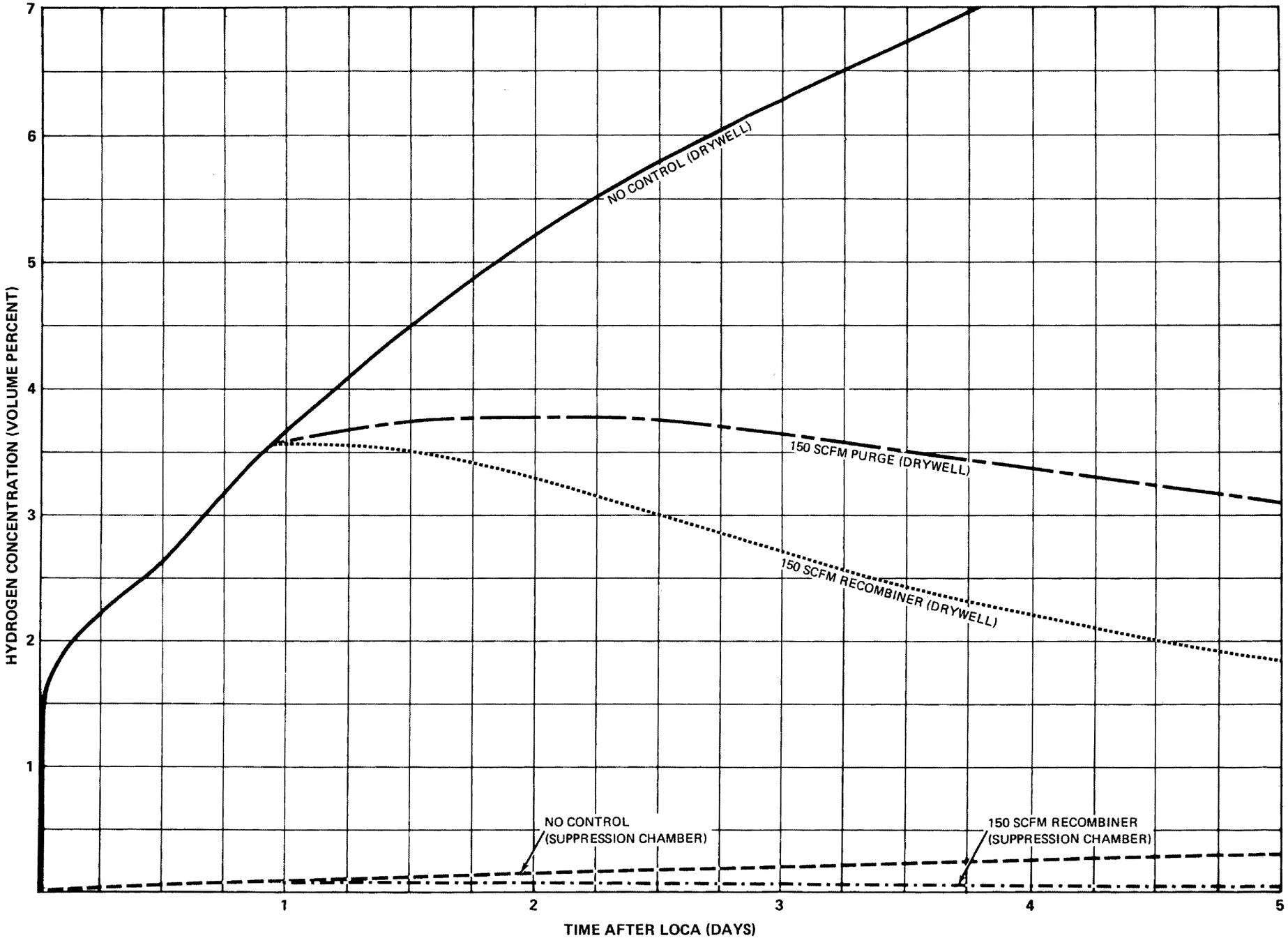
FIGURE 6.2-40



LIMERICK GENERATING STATION
UNITS 1 & 2
UPDATED FINAL SAFETY ANALYSIS REPORT

INTIGRATED HYDROGEN PRODUCTION AS A FUNCTION OF TIME AFTER LOCA

FIGURE 6.2-41 Rev. 11 9/02



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT TERM CONTAINMENT
HYDROGEN CONCENTRATION
AFTER LOCA

FIGURE 6.2-42

NOTE: 150 SCFM RECOMBINER WILL KEEP H_2 CONCENTRATION BELOW 0.08 V% IN THE SUPPRESSION CHAMBER.
150 SCFM PURGE WILL KEEP H_2 CONCENTRATION BELOW 0.09 V% IN THE SUPPRESSION CHAMBER.

HYDROGEN CONCENTRATION (VOLUME PERCENT)

20
18
16
14
12
10
8
6
4
2

NO CONTROL (DRYWELL)

150 SCFM PURGE (DRYWELL)

150 SCFM RECOMBINER (DRYWELL)

NO CONTROL (SUPPRESSION CHAMBER)

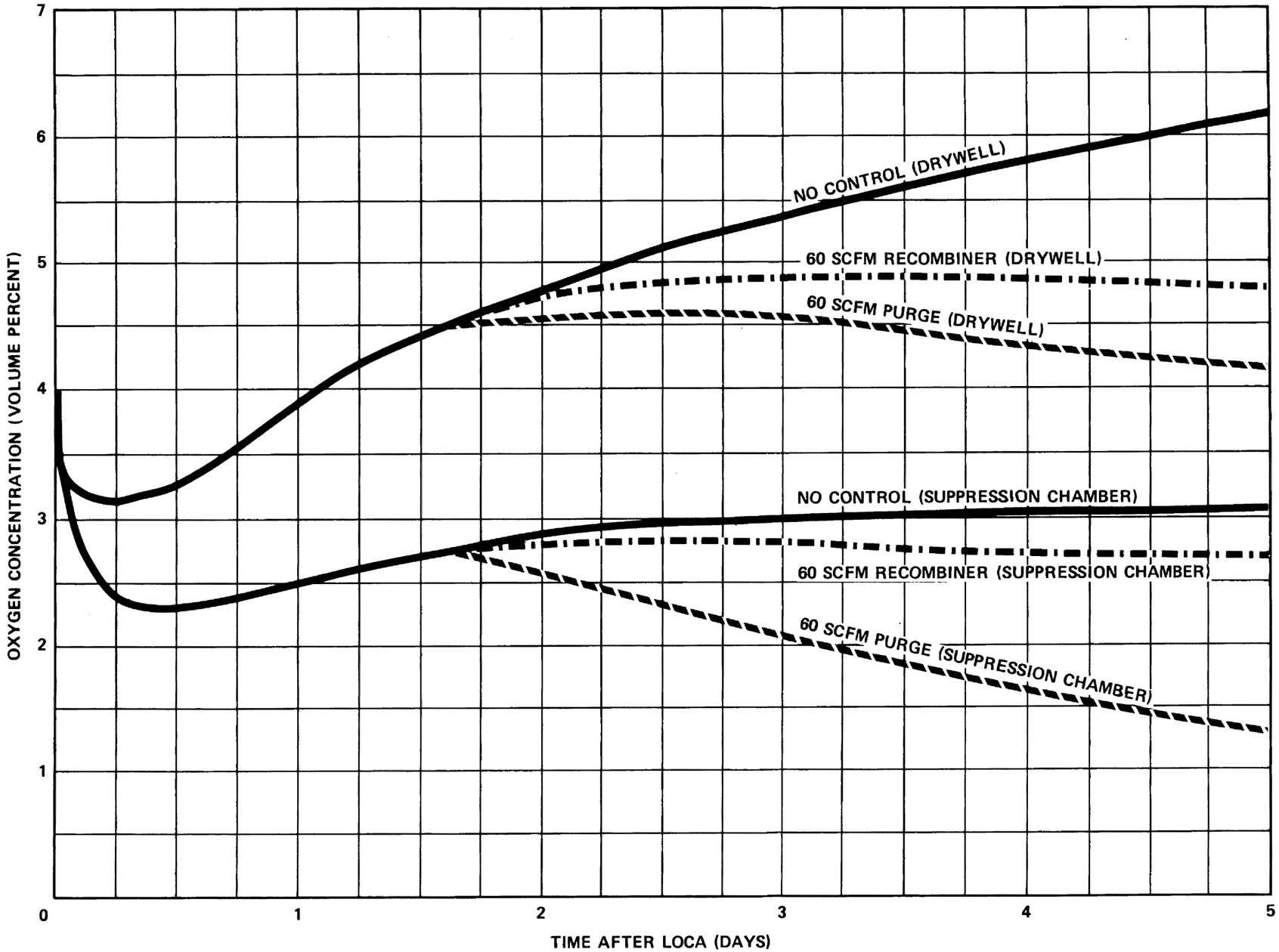
0 5 10 15 20 25 30

TIME AFTER LOCA (DAYS)

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LONG TERM CONTAINMENT HYDROGEN CONCENTRATION AFTER LOCA

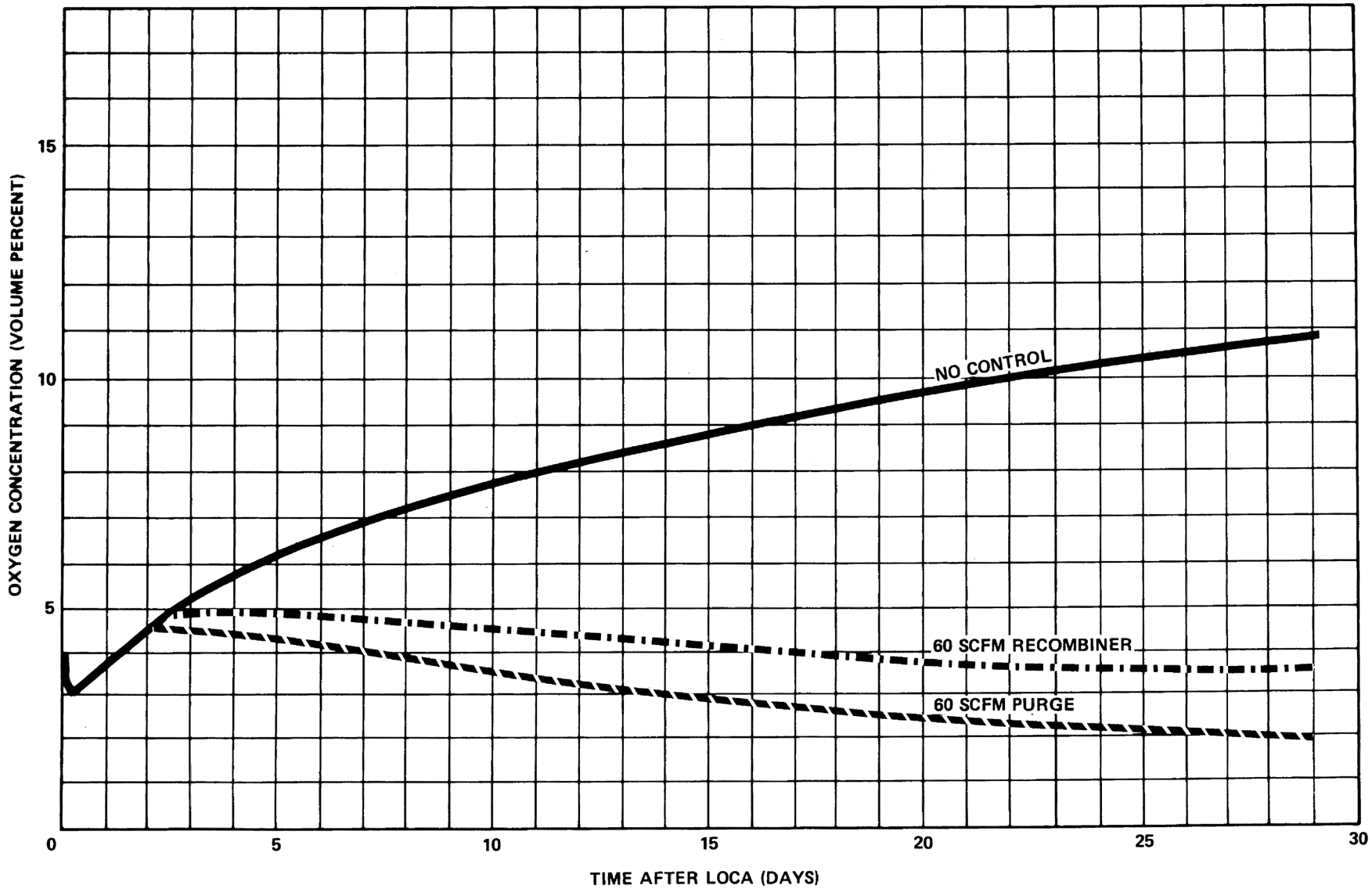
FIGURE 6.2-43



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SHORT TERM CONTAINMENT
OXYGEN CONCENTRATION
AFTER LOCA

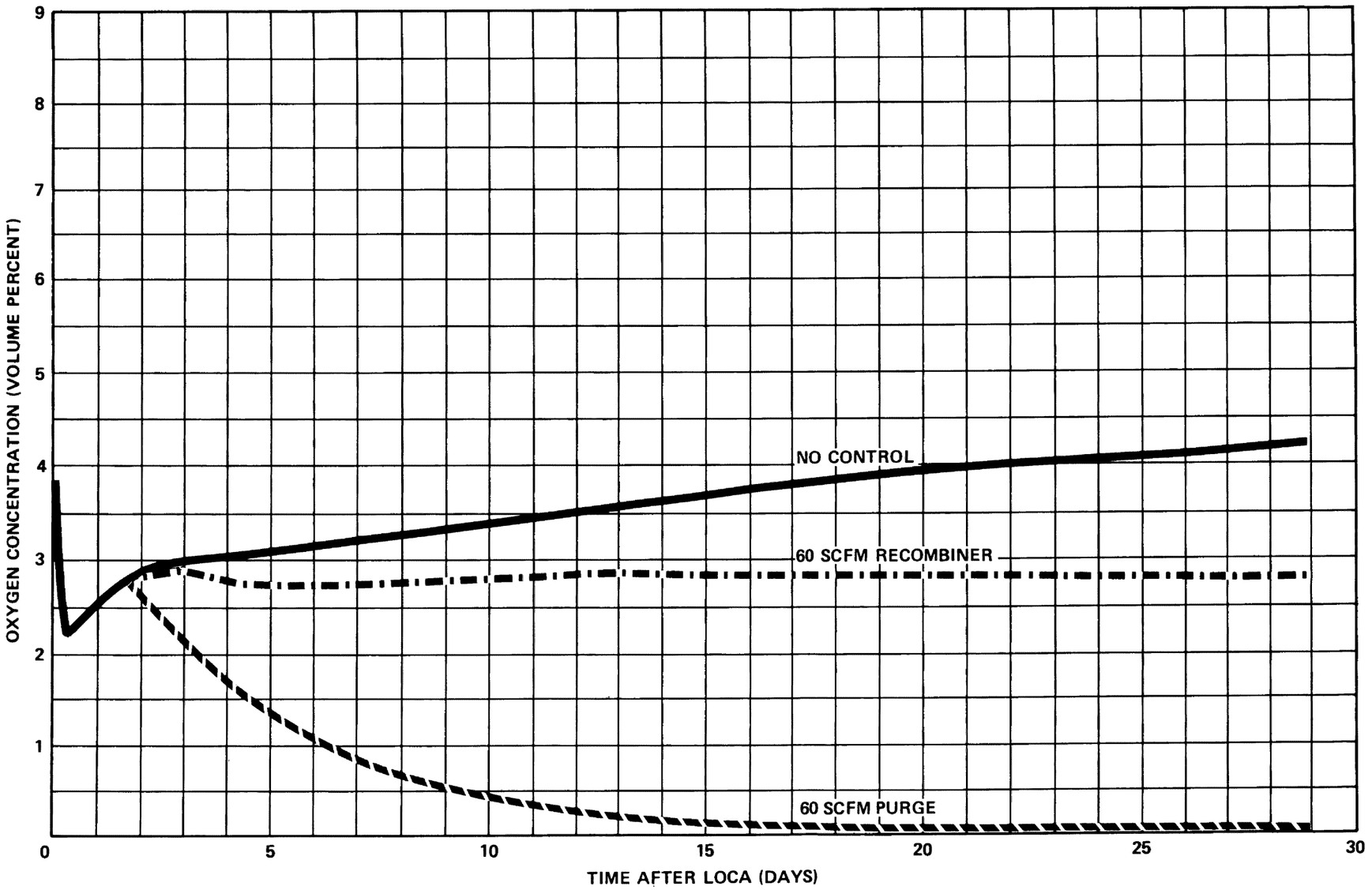
FIGURE 6.2-44



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LONG TERM DRYWELL OXYGEN CONCENTRATION AFTER LOCA

FIGURE 6.2-45



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

LONG TERM SUPPRESSION CHAMBER OXYGEN CONCENTRATION AFTER LOCA

FIGURE 6.2-46

Figure 6.2-47

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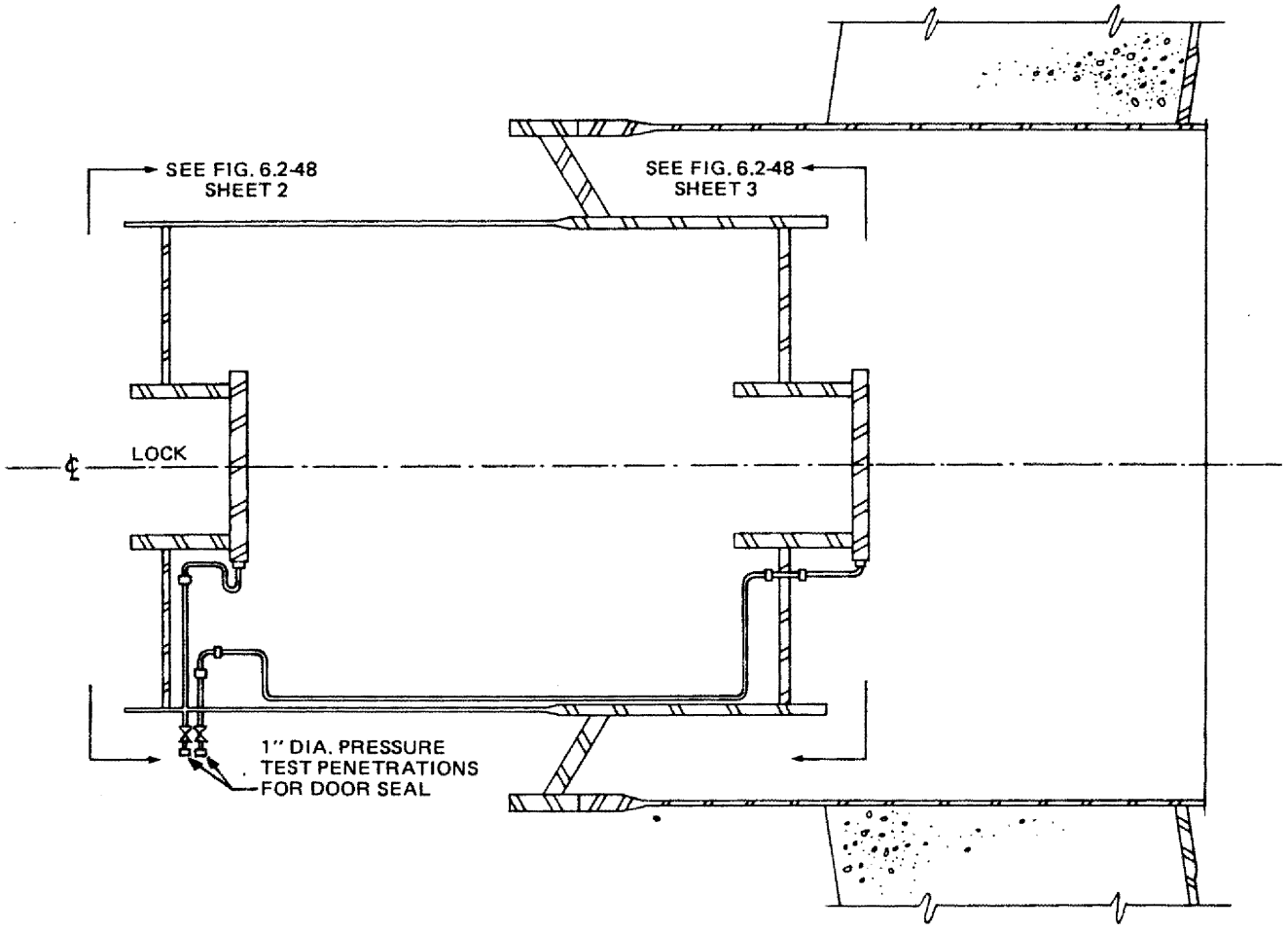
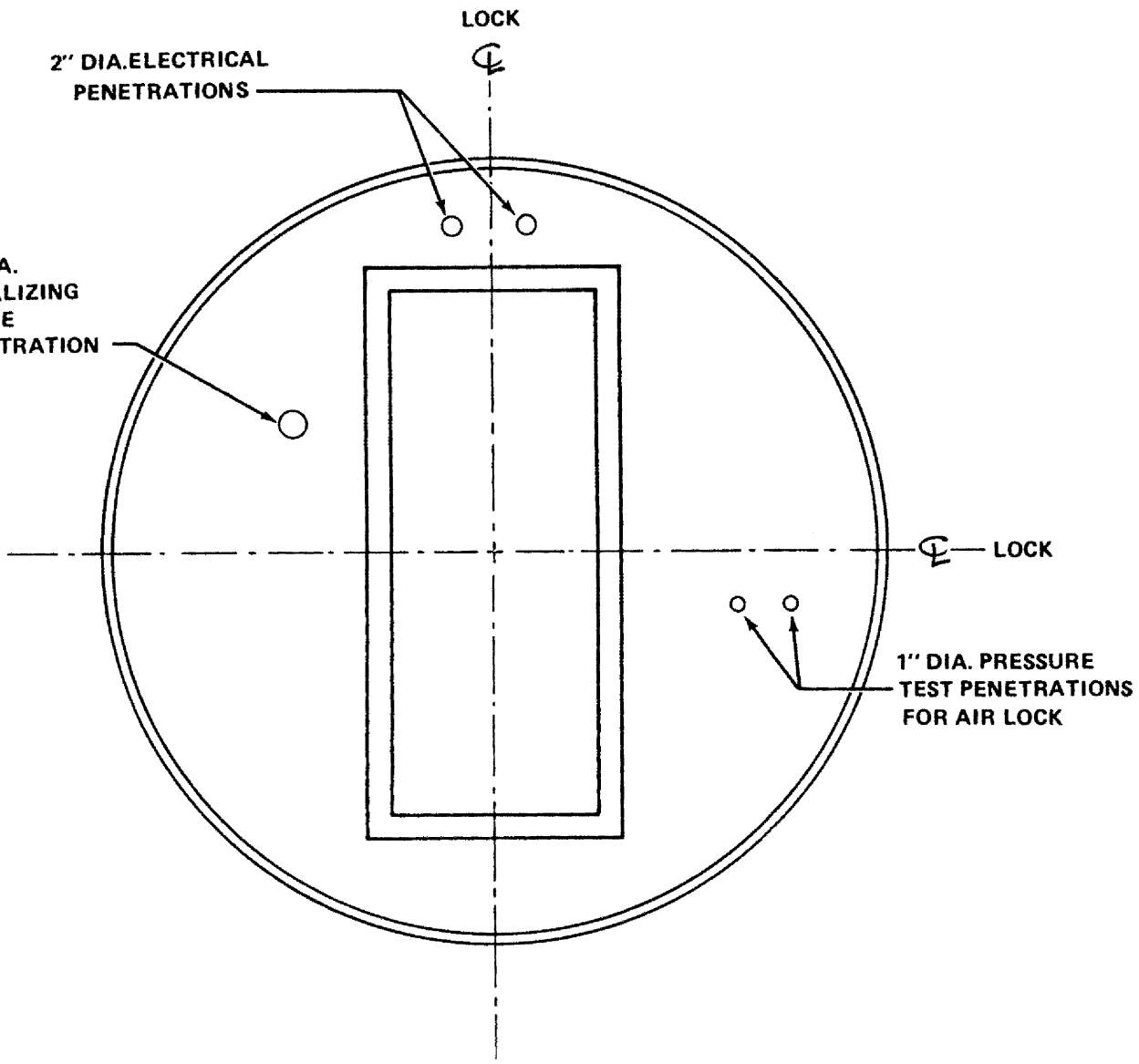


PLAN VIEW OF PERSONNEL LOCK

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL LOCK PENETRATIONS
(SHEET 1 OF 3)

FIGURE 6.2-48

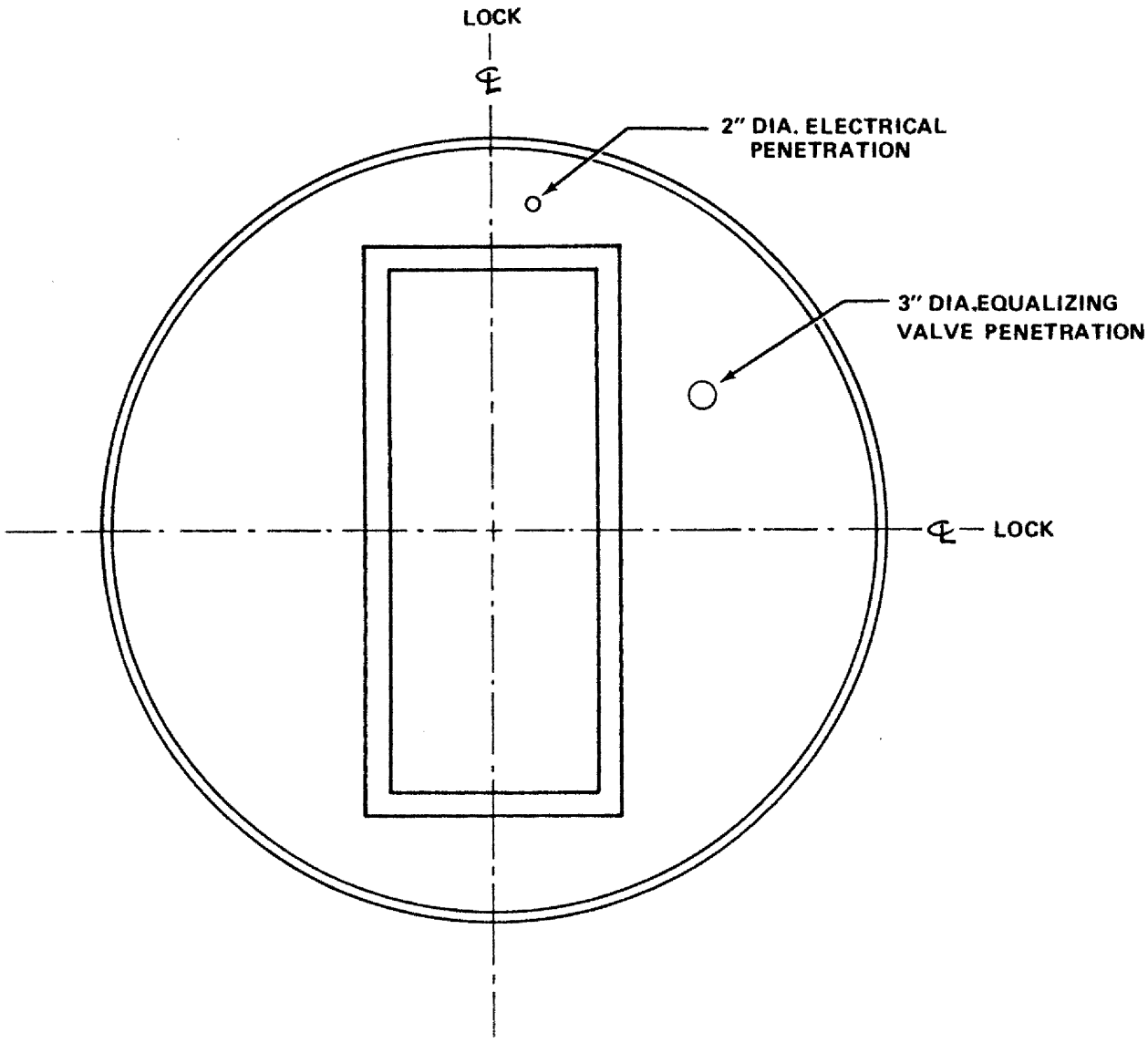


ELEVATION VIEW OF
EXTERIOR BULKHEAD

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR PENETRATIONS
(SHEET 2 0F 3)

FIGURE 6.2-48

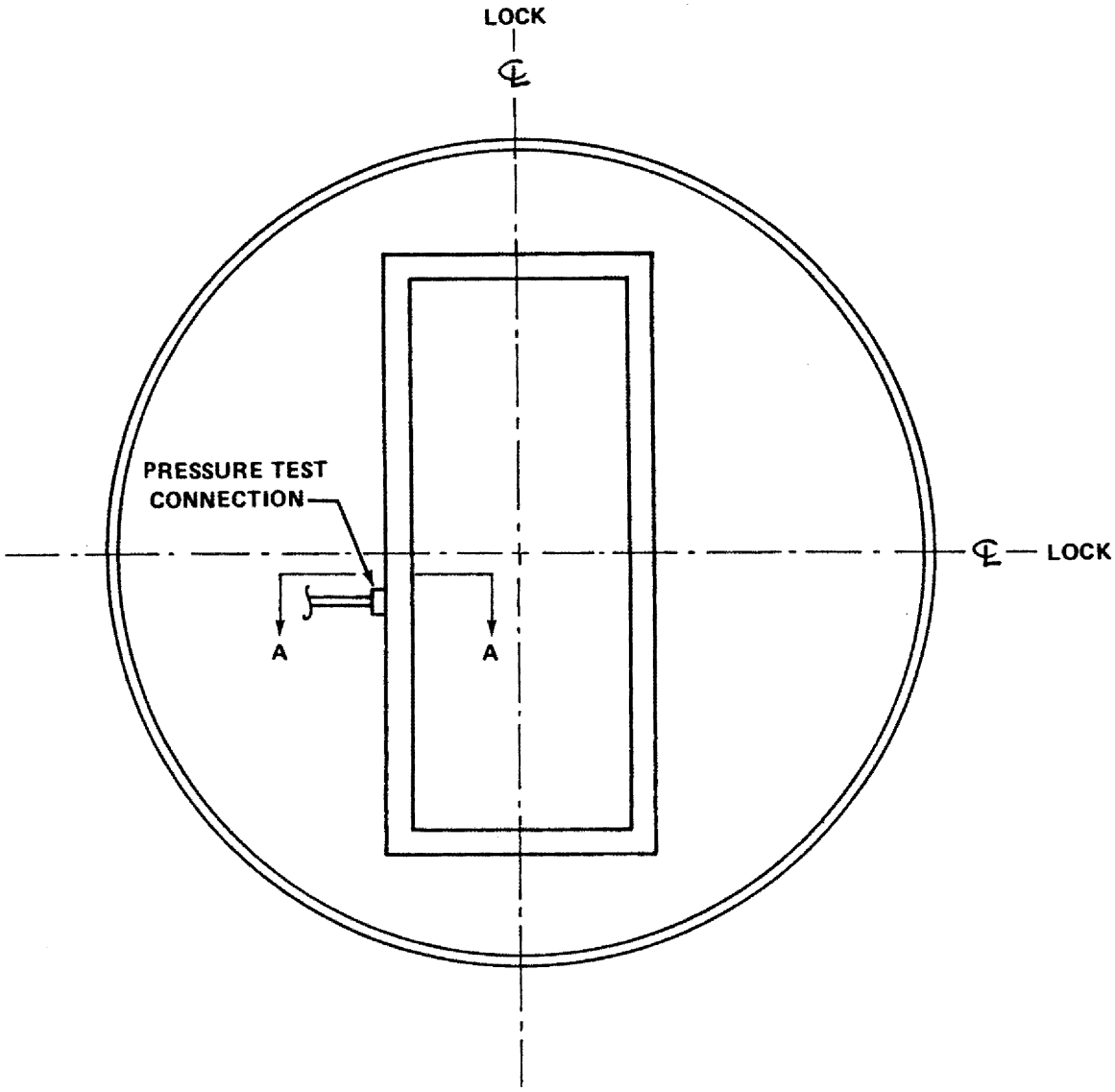


ELEVATION VIEW OF INTERIOR BULKHEAD

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL LOCK PENETRATIONS
(SHEET 3 OF 3)

FIGURE 6.2-48

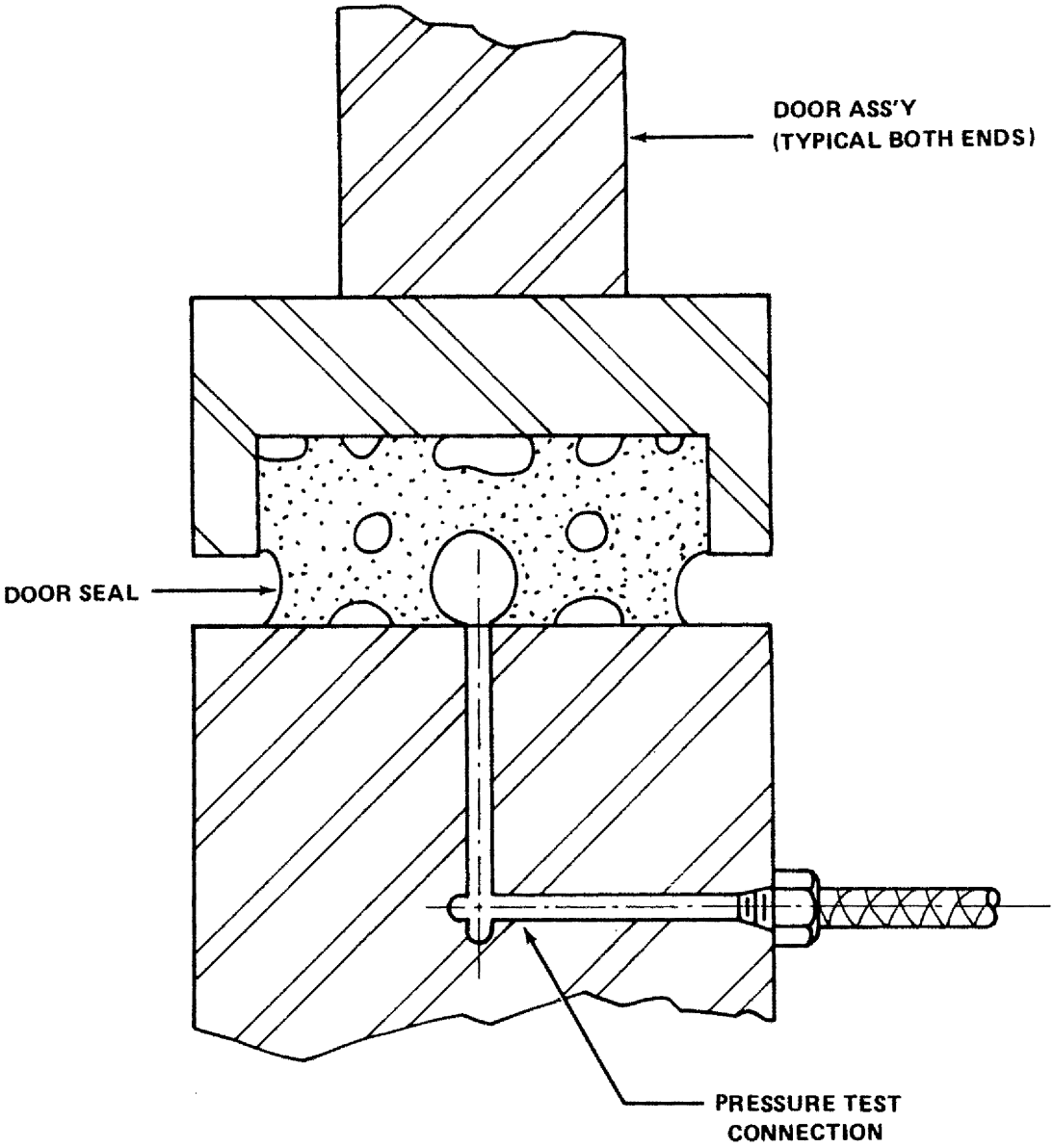


ELEVATION VIEW OF INTERIOR
OR EXTERIOR BULKHEAD

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR SEALS
(SHEET 1 OF 2)

FIGURE 6.2-49

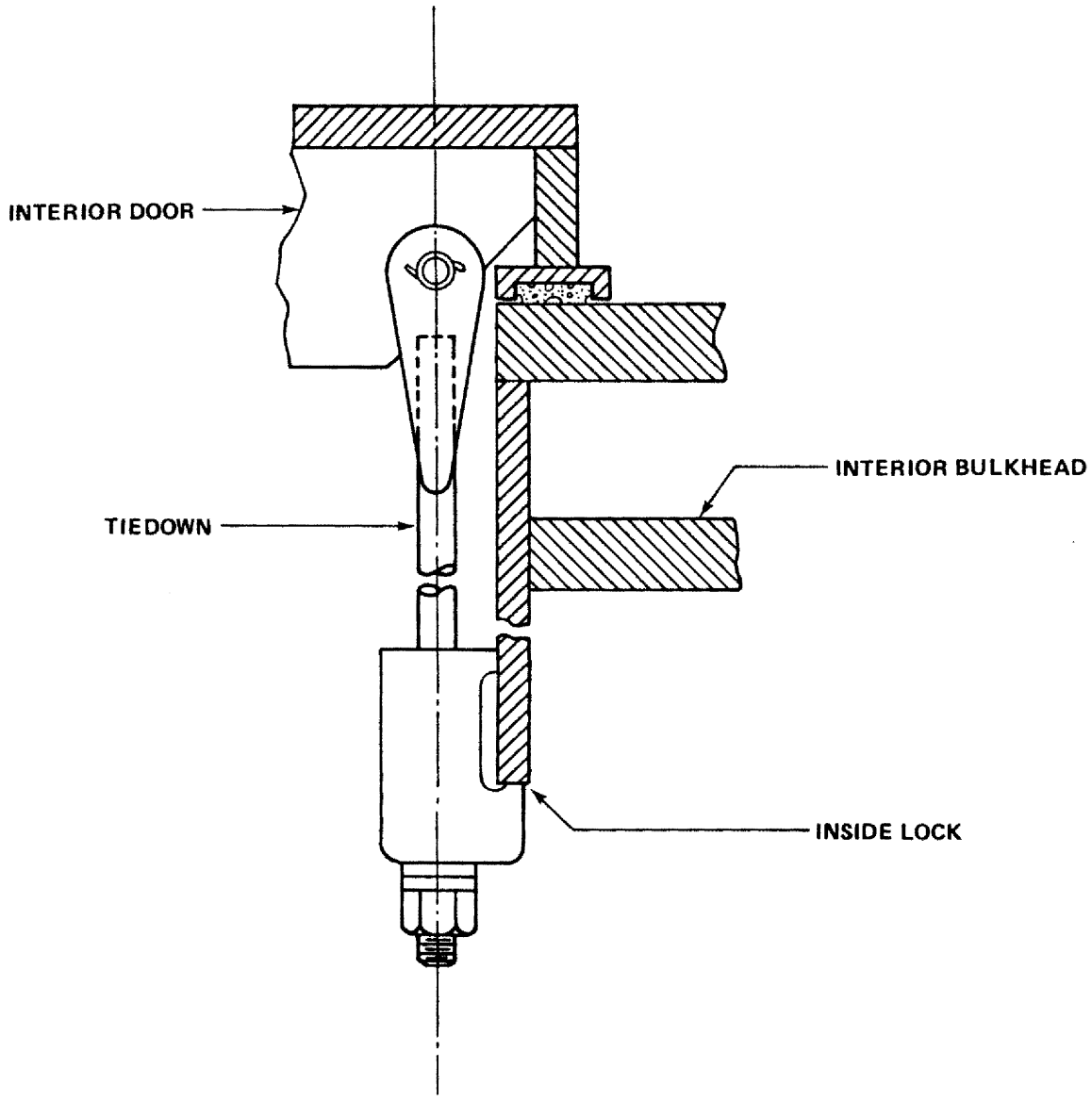


SECTION A–A

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK DOOR SEALS
(SHEET 2 OF 2)

FIGURE 6.2-49



LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

CONTAINMENT PERSONNEL
LOCK INNER DOOR
TIEDOWNS

FIGURE 6.2-50

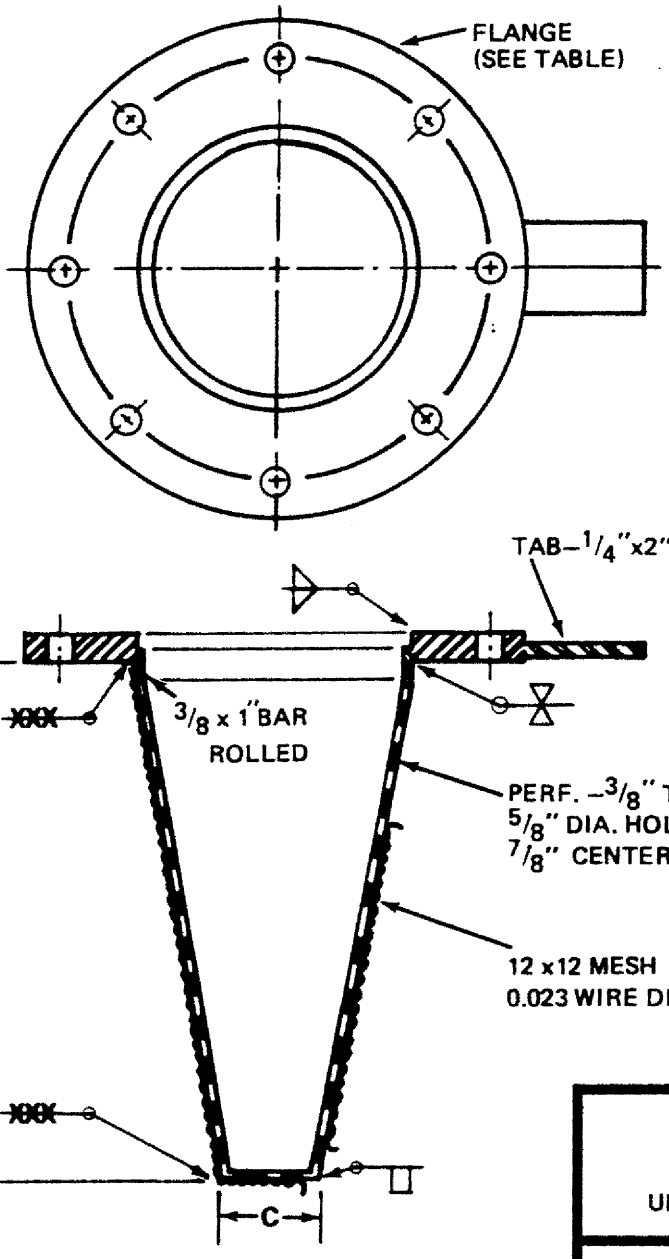
QUANTITY	NPS	A LENGTH	FLANGE O.D. I.D. THK.	NO. OF HOLES	DIA. OF HOLES	BOLT CIRCLE	C DIA.
4	6	$14\ ^{3}/_{16}$	11" - 6.07" - $^{3}/_{8}$"	8	$^{7}/_{8}$"	$9\ ^{1}/_{2}$"	$2\ ^{1}/_{2}$"
4	16	$30\ ^{3}/_{4}$	$23\ ^{1}/_{2}$" - $15\ ^{1}/_{4}$" - $^{1}/_{2}$"	16	$1\ ^{1}/_{8}$"	$21\ ^{1}/_{4}$"	4"

NOTES:

(1) THERE ARE TWO LONGITUDINAL ARC WELDS ON THE PERFORATED PLATE.

(2) THERE IS ONE LONGITUDINAL RESISTANCE WELD ON THE 12 MESH CLOTH.

(3) MATERIAL OF CONSTRUCTION IS STAINLESS STEEL; 304L FOR THE MESH.

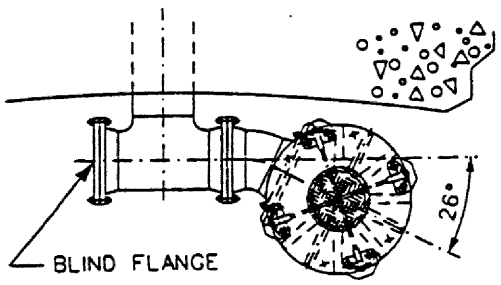


RCIC AND HPCI
STRAINER ARRANGEMENT

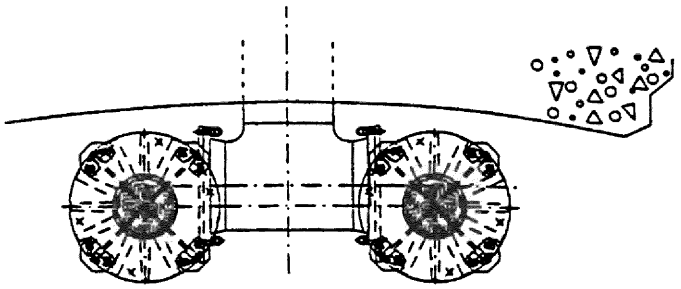
PECO ENERGY COMPANY
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION POOL
SUCTION STRAINERS
(SHEET 1 OF 2)

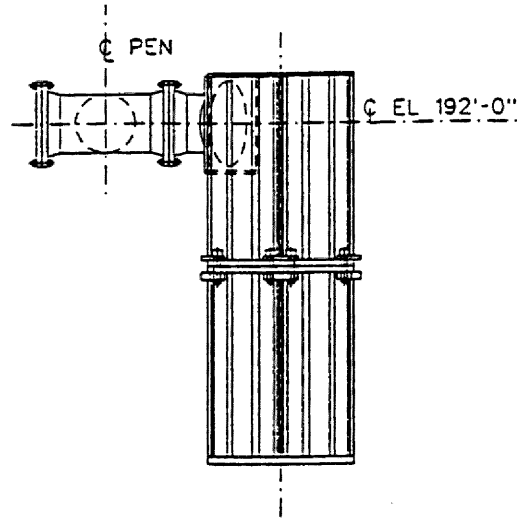
FIGURE 6.2-51 Rev. 09 11/99



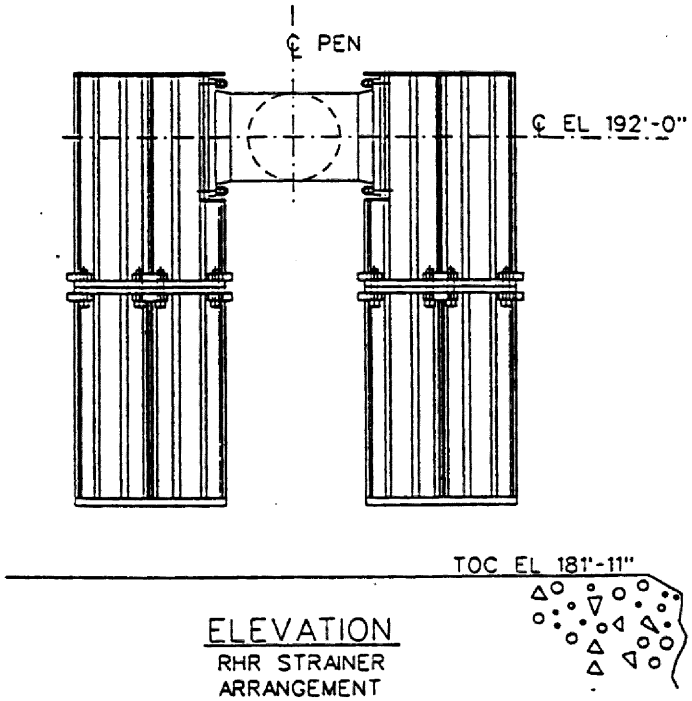
PLAN



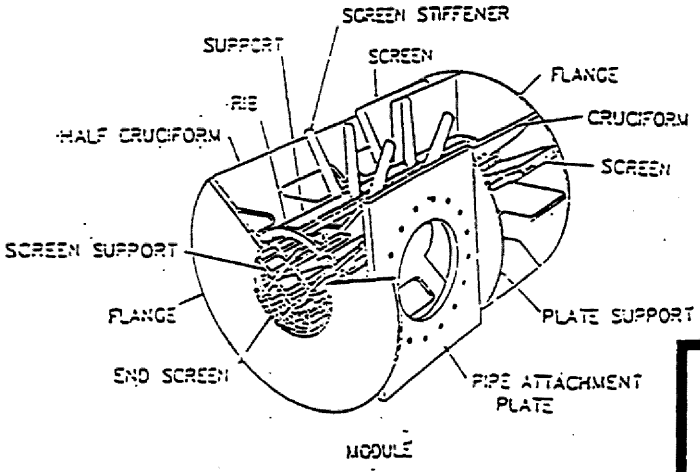
PLAN



ELEVATION
CS STRAINER
ARRANGEMENT



ELEVATION
RHR STRAINER
ARRANGEMENT

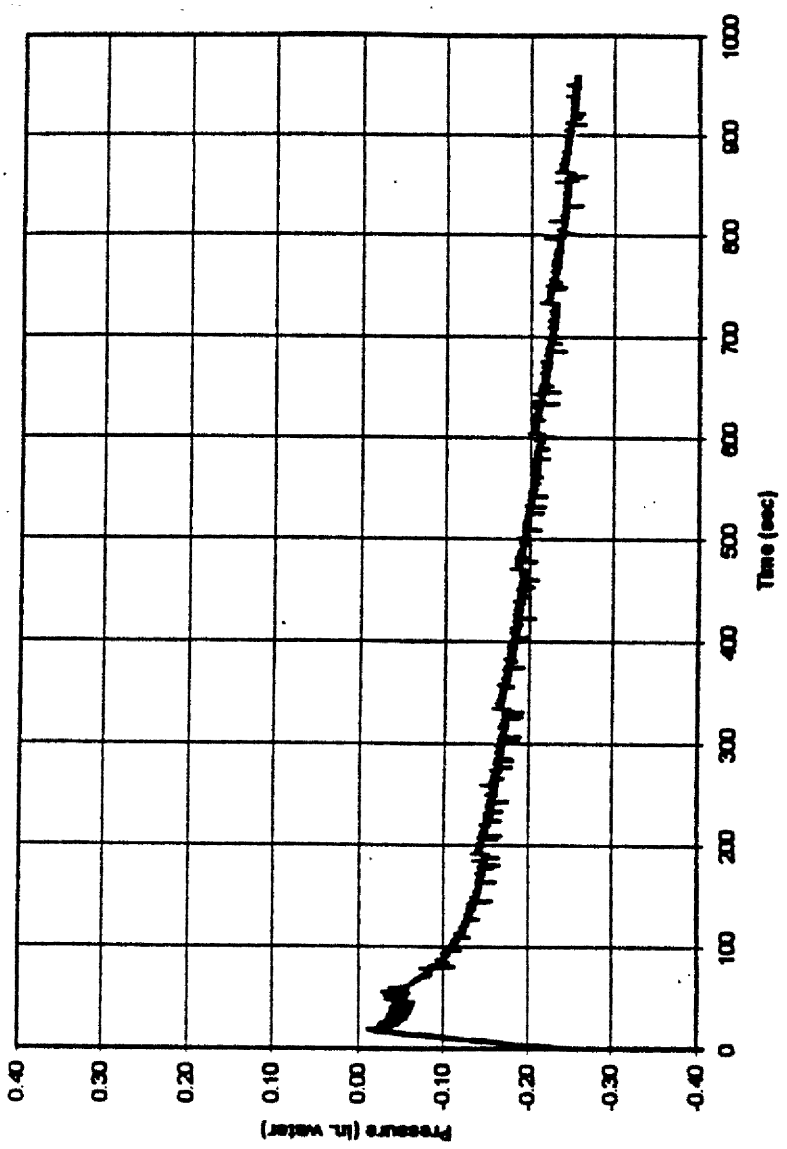


MODULE

PECO ENERGY COMPANY
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

SUPPRESSION POOL
SUCTION STRAINERS
(SHEET 2 OF 2)

FIGURE 6.2-51 Rev. 09 11/99



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REACTOR ENCLOSURE DRAWDOWN

FIGURE 6.2-52 REV. 7 12/97

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EVENT TREE FOR TIP SYSTEM
LINE ISOLATION

FIGURE 6.2-53 Rev. 1 July/91

Figures 6.3-1 through 6.3-10

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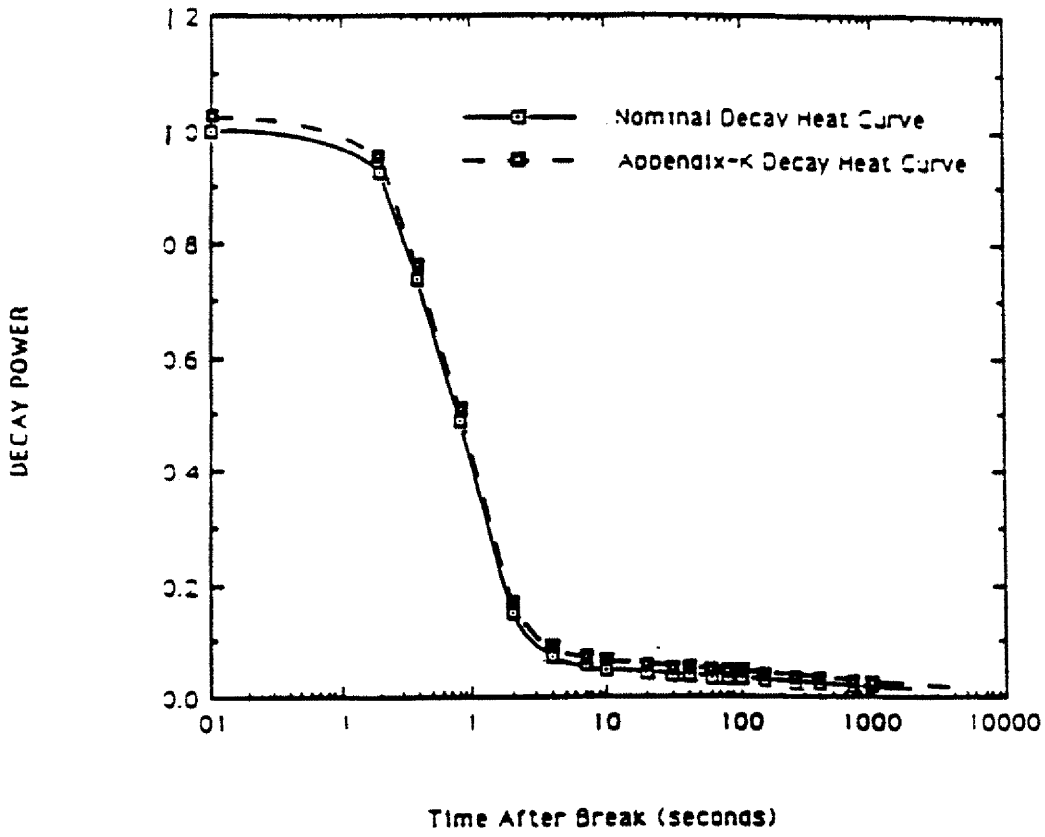

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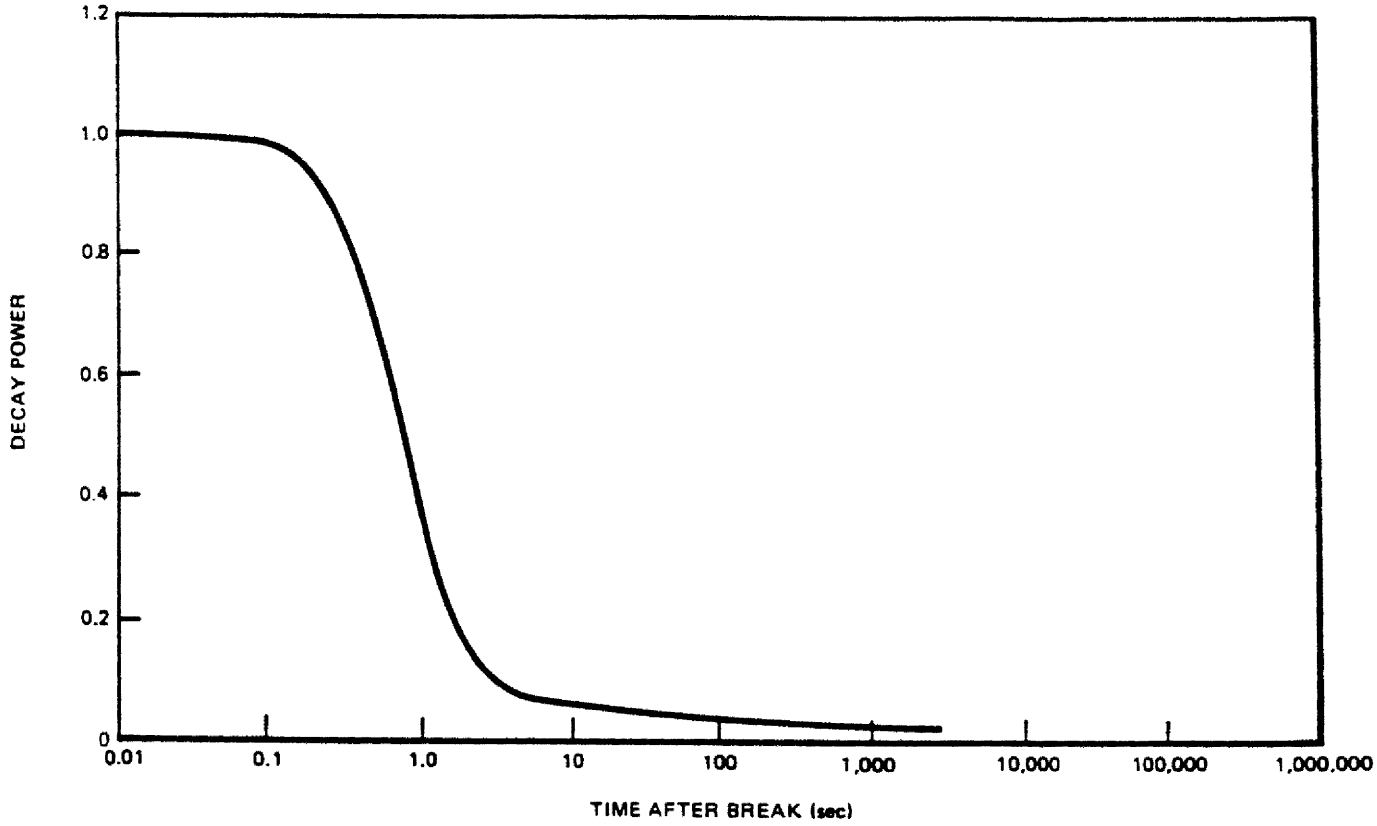
NORMALIZED POWER
VS TIME AFTER BREAK
(SAFER/GESTR METHODOLOGY)

FIGURE 6.3-11 **Rev. 07 12/97**



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NORMAL POWER
VS TIME AFTER BREAK
(ORIGINAL 6.3-1 METHOD)

FIGURE 6.3-11A **Rev. 07 12/97**

Figures 6.3-12 through 6.3-74

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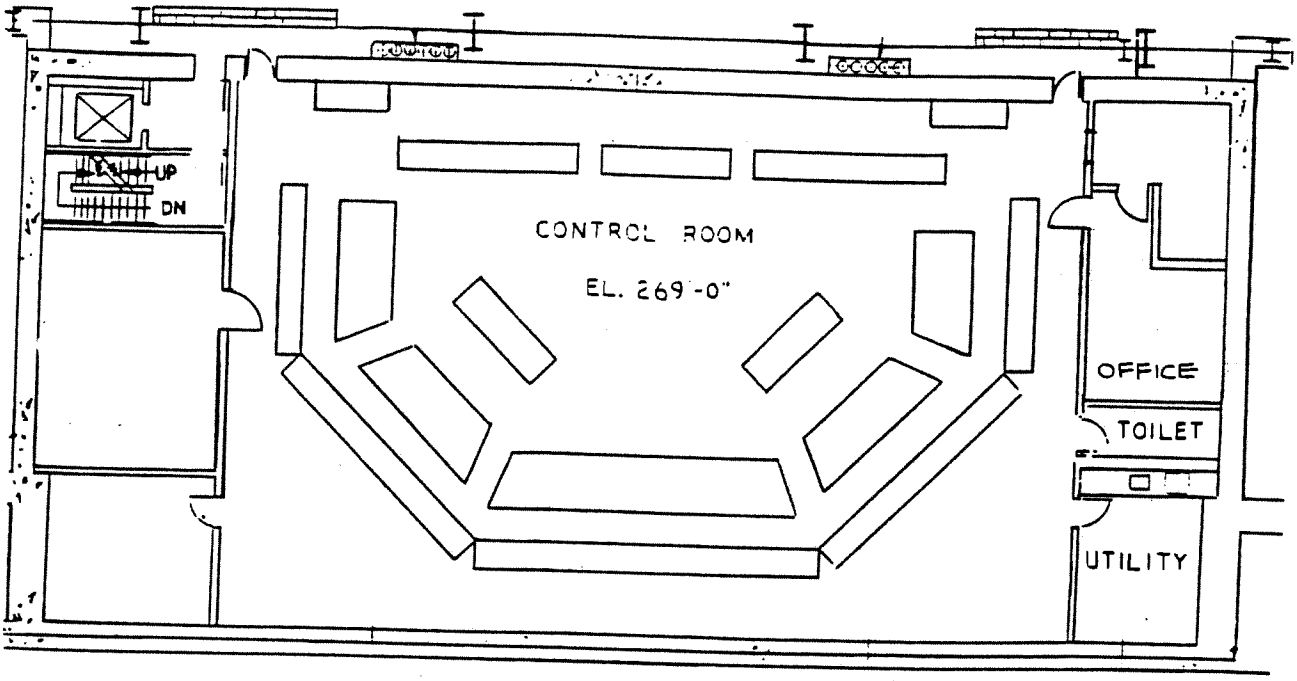

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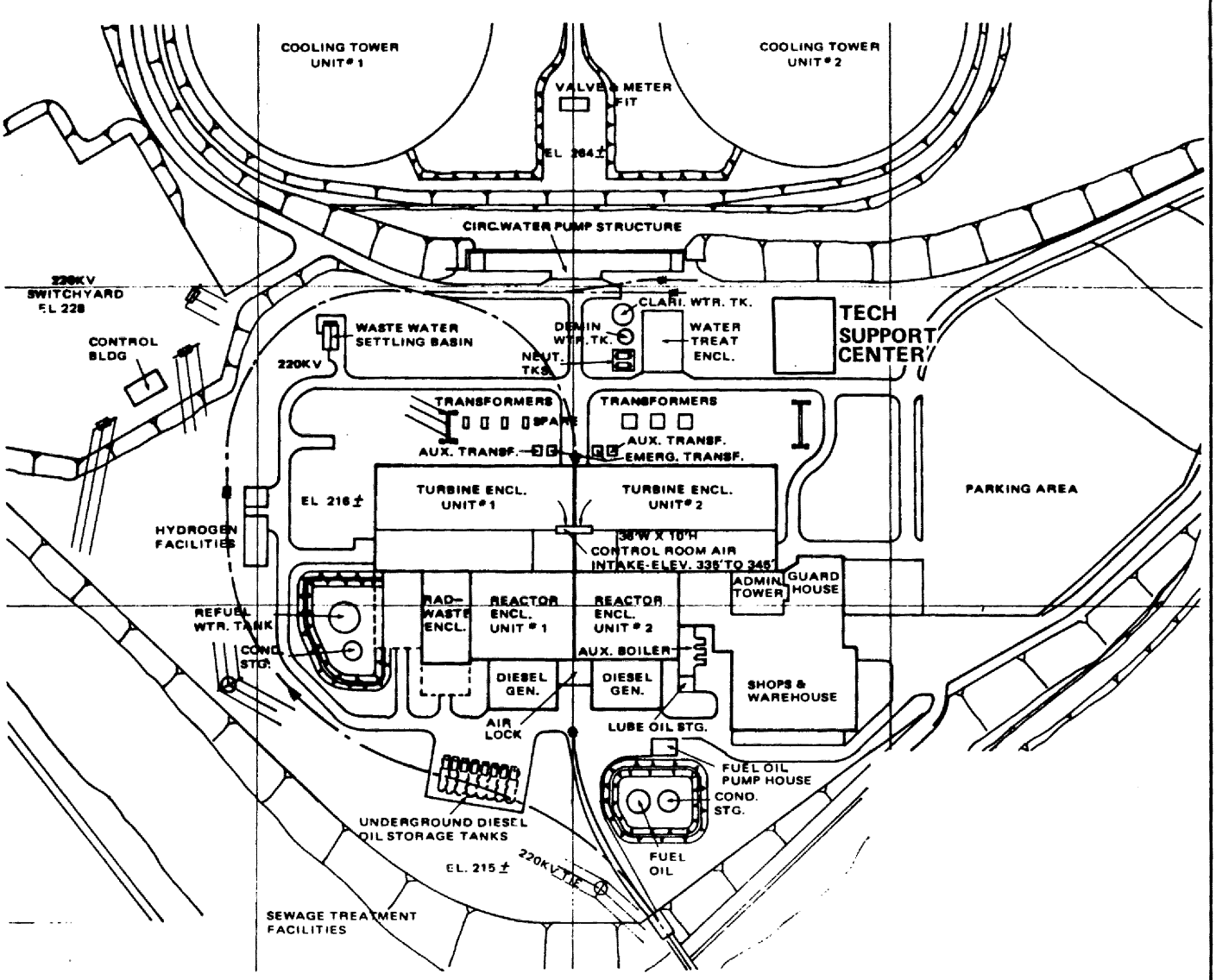
CONTROL ROOM ARRANGEMENT

FIGURE 6.4-1 REV. 13 09/06



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PLANT LAYOUT WITH RESPECT
TO CONTROL ROOM INTAKE

FIGURE 6.4-2

Figures 6.7-1 through 6.7-5

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APPENDIX 6A -SUBCOMPARTMENT DIFFERENTIAL PRESSURE CONSIDERATIONS

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APPENDIX 6A - SUBCOMPARTMENT DIFFERENTIAL PRESSURE CONSIDERATIONS

6A.0 INTRODUCTION

NOTE: The subcompartment differential pressure inputs values and analysis results presented in this section for the recirculation line and feedwater line breaks are based on the original design basis conditions. The blowdown mass and energy releases for the recirculation line and feedwater line breaks were reanalyzed at power rerate conditions. Based on the power rerate analyses, the original analyzed load bounds rerate conditions. Therefore, the shield wall design is not affected by power rerate. The drywell head region pressurization analysis presented in this section was reanalyzed for power rerate conditions. The resulting pressure differential at power rerate conditions is well below pressure differential for the drywell head region.

Differential pressure analyses were performed for the RPV shield annulus and the drywell head region.

The RPV shield annulus, which is 48.95 feet high and 1.70 feet wide at the top, has the 28 inch recirculation pumps suction lines passing through it. The mass and energy release rates from a postulated recirculation outlet line break constitute the most severe transient in the reactor shield annulus. Therefore, this pipe break is selected when analyzing loading of the shield wall and the RPV support skirt for pipe breaks causing annulus pressurization. The estimation of mass and energy release is based on the guidelines set forth in GE's "Generic Annulus Pressurization Mass-Energy Release Methodology" (MFN178-78) and "Technical Description Annulus Pressurization Load Adequacy Evaluation" (NEDO-24548/78NED302). Table 6A-1 presents the full mass and energy release data estimated by applying the finite break opening time/instantaneous break opening time approaches. Because the break location is more than three-fourths of the distance through the penetration, it is conservatively assumed that 50% of the blowdown is released into the annulus, and the remaining 50% is vented to the drywell atmosphere. Table 6A-2 provides, as a function of time, the mass flux and areas used for each side of the break. Physical parameters pertinent to the blowdown rate estimation are noted in the table.

In addition to the analyses for the recirculation outlet line break in the annulus, similar analyses using the same methodology for blowdown rate estimation are performed for a postulated feedwater line break in the annulus. Table 6A-3 presents the mass and energy release rates generated by only applying the very conservative instantaneous break opening time method. Also, it is conservatively assumed in the analyses that the full blowdown is completely released into the annulus. The mass flux as a function of time and areas used for each side of the break are presented in Table 6A-4. Pertinent physical parameters are noted in the table.

Because the main steam lines are not inside the annulus and the recirculation inlet lines are smaller than the outlet lines, the annulus pressurization analyses for these two cases are not needed.

In considering the drywell head region, the maximum blowdown rate stems from a break in the RHR head spray line. The blowdown mass and energy release rates for this line are calculated using Moody Critical Flow of 2800 $lb_m/sec\text{-}ft^2$ and an enthalpy of 1192 Btu/lb_m for the original power level. Pressurization consequences at 3527 MWt are based on the original effects and a multiplier. This multiplier is calulated from the effects of the 3527 MWt on the blowdown mass and energy release rates.. Table 6A-5 shows the blowdown schedule for a 6 inch Schedule 80 line break with an effective break area of 0.181 ft^2. Since this line could singularly pressurize the drywell head region, it is chosen for analysis in a postulated break. The head spray line does not

exist for Unit 2 and has been removed from Unit 1. However, the analysis is still applicable since it envelopes loads from rupture of any other pipe in this region.

All differential pressure analyses were performed according to the analytical techniques described in Reference 6A-1. These adjusted pressures are combined with the other appropriate loads (e.g., seismic and jet impingement) to develop design loads for the affected structures and components. Subcompartment venting is used to ensure that the differential pressures developed will remain below the structural capability of compartment walls.

Mass and energy release rates using the NEDO-20533 methodology for a recirculation line break are shown in Table 6.2-10. Short-term release rates based on NEDO-24548 are shown in Table 6A-1. Comparison of these two tables indicates that mass flow rates and enthalpy calculated using NEDO-24548 are less than the conservative values produced using assumptions consistent with NEDO-20533.

Recirculation line break blowdown data used for containment analysis are based on assumptions and calculations made specifically for the LGS units. These assumptions and calculations are discussed in NEDO-10320 (Reference 6.2-5), which follows the methodology outlined in NEDO-20533. This model has been shown to be quite conservative for long-term containment analysis.

However, for the special cases required to analyze pressurization of the annulus due to a recirculation line or feedwater line break, a more detailed model is used. The NEDO-24548 model for short-term mass and energy release includes the effects of inventory and subcooling for flow rates during the first 5 seconds. Credit may also be taken for a finite break opening time. Blowdown rates from NEDO-24548, which calculates the maximum quasi-steady mass flux based on the Moody steady slip flow model with subcooling, are also considered to be conservative estimates of the mass and energy released from the vessel.

6A.1 BIOLOGICAL SHIELD ANNULUS SUBCOMPARTMENT MODELING PROCEDURES AND ANALYSIS

NOTE: The subcompartment differential pressure inputs values and analysis results presented in this section for the recirculation line and feedwater line breaks are based on the original design basis conditions. The blowdown mass and energy releases for the recirculation line and feedwater line breaks were reanalyzed at power rerate conditions. Based on the power rerate analyses, the original analyzed loads bound rerate conditions. Therefore, the shield wall design is not affected by power rerate. The drywell head region pressurization analysis presented in this section was reanalyzed for power rerate conditions. The resulting pressure differential at power rerate conditions is well below pressure differential for the drywell head region.

An analysis was performed of the pressure distribution around the RPV after a recirculation line break. The general layout of the shield annulus is shown in Figures 3.8-1 through 3.8-8 and in 6A-1. Figure 6A-2 is a schematic of the RPV shield annulus model. The model consists of six major levels. Each level is subdivided into twelve 30^{o} segments to form a total of 72 nodes inside the annulus plus an additional node for the rest of the drywell.

The guidelines of GE's "Generic Annulus Pressurization Load Adequacy Evaluation" (NEDO-24548/78NED302) were followed in treating the entire drywell region (volume number 73) as a single compartment in the RPV shield annulus subcompartment analysis. Treating the drywell region as a single compartment reduces the drywell pressure response due to venting from the annulus, resulting in the greatest ΔP across the shield wall.

The 235,200 ft^3 size of the drywell region used in the analysis is a "free volume." The volume occupied by equipment, structures, and floors (i.e.; obstructions) contained within the drywell was excluded from the "free volume" estimate.

In general, the arrangement of the pipes in the annulus determines the most representative level division, since they constitute the only significant flow restrictions. This 73 node model is considered detailed enough to conservatively predict the maximum pressure loads on the compartment structure. Therefore, a nodalization sensitivity study is not needed.

For the purpose of determining peak pressure in the reactor vessel shield annulus, all insulation is assumed to move flush against the biological shield wall while still maintaining its original thickness. The volume of the insulation is excluded from the net volume of each subcompartment, and the projected area of the insulation that blocks the venting path is also excluded from the free venting area used in the analysis.

Venting to the drywell atmosphere is achieved only through the top of the biological shield annulus. For conservatism, venting through the reactor shield wall is not considered.

Initial conditions used in this analysis are 15.45 psia, 135°F, and 30% relative humidity. Bases for these initial conditions are discussed in the drywell head region subcompartment analysis (Section 6A.2).

Tables 6A-6 and 6A-7 give the subcompartment volumes, flow areas, length/area (L/A) ratio, and flow coefficients (including origins) used in the analysis.

The resultant pressure distributions are shown in Figure 6A-3 for the recirculation outlet line break and Figure 6A-4 for the feedwater line break. The subcompartment pressures existing in each subcompartment at the time of peak differential pressure across the RPV are also shown in these figures. Additionally, the load forcing functions that include both peak and transient loadings on the RPV and the reactor shield wall are presented in Figures 6A-5 and 6A-6 for the recirculation outlet break and in Figures 6A-7 and 6A-8 for the feedwater line break. This forcing function represents the time-dependent resultant force on the structure and originates from the vector sum of the product of compartment pressure and area for each of the many nodes used to represent the surface.

The components of these nodal areas are calculated in the following manner:

$$(A_x)_i = R_i H_i \operatorname{Sin}(\theta_{1_i} - \theta_{2_i}) \qquad \text{(EQ. 6A-1)}$$

$$(A_y)_i = R_i H_i \operatorname{Cos}(\theta_{2_i} - \theta_{1_i}) \qquad \text{(EQ. 6A-2)}$$

where:

R_i = Radius of the i^{th} geometry node, in

H_i = Height of the i^{th} geometry node, in

$\theta_{1_i} + \theta_{2_i}$ = Swept angle of geometry node i

Therefore, the force generated by a pressure, (P), acting on a nodal area (A) has the following components:

$(F_x)_i = P_j (A_x)_i$ (EQ. 6A-3)

$(F_y)_i = P_j (A_y)_i$ (EQ. 6A-4)

The compartment pressure transients resulting from a break in the reactor shield annulus generate a nodal force distribution over exposed surfaces. The resultant of this nodal force distribution is presented in Figures 6A-5, 6A-6, 6A-7 and 6A-8. This nodal force distribution is included in the analysis of nonaxisymmetric loadings on the containment internal structures, which is discussed in Sections 3.8.3.3 and 3.8.3.4.

Blowdown jet loads that include jet impingement and reaction forces against the reactor vessel are also analyzed for the feedwater line break for reference and comparison. Note that these analyses are based on the very conservative assumptions that the first pipe restraint nearest the nozzle fails. For this break, approximately 9.5" pipe center line offset limited by the shield plug opening produces a net break area of 88.53 in^2, which consequently results into a total maximum jet load against the vessel and a maximum reaction force of 158,500 lb_f and 93,230 lb_f, respectively. Note that this blowdown jet load is relatively small compared with the peak load contributed by the unbalanced reactor annulus pressurization due to the same break.

6A.2 DRYWELL HEAD REGION SUBCOMPARTMENT ANALYSIS

The design basis pressure differential between the drywell head region and the rest of the containment is a structural requirement of the drywell head. A pressure analysis of the drywell head region for a postulated head spray line break was performed. The effects of a 6 inch RHR head spray line break bound those of a 2 inch core vent line, which is the only other line that runs through the drywell head region.

Figure 6A-9 illustrates the basic arrangement of the head region. Venting from the head region is accomplished through ventilation openings as shown in Figure 6A-9. These vent openings provide a total of 18.64 ft^2 of vent area with a flow coefficient of 0.64 to relieve pressure buildup caused by the postulated break. Figure 6A-10 is the schematic flow diagram with vent flow areas and discharge coefficient used in the drywell head venting analysis.

For the drywell head region subcompartment analysis, the possibility that insulation from the RPV could break loose and block the vent paths was not considered because the postulated rupture of the RHR head spray line is outside the insulation above the top of the RPV. The jet from the vessel side of the break is above the top of the insulation, which precludes the metallic insulation sections from breaking loose due to the outward flow of the jet. Forces on the insulation from flow from the other side of the break as well as from the subsequent pressurization in the drywell head region would be inward toward the RPV, rather than outward toward the vent paths.

There is only a small amount of insulation on the drywell head region lines. In the event that this insulation should fail to remain on the pipe due to direct jet impingement, the vent paths leading from the drywell region would not become blocked for the following reasons. The openings of each of the six vents and two exhaust lines from the drywell head region are above the floor and have a ¾ inch mesh screen installed over them. To block the vent paths, a substantial amount of insulation would need to fall directly onto the vent path opening and break through the screen. This is considered improbable because there is only a small amount of pipe insulation in this region and not all of the failed insulation would fall on any one vent path opening.

To determine peak pressure in the drywell head, all insulation is assumed to remain in place. Initial conditions of 15.4 psia, 135°F, and 20% relative humidity are used in this analysis.

The initial conditions used for both the RPV shield annulus and drywell head region analyses reflect conservative assumptions to minimize the total heat capacity of the subcompartment, which satisfies SRP Section 6.2.1.2, Item II.B.1. The COPDA (NE699/D2) subcompartment analysis code is designed to handle realistic conditions. Recommended minimum relative humidity for COPDA, which is described in Reference 6A-1, is in the range of 25% to 30%. The available heat capacity at P=15.45 psia, T=135°F, and RH=30% is less than 3% greater than the heat capacity at 14.8 psia, 135°F, and RH=0%, and will not significantly affect the results of the analysis.

The initial pressure of 15.45 psia (0.75 psig) is the nominal drywell pressure under normal operating conditions for this unit. The pressure alarm setpoints are at 14.8 psia (0.1 psig) and 16.2 psia (1.5 psig). The heat capacity gain due to the higher initial pressure of 0.75 psig is less than 0.2% compared to the heat capacity available for T=135°F, RH=30%, and P=14.8 psia.

The drywell air cooling system is designed to limit the maximum average bulk temperature in the drywell to 135°F, with local maxima not exceeding 150°F (Section 9.4.5.2). For a given relative humidity, an increase in the initial temperatures is accompanied by an increase in the steam partial pressure. Consequently, the heat capacity in the compartment increases due to a greater steam mass. For this reason, the maximum bulk temperature of 135°F is used rather than the 150°F local maximum.

For the RPV shield annulus subcompartment analysis, it should be noted that Reference 6A-2 concludes that loads from such annulus pressurization analyses are insensitive to minor variations in initial (P), (T), and (ϕ).

The pressure transient of this analysis is presented in Figure 6A-11. It can be seen that the maximum pressure in the drywell head region is 25.91 psia and occurs 0.82 seconds after the head spray line break. The maximum pressure of 25.91 psia includes an increase of 2.61 psia as a result of power rerate. Considering the containment pressure to be atmospheric (no drywell air displaced into the rest of containment), a differential of 11.2 psid is obtained between the drywell head and the rest of containment. This pressure differential is well below the design pressure differential of 16.0 psid.

6A.3 REFERENCES

6A-1 "Subcompartment Pressure Analyses," BN-TOP-4, Rev 1, Bechtel Power Corporation, San Francisco, California, (November 1972).

6A-2 NUREG/CR-2633, "Containment Reactor Cavity Subcompartment Analysis Procedures for a Boiling Water Reactor", (May 1982).

Table 6A-1

REACTOR PRIMARY SYSTEM BLOWDOWN FLOW RATES AND FLUID ENTHALPY - RECIRCULATION LINE BREAK

TIME (s)	MASS (lb_m/s)	ENTHALPY (Btu/lb_m)
0.000	0.0000	0.000
2.5500×10^{-3}	1.3400×10^{3}	527.9
3.9000×10^{-3}	2.6750×10^{3}	527.9
4.9600×10^{-3}	4.0100×10^{3}	527.9
5.8600×10^{-3}	5.3500×10^{3}	527.9
7.3700×10^{-3}	8.0200×10^{3}	527.9
9.2400×10^{-3}	1.2025×10^{4}	527.9
1.1800×10^{-2}	1.9285×10^{4}	527.9
1.3800×10^{-2}	2.6560×10^{4}	527.9
1.5800×10^{-2}	3.2355×10^{4}	527.9
1.8000×10^{-2}	4.5975×10^{4}	527.9
2.0800×10^{-2}	4.5975×10^{4}	527.9
2.0800×10^{-2}	2.2400×10^{4}	527.9
2.1800×10^{-2}	2.4130×10^{4}	527.9
2.2800×10^{-2}	2.5840×10^{4}	527.9
2.3800×10^{-2}	2.7520×10^{4}	527.9
2.5800×10^{-2}	3.0780×10^{4}	527.9
2.7800×10^{-2}	3.3880×10^{4}	527.9
3.0800×10^{-2}	3.8170×10^{4}	527.9
3.5800×10^{-2}	4.4220×10^{4}	527.9
3.7000×10^{-2}	4.5975×10^{4}	527.9
4.1400×10^{-1}	4.5975×10^{4}	527.9
4.1400×10^{-1}	3.4370×10^{4}	527.9
1.0000	3.4370×10^{4}	527.9

NOTE: The information presented in this table is based on original plant conditions. The values in the table do provide a reasonable representation of the general blowdown characteristics.

Table 6A-2

RECIRCULATION OUTLET LINE BREAK BLOWDOWN
MASS FLUX TIME HISTORY[1][2]

TIME (s)	MASS FLUX ($lb_m/s/ft^2$)	EFFECTIVE BREAK AREA (ft^2)
VESSEL SIDE:		
0.00255	21200	0.0316
0.00496	21200	0.0964
0.00737	21200	0.1892
0.01180	21200	0.4548
0.01580	21200	0.7631
0.02080	21200	1.0843
0.02081	8410	1.3317
0.02180	8410	1.4346
0.02380	8410	1.6361
0.02780	8410	2.0142
0.03580	8410	2.6280
0.03700	8410	2.7333
0.41400	8410	3.6440
0.41410	8410	3.6440
1.0	8410	3.6440
PUMP SIDE:		
0.00255	21200	0.0316
0.00496	21200	0.0964
0.00737	21200	0.1892
0.01180	21200	0.4548
0.01580	21200	0.7631
0.02080	21200	1.0843
0.02081	8410	1.3317
0.02180	8410	1.4346
0.02380	8410	1.6361
0.02780	8410	2.0142
0.03580	8410	2.6290
0.03700	8410	2.7333
0.41400	8410	1.8220
0.41410	8410	0.4420
1.0	8410	0.4420

NOTE: The information presented in this table is based on original plant conditions. The values in the table do provide a reasonable representation of the general blowdown characteristics.

Table 6A-2 (Cont'd)

---

(1) Listed below are pertinent physical parameters used in the blowdown estimation:

A	=	3.644	ft^2	Minimum cross-sectional area between vessel and break
D	=	2.154	ft	Pipe I.D. at the break location
h_o	=	527.85	Btu/lb_m	Vessel enthalpy
L_I	=	2.917	ft	Inventory length
P_o	=	1031.2	psia	Vessel pressure
P_{sat}	=	908	psia	Saturation pressure
ν	=	0.02127	ft^3/lb_m	Specific volume of the fluid initially in the pipe
V	=	135	ft^3	Inventory volume

(2) The postulated break location is at the nozzle safe-end to the pipe weld, which is located about 4.5 inches from the drywell side of the shield wall. A double-ended guillotine break was assumed. This is conservative because there is insufficient clearance for complete separation of the pipe and nozzle.

NOTE: The information presented in this table is based on original plant conditions.

Table 6A-3

REACTOR PRIMARY SYSTEM BLOWDOWN FLOW RATES AND
FLUID ENTHALPY - FEEDWATER LINE BREAK

TIME (s)	MASS FLOW (lb_m/s)	ENTHALPY (Btu/lb_m)
0.0	0	404.5
0.0001	20348	404.5
0.0217	20348	404.5
0.0218	18454	404.5
1.0	18454	404.5

NOTE: The information presented in this table is based on original plant conditions. The values in the table do provide a reasonable representation of the general blowdown characteristics.

Table 6A-4

FEEDWATER LINE BREAK BLOWDOWN MASS FLUX TIME HISTORY[1]

TIME (s)	MASS FLUX ($lb_m/s/ft^2$)	EFFECTIVE BREAK AREA (ft^2)
VESSEL SIDE:		
0.0001	18250	0.3717
0.0217	18250	0.3717
0.0218	18250	0.2679
1.0	18250	0.2679
SUPPLY PIPE SIDE[2]		
0.0001	18250	0.7433
1.0	18250	0.7433

(1) Listed below are some pertinent physical parameters used in the blowdown estimation

A	=	0.7433 ft^2		Minimum cross-sectional area between vessel and break
D	=	0.9728 ft		Pipe I.D. at the break location
h_o	=	404.5		Btu/lb_m Vessel enthalpy
L_l	=	12	ft	Inventory length
P_o	=	1053	psia	Vessel pressure
P_{sat}	=	326	psia	Saturation pressure
ν	=	0.01888	ft^3/lb_m	Specific volume of the feedwater
V	=	2.79	ft^3	Inventory volume

(1) The most restricted flow area on the feedwater supply pipe side is the break area itself. Full break area steady-state blowdown from this side is conservatively assumed to be reached immediately after the pipe rupture.

NOTE: The information presented in this table is based on original plant conditions. The values in the table do provide a reasonably represent the general characteristics of the blowdown mass flux time history.

Table 6A-5

HEAD SPRAY LINE BREAK[1][2]

TIME (s)	STEAM FLOW lb_m/s	STEAM ENTHALPY (Btu/lb)
0.0	506.8	1192
20.0	506.8	1192

(1) Head spray line break is based on 6 inch Schedule 80 pipe with Moody Blowdown corresponding to 2800 $lb_m/sec\text{-}ft^2$. Overall containment response is that of a "small break accident."

(2) This table is based on the original design basis power. the effects of rerate power conditions blowdown are shown in Figure 6A-11.

Table 6A-6

COMPARTMENT VOLUMES USED IN REACTOR VESSEL SHIELD ANNULUS SUBCOMPARTMENT ANALYSIS

COMPARTMENT NO.	DESIGNATION	VOLUME, ft^3
1	V1	54
2	V2	54
3	V3	54
4	V4	54
5	V5	54
6	V6	54
7	V7	54
8	V8	54
9	V9	54
10	V10	54
11	V11	54
12	V12	54
13	V13	69
14	V14	76
15	V15	75
16	V16	76
17	V17	76
18	V18	69
19	V19	69
20	V20	76
21	V21	75
22	V22	76
23	V23	76
24	V24	69
25	V25	59
26	V26	57
27	V27	57
28	V28	57
29	V29	57
30	V30	57
31	V31	57
32	V32	57
33	V33	57
34	V34	57
35	V35	57
36	V36	59
37	V37	60
38	V38	58
39	V39	60
40	V40	76
41	V41	58

Table 6A-6 (Cont'd)

COMPARTMENT NO.	DESIGNATION	VOLUME, ft^3
42	V42	60
43	V43	76
44	V44	58
45	V45	60
46	V46	76
47	V47	58
48	V48	60
49	V49	77
50	V50	71
51	V51	73
52	V52	77
53	V53	75
54	V54	77
55	V55	77
56	V56	74
57	V57	77
58	V58	73
59	V59	71
60	V60	77
61	V61	34
62	V62	34
63	V63	34
64	V64	34
65	V65	34
66	V66	34
67	V67	34
68	V68	34
69	V69	34
70	V70	34
71	V71	34
72	V72	34
73	V73	235200

Table 6A-7

FLOW AREA AND COEFFICIENTS USED IN
REACTOR VESSEL SHIELD ANNULUS SUBCOMPARTMENT ANALYSIS

FLOW PATHS	FLOW AREA (ft^2)	K FACTOR	DESCRIPTION	L/A (ft^{-1})	FLOW COEFFICIENT
1-2,1-12, 2-3,3-4, 4-5,5-6, 6-7,7-8, 8-9,9-10,		0.13	30° turn		
10-11,11-12	10	1.0	Final expansion	0.62	0.94
1-13,2-14, 3-15,4-16, 5-17,6-18, 7-19,8-20, 9-21,10-22,		0.05	Friction		
11-23,12-24	8.5	1.0	Final expansion	1.01	0.97
2-73,3-73, 5-73,6-73, 8-73,9-73,		0.42	Contraction		
11-73,12-73	2	1.0	Final expansion	0.73	0.83
		0.13	30° turn		
13-24,		1.12	Around pipe		
18-19	9.5	1.0	Final expansion	0.54	0.66
13-14,15-16, 16-17,17-18, 19-20,20-21,		0.13	30° turn		
		0.1	Around pipe		
22-23,23-24	13	1.0	Final expansion	0.43	0.9
		0.1	Around pipe		
		0.1	Around instrument pipe		
14-15,		0.13	30° turn		
21-22	12	1.0	Final expansion	0.43	0.86
		1.35	Around pipe		
13-25,18-30,		0.28	Around pipe		
19-31,24-36	4.5	1.0	Final expansion	1.57	0.61
14-26,16-28,		0.28	Around pipe		
17-29,20-32,		0.28	Around pipe		
22-34,23-35,	5.5	1.0	Final expansion	1.17	0.8

Table 6A-7 (Cont'd)

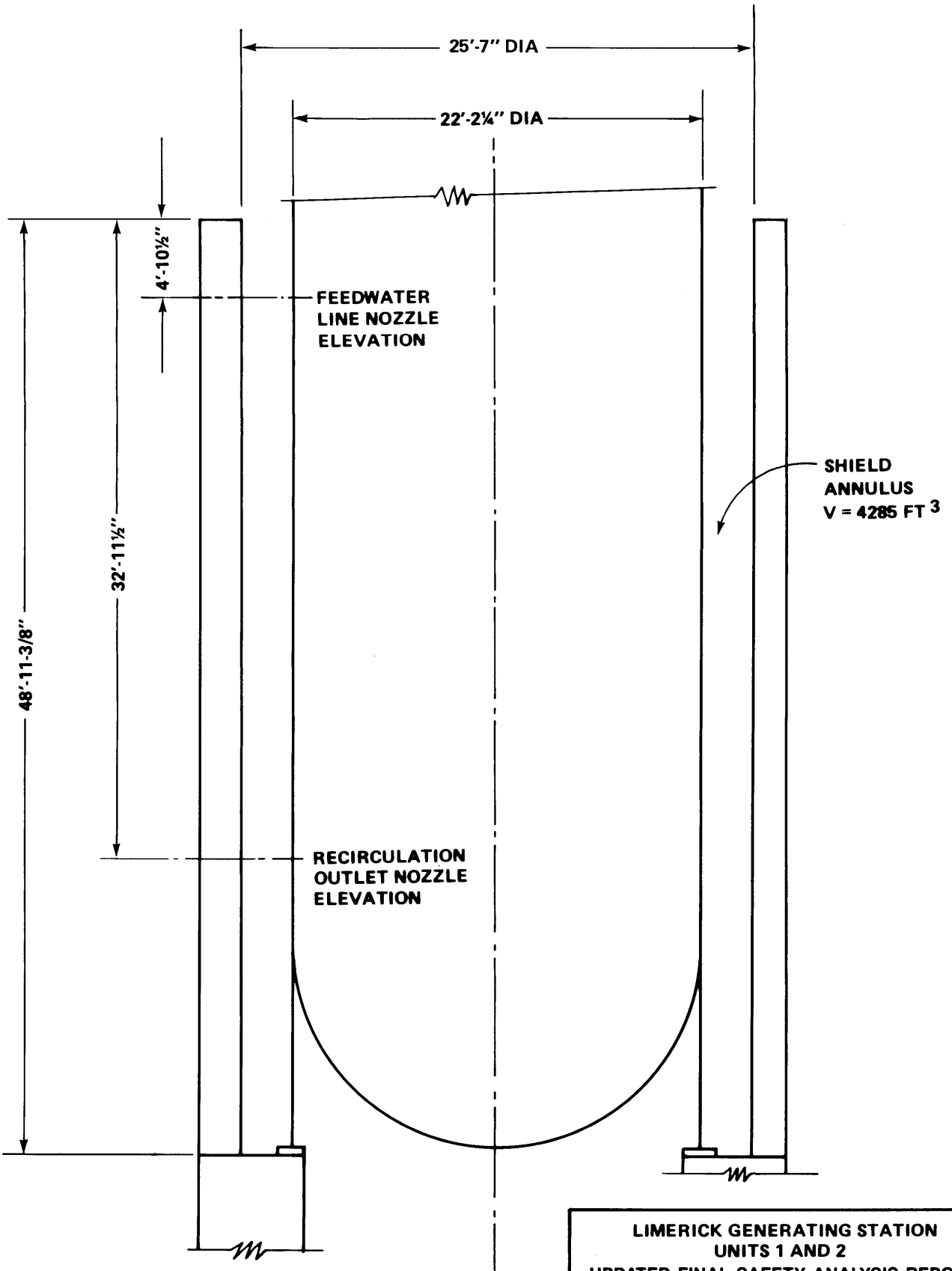
FLOW PATHS	FLOW AREA (ft^2)	K FACTOR	DESCRIPTION	L/A (ft^{-1})	FLOW COEFFICIENT
		0.28	Around pipe		
		0.28	Around pipe		
15-27,		0.31	Around pipe		
21-33	4.5	1.0	Final expansion	1.31	0.73
25-36,		0.13	30° turn		
30-31	11	1.0	Final expansion	0.55	0.94
25-26,26-27, 27-28,28-29, 29-30,31-32,		0.13	30° turn		
32-33,33-34,		0.16	Around pipe		
34-35,35-36,	9.5	1.0	Final expansion	0.58	0.88
25-37,26-38, 27-39,28-40, 29-41,30-42, 31-43,32-44, 33-45,34-46,		0.07	Friction		
33-47,36-48	8.5	1.0	Final expansion	0.92	0.96
		0.13	30° turn		
37-48,38-39		0.01	Around instrument pipe		
41-42,45-46	10.5	1.0	Final expansion	0.55	0.93
		0.13	30° turn		
37-38,40-41,		0.16	Around pipe		
44-45,47-48	9.5	1.0	Final expansion	0.57	0.88
39-40,42-43,		0.13	30° turn		
43-44,46-47	11	1.0	Final expansion	0.55	0.94
		0.01	Around instrument pipe		
37-49,		0.07	Friction		
48-60	8	1.0	Final expansion	1.07	0.96
38-50,41-53,		1.11	Around pipe		
44-56,47-59	6	1.0	Final expansion	1.14	0.68
39-51,42-54,		0.08	Around instrument pipe		
45-57	8	1.0	Final expansion	1.07	0.96

Table 6A-7 (Cont'd)

FLOW PATHS	FLOW AREA (ft^2)	K FACTOR	DESCRIPTION	L/A (ft^{-1})	FLOW COEFFICIENT
40-52,43-55		0.07	Around pipe		
46-58	8.5	1.0	Final expansion	1.06	0.96
		0.13	30° turn		
		0.15	Around pipe		
49-50		0.15	Around pipe		
59-60	11.5	1.0	Final expansion	0.46	0.83
		0.125	30° turn		
		0.01	Around instrument pipe		
49-60	14	1.0	Final expansion	0.42	0.93
		0.13	30° turn		
		0.01	Around instrument pipe		
		0.47	Around pipe		
50-51	10.5	1.0	Final expansion	0.48	0.78
		0.13	30° turn		
51-52,52-53,		0.15	Around pipe		
56-57	13	1.0	Final expansion	0.44	0.88
		0.13	30° turn		
		0.01	Around instrument pipe		
		0.15	Around pipe		
53-54,57-58	12.5	1.0	Final expansion	0.45	0.88
		0.13	30° turn		
54-55	14.5	1.0	Final expansion	0.42	0.94
		0.13	30° turn		
		0.15	Around pipe		
		0.12	Around CRD		
		0.15	Around pipe		
55-56	10.5	1.0	Final expansion	0.5	0.8
		0.13	30° turn		
		0.47	Around pipe		
58-59	11	1.0	Final expansion	0.47	0.79
49-61,52-64,					
53-65,55-67,		0.49	Around pipe		
57-69	6.5	1.0	Final expansion	0.96	0.81

Table 6A-7 (Cont'd)

FLOW PATHS	FLOW AREA (ft^2)	K FACTOR	DESCRIPTION	L/A (ft^{-1})	FLOW COEFFICIENT
		0.49	Around pipe		
54-66,		0.08	Around instrument pipe		
60-72	6	1.0	Final expansion	1.0	0.79
		0.49	Around pipe		
		0.17	Around CRD		
56-68	5.5	1.0	Final expansion	1.07	0.77
		0.11	30^o turn		
61-62,63-64		0.96	Around pipe		
67-68,69-70	5	1.0	Final expansion	1.03	0.69
61-72,62-63					
64-65,66-67		0.11	30^o turn		
68-69,70-71	6.5	1.0	Final expansion	0.9	0.94
		0.11	30^o turn		
		0.96	Around pipe		
65-66,		0.1	Around instrument pipe		
71-72	4.5	1.0	Final expansion	1.1	0.67
61-73,63-73					
64-73,66-73					
67-73,69-73		0.12	Contraction		
70-73,72-73	6	1.0	Final expansion	0.28	0.94
62-73,65-73		0.05	Contraction		
68-73,71-73	7.5	1.0	Final expansion	0.28	0.97
		0.49	Around pipe		
50-62,51-63,		0.49	Around pipe		
58-70,59-71	5	1.0	Final expansion	1.28	0.71



LIMERICK GENERATING STATION
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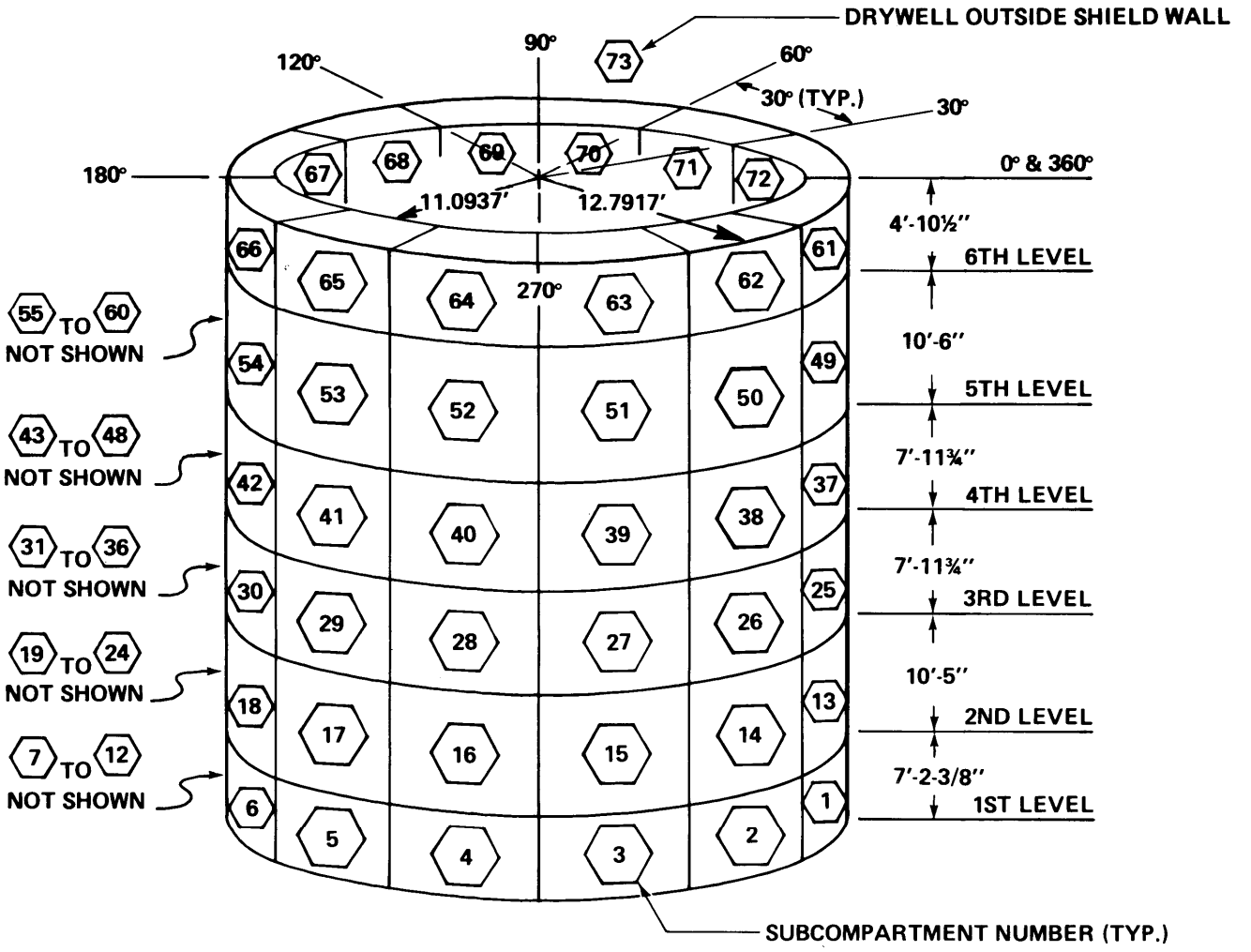
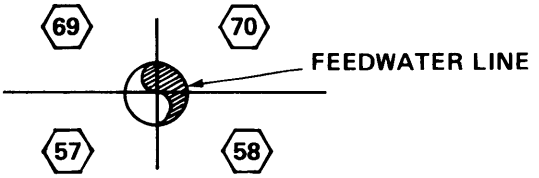
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR SHIELD ANNULUS ARRANGEMENT

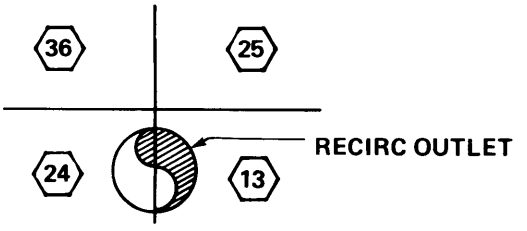
FIGURE 6A-1



FEEDWATER PIPE BREAK IN SUBCOMPARTMENTS 57, 58, 69 AND 70



RECIRCULATION OUTLET PIPE BREAK IN SUBCOMPARTMENTS 13 AND 24



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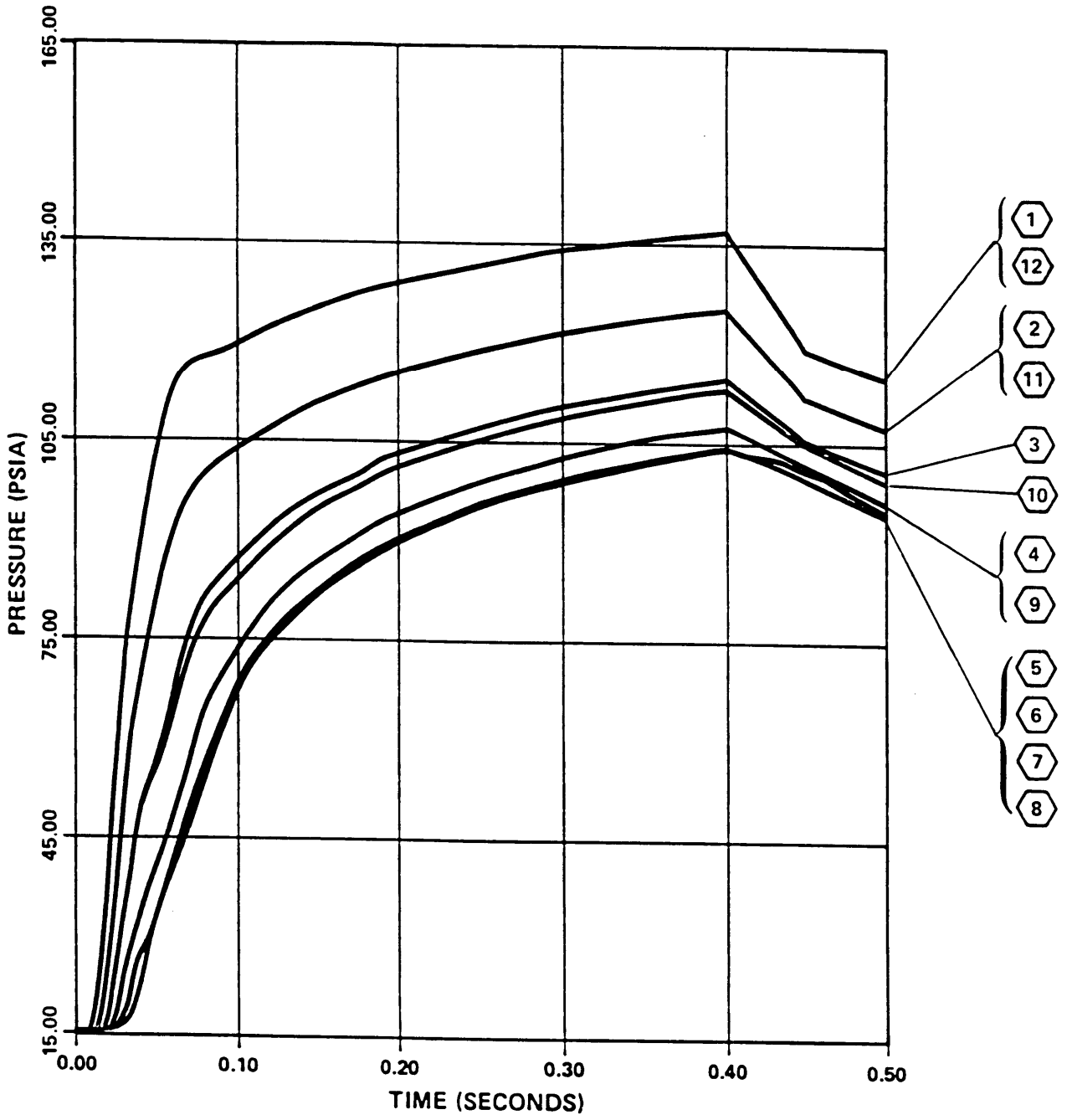
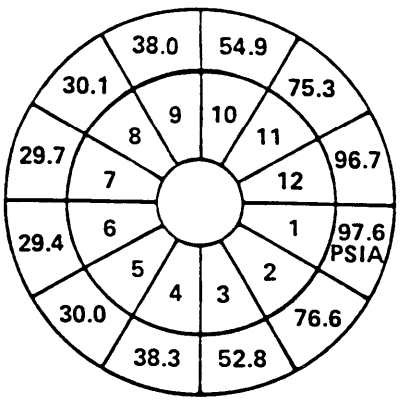
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

REACTOR SHIELD ANNULUS SUBCOMPARTMENT MODEL SCHEMATIC

FIGURE 6A-2



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



1ST LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

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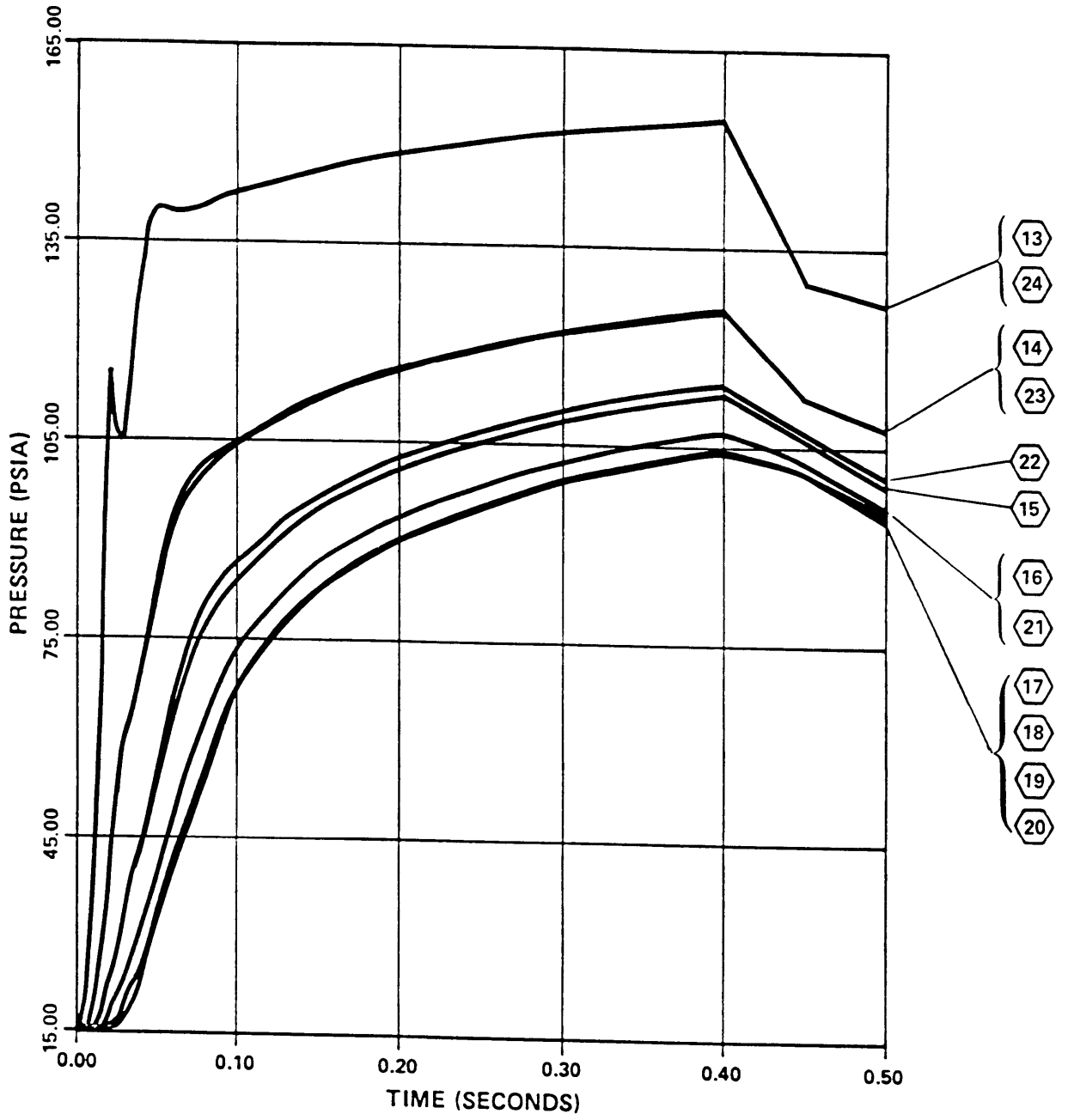
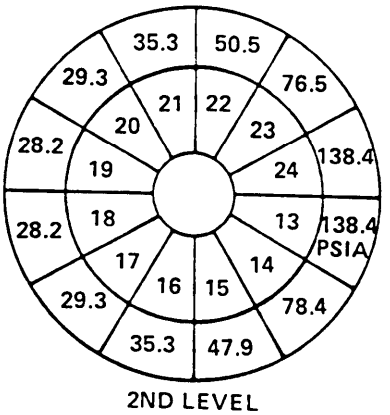
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 1 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



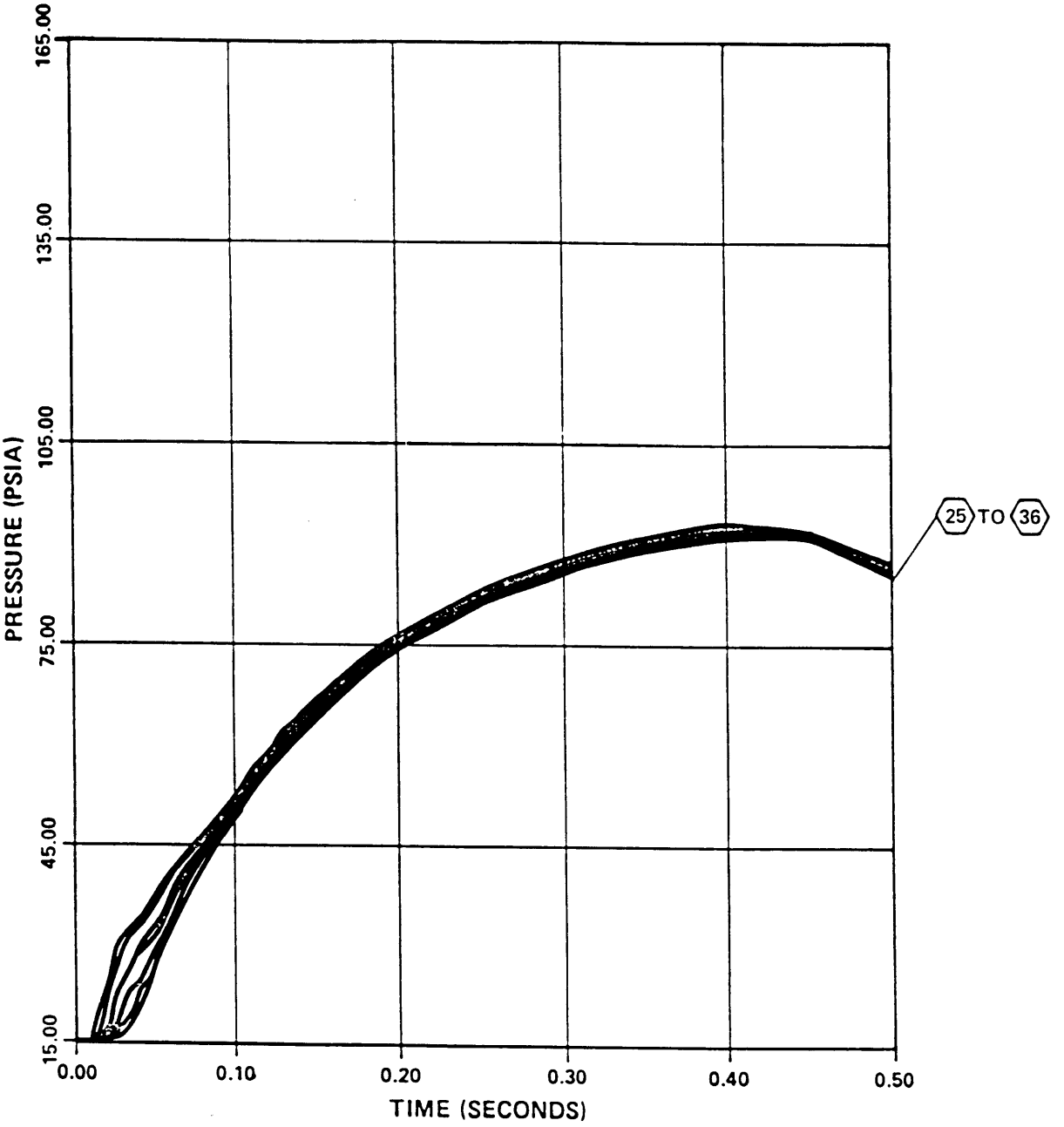
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

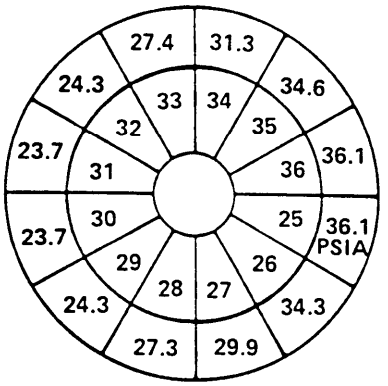
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 2 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



3RD LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

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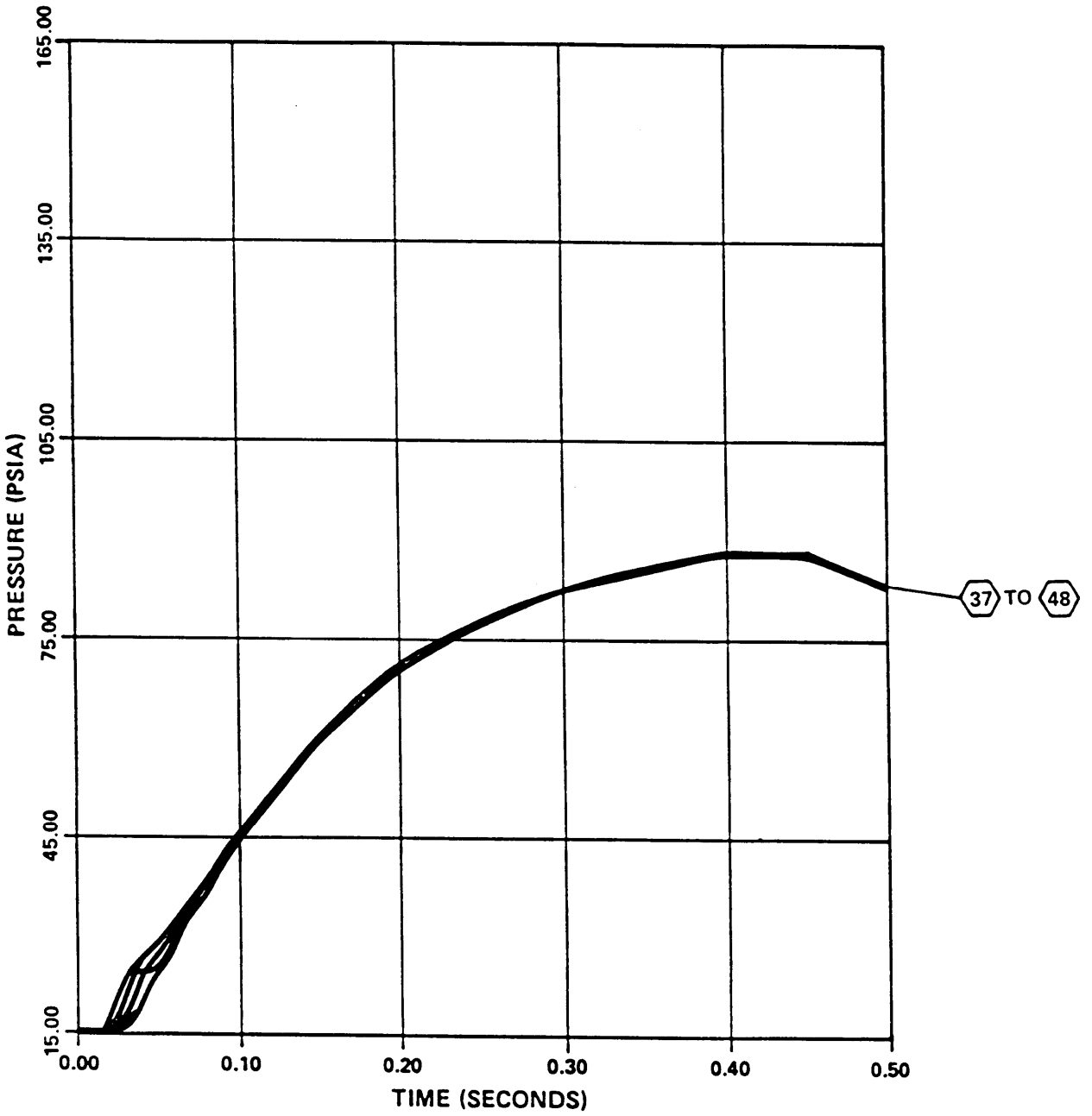
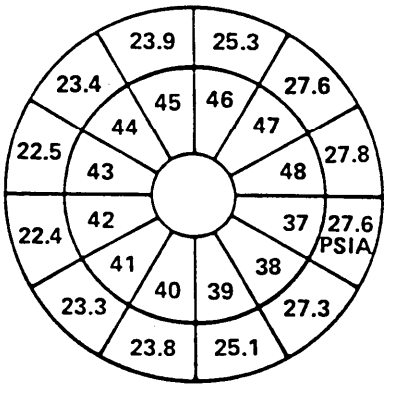
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 3 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



4TH LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

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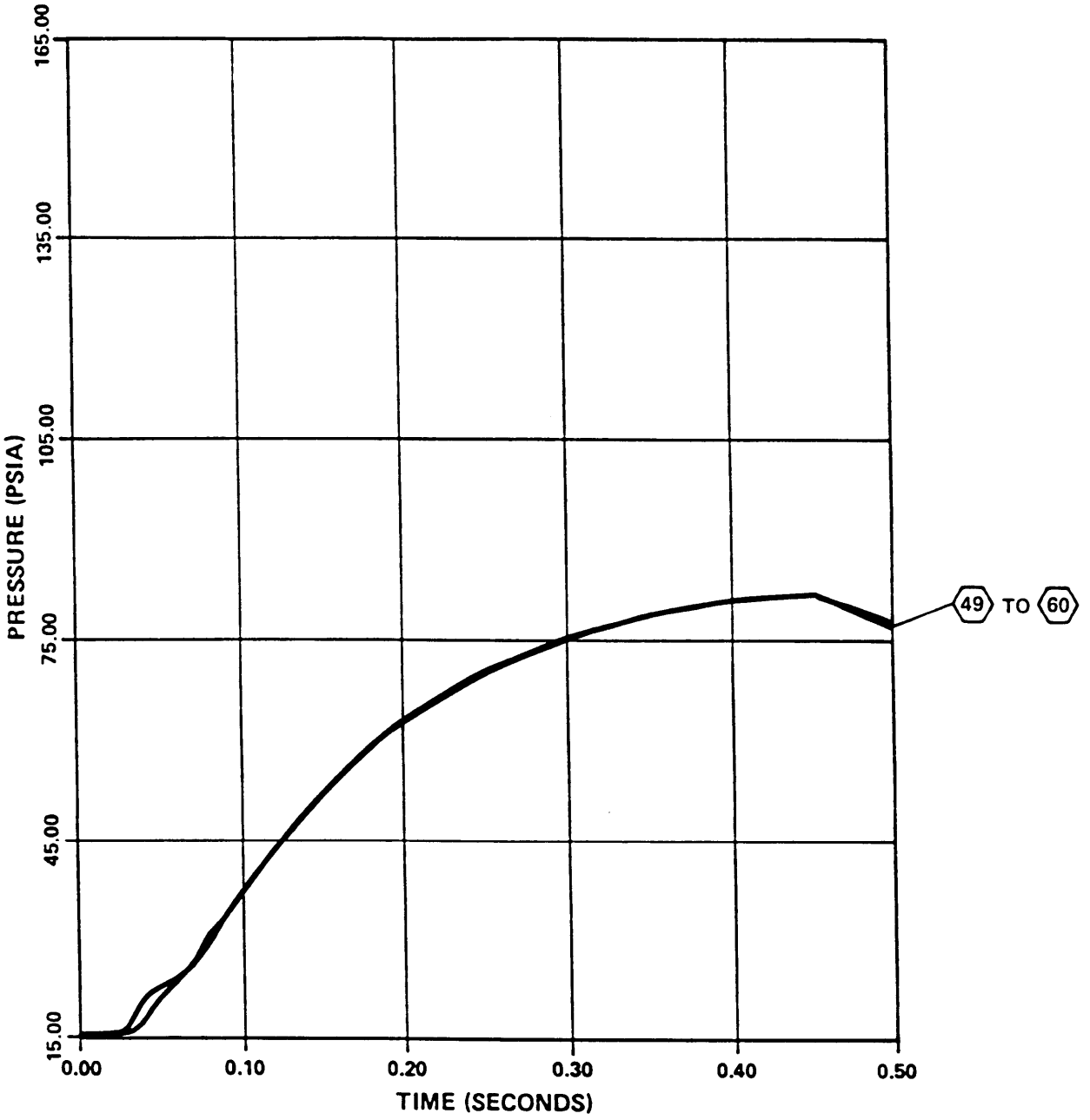
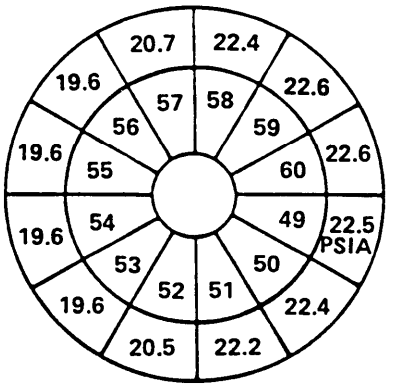
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 4 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



5TH LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
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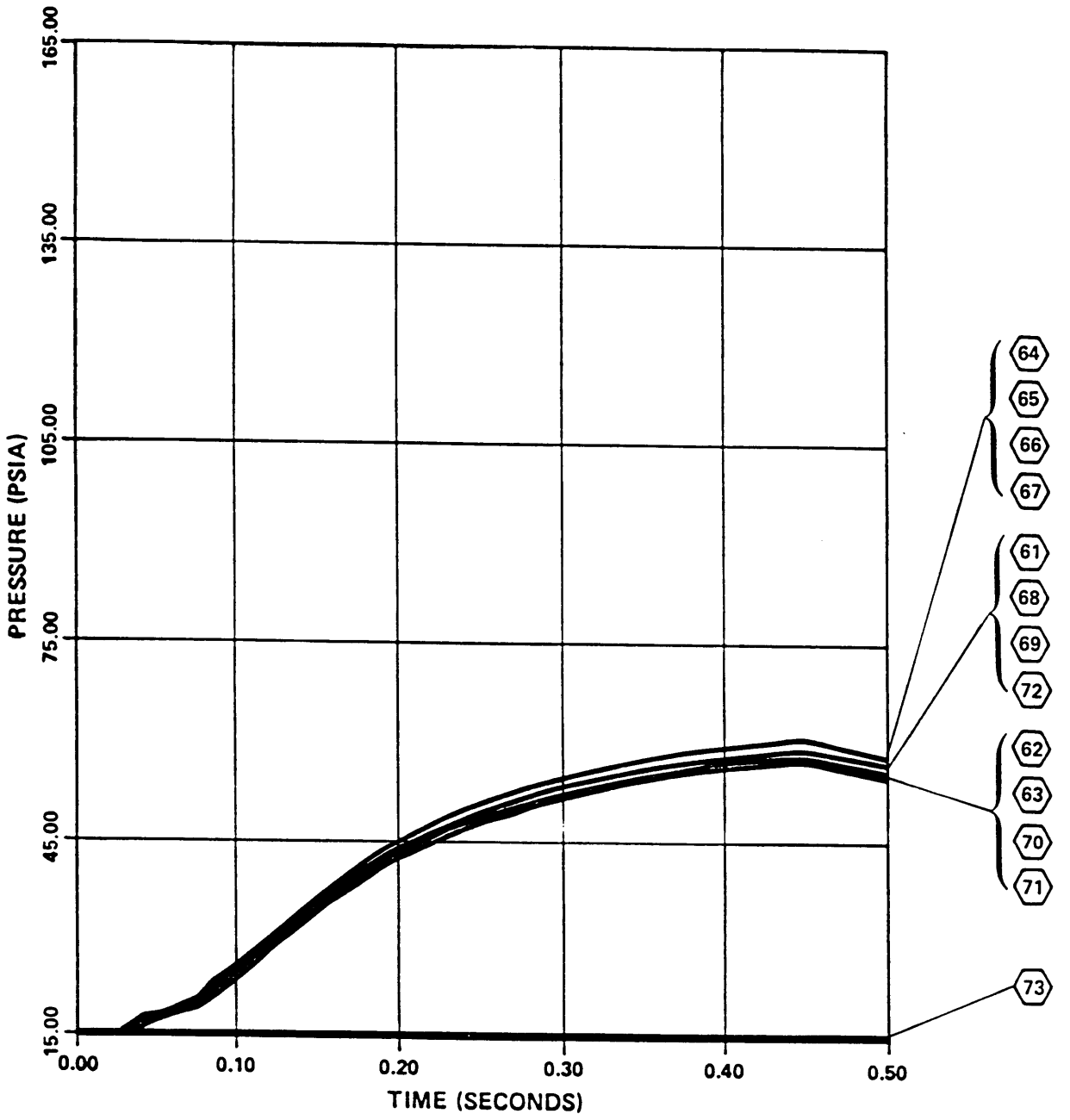
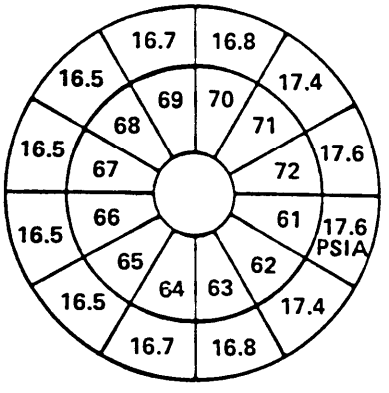
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 5 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



6TH LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.046 SEC, PRODUCING THE MAXIMUM DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

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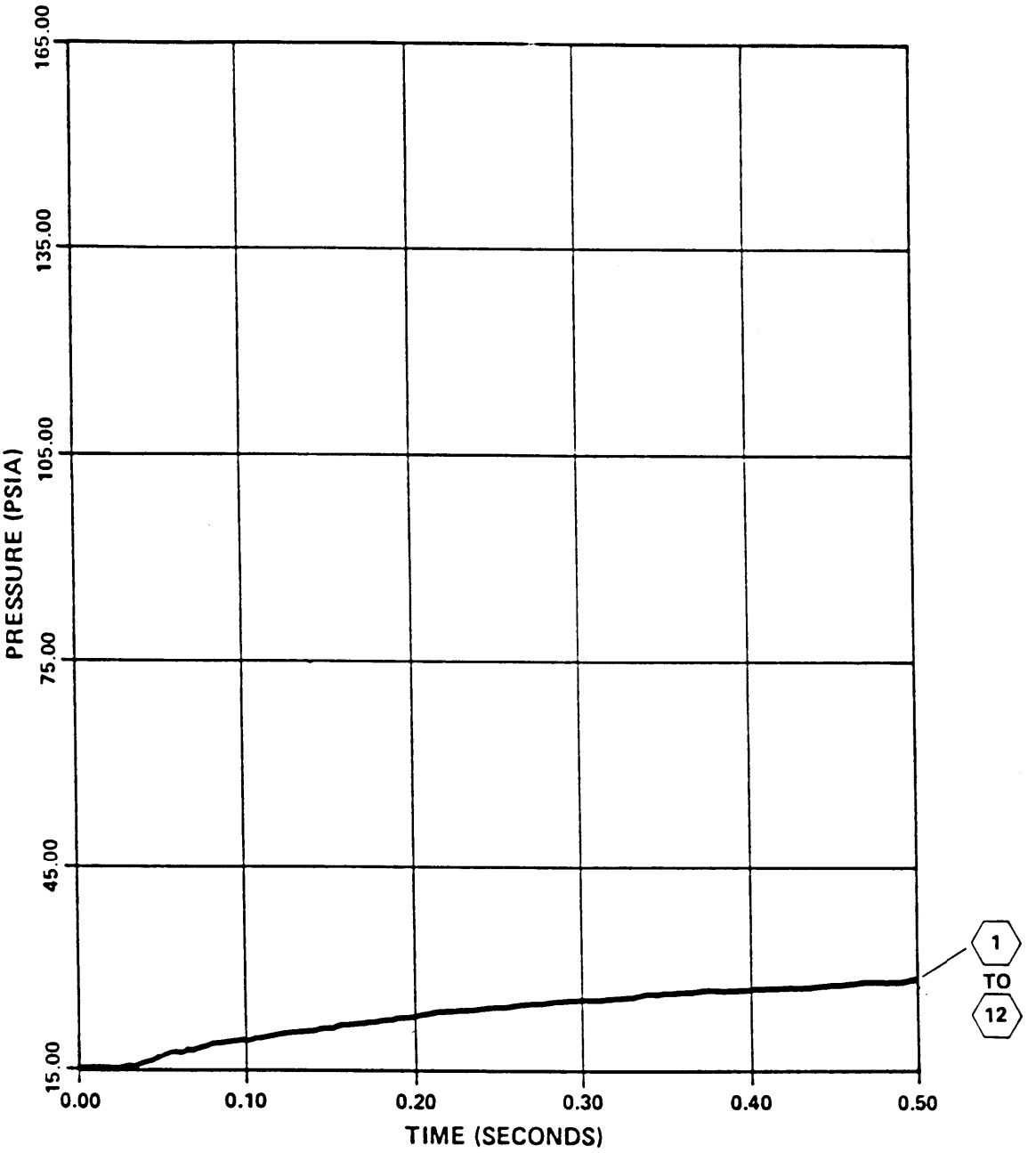
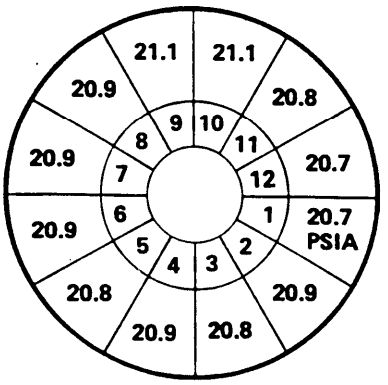
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE SAFE END

SHEET 6 OF 6

FIGURE 6A-3 Rev. 5, 4/96



NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the pressure transient.



1ST LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

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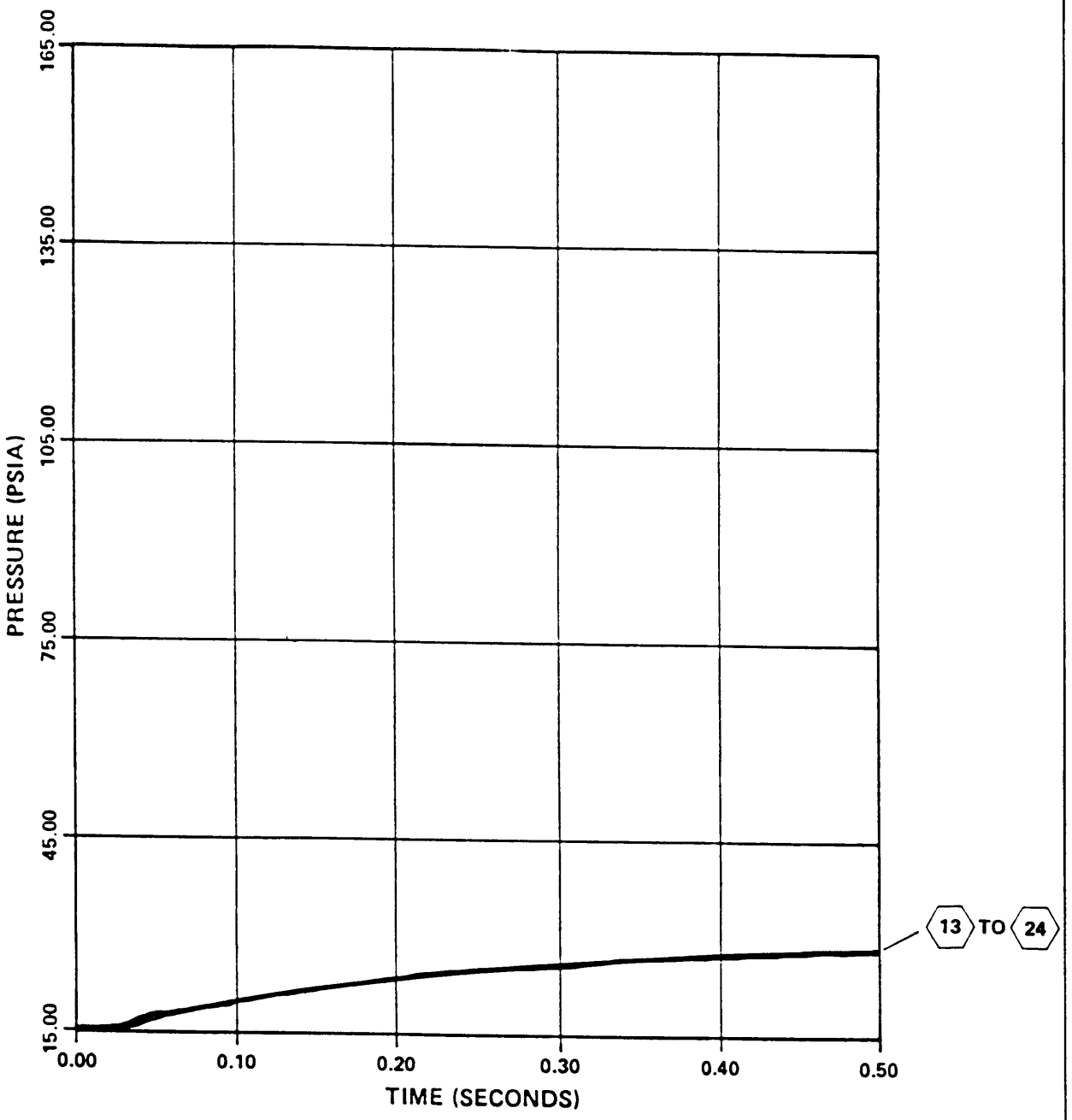
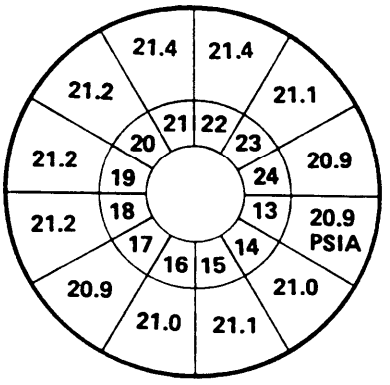
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

SHEET 1 OF 6

FIGURE 6A-4 Rev. 5, 4/96





NOTE:

2ND LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.

LIMERICK GENERATING STATION
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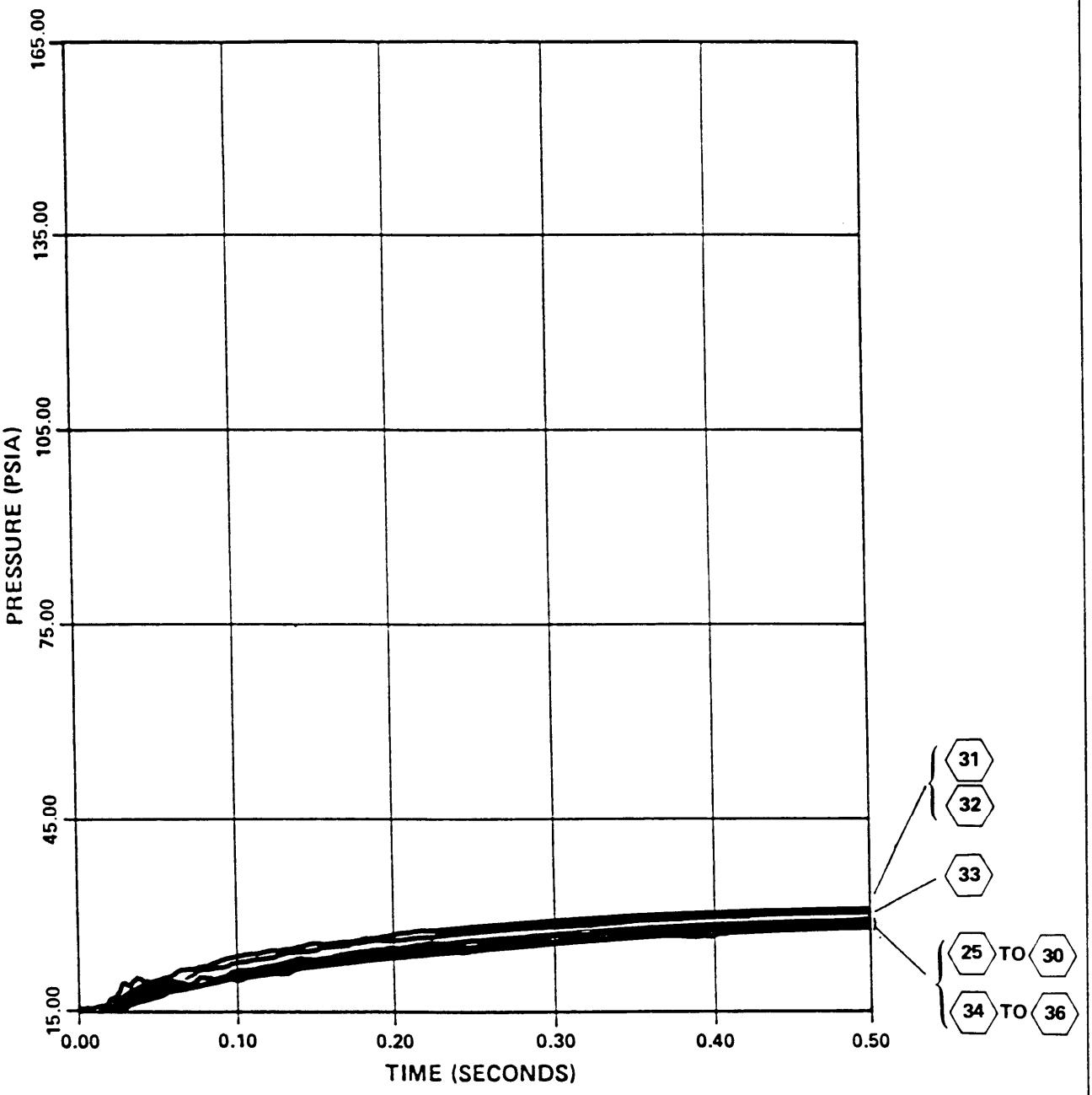
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

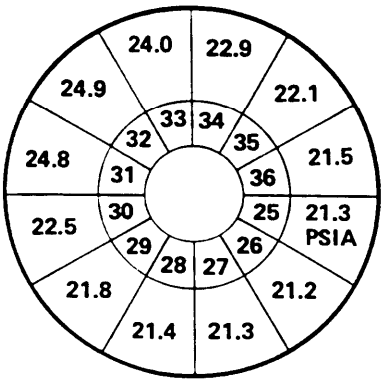
SHEET 2 OF 6

FIGURE 6A-4

Rev. 5, 4/96



NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.



3RD LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

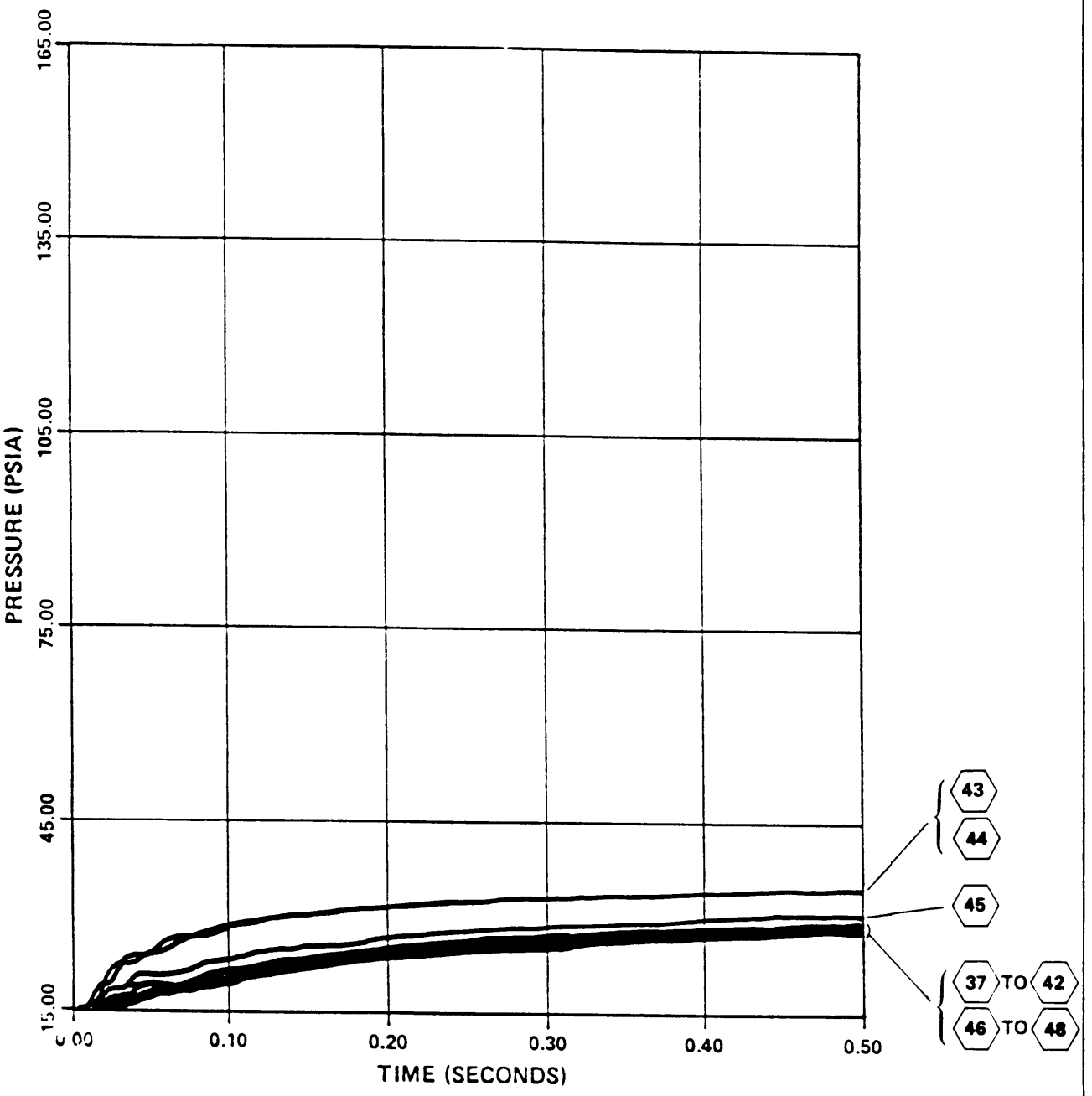
LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

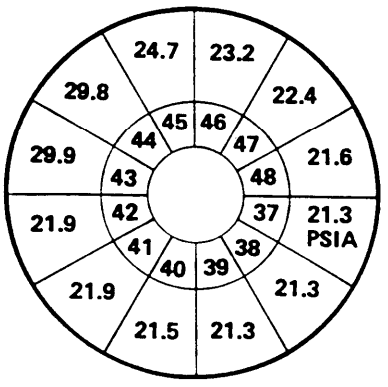
SHEET 3 OF 6

FIGURE 6A-4

Rev. 5, 4/96



NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.



FOURTH LEVEL

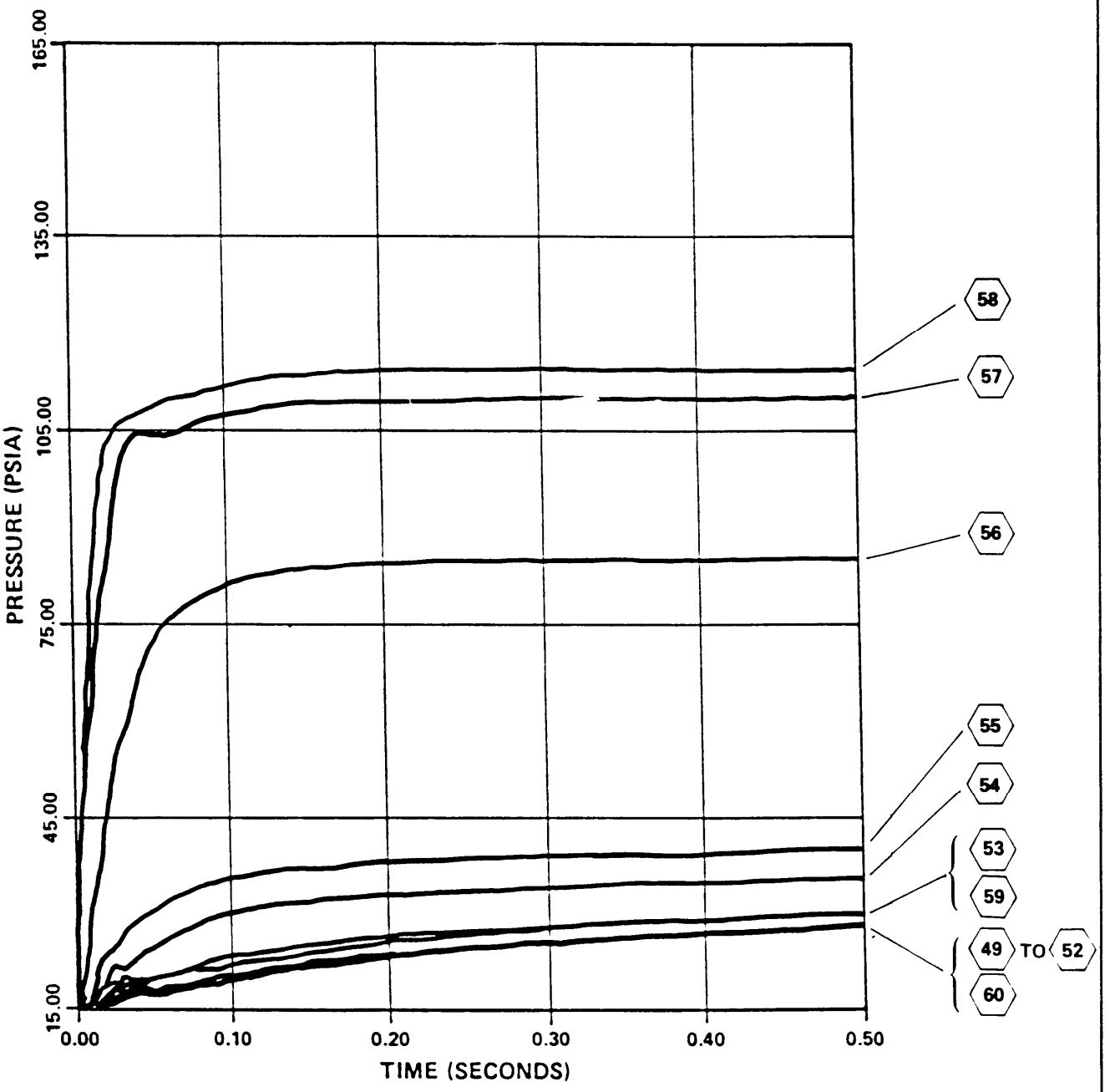
THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

LIMERICK GENERATING STATION
UNITS 1 AND 2
UPDATED FINAL SAFETY ANALYSIS REPORT

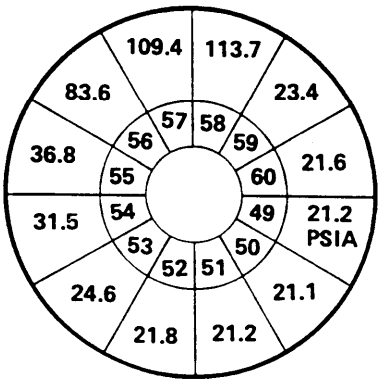
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

SHEET 4 OF 6

FIGURE 6A-4 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.



5TH LEVEL

THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

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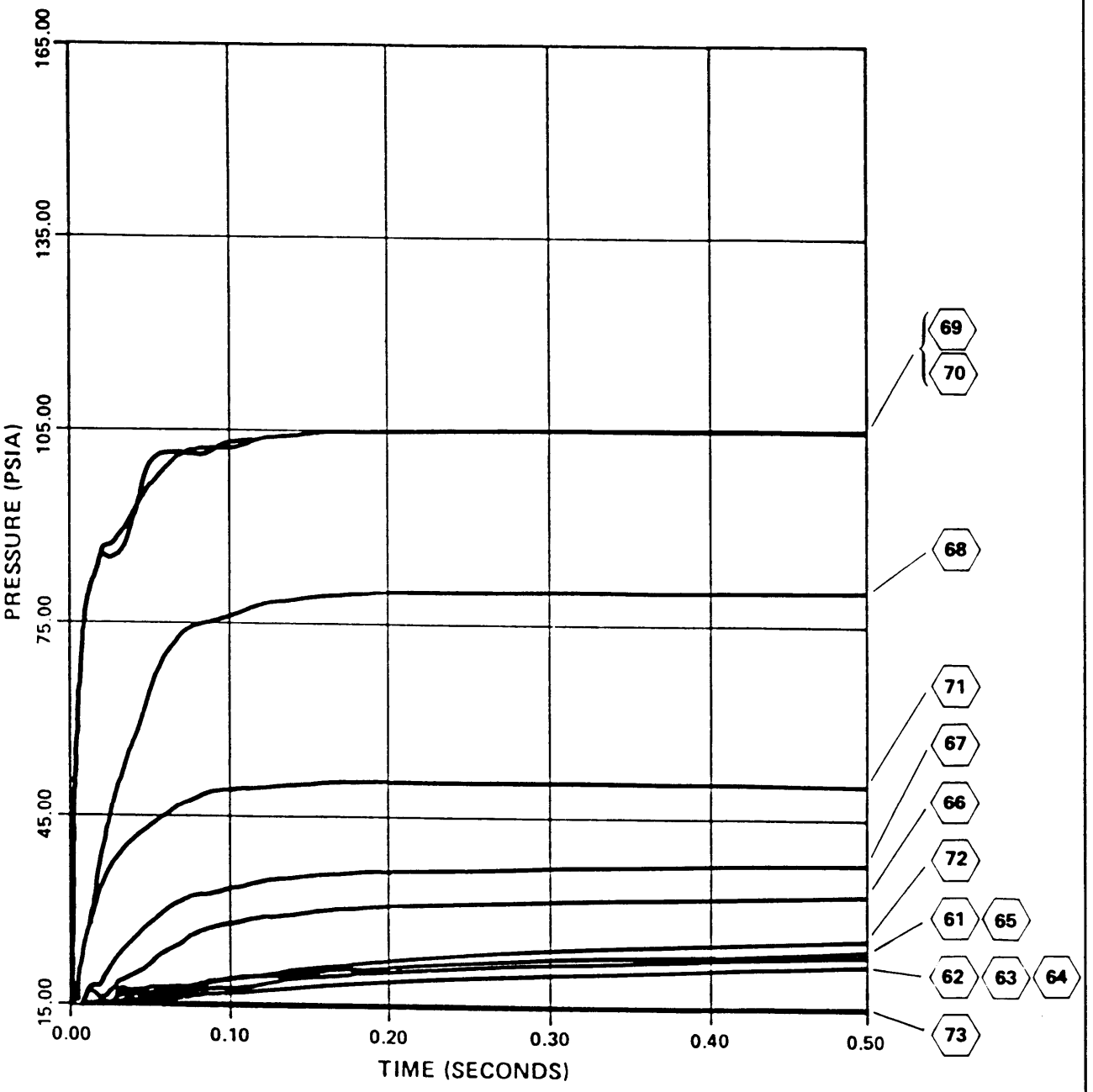
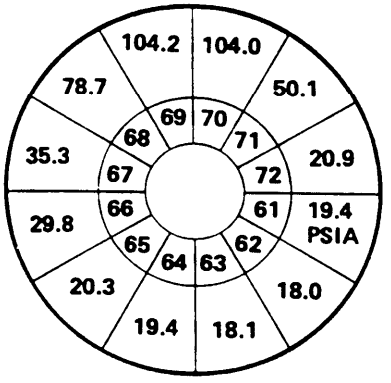
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

SHEET 5 OF 6

FIGURE 6A-4 Rev. 5, 4/96



NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the pressure transient.



THE SPATIAL PRESSURE DISTRIBUTION OCCURS AT 0.14 SECONDS, PRODUCING THE MAX DIFFERENTIAL PRESSURE ACROSS THE VESSEL.

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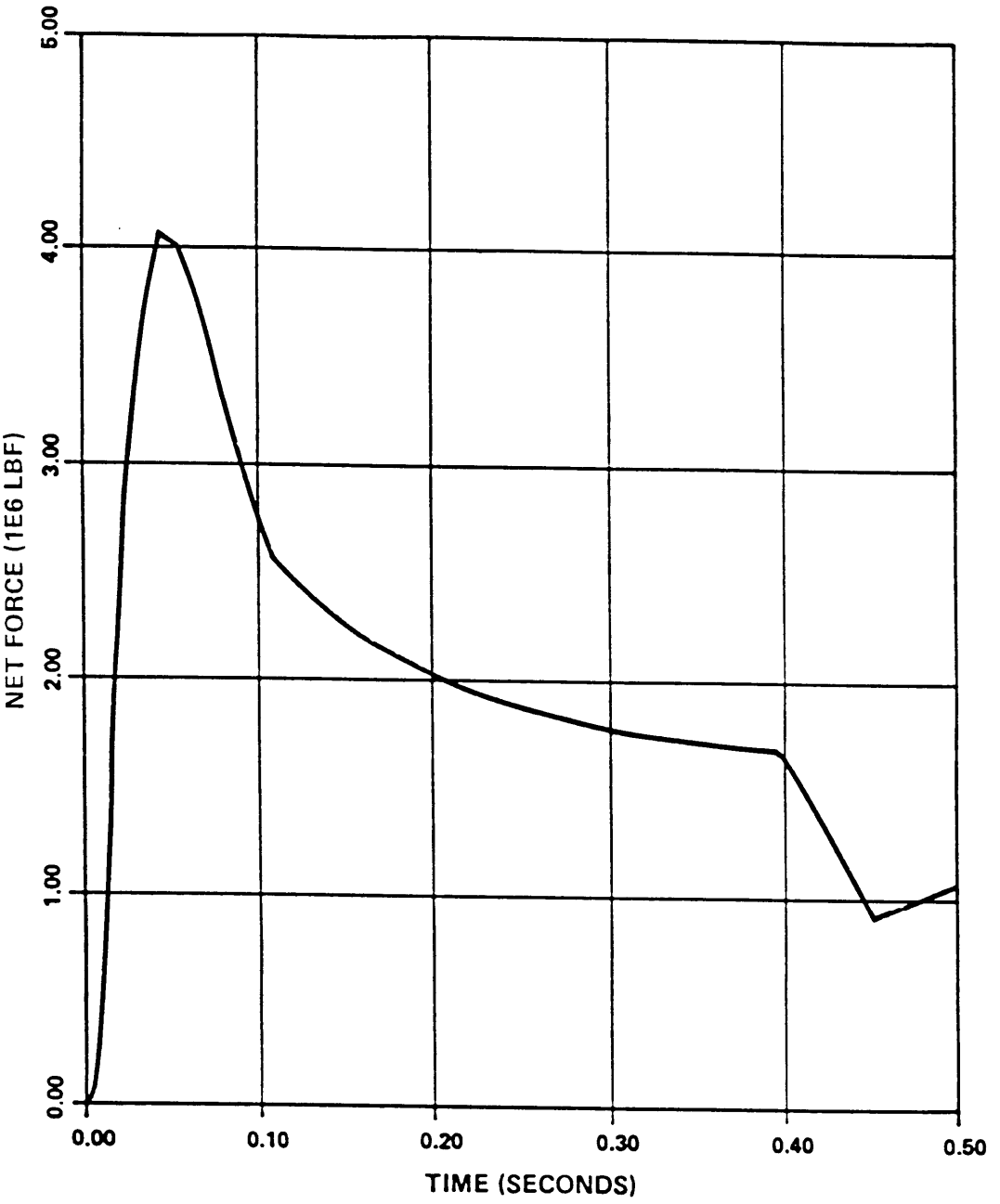
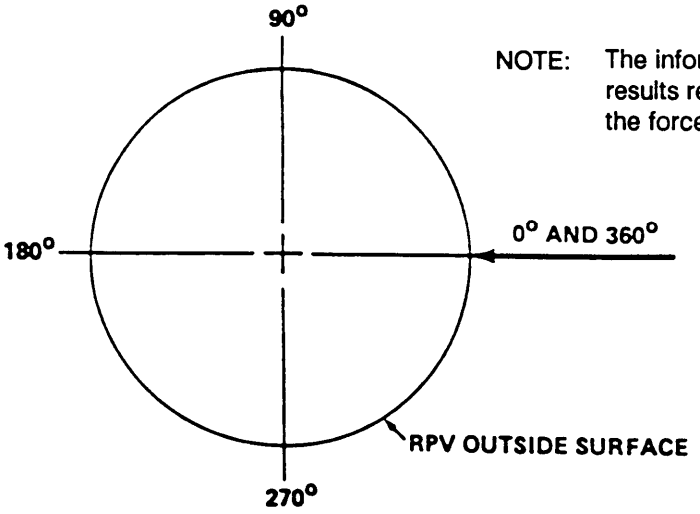
PRESSURE TRANSIENT IN REACTOR SHIELD ANNULUS FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE SAFE END

SHEET 6 OF 6

FIGURE 6A-4 Rev. 5, 4/96





NOTE: The information presented in this figure is historical. The results reasonably represent the general characteristics of the force transient.

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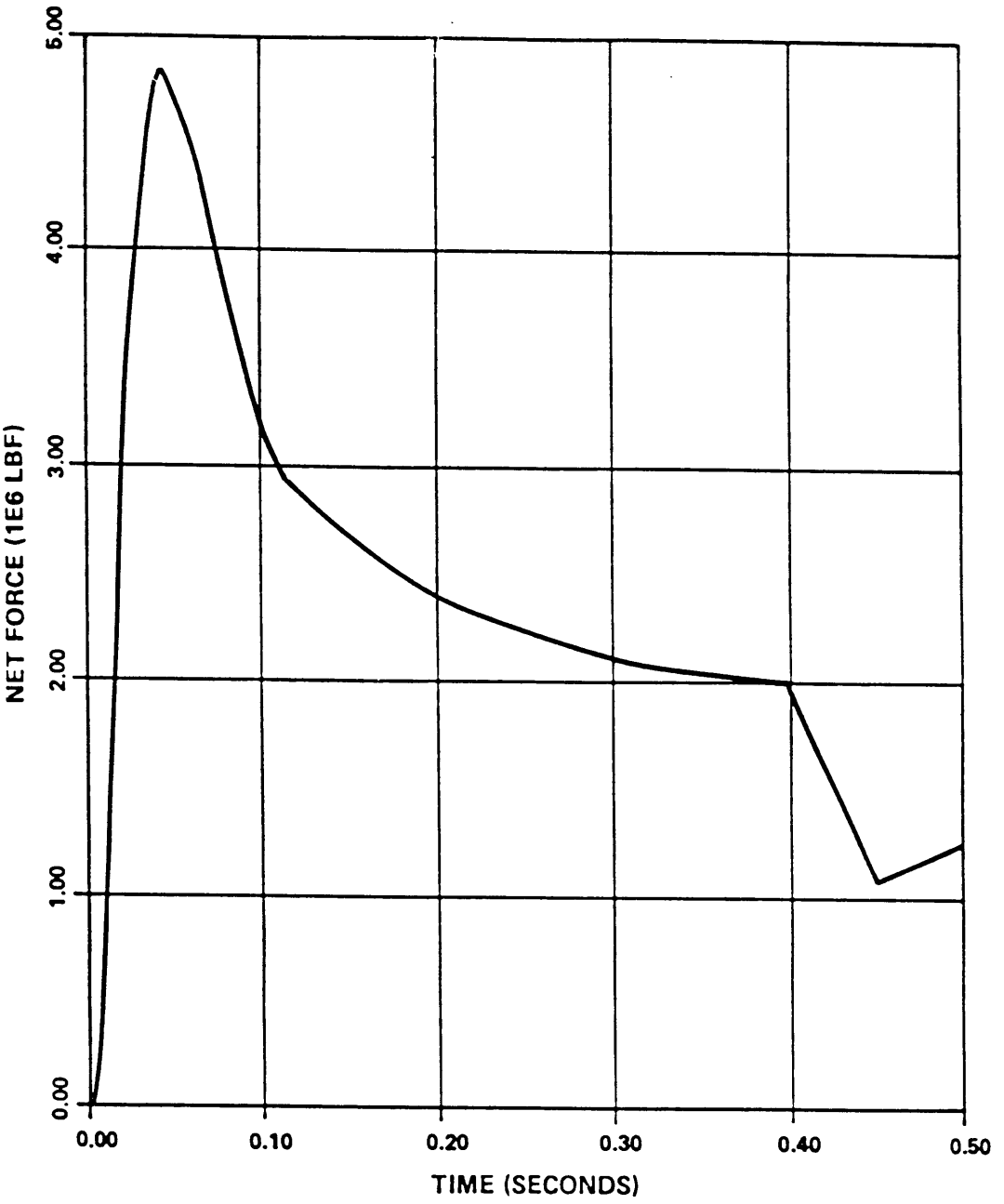
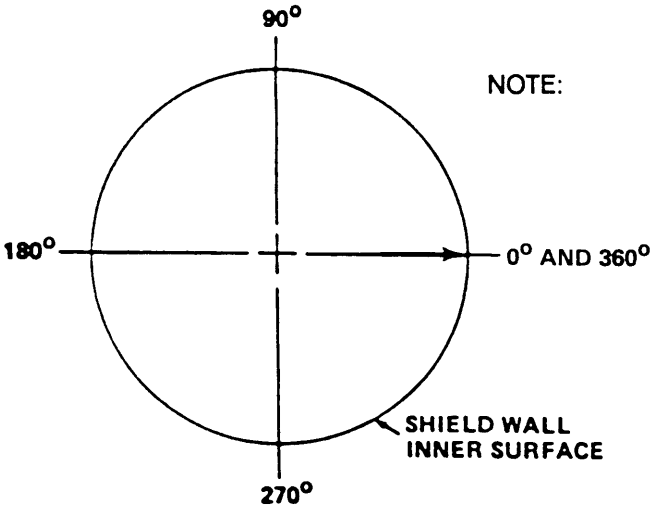
FORCE TRANSIENT ON REACTOR VESSEL FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE

FIGURE 6A-5 Rev. 5, 4/96





NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the force transient.

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FORCE TRANSIENT ON REACTOR SHIELD WALL FOLLOWING A RECIRC. OUTLET LINE BREAK AT THE NOZZLE

FIGURE 6A-6

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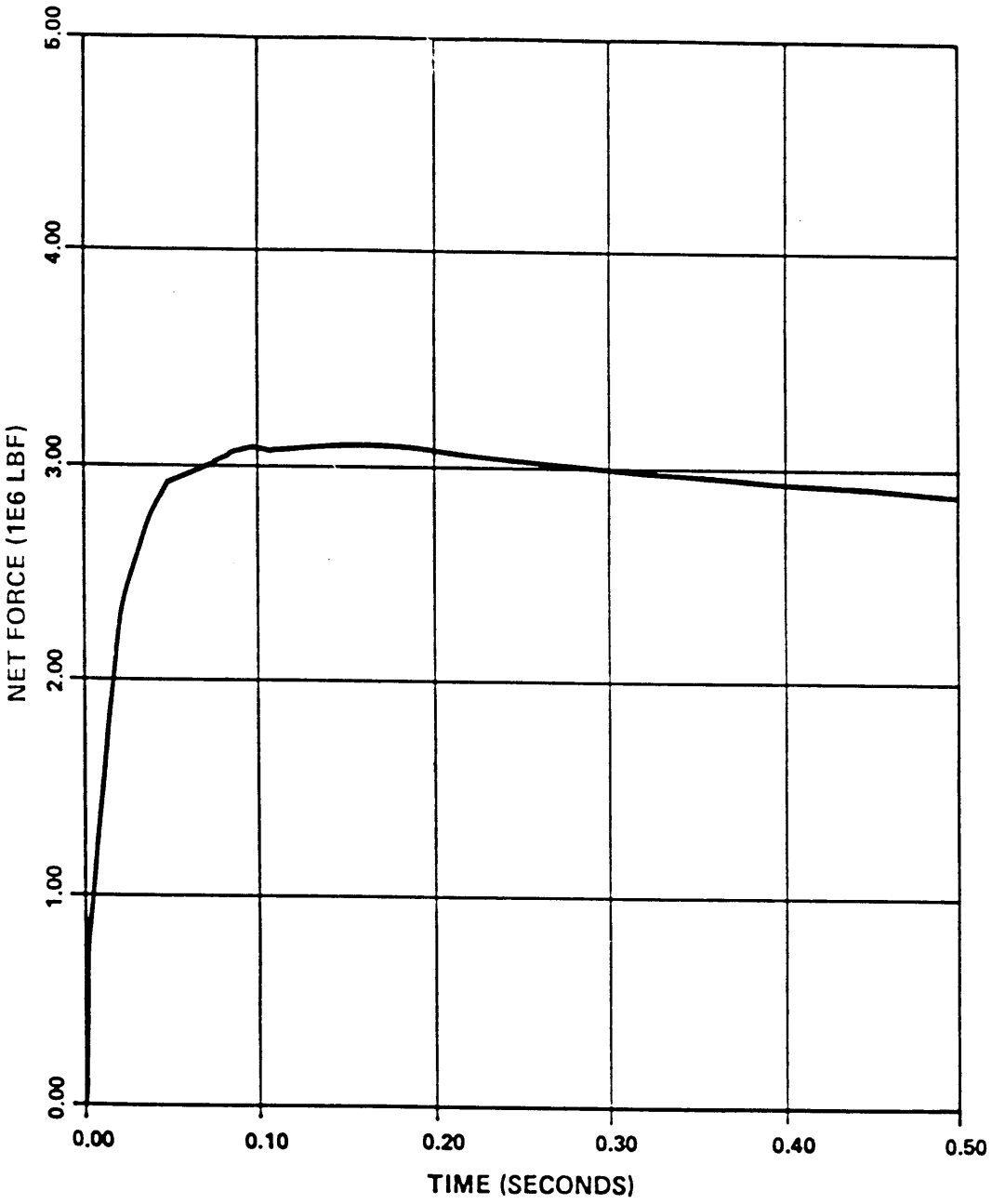

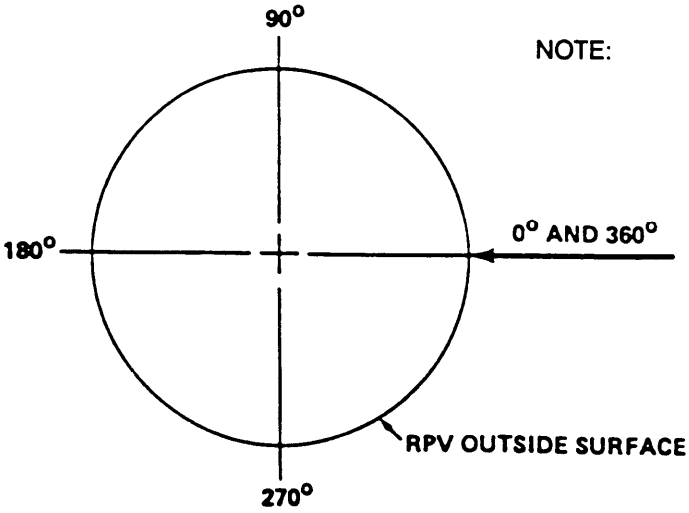

NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the force transient.

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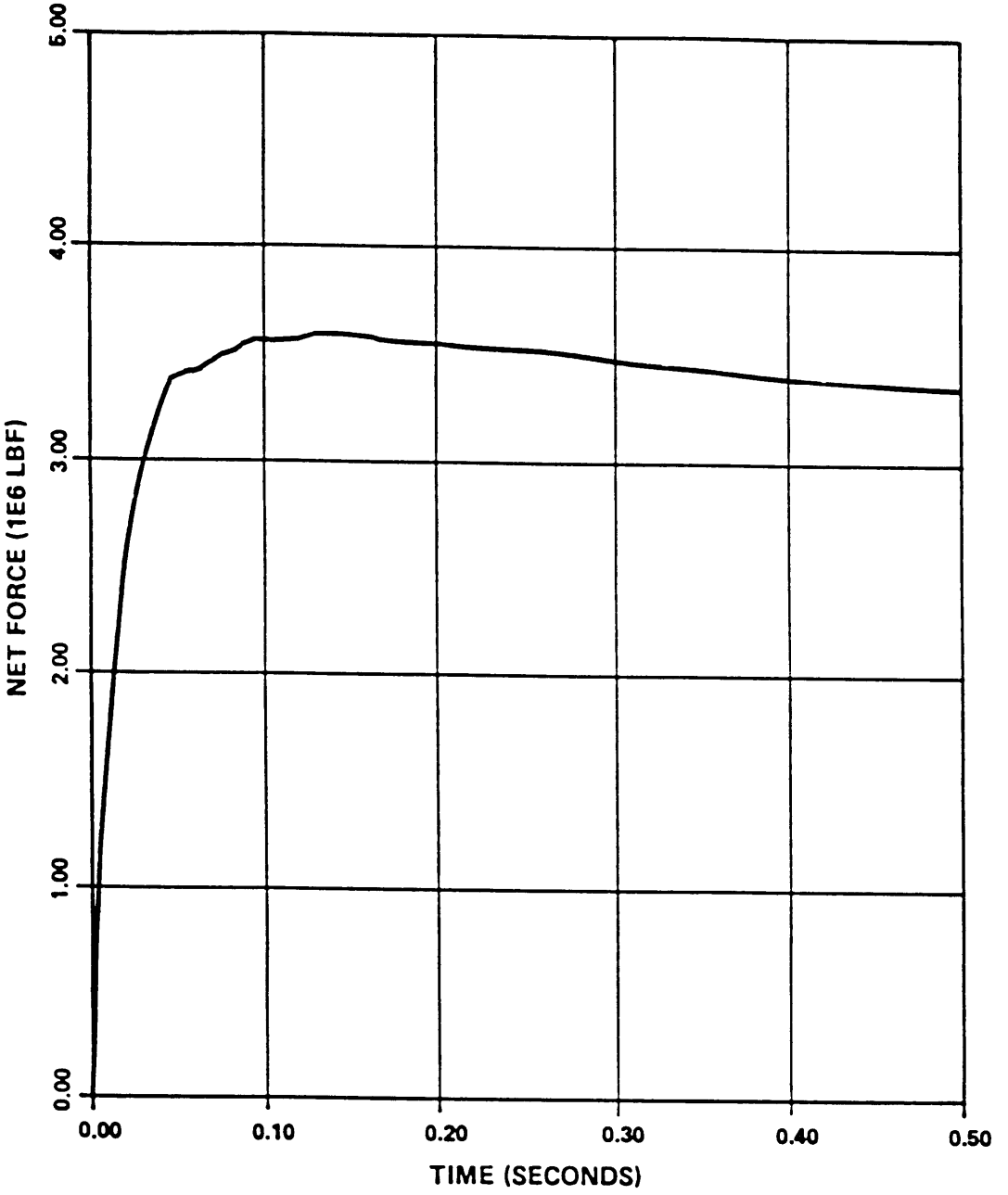
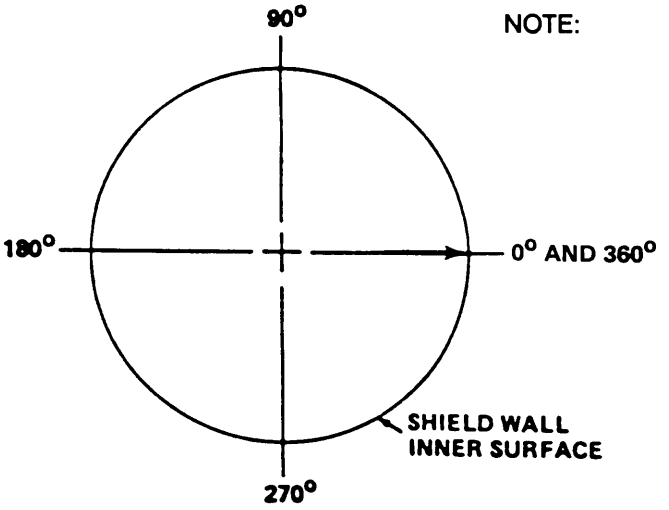
FORCE TRANSIENT ON REACTOR VESSEL FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE

FIGURE 6A-7 Rev. 5, 4/96





NOTE: The information presented in this figure is historical and does not represent current plant conditions. The results reasonably represent the general characteristics of the force transient.

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FORCE TRANSIENT ON REACTOR SHIELD WALL FOLLOWING A FEEDWATER LINE BREAK AT THE NOZZLE

FIGURE 6A-8

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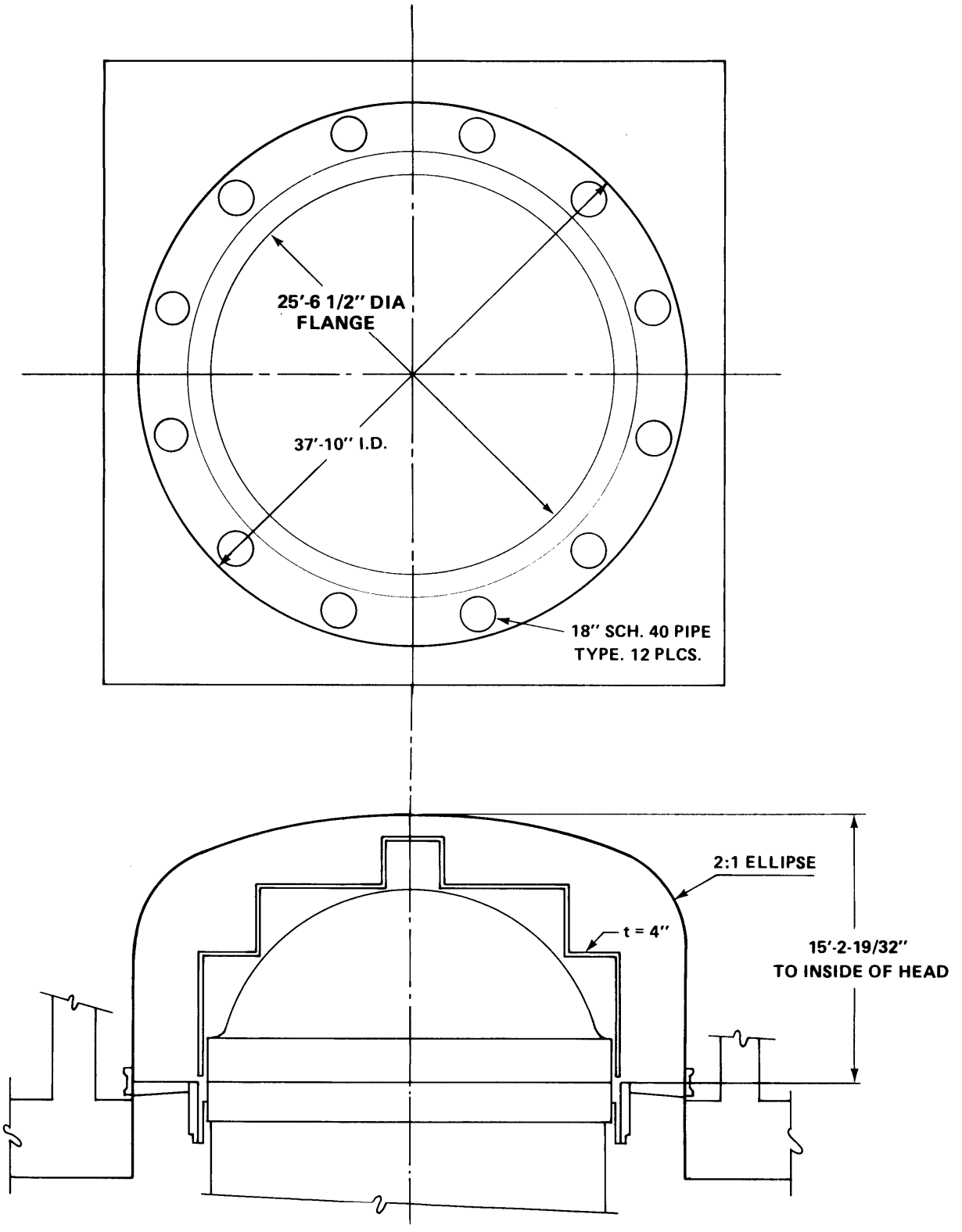

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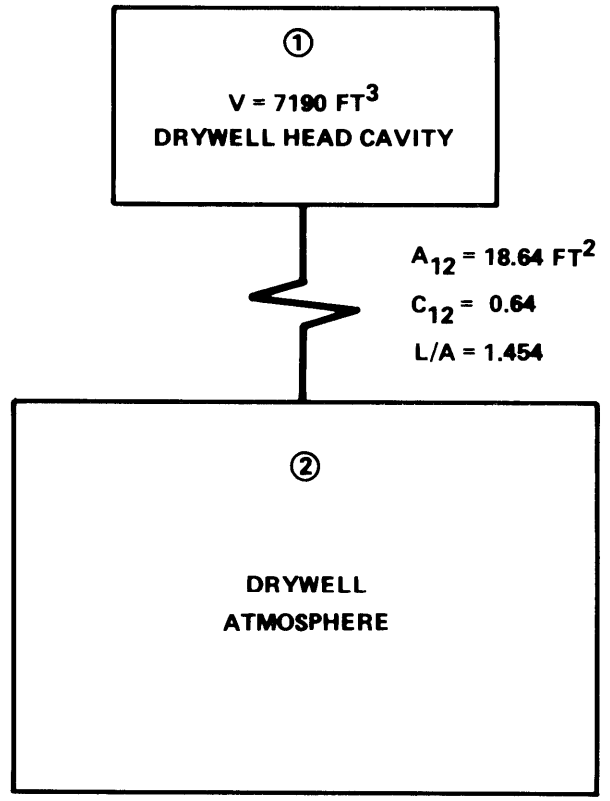
DRYWELL HEAD ARRANGEMENT

FIGURE 6A-9



(HEAD SPRAY LINE BREAK IN COMPARTMENT ①)

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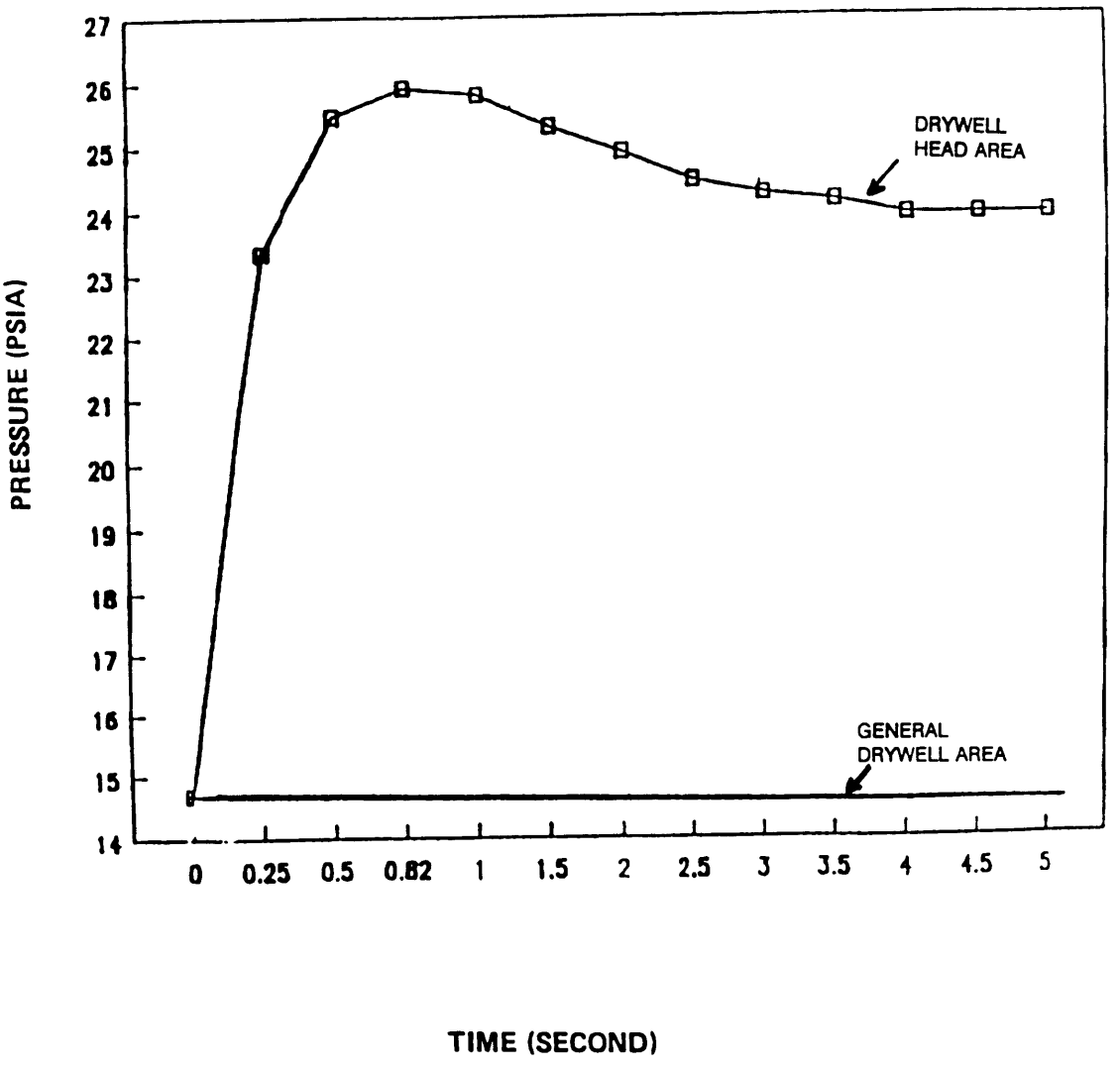
HEAD SPRAY LINE
BREAK GEOMETRY

FIGURE 6A-10



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PRESSURE TRANSIENT IN
DRYWELL HEAD AREA FOR
HEAD SPRAY LINE BREAK

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FIGURE 6A-11