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January 11, 1983

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attention: Ms. E. G. Adensam, Chief
Licensing Branch No. 4

Re: Catawba Nuclear Station
Docket Nos. 50-413 and 50-414

Dear Mr. Denton:

In order to facilitate the completion of the review of the Catawba FSAR, Duke Power Company is transmitting herewith responses or revised responses to open items of the following technical review branches.

Attachment 1 - Mechanical Engineering
Attachment 2 - HGEB
Attachment 3 - Materials Engineering
Attachment 4 - Corrosion Engineering
Attachment 5 - Reactor Systems
Attachment 6 - Containment Systems
Attachment 7 - Core Performance

These responses will be included in FSAR Revision 7.

Very truly yours,

Hal B. Tucker

Hal B. Tucker

ROS/php
Attachments

cc: Mr. James P. O'Reilly, Regional Administrator
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Attachment 1

Mechanical Engineering Branch

Loading combinations and allowable stresses for ASME III Class 1 components and supports are given in Tables 3.9.1-2 and 3.9.1-3. For Faulted condition evaluations, the effects of the safe shutdown earthquake (SSE) and loss-of-coolant accident (LOCA) are combined using the square root of the sum of the squares (SRSS) method. Justification for this method of load combination is contained in References 4 and 5. The responses to other loading combinations defined in Table 3.9.1-2 are combined using the absolute sum method.

3.9.1.4.7 Balance-of-Plant Components, Piping and Supports

Seismic category I piping other than NSSS is analyzed for the faulted condition utilizing elastically-determined stresses compared against allowables provided in Table F-1322.2-1 of Appendix F of the ASME Code Section III. This is in accordance with applicable sections of the ASME Code or ANSI B31.1 as appropriate. Load combinations and allowable stresses for faulted and other plant conditions are discussed in Section 3.9.3.

Dynamic seismic analysis for the SSE is performed on this piping utilizing the model combination method in accordance with USNRC Regulatory Guide 1.92.

All seismic Category 1 supports are designed and analyzed for the Normal, Upset, Faulted and Test Conditions. The stress limits for normal and upset conditions are as presented in ASME III Subsection NF and Subsection NA Appendix XVII for the portion of the support within the NF boundary. The stress limit for the faulted load combination is as specified in Subsection NF with the exception that to avoid column buckling in compression, for members subject to local instability associated with compression flange buckling in flexural members and web buckling in plate guides, the allowable stress has been limited to 2/3 of the critical buckling stress. For support design there is no inelastic analysis. Temperature effects for material properties are considered. For the portion of the support not within the NF boundary and for supports for B31.1 piping, stress limits are as provided in MSC-SP58 or the AISC Manual.

For integral attachments to the pressure boundary the rules of ASME Section III, Subsection NB, NC, ND are used as applicable.

3.9.2 DYNAMIC TESTING AND ANALYSIS

3.9.2.1 System Operational Test Program

3.9.2.1.1 System Vibration Testing

ASME III requires that piping design minimize vibration and that piping systems be observed under startup or initial operating conditions to insure that steady state vibration in piping systems is not excessive. As part of the preoperational test program described in Chapter 14, steady state piping vibration and transient response of piping due to valve closures, pump starts, and other changing configurations are observed. Details of the tests are given in Table 14.2.12-1.

MEB Item 78 Duke Class A, B, C, and F systems satisfy the criteria of Regulatory Guide 1.68, Revision 2, Appendix A, 5.o.o, for systems to be included in the vibration test

program. Systems which will be subject to steady state vibration testing are identified in Table 3.9.2-1. Duke Class A, B, C, and F systems not in this table have been omitted for one or more of the following reasons:

a) Vibration testing is not performed on piping with nominal size 1 in. or less, with the exception of the Reactor Coolant System instrumentation lines (including pressurizer level and reactor vessel level) which are specifically included in the test program. The consequences of the failure of small line does not justify the expense of designing them to meet the vibration requirements.

b) Vibration testing is not performed on piping containing gases, rather than liquids, because the relatively small forces exerted by flowing gases preclude the development of excessive vibration. High flow velocity steam lines are an exception and will be tested.

c) Vibration testing is not performed on piping systems which have no flow, or have less than 1% of the normal operating life span of the station, because of the lack of or relatively short duration of flow induced vibration in these pipes.

The acceptance criteria for piping vibration is that the maximum measured amplitude shall not induce a stress in the piping greater than one-half the endurance limit corresponding to 10^6 cycles as defined in Section III of the ASME Boiler and Pressure Vessel Code, 1974, Summer 1974 Addenda.

MEB Item 77

In the steady state, vibration testing of piping, the systems will be placed in the normal operating mode. Qualified personnel shall perform a visual inspection of the systems, noting locations of maximum vibration. These locations will be used for the measurement of the pipe vibration. Data collected, with suitable instrumentation, will be compared with acceptance criteria based on the piping material (carbon or stainless steel). If an unfiltered vibration reading exceeds the acceptance criteria, a spectrum analyzer will be used to obtain a spectrum plot of the vibration at that point. The location, along with the pertinent thermal and hydraulic conditions of the system at that time, is noted and the results are sent to Design Engineering for evaluation and recommendations.

The piping systems listed in Table 3.9.2-1 will be subjected to routine transients, valve closures, pump starts, etc., during system functional testing. Inspections will be carried out by qualified personnel after the transient event to verify the occurance of any excessive piping motion. Excessive motion will be evidenced by induced damage to piping supports, loosened hangers, out-of-range snubbers, damaged spring cans, etc. If excessive movement or vibration is indicated, an evaluation will be done by Design Engineering and corrective action taken as necessary.

Transient vibration testing will be done on systems as listed in Table 3.9.2-1a. A graded approach is used in testing.

Attachment 2

HGEB

2.4.2 FLOODS

2.4.2.1 Flood History

The maximum flow recorded for the Catawba River at USGS gage number 1460 near Rock Hill, South Carolina is 151,000 cfs (4273 m^3/s) on May 23, 1901. The period of record for this gage is 1895 to 1903 and 1942 to the present. Two major floods not recorded by the gage are the flood of 1916 with an estimated flow at Wylie Dam of 299,400 cfs (8473 m^3/s) and the flood of 1940 with an estimated flow of 169,160 cfs (4748 m^3/s). Six reservoirs exist on the Catawba River upstream from the station and Lake Wylie. They have a combined usable storage of approximately 1.5 million Ac-ft (1.85×10^9 m^3). Because of such a large volume of storage, the floods of record are well modified and the annual flood peaks on the main stem of the Catawba do not represent the uncontrolled flood potential of the basin. Table 2.4.2-1 shows the return period of annual peak floods for the Catawba River at the USGS gage near Rock Hill.

The flood of August 1940 caused Lake Wylie to reach a maximum surface water elevation of 575.0 ft (175 m) msl, 5.6 ft (1.7 m) above full pond.

2.4.2.2 Flood Design Considerations

Flood levels for the site are analysed for the following flood producing phenomena:

a. Probable Maximum Flood (PMF) resulting from the probable maximum precipitation in the drainage area.
b. A 25 year frequency flood passing through Lake Wylie combined with a seismic failure of Cowans Ford Dam, the largest upstream reservoir.
c. A Standard Project Flood (SPF) passing through Lake Wylie combined with the failure of one of the upstream dams due to an Operating Basis Earthquake (OBE). The SPF is considered equal to one-half of the PMF.

The effect of wind on wave height and runup at this site is also analyzed.

The maximum static water elevation of 592.4 ft (180.6 m) msl occurs during a SPF combined with the failure of Cowans Ford Dam. The station yard elevation is at elevation 593.5 ft (180.9 m) msl.

Conservative engineering analysis, such as those presented in Regulatory Guide 1.59 "Design Basis Floods for Nuclear Power Plants", are used in the PMF analysis. Appendix A of Regulatory Guide 1.59 was used in making the flood study evaluation at Catawba. In summary, descriptions for determining probable maximum flood, hydrologic characteristics, flood hydrograph analysis, precipitation losses and base flow, runoff model, probable maximum precipitation estimates, channel and reservoir routing, seismically induced floods, water level determinations, and coincident wind-wave activity are provided in Section 2.4.3.

2.4.2.3 Effects of Local Intense Precipitation

Q240.13 The plant site is provided with a surface water drainage system that is designed and constructed to protect all safety related facilities from flooding

during a local PMP. Modifications to the drainage system will be evaluated and accomplished under the pertinent requirements of the operational quality assurance program to ensure against increasing the flood vulnerability of safety related systems or components. As discussed in Section 2.4.1.1, exterior access to safety related buildings are at elevation 594.0 ft. (181.1m) msl.

The yard drainage system subdivides the plant site into sub-basins, each of which has a catch basin for a runoff water inlet. Each catch basin is sized based on the area of its sub-basin, consequently both 18 inches and 24 inches nominal diameter inlets are used on the site. The individual inlets are connected by corrugated metal pipe, fully coated with a paved invert, which join to provide several different networks that carry the runoff to Lake Wylie. Subdivision of the Powerhouse Yard into sub-basins is established so that runoff water does not flow overland more than 250 feet (76.2 m) to reach a catch basin. The average sub-basin is characterized by an inverted pyramid with a top area of 0.31 acres and a corresponding apex depth of 1.27 feet below the yard high point (Elev. 593.5 feet). Major features of the yard drainage system are shown on Figure 2.4.2-1.

Q240.13 Based upon Hydrometeorological Report No. 33 (Reference 1), the probable maximum precipitation is 29.7 in. (75.4 cm) within a six-hour period. The maximum distribution sequence for this six-hour period, according to U. S. Army Corps of Engineers procedure (Reference 2) is as follows:

Time (Ending Hour)	Incremental PMP Inches	Incremental PMP (cm)	Accumulative PMP Inches	Accumulative PMP (cm)
1	3.0	(7.6)	3.0	(7.6)
2	3.6	(9.1)	6.6	(16.8)
3	4.4	(11.2)	11.0	(27.9)
4	11.3	(28.7)	22.3	(56.6)
5	4.1	(10.4)	26.4	(67.1)
6	3.3	(8.4)	29.7	(75.4)

Inflow from the PMP is due to precipitation which falls directly on the yard, buildings, and the lower Construction Yard.

With the exception of the Reactor Building, the roofs of safety-related structures are designed with no obstructions, so that water flows directly off roofs and there is no accumulation. A gutter drain system catches the water and routes it to collection points. These collection points then discharge directly into the yard drainage system. The Reactor Building roof drainage system is designed for a rainfall intensity of 5.0 in/hr (12.7 cm/hr). Intensities in excess of 5.0 in/hr (12.7 cm/hr) result in ponding. However, once the water level reaches El. 711.34 ft (216.3 m) msl, the water flows directly off the roof. The Reactor Building roof is designed to safely carry live loading due to ponding as discussed in Section 3.8. In determining the effect of a local intense PMP on the Powerhouse Yard, it is assumed that water flows directly off the Reactor Building without ponding or discharging through the roof drainage system.

Total inflow is computed using the rational method which assumes 95 percent runoff and an instantaneous time of concentration. The formula corresponding to this rational method is:

$$Q_i = \frac{CiA}{145.2}$$

where

Q_i = PMP inflow, Ac.-ft. per 5 minutes
C = Runoff coefficient = 0.95
i = Incremental PMP, inches per hour
A = Total drainage area = 139.56 acres

Discharge into the yard drainage system is controlled by slotted catch basin covers. It is conservatively assumed that each catch basin inlet is 18 inches in diameter with a gross area of 1.77 square feet and an effective opening of 0.69 square feet. The effective opening is obtained by reducing the gross area by 61 percent to account for the slotted catch basin covers. The resulting outflow for all basins in the powerhouse yard is calculated using the orifice equation:

Q240.13

$$Q_o = ca\sqrt{2gH}$$

where

Q_o = Orifice outflow, cfs
C = Orifice coefficient = 0.60
a = Total effective opening of catch basins
= (141 C.B.) x (0.69 ft^2 per C.B.) = 97.29 ft^2
g = Acceleration due to gravity = 32.2 ft/sec^2
H = Depth of ponding above average catch basin inlet elevation (592.23 feet).

Once ponding reaches the yard high point (Elev. 593.5), sheet outflow over the northeast and south ends of the yard begins. This sheet outflow is calculated using the weir equation:

$$Q_w = CLh^{3/2}$$

where

Q_w = Weir outflow, cfs
C = Weir coefficient = 2.70
L = Length of weir = 913 feet
h = Depth of ponding above yard high point.

The Puls graphical flood routing method is used to predict the elevation of ponding in the yard due to the previously discussed PMP inflow, catch basin

outflow, and sheet outflow. Results of the flood routing are presented on Figure 2.4.2-2. At no time will ponding exceed Elevation 594.0, and therefore local PMP will not result in flooding of any Category I structures.

All yard drainage pipes individually and within a network are designed using Manning's equation for pipe flowing full. Accumulative totals are used throughout the networks to determine pipe sizes. All pipe gradients are 0.5 percent or greater. The invert elevations of pipe discharge points are shown on Figure 2.4.2-1.

Inspection of the catch-basin inlets to the yard drainage system will be made prior to Unit 1 fuel loading and will be conducted annually until at least two years after Unit 2 fuel loading. The inspections will be performed and documented in accordance with pertinent requirements of the site quality assurance program. Any condition which may increase the flood vul-
Q240.13 nerability of safety related systems and components will be corrected. The inspection program will be re-evaluated two years after Unit 2 fuel loading and the need for any subsequent inspections will be determined at that time.

Ice accumulation occurs only at infrequent intervals because of the temperate climate. Maximum winter precipitation concurrent with ice accumulation do not result in flooding of Category I structures.

2.4.3 PROBABLE MAXIMUM FLOOD (PMF) ON STREAMS AND RIVERS

2.4.3.1 Probable Maximum Precipitation

A search, made of historically great storms which occurred near the Catawba River basin is used to obtain the hypothetical flood characteristics of peak discharge, volume, and hydrograph shape considered to be the most severe "reasonably possible" at the Catawba site. The storms, listed on Table 2.4.3-1, are believed to be the greatest to occur in the southeastern part of the country. Table 2.4.3-1 lists the locations of storm centers and maximum rainfall depths and durations for a drainage area equal to that above the Wylie Dam.

The greatest storm over the Wylie drainage area is recorded for the period July 13-17, 1916. However, greater amounts of precipitation occurred in Elba, Alabama, and Bonitoy and Yankeetown, Florida as shown in Table 2.4.3-1. It is of note that the later storms all occurred immediately along the coastal area and are expected to produce diminishing amounts of precipitation by transposing these storms inland some 200 mi (322 km) to the Wylie watershed. Maximum-depth-duration of rainfall, from a study made by the Hydrometeorological Section of the Weather Bureau for the Savannah River above Hartwell dam site, is included in Table 2.4.3-1 for comparison purposes since the location is very close to the Catawba River watershed. The Savannah River study uses the storm of July 13-17, 1916 as a guide for the determination of maximum rainfall. However, to arrive at a maximum possible precipitation and transposing the storm over the Savannah River basin, an adjustment is made to increase the precipitation values by 42 percent. To arrive at the Probable

Attachment 3

Materials Engineering Branch

6.0 ENGINEERED SAFETY FEATURES

6.1 ENGINEERED SAFETY FEATURE MATERIALS

6.1.1 METALLIC MATERIALS

6.1.1.1 Materials Selection and Fabrication

Typical materials specifications used for components in the Engineered Safety Features (ESF) are listed in Table 6.1.1-1, Engineered Safety Feature Materials. In some cases, this list of materials may not be totally inclusive. However, the listed specifications are representative of those materials used. Materials utilized are procured in accordance with the materials specification requirements of the ASME Boiler and Pressure Vessel Code, Section III, plus applicable and appropriate Addenda and Code Cases.

Even though fracture toughness was not required by the ASME Code, fracture toughness requirements were imposed on the accumulators which were identified as the only ferritic material actually used in Catawba's engineered safety features systems. The material met the ASME Code for the Catawba components.

The welding materials used for joining the ferritic base materials of the ESF conform to or are equivalent to ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18, and 5.20. The welding materials used for joining nickel-chromium-iron alloy in similar base material combination and in dissimilar ferritic or austenitic base material combination conform to ASME Material Specifications SFA 5.11 and 5.14. The welding materials used for joining the austenitic stainless steel base materials conform to ASME Material Specifications SFA 5.4 and 5.9. These materials are tested and qualified to the requirements of the ASME Code, Section III and Section IX rules and are used in procedures which have been qualified to these same rules. The methods utilized to control delta ferrite content in austenitic stainless steel weldments are discussed in Section 5.2.3.

All parts of components in contact with borated water are fabricated of or clad with austenitic stainless steel or equivalent corrosion resistant material. The integrity of the safety-related components of the ESF is maintained during all stages of component manufacture. Austenitic stainless steel is utilized in the final heat treated condition as required by the respective ASME Code, Section II, material specification for the particular type or grade of alloy. Furthermore, it is required that austenitic stainless steel materials used in the ESF components be handled, protected, stored, and cleaned according to recognized and accepted methods which are designed to minimize contamination which could lead to stress corrosion cracking. The rules covering these controls are stipulated in Westinghouse process specifications, which are discussed in Section 5.2.3. Additional information concerning austenitic stainless steel, including the avoidance of sensitization and the prevention of intergranular attack, can be found in Section 5.2.3. No cold worked austenitic stainless steels having yield strengths greater than 90,000 psi are used for components of the ESF within the Westinghouse standard scope.

10.3.6 MAIN STEAM AND FEEDWATER SYSTEM MATERIALS

10.3.6.1 Fracture Toughness

The basic material specifications and thickness for the Main Steam and Feedwater Systems are:

Feedwater

Pipe - SA-106 Gr. B	Thickness = .937" Nom.
Fittings - SA-234 WPB	Thickness = .937" Nom.

Main Steam

Pipe - SA-106 Gr. C	Thickness = 1.375" Min.
	Thickness = 1.750" Min.
	Thickness = 2.375" Nom.
Fittings - SA-234 WPB	Thickness = 1.375" Min.
- SA-105	Thickness = 2.375" Nom.

Even though fracture toughness testing is not required under the effective Edition and Addenda of ASME Section III, NC 2300, materials of similar composition and thickness have been used successfully in the past for service in the range of our lowest service metal temperature (50°F).

Current manufacturing controls SA-105 and SA-106 keep the carbon content well below the maximum allowable by material specification. The strength is maintained by adjusting the other alloying elements, such as Manganese, within the material specification limits. The reduction Carbon and adjustment of Manganese help lower the Nil Ductility Transition Temperature and enhances the fracture toughness properties.

10.3.6.2 Materials Selection and Fabrication

Material selection and fabrication for these systems are based on the following:

1. Materials used are included in Appendix I of Section III of the ASME Code.

2. No austenitic stainless steel piping material is used in these systems.

3. Cleaning and acceptance criteria are based on the requirements of ANSI N45.2.1-73 and the recommendations of Regulatory Guide 1.37.

4. Low-Alloy steels are not used in these systems for piping materials.

5. Duke Power Company complies with Regulatory Guide 1.71, "Welding Qualification for Areas of Limited Accessibility," except that the guide's restriction on access is deemed too stringent and would require unnecessary testing. In that it is impossible to define each variable that is site related

Attachment 4

Corrosion Engineering Branch

282.0 CORROSION ENGINEERING

282.1 (10.3.5) The secondary water chemistry monitoring and control program as you provided in the FSAR is incomplete. Provide a complete secondary water chemistry monitoring and control program following the guidance of Branch Technical Position MTEB 5-3 attached to SRP 5.4.2.1, Revision 2, July 1981.

Response:

See revised Section 10.3.5.2.

Station chemistry procedures will be available for on-site review at least six months prior to fuel load.

The Catawba Chemistry Program will designate the specific responsibilities and authority to take actions to maintain the chemistry program described in Section 10.3.5.2.

Attachment 5

Reactor Systems Branch

the reactor coolant system has been partially drained for steam generator inspection or maintenance.

Response:

Lowering of the reactor coolant level in the system for maintenance is such that the level is maintained in accordance with specific maintenance procedures.

If it is required that the water level be lowered to drain the steam generator tubes, the residual heat removal flow rate is throttled to about 1500 gpm through each of the residual heat removal loops. Draining is to the point where the indicated level is stable and at the elevation of the center of the reactor vessel nozzles. At this point, reactor coolant level is monitored continuously to assure that the RHR system inlet lines do not become uncovered. Inventory makeup, if required, can be accomplished via the chemical and volume control system (CVCS)/centrifugal charging pump(s).

Should a RHR system inlet line become uncovered, air may be drawn into the suction piping and entrained in the fluid. Factors which minimize the effects of air entrainment on pump performance are as follows:

1. the location of the residual heat removal pumps provides positive head on the pump inlet, and

2. the circulation flow rate is kept low and unnecessary circulation of fluid is avoided (i.e., the minimum flow required for core decay heat removal is maintained).

Provisions have been made to minimize the effects of air entrainment; however, should such an event preclude the continued use of the operating train, actions will be taken to permit the utilization of the alternate train by providing sufficient refill/makeup from the CVCS/charging pumps.

440.13 (5.4.7) RHR suction lines can have water trapped between the two isolation valves. Address the possibility of pressure increasing in this pipe due to a temperature rise with respect to protection needed to assure valve and piping integrity.

Response:

Duke will provide a reverse check valve (spring loaded lift check) in parallel with the inner RHR suction isolation valve to provide protection against pressure increases due to heating water trapped between the two isolation valves.

CNS

Valve Function	Number
RHR pump discharge to cold legs	1NI173A, 1NI178B
RHR pump discharge to hot legs	1NI183B
SI pump suction from RWST	1NI100B
SI pump common miniflow	1NI147B
SI pump discharge to cold legs	1NI162A
SI pump discharge to hot legs	1NI121A, 1NI152B

440.126 (6.3) (440.24) Your response to Question 440.24 states that non-seismic piping which connects to the RWST is not required for safety related functions. The piping from safety injection pump miniflow line valve 147B to the RWST is non-seismic as well as connecting piping. This piping could fail due to the initiating accident event and degrade ECCS performance. Address this concern.

Response:

The SI pump common miniflow line, while non-nuclear safety, is protected from high and medium energy line breaks, tornadoes, and is located in a seismic category 1 building. Should the line rupture, redundant safety related, Class 1E powered isolation valves are located upstream and can be closed by the operator to isolate the failure.

The line itself is only used during inservice testing of the SI pumps and during the initial injection phase following receipt of an SI signal. The line is isolated during the switchover from injection to cold leg recirculation.

440.127 (15.0) (440.56) Your response to the steam generator tube rupture portion of Question 440.56 states: "Consideration of the indications provided at the control board, together with the magnitude of the break flow, leads to the conclusion that the isolation procedure can be completed within 30 minutes of accident initiation. Included in this 30 minute time period would be an allowance of 5 minutes to trip the reactor and actuate the safety injection system (automatic actions), 10 minutes to identify the accident as a steam generator tube rupture and 15 minutes to isolate the faulted steam generator." This scenario is not consistent with Table 15.6.3-1, Steam Generator Tube Rupture Sequence of Events, which states the safety injection signal occurs at 773.0 seconds. Evaluate this discrepancy and show that adequate time is available for completion of operator action at 1800 seconds as indicated in Table 15.6.3-1.

Response:

The response to Question No. 440.56 and FSAR Section 15.6.3 have been revised. Please refer to these revisions in response to this question.

440.128 (15.3.3 & 15.3.4) 440.85 & 440.87 It is not apparent from your response to Questions 440.85 and 440.87 that you intend to analyze the locked rotor and shaft break transients consistent with the acceptance criteria in SRP 15.3.3 - 15.3.4 in NUREG-0800. We require that this event be analyzed assuming turbine trip and loss of offsite power to the undamaged pumps. The event should also be analyzed assuming the worst single failure of a safety grade system active component. Maximum primary system activity (in addition to activity from fuel failure resulting from the transient) and maximum steam generator tube leakage as allowed by the technical

440.132 Identify administrative procedures associated with reducing the potential for overpressure events. Identify technical specifications which will be proposed to assure that assumptions used in low-temperature overpressure design analyses are not violated.

Response:

The unit startup and shutdown procedures will utilize a sequence of operations which ensures that a pressure relieving path is always available. The philosophy of operation is essentially the same as utilized at McGuire. A steam bubble is formed in the pressurizer early in the startup sequence. This provides a cushion against pressure surges and over-pressurization when the Reactor Coolant System is isolated from the Residual Heat Removal System.

The Technical Specifications for Catawba will be submitted as discussed in Chapter 16 and should be essentially identical to the McGuire Technical Specifications. The following limiting conditions for operation will assure the validity of assumptions used in the low temperature overpressure design analysis.

1. The Reactor Coolant System lowest operating loop temperature (T_{avg}) shall be $\geq$ 551°F with $K_{eff} \geq 1.0$.

2. One charging pump shall be operable in Modes 3, 4, and 5. The other charging pumps shall be demonstrated inoperable.

3. At least two reactor coolant and/or residual heat removal loops shall be operable in Mode 4.

4. The pressurizer shall be operable with a water volume of less than or equal to 1600 cubic feet in Modes 1, 2, 3, and 4. If a steam bubble is not available in Mode 4, two residual heat removal loops shall be operable.

5. At least two PORV's with a lift setting of $\leq$ 400 psig or a Reactor Coolant System vent of $\geq$ 4.5 square inches is required in Mode 4 when the temperature of any RCS cold leg is $\leq$ 300 °F, Mode 5, and Mode 6 with the reactor vessel head on.

6. The Reactor Coolant System temperature and pressure is limited by the envelope shown on Figures Q440.8-1 and -2.

440.134 RSB 5-1 requires that Catawba be designed such that cold shutdown can be achieved without leaving the control room. Identify all actions (such as power restorations to valves) which the operator at Catawba must take outside the control room to achieve and maintain cold shutdown and provide justifications for these exceptions to RSB 5-1.

Response:

The only valves that have power removed from their operator at a location outside the control room during normal operation and are repositioned to achieve a cold shutdown are the cold leg accumulator isolation valves.

These valves are active, ASME Section III Class 2, electric motor operated gate valves located inside containment. In order to preclude mispositioning these valves during unit operation, power is removed from these valves at the motor breakers in a readily accessible area of the Auxiliary Building. These valves are closed before the RCS pressure is reduced below the accumulator pressure as the plant is cooled from hot standby to cold shutdown. It is felt that the operator will have sufficient time before the need to achieve cold shutdown to reach the breaker locations, restore power, close the valves, and remove power. However, cold shutdown (i.e., RCS $\leq$ 200°F) can be achieved without closing the accumulator isolation valves. This would result in additional fluid that would require processing in the Boron Recycle System but no nitrogen would be injected into the RCS as long as pressure remained above approximately 155 psia.

440.135 (5.4.7) RSB 5-1 requires that Class 2 Plants "provide safety-grade dump valves, operators, and power supply, etc., so that manual action should not be required after SSE except to meet single failure." Discuss Catawba compliance with this position.

Response:

As discussed in the response to Questions 410.20 and 440.22, it is felt that a non-safety related air supply and control system is sufficient and acceptable for the steam generator power operated relief valves (PORVs) since they are not required to mitigate the consequences of an accident. The main points of those responses are as follows:

1. Since hot standby is a safe and stable condition which can be maintained for an extended period of time, there is no safety requirement for reaching cold shutdown within a short period of time.

2. The steam generator PORVs are equipped with redundant safety related solenoid valves (Train A & B) which are deenergized to vent air off the spring loaded PORVs to close them upon receipt of a main steam isolation signal. Continued heat rejection following PORV closure will be provided by the main steam safety valves.

3. The steam generator PORVs are normally closed, active, ASME Section III Class B, containment isolation valves and satisfy the single failure criteria for this function. As discussed above, these valves are not required to perform a safety function to achieve or maintain hot standby. In addition, since hot standby is a safe and stable condition, which can be maintained for an extended period, there is no safety requirement for reaching cold shutdown within a short period of time. The possible function of these valves in achieving cold shutdown is not required to be designed to satisfy single failure criteria since time is available to correct any failures which might occur.

4. Once hot standby is reached there will be ample time to call in additional personnel or expertise to assess the situation and take the necessary corrective action. The plant can then be taken to a cold shutdown condition by manually operating the steam generator PORVs using local handwheels in the event instrument air is not available and cannot be restored.

5. Instrument air can be provided by any of the three instrument air compressors or either of the two station air compressors which automatically back up instrument air. The instrument air compressors and dryers can be manually loaded on the blackout bus during sequence #13 after 12 minutes in the event of a station blackout. Based on the above, complete unrestorable loss of instrument air is very unlikely and manual operation of the PORVs is acceptable.

6. The controls for the steam generator PORVs are standard commerical quality instruments. The pressure transmitter for each main steam line is located in its respective doghouse and supplies a signal to two controllers. One controller is located in the control room and the other controller is located on the auxiliary shutdown panel. The controllers supply control air to the PORVs through two safety grade solenoids described in item 2 above. A harsh environment in one doghouse would not affect the other two transmitters in the other doghouse which could still be used to cool down.

7. Pressure boundary parts of the steam generator PORVs are qualified to ASME Section III Class 2, Duke Class B. Valves are qualified for pressure, seismic and pipe loads by analysis documented in the seismic report. In addition to operability qualification in the seismic report, static deflection test is performed to qualify the valve for operability under pressure and seismic loads. Valve is qualified to fail closed by actuator spring force. Actuator is qualified by analysis to withstand a main steam line break environment in the dog house.

440.137 (6.3) (440.33) The response to Q440.32 and FSAR Section 6.3.2.2 do not provide adequate quantification to verify the NPSH calculations (limiting case), or consistency with RWST sizing basis. Provide the following:

a) values for each term in the NPSH calculation (limiting case)

b) pump flow rate assumed (limiting case)

c) discussion to show that kinetic heat loss ($V^2/2g$) term has been considered consistent wiht the pump manufacturer's method of specifying NPSH required

d) containment water level, pump suction centerline level, and volume of water assumed to determine containment water level.

<u>Response</u>:

a) For ND Pump Limiting Case (see Section 6.3.2.2 and Q440.33):

$NPSH_A = (P_{Cont.} - P_v)(\frac{144}{\rho}) + H_{elevation} - H_{loss} = 25.34$ @ 4600 gpm

$NPSH_R$ @ 4600 gpm is 19 ft.

$P_{Cont.}$ = 14.696 psia = minimum containment pressure post accident

P_v = 9.34 psia - vapor pressure of water at 190°F

ρ = 60.34 lbm/ft³ - water density at 190°F

$H_{elevation}$ = 24.5 ft - assume containment floor elevation for reservoir level minus centerline of pump discharge

H_{loss} = 11.94 ft. - piping losses from sump to pump inlet

We can demonstrate that there is sufficient $NPSH_A$ in the recirculation mode for the ND pump should it runout to values seen during preoperational testing and refueling conditions (when the discharge head is significantly reduced due to lowered back-pressure resulting from removal of the reactor vessel head). Under these conditions the flow rate will be below 5300 gpm. The value of the piping loss component will rise to 15.28 ft. and $NPSH_R$ increases to 23 ft. For this case we will take credit for two feet of water on the containment floor (which translates into approximately 100,000 gallons which is roughly half the minimum volume injected from the FWST and ignores ice melt and RCS spillage). For this case:

$NPSH_A = (14.696-9.34)(2.386) + 26.5 - 15.28 = 24.0$ ft @ 5300 gpm

$NPSH_R$ @ 5300 gpm = 23.0 ft.

b) Pump flow rates are given above.

c) The manufacturer did not add velocity head to the pressure measured during $NPSH_R$ tests so velocity head does not need to be subtracted from $NPSH_A$ calculations.

d) The containment water level in the above analysis was a maximum of 2 feet which corresponds to less than 100,000 gallons or about half the minimum RWST injection volume. Pump discharge centerline was selected since it is higher than pump suction centerline and is thus conservative.

440.141 (6.3) (440.106) (440.108)

The responses to Q440.106 and 440.108 describe power removal and interlocks to prevent spurious mispositioning of valves. Identify and justify any actions outside the control room which the operator must take in a post-accident or normal cold shutdown scenario. Our position is that such actions should be performed from the control room.

Response:

The response for actions taken in the normal cold shutdown scenario is presented in response to Q440.134.

In order for the operator to switch from cold leg recirculation to hot leg recirculation there are six valves which require power be reestablished before they can be repositioned. These valves are 1NI178B, 1NI173A, 1NI152B, 1NI162A, 1NI121A, and 1NI183B. Power is removed from the operators of the last four valves at the motor breakers in a readily accessible area of the Auxiliary Building. Since these valves will not require repositioning until approximately 24 hours after the start of the accident, it is felt that the operator will have sufficient time to perform this task before the need to align for hot leg recirculation.

Valves 1NI173A and 1NI173B could require repositioning as early as one hour after the start of the accident if residual containment spray is required. For this reason, power removal/restoration capability for these valves will be added to the main control room after first refueling.

A summary of operator actions outside the control room is provided in Table Q440.141-1.

Table Q440.141-1 (Page 1)
Operator Actions Outside Control Room

		Operator Action Required Outside the Control Room					Control Room Indication Available to Operator					
Valve No.	Function	To Achieve Normal Cold Shutdown	To Achieve Cold Shutdown Following DBA	Location of Operator Action Bldg	Location of Operator Action Elev	Type of Operator Action	147 Panel	Status Lights/ANN	Monitor Lights	Computer Point	Protective Interlock	Remarks
NI54A	Cold leg accumulator isolation valves	Yes	NR	AB	577	Reestablish power to motor operator at motor control center.	Yes	Yes	Yes	Yes	Yes	Can reach cold shutdown without closing valves
NI65B				AB	560		Yes	Yes	Yes	Yes	Yes	
NI76A				AB	577		Yes	Yes	Yes	Yes	Yes	
NI88B				AB	560		Yes	Yes	Yes	Yes	Yes	
NI184B	Sump isolation valves	NR	No	--	---	----------------	Yes	No	Yes	Yes	Yes	
NI185A							Yes	No	Yes	Yes	Yes	
NI173A	RHR/Cold leg isolation valves	NR	No	--	---	----------------	Yes	No	Yes	Yes	No	Control Room lockout
NI178B							Yes	No	Yes	Yes	No	Control Room lockout
NI121A	SI/Hot leg isolation valves	NR	Yes	AB	577	Reestablish power to motor operator at motor control center	Yes	No	Yes	Yes	No	
NI152B				AB	560		Yes	No	Yes	Yes	No	
NI183B	RHR/Hot leg	NR	Yes	AB	560	Reestablish power to motor operator at motor control center	No	No	Yes	Yes	No	
NI162A	SI/Cold leg	NR	Yes	AB	577	Reestablish power to motor operator at motor control center	Yes	No	Yes	Yes	No	
NI147B	SI miniflow to RWST	NR	No	--	---	----------------	Yes	No	Yes	Yes	Yes	Control Room lockout
NI100B	RWST/SI suction isolation	NR	No	--	---	----------------	Yes	Yes	Yes	Yes	No	Control Room lockout
ND28A	RHR/Chg. suction isolation	NR	No	--	---	----------------	Yes	No	Yes	Yes	Yes	

Table Q440.141-1 (Page 2)
Operator Actions Outside Control Room

Valve No.	Function	To Achieve Normal Cold Shutdown	To Achieve Cold Shutdown Following DBA	Location of Operator Action Bldg	Location of Operator Action Elev	Type of Operator Action	147 Panel	Status Lights/ANN	Monitor Lights	Computer Point	Protective Interlock	Remarks
NI136B	RHR/SI suction isolation	NR	No	--	---	-----------------	Yes	No	Yes	Yes	Yes	
NS38B	RHR Containment spray	NR	No	--	---	-----------------	Yes	No	Yes	Yes	Yes	
NS43A							Yes	No	Yes	Yes	Yes	
ND1B	RHR suction isolation	No	No	--	---	-----------------	No	No	No	Yes	Yes	
ND2A							No	No	No	Yes	Yes	
ND36B							No	No	No	Yes	Yes	
ND37A							No	No	No	Yes	Yes	
SV1	Steam generator PORVs	NR	Yes	DH	634	Local Handwheel	No	No	No	Yes	No	Local handwheels are provided to open valves in the event of loss of normal non-safety grade controls.
SV7				DH	634	Local Handwheel	No	No	No	Yes	No	
SV13				DH	634	Local Handwheel	No	No	No	Yes	No	
SV19				DH	634	Local Handwheel	No	No	No	Yes	No	
NC32B	Pressurizer PORVs	NR	Yes	AB,SB	543,568	Realign Valves	No	Yes	No	Yes	No	Valves require manual loading of air compressers to black out bus if offsite power is lost.
NC34A				SB	594	Close Breakers	No	Yes	No	Yes	No	
NC36B							No	No	No	Yes	No	

Notes:

1) NR - No required function for this scenario
No - No outside control room action needed to reposition valve
Yes - Action outside control room needed to reposition valve

440.145
(6.3)
(440.38)

The response to Q440.38 cited Westinghouse Owners Group "Emergency Response Guidelines" to address concern about loss of offsite power subsequent to manual reset of the ECCS after a LOCA. A preliminary review of these ERGs indicate that they do not provide adequate guidance. We therefore require that this issue be addressed in greater detail.

Response:

The issue regarding loss of offsite power subsequent to manual reset of the ECCS is a long standing issue which was raised before the TMI event. This issue was addressed by Westinghouse and the NRC initially in 1977 where the NRC evaluation is documented in NUREG-0138 (Issue 4). Immediately after the TMI event Westinghouse reiterated its position on this issue in response to IE Bulletin 79-06A and has incorporated the appropriate provisions into the appropriate emergency procedure guidelines which have been approved by the NRC both generically and on specific plant procedures for issuance of an operating license.

Rather than instructing the operator not to reset Safety Injection (SI) for 10 minutes following an ECCS actuation as suggested by NUREG-0138, the Emergency Response Guidelines (ERG's) referenced in response to Q440.38 provide the operator with a symptom based diagnostic procedure. For example, ECCS actuation could be the result of a spurious actuation, a loss of reactor coolant, or a loss of secondary coolant. Following SI actuation the operator would review indications such as Reactor Coolant System pressure; containment temperature, pressure, sump level and radiation level; and secondary side radiation levels in assessing the occurrance. If, as would be most likely, the operator identifies the occurrance as a spurious actuation, he would be required to verify Reactor Coolant System pressure, pressurizer level and subcooling; and a secondary system heat sink all within specified limits prior to resetting SI. The operator would be directed to other appropriate actions if a loss of reactor coolant or secondary coolant had occurred. The operator is specifically cautioned that manual action may be required to restart safeguards equipment if offsite power is lost after SI reset.

440.146 (6.3) (440.30) The response to Q440.34 identified indicators and alarms to alert the operator to a LOCA at shutdown for Catawba, but presented no analytical results to show that this event is not limiting. Analyze this event or reference an analysis for a similar plant to show that a LOCA at shutdown is not limiting for Catawba.

Response:

A LOCA may be postulated to occur during the shutdown procedure at Catawba when all accumulation isolation valves have been closed and locked out. Such a LOCA during shutdown will behave the same for Catawba as for any other four-loop plant (without or with UHI) which has comparable pumped safety injection flow capability and operates at a similar core power level. An analysis of the limiting large break LOCA event during shutdown was previously provided on the Donald C. Cook Unit No. 2 plant docket in response to NRC Question 212.33. The conclusion drawn therein that a postulated LOCA event occurring at shutdown is not limiting is applicable to Catawba as well.

440.147 (6.3) (440.129)

From the response to Q440.129 and discussions with the NSSS vendor it was concluded that in the computer representation of the Catawba vessel the downcomer would be relatively smaller than for most UHI plants. Justify that Catawba is not "imperfect mixing" limited as is the other "small downcomer" UHI plant.

Response:

Three additional breaks will be performed with the imperfect mixing assumption to complete the imperfect mixing FSAR spectrum: C_D = 0.8, 0.6, and 0.4 DECLG break cases. The same version of the UHI Evaluation model as was used in the FSAR will again be used.

440.149 (15.6.3) (440.127)

Table 440.3-3 and the response to Q440.56 indicate that credit has been taken for non-safety grade equipment, without applying single failure, and without loss of offsite power in the analysis of steam generator tube rupture. Provide an analysis fo this event with loss of offsite power, applying single failure, and taking creait only for safety grade systems and instrumentation in the mitigation of the event.

Response:

The analysis of the steam generator tube rupture event assumed the loss of offsite power coincident with reactor trip. Maximization of steam released through the faulted steam generator safety valves and power operated relief valve was obtained by assuming the limiting single failure within the auxiliary feedwater system that then results in minimum delivered auxiliary feedwater flow. As discussed in Section 15.6.3.2, no operator actions are assumed until 30 minutes after the accident. During this time period no credit is taken for non-qualified (i.e., non-safety grade) equipment.

The Chapter 15 analysis assumes that the operator takes action at 30 minutes to depressurize the primary system and, thereby, terminate the steam release to the atmosphere through the faulted steam generator safety valves. Depressurization will be accomplished via any of several methods depending upon the availability of the components and power supplies. Depressurization following a SGTR will be accomplished in three stages. The first stage involves depressurizing the reactor coolant system to a pressure slightly less than that of the faulted steam generator secondary side. The second and third stages bring RCS pressure down to RHRS initiation conditions (approximately 415 psia) and, finally, to atmospheric pressure. Adequate time exists for both the second and third depressurization stages to permit manual actions to recover previously unavailable components.

An adverse environment is not expected within the containment during the initial recovery period of the SGTR and prior to opening of a pressurizer PORV for depressurization. The single opening of a pressurizer PORV is adequate to depressurize the RCS. Should the pressurizer PORV fail in the open position, the pressurizer PORV block valve provides a fully qualified safety related means of isolating the stuck open pressurizer PORV.

Pressure boundary parts of the pressurizer PORVs are qualified to ASME Section III, Class 1, Duke Class A. Valves are qualified for pressure loads, seismic loads and piping loads by analysis documented in the stress/seismic report. In addition to operability qualification in the seismic report, static deflection test is performed to qualify the valve for operability under pressure and seismic loads. Valve is qualified to fail closed by actuator spring force. Actuator is qualified by analysis for temperature and radiation for inside containment LOCA and steam line break environments. Pressurizer PORV's successfully passed full flow, full pressure and temperature testing by Duke at Marshall Steam Station and by EPRI under EPRI's PWS Safety and Relief Valve Test Program.

Attachment 6

Containment Systems Branch

The sequencing system for loading the onsite emergency electrical generators is designed to actuate all valves receiving an engineered safety features actuation signal within adequate time to supply ECCS and auxiliary pumps after the switch to emergency onsite electrical power signal is accomplished.

The Containment Purge System (as described in Section 9.4.5) reduces radioactivity levels in the containment as well as in the Incore Instrumentation Room by taking in fresh air from the outside and exhausting containment air through cleanup filters prior to discharge to atmosphere through the unit vent stack. Expected Containment Purge System usage is described in Section 9.4.5.2 and is further limited by the Station Technical Specifications. The Containment Purge System (VP) is designed to meet the requirements outlined in Branch Technical Position CSB 6-4, Revision 1, dated December 1978. A comparison of the system to CSB 6-4, Revision 2, dated July 1981 is given in Table 6.2.4-2. Other systems similar in function as well as in design requirements are the Containment Air Release and Addition System (VQ), Containment Hydrogen Sample and Purge System (VY), and the Hydrogen Skimmer System (VX). All containment penetrations of the above systems are provided with isolation valves capable of 5 second closure.

Airborne fission products in the ECCS Pump Room should be effectively contained by filters located in the Auxiliary Building Ventilation System (VA). In addition, the VA System contains radiation monitors in the unit vent stacks which check the radiation level in the ECCS Pump Room. This system is discussed further in Section 9.4.3. The VA System in conjunction with the area radiation monitor (see Section 12.3), located at El. 522' and 543' in the ECCS Pump Rooms should satisfactorily serve to detect leakage in the engineered-safety-feature systems.

As described below adequate protection is provided for piping, valves, and vessels against dynamic effects and missiles which might result from plant equipment failures, including a LOCA.

Isolation valves inside the Containment are located between the secondary shield and the inside Containment wall. The secondary shield serves as the missile barrier. Any missile barriers for isolation valves and piping, or vessels which provide one of the isolation barriers outside the Containment, consist of structural steel and concrete which forms walls and floors of adjacent buildings, either the Auxiliary Building or Doghouses.

Piping, isolation valves, and actuators in the Containment Isolation System outside Containment are located inside a Seismic Category 1 enclosure complex, and are located as close as practical to the Containment wall; i.e., in almost all cases, isolation valves will be located immediately after the penetration assembly. There will, however, be exceptions, such as the case of the main steam lines which require a series of safety valves before the isolation valve. Also, there will be some exceptions due to normal structural design arrangements. Actual lengths of pipe from penetrations to the isolation valves outside Containment have been kept to a minimum.

The isolation arrangement of the fuel transfer tube, shown in Figure 6.2.4-3 consists of a transfer tube closure and a blind flange, enclosing the transfer tube. The blind flange contains two 'O' -ring grooves and a pressure tap which runs through the blind flange to the annulus between the two 'O' -rings. When

TABLE 6.2.3-1 (Page 1)

Potential Bypass Leak Paths Through Containment Isolation Valves

Penetration Item Number	Service (Note 1)	Process Fluid	Essential (Note 7)	Design Features to Prevent Bypass Leakage — Attached Closed Systems (Note 2): Presents a Seismic Category 1 Closed Pressure Boundary to Containment Atmosphere Following a LOCA	Presents a Seismic Category 1 Closed Pressure Boundary to Environment Following a LOCA	Designed to Quality Group B or C Standards	Design Pressure Equals or Exceeds Containment Design Pressure (Note 4)	Design Temperature Equals or Exceeds Containment Design Temperature (Note 4)	Protected from Effects of Pipe Whip, Missiles, and Jet Forces Resulting From a LOCA	Pressure Boundary Maintained During Normal Plant Operation	Both Valves Served by Seal Water System	Leakage Path Terminates in Annulus	Remarks	Potential Bypass Leakage Path (Note 2)
01	Pressurizer Relief Tank Makeup	Water	No				X	X		X				Yes
02	Nitrogen to Pressurizer Relief Tank	Nitrogen	No				X	X		X				Yes
03	NC Pump Motor Drain Tank Pump Dischg.	Oil	No		X		X	X		X				Yes
04	NV Letdown Line	Water	No		X	B	X	X	X	X				No
05	Pressurizer Aux. Spray Transient Line	Water	No		X	B	X	X	X	X				No
06	NV Charging Line	Water	Note 8		X	B	X	X	X	X				No
07	NC Pump Seal Water Return	Water	No		X	B	X	X	X	X				No
08-11	NC Pump Seal Inj. Water 1A-1D	Water	Yes		X	B	X	X	X	X			Note 6	No
12	Reactor Makeup Water Tank Flush Hdr.	Water	No				X			X				Yes
13-14	Ice Condenser Ice Blowing Air	Air	No									X	Note 5	No
15	Ice Condenser Glycol Pump Dischg.	Glycol	No				X			X				Yes
16	Ice Condenser Glycol Pump Suction	Glycol	No				X			X				Yes
20	Containment H2 Purge Inlet Blower Dischg	Air	No		X		X	X	X	X			Note 6	Yes
21	Containment H2 Purge Outlet Line	Air	No		X		X	X	X	X		X	Note 6	No
22-23	ND Pump Suction 1A & 1B from Loop	Water	Note 9		X	B	X	X	X	X			Note 6	No

TABLE 6.2.3-1 (Page 2)

Potential Bypass Leak Paths Through Containment Isolation Valves

Penetration Item Number	Service (Note 1)	Process Fluid	Essential (Note 7)	Design Features to Prevent Bypass Leakage — Attached Closed Systems (Note 2): Presents a Seismic Category 1 Closed Pressure Boundary to Containment Atmosphere Following a LOCA	Presents a Seismic Category 1 Closed Pressure Boundary to Environment Following a LOCA	Designed to Quality Group B or C Standards	Design Pressure Equals or Exceeds Containment Design Pressure (Note 4)	Design Temperature Equals or Exceeds Containment Design Temperature (Note 4)	Protected from Effects of Pipe Whip, Missiles, and Jet Forces Resulting From a LOCA	Pressure Boundary Maintained During Normal Plant Operation	Both Valves Served by Seal Water System	Leakage Path Terminates in Annulus	Remarks	Potential Bypass Leakage Path (Note 2)
24	Boron Inj. Tank Line To Cold Legs	Water	Yes		X	B	X	X	X	X			Isolation valves open during LOCA to allow Boron Injection (Note 6)	No
25	Nitrogen to Accumulators	Nitrogen	No				X	X		X				Yes
26	Safety Injection Test Line	Water	No				X	X		X				Yes
27	ND Crossover Dischg. to Hot Legs	Water	Yes		X	B	X	X	X	X			Isolation valves open during LOCA to allow Hot Leg recirculation (Note 6)	No
28-29	NI Pump A & B Dischg. to Hot Legs	Water	Yes		X	B	X	X	X	X			Isolation valves open during LOCA to allow Hot Leg recirculation (Note 6)	No
30-31	ND HX Dischg. A & B to Cold Legs	Water	Yes		X	B	X	X	X	X			Isolation valves open during LOCA to allow Cold Leg recirculation (Note 6)	No
32	NI Pumps A & B Dischg. to Cold Legs	Water	Yes		X	B	X	X	X	X			Isolation valves open during LOCA to allow Cold Leg recirculation (Note 6)	No
33-34	Containment Sump Recirc. Lines A & B	Water	Yes		X	B	X	X	X	X			Isolation valves and penetration located below LOCA recirculation water level (Note 6)	No
35-36	Upper Head Injection Lines	Water	Yes		X	B	X	X	X	X			Isolation valves open during LOCA to allow Boron Injection to upper head (Note 6)	No
37	Upper Head Injection Test Line	Water	No				X	X		X			LOCA to allow Boron Injection to upper head (Note 6)	Yes

TABLE 6.2.3-1 (Page 3)

Potential Bypass Leak Paths Through Containment Isolation Valves

Penetration Item Number	Service (Note 1)	Process Fluid	Design Features to Prevent Bypass Leakage: Essential (Note 7)	Attached Closed Systems (Note 2): Presents a Seismic Category 1 Closed Pressure Boundary to Containment Atmosphere Following a LOCA	Presents a Seismic Category 1 Closed Pressure Boundary to Environment Following a LOCA	Designed to Quality Group B or C Standards	Design Pressure Equals or Exceeds Containment Design Pressure (Note 4)	Design Temperature Equals or Exceeds Containment Design Temperature (Note 4)	Protected from Effects of Pipe Whip, Missiles, and Jet Forces Resulting From a LOCA	Pressure Boundary Maintained During Normal Plant Operation	Both Valves Served by Seal Water System	Leakage Path Terminates in Annulus	Remarks	Potential Bypass Leakage Path (Note 2)
38-41	Containment Spray Lines	Water	Yes		X	B	X		X	X			Isolation valves open during LOCA to allow containment	No
													Spray Flow (Note 6)	No
42,43	ND Containment Spray Lines A & B	Water	Yes		X	B	X		X	X			Isolation valves open during LOCA to allow ND containment spray flow (Note 6)	No
44	NC Drain Tank Gas Space to WG System	Hydrogen	No				X			X				Yes
45	NC Drain Tank HX Dischg.	Water	No				X			X	X			No
46	Vent. Unit Condensate Drain Hdr.	Water	Note 10				X			X	X		3 psi loop seal allows valves to remain open during small leaks inside containment	Yes
47	Cont. Floor Sump & Incore Inst. Sump Dischg.	Water	No				X			X	X			No
48	Steam Generator Drain Pump Dischg.	Water	No				X			X	X			No
49	Equipment Decontamination Line	Water	No				X			X				Yes
50	Fuel Transfer Tube	Water	No				X	X		X			Penetration terminates 30 ft below water level in fuel pool refueling canal	No
51	Refueling Water Pump Suction	Water	No				X			X				Yes
52	Refueling Cavity Fill Line	Water	No				X			X				Yes
53	Pressurizer Sample	Water	No				X	X		X				Yes
54	Reactor Coolant Hot Leg Sample	Water	No				X	X		X				Yes
55	Safety Injection Accumulator Sample	Water	No	X		B	X	X	X	X				No
56-59	Steam Generator Samples 1A, 1B, 1C, 1D,	Water	No	X		B	X	X	X	X				No
60	Comp.Cooling to RC Drain Tank HX	Water	No	X	X	C/C	X		X	X				No

TABLE 6.2.3-1 (Page 4)

Potential Bypass Leak Paths Through Containment Isolation Valves

Penetration Item Number	Service (Note 1)	Process Fluid	Design Features to Prevent Bypass Leakage: Essential (Note 7)	Attached Closed Systems (Note 2): Presents a Seismic Category 1 Closed Pressure Boundary to Containment Atmosphere Following a LOCA	Presents a Seismic Category 1 Closed Pressure Boundary to Environment Following a LOCA	Designed to Quality Group B or C Standards	Design Pressure Equals or Exceeds Containment Design Pressure (Note 4)	Design Temperature Equals or Exceeds Containment Design Temperature (Note 4)	Protected from Effects of Pipe Whip, Missiles, and Jet Forces Resulting From a LOCA	Pressure Boundary Maintained During Normal Plant Operation	Both Valves Served by Seal Water System	Leakage Path Terminates in Annulus	Remarks	Potential Bypass Leakage Path (Note 2)
61	Comp. Cooling from Drain Tank HX	Water	No	X	X	C/C	X		X	X	X			No
62	Comp. Cooling to Reactor Vessel Support & RCP Coolers	Water	Note 10	X	X	C/C	X		X	X				No
63	Comp. Cooling from Reactor Vessel Support & RCP Coolers	Water	Note 10	X	X	C/C	X		X	X	X			No
64	Comp. Cooling to Excess Letdown HX		No	X	X	B/C	X		X	X				No
65	Comp. Cooling from Excess Letdown HX	Water	No	X	X	B/C	X		X	X				No
66	Comp. Cooling to Component Cooling Drain Sump	Water	No				X			X				Yes
67	Nuclear Service Wtr. to NC Pump and Lower Cont. Vent. Units	Water	Note 10				X			X				Yes
68	Nuclear Service Wtr. from NC Pump & Lower Cont. Vent. Units	Water	Note 10				X			X	X			Yes
69	Nuclear Service Wtr. to Upper Cont. Vent.Units In	Water	Note 10				X			X				Yes
70	Nuclear Service Wtr. to Upper Cont. Vent. Units Out	Water	Note 10				X			X	X			Yes
71	Incore Instrumentation Rm Purge In	Air	No				X	X		X				Yes
72	Incore Instrumentation Rm. Purge Out	Air	No				X	X		X			Ducting extends through incore instrument room filter trains	Yes
73-74	Upper Compartment Purge Inlet	Air	No				X	X		X				Yes
75-76	Lower Compartment Purge Inlet	Air	No				X	X		X				Yes
77-79	Containment Purge Exhaust	Air	No				X	X		X			Seismic duct extends through containment purge filter trains	Yes

TABLE 6.2.3-1 (Page 5)

Potential Bypass Leak Paths Through Containment Isolation Valves

Penetration Item Number	Service (Note 1)	Process Fluid	Design Features to Prevent Bypass Leakage: Essential (Note 7)	Attached Closed Systems (Note 2): Presents a Seismic Category 1 Closed Pressure Boundary to Containment Atmosphere Following a LOCA	Presents a Seismic Category 1 Closed Pressure Boundary to Environment Following a LOCA	Designed to Quality Group B or C Standards	Design Pressure Equals or Exceeds Containment Design Pressure (Note 4)	Design Temperature Equals or Exceeds Containment Design Temperature (Note 4)	Protected from Effects of Pipe Whip, Missiles, and Jet Forces Resulting From a LOCA	Pressure Boundary Maintained During Normal Plant Operation	Both Valves Served by Seal Water System	Leakage Path Terminates in Annulus	Remarks	Potential Bypass Leakage Path (Note 2)
80-83	Steam Generator 1A-1D Blowdown	Water	No	X		B	X	X	X	X				No
84	Containment Air Release	Air	No				X			X				Yes
85	Containment Air Addition	Air	No					X		X				Yes
86-89	Feedwater	Water	Note 11	X		B	X	X	X	X			Isolation Valves and penetration located below steam generator water level	No
90-93	Aux. Feedwater	Water	Yes	X		B	X	X	X	X			Isolation Valves and penetration located below steam generator water level	No
94-97	Main Steam	Steam	Yes	X		B	X	X	X	X			Isolation Valves and penetration located below steam generator water level	No
98	Interior Fire Protection - Hose Racks	Water	No				X			X				Yes
99	Demineralized Water	Water	No				X			X				Yes
100	Instrument Air	Air	No				X			X				Yes
101	Station Air	Air	No				X			X				Yes
102	Breathing Air	Air	No				X			X				Yes
103-106	Containment Pressure Sensing											X	Note 6	No
107	Equipment Hatch	Air										X	Note 3	No
108	Personnel Hatch	Air										X	Note 3	No
109	RCP Oil Fill	Oil	No				X	X		X				Yes
110	Interior Fire Protection - Sprinklers	Water	No				X			X				Yes
111	Cont. Valve. Inj. Water "A" Train	Water	Yes		X	B	X		X	X			Note 6	No

TABLE 6.2.3-1 (Page 6)

Potential Bypass Leak Paths Through Containment Isolation Valves

Penetration Item Number	Service (Note 1)	Process Fluid	Design Features to Prevent Bypass Leakage: Essential (Note 7)	Attached Closed Systems (Note 2): Presents a Seismic Category 1 Closed Pressure Boundary to Containment Atmosphere Following a LOCA	Presents a Seismic Category 1 Closed Pressure Boundary to Environment Following a LOCA	Designed to Quality Group B or C Standards	Design Pressure Equals or Exceeds Containment Design Pressure (Note 4)	Design Temperature Equals or Exceeds Containment Design Temperature (Note 4)	Protected from Effects of Pipe Whip, Missiles, and Jet Forces Resulting From a LOCA	Pressure Boundary Maintained During Normal Plant Operation	Both Valves Served by Seal Water System	Leakage Path Terminates in Annulus	Remarks	Potential Bypass Leakage Path (Note 2)
112	Cont. Valve Inj. Water "B" Train	Water	Yes		X	B	X		X	X			Note 6	No
113	Standby Makeup Pump Discharge Line	Water	No				X	X		X		X	Penetration terminates 30 ft. below water level in fuel pool refueling canal	No

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 1)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	(7) Seismic Connections Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size		(4,16) Type Actuator	(2,3) Actuation Signal	(2,3) Actuation Type	(4) Valve Position Normal	(4) Valve Position Failsafe	(4) Valve Position Shutdown	(4) Valve Position Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
01	Pressurizer Relief Tank Makeup	M216	B6	3	In	No	No	NC57	Inside	Check	3"	-	-	-	C	-	C	C	9.1-2	Yes	Yes	----
								NC56B	Outside	Gate	3"	E	T	A,B,M	C	AI	C	C				
02	Nitrogen to Pressurizer Relief Tank	M212	A1	1	In/Out	No	Yes	NC54A	Inside	Globe	1"	E	T	A,B,M	C	AI	C	C	9.1-2	Yes	Yes	----
								NC53B	Outside	Globe	1"	E	T	A,B,M	C	AI	C	C				
03	NC Pump Motor Drain Tank Pump Dischg.	M327	A4	2	Out	No	Yes	NC141	Inside	Gate	2"	MW	-	M	LC	AI	C	C	5.1-4	Yes	Yes	----
								NC142	Outside	Gate	2"	MW	-	M	LC	AI	C	C				
04	NV Letdown Line	M347	A6	2	Out	Yes	Yes	NV10A	Inside	Gate	2"	P	T	A,B	O	C	O	C	9.3.4-1	No	Yes	----
								NV11A	Inside	Gate	2"	P	T	A,B	C	C	C	C				
								NV13A	Inside	Gate	2"	P	T	A,B	C	C	C	C				
								NV15B	Outside	Globe	3"	E	T	A,B,M	O	AI	O	C				
								NV14	Inside	Relief	3"	-	600 PSIG	-	C	AI	C	C				
05	Pressurizer Aux. Spray Transient Line	M273	B2	3	In	Yes	Yes	NV861	Inside	Check	3"	-	-	-	C	-	C	C	9.3.4-1	No	No	(25)
								NV862	Outside	Globe	3"	MW	-	M	LO	-	O	C				
06	NV Charging Line	M330	B1	3	In	Yes	Yes	NV22	Inside	Check	3"	-	-	-	C	-	C	C	[illegible].4-1	No	No	(25)
								NV314B	Outside	Gate	3"	E	S	A,B,M	O	AI	O	C				
07	NC Pump Seal Water Return	M256	A7	4	Out	Yes	Yes	NV89A	Inside	Gate	4"	E	T	A,B,M	O	AI	O	C	9.3.4-1	No	Yes	----
								NV90	Inside	Check	3/4"	-	-	-	C	-	-	-				
								NV91B	Outside	Gate	4"	E	T	A,B,M	O	AI	O	C				
08	NC Pump Seal Inj. Water 1A Supply	M343	D6	2	In	Yes	Yes	NV46	Inside	Check	2"	-	-	-	O	-	O	O	9.3.4-6	No	No	(25)
								NV44A	Outside	Globe	2"	E	-	-	O	AI	O	O				
09	NC Pump Seal Inj. Water 1B Supply	M339	D6	2	In	Yes	Yes	NV57	Inside	Check	2"	-	-	-	O	-	O	O	9.3.4-6	No	No	(25)
								NV55A	Outside	Globe	2"	E	-	-	O	AI	O	O				
10	NC Pump Seal Inj. Water 1C Supply	M344	D6	2	In	Yes	Yes	NV68	Inside	Check	2"	-	-	-	O	-	O	O	9.3.4-6	No	No	(25)
								NV66A	Outside	Globe	2"	E	-	-	O	AI	O	O				
11	NC Pump Seal Inj. Water 1D Supply	M350	D6	2	In	Yes	Yes	NV79	Inside	Check	2"	-	-	-	O	-	O	O	9.3.4-6	No	No	(25)
								NV77A	Outside	Globe	2"	E	-	-	O	AI	O	O				
12	Reactor Makeup Water Flush Header	M259	B1	1	In	No	No	NB262	Inside	Check	3/4"	-	-	-	C	-	-	-	9.3.5-6	Yes	Yes	----
								NB260B	Outside	Globe	1"	E	T	A,B,M	C	AI	C	C				
13	Ice Condenser Ice Blowing Air	M394	C3	5	In	Note 9		-	-	-		-	-	-	-	-	-	-	Not shown	No	No	(9)
14	Ice Condenser Ice Blowing Air	M395	C3	6	Out	Note 9		-	-	-		-	-	-	-	-	-	-	Not shown	No	No	(9)
		M371	C3	6	Out	Note 9		-	-	-		-	-	-	-	-	-	-				
15	Ice Condenser Glycol Pumps Dischg. Line	M373	B1	4	In	No	No	NF228A	Outside	Gate	4"	P	T	A,B	O	C	O	C	Not shown	No (Note 29)	Yes	----
								NF229	Inside	Check	4"	-	-	-	O	-	O	C				
16	Ice Condenserr Glycol Pumps Suction Line	M372	A7	4	Out	No	No	NF233B	Inside	Gate	4"	E	T	A,B,M	O	AI	O	C	Not shown	No (Note 29)	Yes	----
								NF234A	Outside	Gate	4"	P	T	A,B	O	C	O	C				
								NF235	Inside	Check	1/2"	-	-	-	C	-	C	C				
17	Deleted																					
18	Deleted																					
19	Deleted																					
20	Containment Hydrogen Purge Inlet Blower Dischg. Line	M332	B1	4	In	Yes	No	VY15B	Outside	Gate	4"	E	T (14)	A,B,M	C	AI	C	C	6.2.5-3	No	Yes	----
								VY16	Inside	Check	4"	-	-	-	C	-	C	C				
21	Containment Hydrogen Purge Outlet Line	M346	A1	4	In	Yes	Yes	VY17A	Inside	Gate	4"	E	T (14)	A,B,M	C	AI	C	C	6.2.5-3	No	Yes	----
								VY18B	Outside	Gate	4"	E	T (14)	A,B,M	C	AI	C	C				

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 2)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	Seismic Connections Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size		(4,16) Type Actuator	(2,3) Actuation Signal	Actuation Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
22	ND Pump Suction A from Loop	M276	B5	12	Out	Yes	Yes	ND2A	Inside	Gate	12"	E	(10)	A,R,M	C	AI	O	C	5.4.7-1	No (Note 29)	No	(25)
								ND3	Inside	Relief	4"	-	450PSIG	-	C	-	C	C				
23	ND Pump Suction B from Loop	M315	B5	12	Out	Yes	Yes	ND37A	Inside	Gate	12"	E	(10)	A,R,M	C	AI	O	C	5.4.7-2	No (Note 29)	No	(25)
								ND38	Inside	Relief	4"	-	450PSIG	-	C	-	C	C				
24	Boron Inj. Tank Line to Cold Legs	M351	B4	4	In	No	Yes	NI9A	Outside	Gate	4"	E	S	A,R,M	C	AI	C	O	6.3.2-1	No	No	(25)
								NI10B	Outside	Gate	4"	E	S	A,R,M	C	AI	C	O				
								NI11	Inside	Globe	3/4"	D	-	R	C	C	C	C				
								NI12	Inside	Check	2"	-	-	-	C	-	C	C				
								NI13	Outside	Globe	1"	HW	-	M	C	C	C	C				
25	Nitrogen to Accumulators	M331	B1	1	In	No	No	NI46	Inside	Check	1"	-	-	-	C	-	C	C	6.3.2-2	Yes	Yes	----
								NI47A	Outside	Globe	1"	E	T	A,R,M	C	AI	C	C				
26	Safety Injection Test Line	M322	A1	3/4	In	No	No	NI95A	Inside	Globe	3/4"	E	T	A,R,M	C	AI	C	C	6.3.2-2	Yes	Yes	----
								NI96B	Outside	Globe	3/4"	E	T	A,R,M	C	AI	C	C				
								NI120B	Outside	Globe	3/4"	E	T	A,R,M	C	AI	C	C	6.3.2-3			
27	ND Crossover Dischg. to Hot Legs	M207	B5	12	In	No	Yes	NI154B	Inside	Globe	3/4"	E	T	A,R,M	C	AI	C	C	6.3.2-3	No	Yes	----
								NI183B	Outside	Gate	12"	E	-	R,M	C	AI	C	C/O				
								NI125	Inside	Check	8"	-	-	-	C	-	C	C/O				
								NI129	Inside	Check	8"	-	-	-	C	-	C	C/O				
28	NI Pump B Dischg. to Hot Legs	M320	B5	4	In	No	Yes	NI152B	Outside	Gate	4"	E	-	R,M	C	AI	C	C/O	6.3.2-3	No	Yes	----
								NI153A	Inside	Globe	3/4"	E	T	A,R,M	C	AI	C	C				
								NI156	Inside	Check	2"	-	-	-	C	-	C	C/O				
								NI159	Inside	Check	2"	-	-	-	C	-	C	C/O				
29	NI Pump A Dischg. to Hot Legs	M317	B5	4	In	No	Yes	NI121A	Outside	Gate	4"	E	-	R,M	C	AI	C	C/O	6.3.2-3	No	Yes	----
								NI122B	Inside	Globe	3/4"	E	T	A,R,M	C	AI	C	C				
								NI124	Inside	Check	2"	-	-	-	C	-	C	C/O				
								NI128	Inside	Check	2"	-	-	-	C	-	C	C/O				
30	ND HX A Dischg. to Cold Legs	M336	B5	8	In	No	Yes	NI173A	Outside	Gate	8"	E	-	R,M	O	AI	O	O	6.3.2-4	No	Yes	----
								NI174	Inside	Globe	3/4"	D	-	R,M	C	C	C	C				
								NI175	Inside	Check	6"	-	-	-	C	-	O	O				
								NI176	Inside	Check	6"	-	-	-	C	-	O	O				
31	ND HX B Dischg. to Cold Legs	M307	B5	8	In	No	Yes	NI178B	Outside	Gate	8"	E	-	R,M	O	AI	O	O	6.3.2-4	No	Yes	----
								NI179	Inside	Globe	3/4"	D	-	R,M	C	C	C	C				
								NI180	Inside	Check	6"	-	-	-	C	-	O	O				
								NI181	Inside	Check	6"	-	-	-	C	-	O	O				
32	NI Pumps A&B Dischg to Cold Legs	M352	B5	4	In	No	Yes	NI162A	Outside	Gate	4"	E	-	R,M	O	AI	C	O	6.3.2-4	No	Yes	----
								NI163	Inside	Globe	3/4"	D	-	R,M	C	C	C	C				
								NI165	Inside	Check	2"	-	-	-	C	-	C	O/C				
								NI167	Inside	Check	2"	-	-	-	C	-	C	O/C				
								NI169	Inside	Check	2"	-	-	-	C	-	C	O/C				
								NI171	Inside	Check	2"	-	-	-	C	-	C	O/C				
33	Containment Sump Recirc. Line A	M303	C1	18	Out	No	Yes	NI185A	Outside	Gate	18"	E	-	R,M	C	AI	C	C/O	6.3.2-4	No	No	(22)
34	Containment Sump Recirc. Line B	M210	C1	18	Out	No	Yes	NI184B	Outside	Gate	18"	E	-	R,M	C	AI	C	C/O	6.3.2-4	No	No	(22)
35	Upper Head Injection Line	M407	B1	12	In	Yes	Yes	NI245A	Outside	Gate	12"	E	(11)	A,R,M	O	AI	C	O/C	6.3.2-5	No	No	(25)

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 3)

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	(7) Seismic Connections Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	(2,3) Actuation Type	(4) Valve Position Normal	(4) Valve Position Failsafe	(4) Valve Position Shutdown	(4) Valve Position Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
36	Upper Head Injection Line	M406	B1	12	In	Yes	Yes	M1255B	Outside	Globe 2"	E	T	A,R,M	C	AI	C	C	6.3.2-5	No	No	(25)
								M1249	Inside	Check 12"	-	-	-	C	-	C	O/C				
								M1258A	Outside	Globe 3/4"	E	T	A,R,M	C	AI	C	C				
								M1243A	Outside	Gate 12"	E	(11)	A,R,M	O	AI	C	O/C				
								M1248	Inside	Check 12"	-	-	-	C	-	C	O/C				
37	Upper Head Injection Test Line	M454	A6	2	In	No	No	M1266A	Inside	Globe 2"	E	T	A,R,M	C	AI	C	C	6.3.2-5	Yes	Yes	----
								M1267A	Inside	Globe 2"	E	T	3,R,M	C	AI	C	C				
								M1264B	Outside	Globe 2"	E	T	A,2,M	C	AI	C	C				
								M1336	Inside	Relief 2"	-	2485 PSIG	-	C	-	C	C				
38	Containment Spray Line	M362	B1	8	In	Yes	Yes	M532A	Outside	Gate 8"	E	P	A,R,M	C	AI	C	O	6.2.2-1	No	No	(25)
								M533	Inside	Check 8"	-	-	-	C	-	C	O				
39	Containment Spray Line	M370	B1	8	In	Yes	Yes	M529A	Outside	Gate 8"	E	P	A,R,M	C	AI	C	O	6.2.2-1	No	No	(25)
								M530	Inside	Check 8"	-	-	-	C	-	C	O				
40	Containment Spray Line	M380	B1	8	[illegible]	Yes	Yes	M515B	Outside	Gate 8"	E	P	A,R,M	C	AI	C	O	6.2.2-1	No	No	(25)
								M516	Inside	Check 8"	-	-	-	C	-	C	O				
41	Containment Spray Line	M387	B1	8	In	Yes	Yes	M512B	Outside	Gate 8"	E	P	A,R,M	C	AI	C	O	6.2.2-1	No	No	(25)
								M513	Inside	Check 8"	-	-	-	C	-	C	O				
42	HD Containment Spray Line A	M369	B1	8	In	Yes	Yes	M543A	Outside	Gate 8"	E	-	R,M	C	AI	C	C/O	6.2.2-1	No	Yes	----
								M546	Inside	Check 8"	-	-	-	C	-	C	C/O				
43	HD Containment Spray Line B	M381	B1	8	In	Yes	Yes	M538B	Outside	Gate 8"	E	-	R,M	C	AI	C	C/O	6.2.2-1	No	Yes	----
								M541	Inside	Check 8"	-	-	-	C	-	C	C/O				
44	Reactor Coolant Drain Tank Gas Space to WG System	M348	A1	3/4	In/Out	No	No	WL450A	Inside	Globe 3/4"	E	T	A,R,M	O	AI	O	C	11.2.2-9	Yes	Yes	----
								WL451B	Outside	Globe 3/4"	E	T	A,R,M	O	AI	O	C				
45	Reactor Coolant Drain Tank Heat Exchanger Dischg.	M345	A9	3	Out	No	Yes	WL805A	Inside	Gate 3"	E	T	A,R,M	O	AI	O	C	11.2.2-9	No	No	(26)
								WL807B	Outside	Gate 3"	E	T	A,R,M	O	AI	O	C				
								WL806	Inside	Check 1/2"	-	-	-	C	-	C	C				
46	Ventilation Unit Condensate Drain Hdr.	M221	A9	6	Out	No	No	WL867A	Inside	Gate 4"	E	P (14)	A,R,M	O	AI	O	C	11.2.2-10	Yes	Yes	----
								WL869B	Outside	Gate 4"	E	P (14)	A,R,M	O	AI	O	C				
								WL868	Inside	Check 1"	-	-	-	C	-	C	C				
47	Cont. Floor Sump and Incore Instrumentation Sump Pump Dischg.	M374	A9	4	Out	No	No	WL825A	Inside	Gate 4"	E	T (14)	A,R,M	O	AI	O	C	11.2.2-13	No	No	(26)
								WL827B	Outside	Gate 4"	E	T (14)	A,R,M	O	AI	O	C				
								WL321	Inside	Check 3/4"	-	-	-	C	-	C	C				
48	Steam Generator Drain Pump Dischg.	M359	A9	3	Out	No	No	WLA21	Inside	Gate 3"	HW	-	M	LC	-	C	C	11.2.2-15	No	No	(26)
								WLA22	Inside	Check 3/4"	-	-	M	C	-	C	C				
								WLA24	Outside	Gate 3"	HW	-	M	LC	-	C	C				
49	Equipment Decontamination Line (Note 13)	M356	A4	1	In	No	No	WE20	Outside	Globe 1"	HW	-	M	LC	-	C	C	None	Yes	Yes	----
								WE22	Inside	Globe 1"	HW	-	M	LC	-	C	C				
50	Fuel Transfer Tube	-	C2	24	None	Yes	Yes	-	Inside	Double Seal	-	-	M	C	-	O	C	9.1.3-1	No	No	(25)
								-	Inside	Blind Flange	-	-	-	-	-	-	-				
51	Refueling Water Pump Suction	M358	A4	4	Out	Yes	No	FW11	Inside	Plug 4"	HW	-	M	LC	-	C	C	9.2.7-1	Yes	Yes	----
								FW13	Outside	Plug 4"	HW	-	M	LC	-	C	C				
52	Refueling Cavity Fill Line	M377	B2	6	In	Yes	No	FW4	Outside	Gate 6"	HW	-	M	LC	-	C/O	C	9.2.7-1	Yes	Yes	----
								FW5	Inside	Check 6"	-	-	-	C	-	C/O	C				
53	Pressurizer Sample	M235	A6	1/2	Out	Yes	No	HM3A	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C	9.3.2-1	Yes	Yes	----
								HM6A	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAGE 4

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
								NM67	Inside	Relief 3/4"	-	2485 PSIG	-	C	-	C	C				
								NM7B	Outside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
54	Reactor Coolant Hot Leg Sample	M310	A6	1/2	Out	Yes	Yes	NM22A	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C	9.3.2-1	Yes	Yes	----
								NM25A	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM26B	Outside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM68	Inside	Relief 3/4"	-	2485 PSIG	-	C	-	C	C				
55	Safety Injection Accumulator Sample	M236	A6	1/2	Out	Yes	No	NM72B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2-2	No	Yes	----
								NM75B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM78B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM81B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
								NM69	Inside	Relief 3/4"	-	700 PSIG	-	C	-	C	C				
								NM82A	Outside	Globe 1/2"	E	T	A,R,M	C	AI	C	C				
56	Steam Generator 1A Sample	M335	A6	1/2	Out	Yes	No	NM187A	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2-5	No	No	(23)
								NM190A	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM191B	Outside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM255	Inside	Relief 3/4"	-	1185 PSIG	-	C	-	C	C				
57	Steam Generator 1B Sample	M338	A6	1/2	Out	Yes	No	NM197B	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2-5	No	No	(23)
								NM200B	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM201A	Outside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM256	Inside	Relief 3/4"	-	1185 PSIG	-	C	-	C	C				
58	Steam Generator 1C Sample	M340	A6	1/2	Out	Yes	No	NM207A	Inside	Globe 1/2"	E	T	A,R,M	C	AI	C	C	9.3.2-5	No	No	(23)
								NM210A	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM211B	Outside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM257	Inside	Relief 3/4"	-	1185 PSIG	-	C	-	C	C				
59	Steam Generator 1D Sample	M341	A6	1/2	Out	Yes	No	NM217B	Inside	Globe 1/2"	E	T	A,P,M	C	AI	C	C	9.3.2.5	No	No	(23)
								NM220B	Inside	Globe 1/2"	E	T	A,R,M	O	AI	O	C				
								NM221A	Outside	Globe 1/2"	E	T	A,R,M	O	AI	U	C				
								NM258	Inside	Relief 3/4"	-	1185 PSIG	-	C	-	C	C				
60	Component Cooling to RC Drain Tank HX	M376	B6	4	In	Yes	Yes	KC322	Inside	Check 4"	-	-	-	O	-	O	C	9.2.2-4	No	Yes	----
								KC320A	Outside	Gate 4"	E	T	A,R,M	O	AI	O	C				
61	Component Cooling from Drain Tank HX	M355	A9	4	Out	Yes	Yes	KC332B	Inside	Gate 4"	E	T	A,R,M	O	AI	O	C	9.2.2-4	No	No	(26)
								KC280	Inside	Check 1"	-	-	-	C	-	C	C				
								KC333A	Outside	Gate 4"	E	T	A,R,M	O	AI	O	C				
62	Component Cooling to Reactor Vessel Support & RCP Coolers	M328	B6	8	In	Yes	Yes	KC338B	Outside	Gate 8"	E	P	A,R,M	O	AI	O	C	9.2.2-4	No	Yes	----
								KC340	Inside	Check 8"	-	-	-	O	-	O	C				
63	Component Cooling from Reactor Vessel Support & RCP Coolers	M321	A9	8	Out	Yes	Yes	KC424B	Inside	Gate 8"	E	P	A,R,M	O	AI	O	C	9.2.2-4	No	No	(26)
								KC425A	Outside	Gate 8"	E	P	A,R,M	O	AI	O	C				
								KC279	Inside	Check 1"	-	-	-	C	-	C	C				
64	Component Cooling to Excess Letdown HX	M218	B2	4	In	Yes	Yes	KC305B	Outside	Gate 4"	E	T	A,R,M	C	AI	C	C	9.2.2-4	No	Yes	----
65	Component Cooling from Excess Letdown HX	M217	B2	4	Out	Yes	Yes	KC315B	Outside	Gate 4"	E	T	A,R,M	C	AI	C	C	9.2.2-4	No	Yes	----
66	Component Cooling to Component Cooling Drain Sump	M323	A7	2	Out	No	Yes	KC47	Inside	Check 3/4"	-	-	-	C	-	C	C	9.2.2-6	Yes	Yes	----
								KC429B	Inside	Globe 2"	E	T	A,R,M	O	AI	O	C				
								KC430A	Outside	Globe 2"	E	T	A,R,M	O	AI	O	C				

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TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PA

Item Number	Service	Pen. No.	(1,17) Valve Arrangements	Nominal Line Size Inches	Flow Direction Relative to Containment	(7) Seismic Connections Inside	Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	Actuation Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification For Not Testing
67	Nuclear Service Wtr. to NC Pump and Lower Cont. Vent. Units	M240	B6	12	In	Yes	Yes	RN437B	Outside	Gate 12"	E	P	A,R,M	O	AI	O	C	9.2.1-6	Yes	Yes	----
								RN438	Inside	Check 12"	-	-	-	O	-	O	C				
68	Nuclear Service Wtr. from NC Pump and Lower Cont Vent Units	M230	A9	12	Out	Yes	Yes	RN484A	Inside	Gate 12"	E	P	A,R,M	O	AI	O	C	9.2.1-7	Yes	Yes	----
								RN487B	Outside	Gate 12"	E	P	A,R,M	O	AI	O	C				
								RN485	Inside	Check 3/4"	-	-	-	C	-	C	C				
69	Nuclear Service Wtr. to Upper Cont. Vent. Units	M385	B6	6	In	Yes	Yes	RN404B	Outside	Gate 6"	E	P	A,R,M	O	AI	O	C	9.2.1-7	Yes	Yes	----
								RN405	Inside	Check 6"	-	-	-	O	-	O	C				
70	Nuclear Service Wtr. from Upper Cont. Vent. Units	M308	A9	6	Out	Yes	Yes	RN429A	Inside	Gate 6"	E	P	A,R,M	O	AI	O	C	9.2.1-6	Yes	Yes	----
								RN432B	Outside	Gate 6"	E	P	A,R,M	O	AI	O	C				
								RN430	Inside	Check 3/4"	-	-	-	C	-	C	C				
71	Incore Instrumentation Rm. Purge In	M213	A5	12	In	Yes	No	VP17A	Inside	Butterfly 12"	D	T (14)	A,R	C	C	C	C	9.4.5-1	No	Yes	----
								VP18B	Outside	Butterfly 12"	D	T (14)	A,R	LC	C	C	C				
72	Incore Instrumentation Rm. Purge Out	M140	A5	12	Out	Yes	Yes	VP19A	Inside	Butterfly 12"	D	T (14)	A,R	C	C	C	C	9.4.5-1	No	Yes	----
								VP20B	Outside	Butterfly 12"	D	T (14)	A,R	LC	C	C	C				
73	Upper Compartment Purge Inlet	M456	A5	24	In	Yes	No	VP1B	Outside	Butterfly 24"	D	T (14)	A,R	C	C	C	C	9.4.5-1	No	Yes	----
								VP2A	Inside	Butterfly 24"	D	T (14)	A,R	C	C	C	C				
74	Upper Compartment Purge Inlet	M432	A5	24	In	Yes	No	VP3B	Outside	Butterfly 24"	D	T (14)	A,R	C	C	C	C	9.4.5-1	No	Yes	----
								VP4A	Inside	Butterfly 24"	D	T (14)	A,R	C	C	C	C				
75	Lower Compartment Purge Inlet	M357	A5	24	In	Yes	No	VP6B	Outside	Butterfly 24"	D	T (14)	A,R	LC	C	C	C	9.4.5-1	No	Yes	----
								VP7A	Inside	Butterfly 24"	D	T (14)	A,R	C	C	C	C				
76	Lower Compartment Purge Inlet	M434	A5	24	In	Yes	No	VP8B	Outside	Butterfly 24"	D	T (14)	A,R	LC	C	C	C	9.4.5-1	No	Yes	----
								VP9A	Inside	Butterfly 24"	D	T (14)	A,R	C	C	C	C				
77	Containment Purge Exhaust	M368	A5	24	Out	Yes	Yes	VP10A	Inside	Butterfly 24"	D	T (14)	A,R	C	C	C	C	9.4.5-1	No	Yes	----
								VP11B	Outside	Butterfly 24"	D	T (14)	A,R	C	C	C	C				
78	Containment Purge Exhaust	M433	A5	24	Out	Yes	Yes	VP12A	Inside	Butterfly 24"	D	T (14)	A,R	C	C	C	C	9.4.5-1	No	Yes	----
								VP13B	Outside	Butterfly 24"	D	T (14)	A,R	C	C	C	C				
79	Containment Purge Exhaust	M119	A5	24	Out	Yes	Yes	VP15A	Inside	Butterfly 24"	D	T (14)	A,R	C	C	C	C	9.4.5-1	No	Yes	----
								VP16B	Outside	Butterfly 24"	D	T (14)	A,R	LC	C	C	C				
80	Steam Generator 1D Blowdown	M455	A7	4	Out	Yes	Yes	BB8A	Inside	Gate 4"	E	T	A,R,M	O	AI	C	C	10.4.8-1	No	No	(23)
								BB10B	Outside	Gate 4"	E	T	A,R,M	O	AI	C	C				
								BB52	Inside	Check 3/4"	-	-	-	C	-	C	C				
								BB147B	Outside	Globe 1"	E	T	A,R,M	C	AI	C	C				
81	Steam Generator 1A Blowdown	M142	A7	4	Out	Yes	Yes	BB56A	Inside	Gate 4"	E	T	A,R,M	O	AI	C	C	10.4.8-1	No	No	(23)
								BB57B	Outside	Gate 4"	E	T	A,R,M	O	AI	C	C				
								BB53	Inside	Check 3/4"	-	-	-	C	-	C	C				
								BB148B	Outside	Globe 1"	E	T	A,R,M	C	AI	C	C				
82	Steam Generator 1C Blowdown	M3105	A7	4	Out	Yes	Yes	BB60A	Inside	Gate 4"	E	T	A,R,M	O	AI	C	C	10.4.8-1	No	No	(23)
								BB61B	Outside	Gate 4"	E	T	A,R,M	O	AI	C	C				
								BB54	Inside	Check 3/4"	-	-	-	C	-	C	C				
								BB149B	Outside	Globe 1"	E	T	A,R,M	C	AI	C	C				
83	Steam Generator 1B Blowdown	M277	A7	4	Out	Yes	Yes	BB19A	Inside	Gate 4"	E	T	A,R,M	O	AI	C	C	10.4.8-1	No	No	(23)
								BB21B	Outside	Gate 4"	E	T	A,R,M	O	AI	C	C				
								BB55	Inside	Check 3/4"	-	-	-	C	-	C	C				
								BB150B	Outside	Globe 1"	E	T	A,R,M	C	AI	C	C				

TABLE 6.2.4-1

CONTAINMENT ISOLATION VALVE AND ACTUATOR DATA (PAG

Item Number	Service	Pen. No.	(1,17) Valve Arrange-ments	Nominal Line Size Inches	Flow Direction Relative to Contain-ment	(7) Seismic Connections Inside	Outside	(6,15) Valve Number	(19) Valve Location	Type Valve & Size	(4,16) Type Actuator	(2,3) Actuation Signal	Type	(4) Valve Position Normal	Failsafe	Shutdown	Post Accident	FSAR Figure No.	Vent And Drain For Type A Test	(18) Type C Leakage Test	Justification f Not Testing
84	Containment Air Release	M306	A5	4	Out	Yes	No	VQ2A	Inside	Diaphragm 4"	D	T (14)	A,R,M	C	C	C	C	9.5.9-1	No	Yes	----
								VQ3B	Outside	Gate 4"	E	T (14)	A,R,M	C	AI	C	C				
85	Containment Air Addition	M204	A5	4	In	Yes	No	VQ15B	Outside	Gate 4"	E	T (14)	A,R,M	C	AI	C	C	9.5.9-1	No	Yes	----
								VQ16A	Inside	Diaphragm 4"	D	T (14)	A,R,M	C	C	C	C				
86	Feedwater 1A	M110	B1	18	In	Yes	No	CF33	Outside	Gate 18"	H	S	A,R	O	C	C	C	10.4.7-11	No	No	(23)
								CF91	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CF90	Outside	Gate 2"	D	S	A,R	C	C	C	C				
87	Feedwater 1B	M262	B1	18	In	Yes	No	CF42	Outside	Gate 18"	H	S	A,R	O	C	C	C	10.4.7-10	No	No	(23)
								CF93	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CF89	Outside	Gate 2"	D	S	A,R	C	C	C	C				
88	Feedwater 1C	M309	B1	18	In	Yes	No	CF51	Outside	Gate 18"	H	S	A,R	O	C	C	C	10.4.7-10	No	No	(23)
								CF95	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CF88	Outside	Gate 2"	D	S	A,R	C	C	C	C				
89	Feedwater 1D	M422	B1	18	[illegible]	Yes	No	CF60	Outside	Gate 18"	H	S	A,R	O	C	C	C	10.4.7-10	No	No	(23)
								CF97	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CF87	Outside	Gate 2"	D	S	A,R	C	C	C	C				
90	Aux. Feedwater 1A	M143	B1	4	In	Yes	Yes	CA62A	Outside	Gate 4"	E	M	R,M	O	AI	O	O	10.4.9-2	No	No	(23)
								CA66B	Outside	Gate 4"	E	M	R,M	O	AI	O	O				
								CA121	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CA149	Outside	Gate 4"	P	S	A,R	C(12)	C	C	C				
								BW1	Outside	Gate 2"	HW	-	-	LC	-	C	C	Not shown			
								CA185	Outside	Gate 2"	P	S	A,R	O	C	C	C				
91	Aux. Feedwater 1B	M278	B1	4	In	Yes	Yes	CA54B	Outside	Gate 4"	E	M	R,M	O	AI	O	O	10.4.9-10	No	No	(23)
								CA58A	Outside	Gate 4"	E	M	R,M	O	AI	O	O				
								CA123	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CA150	Outside	Gate 4"	P	S	A,R	C(12)	C	C	C				
								BW26	Outside	Gate 2"	HW	-	-	LC	-	C	C	Not shown			
								CA186	Outside	Gate 2"	P	S	A,R	O	C	C	C				
92	Aux. Feedwater 1C	M3106	B1	4	In	Yes	Yes	CA46B	Outside	Gate 4"	E	M	R,M	O	AI	O	O	10.4.9-2	No	No	(23)
								CA50A	Outside	Gate 4"	E	M	R,M	O	AI	O	O				
								CA119	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CA151	Outside	Gate 4"	P	S	A,R	C (12)	C	C	C				
								BW17	Outside	Gate 2"	HW	-	-	LC	-	C	C	Not shown			
								CA187	Outside	Gate 2"	P	S	A,R	O	C	C	C				
93	Aux. Feedwater 1D	M457	B1	4	In	Yes	Yes	CA38A	Outside	Gate 4"	E	M	R,M	O	AI	O	O	10.4.9-2	No	No	(23)
								CA42B	Outside	Gate 4"	E	M	R,M	O	AI	O	O				
								CA118	Outside	Globe 3/4"	HW	-	-	LC	-	C	C				
								CA152	Outside	Gate 4"	P	S	A,R	C (12)	C	C	C				
								BW10	Outside	Gate 2"	HW	-	-	LC	-	C	C	Not shown			
								CA188	Outside	Gate 2"	P	S	A,R	O	C	C	C				

Containment Isolation Valve and Actuation Data

NOTES:

1. Valve arrangements are shown in Figure 6.2.4-1.

2. Definition of Actuation Signals

   S - Safety Injection Signal (T signal also activated by S signal)
   T - Containment Isolation Signal (Phase A containment isolation)
   P - Containment High-High Pressure Signal (Phase B containment isolation)

3. Deleted

4. Symbols:

   Valve Position Abbreviations

O	Open
C	Closed
A	Automatic
R	Remote Operation
M	Manual Local Operation
LC	Locked Closed
C/O	Closed prior to Sump or Hot Leg Recirculation; Open after Sump or Hot Leg Recirculation
LO	Locked Open
AI	Fails As is

   Actuator Type

E	Motor (Power Source - Electricity)
D	Pneumatic Diaphragm (Power Source - Compressed Air)
P	Pneumatic Piston (Power Source - Compressed Air)
HW	Handwheel (Power Source - Manual)

5. Each Personnel Lock will have double doors with an interlocking system to prevent both doors being opened simultaneously.

6. System Identification from valve number.

   BB - Steam Generator Blowdown System
   BW - Steam Generator Wet Layup Recirculation System
   CA - Auxiliary Feedwater System
   CF - Feedwater System
   FW - Refueling Water System
   KC - Component Cooling System
   KF - Spent Fuel Cooling System
   NB - Boron Recycle System

Containment Isolation Valve and Actuator Data

NC - Reactor Coolant System
ND - Residual Heat Removal System
NF - Ice Condenser System
NI - Safety Injection System
NM - Nuclear Sampling System
NS - Containment Spray System
NV - Chemical and Volume Control System
RF - Fire Protection System
RN - Nuclear Service Water System
SA - Main Steam to Auxiliary Equipment
SM - Main Steam System
SV - Main Steam Vent to Atmosphere
VB - Breathing Air System
VE - Annulus Ventilation System
VI - Instrument Air System
VP - Containment Purge System
VQ - Containment Air Release and Addition System
VS - Station Air System
VV - Containment Hydrogen Sample and Purge System
VX - Containment Air Return Exchange and Hydrogen Skimmer System
WE - Equipment Decontamination System
WG - Waste Gas System
WL - Liquid Radwaste System
YM - Demineralized Water System

7. The given response indicates whether or not the penetration is connected to Seismic Category 1 equipment inside and/or outside containment.

8. The Containment pressure control isolation valves are also automatically closed by high containment radiation.

9. Connected Piping is temporary and is removed before startup. Penetrations are closed with blind flanges during all modes containment integrity is required.

10. See FSAR Section 6.3 for automatic actuation signals for these valves.

11. See Section 6.3 for Accumulator Water level signal used to close these valves after initial injection.

12. Open for startup, closed when plant reaches ~ 30% power.

13. As documented in Engineering Justification Report SES-JR-10, the one inch containment isolation valves for this system were purchased as Duke Class F instead of Duke Class B. This was necessary due to the high system design pressure (8000 psig) which exceeded the pressure/temperature ratings of the ASME section III Code.

Containment Isolation Valve and Actuator Data

14. Valve closes upon receipt of a high radiation signal.

15. The following systems are considered Engineered Safety Feature systems:

    FW - Refueling Water System
    NB - Boron Recycle System
    NC - Reactor Coolant System
    ND - Residual Heat Removal System
    NF - Ice Condenser System
    NI - Safety Injection System
    NS - Containment Spray System
    NV - Chemical and Volume Control System
    VE - Annulus Ventilation System

16. Power Source - Refer to Note 4.

17. General Design Criteria met -

    Any valve arrangement designated with an "A" or "B" prefix meets the specifications of GDC 55 and 56 of 10CFR50, Appendix A. Valve arrangements with a "D" prefix meet GDC 57.

    Valve arrangements with a "C" prefix fall into a miscellaneous category in which the piping is considered a part of the containment and meeting GDC 50. In addition, the 'C2' arrangement (the fuel transfer tube) also meets GDC 51, 52, and 53 (see Section 6.2.4.2.1). 'C1' and 'C3' arrangements are considered closed to outside atmosphere. See Note 9 concerning specifics on arrangement 'C3'.

18. All potential bypass leakage paths in dual containment plants are required a Type C test per Position No. 7, Section B, of Branch Technical Position CSB 6-3, "Determination of Bypass Leakage Paths In Dual Containment Plants."

19. Piping, isolation valves, and actuators in the Containment Isolation System outside Containment are located inside a Seismic Category 1 enclosure complex, and are located as close as practical to the Containment wall; i.e., in almost all cases, isolation valves will be located immediately after the penetration assembly. There will, however, be exceptions, such as the case of the main steam lines which require a series of safety valves before the isolation valve. Also, there will be some exceptions due to normal structural design arrangements. Actual lengths of pipe from penetrations to the isolation valves outside Containment have been kept to a minimum.

20. Deleted

21. Deleted

TABLE 6.2.4-1 (Page 12)

Containment Isolation Valve and Actuator Data

22. During the injection phase of safety injection, these valves are closed. Water from the refueling water storage tank (FWST) provides approximately 48 feet of head on these valves (~ 20.8 psig). This head will preclude any leakage through this penetration. During the recirculation phase of safey injection, these valves are open to provide flow to ND pump suction.

23. The main steam, feedwater, auxiliary feedwater, sample and blowdown lines are all connected to the secondary side of the steam generator which is kept at a higher pressure than the primary side soon after a LOCA occurs. Any leakage between the primary and secondary sides of the steam generator is directed inward to the containment.

24. Deleted

25. Type C leak test not required by 10 CFR 50, Appendix J because these containment isolation valves:

    a. Do not provide a direct connection between the inside and outside atmospheres of the primary reactor containment under normal operation.

    b. Are not required to close automatically upon receipt of a containment isolation signal in response to controls intended to effect containment isolation, and

    c. Are not required to operate intermittenly under post accident conditions.

26. These valves are sealed against leakage by the Containment Valve Injection Water System as discussed in Section 6.2.4.4.

27. Type B test performed per 10 CFR 50, Appendix J.

28. Deleted

29. This system is required to be in operation during the Type A test in order to maintain the unit in a safe condition. Therefore, this penetration will not be vented and drained.

30. This penetration is a part of a closed system inside containment. All piping inside containment is seismic Category 1 and therefore not subject to rupture as a result of a LOCA. This penetration will not be drained and vented for the Type A test.

Table 6.2.4-2 (Page 1)

Comparison of Containment Purge System With Branch Technical Position CSB 6-4, Revision 2

Paragraph	Compliance Status
B-1-a	The Containment Isolation System is described in Section 6.2.4. Operability of the containment purge isolation valves is currently under review by the Equipment Qualifications Branch. (Reference E. G. Adensan's April 1, 1982 letter to W. O. Parker.)
B-1-b	The system has a total of nine supply and exhaust penetrations (as shown on Figure 9.4.5-1) in order to serve the upper and lower compartments of the ice condenser containment and to limit the penetration sizes.
B-1-c	Containment penetration and isolation valve sizes are listed in Table 6.2.4-1. Note that SRP 6.2.4 states that the 8 inch maximum duct diameter recommendation is not applicable since purge system operation is Technical Specification limited to $\leq$ 90 hours per year during power, startup, hot standby and shutdown modes of operation.
B-1-d	In Compliance. See Section 6.2.4.
B-1-e	In Compliance. See Section 6.2.4.
B-1-f	In Compliance. See Section 6.2.4.
B-1-g	The potential for entrainment of debris in the containment purge isolation valves is minimized by the ice condenser containment design. Since the lower containment purge isolation valves will be closed during power, startup, hot standby and shutdown modes of operation (Technical Specification requirement), any debris generated from the postulated LOCA would be confined to the lower compartment by the ice condenser's filtering the debris. The upper containment isolation valves are not in the ice condenser blowdown stream, further reducing

Table 6.2.4-2 (Page 2)

Comparison of Containment Purge System
With Branch Technical Position
CSB 6-4, Revision 2

Paragraph	Compliance Status
	the probability of debris entrainment in the valves.
B-2	In Compliance. See description of Containment Purge System in Section 9.4.5.
B-3	In Compliance. See description of Containment Auxiliary Charcoal Filter System in Section 9.4.6.
B-4	In Compliance. See Sections 6.2.4 and 6.2.6.
B-5-a B-5-b	The loss-of-coolant accident analysis does not assume the purge valves are open at the onset of the postulated LOCA. Purge system operation is limited to $\leq$ 90 hours per year in accordance with SRP 6.2.4 guidelines. Lower compartment purge valves are closed during power, startup, hot standby and shutdown modes of operation.
B-5-c	If the system is in operation at the start of an accident the amount of air lost while the valves are closing is insignificant. The minimum containment pressure analysis is presented in Section 6.2.1.5.
B-5-d	An allowable leak rate for these valves will be developed in the Type "C" test program.

Attachment 7

Core Performance Branch

The absorber rods are fastened securely to the spider. The rods are first threaded into the spider fingers and then pinned to maintain joint tightness, after which the pins are welded in place. The end plug below the pin position is designed with a reduced section to permit flexing of the rods to correct for small misalignments.

The overall length is such that when the assembly is withdrawn through its full travel the tips of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Since the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble.

After each refueling, prior to startup, control rod worth measurements are performed on the control banks for at least 1/3 of the total predicted worth of all groups. Normal reload design practice dictates shuffling of RCCA's from control to shutdown banks for subsequent cycles. Greater than expected worth loss would be detected by this surveillance.

4.2.2.3.2 Burnable Poison Assembly

Each burnable poison assembly consists of burnable poison rods attached to a holddown assembly. A burnable poison assembly is shown in the composite core component Figure 4.2.2-12. When needed due to nuclear considerations, burnable poison assemblies are inserted into selected thimbles within fuel assemblies.

The poison rods consist of borosilicate glass tubes contained within Type 304 stainless steel tubular cladding which is plugged and seal welded at the ends to encapsulate the glass. The glass is also supported along the length of its inside diameter by a thin wall tubular inner liner. The top end of the liner is open to permit the diffused helium to pass into the void volume and the liner extends beyond the glass. The liner is flanged at the bottom end to maintain the position of the liner with the glass.

The poison rods in each fuel assembly are grouped and attached together at the top end of the rods to a hold down assembly by a flat perforated retaining plate which fits within the fuel assembly top nozzle and rests on the adaptor plate. The retaining plate and the poison rods are held down and restrained against vertical motion through a spring pack which is attached to the plate and is compressed by the upper core plate when the reactor upper internals assembly is lowered into the reactor. This arrangement ensures that the poison rods cannot be ejected from the core by flow forces. Each rod is permanently attached to the base plate by a nut which is lock welded into place.

The cladding of the burnable poison rods is slightly cold-worked Type 304 stainless steel. All other sturctural materials in the assembly are Types 304 or 308 stainless steel except for the springs which are Inconel-718. The borosilicate glass tube provides sufficient boron content to meet the criteria discussed in Section 4.3.1.

4.2.2.3.3 Neutron Source Assembly