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ENGINEERED SAFETY FEATURES

The engineered safety features (ESF) of this plant are those systems provided to mitigate the consequences of postulated serious accidents, in spite of the fact that these accidents are very unlikely. The ESF can be divided into four general groups: containment systems, emergency core cooling systems, habitability systems, fission product removal and control systems. The systems in each general group are

a. Containment systems

   1. Primary containment,
   2. Secondary containment,
   3. Containment heat removal system,
   4. Containment isolation system, and
   5. Combustible gas control.

b. Emergency core cooling systems

   1. High-pressure core spray,
   2. Automatic depressurization system,
   3. Low-pressure core spray, and
   4. Low-pressure coolant injection.

c. Habitability systems

d. Fission product removal and control systems

Related systems which help to mitigate the consequences of such accidents are discussed in other sections. These are

a. Overpressurization protection,
b. Control rod drive housing support systems,
c. Control rod velocity limiter,
d. Main steam line flow restrictor, and
e. Standby liquid control system.

6.1 ENGINEERED SAFETY FEATURE MATERIALS

Materials used in the engineered safety feature (ESF) components have been evaluated to ensure that material interactions will not occur that could potentially impair operation. Materials have been selected to withstand the environmental conditions encountered during normal operation and postulated accidents. Their compatibility with core and containment spray solutions has been considered and the effects of radiolytic decomposition products have been evaluated.

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

6.1.1 METALLIC MATERIALS

6.1.1.1 Materials Selection and Fabrication

6.1.1.1.1 Material Specifications

Table 5.2-7 lists the principal pressure retaining materials and the appropriate material specifications for the reactor coolant pressure boundary components. Table 6.1-1 lists the principal pressure retaining materials and the appropriate material specifications for the ESF of the plant.

6.1.1.1.2 Compatibility of Construction Materials with Core Cooling Water and Containment Sprays

The compatibility of the reactor coolant with materials of construction exposed to the reactor coolant is discussed in Section 5.2.3. These same materials of construction are found in the ESF components.

Demineralized water with no additives is employed in BWR core cooling water and containment sprays. No detrimental effects will occur on the ESF construction materials from allowable contaminant levels in this high purity water.

6.1.1.1.3 Controls for Austenitic Stainless Steel

a. Control of the use of sensitized stainless steel

Wrought austenitic stainless steels that have been heated to temperatures over 800°F by means other than welding or thermal cutting are either resolution annealed or otherwise demonstrated to be unsensitized in accordance with Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel.

Controls to avoid significant sensitization discussed in Section 5.2.3 are the same for ESF components.

b. Process controls to minimize exposure to contaminants

Process controls for austenitic stainless steel discussed in Section 5.2.3 are the same for ESF components.

c. Use of cold worked austenitic stainless steel

Austenitic stainless steel with a yield strength greater than 90,000 psi was not used in ESF systems with the exception of screen material in the emergency core cooling system (ECCS) suppression pool strainers. Fabrication of the screens entailed operations that cold-worked the screen material (i.e., punching, drilling, de-burring, and/or forming). The cold-working caused yield stresses, as determined by hardness testing, to exceed 90,000 psi. The screens were found to be acceptable due to their nonpressure retaining function and the controlled chemistry and pool temperature of the suppression pool.

d. Thermal insulation requirements

All thermal insulation materials in ESF systems were selected, procured, tested, stored, and installed in accordance with Regulatory Guide 1.36, Revision 0. The leachable concentrations of chlorides, fluorides, sodium, and silicates for nonmetallic thermal insulation for austenitic stainless steel were required to meet the requirements of Regulatory Guide 1.36, Revision 0. Certified reports and test reports for the materials are available.

e. Avoidance of hot cracking of stainless steel

Process controls to avoid hot cracking discussed in Section 5.2.3 are the same for ESF components.

6.1.1.2 <u>Composition, Compatibility, and Stability of Containment and Core Spray Coolants</u>

Containment spray and core cooling water for the ESF systems are supplied from the condensate storage tanks or the suppression pool.

The quality of the water stored in the condensate storage tanks is maintained as follows:

Conductivity*	1 µS/cm at 25°C
Chlorides	0.05 ppm
pH*	6 to 8 at 25°C
Boron (as BO_3)	0.1 ppm

The suppression pool is initially filled with high-purity water from either the condensate storage or demineralized water makeup system. The chloride concentration in the suppression pool water is maintained at less than 0.5 ppm Cl. To maintain suppression pool water quality, provision is made for periodic filtration and demineralization using the fuel pool filter demineralizer or by means of blowdown and reprocessing through the radwaste treatment system.

6.1.2 ORGANIC MATERIALS

Significant quantities of organic materials that exist within the primary containment consist of cable insulating material, motor insulation material and coatings for containment surfaces, equipment, and piping.

Insulation properties for electric power cable are discussed in Section 8.3.1.2.3. Motors for the reactor recirculation pumps and drywell fan coil units contain small quantities of lubricating oil. Motor-operated valve bearings are grease lubricated.

Equipment, piping, and primary surfaces are provided with various coatings including galvanized zinc and aluminum. A minimal amount of hydrogen is liberated from zinc paint, galvanized, radiolytic and thermal decomposition of organic materials. Since Columbia Generating Station (CGS) is an oxygen control plant with an inerted containment, the hydrogen concentration is not flammable. Therefore, the minimal amount of hydrogen potentially generated by organic materials is not a threat to containment integrity.

The suppression chamber (wetwell) above the water level from el. 472 ft 0 in. is coated with one coat of Dimetcote 6 (inorganic zinc). Approximately 4000 ft^2 of this coating do not meet ANSI N101.4 requirements because of damage. The damage to the coating will not result in the failure of the coating to adhere to its substrate. Regardless, the design of the ECCS strainers assumes the complete failure of the coating system and the entrainment of the resulting particles on the strainer bed following a LOCA.

Coatings on insulated piping that were damaged during construction were not repaired, and the insulation will contain any flakes which may form.

* Conductivity and pH limits apply after correction for dissolved CO_2.

In general protective coatings, except NSSS vendor-supplied equipment and valve contracts placed prior to issuance of Regulatory Guide 1.54, Revision 0, have been applied in accordance with the guidelines included in ANSI N101.4-1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities." In addition, the coatings and coating systems used meet the requirements of ANSI N101.2-1972 for the design basis accident. Certain items of equipment in the drywell have been coated with unqualified organic paint. There are an estimated 5000 ft^2 of unqualified organic paint in the drywell. Under certain postaccident conditions, the unqualified organic paint could fail in flakes and, therefore, has been evaluated as a potential source of debris which can clog emergency core cooling suction strainers. It is unlikely that all paint would fail simultaneously or that a significant portion of resulting paint flakes would be transported to the suppression pool. For conservatism, however, the design of the ECCS strainers is based on the complete failure of the unqualified coatings, their transport to the wetwell, and their eventual entrainment on the strainer beds.

6.1.3 POSTACCIDENT CHEMISTRY

Since the water chemistry conditions of the reactor coolant are similar to suppression pool water, with the exception being the addition of activation, corrosion, and fission products, no appreciable pH changes are expected to occur during the LOCA transient.

There are no soluble acids and bases within the primary containment that would change post-LOCA water chemistry. Since the pH does not change appreciably there are no detrimental effects on containment equipment or structures.

The design basis source term LOCA accident requires the addition of sodium pentaborate solution post-accident to maintain the suppression pool pH equal to or greater than 7.0. The Standby Liquid Control (SLC) tank contents are injected and mixed in the suppression pool within 8 hours post-accident. This action is discussed in the dose consequences analysis in Section 15.6.5.

Table 6.1-1

Engineered Safety Features Systems and Related
Systems Component Materials

Component	Form	Material	Specification (A/SA)[a]
RHR heat exchanger			
Head and shell	Plate	Carbon steel	516 Grade 70
Flanges and nozzles	Forging	Carbon steel	105 Grade 2
Tubes	U-Tube	Stainless steel	249 Type 304L
Tube sheet	Forging	Carbon steel	105 Grade 2
Bolts	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
RHR pump			
Shell and dished head	Plate	Carbon steel	516 Grade 70
Suction nozzle	Pipe	Carbon steel	333 Grade 6
Flange	Forging	Carbon steel	350 Grade LF2
Impeller	Casting	Stainless steel	296 CA15
Shaft	Bar	Stainless steel	276 Type 410
Shell/suction/discharge plate	Plate	Carbon steel	516 Grade 70
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
HPCS pump			
Shell and dished head	Plate	Carbon steel	516 Grade 70
Flange	Plate	Carbon steel	516 Grade 70
Discharge elbow	Pipe	Carbon steel	234 Grade WPB
Impeller	Casting	Stainless steel	296 CA15 or A487 CA6NM CL A
Shaft	Bar	Stainless steel	276 Type 410
Shell/suction/discharge plate	Plate	Carbon steel	516 Grade 70
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
LPCS pump			
Shell and dished head	Plate	Carbon steel	516 Grade 70
Suction nozzle	Pipe	Carbon steel	333 Grade 6
Flange	Forging	Carbon steel	350 Grade LF2
Elbow	Pipe	Carbon steel	234 Grade WPB
Impeller	Casting	Stainless steel	296 CA15

Table 6.1-1

Engineered Safety Features Systems and Related
Systems Component Materials (Continued)

Component	Form	Material	Specification (A/SA)[a]
LPCS pump (Continued)			
Shaft	Bar	Stainless steel	276 Type 410
Shell/suction/discharge plate	Plate	Carbon steel	516 Grade 70
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
HPCS valves			
Body, bonnet	Casting	Carbon steel	216 Grade WCB
Disc (globe)	Casting	Carbon steel	216 Grade WCB
Disc (gate)	Forging	Carbon steel	105 Grade 2
Stem (globe)	Bar	Stainless steel	479 Type 410
Stem (gate)	Bar	17-4 pH (H1150)	461 Grade 630
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
Isolation valves			
Body	Casting	Carbon steel	216 Grade WCB
	Forging	Stainless steel	182 Grade F316
	Forging	Carbon steel	350 Grade LF2
	Forging	Carbon steel	105 Grade 2
Bonnet	Forging	Carbon steel	105 Grade 2
	Casting	Carbon steel	216 Grade WCB
	Forging	Carbon steel	350 Grade LF2
Disc	Forging	Alloy steel	182 Grade F11
	Forging	Stainless steel	182 Grade F316
	Casting	Carbon steel	216 Grade WCB
	Forging	Carbon steel	105
	Forging	Carbon steel	350 Grade LF2
Stem	Bar	Stainless steel	276 Type 410
	Bar	Stainless steel	479 Type 410
	Bar	Stainless steel	564 Type 630
	Bar	Stainless steel	461 Type 630
	Forging	Stainless steel	182 Grade F6a
Stud	Bar	Alloy steel	540 Grade B23
	Bar	Alloy steel	193 Grade B7

Table 6.1-1

Engineered Safety Features Systems and Related Systems Component Materials (Continued)

Component	Form	Material	Specification (A/SA)[a]
Isolation valves (Continued)			
Nut	Bar	Carbon steel	194 Grade 7
	Bar	Carbon steel	194 Grade 2H
Safety relief valves			
Body and bonnet	Forging	Carbon steel	105 Grade 2
Disc holder	Forging	Inconel 718	MS 5662B
Shaft	Bar	Stainless steel	582 Type 416
Spindle	Bar	17-4 pH (H1085)	564 Type 630
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Carbon steel	194 Grade 2H (An acceptable equivalent is Grade 7.)
Standby liquid control pump			
Fluid cylinder	Forging	Stainless steel	182 Grade F304
Cylinder head, valve cover, and stuffing box flange plate	Plate	Stainless steel	240 Type 304
Cylinder head extension, valve stop, and stuffing box	Shapes	Stainless steel	479 Type 304
Stuffing box gland and plungers	Bar	17-4 pH (H1075)	564 Grade 630
Studs	Bar	Alloy steel	193 Grade B7
Nuts	Bar	Alloy steel	194 Grade 7
Standby liquid control explosive valve			
Body and fittings	Shapes	Stainless steel	479 Type 304
Flanges	Forging	Stainless steel	182 Grade F304
Pipe	Pipe	Stainless steel	312 Type 304
Control rod velocity limiter			
	Casting	Stainless steel	351 Grade CF8 or 351 Grade CF3
Main steam flow restrictor			
Upstream part	Casting	Stainless steel	351 Grade CF8
Downstream part	Casting	Carbon steel	216 Grade WCB

Table 6.1-1

Engineered Safety Features Systems and Related
Systems Component Materials (Continued)

Component	Form	Material	Specification (A/SA)[a]
Piping			
HPCS	Pipe	Carbon steel	106 Grade B
LPCS	Pipe	Carbon steel	106 Grade B
RHR (unless otherwise noted)	Pipe	Carbon steel	106 Grade B
RHR connection to RRC	Pipe	Stainless steel	312 Type 304 or
	Pipe	Carbon steel	333 Grade 1 or 6
RHR spray headers	Pipe	Carbon steel	333 Grade 1 or 6
SRV discharge line	Pipe	Carbon steel	333 Grade 1 or 6
24-in. downcomer vents	Pipe	Carbon steel	106 Grade B or C and 312 Type 304L or 316L (bottom 6 in. only)
28-in. downcomer vents	Pipe	Carbon steel	155 KC70 Class 2 and 312 Type 304L or 316L (bottom 4 in. only)
	Fittings	Carbon steel	181 Grade II
	Fittings	Carbon steel	234 Grade WPB
	Fittings	Stainless steel	182 Grade F304
	Fittings	Stainless steel	182 Grade WP304
Containment			
Vessel	Plate	Carbon steel	516 Grade 70
	Plate	C-Mn-Si steel	537 Class 1
Structural members	Plate	Carbon steel	36
Downcomer bracing	Pipe	Carbon steel	106 Grade B
	Rings	Carbon steel	572 Grade 60
Pipe restraints	Plate	Carbon steel	516 Grade 70
Penetration nozzle	Pipe	Stainless steel	312 Grade TP 304
	Pipe	Carbon steel	333 Grade 1 or 6

Table 6.1-1

Engineered Safety Features Systems and Related
Systems Component Materials (Continued)

Component	Form	Material	Specification (A/SA)[a]
Containment (Continued)			
Guard pipe	Pipe	Carbon steel	333 Grade 1 or 6
Flued head	Forging	Carbon steel	350 Grade 1 Fl or 2
Drywell floor seal	Pipe	Stainless steel	312 Type 304L

[a] SA materials for ASME Section III pressure boundary item.

6.2 CONTAINMENT SYSTEMS

6.2.1 CONTAINMENT FUNCTIONAL DESIGN

6.2.1.1 Pressure Suppression Containment

6.2.1.1.1 Design Basis

The pressure suppression containment system, including subcompartments, meets the following functional capabilities:

a. The containment has the capability to maintain its functional integrity during and following the peak transient pressures and temperatures which would occur following any postulated loss-of-coolant accident (LOCA). The LOCA includes the worst single failure (which leads to maximum containment pressure and temperature) and is further postulated to occur simultaneously with loss of offsite power. In developing the load combinations, a safe shutdown earthquake (SSE) is postulated to occur simultaneously with the LOCA;

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

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

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

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

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

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

h. The containment system, which includes the wetwell-to-drywell and the reactor building-to-wetwell vacuum breaker systems, can withstand the maximum calculated external pressure on the containment vessel and upward pressure on the drywell floor due to containment spray actuation under the most severe conditions.

6.2.1.1.2 Design Features

A general description of the primary containment and its compliance with applicable codes, standards and guides is given in Section 3.8.2. The design of the primary containment incorporates the following:

a. Protection against dynamic effects

   The design of the containment takes into account dynamic effects such as pipe whip, missiles, and jet loads which could result from a postulated LOCA. The design ensures that the capability of the containment and other engineered safety feature (ESF) equipment which mitigate the consequences of an accident are not impaired by the dynamic effects of the accident. The design provisions are discussed in Section 3.8.2.

   The capability of the primary steel containment vessel to withstand the hydrodynamic effects of safety/relief valve (SRV) actuation or a LOCA and the proposed modifications, if any, for those portions and components of the vessel which are determined to have insufficient capability to accommodate these hydrodynamic effects are discussed in References 6.2-7 and 6.2-8.

b. Pressure suppression

   The primary containment conforms to the fundamental principles of a MKII pressure suppression system. A comparison of the containment with similar containments is made in Table 1.3-4. The water stored in the suppression pool is capable of condensing the steam displaced into the wetwell through the downcomer vents, and the amount of water is sufficient such that operator action is not required for at least 10 minutes immediately following initiation of a LOCA. In addition, the design allows the water from any pipe break within the primary containment to drain back to the suppression pool. This "closed loop" ensures a continuous, adequate supply of water for core cooling.

c. Negative loading

   The primary containment is designed for the following negative loadings:

   1. A drywell pressure of 2.0 psi below reactor building pressure,
   2. A wetwell pressure of 2.0 psi below reactor building pressure, and

3. An upward pressure across the diaphragm floor of 6.4 psid.

The nine 24-in. wetwell-to-drywell (WW-DW) and the three 24-in. reactor building-to-wetwell (RB-WW) vacuum breaker lines are sized to ensure that negative loadings are not exceeded. The vacuum breaker systems are described in Section 3.8.2.

The primary containment is designed for a total external pressure of 4 psid. However, since the compressed insulation between the concrete biological shield and the containment exerts a uniform 2 psid external pressure (half of the total external pressure differential allowed) the drywell pressure may be no less than 2 psi below the reactor building pressure.

d. Environmental conditions

The means to maintain the required environmental conditions inside the primary containment during normal operation is discussed in Section 6.2.1. With the exception of energy removal from the suppression pool, there are no requirements for environmental controls during a LOCA. All equipment required to mitigate the consequences of an accident is designed to perform the required functions for the required duration of time in the accident environment. The equipment accident environment is listed in Table 3.11-2.

e. Insulation

Inside the primary containment, the type of thermal insulation used for piping is primarily reflective metal panel. Nonmetallic mass insulation may also be used, in limited applications, where configuration of the component to be insulated precludes the use of reflective insulation (i.e., at pipe whip restraints, pipe supports, and interferences), and as stop gaskets between circumferential joints of reflective insulation. Also, nonmetallic insulation has been used to expedite the replacement of damaged reflective insulation panels when as low as is reasonably achievable (ALARA) considerations apply.

Reflective metal insulation panels used for the pipes are typically 2 ft long, 3 in. to 4 in. thick, and cover half of the pipe's circumference. These panels have 24-gauge stainless steel sheets which fully encase the 6 mil aluminum sheets. The panels used for the reactor pressure vessel (RPV) are larger, typically 2 ft x 6 ft, and are encased by 18-gauge stainless steel.

Panels on piping covering areas which require inservice inspection, such as welds, are fastened by quick-release buckle bands. Nonremovable insulation panels around pipes are fastened. The fasteners have been designed to be weaker than the panels; therefore, it is postulated that some panels near a pipe break will be blown away, but that the panels themselves will not be sheared open.

The insulation panels and nonmetallic mass insulation that may be blown off constitute a credible debris source within the primary containment following a LOCA and seismic event. Equipment within the primary containment, if not designed to Seismic Category I standards, is at least supported so as to remain fastened during a seismic event.

Large pieces of insulation debris could be lodged against the perimeter of the jet deflectors, but the square footage of panels blown off the piping would not be sufficient to result in significant blockage of the downcomers. If metallic or nonmetallic insulation were blown off in a pipe break accident, it is probable that most debris would remain in large pieces and would be lodged against piping, equipment, or grating before it reached the drywell floor, or remain on the floor or be lodged against the jet deflector stiffener plates rather than be swept through the downcomers into the suppression pool. Insulation fibers and bits of foil liberated by the rupture has a higher potential of reaching the suppression pool, either during the immediate aftermath of the rupture or in the subsequent washdown by the containment sprays.

Insulation that is transported to the suppression pool could affect the performance of strainers in the wetwell. For this reason, the design of the strainers uses the following conservative bases:

1. Unlimited amounts of reflective metal insulation will be transported to the suppression pool;

2. Dependent on location in the drywell, from 21% to 76% of nonmetallic (fibrous) insulation dislodged by a pipe rupture event is transported to the wetwell. The higher transport percentage, 76%, is used when dislodged insulation is below drywell grating that would hinder the transport of insulation to the wetwell; and

3. All metallic and fibrous insulation that reaches the suppression pool following a LOCA is assumed to be entrained on the beds of operating ECCS strainers.

Straine rs on the RHR and LPCS suction lines are located at a centerline of 11 ft 9 in. to 12 ft 4 in. above the pool bottom. The HPCS suction strainers are located 3 ft 6 in. above the pool bottom. These strainers are designed to operate with their beds entrained with the insulation and debris postulated in the suppression pool following a LOCA. Based on the above, neither the metallic insulation panels nor the nonmetallic mass insulation will cause the degradation of the ECCS systems due to clogging of suction strainers. The analysis is discussed in Section 6.3.2.2.6.

6.2.1.1.3 Design Evaluation

6.2.1.1.3.1 Summary Evaluation. The key design parameters for the pressure suppression containment are shown in Table 6.2-1.

The design parameters are not determined from a single event but from an envelope of accident conditions.

A maximum drywell and suppression chamber pressure occurs near the end of a blowdown phase of a LOCA. Approximately the same peak pressure occurs for either the break of 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). To demonstrate that breaks smaller than the rupture of the largest primary system pipe will not exceed the containment design parameters, the containment system responses to an intermediate size liquid break and a small size steam break are evaluated. The results show that the containment design conditions are not exceeded for these smaller break sizes.

A single recirculation loop operation (SLO) containment analysis was performed. The peak wetwell pressure, diaphragm download and pool swell containment responses were evaluated over the entire SLO power/flow region.

The highest peak wetwell pressure during SLO occurred at the maximum power/flow condition of 78.7% power/64.3% core flow. This peak wetwell pressure decreased by about 1% (0.5 psi) compared to the rated two-loop operation pressure. The diaphragm floor download and pool swell velocity evaluated at the worst power/flow condition during SLO were found to be bounded by the rated power analysis.

The analytical results and method of analysis utilized to determine the seismic sloshing effects in the wetwell are discussed in Section 3.8.2.

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 pressure suppression vent system.

The downcomer loss coefficient is 2.77. This value was used in the assessment of the limiting containment performance analysis. The nonlimiting events not reanalyzed for the power uprate assumed a loss of coefficient of 1.9.

There are eighty-four 24-in. diameter downcomers and eighteen 28-in. downcomers. Three of the downcomers are capped.

No known studies have been performed to experimentally determine 4T test downcomer vent loss coefficients. However, in Pool Swell Analytical Model (PSAM)/4T test data comparisons (References 6.2-27 and 6.2-28), General Electric (GE) used downcomer vent loss coefficients of 2.51 and 3.50 for the 4T test 20-in. downcomers and 24-in. downcomers, respectively. These values were used as input to the GE PSAM and were calculated using information from Reference 6.2-15. The Columbia Generating Station (CGS) downcomer friction loss coefficient (fl/D) that is used in pool swell studies is equal to 1.9 (see Table 3.8-1). Use of a value of 1.9 versus a 4T value ensures conservatism in CGS pool swell studies in that lower values of fl/D maximizes pool swell velocity (see Figure 4-24 of Reference 6.2-5).

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

6.2.1.1.3.3 Accident Response Analysis. The containment functional evaluation was initially based on the consideration of several postulated accident conditions resulting in release of reactor coolant to the containment. These accidents include

a. An instantaneous guillotine rupture of a recirculation line,
b. An instantaneous guillotine rupture of a main steam line,
c. An intermediate size liquid line rupture, and
d. A small size steam line rupture.

The containment response to the main steam line, intermediate liquid line, and small size steam line breaks, were bounded by the recirculation line break. As part of the evaluations to support the reactor power uprate to 3486 MWth, only the recirculation line rupture (Case C), the bounding event for containment response, was reanalyzed. The containment response analyses are not cycle specific nor are they part of the analyses performed to support core reload analyses. For further discussion, see Sections 6.2.1.1.3.3.4 and 6.2.1.1.3.3.5.

6.2.1.1.3.3.1 Recirculation Line Rupture. Immediately following the rupture of the recirculation line, the flow out both sides of the break will be limited to the maximum allowed by critical flow consideration. Figure 6.2-2 shows a schematic view of the flow paths to the break. In the side adjacent to the suction nozzle, the flow will correspond to critical flow in the pipe cross section. In the side adjacent to the injection nozzle, the flow will correspond to critical flow at the 10 jet pump nozzles associated with the broken loop. In addition, the cleanup line cross tie will add to the critical flow area. Table 6.2-3 provides a summation of the break areas. References 6.2-1 and 6.2-2 provide a detailed description of the analytical models and assumptions for this event.

6.2.1.1.3.3.1.1 Assumptions for Reactor Blowdown. The response of the reactor coolant system during the blowdown period of the accident is analyzed using the following assumptions:

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

    1. For the nonlimiting events which were not reanalyzed for power uprate, the reactor is operating at 104.2% of maximum power (3323 MWt). This maximizes the postaccident decay heat.

    2. For the limiting events, the reactor is operating at 3702 MWt. This power corresponds to 102% of 3629 MWt. The analysis power was chosen to support a future uprate to 3629 MWt and bounds a power uprate to 3486 MWt (current).

    3. For the nonlimiting events which were not reanalyzed for power uprate, the standby service water (SW) temperature is assumed to be 95°F, which exceeds the maximum expected temperature. For power uprate, a less conservative value of 90°F was assumed.

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

    5. The suppression pool temperature is assumed to be at the maximum value allowed for power operation.

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

c. Reactor power generation ceases at the time of accident initiation because of void formation in the core region. Scram also occurs in less than 1 sec from receipt of the high drywell pressure signal. The difference between the shutdown times is negligible.

d. The vessel depressurization flow rates are calculated using Moody's critical flow model (Reference 6.2-3) assuming "liquid only" outflow, since this assumption maximizes the energy releases to the drywell. "Liquid only" outflow implies that all vapor formed in the RPV by bulk flashing rises to the surface rather than being entrained in the existing flow. In reality, some of the vapor would be entrained in the break flow which would significantly reduce the RPV discharge flow rates. Further, Moody's critical flow model, which assumes annular, isentropic flow, thermodynamic phase equilibrium, and maximizes 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 approximately 550°F are included in the RPV depressurization calculation. The rate of energy release is calculated using a conservatively high heat transfer coefficient throughout the depressurization period. The resulting high-energy release rate causes the RPV to maintain nearly rated pressure for approximately 20 sec. The high RPV pressure increases the calculated blowdown flow rates which is again conservative for analyses purposes. The sensible energy of the fuel stored at temperatures below approximately 550°F is released to the vessel fluid along with the stored energy in the vessel and internals as vessel fluid temperatures decrease below approximately 550°F during the remainder of the transient calculation.

f. The main steam isolation valves (MSIV) start closing at 0.5 sec after the accident. They are fully closed in the shortest possible time of 3 sec following closure initiation. In actuality, the closure signal for the MSIV will occur from low reactor water level, so the valves will not receive a signal close for at least 4 sec, and the closing time may be as long as 5 sec. 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. For the nonlimiting events which are not reanalyzed for power uprate, reactor feedwater flow was assumed to stop instantaneously at time 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 analysis since MSIV closure cuts off motive power to the steam-driven feedwater pumps.

For the limiting events, reactor feedwater flow is assumed to continue until all high-energy feedwater is injected into the reactor.

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

6.2.1.1.3.3.1.2 Assumptions for Containment Pressurization. The pressure response of the containment during the blowdown period of the accident is analyzed using the following assumptions:

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

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

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

d. No heat loss from the gases inside the primary containment is assumed. In reality, condensation of some steam on the drywell surfaces would occur.

6.2.1.1.3.3.1.3 Assumptions for Long-Term Cooling. Following the blowdown period, the ECCS provides water for core flooding, containment spray, and long-term decay heat removal. The containment pressure and temperature response during this period is analyzed using the following assumptions:

a. The low-pressure coolant injection (LPCI) pumps are used to flood the core prior to 600 sec after the accident. The HPCS is assumed available for the entire accident;

b. After 600 sec, the LPCI pump flow may be diverted from the RPV to the containment spray. This is manual operation. Actually, the containment spray need not be activated at all to keep the containment pressure below the containment design pressure. Prior to activation of the containment cooling mode (assumed at 600 sec after the accident) all of the LPCI pump flow will be used to flood the core. In response to indications of significant core damage the operators are directed to initiate containment spray to reduce potential radioactivity released;

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

d. The suppression pool is assumed to be the only heat sink available in the containment system;

e. After approximately 600 sec, it is assumed that the RHR heat exchangers commence to remove energy from the containment by means of recirculation cooling from the suppression pool with the SW system; and

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

   Case A: Offsite power available - all ECCS equipment and containment spray operating.

   Case B: Loss of offsite power, minimum diesel power available for ECCS and containment spray.

   Case C: Same as Case B except no containment spray.

   Case C is limiting as it results in the highest peak suppression pool temperature and containment pressure. Since power uprate does not change the results of the three cases relative to each other, Case C was reevaluated for power uprate conditions.

6.2.1.1.3.3.1.4 Initial Conditions for Accident Analyses. Table 6.2-4 provides the initial reactor coolant system and containment conditions used in the accident response evaluation. The tabulation includes parameters for the reactor, the drywell, the suppression chamber, and the vent system. 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 the depressurization, noncondensables will redistribute between the drywell and suppression chamber by means of the vacuum breaker system. This redistribution takes place as steam in the drywell is condensed by the relatively cool ECCS water which is beginning to cascade from the break causing the drywell pressure to decrease.

The ECCS supplies sufficient core cooling water to control core heatup and limit metal-water reaction to less than 0.07%. After the RPV is flooded to the height of the jet pump nozzles, the excess flow discharges through the recirculation line break into the drywell. This flow of water (steam flow is negligible) transports the core decay heat out of the RPV, through the broken recirculation line, in the form of hot water which flows into the suppression chamber by means of the drywell-to-suppression chamber vent system. 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 corresponds with Figures 6.2-3 and 6.2-4. Figure 6.2-5 shows the time dependent response of the floor (deck) differential pressure.

During the blowdown period of the LOCA, the pressure suppression vent system conducts the flow of the steam-water gas mixture in the drywell to the suppression pool for condensation of the steam. The pressure differential between the drywell and suppression pool controls this flow. Figure 6.2-6 provides the mass flow versus time relationship through the vent system for this accident.

6.2.1.1.3.3.1.6 Long-Term Accident Responses. To assess the adequacy of the containment following the initial blowdown transient an analysis was made of the long-term temperature and pressure response following the accident. The analysis assumptions are those discussed in Section 6.2.1.1.3.3.1.3 for the three cases of interest. The initial pressure response of the containment (the first 600 sec after break) is the same for each case. As can be seen from Figures 6.2-7, 6.2-8, and 6.2-9, Case C is the limiting event.

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 sec following the pipe break, the HPCS, LPCS, and all LPCI pumps are assumed operating. All flow is injected directly into the reactor vessel.

After 600 sec, both RHR heat exchangers are activated to remove energy from the containment. During this mode of operation the flow from two of the LPCI pumps is routed through the RHR heat exchangers where it is cooled before being discharged into the containment spray header.

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 core spray and LPCI core flooding, energy addition due to core decay heat results in a gradual pressure and temperature rise in the containment. When the energy removal rate of the RHR system exceeds the energy addition rate from the decay heat, the containment pressure and temperature reach a second peak value and decrease gradually. Table 6.2-6 summarizes the cooling equipment operation, the peak long term containment pressure following the initial blowdown peak, and the peak suppression pool temperature.

Case B: Loss of offsite power - with delayed containment spray

This case assumes no offsite power is available following the accident and that only the HPCS and one LPCI diesel (Divisions 3 and 2, respectively) are available. For the first 600 sec following the break, one HPCS, and two LPCI pumps are used exclusively for core cooling. After 600 sec, the RHR heat exchanger is activated. The flow from one pump is routed through the heat exchanger and is discharged to the containment spray line. The second LPCI pump is assumed to be shut down. 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: Loss of offsite power - no containment spray

This case assumes no offsite power is available following the accident and that only the HPCS and one LPCI diesel (Divisions 3 and 2, respectively) are available. For the first 600 sec following the accident, one HPCS, and two LPCI pumps are used exclusively to cool the core.

After 600 sec, one RHR heat exchanger is activated to remove energy from the containment, but containment spray is not activated. The LPCI flow cooled by the RHR heat exchanger is discharged into the RPV. The second LPCI pump is assumed to be shut down. The containment pressure response to this set of conditions is shown in Figure 6.2-10. The corresponding drywell and suppression pool temperature responses are shown in Figures 6.2-11 and 6.2-12. A summary of this case is given in Table 6.2-6.

When comparing the “spray” Case B with the “no spray” Case C at the same power level, 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 or into the drywell as spray. Although the peak containment pressure is higher for the "no spray" case, the pressure is significantly less than the containment design pressure.

Figure 6.2-13 shows the rate at which the RHR system heat exchanger will remove heat from the suppression pool following a LOCA.

Cases B and C, above, presume the loss of offsite power concurrent with a single failure that results in the loss of a safety division. In a different scenario, a single failure is presumed to solely affect the cooling of one RHR heat exchanger. This is similar to Cases B and C, above, except that all ECCS pumps are presumed to be available and running. For this alternate scenario, the operator is assumed to shut down LPCS and the Division 1 LPCI pump, along with the extra Division 2 LPCI pump, as postulated in Cases B and C, in order to balance energy removal through pump flows with energy addition from pump heat. When the unneeded pumps are shut down, Case C remains bounding over this alternate scenario.

6.2.1.1.3.3.1.7 Chronology of Accident Events. A complete description of the containment response to the design basis recirculation line break has been given in Sections 6.2.1.1.3.3.1.5 and 6.2.1.1.3.3.1.6. Results for this accident are shown in Figures 6.2-3 through 6.2-6, 6.2-10, 6.2-11, 6.2-12, and 6.2-13. 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. The sequence of events immediately following the rupture of a main steam line between the reactor vessel and the flow limiter have been determined. The flow in both sides of the break will accelerate to the maximum allowed by the critical flow considerations. In the side adjacent to the reactor vessel, the flow will correspond to critical flow in the steam line break area. Blowdown through the other side of the break will occur because the steam lines are all interconnected at a point upstream of the turbine by the bypass header. This interconnection allows primary system fluid to flow from the three unbroken steam lines, through the header and back into the drywell by means of the broken line. Flow will be limited by critical flow in the steam line flow restrictor. The total effective flow area is given in Figure 6.2-14 which is the sum of the steam line cross sectional area and the flow restrictor area. A slower closure rate of the isolation valves in the broken line would result in a slightly longer time before the total valve area of the three unbroken lines equals the flow limiter area in the broken line. The effective break area in this case would start to reduce at 5 sec rather than 4.3 sec as demonstrated in Table 6.2-10. The drywell design temperature (340°F) was determined based on a bounding analysis of the superheated gas temperature. The short-term peak drywell temperature is controlled by the initial steam flow rate during a large steam line break. Since the vessel dome pressure assumed for the original rated analysis (1055 psia) is unchanged by power uprate, the initial break flow rate for this event is not impacted. This event was not reanalyzed for power uprate as there would be no impact on the original rated short-term peak drywell temperature value. The peak drywell pressure occurs before the reduction in effective break area due to MSIV closure and is, therefore, insensitive to a possible slower closure time of the isolation valves in the broken lines. The mass and energy release rates are provided in Section 6.2.1.3.

Immediately following the break, the total steam flow rate leaving the vessel would be approximately 8600 lb/sec, which exceeds the steam generation rate in the core of 4140 lb/sec. This steam flow to steam generation mismatch causes an initial vessel depressurization of the reactor vessel at a rate of approximately 42 psi/sec. Void formation in the reactor vessel water causes a rapid rise in the water level, and it is conservatively assumed that the water level reaches the vessel steam nozzles 1 sec after the break occurs. The water level rise time of 1 sec is the minimum that could occur under any reactor operating condition. From that time on, a two-phase mixture corresponding to the overall average vessel quality would be discharged from the break. The use of the overall average vessel quality results in fluid qualities which are considerably lower than would actually occur. Thus, the drywell peak pressure, which increases with decreasing break flow quality, is maximized. During the first second of the blowdown, the blowdown flow will consist of saturated steam. This steam will enter the containment in a super-heated condition of approximately 330°F.

Figures 6.2-15 and 6.2-16 show the pressure and temperature responses of the drywell and suppression chamber during the primary system blowdown phase of the steam line break accident for original rated power. The short-term performance is not affected by power uprate. The long-term response is bounded by the recirculation suction line break. Therefore, no steam line break analysis was performed for the power uprate condition.

Figure 6.2-16 shows that the drywell atmosphere temperature approaches 330°F after 1 sec of primary system steam blowdown. At that time, the water level in the vessel will reach the steam line nozzle elevation and the blowdown flow will change to a two-phase mixture. This increased flow causes a more rapid drywell-pressure rise. The peak differential pressure occurs shortly after the vent clearing transient. As the blowdown proceeds, the primary system pressure and fluid inventory will decrease, resulting in a decrease in the vent system and the differential pressure between the drywell and suppression chamber.

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

Approximately 50 sec after the start of the accident, the primary system pressure will have dropped to the drywell pressure and the blowdown will be over. At this time the drywell will contain primarily steam, and the drywell and suppression chamber pressures will stabilize. The pressure difference corresponds to the hydrostatic pressure of vent submergence.

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

6.2.1.1.3.3.3 Hot Standby Accident Analysis. This section is not applicable to BWR-5.

6.2.1.1.3.3.4 Intermediate Size Breaks. The failure of a recirculation line results in the most severe pressure loading on the drywell structure. However, as part of the original containment performance evaluation, the consequences of intermediate breaks were also analyzed. This classification covers those breaks for which the blowdown will result in reactor depressurization and operation of the ECCS. This section describes the consequences to the containment of a 0.1 ft^2 break below the RPV water level. This break area was chosen as being representative of the intermediate size break area range. These breaks can involve either reactor steam or liquid blowdown. The consequences of an intermediate size break are less severe than from a recirculation line rupture. Because these breaks are not limiting, they were not reanalyzed for power uprate.

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 vents is negligible and the vents will clear when the drywell-to-suppression chamber differential pressure is equal to the vent submergence hydrostatic pressure.

Figures 6.2-17 and 6.2-18 show the drywell and suppression chamber pressure and temperature response for original rated power conditions at 3323 MWt. The ECCS response is discussed in Section 6.3. Approximately 5 sec after the 0.1 ft^2 break occurs, air, steam, and water will start the flow from the drywell to the suppression pool. The steam will be condensed and the air will enter the suppression chamber free space. The continual purging of drywell air and steam to the suppression chamber will result in a pressurization of both the wetwell and drywell to about 25 and 30 psig, respectively. The containment will continue to gradually increase in pressure due to long-term pool heatup until the vessel is depressurized and reflooded.

The ECCS will be initiated as the result of the 0.1 ft^2 break and will provide emergency cooling of the core. The operation of these systems is such that the reactor will be depressurized in approximately 600 sec. This will terminate the blowdown phase of the transient.

In addition, the suppression pool end of blowdown temperature will be the same as that of the 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 will begin to flow out the break. This flow will condense the drywell steam and eventually cause the drywell and suppression chamber pressures to equalize in the same manner as following a recirculation line rupture.

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

6.2.1.1.3.3.5 Small Size Breaks.

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

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

A small reactor steam leak (resulting in superheated steam) will impose the most severe temperature conditions on the drywell structures and the safety equipment in the drywell. For larger steam line breaks, the superheat temperature is nearly the same as for small breaks, but the duration of the high temperature condition for the larger break is less. This is because the larger breaks will depressurize the reactor more rapidly than the orderly reactor shutdown that is assumed to terminate the small break. Like the main steam line break, the small steam line break is also governed by the dome pressure. The small break response is also governed by the operator actions. Since the vessel dome pressure assumed for the original rated analysis (1055 psia) is unchanged by power uprate the initial break flow rate for this event will be unchanged. Assuming the operator action is the same, the event would be terminated in the same manner as for the original rated power analysis. Thus, the small steam line break was not reanalyzed for power uprate.

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

6.2.1.1.3.3.5.3 Recovery Operations. The plant operators will be alerted to the incident by the high drywell pressure signal and the reactor scram. For the purposes of evaluating the duration of the superheat condition in the drywell, it is assumed that their response is to shut the reactor down in an orderly manner while limiting the reactor cool down rate to 100°F/hr. This will result in the reactor primary system being depressurized within 6 hr. At this time, the blowdown flow to the drywell will cease and the superheat condition will be terminated. If the plant operators elect to cool down and depressurize the reactor primary system more rapidly than at 100°F/hr, then the drywell superheat condition will be shorter.

6.2.1.1.3.3.5.4 Drywell Design Temperature Consideration. For drywell design purposes, it is assumed that there is a blowdown of reactor steam for the 6-hr cool down period. The corresponding design temperature is determined by finding the combination of primary system pressure and drywell pressure that produces the maximum superheat temperature. Drywell design temperature requirements are defined by the most limiting environmental conditions assumed to exist inside primary containment during a design basis accident (see Table 3.11-2). As noted in Table 3.11-2, the design temperature of 340°F is the superheat temperature based on a steam leak with the reactor vessel pressure of 400-500 psi and a design containment pressure of 45 psig.

6.2.1.1.3.4 Accident Analysis Models.

6.2.1.1.3.4.1 Short-Term Pressurization Model. The analytical models, assumptions, and methods used by GE to evaluate the containment response during the reactor blowdown phase of a LOCA are described in References 6.2-1 and 6.2-2.

6.2.1.1.3.4.2 Long-Term Cooling Mode. During the long-term, post-blowdown containment cooling transient, the ECCS flow path is a closed loop and the suppression pool mass will be constant. This closed cooling loop provides subcooled water to the vessel from the suppression pool removing residual decay heat. As a result long-term steaming will not occur. This approach is conservative since removal of energy by steaming would require that more energy be retained in the vessel, and therefore, not released to the containment to maintain the vessel fluid inventory at saturation temperature. The cooling model loop is shown in Figure 6.2-19. There is no change in mass storage in the system (the RPV is reflooded during the blowdown phase of the accident).

The break flow area is assumed to remain constant as a function of time following decompression of the broken line and/or closure of the MSIV during the first few seconds of the reactor blowdown.

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 atmosphere 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, and

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

6.2.1.1.3.4.4 Energy Balance Consideration. The energy balance in the suppression pool is described in References 6.2-1 and 6.2-2.

6.2.1.1.4 Negative Pressure Design Evaluation

Columbia Generating Station does not have automatic initiation of any drywell spray and controls operation of the sprays through procedural guidance. The design and sizing of the reactor building to wetwell (RB-WW) and wetwell to drywell (WW-DW) vacuum breakers considered inadvertent operation of containment sprays as limiting transients. Although this is conservative for design considerations, inadvertent spraying of the drywell is considered more than one single failure or operator error.

The limiting transient for the WW-DW vacuum breaker system for design purposes was considered to be simultaneous operation of both drywell spray loops after a large-break LOCA. Although this event is bounding for design purposes, it is based on more than one single failure or operator error and neglects the consideration for adequate core cooling by using both RHR loops. Using the single-failure criterion and considering the need for adequate core cooling following a large-break LOCA, the containment sprays would not be initiated until later in the event by spraying WW first followed by DW with the worse single failure being a RB-WW vacuum breaker to open. This scenario is nonlimiting with respect to floor uplift or negative pressure.

The limiting transient for negative containment pressurization is a small-break LOCA with a coincident single failure of an RB-WW vacuum breaker. This transient uses both WW and DW sprays of a single RHR loop. WW/DW sprays are initiated when required by the Emergency Operating Procedures. The small break within the drywell forces the noncondensables into the wetwell airspace, leaving a steam atmosphere inside the drywell. Once drywell sprays are initiated, pressure rapidly drops and the RB-WW and WW-DW vacuum breakers open to mitigate the transient.

The analysis performed to determine peak negative pressure after a small-line-break LOCA made the following conservative assumptions:

a. Maximum spray flow of 7900 gpm (combined drywell and wetwell flow),

b. 100% spray efficiency,

c. 35°F spray temperature,

d. Noncondensable gases are purged into the wetwell as a result of the LOCA,

e. The drywell is full of steam at a pressure above wetwell due to the hydrostatic head from downcomer submergence, and

f. Single failure of RB-WW vacuum breaker.

The initial conditions used in the analysis are provided in Table 6.2-19. A summary of the results is provided in Table 6.2-19a. This analysis was evaluated as part of reactor power uprate, but a change to the initial assumption of reactor power at 3702 MWth did not change the results.

Drywell spray is not required to maintain the primary containment below design pressure nor is it required for containment cooling. If, following a small-line-break LOCA, the noncondensable gases are purged into the wetwell airspace, the EOPs would direct the operator to initiate wetwell sprays to control wetwell pressure. If containment pressure continues to increase, drywell sprays will be initiated. The appropriate plant procedures direct the operator to initiate drywell sprays in response to indications of significant fuel failures during a LOCA. For the scenario in which containment sprays are initiated, the limiting single failure (or operator error) would be the failure of a RB-WW vacuum breaker. The results of the analysis indicate that the maximum negative pressure differential will be less than 2.0 psid and within the design values as stated in Section 6.2.1.1.2(c).

Multiple valve failure is not considered or expected. The analysis considers two WW-DW vacuum breakers initially out of service, in addition to the single failure of the RB-WW vacuum breaker, to preclude unnecessary shutdowns due to failure of the testing mechanism or position indication. Failure of the testing mechanism is considered more probable than failure of the vacuum breakers to open. It should also be noted that a single failure of a RB-WW vacuum breaker is more limiting than the single failure of a DW-WW vacuum breaker.

6.2.1.1.5 Suppression Pool Bypass Effects

6.2.1.1.5.1 Protection Against Bypass Paths. The pressure boundary between drywell and suppression chamber including the vent pipes, vent header, and downcomers is fabricated, erected, and inspected by nondestructive examination methods in accordance with the applicable ASME Codes. The design pressure differential for this boundary is 25 psid, which is substantially greater than conditions during a DBA. Actual peak accident differential pressure across this boundary is provided in Table 6.2-5.

Penetrations of this boundary except the vacuum breaker seats and vacuum breaker to downcomer flange are welded. The penetrations can be visually inspected.

Potential bypass leakage paths (such as the purge and vent system) have been considered. Each path has at least two isolation valves in the leakage path during normal system lineup. These valves are leaktight containment isolation valves which are all normally closed.

6.2.1.1.5.2 Reactor Blowdown Conditions and Operator Response. In the unlikely event of a primary system leak in the drywell accompanied by a simultaneous open bypass path between the drywell and suppression chamber, several postulated conditions may occur. For a given primary system break area, the maximum allowable leakage capacity can be determined when the containment pressure reaches the accident pressure at the end of reactor blowdown. The most limiting conditions would occur for those primary system break sizes which do not cause rapid reactor depressurization but rather have long leakage duration. These break sizes which are less than 0.4 ft^2 require operator action to terminate the reactor blowdown if there is a bypass path.

There would also be an increase in drywell pressure which leads to drywell venting to the wetwell by means of the downcomers. Both noncondensables and vapor are vented. If no bypass leakage exists, the maximum suppression chamber pressure would be 28 psig, the pressure resulting from displacing all containment noncondensables into the suppression chamber.

Operator action is required to mitigate the consequences of any bypass leakage. Emergency Operating procedures direct initiation of suppression chamber sprays at a chamber pressure less than the value analyzed in Section 6.2.1.1.5.4. Drywell sprays are initiated if the chamber pressure limit is exceeded.

Class 1E indication is available in the control room allowing the operator to track chamber pressure. Additionally, a two-division system of alarms is provided to alert the operator if the suppression chamber spray initiation value is reached.

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; and

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 will be condensation, especially for the larger primary system break where vigorous agitation at the pool surface will occur during blowdown.

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 6.2-20 shows the allowable leakage capacity $\left(A/\sqrt{K}\right)$ as a function of primary system break area. The area of the leakage flow path is A, and K is the total geometric loss coefficient associated with the leakage flow path.

Figure 6.2-20 is a composite of two curves. If the break area is greater than approximately 0.4 ft^2, natural reactor depressurization will rapidly terminate the transient. For break areas less than 0.4 ft^2, however, continued reactor blowdown limits the allowable leakage to small values.

Burns and Roe, Inc., confirmed the results of the above analysis by GE in Reference 6.2-7. Further evaluation assigned the maximum allowable leakage capacity at $A/\sqrt{K} = 0.050$ ft^2. Since a typical geometric loss factor would be three or greater, the maximum allowable flow path would be about 0.1 ft^2. This corresponds to a 4-in. line size.

A transient analysis using the CONTEMPT-LT (Reference 6.2-8) computer code was performed. The code was modified to include the mass and energy transfer to the suppression pool from relief valve discharge. The limiting case was a very small reactor system break which would not automatically result in reactor depressurization. For this limiting case, it was assumed that the response of the plant operators was to initiate the drywell sprays when the suppression chamber pressure exceeds 30 psig, and then to proceed to cool the reactor down in an orderly manner of 100°F/hr cool down rate. Heat sinks considered were items such as major support steel inside containment, the reactor pedestal, the diaphragm floor and support columns, and the steel and concrete of the primary containment. Based on this analysis, the allowable bypass leakage used was 0.050 ft^2. The drywell pressure transient is shown in Figure 6.2-21 along with the corresponding curves of wetwell pressure, wetwell temperature, and suppression pool temperature for the original rated power condition.

The mandated allowable bypass leakage of 0.050 ft^2 is above the Technical Specifications containment bypass leakage limits. Periodic testing is performed to confirm that the containment bypass leakage does not exceed $\left(A/\sqrt{K}\right) = 0.0045\ ft^2$. Figure 6.2-22 presents the resulting containment transient of 0.0045 ft^2. The peak containment pressure shown in Figure 6.2-22 is well below the containment design pressure.

An evaluation of this scenario with power uprate indicates that the time available for the operator to manually activate the containment spray is not significantly affected by power uprate. Therefore the effect of power uprate on the steam bypass event is determined to be insignificant.

6.2.1.1.6 Suppression Pool Dynamic Loads

A generic discussion of the suppression pool dynamic loads and asymmetric loading conditions is given in Mark II Dynamic Forcing Function Information Report, Reference 6.2-4. A unique plant assessment of these dynamic loads is made in Reference 6.2-5.

The impact of power uprate on the suppression pool dynamic loads defined in Reference 6.2-5 was evaluated for a power uprate to 102% of 110% of the original rated power (3323 MWt) and considering operation with extended load line limit analysis (ELLLA) and SRV out-of-service plus a setpoint tolerance increase to 3%. This evaluation confirmed that there are sufficient conservatism in the suppression pool dynamic loads defined in Reference 6.2-5.

6.2.1.1.7 Asymmetric Loading Conditions

See Section 6.2.1.1.6.

6.2.1.1.8 Primary Containment Environmental Control

6.2.1.1.8.1 Temperature, Humidity, and Pressure Control During Reactor Operation. The drywell is maintained at its normal operating temperature 135°F maximum average/150°F maximum by the use of three lower containment coolers and two upper containment coolers mounted in the drywell area. The cooling coils for these units are supplied with water at 95°F, or less, from the reactor building closed cooling water system. There is no air cooling equipment in the wetwell since there is no heat producing equipment and the air space is normally less than 95°F. However, leakage past the seating surfaces of MSRVs may cause the wetwell air space temperature to increase due to heat transfer from the MSRV tailpipes to the wetwell atmosphere. In this case, the wetwell air space can be periodically cooled by spraying with RHR to maintain wetwell air space temperatures at or below 117°F, the limit for equipment qualification.

The unit coolers are sufficient to control the temperature and humidity from all expected heat sources and leaks during normal reactor operation. The containment purge system is not used to control containment temperature or humidity during reactor operation.

To relieve pressure during reactor operation, the operator can establish a flow path from the drywell to the standby gas treatment (SGT) system through the drywell purge exhaust line. After the first 24 hr of venting, and assuming the containment atmosphere does not contain unacceptable levels of radioactivity, venting can be valved to the reactor building exhaust system. By opening the 2-in. bypass valves around the purge exhaust valves rather than the purge exhaust valve, flow can be limited to 170 scfm. This flow is adequate for a drywell atmosphere temperature rise from 70°F to 150°F in 3 hr while maintaining the primary containment at no greater than 0.5 psi above the reactor building pressure. The 2-in. bypass valves would limit the radioactivity released prior to valve closure to a very small amount in the unlikely event a LOCA occurs with the vent path open. If necessary, the wetwell can be vented in a similar way to relieve pressure.

The RB-WW and WW-DW vacuum breakers operate automatically to control containment vacuum.

6.2.1.1.8.2 Primary Containment Purging. The primary containment is provided with a purge system to reduce residual contamination and deinert the containment prior to personnel access. This system is designed to produce a purge rate equivalent to three air changes per hour to the net free volume.

The drywell is purged of nitrogen for the scheduled refueling shutdown period and as required for inspection or maintenance. The maximum drywell purge rate is 10,500 cfm. For the first 24 hr of a drywell purge, or if residual airborne contamination is higher than allowable limits for direct release to the atmosphere, the purge is routed through the SGT system. Purge air is taken from the reactor building ventilation supply duct through two 30-in. normally closed isolation valves into the primary containment. The purged nitrogen is extracted from the drywell through two 30-in. normally closed isolation valves and is routed to one of two systems. The discharge can be routed through a normally closed isolation valve to the reactor building exhaust air plenum or to the SGT system. If a high airborne activity occurs, the radiation monitors at the exhaust air plenum would cause the reactor building ventilation and primary containment purge systems to isolate.

Provision is also made to purge the nitrogen from the suppression chamber section of the primary containment. Purge air is taken from the reactor building supply duct through two 24-in. normally closed isolation valves into the suppression chamber. The nitrogen is extracted from the suppression chamber through two 24-in. normally closed isolation valves and routed to the exhaust air plenum or SGT system in the same manner as the drywell purge exhaust.

The systems are designed to purge either the drywell or the suppression chamber or the two chambers in series or in parallel. To protect the pressure suppression function of the suppression pool, only one vent line and one purge line will be open at any one time during reactor operation.

Purge system operation during reactor operation including startup, hot standby, and hot shutdown will be limited to inerting (through the purge system), deinerting, and pressure control. The containment purge system will not be used for temperature or humidity control during reactor operation.

All containment purge valves, including the 2-in. bypass valves, are designed to shut within 4 sec of receipt of a containment isolation signal and to shut against full containment design pressure. The containment isolation signals and the purge valves are part of the containment isolation system which is an ESF system. Each purge line has two isolation valves. These valves are opened by allowing compressed air to oppose a spring in the valve actuator. The valve is shut on a loss of compressed air, loss of electrical signal, or on a containment isolation signal. If the purge system is operating at the time of a LOCA, the system will automatically be secured. The level of the activity released through the purge system before isolation would be limited to the activity present in the coolant prior to the accident since the purge system will be isolated before any postulated fuel failure could occur. Dual isolation valves are also provided on the nitrogen inerting makeup piping connecting to the purge piping downstream of the 30-in. and 24-in. isolation valves. The nitrogen inerting system permits up to 75 cfm of nitrogen to be added to the containment during reactor operation to compensate for the postulated leakage listed in Table 6.2-1.

The 2-in. bypass valves, used for pressure control during operations, are located in parallel with each purge system exhaust valve. These 2-in. 150# globe valves meet the design requirements of the containment isolation system. They are designed to the same pressure/temperature ratings of the containment and purge valves and are designed to close within 4 sec against the containment design pressure. All four bypass valves can be remotely operated from the control room; are designed to close on F, A, and Z isolation signals; and are operationally qualified against applicable seismic and hydrodynamic loads.

6.2.1.1.8.3 Post-LOCA. The unit coolers are not required after a LOCA since heat removal is then accomplished by the containment cooling system, a subsystem of the RHR system. The Emergency Operating Procedures stipulate that nitrogen inerting is used as long as nitrogen is available. The operation of purge and vent transitions from oxygen control to hydrogen control upon loss of the ability to continue to inert with oxygen levels increasing. The containment purge system has the capability for a controlled purge of the containment atmosphere to aid in atmospheric control, if necessary, in accordance with the guidance provided in the Emergency Operating Procedures.

Any equipment located inside the primary containment which is required to operate subsequent to a LOCA has been designed to operate in the worst anticipated accident environment for the required period of time.

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 subcompartments in the primary containment analyzed to determine the effects of subcompartment pressurization are the annulus between the sacrificial shield wall and vessel annulus pressurization and the drywell head. For the power uprate evaluation, the limiting breaks in these two regions were analyzed considering reactor operation throughout the power flow map with power uprate, including final feedwater temperature reduction and single loop operation.

Peak subcompartment pressures occur very quickly (during the first few seconds) during the limiting subcompartment pressurization events. Therefore, the pressurization is controlled by the initial break flow rates which are governed by the break size and location and the initial reactor thermal-hydraulic conditions, such as reactor pressure and enthalpy. The limiting operating condition with power uprate with respect to subcompartment pressurization was determined to occur at 3702 MWt, 102% of the uprated power; therefore, the controlling parameters with power uprate were compared to the original values at this condition. The comparison shows that there are negligible differences between the controlling parameters for the original conditions used as the basis for the annulus pressurization and drywell head pressurization analyses and the corresponding parameters with power uprate (Reference 6.2-32). Therefore, the basis for the subcompartment pressurization loads is not affected by power uprate.

	Original Conditions (at 3463 MWt)	Power Uprate Conditions (at 3702 MWt)
Vessel dome pressure (psia)	1055	1055
Core inlet enthalpy (Btu/lbm)	532	532
Recirculation line break critical mass flux (lbm/ft^2-sec)	8900	8900
Feedwater enthalpy (Btu/lbm)	403	406
Feedwater line break critical mass flux (lbm/ft^2-sec)	19,300	19,200

The two areas within the primary containment considered to be subcompartments are the area within the sacrificial shield wall and the area above the refueling bulkhead plate at el. 583 ft.

Potential pipe breaks within the sacrificial shield wall have been evaluated. The information is contained in References 3.8-5, 3.8-6, 3.8-7, and 3.8-23.

Two analyses were performed based on original rated power (3323 MWt) to ensure the adequacy of the refueling bulkhead and inner refueling bellows at el. 583 ft. The first analysis, a break of the RCIC head spray line, determines the maximum downward loading due to pipe breaks. The second analysis, a break of the RRC suction line, determines the maximum upward loading.

Subcompartment analyses for a postulated high-energy pipe break in the primary containment were performed for the annulus inside the sacrificial shield wall, and the regions above and below the bulkhead plate which divides the drywell into the upper head region and the lower region.

The analyses for the annulus were reported in References 6.2-9 through 6.2-11. The result of the case of a 60-node model of the shield wall annulus for pressure transient calculation was confirmed by the NRC, and the analysis was considered acceptable for the shield wall base design and the design of the shield wall above the base, as stated in NRC letters (References 6.2-12 and 6.2-13).

Peak and transient loading used to establish the adequacy of the sacrificial shield wall, including the time/space dependent forcing functions, are presented in References 6.2-9 through 6.2-11 and 6.2-34.

These loads were used to produce response spectra for use in evaluating secondary effects such as the dynamic effects on piping systems, equipment, and components attached to the sacrificial shield wall of the RPV. The following changes were made in the original assumptions used in the sacrificial shield wall analysis:

a. The volume in the annulus was utilized to receive the blowdown, with the RPV installation volume conservatively assumed not to be available;

b. A finite time-dependent blowdown was used for the recirculation break utilizing NSSS supplier methodology (Reference 6.2-22). The effect of subcooling was taken into account; and

c. The feedwater pressurization analysis was developed utilizing blowdown values developed by computer analysis.

Annulus pressurization calculations are briefly summarized as follows:

a. Annular volume

   The annular volume excluded RPV insulation volume which is conservatively assumed not to be available. This approach is conservative and more realistic than other analyses where only the annular volume on one side of the RPV insulation was available;

b. Finite time dependent blowdown

   The blowdown loading values in Reference 6.2-11 were derived with the assumption that the pipe break would occur instantaneously and that the annulus area would see the maximum blowdown at the same time. In actuality, the full flow from the severed pipe ends separate at a distance equal to one-half the pipe diameter. Movement occurs in a finite time and is a function of the stiffness characteristics of the pipe and the restraining capability of the pipe whip restraints.

   Displacement versus time data for a finite break opening was developed and a GE analytical method was used for determining the short-term mass and energy release (Reference 6.2-22). The analysis was used for the recirculation loop break but not for the feedwater line since it was determined that the small percentage reduction for the feedwater would not warrant the additional calculations; and

c. Feedwater break blowdown data

The blowdown analysis for the postulated feedwater line break was based on a comprehensive model developed for the entire feedwater system from the condenser to the reactor vessel. This model, in conjunction with the RELAP4/MOD5 computer program (Reference 6.2-14), was used to calculate the transient and energy blowdown data.

Information pertaining to the analyses for the upper head and lower regions is as follows:

a. For the subcompartment analysis in the upper head region, the worst case is a double-ended guillotine break in the 6-in. RCIC line above the RPV head at approximately el. 595 ft. For the analysis in the lower region, the worst case is a double-ended guillotine break in the 24-in. recirculation line anywhere inside the drywell. The pipe breaks were postulated for the subcompartment structural and component support designs;

b. The blowdown mass and energy release rates as functions of time for the 6-in. RCIC line break are shown in Tables 6.2-20 and 6.2-21. The blowdown mass and energy release rates as functions of time for the 24-in. recirculation line break are shown in Tables 6.2-22 and 6.2-23;

c. The subcompartment analyses for the case of a 6-in. RCIC line break in the upper head region and the case of a 24-in. recirculation line break were performed with the Computer Code RELAP4/MOD5 (Reference 6.2-14).

Figure 6.2-23 shows the nodalization scheme in the drywell. Figure 6.2-24 depicts the plane view of vents in the bulkhead plate and shows the sectional views and dimensions of the bulkhead vents;

d. The nodal volume data used for the analysis of a 6-in. RCIC line break in the upper head region and the analysis of a 24-in. recirculation line break in the lower region is shown in Table 6.2-24. Table 6.2-25 shows the flow path data for the analysis of a 6-in. RCIC line break and Table 6.2-26 shows the flow path data for the analysis of a 24-in. recirculation line break;

e. Since there are no significant obstructions in the proximity of the pipe break considered in the analysis, significant pressure variation in any direction is not expected. The two-node model used for the analyses is considered to be adequate and a sensitivity study is not necessary;

f. There are no movable obstructions in the vicinity of the vents. Insulation for piping and components was assumed to remain intact during the accident, and volume of insulation was subtracted from the nodal volumes;

g. The absolute pressure responses as a function of time in the upper head region and the lower region in the drywell are shown in Figure 6.2-25 for the case of a 6-in. RCIC line break and in Figure 6.2-26 for the case of a 24-in. recirculation line break. Figures 6.2-27 and 6.2-28 represent the pressure differential across the bulkhead plate for the cases of a 6-in. RCIC line break and a 24-in. recirculation line break;

h. The peak differential pressure and the time of the peak for the cases of a 6-in. RCIC line break and a 24-in. recirculation line break are shown in Table 6.2-27; and

i. Peak and transient loading used to establish the adequacy of the sacrificial shield wall, including the time/space-dependent forcing functions are contained in References 6.2-9 through 6.2-11 and 3.8-23.

   Peak and transient loading in other major compartments such as the drywell and the upper head region of primary containment were included in the basic design. Since these compartments are large and relatively unencumbered, the loads are time-dependent but relatively uniform throughout. The time-dependent loads were applied as equivalent static loads, utilizing the appropriate dynamic loads factors. Following a LOCA, the refueling bulkhead would require requalification prior to use. This is acceptable because the refueling bulkhead does not perform a safety-related function and would not become a missile during the postulated LOCA.

   The analyses for the annulus are contained in References 6.2-9 through 6.2-11. Evaluation of potential pipe breaks within the sacrificial shield wall are in Reference 3.8-5, 3.8-6, 3.8-7, and 3.8-23.

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

Where the ECCS enter into the determination of energy released to the containment, the single failure criterion has been applied to maximize the energy release to the containment following a LOCA.

6.2.1.3.1 Mass and Energy Release Data

Table 6.2-9 provides the mass and enthalpy release data for the recirculation line break. Blowdown flow rates do not change significantly during the 24-hr period following the accident. Figures 6.2-29 and 6.2-30 show the blowdown flow rates for the recirculation line break. This data was employed in the DBA containment pressure-temperature transient analyses.

Table 6.2-10 provides the mass and enthalpy release data for the main steam line break. Blowdown flow rates do not change significantly during the 24-hr period following the accident. Figure 6.2-31 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.

6.2.1.3.2 Energy Sources

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

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

a. Stored energy in the reactor system,
b. Energy generated by fission product decay,
c. Energy from fuel relaxation,
d. Sensible energy stored in the reactor structures,
e. Energy being added by the ECCS pumps, and
f. Metal-water reaction energy.

All but the pump heat energy addition is discussed or referenced in this section. The pump heat rate was used in evaluating the containment response to the LOCA and is conservatively selected as a constant input of 4890 Btu/sec to the system. The pump heat rate is added to the decay heat rate for inclusion in the analysis.

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

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

6.2.1.3.3 Reactor Blowdown and Core Reflood Model Description

The reactor primary system blowdown flow and core reflood rates were evaluated with the model described in References 6.2-1 and 6.2-2.

6.2.1.3.4 Effects of Metal-Water Reaction

The containment systems are designed to accommodate the effects of metal-water reactions and other chemical reactions which may occur following a LOCA. The amount of metal-water reaction which can be accommodated is consistent with the performance objectives of the ECCS. Section 6.2.5 provides a discussion on the generation of metal-water hydrogen within the containment.

6.2.1.3.5 Thermal Hydraulic Data for Reactor Analysis

Sufficient data to perform confirming thermodynamic evaluations of the containment has been provided within Section 6.2.1.1.3.3.

6.2.1.3.6 Long Term Cooling Model Description

The long term cooling model is described in Section 6.2.1.1.3.4.

6.2.1.3.7 Single Failure Analysis

Containment analysis results assuming the worst single active failure are presented in Section 6.2.1.

6.2.1.4 Not applicable to BWR plants.

6.2.1.5 Not applicable to BWR plants.

6.2.1.6 Testing and Inspection

6.2.1.6.1 Structural Integrity Test

The test for structural integrity is discussed in Section 3.8.

6.2.1.6.2 Integrated Leak Rate Test

Leak rate tests are conducted to verify that leakage out of the primary containment does not exceed 0.375% per day at 38 psig. This test is discussed in Section 6.2.6.

6.2.1.6.3 Drywell Bypass Leak Test

Tests are conducted, in accordance with the Technical Specifications, to verify that the drywell-wetwell bypass leakage does not exceed an equivalent leakage of $A/\sqrt{K}$ equal to 0.0045 ft^2. This is less than the bypass leakage allowed.

6.2.1.6.4 Vacuum Relief Testing

Tests are conducted in accordance with the Technical Specifications to verify the proper operation of the vacuum relief valves.

6.2.1.7 Required Instrumentation

The instrumentation required to monitor containment parameters and to initiate safety functions is discussed in Chapter 7.

6.2.2 RESIDUAL HEAT REMOVAL CONTAINMENT HEAT REMOVAL SYSTEM

6.2.2.1 Design Bases

The RHR containment heat removal function is accomplished by the use of an operational mode of the RHR system. The purpose of this system is to prevent excessive containment temperatures and pressures, thus maintaining containment integrity following a LOCA. To fulfill this purpose, the RHR containment cooling system meets the following safety design bases:

a. The system will limit the long term bulk temperature of the suppression pool to ≤204.5°F when considering the energy additions to the containment following a LOCA. These energy additions, as a function of time, are provided in Section 6.2.1;

b. The single failure criterion applies to the system;

c. The system is designed to safety grade requirements including the capability to perform its function following an SSE;

d. The system will remain operational during those environmental conditions imposed by a LOCA;

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

f. Minimum net positive suction head (NPSH) is maintained on the RHR pumps even with the containment at atmospheric pressure, the suppression pool at a maximum temperature, and postaccident debris entrained on the beds of the suction strainers; and

g. Withstands dynamic effect of pipe breaks inside and outside of containment (see Section 3.6).

The primary containment unit coolers provide for containment heat removal during nonaccident conditions. These coolers are not an ESF and no credit is taken for them during accident events.

6.2.2.2 Residual Heat Removal Containment Cooling System Design

The RHR containment cooling system is an integral part of the RHR system. Water is drawn from the suppression pool, pumped through one or both RHR heat exchangers and delivered to the vessel, the suppression pool, the drywell spray header, or the suppression pool vapor space spray header.

Water from the SW system is pumped through the heat exchanger tube side to remove heat from the process water. Two cooling loops are provided, each mechanically and electrically separate from the other to achieve redundancy. The process diagram including the process data from all design operating modes and conditions is provided in Section 5.4.

All portions of the RHR containment cooling system are designed to withstand operating loads and loads resulting from natural phenomena.

Construction codes and standards are covered in Section 3.2. Seismic and environmental qualifications are discussed in Section 3.10 and 3.11, respectively.

There are no signals which automatically initiate containment cooling; however, the SW system is automatically initiated by the same signals which start up the ECCS. The capacity of power sources, including the standby diesels, is sufficient to allow operation of the SW pumps simultaneously with the ECCS pumps. An ECCS pump need not be secured prior to starting RHR containment cooling.

To start RHR containment cooling after a LOCA resulting from a large break, the operator needs only to verify that the normally open RHR heat exchanger isolation valves are open and then shut the heat exchanger bypass valve. The rated containment cooling flow, 7450 gpm, can be achieved through the LPCI line, the drywell spray line, or through the test line and wetwell spray line, which directs the heat exchanger discharge directly into the suppression pool. Thus, the design allows containment cooling simultaneously with core flooding or containment spray. If the break size is small enough to limit reactor depressurization, the rated containment cooling flow cannot be established through the LPCI line. The operator must then direct the RHR containment cooling flow through the drywell spray line or through the test line; however, the operator must not divert LPCI flow away from the reactor until adequate core cooling is ensured. In addition, an electrical interlock prevents actuation of a drywell spray loop until the corresponding LPCI injection valve has been shut. A second electrical interlock prevents actuation of drywell spray if there is no high drywell pressure signal present.

When allowed, the operator may start drywell spray by shutting the LPCI injection valve and then opening the drywell spray valves. Similarly, the operator may divert the flow directly to the suppression pool by shutting the LPCI injection valve and then opening the test line valve.

Preoperational tests were 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 were bench tested for flow rate versus pressure drop to evaluate the original hydraulic calculations. The spargers were tested by air and visually inspected to verify that all nozzles were clear.

6.2.2.3 Design Evaluation of the Containment Cooling System

The containment spray system is discussed in Section 5.4.7. Containment spray is not required for heat removal.

In the event of the postulated design basis LOCA, the short-term energy release from the reactor primary system will be dumped to the suppression pool. This will cause a pool temperature rise of approximately 56°F in the short term. Subsequent to the accident, fission product decay heat will result in a continuing energy input to the pool. The RHR containment cooling system will remove this energy which is input to the primary containment system, thus resulting in acceptable suppression pool temperatures and containment pressures.

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

a. With the reactor initially at 3702 MWt, 102% of uprated power, a LOCA occurs;

b. A loss of offsite power occurs and either Division 1 or 2 diesel fails to start and remains out of service during the entire transient. This is the worst single failure;

c. Only three ECCS pumps are activated and operated as a result of there being no offsite power and minimum onsite power; and

d. After 10 minutes it is assumed that the plant operators shut the bypass valve on one RHR heat exchanger to start containment heat removal. Once containment cooling has been established, no further operator actions are required.

Each RHR pump suppression pool suction consists of a pipe "T" with a suction strainer at each end. During normal operation, some fiber and corrosion products have accumulated on the strainers. This accumulation is considered in the design of the strainers, which will entrain additional debris following a LOCA. The potential for the additional accumulation of debris during a LOCA is discussed in Section 6.2.1. Wetwell strainers are periodically cleaned to ensure that post-LOCA accumulation of debris on the strainer beds is within acceptable limits.

The relative locations of the RHR suction and return lines in the suppression pool are shown in Figure 6.2-32. Mixing in the pool is primarily accomplished by the vertical and horizontal displacement between the suction and discharge line for a loop. The structures in the suppression pool act as baffles and improve mixing. Vertical thermal stratification in the suppression pool is prevented by locating the discharge lines above the suction lines.

Required operator actions are minimal. Even without operator action, some heat removal will occur from the suppression pool to the spray ponds. The ECCS initiation signals start up both SW and LPCI flow. The LPCI flow is primarily through the RHR heat exchanger bypass line since the bypass valve is signaled to open. Since the heat exchanger isolation valves are normally open, some of the LPCI flow (approximately 40%) will flow through the heat exchanger. It is estimated that for break sizes resulting in RPV depressurization and rated LPCI flow, the heat exchangers' duty with the partial shell side flow (i.e., no operator action) will be approximately 75% of the heat exchangers' duty with full shell side flow. Thus it is estimated that operator delays after a large break would result in only a moderate increase in suppression pool temperatures.

Summary of Containment Cooling Analysis

When calculating the long-term, post-LOCA pool temperature transient, it is assumed that the initial suppression pool temperature is at its maximum value and that the SW temperature is as described in Table 6.2-4 throughout the accident period. These assumptions maximize the heat sink temperature to which the containment heat is rejected and maximizes the containment temperature. In addition, the RHR heat exchanger is assumed to be in a fully fouled condition at the time the accident occurs. This conservatively minimizes the heat exchanger heat removal capacity. The resultant suppression pool temperature transient is described in Section 6.2.1 and is shown in Figure 6.2-12. Even with the degraded conditions outlined above, the maximum uprate temperature is 204.5°F, which is less than the original 220°F.

When evaluating this long-term suppression pool transient, all heat sources in the containment are considered with no credit taken for any heat losses other than through the RHR heat exchanger. These heat sources are discussed in Section 6.2.1. Figure 6.2-13 shows the actual heat removal rate of the RHR heat exchanger.

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

6.2.2.4 Tests and Inspections

The preoperational test program of the containment cooling system is described in Sections 14.2.12 and 5.4.7. Operational testing is in accordance with the Technical Specifications.

6.2.2.5 Instrumentation Requirements

The details of the instrumentation are provided in Chapter 7. The containment cooling mode of the RHR system is manually initiated from the control room.

6.2.3 SECONDARY CONTAINMENT FUNCTIONAL DESIGN

The secondary containment system includes the secondary containment structure and the safety-related systems provided to control the ventilation and cleanup of potentially contaminated volumes of the secondary containment structure following a DBA. This section discusses the secondary containment design. The SGT system is used to depressurize and clean the secondary containment atmosphere and is discussed in Section 6.5.1.

The secondary containment structure is synonymous with the reactor building. Sufficient openings exist among all areas of the reactor building to ensure that no significant long-term pressure gradients can exist within the secondary containment. In addition, with the exception of the steam tunnel, there are sufficient vent areas in all confined or enclosed spaces such that pressure can be safely relieved into the rest of secondary containment for all postulated pipe breaks within those spaces.

The steam tunnel runs through the reactor building and into the turbine generator building. The portion of the steam tunnel within the reactor building is physically and functionally part of the secondary containment during normal operation, expected transients, and all postulated accident events except for a pipe break within the steam tunnel. The steam tunnel relieves pressure through blowout panels which normally separate the turbine generator and reactor building portions of the steam tunnel.

6.2.3.1 Design Bases

The secondary containment structure completely encloses the primary containment. The secondary containment provides an additional barrier to fission product release when primary containment is operable and provides the primary barrier during operations with the potential to drain the reactor vessel (OPDRV).

The secondary containment structure, in conjunction with other secondary containment systems, provides the means of controlling and minimizing leakage from the primary containment to the outside atmosphere during a LOCA.

The reactor building pressure control system operates together with the reactor building ventilation system during normal operation to maintain building pressure greater than or equal to 0.25 in. of vacuum water gauge as indicated at the reactor building el. 572 ft. During emergency operation the pressure control system operates together with the SGT system to maintain a vacuum in secondary containment at greater than or equal to 0.25 in. vacuum water gauge on all building surfaces. This ensures that leakage is into the secondary containment during normal and emergency operation. Thus, all the reactor building air is either exhausted through the exhaust air plenum, where it is constantly monitored, or discharged through the filtration units of SGT system. The reactor building pressure control system and the reactor building ventilation system are described in Section 9.4.

The secondary containment isolation signals, secondary containment isolation valves, isolation valves for the reactor building ventilation system, SGT system, and reactor building pressure control system are all designed to Seismic Category I, Class 1E requirements. The design bases loads for the SGT system are given in Section 6.5.1. These systems can be periodically inspected and functionally tested.

The secondary containment structure houses the refueling and reactor servicing equipment, the new and spent fuel storage facilities, and other reactor auxiliary or service equipment, including all or part of the reactor core isolation cooling system, reactor water cleanup demineralizer system, standby liquid control system, control rod drive (CRD) system equipment, the ECCS, SGT system, and electrical equipment components. The secondary containment structure protects the equipment from Seismic Category I disturbances, the design basis tornado and tornado-generated missiles, and the design basis wind. The secondary containment structure is designed to meet the following design bases:

a. The reactor building is designed to meet Seismic Category I requirements;

b. The reactor building is designed and constructed in accordance with the structural design criteria presented in Section 3.8, and provides for low inleakage and outleakage during reactor operation. The building is designed to limit the inleakage rate to 100% of the reactor building free volume per day when maintained at a negative building pressure of 0.25 in. of water;

c. The reactor building is designed to withstand applied wind pressures resulting from the design basis wind velocity, including gusts of 100 mph at an elevation of 30 ft above grade. The pressure of the design basis wind velocity on the reactor building is discussed in Section 3.3;

d. The reactor building is designed to withstand pipe whip loads plus jet impingement of jet reaction loads due to high-energy pipe breaks outside primary containment;

e. The reactor building design allows for periodic inspections and functional tests of the penetrations, ventilation system (including automatic isolation), pressure control system, and SGT system;

f. The reactor building is designed to withstand applied wind pressures resulting from the design basis tornado. The effects of the design basis tornado pressures on the structure are discussed in Section 3.3 and tornado-generated missiles are discussed in Section 3.5; and

g. The reactor building is designed for all probable combinations of the design basis wind and the design basis tornado velocities and associated differences of pressure within the structure and atmospheric pressure outside the structure.

6.2.3.2 System Design

See Figures 1.2-7 through 1.2-12 for general arrangement drawings of the reactor building. Also see Figures 3.8-1 and 3.8-2. See Table 6.2-12 for the design and performance data for the secondary containment structure.

The major design provisions that prevent primary containment leakage from bypassing the SGT system, except for those lines identified as potential bypass leakage paths in Table 6.2-16, are the reactor building pressure control system, the reactor building ventilation isolation system, the isolation signals, and the standby power system.

Normal reactor building ventilation system is not required to operate during accident conditions. The system is automatically shut down and the SGT system started in the event of any of the following isolation signals:

a. Reactor vessel low-low water level,
b. High drywell pressure, and
c. High radiation level in the reactor building exhaust air plenum.

All ventilation system penetrations of secondary containment (except those of the SGT system) are fitted with two fail-closed, air-operated butterfly dampers in series. All dampers automatically close on any one of the isolation signals.

Penetrations of the secondary containment associated with the SGT system are fitted with two motor operated butterfly valves in series. The motor operated valves, which are powered from the essential power buses, are opened automatically, and the SGT system is started by any of the signals which isolate the secondary containment.

Penetrations of the reactor building are designed with leakage characteristics consistent with leakage requirements of the entire building. Entrance to the reactor building is through interlocking double door personnel air locks. Entrance to the reactor building vehicle air lock (railroad bay) is through an interlocking air lock system.

The storage/receiving area for casks is the vehicle air lock (railroad bay). The vehicle air lock (railroad bay) is completely within and along the south side of the reactor building at el. 441 ft. One of the interlocked doors is the exterior vehicle door at the east end of the vehicle air lock, and the other interlocked door is the interior person door at the west end of the vehicle air lock. There are also two hatches that are interlocked with the vehicle air lock entrance doors.

All entrances to the reactor building are through interlocking double door air lock systems and, therefore, building ingress and egress do not jeopardize the integrity of the secondary containment. All openings such as personnel doors leading into the secondary containment are under administrative control and are provided with position indication and alarm in the main control room if they are not closed after the time allowed for ingress/egress. An exception is an access hatch which has been provided in one of the steam tunnel blowout panels. When not in use, the hatch is secured closed by security bolts and padlocks. Another exception is the CRD rebuild room drop chute which is used to dispose of contaminated CRD components. The drop chute penetrates the reactor building floor at el. 471 ft and becomes a part of secondary containment when the vehicle air lock (railroad bay) exterior doors are open. A valve at el. 501 ft allows CRD components (e.g., filters) to be dropped down the chute without breaching secondary containment.

The reactor building pressure control system is designed to eliminate fluctuations in reactor building pressure by such factors as wind gusts. Reactor building pressure is indicated and recorded in the main control room and loss of negative pressure is alarmed.

The reactor building pressure control system automatically maintains a subatmospheric pressure in the reactor building by monitoring the differential pressure between the reactor building interior and the external atmosphere. The differential pressure is monitored by eight differential pressure transmitters, four in each division, which measure the differential pressure between the internal reactor building and each of the four external sides of the reactor building. The signal which indicates the least differential pressure controls the position of the blades in the normal reactor building exhaust fan units. In the event of reactor building isolation, the reactor building pressure control system controls reactor building pressure by SGT system fan flow.

Piping that connects to primary containment and passes through secondary containment is not considered a potential secondary containment bypass leak path if isolated by blind flanges.

Condensate from the condensate storage tanks can be used to flush ECCS and RHR shutdown cooling lines. Blind flanges are installed in the condensate system at spool piece COND-RSP-4 and in the RHR system downstream of RHR-V-108 and RHR-V-109 and at spool piece RHR-RSP-1 to isolate potential secondary containment bypass leak paths. The spool pieces are installed to comply with the piping support analyses. The spool pieces COND-RSP-1, COND-RSP-2, COND-RSP-3, COND-RSP-5, and COND-RSP-6 are connected to the condensate piping with blind flanges at the other end. If connected to the corresponding RHR lines, blind flanges would be necessary to isolate potential secondary containment bypass leak paths.

Table 6.2-16 presents a tabulation of primary containment process piping penetrations. The lines that penetrate both the primary and secondary containment were evaluated for potential bypass leakage paths as summarized in Table 6.2-16. The guidance of the NRC Branch Technical Position Containment Systems Branch (BTP CSB) 6-3 (Reference 6.2-40) were addressed in considering potential bypass leakage paths. Designs provided to prevent through-line leakage are dependent on whether the working fluid in the associated system is gaseous or liquid. Lines that vent (gaseous release) into the reactor building, will be treated by the SGT system. Lines that penetrate primary and secondary containment that normally contain water provide a water seal between the primary containment and the environment upon the primary isolation valve closure. If a break were to occur in the lines, the water or gas would evacuate into the reactor building, and any leakage through the failed line would be collected by the floor drain system or processed by the SGT system. Some lines that penetrate both the primary and secondary containment are seismically qualified outside of the secondary containment. These lines are considered closed systems and are not categorized as potential bypass paths. Lines that penetrate the primary and secondary containment are contained in one or more of the categories listed below.

a. Operate post-LOCA at pressure higher than the primary containment pressure or are seismically qualified.

b. Are vented to the secondary containment.

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

Therefore, the primary containment isolation valve leak rate tests and SGT system operability tests are adequate to ensure that bypass leakage will not occur and separate leakage testing of the secondary containment isolation valves is not required. An additional conservative assumption of secondary containment bypass leakage of 0.04% volume per day, the secondary containment bypass limit, for the first 24 hr and 0.02% volume per day after 24 hr was included in dose consequence analyses in Chapter 15. The analyses demonstrated that the potential bypass leakage contribution from water lines to the dose consequences were negligible.

The design and construction codes, standards, and guides applied to the buildings and SSCs are discussed in Chapter 3.

6.2.3.3 Design Evaluation

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

a. The rate of in-leakage assumption in based on the 100% of the secondary containment volume per day.

b. The exhaust flow rate is based on maintaining containment vacuum greater than or equal to 0.25 in. of vacuum water gauge.

The SGT system is described in Section 6.5.

6.2.3.3.1 Calculation Model

The parametric analysis of secondary containment responses following a LOCA were performed using the general purpose thermal-hydraulic computer program GOTHIC (Reference 6.2-39). The GOTHIC program solves conservation of mass, momentum, and energy equations for multi-component, multi-phase flows. The phase balance equations are coupled by mechanistic models for interface mass, momentum, and energy transfers that cover the entire flow regime as well as single-phase flows. Aspects of the reactor building taken into consideration for the model include:

a. Heat loads modeled in the respective rooms (multiple volumes),
b. Heat transfer for primary to secondary containment (negligible),
c. Heat transfer between secondary containment and the outside environment,
d. Heat transfer between rooms and reactor building floors (multiple elevations),
e. Room cooler efficiency, and
f. Secondary containment relative humidity.

6.2.3.3.2 Results

A series of parametric studies were performed to evaluate varying meteorological conditions and heat loads on the drawdown analyses. Representative temperature and pressure response curves are provided as Figures 6.2-34 and 6.2-35. These analyses are based on the following:

	PARAMETER	VALUE
a)	The reactor building was modeled using lumped parameter volumes totaling	Approximately 3,500,000 ft^3
b)	Exhaust rate during drawdown	4800 cfm
c)	Secondary containment in leakage rate	2430 cfm
d)	Initial reactor building temperature range	50°F to 75°F
e)	Outside temperature range	0°F to 94°F
f)	Wind speeds range	0 mph to 17 mph

The drawdown analyses for secondary containment determined that the SGT system can establish and maintain the secondary containment pressure at less than 0.25 inches of vacuum water gauge within 20 minutes.

6.2.3.4 Tests and Inspections.

Components of the SGT system are tested periodically to ensure operability. The capability of the SGT system to maintain the secondary containment operability is tested in accordance with Technical Specifications. Tests are performed by isolating the secondary containment and starting either of the two SGT units. Design pressure is maintained in the secondary containment by operation of one SGT unit for a period of 1 hr. During the test, flow measurements of the SGT system and differential pressure measurements of the secondary containment are taken. If during testing the SGT system fails to maintain the secondary containment pressure at 0.25 inches of water gauge or greater below atmospheric pressure at or below an SGT system air flow rate of 2240 cfm, the reactor building is visually inspected for leakage paths. Leakage paths are repaired permanently (no temporary sealing mechanisms such as tape are used), and the tests are repeated until the acceptance level is met.

Tests are limited to 1 hr because isolation of the secondary containment necessitates the shutdown of the normal reactor building ventilation system which is required for the operation of non-ESF equipment housed in the secondary containment.

6.2.3.5 Instrumentation Requirements

Secondary containment negative pressure is automatically maintained by the reactor building pressure control system. During normal operations, this system controls the position of the blades in the normal reactor building exhaust fan units. During accident conditions, the SGTS is started and the secondary containment is isolated by the primary containment and reactor vessel isolation control system. Under this condition, the system controls reactor building negative pressure by controlling the SGT system fans.

Descriptions of the instrumentation and controls for the reactor building pressure control system, primary containment and reactor vessel isolation control system, and SGT system are contained in Section 7.3.1. The analyses are described in Section 7.3.2.

6.2.4 CONTAINMENT ISOLATION SYSTEM

6.2.4.1 Design Bases

Safety Design Bases

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

b. Capability for rapid closure or isolation of all pipes or ducts that penetrate the containment is achieved by means that provide a containment barrier in such pipes or ducts sufficient to maintain leakage within permissible limits,

c. The design of isolation valving for lines penetrating the containment follows the requirements of General Design Criteria (GDC) 54 through 57 as noted in Table 6.2-16,

d. Isolation valving for instrument lines which penetrate the containment conforms to the requirements of Regulatory Guide 1.11, Revision 0,

e. Isolation valves, actuators, and controls are protected against loss of safety function by missiles,

f. The design of the containment isolation valves and associated piping and penetrations is to Seismic Category I requirements,

g. Containment isolation valves and associated piping and penetrations meet the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Classes 1 or 2, as applicable, and

h. Containment isolation valve closure limits radiological effects from exceeding established requirements (10 CFR 50.67), including the effects of sudden isolation valve closure.

The primary objective of the containment isolation system is to provide protection against releases of radioactive materials to the environment as a result of accidents occurring to the nuclear boiler system, auxiliary systems, and support systems. This objective is accomplished by automatic isolation of appropriate lines that penetrate the containment system. Actuation of the containment isolation systems is automatically initiated at specific limits.

The containment isolation systems, in general, close those fluid lines penetrating containment that support systems not required for emergency operation. Those fluid lines penetrating containment which support ESF systems have remote manual isolation valves which may be closed from the control room.

Redundancy and physical separation are required in the electrical and mechanical design to ensure that no single failure in the containment isolation system prevents the system from performing its intended functions.

The isolation system is designed to Seismic Category I. Classification of equipment and systems is shown in Table 3.2-1.

Actuation of the containment isolation systems is initiated by the signals listed in Table 6.2-16.

The criteria for the design of the containment and reactor vessel isolation control system are listed in Section 7.3.1 and Table 7.3-5. The bases for assigning certain signals for containment isolation are contained in Section 7.3.1.

On signals of high drywell pressure or low-low water level in the reactor vessel, isolation valves that are part of systems not required for emergency shutdown of the plant are closed.

The same signals will initiate the operation of systems associated with the ECCS. The isolation valves which are part of the ECCS may be closed remote manually from the control room or can close automatically.

6.2.4.2 System Design

The general criteria governing the design of the containment isolation systems is provided in Sections 3.1.2 and 6.2.4.1. Table 6.2-16 summarizes the containment penetrations and contains information pertaining to:

a. Open or closed status under normal operating conditions and accident situations,
b. Primary and secondary modes of actuation provided for isolation valves,
c. Parameters sensed to initiate isolation valve closure,
d. Closure time for principal isolation valves to secure containment isolation, and
e. Applicable GDC.

Protection is provided for isolation valves, actuators, and controls against damage from missiles. All potential sources of missiles are evaluated. Where possible hazards exist, protection is afforded by separation, missile shields, or by location. See Section 3.5 for a discussion of evaluation techniques.

Isolation valves are designed to be operable under the most adverse environmental conditions (see Section 3.11) such as operation under maximum differential pressures, extreme seismic occurrences, steam laden atmosphere, high temperature, and high humidity. Electrical redundancy is provided for power-operated valves. Power for the actuation of two isolation valves in line (inside and outside of containment) is supplied by two redundant, independent power sources without cross ties. In general, outboard isolation valves receive power from a Division 1 power supply while isolation valves within containment receive power from a Division 2 power supply. In general, the supply is ac for Division 2 valves and dc for Division 1 valves depending on the system under consideration. The ability to provide appropriate containment integrity during a station blackout is discussed in Section 1.5.2.

The main steam line isolation valves are pneumatic spring-loaded, piston-operated globe valves designed to fail closed. The valves are held open by air pressure against spring force that will close or help close the valve in case of loss of power or air supply. Each main steam line isolation valve has an air accumulator to assist in its closure on loss of the air supply to the solenoid pilot valve. The separate and independent action of either air pressure or spring force will close the outboard MSIV. The inboard MSIV will close on air or springs and air.

Air-operated valves (not applicable to air-testable check valves) close on loss of air, except the butterfly valves on the RB-WW vacuum breaker lines.

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

6.2.4.3 Design Evaluation

6.2.4.3.1 Introduction

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

Mechanical components in process lines, such as isolation valve arrangements or extraordinary ex-containment system quality, are redundant and provide back-up in the event of accident conditions. Instrument lines, in many cases, rely on a single mechanical barrier in the event of accident conditions. These isolation valve arrangements satisfy the requirements specified in GDC 54, 55, 56, and 57, and Regulatory Guide 1.11, Revision 0.

The arrangements with appropriate instrumentation are described in Table 6.2-16 and Figures 6.2-36 through 6.2-59. The isolation valves have redundancy in the mode initiation. Generally, the primary mode is automatic and the secondary mode is remote manual. A program of testing, described in Section 6.2.4.4, is maintained to ensure valve operability and leaktightness.

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

Electrical redundancy is provided in isolation valve arrangements which eliminates dependency on one power source to attain isolation. Electrical cables for isolation valves in the same line have been routed separately.

Provisions are in place to control the position of nonpowered process line, vent, drain, and test connection valves that are containment isolation valves. These provisions meet the applicable requirements of GDC 55 and 56. For power-operated valves, the position is indicated in the main control room. Discussion of instrumentation and controls for the isolation valves is included in Chapter 7.

6.2.4.3.2 Evaluation Against General Design Criteria

6.2.4.3.2.1 Evaluation Against Criterion 55. The reactor coolant pressure boundary (RCPB) consists of the RPV, pressure retaining appurtenances attached to the vessel, and valves and pipes which extend from the RPV up to and including the outermost isolation valve. The lines of the RCPB which penetrate the containment include provisions for isolation of the containment, thereby precluding any significant release of radioactivity. Similarly, for lines which do not penetrate the containment but which form a portion of the RCPB, the design ensures that isolation of the reactor coolant pressure can be achieved.

6.2.4.3.2.1.1 Influent Lines. Influent lines which 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 as close to the external side of the containment as practical.

Table 6.2-16 contains those influent pipes that comprise the RCPB and penetrate the containment.

6.2.4.3.2.1.1.1 Feedwater Lines. The feedwater lines are part of the RCPB as they penetrate the drywell to connect with the RPV. The isolation valve inside the drywell is a swing check valve, located as close as practicable to the containment wall. Outside the containment another swing check valve is located as close as practicable to the containment wall and farther away from the containment is a motor-operated gate valve. Should a break occur in the feedwater line, the check valves prevent significant loss of reactor coolant inventory and offer immediate isolation. The design allows the condensate and condensate booster pumps to supply feedwater to the vessel through a bypass line around the reactor feed pumps (which are tripped on a loss of steam supply) as soon as the vessel is partially depressurized. For this reason, the outermost gate valve does not automatically isolate upon signal from the protection system. The gate valve meets the same environmental and seismic qualifications as the outside check valve. The valve is capable of being remotely closed from the control room to provide long-term leakage protection in the event that feedwater makeup is unavailable or unnecessary. In the control room, the operator can determine if makeup from the feedwater system is unavailable by the use of the feedwater flow indicator which will show high flow for a feedwater pipe break, or no flow for a feedwater pump trip.

The operator can also determine if makeup from the feedwater system is unnecessary by verifying that the ECCS is functioning properly and the reactor water level is being adequately maintained. The ECCS operation signals and reactor vessel water level indication are provided in the control room.

There is no need to specifically alert the operator to isolate the feedwater lines other than as described above since the lines both have check valves. However, for long-term isolation purposes, the operator may close the motor-operated gate valves at any time.

Emergency procedures require the operator to close reactor feedwater block valves within 20 minutes following cessation of feedwater flow. No credit is taken for feedwater flow in assessing core and containment response to a LOCA.

The applicable generic anticipated transients without scram (ATWS) studies (References 6.2-23 and 6.2-24) assumed the use of turbine driven feed pumps and simulated the loss of steam to the turbine and feedwater flow in the most limiting case in which all main steam lines were isolated. In the ATWS situation, the loss of feedwater flow (or limiting of the flow to near zero) causes a decrease in core flow and inlet subcooling which results in a power reduction. This leads to a benefit in mitigating the peak vessel pressure, containment pressure and suppression pool temperature.

6.2.4.3.2.1.1.2 High-Pressure Core Spray Line. The HPCS line penetrates the drywell to inject directly into the RPV. Isolation is provided by a check valve located inside the drywell, and a remote-manually actuated gate valve located as close as practicable to the exterior wall of the containment. Long-term leakage control is maintained by this gate valve. If a LOCA occurred, the gate valve would receive an automatic signal to open.

6.2.4.3.2.1.1.3 Low-Pressure Coolant Injection Lines. Satisfaction of isolation criteria for the three LPCI injection lines of the RHR system is accomplished by use of remote-manually operated gate valves and check valves. Both types of valves are normally closed with the gate valves receiving an automatic signal to open at the appropriate time to ensure that acceptable fuel design limits are not exceeded in the event of a LOCA. The check valves are located as close as practicable to the RPV. The normally closed check valves protect against overpressurization in the reactor coolant pressure boundary (RCPB) by preventing high-pressure reactor water from entering the RHR system low pressure piping. When the reactor pressure is lower than the RHR system pressure, the low energy of the influent fluid (220°F maximum) can open the check valve and inject water into the reactor.

6.2.4.3.2.1.1.4 Control Rod Drive Lines. The CRD system insert and withdraw lines penetrate the drywell. The classification of these lines is Code Group B and they are designed in accordance with ASME Section III, Class 2. The basis to which the CRD insert and withdraw lines are designed is commensurate with the safety importance of maintaining pressure integrity of these lines. The Hydraulic Control Units (HCUs) and scram discharge headers as well as the hydraulic lines are Seismic I, and are qualified to the appropriate accident environment. The failure and scram position of all power operated valves are compatible with system isolation and, at the same time, rod insertion on a scram.

The inboard isolation of insert and withdraw lines for the primary containment is provided by the double seals in the control rod drives and the outboard isolation for the primary containment is provided by valves within the HCUs. The HCU manual isolation valves 101 and 102 are provided for positive isolation in the unlikely event of a pipe break within the HCU. Additional isolation is provided by normally closed, fail-closed, solenoid operated Directional Control Valves (DCV) in the HCUs (see Figure 4.6-5). The DCVs open only during routine movement of their associated control rod and during a reactor scram. In addition, a ball check valve located in the CRD flange housing automatically seals the insert line in the event of a break.

Insert and withdraw lines that extend outside the primary containment are small and terminate in the Reactor building which is served by the SGT system. Containment overpressurization will not result from a line break in containment since these lines contain small volumes at low energy levels. External leak detection of CRD piping outside of primary containment is provided by operations during routing routine inspections.

Two Quality Class I check valves in series (CRD-V-524/525) are located at the discharge of the CRD pumps to prevent significant bypass leakage through the Quality Class II CRD piping to the condensate storage tank that could result if any leakage past the HCU were to exist. If the Quality Class II CRD piping breaks between the check valves and the CRD HCUs, the SGT system will process the effluent prior to release from secondary containment. Thus, the potential bypass path by means of this CRD path is minimized to prevent any significant offsite consequence.

The NRC staff concluded in NUREG-0803, "Safety Evaluation Report Regarding Integrity of BWR Scram Systems," that although the CRD system represents a departure from GDC 55, the CRD containment isolation provision stated above is considered acceptable.

6.2.4.3.2.1.1.5 Residual Heat Removal and Reactor Core Isolation Cooling Head Spray Lines. The RHR head spray and RCIC lines meet outside the containment to form a common line which penetrates the drywell and discharges directly into the RPV. The check valve inside the drywell is normally closed. The check valve is located as close as practicable to the RPV. Two remote-manual block valves are utilized as isolation valves located outside the containment. The check valve ensures immediate isolation of the containment in the event of a line break. The block valve on the RHR line receives an automatic isolation signal while the block valve on the RCIC line is remote manually actuated to provide long-term leakage control.

6.2.4.3.2.1.1.6 Standby Liquid Control System Lines. The standby liquid control system line penetrates the drywell and connects to the HPCS system injection line. In addition to a check valve inside the drywell, a parallel pair of explosive actuated valves are located outside the drywell. Since the standby liquid control line is a normally closed, nonflowing line, rupture of this line is extremely remote. The explosive actuated valves function as outboard isolation valves. These valves provide a seal for long-term leakage control as well as preventing leakage of sodium pentaborate into the RPV during SLC system testing.

6.2.4.3.2.1.1.7 Reactor Water Cleanup System. The RWCU pumps, heat exchangers, and filter demineralizers are located outside the drywell. The return line from the filter demineralizers connects to the feedwater line outside the containment between the block valve and the outside containment feedwater check valve. Isolation of this line is provided by the feedwater system check valve inside the containment, the feedwater system check valve outside the containment, and an RWCU motor-operated gate valve outside the containment. The motor-operated gate valve functions as a third isolation valve.

During the postulated LOCA, it may be desirable to restore reactor coolant cleanup. For this reason, the motor-operated gate valve in the RWCU return line does not automatically isolate upon a containment isolation signal. If reactor coolant cleanup is not required, the return isolation valve RWCU-V-40 can be shut remotely from the control room when the motor-operated feedwater block valves are closed 20 minutes or more after the beginning of a LOCA. Should a break occur in the reactor water cleanup return line, the check valves would prevent significant loss of inventory and offer immediate isolation, while the outermost isolation valve would provide long-term leakage control.

6.2.4.3.2.1.1.8 Recirculation Pump Seal Water Supply Line. The recirculation pump seal water line extends from the recirculation pump through the drywell and connects to the CRD supply line outside the primary containment. The seal water line forms a part of the RCPB. The recirculation pump seal water line is Code Group B from the recirculation pump through the outboard motor operated isolation valve. From this valve to the CRD connection the line is Code Group D. Should this line fail, the flow rate through the broken line has been calculated to be substantially less than that experienced by a broken instrument line.

6.2.4.3.2.1.1.9 Low-Pressure Core Spray Line. The LPCS line penetrates the drywell to inject directly into the RPV. Isolation is provided by a check valve located inside the drywell and a remote-manually actuated gate valve located as close as practicable to the exterior wall of the containment. Long-term leakage control is maintained by this gate valve. If a LOCA occurs, this gate valve will receive an automatic signal to open, delayed only by control circuitry that ensures that the fluid pressure inside the RPV is less than the design pressure of the piping.

6.2.4.3.2.1.1.10 Residual Heat Removal Shutdown Cooling Return Lines. The two shutdown cooling return lines inject into the RRC lines downstream of the RRC pumps. Isolation is accomplished by a normally-closed, motor-operated gate valve outside containment and the parallel arrangement of a full-flow check valve and a normally closed, partial-flow, motor-operated gate valve inside the containment. Both motor-operated valves receive signals to close if RHR system water is needed to support the ECCS mode of the RHR system.

6.2.4.3.2.1.2 Effluent Lines. Effluent lines which 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.

Table 6.2-16 also contains those effluent lines that comprise the RCPB and which penetrate the containment.

6.2.4.3.2.1.2.1 Main Steam, Main Steam Drain Lines, and Residual Heat Removal/Reactor Core Isolation Cooling Steam Supply Lines. The main steam lines extend from the RPV to the main turbine and condenser system, and penetrate the primary containment. Isolation is afforded inside by a normally-open, fail-close, automatic, air-operated, y-pattern globe valve and outside by a similar in-line globe valve paralleled by smaller automatic motor-operated gate valves, one each in the between-MSIV drain line and in the MSLC system tap (isolated – MSLC system is deactivated). The main steam drain line, which comes off a common manifold tapping off each main steam line just upstream of each inside MSIV, also penetrates the containment and is isolated by automatic motor-operated gate valves, one inside the containment and one outside the containment. The RHR steam supply line and RCIC turbine steam line connect to the main steam line inside the drywell and penetrate the primary containment. For these lines, isolation is provided by automatically actuated block valves, two parallel valves inside the containment common to both the RHR steam supply line and the RCIC turbine steam line, and one for each line just outside the containment. The outside RHR steam supply line isolation valve has been deactivated and locked in the closed position.

6.2.4.3.2.1.2.2 Recirculation System Sample Lines. A 0.75-in. diameter sample line from the recirculation system penetrates the drywell and is designed to ASME, Section III, Class l. A sample probe with a 1/8-in. diameter hole is located inside the recirculation line inside the drywell. In the event of a line break, the probe acts as a restricting orifice and limits the escaping fluid. Two automatic valves which fail close are provided; one inside and one outside the containment.

6.2.4.3.2.1.2.3 Reactor Water Cleanup System. The RWCU pumps, heat exchangers, and filter demineralizers are located outside the drywell. The supply line to the RWCU system connects to the reactor recirculation system lines on the suction side of the reactor recirculation pumps and to the RPV by means of the RPV drain line. Isolation of the RWCU lines is provided by two automatically actuated motor-operated gate valves. One valve is located inside containment and the other is located outside containment. Both valves are capable of remote manual operation from the control room.

6.2.4.3.2.1.2.4 Residual Heat Removal Shutdown Cooling Line. This line is common to the two trains of RHR shutdown cooling and is located on the A train RRC line just upstream of the pump. The inside motor-operated isolation gate valve, located as close as practical to the RPV, is paralleled by a small check valve. The valve is oriented to relieve a pressure build-up in the long section of line between the inside isolation valve and the outside isolation valve during those times when both valves are closed and the trapped line fluid heats and expands. The outside motor-operated containment isolation gate valve is located as close as practical to the containment. Both motor-operated valves automatically isolate on Level 3 to prevent further inventory loss in the event of a line break.

6.2.4.3.2.1.3 Conclusion on Criterion 55. To ensure protection against the consequences of accidents involving the release of radioactive material, pipes which form the RCPB have been shown to provide adequate isolation capabilities. A minimum of two barriers were shown to protect against the release of radioactive materials.

In addition to meeting the isolation requirements stated in Criterion 55, the pressure retaining components which comprise the RCPB are designed to meet other appropriate requirements which minimize 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 which comprise the RCPB are designed in accordance with the ASME, Section III, Class l.

Therefore, design of piping system which comprises the RCPB and penetrates containment satisfies Criterion 55.

6.2.4.3.2.2 Evaluation Against Criterion 56. Criterion 56 requires that lines which penetrate the containment and communicate with the containment interior must have two isolation valves, one inside the containment 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.

Table 6.2-16 includes those lines that penetrate the primary containment and connect to the drywell and suppression chamber.

For the lines wherein only a single isolation valve exists, the discussion in Section 6.2.4.3.2.2.1.1 is germane. Also see Table 6.2-16 for further information on specific lines.

For those lines wherein both isolation valves are located outside containment, the discussions in Sections 6.2.4.3.2.2.3.2, 6.2.4.3.2.2.3.10 and 6.2.4.3.2.2.3.11 apply. Also see Table 6.2-16 for further information on specific lines.

6.2.4.3.2.2.1 Influent Lines to Suppression Pool.

6.2.4.3.2.2.1.1 Low-Pressure Core Spray, High-Pressure Core Spray, and Residual Heat Removal Test and Minimum Flow Bypass Lines. The LPCS, HPCS, and RHR test lines have test isolation capabilities commensurate with the importance to safety of isolating these lines. Each line has a normally closed, motor-operated valve located outside the containment. Containment isolation requirements are met on the basis that the test lines are closed, low pressure lines constructed to the same quality standards as the containment. Furthermore, these lines are connected to ESF systems for which a single isolation valve is acceptable [as stated in NRC Standard Review Plan (SRP) 6.2.4, Section II, paragraph 6.e] based on the following prerequisites:

a. System reliability is improved with only one isolation valve in the line,

b. The system is closed outside containment and a single active failure can be accommodated with only one isolation valve,

c. The closed system is protected from missiles,

d. The closed system is designed to Seismic Category I, Safety Class 2, requirements and a minimum temperature and pressure rating at least equal to that for the containment, and

e. The piping between the isolation valve and containment is enclosed in the leak-tight housing, or conservative design of the piping and valve, conforming to SRP 3.6.2, precludes a breach of piping integrity.

The test return lines are also used for suppression chamber return flow during other modes of operation. In this manner the number of penetrations is reduced, minimizing the potential pathways for radioactive material release. Typically, pump minimum flow bypass lines join the respective test return lines downstream of the test return isolation valve. The bypass lines are isolated by motor-operated valves with a restricting orifice downstream of the motor-operated valve.

6.2.4.3.2.2.1.2 Reactor Core Isolation Cooling Turbine Exhaust, Vacuum Pump Discharge, and RCIC Pump Minimum Flow Bypass Lines. These lines, which penetrate the containment and discharge to the suppression pool, are equipped with a motor-operated, remote manually actuated gate valve located as close to the containment as possible. In addition, there is a simple check valve upstream of the gate valve which provides positive actuation for immediate isolation in the event of a break upstream of the check valve. The gate valve in the RCIC turbine exhaust is key-locked open in the control room and interlocked to preclude opening of the inlet steam valve to the turbine while the turbine exhaust valve is not in a full open position. The RCIC vacuum pump discharge line is also normally open but has no requirement for interlocking with steam inlet to the turbine. The RCIC pump minimum flow bypass line is isolated by a normally closed valve. The single valve is allowable because the water side of the RCIC system is a closed system analogous to the lines discussed in Section 6.2.4.3.2.2.1.1.

6.2.4.3.2.2.1.3 Residual Heat Removal Heat Exchanger Vent Lines. The RHR heat exchanger vent lines discharge through the RHR heat exchanger relief valve discharge lines to the suppression pool. Two globe valves in each vent line provide the system pressure boundary and are used to control venting during the RHR heat exchanger filling and draining operations. The outboard globe valve in each line is and meets the criteria for a containment system isolation valve. Both valves are normally closed, remotely controlled motor-operated globe valves. Each vent line is also equipped with a manual block valve and the test connections necessary for Type C testing of the isolation valve.

6.2.4.3.2.2.1.4 Low-Pressure Core Spray, High-Pressure Core Spray, and Residual Heat Removal Relief Valve Discharge Lines. These relief valves discharge to the suppression pool directly. They will not normally lift during operation and, therefore, can be considered as normally closed.

6.2.4.3.2.2.1.5 Fuel Pool Cooling and Cleanup Return Lines. Line is isolated by two normally-closed automatically actuated motor-operated gate valves, which are located outside the containment per NRC SRP 6.2.4, Section II, paragraph 6.d.

6.2.4.3.2.2.1.6 Deactivated Residual Heat Removal Steam Condensing Mode Steam Line Relief and Drain Lines. The four steam line relief valves (two per train) have been removed and the line flanges are blanked by "structural connections."

The two parallel-installed drain pot motor-operated globe valves (per train) are deactivated electrically and locked closed to maintain compliance with Criterion 56. Single isolation barriers are warranted on the basis that the RHR system is a closed system.

The RHR heat exchanger vents and relief valves along with the disabled CAC hydrogen recombiner drains and the discharge from RHR-RV-30 return to the wetwell through the deactivated steam condensing mode lines.

6.2.4.3.2.2.1.7 Process Sampling Suppression Pool Sample Return Line. Dual normally closed remote manual solenoid valves offer containment isolation. The valves are located outside the containment based on NRC SRP 6.2.4, Section II, paragraph 6.d.

6.2.4.3.2.2.2 Effluent Lines From Suppression Pool.

6.2.4.3.2.2.2.1 High-Pressure Core Spray, Low-Pressure Core Spray, Reactor Core Isolation Cooling, and Residual Heat Removal Suction Lines. These lines contain motor-operated, remote manually actuated, gate valves which provide assurance of isolating these lines in the event of 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. Thus, the need for isolation is conditional. The ECCS and RCIC fill systems (ECCS waterleg pumps) take suction from ECCS pump suppression pool suctions downstream of the isolation valve. This system is isolated from the containment by the respective ECCS pump suction valve from suppression pool as listed in Table 6.2-16.

6.2.4.3.2.2.2.2 Fuel Pool Cooling Suction Line. Two normally closed automatic motor-operated gate valves, located outside the containment (based on NRC SRP 6.2.4, Section II, paragraph 6.d), provide containment isolation.

6.2.4.3.2.2.2.3 PSR Suppression Pool Sample Line. Dual normally-closed remote manual solenoid valves offer containment isolation. The valves are located outside the containment (based on NRC SRP 6.2.4, Section II, paragraph 6.d).

6.2.4.3.2.2.3 Influent and Effluent Lines From Drywell and Suppression Chamber Free Volume.

6.2.4.3.2.2.3.1 Containment Atmosphere Control Lines (Deactivated). The containment atmosphere control system lines which penetrate the containment are equipped with two power-operated valves in series, normally closed. Since the CAC system has been deactivated, these valves have been de-energized. The motor operated gate valves have been locked closed, and the electrohydraulic operated valves are de-energized spring-closed. These valves provide assurance of isolating these lines in the event of a break and also provide long-term leakage control. In addition, the piping is considered an extension of containment boundary since it must remain intact following a design basis LOCA and, as such, is designed to the same quality standards as the primary containment.

6.2.4.3.2.2.3.2 Containment Purge Supply, Exhaust, and Inerting Makeup Lines. The drywell and suppression chamber purge lines have isolation capabilities commensurate with the importance to safety of isolating these lines. Each line has two air-operated spring closing isolation valves located outside the primary containment that are fully qualified to close under accident conditions. Containment isolation requirements are met on the basis that the purge lines are low pressure lines constructed to the same quality standards as the containment. Valve operability and reliability are enhanced by placement of both valves outside of the containment. The isolation valves for the purge lines are interlocked to preclude their being opened while a containment isolation signal exists as noted in Table 6.2-16.

Stainless-steel grills are installed across both purge supply line openings (one low in the drywell and the other low in the suppression chamber) and across the purge exhaust line opening high in the drywell. These prohibit debris from entering the purge lines, thus preventing the isolation valves from seating. The two remaining line openings (one purge exhaust and the single vacuum relief line that is not tied into a purge line, both of which are high in the suppression chamber) do not require debris screens because there is no probability of airborne debris during an accident (pipe insulation is not used in the suppression chamber) and the maximum anticipated suppression pool swell elevation is not sufficient to bring the surface of the water to either of these two openings.

There is a small branch line, which provides a makeup supply of nitrogen to inert containment, connected to the purge supply lines for both the drywell and suppression chamber. Each nitrogen makeup taps into its associated purge supply line inboard of the air-operated, spring-closing isolation valves. Therefore, each of these nitrogen lines is equipped with two automatic containment isolation valves, located as close as possible to primary containment.

6.2.4.3.2.2.3.3 Drywell and Suppression Chamber Air Sampling Lines. The radiation monitor lines penetrate the primary containment and are used for continuously sampling containment air during normal operation as part of the leak detection system. The supply lines are equipped with two automatic solenoid-operated isolation valves located outside and as close as possible to the containment. The return lines are equipped with a remotely operated solenoid isolation valve outside of containment and a check valve inside the containment.

The PSR system sample and return lines are normally isolated by dual solenoid valves. These do not receive automatic isolation signals since they may be used to sample the drywell and suppression chamber atmosphere in a post-LOCA situation.

6.2.4.3.2.2.3.4 Suppression Chamber Spray Lines. The suppression chamber spray lines penetrate the containment to remove energy by condensing steam and cooling noncondensable gases in the suppression chamber. Each line is equipped with a normally closed motor-operated valve located outside and as close as possible to the primary containment. This normally closed valve receives an automatic isolation signal. Containment isolation requirements are met on the basis that the spray header injection lines are normally closed, low pressure lines constructed to the same quality standards as the containment.

6.2.4.3.2.2.3.5 Reactor Building to Wetwell Vacuum Relief Lines. The three RB-WW vacuum relief lines are each equipped with a positive closing swing check valve in series with an air-operated, fail-open, butterfly valve. The air operator on the swing check valve is used only for testing. The air-operated butterfly valve is controlled by a differential pressure indicating switch which senses the pressure difference between the suppression chamber and the reactor building. When the negative pressure in the suppression chamber exceeds the instrument setpoint, the butterfly valve opens. The valves are not susceptible to fouling by ingested debris during such an event because they are not targets of missiles and are adequately protected from pipe break damage. The arrangement of valves and instruments is shown in Figure 9.4-8.

6.2.4.3.2.2.3.6 Drywell Spray Lines. The drywell spray lines are equipped with two normally closed, motor-operated gate valves located outside and as close as possible to primary containment. The drywell spray must be manually initiated. The piping from the outermost isolation valve to the spray ring header is constructed to withstand containment design conditions.

6.2.4.3.2.2.3.7 Reactor Closed Cooling Water Supply and Return Lines. Dual motor-operated automatic gate valves isolate each line, the former having both outside the containment and the latter having one inside and one outside the containment. In response to the concerns addressed in Generic Letter 96-06, Energy Northwest installed a bypass line around the inboard isolation valve on the return line. This bypass line is equipped with a check valve oriented against normal system flow. Thus, the check valve functions as an isolation valve in parallel with the main inboard isolation valve and as a means to dissipate pressure built up between the inboard and outboard isolation valves.

6.2.4.3.2.2.3.8 Air Supply Lines.

6.2.4.3.2.2.3.8.1 Check Valve Air Supply Lines. All lines are isolated by two locked-closed manual globe valves located outside the containment and as close as practical to the containment. The air test function is not used. Therefore, the valves are normally closed all of the time.

6.2.4.3.2.2.3.8.2 Primary Containment Instrument Air System Nitrogen Supply Lines. These lines consist of a check valve inside the containment and a motor-operated remote-manual globe valve outside the containment. The globe valves are under the control of the operator who can isolate the single nonsafety-related header should the containment nitrogen (CN) supply be unavailable. The operator can also isolate either or both safety-related headers should either, or both, experience nitrogen supply problems or otherwise require isolation. See Table 6.2-16 for further information.

6.2.4.3.2.2.3.8.3 Service Air System Maintenance Supply Line to the Drywell. This single line is capped with a threaded pipe cap inside the containment and isolated outside the containment by a locked-closed manual globe valve.

6.2.4.3.2.2.3.9 Demineralized Water Maintenance Supply Line to the Drywell. Dual manual gate valves, one inside and one outside the containment, isolate this line at all times except when high purity water is required inside the drywell for maintenance-related activities.

6.2.4.3.2.2.3.10 Drywell Equipment and Floor Drain Lines. Containment isolation is provided by two normally open, air-operated, fail-close automatic valves located outside and as close as practical to the containment.

6.2.4.3.2.2.3.11 Traversing In-Core Probe (TIP) System Guide Tubes. The TIP system consists of five guide tubes which penetrate the containment and interface with the containment atmosphere because of indexer leakage and built-in relief valves that prevent the indexers from collapsing on high pressure. The isolation design basis for these TIP lines is a "specific class of line" considered acceptable under General Design Criterion 56.

Isolation is accomplished by a seismically qualified solenoid-operated ball valve, which is normally closed. To ensure isolation capability, an explosive shear valve is installed in each line. Upon receipt of a signal (manually initiated by the operator) this explosive valve will shear the TIP cable and seal the guide tube.

When the TIP system is inserted, the ball valve of the selected tube opens automatically so that the probe and cable may advance. A maximum of five valves may be opened at any one time to conduct calibration and any one guide tube is used, at most, a few hours per year.

If closure of the line is required during calibration, a signal causes a cable to be retracted and the ball valve to close automatically after completion of cable withdrawal. If a TIP cable fails to withdraw or a ball valve fails to close, the explosive shear valve is actuated. The ball valve position is indicated in the control room.

The ball valve and shear valve are located outside the drywell and as close as practical to the containment. These valves are designed to Code Group B requirements, therefore they are of the same quality class as the containment.

6.2.4.3.2.2.4 Conclusion on Criterion 56. 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 in accordance with Criterion 56 or other defined bases.

In addition to meeting the above isolation requirements, the pressure retaining components of most of these systems are designed to the same quality standards as the containment. For exceptions, see Section 6.2.4.3.2.4.

6.2.4.3.2.3 Evaluation Against Criterion 57. Lines forming a closed system inside the primary reactor containment must have one isolation valve outside if the system boundary penetrates the containment. Columbia Generating Station does not have any systems qualifying under this criterion.

6.2.4.3.2.4 Evaluation Against Regulatory Guide 1.11, Revision 0. Instrument lines which penetrate the containment from the RCPB are equipped with a restricting orifice located inside the drywell and an excess flow check (EFC) valve located outside and as close as practicable to the containment. Those instrument lines which do not connect to the RCPB are equipped with single solenoid-operated or EFC isolation check valves. Valve position indication is available in the control room.

The EFC valves have no active safety function requirements. However, the RCPB instrument line EFC valves close to limit the flow in the respective instrument lines in the event of an instrument line break downstream of the EFC valve outside containment. The instrument lines are Seismic Category I and are assumed to maintain integrity for all accidents except for the instrument line break accident (ILBA) as described in Section 15.6.2. Isolation of the instrument line by the EFC valve is not credited for mitigating the ILBA.

Each EFC valve has an integral manual bypass valve which may be used to reset an actuated disc. The bypass valves are periodically verified to be closed.

The hydrogen/oxygen monitoring lines penetrate primary containment and are used to continuously monitor the containment air during the post-LOCA accident period. These lines are equipped with single solenoid-operated or EFC valves located outside and as close as possible to the containment. Containment isolation requirements are met on the basis that these are low pressure lines constructed to the same quality standards as the containment. The solenoid-operated valves are required to remain open during normal operation and postaccident for those DBAs for which containment isolation is required to limit offsite dose consequences to less than established requirements. Accordingly, they receive no automatic isolation signal or leak rate testing. No credit is taken for either the automatic or remote manual closing of these valves for containment isolation for the DBAs. Therefore, position indication requirements do not apply to the solenoid-operated valves.

6.2.4.3.3 Failure Mode and Effects Analyses

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

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

6.2.4.3.4 Operator Actions

A trip of an isolation control system channel is annunciated in the main control room. Most motor-operated and air-operated isolation valves have open-close status lights. The following general information is presented to the operator by the isolation system:

a. Annunciation of each process variable which has reached a trip point,

b. Computer readout of trips on main steam line tunnel temperature or main steam line excess flow,

c. Control power failure annunciation for each channel, and

d. Annunciation of steam leaks in each of the systems monitored (main steam, reactor water cleanup, and reactor heat removal).

If the primary containment and reactor vessel isolation system does not automatically shut an isolation valve, the "isolation signal" column of Table 6.2-16 references the applicable note which discusses the isolation criteria including operator action based on specific input available to the operator.

This information will enable the operator to determine the need to operate a remote manual valve in the event of a LOCA.

6.2.4.4 Tests and Inspections

The containment isolation system is periodically tested during reactor operation and shutdown. The functional capabilities of power operated isolation valves are tested remote manually from the main control room. By observing position indicators and/or 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. Table 6.2-16 lists the process line isolation valves.

The EFC valves used as single reactor instrument sensor line isolation valves are periodically tested to meet the requirements of Regulatory Guide 1.11 and the Technical Specifications Surveillance Requirements. As these valves are outside the containment and accessible, periodic visual inspection is performed in addition to the operational check. Sensor lines emanating from the suppression pool, the suppression chamber, or the drywell free volume are periodically tested on a sampling basis in accordance with the plant maintenance program.

Preoperational testing is discussed in Section 14.2.12. Containment isolation valve leakage rate testing is discussed in the notes in Figures 6.2-36 through 6.2-59.

6.2.5 COMBUSTIBLE GAS CONTROL IN CONTAINMENT

Combustible gas control is provided to ensure containment integrity when hydrogen and oxygen gases are generated following a postulated LOCA. The RHR system operating in containment spray mode and redundant reactor head area return fans augment the natural processes to mix the containment atmosphere. The oxygen and hydrogen concentrations in the containment atmosphere are monitored by instrumentation discussed in Section 7.5.1.5. To supplement the combustible gas control system, the containment nitrogen inerting system provides a nitrogen atmosphere in primary containment.

6.2.5.1 Design Bases

The design bases for the containment atmosphere control system are as follows:

a. The system is designed in accordance with 10 CFR 50.44;

b. Primary containment will be inerted to an oxygen concentration of less than or equal to 3.5% by volume during normal plant operation;

c. Containment sprays, natural turbulence resulting from diffusion and convection caused by the elevated temperatures, and operation of the containment head area return fans, if necessary, ensure that no local pocket with greater than 5% oxygen can occur within containment;

6.2.5.2 System Design

The system consists of the following:

a. An atmosphere mixing system which could operate if necessary to ensure a well mixed atmosphere in both the drywell and suppression chamber. This system consists of the containment spray system which can be actuated approximately 10 minutes after the postulated LOCA, and containment head area return fans which start on receipt of a reactor scram signal;

b. A monitoring system measures the concentration of hydrogen and oxygen in the drywell and suppression chamber atmosphere; and

c. Two hydrogen-oxygen recombiners are deactivated and isolated from primary containment. Attached piping and components are similarly deactivated, retaining solely their structural continuity with the containment penetrations. The recombiners are Seismic Category I.

6.2.5.2.1 Atmosphere Mixing System

The function of the atmosphere mixing system is to provide a well mixed atmosphere in the drywell and suppression chamber.

Using experimental results (Reference 6.2-18) as a basis for hydrogen and oxygen mixing within the containment, hydrogen or oxygen distribution in the steam nitrogen-oxygen atmosphere would simulate that of the iodine fission products (References 6.2-19 and 6.2-20) and it would be uniform throughout the containment. Accordingly, it is extremely unlikely that an atmosphere mixing system would be required.

However, the RHR system operating in containment spray mode and redundant reactor head area return fans are available to augment these natural processes.

The RHR system containment spray system is described in Section 5.4.7. It may be manually actuated from the main control room to provide mechanical mixing of the drywell atmosphere.

The two head area return fans are part of the primary containment cooling system, discussed in Section 9.4.11.2.

The redundant reactor head area return fans are available to exhaust atmospheric gases and vapors from the reactor head area above the refueling bulkhead plate to the main portion of the drywell. Both fans start automatically upon reactor scram and are powered from different Class 1E electrical divisions. Atmospheric gases and vapors exhausted from the reactor head area by the fan(s) are replaced by flow from the drywell area through the two vent paths through the bulkhead plate as portrayed in Figure 6.2-24. This recirculation prevents formation of pockets of combustible gases both in the reactor head area and in the drywell below the bulkhead plate.

6.2.5.2.2 Hydrogen and Oxygen Concentration Monitoring System

Both the oxygen and the hydrogen concentrations are continuously monitored during normal operation and following the postulated LOCA, and are displayed in the control room. A visual and audible alarm initiates in the control room if the oxygen concentration reaches 3.5% by volume. This alarm alerts operators to take action to limit the pre-LOCA oxygen concentration to 3.5% or less to ensure that post-LOCA oxygen concentrations will not exceed the limit of 4.8%. If oxygen concentration approaches 4.4% by volume, a visual and audible high-high level alarm initiates in the control room.

The hydrogen and oxygen gas analyzers, number and location of sampling points, and instrumentation are discussed in Section 7.5.1.5.

Calibration tests are routinely performed to calibrate and verify instrument accuracy against known gas compositions.

Two redundant hydrogen and oxygen concentration monitoring systems are provided.

6.2.5.2.3 Containment Purge

Containment purge is discussed in Section 6.2.1.1.8.

6.2.5.3 Design Evaluation

The determination of the time-dependent oxygen and hydrogen concentrations in the drywell and suppression chamber atmospheres is based on a two-region model of the primary containment: a drywell and suppression chamber atmosphere. The rate of radiolytic hydrogen and oxygen generation varies linearly with power.

The released fission products, excluding noble gases, that are mixed with the coolant are assumed to be swept out of core as the core cooling waters exit the break and flow by gravity by means of the downcomers to the suppression chamber.

Hydrogen generated from the metal-water reaction and both hydrogen and oxygen generated from core radiolysis are assumed released to the drywell atmosphere and mix homogeneously. Hydrogen as well as oxygen generated from suppression pool radiolysis are assumed released to the suppression chamber atmosphere and mix homogeneously.

The hydrogen and oxygen monitors are accurate at the anticipated concentration in the primary containment.

6.2.5.3.1 Hydrogen and Oxygen Generation

In the period immediately after the postulated LOCA, hydrogen can be generated by radiolysis, metal-water, and metallic paint-water reactions. However, in evaluating short-term hydrogen generation, the contribution from radiolysis and metallic paint-water reactions are insignificant in comparison with the hydrogen generated by the metal-water reaction.

During the same time period oxygen is generated by radiolysis only. However, the contribution from radiolysis is small compared with the initial 3.5% oxygen concentration within containment prior to the postulated LOCA.

The generation of hydrogen by metal-water reaction is dependent on the temperature of the cladding at the time the postulated LOCA occurs. Based on LOCA calculations and ECCS performance in accordance with 10 CFR 50.46, the extent of metal-water reaction in the BWR/5 core is negligible. The design of the BWR/5 ECCS is such that the peak Zircaloy clad temperature is 2000°F. At this temperature virtually no metal-water reaction occurs and, therefore, hydrogen production by this means is insignificant.

6.2.5.4 Testing and Inspections

The RHR drywell spray mode of operation is tested in accordance with Technical Specifications. The head area return fan testing is discussed in Section 9.4.11.4. Testing of the hydrogen and oxygen monitoring is discussed in Section 7.5.1.5.4.

6.2.5.5 Instrumentation Requirements

See Sections 7.5.1.5.4 and 9.4.11.5.

6.2.5.6 Materials

See Section 6.2.5.2.

6.2.5.7 Containment Nitrogen Inerting System

The system is designed to establish and maintain a nitrogen atmosphere in which the oxygen concentration can be controlled at less than 3.5% by volume in both the drywell and suppression pool during normal operation. The system is designed to comply with NRC staff position of April 2, 1981, requiring that "the GE pressure suppression containment systems identified by Mark I and Mark II, be inerted."

6.2.6 CONTAINMENT LEAKAGE TESTING

General Design Criteria 52, 53, and 54 have been met.

6.2.6.1 Containment Leakage Rate Tests

The primary containment system is a steel pressure suppression system of the over and under configuration with a designed leakage rate of 0.5% by volume per day at 45 psig. A maximum allowable integrated vessel leak rate of 0.5% by weight per day at 38 psig has been established to limit leakage during and following the postulated DBA to less than that which would result in offsite doses greater than those specified in 10 CFR 50.67. Leakage rate tests at reduced pressures may be established such that the measured leakage rate does not exceed the maximum allowable at that reduced pressure.

A structural integrity test involving pneumatic pressurization of the drywell and suppression chamber was performed at 51.8 psig, 1.15 times the containment vessel design pressure of 45 psig. This test was conducted in accordance with the ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition through the Summer 1972 Addenda, Subarticle NE-6300. See Section 3.8.2.7 for a description of the test.

Testing involves performing periodic Type A, B, and C tests. These tests are conducted in accordance with the Technical Specifications and 10 CFR 50, Appendix J. Table 6.2-14 lists the containment penetrations subject to Type B tests. Table 6.2-16 lists the primary containment isolation valves subject to Type C tests unless otherwise noted.

6.2.6.2 Special Testing Requirements

The secondary containment is tested at each refueling outage to ensure the maximum allowable leakage rate of 100% of secondary containment free volume per day at negative 0.25-in. water gauge pressure with respect to outside atmospheric pressure. Further testing is summarized in Section 6.2.3.4. Other testing requirements are contained in the Technical Specifications.

6.2.7 REFERENCES

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Table 6.2-1

Containment Design Parameters

			Drywell	Suppression Chamber
A.	Drywell and Suppression Chamber			
	1.	Internal design pressure, psig	45	45
	2.	External design pressure, psig	2	2
	3.	Drywell deck design differential pressure, psid	25 (downward) 6.4 (upward)	
	4.	Design temperature, °F	340	275
	5.	Net free volume, ft^3 (drywell includes vents)	200,540	144,184 maximum
	6.	Maximum allowable leak rate, %/day	0.5	0.5
	7.	Suppression chamber free volume, minimum, ft^3		142,500
	8.	Suppression chamber water volume minimum,[a] ft^3		112,197
	9.	Pool cross section area, ft^2		5,770
	10.	Pool free surface cross section area, ft^2		4,520
	11.	Pool depth (normal), ft		31
B.	Vent System			
	1.	Number of downcomers		99
	2.	Downcomer inside diameter, ft		1.9375
	3.	Total vent area, ft^2		309
	4.	Downcomer maximum submergence, ft		12
	5.	Downcomer loss factor		2.77

[a] This volume does not include the water within the pedestal (10,065 ft^3) nor the water 12 ft below the downcomer exits (15,000 ft^3)

Table 6.2-2

Engineered Safety Systems Information
for Containment Response Analyses

	Full Capacity	Value Used in Containment Analysis Case A	Case B	Case C
A. Drywell Spray System				
1. Number of pumps	2	2	1	N/A
2. Number of lines	2	2	1	N/A
3. Number of headers/line	1	1	1	N/A
4. Spray flow rate, gpm/pump	7450	6713[b,d]	6713[b]	N/A
5. Spray thermal efficiency, %	100	100	100	N/A
B. Suppression Pool Spray				
1. Number of pumps	2	2	1	N/A
2. Number of lines	2	2	1	N/A
3. Number of headers/line	1	1	1	N/A
4. Spray flow rate, gpm/pump	450	353[b]	353[b]	N/A
5. Spray thermal efficiency, %	100	100	100	N/A
C. Containment Cooling System				
1. Number of pumps	2	2	1	1[a]
2. Pump capacity, gpm/pump	7900	7067[b]	7067[b]	7067[b]
3. Heat Exchangers RHR system-inverted U-tube, single pass shell, multi-pass tubes, vertical mounting				
a. Number	2	2	1	1[a]
b. Heat transfer area, ft^2/Unit	7641	7641	7641	7641
c. Overall heat transfer coefficient, Btu/hr ft^2 °F	195(fouled) 400(clean)	195	195	195
d. Standby service water flow rate per exchanger, gpm	7400	7400	7400	N/A
e. RHR heat exchanger K value Btu/sec-°F	414(fouled) 849(clean)	N/A	N/A	289
f. Design service water temperature minimum, °F maximum, °F	32°F 85°F	95[b]	95[b]	90
g. Containment heat removal capability per loop, using 85°F service water and 165°F pool temperature; Btu/hr			83.23×10^6	

Table 6.2-2

Engineered Safety Systems Information
for Containment Response Analyses (Continued)

	Full Capacity	Used in Containment Analysis Value		
		Case A	Case B	Case C
D. ECCS Systems				
1. High pressure core spray (HPCS)				
a. Number of pumps	1	1	1	1[a]
b. Number of lines	1	1	1	1[a]
c. Flow rate, gpm	6250	6250	6250	6250[a]
2. Low pressure core spray (LPCS)				
a. Number of pumps	1	1	0	0[a]
b. Number of lines	1	1	0	0[a]
c. Flow rate, gpm	6250	6250	0	0[a]
3. Low-pressure coolant injection (LPCI)				
a. Number of pumps	3	1[e]	1	1[a]
b. Number of lines	3	1[e]	1	1[a]
c. Flow rate, gpm 1 pump	7450[c]	7067[b]	7067[b]	7067[a,b]
4. Residual heat removal (RHR)				
a. Pump flow rate: shell side	7450	0	0	0
tube-side	7400	0	0	0
b. Source of cooling water		Standby service water		
E. Automatic Depressurization System				
1. Total number of safety/relief valves	18[a]			
2. Number actuated on ADS	7[a]			

[a] No change due to uprate.
[b] Represents conservative value used in analysis.
[c] Increase to 7900 gpm with zero differential pressure between RPV and wetwell.
[d] Only 2 of 3 LPCI pumps available for spray, and only after 600 seconds.
[e] Three LPCI pumps available; 2 pumps directed to drywell sprays after 600 seconds, with third pump continuing in LPCI mode.

Table 6.2-3

Accident Assumptions and Initial
Conditions for Recirculation Line Break

A. Effective accident break area (total), ft^2	3.106[a]
B. Components of effective break area:	
1. Recirculation line suction nozzle area, ft^2	2.508[a]
2. RWCU cross tie line ft^2	0.078[a]
3. Jet pump nozzles, ft^2	0.520[a]
C. Break area/vent area ratio	0.0105[a]
D. Primary system energy distribution[b]	
1. Steam and liquid energy, 10^6 Btu	414/361[d]
2. Sensible energy, 10^6 Btu	
a. Reactor vessel	106.1/220[d]
b. Reactor internals (less core)	58.6[e]
c. Primary system piping	34.6[e]
d. Fuel	(c)
E. Assumptions used in pressure transient analysis	
1. Feedwater flow coastdown time	39.6
2. MSIV closure time (sec)	3.5
3. Scram time (sec)	< 1[a]
4. Liquid carryover, %	100[a]
5. Turbine throttle valve closure (sec)	0.2

[a] No change due to uprate.
[b] All energy values except fuel are based on a 32°F datum.
[c] Fuel energy is based on a 285°F datum.
[d] Original rated power/uprated power analysis.
[e] Reactor vessel sensible energy includes reactor internals (less core) and primary system piping.

Table 6.2-4

Initial Conditions Employed
in Containment Response Analyses

	Original Rated Power Cases	Uprated Power
A. Reactor coolant system (at 105% of rated steam flow and at normal liquid levels)		
1. Reactor power level, MWt	3462	3702
2. Average coolant pressure, psig	1020	1020
Peak coolant pressure, psia	1055	1055
3. Average coolant temperature, °F	547	551
4. Mass of reactor coolant system liquid, lb	676,700	634,300
5. Mass of reactor coolant system steam, lb	24,900	24,740
6. Volume of water in vessel,[a] ft^3	12,743	13,282
7. Volume of steam in vessel,[b] ft^3	10,167	10,397
8. Volume of water in recirculation loops, ft^3	670	(a)
9a. Volume of water in feedwater line,[c] ft^3	543	
9b. Mass of water in feedwater line, lb		693,034
10. Volume of water in miscellaneous lines,[c] ft^3	121	(a)
11. Total reactor coolant volume, ft^3	23,580	23,679
12. Stored water		
a. Condensate storage tanks, gal (min)	135,000	N/A
b. Fuel storage pool, gal	350,000	N/A

Table 6.2-4

Initial Conditions Employed
in Containment Response Analyses (Continued)

	Original Rated Power Cases	Uprated Power
	Drywell/Suppression Chamber	Drywell/Suppression Chamber
B. Containment		
1. Pressure, psig	0.7/0.7	2.0/2.0
2. Inside temperature, °F	135/90	135/90[d]
3. Outside temperature, °F	NA/NA	NA/NA
4. Relative humidity, %	50/100	50/100
5. Service water temperature, °F	95/95	90/90
6. Water volume, ft^3	NA/107,850	NA/107,850
7. Vent submergence, ft	NA/12	NA/12

[a] Item 6 includes items 8 and 10.
[b] Item 7 includes the main steam lines up to the inboard MSIV.
[c] Up to inboard isolation valve.
[d] Analysis was performed assuming an initial wetwell air space temperature of 150°F and suppression pool temperature of 90°F.

Table 6.2-5

Summary of Accident Results for
Containment Response to Limiting Line Breaks

	Original Rated Power		Uprated Power
Accident Parameters	Recirculation Line Break[a]	Steam Line Break[b]	Recirculation Line Break
1. Peak drywell pressure, psig	34.69	34.0	37.4[c,d]
2. Peak drywell diaphragm floor differential pressure, psid	19.39	19.1	21.7
3. Time (S) of Peak Pressures, Sec.	19.0	12.0	11.9
4. Peak drywell temperature, °F	280.2	328	283[c]
5. Peak suppression chamber pressure, psig	27.3		31.3
6. Time of peak suppression chamber pressure, sec.	55	55	139
7. Peak suppression pool temperature during blowdown, °F (~100 sec.)	140	140	146
8. Peak suppression pool temperature, long term, °F	220	220	$\boxed{204.5}$
9. Calculated drywell margin, %[e]	22.9	24.5	16.9
10. Calculated suppression chamber margin, %[e]	38.6	38.0	30.4
11. Calculated deck differential pressure margin, %	22.44	23.6	13.2
12. Energy released to containment at time of peak pressure, 10^6 Btu	260	204	174
13. Energy absorbed by passive heat sinks at time of peak pressure, 10^6 Btu	0	0	0

[a] See Figures 6.2-3 and 6.2-7 for plots of pressures versus time and Figures 6.2-4 and 6.2-9 for plots of temperature versus time.

[b] See Figures 6.2-15 and 6.2-16 for plots of pressure and temperature versus time respectively.

[c] For initial containment pressure of 2.0 psig.

[d] The value of P_a to be used for 10 CFR 50 Appendix J testing was conservatively chosen to be 38 psig.

[e] $\frac{\text{(Design Pressure - Maximum Calculated Pressure)}}{\text{Design Pressure}}$

Table 6.2-6

Loss-of-Coolant Accident Long-Term
Primary Containment Response Summary

	Case	LPCI and LPCS Pumps	Service Water Pumps	Containment Spray (gal/min)	HPCS (gal/min)	LPCI and LPCS (gal/min)	Peak Pool Temp (°F)	Secondary Peak Pressure (psig)
A	Original rated power 3462 MWt							
	Before 600 seconds	3/1	3	0	6250	21,200/6250	180	7.3
	After 600 seconds	3/1	3	14,134	6250	7067/6250		
B	Original rated power 3462 MWt							
	Before 600 seconds	2/0	2	0	6250	14,134/0	220	13.5
	After 600 seconds	1/0	2	7067	6250	7067/0		
C	Original rated power 3462 MWt							
	Before 600 seconds	2/0	2	0	6250	14,134/0	220	18.3
	After 600 seconds	1/0	2	0	6250	7067/0		
C	Uprated power 3702 MWt							
	Before 600 seconds	2/0	2	0	6250	14,134/0	204.5	14.3
	After 600 seconds	1/0	2	0	6250	7067/0		

Table 6.2-7

Energy Balance for Design Basis
Recirculation Line Break Accident

		Prior to DBA (0 sec)	Time of Peak Pressure Difference Across Drywell Deck	End of Blowdown	Time of Peak [a] Containment Pressure	Unit
1)	Reactor coolant (vessel & pipe inventory)	414.0×10^6	400×10^6	12.2×10^6	$49.4 \times 10^6/44.8 \times 10^6$	Btu
2)	Fuel and cladding					
	Fuel	34.5×10^6	32.3×10^6	12.3×10^6	$4.42 \times 10^6/4.0 \times 10^6$	Btu
	Cladding	3.05×10^6	3.05×10^6	2.99×10^6	$1.07 \times 10^6/0.972 \times 10^6$	Btu
3)	Core internals, also reactor coolant piping, pumps, and valves	91.2×10^6	91.2×10^6	91.2×10^6	$34.0 \times 10^6/57.4 \times 10^6$	Btu
4)	Reactor vessel metal	107×10^6	107×10^6	107×10^6	$40 \times 10^6/66.6 \times 10^6$	Btu
5)	Reactor coolant piping, pumps, and valves	Included in item 3				
6)	Blowdown enthalpy	NA	551	NA	NA	Btu/lbm
7)	Decay heat	0	0.463×10^6	8.8×10^6	$1020 \times 10^6/222 \times 10^6$	Btu
8)	Metal-water reaction heat	0	0	0.01×10^6	$0.471 \times 10^6/0.471 \times 10^6$	Btu
9)	Drywell structures	0	0	0	0	
10)	Drywell air	1.3×10^6	1.6×10^6	0	$1.61 \times 10^6/1.41 \times 10^6$	
11)	Drywell steam	0.759×10^6	7.75×10^6	24.8×10^6	$8.43 \times 10^6/6.06 \times 10^6$	
12)	Containment air	0.951×10^6	0.951×10^6	2.35×10^6	$1.13 \times 10^6/1.24 \times 10^6$	
13)	Containment steam	0.365×10^6	0.365×10^6	1.18×10^6	$6.04 \times 10^6/2.9 \times 10^6$	
14)	Suppression pool water	639×10^6	629×10^6	1040×10^6	$1450 \times 10^6/1200 \times 10^6$	
15)	Heat transferred by heat exchangers	0	0	0	$818 \times 10^6/289 \times 10^6$	

[a] Values given are for minimum ECCS available and for all ECCS available. The information presented in this table is based on the original design basis conditions and represents the general characteristics of the recirculation line break analysis results.

Table 6.2-8

Accident Chronology Design Basis
Recirculation Line Break Accident

	Minimum ECCS Time (sec)	
	Original Rated Power	Uprated Power
1. Vents cleared	0.776	0.709
2. Drywell reaches peak pressure	19.08	11.9
3. Maximum positive differential pressure occurs	0.749	0.600
4. ECCS initiation sequence completed	30	30
5. End of blowdown	53.24	131
6. Vessel reflooded	160	153
7. Introduction of RHR heat exchanger	600	600
8. Containment reaches peak secondary pressure	29,463	25,382

Table 6.2-9a

Reactor Blowdown Data for Recirculation Line Break

Original Rated Power

Time (sec)	Steam Flow (lb/sec)	Liquid Flow (lb/sec)	Steam Enthalpy (Btu/lb)	Liquid Enthalpy (Btu/lb)
0	0	25,690	----	550.73
10.33	0	26,020	----	555.9
19.08	0	25,570	----	548.79
19.12	3679	13,320	1190	550
25.33	3213	8,493	1200.6	502
32.02	2420	4,974	1205.4	446.68
39.05	1494	2,423	1203.13	396.1
45.02	729.2	2,003	1193.79	325.16
53.37	0	0	----	----

Table 6.2-9b

Reactor Blowdown Data for Recirculation Line Break

Uprated Power

Time (sec)	Pressure (psia)[a]	Liquid Flow (lbm)	Steam Flow (lbm)
1.01	1018	3.246E+04	0
5.04	1027	2.625E+04	0
10.23	1039	2.485E+04	31.07
15.04	919	1.161E+04	3112
20.04	774.3	1.180E+04	2404
25.04	641.1	1.076E+04	1985
30.04	533.1	8.849E+03	1759
34.42	433.9	7.179E+03	1559
49.76	205.4	1.162E+04	0
62.26	147.0	9708	0
71.63	122.0	8858	0
81.01	105.6	8306	0
90.38	88.42	7560	0
102.88	71.76	6752	0
112.26	62.71	6369	0
121.63	50.97	5976	0
131.01	42.81	741.6	0

[a] Containment codes assume saturated conditions in vessel.

Table 6.2-10

Reactor Blowdown Data for Main Steam Line Break

Time (sec)	Steam Flow (lb/sec)	Liquid Flow (lb/sec)	Steam Enthalpy (Btu/lb)	Liquid Enthalpy (Btu/lb)
0	8646	0	1190.16	----
4.3	1308	27,480	1190.45	549.66
10.43	2084	24,220	1192.72	540.93
20.43	2843	15,730	1201.0	499.0
30.12	2380	7386	1205.6	432.78
40.21	1110	2734	1197.45	344.32
54.65	0	0	----	----

Table 6.2-11

Core Decay Heat Following Loss-of-Coolant Accident
for Containment Analyses

Time (sec)	Original Rated Power Normalized Core Heat[a]	Uprated Power Normalized Core Heat[b]
0.0	1.0	1.0029
0.9	0.9330	0.7053
2.1	0.7662	0.5468
5.0	0.5005	0.5533
6.93	0.3850	0.4975
9.03	0.2955	0.4119
15.93	0.1491	0.2182
30.0	0.0471	0.07730
10^2	0.0381	0.03436
10^3	0.0223	0.01956
10^4	0.0119	0.01012
10^5	0.00668	0.00546
10^6	0.00267	
3×10^6	0.00190	

[a] A normalized power level of 3462 MWt was used for analyses of original rated power and includes fuel relaxation energy.

[b] A normalized power level of 3702 MWt was used for analyses at uprated power. Uprated power case includes metal water reaction and fuel relaxation energy.

Table 6.2-12

Secondary Containment Design and Performance Data

I. Secondary Containment Design

A. Free volume:

3.5×10^6 ft^3; the entire secondary containment is considered as one volume.

B. Pressure

1. Normal operation:

Vacuum greater than or equal to 0.25 in. of vacuum water gauge as indicated at the reactor building el. 572 ft

2. Postaccident:

Vacuum greater than or equal to 0.25 in. of vacuum water gauge on all building surfaces

C. Infiltration rate during postaccident period:

100% of free volume in a 24-hr period.

D. Exhaust fans (SGT system):

Two independent and redundant filter trains each with two full capacity exhaust fans (see Section 6.5.1)

E. The secondary containment model after a design basis LOCA is discussed in Section 6.2.3.3.1.

Table 6.2-14

Containment Penetrations Subject to Type B Tests

Penetration Number	Type Service	Comments
I. Electrical Penetrations		
X-100 A, B, C, and D	Neutron monitoring	Electrical penetrations are provided with double seals and are separately testable. The test taps and seals are located such that tests of the primary can be conducted without entry into or pressurization of containment
X-101 A, B, C, and D	Control rod position indicator	
X-102 A and B	Thermocouple and RTD	
X-103 A, B, C, and D	Medium voltage power	
X-104 A, B, C, and D	Low voltage power	
X-105 A, B, C, and D	Control and indication	
X-106 C and D	neutron monitoring	
X-107 A and B	Low voltage power control and indication	
II. Personnel And Equipment Access Penetrations		
X-15	Equipment hatch	Separately testable without pressurization of the primary containment.
X-16	Personnel access lock	
X-28	CRD removal hatch	
X-51	Suppression chamber access hatch	
X-1A through 1H	Inspection ports	
X27-A through 27F	TIP drive flanges	
N/A	Drywell head	
X-23	EDR-V-18	Inboard flange
X-24	FDR-V-15	Inboard flange
X-77Aa	RRC-V-19	Inboard & outboard flanges
	RRC-V-20	Inboard flange
X-77Ac	PSR-V-X77A/1	Inboard & outboard flanges
	PSR-V-X77A/2	Inboard flange
X-77Ad	PSR-V-X77A/3	Inboard & outboard flanges
	PSR-V-X77A/4	Inboard flange

Table 6.2-16

Primary Containment Isolation Valves

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
CRD 185 insert lines	9	4.6-5	55	B	--	--	--	--	--		--	--	--	--	--	--	--	--	--	--	--	--	Yes	5	4, 48a
CRD 185 withdrawal lines	10	4.6-5	55	B	--	--	--	--	--		--	--	--	--	--	--	--	--	--	--	--	--	Yes	5	4, 48a
Air line for maintenance	93	6.2-55	56	B	--	Pipe cap	I	--	--	--	--	--	O/C	LC	--	2	--	--	No	A	Cap	SB	No	5	54
All inst lines from pri cont	--	--	56	B	--	EF check	O	Spring	EF			O	O	O	--	1/1.5	--	--	--	--	Vlv	RB	No	5	53
All inst lines from pri cont	--	--	56	B	--	Globe	O	Manual	Manual	--	--	O	O	O	--	1/1.5	--	--	--	--	Vlv	RB	No	5	
All inst lines from RPV	--	--	55	A	--	EF check	O	Spring	EF	--	--	O	O	O	--	.75/1	--	--	--	--	Vlv	RB	No	5	27
All inst lines from RPV	--	--	55	A	--	Globe	O	Manual	Manual	--	--	O	O	O	--	.75/1	--	--	--	--	Vlv	--	No	5	
Deacon soltn return header	95	6.2-59	56	B	--	Pipe cap	O	--	--	--	--	C	C	C	--	.75	--	--	No	W	Cap	RB	No	4	
Deacon soltn supply header	94	6.2-59	56	B	--	Pipe cap	O	--	--	--	--	C	C	C	--	.75	--	--	No	W	Cap	RB	No	4	
Air line WW-DW vac RVs	82e	6.2-41	56	B	CAS-V-730	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	5	No	A	Vlv	RB	No	5	44, 54
Air line WW-DW vac RVs	82e	6.2-53	56	B	CAS-VX-82e	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	--	No	A	Vlv	RB	No	5	44, 54
DW vent ex	3	6.2-45	56	B	CEP-V-1A	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	30	4	12	No	A	Vlv	RB	No	2	56
DW vent ex	3	6.2-45	56	B	CEP-V-1B	AO globe	O	Air	Spring	F,A,Z	RM	C	C	C	C	2	4	12	No	A	Vlv	RB	No	5	56
DW vent ex	3	6.2-45	56	B	CEP-V-2A	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	30	4	8	No	A	Vlv	RB	No	2	56
DW vent ex	3	6.2-45	56	B	CEP-V-2B	AO globe	O	Air	Spring	F,A,Z	RM	C	C	C	C	2	4	8	No	A	Vlv	RB	No	5	56
WW vent ex	67	6.2-45	56	B	CEP-V-3A	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	24	4	12	Yes	A	Vlv	RB	No	2	56
RB to WW vac bkrs	67	6.2-45	56	B	CEP-V-3B	AO globe	O	Air	Spring	F,A,Z	RM	C	C	C	C	2	4	12	No	A	Vlv	RB	No	5	56
WW vent ex	67	6.2-45	56	B	CEP-V-4A	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	24	4	10	No	A	Vlv	RB	No	2	56
RB to WW vac bkrs	67	6.2-45	56	B	CEP-V-4B	AO globe	O	Air	Spring	F,A,Z	RM	C	C	C	C	2	4	10	No	A	Vlv	RB	No	5	56
CIA for SRV accum	56	6.2-38	56	B	CIA-V-20	MO globe	I	ac	ac	41	RM	O	O	O	As is	.75	No	10	No	A	Vlv	RB	Yes	5	56, 52
CIA for SRV accum	56	6.2-38	56	B	CIA-V-21	Check	I	Process	Process	--	--	C	C	C	--	.75			No	A	Vlv	RB	Yes	5	52
CIA line A for ADS accum	89B	6.2-38	56	B	CIA-V-30A	MO globe	I	ac	ac	42	RM	O	O	O	As is	.5	No	15	No	A	Vlv	RB	No	5	56

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
CIA line B for ADS accum	91	6.2-38	56	B	CIA-V-30B	MO globe	I	ac	ac	42	RM	O	O	O	As is	.5	No	15	No	A	Vlv	RB	No	5	56
CIA line A for ADS accum	89B	6.2-38	56	B	CIA-V-31A	Check	I	Process	Process	--	--	C	C	C	--	.5	--	--	No	A	Vlv	RB	No	5	
CIA line B for ADS accum	91	6.2-38	56	B	CIA-V-31B	Check	I	Process	Process	--	--	C	C	C	--	.5	--	--	No	A	Vlv	RB	No	5	
DW vent supply	53	6.2-37	56	B	CSP-V-1	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	30	4	4	No	A	Vlv	RB	Yes	2	56, 52
RB to WW vac bkrs	119	6.2-52	56	B	CSP-V-10	PC check	O	Process	Process	--	RM	C	C	C	--	24	--	4	Yes	A	Vlv	RB	No	3	26, 56
DW vent supply	53	6.2-37	56	B	CSP-V-2	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	30	4	1	No	A	Vlv	RB	Yes	2	56, 52
WW vent supply	66	6.2-37	56	B	CSP-V-3	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	24	4	17	No	A	Vlv	RB	Yes	2	56, 52
WW vent supply	66	6.2-37	56	B	CSP-V-4	AO butfy	O	Air	Spring	F,A,Z	RM	C	C	C	C	24	4	14	No	A	Vlv	RB	Yes	2	56, 52
RB to WW vac bkrs	66	6.2-52	56	B	CSP-V-5	AO butfy	O	Spring	Air	40	RM	C	C	C	O	24	No	7	Yes	A	Vlv	RB	No	C	56
RB to WW vac bkrs	67	6.2-45 6.2-52	56	B	CSP-V-6	AO butfy	O	Spring	Air	40	RM	C	C	C	O	24	No	9	Yes	A	Vlv	RB	No	C	56
RB to WW vac bkrs	66	6.2-52	56	B	CSP-V-7	PC check	O	Process	Process	--	RM	C	C	C	--	24	--	10	Yes	A	Vlv	RB	No	3	26, 56
RB to WW vac bkrs	67	6.2-45 6.2-52	56	B	CSP-V-8	PC check	O	Process	Process	--	RM	C	C	C	--	24	--	16	Yes	A	Vlv	RB	No	3	26, 56
RB to WW vac bkrs	119	6.2-52	56	B	CSP-V-9	AO butfy	O	Spring	Air	40	RM	C	C	C	O	24	No	1	Yes	A	Vlv	RB	No	C	56
RB to WW vac bkrs and vent supply	66	6.2-37	56	B	CSP-V-93	SO globe	O	ac	Spring	F,A,Z	RM	C	C	C	C	1	4	4	No	A	Vlv	RW	Yes	5	52, 56
DW vent supply	53	6.2-37	56	B	CSP-V-96	SO globe	O	ac	Spring	F,A,Z	RM	C	C	C	C	1	4	3	No	A	Vlv	RW	Yes	5	52, 56
DW vent supply	53	6.2-37	56	B	CSP-V-97	SO globe	O	ac	Spring	F,A,Z	RM	C	C	C	C	1	4	5	No	A	Vlv	RB	Yes	5	52, 56
RB to WW vac bkrs and vent supply	66	6.2-37	56	B	CSP-V-98	SO globe	O	ac	Spring	F,A,Z	RM	C	C	C	C	1	4	6	No	A	Vlv	RB	Yes	5	52, 56
DW service line	92	6.2-47	56	B	DW-V-156	Gate	O	Manual	Manual	--	--	LC	LC	LC	--	2	--	5	No	W	Vlv	SB	Yes	5	
DW service line	92	6.2-47	56	B	DW-V-157	Gate	I	Manual	Manual	--	--	LC	LC	LC	--	2	--	--	No	W	Vlv	SB	Yes	5	
Drywell equip drain	23	6.2-39	56	B	EDR-V-19	AO gate	O	Air	Spring	F,A	RM	O	O	C	C	3	Std	2	No	W	Vlv	RB	No	2	56
Drywell equip drain	23	6.2-39	56	B	EDR-V-20	AO gate	O	Air	Spring	F,A	RM	O	O	C	C	3	Std	4	No	W	Vlv	RB	No	2	56
Drywell floor drain	24	6.2-46	56	B	FDR-V-3	AO butfy	O	Air	Spring	F,A	RM	O	O	C	C	3	Std	2	No	W	Vlv	RB	No	2	56
Drywell floor drain	24	6.2-46	56	B	FDR-V-4	AO butfy	O	Air	Spring	F,A	RM	O	O	C	C	3	Std	3	No	W	Vlv	RB	No	2	56
SP pool cleanup return	101	6.2-50	56	B	FPC-V-149	MO gate	O	ac	ac	F,A	RM	C	C	C	As is	6	35	41	No	W	Vlv	RB	Yes	P	48a, 56
SP pool cleanup suction	100	6.2-44	56	B	FPC-V-153	MO gate	O	ac	ac	F,A	RM	C	C	C	As is	6	35	2	No	W	Vlv	RB	Yes	P	48a, 56

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
SP pool cleanup suction	100	6.2-44	56	B	FPC-V-154	MO gate	O	ac	ac	F,A	RM	C	C	C	As is	6	35	7	No	W	Vlv	RB	Yes	M	48a, 56
SP pool cleanup return	101	6.2-50	56	B	FPC-V-156	MO gate	O	ac	ac	F,A	RM	C	C	C	As is	6	35	3	No	W	Vlv	RB	Yes	M	56, 48a
HPCS suction relief	49	6.2-41	56	B	HPCS-RV-14	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	65	Yes	W	Vlv	RB	No	5	19, 18, 48a
HPCS discharge	49	6.2-41	56	B	HPCS-RV-35	Relief	O	pp	Spring	--	--	C	C	C	--	2	--	70	Yes	W	Vlv	RB	No	5	19, 18, 48a
HPCS min flow	49	6.2-41	56	B	HPCS-V-12	MO gate	O	ac	ac	38	RM	C	C	O/C	As is	4	20	53	Yes	W	Vlv	RB	No	H	56, 18, 66
HPCS suction from SP	31	6.2-49	56	B	HPCS-V-15	MO gate	O	ac	ac	46	Manual	C	C	O/C	As is	18	18	3	Yes	W	Vlv	RB	No	H	48a, 56, 18
HPCS test line	49	6.2-41	56	B	HPCS-V-23	MO globe	O	ac	ac	F,A	RM	C	C	C	As is	12	Std	6	Yes	W	Vlv	RB	No	H	56, 18, 66
HPCS to RPV	6	6.2-47	55	A	HPCS-V-4	MO gate	O	ac	ac	46	Manual	C	C	O/C	As is	12	17	9	Yes	W	Vlv	RB	No	C	56, 48b, 18
HPCS to RPV	6	6.2-47	55	A	HPCS-V-5	Check	I	Process	Process	--	--	C	C	O/C	--	12	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18
Air line for HPCS-V-5	78e	6.2-53	56	B	HPCS-V-65	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for HPCS-V-5	78e	6.2-53	56	B	HPCS-V-68	Globe	O	Manual	Manual		--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
LPCS min flow	63	6.2-41	56	B	LPCS-FCV-11	MO globe	O	ac	ac	38	RM	C	C	O/C	As is	3	No	87	Yes	W	Vlv	RB	No	N	56, 66, 18
LPCS discharge RV	63	6.2-41	56	B	LPCS-RV-18	Relief	O	pp	Spring	--	--	C	C	C	--	2	--	50	Yes	W	Vlv	RB	No	5	19, 18, 48a
LPCS suction RV	63	6.2-41	56	B	LPCS-RV-31	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	25	Yes	W	Vlv	RB	No	5	19, 18, 48a
LPCS pump suction	34	6.2-49	56	B	LPCS-V-1	MO gate	O	ac	ac	46	Manual	O	O	O/C	As is	24	No	2	Yes	W	Vlv	RB	No	L	48a, 56, 18
LPCS test line	63	6.2-41	56	B	LPCS-V-12	MO globe	O	ac	ac	F,V	RM	C	C	C	As is	12	Std	4	Yes	W	Vlv	RB	No	N	18, 56, 58, 66
LPCS to RPV	8	6.2-47	55	A	LPCS-V-5	MO gate	O	ac	ac	46	Manual	C	C	O/C	As is	12	27	22	Yes	W	Vlv	RB	No	C	56,48b, 18, 58
LPCS to RPV	8	6.2-47	55	A	LPCS-V-6	Check	I	Process	Process	--	--	C	C	O/C	--	12	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 58
Air line for LPCS-V-6	78d	6.2-53	56	B	LPCS-V-66	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for LPCS-V-6	78d	6.2-53	56	B	LPCS-V-67	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
MS lines drain inboard	22	6.2-41	55	A	MS-V-16	MO gate	I	ac	ac	V,G, D,P	RM	C	C	C	As is	3	25	--	No	S	Vlv	TB	Yes	M	52, 56, 15

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
MS lines drain outboard	22	6.2-41	55	A	MS-V-19	MO gate	O	dc	dc	V,G, D,P	RM	C	C	C	As is	3	25	6	No	S	Vlv	TB	Yes	N	52, 56, 15
MS line A inboard MSIV	18A	6.2-45	55	A	MS-V-22A	AO globe	I	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	--	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line B inboard MSIV	18B	6.2-45	55	A	MS-V-22B	AO globe	I	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	--	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line C inboard MSIV	18C	6.2-45	55	A	MS-V-22C	AO globe	I	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	--	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line D inboard MSIV	18D	6.2-45	55	A	MS-V-22D	AO globe	I	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	--	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line A outboard MSIV	18A	6.2-45	55	A	MS-V-28A	AO globe	O	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	4	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line B outboard MSIV	18B	6.2-45	55	A	MS-V-28B	AO globe	O	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	4	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line C outboard MSIV	18C	6.2-45	55	A	MS-V-28C	AO globe	O	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	4	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line D outboard MSIV	18D	6.2-45	55	A	MS-V-28D	AO globe	O	Air	Air/sp	V,G, D,P	RM	O	O/C	C	C	26	3-5	4	No	S	Vlv	TB	Yes	2	1, 15, 56, 63
MS line A drain isolation	18A	6.2-45	55	A	MS-V-67A	MO gate	O	ac	ac	V,G, D,P	RM	C	C	C	As is	1.5	15	5	No	S	Vlv	TB	Yes	5	15, 56, 63
MS line B drain isolation	18B	6.2-45	55	A	MS-V-67B	MO gate	O	ac	ac	V,G, D,P	RM	C	C	C	As is	1.5	15	5	No	S	Vlv	TB	Yes	5	15, 56, 63
MS line C drain isolation	18C	6.2-45	55	A	MS-V-67C	MO gate	O	ac	ac	V,G, D,P	RM	C	C	C	As is	1.5	15	5	No	S	Vlv	TB	Yes	5	15, 56, 63
MS line D drain isolation	18D	6.2-45	55	A	MS-V-67D	MO gate	O	ac	ac	V,G, D,P	RM	C	C	C	As is	1.5	15	5	No	S	Vlv	TB	Yes	5	15, 56, 63
MS line A loop isolation	18A	6.2-45	55	A	MSLC-V-3A	Gate	O	Manual	Manual	--	--	C	C	C	--	1.5	--	10	No	S	Vlv	RB	Yes	5	63
MS line B loop isolation	18B	6.2-45	55	A	MSLC-V-3B	Gate	O	Manual	Manual	--	--	C	C	C	--	1.5	--	10	No	S	Vlv	RB	Yes	5	63
MS line C loop isolation	18C	6.2-45	55	A	MSLC-V-3C	Gate	O	Manual	Manual	--	--	C	C	C	--	1.5	--	10	No	S	Vlv	RB	Yes	5	63
MS line D loop isolation	18D	6.2-45	55	A	MSLC-V-3D	Gate	O	Manual	Manual	--	--	C	C	C	--	1.5	--	10	No	S	Vlv	RB	Yes	5	63
Decon soltn supply header	94	6.2-59	56	B	MWR-V-124	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	.75	--	--	No	W	Cap	RB	No	5	

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
Decon soltn return header	95	6.2-59	56	B	MWR-V-125	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	.75	--	--	No	W	Cap	RB	No	5	
Rad mon return (S-SR-20)	72f	6.2-54	56	B	PI-V-X72f/l	Check	I	Process	Process	--	--	O	O	C	--	1	--	--	No	A	Vlv	RB	No	5	
Rad mon return (S-SS-21)	73e	6.2-54	56	B	PI-V-X72e/l	Check	I	Process	Process	--	--	O	O	C	--	1	--	--	No	A	Vlv	RB	No	5	
Inst lines - H2 to cont	42c	9.4-8	56	B	PI-EFC-X42C	EF check	O	Spring	EF	--	--	O	O	O	--	1	--	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 to cont	78a	9.4-8	56	B	PI-EFC-X78A	EF check	O	Spring	EF	--	--	O	O	O	--	1	--	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 to cont	42c	9.4-8	56	B	PI-V-X42C	Globe	O	Manual	Manual	--	--	O	O	O	--	1	--	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	72c	9.4-8	56	B	PI-V-X72C	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	72d	9.4-8	56	B	PI-V-X72D	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	72e	9.4-8	56	B	PI-V-X72E	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	73c	9.4-8	56	B	PI-V-X73C	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	73d	9.4-8	56	B	PI-V-X73D	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 to cont	78a	9.4-8	56	B	PI-V-X78A	Globe	O	Manual	Manual	--	--	O	O	O	--	1	--	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	82c	9.4-8	56	B	PI-V-X82C	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Inst lines - H2 fm cont	84b	9.4-8	56	B	PI-V-X84B	Globe	O	Manual	Manual	--	--	O	O	O	--	1					Vlv		No	5	
Air line for RHR-V-50A	42d	6.2-53	56	B	PI-VX-216	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41B	54Bf	6.2-53	56	B	PI-VX-218	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41A	61f	6.2-53	56	B	PI-VX-219	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41C	62f	6.2-53	56	B	PI-VX-220	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-50B	69c	6.2-53	56	B	PI-VX-221	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Rad mon supply (S-SR-20)	85a/c	6.2-54	56	B	PI-VX-250	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Rad mon supply (S-SR-20)	85a/c	6.2-54	56	B	PI-VX-251	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Rad mon return (S-SR-20)	72f	6.2-54	56	B	PI-VX-253	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
Rad mon return (S-SR-21)	29a/c	6.2-54	56	B	PI-VX-256	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Rad mon return (S-SR-21)	29a/c	6.2-54	56	B	PI-VX-257	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Rad mon return (S-SR-21)	73e	6.2-54	56	B	PI-VX-259	SO globe	O	ac	Spring	F,A	RM	O	O	C	C	1	5	--	No	A	Vlv	RB	No	5	56
Inst lines - H2 fm cont	72c	9.4-8	56	B	PI-VX-262	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	72d	9.4-8	56	B	PI-VX-263	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	72e	9.4-8	56	B	PI-VX-264	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	82c	9.4-8	56	B	PI-VX-265	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	73c	9.4-8	56	B	PI-VX-266	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	73d	9.4-8	56	B	PI-VX-268	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Inst lines - H2 fm cont	84b	9.4-8	56	B	PI-VX-269	SO globe	O	ac	Spring	--	RM	O	O	O	C	1	NA	--	Yes	A, S	Vlv	RB	No	5	53
Air line for RHR-V-50A	42d	6.2-53	56	B	PI-VX-42d	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41B	54Bf	6.2-53	56	B	PI-VX-54Bf	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41A	61f	6.2-53	56	B	PI-VX-61f	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-41C	62f	6.2-53	56	B	PI-VX-62f	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
Air line for RHR-V-50B	69c	6.2-53	56	B	PI-VX-69c	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
PASS DW atm	73f	6.2-57	56	B	PSR-V-X73-1	SO gate	I	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS DW atm	73f	6.2-57	56	B	PSR-V-X73-2	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS jet pump #10	77Ac	6.2-57	55	A	PSR-V-X77A1	SO globe	I	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 48a
PASS jet pump #10	77Ac	6.2-57	55	A	PSR-V-X77A2	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 48a
PASS jet pump #20	77Ad	6.2-57	55	A	PSR-V-X77A3	SO globe	I	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 48a
PASS jet pump #20	77Ad	6.2-57	55	A	PSR-V-X77A4	SO globe	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 48a

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
PASS DW atm	80b	6.2-57	56	B	PSR-V-X80-1	SO gate	I	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS DW atm	80b	6.2-57	56	B	PSR-V-X80-2	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS SP return	82d	6.2-58	56	B	PSR-V-X82-1	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 48a 56
PASS SP return	82d	6.2-58	56	B	PSR-V-X82-2	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 48a
PASS WW atm return	82f	6.2-58	56	B	PSR-V-X82-7	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm return	82f	6.2-58	56	B	PSR-V-X82-8	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm	83a	6.2-58	56	B	PSR-V-X83-1	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm	83a	6.2-58	56	B	PSR-V-X83-2	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm	84f	6.2-58	56	B	PSR-V-X84-1	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS WW atm	84f	6.2-58	56	B	PSR-V-X84-2	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	A	Vlv	RW	Yes	5	50, 56, 52
PASS line SP	88	6.2-58	56	B	PSR-V-X88-1	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	48a, 50, 56, 64
PASS line SP	88	6.2-58	56	B	PSR-V-X88-2	SO gate	O	ac	Spring	--	RM	C	C	O	C	1	No	--	No	W	Vlv	RW	Yes	5	50, 56, 64, 48a
RCC inlet header	5	6.2-55	56	B	RCC-V-104	MO gate	O	ac	ac	F,A	--	O	O	C	As is	10	60	5	No	W	Vlv	RB	Yes	4	56
RCC outlet header	46	6.2-50	56	B	RCC-V-21	MO gate	O	ac	ac	F,A	--	O	O	C	As is	10	60	3	No	W	Vlv	RB	No	4	56
RCC outlet header	46	6.2-50	56	B	RCC-V-40	MO gate	I	ac	ac	F,A	--	O	O	C	As is	10	60	--	No	W	Vlv	RB	No	4	56
RCC outlet header	46	6.2-50	56	B	RCC-V-219	Check	I	Process	Process	--	--	C	C	C	--	0.5	--	--	No	W	Vlv	RB	No	3	
RCC inlet header	5	6.2-55	56	B	RCC-V-5	MO gate	O	ac	ac	F,A	--	O	O	C	As is	10	60	3	No	W	Vlv	RB	Yes	4	56
RPV head spray	2	6.2-40	55	A	RCIC-V-13	MO gate	O	dc	dc	34	RM	C	O/C	O/C	As is	6	15	21	No	W	Vlv	RB	No	C	56, 48b, 18
Air line - spare	54Aa	6.2-53	56	B	RCIC-V-184	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	W	Vlv	RB	No	5	
RCIC min flow	65	6.2-43	56	B	RCIC-V-19	MO globe	O	dc	dc	33	RM	C	C	O/C	As is	2	22	7	No	W	Vlv	RB	No	5	22, 56, 18, 66

LDCN-08-028

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
RCIC vac pump dis	64	6.2-52	56	B	RCIC-V-28	Check	O	Process	Process	--	--	C	O	O/C	--	1.5	--	5	No	W	Vlv	RB	No	5	18, 66
RCIC suct from SP	33	6.2-49	56	B	RCIC-V-31	MO gate	O	dc	dc	32	RM	C	O	O/C	As is	8	No	2	No	W	Vlv	RB	No	N	48a, 56, 18
RCIC turb ex and ex vacuum breaker	4/116	6.2-58	56	B	RCIC-V-40	Check	O	Process	Process	--	--	O	C	O/C	--	10	--	17	No	S	Vlv	RB	No	3	49
RCIC turb steam supply	21/45	6.2-40	55	A	RCIC-V-63	MO gate	I	ac	ac	K	RM	O	O/C	O/C	As is	10	16	--	Yes	S	Vlv	RB	Yes	M	51, 56, 52
RHR cond mode steam supply	21	6.2-40	55	A	RCIC-V-64	MO gate	O	Manual	Manual	--	--	LC	LC	LC	As is	10	--	2	Yes	S	Vlv	RB	No	1	39
RPV head spray	2	6.2-40	55	A	RCIC-V-66	Check	I	Process	Process	--	--	C	O	O/C	--	6	--	--	No	W	Vlv	RB	No	3	48b, 18
RCIC turb ex and ex vacuum breaker	4/116	6.2-58	56	B	RCIC-V-68	MO gate	O	dc	dc	35	RM	O	O	O/C	As is	10	No	10	No	S	Vlv	RB	No	C	22, 56
RCIC vacuum pump dis	64	6.2-52	56	B	RCIC-V-69	MO gate	O	dc	dc	36	RM	O	O	O/C	As is	1.5	No	3	No	W	Vlv	RB	No	5	22, 56, 18, 66
Air line - spare	54Aa	6.2-53	56	B	RCIC-V-740	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	1	--	7	No	A	Vlv	RB	No	5	
RPV head spray	2	6.2-40	55	A	RCIC-V-742	Globe	O	Manual	Manual	--	--	LC	LC	LC	--	0.75	--	3	No	W	Vlv	RB	No	5	48b
RCIC steam supply bypass	21/45	6.2-40	55	A	RCIC-V-76	MO globe	I	ac	ac	K	RM	C	C	C	As is	1	22	--	No	S	Vlv	RB	Yes	5	56, 52
RCIC turbine steam supply	45	6.2-40	55	A	RCIC-V-8	MO gate	O	dc	dc	K	RM	O	O/C	O/C	As is	4	26	2	No	S	Vlv	RB	Yes	P	51, 56, 52
RFW line A	17A	6.2-37	55	A	RFW-V-10A	Check	I	Process	Process	--	--	O	O/C	O/C	--	24	--	--	No	W	Vlv	TB	Yes	3	16, 52, 31
RFW line B	17B	6.2-37	55	A	RFW-V-10B	Check	I	Process	Process	--	--	O	O/C	O/C	--	24	--	--	No	W	Vlv	TB	Yes	3	16, 52, 31
RFW line A	17A	6.2-37	55	A	RFW-V-32A	PC check	O	Process	Process/ spring	--	--	O	O/C	O/C	--	24	--	2	No	W	Vlv	TB	Yes	3	52, 31
RFW line B	17B	6.2-37	55	A	RFW-V-32B	PC check	O	Process	Process/ spring	--	--	O	O/C	O/C	--	24	--	2	No	W	Vlv	TB	Yes	3	52, 31
RFW line A	17A	6.2-37	55	A	RFW-V-65A	MO gate	O	ac	ac	31	Manual	O	O/C	O/C	As is	24	No	8	No	W	Vlv	TB	Yes	C	56, 52, 31
RFW line B	17B	6.2-37	55	A	RFW-V-65B	MO gate	O	ac	ac	31	Manual	O	O/C	O/C	As is	24	No	8	No	W	Vlv	TB	Yes	C	56, 52, 31
Pump min flow	47	6.2-51	56	B	RHR-FCV-64A	MO globe	O	ac	ac	38	RM	C	C	O/C	As is	3	20	22	Yes	W	Vlv	RB	No	L	18, 56, 66
Pump min flow	48	6.2-51	56	B	RHR-FCV-64B	MO globe	O	ac	ac	38	RM	C	C	O/C	As is	3	20	22	Yes	W	Vlv	RB	No	L	18, 56, 66

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
Pump min flow	26	6.2-41	56	B	RHR-FCV-64C	MO globe	O	ac	ac	38	RM	C	C	O/C	As is	3	20	30	Yes	W	Vlv	RB	No	L	18, 56, 66
Heat exch thermal RV	117	6.2-51	56	B	RHR-RV-1A	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	188	No	W	Vlv	RB	No	5	18, 19, 48a
Heat exch thermal RV	118	6.2-51	56	B	RHR-RV-1B	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	189	No	W	Vlv	RB	No	5	18, 19, 48a
Discharge header RV	47	6.2-51	56	B	RHR-RV-25A	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	33	Yes	W	Vlv	RB	No	5	18, 19, 48a
Discharge header RV	48	6.2-51	56	B	RHR-RV-25B	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	30	Yes	W	Vlv	RB	No	5	18, 19, 48a
Discharge header RV	26	6.2-41	56	B	RHR-RV-25C	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	30	Yes	W	Vlv	RB	No	5	18, 19, 48a
Flush line RV	118	6.2-39	56	B	RHR-RV-30	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	34	No	W	Vlv	RB	No	5	18, 19, 48a
Pump A and B suction RV	48	6.2-51	56	B	RHR-RV-5	Relief	O	pp	Spring	--	--	C	C	C	--	1	--	20	Yes	W	Vlv	RB	No	5	18, 19, 48a
Pump A suction RV	47	6.2-51	56	B	RHR-RV-88A	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	30	Yes	W	Vlv	RB	No	5	18, 48a
Pump B suction RV	48	6.2-51	56	B	RHR-RV-88B	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	30	Yes	W	Vlv	RB	No	5	18, 48a
Pump C suction RV	26	6.2-41	56	B	RHR-RV-88C	Relief	O	pp	Spring	--	--	C	C	C	--	.75	--	37	Yes	W	Vlv	RB	No	5	18, 19, 48a
Heat exch cond	47	6.2-51	56	B	RHR-V-11A	MO gate	O	Manual	Manual	--	--	LC	LC	LC	As is	4	--	18	Yes	W	Vlv	RB	No	1	18, 39, 66
Heat exch cond	48	6.2-51	56	B	RHR-V-11B	MO gate	O	Manual	Manual	--	--	LC	LC	LC	As is	4	--	No	Yes	W	Vlv	RB	No	1	18, 39, 66
FDR system intertie	47	6.2-51	56	B	RHR-V-120	Gate	O	Manual	Manual	--	--	LC	LC	LC	--	3	--	7	No	W	Vlv	RB	No	1	54, 18, 66
FDR system intertie	47	6.2-51	56	B	RHR-V-121	Gate	O	Manual	Manual	--	--	LC	LC	LC	--	3	--	6	No	W	Vlv	RB	No	1	54, 18, 66
SDC return A	19A	6.2-48	55	A	RHR-V-123A	MO gate	I	ac	ac	F,L	RM	C	O/C	--	As is	1	15	--	Yes	W	Vlv	RB	No	5	56, 48b, 18
SDC return B	19B	6.2-48	55	A	RHR-V-123B	MO gate	I	ac	ac	F,L	RM	C	O/C	--	As is	1	15	--	Yes	W	Vlv	RB	No	5	56, 48b, 18
RHR cond pot drain A	117	6.2-39	56	B	RHR-V-124A	MO globe	O	Manual	Manual	39	RM	LC	LC	LC	As is	1.5	Std	11	Yes	W	Vlv	RB	No	5	38, 18, 66
RHR cond pot drain A	117	6.2-39	56	B	RHR-V-124B	MO globe	O	Manual	Manual	39	RM	LC	LC	LC	As is	1.5	Std	12	Yes	W	Vlv	RB	No	5	39, 18, 66

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
RHR cond pot drain B	118	6.2-39	56	B	RHR-V-125A	MO globe	O	Manual	Manual	39	RM	LC	LC	LC	As is	1.5	Std	17	Yes	W	Vlv	RB	No	5	39, 18, 66
RHR cond pot drain B	118	6.2-39	56	B	RHR-V-125B	MO globe	O	Manual	Manual	39	RM	LC	LC	LC	As is	1.5	Std	14	Yes	W	Vlv	RB	No	5	39, 18, 66
CAC drain A	117	6.2-39	56	B	RHR-V-134A	MO globe	O	Manual	Manual	--	--	LC	LC	LC	LC	2	No	44	No	W	Vlv	RB	No	5	18, 65, 66
CAC drain B	118	6.2-39	56	B	RHR-V-134B	MO globe	O	Manual	Manual	--	--	LC	LC	LC	LC	2	No	44	No	W	Vlv	RB	No	5	18, 65, 66
Drywell spray A	11A	6.2-42	56	B	RHR-V-16A	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	16	Std	26	Yes	W	Vlv	RB	No	I	56, 18
Drywell spray B	11B	6.2-42	56	B	RHR-V-16B	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	16	Std	12	Yes	W	Vlv	RB	No	I	56, 18
Drywell spray A	11A	6.2-42	56	B	RHR-V-17A	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	16	Std	24	Yes	W	Vlv	RB	No	I	56, 18
Drywell spray B	11B	6.2-42	56	B	RHR-V-17B	MO gate	O	ac	ac	46	RM	C	O	O/C	As is	16	Std	2	Yes	W	Vlv	RB	No	I	56, 18
SDC	20	6.2-46	55	A	RHR-V-209	Check	I	Process	Process	--	--	C	C	--	--	.75	--	--	No	W	Vlv	RB	No	5	48b, 18
RHR test line C	26	6.2-41	56	B	RHR-V-21	MO globe	O	ac	ac	F,V	RM	C	C	C	As is	18	Std	34	Yes	W	Vlv	RB	No	L	18, 56, 60, 66
RPV head spray	2	6.2-40	55	A	RHR-V-23	MO globe	O	ac	dc	L, U, M, R	RM	C	O/C	C	As is	6	Std	28	Yes	W	Vlv	RB	No	C	56, 57, 59,48b, 18
RHR test A	47	6.2-51	56	B	RHR-V-24A	MO globe	O	ac	ac	F,V	RM	C	C	C	As is	18	Std	12	Yes	W	Vlv	RB	No	N	2, 18, 66, 28, 56
RHR test B	48	6.2-51	56	B	RHR-V-24B	MO globe	O	ac	ac	F,V	RM	C	C	C	As is	18	Std	12	Yes	W	Vlv	RB	No	N	2, 18, 66, 56, 57, 59
SP spray A	25A	6.2-43	56	B	RHR-V-27A	MO gate	O	ac	ac	F,V	RM	C	C	O/C	As is	6	36	5	Yes	W	Vlv	RB	No	N	2, 18, 56
SP spray B	25B	6.2-43	56	B	RHR-V-27B	MO gate	O	ac	ac	F,V	RM	C	C	O/C	As is	6	36	6	Yes	W	Vlv	RB	No	N	2, 18, 56
LPCI A	12A	6.2-47	55	A	RHR-V-41A	Check	I	Process	Process	--	--	C	C	O/C	--	14	--	--	Yes	W	Vlv	RB	No	3	3, 28, 48b, 18
LPCI B	12B	6.2-47	55	A	RHR-V-41B	Check	I	Process	Process	--	--	C	C	O/C	--	14	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 57, 59
LPCI C	12C	6.2-47	55	A	RHR-V-41C	Check	I	Process	Process	--	--	C	C	O/C	--	14	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 60

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
LPCI A	12A	6.2-47	55	A	RHR-V-42A	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	14	27	21	Yes	W	Vlv	RB	No	C	48b,56, 18, 28
LPCI B	12B	6.2-47	55	A	RHR-V-42B	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	14	27	20	Yes	W	Vlv	RB	No	C	48b, 56, 18, 57, 59
LPCI C	12C	6.2-47	55	A	RHR-V-42C	MO gate	O	ac	ac	46	RM	C	C	O/C	As is	14	27	20	Yes	W	Vlv	RB	No	C	48b,56, 18, 60
RHR SP suction A	35	6.2-49	56	B	RHR-V-4A	MO gate	O	ac	ac	46	RM	O	O/C	O	As is	24	No	2	Yes	W	Vlv	RB	No	L	48a, 56, 61, 18, 20
RHR SP suction B	32	6.2-49	56	B	RHR-V-4B	MO gate	O	ac	ac	46	RM	O	O/C	O	As is	24	No	2	Yes	W	Vlv	RB	No	L	48a, 56, 61, 18, 20
RHR SP suction C	36	6.2-49	56	B	RHR-V-4C	MO gate	O	ac	ac	46	RM	O	O/C	O	As is	24	No	2	Yes	W	Vlv	RB	No	L	48a, 56, 61, 18, 20
SDC return A	19A	6.2-48	55	A	RHR-V-50A	Check	I	Process	Process	--	--	C	O	--	--	12	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 28
SDC return B	19B	6.2-48	55	A	RHR-V-50B	Check	I	Process	Process	--	--	C	O	--	--	12	--	--	Yes	W	Vlv	RB	No	3	3, 48b, 18, 57, 59
SDC return A	19A	6.2-48	55	A	RHR-V-53A	MO gate	O	ac	ac	M, L, U, R	RM	C	O	--	As is	12	40	5	Yes	W	Vlv	RB	No	C	56,48b, 18, 28
SDC return B	19B	6.2-48	55	A	RHR-V-53B	MO gate	O	ac	ac	M, L, U, R	RM	C	O	--	As is	12	40	5	Yes	W	Vlv	RB	No	C	56, 57, 59, 48b, 18
Heat exch vent	117	6.2-51	56	B	RHR-V-73A	MO globe	O	ac	ac	39	RM	C	O/C	C	As is	2	No	175	No	A/W	Vlv	RB	No	5	18, 56, 66
Heat exch vent	118	6.2-51	56	B	RHR-V-73B	MO globe	O	ac	ac	39	Manual	C	O/C	C	As is	2	No	190	No	A/W	Vlv	RB	No	5	18, 56, 66
SDC	20	6.2-46	55	A	RHR-V-8	MO gate	O	dc	dc	L, U, M, R	RM	C	O	--	As is	20	40	14	Yes	W	Vlv	RB	No	N	56, 20, 48b, 61, 18
SDC	20	6.2-46	55	A	RHR-V-9	MO gate	I	ac	ac	L, U, M, R	RM	C	O	--	As is	20	40	--	Yes	W	Vlv	RB	No	N	48b, 56, 61, 18, 20
RRC pump A seal	43A	6.2-38	56	B	RRC-V-13A	Check	I	Process	Process	--	--	O	O	O	--	.75	No	--	No	W	Vlv	RB	No	5	--
RRC pump B seal	43B	6.2-38	56	B	RRC-V-13B	Check	I	Process	Process	--	--	O	O	O	--	.75	No	--	No	W	Vlv	RB	No	5	--

Table 6.2-16

Primary Containment Isolation Valves (Continued)

Line Description	Pent	Figure	GDC	Code Gp (12)	Valve EPN	Valve Type	Loc	Pwr to Open (5)	Pwr to Close (5)	Iso sig (9)	Back Up	Norm Pos (10)	SD Pos	Post LOCA	Fail Pos (6)	Valve Size (14)	Close Time (7,11)	Dist to Pent	Leads to ESF	Proc Fld	Leak Bar (13)	Term Zone (13)	Pot Bypass Leak	SBO (62)	Notes
RRC pump A seal	43A	6.2-38	56	B	RRC-V-16A	MO gate	O	ac	ac	45	RM	O	O	O	As is	.75	No	2	No	W	Vlv	RB	No	5	56
RRC pump B seal	43B	6.2-38	56	B	RRC-V-16B	MO gate	O	ac	ac	45	RM	O	O	O	As is	.75	No	2	No	W	Vlv	RB	No	5	56
RRC sample line	77Aa	6.2-39	55	A	RRC-V-19	SO globe	I	ac	Spring	A,C	RM	O	C	C/O	C	.75	5	--	No	W	Vlv	TB	Yes	5	56, 48a
RRC sample line	77Aa	6.2-39	55	A	RRC-V-20	SO globe	O	ac	Spring	A,C	RM	O	C	C/O	C	.75	5	--	No	W	Vlv	TB	Yes	5	56, 48a
RWCU from reactor	14	6.2-46	55	A	RWCU-V-1	MO gate	I	ac	ac	A,J,E	RM	O	O	C	As is	6	16, 25	--	No	W	Vlv	RW	Yes	M	51, 48a, 56
RWCU from reactor	14	6.2-46	55	A	RWCU-V-4	MO gate	O	dc	dc	A,J,E, Y, W	RM	O	O	C	As is	6	16, 25	4	No	W	Vlv	RW	Yes	2	51, 48a, 56
RFW line A	17A/ 17B	6.2-37	55	A	RWCU-V-40	MO gate	O	ac	ac	47	Manual	O	O	O/C	As is	6	No	24	No	W	Vlv	TB	Yes	C	56, 52
Air line for maintenance	93	6.2-55	56	B	SA-V-109	Gate	O	Manual	Manual	--	--	LC	LC	LC	--	2	--	1	No	A	Cap	SB	No	5	54
SLC to RPV	13	6.2-48	55	A	SLC-V-4A	Explosive	O	--	--	--	--	C	C	C	--	1.5	--	136	No	W	Vlv	RB	No	5	21
SLC to RPV	13	6.2-48	55	A	SLC-V-4B	Explosive	O	--	--	--	--	C	C	C	--	1.5	--	136	No	W	Vlv	RB	No	5	21
SLC to RPV	13	6.2-48	55	A	SLC-V-7	Check	I	Process	Process		--	C	C	C	--	1.5	--	--	No	W	Vlv	RB	No	5	
TIP lines	27A	--	56	B	TIP-V-1	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27D	--	56	B	TIP-V-10	Exp shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29
TIP lines	27E	--	56	B	TIP-V-11	Exp shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29
TIP lines	27F	--	56	B	TIP-V-15	SO globe	O	ac	Spring	A,F	--	O	O	C	C	1	--	2	No	A	Vlv	RB	Yes	5	52, 56
TIP lines	27B	--	56	B	TIP-V-2	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27C	--	56	B	TIP-V-3	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27D	--	56	B	TIP-V-4	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27E	--	56	B	TIP-V-5	SO ball	O	ac	Spring	A,F	RM	C	C	C	C	.375	5	2	No	A	Vlv	RB	No	5	29, 56
TIP lines	27F	--	56	B	TIP-V-6	Check	I	Process	Process	--	--	O	C	C	--	.5	--	1	No	A	Vlv	RB	Yes	5	52
TIP lines	27A	--	56	B	TIP-V-7	Exp Shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29
TIP lines	27B	--	56	B	TIP-V-8	Exp Shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29
TIP lines	27C	--	56	B	TIP-V-9	Exp Shear	O	--	Exp	43	--	O	O	O	O	.375	--	2	No	A	Vlv	RB	No	5	29

Table 6.2-16

Primary Containment Isolation Valves (Continued)

ISOLATION SIGNAL CODES[a]

Signal	Description
A[b]	Reactor vessel low-low water level (Trip level 2)
C[b]	High radiation - main steam line
D[b]	Line break - main steam line (steam line tunnel high temperature, high differential temperature or steam line high flow)
E[b]	Reactor water cleanup system high differential flow or high blowdown flow
F[b]	High drywell pressure
G[b]	Low condenser vacuum
J[b]	Line break in RWCU system – area high temperature or high differential temperature
K[b]	Line break in RCIC system (RCIC area high temperature, high differential temperature, or high steam flow), [Low steam pressure or turbine exhaust diaphragm high pressure are other signals not part of PCRVICS]
L[b]	Reactor vessel low water level (Trip level 3) (A scram occurs at this level. This is the higher of the three low water level signals)
M[b]	Line break in RHR shutdown cooling (high suction flow)
P[b]	Low main steam line pressure at turbine inlet (RUN mode only)
R[b]	RHR equipment area high temperature or high differential temperature
RM	Remote manual switch located in main control room
U	High reactor vessel pressure
V[c]	Reactor vessel low-low-low water level (Trip level 1)
W	High temperature at outlet of RWCU system nonregenerative heat exchanger
Y	Standby liquid control system actuated
Z[b]	Reactor building ventilation exhaust plenum high radiation

[a] See notes 30 through 46 for isolation signals generated by the individual system process control signals or for remote-manual closure based on information available to the operators. These notes are referenced in the "isolation signal" column.

[b] These are the isolation functions of the primary containment and reactor vessel isolation control system (PCRVICS). Other functions are provided for information only.

[c] Reactor vessel low-low-low water level (Trip level 1) is an isolation function of the primary containment and reactor vessel isolation control system (PCRVICS) for Group 1 valves only.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

ABBREVIATIONS/LEGEND

Valve Type	
AO	air-operated
EHO	electrohydraulic operated
MO	motor-operated
PC	positive closing
SO	Solenoid operated
Location	
I	inside containment
O	outside containment
Power to Open/Close	
AC	ac electrical power
DC	dc electrical power
EF	excess flow
pp	process fluid overpressurization
pro	process, process flow
spr	spring
Normal Position	
C	closed
LC	locked closed
LO	locked open
O	open
SC	sealed closed (lead)
Process Fluid	
A	air
H	hydraulic fluid
S	steam
W	water
Termination Zone	
CS	condensate storage tank
RR	reactor building
RW	radwaste building
SB	service building
TB	turbine building

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

Type C testing is discussed in Figures 6.2-36 through 6.2-59 which shows the isolation valve arrangement. Unless otherwise noted all valves listed in Table 6.2-16 are Type C tested.

1. Main steam isolation valves require that both solenoid pilots be deenergized to close valves. Accumulator air pressure plus spring set act together to close valves when both pilots are deenergized. Voltage failure at only one pilot does not cause valve closure. The valves are designed to fully close in less than 10 sec.

2. Suppression cooling valves have interlocks that allow them to be manually reopened after automatic closure. This setup permits suppression pool spray, for high drywell pressure conditions and/or suppression water cooling. When automatic signals are not present, these valves may be opened for test or operating convenience.

3. The air test function is not used.

4. The CRD insert and withdraw lines are not subject to Type A testing since these pathways are not open to the Primary Containment atmosphere under post-DBA conditions (ANSI/ANS-56.8-1994, Section 3.2.5). These lines would always remain filled with water and provide a water seal following a design basis accident (DBA) and therefore do not represent a gaseous fission product release pathway.

   The CRD insert and withdraw lines are not subject to Type C testing, since these Primary Containment boundaries do not constitute potential Primary Containment Atmospheric pathways during and following a design basis accident (NEI 94-01, Section 6.0, and ANSI/ANS-56.8-1994, Section 3.3.1(1)).

   The above positions are in compliance with NRC Regulatory Guide 1.163.

   See Section 6.2.4.3.2.1.1.4 for additional design information.

5. Alternating current motor-operated valves required for isolation functions are powered from the ac standby power buses. Direct current operated isolation valves are powered from station batteries.

6. All motor-operated isolation valves remain in the last position upon failure of valve power. All air-operated valves close in the safest position on motive air failure.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

7. STD - The close limit is based on a standard minimum closing rate of 12 in. of nominal valve diameter per minute for gate valves and 4 in. of valve stem travel per minute for globe valves.

   No - No limiting value of full stroke closure time is specified. The close limit is based on results from testing performed in accordance with ASME/ANSI OM Part 10 Section 3 Testing Requirements.

8. Reactor building ventilation exhaust plenum high radiation signal (Z) is generated by two trip units in each safety division. This requires a trip from both units in a division (fail-safe design) to initiate isolation.

9. Primary containment and reactor vessel isolation signals (PCRVIS) are indicated by letters. Isolation signals generated by the individual system process control signals or for remote manual closure based on information available to the operator are discussed in the referenced notes in the "isolation signal" column.

10. Normal status position of valve (open or closed) is the position during normal power operation of the reactor (see Normal Position column). Valves, blind flanges, and deactivated automatic valves that are within the primary containment or other areas administratively controlled to prohibit access for reasons of personnel safety are locked, sealed, or otherwise secured in the closed position. Valves 1.5 in. and smaller connected to vents, drains, or test connections must be closed but need not be sealed.

11. The specified closure rates are as required for containment isolation or system operation, whichever is less. Reported times are in seconds.

12. All isolation valves are Seismic Category I.

13. Used to evaluate primary containment leakage which may bypass the secondary containment emergency filtration system.

14. Reported sizes are the valve nominal diameters in inches. Size indicated is containment side of relief valve when relief valve size is not equal on both sides.

15. Reactor vessel low-low-low water level (Trip level 1) is an isolation function of the primary containment and reactor vessel isolation control system (PCRVICS) for Group 1 valves only.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

16. Not Used.

17. Not Used.

18. These lines connect to systems outside of the primary containment which meet the requirements for a closed system. These systems are considered an extension of the primary containment. Any external leakage out of these systems, within the Reactor Building, is processed by the SGT system.

19. Relief valve setpoint greater than 77.5 psig (1.5 times containment design pressure).

20. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange. The spool piece, COND-RSP-1, is connected to the condensate system with a blind flange on the other end.

21. Cannot be reshut after opening without disassembly.

22. See 6.2.4.3.2.2.1.2.

23. See 6.2.4.3.2.2.2.

24. Not Used.

25. DELETED.

26. The disc on the check valve is maintained in the close position during normal operation by means of a spring actuated lever arm and magnets embedded in the periphery of the disc. The magnetic and spring forces maintain the disc shut until the differential force to open the valve exceeds approximately 0.2 psid. The check valves have position indication lights which can alert the operators to the fact that the check valve is not fully closed. The operator can then remotely shut the valve by means of a pneumatic operator. The operating switch is spring-return to neutral so the vacuum breaker function will not be impaired.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

27. Instrument lines that penetrate primary containment conform to Regulatory Guide 1.11. The lines that connect to the reactor pressure boundary include a restricting orifice inside containment, are Seismic Category I and terminate in instruments that are Seismic Category I. The instrument lines also include manual isolation valves and excess flow check (EFC) valves. Manual and EFC valves have no active safety (containment isolation) function requirements. These penetrations will not be Type C tested since the integrity of the lines are continuously demonstrated during plant operations where subject to reactor operating pressure. In addition, all lines are subject to the Type A test pressure on a regular interval. Leaktight integrity is also verified with completion of functional and calibration surveillance activities as well as by visual inspection.

28. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange. The spool piece, COND-RSP-2, is connected to the condensate system with a blind flange on the other end.

29. The ball valves are Type C tested in accordance with Appendix J of 10 CFR 50. Because the shear valves have explosive squibs and require testing to destruction, they are not Type C tested. Technical Specifications surveillance requirements ensure shear valve operability.

    See subsection 6.2.4.3.2.2.3.11 for a TIP system isolation evaluation against General Design Criterion 56.

30. Deleted.

31. PCRVIS is not desirable since the feedwater system, although not an ESF system, could be a significant source of makeup after a LOCA which is not concurrent with a seismic event.

    Feedwater check valves on either side of the containment can provide immediate leak isolation. The feedwater block valves can, however, be remote-manually closed if there is no indication of feedwater flow.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

32. The RCIC suppression pool suction valve is normally closed and does not receive an automatic isolation signal.

    Operator action can be taken to remote-manually shut isolation valve RCIC-V-31. The system would be manually isolated on a reactor building sump high level alarm if RCIC is determined to be the source of leakage in the reactor building.

33. The RCIC minimum flow valve is open only between the time of system initiation and the time at which the system flow to the RPV exceeds the pump minimum flow requirement. The valve is shut at all other times. Valve RCIC-V-19 auto closes when the turbine throttle valve is closed following a turbine trip. Should a leak occur when the valve is open, it will be detected by a high level alarm in the appropriate reactor building sump.

34. The RCIC injection valve is open only during RCIC turbine operation. Injection line check valves on either side of the containment can provide immediate leak isolation. Valve RCIC-V-13 auto closes when the turbine throttle valve is closed following a turbine trip.

35. The RCIC steam exhaust valve, RCIC-V-68, is normally open at all times. Should a leak occur, it would be detected and alarmed by the RCIC room high temperature leak detection system.

36. The RCIC vacuum pump discharge valve, RCIC-V-69, is normally open at all times. The valve could be remote-manually closed by the operator upon control room indication that vacuum can no longer be maintained in the barometric condenser.

37. DELETED

38. The minimum flow valve for an ECCS pump is open whenever the pump is running and the flow in the pump discharge line is below the trip setpoint. The valve is shut at all other times. Should a leak occur when the valve is open, it will be detected by a high level alarm in the appropriate reactor building sump.

39. These valves are deactivated. The valves are shown as motor operated, however, the power leads to the motors have been disconnected and the handwheels have been chained and padlocked in the closed position.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

40. Normally closed. Signaled to open if reactor building pressure exceeds wetwell pressure by 0.5 psid (analytical limit). Valves automatically reshut when the above condition no longer exists. Operators use valve position indicator as confirmation of valve status.

41. Indication of containment instrument air main header pressure and a low pressure alarm exist in the main control room. The operator can remote-manually shut valve CIA-V-20 should the supply from the CN system or from the CAS cross-tie becomes unavailable. Isolation check valve CIA-V-21 provides immediate isolation.

42. Indication of nitrogen bottle header pressure and a low pressure alarm exist in the main control room. The operator can remote-manually shut valve CIA-V-30(A, B) should the nitrogen bottle bank pressure decrease below the alarm setpoint. Isolation check valves CIA-V-31(A, B) provide immediate isolation.

43. The TIP shear valves are remote-manually closed following control room indication of the failure of the TIP ball valves to close.

44. Normally closed. Opened only when testing wetwell-to-drywell (WW-DW) vacuum breakers. Test connection upstream of outer isolation valve is normally open. Closed during testing.

45. The isolation valve can be remote-manually closed upon indication that the CRD or the RRC pumps have tripped. Isolation check valves RRC-V-13 (A, B) provide immediate isolation.

46. These valves are the ECCS and drywell spray suction and discharge isolation valves. There are no automatic isolation signals. The valve closure requirement is indicated by a high level alarm in the appropriate reactor building sump.

47. The isolation valve can be remote-manually closed upon indication that the RWCU pumps have tripped. The reactor feedwater isolation check valves provide immediate isolation.

48a. Not subject to Type C leak testing, per Primary Containment Leakage Rate Testing Program. Prepared per Option B of 10 CFR 50 Appendix J.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

48b. The isolation valve is tested with water. The maximum allowable leakage rate is included in the Technical Specifications.

49. Isolation for the RCIC turbine exhaust vacuum breaker lines (X-116) is provided by containment isolation valves in the RCIC turbine exhaust line (X-4) and the RHR combined return line (X-47, X-48) to the suppression pool. Valves RCIC-V-110 and RCIC-V-113 serve as an extension of containment but do not function as containment isolation valves and will not require Type C testing.

50. System isolation valves are normally closed. The system is placed in operation following a LOCA for post accident sampling. Valve position indication is provided in the main control room.

51. The limiting times for valve closure are based on the pipe break isolation times used in the Environmental Equipment Qualification Program to establish the environmental profiles for qualifying safety-related equipment within the reactor building.

52. The sum of the Type C leak rate tests for the potential bypass leak paths will not exceed 0.04 percent of primary containment volume per day.

53. Instrument lines that penetrate primary containment conform to Regulatory Guide 1.11. These lines include manual isolation valves and excess flow check (EFC) valves, or solenoid-operated valves capable of remote operation from the control room. These lines are Seismic Category I and terminate at instrument racks that are Seismic Category I. Manual and EFC valves have no active safety (containment isolation) function requirements. These penetrations will not be Type C tested since the communicating lines are extensions of primary containment and the valves do not receive automatic isolation signals. In addition, all lines are subject to the Type A test on a regular interval (excluding some local pressure instruments which are over-ranged or initiate RPS actuations by Type A test pressure). Section 6.2.4.4 discusses periodic actuation testing requirements.

54. These paths are not potential secondary containment bypass leakage paths and are not required to meet the requirements for secondary containment design. The piping system outside of the outermost containment isolation valve is aligned such that leakage past these valves will be released to secondary containment and be processed by standby gas treatment.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

55. Not Used.

56. A channel check and channel calibration is required of the remote valve position indication.

57. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange. The spool piece, COND-RSP-3, is connected to the condensate system with a blind flange on the other end.

58. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the LPCS piping flange. The spool piece, COND-RSP-5, is connected to the condensate system with a blind flange on the other end.

59. The condensate system can be used to flush ECCS when connected by a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange. The spool piece, COND-RSP-6, is connected to the condensate system with a blind flange on the other end.

60. The condensate system can be used to flush LPCI C through a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on the RHR piping flange of COND-RSP-4.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

61. A blind flange is installed downstream of valves RHR-V-108 and RHR-V-109. This blind is located in the RHR pump room C and ensures that there is no by-pass leakage from the RHR pump suction line to the condensate storage tanks. The condensate system can be used to flush RHR shutdown cooling through a spool piece. The connection creates a potential secondary containment bypass leak path. This penetration is isolated from a potential secondary containment bypass leak path through the condensate system by a blind flange installed on RHR-RSP-1.

62. This column provides the station blackout (SBO) criterion that was used for each primary containment isolation valve to establish whether or not the valve needed to be assessed for closure capability in the event of an extended SBO. The values provided in this column are defined as follows:

Criterion	Basis for Exclusion
1	Valve is normally locked closed during operation.
2	Valve auto closes or fails closed on loss of ac power or air.
3	Valve is a check valve.
4	Valve is in nonradioactive closed-loop systems not expected to be breached during a SBO (the valve cannot be in a line that communicates directly with the containment atmosphere).
5	Valve is less than 3 in. nominal diameter.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

Valves that did not meet one of these exclusion criteria were considered as "valves of concern." The alphabetic data provided in this column identifies how this set of valves was addressed:

Criterion	Additional Basis for Exclusion
C	Valve has an in-series check valve that will provide for isolation of the penetration.
D	Valve has an in-series valve that fails closed on an SBO.
M	Valve has an in-series valve with SBO closure capability.
I	The penetration is provided with an interlock that ensures closure of at least one of the containment isolation valves during operation.
H	Valve is required to provide for HPCS operation.
L	For the associated penetration, GDC 56 is satisfied by a single isolation valve, connected to the suppression pool with the line submerged and a high integrity closed loop system outside containment.
N	Valve is required to be closed during power operation (open for brief periods for the purpose of performing a surveillance is acceptable) and the piping outside containment being a high integrity closed loop system.
P	Valve is included in the table as being associated with a potential secondary containment bypass leakage path. It is not a primary containment isolation valve.

Table 6.2-16

Primary Containment Isolation Valves (Continued)

NOTES

63. Leakage rate not included in sum of Type B and C test.

64. These are potential secondary containment bypass leakage paths whenever the railroad bay doors are open. The valves are tested for leakage to ensure requirements for limiting secondary containment bypass leakage are satisfied.

65. Valves RHR-V-134A and RHR-V-134B have been deactivated. Blind flanges CAC-BF-3A and CAC-BF-3B provide containment pressure boundaries in the lines outboard of valves.

66. These valves are in lines that are below the minimum water level in the suppression pool and are part of closed systems outside of the primary containment. Therefore, 10 CFR 50 Appendix J Type C and hydraulic local leak rate testing is not required.

Table 6.2-17

Hydrogen Recombiner
(Historical Information Only - System Has Been Deactivated In-Place)

1.	Tag number		CAC-HR-1A & 1B
2.	Number of units		2
3.	Type		Skid-mounted package
4.	Nominal flow		200 acfm at blower
5.	Canned blower		Rotary lobe, positive displacement pump enclosed within an ASME vessel
6.	Drive		Direct (15 hp motor)
7.	Motor type		Totally enclosed fan-cooled, Class H insulation, with maximum temperature rise of 125°C above 40°C ambient
8.	Nominal pressure across blower		7 psi
9.	Scrubber		
	a.	Type	Stainless steel, ring packed tower
	b.	Water flow	10 gpm (maximum)
10.	Heater/Recombiner		
	a.	Heater type	Electric, 27 U-tube elements
	b.	Heater capacity	37 kW
	c.	Recombiner type	Catalytic
	d.	Recombiner catalyst	Houdry HSC-931, 0.5% Platinum on alumina
11.	Aftercooler		
	a.	Type	Shell and tube heat exchanger
	b.	Water flow	50 gpm (maximum)
12.	Moisture Separator		
	a.	Type	Vertical vessel with demister at top
13.	Seismic Category		I

Table 6.2-19

Assumptions and Initial Conditions for Negative Pressure Design Evaluation

A. Containment preincident conditions used for sizing internal vacuum breakers (wetwell to drywell)

		Drywell (DW)	Suppression Chamber (WW)
1.	Pressure, psig	0	0
2.	Temperature, °F	150	50
3.	Relative humidity, %	100	100

B. Containment preincident conditions used for sizing external vacuum breakers (reactor building to wetwell).

		Drywell (DW)	Suppression Chamber (WW)
1.	Pressure, psig	-1.0	-0.5
2.	Airspace temperature, °F	135	150
	Pool temperature, °F	N/A	35
3.	Relative humidity, %	100	100

Spray temperature is equivalent to suppression pool temperature.

Table 6.2-19a

Limiting Conditions for Maximum
Negative Pressure Differentials Applied
to Columbia Generating Station Specifications

Hypothetical Event	DW-WW VBs	RB-WW VBs	DW Sprays	Maximum Negative Pressure Differential (psid) WW-DW	RB-WW	DW-RB	Remarks
(1) Inadvertent spray activation	7	3	NA	-	-	-	Not possible due to containment high pressure interlock
(2) Small pipe break							
liquid	7	2	1[a]	0.5	0.66	1.16	
steam	7	2	1[a]	0.5	0.51	1.01	
(3) DBA	7	2	1	0.84	0.79	1.11	1 RB-WW VB failure
	7	3	2	0.94	0.94	1.39	Use of two sprays No VB failure VBs adequate
(4) Vented drywell with a small steam leak	7	3	NA	-	-	-	Included in small pipe break event (2)
(5) Normal heating and cooling cycles	7	3	NA	-	-	-	Controlled with the primary containment cooling system

[a] Drywell and wetwell sprays used in event mitigation from one RHR loop only.

Table 6.2-20

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 6-in. RCIC Line*
Steam

Time (sec)	Mass Rate (lb/sec)	Energy Rate (Btu/sec x 10^3)
0.0	398.2	474.694
3.0	398.2	474.694

* Original rated power – Reference 6.2-29.

Table 6.2-21

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 6-in. RCIC Line*
Water

Time (sec)	Mass Rate (lb/sec)	Energy Rate (Btu/sec x 10^3)
0.0	0.0	0.0
0.001	331.1	388.347
0.004	205.6	195.094
0.010	398.3	231.811
0.015	598.8	329.639
0.020	700.0	381.430
0.025	724.4	392.915
0.050	580.0	311.576
0.10	394.2	198.953
0.20	144.6	59.387
0.30	52.4	18.555
0.40	35.1	8.884
0.50	46.1	11.046
1.00	45.9	10.585
1.50	36.0	7.639
1.90	30.4	6.314

* Original rated power – Reference 6.2-30.

Table 6.2-21

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 6-in. RCIC Line*
Water (Continued)

Time (sec)	Mass Rate (lb/sec)	Energy Rate (Btu/sec x 10^3)
2.00	21.1	4.378
2.50	23.3	4.523
3.00	3.2	0.611

* Original rated power – Reference 6.2-30.

Table 6.2-22

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 24-in. Recirculation Line*
Steam

Time (sec)	Mass Rate (lb/sec x 10^3)	Energy Rate (Btu/sec x 10^6)
0.0	0.0	0.0
21.0	0.0	0.0
21.01	3.2	3.815
30.00	2.4	2.861
40.00	1.3	1.550
47.00	2.0	2.384
47.01	4.0	4.768
48.00	0.0	0.0
50.00	0.0	0.0

* Original rated power – Reference 6.2-31.

Table 6.2-23

Blowdown Mass/Energy Release Rates for a Double Ended Guillotine Break in 24-in. Recirculation Line*
Water

Time (sec)	Mass Rate (lb/sec x 10^3)	Energy Rate (Btu/sec x 10^6)
0.00	22.72	12.393
0.00159	22.72	12.393
0.00171	34.07	18.585
1.537	34.07	18.585
1.568	27.56	15.033
2.037	27.56	15.033
2.040	25.00	13.637
21.00	25.00	13.637
21.01	11.80	6.437
30.00	7.00	3.818
40.00	3.50	1.909
45.00	3.80	2.073
47.00	3.70	2.018
47.01	0.0	0.0
50.00	0.0	0.0

* Original rated power – Reference 6.2-31.

Table 6.2-24

Nodal Volume Data
for the Case of a 6-in. RCIC Line Break and the Case of a 24-in. Recirculation Line Break*

Node Number	Description	Net Volume (ft^3)	Elevation (Bottom, ft)	Height (ft)
1	Drywell above Bulkhead Plate	4,789.5	582.6	15.98
2	Drywell below Bulkhead Plate	195,759.5	499.6	83.1

* Original rated power.

Table 6.2-25

Flow Path Data
for the Case of a 6-in. RCIC Line Break*

From Node	To Node	Flow Area (ft^2)	Inertia (L/A, ft^{-1})	Form Loss Coefficient K_F*	Form Loss Coefficient K_R**	Friction Factor f
1	2	4.926	0.4107	1.6	1.6	(See Note)
1	2	4.666	1.60	4.090	4.102	(See Note)

Note: The fanning friction factor is automatically included by an internal calculation in the computer program and is variable with reynolds number.

K_F* = $K_{Forward}$

K_R** = $K_{Reverse}$

* Original rated power.

Table 6.2-26

Flow Path Data
for the Case of a 24-in. Recirculation Line Break*

From Node	To Node	Flow Area (ft^2)	Inertia (L/A, ft^{-1})	Form Loss Coefficient K_F*	Form Loss Coefficient K_R**	Friction Factor f
2	1	4.926	0.4107	1.6	1.6	(See Note)
2	1	4.666	1.60	4.102	4.090	(See Note)

Note: The fanning friction factor is automatically included by an internal calculation in the computer program and is variable with reynolds number.

K_F* = $K_{Forward}$

K_R** = $K_{Reverse}$

* Original rated power.

Table 6.2-27

Peak Differential Pressure and Time of Peak*

Case		Peak Differential Pressure, psi	Time of Peak Differential Pressure, sec
6 in.	RCIC Line Break In Upper Head Region	11.46	0.75
24 in.	Recirculation Line In Lower Region	11.17	1.10

* Original rated power.

Table 6.2-28

Analytical Sequence of Events in Secondary Containment

Post-LOCA Time		Events in Secondary Containment
0	-	Reactor building differential pressure is 0.0-in. w.g. between inside and outside of building
	-	Loss of offsite power
	-	All normal operating equipment ceases to function
0.1 sec[a]	-	Emergency building lighting on (automatic)
15 sec	-	Emergency power on (automatic)
120 sec	-	Standby gas treatment system on (automatic)
300 sec	-	Full service water flow to ECCS pump room coolers
20 min	-	Building pressure reduced to -0.25-in. w.g.
1 hr[b]	-	Normal lighting off (manual)
12 hr	-	One fuel pool cooling loop on (manual)

[a] Analysis conservatively assumes emergency lighting is on after 0.1 sec even though diesels take 15 sec to restore power.

[b] Normal lighting terminates on FAZ. Analysis conservatively assumes failure to terminate for 1 hr.

Table 6.2-30

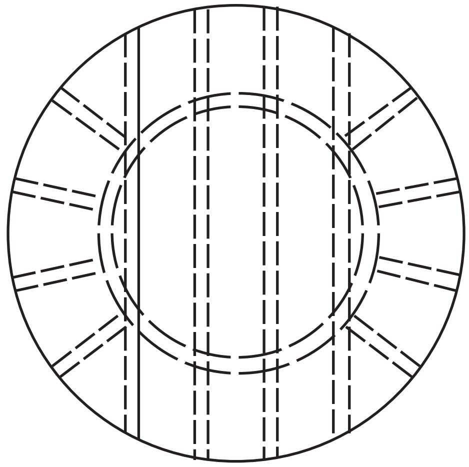
Post-LOCA Transient Heat Input Rates
to Secondary Containment

Heat Source	Heat Input, Btu/hr	Remarks
Primary containment walls (PCW)	$q_1 = 33{,}161\,(t_{pcw}-t_{air})$, for $t_{air} < t_{pcw}$ $q_1 = 0$, for $t_{air} > t_{pcw}$	$t_{pcw} = 105°F$ constant $t_{air,\,r}$ = reactor building air temperature
Normal equipment decay heat	Electrical equipment (combined)	Max. eq. surface
	$q_2 = 1475\,(150e^{-T}-t_{air})$, for $t_{air} < 150e^{-T}$	Temperature = 150°F for $T \leq 0$
	$q_2 = 0$, for $t_{air} \geq 150e^{-T}$	
	Piping (combined)	Max. eq. surface Surface temp = 182°F
	$q_3 = 664\,(182e^{-T} - t_{air})$, for $t_{air} < 182\,e^{-T}$	for $t \leq 0$
	$q_3 = 0$, for $t_{air} \geq 182e^{-T}$	
Emergency equipment	Emergency lighting ($t \geq 0$ sec)	
	$q_4 = 203{,}700$	
	Standby gas treatment system ($T \geq 34$ sec) $q_5 = 8800$	
	Emergency core cooling system ($T \geq 30$ sec) $q_6 = 4476\,(t_{cw} - t_{air})$, for $t_{air} < t_{cw}$ $q_6 = 0$, for $t_{air} \geq t_{cw}$	T,hr / tcw,* °F 0 / 95 2 / 180 50 / 143 100 / 132 *cw = cooling water

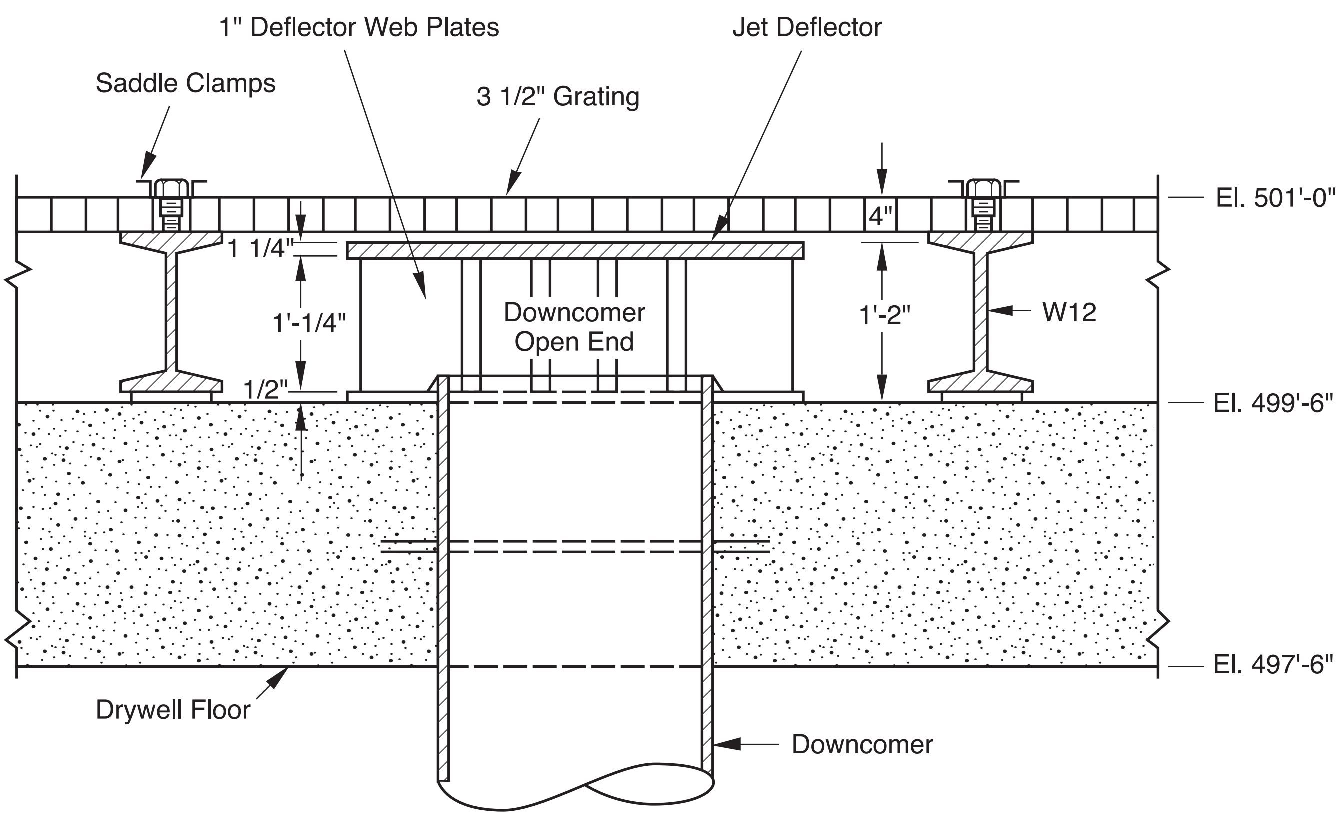
Table 6.2-30

Post-LOCA Transient Heat Input Rates
to Secondary Containment (Continued)

Heat Source	Heat Input, Btu/hr	Remarks
Fuel pool sensible heat	$q_7 = 299.2\ (t_{pw}\text{-}t_{air})^{4/3}$	t_{pw} = pool water temp. °F
Pool evaporation heat	$q_8 = 1385.19\ (t_{pw} - t_{air})^{1/3}\ (W_{ps} - W_{air})\lambda p$	t_{pw} = pool water temp. °F W_{ps} = humidity ratio ° Saturated moist air Evaluated at t_{pw} of wet surface (1bw/1ba) W_{ps} = humidity ratio of moisture air (1bw/1ba) λp = heat of vaporization (1bw/1ba)
Infiltration air heat-up	$q_9 = -0.24945\ (t_{air} - 100) >$	
Structural steel heat-up	$q_{10} = -\ 11400\ (t_{air} - t_{steel})^{4/3}$	t_{steel} = steel temp (°F)
Total	$Q = q_1 + q_2 + q_3 + q_4 + q_5 + q_6 + q_7 + q_8 + q_9 + q_{10}$	$Q = \sum_{1=10}^{10} q_1$



Top View Of Jet Deflector



Typical 24 in. Downcomer Vent with Jet Deflector

Draw. No. 900547.40 | Rev. | Figure 6.2-1

Point Of Critical Flow

A. Recirculation Line
B. Cleanup Line
C. Combined Area of All Jet Pump Nozzles Associated with the Broken Loop

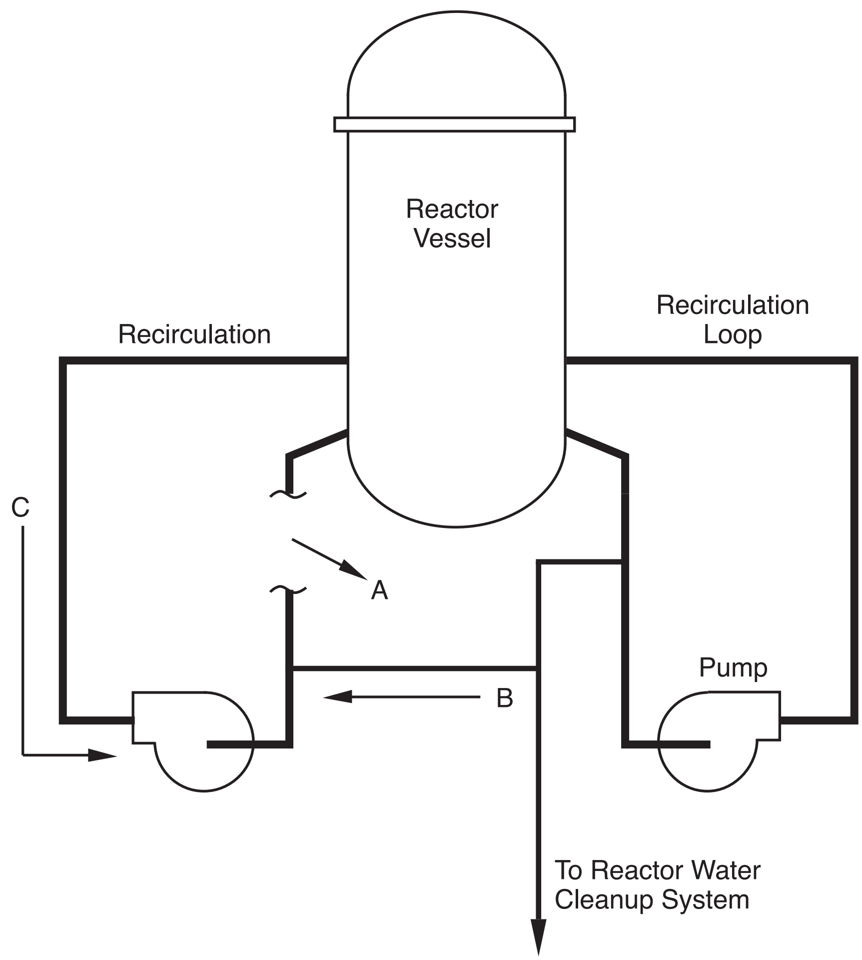
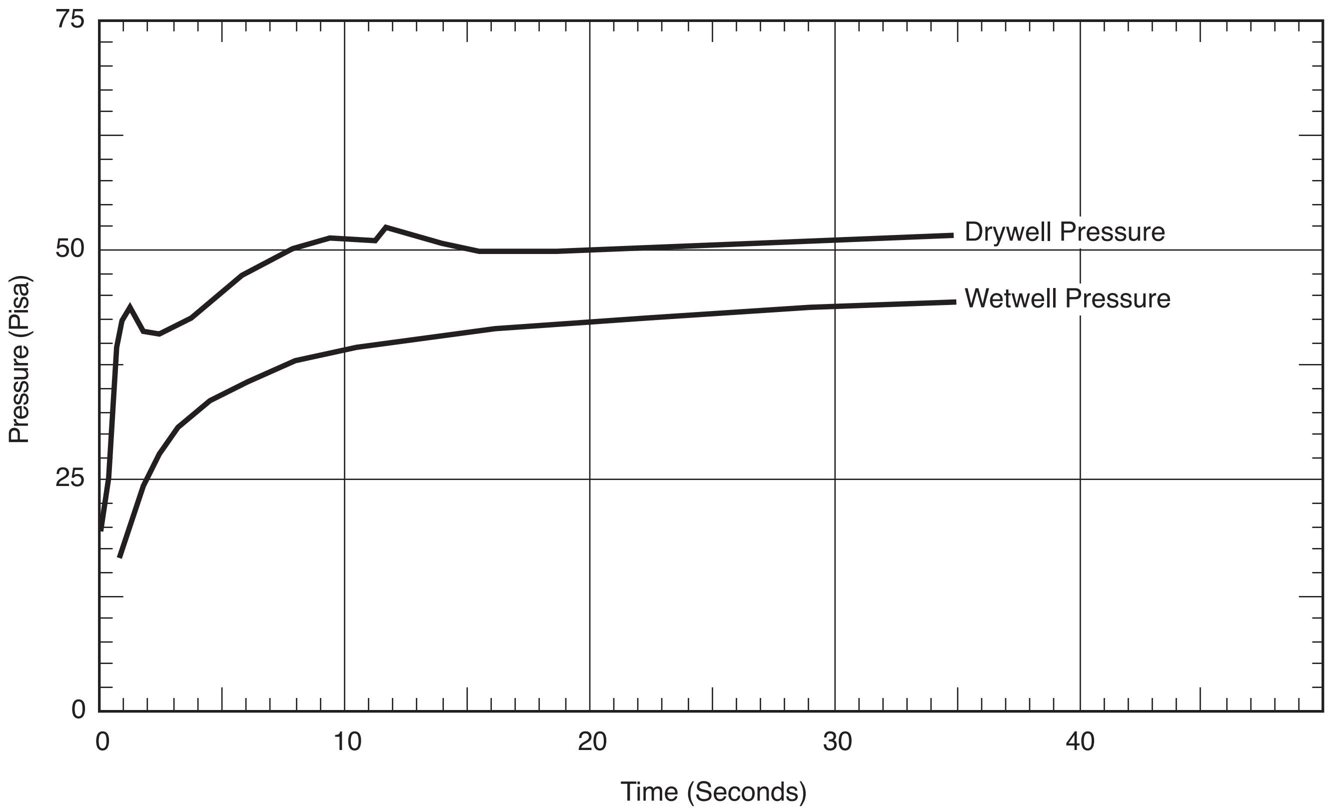
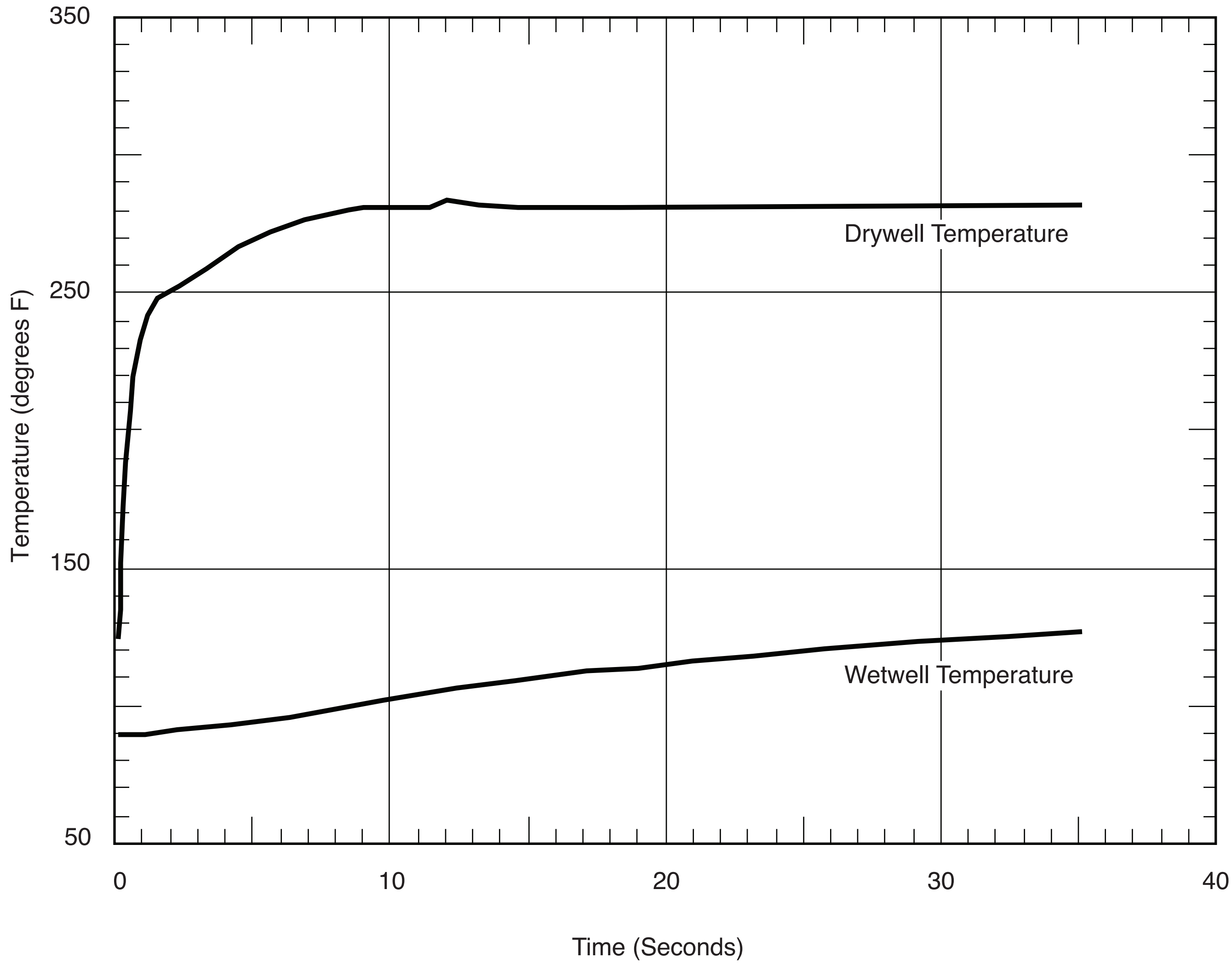


Diagram of the Recirculation Line Break Location



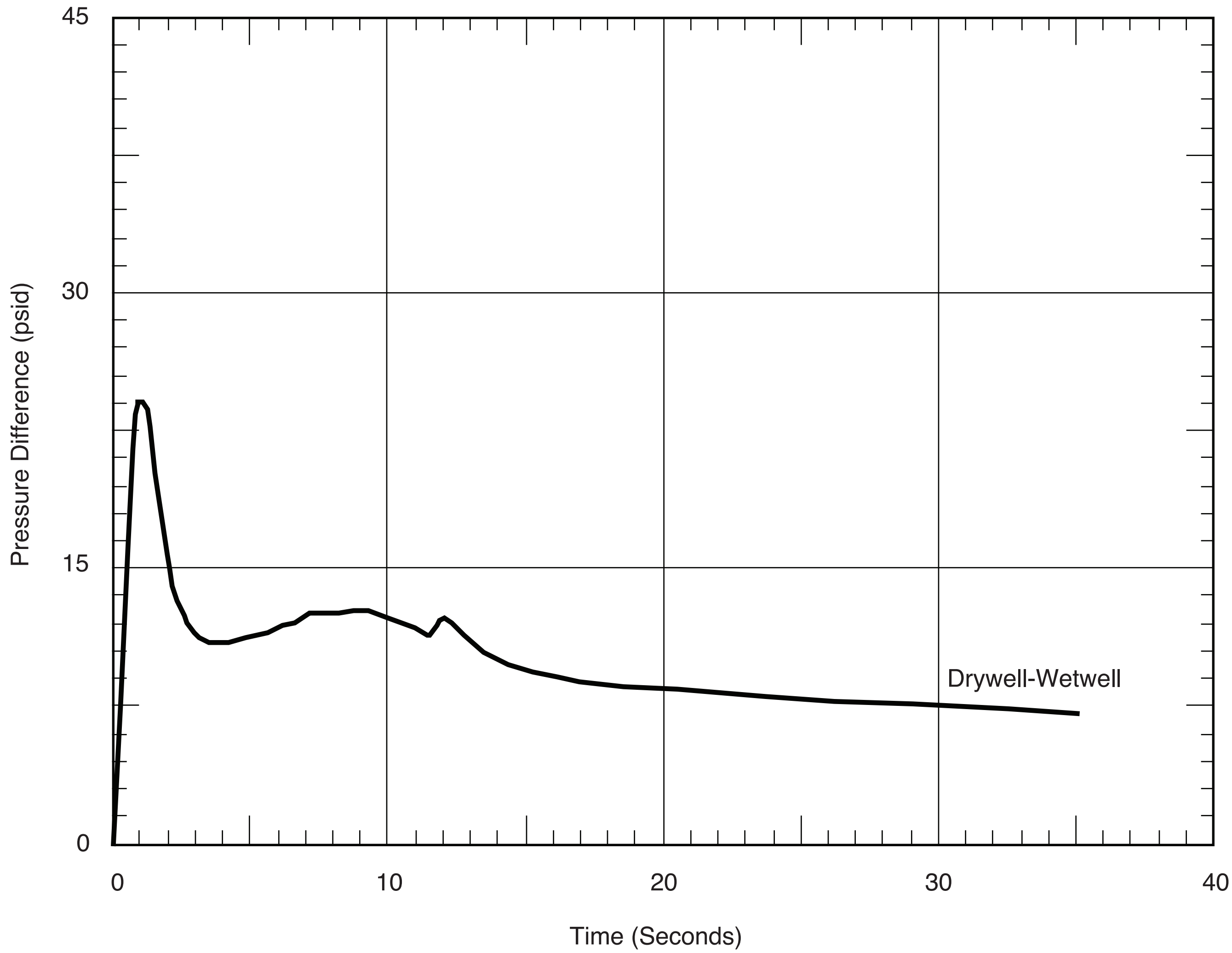
Pressure Response for Recirculation Line Break (Initial Containment Pressure 2 psig)

Draw. No. 900547.37 | Rev. | Figure 6.2-3

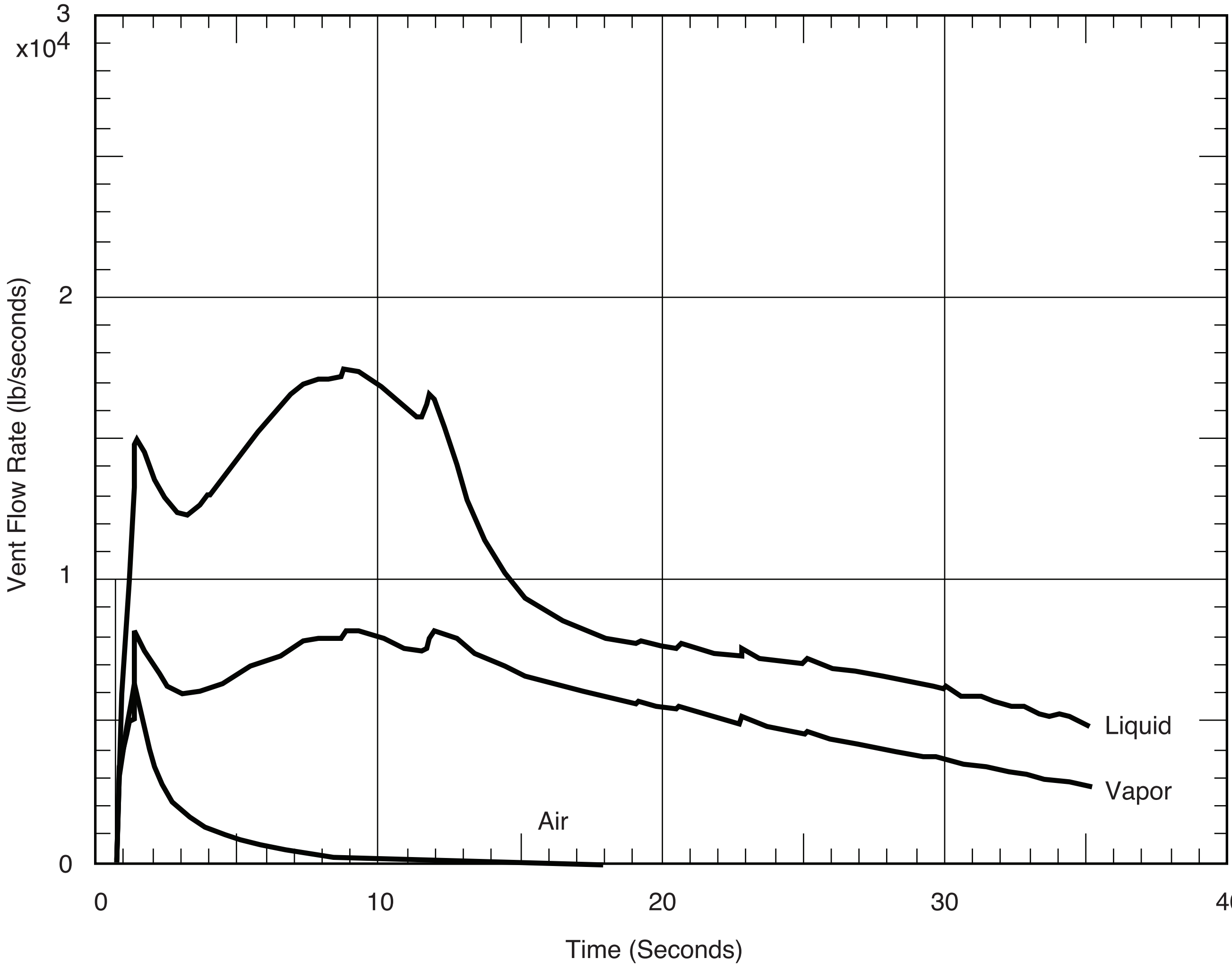


Temperature Response for Recirculation Line Break (Initial Containment Pressure 2 psig)

Draw. No. 960222.02 | Rev. | Figure 6.2-4

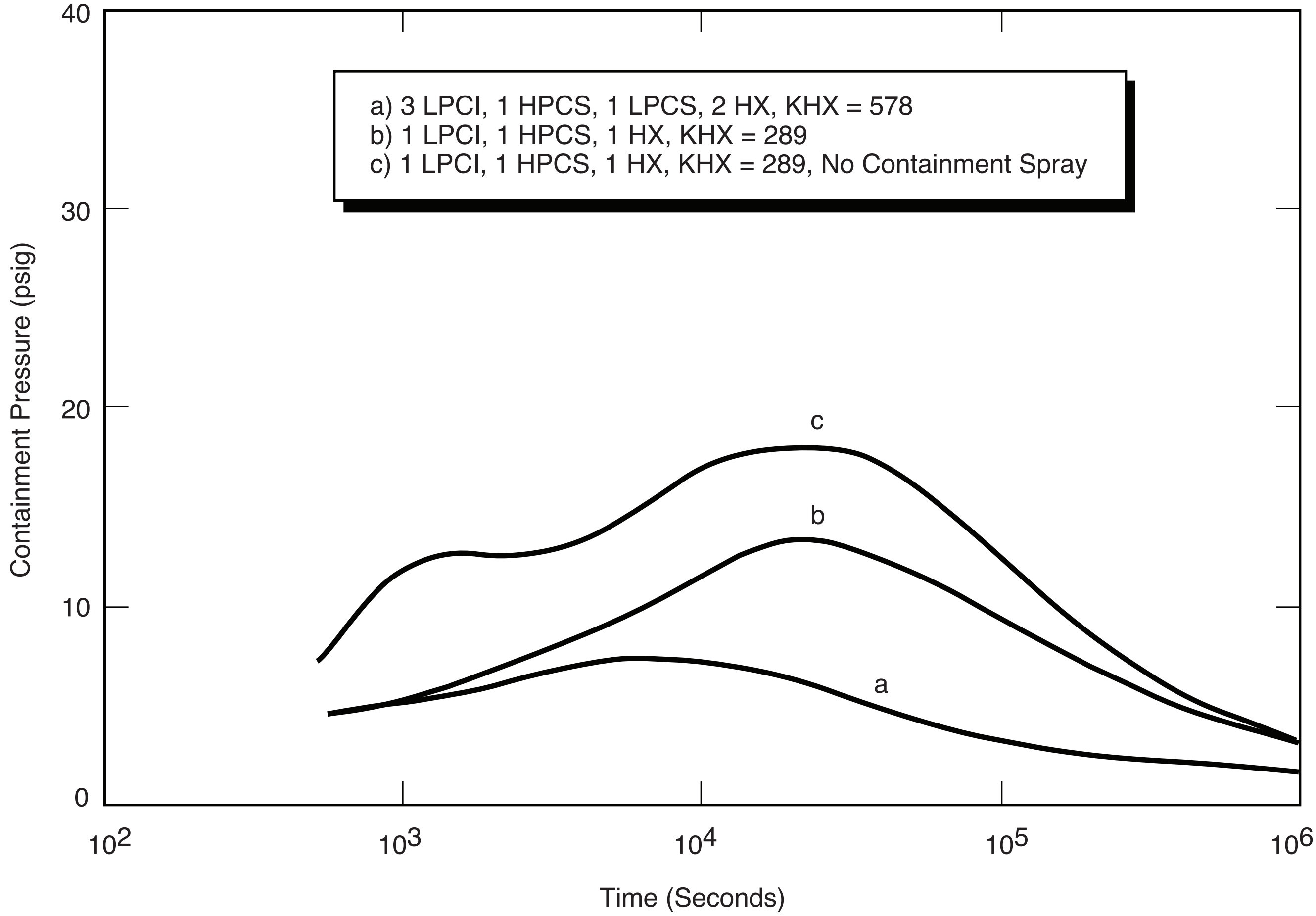


Drywell Floor ΔP Response for Recirculation Line Break (Initial Containment Pressure 2 psig)



Columbia Generating Station Final Safety Analysis Report	Containment Vent System Flow Rate for Recirculation (Initial Containment Pressure 2 psig)

Draw. No. 960222.04 | Rev. | Figure 6.2-6



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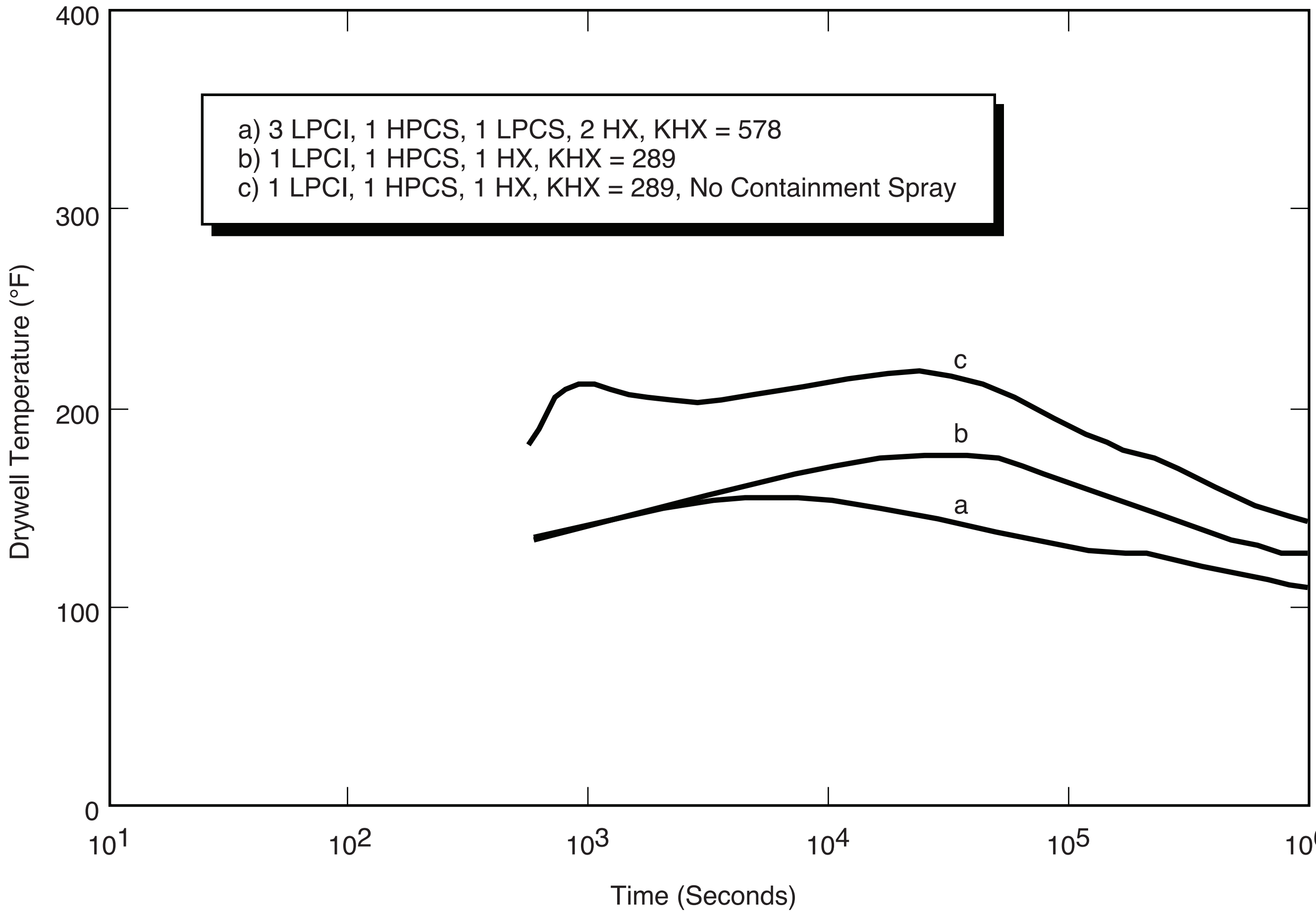
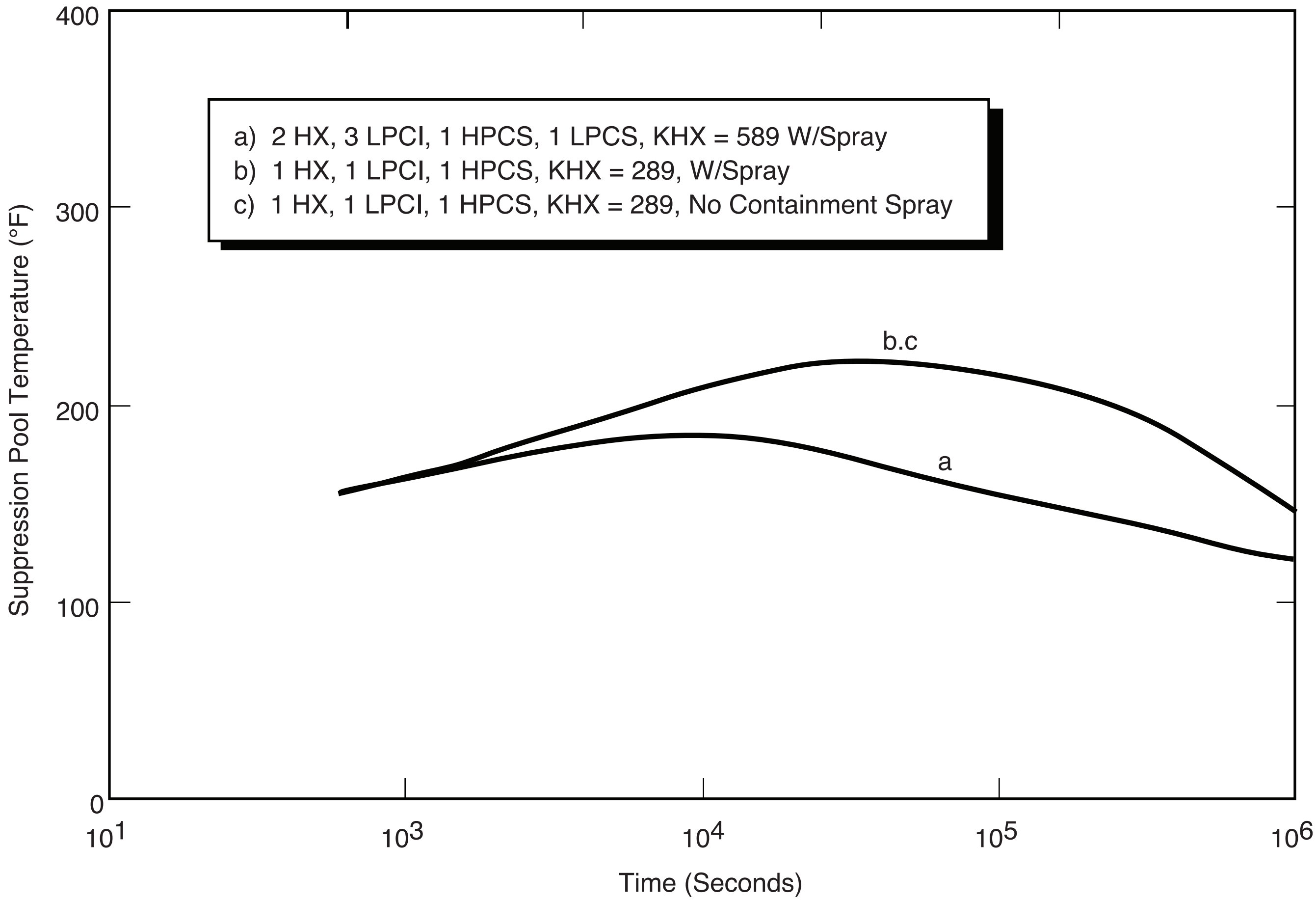
Containment Pressure Response Cases A, B, and C - Original Rated Power

Draw. No. 960222.67	Rev.	Figure 6.2-7



Drywell Temperature Response Cases A, B, and C - Original Rated Power



Columbia Generating Station
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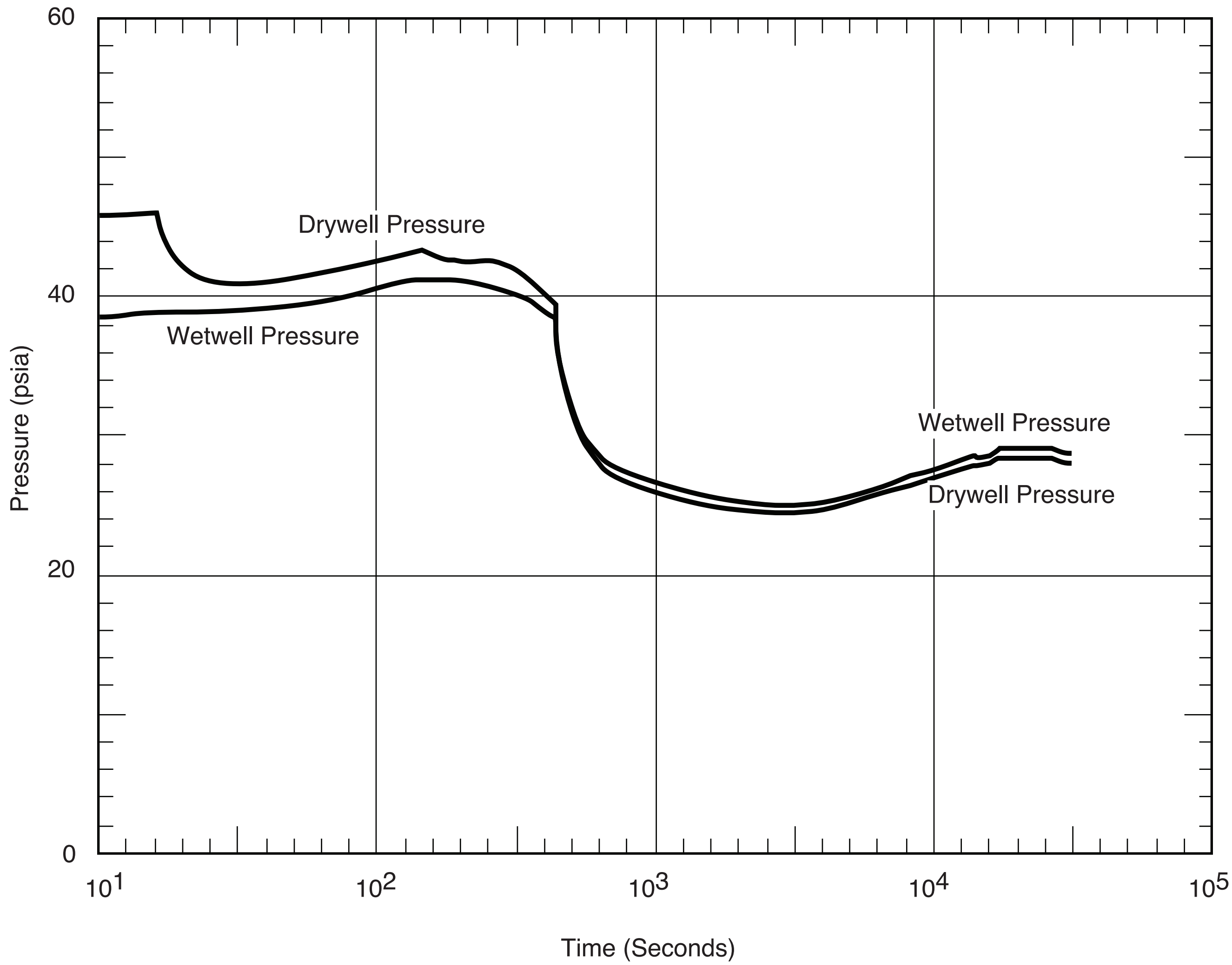
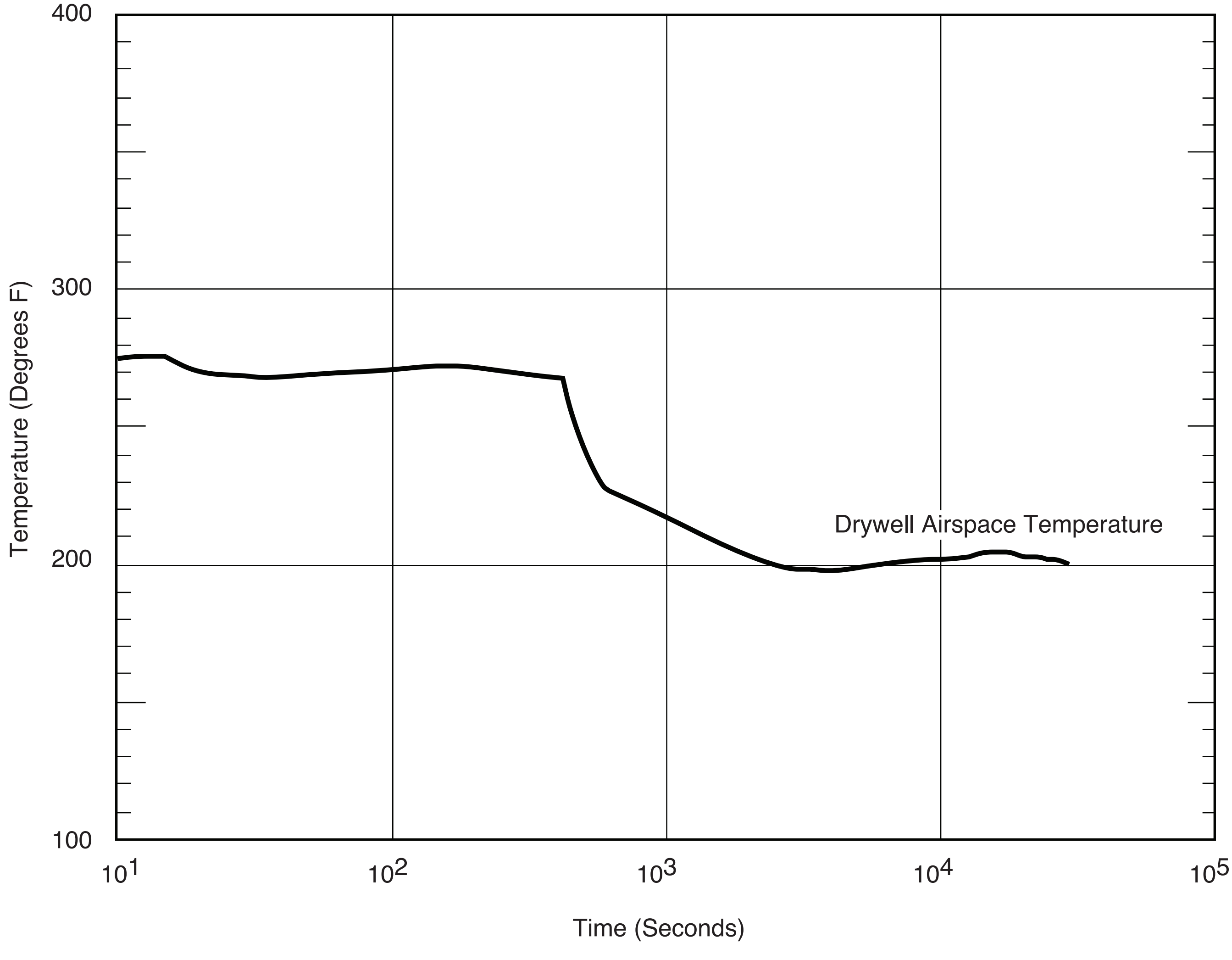
Suppression Pool Temperature Response, Long-Term Response - Original Rated Power

Draw. No. 960222.27	Rev.	Figure 6.2-9



Containment Pressure Response - Case C
Uprated Power

Draw. No. 960222.05 | Rev. | Figure 6.2-10



Columbia Generating Station
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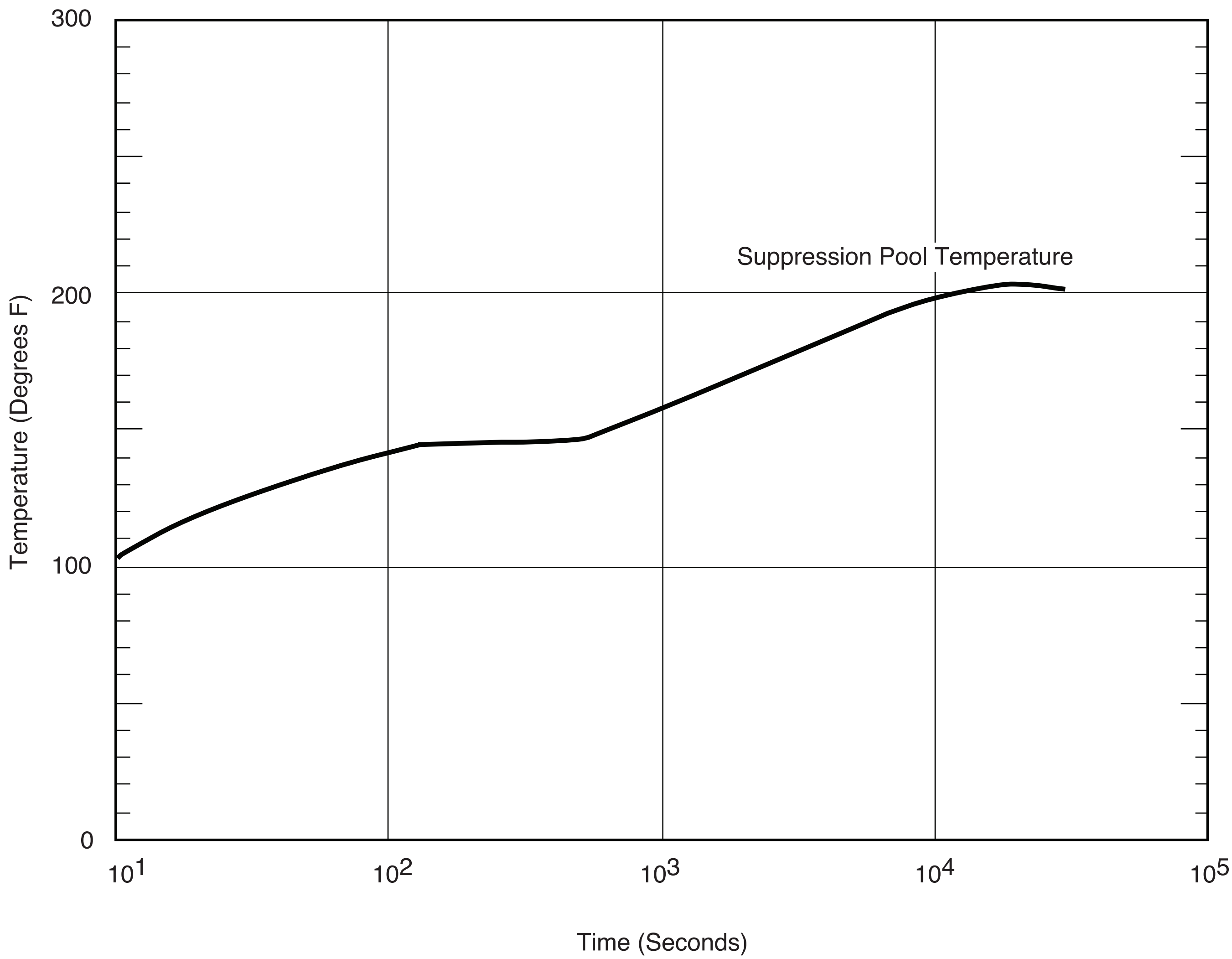
Drywell Temperature Response - Case C
Uprated Power

Draw. No. 960222.06	Rev.	Figure 6.2-11



Columbia Generating Station
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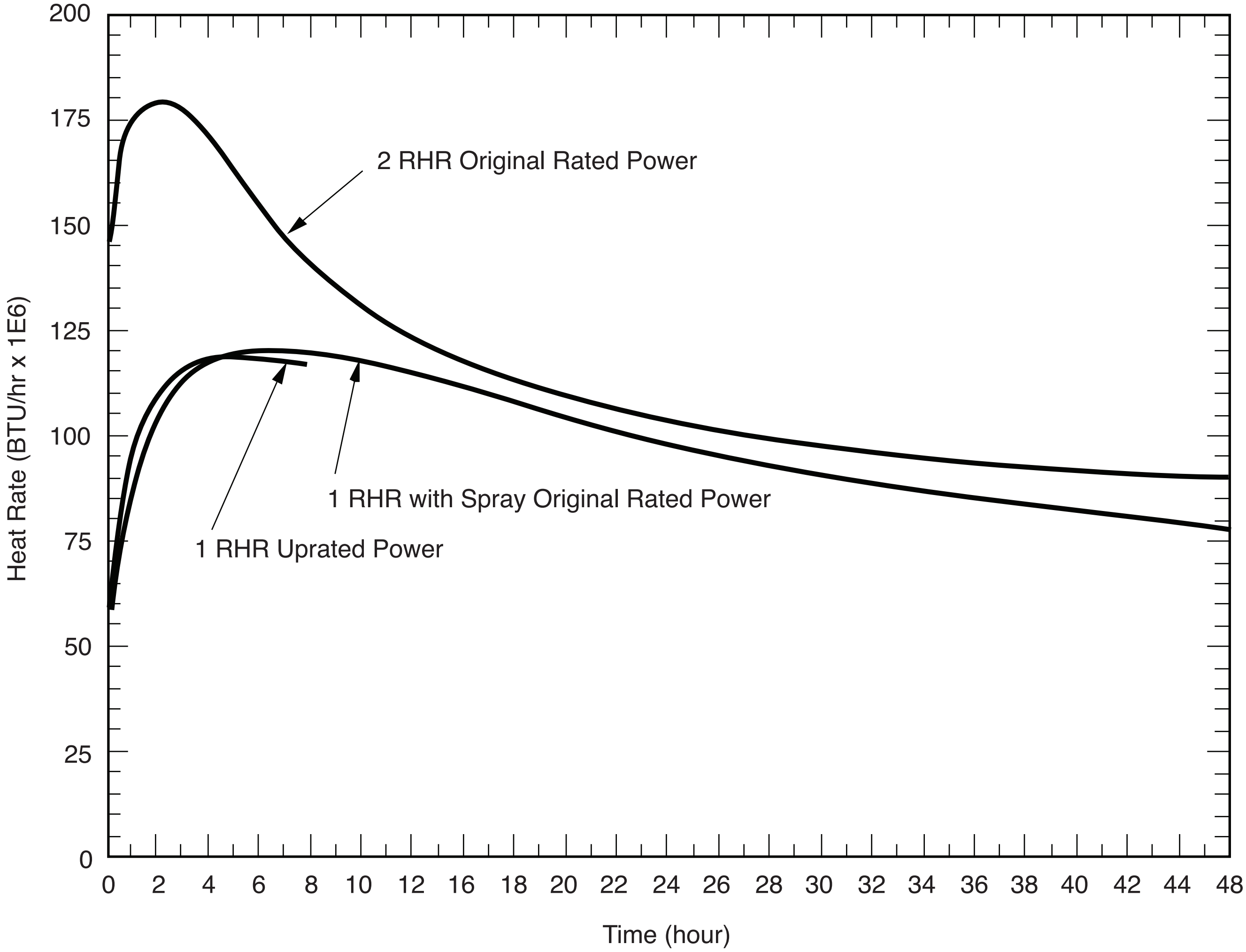
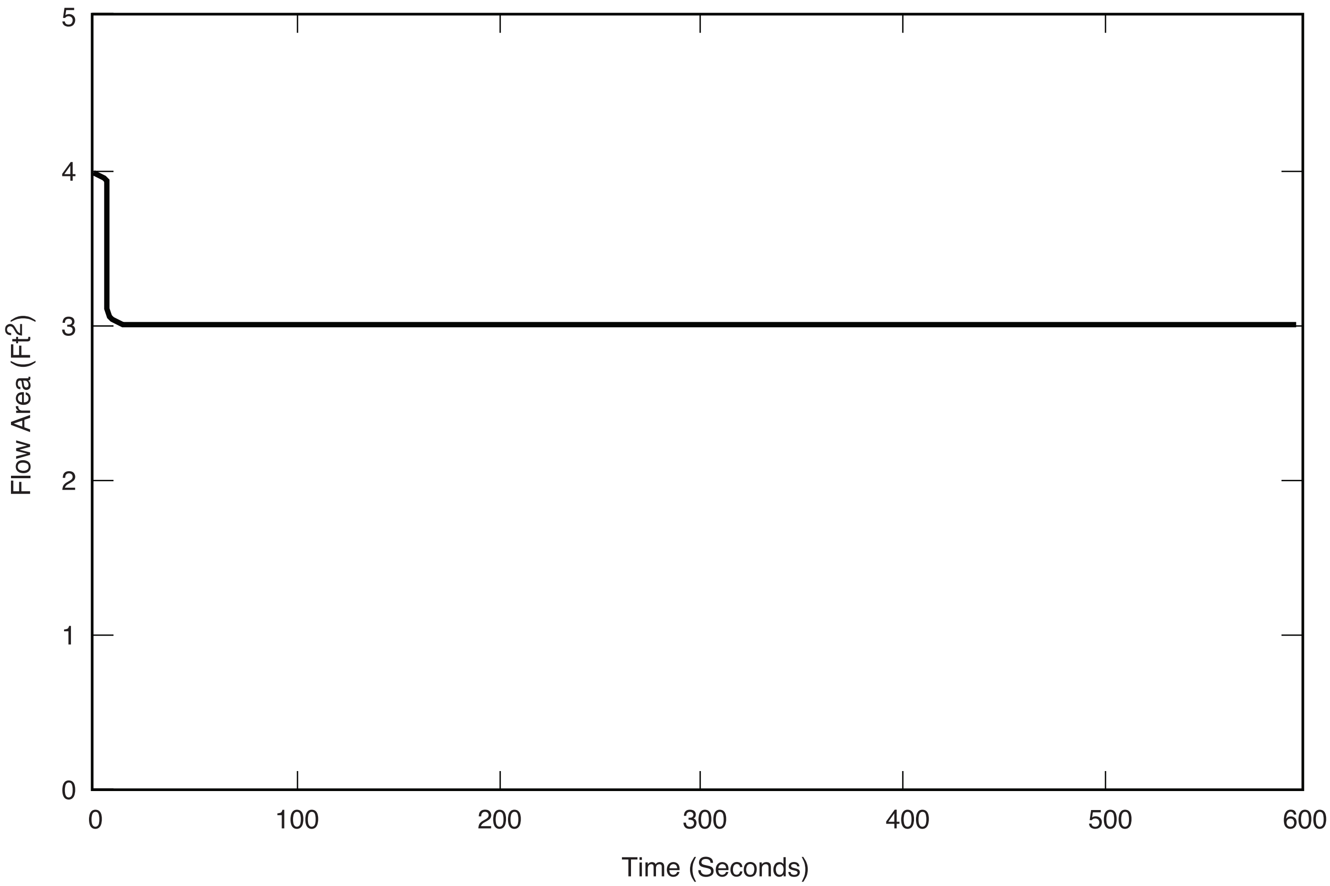
Suppression Pool Temperature Response - Case C
Uprated Power

Draw. No. 960222.07	Rev.	Figure 6.2-12



Columbia Generating Station Final Safety Analysis Report	Residual Heat Removal Rate		
	Draw. No. 960222.15	Rev.	Figure 6.2-13



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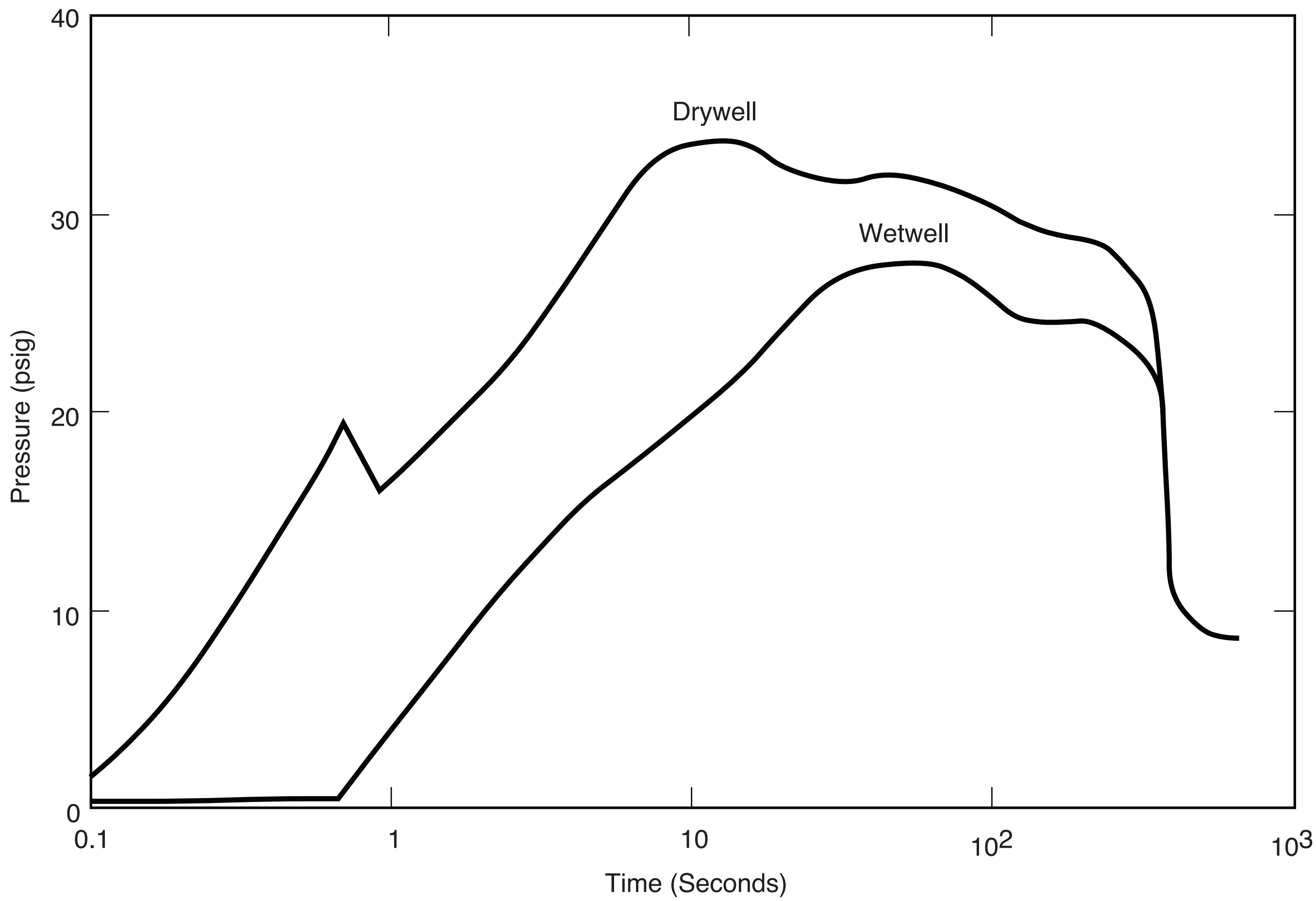
Effective Blowdown Area Main Steam Line Break

Draw. No. 960222.28

Rev.

Figure 6.2-14



Columbia Generating Station
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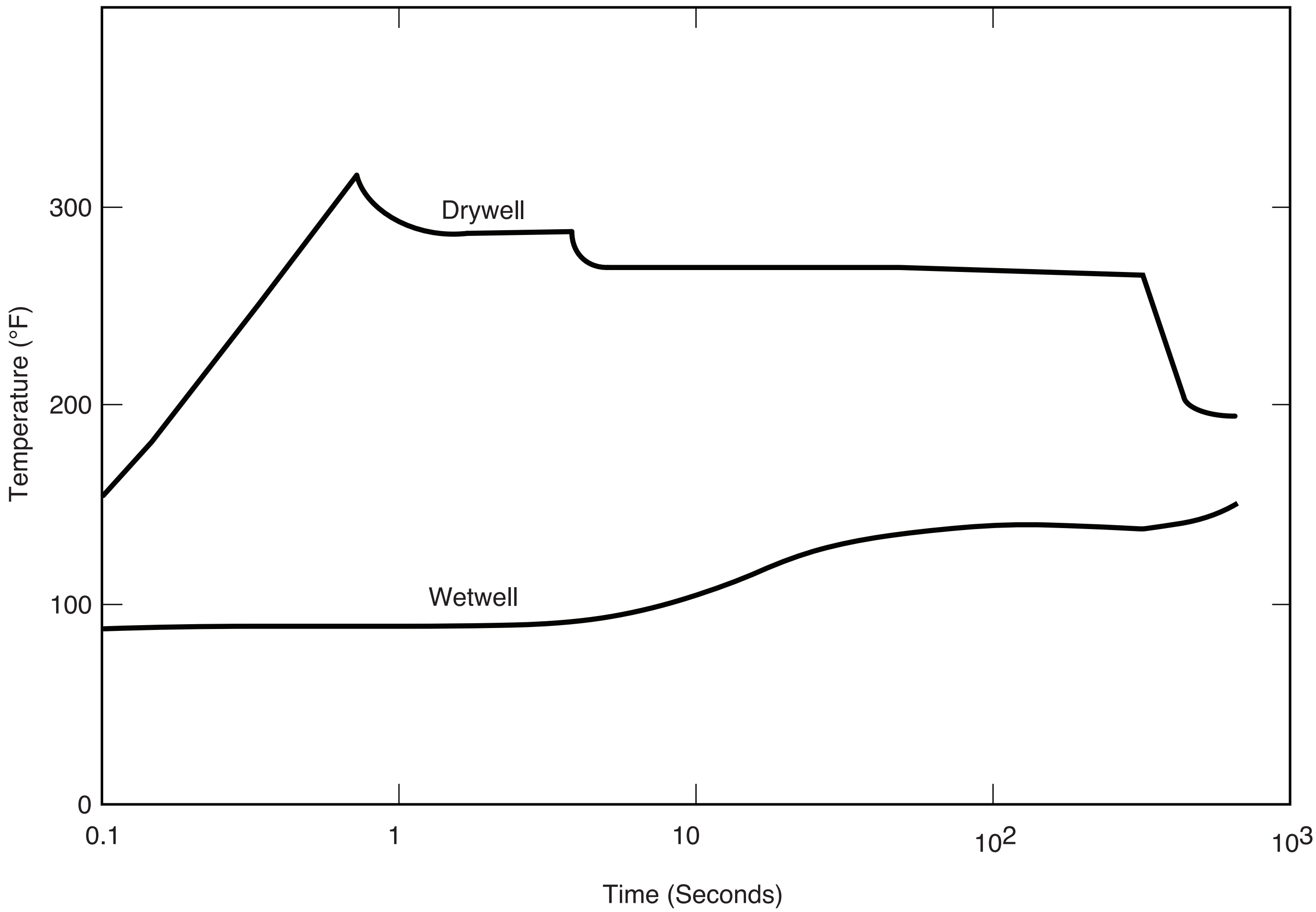
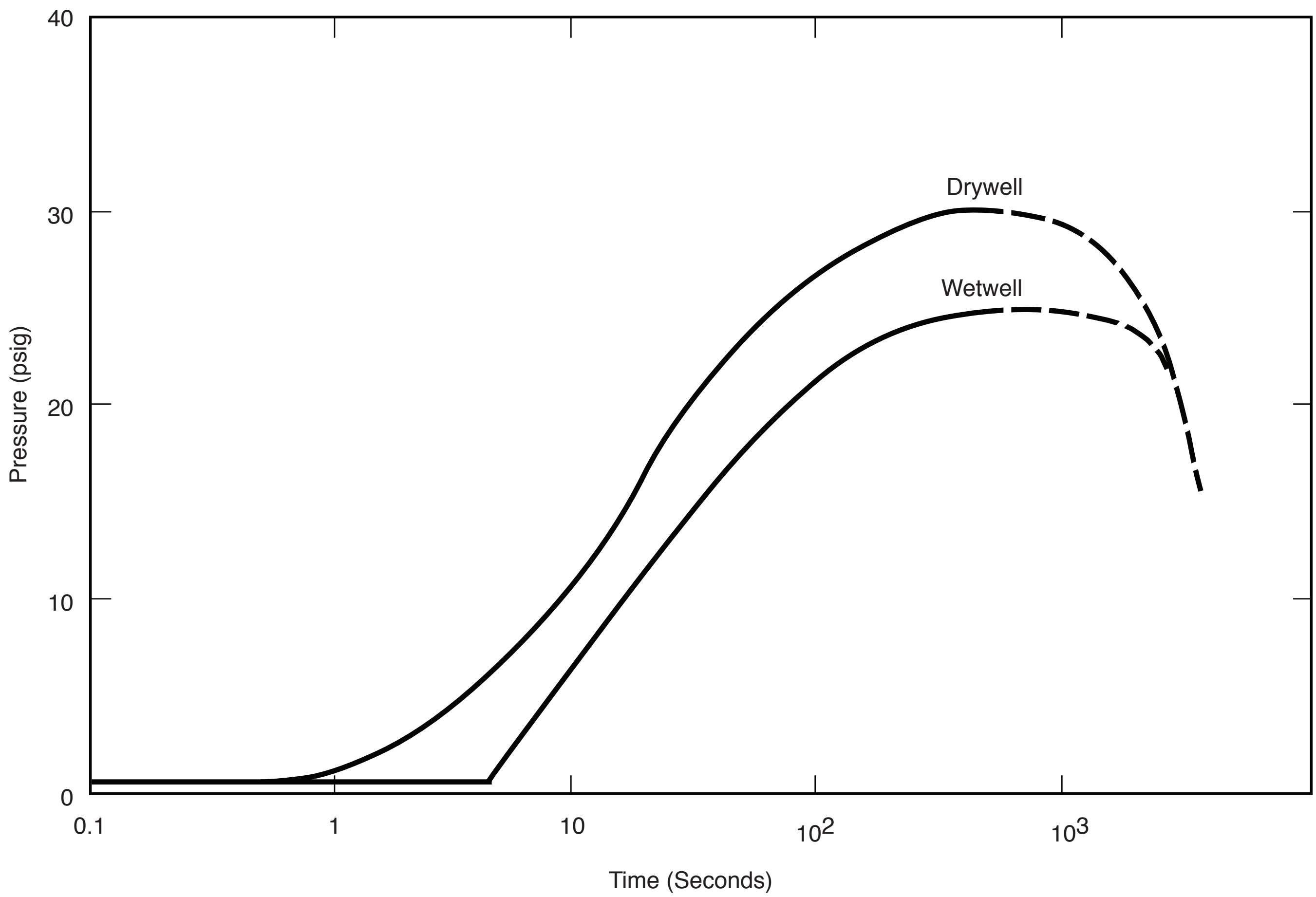
Bounding Pressure Response - Main Steam Line Break Original Rated Power

Draw. No. 960222.30 | Rev. | Figure 6.2-15

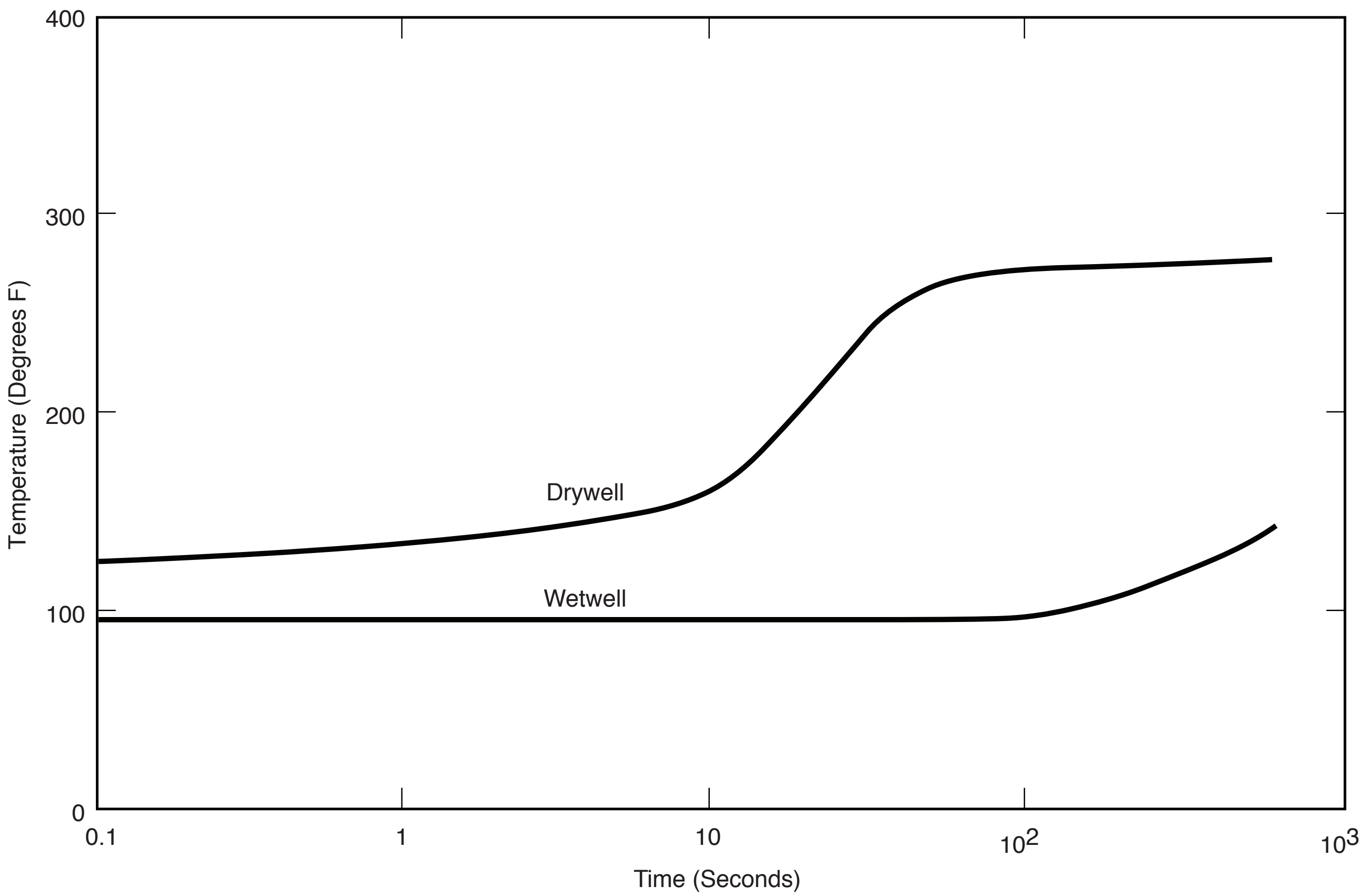


Bounding Temperature Response - Main Steam Line Break Original Rated Power

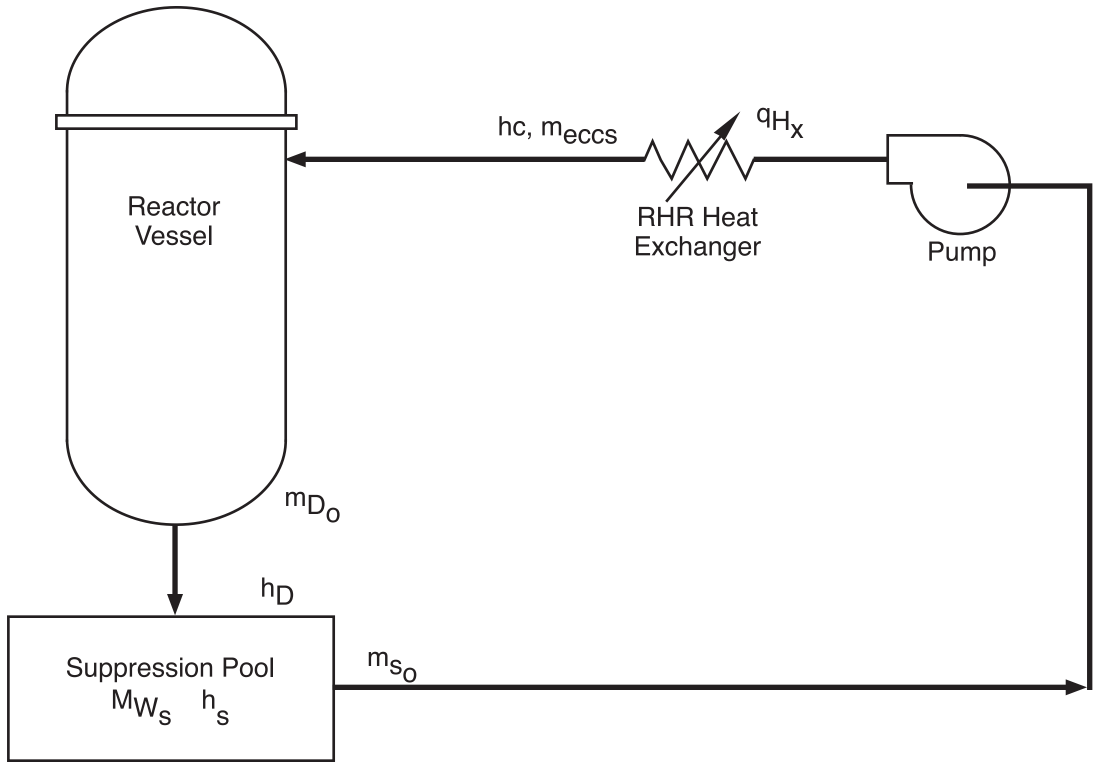


Pressure Response - Recirculation Line Break ($0.1\ ft^2$) Original Rated Power

Draw. No. 960222.31 | Rev. | Figure 6.2-17



Temperature Response - Recirculation Line Break ($0.1\ ft^2$) Original Rated Power



h_D = Enthalpy Of Water Leaving Reactor, Btu/Lb

m_{D_o} = Flow Rate Out Of Reactor, Lb/Sec

h_s = Enthalpy Of Water In Suppresion Pool, Btu/Lb

m_{s_o} = Flow Out Of Suppression Pool, Lb/Sec

q_{H_x} = Heat Removal Rate Of Heat Exchanger, Btu/Sec

M_{W_s} = Mass Of Water In Suppression Pool

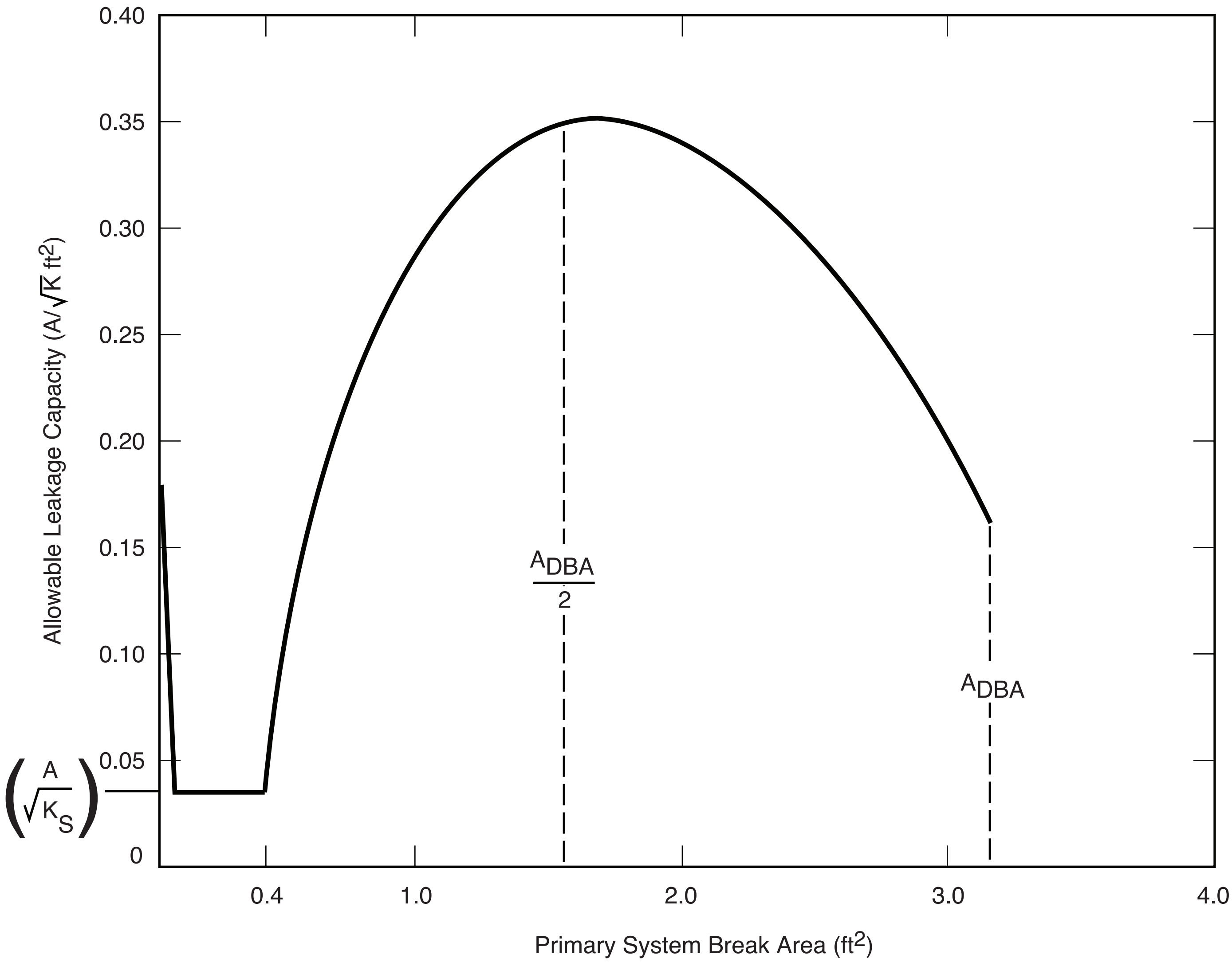
q_D = Core Decay Heat Rate, Btu/Sec

q_e = Stored Energy Release Rate, Btu/Sec

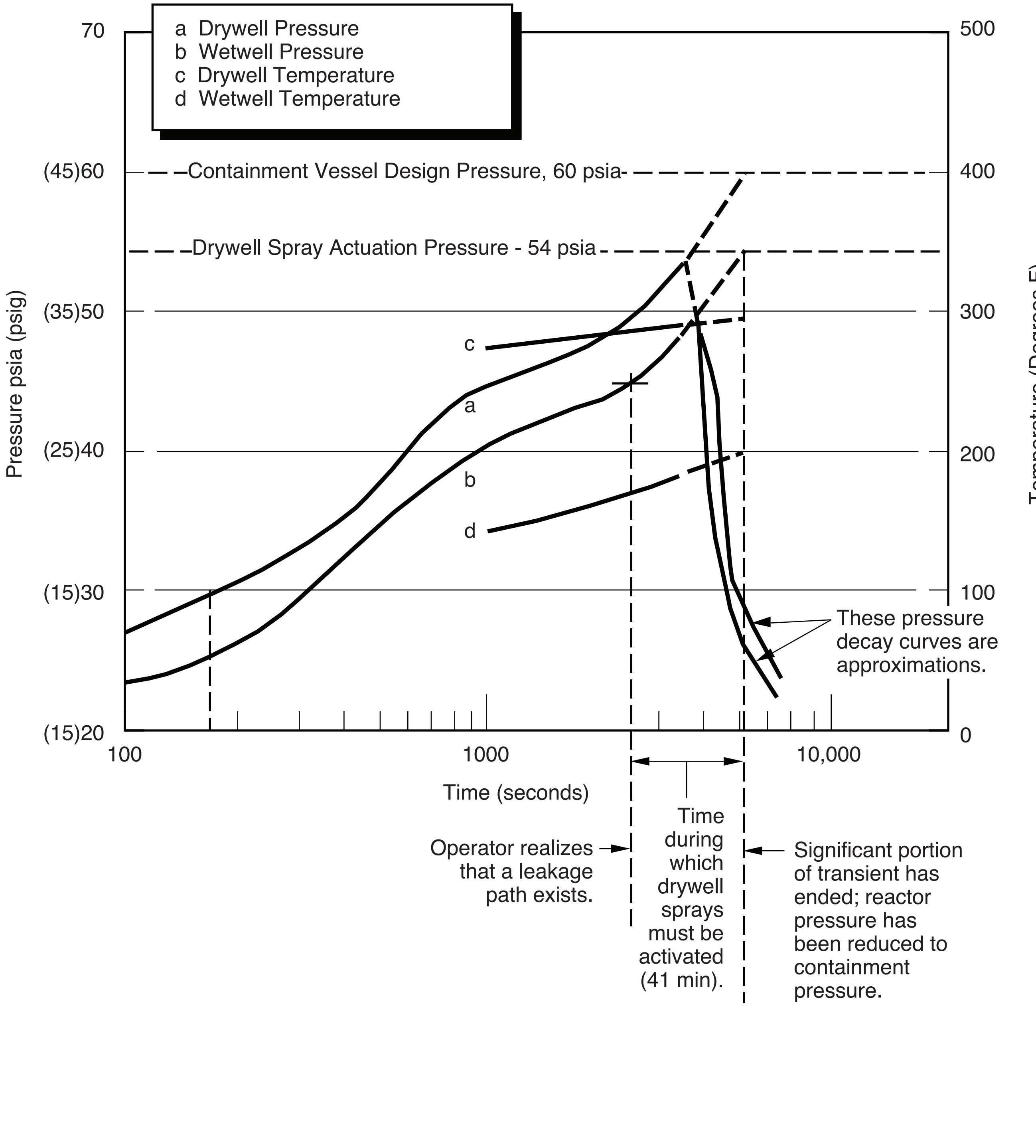
h_c = Enthalpy Of ECCS Flow To Reactor, Btu/Lb

m_{eccs} = ECCS Flow Rate, Lb/Sec

Columbia Generating Station **Final Safety Analysis Report**	**Schematic of ECCS Loop**
	Draw. No. 900547.39 | Rev. | Figure 6.2-19



Allowable Leakage Capacity



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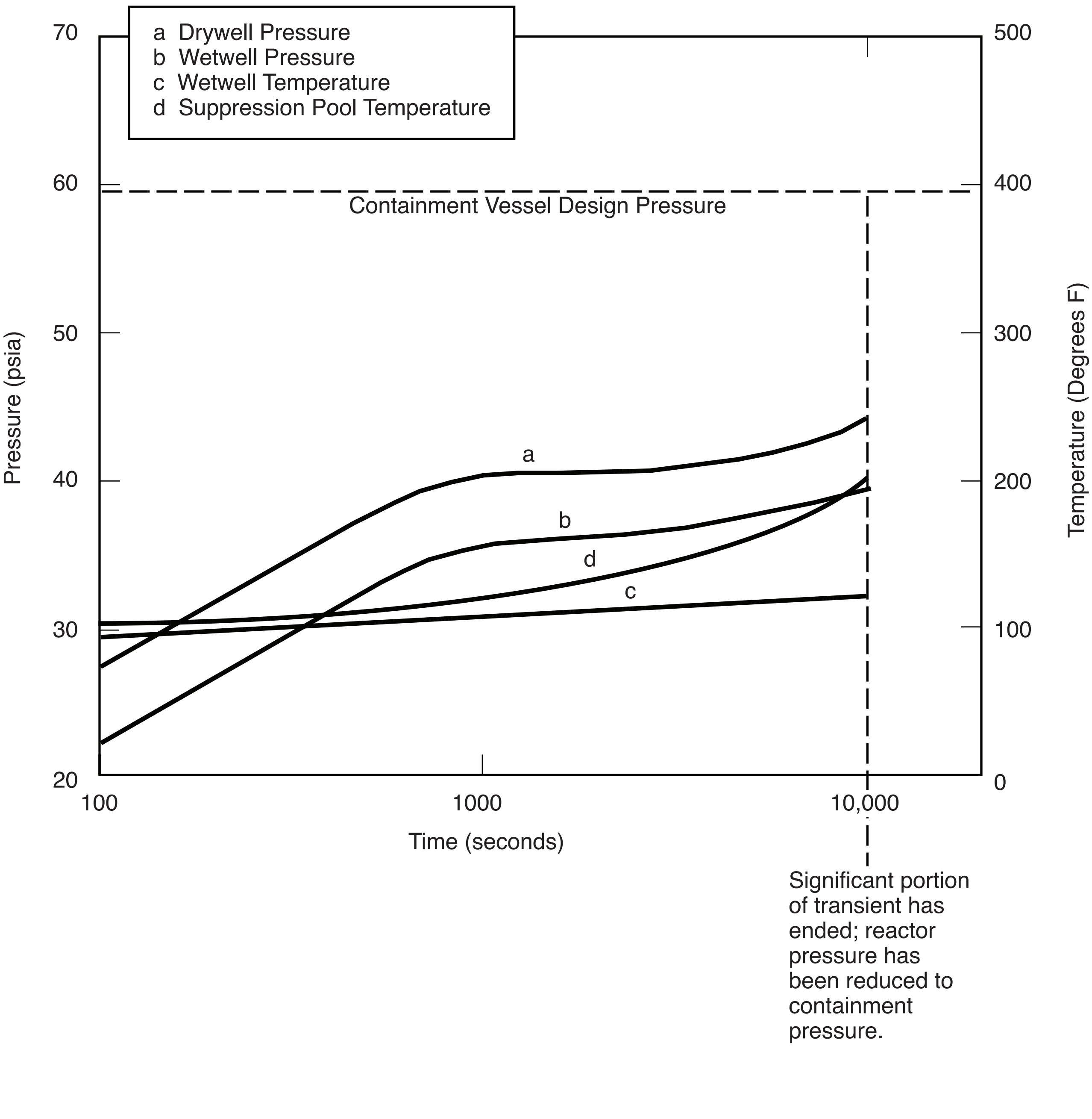
Containment Transient for Maximum Allowable Bypass Capacity $A\sqrt{x} = 0.050$

Draw. No. 960222.38 | Rev. | Figure 6.2-21

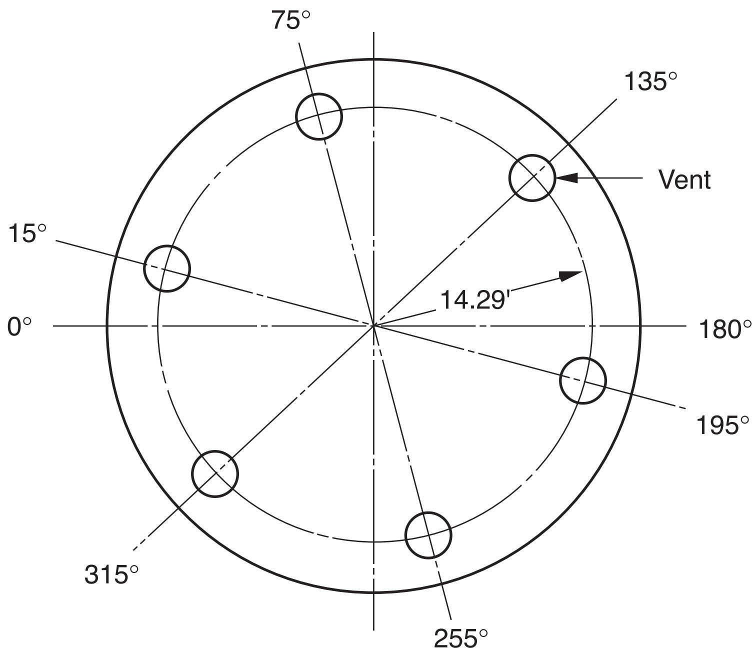


Containment Transient for $A/\sqrt{K} = 0.0045\ ft^2$

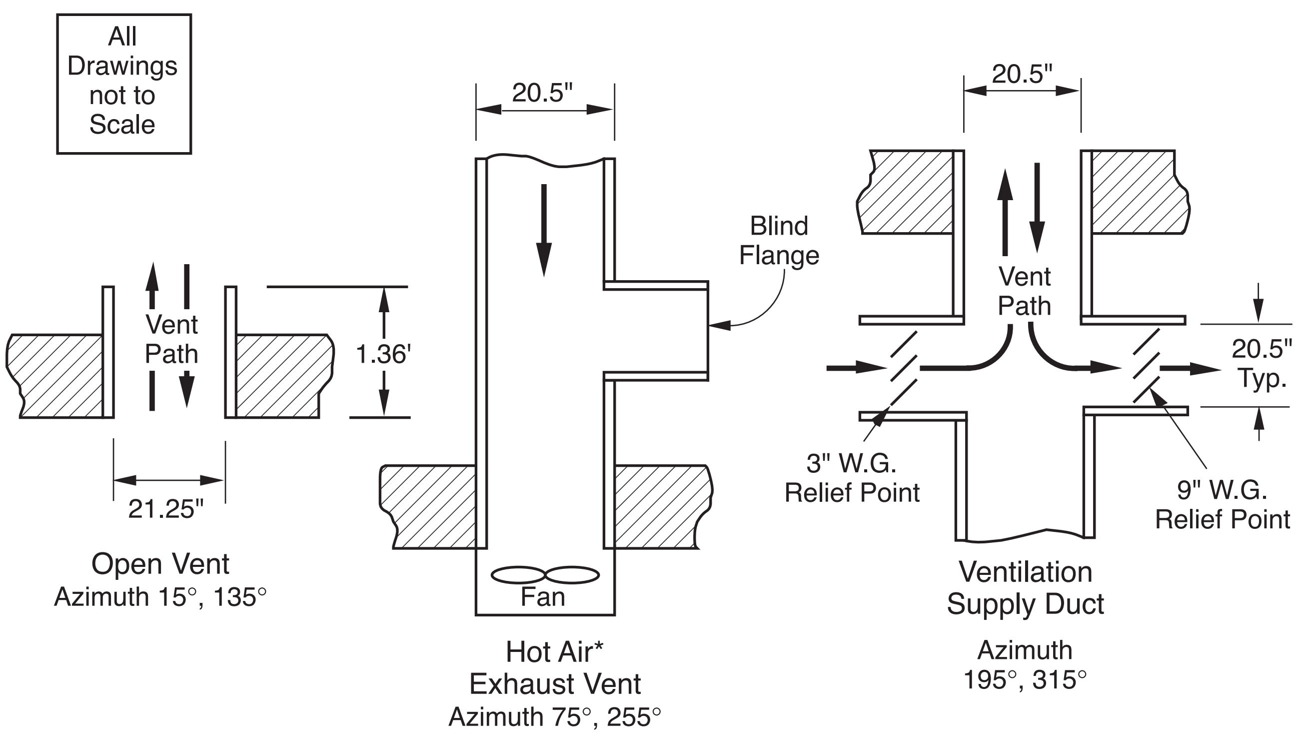
Draw. No. 960222.37 | Rev. | Figure 6.2-22

Figure Not Available For Public Viewing

Upper/Lower Bulkhead Plate Venting



Plan View of Bulkhead Plate

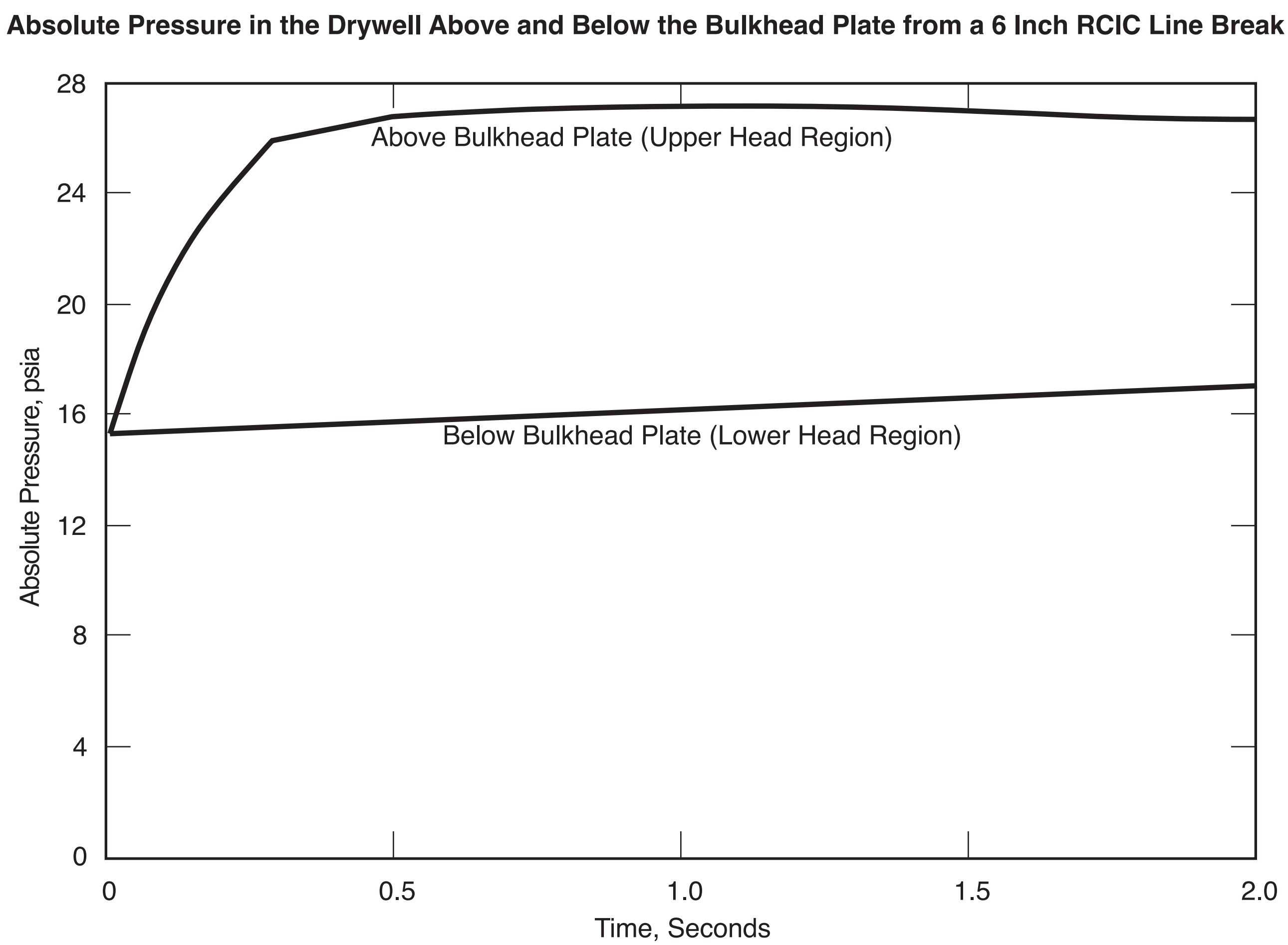


*Not Used in Compartment Pressure Analysis of Upper Head Region

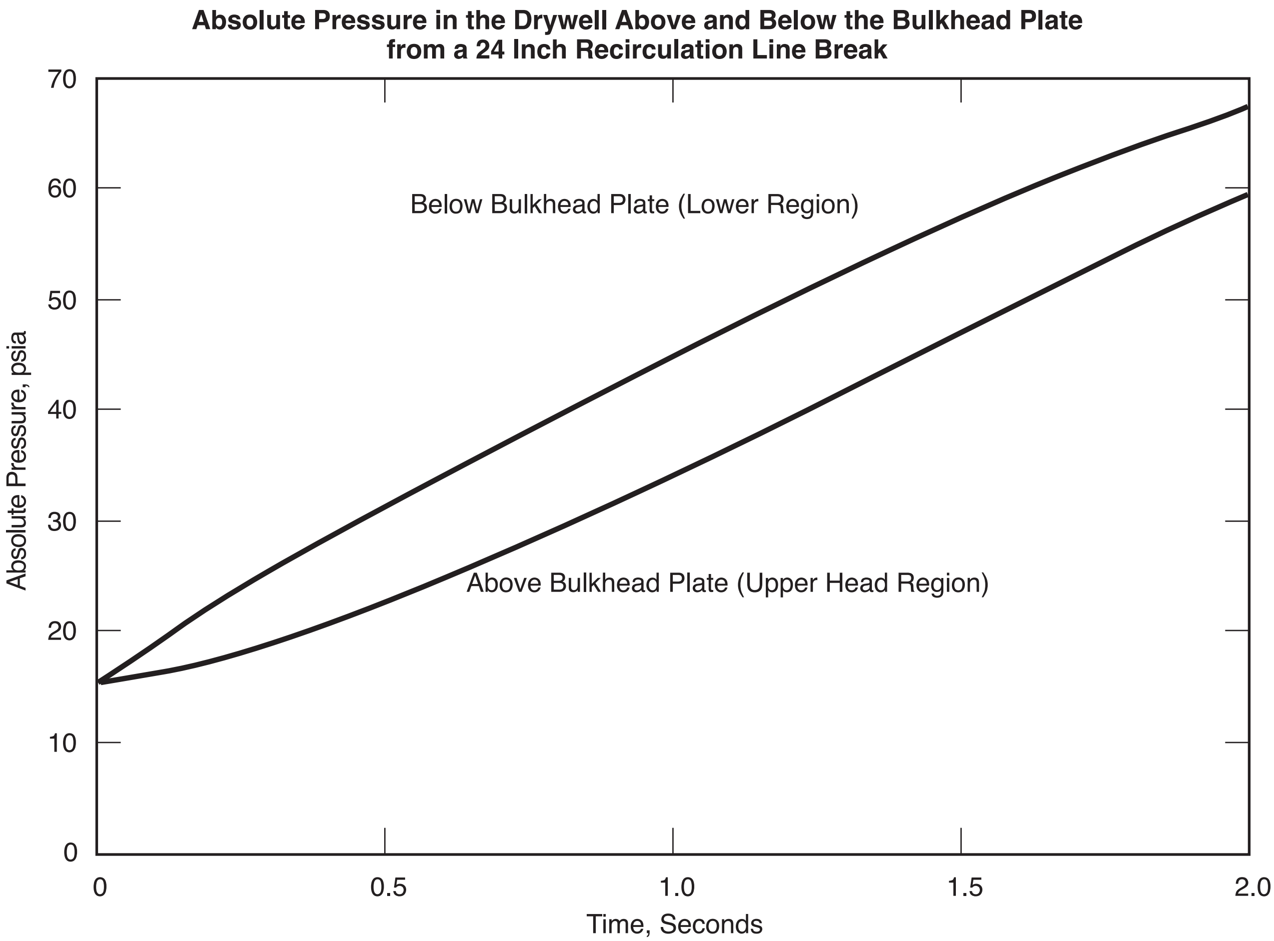
Columbia Generating Station
Final Safety Analysis Report

Venting Through Bulkhead Plate

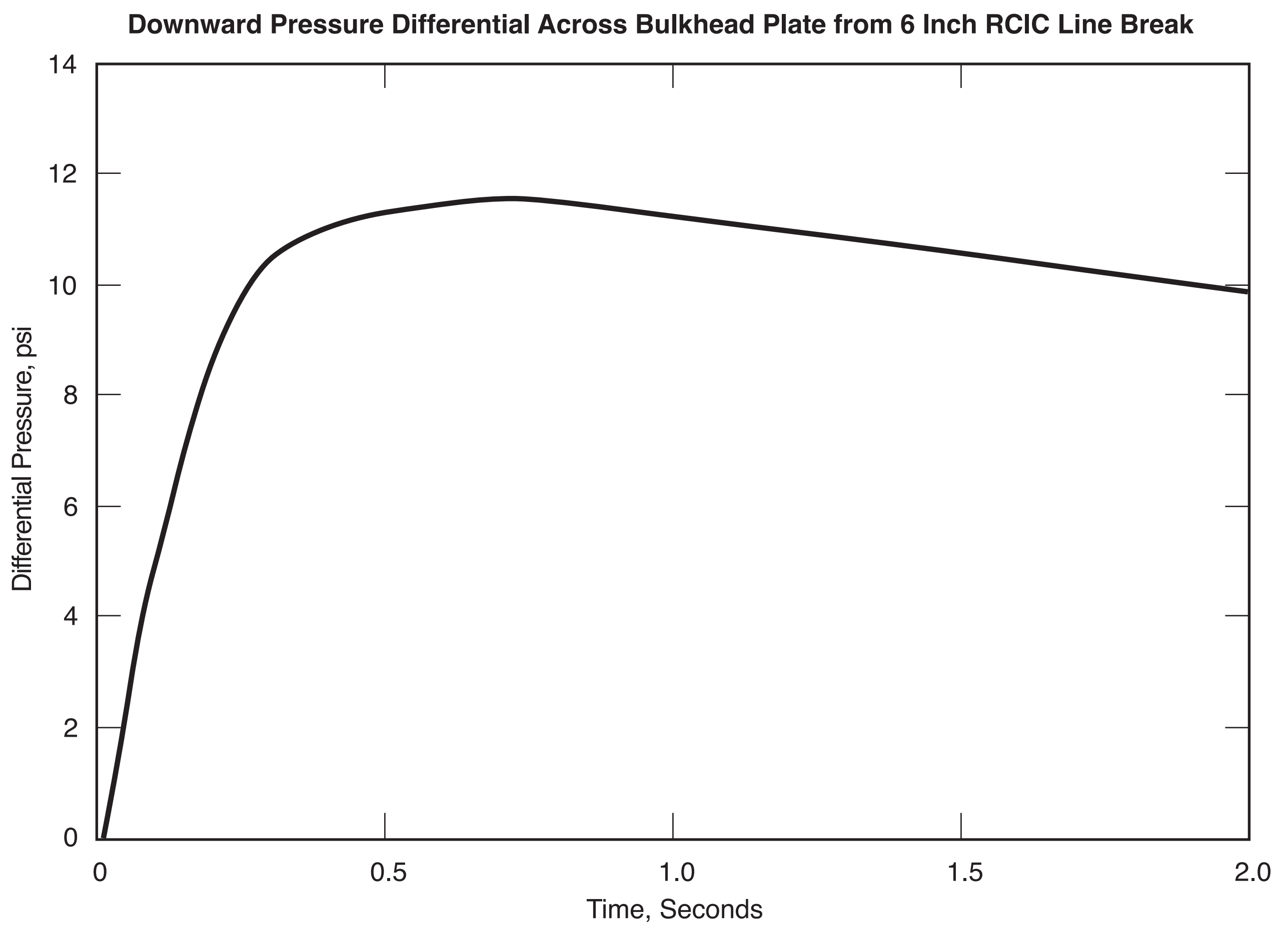
Draw. No. 920843.15	Rev.	Figure 6.2-24



Columbia Generating Station Final Safety Analysis Report	Absolute Pressure in Upper Head Region and Lower Region from 6 in. RCIC Line Break		
	Draw. No. 920843.11	Rev.	Figure 6.2-25



Columbia Generating Station Final Safety Analysis Report	Absolute Pressure in Lower Region and Upper Head Region from 24 in. Recirculation Line Break		
	Draw. No. 920843.12	Rev.	Figure 6.2-26



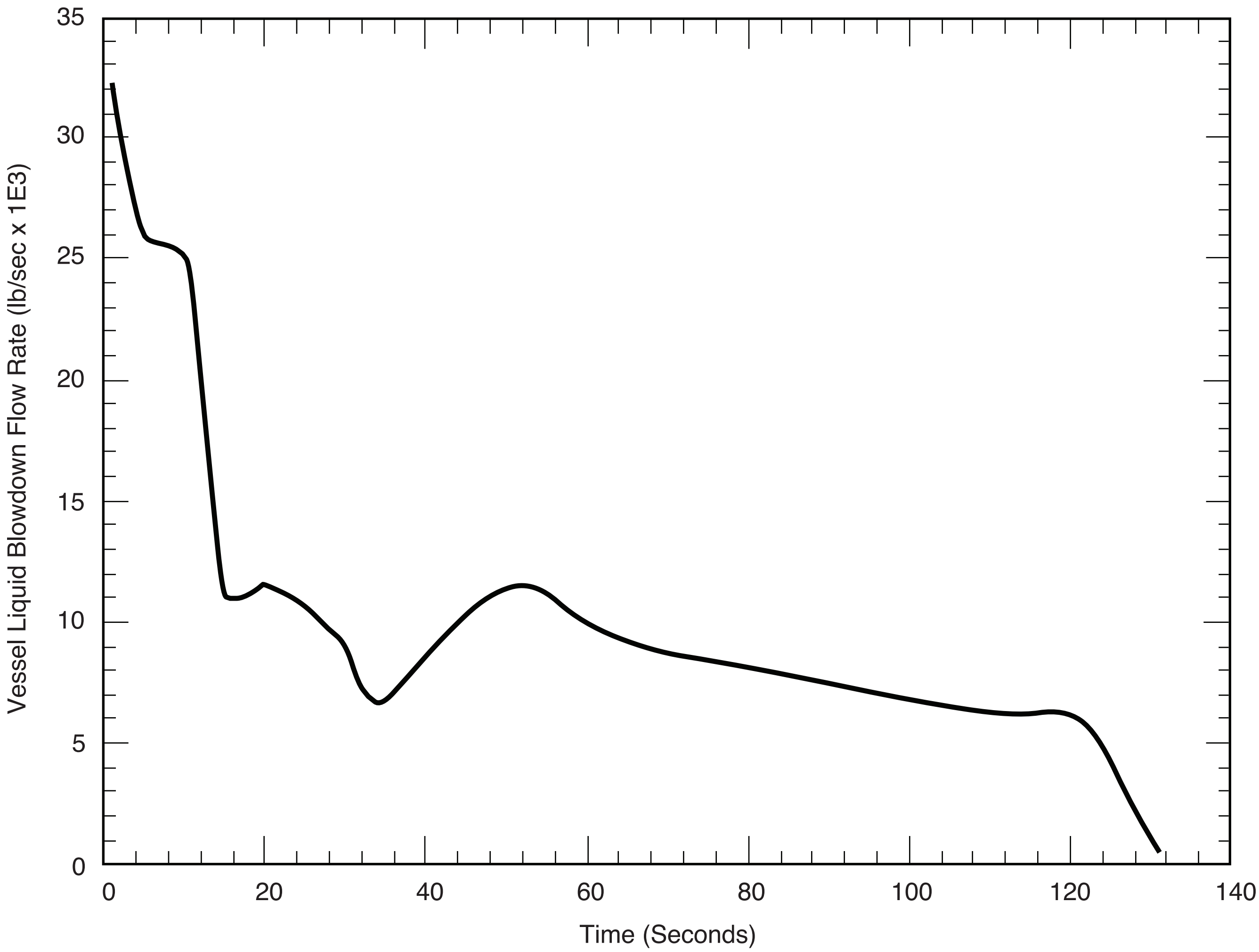
Columbia Generating Station
Final Safety Analysis Report

Downward Pressure Differential Across Bulkhead Plate from 6 In. Line Break

Draw. No. 920843.13	Rev.	Figure 6.2-27

Upward Pressure Differential Across Bulkhead Plate from 24 In. Recirculation Line Break

Draw. No. 920843.14	Rev.	Figure 6.2-28

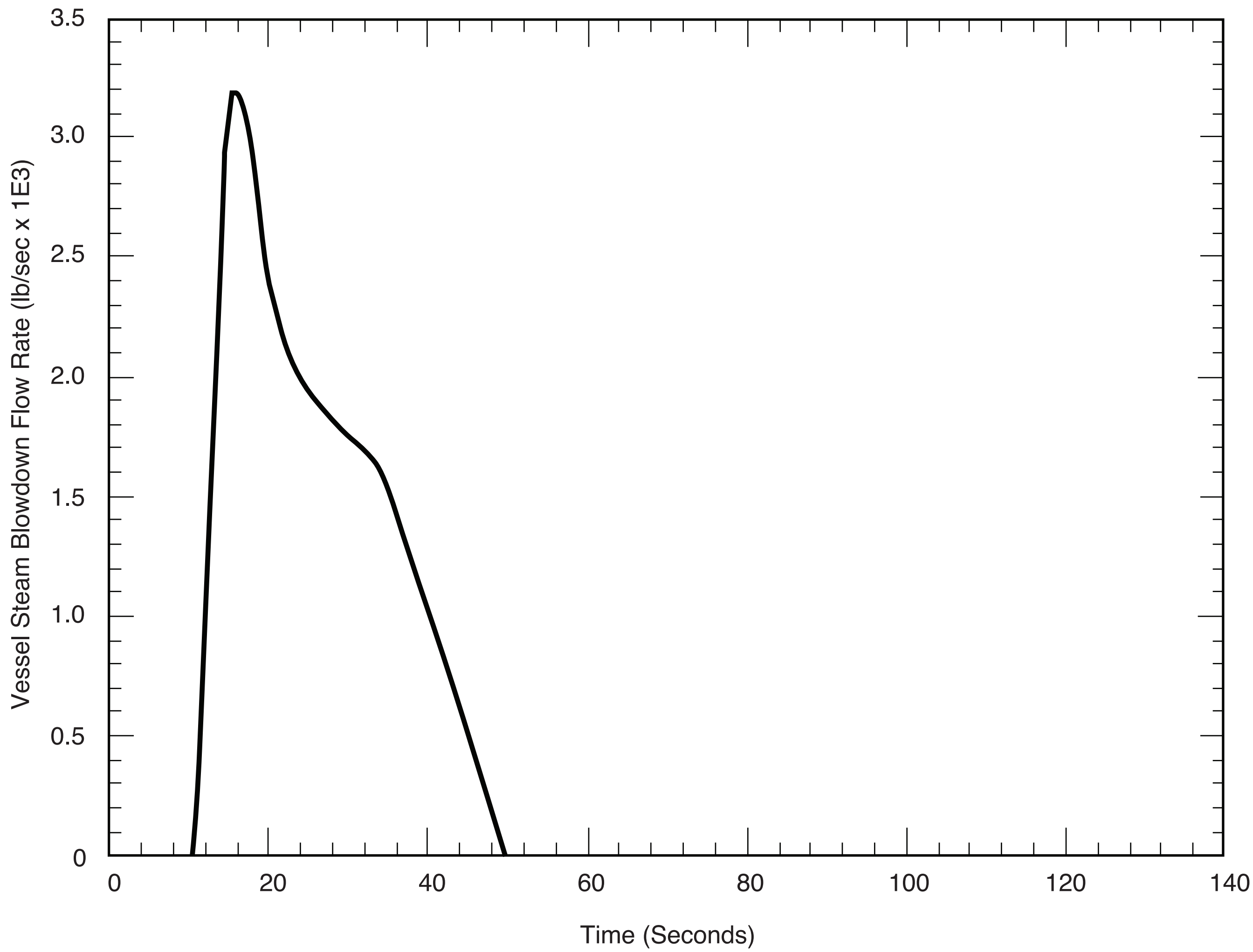


Columbia Generating Station
Final Safety Analysis Report

Recirculation Break Blowdown Flow Rates Liquid Flow - Short-Term Original Rated Power

Draw. No. 960222.10 | Rev. | Figure 6.2-29

Amendment 53
November 1998

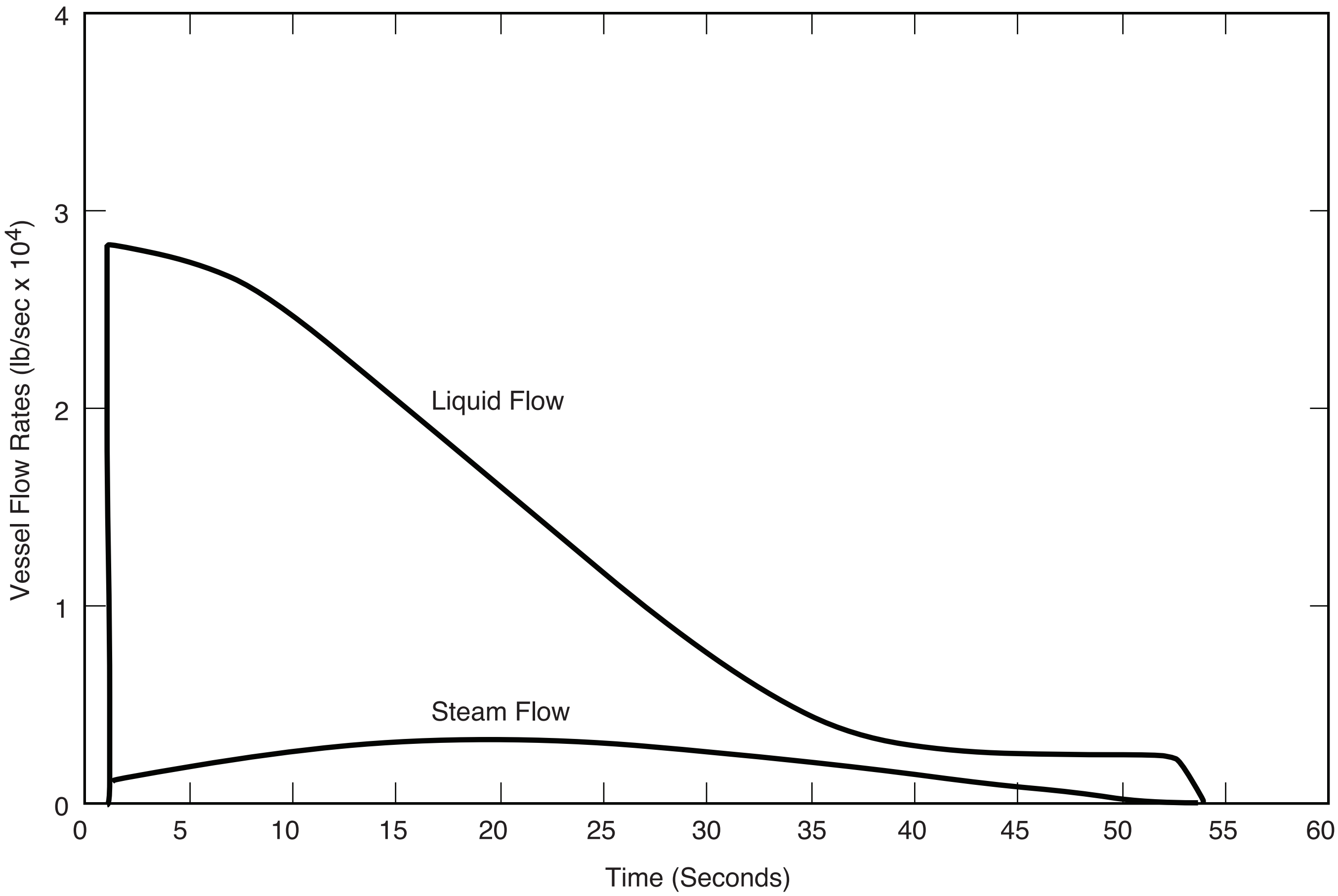


Columbia Generating Station
Final Safety Analysis Report

Recirculation Break Blowdown Flow Rates Steam Flow - Short-Term Original Rated Power

Draw. No. 960222.11	Rev.	Figure 6.2-30

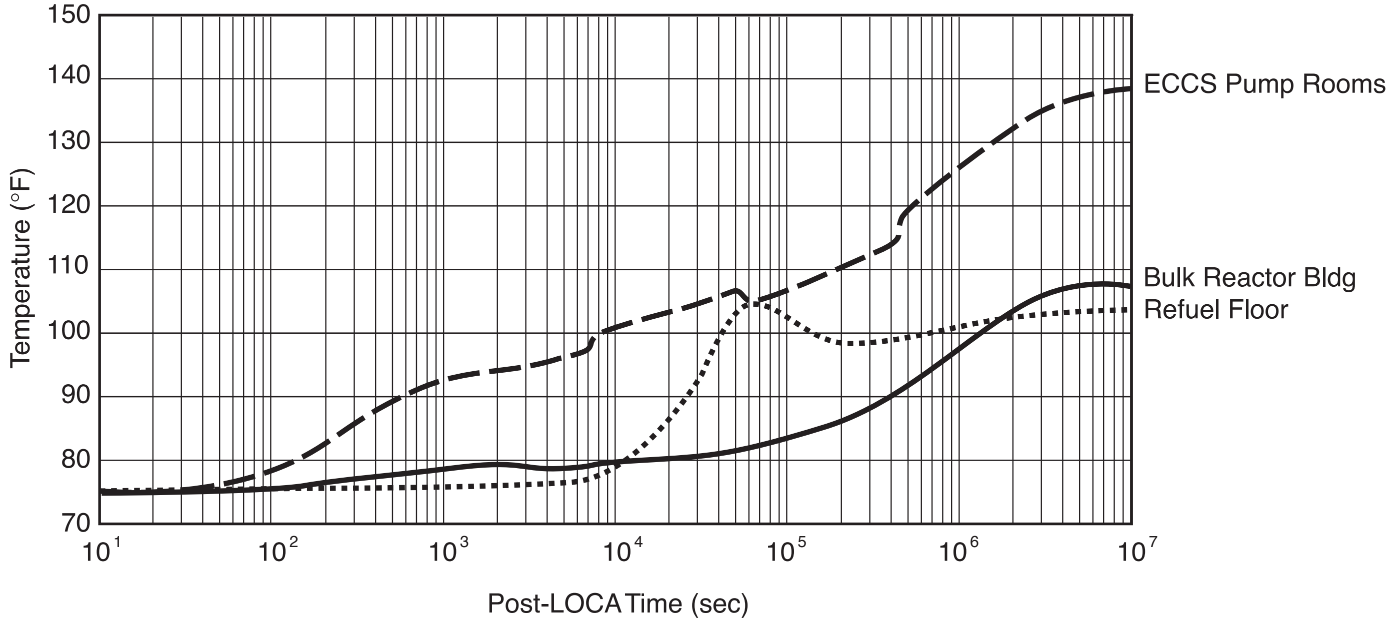
Form No. 960690



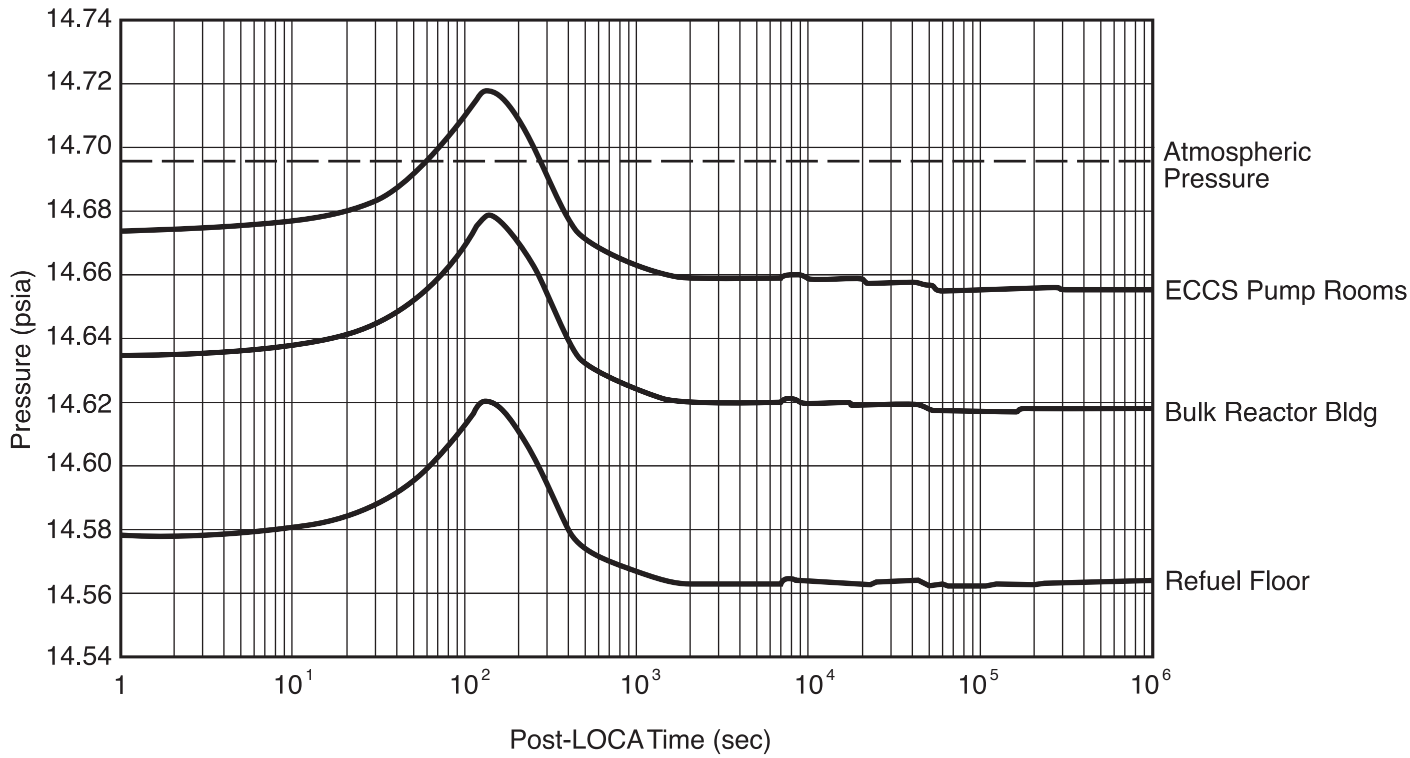
Main Steam Line Break Blowdown Flow Rates

Figure Not Available For Public Viewing

Figure Not Available For Public Viewing



Columbia Generating Station Final Safety Analysis Report	Long-Term Post-LOCA Secondary Containment Temperature Transient
	Draw. No. 920843.17 | Rev. | Figure 6.2-34



Columbia Generating Station Final Safety Analysis Report	Short-Term Post-LOCA Secondary Containment Pressure Transient		
	Draw. No. 920843.16	Rev.	Figure 6.2-35

Notes on Type C Testing (Isolation Valve Leakage Testing)

1. Type C testing is performed by applying a differential pressure in the same direction as seen by the valves during containment isolation.

2. Type C testing is performed by pressurizing between the two-piece disk gate valve.

3. Type C testing is performed by pressurizing between the isolation valves. The test yields conservative results since the inboard, globe valve is pressurized under the seat during the test; whereas, during containment isolation, it is pressurized above the seat.

4. Type C testing is performed by pressurizing between the isolation valves. The test yields equivalent results for the inboard gate or butterfly valve. *

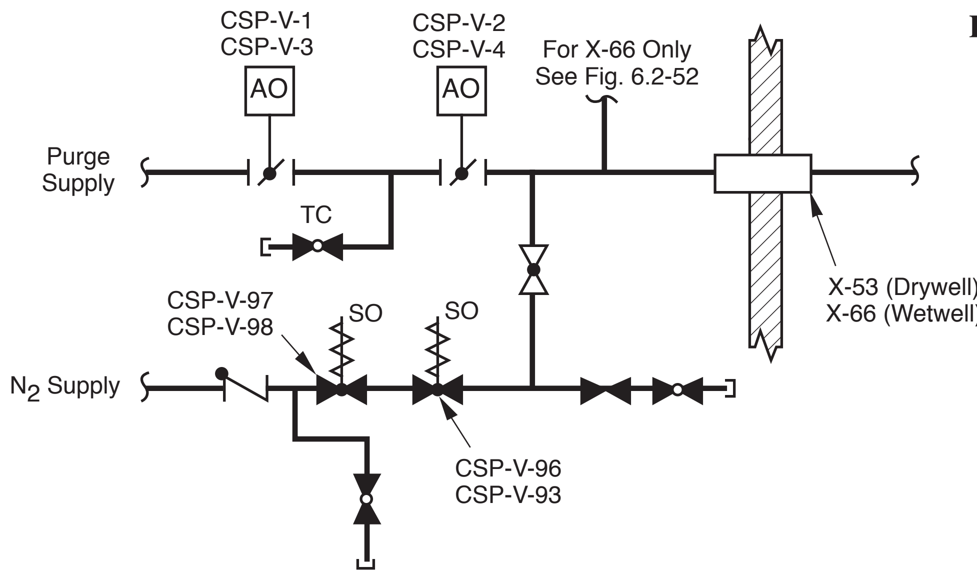
5. Type C testing is not required since a water seal is provided by the supression pool.

6. Type C testing is performed by pressurizing between the isolation valves. The test yields equivalent results for the inboard gate valve. * The one-inch globe valve will have test pressure applied under the seat; however, the difference between testing a one-inch globe valve over or under the seat is considered negligible.

7. Type C testing is performed by pressurizing between the isolation valves. The one-inch globe valve will have test pressure applied over the seat for the inboard isolation valve and under the seat for the outboard isolation valve. The difference between testing under and over the seat for a one-inch globe valve is considered negligible.

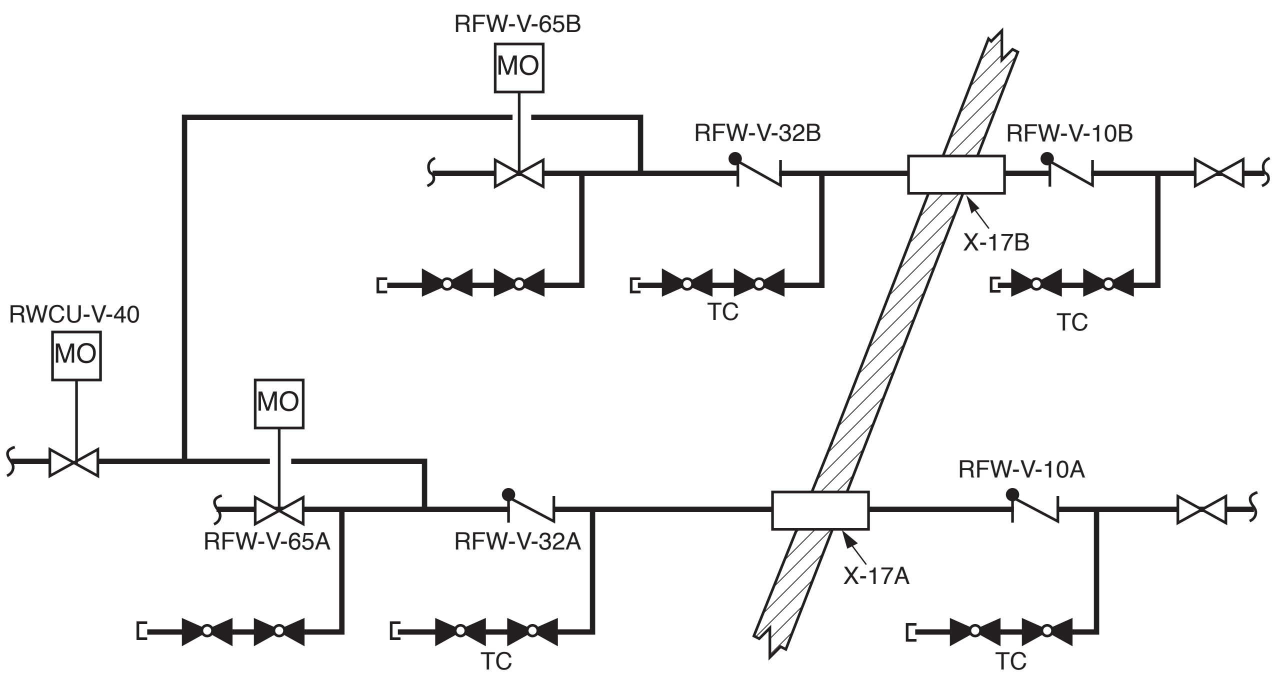
8. Type C testing is performed by pressurizing between the isolation valves. The one-inch globe valve will have test pressure applied under the seat; however, the difference between testing a one-inch globe valve over or under the seat is considered negligible.

* The gate and butterfly valves are because of symmetry of design and because of construction equally leak tight in either direction. This fact has been confirmed by review of leakage test data and other information supplied by the valve manufacturers.



Note: See Note 4 on Figure 6.2-36

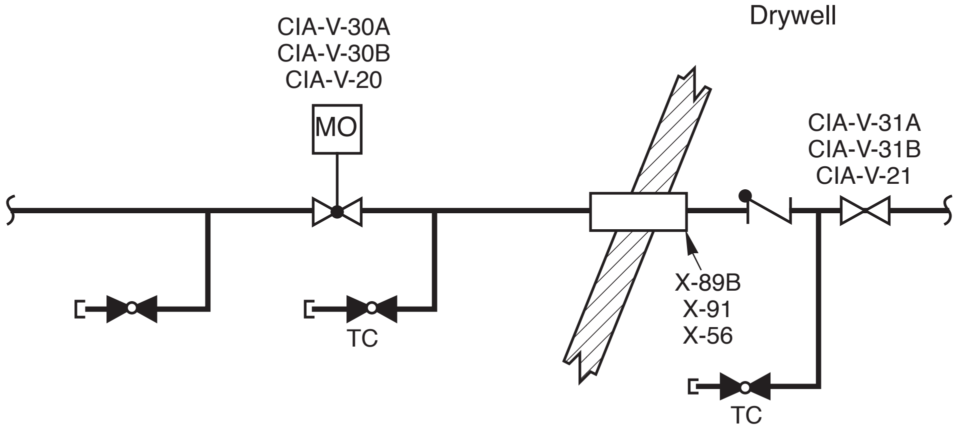
X-53 Drywell Purge and Inerting Makeup
X-66 Wetwell Purge and Inerting Makeup



Note: See Note 1 on Figure 6.2-36

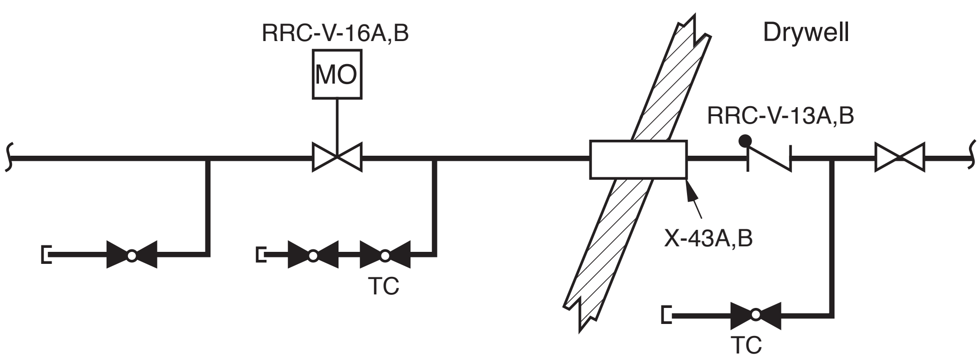
Reactor Feedwater Lines

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-53, X-66, X-17A and X-17B		
	Draw. No. 920843.18	Rev.	Figure 6.2-37



Note: See Note 1 on Figure 6.2-36

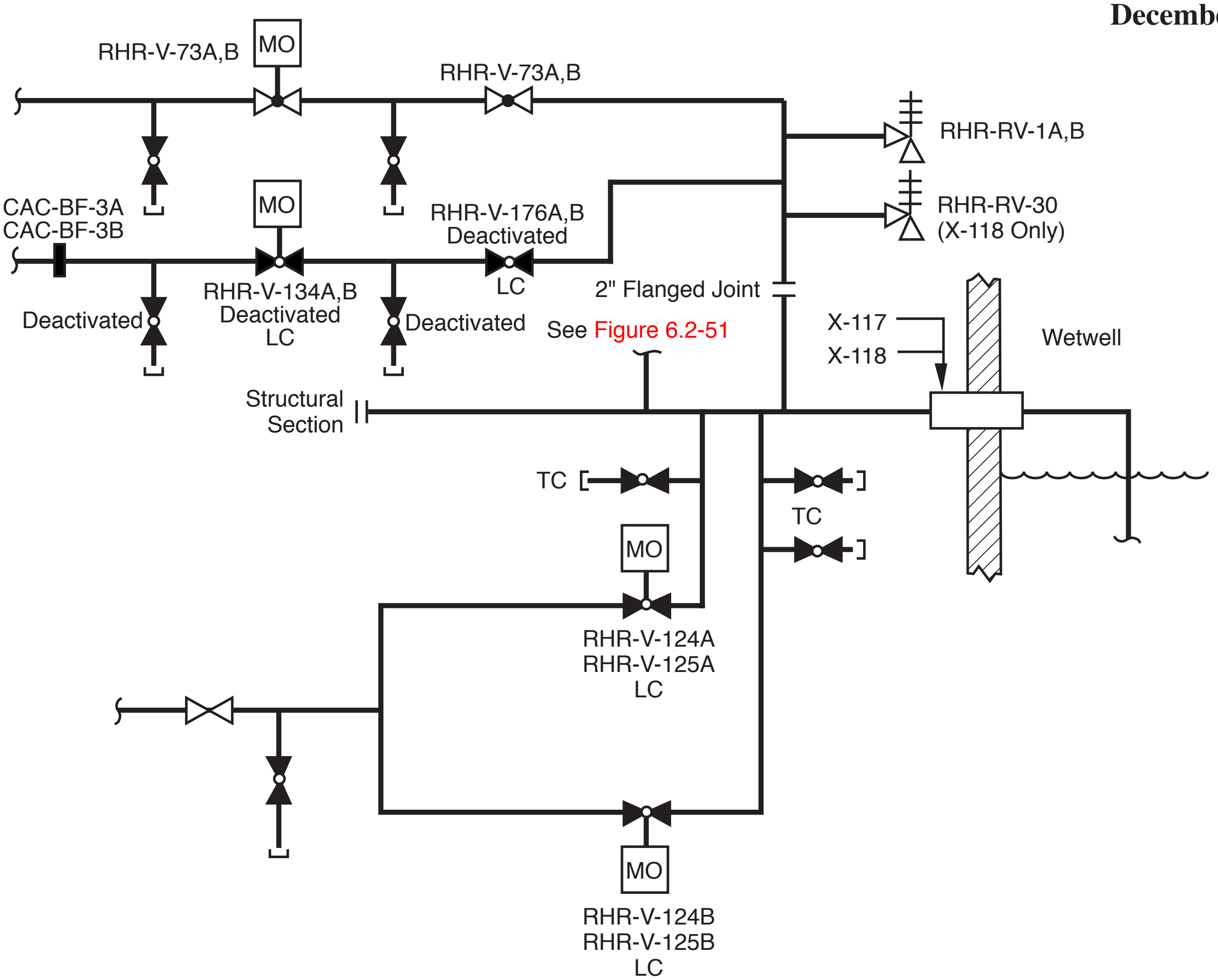
Containment Instrument Air



Note: See Note 1 on Figure 6.2-36

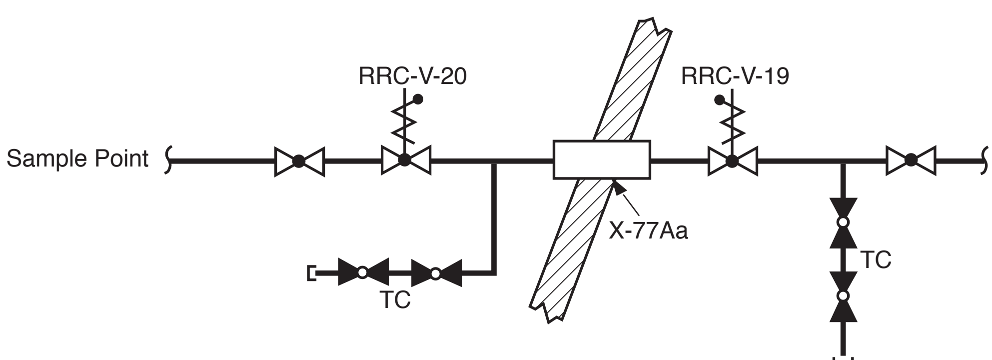
RRC Pump Seal Purge

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-89B, X-91, X-56, X-43A, and X-43B
	Draw. No. 920843.19 / Rev. / Figure 6.2-38



RHR Steam Lines

Note: See Note 5 on Figure 6.2-36



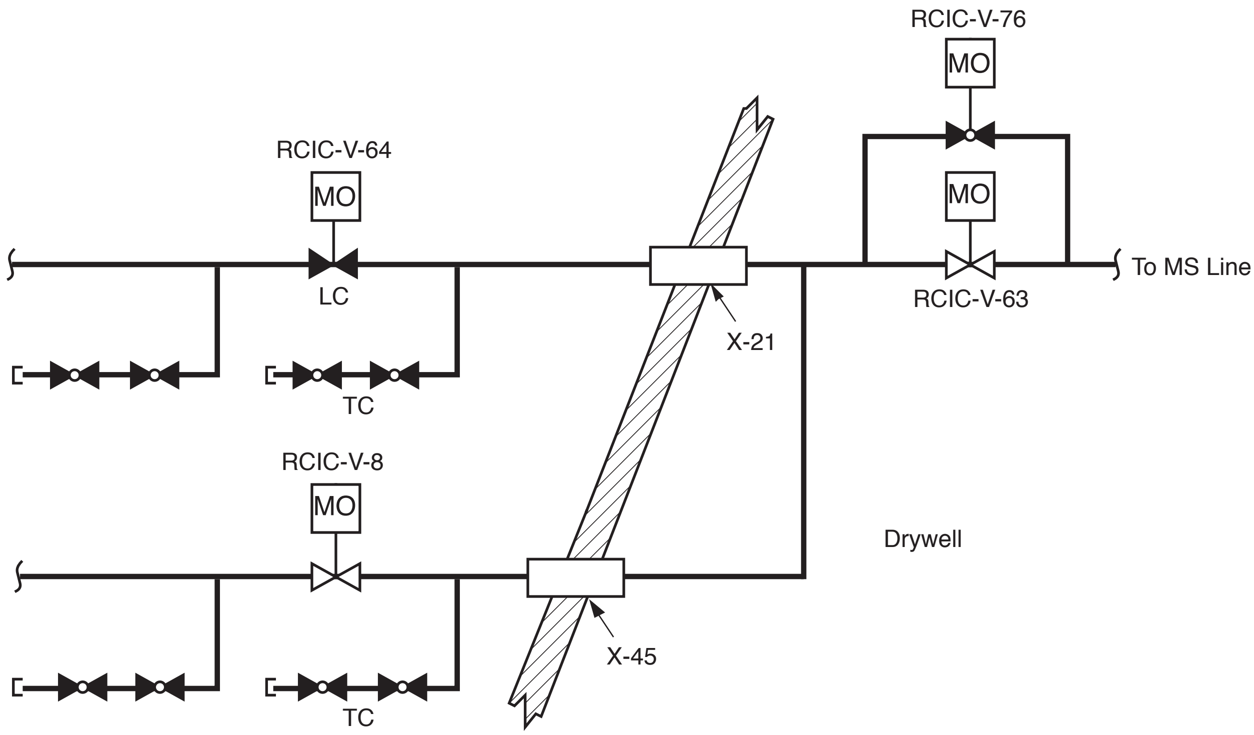
Note: See Note 1 on Figure 6.2-36

RCC Sample Line

Columbia Generating Station
Final Safety Analysis Report

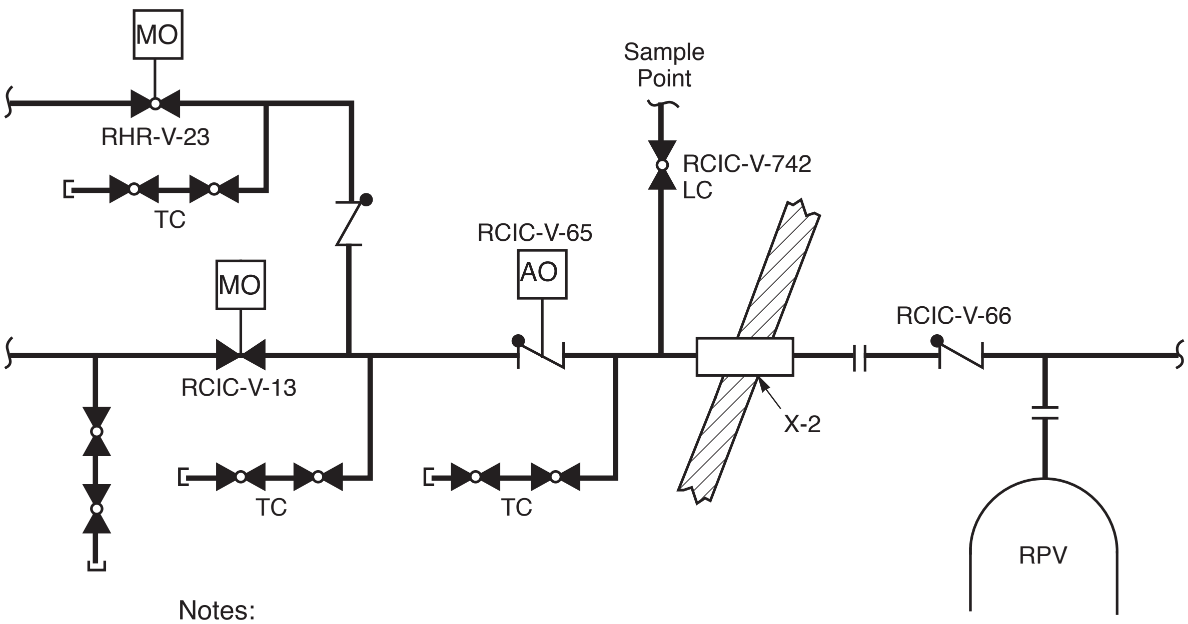
Isolation Valve Arrangement for Penetrations X-117, X-118 and X-77Aa

Draw. No. 920843.21	Rev.	Figure 6.2-39



Note: See Note 6 on Figure 6.2-36

Steam to RCIC Turbine and RHR Heat Exchanger

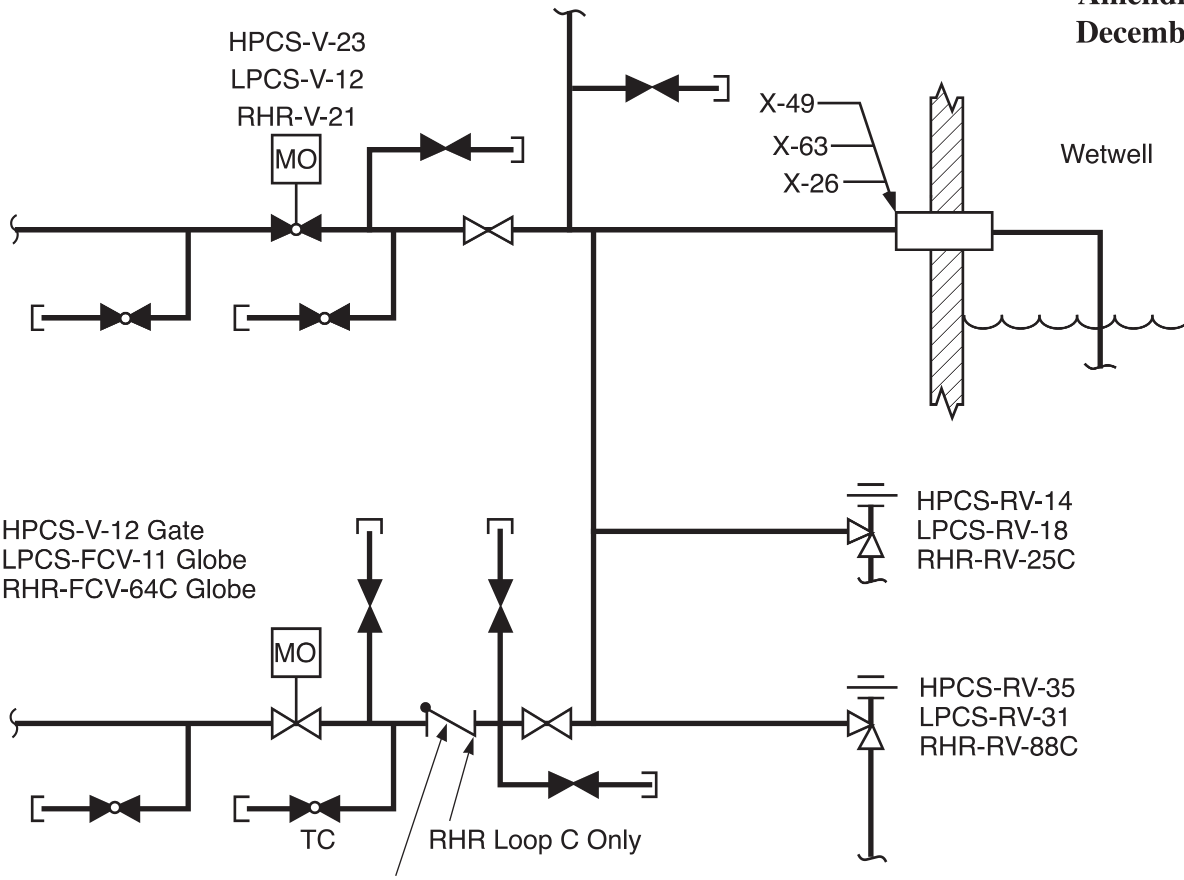


Notes:

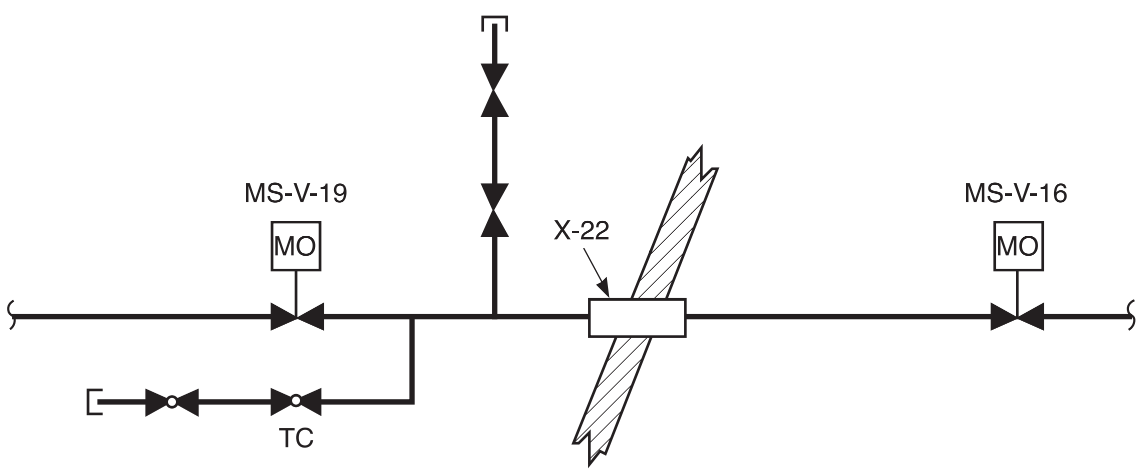
RCIC-V-66 will be "bench tested" once the line is removed for refueling.
RHR-V-23 and RCIC-V-13 can be tested once the flanged connection is blanked off as per note 1 on figure 6.2-36

RCIC/RHR Head Spray

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-21, X-45 and X-2
	Draw. No. 920843.22 | Rev. | Figure 6.2-40



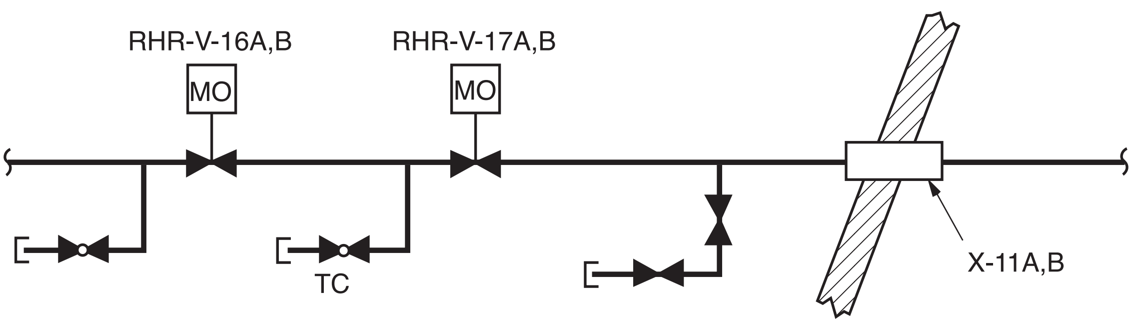
Note: See Note 5 on Figure 6.2-36
X-49 HPCS Test Line
X-63 LPCS Test Line
X-26 RHR Loop C Test Line



Note: See Note 4 on Figure. 6.2-36

MS Drain Line

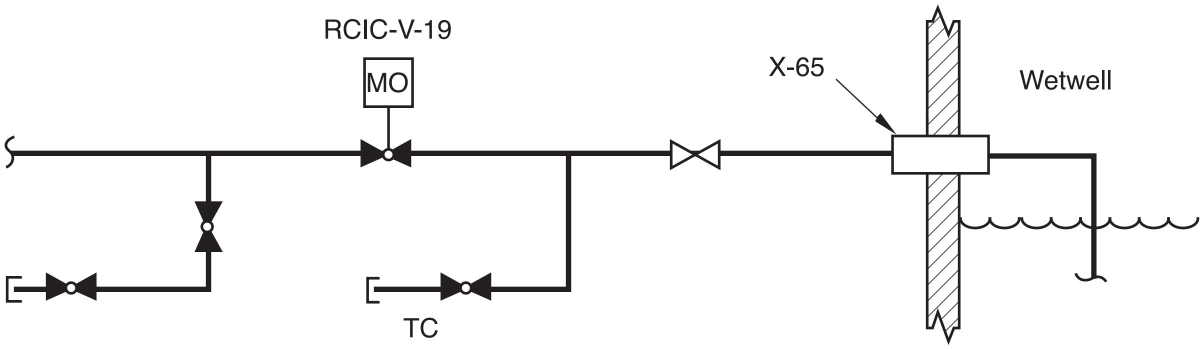
Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-49, X-63, X-26 and X-22
	Draw. No. 950021.13 | Rev. | Figure 6.2-41



Note: See Note 4 on Figure 6.2-36

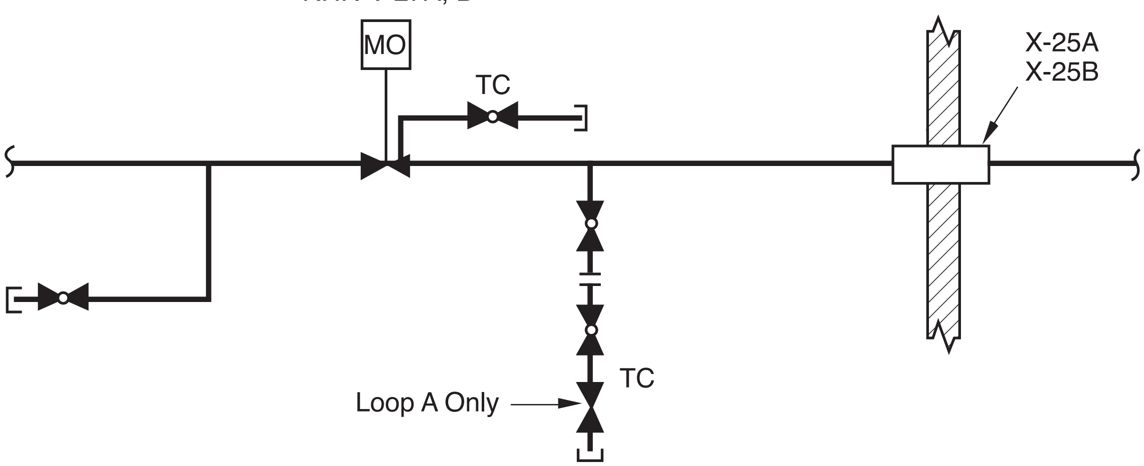
RHR Drywell Spray

Isolation Valve Arrangement for Penetrations X-11A and X-11B



Note: See Note 5 on Figure 6.2-36

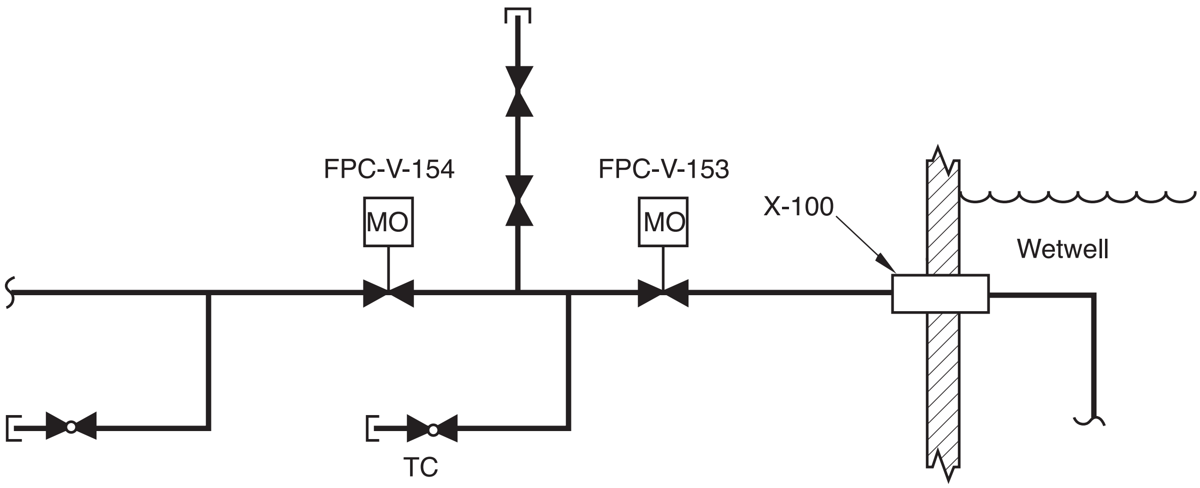
RCIC Pump Min. Flow



Note: See Note 2 on Figure 6.2-36

RHR Wetwell Spray

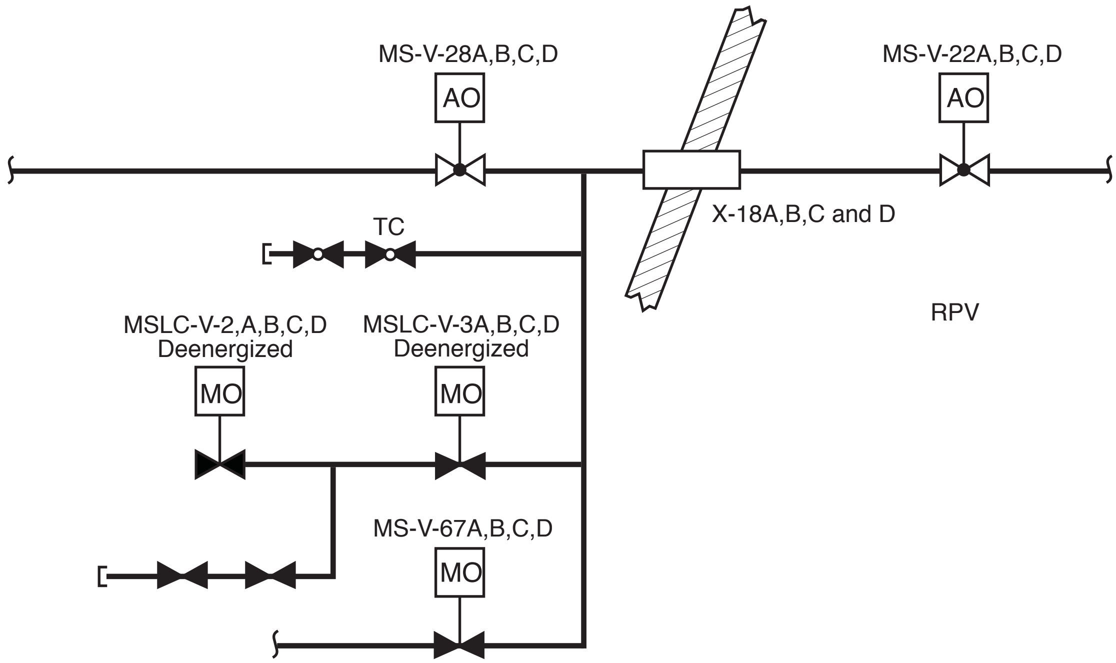
Isolation Valve Arrangement for Penetrations X-65, X-25A and X-25B



Note: See Note 4 on Figure 6.2-36

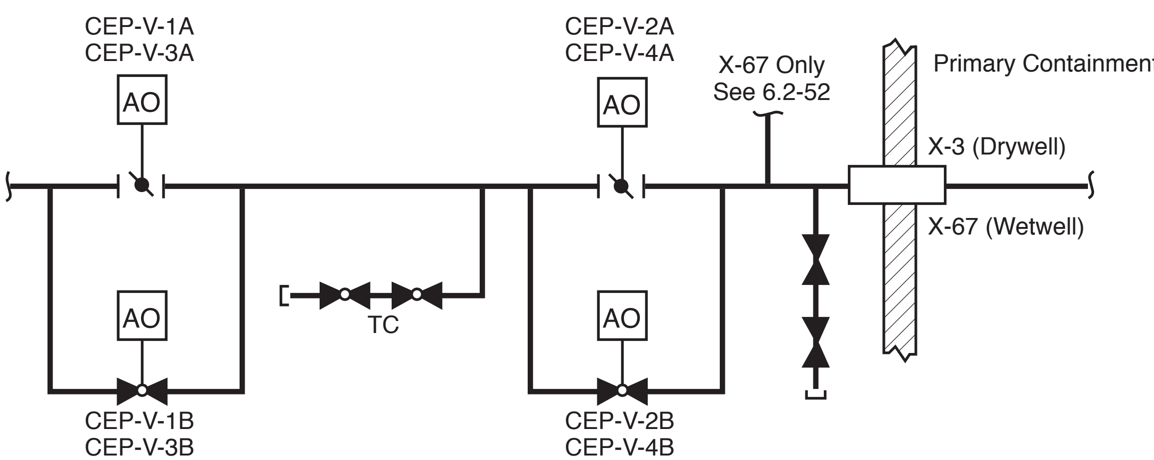
Suppression Pool Cleanup Suction Line

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetration X-100	
Draw. No. 920843.10	Rev.	Figure 6.2-44



Note: See Note 3 on Figure 6.2-36

Main Steamlines



Note: See Note 4 on Figure 6.2-36

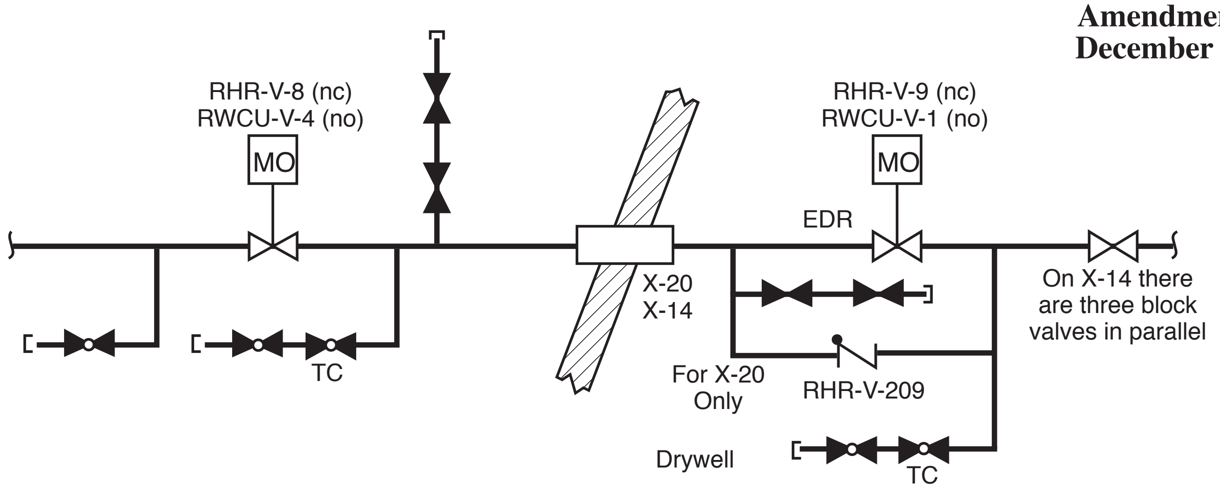
X-3 Drywell Purge Exhaust

X-67 Wetwell Purge Exhaust

Columbia Generating Station
Final Safety Analysis Report

Isolation Valve Arrangement for Penetrations X-18A, X-18B, X-18C, X18D, X-3 and X-67

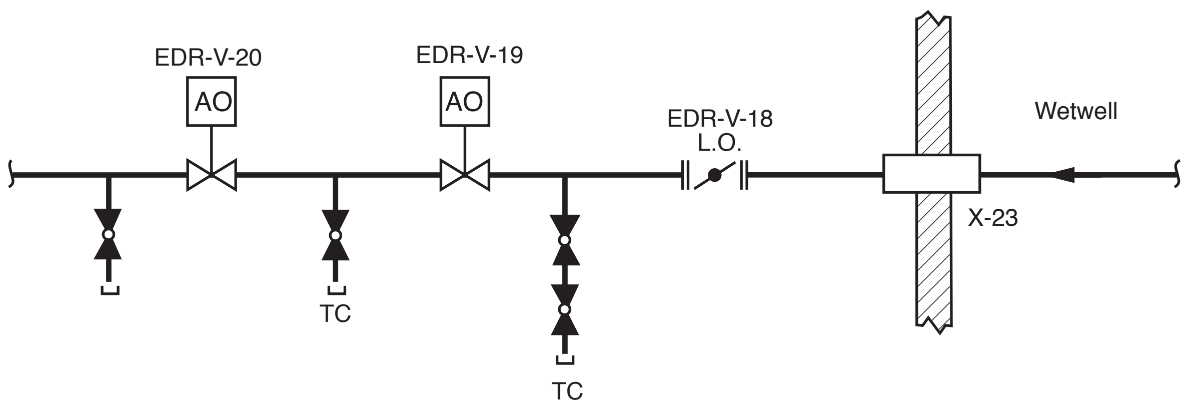
Draw. No. 920843.23	Rev.	Figure 6.2-45



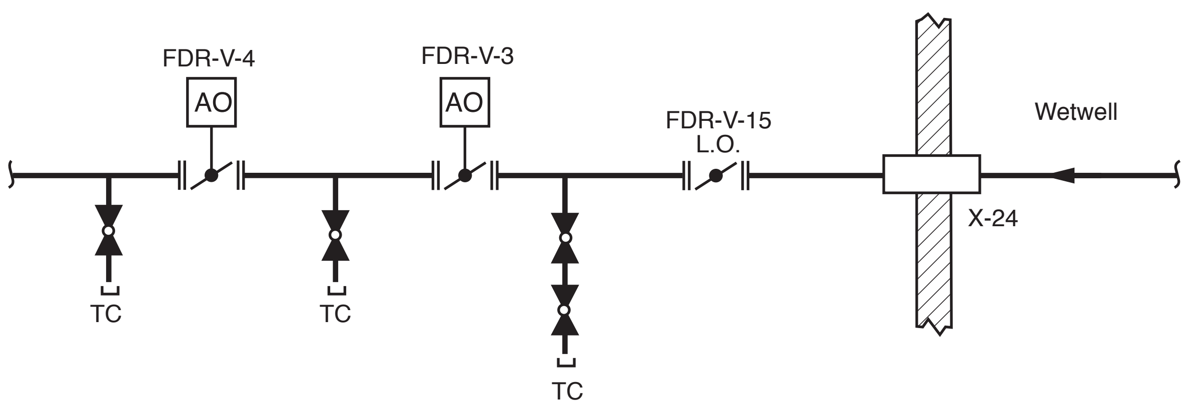
Note: See Notes 1 (X-20 Only), and 4 (X-14 Only) on Figure 6.2-36

X-20 RHR Shutdown Cooling Supply

X-14 RWCU Suction



X-23 EDR from Primary Containment

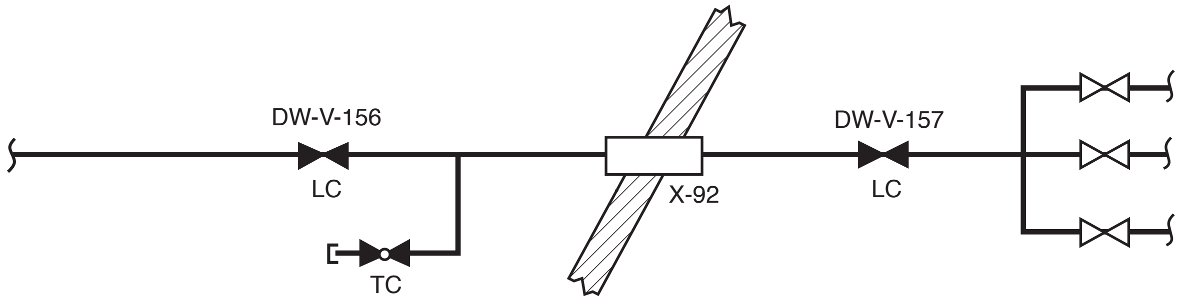


X-24 FDR from Primary Containment

Note: See Note 1 on Figure 6.2-36 for X-23 And X-24

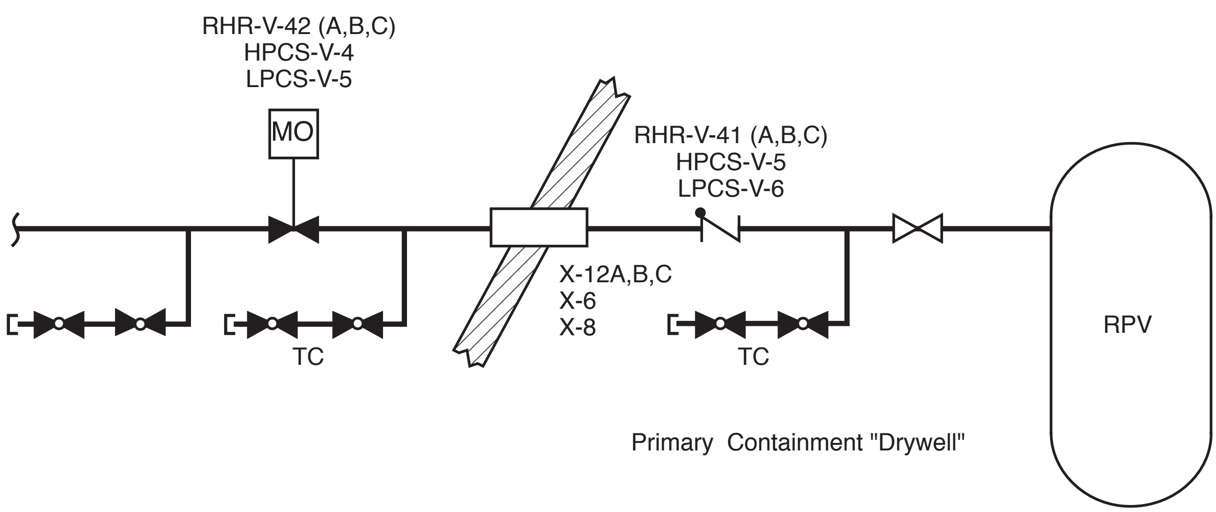
Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-20, X-14, X-23 and X-24	
Draw. No. 920843.24	Rev.	Figure 6.2-46

Form No. 960690FH
LDCN-05-007



Note: See Note 4 on Figure 6.2-36

DW System



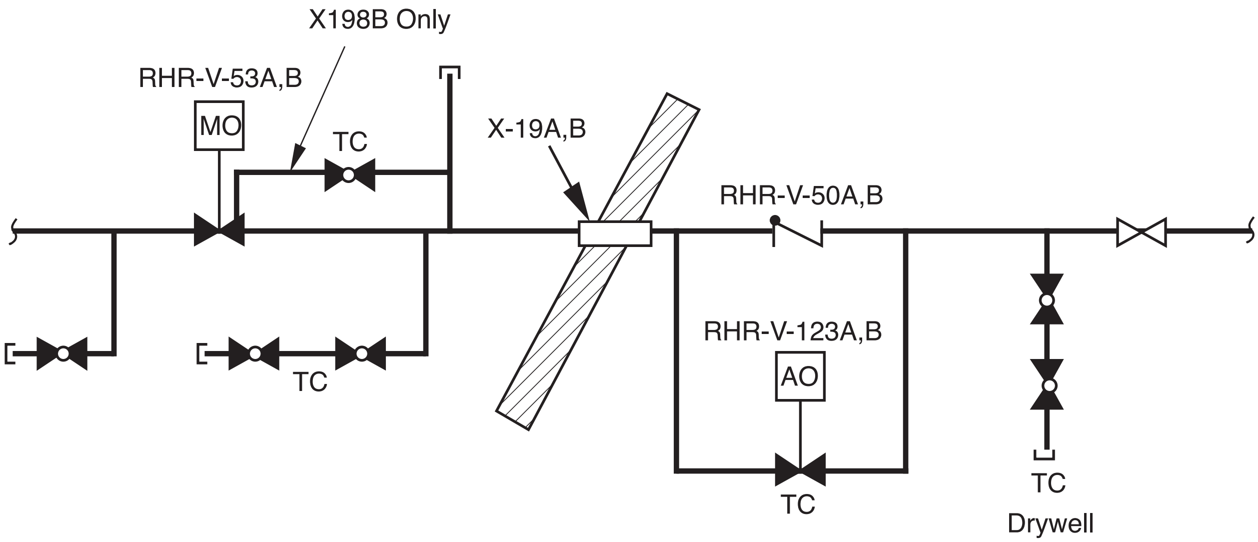
Note: See Note 1 on Figure 6.2-36

X-12A RHR Loop A LPCI to RPV
X-12B RHR Loop B LPCI to RPV
X-12C RHR Loop C LPCI to RPV
X-6 HPCS to RPV
X-8 LPCS to RPV

Columbia Generating Station
Final Safety Analysis Report

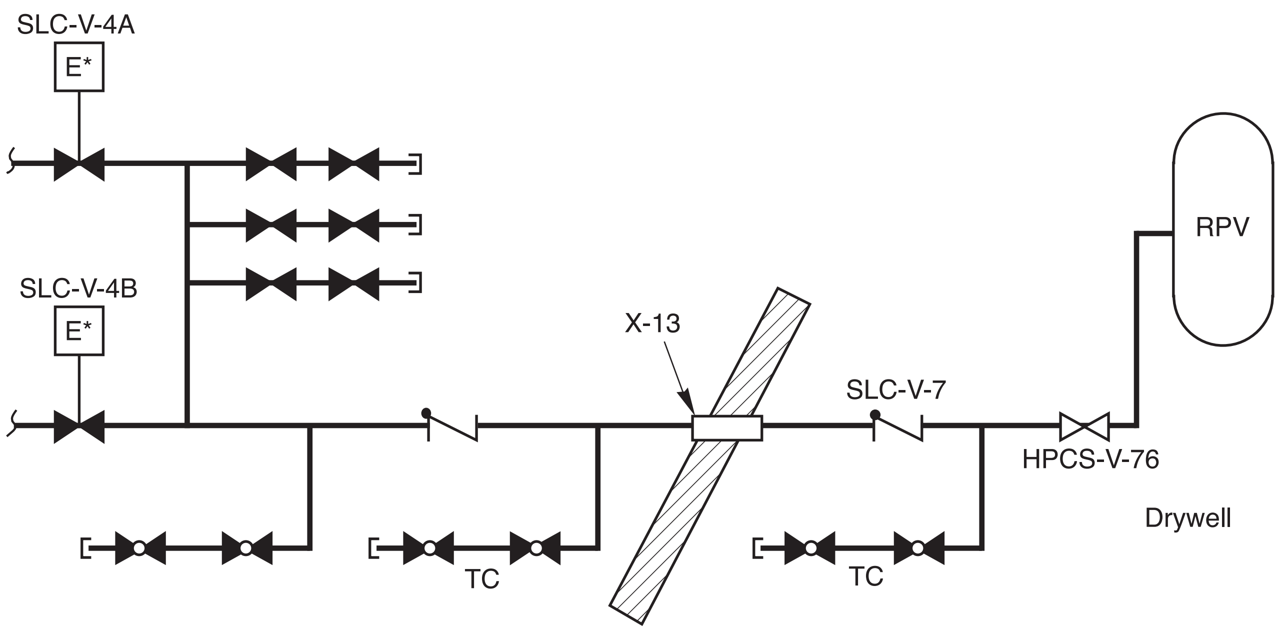
Isolation Valve Arrangement for Penetrations X-92, X-12A, X-12B, X-12C, X-6 and X-8

Draw. No. 920843.25	Rev.	Figure 6.2-47



Note: See Note 2 on Fig. 6.2-36

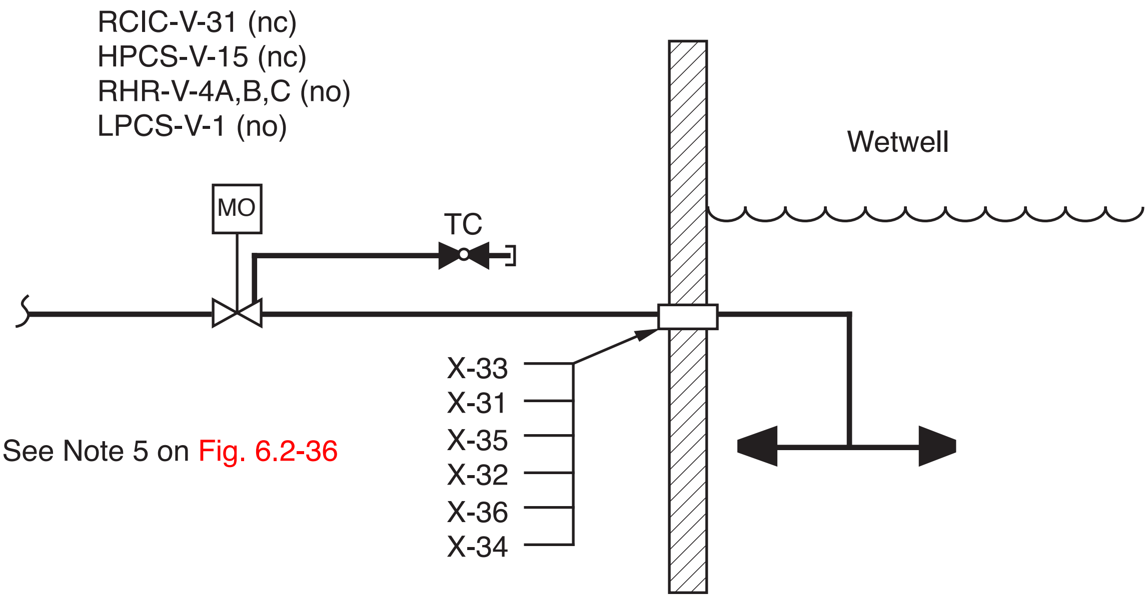
RHR SHUTDOWN COOLING RETURN



*Explosive Actuated Valve

Note: See Note 2 on Fig. 6.2-36

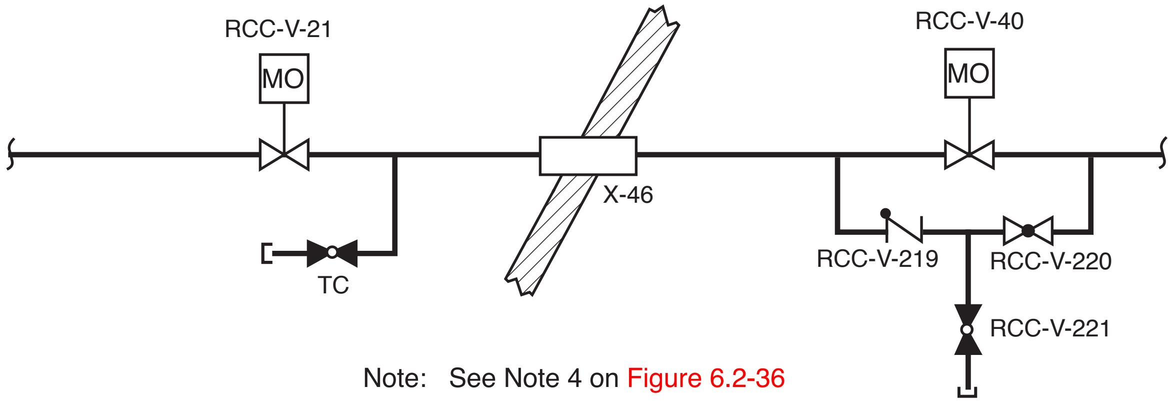
SLC SYSTEM INJECTION LINE



Note: See Note 5 on Fig. 6.2-36

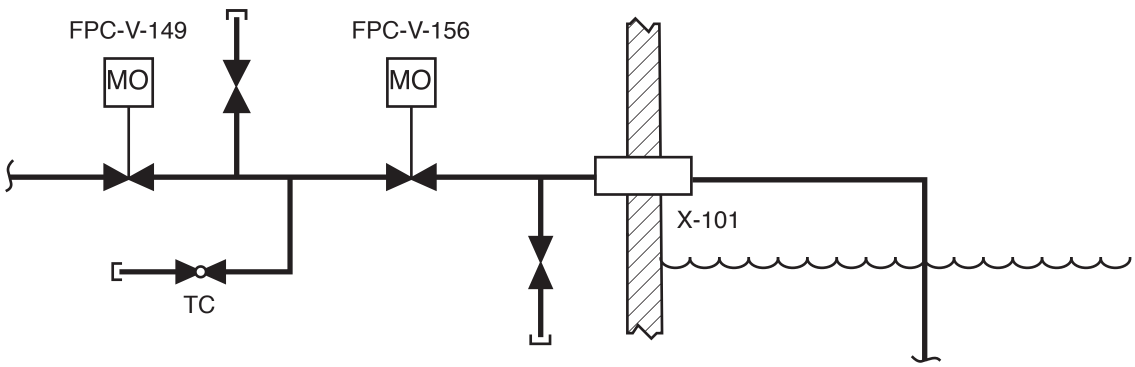
X-33 RCIC Pump Suction from Suppression Pool
X-31 HPCS Pump Suction from Suppression Pool
X-35 RHR"A" Pump Suction from Suppression Pool
X-32 RHR"B" Pump Suction from Suppression Pool
X-36 RHR"C" Pump Suction from Suppression Pool
X-34 LPCS Pump Suction from Suppression Pool

Columbia Generating Station **Final Safety Analysis Report**	**Isolation Valve Arrangement for Penetrations X-33, X-31, X-35, X-32, X-36 and X-34**
	Draw. No. 920843.04 | Rev. | Figure 6.2-49



Note: See Note 4 on Figure 6.2-36

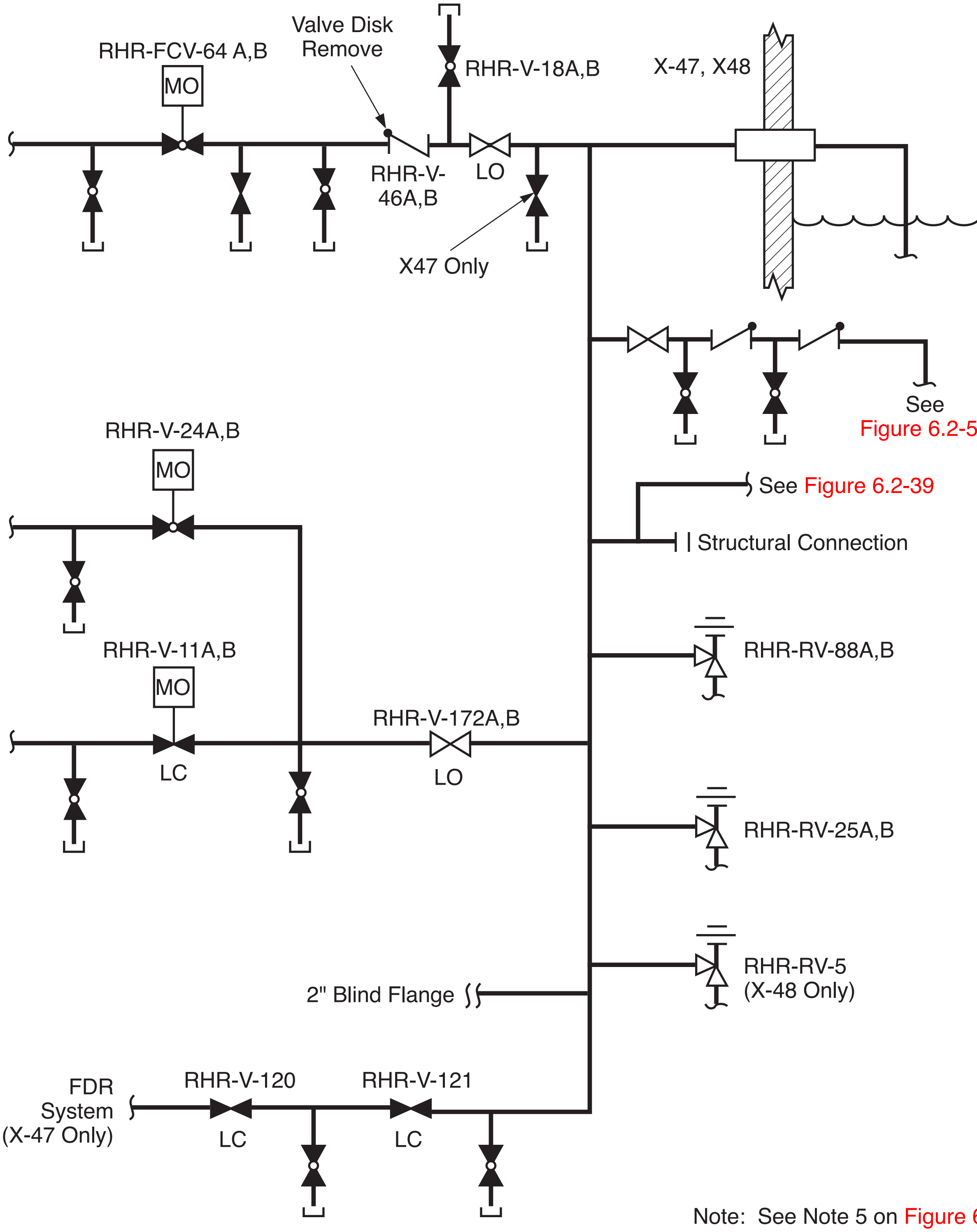
RCC Return Line



Note: See Note 4 on Figure 6.2-36

Suppression Pool Cleanup Return Line

Amendment 61
December 2011

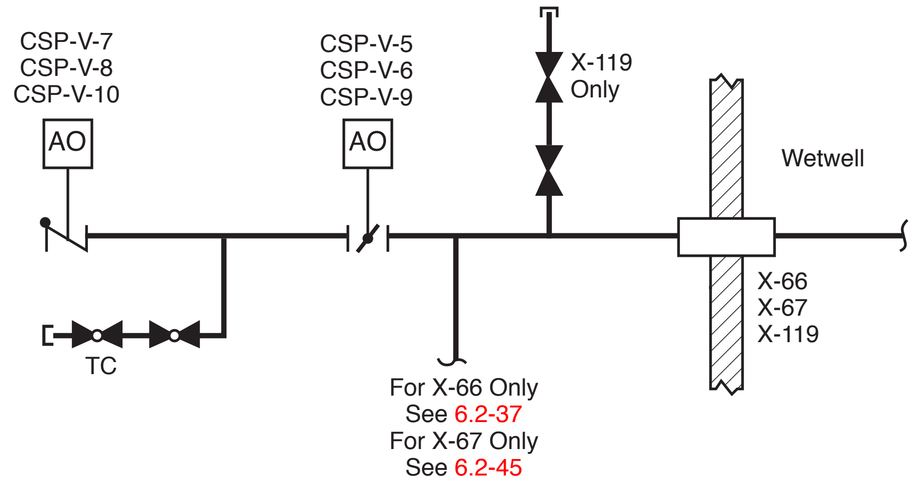


Note: See Note 5 on Figure 6.2-36

RHR Combined Return Line to
Suppression Pool

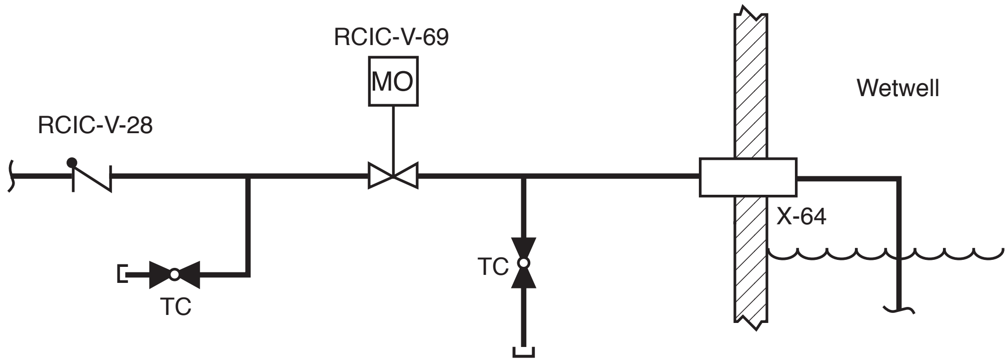
Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-47 and X-48		
	Draw. No. 950021.14	Rev.	Figure 6.2-51

Form No. 960690FH
LDCN-08-028



Note: See Note 4 on Figure 6.2-36

Reactor Building To Wetwell Vacuum Relief



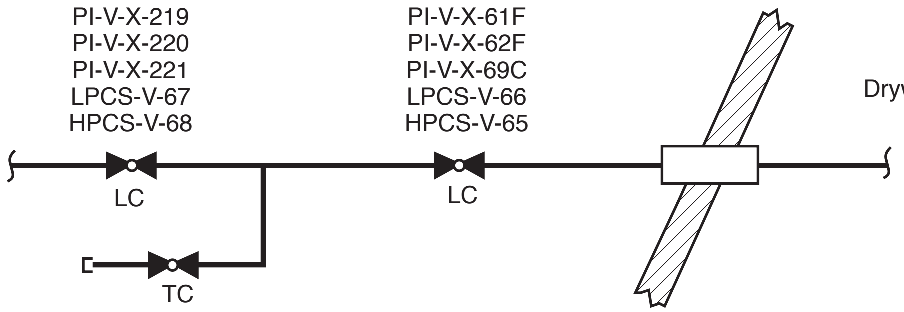
Note: See Note 5 on Figure 6.2-36

RCIC Vacuum Pump Discharge

Columbia Generating Station
Final Safety Analysis Report

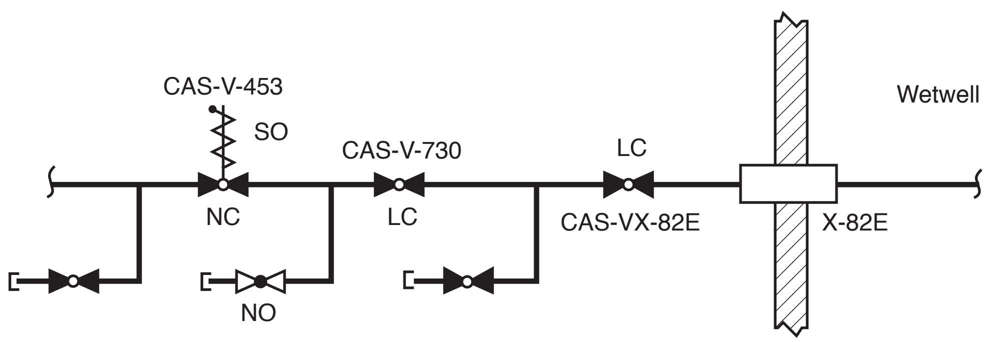
Isolation Valve Arrangement for Penetrations X-66, X-67, X-119, X-64

Draw. No. 920843.27	Rev.	Figure 6.2-52



Note: See Note 7 on Figure 6.2-36

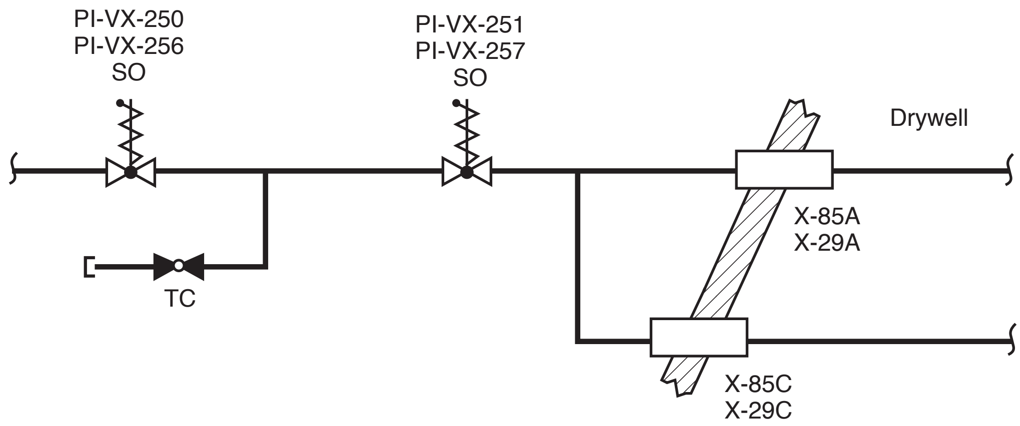
X-42D Air Line for RHR-V-50A
X-54Aa Spare Air Line
X-54Bf Air Line for RHR-V-41B
X-61F Air Line for RHR-V-41A
X-62F Air Line for RHR-V-41C
X-69C Air Line for RHR-V-50B
X-78D Air Line for LPCS-V-6
X-78E Air Line for HPCS-V-5



Note: See Note 8 on Figure 6.2-36

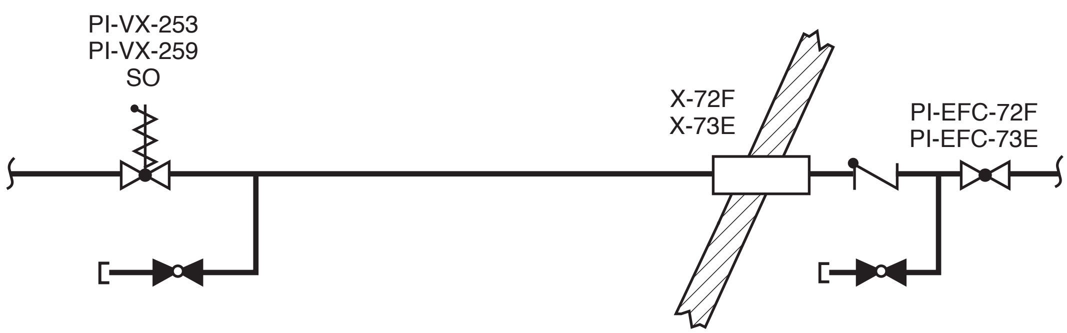
N_2/Air Supply for Testing Wetwell to Drywell Vacuum Breakers

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-42D, 54Aa, 54Bf, 61F, 62F, 69C, 78D, 78E and 82E,
	Draw. No. 920843.28 | Rev. | Figure 6.2-53



Note: See Note 1 on Figure 6.2-36

Radiation Monitor Supply Line Division A
Radiation Monitor Supply Line Division B

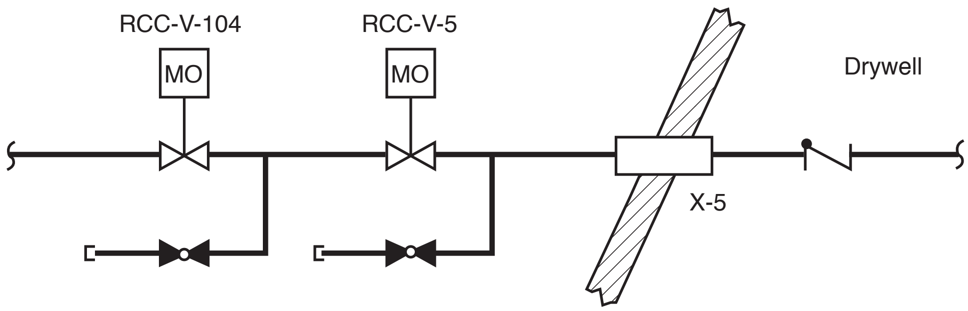


Note: See Note 1 on Figure 6.2-36

Radiation Monitor Return Line Division A
Radiation Monitor Return Line Division B

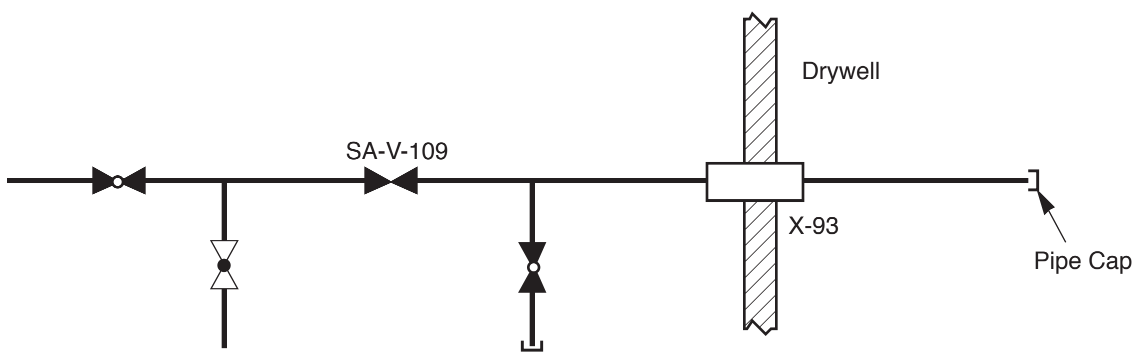
Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-85A, X-29A, X-85C, X-29C, X-72F, and X-73E		
	Draw. No. 920843.29	Rev.	Figure 6.2-54

Form No. 960690



Note: See Note 4 on Figure 6.2-36

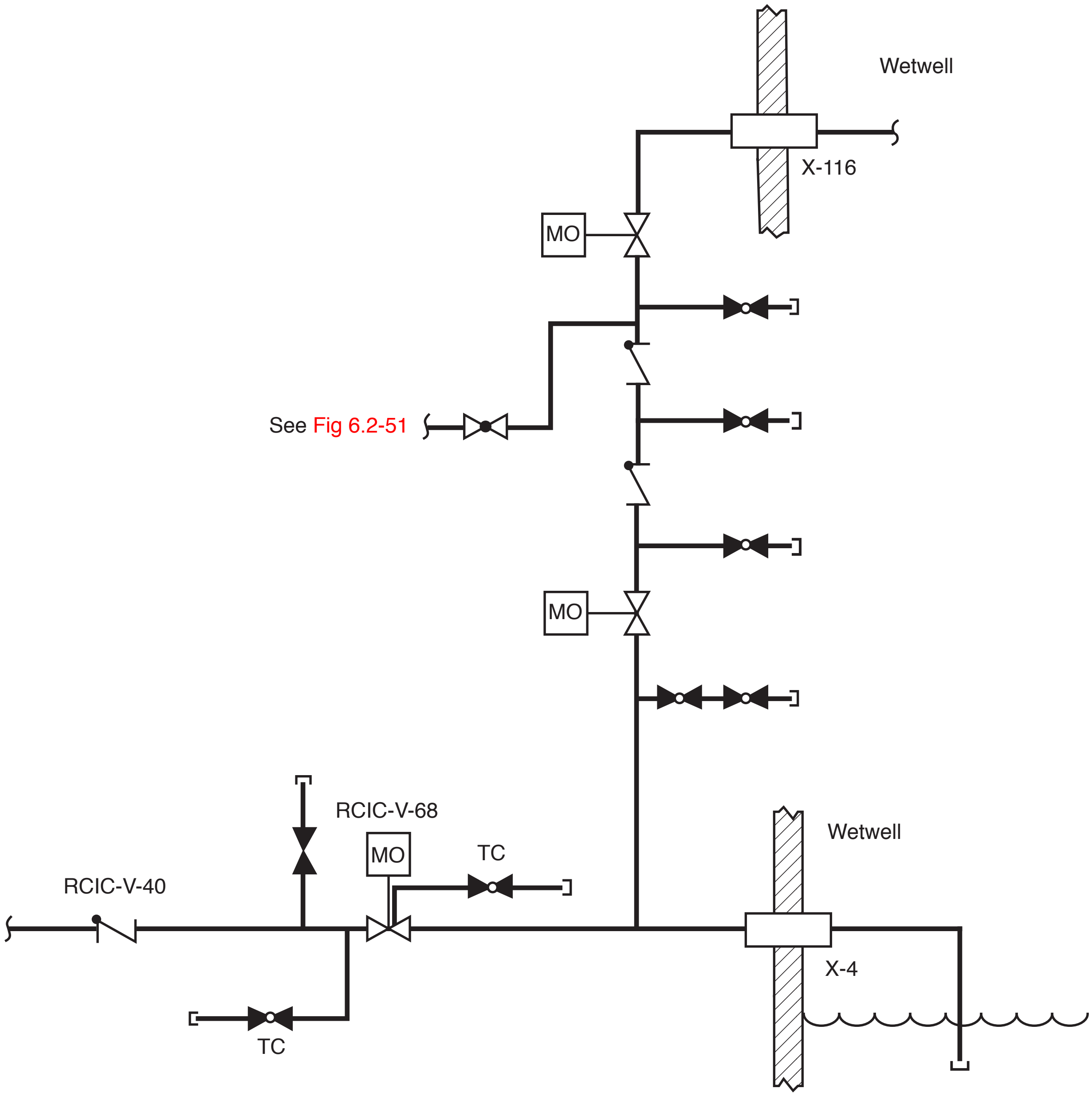
RCC Supply Line



Note: See Note 1 on Figure 6.2-36

Service Air for Maintenance

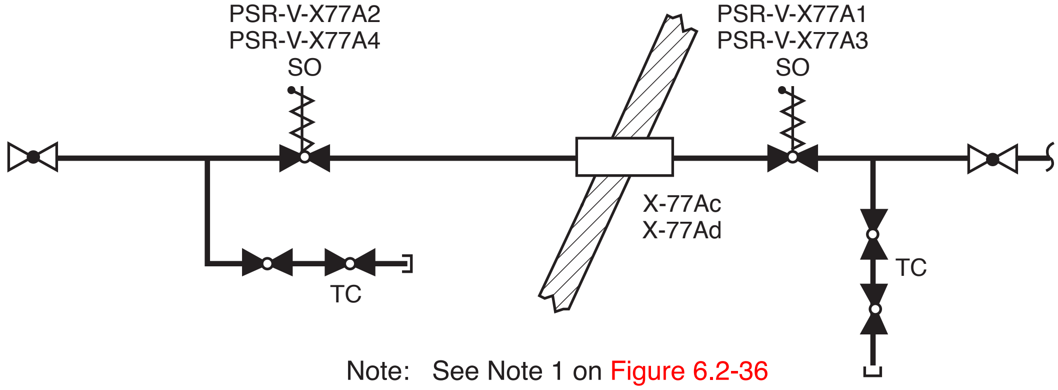
Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-5 and X-93		
	Draw. No. 920843.30	Rev.	Figure 6.2-55



Note: See Note 4 on Figure 6.2-36

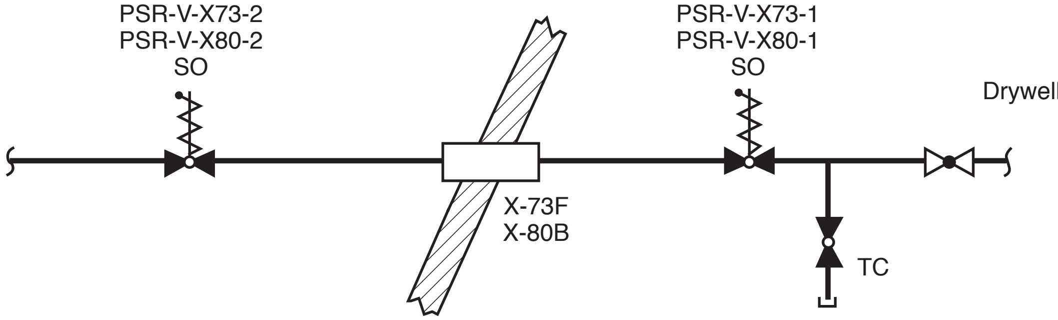
RCIC Turbine Exhaust and
Turbine Exhaust Vacuum Breaker

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-4 and X-116		
	Draw. No. 920843.31	Rev.	Figure 6.2-56



Note: See Note 1 on Figure 6.2-36

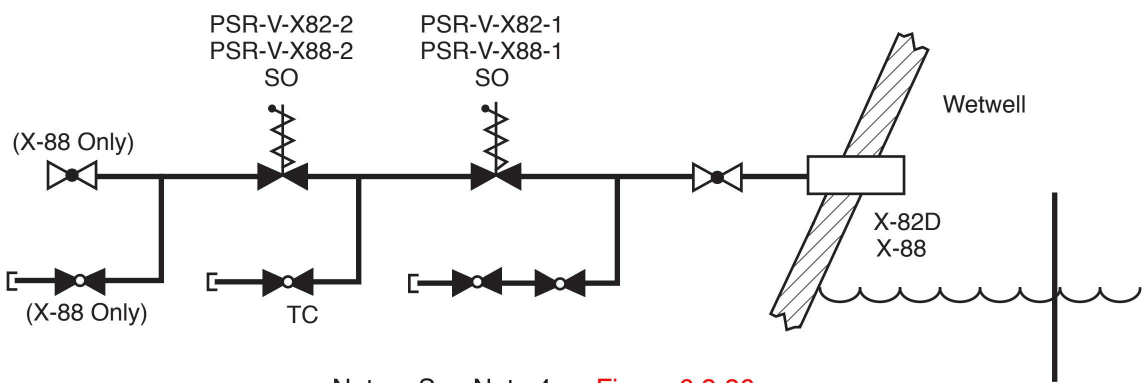
X-77Ac Jet Pump #10 Sample Line
X-77Ad Jet Pump #20 Sample Line



Note: See Note 1 on Figure 6.2-36

X-80B Drywell Atmosphere Sample Line
X-73F Drywell Atmosphere Sample Line

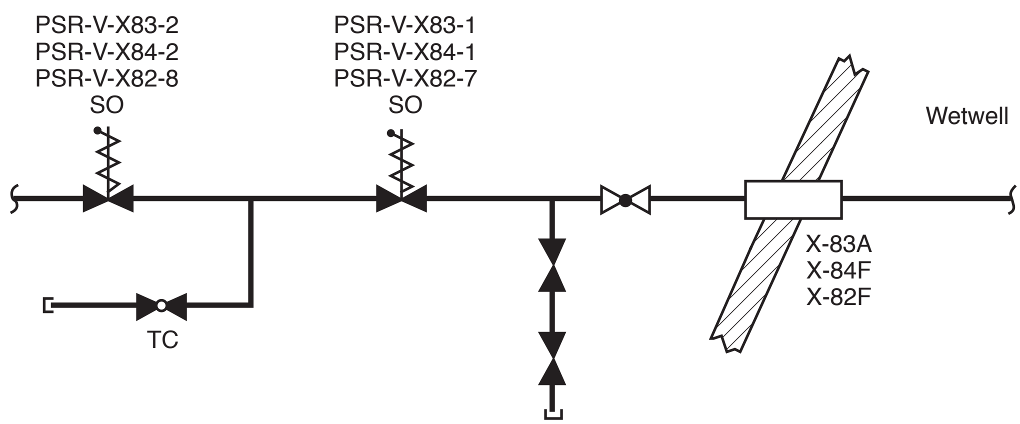
Columbia Generating Station **Final Safety Analysis Report**	**Isolation Valve Arrangement for Penetrations X-73F, X-77Ac, X-77Ad, X-80B**
	Draw. No. 920843.32 | Rev. | Figure 6.2-57



Note: See Note 4 on Figure 6.2-36

X-82D - Sample Return to Suppression Pool

X-88 - Suppression Pool Sample Line



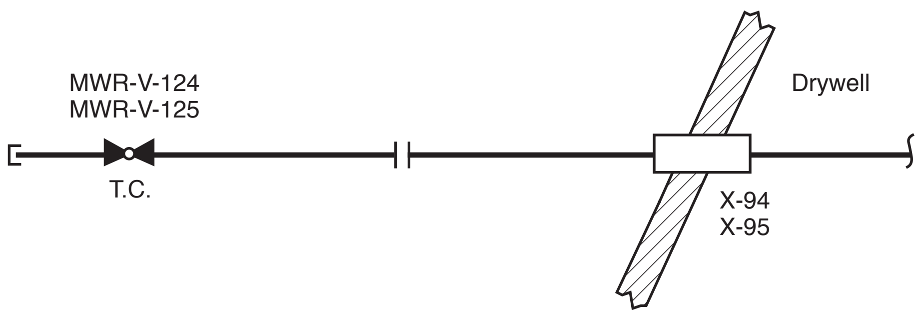
Note: See Note 4 on Figure 6.2-36

X-82F- Suppression Pool Atm. Sample Return

X-83A- Suppression Pool Atm. Sample Line

X-84F- Suppression Pool Atm. Sample Line

Columbia Generating Station Final Safety Analysis Report	Isolation Valve Arrangement for Penetrations X-82D, X-82F, X-83A, X-84F, X-88		
	Draw. No. 920843.33	Rev.	Figure 6.2-58



X-94 - Decon Solution Supply Header
X-95 - Decon Solution Return Header

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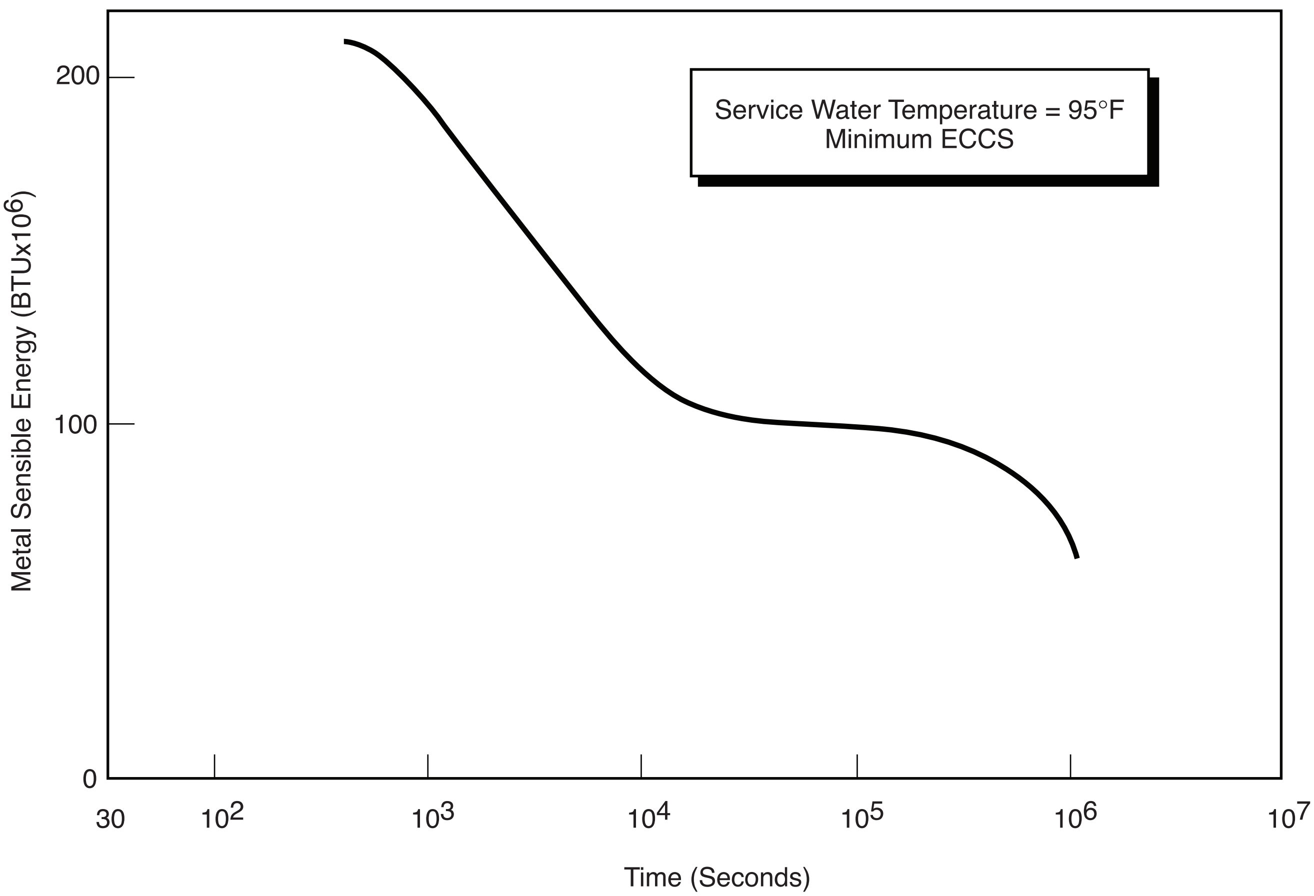
(SHEETS 1 THROUGH 4)



Columbia Generating Station
Final Safety Analysis Report

Sensible Energy Transient in the Reactor Vessel and Internal Metals - Original Rated Power

Draw. No. 960222.66 | Rev. | Figure 6.2-61

6.3 EMERGENCY CORE COOLING SYSTEM

This section provides the design bases for the emergency core cooling systems (ECCS), the description of the systems, the postulated ECCS response to a spectrum of accidents, and a performance evaluation. Subsection 6.3.1 discusses the design bases. Subsection 6.3.2 describes the systems. Subsection 6.3.3 discusses the system responses and the evaluation of the system performance. The ECCS design and postulated response are based on information developed by the original nuclear steam supply system (NSSS) vendor, General Electric. Subsequent reload analyses have been provided by fuel vendors for initial system performance (time from the event to core reflood) and General Electric for the long-term performance.

6.3.1 DESIGN BASES AND SUMMARY DESCRIPTION

Reload analysis performed by the fuel vendor in support of the current cycle of operation is performed in a manner that maintains the validity of the design analysis discussed in this section. The operational limits resulting from this cycle-specific analysis are reported in the cycle-specific Core Operating Limits Report (COLR).

6.3.1.1 Design Bases

6.3.1.1.1 Performance and Functional Requirements

The ECCS is designed to provide protection against postulated loss-of-coolant accidents (LOCAs) caused by ruptures in primary system piping. The functional requirements are such that the system performance under all postulated LOCA conditions satisfies the requirements of 10 CFR 50.46. The ECCS is designed to meet the following requirements:

a. Protection is provided for any primary line break up to and including the double-ended guillotine (DEG) break of the largest line,

b. Two independent and diverse cooling methods (flooding and spraying) are provided to cool the core,

c. One high-pressure cooling system is provided which is capable of maintaining water level above the top of the core and preventing automatic depressurization system (ADS) actuation for line breaks less than 1 in. nominal diameter,

d. No operator action is required until 10 minutes after an accident, and

e. 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 licensing requirements and design practices of isolation, separation, and single failure considerations.

b. The ECCS network has a built-in redundancy so that adequate cooling can be provided, even in the event of specified failures. The following equipment makes up the ECCS:

   1. High-pressure core spray (HPCS),
   2. Low-pressure core spray (LPCS),
   3. Low-pressure coolant injection (LPCI), three loops, and
   4. Automatic depressurization system (ADS).

c. The ADS is designed to remain operational following a single active or passive component failure, including power buses, electrical and mechanical parts, cabinets, and wiring.

d. In the event of a break in a pipe that is not a part of the ECCS, no single active component failure in the ECCS can prevent automatic initiation and successful operation of less than the following combination of ECCS equipment:

   1. Three LPCI loops, the LPCS and the ADS (i.e., HPCS failure), or

   2. Two LPCI loops, the HPCS and the ADS (i.e., LPCS diesel generator failure), or

   3. One LPCI loop, the LPCS, the HPCS and ADS (i.e., LPCI diesel generator failure).

e. In the event of a break in a pipe that is a part of the ECCS, no single active component failure in the ECCS can prevent automatic initiation and successful operation of less than the following combination of ECCS equipment:

   1. Two LPCI loops and the ADS, or
   2. One LPCI loop, the LPCS and the ADS, or
   3. One LPCI loop, the HPCS and the ADS, or
   4. The LPCS, the HPCS, and ADS.

These are the minimum ECCS combinations which result after assuming any single active component failure and assuming that the ECCS line break disables the affected system.

f. Long term (10 minutes after initiation signal) cooling requires the removal of decay heat by means of the standby service water system. In addition to the break which initiated the loss of coolant event, the system is able to sustain one failure, either active or passive, and still have at least one ECCS pump (LPCI, HPCS, or LPCS) operating with a residual heat removal (RHR) heat exchanger loop with 100% service water flow.

g. Offsite power is the preferred source of power for the ECCS network and every reasonable precaution is made to ensure its high availability. However, onsite emergency power is provided with sufficient diversity and capacity so that all the above requirements can be met if offsite power is not available.

h. The onsite diesel fuel reserve is designed in accordance with IEEE 308-1971 criteria.

i. Diesel-load configuration is as follows:

   1. LPCI loop A (with heat exchanger) and the LPCS connected to the Division 1 diesel generator.

   2. LPCI loop B (with heat exchanger) and loop C connected to the Division 2 diesel generator.

   3. The HPCS connected to the Division 3 diesel generator.

j. Systems which interface with but are not part of the ECCS are designed and operated such that failure(s) in the interfacing systems do not propagate to and/or affect the performance of the ECCS.

k. Non-ECCS systems interfacing with the ECCS buses are automatically shed from and/or isolated from the ECCS buses when a LOCA signal exists and offsite ac power is not available.

l. No more than one storage battery is connected to a dc power bus.

m. The logic required to automatically initiate the ECCS is capable of being tested during plant operation. Each system of the ECCS including flow rate and sensing network is capable of being tested during shutdown or during reactor operation. Pump discharge is routed to the suppression pool or condensate storage tank through a test line. The injection line isolation valves and isolation check valves are tested in accordance with Section 3.9.6.

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.

6.3.1.1.3 Emergency Core Cooling System Requirements for Protection from Physical Damage

The ECCS piping and components are protected against damage from movement, thermal stresses, the effects of the LOCA, and the safe shutdown earthquake (SSE).

The ECCS is protected against the effects of pipe whip which might result from piping failures up to and including the LOCA. This protection is provided by separation, pipe whip restraints, or energy absorbing materials. Any of these three methods is applied to provide protection against damage to ECCS piping and components which otherwise could result in a reduction of ECCS effectiveness to an unacceptable level.

Physical separation outside the drywell is achieved as follows:

a. The ECCS is separated into three functional groups:

    1. HPCS

    2. LPCS and LPCI loop A with 100% service water and one RHR heat exchanger

    3. LPCI loops B and C with 100% service water and one RHR heat exchanger

b. The equipment in each group is separated from that in the other two groups. In addition, HPCS and the reactor core isolation cooling (RCIC) (which is not an ECCS) are separated.

c. Separation barriers exist between the functional groups and between HPCS and RCIC as required to ensure that environmental disturbances affecting one functional group will not affect the remaining groups.

6.3.1.1.4 Emergency Core Cooling System Environmental Design Basis

The only active components in the HPCS, LPCS, or LPCI systems located in the drywell are the check valves. These safety-related, injection/isolation check valves are qualified for the accident environmental requirements specified in Section 3.11 and are installed above the expected flood level in the drywell. The ADS valves are located in the drywell and are qualified to the accident environmental conditions specified in Section 3.11.

The balance of the ECCS equipment (e.g., pumps, motors) is qualified for accident environmental requirements specified in Section 3.11.

Note: "Qualification" of safety-related mechanical (SRM) equipment is not part of the Columbia Generating (CGS) Station Environmental Qualification (EQ) 10 CFR 50.49 program but is part of the process that maintains the plant design basis.

6.3.1.2 Summary Descriptions of Emergency Core Cooling System

The ECCS injection network consists of an HPCS system, an LPCS system, and the LPCI mode of the RHR system. The ADS assists the injection network under certain conditions. These systems are briefly described in this section as an introduction to more detailed system descriptions in Section 6.3.2.

6.3.1.2.1 High-Pressure Core Spray

The HPCS pumps water through a peripheral ring spray sparger mounted above the reactor core. Coolant is supplied over the entire range of system operation pressures. The primary purpose of HPCS is to maintain reactor vessel inventory after small breaks which do not depressurize the reactor vessel. The HPCS also provides spray cooling heat transfer during breaks which uncover the core. The standby liquid control (SLC) system also injects to the reactor pressure vessel (RPV) by means of the HPCS core spray header. An SLC injection will occur with HPCS flow either on or off.

6.3.1.2.2 Low-Pressure Core Spray

The LPCS is an independent loop similar to the HPCS, the primary difference being the LPCS delivers water over the core at low reactor pressures. The primary purpose of the LPCS is to provide inventory makeup and spray cooling during large breaks which uncover the core. When assisted by the ADS, LPCS also provides protection for small breaks.

6.3.1.2.3 Low-Pressure Coolant Injection

The LPCI is an operating mode of the RHR system. Three pumps deliver water from the suppression pool to the bypass region inside the shroud through three separate reactor vessel penetrations to provide inventory makeup following large pipe breaks. When assisted by the ADS, LPCI also provides protection for small breaks.

6.3.1.2.4 Automatic Depressurization System

The ADS utilizes seven of the reactor safety/relief valves (SRVs) to reduce reactor pressure during small breaks in the event of HPCS failure. When the vessel pressure is reduced to within the capacity of the low pressure systems (LPCS and LPCI), the systems provide inventory makeup so that acceptable postaccident temperatures are maintained in the core.

6.3.2 SYSTEM DESIGN

6.3.2.1 Schematic Piping and Instrumentation Diagrams

The process and flow diagrams for the ECCS are specified in the various Sections of 6.3.2.2.

6.3.2.2 Equipment and Component Descriptions

The starting signal for the ECCS comes from at least two independent and redundant sensors of drywell pressure and low reactor water level, except ADS which requires low reactor water level and indication that LPCI or LPCS is available. The ECCS is actuated automatically and requires no operator action during the first 10 minutes following the accident.

The preferred source of power for all three ECCS divisions is from regular ac power to the plant. Regular ac power is from the main transformers [TR-N(1) and (2)] during plant operation or from the startup transformer (TR-S) (an offsite power source) when the main generator is off-line. Should regular ac power be lost, Division 1 (LPCS and LPCI loop A) and Division 2 (LPCI loops B and C) would be transferred to a second offsite power supply and backup transformer (TR-B). Division 3 (HPCS) would be powered from its onsite standby diesel. If the backup transformer were also lost, Divisions 1 and 2 would then be powered from their respective and independent onsite standby diesels. A more detailed description of the power supplies for the ECCS is contained in Section 8.3.

6.3.2.2.1 High-Pressure Core Spray System

Process and flow diagrams are shown in Figures 6.3-3 and 6.3-4. The HPCS system consists of a single motor-driven centrifugal pump, a spray sparger in the reactor vessel located above the core (separate from the LPCS sparger), and associated system piping, valves, controls, and instrumentation. The system is designed to operate from regular ac or from a standby diesel generator supply if offsite power is not available. The system is designed to the requirements of ASME Section III.

With the exception of the check valve on the discharge line, all active HPCS equipment is located outside the primary containment. Suction piping is provided from the condensate storage tanks and the suppression pool. This arrangement provides HPCS the capability to use high quality water from the condensate storage tanks. In the event that the condensate storage water supply becomes exhausted or is not available, automatic switchover to the suppression pool water source will ensure a closed cooling water supply for continuous operation of the HPCS system. The HPCS pump suction is also automatically transferred to the suppression pool if the suppression pool water level exceeds a prescribed value. The condensate storage tanks contain a reserve of approximately 135,000 gal of water just for use by HPCS and RCIC.

Remote controls for operating the motor-operated components and diesel generator are provided in the main control room. The HPCS controls and instrumentation are described in Section 7.3.1.

The system is designed to pump water into the reactor vessel over a wide range of pressures. For small breaks that do not result in rapid reactor depressurization, the system maintains reactor water level. For large breaks the HPCS system cools the core by a spray. The HPCS also provides for core cooling in the event of a station blackout. If a LOCA should occur, a low water level signal or a high drywell pressure signal initiates the HPCS and its support equipment. The system can also be manually placed in operation.

The HPCS injection automatically stops with a high water level in the reactor vessel by signaling the injection valve to close and it automatically starts again when a low water level signals the injection valve to open. The HPCS system also serves as a back-up to the RCIC system in the event the reactor becomes isolated from the main condenser during operation and feedwater flow is lost.

The HPCS system head flow characteristic used for LOCA analyses is shown in Figure 6.3-5. When the system is started, initial flow rate is established by primary system pressure. As vessel pressure decreases, flow will increase.

When vessel pressure reaches 200 psid* the system reaches rated core spray flow. The HPCS motor size is based on peak horsepower requirements.

The elevation of the HPCS pump is sufficiently below the water level of both the condensate storage tanks and the suppression pool to provide a flooded pump suction and to meet pump net positive suction head (NPSH) requirements with the containment at atmospheric pressure and the suction strainer bed entrained with debris washed into the wetwell following a LOCA. The available NPSH at the pump suction is sufficient to meet the NPSH required (see Section 6.3.2.2.6). The available NPSH also ensures that no cavitation occurs anywhere in the pump suction line between the wetwell strainers and the pump suction.

A motor-operated valve is provided in the suction line from the suppression pool. The valve is located as close to the suppression pool penetration as practical. This valve is used to isolate the suppression pool water source when HPCS system suction is from the condensate storage

* psid - differential pressure between the reactor vessel and the suction source.

system and to isolate the system from the suppression pool in the event of a leak in the HPCS system.

A check valve, flow element, and restricting orifice are provided in the HPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system. The flow element is provided to measure system flow rate during LOCA and test conditions and for automatic control of the minimum low flow bypass gate valve. The measured flow is indicated in the main control room. The restricting orifice was sized during the system preoperational test to limit system flow to prescribed values.

A low flow bypass line with a motor-operated gate valve connects to the HPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage from overheating when other discharge line valves are closed. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

To ensure continuous core cooling, primary containment isolation does not interfere with HPCS operation.

The HPCS system incorporates relief valves to protect the components and piping from inadvertent overpressure. One relief valve with required capacity is located on the discharge side of the pump downstream of the check valve to relieve thermally-expanded fluid or leakage. A second relief valve is located on the suction side of the pump. The HPCS components and piping are positioned to avoid damage from the physical effects of design basis accidents such as pipe whip, missiles, high temperature, pressure, and humidity. The HPCS equipment and support structures are designed in accordance with Seismic Category I criteria. The system is assumed to be filled with water for seismic analysis.

Provisions are included in the HPCS system which will permit the HPCS system to be tested. These provisions are

a. Active HPCS components are testable during normal plant operation and/or during shutdown,

b. A full flow test line is provided to route water from and to the condensate storage tanks without entering the RPV,

c. A full flow test line is provided to route water from and to the suppression pool without entering the RPV,

d. Instrumentation is provided to indicate system performance during normal and test conditions,

e. Check valves and motor-operated valves are capable of operation for test purposes, and

f. System relief valves are removable for bench-testing during plant shutdown.

6.3.2.2.2 Automatic Depressurization System

If the HPCS cannot maintain reactor water level, the ADS, which is independent of any other ECCS, reduces the reactor pressure so that flow from LPCI and LPCS systems can enter the reactor vessel for core cooling.

The ADS employs seven of the nuclear system pressure relief valves to relieve high pressure steam to the suppression pool. The design, location, description, operational characteristics, and evaluation of the pressure relief valves are discussed in detail in Section 5.2.2. The operation of the ADS is discussed in Section 7.3.1.

6.3.2.2.3 Low-Pressure Core Spray System

Process and flow diagrams are shown in Figures 6.3-4 and 6.3-6. The LPCS system consists of a single motor-driven centrifugal pump, a spray sparger in the reactor vessel above the core (separate from the HPCS sparger), piping and valves to convey water from the suppression pool to the sparger, and associated controls and instrumentation. Design pressure and temperature of system components are based on ASME Section III.

The LPCS is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCS operates in conjunction with the ADS, the effective core cooling capability of the LPCS is extended to all break sizes because the ADS can rapidly reduce the reactor vessel pressure to the LPCS operating range. The system head flow characteristic assumed for LOCA analyses is shown in Figure 6.3-1.

The LPCS pump and all motor-operated valves can be operated individually in the control room. Operating flow and valve position indication is provided in the control room.

To ensure continuity of core cooling, primary containment isolation signals do not interfere with LPCS operation.

The LPCS discharge line to the reactor is provided with two isolation valves. One of these valves is a check valve located inside the drywell as close as practical to the reactor vessel. The LPCS injection flow causes this valve to open during LOCA conditions (i.e., no power is required for valve actuation during LOCA). If the LPCS line should break outside the containment, the check valve in the line inside the drywell will prevent loss of reactor water outside the containment.

The other isolation valve (which is also referred to as the LPCS injection valve) is a motor-operated gate valve located outside the primary containment as close as practical to LPCS discharge line penetration into the containment. The valve is capable of opening against a differential pressure equal to normal reactor pressure, minus the minimum LPCS system shutoff pressure. A permissive switch prevents the valve operator from being energized to open until the reactor vessel pressure is less than the value in Table 6.3-1. This valve is normally closed to back up the inside check valve for containment integrity purposes. A test line is provided between the two valves. The test connection line has two normally closed valves to ensure containment integrity.

The LPCS system components and piping are arranged to avoid damage from the physical effect of design-basis accidents, such as pipe whip, missiles, high temperature, pressure, and humidity.

With the exception of the check valve on the discharge line, all active LPCS equipment is located outside the primary containment.

A check valve, flow element, and restricting orifice are provided in the LPCS discharge line from the pump to the injection valve. The check valve is located below the minimum suppression pool water level and is provided so the piping downstream of the valve can be maintained full of water by the discharge line fill system. 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 globe valve. The measured flow is indicated in the main control room. The restricting orifice was sized during the system preoperational test to limit system flow to prescribed values.

A low flow bypass line with a motor-operated globe valve connects to the LPCS discharge line upstream of the check valve on the pump discharge line. The line bypasses water to the suppression pool to prevent pump damage due to overheating when other discharge line valves are closed or reactor pressure is greater than the LPCS system discharge pressure following system initiation. The valve automatically closes when flow in the main discharge line is sufficient to provide required pump cooling.

The LPCS flow passes through a motor-operated pump suction valve that is normally open. This valve can be closed from the control room to isolate the LPCS 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. Since the LPCS takes a suction on the suppression pool, a closed loop is established for the water escaping from the break.

The LPCS pump is located in the reactor building sufficiently below the water level in the suppression pool to ensure a flooded pump suction and to meet pump NPSH requirements with the containment at atmospheric pressure and postaccident debris entrained on the beds of the suction strainers. A pressure gauge is provided to indicate the suction head. The available NPSH at the pump suction is sufficient to meet the NPSH required (see Section 6.3.2.2.6). The LPCS system incorporates relief valves to prevent the components and piping from inadvertent overpressure conditions. One relief valve is located on the pump discharge. A second relief valve is located on the suction side of the pump.

The LPCS system piping and support structures are designed in accordance with Seismic Category I criteria. The system is assumed to be filled with water for seismic analysis. Provisions are included in the LPCS system which will permit the system to be tested. These provisions are

a. All active LPCS components are testable during normal plant operation and/or shutdown,

b. A full flow test line is provided to route water from and to the suppression pool without entering the RPV,

c. A suction test line supplying high quality water is provided 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. Check valves and motor-operated valves are capable of operation for test purposes, and

f. Relief valves are removable for bench-testing during plant shutdown.

6.3.2.2.4 Low-Pressure Coolant Injection System

The LPCI system is an operating mode of the RHR system. The LPCI system is automatically actuated by low water level in the reactor and/or high pressure in the drywell and, when reactor vessel pressure is low enough, uses the three RHR motor-driven pumps to draw suction from the suppression pool and inject cooling water flow into the reactor core to cool the core by flooding. Each loop has its own suction and discharge piping and separate vessel nozzle which connects with the core shroud to deliver flooding water on top of the core. The system is a high volume core flooding system. The design pressure and temperature of system components is based on ASME Section III.

The LPCI system, like the LPCS system, is designed to provide cooling to the reactor core only when the reactor vessel pressure is low, as is the case for large LOCA break sizes. However, when the LPCI operates in conjunction with the ADS, then the effective core cooling capability of the LPCI is extended to all break sizes because the ADS will rapidly reduce the reactor vessel pressure to the LPCI operating range. The head flow characteristic assumed in the LOCA analyses for the LPCI system is shown in Figure 6.3-2.

The process and flow diagram for the RHR system is contained in Section 5.4.7.

The pumps, piping, controls, and instrumentation of the LPCI loops are separated and protected so that no single physical event, including missiles, can make all loops inoperable.

To ensure continuity of core cooling, primary containment isolation signals do not interfere with the LPCI mode of operation.

Each LPCI discharge line to the reactor is provided with two isolation valves. The valve inside the drywell is a check valve and the valve outside the drywell is a motor-operated gate valve. No power is required to operate the check valve inside of the drywell since it opens with LPCI injection flow. If a break were to occur outboard of the check valve, the valve would shut isolating the reactor from the line break.

The motor-operated isolation valve outside of the drywell is also the LPCI injection valve and it is located as close as practical to the drywell wall. It is capable of opening against a differential pressure equal to normal reactor pressure minus the upstream pressure with the RHR pump running at minimum flow. A permissive switch prevents the valve operator from energizing open until the reactor vessel pressure is as shown in Table 6.3-1.

Figure 5.4-16 process diagram shows the additional flow paths available other than the LPCI mode. However, the low water level or high drywell pressure signals which automatically initiate the LPCI mode are also used to isolate all other modes of operation and revert system valves to the LPCI lineup. Inlet and outlet valves from the heat exchangers however receive no automatic signals. The heat exchanger inlet valves are key-locked open and the outlet valves are administratively controlled in the open position. The RHR system continues in the LPCI mode until the operator determines that another mode of operation is needed (such as containment cooling) and takes action to manually initiate that mode. The LPCI will not be diverted to any other mode of operation until adequate core cooling is ensured. No operator actions are needed during the short term.

A check valve in the pump discharge line is used together with a discharge line fill system to keep the discharge lines full of water, thereby, preventing water hammer on pump start. A flow element in each pump discharge line is used to provide a measure of system flow and to originate automatic signals for control of the pump minimum flow valves. The minimum flow valve permits a small flow to the suppression pool in the event no discharge valve is open or in the case of a LOCA where vessel pressure is higher than pump shutoff head.

Using the suppression pool as the source of water, the LPCI pump establishes a closed loop for recirculation of LPCI water escaping from the break.

The design pressures and temperatures, at various points in the system, during each of the several modes of operation of the RHR system can be obtained from the RHR process diagram in Figures 5.4-16 and 5.4-17.

The LPCI pumps and equipment are described in detail in Section 5.4.7. The RHR heat exchangers are not associated with the emergency core cooling function. The heat exchangers are discussed in Section 6.2.2. The portions of the RHR required for accident protection including support structures are designed in accordance with Seismic Category I criteria. The available NPSH at the pump suction is sufficient to meet the NPSH required (see Section 6.3.2.2.6). The characteristics for the RHR (LPCI) pumps are shown in Figures 5.4-18, 5.4-19, and 5.4-20.

The LPCI system incorporates a relief valve on each of the pump discharge lines which protects the components and piping from overpressure conditions.

There is a relief valve on the common suction header from the reactor recirculation piping for loops A and B. In addition, each of the three suction pipes from the suppression pool for loops A, B, and C is provided with a relief valve.

The following provisions are included in the LPCI system to permit testing of the system:

a. Active LPCI components are designed to be testable during normal plant operation and/or during plant shutdown,

b. A discharge test line is provided for the three pumps to route suppression pool water back to the suppression pool without entering the RPV,

c. A suction test line, supplying high quality water, is provided to test discharge into the RPV during normal plant shutdown,

d. Instrumentation is provided to indicate system performance during normal and test operations,

e. Check valves and motor-operated valves are capable of operation for test purposes,

f. Lines taking suction from the recirculation system are provided for loops A and B to provide for shutdown cooling and to test pump discharge into the RPV during plant shutdown, and

g. System relief valves are removable for bench-testing during plant shutdown.

6.3.2.2.5 Emergency Core Cooling System Discharge Line Fill System

The ECCS discharge line fill system is designed to maintain the pump discharge lines in a filled condition to ensure the time between the signal to start the pump and the initiation of flow into the RPV is minimized.

Since the ECCS discharge lines are elevated above the suppression pool, check valves are provided near the pumps to prevent back flow from emptying the lines into the suppression pool. To ensure that any leakage from the discharge lines is replaced and the lines are always kept full, a water leg pump system is provided for each of the three ECCS divisions. The power supply to these pumps is classified as essential when the main ECCS pumps are not operating. Indication is provided in the control room as to whether the water leg pumps are operating.

6.3.2.2.6 Emergency Core Cooling System Suction Strainers

NRC Bulletin 96-03, Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors, requested that the ECCS suction strainers be evaluated with regard to the potential for plugging during accident conditions. The ECCS suction strainers were replaced to conform with the requirements of the bulletin.

There are two suction strainers for each ECCS pump. Each strainer is Quality Class I, Seismic Category I, Cleanliness Class B, and has a service rating of ANSI 150#. Strainer materials and fabrication meet ASME Section III, Class 2 requirements. The “N” stamp is not applied since the strainers cannot be hydrostatically tested. The strainer body is stainless steel 304 or 316, or engineer approved equal, suitable for submergence in high quality water during a 40-year lifetime.

The ECCS suction strainers have a cylindrical stacked disk configuration, as shown on Figures 6.3-7 and 6.3-8. The strainers are attached to ANSI 150# RF flanges. The following information identifies the overall dimensions, rated flow conditions, and other considerations used in the design of the ECCS strainers.

Strainer sizes were selected based on several criteria. The strainer beds had to be big enough to entrain post-LOCA wetwell debris without exceeding the maximum allowable head losses. The maximum head losses across the strainers were determined based on maintaining sufficient pressure in the pump suction lines to preclude cavitation under run-out conditions with the suppression pool water at 204.5°F. The strainer sizes were also limited by physical constraints in the suppression pool and hydrodynamic design considerations.

The screen size for the suction strainers on the RHR system is based on the more restrictive criteria set by the pump manufacturer or the spray nozzle orifice opening. The pump manufacturer imposed a maximum particle size of 0.09375 in., based on the size of the smallest orifice/flow path in the pump mechanical seal. This is significantly more restrictive than the requirement imposed by the spray nozzles which have an orifice opening of 0.26563 in. Accordingly, the strainers were specified to prevent the passage of particles 0.09375 in. or greater. The diameter of the holes in the strainer perforated plate is 0.09375 in. Particles smaller than 0.09375 in. (3/32 in.) would normally pass through the ECCS strainers. However, following a LOCA, fibrous debris is postulated to be in the wetwell. This debris, once deposited on the strainers, would cause particles finer than 3/32 in. to be entrained on the strainer bed.

Hydrodynamic and pressure loads were developed which were applied concurrently with the load due to process flow through the strainer. The hydrodynamic pressure loads on the strainer address actual strainer geometries and the drag effects resulting from the strainers, dimensional, and porous properties.

The following information provides details regarding location, size, and submergence of each ECCS strainer, relative to the minimum suppression pool water level of 466 ft 0.75 in. The location of the RHR strainers is also shown in Figure 6.2-32.

ECCS Pump	Quantity	Centerline Elevation	Approximate Azimuth	Minimum Submergence (ft)	Outer Diameter (in.)	Length (in.)
RHR-P-2A	2	447 ft	26°	17.1	47.5	28
RHR-P-2B	2	447 ft	153°	17.1	47.5	28
RHR-P-2C	1	447 ft 7 in.	38°	17.0	36	42
RHR-P-2C	1	447 ft 7 in.	38°	17.0	36	70
LPCS-P-1	1	447 ft 7 in.	58°	17.0	36	36
LPCS-P-1	1	447 ft 7 in.	38°	17.0	36	76
HPCS-P-1	2	438 ft 9 in.	90°	25.8	36	51

During normal operation, corrosion products accumulate in the suppression pool forming a sediment on the pool surfaces. Following a LOCA, those sediments are assumed to be resuspended in the suppression pool water and entrained on the strainer beds, together with other debris.

A spectrum of breaks were analyzed to determine the maximum amount of debris which could be in the wetwell following a LOCA. The ECCS strainers have been designed to provide a satisfactory head loss after entraining all wetwell debris following a LOCA. The analysis was performed using the guidance provided in Reference 6.3-3 and determined the maximum postulated quantities of debris that would be in the suppression pool following a LOCA. The debris types that are assessed in the analysis include the following:

Fiber	TempMat Fiber Insulation, miscellaneous fiber sources (i.e., cloth, rope)
RMI	Reflective Metal Insulation foils, equipment tags (modeled as RMI)
Sediment	Suppression pool sediment, dirt, dust, and concrete dust
Coatings	Qualified epoxy coating within the break zone of influence
Coatings	Unqualified (latent) paint in drywell
Coatings	Zinc unqualified coating in wetwell
Labels	Adhesive backed labels
Rust	Rust flakes from uncoated surfaces in drywell and wetwell

A portion of the strainer surface area was reserved (presumed unavailable in the analysis) to provide for additional design margin.

The debris that is postulated to reach the suppression pool is assumed to be fully entrained on the strainers of ECCS pumps that are available to operate, in proportion to their relative flow rates.

Calculations demonstrating the acceptability of the new strainers and the NPSH for all ECCS pumps were performed in accordance with Regulatory Guide 1.1.

NPSH = Wetwell air space pressure + static pressure - friction losses - vapor pressure

The NPSH calculations are based on a peak suppression pool temperature of 204.5°F. The analysis which established the 204.5°F temperature used the following conservative assumptions:

a. The suppression pool is the only heat sink available to the containment system. No credit is taken for passive structural heat sinks in the drywell, suppression chamber air space, or in the suppression pool;

b. No cooling is assumed for 10 minutes. After 10 minutes, the RHR heat exchangers are assumed to remove energy by recirculating water from the suppression pool through the RHR heat exchangers; and

c. The suppression pool volume is at minimum Technical Specifications level (112,197 ft^3), with an initial condition of 90°F. Standby service water, which cools the RHR heat exchanger, is also at 90°F.

In addition, the NPSH calculation used the following conservative assumptions:

a. The suppression chamber is assumed to be at 14.7 psia throughout the event,

b. No credit is taken for expansion of the suppression pool volume from its initial volume at 90°F to 204.5°F, and

c. The NPSH required is the pump manufacturer's NPSH required plus two feet.

Vapor pressure at the peak suppression pool temperature of 204.5°F is 12.6 psia (30.3 ft). In accordance with Regulatory Guide 1.1, "no increase in containment pressure from that present prior to postulated loss-of-coolant accidents" is assumed. Therefore, the wetwell air space pressure is assumed to be 0 psig. Based on a minimum suppression pool level of 466 ft 0.75 in., summary NPSH data for each of the ECCS systems is provided below:

Summary of ECCS Pumps NPSH	RHR	LPCS	HPCS
NPSH available at pump suction (ft)	34.2	37.7	40.7
NPSH required (ft)	16	15	26
NPSH margin at pump suction (ft)	18.2	22.7	14.7

The ECCS strainers were designed to ensure that with the strainers entrained with debris there was sufficient pressure in the suction line to preclude cavitation at the high points of the suction lines.

The strainer designs are based upon the suppression pool temperature and pressure of 204.5°F and 14.7 psia, respectively. The actual suppression pool atmosphere is calculated to be higher than 14.7 psia following a LOCA, adding pressure to the suction lines, and increasing the margin to cavitation at the lines' high points.

With no operator action, the RHR valve alignment will result in approximately 40% of its LPCI flow through the RHR heat exchangers, with the balance of the flow through the open heat exchanger bypass valve. For a design basis recirculation line break, the partial flow through the heat exchangers will remove heat at about 75% of their design heat rate. At 10 minutes, the operator must close the bypass valve to achieve full cooling.

There are sufficient margins in the NPSH and suppression pool analyses to ensure that the lack of operator action for 20 minutes will not challenge the required NPSH for the ECCS pumps at the pump nozzles or allow cavitation anywhere in the suction lines.

All ECCS suction lines in the suppression pool have been designed with large diameter piping (24 in.) to reduce the inlet velocity (maximum 6.67 ft/sec). This inlet velocity will support a vortex of no more than 2.5 ft in height. The inlet to each of the ECCS suction lines is at least 17 ft below the minimum suppression pool level. Vortex formation at the ECCS pump inlets as a result of lowered suppression pool level is thus not considered a problem.

Since it has been conservatively established that all ECCS suction lines are adequately submerged to preclude formation of an undesirable vortex, no confirmatory preoperational testing is required.

6.3.2.3 Applicable Codes and Classifications

The applicable codes and classification of the ECCS are specified in Section 3.2. All vital piping systems and components (pumps, valves, etc.) for the ECCS comply with ASME Section III of the Edition and Addenda that were mandatory at the time of their order or a later Edition and Addenda. The piping and components of the ECCS which form part of the reactor coolant pressure boundary are Safety Class 1. The remaining piping and components are Safety Class 2, 3, or G, as indicated in Section 3.2. The equipment and piping of the ECCS are designed to the requirements of Seismic Category I. This seismic designation applies to all structures and equipment essential to the core cooling function. The IEEE codes applicable to the controls and power supplies are specified in Section 7.1.

6.3.2.4 Materials Specifications and Compatibility

Materials specifications and compatibility for the ECCS are presented in Section 6.1. Nonmetallic materials such as lubricants, seals, packings, paints and primers, insulation, as well as metallic materials, etc., are selected as a result of engineering evaluation for compatibility with other materials in the system and the surroundings pertaining to chemical, radiolytic, mechanical, and nuclear effects. Materials used were reviewed and evaluated and found to be acceptable 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 or the delivery of coolant to the reactor vessel. No individual system of the ECCS is single failure proof, with the exception of the LPCI and ADS. Therefore, it is expected that single failures will disable individual systems of the ECCS. The consequences (remaining available systems) of the most severe single failures are shown in Table 6.3-3. The LOCA caused by a pipe break in an ECCS, with the single failure of a DG in another division and the loss of offsite power, will result in the minimum available ECCS.

During a LOCA, for protection against and mitigation of a single passive ECCS failure (pump seal or valve bonnet leak), a Class 1E level instrument is mounted just above floor level in each ECCS pump room and in the RCIC pump room to detect such failures (after 24 hours) during long-term cooling (assuming loss of the other non-Class 1E leak detection equipment). The maximum leak rate postulated is 23 gpm, which results from the total failure of an RHR pump seal. Operator action will isolate the source of the leak after detection and before it has any adverse effects on ECCS operation.

The functional testing and calibration of the ECCS is prescribed by the Technical Specifications.

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 inside the ECCS and RCIC/CRD pump rooms are protected from flooding and missiles generated outside the room in which the particular pump is located by the reinforced-concrete structure, including doors and wall penetrations, which minimize the effects of missiles and flooding. Each pump room contains the majority of the active components of one emergency core cooling or RCIC/CRD subsystem.

The ECCS is protected against the effects of pipe whip which might result from piping failures up to and including the design basis 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.

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.

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 and in Section 6.3.1.1.2 as part of the overall system description.

6.3.2.8 Manual Actions

The ECCS is actuated automatically and requires no operator action during the first 10 minutes following an accident. During the long-term cooling period (after 10 minutes), the operator will initiate the RHR system heat exchangers in the suppression pool cooling mode.

6.3.3 EMERGENCY CORE COOLING SYSTEM PERFORMANCE EVALUATION

The ECCS performance is evaluated using analytical methods in compliance with the requirements of 10 CFR 50 Appendix K to show conformance to the acceptance criteria of 10 CFR 50.46. The methods used analyze the full LOCA break spectrum, including small, intermediate, and large size breaks. A spectrum of breaks and single failures is run using a consistent set of initial conditions to determine the resultant peak clad temperature (PCT). The PCT is calculated for the potentially limiting events and the design basis break is identified based on that parameter. The break spectrum analysis results confirm that considerable margin exists to the acceptance criteria of 10 CFR 50.46. The break spectrum analysis addresses two loop and single loop operation. The following Chapter 15 accidents require ECCS operation:

a. Steam system piping break - outside containment, Section 15.6.4,
b. Loss-of-coolant accidents - inside containment, Section 15.6.5, and
c. Feedwater line break - outside containment, Section 15.6.6.

The baseline analyses to verify the adequacy of ECCS design were performed by the NSSS vendor for the initial core, a GE 8 x 8 fueled core. The adequacy of the ECCS design was verified subsequently for Single Loop Operation (SLO), Extended Load Line Limit Analysis (ELLLA), reactor power uprate, changes in fuel design, and adjustable speed drive reactor recirculation pumps.

The NSSS vendor analysis established the large break in the reactor recirculation suction line, with failure of the HPCS diesel generator as the limiting (design basis) event. The NSSS vendor analyses are described in References 6.3-1, 6.3-2, 6.3-4 and 6.3-7.

The AREVA NP break spectrum analysis for the ATRIUM-10 fuel identified the limiting break as a 100% double-ended guillotine (DEG) break in the reactor recirculation coolant (RRC) pump suction line with the coincident failure of a LPCI diesel generator (Reference 6.3-14). The break spectrum analyses were performed at a point on the power/flow map to support the plant rated thermal power operation with increased core flow. The applicable limiting break is then used in the ECCS heatup analyses to determine the maximum average planar linear heat generation rate (MAPLHGR) limits for the specific fuel type.

The GE14 analysis establishes the small break of 0.07 ft^2 in the recirculation suction line with top peaked axial power shape and failure of the HPCS diesel generator as the limiting break event. The GE14 analysis is described in Reference 6.3-17.

A summary description of the reload design basis LOCA analysis methods is provided in this section. For a complete description of the design basis LOCA event see References 6.3-13, 6.3-14, and 6.3-17.

6.3.3.1 Emergency Core Cooling System Bases for Technical Specifications

The MAPLHGRs calculated in this performance evaluation provide a basis to ensure conformance with the acceptance criteria of 10 CFR 50.46. For ATRIUM-10 and GE14, the MAPLHGR limits are determined from ECCS limits (PCT) only, because the thermal-mechanical limits are incorporated into the LHGR limits. The MAPLHGR limits are provided in the COLR. Testing requirements for ECCS are discussed in Section 6.3.4. Limits on minimum suppression pool water level are discussed in Section 6.2.

6.3.3.2 Acceptance Criteria for Emergency Core Cooling System Performance

The applicable acceptance criteria, extracted from 10 CFR 50.46, are listed and a discussion of conformance is provided. The reload fuel vendors ECCS licensing methodologies (References 6.3-9, 6.3-10, 6.3-11, and 6.3-12) require demonstration of compliance with the first three criteria. Descriptions of the methods used to demonstrate compliance are shown in Reference 6.3-13.

Criterion 1, Peak Cladding Temperature
"The calculated maximum fuel element cladding temperature shall not exceed 2200° F."

Criterion 2, Maximum Cladding Oxidation
"The calculated total local oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation."

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."

- Compliance with Criteria 1, 2, and 3 is summarized in Table 6.3-5 and Figure 6.3-9.

Criterion 4, Coolable Geometry
"Calculated changes in core geometry shall be such that the core remains amenable to cooling."

- As described in Reference 6.3-13, Section 3.2 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."

- Compliance with this criterion was demonstrated during the original and uprate review of the plant ECCS design (Reference 6.3-1 and 6.3-7). Briefly summarized, the core remains covered to at least the jet pump suction elevation and spray cooling cools the uncovered region. As discussed in Reference 6.3-14, Section 8.0, since the ECCS design and performance do not change with fuel reloads, compliance is maintained in subsequent reload cycles.

The ECCS LOCA licensing methodologies for GE14 and the compliance with the acceptance criteria as described above are documented in References 6.3-18 through 6.3-23. Compliance with Criteria 1, 2, 3, 4 and 5 for GE14 is summarized in Table 6.3-5 and Figure 6.3-9.

6.3.3.3 Single Failure Considerations

The consequences of potential operator errors and single failures and potential for submergence of valve motors in the ECCS are discussed in Section 6.3.2. The following bounding single failures are described in Table 6.3-3:

a. Low-pressure coolant injection emergency diesel generator, which powers two LPCI pumps,

b. Low-pressure core spray emergency diesel generator, which powers one LPCI pump and one LPCS pump, and

c. High-pressure core spray.

The systems that remain operational after these failures are shown in Table 6.3-3. For large breaks, failure of one of the diesel generators is, in general, the more severe failure. Substantial amounts of initial vessel inventory are lost through the break during the blowdown. With fewer systems available, there is less ECCS flow available for reflooding the core and the core will reflood later. The later reflooding results in higher peak cladding temperatures. For small breaks LOCAs, a HPCS failure is the worst single failure.

As shown in Table 6.3-3, at least one core spray system remains operational, if the break is not in the ECCS piping. If the break occurred in the HPCS or LPCS and the single failure were the other spray system, no core spray system would be available to provide long term cooling. Because the remaining core cooling systems would be able to maintain the water level above the top of the fuel, adequate core cooling is provided without a spray system.

The SAFER/GESTR-LOCA methodologies by GE Hitachi Nuclear Energy consider the single failures for recirculation suction line break as described in Table 6.3-3a. The worst single failure for both large and small recirculation line breaks is HPCS failure, in which ADS, LPCS and 3 LPCIs remain operational. Table 6.3-3a also shows the limiting single failures and remaining systems for non-recirculation line breaks.

6.3.3.4 System Performance During the Accident

In general, the system response to an accident is as follows:

a. Receiving an initiation signal,
b. A small lag time (to open all valves and have pumps to rated speed), and
c. ECCS flow entering the vessel.

Key ECCS initiation and operating parameters used in the LOCA analyses are provided in Table 6.3-2. The representative sequence of events is presented in Table 6.3-4. System flow curves are provided in Figures 6.3-1 and 6.3-2.

Operator action is not required during the short-term cooling period following the LOCA. During the long-term cooling period (after 10 minutes), the operator may take actions to:

a. Use ECCS for vessel level control,

b. Use ADS or SRVs for vessel pressure control, or

c. Place systems into operation, such as containment cooling, standby liquid control, or drywell spray.

Key operating parameters, GE14 fuel parameters and ECCS initiation parameters used in the GE14 LOCA analysis are provided in Tables 6.3-2a, 6.3-2b and 6.3-2c, respectively. The representative sequences of events are presented in Tables 6.3-4a and 6.3-4b.

6.3.3.5 Use of Dual Function Components for Emergency Core Cooling System

With the exception of the LPCI system, the systems of the ECCS are designed only to cool the reactor core following a loss of reactor coolant. To this extent, components or portions of these systems (except for pressure relief) are not required for operation of other systems that have emergency core cooling functions, or vice versa. Because the ADS initiating signal or the overpressure signal opens the SRVs there is no conflict between the two SRV functions.

The LPCI subsystem uses the RHR pumps and some of the RHR valves and piping. When reactor water level is low or a high drywell pressure exists, the LPCI subsystem has priority through the valve control logic over the other RHR subsystems for containment cooling or shutdown cooling. Immediately following a LOCA, the RHR system is aligned to the LPCI mode.

The primary storage facility for ECCS water is the suppression pool which is not shared with any other systems except as a secondary source for RCIC. The RCIC system, although not an ECCS, may supply water to the reactor during LOCA conditions while reactor pressure is above the minimum credited pressure. Since any leakage from the core and safety/relief discharge drains back to the suppression pool, sufficient quantity of water is available for core cooling (see Table 6.2-4).

The condensate storage tanks comprise the normal water source for HPCS and RCIC. A minimum of 135,000 gal is required exclusively for RPV makeup. The HPCS and RCIC systems will automatically switch suction to the suppression pool when the minimum condensate storage tank supply is exhausted. The HPCS system will also automatically switch suction to the suppression pool when suppression pool level reaches a predetermined high level limit.

6.3.3.6 Emergency Core Cooling System Analyses for Loss-of-Coolant Accident

A LOCA may occur over a wide spectrum of break locations and sizes. Responses to the break vary significantly over the break spectrum. The largest possible break is a DEG; however, this is not necessarily the most severe challenge to the ECCS. Because of these complexities, an analysis covering the full range of break sizes and locations is required. The LOCA analysis also assumes a coincident loss of power and an additional single failure. See References 6.3-7 and 6.3-14 for more detail.

Regardless of the initiating break characteristics, the event response is separated into three phases; blow down, refill and reflood. The relative duration of each phase is dependant on break size and location.

During the blow down phase of the LOCA, there is a net loss of coolant inventory, an increase in fuel cladding temperature due to core flow degradation and, for the larger breaks, the core becomes fully or partially uncovered. There is a rapid decrease in pressure during the blow down phase. During the early phase of the depressurization, the exiting coolant provides core cooling. The HPCS and LPCS systems also provide some heat removal. The blow down phase is defined to end when LPCS reaches rated flow. When the LPCS diesel generator is the single failure, the blow down phase end is defined as when LPCS, if operational, would have reached rated flow.

During single loop operation (SLO) the break may occur in either loop. The results of a break in the inactive loop would be similar to those from a break in two-loop operation. The break in the active loop during SLO results in a more rapid loss of core flow and earlier degraded core conditions.

In the LOCA refill phase, the ECCS is functioning and there is a net increase of coolant inventory. During this phase the core sprays provide core cooling and, along with LPCI, supply liquid to refill the lower portion of the reactor vessel. In general, the core heat transfer to the coolant is less than the fuel decay heat rate and the fuel cladding temperature continues to increase during the refill phase.

In the reflood phase, the coolant inventory has increased to the point where the mixture level reenters the core region. During the core reflood phase, cooling is provided above the mixture level by entrained reflood liquid and below the mixture level by pool boiling. Sufficient coolant eventually reaches the core hot node and the fuel cladding temperature decreases, terminating the event.

6.3.3.6.1 Loss-of-Coolant Accident Description

Immediately after the postulated double-ended recirculation suction line break, vessel pressure and core flow begin to decrease. The initial pressure response is governed by the closure of the main steam isolation valves and the relative values of energy added to the system by decay heat and energy removed from the system by the initial blowdown of fluid from the downcomer. The initial core flow decrease is rapid because the recirculation pump in the broken loop loses suction and almost immediately ceases to pump. The pump in the intact loop coasts down relatively slowly. This pump coast down governs the core flow response for the next several seconds. When the jet pump suctions uncover, calculated core flow decreases to near zero. When the recirculation pump suction nozzle uncovers, the pressure begins to decay more rapidly. As a result of the increased rate of vessel pressure loss, the initially subcooled water in the lower plenum saturates and flashes up through the core, increasing the core flow. This lower plenum flashing continues at a reduced rate for the next several seconds.

Heat transfer rates on the fuel cladding during the early stages of the blowdown are governed primarily by the core flow response. Nucleate boiling continues in the high power plane until shortly after the core flow loss that results from jet pump uncovery. Film boiling heat transfer rates then apply, with increasing heat transfer resulting from the core flow increase during the lower plenum flashing period. Heat transfer then slowly decreases until the high power axial plane uncovers. At that time, convective heat transfer is assumed to cease.

Water level inside the shroud remains high during the early states of the blowdown because of flashing of the water in the core. After a short time, the level inside the shroud has decreased to uncover the core. Several seconds later, the ECCS is actuated. As a result the vessel water level begins to increase. Some time later the lower plenum is filled and the core is then rapidly recovered.

The cladding temperature at the high power plane decreases initially because nucleate boiling is maintained, the heat input decreases, and the sink temperature decreases. A rapid, short duration cladding heatup follows the time of boiling transition when film boiling occurs and the cladding temperature approaches that of the fuel. The subsequent heatup is slower, being governed by decay heat and core spray heat transfer. Finally the heatup is terminated when the core is recovered by the accumulation of ECCS water.

6.3.3.6.2 Loss-of-Coolant Accident Analysis Procedures and Input Variables

The GE Hitachi Nuclear Energy ECCS-LOCA licensing evaluation methodologies are described in References 6.3-18 through 6.3-23. The GE14 analysis is documented in Reference 6.3-17, consistent with References 6.3-1 and 6.3-2. The AREVA NP LOCA-ECCS evaluation model is identified as EXEM BWR-2000 LOCA analysis methodology. The EXEM BWR-2000 is documented in References 6.3-9, 6.3-10, 6.3-11, and 6.3-12. These vendor methodologies cover the time from the event until the reactor has been reflooded. The NSSS vendor, GE, performed the long term ECCS evaluation, as described in Reference 6.3-7. The evaluation documents that the ECCS satisfy the requirements described in Section 6.3.3.2. As documented in References 6.3-1 and 6.3-14, the reactor power uprate and the new fuel did not impact the conclusions reached in Reference 6.3-7.

6.3.3.6.2.1 LOCA Analysis Methodology, GE Hitachi Nuclear Energy

Several computer models are used in the LOCA analysis to determine the LOCA response. These models are LAMB, SCAT/TASC, GESTR-LOCA, and SAFER (References 6.3-7, 6.3-18 through 6.3-23). Together, these models evaluate the short-term and long-term reactor vessel blowdown response to a pipe rupture, the subsequent core flooding by ECCS, and the final rod heatup.

The LAMB model analyzes the short-term blowdown phenomena for postulated large pipe breaks in which nucleate boiling is lost before the water level drops sufficiently to uncover the active fuel. The LAMB output (primarily core flow as a function of time) is used in the SCAT model for calculating blowdown heat transfer and fuel dryout time.

The SCAT/TASC model completes the transient short-term thermal-hydraulic calculation for large recirculation line breaks. Developed for GE11 and later fuels with partial-length rods, an improved SCAT model (designated “TASC”) is used to predict the time and location of boiling transition and dryout. The time and location of boiling transition is predicted during the period of recirculation pump coastdown. When the core inlet flow is low, TASC also predicts the resulting bundle dryout time and location. The calculated fuel dryout time is an input to the long-term thermal-hydraulic transient model, SAFER.

The GESTR-LOCA model provides the parameters to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA for input to SAFER. GESTR-LOCA also establishes the transient pellet-cladding gap conductance for input to both SAFER and SCAT/TASC.

The SAFER model calculates the long-term system response of the reactor over a complete spectrum of hypothetical break sizes and locations. SAFER is compatible with the GESTR-LOCA fuel rod model for gap conductance and fission gas release. SAFER calculates the core and vessel water levels, system pressure response, ECCS performance, and other primary thermal-hydraulic phenomena occurring in the reactor as a function of time. SAFER realistically models all regimes of heat transfer that occur inside the core, and provides the heat transfer coefficients (which determine the severity of the temperature change) and the resulting PCT as functions of time. For GE11 and later fuel analysis with the SAFER code, the part length fuel rods are treated as full-length rods, which conservatively overestimate the hot bundle power.

6.3.3.6.2.2 LOCA Analysis Methodology, AREVA NP

The AREVA NP methodology employs three major computer codes to evaluate the system and fuel response during the LOCA. The RELAX code is used to calculate the system and hot channel response during the blow down, refill, and reflood phases of the LOCA. The HUXY code is used to perform heat up calculations for the LOCA, and to calculate PCT and local clad oxidation at the high power axial plane. The RODEX2 code is used to determine fuel parameters, such as stored energy, for input into the other LOCA codes.

The analysis starts with the specification of fuel parameters using RODEX2 to determine the initial store energy for both the blow down analysis and the heat up analysis. This is accomplished by ensuring that the initial stored energy in RELAX and HUXY is the same or higher than that calculated by RODEX2 for the power, exposure, and fuel design.

The RELAX code is used to calculate the system thermal-hydraulic response during the blow down phase of the LOCA. Following the blow down calculation, another RELAX analysis is performed to analyze the maximum power assembly (hot channel) of the core.

The RELAX code is also used to compute the system and hot channel hydraulic response during the refill and reflood phase of the LOCA.

The ATRIUM-10 fuel rod models are developed using RODEX2. Data from the RELAX and RODEX2 analyses are used to create a detailed model of the highest power plane of the hot channel with the HUXY code.

6.3.3.6.2.3 LOCA Analysis Input Variables

The significant input variables used by the LOCA codes are listed in Tables 6.3-1 and 6.3-2. The plant operating parameters and GE14 fuel parameters used for the GE14 LOCA analysis are summarized in Tables 6.3-2a and 6.3-2b, respectively. The limiting calculation for CGS has been performed for 3716 MWt (106.6% power) and 115 Mlb/hr (106% core flow) to support operation within the power/flow map. The 106.6% power represents 102% of the power that produces 105% of the rated steam flow. The 106% core flow represents the maximum increased core flow. The performance of the ECCS analysis at the maximum core flow results in the highest radial peaking factor given that the calculations are initialized at the same MAPLHGR and minimum critical power ratio (MCPR) limits. Therefore, this analysis envelopes lower flow conditions at rated core power because the calculations would be initialized with a lower radial peaking factor while maintaining the same initial MAPLHGR and MCPR values.

For SLO, the LOCA behavior is modeled by assuming reactor power at 106.6% and by closing a valve that isolates the intact (inactive) loop almost immediately after the LOCA initiation time. Since the power level is much greater than the maximum allowed in SLO, the LOCA analysis predicts a higher core steam generation rate and a longer period of core uncovery than would be calculated if the reduced SLO power were modeled.

6.3.3.7 Break Spectrum Calculations

Break spectrum analyses have been performed to establish the limiting break for the CGS boiling water reactor (BWR) 5 reactor system. Previous analyses by GE, the NSSS vendor have shown that a large pipe break in the recirculation line on the suction side of the recirculation pump is the most limiting break for a BWR 5. The GE analysis includes breaks in both recirculation and non-recirculation piping. Figure 6.3-9 shows the original plant break spectrum analysis for the GE fuel. For the GE14 analysis, the break spectrum is determined and documented in Reference 6.3-17, consistent with original plant break spectrum analysis in Reference 6.3-1.

Two break types (geometry) are considered for the recirculation pipe break; the DEG break and the split break. For the DEG break, the pipe is completely severed, resulting in two independent flow paths to the containment. The DEG break is modeled by setting the break area equal to the full pipe cross-sectional area and varying the discharge coefficient.

The split break is a longitudinal opening or hole that results in a single break flow path to the containment. Appendix K of 10 CFR 50 defines the cross-sectional area of the piping as the maximum split break area required for analysis.

6.3.3.7.1 Break Spectrum Calculation, GE Hitachi Nuclear Energy

A sufficient number of breaks for recirculation suction line are analyzed for GE14 with the potentially limiting single failures using nominal assumptions. This ensures that the limiting combination of break size, location, axial power shape and single failure has been identified. The limiting large break for nominal assumptions is the 100% DBA with mid-peaked axial power shape and HPCS DG failure. The overall limiting LOCA is the small recirculation suction line break of 0.08 ft^2 for nominal assumptions with top peaked axial power shape and HPCS DG failure.

Using the Appendix K input assumptions, analyses of large breaks for GE14 fuel type, are also performed with the limiting single failure. The 100%, 80%, and 60% DBA cases also satisfy the Appendix K requirement for using the Moody Slip Flow Model with three discharge coefficients of 1.0, 0.8, and 0.6, respectively. The limiting Appendix K case for large break is the 100% DBA with mid-peaked axial power shape and HPCS DG failure. The overall limiting LOCA is the small recirculation suction line break of 0.07 ft^2 for Appendix K assumptions with top peaked axial power shape and HPCS DG failure.

The GE14 analysis also considers the non-recirculation line breaks (CS line, LPCI line and etc.) as well as alternate operating modes (ELLLA, ICF, FFWTR and SLO) Reference 6.3-17 documents all the analysis results.

6.3.3.7.2 Break Spectrum Calculation, AREVA NP

The AREVA NP break spectrum analysis considers a full range of break sizes, break locations, break geometry, ECCS system single failures, axial power shapes, and initial operating conditions. Breaks in the recirculation pump suction and discharge lines were analyzed as potentially limiting break locations. The DEG break was modeled by setting the break area equal to the full pipe cross-sectional area and varying the discharge coefficient between 1.0 and 0.4. The range in the discharge coefficient was used to cover uncertainty in the actual geometry at the break. The split break areas ranged from full pipe area to 0.04 ft^2. Non-recirculation line breaks are not limiting LOCAs (Reference 6.3-14). The break spectrum calculations were performed with an assumed failure of one ECCS. Table 6.3-3 lists the assumed single failures and available ECCS for the single failure.

The hot channel is modeled at the highest exposure dependent MAPLHGR and at a conservative MCPR limit for the break spectrum analysis. Reactor operation with a recirculation loop drive flow mismatch of up to 5% is supported in the break spectrum calculations.

The limiting break configuration and size were determined to be a 1.0 DEG recirculation suction line break along with failure of the LPCI diesel generator.

6.3.3.8 Loss-of-Coolant Accident Analysis Conclusions

The ECCS will perform the required design functions and comply with 10 CFR 50.46 acceptance criteria.

6.3.3.8.1 Loss-of-Coolant Accident Analysis Conclusions, GE Hitachi Nuclear Energy

The GE14 limiting large break for two loop operation is the recirculation suction line break of DBA with HPCS diesel generator failure at 104.1% rated power (3629 MWt)/100% rated flow conditions with a mid peaked axial power shape (Reference 6.3-17).

The overall GE14 limiting LOCAs are the small recirculation suction line breaks of 0.07 ft^2 and 0.08 ft^2 for Appendix K and nominal assumptions, respectively, with high pressure core spray diesel generator failure at 104.1% rated power (3629 MWt)/100% rated flow conditions and a top peaked axial power shape (Reference 6.3-17).

The SLO case is performed at the maximum attainable power and flow on the ELLLA rod line. The case conservatively assumes the simultaneous dryout of all axial fuel nodes almost immediately following the initiation of the event. A SLO multiplier of 1.0 on MAPLHGR is applied (Reference 6.3-17).

6.3.3.8.2 Loss-of-Coolant Accident Analysis Conclusions, AREVA NP

The limiting LOCA for AREVA NP ATRIUM-10 fuel is a 100% DEG break of the recirculation pump suction line with a coincident failure of the LPCI diesel generator, for both two loop and single loop recirculation pump operation. The limiting axial power shape in the core is peaked at the location 80% of the active fuel length above the bottom of the active fuel (top-peaked). The initial operating state modeled is 106.6% rated thermal power and 106% of rated core flow. Using the high power and flow conditions for the SLO analysis supports the entire range of SLO initial power/flow condition. The exposure dependent MAPLHGR limits for ATRIUM-10 fuel are documented in Reference 6.3-13. A multiplier is applied to the normal (two loop) operation MAPLHGR limit to obtain the SLO MAPLHGR (References 6.3-13 and 6.3-14).

6.3.4 TESTS AND INSPECTIONS

6.3.4.1 Emergency Core Cooling System Performance Tests

The systems of the ECCS were tested for their operational ECCS function during the preoperational and/or startup test program. Each component was tested for power source, range, direction of rotation, set point, limit switch setting, torque switch setting, etc. Each pump was tested for flow capacity for comparison with vendor data (this test was also used to verify flow measuring capability.) The flow tests involved the same suction and discharge source; i.e., suppression pool or condensate storage tank.

All logic elements were tested individually and then as a system to verify complete system response to emergency signals including the ability of valves to revert to the ECCS alignment from other positions.

During preoperational tests each system was tested for response time and flow capacity while taking suction from its normal source and delivering flow into the reactor vessel. See Section 14.2 for a thorough discussion of preoperational testing for these systems. Pump and valve periodic tests are discussed in Section 3.9.6.

6.3.4.2 Reliability Tests and Inspections

Active components of the HPCS, ADS, LPCS, and LPCI systems are designed so that they may be tested during normal plant operation. Full flow test capability is provided by a testing path back to the suction source. The full flow test is used to verify the capacity of each ECCS pump loop while the plant remains undisturbed in the power generation mode. In addition, each individual valve may be tested in accordance with Inservice Testing Program requirements. Input jacks are provided such that each ECCS loop can be tested for response time.

Testing of the initiating instrumentation and controls portion of the ECCS is discussed in Section 7.3.1. The emergency power system, which supplies electrical power to the ECCS in the event that offsite power is unavailable, is tested as described in Section 8.3.1. The frequency of testing is prescribed by the Technical Specifications. Visual inspections of ECCS components located outside the drywell can be made at any time during power operation. Components inside the drywell can be visually inspected only during periods of access to the drywell. When the reactor vessel is open, the spargers and other internals can be inspected.

6.3.4.2.1 High-Pressure Core Spray Testing

The HPCS can be tested at full flow with condensate storage tank water at any time during plant operation, except when the reactor vessel water level is low or when the condensate level in the condensate storage tanks is below the reserve level (135,000 gal) or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while the HPCS is being tested, the system automatically returns to the operating mode. The two motor-operated valves in the test line to the condensate storage system are interlocked closed when the suction valve from the suppression pool is open.

A design flow functional test of the HPCS over the operating pressure and flow range is performed by pumping water from the condensate storage tanks and back through the full flow test return line to the condensate storage tanks.

The suction valve from the suppression pool and the discharge valve to the reactor remain closed. These two valves are tested separately to ensure operability.

6.3.4.2.2 Automatic Depressurization System Testing

The ADS valves are fully tested during the time when the reactor is being depressurized prior to or repressurized following a refueling outage. This testing includes simulated automatic actuation of the system throughout its emergency operating sequence, but excludes actual valve actuation. Each individual ADS valve is manually actuated.

During plant operation the ADS system can be checked as discussed in Section 7.3.1.

6.3.4.2.3 Low-Pressure Core Spray Testing

The LPCS pump and valves are tested periodically. With the injection valve closed and the return line open to the suppression pool, full flow pump capability is demonstrated. The injection valve and the check valve are tested in a manner similar to that of the LPCI valves.

6.3.4.2.4 Low-Pressure Coolant Injection Testing

Each LPCI loop can be tested during reactor operation. The test conditions are tabulated in Chapter 5. During plant operation, this test does not inject cold water into the reactor because the injection line check valve is held closed by vessel pressure, which is higher than the pump pressure. The injection line portion is tested with reactor water when the reactor is shut down and when a closed system loop is created. This prevents unnecessary thermal stresses.

To test an LPCI pump at rated flow, the test line valve to the suppression pool is opened and the pump suction valve from the suppression pool is opened (this valve is normally open). For loops A and B, the valve to the suppression chamber spray ring header is also opened. Correct operation is determined by observing the instruments in the control room.

If an initiation signal occurs during the tests, the LPCI system automatically returns to the operating mode. The valves in the test lines are closed automatically to ensure that the LPCI pump discharge is correctly routed to the reactor vessel.

6.3.5 INSTRUMENTATION REQUIREMENTS

Design details including redundancy and logic of the ECCS instrumentation are discussed in Section 7.3.1.

Instrumentation required for automatic and manual initiation of the HPCS, LPCS, LPCI, and ADS is discussed in Section 7.3.1 and is designed to meet the requirements of IEEE 279 and other applicable requirements. The HPCS, LPCS, LPCI, and ADS can be manually initiated from the control room.

The HPCS, LPCS, and LPCI are automatically initiated on low reactor water level or high drywell pressure (see Table 6.3-1 for specific initiation levels for each system). The ADS is automatically actuated by sensed variables for reactor vessel low water level plus indication that at least one RHR or LPCS pump is operating. The HPCS, LPCS, and LPCI automatically return from system flow test modes to the emergency core cooling mode of operation following receipt of an initiation signal. The LPCS and LPCI system injection into the RPV begin when reactor pressure decreases to system discharge shutoff pressure. HPCS injection begins as soon as the HPCS pump is up to speed and the injection valve is open since the HPCS is capable of injecting water into the RPV over a pressure range from 0 psid* to 1160 psid.*

6.3.6 REFERENCES

6.3-1 GE Nuclear Energy, "Washington Public Power Supply System Nuclear Project 2, SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis," NEDC-32115P, Class III (Proprietary), DRF A00-05078, Revision 2.

6.3-2 GE Nuclear Energy, "Washington Public Power Supply System Nuclear Project 2, SRV Setpoint Tolerance and Out-of-Service Analysis," GE-NE-187-24-0992, Revision 2.

6.3-3 GE BWROG Committee on ECCS Suction Strainers, "Utility Resolution Guidance for ECCS Suction Strainer Blockage," NEDO-32686, Revision 0.

6.3-4 GE Nuclear Energy, Washington Public Power Supply System Nuclear Project 2, "WNP-2 Power Uprate Transient Analysis Task Report," GE-NE-208-08-0393, DRF A00-05078 and -05371.

6.3-5 Deleted.

6.3-6 Deleted.

* psid - differential pressure between RPV and pump suction source.

6.3-7 General Electric Company, "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K," NEDO-20566A, September 1986.

6.3-8 Framatome ANP, "Mechanical and Thermal-Hydraulic Design Report for Columbia Generating Station ATRIUM-10 Fuel Assemblies," EMF-2865(P), Revision 1, April 2003.

6.3-9 Framatome ANP, "EXEM BWR-2000 ECCS Evaluation Model," EMF-2361(P)(A), Revision 0, May 2001.

6.3-10 Exxon Nuclear Company, "HUXY: A Generalized Multirod Heatup Code with 10 CFR 50 Appendix K Heatup Option Users Manual," XN-CC-33(P)(A), Revision 1, November 1975.

6.3-11 Exxon Nuclear Company, "Exxon Nuclear Company ECCS Cladding Swelling and Rupture Model," XN-NF-82-07(P)(A), Revision 1, November 1982.

6.3-12 Exxon Nuclear Company, "RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model," XN-NF-81-58(P)(A), Revision 2 and Supplements 1 and 2, March 1984.

6.3-13 Framatome ANP, "Columbia Generating Station LOCA-ECCS Analysis MAPLHGR Limit for ATRUIM-10 Fuel," EMF-3172(P), Revision 1, June 2005.

6.3-14 Framatome ANP, "Columbia Generating Station LOCA Break Spectrum Analysis for ATRIUM-10 Fuel," EMF-3171(P), Revision 1, June 2005.

6.3-15 "High Pressure Core Spray System (HPCS)," Design Basis Document, Section 308.

6.3-16 "Low Pressure Core Spray System (LPCS)," Design Basis Document, Section 316.

6.3-17 "Columbia Generating Station GE14 ECCS-LOCA Evaluation," GE Hitachi Nuclear Energy, 0000-0090-6853-R0, February 2009.

6.3-18 "The GESTR -LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 1, GESTR-LOCA – A Model for the Prediction of Fuel Rod Thermal Performance," NEDE-23785-1-PA, Revision 1, October 1984.

6.3-19 "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 2, SAFER – Long Term Inventory Model for BWR Loss-of-Coolant Analysis," NEDE-23785-1-PA, Revision 1, October 1984.

6.3-20 "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 3, SAFER/GESTR Application Methodology," NEDE-23785-1-PA, Revision 1, October 1984.

6.3-21 "The GESTR-LOCA and SAFER Models for the Evaluation of the Loss-of-Coolant Accident. Vol. 3. Supplement 1, Additional Information for Upper Bound PCT Calculation," EDE-23785P-A, Revision 1, March 2002.

6.3-22 "TASC-03A A Computer Program for Transient Analysis of a Single Channel," NEDC-32084P-A, Revision 2, July 2002.

6.3-23 "Compilation of Improvements to GENE's SAFER ECCS-LOCA Evaluation Model," NEDC-32950P, Revision 1, July 2007.

Table 6.3-1

Emergency Core Cooling System Design Parameters

Parameter	Value	
Initiation Signals		
High drywell pressure	2.0 psig (not credited)	
L2 (Low low water level)	9.26 ft above top of active fuel	
L1 (Low low low water level)	2.68 ft. above top of active fuel	
LPCS pump running	150 psig pump discharge pressure	
LPCI pump running	100 psig pump discharge pressure	
High Pressure Core Spray System		
Minimum rated flow at vessel pressure (differential pressure between vessel head and suction source)	psid	gpm
	200	6350
	1130	1550
	1160	516
Vessel pressure that injection valve may open	1175 psia	
Maximum flow (runout)	7341 gpm	
Low Pressure Core Spray System		
Minimum rated flow at vessel pressure (differential pressure between vessel head and suppression pool air volume)	psid	gpm
	128	6350
Vessel pressure that injection valve may open	485 psia	
Maximum flow (runout)	7800 gpm	
Low Pressure Coolant Injection Mode RHR System		
Minimum rated flow at vessel pressure (differential pressure between vessel head and suppression pool air volume)	psid	gpm
	26	7450
Vessel pressure that injection valve may open	485 psia	
Maximum flow (runout) three pumps	24000 gpm	
Automatic Depressurization System		
Number of safety relief valves with ADS function	7 valves	
Time delay: - Initiation signal to valves open	105 seconds[a]	

[a] Either of both ADS trip systems may be manually inhibited, if necessary, to eliminate resetting the timer.

Table 6.3-2

Loss-Of-Coolant Accident Analysis Initial
Conditions and Input Parameters – ATRIUM-10

Parameter	Value
Plant Parameters	
Core thermal power (includes 2% power uncertainty)	3716 MWt (106.6% of rated)
Total core flow rate	115.0 Mlb/hr (106% of rated)
Steam flow rate	16.1 Mlb/hr (107.3% of rated)
Steam dome pressure	1055 psia
Core inlet temperature	536°F
Core inlet enthalpy	530.0 Btu/lb (Calculated by AREVA NP)
ECCS fluid temperature	120° F
Fuel design	ATRIUM-10 (10x10 array)
Initial minimum critical power ratio	1.25 ATRIUM-10 hot assembly (two loop and single loop operation)
Recirculation pump moment of inertia (pump, motor, and drive line)	22,700 lbm-ft^2 (AREVA NP analysis limiting value)
Initiation Signals	
L2 (Low low water level)	5.9 ft. above top of active fuel/ 437.5 in above vessel zero
L1 (Low low low water level)	1.0 ft. above top of active fuel/ 378.5 in above vessel zero
LPCS pump running	150 psig pump discharge pressure
LPCI pump running	100 psig pump discharge pressure

Table 6.3-2

Loss-Of-Coolant Accident Analysis Initial Conditions
and Input Parameters – ATRIUM-10 (Continued)

High Pressure Core Spray System	
Initiation signal	L2
Time delay; initiation signal to pump at rated speed	27 sec
Time delay; initiation signal to injection valve open[a]	37 sec
Maximum injection valve stroke time	17 sec
Vessel pressure that injection valve may open	1175 psia
Pressure that flow may commence (differential pressure between vessel head and drywell)	1160 psid
Minimum rated flow at 1160 psid[b]	413 gpm
Minimum rated flow at 0 psid[b]	6250 gpm
Vessel head v HPCS flow curve	Figure 6.3-5
LPCS	
Initiation signal	L1
Time delay; initiation signal to pump at rated speed	27 sec
Maximum injection valve stroke time	22 sec
Time delay; initiation signal to injection valve open[a]	42 sec
Vessel pressure that injection valve may open	351 psia
Pressure that flow may commence (differential pressure between vessel head and drywell)	285 psid
Minimum rated flow at 122 psid[b]	5625 gpm
Minimum rated flow at 0 psid[b]	7030 gpm
Vessel head v LPCS flow curve	Figure 6.3-1

Table 6.3-2

Loss-Of-Coolant Accident Analysis Initial Conditions
and Input Parameters – ATRIUM-10 (Continued)

<table>
<tr><th colspan="4">LPCI</th></tr>
<tr><td>Initiation signal</td><td colspan="3">L1</td></tr>
<tr><td>Time delay; initiation signal to pump at rated speed</td><td colspan="3">27 sec</td></tr>
<tr><td>Maximum injection valve stroke time</td><td colspan="3">26 sec</td></tr>
<tr><td>Time delay; initiation signal to injection valve open[a]</td><td colspan="3">46 sec</td></tr>
<tr><td>Vessel pressure that injection valve may open</td><td colspan="3">351 psia</td></tr>
<tr><td>Pressure that flow may commence (differential pressure between vessel head and drywell)</td><td colspan="3">222 psid</td></tr>
<tr><td>Rated flow at 200 psid[b]</td><td colspan="3">6672 gpm 3 loops / 2224 1 pump</td></tr>
<tr><td>Minimum rated flow at 0 psid[b]</td><td colspan="3">21102 gpm 3 loops / 7034 1 pump</td></tr>
<tr><td>Vessel head v LPCI flow curve</td><td colspan="3">Figure 6.3-2</td></tr>
<tr><th colspan="4">ADS</th></tr>
<tr><td>Initiation signal</td><td>L1</td><td>AND</td><td>LPCI pump running
OR
LPCS pump running</td></tr>
<tr><td>Number of safety relief valves with ADS function</td><td colspan="3">5 valves</td></tr>
<tr><td>Time delay; initiation signal to valves open</td><td colspan="3">120 sec (maximum)</td></tr>
<tr><td>Minimum flow capacity for 5 valves at 1205 psig in the vessel</td><td colspan="3">4.5 Mlbm/hr</td></tr>
</table>

[a] Including instrumentation response time of 5 seconds and diesel generator start/load time of 15 seconds and assuming vessel pressure permissive is satisfied.
[b] psid: pressure differential between reactor vessel and drywell.

Table 6.3-2a

Plant Operational Parameters (GE14)

Parameter	Nominal Assumption	Appendix K Assumption
Rated Case Core Thermal Power (MW)	3629	3702
Rated Case Core Flow (Mlbm/hr)	108.5	108.5
ELLLA Case Core Thermal Power (MW)	3629	3702
ELLLA Case Core Flow (Mlbm/hr)	102	102
SLO Case Core Thermal Power (MW)	2684.2	2737.9
SLO Case Core Flow (Mlbm/hr)	61.845	61.845
Vessel Steam Dome Pressure (psia)	1055	1055
Feedwater Temperature (°F)	425.7	428
PLHGR Uncertainty (%)	N/A	2
Number of ADS Valves Assumed Available	5	5
Feedwater Temperature Reduction (°F)	65[1]	65[1]
ICF Core Flow (Mlbm/hr)	115	115

[1] See the discussion in Section 5.4.3 of Reference 6.3-17.

Table 6.3-2b

GE14 Fuel Parameters

Parameter		Analysis Value
PLHGR (kW/ft)	– LOCA Analysis Limit	13.40
	– Appendix K	13.40 × 1.02
	– Nominal	12.80
MAPLHGR (kW/ft)	– LOCA Analysis Limit	12.82
	– Appendix K	12.82 × 1.02
	– Nominal	12.24
Rod Average Exposure (MWd/MTU)		16,000
Initial Operating MCPR	– LOCA Analysis Limit	1.25
	– Appendix K	1.25 ÷ 1.02
	– Nominal	1.25 + 0.02
Fueled Rods per Assembly		92

Table 6.3-2c

SAFER/GESTR-LOCA ECCS Parameters (GE14)

Low Pressure Coolant Injection (LPCI) System		
Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	222
b. Minimum rated flow (into shroud)		
• Vessel pressure at which below listed flow rates are quoted	psid (vessel to drywell)	20
• One (1) LPCI pump injecting inside shroud	gpm	6,713
• Two (2) LPCI pumps injecting inside shroud	gpm	13,426
• Three (3) LPCI pumps injecting inside shroud	gpm	20,139
c. Run-out flow at 0 psid (vessel to drywell)		
• One (1) LPCI pump injecting inside shroud	gpm	7,034
• Two (2) LPCI pumps injecting inside shroud	gpm	14,068
• Three (3) LPCI pumps injecting inside shroud	gpm	21,102
d. Initiating signals		
• Low low low water level (Level 1)	inches above vessel “zero”	378.5
e. Vessel pressure at which injection valve may open	psig	336
f. Maximum delay time from pump start until pump is at rated speed	sec	26
g. Maximum injection valve stroke time-opening	sec	26
h. Delay time to process initiation signal	sec	5

Table 6.3-2c

SAFER/GESTR-LOCA ECCS Parameters (GE14)
(Continued)

Low Pressure Core Spray (LPCS) System		
Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	285
b. Minimum rated flow at vessel-to-drywell pressure (into shroud)	gpm psid	5625 122
c. Run-out flow at 0 psid (vessel to drywell)	gpm	7030
d. Initiating signals		
• Low low low water level (Level 1)	inches above vessel "zero"	378.5
e. Vessel pressure at which injection valve may open	psig	336
f. Maximum delay time from pump start until pump is at rated speed	sec	7
g. Maximum injection valve stroke time-opening	sec	22
h. Delay time to process initiation signal	sec	5

Table 6.3-2c

SAFER/GESTR-LOCA ECCS Parameters (GE14)
(Continued)

High Pressure Core Spray (HPCS) System		
Variable	Units	Analysis Value
a. Vessel Pressure at which flow may commence	psid (vessel to source)	1160
b. Minimum rated flow and vessel pressure	gpm/psid (vessel to source of suction)	413/1160 920/1130 5000/200 6250/0
c. Run-out flow at 0 psid (vessel to source of suction)	gpm	6250
d. Initiating signals		
• Low low water level (Level 2)	inches above vessel "zero"	437.5
e. Maximum delay time from pump start until pump is at rated speed	sec	7
f. Maximum injection valve stroke time-opening	sec	17
g. Delay time to process initiation signal	sec	5

Table 6.3-2c

SAFER/GESTR-LOCA ECCS Parameters (GE14)
(Continued)

Automatic Depressurization System (ADS)		
Variable	Units	Analysis Value
a. Total number of valves with ADS function available		7
b. Number of ADS valves assumed in the analysis		5
c. Pressure at which below listed capacity is quoted	psig	1205
d. Minimum flow capacity at pressure given in c with all available ADS valves open	lbm/hr	9.0×10^5
e. Initiating Signals		
• Low low low water level (Level 1) and	inches above vessel "zero"	378.5
• ADS Timer Delay from initiating signal completed to the time valves are open	sec	120
f. Delay time to process initiation signal	sec	5

Table 6.3-3

Single Failures Considered in the ECCS Performance Evaluation – AREVA

Location	Failure	Systems Remaining[a]
Recirculation Suction Line	LPCS Diesel Generator Failure	ADS, HPCS, 2 LPCI
Recirculation Suction Line	HPCS Failure	ADS, LPCS, 3 LPCI
Recirculation Suction Line	LPCI Diesel Generator Failure	ADS, HPCS, LPCS, 1 LPCI
HPCS Spray Line	LPCS Diesel Generator Failure	ADS, 2 LPCI
LPCS Spray Line	HPCS Diesel Generator Failure	ADS, 3 LPCI

[a] For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS system in which the break is assumed.

Table 6.3-3a

Single Failure Considered in ECCS Performance Evaluation
Based on SAFER/GESTR-LOCA (GE14)

Break Location	Assumed Failure[1]	Systems Remaining[2] [3]
Recirculation Suction Line	LPCI Emergency D/G	ADS, HPCS, LPCS, 1 LPCI
Recirculation Suction Line	LPCS Emergency D/G	ADS, HPCS, 2 LPCI
Recirculation Suction Line	HPCS Emergency D/G	ADS, LPCS, 3 LPCI
Core Spray Line	LPCS Emergency D/G	ADS, 2 LPCI
Steamline Inside Containment	LPCI Emergency D/G	ADS, HPCS, LPCS, 1 LPCI
Steamline Outside Containment	HPCS Emergency D/G	ADS, LPCS, 3 LPCI
Feedwater Line	HPCS Emergency D/G	ADS, LPCS, 3 LPCI
LPCI Line	HPCS Emergency D/G	ADS, LPCS, 2 LPCI

[1] Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above assumed 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] The analyses are performed with two non-function ADS valves in addition to the single failure.

Table 6.3-4

Loss-Of-Coolant Accident Sequence of Events for Limiting Break
(AREVA NP Analysis)

Time (second)	Event
0.0	Break initiation
0.8	Reactor scram initiated
7.9	Level 2 reached (low-low RPV level)
9.3	Level 1 reached (low-low-low RPV level)
10.9	Jet pumps uncover
15.0	RRC pump suction uncovered
17.5	Start lower plenum flashing
44.9	Start HPCS flow
72.7	Start LPCS flow
76.7	Start LPCI flow
79.8	Reach rated LPCS flow
79.8	End of blowdown
118.9	Core reflooded
118.9	Peak cladding temperature reached
129.3	ADS valves open

Table 6.3-4a

Event Scenario for 100% DBA Recirculation Suction Line Break
HPCS DG Failure (Appendix K, GE14)

Event	Time (sec)
Break Occurs	0.0
Scram Initiated and Occurs	0.01
Level 1 Trip	4.97
Feedwater Flow Reaches Zero	5.00
First Peak PCT GE14 Fuel (1232°F) Occurs	5.50
Jet Pump Suction Uncovers	5.98
Main Steamline Flow Stops	6.14
Suction Line Uncovers	8.54
Lower Plenum Flashes	9.15
LPCS/LPCI IV Pressure Permissive Reached	30.45
LPCS Injection Occurs	57.45
LPCI Injection Occurs	61.45
Second Peak PCT GE14 Fuel (1346°F) Occurs	148.18

Table 6.3-4b

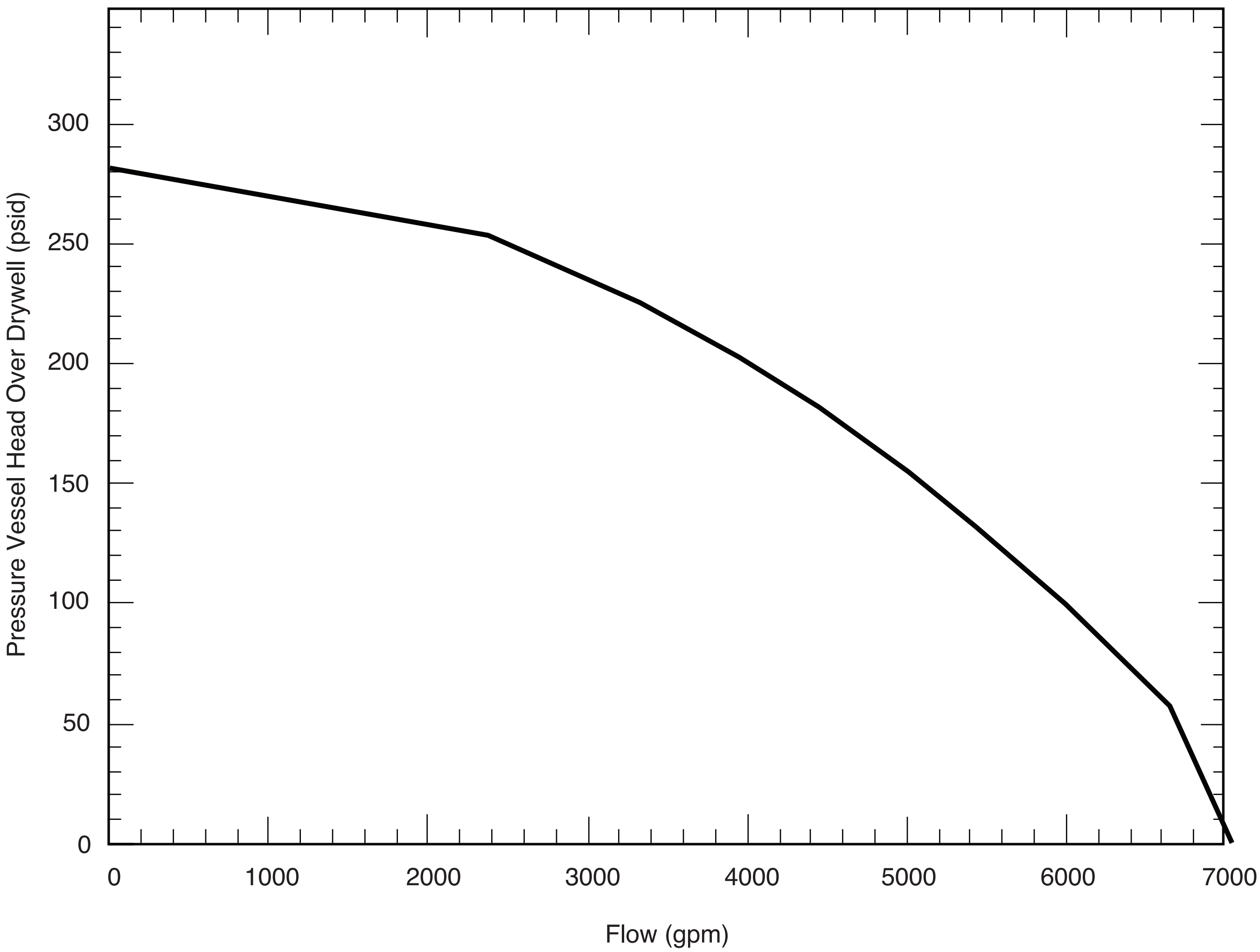
Event Scenario for 0.07 ft^2 Recirculation Suction Line Break
HPCS DG Failure (Appendix K, GE14)

Event	Time (sec)
Break Occurs	0.0
Scram Initiated and Occurs	0.01
Feedwater Flow Reaches Zero	5.00
Level 1 Trip	114.50
SRVs Open	178.47
Jet Pump Suction Uncovers	221.47
ADS Valves Open	239.50
Main Steamline Flow Stops	246.99
Lower Plenum Flashes	248.61
Suction Line Uncovers	369.46
LPCS/LPCI IV Pressure Permissive Reached	394.23
LPCS Injection Occurs	421.23
LPCI Injection Occurs	425.23
Peak PCT GE14 Fuel (1647°F) Occurs	450.81

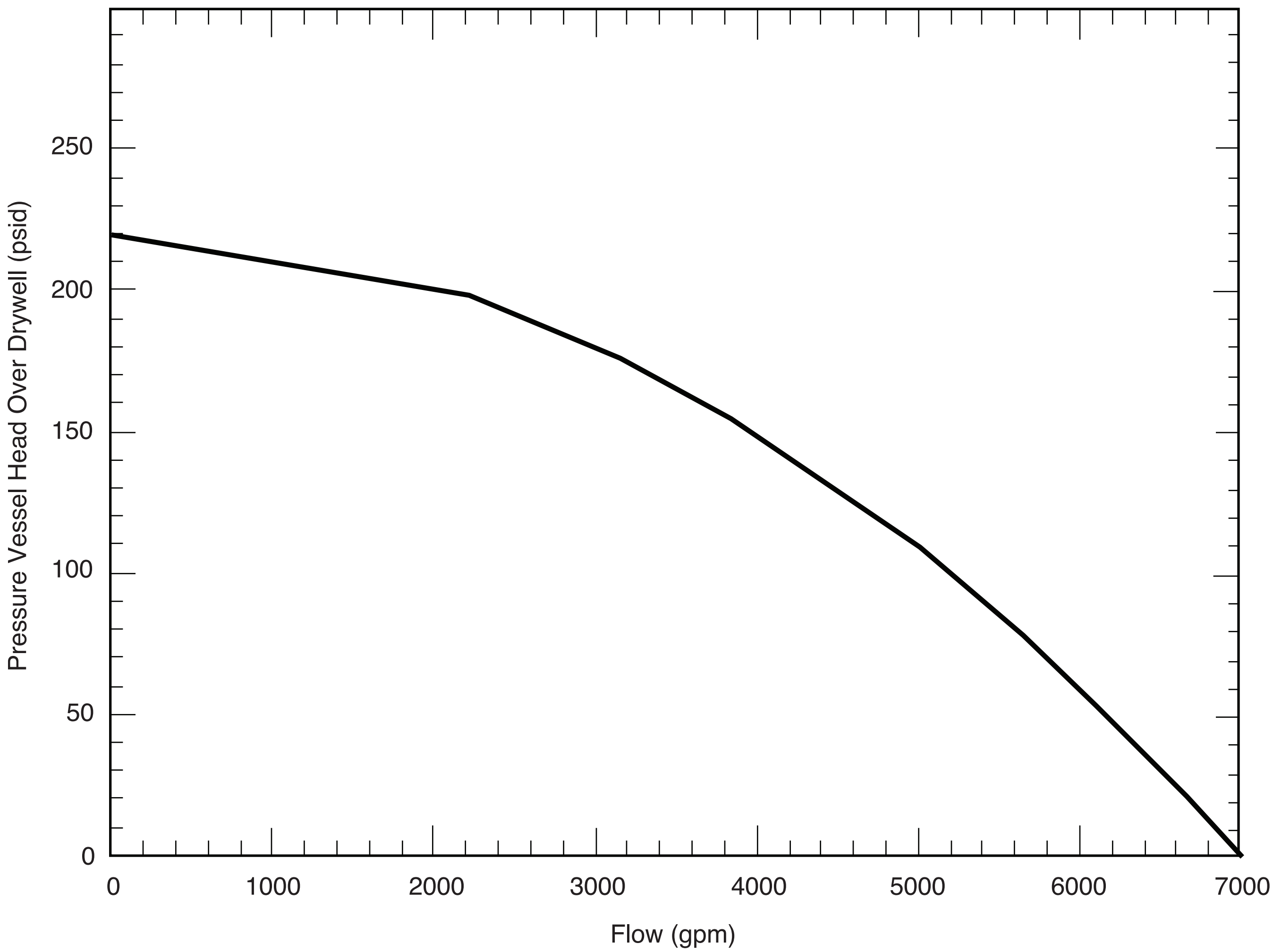
Table 6.3-5

ECCS Performance Analysis Results

Parameter	GE14 Value		AREVA NP Value	
	Two loop operation	Single loop operation	Two loop operation	Single loop operation
Thermal power (including 2% power uncertainty)	106.2% rated power (3702 MWt)	78.5% rated power (2737.9 MWt)	106.6% rated power (3716 MWt)	106.6% rated power (3716 MWt)
Core flow	100% rated flow (108.5 Mlb/hr)	57% rated flow (61.845 Mlb/hr)	106% rated flow 115 Mlb/hr	106% rated flow 115 Mlb/hr
Limiting break	0.07 ft^2 Recirculation suction line, HPCS DG failure	100% DBA Recirculation suction line, HPCS DG failure	100% DEG RRC suction line LPCI DG failure	100% DEG RRC suction line LPCI DG failure
Peak cladding temperature (Appendix K)	1647°F	1210°F	1604°F	1601°F
Licensing basis peak cladding temperature	1710°F			
Maximum cladding oxidation	≤ 1%		0.26%	0.26%
Total core hydrogen generation	≤ 0.1%		< 1.0%	< 1.0%

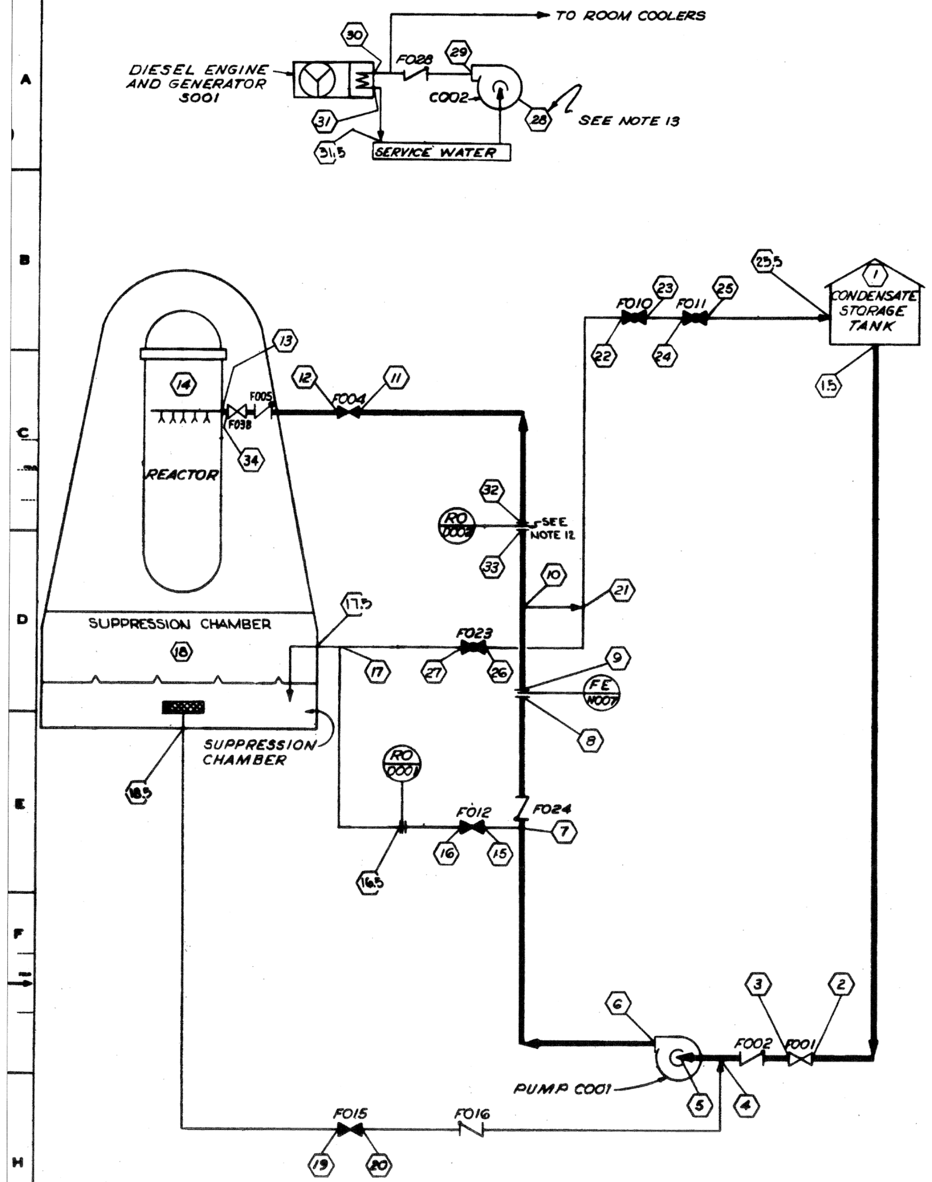


Columbia Generating Station **Final Safety Analysis Report**	**Head Versus Low-Pressure Core Spray Flow used in LOCA Analysis**
	Draw. No. **960222.13** / Rev. / Figure **6.3-1**



Head Versus Low-Pressure Coolant Injection Flow used in LOCA Analysis

Draw. No. 960222.14 | Rev. | Figure 6.3-2



PRIMARY MODES

(SEE NOTE 21)
MODE A ACCIDENT OR RCIC BACKUP, REACTOR AT HIGH PRESSURE, SUCTION FROM CONDENSATE STORAGE

POSITION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM	N/A	1550	←									→	1550	N/A
PRESS. PSIA	14.7													1145
TEMP. °F	AMB	120/40	←									→	120/40	AMB.
MAX. PRESS. DROP FEET					←2787→									

(SEE NOTE 21)
MODE B ACCIDENT, REACTOR AT HIGH PRESSURE, SUCTION FROM SUPPRESSION POOL

POSITION ⬡	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM	1550	←							→	1550	N/A	1550	1550	N/A
PRESS. PSIA											1145			14.7
TEMP. °F	120/40	←							→	120/40	AMB	120/40	120/40	AMB
MAX. PRESS. DROP FEET		←2787→												

MODE C ACCIDENT, SYSTEM INJECTION AT RATED CORE SPRAY, SUCTION FROM SUPPRESSION POOL

POSITION ⬡	4	5	6	7	8	9	10	11	12	13	14	19	20	18	28	29	30	31
FLOW GPM	6350	←							→	6350	N/A	6350	6350	N/A	←1200→		←1000→	
PRESS PSIA											215			14.7	SEE NOTE 13			
TEMP. °F	170/40	←							→	170/40	AMB	170/40	170/40	AMB	←95→			
MAX. PRESS. DROP FEET		←865→			←21→			←2.2→		←198→		←.30→			←123→		←14→	

MODE D ACCIDENT, SYSTEM INJECTION AT RATED CORE FLOOD, SUCTION FROM SUPPRESSION POOL

POSITION ⬡	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM	6856	←							→	6856	N/A	6856	6856	N/A
PRESS. PSIA											41		-	14.7
TEMP. °F	170/40	←							→	170/40	AMB	170/40	170/40	AMB
MAX. PRESS. DROP FEET		←594→			←24→			←2.5→		←231→				

MODE E ACCIDENT, SYSTEM INJECTION AT RATED CORE FLOOD, SUCTION FROM CONDENSATE STORAGE

POSITION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM SEE NOTE 5 & 8	N/A	6856	←									→	6856	N/A
PRESS PSIA	14.7				SEE NOTE 6									80
TEMP. °F	AMB	120/40	←									→	120/40	AMB
MAX. PRESS DROP FEET		←.79→			←594→ SEE NOTE 6			←24→			←2.5→		←231→	

MODE F ACCIDENT, SYSTEM OPERATING AT RUNOUT, SUCTION FROM SUPPRESSION POOL

POSITION ⬡	4	5	6	7	8	9	10	11	12	13	14	19	20	18
FLOW GPM SEE NOTE 9.	7175/7300	←							→	7175/7300	N/A	7175/7300	7175/7300	N/A
PRESS. PSIA		SEE NOTE 7									14.7			14.7
TEMP. °F	212/40	←							→	212/40	AMB	212/40	212/40	AMB
MAX. PRESS. DROP FEET		←437→										←.4→		

SEE NOTE 27

MODE G SYSTEM TEST, SUCTION FROM SUPPRESSION POOL

POSITION ⬡	4	5	6	7	8	9	10	21	26	27	17	19	20	18
FLOW GPM SEE NOTE 9	7175/7300	←										→	7175/7300	N/A
PRESS. PSIA	⊠	⊠	⊠	⊠	⊠	⊠	⊠	⊠	⊠	⊠	⊠	⊠	⊠	14.7
TEMP. °F	120/40	←										→	120/40	AMB
MAX. PRESS. DROP FEET		←437→							←59→ SEE NOTE 10					

SEE NOTE 27

TABLE I
VALVE POSITION TABLE

VALVE	F001	F004	F010	F011	F012	F015	F023	F039
MODE A	O	O	C	C	C	C	C	O
MODE B	C	O	C	C	C	O	C	O
MODE C	C	O	C	C	C	O	C	O
MODE D	C	O	C	C	C	O	C	O
MODE E	O	O	C	C	C	C	C	O
MODE F	C	O	C	C	C	O	C	O
MODE G	C	C	C	C	C	O	O	O
MODE H	O	C	O	O	C	C	C	O
MODE J	O	C	C	C	O	C	C	O
MODE S	O	C	C	C	C	C	C	O
MODE CC	C	O	C	C	O	O	C	O

O VALVE OPEN
C VALVE CLOSE

MODE J PUMP OPERATING ON BYPASS, SUCTION FROM CONDENSATE STORAGE

POSITION ⬡	1	2	3	4	5	6	7	15	16	17	18
FLOW GPM	N/A	1150	←						→	1150	N/A
PRESS. PSIA	14.7	⊠	⊠	⊠	⊠	⊠	⊠	⊠	⊠	⊠	14.7
TEMP. °F	AMB	120/40	←						→	120/40	AMB
MAX. PRESS. DROP FEET					←3000→			←65→			

LOCATION 1.5 2 4 18.5 4 5

DESIGN TEMP (°F)	140	212		212
DESIGN PRESS (PSIG)	100			100
ESTIMATED LINE SIZE (IN.)	14			18
	CONDENSATE STG SUCTION LINE			SUPPRESSION POOL SUCTION LINE

NOTES:

1. ALL EMPTY PRESSURE DATA BLANKS CAN BE FILLED IN BY OTHER (BASED ON ACTUAL ARRAGNEMENT) OR EQUIV. HYDRAULIC DATA SU MITTED TO APED FOR REVIEW. ⊠ INDICATES THE DATA IS SIGNIFICANT.
2. MAX/MIN INDICATES MAXIMUM & MINIMUM VALUE OF PARAMETER THE MODE SPECIFIED.
3. ELEVATIONS ARE NOT INCLUDED IN ΔP VALUES GIVEN. ELEVATIO SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY PRESSURE DATA BLANKS.
4. THE PUMP MAXIMUM SHUTOFF HEAD WILL NOT EXCEED 3450 FT.
5. IN MODE E WITH A PUMP TDH OF 865 FT AND A VESSEL PRESSUR OF 215 PSIA THE FLOW MUST BE EQUAL TO OR GREATER THAN 6350 GPM.
6. THE PUMP TDH GIVEN FOR MODE E IS BASED ON A MAXIMUM CON-TAINMENT PRESSURE OF 45 PSIG. BWRSD MUST BE ADVISED IF TH CONTAINMENT DESIGN IS BASED ON A HIGHER PRESSURE AND THE IMPACT ON THE HIGH PRESSURE CORE SPRAY SYSTEM EVALUATED.
7. IN MODE F THE NET POSITIVE SUCTION HEAD (NPSH) AVAILABLE AT THE CENTER LINE OF THE PUMP SUCTION NOZZLE MUST EQUAL OR EXCEED 32.2 FEET.
8. IN MODE E AND AT A FLOW RATE OF 7349 GPM OR LESS, THE AVAILABLE NPSH MUST EQUAL OR EXCEED THE VALUE SPECIFIED IN NOTE 7
9. THE FLOW SPECIFIED FOR MODES F AND G IS APPROXIMATE AND BE DETERMINED BASED ON FINAL SYSTEM DESIGN. THE FLOW GIV FOR THESE MODES IS THE MAXIMUM ALLOWABLE.
10. THE ΔP GIVEN FOR THE VALVES IN MODES G AND H IS THE MINI POSSIBLE AND MAY BE INCREASED BY OTHERS (THROTTLING) TO ACCOMMODATE PIPING ARRANGEMENT.
11.
12. ORIFICE RO-2 PROVIDES NO RESTRICTION, AS ITS BORE COINCIDES WITH THE INNER DIAMETER OF THE 16" DISCHARGE HEADER. THE SYSTEM RESISTANCE-WITHOUT RES IS SUFFICIENT TO ENSURE PUMP RUN OUT WILL NOT EXCEED SPECIFIED LIMITS.
13. THE MIMIMUM AVAILABLE NPSH TO THE DIESEL SERVICE WATER P MUST BE 22 FT OR GREATER.
14. VALUES WILL BE ADDED FOR INDIVIDUAL PROJECT BASED ON AC COOLING WATER TEMPERATURE.
15.
16. ΔP VALUES FOR EQUIPMENT WITHIN GE-APED SCOPE ARE AS NOTE
17. TABLE I INDICATES VALVE POSITION DURING VARIOUS OPERATIN MODES.
18. PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ES IMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIG TEMPERATURE AND PRESSURE AND LINE SIZES AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DIAGRAM HYDRAULIC REQUIRE
19.
20. IN MODE E AND WITH A VESSEL PRESSURE OF 14.7 PSIA. THE F SHALL NOT EXCEED 7175/7300 GPM (SEE NOTE 27).
21. FOR MODES A & B, ONE THIRD OF TABULATED FLOW SHALL BE DEL TO THE VESSEL WITH REACTOR VESSEL PRESSURE AT 1175 PSI THE LOW FLOW BYPASS VALVE (E22-F012) OPEN.
22. THE FLOW SPECIFIED FOR MODE CC MUST BE EQUALED OR EXCE WITH THE SUCTION FROM THE CONDENSATE STORAGE SYSTEM WITH THE REACTOR PRESSURE EQUAL TO 1225 PSIA.
23. CAUTION: TO AVOID PUMP DAMAGE/FAILURE, THE MAXIMUM RUNOUT FLOW PUMP OPERATING MODE (e.g. PREOPERATION TEST, PRELIMINARY PUMP CHECK AND ALL MODES ON THE PROCESS DIAGRAM) SHALL NOT EXCEED 7175/7300 GPM THE MINIMUM FLOW SHALL NOT BE BELOW 1150 GPM.

(NOTES CONT'D. TO ZONE M/1)

SUPPLEMENTAL DOCUMENTS UNDER THE FOLLOWING IDENTITIES ARE TO BE USED IN CONJUNCTION WITH THIS DRAWING.

	REFERENCE DESIGNATOR
1. HIGH PRESSURE CORE SPRAY P&ID	E22-1010
2. NUCLEAR BOILER SYSTEM PROC. DIA	B22-1020
3. H	

NOTES (CONT'D FROM ZONE J/11)

24. ONLY MODE CC WAS UPDATED FOR RPU. THIS WAS CONSIDERED THE MOST AFFECTED AND LIMITING MODE FOR RPU.
25. MAX. PRESS DROP FEET VALUES ARE APPROXIMATE. REFER TO DESIGN CALCULATIONS FOR ACTUAL VALUES.
26. FOR MODES D AND E, THE FLOWS INDICATED ARE APPROXIMATE. REFER TO DESIGN CALCULATIONS FOR ACTUAL VALUES.
27. 7175 GPM WITH MODEL 12X20KD-8 HPCS-P-1 PUMP INSTALLED. 7300 GPM WITH MODEL 10154123 HPCS-P-1 PUMP INSTALLED. THE MAXIMUM BOUNDING FLOW PER ANALYSIS IS 7349 GPM.

Columbia Generating Station Final Safety Analysis Report	High-Pressure Core Spray - Process Diagram		
	Draw. No. 02E22-04,7,1	Rev. 7	Figure 06.3-3.1

MODE H SYSTEM TEST. SUCTION FROM CONDENSATE STORAGE

POSITION ⬡	1	2	3	4	5	6	7	8	9	10	21	22	23	24	25
FLOW GPM	N/A	[illegible] ←												→	[illegible]
PRESS PSIA	14.7	X	X	X	X	X	X	X	X	X	X	X	X	X	X
TEMP °F	AMB	[illegible]/40 ←												→	[illegible]/40
MAX PRESS DROP FEET					←594→							←95→ SEE NOTE 10		←95→ SEE NOTE 10	

MODE S SYSTEM ON STANDBY DUTY

POSITION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW GPM	N/A	0	←									→	0	N/A
PRESS PSIA	14.7	X	X	X		X	X	X	X	X	X	X	X	SEE REF 2
TEMP °F	AMB	[illegible]/40	←						→	[illegible]/40	AMB	←	→	AMB
MAX PRESS DROP FEET					←0→									

MODE CC ACCIDENT OR RCIC BACK-UP, REACTOR AT HIGH PRESSURE (SEE NOTE 22), SUCTION FROM THE SUPPRESSION POOL

POSITION ⬡	18.5	19	20	4	5	6	7	8	9	10	11	12	13	14	15	16	17	17.5	18
FLOW GPM	←			1563			→	←		413			→	N/A	←	1150		→	N/A
PRESS PSIA														1225					14.7
TEMP °F	140/40	←										→	140/40	AMB	140/40	←		→ 140/40	AMB
MAX PRESS DIFFERENCE FT					←3025→										←4.5→				

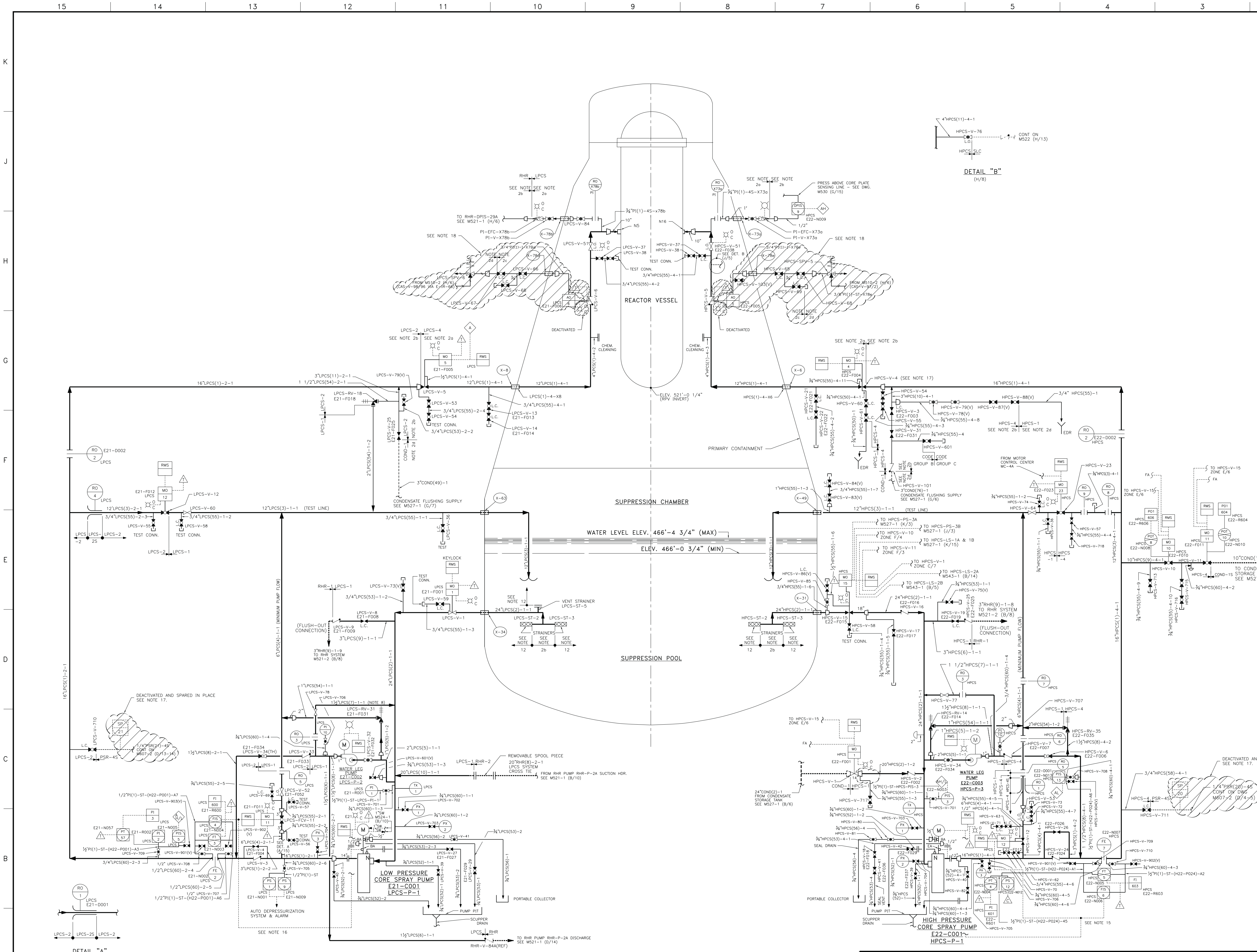
TABLE II
LIMITING LINE LOSS

MODE	FLOW PATH	COMMENT
F	18.5-19-20-4-5	SEE NOTE 7
È	1.5-2-3-4	SEE NOTE 8
CORE	6-7-8-9-10-11-12-13	SEE NOTE 5
J	7-15-16-16.5-17	
H	10-21-22-23-24-25-25.5	
G	21-26-27-17-17.5	

Columbia Generating Station
Final Safety Analysis Report

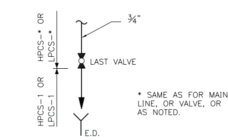
High-Pressure Core Spray - Process Diagram

Draw. No. 02E22-04,7,2 | Rev. 5 | Figure 6.3-3.2



NOTES

1. ALL INSTRUMENT ROOT VALVES NOT LABELED WILL BE 3/4" GLOBE VALVES UNLESS SPECIFICALLY NOTED OTHER WISE.
2. PIPING, VALVES AND ASSOCIATED COMPONENTS ON THIS DRAWING SHALL BE CLASSIFIED AS FOLLOWS EXCEPT AS STATED IN NOTES 12 & 13: (BREAK POINTS ARE INDICATED ON FLOW DIAGRAM)
   a. PIPING AND VALVES OUT THROUGH OUTERMOST REACTOR ISOLATION VALVES
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP A
   b. PIPING AND VALVES BEYOND OUTERMOST REACTOR ISOLATION VALVES PLUS ALL INSTRUMENT LINES, EXCEPT THE PUMP SEAL DRAIN LINES DESIGNATED AS 3/4" LPCS(56)-2 AND 3/4"HPCS(56)-4
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP B
   c. INSTRUMENTATION AIR LINES AND LEAK-OFF PIPING INSIDE CONTAINMENT ISOLATION VALVE:
      SEISMIC CATEGORY I
      QUALITY CLASS I
      CODE GROUP B
   d. INSTRUMENTATION AIR LINES AND LEAK-OFF PIPING OUTSIDE CONTAINMENT ISOLATION VALVE: AND THE PUMP SEAL DRAIN LINES DESIGNATED 3/4"LPCS(56)-2 AND 3/4"HPCS(56)-4 AND OTHER PIPING AND VALVES DESIGNATED BY THIS NOTE
      SEISMIC CATEGORY II ⊕ } Ø
      QUALITY CLASS II } Ø
      CODE GROUP D } Ø
      ⊕ HANGERS TO BE DESIGNED TO SEISMIC CATEGORY I LOADS.
      Ø EXCEPT AS NOTED ON M619 INSTR. CONN. DIAG.
3. FOR DRAIN OR LEAK-OFF LINES, THE PIPING CLASSIFICATION IS AS SHOWN ON DETAIL BELOW.



4. DELETED
5. DELETED
6. ALL PIPING SYSTEMS IDENTIFIED BY THE PREFIX "PI" SHALL BE SUPPLIED AND INSTALLED BY CONTRACT #220.
7. DELETED
8. ALLOWED ADEQUATE PIPING SURFACE AREA FOR COOLING OF PUMP LPCS-P-2.
9. DELETED
10. DELETED
11. DELETED
12. PIPING, VALVES AND ASSOCIATED COMPONENTS ON THIS DRAWING SHALL BE CLASSIFIED AS FOLLOWS (BREAK POINTS ARE INDICATED ON THIS DIAGRAM)
    SIESMIC CATEGORY I
    QUALITY CALSS I
    CODE GROUP B*
    *ASME III/2 WITH EXCEPTIONS. SEE PROCUREMENT SPECIFICATION 12023.
13. ALL PIPING DOWNSTREAM OF THE LAST ISOLATION VALVE AND OPEN TO THE ATMOSPHERE WITH THE SUBSYSTEM DESIGNATION SYSTEM (50) THROUGH (59) SHALL BE CLASSIFIED AS CODE GROUP D WITH QUALITY CLASS AND SEISMIC CATEGORY PROVIDED BY THE APPLICABLE NOTES ON THIS DRAWING.
14. ALL INSTRUMENT LINES ARE DESIGNATED BY CODE AND LINE NUMBER, EXAMPLES;
    A. LINE ORIGINATING OUTSIDE CONTAINMENT.
       $\underbrace{\text{1/2"PI(1)-4S}}_{\text{CODE DESIGNATION}}\text{-}\underbrace{\text{(H22-P021)-A6}}_{\text{LINE NO.}}$
    B. LINES ORIGINATING INSIDE CONTAINMENT.
       $\underbrace{\text{1/2"PI(1)-4S}}_{\text{CODE DESIGNATION}}\text{-}\underbrace{\text{X106}}_{\text{LINE NO.}}$
    C. CONTINUATION OF THE ABOVE LINE OUTSIDE CONTAINMENT IS DESIGNATED AS FOLLOWS W/LINE NUMBERS NOT SHOWN.
       $\underbrace{\text{1/2"PI(1)-ST-X106}}_{\text{LINE DESIGNATION}}\text{-}\underbrace{\text{(H22-P021)}}_{\text{LINE NO.}}$
15. FOR DETAILED WIRING SEE EWD-7E-0023.
16. FOR DETAILED WIRING SEE EWD-8E-0008.
17. SAMPLE POINT IS NO LONGER FUNCTIONAL. ALTERNATE METHOD OF SAMPLING IS DONE PER THE APPLICABLE PPM.
18. AIR OPERATOR AND AIR SUPPLY FOR TESTABLE CHECK VALVES HPCS-V-5 AND LPCS-V-6 ARE DEACTIVATED AND SPARED IN PLACE. THESE VALVES ARE TESTED PER THE IST PROGRAM. PENETRATION AND ISOLATION/TEST VALVES ARE STILL ACTIVE.

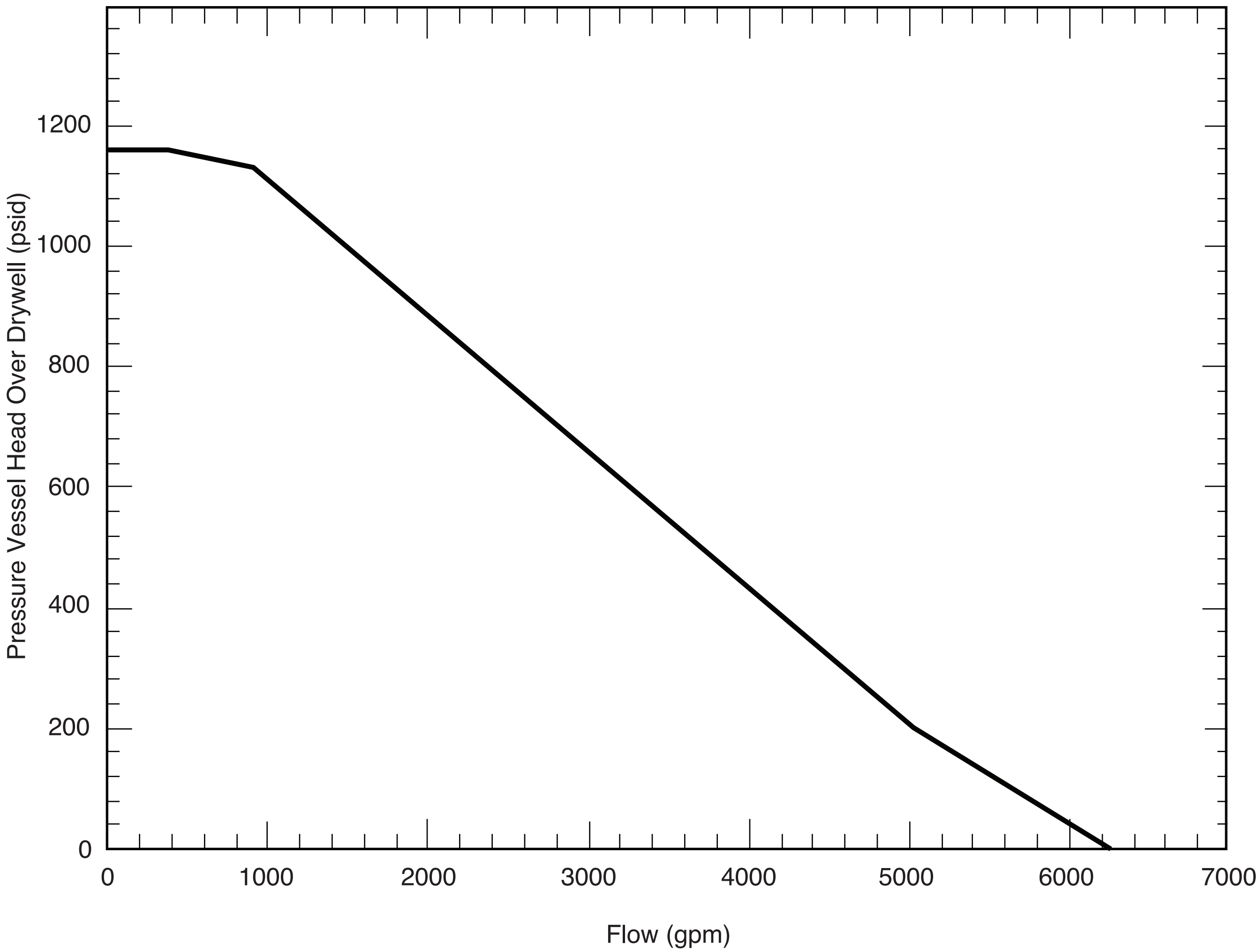
LEGEND

1. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (V) DENOTE A 3/4" VENT VALVE EXCEPT AS NOTED.
2. ALL VALVES (EXCEPT THOSE ON INSTRUMENT LINES) SUFFIXED WITH A (D) DENOTE A 3/4" DRAIN VALVE.
3. ALL VALVES SUFFIXED WITH A (TH) DENOTE A THROTTLED VALVE.

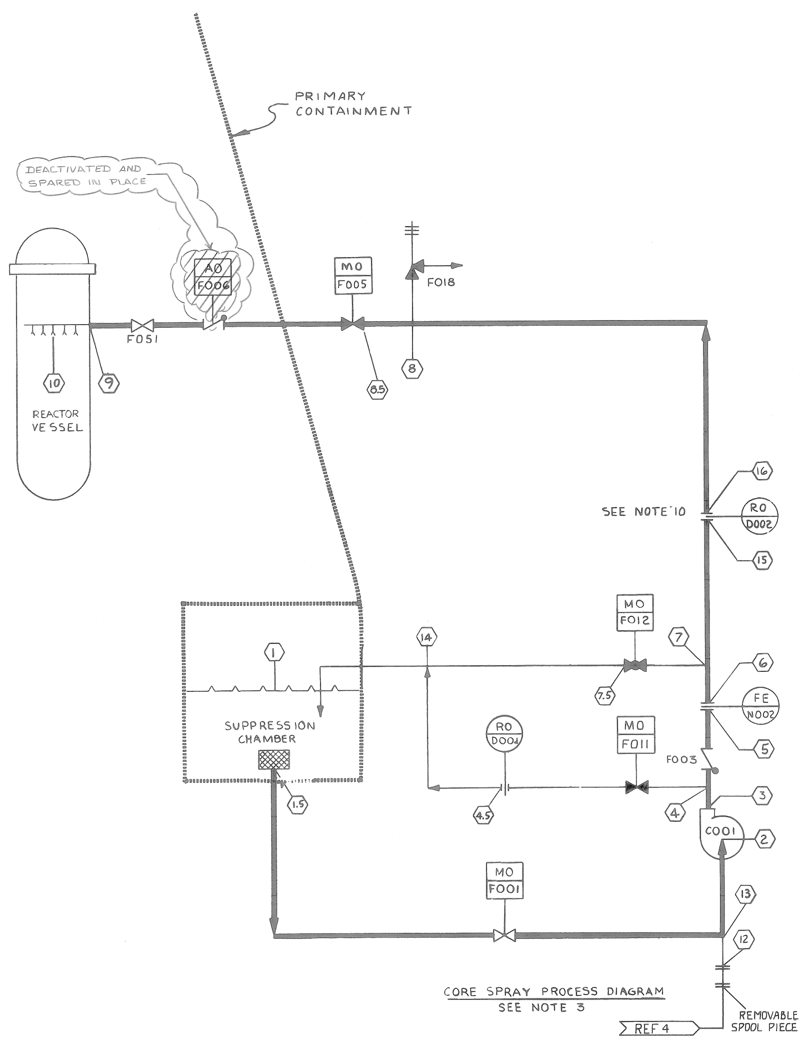
Columbia Generating Station
Final Safety Analysis Report

High–Pressure Core Spray and Low–Pressure Core Spray Flow Diagrams

Draw. No. M520	Rev. 98	Figure 6.3-4



Head Versus High-Pressure Core Spray Flow used in LOCA Analysis



MODE A (NOTE 13) SYSTEM TEST, SUCTION FROM SUPPRESSION POOL

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10		12	13	14
FLOW - GPM	N/A	7800 ←					→ 7800	0	0	0		0	0	7800
PRESS - PSIA	14.7	X	X	X	X	X		X	X			X	X	
TEMP - °F	120/40	←					→ 120/40	AMB ←					→ AMB	120/40
MAX PRESS DROP - FT		•500•												

MODE B SYSTEM TEST, SUCTION FROM RESIDUAL HEAT REMOVAL SYSTEM

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10		12	13	14
FLOW - GPM	N/A	8200 ←								→ 8200		8200	8200	0
PRESS - PSIA	14.7		X	X	X	X	X	X	X	14.7				X
TEMP - °F	N/A	125/40 ←								→ 125/40		125/40	125/40	AMB
MAX PRESS DROP - FT		•450•												

MODE C PUMP OPERATING ON BYPASS, SUCTION FROM SUPPRESSION POOL

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10		12	13	14
FLOW - GPM	N/A	635	635	635	0	0	0	0	0	0		0	0	635
PRESS - PSIA	14.7	X	X		X	X	X	X	X	X		X	X	
TEMP - °F	212/40	←	→	212/40	AMB ←							→	AMB	212/40
MAX PRESS DROP - FT		1075/820												

MODE D ACCIDENT, SYSTEM INJECTION AT RATED CORE SPRAY (128 PSID)

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10
FLOW - GPM	N/A	6350 ←								→ 6350
PRESS - PSIA	14.7									142.7
TEMP - °F	170	←								→ 170
MAX PRESS DROP - FT		•674•			•17•				•198•	

MODE E ACCIDENT, SYSTEM INJECTION AT RATED CORE FLOOD

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10
FLOW - GPM	N/A	7214 ←								→ 7214
PRESS - PSIA	14.7	X	X	X	X	X	X	X	X	40.7
TEMP - °F	170/40	←								→ 170/40
MAX PRESS DROP - FT		•515•								

MODE F ACCIDENT, SYSTEM OPERATING AT RUNOUT

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10
FLOW - GPM	N/A	8100 ←								→ 8100
PRESS - PSIA	14.7		X	X	X	X	X	X	X	14.7
TEMP - °F	212	←								→ 212
MAX PRESS DROP - FT		•500•								

MODE S SYSTEM ON STANDBY DUTY

LOCATION ⬡	1	2	3	4	5	6	7	8	9	10	11	12	13	14
FLOW - GPM	N/A	0	←										→	0
PRESS - PSIA	14.7		X	X	X	X	X	X	X	REF 3	14.7	X	X	X
TEMP - °F	120/40	←				→	120/40	AMB	AMB	AMB	120/40	←	→	120/40
MAX PRESS DROP - FT		•0•												

MISCELLANEOUS INFORMATION SEE NOTE 12

LOCATION ⬡	1.5 – 2	2 – 3	3 – 8	8 – 8.5	8.5 – 9	4 – 4.5 – 14	7 – 7.5 – 14	12 – 13
DESIGN TEMP (°F)	212	LPCS PUMP	← 212 →	488	SEE REF 3	← 212 →	← 212 →	← 212 →
DESIGN PRESS (PSIG)	100		← 427 →		SEE REF 3	427 / 100	427 / 100	← 100 →
ESTIMATED LINE SIZES (IN.)	18"		← 16" →		12"	← 4" →	← 12" →	← 16" →
	MAIN CORE SPRAY LINE TO REACTOR					BYPASS LINE	TEST LINE	RHR SUCTION TEST LINE

FCF-239X287AD (E21-1020)

NOTES:

1. ALL EMPTY PRESSURE DATA BLANKS CAN BE FILLED IN BY OTHERS BASED ON ACTUAL ARRANGEMENTS OR EQUIVALENT HYDRAULIC DATA SUBMITTED TO APED FOR REVIEW. ☒ INDICATES THE DATA IS NOT SIGNIFICANT.
2. ▭ INDICATES MAXIMUM & MINIMUM VALUE OF PARAMETER FOR THE MODE SPECIFIED.
3. ELEVATIONS ARE NOT INCLUDED IN THE ΔP VALUES GIVEN. ELEVATIONS SHALL BE INCLUDED WHEN DETERMINING FINAL VALUES FOR THE EMPTY DATA BLANKS.
4. THE BY-PASS FLOW SPECIFIED IN MODE C IS APPROXIMATED AND WILL BE SPECIFIED BY THE PUMP VENDOR.
5. IN MODE F, THE NET POSITIVE SUCTION HEAD (NPSH) AVAILABLE AT A REFERENCE LOCATION 2 FEET ABOVE THE PUMP MOUNTING FLANGE MUST EQUAL OR EXCEED 30 FT. THE NPSH AVAILABLE AT THE PUMP SUCTION NOZZLE MUST EQUAL THIS VALUE PLUS THE DIFFERENCE IN ELEVATION BETWEEN THE REFERENCE LOCATION AND THE CENTERLINE OF THE PUMP SUCTION NOZZLE.
6. IN MODE B, THE NPSH AVAILABLE MUST EQUAL THE VALUE SPECIFIED IN NOTE 5 PLUS 20 FT.
7. 100 GPM IS INCLUDED IN THE FLOW GIVEN FOR MODE D TO COMPENSATE FOR LEAKAGE IN THE REACTOR INTERNALS. (114 GPM IN MODE E).
8. IN MODE D, 128 IS THE DIFFERENTIAL PRESSURE BETWEEN THE REACTOR VESSEL AND THE SUPPRESSION POOL.
9. THE FLOW SPECIFIED FOR MODE F IS THE MAXIMUM ALLOWABLE.
10. THE ΔP BETWEEN LOCATION 15 AND 16 WILL BE DETERMINED IN PRE-OPERATIONAL TEST. THE ΔP WILL BE ADJUSTED TO MEET THE FLOW REQUIREMENTS OF MODE D, E OR F.
11.
12. PIPING SYSTEM DESIGN PRESSURE AND TEMPERATURE AND THE ESTIMATED LINE SIZES ARE FOR INFORMATION ONLY. ACTUAL DESIGN TEMPERATURE AND PRESSURE AND LINE SIZES AS DETERMINED BY OTHERS SHALL MEET THE PROCESS DIAGRAM HYDRAULIC REQUIREMENT.

REFERENCE DOCUMENTS:	MPL ITEM NO.
1. LPCS SYSTEM P&ID	E21-1010
2. LPCS SYS. DESIGN SPEC.	E21-4010
3. NUCLEAR BOILER SYS. PROC. DIAG.	B22-1020
4. RESIDUAL HEAT REMOVAL SYSTEM P&ID	E12-1010

SUPPLEMENTAL DOCUMENTS:

1. PIPING & INSTRUMENT SYMBOLS	A42-1010

NOTES: (CONT'D)

13. TO ADDRESS MODE A, THE LPCS RECIRCULATION LINE AND ITS ORIFICE LPCS-RO-4 IS SIZED FOR THE PUMP RUN-OUT FLOW OF 7800 GPM (REF. CVI 215-04-51). DURING ACTUAL TESTING, VALVE LPCS-V-12 IS THROTTLED TO CONFIRM COMPLIANCE WITH THE TDH AND FLOW REQUIREMENTS OF TECH SPEC SR 3.5.1.4.

TABLE II
LIMITING LINE LOSS

MODE	FLOW PATH	COMMENTS
F	1-5-13-2	SEE NOTE 5
D OR E	3-4-5-6-15-16-8-8.5-9-10	
A	7-7.5-14	
C	4-4.5-14	
B	12-13	SEE NOTE 6

VALVE POSITIONS

CONDITION	VALVE NO. F001		F005	F012	F011
MODE A	O		C	P	C
MODE B	C		O	C	C
MODE C	O		C	C	O
MODE D	O		O	C	C
MODE E	O		O	C	C
MODE F	O		O	C	C
MODE S	O		C	C	C

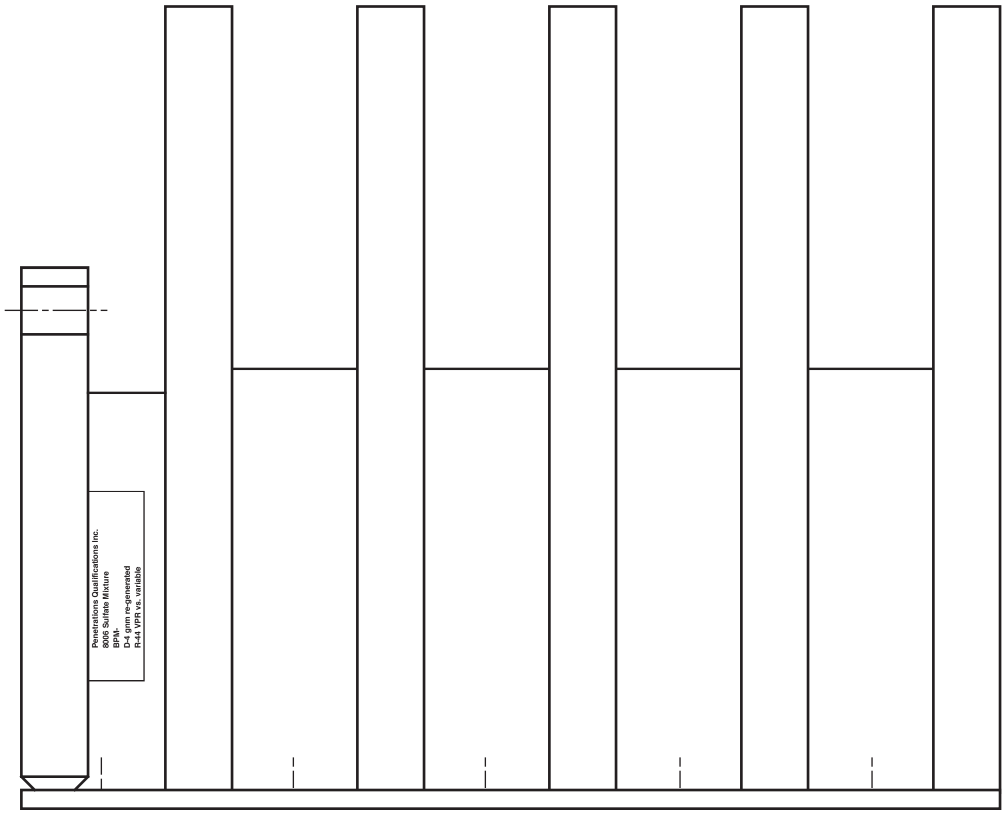
P - PARTIALLY OPEN
C - FULLY CLOSED
O - FULLY OPEN

Columbia Generating Station
Final Safety Analysis Report

Low-Pressure Core Spray - Process Diagram

Draw. No. 02E21-04,4,1 | Rev. 8 | Figure 6.3-6

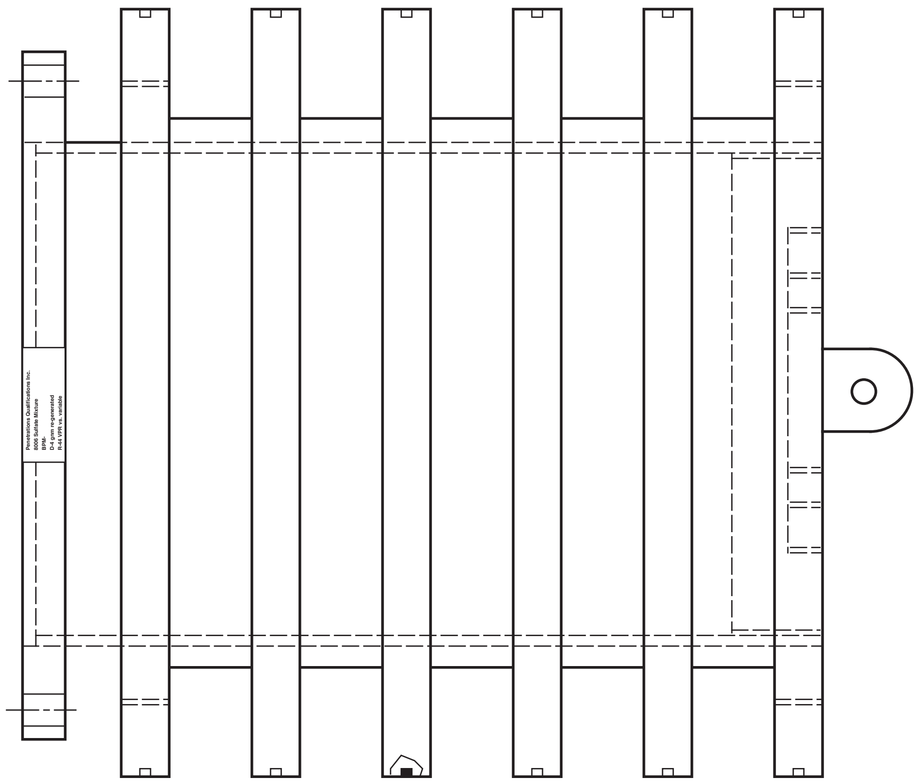
48 inch Diameter Half - Strainer Configuration
for Penetrations X-32, X-35



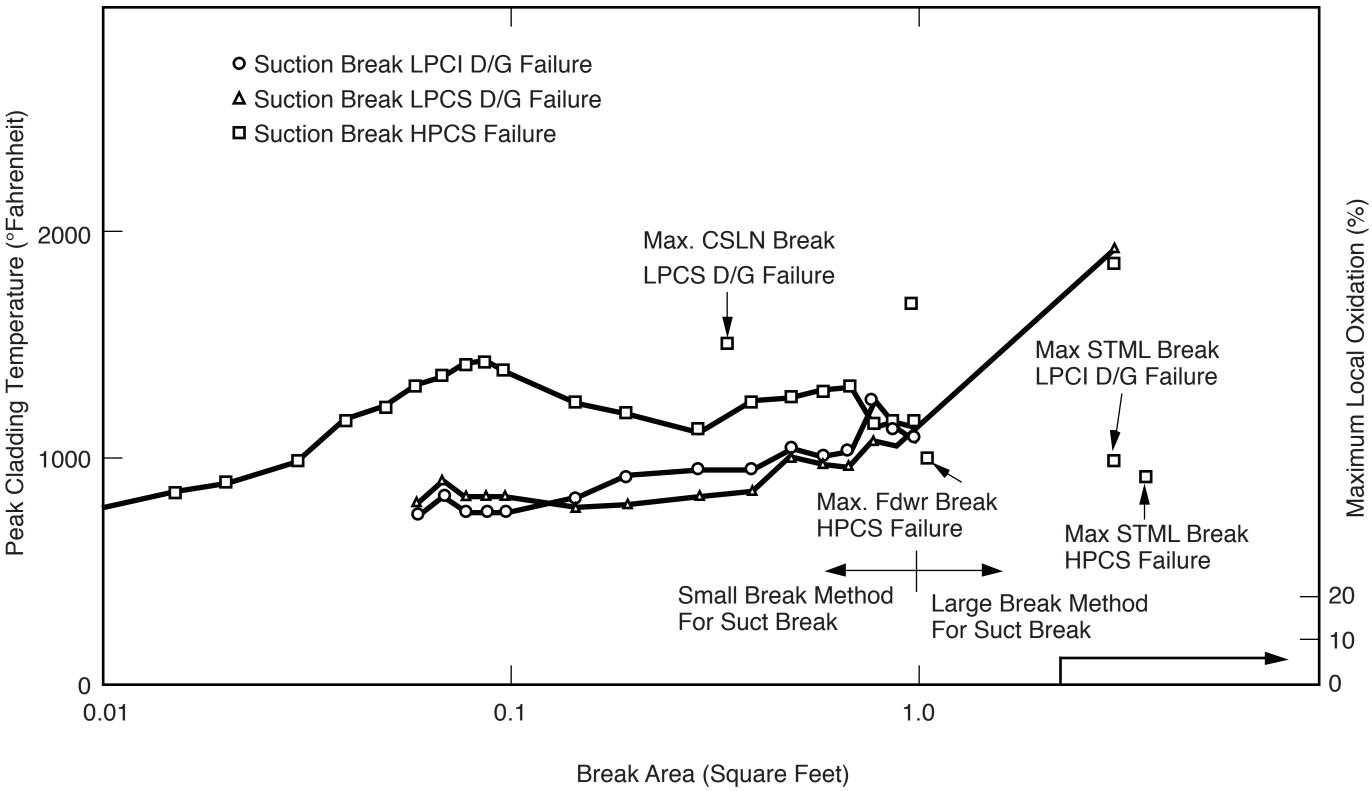
Note: Strainer halves are bolted together to form one strainer with a 47.5 inch Outer Diameter

Columbia Generating Station **Final Safety Analysis Report**	**Typical 48 in. Diameter Strainer**		
	Draw. No. **920843.07**	Rev.	Figure **6.3-7**

36 inch Diameter Strainer Configuration
for Penetrations X-31, X-34, and X-36



Note: The number of disks varies with strainer length.



Columbia Generating Station
Final Safety Analysis Report

Peak Cladding Temperature and Maximum Local Oxidation Versus Break Area - Hanford Original Rated Power

Draw. No. 960222.23 | Rev. | Figure 6.3-9

6.4 HABITABILITY SYSTEMS

6.4.1 DESIGN BASIS

The main Control Room Envelope Habitability (CREH) systems are designed to ensure habitability inside the main control room. The CREH systems ensure the Control Room Envelope (CRE) occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, a hazardous chemical release, or a smoke challenge. The CREH systems ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions. Under DBA conditions, personnel will receive radiation exposures no greater than 5 rem total effective dose equivalent (TEDE) for the duration of the accident in accordance with 10 CFR part 50.67 as discussed in Chapter 15. The CREH Program ensures the CREH system is in compliance with General Design Criterion 19 (GDC 19) of 10 CFR 50, Appendix A, and in compliance with the guidance of Regulatory Guide 1.196.

Emergency supplies for the control room, technical support center (TSC), and operational support center will be provided by the Emergency Response Organization. Portable breathing apparatus is also provided in the control room for operating personnel protection in the event of a fire external to the plant or a chemical spill on or offsite. The control room heating, ventilating, and air conditioning (HVAC) is operated in the recirculation mode without filtration by the emergency filter units for both of these scenarios.

In the event of a LOCA, operating personnel within the control room are protected from airborne radioactivity for up to 30 days by means of pressurizing the control room with filtered air drawn from two separate remote fresh air intakes through the control room emergency filtration (CREF) system. Both intakes are physically remote from all plant structures. The CREF system has two redundant trains which can filter air drawn for the intakes. The system is designed such that both trains will start simultaneously, however a single train operation results in higher LOCA dose than a dual train operation, therefore the license basis LOCA dose analysis assumes a single train operation. If two trains start, the operator will be directed to not stop the second train until at least 10 hours post accident.

Redundant radiation monitors are located at each of the two remote intake headers. If desired, the valves in the most contaminated remote intake may be manually closed at any time post accident. However, to maintain control room pressurization at least one remote intake must be open at any time post accident.

Adequate shielding is also provided to protect operating personnel from radiation streaming. The control room doors are adequately designed to protect operating personnel from a steam pipe break in the turbine generator building.

The control room HVAC is also pressurized in the event of a fire within the plant, but external to the control room, to prevent ingress of smoke or combustion vapors.

Components of the HVAC systems serving the control room that are required to ensure control room habitability and essential equipment operations are redundant, Seismic Category I, and powered from Class 1E buses.

6.4.2 SYSTEM DESIGN

6.4.2.1 Definition of Main Control Room Envelope

The main control room is located on el. 501 ft of the radwaste building. Included in the CRE are all essential control equipment of the plant plus a toilet, kitchen, dining area, and an office area. These areas are frequently occupied.

The CRE boundary is the combination of walls, floor, ceiling, doors, penetrations, ducting, and equipment that physically form the boundary of the CRE. The equipment boundary includes fan housings, air handlers, and associated drain loop seals of the control room ventilation systems. The ducting boundary includes the HVAC ducts serving the control room starting from the fresh air isolation dampers to the common supply header penetrating the control room ceiling, and up to the isolation damper in the kitchen and bathroom exhaust duct. The enclosed volume of the CRE is approximately 214,000 ft^3. See Reference 6.4-1 for a more detailed description of the CRE.

6.4.2.2 Ventilation System Design

A description of the ventilation systems serving the control room and a listing of the design and performance parameters of the ventilation system equipment is provided in Section 9.4.1.

6.4.2.3 Leaktightness

A description of system leaktightness is discussed in Section 9.4.1.

6.4.2.4 Interaction With Other Zones and Pressure Containing Equipment

Normal access into the main control room is through corridors that are radiologically clean. Chemicals stored within the radwaste building or the immediately adjacent structures are in small quantities and are not hazardous to control room personnel.

Within the main CRE, there are no pressure vessels or piping systems that would affect control room habitability, except for the individual Halon fire extinguishing system within the control panels. Halon emitted to the main control room would be in the form of leakage from the Halon flooding systems. If all the Halon cylinders in the largest system were to release simultaneously, the projected concentration in the CRE would be about 2690 ppm (< 0.3% by volume). This concentration is significantly less than the 50,000 ppm level at which the concentration would be immediately dangerous to life and health (IDLH). The decrease in oxygen concentration in the control room would be approximately 0.1%. The main control room is protected from external pressurized systems by distance and concrete shield walls.

6.4.2.5 Shielding Design

The control room is designed with adequate shielding to protect occupants from conditions of airborne activity in containment and the reactor building, airborne activity in the radwaste building, the activity surrounding the building as a result of isotopes released to the environment, and activity built up on the main control room filters (located one floor above the control room). The concrete walls surrounding the control room are a minimum 2 ft thick and the floor and ceiling slabs are a minimum 1 ft thick. Radiation streaming is minimized by locating equipment, cable tray, and duct penetrations in the areas where radioactive sources are weak or nonexistent. There are no significant piping penetrations into the main control room. The normal primary access doors have been designed with air locks and may be used to prevent air inleakage into the control room during ingress and egress. The control room dose analysis for a LOCA does not take credit for the installed control room door air locks to minimize air inleakage. Radiation streaming through the doors has also been analyzed and evaluated as insignificant.

Direct doses to the control room from confined sources such as in some areas of the radwaste building, the turbine building, and from potential DBA sources in containment and in the reactor building are negligible due to local shielding provided around the source and shielding around the control room. Radiation from containment must penetrate the following shielding before reaching the control room: the 0.75-in. steel containment shell, the 5-ft-thick concrete biological shield wall, the 2-ft-thick concrete reactor building wall, and the 2-ft-thick concrete control room wall. Similarly, a 2-ft-thick concrete wall exists between the turbine building and the 2-ft-thick control room wall. In areas, the turbine building wall is 42 in. thick for shielding and missile purposes yielding 5.5 ft of protection to the control room from turbine building radiation areas. The HVAC room above the control room has an 18-in. concrete roof slab. This room coupled with the 1-ft-thick concrete control room ceiling yields an effective 2.5 ft of concrete shielding for the control room ceiling.

Details of the dose evaluation for the control room are given in Chapter 15.

6.4.3 SYSTEM OPERATIONAL PROCEDURES

During normal and emergency operation the control room operator selects the air handling unit which operates to maintain design temperatures in the control room. Periodically the operating unit is exchanged with the standby unit so that the service time of both units is approximately equal. In the event the operating unit fails, control room personnel start the standby unit from the control room.

The responses of the control room habitability system to either hazardous chemical or airborne radioactivity are compatible. In the event of a hazardous chemical release, the operators may take action to stop the exhaust fan, shut the associated damper, and close the fresh air inlet damper for each HVAC train. On receipt of a high-high airborne radioactivity level alarm signal at a remote intake, the operators may respond by closing the appropriate remote intake isolation valves. Portable breathing apparatus is available.

6.4.4 DESIGN EVALUATION

6.4.4.1 Radiological Protection

Personnel in the main control room are protected from the radiological effects of a postulated accident by pressurizing the main control room with 1000 cfm of filtered air drawn from either of two remote fresh air intakes. This operation limits the 30-day dose to operators to below that of GDC 19 of 10 CFR 50, Appendix A, and 10 CFR 50.67. Essential components of the control room habitability systems are redundant, Seismic Category I, and powered from Class 1E buses.

The emergency ventilation system is of the dual inlet design with manual isolation valves above the control room. See Section 9.4.1 for the system description. The guidance in Regulatory Guide 1.183 was used in the control room dose analyses for Columbia Generating Station (CGS) and is addressed in the individual event evaluations in Chapter 15.

6.4.4.2 Toxic Gas Protection

6.4.4.2.1 Chlorine

Chlorine is not used at CGS. Transportation routes involved in chlorine movements include Hanford Route 4 South to the west on which there may be four shipments per year. In the past, 1-ton cylinders have been shipped two or three times per year on the Hanford Railroad (750 ft east of CGS); however there have been none since June 1983 and it is anticipated that chlorine will continue to be transported on the highway instead.

Control room concentrations from a postulated accident were calculated using the methodology of References 6.4-2 and 6.4-3. Assuming no operator action, the maximum control room concentration of gaseous chlorine from an offsite accident involving the rupture of a 1-ton cylinder at a point 4500 ft directly upwind of the control room air intake is 29 mg/m^3 at 32 minutes after the arrival of the leading edge of the initial vapor cloud. This is below the 45 mg/m^3 2-minute toxicity limit specified in Reference 6.4-4.

The protection provided to the control room operators from an offsite chlorine release includes the capability of closing the control room air ducts with dampers and isolating the control room. The postulated accident and associated assumptions would yield concentrations exceeding the short-term exposure limit of 11.5 mg/m^3 specified by Reference 6.4-5 for approximately 3.5 hr assuming no operator action. Since the odor threshold is approximately 0.01 ppm (0.03 mg/m^3), per Reference 6.4-6, operators could quickly detect the presence of chlorine and isolate the control room. With this realistic assumption, there would be no hazardous exposure to chlorine.

In summary,

a. The CGS control room fresh air intake is not equipped with chlorine detectors and automatic isolation equipment,

b. No chlorine is stored onsite, and

c. Chlorine storage and movement within 5 miles is less than thresholds specified in Reference 6.4-4.

6.4.4.2.2 Sodium Oxide

The Department of Energy Fast Flux Test Facility (FFTF) is located approximately 4000 m southwest of CGS. A large quantity of liquid sodium was used in the operation of the FFTF. The facility is shut down and in the process of deactivation and decommissioning. Sodium has been drained from the primary and secondary heat transfer system loops and is being maintained in solid state in the Sodium Storage Facility tanks. A small amount of residual sodium remains in the piping systems and has been solidified (Reference 6.4-7).

The accident evaluated during the initial licensing of CGS was a liquid sodium release from a FFTF secondary loop component failure due to a tornado. The probability of such a release is significantly reduced because the primary and secondary loops are now drained and the sodium solidified. Since solidified sodium continues to be located at the site, this analysis is retained as a bounding event until the solidified sodium is removed from the site or the possibility of a release is further reduced.

The analysis is assumed that a failure occurs in the FFTF secondary loop component due to a tornado. A resulting postulated 100,000-lb sodium release over 20 hr was considered bounding for CGS control room habitability purposes (Reference 6.4-8).

The following assumptions are made:

a. Two million pounds of liquid sodium contained in the primary coolant loop are not considered in the analysis since it is contained in the FFTF reactor containment building,

b. 100,000 lb of liquid secondary sodium may be released and ignited,

c. Up to 36% of the sodium oxide formed in the combustion of the 100,000 lb of sodium may be released and transported away as an aerosol,

d. Fire resulting from the accidental release of 100,000 lb of sodium would consume the available sodium at whatever rate it is released, and

e. The average sodium oxide release rate assumed was for a 20-hr postulated incident at 2426.4 lb/hr.

Where applicable, Reference 6.4-4 was utilized. However, due to the nature of the postulated sodium fire and the complexities of the dispersion analysis, the following additional modeling assumptions were utilized:

a. CGS onsite meteorological data collected from April 1974 through March 1976 was used to establish the upper wind speed values in addition to the established 5% dispersion meteorology for the CGS site;

b. To account for the rise of sodium oxide aerosol due to the buoyancy of the hot gases, the height of rise of the aerosol plume was conservatively predicted using Part 1, References 6.4-9 and 6.4-10;

c. To account for settling and deposition of the sodium oxide particulates within the plume, depleted source terms were established (Reference 6.4-11); and

d. Six plume dispersion modeling equations were used to calculate concentrations outside the CGS control room fresh air intakes as a function of wind speed and stability. Credit for FFTF building wake dilution effects during high wind speed conditions, plume meandering for stable low wind speed conditions, and both a depleted plume equation and tilted plume equation to account for deposition were included as discussed in References 6.4-11, 6.4-12, and 6.4-13.

The analysis resulted in a maximum sodium oxide concentration outside the control room intakes of 8.7 mg/m^3. A wind speed of 1.2 m/sec would allow FFTF approximately 55 minutes to warn CGS control room personnel of the approaching sodium oxide cloud, assuming that the cloud was traveling directly toward the CGS site. The permissible warning time, as well as the cloud concentration, would increase for lighter wind speed conditions, i.e., up to approximately 1.5-hr warning time for a 0.75 m/sec wind producing a maximum cloud concentration of 8.7 mg/m^3. Wind speeds greater than 1.2 m/sec yield concentrations less than the long-term toxicity limit of 2 mg/m^3.

A warning time of approximately 55 minutes is sufficient to permit proper notification to take place between FFTF and Energy Northwest personnel, to isolate the CGS control room. Procedural arrangements are in place between FFTF and Energy Northwest for timely notification of the control room in the event of a sodium oxide release. In the unlikely event that sodium oxide enters the control room, portable breathing equipment is available.

6.4.4.2.3 Miscellaneous Chemicals

Other onsite stored chemicals were reviewed in accordance with Reference 6.4-4 to assess their potential impact on the habitability of the control room in the event of postulated hazardous chemical releases. Chemicals stored onsite and analyzed for impact on the control room habitability are ammonium hydroxide, carbon dioxide, trichlorofluoromethane (Freon-11), dichlorodifloromethane (Freon-12), chlorodifluoromethane (Freon-22), trichlorotrifluoromethane (Freon-113), and 1,1,1,2-tetrafluoromethane (Freon-134a), hydrogen peroxide, hydrogen, isopropyl alcohol, methyl ethyl ketone, nitrogen (liquid), propane, sodium hydroxide (in solution), sodium hypochlorite, sodium bromide, and sulfuric acid, diesel fuel, ethylene glycol, fyrquel, GE Betz Dearborn inhibitor AZ8104, gasoline, Halon 1301, hydrochloric acid, mineral spirits, insecticide, herbicides, fertilizers, lubricants, transformer oils, ONDEO NALCO chemicals, paint products, propylene glycol, and polyaluminum chloride solution.

The analysis (Reference 6.4-14) indicated that most of these chemicals did not require chemical hazard evaluations due to the fact that they exist in small quantities, are stored far away from the control room intakes, have a very low vapor pressure, or are bounded by the results of the calculations performed on the chemicals listed below.

The following chemicals met the screening criteria of Reference 6.4-4 required a chemical hazard evaluation:

a. A liquid nitrogen storage tank containing 75,000 lb of nitrogen located at the corner of the diesel generator building.

b. A tank containing 12,000 lb of cardox (CO2) stored in the turbine generator building.

c. A 55-gallon drum containing ammonium hydroxide stored approximately 100 ft from building 74 (warehouse for maintenance lubricants).

d. Two tanks containing 1700 gallons each of Freon-11 stored in the Refrigerant Storage and Maintenance building (Building 72) approximately 800 ft from the nearest control room air intake.

Postulated releases to the atmosphere and subsequent transport to control room fresh air intakes of these chemicals were evaluated. The results of the analysis (Reference 6.4-14) indicated that an accidental release of these chemicals will result in concentrations in the control room that are well below the toxicity limit of each of the chemicals. Therefore, these chemicals do not pose a hazard to the control room operators.

There are a significant number of compressed gas bottles containing process gasses such as nitrogen, hydrogen, argon, helium and others containing acetylene, argon/methane and oxygen used within the plant buildings and onsite bottle storage locations. These gas bottles do not represent a control room habitability concern due to the small quantity of gas contained in each bottle.

Maximum quantities of hydrogen gas stored in the gas bottle storage building (120 bottles containing a total of 144 lb) and in a trailer parked adjacent to the gas bottle storage building containing 294 lb will not pose any problem because the lightness and dispersal qualities of the gas and the distances (approximately 400 ft) to the nearest control room air intake would result in negligible concentrations at that location.

The Hydrogen Storage and Supply Facility (HSSF) has a maximum storage capacity of approximately 9800 pounds of liquid and gaseous hydrogen. The storage of this amount of hydrogen at the HSSF is not considered a hazard for control room habitability due to the distance (approximately 2900 ft) between the closest fresh air intake and the HSSF.

An 18,000-gal sulfuric acid storage tank, one 5000-gal tank of sodium hypochlorite, and one 5000-gal tank of sodium bromide are located near the circulating water pump house approximately 570 ft from the control room intake. Two 2100-gal tanks of hydrogen peroxide are located near pump house 1B (approximately 300 ft from the control room intake). Other stored chemicals include 500-gal propane tanks (located over 1100 ft from the control room intake), as well as other miscellaneous or transient storage of lesser quantities of chemicals that are bounded by the analyses performed for the chemicals stored in bulk quantities.

6.4.5 TESTING AND INSPECTION

The main control room HVAC system and its components are tested as follows:

a. Predelivery and component qualification tests,
b. Postdelivery acceptance tests, and
c. Postoperation surveillance tests.

Written test procedures establish acceptable criteria for the tests. The tests are performed to meet the objectives of Regulatory Guide 1.52 and Regulatory Guide 1.197.

The factory and component qualification tests consist of the following:

a. All equipment was factory inspected and tested in accordance with the applicable equipment specifications, codes, and quality assurance requirements. System ductwork and erection of equipment was inspected during various construction stages for quality assurance. Construction tests were performed on all mechanical components and the system was balanced for the design air and water flows and system operating pressures. Controls, interlocks, and safety devices were checked, adjusted, and tested to ensure the proper sequence of operation.

b. The emergency filter units, which are normally in standby, are started periodically to ensure fan operation. The fans are factory tested in accordance with AMCA Standard 210, "Air Moving and Conditioning Association, Test Code for Air Moving Devices."

   Filters are tested as described in Section 9.4.1.

c. All valves associated with the control room HVAC system are factory leak tested, bubble tight, at a pressure differential of 0.2 psig. Electrically operated valves are factory tested to ensure that valve stroke time, full open to full close, does not exceed 4 sec. Once installed, the valves are stroked to verify operability. The fresh-air intake valves are periodically tested to ensure control room inleakage through closed intake valves is minimized.

d. The postdelivery acceptance tests are performed as described in Section 14.2.

e. The operational surveillance testing is described in the Technical Specifications.

6.4.6 INSTRUMENTATION REQUIREMENTS

A discussion of instrumentation associated with main control room habitability systems is provided in Sections 9.4.1 and 7.3.1.1.7.

6.4.7 REFERENCES

6.4-1 "Control Room Boundary Leakage Limitations," TM-2082, Revision 5.

6.4-2 Turner, D. B., Workbook of Atmospheric Dispersion Estimates, Public Health Service, U.S. Department of Health Education, and Welfare, Figures 3.2 and 3.3, 1970.

6.4-3 Wing, J., Toxic Vapor Concentration in the Control Room Following a Postulated Accidental Release, NUREG-0570, Nuclear Regulatory Commission, June 1979.

6.4-4 "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release," Regulatory Guide 1.78, June 1974.

6.4-5 Nuclear Regulatory Commission, Standard Review Plan, Section 6.4, NUREG-0800 (Revision 2), July 1981.

6.4-6 Occupational Health Guidelines for Chemical Hazards, NIOSH, U.S. Department of Health and Human Services, August 1981.

6.4-7 FFTF Hazard Analysis Supporting Discussion & Analysis, "Fast Flux Test Facility Hazard Assessment," HNF-SD-PRP-HA-0.15 Revision 6, April 31, 2007.

6.4-8 Excerpts from Sections 6.4, "Habitability System," and 15.2, "Accident Analyses," of the FFTF FSAR (Amendment 3, February 1, 1977).

6.4-9 Briggs, G. A., "Plume Rise: A Recent Critical Review," Nuclear Safety Vol. 12, No. 1, 1971.

6.4-10 Briggs, G. A., "Plume Rise Predictions," Lectures on Air Pollution and Environmental Impact Analysis, American Meteorological Society, Boston, Mass., 1975.

6.4-11 Slade, D., Meteorology and Atomic Energy, U.S. Atomic Energy Commission, Division of Technical Information, Springfield, VA 1968.

6.4-12 Stern, A. C., Air Pollution, Their Transformation and Transport, Vol. I Third Edition, Academic Press, New York, 1976.

6.4-13 Nuclear Regulatory Commission, BTP HMB, Diffusion Conditions for Design Basis Accident Evaluations, 1977.

6.4-14 "Chemical Hazard Analysis for Control Room Habitability," CGS calculation number NE-02-06-02, April 2007.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 ENGINEERED SAFETY FEATURE FILTER SYSTEMS

There are two air filtration systems that are required to perform safety-related functions following a design basis accident. They are the control room emergency filtration (CREF) system, which is described in Sections 6.4 and 9.4.1, and the standby gas treatment (SGT) system described in this section.

6.5.1.1 Design Bases

The SGT system is designed to maintain airborne radioactive release from the secondary containment to the atmosphere within the limits required by 10 CFR 50.67. The system is designed to enable purging of the primary containment through the SGT system filters when airborne radiation levels inside the primary containment are too high to permit direct purging to atmosphere by means of the reactor building exhaust system as discussed in Section 9.4.

The SGT system design meets seismic requirements and single failure criterion. Each SGT system filter train is sized to maintain the secondary containment (reactor building) at least 0.25-in. water gauge below atmospheric pressure under the following conditions:

a. Air leakage into the secondary containment at a continuous rate of one building air change per day,

b. A drop in barometric pressure at the rate corresponding to adverse meteorological conditions,

c. Relative humidity increase resulting from vapor from the spent fuel pool, and

d. The volumetric expansion of air within the secondary containment due to the heat sources in the reactor building.

6.5.1.2 System Design

The SGT system is shown in Figure 3.2-2. The layout of the SGT system units is shown in Figure 12.3-23. Principal system components are listed and described in Table 6.5-1. The system consists of two fully redundant filter trains, each of which consists of the following components in series:

a. A demister (moisture separator) to remove entrained water particles in the incoming air stream;

b. Two banks of electric blast coil heaters, one primary and one backup, each powered from separate emergency diesel buses. Each heater is composed of three 6.9 kW stages and is sized to limit the relative humidity of the heated air to 70% at design flow during post-LOCA conditions;

c. A bank of prefilters to remove most particulates from the air stream. The filters have an atmospheric dust spot efficiency of 80-85% by ASHRAE Standard 52-68;

d. A bank of high-efficiency particulate air (HEPA) filters to remove virtually all particulates, including iodine fission products from the airstream;

e. Two 4-in.-deep bank of charcoal adsorber filters are installed in series. Filters are of an all-welded, gasketless design. Each charcoal adsorber filter has electric strip heaters.

f. A second bank of HEPA filters, identical to item d. The function of this second HEPA filter bank is to capture charcoal dust as well as particulate fission product releases that may escape from the charcoal filters.

All of the above components are mounted in an all welded steel housing. The SGT filter trains are located on the el. 572 ft of the reactor building. A 12-in.-thick concrete partition wall, 14 ft high, separates the two trains. The Seismic Category I design partition wall serves as both a missile barrier and fire barrier between the two trains.

There are at least 2268 lb of charcoal in each of the two adsorber units. The adsorbing capability of each unit is 2.5 mg of halogens per gram of charcoal or a total of 2577 g. The maximum theoretical accumulation of halogens on the SGT system adsorbers for a 30-day period after a LOCA is 67 g.

Three independent deluge spray systems are provided for fire protection in each SGT filter train. One deluge spray system is provided for protection of the prefilter and a deluge spray system is provided for each of the two charcoal filter beds.

Two centrifugal fans are provided with each SGT filter train. The primary fan starts automatically upon receipt of an initiation signal. The backup fan operates only in the event of primary fan failure. The two fans of each unit are powered from separate emergency diesel buses. Two identical control systems which are supported by emergency power adjust the automatic inlet vanes on the fans to control flow rate. See Section 7.3.1.1.9. Ductwork and butterfly valves on the discharge air side of each filter train are arranged such that either fan can draw air through the filter train and discharge it either out of the reactor building, by means of the reactor building elevated release duct, or back into the reactor building.

Provision is made to return air to the reactor building so that decay heat generated within the SGT unit due to the collection of radioactive contaminants is removed.

Ductwork and valving for the intake of each SGT unit is configured so that the units can draw air from the reactor building in the immediate vicinity of the unit, the primary containment drywell, the wetwell, or from any combination of the three locations. The connection to primary containment is through the primary containment purge exhaust lines.

During normal plant operation both SGT units are on standby. In standby, only the strip heaters in the charcoal sections operate. The strip heaters cycle to maintain the filter plenum temperature to ensure that the relative humidity within the plenum does not exceed 70%. This protects the charcoal adsorber from condensed moisture.

The maximum dewpoint temperature in the reactor building during normal plant operation is 75°F. When in standby, all isolation valves downstream of the unit fans are closed. Whenever the drywell requires venting to relieve pressure, purging to inert or to deinert, or purging to improve the quality of the drywell atmosphere, the SGT system can be used to treat the effluent gas before release. For this process, the system is manually operated from the control room. The operator initiates the SGT system and adjusts SGT flow to the required flow rate. A sensor in the fan discharge duct transmits a flow signal to a recorder monitored by the operator during the evolution. Purge supply air to the primary containment is supplied from the reactor building supply air system. During the process of inerting, nitrogen gas is supplied from the containment nitrogen inerting system.

Both SGT filter trains are automatically actuated by the following signals:

a. High radiation in the reactor building ventilation exhaust duct,
b. High pressure in the drywell, and
c. Reactor vessel low-low water level.

When actuated the following sequence of events occur in each SGT train:

a. The primary bank of electric blast coil heaters is energized and all valves begin to move to their proper positions;

b. After the primary bank of heaters has time to reach a temperature that will ensure air entering the charcoal bed is maintained below 70% relative humidity, the primary fan receives a start signal;

c. If the primary fan fails to start or run, following a time delay, the primary fan and heater are deenergized. Then the primary fan inlet valve receives a close signal and the backup heater is energized. Next, following an additional time delay to reach temperature, the backup fan isolation valve is opened and the backup fan receives a start signal;

d. The operating fan inlet vane position is controlled by the reactor building pressure control system to ensure that secondary containment pressure is reduced to at least a negative pressure of 0.25 in. w.g.. The control system will adjust fan flow rate as needed to maintain the negative pressure.

Both SGT units are operating within two minutes following the initiation signal. The same sequence is followed if the initiation signal is coincident with a loss of offsite power.

The operator may stop one of the SGT trains from the control room after startup is complete. In the event that the radiation monitors in the discharge duct indicate an unacceptable radiation level in the system discharge air, the operator starts the second unit and diverts the discharge air of the operating unit back into the reactor building to minimize offsite release of halogens and to cool the charcoal bed.

The following is a comparison of the engineered safety feature (ESF) filtration systems with each position detailed in Regulatory Guide 1.52, Revision 2.

Article A - Introduction

The ESF filtration systems provided for CGS are designed to the General Design Criterion referenced in Article A. Those systems designed to meet the criterion are:

a. Standby gas treatment system, and
b. Control room emergency filtration system.

Article B - Discussion

The two systems are both classed as secondary systems and are not subject to the drywell environment during any design basis accident and are not subject to containment cooling sprays. Equipment design includes the ability to operate under all environmental conditions to which they can be subjected during accident conditions. The components of each control room filter unit are as described in this article except that no demisters are required and HEPA filters are not provided downstream of the charcoal adsorber section. The effects of aging, weathering, and relative humidity have been considered in the design of these atmosphere cleanup systems, and they are tested periodically to verify required performance capability.

The effects of moisture on the charcoal adsorber media is minimized by the use of strip heaters for humidity control in the plenum of the charcoal adsorbers section of the SGT system units and by periodically circulating heated air through the control room emergency filtration units. Adequate space and accessibility for personnel has been incorporated in filter unit design to ensure maintainability and testability. Testing of filters is performed as specified in the Technical Specifications.

Article C - Regulatory Position

Section 1.8.3 provides an analysis of the engineered safety feature air filtration systems with respect to the regulatory positions of Regulatory Guide 1.52, Revision 2.

6.5.1.3 Design Evaluation

The SGT system is designed to prevent the exfiltration of contaminated air from the secondary containment following an accident or abnormal occurrence. All necessary equipment and surrounding structures are Seismic Category I. The ESF buses supply power to the SGT system in the event of loss of normal ac power. Two fully redundant equipment trains separated by a missile wall are provided to ensure that a single failure does not impair or preclude system operation.

6.5.1.4 Tests and Inspections

The SGT system and its components are thoroughly tested in a program consisting of the following classifications:

a. Predelivery tests and component qualification tests,
b. Postdelivery acceptance tests, and
c. Postoperation surveillance tests.

All SGT system fans were factory tested in accordance with AMCA Standard 210, "Air Moving and Conditioning Association Test Code for Air Moving Devices." Fans are started once per month to ensure operability.

Written test procedures establish acceptance criteria for all tests. Test results are recorded in performance records.

Predelivery tests were performed to meet the objectives of Regulatory Guide 1.52, Revision 2. Postdelivery tests were performed to meet the objectives of Regulatory Guide 1.52, Revision 2 (using ANSI N510-1980). Postoperation tests are performed as specified in the Technical Specifications.

The HEPA filters are factory tested to a minimum efficiency of 99.97% when measured with a 0.3-micron dioctyl phthalate (DOP) aerosol. Tests are performed in accordance with ASME AG-1-1997. See Section 1.8.3 for compliance by alternate approach to Regulatory Guide 1.52, Revision 2.

In place leak testing of the HEPA filters is conducted in accordance with Regulatory Guide 1.52, Revision 2, as discussed in Section 1.8.3, to demonstrate a penetration and system bypass of less than 0.05%.

Charcoal media qualification tests meet the objectives of Regulatory Guide 1.52, Revision 2.

Charcoal samples laboratory test results are required within 31 days of removal.

Charcoal beds are leak tested in accordance with the Technical Specifications to demonstrate a penetration and system bypass of less than 0.05%.

Valves associated with the SGT system were factory leak tested, bubble tight, at a pressure differential of 2 psig. Valves were factory tested to ensure that valve stroke time, full close to full open, did not exceed 4 sec. The SGT system valves are periodically stroked as specified in the Technical Specifications to ensure operability.

6.5.1.5 Instrumentation Requirements

Additional information regarding the instrumentation and control system for SGT is contained in Section 7.3.1.

The instrumentation and controls are designed to meet the objectives of Regulatory Guide 1.52, Revision 2.

The following instrumentation is provided for each SGT train in addition to that previously described:

a. An indicating differential pressure gauge is provided across each element (excluding heaters) in the SGT train. High differential pressure alarms in the main control room and is recorded by computer;

b. Relative humidity detectors with humidity indication in the main control room are located before the electric blast coil heaters and the charcoal adsorber banks. High humidity alarms in the main control room and is recorded by computer;

c. Thermostats with sensors on either side of an adsorber section control strip heaters in both adsorber plenum sections. Two thermostats in parallel energize the heaters on a temperature drop to 90°F. Another thermostat deenergizes the heaters on a temperature rise to 110°F, with a manual reset thermostat cutting out the heaters on a temperature rise to 125°F; and

d. Temperature indication is provided in the main control room for air entering the electric blast coil heater section and the air leaving both banks of charcoal filters. Temperature switch sensors are located on the downstream side of the prefilter and adsorber sections. A temperature rise to 250°F causes an alarm in the main control room. The control room operator determines the cause of the temperature rise and can manually initiate the deluge spray system if necessary.

6.5.1.6 Materials

The housings and framing materials of the SGT filter units are fabricated of steel alloys and, as such, are nonflammable. The following is a list of the materials used in the various components of the SGT filter units.

Demisters - The demister (moisture separator) section of each SGT unit consists of four assemblies of metal baffle plates and fiberglass separator pads. Each assembly has three fiberglass pads and one 4-in.-thick galvanized metal moisture eliminator with a nominal face area of 16 x 20 in.

Prefilters - There are four 24 in. x 24 in. prefilters in each SGT unit. The prefilters are a pleated, U.L. Class 1, fiberglass mounted on a metal retainer frame.

Absolute Particulate Filters - There are two banks of HEPA filters, one before and one after the charcoal adsorber section, on each SGT filter unit. The HEPA filters consist of U.L. Class 1 fiberglass media in stainless steel frames with aluminum separators. There are four 24 in. x 24 in. filters in each filter bank.

Charcoal Adsorber Media - Each charcoal adsorber filter unit (two per SGT train) contains about 40 ft^3 of charcoal. The charcoal used in the filters is a potassium iodide or triethylenediamine (TEDA) impregnated coconut base charcoal. Typically, over 1000 lbs of charcoal are contained in each of the four filter units.

The only material in the SGT units that supports combustion is the charcoal, which has a minimum ignition temperature of 330°C. The charcoal is provided with a deluge spray system. A 12-in.-thick concrete partition wall is provided between the two SGT units for fire protection.

6.5.2 CONTAINMENT SPRAY SYSTEM

Design Bases

The containment spray system is capable of reducing containment pressure during the postaccident period of a LOCA through condensation of steam in the drywell and through cooling of the noncondensable gases in the free volume above the suppression pool. Containment spray is not required to prevent overpressurization of the containment.

The containment spray system also provides for fission product removal from the containment atmosphere. During a LOCA a substantial fraction of the fission product release occurs after initial blowdown is complete. No credit is taken for suppression pool scrubbing of the wetwell air space. A portion of the fission products released from the reactor pressure vessel will be removed from the drywell atmosphere by drywell sprays. The drywell sprays are assumed to be initiated 15 minutes after the LOCA and turned off after one day.

6.5.3 FISSION PRODUCT CONTROL SYSTEMS

The release of fission products to the environment in the event of a LOCA is controlled passively by the leaktight integrity of the primary and secondary containments and actively by the SGT system that filters the effluent from the secondary containment.

6.5.3.1 Primary Containment

Primary containment response to a design basis accident is discussed in Section 6.2.1. Figure 6.2-23 provides a basic layout of the primary containment.

In the event of a LOCA, oxygen concentration is controlled by the containment atmosphere control system which mixes, monitors, and controls the containment atmosphere as described in Section 6.2.5. Primary containment purging is discussed in Section 6.2.1.

6.5.3.2 Secondary Containment

The SGT system is provided to control the release of fission products from the secondary containment to the environment. Secondary containment details are provided in Section 6.2.3 and SGT system details are provided in Section 6.5.1.

6.5.3.3 Standby Liquid Control (SLC) System

The SLC system is initiated as directed by procedure to inject sodium pentaborate solution into the reactor pressure vessel when there is evidence of fuel damage following a LOCA. Flow from the break will carry the boron to the suppression pool. Maintaining the pool pH above 7.0 for the duration of the accident will minimize the re-evolution of gaseous iodine. See Section 9.3.5.

Table 6.5-1

Standby Gas Treatment System
Component Description Per Unit

Charcoal Filters

Type	Deep bed
Quantity	Two in series
Design Flow (acfm)	4800
Media	Charcoal
Radioiodine removal	Not less than 99.5% methyl iodide, tested at 30°C and 70% relative humidity
Depth of each bed (in.)	4
Pressure drop, clean (in. wg)	2.0
Residence time each train (sec.)	≥ 0.5
Ignition temperature, minimum (°C)	330
Iodine desorption temperature range (°F)	250-300 (low threshold)
Charcoal halogen loading, gm	67 (maximum theoretical loading for 30-day accident duration) 2577 (absorbing capability)

HEPA Filters

Type	High efficiency, dry
Quantity	Two banks, four filters each
Capacity (acfm)	4800 each bank
Media	Fiberglass U.L. Class 1
Efficiency (%)	99.97 with 0.3-micron DOP aerosol
Pressure drop, clean (in. wg)	1.0 nominal

Prefilter

Type	Medium efficiency, dry
Quantity	One bank, four filters
Design Flow (acfm)	4800
Media	Fiberglass
Efficiency (%)	80-85% NBS dust spot
Pressure drop, clean (in. wg)	0.5 nominal

Table 6.5-1

Standby Gas Treatment System
Component Description Per Unit (Continued)

Heater

Type	Electric, on-off
Quantity	Two banks
Capacity (kW)	20.7 (nominal each bank)
Stages	Three

SGT System Exhaust Fans

Type	Centrifugal (with volume control)
Quantity	Two 100% capacity units
Design Flow (acfm)	4800
Static Pressure (in. wg)	16 nominal
Drive	Direct
Motor (hp)	25

Demister

Type	Multiple bed
Quantity	One bank, four filter units
Design Flow (acfm)	4800
Media	Metal baffle plate and fiberglass pads
Pressure drop, clean (in. wg)	0.8 nominal

6.6 INSERVICE INSPECTION OF ASME CODE CLASS 2 AND CLASS 3 COMPONENTS

The structural integrity of ASME Code Class 2 and 3 components is maintained as required by the Inservice Inspection (ISI) Program in accordance with 10 CFR 50.55a. With the structural integrity of any component not conforming to the above requirements, the structural integrity will be restored to within its limits or the affected component will be isolated. For Class 2 components, isolation will be accomplished prior to increasing reactor coolant system temperature above 200°F.

The Preservice Inspection Program Plan (Reference 5.2-6) addresses preservice inspections of Quality Groups B and C (ASME Boiler and Pressure Vessel Code, Section III Class 2 and 3) components as required by Section XI of the ASME Boiler and Pressure Vessel Code.

The Inservice Inspection Program (ISI) addresses inservice inspections of Quality Groups B and C (ASME Boiler and Pressure Vessel Code, Section III, Class 2 and 3) components as required by Section XI of the ASME Boiler and Pressure Vessel Code.

6.7 MAIN STEAM ISOLATION VALVE LEAKAGE CONTROL SYSTEM

The main steam isolation valve leakage control system (MSLC) is isolated and deactivated. The structural integrity of piping systems and components left in place is maintained.