TABLE OF CONTENTS

Section		Page
5.1	**Summary Description**	**1**
5.2	**Primary Containment System**	**1**
5.2.1	Design Criteria	1
5.2.1.1	Containment Systems Criteria	1
5.2.1.2	Containment Auxiliary Systems Criteria	2
5.2.1.2.1	Cooling and Ventilation System	2
5.2.1.2.2	Isolation System	3
5.2.1.2.3	Vent and Vacuum Relief System	5
5.2.1.3	Containment Penetrations	6
5.2.1.4	Primary Containment Atmospheric Control	7
5.2.1.5	Hard Pipe Vent System	7
5.2.2	Description	7
5.2.2.1	Pressure Suppression System	7
5.2.2.2	Primary Containment	8
5.2.2.3	Suppression Chamber	9
5.2.2.4	Containment Penetrations	12
5.2.2.4.1	Electrical Penetration	12
5.2.2.4.1.1	Low Voltage Assembly	13
5.2.2.4.1.2	Shielded Signal Cables	13
5.2.2.4.1.3	High Voltage Cable	13
5.2.2.4.2	Piping Penetrations	14
5.2.2.5	Primary Containment Auxiliary Systems	15
5.2.2.5.1	Spray Cooling System	15
5.2.2.5.2	Cooling and Ventilation System	15
5.2.2.5.3	Containment Isolation Valves	15
5.2.2.5.3.1	Description of Inboard MSIVs	18
5.2.2.5.3.2	Description of Outboard MSIVs	19
5.2.2.5.4	Vent and Vacuum Relief System	21
5.2.2.5.5	Containment Monitors	21
5.2.2.6	Primary Containment Atmospheric Control System	22
5.2.2.7	Containment Atmosphere Monitoring System	23
5.2.2.8	Suppression Pool Temperature Monitoring System	23
5.2.2.9	Hard Pipe Vent System	24

Section		Page
5.2.3	Performance Analysis	24
5.2.3.1	Sizing of the Primary Containment	24
5.2.3.2	Containment Response to a Loss of Coolant Accident and SRV Actuations	26
5.2.3.2.1	Containment Dynamic Response	26
5.2.3.2.2	Design Basis Accident of Coolant Accident (DBA-LOCA) Break Area	28
5.2.3.2.3	Containment Temperature and Pressure Response	29
5.2.3.2.4	Licensing Basis Ultimate Heat Sink Limit	31
5.2.3.3	Containment Temperature and Pressure for ECCS Pump NPSH	32
5.2.3.4	Hydrogen and Oxygen Generation in Containment	34
5.2.3.4.1	Metal-Water Reaction	34
5.2.3.4.2	Radiolysis	34
5.2.3.4.3	Corrosion Reactions	34
5.2.3.5	Miscellaneous Containment Performance Analyses	35
5.2.3.5.1	Seismic Analysis for Primary Containment	35
5.2.3.5.2	Drywell Expansion Gap Design Allowance	35
5.2.3.5.3	Drywell Missile Protection	36
5.2.3.5.4	Mark I Containment Program	38
5.2.3.5.5	Suppression Chamber - to - Drywell Allowable Bypass Leakage	40
5.2.3.6	Primary Containment Auxiliary Systems	41
5.2.3.6.1	Cooling and Ventilation Systems	41
5.2.3.6.2	Isolation System	41
5.2.3.6.3	Vent and Vacuum Relief System	43
5.2.3.7	Penetrations	43
5.2.3.8	Primary Containment Atmospheric Control	45
5.2.3.9	Drywell Temperature Analysis for Small Break Accidents	46
5.2.3.10	Post Accident Containment Mixing	46
5.2.3.11	Hard Pipe Vent System	47
5.2.4	Inspection and Testing	47
5.2.4.1	Primary Containment	47
5.2.4.2	Containment Penetrations	48
5.2.4.3	Containment Isolation Valves	48
5.2.4.4	Containment Ventilation System	50
5.2.4.5	Primary Containment Atmospheric Control	50

Section		Page
Table 5.2-1	Principal Design Parameters of Primary Containment	51
Table 5.2-2	Electrical Penetration Environmental Design Conditions	53
Table 5.2-3a	Monticello Containment Penetrations	54
Table 5.2-3b	Primary Containment Automatic Isolation Valves	68
Table 5.2-4	Maximum Containment Conditions for a Design Basis Accident	72
Table 5.2-7	Assumptions for the LOCA Containment Evaluation	73
Table 5.2-8	Drywell Temperature Envelopes for Small Steam Breaks	75
5.3	**Secondary Containment System and Reactor Building**	**1**
5.3.1	General	1
5.3.2	Design Basis	1
5.3.3	Description	2
5.3.3.1	Reactor Building	2
5.3.3.2	Secondary Containment Penetrations	2
5.3.4	Reactor Building Heating and Ventilation Systems	2
5.3.4.1	Standby Gas Treatment System (SGTS)	3
5.3.5	Performance Analysis	4
5.3.6	Inspection and Testing	6
5.4	**References**	**1**
5.FIGURES		**1**
5.2-1	Pressure Suppression Containment System	2
5.2-2	Typical Electrical Penetration Assembly Canister	3
Figure 5.2-2a	Modular Electrical Penetration Assembly	4
5.2-3	Center Section - Low Voltage Power and Control Electrical Penetration Assembly	5
5.2-4	Center Section - Shielded Signal Cable Electrical Penetration Assembly	6
5.2-5	Center Section - High Voltage Power Electrical Penetration Assembly	7
5.2-5a	Electrical Penetration Assembly (Drywell Penetrations X-106 & X-107)	8
5.2-6	Center Section - Hot Fluid Piping Penetration Assembly	9

Section		Page
5.2-7	Center Section - Cold Fluid Piping Penetration Assembly	10
5.2-8	Main Steam Isolation Valves	11
5.2-9	Recirculation Line Break - Illustration	12
5.2-oa	Drywell and Wetwell Pressure DBA-LOCA-Short Term	13
5.2-ob	Drywell and Wetwell Pressure DBA-LOCA-LongTerm	14
5.2-oc	DBA-LOCA Short Term Analysis - Core Spray Pump NPSH Available	15
5.2-od	DBA-LOCA Long Term Analysis - Core Spray Pump NPSH Margin	16
5.2-p	Drywell Temperature Response	17
5.2-q	Suppression Pool Temperature Response	18
5.2-23	Energy Requirement to Penetrate Drywell	19
5.2-28	Elevation View of Containment	20
5.2-29	Plan View of Containment	21
5.2-30	Developed View of Suppression Chamber Segment	22
5.3-2	Calculated Range of Reactor Building Exfiltration Rates as a Function of Wind Velocity	23

5.1 Summary Description

The containment systems provide a multibarrier, pressure suppression containment employing containment-in-depth principles in the design. The fuel cladding, and reactor pressure vessel form barriers to the release of fission products and are described in other sections of this report. This section describes a containment system which is composed of a primary containment and a secondary containment.

The primary containment consists of a drywell, which encloses the reactor vessel and recirculation pumps, a pressure suppression chamber which stores a large volume of water, a connecting vent system between the drywell and the suppression chamber, and isolation valves.

The secondary containment consists of (1) the portion of the Reactor Building which encloses the primary containment, the refueling facilities, and most of the nuclear steam supply system, (2) the Standby Gas Treatment System, and (3) the offgas dilution subsystem. During periods when the primary containment vessel is open, the secondary containment system provides all containment functions when containment is required. 01081199 In addition to the Reactor Building passive barrier, a Standby Gas Treatment System can automatically or manually exhaust the building atmosphere via filters to the offgas dilution subsystem in the offgas stack. 01081199

5.2 Primary Containment System

5.2.1 Design Criteria

5.2.1.1 Containment Systems Criteria

The primary performance objectives of the primary containment system are:

a. To provide a barrier which, in the event of loss-of-coolant accident, controls the release of fission products to the secondary containment, and

b. To rapidly reduce the pressure in the containment resulting from the loss-of-coolant accident.

To achieve these objectives the primary containment system was designed to meet the following criteria:

Maximum Pressure of Drywell and Pressure Suppression Chamber[1]	62 psig
Internal Design Pressure[1]	56 psig
External Design Pressure[1]	2 psig
Design Temperature	281°F
Design Leak Rate	0.5 percent per day at 56 psig (1.2 percent per day plus 200 scfh Main Steam Pathway (MSIV) leakage are initially assumed for radiological evaluations, See Section 14.7.)
Design Code	ASME Section III Subsection B, 1965 Edition with Winter 1965 Addenda. Mark I Containment modifications in accordance with the PUAR (References 72 and 75)
Seismic Criteria	As specified in Section 12 and Appendix A

1. ASME Code Rating

The free volume of the drywell was dictated by the space required to contain the reactor vessel, the recirculation system and necessary reactor auxiliary equipment. The free volume of the suppression chamber was determined from the drywell volume by using the results of the Bodega Bay containment tests as discussed in Section 5.2.3. The suppression chamber water volume was determined by the required heat sink capacity as described in Section 5.2.3. These considerations resulted in a containment system with the following volumes:

Design Free Volume	
Drywell	134,200 ft^3
Pressure Suppression Chamber	108,250 ft^3 maximum 103,340 ft^3 minimum
Pressure Suppression Pool Water Volume	72,910 ft^3 maximum 68,000 ft^3 minimum

The containment design accounts for the pressure stresses and the weight of the massive structures and large equipment. It also includes thermal and hydrodynamic stresses due to the postulated loss-of-coolant accident (LOCA) and safety relief valve operations, simultaneous seismic stresses in accordance with the seismic criteria listed in Section 12.2, and impact loads from missiles and jet forces due to reactions from postulated breaks in pressurized pipes. For additional technical information on the design of this containment vessel, see Appendix F and the Monticello Mark I Containment Long Term Program Plant Unique Analysis Reports (Reference 72 and 75).

5.2.1.2 Containment Auxiliary Systems Criteria

5.2.1.2.1 Cooling and Ventilation System

The primary containment cooling and ventilation system consists of four air coolers, ductwork, fans, and controls which maintain the drywell atmosphere below a 135°F bulk average temperature. They reduce air temperature to 105°F in 8 to 10 hours after shutdown. The drywell atmosphere is circulated through the drywell by the cooler fans, and the reactor building closed cooling water system is employed to remove heat from the air coolers.

5.2.1.2.2 Isolation System

One of the basic purposes of the primary containment system is to provide a minimum of one protective barrier between the reactor core and the environmental surroundings subsequent to an accident involving failure of the piping components of the reactor primary system. To fulfill its role as a barrier, the primary containment is designed to remain intact before, during, and after any design basis accident of the process system installed either inside or outside the primary containment. The process system and the primary containment are considered as separate systems, but where process lines penetrate the containment, the penetration design achieves the same integrity as the primary containment structure itself. The process line isolation valves are designed to achieve the containment function inside the process lines when required.

The general criteria governing isolation valves for the various categories of penetrations are as follows:

a. Pipes or ducts which penetrate the primary containment and that connect to the reactor primary system, or are open to the drywell free air space are provided with at least two isolation valves in series.

   Valves in this category are capable of remote manual actuation from the main control room and are designed to close automatically from selected signals or are de-activated and secured in their closed position at reactor coolant temperatures greater than 212°F.

   On lines connecting to the reactor primary system, one valve is located inside the primary containment and the second outside the primary containment as close to the primary containment as practical.

b. Lines that penetrate the primary containment and neither connect to the reactor primary system nor open into the primary containment are provided with at least one valve that is located outside the primary containment. Process lines in this category are provided with valves capable of remote actuation from the control room, valves that close automatically by process action, or by administratively controlled manual isolation valves that are closed when primary containment is required.

c. Motive power for the valves on process lines that require two valves is from physically independent sources to provide a high probability that no single accidental event could interrupt motive power to both closure devices. Loss of valve actuation power is detected and annunciated.

d. Main steam line isolation valve closure time is such that for any design basis break, the coolant loss is restricted so that the reactor core would not be uncovered. These valves must close slowly enough such that closure does not induce transients more severe than a turbine stop valve closure.

e. Valves, sensors, and other automatic devices essential to the isolation of the containment are provided with means to periodically test the functional performance of the equipment. Such tests include demonstration of proper working conditions, correct set point of sensors, proper speed of responses, and operability of fail-safe features.

The following are exceptions to the above isolation valve criteria:

a. Automatic isolation valves, in the usual sense, are not used on inlet lines of the reactor core and containment cooling systems, and reactor feedwater systems, since operation of these systems is essential following a design loss-of-coolant accident. Since normal flow of water in these systems is inward to the reactor vessel or to the primary containment, containment isolation is accomplished by check valves and/or manually controlled power operated valves. In those cases where two manually controlled power operated valves are used for a process line, both may have the same power supply and be located outside of the containment penetration. At least one of these power operated valves is normally closed.

b. No automatic isolation valves are provided on the control rod drive system hydraulic lines. These lines are isolated by the normally closed hydraulic system directional control valves, scram discharge vent and drain valves, charging and cooling water check valves located in the reactor building, and by ball check valves and double seals within each hydraulic control unit.

c. TIP isolation valves and small diameter instrument lines.

d. No automatic isolation valves are provided on the Hard Pipe Vent Line. This line is isolated by valves in the “normally closed” position which are locked closed via key-locked hand switches.

e. A containment isolation check valve acts as a thermal pressure relieving device to the RHR Shutdown Cooling Primary Containment Piping Penetration (SDCL) so the penetration can withstand drywell heat up during a LOCA. The check valve relieves thermal pressure between the containment isolation valves of the SDCL and discharges to the A RHR injection penetration where the discharge is directed back to the vessel.

NRC Generic Letter 96-06 (References 146 and 147) included a request for information relative to thermally induced overpressurization of isolated water filled piping sections in the containment. An evaluation of the applicable piping configurations was performed and pressure relief devices, operating procedures or bypass features were identified in those instances where heatup of these pipe sections could result in exceeding design allowables. Descriptions of these actions were submitted to the NRC for review. The NRC determined that the evaluation and corrective actions were reasonable and acceptable and considered the Generic Letter 96-06 issue closed for Monticello (Reference 148). The NRC reviewed the impact of operation up to 2004 MWt on the requirements of Generic Letter 96-06. The responses previously provided were not impacted by operation up to 2004 MWt (Reference 168 and 169). 01101248

5.2.1.2.3 Vent and Vacuum Relief System

The vent and vacuum relief system is designed to limit the negative pressure in either the suppression chamber or the drywell to less than the design pressure of -2 psid. Two vacuum breakers in series are used in each of two large vent lines which permit air to flow from the reactor building to the suppression chamber.

Vendor-supplied, flow-versus-pressure drop information was used to ensure that sufficient flow area is available to accommodate maximum obtainable vacuum relief flow conditions. Each of the reactor building to suppression chamber lines contains two valves in series, each rated at 0.5 psi differential pressure (1.0 psid total). Each of these two parallel lines was sized for 100% requirements in order to provide fully redundant capacity.

The suppression chamber-to-drywell vacuum breaker valves permit gases to flow from the pressure suppression chamber to the drywell. Eight 18-in. valves are used in parallel. These valves are sized on the results of the Bodega Bay pressure suppression system tests. Their chief purpose is to prevent excessive water level variation in the downcomers submerged in suppression pool water. The Bodega Bay tests regarding vacuum breaker sizing were conducted by simulating a small system rupture, which tended to cause downcomer water level variation, as a preliminary step in the large rupture test sequence. The vacuum breaker capacity selected on this test basis is more than adequate to limit the pressure differential between the suppression chamber and drywell during post-accident drywell cooling.

One of the tasks of the Mark I Containment Program was to develop methods which could be used for determining the plant-unique vacuum breaker cyclic response, as well as the necessary size, to meet various design conditions for which the vacuum breaker must function (Reference 1). An analysis of the Monticello drywell negative pressure requirements was performed by NUTECH using the computer program developed by General Electric Company as part of this task. The intent of the plant-unique analysis was to confirm the adequacy of the system which consisted of 10 vacuum breakers. This analysis demonstrated that the capacity of six drywell vacuum relief valves would be sufficient to limit the pressure differential between the suppression chamber and drywell to less than the design limit of 2 psi even if both drywell spray loops actuated simultaneously following a LOCA. If only one spray loop is actuated, three vacuum breakers are sufficient. Details of the analysis and results are given in Reference 2.

During the 1981 refueling outage, a number of modifications were made to the pressure suppression system to address generic Mark I Program conclusions. One of these modifications involved removal of two vacuum breakers and installation of blind flanges on their vent header penetrations. License Amendment 8 approved Technical Specification changes which reflected the reduction to 8 vacuum breakers.

During the steam condensation testing performed in the Mark I Containment Program Full Scale Test Facility, the vacuum breakers were subjected to cycling during the chugging phase of the tests. This cyclic impact of the valve pallet on the seat had not been specifically included in the vacuum breaker design requirements. The Long-Term Mark I Containment Program added tasks to quantify the effects from valve cycling and to respond to Generic Letter 83-03 (Reference 76). The Monticello vacuum breakers were evaluated for these loading conditions (Reference 77) and modifications were implemented by utilizing higher strength materials for certain valve components as described in detail in Reference 78. The evaluation methodology and its application to the modified vacuum breakers were approved by the NRC in Reference 97.

Further evaluation was also performed to address a concern that drywell spray initiation into a steam and air-filled drywell might result in loads in excess of those evaluated as part of the Mark I Containment Program. The evaluation (Reference 96) concluded that the body impact velocity will be less than the seat impact velocities produced by chugging.

The primary containment is periodically vented to eliminate pressure fluctuations caused by air temperature changes during various operating modes. This is accomplished through ventilation purge connections which are normally closed while the reactor coolant is at a temperature greater than 212°F.

5.2.1.3 Containment Penetrations

The design, fabrication, materials, inspection, and testing of primary containment penetrations are in accordance with the intent of the ASME, Section III, Subsection B, 1965 Edition (Reference 112).

The basic design objective for the penetrations was to ensure that the integrity of the containment is maintained under the loading conditions defined below:

a. Normal operating conditions

   The penetrations were designed for loads resulting from the full combination of normal operating pressure, thermal expansion, seismic, and dead loads.

b. Accident conditions

   The penetrations were designed for the loads resulting from the full combination of dead loads, seismic, thermal growth, and pressure conditions due to loss of coolant within the drywell, acting coincident with the larger of the following:

   1. The jet reaction force on a penetration resulting from a circumferential (guillotine-type) break of the associated process line.

2. The jet reaction force on a penetration resulting from a longitudinal-type break of the associated process line.

3. The jet impingement loading on a penetration and its associated process line resulting from rupture of an adjacent process line.

c. Hydrodynamic LOCA Loads

Suppression chamber penetrations and torus attached piping systems, including the suction ring header, were re-evaluated and appropriately modified to account for the hydrodynamic loads identified as a result of the Mark I Containment Program. The evaluation and modifications are described in Reference 75. In 1997, new ECCS suction strainers were installed. The strainers and support assemblies were designed to be structurally independent from the torus penetrations. Therefore, the new strainers do not affect the Mark I program torus penetration and torus attached piping evaluation results.

5.2.1.4 Primary Containment Atmospheric Control

The primary containment atmospheric control system provides the ability to maintain an atmosphere of low oxygen content within the primary containment by use of an inert gas.

5.2.1.5 Hard Pipe Vent System

The Hard Pipe Vent (HPV) System is designed to prevent containment pressure from increasing under conditions of constant heat input at a rate equal to 1% of rated thermal power and containment pressure equal to the Primary Containment Pressure Limit (PCPL). The Hard Pipe Vent System was installed in response to Generic Letter 89-16 (Reference 114) and meets the design criteria established by the BWR Owners Group (Reference 107).

5.2.2 Description

5.2.2.1 Pressure Suppression System

The Primary Containment System, which employs a pressure suppression containment system (constructed of steel), houses the reactor primary vessel, the reactor coolant Recirculation System loops, and other branch connections of the reactor primary system (see Figure 5.2-1). The system consists of a drywell, a pressure suppression chamber (wetwell) that stores a large volume of water, a connecting vent system between the drywell and the chamber water pool, isolation valves, ventilating and cooling systems, and other service equipment (see Figure 5.2-28 and 29).

In the event of a process system piping failure within the drywell, reactor water and steam would be released into the drywell air space. The resulting increased drywell pressure then forces a mixture of non condensible gases, steam, and water through the vents into the pool of stored water in the suppression chamber. The steam condenses rapidly and completely in the suppression pool, resulting in rapid pressure reduction in the drywell.

Non condensible gases forced into the suppression chamber with the steam and water may tend to leave the suppression chamber pressurized with respect to the drywell upon condensation of vapor in the drywell. Vacuum relief valves are provided to prevent such pressurization and the possible accompanying back flow of water from the suppression chamber to the drywell. Cooling systems are provided to remove heat from the drywell, and from the water in the suppression chamber and thus provide continuous cooling of the primary containment under accident conditions. Appropriate isolation valves are actuated during this period to ensure containment of radioactive materials which might otherwise be released from the reactor during the course of the accident. Table 5.2-1 summarizes the parameters of the containment system.

5.2.2.2 Primary Containment

The drywell portion of the Primary Containment is a steel pressure vessel with a spherical lower portion and a cylindrical upper portion (see Figure 5.2-28). The steel head and shell of the drywell are fabricated of SA-516-70FBX plate manufactured to A-300 requirements. The top head closure is made with a double tongue and groove seal that permits periodic checks for tightness without pressurizing the entire vessel.

The drywell is enclosed in reinforced concrete for shielding purposes and to provide additional resistance to deformation and buckling of the drywell over areas where the concrete backs up the steel shell. Above the foundation transition zone the drywell is separated from the reinforced concrete by a gap of approximately 2-in. for thermal expansion. Shielding over the top of the drywell is provided by a removable, cemented, reinforced concrete shield plug.

In addition to the drywell head with its bolted manway and one double door personnel air lock, two hatches (one large equipment hatch and one control rod drive hatch) are provided for access to the drywell. The locking mechanism on each air lock door is designed so that a tight seal is maintained when the doors are subjected to either internal or external pressure. The doors are mechanically interlocked to maintain primary containment integrity. The airlock is tested by pressurizing the space between the inner and outer doors. Individual door seal leakage tests cannot be performed. Since the inner door is designed to seat with containment pressure forcing the door closed, special bracing must be installed for each leakage test. The outer door must be opened to install and remove this bracing. The equipment hatch cover is bolted in place and sealed with a double tongue and groove seal. The CRD hatch is held in place by a yoke and clamp and is sealed with a double O-Ring seal. The seals on the access hatch covers are capable of being tested for leakage.

The drywell is not entered during high power operation. Access is permissible during low power operation under strict procedural control. Under normal conditions, personnel entry is not permitted until the containment is de-inerted and thoroughly checked for pockets of nitrogen. The normal environment in the drywell during plant operation is essentially atmospheric pressure at a bulk average temperature of less than 135°F. This bulk average temperature is assumed as an initial condition for evaluation of NPSH for the ECCS pumps 01101248 (References 79, 80, 182, and 183). This temperature is maintained by recirculating the drywell air across forced air cooling units which, in turn, are cooled by the reactor building closed cooling water system.

The top portion of the drywell vessel is removed during refueling operations. The head is held in place by bolts and is sealed with a double seal arrangement to provide primary containment integrity.

Eight large circular vent lines form a connection between the drywell and the pressure suppression chamber. Jet deflectors are provided in the drywell at the entrance of each vent line to prevent possible damage to the vent pipes from jet forces which might accompany a pipe break in the drywell. The vent lines are enclosed with sleeves and are provided with expansion joints to accommodate differential motion between the drywell and suppression chamber.

5.2.2.3 Suppression Chamber

The suppression chamber is in the general form of a torus which is below and encircles the drywell (see Figure 5.2-29). The suppression chamber is actually constructed of 16 mitered cylindrical shell segments. A reinforcing ring girder with two supporting columns and a saddle is provided at the miter joint of the adjoining shell segments.

The suppression chamber is connected to the drywell by eight vent lines (see Figure 5.2-28, 29 and 30). Within the suppression chamber, the vent lines are connected to a common vent header. Connected to the vent header are 48 pairs of downcomers which terminate below the water level of the suppression pool. The vent lines are shielded from jet impingement loads at each vent line - drywell penetration location by jet deflectors which span the openings of the vent lines. A bellows assembly connecting the suppression chamber to the vent line allows for differential movement between the drywell and the suppression chamber.

Eight vacuum breakers are provided to equalize the pressure between the suppression chamber and the drywell to prevent a backflow of water from the suppression pool into the vent header system. Each vacuum breaker is an 18-in. check valve with an air operator provided for testing purposes. There is one breaker located at each of the vent-to-vent header positions. The vacuum breakers are designed to be full open at 0.5 psid. See Technical Specification 3.6.1.7 for the operational limits.

The suppression chamber is supported vertically at each miter joint location by inside and outside columns and by a saddle support located between the inside and outside columns. The columns, column connection plates, and saddle supports are located parallel to the associated miter joint in the plane of the ring girder web. At each miter joint, the ring girder, columns, column connections, and saddle support form an integral support system which takes vertical loads acting on the suppression chamber shell and transfers them to the Reactor Building basemat. The support system provides full vertical support for the suppression chamber while allowing lateral movement and thermal expansion to occur; a load transfer mechanism which reduces local suppression chamber shell stresses and more evenly distributes reaction loads to the basemat; and increases the suppression chamber natural frequencies beyond the critical frequencies of most hydrodynamic loads, thereby reducing dynamic amplification effects.

Four seismic restraints located 90° apart provide lateral support for the suppression chamber. The seismic restraints permit vertical and radial movement of the suppression chamber while restraining longitudinal movement resulting from lateral loads. The pad plates distribute loads over a large area of the suppression chamber shell and provide an effective means of transferring suppression chamber lateral loads to the basemat.

The vent system is supported vertically by two column members at each miter joint location. The support column members are constructed with 6″ diameter, Schedule 80 pipe. Built-up clevis assemblies are attached to each end of the columns. The columns are pinned top and bottom to accommodate the differential horizontal movement between the vent header and the suppression chamber. The support column assemblies are designed to transfer vertical loads acting on the vent system to the suppression chamber ring girders while simultaneously resisting drag loads on submerged vent system structures. The vent system is supported horizontally by the vent lines which transfer lateral loads acting on the vent system to the drywell at the vent line drywell penetration locations.

The intersections of the downcomers and the vent header are reinforced with a system of stiffener plates and bracing members. The bracing system stiffens the downcomer intersection in a direction parallel to the vent header longitudinal axis. For horizontal loadings in a direction perpendicular to the vent header longitudinal axis, the downcomer-to-vent-header intersection is stiffened by means of lateral restraints and gusset plates.

Vent header deflectors are provided underneath the vent header to shield the vent header from impact loads which occur during the initial phase of a postulated Design Basis Accident event. The vent header deflectors are constructed from 14″ diameter, Schedule 160 pipe with WT6 x 32.5 split tee sections attached to either side. The vent header deflectors are designed to completely mitigate impact loads on the vent header.

The vent system also provides support for a portion of the SRV piping inside the vent line and suppression chamber. Loads which act on the SRV piping are transferred to the vent system by the penetration assembly which is welded to the vent line.

Torus attached piping penetrations requiring additional load carrying capabilities to meet the original safety margins were modified as required. A typical penetration consists of four base plates welded to the torus shell 90° apart circumventing the penetrating pipe. A gusset plate spans between the base plate and a split sleeve around the penetrating pipe to form a rigid support. The loads are effectively distributed over a larger area through the base plates thereby reducing stresses in the torus shell. The torus attached piping penetrations 4-in. in diameter or greater, the HPCI and RCIC 2-in. diameter condensate drain penetrations, and the four torus penetrations to the ECCS suction header were modified as described.

The piping systems attached to the suppression chamber, including the suction ring header, are supported to withstand the loads generated from torus motions during normal and accident conditions. The following torus attached piping systems were evaluated: PCAC, HPCI turbine exhaust, HPCI condensate drain, RCIC turbine exhaust, RCIC off-gas, loops A and B of RHR, Core Spray discharge piping, and Hard Pipe Vent. The Emergency Core Cooling System (ECCS) suction ring header is part of the Primary Containment and therefore is supported to meet the as-analyzed conditions. The junctions of the ring header and the pump suction piping to the A and B loops of RHR and Core Spray, HPCI and RCIC are supported with T-stoppers. The T-stopper design consists of two snubbers and struts on either side of a suction pipe juncture with the ring header. By design, these T-stopper supports virtually eliminates any Mark I program hydrodynamic load input from the suction header to the suction lines (Reference 75). Therefore, the portion of the suction lines beyond these supports are analyzed to B31.1 load combinations instead of Mark I program combinations.

Small bore piping in the envelope requiring analysis was modified to meet code allowable stress levels with the installation of expansion loops.

The suppression chamber and vent system design discussed above has been evaluated for the effects of LOCA-related loads and SRV discharge-related loads defined by the Nuclear Regulatory Commission Safety Evaluation Report NUREG-0661 (Reference 23) and the General Electric Report NEDO-21888, “Mark I Containment Program Load Definition Report” (Reference 116). A detailed discussion of these evaluations and their results are provided in the Monticello Mark I Containment Long Term Program Plant Unique Analysis Reports (References 72 and 75). See USAR Section 5.2.3.2 for further discussion. 01101248

Access from the Reactor Building to the pressure suppression chamber is provided through two manholes with double gasketed bolted covers. These access ports are bolted closed when Primary Containment integrity is required (Reference 145). A test connection is provided between the double gaskets on each cover such that gasket tightness can be checked without pressurizing the containment.

A vent from the Primary Containment System is provided that is normally closed, but can permit the vent discharge to be routed to the Standby Gas Treatment System so that release of gases from the Primary Containment is controlled, with the effluents being filtered and monitored before discharge through the off-gas stack. Test connections are provided between the double inlet and outlet valves to permit checking for leak tightness.

A zero inch corrosion allowance was specified for the suppression chamber according to the original manufacturer's data report found in USAR Appendix F page F.B-1. However, engineering analysis justified a 1 mil design metal loss (corrosion) allowance for the suppression chamber.

5.2.2.4 Containment Penetrations

5.2.2.4.1 Electrical Penetration

Electrical penetration seals were designed to accommodate the electrical requirements of the plant. These are functionally grouped into low voltage power and control cable penetration assemblies, high voltage power cable penetration assemblies, and shielded cable penetration assemblies. All canister type electrical penetration seals have essentially the same basic configuration shown in Figure 5.2-2. The modular type electric penetration assembly basic configuration is shown in Figure 5.2-2a. The assemblies are sized to be inserted in the 12-in. schedule 80 penetration nozzles which are furnished as part of the containment structure. The principal penetrations are listed in Table 5.2-3a.

On canister type penetrations, header plates conforming to the inner diameter of the penetration nozzle are provided at each end of the penetration assembly, forming a double pressure barrier. On modular type penetration X-101a, double electric conductor seals and a single aperture seal are provided. Double aperture seal is provided by a leak-chase-channel that monitors the EPA/nozzle weld. Radiation Shielding is attached to many of the penetrations on the drywell side to provide external access to the electrical connections during plant operation.

The design and fabrication of the canister type of penetration assemblies is in accordance with the requirements of ASME, Section III, Class B Vessel (Reference 112). The modular type of penetration assembly X-101a and penetrations X-106 and X-107 meet ASME, Section III, Subsection NE, Class MC 2004 Code Edition and 1980 Code edition with Summer 1980 Addenda respectively (Reference 125 and 118). Materials of construction are self-extinguishing in accordance with ASTM-D635. The modular type of penetration assembly X101a and penetrations X-106 and X-107 meet IEEE Standard 317, 1976 (Reference 119).

The electrical penetrations were designed to withstand environmental conditions present during a postulated loss-of-coolant accident, as well as maintaining containment integrity for extended periods of time at a post-accident environment. These conditions, including the original (historical) normal operating environment condition, are shown in Table 5.2-2.

The installed assemblies are designed to withstand a continuous internal pressure of 125 psi during normal environmental conditions, and to meet a leak rate of 1.16 x 10^{-6} cc per second when pressurized to 62 psig with dry helium at an ambient temperature of 175°F. These conditions were verified prior to installation in the primary containment. Once installed, penetration assemblies are periodically tested. Penetrations X-106 and X-107 are designed to meet a continuous internal pressure of 62 psi during accident environmental conditions, and to meet a leak rate of less than 1.0 x 10^{-6} cc per second dry helium at this pressure.

Penetration X-101a is designed to meet a continuous internal pressure of 62 psi during accident environmental conditions. The design gas leak rate of this penetration is not greater than 1.0x10^{-2}cc per second of dry nitrogen at the design temperature and pressure.

5.2.2.4.1.1 Low Voltage Assembly

The low voltage assembly is suitable for voltages of 600 V or less and is designed for conductors varying in size from 18 to 4/0 awg. The cables are grouped and passed through openings in the header plates as shown in Figure 5.2-3. Potting compound is applied at each end of the penetration to seal the assemblies. Cables are terminated at either splices, or at environmental-resistant connectors. The maximum wire density is restricted to 42% of the end flange cross-sectional area.

5.2.2.4.1.2 Shielded Signal Cables

Shielded signal cables are provided to interconnect low noise circuits between the reactor and the control room; in particular, the reactor neutron monitoring channels. Figure 5.2-4 shows a cut-away view of the containment penetration assembly for shielded signal cables. One type of circuit uses coax connectors mounted directly on the header plates and is isolated from ground. Another type of circuit uses connectors mounted on the penetration assembly auxiliary structure. The cable density is restricted to one circuit per 3 square inches of header plate surface for the first type, and approximately 80 circuits of the latter type for each 12-in. penetration nozzle. Penetrations X-106 and X-107 have six triaxial connectors and one thermocouple connector (with 18 circuits). All connectors are mounted as above on the header plate (see Figure 5.2-5a). Penetration X-101a can accomodate shielded twisted pair and triples, coaxial and triaxial circuits (See Figure 5.2-2a.

5.2.2.4.1.3 High Voltage Cable

A sectional view of the high voltage power cable penetration assembly is shown on Figure 5.2-5. The penetration assembly accommodates voltages up to 5 KV and cables as large as 1000 MCM and is designed to maintain low gas leakage rates and high insulation resistance. The high voltage cables are passed through openings in the header plates and potting compound applied to both sides of the header plates to effect a pressure seal. The header plates are constructed of nonmagnetic stainless steel in order to eliminate the possibility of eddy current heating.

5.2.2.4.2 Piping Penetrations

Pipe penetrations are of two general types; i.e., those that accommodate thermal movement (hot), and those that experience relatively little thermal movement (cold).

Fluid piping penetrations for which movement provisions are made are high temperature lines such as the main steam line and certain other reactor auxiliary and cooling system lines. A typical penetration of this type is shown in Figure 5.2-6. These penetrations have a guard pipe between the hot line and the penetration nozzle in addition to a double-seal arrangement. This permits the penetration to be vented to the drywell should a rupture of the hot line occur within the penetration. The guard pipes are designed to the same pressure and temperature as the fluid line and are attached to a penetration head fitting, a one-piece forging with integral flues or nozzles. These were designed to the ASME, Section III, Class B (Reference 112). The penetration sleeve is welded to the drywell and extends through the biological shield where it is welded to a bellows which in turn is welded to the guard pipe. The bellows accommodates the thermal expansion of the drywell. A double bellows arrangement permits leak testing of the penetration seal. The lines are constrained to limit the movement of the line relative to the containment, yet permit pipe movement parallel to the penetration.

Small bore lines which connect to high-pressure systems, such as instrument lines and control rod drive hydraulic lines, do not have a double-seal penetration sleeve. These lines are either bunched in groups of six lines and welded in a single pipe sleeve or shop welded in large groups directly to the drywell plate. The mechanical problems involved with this number of small penetrations in a relatively small area make it impractical to provide individual penetration sleeves. The pipes are designed to deflect with the drywell shell.

Penetration details of cold piping lines are shown in Figure 5.2-7. The pipe sleeve which attaches to the drywell is designed for 62 psig, but because of structural thickness, can withstand a substantially higher pressure. No bellows are required, since thermal expansion is minimal. A tabulation of the type of penetration used for each service is shown in Table 5.2-3a.

All pipes that penetrate the Primary Containment are welded to a containment sleeve with the sleeve welded to the containment shell. There is no direct weldment of the pipe to the containment shell.

5.2.2.5 Primary Containment Auxiliary Systems

5.2.2.5.1 Spray Cooling System

A spray cooling system is provided in both the drywell and suppression chamber for post-accident use. Water pumped through the RHR heat exchangers can be diverted to either or both the drywell and suppression chamber. These sprays condense steam that may exist in either chamber and, therefore, substantially reduce pressure in the containment. Since this system is part of the RHR system, it is further described in Section 6.2.3.

5.2.2.5.2 Cooling and Ventilation System

The primary containment ventilating and cooling system consists of four air coolers which cool the atmosphere to below a 135°F bulk average drywell temperature during normal plant operation. This temperature is assumed as an initial condition for evaluation of NPSH for the ECCS pumps (References 79, 80, 182, and 183). The drywell atmosphere is circulated through the drywell and the air coolers by fans, and the reactor building closed cooling water system is employed to remove heat from the air coolers. By maintaining the bulk average drywell temperature well below the 150°F localized limit during normal plant operation, the insulation on motors, isolation valves, operators and sensors, instrument and electrical cables, and sealants used in the penetration have a sustained life. 01101248

5.2.2.5.3 Containment Isolation Valves

Table 5.2-3b (Primary Containment Automatic Isolation Valves) provides a listing of all the primary containment automatic isolation valves along with pertinent information specific to each valve listed (e.g., isolation signal, actuation mode, normal operating position, closure time, etc.). Table 5.2-3a provides a listing of containment penetrations with specific description and applicable Appendix J type test.

Effluent lines such as main steam lines which connect to the reactor primary vessel or which are open to the primary containment have air, solenoid, or motor operated valves. Studies have shown this arrangement to have a high reliability with respect to functional performance. These valves are closed automatically by the signals indicated in Table 5.2-3b.

On inflowing lines either of two valve arrangements is used. Either both isolation valves in series are self-actuated check valves, one inside and one outside the containment, or one is a check valve and the other is a power-operated valve (electric motor, solenoid, or air). On lines where flow may be in either direction, both valves are power operated. See Section 5.2.1.2.2 for isolation criteria exceptions.

TIP system guide tubes are provided with an isolation valve which closes automatically upon receipt of proper signal and after the TIP cable and fission chamber have been retracted. Valve position (full open or full closed) of the automatic closing valves is indicated in the control room. In series with this isolation valve, an additional or backup isolation shear valve is included. Both valves are located outside the drywell. The function of the shear valve is to assure integrity of the containment even in the unlikely event that the other isolation valve should fail to close, or the chamber drive cable should fail to retract if it should be extended in the guide tube during the time that containment isolation is required. This valve is designed to shear the cable and seal the guide tube upon an actuation signal. Each shear valve is operated independently. The valve is an explosive type valve, DC operated, with monitoring of each actuating circuit provided.

In the event of a containment isolation signal, the TIP system receives a command to retract the traveling probes for all mechanisms. Upon full retraction, the isolation valves are then closed automatically. If a traveling probe is jammed in the tube run such that it does not retract, instruments supply this information to the operator, who in turn investigates to determine if the shear valve should be operated.

Process lines which do not connect to the reactor primary system or open into the primary containment, are provided with at least one remotely operated valve located outside the primary containment, a check valve on the influent line outside the containment, or a valve on the influent line that is normally closed.

Instrumentation piping connecting to the reactor primary system which leaves the primary containment is dead-ended at instruments located in the reactor building. These lines are provided with a flow limiting check valve as well as manual isolation valves.

The inboard primary containment isolation for the control rod drive hydraulic system is provided by the double seals for the withdrawal lines and by a ball check valve for the insert lines in each control rod drive mechanism. The outboard primary containment isolation for the withdrawal lines is provided by the scram discharge vent and drain valves and the hydraulic control unit (HCU) directional control valves. The outboard primary containment isolation for the insert lines is provided by the charging and cooling water check valves, HCU accumulator, and the HCU directional control valves with each hydraulic control unit. This design has been reviewed and found acceptable by the NRC (References 103, 104, 105, and 106).

Each motor operated valve is provided with limit switches which are used to indicate that the valves are either open or closed. Each motor operated valve is capable of being actuated from the main control room.

Motive power for each of a pair of power-operated isolation valves in series is normally from physically independent sources to preclude the possibility of a single malfunction interrupting power to both valves. Air-operated valves which close for the normal containment isolation mode, fail closed on loss of air pressure. Electric motor operated valves fail as is. Solenoid valves fail closed on loss of power.

All containment isolation valves, including their power operators, are designed to operate under the most extreme ambient conditions of pressure, temperature, etc., to which they may be exposed after a major accident. Alternately, as noted in Table 5.2-3b, automatic isolation valves may be de-activated and secured in their closed position at reactor coolant temperature greater than 212°F. All isolation valves in lines connecting to the reactor primary system and all accessible welded pipe connections were fully radiographed to assure their integrity (References 141, 142, 143 and 144). They are built to the applicable ASME Codes and all nuclear interpretations applying to these codes. Due to concerns over motor operated valve performance raised by NRC Generic Letter 89-10 (Reference 120) and ensuing supplements, a safety assessment of containment isolation motor operated valves was performed. Although the assessment confirmed that all of the valves were operable, upgrades were made during the 1991 refueling outage to increase performance margins (Reference 100).

Two Main Steam Isolation Valves (MSIVs) are welded in a horizontal run of each of the four main steam pipes, with one valve as close as possible to the primary containment barrier inside and the other just outside the barrier. The valves, when closed, form part of the reactor system process barrier for openings outside the primary containment, and part of the primary containment barrier for nuclear supply system breaks inside the containment.

The main steam isolation valves are shown in Figure 5.2-8. The Monticello valves are nominal 18-in. in diameter. High pressure, high temperature steam flows through the valves. The valves are designed for saturated steam at 1250 psig and 575°F with a moisture content of approximately 0.23%.

The design objective for the valves is a minimum of 40 years service at the specified operating conditions. The estimated operating cycles (full stroke) per year are 100 cycles during the first year and 50 cycles per year thereafter.

In addition to minimum wall thickness required by applicable codes, a corrosion allowance of 0.088 in. minimum is added to provide for 40 years service.

The control unit for each MSIV is attached to its air cylinder and contains the pneumatic control valves and solenoid valves used for opening, closing, and slow speed exercising of the main valve. Remote manual switches in the control room enable the operator to operate or close each valve for exercising or testing. The description and testing of the controls for the main steam line isolation valves are included in Section 7.6.

The main steam line valve installations are designed as Class I equipment to resist the design basis earthquake (see Section 12). Each valve assembly is manufactured to withstand the design basis seismic forces applied at the mass center assuming the cylinder/spring operator is cantilevered from the valve body and the valve is located in a horizontal run of pipe. The stresses caused by horizontal and vertical seismic forces are considered to act simultaneously and are added directly. The stresses in the actuator supports caused by seismic loads are combined with the stresses caused by other live and dead loads including the operating loads. The control valves and other equipment provided in the valve assemblies are designed, manufactured, and shop tested in accordance with applicable portions of the applicable revision of the following codes:

ANSI B31.1 and B16.34, USAS B31.1 and B16.5
ASME, Sections I, III, and VIII

5.2.2.5.3.1 Description of Inboard MSIVs

The inboard MSIVs are wye pattern globe valves. The main disc or poppet is attached to the lower end of the stem and moves in guides at a 45° angle from the inlet pipe. Normal steam flow tends to close the valve and inlet pressure tends to hold the valve closed.

The diameter of the poppet seat is approximately the same size as the inside diameter of the pipe, and the 45° angle permits streamlining of the inlet and outlet passage to minimize pressure drop during normal steam flow and to avoid blockage by debris. The pressure drop at 102% of rated power is approximately 9.45 psid (Reference 175). The valve backseats in the fully open position to prevent leakage through the stem packing. The bonnet has provisions for seal welding in case leaks develop after the valve has extensive service. 01101248

The upper end of the stem is attached to a combination air cylinder and hydraulic dashpot that is used for opening and closing the valve and for speed control respectively. Speed is adjusted by a valve in the hydraulic return line alongside the dashpot; the valve closing time is adjustable between 3 and 10 sec.

The cylinder is supported on large shafts screwed and pinned into the valve bonnet. Four of the shafts are also used as guides for the helical springs. These springs maintain the valves in the closed position once they are shut by the valves' air operator. The springs exert downward force on the spring seat member which is attached to the stem. Spring guides prevent scoring in normal operation and prevent binding if a spring breaks. The spring seat member is also closely guided on the support shafts and rigidly attached to the stem to control any eccentric force in case of a broken spring.

Original design specification ambient operating conditions for the inboard MSIVs are 135°F normal, 150°F maximum at 100% humidity, in a radiation field of 15 R/hr gamma and 25 R/hr neutron plus gamma, continuous for design life. The normal and accident temperature, humidity and radiation levels associated with the environmental qualification of the MSIVs is provided in the EQ Central File Part B, Environmental Specifications. The evaluation of qualification was submitted to the NRC in Reference 181. 01101248

The normal pilot and main pneumatic supplies for the inboard MSIVs are provided by the plant Instrument Nitrogen System at a nominal pressure of 105 psig. If the Instrument Nitrogen System becomes unavailable, the supply will automatically transfer to the Instrument Air System or safety grade Alternate Nitrogen System. Refer to Section 10.3.4 for more information on the Instrument Nitrogen System, Instrument and Service Air System, and the Alternate Nitrogen System.

When spring seat member position for an inboard MSIV corresponds to a valve open position of 90% or greater, a pair of switches on the valve are actuated and provide input to the reactor scram logic, as described in Section 7.6.1.2.6. Allowable scram trip settings are addressed in the Technical Specifications. Separate single switches actuate individual MSIV position indication lights in the Main Control Room when the associated valve is either fully open or fully closed.

5.2.2.5.3.2 Description of Outboard MSIVs

The outboard MSIVs are double disc gate valves equipped with spring actuated operators. The valves are designed to meet the two main requirements for MSIVs - rapid closure under steam line break conditions and leak tight seating at low differential pressures.

The valve body pattern is an 18-in. venturi design having a class 900 pressure rating. The key feature of the valve is its four piece double disc wedge assembly. An upper and lower wedge are attached to the bottom of the valve stem. Connected loosely to each wedge is an independent disc, one facing upstream and the other facing downstream. Each disc has one flat seat which runs parallel to a corresponding valve body seat which is also flat. Sealing is achieved when the body and disc seats are lined up with each other and pressed together from the outward force of the wedges and system pressure. A 1/8 in. diameter hole is installed in the upstream disc of each valve to prevent pressure locking of the valve during depressurization following upstream hydrostatic testing of the steam lines or reactor vessel. Each valve is equipped with a hard faced backseat on the stem to minimize and mitigate packing leakage.

The valve wedge assembly is designed to impart sufficient thrust, by itself, on each disc to maintain a leak tight seat at low differential pressures. As the differential pressure across the disc increases, the force imparted on the disc from system pressure also increases thereby providing a greater sealing force and maintaining a leak tight seat throughout the entire range of operating differential pressures. The wedging design also permits rapid valve closure without seat distortion. Internal moving parts decelerate independently of each other with the result that inertial forces are dissipated

in a series of impacts over a period of time. The largest of these is transmitted directly to the bottom of the valve body on a non-sealing surface.

The outboard MSIV actuators are mounted vertically on their respective valve's yoke. The actuator provides closing thrust using springs only. Pneumatic pressure (280 psig nominal) is required to open the actuator and cock its springs. The main components of the actuator are cylinder, piston, springs, and hydraulic dashpot. The springs and dashpot are located above the piston inside the actuator cylinder. A shaft is connected to the piston and penetrates the bottom of the actuator where it is directly coupled to the valve stem. The dashpot controls the closing speed of the actuator. Dashpot speed control valves and hydraulic oil reservoir are located externally on the actuator at its top; valve closing time is designed to be adjustable between 3 and 10 sec.

The outboard MSIVs have design specification normal maximum operating conditions of 135°F, 90% humidity, and 2.5 x 10^6 rads of integrated dose over 40 years (Reference 149). The normal and accident temperature, humidity and radiation levels associated with the environmental qualification of the MSIVs is provided in the EQ Central File Part B, Environmental Specifications. The evaluation of qualification was submitted to the NRC in Reference 181. 01101248

The pilot and main pneumatic supplies for the outboard MSIVs are provided by the Instrument Air System and Outboard MSIV Main Air Supply System, respectively. Refer to Section 10.3.4 for more information on the Instrument and Service Air System and the outboard MSIV main air supply.

When steam position for an outboard MSIV corresponds to a valve open position of 90% or greater, a pair of switches for the valve are actuated and provide input to the reactor scram logic, as described in Section 7.6.1.2.6. Allowable scram trip settings are addressed in the Technical Specifications. Separate single switches actuate individual MSIV position indication lights in the Main Control Room when the associated valve is either fully open or fully closed.

The outboard MSIVs are designed to close with a maximum differential pressure of 1000 psid. The steam dome pressure for the outside primary containment steam line break has been analyzed and shows that the steam dome pressure is less than 1000 psia after two seconds for all analyzed scenarios. The MSIVs are designed to close in 3 to 10 seconds. Thus the differential pressure across the outboard MSIV for an outside primary containment steam line break will be less than 1000 psid (Reference 175). 01101248

5.2.2.5.4 Vent and Vacuum Relief System

Automatic vacuum relief devices are employed to prevent the primary containment from exceeding the external design pressure. The primary containment is designed for external pressure not more than 2 psi greater than the concurrent internal pressure. The containment is periodically vented to eliminate pressure fluctuations caused by temperature changes during various operating modes. This is accomplished through ventilation purge connections which are normally closed while the reactor is at a temperature greater than 212°F. The suppression chamber is vented separately. The drywell vacuum relief valves draw the atmosphere from the pressure suppression chamber and the pressure suppression chamber vacuum relief device draws air from the reactor building in the event vacuum conditions develop.

The suppression chamber vacuum relief system consists of two vacuum breaker valves in series in each of two lines which are joined into one larger line attaching to the suppression chamber.

One of each pair of vacuum breakers is an air-operated butterfly valve which is AC solenoid-controlled from a differential pressure switch signal and is designed to fail open on loss of power and loss of air. A safety grade nitrogen supply system is available to close these vacuum breakers if instrument air pressure is lost (see 10.3.4.2 for additional information on the alternate nitrogen supply system). The second vacuum breaker is a self-activating swing check and is designed to start opening at a negative pressure differential of 0.25 psi and is full open if the pressure differential should drop to a negative 0.5 psi. The combined pressure drop at rated flow through both valves does not exceed 2 psi, the suppression chamber design external pressure.

5.2.2.5.5 Containment Monitors

Monitors which indicate and record containment pressure and hydrogen concentration in the containment atmosphere are provided in the control room as required by NUREG-0737 (Reference 121), Items II.F.1.4 and II.F.1.6 (see 5.2.2.7 for additional information on hydrogen monitors).

A wide-range monitor system which continuously indicates and records the water level in the suppression pool is provided in the control room as required by NUREG-0737, Item II.F.1.5.

5.2.2.6 Primary Containment Atmospheric Control System

The primary containment atmospheric control system introduces a nitrogen atmosphere into the primary containment. By reducing the oxygen content, hydrogen generated by a metal-water reaction with the fuel cladding during early phases of loss-of-coolant accidents cannot ignite and damage the containment structure. The system is capable of reducing and maintaining the oxygen content of the atmosphere to less than four percent by volume.

The equipment for the primary containment atmospheric control system performs two functions: 1) initial purge of containment; and 2) automatic control of the supply of make-up gas (nitrogen).

The system utilizes a liquid nitrogen supply and a steam vaporizer for initial purging. The steam vaporizer unit converts the liquid nitrogen into a gas. As a gas, the nitrogen then flows through a pressure reducing valve and flow meter into the drywell and pressure-suppression chamber of the primary containment.

The drywell ventilation coolers are utilized during the purging operation to maximize the mixing of nitrogen and oxygen. Primary containment pressure is maintained by either venting the gas to the standby gas treatment system or the reactor building exhaust. The makeup supply utilizes a liquid nitrogen supply and an atmospheric vaporizer.

Instrumentation in the control room indicates oxygen concentration in the primary containment.

An air purge fan with ducting to the nitrogen purge line is incorporated as part of the atmospheric control system. This arrangement permits restoration of a breathable atmosphere within the drywell and suppression chamber prior to maintenance operations.

Debris screens are installed on the drywell and wetwell purge and vent penetrations. The function of the primary containment debris screens is to prevent the entry of foreign material into the purge and vent lines during a postulated design basis accident.

The Primary Containment Atmospheric Control System P&ID is shown in Drawing NH-36258, Section 15, and the Primary Containment Nitrogen Control System P&ID is shown in Drawing NH-46162, Section 15.

5.2.2.7 Containment Atmosphere Monitoring System

The containment atmosphere monitoring system was installed in response to NUREG-0737, “Clarification of TMI Action Plan Requirements”. It was originally installed as a safety grade system intended for use after an accident to monitor the hydrogen and oxygen concentration in the drywell and suppression chamber and shares a common sample point for the post-accident sample system. The revised 10CFR50.44 no longer defines a design-basis LOCA hydrogen release, and eliminates requirements for hydrogen control systems to mitigate such a release. The hydrogen monitors are required to assess the degree of core damage during a beyond design-basis accident. If an explosive mixture that could threaten containment integrity exists during a beyond design-basis accident, then other severe accident management strategies, such as purging and/or vent, would need to be considered. The hydrogen and oxygen monitors are needed to implement these severe accident management strategies. The amended rule implements performance-based requirements for hydrogen and oxygen monitors to be functional, reliable, and capable of continuously measuring the appropriate parameter in the beyond-design accident environment. (References 155 and 156).

The system consists of two redundant and independent monitoring divisions with each division having an analyzer panel, associated valves and piping, separate sample points, and associated electrical control and indication powered from one of the emergency divisions. The primary containment nitrogen control system P&ID shown in Drawing NH-46162, Section 15, has been revised to show the addition of this system. The Containment Atmosphere Monitoring System is shown on Drawing NH-91197, Section 15.

5.2.2.8 Suppression Pool Temperature Monitoring System

The Suppression Pool Temperature Monitoring System (SPOTMOS) is an integral part of the overall post-accident monitoring capability of the plant. The SPOTMOS consists of two independent and redundant divisions. The safety function of the SPOTMOS is to provide the plant operator with reliable information on the suppression pool temperature such that the plant can be operated within Technical Specification limits. All electrical components for the system are classified as Class 1E. The mechanical and pressure boundary components are Quality Group B and meet the seismic requirements for Class I equipment. In addition, the system is designed in accordance with the applicable portions of the Nuclear Regulatory Commission Safety Evaluation Report NUREG-0661 (Reference 23) and Regulatory Guide 1.97, Revision 2 (Reference 122) (except for the power supply). Applicable SPOTMOS equipment has been environmentally qualified as required by MNGP’s EQ program (see Section 8.9.1). Each division of the SPOTMOS is physically separated from the other, and either division is capable of providing an accurate measure of the suppression pool bulk temperature.

Each division of the SPOTMOS has eight thermowells located in each of the Safety Relief Valve discharging bays of the suppression chamber. The thermowells are located approximately symmetrically around the outside of the suppression chamber at the centroid elevation of the suppression pool water mass. The centroid elevation is below the suppression pool minimum level, so that uncovering of the thermowells after a postulated LOCA event will not occur. The thermowells for each division in each discharging bay are located approximately 6 ft apart. The locations of the thermowells on the suppression chamber wall were chosen so that the response of the thermowells would lead to a conservative determination of the bulk temperature.

A detailed description of the Suppression Pool Temperature Monitoring System is provided in the Monticello Mark I Containment Long Term Program Plant Unique Analysis Report and its Appendix (Reference 72).

5.2.2.9 Hard Pipe Vent System

The Hard Pipe Vent System (HPV) provides a vent path from the pressure suppression chamber (the wetwell) vapor space to a release point above the Reactor Building. The vent path is comprised of an 8-in. penetration in the top of the suppression chamber, two pneumatically operated primary containment isolation valves, a rupture disc, a radiation monitor and piping routed from the primary containment penetration through secondary containment and up the outside of the Reactor Building to a point above the roof. Controls and indication for the HPV are located on or near the Alternate Shutdown System (ASDS) panel.

5.2.3 Performance Analysis

5.2.3.1 Sizing of the Primary Containment

The design parameters for the primary containment system are based on data obtained from tests conducted by the Pacific Gas & Electric Company for the proposed Bodega Bay Reactor in 1962 (Reference 3). These tests and subsequent analysis identified the parameters which most strongly influence the performance of pressure suppression systems. These parameters include:

a. Ratio of the design break area to the total vent flow area.

b. Ratio of the drywell volume to the wetwell air volume.

c. Downcomer submergence in pool water.

d. Vent system flow resistance.

The design basis break/vent area ratio for the Bodega tests was 0.0194. The equivalent break flow area for Monticello is 4.09 sq-ft which would result in a vent flow area of 4.09/0.0194 = 211 sq-ft. The original Monticello design was based on an equivalent break flow area of 5.6 which resulted in a vent flow area of 288 sq-ft. The installed design consists of eight vents having a total minimum area of 286 sq-ft. The accident analysis discussed in Section 5.2.3.2 was calculated on the basis of 286 sq-ft vent area.

The reactor vessel and associated auxiliary equipment dictate the required drywell dimensions. The lower part of the drywell is a sphere 62 ft inside diameter; the upper part of the drywell is a cylindrical shell of 33 ft inside diameter by 46 ft 4-1/2 in. high. When these volumes are combined, the free volume of the drywell vessel, including the vent tubes is 134,200 cu. ft.

The minimum suppression chamber air volume is 103,340 cu. ft. which gives a maximum drywell/wetwell air volume ratio of 1.29 compared to 1.42 for most of the Bodega tests. The Bodega data and analysis show that a variation of this magnitude has a negligible effect on the containment pressure transient. The effects that other containment geometric parameters have on the LOCA hydrodynamic loads were investigated as part of the Mark I Containment Program (see Section 5.2.2.3) in the Full Scale Test Facility (FSTF) and the Quarter-Scale Test Facility (QSTF). Although, the FSTF geometry resembled the Monticello containment, selected FSTF features were adjusted to ensure a conservative development of the loads.

The water volume in the suppression chamber is sized to absorb the energy release from a loss-of-coolant accident without exceeding the thermal limits established as a result of the Bodega pressure suppression development tests. The suppression chamber water level is monitored by two wide range water level instruments. The maximum end of blowdown bulk pool temperature was established at 170°F. The Monticello design contains a minimum water volume of 68,000 ft^3 and the resulting pool temperature during a reactor blowdown does not exceed 170°F assuming an initial pool temperature of 90°F (Reference 167). 01101248 During normal operation, the pool temperature is maintained less than 90°F and is only allowed to rise above that value for short durations during RCIC or HPCI testing (Reference 140). Procedural controls limit the pool temperature when the reactor is pressurized so that the 170°F end of blowdown temperature is not exceeded in the event of a LOCA. Temperature is monitored by SPOTMOS; see discussion in Section 5.2.2.8.

The minimum downcomer submergence for the Monticello wetwell design is 3 ft. General Electric has performed a functional assessment of reducing the downcomer minimum submergence from a nominal 4.0 ft to 3.0 ft (Reference 54). The Bodega tests demonstrated complete condensation of the steam with no submergence. The vent/header/downcomer system was designed to yield the same total flow resistance as the Bodega test geometry.

Quencher devices are provided at the termination of each of the eight safety-relief valve discharge lines. The quencher devices ensure stable steam condensation at expected pool temperatures during safety relief valve discharges.

5.2.3.2 Containment Response to a Loss of Coolant Accident and SRV Actuations 01101248

5.2.3.2.1 Containment Dynamic Response

The loads considered in the original design of the containment included dead weight loads, seismic loads, and pressure and temperature loads associated with normal operating conditions and a postulated LOCA event. Additional Mark I hydrodynamic loads resulting from postulated LOCA events and SRV actuations were subsequently identified then defined and assessed during implementation of the Mark I Long Term Program (LTP) as described in USAR section 5.2.3.5.4 (Mark I Containment Program). These additional loads include pool swell, vent system thrust, condensation oscillation, chugging loads, and SRV discharge loads associated with a design basis accident (DBA), intermediate break accident (IBA), small break accident (SBA), and SRV actuation. They are defined by General Electric Report NEDO-21888, “Mark I Containment Program Load Definition Report” (LDR) (Reference 116) and Nuclear Regulatory Commission Safety Evaluation Report NUREG-0661 (Reference 23). Using the guidance of NEDO-21888, Monticello plant specific time history plots for vent thrust loads and pool swell loads, and containment temperature and pressure for enveloping DBA, IBA, and SBA events were developed and compiled in GE report NEDO-24576, “Mark I Containment Program Plant Unique Load Definition Monticello Nuclear Power Plant” (PULD) (Reference 73).

The impact of all postulated containment loads and load combinations defined by the LDR and PULD on the suppression chamber, vent system, suppression chamber internal structures, SRV discharge line piping, torus attached piping, and suppression chamber penetrations were evaluated at original licensed thermal power conditions. A detailed discussion of these evaluations and their results are provided in the Monticello Mark I Containment Long Term Program Plant Unique Analysis Reports (PUARs) (References 72 and 75). The overall conclusions of the PUARs are that the stresses and reactions applied to the evaluated components and structures as a result of the postulated loads and load combinations are within the allowable limits. The PUARs were reviewed and approved by the NRC (Reference 94). 01101248

NUREG-0661 requires that procedures be specified to initiate the automatic depressurization system (ADS) by manual operator action within the 10 minute time period assumed in the LDR in order to limit chugging duration for a SBA. This requirement was addressed by the BWR Owners’ Group (BWROG) Emergency Procedure Guidelines (EPG’s) (References 172 and 178). Chugging is the cyclic condensation of steam at the downcomer openings of the drywell vents. When a steam bubble collapses at the exit of the downcomers, the rush of water drawn into the downcomers to fill the void induces stress at the junction of the downcomers and the vent header. Repeated application of such stresses could cause fatigue failure of these joints, thereby creating a direct path between the drywell and torus airspace. Steam discharged through the downcomers could then bypass the suppression pool and directly pressurize the torus airspace.

Scale model tests demonstrate that chugging occurs only when flow through the downcomers is low and the drywell atmosphere contains more than 99% steam. Chugging can thus be prevented by maintaining the drywell noncondensible fraction above 1%. The condition can be maintained by operating drywell sprays. Initiating sprays reduces drywell pressure, opening the drywell-to-torus vacuum breakers and drawing noncondensibles back into the drywell. The drywell noncondensible content thus remains high enough to preclude chugging. While the drywell noncondensible content cannot be monitored directly, an EPG action level has been established based upon torus pressure. As drywell noncondensibles are purged to the torus airspace and replaced by steam, torus pressure increases. The drywell noncondensible content can thus be related to torus pressure. For conservatism, drywell sprays are initiated at a torus pressure corresponding to a drywell noncondensible content of 5%. This is the “Suppression Chamber Spray Initiation Pressure (SCSIP),” defined to be the lowest pressure which can occur when 95% of the noncondensibles in the drywell have been transferred to the torus. The SCSIP for Monticello is defined in each cycle specific emergency operating procedure (EOP) calculation in accordance with EPG guidance. The SCSIP is implemented at a drywell pressure of 12 psig in the EOPs, since the torus pressure indicating range does not extend to the SCSIP (Reference 179). The BWROG EPG’s are the basis for Monticello’s EOPs (see USAR section 13.7).

The RHR intertie line was installed after issuance of the PUARs. Consequently, another analysis (Reference 89) was performed to evaluate the pool swell loads on the torus shell and internals. The maximum suppression pool mass was used in order to maximize the pool swell loads which resulted in a slightly higher peak pressure than reported in Reference 73. The pool swell loads increased by less than 1% due to the increased drywell pressure. The RHR intertie line was therefore determined to have a negligible impact on containment loads.

01101248

The containment response to dynamic loads resulting from postulated LOCA and SRV actuation events has been re-evaluated for plant operation at 2004 MWt extended power uprate (EPU) conditions (Reference 167 and 168). The LOCA containment dynamic loads analysis for EPU conditions is based primarily on the short-term LOCA analyses. These analyses were performed using the Mark I LTP method, except that the break flow was calculated using a more detailed RPV model (Reference 176) and includes the break area of the RHR intertie line. The application of this model to EPU containment evaluations is identified in GE Report NEDC-32424P-A (Reference 177). These analyses provide calculated values for the controlling parameters for the dynamic loads throughout the blowdown. The key parameters are drywell and wetwell pressure, vent flow rates and suppression pool temperature. The LOCA dynamic loads evaluated included pool swell, vent system thrust, condensation oscillation, and chugging loads.

The short-term containment response conditions at EPU conditions are within the range of test conditions used to define the pool swell and condensation oscillation loads for Monticello in accordance with the LDR (Reference 116). The long-term response conditions that are present when chugging would occur under EPU are enveloped by the range of conditions used in the LDR to define the chugging loads. The vent thrust loads were calculated to be less than the plant specific values contained in the PULD (Reference 73). Therefore, the LOCA dynamic loads and load definitions determined for original licensed thermal power conditions are not affected by EPU.

The SRV loads at EPU conditions were evaluated for two different actuation phases: initial actuation and subsequent actuation. Loads due to initial SRV actuation are determined by parameters including the SRV setpoints, SRV Discharge Line (SRVDL) volume, line lengths and friction losses, and number of turns. Because all these parameters including the SRV setpoints do not change, loads due to initial SRV actuations are not impacted by EPU. Loads due to subsequent SRV actuations depend primarily on the SRVDL reflood height at the time of SRV opening and SRV setpoints. The number of SRV cycles will increase with EPU due to a higher steaming rate at increased decay power levels. EPU will also reduce the minimum postulated time between SRV actuations. However, the time between actuations is still well above the 5.75 second time required to re-establish the SRV discharge line equilibrium height, which is independent of reactor power level (see USAR section 4.4.2). The SRV low-low set logic prevents subsequent SRV actuations until after the SRVDL reflood level stabilizes to the equilibrium height. Consequently, the SRV loads and load definitions due to initial and subsequent SRV actuations are not changed for EPU (References 167,168, and 180). 01101248

The containment hydrodynamic loads resulting from postulated LOCA events or SRV actuations were also evaluated at Maximum Extended Load Limit Line Plus operating domain conditions. The results of this evaluation demonstrate that existing vent thrust, pool swell, condensate oscillation, and chugging load definitions remain bounding. In addition, there are no changes to the SRV actuation loads (Reference 184). 01101248/01457570

Since the LOCA dynamic loads and SRV actuation loads determined for original licensed thermal power conditions are not affected by plant operation at EPU and MELLLA+ conditions, the results of the PUARs (References 72 and 75) are bounding and governing for 2004 MWt conditions. The NRC concluded that the containment response to dynamic loads resulting from postulated LOCA and SRV actuation events at EPU and MELLLA+ conditions is satisfactory (Reference 169 and 185).

5.2.3.2.2 Design Basis Accident of Coolant Accident (DBA-LOCA) Break Area

The total break area is equal to the sum of all parallel flow areas. With the RHR Intertie line valves open, the break area is given by (see Figure 5.2-9):

$A_B = A_R + A_E + NA_N$

where:

A_B = Total equivalent break area

A_R = Flow area of recirculation line = 3.616 ft^2

A_E = Flow area of RHR Intertie line valve port = 0.08 ft^2

N = Number of jet pumps on one header = 10

A_N = Flow area of a single jet pump nozzle = 0.0399 ft^2

Therefore,

A_B = 4.095 ft^2

5.2.3.2.3 Containment Temperature and Pressure Response

Short and long term thermodynamic calculations were performed in support of extended power uprate (EPU) (Reference 167) and to determine the limiting containment response for emergency core cooling system (ECCS) pump net positive suction head (NPSH) (References 79, 80, 81, 182, and 183). The NRC concluded that the containment response at EPU conditions was satisfactory (Reference 169). 01101248

The parameters used in the containment response evaluations are provided in the Containment Analysis Input Parameter Form (OPL-4A). The major parameters from the form are listed in Table 5.2-7. The OPL-4A form (Reference 166) also includes the basis for each containment parameter. The assumptions, computer codes, initial conditions, and methods used in the LOCA containment response evaluations are described in References 167, 168, and 171. The decay heat assumptions are described in Reference 171. Various accident scenarios were developed to support short term and long term (as required) maximum containment response to small break, intermediate break, DBA, steam line breaks, EQ, and Mark I loads. NPSH minimum containment response evaluations were completed for DBA, ATWS, SBO and Appendix R. Further evaluations were completed to demonstrate that there is minimal impact on suppression pool temperature from performance of containment cooling using any of the available modes including suppression pool cooling, containment spray or core injection cooling. Drywell spray is considered the normal mode of containment cooling to comply with EOP requirements from the expected drywell pressure response. 01101248

Short-term (<30 seconds) bounding EPU thermodynamic containment analyses of a double-ended pipe break for a recirculation suction line (DBA-LOCA) were developed and evaluated. These analyses cover the blowdown period where the maximum drywell airspace temperature and pressure occurs. Peak drywell pressure for a DBA-LOCA is reached within about 6 seconds. (As break size decreases, the time to reach peak drywell pressure increases. The short-term thermodynamic analyses utilized assumptions to maximize the peak DBA-LOCA drywell pressure. The drywell and wetwell short-term peak pressure and temperature responses are shown in Figure 5.2-oa (Reference 167).

The MNGP short term containment response for MELLLA+ operation was evaluated. The pressure and temperature results were less limiting than those for the existing design basis, i.e. 2004 MWt in the MELLLA operating domain. The long term containment response does not change for MELLLA+ (Reference 184). 01457570

For DBA-LOCA the reactor quickly blows down due to the large break size. The vessel pressure drops too rapidly for the high-pressure coolant injection system to supply any makeup water. At the time of the break, it is assumed that the off-site AC power is lost with the limiting single active failure of one emergency diesel generator (EDG) considered for containment analysis only. The emergency core cooling system (ECCS) power must, therefore, be supplied by the remaining EDG. This causes a delay of more than 30 sec before rated ECCS flow is available (See Table 14.7-13). 01101248

The maximum pressure and temperature expected in the containment as a result of a DBA-LOCA are 44.1 psig and 291°F, respectively (Reference 167). The bounding maximum pressures and temperatures postulated for all LOCA break cases are summarized in Table 5.2-4. For the drywell compartment, the maximum pressure and temperature occur early in the DBA-LOCA during the blow down phase. At this time the inertial effects of the flow in the vent system cause the drywell to remain at a much greater pressure than the wetwell. These high pressures are quickly dissipated as can be seen in Figure 5.2-oa. 01101248 01101248

The long-term containment response to a postulated recirculation suction line break is illustrated in Figures 5.2-ob, p and q. Figure 5.2-ob shows the expected pressures in the drywell and pressure suppression chamber (wetwell). After the vessel is flooded, ECCS flow cascades from the break and quenches the steam in the drywell rapidly dropping the drywell pressure. The wetwell-to-drywell vacuum breakers open and allow nitrogen to return to the drywell.

EOP guidance requires use of containment spray if pressure is not maintained below 12 psig. The containment response analysis assumes a river temperature of 90°F. Use of containment spray with a cooler river will reduce containment temperature and pressure from what is shown in the analysis. EOP guidance notes that containment pressures below 8.6 psig may not provide adequate NPSH for the ECCS pumps. It is recognized that operator action is required to maintain adequate NPSH by throttling pump flow from the unrestricted ECCS pump flow rates provided to reflood the core. (Reference 79, 81, and 169). 01101248

The drywell temperature response is plotted in Figure 5.2-p. Figure 5.2-q gives the suppression pool temperature response. The wetwell airspace is assumed to be in thermal equilibrium with the suppression pool for the first 30 seconds as the large vent flow promotes mixing. Thereafter the energy and mass transfer is mechanistically modeled (Reference 167).

The wetwell experiences its maximum temperature later in the transient than the drywell. The suppression pool continues to heat up due to decay heat from the reactor and the transfer of heat from the reactor, reactor internals and coolant to the suppression pool. The heat is transferred to the pool by the steam and ECCS water coming out of the reactor and flowing through the vent system. Eventually the residual heat removal (RHR) system is able to turn the transient around and remove the heat from the pool faster than it is added. This turn-around point corresponds to the maximum suppression pool temperature. The timing of when this point occurs is a function of how fast heat is transferred from the reactor to the suppression pool. A DBA-LOCA provides the fastest heat transfer and results in a peak at about 9-10 hours. Slower heat transfer rates such as from an SBA event delays when the peak occurs (Reference 167). After the temperature transient turns around, RHR containment spray/cooling will be operated for an extended period of time required by the long-lived radioactivity remaining in the core until a normal or alternate method of decay heat removal has been established. This event assumes the loss of an emergency diesel generator, which limits containment spray/cooling to one division of RHR. If the operator were to use the full RHR capacity or if river temperature was lower such that increased containment cooling capacity exists, then this transient would turn around sooner, and the maximum suppression pool temperature would be less. 01101248 01101248 01101248

During the long-term containment response for a DBA-LOCA (after blow down of the reactor vessel is complete), heat transfer to the suppression pool continues and passive containment heat sinks are assumed. A variable heat exchanger K-value is used that is a function of the hot RHR inlet temperature for suppression pool cooling cases. Limitations in model capability did not allow use of a variable K-value for containment cooling with containment spray cooling (References 167 and 171). The effects of decay energy, stored energy, and energy from metal-water reaction on the pool temperature are considered. This long-term analysis uses the minimum Technical Specification value for the suppression pool volume and the associated vent submergence to maximize the suppression pool temperature. 01101248

One operator option is to align the RHR in the containment spray mode. This would quench the steam in the containment airspace and rapidly drop the temperature and pressure.

For the DBA-LOCA, it is assumed that the operator realigns one RHR pump, starts one RHR service water pump, and initiates flow through the RHR heat exchanger to initiate containment cooling at 10 minutes into the event. One core spray pump operating at the design injection rate of 3020 gpm delivered to the sparger spray nozzles is assumed to continue to provide vessel injection after 10 minutes. 01101248

The design temperature of piping attached to the wetwell establishes the long-term wetwell temperature limit. The limiting piping design temperature is 212°F. The limit is not exceeded with RHR service water temperatures of up to 90°F (Reference 168 and 170).

The effect of various containment cooling methods on the peak suppression pool temperature during a DBA-LOCA was evaluated (References 167). The cooling methods included suppression pool cooling, containment spray cooling, and coolant injection cooling. The calculated peak suppression pool temperatures for each case are within a few degrees and are below the bounding design value of 212°F. 01101248

5.2.3.2.4 Licensing Basis Ultimate Heat Sink Limit

The long term containment analysis was evaluated in References 167 and 168 and accepted in Reference 169. This established the licensing basis value for service water temperature. 01101248 The design-basis service water temperature for the long-term, loss-of-coolant accident calculations and for NPSH calculations covering small break accidents, Appendix R, station blackout and ATWS events is 90°F. 01101248

5.2.3.3 Containment Temperature and Pressure for ECCS Pump NPSH

Under certain conditions containment pressure is required to assure adequate NPSH is available for operation of RHR and Core Spray pumps following a loss of coolant accident. All accidents and license basis events were evaluated. Those events requiring specific analysis included DBA-LOCA, SBA, Appendix R, SBO and ATWS (References 79, 80, 81, 169, and 183).

A detailed assessment of the use of containment accident pressure (CAP) in relation to the MNGP RHR and CS pumps was performed (Reference 182). The assessment was based on comparison to sections 6.6.1 through 6.6.10 of Enclosure 1 to SECY 11-0014 (Reference 82). The evaluation concludes that the MNGP ECCS pumps can reliably perform their required design functions to mitigate the consequences of accidents and events for the required mission time while using appropriate uncertainties defined for NPSHreff for DBA-LOCA and NPSHr for all other events evaluated. The ECCS pumps meet the requirements of SECY-11-0014, Enclosure 1.

For the long term and short term DBA-LOCA evaluations, 21% and 23% uncertainty, respectively, were applied to the NPSHr values to define NPSHreff for the evaluation of pump capabilities to support ECCS analysis assumptions. NPSHr for a pump is defined as the suction head at which cavitation impacts the head performance leading to a three percent loss in head at a given flow and pump speed. During an NPSHr test, the pump is run at a constant flow and speed with the suction head reduced gradually to the point where cavitation and a 3% head loss are observed. The uncertainties in NPSHr included in the staff's guidance address the possibility that conditions during the NPSHr vendor tests could be different than those seen by the pumps during operation at the plant, effectively increasing the NPSHr values. The differences could arise due to pump inlet temperature variation, pump inlet piping geometry variation, dissolved gas evolution, variation in pump speed, vendor test uncertainty and increases in mechanical wear ring clearance. 01101248

NPSHreff = (1 + uncertainty)NPSHr3%

In addition to the application of uncertainties on the pump NPSH required values assuming EPU conditions, conservative assumptions of post-accident conditions were considered in the calculation of the NPSHa, including: worst single failure, suppression pool temperature maximized, calculated suppression pool level response, pump run-out flow, maximum containment leakage, head loss due to LOCA generated debris on suction strainers, and other conservatisms listed in Table 4 of SECY 11-0014, Enclosure 1 (References 79, 80, 81, and 82).

At MNGP, the limiting Design Basis Accident (DBA) for consideration of the impact of NPSHr is the large break LOCA with failure of the LPCI loop select logic. The analysis is divided into two parts; a short-term analysis and a long-term analysis. Results from these bounding analyses are presented in Figures 5.2-oc (short term < 600 sec) and Figures 5.2-od (long term ≥ 600 sec). The short-term analysis covers that period from the time of the break until operator action is taken to throttle the ECCS pumps and establish containment cooling. This period is defined as occurring at or before 600 seconds. For conservatism, during the short-term analysis, LPCI flow is assumed to be injected into the broken loop for this event. This results in the minimum system

resistance for LPCI and therefore the maximum pump run-out flow rate for these pumps. Two CS pumps are available to quench fuel temperatures and reflood the core to 2/3 core height. Since all six ECCS pumps are available for this scenario, the pump suction piping system resistance is maximized which results in the minimum NPSHa. NPSH is assessed (Reference 182) for these conditions and the potential impact on pump reliability has been assessed.

There is a short period of several minutes after the core is reflooded to 2/3 core height where NPSHa < NPSHreff3%. This condition exists until the ECCS pumps are throttled to support long term scenario assumptions, i.e. after 600 seconds. The impact of having negative margin for NPSH has been assessed (Reference 182) including pump reliability and the capability of the ECCS to provide flow rates required to support the ECCS analysis for demonstration of adequate core cooling. When operator action is taken to throttle the pumps to reduce pump flow rate NPSH margin is restored. For the DBA-LOCA indication of level restoration in the reactor to 2/3 core height is expected prior to 300 seconds. At this point it is acceptable to throttle the ECCS pumps to establish conditions for long term operation.

Failure of an emergency diesel generator or battery in combination with a loss of off-site power results in the availability of one CS pump to maintain core cooling, one RHR pump to cool containment and one RHRSW pump to remove decay heat from the RHR heat exchanger. This configuration defines the limiting set of equipment in service for the long-term analysis, i.e. after 600 seconds. In this mode of operation the operators will control RHR pump flow through the RHR heat exchanger at a nominal rate of 4000 gpm. One CS pump will be in service for core cooling at a flow rate of 3020 gpm delivered to the CS sparger nozzles and one RHRSW pump is operating at a nominal flow rate of 3500 gpm. RHR is conservatively assumed to be operating in containment spray mode. CS flow to the reactor must be increased above 3020 gpm by the amount required to include leakage for the CS delivery system inside the reactor (Reference 182). For smaller break sizes the core may be re-flooded to above top of active fuel. In this case flow delivered to the reactor can be reduced while maintaining the core covered.

01101248

RHR pump flow rate is assumed to be increased to account for the pump minimum flow valve failing open due to loss of air pressure on the air accumulator after 10 minutes. It is assumed that indicated pump flow is maintained at 4000 gpm to provide required flow thru the RHR heat exchangers.

The other license basis events evaluated (i.e., ATWS, SBO, and Appendix R) used NPSHr with no uncertainties applied for the evaluation of pump capability and reliability. The remaining aspects of sections 6.6.1 through 6.6.10 of Enclosure 1 to SECY 11-0014 were considered for these events(References 79, 80, 81, 182, and 183).

5.2.3.4 Hydrogen and Oxygen Generation in Containment

Following a loss-of-coolant accident (LOCA), hydrogen gas may be generated in the reactor containment as a result of:

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

b. Radiolytic decomposition of the coolant solution during the post-accident situation, with oxygen also being produced in stoichiometric amounts and

c. Corrosion of metals by solutions used for emergency cooling or containment spray.

5.2.3.4.1 Metal-Water Reaction

If Zircaloy in the reactor core is heated to temperatures above approximately 2000°F in the presence of steam, a chemical reaction occurs in which zirconium oxide and hydrogen are formed. This is accompanied with an energy release of approximately 2800 Btu/lb of zirconium reacted. The energy produced is accommodated in the suppression chamber pool. The metal water reaction is explicitly accounted for in the containment analyses (Reference 167). 01101248

Code of Federal Regulations, Section 50.44, requires all boiling-water reactor (BWR) Mark I and Mark II type containments to be inerted. By maintaining an oxygen-deficient atmosphere, combustible gas combustion that could threaten containment integrity is prevented (Reference 164).

5.2.3.4.2 Radiolysis

After the initial metal-water reaction has occurred, hydrogen continues to be formed along with stoichiometric amounts of oxygen because of radiolysis of the coolant solutions.

The revised 10 CFR50.44 no longer defines a design-basis LOCA hydrogen release, and eliminates requirements for hydrogen control systems to mitigate such a release. (Reference 156).

5.2.3.4.3 Corrosion Reactions

Hydrogen generation due to aluminum corrosion would be the chief corrosion reaction expected. The aluminum corrosion rate is only significant when alkaline solutions are used for reactor cooling. Generally the reaction rates are small and the zirconium-water reaction is predominant.

5.2.3.5 Miscellaneous Containment Performance Analyses

5.2.3.5.1 Seismic Analysis for Primary Containment

John A. Blume and Associates of San Francisco, California have made a seismic study of the drywell and the pressure suppression chamber. The analyses were based on the seismic criteria defined in Section 12. The results of these analyses are summarized in Appendix A. The torus ring header was the subject of a similar study by J. A. Sexton and Associates.

The drywell was designed on the basis of the acceleration and damping factors recommended by Blume and Associates. A mathematical analysis was made idealizing the drywell structure as a lumped mass system supported by elastic columns (the reactor building) at fixed locations. Curves of acceleration, shear force, moment, and displacement were plotted for various elevations of the structure. The most severe N-S and E-W accelerations were combined with a recommended .04 g vertical acceleration to analyze the structure. A damping factor of 3% was used for the drywell design.

Using this information, the drywell, pressure suppression chamber, and torus ring header have been analyzed to determine the adequacy to resist the stresses induced by an earthquake coincident with a break in the main steam or recirculation pipelines. The suppression chamber, vent system, torus attached piping, and suction header were also analyzed for load combinations including seismic and hydrodynamic loads resulting from LOCA-related and safety relief valve discharge events. These analyses were reported in the Monticello Mark I Containment Long Term Program Plant Unique Analyses (References 72 and 75).

5.2.3.5.2 Drywell Expansion Gap Design Allowance

The steel drywell shell is largely enclosed within the structural and shielding concrete of the reactor building. Thermal expansion, as a result of a normal reactor operation or postulated accidents, causes the steel shell to expand both radially and tangentially. To accommodate this expansion, an air space was provided between the concrete and the drywell shell.

From other considerations, such as missiles and possible local high pressure jets from postulated breaks in the steam line, it is desirable that the concrete structure be as close to the drywell shell as possible to prevent rupture of the steel shell from jet or missile impingement.

The maximum expansion, considering the expansion due to pressure and the expansion due to temperature, occurs at the transition between the spherical lower portion and the cylindrical upper portion of the drywell. This expansion is approximately 1.2-in. which is less than the 2-in. gap provided. Further, a shell deflection of 2-in. is well under the nearly 3-in. total deflection necessary to rupture the steel shell, according to the tests (Reference 6).

In the construction method used at Monticello to achieve the gap, 2-in. thick sheets of Ethafoam, slightly compressible material, were sprayed with silicone lubricant and attached to the drywell to provide a removable form. Concrete was poured in 3-ft lifts against the Ethafoam. After the concrete was set, the

Ethafoam was pulled out. Each lift was inspected to ensure that a 2-in. gap had been achieved. After this inspection, a strip of porous polyurethane foam was inserted to prevent objects being dropped into the air gap. This method provides positive assurance that the gap is achieved and that no foreign objects have been inadvertently left therein. Since the polyurethane strip is very soft, its compression does not induce any undue stresses on the containment vessel shell. Drainage of this space is permitted by drains installed above the sand pockets at elevation 920.5 ft in addition to drainage that occurs through the shield penetrations. This material is so porous that drainage is not inhibited and ventilation is not prevented.

5.2.3.5.3 Drywell Missile Protection

Missile protection is given special consideration under assumed accident conditions. The following summarizes the pertinent design consideration.

The driving force for potential missiles within the containment is assumed to come from the energy within the working fluid. In the case of a break in a pipe carrying liquid, the maximum liquid velocity attainable at the break is 200 ft/sec because of choking. Similarly, the velocity of fluid from a steam line break is limited to the critical velocity of 1500 ft/sec at the break. The drag force of the fluid which propels any potential missile is proportional to the product of the density and the velocity squared. Even though the velocity of the steam exceeds that of the water, the even larger ratio of water density to steam density at containment ambient conditions means that projectiles originating from a water line have a greater drag force applied, and therefore achieve a larger kinetic energy.

Consideration was given to the possibility of having missiles in the following forms:

a. Valve bonnets (large and small)

b. Valve stems

c. Thermowells

d. Vessel head bolts

e. Instrument thimbles

f. Nuts and bolts

g. Pieces of pipe

Missiles originating from steam lines were neglected as being insignificant relative to missiles originating from liquid lines. All small missiles propelled by liquid were assumed to achieve and maintain until impact the maximum liquid velocity of 200 ft/sec. This is conservative because a missile after being dislodged requires a finite time for acceleration before it can approach a velocity of 200 ft/sec. In addition, for missiles directed in a horizontal direction, there is a tendency for the missile, which is traveling slower than the driving jet, to fall out of the jet as it is acted upon by gravity. Therefore, the driving force acts for a shorter time and the missile achieves a lower maximum velocity.

Using the above conservative design criteria it was found that no small missiles (e.g., thermowells, small valve components, etc.) originating from the liquid lines would achieve sufficient energy to penetrate the drywell nor was there sufficient strain energy in the pressure vessel head bolts to cause penetration.

The method of calculation used to determine the energy required to penetrate the containment shell is based on extensive tests conducted by the Stanford Research Institute. During these tests rod shaped missiles were impacted against square steel plates having clamped edges. The results of the tests have been described by the following expression for minimum energy per unit diameter of missile required for perforation of a steel plate:

$$\frac{E}{D} = U\,(0.344T^2 + 0.032T)$$

where

E = Critical kinetic energy required for penetration, ft-lbs

D = Diameter of missile, in.

U = Ultimate tensile strength, psi

T = Plate thickness, in.

This equation has been plotted for the various thickness of the drywell shell and is shown in Figure 5.2-23.

The most serious potential missile appeared to be a dislodged valve bonnet originating from a recirculation loop valve. It was assumed that the face of the bonnet (35-in. diameter) was acted upon by the water jet, and that the massive (3000 lbs) bonnet-stem assembly impacted with the containment with the stem (4-in. diameter) making initial contact. This is a conservatively chosen event because it requires that all bolts holding the bonnet sever completely, that the bonnet and stem move as a massive unit and that the stem end (smallest impact area) strike the containment first.

The valve bonnet is so heavy, it would achieve a kinetic energy of 1,860,000 ft-lbs, if it were traveling at 200 ft/sec. Therefore, a more refined calculation was necessary to show that a velocity of 200 ft/sec is not actually attained. This calculation found that the bonnet would have to accelerate a distance of about 20 ft and reach a velocity slightly in excess of 33 fps in order to acquire the energy (52,000 ft-lbs) necessary for the 4-in. diameter bonnet to penetrate the 0.6875-in. containment.

It was determined from the arrangement of components within the drywell that, even though the recirculation valves are oriented such that a dislodged valve bonnet could strike the containment directly, there is either insufficient distance available between the stem and drywell to achieve the energy necessary to penetrate, or the bonnet is deflected by obstructions, hangers, or uneven failure of the bolting.

It has been shown in experiments conducted by CB&I (Reference 6) that large loads acting over an area of 1.08 sq-ft on a plate 3/4 in. thick would not cause cracking to develop in the plates until a deflection greater than 3-in. had occurred. Since the drywell shell is reinforced by concrete, located nominally 2-in. away, it appears improbable that objects having a large impact area are

able to penetrate the steel without also penetrating the concrete. As stated above, small missiles do not achieve a high enough velocity to attain an energy level sufficient to penetrate sound containment shell material. Therefore, it is concluded that missile penetration of the containment is a highly improbable event.

Where possible, consideration has been given to achieving missile protection through basic plant component arrangement such that, if failure should occur, the direction of flight of the missile is away from the containment vessel. In addition to the care with which equipment is oriented with regard to missiles, special care has been taken in component arrangements to see that equipment associated with engineered safety systems, such as the core spray and the containment spray, were segregated in such a manner that the failure of one would not cause the failure of the other. The failure of any component which would bring about the need for these engineered safeguards systems does not render the system inoperable. Additionally, the control rod drive mechanisms are located in a concrete vault that provides protection from potential missiles. The suppression chamber has no source of internal or external missile generation and the vent pipes connecting it to the drywell are protected by the jet deflectors. The vent discharge headers and piping were designed to withstand the jet reaction force caused by flow discharge into the suppression pool.

The primary containment vessel is completely enclosed in a reinforced concrete structure having a thickness of 4 to 6 ft. This concrete structure, in addition to serving as the basic biological shielding for the reactor system, also provides a major mechanical barrier for the protection of the containment vessel and the reactor system against potential missiles generated external to the primary containment. The space between the containment vessel and the concrete is controlled so that areas which are backed up by concrete withstand the jet forces which may occur upon failure of any system piping. Where concrete is not available, such as at the vent openings, barriers were placed for jet protection.

All large pipes which penetrate the containment were designed so that they have anchors or limit stops located outside the containment to limit the movement of the pipe. These stops were designed to withstand the jet forces associated with the clean break of the pipe and thus maintain the integrity of the containment. Jet forces which may act on the containment were taken as equal to reactor pressure acting directly on the containment over an area equal to the cross-sectional area of the largest local pipe or nozzle. The recirculation lines within the primary containment have been provided with a system of pipe supports designed to limit excessive motion associated with a pipe split or circumferential break.

5.2.3.5.4 Mark I Containment Program

For the Mark I containment design, the pressure and temperature loads associated with a LOCA were based on experimental technology obtained from testing of the Bodega Bay and Humboldt Bay Power Plant pressure suppression concepts. The tests were performed to demonstrate the viability of the pressure suppression concept for reactor containment design by simulating the LOCA with various equivalent piping break sizes up to twice the cross-sectional break area of the largest reactor system pipe. The test data provided quantitative information for establishing containment design pressures.

In performing large scale testing of an advanced design pressure-suppression containment (Mark III), and during in-plant testing of Mark I containments, suppression pool hydrodynamic loads not explicitly included in the original Mark I containment design basis were identified. These additional loads could result from dynamic effects of drywell air and steam being rapidly forced into the suppression pool during a postulated LOCA, and from suppression pool response to SRV operation generally associated with plant transient operating conditions. Since these hydrodynamic loads were not explicitly considered in the original design of the Mark I containment, the NRC staff in early 1975 requested a detailed reevaluation of the containment system from each domestic utility with a Mark I containment.

Recognizing the joint need to respond to the NRC requests for additional information and the essential similarity of all the Mark I plants, the domestic Mark I utilities formed an Owners Group on April 23, 1975. The Owners Group provided a strong, unified, and consistent approach to resolution of the open issues through the pooling of individual resources. The Mark I Owners Group retained the General Electric Company to develop and manage a program which would address and resolve the stated concerns.

A two-phase program was established; it was described to the NRC in letters submitted during the week of May 5, 1975. The Phase I effort, called the Short Term Program (STP), provided a rapid confirmation of the adequacy of the containment to maintain its integrity under the most probable course of the postulated LOCA considering the latest available information on the important suppression pool dynamic loads. The first phase demonstrated the acceptability of continued operation during the performance of Phase II, called the Long Term Program (LTP). The LTP included detailed testing and analytical work to define precisely the specific hydrodynamic loads for which each containment would be assessed to establish conformance to the original intended design safety margins.

The STP was completed in late 1976 following the docketed submittal by each utility of the documentation listed in References 7 through 17. Review of this documentation by the NRC subsequently resulted in the issuance of the Mark I Containment Short Term Program Safety Evaluation Report in December 1977 (Reference 18). This report concluded that licensed domestic BWR Mark I facilities could continue to operate safely, without undue risk to the health and safety of the public, during an interim period while the Long Term Program was conducted.

In June 1976, activities relevant to the Long Term Program commenced. A detailed description of the Long Term Program and plans for its implementation are available in References 19 and 20. Extensive experimental and analytical programs performed by the members of the Mark I owners group yielded new insights relative to load definition and structural assessment techniques as set forth in References 21 and 22. The methodology utilized as reviewed and accepted by the NRC provides a conservative and uniform basis for the evaluation of containment structures and torus attached piping to ensure the margin of safety as per the original containment design. See Reference 23 for the NRC’s acceptance criteria utilized in the formulation of the methodology employed by the program. Documents concerning the experimental and analytical programs undertaken for the Long Term Program are presented as References 24 through 62. The Monticello Long Term Program Plant Unique Analysis Reports (References 72 and 75) documents the efforts undertaken to

address and resolve each of the applicable Reference 23 requirements. The Monticello Long Term Program Plant Unique Analysis Reports were reviewed by the NRC Staff and found to verify that the containment modifications made have restored the original design safety margin to the Mark I containment at the Monticello Plant (Reference 94).

The Monticello Mark I Long Term Program performed uncoupled dynamic analyses of the suppression chamber and suppression chamber attached piping systems. Another acceptable approach is to perform a dynamic analysis in which the suppression chamber and associated piping are combined in a single coupled model (References 75 and 94).

In May, 1982, a number of concerns regarding the adequacy of the General Electric (GE) Mark III containment design were raised by a former GE employee, J M Humphrey. Although these concerns were specifically raised for the Mark III Containment, the Nuclear Regulatory Commission (NRC) felt that some of the issues may apply to the Mark I Containment design. In July, 1982, the NRC requested the Mark I Owners Group to address those concerns which they had identified as being potentially applicable to the Mark I Containment. A generic response was prepared and transmitted by the Mark I Owners Group in References 90 and 91. Independently, a review was performed of the applicability of the generic responses to Monticello and is documented in Reference 92. The conclusions of both the generic responses and review for applicability were that the “Humphrey Containment Concerns” were either not applicable or were being adequately addressed under the Mark I Containment Program.

The Monticello Nuclear Generating Plant takes advantage of the large thermal capacitance of the suppression pool during plant transients requiring safety/relief valve (SRV) actuation. Steam is discharged from the main steam lines through the SRVs and their accompanying discharge lines into the suppression pool where it is condensed, resulting in an increase in the temperature of the suppression pool water. Stable steam condensation is expected at all pool temperatures (References 150 and 151). If an extended steam discharge to the suppression pool under stagnant and saturated conditions were to occur, it could create the potential for a steam plume or steam bubbles being ingested by the ECCS pump strainer inlets. Evaluation of this concern determined that it is not an issue for the Monticello Nuclear Generating Plant (References 152 and 153).

5.2.3.5.5 Suppression Chamber - to - Drywell Allowable Bypass Leakage

The suppression chamber - to - drywell vacuum breakers protect the drywell from damage by a drywell negative pressure differential that could result with most of the non-condensable gas collected in the torus above the suppression pool after the water vapor in the drywell condenses following a design basis loss-of-coolant accident. Concerns were raised in Reference 160, that a partly open vacuum breaker would permit steam to bypass the suppression pool following loss-of-coolant accidents causing higher than design containment pressure. In response to Reference 160, calculation was provided in Reference 161, that showed the drywell to suppression chamber leak rates that could be tolerated for primary system break areas as large as the design basis accident (DBA) break. The results showed the variation in allowable drywell to suppression chamber leakage with the primary system break area. For primary

system breaks greater than 0.3 $ft.^2$, the allowable drywell to suppression chamber leakage increases, i.e., the drywell to torus equivalent bypass leakage increases from about 0.2 $ft.^2$ to more than 1 $ft.^{2.}$ For primary system breaks less than 0.3 $ft.^2$, the allowable drywell to torus leakage is less than 0.2 $ft.^2$. The calculated drywell to torus bypass leakage equivalent to that from a 0.2 $ft.^2$ (6 inch diameter) equivalent orifice has been reviewed in Reference 162 and was found to be a justifiable limit for the entire range of core coolant breaks up to the design basis accident.

5.2.3.6 Primary Containment Auxiliary Systems

5.2.3.6.1 Cooling and Ventilation Systems

Maintaining the bulk average drywell ambient temperature less than 135°F and localized temperatures below 150°F during normal plant operation assures that the insulation on motors, isolation valves, operators and sensors, instrument cable, electrical cable and gasket materials or sealants used at the penetrations will have a sustained life. Drywell atmosphere is circulated through the drywell and the coolers by fans, and the reactor building closed cooling water system is employed to remove heat from the air coolers. Four coolers are provided. One of these coolers is designed for use as a spare during normal operation. A separate fan located outside the drywell is used to purge the drywell before the drywell is entered for maintenance or inspection.

5.2.3.6.2 Isolation System

Since a rupture of a large line penetrating the containment and connecting to the reactor coolant system may be postulated to take place at the containment boundary, the isolation valve for that line is required to be located within the containment. This inboard valve in each line is required to be closed automatically on various indications of reactor coolant loss. Additional reliability is added if a second valve is located outboard of the containment and as close as practical to the containment. This second valve also closes automatically if the inboard valve is normally open during reactor operation. If a failure involves one valve, the second valve is available to function as the containment barrier. The two valves in series are provided with independent power sources.

Main Steam Isolation Valve closure is required in the case of a steam line break outside the primary containment. An analysis of a complete sudden steam line break outside the primary containment is described in Section 14. It shows that the fuel clad is protected against loss of cooling if main steam isolation closure takes as long as 10.5 sec. The calculated radiological effects of the radioactive material assumed released with the steam are shown to be well within the 10CFR50.67 guide values for an accident.

Closure of the main steam line isolation valves initiates a reactor scram. This scram function is discussed in Section 7.6. The transient resulting from inadvertent isolation of the main steam line is described in Section 14.7.

The ability of these isolation valves to close in a few seconds after a steam line break, under conditions of high pressure differentials and fluid flows, with fluid mixtures ranging from mostly steam to mostly water, has been demonstrated in a series of tests in dynamic test facilities. Dynamic tests with a 1-in. valve show that the analytical method is valid. A full-size, 20-in. valve has been tested in a range of steam/water blowdown conditions simulating postulated accident conditions. The description, results, and evaluations of these tests have been issued as a report for inclusion in the NRC file of topical reports on General Electric boiling water reactors.

Two redundant isolation valves are provided in each steam line so that either can perform the isolation function, and provisions have been provided for leak rate testing of both valves. The inside valve and the outside valve and their control systems are separated physically. Considering the redundancy, the mechanical strength, the closing forces, and the leakage tests discussed above, the main steam isolation valves satisfy the safety design basis to limit the release of reactor coolant or radioactive materials.

The isolation valves and their installation are designed as Class I equipment. The design of the isolation valve for seismic loadings is discussed in Section 5.2.2.5.3. These loads are small compared with the pressure and operating loads the valve components are designed to withstand.

The TIP system isolation valves are normally closed. When the TIP system cable is inserted, the valve of the selected tube opens automatically. Retraction, when required, is accomplished in a maximum of 1-1/2 minutes. If closure of the valve is required during calibration, the isolation signal causes the cable to be retracted and the valve to close automatically on completion of cable withdrawal. If retraction does not occur, backup is provided by explosive actuated shear valves.

It is not necessary, nor desirable, that every isolation valve close simultaneously with a common isolation signal. For example, if a process pipe were to rupture in the drywell, it would be important to close all lines which are open to the drywell, and some effluent process lines such as the main steam lines. However, under these conditions, it is essential that containment and core cooling systems be operable. For this reason, specific signals are utilized for isolation of the various process and safeguards systems.

Isolation valves must be closed before significant amounts of fission products are released from the reactor core under design basis accident conditions. Because the amount of radioactive materials in the reactor coolant is small, a sufficient limitation of fission product release is accomplished if the isolation valves are closed before the coolant drops below the top of the core.

The main condenser serves as an effective collection point for potential MSIV leakage following a loss of coolant accident. Methods consistent with the Seismic Qualification Utility Group (SQUG) seismic equipment qualification guidelines have been used to assure that the MSIV leakage collection path would remain intact following a design basis earthquake (References 135 and 136). Section 4.0 in the NRC's Safety Evaluation Report for License Amendment 102 (Reference 137) summarizes the review and acceptance of the methodology and conclusions regarding the integrity of the MSIV leakage collection path at Monticello.

5.2.3.6.3 Vent and Vacuum Relief System

The containment temperature is controlled by the Containment Cooling and Ventilation System described in Section 5.2.2.5.2, however, for some major transients such as startup and shutdown, the temperature may change enough to cause a change in pressure. Excess pressure during conditions at which the reactor temperature is less than about 212°F is relieved through the purge line. When the reactor temperature is above 212°F, a 2-in. bypass valve can be opened to vent containment through the Standby Gas Treatment System. Low pressure, resulting from cooling the primary containment atmosphere, is equalized by the addition of air into the torus via the torus-reactor building vacuum breakers, and then into the drywell via the drywell-torus vacuum breakers.

A single 20-in. line from the torus divides to provide parallel paths to the reactor building atmosphere with two vacuum breakers in series in each of the two paths. One of each pair is actuated electrically from AC power by a differential pressure switch signal. The second is self-actuating. The combined pressure drop, at rated flow, through both valves does not exceed the suppression chamber design external pressure (2 psi).

Eight vacuum breaker valves between the suppression chamber and the drywell provide the capability to vent the torus air space gases back to the drywell in order to assure pressure equilibrium between the compartments. Without this capability, the potential exists to exceed the design limits of the vent header and the drywell such that buckling would occur due to external pressure. For Monticello, the design differential pressure is 2 psid for the torus, drywell, and vent system.

5.2.3.7 Penetrations

The following analytical methods were used to evaluate the stresses in the drywell shell due to the penetration loading conditions as specified in Section 5.2.1.3. The analytical methods for the suppression chamber penetrations are described in Reference 75.

The shell stresses resulting from the pipe rupture loads were calculated at the shell nozzle-to-reinforcing insert plate juncture and at the outer edge of the insert plate using the “Bijlaard” method as described in Welding Research Council Bulletin No. 107 (Reference 127). The definition, classification, and combination of stresses was in accordance with paragraph N-414, Table N-413, and Figure N-414 of Section III of the ASME Code (Reference 112). The maximum allowable stress levels in the vessel shell were:

a. Local membrane stresses ≤ 1.5 Sm

b. Local membrane + secondary membrane + secondary bending ≤ 3 Sm

   Where Sm is the allowable stress intensity for the specified material per Section VIII of the ASME Code (Reference 128).

The primary containment shell stresses calculated by the above methods did not exceed the allowable stresses as specified in the ASME, Section III, Subsection B (Reference 112).

The methods used to evaluate the stresses in the penetration nozzles, bellows guard pipes, and process piping were:

a. Penetration nozzles form a part of the primary containment and as such are subject to the same design criteria. The stresses in nozzles resulting from pipe rupture loads were evaluated using the procedures noted above.

b. Original penetration bellows assemblies and expansion joints were designed in accordance with ASME, Section III, 1965 Edition and Code Case No. 1330. The design analysis for the bellows expansion joints is determined by the primary containment design pressure of 56 PSIG and design temperature of 281°F.

   Consistent with ASME Section XI, 1992 Edition, for repair/replacement activities, the replacement bellows assembly for X-16B is designed and fabricated to ASME, Section III, Division I, 1977 Edition up to and including the Winter 1978 Addenda; with materials in accordance with ASME, Section III, Division I, 1980 Edition, including the Summer 1982 Addenda. The later code incorporates Code Case No. 1330 and revises the allowable stress and defined design pressure. These code changes have been reconciled to the original requirements by performance of design analysis for the replacement assembly to 62 psig and 281°F in accordance with the later code.

   Penetration guard pipes for assemblies employing an expansion bellows were designed for the maximum design pressure and temperature of the associated process line with stresses limited to 90 percent of yield strength.

c. The guard pipes have been provided with a continuous jet deflector ring to protect bellows from overpressure resulting from jet impingement loading. The jet deflector ring was designed for this jet impingement with stresses limited to 90 percent of yield strength.

d. Process lines were designed for normal operating loads of pressure, thermal expansion, seismic and dead loads in accordance with the design specification for the associated process system.

   Process lines were not designed to withstand the jet reaction loads; however, pipe restraints, anchors and supports were provided on the pipe penetrations and process line to limit transmission of these loads to the nozzle and vessel shell.

Use of the above methods and procedures has resulted in considerable margin in the penetration design as follows:

a. Limiting the stress to 3 Sm resulted in a maximum stress level equal to 75 percent of the ultimate strength of the material. Use of a 3 Sm as the upper limit for stresses assures that adequate margin is available so that the ultimate load capability of the containment boundary is not reached.

b. The maximum jet force for reaction and impingement was based on nominal line pressure with no reduction due to pressure drop in the system from the reactor vessel to the point of pipe rupture.

c. Conservative assumptions were used for attenuation of the jet impingement loads, i.e., the attenuation factor for curvature of the target pipe was based on two analyses. The first analysis assumed a homogeneous mixture and streamline flow. The procedure consisted of the integration between 0 and $\pi/2$ of $(1 - \cos\beta)\, d\beta$ (Reference 65) and gives an attenuation constant of 0.57. The second analysis considered the "drag coefficient approach" similar to the design of chimneys for wind (Reference 66) and given an attenuation constant of 0.38.

   For the design of the primary containment penetrations, the attenuation constant of 0.57 was used. Such use is conservative.

d. The simultaneous occurrence of the maximum loads due to accident pressure, pipe rupture jet reaction or jet impingement and maximum seismic without consideration to time after accident is conservative.

e. For longitudinal loading from pipe rupture jet reaction of jet impingement, the design of pipe anchors and restraints did not include the internal support from the pipe system or existing pipe suspension.

5.2.3.8 <u>Primary Containment Atmospheric Control</u>

It has been shown in the 10CFR50, Appendix K, analysis of the design basis loss-of-coolant accident that the operation of the reactor core and containment cooling systems maintains continuity of reactor core and containment cooling and flooding such that the extent of the resultant core wide metal-water reaction would be less than 0.2% (Reference 169). The hydrogen produced by a metal-water reaction if mixed with the air in the primary containment would result in a hydrogen concentration of approximately 0.6%. This concentration is significantly below the concentration at which hydrogen could be ignited. Research (Reference 139) indicates that hydrogen cannot be ignited in air if the hydrogen concentration is less than 4%. Data (Reference 67) also indicates that the possibility of a hydrogen-oxygen reaction can be eliminated for all concentrations of hydrogen present if the concentration of oxygen in the primary containment is less than 5%. 01101248

Should a design basis loss-of-coolant accident occur, the safeguards features provided by the reactor core and containment cooling systems prevents generation of quantities of hydrogen capable of being ignited. Inerting is performed, therefore, to meet NRC requirements and preclude hydrogen ignition in the case of degraded safeguards system performance or other postulated instances of inadequate core cooling.

5.2.3.9 Drywell Temperature Analysis for Drywell Wall Temperature 01101248

The effect of steam breaks on the drywell wall were considered to ensure the drywell design temperature of 281°F would not be exceeded. Steam breaks were considered since steam breaks inside the drywell are limiting with respect to drywell temperature and pressure.

Three sizes of steam breaks were considered: 0.01 ft^2, 0.1 ft^2 and 0.5 ft^2. The analysis performed conformed to Part 1, Appendix B of NUREG-0588 (Reference 129 and 167). 01101248

The analysis assumed that containment sprays were initiated when drywell gas temperature reaches 281°F, but not earlier than 10 minutes into the event. The drywell sprays maintain the drywell wall temperatures within the drywell design temperature of 281°F. The wetwell sprays are not required to maintain the wetwell wall temperatures within the wetwell design temperature of 281°F.

The results from the steam line break analysis are included in sections 5.3.1.5 and 5.3.2 of Reference 167 and in the associated output data files attached to Reference 167. The calculated peak drywell wall temperature is 278°F, which occurs during the 0.5 ft^2 break assuming UCHIDA condensing heat transfer to the drywell wall until the wall temperature reaches the saturation temperature for the drywell pressure. The calculated peak drywell gas temperature is 338°F. The limiting temperature envelopes for the drywell and maximum drywell wall temperature are shown in Table 5.2-8 and Table 5.2-4, respectively. The drywell wall temperature does not exceed the original design value. 01101248

5.2.3.10 Post Accident Containment Mixing

No containment post-accident mixing system is required. The Monticello combustible gas control concept is based on maintaining the oxygen concentration below the Safety Guide 7 (Reference 113) limit of 5%. Thus, the only concern from a mixing viewpoint is the potential degree of non-uniformity in oxygen concentration that would occur in the containment. There are three mixing forces existing in the containment after a loss of coolant accident; they are diffusion, natural convection and forced convection. Of these three, the most dominant mixing force would be forced convection. Forced convection would be induced by such things as containment sprays, flow out of the broken pipe, flow through the drywell vent pipes and vacuum relief lines, and the drywell fan coolers, if available. Forced convection is, however, the most difficult mixing force to quantitatively evaluate and detailed calculations of its effects on concentration gradients have not been done.

Detailed calculations have, however, been done on the other two mixing forces, i.e., diffusion and natural convection. The details of this analysis were presented in Amendment 2 to the Duane Arnold Energy Center FSAR in response to question Gl.l(d). These calculations showed that the maximum oxygen concentration deviation would be 2% from the average at the surface of the suppression pool using conservative assumptions relative to the natural convection driving force. Less conservative assumptions for natural convection would result in a maximum concentration deviation of 0.3%. In other words, given an average oxygen concentration of 5%, the maximum concentration at

the suppression pool surface would be 5.10%, or less conservatively, 5.015%. Based on the results of this analysis, it has been concluded that the assumption of a uniform oxygen concentration in the containment is reasonable for performing analyses related to inerted containment operation.

5.2.3.11 Hard Pipe Vent System

The Hard Pipe Vent (HPV) System reduces the vulnerability of primary containment to severe accident challenges which are beyond the analyzed design basis of the plant. The HPV provides a controlled release path to maintain core cooling and to prevent the irreversible and unpredictable rupture of the containment which could otherwise lead to a larger release. The HPV will be used irrespective of the off-site radioactive release rates; however, scrubbing from the suppression pool will minimize the amount of radioactivity released.

The HPV isolation valves are considered manual valves since they are locked closed and are not required to be opened for any design basis accident. To preclude seat leakage past these valves from being discharged through the vent line during a design basis accident, the system is equipped with a rupture disc downstream of the isolation valves.

5.2.4 Inspection and Testing

A program of testing the primary containment system has been developed which includes integrated leakage rate tests of penetrations and valves, and operability tests of isolation valves.

The NRC, by Reference 99, provided NSP with a listing of all clarifications to 10CFR Part 50 Appendix J that had been issued as of January 23, 1991.

5.2.4.1 Primary Containment

Following construction of the primary containment, it was pressure tested at 1.25 times design pressure. Penetrations were sealed with welded end caps. Following the strength test the containment was tested for leakage rate at design pressure. The containment leakage rate was less than 0.2% per day. The suppression chamber was filled to design operating level with water for this test.

After complete installation of all penetrations, an integrated leak rate test of the primary containment and associated penetrations was conducted.

A periodic integrated primary containment leak test is conducted in accordance with the requirements of 10CFR50, Appendix J Option B. The Type A test may be performed in accordance with BN-TOP-1. (Reference 165)

5.2.4.2 Containment Penetrations

Leakage rate tests of penetrations and access openings are conducted to verify the capability of the penetrations to maintain overall containment leakage within acceptable limits. Testable penetrations are tested in accordance with the requirements of 10CFR50, Appendix J Option B.

Whenever a double-gasketed penetration (primary containment head and manway, equipment hatch, CRD removal hatch, and the suppression chamber access hatches) is broken and remade, the space between the gaskets is pressurized to determine that the seals are performing properly. The minimum test pressure of 44.1 psig is consistent with the accident analyses and the maximum preoperational leak rate test pressure. 01101248

The airlock is tested after periods when the airlock is opened and containment integrity is not required and at intervals of not more than 30 months at a minimum pressure of 44.1 psig. 01101248 / 01482495

5.2.4.3 Containment Isolation Valves

The operable isolation valves that are power operated and automatically initiated, are tested for simulated automatic initiation and closure times. Operation of normally-open power-operated valves are verified by fully closing and reopening. The frequency and time intervals, and acceptance criteria for testing are as specified in the Technical Specifications and Technical Requirements Manual (TRM). In response to issues raised by NRC Generic Letter 89-10 and various supplements thereto, a motor operated valve program has been implemented to ensure that all safety-related motor operated valves are selected, set and maintained in a manner that will ensure operation under design basis conditions (Reference 101 and 102).

Main steam isolation valve exercise testing can be accomplished both during reactor operation and during shutdowns. Functional performance and leakage tests must be performed during reactor shutdowns when access to the area of the valves is permitted. Inservice exercising is used to demonstrate operability and to check closure times. These valves may be tested and exercised individually to the 90% open position. It is not necessary to reduce reactor power because the valves still pass rated steam flow when 90% open. Test buttons are provided in the control room to perform this test. Release of the button returns the valve to full open. They may be tested and exercised individually to the fully closed position. With the reactor power reduced to 1600 MWt, the valves can be fully closed, one at a time to check operation and operating time. 01101248 Shutdown tests include actuation and closure time tests to assure that the valves operate properly, that the sensors are set correctly and cause the proper actuation, that the response speed is correct, and that the fail-safe features are operable.

Valves in lines penetrating containment are given Type C local leakage tests in accordance with the requirements of Appendix J where plant design permits such testing to be performed. Modifications to permit proper testing of valves where testing did not conform to Appendix J have been made. In addition, the Commission has granted a specific exemption from the requirement to perform Type C testing for a number of valves (Reference 93). These valves are:

Torus Spray Line	MO-2006, MO-2007
Drywell Spray Line	MO-2020, MO-2021[2]
Torus Recirculation Line	MO-2008, MO-2009

Instrument lines penetrating containment connected to the reactor coolant system are provided with excess flow check valves which limit the flow from a broken line outside containment. These valves are functionally tested each refueling outage. Instrument lines not equipped with these excess flow check valves are connected to sealed transducers and designed to withstand the stresses of a loss of coolant accident. These lines are tested during the containment Type A integrated leak rate test (Reference 93).

Both the inboard and outboard Main Steam Isolation Valves (MSIVs) may be tested by pressurizing between the valves at 25 psig and the total observed leakage through both valves (inboard and outboard) is then conservatively assigned to the penetration. Alternatively, the inboard valves can be tested by pressurizing the upstream side of the valves to Pa and the outboard valves may be tested by pressurizing between the valves to Pa while maintaining a block pressure on the inboard valves to prevent lifting of the inboard valves. The inboard MSIVs are angled in the main steam lines in the direction of flow to afford better sealing upon closure. Type C testing of these valves at a reduced pressure of 25 psig has been approved by the Commission (Reference 93) when pressurizing between the valves. The Main Steam Pathway (main steam lines and main steam line drains) leakage is excluded from the sum of the leakage rates of Type B and C tests, and from the overall integrated leakage rate from Type A tests (Reference 163).

In general, valves in lines which terminate below the surface of the suppression pool do not require Appendix J testing. Since the suppression pool provides an effective water seal, these valves are not relied upon to perform a containment isolation function (Reference 93). The valves in these lines are, by definition, PCIVs and are included in Table 5.2-3a. The valves may have safety functions in the Open and/or Closed position to support other Systems/functions.

The inner airlock equalizing valve is Type C tested individually. The outer airlock equalizing valve is tested during the Type B overall airlock leak rate test. 01488437

2. Subsequent analysis determined that RHR system pressure may not be sufficient to ensure the water seal that was the basis for the NRC approved testing exemption for MO-2020 and MO-2021. As indicated in Table 5.2-3a, Type C appendix J testing is performed on these valves.

5.2.4.4 Containment Ventilation System

The drywell coolers (water-cooled heat exchanger-fan units) are checked at each major outage. Surveillance testing includes monitoring fan and damper performance during the various cooling modes of operation. During normal reactor operation, the temperature indicators in the drywell monitor the effectiveness of the coolers.

Leakage into the drywell is monitored on a continuous basis. Should a leak develop in the drywell coolers, it would show up as an increase in drywell unidentified leakage concurrent with a loss of inventory from the Reactor Building Closed Cooling Water system.

5.2.4.5 Primary Containment Atmospheric Control

Instrumentation is provided in the design to enable analysis of the concentration of oxygen in the primary containment. A sample point from the central drywell area and one from the torus are used to obtain samples of the primary containment atmosphere during plant operation. Drywell fans continuously mix and circulate the drywell atmosphere assuring that the drywell sample is representative of the oxygen concentration value. The oxygen analyzer is located outside the drywell.

Table 5.2-1 Principal Design Parameters of Primary Containment
(Page 1 of 2)

GENERAL	
Metal Material	SA516-70FBX made to A300 standards
Design Code	ASME Code Section III - Class B, 1965 Edition
DRYWELL	
Cylindrical section - diameter	33 ft
Spherical section - diameter	62 ft inside diameter
Drywell overall height	105 ft 10-7/8 in.
Free air volume	134,200 ft^3
Wall plate thickness	
Spherical shell	11/16 in. to 2-1/2 in.
Spherical shell to cylinder neck	2-1/2 in.
Cylindrical neck	Varies 0.635 in. to 1-1/2 in.
Top head	1-5/16 in.
Bottom head	1-1/4 in.
VENT SYSTEM	
Vent pipes	
Number	8
Internal diameter	6 ft 9 in.
Vent tubes flow area, total	286 ft^2
Vent tube entrance area, total	481 ft^2
Vent header internal diameter	4 ft 9 in.
Downcomer pipes	
Number	96
Diameter	24 in. nominal outside diameter
Submergence below absorption pool water level	3 ft min
PRESSURE SUPPRESSION CHAMBER	
Water volume	72,910 ft^3 max; 68,000 ft^3 min
Free air volume	108,250 ft^3 max; 103,340 ft^3 min
Torus minor diameter	27 ft 8 in.
Torus major diameter	98 ft 0 in.

Table 5.2-1 Principal Design Parameters of Primary Containment
(Page 2 of 2)

VACUUM BREAKERS	
Suppression chamber to drywell	
Number valves	8 - 18-inch valves
Vent area, total	1971 in.^{2}
Full Open Pressure	0.5 psid
Actuation time	1 sec
Reactor building to suppression chamber	
Number valves	2 sets of 2 - 20-in. valves (in series)
Vent area, total	628 in.^{2}
Full Open Pressure	0.5 psid
INERTING SYSTEM	
Oxygen in Primary Containment when Inerted, % by Volume	<4
N_2 required for Initial Purge, approximate ft^3	1,000,000
DESIGN CONDITIONS	
Maximum internal pressure and temperature	62 psig @ 281°F
Design internal pressure and temperature	56 psig @ 281°F
Design external pressure and temperature	--
Drywell	2 psig @ 281°F
Suppression chamber	2 psig @ 281°F
Normal internal pressure	0-1.5 psig
Temperature	normal - 135°F; maximum - 150°F

NOTE: For additional containment parameters, see the Containment Data Specification 22A5751, Revision 4 (Reference 131) transmitted to NSP December 28, 1983.

Table 5.2-2 Electrical Penetration Environmental Design Conditions

Normal Operating Environment[1] - Capable of continuous operation at the environmental conditions listed below: 01101248

Parameter	Inside Primary Containment	Outside Primary Containment
Temperature	150°F	60 to 104°F
Pressure	-2 to +2 psig	0 psig
Relative Humidity	20% - 100%	20% - 100%
Radiation Dose (without shielding)	10 R/h	< 1 R/h

Maximum Emergency Environment - Each penetration assembly is capable of maintaining containment integrity when subjected to the environmental conditions listed below. The canister leak rate does not exceed 24 standard cubic centimeters/hour/12-inch penetration.

Parameter	Inside Primary Containment
Temperature	281°F
Pressure	62 psig
Relative Humidity	100% RH

1. Normal operating environmental values are the original design criteria. The radiation dose rate has changed with EPU conditions. Refer to the Environmental Qualification program for updated values. 01101248

Table 5.2-3a Monticello Containment Penetrations
(Page 1 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
-	Seismic Restraint Port A	B	-	1	YES	-	-	-
-	Seismic Restraint Port B	B	-	1	Yes	-	-	-
-	Seismic Restraint Port C	B	-	1	Yes	-	-	-
-	Seismic Restraint Port D	B	-	1	Yes	-	-	-
-	Seismic Restraint Port E	B	-	1	Yes	-	-	-
-	Seismic Restraint Port F	B	-	1	Yes	-	-	-
-	Seismic Restraint Port G	B	-	1	Yes	-	-	-
-	Seismic Restraint Port H	B	-	1	Yes	-	-	-
-	Drywell Head	B	-	1	Yes	-	-	-
X-1	Equipment Hatch	B	-	-	-	-	1	Yes
X-2	Air Lock (Note 6)	B	-	-	-	-	-	-
	Equalizing Valves (Note 6)	C / B	PCT-2	15	Yes	PCT-3	15	Yes
X-3	Spare	NONE	-	17	-	-	-	-
X-4	Head Access Hatch	B	-	-	-	-	1	Yes

01488437

Table 5.2-3a Monticello Containment Penetrations
(Page 2 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-5A-5H	Drywell-Torus Vent Lines	NONE (Note 7)	-	-	-	-	-	-
X-6	CRD Access Hatch	B	-	-	-	-	1	Yes
X-7A	Bellows	B	-	-	-	-	2	Yes
	Primary Steam Line A	C (Notes 1, 14)	AO-2-80A	3	Yes	AO-2-86A	7	Yes
X-7B	Bellows	B	-	-	-	-	2	Yes
	Primary Steam Line B	C (Notes 1, 14)	AO-2-80B	3	Yes	AO-2-86B	7	Yes
X-7C	Bellows	B	-	-	-	-	2	Yes
	Primary Steam Line C	C (Notes 1, 14)	AO-2-80C	3	Yes	AO-2-86C	7	Yes
X-7D	Bellows	B	-	-	-	-	2	Yes
	Primary Steam Line D	C (Notes 1, 14)	AO-2-80D	3	Yes	AO-2-86D	7	Yes
X-8	Bellows	B	-	-	-	-	2	Yes
	Primary Steam Drain	C (Note 14)	MO-2373	12	Yes	MO-2374	12	Yes
X-9A	Bellows	B	-	-	-	-	2	Yes
	Feedwater Line	C	FW-97-2	5	Yes	FW-94-2	5	Yes
X-9B	Bellows	B	-	-	-	-	2	Yes
	Feedwater Line	C	FW-97-1	5	Yes	FW-94-1	5	Yes
X-10	Bellows	B	-	-	-	-	2	Yes
	Steam to RCIC	C	MO-2075	4	Yes	MO-2076	4	Yes
X-11	Bellows	B	-	-	-	-	2	Yes
	Steam to HPCI	C	MO-2034	4	Yes	MO-2035	4	Yes
X-12	Bellows	B	-	-	-	-	2	Yes
	RHR Supply	C	MO-2029	4	Yes	MO-2030	4	Yes

Table 5.2-3a Monticello Containment Penetrations
(Page 3 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-13A	Bellows	B	-	-	-	-	2	Yes
	LPCI to B Loop	C	-	-	-	MO-2013	12	Yes
						MO-2015	4	Yes
X-13B	Bellows	B	-	-	-	-	2	Yes
	LPCI to A Loop	C	-	-	-	MO-2012	12	Yes
						MO-2014	4	Yes
						RHR-81	5	Yes
X-14	Bellows	B	-	-	-	-	2	Yes
	RWCU Supply	C	MO-2397	4	Yes	MO-2398	4	Yes
X-15	Spare Penetration	NONE	-	-	-	-	17	-
X-16A	Bellows	B	-	-	-	-	2	Yes
	Core Spray B	C	-	-	-	MO-1752	4	Yes
						MO-1754	4	Yes
X-16B	Bellows	B	-	-	-	-	2	Yes
	Core Spray A	C	-	-	-	MO-1751	4	Yes
						MO-1753	4	Yes
X-17	Bellows	B	-	-	-	-	2	Yes
X-18	Floor Sump Discharge	C	-	-	-	AO-2541A	7	Yes
						AO-2541B	7	Yes
X-19	Equip Sump Discharge	C	-	-	-	AO-2561A	7	Yes
						AO-2561B	7	Yes
X-20	Demin Water Supply	C (Note 2)	-	-	-	DM-152	8	Yes
						DM-151	8	Yes
X-21	Service Air Supply	C (Note 2)	-	-	-	AS-79	8	Yes
						AS-78	8	Yes

Table 5.2-3a Monticello Containment Penetrations
(Page 4 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-22	Instrument Air	C	-	-	-	CV-1478 AI-571	9 5	Yes Yes
X-23	RBCCW to Drywell	C	-	-	-	RBCC-15 MO-4229	5 4	Yes Yes
X-24	RBCCW from Drywell	C	-	-	-	MO-1426 MO-4230	4 4	Yes Yes
X-25	Drywell Ventilation Exhaust	C	-	-	-	AO-2386 AO-2387 CV-2385	10 10 9	Yes Yes Yes
X-26	Drywell Ventilation Supply	C	-	-	-	AO-2377 AO-2381 CV-3268 CV-3269	10 10 9 9	Yes Yes Yes Yes
X-27A-27C	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-27D	Drywell to CAM Analyzer B (Supply)	C	-	-	-	SV-4001B SV-4020B	16 16	Yes Yes
X-27E	CAM Sample Line (Drywell)	C	-	-	-	SV-3307 SV-4081 SV-3308 SV-4082	16 16 16 16	Yes Yes Yes Yes
X-27F	Drywell to CAM Analyzer A (Supply)	C	-	-	-	SV-4020A SV-4001A	16 16	Yes Yes
X-28A, 28E, 28F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-28B, 28C, 28D	Spare	NONE	-	-	-	-	17	-

Table 5.2-3a Monticello Containment Penetrations
(Page 5 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-29A	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-29B, 29C, 29D	Spare	NONE	-	-	-	-	17	-
X-29E, 29F	Instrumentation	A (Note 8)	-	-	-	-	19	-
X-30A	Spare Penetration	NONE	-	-	-	-	17	-
X-30B,C,E,F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-30D	Instrumentation	A (Note 8)	-	-	-	-	19	-
X-31A,B,D, E,F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-31C	Spare	NONE	-	-	-	-	17	-
X-32A,B, D,E,F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-32C	Drywell Flood Level Switch	A (Note 8)	-	-	-	-	19	-
X-33A-33F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-34A	Alternate N_2 Supply	C	-	-	-	AI-708 AI-598	5 5	Yes Yes
X-34B	Spare Penetration	NONE	-	17	-	-	20	-
X-34C-34F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-35A,B,C	Flange TIP Probes (Note 4)	B C	- -	- -	- -	- TIP 1-1,2-1,3-1	1 15	Yes Yes

Table 5.2-3a Monticello Containment Penetrations
(Page 6 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-35D	Spare Penetration	B	-	-	-	-	1	Yes
X-35E	Flange	B	-	-	-	-	1	Yes
	TIP Purge Supply	C	-	-	-	AI-626-1	5	Yes
						AI-625	5	Yes
X-36	Spare	NONE	-	-	-	-	17	-
X-37B	11 Recirc Seal Inj	C	XR-27-1	5	Yes	XR-25-1	5	Yes
X-38B	12 Recirc Seal Inj	C	XR-27-2	5	Yes	XR-25-2	5	Yes
X-37A-37D	CRD Insert Lines (121)	NONE (Note 5)	-	5	-	-	-	-
X-37C-37D	Spare(2)	NONE	-	-	-	-	17	Yes
X-38A-38D	CRD Withdraw(121)	NONE (Note 5)	-	5	-	-	-	-
X-38C-38D	Spare(2)	NONE	-	-	-	-	17	-
X-39A	Drywell Spray B	C	-	-	-	MO-2021	4	Yes
						MO-2023	4	Yes
X-39B	Drywell Spray A	C	-	-	-	MO-2020	4	Yes
						MO-2022	4	Yes
X-40AA-40DF	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-41	Recirc Loop B Sample	C	CV-2790	9	Yes	CV-2791	9	Yes
X-42	Standby Liquid Control	C	XP-7	5	Yes	XP-6	5	Yes
X-43-46	Spare Penetrations	NONE	-	-	-	-	17	-

Table 5.2-3a Monticello Containment Penetrations
(Page 7 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-47	Spare Penetration							
X-48	Spare Penetration	NONE	-	-	-	-	17	-
X-49A-49F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-50A-50D	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-50E-50F	Instrumentation	A (Note 8)	-	-	-	-	19	-
X-51A-51F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-52A-52F	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-53A-53B	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-54A-54B	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-55-X-99	Not Assigned	NONE	-	-	-	-	-	-
X-100A - 100D	Electrical Penetration	B	-	-	-	-	11	Yes
X-100E	Spare Penetration	NONE	-	-	-	-	17	-
X-101A	Instrumentation	B	-	-	-	-	11	Yes
101C	Spare Penetrations	NONE	-	-	-	-	17	-
X-101B, 101D	Electrical Penetration	B					11	Yes
X-102	Spare Penetration	NONE	-	-	-	-	17	-

Table 5.2-3a Monticello Containment Penetrations
(Page 8 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-103	Electrical Penetration	B	-	-	-	-	11	Yes
X-104A - 104D	Electrical Penetration	B	-	-	-	-	11	Yes
X-104E	Spare Penetration	NONE	-	-	-	-	17	-
X-105A, 105C,105D	Electrical Penetration	B	-	-	-	-	11	Yes
X-105B (B,D,F)	Spare	NONE	-	-	-	-	20	-
X-105B(G)	Alternate N_2 Supply	C	-	-	-	AI-700 AI-599	5 5	Yes Yes
X-105B (A,C,H,I)	Instrumentation	NONE (Note 3)	-	-	-	-	18	-
X-105B(E)	Instrumentation	A (Note 8)	-	-	-	-	19	-
X-106	Electrical Penetration Flange	B B	-	-	-	-	11 1	Yes Yes
X-107	Electrical Penetration Flange	B B	-	-	-	-	11 1	Yes Yes
X-108 - X-199	Not Assigned	NONE	-	-	-	-	-	-
X-200A	Torus Hatch(45°)	B	-	-	-	-	1	Yes
X-200B	Torus Hatch(225°)	B	-	-	-	-	1	Yes
X-201A - 201H	Torus Vent Lines	NONE (Note 7)	-	-	-	-	2	No

Table 5.2-3a Monticello Containment Penetrations
(Page 9 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-202A,B C,D,E,F, G,H,J,K	Drywell-Torus Vacuum Breakers	NONE (Note 7)	-	-	-	-	-	-
X-202I	Not Assigned	NONE	-	-	-	-	-	-
X-203	Not Assigned	NONE	-	-	-	-	-	-
X-204A - 204D	Torus Ring Header	NONE (Note 7)	-	-	-	-	-	-
X-205	Torus Ventilation Exhaust	C	-	-	-	AO-2383 CV-2384 AO-2896	10 9 10	Yes Yes Yes
X-206A,D, -E,G	Torus Instrumentation	A (Note 8)	-	-	-	-	19	-
X-206B,C, F,H	Torus Instrumentation	NONE (Note 9)					19	-
X-207A - 207H	Torus Vent Pipe Drains	NONE (Note 7)	-	-	-	-	-	-
X-208A - 208H	Relief Valve Discharge Pipes	NONE (Note 7)	-	-	-	-	-	-
X-209A,D	Torus Instrumentation	A (Note 8)	-	-	-	-	19	-
X-209B,C	Torus Instrumentation	NONE (Note 9)					19	-

Table 5.2-3a Monticello Containment Penetrations
(Page 10 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-210A	RHR and Core Spray B Test Line to Torus	NONE (Note 9)	-	-	-	RHR-8-2 MO-2007 MO-2009 MO-1750 CS-10-2	5 4 12 12 13	- - - - -
X-210B	RHR and Core Spray A Test Line to Torus	NONE (Note 9)	-	-	-	RHR-8-1 MO-2006 MO-2008 MO-1749 CS-10-1	5 4 12 12 13	- - - - -
X-211A	RHR B Torus Spray	NONE (Note 12) NONE (Note 13) C	- - -	- - -	- - -	MO-2007 MO-2009 MO-2011	4 12 12	- - Yes
X-211B	RHR A Torus Spray	NONE (Note 12) NONE (Note 13) C	- - -	- - -	- - -	MO-2006 MO-2008 MO-2010	4 12 12	- - Yes
X-212	RCIC Turbine Exhaust	C	-	-	-	RCIC-9 RCIC-10	5 5	Yes Yes
X-213A, 213B	Flanged Bottom Torus Drains	NONE (Note 10)	-	-	-	-	1	-
X-214	CAM Analyzer A to Torus (Return)	C	-	-	-	SV-4004A SV-4005A	16 16	Yes Yes
	CAM Analyzer B to Torus (Return)	C	-	-	-	SV-4004B SV-4005B	16 16	Yes Yes
	Oxygen Analyzer to Torus (Return)	C	-	-	-	CV-3313 CV-3314	9 9	Yes Yes

Table 5.2-3a Monticello Containment Penetrations
(Page 11 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-215	Torus to CAM Analyzer A (Supply)	C	-	-	-	SV-4002A	16	Yes
						SV-4003A	16	Yes
216	Spare Penetration	NONE	-	-	-	-	17	-
X-217	HPCI Exhaust Vac Bkr	B (Note 11)	-	-	-	HPCI-65	5	Yes
						HPCI-71	5	Yes
X-218	Torus-Reactor Building Vacuum Breaker and Ventilation Supply	C	-	-	-	AO-2379	10	Yes
						DWV-8-2	14	Yes
						AO-2380	10	Yes
						DWV-8-1	14	Yes
						AO-2377	10	Yes
						AO-2378	10	Yes
	Nitrogen Purge	C	-	-	-	CV-3267	9	Yes
						CV-3269	9	Yes
X-219	RCIC Exhaust Vac Bkr	B (Note 11)	-	-	-	RCIC-57	5	Yes
						RCIC-59	5	Yes
X-220	Torus to CAM Analyzer B (Supply)	C	-	-	-	CV-3311	9	Yes
						CV-3312	9	Yes
						SV-4002B	16	Yes
						SV-4003B	16	Yes
X-221	HPCI Turbine Exhaust	C	-	-	-	HPCI-9	5	Yes
						HPCI-10	5	Yes

Table 5.2-3a Monticello Containment Penetrations
(Page 12 of 14)

Penetration Designation	Description	Applicable Appendix J Type Test	INNER BARRIER Designation	INNER BARRIER Type	INNER BARRIER Testable	OUTER BARRIER Designation	OUTER BARRIER Type	OUTER BARRIER Testable
X-222	HPCI Steam Line Drains	NONE (Note 9)	-	-	-	HPCI-14 HPCI-15	5 5	- -
X-223	RCIC Steam Line Drains	NONE (Note 9)	-	-	-	RCIC-16 RCIC-17	5 5	- -
X-224A	RHR B Suction	NONE (Note 9)	-	-	-	MO-1987	4	-
X-224B	RHR A Suction	NONE (Note 9)	-	-	-	MO-1986	4	-
X-225	HPCI Suction	NONE (Note 9)	-	-	-	MO-2061 MO-2062	4 4	- -
X-226A	Core Spray B Suction	NONE (Note 9)	-	-	-	MO-1742	4	-
X-226B	Core Spray A Suction	NONE (Note 9)	-	-	-	MO-1741	4	-
X-227	RCIC Suction	NONE (Note 9)	-	-	-	MO-2100 MO-2101	4 4	-
X-228	Included to retain numerical sequence only. No penetration.							
X-229A, C - H, J, K	Spare Penetrations	NONE	-	-	-	-	17	-
X-229B	Instrument Air to Torus	C	-	-	-	CV-7956 AI-629	9 5	Yes Yes
X-230	Electrical Penetration	B	-	-	-	-	11	Yes
X-231A&B X-238A&B	Instrumentation	NONE	-	-	-	-	21	-
X-239A-H, J-N, P-R	Spare	NONE	-	-	-	-	21	-
X-240	Hard Pipe Vent	C	-	-	-	AO-4539 AO-4540	10 10	Yes Yes

Table 5.2-3a Monticello Containment Penetrations
(Page 13 of 14)

(1) During refueling outages, MSIVs may be tested by pressurization between valves. Since test pressure tends to unseat the inboard valve, a lower test pressure than P_a has been approved by the NRC (Reference 93). Alternatively, the inboard valve may be pressurized on the reactor side for exclusive testing of that valve and to help seat the valve for subsequent outboard valve testing with pressurization between the valves.

(2) Isolation is accomplished using manual valves in the containment supply line. These valves are opened only when containment integrity is not required. The valves are closed in accordance with lineup checklists which are completed prior to plant heatup.

(3) One-inch instrumentation lines equipped with excess flow check valves. Subject to leakage testing in accordance with Technical Specification SR 3.6.1.3.8. Leakage can occur only through rupture of the line or its associated instrument outside of containment.

(4) TIP probes are withdrawn on a containment isolation signal and the line is isolated by automatic closure of a ball valve. A shear valve can be manually actuated from the Control Room in the event a probe fails to retract. Check valves in the purge supply line outside the drywell close to provide containment isolation.

(5) Containment isolation of the CRD hydraulic control lines is provided by double seals within each control rod drive mechanism, and check valves and normally closed valves within each hydraulic control unit. (References 103,104,105 and 106).

(6) The drywell air lock is constructed with both doors opening inward so that containment pressure will tend to seat the door seals. During overall air lock pressure tests, a support member is installed on the inner door to prevent the door from being forced open. The outer airlock equalizing valve is tested during the overall air lock pressure test. 01488437

(7) These are internal penetrations between sections of the containment structure.

(8) Instrumentation lines not equipped with excess flow check valves. These instrument lines are connected to sealed transducers and are designed to withstand the stresses of a loss-of-coolant accident. These lines are tested during the containment Type A integrated leak rate test (Reference 93).

(9) This penetration terminates below the minimum post accident level of the suppression pool. It is not exposed to the containment atmosphere.

(10) These drains are installed at the bottom of the suppression pool.

(11) The HPCI and RCIC steam exhaust line vacuum breaker penetrations utilize the HPCI and RCIC steam exhaust line check valves for containment isolation. The check valves are installed with resilient seals.

Table 5.2-3a Monticello Containment Penetrations
(Page 14 of 14)

(12) Holes drilled in the RHR pump side disc of valves MO-2006 and MO-2007 to address NRC Generic letter 95-07 (Reference 138) on Pressure Locking and Thermal Binding will allow water to pressurize the valve bonnet/packing area and eliminate this potential fission product leakage path. This provision allows removal of these valves from Type C testing under the exemption provided in the NRC's June 3, 1983 Appendix J Safety Evaluation (Reference 93).

(13) MO-2008 and MO-2009 are globe valves installed with the valve bonnet/packing area exposed to the Torus side. This results in the valve disks, stem packing, and body to bonnet gasket being water sealed post accident and no Appendix J local leak rate tests of these valves are required (Reference 93).

(14) The Main Steam Pathway (main steam lines and main steam line drains) leakage is excluded from the sum of the leakage rates of Type B and C tests, and from the overall integrated leakage rate from Type A tests (Reference 163).

Barrier Type Codes

1	Double gasket or O-ring seal
2	Hot pipe expansion bellows
3	Air operated globe valve
4	Motor operated gate valve
5	Check valve
6	Testable check valve
7	Air operated gate valve
8	Manual gate valve
9	Diaphragm air operated control valve
10	Air operated butterfly valve
11	Electrical penetration
12	Motor operated globe valve
13	Manually operated globe valve
14	Self-actuating vacuum breaker
15	Ball Valve
16	Solenoid Valve
17	Spare Penetration - welded cap
18	Instrument Line with excess flow check valve
19	Instrument Line without excess flow check valve
20	Spare penetration - isolation valve and cap
21	Thermowell

Table 5.2-3b Primary Containment Automatic Isolation Valves
(Page 1 of 4)

01101248

Isolation Group (Note 1)	Application	Isolation Valves Inboard	Isolation Valves Outboard	Maximum Operating Time (sec) (Note 6)	Normal Position (Note 3)
1	Main Steam Isolation	AO-2-80A AO-2-80B AO-2-80C AO-2-80D	AO-2-86A AO-2-86B AO-2-86C AO-2-86D	3 ≤ t ≤ 9.9	Open
1	Main Steam Line Drain	MO-2373	MO-2374	60	Closed
1	Reactor Water Sample	CV-2790	CV-2791	60	Open
2	Drywell Equipment Sump	AO-2561A	AO-2561B	60	Open
2	Drywell Floor Sump	AO-2541A	AO-2541B	60	Open
2	Torus Vent Bypass	-	CV-2384	15	Closed
2	Torus Vent (Note 5)	-	AO-2383 AO-2896	15 15	Closed Closed
2	Drywell Vent Bypass	-	CV-2385	15	Closed
2	Drywell Vent (Note 5)	-	AO-2386 AO-2387	15 15	Closed Closed
2	Torus Air Purge Air Supply (Note 5)	-	AO-2378	15	Closed
2	Drywell Air Purge Supply (Note 5)	-	AO-2381	15	Closed
2	Containment Air Purge Supply (Note 5)	-	AO-2377	15	Closed
2	TIP Ball Valves (3)	-	-	Note 2	Closed

Table 5.2-3b Primary Containment Automatic Isolation Valves
(Page 2 of 4)

Isolation Group (Note 1)	Application	Isolation Valves Inboard	Isolation Valves Outboard	Maximum Operating Time (sec) (Note 6)	Normal Position (Note 3)	
2	RHR Supply	MO-2029	MO-2030	120	Closed	
2	RHR Return to A Loop	-	MO-2014	120	Closed	(Note 4)
2	RHR Return to B Loop	-	MO-2015	120	Closed	(Note 4)
2	Containment Nitrogen Supply	-	CV-3269	60	Closed	
2	Torus Nitrogen Supply	-	CV-3267	60	Closed	
2	Drywell Nitrogen Supply	-	CV-3268	60	Closed	
2	Oxygen Analyzer Sample Point	-	CV-3311 CV-3312	60 60	Open Open	
2	Oxygen Analyzer Return	-	CV-3313 CV-3314	60 60	Open Open	
2	CAM Sample Line (Drywell)	-	SV-3307 SV-3308	30 30	Open Open	
2	PASS Sample Line (Drywell)	-	SV-4081 SV-4082	30 30	Closed Closed	
2	Drywell to CAM Analyzer A (Supply)	-	SV-4001A SV-4020A	30 30	Closed Closed	
2	Drywell to Cam Analyzer B (Supply)	-	SV-4001B SV-4020B	30 30	Closed Closed	
2	Torus to CAM Analyzer A (Supply)	-	SV-4002A SV-4003A	30 30	Closed Closed	

01101248

Table 5.2-3b Primary Containment Automatic Isolation Valves
(Page 3 of 4)

Isolation Group (Note 1)	Application	Isolation Valves Inboard	Isolation Valves Outboard	Maximum Operating Time (sec) (Note 6)	Normal Position (Note 3)
2	Torus to CAM Analyzer B (Supply)	-	SV-4002B SV-4003B	30 30	Closed Closed
2	CAM Analyzer A to Torus (Return)	-	SV-4004A SV-4005A	30 30	Closed Closed
2	CAM Analyzer B to Torus (Return)	-	SV-4004B SV-4005B	30 30	Closed Closed
3	Reactor Water Cleanup Supply	MO-2397	MO-2398	40	Open
3	Reactor Water Sample	CV-2790	CV-2791	60	Open
4	HPCI Steam Supply	MO-2034	MO-2035	40*	Open
5	RCIC Steam Supply	MO-2075	MO-2076	30	Open

* With normal off-site power (and battery chargers) available, the maximum operating (closing) times of MO-2034 and MO-2035 are 40 seconds. For MO-2035 in a Design Basis HELB Scenario (battery chargers NOT available), the closing time is bound to 45 seconds.

01101248

Table 5.2-3b Primary Containment Automatic Isolation Valves
(Page 4 of 4)

Note (1): Containment isolation groupings as follows:

Group 1 The valves in Group 1 are closed upon any one of the following conditions:

1. Reactor low low water level
2. Main steam line high flow
3. Main steam line tunnel high temperature
4. Main steam line low pressure (RUN mode only)

Group 2 The valves in Group 2 are closed upon any one of the following conditions:

1. Reactor low water level
2. High Drywell pressure

Group 3 The valves in Group 3 are closed upon any one of the following conditions:

1. Reactor low-low water level
2. High Drywell pressure
3. High RWCU flow
4. High RWCU room temperature

Group 4 Isolation valves in the HPCI System are closed upon any one of the following conditions:

1. HPCI steam line high flow
2. HPCI steam line low pressure
3. High temperature in the vicinity of the HPCI steam line.

Group 5 Isolation valves in the RCIC System are closed upon any one of the following conditions:

1. RCIC steam line high flow
2. RCIC steam line low pressure
3. High temperature in the vicinity of the RCIC steam line.

Note (2): Testing consists of verifying ball valve closure on a simulated Group 2 isolation signal.

Note (3): The normal position of the valves during operation is indicated. However, valve positions may be changed as required to support plant operation, such as containment nitrogen addition and venting, or to allow for surveillance testing, such as valve stroke timing.

Note (4): These valves are controlled by LPCI Loop selection during normal operation. During operation of the RHR system in the Shutdown Cooling Mode, these valves will receive a Group 2 isolation signal.

Note (5): These valves are limited to a stroke of full closed to ≤40° open. This ensures the valves can close under design basis conditions.

Note (6): Indicated maximum operating time is limited to valve stroke time. Additional time associated with signal development or automatic logic actuation is not included in the values shown. 01101248

Table 5.2-4 Maximum Containment Conditions for a Loss of Coolant Accident

Maximum Drywell Pressure (DBA-LOCA) = 44.1 psig

Maximum Drywell Gas Temperature (Steam Line Break)[1] = 338°F

Maximum Drywell Wall Temperature (Steam Line Break)[1] = 278°F

Maximum Wetwell Pressure (DBA-LOCA) = 32.7 psig

Maximum bulk Suppression Pool Temperature (DBA-LOCA) = 203/207[2]°F

01101248

1. The analysis is based on the 0.5 ft^2 steam line break assuming UCHIDA condensing heat transfer to the drywell wall until the wall temperature reaches the saturation temperature for the drywell pressure with initiation of drywell sprays at a drywell gas temperature of 281°F but not before 10 minutes after the break.
2. The first value is the peak suppression pool temperature for the DBA-LOCA with direct suppression cooling and an RHR heat exchanger K-value that increases with increasing RHR water temperature. The second number is the peak suppression pool temperature from the NPSH evaluation for the same DBA-LOCA but with containment cooling using containment sprays and a constant K-value of 147 BTU/sec°F.

(References 167 and 168)

Table 5.2-7 Assumptions for the LOCA Containment Evaluation

ASSUMPTION	BASIS	
1. Reactor is at 102% of 2004 MWt.	1. Reference 166	01101248
2. Suppression pool temperature are initially 90°F.	2. Technical Specification Maximum.	
3. Suppression pool water volume is initially 68,000 ft^3	3. Technical Specification Minimum.	
4. Drywell temperature and humidity are assumed to be 135°F and 20% relative humidity, respectively, for DBA LOCA (long term with SPC), intermediate, and small break cases. For NPSH cases, drywell temperature and humidity are assumed to be 135°F and 100% RH, respectively.	4. Reference 166	01101248
5. Wetwell airspace is initially 90°F and 100% relative humidity.	5. Thermal equilibrium with the suppression pool water at normal operating Technical Specification limit; maximum humidity.	
6. The wetwell air space is in thermal equilibrium with the suppression pool during the early blow down period for a DBA LOCA, then a mechanistic heat and mass transfer is assumed.	6. Reference 166	01101248
7. Initial drywell pressure and wetwell pressure assumed to be 17.7 psia, except for NPSH and PULD cases, where 14.26 psia and 15.45 psia, respectively, are assumed.	7. Reference 166	01101248
8. Drywell fan coolers are inactive.	8. Non-safety equipment.	
9. Control rod drive flow is zero.	9. Non-safety equipment.	
10. Initial downcomer submergence is 3.00 ft.	10. Derived from minimum Technical Specification water volume.	
11. Normal operation of the plant system is assumed except for a single active failure.	11. Licensing requirement.	
12. Decay heat for long-term response calculated using ANSI/ANS 5.1-1979 standard consistent with GE SIL 636. A 2-sigma uncertainty was added to nominal decay heat values.	12. Reference 166	01101248
13. The RHR pool cooling mode starts at 10 minutes after the line break.	13. Accepted by NRC for Mark I containment evaluation.	

14.	One Emergency Diesel Generator is inoperative.	14.	Limiting single failure for containment.	
15.	Use of passive heat sinks per analysis.	15.	Reference 166	01101248
16.	Instantaneous guillotine break of recirculation suction line is used.	16.	Worst case break.	
17.	RHR intertie is present during break.	17.	Monticello configuration.	
18.	The Emergency-Core-Cooling System starts injecting at 38 seconds for DBA LOCA.	18.	Reference 166	01101248
19.	For first 10 minutes ECCS consists of one core spray and two LPCI pumps.	19.	Nominal injection rate.	
20.	Pool cooling consists of 1 LPCI pump, and 1 RHR SW pump with one heat exchanger.	20.	Limiting single failure	
21.	RHR Heat Exchanger K = 147 Btu/sec-°F is used for containment spray, NPSH, and PULD cases. A variable K from 146.5 Btu/sec-°F to 151.6 Btu/sec-°F is used for DBA LOCA suppression pool cooling and core injection cooling.	21.	Reference 166	01101248
22.	Loss-of-coolant accident calculations use service water temperature of 90°F.	22.	Reference 166	

Table 5.2-8 Drywell Temperature Envelopes for Steam Breaks 01101248

DRYWELL TEMPERATURE ENVELOPE*

TIME AFTER ACCIDENT	DRYWELL TEMP. (°F)
0 - 300 seconds	338
300 - 600 seconds	335
600 - 1500 seconds	285
1500 - 3600 sec	285 - 230
1 - 24 hrs	230 - 200
1 - 5 days	200 - 155
5 - 50 days	155 - 125
50 - 400 days	125 - 110

01101248

* Analysis performed at 102% of 2004 MWt and 90°F RHR Service Water (Reference 167 and 170)

5.3 Secondary Containment System and Reactor Building

5.3.1 General

The secondary containment completely encloses the reactor and its pressure suppression primary containment. The secondary containment enclosure structure provides secondary containment when the primary containment is closed and in service, and primary containment when the primary containment is open, as during refueling. The reactor building houses the refueling and reactor servicing equipment, new and spent fuel storage facilities and other reactor auxiliary systems or service equipment. The primary purposes for the secondary containment are to minimize ground level release of airborne radioactive materials to the environs, and to provide means for a controlled elevated release of the building atmosphere if an accident should occur . For the design basis fuel-handling accident, analysis using Alternative Source Term methodology has demonstrated that secondary containment integrity and operation of the Standby Gas Treatment System are not required to maintain offsite and Control Room operator doses below 10CFR50.67 limits. Secondary containment and SBGT are not required for the design basis main steam line break and control rod drop accidents since releases from those accidents are outside the secondary containment.

5.3.2 Design Basis

a. The secondary containment is designed so that its in-leakage rate is not greater than 4,000 cfm (approximately 3 building volume changes per day) under neutral wind conditions when the building is subjected to an internal negative pressure of 0.25 in. of water.

b. Exfiltration from secondary containment should not exceed one building volume per day with wind speed of 60 miles per hour when initial secondary containment pressure is 0.25 inch water column vacuum under calm wind conditions.

c. The structural design basis is discussed in Section 12.

d. The Reactor Building structure is designed to withstand an internal pressure of 7 in. of water without structural failure or pressure relief. The building is evaluated for the maximum internal pressures caused by a High Energy Line Break within the building. Provisions are made to relieve secondary containment pressure to prevent exceeding the internal pressure limit within the building in the unlikely event of a pipe rupture. Relief devices (blow-out panels) are provided to assure that reactor building structural integrity will not be impaired.

e. Means are provided for exhausting treated air from the secondary containment.

f. Means are provided for periodically monitoring the leak tightness of the reactor building.

g. The reactor building structure is designed and constructed in accordance with applicable state and local building code requirements.

5.3.3 Description

5.3.3.1 Reactor Building

The structural and shielding design features of the reactor building are discussed in Section 12. The substructures and the building to the level of the refueling floor consist of poured-in-place reinforced concrete. Above the level of the refueling floor, the building structure consists of a steel frame with insulated metal siding and built-up roof on steel decking. The siding and decking have sealed joints.

5.3.3.2 Secondary Containment Penetrations

The openings in the secondary containment, including personnel and equipment access openings and piping or duct penetrations are designed to provide containment which is consistent with the secondary containment leakage rates specified above. To accomplish this, double interlocked doors with weather strip type seals are provided for access to the secondary containment for both personnel and equipment. Some airlock doors contain windows to minimize challenging the airlock interlock. Inlet and outlet ventilation ducts are sealed at the secondary containment enclosure perimeter and are provided with automatic closing double isolation dampers.

5.3.4 Reactor Building Heating and Ventilation Systems

Normal ventilation system operation provides outside air to all levels and equipment rooms of the Reactor Building. This supply air may be filtered or unfiltered depending on seasonal conditions. The air is exhausted through a ventilation duct that discharges at the Reactor Building roof, also known as the Reactor Building vent. Cooling units maintain air temperatures for personnel comfort and equipment protection as required. The normal ventilation system has the capacity to provide a minimum of one air change per hour of filtered air to all portions of the Reactor Building requiring ventilation.

The Reactor Building is provided with both supply and exhaust ventilation to ensure proper air flow direction and remove the heat generated by the equipment. Air flow is directed from areas of least potential for radioactive contamination to areas of greater potential contamination prior to final exhaust through the Reactor Building vent as mentioned above.

The supply system includes fans, filters, and steam heating coils to temper the outside air in the winter. Steam unit heaters are furnished on the operating levels to maintain desired temperature.

Air pressure in the secondary containment is maintained at a slightly negative pressure by operating exhaust fans at a higher rating than the supply fans. The negative pressure, together with the integrity of the secondary containment minimizes exfiltration from the secondary containment.

Both the inlet and outlet ventilation ducts of the secondary containment are provided with two isolation dampers in series which are closed automatically when high radiation levels in the reactor building ventilation plenum, or high radiation in the area of the fuel pool is detected. For the design basis fuel-handling accident, analysis using Alternative Source Term methodology has demonstrated that secondary containment integrity and operation of the Standby Gas Treatment System are not required to maintain offsite and Control Room operator doses below 10CFR50.67 limits. A secondary containment isolation is also initiated when SGTS is initiated on low-low reactor water level or high drywell pressure. During this situation the normal ventilation system is shutdown and the secondary containment is ventilated through the standby gas treatment system. The ventilation system dampers' closure time is 10 sec or less.

The drawdown time is the time period following the start of the accident during which loss of offsite power causes loss of secondary containment vacuum (relative to atmospheric pressure). This is assumed to result in releases from primary containment directly to the environment without filtering. The Alternate Source Term (AST) project used 5 minutes for the positive pressure period as the estimated system performance. During the positive pressure period, radionuclide removal from Standby Gas Treatment System (SBGT) operation is not credited. An evaluation of the secondary containment drawdown time was completed. The drawdown calculation using GOTHIC code and a single lumped node determined that the positive pressure period was less than 2 minutes (Reference 171). 01101248

The reactor building vent is provided with wide-range radiation monitors. The monitor is used to quantify noble gas releases during normal operation and during the course of an accident. See Section 7.5.2.6.2 for details.

5.3.4.1 Standby Gas Treatment System (SGTS)

The standby gas treatment system is provided to maintain, whenever secondary containment isolation conditions exist, a small negative pressure to minimize ground level escape of airborne radioactivity. (See Drawing NH-36881, Section 15). Filters are provided in the system to remove radioactive particulates, and charcoal adsorbers are provided to remove radioactive halogens. All flow from the standby gas treatment system is released through the elevated off-gas vent stack and continuously monitored by the stack gas monitoring system as described in Section 7.5.2.3. The SGTS initiation monitors are described in Sections 7.5.2.6 and 7.5.2.7. In addition, the SGTS is initiated via primary containment isolation logic due to low low reactor water level or high drywell pressure. The system may also be used to vent the primary containment during plant operation.

The system is sized to provide up to 4,000 cfm exhaust from the secondary containment with a negative enclosure internal pressure of at least 0.25 in. of water under calm wind conditions. Two separate full-capacity filter adsorber/fan units are provided. If one unit fails to function properly, the other unit is started automatically. A time delay prevents the B Train from starting if the A Train achieves flow on initial SGTS initiation. Both units receive power from the Essential Power Distribution Center. Remote manual control is available for all functions.

The two filter/adsorber units are physically separated within the SGTS room by vertical and horizontal concrete walls. These walls act as fire retardant barriers as well as providing protection for B train filters from internally generated missiles.

Each standby gas treatment unit has the following major components:

a. Demister and a preheater to reduce relative humidity. The heater function was determined to not be required for iodine removal efficiency since the charcoal is tested at 95% humidity.

b. Two high efficiency filters with required capability for removing at least 99 percent of particles larger than 0.3 micron. The filters are designed to withstand 250°F maximum temperature.

c. Co-impregnated (potassium iodine/triethylene diamine) charcoal adsorber required to remove at least 95 percent of iodine under entering conditions of 95 percent RH and 150°F. Co-impregnated charcoal is specified because it provides greater resistance to aging and solvent poisoning and therefore will improve adsorber performance. Carbon samples are periodically removed for analysis. High temperature carbon (644°F) is specified.

Automatic remotely controlled valves provide for isolation of each standby gas treatment unit. Means are provided to draw air into the filter/adsorber to remove radioactive decay heat.

Instrumentation is provided to measure air flow, temperature, pressure, valve positions, and fan operations. Instrumentation and controls for the two filter trains are separated to prevent failure of the system due to localized damage.

5.3.5 Performance Analysis

The secondary containment provides a containment system for the potential releases which may occur within it. This is accomplished by a low leakage enclosure and a standby gas treatment system which has a capacity greater than the in-leakage rate. This system purifies air from the secondary containment and exhausts it to the outside by maintaining a negative pressure in the containment relative to outside and assuring that leakage flows into the secondary containment and no significant exfiltration of untreated gases exists. The fans are designed to achieve a minimum of 0.25 in. water of negative pressure within the secondary containment enclosure. The normal full-open operation of the flow control valves provides exhaust adequate to maintain the desired negative pressure.

Maximum and minimum calculated secondary containment exfiltration rates as functions of wind velocity are provided in Figure 5.3-2. This data indicates that when secondary containment pressure starts at 0.25 inch water column vacuum for calm wind conditions, at wind velocities up to 35 mph, there is little exfiltration from the reactor building. If secondary containment pressure is higher (closer to atmospheric pressure), then exfiltration starts at lower wind speed. The calculations indicate that the exfiltration rate is almost directly proportional to the initial in-leakage rate for a negative building pressure. These analyses also

indicate that the exfiltration rate could be many orders of magnitude larger, due to higher wind speed, without increasing the post-accident doses above the limits set in 10CFR50.67.

Analyses have been performed to determine the radiological effects of various pipe breaks in the reactor building. The most limiting of these breaks, the main steam line break, is included in Section 14.7.3.

For an evaluation of environmental conditions for postulated high energy line pipe breaks in the reactor building refer to Appendix I.

Except for a main steam line break, postulated high energy line breaks in the reactor building can not cause structural damage to primary or secondary containment structures or components required for safe shutdown. Primary or secondary leak tightness is not assured for a high energy line break since the resulting pressure may blow open the reactor building railroad doors or adversely affect primary containment isolation valves. Leak tightness of these structures is not required to place the plant in a safe shutdown condition following a high energy line break in the reactor building or limit the radiological consequences of the break to within the guidelines of 10CFR50.67 or 10CFR Part 50, Appendix A, GDC 19.

A pipe break in the main steam system could release sufficient energy to cause failure of the secondary containment boundary. The main steam pipes are located in the steam tunnel and blowout panels are located in the north wall of the steam tunnel at elevation 951 ft to provide a release path into the turbine building and prevent structural failure.

These blowout panels are designed to fall out at a differential pressure of less than 0.25 psi (7 in. of water) and would require resealing after blowout. Each of the two panels has an equivalent area of 75 ft^2. Steam flow is shown in Figure 14.6-6 of the FSAR. Venting of this quantity of steam within the turbine building does not require relief devices for building integrity. Other features are utilized to protect individual equipment cubicles, however, no other line failure releases sufficient energy to require building relief protection.

Analysis of the design basis Fuel Handling Accident (FHA) using Alternative Source Term methodology has demonstrated that secondary containment integrity is not required to maintain offsite and Control Room Operator doses below 10CFR50.67 limits (reference USAR Section 14.7.6). MNGP has committed to providing secondary containment closure controls that are in effect whenever secondary containment penetrations are open with movement of irradiated fuel assemblies in progress (Reference 159) (MNGP Commitment M04003A). Procedures for response to a fuel-handling accident will direct that secondary containment penetrations are closed expeditiously.

Integrated dose calculations have been made for components of the standby gas treatment system (SGTS) to determine exposure to components of the system following a design basis accident. The bounding post-LOCA component head loads for a single SBGT train are 10,000 watts for the upstream HEPA filter bank and 1,000 watts for the charcoal adsorber bank (Reference 173). 01101248

The performance of the Standby Gas Treatment System was confirmed to be within the constraints of the bounding Alternate Source Term (AST) evaluations of these systems, which are detailed in the Licensing Topical Report for Constant Pressure Power Uprates (References 168 and 174). The post-LOCA iodine loading on the charcoal is well within the guidelines of Regulatory Guide 1.52, and the charcoal removal efficiency for radioiodine is not affected by operation up to 2004 MWt. The cooling air flow required to maintain system components below operating temperature limits is well below the cooling flow capability of the system. In addition, the SBGT flow capacity is not adversely affected by the HEPA filter loading (Sections 2.5.2 and 2.6.6 of Reference 168). 01101248

The SBGT performance assumptions used in the LOCA radiological consequences analysis are included in USAR Section 14.7.2.4.

5.3.6 Inspection and Testing

The secondary containment leakage rate is tested by isolating the secondary containment, operating the standby gas treatment system, and tripping the Reactor Building Plenum and Radwaste Building Exhaust Fans. Tripping the Reactor Building Plenum and Radwaste Building Exhaust Fans ensures that only the Standby Gas Treatment System Fans contribute to achieving 0.25 in. of vacuum and no significant bypass of the Standby Gas Treatment System occurs. The Standby Gas Treatment System flow control valve is normally full open to obtain maximum flow (but less than 4000 cfm) and may be adjusted to reduce flow for determination of limiting conditions. The rate at which air is exhausted through the system, as measured by the flow indicator, indicates building in-leakage. Each train of the SGTS is required to maintain at least 0.25 in. of water negative pressure relative to atmosphere, measured at grade with no correction for stack effect. Data from this test is, however, corrected to calm wind conditions (v<5 mph).

Periodic testing can be performed during normal plant operation by operating each fan and all controls. Provisions are made for periodic tests of each filter unit at approximately full flow capacity. These tests include determinations of differential pressure across each filter and of filter efficiency. Connections for testing, such as injection and sampling, are located to provide adequate mixing of the injected fluid and representative sampling and monitoring, so that test results are indicative of performance.

Laboratory analysis of a representative sample of the charcoal adsorber is performed in accordance with Regulatory Guide (RG) 1.52, revision 2. Adsorber samples are obtained by either removing a test canister or by alternate sampling in accordance with RG 1.52, revision 4, which permits sampling per ASME N509-2002 Appendix I. The samples are tested at 95% humidity, 30 degrees Celsius (86 degrees Fahrenheit).

Heater testing requirements were removed as part of implementation of TSTF-522, Revise Ventilation System Surveillance Requirements to Operate for 10 Hours per Month. RG 1.52, revision 3, states humidity control is accounted for when testing charcoal at 95% relative humidity. Since the Ventilation and Filter Testing Program tests the charcoal at 95% relative humidity, the in-line heaters are not required. The standby gas trains are operated monthly for at least 15 minutes to demonstrate the equipment and controls are functioning properly.

5.4 References

1. General Electric report, NEDE-24802, “Mark I Containment Program, Mark I Wetwell-to-Drywell Vacuum Breaker Functional Requirements, Task 9.4.3”, W L Wolfe, April 1980.

2. NUTECH report, NSP-53-004, “Monticello Torus-to-Drywell Vacuum Breaker Requirements”, December 1980.

3. Bodega Bay Preliminary Hazards Summary Report, Appendix 1, “Pressure Suppression Test Program”, Docket 50-205, December 28, 1962.

4. Deleted.

5. Deleted.

6. Chicago Bridge & Iron Report, “Loads on Spherical Shells”, P. Thullen, Oak Brook Engineering Department, August 1964.

7. General Electric report, NEDC-20989-1, “Mark I Containment Evaluation Short Term Program Final Report, Volume I - Program Description and Summary of Conclusions”, J M Humphrey, et. al., September 1975.

8. General Electric report, NEDC-20989-2P, “Mark I Containment Evaluation Short Term Program Final Report, Volume II - LOCA Related Hydrodynamic Loads”, R H Buchholz, et. al., September 1975.

9. General Electric report, NEDC-20989-3P, “Mark I Containment Evaluation Short Term Program Final Report, Volume III - Load Application and Screening of Structural Elements”, J M Humphrey, et. al., September 1975.

10. General Electric report, NEDC-20989-4P, “Mark I Containment Evaluation Short Term Program Final Report, Volume IV - Structural Evaluation”, September 1975.

11. General Electric report, NEDC-20989-5, “Mark I Containment Evaluation Short Term Program Final Report, Volume V - Independent Assessment of the Mark I Short Term Program”, September 1975.

12. General Electric report, NEDC-20989-4PA, “Mark I Containment Evaluation Short Term Program Final Report, Addendum 1 to Volume IV - Structural Evaluation”, November 1975.

13. General Electric report, NEDC-20989, “Mark I Containment Evaluation Short Term Program Final Report, Addendum 2, Loads and Their Application for Torus Support System Evaluation”, June 1976.

14. General Electric report, NEDC-20989-P, “Mark I Containment Evaluation Short Term Program Final Report, Addendum 3, Vent Header and Vent Pipe Impact Load”, S Kayhan, et. al., August 1976.

15. General Electric report, NEDC-20989-4A, “Mark I Containment Evaluation Short Term Program - Final Report, Addendum 4, Revisions to Volume IV - Structural Evaluation”, November 1976.

16. NUTECH report, MK1-02-012, “Description of Short Term Program Plant Unique Torus Support Systems and Attached Piping Analysis”, Revision 2, June 1976.

17. General Electric (L J Sobon) letter to the NRC (V Stello), “Mark I Short Term Program Report Questions”, dated October 29,1976.

18. NUREG-0408, “Mark I Containment Short Term Program Safety Evaluation”, December 1977.

19. General Electric (L J Sobon) letter to the NRC (V Stello), “Mark I Containment Program- Program Action Plan, Revision 3”, dated February 15, 1978.

20. General Electric report, “Mark I Containment Program-Program Action Plan, Revision 3”, February 1978.

21. General Electric report, NEDO-21888, “Mark I Containment Program Load Definition Report”, December 1978.

22. General Electric report, NEDO-24583-1 “Acceptance Criteria Plant-Unique Analysis Applications Guide, Task Number 3.1.3”, October 1979.

23. NUREG-0661, “Safety Evaluation Report, Mark I Containment Long-Term Program, Resolution of Generic Technical Activity A-7”, July, 1980.

24. General Electric report, NEDM-13377, “Mark III Confirmatory Test Program Phase I - Large-Scale Demonstration Test, Test Series 5701 through 5703”, L L Myers, T R McIntyre, and R J Ernst, October 1974.

25. General Electric report, NEDE-21078-P, “Test Results Employed by GE for BWR Containment and Vertical Vent Loads”, T Y Fukushima and others, October 1975.

26. General Electric report, NEDE-21944-P, “Mark I Containment Program 1/4-Scale Plant-Unique Tests, Task Number 5.5.3, Series 2”, Volumes 1-4, Main Report, April 1979.

27. General Electric report, NEDE-21627-P, “Mark I Containment Program 1/4 Scale Pressure Suppression Pool Swell Test Program: Scaling Evaluation, Task Number 5.5.1”, D L Galyardt, C G Hayes, and S L Kushman, January 1978.

28. Electric Power Research Institute report, EPRI NP-906, “Three-Dimensional Pool Swell Modeling of a Mark I Suppression System”, R L Kiang and B J Grossi, October 1978.

29. General Electric report, NEDE-21973-P, “Mark I Containment Program Comparison of GE and EPRI Torus Load Test Results, Task Number 5.10”, February 1979.

30. General Electric report, NEDE-23545-P, “Mark I Containment Program 1/4-Scale Pressure Suppression Pool Swell Test Program: LDR Load Tests - Generic Sensitivity, Task Number 5.5.3, Series 1”, December 1978.

31. General Electric report, NEDE-13426-P, “Mark III Confirmatory Test Program, 1/3 Scale Pool Swell Impact Tests, Test Series 5805”, T R McIntyre, et. al., August 1975.

32. General Electric report, NEDE-24539-P, “Mark I Containment Program Full-Scale Test Program, Final Report, Task Number 5.11”, G W Fitzsimmons, et. al., April 1979.

33. NRC (D G Eisenhut) Generic Letter 79-48, “Confirmatory Requirements Relating to Condensation Oscillation Loads for the Mark I Containment Long-Term Program”, dated October 2, 1979.

34. General Electric report, NEDE-24645-P, “Mark I Containment Program, Analysis of Full-Scale Test Facility for Condensation Oscillation Loading, Task 5.17.3”, July 1979.

35. General Electric (L J Sobon) letter to the NRC (D G Eisenhut), “Mark I Containment Program Additional Information on NEDO-21888 - Mark I Containment Program Load Definition Report”, September 7, 1979.

36. General Electric report, NEDE-24537-P, “Mark I Containment Long-Term Program - Development of Downcomer Lateral Loads from Full-Scale Test Facility Data, Task Number 7.3.2”, May 1979.

37. General Electric report, NEDE-21864-P, “Mark I Containment Program Final Report, Monticello T-Quencher Test,” R A Asia, et. al., July 1978.

38. General Electric report, NEDE-24549-P, “Mark I Containment Program, 1/4-Scale T-Quencher Test, Task Number 6.2.1”, C T Sawyer, et. al., December 1978.

39. General Electric report, NEDE-23749-P, “Analytical Model for Computing Transient Pressures and Forces in the Safety-Relief Valve Discharge Line, Mark I Containment Program, Task Number 7.1.2”, A J Wheeler, February 1978.

40. General Electric report, NEDE-23749-1-P, “Mark I Containment Program, Topical Report Addendum, Comparison of Analytical Model for Computing Safety/Relief Valve Discharge Line Transient Pressures and Forces to Monticello T-Quencher Test Data, Task Number 7.1.2.2”, A J Wheeler and D A Dougherty, February 1979.

41. General Electric report, NEDE-21878-P, “Mark I Containment Program, Analytical Model for Computing Air Bubble and Boundary Pressures Resulting from an S/RV Discharge Through a T-Quencher Device, Task Number 7.1.1.2”, P Valandani and W T Hsiao, January 1979.

42. General Electric report, NEDE-23713-P, “Mark I Containment Program, Scaling Analysis for Modeling Initial Air-Clearing Caused by Reactor Safety-Relief Valve Discharge”, R Schrim, February 1978.

43. General Electric report 22A4365, “Interim Containment Loads Report (ICLR), Mark III Containment”, Revision 2, October 1978.

44. Pennsylvania Power and Light Company (N W Curtis) letter to the NRC (O D Parr), “Revisions to Susquehanna Steam Electric Station Final Safety Analysis Report, Chapter 8, SSES Quencher Verification Test” (Proprietary), Docket Number 50-387/388, April 14, 1979.

45. General Electric report, NEDE-23898-P, “Mark I Containment Program Analytical Model for Computing Water Rise in a Safety-Relief Discharge Line Following Valve Closure, Task 7.1.2.2”, A J Wheeler and D A Dougherty, October 1978.

46. General Electric report, NEDE-24542-P, “Mark I Containment Program, Monticello T-Quencher Thermal Mixing Test, Final Report, Task Number 7.5.2”, B J Patterson, April 1979.

47. General Electric report, NEDE-21472, “Analytical Model for Liquid Jet Properties for Predicting Forces on Rigid Submerged Structures”, F J Moody, September 1977.

48. General Electric report, NEDE-23817-P, “Mark I Containment Program, 1/4 Scale Test Report Loads on Submerged Structures Due to LOCA Air Bubbles and Water Jets”, September 1978.

49. General Electric report, NEDE-21983-P, “Mark I Containment Program, Submerged Structures Model Main Vent Air Discharges Evaluation Report, Task Number 5.14.1”, S L Liu and L E Lasher, March 1979.

50. General Electric report, NEDO-25070, “Analytical Model for Estimating Drag Forces on Rigid Submerged Structures Caused by Condensation Oscillations and Chugging - Mark I Containment”, L E Lasher, April 1979.

51. General Electric report, NEDE-25090-P, “Mark I Containment Program, Analytical Model for T-Quencher Water-Jet Loads on Submerged Structures Task 5.14.2”, F T Dodge, May 1979.

52. General Electric report, NEDO-21471-2, “Analytical Model for Estimating Drag Forces on Rigid Submerged Structures Caused by LOCA and Safety-Relief Valve Ramshead Air Discharges”, L E Lasher, April 1979.

53. General Electric report, NEDC-23702, “Mark I Containment Program Seismic Slosh Evaluation, Mark I Containment Program, Task Number 5.4 ”, S M Arian, March 1978.

54. General Electric report, NEDE-21885-P, “Mark I Containment Program, Downcomer Reduced Submergence Functional Assessment Report, Task Number 6.6”, K W Wong, June 1978.

55. General Electric report, NEDM-24527, “Long-Term Application of Drywell/Wetwell Differential Pressure Control,” L D Steinart, March 1978.

56. General Electric report, NEDE-21887-P, “Mark I Containment Program, Limit Analysis of Downcomer-Ring Header Intersection”, July 1978.

57. General Electric report, NEDO 24529, “Analysis to Justify Increased Allowable Stresses for the Mark I Vent Header When Subjected to Pool Swell Impact Loading, Task Number 3.1.5.1”, R P Kennedy, et. al., May 1978.

58. General Electric report, NEDO-21991, “Mark I Containment Program, Basic Torus Shell Analysis, Task Number 3.1.5.3”, February 1979.

59. General Electric report, NEDE-21492-P, “Mark I 1/12-Scale Pressure Suppression Pool Swell Test Program: Phase IV Tests”, D L Galyardt, March 1977.

60. General Electric report, NEDE-21943-P, “Mark I Containment Program, 1/4-Scale Pressure Suppression Pool Swell Test Program - Download Oscillation, Task Number 5.5.2”, September 1978.

61. General Electric report, NEDO-24612, “Mark I Containment Program, Vent Header Deflector Load Definition, Task 7.3.3”, W Kennedy and V Kulkarni, April 1979.

62. General Electric report, NEDE-24520-P, “Rigid and Flexible Vent Header Testing in the Quarter-Scale Test Facility, Mark I Containment Program, Task 5.5.3”, W Kennedy et. al., March 1978.

63. Deleted.

64. Deleted.

65. “Elementary Fluid Mechanics”, Vennard, p. 102.

66. “Journal of Structural Division”, ASCE, Papers 1708-9, July 1958.

67. ORNL-NSIC-5-VI, “U.S. Reactor Containment Technology, A Compilation of Current Practice in Analysis, Design, Construction, Test and Operation”, Oak Ridge National Laboratory and Bechtel, August 1965, Section 5.2.2.4 - “Hydrogen-Oxygen Reaction”, p. 5.83, Figure 5.43a.

68. Deleted.

69. Deleted.

70. Deleted.

71. Deleted.

72. NUTECH reports NSP-74-101 through 105, “Monticello Nuclear Generating Plant Unique Analysis Report”, Revision 1, November 1982.

73. General Electric report, NEDO-24576, “Mark I Containment Program, Plant Unique Load Definition - Monticello Nuclear Power Plant”, Revision 1, October 1981.

74. Deleted. 01101248

75. NUTECH report, NSP-56-121-6, “Monticello Nuclear Generating Plant, Plant Unique Analysis Report, Torus Attached Piping and Suppression Chamber Penetrations”, Revision 1, May 1995.

76. NRC (D G Eisenhut) Generic Letter 83-08, “Modification of Vacuum Breakers on Mark I Containment”, dated February 2, 1983.

77. General Electric (H Pfefferlen) letter MFN-159-82 to the NRC (D Vassallo) transmitting on behalf of the Mark I Owners, “Mark I Vacuum Breaker Improved Valve Dynamic Model - Model Development and Validation, CDI Technical Note No. 82-31, August 1982”, dated October 28, 1982.

78. NSP(D M Musolf) letter to the NRC, “Monticello Nuclear Generating Plant, Evaluation of the Monticello Wetwell-to-Drywell Vacuum Breaker Valves”, dated April 15, 1983.

79. NSPM letter L-MT-12-082 (M A Schimmel) to NRC, "Monticello Extended Power Uprate and Maximum Extended Load Line Limit Analysis Plus License Amendment Requests: Supplement to Address SECY 11-0014 Use of Containment Accident Pressure (TAC Nos. MD9990 and ME3145)," dated September 28, 2012.

80. NSPM letter L-MT-12-107 (M A Schimmel) to NRC, "Monticello Extended Power Uprate and Maximum Extended Load Line Limit Analysis Plus License Amendment Requests: Supplement to Address SECY 11-0014 Use of Containment Accident Pressure, Sections 6.6.4 and 6.6.7 (TAC Nos. MD9990 and ME3145)," dated November 30, 2012. 01101248

81. NSPM letter L-MT-13-033 (M A Schimmel) to NRC, "Monticello Extended Power Uprate: SECY 11-0014 Use of Containment Accident Pressure - Responses to Requests for Additional Information (TAC MD9990)," dated March 21, 2013.

82. SECY-11-0014, Enclosure 1, "The Use of Containment Accident Pressure in Reactor Safety Analysis," ADAMS ML102110167.

83. Deleted.

84. Deleted.

85. Deleted.

86. Deleted.

87. Deleted.

88. Deleted.

89. General Electric report, NEDO-30477, "Safety Analysis of the RHR Intertie Line, Monticello Nuclear Generating Plant", June 1984.

90. General Electric (G H Scott) letter MI-G-63 to NSP (G H Neils), "Mark I Containment Program, Response to NRC on Humphrey Containment Concerns", dated September 29, 1982.

91. General Electric report, NSEO-88-0982, "Mark I Owners Response to Humphrey Containment Concerns", September 1982.

92. Multiple Dynamics Corporation (D F Lehnert) letter No. NSP-01-1908 to NSP (D M Musolf), "Technical Review of GE's Response to the Humphrey Containment Concerns and Their Applicability to the Monticello Plant", dated, May 4, 1984.

93. NRC (D G Eisenhut) letter to NSP (D M Musolf) "Safety Evaluation by the Office of Nuclear Reactor Regulation, Appendix J Review", dated June 3, 1984.

94. NRC (D B Vassallo) letter to NSP, (D M Musolf), "Mark I Containment Long Term Program", dated September 11, 1985.

95. Deleted.

96. NUTECH report, NSP-23-006, "Evaluation of Wetwell-To-Drywell Vacuum Breaker Response to Drywell Spray Initiation", April 7, 1986.

97. NRC (J A Zwolinski) letter to NSP (D M Musolf), "Mark-I Containment Drywell Vacuum Breakers (TAC 57159)", dated January 14, 1987.

98. Deleted.

99. NRC (M P Phillips) letter to NSP (L R Eliason), "Clarifications of Appendix J Requirements", dated January 23, 1991.

100. NSP (T M Parker) letter to the NRC, "Response to Generic Letter 89-10, Supplement 3, Consideration of the Results of NRC-sponsored Tests of Motor Operated Valves", dated April 8, 1991.

101. NRC (W O Long) letter to NSP (T M Parker), "Monticello - Acknowledgement of Generic Letter 89-10 Response (TAC No. 75559)", dated May 18, 1990.

102. NSP Program Document, EWI-08.15.01 "Monticello Nuclear Generating Plant, Motor Operated Valve Program".

103. General Electric report, NEDO-24342, "GE Evaluation in Response to NRC Request Regarding BWR Scram System Piping Breaks", April 1981.

104. NSP (L O Mayer) letter to the NRC, “GE Evaluation of Potential BWR Scram Pipe Breaks - NEDO-24342”, dated June 1, 1981.

105. NUREG-0803, “Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping”, August 1981.

106. NSP (L O Mayer) letter to the NRC, “120 day response to NUREG-0803”, dated December 30, 1981.

107. BWR Owners Group Chairman (S D Floyd) letter to the NRC, “Mark I Hard Pipe Vent Criteria”, dated March 30, 1990.

108. Deleted.

109. Deleted.

110. Deleted. 01101248

111. Deleted.

112. ASME Boiler and Pressure Vessel Code, Section III, Subsection B, 1965 Edition.

113. Deleted.

114. NRC (J G Partlow) Generic Letter 89-16, “Installation of a Hardened Wetwell Vent”, dated September 1, 1989.

115. Deleted.

116. General Electric report NEDO-21888, “Mark I Containment Program, Load Definition Report”, Revision 2, November 1981.

117. Deleted.

118. ASME Boiler and Pressure Vessel Code, Section III, 1980 Edition with Summer 1980 Addenda.

119. ANSI/IEEE Standard 317-1976, “IEEE Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations”.

120. NRC (J G Partlow) Generic Letter 89-10, “Safety-Related Motor-Operated Valve Testing and Surveillance - 10CFR 50.54(f)”, dated June 28, 1989.

121. NUREG-0737, “Clarification of TMI Action Plan Requirements”, November 1980.

122. NRC Regulatory Guide 1.97, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following An Accident”, Revision 2, December 1990.

123. IEEE Standard 323-1974, “IEEE Standard for Qualifying Class IE Equipment for Nuclear Power Generating Stations”.

124. ANSI/IEEE Standard 344-1975, “IEEE Recommended Practices for Seismic Qualification of Class IE Equipment for Nuclear Power Generating Stations”.

125. ASME Boiler and Pressure Vessel Code, Section III, 2004 Edition.

126. Deleted.

127. WRC Bulletin No. 107, “Local Stresses in Spherical and Cylindrical Shells Due to External Loadings”, K R Wichman, A G Hopper and J L Mershon, March 1979.

128. ASME Boiler and Pressure Vessel Code, Section VIII, 1965 Edition.

129. NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment, Resolution of Generic Technical Activity A-24”, December 1979.

130. AEC Report TID-14844, “Calculation of Distance Factors for Power and Test Reactor Sites”, March 23, 1962.

131. General Electric document, 22A5751, “Containment Data Specification, Customer Interface Data”, Revision 4, November 1983.

132. ANSI/ANS 5.1-1979, “American National Standard for Decay Heat Power in Light Water Reactors”.

133. Deleted.

134. Deleted. 01101248

135. NSP (M F Hammer) letter to the NRC, “Seismic Verification of the MSIV Leakage Path at Monticello (TAC No. M96238)”, dated June 15, 1998.

136. NSP (M F Hammer) letter to the NRC , “Supplemental Information Regarding the Seismic Verification of the MSIV Leakage Path at Monticello (TAC No. M96238)”, dated July 20, 1998.

137. NRC (T Kim) letter to NSP (R O Anderson), “Issuance of Amendment Re: Power Uprate Program (TAC No. M96238)”, dated September 16, 1998.

138. NRC (D M Crutchfield) Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety Related Power-Operated Valves”, dated August 17, 1995.

139. Handbook of Chemistry and Physics, 69th Edition, 1988-1989, page D-124, “Limits of Inflamability of Gases and Vapors in Air.”

140. NRC (D L Ziemann) letter to NSP (L O Mayer), License Amendment No. 13, dated October 6, 1975.

141. NRC (J G Keppler) letter to NSP (D E Gilberts), Request for Response to IE Bulletin 80-08 - Examination of Containment Liner Penetration Welds, dated April 9, 1980.

142. NSP (D E Gilberts) letter to the NRC, “Response to IE Bulletin 80-08”, dated July 1, 1980.

143. NSP (C E Larson) letter to the NRC (J G Keppler), Additional Response to IE Bulletin 80-08, “Examination of Containment Liner Penetration Welds”, dated November 10, 1986.

144. NRC report NUREG/CR-3053, “Closeout of IE Bulletin 80-08: Examination of Containment Liner Penetration Welds”, dated July 1984.

145. NRC (C F Lyon) letter to NSP (R O Anderson), Issuance of Amendment 107, re: Reactor Vessel Hydrostatic and Leakage Testing (TAC No. MA4867), dated November 24, 1999.

146. NRC (B K Grimes) Generic Letter 96-06, “Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions”, dated September 30, 1996.

147. NRC (J W Roe) Generic Letter 96-06, “Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions”, Supplement 1, dated November 13, 1997.

148. NRC (C F Lyon) letter to NSP (M F Hammer), “Completion of Licensing Action for Generic Letter 96-06 - Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions” (TAC No. M96835), dated May 18, 2000.

149. Specification NPD-M-43, Rev. 1, “Valve and Actuator Requirements for the Main Steam Isolation Valves”, dated April 5, 1994.

150. General Electric Report NEDO-30832, “Elimination of Limit on Local Suppression Pool Temperature for SRV Discharge with Quenchers”, December 1984.

151. NRC (G M Holahan) letter to BWROG (R Pinelli), “Transmittal of Safety Evaluation General Electric Company Topical Reports: NEDO-30832 entitled *Elimination of Limit on Local Suppression Pool Temperature for SRV Discharge with Quenchers*, and NEDO-31695 entitled *BWR Suppression Pool Temperature Technical Specification Limits*, dated August 29, 1994.

152. NRC (C F Lyon) letter to NMC (J S Forbes), “Monticello Nuclear Generating Plant - Issuance of Amendment RE: Elimination of Local Suppression Pool Temperature Limits (TAC No. MB2064)”, dated January 18, 2002.

153. NMC (J S Forbes) letter to NRC, “License Amendment Request, Elimination of Local Suppression Pool Temperature Limits”, dated May 30, 2001.

154. NRC (D S Hood) to NMC (J S Forbes), “Monticello Nuclear Generating Plant: Issuance of Amendment re: License Amendment Request for Conversion to Option B for Containment Leakage Rate Testing (TAC No. MB4975), dated 2/4/03 (LAR 132).

155. NMC (E.J. Weinkam) letter to NRC, “Application for Technical Specification Improvement to Eliminate Requirements for Hydrogen Recombiners and Hydrogen/Oxygen Monitors Using the Consolidated Line Item Improvement Process”, dated January 30, 2004.

156. NRC (L.M. Padovan) letter to NMC (T.J. Palmisano), “Monticello Nuclear Generating Plant - Issuance of Amendment RE: Elimination of Requirements for Hydrogen Recombiners and Hydrogen and Oxygen Monitors” (TAC No. MC1902), dated May 21, 2004 (LAR 138).

157. Deleted.

158. Deleted. 01101248

159. NMC (TJ Palmisano) letter to NRC, “Supplement 1 to License Amendment Request: Selective Scope Application of an Alternative Source Term Methodology for Re-evaluation of the Fuel Handling Accident”, dated November 23, 2004.

160. Letter from Donald J. Skovhot, AEC to Arthur V. Diehart, NSP; Subject: Drywell to Suppression Chamber immediate actions and requested information, dated January 12, 1973.

161. Letter from L.O. Mayer, NSP to Donald J. Skovhot, AEC; Subject: Report on Torus to Drywell Vacuum Breakers, dated March 12, 1973.

162. Letter from Dennis L. Ziemann, NRC to L.O. Mayer, NSP; Subject: Amendment change #17 to the Technical Specifications, dated February 26, 1975.

163. NRC (P S Tam) letter to NMC (J T Conway), “Monticello Nuclear Generating Plant - Issuance Of Exemption To Certain 10 CFR Part 50, Appendix J, Requirements (TAC No. MD2395)”, dated December 7, 2006.

164. Regulatory Guide 1.7, “Control of Combustible Gas Concentrations in Containment”, Revision 3, March 2007.

165. Topical Report BN-TOP-1,Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants, Revision 1.

166. GE Document GE-NE-0000-0060-9174-R1, "Containment Analysis Input Parameters (Data Form OPL-4A)," April 19, 2007.

167. GE Hitachi EPU Project Task Report GE-NE-0000-0060-9229-TR-R3, Revision 3, "Task T0400: Containment System Response," February 2011 (Monticello calculation number 11-173) 01101248

168. GE Hitachi Report NEDC-33322P, Revision 3, "Safety Analysis Report for Monticello Constant Pressure Power Uprate," October 2008.

169. NRC (T A Beltz) letter to NSPM (K D Fili), "Monticello Nuclear Generating Plant - Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate (TAC No. MD9990)," dated December 9, 2013.

170. NSPM letter L-MT-10-002 (T J O'Connor) to NRC, "Monticello Extended Power Uprate: Updates to Enclosures 1, 3, 5 and 7 of L-MT-08-052, and Enclosure 3 of L-MT-09-047 (TAC MD9990)," dated January 25, 2010.

171. NSPM letter L-MT-09-048 (T J O'Connor) to NRC, "Monticello Extended Power Uprate: Response to NRC Containment and Ventilation Review Branch Request for Additional Information dated March 19, 2009 and March 26, 2009 (TAC No. MD9990), dated July 13, 2009.

172. NSP (D M Musolf) letter to NRC "Submittal of the Monticello Mark I Containment Long Term Program Plant Unique Analysis Report," dated December 15, 1982.

173. NMC EPU Project Task Report T0409, Rev. 0, "Task T0409: Standby Gas Treatment System," January 2008 (Monticello calculation 11-237).

174. GE Licensing Topical Report NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, July 2003.

175. GE Hitachi EPU Project Task Report GE-NE-0000-0060-8791-TR-RO, Revision 0, "Task T0300: Nuclear Boiler System," November 2007 (Monticello calculation number 11-221). 01101248

176. GE Report NEDE-20566P-A, "General Electric Model for LOCA Analysis in Accordance with 10CFR50 Appendix K," dated September 1986.

177. GE Licensing Topical Report NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," dated February 1999.

178. BWR Owner's Group Emergency Procedure and Severe Accident Guidelines, Appendix B, Revision 3, February 2013.

179. Monticello procedure C.5-GM-02.02, Revision 17, "Emergency Procedures Guideline to Plant Specific Technical Guideline Differences Document."

180. GE Hitachi EPU Project Task Report GE-NE-0000-0062-2954-TR-R0, Revision 0, "Task T0900: Transient Analysis," December 2007.

181. NSPM letter L-MT-13-034 (M A Schimmel) to NRC, "Monticello Extended Power Uprate (EPU): Response to Request for Additional Information - Electrical Engineering Branch (TAC MD9990)," dated April 10, 2013.

182. Monticello Calculation 12-040, Revision 0A, "Containment Accident Pressure Assessment of ECCS Pump NPSHA Requirements for Extended Power Uprate (EPU)."

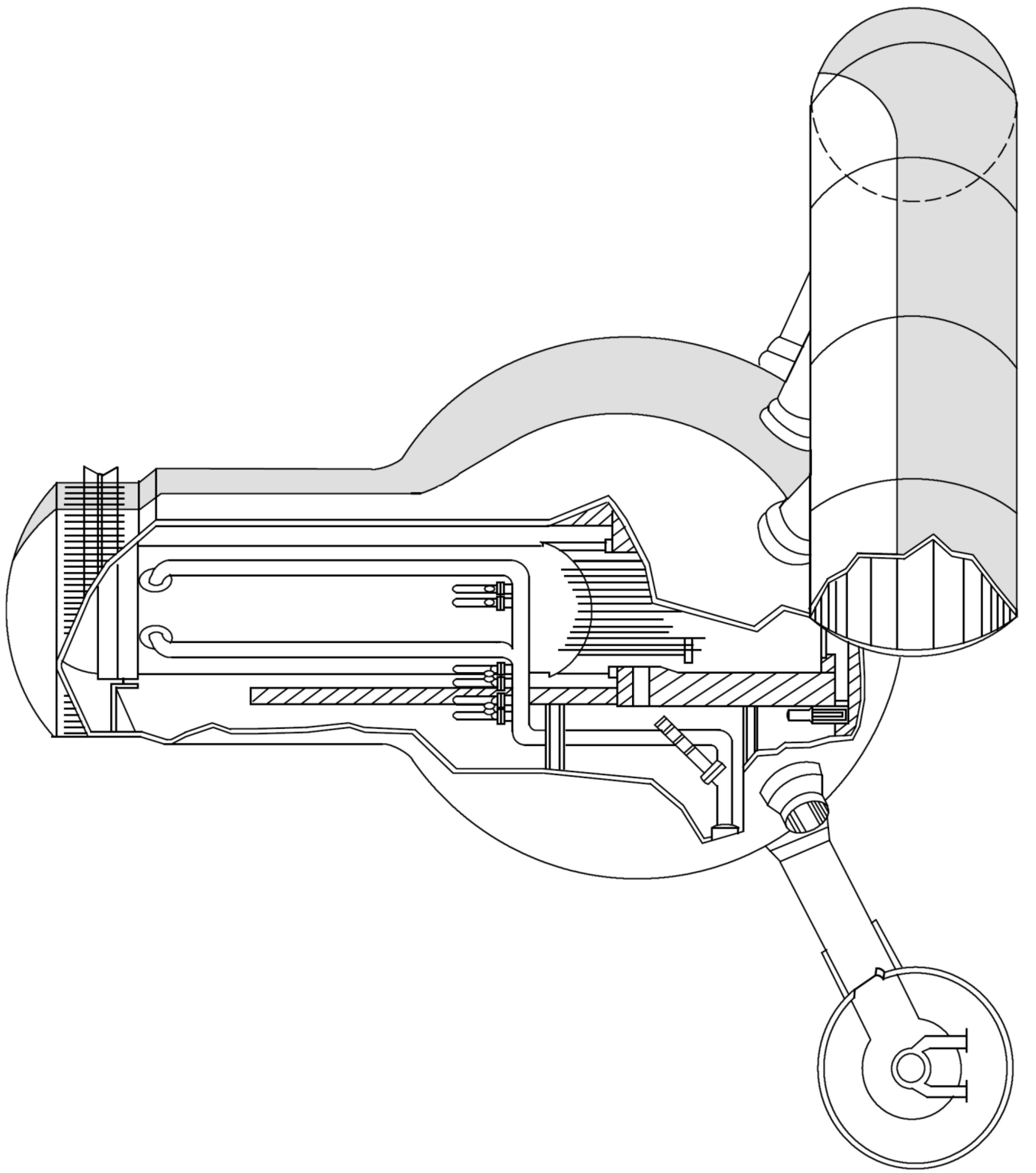
183. Engineering Change 20901, Revision 0, "NPSH Margin Assessment of the ECCS Pumps During Appendix R Events."

184. GE Hitachi Report NEDC-33435P, Revision 1, "Safety Analysis Report Monticello Maximum Extended Load Line Limit Analysis Plus," December 2009.

185. NRC (T A Beltz) letter to NSPM (K D Fili), "Monticello Nuclear Generating Plant - Issuance of Amendment No. 180 to Renewed Facility Operating License Regarding Maximum Extended Load Line Limit Analysis Plus (TAC No. ME3145)," dated March 28, 2014. 01457570

FIGURES

Figure 5.2-1 Pressure Suppression Containment System



USAR5.2- 1

Figure 5.2-2 Typical Electrical Penetration Assembly Canister

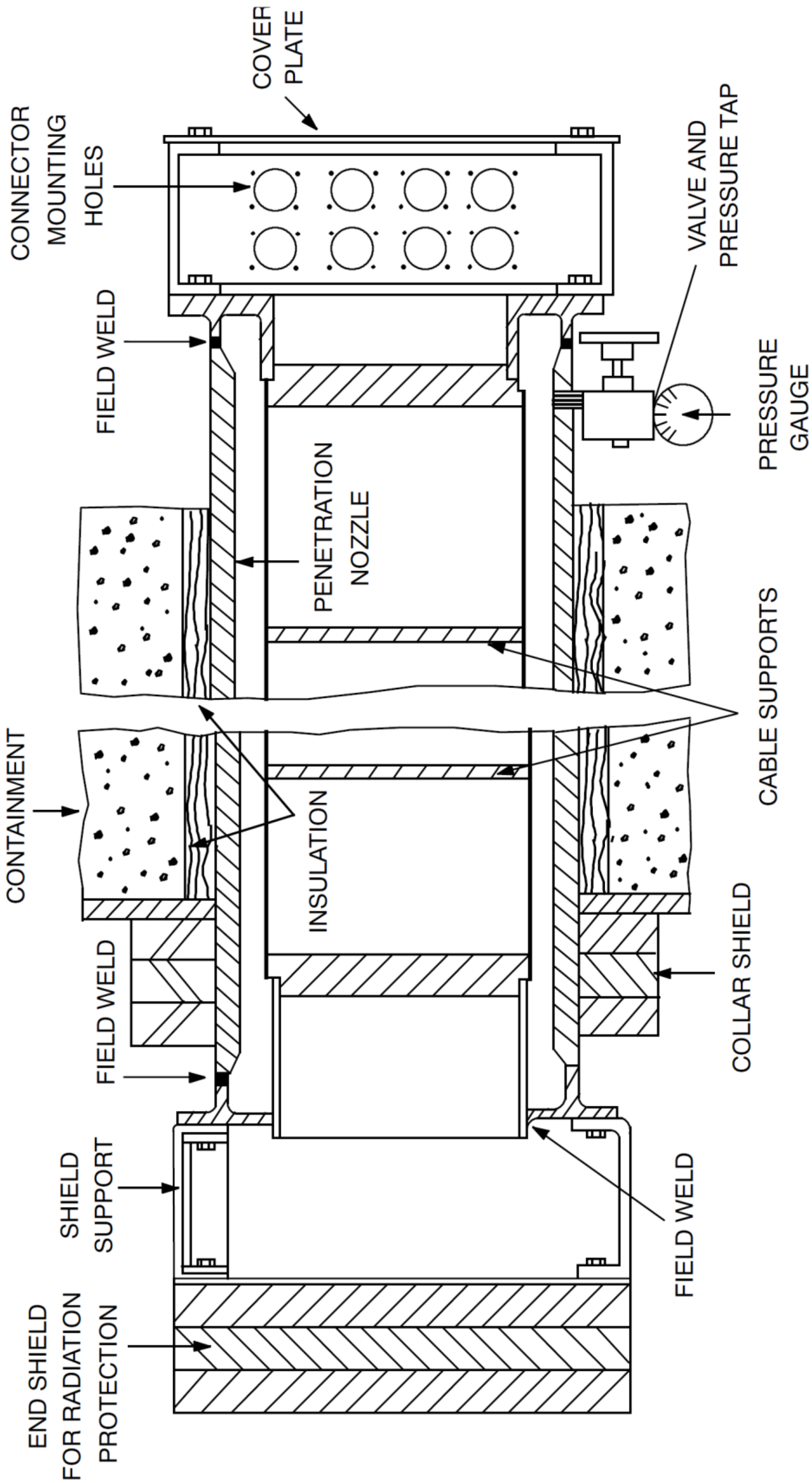


Figure 5.2-2a Modular Electrical Penetration Assembly

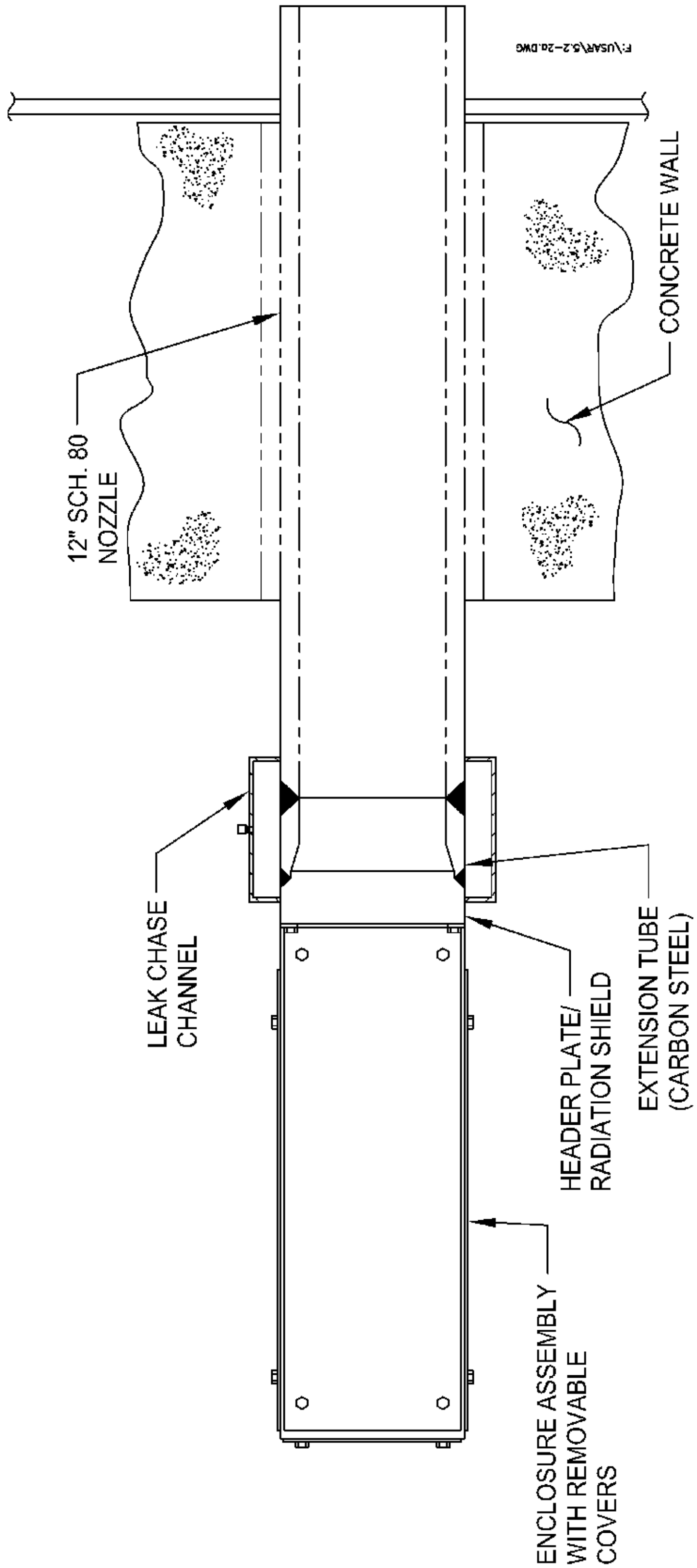


Figure 5.2-3 Center Section - Low Voltage Power and Control Electrical Penetration Assembly

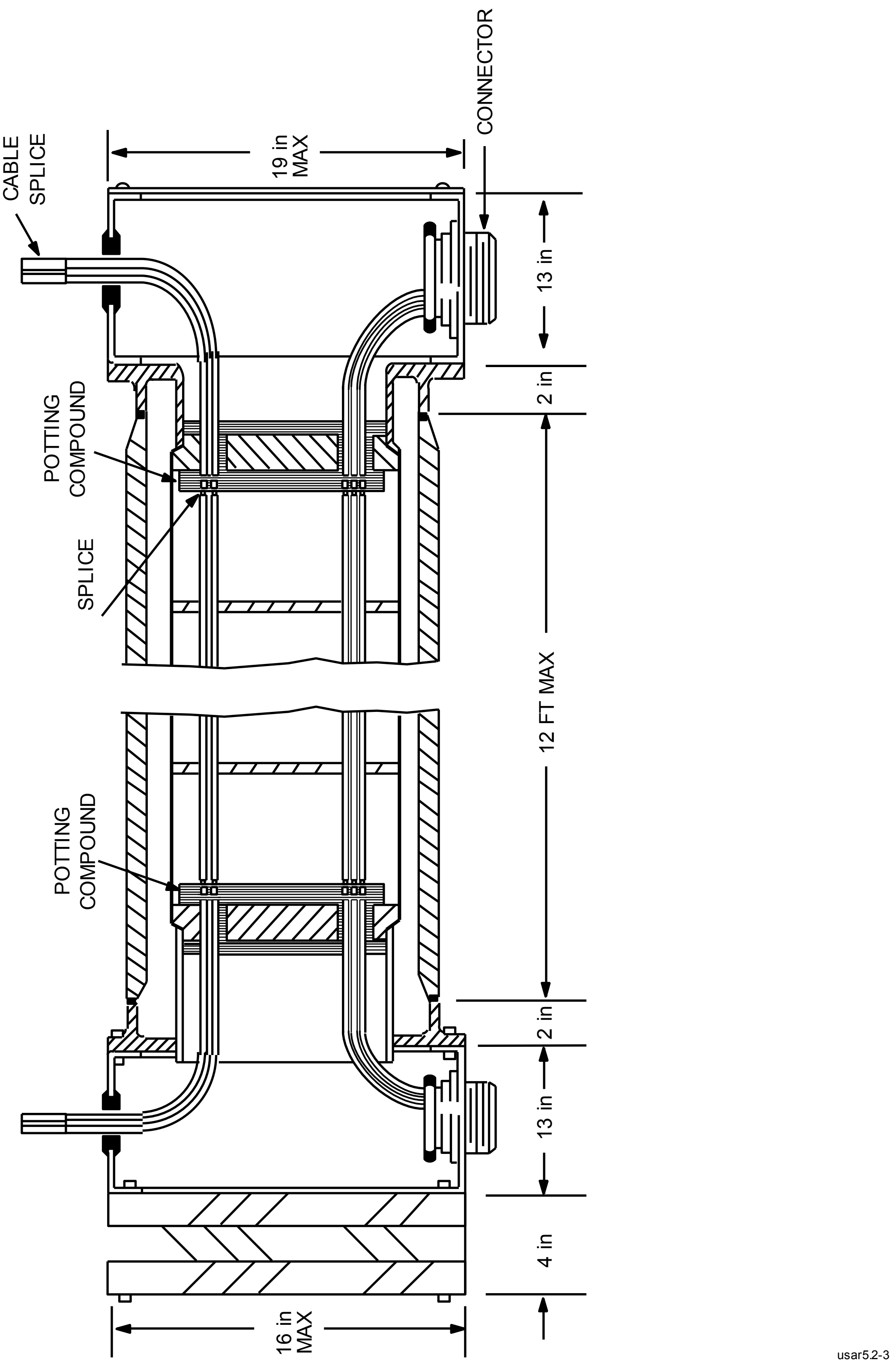


Figure 5.2-4 Center Section - Shielded Signal Cable Electrical Penetration Assembly

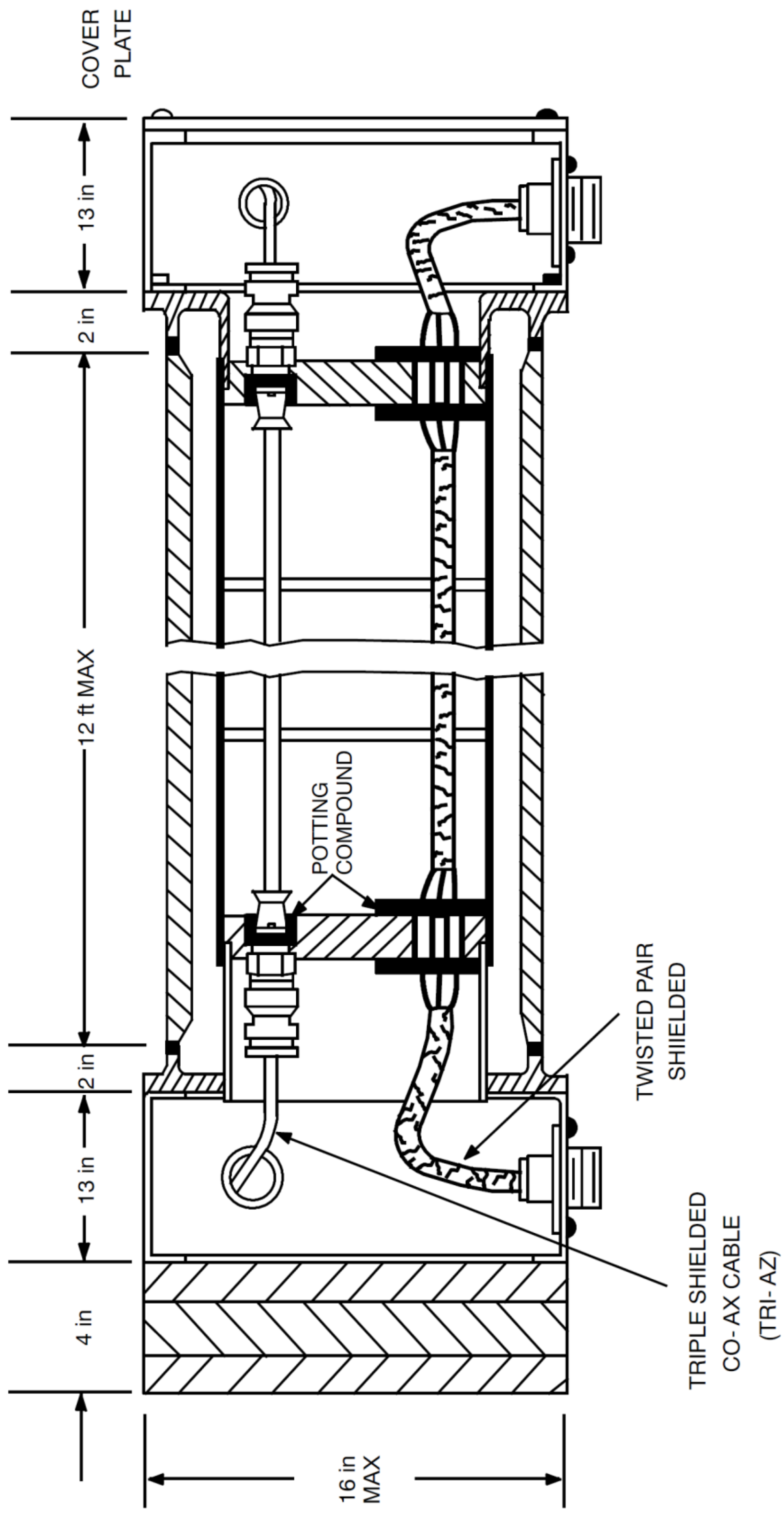


Figure 5.2-5 Center Section - High Voltage Power Electrical Penetration Assembly

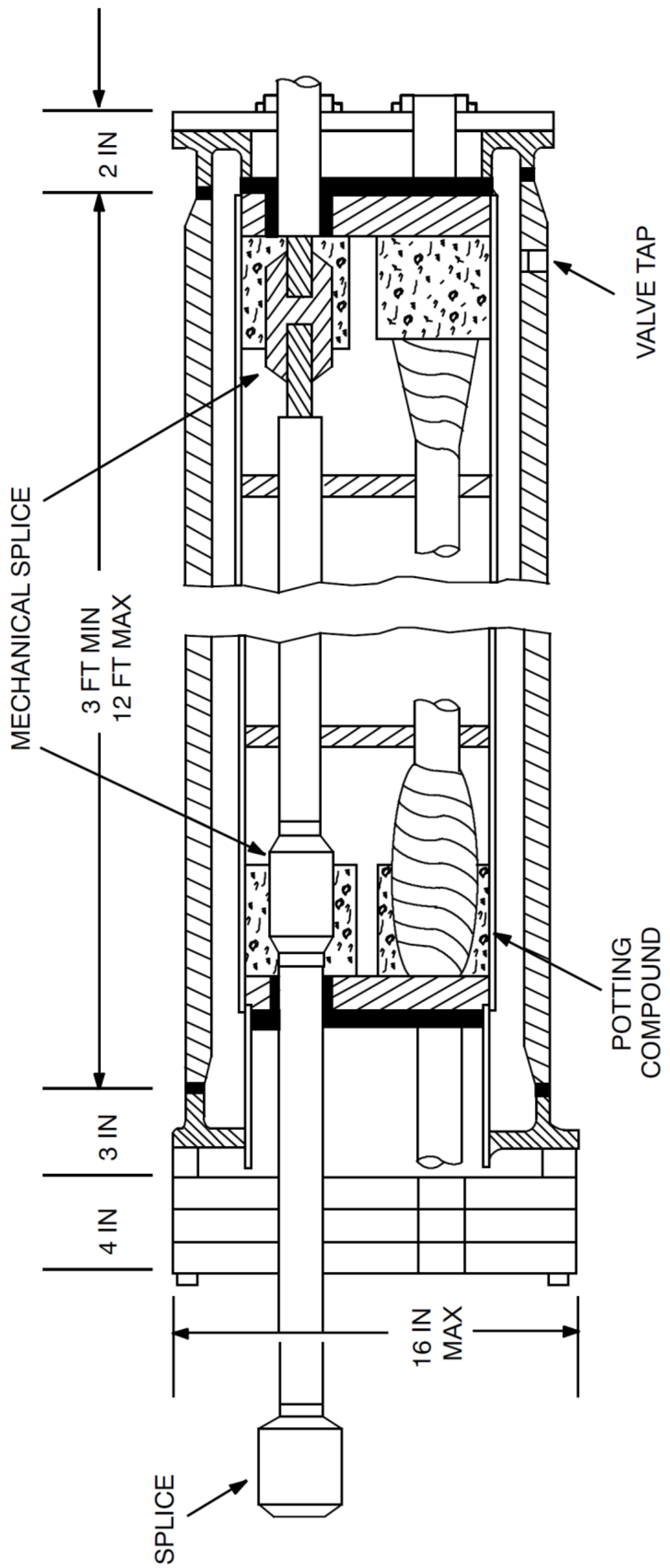
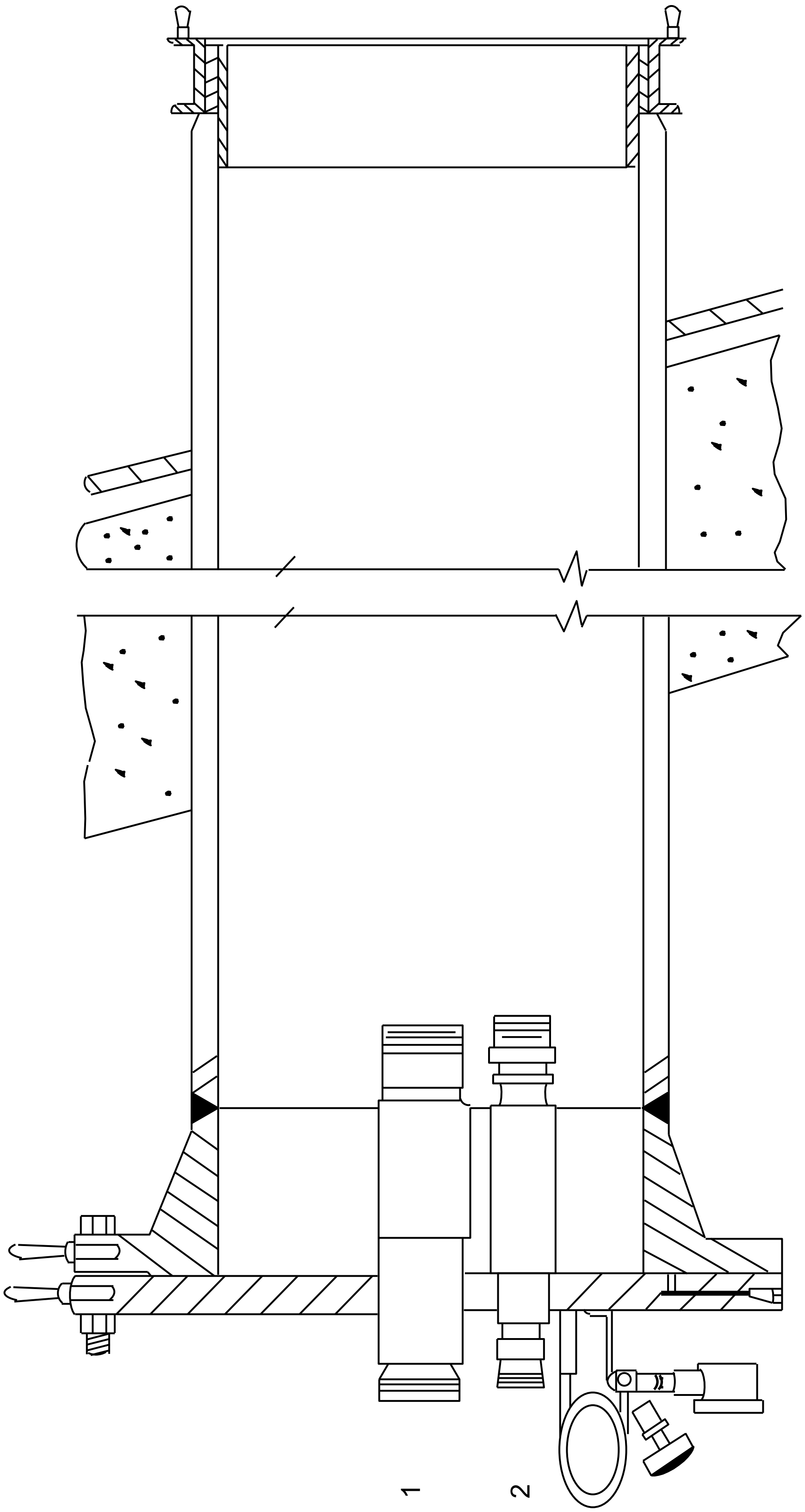


Figure 5.2-5a Electrical Penetration Assembly (Drywell Penetrations X-106 & X-107)



1. Thermocouple Connector (18 circuits)
2. Triaxial Connector (total of six - only one shown)

USAR5.2-6

Figure 5.2-6 Center Section - Hot Fluid Piping Penetration Assembly

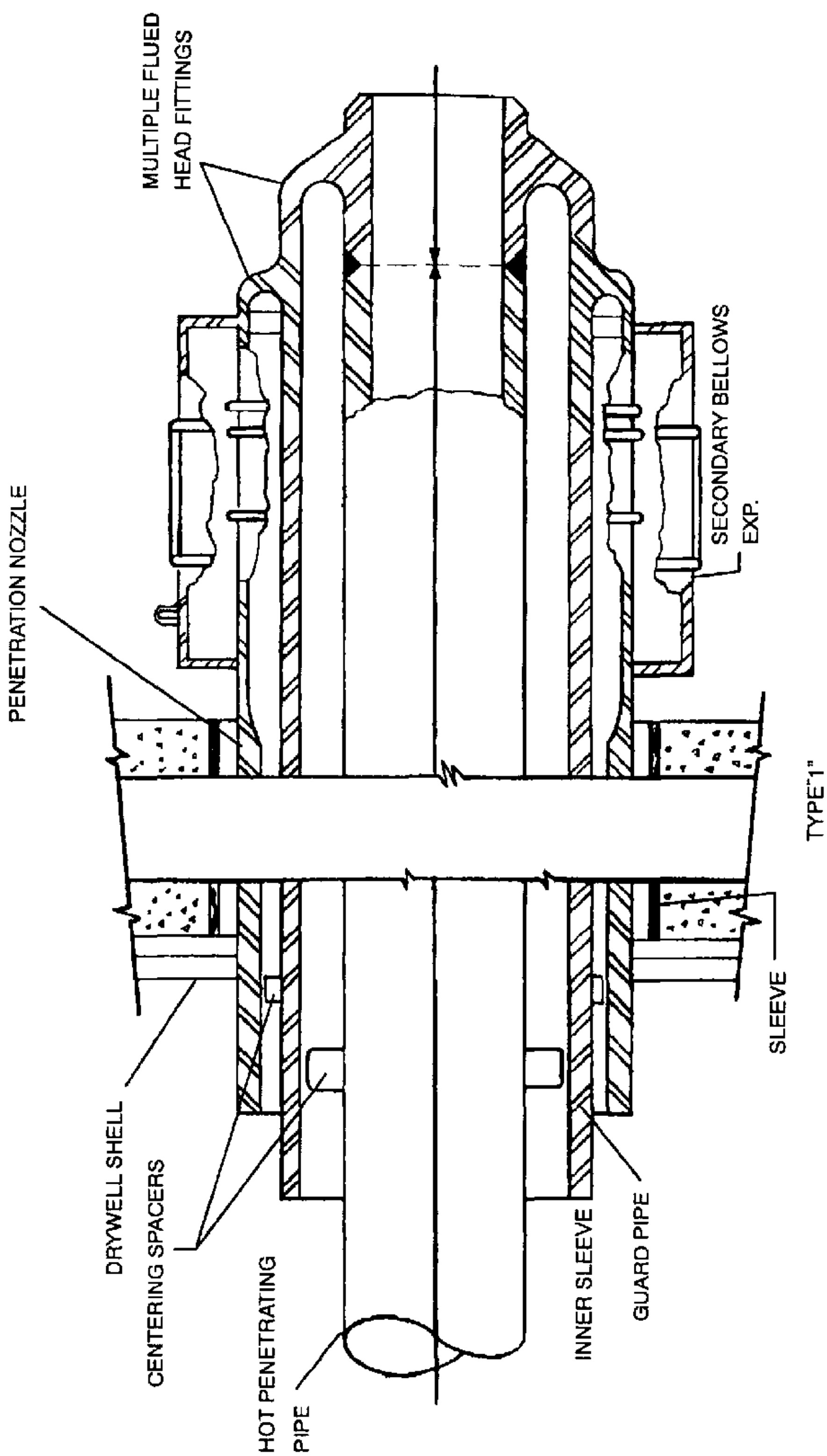


Figure 5.2-7 Center Section - Cold Fluid Piping Penetration Assembly

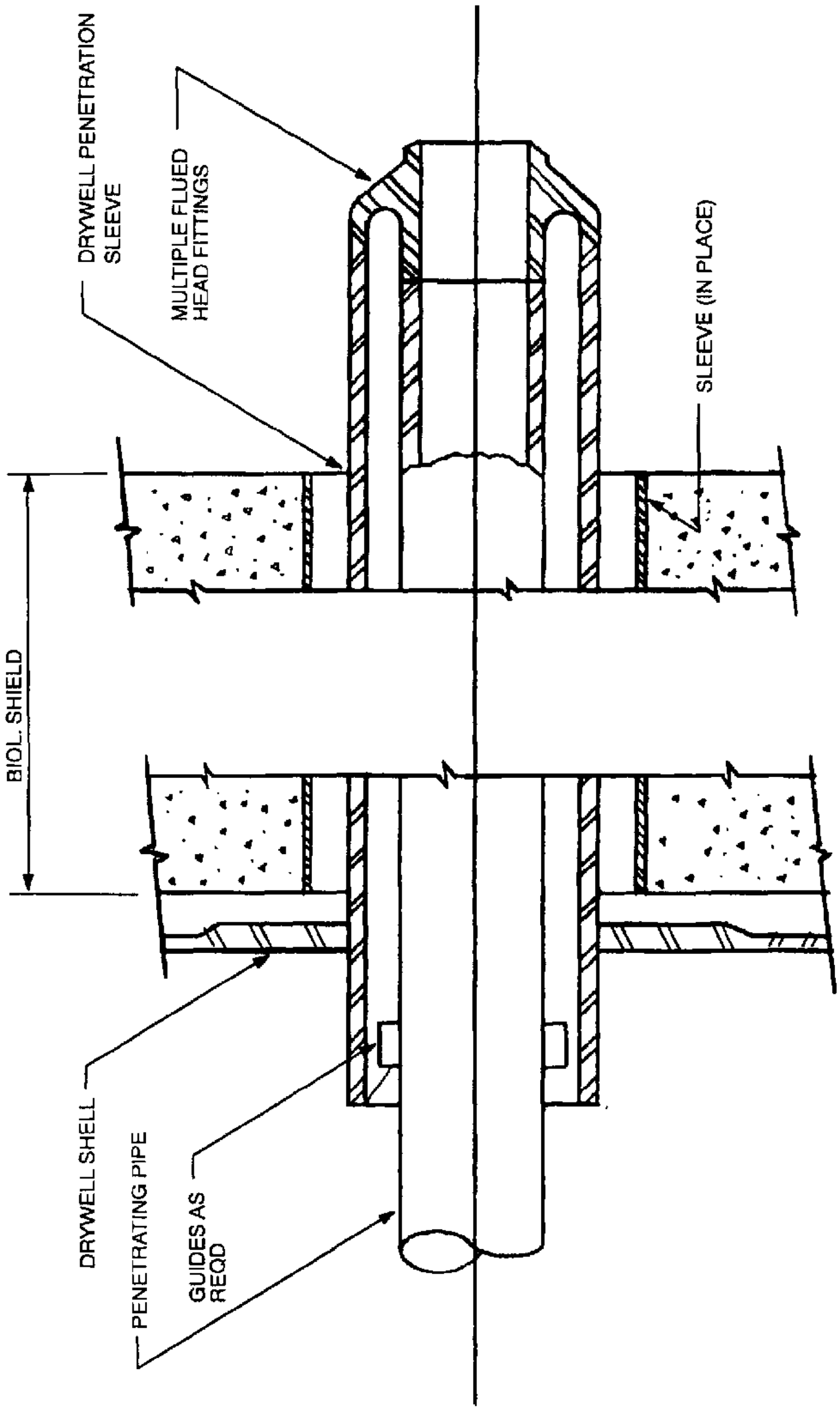
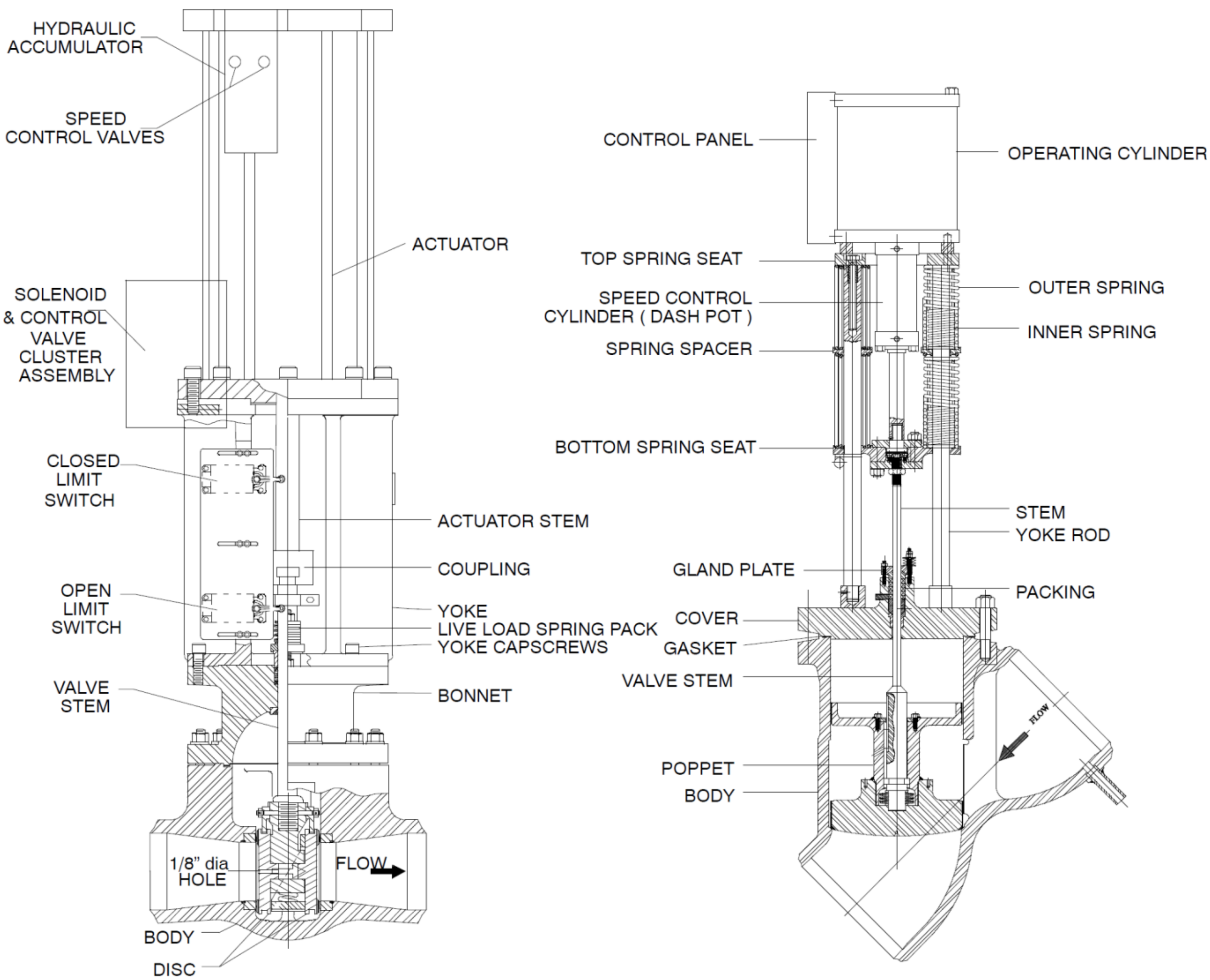


Figure 5.2-8 Main Steam Isolation Valves

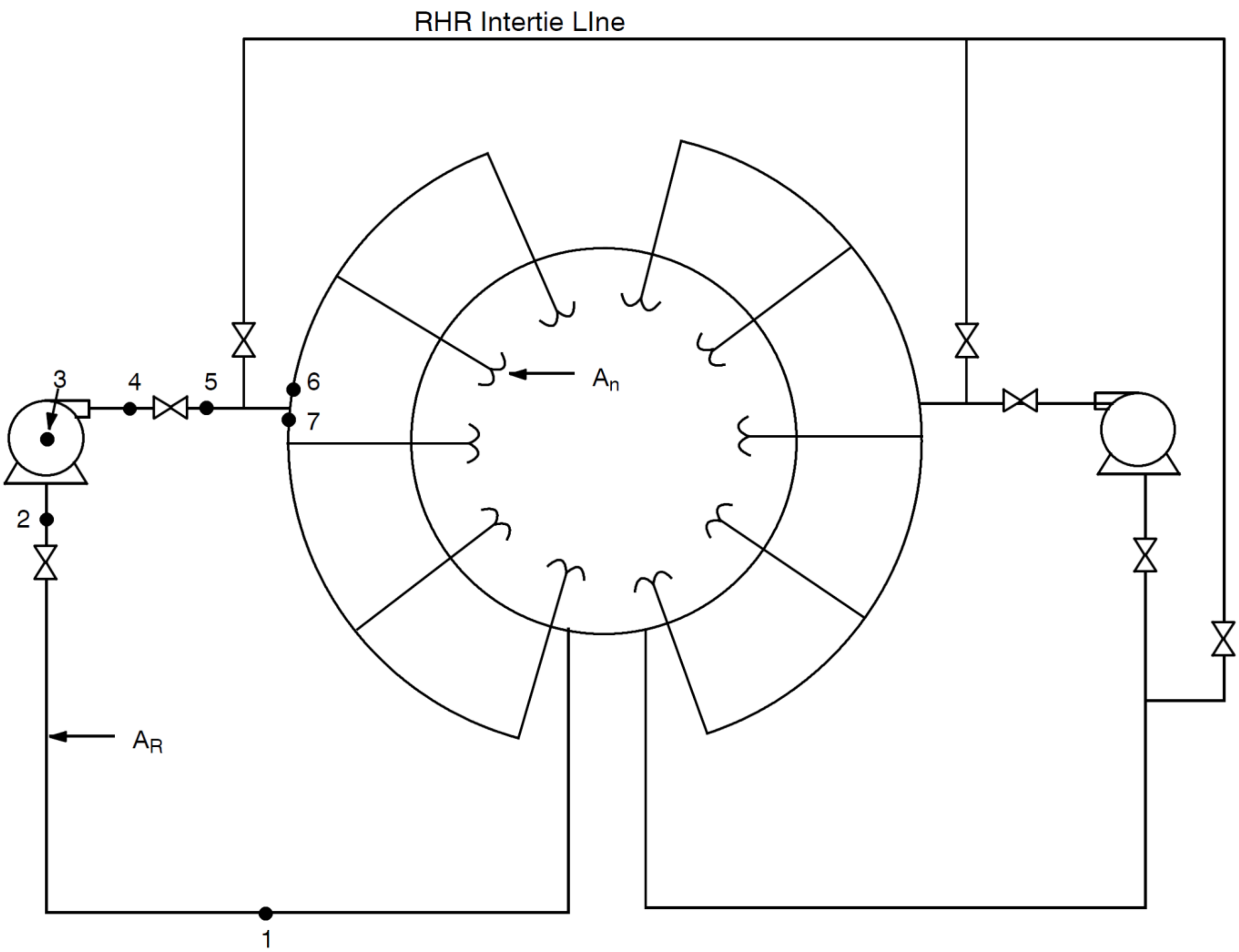


OUTBOARD MSIVs
DOUBLE DISC GATE VALVE

INBOARD MSIVs
WYE TYPE GLOBE VALVE

u00001
USAR5.2-8

Figure 5.2-9 Recirculation Line Break - Illustration



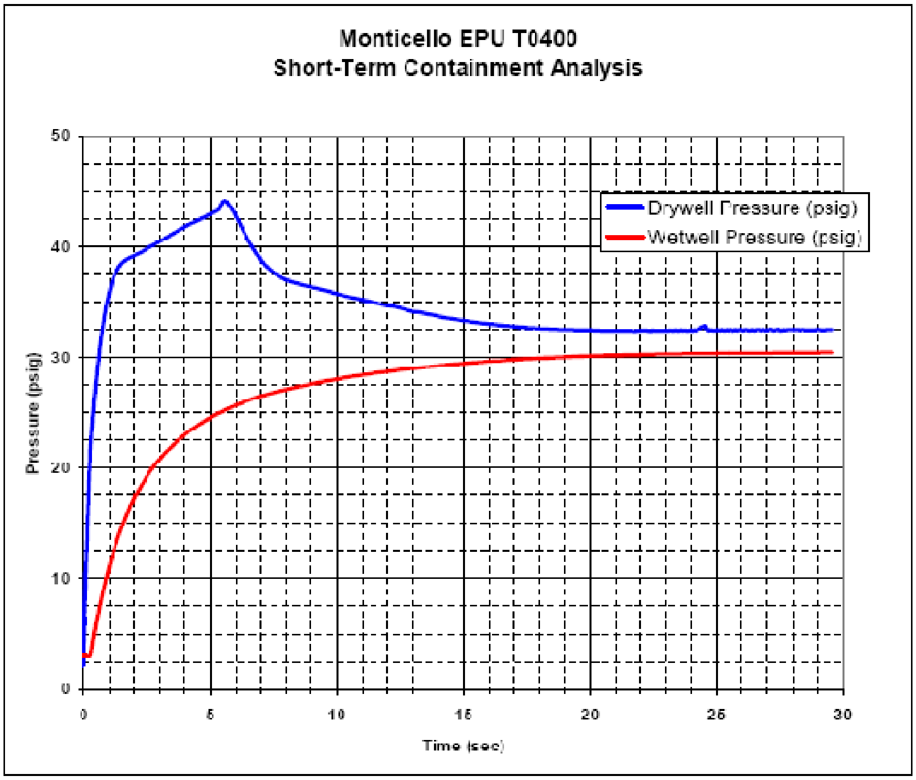
A_R = Flow area in recirculation line

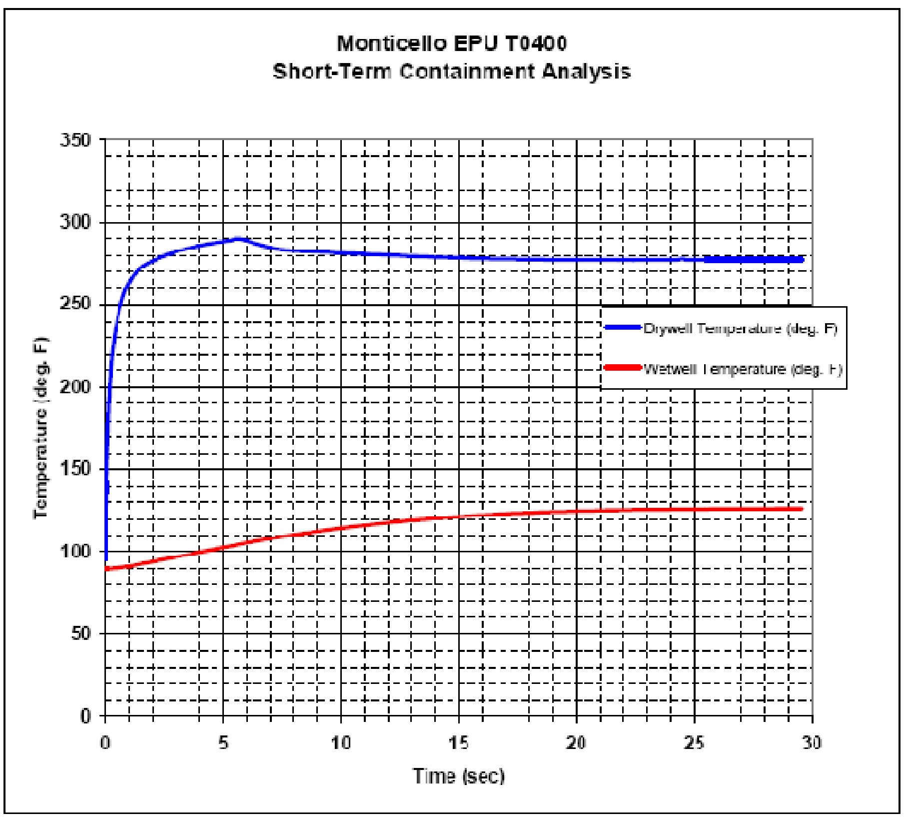
A_E = Flow area through RHR Intertie LIne

A_n = Flow area of a jet pump nozzle

N = Number of jet pumps per header

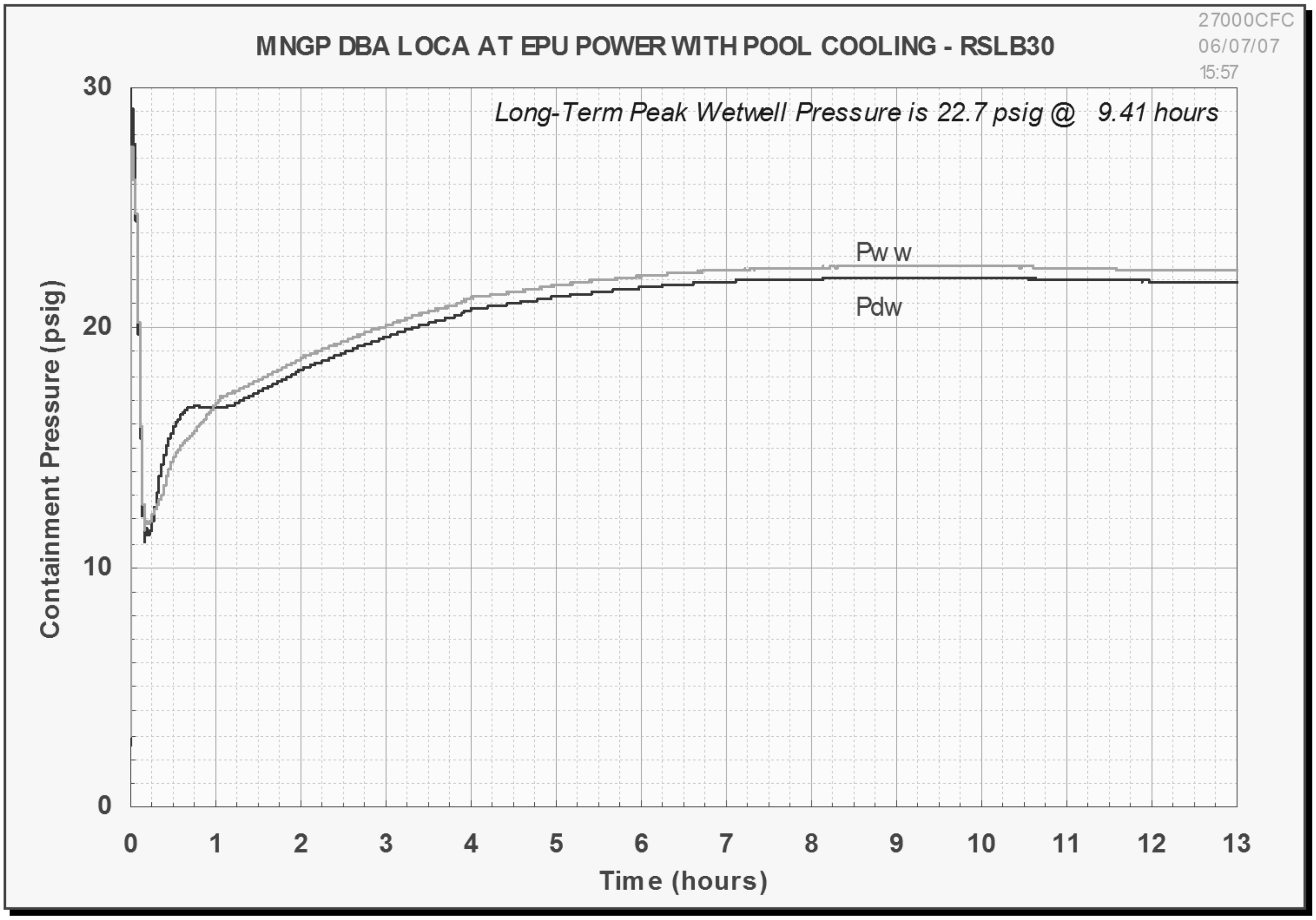
Figure 5.2-oa Drywell and Wetwell Response DBA-LOCA-Short Term





01101248

Figure 5.2-ob Drywell and Wetwell Pressure DBA-LOCA-LongTerm

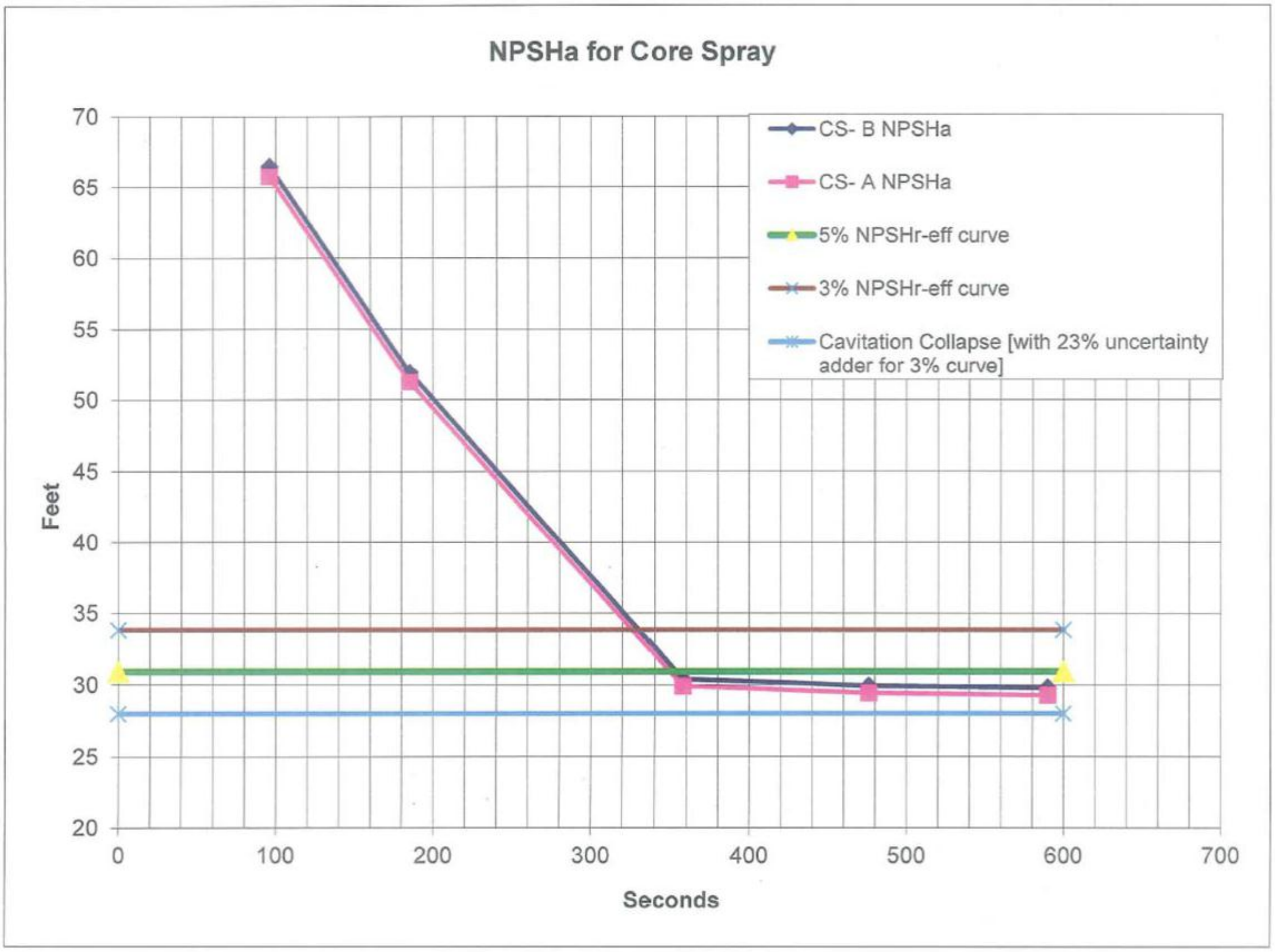


01101248

Pdw and Pww

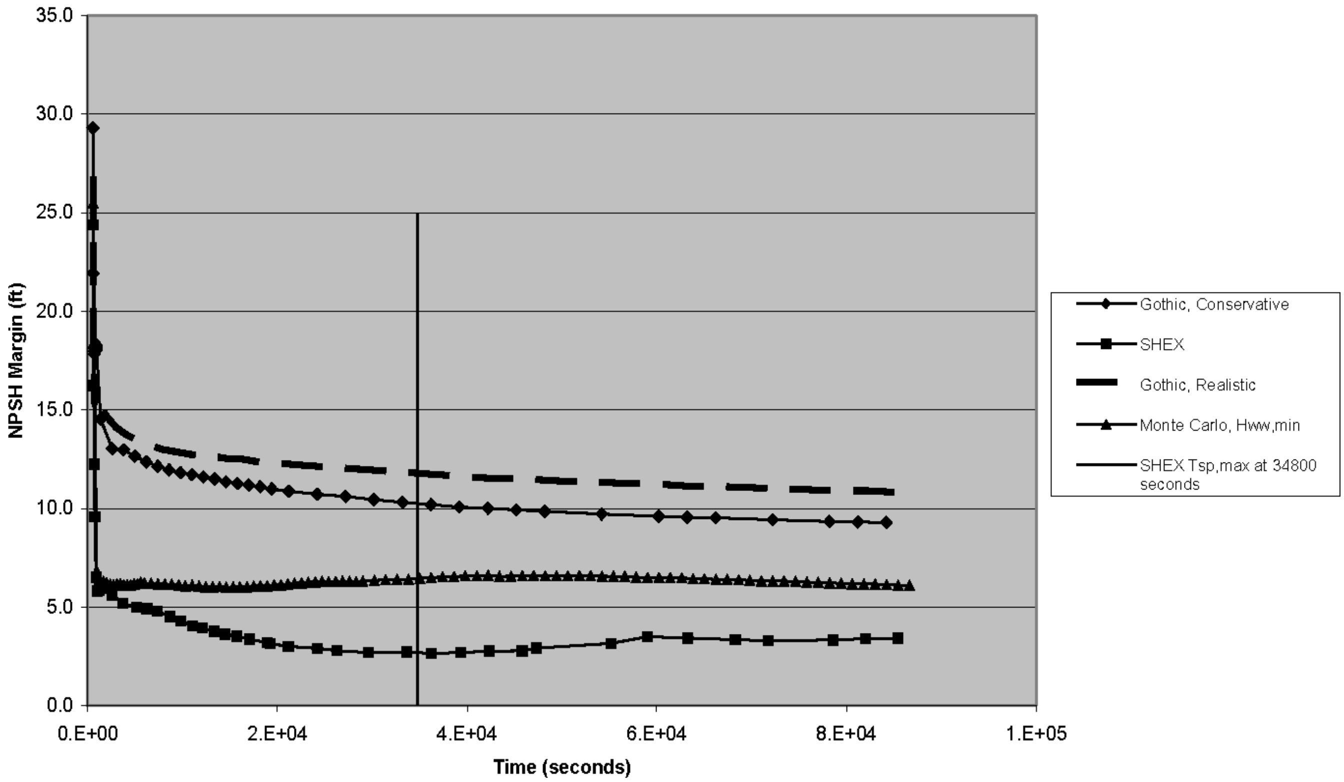
This figure provides wetwell and drywell pressures for the case that maximizes suppression pool temperature. The peak wetwell pressures are for the case that maximizes containment pressures which is the single active failure of an emergency diesel generator.

Figure 5.2-oc DBA LOCA Short Term Analysis - Core Spray Pump NPSH Available



01101248

Figure 5.2-od DBA-LOCA Long Term Analysis - Core Spray Pump NPSH Margin



01101248

GOTHIC Realistic – This analysis used inputs that are met 98% of the time at MNGP for suppression pool temperature, service water temperature, suppression pool volume and drywell temperature.

GOTHIC Conservative – This analysis used the same inputs as the SHEX analysis except that a temperature dependent K-value is used for RHR heat exchanger performance. In addition the code used is the best estimate GOTHIC code vs. the conservative SHEX code.

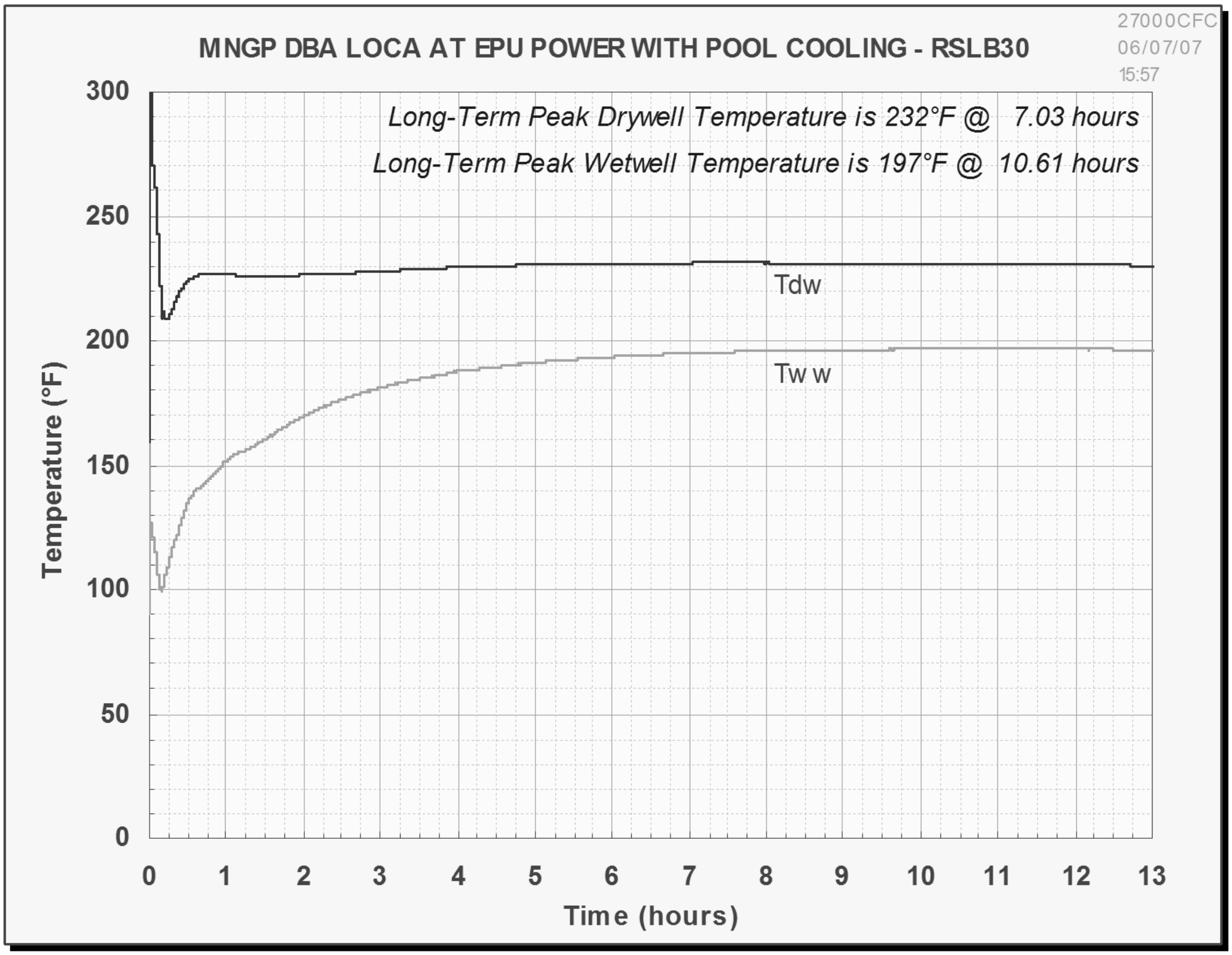
Monte Carlo – This analysis was provided in NEDC-33347P, Appendix A (Reference 85). This allowed inputs to vary from the most limiting deterministic values while maintaining a 95/95 assessment of containment response.

SHEX – This analysis is the licensing basis analysis performed using a combination of the most limiting input assumptions and containment cooling provided by containment spray with a constant K-value for RHR heat exchanger performance.

Note: The time of the maximum suppression pool temperature based on the SHEX analysis is 34,800 seconds and is 207F.

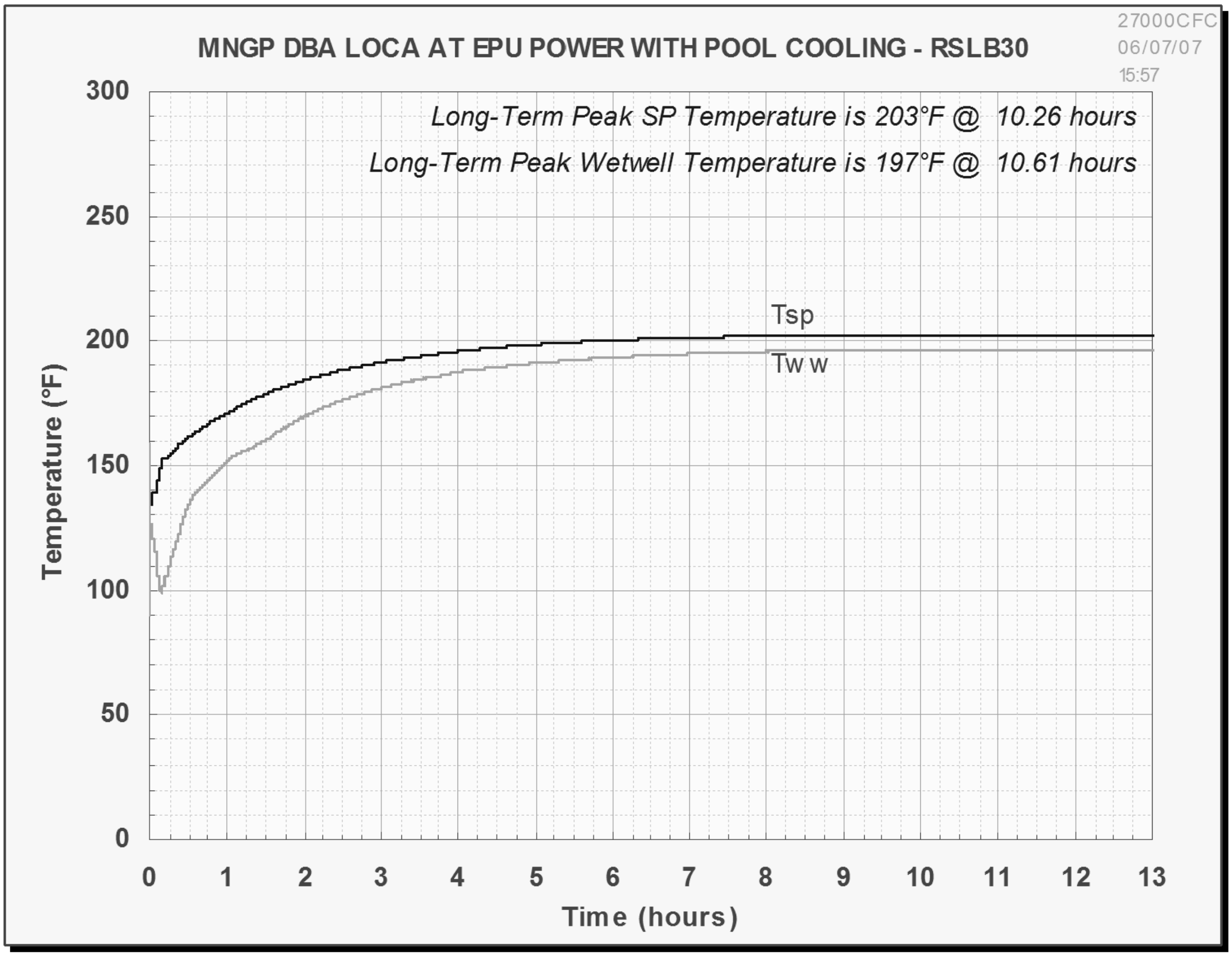
This shows the limiting core spray pump NPSH response for the long term, i.e. >600 seconds. In the first 600 seconds of the event NPSH margin is negative after about 300 seconds until operator action is taken to reduce pump flow rates to values assumed in the long term core cooling analysis.

Figure 5.2-p Drywell Temperature Response



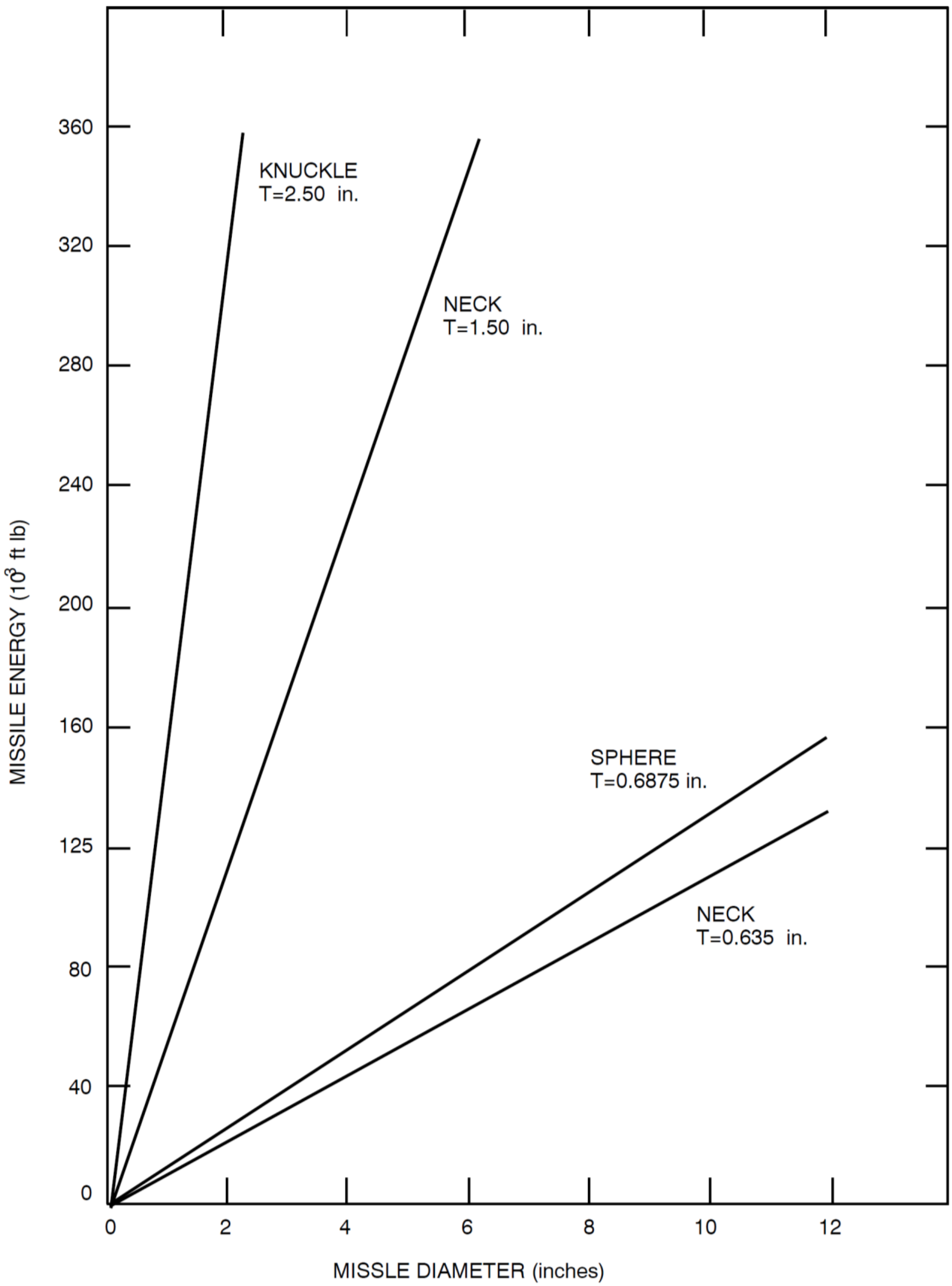
01101248

Figure 5.2-q Suppression Pool Temperature Response



01101248

Figure 5.2-23 Energy Requirement to Penetrate Drywell



01101248

Figure 5.2-28 Elevation View of Containment

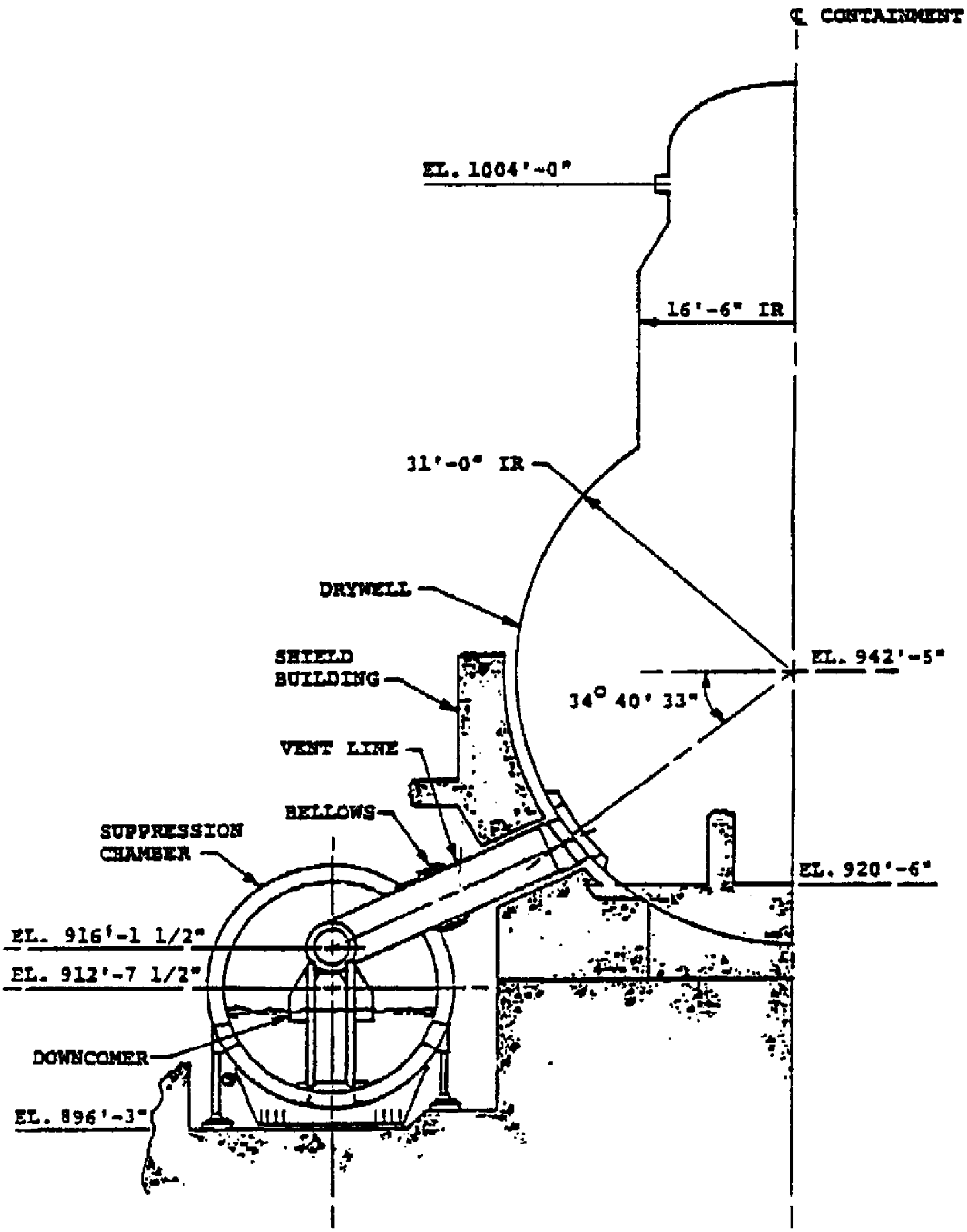


Figure 5.2-29 Plan View of Containment

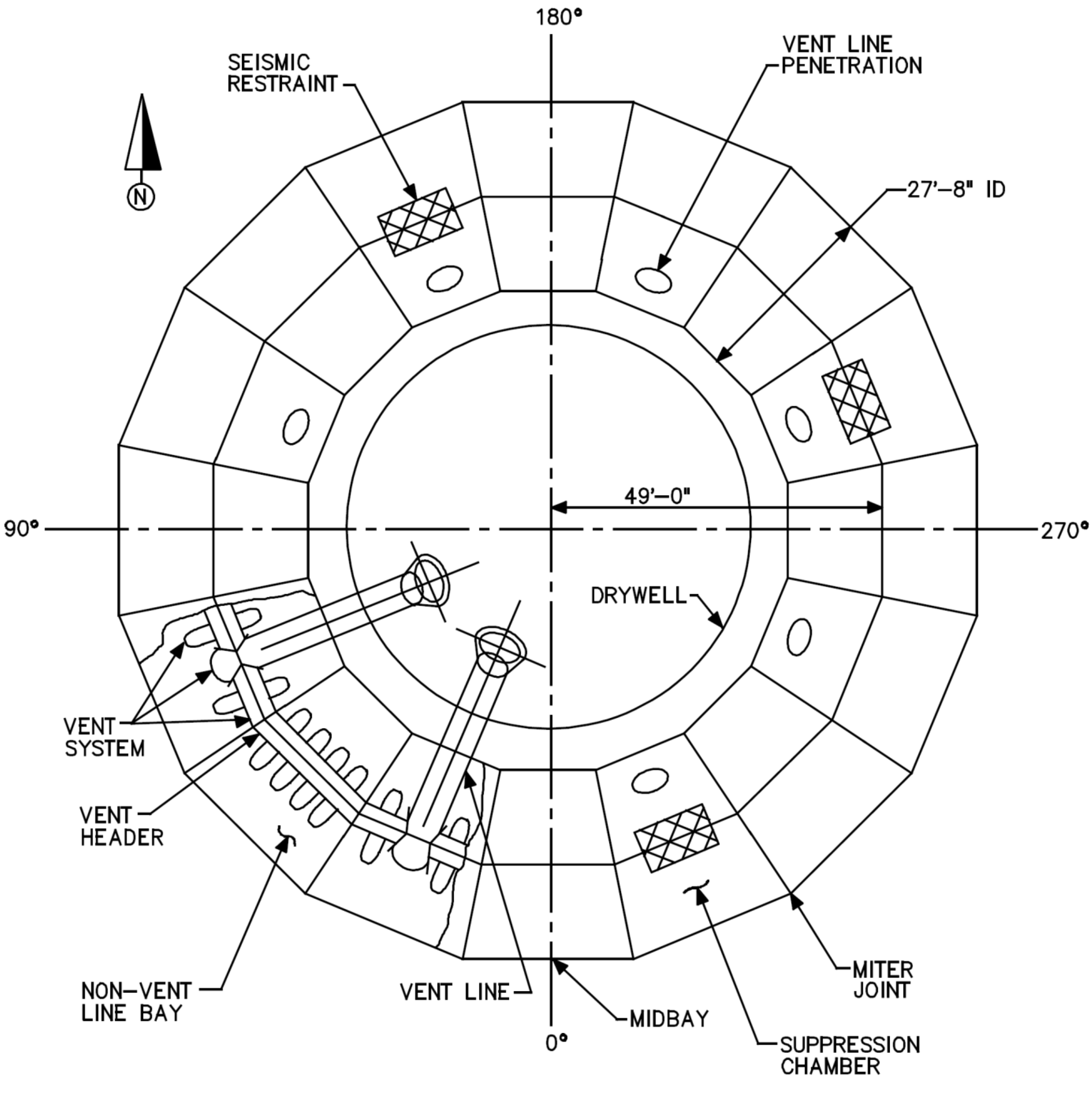


Figure 5.2-30 Developed View of Suppression Chamber Segment

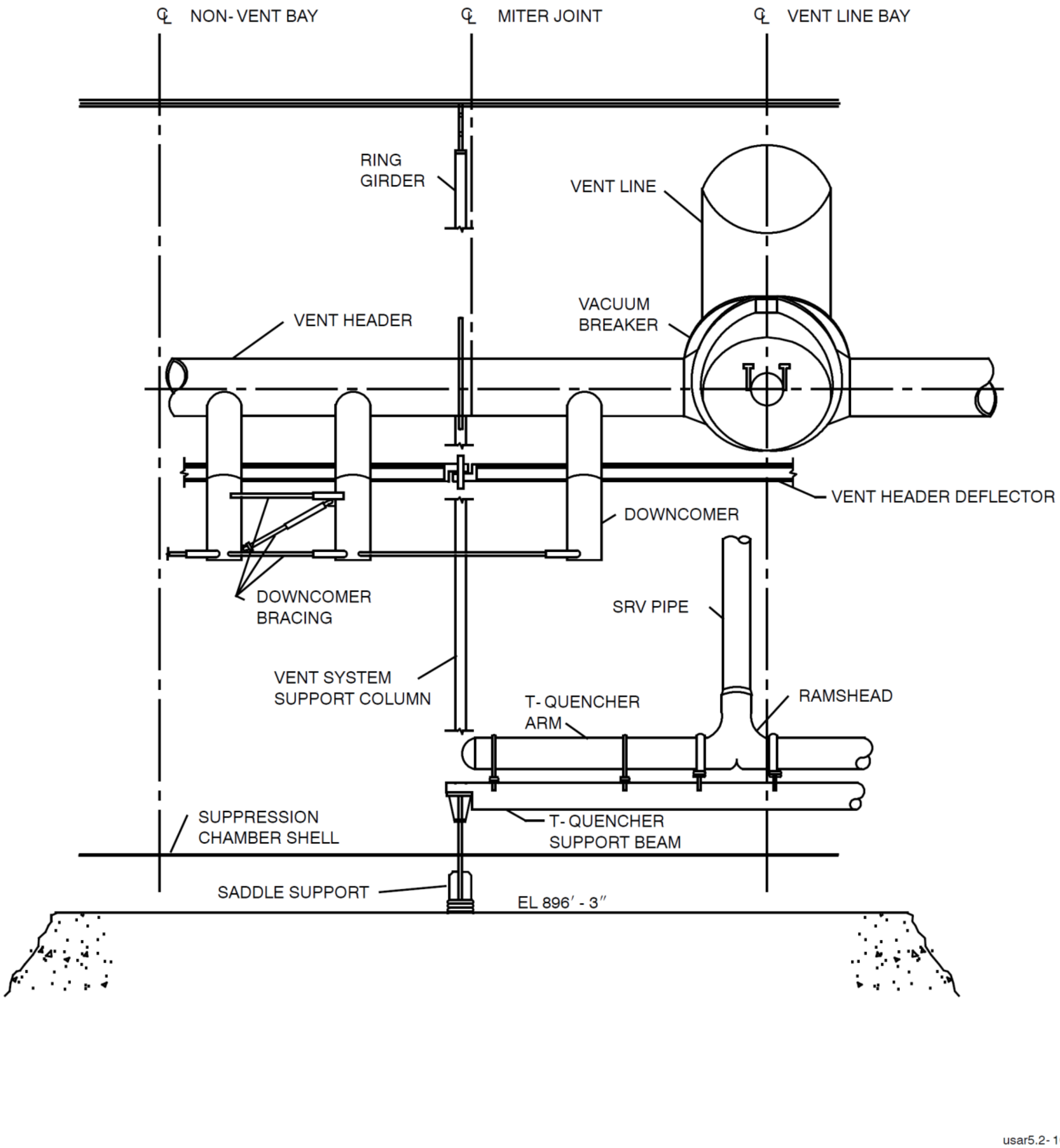


Figure 5.3-2 Calculated Range of Reactor Building Exfiltration Rates as a Function of Wind Velocity