SECTION 10

STEAM AND POWER CONVERSION SYSTEM

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SECTION 10

STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The Steam and Power Conversion System operates as a closed, condensing cycle with six stages of regenerative feedwater heating. Turbine exhaust steam is condensed in a triple shell, surface-type condenser and returned to the steam generators through two stages of feedwater pumping. The entire system is designed to receive and transfer the heat absorbed from the Reactor Coolant System following an emergency shutdown of the turbine generator from a full load condition. Heat rejection under this condition is accomplished by turbine bypass to the condenser and steam generator pressure relief to the atmosphere.

Means are provided to monitor and restrict the migration of radioactivity to the main condenser or to the environment such that the limits of 10CFR20 are not exceeded under normal operating conditions.

The main steam lines of the power conversion system convey the steam leaving the steam generators to the turbine throttle valves with less than 40 psi pressure drop when the turbine is operating at maximum load.

The Turbine Bypass and Pressure Relief Systems dissipate the heat from the Reactor Coolant System following a full load trip.

A turbine steam bypass system is provided to convey 40 percent of the steam developed in the steam generators to the main surface condenser. The remaining 60 percent can be exhausted to the atmosphere through a pressure relieving system which passes the maximum calculated steam generator output.

The steam generator feed pumps are designed for normal full load operating conditions and are also capable of supplying the required flow of feedwater to the steam generators under transient load rejection conditions. Auxiliary feed pumps are also provided to ensure complete reactor decay heat removal under all fault conditions including loss of power.

The main turbine generator and its component systems are designed to withstand larger instantaneous load changes than the Nuclear Steam Supply System. Because of this, the design capabilities for handling transient conditions such as loss of electrical load are not limited by the Steam and Power Conversion Systems. The exact operating functions are based upon the maximum rate of load change dictated by the Reactor Systems both with and without control rod actuation.

10.2 TURBINE GENERATOR

10.2.1 Design Bases

The Steam and Power Conversion System is designed to convert the heat produced in the reactor to electrical energy. Heat absorbed by the Reactor Coolant System (RCS) is transferred to the feedwater in four steam generators. The Feedwater System provides sufficient feedwater flow to the four steam generators where removal of heat from the RCS results in sufficient steam formation to drive the turbine generator units as follows:

	Unit 1	Unit 2
At 100% Reactor Power (Power Plant PEPSE)		
Gross Output, MWe	1214	1225
Anticipated Net Output, MWe	1195	1213
VWO Calculated Load (Power Plant PEPSE)		
Gross Output, MWe	1234	1249*
Anticipated Net Output, MWe	1215	1237

* Generator output is limited to 1232 MWe per Artificial Island Operating Guidelines and Documents A-5-500-EEE-1686.

10.2.2 System Description

10.2.2.1 Turbine Generator

The turbine is a four-casing, tandem-compound, six flow exhaust, 1800 rpm unit. The Unit 1 last stage blades are 46 inches long. The Unit 2 last stage blades are 47 inches long. The turbine shaft is directly connected to the ac generator. A brushless exciter (Unit 1) or alternator-exciter (Unit 2) is coupled to the generator. The generator is hydrogen cooled with water-cooled stator windings. It is rated at 1,300,000 KVA at 75 psig hydrogen pressure, 0.90 PF, 0.48 SCR, 3 phase, 60 cps, 25 KV, and 1800 rpm. Generator rating, temperature rise, and insulation class are in accordance with the latest ANSI standards.

The voltage regulator has automatic and manual controllers. The regulator automatically transfers to manual regulation upon an automatic controller problem or protective circuit initiation. After automatic or manual transfer to manual regulation, the voltage regulator may be transferred to automatic regulation when available.

The turbine consists of one double-flow high pressure (HP) element in tandem with three double-flow low pressure (LP) elements. Moisture separation and two stage reheating of the steam is provided between the HP and LP elements utilizing six horizontal-axis, cylindrical-shell, combined moisture separator-reheater assemblies. Three of these assemblies are located on each side of the LP turbine elements.

Additional moisture removal is accomplished inside the turbine by use of blades constructed with slingers. The slingers direct the moisture radially to the turbine casing drain passages.

A diagram of the Lubricating Oil System is shown on Plant Drawing 205218. The turbine generator bearings are lubricated by a conventional oil system. The main lubricating oil pump, a centrifugal volute type, is mounted on the end of the turbine shaft and supplies all of the lubricating oil requirements for the Lubrication System during normal operation. The ac motor-driven auxiliary centrifugal lubricating oil pump supplies bearing oil when operating the unit on turning gear during startup and shutdown. The dc motor-driven emergency lubricating oil pump operates in the event of loss of ac power or failure of the ac motor-driven pump, to protect the turbine generator bearings during coastdown. The hydraulic lift pump supplies a small quantity of high pressure oil to selected turbine bearings during startup. The seal oil backup pump provides oil to the Hydrogen Seal System upon loss of the seal oil pump in the Hydrogen Seal System. Part of the oil in the reservoir is continuously bypassed to an oil purification system. Lubricating oil is received in the makeup tank and is pumped by the positive displacement pump to either the lubricating oil storage tanks, reservoir or lubricating oil purifier.

10.2.2.2 Steam Cycle

Steam from each of the four steam generators supplies the tandem-compound turbine generator unit. The steam enters the HP

turbine through four stop valves and four governor control valves. One stop valve and one control valve form a single assembly. After expanding through the HP turbine, steam flows through moisture separators and two-stage reheaters to three LP turbines. A stop valve and an intercept valve are provided at the discharge of each moisture separator-reheater. Six stages of extraction for feedwater heating are provided.

Steam from the exhaust of the HP turbine element enters each moisture separator-reheater assembly at one end. Internal manifolds in the lower section distribute the wet steam. The steam then rises through chevron plate moisture separators where the moisture is removed and drained to a drain tank from which it is pumped to the main feed pump suction. The steam leaving the chevron plate separators flows over two tube bundles where it is reheated in two stages. The moisture separator-reheater of the Steam and Drains System is shown diagrammatically on Plant Drawings 205245 and 205345. This reheated steam leaves through nozzles in the top of the assemblies and flows to the LP turbines through a stop valve and an interceptor valve located in each reheated steam line. Two moisture separator-reheater assemblies furnish steam to each of the three LP turbines. The first stage bundle in the reheater is supplied with extraction steam from the HP turbine and the second stage tube bundle is supplied with main steam (steam generator outlet). The heating steam condenses in the tubes and the condensate from both reheaters flows to the HP feedwater heater.

10.2.2.3 Turbine Electro-Hydraulic Control System

The turbine is equipped with an Electro-Hydraulic Control System to control turbine valve movement. The system regulates turbine speed prior to the time that the generator is synchronized and controls unit output when the generator is connected to the power grid. Control is accomplished by regulating the flow of steam through the turbine.

The control of the main steam at the turbine inlet is accomplished through the use of four stop valves and four control valves.

A hydraulic actuator controls each stop valve so that it is either in the fully open or fully closed position. The prime function of these stop valves is to shut off the flow of steam to the turbine. The stop valves are closed immediately by actuation of trip devices (see Section 10.2.2.4 below), which are independent of the controller.

The turbine control valves are positioned by a servo-actuator which responds to a signal from the controller. The controller signal positions the control valves for wide-range speed control during startup and for load control after the unit is synchronized on the grid.

The reheat stop valves and the reheat interceptor valves control the flow of steam to the LP sections of the turbine. These valves are closed immediately by actuation of the emergency trip devices.

Overspeed Protection Controller (OPC) is a turbine trip. See 10.2.2.4.

10.2.2.4 Turbine Protection

The following protective devices are independent of the electronic controller and, when initiated, will cause tripping of all turbine valves:

1. Mechanical overspeed trip
2. Low bearing oil pressure trip
3. Low vacuum trip
4. Thrust bearing trip

5. Electrical solenoid trip actuated by:

    a. Reactor trip
    b. Generator electrical trips
    c. Manual trip from Control Room
    d. Loss of electro-hydraulic system control voltage
    e. EHC Overspeed Setpoint (108% or 110%)
    f. Loss of EHC speed signals
    g. Fail to accelerate signals
    h. EHC Power Up
    i. Load Drop Anticipator (LDA)

6. Manual trip lever located at the turbine

7. Loss of primary/secondary 24 V dc power

8. High-high steam generator water level or safety injection

9. Overspeed Protection Controller (OPC) solenoids actuated by:
    a. EHC Overspeed Setpoint (108%)
    b. Load Drop Anticipator (LDA)

The mechanical overspeed trip mechanism consists of an eccentric weight mounted on the end of the turbine shaft, which is balanced in position by a spring until the speed reaches approximately 108 percent of rated speed. Centrifugal force then overcomes the spring force and the weight flies out striking a trigger which actuates the overspeed trip valve and releases the protection system fluid (autostop oil) to drain. The resulting decrease in autostop pressure causes the governor emergency trip valve to dump the hydraulic fluid to a drain, thereby closing the turbine stop and control valves and the reheat stop and interceptor valves.

The autostop dump valve is also tripped when any one of the previously mentioned protective devices is actuated.

In addition to these devices, other protective features of the Turbine and Steam System are:

1. Turbine trip following a reactor trip
2. Automatic load runback initiated by overpower or overtemperature ΔT
3. MSIV in each steam generator steam line
4. Safety and relief valves in each steam generator steam line
5. Safety valves mounted on the moisture separator-reheater vessels

6. Extraction line nonreturn valves
7. Automatic load runback initiated by generator stator water turbine runback (Unit 2).
8. Automatic load runback initiated by main feedwater pump trip.

A trip of the turbine generator, when unit load is greater than a present limit, initiates a reactor trip to prevent excessive reactor coolant temperature and pressure.

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation which might lead to an overpower or overtemperature ΔT trip.

For Unit 2, an automatic turbine load runback can also be initiated by an input from the generator stator water turbine runback schemes. Generator runback is initiated by 2 out of 3 logic for low water pressure, 2 out of 3 logic for outlet water temperature, 2 out of 3 logic for low stator winding water flow or 2 out of 3 logic for low bushing water flow when the No. 2 voltage regulator is in the automatic permissive for runback condition. Stator current is monitored during this runback. Stator current must be less than 79% of rated load at the 2 minute mark and less than 23% of rated load at the 3.5 minute mark or a main turbine trip will be initiated. This will prevent damage to the Generator winding.

An automatic turbine load runback can also be initiated by a trip of either main feedwater pump when turbine power is greater than 69%.

The extraction nonreturn valves are closed through an air pilot valve which is actuated by the loss of autostop oil pressure when the turbine generator is tripped.

Overspeed Protection Control (OPC) is a turbine trip. See 10.2.2.4.

To prevent potential damage to the turbine due to the generator motoring, an electrical reverse power device interlocked with the turbine trip signal is incorporated. This protective measure ensures that the turbine is tripped before the generator circuit breakers are open, and provides the 30 seconds delay between the turbine trip and the generator trip upon detection of motoring condition.

10.2.2.5 Instrumentation

Instrumentation is provided to continuously monitor and/or alarm such turbine generator parameters as the following:

1. Generator load
2. Shaft vibration at bearings
3. Shaft eccentricity
4. Shell expansion
5. Differential expansion between turbine shell and rotor
6. Turbine speed
7. Turbine casing temperatures
8. Bearing temperatures
9. Hydrogen gas and stator cooling water temperatures
10. Generator frequency
11. Exhaust hood temperature
12. Condenser vacuum
13. Stator winding temperatures
14. Hydrogen pressure and purity
15. Bearing lube oil and hydraulic oil pressure

10.2.2.6 TURBINE OVERSPEED PROTECTION

The information in this section was relocated to the Salem Technical Requirements Manual.

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10.2.3 Turbine Missiles

The subject of turbine missile characteristics, probability of occurrence and protection of essential safety equipment is covered in Section 3.5.

Section 3.5 also deals with characteristics of the turbine discs, blades, and rotors as they relate to the subject of turbine missile formation.

10.2.4 Evaluation

Automatic control actions, alarms and trips are initiated by deviations of system variables from preset values. In every instance automatic control functions are programmed such that appropriate corrective action is taken to protect the RCS as well as the Steam and Power Conversion Systems.

10.2.5 Turbine Generator Test and Inspection

10.2.5.1 Turbine Generator Monitoring

Each turbine generator is equipped with supervisory instrumentation that monitor such variables as pressure, temperatures, flows, speed, vibration, eccentricity, rotor position, casing differential and rotating differential expansion. In the event that abnormal readings are being received, investigations will be made to ascertain the cause of the abnormal readings and, if necessary, the unit will be shut down. Investigations made may consist of nondestructive tests, such as visual, magnetic particle, liquid penetrant, ultrasonic and radiographic, where deemed possible.

Periodic inspections will be made as recommended by the turbine generator manufacturer.

Detectable flaws will be evaluated by both the turbine generator manufacturer's and owner's technical staff to determine the severity of removal and repair of the flaw. Relationship to the critical flaw size is a part of this evaluation.

10.2.5.2 Turbine Generator Inspection and Repair

Base loaded units are usually operated for a number of years between overhauls, unless operating parameters (such as unusual vibration, pressure and temperature variations throughout the steam path, or bearing temperature indications) indicate the need for an earlier inspection. The outline of typical procedures for performing turbine and generator repair and inspection is provided below.

If any crack is found in the blading, the blade must either be replaced or cut off in the cracked section or at the blade root section.

Depending upon the physical arrangement of the blading and the contour surfaces that are to be inspected, any of the following nondestructive techniques might be used: visual magnaflux, magnaglo, liquid penetrant, or ultrasonic.

10.2.5.3 Outline of Typical Procedures for Turbine and Generator Repair and Inspection

Prior to Outage

The following would be performed prior to shutting down the unit:

1. Stop and control valves shall be exercised.

2. Readings shall be taken of temperatures and pressures on oil, water, steam and hydrogen systems.

3. Inspection of operating equipment will be performed.

Outage

Competent personnel would maintain schedules of the work to be performed on the turbine generator unit, which would include required replacement parts, rigging requirements, tools, special services (such as air, electric power, etc.). Schedules would also be maintained for disassembly of component sections of the unit, such as lagging, cylinder and pedestal covers, piping, thermocouples, wiring, etc. Coupling alignments would be checked prior to complete disassembly. Axial and radial clearances would also be checked.

Inspection would be made of pedestals, oil reservoir, seals, rotors, blading, journals, thrust collars, bearings, spindle, support keys, nozzle blocks, bolting, oil pumps, turning gear, lift pumps, stop and control valves, steam strainers, joints, castings and forgings, cylinder and blade rings and diaphragms. Grout under the pedestals would also be inspected. Inspection would also be made of generator parts such as windings, retaining rings, stud assemblies, slot coils, end winding coils, hydrogen ventilating systems, core and magnetic end shields, bushings, gland seal rings, bearings, blower blades and hydrogen coolers.

Such inspections could result in replacements, adjustments, machining, cleaning, realignment, nondestructive testing, etc., as deemed necessary prior to assembly of each part. Various measurements would be made of journal and bearing bores.

Overspeed mechanism would be exercised by hand. Balance weight holes would be checked. Weight locations would be recorded.

Electrical tests would be made as deemed necessary. Such tests would include air leakage, insulation resistance, impedance and overpotential tests. In addition to visual inspection of components, nondestructive testing of field retaining rings and blower blades would be conducted as deemed necessary.

The following equipment associated with the turbine generator unit would be inspected, cleaned, repaired when necessary, and tested in cooperation with the manufacturer:

1. Brushless Excitation System

2. E-H Control System

3. Lubrication System

4. Gland Steam Supply and Exhaust System

5. Seal Oil and Hydrogen Gas System

6. Supervisory instruments

7. Protective devices

Records of significant changes, additions, replacements, deviations would be maintained during reassembly of the turbine generator unit. Reassembly of the unit would be in accordance with the manufacturer's accepted practices.

10.2.6 Hydrogen Supply

Three banks of storage tubes supply hydrogen through pressure reducing stations to a header, which is pipe sleeve protected. The header is run underground into the Turbine Building. Within the building, the header divides to supply hydrogen to each generator through individual pressure regulators. An emergency header supplies hydrogen individually to each generator through a pressure reducing station.

Hydrogen storage tubes are located in the yard on a concrete pad. The ground is covered with crushed stone. The Hydrogen Supply System is shown on Plant Drawing 205220.

The following protective measures are used to prevent fires and explosions:

1. Carbon dioxide is used as an intermediate gas when changing from hydrogen to air or air to hydrogen.

2. Each generator is vented when changing from one gas to another.

3. Gas changing operations are performed with the generator at standstill or on turning gear.

4. For Unit 1, a line blind flange, in individual hydrogen piping to the generator, is placed in the blind position to isolate the generator from the hydrogen supply whenever hydrogen is not needed in the generator. For Unit 2, a spool piece is removed from the hydrogen supply line and blank flanges are installed to isolate the generator from the hydrogen supply whenever hydrogen is not needed in the generator.

10.2.7 Turbine Auxiliaries Cooling System

The Turbine Auxiliaries Cooling System, shown on Plant Drawing 205210, provides the cooling water for the following turbine generator auxiliary components:

1. Generator hydrogen coolers

2. Generator stator water coolers

3. Generator exciter coolers

4. Generator seal oil coolers

5. Turbine electro-hydraulic control fluid coolers

6. Gland seal steam condenser

7. Main bus air cooler

8. Feedwater sample coolers

9. Bleed steam coil drain pump mechanical seal coolers

10. Heater drain pump stuffing box water jacket

11. Condensate and heater drain pump motor upper/lower bearing coolers

12. Bleed steam coil drain tank pump lube oil coolers

13. Vacuum pump seal water coolers

The system consists of a single closed loop employing condensate quality water as a coolant with the following major components:

1. Makeup and expansion tank

2. Main heat exchangers

3. Pumps

The pumps are used to circulate the coolant through the shell side of the main heat exchangers where its heat is given up to service water on the tube side. The tank provides a makeup water source for the system from the main condensate cycle.

Figure F10.2-1 Sheets 1, 2 & 3 of 3 intentionally deleted.

Refer to plant drawing 205218 in DCRMS

Figure F10.2-2A Sheets 1, 2 & 3 of 3 intentionally deleted.

Refer to plant drawing 205245 in DCRMS

Figure F10.2-2B Sheets 1, 2 & 3 of 3 intentionally deleted.

Refer to plant drawing 205345 in DCRMS

Figure F10.2-3 Sheets 1 & 2 of 2 intentionally deleted.

Refer to plant drawing 205220 in DCRMS

Figure F10.2-4 Sheets 1, 2, 3 & 4 of 4 intentionally deleted.

Refer to plant drawing 205210 in DCRMS

10.3 MAIN STEAM SYSTEM

10.3.1 Design Bases

The Main Steam System is designed to convey saturated steam to the turbine from the four steam generators. Steam is also supplied to the steam generator feedpump turbines, auxiliary feedpump turbine, moisture separator-reheaters, gland sealing steam controllers, and No. 15 feedwater heater. Provision is made to dump up to 40 percent of full load steam flow directly into the condenser (turbine bypass) to aid the reactor in accommodating electric generator load rejections without reactor trip.

The main steam piping from the steam generators through the main steam isolation valves (MSIVs) is classified as Seismic Category I. Beyond the MSIVs, the main steam piping is designed to conventional standards.

The main steam piping in the containment has been analyzed to ascertain the effects of guillotine-type pipe rupture, and restraints have been provided to ensure that such a rupture will not compromise containment integrity.

The pressure retaining components or compartments utilize the following codes as minimum design criteria:

1. System pressure vessels - ASME Boiler and Pressure Vessel Code, Section VIII.

2. System fittings and piping - ANSI Standard Code for Pressure Piping ANSI-B31.1.0, Power Piping. For nuclear piping not supplied by the Nuclear Steam Supply System (NSSS) supplier, material, inspections, fabrication, and quality control conform to ANSI Code for Pressure Piping, ANSI-B31.7, Nuclear Power Piping. Where not possible to comply with ANSI B31.7, the requirements of

ASME III-1971, which incorporated ANSI B31.7, were adhered to. Main Steam piping fabrication, installation welding, and examination involved in installing the Unit 2 replacement Steam Generators utilized ASME Section XI (1998 Edition with 2000 Addenda) and ASME Section III, Subsection NC (1995 Edition with 1996 Addenda). Both of these later codes are NRC-endorsed per 10CFR50.55a and were reconciled to the original construction codes.

Principal system valves - Main Steam Safety Valves - ASME Boiler and Pressure Vessel Code, Section III, Class A.

Main Steam Relief Valves - ASME Boiler and Pressure Vessel Code, Section III, Class II (Class I for materials, inspections, fabrication, and quality control).

MSIVs - ASME Boiler and Pressure Vessel Code, Section III, Class II (Class I for materials, inspections, fabrication, and quality control).

Feedwater Isolation Valves - ASME Boiler and Pressure Vessel Code, Section III, Class II or ASME Code for Pumps and Valves for Nuclear Power, Class II (Class I for materials, inspections, fabrication, and quality control) as applicable for individual valves based on procurement documents.

10.3.2 System Description

10.3.2.1 Main Steam System

The Main Steam System is shown on Plant Drawings 205203 and 205303.

The Main Steam System for each unit conveys saturated steam from four steam generators to the high pressure (HP) turbine with less than 40 psi pressure drop. The steam conditions of approximately 3,900,000 pounds per hour, and a density based on 750 psig (nominal) 513°F steam, were used for the system design of both units. Reheat is provided, external to the steam generators, between the HP and low pressure (LP) turbines.

For Unit 1, the steam pressure is 814 psig, and the temperature is 522°F at the steam generator exit nozzle. For Unit 2, the steam pressure is 885 psig, and the temperature is 532°F at the steam generator exit nozzle.

A turbine bypass system bypasses up to 40 percent of full load flow directly from the main steam lines to the condenser.

In addition, the bypass system supplies steam to the main steam coils of the moisture separator - reheaters (MSR), steam generator feed pump turbines (during low load operation) and the gland steam controller. The auxiliary feed pump turbine is fed from the Main Steam System. Cold reheat steam is used in the No. 3 feedwater heater while hot reheat steam is used to supply the steam generator feed pump turbines.

Four lines convey the steam from the steam generators, in the containment, through the wall penetrations to an anchored mixing bottle in the yard. This piping is 30 inches outside diameter (OD) within the containment, 32 inches OD within the penetrations, 32 inches OD inside the penetration areas (except 34 inches OD from the safety valve headers) and 32 inches OD from the MSIVs to the mixing bottle. The mixing bottle has an OD of 43 inches.*

Following temperature and pressure equalization in the mixing bottle, steam is carried to the turbine by two parallel 40-inch OD pipes. Each of these pipes bifurcates to a pair of 28-inch lines which supply the four sets of turbine stop and governor control valves.

Equalization of steam pressure near the turbine is provided by a 24-inch OD pipe interconnecting the two main steam pipes just upstream of their respective bifurcations.

The exhaust from the high pressure turbine (cold reheat steam) is carried to six combination MSR assemblies. These assemblies have

*All piping outside diameters (OD) given are nominal sizes.

horizontal cylindrical shells and are located alongside the LP turbine elements, three to a side. On each side of the turbine the cold reheat steam passes through two 44-inch OD pipes into a 62-inch OD pipe. The 62-inch pipes reduce to 54.5 inches and then 37.5 inches OD after feeding No. 1 and 2 MSRs respectively. The feed pipes to the No. 1 and 3 MSRs are 37.5-inches OD, while those to the No. 2 MSRs are 42-inch OD. The steam leaving each of the six MSRs is conveyed to its respective LP turbine element by a 37.5-inch OD pipe.

The Turbine Bypass System removes steam from the two 40-inch OD main steam pipes through two 16-inch OD pipes just upstream of the main steam line bifurcations. A portion (up to 40 percent of full load flow) of the steam thus removed can be routed to the condenser through six 12-inch OD pipes, each of which branches into two 10-inch OD pipes, while the remainder of this flow is used to feed the MSR main steam coils through six additional 10-inch OD pipes.

The main steam piping is in compliance with ANSI B31.1.0, and was designed using the appropriate wall thickness formula from the ASME Boiler and Pressure Vessel Code (1965 edition and summer addendum of 1966) with allowable stress values from ANSI B31.1.0. Main Steam piping fabrication, installation welding, and examination involved in installing the Unit 2 replacement Steam Generators utilized ASME Section XI (1998 Edition with 2000 Addenda) and ASME Section III, Subsection NC (1995 Edition with 1996 Addenda). Both of these later codes are NRC-endorsed per 10CFR50.55a and were reconciled to the original construction codes.

The piping between the steam generators and the MSIVs outside the containment is designed to Seismic Category I criteria with materials quality governed by ANSI B31.7. The principal piping is rolled electric - fusion welded carbon steel, manufactured to ASTM Specification A155, Grade KC 70, Class I, or a substitutable chrome alloy or stainless steel material. A portion of the main steam piping replaced during the Steam Generator Replacement Project for Units 1 and 2, uses ASME SA 672, Grade C70, Class 22 material. The entire system has been stress analyzed for the forces and moments resulting from thermal growth, and the piping upstream of the MSIVs has been dynamically analyzed for seismically induced stresses. The main steam piping within the containment has been analyzed to ascertain the effects of a guillotine rupture and restraints have been provided to ensure that such a rupture will not compromise containment integrity. Main steam piping at the safety and relief valves has been

analyzed to determine its ability to withstand full valve force and moment reaction loadings.

Steam flow is metered and limited in each line by a dual purpose flow restrictor located inside the containment. Outside the containment a power-operated relief valve (PORV), five safety valves and a quick acting self-actuating MSIV are provided in each of the four lines to the mixing bottle. The main steam safety valves, set at 1070, 1100, 1110, 1120 and 1125 psig respectively, have a total relief capacity of 100 percent of full load flow, while the PORVs can pass a total of 10 percent of full load flow to atmosphere. Hot reheat stop and intercept valves are provided in each of the six hot reheat lines (as are bypass stop and control valves in each turbine bypass line).

A pneumatically-operated bypass valve around each MSIV, steam traps, strainer/orifice assemblies and power-and manually-operated startup drain valves are provided at appropriate locations to ensure proper warmup of the entire Main Steam System to prevent condensate collection during operation and to prevent freezeup during outages.

During operational transients, the excess steam generated is normally bypassed directly to the condenser through the Bypass System. The Bypass System can accommodate 40 percent of full load flow, which, in conjunction with the 10-percent step load change capability of the NSSS, enables the plant to accept a 50-percent load rejection from full load without reactor trip, turbine trip, or safety valve actuation. A description of the operation of the Bypass System is included in Section 10.4.4.

10.3.2.2 Main Steam Isolation Valves

A schematic diagram of the MSIVs is provided on Figure 10.3-2. The MSIVs are installed in each main steam header at the outlet of each steam generator. The

valves are located outside of the containment, downstream of the safety valve manifold.

The valves are 32 x 24 x 32-inch Hopkinson parallel slide gate valves with double discs. They are operated by means of an integral piston and cylinder, utilizing steam within the valve and piping. The piston, attached to the valve stem, is at the lower end of its cylinder when the valve is in the open position. It has a small orifice to permit pressure equalization in the open position. A vent line from the upper end of the cylinder branches to two diaphragm-operated dump valves which are connected in parallel to provide redundant control of the main valve.

Upon receipt of a closure signal, the dump valves open and release steam from the upper side of the main valve piston, thereby closing the valve. The movement of the valve stem is damped at the upper end of its travel by a hydraulic cylinder and piston (snubber) mounted integrally on the valve. The snubber incorporates an integral electric motor-operated hydraulic power unit which permits remote manual operation of the valve at conventional speed.

The valves can be operated from the Control Room. They may be partially closed by remote manual (electro- hydraulic) control for testing operability at any steam flow or pressure.

A motor-operated three-way valve is installed in the steam cylinder vent line of each MSIV, and is normally in the mid-position; however, it does permit isolation of one dump valve and its controls without affecting the operation of the remaining one. Each valve has a local control station with position indicating lights in the Control Room.

The MSIVs have a detent mechanism which maintains the valves in the open or closed position and yet permits operation when sufficient differential pressure across the steam

piston is established or the valve is operated hydraulically. Position indicating lights and control switches are provided on the valves for open, closed, and test positions.

The MSIVs close automatically on the initiation of a steam line isolation signal. If the closure time of the MSIV during a Tech. Spec. Surveillance test (between 800 psig and 1000 psig Steam Generator pressure) is 5.0 seconds or less and the ESF response time (including valve closure time) for the steam line isolation signal (Table 3.3-5) is 5.5 seconds or less, then assurance is provided that main steam isolation (MSI) occurs within 12 seconds under accident conditions, where Steam Generator pressure may be lower. The 5.0 seconds of the surveillance test consists of a 1.5 second timer delay and a 3.5 second mechanical stroke time.

This method of testing assures that for main steam line ruptures that are initiated from Modes 1-3 conditions that generate a MSI signal via automatic or manual initiation and have adequate steam line pressure to close, the main steam lines isolate within the time required by the accident analysis. Fast closure of the MSIVs is assured at a minimum steam pressure of 170 psia. However, the MSIVs will still close via the steam assist function between 118 - 170 psia with slightly greater closure times. For main steam line ruptures that receive an automatic or manual signal for MSI and do not have adequate steam pressure to close the MSIVs (less than 118 psia), the event does not require MSIV closure to provide protection to satisfy design basis requirements (i.e., DNBR remains above the minimum DNBR limit value and peak containment pressure remains below 47 psig).

In summary, steam line breaks that occur in Mode 3 and that require steam line isolation will result in a steam line isolation signal and have sufficient steam pressure to close the MSIVs within the time assumed for fast closure in the Chapter 15 accident analyses. Any steam line breaks that occur in Mode 3 and that are too small to generate a steam line isolation signal do not require steam line isolation for core protection and are not limiting with respect to DNBR.

The valves are operated by an integral piston and cylinder utilizing steam within the valve and piping as the power media. The valve is maintained in the open position by steam applied to the upper side of the piston which is attached to the valve stem. Valve closure is achieved by venting the steam from the upper side of the piston cylinder through either of two redundant diaphragm operated vent valves.

Valve stem travel is damped by a hydraulic cylinder and piston integrally mounted on the topworks. In addition, the hydraulic cylinder and piston includes an electric motor to permit remote manual hydraulic operation of the valve.

A motor-operated three-way valve is installed between the MSIV vent connection and the two redundant vent valves. The three-way valve is normally in the mid-position permitting venting of the cylinder through either vent valve. The three-way valve may be positioned in either of its extreme positions to isolate one vent valve without affecting operation of the other.

The MSIV vent valves are normally closed, air to close, solenoid actuated diaphragm-operated valves. The vent valve solenoid actuators are normally de-energized requiring the initiation of a steam line isolation signal to energize the solenoid to perform the following sequence of events:

1. Initiation of main steam isolation signal energizes solenoid.

2. Solenoid exhausts vent valve diaphragm opening vent valve.

3. Vent valve relieves steam from MSIV upper cylinder which closes the MSIV.

Design features to meet the single failure criterion are as follows:

1. Each MSIV cylinder may be exhausted through one of two redundant vent valves piped in parallel.

2. The solenoid actuators for the vent valves are powered by redundant vital buses.

3. The air supply for the vent valves are fed from redundant air headers.

4. The vent valves are actuated from separate protection system logic trains.

A failure of an air supply, logic train, power supply, or vent valve will not prohibit isolation of the steam line by the redundant equipment.

A failure of the pressure boundary at any point in the steam cylinder above the piston, in the vent line, or in the three-way

or vent valve bodies will result in one of two consequences, either of which is considered acceptable:

1. If the pressure boundary failure is of such a size that steam leaks from above the piston at a rate greater than that which can be replenished through the equalizing orifice in the piston, the valve will close.

2. If the pressure boundary failure is of such a size that its leakage can be replenished by flow through the piston orifice, the valve will remain in its open position until closed by the appropriate isolation signal.

If the valve fails to close upon venting of the steam above the piston, the hydraulic operator may be used to close the valve.

10.3.2.3 Flow Limiters

Each steam line is provided with a venturi-type restrictor. The flow restrictors are designed to increase the margin to departure from nucleate boiling (DNB), and thereby reduce fuel clad damage, by limiting steam flow rate consequent to a steam line rupture and thereby reducing the cooldown rate of the primary system.

Design criteria for the steam line flow restrictors provide the following:

1. Provide plant protection in event of a steam line rupture downstream of the restrictor. In such an event, the flow restrictor reduces steam flow rate from the break, which in turn reduces the cooling rate of the primary system. This increases the margin to DNB and fuel clad damage, as shown in Section 15.

2. Minimize unrecovered pressure loss across the restrictor coincident with limiting accident flow rate to an acceptable value (less than 5 psi at 120 percent of rated steam flow).

Design requirements imposed in addition to the design criteria include the following:

1. Reduce thrust forces on the main steam piping in the event of a steam line rupture, thereby minimizing the potential for pipe whip.

2. Provide a portion of the pressure differential necessary for steam flow measurement.

3. Withstand the number of pressure and thermal cycles experienced in the life of the plant.

4. Maintain restrictor integrity in event of double-ended severance of a main steam line immediately downstream of the restrictor.

The location of the flow restrictors is shown on Plant Drawings 205203 and 205303. Restrictors are positioned approximately 24 pipe diameters downstream of each steam generator in vertical sections of piping in order to minimize the length of piping preceding the restrictor, thereby reducing the probability of an upstream pipe break.

Each flow restrictor is provided with two steam flow transmitters which provide inputs to the Reactor Protection System. These transmitters have variable damping which is adjusted to minimize false safety injection signals caused by spurious transient high steam flow signals. The damping is selected so that the transmitter and protection channel response times do not exceed Technical Specification time response requirements and hence do not affect any safety margin.

All the statements above are applicable to both units. In addition, each steam generator also has an integral flow restricting device in the steam nozzle, with a flow area of 1.4 ft^2.

10.3.3 Evaluation

10.3.3.1 Transient Effects

A reactor trip from power requires subsequent removal of core stored and decay heat. Immediate heat removal requirements are normally satisfied by the steam bypass to the condensers and pressure relief system. Thereafter, core decay heat can be continuously dissipated as feedwater in the steam generator is converted to steam by heat absorption. The capability to return

feedwater flow to the steam generators is provided by operation of the Main or Auxiliary Feedwater Systems.

In the unlikely event of a loss of offsite power, decay heat removal would continue to be assured by the availability of one steam-driven and two motor-driven auxiliary feed pumps, and steam discharge to atmosphere via the power relief valves and/or the steam generator safety valves. In this case, feedwater is available from the auxiliary feedwater storage tank by gravity feed to the auxiliary feed pumps. The water supply in the auxiliary feed storage tank is adequate for decay heat removal for a period of about eight hours. Alternate sources of water are available from the demineralized water storage tanks, fresh water storage tanks and Service Water System. The analyses of the effects of loss of load and steam line breaks on the Reactor Coolant System are discussed in Section 15.

10.3.3.2 Reliability and Integrity of Safety-Related Equipment

All Steam and Power Conversion System equipment required for reactor plant safety is designed as Seismic Category I and the appropriate systems are sufficiently redundant to ensure performance of their safety functions. Specifically, the Auxiliary Feedwater System and portions of the Service Water System are required to perform various plant safety functions.

The effects of a main steam pipe break outside the containment have been evaluated with regard to potential damage to safeguards equipment.

The main steam pipes penetrate the containment into an enclosed penetration area. From this space, the pipes are routed vertically through the roof to the outdoors. This space is the only enclosed space that the pipes pass through before they reach the Turbine Building, as indicated on Plant Drawings 204803, 204804 and 204808.

The main steam pipe is restrained within the penetration area in order to prevent damage to safeguards equipment in those areas due to pipe whip. The penetration areas are provided with blow-out dampers which vent to atmosphere when pressure within the penetration area exceeds 2 psig.

Outside of the penetration areas, two out of the four main steam lines for each unit run adjacent to the Auxiliary Building outdoors. To preclude damage to safeguards equipment within the Seismic Category I Auxiliary Building, however, a 13-foot space has been provided between the pipes and the building wall. Additionally, the wall has been designed as a missile barrier with a 2-foot concrete thickness.

10.3.3.3 Pressure Relief

Self-actuated safety valves are provided to insure the integrity of the Steam and Power Conversion System. These valves are designed to pass 100 percent of the maximum calculated steam generator capacity. Five valves are installed on each steam generator outlet steam line with the lowest set pressure at 1070 psig. In addition to the above, each steam generator has a 10-percent capacity PORV.

A turbine bypass system having a capacity to exhaust 40 percent of maximum calculated turbine flow to the condenser is also provided.

10.3.3.4 Radioactivity

HISTORICAL NOTE:

The radiological dose values contained in this section were calculated in support of initial licensing. Currently, occupational dose is managed through the Radiological Controls Program, ALARA, and the Technical Specifications.

Under normal conditions, there is no radioactivity present in the system. The system may only become contaminated through primary to secondary leaks in the steam generators. Should this occur, radiation monitors installed in the steam generator blowdown, each main steam line, and condenser vacuum pump effluent streams detect and indicate the presence of radioactivity.

(Historical Information)

Assuming operation with the maximum permissible primary system activity and a greater than maximum permissible primary to secondary system leakage rate, the dose rate around the steam generator is approximately 325 mR/hr at contact with the steam generator secondary water section just above the U-tubes. The dose rate on the operating floor outside the steam generator biological shield would be approximately 150 mR/hr, due to the secondary water in the steam generator which is above the top of the biological shield.

The dose rates from a main steam line were calculated to be about 8 mR/hr at contact and less than 1 mR/hr at 10 feet away. Dose rates from the turbine will be less than this due to the thick steel turbine casing serving as a shield, and lower source densities as the steam travels through the turbine. The primary contributors to the dose rates from the main steam lines and turbine are the noble gases and N-16. Since the noble gases are removed at the condenser by the condenser Air Removal System and there is sufficient storage time in the hotwell to allow for the decay of the N-16 to negligible levels, the only remaining source in the feedwater is 0.25 percent of the nongaseous fission products that are carried over with the steam. Dose rates from feedwater lines were calculated to be approximately 4 mR/hr at contact and less than 1 mR/hr at 10 feet away.

Dose rates from a 3-inch blowdown line were calculated to be approximately 280 mR/hr at 1 foot away and 75 mR/hr at 3 feet away. The dose rate from the blowdown tank was approximately 800 mR/hr at 3 feet away.

Shielding around the steam generators is designed to reduce radiation levels from the U-tubes. Since primary to secondary leakage is not expected to occur at all times, and access to the containment is minimal during operation, higher dose rates on the operating floor are acceptable. However, high dose rates in this area may require reduced access time. Radiation levels in other

accessible areas of the containment (outside the crane wall and below the operating floor) will not be severely affected.

Shielding around the main steam line, turbine, condenser, feedwater and heat recovery blowdown system piping is not necessary since radiation levels in this area would only occur in the event of primary to secondary leakage, and the dose rates would be low. In this event, access to the Turbine Building would be controlled.

The blowdown lines pass through the mechanical penetration area where some higher radiation levels normally exist, and no additional shielding is required. The blowdown tank is in a relatively low radiation area, but can be temporarily shielded if access to the area is necessary. Piping to the blowdown demineralizer is in a shielded pipe alley and the demineralizer is in a shielded cubicle. The remainder of the system is in an area where access can be controlled. If access to Blowdown System components is necessary for maintenance while the higher dose rates exist, temporary shielding can be installed and access times limited.

Assumptions

(Historical Information)

1. A conservative primary to secondary leak rate of 8 gpm was assumed (the expected leak rate is currently being determined - a lower value will decrease the main steam line and turbine dose rates).

2. 100 percent of noble gases

3. Fission product carryover: 0.25 percent

4. Steam generator flow rate: 3.6×10^6 lb/hr/stm gen

5. Calculations based on 1 defective steam generator

(Historical Information -cont'd)

6. N-16 concentration at steam generator inlet used (no further decay assumed before condenser)

7. Steam generator secondary side dose rates:

   a. Steam: noble gases plus N-16

   b. Secondary water: Fission product activity associated with 1 percent fuel defects. Noble gas activity associated with 1 percent fuel defects (adjusted for dilution in steam generator) and N-16

8. Blowdown sources: same as steam generator

9. Condenser has water storage capacity of 3 to 5 minutes

10.3.3.5 Main Steam Isolation Valve Integrity and Reliability Test

(Historical Information)

The capability of the main steam isolation valves (MSIVs) to fully close under full differential pressure, occasioned by a main steam line rupture immediately downstream of the valve, was demonstrated by testing a full size valve, similar to the Salem valves, at the manufacturer's facility. The following tests were made:

1. Hydrostatic test of valve body, with valve in open position, at 2175 psig - one hour - no leakage.

2. Seat tightness test with valve closed and 1500 psi intergate pressure (full differential across each seat) and valve ends open for inspection - one hour - no leakage; valve operated over seat overlap range (1-inch) with 600 psig intergate pressure and held one hour - no leakage.

3. For steam testing, the valve itself was made to simulate a boiler and generate steam by carefully controlled

(Historical Information - cont'd)

electric heating. In 409 hours of steam testing 62 fast closings were made at steam pressures of 80-1050 psig (sat.). These closings were made from full open to full close with no differential across the seats. Closure speed at 640 psig steam pressure was 3 seconds with nominally uniform travel speed. Steam operation tests were made over the seat overlap range (1-inch) at pressures from 80-1050 psig between discs (intergate) to check capability of valves to operate on steam with full differential across seats and maximum seat contact. During this testing the valve ends were vented to atmosphere.

4. Tests were made with the hydraulic unit uncoupled using nitrogen at 400 psig and 360 psig as the operating media. Closure times were 0.94 and 1.03 seconds, respectively.

At the conclusion of operational tests a seat tightness test produced leakage of 16 cc/hr at one seat and 275 cc/hr at the other seat. Little wear was evidenced on seats. However, there was indication that the discs, as anticipated, do rotate during the valve stroke.

The valves are periodically exercised in accordance with the requirements set forth in the Technical Specifications.

10.3.3.6 Main Steam Isolation Valve Restraints

Mechanical restraints have been provided at and adjacent to the MSIVs. Several types of restraints have been used, each serving a distinct function. Restraints are provided on the steam lines adjacent to the MSIVs. These restraints serve to limit pipe motion following a postulated rupture such that neither excessive moments nor physical impact can damage the containment, containment penetrations, or MSIVs. Supports are provided on the valve body to aid in supporting valve weight

and supply restraint against undesired motion. Where necessary, the valve operator has also been restrained to limit seismically induced motions.

10.3.4 Inspection and Testing Requirements

The MSIVs (MS167) and automatic drain stop valves (MS7) shall be tested periodically as set forth in the Technical Specifications.

The main steam drain traps are periodically tested to ascertain their proper functioning and, hence, prevent any unnecessary water accumulations.

Removable insulation panels have been provided at welds in the Main Steam System between the steam generator and the MSIVs in order to accommodate volumetric and surface weld examination as specified by periodic inservice inspection requirements.

A functional test of the turbine governor control valves is performed periodically and can be made while the unit is carrying load. The purpose of this test is to ensure proper operation of the turbine stop valves, control valves, reheat stop valves, and interceptor valves.

The controls and protective devices associated with system components, including steam generator safety valves, are tested as set forth in the Technical Specifications.

10.3.5 Water Chemistry

10.3.5.1 Chemical Feed System

The Chemical Feed System is shown on Plant Drawing 205214. Chemical feed equipment is provided to add hydrazine, ammonium hydroxide, ethanolamine (ETA), polyacrylic acid (PAA), and/or ammonium chloride to various locations throughout the feedwater and condensate systems, including the discharge of each condensate pump, the outlet of each condensate polisher and the discharge header, and the inlet of the steam generators. In addition, equipment is available to feed a solution of hydrazine and ammonium hydroxide to the inlet main and auxiliary feedwater line of each steam generator.

Hydrazine is added to the Condensate System and the main and auxiliary feedwater system for control of residual oxygen. Ammonium hydroxide and/or ethanolamine (ETA), which is an alternate amine, is added for corrosion and pH control and minimizes metal pickup through the cycle. Ammonium chloride is used to decrease the sodium to chloride molar ratio in SG blowdown. Polyacrylic acid (PAA) is added to hold iron in suspension in order to prevent its plating out on steam generator tubing.

The chemical solutions are stored in totes (tanks). All chemicals are injected by motor-driven positive displacement pumps with manual and/or automatic control. Hydrazine can alternatively be injected by vacuum drag into the suction side of the condensate pump.

10.3.5.2 Secondary Water Chemistry Control Program

The Secondary Water Chemistry Control Program is designed to limit the corrosion of the tubing and internals of the steam generators. The basis of the program is to control the levels of the critical parameters in the steam generator bulk water such that maximum protection to the steam generators is provided and tube integrity is maintained.

Protection of the steam generator tubing is accomplished by maintaining the water quality of the condensate and condensate polishing effluent and adjusting the blowdown on each of the four steam generators. The feedwater and steam generator bulk water treatment consists of introducing ammonium hydroxide and/or ethanolamine (ETA), which is an alternate amine for pH control and hydrazine for oxygen scavenging. This treatment is recommended by industry guidelines.

Ammonium chloride also treats the feedwater and steam generator systems. Ammonium chloride is used to decrease the sodium to chloride molar ratio in steam generator blowdown. Polyacrylic acid (PPA) holds iron, from sources throughout the secondary plant, in suspension such that it is removed via the steam generator blowdown.

Steam Generator Blowdown Sample is measured for the following critical parameters: pH, cation conductivity, and sodium. The critical parameters measured at the condensate pump discharge include cation conductivity and sodium. The critical parameter measured at the condensate polishing effluent is total conductivity.

Steam Generator Blowdown Sample is analyzed in accordance with industry and vendor guidelines. Sampling frequencies and specifications may be found in the following industry and vendor guidelines: The EPRI PWR Secondary Water Chemistry Guidelines, INPO document 88-021, Westinghouse Technical Bulletin NISD-TB-85-12 and Westinghouse Report 83428. The sample frequency is increased when the normal control limits are exceeded to assure that operation is within the limiting specifications indicated in the above guidelines. The secondary system is monitored on a continuous basis with online chemistry monitors.

Out-of-specification chemistry is returned to within the normal limits of control within the times specified in the limiting specifications contained in the above guidelines. In the event that the limiting specifications cannot be maintained, a review is conducted by the Operations Director who will initiate additional corrective actions (which can include removing the Unit from service if conditions warrant this course of action).

Should a condenser leak be confirmed, corrective actions will be taken to mitigate the leak in a time period consistent with its impact upon the Action Levels specified in the guidelines.

TABLE 10.3-1

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TABLE 10.3-2

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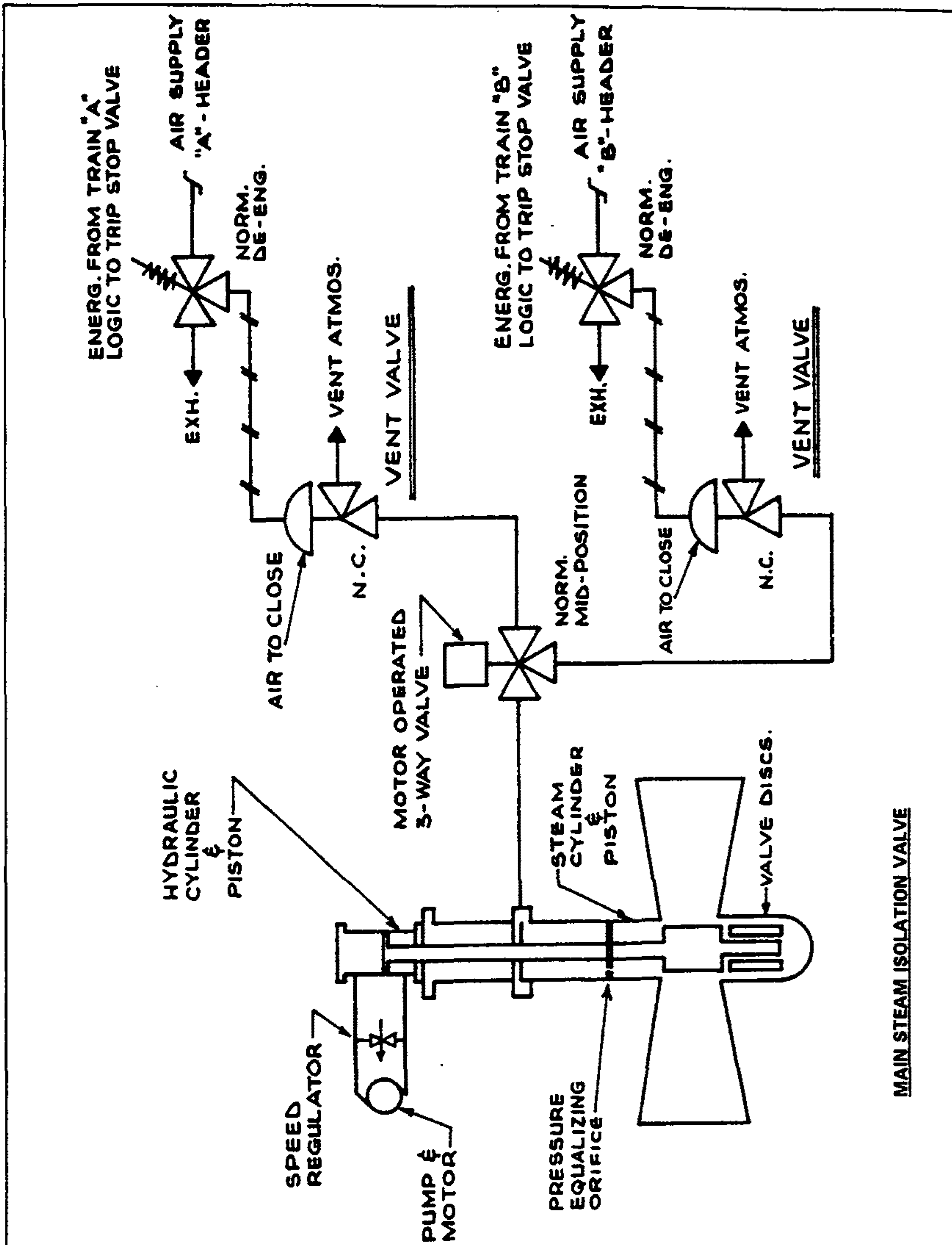
Figure F10.3-1A Sheets 1 through 6 of 6 intentionally deleted.

Refer to plant drawing 205203 in DCRMS

Figure F10.3-1B Sheets 1 through 6 of 6 intentionally deleted.

Refer to plant drawing 205303 in DCRMS



PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Main Steam Isolation Valve
	Updated FSAR Revision 15 June 12, 1996 Figure 10.3-2

Figure F10.3-3 Sheets 1 & 2 of 2 intentionally deleted.

Refer to plant drawing 205214 in DCRMS

10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

10.4.1 Main Condensers

10.4.1.1 Design Basis

The condenser for each turbine generator unit consists of three single pass rectangular shells equipped with divided waterboxes and interconnected steam spaces for added flexibility of system operation. Each condenser is of the shell and tube design and arranged within the circulating water circuit for single pressure operation with the six-flow, tandem compound steam turbine.

The design parameters for the condenser are as follows:

Steam Loading, Btu/hr	7.636×10^9
Circulating Water, gpm	1,110,100
Inlet Water Temp., °F	61.8
Condensing Surface, sq ft	800,000
Tube Material	Al 6x*
Tubes, O.D. x M.W.C. x Eff. Length	1" x 19 x 44' - 9 3/4"
Tube Quantity	68,001
Design Pressure, in. Hg. abs.	1.3

* Unit 2 condensers contain some tubes which are AL6xN material.

10.4.1.2 System Description

The triple shell condenser is mounted beneath the low pressure turbine exhausts with the condenser tubes oriented perpendicular to the turbine shaft and are designed to accept up to 40-percent

instantaneous turbine load rejection. Four 10-inch diameter turbine bypass steam inlets per shell provide ample means of exhausting the rejected load into the steam lanes without any detrimental effects to the condenser internals. The condenser hotwell is designed for 5 minutes' storage capacity (approximately 120,000 gallons at maximum load) and to maintain 0.005 cc/1 of dissolved oxygen in the effluent condensate.

The condensers are equipped with bolted, bonnet-type steel waterboxes and include Cathodic Protection System. Both waterboxes and tubesheets are coated with a high performance epoxy polymer. Fiberglass ladders are included in the waterboxes to provide access for maintenance purposes. Safety grids shield the waterbox nozzle openings for the protection of personnel during inspection or maintenance periods.

Each condenser shell is connected to the turbine exhaust via a continuous rubber belt (dog bone) type expansion joint located in the condenser neck. Two low pressure feedwater heaters are mounted in each condenser shell neck with their channel heads extending through the inlet end of the condenser. Steel flexure plates mounted in individual heater closures accommodate any differential expansion between the condenser and heater.

The vacuum system is capable of performing inleakage detection tests on the condenser shells without interruption of service.

10.4.2 Main Condenser Evacuation System

The Condenser Air Removal and Primary System is shown on Plant Drawing 205208. There are eight rotary-type vacuum pumps provided, four for each unit. Three pumps (12, 13 & 14/22, 24 & 25) for each Unit are used for condenser vacuum and one pump (11/23) per Unit is used for waterbox priming tank vacuum.

Each condenser vacuum pump has an individual holding capacity of 15 scfm of free dry air at a suction pressure of 1 in. Hg. absolute. Each condenser vacuum pump's hogging capacity is 1500 scfm at 15 in. Hg. absolute. Each vacuum pump requires 144 gpm of seal water cooling which is furnished by the Turbine Auxiliaries Cooling System. Seal water makeup

is provided by the Demineralized Water System by means of a float control valve.

Air and other noncondensable gases removed from the condensers are continuously analyzed by a radiation monitor located in the pump discharge piping prior to release into the atmosphere (See Section 11). Nonradioactive effluent is routed to the plant vent alongside each containment dome for release at an elevated point.

The vacuum pumps are of the centrifugal displacement type employing a rotating ring of water to form a seal between its elliptically shaped casing and its curved radial bladed rotor. Centrifugal force causes the water to follow the contour of the casing, thereby changing the volume of the air space at the stationary suction and discharge ports resulting in air pumping.

Each condenser vacuum pump suction line is so valved as to permit automatic changeover from a direct tie to the condenser to a tie having an air ejector which serves as the primary stage when an absolute pressure of less than 5 in. Hg absolute is realized. The air ejector uses atmospheric air as the motive fluid. The waterbox priming tank vacuum pump (No. 11/23) is a single stage pump which does not require an air ejector.

Each vacuum pump is provided with a seal water pump which circulates water to the vacuum pump for the separator tank via a seal water cooler. The cooling water for the seal water cooler is supplied by the Demineralized Water System. Seal water cooling is provided to minimize flashing of the pump seal. The sealing water temperature affects the capacity of the vacuum pump. As the temperature increases, there is a reduction in vacuum pump capacity. It is therefore essential that the cooler be kept in a clean condition on both the tube side and water side, with the total temperature difference kept at less than 15° F. The seal water heat exchanger supplied with each vacuum pump utilizes stainless steel tubes and tube sheets.

Exhausted air from each vacuum pump separating tank discharges to a common header and then to atmosphere via the plant vent. The flow is measured at the common header.

The common discharge header is provided with radiation monitoring instrumentation to alarm in the Control Room if radioactivity is sensed at the vacuum pump discharged.

10.4.3 Turbine Gland Sealing System

The Turbine Shaft Sealing System uses steam to seal the annular openings where the shaft emerges from the casings, thereby preventing steam outleakage and air inleakage along the shaft. The Turbine Gland Sealing Steam and Leakoff System is shown diagrammatically on Plant Drawing 205207.

10.4.4 Turbine Bypass System

10.4.4.1 Steam Dump Control System

The Steam Dump Control System serves to remove heat stored in the Reactor Coolant System (RCS). The full load average coolant temperature is significantly greater than the saturation temperature corresponding to the pressure setting of the steam generator safety valves. This, together with the fact that the thermal capacity of the primary system is greater than that of the steam system, requires that a heat sink be available to prevent lifting of the steam generator safety valves following a reactor turbine trip.

The Turbine Bypass System provides the capability to dump up to 40 percent of full load steam flow directly to the condenser. This enables the plant to accept a step load decrease of 50 percent of full load from full load without reactor trip (the remaining 10 percent of the 50 percent is an inherent capability of the Nuclear Steam Supply System (NSSS) to accept a 10 percent step load change). Twelve bypass valves are required (4 per condenser shell) as there is a limitation on the maximum flow permissible through any one valve of 1,100,000 lb/hr should it fail in the open position.

After a reactor turbine trip, the stored heat in the primary system is removed by the combination of steam dump to the condenser and atmospheric relief.

Should the condenser not be available as a heat sink, the steam generator safety valves and power operated relief valves (PORVs) will open to dump steam to the atmosphere. When the steam generator safety valves are reseated, the PORVs are used to remove residual heat and control steam pressure. The Auxiliary Feedwater System is used to maintain steam generator level.

The Steam Dump System also acts as a supplemental heat sink for a load reduction of up to 50-percent of rated load, including the 10-percent step load change capability of the NSSS, without a reactor trip.

Should a load drop in excess of 50 percent of full load occur, or should it be necessary to close the MSIVs with the plant under load, safety valve capacity equal to 100 percent of full load flow is provided on the piping just upstream of the MSIVs. This capacity is provided by five main steam safety valves on each main steam line with setpoints of 1070, 1100, 1110, 1120, and 1125 psig. The valves are located in the penetration area and are vented via umbrella-type vents to atmosphere through the roof of the penetration area.

Additionally, a power operated main steam relief valve (MSIO) is provided on each main steam line upstream of the MSIVs (total relief capacity for 4 valves equals 10 percent of full load flow). These valves, with a remotely variable pressure setpoint, can be used to bleed off reactor decay heat during cooldown.

10.4.4.2 System Evaluation

The atmospheric dump capacity of the steam generator safety valves is 100 percent of full load flow and the PORVs can pass an

additional 10 percent of full load flow. The number of turbine trips per year has been estimated to be 1.36, based on data from 60 plant-years of operating experience compiled by the Edison Electric Institute.

HISTORICAL NOTE

The radiological exposure values contained in this section were originally calculated in response to SNGS-FSAR Question 10.1.1.

(Historical Information)

In the event that the PORVs in the secondary system failed to open when required, secondary system pressure would increase to the setpoint of the first of the five main steam safety valves. The five safety valves are set at 1070, 1100, 1110, 1120 and 1125 psig, respectively, and have a total relief capacity of 100 percent of full load flow to the atmosphere. The radiological consequences of this discharge to the atmosphere are calculated as described below.

The maximum postulated total steam release is 3,356,100 lb (1.52×10^9 g). The postulated amount of steam released in the first two hours is 654,600 lb (2.97×10^8 g). The maximum permitted concentration of specific activity in the secondary system is 0.10 μCi/g of dose equivalent I-131. The calculated offsite exposure from the postulated release to the atmosphere of secondary coolant equivalent to the amount of steam released in the first two hours due to a net load rejection with loss of offsite power is less than 1.5 rem to the thyroid (whole body doses are negligible). This was calculated from the equation:

$$\text{Dose(rem)} = C \times M \times B(t) \times X/Q \times DCF$$

where:

C	=	secondary coolant specific activity, 0.10 μCi/g
M	=	amount of steam released in the first two hours, 2.97×10^8 g
B(t)	=	breathing rate, 3.47×10^{-4} m^3/sec
X/Q	=	atmospheric dispersion factor, 1.30×10^{-4} sec/m^3
DCF	=	1.08 rem/μCi dose equivalent I-131 inhaled

(Historical Information)

Anticipated secondary system iodine concentration is at least a factor of 10 less than the 0.10 μCi/g value used in the above calculation. Additionally, the "realistic estimate" atmospheric dispersion factor is 3.00 x 10^{-5} sec/m^3. Using the more realistic values for these parameters reduces the calculated thyroid exposure for this potential release path to less than 35 mrem.

The condenser air removal gas monitors and the steam generator blowdown liquid monitors are described in Section 11.2.3.1. These monitors can be checked for proper operation by means of a check source. The range of detection selected for these monitors is based on the anticipated range and maximum activity to be measured.

10.4.5 Circulating Water System

The Circulating Water System furnishes the main steam condenser with cooling water from the Delaware River and is shown on Plant Drawings 205209 and 205309. The Circulating Water System is a separate entity apart from the seismically designed Service Water System, which is covered in Section 9.2.

10.4.5.1 System Description

The siphon recovery Circulating Water System supplies 1,110,000 gpm of Delaware River water to each unit's triple-shell condenser. The three condenser shells are single pass with divided waterbox circulation. Each condenser shell half is

185,000 gpm and 27-foot total dynamic head (TDH). Driven by 2000 hp induction motors, the six circulators per unit are mounted in individual pump cells in the intake structure, which is common to Units 1 and 2.

The circulating water pumps are powered from their respective unit's 4160-V circulating water distribution system. Remote control of all pumps is maintained by the operator in the respective unit's control room.

The 500-foot offshore circulating water system discharge is arranged to prevent recirculation while limiting the overall temperature rise of the river to 4°F or less in the vicinity of the outlet. The system is constructed of prestressed concrete, embedded steel cylinder pipe. Subaqueous piping is employed in the portion of the discharge piping submerged in the river. The inlet velocity to the intake screen wall is 1 fps at mean low tide which is compatible with local marine life. The intake includes 2-foot wide fish escape passages immediately in front of the traveling screens. The traveling water screens extend the full length and height of the 12-bay structure.

The circulating water pumps are of the pullout-type design to operate at the lowest recorded river elevation of 81.0 feet. All electrical components associated with the intake are mounted above the highest recorded water elevation for flood protection. An 8-foot high concrete wall is provided to protect the equipment from wave runup.

A full depth heavy duty trash rack is located at the entrance to each pump cell to protect the circulating pumps and traveling screens from damage by large debris. Two mobile mechanical rakes are included to remove debris from the face of the trash racks. Refuse pits with removable bins are provided at each end of the intake structure for collecting the debris raked off of the trash rack and traveling screens for offsite disposal.

Each circulating water pump is provided with a pump "READY TO START" circuit with associated pushbutton and "READY TO START" indicating light. Prior to a pump start, the "READY TO START" pushbutton is depressed. The "READY TO START" indicating light will flash while the pump permissives are being met and go solid when the pump is ready for starting. If the waterbox is under a vacuum of > 2.5" Hg vacuum then the "READY TO START" circuit will open the pump's associated waterbox vacuum breakers allowing the waterbox to fill with air and reduce the vacuum to < 1" Hg.

After the pump is started and

brought up to design speed, the valve in the condenser discharge line is opened, the pump bypass valve is then closed and full circulating water flow is established. The circulating water circuit can be primed after the circulating pumps are put in operation. This eliminates the hydraulic surges encountered with conventional startup practices. Any entrapped air will be self-vented continuously through the water box bypass line. This will ensure that the water boxes are full for plant operation and will eliminate accumulated dissolved air which may be released under siphon conditions.

Each circulating water circuit is equipped with quick opening vacuum breaker valves designed to admit air into the circuit in the event of a circulator trip out.

The arrangement of the circulating water intakes is shown on Plant Drawing 208997. This area is served by temporary cranes, as required.

The circulating water intake contains vertical, turbine-type auxiliary service pumps which supply the traveling screen spray wash system. There are four pumps per unit, each with automatic strainers in their discharge line. Two bearing lubrication pumps and strainers provide river water to the circulating water pump bearing and motor coolers for each unit. A standby backup line from the screen wash header to the lubrication system is provided for use during emergency and/or maintenance situations.

10.4.5.2 Performance Analysis

All six circulating water pumps are normally in service. The condenser steam spaces are interconnected to permit operation with less than the full complement of circulating water pumps.

For performance analysis, the Circulating Water System is equipped with test connections to evaluate flow conditions. In addition,

the discharge pressure of each pump is monitored at the intake structure.

10.4.6 Condensate Polishing System

10.4.6.1 Design Bases

The Condensate Polishing System (CPS) was designed to perform the following functions:

1. Removes the low levels of dissolved solids present in the feedwater or secondary system and feedwater path. The CPS also acts as a high rate filter to remove suspended matter.

2. Provides the plant with a feedwater system cleanup capability. The CPS together with the Condensate Bypass System allows for the flushing of feedwater lines and recirculation back to the condenser during startup to ensure that the water quality is within specification prior to its admission to the steam generator. Heater drains may also be recycled back to the condenser to permit feedwater cleanup.

10.4.6.2 System Description

From the hotwells, condensate is directed through a full flow, high pressure, deep bed demineralizer CPS by three condensate pumps. The primary purpose of the polisher is to reduce, by ion exchange, the level of the dissolved solids in the Steam Generator Feed and Condensate System. The polishing system also filters out scale and particulate matter which may be present either as construction debris or as a result of corrosion products generated in the system. Secondary system cleaning may also be done by the Steam Generator Blowdown System, and the Condensate Polishing System may be bypassed.

The CPS is of the full flow, deep bed type and is designed to handle condensate at temperatures from 50°F to 130°F at pressures to 700 psig. Normal operating pressure will be about 475 psig.

The CPS is designed to handle a normal and a maximum continuous flow of 22,000 gpm and 24,000 gpm, respectively, with five of the six demineralizers operating in parallel.

A feedwater pH range of 8.8 - 9.6, is recommended for Salem with alternate amine chemistry (ethanolamine). While using ammonia only for pH control a range of 8.8 - 9.2 is recommended by EPRI. However, sodium levels in the feedwater become extremely critical in this pH range since sodium may be converted to sodium hydroxide. Sodium hydroxide, if carried over into the steam generators, will increase the possibility of caustic embrittlement of steel and stress corrosion cracking of Inconel components of the steam generator.

Ammonium chloride is used for Molar Ratio Control (MRC). MRC is the control of cations to anions. Sodium minimization is the primary control. Ammonium chloride injection can also be used to achieve the cation to anion balance, if sodium concentrations have been minimized, as ammonium already exists in large quantities and is volatile. The goal of MRC is to achieve near neutral crevice pH by controlling the molar ratio of cations and anions in the steam generator blowdown, thereby controlling steam generator corrosion.

When the Condensate Polishing System is in full flow operation, the operator is alerted to (partial) bypass of the CPS when valve 1(2)CN-109 is open and either valve 11(21)CN-108, 12(22)CN-108 or 13(23)CN-108 are not fully shut (valves are shown on Plant Drawings 205202 and 205302).

10.4.7 Condensate and Feedwater Systems

10.4.7.1 Main Condensate and Feedwater System

10.4.7.1.1 System Description

The Steam Generator Feedwater and Condensate System is shown on Plant Drawings 205202 and 205302. Condensate is withdrawn from the condenser hotwells through a common suction header by three motor-driven, multi-stage, vertical centrifugal condensate pumps rated at 8000 gpm and 575 psi TDH. These pumps discharge into a common header which carries the condensate into the first five stages of feedwater heating. 900 gpm comes off of this line to supply the steam generator blowdown heat exchanger. This 900 gpm comes back into the condensate header after the first feedwater heater. A low flow recirculation line is provided on the discharge of each condensate pump to maintain a minimum flow of 1800 gpm for pump protection. The vertical motors are located at an elevation above the highest recorded river water level.

Two, one-half capacity, high speed, barrel-type feed pumps take suction from a common header receiving feedwater from the discharge of the No. 5 heater. These feed pumps discharge into a common header, through the No. 6 high pressure feedwater heater and into a collecting header. Feedwater then flows through one line into the steam generator inlet header which is located outside the containment.

Feedwater enters the containment vessel through four lines penetrating the containment wall, one line feeding each steam generator. Feedwater flow control valve, motor-operated stop check valve, and isolation valves are installed in each steam generator feedwater line outside the containment. Each feedwater control valve is positioned by its own three-element control of feedwater flow to maintain steam generator level during startup and low power operation. All feedwater piping downstream from, and including, the isolating motor operated stop check valve is designed to meet Class I seismic requirements. A low flow recirculation line is provided on the discharge of each steam generator feed pump to maintain a minimum flow of 2300 gpm at design conditions for pump protection.

Each steam generator feed pump is designed for a capacity of 18,600 gpm and total developed head of 884 psi. These design conditions were based on the maximum calculated turbine load plus allowance for pump wear and steam generator blowdown.

Each steam generator feed pump is driven by a variable speed steam turbine with throttle steam supplied from the reheater outlet for normal two pump operation and from the Main Steam System during periods of low load. During startup, steam is supplied from the station heating steam system. Each steam generator feed pump turbine exhausts separately into one of the three condenser shells.

The Feedwater Heating System utilizes six stages of closed feedwater heaters. All feedwater heaters are horizontal "U" tube, one-third size units, (three strings) with each heater string capable of satisfactory operation at 150 percent of its design feedwater flow. The feedwater heaters and piping are arranged to allow balanced turbine operation resulting from forced load limitation due to heater system outages. Bleed steam is provided from the following sources:

Heater No.	Extraction Source
6	High-pressure (HP) turbine bleed
5	HP turbine exhaust
4	Low-pressure (LP) turbine bleed
3	LP turbine bleed
2	LP turbine bleed
1	LP turbine bleed

Drains from heaters No. 5 & 6 go to the drain tanks. Three heater drain pumps take suction from the drain tanks and discharge to the feed pump suction. Drains from the four LP heaters cascade in sequence to the condenser. The Bleed Steam and Heater Drains System is shown on Plant Drawings 205205 and 205305.

Design parameters of equipment in the Main Condensate and Feedwater System are listed in Table 10.4-1. The design codes for the Safety Related portion of the feedwater piping are ANSI B31.1.0 (1967) (see also Section 3.6.5.3). The design codes for the Non-Safety Related portion of the feedwater piping are ANSI B31.1.0 (1967) and later editions of B31.1 and alternate ASME codes/code cases. The design code for the condensate system is as defined in Reference 7 utilizing reduced ANSI B31.1.0 (1967) code allowables. Feedwater piping fabrication, installation welding, and examination involved in installing the Unit 2 replacement Steam Generators utilized ASME Section XI (1998 Edition with 2000 Addenda) and ASME Section III, Subsection NC (1995 Edition with 1996 Addenda). Both of these later codes are NRC-endorsed per 10CFR50.55a and were reconciled to the original construction codes.

The possible effects of a postulated rupture of a feedwater line have been minimized by judicious pipe routing and adequate pipe whip restraint.

To ensure their integrity, the main and auxiliary feedwater lines inside the containment (out to their respective isolation valves) were constructed with materials, fabrication, inspection, and quality control in accordance with Nuclear Class 1 standards.

Group bus undervoltage protection (68 percent of nominal) will automatically trip the condensate pump 4-kV breaker upon sensing an undervoltage (i.e., loss of voltage) condition on its respective 4-kV group bus (1E, 1F, 1G, and 1H) using 1/1 logic taken once.

10.4.7.1.2 Feedwater Piping Integrity

Unit 2 only

The AREVA NP Model 61/19T steam generator feedwater distribution system (shown in Figures 10.4-7 and 10.4-8) is a split ring design connected via a T-section to a "helix" assembly welded to the thermal sleeve in the feedwater piping. The feedwater ring is supported by the thermal sleeve/helix weld interface and by sliding supports around the ring circumference attached to the internals. The ring supports are vertical structures that restrain motion in the vertical direction, while allowing thermal growth in the horizontal plane. This design provides a support system that accommodates thermal motions and pump pressure pulses as well as all operational, seismic, and pipe break loads.

The J-tube discharge is oriented to preclude direct impingement of feedwater on internal surfaces. This reduces the possibility of erosion. (J-tube arrangement is shown in Figures 10.4-7 and 10.4-8). Feedwater distribution system materials are selected to optimize resistance to erosion/corrosion, thermal fatigue, and corrosion cracking. The austenitic stainless steel used for all the internal feedwater distribution system provides erosion resistance. Feedwater is distributed 50 percent to the cold side and 50 percent to the hot side.

The Model 61/19T steam generator incorporates a "helix" between the feedwater pipe and feedring (Figures 10.4-7) to minimize the potential for thermal stratification. The helix allows the upstream part of the feedwater piping to rapidly fill even during feeding with cold feedwater at low flow. This reduces temperature distributions and stresses in the pipe wall. The feedwater distribution design, equipped with the helix, minimizes the risk of thermal stratification damage. The helix also helps to minimize blowdown during a feedwater line break.

The design of the Salem Unit 2 RSGs feedwater distribution system (J-tubes, all welded thermal sleeve/ring assembly and anti-stratification device) fully satisfies the design recommendations provided in BTP ASB 10.2. The Water Hammer Prevention Report, Reference 10, justifies that water hammer is not expected to occur inside the feedwater distribution system of the Salem Unit2 RSG during anticipated feedwater transients to the steam generator. This conclusion is confirmed by (1) mock-up tests representing or bounding all plant operational modes, (2) review of the limiting operational and design transients such as LOFW, (3) AREVA NP on-site tests and operating experience, and (4) previous specific tests for water hammer performed at Unit 2.

Feedring and J-Nozzle Modifications - (Unit 1 only)

The Model-F steam generators were designated for service at Seabrook Unit 2 originally. The steam generators were originally furnished with a carbon steel feedring and carbon steel J-nozzles installed on the top of the feedring. Service at Salem and other stations has shown that the carbon steel J-nozzles are subject to accelerated erosion and corrosion.

Design changes have been made and were implemented before the four steam generators were removed from the Seabrook site. The carbon steel J-nozzles were removed by mechanical machining operations, and new J-nozzle assemblies, similar to Unit 2, welded in place. The new J-nozzle design in made of Inconel with a transition sleeve of carbon steel that is shop welded and examined to assure the integrity of the dissimilar weld. The inlet side of the carbon steel transition sleeve is buttered with Inconel to reduce the potential of erosion. The new J-nozzle assemblies are re-installed by welding the carbon steel sleeve to the carbon steel feedring.

In normal operation, the feedring is filled with water. When this condition exists, there is no mechanism for initiation of water hammer. With the J-nozzles on top, the large vented area makes it very difficult to trap a bubble of steam in the feedring. Also, with the J-nozzles on top, the feedring fills first, and any refilling or recovering will not cause depressurization inside the feedring. Therefore, with the new J-nozzle installation, there are no expected operating occurrences that would allow steam to become trapped in the feedring and feedwater piping following a drop in steam generator water level below the feedring.

The feedring configuration is shown in Figure 10.4-8a. This is a typical arrangement and each steam generator has a slightly different arrangement of J-tubes. Isometric diagrams of feedwater piping to the Salem Unit 1 steam generators are shown in figures 10.4-9 through 10.4-12.

Feedwater Pipe Cracking

Circumferential cracks were found in Unit 1 feedwater piping as a result of inspections pursuant to I and E Bulletin 79-13. These cracks were evaluated by the Westinghouse Research Center where the cause was attributed to cyclic stress assisted or accompanied by corrosion. The detailed evaluation of this matter, including corrective action taken, is contained in a report transmitted

to the NRC by letter dated August 24, 1979. Action on Unit 2 is being taken as outlined in a letter dated September 18, 1979.

The Unit 1 modifications to address the feedwater pipe cracking involved a replacement of the reducers adjacent to the nozzles. These replacements were performed with essentially a replacement-in-kind approach. Subsequent inspections of the Unit 1 feedwater piping and steam generator feedwater nozzle thermal sleeves identified additional cracking at piping welds and flaw indications on the thermal sleeves. This cracking has been attributed to cyclic stresses resulting from stratification loads due to cold feedwater injection into hot steam generators. The Unit 2 modifications to address the feedwater pipe cracking involved a replacement of two of the four reducers adjacent to the nozzles. These replacements were also performed with essentially a replacement-in-kind approach. This cracking, like Unit 1, has also been attributed to cyclic stresses resulting from stratification loads due to cold feedwater injection into hot steam generators. During the Unit 2 Steam Generator replacement, all removed piping and fittings, including the one piece flued forgings, were replaced with erosion/corrosion resistant pipe and fittings. Enhancements were made to the Unit 2 replacement steam generators to mitigate thermal stratification. As described in Section 3.6.5.3, one piece flued forging pieces have been attached to the Unit 1 steam generator feedwater nozzles to minimize the potential for thermal fatigue cracking concerns at the nozzle and inlet pipe locations. The one piece design replaces the various fitting and fitting welds on the inlet piping thus eliminating the welds in the stratification zone. These forging pieces have integral thermal sleeves and are constructed of erosion/corrosion resistant materials to minimize the effects of erosion/corrosion on the existing steam generator thermal sleeves.

The circumferential location of the feedwater nozzles for the replacement Unit 1 steam generators differs by approximately 90□. from the original design. The feedwater piping in the vicinity of the steam generators was rerouted to accommodate the new locations considering existing structural interferences and thermal stratification. There is no significant change to the likelihood of thermal stratification with the revised piping layout.

10.4.7.2 Auxiliary Feedwater System

10.4.7.2.1 Design Basis

The AFW System serves as a backup system for supplying feedwater to secondary side of the steam generators at times when the Main Feedwater System is not available. The AFW System is relied upon to prevent core damage and system overpressurization in the event of accidents such as a loss of normal feedwater or a secondary system pipe rupture, and to provide a means for plant cooldown.

The AFW System is capable of functioning for extended periods, allowing time either to restore normal feedwater flow or to proceed with an orderly cooldown of the plant to design temperature of the Residual Heat Removal (RHR) System. The AFW System flow and the water supply capacity is sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant cooldown.

Provisions are made to limit or terminate auxiliary feedwater flow to the affected loop 1) in the case of feedwater line break to ensure adequate flow to the effective steam generators and 2) in the case of a steam line break inside containment, to also limit the containment pressure.

Plant conditions which form the basis for AFW System performance requirements are the following:

1. Loss of main feedwater transient (with and without offsite power)

2. Feedline rupture

3. Steamline rupture

4. Loss of all ac power

5. Loss-of-coolant accident (LOCA)

6. Plant cooldown

10.4.7.2.2 System Description

The AFW System, shown on Plant Drawings 205236 and 205336, supplies water to the steam generators for reactor decay heat removal if the normal feedwater sources are unavailable due to loss of outside power or other malfunction. Each unit is equipped with one turbine-driven and two motor-driven auxiliary feed pumps. Steam for the

turbine-driven pump is taken from two of the four main steam lines upstream of the MSIVs. Separate isolation valves are provided for these connections. The motor driven pumps receive power from the 4 KV vital buses. The Auxiliary Feedwater System is designed as a Class 1E Safety Grade System.

The turbine-driven auxiliary feed pump, nominally rated at 880 gpm (plus 100 gpm continuous recirculation flow) and 1550 psid at 3840 rpm, and the motor-driven auxiliary feed pumps, nominally rated at 440 gpm and 1300 psid*, receive suction from the 220,000-gallon auxiliary feedwater storage tank.

The minimum performance limits required for the auxiliary feedwater pumps to satisfy the design bases analyses, as verified during Technical Specification Inservice Testing, are included below. Note that these values account for test instrumentation uncertainties.

- 11 motor-driven AFWP   160 gpm and 1361 psid
- 12 motor-driven AFWP   160 gpm and 1361 psid
- 13 turbine-driven AFWP   400 gpm and 1395 psid at 3450 rpm
- 21 motor-driven AFWP   160 gpm and 1369 psid
- 22 motor-driven AFWP   160 gpm and 1389 psid
- 23 turbine-driven AFWP   400 gpm and 1506 psid at 3600 rpm

Each motor-driven pump discharges to two steam generators with a normally isolated cross-connect line joining the motor-driven pump discharge headers. The turbine-driven pump feeds all four steam generators. Feedwater flow is controlled from the Control Room by remotely operated flow control valves in the supply lines to each steam generator. For Units 1 and 2, reduced capacity trim has been installed on all eight flow control valves (AF11 and AF21) to limit the maximum flow under certain plant conditions. Safety grade indication of auxiliary feedwater flow to each steam generator is provided in the Control Room.

The AFW System circuits and initiation signals receive power from unit vital buses. System initiation signals and circuits are designed for complete testing.

The AFW pumps are capable of being started in either the manual or automatic mode. Manually, the pumps can be started at their local control panel or from the main Control Room. Manual start circuits are designed for single failure, and failure of the automatic initiation signals or circuits will not affect the capability for manual starting.

Automatic initiation signals and circuits are designed to prevent system malfunction for a single failure.

* No. 22 motor driven auxiliary feedwater pump rated at 450 gpm and 1175 psi.

The motor-driven auxiliary feedwater pumps are started automatically by any of the following conditions: loss of offsite power, loss of main feedwater system, safeguards sequence signal, or low-low level signal from any one steam generator.

When either of these pumps are started automatically, a signal is sent to close Steam Generator Blowdown and Sampling Systems' isolation valves. The isolation signal to the Sampling System isolation valves can be bypassed by the use of a keylock switch located on the control room console. This bypass capability allows control room operators to open the Sampling System isolation valves when sampling is required by the EOPs in the event that a faulted steam generator with a low-low level condition is experienced.

For the pumps to start in automatic mode, the REMOTE-LOCAL MANUAL switch located on the local panel must be in the REMOTE position.

The motor-driven auxiliary feedwater pumps are among the loads included in the diesel generator's automatic loading sequence.

The turbine-driven auxiliary feedpump is started automatically by any of the following conditions: low-low level in two of the four steam generators or undervoltage on the reactor coolant pump group buses using 1/2 twice logic. For the pump to start in the automatic mode, the REMOTE-LOCAL MANUAL switch located on the local panel must be in the REMOTE position.

When the turbine-driven pump is started automatically, Steam Generator Blowdown System valves and Sampling System valves are automatically closed. The isolation signal to the Sampling System isolation valves can be bypassed by the use of a keylock switch located on the control room console. This bypass capability allows control room operators to open the Sampling System isolation valves when sampling is required by the EOPs in the event that a faulted steam generator with a low-low level condition is experienced.

The steam supply line up to the stop-start valve is continuously warmed by main steam. Traps and/or strainers/orifices are provided to ensure that condensate is removed from turbine steam piping. The turbine is a single inlet, single stage unit of rugged design such that water impingement will not impair its operation.

Each of the two motor-driven pumps is provided with a minimum flow recirculation system to prevent damage to the pumps from low flow. In order to prevent a runout of the motor-driven pumps the steam generator level control valves (AF21s) are throttled back when pump discharge pressure drops below 1350 psig and are closed at

1150 psig*. This runout protection feature can be overridden in the Control Room. The steam turbine driven pump is protected from operation with insufficient flow by a continuous recirculation flow. The required margin of 100 gpm is built into the pump rated flow.

All auxiliary feed pumps normally take suction from the auxiliary feed storage tank. The tank is adequately protected from the effects of earthquakes, tornado wind loads, and floods. A safety grade, automatic low pressure trip is provided as backup protection for each pump in the event that tornado missile damage to the auxiliary feedwater storage tank results in loss of suction pressure. To protect against spurious activation, this trip will be made operable only during "tornado warnings" issued by the National Weather Service. The tank has sufficient capacity to allow residual heat removal for 8 hours. Backup water sources for the auxiliary feed pumps are the two demineralized water storage tanks (500,000 gallons capacity each), the two fire protection and domestic water storage tanks (350,000 gallons capacity each) and the station Service Water System, which must first have a spectacle flange rotated into place. The quality of water from these sources is lower and is therefore intended for use only in the event of emergency situations. See Section 10.4.7.2.4 for an evaluation of service water usage in the AFW System.

The Unit 1 & Unit 2 auxiliary feedwater storage tanks are provided with a nitrogen purge/blanket system in order to control the dissolved oxygen concentration in the water. Each nitrogen purge/blanket system is provided with a dedicated nitrogen source.

The AFW tank has low and low-low level alarms which alert the operator to align pump suction to an alternate source. An alarm is also received when AFW Storage Tank level is approaching the minimum required volume by the Technical Specifications. Plant emergency instructions caution the operator to monitor the AFW water supply while in use. The low level alarm sounds at a level of 100,000 gallons and the low-low level alarm sounds at 30,000 gallons. The AFW tank has redundant channels of level indication. In addition, the demineralized water makeup

* Setpoints for the control valves for No. 22 motor driven pump (Valves 21 & 22AF21) are 1200 psig and 1000 psig, respectively. For No. 21 motor driven pump (Valves 23AF21 & 24AF21) setpoints are 1285 and 1085, respectively.

supply valve to the AFW storage tank can be opened from the Control Room. In order to provide assurance that inadvertent failure (or closure) of the suction valve from the AFW storage tank will not result in a degraded condition of the AFW System, the valve was first radiographed to ensure an open flow path and the yoke bushing and stem were then drilled and pinned in the open position. The handwheel was removed with the valve stem left in place to provide visual indication that the valve is open.

There is adequate redundancy in the AFW System to provide reactor cooldown capability when necessary. During normal plant cooldown, each pump has the capacity to remove heat from the steam generators at a sufficient rate to prevent over-pressurization of the RCS and to maintain steam generator levels to prevent thermal cycling. Once the normal steam generator level is re-established the AFW System can cool down the RCS at a rate of 50°F/hr. Feedwater flow can be stopped when the reactor coolant has been cooled to approximately 350°F and 400 psig at which time the RHR System is used to continue the cooldown process. For mitigation of a design basis event (small break LOCA, loss-of-offsite-power, loss of normal feedwater, feedwater line break, main steam line break), two pumps are required.

The pumps, drives, valves, tanks, piping and appurtenances within the AFW System have been designed as Seismic Category I components.

The AFW System piping and components are designed to the following codes and standards:

Aux. Feed System Piping	ANSI B31.1*
Aux. Feed Storage Tank	ASME Section III, sub-section N.D.
Aux. Feed Pump (except No 22 Aux Feed Pump)	ASME Section III
No. 22 Aux. Feed Pump	Hydraulic Institute
Aux. Feed System Valves	ASME Section III

*The Aux. Feed System piping is designed to ANSI B31.1; material fabrication, inspections, and quality control conform to ANSI B31.7, 1969 Edition. Where not possible to comply to ANSI B31.7, the requirements of ASME III-1973 which incorporated ANSI B31.7, were adhered to. Additionally, to upgrade material to original plant requirements, additional NDE requirements will be imposed to meet PSE&G piping specification S-C-MPOO-MGS-0001, addendum XVI.

At the AFW System seismic boundary, valves AF-71 and AF-72 are not anchored with three orthogonal restraints. These valves are, however, anchored to the Seismic Category I Auxiliary Building wall. A stress review has shown that the anchors meet the intent of the system boundary definition given in NRC Generic Letter 81-14. In addition, the valves are protected from debris by a steel protective structure mounted to the Seismic Category I wall. This protective structure also provides seismic guides for additional protection of the seismic boundary valves.

The AFW System is periodically tested in accordance with the Technical Specifications.

10.4.7.2.3 System Evaluation

Detailed thermal-hydraulic analyses have been conducted to verify that the AFW system design is adequate to meet design objectives. The results of these analyses satisfy the AFW flow requirements included in the Chapter 15 analyses, as summarized in References 1, 2 and 8. The single failure analysis, which is summarized in Table 10.4-2, verified that the flow required to meet system performance objectives will be delivered with two pumps, considering a single failure of a pump. The AFW System has also been shown to deliver adequate flow to the two intact steam generators following a rupture in the steam line to the turbine pump and assuming the failure of a single motor-driven pump. In addition, the AFW flow rates are sufficiently small to avoid overpressurizing the containment following a steam line or feedwater line break.

10.4.7.2.4 Potential Effects of Salt Water as a Long-Term Source of Auxiliary Feedwater

Assumptions

The use of service water for a long-term makeup source to the AFW System is evaluated based on the scenario described in Section 5.5 (in response to Branch Technical Position RSB 5-1) and on the following assumptions:

1. Following plant trip and loss of offsite power, auxiliary feedwater is initially provided from the 220,000 gallon AFW storage tank (AFST). When the supply of water in the AFST has been depleted, AFW pump suction is transferred to the Service Water System (SWS).

2. River water has a total dissolved solid (TDS) value of 35,000 ppm as sodium chloride.

3. Decay heat removal is achieved using three of the four steam generators and the normal working level is maintained throughout the major part of the scenario.

4. Following the loss of offsite power the unit is held at the hot standby for 43 hours at which time cooldown is initiated. After 5 hours of cooldown, the RHR System is placed in operation.

Salt Water Concentration

Approximately 600,000 gallons of water are required to maintain the plant at the no load condition for 43 hours followed by a 5-hour cooldown to 350°F. Thus the salt water requirement during this period is 600,000 gallons minus 220,000 gallons or 380,000 gallons for Unit 1. Unit 2 was based on 410,000 gallons, which includes 30,000 of additional volume for conservatism.

Based upon the assumption that this salt water will contain 35,000 ppm TDS as sodium chloride, then the weight of salt introduced into the three available steam generators will be 51 tons for Unit 1 and 61.2 tons for Unit 2. At 350°F, the three Unit 1 steam generators will contain 259 tons of water and the concentration of salt in the steam generator water will be 0.2 t/t. At 350°F, the three Unit 2 steam generators will contain 259.3 tons of water and the concentration of salt in the steam generator water will be 0.236 t/t.

From standard solubility tables, and using the same notation as above, the solubility of sodium chloride at room temperature is 0.36 t/t, increasing to 0.58 t/t at the no load temperature.

Degradation of Heat Transfer due to Salt Plate-out

Salt water would be first admitted to the steam generators 12 hours after the loss of offsite power. By this time the thermal flux at the steam generator tube wall will be relatively low, and there will be no tendency to hide out normally soluble ionic species. It is anticipated that steam release from the PORVs will tend to be increasingly intermittent as decay heat decreases. Thus, the net effect would be similar to bulk boiling, rather than the superheat-driven mode of boiling normally associated with steam generation for power production purposes.

In addition, the concentration of salt in the bulk steam generator water is well below the solubility limit of sodium chloride throughout the range of temperatures encountered.

Therefore, no decrease in heat transfer capability due to the deposition of salt on the steam generator tube surfaces is expected for either Unit 1 or Unit 2 steam generators.

Clogging of Steam Generator Flow Paths by Salt Accumulation

For both Unit 1 and Unit 2, the concentration and solubility of sodium chloride indicate that the internals of the steam generator totally immersed in the bulk liquid phase would not be subject to salt precipitation and clogging. Similar consideration of the steel surfaces at the water/steam interface suggests that although some salt deposition is likely, the deposition will not be at a fixed boundary because of level changes caused by intermittent steam release via the PORVs. In addition, any rewetting will be carried out with water which has considerable salt solubilization capability. It is therefore unlikely that salt bridging will occur at the water/steam interface. Zones above this interface are not expected to become clogged with salt, since the evaporation purified the solvent phase. Thus any salt carried upward by liquid phase entrainment should be washed back down into the bulk liquid by relatively pure water (condensed steam).

Corrosion Effects of Salt

The corrosion of carbon steels in hot concentrated sodium chloride solutions is controlled by the metal alloying constituents, solution flow rate, oxygen concentration, temperature, and solution pH. Literature values for carbon steel corrosion rates at steam generator operating temperatures vary from 0.012 inch/week (3) to 0.21 inch/ week (4). Tests carried out on ASTM SA 285 Grade C steel show that a corrosion rate of approximately 0.015 inch/week can be expected when this material is exposed to concentrated sea water at 540°F (5). Based upon these data, some corrosion must be expected for carbon steels present in the steam generator due to the hot concentrated sea water. The condition of these carbon steel internals under hot standby conditions does not compromise the integrity of the primary to secondary steam generator boundary during normal power operation.

The materials of the tube support plates and anti-vibration support systems for both the Unit 1 and Unit 2 steam generators are stainless steel or Inconel. Calculation of general corrosion rates of stainless steel materials, based on a 58% NaCl solution at steam generator operating temperatures, vary from 0.0002 inch/week to 0.0413 inch/week (9). Therefore, for 36 hours exposure, the general corrosion would be 0.0089 inch. For longer exposure periods, the material most affected by the NaCl solution is 304L stainless steel, which is used for the Unit 2 RSG cyclones and dryer vanes and would be subject to potential pitting. However, due to the base material thickness of these components, there is no concern for the integrity of the cyclones and dryer vanes, i.e., to have any structurally significant changes.

Data generated in single tube model boiler tests performed by Westinghouse indicate that Inconel 600 will pit at about 0.005 inch/week in hot concentrated sea water environments. Corroborative information of this behavior is contained in Reference 6. Nominal tube wall thickness in the Salem steam generators is 0.050 inch. Thus only shallow tube wall penetration should be anticipated as a result of 36 hours of operation at hot standby with concentrated sea water in the steam generators. No perforation of tube wall is anticipated.

Corrosion data generated for Inconel 690 indicates that it can also experience pitting at a conservative rate of 0.0002 inch/week in hot concentrated sea water environments (9). The nominal tube wall thickness in the Salem Unit 2 replacement steam generators is 0.043 inch and in 36 hrs the maximum pitting depth is considered to be 4.3×10^{-5} inch.

Thus, only shallow tube wall penetration should be anticipated as a result of 36 hours of operation at the postulated conditions with concentrated sea water. Like Inconel 600, no perforation of tube wall is anticipated.

Conclusion

Both primary circuit integrity and heat removal capability would be maintained and no provisions are necessary to attenuate the effects of service water addition to the steam generators.

10.4.7.3 Non Safety-Related Mitigating Safety Performance Index Auxiliary Feedwater System

10.4.7.3.1 System Description

The Non Safety-Related (NSR) Mitigating Safety Performance Index (MSPI) AFW System supplies water to the steam generators for reactor decay heat removal if the normal feedwater sources, and safety-related AFW sources, are unavailable, possibly during a Station Blackout. This system consists of one diesel generator as well as one motor-driven auxiliary feed pump. This single diesel generator and motor-driven auxiliary feed pump is configured to supply either Salem Units 1 or 2.

This NSR MSPI AFW system is manually started and operated. The remote start panel for both the diesel generator and motor-driven pump are located on Elevation 120’ within the Unit 1 Turbine Generator Area.

The NSR MSPI AFW motor-driven pump takes suction from the demineralized water storage tanks (500,000 capacity each).

The pumps, drives, valves, tanks, piping and appurtenances within the NSR MSPI AFW System have been designed as Seismic Category III components.

10.4.8 Steam Generator Blowdown System

10.4.8.1 Design Basis

The Steam Generator Blowdown System is designed to be operable in all normal operating modes. During periods of primary to secondary leakage, operation is controlled to ensure compliance with effluent regulations. To accomplish this, three possible blowdown paths are provided: (1) a blowdown path which utilizes a conventional blowdown system that discharges the effluent to the chemical waste basin for neutralization and disposal; (2) a blowdown path which utilizes a flash tank, a heat exchanger, a filter, a demineralizer, and then to the condenser; and (3) a blowdown path which discharges the blowdown to condenser. Operating conditions dictate which path should be used.

10.4.8.2 System Design and Operation

The system flow diagram and operational logic are shown on Plant Drawings 205225 and 205325 and Figure 10.4-19, respectively.

Operation of the Blowdown System is initiated remotely from the Control Room. The blowdown rate of each steam generator is indicated on and controlled from the main console.

During startup (as well as up to 20 percent power, if required) the blowdown is directed to the No. 12 (22) steam generator blowdown tank. As soon as possible once the unit is online, the blowdown is transferred to the No. 12 (22) condenser.

When blowdown is directed to the steam generator blowdown tank, a portion of the water, which is at saturated conditions, flashes to steam. The steam is vented to the atmosphere through a rooftop vent and the remaining water is gravity drained to the chemical waste basin. The water is treated and then discharged to the Delaware River through the Circulating Water System discharge lines. It is anticipated that this blowdown path will only be used intermittently at those times when the condenser is not available. When the blowdown is directed through the heat recovery system, the water passes through a flash tank, a heat exchanger, a filter (in which the iron particles, suspended in solution by polyacrylic acid are removed), a demineralizer, and then enters the condenser. A portion of the blowdown flashes to steam in the flash tank and is vented to the feedwater heaters 4. The liquid from the tank transfers its heat to the portion of the condensate that bypasses feedwater heater number 1.

If a steam generator should develop a primary to secondary leak in excess of the radiation monitor setpoint while the Blowdown System is discharging to the condenser No. 12(22), 13(23) or the chemical waste basin, high radiation signal from any of the blowdown sample radiation monitors will close the isolation valves and terminate blowdown.

10.4.8.3 Design Evaluation

If a steam generator should develop a primary to secondary leak while the blowdown system is discharging to the condenser or the chemical waste basin, the blowdown radiation monitor will alarm. The radiological warning, alarm and isolation functions of the steam generator blowdown system are described in section 11.4. Steam generator water chemistry will be monitored to ensure chemistry conditions are maintained as described in section 10.3.5.2.

Blowdown and sampling line piping fabrication, installation, welding, and examination involved in installing the Unit 2 Replacement Steam Generators utilized ASME Section XI (1998 Edition with 2000 Addenda) and ASME BPVC, Section III, Division I, Subsection NC, (1995 Edition with 1996 Addenda). Both of these later codes are NRC endorsed per 10 CFR 50.55a and were reconciled to the original construction codes.

10.4.9 References for Section 10.4

1. E.S. Rosenfeld to J.R. Gasperini, "Salem Units 1 and 2, Final Definition of AFW Flow Assumptions To Be Used In Fuel Upgrade/Margin Recovery Project and Steam Line Break Analyses," NFU-93-083, February 11, 1993.

2. E.S. Rosenfeld to J. Huckabee, "Salem Units 1 and 2, Steam Line Break Analyses Assumptions," NFU-93-303, May 28, 1993.

3. Potter and Tease, Corrosion Science Vol. 12, No. 4, April 1972.

4. Huijbregts, W. M., VGB Speiswassertagung 1970.

5. Wootton, M. J., Westinghouse Class 2 Research Report 77-IB6-DENTS-R1.

6. Roberts, D. J., et al., AEC Research and Development Report GA-9299.

7. PSE&G Report S-C-CN-MEE-1073, "Condensate System Design Pressure Reconciliation," Revision 1.

8. Nuclear Fuels Letter NFS-00-264, “Salem Units 1 and 2 – Reduced AFW Flow Evaluation”, dated 12/12/00.

9. VTD 900031, AREVA NP Document No. 12-9018620-002, “Salem Unit 2 – Effect of Seawater Intrusion on Salem 2 RSG Corrosion.”

10. VTD 900175, AREVA NP SAS Document No. NFPMG DC 0019 Revision C, “Salem Unit 2 RSG – Water Hammer Prevention (ASB-BTP 10-2).”

TABLE 10.4-1

MAIN CONDENSATE AND FEEDWATER SYSTEM COMPONENTS

<u>Condensate Pumps</u>	
Number of pumps	3
Design Capacity of each	8,000 gpm at 1,328 feet (575 psi)
Manufacturer	Ingersoll-Rand
Size and Type	32 APKD 9 stage vertical
Speed	1,170 rpm
Motor Size	4,000 hp
Shutoff Pressure	693 psig
<u>Condensate Pump Motors</u>	
Quantity	3
Manufacturer	Electric Machinery Co.
Horsepower	4,000
Current	498 amps
Voltage	4,160 V
Speed	1,190 rpm
Hertz	60
Upper BRG Cooling Water	13 gpm
Space Heater	2 kW 240 V (for storage only)
<u>Steam Generator Feed Pumps</u>	
Number of Pumps	2
Design Capacity of each	18,613 gpm and 2,320 feet (884 psi) at 370°F
Manufacturer	Worthington
Size and Type	24 WGID-171 single stage Horizontal centrifugal
Number of Stages	1
Speed	5530
Maximum Discharge Pressure limited by trip for high discharge pressure	1,620 psig
<u>Steam Generator Feed Pump Turbines</u>	
Number of Drive Turbines	2
Rating	10,970 hp at 5530 rpm
Manufacturer	DeLaval
Number of Stages	9-double flow exhaust
Exhaust Pressure	2.0 inches hg. abs.
<u>Feedwater Heaters</u>	
<u>First Stage Feedwater Heaters</u> (Except 11C, 21A, 21B & 21C)	
Number of Shells	3
Flow Rate per Shell	3,792,475 lb/hr
Temperature, In	92.6°F
Temperature, Out	164°F
Flow is directed through tube side of exchanger	
Number of Passes	2
Pressure Drop	12 psi
Design Pressure	700 psig
Tube Channel Material	A-515-70

TABLE 10.4-1 (Cont)

Tubes:		
Material	304 SS A-249	
Number	1659	
O.D.	5/8 in.	
Gauge	0.035 Ave Wall	
Length	43 feet 0 in.	

<u>First Stage Feedwater Heater -11C, 21A, 21B & 21C</u>		
Number of Shells	3	1 (21B)
Flow Rate per Shell	3,792,475 lb/hr	
Temperature, In	92.6°F	
Temperature, Out	164°F	
Flow is directed through tube side of exchanger		
Number of Passes	2	
Pressure Drop	12 psi	
Design Pressure	800 psig	
Tube Channel Material	A-516-70	
Tubes:		
Material	304 SS SA-688	
Number	1570	
O.D.	5/8 in.	
Gauge	0.035 Ave Wall	
Length	41 feet 3-5/8 in. 41 feet 4 in. (21B)	

<u>Second Stage Feedwater Heaters</u>	<u>Unit 1</u>	<u>Unit 2</u>
Number of Shells	3	3
Flow Rate per Shell	3,548,026 lb/hr	3,792,475 lb/hr
Temperature, In	168.3°F	164°F
Temperature, Out	202.8°F	202°F
Number of Passes	2	2
Pressure Drop	19 psi	18.3 psi
Design Pressure	700 psig	800 psig
Tube Channel Material	A-515-70	A-516-70
Tubes:		
Material	304 S.S. A-249	304 S.S. SA-688
Number	1,119	1,090
O.D.	5/8 in.	5/8 in.
Gauge	0.035 Ave Wal1	0.035 Ave Wal1
Length	37 feet 11 in.	36 feet 7 in.

<u>Third Stage Feedwater Heaters</u>	<u>Unit 1</u>	<u>Unit 2</u>
Number of Shells	3	3
Flow Rate per Shell	3,792,475 1b/hr	3,611,136 lb/hr
Temperature, In	202.0°F	202°F
Temperature, Out	256.7°F	251.2°F
Flow is directed through tube side of exchanger		
Number of Tube Passes	2	2
Pressure Drop	12.8	13.5
Design Pressure	800 psig	800 psi
Tube Channel Material	SA-516-70	SA-516-70

Tubes:	Unit 1	Unit 2
Material	SA-688-TP304/304L w/Max 0.035%	SA-688-TP316L
Number	851 (includes 2 spares)	840
O.D.	3/4 in.	3/4 in.
Gauge	0.035 Avg Wall	0.035 in. Avg. Wall
Length	41 feet 11 inches	43 feet 8 inches

Fourth Stage Feedwater Heaters	Unit 1	Unit 2
Number of Shells	3	3
Flow Rate per Shell	3,548,026 lb/hr	3,611,136 lb/hr.
Temperature, In	253.5°F	251.2°F
Temperature, Out	307.2°F	303.7°F
Flow is directed through tube side of exchanger		
Number of Tube Passes	2	2
Pressure Drop	16.0 psig	17 psig
Design Pressure	700 psig	800 psig
Tube Channel Material	A-515-70	SA-516-70
Tubes:		
Material	304 SS A-249	SA688 TP 316L
Number	782	726
O.D.	3/4 in.	3/4 in.
Gauge	0.035 Ave Wall	0.035 Avg. Wall
Length	43 feet 3 inches	43 feet 11 inches

Fifth Stage Feedwater Heaters	Unit 1	Unit 2 (25B, 25C)
Number of Shells	3	2
Flow Rate per Shell	3,548,026 1b/hr	3,792,475 lb/hr
Temperature, In	307.2°F	309.3°F
Temperature, Out	365°F	369.4°F
Flow is directed through tube side of Exchanger		
Number of Tube Passes	2	2
Pressure Drop	13.6 psig	13.5 psig
Design Pressure	700 psig	800 psig
Tube Channel Material	A-515-70	SA 516-70
Tubes:		
Material	304 SS A-249	SA688-TP304/304L w/Max 0.035% C
Number	845	789
O.D.	3/4 in.	3/4 in.
Gauge	0.035 Ave Wall	0.035 Ave Wall
Length	43 feet 7 inches	42 feet 4 inches

TABLE 10.4-1 (Cont)

Fifth Stage Feedwater Heaters		Unit 2 (25A)
Number of Shells		1
Flow Rate per Shell		3,792,475 lb/hr
Temperature, In		309.3°F
Temperature, Out		369.4°F
Flow is directed through tube side of Exchanger		
Number of Tube Passes		2
Pressure Drop		13.5 psig
Design Pressure		800 psig
Tube Channel Material		A-515-70
Tubes:		
Material		SA-688 Type 304
Number		789
O.D.		3/4 in.
Gauge		0.035 Ave Wall
Length		42 feet 4 inches

Sixth Stage Feedwater Heaters	Unit 1	Unit 2
Number of Shells	3	3
Flow Rate per Shell	4,995,701 lb/hr	4,982,149 lb/hr
Temperature, In	368.1°F	368.5°F
Temperature, Out	427.5°F	427°F
Flow is directed through tube side of exchanger		
Number of Tube Passes	2	2
Pressure Drop	20.7 psig	20.7 psig
Design Pressure	2100 psig	2100 psig
Tube Channel Material	A-516-70 FB	A-516-70 FB
Tubes:		
Material304	SS A-249304	SS A-249
Number	1805	1805
O.D.	3/8 in.	3/8 in.
Gauge	0.055 Ave Wall	0.055 Ave Wall
Length	39 feet 2 in.	39 feet 2 in.

TABLE 10.4-2

TOTAL AUXILIARY FEEDWATER FLOW

Transient Scenario (1)	No Single Failure In AFW System	Failure of Turbine AFW Pump	Failure of 1 Motor AFW Pump
Loss of Main FW	≥1600 gpm (2)	≥700 gpm (2)	≥1120 gpm (2)
Loss of Offsite Power	≥1600 gpm (2)	≥700 gpm (2)	≥1120 gpm (2)
Plant Cooldown	≥1600 gpm (2)	≥880 gpm (2)	≥1120 gpm (2)

NOTES:

1. AFW flows during steam line break transients (both inside and outside Containment) and feed line break transients vary considerably during the event and are summarized in Reference 2 but not included in this table.

2. Flows represent bounding values for steam generator pressures of 1117 PSIA or less.

TABLE 10.4-3

ASSUMPTIONS USED IN BLOWDOWN WATER TRANSIT TIME CALCULATIONS

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TABLE 10.4-4

BLOWDOWN TRANSIT TIMES

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TABLE 10.4-5

POSTULATED RELEASE OF LIQUID ACTIVITY THROUGH BLOWDOWN SYSTEM

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TABLE 10.4-6

POSTULATED RELEASE OF GASEOUS ACTIVITY THROUGH CONDENSER AIR REMOVAL SYSTEM

THIS TABLE HAS BEEN DELETED

Figure F10.4-1 Sheets 1 & 2 of 2 intentionally deleted.

Refer to plant drawing 205208 in DCRMS

Figure F10.4-2 intentionally deleted.

Refer to plant drawing 205207 in DCRMS

Figure F10.4-3A Sheets 1 through 5 of 5 intentionally deleted.

Refer to plant drawing 205209 in DCRMS

Figure F10.4-3B Sheets 1, 2, 3 & 4 of 4 intentionally deleted.

Refer to plant drawing 205309 in DCRMS

Figure F10.4-4 intentionally deleted.

Refer to plant drawing 208997 in DCRMS

Figure F10.4-5A Sheets 1, 2 & 3 of 3 intentionally deleted.

Refer to plant drawing 205202 in DCRMS

Figure F10.4-5B Sheets 1, 2 & 3 of 3 intentionally deleted.

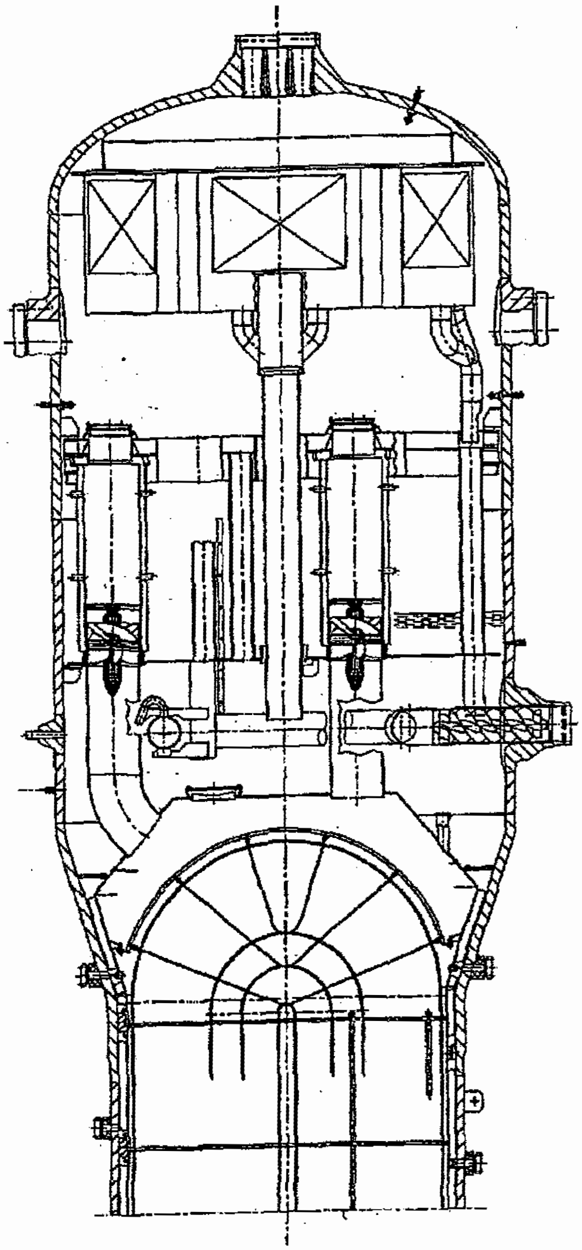
Refer to plant drawing 205302 in DCRMS

Figure F10.4-6A Sheets 1 through 6 of 6 intentionally deleted.

Refer to plant drawing 205205 in DCRMS

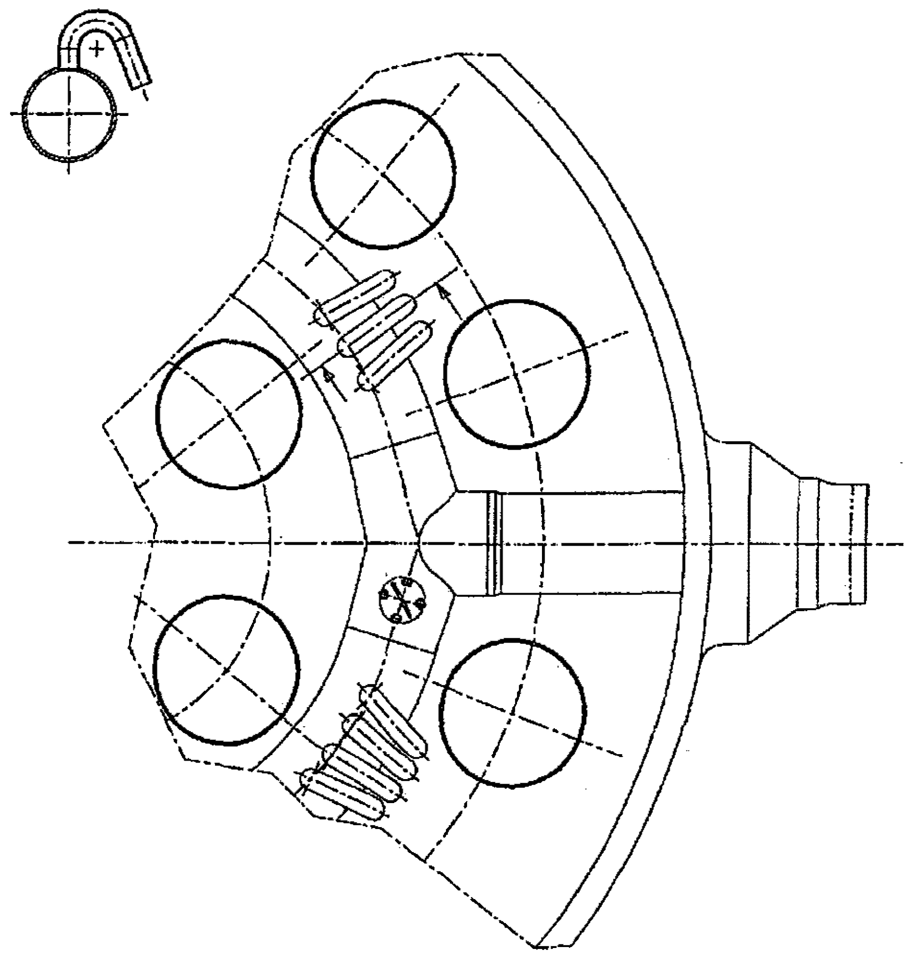
Figure F10.4-6B Sheets 1 through 6 of 6 intentionally deleted.

Refer to plant drawing 205305 in DCRMS



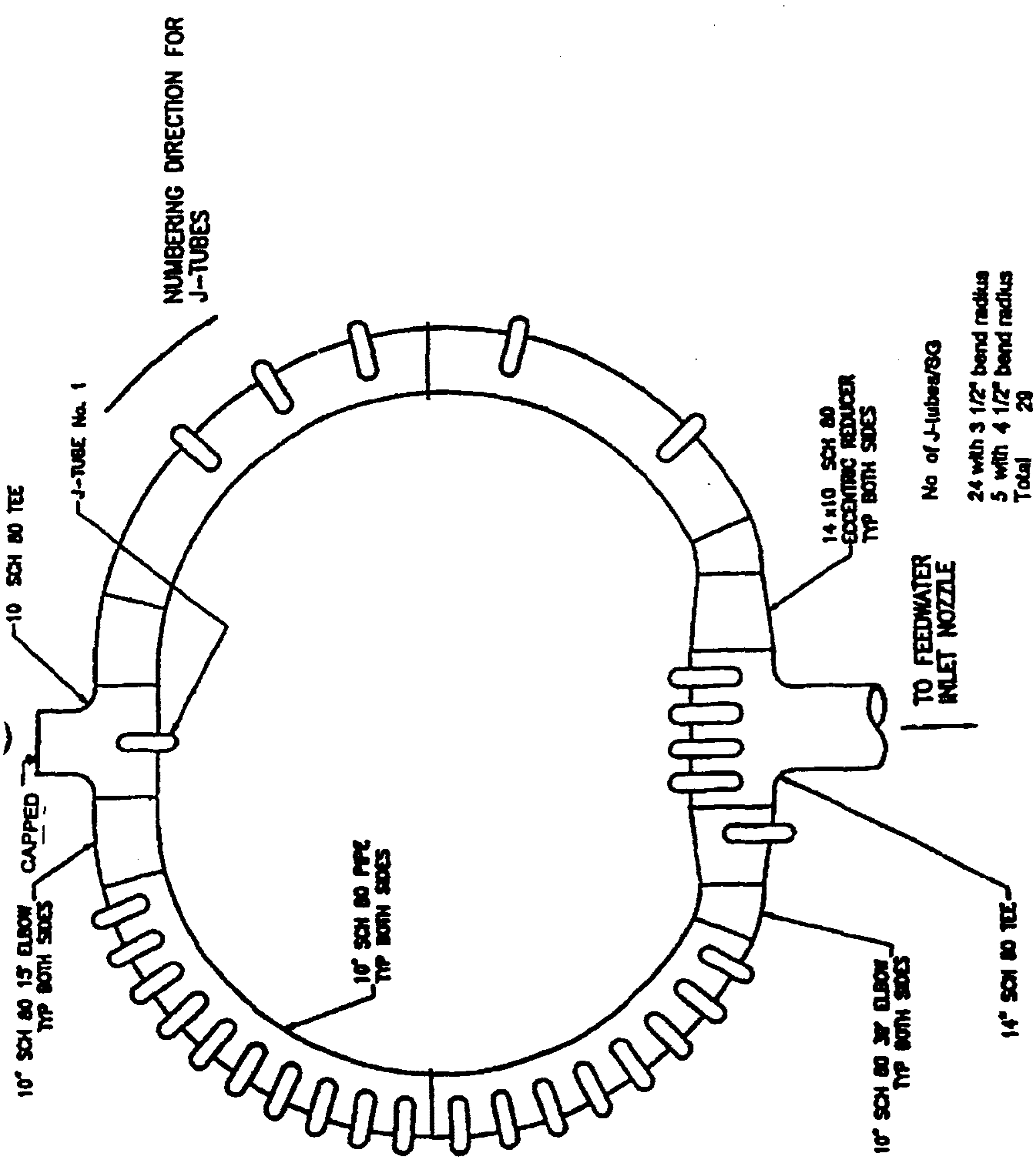
Revision 24
May 11, 2009

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station FEEDWATER DISTRIBUTION SYSTEM APPLICABLE TO UNIT 2 ONLY
	Updated FSAR — Figure 10.4-7



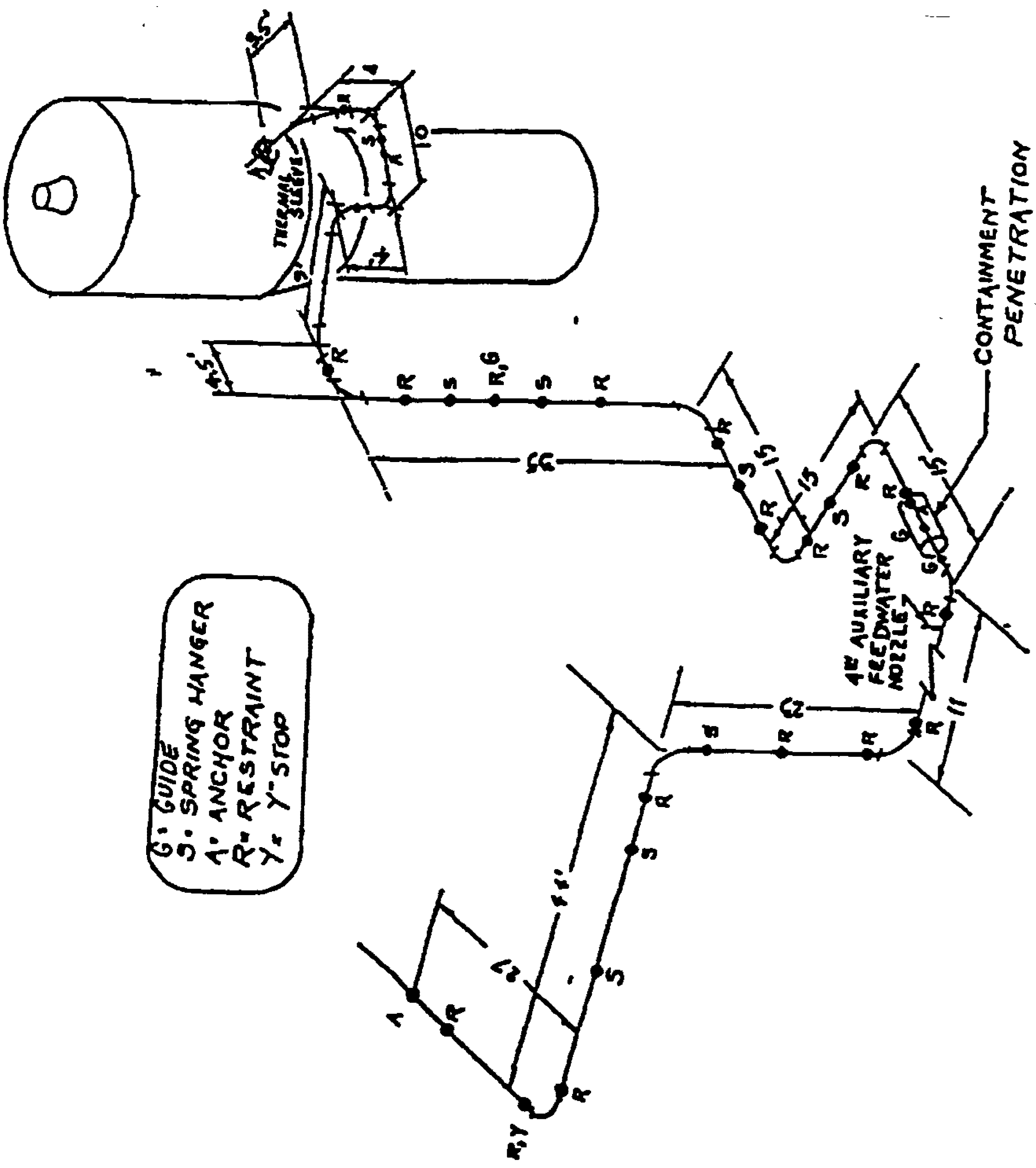
Revision 24
May 11, 2009

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station DISTRIBUTION TEE AND J-TUBES APPLICABLE UNIT 2 ONLY Updated FSAR Figure 10.4-8



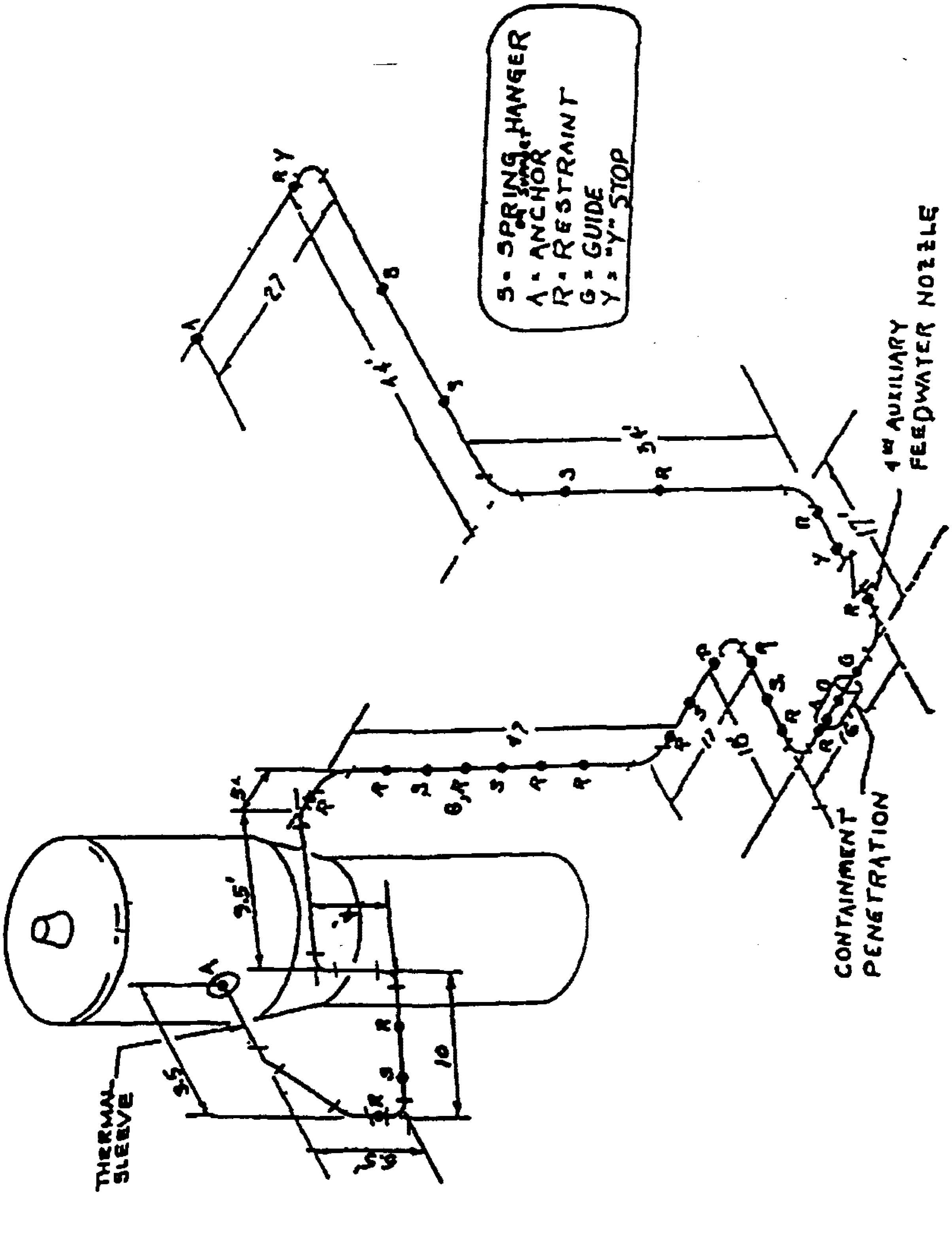
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station TYPICAL FEED RING CONFIGURATION UNIT 1 MODEL FSG
	Updated FSAR — Figure 10.4-8A



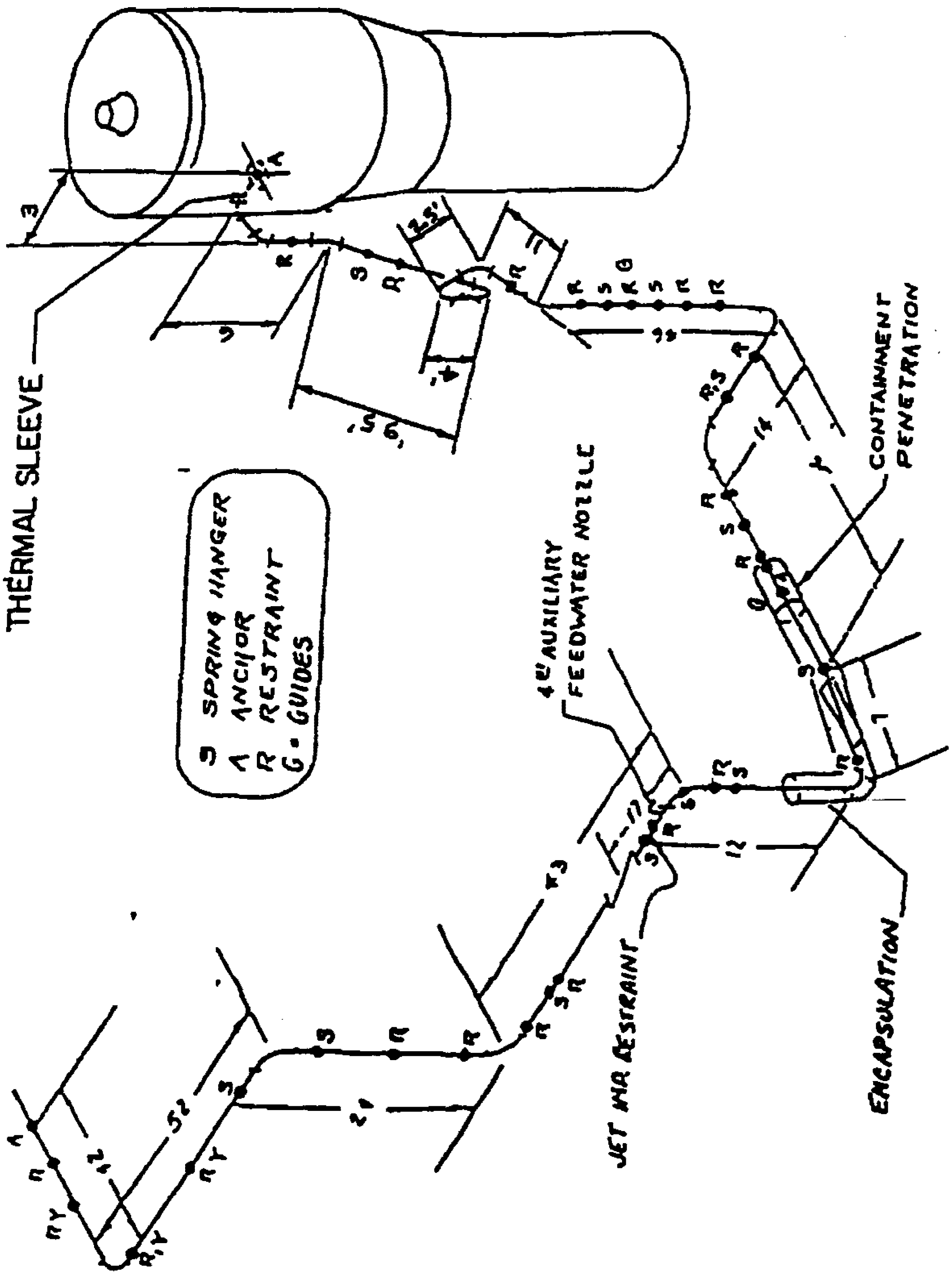
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ISOMETRIC DIAGRAM-FEEDWATER PIPING NO.11 STEAM GENERATOR-UNIT 1 ONLY
	Updated FSAR — Figure 10.4-9



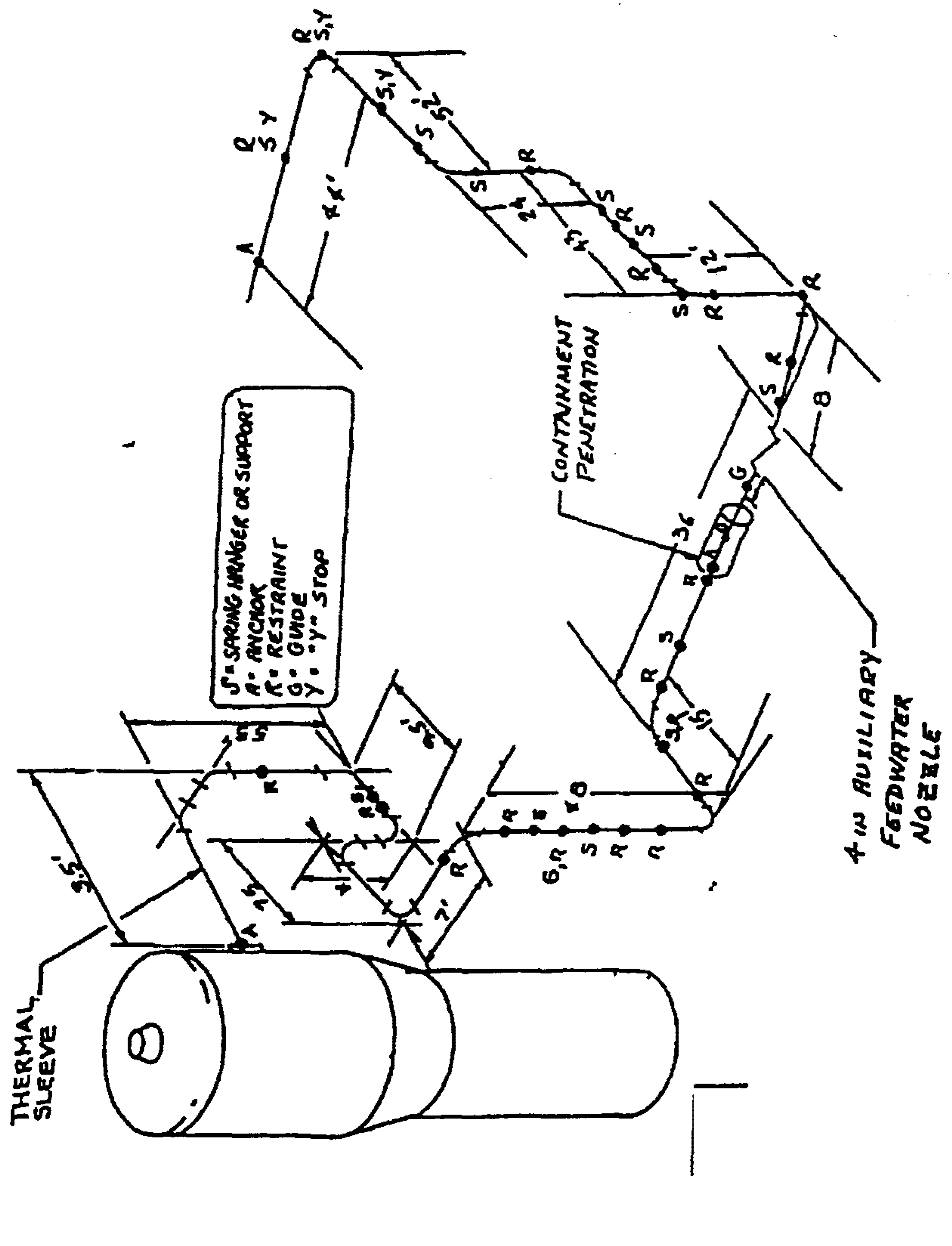
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ISOMETRIC DIAGRAM-FEEDWATER PIPING NO. 12 STEAM GENERATOR-UNIT 1 ONLY
	Updated FSAR — Figure 10.4-10



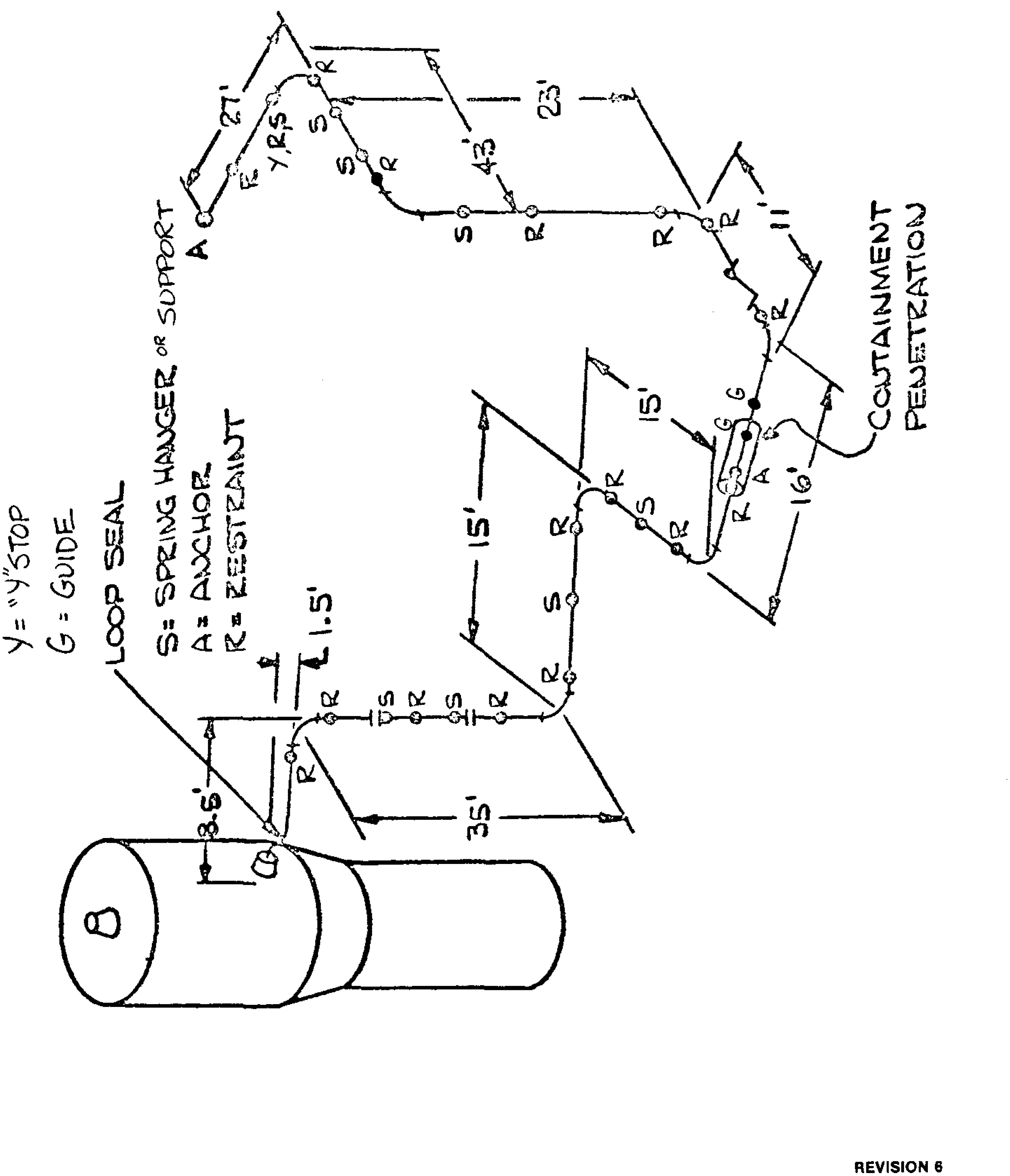
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ISOMETRIC DIAGRAM-FEEDWATER PIPING NO. 13 STEAM GENERATOR-UNIT 1 ONLY
	Updated FSAR — Figure 10.4-11



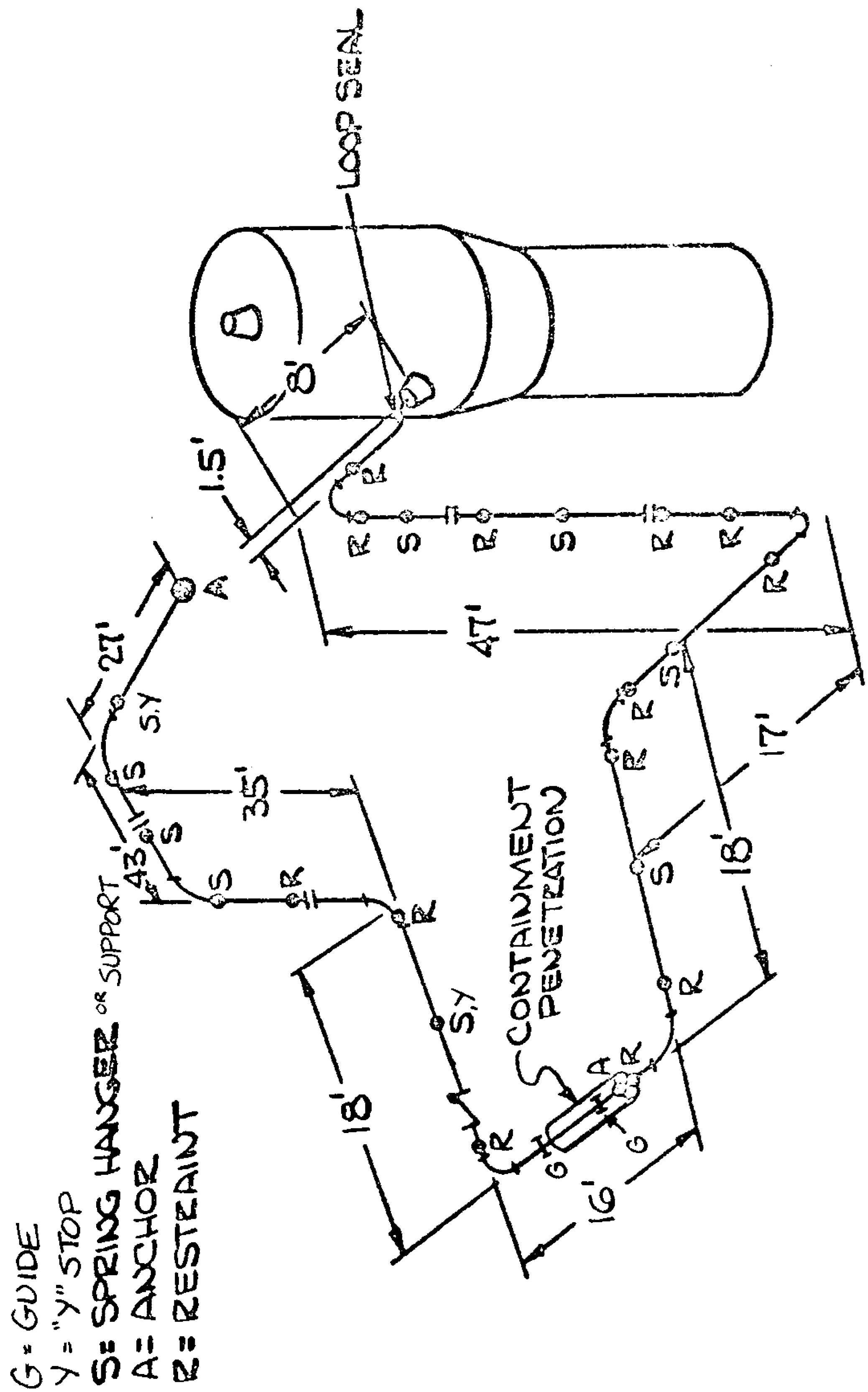
Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station ISOMETRIC DIAGRAM-FEEDWATER PIPING NO.14 STEAM GENERATOR-UNIT 1 ONLY
	Updated FSAR — Figure 10.4-12



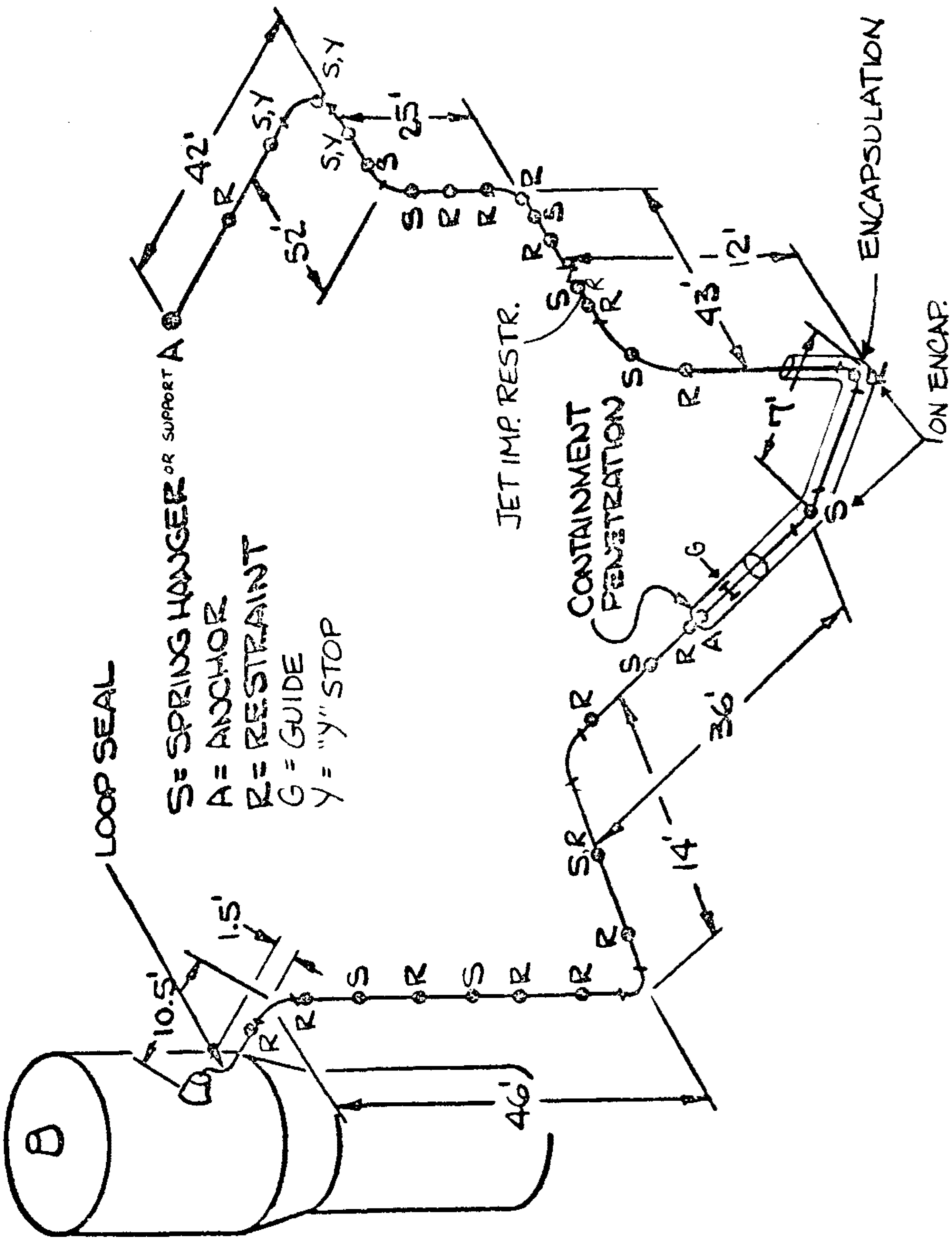
REVISION 6
FEBRUARY 15, 1987

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Isometric Diagram – Feedwater Piping No. 21 Steam Generator	
	Updated FSAR	Figure 10.4-13



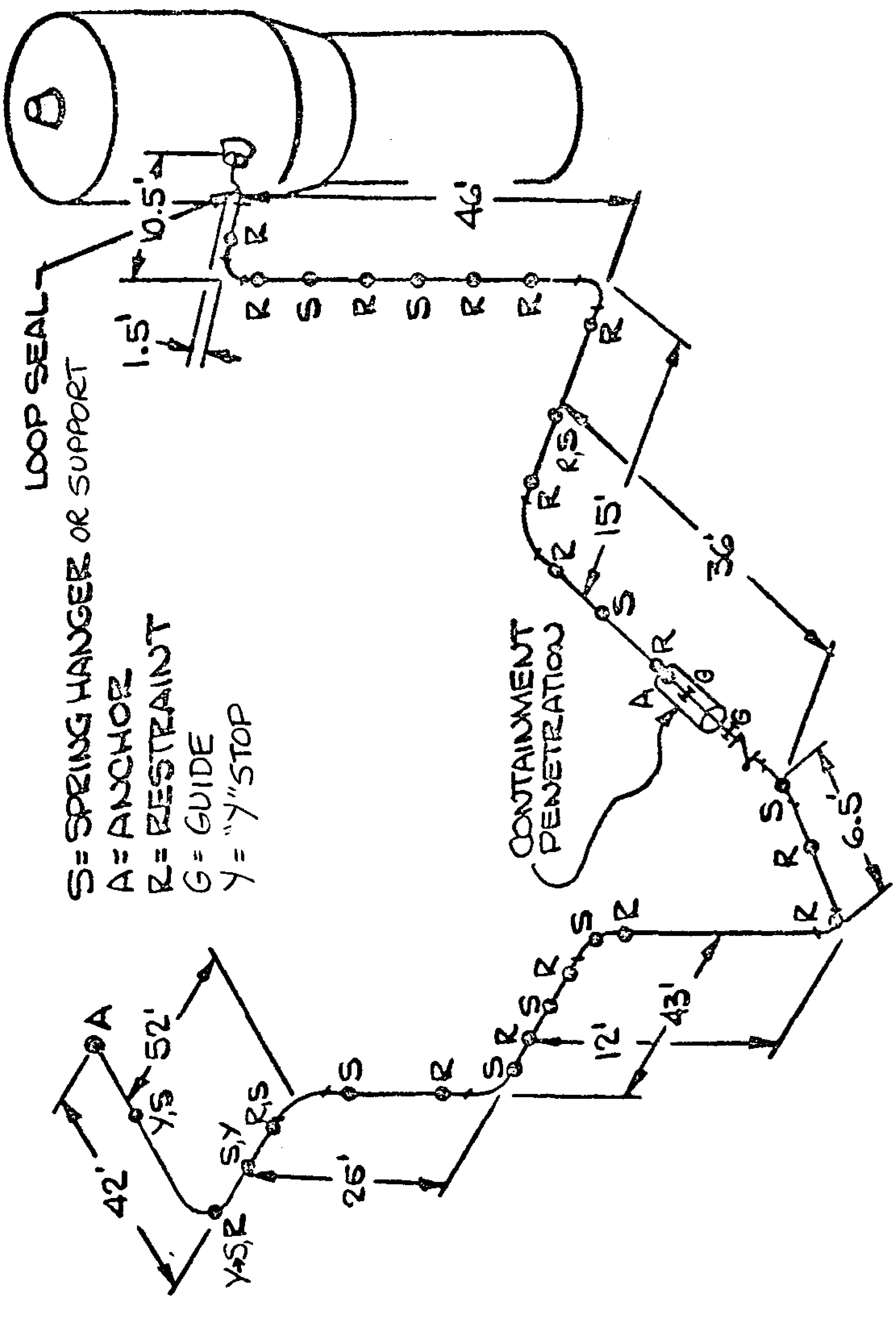
REVISION 6
FEBRUARY 15, 1987

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Isometric Diagram – Feedwater Piping No. 22 Steam Generator
	Updated FSAR — Figure 10.4-14



REVISION 6
FEBRUARY 15, 1987

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Isometric Diagram – Feedwater Piping No. 23 Steam Generator
	Updated FSAR Figure 10.4-15



REVISION 6
FEBRUARY 15, 1987

PUBLIC SERVICE ELECTRIC AND GAS COMPANY SALEM NUCLEAR GENERATING STATION	Isometric Diagram – Feedwater Piping No. 24 Steam Generator
	Updated FSAR — Figure 10.4-16

Figure F10.4-17A intentionally deleted.

Refer to plant drawing 205236 in DCRMS

Figure F10.4-17B intentionally deleted.

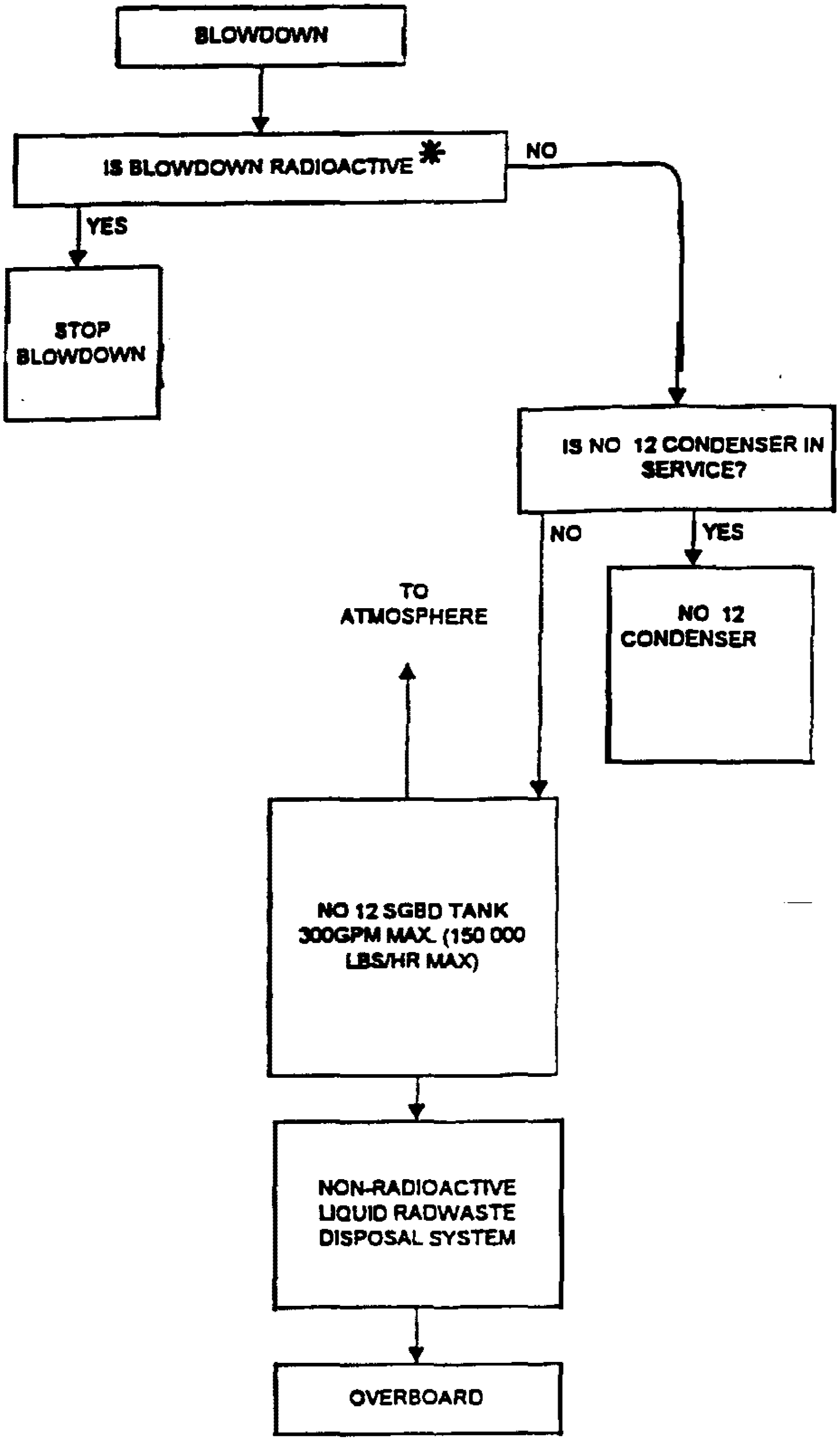
Refer to plant drawing 205336 in DCRMS

Figure F10.4-18A Sheets 1, 2 & 3 of 3 intentionally deleted.

Refer to plant drawing 205225 in DCRMS

Figure F10.4-18B Sheets 1, 2 & 3 of 3 intentionally deleted.

Refer to plant drawing 205325 in DCRMS



* (in excess of the radiation monitor setpoint)

Revision 18, April 26, 2000

PSEG Nuclear, LLC SALEM NUCLEAR GENERATING STATION	Salem Nuclear Generating Station STEAM GENERATOR BLOWDOWN LOGIC DIAGRAM
	Updated FSAR Figure 10.4-19