Table of Contents

5.0 Reactor Coolant System and Connected Systems

5.1 Summary Description
5.1.1 Schematic Flow Diagram
5.1.2 Piping and Instrumentation Diagram
5.1.3 Elevation Drawings

5.2 Integrity of Reactor Coolant Pressure Boundary
5.2.1 Compliance With Codes and Code Cases
5.2.1.1 Compliance with 10CFR Section 50.55a
5.2.1.2 Applicable Code Cases
5.2.1.2.1 Fabrication and Construction Activities
5.2.1.2.2 Operation, Maintenance, and Testing Activities
5.2.2 Overpressure Protection
5.2.2.1 Design Bases
5.2.2.2 Design Evaluation
5.2.2.3 Piping and Instrumentation Diagrams
5.2.2.4 Equipment and Component Description
5.2.2.5 Mounting
5.2.2.6 Applicable Codes and Classification
5.2.2.7 Material Specifications
5.2.2.8 Process Instrumentation
5.2.2.9 System Reliability
5.2.2.10 Testing and Inspection
5.2.3 Materials Selection, Fabrication, and Processing
5.2.3.1 Material Specifications
5.2.3.2 Compatibility with Reactor Coolant
5.2.3.2.1 Chemistry of Reactor Coolant
5.2.3.2.2 Compatibility of Construction Materials With Reactor Coolant
5.2.3.2.3 Compatibility With External Insulation and Environmental Atmosphere
5.2.3.3 Fabrication and Processing of Ferritic Materials
5.2.3.3.1 Fracture Toughness
5.2.3.3.2 Control of Welding
5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel
5.2.3.4.1 Cleaning and Contamination Protection Procedures
5.2.3.4.2 Solution Heat Treatment Requirements
5.2.3.4.3 Material Inspection Program
5.2.3.4.4 Prevention of Intergranular Attack of Unstabilized Austenitic Stainless Steels
5.2.3.4.5 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitization Temperatures
5.2.3.4.6 Control of Welding
5.2.4 Inservice Inspection and Testing of Reactor Coolant Pressure Boundary
5.2.4.1 System Boundary
5.2.4.2 Accessibility
5.2.4.3 Examination Techniques and Procedures
5.2.4.4 Inspection Schedule
5.2.4.5 Examination Categories and Requirements
5.2.4.6 Evaluation of Examination Results
5.2.4.7 System Leakage and Hydrostatic Pressure Test
5.2.5 Detection of Leakage Through Reactor Coolant Pressure Boundary
5.2.5.1 Leakage Classification and Limits
5.2.5.2 Leakage Detection Methods

5.2.5.2.1 Identified Leakage
5.2.5.2.2 Intersystem Leakage
5.2.5.2.3 Unidentified Leakage
5.2.5.3 System Sensitivity and Response Time
5.2.5.4 Testability
5.2.6 References

5.3 Reactor Vessel
5.3.1 Reactor Vessel Materials
5.3.1.1 Material Specifications
5.3.1.2 Special Processes Used For Manufacturing and Fabrications
5.3.1.3 Special Methods For Nondestructive Examination
5.3.1.3.1 Ultrasonic Examination
5.3.1.3.2 Penetrant Examinations
5.3.1.3.3 Magnetic Particle Examination
5.3.1.4 Special Controls For Ferritic and Austenitic Stainless Steels
5.3.1.5 Fracture Toughness
5.3.1.6 Material Surveillance
5.3.1.6.1 Ex-Vessel Neutron Dosimetry System
5.3.1.6.2 Measurement of Integrated Fast Neutron (E>1.0MeV) Flux at the Irradiation Samples
5.3.1.6.3 Calculation of Integrated Fast Neutron (E>1.0MeV) Flux at the Irradiation Samples
5.3.1.7 Reactor Vessel Fasteners
5.3.1.7.1 Reactor Vessel Closure Nuts and Washers
5.3.2 Pressure - Temperature Limits
5.3.2.1 Limit Curves
5.3.2.2 Operating Procedures
5.3.3 Reactor Vessel Integrity
5.3.3.1 Design
5.3.3.2 Materials of Construction
5.3.3.3 Fabrication Methods
5.3.3.4 Inspection Requirements
5.3.3.5 Shipment and Installation
5.3.3.6 Operating Conditions
5.3.3.7 Inservice Surveillance
5.3.3.8 Deleted Per 2004 Update
5.3.4 References

5.4 Component and Subsystem Design
5.4.1 Reactor Coolant Pumps
5.4.1.1 Design Bases
5.4.1.2 Design Description
5.4.1.3 Design Evaluation
5.4.1.3.1 Pump Performance
5.4.1.3.2 Coastdown Capability
5.4.1.3.3 Bearing Integrity
5.4.1.3.4 Locked Rotor
5.4.1.3.5 Critical Speed
5.4.1.3.6 Missile Generation
5.4.1.3.7 Pump Cavitation
5.4.1.3.8 Pump Overspeed Considerations
5.4.1.3.9 Anti-Reverse Rotation Device
5.4.1.3.10 Shaft Seal Leakage
5.4.1.3.11 Seal Discharge Piping
5.4.1.4 Tests and Inspections
5.4.1.5 Pump Flywheels
5.4.1.5.1 Design Basis

5.4.1.5.2 Fabrication and Inspection
5.4.2 Steam Generator
5.4.2.1 Steam Generator Materials
5.4.2.1.1 Selection and Fabrication of Materials
5.4.2.1.2 Steam Generator Design Effects on Materials
5.4.2.1.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants
5.4.2.1.4 Cleanup of Secondary Side Materials
5.4.2.2 Steam Generator Inservice Inspection
5.4.2.3 Design Bases
5.4.2.4 Design Description
5.4.2.5 Design Evaluation
5.4.2.5.1 Forced Convection
5.4.2.5.2 Natural Circulation Flow
5.4.2.5.3 Mechanical and Flow Induced Vibration Under Normal Operation
5.4.2.5.4 Allowable Tube Wall Thinning Under Accident Conditions
5.4.2.6 Quality Assurance
5.4.3 Reactor Coolant Piping
5.4.3.1 Design Bases
5.4.3.2 Design Description
5.4.3.3 Design Evaluation
5.4.3.3.1 Material Corrosion/Erosion Evaluation
5.4.3.3.2 Sensitized Stainless Steel
5.4.3.3.3 Contaminant Control
5.4.3.4 Tests and Inspections
5.4.4 Main Steam Line Flow Restrictor
5.4.4.1 Design Basis
5.4.4.2 Design Description
5.4.4.3 Design Evaluation
5.4.4.4 Tests and Inspections
5.4.5 Main Steam Line Isolation System
5.4.6 Reactor Core Isolation Cooling System
5.4.7 Residual Heat Removal System
5.4.7.1 Design Bases
5.4.7.2 System Design
5.4.7.2.1 Schematic Piping and Instrumentation Diagrams
5.4.7.2.2 Equipment and Component Descriptions
5.4.7.2.3 Control
5.4.7.2.4 Applicable Codes and Classifications
5.4.7.2.5 System Reliability Considerations
5.4.7.2.6 Evaluation of Compliance with NRC Branch Technical Position RSB 5-1
5.4.7.2.7 Manual Actions
5.4.7.3 Performance Evaluation
5.4.7.4 Preoperational Testing
5.4.8 Reactor Water Cleanup System
5.4.9 Main Steam Line and Feedwater Piping
5.4.10 Pressurizer
5.4.10.1 Design Bases
5.4.10.1.1 Pressurizer Surge Line
5.4.10.1.2 Pressurizer
5.4.10.2 Design Description
5.4.10.2.1 Pressurizer Surge Line
5.4.10.2.2 Pressurizer
5.4.10.3 Design Evaluation
5.4.10.3.1 System Pressure
5.4.10.3.2 Pressurizer Performance
5.4.10.3.3 Pressure Setpoints

5.4.10.3.4 Pressurizer Spray
5.4.10.3.5 Pressurizer Design Analysis
5.4.10.4 Tests and Inspections
5.4.11 Pressurizer Relief Discharge System
5.4.11.1 Design Basis
5.4.11.2 System Description
5.4.11.2.1 Pressurizer Relief Tank
5.4.11.3 Safety Evaluation
5.4.11.4 Instrumentation Requirements
5.4.11.5 Inspection and Testing Requirements
5.4.12 Reactor Coolant System Pressure Boundary Valves
5.4.12.1 Design Bases
5.4.12.2 Design Description
5.4.12.3 Design Evaluation
5.4.12.4 Tests and Inspections
5.4.13 Safety and Relief Valves
5.4.13.1 Design Bases
5.4.13.2 Design Description
5.4.13.3 Design Evaluation
5.4.13.4 Tests and Inspections
5.4.14 Component Supports
5.4.14.1 Design Bases
5.4.14.2 Design Description
5.4.14.2.1 Steam Generator
5.4.14.2.2 Reactor Coolant Pump
5.4.14.2.3 Pressurizer
5.4.14.2.4 Reactor Vessel
5.4.14.3 Fabrication
5.4.14.4 Materials
5.4.15 References

List of Tables

Table 5-1 System Design and Operating Parameters

Table 5-2. Applicable Code Addenda for RCS Components

Table 5-3. Code Cases Applicable for Operation, Maintenance, and Testing Activities

Table 5-4. ASME Code Cases Used For Catawba Units 1 & 2 Class 1 Components

Table 5-5. Typical Plant Thermal-Hydraulic Parameters.

Table 5-6. Class 1 Primary Components Material Specifications

Table 5-7. Class 1 and 2 Auxiliary Components Material Specifications

Table 5-8. Reactor Vessels Internals for Emergency Core Cooling

Table 5-9. Deleted Per 1998 Update

Table 5-10. Leakage Detection Sensitivity

Table 5-11. Reactor Vessel Quality Assurance Program

Table 5-12. Initial (Unirradiated) Toughness Properties for the Catawba Unit 1 Reactor Vessel3

Table 5-13. Initial (Unirradiated) Toughness Properties for the Catawba Unit 2 Reactor Vessel3

Table 5-14. Comparison of Initial (Unirradiated) and Projected EOLE (54 EFPY) Fracture Toughness Properties Of The Catawba Unit 1 Reactor Vessel Beltline Region Material

Table 5-15. Comparison of Initial (Unirradiated) and Projected EOLE (54 EFPY) Toughness Properties for the Catawba Unit 2 Reactor Vessel

Table 5-16. Catawba Unit 1 Closure Head Bolting Material Properties

Table 5-17. Catawba Unit 2 Closure Head Bolting Material Properties

Table 5-18. Reactor Vessel Design Parameters

Table 5-19. Chemical Composition Of The Catawba Unit 1 Reactor Vessel Beltline Region Material3

Table 5-20. Chemical Composition of the Catawba Unit 2 Reactor Vessel Beltline Region Material

Table 5-21. Catawba Unit 1 Reactor Vessel Beltline Region Toughness Properties

Table 5-22. Catawba Unit 2 Reactor Vessel Beltline Region Toughness Properties

Table 5-23. Reactor Coolant Pump Design Parameters

Table 5-24. Reactor Coolant Pump Quality Assurance Program

Table 5-25. Steam Generator Design Data

Table 5-26. Steam Generator Quality Assurance Program

Table 5-27. Reactor Coolant Piping Design Parameters

Table 5-28. Reactor Coolant Piping Quality Assurance Program

Table 5-29. Design Bases for Residual Heat Removal System Operation

Table 5-30. Residual Heat Removal System Component Data

Table 5-31. Failure Mode and Effects Analysis-Residual Heat Removal System Active Components-Plant Cooldown Operation

Table 5-32. Pressurizer Design Data

Table 5-33. Pressurizer Quality Assurance Program

Table 5-34. Pressurizer Relief Tank Design Data

Table 5-35. Relief Valve Discharge To The Pressurizer Relief Tank

Table 5-36. Reactor Coolant System Boundary Valve Design Parameters

Table 5-37. Pressurizer Valves Design Parameters

Table 5-38. Component Supports. Loading Combinations and Code Requirements

Table 5-39. Materials

Table 5-40. Reactor Vessel Material Surveillance Program - Withdrawal Schedule

Table 5-41. Reactor Coolant System Pressure Isolation Valves

Table 5-42. RT PTS Calculations for Catawba Unit 1 Beltline Region Materials at 54 EFPY

Table 5-43. RT PTS Calculations for Catawba Unit 2 Beltline Region Materials at 54 EFPY

Table 5-44. Evaluation of Upper Shelf Energy for Catawba Unit 1 Beltline Region Materials at 54 EFPY

Table 5-45. Evaluation of Upper Shelf Energy for Catawba Unit 2 Beltline Region Materials at 54 EFPY

Table 5-46. Summary of Reactor Coolant System Leakage Detection Instrumentation Exceptions and Comments to Regulatory Guide (RG) 1.45, “Reactor Coolant Pressure Boundary Leakage Detection Systems”, (Rev. 0)

List of Figures

Figure 5-1. Flow Diagram of Reactor Coolant System (Unit 1 Only)

Figure 5-2. Flow Diagram of Reactor Coolant System (Unit 2 Only)

Figure 5-3. Flow Diagram of Reactor Coolant System

Figure 5-4. Simplified Schematic of Reactor Vessel Head Vent System

Figure 5-5. Flow Diagram of Reactor Coolant System (Unit 1 Only)

Figure 5-6. Flow Diagram of Reactor Coolant System

Figure 5-7. Identification and Location of Catawba Unit 1 Reactor Vessel Beltline Region Weld and Forging Material

Figure 5-8. Identification and Location of Catawba Unit 2 Reactor Vessel Beltline Region Weld and Plate Material

Figure 5-9. Reactor Vessel

Figure 5-10. Reactor Vessel Head View Showing Top-Mounted Control Rod Mechanism Housing Locations and Capped UHI Head Adaptors

Figure 5-11. CRDM Head Adaptor

Figure 5-12. Reactor Coolant Controlled Leakage Pump

Figure 5-13. Reactor Coolant Pump Hot Performance Curve

Figure 5-14. Steam Generator (Unit 1)

Figure 5-15. Counter Flow Preheat Steam Generator (Unit 2)

Figure 5-16. Flow Diagram of Conventional Chemical Addition System

Figure 5-17. Flow Diagram of Residual Heat Removal System

Figure 5-18. Flow Diagram of Residual Heat Removal System

Figure 5-19. Deleted Per 2000 Update

Figure 5-20. Deleted Per 2000 Update

Figure 5-21. Pressurizer

Figure 5-22. Pressurizer Relief Tank

Figure 5-23. Typical Steam Generator Lower Lateral Support

Figure 5-24. Typical Steam Generator Upper Support (Unit 2)

Figure 5-25. Typical Column Assembly for the Steam Generator and Reactor Coolant Pump

Figure 5-26. Typical Reactor Coolant Pump Lateral Support

Figure 5-27. Typical Reactor Coolant Pump Lateral Support

Figure 5-28. Pressurizer Support System Elevation

Figure 5-29. Pressurizer Lower Lateral Support

Figure 5-30. Pressurizer Upper Lateral Support

Figure 5-31. Typical Reactor Vessel Support

Figure 5-32. Typical Unit 1 Steam Generator Upper Support

Figure 5-33. Flow Diagram of Unit 2 Reactor Coolant System (NC)

Figure 5-34. Flow Diagram of Unit 2 Reactor Coolant System (NC)

Figure 5-35. Reactor Coolant System

Figure 5-36. Conventional Chemical Addition (YA)

5.0 Reactor Coolant System and Connected Systems

THIS IS THE LAST PAGE OF THE TEXT SECTION 5.0.

THIS PAGE LEFT BLANK INTENTIONALLY.

5.1 Summary Description

The Reactor Coolant System (RCS) shown in Figure 5-1, Figure 5-2, Figure 5-3 and Figure 5-5 consists of four similar heat transfer loops connected in parallel to the reactor pressure vessel. Each loop contains a reactor coolant pump, steam generator and associated piping and valves. In addition, the system includes a pressurizer, pressurizer relief and safety valves, a pressurizer relief tank interconnecting piping, and instrumentation necessary for operational control. All the above components are located in the Containment building.

During operation, the RCS transfers the heat generated in the core to the steam generators where steam is produced to drive the turbine generator. Borated demineralized water is circulated in the RCS at a flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water also acts as a neutron moderator and reflector, and as a solvent for the neutron absorber used in chemical shim control.

The RCS pressure boundary provides a barrier against the release of radioactivity generated within the reactor, and is designed to ensure a high degree of integrity throughout the life of the plant.

RCS pressure is controlled by the use of the pressurizer where water and steam are maintained in equilibrium by electrical heaters and water sprays. Steam can be formed (by the heaters) or condensed (by the pressurizer spray) to minimize pressure variations due to contraction and expansion of the reactor coolant. Spring-loaded safety valves and power operated relief valves from the pressurizer provide for steam discharge to the pressurizer relief tank, where the steam is condensed and cooled by mixing with water.

The extent of the RCS is defined as:

1. The reactor vessel including control rod drive mechanism housings.
2. The reactor coolant side of the steam generators.
3. Reactor coolant pumps.
4. A pressurizer attached to one of the reactor coolant loops.
5. Safety and relief valves.
6. The pressurizer relief tank.
7. The interconnecting piping, valves and fittings between the principal components listed above.
8. The piping, fittings and valves leading to connecting auxiliary or support systems up to and including the second isolation valve (from the high pressure side) on each line.

<u>REACTOR COOLANT SYSTEM COMPONENTS</u>

<u>Reactor Vessel</u>

The reactor vessel is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The vessel contains the core, core supporting structures, control rods and other parts directly associated with the core.

The vessel has inlet and outlet nozzles located in a horizontal plane just below the reactor vessel flange but above the top of the core. Coolant enters the vessel through the inlet nozzles and flows down the core barrel-vessel wall annulus, turns at the bottom and flows up through the core to the outlet nozzles.

Steam Generators

The steam generators are vertical shell and U-tube evaporators with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the hemispherical bottom head of the steam generator. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel.

Reactor Coolant Pumps

The reactor coolant pumps are identical single-speed centrifugal units driven by water/air-cooled, three-phase induction motors. The shaft is vertical with the motor mounted above the pump. A flywheel on the shaft above the motor rotor provides additional inertia to extend pump coastdown. The inlet is at the bottom of the pump; discharge is on the side.

Piping

The reactor coolant loop piping is specified in sizes consistent with system requirements.

The hot leg inside diameter is 29 inches and the inside diameter of the cold leg return line to the reactor vessel is 27½ inches. The piping between the steam generator and the pump suction is increased to 31 inches in inside diameter to reduce pressure drop and improve flow conditions to the pump suction.

Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads. Electrical heaters are installed through the bottom heads of the vessel while the spray nozzle, relief and safety valve connections are located in the top head of the vessel.

Safety and Relief Valves

The pressurizer safety valves are of the totally enclosed pop-type. The valves are spring-loaded, self-activated with back-pressure compensation. The power-operated relief valves limit system pressure for large power mismatch. They are operated automatically or by remote manual control. Remotely operated valves are provided to isolate the inlet to the power-operated relief valves if excessive leakage occurs. Normally, the Instrument Air System provides the motive force to stroke the power-operated relief valves. Safety related backup sources of compressed gas (nitrogen) are two cold leg accumulators which can be aligned to respective power-operated relief valves by the operator from the control room.

Steam from the pressurizer safety and relief valves is discharged into the pressurizer relief tank through a sparger pipe under the water level. This condenses and cools the steam by mixing it with water that is near ambient temperature.

REACTOR COOLANT SYSTEM PERFORMANCE CHARACTERISTICS

Tabulations of important design and performance characteristics of the RCS are provided in Table 5-1.

Reactor Coolant Flow

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

The reactor coolant flow, a major parameter in the design of the system and its components, is established with a detailed design procedure supported by operating plant performance data, by pump model tests and analysis, and by pressure drop tests and analyses of the reactor vessel and fuel assemblies. Data from all operating plants have indicated that the actual flow has been well above the flow specified for the thermal design of the plant. By applying the design *procedure described below, it is possible to specify the expected operating flow with reasonable accuracy.*

Three reactor coolant flow rates are identified for the various plant design considerations. The definitions of these flows are presented in the following paragraphs.

Best Estimate Flow

The best estimate flow is the most likely value for the actual plant operating condition. This flow is based on the best estimate of the reactor vessel, steam generator and piping flow resistance, and on the best estimate of the reactor coolant pump head-flow capacity, with no uncertainties assigned to either the system flow resistance or the pump head. System pressure drops, based on best estimate flow, are presented in Table 5-1. Although the best estimate flow is the most likely value to be expected in operation, more conservative flow rates are applied in the thermal and mechanical designs.

Thermal Design Flow

Thermal design flow is the basis for the reactor core thermal performance, the steam generator thermal performance, and the nominal plant parameters used throughout the design. To provide the required margin, the thermal design flow accounts for the uncertainties in reactor vessel, steam generator and piping flow resistances, reactor coolant pump head, and the methods used to measure flow rate. The thermal design flow is approximately 6.5 percent less than the best estimate flow. The thermal design flow is confirmed when the plant is placed in operation. Tabulations of important design and performance characteristics of the RCS as provided in Table 5-1 are based on the thermal design flow.

Mechanical Design Flow

Mechanical design flow is the conservatively high flow used in the mechanical design of the reactor vessel internals and fuel assemblies. To assure that a conservatively high flow is specified, the mechanical design flow is based on a reduced system resistance and on increased pump head capability. The mechanical design flow is approximately 4.0 percent greater than the best estimate flow.

Pump overspeed, due to a turbine generator overspeed of 11.5 percent, results in a peak reactor coolant flow of 111.5 percent of the mechanical design flow. The overspeed condition is applicable only to operating conditions when the reactor and turbine generator are at power.

INTERRELATED PERFORMANCE AND SAFETY FUNCTIONS

The interrelated performance and safety functions of the RCS and its major components are listed below:

1. The RCS provides sufficient heat transfer capability to transfer the heat produced during power operation and when the reactor is subcritical, including the initial phase of plant cooldown, to the steam and power conversion system.
2. The system provides sufficient capability to transfer the heat produced during the subsequent phase of plant cooldown and cold shutdown to the Residual Heat Removal System.
3. The system heat removal capability under power operation and normal operational transients, including the transition from forced to natural circulation, assures no fuel damage within the operating bounds permitted by the Reactor Control and Protection Systems.
4. The RCS provides the water used as the core neutron moderator and reflector and as a solvent for chemical shim control.

5. The system maintains the homogeneity of soluble neutron poison concentration and rate of change of coolant temperature such that uncontrolled reactivity changes do not occur.
6. The reactor vessel is an integral part of the RCS pressure boundary and is capable of accommodating the temperatures and pressures associated with the operational transients. The reactor vessel functions to support the reactor core and control rod drive mechanisms.
7. The pressurizer maintains the system pressure during operation and limits pressure transients. During the reduction or increase of plant load, reactor coolant volume changes are accommodated in the pressurizer via the surge line.
8. The reactor coolant pumps supply the coolant flow necessary to remove heat from the reactor core and transfer it to the steam generators.
9. The steam generators provide high quality steam to the turbine. The tube and tubesheet boundary are designed to prevent or control to acceptable levels the transfer of activity generated within the core to the secondary system.
10. The RCS piping serves as a boundary for containing the coolant under operating temperature and pressure conditions and for limiting leakage (and activity release) to the containment atmosphere. The RCS piping contains demineralized borated water which is circulated at the flow rate and temperature consistent with achieving the reactor core thermal and hydraulic performance.

5.1.1 Schematic Flow Diagram

The Reactor Coolant System is shown schematically in Figure 5-1, Figure 5-3 and Figure 5-5. Principal pressures, temperatures, flow rates and coolant volume data under normal steady state full power operating conditions are provided in Table 5-1.

5.1.2 Piping and Instrumentation Diagram

A piping and instrumentation diagram of the Reactor Coolant System is shown on Figure 5-1, Figure 5-3 and Figure 5-5. The diagram shows the extent of the systems located within the containment, and the points of separation between the Reactor Coolant System, and the secondary (heat utilization) system.

5.1.3 Elevation Drawings

Elevation drawings providing principal dimensions of the Reactor Coolant System in relation to surrounding concrete structures are presented on Figure 1-17.

THIS IS THE LAST PAGE OF THE TEXT SECTION 5.1.

5.2 Integrity of Reactor Coolant Pressure Boundary

This section presents a discussion of the measures employed to provide and maintain the integrity of the Reactor Coolant Pressure Boundary (RCPB) for the plant design lifetime. In this context, the RCPB is as defined in Section 50.2 of 10CFR Part 50. In that definition, the RCPB extends to the outermost containment isolation valve in system piping which penetrates the containment and is connected to the Reactor Coolant System (RCS). Since other sections of the FSAR already describe the components of these auxiliary fluid systems in detail, the discussions in this section will be limited to the components of the RCS as defined in Section 5.1, unless otherwise noted.

For additional information on the RCS and for components which are part of the RCPB (as defined in 10CFR 50) but are not described in this section, refer to the following sections:

Section 6.3	-	For discussions of the RCPB components which are part of Emergency Core Cooling System.
Section 9.3.4	-	For discussions of the RCPB components which are part of the Chemical and Volume Control System.
Section 3.9.1	-	For discussions of the design loadings, stress limits, and analyses applied to the RCS and ASME Code Class 1 components.
Section 3.9.3	-	For discussions of the design loadings, stress limits, and analyses applied to ASME Code Class 2 and 3 components.

The phrase RCS used in this section is as defined in Section 5.1. When the term RCPB is used in this section, its definition is that of Section 50.2 of 10CFR Part 50.

5.2.1 Compliance With Codes and Code Cases

5.2.1.1 Compliance with 10CFR Section 50.55a

RCS components are designed and fabricated in accordance with the rules of 10CFR 50 Section 50.55a, "Codes and Standards," except for the Catawba Unit 1 reactor vessel which is designed and fabricated to ASME Section III, 1971 Edition through Winter 1971 Addenda and the Unit 1 steam generators are designed and fabricated to ASME Code, 1986 Edition, no addenda.

The exception for the Catawba Unit 1 reactor vessel results from issue of the construction permit (CP) being delayed beyond the originally anticipated CP date. The purchase order for the reactor vessel was placed in advance of the CP due to the length of component design and manufacturing lead time. If updating this vessel to a later ASME Code Addenda were possible, it would require additional cost and administrative burden without a compensating increase in the level of quality of safety; because base and welding materials are no longer available to perform the additional fracture toughness tests required by later ASME Codes, it is virtually impossible to upgrade this vessel. Although all of the fracture toughness tests required by later ASME Codes have not been performed, the Unit 1 vessel material has been tested in accordance with ASME Code Section III, 1971 Edition through Winter 1971 Addenda and, in addition, the available test data is used to estimate the fracture toughness in the same terms as the newer requirements (see fracture toughness information in Section 5.3). It should be noted that the actual hardware configuration and material selection would not have been changed by upgrading to a later ASME Code. Thus, the Unit 1 reactor vessel, although not in strict accordance with 10CFR 50.55a, is acceptable as built to ASME Code Section III, 1971 Edition through Winter 1971 Addenda.

The actual addenda of the ASME Code applied in the design of each component is listed in Table 5-2.

Inservice Inspection will be performed in accordance with 10CFR 50.55a(g) to the extent practical. Requests for waiver from the requirements of the ASME Code Section XI in effect per 10CFR 50.55a(g) will be submitted to the NRC for review and disposition. Code cases applicable to preservice and inservice inspection are addressed in Section 5.2.1.2.2.

5.2.1.2 Applicable Code Cases

5.2.1.2.1 Fabrication and Construction Activities

Conformance with Regulatory Guide 1.84 and 1.85 is discussed in Section 1.7. ASME Code cases used for Catawba Class 1 components are listed in Table 5-4.

Code Case 1528 (SA 508 Class 2a) material has been used in the manufacture of the Catawba Unit 2 steam generators and Units 1 and 2 pressurizers. It should be noted that the purchase orders for this equipment were placed prior to the original issue of Regulatory Guide 1.85 (June 1974); Regulatory Guide 1.85 presently reflects a conditional NRC approval of Code Case 1528. Westinghouse has conducted a test program which demonstrates the adequacy of Code Case 1528 material. The results of the test program are documented in Reference 1. Reference 1 and a request for approval of the use of Code Case 1528 have been submitted to the NRC (letter NS-CE-1730 dated March 17, 1978, to Mr. J. F. Stolz, NRC Office of Nuclear Reactor Regulation, from Mr. C. Eicheldinger, Westinghouse Nuclear Safety Department). Responses to NRC questions on their review of this report (Reference 1) were transmitted to the NRC (letter NS-TMS-2312, dated September 18, 1980, to Mr. J. R. Miller, Special Projects Branch, from Mr. T. M. Anderson, Westinghouse Nuclear Safety Department).

5.2.1.2.2 Operation, Maintenance, and Testing Activities

Requests for use of Code Cases concerning operation, maintenance, and testing activities will be submitted to the NRC as necessary. Table 5-3 lists the Code Cases whose use is anticipated.

5.2.2 Overpressure Protection

RCS overpressure protection at operating conditions is accomplished by the utilization of pressurizer safety valves along with the Reactor Protection System and associated equipment. Combinations of these systems provide compliance with the overpressure requirements of the ASME Boiler and Pressure Vessel Code Section III, paragraph NB-7300 and NC-7300, for Pressurized Water Reactor Systems.

5.2.2.1 Design Bases

Overpressure protection is provided for the RCS by the pressurizer safety valves which discharge thru a common header to the pressurizer relief tank. The design requirements for the primary system overpressure protection are based on the transient of a complete loss of steam flow to the turbine with credit taken for steam generator safety valve operation and main feedwater flow maintained. For this transient, the peak RCS and peak Main Steam System pressure must be limited to 110% of their respective design values. However, for the sizing of the pressurizer safety valves; no credit is taken for reactor trip nor the operation of the following:

1. Pressurizer Power Operated Relief Valves
2. Steam Line Relief Valve
3. Steam Dump System
4. Reactor Control System
5. Pressurizer Level Control System
6. Pressurizer Spray Valve

Assumptions for the overpressure analysis include (1) the unit is operating at the power level corresponding to the Engineered Safeguards design rating and (2) the RCS average temperature and pressure are at their maximum values. These are the most limiting assumptions with respect to system overpressure.

Overpressure protection for the Main Steam System is provided by main steam safety valves. The Main Steam System safety valve capacity is based on providing enough relief to remove 105% of the Engineered Safeguards design steam flow. This must be done by limiting the maximum Main Steam System pressure to less than 110% of the steam generator shell side design pressure.

Blowdown and heat dissipation systems of the NSSS connected to the discharge of these pressure relieving devices are discussed in Section 5.4.11.

Steam generator blowdown systems for the balance of plant are discussed in Section 10.4.8.

Postulated events and transients on which the design requirements of the over-pressure protection system are based are discussed in Reference 2, report on overpressure protection.

5.2.2.2 Design Evaluation

The relief capacities of the pressurizer and main steam safety valves are determined from the postulated overpressure transient conditions in conjunctional design of the system and an analysis of the capability of the system to perform its function is presented in Reference 2. The report describes in detail the types and number of pressure relief devices employed, relief device description, locations in the systems, reliability history, and the details of the methods used for relief device sizing based on typical worst case transient conditions and analysis data for each transient condition. As stated in WCAP-7769, Topical Report Overpressure Protection for Westinghouse Pressurized Water Reactors (Revision 1), the pressurizer safety valve is sized based upon the peak surge rate into the pressurizer following a complete loss of load without reactor trip and with energy relief only through the steam generator safety valves and pressurizer safety valves. The actual safety valve capacity must be greater than or equal to this required capacity. The ratio between the actual safety valve capacity and the peak surge rate into the pressurizer is an entry in Table 5-5. If this ratio is greater than the ratio for that type of plant in Table 5-5, then the assumptions in WCAP-7769 envelope the plant under consideration. This is the case for Catawba and the pertinent values are given in FSAR Table 5-5. The description of the analytical model used in the analysis of the overpressure protection system and the basis for its validity is discussed in Reference 3.

The protection against low temperature overpressure transient conditions is provided by a combination of interlocks, design features and administrative procedures. The low temperature overpressure protection is enabled only on coincidence of: 1. RCS temperature decreasing to a predetermined set point; and 2. The operator placing the key-lock switch to the LOW PRESSURE position.

Once the low temperature overpressure is enabled the PORV requirements are provided via the plant instrument air or the nitrogen supply from the cold leg accumulators whichever has the higher pressure. Normally instrument air has a higher pressure than the nitrogen pressure regulator when the NI438A and NI439B CLA isolation valves are opened by placing the key-lock switch in the low pressure position. The PORVs are thus provided a seismically qualified source of nitrogen from the cold leg accumulators. The nitrogen supply valves NI438A and NI439B are shown in Figure 6-129. The cold leg accumulators A and B of the Safety Injection System provide the regulated, safety grade nitrogen gas backup to the normal Instrument Air Supply to the PORVs NC34A and NC32B, respectively.

Each CLA contains Nitrogen at a sufficient pressure and volume that it would be negligibly affected by manual or automatic response to any subsequent design basis accident. It has been shown that, assuming a minimum gas volume at nominal CLA pressure of 650 psig, up to 20 cycles of the connected PORV will not bleed the CLA pressure below Technical Specification minimum of 585 psig, including a reasonable leakage allowance. From this calculation it is evident that PORV air supply alignment to the safety related Nitrogen source is allowable if an accident has occurred, normal Instrument Air supply to the PORV has been lost due to containment isolation or LOOP, and it is preferable to utilize the PORVs for automatic overpressure protection or manual depressurization. It is also acceptable to align the backup CLA Nitrogen to the PORVs during the normal cooldown sequence by placing the LTOP key-lock switch in the LOW PRESSURE position (for low pressure) or in the NORMAL position (prior to reaching low pressure).

Thus the safety-grade PORVs are made automatically available to mitigate any overpressure transient in either the low temperature, low pressure mode, or in the high temperature, high pressure mode; and are made manually available in Abnormal Procedures following the loss of Instrument Air alone or in combination with other design basis events. The actuation circuitry for valves NI438A and NI439B is designed to allow automatic or manual actuation of the PORVs in either the NORMAL or LOW TEMPERATURE mode. PORV actuation is periodically tested to assure operability from the CLA Nitrogen source, including backflow prevention of the check valves in the normal Instrument Air supply lines.

Administrative procedures associated with reducing the potential for overpressure events utilize a sequence of operations which ensure that a pressure relieving path is always available. A steam bubble is formed in the pressurizer early in the startup sequence. This provides a cushion against pressure surges and overpressurization when the Reactor Coolant System is isolated from the Residual Heat Removal System.

The Low Temperature Overpressure Protection (LTOP) would remain functional in the event of a postulated single failure. There are two independent trains and associated PORVs to relieve pressure at low temperature. In order to ensure independence of the PORV trains, a single power supply failure should not result in a Loss of Letdown which could initiate a pressure transient and a simultaneous result in loss of a LTOP PORV. Such a power supply failure would result in loss of one of the two LTOP PORV trains and initiate a LTOP challenge due to loss of letdown. A Failure Modes Effects Analysis (FMEA), Reference 16, was performed and determined the following common failures between normal or excess letdown and the train A and Train B PORV's.

- Failure of EDE results in lossof normal letdown and the A train PORV
- Failure of EDF results in loss of excess letdown and the B train PORV

- Failure of EPD, with NV pump B in operation, results in loss of normal letdown and the B train PORV

Because of these common mode failures, administrative controls have been implemented to prohibit crediting the affected PORV under the configurations described above. License amendment 212/206 lowered the LTOP applicability to 210° F and allows credit of the Residual Heat Removal (RHR) suction relief valves for a LTOP relief path when the associated RHR suction is aligned to the Reactor Coolant System (RCS). At least one RHR train must be aligned to the RCS loops in order to achieve < 210° F in any reasonable length of time. Therefore at least one RHR train will be aligned to the RCS loops during cooldown to LTOP applicability. During unit heat up at least one train of RHR may be maintained aligned to the RCS loops until LTOP applicability is exited. Therefore the RHR suction relief valves in conjunction with the LTOP PORV's allow sufficient flexibility to maintain two LTOP relief paths when the A or B PORV's cannot be credited for LTOP.

When the RHR system is in operation or the associated RHR suction is aligned to the RCS, the suction relief valves provide additional low temperature overpressure protection. These relief valves are sized to relieve the combined flow of all the charging pumps at their set pressure of 450 psig (see Section 5.4.7.1). When the RHR system is isolated from the RCS, a pressurizer steam bubble is maintained. If the postulated scenario were to occur under those conditions, adequate time is available for the operator to mitigate the event.

The Technical Specifications for Catawba impose limiting conditions of operation as well as surveillance requirements to assure the validity of the assumptions used in the low temperature overpressure design analyses. Catawba Nuclear Station is in conformance with the applicable items of Branch Technical Position RSB 5-2 as modified by application of ASME Code Case N-641, "Alternative Pressure – Temperature Relationship and Low Temperature Overpressure Protection System Requirements – Section XI, Division 1". ASME Code Case N-641 allows alternative methods relative to Branch Technical Position RSB 5-2 for calculating the enable temperature for LTOP systems and also establishes the allowable pressures for LTOP systems based on the fracture mechanics methodology used to construct the pressure-temperature limits for reactor operation, plant heatup and cooldown.

A description of the pressurizer safety valves performance characteristics along with the design description of the incidents, assumptions made, method of analysis and conclusions are discussed in Section 15.1.

5.2.2.3 Piping and Instrumentation Diagrams

Overpressure protection for the Reactor Coolant System is provided by pressurizer safety valves shown in Figure 5-3. These discharge to the pressurizer relief tank by a common header.

The main steam safety valves are discussed in Section 10.3 and are shown on Figure 10-5.

5.2.2.4 Equipment and Component Description

The operation, significant design parameters, number and types of operating cycles of the pressurizer safety valves are discussed in Section 5.4.13.

A discussion of the equipment and components of the steam system overpressure system is discussed in Section 10.3.

5.2.2.5 Mounting

Westinghouse provides Duke with installation guidelines and suggested physical layout. This information is transmitted to Duke as part of a systems standard design criteria document. Duke is required by Westinghouse to limit the piping reaction loads on the safety valves to acceptable values.

Westinghouse provides mounting brackets on the pressurizer which can be used to support the pressurizer safety valves. Duke is responsible for the design and mounting of the supports for these valves. They are also responsible for determining reactions on the pressurizer mounting brackets.

Design and installation details for the pressure relief devices are provided in Section 3.9.3.3.

5.2.2.6 Applicable Codes and Classification

The requirements of ASME Boiler and Pressure Vessel Code Section III, NB-7300 (Relieving Capacity Requirements) and NC-7300 (Relieving Capacity Requirements), are followed and complied with for Pressurized Water Reactor Systems.

Piping, valves and associated equipment used for overpressure protection are classified in accordance with ANS-N18.2, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants. These safety class designations are delineated on Table 3-3 and shown on Figure 5-1, Figure 5-3, and Figure 5-5.

For further information, refer to Section 3.9.

5.2.2.7 Material Specifications

Please refer to Section 5.2.3, Reactor Coolant Pressure Boundary Material for a discussion on this subject.

5.2.2.8 Process Instrumentation

Each pressurizer safety valve discharge line incorporates a control board temperature indicator and alarm to notify the operator of steam discharge due to either leakage or actual valve operation. For a further discussion on process instrumentation associated with the system, refer to Chapter 7.

5.2.2.9 System Reliability

The reliability of the pressure relieving devices is discussed in Section 4 of Reference 2.

5.2.2.10 Testing and Inspection

Testing and inspection of the overpressure protection components are discussed in Section 5.4.13.4 and Chapter 14.

5.2.3 Materials Selection, Fabrication, and Processing

5.2.3.1 Material Specifications

Material specifications used for the principal pressure retaining applications in each component comprising the Reactor Coolant Pressure Boundary (RCPB) are listed in Table 5-6 for ASME Class I Primary Components and Table 5-7 for ASME Class 1 and 2 Auxiliary Components.

Table 5-6 and Table 5-7 also include the unstabilized austenitic stainless steel material specifications used for the components in systems required for reactor shutdown and for emergency core cooling.

The unstablized austenitic stainless steel material for the reactor vessel internals which are required for emergency core cooling for any mode of normal operation or under postulated accident conditions and for core structural load bearing members are listed in Table 5-8.

All of the materials utilized conform to the material specification requirements and include the special requirements of applicable ASME Code Rules.

In some cases, Table 5-7 may not be inclusive of the material specifications used in the listed applications. However, the listed specifications are representative of those materials utilized.

The welding materials used for joining the ferritic base materials of the RCPB, conform to, or are equivalent to, ASME Material Specifications SFA 5.1, 5.2, 5.5, 5.17, 5.18 and 5.20. They are tested and qualified to the requirements of ASME Section III.

The welding materials used for joining the austenitic stainless steel base materials of the RCPB conform to ASME Material Specifications SFA 5.4 and 5.9. They are tested and qualified according to the requirements of ASME Section III.

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. They are tested and qualified to the requirements of ASME Section III.

5.2.3.2 Compatibility with Reactor Coolant

5.2.3.2.1 Chemistry of Reactor Coolant

In addition to the Selected Licensee Commitments, the primary coolant chemistry specification will be derived from NSSS vendor specifications and EPRI Primary Water Chemistry Guidelines. Operating guidelines will be addressed in Chemistry Section documents which are reviewed and approved per the 10CFR 50.59 process. The RCS water chemistry is selected to minimize corrosion. A routinely scheduled analysis of the coolant chemical composition is performed to verify that the reactor coolant chemistry meets the specifications.

The Chemical and Volume Control System provides a means for adding chemicals to the RCS which control the pH of the coolant during pre-startup testing and subsequent operation, scavenge oxygen from the coolant during heatup, and control radiolysis reactions involving hydrogen, oxygen and nitrogen during all power operations subsequent to startup.

The pH control chemical specified is lithium hydroxide monohydrate, enriched in Li-7 isotope to 99.9%. This chemical is chosen for its compatibility with the materials and water chemistry of borated water/stainless steel/zirconium/inconel systems. In addition, Li-7 is produced in solution from the neutron irradiation of the dissolved boron in the coolant. The lithium-7 hydroxide is introduced into the RCS via the charging flow. The solution is prepared in the laboratory and transferred to the chemical addition tank. Reactor makeup water is then used to flush the solution to the suction header of the charging pumps. The concentration of lithium-7 hydroxide in the RCS is maintained in the range specified for pH control. If the concentration exceeds this range, the cation bed demineralizer is employed in the letdown line in series operation with the mixed bed demineralizer.

In order to minimize radiation exposure while performing maintenance and fuel handling activities during refueling outages, it is necessary to oxygenate the primary coolant with hydrogen peroxide. The result of injecting hydrogen peroxide into primary coolant for oxidation is the subsequent removal of released activity via the CVCS demineralizers and overall plant ALARA.

During reactor startup from the cold condition, hydrazine is added to the coolant as an oxygen scavenging agent. The hydrazine solution is introduced into the RCS in the same manner as described above for the pH control agent.

The reactor coolant is treated with dissolved hydrogen to control the net decomposition of water by radiolysis in the core region. The hydrogen also reacts with oxygen and nitrogen introduced into the RCS as impurities under the impetus of core radiation. Sufficient partial pressure of hydrogen is maintained in the volume control tank such that the specified equilibrium concentration of hydrogen is maintained in the reactor coolant. A self-contained pressure control valve maintains a minimum pressure in the vapor space of the volume control tank. This can be adjusted to provide the correct equilibrium hydrogen concentration.

Boron, in the chemical form of boric acid, is added to the RCS to accomplish long term reactivity control of the core. The mechanism for the process involves the absorption of neutrons by the B-10 isotope of naturally occurring boron.

Suspended solids (corrosion product particulates) and other impurity concentrations are maintained below specified limits by controlling the chemical quality of makeup water and chemical additives and by purification of the reactor coolant through the CVCS mixed bed demineralizer.

5.2.3.2.2 Compatibility of Construction Materials With Reactor Coolant

All of the ferritic low alloy and carbon steels which are used in principal pressure retaining applications are provided with corrosion resistant cladding on all surfaces that are exposed to the reactor coolant. This cladding material's corrosion resistance is at least equivalent to the corrosion resistance of Types 304 and 316 austenitic stainless steel alloys or nickel-chromium-iron alloy, martensitic stainless steel and precipitation hardened stainless steel. The cladding on ferritic type base materials receives a post weld heat treatment as required by the ASME Code.

Ferritic low alloy and carbon steel nozzles are safe ended with either stainless steel wrought materials, stainless steel weld metal analysis A-7 (designated A-8 in the 1974 Edition of the ASME Code) or nickel-chromium iron alloy weld metal F-Number 43. The latter buttering material requires further safe ending with austenitic stainless steel base material after completion of the post weld heat treatment.

All of the austenitic stainless steel and nickel-chromium-iron alloy base materials with primary pressure retaining applications are used in the solution anneal heat treat condition. These heat treatments are as required by the material specifications.

During subsequent fabrication, these materials are not heated above 800°F other than locally by welding operations. The solution annealed surge line material is subsequently formed by hot bending followed by a re-solution annealing heat treatment.

Components with stainless steel sensitized in the manner expected during component fabrication and installation will operate satisfactorily under normal plant chemistry conditions in PWR systems because chlorides, fluorides and oxygen are controlled to very low levels.

The NRC issued Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," on March 17, 1988. This generic letter was issued to alert licensees of conditions for which boric acid RCS leakage could potentially affect the integrity of the reactor coolant pressure boundary. The Generic Letter 88-05 response requirement included the establishment of a CNS systematic program of measures necessary to ensure that boric acid corrosion does not lead to degradation of the assurance that the reactor coolant pressure boundary will have an extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture. Duke Power Company responses to Generic Letter 88-05 were submitted to the NRC in letters dated May 23, August 1, 1988, and March 1, 1989.

In response to NRC Generic Letter 88-05 concerning the boric acid corrosion of carbon steel reactor pressure boundary components in pressurized water reactors, the following efforts to control boric acid corrosion were instituted: 1) upgrading of steam generator manway installation procedures which address tensioning, lubricants, gaskets and gaskets surface preparation, stud materials, and stud coating, 2) extensive upgrades and comprehensive inspections of reactor coolant pumps at each outage with detailed inspections and evaluation for possible damage if boric acid build-up is present, and 3) enhanced valve inspection and maintenance programs.

In addition, implementation of procedures such as reactor coolant system (NC system) leak test, containment cleanliness inspection and visual inspection of radioactive systems outside containment assure that borated water leaks are identified and evaluated for corrective actions. Furthermore, Operation groups make hot shutdown tours to inspect and initiate repair as necessary for any NC system leakage.

Generic Letter 88-05 identified four basis elements that should be included in an auditable and systematic program to address the corrosive effects of reactor coolant system leakage at less than technical specification. Catawba's program relating to each of these elements is discussed as follows:

1. A determination of the principal locations where leaks that are smaller than the allowable technical specification limit can cause degradation of the primary pressure boundary by boric acid corrosion. The primary method used to locate boric acid leaks will be the plant surveillances.
2. Procedures for locating small coolant leaks (i.e., leakage rates at less than technical specification limits.) Implementation of surveillance procedures for detection of reactor coolant leakage, as required by Technical Specifications are the principal methods currently used at Catawba to detect, identify, evaluate and correct any reactor coolant pressure boundary leakage. Continuous surveillance of coolant inventory, activity monitoring, sump level monitoring, and physical inspection by operating personnel will identify coolant leakages during normal operation. In addition, a physical inspection of the reactor coolant system during each refueling shutdown is performed which will identify boric acid crystalline deposits from minute leakage during operation. Also, prior to startup following each refueling outage, the reactor coolant system is inspected under not less than operating pressure to ensure leak tight integrity during operation as required by Technical Specifications.
3. Methods for conducting examinations and performing evaluations to establish the impact on the reactor coolant pressure boundary when leakage is noted. Within the current practices at Catawba, Work Request(s) are initiated for any identified NC system leakage to inspect and repair the leak or any damage. Specific procedures were developed to ensure that a thorough inspection of the leakage path and any surrounding component is conducted.
4. As a result of the evaluations, corrective actions (repairs) will be initiated through the work request system or corrective action program. Trends will be evaluated to reduce the probability of boric acid leaks where they may cause corrosion damage to components.

NRC acceptance of the CNS program for addressing the concerns of Generic Letter 88-05 is documented in the letter from K.N. Jabbour (NRC) to H.B. Tucker (DPC), dated September 28, 1989. Catawba's Fluid Leak Management and Boric Acid Corrosion Control Programs and practices are defined within AD-MN-ALL-0006, PD-EG-PWR-1611, and AD-EG-PWR-1611, respectively.

5.2.3.2.3 Compatibility With External Insulation and Environmental Atmosphere

In general, all of the materials listed in Table 5-6 and Table 5-7 which are used in principal pressure retaining applications and which are subject to elevated temperature during system operation are in contact with thermal insulation that covers their outer surfaces.

The thermal insulation used on the reactor coolant pressure boundary is either reflective stainless steel type, flexible fiberglass blanket type, or made of compounded materials which yield low leachable chloride and/or fluoride concentrations. The compounded materials in the form of blocks, boards, cloths, tapes, adhesives, cements, etc., are silicated to provide protection of austenitic stainless steels against stress corrosion which may result from accidental wetting of the insulation by spillage, minor leakage or other contamination from the environmental atmosphere. A discussion indicating the degree of conformance with Regulatory Guide 1.36, "Non-metallic Thermal Insulation for Austenitic Stainless Steel," is provided below.

In the event of coolant leakage, the ferritic materials will show increased general corrosion rates. Where minor leakage is anticipated from service experience, such as valve packing, pump seals, etc., only materials which are compatible with the coolant are used. These are as shown in Table 5-6 and Table 5-7. Ferritic materials exposed to coolant leakage can be readily observed as part of the in-service visual and/or nondestructive inspection program to assure the integrity of the component for subsequent service.

Regulatory Guide 1.36

Nonmetallic Thermal Insulation for Austenitic Stainless Steel (2/23/7 3)

Discussion

The flexible fiberglass blanket type of insulation meets all of the requirements of Regulatory Guide 1.36.

The Westinghouse practice meets the recommendations of Regulatory Guide 1.36 and is more stringent in several respects as discussed below.

The tests for qualification specified by this regulatory guide (ASTM C692-71 or RDT M12-1T) allow use of the tested insulation materials if no more than one of the metallic test samples crack. Westinghouse rejects the tested insulation material if any of the test samples crack.

The Westinghouse procedure is more specific than the procedures suggested by this regulatory guide, in that the Westinghouse specification requires determination of leachable chloride and fluoride ions from a sample of the insulating material. The procedures in this regulatory guide (ASTM D512 and ASTM D1179) do not differentiate between leachable and unleachable halogen ions.

In addition, Westinghouse experience indicates that only one of the three methods allowed under ASTM D512 and ASTM D1179 for chloride and fluoride analysis is sufficiently accurate for reactor applications. This is the "referee" method, which is used by Westinghouse.

5.2.3.3 Fabrication and Processing of Ferritic Materials

5.2.3.3.1 Fracture Toughness

The fracture toughness properties of the RCPB components meet the requirements of ASME Section III paragraph NB, NC, and ND-2300 as appropriate.

The fracture toughness properties of the reactor vessel material is discussed in Section 5.3.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

Limiting steam generator and pressurizer RT_{NDT} temperatures are guaranteed at 60°F for the base materials and the weldments. These materials will meet the 50 ft-lbs absorbed energy and 35 mils lateral expansion requirements of the ASME code section III at 120°F. *The actual results of these tests are provided in the ASME material data reports which are supplied for each component and submitted to the owner at the time of shipment of the component*. Calibration of temperature instruments and Charpy impact test machines are performed to meet the requirements of the ASME Code Section III, paragraph NB-2360.

Westinghouse has conducted a test program to determine the fracture toughness of low alloy ferritic materials with specified minimum yield strengths greater than 50,000 psi to demonstrate compliance with Appendix G of the ASME Code, Section III. In this program, fracture toughness properties were determined and shown to be adequate for base metal plates and forgings, weld metal and heat affected zone (HAZ) metal for higher strength ferritic materials used for components of the reactor coolant pressure boundary. The results of the program are documented in WCAP 9292 (Reference 1) *which has been submitted to NRC for review via letter NS-CE-1730 dated March 17, 1978 to Mr. J. F. Stolz, NRC Office of Nuclear Reactor Regulation from Mr. C. Eicheldinger, Westinghouse PWRSD Nuclear Safety.*

With regard to fracture toughness, the B&W steam generators are designed in compliance with the requirements of 10 CFR 50, Appendix G, Fracture Toughness Requirements and paragraph NB-2300 or NC-2300 of the ASME Code Section III for primary and secondary ferritic pressure boundary materials. Appropriate tests are required to qualify the steam generator for primary and secondary hydrotests at temperatures as low as 70°F.

The BWI steam generators exceed the requirement as actual test results showed RT_{NDT} equal to 0°F by drop weight determination. The subsequent Charpy test results met the 50 ft-lb absorbtion 35 mil lateral expansion criteria of ASME Section III at 60°F.

Additional analysis justifies pressurization of the secondary side of the vessel to 200psig at temperatures below 70°F.

5.2.3.3.2 Control of Welding

All welding is conducted utilizing procedures qualified according to the rules of Sections III and IX of the ASME Code where applicable. Control of welding variables, as well as examination and testing, during procedure qualification and production welding is performed in accordance with ASME Code requirements.

Section 5.3.1.4 includes discussions which indicate the degree of conformance of the ferritic materials components of the reactor coolant pressure boundary with Regulatory Guides 1.43, "Control of Stainless Steel Weld Cladding of Low-Allow Steel Components", Regulatory Guide 1.50, "Control of Preheat Temperature for Welding of Low-Alloy Steel," and Regulatory Guide 1.71, "Welder Qualification for Areas of Limited Accessibility". Regulatory Guide 1.34, "Control of Electroslag Properties," is discussed in Section 1.7.1, "Regulatory Guides." .

5.2.3.4 Fabrication and Processing of Austenitic Stainless Steel

Sections 5.2.3.4.1 to 5.2.3.4.5 address Regulatory Guide 1.44, "Control of the Use of Sensitized Stainless Steel," and present the methods and controls utilized by Westinghouse to avoid sensitization and prevent intergranular attack of austenitic stainless steel components. Also, a discussion indicating the degree of conformance with Regulatory Guide 1.44 is provided below.

Regulatory Guide 1.44

Control of the Use of Sensitized Stainless Steel (5/73)

Discussion

Westinghouse compliance with the separate positions of this regulatory guide are as follows:

The use of processing, packaging and shipping controls, and preoperational cleaning to preclude adverse effects of exposure to contaminants on all stainless steel materials is in accordance with Regulatory Position C.1.

Austenitic stainless steel materials are utilized in the final heat treated conditions required by the respective ASME Code, Section II, material specification for the particular type or grade of alloy in accordance with Regulatory Position C.2.

The Westinghouse position concerning material inspection programs and Regulatory Position C.3 is discussed in this section.

Westinghouse meets the intent of Regulatory Position C.4 in the manner discussed in detail in this section. Exception (b) to Regulatory Position C.4 is covered in the discussion of delta ferrite in this section.

Westinghouse practices are in agreement with Regulatory Position C.5 in the manner discussed in this section. Exception (a) to Regulatory Position C.5 is covered in the discussion of delta ferrite in this section.

Westinghouse practices are in agreement with Regulatory Position C.6 in the manner discussed in this section.

The design and fabrication of the BWI steam generator is accomplished in full compliance with Regulatory Guide 1.44 as applicable. Sensitized stainless steels are only used in the cladding of the primary head assembly, and gasket and diaphragm seating surfaces. In cladding applications the sensitized stainless steel material does not serve a pressure retaining function and is L grade material on all wetted primary system surfaces.

5.2.3.4.1 Cleaning and Contamination Protection Procedures

It is required that all austenitic stainless steel materials used in the fabrication, installation and testing of nuclear steam supply components and systems 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 the Westinghouse Electric Corporation process specifications. As applicable, these process specifications supplement the equipment specifications and purchase order requirements of every individual austenitic stainless steel component or system which Westinghouse procures for the Catawba Nuclear Steam Supply System (NSSS), regardless of the ASME Code Classification. They are also given to Duke for use within their scope of supply and activity.

The process specifications which define these requirements and which follow the guidance of The American National Standards Institute N-45 Committee specification are as follows:

Number Process Specification	
82560HM	Requirements for Pressure Sensitive Tapes for use on Austenitic Stainless Steels.
83336KA	Requirements for Thermal Insulation Used on Austenitic Stainless Steel Piping and Equipment.
83860LA	Requirements for Marking of Reactor Plant Components and Piping.
84350HA	Site Receiving Inspection and Storage Requirements for Systems, Material and Equipment.
84351NL	Determination of Surface Chloride and Fluoride on Austenitic Stainless Steel Materials.
85310QA	Packaging and Preparing Nuclear Components for Shipment and Storage.
292722	Cleaning and Packaging Requirements of Equipment for Use in the NSSS.
597756	Pressurized Water Reactor Auxiliary Tanks Cleaning Procedures.
597760	Cleanliness Requirements During Storage, Construction, Erection and Start-Up Activities of Nuclear Power System.

A discussion of the degree of conformance of the austenitic stainless steel components of the reactor coolant pressure boundary with Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," is presented below.

Regulatory Guide 1.37

Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power plants (3/16/73)

Discussion

This regulatory guide endorses ANSI N45.2.1-1973, which applies to cleaning procedures at the construction site and is therefore not in the Westinghouse scope. Westinghouse procurement orders apply cleaning requirements during fabrication and packaging of safety-related components so that nuclear steam supply system equipment is delivered to the site in a properly cleaned condition. A Westinghouse process specification provides detailed cleaning requirements for equipment manufacturers, and is included as a procurement requirement, where appropriate.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

The initial quality assurance program implemented by Westinghouse for the Catawba Nuclear Station was described in RESAR-3, Amendment 6, as supplemented by PSAR Chapter 17. The Westinghouse Quality Assurance Program discussed in Reference 4 was applicable to activities within Westinghouse scope performed for the Catawba Nuclear Station which were initiated between January 1, 1975 and October 1, 1977. Subsequently, the present Westinghouse Quality Assurance Program, which is described in Reference 5, is applicable to activities within Westinghouse scope which were initiated after October 1, 1977.

With respect to the BWI steam generators compliance with Regulatory Guide 1.37 is applicable only to tubing. The requirements of Regulatory Guide 1.37 are fully imposed on the tubing supplier through the BWI tubing specification with the minor exception that the 1980 edition of ANSI 45.2.1 is used rather than the 1973 edition referenced in the Regulatory Guide.

5.2.3.4.2 Solution Heat Treatment Requirements

The austenitic stainless steels listed in Table 5-6, Table 5-7, and Table 5-8 are utilized in the final heat treated condition required by the respective ASME Code Section II materials specification for the particular type or grade of alloy.

5.2.3.4.3 Material Inspection Program

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

The Westinghouse practice is that austenitic stainless steel materials of product forms with simple shapes need not be corrosion tested provided that the solution heat treatment is followed by water quenching. Simple shapes are defined as all plates, sheets, bars, pipe and tubes, as well as forgings, fittings, and other shaped products which do not have inaccessible cavities or chambers that would preclude rapid cooling when water quenched. When testing is required, the tests are performed in accordance with ASTM A 262-70, Practice A or E, as amended by Westinghouse Process Specification 84201 MW.

5.2.3.4.4 Prevention of Intergranular Attack of Unstabilized Austenitic Stainless Steels

Unstabilized austenitic stainless steels are subject to intergranular attack (IGA) provided that three conditions are present simultaneously. These are:

1. *An aggressive environment, e.g., an acidic aqueous medium containing chlorides or oxygen.*
2. *A sensitized steel.*
3. *A high temperature.*

If any one of the three conditions described above is not present, intergranular attack will not occur. Since high temperatures cannot be avoided in all components in the NSSS, Westinghouse relies on the elimination of conditions 1 and 2 to prevent intergranular attack on wrought stainless steel components.

The water chemistry in the Reactor Coolant System of a Westinghouse Pressurized Water Reactor (PWR) is rigorously controlled to prevent the intrusion of aggressive species. In particular, the maximum permissible oxygen and chloride concentrations are 0.005 ppm and 0.15 ppm, respectively. Reference 6 describes the precautions taken to prevent the intrusion of chlorides into the system during fabrication, shipping, and storage. The use of hydrogen overpressure precludes the presence of oxygen during operation. The effectiveness of these controls has been demonstrated by both laboratory tests and operating experience. The long term exposure of severely sensitized stainless in early plants to PWR coolant environments has not resulted in any sign of intergranular attack. Reference 6 describes the laboratory experimental findings and the Westinghouse operating experience. The additional years of operations since the issuing of Reference 6 have provided further confirmation of the earlier conclusions. Severely sensitized stainless steels do not undergo any intergranular attack in Westinghouse PWR coolant environments.

In spite of the fact there never has been any evidence that PWR coolant water attacks sensitized stainless steels, Westinghouse considers it good metallurgical practice to avoid the *use of sensitized stainless steels in the NSSS components. Accordingly measures are taken to prohibit the purchase of sensitized stainless steels and to prevent sensitization during component fabrication. Wrought austenitic stainless steel stock used for components that are part of 1) the reactor coolant pressure boundary, 2) systems required for reactor shutdown, 3) systems required for emergency core cooling, and 4) reactor vessel internals (relied upon to permit adequate core cooling for normal operation or under postulated accident conditions) is utilized in one of the following conditions:*

1. *Solution annealed and water quenched, or*
2. *Solution annealed and cooled through the sensitization temperature range within less than approximately five minutes.*

It is generally accepted that these practices will prevent sensitization. Westinghouse has verified this by performing corrosion tests (ASTM 393) on asreceived wrought material.

Westinghouse recognizes that the heat affected zones of welded components must, of necessity, be heated into the sensitization temperature range, 800° to 1500°F. However, severe sensitization, i.e. continuous grain boundary precipitates of chromium carbide with adjacent chromium depletion, can still be avoided by control of welding parameters and welding processes. The heat input[1] and associated cooling rate through the carbide precipitation range are of primary importance. Westinghouse has demonstrated this by corrosion testing a number of weldments.

Of 25 production and qualification weldments tested, representing all major welding processes and a variety of components and incorporating base metal thickness's from 0.10 to 4.0 inches, only portions of two were severly sensitized. Of these, one involved a heat input of 120,000 joules, and other involved a heavy socket weld in relatively thin walled material. In both cases, sensitization was caused primarily by high heat inputs relative to the section thickness. However, in only the socket weld did the sensitized condition exist at the surface, where the material is exposed to the environment; a material change has been made to eliminate this condition.

Westinghouse controls the heat input in all austenitic pressure boundary weldments by:

1. *Prohibiting the use of block welding.*
2. *Limiting the maximum interpass temperature to 350°F.*
3. *Exercising approval rights on all welding procedures.*

To further assure that these controls are effective in preventing sensitization, Westinghouse will, if necessary, conduct additional intergranular corrosion tests of qualification mock-ups of primary pressure boundary and core internal component welds, including the following:

Reactor Vessel Safe Ends

Pressurizer Safe Ends

Surge Line and Reactor Coolant Pump Nozzles

---

[1] *Heat input is calculated according to the formula* $H = \frac{(E)(I)(60)}{S}$ *where H = joules/in; e=volts; I=Amperes; and S=Travel Speed in inches/minute.*

Control Rod Drive Mechanisms Head Adaptors

Control Rod Drive Mechanisms Seal Welds

Control Rod Extensions

Lower Instrumentation Penetration Tubes

To summarize, Westinghouse has a four point program designed to prevent intergranular attack of austenitic stainless steel components.

1. *Control of primary water chemistry to ensure a benign environment.*
2. *Utilization of materials in the final heat treated condition and the prohibition of subsequent heat treatments in the 800 and 1500°F temperature range.*
3. *Control of welding processes and procedures to avoid HAZ sensitization.*
4. *Confirmation that the welding procedures used for the manufacture of components in the primary pressure boundary and of reactor internals do not result in the sensitization of heat affected zones.*

Both operating experience and laboratory experiments in primary water have conclusively demonstrated that this program is 100 percent effective in preventing intergranular attack in Westinghouse NSSS's utilizing unstabilized austenitic stainless steel.

In the fabrication of the BWI steam generators the following requirements are imposed by the Certified Design Specification to prevent IGA on unstabilized austenitic stainless steels:

All austenitic stainless steels are to be procured in the solution annealed condition.

Wrought or cast austenitic stainless steels should not be subjected to fabrication processes or conditions which cause sensitization. If exposure to conditions which cause sensitization are unavoidable, the effects shall be mitigated by:

Specification of a stabilized or low carbon grade of the subject material

AND

Performance of a solution anneal treatment after exposure to conditions conducive to sensitization or performance of ASTM A 262 Practices A and E on coupons of the same material exposed to the same sensitizing conditions to demonstrate the extent of sensitization.

Austenitic stainless steels should not be subjected to manufacturing conditions which result in outer fiber strain on wetted surfaces greater than 2%. If these conditions are unavoidable, the effects shall be mitigated by:

Performance of a solution anneal treatment after exposure to conditions which induce greater than 2% strain.

AND

Conduct ASTM A 262 Practice A and E on coupons of the same material exposed to the same conditions to demonstrate that neither the manufacturing process nor the solution anneal treatment results in a sensitization of the material.

All austenitic stainless steel castings shall have a ferrite content of 5 - 20 FN and be solution annealed.

5.2.3.4.5 Retesting Unstabilized Austenitic Stainless Steels Exposed to Sensitization Temperatures

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

It is not normal Westinghouse practice to expose unstabilized austenitic stainless steels to the sensitization range of 800 to 1500°F during fabrication into components. If, during the course of fabrication, the steel is inadvertently exposed to the sensitization temperature range, 800 to 1500°F, the material may be tested in accordance with ASTM A262 as amended by Westinghouse Process Specification 84201 MW to verify that it is not susceptible to intergranular attack except that testing is not required for:

1. *Cast metal or weld metal with a ferrite content of five percent or more,*
2. *Material with a carbon content of 0.03 percent or less that is subjected to temperatures in the range of 800 to 1500°F for less than one hour,*
3. *Material exposed to special processing provided the processing is properly controlled to develop a uniform product and provided that adequate documentation exists of service experience and/or test data to demonstrate that the processing will not result in increased susceptibility to intergranular stress corrosion.*

If it is not verified that such material is not susceptible to intergranular attack, the material will be re-solution annealed and water quenched or rejected.

5.2.3.4.6 Control of Welding

The following paragraphs address Regulatory Guide 1.31, "Control of Stainless Steel Welding," and *present the methods used, and the verification of these methods, for austenitic stainless steel welding.*

The welding of austenitic stainless steel is controlled to mitigate the occurrence of microfissuring or hot cracking in the weld. Although published data and experience have not confirmed that fissuring is detrimental to the quality of the weld, it is recognized that such fissuring is undesirable in a general sense. Also, it has been well documented in the technical literature that the presence of delta ferrite is one of the mechanisms for reducing the susceptibility of stainless steel welds to hot cracking. However, there is insufficient data to specify a minimum delta ferrite level below which the material will be prone to hot cracking. It is assumed that such a minimum lies somewhere between 0 and 3 percent delta ferrite.

The scope of these controls discussed herein encompasses welding processes used to join stainless steel parts in components designed, fabricated or stamped in accordance with ASME Boiler and Pressure Vessel Code, Section III Class 1, 2, and core support components. *Delta ferrite control is appropriate for the above welding requirements except where no filler metal is used or for other reasons such control is not applicable. These exceptions include electron beam welding, autogenous gas shielded tungsten arc welding, explosive welding, and welding using fully austenitic welding materials.*

The fabrication and installation specifications require welding procedure and welder qualification in accordance with Section III, and include the delta ferrite determinations for the austenitic stainless steel welding materials that are used for welding qualification testing and for production processing. Specifically, the undiluted weld deposits of the "starting" welding materials are required to contain a minimum of 5 percent delta ferrite[2] as determined by

---

[2] The equivalent ferrite number may be substituted for percent delta ferrite.

chemical analysis and calculation using the appropriate weld metal constitution diagrams. When new welding procedure qualification tests are evaluated for these applications, including repair welding of raw materials, they are performed in accordance with the requirements of Section III and Section IX.

The results of all the destructive and non-destructive tests are reported in the procedure qualification record in addition to the information required by Section III.

The "starting" welding materials used for fabrication and installation welds of austenitic stainless steel materials and components meet the requirements of Section III. The austenitic stainless steel welding material conforms to ASME weld metal analysis A-7 (designated A-8 in the 1974 Edition of the ASME Code) Type 308 or 308L for all applications. Bare weld filler metal, including consumable inserts, used in inert gas welding processes conform to ASME SFA-5.9, and are procured to contain not less than 5 percent delta ferrite according to Section III. Weld filler metal materials used in flux shielded welding processes conform to ASME SFA-5.4 or SFA-5.9 and are procured in a wire-flux combination to be capable of providing not less than 5 percent delta ferrite in the deposit according to Section III. Welding materials are tested using the welding energy inputs to be employed in production welding.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

Combinations of approved heat and lots of "starting" welding materials are used for all welding processes. The welding quality assurance program includes identification and control of welding material by lots and heats as appropriate. All of the weld processing is monitored according to approved inspection programs which include review of "starting" materials, qualification records and welding parameters. Welding systems are also subject to quality assurance audit including calibration of gages and instruments: identification of "starting" and completed materials; welder and procedure qualifications; availability and use of approved welding and heat treating procedures; and documentary evidence of compliance with materials, welding parameters and inspection requirements. Fabrication and installation welds are inspected using non-destructive examination methods according to Section III rules.

To assure the reliability of these controls, Westinghouse has completed a delta ferrite verification program, described in Reference 7 which has been approved as a valid approach to verify the Westinghouse hypothesis and is considered an acceptable alternative for conformance with the NRC Interim Position on Regulatory Guide 1.31. The Regulatory Staff's acceptance letter and topical report evaluation were received on December 30, 1974. The program results, which do support the hypothesis presented in Reference 7, are summarized in Reference 8.

Section 1.7 includes discussion which indicates the degree of conformance with Regulatory Guides 1.34, "Control of Electroslag Properties". The degree of conformance of the austenitic stainless steel components of the reactor coolant pressure boundary with Regulator Guide 1.71, "Welder Qualification for Areas of Limited Accessibility" is discussed in section 5.3.1.4.

Control of welding in the BWI steam generators is as follows:

The requirements of Regulatory Guide 1.31 shall be imposed for welding of austenitic stainless steel. All ASME Code welds performed between austenitic stainless steel and ferritic steels or nickel-base alloys shall be performed with ASME II, Part C SFA 5.14 ERNiCr-3 filler metal. Stainless steel filler material used to join austenitic steel to itself shall conform to Regulatory Guide 1.31 with a delta-ferrite requirement for the deposit of δ5 - 15 FN. The maximum limit for carbon content in austenitic stainless steel filler material is 0.02%

5.2.4 Inservice Inspection and Testing of Reactor Coolant Pressure Boundary

5.2.4.1 System Boundary

The reactor coolant pressure boundary includes all Duke Class A (ASME Class 1) pressure vessels, piping, pumps, and valves, including support components and pressure retaining bolting.

5.2.4.2 Accessibility

The various components of the ASME Class 1 Systems have been designed with provisions for access as required by Section XI of the ASME Code. Access for manual and/or remote examination has been considered when specifying component design, equipment layout, and support component placement.

5.2.4.3 Examination Techniques and Procedures

The examination techniques to be used for inservice inspection include Radiographic, Ultrasonic, Magnetic Particle, Liquid Penetrant, Eddy Current, and Visual examination methods. For all examinations, both remote and manual, specific procedures will be prepared describing the equipment, inspection technique, operator qualifications, calibration standards, flaw evaluation, and records. These techniques and procedures shall meet the requirements of the Section XI edition in effect as stated in Section 5.2.1.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

The preservice inspection program was submitted on June 9, 1981. *The Inservice Inspection Plan was submitted on May 22, 1985 for Unit 1 and on August 18, 1986 for Unit 2*. The 1974 edition of ASME Section XI with Addenda through summer 1975 was used for the preservice inspection.

5.2.4.4 Inspection Schedule

The inservice inspection interval is 10 years. Detailed inspection listings and scheduling is contained in the Catawba Inservice Inspection Plan.

5.2.4.5 Examination Categories and Requirements

The examination categories and requirements shall meet the Section XI in effect as stated in Section 5.2.1 except where specific relief has been requested in accordance with NRC guidelines.

5.2.4.6 Evaluation of Examination Results

Evaluation of examination results shall be in accordance with the Section XI in effect as stated in Section 5.2.1 where these evaluation standards are contained in Section XI. Examinations for which evaluation standards are not contained in Section XI shall be evaluated in accordance with the original construction code.

5.2.4.7 System Leakage and Hydrostatic Pressure Test

Pressure testing shall be performed in accordance with the Section XI in effect as stated in Section 5.2.1.

5.2.5 Detection of Leakage Through Reactor Coolant Pressure Boundary

The leakage-detection systems provide a means for identifying and quantifying any significant leakage through the reactor coolant pressure boundary (RCPB). The leakage-detection systems comply with applicable parts of GDC 30 and Regulatory Guide 1.45, except as noted in Section 5.2.5.2.3 and Table 5-46.

Additionally, the technical bases for the Catawba leak-before-break (LBB) analysis relies upon the capability of the RCS leakage detection systems. The LBB analyses indicate that given the leakage crack size associated with a referenced leak (based on RG 1.45 leak rate detection capability of 1 gpm multiplied by a safety factor of 10), the crack is stable under the worst case design load combination of deadweight, pressure, thermal expansion, and seismic (SSE) loads. There is a factor of safety of approximately 4 between the reference leakage crack size and the critical crack size. As discussed in Reference 15, the capability of the leakage detection systems supports the LBB analysis.

5.2.5.1 Leakage Classification and Limits

Leakage is classified as identified, unidentified and pressure boundary leakage. Each classification is defined in the Technical Specifications, including limiting conditions for continued plant operations, as recommended in Regulatory Guide 1.45, Position C9.

Methods for detecting reactor coolant pressure boundary leakage inside the containment area include containment floor and equipment sump level monitoring system, containment atmosphere particulate radioactivity monitor, and containment ventilation unit condensate drain tank level monitor (VUCDT). Indications and alarms for each of these leakage detection methods are provided in the control room along with procedures for converting various indications to leakage rate equivalents. These leakage detection methods are also equipped with provisions for testing and calibration during operation. Limiting conditions for continued plant operation are established within plant technical specifications when these leakage detection methods are determined to be inoperable.

Another method of leakage detection within containment is the incore instrumentation sump level monitor, which is located in the tunnel area under the reactor vessel where reactor coolant pressure boundary leakage is not expected during normal plant operation. High radiation levels make this sump inaccessible during normal plant operation. The incore instrumentation sump level provides a digital alarm on the Operator Aid Computer at established sump volumes to notify the control room of an input. Due to its limited accessibility and limited alarming functions, the incore instrumentation sump level monitor is an exception to Regulatory Guide 1.45 as noted in Table 5-46.

Other methods of leakage detection within the containment area are volume control tank level, containment atmosphere gaseous radioactivity monitor, containment atmosphere humidity, temperature, and pressure indications. These provide indirect indication of leakage to the containment and, therefore, are not required to meet the recommendations Regulatory Guide 1.45, Position C7, C8, and C9.

5.2.5.2 Leakage Detection Methods

5.2.5.2.1 Identified Leakage

Design features have been incorporated to limit leakage inside the Containment. These features include double isolation valves, packless valves, and packing leakoffs piped to collection tanks, as recommended in Regulatory Guide 1.45, position C1. Leakage from the reactor coolant pump shaft seals and valve stem leakoffs are piped to the reactor coolant drain tank, where excessive leakage is indicated and approximately established by measuring increases in tank level and by measuring water inventory balances.

Leakage from the reactor vessel main flange flows between the double O-ring seal to a leakoff line which is also piped to the reactor coolant drain tank when the system is in the alignment monitoring leakage from the inner O-ring. In the event the inner O-ring is determined to be leaking, the system may be re-aligned to monitor for leakage past the outer O-ring. A temperature sensor with control room indication is provided in the leakoff line to detect leakage from either O-ring depending on system alignment. Figure 5-1 shows the alignment which monitors for leakage past the inner O-ring. The alternate alignment with NC 23 closed and NC 24 open is used to monitor for leakage past the outer O-ring which is also considered acceptable for power operation.

Leakage from safety and relief valves is piped to the pressurizer relief tank, where excessive leakage is approximately established by measuring increases in tank level and by measuring water inventory balances. Temperature sensors with control room indication are provided on the valve discharge lines to detect leakage.

5.2.5.2.2 Intersystem Leakage

Leakage from the reactor coolant pressure boundary into connected systems is indicated by various radiation monitors, tank levels and other methods, as recommended in Regulatory Guide 1.45, position C4.

Leakage from the reactor coolant system to the main steam and feedwater systems through failed steam generator tubes is detected and monitored by radiation monitors located in the steam generator sample line and in the condenser steam air ejector exhaust. In the event of high radioactivity in the condenser steam air ejector exhaust, sample and blowdown flows are terminated, preventing the release of radioactivity to the environment. Blowdown may be continued by realigning the flow to the polishing demineralizers in the condensate system. A control room alarm is actuated in all cases.

Leakage from the reactor coolant system to the component cooling system through failed tubes in the reactor coolant pump thermal barrier is detected and monitored by flow instrumentation located downstream of each thermal barrier, off-line gamma detectors located downstream of each component cooling heat exchanger, and level indication in each component cooling surge tank. In the event of a thermal barrier tube leak, the flow instrumentation will detect inleakage as increased flow and isolate the affected thermal barrier. The component cooling radiation monitors actuate a control room alarm upon high radioactivity, and inleakage will be detected by an increase in surge tank level. Leakage into parts of the safety injection systems is detected by pressure changes and increases in tank levels.

5.2.5.2.3 Unidentified Leakage

Indication of unidentified leakage from the reactor coolant pressure boundary to the Containment is provided by various direct and indirect methods with diverse principles of detection. The primary method of detecting unidentified leakage is by trending of the periodic reactor coolant system leakage calculations. This method accounts for reactor coolant system inventory by monitoring its identified locations while the volume control tank (VCT) is isolated from the VCT makeup system and VCT divert operation. Leakage from the reactor coolant system which cannot be accounted for are considered unidentified leakage. During normal operations between these periodic calculations, increased leakage is detected by monitoring volume control tank level rate of change and increase in the frequency of makeup to the reactor coolant system. The periodic makeup is trended on a Control Room recorder.

Methods of detection, as recommended in Regulatory Guide 1.45, position C3, are the containment sump level (containment floor and equipment sumps and incore instrument sump), the containment atmosphere particulate radioactivity monitor, and the containment ventilation unit condensate drain tank level. Other indications of leakage include containment temperature, pressure, humidity monitors, containment atmosphere paseous radioactivity monitor, and volume control tank level.

5.2.5.2.3.1 Containment Sumps

One method of detecting leakage into the containment is the level instrumentation in containment floor and equipment (CFAE) sump A and CFAE sump B. The CFAE sumps are small sumps located on opposite sides of the containment and outside of the crane wall. Any leakage in the lower containment inside the crane wall would fall to the floor and run via embedded floor drains to one of the two CFAE sumps. Any leakage outside the crane wall would fall to the floor and gravity drain to these sumps. The sump level rate of change, as calculated by the plant computer, would indicate the input rate. This method of detection would indicate in the Control Room a leak from any liquid system including the Reactor Coolant System and the Main Steam and Feedwater Systems. As leakage may go to either or both of the two CFAE sumps, a 1 gpm sump input (cumulative between sumps A and B) is detectable in 1 hour after leakage has reached the sumps. During periods of pump down of the CFAE sumps, the CFAE level instrumentation remains operable since operating experience has shown that this process typically takes only minutes to complete.

The containment floor and equipment (CFAE) sump level instrumentation inputs to a plant computer program designed to detect unidentified leakage inside containment in excess of one gpm in less than an hour once leakage enters the sump, as recommended in Regulatory Guide 1.45, position C2 and C5. In conjunction with the operator aid computer, sump level instrumentation monitors water level between the low and high setpoints and calculates a rate of change. These values for both sumps are totaled and yield a computer alarm if the sum is greater than 1 gpm. In the event of a loss of the plant computer, procedures are in place to manually acquire and analyze the data.

The environmental conditions during plant power operations and the physical configuration of lower containment will obstruct the total reactor coolant system leakage (including steam) from directly entering the CFAE sump and subsequently, will lengthen the sump's level response time. Therefore, leakage detection by the CFAE sump will typically occur following other means of leakage detection. Operating experience with high enthalpy primary and secondary water leaks indicates that flashing of high temperature liquid produces steam and hot water mist that is readily absorbed in the containment air. Much of the hot water that initially hits the containment floor will evaporate in a low relative humidity environment as it migrates towards a sump. Local low points along the containment floor provide areas for water to form shallow pools that increase transport time to one or more building sumps. The net effect is that only a fraction of any high enthalpy water leakage will eventually collect in a sump and early leak detection may rely on alternate methods.

The incore instrumentation sump is located under the reactor vessel where no leakage is expected under normal conditions. The incore instrumentation sump is 5 feet x 5 feet x 1 foot deep, which corresponds to a capacity of approximately 186 gallons. The setting for alarms on the plant computer are at sump HI level and HI-HI level, which are approximately the 9 inch and 11 inch sump water level, respectively. For an initial condition prior to the development of a primary system leak, it is conservative to assume that the incore instrumentation sump is empty (i.e., dry) due to evaporation. Once a leak develops, the plant computer provides an alarm in the control room when the sump pump starts at the HI level. A second backup alarm is provided at the HI-HI sump level. As such, the plant computer will alert the control room to a primary system leak of 1 gpm into the incore instrumentation room sump in less than 4 hours after leakage has reached the sump. Because the both Hi and Hi-Hi level setpoints will alarm within the required 4 hour response time, either alarm may be credited for Technical Specification incore instrument sump level alarm. In the event of a loss of the plant computer, there is no alternate method for detection of water leakage to the incore instrumentation sump. The incore sump leakage detection system is an exception to flow rate and sensitivity recommendations of positions C2 and C5, the indication and alarm recommendation of position C7, and accessibility recommendation of C.8 as discussed in Table 5.46. However, the incore sump does provide direct indication of leakage within the area under the reactor vessel as recommended by Position C3 of Regulatory Guide 1.45.

5.2.5.2.3.2 Containment Atmosphere Particulate Radioactivity Monitor

The containment atmosphere particulate monitor continuously monitors activity levels in the containment atmosphere, as described in Section 11.5.1.2.2.2. In conjunction with the Operator Aid Computer (OAC), unidentified leakage is detected and, to the extent practicable, quantified by the particulate monitor with response times dependent upon the sum of the time for the leakage to mix with the containment volume and the time of transit from the point of leakage, the unidentified leakage rate, the identified baseline leakage rate, and the amount of activated corrosion product activity in the coolant. In addition, the response time depends on the amount of corrosion and fission product activity in the coolant, the fraction of particulates which escape into the containment atmosphere, the amount of plate out on containment surfaces, and the collection rate of the filter mechanism. The amount of fission product inventory in the reactor coolant depends on the fraction of failed fuel, fission product inventory in the core, fission product escape rates, and reactor coolant processing history. The OAC alarm setpoint is set as low as practicable, considering the actual concentration of radioactivity in the RCS and the containment background radiation concentration. As low as practicable alarm setpoint is a balance between sufficiently high enough above typical background radiation variations to preclude spurious alarms while sufficiently low enough to assure reasonable sensitivity for early detection of an RCS leak. The alarm is only required during Mode 1. If the OAC alarm setpoint is too low such that nuisance alarms are produced, the alarm may be increased incrementally to prevent nuisance alarms. In the event of a loss of the Operator Aid Computer, procedures are in place to manually acquire and analyze data. Table 5-10 presents information on the sensitivity of the monitors.

The containment atmosphere particulate monitor is not required to meet seismic Category I design requirements per Reference 9. This is an exception to position C6 of Regulatory Guide 1.45, which recommends that the subject monitor remain functional during and following a safe shutdown earthquake. The containment atmosphere particulate monitor is not required to meet time response requirements per Reference 9. This is an exception to position C5 of Regulatory Guide 1.45, which recommends that the subject monitor be able to detect a 1 gpm leak within 1 hour.

5.2.5.2.3.3 Containment Ventilation Unit Condensate Drain Tank (CVUCDT)

The quantity and activity of the CVUCDT contents will also be an indicator of excessive leakage from the Reactor Coolant System. A sudden increase in the flow rate of ventilation unit condensate indicates an increase in the relative humidity of the containment atmosphere. The operator aid computer calculates a CVUCDT level change rate and provides an alarm if the rate equivalent to 1 gpm is exceeded after condensate has reach the tank. In the event of a loss of the Operation Aid Computer, procedures are in place to acquire and analyze the data.

5.2.5.2.3.4 Other Leakage Detection Instrumentation

The containment atmosphere monitor continuously monitors the gaseous and air particulate activity levels in the containment atmosphere. Of the two channels (gaseous, and particulate), only the particulate channel is credited as one of the Ractor Coolant System Leakage Detection Instruments. Due to improved fuel integrity and resulting reduced RCS radioactivity levels, the gaseous channel has become less effective for RCS leakage detection and cannot meet the originally accepted basis for the equivalent of detecting one gallon per minute within one hour. Therefore, the gaseous channel is not required for the Technical Specifications for RCS Leakage Detection Instrumentation. The gaseous channel, however, is available and maintains its function to provide operators qualitative information as an additional diverse method of detecting leakage.

The volume control tank (VCT) level change offers another means of detecting leakage into containment. This enhances the diversity of the leakage detection function as recommended in Regulatory Guide 1.45. The VCT level instrumentation is not required by the Technical Specifications for RCS Leakage Detection Instrumentation.

Two humidity detectors are installed within Containment. An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid level into the CFAE and condensate level from air coolers. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by the Technical Specifications for RCS Leakage Detection Instrumentation.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS Leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by the Technical Specifications for RCS Leakage Detection Instrumentation.

5.2.5.2.3.5 Deleted Per 2007 Update

5.2.5.3 System Sensitivity and Response Time

The leakage detection systems provided vary in sensitivity and response to various postulated leaks inside containment. Because of the diverse detection methods and location of sensors, the operator is provided with sufficient information to take corrective action in compliance with the Technical Specification. Additional information on the sensitivity and response time of the primary detection methods is provided in Table 5-10.

5.2.5.4 Testability

All components used for leakage detection will be calibrated and operational tests will be performed before initial use. Many of the detectors (e.g., level detectors and activity monitors) are in frequent use during normal operation, thus verification of their operability is assured. Visual inspections and periodic calibration and maintenance will be performed in accordance with the Technical Specifications. Calibration of this instrumentation is subject to the pertinent requirements of the 10CFR50 Appendix B Quality Assurance Program.

5.2.6 References

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

1. *Logsdon, W. A., Begley, J. A., Gottshall, "Dynamic Fracture Toughness of ASME SA508 Class 2a and ASME SA533 Grade A Class 2 Base and Heat Affected Zone Material and Applicable Weld Metals," WCAP 9292, March 1978.*
2. *Cooper, L., Miselis, V. and Starek, R. M., "Overpressure Protection for Westinghouse Presssurized Water Reactors," WCAP-8879, Revision 1, June 1972 (also letter NS-CD-622, dated April 16, 1975, C. Eicheldinger (Westinghouse) To D. B. Vassallo (NRC), additional information on WCAP-7769, Revision 1).*
3. *Burnett, T.W.T., et al., "LOFTRAN Code Discription," WCAP-7907, June 1972.*
4. "Westinghouse Nuclear Energy Systems Divisions Quality Assurance Plan," WCAP-8370, Revision 7A February, 1975.
5. "Westinghouse Water Reactor Divisions Quality Assurance Plan," WCAP-8370, Revision 8A, September, 1977.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

6. *Golik, M. A., "Sensitized Stainless Steel in Westinghouse PWR Nuclear Steam Supply Systems," WCAP-7735, August, 1971.*
7. *Enrietto, J. F., "Control of Delta Ferrite in Austenitic Stainless Steel Weldments," WCAP-8324-A, June, 1974.*
8. *Enrietto, J. F., "Delta Ferrite in Production Austenitic Stainless Steel Weldments," WCAP-8693, January, 1976.*
9. Amendments No. 140 to Facility Operating License NPF-35 and No. 134 to Facility Operating License NPF-52, transmitted by letter to W.R. McCollum from R.E. Martin dated December 29, 1995, titled "Issuance of Admendments- Catawba Nuclear Station, Units 1 and 2, Seismic Classification of Containment Airborn Particulate Radiation Monitor (TAC No.s M90439 and M90440)."
10. Nuclear Regulatory Commission, Letter to All Licensees of Operating Plants and Applicants for Operating Licenses and Holders of Construction Permits, from Frank Miraglia, March 17, 1988, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants (Generic Letter 88-05)."
11. Duke Power Company, Letter from H.B. Tucker to the NRC, May 23, 1988, re: Response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants."
12. Duke Power Company, Letter from H.B. Tucker to the NRC, August 1, 1988, re: Response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants."

13. Duke Power Company, Letter from H.B. Tucker to the NRC, March 1, 1989, re: Response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants."

14. Nuclear Regulatory Commission, Letter from J.N. Jabbour to the H.B. Tucker (DPC), September 28, 1989, re: Response to Generic Letter 88-05 for Catawba Nuclear Station (TAC Nos. 68910 and 68911).

15. Regulatory Guide 1.45 comments and exceptions are based on Duke letter dated May 4, 2006 and NRC amendments dated September 30. 2006 and December 29, 1995. License amendment changes were associated with Reactor Coolant Sysem Leakage Detection Instrumentation.

16. CNC-1223.03-00-0040, Low Temperature Overpressure Protection {LTOP} Failure Modes and Effects analysis (FMEA), Revision 1.

THIS IS THE LAST PAGE OF THE TEXT SECTION 5.2.

5.3 Reactor Vessel

5.3.1 Reactor Vessel Materials

5.3.1.1 Material Specifications

Material specifications are in accordance with the ASME Code requirements and are given in Section 5.2.3.

5.3.1.2 Special Processes Used For Manufacturing and Fabrications

1. The vessel is Safety Class 1. Design and fabrication of the reactor vessels is carried out in strict accordance with ASME Code, Section III, Class I requirements. The head flanges and nozzles are manufactured as forgings. The cylindrical portion of the Unit 1 vessel is made up of forgings; the cylindrical portion of the Unit 2 vessel is made up of several shells, each consisting of formed plates joined by full penetration longitudinal weld seams. The hemispherical heads are made from dished plates. The reactor vessel parts are joined by welding, using the single or multiple wire submerged arc and the shielded metal arc processes.
2. The use of severely sensitized stainless steel as a pressure boundary material has been prohibited and has been eliminated by either a select choice of material or by programming the method of assembly.
3. The threads of the control rod drive mechanism head adaptor and surfaces of the guide studs are chrome plated to prevent possible galling of the mated parts.
4. At all locations in the reactor vessel where stainless steel and Inconel are joined, the final joining beads are Inconel weld metal in order to prevent cracking.
5. The Unit 2 core region shells are fabricated of plate material have longitudinal welds which are angularly located away from the peak neutron exposure experienced in the vessel, where possible.
6. The location of full penetration weld seams in the upper closure head and bottom head are restricted to areas that permit accessibility during inservice inspection.
7. The stainless steel clad surfaces are sampled to assure that composition requirements are met.
8. Minimum preheat requirements have been established for pressure boundary welds using low alloy weld material. Special preheat requirements have been added for stainless steel cladding of low stressed areas. Preheat must be maintained until post weld heat treatment, except for overlay cladding where it may be lowered to ambient temperature under restrictive conditions. The purpose of placing limitations on preheat requirements is to provide additional precautionary measures that decrease the probabilities of weld cracking by decreasing temperature gradients, lower susceptibility to brittle transformation, prevent hydrogen embrittlement, and reduce peak hardness.
9. The procedure qualification for cladding low alloy steel (SA508 Class 2) requires a special evaluation to assure freedom from underclad cracking.

5.3.1.3 Special Methods For Nondestructive Examination

The non-destructive examination of the reactor vessel and its appurtenances is conducted in accordance with the ASME Code Section III requirements; also numerous examinations are performed in addition to ASME Code Section III requirements. Nondestructive examination of the vessel is discussed in the following paragraphs and the reactor vessel quality assurance program is given in Table 5-11.

5.3.1.3.1 Ultrasonic Examination

In addition to the design code straight beam ultrasonic test, angle beam inspection of l00 percent of plate material is performed during fabrication to detect discontinuities that may be undetected by longitudinal wave examination.

In addition to ASME Section III nondestructive examination, all full penetration ferritic primary pressure boundary welds in the reactor vessel are ultrasonically examined during fabrication. This test is performed upon completion of the welding and intermediate heat treatment but prior to the final post-weld heat treatment.

After hydrotesting, all full penetration ferritic pressure boundary welds in the reactor vessel are ultrasonically examined. This inspection is also performed in addition to the ASME Code Section III nondestructive examinations.

5.3.1.3.2 Penetrant Examinations

The partial penetration welds for the control rod drive mechanism head adaptors and the bottom instrumentation tubes are inspected by dye penetrant after the root pass and after the final layer in addition to code requirements. Core support block attachment welds are inspected by dye penetrant after first layer of weld metal, after each l/2 inch of weld metal, and after the final layer. All clad surfaces and other vessel and head internal surfaces are inspected by dye penetrant after the hydrostatic test.

5.3.1.3.3 Magnetic Particle Examination

The magnetic particle examination requirements below are in addition to the magnetic particle examination requirements of Section III of the ASME Code.

All magnetic particle examinations of materials and welds are performed in accordance with the following:

1. Prior to the Final Post Weld Heat Treatment - Only by the Prod, Coil or Direct Contact Method.
2. After the Final Post Weld Heat Treatment - Only by the Yoke Method.

The following surfaces and welds shall be examined by magnetic particle methods. The acceptance standards shall be in accordance with Section III of the ASME Code.

<u>Surface Examinations</u>

1. Magnetic particle examine all exterior vessel and heat surfaces after the hydrostatic test.
2. Magnetic particle examine all exterior closure stud surfaces and all nut surfaces after final matching. Continuous circular and longitudinal magnetization shall be used.
3. Magnetic particle examine all inside diameter surfaces of carbon and low alloy steel products that have their properties enhanced by accelerated cooling. This inspection to be performed after forming, heat treating, and machining (if performed) and prior to cladding.

Weld Examination

Magnetic particle examination of the weld metal build-up for vessel support welds attaching the closure head lifting lugs and refueling seal ledge to the reactor vessel after the first layer and each l/2 inch of weld metal is deposited. All pressure boundary welds shall be examined after back chipping or back grinding operations.

5.3.1.4 Special Controls For Ferritic and Austenitic Stainless Steels

Welding of ferritic steels and austenitic stainless steels is discussed in Section 5.2.3.4.6. Section 5.2.3.4 includes discussions which indicate the degree of conformance with Regulatory Guide 1.44. The degree of conformance with Regulatory Guides 1.43, 1.50, and 1.71 is discussed below. Regulatory Guide 1.31 is discussed in Section 5.2.3.4.6. Regulatory Guides 1.34 and 1.99 are discussed in Section 1.7.

Regulatory Guide 1.43

Control of Stainless Steel Weld Cladding of Low-Allow Steel Components (5/73).

Discussion

Westinghouse practices achieve the same purpose as Regulatory Guide 1.43 by requiring qualification of any high head input process, such as the submerged-arc wide-strip welding process and the submerged-arc 6-wire process used on ASME SA-508, Class 2, material, with a performance test as described in Regulatory Position 2 of the guide. No qualifications are required by the regulatory guide for ASME SA-533 material and equivalent chemistry for forging grade ASME SA-508, Class 3, material.

The fabricator monitors and records the weld parameters to verify agreement with the parameters established by the procedure qualification as stated in Regulatory Position C.3.

Regulatory Guide 1.50

Control of Preheat Treatment for Welding of Low-Alloy Steel Welding.

Discussion

Westinghouse considers that this regulatory guide applies to ASME Code, Section III, Class 1 components.

The Westinghouse practice for Class 1 components is in agreement with the recommendations of Regulatory Guide 1.50 except for Regulatory Positions C.1.b and C.2. For Class 2 and 3 components, Westinghouse does not apply any of the recommendations of Regulatory Guide 1.50.

In the case of Regulatory Position C.1.b, the welding procedures are qualified within the preheat temperature ranges required by Section IX of the ASME Code. Westinghouse experience has shown excellent quality of welds using the ASME qualification procedures.

In the case of Regulatory Position C.2, the Westinghouse position documented in Reference 6 has been found acceptable by the NRC.

Regulatory Guide 1.71

Welder Qualification for Areas of Limited Accessibility (l2/73).

Discussion

Westinghouse practice does not require qualification or requalification of welders for areas of limited accessibility as described by Regulatory Guide 1.71. Experience shows that the current

Westinghouse shop practice produces high quality welds. In addition, the performance of required nondestructive evaluations provided further assurance of acceptable weld quality.

Westinghouse believes that limited accessibility qualification or requalification, which is in excess of ASME Code Section III and IX requirements, is an unduly restrictive requirement for component fabrication, where the welders' physical position relative to the welds is controlled and does not present any significance. In addition, shop welds of limited accessibility are repetitive due to multiple production of similar components, and such welding is closely supervised.

For field application, the type of qualification should be considered on a case-by-case basis due to the great variety of circumstances encountered.

5.3.1.5 Fracture Toughness

Assurance of adequate fracture toughness of the ferritic materials in the Unit 1 reactor vessel is provided by compliance with Section III of the 1971 ASME Boiler and Pressure Vessel Code, plus Addenda to Winter 1971. The Unit 2 reactor vessel complies with Section III of the 1971 ASME B&PV Code, plus Addenda to Winter 1972. The reactor vessel materials meet the fracture toughness requirements of 10CFR 50, Appendix G, to the extent possible. The pressure-temperature limitations on reactor operation, as well as leak and hydrostatic test conditions are determined in accordance with Appendix G to Section XI of the ASME B&PV Code as modified by ASME Code Case N-640, “Alternative Reference Fracture Toughness for Development of PT Limit Curves for Section XI”, and Appendix G, 10CFR 50. Code Case N-640 allows an alternative expression for reference fracture toughness – K_{Ic} which bounds the static stress intensity conditions necessary for crack initiation as opposed to K_{Ia} which bounds the conditions representative of crack arrest under dynamic conditoins. Since the fracture toughness testing performed on vessel material from Units 1 and 2 did not include all of the tests necessary to determine RT_{NDT} in the manner prescribed in NB-2300 of ASME III, Summer 1972 Addenda, the necessary properties were estimated using the procedures provided in Branch Technical Position MTEB 5-2, "Fracture Toughness Requirements for Older Plants".

A summary of the fracture toughness data for the Unit 1 and Unit 2 reactor pressure vessel material is given in Table 5-12, Table 5-13, Table 5-14, and Table 5-15. The material (plate, and/or forging and weld metal) in the reactor vessel beltline region is identified in Figure 5-7 and Figure 5-8.

In response to NRC Generic Letter 92-01, Reactor Vessel Structural Integrity, the requested information on the structural integrity of both Unit 1 and Unit 2 reactor vessels was provided to the USNRC. The USNRC found that the Reactor Pressure Vessel integrity data on the Unit 1 and Unit 2 reactor vessels was both complete and satisfactory. A detailed discussion of the requests made by the NRC and the responses provided by Duke Power can be found in references 10, 11, 12 and 16.

5.3.1.6 Material Surveillance

In the surveillance program, the evaluation of the radiation damage is based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, tensile and 1/2 T (thickness) compact tension (CT) fracture mechanics test specimens. The program is directed toward evaluation of the effect of radiation on the fracture toughness of reactor vessel steels based on the transition temperature approach and the fracture mechanics approach. The program will conform with ASTM E-185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels", and 10CFR Part 50, Appendix H to the greatest extent practicable. The individual programs for Unit 1 and Unit 2 were originally developed to meet the requirements of the 1973 and 1982 versions of the specification, respectively. Each reactor vessel had six specimen capsules located in guide baskets welded to the outside of the neutron shield pads and were positioned directly opposite the center portion of the core. The capsules can be removed when the vessel head is removed and can be replaced when the internals are removed. Each capsule contains reactor vessel steel specimens oriented both parallel and normal (longitudinal and transverse) to the principal rolling direction of the limiting shell plate located in the core region of the Catawba Unit 2 reactor vessel. Catawba Unit 1 reactor vessel specimen are oriented both parallel and normal to the major working direction of the limiting core region shell forging. Associated weld metal and weld heat affected zone metal specimens are also included in each capsule.

The six capsules contain 54 tensile specimens, 360 Charpy V-notch specimens (which include weld metal and weld heat-affected zone material), and 72 CT specimens. Archive material sufficient for two additional capsules will be retained. Dosimeters, including Ni, Cu, Fe, Co-Al, Cd shielded Co-Al, Cd shielded Np-237, and Cd shielded U-238, are placed in filler blocks drilled to contain them. The dosimeters permit evaluation of the flux seen by the specimens and the vessel wall. In addition, thermal monitors made of low melting point alloys are inlcuded to monitor the maximum temperature of the specimens. The specimens are enclosed in a tight fitting stainless steel sheath to prevent corrosion and ensure good thermal conductivity. The complete capsule is helium leak tested. As part of the surveillance program, a report of the residual elements in weight percent to the nearest 0.01 percent will be made for surveillance material and as deposited weld metal.

Each of the six capsules contains the following specimens:

Material	Number of Charpys	Number of Tensiles	Number of CT's
Limiting Base Material[1]	15	3	4
Limiting Base Material[2]	15	3	4
Weld Metal[3]	15	3	4
Heat Affected Zone	15	-	-

Notes:

1. Specimens oriented in the major rolling or working direction.
2. Specimens oriented normal to the major rolling or working direction.
3. Weld metal to be selected per ASTM El85.

The following dosimeters and thermal monitors are included in each of the six capsules:

<u>Dosimeters</u>

Iron

Copper

Nickel

Cobalt-Aluminum (0.I5 percent Co)

Cobalt-Aluminum (Cadmium shielded)

U-238 (Cadmium shielded)

Np-237 (Cadmium shielded)

Thermal monitors

97.5 percent Pb, 2.5 percent Ag (579 F Melting Point)

97.5 percent Pb, 1.75 percent Ag, 0.75 percent Sn (590 F Melting Point)

The fast neutron exposure of the specimens occurs at a faster rate than that experienced by the vessel wall, with the specimens being located between the core and the vessel. Since these specimens experience accelerated exposure and are actual samples from the materials used in the vessel, the transition temperature shift measurements are representative of the vessel at a later time in life. Data from CT fracture toughness specimens are expected to provide additional information for use in determining allowable stresses for irradiated material.

Correlations between the calculations and the measurements of the irradiated samples in the capsules, assuming the same neutron spectrum at the samples and the vessel inner wall, are described in Section 5.3.1.6.2. They have indicated good agreement. The anticipated degree to which the specimens will perturb the fast neutron flux and energy distribution will be considered in the evaluation of the surveillance specimen data. Verification and possible readjustment of the calculated wall exposure will be made by use of data on all capsules withdrawn. The schedule for removal of the capsules for post-irradiation testing conforms to ASTM E-185-82 and Appendix H of 10CFR 50. The capsule withdrawal schedule is provided in Table 5-40. Surveillance capsule specimens are tested in accordance with approved industry standards. The test results from the encapsulated specimens represent the actual behavior of the material in the vessel. Data from testing of the surveillance capsule specimens are used to analyze Pressurized Thermal Shock, Upper Shelf Energy and to generate pressure-temperature curves for future operation of each unit.

5.3.1.6.1 Ex-Vessel Neutron Dosimetry System

The Ex-Vessel Neutron Measurement Program provides a verification of fast neutron exposure distributions within the reactor vessel wall beltline region and establishes a mechanism to enable long term monitoring of this portion of the reactor vessel. This neutron measurement system is located external of the reactor vessel which allows for ease of dosimetry removal and replacement. The program assists in the evaluation of radiation damage of the reactor vessel beltline region by measuring the fluence to this region which can be used to predict the shift in the reference nil ductility transition temperature (RT_{NDT}). When used in conjunction with dosimetry from internal surveillance capsules and with the results of neutron transport calculations, the ex-vessel neutron measurements allow the projection of embrittlement gradients through the reactor vessel wall with minimum uncertainty. Comprehensive sensor sets including radiometric monitors are employed at discrete locations within the reactor cavity to characterize the neutron energy spectrum variations axially and azimuthally over the beltline region of the reactor vessel. In addition, stainless steel gradient chains are used in conjunction with the encapsulated dosimeters to complete the mapping of the neutron environment between the discrete locations chosen for spectrum determinations.

The ex-vessel neutron dosimetry is installed in the annular air gap between the reactor vessel insulation and the primary concrete shield wall in both Units 1 and 2. The ex-vessel neutron dosimetry consists of aluminum dosimeter capsules (containing Radiometric Monitors) connected to and supported by four stainless steel bead chains, which are supported by tubular brackets attached to a support bar. The support bar is suspended by two support chains that are connected to plates welded to the reactor cavity liner plate. The bead chains are mechanically secured to the concrete wall below the reactor vessel. The ex-vessel neutron dosimetry measures fluence for approximately 1/8 of the vessel wall circumference relative to well known reactor features. Neutron transport calculations then determine the fluence for the entire vessel beltline wall.

5.3.1.6.2 Measurement of Integrated Fast Neutron (E>1.0MeV) Flux at the Irradiation Samples

The use of passive neutron sensors such as those included in LWR internal surveillance capsules does not yield a direct measure of the energy-dependent neutron flux at the measurement location. Rather, the activation or fission process is a measure of the integrated effect that the time- and energy-dependent neutron flux has on the target material over the course of the irradiation period. An accurate assessment of the desired exposure rates averaged over the irradiation period and, hence, the time-integrated exposures experienced by the sensor sets may be developed from the measurements only if the sensor characteristics and the parameters of the irradiation are well known. In particular, the following variables are of interest:

1 - The measured reaction rate for each sensor,
2 - The energy response of each sensor,
3 - The neutron energy spectrum at the sensor set location,
4 - The physical characteristics of each sensor,
5 - The operating history of the reactor.

Procedures applicable to the evaluation of the neutron sensor sets contained in individual surveillance capsules are described in ASTM Standard E853, "Standard Practice for Analysis and Interpretation of Light Water Reactor Surveillance Results". This umbrella practice relies on, and ties together, the application of several supporting ASTM standard practices, methods, and guides dealing with the general areas of activation measurements, neutron transport calculations, and dosimetry data interpretation.

The determination of individual reaction rates for the sensors comprising the multiple foil neutron dosimeter sets involves laboratory counting procedures, decay corrections to account for the operating history of the reactor, and corrections for competing reactions within the sensor materials. Following withdrawal from the reactor, the specific activity of each of the irradiated radiometric sensors is determined using the latest version of ASTM counting procedures for each reaction of interest. In particular, the following standards are applicable to the radiometric sensors utilized in LWR programs:

E181	Standard General Methods for Detector Calibration and Analysis of Radionuclides
E263	Standard Test Method for Measuring Fast Neutron Reaction Rates by Radioactivation of Iron
E264	Standard Test Method for Measuring Fast Neutron Reaction Rates by Radioactivation of Nickel
E523	Standard Test Method for Measuring Fast Neutron Reaction Rates by Radioactivation of Copper
E704	Standard Test Method for Measuring Reaction Rates by Radioactivation of Uranium-238
E705	Standard Test Method for Measuring Reaction Rates by Radioactivation of Neptunium-237

E481 Standard Test Method for Measuring Neutron Fluence Rate by Radioactivation of Cobalt and Silver

E1005 Standard Method for Application and Analysis of Radiometric Monitors for Reactor Vessel Surveillance

Following sample preparation and weighing, the specific activity of each sensor is determined by means of a high purity germanium, HPGe, gamma spectrometer. In the case of these multiple foil sensor sets, these analyses are performed by direct counting of each of the individual sensors, or, as is sometimes the case with U-238 and Np-237 fission monitors, by direct counting preceded by dissolution and chemical separation of cesium from the sensor.

Having the measured specific activities, the operating history of the reactor, and the physical characteristics of the sensors, reaction rates referenced to full-power operation can be determined from the following equation:

$$R = \frac{A}{N_0 \, F \, Y \sum \frac{P_j}{P_{ref}} C_j [1 - e^{-\lambda t_j}][e^{-\lambda t_{d,j}}]}$$

where:

A = Measured specific activity (dps/g)

R = Reaction rate averaged over the irradiation period and referenced to operation at a core power level of P_{ref} (rps/nucleus)

N_0 = Number of target element atoms per gram of sensor

F = Weight fraction of the target isotope in the sensor material

Y = Number of product atoms produced per reaction

P_j = Average core power level during irradiation period j (MW)

P_{ref} = Maximum or reference power level of the reactor (MW)

C_j = Calculated ratio of ϕ (E > 1.0 MeV) during irradiation period j to the time-weighted average ϕ (E > 1.0 MeV) over the entire irradiation period

λ = Decay constant of the product isotope (sec^{-1})

t_j = Length of irradiation period j (sec)

$t_{d,j}$ = Decay time following irradiation period j (sec)

and the summation is carried out over the total number of monthly intervals comprising the irradiation period.

In the above equation, the ratio $[P_j]/[P_{ref}]$ accounts for month-by-month variation of core power level within any given fuel cycle as well as over multiple fuel cycles. For the sensor sets utilized in surveillance capsule dosimetry programs, the half-lives of the product isotopes are long enough that a monthly histogram describing reactor operation has proven to be an adequate representation for use in radioactive decay corrections.

The ratio C_j, which can be calculated for each fuel cycle using the neutron transport methodology described in Section 5.3.1.6.3, accounts for the change in sensor reaction rates caused by variations in flux level induced by changes in core spatial power distributions from fuel cycle to fuel cycle. Since the neutron flux at the measurement locations within the surveillance capsules is dominated by neutrons produced in the peripheral fuel assemblies, the change in the relative power in these assemblies from fuel cycle to fuel cycle can have a significant impact on the activation of neutron sensors. For a single-cycle irradiation, C_j = 1.0. However, for multiple-cycle irradiations, particularly those employing low-leakage fuel management, the additional C_j correction must be utilized in order to provide accurate determinations of the decay-corrected reaction rates for the dosimeter sets contained in the surveillance capsules.

Prior to using the measured reaction rates in dosimetry evaluation procedures, additional corrections are made to the U-238 measurements to account for the presence of U-235 impurities in the sensors as well as to address the effects of build-in of plutonium isotopes over the course of the irradiation. These corrections are location- and fluence-dependent and can be derived from the plant-specific transport calculations described in Section 5.3.1.6.3.

In addition to the corrections made for the presence of U-235 in the U-238 fission sensors, corrections are also made to both U-238 and Np-237 sensors to account for gamma-ray-induced fission reactions occurring over the course of the irradiation. These photo-fission corrections are, likewise, location-dependent and are based on plant-specific calculations described in Section 5.3.1.6.3.

The derivation of fast neutron exposure rates from a set of measured reaction rates has historically proceeded along one of two avenues. One common method, referred to as the spectrum-averaged cross section approach, employs a calculated neutron energy spectrum at the sensor set locations to determine a spectrum-averaged reaction cross section for each sensor included in the dosimetry set. These calculated spectrum-averaged cross sections are, in turn, used to compute appropriate exposure rates from individual sensors; and an evaluation of the desired exposure rates characteristic of the irradiation is obtained via an average of the individual sensor results. The uncertainties associated with the exposure rates derived using this approach are usually determined from elementary statistics as the standard deviation of the mean.

The second common approach used in the evaluation of multiple foil dosimetry sets utilizes a least-squares adjustment procedure to produce a best fit of the calculated spectrum at the sensor set location to the measured reaction rates from all sensors. In this methodology, uncertainties in the derived exposure rates are dependent on the resultant fit of the calculated spectrum to the measured data; and include a combination of the uncertainties in measured reaction rates, sensor cross sections, and the trial spectrum. As in the case of the spectrum-averaged cross section approach, best results are generally achieved when the trial spectrum closely approximates the actual spectrum experienced by the sensors. However, when foil coverage is sufficient, the impact of differences between the trial spectrum and the actual spectrum on derived exposure rates is normally less severe when the adjustment method is employed.

The use of the least-squares adjustment methodology in the evaluation of light water reactor dosimetry is addressed in ASTM Standard E944 "Application of Neutron Spectrum Adjustment Methods in Reactor Surveillance". In that guide, the recommended approach to be used in the application of adjustment methods to determine best estimates of neutron exposure parameters and their associated uncertainties is described and a list of several available computer codes capable of performing the adjustment function is provided.

In the overall dosimetry evaluation, these two approaches to sensor set analysis are viewed as complementary. Since the least-squares adjustment approach results in reduced uncertainties in the final exposure estimates, this avenue is considered to be the prime methodology for the determination of exposure rates and associated uncertainties from the sensor set reaction rates.

However, evaluations using spectrum-averaged cross sections are also considered as an additional check on the adjustment results as well as an indicator of the appropriateness of the trial spectrum used as input to the adjustment procedure.

In the measurement uncertainty recapture uprate evaluation, the least-squares adjustment method has been used. Least-squares adjustment methods provide the capability of combining the measurement data with the neutron transport calculation resulting in a best-estimate neutron energy spectrum with associated uncertainties. Best-estimates for key exposure parameters such as fast flux [$\phi(E > 1.0 \text{ MeV})$] or dpa/s along with their uncertainties are then easily obtained from the adjusted spectrum.

In general, the least-squares methods, as applied to surveillance capsule dosimetry evaluations, act to reconcile the measured sensor reaction rate data, dosimetry reaction cross sections, and the calculated neutron energy spectrum within their respective uncertainties. For example,

$$R_i \pm \delta_{R_i} = \sum_g (\sigma_{ig} \pm \delta_{\sigma_{ig}})(\phi_g \pm \delta_{\phi_g})$$

relates a set of measured reaction rates, Ri, to a single neutron spectrum, ϕ_g, through the multigroup dosimeter reaction cross section, σ_{ig}, each with an uncertainty δ. The primary objective of the least-squares evaluation is to produce unbiased estimates of the neutron exposure parameters at the location of the measurement.

For the least-squares evaluation of the surveillance capsule dosimetry, the FERRET code (Reference 27) was employed to combine the results of the plant-specific neutron transport calculations and sensor set reaction rate measurements to determine best-estimate values of exposure parameters (fast fluence [$\phi(E > 1.0 \text{ MeV})$] and dpa) along with associated uncertainties.

The application of the least-squares methodology requires the following input:

1. The calculated neutron energy spectrum and associated uncertainties at the measurement location.
2. The measured reaction rates and associated uncertainty for each sensor contained in the multiple foil set.
3. The energy-dependent dosimetry reaction cross sections and associated uncertainties for each sensor contained in the multiple foil sensor set.

For a given application, the calculated neutron spectrum is obtained from the results of plant-specific neutron transport calculations applicable to the irradiation period experienced by the dosimetry sensor set. For the current measurement uncertainty recapture uprate application, the calculated neutron spectrum was obtained from the results of plant-specific neutron transport calculations described in Section 5.3.1.6.2.

The sensor reaction rates are derived from the measured specific activities obtained from the counting laboratory using the specific irradiation history of the sensor set to perform the radioactive decay corrections. The dosimetry reaction cross sections and uncertainties were obtained from the SNLRML dosimetry cross section library (Reference 28). The dosimetry reaction cross sections and uncertainties that are utilized in LWR evaluations comply with ASTM Standard E1018, Application of ASTM Evaluated Cross-Section Data File, Matrix E706 (IIB).

The uncertainties associated with the measured reaction rates, dosimetry cross sections, and calculated neutron spectra are input to the least-squares procedure in the form of variances and covariances. The assignment of the input uncertainties also follows the guidance provided in ASTM Standard E944.

While the uncertainties associated with the reaction rates were obtained from the measurement procedures and counting benchmarks, and the dosimetry cross section uncertainties were supplied directly with the SNLRML library, the uncertainty matrix for the calculated spectrum was constructed from the following relationship:

$$M_{gg'} = R_n^2 + R_g \times R_{g'} \times P_{gg'}$$

where Rn specifies an overall fractional normalization uncertainty, and the fractional uncertainties Rg and Rg′ specify additional random groupwise uncertainties that are correlated with a correlation matrix given by:

$$P_{gg'} = [1-\theta]\,\delta_{gg'} + \theta\, e^{-H}$$

where

$$H = \frac{(g-g')^2}{2\gamma^2}$$

The first term in the correlation matrix equation specifies purely random uncertainties, while the second term describes the short-range correlations over a group range γ (θ specifies the strength of the latter term). The value of δ is 1.0 when g = g' and is 0.0 otherwise.

5.3.1.6.3 Calculation of Integrated Fast Neutron (E>1.0MeV) Flux at the Irradiation Samples

Discrete ordinates transport calculations are performed on a fuel cycle-specific basis to determine the neutron and gamma ray environment within the reactor geometry. The specific methods applied have been benchmarked according to the guidelines of Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," U. S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001 (Reference 24) and have been approved by the NRC staff for general application to PWR analysis. A description of the transport methodology along with the SER documenting NRC staff approval of the method is provided in WCAP-16083-A, Rev. 0 (Reference 25). Evaluations and benchmark tests using the RAPTOR-M3G discrete ordinates code instead of the TORT (Reference 29) discrete ordinates code are provided in WCAP-16083-NP, Rev. 1 (Reference 26). Also included in Reference 26 are evaluations of the latest-available ENDF-VII based cross sections contained in the BUGLE-B7 library which indicate that no significant differences exist between the BUGLE-B7 and BUGLE-96 cross section libraries and that both data sets are acceptable for the methodology described in Reference 25.

In the application of this methodology to the fast neutron exposure evaluations for the surveillance capsules and reactor vessel, a series of three-dimensional plant-specific transport calculations are carried out throughout the geometry of interest using the procedures outlined in Regulatory Guide 1.190. These three-dimensional mappings of the neutron environment are completed for each operating fuel cycle and then integrated to determine the neutron fluence experienced by the surveillance test specimens and the pressure vessel wall.

In the approved analysis methodology, the transport calculations are completed using the RAPTOR-M3G discrete ordinates code and the BUGLE-96 cross section library (Reference 30). The BUGLE-96 library provides a 67-group coupled neutron-gamma ray cross-section data set produced specifically for light water reactor application. In these analyses, anisotropic scattering is treated with a P_3 legendre expansion, and the angular discretization is modeled with an S_8 order of angular quadrature.

Energy- and space-dependent core power distributions as well as system operating temperatures are treated on a fuel-cycle-specific basis. The spatial variation of the neutron source is obtained from a burnup-weighted average of the respective power distributions from individual fuel cycles including pinwise gradients for all fuel assemblies located on the periphery of the core. The energy distribution of the source is determined on a fuel-assembly-specific basis and includes the effects of fissioning in both uranium and plutonium isotopes.

The results of the transport calculations are validated on a plant-specific basis by comparison with the results of surveillance capsule dosimetry developed using the procedures described in Section 5.3.1.6.2. These comparisons are used to demonstrate that the plant-specific application is consistent with the uncertainty evaluations provided in Reference 25 and to establish that the 20% uncertainty criterion listed in Regulatory Guide 1.190 is met. These comparisons are not used to modify or bias the results of the transport calculations.

In recognition of the crucial role played by reactor physics computations, ASTM Standard Practice E853 "Analysis and Interpretation of Light-Water Reactor Surveillance Results" requires that the transport methodology used in the performance of these calculations be benchmarked and qualified for application to LWR configurations. These benchmarking and qualification studies are generally based on a series of calculation/measurement comparisons for reactor configurations exhibiting increased levels of complexity. Examples of facilities available for these studies are the PCA benchmark facility, the VENUS benchmark facility, and power reactor surveillance capsule and cavity dosimetry data bases.

The PCA (Pool Critical Assembly) experiments documented in References 20, 21 and 22 provide a well characterized, clean geometry benchmark against which neutron transport techniques may be tested. The nature of the PCA configuration permits the benchmarking of basic discrete ordinates modeling techniques and neutron transport cross sections in a water/steel environment similar to that observed within a light water power reactor.

The VENUS experiments described in Reference 25 also qualify as a controlled benchmark. However, in contrast to the slab geometry of the PCA, the VENUS core consists of pin-type fuel assemblies arrayed in a fashion designed to simulate the irregular shape of an LWR core. In addition, the VENUS mockup includes cylindrical stainless steel components external to the core. Thus, along with the test of basic nuclear data, comparisons of calculations and measurements for the VENUS facility provide the additional benefit of a verification of the R,Θ modeling approach used in LWR analyses.

Final verification of the analytical approach used in neutron exposure evaluations occurs via direct comparison with measurements obtained from power reactor surveillance capsule and reactor cavity dosimetry data bases. These comparisons define the effects of long-term irradiations with multiple core power distributions as well as provide insight into biases and uncertainties that may exist due to construction and operational variables characteristic of a commercial plant.

The validation of the transport calculational methodology used in support of the measurement uncertainty recapture uprate program for Catawba Unit 1 is provided in WCAP-16083-A (Reference 25).

5.3.1.7 Reactor Vessel Fasteners

The reactor vessel closure studs, nuts, and washers are designed and fabricated in accordance with the requirements of the ASME Code Section III. The closure stud bolting material is SA540, Class 3, grades B23 and B24. (Section 5.3.1.7 documents the originally supplied reactor vessel closure studs, nuts and washers. See Section 5.3.1.7.1 for alternative reactor vessel closure nuts and washers.)

The bolting material qualification tests meet the requirements of the ASME Code Section III in effect at the time of material procurement; this material was procured prior to issuance of Regulatory Guide 1.65, Revision 1. The closure studs, nuts, and washers material properties are given in Table 5-16 and Table 5-17 for Units 1 and 2, respectively. All bars and tubes tested on Units 1 and 2 meet the measured yield strength criterion of Regulatory Guide 1.65, Revision 1, which states that the measured yield strength should not exceed 150 ksi. For the bars showing 10°F impact data less than 45 ft-lbs and 25 mils lateral expansion, the intent of the Regulatory Guide is satisfied since sufficient fracture toughness is expected at the specified preload temperature or at the lowest service temperature, both of which are significantly above the 10°F Charpy test temperature.

The non-destructive examinations are performed in accordance with the ASME Code Section III. The procedure for ultrasonic examination of the bolting material requires that:

1. The 100% examination is conducted after heat treatment and prior to threading.
2. The material is scanned in both the radial and axial directions.
3. The calibration for the radial examination is based on a standard back reflection established in an indication-free area of each stud.
4. The calibration for the axial scan is based on a distance corrected reference level established on the responses from 3/8 in. diameter flat bottomed holes in a representative calibration block.
5. For radial testing, material containing discontinuities that produce an indication exceeding 20% of the calibration back reflection amplitude, or that cause a 50% or greater loss in back reflection is unacceptable. For axial testing, material containing a discontinuity or discontinuities producing an indication or indications, equal to or greater than the primary DAC reference line is unacceptable.

Magnetic particle testing of the studs and nuts is performed after heat treatment and threading.

The Inservice Inspection (ISI) examinations of reactor pressure vessel bolting (i.e., closure head studs, nuts, washers, etc.) are performed in accordance with ASME Section XI. Volumetric examination of bolting is performed in accordance with ASME Section XI, Mandatory Appendix VIII, Supplement 8.

Compliance with Regulatory Guide 1.65, Revision 1 is further discussed below.

<u>Regulatory Guide 1.65</u>

Materials and Inspections for Reactor Vessel Closure Studs (Revision 1, 4/2010).

<u>Discussion</u>

The reactor vessel closure studs, nuts, and washers meet the material guidance of NRC Regulatory Guide 1.65, Revision 1, Section C (excerpted below with Duke's position).

C. REGULATORY POSITION

1) Bolting Materials

a) In accordance with Section III of the ASME BPV Code, as incorporated by reference into 10 CFR 50.55a, "Codes and Standards," reactor vessel closure stud bolting must be fabricated from materials that have adequate toughness throughout the life cycle of the reactor. The staff's position is that applicants can meet the applicable requirements by following this guidance to ensure that reactor vessel closure stud bolting is designed and tested in an appropriate manner:

i) The measured yield strength of the stud bolting material should not exceed 1,034 MPa (150 ksi).

Duke Position: The materials used to fabricate the reactor pressure fasteners do not exceed 150 ksi yield strength as confirmed by the material certifications.

ii) Stud bolting should not be metal-plated unless it has been demonstrated that the plating will not degrade the quality of the stud in any significant way (e.g., corrosion and hydrogen embrittlement) or reduce the quality of results attainable by the various required inspection procedures. The stud bolting may have a manganese phosphate (or other acceptable) surface treatment. Lubricants for the stud bolting are permissible, provided that they are stable at operating temperatures and are compatible with the bolting and vessel materials and with the surrounding environment.

Duke Position: The reactor vessel closure stud bolting are not metal-plated. However, additional protection against the possibility of incurring corrosion effects is assured by the use of a manganese base phosphate surface treatment.

2) Protection against Corrosion

a) As provided in Section 3.13 of NUREG-0800, lubricants with deliberately added halogens, sulfur, or lead should not be used for any reactor coolant pressure boundary components or other components in contact with reactor water. Lubricants containing molybdenum sulfide (disulfide or polysulfide) should not be used for any safety-related applications. Fasteners should not be plated with low melting point materials such as zinc, tin, cadmium, etc.

Duke Position: The reactor vessel closure stud bolting does not come with the above prohibited lubricants. The reactor vessel closure stud bolting is not plated with low melting point materials.

b) During the venting and filling of the pressure vessel and while the head is removed, the stud bolts and stud bolt holes in the vessel flange should be adequately protected from corrosion and contamination.

Duke Position: The design of the reactor vessel closure studs, nuts, and washers allows them to be completely removed during each refueling permitting visual and non-destructive inspection in parallel with refueling operations to assess protection against corrosion. Refueling procedures require that each stud be removed, inspected, and placed in a rack. After the studs are removed, the stud holes in the vessel flange are sealed with a special plug. The studs are lifted and moved to a storage area before the water level is raised in the refueling cavity. Thus, the bolting materials and stud holes should not be exposed to the borated refueling cavity water. Additional protection against the possibility of incurring corrosion effects is assured by the use of a manganese base phosphate surfacing treatment.

5.3.1.7.1 Reactor Vessel Closure Nuts and Washers

Engineering Change EC104610 allows the option of using alternative reactor vessel closure nuts and washers. The approved nuts and washers are the HydraNuts® provided by Nova Machine Products Inc. of Curtiss Wright Flow Control Company. The nuts can be used with the existing reactor vessel closure studs.

These alternatives nuts and washers are designed and fabricated in accordance with the requirements of the ASME Code Section III. The nut and washer load bearing material is the same as the existing closure stud bolting material, SA540, Class 3, grade B24.

Nova Machine Products follows the recommendations of Regulatory Guide 1.65, Revision 1 as discuss below:

<u>Regulatory Guide 1.65</u>

Materials and Inspections for Reactor Vessel Closure Studs (Revision 1, 4/2010).

<u>Discussion</u>

The HydraNuts meet the material guidance given in NRC Regulatory Guide 1.65, Revision 1, Section C (excerpted below with Nova's position).

C. REGULATORY POSITION

1. Bolting Materials
   a. In accordance with Section III of the ASME BPV Code, as incorporated by reference into 10 CFR 50.55a, "Codes and Standards," reactor vessel closure stud bolting must be fabricated from materials that have adequate toughness throughout the life cycle of the reactor. The staff's position is that applicants can meet the applicable requirements by following this guidance to ensure that reactor vessel closure stud bolting is designed and tested in an appropriate manner:
      i. The measured yield strength of the stud bolting material should not exceed 1,034 MPa (150 ksi).

         Nova Position: The materials used to fabricate the HydraNuts do not exceed 150ksi as confirmed by the material certifications shipped with the HydraNuts.
      ii. Stud bolting should not be metal-plated unless it has been demonstrated that the plating will not degrade the quality of the stud in any significant way (e.g., corrosion and hydrogen embrittlement) or reduce the quality of results attainable by the various required inspection procedures. The stud bolting may have a manganese phosphate (or other acceptable) surface treatment. Lubricants for the stud bolting are permissible, provided that they are stable at operating temperatures and are compatible with the bolting and vessel materials and with the surrounding environment.

          Nova Position: The components of HydraNuts are not metal-plated. The nut body, lockring and washer have a manganese phosphate surface treatment, for corrosion protection. The top and bottom cell and rams are nitrided which is an acceptable surface treatment for the purpose of strengthening the seal wear surface, as well as providing corrosion protection. No additional lubricants are used. The UCONALL 220 hydraulic fluid is analyzed to be compatible with the bolting and vessel materials and with the surrounding environment (reference Duke Energy Analytical Laboratory Order J10110297, Power Chemistry Material Guide (PCMG) #1221 Category I lubricant).

2. Protection against Corrosion

    a. As provided in Section 3.13 of NUREG-0800, lubricants with deliberately added halogens, sulfur, or lead should not be used for any reactor coolant pressure boundary components or other components in contact with reactor water. Lubricants containing molybdenum sulfide (disulfide or polysulfide) should not be used for any safety-related applications. Fasteners should not be plated with low melting point materials such as zinc, tin, cadmium, etc.

        Nova Position: The HydraNuts do not come with the above prohibited lubricants. The components of the HydraNuts are not plated with low melting point materials.

    b. During the venting and filling of the pressure vessel and while the head is removed, the stud bolts and stud bolt holes in the vessel flange should be adequately protected from corrosion and contamination.

        Nova Position: Nova concurs that Catawba Nuclear Station needs to take the suggested measures.

5.3.2 Pressure - Temperature Limits

Pressure – Temperature Limits for License Renewal

Appendix G of 10 CFR Part 50 requires heatup and cooldown of the reactor pressure vessel be accomplished within established pressure-temperature limits. These limits are established by calculations that utilize the materials and fluence data obtained through the unit specific reactor surveillance capsule program. Normally, the pressure-temperature limits are calculated for several years into the future and remain valid for an established period of time not to exceed the current operating license expiration. For Catawba Unit 1 and Unit 2, the heatup and cooldown limit curves for normal operation at 30.7 and 34 EFPY, respectively, provide a predicted operating window that is sufficient to conduct heatups and cooldowns. Prior to their expiration, the current Catawba heatup and cooldown limit curves must be replaced by curves that are valid during the period of extended operation.

5.3.2.1 Limit Curves

Startup and shutdown operating limitations are based on the properties of the core region materials of the reactor pressure vessel (Reference 3). Actual material property test data is used. The methods outlined in Appendix G to Section XI of the ASME Code, as modified by ASME Code Case N-640 which allows the use of an alernate reference fracture toughness curve (K_{IC}), are employed for the shell regions in the analysis of protection against non-ductile failure. The initial operating curves are calculated assuming a period of reactor operation such that the beltline material will be limiting. The heatup and cooldown curves are given in the Technical Specifications. Beltline material properties degrade with radiation exposure, and this degradation is measured in terms of the adjusted reference nil-ductility temperature (RT_{NDT}) which includes a radiation induced reference nil-ductility temperature shift (ΔRT_{NDT}).

Predicated ΔRT_{NDT} values are derived using the method outlined in Regulatory Guide 1.99 Revision 2 "Radiation Embrittlement of Reactor Vessel Materials". The operating curves are calculated using the most limiting value of RT_{NDT} for the reactor vessel at the 1/4 T (thickness of the vessel at the beltline region) and 3/4 T locations. The most limiting RT_{NDT} of the material in the core region of the reactor vessel is determined by using the preservice (unirradiated or initial) reactor vessel material adjusted reference temperature (IRT_{NDT}), estimating the radiation-induced shift (ΔRT_{NDT}), and applying an appropriate margin for uncertainties. The IRT_{NDT} is designated as the higher of either the drop weight nil-ductility transition temperature (NDDT) or the temperature at which the material exhibits at least 50 ft-lb of impact energy and 35-mil lateral expansion (normal to the major working direction) minus 60°F.

The operating curves including pressure-temperature limitations are calculated in accordance with I0 CFR Part 50, Appendix G and ASME Code Section XI, Appendix G, requirements, as modified by ASME Code Case N-640. Code Case N-640 allows an alternative expresion for reference fracture toughness – K_{Ic} which bounds the static stress intensity conditions necessary for crack initiation as opposed to K_{Ia} which bounds the conditions representative of crack arrest under dynamic conditions. Operating curves out to 34 EFPY were originally developed for both CNS Unit 1 (Reference 14) and Unit 2 (Reference 15). Both units are base metal limited with regard to plant heatup and cooldown limitations. An applicability evaluation has been performed in WCAP-17669 (Reference 31) using updated Measurement Uncertainty Recapture (MUR) power uprate fluence and materials data. The applicability evaluation concludes that the heatup and cooldown curves are applicable to 30.7 EFPY for Catawba Unit 1. The limiting materials for the Unit 1 reactor vessel are the upper shell ring forging 06 with an ART of 42°F at the ¼ T location, and the immediate shell ring forging 05 (using credible surveillance data) and bottom head ring foring 03, with an ART of 31°F at the ¾ T location. The limiting material for the Unit 2 reactor vessel is the intermediate shell plate B8605-2; this material has the ARTs of 121°F and 106°F for the ¼ T and ¾ T locations, respectively. Changes in fracture toughness of the core region plates or forgings, weldments and associated heat affected zones due to radiation damage will be monitored by a surveillance program which conforms with ASTM E-185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels" and 10CFR Part 50, Appendix H. The evaluation of the radiation damage in this surveillance program is based on pre-irradiation testing of Charpy V-notch and tensile specimens and post-irradiation testing of Charpy V-notch, and tensile specimens. The post-irradiation testing will be carried out during the lifetime of the reactor vessel. Specimens are irradiated in capsules located near the core midheight and are removed from the vessel at specified intervals. After all specimens have been removed before operating license expiration, the collected data can still be used in conjunction with the Ex-Vessel Neutron Measurement Program to allow the projection of embrittlement gradients through the reactor vessel wall.

Compliance with Regulatory Guide I.99 "Radiation Embrittlement of Reactor Vessel Materials" is discussed in Section 1.7.

Deleted per 2004 update.

5.3.2.2 Operating Procedures

The transient conditions that are considered in the design of the reactor vessel are presented in Section 3.9.1.1. These transients are representative of the operating conditions that are postulated to occur during plant operation. The transients selected form a conservative basis for evaluation of the RCS to insure the integrity of the RCS equipment.

Those transients listed as upset condition transients are listed in Table 3-50. None of these transients will result in pressure-temperature changes which exceed the heatup and cooldown limitations as described in Section 5.3.2.1 and in the Technical Specifications.

5.3.3 Reactor Vessel Integrity

Pressurized Thermal Shock Evaluation for License Renewal

The requirements of 10 CFR 50.61 are designed to protect against pressurized themal shock transients in pressurized-water reactors. The screening criterion established by §50.61 is 270ºF for plates, forgings, and axial welds, and 300ºF for circumferential welds. According to this regulation, if the calculated RT_{PTS} for the limiting reactor beltline materials is less than the specified screening criterion, then the vessel is acceptable with regard to the risk of vessel failure during postulated pressurized thermal shock transients. Plant classification with regard to PTS risk and recommended operator actions under PTS conditions are provided in the Emergency Response Guidelines. The regulations require updating of the pressurized thermal shock assessment upon a request for a change in the expiration date of the facility operating license. The RT_{PTS} calculations are time-limited aging analyses because all six of the criteria contained in 10 CFR §54.3 are met. The RT_{PTS} values have been projected to the end of the period of extended operation using the methods provided in §50.61.

The reactor vessels for Catawba Nuclear Station were constructed from materials having a low copper content making them less sensitive to radiation induced embritlement. The predicted values for the EOLE RT_{PTS} for the Catawba vessels are more than 100°F below the PTS criterion required by §50.61 (Reference 13). The RT_{PTS} results for all beltline materials are presented in Table 5-42 for Catawba Unit 1 and in Table 5-43 for Catawba Unit 2. The upper shell forging 06 material is most limiting for Catawba Unit 1 with a 54 EFPY PTS value of 63°F. The intermediate shell plate B8605-2 is the most limiting material for Catawba Unit 2 with a 54 EFPY PTS value of 133°F. For the above reasons, pressurized thermal shock events are not expected to be a problem for the Catawba reactor vessels.

Upper Shelf Energy Evaluation for License Renewal

Appendix G of 10 CFR Part 50 requires that reactor vessel beltline materials must have an initial Charpy Upper Shelf Energy (USE) of no less than 75 ft-lb and must maintain a Charpy USE of no less than 50 ft-lb throughout the life of the reactor vessel, unless it is demonstrated, in a manner approved by the Director, Office of Nuclear Reactor Regulation (NRR), that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. The USE calculations are time-limited aging analyses because all six of the criteria contained in 10 CFR 54.3 are met. The USE analyses for each vessel have been projected to the end of the period of extended operation using the guidance provided in Regulatory Guide 1.99, Revision 2, *Radiation Embrittlement of Reactor Vessel Materials.*

The USE values for Catawba Units 1 and 2 reactor vessel beltline materials at 54 EFPY are presented in Table 5-44 for Catawba Unit 1 and Table 5-45 for Catawba Unit 2. All of the beltline materials in the Catawba reactor vessels have USE above the 50 ft-lb limit. The bottom head ring 03 material is the most limiting material for Catawba Unit 1 with a 54 EFPY USE value of 60 ft-lbs. The bounding nozzle shell material is the most limiting material for Catawba Unit 2 with a 54 EFPY USE value of 58.5 ft-lbs.

5.3.3.1 Design

The reactor vessel for Unit I was fabricated by DeRotterdame Drodgdak Mattschappu N.V. (The Rotterdam Dockyard Company) and the reactor vessel for Unit 2 was fabricated by Combustion Engineering. Both vessels are cylindrical with a welded hemispherical bottom head and a removable, bolted flanged and gasketed, hemispherical upper head (See Figure 5-9). The reactor vessel closure region is sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leakoff connections: one between the inner and outer ring and one outside the outer O-ring. The vessel contains the core, core support structures, control rods, and other parts directly associated with the core. The reactor vessel closure head contains CRDM head adaptors (See Figure 5-10). These head adaptors are tubular members, attached by partial penetration welds to the underside of the closure head for the CRDM head adaptors (see Figure

5-11). The upper end of these adaptors contain acme threads for the assembly of control rod drive mechanisms and instrumentation adaptors. The seal arrangement at the upper end of these adaptors consists of a welded flexible canopy seal. Inlet and outlet nozzles are spaced evenly around the vessel. Outlet nozzles are located on the vessel to facilitate optimum layout of the Reactor Coolant System equipment. The inlet nozzles are tapered from the coolant loop vessel interfaces to the vessel inside wall to reduce loop pressure drop.

The bottom head of the vessel contains penetration nozzles for connection and entry of the nuclear in-core instrumentation. Each nozzle consists of a tubular member made of an Inconel tube. Each tube is attached to the inside of the bottom head by a partial penetration weld.

Internal surfaces of the vessel which are in contact with primary coolant are weld overlay with 0.125 inch minimum of stainless steel or Inconel. The exterior of the reactor vessel is insulated with canned stainless steel reflective sheets. The insulation is a minimum of three inches thick and contoured to enclose the top, sides and bottom of the vessel. Provisions are made for the removability of the insulation covering the closure and bottom heads to allow access for inservice inspection; access to the vessel side insulation is limited by the surrounding concrete.

The reactor vessel is designed and fabricated in accordance with the appropriate requirements of the ASME Code Section III.

Principal design parameters of the reactor vessel are given in Table 5-18. The chemical composition of the materials in the reactor vessel beltline region are given in Table 5-19 and Table 5-20.

Deleted per 2004 update.

The reactor vessel materials surveillance program is adequate to accommodate the annealing of the reactor vessel. Sufficient specimens are available to evaluate the effects of the annealing treatment.

Cyclic loads are introduced by normal power changes, reactor trip, startup and shutdown operations. These design base cycles are selected for fatigue evaluation and constitute a conservative design envelope for the projected plant life. Vessel analyses result in a usage factor that is less than 1.

The design specifications require analysis to prove that the vessel is in compliance with the fatigue and stress limits of ASME III and XI as applicable. The loadings and transients specified for the analysis are based on more severe conditions than those expected during service. The heatup and cooldown rates imposed by plant operating limits are 50°F per hour and 80°F per hour, respectively, for normal operations. The heatup and cooldown rate limits are 60°F per hour and 100°F per hour, respectively, for abnormal or emergency conditions. The rate of 100°F per hour is reflected in the vessel design specifications as a normal condition for conservatism for both heatup and cooldown.

5.3.3.2 Materials of Construction

The materials used in the fabrication of the reactor vessel are discussed in Section 5.2.3.

5.3.3.3 Fabrication Methods

The fabrication methods used in the construction of the reactor vessel are discussed in Section 5.3.1.2.

5.3.3.4 Inspection Requirements

The nondestructive examinations performed on the reactor are described in Section 5.3.1.3.

5.3.3.5 Shipment and Installation

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

The reactor vessel is shipped in a horizontal position on a shipping sled. All vessel openings are sealed to prevent the entrance of moisture and an adequate quantity of desiccant bags is placed inside the vessel. These are usually placed in a wire mesh basket attached to the vessel cover. All carbon steel surfaces are painted with a heat-resistant paint before shipment except for the vessel support surfaces and the top surface of the external seal ring.

The closure head is also shipped with a shipping cover and skid. An enclosure attached to the ventilation shroud support ring protects the control rod mechanism housings. All head openings are sealed to prevent the entrance of moisture. All carbon steel surfaces are painted with heat-resistant paint before shipment.

5.3.3.6 Operating Conditions

Operating limitations for the reactor vessel are presented in Section 5.3.2, as well as in the Technical Specifications.

In addition to the analysis of primary components discussed in Section 3.9.1.4, the reactor vessel is further evaluated to ensure against unstable crack growth under faulted conditions. Actuation of the Emergency Core Cooling System (ECCS) following a loss of coolant accident produces relatively high thermal stresses in regions of the reactor vessel, which come into contact with ECCS water. Primary consideration is given to these areas, including the reactor vessel beltline region and the reactor vessel primary coolant nozzle, to ensure the integrity of the reactor vessel under this severe postulated transient.

The principles and procedures of linear elastic fracture mechanics (LEFM) are used to evaluate thermal effects in the regions of interest. The LEFM approach to the design against failure is basically a stress intensity consideration in which criteria are established for fracture instability in the presence of a crack. Consequently, a basic assumption employed in LEFM is that a crack or crack-like defect exists in the structure. The essence of the approach is to relate the stress field developed in the vicinity of the crack top to the applied stress on the structure, the material properties, and the size of defect necessary to cause failure.

The elastic stress field at the crack-tip in any cracked body can be described by a single parameter designated as the stress intensity factor, K. The magnitude of the stress intensity factor K is a function of the geometry of the body containing the crack, the size and location of the crack, and the magnitude and distribution of the stress.

The criterion for failure in the presence of a crack is that failure will occur whenever the stress intensity factor exceeds some critical value. For the opening mode of loading (stresses perpendicular to the major plane of the crack) the stress intensity factor is designated as K_I and the critical stress intensity factor is designated K_{IC}. Commonly called the fracture toughness, K_{IC} is an inherent material property which is a function of temperature and strain rate. Any combination of applied load, structural configuration, crack geometry and size which yields a stress intensity factor K_{IC} for the material will result in crack instability.

The criterion of the applicability of LEFM is based on plasticity considerations at the postulated crack tip. Strict applicability (as defined by ASTM) of LEFM to large structures where plan strain conditions prevail requires that the plastic zone developed at the tip of the crack does not exceed 2.25 percent of the crack depth. In the present analysis, the plastic zone at the tip of the postulated crack can reach 20 percent of the crack depth. However, LEFM has been successfuly used quite often to provide conservative brittle fracture prevention evaluations, even in cases where strict applicability of the theory is not permitted due to excessive plasticity. Recently, experimental results from Heavy Section Steel Technology (HSST) Program intermediate pressure vessel tests, have shown that LEFM can be applied conservatively as long as the pressure component of the stress does not exceed the yield strength of the material. The addition of the thermal stresses, calculated elastically, which results in total stresses in excess of the yield strength does not affect the conservatism of the results, provided that these thermal stresses are included in the evaluation of the stress intensity factors. Therefore, for faulted condition analyses, LEFM is considered applicable for the evaluation of the vessel inlet nozzle and beltline region.

In addition, it has been well established that the crack propagation of existing flaws in a structure subjected to cyclic loading can be defined in terms of fracture mechanics parameters. Thus, the principles of LEFM are also applicable to fatigue growth of a postulated flaw at the vessel inlet nozzle and beltline region.

An example of a Faulted Condition evaluation carried out according to the procedure discussed above is given in Reference 4. This report discusses the evaluation procedure in detail as applied to a severe faulted condition (a postulated loss of coolant accident), and concludes that the integrity of the reactor coolant pressure boundary would be maintained in the event of such an accident.

5.3.3.7 Inservice Surveillance

The internal surface of the reactor vessel is capable of inspection periodically using visual and/or nondestructive techniques over the accessible areas. During refueling, the vessel cladding is capable of being inspected in certain areas between the closure flange and the primary coolant inlet nozzles, and, if deemed necessary, the core barrel is capable of being removed, making the entire inside vessel surface accessible.

The closure head is examined visually during each refueling. Optical devices permit a selected inspection of the cladding, control rod drive mechanism housings, and the gasket seating surface. The knuckle transition piece, which is the area of highest stress of the closure head, is accessible on the outer surface for visual inspection, dye penetrant or magnetic particle, and ultrasonic testing. The closure studs can be inspected periodically using visual, magnetic particle and/or ultrasonic techniques.

The closure studs, nuts, washers, and the vessel flange seal surface, as well as the full penetration welds in the following areas of the installed irradiated reactor vessel, are available for visual and/or non-destructive inspection:

1. Vessel shell - from inside surface.
2. Primary coolant nozzles - from the inside surface.
3. Closure head - from the inside and outside surfaces. Bottom head - from the outside surfaces.
4. Field welds between the reactor vessel nozzles and the main coolant piping.

The design considerations which have been incorporated into the system design to permit the above inspection are as follows:

1. All reactor internals are completely removable. The tools and storage space required to permit these inspections are provided.
2. The closure head is stored dry on the reactor operating deck during refueling to facilitate direct visual inspection.
3. All reactor vessel studs, nut and washers can be removed to dry storage during refueling.
4. Removable plugs are provided in the primary shield. The insulation covering the nozzle to pipe welds may be removed.

The reactor vessel presents access problems because of the radiation levels and remote underwater accessibility to this component. Because of these limitations on access to the reactor vessel, several steps have been incorporated into the design and manufacturing procedures in preparation for the periodic non-destructive tests which are required by the ASME inservice inspection code. These are:

1. Shop ultrasonic examinations are performed on all internally clad surfaces to an acceptance and repair standard to assure an adequate cladding bond to allow later ultrasonic testing of the base metal from inside surface. The size of cladding bonding defect allowed is l/4 inch by 3/4 inch.
2. The design of the reactor vessel shell is a clean, uncluttered cylindrical surface to permit future position of the test equipment without obstruction.
3. The weld deposited clad surface on both sides of the welds to be inspected is specifically prepared to assure meaningful ultrasonic examinations.
4. During fabrication, all full penetration ferritic pressure boundary welds are ultrasonically examined in addition to Code examinations.
5. After the shop hydrostatic testing, all full penetration ferritic pressure boundary welds are ultrasonically examined in addition to ASME Code Section III requirements.

The vessel design and construction enables inspection in accordance with ASME Section XI.

5.3.3.8 Deleted Per 2004 Update

5.3.4 References

1. (deleted)

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

2. *Soltesz, R. G., et al, "Nuclear Rocket Shielding Methods, Modification, Updating, and Input Data Preparation, Volume 5 - Two-Dimensional Discrete Ordinates Technique," WANL-PR-(LL)-034, August, l970.*
3. W.H. Bamford, et al, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves”, *WCAP-14040*, Revision 3, April 2002.

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

4. *Buchalet, C. and Mager, T. R., "A Summary Analysis of the April 30 Incident at the San Onofre Nuclear Generating Station Unit I", WCAP-8099, April l973.*
5. *Meyer, T. A., "Summary Report on Reactor Vessel Integrity for Westinghouse Operating Plants," WCAP-10019, December 1981.*

6. *WCAP-9734*, "Duke Power Company Catawba Unit No. 1 Reactor Vessel Radiation Surveillance Program", S. E. Yanichko, July 1980.

7. Rotterdam Dockyard Company Material Certification Report Order No. 743-04-004, May 29, 1973.

8. Rotterdam Dockyard Company Material Certification Report Order No. 743-05-004, May 29, 1973.

9. *WCAP-10868*, "Duke Power Company Unit No. 2 Reactor Vessel Radiation Surveillance Program", L. R. Singer, November 1985.

10. Letter to All Holders of Operating Licenses from the US Nuclear Regulatory Commission dated March 6, 1992, titled "Reactor Vessel Structural Integrity, 10CFR50.54(f), (Generic Letter 92-01, Revision 1)."

11. Letter to the US Nuclear Regulatory Commission from H.B. Tucker dated July 3, 1992, titled "Response to Generic Letter 92-01, Revision 1, Reactor Vessel Structural Integrity."

12. Letter to W.R. McCollum from the US Nuclear Regulatory Commission dated July 29, 1996, titled "Catawba Nuclear Station - Close-out for Response to Generic Letter 92-01, Revision 1, Supplement 1 (TAC NOS. M92659 and M92660)."

13. WCAP-15449, Revision 1, “Evaluation of Pressurized Thermal Shock for Catawba and McGuire Units 1 & 2 @ 54 EFPY”, T. J. Laubham, October 2002.

14. WCAP-15203, Revision 1, “Catawba Unit 1 Heatup and Cooldown Curves for Normal Operation Using Code Case N-640”, J. H. Ledger, April 2001.

15. WCAP-15285, “Catawba Unit 2 Heatup and Cooldown Curves for Normal Operation Using Code Case N-640”, T. J. Laubham, October 1999.

16. Letter to G.R. Peterson from P.S. Tam (US Nuclear Regulatory Commission) dated June 24, 1999, titled "Catawba Nuclear Station, Units 1 and 2 - Closure of the Review of Response to Generic Letter 92-01, Revision 1, Supplement 1, "Reactor Vessel Structural Integrity" (TAC Nos. MA0534 and MA0535).

17. USE and RT_{PTS} Values for Reactor Vessel Nozzle Region Locations, CNC-1201.01-00-0020.

18. Letter to Steve Adams from Curtiss Wright Flow Control Company subsidiary Nova Machine Products Inc. dated November 9, 2012, titled "Catawba Unit 1 HydraNuts compliance with NRC Reg. Guide 1.65, Rev 1" filed in CNM 1201.01-1252.001.

19. Letter to Steve Adams from Curtiss Wright Flow Control Company subsidiary Nova Machine Products Inc. dated October 27, 2012, titled "Catawba Unit 2 HydraNuts compliance with NRC Reg. Guide 1.65, Rev 1" filed in CNM 1201.01-1252.001.

20. W. N. McElroy, et. al., "LWR Pressure Vessel Surveillance Dosimetry Improvement Program: PCA Experiments and Blind Test", NUREG/VR-1861, July 1981.

21. W. N. McElroy, et. al., "LWR Pressure Vessel Surveillance Dosimetry Improvement Program: PCA Experiments, Blind Test, and Physics-Dosimetry Support for the PSF Experiments", NUREG/CR-3318, September 1984.

22. W. N. McElroy, et. al., "LWR Pressure Vessel Surveillance Dosimetry Improvement Program: 1986 HEDL Summary Annual Report", NUREG/CR-4307, January 1987.

23. A. Fabry, et. al., "VENUS PWR Engineering Mockup: Core Qualification, Neutron and Gamma Field Characterization", published in the Proceedings of the Fifth ASTM-EURATOM

Symposium on Reactor Dosimetry, GKSS Research Center, Geesthacht, F.R.G., September 24-28, 1984.

24. Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," U. S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001.
25. Anderson, S. L., Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Dosimetry," WCAP-16083-A, Revision 0, May 2006.
26. Fischer, G. A, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Dosimetry," WCAP-16083-NP, Revision 1, April 2013.
27. RSICC Peripheral Shielding Routine PSR-145, "FERRET: Least-Squares Solution to Nuclear Data and Reactor Physics Problems," Radiation Safety Information Computational Center, March 1984.
28. RSICC Data Library Collection DLC-178, "SNLRML Recommended Dosimetry Cross-Section Compendium," Radiation Safety Information Computational Center, Oak Ridge National Laboratory, July 1994.
29. RSICC Computer Code Collection CCC-650, "DOORS 3.2: One, Two- and Three-Dimensional Discrete Ordinates Neutron/Photon Transport Code System," Radiation Safety Information Computational Center, April 1998.
30. RSICC Data Library Collection DLC-185, "BUGLE-96: Coupled 47 Neutron, 20 Gamma-Ray Group Cross Section Library Derived from ENDF/B-VI for LWR Shielding and Pressure Vessel Dosimetry Applications," Radiation Safety Information Computational Center, Oak Ridge National Laboratory, July 1999.
31. WCAP-17669-NP, Revision 0, "Catawba Unit 1 Measurement Uncertainty Recapture (MUR) Uprate: Reactor Vessel Integrity and Nuetron Fluence Evaluations," June 2013. (CNC-1210-06-00-0006)

THIS IS THE LAST PAGE OF THE TEXT SECTION 5.3.

5.4 Component and Subsystem Design

5.4.1 Reactor Coolant Pumps

5.4.1.1 Design Bases

The reactor coolant pump ensures an adequate core cooling flow rate for sufficient heat transfer to maintain a Departure from Nucleate Boiling Ratio (DNBR) greater than the limiting value specified in Section 4.4.2.1 within the parameters of operation. The required net positive suction head is, by conservative pump design, always less than that available by system design and operation.

Sufficient pump rotation inertia is provided by a flywheel, in conjunction with the impeller and motor assembly, to provide adequate flow during coast-down. This forced flow following an assumed loss of pump power and the subsequent natural circulation effect provides the core with adequate cooling.

The reactor coolant pump motor is tested, without mechanical damage, at over-speeds up to and including 125 percent of normal speed. The integrity of the flywheel during a LOCA is demonstrated in Reference 1 which is undergoing generic review by the Staff.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

Steam/water tests planned jointly by Westinghouse, Framatone, and the French Atomic Energy Commission (CEA) are described in Section 1.5. The ultimate use of the data from these tests will be to develop an empirical two phase flow pump performance model. It is expected that this new model will confirm that the present pump model conservatively predicts performance in all LOCA conditions and thus increases the safety margin available in ECCS and reactor coolant pump overspeed analyses.

The reactor coolant pump is shown in Figure 5-12. The reactor coolant pump design parameters are given in Table 5-23.

Code and material requirements are provided in Section 5.2.

5.4.1.2 Design Description

The reactor coolant pump is a vertical, single stage, centrifugal, shaft seal pump designed to pump large volumes of main coolant at high temperatures and pressures.

The pump consists of three areas from bottom to top. They are the hydraulics, the shaft seals, and the motor.

1. The hydraulic section consists of an impeller, diffuser-turning vane, casing thermal barrier, heat exchanger, radial bearing, main flange, motor stand, and pump shaft.
2. The shaft seal section consists of three devices. They are the number 1 controlled leakage, film riding face seal and the number 2 and number 3 rubbing face seals. These seals are contained within the main flange and seal housing.
3. The motor section consists of a vertical solid shaft, squirrel cage induction type motor, an oil lubricated double-acting Kingsbury type thrust bearing, two oil lubricated radial bearings, and a flywheel.

Attached to the bottom of the pump shaft is the impeller. The impeller rotation draws the reactor coolant up into the pump suction, through the diffuser turning vane region where the velocity head at the suction is transformed into the pressure head at the discharge, and then finally out from the pump discharge. Above the impeller is a thermal barrier heat exchanger which limits heat transfer between hot system water and seal injection water. Component cooling water is supplied to the thermal barrier heat exchanger.

High pressure seal injection water is introduced through a connection on the thermal barrier flange. A portion of this water flows through the seals; the remainder flows through the radial bearing and down the shaft through the thermal barrier where it acts as a buffer to prevent system water from entering the radial bearing and seal section of the unit. The thermal barrier heat exchanger provides a means of cooling system water to an acceptable level in the event that seal injection flow is lost. The water lubricated journal-type pump bearing, mounted above the thermal barrier heat exchanger, has a self-aligning spherical seat.

The reactor coolant pump motor bearings are of conventional design. The radial bearings are the segmented pad type, and the thrust bearings are pivoted pad Kingsbury bearings. All are oil lubricated. The lower radial bearing and the thrust bearings are submerged in oil, and the upper radial bearing is oil fed from an impeller integral with the thrust runner. Component cooling water is supplied to the two oil coolers on the pump motor.

The motor is a water/air cooled, Class F thermalastic epoxy insulated, squirrel cage induction motor. The rotor and stator are of standard construction and are cooled by air. Six resistance temperature detectors are imbedded in the stator windings to sense stator temperature. The top of the motor consists of a flywheel and an anti-reverse rotation device.

The internal parts of the motor are cooled by air. Integral vanes on each end of the rotor draw air in through cooling slots in the motor frame. This air passes through the motor with particular emphasis on the stator end turns. It is then routed to the external water/air heat exchangers, which are supplied with Nuclear Service Water. Each motor has two such coolers, mounted diametrically opposed to each other. In passing through the coolers the air is cooled to below 122°F so that minimum heat is rejected to the containment from the motors.

A removable shaft segment, the spool piece, is located between the motor coupling flange and the pump coupling flange; the spool piece allows removal of the pump seals with the motor in place. The pump internals, motor, and motor stand can be removed from the casing without disturbing the reactor coolant piping. The flywheel is available for inspection by removing the flywheel cover.

Each of the reactor coolant pumps is equipped for continuous monitoring of reactor coolant pump shaft and frame vibration levels. Shaft vibration is measured by two relative shaft probes mounted on top of the pump seal housing; the probes are located ninety degrees apart in the same horizontal plane and are mounted near the pump shaft. Frame vibration is measured by two velocity seismoprobes located ninety degrees apart in the same horizontal plane and mounted at the top of the motor support stand. Proximeters and converters linearize the probe output which is displayed on monitor meters in the control room. The monitor meters automatically indicate the highest output from the relative probes and seismoprobes; manual selection allows monitoring of individual probes. Indicator lights display caution and danger limits of vibration.

All parts of the pump in contact with the reactor coolant are austenitic stainless steel except for seals, bearings and special parts.

5.4.1.3 Design Evaluation

5.4.1.3.1 Pump Performance

The reactor coolant pumps are sized to deliver flow at rates which equal or exceed the required flow rates. Initial Reactor Coolant System tests confirm the total delivery capability. Thus, assurance of adequate forced circulation coolant flow is provided prior to initial plant operation.

The estimated performance characteristic is shown in Figure 5-13. The "knee" at about 62 percent design flow introduces no operational restrictions, since the pumps operate at full flow.

The Reactor Trip System ensures that pump operation is within the assumptions used for loss of coolant flow analyses.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

An extensive test program has been conducted for several years to develop the controlled leakage shaft seal for pressurized water reactor applications. Long term tests were conducted on less than full scale prototype seals as well as on full size seals. Operating plants continue to demonstrate the satisfactory performance of the controlled leakage shaft seal pump design.

The support of the stationary member of the number 1 seal ("seal ring") is such as to allow large deflections, both axial and tilting, while still maintaining its controlled gap relative to the seal runner. Even if all the graphite were removed from the pump bearing, the shaft could not deflect far enough to cause opening of the controlled leakage gap. The "spring-rate" of the hydraulic forces associated with the maintenance of the gap is high enough to ensure that the ring follows the runner under very rapid shaft deflections.

Testing of pumps with the number 1 seal entirely bypassed (full system pressure on the number 2 seal) shows that relatively small leakage rates would be maintained for a period of time which is sufficient to secure the pump. Even if the number 1 seal fails entirely during normal operation, the number 2 seal would maintain these small leakage rates if the proper action is taken by the operator. The operator is warned of number 1 seal damage by the increase in number 1 seal leakoff. Following warning of excessive seal leakage conditions, the operator should close the number 1 seal leakoff line and secure the pump, as specified in the instruction manual. Gross leakage from the pump does not occur if the proper operator action is taken subsequent to warning of excessive seal leakage conditions.

The effect of loss of offsite power on the pump itself is to cause a temporary stoppage in the supply of injection flow to the pump seals and also of the cooling water for seal and bearing cooling. The emergency diesel generators are started automatically due to loss of offsite power so that component cooling flow is automatically restored; seal injection flow is subsequently restored.

5.4.1.3.2 Coastdown Capability

It is important to reactor protection that the reactor coolant continues to flow for a short time after reactor trip. In order to provide this flow in a station blackout condition, each reactor coolant pump is provided with a fly-wheel. Thus, the rotating inertia of the pump, motor and flywheel is employed during the coastdown period to continue the reactor coolant flow. The coastdown flow transients are provided in the figures in Section 15.3. The pump/motor system is designed for the safe shutdown earthquake at the site. Hence, it is concluded that the coastdown capability of the pumps is maintained even under the most adverse case of a blackout coincident with the safe shutdown earthquake. Core flow transients and figures are provided in Sections 15.2.5 and 15.2.4.

5.4.1.3.3 Bearing Integrity

The design requirements for the reactor coolant pump bearings are primarily aimed at ensuring a long life with negligible wear, so as to give accurate alignment and smooth operation over long periods of time. The surface-bearing stresses are held at a very low value, and even under the most severe seismic transients do not begin to approach loads which cannot be adequately carried for short periods of time.

Because there are no established criteria for short time stress-related failures in such bearings, it is not possible to make a meaningful quantification of such parameters as margins to failure, safety factors, etc. A qualitative analysis of the bearing design, embodying such considerations, gives assurance of the adequacy of the bearing to operate without failure.

Low (and high) oil level alarms are provided for both motor bearings. Embedded temperature detectors are monitored in one shoe of each radial bearing and in both the lower and upper thrust bearings. A high temperature alarm is set with margin to the high-high temperature alarm which is used to direct a pump shutdown. Even if a bearing proceeded to failure, low melting point of Babbitt metal on the pad surfaces ensures that sudden seizure of the shaft will not occur.

5.4.1.3.4 Locked Rotor

It may be hypothesized that the pump impeller might severly rub on a stationary member and then seize. Analysis has shown that under such conditions, assuming instantaneous seizure of the impeller, the pump shaft fails in torsion just below the coupling to the motor, disengaging the flywheel and motor from the shaft. This constitutes a loss of coolant flow in the loop. Following such a postulated seizure, the motor continues to run without overspeed, and the flywheel maintains its integrity, as it is still supported on a shaft with two bearings. Flow transients are provided in the figures in Section 15.3.3 for the assumed locked rotor.

There are no other credible sources of shaft seizure other than impeller rubs. A sudden seizure of the pump bearing is precluded by graphite in the bearing. Any seizure in the seals results in a shearing of the anti-rotation pin in the seal ring. The motor has adequate power to continue pump operation even after the above occurrences. Indications of pump malfunction in these conditions are initially by high temperature signals from the bearing water temperature detector, and excessive number 1 seal leakoff indications respectively. Following these signals, pump vibration levels are checked. Excessive vibration indicates mechanical trouble and the pump is shutdown for investigation.

5.4.1.3.5 Critical Speed

The reactor coolant pump shaft is designed so that its operating speed is below its first critical speed. This shaft design, even under the most severe postulated transient, gives low values of actual stress.

5.4.1.3.6 Missile Generation

Precautionary measures taken to preclude missile formation from primary coolant pump components assure that the pumps will not produce missiles under any anticipated accident condition. Each component of the primary pump motors has been analyzed for missile generation. Any fragments of the motor rotor would be contained by the heavy stator. The same conclusion applies to the pump impeller because the small fragments that might be ejected would be contained by the heavy casing. Further discussion and analysis of missile generation is contained in Reference 1.

5.4.1.3.7 Pump Cavitation

The minimum net positive suction head required by the reactor coolant pump at running speed is approximately a 250 foot head. (approximately 110 psi). In order for the controlled leakage seal to operate correctly, it is necessary to require a minimum differential pressure of approximately 200 psi across the number 1 seal. This corresponds to a primary loop pressure at which the minimum net positive suction head is exceeded and no limitation on pump operation occurs from this source.

5.4.1.3.8 Pump Overspeed Considerations

For turbine trips actuated by either the Reactor Trip System or the Turbine Protection System, the generator and reactor coolant pumps are maintained connected to the external network for 30 seconds to prevent any pump overspeed condition.

A loss of off-site power resulting in isolation of the generator from the external network could result in an overspeed condition. The turbine control system limits the overspeed to less than 103 percent by actuation of the turbine control and intercept valves. As additional backup, the turbine protective system has redundant and diverse overspeed protection which will trip the turbine at 110 or 111.5% speed, as described in Section 10.2.2.

5.4.1.3.9 Anti-Reverse Rotation Device

Each of the reactor coolant pumps is provided with an anti-reverse rotation device in the motor. This anti-reverse mechanism consists of pawls mounted on the outside diameter of the flywheel, a serrated ratchet plate mounted on the motor frame, a spring return for the ratchet plate, and shock absorbers.

At an approximate forward speed of 70 rpm, the pawls drop and bounce across the ratchet plate; as the motor continues to slow, the pawls drag across the ratchet plate. After the motor has slowed and come to a stop, the dropped pawls engage the ratchet plate and, as the motor tends to rotate in the opposite direction, the ratchet plate also rotates until it is stopped by the shock absorbers. The shock absorbers prevent reverse shock from being transmitted to other motor parts. The rotor remains in this position until the motor is energized again. When the motor is started, the ratchet plate is returned to its original position by the spring return. The ratchet plate is normally stationary except with it absorbs shock and when it is returned to its original position.

As the motor begins to rotate, the pawls drag over the ratchet plate. When the motor reaches sufficient speed, the pawls are bounced into an elevated position and are held in that position by friction resulting from centrifugal forces acting upon the pawls. While the motor is running at speed, there is no contact between the pawls and the ratchet plate.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

Considerable plant experience with the design of the anti-reverse rotation device has shown high reliability of operation.

The anti-reverse rotation device prevents reverse rotation with a maximum reverse movement of less than 5°.

5.4.1.3.10 Shaft Seal Leakage

Leakage along the reactor coolant pump shaft is controlled by three shaft seals arranged in series. Charging flow is directed to each reactor coolant pump via a seal water injection filter. It enters the pump through a connection on the thermal barrier flange and is directed down to a point between the pump radial bearing and the thermal barrier heat exchanger. Here the flow splits. A portion flows down past the thermal barrier heat exchanger and into the Reactor Coolant System; the remainder flows up the pump shaft annulus and enters the number 1 seal. Above the seal most of the flow leaves the pump via the number 1 seal discharge line. Minor flow passes through the number 2 seal and discharge line and the number 3 seal and the discharge line. This arrangement assures essentially zero leakage of reactor coolant or trapped gases from the pump.

5.4.1.3.11 Seal Discharge Piping

Discharge pressure from the number 1 seal is reduced to that of the volume control tank. Water from each number 1 seal is piped to a common manifold, and through the seal water return filter and through the seal water heat exchanger where the temperature is reduced to that of the volume control tank. The number 2 and number 3 leakoff lines route number 2 and 3 seal leakage to the reactor coolant drain tank.

5.4.1.4 Tests and Inspections

The reactor coolant pumps can be inspected in accordance with ASME Section XI, Code for Inservice Inspection of Nuclear Reactor Coolant Systems.

The pump casing is cast in one piece, eliminating welds in the casing. Support feet are cast integral with the casing to eliminate a weld region.

The design enables disassembly and removal of the pump internals for usual access to the internal surface of the pump casing.

The reactor coolant pump quality assurance program is given in Table 5-24.

5.4.1.5 Pump Flywheels

The integrity of the reactor coolant pump flywheel is assured on the basis of the following design and quality assurance procedures. Regulatory Guide 1.14 is further discussed in Section 1.7.

An inservice inspection program is maintained for the reactor coolant pump flywheels. This program provides for the inspection of each reactor coolant pump flywheel, as stated below, per the actions of Regulatory Guide 1.14 or the recommendations of Westinghouse Electric Corporation Topical Report WCAP-14535A, “Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination,” dated November 1996. The acceptability for referencing this topical report in lieu of Positions C.4.b(1) and C.4.b(2) of Regulatory Guide 1.14 was approved by NRC letter and safety evaluation dated September 12, 1996.

Ten year Inspection Requirement:

In lieu of Position C.4.b(1) and C.4.b(2) of Regulatory Guide 1.14, a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at approximately 10 year intervals coinciding with the Inservice Inspection schedule as required by ASME Section XI.

Subsequent to adopting the revised inspection requirement as recommended in WCAP-14535A, the inspection period was extended from ten years to twenty years as supported in WCAP-15666, “Extension of Reactor Coolant Pump Motor Flywheel Examination.”

5.4.1.5.1 Design Basis

The calculated stresses at operating speed are based on stresses due to centrifugal forces. The stress resulting from the interference fit of the flywheel on the shaft is less than 2000 psi at zero speed, but this stress becomes zero at approximately 600 rpm because of radial expansion of the hub. The primary coolant pumps run at approximately 1190 rpm and may operate briefly at overspeeds up to 111.5 percent (1326 rpm) during loss of outside load. For conservatism, however, 125 percent of operating speed was selected as the design speed for the primary coolant pumps. The flywheels are given a preoperational test of 125 percent of the maximum synchronous speed of the motor.

5.4.1.5.2 Fabrication and Inspection

The flywheel consists of two thick plates bolted together. The flywheel material is produced by a process that minimizes flaws in the material and improves its fracture toughness properties, such as vacuum degassing, vacuum melting, or electroslag remelting. Each plate is fabricated from A533, Grade B, Class 1 steel. Supplier certification reports are available for all plates and demonstrate the acceptability of the flywheel material on the basis of the requirements of Regulatory Guide 1.14.

Flywheel blanks are flame-cut from A533, Grade B, Class 1 plates with at least 1/2 inch of stock left on the outer and bore radii for machining to final dimensions. The finished machined bores, keyways, and drilled holes are subjected to magnetic particle or liquid penetrant examinations in accordance with the requirements of Section III of the ASME Code. The finished flywheels, as well as the flywheel material (rolled plate), are subjected to 100 percent volumetric ultrasonic inspection using procedures and acceptance standards specified in Section III of the ASME Code.

5.4.2 Steam Generator

5.4.2.1 Steam Generator Materials

5.4.2.1.1 Selection and Fabrication of Materials

All pressure boundary materials used in the steam generator are selected and fabricated in accordance with the requirements of Section III of the ASME code. A general discussion of materials specifications is given in Section 5.2.3, with types of materials listed in Table 5-6 and Table 5-7. Fabrication of Reactor Coolant Pressure Boundary materials is also discussed in Section 5.2.3, particularly in Sections 5.2.3.3 and 5.2.3.4.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

Testing has justified the selection of corrosion resistant thermally treated Inconel-690 (Unit 1) and Inconel-600 (Unit 2), a nickel-chromium-iron alloy, for the steam generator tubes (SB-163). The channel head divider plate is Inconel (SB-168). The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary side of the tube sheet is weld clad with Inconel. The tubes are hydraulically expanded for the full depth of the tube sheet after the ends are seal welded to the tube sheet cladding. The recessed fusion welds (Unit 2) and flush fusion welds (Unit 1) are performed in compliance with Sections III and IX of the ASME Code and are thoroughly inspected before each tube is expanded.

Code cases used in material selection are discussed in Section 5.2.1. The extent of conformance with Regulatory Guides 1.84 and 1.85 is also discussed there.

During manufacture, cleaning is performed on the primary and secondary sides of the Unit 2 steam generators in accordance with written procedures which follow the guidance of Regulatory Guide 1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants," and the ANSI Standard N45.2.1-1973, "Cleaning of Fluid Systems and Associated Components for Nuclear Power Plants". Onsite cleaning and cleanliness control are done by the applicant. Westinghouse recommendations for cleaning are given in Westinghouse process specifications, as discussed in Section 5.2.3.4.

During fabrication of the Unit 1 steam generators, BWI maintained cleanliness (including loose parts accountability and foreign material exclusion) in accordance with written procedures which as a minimum satisfy the applicable requirements of ASME NQA-2 and ANSI N45.2.1 Cleanliness Class B for primary side surfaces and tube OD and Class C for secondary side surfaces.

The fracture toughness of the materials is discussed in Section 5.2.3.3. Adequate fracture toughness of ferritic materials in the RCPB is provided by compliance with Appendix G of 10CFR 50 and with Article NB-2300 of Section III of the ASME Code. Per the discussion in Section 5.4.2.3, consideration of fracture toughness is only necessary for materials in Class 1 components.

5.4.2.1.2 Steam Generator Design Effects on Materials

Several features are employed to control the regions where deposits would tend to accumulate hydraulically. To avoid extensive crevice areas at the tube sheet, the tubes are hydraulically expanded to the secondary surface of the tube sheet, where their ends are seal welded to the Inconel cladding on the primary side of the tube sheet. For the Unit 2 steam generators, a flow distribution plate located below the preheat section encourages recirculating flow to sweep the tube sheet before turning upward through the tube bundle. This plate also serves to separate the tube sheet from the colder feedwater entering at the preheat section. A separate auxiliary feedwater nozzle provided in the upper shell avoids introducing cold water into the preheat section, and, thus, maximizes the integrity of steam generator materials.

5.4.2.1.3 Compatibility of Steam Generator Tubing with Primary and Secondary Coolants

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

As mentioned in Section 5.4.2.1.1, corrosion tests of thermally treated Inconel 600, and Inconel-690 which subjected the steam generator tubing material to simulated steam generator water chemistry, have indicated that the loss due to general corrosion over the 40 year plant life is insignificant compared to the tube wall thickness. Testing to investigate the susceptibility of heat exchanger construction materials to stress corrosion in caustic and chloride aqueous solutions has indicated that thermally treated Inconel-600 and Inconel-690 has excellent resistance to general corrosion in severe operating water conditions. Many reactor years of successful operation have shown the same low general corrosion rates as indicated by the laboratory tests. Refer to Section 9.3.2.2.2, concerning methods used to monitor secondary coolant purity.

Recent operating experience, however, has revealed areas on secondary surfaces where localized corrosion rates were significantly greater than the low general corrosion rates. Both intergranular stress corrosion and tube wall thinning were experienced in localized areas, although not at the same location or under the same environmental conditions (water chemistry, sludge composition).

To eliminate these localized areas of corrosion over the long term operation of the unit, it was decided that the use of phosphates for steam generator control would be eliminated. The adoption of the Advanced Amine along with All Volatile Treatment (AVT) control program will minimize the possibility for recurrence of the tube wall thinning phenomenon related to phosphate chemistry control. Successful AVT/Advanced Amine operation requires maintenance of low concentrations of impurities in the steam generator water, thus reducing the potential for formation of highly concentrated solutions in low flow zones, the precursor of the corrosion mechanisms. By restriction of the total alkalinity in the steam generator and prohibition of extended operation with free alkalinity, the Advanced Amine along with AVT program will minimize the recurrence of intergranular corrosion in localized areas due to excessive levels of free caustic.

Localized steam generator tube diameter reductions were first discovered during the April 1975 steam generator inspection at the Surry Unit No. 2 plant. This discovery was evidenced by eddy current signals, resembling those produced by dents, and by difficulty in passing the standard eddy current probe through the tubes at the intersections with the support plates. Subsequent to the initial finding, steam generator inspections at other operating plants revealed indications of denting to various degrees.

Denting is a term which describes a group of related phenomena resulting from corrosion of carbon steel in the crevices formed between the tubes and the tube support plates. The term "denting" has been applied to the secondary effects which include:

1. Tube diameter reduction
2. Tube support plate hole dilation
3. Tube support plate flow hole distortion, flow slot hourglassing
4. Tube support plate expansion
5. Tube leakage
6. Wrapper distortion

The mechanism which produces the effects cited involves an acid chloride environment in the tube crevices, in sequence, the process appears to occur as follows:

The crevice betweeen the tube and the support plate is blocked as a result of deposition of chemical species present in the bulk water, including phosphate compounds, secondary system corrosion products and minimal tube corrosion products. Once plugged the annulus provides a site for concentration of various nominally soluble contaminants, such as chlorides, sulfates, etc. Recent studies indicate that in the absence of non-volatile, alkalizing species, there may exist the potential for production of an acid solution by hydrolysis of such compounds as magnesium chloride, nickel phosphate, copper-chloride, various ferrous salts, etc. In an acid chloride solution, the corrosion film on the carbon steel is converted from protective in character, to a thick, non-protective oxide which assumes a laminar configuration subject to disruption due to the volume mismatch between the oxide and the base metal. The buildup of the thick oxide in the nominal 14 mil radial gap between the tube and the support plate causes sufficient force to be exerted against the tube to cause plastic deformation locally. The reaction to these forces can cause distortion of the circulation holes in the plate, both the flow holes between the tubes and the central flow slots between the inlet and outlet halves of the tube bundle. In the most extreme cases as corrosion proceeds and in-plate forces accumulate, the entire plate increases in diameter and the ligaments between the holes in the plate may crack. Ovalization of the tubes at the intersections results in high strains, leading to tensile stress on the tube ID and possible leakage by intergranular stress corrosion cracking. A similar result may occur at the apex of first row; i.e., the smallest radius U-bends, if sufficient distortion of the top support plate flow slots occurs, resulting in leg displacement, ovalization, and high strains.

The tube leakage and support plate effects do not pose a safety problem with respect to release of radioactivity or effects on accident calculations, but the frequency of leakage and resultant repair shutdowns does present an economic concern to the operators. The utilization of preventive plugging therefore serves to maintain availability and to permit orderly planning for long-term corrective action.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

The occurrence of denting has thus far been associated exclusively with plants having a history of chloride contamination due to condenser leakage. However, it has recently been noted that Maine Yankee and Millstone Point 2, non-Westinghouse plants which have used AVT exclusively, have apparently incurred denting also; sea water is used for cooling the condensers at both of these plants.

Research into the causes of denting was initiated shortly after the discovery of the denting condition. Initially dented tubes were removed for laboratory examination. Subsequently tube support plate samples containing sections of tubing were also removed for analysis from operating plants.

The initial hard data on the nature of the denting phenomenon were derived from these tube/support plate samples which revealed the thick oxide buildup, the tube diameter reduction, and chemical makeup of the crevice-filling materials. It was observed that there was only minor corrosive attack on the tube material, approximately 0-2 mil circumferential thinning, and that the crevice contained a thick layer of almost pure magnetite (Fe_3O_4); other chemical constituents included Inconel-metal-phosphate corrosion products close to the tube, and general secondary system contaminants between the Fe_3O_4 and the phosphate layer. Therefore copper deposits and the oxide was laced with chlorides.

Armed with those general observations, a series of crevice-with-contaminants test geometrics were evaluated; denting was produced first in reverse as "bulging" when a carbon steel plug was inserted into an Inconel tube to form the crevice; later heated crevice assemblies with heat transfer were shown to be effective dent simulators; finally denting in model boilers equipped with plant-type geometrical configurations was demonstrated. While pure, uncontaminated AVT environments have to date been found to be innocuous, it has been shown that the PO_4 to AVT transition was unnecessary to initiate the denting process. Only the presence of acid chloride solutions has been found to be a common factor. Nickel chloride, ferrous or cupric chloride solutions have been shown to be corrosive, and have also produced measurable denting. Thus far, test data indicate that phosphates, calcium hydroxide, and borates seem to retard the dent process; morpholine, among the common volatile amines, shows a beneficial effect on the corrosion rate of carbon steel.

Model boiler tests have been used to evaluate the adequacy of the AVT chemistry specifications adopted in 1974. The guidelines appear to be adequate to preserve tube integrity with one significant alteration: operation with containment ingress must be limited. Operation with strict AVT specifications will maintain the most functional steam generator environment.

Operating experience, verified in numerous steam generator inspections, indicates that the tube degradation associated with phosphate water treatment is not occurring where only AVT has been utilized. Adherence to the AVT chemical specifications and close monitoring of the condenser integrity will aid in the continued good performance of the steam generator tubing.

Increased margin against stress corrosion cracking has been obtained by employing thermally treated Inconel-600 tubing. Laboratory testing has shown that the thermally treated Inconel-600 tubing is compatible with the AVT environment. Isothermal corrosion testing in high purity water has shown that thermally treated Inconel-600 exhibiting normal microstructures tested at normal engineering stress levels does not suffer integrannular stress corrosion cracking in extended high temperature exposure. Thermal treatment of Inconel tubes has been shown to be particularly effective in resisting caustic corrosion. Tubing used in the model D5 Steam Generator is thermally treated in accordance with a laboratory derived treatment process.

A comprehensive program of steam generator inspections, including the requirements of Regulatory Guide 1.83, should provide for detection and correction of any unanticipated degradation that might occur in the steam generator tubing.

Water purity in the secondary system, especially in the steam generators, is maintained within specified limits in order to minimize corrosion and to minimize corrosion of steam generator heat transfer surfaces. The quality of the feedwater exposed to the units is controlled by properly operating the polishing demineralizers as well as maintaining condenser vacuum.

In addition, the Steam Generator Blowdown System is designed to maintain the correct shell side water chemistry by removing non-volatile materials due to steam generator tube leaks, corrosion or condenser tube leaks. The blowdown system also provides a normal path for the steam generator blowdown fluid to the inlet of the condensate polishing demineralizer for purification and reuse in the condensate cycle.

The Condensate Cleanup System is designed to remove dissolved and suspended impurities which can cause corrosion damage to secondary system equipment. The condensate polishing demineralizers are also used to remove impurities which could enter the system due to a condenser circulating water tube leak.

Yet another method used to clean operating steam generators of corrosion causing secondary side deposits is sludge lancing. This procedure is one in which a hydraulic jet, which is inserted through an access opening (inspection port), loosens deposits which are then removed by means of a suction pump. Sludge lancing can be performed when the need is indicated by the results of steam generator tube inspection.

A number of design changes have been incorporated in the Model D5 steam generator for Catawba Unit 2. These changes have been incorporated to reduce the consequences of adverse secondary side environmental conditions and hence improve overall steam generator reliability.

The tube support plates used in the Model D5 are ferritic stainless steel which has been shown in laboratory tests to be resistant to corrosion in the AVT environment. When corrosion of ferritic stainless steel does occur, the volume of the corrosion products is equivalent to the volume of the consumed material. The support plates will also be designed with broached tube holes rather than drilled holes. The broached tube hole design promotes high velocity flow along the tube sweeping any impurities away from the support plate location.

The tube support material for the Unit 1 BWI steam generators is SA-240 Type 410S, a 12% chromium martensitic stainless steel. It is supplied in the quenched and tempered, cold rolled, stress relieved condition. The tube support material resists corrosion, has adequate strength to support design loads and effectively resists wear when coupled with Inconel 690 tubing. Type 410S is compatible with manufacturing operations such as welding and machining. This material forms a tight, adherent oxide in secondary side water which is not greater in volume than the original metal. This greatly reduces the potential for tube denting. In addition, the 410S bars are arranged in a lattice grid assembly which, by design, creates more open areas between the tube and support contact area than is achieved with broached or drilled plates. The design allows for higher flow in the support area which tends to flush crevices clean and avoids small tube to support crevices which trap debris and provide a site for initiation and collection of corrosion products. After any applied welding processes, Type 410S stainless steel is stress relieved to reduce hardness of the weld joint and to maintain adequate stress corrosion resistance. Yield strength above 50 ksi is easily achieved with 410S.

The NRC issued IE Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes," on February 5, 1988, requesting that licensees with Westinghouse steam generators that utilize carbon steel support plates evaluate the potential for a steam generator tube rupture event caused by a rapidly propagating fatigue crack such as occurred at North Anna Unit 1 on July 15, 1987. At the time of issuance of IE Bulletin 88-02, for Catawba Nuclear Station, the specific evaluation and requirements for establishing programs and procedures for minimizing the potential for this type of steam generator tube degradation applied only to Unit 1 steam generators (Westinghouse Model D3); Unit 2 (Westinghouse Model D5) steam generators were listed in IE Bulletin 88-02 to be considered for information only. The bulletin-required Unit 1 steam generator inspections, evaluations, and programmatic descriptions were submitted to the NRC formally on February 20, 1989 by letter from H.B. Tucker (DPC) to M.L. Ernst (NRC). The NRC SER evaluating the acceptability of this response was transmitted to Duke Power Company on July 27, 1990 by letter from K.N. Jabbour (NRC) to H.B. Tucker.

With the replacement of the Catawba Nuclear Station Unit 1 steam generators during the 1EOC9 outage, the steam generators subject to IE Bulletin 88-02 and responses were removed and replaced with CFR-80 steam generators, manufactured by BWI Canada. These replacement steam generators do not utilize the carbon steel support plates which were attributed in IE Bulletin 88-02 to have caused rapidly propagating fatigue cracks in steam generator tubes.

Additional measures are incorporated in the Model D5 design to prevent areas of dryout in the steam generator and accumulations of sludge in low velocity areas. Modifications to the wrapper have increased water velocities across the tubesheet. A flow distribution baffle is provided which forces the low flow area to the center of the bundle. Increased capacity blowdown pipes have been added to enable continuous blowdown of the steam generators at a high volume. The intakes of these blowdown pipes are located below the center cutout section of the flow distributed baffle in the low velocity region where sludge may be expected to accumulate. Continuous blowdown provides maximum protection against inleakage of impurities from the condenser.

The following highlights steam generator failure modes related to tubing and design improvements implemented by BWI in the Unit 1 steam generators to address the problems:

Tube to tubesheet crevice IGA is avoided by selection and control of the tube alloy and the development and implementation of tube expansion tooling and procedures which minimize the crevice at the tubesheet secondary face.

Tube to tubesheet crevice and primary side stress corrosion cracking is avoided by using tube expansion techniques which minimize residual stresses.

Tube sensitization is avoided by stress relieving the pressure boundary of the steam generator, including the primary head to tubesheet weld (but excluding the steam drum to heat exchanger closing seam) prior to tubing the generator. Stress relief of the closing seam weld is performed locally and the tube bundle is insulated to maintain the bundle well below sensitization temperatures.

The tube sheet sludge pile is minimized through achievement of a high circulation ratio in the generator, creating high volume cross flow which is evenly distributed on the tubesheet secondary face, high capacity blowdown capability, water chemistry limits and provision of multiple access ports for sludge lancing.

Tube support crud accumulation and consequent undesirable increases in pressure drop across tube supports is avoided through the use of 'open-flow' lattice grids.

Denting at tube support locations is precluded by open-flow lattice grid supports, line contact between tubes and supports, high circulation flows and selection of 410S tube support material which resists corrosion.

Tube vibration fretting wear at lattice grid and U-bend supports is avoided by maintaining optimum tube to support contact/clearance, installing U-bend supports as the tubing process proceeds, applying conservative analytical predictive techniques and selection of tube support material that resists wear with the Inconel 690 interface.

U-bend cracking of inner row tubes is avoided by use of large minimum radius bends and application of stress relief in the tightest bends.

Another feature of the Model D5 generator that helps prevent tube damage is the higher circulation ratio. Increased circulation flow is vital for proper thermal hydraulic performance and also for control of the inventory of corrosion products, erosion products, and impurities (sludge) at the tube sheet. A high circulation flow results in increased fluid velocity into the tube bundle region which sweeps these undesirable products into the tube lane where this sludge is readily removed by the blowdown system.

5.4.2.1.4 Cleanup of Secondary Side Materials

Several methods are employed to clean operating steam generators of corrosion causing secondary side deposits. Sludge lancing, a procedure in which a hydraulic jet inserted through an access opening (inspection port) loosens deposits which are removed by means of a suction pump, can be performed when the need is indicated by the results of Steam Generator tube inspection. Blowdown procedures are performed as deemed necessary by regular water chemistry testing. The location of the blowdown piping suction, adjacent to the tube sheet and in a region of relatively low flow velocity, facilitates the removal of impurities that have accumulated on the tube sheet.

5.4.2.2 Steam Generator Inservice Inspection

The steam generator is designed to permit inservice inspection of Class 1 and 2 components, including individual tubes. The design aspects that provide access for inspection and the proposed inspection program comply with the edition of Section XI of the ASME Code, Division 1, "Rules for Inspection and Testing of Components of Light-Water-Cooled Plants", required by 10CFR 50.55a, paragraph g. A number of access openings make it possible to inspect and repair or replace a component according to the techniques specified. In the Unit 2 steam generators these openings include four manways, two of them for access to both sides of the reactor coolant channel head and two of them for inspection and maintenance of the steam dryers, and four 2 inch inspection ports located just above the tube sheet surface. Two additional 2 inch inspection ports are located on generator 2A. One 2.7" port is located on generator 2C. The steam generator also has five 6 inch handholes and two 2.5 inch instrument openings for additional access through the secondary side pressure boundary.

The Unit 1 steam generators are provided with two 21" diameter primary manways which allow access to each channel of the primary head and one 21" diameter secondary manway on the steam drum dome to permit access to the steam drum, moisture separation equipment, feedring and top of the tube bundle. Eight 6" diameter handholes are provided at the top (secondary side) of the tubesheet. One 2" inspection port provides access to the tube free lane just above the first two tube supports closest to the tubesheet. From the third support toward the top of the tube bundle each support, except the last or eighth, has two 2" ports positioned on either end of the tube free lane just above the support. A 6" handhole is provided on the transition cone to facilitate inspection of the feedring.

Inservice inspection of Class I components includes that of individual Steam Generator tubes. Equipment and access openings provided make it possible to detect and locate tubes with a wall defect penetrating 20% or more. Recommendations for such a program, including description of equipment, baseline and internals of inspection, criteria for selection, methods of recording, and actions to be taken if a defect is found, are given in Regulatory Guide 1.83, "Inservice Inspection of Pressurizer Water Reactor Steam Generator Tubes". Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes", provides recommendations concerning tube plugging. Supplementary information, including tube plugging criteria, can be found in the Technical Specifications.

The NRC issued IE Bulletin 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs," on May 15, 1989, requesting that licensees determine whether certain mechanical plugs supplied by Westinghouse were installed in their steam generators and if so, that an action plan be implemented to ensure that these plugs would continue to provide adequate assurance of reactor coolant system (RCS) pressure boundary integrity under normal operating, transient, and postulated accident conditions. Duke Power Company responded that none of the steam generator plugs applicable to the bulletin were installed on Catawba Nuclear Station Unit 1 and 2 steam generators (letter from H.B. Tucker to the NRC, dated June 20, 1989). Supplements 1 and 2 to the bulletin (dated November 14, 1990 and June 28, 1991) expanded the class of steam generator tube plugs to include all Westinghouse mechanical plugs fabricated from thermally treated Inconel 600. Duke Power Company's comprehensive response was submitted to the NRC December 18, 1991 by letter from M.S. Tuckman to the NRC. Final closure of IE Bulletin 89-01 was issued in a letter from the NRC to M.S. Tuckman on March 25, 1993.

5.4.2.3 Design Bases

Steam generator design data are given in Table 5-25. Code classifications of the steam generator components are given in Section 3.2. Although the ASME classification for the secondary side is specified to be Class 2, the current philosophy is to design all pressure retaining parts of the steam generator, and thus both the primary and secondary pressure boundaries, to satisfy the criteria specified in Section III of the ASME Code for Class 1 components. The design stress limits, transient conditions and combined loading conditions applicable to the steam generator are discussed in Section 3.9.1. Estimates of radioactivity levels anticipated in the secondary side of the steam generators during normal operation, and the bases for the estimates are given in Chapter 11. The accident analysis of a steam generator tube rupture is discussed in Chapter 15. The internal moisture separation equipment is designed to ensure that moisture carryover does not exceed 0.25 percent by weight under the following conditions:

1. Steady state operation up to 100 percent of full load steam flow, with water at the normal operating level for original licensed thermal power (3411 MWt). For Unit 1 operation at 3469 MWt (Measurement Uncertainty Recapture (MUR) power uprate thermal power), resultant moisture carryover does not exceed 0.25 percent by weight (Reference 26).

2. Loading or unloading at a rate of five percent of full power steam flow per minute in the range from 15 percent to 100 percent of full load steam flow.
3. A step load change of ten percent of full power in the range from 15 percent to 100 percent full load steam flow.

The water chemistry on the reactor side is selected to provide the necessary boron content for reactivity control and to minimize corrosion of Reactor Coolant System surfaces. The water chemistry of the steam side and its effectiveness in corrosion control are discussed in Chapter 10. Compatibility of steam generator tubing with both primary and secondary coolants is discussed further in Section 5.4.2.1.3.

The steam generator design is evaluated to minimize the possibility of mechanical failure or flow induced vibration. Tube support adequacy is discussed in Section 5.4.2.5.3. The tubes and tube sheet are analyzed in WCAP-7832 (Reference 2) and confirmed to withstand the maximum accident loading condition as it is defined in Section 3.9.1. Further consideration is given in Section 5.4.2.5.4 to the effect of tube wall thinning on accident condition stresses.

The preheat section of the Unit 2 steam generators is arranged to provide the maximum amount of counter flow feasible and, therefore, more efficient heat transfer.

A separate auxiliary feedwater nozzle is provided in the upper shell in order to avoid introducing cold water into the possibly hot and empty preheater in Unit 2 or directly on the top of the hot tubesheet in either unit. The design avoids problems such as accelerated corrosion and water hammer which may result from boiling in regions which are not designed to accommodate two phase flow. Protection of steam generator integrity is thereby optimized.

5.4.2.4 Design Description

The steam generators shown in Figure 5-14 and Figure 5-15 are a vertical shell and U-tube evaporator with integral moisture separating equipment.

On the primary side, the reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles located in the hemispherical bottom head of the steam generator. The head is divided into inlet and outlet chambers by a vertical divider plate extending from the head to the tube sheet.

Steam is generated on the shell side, flows upward and exits through the outlet nozzle at the top of the vessel. During normal operation, feedwater flows through a flow restrictor, directly into the counter flow preheat section and is heated almost to saturation temperature before entering the boiler section. In addition, a portion of the feedwater enters the system through the auxiliary nozzle in the upper shell, reducing the magnitude of feedwater flow into the preheat section. Subsequently the water-steam mixture flows upward through the tube bundle and into the steam drum section, where individual centrifugal moisture separators remove most of the entrained water from the steam. The steam continues to the secondary separators for further moisture removal, increasing its quality to a minimum of 99.75 percent. The moisture separators recirculate the separated water through the annulus between the shell and tube bundle wrapper via the space formed by the disflow then combines with the already preheated water-steam mixture for another passage through the steam generator. Dry steam exits through the outlet nozzle which is provided with a steam flow restrictor, described in Section 5.4.4.

While significant hardware differences exist between the Unit 2 Westinghouse and Unit 1 BWI steam generators, the basic function as stated in this design description is essentially identical with one crucial exception. The exception lies in the feedwater delivery system. The Unit 2 generators are equipped with a preheater and feedwater flow restrictor with main feedwater delivered just above the tubesheet while feedwater in the Unit 1 generators is delivered to the annulus area outside the top of the tube bundle and distributed by a feedring header. Feedwater in the BWI generator is not introduced directly into the tube bundle area but must flow down the annulus between the wrapper and shell to the inlet openings located at the top of the tubesheet.

As part of the Measurement Uncertainty Recapture (MUR) power uprate performed for Unit 1, the BWI steam generators were specifically evaluated for the MUR power uprate conditions. These evaluations concluded that the MUR conditions are bounded by the thermal hydraulic conditions used as the design basis for the Unit 1 installed BWI steam generators. As a result, there are not adverse impacts to steam generator performance and reliability concerning flow-induced vibration (FIV), component structural analyses, and Regulatory Guide 1.121 compliance for tube plugging criteria (Reference 27).

5.4.2.5 Design Evaluation

5.4.2.5.1 Forced Convection

The limiting case for heat transfer capability is the "nominal 100 percent design" case. The steam generator effective heat transfer coefficient is based on the coolant conditions of temperature and flow for this case, and includes a conservative allowance for tube fouling. Adequate tube area is selected to ensure that the full design heat removal rate is achieved.

5.4.2.5.2 Natural Circulation Flow

The driving head created by the change in coolant density as it is heated in the core and rises to the outlet nozzle initiates convection circulation. This circulation is enhanced by the fact that the steam generators, which provide a heat sink, are at a higher elevation than the reactor core which is the heat source. Thus natural circulation is assured for the removal of decay heat during hot shutdown in the unlikely event of loss of forced circulation.

5.4.2.5.3 Mechanical and Flow Induced Vibration Under Normal Operation

In the design of Westinghouse steam generators, the potential for tube wall degradation attributable to mechanical or flow induced excitation has been thoroughly evaluated. The evaluation included detailed analyses of the tube support systems for various mechanisms of tube vibration.

The primary cause of tube vibration in heat exchangers is hydrodynamic excitation due to secondary fluid flow on the outside of the tubes. In the range of normal steam generator operating conditions, the effects of primary fluid flow inside the tubes and mechanically induced tube vibration are considered to be negligible.

To evaluate flow induced tube vibration in the preheater region of the tube bundle, Westinghouse undertook an extensive program employing data from operating plants, full and partial scale model tests and analytical tube vibration models. Operating plant data consisted of tube wear data from pulled tube evaluations and eddy current tests, and tube motion data from accelerometers installed inside selected tubes. Model testing generated tube wear data, flow velocity distributions, tube motion parameters and flow induced tube vibration forcing functions. The tube vibration analyses applied the forcing functions to produce tube motion data. The results of this evaluation were consistent with the early operating experience of preheat steam generators.

On the basis of an extensive model test and analysis program, Westinghouse designed, verified and implemented a modification to the steam generator to reduce tube vibratory response to preheater inlet flow excitation. Additionally, the magnitude of the flow forcing function was reduced thru implementation of a preheater flow bypass arrangement in the feedwater system. The verification of the performance of the modifications in reducing tube excitation and response was done with input from a full scale test under simulated conservative flow and tube support conditions.

Fatigue of the tubes in the preheater region which are subject to flow induced excitation is not a concern since the maximum resultant stresses in the tube are below the endurance limit of the material.

For areas of the tube bundle other than the preheater, parallel flow analyses were performed to determine the vibratory deflections. These analyses indicate that the flow velocities are sufficiently low such that they result in negligible fatigue and vibratory amplitudes. The support system, therefore, is deemed adequate with regard to parallel flow excitation.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

To evaluate cross flow at the exit of the downcomer flow to the tube bundle and at the top of the bundle in the U-bend area, Westinghouse performed an experimental research program of cross flow in tube arrays with the specific parameters of the steam generator. Air and water model tests were employed. The results of this research indicate that these regions of the bundle are not subject to the vortex shedding mechanism of tube excitation. Vortex shedding was found not to be a significant mechanism in these two regions for the following reasons:

1. *Flow turbulence in the downcomer and tube bundle inlet region inhibit the formation of Von Karman vorticies.*

2. *Both axial and cross flow velocity components exist on the tubes. The axial flow component disrupts the Von Karman vortices.*

This research program was also the basis for evaluation of the fluidelastic mechanism due to cross flow at the tubesheet. The evaluation showed the adequacy of the tube support arrangement.

Flow turbulence can result in some tube excitation in these regions. This excitation is of little concern, however, since:

1. Maximum stresses in the tubes are at least an order of magnitude below the fatigue endurance limit of the tube material, and

2. Tube support arrangements preclude significant vibratory motion.

In summary, tube vibration has been thoroughly evaluated. Mechanical and primary flow excitation are considered negligible. Secondary flow excitation has been evaluated. From this evaluation, it is concluded that if tube vibration does occur, the magnitude will be limited. Tube fatigue due to the vibration is judged to be negligible. Any tube wear resulting from the tube vibration would be limited and would progress slowly. This allows use of a periodic tube inservice inspection program for detection and follow of any tube wear. This inservice inspection program, in conjunction with tube plugging criteria, provides for safe operation of the steam generators.

In the design of the BWI steam generators, consideration has been given to the possibility of vibratory failure of tubes due to mechanical or flow induced excitation. This consideration includes detailed analysis of the tube support system.

The primary cause of tube vibratory failure in heat exchanger components due to hydrodynamic excitation is fluid outside the tube. The dominant source of hydrodynamic excitation is fluid cross flow and therefore analyses focus on the two regions where the tube bundle is subject to cross flow. These areas are at the entrance of the downcomer feed to the tube bundle and in the curved tube section of the U-bend.

Analysis of the steam generator tubes indicates the flow velocities to be sufficiently below that which is required for damaging fatigue or impacting vibratory amplitudes. The support system, therefore is deemed adequate to preclude excessive tube motion.

In the analyses, all three known potential flow-induced vibration mechanisms were taken into account: fluid-elastic instability, vortex shedding resonance and random turbulence excitation. Of these mechanisms, fluid-elastic instability is the most significant. As a result, the evaluation of this mechanism was performed with highly conservative analysis parameters drawn from published empirical data bases.

Summarizing the results of analyses and tests of steam generator tubes and various support structures for flow induced vibration, it can be stated that an evaluation of support adequacy has been completed using all published techniques believed to be applicable to heat exchanger tube support design. In addition, the tube support system used is consistent with accepted standards of heat exchanger design utilized throughout the industry (spacing, clearance, etc.). Furthermore, the design techniques are supplemented with a continuing literature search effort to maintain current understanding of the complex mechanism of concern.

Further consideration is given to the possibility of mechanically excited vibration, in which resonance of external forces with tube natural frequencies must be avoided. Evidence indicates that the transmissibility of external forces either through the structure or from fluid within the tubes is negligible and provides little causes for concern.

5.4.2.5.4 Allowable Tube Wall Thinning Under Accident Conditions

An evaluation is performed to determine the extent of tube wall thinning that can be tolerated under accident conditions. Under such a postulated design basis accident, vibration is of short enough duration that the endurance problem is insignificant. The results of a study made on "D series" (.75 inch nominal diameter, .043 inch nominal thickness) tubes under accident loading are discussed in WCAP-7832 (Reference 2) and show that a minimum wall thickness of .026 inches would have a maximum faulted condition stress (i.e., due to combined LOCA and Safe Shutdown Earthquake loads) that is less than the allowable limit. This thickness is .010 inches less than the minimum steam generator tube wall thickness .039 reduced to .036 inches by the assumed general corrosion and erosion loss of .003 inches.

The corrosion rate is based on a conservative weight loss rate for Inconel tubing in flowing 629°F primary side reactor coolant fluid. The weight loss, when equated to a thinning rate and projected over a 40 year plant life with appropriate reduction after initial exposure, is equivalent to 0.083 mils thinning. The assumed corrosion rate of 3 mils leaves a conservative 2.917 mils for general corrosion thinning on the secondary side.

The steam generator tubes, existing originally at their minimum wall thickness and reduced by a very conservative general corrosion loss, still provide quite an adequate safety margin. Thus, it can be concluded that the ability of the steam generator tubes to withstand accident loadings is not affected by the maximum corrosion rate assumed.

Regulatory Guide 1.121, Basis For Plugging Degraded PWR Steam Generator Tubes, Revision 0, August 1976, presents detailed analytical and loading criteria to be used in determining the plugging limit as defined in the steam generator tube surveillance program section of the Technical Specifications. Westinghouse considers some of these criteria unnecessarily conservative and, in some cases, unworkable. Detailed comments to this guide were transmitted to the NRC on November 22, 1977 by Westinghouse Letter NS-CE-1282 from C. Eicheldinger to S. J. Chilk.

Position C.1

Westinghouse interprets the term "Unacceptable defects" to apply to those imperfections resulting from service induced mechanical or chemical degradation of the tube walls which have penetrated to a depth in excess of the Plugging Limit.

Positions C.2.a(2) and C.2.a(4)

Westinghouse will use a 200 percent margin of safety based on the following definition of tube failure. Westinghouse defines tube failure as plastic deformation of a crack to the extent that the sides of the crack open to a nonparallel, elliptical configuration. This 200 percent margin of safety compares favorably with the 300 percent margin requested by the NRC against gross failure.

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

Position C.2.b

In cases where sufficient inspection data exist to establish degradation allowance, the rate used will be an average time-rate determined from the mean of the test data.

Where requirements for minimum wall are markedly different for different areas of the tube bundle, e.g., U-bend area versus straight length in Westinghouse designs, two plugging limits may be established to address the varying requirements in a manner which will not require unnecessary plugging of tubes.

Position C.3.d(1) and C.3.d(3)

The combined effect of these requirements would be to establish a maximum permissible primary-to-secondary leak rate which may be below the threshold of detection with current methods of measurement. Westinghouse has determined the maximum acceptable length of a through-wall-crack based on secondary pipe break accident loadings which are typically twice the magnitude of normal operating pressure loads. Westinghouse will use a leak rate associated with the crack size determined on the basis of accident loadings.

Position C.3.e(6)

Westinghouse will supply computer code names and references rather than the actual codes.

Position C.3.f(1)

Westinghouse will establish a minimum acceptable tube wall thickness (Plugging Limit) based on structural requirements and consideration of loadings, measurement accuracy and, where applicable, a degradation allowance as discussed in this position and in accordance with the general intent of this guide. Analyses to determine the maximum acceptable number of tube failures during a postulated condition are normally done to entirely different bases and criteria are not within the scope of this guide.

Tubing for the Unit 1 BWI steam generators meets the requirements of the ASME Code for the Design, Test and Levels A, B, C and D Service (accident conditions) loading conditions specified in the DPC Certified Design Specification.

Tube to tubesheet attachment welds are made in accordance with ASME NB-4350. In addition, it is shown by analysis that the welds meet the requirements of the ASME Code when subjected to tube axial forces and torsional moments under the Design, Test and Levels A, B, C and D

Service (accident conditions) loading conditions specified in the DPC Certified Design Specification.

It is concluded that the tubes meet the ASME Section XI, IWB-3630 for OD flaws. A wasted tube with 40% loss of nominal wall thickness uniformly around the OD satisfies acceptance criteria for the minimum acceptable wall thickness established in Regulatory Guide 1.121 paragraph C.2 and the ASME Code. Loads are based on Regulatory Guide 1.121 paragraph C.3 [a]-[c] from the nominal and faulted conditions given in the DPC Certified Design Specification. Note that an additional tube thickness allowance should be added the analyzed minimum acceptable tube wall thickness to establish the operational tube thickness acceptable for continued service, per Regulatory Guide 1.121 C.2(b). This tube shall exhibit an overall fatigue strength reduction factor (FSRF) no larger than 2.15 in the U-bend region above the top lattice grid or 2.75 in the straight tube section below the top lattice grid in consideration of geometric and/or environmental effects. *The limiting FSRF's were conservatively derived in the fatigue analysis based on the entire 60 year design service life. Higher FSRF may be justified for shorter service intervals between tube inspection periods*.

5.4.2.6 Quality Assurance

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

The steam generator quality assurance program is given in Table 5-26.

Radiographic inspection and acceptance standards shall be in accordance with the requirements of Section III of the ASME Code.

Liquid penetrant inspection is performed on weld deposited tube sheet cladding, channel head cladding, tube to tube sheet weldments, and weld deposit cladding. Liquid penetrant inspection and acceptance standards are in accordance with the requirements of Section III of the ASME Codes.

Magnetic particle inspection is performed on the tube sheet forging, channel head casting, nozzle forgings, and the following weldments:

1. *Nozzle to shell*
2. *Support brackets*
3. *Instrument connection (primary and secondary)*
4. *Temporary attachments after removal*
5. *All accessible pressure containing welds after hydrostatic test.*

Magnetic particle inspection and acceptance standard are in accordance with requirements of Section III of the ASME Code.

An ultrasonic test is performed on the tube sheet forging, tube sheet cladding, secondary shell and head plate and nozzle forgings.

The heat transfer tubing is subjected to eddy current test.

Hydrostatic tests are performed in accordance with Section III of the ASME Code.

In addition, the heat transfer tubes shall be subjected to a hydrostatic test pressure prior to installation into the vessel which is not less than 1.25 times the primary side design pressure.

5.4.3 Reactor Coolant Piping

5.4.3.1 Design Bases

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

The Reactor Coolant System (RCS) piping is designed and fabricated to accomodate the system pressures and temperatures attained under all expected modes of plant operation or anticipated system interactions. Stresses are maintained within the limits of Section III of the ASME Nuclear Power Plant Components Code. Code and material requirements are provided in Section 5.2.

Materials of construction are specified to minimize corrosion/erosion and ensure compatibility with the operating environment.

The piping in the RCS is Safety Class 1 and is designed and fabricated in accordance with ASME Section III, Class 1 requirements.

Stainless steel pipe conforms to ANSI B36.19 for sizes 1/2 inch through 12 inches and wall thickness Schedules 40S through 80S. Stainless steel pipe outside of the scope of ANSI B36.19 conforms to ANSI B36.10.

The minimum wall thicknesses of the loop pipe and fittings are not less than that calculated using the ASME III Class 1 formula of Paragraph NB-3641.1 (3) with an allowable stress value of 17,550 psi. The pipe wall thickness for the pressurizer surge line is Schedule 160. The minimum pipe bend radius is 5 nominal pipe diameters; ovality does not exceed 6 percent.

All butt welds, branch connection nozzle welds, and boss welds, shall be of a full penetration design.

Processing and minimization of sensitization are discussed in Section 5.2.3.

Flanges conform to ANSI B16.5.

Socket weld fittings and socket joints conform to ANSI B16.11.

Inservice inspection is discussed in Section 5.2.4.

5.4.3.2 Design Description

Principal design data for the reactor coolant piping are given in Table 5-27. Pipe and fittings are cast, seamless without longitudinal or electroslag welds, and comply with the requirements of the ASME Code, Section II, Parts A and C, Section III, and Section IX.

The RCS piping is specified in the smallest sizes consistent with system requirements. This design philosophy results in the reactor inlet and outlet piping diameters given in Table 5-27. The line between the steam generator and the pump suction is larger to reduce pressure drop and improve flow conditions to the pump suction.

The reactor coolant piping and fittings which make up the loops are austenitic stainless steel. There will be no electroslag welding on these components. All smaller piping which comprise part of the RCS such as the pressurizer surge line, spray and relief line, loop drains and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is stainless steel. All joints and connections are welded, except for the pressurizer code safety valves and the Reactor Head Vent piping, where flanged joints are used.

All piping connections from auxiliary systems are made above the horizontal centerline of the reactor coolant piping, with the exception of:

1. Residual heat removal pump suction lines, which are 45° down from the horizontal centerline. This enables the water level in the RCS to be lowered in the reactor coolant pipe while continuing to operate the Residual Heat Removal System, should this be required for maintenance.
2. Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.
3. The differential pressure taps for flow measurement, which are downstream of the steam generators on the first 90° elbow.
4. The pressurizer surge line, which is attached at the horizontal centerline.
5. The hot leg sample connections, the loop 3 thermowell, and the loop 4 injection connection, all located on the horizontal centerline.

Penetrations into the coolant flow path are limited to the following:

1. The spray line inlet connections extend into the cold leg piping the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force.
2. The reactor coolant sample system taps protrude into the main stream to obtain a representative sample of the reactor coolant.
3. Fast response narrow-range thermowell-type, in-line resistance temperature detectors (RTDs) are installed in the existing hot legs and cold legs of each RCS Loop.
4. The wide range hot and cold leg RTDs are located in thermowells that extend into both hot and cold legs of the reactor coolant piping.

The RCS piping includes those sections of piping interconnecting the reactor vessel, steam generator, and reactor coolant pump. It also includes the following:

1. Charging line and alternate charging line from the system isolation valve up to the branch connections on the reactor loop.
2. Letdown line and excess letdown line from the branch connections on the reactor coolant loop to the system isolation valve.
3. Pressurizer spray lines from the reactor coolant cold legs to the spray nozzle on the pressurizer vessel.
4. Residual heat removal lines to or from the reactor coolant loops up to the designated check valve or isolation valve.
5. Safety injection lines from the designated check valve to the reactor coolant loops.
6. Accumulator lines from the designated check valve to the reactor coolant loops.
7. Loop fill, loop drain, sample[1] and instrument[1] lines to or from the designated isolation valve to or from the reactor coolant loops.

[1] Lines with a 3/8 inch or less flow restricting orifice qualify as Safety Class 2 ; in the event of a break in one of these Safety Class 2 lines, the normal makeup system is capable of providing makeup flow while maintaining pressurizer water level.

8. Pressurizer surge line from one reactor coolant loop hot leg to the pressurizer vessel inlet nozzle.
9. Pressurizer spray scoop, sample connection[2] with scoop, reactor coolant temperature RTD thermowell installation boss, and the thermowell itself.
10. All branch connection nozzles attached to reactor coolant loops.
11. Pressure relief lines from nozzles on top of the pressurizer vessel up to and through the power-operated pressurizer relief valves and pressurizer safety valves.
12. Seal injection water lines to or from the reactor coolant pump to the designated check valve (injection line) or orifice[2] (seal bypass line).
13. Auxiliary spray line from the isolation valve to the pressurizer spray line header.
14. Sample lines[2] from pressurizer to the isolation valve.

Details of the materials of construction and codes used in the fabrication of reactor coolant piping and fittings are discussed in Section 5.2.

5.4.3.3 Design Evaluation

Piping load and stress evaluation for normal operating loads, seismic loads, blowdown loads, and combined normal, blowdown and seismic loads is discussed in Section 3.9.

5.4.3.3.1 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications.

The design and construction are in compliance with ASME Section XI. Pursuant to this, all pressure containing welds out to the second valve that delineates the RCS boundary are available for examination with removable insulation.

Components constructed with stainless steel will operate satisfactorily under normal plant chemistry conditions in pressurized water reactor systems, because chlorides, fluorides, and particularly oxygen, are controlled to very low levels. (See Section 5.2.3)

Periodic analysis of the coolant chemical composition is performed to monitor the adherence of the system to desired reactor coolant water quality. The reactor coolant specifications will be derived from Catawba Technical Specifications and EPRI Primary Water Chemistry Guidelines. Establishing reactor coolant purity within these limits will minimize fuel clad crud deposition which affects the corrosion resistance and heat transfer of the clad. Maintenance of the water quality to minimize corrosion is accomplished using the Chemical and Volume Control system and Sampling System which are described in Chapter 9.

5.4.3.3.2 Sensitized Stainless Steel

Sensitized stainless steel is discussed in Section 5.2.3.

---

[2] Lines with a 3/8 inch or less flow restricting orifice qualify as Safety Class 2 ; in the event of a break in one of these Safety Class 2 lines, the normal makeup system is capable of providing makeup flow while maintaining pressurizer water level.

5.4.3.3.3 Contaminant Control

Contamination of stainless steel and Inconel by copper, low melting temperature alloys, mercury and lead is prohibited. Colloidal graphite is the only permissible thread lubricant.

Prior to application of thermal insulation, the austenitic stainless steel surfaces are cleaned and analyzed to a halogen limit of 0.75 mg/ft^2 Cl and 0.14 mg/ft^2 F.

5.4.3.4 Tests and Inspections

The RCS piping/fitting NDE inspection program is given in Table 5-28.

Volumetric examination is performed throughout 100 percent of the wall volume of each pipe and fitting in accordance with the applicable requirements of Section III of the ASME Code for all pipe 27-1/2 inches and larger. All unacceptable defects are eliminated in accordance with the requirements of the same section of the code.

A liquid penetrant examination is performed on both the entire outside and inside surfaces of each finished fitting in accordance with the criteria of ASME Section III. Acceptance standards are in accordance with the applicable requirements of ASME Section III.

The pressurizer line conforms to SA-376 Grade 304, 304N, or 316 with supplementary requirements S2 (transverse tension tests), and S6 (ultrasonic test). The S2 requirement applies to each length of pipe. The S6 requirement, applies to 100 percent of the piping wall volume.

The end of pipe sections, branch ends and fittings are machined back to provide a smooth weld transition adjacent to the weld path.

5.4.4 Main Steam Line Flow Restrictor

5.4.4.1 Design Basis

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

The outlet nozzle of the steam generator is provided with a flow restrictor designed to limit steam flow in the unlikely event of a break in the main steam line. A large increase in steam flow will create a back pressure which limits further increase in flow. *Several protective advantages are thereby provided: rapid rise in containment pressure is prevented, the rate of heat removal from the reactor coolant is kept within acceptable limits, thrust forces on the main steam line piping are reduced, and most important, stresses on internal steam generator components, particularly the tube sheet and tubes, are limited. The restrictor is also designed to minimize the unrecovered pressure loss across the restrictor during normal operation.*

5.4.4.2 Design Description

The flow restrictor consists of seven SA316-304L (Unit 1) and Inconel (ASME SB-163) (Unit 2) venturi inserts which are inserted into the holes in an integral steam outlet low alloy steel forging. The inserts are arranged with one venturi at the centerline of the outlet nozzle and the other six equally spaced around it. After insertion into the low alloy steel forging holes, the venturi nozzles are retained with a SA516 Gr 70 retainer plate (Unit 1) and welded to the Inconel cladding on the inner surface of the forging (Unit 2).

5.4.4.3 Design Evaluation

The flow restrictor design has been sufficiently analyzed to assure its structural adequacy. The equivalent throat diameter of the steam generator outlet is 15.87 inches (Unit 1) and 16 inches

(Unit 2), and the resultant pressure drop through the restrictor at 100 percent steam flow is approximately 2.7 psig (Unit 1) and 3.4 psig (Unit 2). This is based on a design flow rate of 3.79 x 10^6 1b/hr. Materials of construction and manufacturing of the flow restrictor are in accordance with Section III of the ASME Code.

5.4.4.4 Tests and Inspections

HISTORICAL INFORMATION NOT REQUIRED TO BE REVISED

Since the restrictor is not a part of the steam system boundary, no tests and inspection beyond those during fabrication, are anticipated.

5.4.5 Main Steam Line Isolation System

Refer to Section 10.3 for a discussion of main steam line isolation.

5.4.6 Reactor Core Isolation Cooling System

This section is not applicable to Pressurized Water Reactors.

5.4.7 Residual Heat Removal System

5.4.7.1 Design Bases

The Residual Heat Removal System (RHRS) transfers heat from the Reactor Coolant System (RCS) to the Component Cooling System (CCS) to reduce the temperature of the reactor coolant to the cold shutdown temperature at a controlled rate during the second part of normal plant cooldown and maintains this temperature until the plant is started up again.

Parts of the RHRS also serve as parts of the Emergency Core Cooling System (ECCS) and the Containment Spray System (CSS) during the accident recovery phases. (See Sections 6.3 and 6.2 respectively.)

The RHRS also is used to transfer refueling water between the refueling cavity and the refueling water storage tank at the beginning and end of the refueling operations.

Nuclear plants employing the same RHRS design as the Catawba Nuclear Station are given in Section 1.3.

RHRS design parameters are listed in Table 5-29.

Section 9.2.2 contains a description of the RHRS heat loads for both the LOCA and the non-LOCA units during the two unit design basis event. This design basis safety evaluation demonstrates that acceptance criteria are met, including assumptions intended to maximize the heat load rejected to the ultimate heat sink (Standby Nuclear Service Water Pond). RHR heat exchanger heat load for the non-LOCA unit is assumed to begin following a 4 hour decay time. Cooldown time for the non-LOCA unit from 350°F to 200°F and down to 140°F is not time-limiting, and heat load would be similar to that experienced for normal cooldown at 4 hours and at 20 hours. Decay heat at 4 hours is significant since this is the earliest time following reactor trip or shutdown that it is practical to reach RHR entry conditions of 350°F and 385 psig. Decay heat at 20 hours is significant since it is considered to be the target to achieve cold shutdown under a unit "fast cooldown" scenario typical of required cold shutdown per plant Technical Specifications.

The limiting parameter used in the Offsite Dose Analysis is 8 hours (time), which corresponds to the duration of plant cooldown by the secondary system (Steam Generators) after for the Postulated Locked Rotor Accident (15.0, Table 15-22). This function is accomplished by the Steam Generators during the initial stage of reactor cooldown, described previously, and does not depend on performance of the RHR System, pumps and heat exchangers. As soon as the RHRS is placed in service at approximately 4 hours, the subsequent cooldown from 350°F to 200°F and down to 140°F is not time-limiting, and would be similar to that experienced for normal cooldown at 4 hours and at 20 hours. The RHRS performance in this mode would be similar to normal plant cooldown using either one or two strains of the RHRS.

During a forced shutdown for maintenance, or during a refueling outage cooldown, the RHRS is placed in operation approximately four (4) hours after reactor shutdown when the temperature and pressure of the RCS are approximately 350°F and 385 psig, respectively. Orginial cooldown analyses were developed by Westinghouse based on original plant heat exchanger data sheet information. This original analysis demonstrated that with two RHR pumps and two RHR heat exchangers in service and with each heat exchanger supplied with component cooling water at design flow and temperature, the RHRS is capable of reducing the temperature of the reactor coolant from 350°F to 140°F within 16 hours. Additional cooldown analyses were developed by Westinghouse assuming that only one RHR heat exchanger and RHR pump is in service. This analysis demonstrated that with only one RHR train in service, no reactor coolant pumps operating. and with the heat exchanger supplied with component cooling water at design flow and temperature, the RHRS is capable of reducing the temperature of the reactor coolant from 350°F to 200°F within 24.4 hours.

Current analyses demonstrate that with only one RHR train in service, no reactor coolant pumps operating, and with the heat exchanger supplied with component cooling water at design flow and temperature, the RHRS is capable of reducing the temperature of the reactor coolant from 350°F to 200°F with decay heat at 20 hours after reactor shutdown. Thus, single failure design basis capability has been demonstrated consistent with the original Westinghouse analysis. Current analysis is not available to confirm the two-train cooldown to 140°F in 16 hours. The cooldown time from 200°F to 140°F is useful for predicting and scheduling outages, but is not a safety related input to safety analyses or dose analyses described in the preceding paragraphs. Actual plant cooldown is influenced by a variety of factors including planned delays for chemistry control, crud dissolution and removal using multiple Reactor Coolant Pump operation (heat load for each RCP is equivalent to a significant fraction of decay heat), lake temperatures, and the position, or failed-open position of control valves in the ND, KC and RN Systems, as allowed by plant procedures to hasten cooldown.

Historically, Unit cooldown (from 557°F to 200°F) using either one or two RHR trains has been possible in 9.5 to 16 hours. Unit cooldown from 200°F to 140°F is a function of lake temperature. It varies widely with seasonal differences, the number of Reactor Coolant Pumps in service for crud cleanup, and with RHR flow rate. Lake temperatures generally support one train's ability to maintain 140°F or less, after 2 or 3 days decay; however, this could take up to 7 days or slightly longer at maximum summer time take temperature conditions. There is no safety analysis requirement or acceptance criteria associated with maintaining temperature any less than 200°F. Mode 5 Cold Shutdown (<200°F) is the required safety state for all plant Technical Specifications requiring shutdown from operating conditions.

Plant Technical Specifications recognize the potential effects of Catawba design as a multi-unit plant. Under specified conditions, Technical Specification 3.7.8 permits operation when one unit is operating, and the other is shutdown in Modes 5 or 6, and a Nuclear Service Water pump or diesel generator associated with the shutdown unit is in maintenance. Under these conditions, a single failure may occur which results in isolating two NSW pumps on one train from the ultimate heat sink. This results in only one NSW pump capable of providing shutdown cooling for both the LOCA unit and the shutdown unit. The NSW System "one-pump analysis" demonstrates that one NSW pump has sufficient capacity to maintain the shutdown unit in cold shutdown (below 200°F), commencing 36 hours following a trip from full power, while supplying the post-LOCA loads on the other unit.

The RHRS is designed to be isolated from the RCS whenever the RCS pressure exceeds the RHRS design pressure. The RHRS is isolated from the RCS on the suction side by two motor operated valves in series on each suction line. Each motor operated valve is interlocked to prevent its opening if RCS pressure is greater than 385 psig. The RHRS is isolated from the RCS on the discharge side by two check valves in each return line. Also provided on the discharge side is a normally open motor operated valve downstream of each RHRS heat exchanger. (These check valves and motor operated valves are not considered part of the RHRS; they are shown as part of the ECCS, see Figure 6-131.)

Each inlet line to the RHRS is equipped with a pressure relief valve designed to relieve the combined flow of all the charging pumps at the relief valve set pressure. These relief valves also protect the system from inadvertant over pressurization during plant cooldown or startup. Each discharge line from the RHRS to the RCS is equipped with a pressure relief valve designed to relieve the maximum possible back leakage through the valves isolating the RHRS from the RCS.

The RHRS is designed for a single nuclear power unit and is not shared with another nuclear power unit as required by General Design Criterion 5.

The RHRS is designed to be fully operable from the control room when power is restored to the suction isolation valves that have had power removed. Manual operations required of the operator are: opening the suction isolation valves, positioning the flow control valves downstream of the RHRS heat exchangers, and starting the RHR pumps. By nature of its redundant two train design, the RHRS is designed to accept all major component single failures with the only effect being an extension in the required cooldown time. For two low probability electrical system single failures, i.e., failure in the suction isolation valve interlock circuitry, or diesel generator failure in conjunction with loss of offsite power, limited operator action outside the control room is required to open the suction isolation valves. Manual actions are discussed in more detail in Sections 5.4.7.2.7. (This is in addition to the normal procedure for restoring power to the suction isolation valves that have had power removed.) The only motor operated valves in the RHRS which are subject to flooding are the suction isolation valves which are not required to function after a loss of coolant accident. Although Westinghouse considers it to be of low probability, spurious operation of a single motor operated valve can be accepted without loss of function as a result of the redundant two train design.

Missile protection, protection against dynamic effects associated with the postulated rupture of piping, and seismic design are discussed in Sections 3.5, 3.6, and 3.7 respectively.

The NRC issued Generic Letter 87-12, "Loss of Residual Heat Removal (RHR) while the Reactor Coolant System (RCS) is Partially Filled," on July 9, 1987. This generic letter was issued to alert licensees the potential for losing the RHR system during RCS drained down conditions, due to insufficient NPSH. Specifically, the generic letter required that evaluations and programmatic improvements be performed for operating procedures which control RCS draindown activities, training of personnel, statusing instrumentation (RCS level, temperature), contingency procedural use of other designated pumps in the event that RHR is lost, and assurance of the capability for the containment to achieve "closure" in the event of RHR loss and RCS boiling. Duke Power Company incorporated aspects of all the Generic Letter 87-12 requirements into its response for all three of its nuclear stations in the letter from W.H. Owen to the NRC, dated October 2, 1987.

The NRC issued Generic Letter 88-17, "Loss of Decay Heat Removal," on October 17, 1988. This generic letter was issued to alert licensees the continued need for plants to address the issue (in addition to actions taken in response to Generic Letter 87-12) of loss of decay heat removal capability during plant shutdown/drained down conditions, due to insufficient NPSH. Specifically, Generic Letter 88-17 required implementation of eight expeditious actions and six programmatic actions to address this issue. Among these were training, establishing procedures that control containment closure, providing redundant RCS temperature and level indications for the RHR shutdown condition, refinement of RHR operating procedures to avoid conditions which could result in loss of RHR, and procedural designation of pumps for standby RCS inventory addition. The response for Catawba Nuclear Station incorporated the appropriate requirements of Generic Letter 88-17, since the majority had already been incorporated as part of the response to Generic Letter 87-12. The Generic Letter 88-17 response was transmitted to the NRC in the letter from H.B. Tucker to the NRC, dated January 3, 1989.

The NRC issued Generic Letter 98-02, "Loss of Reactor Coolant Inventory and Associated Potential for Loss of Emergency Mitigation Function While in a Shutdown Condition," on May 28, 1998. This generic letter was issued to alert licensees of a potential to drain down the RCS system when the reactor is in hot shutdown conditions. The Catawba system design has a common ECCS / RHR suction header that can be connected to the RWST. If the RWST isolation valve is opened in these conditions, there is a potential for hot RCS water to drain to the RWST through the suction header. In addition, this hot water could flash to steam creating steam voiding that could adversely affect operation of the ECCS and RHR pumps. Catawba's administrative controls include engineering controls, training initiatives, scheduling controls, and operating and abnormal procedures that preclude alignments and conditions that would allow an inadvertent draindown event. The generic letter response was transmitted to the NRC in a letter from M.S. Tuckman to the NRC dated November 24, 1998.

5.4.7.2 System Design

5.4.7.2.1 Schematic Piping and Instrumentation Diagrams

The RHRS, as shown in Figure 5-17 and Figure 5-18, consists of two residual heat exchangers, two residual heat removal pumps, and the associated piping, valves, and instrumentation necessary for operational control. The inlet lines to the RHRS are connected to the hot legs of two reactor coolant loops, while the return lines are connected to the cold legs of each of the reactor coolant loops. These return lines are also the ECCS low head injection lines. (See Figure 6-131.)

The RHRS suction lines are isolated from the RCS by two motor-operated valves in series located inside the containment. Each discharge line is isolated from the RCS by two check valves in series located inside the containment and by a normally open motor-operated valve located outside the containment. (The check valves and the motor-operated valve on each discharge line are not part of the RHRS; these valves are shown as part of the ECCS, see Figure 6-131.)

During RHRS operation, reactor coolant flows from the RCS to the residual heat removal pumps, through the tube side of the residual heat exchangers, and back to the RCS. The heat is transferred to the component cooling water circulating through the shell side of the residual heat exchangers.

Coincident with operation of the RHRS, a portion of the reactor coolant flow may be diverted from downstream of the residual heat exchangers to the Chemical and Volume Control System (CVCS) low pressure letdown line for cleanup and/or pressure control. By regulating the diverted flowrate and the charging flow, the RCS pressure may be controlled. Pressure regulation is necessary to maintain the pressure range dictated by the fracture prevention criteria requirements of the reactor vessel and by the number 1 seal differential pressure and net positive suction head requirements of the reactor coolant pumps.

The RCS cooldown rate is manually controlled by regulating the reactor coolant flow through the tube side of the residual heat exchangers. The flow control valve in the bypass line around each residual heat exchanger automatically maintains a constant return flow to the RCS. Instrumentation is provided to monitor system pressure, temperature and total flow.

The RHRS is also used for filling the refueling cavity before refueling. After refueling operations, water is pumped back to the refueling water storage tank until the water level is brought down to the flange of the reactor vessel. The remainder of the water is removed via a drain connection at the bottom of the refueling canal.

When the RHRS is in operation, the water chemistry is the same as that of the reactor coolant. Provision is made for the Process Sampling System to extract samples from the flow of reactor coolant downstream of the residual heat exchangers. A local sampling point is also provided on each residual heat removal train between the pump and heat exchanger.

The RHRS functions in conjunction with the high head portion of the ECCS to provide direct injection of borated water from the refueling water storage tank into the RCS cold legs during the injection phase following a loss of coolant accident. During normal operation the RHRS is aligned to inject borated water upon receipt of a safety injection signal.

In its capacity as the low head portion of the ECCS, the RHRS also provides long term recirculation capability for core cooling following the injection phase of the loss of coolant accident. This function is accomplished by aligning the RHRS to take fluid from the containment sump, cool it by circulation through the residual heat exchangers, and supply it to the core directly as well as via the centrifugal charging pumps and safety injection pumps. The RHRS can also be used during the recirculation phase to provide a residual spray by closing the direct flow paths to the core and opening the flow paths to the residual spray headers.

The use of the RHRS as part of the ECCS and for residual spray is more completely described in Sections 6.3 and 6.2.2 respectively.

<u>Description of Component Interlocks:</u>

The RHR pumps, in order to perform their ECCS function, are interlocked to start automatically on receipt of a safety injection signal. (See Section 6.3).

The RHR suction isolation valves in each inlet line from the RCS are separately interlocked to prevent their being opened when RCS pressure is greater than 385 psig. This interlock is described in more detail in Sections 5.4.7.2.4 and 7.4.5.

An annunciator will alarm in the control room whenever reactor coolant system pressure is greater than 440 psig concurrent with an isolation valve being in the open or intermediate position. The alarm will notify the operator that double barrier isolation between the reactor coolant system and the residual heat removal system is not being maintained.

At least one of the two series suction isolation valves have power removed prior to power operation.

The RHR suction isolation valves are also interlocked to prevent their being opened unless the isolation valves in the following lines are closed:

1. Recirculation lines from the residual heat exchanger outlets to the suctions of the safety injection pumps and centrifugal charging pumps.
2. RHR pump suction line from the refueling water storage tank.
3. RHR pump suction line from the containment sump.

The motor operated valves in the RHR mini-flow bypass lines are interlocked to open when the RHR pump discharge flow is less than 533 gpm and close when the flow exceeds 1400 gpm.

5.4.7.2.2 Equipment and Component Descriptions

The materials used to fabricate RHRS components are in accordance with the applicable code requirements. All parts of components in contact with borated water are fabricated or clad with austenitic stainless steel or equivalent corrosion resistant material. Component parameters are given in Table 5-30.

<u>Residual Heat Removal Pumps</u>

Two pumps are installed in the RHRS. The pumps are sized to deliver reactor coolant flow through the residual heat removal heat exchangers to meet the plant cooldown requirements. The use of two separate residual heat removal trains assures that cooling capacity is only partially lost should one pump become inoperative.

The residual heat removal pumps are protected from overheating and loss of suction flow by miniflow by-pass lines that assure flow to the pump suction. A valve located in each miniflow line is regulated by a signal from the differential pressure switches located in each pump discharge header. The valves open when the residual pump discharge flow is less than 533 gpm and close when the flow exceeds 1400 gpm.

A pressure sensor in each pump discharge header provides a signal for an indicator in the control room. A high pressure alarm is also actuated by the pressure sensor.

The two pumps are vertical centrifugal units with mechanical seals on the shafts. All pump surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

The RHR pumps also function as the low head safety injection pumps in the ECCS. (See Section 6.3 for further information and for the RHR pump performance curves.)

<u>Residual Heat Exchanger</u>

Two residual heat exchangers are installed in the system. The heat exchanger design is based on heat load and temperature differences between reactor coolant and component cooling water existing twenty hours after reactor shutdown when the temperature difference between the two systems is small.

The installation of two heat exchangers in separate and independent residual heat removal trains assures that the heat removal capacity of the system is only partially lost if one train becomes inoperative.

The residual heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell. The tubes are welded to the tube sheet to prevent leakage of reactor coolant.

The residual heat exchangers also function as part of the ECCS (See Section 6.3).

Residual Heat Removal System Valves

Valves that perform a modulating function are equipped with two sets of packings and an intermediate leakoff connection that discharges to the drain header.

The design bases for the RHRS isolation valves are Branch Technical Position RSB5-1 and ICSB-3.

Manual and motor operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. Leakage connections are provided where required by valve size and fluid conditions.

5.4.7.2.3 Control

Each inlet line to the RHRS is equipped with a pressure relief valve sized to relieve the combined flow of all the charging pumps at the relief valve set pressure. These relief valves also protect the system from inadvertent overpressurization during plant cooldown or startup. Each valve has a relief flow capacity of 900 gpm at a set pressure of 450 psig.

The RHR suction relief valve design assumes that one RHRS train is isolated from the RCS thereby requiring the injection flow from two charging pumps be accomodated by one relief valve. The combined flow delivered by two charging pumps is not, however, twice that of a single pump since the two pumps deliver to a common charging header. The combined flow has been calculated and found to be less than 600 gpm at the valve set pressure of 450 psig.

Two limiting situations were analyzed to confirm the capability of the RHRS relief valve to prevent overpressurization in the RHRS.

The first consists of the Reactor Coolant System (RCS) in the initial phase of the RHRS cooldown. RCS temperature and pressure are 350°F and 450 psig respectively and one charging pump is in operation. The operator initiates RHRS operation by opening one suction line and starts the pump. At this point a complete loss of plant air occurs, the charging line flow control valve fails open and the low pressure letdown flow control valve fails closed. The maximum charging pump injection rate is 400 gpm for Catawba at 450 psig RCS pressure. To avoid overpressurizing the RHRS, the suction relief valves must pass these flows at set pressure plus accumulation. The second consists of the RCS in the last part of cooldown. RCS temperature and pressure are less than 200°F and 450 psig, respectively. The additional conservatism of a second charging pump in operation was added since the RHRS is used for extended periods below 200°F. The combined flow of the charging pumps is less than 600 gpm. Each relief valve has a relief flow capacity of 900 gpm at a set pressure of 450 psig. This capacity provides adequate protection for the RHRS overpressurization.

All credible events were examined for their potential to overpressurize the RHRS. These events included normal operating conditions, infrequent transients, and abnormal occurrences. The analysis confirmed that one relief valve has the capability to maintain the RHRS maximum pressure within code limits.

Each discharge line from the RHRS to the RCS is equipped with a pressure relief valve to relieve the maximum possible back-leakage through the valves separating the RHRS from the RCS. Each valve has a relief flow capacity of 20 gpm at a set pressure of 600 psig. These relief valves are located in the ECCS (See Figure 5-17 and Figure 5-18).

The fluid discharged by the suction side relief valves is collected in the pressurizer relief tank. The fluid discharged by the discharge side relief valves is collected in the recycle holdup tank of the boron recycle system. The operator is alerted to the lifting of the RHR relief valves by increasing pressurizer relief tank level, pressure and temperature indications and alarms or by increasing recycle holdup tank level indication and alarm.

The design of the RHRS includes two motor-operated gate isolation valves in series on each inlet line between the high pressures RCS and the lower pressure RHRS. They are closed during normal operation and are only opened for residual heat removal during a unit cooldown after the RCS pressure is reduced to approximately 385 psig and RCS temperature is reduced to approximately 350°F. During a unit startup the inlet isolation valves are shut after drawing a bubble in the pressurizer and prior to increasing RCS pressure above approximately 385 psig. These isolation valves are provided with "prevent-open" interlocks which are designed to prevent possible exposure of the RHRS to normal RCS operating pressure. The two inlet isolation valves in each subsystem are separately and independently interlocked with pressure signals to prevent their being opened whenever the RCS pressure is greater than approximately 385 psig. An annuniciator will alarm in the control room whenever reactor coolant system pressure is greater than 440 psig concurrent with an isolation valve being in the open or intermediate position. A reverse check valve (spring loaded lift check) in parallel with inner RHR suction isolation valve is provided for protection against pressure increases due to heating water trapped between the two isolation valves. During power operation, power is removed from at least one of the two series suction isolation valves in each inlet line.

The use of two independently powered motor-operated valves in each of the two inlet lines, along with two-independent pressure interlock signals for the "prevent-open" function and an alarm at 440 psig and operator action, assures a design which meets applicable single failure criteria. Not only more than one single failure but also different failure mechanisms must be postulated to defeat the function of preventing possible exposure of the RHR system to normal RCS operating pressure. These protective interlock designs, in combination with plant operating procedures, provide diverse means of accomplishing the protective function. For further information on the instrumentation and control features, see Section 7.4.5.

The RHR inlet isolation valves are provided with red-green position indicator lights on the main control board. The indicator lights are powered independently of valve power, thus enabling the lights to remain functional after power has been removed from the valves.

Isolation of the low pressure RHRS from the high pressure RCS is provided on the discharge side by two check valves in series. These check valves are located in the ECCS and their testing is described in Section 6.3.4.2.

The ND pump suction can pressurize after ND pump automatic start for small break LOCA scenarios where reactor coolant system pressure remains above the ND injection pressure. A pressure conrolling bypass line is installed around ND suction check valves FW28 and FW56 to control ND pump suction pressure by venting excess suction volume to the FWST. Each bypass line contains a spring loaded check valve, FW96 on A train and FW97 on B train, designed to remain closed during sump recirculation conditions and open to relieve excess pressure to the FWST prior transfer to cold leg recirculation. The control pressure is determined in CNC-1223.21-00-0020, reference 24. The ND suction pressure control is required to assure that the generic letter 89-10 limits for motor operators on the containment sump isolation valves, NI185A and NI184B, are not exceeded during the transfer to cold leg recirculation in a small break LOCA scenario. The bypass line is isolated from the FWST when the motor operated ND suction valves isolation valves, FW27A (FW55B), are closed to place the associated ND train in RHR operation.

5.4.7.2.4 Applicable Codes and Classifications

The entire RHRS is designed as Nuclear Safety Class 2, with the exception of the suction isolation valves which are Safety Class 1. Component codes and classifications are given in Section 3.2.

5.4.7.2.5 System Reliability Considerations

General Design Criterion 34 requires that a system to remove residual heat be provided. The safety function of this required system is to transfer fission product decay heat and other residual heat from the core at a rate sufficient to prevent fuel or pressure boundary design limits from being exceeded. Safety grade systems are provided in the plant design, both NSSS scope and BOP scope, to perform this function. The NSSS scope safety grade systems which perform this function for all plant conditions except a LOCA are: the Reactor Coolant System (RCS) and steam generators (which operate in conjunction with the auxiliary feed-water system, the steam generator safety, and power operated relief valves) and the Residual Heat Removal (RHR) System (which operates in conjunction with the Component Cooling Water and Nuclear Service Water Systems). The BOP scope safety grade systems which perform this function, for all plant conditions except LOCA, are: the auxiliary feedwater system, the steam generator safety and power operated relief valves, which operate in conjunction with the reactor coolant system and the steam generators; and the Component Cooling Water and Nuclear Service Water Systems, which operate in conjunction with the RHR System. For LOCA conditions, the safety grade system which performs the function of removing residual heat from the reactor core is the ECCS, which operates in conjunction with the Component Cooling Water System and the Nuclear Service Water System.

The Auxiliary Feedwater System, along with the steam generator safety and power operated relief valves, provides a completely separate, independent, and diverse means of performing the safety function of removing residual heat, which is normally performed by the RHR System when RCS temperature is less than 350°F. The Auxiliary Feedwater System is capable of performing this function for an extended period of time following plant shutdown.

The RHR System is provided with two residual heat removal pumps and heat exchangers arranged in two separate, independent flow paths. To assure reliability, each residual heat removal pump is connected to a different vital bus. Each train is isolated from the RCS on the suction side by two motor operated valves in series with each valve receiving power via a separate motor control center and a different vital bus. The power sources for the motor control centers are separate and redundant such that a single failure will not prevent accomplishment of the safety function of these valves which is to isolate the suction line. Each suction isolation valve is also interlocked to prevent exposure of the RHR System to the normal operating pressure of the RCS. (See Section 5.4.7.2.3.)

RHR System operation for normal conditions and for major failures is accomplished completely from the control room when power is restored to the suction isolation valves that have had power removed. This action is discussed in Section 5.4.7.2.7. The redundancy in the RHR System design provides the system with the capability to maintain its cooling function even with major single failures, such as failure of an RHR pump, valve, or heat exchanger without impact on the redundant train's continued heat removal. Additionally, the unit can be maintained safely at hot standby for an extended period of time from outside the control room. A list of instrumentation and controls and a description of the remote shutdown panels is in Section 7.4.

Although such major system failures are within the system design basis, there are other less significant failures which can prevent opening of the RHR suction isolation valves from the control room. Since these failures are of a minor nature, improbable to occur, and easily corrected outside the control room, with ample time to do so, they have been realistically excluded from the engineering design basis. Such failures are not likely to occur during the limited time period in which they can have any effect (i.e., when opening the suction isolation valves to initiate RHR operation); however, even if they should occur, they have no adverse safety impact and can be readily corrected. In such a situation, the auxiliary feedwater system and steam generator power operated relief valves can be used to perform safety function of removing residual heat and in fact can be used to continue the plant cooldown below 350°F, until the RHR System is made available.

One failure of this type is a failure in the interlock circuitry which is designed to prevent exposure of the RHR System to the normal operating pressure of the RCS (See Section 5.4.7.2.3). In the event of such a failure, RHR System operation can be initiated by defeating the failed interlock through corrective action at the Solid State Protection System cabinet or at the individual affected motor control centers.

The other type of failure which can prevent opening the RHR suction isolation valves from the control room is a failure of an electrical power train. Such a failure is extremely unlikely to occur during the few minutes out of a year's operating time during which it can have any consequence. If such an unlikely event should occur, several alternatives are available. The most realistic approach would be to obtain restoration of offsite power, which can be expected to occur in less than 1/2 hour. Other alternatives are to restore the emergency diesel generator to operation, to bring in an alternate power source, or to open the affected valves with their manual handwheels.

The only impact of either of the above types of failures is some delay in initiating RHR operation, while action is taken to open the RHR suction isolation valves. This delay has no adverse safety impact because of the capability of the Auxiliary Feedwater System and steam generator power operated relief valves to continue to remove residual heat, and in fact to continue plant cooldown.

An RHR pump failure and loss of reactor shutdown cooling would result due to inadvertant draining of the reactor coolant below the level of the reactor vessel nozzles. This type of RHR pump failure due to air suction and air entrainment in the suction piping does not have any significant consequences. The possibility of such a pump failure is reduced by the plant operations procedures which require continuous monitoring of water level below a preset level during reactor shutdown. The location of the RHR pumps is such that it provides positive head on the pump inlet and the circulation flow rate is kept low during reactor vessel draining activities to further reduce the possibility of pump failure due to inadvertant errors. Provisions have been made to minimize effects of air entrainment. The operating RHR train would become inoperable due to air entrainment. The alternate RHR train would then be utilized for providing core cooling after sufficient Reactor Coolant System level has been established to support Residual Heat Removal pump operation.

As a result of several "Loss of RHR" events throughout the Nuclear Power Industry, Generic Letter 87-12, "Loss of Residual Heat Removal (RHR) while the Reactor Coolant System (RCS) is Partially Filled", was issued on July 9, 1987. In response to this Generic Letter and Generic Letter 88-17, "Loss of Decay Heat Removal" (issued October 17, 1988), Catawba undertook an extensive review of the physical plant configuration, training programs for plant personnel, administrative procedures, and programmatic enhancements for the plant. The emphasis of these reviews was on improvements to plant operations while the reactor coolant system is partially filled. The changes made to all phases of plant operation are detailed in References 17, 18, and 19.

In response to Generic Letter 2008-01 "Managing Gas Accumulation in ECCS, Decay Heat Removal, and Containment Spray Systems" the RHR system was extensively evaluated for the potential to accumulate gas. Inadequate fill and venting can lead to loss of NPSH, pump cavitation, gas binding the pump, or water hammer. The Generic Letter 2008-01 evaluation concluded that system procedures and design are adequate to maintain the RHR system sufficiently full of water to ensure operability.

A Failure Modes and Effects Analysis of the Residual Heat Removal System is provided in Table 5-31.

The design of the system permits complete isolation of a faulted RHRS loop outside containment with no impact on plant safety.

The major portion of the RHRS is contained in the auxiliary building. Leakages resulting from a passive failure of the RHRS piping will be collected by the floor drain system. The effects of leaks will be detected in the control room via area radiation monitoring alarms. Large leaks in the RHRS will be detected by interpretation of RHRS flow parameters, area radiation monitoring alarms, and high level alarms of the floor drain sumps. Small leaks will be alarmed in the control room by the area radiation monitors in the auxiliary building.

By interpretation of process parameters and alarms, the operators will determine the area where the leakage has occurred. Further information may be obtained by visual observation. Depending on the severity of the leak, the operator will make the determination of the proper course of action.

The RHRS design provides two separate and redundant trains of operational capability. Any single failure (i.e., passive failure of RHRS piping) that would prevent the use of one train of the RHRS will not compromise plant safety. The operational train would continue to remove the decay heat and sensible heat from the RCS and at no time would the reactor core be unprotected. The only consequence would be an extension of the cooldown time.

The RHRS meets the requirements of General Design Criteria 34.

5.4.7.2.6 Evaluation of Compliance with NRC Branch Technical Position RSB 5-1

The following is a discussion of the means by which Catawba Nuclear Station complies with the technical requirements of BTP RSB 5-1.

1. Provide safety-grade steam generator dump valves, operators, air and power supplies which meet the single failure criterion.

   One safety-grade steam generator power operated relief valve is provided for each of the four steam generators. The steam generator power operated relief valves can be operated locally to permit plant cooldown. An in-plant test shall be conducted to demonstrate local manual operation. Hot standby can be achieved and maintained using the safety-grade steam generator safety valves. See the cold shutdown scenario and single failure evaluation provided below (Part II - Removal of Residual Heat).

2. Provide the capability to cooldown to cold shutdown in a reasonable amount of time assuming the most limiting single failure and only offsite power or onsite power available or show that manual actions inside or outside containment or return to hot standby until the manual actions or maintenance can be performed to correct the failure provides an acceptable alternative.

   The plant can be maintained in a safe hot standby condition while any necessary manual actions are taken. The plant is capable of being cooled via natural convection and reaching

Residual Heat Removal System (RHRS) initiation conditions in approximately 36 hours time including the time required to perform any manual actions. See the cold shutdown scenario and single failure evaluation provided below (Part II - Removal of Residual Heat).

3. Provide the capability to depressurize the Reactor Coolant System with only safety-grade systems assuming a single failure and only offsite power or onsite power available or show that manual actions inside or outside containment or remaining at hot standby until manual actions or repairs are complete provides an acceptable alternative.

   The plant can be maintained in a safe hot standby condition while any required manual actions are taken. See the cold shutdown scenario and single failure evaluation provided below (Part IV - Depressurization).

4. Provide the capability for borating with only safety-grade systems assuming a single failure and only offsite power or onsite power available or show that manual actions inside or outside containment or remaining at hot standby until manual actions or repairs are completed provides an acceptable alternative.

   The plant can be maintained in a safe hot standby condition while any required manual actions are taken. See the cold shutdown scenario and single failure evaluation provided below (Part III - Boration and Makeup).

5. Provide the system and component design features necessary for the prototype testing of both the mixing of the added borated water and the cooldown under natural circulation conditions with and without a single failure of a steam generator atmospheric dump valve. These tests and analyses will be used to obtain information on cooldown times and the corresponding AFW requirements.

   HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

   The Catawba test program does not include tests to verify boration or cooldown under natural circulation conditions. *The natural circulation evaluation provided below presents a comparison of Catawba Unit 1 and 2 and Diablo Canyon Unit 1 showing that the natural circulation cooldown tests performed at Diablo Canyon are representative of the natural circulation cooldown and boron mixing capability at Catawba. The results of the testing at Diablo Canyon were reviewed and found to be representative of the natural circulation and cooldown and boron mixing capability at Catawba.*

6. Commit to providing specific procedures for cooling down using natural circulation and submit a summary of these procedures.

   Specific procedures for cooling down using natural circulation will be prepared and submitted to the NRC. A summary of the procedures is provided in the cold shutdown scenario and single failure evaluation provided below.

7. Provide a seismic Category I AFW supply for at least 4 hours at Hot Shut down plus cooldown to the RHR system cut-in based on the longest time (for only onsite or offsite power and assuming the worst single failure), or show that an adequate alternate seismic Category I source will be available.

   Sufficient emergency feedwater is available from the Seismic Category I Standby Nuclear Service Water Pond to permit four hours of operation at hot standby plus cooldown to RHRS initiation conditions. See the cold shutdown scenario and single failure evaluation provided below (Part II Removal of Residual Heat).

8. Provide for collection and containment of RHR pressure relief or show that adequate alternative methods of disposing of discharge are available.

The RHR relief valves located inside containment discharge to the pressurizer relief tank. Those located outside containment discharge to the recycle holdup tank.

COLD SHUTDOWN SCENARIO

The safe shutdown design basis for Catawba is hot standby. The plant can be maintained in a safe hot standby condition while manual actions are taken to permit achievement of cold shutdown conditions following a safe shutdown earthquake with loss of offsite power. Under such conditions the plant is capable of achieving RHRS initiation conditions (approximately 350°F, 385 psig) in a reasonable amount of time, including the time required for any manual actions. To achieve and maintain cold shutdown, four key functions must be performed. These are (1) circulation of the reactor coolant, (2) removal of residual heat, (3) boration and makeup, (4) depressurization of the RCS.

In accordance with RSB 5-1 Catawba is designed such that cold shutdown can be achieved without leaving the control room. The only valves requiring repositioning from outside the control room to achieve cold shutdown are the cold leg accumulator isolation valves. In order to preclude the possibility of mispositioning these valves during normal operation, power to the motor operators of these valves is removed during unit operation. These valves are closed before RCS pressure is reduced below the accumulator pressure as the plant is cooled down from hot standby to cold shutdown. The motor breakers of these valves are located in a readily accessible area of the auxiliary building. The operators have sufficient time to reposition the valves before the plant is cooled from hot standby to cold shutdown. However, cold shutdown can be achieved without closing the accumulator isolation valves, but this would require that additional fluid be reprocessed in the Boron Recycle System.

1. Circulation of Reactor Coolant

   Circulation of the reactor coolant has two stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F. During this stage, circulation of the reactor coolant is provided by natural circulation with the reactor core as the heat source and steam generators as the heat sink. Steam release from the steam generators is initially via the steam generator safety valves and occurs automatically as a result of turbine and reactor trip. Steam release for cooldown is via the steam generator power operated relief valves which may be operated manually. The steam generator power operated relief valves are accessible for local operation. Redundant level and pressure indication is provided in the control room for each steam generator. Power for this instrumentation is derived from the 120 VAC Vital Instrumentation and Control Power System.

   Feedwater to the steam generators is provided by the Auxiliary Feedwater System. The AFS is provided with two 100 percent capacity electric motor driven pumps and one 100 percent capacity turbine driven pump. Each of the motor driven pumps supplies two steam generators and the turbine driven pump supplies water to four steam generators. A seismic Category 1 source of water for the AFS is available from the Standby Nuclear Service Water Pond which has more than sufficient in ventory for the longest cooldown time needed with either only onsite or only offsite power available with an assumed single failure. AFS pump suction switch over to this assured source occurs automatically upon loss of pump suction supply. Sufficient safety-grade instrumentation will be provided in the control room to monitor AFS operation.

   The second stage of reactor coolant circulation is from 350°F to cold shutdown. During this stage, circulation of the reactor coolant is provided by the RHR pumps.

2. Removal of Residual Heat

Removal of residual heat also has two stages in a cooldown from hot standby to cold shutdown. The first stage is from hot standby to 350°F.

During this stage, the steam generators act as the means of heat removal from the Reactor Coolant System (RCS). Initially, steam is released from the steam generators via the steam generator safety valves to maintain hot standby conditions. When the plant operators are ready to begin the cooldown, the steam generator power operated relief valves are opened slightly. As the cooldown proceeds, the operators will occasionally adjust these valves as required to maintain a reasonable cooldown rate. Feedwater makeup to the steam generators is provided from the Auxiliary Feedwater System. The Auxiliary Feedwater System has the ability to remove decay heat by providing feedwater to all four steam generators for extended periods of operation.

The second stage is from 350°F to cold shutdown. During this stage, the RHRS is brought into operation. The heat exchangers in the RHRS act as the means of heat removal from the RCS. In the RHR heat exchangers, the residual heat is transferred to the Component Cooling System which in turn transfers the heat to the Nuclear Service Water System. The Component Cooling and the Nuclear Service Water Systems are both designed to seismic Category I. The RHRS includes two RHR pumps and two RHR heat exchangers.

Each RHR pump is powered from a different emergency power train and each RHR heat exchanger is cooled by a different Component Cooling System loop. If any component in one RHR subsystem becomes inoperable, cooldown of the plant is not compromised; however, the time for cooldown would be extended. The status of the RHRS can be monitored using Class 1E instrumentation in the control room.

The RHRS is protected from overpressurization when it is not isolated from the RCS. Each inlet line as well as each discharge line from the RHRS is equipped with a pressure relief valve. Additionally, an annunciator will alarm in the control room whenever Reactor Coolant System pressure is greater than 440 psig concurrent with an isolation valve being in the open or intermediate position. The alarm will notify the operator that double barrier isolation between the Reactor Coolant System and the Residual Heat Removal System is not being maintained.

If RHRS is unavailable for any reason, cold shutdown may be achieved utilizing alternative methods as discussed in Section II.C of the Single Failure Evaluation.

3. Boration and Makeup

Boration is accomplished using portions of the Chemical and Volume Control System (CVCS). Four wt % boric acid from the boric acid tanks is supplied to the suction of the centrifugal charging pumps by the boric acid transfer pumps. The centrifugal charging pumps inject the borated water into the RCS via the normal charging and/or reactor coolant pump seal injection flow paths. Two boric acid tanks are provided for the plant. They are interconnected so that either tank may be aligned to either unit. Two boric acid transfer pumps are provided for each Unit. The boric acid tanks, boric acid transfer pumps, centrifugal charging pumps, and associated piping are of seismic Category I design. The boric acid transfer pumps and centrifugal charging pumps are powered from emergency power trains.

There is sufficient boric acid volume stored in each tank to provide for a cold shutdown with the most reactive rod withdrawn. Boric acid tank level can be monitored using redundant control room instrumentation which has its power derived from the 120 VAC Vital Instrumentation and Control Power System.

Makeup, in excess of that required for boration can be provided from the Refueling Water Storage Tank (RWST) using centrifugal charging pumps and the same injection flow paths as described for boration. Two motor operated valves, each powered from different emergency power trains and connected in parallel, would transfer the suction of the charging pumps to the RWST. RWST level can be monitored using redundant control room instrumentation which has its power derived from the 120 VAC Vital Instrumentation and Control Power System.

4. <u>Depressurization</u>

Depressurization of RCS is accomplished using portions of the Chemical and Volume Control System (CVCS). Either four wt. % boric acid or refueling water may be used for depressurization with the flow path being from the centrifugal charging pumps via the auxiliary spray valve to the pressurizer. The centrifugal charging pumps of the CVCS are of seismic Category I design and are powered from separate emergency power trains. The pumps can be operated and monitored from the control room. Redundant pressurizer level and RCS pressure indication is provided in the control room for monitoring depressurization. Power for this instrumentation is derived from the 120 VAC Vital Instrumentation and Control Power System.

An alternative method of depressurization consists of discharging reactor coolant from the pressurizer to the pressurizer relief tank via the pressurizer power operated relief valves. Two of each Unit's PORV's including their compressed gas supply have been upgraded to safety grade. Refer to Section 5.2.2.2 for a discussion of PORV capabilities and evaluation of the impact on other safety systems.

5. <u>Instrumentation</u>

Redundant instrumentation which has its power derived from the 120 VAC Vital Instrumentation and Control Power System is available in the control room to monitor key functions associated with achieving cold shutdown. This instrumentation, with the exception of RWST level and Boric Acid Tank level, is discussed in FSAR Section 7.5 in the referenced Table 7-11. Discussions of the RWST Level instrumentation and the Boric Acid Tank Level instrumentation are contained in UFSAR Sections 7.6.5.1 and 9.3.4.2.3.8, respectively.

a. RCS wide range temperature

b. RCS wide range pressure

c. Pressurizer water level

d. Steam generator narrow range water level

e. Steam line pressure

f. RWST wide range level

g. Containment pressure

h. Boric acid tank level

This instrumentation is sufficient to monitor the key functions associated with cold shutdown and to maintain the RCS within the desired pressure, temperature and inventory relationships. Alternatively, operation of the auxiliary systems that service the RCS can be monitored by the control room operator via remote communication with an operator in the plant.

<u>MAINTAINING RCS TEMPERATURE AND PRESSURE DURING COOLDOWN</u>

The plant will be maintained in a hot standby condition while the operator evaluates the initial plant conditions and the availability of equipment and systems (including non-safety grade equipment) that can be used in shutdown. Prior to initiating cooldown, the operator will determine the boration requirements and the method by which the plant will be taken to cold shutdown. In performing the cooldown, the operator will integrate the functions of heat removal, boration and makeup, and depressurization in order to accomplish these functions without letdown from the RCS. Once the plant is cooled to 350°F and depressurized to 385 psig, RHRS operation will be initiated and the RCS will be taken to cold shutdown conditions.

Boration, cooldown, and depressurization will be accomplished in a series of short steps arranged to keep RCS temperature and pressure and pressurizer level in the desired relationships. However, to demonstrate that boration and depressurization can be done without letdown, a simpler scenario can be used. First the operators integrate the cooldown and boration functions taking advantage of the RCS inventory contraction resulting from the cooldown. Then, the operators use auxiliary spray from the CVCS to depressurize the plant to RHRS initiating conditions. Finally, the RCS is cooled to cold shutdown conditions using the RHRS while makeup with borated water continues as necessary.

The calculation to demonstrate this capability assumes worst case boration requirements based on core end of life/peak xenon conditions and the following RCS initial conditions following plant trip:

RCS Temperature	557°F
RCS Pressure	2250 psia
Pressurizer Water Volume	450 ft^3
Pressurizer Steam Volume	1350 ft^3

The cooldown from 557°F to 350°F decreases the volume of water in the RCS by approximately 1610 cubic feet assuming that the pressurizer is not cooled and the water level is maintained at the initial condition. Makeup for contraction is supplied by 4 wt % boric acid stored in the boric acid tanks at 70°F. A boric acid tank volume of approximately 1450 cubic feet will expand to approximately 1610 cubic feet as it is heated to the RCS temperature 350°F. The volume of four wt % boric acid at 70°F required for boration to technical specification requirements at 350°F is approximately 1350 cubic feet. Thus the volume required for boration is significantly less than the volume available due to contraction.

To calculate if depressurization can be accomplished without letdown and without taking the plant water solid, it was assumed that the pressurizer was initially in the following state:

STATE 1	
Volume, Total, Ft^3	1800
Volume, Liquid, Ft^3	450
Volume, Steam, Ft^3	1350
T_1 = Tsat, °F	653
P_1 = Psat, psia	2250
Quality, X	0.337

It was further assumed that no additional water would be removed from the pressurizer by cooldown contraction. With these assumptions, and including the effect of heat input from the pressurizer metal, it was determined that spraying approximately 36,003 lbm of 70°F water would produce the following state:

STATE 2	
Volume, Total, Ft^3	1800
Volume, Liquid, Ft^3	1180
Volume, Steam, Ft^3	620
T_2 = Tsat, °F	450
P_2 = Psat, psia	422.1
Quality, X	0.0092

Additionally, note that the safety grade means of RCS depressurization is release of steam from the pressurizer by opening a safety grade PORV, utilizing safety-grade nitrogen gas supplied from the associated Cold Leg Accumulator. Refer to Section 5.2.2.2 for a discussion of PORV capabilities and evaluation of the impact on other safety systems.

Once depressurized to 385 psig, RHRS operation may be initiated and cooldown can continue to cold shutdown conditions. The cooldown from 350°F to 200°F further decreases the volume of water in the RCS by approximately 550 cubic feet assuming that the pressurizer is not cooled. Makeup for contraction is again supplied by 4 wt % boric acid. A boric acid tank volume of approximately 530 cubic feet will expand to approximately 550 cubic feet as it is heated to the RCS temperature of 200°F. The additional volume required for boration at 200°F, to maintain the reactor within the technical specification shutdown requirements, is no more that 260 cubic feet, the operator having taken full advantage of the previous contraction. Thus, the technical specification requirements for cold shutdown conditions are satisfied.

The results of the calculations described above demonstrate that, based on the assumed initial conditions, boration and depressurization with 4 wt % boric acid can be accomplished without letdown and without taking full credit for the available volume created by the cooldown contraction. Should boration without letdown prove impractical due to any combination of plant conditions or equipment failures, letdown can be achieved by discharging RCS inventory via the pressurizer power operated relief valves or the reactor vessel head vent valves.

<u>SINGLE FAILURE EVALUATION</u>

1. <u>Circulation of the Reactor Coolant</u>

   a. From Hot Standby to 350°F (refer to FSAR Figure 5-1, Figure 10-5, and Figure 10-27) - four reactor coolant loops and four steam generators are provided, any two of which can provide sufficient natural circulation flow to provide adequate core cooling. Even with the most limiting single failure (loss of single channel power to PORV's resulting in loss of one PORV), two of the reactor coolant loops and steam generators remain available. Local operation of these PORVs is credited in the event that remote operation is unavailable.

   b. From 350°F to cold shutdown (refer to FSAR Figure 5-17 and Figure 5-18) two RHR pumps are provided, either one of which provide adequate circulation of the reactor coolant.

2. <u>Removal of Residual Heat</u>

a. From Hot Standby to 350°F (refer to FSAR Figure 10-5, Figure 10-33, Figure 10-34, Figure 9-27 and Figure 9-31).

   1) Steam Generator Power Operated Relief Valves - These are air operated valves. Four are provided (one per steam generator), any two of which are sufficient for residual heat removal. In the event of a single failure, three power operated relief valves remain available. Loss of single channel power supply results in the loss of one PORV (fail closed). In case of air supply failure, these valves fail to the closed position. The valves are qualified as safety grade and have safety grade controls and backup nitrogen supply in the event instrument air is lost. These features assure operability from the main control room. Additionally, each valve is provided with a handwheel to allow manual control if necessary. The valves are located in the doghouse and are accessible by means of a permanent ladder and scaffolding arrangement. The environment in the doghouse during this cooldown event will not prevent entry for access to the valve. These valves may be reached by an operator in a few minutes. Local operation of these PORVs is credited in the event that remote operation is unavailable.

   2) Auxiliary Feedwater Pumps - Two 100% capacity motor driven pumps and one 100% capacity turbine driven pump are provided. In the event of a single failure, two pumps remain available to provide sufficient feedwater flow.

   3) Auxiliary Feedwater Flow Control Valves CA36, 40, 44, 48, 52, 56, 60, 64 - These are air operated valves. In the event of a single failure of one flow control valve (which affects flow to one steam driven pump) emergency feed flow can still be provided to all four steam generators from the other pumps. In case of air supply failure these valves fail open to a throttled position set to assure adequate flow to the steam generators while, at the same time, preventing unacceptable runout of the auxiliary feed water pumps. As cooldown progresses, flow may be reduced by tripping auxiliary feedwater pump(s) and manually throttling the control valves on the discharge of the operating auxiliary feedwater pumps with handwheels provided. The motor driven pump control valves are located in the auxiliary feedwater pump room and may be reached in a few minutes. Two of the turbine driven pump control valves (CA36, 64) are also located in the auxiliary feedwater pump room. The other two turbine driven pump control valves (CA48, 52) are located in the mechanical penetration room and may also be reached in a few minutes. The environment in this room during this cooldown event will not prevent entry for access to the valves. Time required for setting each valve is estimated to be less than 15 minutes.

   4) If the normal non-seismic sources of auxiliary feedwater are not available, automatic re-alignment to the seismic Category 1 Standby Nuclear Service Water Pond is provided. Separate and redundant lines provide water to the suction of the AFS pumps.

b. From 350°F to 200°F Utilizing RHR System (refer to FSAR Figure 5-17, Figure 5-18, Figure 6-131, Figure 9-89, Figure 9-27, Figure 9-31, and Figure 9-35.

   1) RHR suction isolation valves ND1B and ND2A (to RHR pump 1A) and ND36B and ND37A (to RHR pump 1B) - The two valves in each RHR subsystem are each powered from different emergency power trains. Failure of either power train can prevent initiation of RHR cooling in the normal manner from the control room. In the event of such a failure, the affected valve(s) can be deenergized and opened with its handwheel or can be opened using alternate power via programmed operator action outside of the control room. Any other single failure can be tolerated as it would only

affect one of the RHR subsystems and adequate cooling can be provided by the redundant subsystem. Alternatively, in the event of a power train failure, the plant could remain in a safe hot standby condition with heat removal via the steam generators until an alternative method of cooldown can be established as described in C below.

2) RHR Pumps A and B - Each pump is powered from a different emergency power train. In the event of a single failure, either pump can provide sufficient RHR flow.

3) RHR Heat Exchangers A and B - If either heat exchanger is unavailable for any reason, the remaining heat exchanger can provide sufficient heat removal capability.

4) RHR Flow Control Valves ND26 and ND60 - These are air operated valves. Upon loss of air these valves would fail in the open position, thus guaranteeing sufficient RHR flow. If a single failure causes one of the valves to fail in a closed or partially closed position, the remaining RHR train can provide sufficient RHR flow.

5) RHR/SIS Cold Leg Isoltion Valves NI173A and NI178B - These are parallel, normally open, motor operated valves which are powered from separate emergency power trains. Sufficient RHR cooling flow can be provided through either valve. These valves are also equipped with handwheels for manual operation.

6) Component Cooling System - Two redundant trains are provided, either of which can provide sufficient heat removal capacity via one of the RHR heat exchangers.

7) Nuclear Service Water System - Two redundant trains are provided, either of which can provide sufficient heat removal via one of the Component Cooling System heat exchangers.

c. From 350°F to 200°F Utilizing Secondary Plant Systems (refer to FSAR Figure 10-5, Figure 10-33, and Figure 10-34)

Cooldown to a main steam temperature of 212°F may be accomplished utilizing natural RCS circulation with auxiliary feedwater to no more than two steam generators and associated power operated relief valves. Coincident with this operation, the remaining steam generators may be prepared for cooldown to a RCS temperature of 200°F utilizing feed and bleed of cold feedwater.

As an example, assume steam generators A and B, their associated power operated relief valves, and motor driven auxiliary feedwater pump A are being used to cooldown to a main steam temperature of 212°F. Concurrently, main feedwater and auxiliary feedwater lines to steam generators C and D may be isolated, and crossover and drain lines installed to allow cold lake water to be fed by motor driven auxiliary feedwater pump B through the main feed nozzles and out the auxiliary feedwater nozzles which are located well above the tubes. This would require filling the generators to a level above the auxiliary feed nozzle. Monitoring of levels in this range may be established utilizing instrumentation provided for steam generator wet layup recirculation.

This is but one of several alternative means of achieving cold shutdown. For instance, a less desirable but workable method would be to feed and bleed the reactor coolant system utilizing ECCS and the pressurizer power operated relief valves.

3. <u>Boration and Makeup</u> (refer to FSAR Figure 9-89, Figure 9-90, Figure 9-91, Figure 9-94, Figure 9-96, Figure 6-128 and Figure 6-130)

a. Boric Acid Tanks 1 and 2 - Two boric acid tanks are provided with one aligned to each unit. Each tank contains sufficient 4 wt % boric acid to borate the RCS to cold shutdown with the most reactive rod with drawn.

b. Boric Acid Transfer Pumps A and B - Two pumps are aligned to each tank. Each pump is powered from a different emergency power train. In the event of a single failure, either pump can provide sufficient boric acid flow.

c. Flow Control Valve NV238A - This is an air operated valve which fails open on loss of air or power to allow boric acid flow to the suction of the centrifugal charging pumps. MOV NV236B, which is supplied from a separate power train, may be opened to supply boric acid flow directly to the suction header or the centrifugal charging pumps if required.

d. Isolation Valves NV181A and NV186A - These are air operated valves. If either of these valves fails closed, the alternative valve may be opened. If both valves fail closed due to loss of air or power, MOV NV236B may be opened to supply boric acid flow directly to the suction header of the centrifugal charging pumps.

e. Charging Pump Suction Isolation Valves NV188A and NV189B. These normally open, motor operated valves are piped in series. If one of these valves closes spuriously, an operator can de-energize the valve operator and reopen the valve with its handwheel. If mechanical failure makes it impossible to open one of these valves, refueling water storage tank isolation valve NV252A or NV253B may be opened to provide makeup flow to the charging pumps. Boration flow may be provided via MOV NV236B directly to the suction of the charging pumps.

   Unit 1 Only: Valves 1NV188A and 1NV189B are electrically interlocked with isolation valves 1NV252A and 1NV253B. When either 1NV188A or 1NV189B starts to close, both 1NV252A and 1NV253B will go open.

f. Centrifugal Charging Pumps A and B - Pumps A and B are powered from redundant emergency power trains. In the event of a single failure, either pump can provide sufficient boration or makeup flow.

g. Normal Charging Flow Control Valve NV294 - This is an air operated valve which fails open upon loss of air to assure a charging flow path. If the valve will not open due to a mechanical problem, a charging flow path may be established by opening valves NI9A or NI10B. Since its normal function is to ensure normal RCP seal injection flow, its failure to the open position reduces this flowrate. Alternate means of RCP seal cooling is provided by reactor coolant seal leakage cooled by the KC System via the thermal barrier cooler.

h. Charging Flow Control Valve NV309 - This is an air operated valve which fails open upon loss of air or power to assure a charging flow path. If the valve will not open due to a mechanical problem, a flow path may be established as explained in 3g above.

i. Charging Line Isolation Valves NV312A and NV314B - If either of these normally open motor operated valves closes spuriously, an operator may de-energize the valve operator and reopen the valve with its hand wheel. If this is not possible a flow path can be established as in 3g above.

j. Reactor Coolant Loop A Charging Isolation Valve NV32B - This is an air operated valve which fails open upon loss of air or power to assure a charging flow path. It is supplied with Train B emergency power. Loop 4 charging isolation valve NV39A which also fails open upon loss of air or power, may also be opened to provide a charging flow path. NV39A is supplied with Train A emergency power.

k. Centrifugal Charging Pump to the Cold Leg Discharge Isolation Valves NI9A and NI10B - Each valve is powered from a different emergency power train; only one of these normally closed, motor operated valves needs to be opened to provide an alternate path and source for boration.

l. Refueling Water Storage Tank Isolation Valves NV252A and NV253B - Each valve is powered from a different emergency power train. Only one of these normally closed motor operated valves needs to be opened to provide an alternate makeup flow path from the RWST to the centrifugal charging pumps.

   Unit 1 Only: Valves 1NV252A and 1NV253B are electrically interlocked with isolation valves 1NV188A and 1NV189B. When either 1NV188A or 1NV189B starts to close, both 1NV252A and 1NV253B will go open.

4. <u>Depressurization</u> (refer to FSAR Figure 5-2, Figure 5-17, Figure 5-18, and Figure 9-89)

   a. Auxiliary Spray Valve NV37A This is a motor operated valve which receives train A essential power. In the event train A power is lost, this valve may be manually operated via a handwheel. This valve is located in the pipe chase behind the crane wall inside the Containment Building and is readily accessible. Estimated amount of time to perform this operation is under one hour. Temperatures and pressures in this area for this cooldown mode will be in the normal range (< 120°F, 0 psig). Radioactivity at this location will not hinder the operation.

      If NV37A is stuck closed as a result of mechanical failure, the redundant seismic Category 1 pressurizer power operated relief valves may be used to depressurize the RCS by discharging to the pressurizer relief tank as described in item 4c.

      The PORV valve operators are provided safety grade nitrogen supplies to the air piston actuators in addition to the compressed air to assure operability from the main control room assuming worst single failure. Also available is a line from the residual heat removal pumps which is controlled by NV857. NV857 is operated from the control room, and was added in order to eliminate temperature transients that exist at the pressurizer nozzles during auxiliary pressurizer spray. NV857 will be used for normal auxiliary spray, even though NV37A is available.

   b. Charging Valves NV39A and NV32B - These air operated valves fail open on loss of air or power. In this case, NV39A and NV32B may be closed by using portable compressed air or nitrogen bottles. Both of these valves are located in the pipe chase behind the crane wall inside the Containment Building and are readily accessible. Estimated amount of time to perform this operation is less than one hour. Temperatures and pressures in this area for this cooldown mode will be in the normal range (< 120°F, 0 psig). Radioactivity at this location will not hinder the operation.

      If NV39A and NV32B is stuck open as a result of mechanical failure, the redundant seismic Category 1 pressurizer power operated relief valves may be used to depressurize the RCS by discharging to the pressurizer relief tank as described in item c below.

      Certain conditions may make normal or excess letdown either impractical or impossible. A loss of electrical power such as a vital AC bus, could lead to isolation of the normal letdown path since the motor-operated letdown isolation valves are assumed to fail in the most disadvantageous position. For this reason, given a loss of electrical power, the normal and excess letdown paths would be isolated. A loss of air to the air operated valves in the letdown line would cause isolation of the letdown path since several of the air operated valves affected are flow control valves. If for any reason, the Reactor Coolant indicates a high level of activity, then letdown to the Auxiliary Building may not be feasible since this action could limit access to this building. A safety grade means of letdown is available through the pressurizer PORV's to the pressurizer relief tank (PRT) or through the Reactor Vessel head vent valves to the PRT. For Catawba, depressurization and boration can be achieved without letdown. However, should letdown occur to the PRT it will be a problem for containment access.

c. Pressurizer Power Operated Relief Valves (PORV's), NC32B, NC34A, NC36B - These are air operated valves which fail to the closed position on loss of air or power. As indicated above, these valves may be used to depressurize the RCS. The operator may open them from the control room, thus discharging steam from the pressurizer to the pressurizer relief tank. If the normal air supply is not available to actuate these valves, a supply of nitrogen may be made available to either NC34A or NC32B from cold leg safety injection accumulators A or B, respectively.

   Two of each Unit's PORV's (NC32B and NC34A) including their nitrogen supply from separate cold leg accumulators have been upgraded to safety grade. Thus even with a single failure of one of these valves the other will remain operable and capable of reducing RCS pressure. Refer to Section 5.2.2.2 for a discussion of PORV capabilities and circulation of the impact on other safety systems.

d. RHR Suction Isolation Valves ND1B, ND2A, ND36B, and ND37A - The RHR suction isolation valves are qualified for the steam line break environment. Therefore, they are qualified for the less severe environment that would result if, as described in 4c, the RCS is depressurized by discharging the pressurizer to the pressurizer relief tank.

5. Instrumentation

   Sufficient instrumentation is provided in the control room to monitor key functions. In the event of a single failure, the operator can make comparisons between duplicate information channels or between functionally related channels in order to identify the particular malfunction. Refer to FSAR Section 7.5 for applicable details.

NATURAL CIRCULATION

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

Catawba Unit 1 and Unit 2 and Diablo Canyon Unit 1 have been compared in detail to ascertain any differences between the two plants that could potentially affect natural circulation flow and attendant boron mixing.

The general configuration of the piping and components in each reactor coolant loop is the same in both Catawba and Diablo Canyon. Both plants have Model 93A reactor coolant pumps. Catawba Unit 1 has BWI steam generators, Catawba Unit 2 has Westinghouse Model D5 *and Diablo Canyon has Westinghouse Model 51 steam generators. The elevation head and flow resistances represented by these components and the system piping is similar.*

The following comparisons are based on Catawba Unit 1 having the original Westinghouse Model D3 steam generators. The BWI replacement steam generators have a lower flow resistance than the Model D3 steam generators. Therefore the following comparision is conservative for Catawba Unit 1 with BWI steam generators.

To compare the natural circulation capabilities of Catawba and Diablo Canyon, the hydraulic resistance coefficients were compared. The hydraulic resistance coefficients applicable to normal flow conditions are as follows:

	Diablo Canyon Unit 1	*Catawba Unit 1*	*Catawba Unit 2*
Reactor Core & Internals	*8.0 x 10^{-10}ft/(loop gpm)^2*	*6.9 x 10^{-10}*	*6.9 x 10^{-10}*
Reactor Nozzles	*36.8*	*27.6*	*27.6*
RCS Piping	*24.0*	*24.0*	*24.0*
Steam Generator	*114.0*	*110.6*	*116.8*
TOTAL LOOP	*182.8*	*169.1*	*175.3*

Note: *The following ratios were revised in 2003 update.*

$$Flow\ Ratio\,\frac{Diablo\ Canyon}{Catawba\ Unit\ 1} = \frac{182.8}{169.1} = 1.04$$

$$Flow\ Ratio\,\frac{Diablo\ Canyon}{Catawba\ Unit\ 2} = \frac{182.8}{175.3} = 1.02$$

The general arrangement of the reactor core and internals is the same in Catawba and Diablo Canyon. The coefficients indicated represent the resistance seen by the flow in one loop.

The reactor vessel outlet nozzle configuration for both plants is the same. The radius of curvature between the vessel inlet nozzle and downcomer section of the vessel on the two plants is different. Based on 1/7 scale model testing performed by Westinghouse and other literature, the radius on the vessel nozzle/vessel downcomer juncture influences the hydraulic resistance of the flow turning from the nozzle to the downcomer. The Diablo Canyon vessel inlet nozzle radius is significantly smaller than that of Catawba, as reflected by the higher coefficient for Diablo Canyon.

The coefficient of resistance for the RCS piping for both plants is the same.

Details of the specific steam generator units were also compared to ascertain any variation (e.g., primary volume, tube height, tube diameter) that could affect natural circulation capability by changing the effective elevation of the heat sink or the hydraulic resistance seen by the primary coolant. It was concluded that there are no differences in the design of the steam generators in these plants that would significantly affect the natural circulation characteristics.

As indicated, the difference between the total resistance coefficients for the two plants is insignificant. It is expected that the relative effect of the coefficients would be the same under natural circulation conditions resulting in a natural circulation loop flow rate for Catawba Unit 1 within 4 percent of that for Diablo Canyon Unit 1 and for Catawba Unit 2 within 2 percent of Diablo Canyon Unit 1.

The coefficients provided reflect the flow rate and associated heat removal capability of an individual loop in the plant. The comparison, therefore, does not take into consideration the number of loops available nor the core heat to be removed. An evaluation of the Catawba Steam Relief and Auxiliary Feedwater Systems has been performed to demonstrate that cooling can be provided via three steam generators following the most limiting single active failure, i.e., the failure of steam generator power operated relief valve.

Loop natural circulation flow is dependent on reactor core decay heat which is a function of time based on core power operating history. Under natural circulation flow conditions, flow into the *upper head area will constitute only a small percentage of the total core natural circulation flow and therefore will not result in an unacceptable thermal/hydraulic impedance to the natural circulation flow required to cool the core.*

For typical 4-loop plants (including Catawba and Diablo Canyon), there are three potential flow paths by which flow crosses the upper head region boundary in a ractor. These three paths are head cooling spray nozzles, the support columns[3] and the guide tubes. The head cooling spray nozzle is a flow path between the downcomer region and the upper head region. The temperature of the fluid which enters the head via this path corresponds to the cold leg value (i.e., T[cold]).

Fluid may also be exchanged between the upper plenum region (i.e., the portion of the reactor between the upper core plate and the upper support plate) and the upper head region via the guide tubes and support columns. Guide tubes and support columns are dispersed in the upper plenum region from the center to the periphery. Because of the non-uniform pressure distribution at the upper core plate elevation and the flow distribution in the upper plenum region, the pressure in the support columns and guide tubes varies from location to location. These support column and guide tube pressure variations create the potential for flow to either enter or exit the upper head region via the support columns or guide tubes.

To ascertain any difference between the upper head cooling capabilities between Diablo Canyon and Catawba, a comparison of the hydraulic resistance of the upper head regions was made. These flow paths were considered in parallel to obtain the following results.

	Catawba Units 1 and 2	***Diablo Canyon Unit 1***
Flow Area (ft^2)	*2.71*	*0.77*
Loss Coefficient	*2.03*	*1.51*
Overall Hydraulic Resistance (ft^4)	*0.276*	*2.57*
Relative Head Region Flow Rate	*3.05*	*1.00*

As indicated above the effective hydraulic resistance to flow in Caawba is only 11% of that in Diablo Canyon. Assuming that the same pressure differential existed in both plants the Catawba head flow rate would be three times the Diablo Canyon flow. Thus, the upper head cooling capability at Catawba would be no worse and would likely be better than demonstrated by the Diablo Canyon natural circulation cooldown test.

In conclusion, the results of the natural circulation cooldown tests performed at Diablo Canyon are representative of the natural circulation and boron mixing capability of Catawba, and the results of these tests have been reviewed and found to be acceptable.

5.4.7.2.7 Manual Actions

The RHRS is designed to be fully operable from the control room for normal operation when power is restored to the suction isolation valves that have had power removed. This requires an operator be dispatched to the valve motor control center to close the motor control center compartment breaker. Manual operations required of the operator are: restoring power to the suction isolation valves that have power removed, opening the suction isolation valves, positioning the flow control valves down stream of the RHRS heat exchangers, and starting the RHR pumps.

[3] Support columns are not a potential path for Diablo Canyon, a non-UHI plant.

Manual actions required outside the control room, under conditions of single failure, are discussed in Section 5.4.7.2.5.

5.4.7.3 Performance Evaluation

The performance of the RHR system in reducing reactor coolant temperature is evaluated through the use of heat balance calculations on the Reactor Coolant System, and the Component Cooling Water System at stepwise intervals following the initiation of RHR operation. Heat removal through the RHR and CCW heat exchangers is calculated at each interval by use of standard water-to-water heat exchanger performance correlations; the resultant fluid temperatures for the RHR and CCW systems are calculated and used as input to the next interval's heat balance calculation.

Assumptions utilized in the series of heat balance calculations describing plant RHR cooldown are as follows:

1. RHR operation is initiated four (4) hours after reactor shutdown.
2. RHR operation begins at a reactor coolant temperature of 350°F.
3. Thermal equilibrium is maintained throughout the Reactor Coolant System during the cooldown.
4. Component Cooling Water temperature during cooldown is limited to a maximum of 120°F.

Refer to section 5.4.7.1 for a discussion of the expected cooldown performance.

5.4.7.4 Preoperational Testing

Preoperational testing of the RHRS is addressed in Section 14.4.

5.4.8 Reactor Water Cleanup System

The Chemical and Volume Control System provides reactor coolant cleanup and is discussed in Chapter 9. The radiological considerations are discussed in Chapter 11.

5.4.9 Main Steam Line and Feedwater Piping

Refer to Sections 10.3 and 10.4.7 for a discussion of main steam line and feed-water piping.

5.4.10 Pressurizer

5.4.10.1 Design Bases

The general configuration of the pressurizer is shown in Figure 5-21. The design data of the pressurizer are given in Table 5-32. Codes and material requirements are provided in Section 5.2.

The pressurizer provides a point in the Reactor Coolant System (RCS) where liquid and vapor can be maintained in equilibrium under saturated conditions for pressure control purposes.

5.4.10.1.1 Pressurizer Surge Line

The surge line is sized to minimize the pressure drop between the RCS and the safety valves with maximum allowable discharge flow from the safety valves.

The surge line and the thermal sleeves are designed to withstand the thermal stresses resulting from volume surges of relatively hotter or colder water which may occur during operation.

The pressurizer surge line nozzle diameter is given in Table 5-32 and the pressurizer surge line dimensions are shown in Figure 5-3.

In response to NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification, analyses were performed to confirm the adequacy of the existing surge line piping. These analyses provided Catawba specific data to augment the results obtained from the Westinghouse Owners Group Pressurizer Surge Line Thermal Stratification Generic Detailed Analysis (WCAP-12639).

The following applicability analyses were conducted: a specific review of operating records to ensure that system ΔT limits assumed in WCAP-12639 were not exceeded, a verification of operational methods to ensure that they were consistent with the methods assumed in WCAP-12639 (Limits on system ΔT for future operation are recommended), and a verification of applicability of seismic OBE bending moments used in the fatigue analysis and combined deadweight and OBE moments at the hot leg nozzle.

The following Catawba specific evaluations were performed: an evaluation of the adequacy of pipe support(s) for loads and displacements, an evaluation of the effects of stratification on stress and fatigue at integral welded attachments (lugs, plates, etc.), and an evaluation of the effects of stratification on stress and fatigue of the pressurizer nozzle.

In addition to the applicability and plant specific evaluations, the following was also evaluated: the new maximum pipe movements aganist available rupture restraint gaps, the effect of stratified movements on rupture restraint blowdown loads; and the effect of stratification on postulated break locations.

The results of Licensee Event Reports (LERs) 413/90-22, 413/90-25, 414/90-12 and 413/90-13 were adequately accounted for in the response to NRC Bulletin 88-11.

The results of all of the above analyses confirmed the adequacy of the existing design for Catawba. See references 20, 21 and 22 for detailed discussions of the analyses and the results.

5.4.10.1.2 Pressurizer

The volume of the pressurizer is equal to, or greater than, the minimum volume of steam, water, or total of the two which satisfies all of the following requirements:

1. The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to system volume changes.
2. The water volume is sufficient to prevent the heaters from being uncovered during a step load increase of ten percent at full power.
3. The steam volume is large enough to accomodate the surge resulting from 95 percent reduction of full load with automatic reactor control and 70 percent steam dump without the water level reaching the high level reactor trip point.
4. The steam volume is large enough to prevent water relief through the safety valves following a loss of load with the high water level initiating a reactor trip, without reactor control or steam dump.
5. The pressurizer will not empty following reactor trip and turbine trip.
6. The emergency core cooling signal is not activated during reactor trip and turbine trip.

5.4.10.2 Design Description

5.4.10.2.1 Pressurizer Surge Line

The pressurizer surge line connects the pressurizer to one reactor hot leg and enables continuous coolant volume pressure adjustments between the RCS and the pressurizer.

5.4.10.2.2 Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads constructed of carbon steel, with austenitic stainless steel cladding on all internal surfaces exposed to the reactor coolant. A stainless steel liner or tube may be used in lieu of cladding in some nozzles.

The surge line nozzle and removable electric heaters are located in the bottom of the pressurizer. The heaters are removable for maintenance or replacement.

A thermal sleeve is provided to minimize thermal stresses in the surge line nozzle. A retaining screen at the nozzle prevents any foreign matter from entering the RCS and baffles in the lower section of the pressurizer prevent an insurge of cold water from flowing directly to the steam/water interface and assist in mixing.

Spray line nozzles, relief and safety valve connections are located in the top of the vessel. Spray flow is modulated by automatically controlled air-operated valves. The spray valves also can be operated manually by a switch in the control room.

A small continuous spray flow is provided through a manual bypass valve around the power-operated spray valves to assure that the pressurizer liquid is homogenous with the coolant and to prevent excessive cooling of the spray piping.

During an outsurge from the pressurizer, flashing of water to steam and generation of steam by automatic actuation of the heaters keep the pressure above the minimum allowable limit. During an insurge from the RCS, the spray system, which is fed from two cold legs, condenses steam in the vessel to prevent the pressurizer pressure from reaching the setpoint of the power-operated relief valves for normal design transients. Heaters are energized on high water level during insurge to heat the subcooled surge water that enters the pressurizer from the reactor coolant loop.

Material specifications are provided in Table 5-6 for the pressurizer, and the surge line. Material Specifications are provided in Table 5-7 for the pressurizer relief tank. Design transients for the components of the RCS are discussed in Section 3.9.1. Additional details on the pressurizer design cycle analysis are given in Section 5.4.10.3.5.

<u>Pressurizer Instrumentation</u>

Refer to Chapter 7 for details of the instrumentation associated with pressurizer pressure, level, and temperature.

<u>Spray Line Temperatures</u>

Temperatures in the spray lines from the two cold leg loops are measured and indicated. Alarms from these signals are actuated to warn the operator of low spray water temperature, or indicate insufficient flow in the spray lines.

<u>Safety and Relief Valve Discharge Temperatures</u>

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage or relief through the associated valve.

5.4.10.3 Design Evaluation

5.4.10.3.1 System Pressure

Whenever a steam bubble is present within the pressurizer, the RCS pressure will be maintained by the pressurizer. Analyses have been done to indicate that proper control of pressure is maintained for the operating conditions.

A safety limit has been set to ensure that the RCS pressure does not exceed the maximum transient value allowed under the ASME Code, Section III, and thereby assure continued integrity of the RCS components.

An evaluation of plant conditions of operation, which follow, indicates that this safety limit is not reached.

During startup and shutdown, the rate of temperature change in the RCS is controlled by the operator. Heatup rate is controlled by pump energy and by the pressurizer electrical heating capacity. This heatup rate takes into account the continuous spray flow provided to the pressurizer.

During startup and shutdown, RCS pressure is controlled by use of the pressurizer heaters and the pressurizer spray.

5.4.10.3.2 Pressurizer Performance

The normal operating water volume at full load conditions is a percentage of the internal vessel volume. Under part load conditions, the water volume in the vessel is reduced for proportional reductions in unit load to accommodate the accompanying thermal contractions of the reactor coolant. The various unit operating transients are analyzed and the design pressure is not exceeded with the pressurizer design parameters as given in Table 5-32.

5.4.10.3.3 Pressure Setpoints

The RCS design and operating pressure together with the safety, power relief and pressurizer spray valves setpoints, and the protection system setpoint pressures are listed in Table 5-37. The design pressure allows for operating transient pressure changes. The selected design margin considers core thermal lag, coolant transport times and pressure drops, instrumentation and control response characteristics, and system relief valve characteristics.

5.4.10.3.4 Pressurizer Spray

Two separate, automatically controlled spray valves with remote manual overrides are used to initiate pressurizer spray. In parallel with each spray valve is a manual throttle valve which permits a small continuous flow through both spray lines to reduce thermal stresses and thermal shock when the spray valves open, and to help maintain uniform water chemistry and temperature in the pressurizer. Temperature sensors with low alarms are provided in each spray line to alert the operator to insufficient bypass flow. The common spray line piping routed to the pressurizer forms a water seal which prevents the buildup of steam back to the control valves. The spray rate is selected to prevent the pressurizer pressure from reaching the operating setpoint of the power relief valves during a step reduction in power level of ten percent from full load.

The pressurizer spray lines and valves are large enough to provide adequate spray using as the driving force the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg. The spray line inlet connections extend into the cold leg piping in the form of a scoop in order to utilize the velocity head of the reactor coolant loop flow adds to the spray driving force. The spray valves and spray line connections are arranged so that the spray will operate when one reactor coolant pump is not operating. The line may also be used to assist in equalizing the boron concentration between the reactor coolant loops and the pressurizer.

A flow path permits uncooled hot leg fluid from the discharge of the RHR pump to be directed to the pressurizer spray line. This piping provides normal auxiliary pressurizer spray which is required to lower the RCS pressure during cool-down once the reactor coolant pumps have been secured (normal pressurizer spray is not possible when the A & B reactor coolant pumps are not operating). A backup source of auxiliary spray is available by diverting a portion of the charging flow into the pressurizer. This was the intended means of auxiliary spray until stress analysis revealed that an acceptable number of cycles could not be accommodated due to the temperature transient on the piping. Hot leg fluid is warmer than charging fluid and therefore does not produce as extreme a transient. A minimial number of charging auxiliary spray has been included in the piping analysis for inadvertent operation and for emergencies.

5.4.10.3.5 Pressurizer Design Analysis

The occurrences for pressurizer design cycle analysis are defined as follows:

1. The temperature in the pressurizer vessel is always, for design purposes, assumed equal to the saturation temperature for the existing RCS pressure, except in the pressurizer steam space subsequent to a pressure increase. In this case the temperature of the steam space will exceed the saturation temperature since an isentropic compression of the steam is assumed.

   The only exception of the above occurs when the pressurizer is filled water solid during RCS venting.

2. The temperature shock on the spray nozzle is assumed to equal the temperature of the nozzle minus the cold leg temperature and the temperature shock on the surge nozzle is assumed to equal the pressurizer water space temperature minus the hot leg temperature.

3. Pressurizer spray is assumed to be initiated instantaneously to its design value as soon as the RCS pressure increases 40 psi above the nominal operating pressure. Spray is assumed to be terminated as soon as the RCS pressure falls 40 psi below normal operating pressure.

4. Unless otherwise noted, pressurizer spray is assumed to be initiated once per occurrence of each transient condition. The pressurizer surge nozzle is also assumed to be subject to one temperature transient per transient condition, unless otherwise noted.

5. At the end of each transient, except the faulted conditions, the RCS is assumed to return to a load condition consistent with the unit heat-up transient.

6. Temperature changes occurring as a result of pressurizer spray are assumed to be instantaneous. Temperature changes occurring on the surge nozzle are also assumed to be instantaneous.

7. Whenever spray is initiated in the pressurizer, the pressurizer water level is assumed to be at the no load level.

5.4.10.4 Tests and Inspections

The pressurizer is designed and constructed in accordance with ASME Section III.

To implement the requirements of ASME Section XI the following welds are designed and constructed to present a smooth transition surface between the parent metal and the weld metal. The path is ground smooth for ultrasonic inspection.

1. Support skirt to the pressurizer lower head.
2. Surge nozzle to the lower head.
3. Nozzles to the safety, relief, and spray lines.
4. Nozzle to safe end attachment welds.
5. Girth and longitudinal full penetration welds.

The liner within the safe end nozzle region extends beyond the weld region to maintain a uniform geometry for ultrasonic inspection.

Peripheral support rings are furnished for the removable insulation modules.

5.4.11 Pressurizer Relief Discharge System

The Pressurizer Relief Discharge System collects, cools, and directs for processing, the steam and water discharged from the various safety and relief valves in the containment. The system consists of the pressurizer relief tank, the safety and relief valve discharge piping, the relief tank internal spray header and associated piping, the tank nitrogen supply, the vent to containment, and the drain to the Liquid Radwaste System.

5.4.11.1 Design Basis

Codes and materials of the pressurizer relief tank and associated piping are given in Section 5.2. Design data for the tank are given in Table 5-34.

The system design is based on the requirement to absorb a discharge of steam equivalent to 110 percent of the full power pressurizer steam volume. The steam volume requirement is approximately that which would be experienced if the plant were to suffer a complete loss of load accompanied by a turbine trip but without the resulting reactor trip. A delayed reactor trip is considered in the design of the system.

The minimum volume of water in the pressurizer relief tank is determined by the energy content of the steam to be condensed and cooled, by the assumed initial temperature of the water, and by the desired final temperature of the water volume. The initial water temperature is assumed to be 120°F, which corresponds to the design maximum expected containment temperature for normal conditions. Provision is made to permit cooling the tank should the water temperature rise above 120°F during plant operation. The design final temperature is 200°F, which allows the contents of the tank to be drained directly to the Liquid Radwaste System without cooling.

The vessel saddle supports and anchor bolt arrangement are designed to withstand the loadings resulting from a combination of nozzle loadings acting simultaneously with the vessel's seismic and static loadings.

5.4.11.2 System Description

The piping and instrumentation diagram for the Pressurizer Relief Discharge System is given in Figure 5-3.

The steam and water discharged from the various safety and relief valves inside containment is routed to the pressurizer relief tank if the discharged fluid is of reactor grade quality. Table 5-35 provides an itemized list of valves discharging to the tank together with references to the corresponding piping and instrumentation diagrams.

The tank normally contains water and a predominantly nitrogen atmosphere. In order to obtain effective condensing and cooling of the discharged steam, the tank is installed horizontally with the steam discharged through a sparger pipe located near the tank bottom and under the water level. The sparger holes are designed to insure a resultant steam velocity close to sonic.

The tank is also equipped with an internal spray and a drain which are used to cool the water following a discharge. Cold water is drawn from the reactor makeup water system, or the contents of the tank is circulated through the reactor coolant drain tank heat exchanger of the Liquid Radwaste System and back into the spray header.

The nitrogen gas blanket is used to control the atmosphere in the tank and to allow room for the expansion of the original water plus the condensed steam discharge. The tank gas volume is calculated using a final pressure based on an arbitrary design pressure of 100 psig. The design discharge raises the worst case initial conditions to 50 psig, a pressure low enough to prevent fatigue of the rupture disks. Provision is made to permit the gas in the tank to be periodically analyzed to monitor the concentration of hydrogen and/or oxygen.

The contents of the vessel can be drained to the waste evaporator feed tank in the Liquid Radwaste System or the recycle holdup tank in the Boron Recycle System via the reactor coolant drain tank pumps in the Liquid Radwaste System.

5.4.11.2.1 Pressurizer Relief Tank

The general configuration of the pressurizer relief tank is shown, in Figure 5-22. The tank is a horizontal, cylindrical vessel with elliptical dished heads. The vessel is constructed of austenitic stainless steel and is overpressure protected in accordance with ASME Code Section VIII, Division 1, by means of two safety heads with stainless steel rupture discs.

A flanged nozzle is provided on the tank for the pressurizer discharge line connection to the sparger pipe. The tank is also equipped with an internal spray connected to a cold water inlet and with a bottom drain, which are used to cool the tank following a discharge.

5.4.11.3 Safety Evaluation

The Pressurizer Relief Discharge System does not constitute part of the Reactor Coolant Pressure Boundary per 10CFR 50, Section 50.2, since all of its components are downstream of the Reactor Coolant System safety and relief valves. Thus, General Design Criteria 14 and 15 are not applicable. Futhermore, complete failure of the auxiliary systems serving the pressurizer relief tank will not impair the capability for safe plant shutdown.

HISTORICAL INFORMATION IN ITALICS NOT REQUIRED TO BE REVISED

The design of the system piping layout and piping restraints is consistent with Regulatory Guide 1.46. Regulatory Guide 1.67 is not applicable since the system is not an open discharge system.

The Pressurizer Relief Discharge System is capable of handling the design discharge of steam without exceeding the design pressure and temperature. The volume of water in the pressurizer relief tank is capable of absorbing the heat from the assumed discharge maintaining the water temperature below 200°F. If a discharge exceeding the design basis should occur, the relief device on the tank would pass the discharge through the tank to the containment.

The rupture discs on the relief tank have a relief capacity equal to or greater than the combined capacity of the pressurizer safety valves. The tank design pressure is twice the calculated pressure resulting from the design basis safety valve discharge described in Section 5.4.11.1. The tank and rupture discs holders are also designed for full vacuum to prevent tank collapse if the content cools following a discharge without nitrogen being added.

The discharge piping from the safety and relief valves to the relief tank is sufficiently large to prevent backpressure at the safety valves from exceeding 20 percent of the setpoint pressure at full flow.

5.4.11.4 Instrumentation Requirements

The pressurizer relief tank pressure transmitter provides an indication of pressure relief tank pressure. An alarm is provided to indicate high tank pressure.

The pressurizer relief tank level transmitter supplies a signal to an indicator with high and low level alarms.

The temperature of the water in the pressurizer relief tank is indicated, and an alarm actuated by high temperature informs the operator that cooling of the tank contents is required.

5.4.11.5 Inspection and Testing Requirements

The Pressurizer Relief Tank is subject to non-destructive and hydrostatic testing during construction in accordance with Section VIII, Division 1 of the ASME Code. The system piping valves are constructed and tested in accordance with the requirements of ANSI B31.1.

During plant operation, periodic visual inspections and preventive maintenance are conducted on the system components according to normal industrial practice.

5.4.12 Reactor Coolant System Pressure Boundary Valves

5.4.12.1 Design Bases

As noted in Section 5.2, all valves out to and including the second valve normally closed or capable of automatic or remote closure, larger than three-fourths inch, are ANS Safety Class 1, and ASME III, Code Class 1 valves.[4] All three-fourths inch valves are Class 2 since the interface with the Class 1 piping is provided with suitable orificing for such valves. If the second of two normally open check valves is considered the boundary, means are provided to periodically assess backflow leakage of the first valve when closed. For a check valve to qualify as the system boundary, it must be located inside the Containment. Valves in the reactor pressure boundary are tabulated in Table 5-41, Reactor Coolant System Pressure Isolation Valves. Each

---

[4] Valve closure time must be such that for any postulated component failure outside the system boundary, the loss of reactor coolant would not prevent orderly reactor shutdown and cooldown assuming makeup is provided by normal makeup systems. Normal makeup systems are those systems normally used to maintain reactor coolant inventory under respective conditions of startup, hot standby, operation or cooldown.

valve is designed to withstand the most severe environmental conditions applicable to that valve. Valves may be subjected to various conditions such as post LOCA radiation, extreme temperatures and pressures. Each valve's applicable conditions are specified in the valve specification.

Materials of construction are specified to minimize corrosion/erosion and to assure compatability with the environment.

Valve leakage is minimized to the extent practicable by design. Valves have been specified which will either prevent or collect stem leakage, as discussed in Section 11.2.1.

Valve stresses are also maintained within the limits of ASME Section III and the requirements specified in Subsection 3.7.2.

Applicable code cases and addenda are determined by purchase date subject to the limitations of 10CFR 50, Section 55.55a.

5.4.12.2 Design Description

All valves in the Reactor Coolant System which are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant, such as for hard surfacing and packing, are special materials.

Packless globe valves have been used for most Reactor Coolant System applications 2 inches and smaller. All manual and motor-operated valves of the Reactor Coolant System which are larger than two inches are provided with double-packed stuffing boxes and stem intermediate lantern gland leakoff connections. All throttling control valves, regardless of size, are provided with double-packed stuffing boxes and with stem leakoff connections. Leakoff connections are piped to a collection system as described in Sections 9.3.5, and 11.2.2, Liquid Radwaste System.

Gate valves at the Engineered Safety Features interface are either wedge design or parallel disc and are essentially straight through. The wedge may be either split or solid. All gate valves have backseat and outside screw and yoke. Globe valves, "T" and "Y" style, are full ported with outside screw and yoke construction. Check valves are either swing type or spring loaded, lift piston type for sizes two inches and smaller and swing type or tilting disc type for sizes two and one-half inches and larger. No stainless steel check valves have body penetrations other than the inlet, outlet and bonnet. The check hinge is serviced through the bonnet.

Valves at the Residual Heat Removal System interface are provided with interlocks that meet the intent of IEEE-279. Interlocks prevent opening these valves whenever the pressure in the Reactor Coolant System exceeds a specified pressure. These interlocks are discussed in detail in Sections 5.4.7 and 7.4.5.

The isolation valves between the accumulators and the Reactor Coolant System are normally open with power disconnected; however, these valves are provided with controls to assure opening (if closed for testing purposes) on a safety injection signal. In that the subject valves are normally open and do not serve as an active device during LOCA, IEEE 279 (1971) is not applicable in this situation. Therefore, the subject valve control circuit is not designed to this standard. The controls are discussed in detail in Section 6.3.

Design parameters for reactor coolant boundary valves are given in Table 5-36.

5.4.12.3 Design Evaluation

Stress analysis of the Reactor Coolant Loop/Support System, discussed in Sections 3.9.1.4.2 and 5.2 assures acceptable stresses for all valves in the reactor coolant pressure boundary under every anticipated condition.

Reactor coolant chemistry parameters are specified to minimize corrosion. Periodic analyses of coolant chemical composition, discussed in the Selected Licensee Commitments assure that the reactor coolant meets these specifications. The upper-limit coolant velocity of about 50 feet per second precludes accelerated corrosion.

Valve leakage is minimized by design features as discussed above.

The valves are designed and fabricated to meet the requirements of ASME III.

All Reactor Coolant System boundary valves required to perform a safety function, during the short term recovery from transients or events considered in the respective operating condition categories, operate in less than ten seconds.

5.4.12.4 Tests and Inspections

Hydrostatic seat leakage and operation tests are performed on reactor coolant boundary valves as required by ASME XI and Technical Specifications.

There are no full-penetration welds within valve body walls. Valves are accessible for disassembly and internal visual inspection.

5.4.13 Safety and Relief Valves

5.4.13.1 Design Bases

The combined capacity of the pressurizer safety valves is designed to accommodate the maximum surge resulting from complete loss of load. This objective is met without reactor trip or any operator action provided that the steam safety valves open as designed when steam pressure reaches the steam-side safety setting.

The power-operated pressurizer relief valves are designed to limit pressurizer pressure to a value below the fixed high pressure reactor trip setpoint.

5.4.13.2 Design Description

The pressurizer safety valves are the totally enclosed pop type. The valves are spring loaded self-activated and with back pressure compensation features. Six-inch pipe connects the pressurizer nozzles to their respective code safety valves.

The relief valves are quick-opening, operated automatically or by remote control. Remotely operated stop valves are provided to isolate the power operated relief valves if excessive leakage develops.

Temperatures in the pressurizer safety and relief valve discharge lines are measured and indicated. An increase in a discharge line temperature is an indication of leakage through the associated valve.

The power operated pressurizer valves may also be used to vent the Reactor Coolant System. However, the Reactor Vessel Head Vent System would be normally used for this purpose.

The Pressurizer Power Operated Relief Valves are air-operated. Air to these valves is supplied by the Instrument Air Compressors. Power to the Instrument Air Compressors is supplied from 4160 VAC blackout Auxiliary Power System (FSAR Section 8.3.1.1.1.4). This arrangement meets the requirements of NUREG 0737, Item II.G.1.

Design parameters for the pressurizer spray control, safety and power relief valves are given in Table 5-37.

5.4.13.3 Design Evaluation

The pressurizer safety valves prevent Reactor Coolant System pressure from exceeding 110 percent of system pressure, in compliance with the ASME Nuclear Power Plant Components Code, Section III. The pressurizer safety valve discharge capacity values used in 15.1 have been verified by the Electric Power Research Institute (EPRI) PWR Safety and Relief Valve Test Program and found to be appropriate.

The pressurizer power relief valves prevent actuation of the fixed high-pressure trip for all design transients up to and including the design step load decrease, with steam dump but without reactor trip. The relief valves also limit in a desirable manner opening of the spring-loaded safety valves. The Pressurizer Power Operated Relief valve stroke time and discharge capacity has been verified through results from EPRI's PWR Safety and Relief Valve Test Program and found to be satisfactory. The test program was performed in response to NUREG 0737 and is documented in EPRI Report NP 2770.

5.4.13.4 Tests and Inspections

Testing performed on safety and relief valves consists of operational and hydrostatic tests.

The safety valves are tested for operability with steam by the manufacturer. The setpoints of the safety valves are established with steam pressure and documented by the valve manufacturer. Inservice testing of the safety valves is performed in accordance with ASME Code. Valve capacity is verified through results from EPRI's PWR Safety and Relief Valve Test Program.

NRC Generic Letter (GL) 90-06, "Resolution of Generic issue 70, "Power Operated Relief Valve and Block valve reliability," and Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors," was issued on June 25, 1990. In response to the issues identified in the GL, Catawba evaluated the treatment of the Pressurizer PORVs and Block Valves. The results of that study are enumerated in Reference 23, "Generic Letter 90-06". The pressurizer PORVs and Block Valves at Catawba and associated testing programs meet or exceed the minimum requirements suggested by the NRC as an acceptable response to Generic Letter 90-06.

There are no full penetration welds within the valve body walls. Valves are accessible for disassembly and internal visual inspection.

5.4.14 Component Supports

5.4.14.1 Design Bases

The design concept of the primary loop component supports is identical to that at the McGuire Nuclear Station. The component support points and attachments are also identical for both stations. The design and fabrication of the primary loop components is in accordance with the 1971 ASME Code through the 1973 Summer Addenda. The equipment supports are designed to sustain the loads imposed on the system under normal operating conditions and abnormal loading conditions. The abnormal loadings include the effects of pipe rupture, operating basis earthquake, and safe shutdown earthquake. The load combinations considered for the preliminary analysis and design of the steel supports and the associated stress allowables are shown in Table 5-38. In addition, buckling is limited to 2/3 critical buckling. Concrete support structures are designed in accordance with the ACI Code 318-71 using the loading combinations of Table 3-32.

The "As Built" configuration of the steel supports, except the Reactor Coolant Pump Bolts, is checked for final Westinghouse specified loadings to verify that all stress levels conform to the allowables as defined in Subsection NF of Section III of the 1974 ASME Code, Summer of 1974 Addenda, including Appendix F and Appendix XVII, published subsequent to the original design. The design of the Reactor Coolant Pump Bolts conforms to the stress allowables defined in Table 5-38 for preliminary design. All other bolting allowables are 0.9 fy for tension and 1.5 fv for shear, in the faulted condition. The Unit 1 Steam Generator Upper Lateral Supports were replaced during the steam generator replacement outage. The new design and fabrication is in accordance with subsection NF of Section III of the 1986 edition including addenda through December of 1988.

Equipment supports are designed in a way to allow virtually unrestrained lateral thermal movement of the loop during normal operating conditions.

As an exception to the above, an exemption has been granted to eliminate the dynamic loads from postulated pipe breaks in the primary loop from the design basis. Therefore protection devices associated with dynamic loads from postulated pipe ruptures in the primary coolant system are not required; however these pipe breaks are not eliminated as a design basis for containment design, adequacy of the Emergency Core Cooling System, environmental qualifiaction of equipment, design of supports for heavy equipment, or reactor cavity and subcompartmental pressurization anaylses. References 3 and 4 document this exculsion for Unit 2 and Unit 1, respectively.

5.4.14.2 Design Description

5.4.14.2.1 Steam Generator

The steam generator support system consists of vertical steel columns at the base and lateral steel frames at lower and upper elevations. Figure 5-23 through Figure 5-25 and Figure 5-32 show outlines of the steam generator support system.

5.4.14.2.2 Reactor Coolant Pump

The reactor coolant pump support system consists of vertical steel columns and a lateral steel frame. Figure 5-25 through Figure 5-27 show outlines of the support system of the reactor coolant pump.

5.4.14.2.3 Pressurizer

The pressurizer support system consists of vertical steel hangers from the operating floor to the base of the pressurizer, a lateral frame at the base anchored to the crane wall and tied to the vertical hangers, and an upper lateral steel ring anchored to the crane wall and pressurizer enclosure walls. Figure 5-28 through Figure 5-30 show outlines of the pressurizer support system.

5.4.14.2.4 Reactor Vessel

The reactor vessel supports are individual water-cooled rectangular box structures beneath the vessel nozzles and anchored to the primary shield wall. Figure 5-31 shows an outline of a typical reactor vessel support.

5.4.14.3 Fabrication

The fabrication of all steel component supports is in accordance with Subsection NF of Section III of the 1974 or 1977 ASME Code, depending on the contract date for the particular support. A code stamp is not required.

5.4.14.4 Materials

The materials used for all steel supports are listed in Table 5-39. For all materials except the reactor coolant pump bolts (See Figure 5-25), the materials meet the requirements of Article NF-2000 of Section III of the ASME Code. The reactor coolant pump bolt material is a high strength steel (modified 4340) not defined in Appendix I of Section III. This material is required to pass Charpy V-notch impact tests. In addition, the material is not subjected to stress corrosion cracking by virtue of the fact that a corrosive environment is not present and the bolt has essentially no residual stresses and does not experience any significant sustained loads during normal service.

Concrete support structures are constructed in accordance with the ACI Code 318-71 using grade 60 reinforcing and 5000 psi concrete.

5.4.15 References

HISTORICAL INFORMATION IN ITALICS BELOW NOT REQUIRED TO BE REVISED

1. "Reactor Coolant Pump Integrity in LOCA," WCAP 8163, September 1973.

2. "Evaluation of Steam Generator Tube, Tube Sheet, and Divider Plate Under Combined LOCA Plus SSE Conditions," WCAP-7832A, April, 1978.

3. "Request for exemption from a portion of GDC 4 of Appendix A to 10 CFR Part 50 regarding the need to analyze large primary loop pipe ruptures as a structural design basis for Catawba Nuclear Station, Unit 2", transmitted by letter dated April 23, 1985 from E. G. Adensam (NRC) to Hal B. Tucker (Duke).

4. "Elimination of Large Primary Loop Pipe Ruptures," transmitted by letter dated April 7, 1987 from K.N. Jabbour (NRC) to H.B. Tucker (Duke)

5. Nuclear Regulatory Commission, Letter to All Licensees of Operating PWRs and Holders of Construction Permits for PWRs, from Frank J. Miraglia, July 9, 1987, "Loss of Residual Heat Removal (RHR) While the Reactor Coolant System (RCS) is Partially Filled (Generic Letter 87-12)."

6. Duke Power Company, Letter from W.H. Owen to the NRC, October 2, 1987, re: Response to Generic Letter 87-12, "Loss of Residual Heat Removal (RHR) While the Reactor Coolant System (RCS) is Partially Filled."

7. Nuclear Regulatory Commission, Letter to All Licensees of Operating PWRs and Holders of Construction Permits for PWRs, from Dennis M. Crutchfield, October 17, 1988, "Loss of Decay Heat Removal (Generic Letter 88-17) 10 CFR 50.54(f)."

8. Duke Power Company, Letter from H.B. Tucker to the NRC, January 3, 1989, re: Response to Generic Letter 88-17, "Loss of Decay Heat Removal."

9. Nuclear Regulatory Commission, Letter to All Holders of Operating Licenses or Construction Permits for Westinghouse (W)-Designed Nuclear Power Reactors With Steam Generatgors Having Carbon Steel Support Plates, from Charles E. Rossi, February 5, 1988, "Rapidly Propagating Fatigue Cracks in Steam Generator tubes (IE Bulletin 88-02)."

10. Duke Power Company, Letter from H.B. Tucker to M.L. Ernst (NRC), February 20, 1989, re: NRC Bulletin No. 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes," Catawba Final Response.

11. Nuclear Regulatory Commission, Letter from K.N. Jabbour to H.B. Tucker (DPC), July 27, 1990, re: Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes" - Catawba Nuclear Station, Unit 1 (TAC 67300).

12. Nuclear Regulatory Commission, Letter to All Holders of Operating Licenses or Construction Permits for Pressurized Water Reactors (PWRs), from Charles E. Rossi, May 15, 1989, NRC Bulletin No. 89-01: "Failure of Westinghouse Steam Generator Tube Mechanical Plugs."

13. Nuclear Regulatory Commission, Letter to All Holders of Operating Licenses or Construction Permits for Pressurized Water Reactors (PWRs), from Charles E. Rossi, November 14, 1990, NRC Bulletin No. 89-01, Supplement 1: "Failure of Westinghouse Steam Generator Tube Mechanical Plugs."

14. Duke Power Company, Letter from H.B. Tucker to NRC, June 20, 1989, re: Response to NRC Bulletin No. 89-01, "Failure of Westinghouse Steam Generator Tube Mechanical Plugs."

15. Duke Power Company, Letter from M.S. Tuckman to NRC, December 18, 1991, re: NRC Bulletin 80-01, Supplement 2.

16. Nuclear Regulatory Commission, Letter from R.E. Martin to M.S. Tuckman (DPC), March 25, 1993, re: NRC Bulletin 89-01, Supplement 2, Steam Generator Tube Mechanical Plugs for Catawba, Unit 1 (TAC No. M81601).

17. "Generic Letter 87-12, Loss of RHR", transmitted by letter dated October 2, 1987 from Warren H. Owen, Duke Power Company, to U.S. Nuclear Regulatory Commission, Attention: Document Control Desk.

18. "Generic Letter 88-17, Loss of Decay Heat Removal", transmitted by letter dated January 3, 1989, H.B. Tucker, Duke, to Document Control Desk, U.S. Nuclear Regulatory Commission.

19. "Generic Letter 88-17, Loss of Decay Heat Removal", transmitted by letter dated February 2, 1989, H.B. Tucker, Duke, to Document Control Desk, U.S. Nuclear Regulatory Commission.

20. Letter to the U.S. Nuclear Regulatory Commission from M.S. Tuckman dated January 30, 1992, titled "Catawba Nuclear Station Units 1 and 2, Docket Nos. 50-413 and 50-414, NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification."

21. Letter to the U.S. Nuclear Regulatory Commission from M.S. Tuckman dated April 08, 1992, titled "Catawba Nuclear Station Units 1 and 2, Docket Nos. 50-413 and 50-414, NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification, NRC TAC NOS. M72121/M72122".

22. Coslow, B.J., et al., "Pressurizer Surge Line Thermal Stratification Generic Detailed Analysis", WCAP-12639, June 1990.

23. "Generic Letter 90-06", transmitted by letter dated December 20, 1990 from H.B, Tucker, Duke Power Company, to U.S. Nuclear Regulatory Commission, Document Control Desk.
24. ND Suction Pressure Control Setpoint Determination for 1(2)FW96 and 1(2)FW97, CNC-1223.21-00-0020.
25. Letter to the U.S. Nuclear Regulatory Commission from T.P. Harrall dated October 13, 2008, titled "Duke Energy Carolinas, LLC (Duke) Oconee Nuclear Station, Units 1, 2 & 3, Docket Nos. 50-269, 50-270, 50-287, McGuire Nuclear Station, Units 1 & 2, Docket Nos. 50-369, 50-370, Catawba Nuclear Station, Units 1 & 2, Docket Nos. 50-413, 50-414, Generic Letter 2008-01, 9-Month Response.
26. Babcock & Wilcox International Report No. BWI-222-7693-LR-01, Rev. 5, dated January 1996, "Replacement Steam Generator Topical Report"
27. Letter from A. Thompson (Babcock & Wilcox) to R.S. Nelson (Duke Energy), dated April 25, 2013. Subject: Catawba Unit 1, LAR Input for MUR. (CNC-1210.06-00-0007)

THIS IS THE LAST PAGE OF THE TEXT SECTION 5.4.

THIS PAGE LEFT BLANK INTENTIONALLY