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10.0 Steam and Power Conversion System

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10.1 Summary Description

The Steam and Power Conversion System is designed to convert the heat produced in the reactor to electrical energy.

The saturated steam produced by the steam generators is expanded through the high pressure turbine and then exhausted to the moisture separator reheaters. The moisture separator section removes the moisture from the steam and the two stage reheaters superheat the steam before it enters the low pressure turbines. The steam then expands through the low pressure turbines and exhausts into the main condenser where it is condensed and returned to the cycle as condensate. The heat rejected in the main condenser is removed by the Condenser Circulating Water System.

The first stage reheaters are supplied with steam from the A bleed steam line and the condensed steam is cascaded to the B feedwater heaters. The second stage reheaters are supplied with the main steam and the condensed steam cascades to the A feedwater heaters. Heat for the feedwater heating cycle is supplied by the moisture separator reheater drains and by steam from the turbine extraction points.

The hotwell pumps take suction from the condenser hotwell and discharge to the condensate polishing demineralizers. Downstream of the polishers, the condensate flows through the condenser steam air ejectors, gland steam condenser, and steam generator blowdown recovery heat exchangers before passing through two stages of low pressure feedwater heaters (F and G), before discharging to the suction of the condensate booster pumps. Each stage of low pressure feedwater heating consists of three horizontal heaters mounted in the condenser neck. After the condensate booster pumps, the condensate passes through three stages of intermediate pressure feedwater heaters (C, D, and E) consisting of two horizontal heaters per stage located on the mezzanine floor, before combining with the C heater drain pumps discharge and splitting to the suction of the steam generator feedwater pumps. The steam turbine driven feedwater pumps deliver feedwater through two stages of high pressure feedwater heaters (A and B) consisting of two horizontal heaters per stage located on the mezzanine floor to a single feedwater distribution header where the feedwater flow is divided into four lines to the steam generators.

The turbine nameplate rating is approximately 1205 MWe at a backpressure of 2.5 In. Hg. Abs. and 0 percent makeup. The generator is rated at 1,450,000 KVA with 75 PSIG hydrogen pressure and a .90 power factor. Each unit is expected to produce a net electrical output of approximately 1165 MW net (Unit 1) / 1145 MW net (Unit 2). Heat balances at valves wide open and rated power are shown on Figure 10-1 and Figure 10-43 (Unit 1) / Figure 10-44 (Unit 2).

The safety-related features of the steam and power conversion system include the main steam piping from the steam generators up to and including the main steam isolation valves. The steam lines supplying the auxiliary feedwater pump turbine are also safety-related. The feedwater piping from the feedwater isolation valves to the steam generator and the Auxiliary Feedwater System are also safety-related.

The only safety related instrumentation in the Steam and Power Conversion System is the wide range and narrow range steam generator level instrumentation for each steam generator and doghouse level in the Feedwater System (Section 10.4.7) and the steamline pressure for each steam generator in the Main Steam System (Section 10.3). All other instrumentation in the Steam and Power Conversion System is not required for a safe reactor shutdown.

The design and performance characteristics of major equipment and tanks in the steam and power conversion system are given in Table 10-1.

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10.2 Turbine-Generator

10.2.1 Design Bases

The turbine-generator converts the thermal energy of steam produced in the steam generators into mechanical shaft power and then into electrical energy. Each unit is operated primarily as a base loaded unit with an output of 1165 MW net (Unit 1) / 1145 MW net (Unit 2), but may be used for load following when required. The unit is capable of taking a 10 percent step load change or a ramp change of 5 percent per minute without steam bypass, as dictated by the Reactor Coolant System.

Steam dump capability is provided for operational considerations to allow more rapid load changes without causing reactor trip. The dump system is controlled to give the required ramp load change to prevent reactor trip. The reactor control rods correct the reactor output while the dump creates an artificial load to prevent reactor trip and insertion of the shutdown control rods during the transient.

Turbine-generator functions under normal, upset, emergency, and faulted conditions are monitored and controlled automatically by the turbine control system described in Section 10.2.2. The control system includes redundant mechanical and electrical trip devices to prevent excessive over-speed of the turbine-generator. Additional external trips are provided to ensure operation within conditions that preclude damage to the turbine-generator. A manual control system is also provided in the event that the automatic control system is not available. The application of design codes to the turbine-generator is discussed in Section 10.2.3.6.

10.2.2 Description

Each unit's turbine-generator consists of a tandem (single shaft) arrangement of a double-flow, high-pressure turbine and three identical double-flow low pressure turbines driving a direct-coupled generator at 1800 rpm. The turbine-generator is manufactured by the General Electric Company of Schenectady, New York.

The flow of main steam is from the steam generators to the high-pressure turbine through four stop valves and four control valves. After expanding through the high-pressure turbine, exhaust steam passes through external moisture separators and two stage steam-to-steam shell and tube type reheaters. Extraction steam from the high-pressure turbine is supplied to the first reheater stage tube bundle in each reheater. Main steam is supplied to the second reheater stage tube bundle in each reheater. Reheated steam is admitted to the three low pressure turbines through six intermediate stop valves and six intercept valves and expands through the low-pressure turbines to the main condensers.

The closure times of the main stop, main control, intermediate stop, and intercept valves are shown in Table 10-3.

Bleed steam for the seven stages of feedwater heating is provided from the following sources:

Heater	Extraction Source
A	H-P turbine
B	H-P turbine
C	H-P turbine exhaust
D	L-P turbines

Heater	Extraction Source
E	L-P turbines
F	L-P turbines
G	L-P turbines

Provided in extraction lines A, B, C, D, and E are piston-assist spring-closed swing check valves. The piston-assist spring-closed actuators are designed to overcome friction and allow the valves to rapidly close on turbine trip. (See Table 10-3 for closure times) Bleed lines F and G are not provided with check valves since installation in the condenser neck would be impractical. However, heaters F and G are provided with anti-flash baffle plates located below the tube bundles and above the water volume. The extraction design was approved by the turbine manufacturer in regard to turbine overspeed protection. Postulating turbine trip and failure of a single extraction check valve, the manufacturer concluded that unacceptable turbine overspeed would not occur.

Each of the two generators is a 1450 MVA, 1800 rpm, direct connected, 3 phase cycle, 22,000 volt conductor cooled synchronous generator rated at .90 P.F, SCR at a maximum hydrogen pressure of 75 psig. Generator rating, temperature rise, and class of insulation are in accordance with IEEE standards. Excitation is provided by a shaft driven alternator with its output rectified.

A conventional oil-sealed hydrogen cooling system provides rotor cooling. The stator conductors are water cooled by a stator water cooling system. Differential relays protect the generator against electrical faults.

The hydrogen bulk storage facility is located outdoors, on the south side of the station between the Unit 1 Turbine Building and the low pressure service water discharge to Lake Wylie (see Figure 1-20). This facility is open on three sides so that an adequate air exchange is allowed around the storage tanks. The hydrogen is stored in six seamless cylinders, each cylinder having the internal capacity of 51 cubic feet. This bulk storage provides the station supply of hydrogen to the Unit 1 and Unit 2 Turbine generators, the Unit 1 and Unit 2 Volume Control Tanks, and the Waste Gas Decay Tanks.

The inventory of the bulk hydrogen supply is maintained through the delivery from local suppliers. The original hydrogen/oxygen gas generator has been abandon in place. The explosion hazard to the safety related SSCs (Structures, Systems, and Components) associated with the delivery of hydrogen to the site facility has been evaluated. The risk of damage due to the delivery is in accordance with the methodology of Regulatory Guide 1.91: "Evaluations of Explosions Postulated to Occur on Transportation Routes near Nuclear Power Plants".

The hydrogen distribution system is shown on Figure 10-4. In order to prevent explosions or fires, the hydrogen piping and the main generator are checked for leaks and then purged with CO_2 to remove all air and oxygen before the introduction of hydrogen. The hydrogen purged from the generator is vented through the Turbine Building roof and dissipates in the outside air. Provisions are provided at various points in the distribution system to allow for CO_2 purging and safe venting of the hyrdogen in the generator and piping prior to maintenance.

Turbine-generator bearings are lubricated by a conventional oiling system of proven components. The main oil pump, which supplies oil to the bearings of the turbine-generator shaft, is a centrifugal pump mounted on the turbine shaft. It is supplied with suction oil by an oil-driven booster pump located in the oil tank. Oil discharging from the main oil pump is piped to

the oil tank where it passes through the oil turbine which drives the booster pump. The oil then goes through the oil cooler and on to the bearings. The two oil coolers are each full capacity and use conventional L. P. service water for cooling.

Two motor-driven centrifugal oil pumps are provided to supply bearing oil to the turbine bearings while the turbine is on turning gear, while the turbine is coming up to speed, or in an emergency condition. These pumps are the turning-gear oil pump and the emergency bearing oil pump. They take suction oil directly from the oil tank and discharge it into the bearing header prior to the main oil coolers.

One ac motor-driven centrifugal oil pump is provided to perform the function of the booster pump until the turbine shaft has reached approximately 90 percent of rated speed. This pump, called the motor suction pump, is needed since high-pressure operating oil is not available to drive the booster pump until the main oil pump has reached about 90 percent of rated speed. Thus, until this speed is reached, the function of the booster pump, which is to provide the main oil pump with suction oil at a positive pressure, must be provided by this motor suction pump.

The Electro-Hydraulic Control (EHC) System incorporates the circuitry and equipment required to provide the following basic turbine control functions:

1. Automatic control of turbine speed and acceleration through the entire speed range.
2. Automatic control of load and loading rate from auxiliary to full load, with continuous load adjustment and discrete or variable loading rates.
3. Manual control of speed and load when it becomes necessary to take the primary automatic control out of service.
4. Limiting of load in response to preset limits on operating parameters.
5. Detection of dangerous or undesirable operating conditions, annunciation of detected conditions, and initiation of proper control response to such conditions.
6. Monitoring the status of the control system, including the power supplies and redundant control circuits.
7. Testing of valves and controls.
8. Prewarming of valve chest and turbine rotor.

The hydraulic power unit, associated with the EHC, supplies high pressure fluid directly to the control pacs on the steam valves for controlling the valves, and to the trip devices in the trip and overspeed protection circuits. The unit accommodates both steady state and transient requirements.

The fluid is supplied to all components at the correct temperature and required cleanliness, and the unit is equipped with special chemically active filters to maintain the properties of the fluid over very long service times. The unit offers two complete pumping systems, allowing the turbine to operate while maintenance work is taking place on either pump system. The unit incorporates various alarms and pressure switches which will auto-start the stand-by pumping system or trip the turbine should a malfunction occur in the system which is operating. The unit is designed to maximize reliability.

The electrical power required by the EHC equipment is supplied from two different power sources for redundancy. The 120VAC regulated power source provides one input source and the inverter power source provides the other input source. Both of these power sources provide power availability during unit start-up and normal operation.

The EHC equipment develops six electrical power voltage levels from the 120VAC input power source; these are +5VDC, +15VDC, -15VDC, +24VDC, -30VDC and +125VDC. Two regulated power supplies are provided for each voltage level, one from the 120VAC regulated power input source and one from the 120VAC inverter power source. Redundancy is thus provided for system power needs. All of the power supplies as well as the 120VAC input power sources are monitored. Should either 120VAC input power source or either redundant D.C. power supply fail, a control room annunciator is initiated as well as an alarm on the EHC control room video monitor. Should a malfunction occur in either of the voltage levels, backup power is maintained at the proper voltage level to allow for proper EHC turbine control.

The speed control unit of the EHC system provides a speed signal for input to the load control unit. Three distinct speed signals are derived by the circuit. A median speed signal is developed and permits propagation of the signal which results in valve openings or closings or no valve movement at all. The desired speed reference is manually selected using pushbuttons mounted on the operating panel. Speed references are provided for steady-state operation at the speeds required for thermal soaking holds as well as at rated speed. Pushbuttons are also provided that, when selected, overspeeds the turbine for purposes of testing the overspeed protective equipment. The maximum overspeed that the unit will reach should this function be selected does not exceed the turbine overspeed capabilities. The machine coasts down to rated speed when the test is completed. Variable and discrete acceleration reference signals are selected manually to provide for controlled rotor acceleration during startup. Three independent rotor speed circuits are provided for redundancy, and the redundant overspeed processor protects the turbine in the event of failure of the primary overspeed processor.

The turbine overspeed protection is divided into two basic categories of mechanical overspeed protection in the turbine and electrical overspeed protection in the EHC controller.

Mechanical overspeed protection which is independent of the EHC controller is provided by the mechanical overspeed trip mechanism which is located in the turbine front standard on the end of the control rotor stub shaft. The overspeed trip device consists of an unbalanced ring which is actuated by centrifugal force against the force of a spring when the turbine overspeeds. This movement puts the ring in an eccentric position so that it strikes the trip finger of the mechanical trip linkage which operates the mechanical trip valve to close all turbine valves. The mechanical overspeed trip device is set to activate at 110% of rated speed.

Electrical overspeed protection, which is set at 111.5% of rated speed is provided as a backup to the mechanical overspeed trip device. When an overspeed condition is detected, the turbine logic provides outputs which 1) de-energize the electrical trip solenoid valve and 2) energize the mechanical trip solenoid valve, either one or both of these will trip the turbine.

In addition to the overspeed protection, control, and trip functions provided by the EHC, a diverse method of tripping is provided by an independent overfrequency relay which is used to trip the turbine if the generator frequency reaches approximately 111% of its rated value.

To further decrease the possibility of an overspeed condition occurring during unit shutdown, a sequential generator trip is provided. The turbine is manually tripped after the load reference has been runback. The reverse power relay must then sense a reverse power condition prior to initiating a generator breaker trip (unit disconnect). This sequence is to assure that all steam capable of adding to a potential overspeed condition has been expanded through the turbine.

The turbine speed control system protection devices are listed in Table 10-2. Also reference the system overview of control system as shown in Figure 10-41.

The basic purpose of the load control unit is to accept input signals from other units of the EHC system and to use these signals in conjunction with functions designated as load control unit

functions to compute control valve reference signals for the EHC control system. Switching signals indicating operating conditions are also supplied to other units of the EHC systems.

The load control unit functions may be grouped as follows:

1. Sensing functions are provided to detect and generate signals proportional to parameters that affect loading of the unit.
2. Limiting functions are provided to electrically constrain the control valve reference signals in response to signals from the sensing circuits, from the speed control unit, or from devices detecting the state of plant components.
3. Computing functions are provided to generate control valve reference signals for the valve sets, considering the desired load signal, the limiting functions, and the speed error signal from the speed control unit.
4. Logic functions are provided to ensure that necessary permissives have been satisfied prior to changes in mode of operation, to communicate status information between the load control unit and other elements of the EHC system, and to provide switching signals to devices in the EHC system.

The load set circuit provides a digital signal used for synchronizing the main generator and for establishing the final value of desired load. It is generated by a digital demand input through the EHC control panel. A meter on the EHC control panel indicates the megawatts of load being called for by the load set circuit. Switching circuits provide for selecting one of several variable or discrete loading rates. Circuitry is incorporated to change the load target when certain abnormal operating conditions are detected. Load reduction may be initiated by a signal from the speed control logic unless rated speed is selected, by indication that the load reference signal exceeds a preset load value, by loss of generator stator coolant, by a signal from the Westinghouse Process Control System, by a loss of a feedwater pump turbine, or by a partial loss of load. A load limit pushbutton is located on the control panel to allow the operator to select the maximum load to be carried by the turbine. If the load value exceeds the limit established by the operator, the output load reference signal is limited to that limit value. To prevent excessive decrease of the main steam (throttle) pressure, a main steam (throttle) pressure regulator is provided to close the controlling valve set when the main steam (throttle) pressure falls below a preset level.

Stage pressure feedback circuitry is incorporated in the EHC system to maintain near constant turbine output while testing control valves. During control valve testing, a feedback signal opens the control valves that are not being tested as the tested valve closes to maintain near constant turbine output during the test.

The turbine and its control valves must be designed to pass the rated flow at throttle pressure existing at the main stop valves at rated output of the NSSS, i.e., at the lowest point of the pressure range. At higher throttle pressure the CV's will, therefore, have excess capacity which would cause a non-linear regulation characteristic. In addition, overload could occur if the pressure does not follow the design steady state curve during load changes or even in steady state. The control valve positioning system is designed to account for these affects by use of the megawatt feedback loop. Pressure excursions, should they occur would be compensated for by positioning of the control valves, thus maintaining the required load set value.

The main stop valve position loop consists of electronic circuitry, a hydraulic actuator and a linear position transducer. Main stop valve testing is provided to determine the operational status of the valve system during normal operation and to increase the probability that the valves will fast close on a turbine trip. When a given valve is tested it slowly closes until its

linear positional circuitry energizes the associated solenoid valve which tests the valve fast operation through a short stroke near bottom. (**NOTE**: Per Temp EC 401688/000 installation the fast operation near the bottom is disabled for the Unit 2 Main Stop Valve#2. The Main Stop Valve #2 continues to meet required closure times per Table 10-3 and failure of a fast acting solenoid valve is included in the failure analysis per Table 10-4.) The individual main stop valve test also results in actuation of the dedicated limit switch which provides an input to the four out of four reactor trip logic. The individual stop valve test also results in actuation of the dedicated pressure switch which provides an input to the two out of four reactor trip logic. The 103% overspeed and load drop anticipate circuits directly energizes all control valve and intercept valve fast acting solenoid valves through full stroke.

The control valve position loop consists of electronic circuitry, an electrohydraulic servovalve, a hydraulic actuator and a linear position transducer. By use of valve position feedback control, the control valve control unit positions the control valves according to the reference demand signal from the load control unit, or directly from the control panel. The purpose of the valve position feedback control is to keep the valve stem of the control valve at a desired position regardless of disturbances in the steam path as well as in the position control system itself. Valve position control is performed by using a feedback path that transmits the actual valve position back to a point where it is compared algebraically with the reference input. The error signal, when different from zero, positions the hydraulic actuator via the servovalve in order to make it zero. Control valve testing is designed to allow regular testing of each valve with the effects to on-line turbine operation minimized. Both normal and fast-acting valve operation are tested. On loss of feedback signal a fully open valve will remain open and a partially open valve (< 50%) will close. The control valves will also close on servovalve failures and loss of emergency trip oil pressure.

The intercept valve position loop for valves #1, #2, and #3 consists of electronic circuitry, electro-hydraulic servovalve, a hydraulic actuator and a linear position transducer. By use of valve position feedback control, the intercept valve control unit positions the intercept valves according to the flow setpoint reference signal received from the load control unit, or directly from the control panel. Intercept valves #4, #5, and #6 open after valves #1, #2, and #3 have opened; these valves do not have the electrohydraulic servovalve. The purpose of valve position feedback control is to keep the valve stem of the intercept valve at a desired position regardless of disturbances in the steam path as well as in the position control system itself. Valve position control is performed by using a feedback path that transmits the actual valve position back to a summing point where it is compared algebraically with the reference input. The error signal, when different from zero, positions the hydraulic actuator via the servo valve in order to make it zero. Intercept valve testing is designed to allow regular testing of each valve and its intermediate stop valve with the effects to on-line turbine operation minimized. The intercept valve master-slave relationship is disrupted while both normal and fast-acting valve operations are tested. The intercept valves will fast close when the fast acting solenoid valve is energized.

The EHC system incorporates a manual and emergency manual control system which provides for the capability of manual turbine control in the event of failure of both of the automatic control processors. These control processors are independent of the redundant speed processors, and may be used to maintain power output while the failed subsystems are being repaired. Although the valve loops and power supplies are common to both systems, they incorporate sufficient redundancy to prevent shutdown of the unit if a malfunction in a valve loop or power supply should occur. Three lines of defense are provided against overspeed while operating in the automatic, manual, or emergency manual modes. The first line of defense is provided by the 103% (electrical) overspeed circuit. The mechanical overspeed trip becomes the first backup

mechanical overspeed system, since its trip setting remains at 110%. The 111.5% (electrical) overspeed trip circuit provides a second backup overspeed to the 103% (electrical) overspeed circuit. The machine may be rolled off turning gear, accelerated to rated speed and synchronized using the manual and automatic control modes. An acceleration meter is provided to monitor rotor acceleration during startup using the manual or automatic mode.

If the unit is running and turbine intermediate pressure is greater than 15% relative load value, and the system tie is lost, the following events will take place in rapid succession through operation of the Load Drop Anticipate (LDA) circuit:

1. The LDA circuit will sense that the system tie is lost, the unit now goes from a load control reference to a speed control reference.
2. The turbine will accelerate in speed.
3. The control valves and intercept valves will close at the maximum rate by means of the fast acting solenoid valves.
4. The entrained steam between the valves and the turbine, in the turbine casings, and in crossover and extraction lines, will expand within approximately 1.5 seconds.
5. The turbine speed will level off at a speed below the overspeed trip setting when the entrained steam has ceased expending and will start decreasing gradually at a rate depending on auxiliary load left on the generator.
6. When the speed has decreased below the 1,800 RPM speed target value, the intercept and control valves are permitted to reopen under speed control. The energy stored in the intermediate piping will be gradually bled off at a rate sufficient to maintain the rotor speed and supply the auxiliary load still connected to the generator, as well as, the no-load losses in the unit.
7. After the reheat pressure has bled down and a steady-state speed value has been reached, the unit will be running at or near rated speed ready to be synchronized.

In case of malfunction of any portion of the electrical protection against overspeed when load is lost, the turbine will accelerate to the trip speed where the overspeed trip will activate. This will directly trip the disc-dump valves of the main and intermediate stop valves, as well as the control and intercept valves. Subsequently, the turbine will coast down to zero speed.

The EHC and Monitoring System will initiate appropriate action on abnormal operating conditions and indicate the existence of these conditions to the operator.

In addition to the internally generated turbine trips, any of the following externally generated trip inputs will result in removing the hydraulic fluid pressure from the emergency trip system (ETS). The removal of this pressure will result in rapid closure of all turbine valves.

External Trip Inputs:

1. Low Condenser Vacuum
2. Thrust Bearing Failure
3. Low Bearing Oil Pressure
4. Internal Fault in Generator
5. Generator Breaker Failure
6. Reactor Trip
7. Loss of Generator Stator Coolant Without EHC Runback

8. Steam Generator Hi-Hi Level
9. Safety Injection
10. Both Main Feedwater Pumps Tripped
11. High Exhaust Hood Temperature
12. Manual Turbine Trip
13. Turbine Oil Fire Trip
14. Moisture Separator Reheater Hi Level
15. Low Hydraulic Fluid Pressure
16. Low Turbine Shaft Pump Discharge Pressure
17. Low Emergency Trip System Pressure

Circuitry is also provided to test most components of the trip system during operation.

When a signal is received from the sensing devices indicating that a condition exists requiring a turbine trip of the ETS, the trip valves described below will act to release the hydraulic fluid pressure in the valve actuators, thus rapidly closing all steam valves. The pressure may be released by either the electrical trip valve (ETV) or the mechanical trip valve (MTV). The mechanical trip valve (MTV) is operated by the mechanical trip pilot valve (MTPV). The trip mechanism is reset by the oil reset piston (ORP) operated by the oil reset solenoid valve (ORSV). The mechanical lockout valve is a solenoid pilot operated three way valve that permits testing of the MTV during normal operation by admitting H.P. Fluid to the electrical trip valve (ETV) and closing off the output line of the MTV. The electrical trip valve (ETV) is a three way valve, fluid pilot operated by the electrical trip solenoid valve (ETSV) which is held in a reset position by energizing the 24 VDC solenoid from the 24 VDC trip system. This solenoid must be de-energized to trip the ETV. The electrical lockout valve (ELV) is a solenoid, pilot operated three way valve that permits testing of the ETV and ETSV during normal operation by shutting off the ETV output and admitting the MTV output pressure directly to the ETS. The two air relay dump valves (ARDV-1 and ARDV-2) are high pressure fluid, pilot operated, three way air valves that permit normal instrument air (VI) system pressure to enter the emergency trip air system (ETAS). The ETAS pressure is used for the operation of positive closed extraction check valves and some auxiliary valves.

The first out graphic on the operator interface unit provides indication of the reasons for a trip by alarming the trip input and displaying it on the control room video monitor. The first out graphic thus aids analysis of trip incidents, and may enable quick correction of system malfunctions without relying on event records.

10.2.3 Turbine Disk Integrity

10.2.3.1 Materials Selection

Turbine wheels and rotors are made from vacuum melted or vacuum degassed Ni-Cr-Mo-V alloy steel by processes which minimize flaw occurrence and provide adequate fracture toughness. Tramp elements are controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long life fracture toughness for the environment in which the parts operate. The turbine wheel and rotor materials have the lowest fracture appearance transition temperatures (FATT) and highest Charpy V-notch energies obtainable, on a consistent basis from water quenched Ni-Cr-

Mo-V material at the sizes and strength levels used. Since actual levels of FATT and Charpy V-notch energy vary depending upon the size of the part and the location within the part, etc., these variations are taken into account in accepting specific forgings for use in turbines for nuclear application. Charpy tests essentially in accordance with Specification ASTM A-370 are included.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in Section 10.2.3.1 to produce a balance of adequate material strength and toughness to ensure safety while simultaneously providing high reliability, availability, and efficiency, during operation. Bore stress calculations include components due to centrifugal loads, interference fit, and thermal gradients where applicable. The ratio of material fracture toughness, K_{IC} (as derived from material tests on each wheel or rotor) to the maximum tangential stress for wheels and rotors at speeds from normal to 115% of rated speed (the highest anticipated speed resulting from a loss of load is 110%) is at least $2\sqrt{\text{in}}$. Adequate material fracture toughness needed to maintain this ratio is assured by destructive tests on material taken from the wheel or rotor using correlation methods which are more conservative than that presented by J. A. Begley and W. A. Logsdon in Westinghouse Scientific Paper 71-1E7-MSLRF-P1.

Turbine operating procedures are employed to preclude brittle fracture at start-up by ensuring that the metal temperature of wheels and rotors is adequately above the FATT and, as defined above, is sufficient to maintain the fracture toughness to tangential stress ratio at or above $2\sqrt{\text{in}}$.

10.2.3.3 High Temperature Properties

(See Sections 10.2.3.1, 10.2.3.2, 10.2.3.4)

10.2.3.4 Turbine Design

The turbine assembly is designed to withstand normal conditions and anticipated transients including those resulting in turbine trip without loss of structural integrity. The design of the turbine assembly meets the following criteria:

1. Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.
2. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20% overspeed is controlled in the design and operation so as to cause no distress to the unit during operation.
3. The maximum tangential stress in wheels and rotors resulting from centrifugal forces, interference fit and thermal gradients does not exceed 0.75 of the yield strength of the materials at 115% of rated speed.

10.2.3.5 Pre-Service Inspection

The pre-service inspection program is as follows:

1. Wheel and rotor forgings are rough machined with minimum stock allowance prior to heat treatment.
2. Each finish machined wheel and rotor is subjected to 100% volumetric (ultrasonic), surface, and visual examinations using General Electric acceptance criteria. These criteria are more

restrictive than those specified for Class 1 components in the ASME Boiler and Pressure Code, Sections III and V, and include the requirement that subsurface sonic indications are either removed or evaluated to assure that they will not grow to a size which compromises the integrity of the unit during the service life.

3. All finish machined surfaces are subjected to a magnetic particle test with no flaw indications permissible.
4. Each fully bucketed turbine rotor assembly is spin tested at or above the maximum speed anticipated following a turbine trip from full load.

10.2.3.6 In-Service Inspection

The in-service inspection program for the turbine assembly includes disassembly of the turbine in stages to meet OEM/NEIL requirements. These inspections will be performed during plant shutdowns. This includes complete inspection of all normally inaccessible parts, such as couplings, coupling bolts, turbine shafts, low pressure turbine buckets, low pressure wheels, and high pressure rotors. This inspection consists of visual, surface, and volumetric examinations, as indicated below:

1. A thorough volumetric examination of all low pressure wheels, including areas immediately adjacent to keyways and bores, is conducted.
2. Visual examination of all accessible surfaces of rotors and wheels.
3. Visual and surface examination of all low pressure buckets.
4. 100% surface examination of couplings and coupling bolts.

The in-service inspection of main steam and reheat valves includes the following:

1. Dismantle each main stop valve, main steam control valve, reheat stop valve, and reheat intercept valve at the OEM/NEIL recommended intervals during refuelings. A complete inspection including visual and surface examinations of the valve seats, discs and stems will be conducted. All major valve components will be cleaned, inspected and measured for proper clearance.
2. Main stop and combined intermediate valves are exercised at least once a month by closing each valve and observing by the valve position indicator that it moves smoothly to a fully closed position. At least once a quarter observation of this valve and the control valves is made by actually watching the valve motion.

The extraction check valves will be tested to assure that each valve is capable of being actuated by its power cylinder, and to exercise the mechanism so as to keep it free to move.

The extraction check valves will be tested periodically with the turbine on line and loaded.

The turbine system maintenance program described above is based on the manufacturer's calculations of missile generation probabilities.

Under normal operating conditions, there are no radioactive contaminants present. It is possible for this system to become contaminated only through steam generator tube leaks. In this event, radioactivity in the steam is detected and measured by monitoring condenser air ejector off-gas which is released through the unit vent, and by monitoring the steam generator blowdown samples.

No radiation shielding is required for the components of the turbine-generator and related steam handling equipment. Continuous access to the components of this system is possible during normal conditions.

The turbine-generator is designed and manufactured in accordance with General Electric Company design criteria and manufacturing practices, procedures, and processes, as well as its Quality Assurance Program. National codes are not included since existing national codes do not apply to nuclear turbine-generators.

The moisture separator reheaters and drain tanks are designed and constructed to ASME Section VIII.

The orientation of the turbine provides additional assurance that safety-related structures and components will not be affected in the extremely unlikely event a turbine missile is generated. Further analysis of turbine missiles is provided in Section 3.5.

10.2.4 Safety Evaluation

The turbine-generator and all related steam handling equipment are of conventional proven design. This unit automatically follows the electrical load requirements from station auxiliary load to turbine full load.

The turbine-generator is located entirely in the turbine building. Thus no safety related system or portion of safety related system is close enough to the turbine-generator to be affected by the failure of a high or moderate energy line associated with the turbine-generator or the low pressure turbine/condenser connection. The effects of piping failure on the turbine speed control system are discussed in Section 10.4.4 and it is concluded that an unacceptable overspeed condition due to piping failure is highly unlikely.

The results of a failure analysis of the turbine speed control system are tabulated in Table 10-4. The analysis shows that the single failure of a main stop, main control, intermediate stop, or intercept valve does not disable the turbine overspeed trip function.

Under normal operating conditions, there are no radioactive contaminants present. It is possible for this system to become contaminated only through steam generator tube leaks. In this event, radioactivity in the Main Steam System is detected and measured by monitoring condenser air ejector off-gas which is released through the unit vent, Section 10.4.2, and by monitoring the steam generator blowdown samples, Section 10.4.8.

No radiation shielding is required for the components of the turbine-generator and related steam handling equipment. Continuous access to the components of this system is possible during normal conditions.

The condensate polisher demineralizers are available to remove radioactive particulates from the condenser hotwell, Section 10.4.7, in the event of primary to secondary leakage. Two feet of concrete block surrounds an area containing five condensate polisher demineralizers, the backwash tank, the decant monitor tank, and associated pumps. The control panel is located outside of the labyrinth shield wall for accessibility.

The turbine-generator is designed and manufactured in accordance with General Electric Company design criteria and manufacturing practices, procedures, and processes, as well as its Quality Assurance Program.

The moisture separator reheaters and drain tanks are designed and constructed to ASME Section VIII. The generator rating, temperature rises and insulation class are in accordance with ASA Standards.

For information concerning system activity concentrations see Section 11.1. For information concerning area airborne activity and radiation levels see Section 12.2.

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10.3 Main Steam Supply System

Note:

This section of the FSAR contains information on the design bases and design criteria of this system/structure. Additional information that may assist the reader in understanding the system is contained in the design basis document (DBD) for this system/structure.

10.3.1 Design Bases

The Main Steam Supply System is designed to achieve the following:

1. Provide steam flow requirements at main turbine inlet design conditions.
2. Dissipate heat from the Reactor Coolant System following a turbine and/or reactor trip by dumping steam to the condenser and atmosphere.
3. Provide steam as required for:
   a. Main and auxiliary feedwater pump turbines.
   b. Condenser steam air ejectors.
   c. Main and feedwater pump turbine seals.
   d. Miscellaneous auxiliary equipment.
4. Conform to applicable design codes presented in Table 3-4.
5. Allow visual in-service inspection.
6. Protect adjacent equipment against heat damage.

10.3.2 Description

Main steam is generated in the four steam generators by feedwater absorbing heat from the Reactor Coolant System. Main steam is conveyed by four lines, one per steam generator, to the turbine inlet valves. A pressure equalization and steam distribution header is connected to each main steam line upstream of the turbine inlet valves. A flow restrictor is provided in each steam generator outlet nozzle to limit maximum flow and the resulting thrust forces caused by a steam line rupture. The steam generators and all main steam piping and valves to the outer doghouse walls are Duke Safety Class B. All lines greater than 2½ inch which connect to the main steam lines upstream of the main steam isolation valves are also Duke Safety Class B. Main steam piping between the main steam isolation valves and the Turbine Building wall is Duke Safety Class F. All other piping is Duke Class G except the 4" CF to CA "tempering flow to SG A and D upper nozzle" lines which have been upgraded to Duke Class F to preclude failure due to seismic and tornado wind loads. See Figure 10-5, Figure 10-6, Figure 10-7, Figure 10-8, Figure 10-9, Figure 10-10, Figure 10-11, and Figure 10-12. The steam generator steam flow restrictors are integral with the steam generator steam outlet nozzle. The flow restrictors are qualified with and subject to the same QA program as the steam generators. See Section 10.3.4 for inspection and testing requirements.

Five self-actuated safety valves are located on each main steam line (a total of twenty) in the doghouses to prevent overpressurization of the Main Steam System under all conditions. The valves are designed to pass 105 percent of the Engineered Safeguard Design (ESD) steam flow

at a pressure not exceeding 110 percent of the system design pressure (1200 psia). All piping up to and including the valves is Duke Safety Class B. The safety valve discharge piping is Duke Safety Class F. See Table 3-3 and Table 3-4 for applicable codes.

An automatically operated main steam isolation valve is installed in each main steam line to stop the uncontrolled steam flow from the steam generators in the event of a break in the main steam piping. The valve will stop flow from either direction when it is closed. These valves serve only a safety function and are not used during normal power operation. See Table 3-3 and Table 3-4 for applicable codes. The valves are held against four actuator springs by control air applied to the bottom of the actuator piston. Loss of control air allows the springs to force the valve closed. The main steam isolation valves close under actuator spring force and an air-assist force. The air-assist, directed to the top of the actuator piston, is supplied by a safety-related accumulator located near the valve. A safety-related check valve is located in the accumulator air supply piping to keep the accumulator pressurized during a depressurization or loss of the VI System.

A wall mounted, single failure proof, electro-pneumatic control panel is located near the valve. It consists of four solenoid valves and four 3-way pneumatic shuttle valves that operate in concert to supply and vent air to/from the actuator. The vent ports on the 3-way pneumatic shuttle valves have flow control orifices and/or needle valves installed to adjust opening and closing speed of the main steam isolation valve. In addition to the normal VI supply, the control panel is connected to the safety-related accumulator which provides an air-assist force for additional closing margin. The air assisted closure is credited for margin purposes only; the air-assist is not needed for operability. The valves are capable of closing on spring force alone and are considered operable with zero pressure in the accumulators. The performance tests carried out by operations to demonstrate valve operability through measurement of stroke time are performed with the associated accumulator isolated and the top of the actuator piston depressurized vented to atmosphere. Additionally, the accumulator and associated check valve can not degrade the ability of the main steam isolation valve to close.

These air operated valves are required to close in 8 seconds or less (per Tech Spec Bases 3.7.2) on the following signals:

1. High steam line pressure rate and 2/3 pressurizer pressure below setpoint. (See interlock P-11 in Table 7-7)
2. Low steam line pressure and 2/3 pressurizer pressure above setpoint. (See interlock P-11 in Table 7-7)
3. High-high containment pressure.
4. Manual operator actuation of the control switches.

The isolation valves for all loops of the unit will close on receipt of any signal to close, and the valves will remain in the closed position even if the signal is terminated. The valves may be reopened only by manual operator action. These valves may be remote manually operated from the control room. The valves will fail closed on loss of air.

A bypass line with a valve is provided to equalize pressure across the main steam isolation valve before opening during startup for the purpose of main steam line warmup and to pass steam for steam auxiliary systems as needed. The bypass valve is designed to stop flow from either direction when it is closed. The automatically operated bypass valve has a closure time of 10 seconds or less.

The main steam isolation valves and main steam isolation bypass valves are controlled by solenoids which are divided between Train A and Train B for redundancy, have wiring separated

on a train basis per Duke separation criteria, and are designed for the Safe Shutdown Earthquake. Individual main steam isolation valves have open and close buttons in the control room which activate relays in both trains. These relays energize two solenoid valves in each train that in turn control air to the main steam isolation valves. The two trains differ in that once the Train B solenoids are energized, they remain in that state continuously, with the Train A solenoids providing actual control of the valve. However, upon receipt of a Main Steam Isolation signal, either automatic or manual, both trains of solenoid valves are de-energized to ensure the MSIV closes given a similar failure.

The main steam isolation bypass valves are normally controlled by manual loaders located in the control room. Two train-related solenoids on each valve are available to trip the valves closed.

The Solid State Protection System (SSPS) provides for automatic emergency closure of the main steam isolation valves and their bypasses on any of the three automatic signals listed above. This automatic action by either train of the SSPS will close all the main steam isolation valves and their bypasses.

The 90% test circuit for each main steam isolation valve, when was originally provided so that the valve could be tested during plant operation, has been deleted.

A power-operated relief valve (PORV) is provided in the safety grade portion of each main steam line upstream of the isolation valve. The PORVs:

1. Prevent lifting of the safety valves during mild pressure transients.
2. Assist reseating actuated safety valve(s).
3. Provide a means for plant cooldown when the steam dump system is not operable.
4. Provides a safety grade means of achieving RCS cooldown to ND initiation temperature in compliance with BTP RSB 5-1.

The PORVs are not required for overpressure protection. However, they are required to achieve and maintain a hot shutdown condition. Thus, these valves are safety related and are seismically qualified to achieve RCS cooldown to ND initiation temperature. In addition, these valves must close in 8 seconds or less after receiving a closure signal. The pressure boundary defined by the PORV's is Duke Class B. See Table 3-3 and Table 3-4 for applicable codes.

The PORVs can be actuated by either a pneumatic piston operator or local handwheel. The pneumatic operator has two modes of operation. One mode provides non-adjustable automatic pressure control. This mode of operation is non-safety. The safety grade mode of operation is provided by the use of a nitrogen control system. All components of this system are seismically qualified. Nitrogen is supplied by seismically mounted cylinders located in the doghouse. The two PORV's in each doghouse have independent nitrogen supplies with solenoids and controllers powered from independent essential electrical trains. Safety grade control for the nitrogen control system is provided in the control room. Control for these valves is also provided from the auxiliary feedwater pump turbine control panel.

Each PORV is provided with an upstream electric motor operated block valve whose primary purpose is to allow PORV isolation for repair or maintenance. Although not required for nuclear safety, the block valve can be used to isolate a partially or fully stuck open PORV. The motor operators fail "as is" and can be controlled from the control room. The Steam Generator PORV block valves power supplies and controls are IE.

Loss of off site power will close the main steam isolation valves and their bypasses.

The dump systems are located in the Main Steam System between the main steam isolation valves and the turbine stop valves. There are nine valves discharging to atmosphere and nine condenser dump valves. An artificial steam load is induced to enable the Nuclear Steam Supply System to follow turbine load reductions which exceed 10 percent step or 5 percent per minute ramp. This load is created by dumping steam to the condenser and/or atmosphere. The dump system is controlled to give the required ramp load change to prevent reactor trip. The reactor control rods correct the reactor output while the dump creates an artificial load to prevent reactor trip and insertion of the control rods during the transient. See Section 10.4.4.

The auxiliary feedwater pump turbine is supplied with steam from two main steam lines upstream of the main steam isolation valves to obtain redundancy of supply. The piping from the takeoffs to the pump turbine is classified as Duke Class B. Each supply line has a normally closed air operated piston isolation valve with the air controlled by two solenoid valves. The isolation valves will open on a signal from the Reactor Control and Protection System, by a blackout, or can be operated remote manually. The valves will fail open.

Water formation in the steam supply header to the auxiliary feedwater pump turbine could potentially cause damage to the pump turbine due to water slugging. In order to minimize water formation in this line, the pipe is electrically trace heated.

10.3.3 Evaluation

A failure of any main steam line or malfunction of a valve in the system does not:

1. Reduce flow capability of Auxiliary Feedwater System below the minimum required.
2. Prohibit function of any Engineered Safety Feature.
3. Initiate a loss-of-coolant accident.
4. Jeopardize Containment integrity.

The Main Steam System delivers the generated steam from the outlet of the steam generators to the various system components throughout the Turbine Building without incurring excessive pressure losses. Steam is generated at essentially dry and saturated conditions. Functional requirements of the system are as follows:

1. Achieve optimum pressure drop between the steam generators and the turbine steam stop valves.
2. Assure similar steam conditions between each steam stop valve and between each steam generator.
3. Achieve adequate piping flexibility for acceptable forces and moments at equipment interfaces.
4. Assure adequate draining provisions for startup and for operation with saturated steam.

Safety class requirements of the Main Steam Supply System are presented in Table 3-4. The steam generated in the four steam generators is normally not radioactive; however, in the event of primary-to-secondary leakage due to a steam generator tube leak, it is possible for the main steam to become radioactively contaminated. A discussion of the radiological aspects of primary-to-secondary leakage, including anticipated releases to the environment as a result of the opening of the power-operated relief valves and the safety valves, is contained in Chapter 15. The maximum actual flow capacity of any safety, dump, or power operated relief valve at an inlet saturated steam pressure of 1200 psia will not exceed 970,000 pounds per hour to limit steam release if any one valve inadvertently sticks open.

Table 10-5 gives all flow paths that could contribute to the blowdown of a second steam generator following a break upstream of one main steam isolation valve (MSIV) and the failure of a second MSIV to close. The flows given are maximum with all equipment functioning as designed. Steam flow to the auxiliary steam and steam seal headers can be terminated by operation of control room switches. The remaining flow paths, which are all low point drains, can be terminated by manually closing the appropriate valves. However, since maximum drain flow is less than 10,000 lb/hr, termination of drain flow is not essential for orderly shutdown.

The effects of natural phenomena, external missiles, internally generated missiles, pipe whip, jet impingement forces associated with pipe breaks, and breaks in high and moderate energy piping systems, are discussed in Chapter 3.

10.3.4 Inspection and Testing Requirements

The Main Steam Supply System is fully tested and inspected before initial unit startup. Visual in-service inspection of the system is performed periodically by station operating personnel. See Section 6.2.4.4 and the Inservice Pump and Valve Testing Program for the testing and inspection of the main steam isolation valves. Portions of the Main Steam System at Catawba are enclosed in a guard pipe which does not allow access for performing ultrasonic inspection. All preservice and inservice radiographic inspection at Catawba Nuclear Station are to be performed in accordance with the applicable requirements of ASME Section XI.

10.3.5 Water Chemistry

10.3.5.1 Effect of Water Chemistry on the Radioactive Iodine Partition Coefficient

As a result of the basicity of the secondary side water, the radioiodine partition coefficients for both the steam generator and the air ejector system are decreased (i.e., a greater portion of radioiodine remains in the liquid phase). However, the lack of data on the exact iodine species and concentrations present prevents a quantitative determination of the coefficient decrease for these systems. The partition coefficients used for site boundary dose calculations are those given in NUREG 0017. For the steam generators, a partition coefficient of 0.01 was used while for the main condenser air ejector the partition coefficients used were 0.15 for volatile iodine species and zero for non-volatile species, assuming 5% of the iodine species are volatile.

10.3.5.2 Secondary Side Water Chemistry

Water purity in the secondary system, and in the steam generators in particular, is maintained within specified limits in order to minimize corrosion and to minimize fouling of steam generator heat transfer surfaces.

10.3.5.2.1 Treatment

All volatile treatment (AVT) is provided by the chemical addition of hydrazine for oxygen scavenging and ammonia/ approved amine for maintaining pH. A program of secondary side boric acid addition may be used to mitigate caustic conditions in the steam generator crevices, especially if evidence of stress corrosion cracking/intergranular attack (SCC/IGA) has been observed.

In addition, powdered resin demineralizers are used for condensate polishing, and an air removal section in the condenser is used to remove oxygen from the feedwater.

10.3.5.2.2 Monitoring

Samples are collected from the steam generators, condensate and feedwater. Instrumentation is provided to monitor pH, conductivity, hydrazine, sodium, and oxygen. Current operating guidelines (including those for boric acid chemistry) are derived from vendor recommendations and the current revision of the EPRI PWR Secondary Water Chemistry Guidelines, with exceptions as technically justified and determined by management.

10.3.5.2.3 Controlling Chemistry

Operating the polishing and steam generator blowdown demineralizers properly and maintaining condenser vacuum will control the quality of feedwater. In addition, blowdown of the steam generators is used to maintain chemistry limits. The chemistry guidelines addressed in Section 10.3.5.2.2 will be used as the controlling chemistry criteria. High purity makeup water and chemical additives are added as needed.

10.3.6 Main Steam and Feedwater System Materials

10.3.6.1 Fracture Toughness

For original materials, fracture toughness testing was not required under the effective (1974) Edition and Addenda of ASME Section III, NC 2300. Materials of similar composition and thickness had been used successfully in the past for service in the range of our lowest service metal temperature (50°F). Any new materials may require fracture toughness testing depending on what edition of the ASME Code to which it is purchased.

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

10.3.6.2 Materials Selection and Fabrication

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

1. Materials used are included in Appendix I of Section III and to parts A, B, or C of Section II of the ASME Code.
2. Conformance to Regulatory Guide 1.26 is discussed in Section 3.2.2.
3. Cleaning and acceptance criteria are based on the requirements of ANSI N45.2.1-73 and the recommendations of Regulatory Guide 1.37.
4. Austenitic stainless steel and low alloy steels are used as replacement materials where flow assisted erosion/corrosion is a potential problem for carbon steel piping. Conformance to Regulatory Guide 1.50, "Control of Preheat Temperature for Welding Low-Alloy Steel" is discussed in Section 1.7.1.1.
5. Duke Power Company complies with Regulatory Guide 1.71, "Welding Qualification for Areas of Limited Accessibility," except that the guide's restriction on access is deemed too stringent and would require unnecessary testing. In that it is impossible to define each variable that is site related in an overall procedure of this type, it is Duke's approach to use only highly skilled personnel as a means of assuring acceptable welds. Qualification of these personnel is based on Regulatory Guide 1.71 and an approved procedure.

6. The nondestructive examination procedure used for the examination of tubular products conforms to the requirements of the ASME Boiler and Pressure Vessel Code, Section III, NC-2000 for Class 2 materials.

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10.4 Other Features of Steam and Power Conversion System

10.4.1 Main Condenser

10.4.1.1 Design Bases

The main condenser is designed to condense turbine exhaust steam for reuse in the steam cycle. The main condenser also serves as a collecting point for various steam cycle vents and drains to conserve condensate which is stored in the condenser hotwell. The condenser also serves as a heat sink for the Turbine Bypass System and is capable of handling 40 percent of rated main steam flow. Rejected heat is removed from the main condenser by the Condenser Circulating Water System.

10.4.1.2 System Description

The main condenser consists of three surface type deaerating condenser shells with each shell condensing the exhaust steam from one of the three low pressure turbines. The condenser shells are of conventional shell and tube design with steam on the shell side and circulating water in the tubes. Each condenser shell is joined to the turbine by a rubber belt type expansion joint. Provisions have been made for mounting two low pressure feedwater heaters in the neck of each of the three condenser shells. The combined hotwells of the three condenser shells have a water storage capability equivalent to approximately 7.5 minutes of full load operation. The internal condenser design provides for the effective condensing of steam, scavenging and removal of noncondensable gases, and the deaeration of the condensate. The condenser tubes are protected from failure due to high temperature drains and blowdown by spray headers and impingement baffles.

The circulating water side of the main condenser is a triple pass arrangement having two vertically divided water circuits. Each of the two water circuits can be isolated for the repair of leaking tubes by closing the motor operated butterfly valves on the condenser inlet and outlet connections. The main condenser will maintain back pressures of 2.4, 2.9, and 3.7 In. Hg. Abs in the three condenser shells when operating at rated turbine output with 89°F inlet circulating water temperature and 95 percent clean tubes. Loss of condenser vacuum due to the accumulation of non-condensable gases is prevented by the steam air ejectors described in Section 10.4.2. However, if vacuum loss should occur, high back pressure signal(s) from turbine exhaust instrumentation will trip the turbine, low vacuum signal(s) from condenser instrumentation will block the condenser steam dump valves (see Section 10.4.4), and the condenser will in effect be isolated from all direct sources of main steam. Loss of condenser vacuum does not affect operation of the main steam isolation valves. The condenser tubes and components are constructed of corrosion/erosion resistant materials. In addition, a continuous tube cleaning system (Amertap) is provided to keep the inside tube surfaces clean and the condenser operating at peak performance.

The main condenser can accept a bypass steam flow of approximately 40% of rated main steam flow without exceeding the turbine high backpressure trip point with design inlet circulating water temperature. This bypass steam dump to the condenser is in addition to the normal duty expected with a throttle flow of 60% of rated main steam flow. The steam dump flow is distributed by a 20 inch perforated pipe in each of the three condenser shells. These perforated pipes are designed to ensure that no high velocity steam can impinge on the tubes, and are supported for the dynamic loading which the bypass flow will impose.

10.4.1.3 Safety Evaluation

The main condenser is not assigned a safety class as it is not required for a safe reactor shutdown. Radioactive contamination of the main condenser is a function of primary to secondary leakage and can be detected by the condenser steam air ejector discharge radiation monitor. (See Chapter 11 for a full discussion of the radiological aspects of primary to secondary leakage including operating concentrations of radioactive contaminants.) The level of main condenser contamination can be controlled to some extent by steam generator blowdown and the condensate polishing demineralizers. Any radioactive leakage from the main condenser will enter the Turbine Building sump and can be detected by the sump's continuous radiation monitor. Excessive radioactive leakage can be processed by pumping the contents of the contaminated sump to the Liquid Radwaste System. Since the potential hydrogen release rate is small when compared to the Main Condenser Evacuation System capacity, any hydrogen entering the condenser is effectively exhausted and the potential for hydrogen buildup is negligible.

The condenser could become ineffective due to loss of cooling water or excessive air inleakage. These conditions would result in a high backpressure alarm at 5.0 In. Hg. Abs., and at 7.5 In. Hg. Abs. the turbine would be automatically tripped. The excess reactor heat would then be removed as steam through the condenser dump valves until these valves are tripped closed on loss of condenser vacuum or loss of circulating water pumps. After closing the condenser dump valves, the excess heat would be relieved to atmosphere through the atmospheric dump valves, power operated relief valves and/or the ASME Code safety valves. There is no maximum permissible cooling water inleakage limit nor time of operation with inleakage.

A leak or failure in the condenser shell would allow condensate to drain out, but the pits located below the condenser will hold more water than the condenser hotwell volume. The flooding due to a loss of a condenser waterbox or circulating water piping would be limited to the Turbine Building and is discussed in Section 10.4.5.

10.4.1.4 Tests and Inspections

The main condenser is tested in accordance with the Heat Exchange Institute Standards for Steam Surface Condensers. Manways in the condenser provide access to waterboxes, tube sheets, shell, and hotwell for inspection, repair and tube plugging. The pH, sodium content, and oxygen content of the condensate leaving the hotwell are continuously monitored for any abnormal change which may be indicative of condenser cooling water leakage into the condenser. The leakage can be controlled to some extent by isolating the half of the condenser containing the leaking tubes and operating at partial load. The effect of condenser cooling water leakage on steam generator blowdown chemistry may be controlled somewhat by the condensate system's polishing demineralizer which will remove contaminants.

The effect of the leakage upon unit operation can range from no effect in the case of very small leakage to unit shutdown for condenser repair in the case of more severe leakage.

During each refueling, a visual inspection of each main condenser hotwell and waterbox is performed. The inspection is conducted to detect any abnormal degradation or damage to the main condenser.

10.4.1.5 Instrumentation Application

The main condenser hotwell is equipped with level control devices for automatic control of condensate makeup and rejection. On low water level in the hotwell, control valves supply condensate from the upper surge tanks to the hotwell by gravity. The CS33 and CS57 valves

are isolated whenever the CM127 valve is isolated to prevent a loss of CA inventory from the UST. On high water level in the hotwell, another control valve opens to pump condensate from the hotwell pump discharge to the upper surge tanks. This control valve (CM33) is isolated in Modes 1, 2, and 3, and Mode 4 when the steam generator is relied upon for heat removal, by maintaining the associated control room handswitch in the CLOSED position. In Modes 2 and 3, and Mode 4 when the steam genrator is relied upon for heat removal, CM33 may be opened to control hotwell level provided strict administrative controls are taken to ensure CA operability. A low hotwell level alarm is provided in the control room. Local and remote indicating devices are provided for monitoring pressures and water levels in the condenser shells. All instrumentation for this system is operating instrumentation, and none is required for safe shutdown of the reactor.

10.4.2 Main Condenser Evacuation System

10.4.2.1 Design Bases

The Main Condenser Evacuation System is designed to remove noncondensable gases and air inleakage from the steam space of the three shells of the main condenser. The Main Condenser Evacuation System consists of the Condenser Steam Air Ejector System which is shown on Figure 10-13 and the Main Vacuum System which is shown on Figure 10-14.

10.4.2.2 System Description

The Condenser Steam Air Ejector System consists of three condenser steam air ejectors (CSAE) per unit. Each CSAE has two sets of two stage jets with each set of jets capable of handling full design capacity of 20 cfm of saturated air at 71.5°F and 1.0 In. Hg. Abs. when supplied with steam at 125 psia. Normally each CSAE draws the noncondensable gases and water vapor mixture from one of the three main condenser shells to the first air ejector stage. The mixture then flows to the intercondenser where it is cooled to condense the water vapor and motive steam. The second air ejector stage draws the uncondensed portion of the cooled mixture from the intercondenser and compresses it further. The compressed mixture then passes through the aftercondenser where it is cooled and more water vapor and motive steam are condensed. The intercondenser drains back to the main condenser and the aftercondenser drains to the condensate storage tank. The CSAE air discharge is monitored for radiation before discharging to carbon filters in the Auxiliary Building filtered exhaust duct which discharges to the unit vent. An alternate path for CSAE exhaust is provided to the gland seal condenser (TL) exhaust line (bypassing the Auxiliary Building Filtered Exhaust Duct Header). If the exhaust duct is unable to receive any exhaust air then the gas can be directed to the TL System and out the Unit Vent.

The Main Vacuum System consists of two main vacuum pumps connected to the condenser crossties on the Condenser Steam Air Ejector System to allow the main vacuum pumps to evacuate the main condenser, the main turbine casing and the upper surge tanks during startup. Each main vacuum pump is designed to remove 3050 cfm of air with suction conditions of 20 In. Hg. Vacuum and 80°F. These pumps are only used during startup since normal operation requires the use of the CSAE's only.

10.4.2.3 Safety Evaluation

The Main Condenser Evacuation System is not assigned a safety class as it is not required for a safe reactor shutdown. Control functions of the Main Condenser Evacuation System indirectly

influence Reactor Coolant System operation in that upon loss of vacuum the main condenser no longer provides a heat sink.

The noncondensable gases and water vapor mixture discharged to the atmosphere from the Main Condenser Evacuation System are not normally radioactive; however, in the event of primary to secondary system leakage due to a steam generator tube leak, it is possible for the mixture discharged to become radioactive. A full discussion of the radiological aspects of a primary to secondary leakage including radioactive discharge rates under postulated design conditions is discussed in Chapter 11 and Chapter 15.

10.4.2.4 Tests and Inspections

Proper operation of the Main Condenser Evacuation System is verified during unit startup, and is subject to periodic inspections by plant operating personnel. A flowmeter is provided in the discharge piping of each CSAE. Periodic readings of these flowmeters will indicate whether or not the air inleakage to the condenser is within acceptable limits. These readings will also indicate the operating effectiveness of the CSAE's.

10.4.2.5 Instrumentation Applications

A radiation monitor is provided in the exhaust line from the CSAE's with remote indicator, recorder, and alarm located in the Control Room. Local indicating devices for pressure, temperature, and flow are provided as required for monitoring system operation. All instrumentation for this system is operating instrumentation and none is required for safe shutdown of the reactor.

10.4.3 Turbine Gland Sealing System

10.4.3.1 Design Bases

The Turbine Gland Sealing System (TGS) is designed to seal the annular openings around the rotor shafts of the high pressure (HP) and low pressure (LP) main turbines and the feedwater pump (FDWP) turbines where the shafts emerge from the shell casings. All seals for the LP main turbines and the exhaust end seals for the FDWP turbines are designed to prevent the leakage of atmospheric air into the turbines since the turbine shell pressures at these seal locations are subatmospheric at all unit loads. All seals for the HP main turbine and the steam inlet end seals for the FDWP turbines are designed to prevent the leakage of steam from the turbines as well as to prevent atmospheric air leakage into the turbines since the turbine shell pressures at these seal locations vary from subatmospheric to above atmospheric as these turbines progress from startup to normal operation. During startup operations, steam is also supplied to seal the main turbine stop valves, control valves, and combined intercept valves. Sufficient sealing steam can be supplied automatically at startup with the main steam supply as low as 25% of the rated throttle pressure or with the Auxiliary Steam System supply at approximately 170 psia. For lower steam supply pressures and/or larger steam seal clearances, manual provisions allow for the additional required capacity. Sufficient sealing steam may be supplied to seal the turbines with double the normal steam seal clearances.

10.4.3.2 System Description

The shaft seals of the turbines are provided with a series of labyrinth type, spring-backed, segmented packing rings which are fastened in the bores of the turbine shells and hoods at every point where the shaft emerges from the steam to the atmosphere. These rings are

machined with specially designed teeth which are fitted with minimum radial clearance between the teeth and turbine shaft. The small clearance and resistance offered by this arrangement restricts the steam and air flow leakage to a minimum.

The sealing steam supplied to or from each of the inner shaft seals and valve stem leakoffs is piped to a common steam seal header. At startup and low loads, the steam seal header is maintained at constant pressure by a steam supply control valve which throttles main steam and/or auxiliary steam to the steam seal header in addition to a very small supply (if any) of leakoff steam. At higher loads, the steam seal header is maintained at constant pressure by a steam supply control valve which throttles steam from the turbine ninth stage extraction (E Bleed Steam System) to the steam seal header in addition to a large supply of leakoff steam from the HP main turbine packings, steam inlet end packings of the FDWP turbines, and turbine stop, control, and combined intercept valve stem leakoffs. At full load, the total leakoff steam supply to the steam seal header may be as much as 60% of the total TGS System requirements. When more steam is supplied to the steam seal header than is needed, a control valve automatically discharges the excess steam to the condenser. Manually controlled motor operated valves are provided to allow transfer between the auxiliary steam supply and the main steam supply during startup. Additional manually controlled motor operated valves are provided to allow override of the automatic controls, remotely from the control room.

Steam and air leaking into the outer seals of the turbines are exhausted to the shell side of the gland steam condenser which is maintained at a pressure of approximately 10 to 12 inches water vacuum. The steam is condensed and returned to the condensate storage tank. Any remaining moisture and noncondensibles are exhausted by a blower to the Unit Vent provided in the Auxiliary Building Ventilation System.

System flow diagrams are shown in Figure 10-15, Figure 10-16, and Figure 10-17.

10.4.3.3 Safety Evaluation

Considering the PWR design of this unit, any radioactivity in the gland steam condenser blower discharge is expected to be extremely low. However, any radioactive release from the TGS System during normal operation will be monitored and controlled by the Auxiliary Building Ventilation System. All TGS System controls and valves are arranged in the fail safe configuration to protect the turbine. Adequate indication, alarms, and controls are provided in the control room to allow manual override of the system if a malfunction of the normal automatic control system does occur. Four relief valves are provided on the steam seal header to prevent overpressurization due to a control malfunction or valve failure.

10.4.3.4 Inspection and Testing Requirements

The equipment will be tested by the manufacturer in accordance with the various applicable code requirements. Proper operation of the TGS System is verified during unit startup. During normal operation of system, periodic checks of operating conditions will detect any deterioration in the performance of system components.

10.4.3.5 Instrumentation Requirements

The steam seal header pressure is displayed in the control room. Alarms are provided for both high and low steam seal header pressures. All of the instrumentation for the TGS System is operating instrumentation, and none is required for safe shutdown of the reactor.

10.4.4 Turbine Bypass System

10.4.4.1 Design Bases

The Turbine Bypass System (TBS) is designed to reduce the magnitude of nuclear system transients following large turbine load reductions by dumping main steam directly to the main condenser and/or to the atmosphere, thereby creating an artificial load on the reactor. The reactor can accept a 10% step change or a 5% per minute ramp change in load without tripping or steam dump. For load reductions greater than 10% step or 5% per minute ramp, the dump system is controlled to give the required ramp load change to prevent reactor trip and insertion of the shutdown control rods.

The dump system:

1. Enables the unit to accept up to 100% turbogenerator load reduction without tripping the reactor or main steam relief valve actuation.
2. Removes stored and decay heat following a reactor trip to bring the unit to hot standby without main steam relief valve actuation.
3. Can maintain the unit at hot standby condition.
4. Allows the unit to be manually cooled down to the point where the Residual Heat Removal System can be placed into service.

10.4.4.2 System Description

The Condenser Dump System and the Atmospheric Dump System both dump steam from the main steam pressure equalization header downstream of the main steam isolation valves. The nine condenser dump valves are shown on Figure 10-6 and, for uniform condenser loading, are grouped into three banks as shown below.

Dump Valve Bank	Valves
1	SB9, SB18, SB27
2	SB6, SB15, SB24
3	SB3, SB12, SB21

The nine atmospheric dump valves are shown on Figure 10-11 and are grouped into two banks as follows.

Dump Valve Bank	Valves
4	SV30, 32, 34, & 36
5	SV38, 40, 42, 44, & 54

The dump valves are manufactured by Control Components, Inc., and are basically over-the-plug-flow angle valves with a drag element designed to reduce noise, vibration, and trim erosion. The drag element consists of a stack of disks into which labyrinth flow passages have been etched to allow a fixed resistance. In operation, steam enters the sides of the disk stack, flows past the valve plug, and exits. The position of the valve plug is controlled by a pneumatic piston actuator which fails closed. Air to the piston actuator is regulated by four electrically operated solenoid valves. The solenoid valves accomplish their function by providing or by removing an air signal to air relay valves, which in turn control the supply and venting of air to the actuator. Each solenoid valve provides an air signal to two air relay valves when energized.

Upon loss of power, the solenoids de-energize and vent the air signal to the air relays. The spring return air relays return to their normal state, and align such that the dump valves fail closed.

The air relay logic is designed such that the first three solenoid valves must energize before the dump valve can open or modulate. Upon de-energization of any of the three solenoids, the dump valve will fail closed.

Two of these solenoid valves are redundant and prevent operation of the dump valve on Lo-Lo Tavg. An exception to this are the valves associated with Dump Valve Bank 1. These valves can have their Lo-Lo Tavg interlock blocked such that they can be used for cooldown operation. The third solenoid valve prevents operation of the dump valve during the situations described later in the section. In addition, each dump valve features a fourth solenoid valve and its associated relays located upstream of the rest. If the other three solenoid valves are energized, energizing this solenoid in effect bypasses the positioner and supplies instrument air to the actuator which causes the dump valve to trip open. Also on the dump valves are limit switches which provide open/closed information in the control room.

The condenser dump valves can be set to control T_{avg} or steam header pressure. The atmospheric dump valves can only control on $T_{avg.}$ T_{avg} control mode is considered to be the automatic mode and is selected during normal unit operation. Upon reduction of turbogenerator load, appropriate dump valves open and allow reactor power to decrease to the proper level without actuating any main steam relief valves or tripping the reactor. The number of dump valves actuated depends on the required steam dump as shown below. Here it should be noted that if a valve bank is opened fully, it is maintained open while the subsequent banks open.

Steam Dump Demand	Valve Bank Modulated (Zero To Fully Open)
0 - 16.2%	1
16.2 - 32.6%	2
32.6 - 49.0%	3
49.0 - 71.6%	4
71.6 - 100.0%	5

Under certain conditions, banks of dump valves will be blocked from operation.

Those conditions are:

1. Block all dump valves if load reduction is less that 10%.
2. Block all atmospheric dump valves if load reduction is less than 30%.
3. Block condenser dump valves if condenser is unavailable (i.e., loss of vacuum or circulating water).
4. Block all dump valves on Lo-Lo T_{avg}

If operating in the T_{avg} control mode and reactor trip occurs, the dump system will modulate appropriate condenser dump valves to bring the unit to hot standby without main steam relief valve actuation. As for load reduction, the number of dump valves actuated depends upon the steam demand except that the atmospheric dumps are blocked. Also, as for the load reduction case, condenser dump valves that are fully opened are maintained open. Conditions that will result in dump valve blockage for this case are as follows:

1. Block all atmospheric dump valves upon reactor trip.

2. Block all condenser dump valves if condenser is unavailable (i.e., loss of vacuum or circulating water.)
3. Block all condenser dump valves on Lo-Lo T_{avg}

The pressure control mode of steam dump system operation is selected during startup and shutdown of the unit and is considered to be the manual mode of operation. When in the pressure control mode, the condenser dump valves simply modulate as necessary to maintain the steam header pressure at an adjustable setpoint. The following conditions will cause blockage of steam dump valves.

1. Block all atmospheric dump valves upon selection of pressure control mode.
2. Block all condenser dump valves if condenser is unavailable.
3. Block all dump valves on Lo-Lo T_{avg} except during cooldown, then block all but SB9, SB18, and SB27.

When shutting the unit down, the pressure control mode allows the reactor coolant to be cooled at a controlled rate by decreasing the steam pressure correspondingly. The Lo-Lo T_{avg} dump valve blockage logic is bypassed by actuating a momentary switch in the control room. The dump valves used to cool down (i.e., SB9, SB18, SB27) are known as the cooldown valves. Once the hot leg temperature has decreased to 350°F, steam dump can be terminated and further cooldown can be provided by the Residual Heat Removal System.

Operational ALARA advantages exist from a continued cooldown using steam dumps well below 350°F and delaying placing the Residual Heat Removal (ND) System in service. This optional cooldown method has been incorporated into operations procedures. A successful Reactor Coolant (NC) System shutdown cleanup phase while cooling down using steam dumps well into the ND design temperature range (below 350°F), can significantly reduce general area dose rates in the Auxiliary Building which would otherwise occur if ND were placed in service at 350°F without the successful shutdown cleanup phase mentioned earlier.

10.4.4.3 Safety Evaluation

The steam dump system is not essential for safe shutdown of the unit, thus it is not designated as safety related. (See Table 3-4 for system component design criteria.) The steam dump system merely provides added flexibility in unit operation. Failure of the steam dump system will not preclude operation of any essential system. A failure mode and effects analysis is described below and summarized in Table 10-8. The worst operational consequence of system failure is reactor and turbine generator trip.

In the event of complete loss or reduction in steam dump capacity, full load steam flow to atmosphere is assured by the steam generator code safety relief valves. If tube leaks are present prior to the transient, some radioactivity accumulated in the steam generator shell side water will be discharged to atmosphere. However, the radioactivity will be well within the limits established by 10CFR 100.

The maximum flow through any one condenser or atmospheric dump valve is less than 970,000 pounds per hour. This is in accordance with Westinghouse recommendations to preclude excessive one dump valve or power operated relief valve spuriously or inadvertently open at worst case conditions with the steam generators at no load conditions. Furthermore, the atmospheric dump and power operated relief valves are provided with electric motor operator root valves that can be remotely closed from the control room. Should there be several stuck open valves or a large break, main steam isolation will automatically occur and thus stop steam flow.

The steam bypass system is located entirely in the turbine building. Thus, no safety related components or systems are close enough to be affected by failure of any steam bypass system line. A break in the condenser steam dump lines could possibly damage the hydraulic oil lines beneath the turbine. However, all main turbine steam valves are designed to trip closed upon loss of hydraulic oil pressure. The atmospheric dump lines are located on the operating floor as is the turbine trip mechanism. However, the distance between the trip mechanism and the high energy lines is sufficient to prohibit any unacceptable pipe whip or jet interactions. Thus, no turbine bypass system high energy line failure can adversely affect or negate operation of the turbine speed controls in regard to the overspeed trip function.

If the turbine generator is subjected to a 100% load reduction, the maximum voltage on the output of the generator is estimated to be approximately 129% of rated with the period of the excursion where voltage is above 110% of rated being approximately 3.2 seconds. The maximum frequency is estimated to be approximately 107.5% of rated. The minimum values of voltage and frequency do not exceed normal equipment ratings.

Per industry standards, power equipment such as 4 KV switchgear, 4160/600 V transformers, and 600 V switchgear is designed to withstand voltages in excess of 1.4 per unit for a duration of 60 seconds. Motors are typically subjected to hi-pot tests at 2150 volts for 575 volt motors, and 9000 volts for 4 KV motors for a duration of 60 seconds. Based on vendor information and test results, electronic equipment and control components are also capable of withstanding the transient following a 100% load rejection. The frequency excursion would result in a motor speed increase of 7½%; however, NEMA standards require that motors be designed to withstand overspeeds of 20% for short durations without damage.

The value above for maximum voltage is very conservative as it is based on initial conditions where the generator is operating 5% above rated voltage with a power factor of 0.9. Since the Catawba generators have a rated voltage approximately 5% higher than the connected transformers, the generators are not likely to be operated above rated voltage. It is also unlikely that the unit would be operating with a power factor below 0.95. Based on actual operating conditions, the maximum voltage should not exceed 122%.

Although the turbine generator is designed to accept a 100% load rejection, it is extremely unlikely that the unit will be subjected to a 100% load reduction while remaining on line powering station loads. This is especially the case since the unit is tied to the switchyard through two separate circuits which terminate in separate bays of a breaker-and-a-half arrangement.

10.4.4.4 Inspection and Testing

Proper operation of the condenser dump valves and the atmospheric dump valves is verified during each unit startup and shutdown. A dynamic test of the steam dump control system is performed during the startup sequence.

10.4.4.5 Instrumentation Application

The steam dump system, during normal operating transients, is automatically regulated by the reactor coolant system to maintain the desired reactor coolant temperature. Following a transient condition, the operator may place the bypass to the condenser in the main steam pressure control mode for a more precise control capability. The control sequence for the TBS is arranged for preferential operation of the bypass to the condenser to conserve condensate. All of the instrumentation for this system is operating instrumentation and none is required for safe shutdown of the reactor.

10.4.5 Condenser Circulating Water System

10.4.5.1 Design Bases

The Condenser Circulating Water System supplies cooling water to the main and feedwater pump turbine condensers to condense the turbine exhaust steam. The rejected heat from the condensers is dissipated to the ambient surroundings by the cooling towers while meeting all applicable chemical and thermal effluent criteria.

10.4.5.2 System Description

The Condenser Circulating Water System is a closed loop cooling system consisting of the following:

1. Three round mechanical draft cooling towers
2. Three main condenser shells
3. Two feedwater pump turbine condensers
4. Four condenser circulating water pumps
5. Piping, valves, and instrumentation

Condenser circulating water from the three cooling tower basins combine in a 14 ft. diameter equalizer pipe and split into two 10 ft. pipes which supply cooling water to the two low pressure condenser shell inlet waterboxes. After condensing the turbine exhaust steam in the low pressure condenser shell, the condenser circulating water flows to the intermediate pressure condenser shell through two 10 ft. crossaround pipes. After condensing the turbine exhaust steam in the intermediate pressure condenser shell, the condenser circulating water flows to the high pressure condenser shell through two more 10 ft. crossaround pipes. After condensing the turbine exhaust steam in the high pressure condenser shell, the two 10 ft. condenser discharge pipes combine into a 14 ft. equalizer section before splitting into four 7 ft. pipes at the suction of the condenser circulating water pumps. After the four condenser circulating water pumps, the 6 ft. pump discharge lines combine into a 14 ft. equalizer section before splitting into two 10 ft. pipes which carry the condenser circulating water to the cooling tower yard. In the cooling tower yard the two 10 ft. pipes combine into a 14 ft. equalizer section before splitting into three 9 ft. pipes, one going to each cooling tower riser.

The feedwater pump turbine condensers operate in parallel with the main condenser by taking their supply from the two 10 ft. intake lines ahead of the low pressure condenser shell, and discharging to the 14 ft. equalizer pipe after the high pressure condenser shell.

An Amertap System on the main and feedwater pump turbine condensers is used to clean the condenser tubes while the plant is in operation. Elastic sponge rubber balls slightly larger in diameter than the condenser tubes, are injected into the condenser circulating water flow ahead of the condenser inlet waterboxes. The sponge rubber balls are forced through the tubes by the pressure differential across the condenser and scrub the tubes clean as they go through. After passing through the condenser, the balls are caught by collectors mounted on the discharge pipes, and pumped back to the waterbox inlet. Cooling tower makeup to replace evaporation, drift, and blowdown losses from the system is provided from the Conventional Low Pressure Service Water System to the cooling tower return piping to the main condenser. Cooling tower blowdown is extracted from the cooling tower outlet header and is normally returned to the Conventional Low Pressure Service Water System discharge piping which returns the blowdown to the lake.

The normal chemical additives for the Cooling Towers will be A) Sulfuric Acid for pH Control B) An Algaecide (ex. Sodium Hypochlorite/Bromine) for biological control, C) a silt dispersant for silt control and D) a biodetergent or biopenetrant to enhance the effectiveness of the biocide treatment. If required, a dechlorination agent may be added to the Cooling Towers prior to blowing down to the Lake. Provisions are made to comply with applicable environmental guidelines concerning discharge limits. No corrosion problems are expected based on operating experience and on a cooling tower pilot test study at the Catawba site.

10.4.5.3 Safety Evaluation

The Condenser Circulating Water System is not assigned a safety class as it is not required for a safe reactor shutdown. The cooling towers are located such that their structural failure due to a seismic event, a tornado, or any other natural phenomenon could not damage any safety related structure, system, or component.

There is no equipment essential to plant safety located in either the Turbine or Service Buildings. All penetrations and passageways from the Turbine or Service Buildings to the Auxiliary Building will be watertight to EL. 577.5. The maximum water level due to a simultaneous failure of the CCW systems on both units and the subsequent draining of all water in the two closed loop cooling systems back to their respective Turbine Buildings resulting in a maximum water elevation of 576.95. The available storage volume in both turbine and service buildings is 2,169,000 ft^3. The volume of condenser cooling water from both systems that could flood into the turbine and service buildings is 2,069,000 ft^3.

A failure in the CCW System or the main condenser large enough to cause flooding will be detected by high level alarms in the turbine room sumps. These high level alarms will alert the operator to check other control room instrumentation such as condensate flow, condenser differential pressure, and cooling tower basin level to see which system has failed. The control room indication will allow the operator to take corrective action immediately on a major failure to isolate the faulty piece of equipment. All major isolation valves in the CCW System are electric motor operated from the control room and are capable of closing in 60 seconds.

The CCW System is designed to withstand any pressure peaks due to a valve closure or pump power failure. The pressure peaks and other hydraulic transients and the closing time for the CCW pump discharge valves were obtained by a transient fluid simulation model analysis of the CCW System.

10.4.5.4 Tests and Inspections

The CCW System components are fully tested and inspected before initial unit operation and are subjected to periodic inspections by plant operating personnel during the life of the plant. A performance test will be conducted on the cooling towers which will also verify overall system performance. Once the system becomes operational, routine visual inspection of the system components and instrumentation will assure proper functioning of the system.

10.4.5.5 Instrumentation Application

The CCW System includes sufficient instrumentation to assure proper functioning of the system and related components. Each cooling tower fan motor has a high vibration trip. The level in each cooling tower basin, the condenser shell differential pressures, and the condenser shell inlet and outlet temperatures are continuously monitored by the computer. The chemical addition and blowdown are adjusted manually to maintain the desired water chemistry. The cooling tower makeup is automatically controlled off cooling tower basin level.

The CCW pump discharge valves are interlocked with their respective pumps so that the valve must be closed before the pump can be started. This will prevent the pump motors from being energized during reverse flow. The CCW pump discharge valves are also interlocked so that they will close when their respective pumps are shutdown. The CCW pump discharge valves are also interlocked with their respective pumps so that the valve will start opening 6 seconds after the pump is started. In addition, the CCW pump suction and discharge valves are interlocked so that a suction valve must be opened before and closed after the discharge valve to prevent over pressurizing the suction side of the pump. The CCW pump suction valves are interlocked with their respective pumps so that the valve must be open before the pump can be started, and so that the valve cannot be closed if the pump is running.

The cooling tower inlet isolation valves 1RC25, 1RC26, and 1RC27 will be interlocked with the CCW pumps so that:

1. One of the three cooling tower inlet isolation valves cannot be closed if more than two CCW pumps are operating and only two CCW pumps can be started if one cooling tower inlet isolation valve is closed.
2. Two of the three cooling tower inlet isolation valves cannot be closed if more than one CCW pump is operating and only one CCW pump can be started if two cooling tower inlet isolation valves are closed.
3. All three cooling tower inlet isolation valves cannot be closed if any of the CCW pumps are operating and none of the CCW pumps can be started if all three cooling tower inlet isolation valves are closed.

Note: Power (600 VAC) has been removed from the electric motor operator (EMO) of valve 1RC26; therefore, valve 1RC26 cannot be controlled remotely from a pushbutton.

Local indicating devices for pressure, temperature, and flow are provided as required for monitoring system performance. All of the instrumentation for this system is operating instrumentation, and none is required for a safe shutdown of the reactor.

10.4.6 Condensate Cleanup System

10.4.6.1 Design Bases

The Condensate Cleanup System (CCS) is an integral part of the Condensate System. (Refer to Figure 10-18, Figure 10-19, Figure 10-20, and Figure 10-21). The CCS is designed to remove dissolved and suspended impurities which can cause corrosion damage to secondary system equipment. The CCS also removes radioisotopes which might enter the system in the event of a primary to secondary steam generator tube leak. The condensate polishing demineralizers (CPD) will also be used to remove impurities which could enter the system due to a condenser circulating water tube leak.

10.4.6.2 System Description

The CCS for each unit consists of five powdered resin condensate polishing demineralizer vessels. There is also a separate pre-coat skid for each unit consisting of a recirculation tank, a resin feed tank, and a precoat pump.

The polishers are mainly carbon steel. The interior of the polishers is coated with Placite 7155 and the internals are of stainless steel or polypropylene. The piping is carbon steel.

The condensate polishing demineralizers are designed for automatic or manual operation following mode initiation.

Polisher vessels are backwashed based on process flow rates, system chemistry, differential pressure, or for any other reason that could degrade their performance or reduce system integrity. The vessels are backwashed to the Backwash Tank which has a holding capacity of four backwashes. Each backwash is approximately 5000 gallons (or 668 cubic feet) of which 16 cubic feet is spent resin (except for the vessels that contain the nonprecoatable type filter elements) with the remainder being water. After the backwash settles for some time, the supernatant water will be drawn off through the decant connections on the Backwash Tank and pumped by the CPD Backwash Decant Pump through the CPD Backwash Resin Filters to the CPD Decant Monitor Tank. The backwash water in the Decant Monitor Tank will be recirculated and sampled for radioactivity prior to discharge to the Conventional Waste Water Treatment (WC) System. If any significant radioactivity (greater than the allowable activity of Selected Licensee Commitment 16.11-1) is present, the backwash water will be released through the radiation monitor OEMF49 or sent to the Floor Drain Tank in the Liquid Radwaste System (WL) for further processing. If radioactivity is present but below the limits of Selected Licensee Commitment 16.11-5, the backwash water will be discharged to the WC System. The resin (and some remaining water) in the Backwash Tank will be agitated and sampled prior to being pumped by the CPD Backwash Resin Pump to a contain suitable for disposal.

10.4.6.3 Safety Evaluation

The Condensate Cleanup System is not assigned a safety class as it is not required for a safe reactor shutdown. The condensate polishing demineralizer vessels and all pre-coat equipment are located in a shielded room in the Turbine Building which contains no safety related equipment. The spent resin and water mixture discharged to the backwash tank from the polisher vessels is not normally radioactive; however, in the event of a primary to secondary steam generator tube leak, it is possible for the spent resins to become radioactive. A full discussion of the radiological aspects of a primary to secondary leakage including radioactive discharge rates under postulated design conditions is discussed in Chapter 11 and Chapter 15.

10.4.6.4 Tests and Inspections

Proper operation of the Condensate Cleaning System is verified during unit startup, and is subject to periodic inspections by plant operating personnel. Conductivity monitors and alarms on the outlet of each polisher vessel and the main effluent header continuously monitor the performance of the system.

10.4.6.5 Instrumentation Application

A condensate polishing demineralizer control panel trouble alarm will sound on any of the following:

1. High resin trap differential pressure

   Alarm on high differential pressure to indicate need for cleaning resin trap.

2. High polisher differential pressure

   Alarms on high polisher differential to indicate the need for backwashing.

3. Low recirculation tank level

Alarms on low recirculation tank level and trips precoat pump to prevent loss of pump suction.

4. High recirculation tank level

   If the tank level rises to a point indicating excessive overflow, this alarm will sound.

   Deleted Per 2006 Update.

5. Low polisher flow

   When the individual polisher effluent flow reaches a preset minimum, an alarm will sound. In addition, the holding pump on the polisher will start to maintain the precoat on the polisher tubes.

6. Loss of Cake

   If the "Essential Power Circuit" fails indicating a loss of condensate motive power, or the individual filter effluent flow reaches a preset low-low minimum before the holding pump starts, an alarm will sound and the unit must be backwashed and precoated.

7. Programmer Malfunction

   When any automatically sequenced valve or pump fails to provide a correct feedback within a preset adjustable time, an alarm will sound.

8. High backwash tank level

   Alarm on high backwash tank level.

9. Low backwash tank level

   Alarm on low backwash tank level and trip the backwash tank pumps.

10. High decant monitor tank level

    Alarm on high decant monitor tank level.

11. Low decant monitor tank level

    Alarm on low decant monitor tank level and trip the backwash decant pump.

10.4.7 Condensate and Feedwater Systems

Note:

This section of the FSAR contains information on the design bases and design criteria of this system/structure. Additional information that may assist the reader in understanding the system is contained in the design basis document (DBD) for this system/structure.

10.4.7.1 Design Bases

The Condensate and Feedwater Systems are designed to return condensate from the condenser hotwells through the condensate polishing demineralizers and the regenerative feedwater heating cycle to the steam generators while maintaining proper water inventories throughout the cycle.

The entire Condensate System is non-safety-related. The portions of the Feedwater System that are required to mitigate the consequences of an accident and allow safe shutdown of the

reactor are safety-related. The safety-related portions of the system are designed in accordance with the following design bases:

1. The system is designed such that failure of a feedwater supply line coincident with a single active failure will not prevent safe shutdown of the reactor.
2. The system components are designed to withstand the effects of and perform their safety functions during a safe shutdown earthquake.
3. Components and piping are designed, protected from, or located to protect against the effects of high and moderate energy pipe rupture, whip, and jet impingement.
4. The system is designed such that adverse environmental conditions such as tornados, floods, and earthquakes will not impair its safety function.
5. The system is designed such that the loss of offsite power will not prevent safe shutdown of the reactor.
6. The main feedwater lines are restrained or isolated to prevent damage to the coolant pressure boundary and containment in the event of a feedwater pipe rupture.

Piping and valves in the non safety-related portions of the systems are designed to ANSI B31.1.0. The feedwater heaters and condensate polishing demineralizers are designed per ASME Boiler and Pressure Vessel Code, Section VIII, Division 1. The piping and valves in the safety-related portion of the system are designed per ASME Boiler and Pressure Vessel Code, Section III, Class 2.

The Condensate and Feedwater Systems are shown in Figure 10-18 through Figure 10-28.

10.4.7.2 System Description

The Condensate System consists of the following:

1. Three 50% capacity hotwell pump strainers
2. Three 50% capacity hotwell pumps
3. Five 25% capacity condensate polishing demineralizers and associated regeneration equipment.
4. Two stages of low pressure feedwater heaters (F and G)
5. Three 50% capacity condensate booster pumps
6. Three stages of intermediate pressure feedwater heaters (C, D, and E)
7. Piping, valves, and instrumentation.

The hotwell pumps take suction from the condenser hotwell. During normal operation, two hotwell pumps will be operating with the third on standby. After the hotwell pumps, the condensate flows to the condensate polishing demineralizers. Vessels can be placed in service as needed based on system conditions. Downstream of the condensate polishing demineralizers, the condensate is divided equally between the three condenser steam air ejectors where it is used as a coolant in the CSAE inner and after condensers. All three ejectors are normally in service with each air ejector removing noncondensable gases from one of the three condenser shells. After the CSAE's the condensate flows in parallel through the gland steam condenser and the blowdown recovery heat exchangers. The condensate then passes through two stages of low pressure feedwater heating to the suction of the condensate booster pumps.

During normal operation, two condensate booster pumps will be in operation with the third on standby. Downstream of the condensate booster pumps, the condensate passes through three stages of intermediate pressure feedwater heating before combining with the C heater drain pump flow and discharging to the suction of the feedwater pumps.

The Feedwater System consists of:

1. Two 50% capacity steam generator feedwater pumps
2. Two stages of high pressure feedwater heaters (A and B)
3. Piping, valves, and instrumentation.

The pumps casings are made of ASTM-A296-CA6NM steel. The impellers are constructed from ASTM-A315-CA15 steel. The heaters have shells of carbon steel and tubing of stainless steel. The piping material is per the CNS Piping Specification "CNS 1206.00-02-1002".

Normally, both feedwater pumps will be operating with each pump handling half the feedwater flow. Downstream of the feedwater pumps, the feedwater passes through two stages of high pressure feedwater heating to a final feedwater header where the final feedwater temperature is equalized. The feedwater is then admitted to the steam generators through 4 steam generator feedwater lines, each of which contains a feedwater control valve and a feedwater flow nozzle. Feedwater flow to the individual steam generators is controlled by a three element feedwater control system using feedwater flow, steam generator water level, and main steam flow as control parameters for steam generator feedwater control valves (CF28, CF37, CF46, and CF55). In addition to the originally-installed venturi flow nozzle instruments, ultrasonic flow meters were later installed on Unit 1 to provide more precise feedwater measurement. These ultrasonic flowmeters measure both feedwater flow and temperature, and provide input to the core power calorimetric calculation.

The Auxiliary Feedwater System is the assured source of feedwater to the steam generators during accident conditions. The primary safety function of the Feedwater System is to isolate the steam generators on a feedwater isolation signal. A feedwater isolation signal initiates isolation of each steam generator in order to:

1. rapidly terminate feedwater flow and steam blowdown inside the containment following a main steam or feedwater line break inside the containment,
2. prevent loss of steam generator water inventory due to a pipe rupture outside the containment, and
3. prevent overfilling the steam generators should the normal means of controlling steam generator level malfunction.

Feedwater isolation is actuated by any one of the following signals:

1. safety injection,
2. reactor trip coincident with low reactor coolant average temperature,
3. steam generator level high-high.

A feedwater isolation signal closes the feedwater isolation valves (CF33, 42, 51, 60), feedwater reverse purge valves (CF87, 88, 89, 90), feedwater control valves (CF28, 37, 46, 55), feedwater control bypass valves (CF30, 39, 48, 57), feedwater preheater bypass valves (CA149, 150, 151, 152), and feedwater by-pass tempering flow valves (CA185, 186, 187, 188). A safety injection signal and a steam generator High-High water level signal will trip the feedwater pumps. A reactor trip will run the feedwater pump speed back.

The Auxiliary Feedwater System is discussed in Section 10.4.9, and the supply of condensate available for emergency purposes is discussed in Sections 9.2.6 and 10.4.9.

10.4.7.3 Safety Evaluation

The safety-related portion of the Feedwater System is designed in accordance with the design bases presented in Section 10.4.7.1. The system has been analyzed to assure it meets these bases. Any failure in the non-safety class portions of the Condensate and Feedwater Systems does not prevent safe shutdown of the reactor.

The Condensate and Feedwater System is designed to automatically maintain the water level in the steam generators during steady state and transient operating conditions. Uniform feedwater temperature, pressure, and flow are maintained to all steam generators at all loads. Sufficient condensate storage capacity is provided to accommodate the mass transfer of fluid due to expansion and contractions arising from thermal and pressure transients in the steam generators and the Condensate and Feedwater System.

Waterhammer and other system flow instabilities are not expected to occur in the main feedwater lines during anticipated operational occurrences. A complete discussion of steam generator waterhammer is provided in Section 10.4.9.

The following precautions are taken to protect plant personnel from the possible adverse effects of contact with hydrazine, ammonium hydroxide, and approved amines used for feedwater treatment.

1. An emergency shower and wash facility is located in the storage area.

10.4.7.4 Tests and Inspections

The operating characteristics of the hotwell, condensate booster, and feedwater pumps will be established throughout the operating range by factory tests. The main condensers, the hotwell pumps, the condensate polishing demineralizer vessels, the condenser steam air ejectors, the gland steam condenser, the condensate booster pumps, the feedwater heaters, and the feedwater pumps will all be hydrostatically tested to the applicable code or standard.

Manways or removable heads are provided on all heat exchangers to provide access to the tube sheets for inspection and maintenance. A general routine visual surveillance of the system components and piping during operation and maintenance periods for signs of leakage or distress will be performed to verify system integrity.

All active valves in the Feedwater System (as listed in Table 3-104) are inservice tested in accordance with ASME Code.

10.4.7.5 Instrumentation Application

Sufficient instrumentation is provided to monitor system performance and to control the system automatically or manually under all operating conditions.

10.4.7.5.1 Alarms and Trips

1. Hotwell low Level

   Alarm on low level and computer alarm on low-low level with five second time delay to alert operators of loss of hotwell pump suction. Two out of three trip logic is provided on low-low computer alarm.

2. Hotwell pump strainer high differential pressure

   Alarm on high differential pressure to indicate need for cleaning strainer.

3. Condensate polishing demineralizer control panel trouble

   Alarm when any of the polisher control panel alarms sound.

4. Condensate booster pump low suction pressure

   Alarm on low suction pressure and trip the condensate booster pumps on low-low pressure with a twenty second time delay to prevent the pumps from cavitating. Two out of three trip logic is provided on low-low pressure trip.

5. Condensate booster pump low lube oil pressure

   When the condensate booster pump lube oil pressure decreases to a preset amount, this alarm will sound.

6. Condensate system low flow

   Alarm on low condensate flow and trip the condensate booster pumps on low-low flow after a twenty second time delay. Two out of three trip logic is provided on low-low flow trip.

7. Feedwater pump low suction pressure

   Alarm on low suction pressure and trip the feedwater pumps on low-low pressure to prevent the pumps from cavitating. The trip logic has a twenty second time delay. Two out of three trip logic is provided on low-low pressure trip.

8. Feedwater pump low flow

   Alarm on low suction flow to each feedwater pump and trip a feedwater pump on low-low flow with a twenty second time delay. Two out of three trip logic is provided on low-low flow trip.

9. Feedwater pump high discharge pressure

   Alarm on high feedwater pump discharge pressure and trip the feedwater pumps on high-high pressure with a two out of three trip logic.

10. Feedwater pump lube oil pressure

    The hotwell pumps will trip on loss of feedwater pump lube oil pressure when the feedwater pump suction valve is open coincident with low feedwater pump discharge header pressure. This is to prevent inadvertent windmilling of a feedwater pump without lube oil to the bearings.

11. Loss of all hotwell pumps

    Trip the condensate booster pumps on loss of all hotwell pumps.

12. Feedwater header pressure

    Alarm on high or low pressure.

13. Condensate System Flow

    Alarm on decreasing flow set point to indicate only two condensate booster pumps and two hotwell pumps are required. Alarm on decreasing flow set point to indicate only one condensate booster pump and one hotwell pump are required.

14. Hotwell pump high discharge pressure

Alarm on high hotwell pump discharge pressure.

15. High polisher system differential pressure

    When the system differential pressure across the condensate polishing demineralizers main influent and effluent headers reaches a preset amount, this alarm will sound.

10.4.7.5.2 Controls

1. Condensate polishers differential pressure

   Condensate polishers bypass control valves 1CM42 and 1CM186 will open on high polisher influent to effluent header differential to bypass condensate around the polishers. These valves can also be manually controlled by the operator to regulate hotwell pump discharge flow on startup.

2. Generator load rejection bypass

   Generator load rejection bypass control valve 1CM83 opens on a generator load rejection to bypass the additional flow caused by dumping the C heater drains to the condenser.

3. Condensate system recirculation

   Condensate recirculation control valve 1CM127 is controlled by condensate flow and the number of hotwell and condensate booster pumps running to provide a minimum flow recirculation path for the pumps. 1CM127 is isolated in Modes 1, 2, and 3, and Mode 4 when the steam generator is relied upon for heat removal, by maintaining valves 1CM125, 126, and 185 closed. In Mode 3 and Mode 4 when the steam generator is relied upon for heat removal, 1CM127 can be un-isolated provided strict administrative controls are taken to ensure CA operability.

4. Low condensate booster pump suction pressure

   The next hotwell pump will be started when the condensate booster pump suction pressure decreases to a preset amount.

5. Low feedwater pump suction pressure

   The next condensate booster pump will be started when the feedwater pump suction pressure decreases to a preset amount.

6. Feedwater pump recirculation control

   Feedwater pump recirculation control valves CF6 and CF13 provide a minimum flow path from the feedwater pump discharge back to the main condenser. These valves will be controlled by low feedwater pump suction flow.

7. Steam generator feedwater control valves

   Feedwater flow to the individual steam generators is controlled by a digital feedwater control system using feedwater flow, steam generator water level, and main steam flow as control parameters for steam generator feedwater control valves and feedwater control valve bypass valves.

8. Steam generator feedwater control valve bypass valves

   The bypass valves around the steam generator feedwater control valves are automatically controlled by the digital feedwater control system from no load to 100% power.

9. Hotwell low level

Normal hotwell makeup control valve CS47 will open on low hotwell level. Hotwell recirculation makeup control valves CS33 and CS57 will open on low-low hotwell level. The CS33 and CS57 valves are isolated whenever the CM127 valve is isolated to prevent a loss of CA inventory from the UST.

10. Hotwell high level

    Hotwell high level control valve CM33 will open on high hotwell level. This valve will also be controlled off of high hotwell pump discharge pressure. The valve is equipped with a manual control to allow operation from the control room. The CM33 valve is isolated in Modes 1, 2, and 3, and Mode 4 when the steam generator is relied upon for heat removal, by maintaining the associated control room handswitch in the CLOSED position. In Modes 2 and 3, and Mode 4 when the steam generator is relied upon for heat removal, CM33 may be opened to control hotwell level provided strict administrative controls are taken to ensure CA operability.

10.4.8 Steam Generator Blowdown System

10.4.8.1 Design Bases

The design bases for the Steam Generator Blowdown System are:

1. Maintain proper steam generator shell side water chemistry by removing non-volatile materials due to condenser tube leaks, primary to secondary tube leaks, and corrosion that would otherwise become more concentrated in the shell side of the steam generators.
2. Size all equipment to handle the maximum allowable blowdown flowrate from all steam generators simultaneously. Maximum allowable blowdown flowrate is specified by the steam generator manufacturer based on steam generator blowdown nozzle erosion considerations.
3. Provide equipment and flowpath to allow purification and recovery of steam generator blowdown for reuse in the condensate cycle.
4. Provide equipment and flowpath to allow discarding of blowdown.
5. Provide a continuous sample for measurement of the radioactivity and conductivity of the steam generator blowdown.
6. Isolate the blowdown lines leaving the containment on a containment isolation signal and on an auxiliary feedwater automatic start signal.
7. Seismic quality group classifications, and code requirements of the Steam Generator Blowdown System and components are provided in Table 3-4.

10.4.8.2 System Description

A separate Steam Generator Blowdown System (BB) serves each of the two units at Catawba. The separate units' BB Systems are similar but do differ slightly and are shown on Figure 10-29, Figure 10-30, Figure 10-31, Figure 10-32.

The BB System is used in conjunction with the Condensate System (CM) to maintain proper secondary side water chemistry. Non-volatile solids resulting from corrosion, steam generator tube leaks, or condenser tube leaks tend to concentrate in the steam generators. The BB System is designed to control the concentration of these impurities by continuously removing a

portion of fluid from the shell side of the steam generators. This blowdown is either discarded or purified for makeup to the CM System.

The BB System consists of the following:

1. One steam generator blowdown tank
2. Two 100% capacity steam generator blowdown pumps
3. Two 100% capacity steam generator blowdown recovery heat exchangers
4. Two 100% capacity steam generator blowdown demineralizer prefilters
5. Two 100% capacity steam generator blowdown demineralizers
6. Piping, valves, and instrumentation

The blowdown tank, pumps, demineralizer prefilters, and the shell of the blowdown recovery heat exchangers are constructed of carbon steel. The blowdown demineralizer and the blowdown recovery heat exchanger tubes are stainless steel. System piping and valves consist of carbon steel and stainless steel. Table 10-13 presents the BB System component design data. System safety class requirements are presented in Table 3-4.

The BB System begins at the steam generator blowdown nozzles where blowdown flow is extracted from the steam generators. The blowdown is withdrawn from above the steam generator tube sheets by holes drilled in the tube sheets themselves. The Unit 1 BB System connects to both of two blowdown nozzles on each steam generator. The Unit 2 BB System connects to one of two available blowdown nozzles on each steam generator. This difference results from different manufacturer and model steam generators being used in the two units and the different internal blowdown header design associated with each model steam generator.

On Unit 1, the piping from each blowdown nozzle joins into a common header. Each line contains a globe valve in the event that flow adjustment is required. On Unit 2, the piping connects to just one nozzle per steam generator, and an isolation valve is provided. The blowdown header from each steam generator then runs from inside containment, out through containment isolation valves, and eventually to the steam generator blowdown tank in the Turbine Building. A single blowdown flow control valve per header is provided to control blowdown flow rate from each steam generator. These valves are located close to the blowdown tank. These valves control blowdown flowrate to a given setpoint. This setpoint is provided to local controllers by manual loaders in the Control Room. During most modes of operation, the fluid in the blowdown headers will be two-phase.

On Unit 1, the 100% maximum flow limit of 76,300 lbm/hr will be used as an operating limit. The Unit 1 BB system design and flow accelerated corrosion limits are based on this flow. The maximum volumetric flow rate is calculated at this flow. On Unit 2, the maximum allowable blowdown flowrate per steam generator is 55,000 lbm/hr for a cumulative time of 3.3 years and 35,000 lbm/hr for the remainder of the steam generator service life. These maximum values apply at all loads. No such cumulative time limitations apply to the Unit 1 steam generators. The time limitation for the higher flow rate has been depleted, therefore, the maximum flowrate per steam generator is 35,000 lbm/hr. This maximum value applies at all loads. No such cumulative time limitations apply to the Unit 1 steam generators. Converted to volumetric units of gallons per minute, the Unit 1 maximum allowable flowrate is 200 gpm and for Unit 2, the maximum allowable flowrate is 94 gpm.

Downstream of the blowdown flow control valves, the blowdown flashes to the steam generator blowdown tank. The blowdown tank separates the water and steam phases of the blowdown.

The steam phase is normally routed to the "D" heater extraction lines to recover thermal energy and conserve condensate.

Alternately, the steam from the blowdown tank can be vented to atmosphere. On both units, blowdown tank pressure is controlled to a constant value by valve BB250 which is located in the vent line to "D" heaters. The blowdown tank is protected from overpressurization by a safety valve located on top of the tank. "D" heaters and "D" heater extraction lines are protected from overpressurization from the blowdown tank by a safety valve located in the steam vent line near "D" heaters. Blowdown tank level is automatically controlled by valve BB39 which is located downstream of the blowdown demineralizers.

The water which is separated from the flashed fluid in the blowdown tank is pumped from the tank by one of two 100% capacity blowdown pumps. Each blowdown pump provides its own seal water from the pump discharge through a seal water cooler. Blowdown pumps are provided minimum flow protection by valve BB86. This valve is controlled off of tank level along with valve BB39 such that BB86 is full open if BB39 is full closed and modulates closed as BB39 opens. In this way, minimum flow is always assured through an operating blowdown pump. The minimum flow path discharges back to the blowdown tank.

Blowdown pump discharge is routed to the blowdown recovery heat exchangers. Two 100% capacity heat exchangers are provided with both normally in use to provide a lower blowdown demineralizer inlet temperature. The blowdown recovery heat exchangers are regeneratively cooled by flow from the Condensate System (CM) to recover thermal energy and reduce blowdown temperature to a point suitable for demineralization or discharge to the turbine building sump. Normally, blowdown will be cooled, demineralized, and discharged to the condenser hotwell to conserve condensate quality water. However, a bypass line is provided upstream of the heat exchangers to allow bypass flow around the prefilters and demineralizers and allow blowdown pump discharge directly to the turbine building sump. A bypass is also provided downstream of the heat exchangers to bypass flow around the prefilters and demineralizers and directly to the turbine building sump after being cooled by the blowdown recovery heat exchangers. These bypass lines join into a common header and intersect the common demineralizer effluent line upstream of valve BB39.

Downstream of the blowdown recovery heat exchangers, blowdown flow is routed to two 100% capacity demineralizer prefilters, which serve to remove corrosion products from the blowdown stream. These cartridge type filters can be operated individually or in parallel. The prefilters will become highly radioactive during plant operation with any steam generator tube leaks and are shielded accordingly.

Downstream of the blowdown demineralizer prefilters, blowdown flow is routed to two 100% capacity mixed bed demineralizers. The blowdown demineralizers are arranged in parallel with one normally in operation and one isolated. The blowdown demineralizers are nonregenerative, i.e., when the ion exchange capacity of the bead resins is depleted, the resins will be discharged and replaced with new resins. The demineralizers are designed for manual operation during all operating modes. Run length between resin replacement will vary depending on operating conditions but should normally be between one and three months. The demineralizers will become highly radioactive during plant operation with any steam generator tube leaks. Shielding is provided around the demineralizers. All normally used valves, instrumentation and controls are located outside of the shield walls to minimize operator exposure to radiation. Resin traps are provided in the demineralizer effluent lines to catch any resins released due to faulted demineralizer resin retention strainers. The resin traps are located within the demineralizer shield walls to provide radiation shielding if the released resins are radioactive.

Instrument air and demineralized water is supplied to the demineralizers for use in resin fill, resin mix, slow fill, and resin removal modes of operation. Pressure regulators, valves, and instrumentation are provided to control instrument air and demineralized water supply during these operating modes. The resins which are removed from the demineralizers following depletion can be sluiced to the condensate polishing demineralizer backwash tank or to a portable cask liner located near the polishers.

Downstream of the blowdown demineralizers, the individual effluent lines join into a common header. This header joins with the demineralizer bypass header upstream of blowdown tank level control valve BB39. BB39 automatically modulates to regulate flow from the blowdown tank to maintain tank level at set point. Downstream of BB39 the flow path splits and blowdown can be routed to either the condenser hotwell or the turbine building sump. Normally, blowdown will be routed through a blowdown recovery heat exchanger, a prefilter, a demineralizer, and discharged to the condenser hotwell. However, during operation with high blowdown impurities or the blowdown demineralizers unavailable, it may be desirable or necessary to bypass the demineralizers and route the blowdown to the Turbine Building sump for disposal.

Motor operated or pneumatic isolation valves are provided at various points throughout the system to allow blowdown flow path determination from the Control Room. Containment isolation valves are provided for each steam generator blowdown header at the containment penetrations. These containment isolation valves automatically close on a auxiliary feedwater auto-start signal.

Samples are taken from the BB System at several points by the Nuclear Sampling System (NM) and conventional Sampling System (CT). Local grab samples are also provided at various points through the system.

The NM System takes samples of each steam generator's shell side water in the vicinity of the downcomer and also samples blowdown from each steam generator blowdown header. Radiation monitor 1 (2) EMF33 located in the ZJ System continuously monitors condenser off-gas and will automatically close the blowdown flow control valves BB24, 65, 69, 73, blowdown tank steam vent to atmosphere isolation valve BB27, and blowdown pump discharge to Turbine Building sump isolation valve BB48 if activity of the blowdown fluid is too great. Blowdown can be continued during periods of high activity by overriding the radiation monitor, opening the blowdown flow control valves, and routing blowdown tank steam and water to the "D" heaters and condenser hotwell, respectively. Radiation monitor 1 (2) EMF34, which monitors steam generator blowdown, can be valved in to determine which steam generator is potentially faulted and then to trend the primary to secondary leak.

The Liquid Radwaste System (WL) has a connection to each steam generator blowdown header upstream of the containment isolation valves. These connections are piped to the steam generator drain pump which can be used to drain the steam generators. The WL System is normally isolated from the BB System by two WL isolation valves per line which are locked closed.

The Steam Generator Wet Lay-up Recirculation System (BW) is connected to each steam generator blowdown header in the doghouse downstream of the containment isolation valves. The BW System is normally isolated from the BB System by blind spectacle flanges. For Unit 2, during steam generator wet lay-up recirculation, water will be recirculated through the steam generators by pumping into the steam generators through the blowdown headers and withdrawing water through the auxiliary feedwater nozzles. The Unit 1 steam generators accomplish wet-layup recirculation by pumping water directly to the upper bundle area through a recirculation header and withdrawing water through the blowdown system. The flowpath is directed through the BB containment penetration then up to the (BW) nozzle on the replacement

steam generator. These (BW) lines between the BB piping and the SG (BW) nozzle contain manual isolation valves which are normally closed unless the wet lay-up (BW) system is in operation.

The BB System contains Duke Class B, F and G piping. Class B piping is provided inside containment and through containment penetrations. Class F piping is provided in the doghouse and Auxiliary Building, and Class G piping is provided in the Turbine Building. The presence of Duke Class B (ASME Section III-Class 2) piping and the system containment isolation function requires the system to be designated "Nuclear Safety Related."

10.4.8.3 Safety Evaluation

The Steam Generator Blowdown System is designed to operate manually and on a continuous basis as required to maintain acceptable steam generator secondary side water chemistry. The presence of ASME Section III - Class 2 piping and the system containment isolation function requires the system to be designated "Nuclear Safety Related". All blowdown lines which penetrate the Containment are isolated automatically upon containment isolation signal and auxiliary feedwater automatic start signal. The portion of the system inside the containment and the portion utilized as containment isolation are designed in accordance with applicable safety class requirements. A failure analysis is presented in Table 10-14.

The Steam Generator Blowdown System is designed to prohibit radioactive discharge to the environment from the blowdown liquid. During times of abnormally high primary-to-secondary leakage, blowdown is terminated by the radiation monitors. At this point the operator analyzes the situation and aligns the Steam Generator Blowdown System in the proper mode of operation.

In addition to the Condensate Cleanup System, Component Cooling System, and Containment Isolation System, the Steam Generator Blowdown System also interfaces with the Steam Generator Wet Layup System (BW). The BW System is used to maintain satisfactory secondary side water chemistry during periods of wet layup.

10.4.8.4 Tests and Inspections

The equipment will be tested by the manufacturer in accordance with the various applicable code requirements. Proper operation of the System is verified during unit startup. During normal operation of system, periodic checks of operating conditions will detect any deterioration in the performance of system components.

The Containment Isolation valves are functionally tested per the Catawba Nuclear Station Pump and Valve Inservice Testing Program.

10.4.8.5 Instrumentation Applications

10.4.8.5.1 Flow Instrumentation

Flow instrumentation is provided in each of the blowdown lines to give control room indication of each steam generator blowdown flow. Flow rate can be controlled from the control room.

Flow instrumentation is provided in the steam generator blowdown pumps discharge header to monitor pump discharge flow. Also flow instrumentation is provided in this line to indicate flowrate to the BB demineralizers or Turbine Building sump.

10.4.8.5.2 Level Instrumentation

Level instrumentation is provided in the steam generator blowdown tank to throttle the control valve located in the steam generator blowdown pump discharge header to keep a set level in the tank. If the level becomes too high, each of the blowdown flow control valves is automatically shut. If the level becomes too low, blowdown tank level control valve BB39 is automatically closed and the steam generator blowdown pumps are tripped. Local level indication is given.

10.4.8.5.3 Pressure Instrumentation

Pressure instrumentation is provided on the steam generator blowdown tank to provide pressure indication and high pressure alarm and trip. Controls are provided to maintain blowdown tank pressure at a constant value.

Pressure instrumentation is provided in the discharge of each steam generator blowdown pump to give local indication of pump discharge pressure.

Differential pressure is indicated and high differential pressure is alarmed across the BB demineralizer prefilters, BB demineralizers, and BB demineralizer resin traps.

10.4.8.5.4 Temperature Instrumentation

Temperature instrumentation is provided in each blowdown line to give control room indication of blowdown temperature. Blowdown temperature to the BB demineralizers is indicated and high temperature gives an alarm. High-high temperature isolates the BB demineralizers from flow.

10.4.9 Auxiliary Feedwater System

Note:

This section of the FSAR contains information on the design bases and design criteria of this system/structure. Additional information that may assist the reader in understanding the system is contained in the design basis document (DBD) for this system/structure.

10.4.9.1 Design Bases

The Auxiliary Feedwater System (CA) assures sufficient feedwater supply to the steam generators (S/G), in the event of loss of the Condensate/Feedwater System, to remove energy stored in the core and primary coolant. The CA System may also be required in some other circumstances such as evacuation of the main control room or cooldown after a loss-of-coolant accident for a small break, including maintaining a water level in the steam generators following such a break.

The two units are provided with separate CA Systems.

The CA System is designed to start automatically in the event of loss of offsite electrical power, trip of both main feedwater pumps, safety injection signal, or low-low S/G water level; any of which may result in, coincide with, or be caused by a reactor trip. The CA System will supply sufficient feedwater to maintain the reactor at hot standby for two hours followed by cooldown of the Reactor Coolant System (NC) to the temperature at which the Residual Heat Removal System (ND) may be operated.

Three CA pumps are provided, powered from separate and diverse power sources. Two motor driven pumps are powered from two separate trains of emergency on-site electrical power, each normally supplying feedwater to two steam generators. One turbine driven pump, supplying feedwater to all four steam generators is driven from steam contained in either the B or C steam generators. Sufficient diversity and redundancy is provided such that the CA System is capable of delivering the minimum required flowrate to effective steam generators during all modes of operation. The CA System is capable of delivering the required flowrate to effective steam generators at a pressure corresponding to the lowest S/G safety valve set pressure plus 3% accumulation. Design data for the CA pumps are shown in Table 10-15 and Table 10-16.

For a transient or accident condition, CA flow must be delivered within one minute of any actuation signal to start the CA pumps. The minimum flow is considered the flow delivered only to steam generators effective in cooldown. The minimum flowrate is verified in Section 15.2 to be sufficient to provide adequate protection for the core and ensure an orderly cooldown. Maximum CA temperature at Catawba may reach 138°F based on maximum operating condenser pressure of 24.0 inches Hg vacuum.

Standards for nuclear safety related systems are met for the CA System except for the condensate quality feedwater sources. The nuclear safety related portion of the CA System is designed for seismic and single failure requirements. The CA System will provide the required flow to two or more steam generators regardless of any single active or passive failure in the long term. Safety classifications of the Auxiliary Feedwater System components are presented in Table 3-4.

For the postulated non-seismic event of loss of all offsite and all onsite emergency A.C. electrical power, the CA System will perform its safety related function with the limitation that no single failure that would prevent the single A.C. power independent turbine driven pump subsystem from functioning occurs during this limiting event.

Design features and operational precautions are provided to preclude the possibility of hydraulic instability (water hammer) in both the CA System and the Condensate/Feedwater System during all anticipated operating transients. The conditions necessary to produce water hammer in the main feedwater piping and/or steam generators must occur simultaneously as either low S/G temperature and extremely low S/G level (below the level which initiates the CA System) or low S/G temperature and low S/G pressure. Although piping and operational provisions preclude such conditions from occurring during normal operation, it has been determined through model testing and analyses by the S/G manufacturer that maximum theoretical water hammer loadings are far below allowable stresses for the S/G vessel, internals, and piping. Analysis of worst case conditions produced by main steam line rupture indicates that the resulting water hammer does not reduce the safety related functional capability of the S/G or feedwater piping. Design features are incorporated to minimize the potential and severity of any possible water hammer event. Loop seals in the feedwater piping minimize the volume of possible steam voids if the unlikely event occurs that the S/G water level falls below the main feedwater nozzle.

The following provisions are utilized to minimize the potential for condensation induced water-hammer.

Auxiliary Feedwater System

1. Piping around upper steam generator nozzle is routed to prevent steam voids.
2. Steam Generator programmed water level is above auxiliary feedwater nozzles during most power operation.

3. System check valves will minimize backleakage.
4. Two check valves are installed in series to prevent backleakage.

The feedwater nozzle on the Unit 1 steam generators enter the steam generator above the tube bundle. Therefore, the following design features are incorporated into the Unit 1 feedwater system.

1. Steam generator feedring and gooseneck design for internal piping.
2. An all welded internal piping design.
3. Schedule 80 feedwater piping system.
4. The feedwater isolation valve opening time is very slow (4 - 6 minutes).
5. Top discharging hairpin bend J-tubes coming off of the feedring on the steam generator.
6. Horizontal run of piping is minimized at feedwater nozzle.

10.4.9.2 System Description

Each unit is provided with a separate CA System, as shown in Figure 10-33 and Figure 10-34. Controls for each system are located in the control room, common to both units, and in separate, independent auxiliary shutdown control panels. The control room controls may be overridden at the individual Train A, Train B, and turbine driven pump auxiliary shutdown control panels supplied for each unit. The individual auxiliary shutdown control panels A and B, separate and redundant in design, contain the controls for the motor driven pumps. The turbine driven pump controls are incorporated into the separate turbine driven pump auxiliary shutdown control panel. The CA flow to the steam generators may be monitored and controlled from any one of the three control panels. The safety related control room controls are redundant in design as described for the auxiliary shutdown panels.

Power for the motor driven pumps is normally provided by the station auxiliary power system. Each motor driven pump is provided emergency power from one of the two unit emergency diesel generators. Motor driven pump A is supplied by diesel generator A, and motor driven pump B is supplied by diesel generator B. The power supply train for each pump is physically separated from the other pump. This physical separation is followed throughout on the control and instrumentation systems for each motor driven pump.

The motor driven pumps will automatically start and provide the minimum required feedwater flow within one minute following any of these conditions:

1. Two out of four low-low level alarms in any one of the four steam generators.
2. Loss of both main feedwater pumps
3. Initiation of the safety injection signal
4. Loss of station normal auxiliary electric power
5. AMSAC signal.

Driving steam for the turbine driven pump is provided from either the steam generator B or C main steam lines upstream of the main steam containment isolation valves and is discharged to the atmosphere from the turbine. Each steam supply is provided with a piston operated valve that opens on a signal to start the turbine driven pump. Redundant control systems are provided to assure opening of each valve on a turbine driven pump start signal. Any electrical

or air failure will result in the valve failing open. A check valve is provided in each steam supply to prevent flow reversal.

The Auxiliary Feedwater Pump Turbine steam supply piping is equipped with electrical heat trace and insulation. The heat trace is designed to maintain the piping in a specific temperature range – to both minimize condensate generation during turbine start-up and to prevent the design temperature of the piping from being exceeded. The steam supply piping temperature is monitored on the Operator Aid Computer via thermocouples and a local chart recorder. The chart recorder also provides low and high temperature alarm signals to an annunciator in the Control Room. The heat trace, chart recorder, Operator Aid Computer, and annunciator are all non-safety class equipment which is relied upon to maintain the operability of the safety class Turbine-Driven Auxiliary Feedwater Pump (during pump standy-by readiness mode only). However the non-safety class equipment is operated, maintained and tested in accordance with administrative controls that are adequate to ensure the operability of the pump.

The turbine driven pump will automatically start and provide the minimum required feedwater flow within one minute following either of these conditions:

1. Two out of four low-low level alarms in any two of the four steam generators.
2. Loss of station normal auxiliary electric power.

Adequate auxiliary feedwater flow is assured to the steam generators in the event of the loss of offsite and all emergency AC power by relying upon the safety related turbine driven pump subsystem which can perform its safety function independent of AC power. Loss of all AC power will not adversely affect the position of motor operated valves in the turbine driven pump subsystem. All electrically operated valves in the normal turbine driven pump discharge path to all steam generators are assured open by operating procedures on plant startup and fail as is on loss of AC power. The motor operated turbine driven pump suction isolation valve CA7A and hotwell source isolation valve CA2 are assured open by operating procedures on plant startup and fail as is on loss of all AC power. Additionally, these valves have their motor operator breakers locked open. The motor operated supply valve CA175 from the Condenser Circulating Water System is supplied DC power from the standby shutdown facility (SSF) batteries. CA174 is a fail-open air-operated valve that opens on either loss of condensate grade suction sources, or loss of SSF battery power. Motor operated supply valve CA178 is assured open by operating procedures on plant startup. This valve is powered from the standby shutdown facility diesel and fails as is on loss of power.

The CA System will respond to the loss of offsite and all emergency AC power by starting the turbine driven pump. The turbine driven pump will take suction from the condensate grade sources to which it is normally aligned. Should loss of this supply occur, the turbine driven pump will transfer suction to the Condenser Circulating Water System supply which is supplied by a battery powered motor-operated valve and a fail-open air-operated valve. If it is desired, water contained in the nuclear service water piping may supply the turbine driven pump by manually opening the nuclear service water valves. The condensate grade sources and the condenser circulating water source are not safety grade sources. However, for the postulated loss of all AC power event, it is not necessary to design these sources as safety grade since these sources are only relied upon for the purpose of meeting this loss of all AC power event and are not relied upon to operate for any Condition III or IV occurrences. The condenser circulating water source, though available on loss of condensate sources, is provided to meet postulated fire and sabotage events, as well as loss of all AC power event. NSM CN-50474/00 added some portable equipment to the SSF including submersible pumps, hosing, and electric power cables. This equipment supplements the RC System's ability to provide CA suction

supply following a sabotage event involving a Turbine Building flood induced by an RC pipe failure.

Once automatically started, the CA pumps will continue to operate until manually tripped by the operator. Each auxiliary feedwater pump discharge line is provided with a motor operated isolation valve, an air operated fail open control valve, and a check valve. Air accumulators are provided on the CA System Flow Control Valves (CA36, 40, 44, 48, 52, 56, 60, 64) to allow the valves to be remotely operated on loss on Instrument Air (VI). The accumulators are sized so that the FCVs can be operated until Operations can manually secure flow to a Steam Generator following a SG Tube Rupture (SGTR) accident in order to prevent overfill. The flow control valves (and thus, the accumulators) provide a non-safety, back-up method of steam generator isolation. The turbine and motor driven pump discharge lines to each individual steam generator join into a single line outside containment. These individual lines penetrate the containment and enter each steam generator through the auxiliary feedwater nozzle. Piping and valves are provided to allow interconnection between each steam generator main feedwater line and the corresponding auxiliary feedwater nozzle to allow feeding the steam generators through the auxiliary feedwater nozzles during some modes of operation. These lines, the main feedwater bypass line and the main feedwater tempering flow line, are safety related at their intersection with the CA System and contain safety related valves. Failure of these lines and valves has been postulated in accordance with safety evaluation criteria and does not prevent the CA System from performing its safety related function. The main feedwater bypass line is provided to allow main feedwater to feed the steam generators through the auxiliary feedwater nozzles during hot standby, startup, low power operation, and cooldown. This is done in an effort to minimize the possibility of steam generator water hammer during these modes of operation. The main feedwater tempering flow line is provided to allow main feedwater to feed the steam generators through the auxiliary feedwater nozzles during normal operation. The tempering flow lines between the outboard doghouses and the turbine building have been upgraded from Class G to Class F (including tornado wind loads). A small tempering flow is provided to the auxiliary nozzles at all times when the main feedwater bypass line is isolated, except when a feedwater isolation signal is activated. This flow cools the inner surfaces of the auxiliary nozzles and adjacent connecting piping and maintains the water temperature in the piping connecting to the nozzles at approximately feedwater temperature, which should cause the thermal stresses induced in the nozzles and connecting pipe to be reduced when main feedwater flow is transferred to the auxiliary nozzles. Isolation valves in the main feedwater bypass lines and tempering flow lines close automatically on a feedwater isolation signal. During normal operation, these valves are controlled manually from the control room. The auxiliary feedwater pump discharge lines to the upper surge tank are provided for minimum flow and testing purposes. Self-contained automatic recirculation valves are provided to assure individual pump minimum flow when needed during operation.

Flow of the auxiliary feedwater to each steam generator is monitored and controlled in each of the motor driven and turbine driven pump discharge lines. Flow is modulated by air operated control valves provided in each discharge line. Upon loss of air, these valves will fail open. Valve travel stops are set at predetermined positions to provide pump runout protection and to optimize the system resistance for various accident cases.

All of the preferred normal sources of condensate quality water are normally aligned to the CA pump suctions. The condensate reserve for each unit is maintained among the following sources:

Source	Max. Capacity

	Source	Max. Capacity
a.	Auxiliary Feedwater Condensate Storage Tank	42500 gallons/unit (one tank per unit)
b.	Upper Surge Tanks	85000 gallons/unit (two 42500 gallon tanks per unit)
c.	Condenser Hotwell	170000 gallons/unit (Normal operating level)

The preferred normal sources of condensate quality water are the Auxiliary Feedwater Condensate Storage Tank, the Upper Surge Tanks and the Condenser Hotwell. (Note: Auxiliary Feedwater Condensate Storage Tank is currently isolated due to vortexing concerns)

As the CA System serves a vital safety related function during all postulated occurrences, two trains supplied by a safety grade, seismically designed water source must be assured at the pump suctions to assure pump operability and function. The Standby Nuclear Service Water Pond, with a maximum capacity of 2.74 (10^8) gallons total for the station, serves as the ultimate long-term safety related source of water for the CA System. To maintain steam generator water chemistry, especially for such fast recovery events as blackout, loss of normal feedwater, or main steam system malfunction, the CA pumps should be normally aligned to condensate quality water. The only available sources of the quality and quantity required exist as non-seismic grade sources in the Turbine Building. All necessary means to prevent inadvertent injection of out of chemistry nuclear service water to the steam generators must be employed. To meet these requirements, a reliable means of detecting loss of condensate source and automatic transfer of the pump suctions to the nuclear service water source is employed. Such detection and transfer controls are automatic since CA System flow must be established within one minute from the initiating event. The automatic detection and transfer controls will detect and transfer the pump suctions to nuclear service water upon detection of any of the listed postulated failures of the non-seismic condensate supplies:

1. Depletion of all condensate sources
2. Loss of source due to pipe break
3. Partial or complete loss of source due to air leakage into the system from a pipe crack, or failure to isolate a depleted source.
4. Partial loss of source due to steam void formation in the suction piping caused by excessive friction loss associated with a high flow rate, failure or spurious operation of a valve causing partial closure, or bending or partial obstruction in the pipe.

The detection scheme incorporates three trains of three differential pressure switches located in the Auxiliary Building in a vertical leg of the common condensate supply pipe to all three CA pumps. Two trains of pressure switches serve the two safety-grade RN trains, and the remaining train of pressure switches serves the SSF related RC system supply. Upon two out of three indication of low suction pressure from any train, the transfer logic will be activated for that train. The instrumentation and controls for the RN trains meet the standards for nuclear safety related systems, including requirements for redundancy and separation. If the station normal auxiliary electrical power is available during the initiating occurrence, a maximum 30000 gallons additional condensate supply is available from the condensate storage tank. If the two makeup demineralizers are available, a maximum condensate supply of 950 GPM is available for the short term or 475 GPM for an indefinite period. Additional condensate may also be

provided from condensate sources associated with the other unit, if these sources are available, operable, and a loss of normal station auxiliary electric power has not occurred.

A separate plant subsystem has been incorporated into the Catawba design to allow a means of limited plant shutdown, independent from the control room and auxiliary shutdown panels. This system, known as the Standby Shutdown System, provides an alternate means to achieve and maintain a hot shutdown condition following postulated fire and sabotage events. The Standby Shutdown Facility (SSF) and its 700 kw diesel generator are also relied upon for the required duration of a station blackout event, as described in Section 8.4. This system is in addition to the normal shutdown capabilities available. The Standby Shutdown System (except for interfaces to existing safety related systems) is designed in accordance with accepted fire protection and security requirements and is not designed as a safety related system. The Standby Shutdown System utilizes the turbine driven CA pump to provide adequate secondary side makeup independent from all A.C. power and normal sources of water. During this mode of operation, the turbine driven subsystem operates remotely controlled from the Standby Shutdown Facility. If the turbine has not started automatically prior to the security event, it may be manually started and receives suction water from condensate sources. If condensate sources are depleted or lost, the turbine will automatically transfer suction to an independent source initiated by the SSF related train of the condensate source loss detection logic and uses a battery-powered motor-operated valve and a fail-open air-operated valve. The independent source of water is the buried piping of the Condenser Circulating Water System, which contains sufficient water in the imbedded pipe, inaccessible for sabotage, to enable the plant to be maintained at hot standby for at least 3 days. In this manner, sufficient CA flow may be maintained even if all normal and emergency A.C. power is lost, and all condensate and safety-grade water sources are lost due to sabotage. All components necessary for function in this manner are protected in vital, high security areas of the plant.

Provisions have been incorporated into the Catawba CA System design to allow the system to withstand the effects of a fire involving the system and nearby surroundings. The motor driven pump subsystem and the turbine driven pump subsystem are separated by 3 hour fire barriers into two fire zones. The turbine driven pump constitutes one zone, and the two motor driven pumps constitute the second zone. The instrumentation necessary for loss of condensate detection logic is separated such that train A and SSF instrumentation is located in the turbine fire zone, and the train B instrumentation is located in the motor driven pump fire zone. This measure prevents loss of supply water to a sub-system if a fire damages instrumentation in the other subsystem.

The CA System is designed to supply 32°F to 138°F water to the S/G nozzles in the pressure range from the ND System cut-in conditions (equivalent to approximately 110 psig S/G secondary side pressure) to the relieving pressure of the lowest safety relief valve (1210 psig).

10.4.9.3 Safety Evaluation

For the design bases considerations given in Section 10.4.9.1, sufficient feedwater can be provided at required temperature and pressure even if a secondary pipe break is the initiating event, any one CA pump fails to start, and no operator action is taken for up to 30 minutes following the event. Because the Auxiliary Feedwater System is the only source of makeup water to the steam generators for decay heat removal when the Main Feedwater System becomes inoperable, it has been designed with special considerations. The use of redundancy, diversity, and separation has been incorporated into the design of the CA System to ensure its capability to function.

Redundancy is provided by using two motor driven pumps and one turbine driven pump. Diversity is provided by using several water sources, two types of pump drivers, and adequate valving for source selection, isolation, and cross-connection. Separation is provided with separated power, instrumentation and control subsystems with appropriate measures precluding interaction between subsystems. Independent piping subsystems are incorporated into the design, protected at interconnection points with appropriate isolation and/or check valves to ensure a high degree of piping separation, redundancy, and diversity. A CA System component failure analysis is presented in Table 10-17. Transients and accidents requiring the CA System to function, discussed in Chapter 15, demonstrate that the CA System satisfies the design bases described in Section 10.4.9.1.

Following a loss-of-coolant accident, the CA System may be used for supplying water to the steam generators to develop a water head and thereby prevent potential tubesheet leakage from the primary to the secondary side of the steam generators. The two motor driven pumps will be used for this purpose as steam for the turbine driven pump may or may not be available. In the event of failure of one of the motor driven pumps, the water supply to two of the steam generators would be temporarily unavailable. By opening the crossconnection valves between the motor driven pump discharge lines, the one operating motor driven pump may be used to fill and maintain level in all four steam generators.

The CA System piping has been optimized to prevent water hammer occurrences induced by the piping system. Specific design considerations and analyses are covered in Section 10.4.9.1. It has been determined that no significant water hammer will occur during any anticipated operating transients and that any possible water hammer occurrences would fall within allowable system stresses.

The pipe break study considers pipe failures postulated per the pipe break criteria. This study assures that the CA System can withstand the effects of any postulated pipe failure for the design basis considerations given in Section 10.4.9.1.

10.4.9.4 Inspection and Testing Requirements

A comprehensive test program is followed for the CA System. The program consists of performance tests of individual components in the manufacturers' shops, preoperational tests of the system (see Section 14.1), and periodic tests of the activation logic and mechanical components to assure reliable performance during the life of the plant.

During plant operation, the system may be tested by pumping condensate storage water through a recirculation line to the upper surge tank.

Catawba Nuclear Station Units 1 and 2 were determined to be in compliance with the directives of NRC IE Bulletin 85-01, "Steam Binding of Auxiliary Feedwater Pumps," as described in the response to the NRC (letter to Dr. J.N. Grace (NRC) from H.B. Tucker (DPC), dated February 25, 1986). As stated in the DPC response, monitoring of CA System fluid conditions by local inspection/OAC data recording is procedurally performed daily during times when the CA System is required to be operable. Additionally, plant procedures provide for taking operator actions to recognize steam binding of the CA pumps and restore the CA system to operable status by pump venting/line cooling should steam binding occur.

10.4.9.5 Instrumentation Requirements

Sufficient instrumentation and controls are provided to adequately monitor and control the CA System. The safety related instrumentation and controls which monitor steam generator level and pressure, automatically start the CA pumps, and automatically align the safety related RN

supply meet the system requirements for redundancy, diversity, and separation. Appropriate methods are employed to assure independent operation of the three instrumentation and control channels and to prevent any interaction between subsystems. All nonsafety related instrumentation and controls are designed such that any failure will not cause degradation of any safety related equipment function.

The instrumentation and controls for the CA System are listed in Table 10-18.

10.4.10 Moisture Separator/Reheater and Feedwater Heater Drains System

10.4.10.1 Design Bases

The Moisture Separator/Reheater and Feedwater Heater Drains System is designed to return to the Condensate/Feedwater System all condensate drains from the following equipment:

1. Five stages of high and low pressure feedwater heaters (two parallel heater trains per stage) and two stages of low pressure feedwater heaters located in the condenser necks (three parallel heater trains per stage)
2. Four moisture separator drains, one from each of the four moisture separator/reheaters
3. Four first stage reheater drains, one from each of the four moisture separator/reheaters
4. Four second stage reheater drains, one from each of the four moisture separator/reheaters
5. Feedwater pump seal bleedoff flow from the Feedwater Pump Condensate Seal System

10.4.10.2 System Description

The Moisture Separator/Reheater and Feedwater Heater Drains System is shown on Figure 10-35 thru Figure 10-40.

Drain flows from the moisture separators, and first and second stage reheaters are regulated by level controls on each of the individual drain tanks associated with each of the moisture separator/reheaters. Normal drain flows from the drain tanks associated with moisture separator/reheaters A and B are piped to one train of the Heater Drain System and the drains from moisture separator/reheaters C and D are piped to the other train. Normal flows from the second stage reheater, first stage reheater, and moisture separator drain tanks are to the A feedwater heater shells, B feedwater heater shells, and C feedwater heater drain tanks, respectively. A small flow of feedwater pump seal bleedoff from the Feedwater Pump Condensate Seal System is also normally drained to each of the C feedwater heater drain tanks. Individual emergency drains to the condenser are provided for all of the equipment draining to the Heater Drain System.

Drain flows from each of the feedwater heater shells and C feedwater heater drain tanks are regulated by shellside level controls with the exception of the C feedwater heaters which operate with no drain level. The drain level controls for the E feedwater heaters are also arranged to evenly divide the drain flows from the two E feedwater heaters to the three F feedwater heaters. The A feedwater heaters normally drain to the B feedwater heaters. The combined drains from heaters A and B and the drains from the C feedwater heaters drain to the C feedwater heater drain tanks. All of the drains collected in the two C feedwater heater drain tanks are pumped forward to a point immediately upstream of the main feedwater pump suctions in the Condensate/Feedwater System by two C feedwater heater drain tank pumps. Level control is maintained in the drain tanks by regulating the discharge flow of these pumps. Design data for the C feedwater heater drain tank pumps is shown in Table 10-19.

Drains from the D, E, and F feedwater heaters normally cascade consecutively to the G feedwater heaters which drain to the condenser. Individual emergency drains are provided for each feedwater heater shell and C feedwater heater drain tank.

10.4.10.3 Safety Evaluation

The Moisture Separator/Reheater and Feedwater Heater Drains System is conservatively designed to maintain required equipment drain flow during all anticipated normal and transient operating conditions. Controls and condenser emergency drains are arranged in the fail safe configuration to protect the turbine and associated equipment from water induction. Multiple alarms, controls and automatic protective logic in addition to separate condenser emergency drains are provided in accordance with latest accepted industry practice for the prevention of turbine water induction. Sufficient indication, alarms, and controls are provided for manual operator initiation of protective measures, if, for any reason, the automatic controls and protective logic do not function.

10.4.10.4 Inspection and Testing Requirements

The equipment will be tested by the manufacturers in accordance with the various specifications and applicable code requirements. Proper operation of the Moisture Separator/Reheater and Feedwater Heater Drains System is verified during unit startup. During normal operation of the system, periodic checks of operating conditions will detect any deterioration in the performance of system components. In the turbine extraction steam lines and normal drain lines from the moisture separator/reheater drain tanks where power-assisted swing check valves are provided, periodic tests will be performed to assure functional capability of the power-assist cylinders.

10.4.10.5 Instrumentation Requirements

Proper drain tank and feedwater heater water levels are automatically maintained by normal and condenser emergency drain control valves. Sufficient instrumentation, controls, and alarms are provided to monitor the state of the system and to allow manual operator initiation of protective functions if multiple failure of the automatic control system were to occur. The C feedwater heater drain tank pumps are protected by automatic flow recirculation controls.

All of the instrumentation for this system is operating instrumentation and none is required for safe shutdown of the reactor.

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