Chapter 10: Steam and Power Conversion

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STEAM AND POWER CONVERSION

10.1 GENERAL DESCRIPTION

Note: As required by the Renewed Operating Licenses for Surry Units 1 and 2, issued March 20, 2003, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

This chapter describes the systems and equipment that are required to convert steam energy to electrical energy. The following sections describe separate equipment and systems required for each unit:

10.3.1 Main steam system

10.3.2 Auxiliary steam system

10.3.3 Turbine generator

10.3.5 Condensate and feedwater system

10.3.6 Condenser

10.3.7 Lubricating-oil system

10.3.9 Bearing cooling water system

The following sections describe those systems that are shared in the operation of both units:

10.3.4 Circulating water system

10.3.8 Secondary vent and drain system

The potential for radioactive contamination of the secondary steam system is discussed in Chapter 11.

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10.2 DESIGN BASES

The design bases of the steam and power conversion equipment and systems are largely derived from past design experience with fossil-fueled stations, and have evolved over a long period of time. Specifically, the design bases are oriented to a high degree of operational reliability at optimal thermal performance. The performance of the collective equipment and systems is a function of environmental conditions and the selection of design options. Therefore, the principal design basis is represented by the design heat balances, which incorporate all of the applicable design considerations.

Figure 10.2-1 and Reference Drawing 1 shows the heat balance for the extended rating equivalent to 2558 MWt.

The conventional design bases have been modified in order to provide suitability for nuclear application, and these include provisions for specific earthquake, tornado, and missile protection as further described in other sections.

Turbine building Reference Drawings 2 through 9 show equipment locations.

A steam generator repair program was completed at the Surry Power Station in 1980 and 1981 for Units 2 and 1, respectively. The purpose of the program was to repair degradation caused by corrosion-related phenomena and to restore the integrity of the steam generators to a level equivalent to new equipment. The repair program basically consisted of replacing the steam generator lower assembly and refurbishing the upper assembly. New primary moisture separation equipment was installed in the upper assembly. The steam generators are described in Section 4.2.2.3 (primary-side characteristics) and Section 10.3.1.2 (secondary-side characteristics).

10.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-59M	Heat Balance Diagram: 100% Core Power, Unit 1
	11548-FM-59A	Heat Balance Diagram: 100% Core Power, Unit 2
2.	11448-FM-6A	Machine Location: Turbine Area, Plan, Operating Level, Unit 1
	11548-FM-6A	Machine Location: Turbine Area, Plan, Operating Level, Unit 2
3.	11448-FM-6B	Machine Location: Turbine Area, Plan, Mezzanine Level, Unit 1
	11548-FM-6B	Machine Location: Turbine Area, Plan, Mezzanine Level, Unit 2
4.	11448-FM-6C	Machine Location: Turbine Area, Plan, Ground Floor, Unit 1
	11548-FM-6C	Machine Location: Turbine Area, Plan, Ground Floor, Unit 2
5.	11448-FM-6D	Machine Location: Turbine Area, Sections, Sheet 1, Unit 1
	11548-FM-6D	Machine Location: Turbine Area, Sections, Sheet 1, Unit 2
6.	11448-FM-6E	Machine Location: Turbine Area, Sections, Sheet 2, Unit 1
	11548-FM-6E	Machine Location: Turbine Area, Sections, Sheet 2, Unit 2
7.	11448-FM-6F	Machine Location: Turbine Area, Sections, Sheet 3, Unit 1
	11548-FM-6F	Machine Location: Turbine Area, Sections, Sheet 3, Unit 2
8.	11448-FM-6G	Machine Location: Turbine Area, Sections, Sheet 4, Unit 1
	11548-FM-6G	Machine Location: Turbine Area, Sections, Sheet 4, Unit 2
9.	11448-FM-6H	Machine Location: Turbine Area, Sections, Sheet 5, Unit 1
	11548-FM-6H	Machine Location: Turbine Area, Sections, Sheet 5, Unit 2

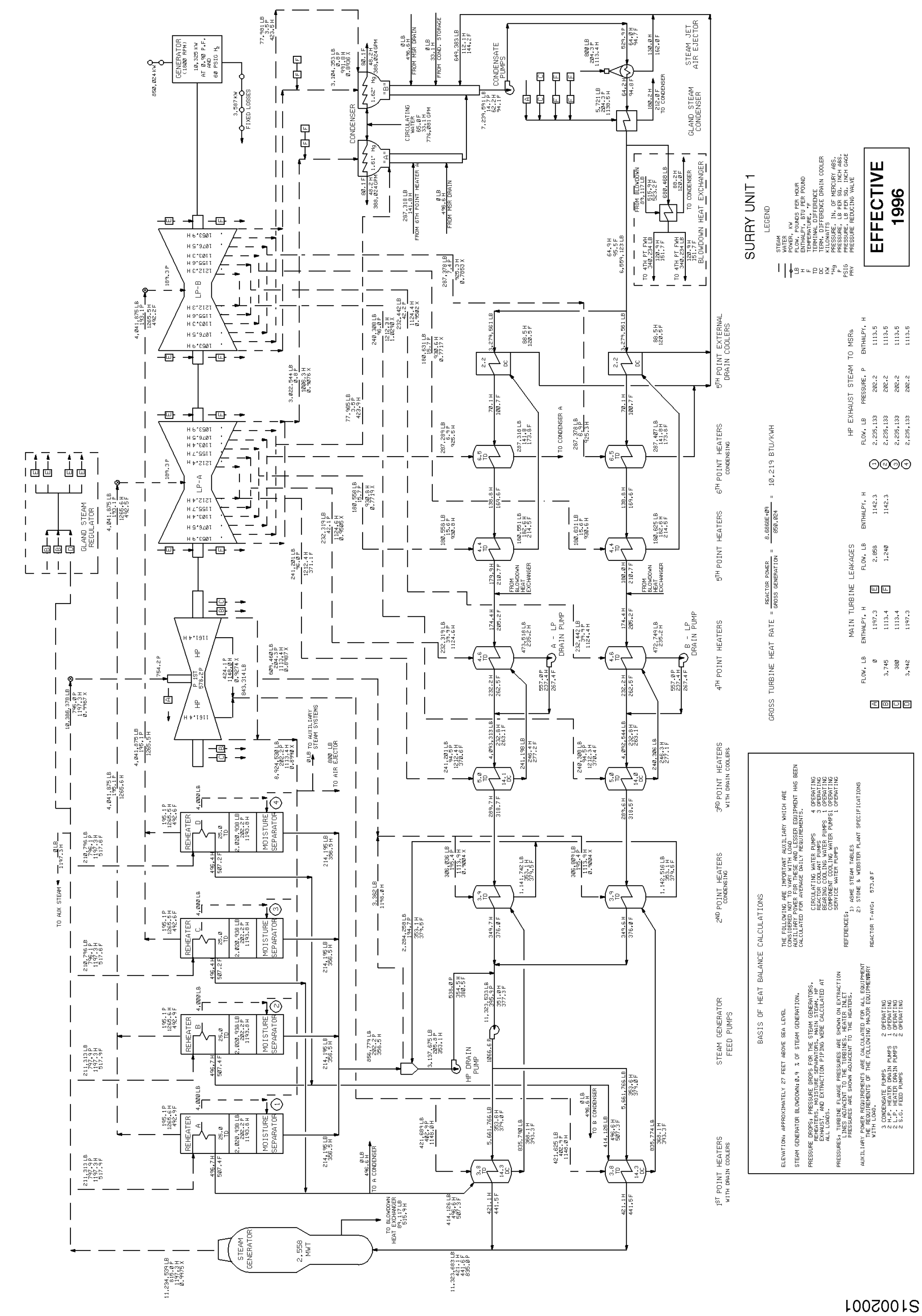
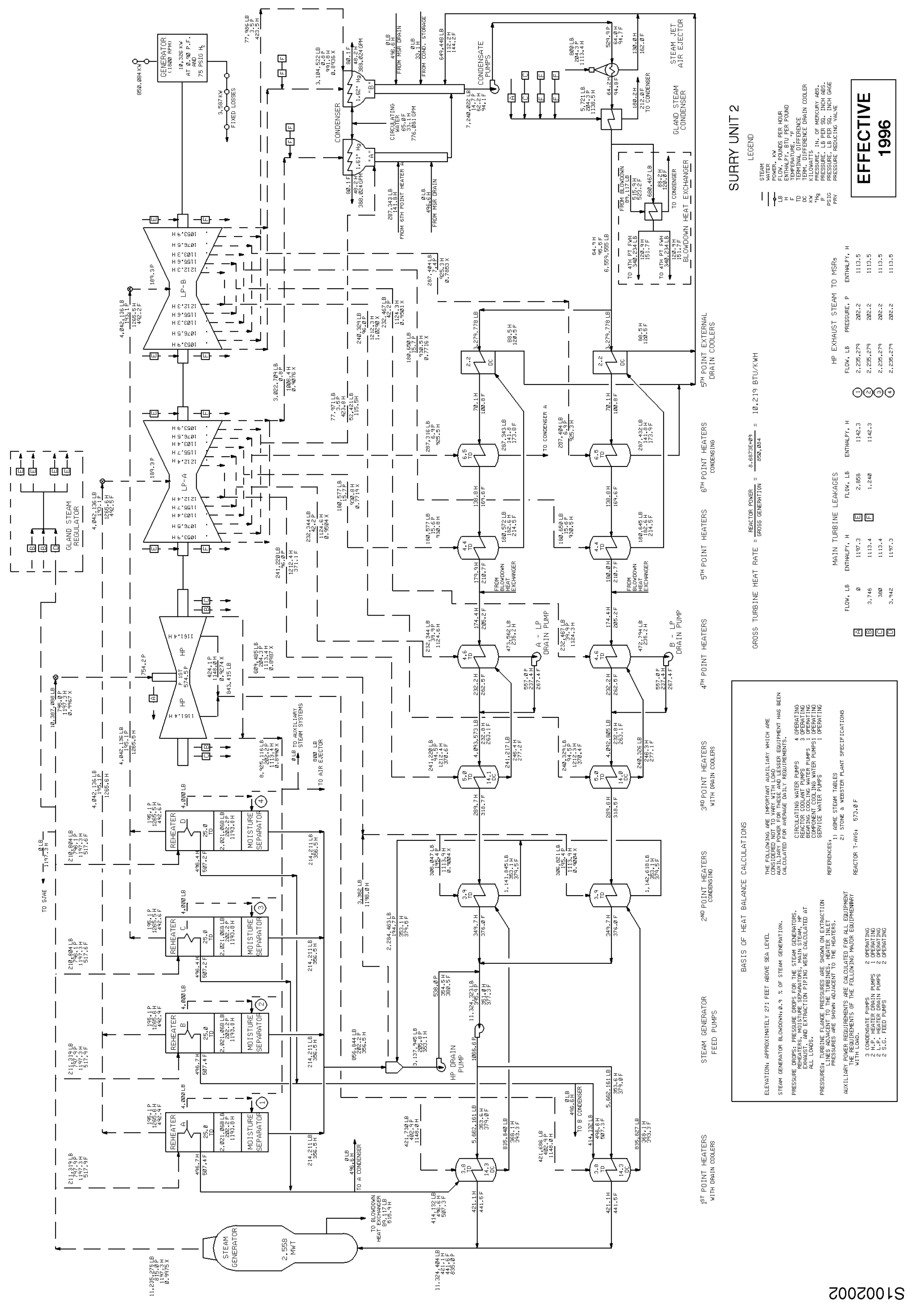


Figure 10.2-1 (SHEET 1 OF 2)
HEAT BALANCE DIAGRAM

Figure 10.2-1 (SHEET 2 OF 2)
HEAT BALANCE DIAGRAM



10.3 SYSTEM DESIGN AND OPERATION

10.3.1 Main Steam System

The main steam system is shown on Figure 10.3-1 and Reference Drawing 1. The turbine generator heat balance for the 100% core power rating of 2546-MWt is shown on Figure 10.2-1 and Reference Drawing 10. A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the main steam system was found to be adequate.

10.3.1.1 **Design Basis**

Each of the three main steam pipes is designed in accordance with the ASME Code for Pressure Piping, ANSI B31.1, for a flow of 3,722,641 lb/hr of steam at 1085 psig, 555°F. The pipes are each 30-inch o.d. ASTM A-155, Class 1, Gr. CMS-75 carbon steel, 1-inch nominal wall thickness, and join to form a common 36-inch o.d. header. Additional discussion of main steam piping materials may be found in Section 14B.5.1.6.3. Steam flows from this header through four 28-inch o.d. pipes to the stop trip valves and the turbine.

The steam dump system is sized to take the excess steam flow associated with a 50% load rejection, which results in a 10% step change in reactor power and a 40% steam dump, having a steam flow of approximately 4,504,000 lb/hr. This flow can be divided equally through the eight bypass control valves, with each valve having a maximum capacity of 890,000 lb/hr at full load steam conditions.

The 4200-rpm turbine-driven auxiliary feedwater pump is designed to deliver 700 gpm of auxiliary feedwater to the steam generators at main steam pressures from 600 psig to 1100 psig. The turbine-driven auxiliary feedwater pump will also operate at main steam pressures from 600 psig down to less than 120 psig and deliver the required auxiliary feedwater flow to the steam generators to support RCS decay heat removal prior to placing the residual heat removal system in service. A main steam pressure of 120 psig corresponds to the approximate RCS conditions at which the residual heat removal system can be placed in service to remove decay heat. Steam traps drain condensate from upstream of the inlet control valves to prevent water slugs from entering the turbine. Removal of this condensate minimizes the risk of water slugs entering the turbine, flashing, and causing a pump trip on turbine overspeed.

The main steam piping supports were initially analyzed for turbine trip forces as well as for seismic forces. Since the turbine trip results in a more severe shock to the piping system than the design-basis earthquake, as set forth in Section 2.5, the turbine trip data were used in the design of the piping supports. In addition, the system was stress-analyzed for the forces and moments that result from thermal growth. The main steam piping within the containment annulus was reviewed for possible pipe rupture, and sufficient supports and guides were provided to prevent damage to the containment liner and adjacent piping. Stresses in the main steam piping inside containment have been reviewed and, in accordance with NRC Generic Letter 87-11, are sufficiently low that only terminal end breaks need be postulated.

As a result of IE Bulletin 79-14 (Reference 1), the main steam piping and supports were reanalyzed in accordance with updated regulatory requirements. Minor support modifications were made to satisfy analytical load limits. Pipe stresses were within allowable limits, so no piping modifications were necessary. The reanalysis of safety-related piping systems and supports is discussed in Appendix 15A.

10.3.1.2 **Description**

Each loop of the reactor coolant system contains a vertically mounted U-tube steam generator. The secondary-side characteristics of the steam generators are described below. The primary-side characteristics are described in Chapter 4. Steam generator design data are given in Table 4.1-4.

The steam generators, as shown on Figures 10.3-2 and 10.3-3, consist of two integral sections: an evaporator section and a steam drum section. The evaporator section consists of a U-tube heat exchanger, while the steam drum section houses moisture-separating equipment. The steam drum section is located in the upper part of the steam generator. In general, the steam generators are designed and manufactured in accordance with Sections II, III, and IX of the ASME Boiler and Pressure Vessel Code. The lower assemblies are designed and manufactured in accordance with the 1974 Edition of the ASME Code, including Addenda through Winter 1976. All components are designed to meet Section XI, *Rules For Inservice Inspection of Nuclear Power Plant Components*. The steam generator lower assemblies bear the applicable ASME Code stamp.

Feedwater enters the unit through the nozzle located on the upper shell and is distributed by a feedwater ring into the downcomer annulus formed by the tube wrapper and steam generator shell. The feedwater mixes with recirculation flow and enters the tube bundle near the tubesheet. Feedwater flow within the steam generators is divided so that a larger percentage of the flow is directed to the hot-leg side of the tube bundle. This reduces the steam quality in the hot-leg side of the bundle and raises the steam quality in the cold-leg side. The effect of these changes in steam quality is to shift the point of highest steam quality at the tubesheet elevation toward the center of the bundle. Boiling occurs as the flow rises in the tube bundle.

The circulation ratio, which is defined as the total tube bundle flow divided by the feedwater flow and is directly proportional to the steam quality exiting the tube bundle, is approximately 3.8. As circulation ratio increases, certain parameters of the steam generator, such as lateral velocity, steam quality, void fraction, and number of tubes exposed to sludge, change in a favorable direction. Low steam quality in the bundle reduces tube exposure to local steam blanketing. This also reduces the number of potential areas of concentration for chemical impurities. In addition, higher circulation ratios increase the flow exiting the downcomer and sweeping across the tubesheet to the center of the bundle. The point of highest steam quality and thus the lowest density is the center of the tube bundle, though, and is thus more susceptible to chemical concentration and sludge deposition. It is for this reason that the blowdown intake is located in this region.

A set of sixteen 20-inch-diameter centrifugal moisture-separators, located 13 inches above the tube bundle, removes most of the entrained water from the steam. Steam dryers are employed to increase the steam quality to a minimum of 99.75% (0.25% moisture). The steam drum has two bolted and gasketed access openings for inspection and maintenance of the dryers, which can be disassembled and removed through the opening.

The lower assemblies are constructed with four additional 6-inch access ports and two 2-inch access ports in the area of the tubesheet. Four 6-inch access ports are located slightly above the tubesheet 90 degrees apart, with two located on the tube lane. Two additional 6-inch access ports are located on the tube lane, between the flow distribution baffle and the first support plate. At this same elevation, 90 degrees away, are two 2-inch access ports. The addition of these access ports improves and promotes inspection of the tubesheet and flow distribution baffle and assists in the sludge-lancing procedure. The steam generator wrapper is designed to discourage flow in the tube lane yet allow clear access from the access ports.

Feedwater exiting from behind the wrapper in the vicinity of the tube lane will tend to preferentially channel to this path of less resistance and bypass part of the tube array. In order to prevent this flow channeling, a series of plates are placed in the tube lane. These plates block the flow into the tube lane and prevent channeling. These plates are arrayed so that there will be no interference with the sludge-lancing procedure.

A flow distribution baffle is located approximately 18 inches above the tubesheet. This baffle has a cutout center section and quatrefoil tube holes. The increased circulation ratio provides a greater lateral flow across the tubesheet surface. The baffle plate will assist in redirecting the flow across the tubesheet, then up the center of the bundle through the center cutout. The design is sized to minimize the number of tubes exposed to sludge. Consistent with this purpose, the design causes the sludge to deposit in and near the center of the bundle at the blowdown intake. The flow distribution baffle plate material is SA-240 type 405 ferritic stainless steel.

The tube support plates are SA-240 type 405 ferritic stainless steel. This material is ASME Code approved and is resistant to corrosion with the chemistry expected during the operation of the steam generator. In addition, SA-240 has a low wear coefficient when paired with Inconel and has a coefficient of thermal expansion similar to carbon steel. Corrosion of SA-240 results in an oxide which has approximately the same volume as the parent material, whereas corrosion of carbon steel results in oxides that have a greater volume than the parent material. Type 405 also has material properties important to fabrication that are equivalent to carbon steel.

The quatrefoil tube support plate design, as shown on Figure 10.3-4, consists of four flow lobes and four support lands. The lands provide support to the tube during all operating conditions, while preventing wear or fretting. This design has a lower pressure drop than the most current circulation hole designs. This low secondary pressure drop will cause a high circulation ratio which, when combined with other improvements, translates into higher sweeping velocities and fewer tubes exposed to a low steam quality at the tubesheet. This design directs the flow along the tubes, which limits steam formation and chemical concentrations at the tube-to-tube support plate intersections.

Each steam generator has two 2-inch, schedule 40 Inconel internal blowdown pipes. The blowdown rate from the steam generator is varied as required by chemistry conditions in the feedwater and as monitored in the blowdown. Maintenance of the steam-side water chemistry is assisted through the use of the blowdown system. Therefore, a continuous blowdown is preferred to intermittent blowdown. Continuous blowdown of the steam generator provides a dynamic system that is constantly removing impurities from the steam generator. During hot standby and hot functional testing, blowdown is employed as needed to maintain the steam generator chemistry within specification. The blowdown intake location is coordinated with the baffle plate design so that the intake is located where the greatest amount of sludge deposition is expected to occur. The design of the steam generators allows the use of an efficient sludge removal system; a typical system is shown on Figure 10.3-5. A permanent sludge removal system is not installed. A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the main steam generator blowdown system was found to be adequate.

Steam-generator blowdown is discharged from the steam generators through two 2-inch schedule 40 Inconel internal blowdown pipes. The steam generators are designed to allow blowdown rates up to 7.4% of the feedwater flow rate; however, much of this is excess capacity because the blowdown system has a capacity of 1% of the feedwater flow rate.

A 3-inch line downstream of each steam generator blowdown containment isolation valve carries the blowdown effluent from the auxiliary building into the turbine building through the pipe tunnel. Each blowdown line has a manual isolation valve, with a bypass valve provided for system start-up. Each blowdown line has a heat exchanger located adjacent to the east wall of the respective turbine building.

The system is designed for a maximum continuous blowdown from each steam generator of 70 gpm at 750 psig and 510°F, and reduces the blowdown water to a maximum temperature and pressure of 130°F and 60 psig.

During power operation, after the blowdown is cooled, it is normally directed to the condenser hotwell. The blowdown, along with condensate in the condenser, is filtered and treated by condensate polishing prior to being returned to the steam generators. Alternately, steam generator blowdown may be released to the discharge canal through the condenser outlet waterbox. This activity is described in Section 10.3.5.2. Releasing to the discharge canal is normally limited to unit start-up operation.

A pressure control valve (PCV) and a hand control valve (HCV) are provided downstream of each heat exchanger assembly. The PCV will maintain a constant nominal pressure of 250 psig upstream of the HCV. If pressure upstream of the PCV decreases below 250 psig, the valve will travel to the full-open position. The PCV will fail closed on a loss of control air, blowdown flow greater than 75 gpm, or heat exchanger assembly outlet temperature greater than 145°F. The HCV is provided for remote/manual control of the steam generator blowdown rate. A remote control station is provided in the control room to position the HCV. The HCV is sized for a maximum blowdown rate of 70 gpm with an upstream pressure of 250 psig and a downstream pressure of 50 psig. A pressure relief valve, set for approximately 200 psig, is provided to protect the system downstream of the HCV from overpressurization. A manually operated bypass valve is provided around both the PCV and the HCV to allow manual control of the blowdown flow. Two flow elements are provided between the heat exchanger assembly and the PCV for high-range and low-range flow indication.

Main condensate is used as the cooling medium for the heat exchangers. Approximately 1260 gpm per unit (three heat exchangers) is supplied through an 8-inch supply header and isolation valve. The supply connection from the condensate system is located on the 24-inch condensate header between the gland exhaust condenser and the flash evaporator. The return line ties into the condensate system at the cross-connect line between the fourth and fifth point feedwater heaters. Manual isolation valves are provided on each heat exchanger assembly. The outlet isolation valve is a globe valve to permit throttling of the cooling water flow. Thermometers are installed in the cooling water lines at the outlet of the heat exchanger assemblies to monitor condensate return temperature. A relief valve is provided for each heat exchanger assembly between the isolation valves. The differential pressure across the drain coolers, fifth, and sixth point heaters will provide sufficient head for condensate flow through the steam generator blowdown (SGBD) heat exchangers. To increase the condensate cooling capacity of the SGBD heat exchangers during low main condensate flow conditions, an independent SGBD heat exchanger condensate return divert line is added. The diverted heat exchanger condensate return flow is controlled by a temperature controlled valve (TCV) which allows the diverted flow to be discharged to the main condenser when the heat exchangers' blowdown exit temperature reaches 135°F.

Codes and standards applied to the steam generator blowdown system are listed in Table 10.3-1. The piping from the 3-inch connection downstream of the steam generator blowdown containment isolation valves to the heat exchanger assemblies is classified as high-energy piping. This portion of the steam generator blowdown system is not safety related and has no seismic or tornado design requirements, except that its failure must not cause a functional loss of any safety-related equipment. Postulated breaks have been analyzed, and restraints added to prevent pipe whip or jet impingement damage to systems in the auxiliary building that are required for safe shutdown.

A blowdown sampling system is provided in the Unit 1 turbine building. The system is used to analyze a cooled blowdown sample before the blowdown stream is discharged to the discharge canal through the condenser waterbox outlet.

A 2-inch nozzle in the upper shell facilitates the wet layup of the steam generators during the periods of inactivity. The wet layup nozzle can be used for addition of chemicals during these periods to prevent any excursions of the water quality in the steam generator. The nozzle can also be used in conjunction with other systems to circulate water through the steam generator during periods of layup to prevent localized chemical concentrations. These same connections can also be used for chemical cleaning.

A steam generator recirculation and transfer system is provided to protect the steam generator internals from corrosive attack during inactive periods by enabling the water chemistry to be controlled during such periods. The system is used in conjunction with the steam generator nitrogen system described below to ensure the exclusion of oxygen from the steam generator internals during wet layup conditions. Each steam generator has an independent external recirculation loop with 150-gpm pumping capacity, which provides a complete volume turnover approximately every 4 hours. The recirculation and transfer system pump takes suction from the steam generator upper shell. The pump discharges to the steam generator through the blowdown pipe via a connection to the steam generator blowdown system. Each circulation loop has a cross connect to facilitate the transfer of a steam generator's contents to either of the other two steam generators, the liquid waste system, or the circulating water discharge. During normal plant operation, the system will be isolated from the steam generator by double isolation valves. A typical wet-layup system is shown in Figure 10.3-6.

The steam generator nitrogen system is utilized in conjunction with the steam generator recirculation and transfer system to protect the steam generators during long layup periods from corrosive attack by ensuring the exclusion of oxygen from the secondary side of the steam generators. The system includes a vacuum pump to enable the air to be evacuated from the steam generator before nitrogen is introduced from a nitrogen supply. However, the vacuum pump is no longer used. Connection to the secondary side of the steam generator is made by a 2-inch line connected to the 6-inch main steam trip valve bypass line in the main steam valve house. An isolation valve is provided to isolate this system from the steam system during unit operation. This system is a quality group B system from the bypass line up to and including the isolation valve, with the rest of the system being quality group E.

A loose parts monitoring system has been installed and provides the ability to monitor the primary system and secondary side of the steam generators for the presence of loose circulating parts and other foreign objects. See Section 4.2.10 for further information.

All pressure-containing parts, with the exception of the Inconel tubes, are made of carbon or low-alloy steel. The stainless steel insulation of the steam generator is designed to facilitate removal for maintenance and inservice inspection activities.

Steam is conducted from each of the three steam generators through a steam flowmeter (venturi), a swing disk-type valve and an angle-type nonreturn valve into a common header outside the containment. The steam passes from the header to the turbine stop-trip valves and then to the governor valves. The steam flowmeter sends a signal to the feedwater control system.

The swing disk-type trip valves in series with the nonreturn valves contain swinging disks that are normally held up and out of the main steam flow path by air cylinder operators. Three-way solenoid-operated air control valves function to hold the trip valves open when air pressure is applied. The valves are designed to close on release of air pressure, but are not dependent on air pressure to assist closure. When the air pressure is vented, the valve discs shut rapidly due to spring pressure and the steam flow differential pressure. The air cylinders are equipped with rupture discs to prevent damage to valve and actuator parts from being overstressed due to the rapid cylinder pressure increase when the valves shut at high steam flow rates. Air is normally available at 100 psig, but the equipment is designed to operate at a minimum air pressure of 70 psig. Electrical power to the solenoid-operated air control valves is available at 125V dc.

The main steam-line trip valve circuitry has been modified to ensure that the trip valves will not return to their non-safety position (open) following the resetting of the consequence limiting safeguards (CLS) system signal when power to train A or B is lost. The modification required the installation of an additional contact deck to each trip valve selector switch located at the benchboard in the control room and the installation of a new limit switch to each trip valve. This modification provides a seal-in function in the train B control circuitry similar to that existing in the train A portion of the circuit. As a result, when resetting a CLS signal, if power is lost in either train A or B, the valve will not return to its non-safety position. All electrical equipment installed due to the above modification that could experience a harsh environment is qualified to IEEE 323-1974, IEEE 344-1975, and IEEE 383-1974.

The trip valves close following receipt of an excess flow signal from the steam flowmeter to the solenoid-operated air control valves. The electrical signal positions the air control valves to release air pressure on the air cylinder operators, and spring action causes the trip valve disks to move into the steam path and trip closed. The operating mechanisms are designed and constructed to withstand the pressures and temperatures that result from dashpot action after the valve disk has moved into the steam path. Rapid closure of the trip valves prevents flashing of the water on the shell side of the steam generators, which in turn prevents a rapid decrease in reactor coolant temperature on the tube side of the steam generators.

In addition to the three-way solenoid-operated air control valves described in this section, two solenoid-operated valves have been added to each main steam line trip valve to provide an alternate means of closure at either the control room (in the event of a fire in the emergency switchgear room) or at the emergency switchgear room (in the event of a fire in the control room). The cables, solenoid valves, control switches, and battery/battery chargers required to power the two additional SOV's are qualified to meet or exceed the normal environmental conditions for the areas where they will be installed. The cables that supply the two SOVs are environmentally qualified in accordance with IEEE 323-1974. See Section 9.10.4.1 for information on 10 CFR 50 Appendix R requirements in relation to this modification.

The air operators are also used to open the trip valves. With 70 psig applied to both operators, the trip valves will open with a maximum differential pressure of 4 psi across the valve seat. Manually operated bypass valves permit pressure to be balanced across the valve before reopening.

The motor-operated nonreturn (stop-check) valves automatically prevent reverse flow of steam in the case of accidental pressure reduction in any steam generator or its piping, and also provide a shut-off of steam from its respective steam generator.

A total of five ASME Code safety valves are located on each main steam line outside the reactor containment and upstream of the trip valves. Four 6-inch by 10-inch valves and one 4-inch by 6-inch valve are provided, for a total relieving capacity of 3,842,454 lb/hr.

Excess steam generated by the residual and sensible heat in the core and the reactor coolant system is normally bypassed directly to the condensers by means of two 14-inch steam dump lines, which provide a total bypass capacity of 40% of normal full-load steam flow. Each steam dump line contains a bank of four steam dump control valves arranged in parallel. These valves are controlled by reactor coolant average temperature with provisions to control a portion of the valves with steam pressure. An uncontrolled unit cooldown caused by a single valve sticking open is minimized by the use of a group of valves installed in parallel.

All or several of the steam dump valves open under the following conditions, provided a condenser vacuum permissive interlock is satisfied:

1. On a large step load decrease, the steam dump system creates an artificial load on the steam generators, thus enabling the nuclear steam supply system to accept a 50% load rejection from the maximum capability power level without reactor trip. An error signal exceeding a set value of reactor coolant T_{avg} minus T_{ref} will fully open all valves in 5 seconds. T_{ref} is a function of load and is set automatically. The temperature-controlled valves close automatically as reactor coolant conditions approach their programmed set-point for the new load.

2. On a turbine trip with a reactor trip, the pressure in the steam generators rises. To prevent overpressure without main steam safety valve operation, the steam dump valves open and discharge to the condenser for several minutes, to provide time for the reactor control system (Section 7.3) to reduce the thermal output of the reactor without exceeding acceptable core and coolant conditions.

3. After a normal orderly shutdown of the turbine generator leading to unit cooldown, the steam dump valves are used to release steam generated from the residual and sensible heat for several hours. Unit cooldown is controlled to minimize thermal transients and is based on

residual and sensible heat release. It is effected by manual control of the steam dump valves until the cooldown process is transferred to the residual heat removal system (Section 9.3).

4. During start-up, hot standby service, or physics testing, the steam dump valves are operated from the control room. The Steam Header Pressure Controller can be used in the Automatic or Manual control mode while maintaining the plant at no load conditions or during start-up with power less than approximately 15%.

All steam dump valves are prevented from opening on loss of condenser vacuum, and excess steam pressure is relieved to the atmosphere through the steam generator power operated relief valves or the main steam safety valves. Interlocks are provided to reduce the probability of spurious opening of the steam dump valves.

An interlock is also provided to close all steam dump valves by venting the valve actuators whenever the reactor coolant system temperature in two out of three loops falls below 543°F (nominal). This interlock is redundant down to two solenoids per steam dump valve, which vent the valve actuator. This interlock ensures that any failure in the steam dump control system occurring in the normal operating temperature range above 543°F (nominal) can cause a cooldown only to 543°F (nominal) at which point all valve actuators are vented and, thus, all valves are closed.

A steam generator power operated relief valve with an adjustable setpoint is provided on each main steam safety valve header, upstream of the trip valve outside the containment. The relieving pressure of these valves, normally 1035 psig, is individually controlled from the control room, and each valve has a capacity of 373,000 lb/hr. A key lock selector switch EMERG CLOSE—NORMAL has been added to the existing analog circuit of the associated controls for each of the three power operated atmospheric relief valves. This provides the operator with the ability to close the relief valves by interrupting the analog signal, which normally controls the position of the relief valves. These selector switches are located in the cable vault and tunnel where the operator can operate the relief valves in the event of a fire in the control room or the emergency switchgear room. These valves which are equipped with quick-connect instrument air fittings can be operated locally with a portable air source if required. The steam generator power operated relief valves are equipped with a backup bottled air system so that they can be operated from within the containment spray pump house in the event of loss of offsite power.

Steam leaving the high pressure turbine passes through four moisture separator-reheater units in parallel to the inlets of the low pressure turbine cylinders. Each of the four steam lines between the reheater outlet and LP turbine inlet is provided with a crossover stop valve and an intercept valve in series. These valves, operated by the turbine control system, function to control turbine overspeed. Six ASME code safety valves are installed on each crossunder line between the high pressure turbine exhaust and the moisture separator inlet to protect the separators and crossunder system from overpressure. The valves are sized to pass the flow resulting from closure of the crossover stop and intercept valves with the main steam inlet valves wide open. Although this event is unlikely, the valves discharging to atmosphere prevent equipment damage.

Steam is supplied to the turbine drive for the auxiliary feedwater pump from each steam line upstream of the main steam trip valves. The steam lines to the turbine are continuously under steam generator pressure up to the shut-off valves located at the turbine drive. The air-operated steam supply valves for the auxiliary feedwater pump are operable from the control room or the auxiliary shutdown panel. Operation of these valves is also initiated automatically from a loss of power signal or on a low-low level signal in two of three steam generators. Indication of operating conditions is provided in the control room to enable the operator to adjust feedwater flow with any of the six motor operated valves shown on Reference Drawing 6.

Temperature flow probes are installed on the discharge side of the 15 main steam safety valves to monitor safety relief valve position on the main steam system. Valve position is indirectly “measured” by comparing discharge temperatures with respect to ambient temperatures with the valve closed. This indirectly determined valve status is transmitted through the ERFDAS (Emergency Response Facility Data Acquisition System) which provides the control room operator with a CRT display on the open or closed valve status for each of the main steam safety relief valves.

10.3.1.3 **Performance Analysis**

The steam generator repairs effected in 1979 and 1981 incorporated design features to eliminate various forms of tube degradation. The design features combined with inservice inspections will help ensure that tube integrity is maintained. The acceptability of the repaired steam generators is discussed in detail in a safety evaluation by the Office of Nuclear Reactor Regulation dated December 15, 1978 (Reference 2).

Design criteria for the steam generator lower assemblies require that tube vibration, tube fatigue, and tube support plate hole enlargement be within acceptable limits. As a result, flow-induced tube vibration caused by turbulence, fluid elastic excitation, and vortex shedding has been evaluated. The evaluation shows that the maximum alternating bending stress in a tube is 1.2 ksi. The code allowable number of cycles at this stress level is infinite and the fatigue usage factor is zero. Furthermore, the wear coefficient of SA-240 type 405 stainless steel, when paired with Inconel tubing at normal operating temperatures, is lower than that for carbon steel; therefore, initial tube clearances will be maintained and tube support conditions will not change noticeably during the lifetime of the steam generator.

If a main steam pipe rupture occurs, a flow signal measured by the venturi flowmeter located in that main steam line causes the swing check trip valves in all three main steam lines to trip closed. The trip valves are assumed to close within 10 seconds from the time the process variable reaches the trip setpoint. This time is comprised of three components: one second for the instrument response time delay from the time the setpoint is reached until bleed off of instrument air pressure is initiated, a maximum of 4 seconds to bleed off the instrument air pressure from the main steam trip valve operating cylinders, and a maximum of 5 seconds as closure time for the valve. If the rupture occurs downstream of the trip valves, valve closure stops the flow of steam through the pipe rupture, thus checking the sudden and large release of energy in the form of main steam. This prevents rapid cooling of the reactor coolant system and an ensuing positive reactivity insertion. Trip valve closure also ensures a supply of steam to the turbine drive for the steam-driven auxiliary feedwater pump described in Section 10.3.5.

If a steam line breaks between a trip valve and a steam generator, the affected steam generator continues to blow down. The nonreturn valve in the ruptured line prevents blowdown from the other steam generators. Steam-break accidents are discussed in Section 14.3.2.

10.3.1.4 **Secondary Plant All-Volatile Chemistry Treatment**

Phosphate chemistry was used prior to 1975, but both units changed to all-volatile treatment (AVT) in January 1975. A chemistry monitoring program has been implemented to inhibit steam generator tube degradation. Discussion of the monitoring system is provided in Section 9.6, Sampling System.

Condenser inleakage, contaminants from condensate polishing, and condensate/feedwater system corrosion products are the major sources of chemical agents that have the potential for accumulating as sludge on the steam generator tubesheet, producing deposits on steam generator heat transfer surfaces. The feedwater is the means by which these chemical agents are transported to the steam generator. AVT chemistry provides no buffer against the effects of condenser inleakage; it is incapable of preventing the formation of scale should the chemical agents that have the propensity for scale formation be present, and the ammonium hydroxide or the amines added to the system for feedwater pH control have minimum effectiveness as steam generator pH control agents at the operating temperature in the steam generator. Therefore, to accomplish the goal of maintaining the secondary system in an all-volatile chemistry environment that is innocuous to the steam generator materials, it is necessary to minimize the introduction of contaminants and corrosion products to the system. In addition to providing the proper environment for the steam generator, a well-maintained AVT chemistry program will accomplish the following:

1. Maintain the integrity of system components.
2. Minimize turbine deposits due to carryover from the steam generators.
3. Minimize sludge in the steam generators.
4. Minimize scale deposits on the steam generator heat transfer surfaces.
5. Minimize feedwater oxygen content prior to entry into the steam generators.
6. Minimize corrosion of the condensate/feedwater system materials.
7. Maintain chemistry near neutral in steam generator crevices.
8. Maintain desired dissolved oxygen level.

These objectives can be achieved by exercising chemistry control over the systems, including sampling and analysis, chemical injection at selected points, continuous system blowdown from the steam generator, and effective protection of the steam generator and feedwater train internals during periods of inactivity. The objectives are accomplished by meeting steam generator control parameters specified by the Nuclear Plant Chemistry Program. The specifications are based on the EPRI, PWR Secondary Water Chemistry Guidelines, including:

1. The use of approved amine(s) for feed water and steam pH control (ammonium hydroxide, morpholine, ethanolamine, and cyclohexylamine are acceptable).
2. The use of an approved oxygen scavenger in the feedwater train.
3. Continuous blowdown and continuous chemical addition.
4. Limiting the concentrations of contaminants in the feedwater and in the steam generator.

For corrosion prevention, the ingress of oxygen into the steam generators should be minimized. Oxygen should be less than 0.005 ppm in the blowdown under any operating or test condition. Oxygen is controlled by the addition of an oxygen scavenger. During hot standby, the concentration of oxygen in the feedwater can be 0.1 ppm or less, provided the concentration of oxygen scavenger injection into the steam generator is within recommended limits.

The concentration of oxygen scavenger in the steam generators during hydro and wet layup must be adequate to minimize dissolved oxygen and passivate the covered metal surfaces.

When controlling steam generator chemistry on AVT chemistry, it must be recognized that (1) AVT provides no buffering capacity for contaminants entering the steam generator, and (2) the steam generator bulk water pH is at or slightly in excess of the neutral pH for water at the operating temperature of the steam generator. The absence of alkalinity in the steam generator at its operating temperature is due to the low ionization of the feedwater pH control amines at these temperatures. Therefore, contaminants entering the steam generator that are more strongly ionized than the feedwater pH control amines have the potential for producing perturbations to the bulk water either in the form of free hydroxide (from fresh waters) or acidity (sea water or treated circulating water). The objectives of the steam generator chemistry control parameters are to provide a means for controlling the steam generator crevice chemistry to minimize corrosion of the steam generator and turbine cycle materials, and to provide a means whereby perturbations to the steam generator chemistry from sources such as condenser inleakage can be recognized.

In the recirculating steam generator, the only bulk water losses from the steam generator are the blowdown and the moisture that is entrained in the steam. Therefore, any contaminant entering the steam generator will tend to concentrate until corrective action is taken.

Based on the type of steam generator degradation that has been observed at pressurized water reactors (PWRs) cooled by seawater and brackish water, emphasis should also be placed on the control of sodium. Inconel 600 steam generator tubing is susceptible to caustic induced IGA/IGSCC, and because of this, every effort must be made to exclude free hydroxide from the steam generator environment. Operational control of the steam generator sodium to chloride molar ratio is recommended to achieve near-neutral chemistry in the steam generator crevices. The controlled addition of chloride may be warranted to counter excess sodium ions.

Protection of the steam generators during inactive periods due to maintenance and refueling requires placing the steam generators in a layup condition. To ensure the long-term performance of the steam system, the same degree of chemical control exercised during normal operation should be exercised during shutdown conditions.

Periods of hot shutdown and hot standby operation require that steam be released from the steam generators to release heat in the reactor coolant system due to heat input from reactor core decay heat and reactor coolant pump heat. Chemistry control is applied during such operations similar to that exercised during normal operating conditions.

Secondary-water chemistry specifications should be adhered to during all phases of unit operation. When specifications are exceeded, operator action is taken as recommended in the station's chemistry control program.

10.3.1.5 **Tests and Inspections**

The turbine overspeed protection is checked during normal unit start-up. The steam dump system also functions during unit start-up. Operation of the steam generator power operated relief valves is checked at start-up and also periodically during normal operation.

The turbine-driven auxiliary feedwater pump is tested in accordance with the Technical Specifications.

Safety-related main steam components are tested in accordance with Technical Specifications.

During unit shutdown, the tripping mechanisms for the trip valves are tested for proper operation. The nonreturn valves are also tested to verify that they are functional.

10.3.2 Auxiliary Steam System

An auxiliary steam system is provided as shown in Figure 10.3-7 and Reference Drawings 2 and 3. All piping is designed in accordance with the ASME Code for Pressure Piping, ANSI B31.1. A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the auxiliary steam system was found to be adequate.

10.3.2.1 **Design Basis**

Steam from the secondary system is reduced in pressure and supplied to the auxiliary steam system for space heating, process system heat exchangers, and process system air ejectors. Nearly all secondary steam used in the auxiliary steam system is condensed, returned to the condensate system, and then sent to either the condensate storage tank or the main condenser. A small quantity of secondary steam used in the auxiliary steam system for the after condenser air ejectors and containment vacuum ejectors is not returned to the condensate system for reuse. Auxiliary steam used in the after-condenser air ejectors is condensed and drained to the storm sewage system or returned to the condenser. Auxiliary steam used in the containment vacuum ejectors is ejected to the atmosphere through the roof of the auxiliary building.

The auxiliary steam system supplies 150 psig saturated steam throughout the station for auxiliary services.

Turbine building uses of auxiliary steam are as follows:

1. Main condenser air ejector.
2. Space heating.
3. Gland seal steam.

Auxiliary building uses of auxiliary steam are as follows:

1. Boron recovery system heat exchangers.
2. Chemical and volume control system (boric acid batch tank heating).
3. Containment vacuum ejectors.
4. Space heating.

Auxiliary steam is used in the yard for the following purposes:

1. Boron recovery tank heating.
2. Primary-grade water tank heating.

Auxiliary steam is used for space heating in the following additional areas:

1. Fuel building.
2. Decontamination building.
3. Safeguards area.
4. Service building area.
   a. Shops.
   b. Mechanical equipment rooms 1 and 2.
   c. Emergency generator rooms.
   d. Boiler room.

The service building, including locker rooms, laboratories, offices, instrument shop, mechanical room, assembly room, and first-aid room are heated by steam coils in air-handling and air-conditioning units that serve these areas. All of these air-handling units are installed in the mechanical equipment rooms 1 and 2.

No auxiliary steam is used in the operations administration building. It is heated by hot water and steam-heated ventilation air. The hot water converter and the air-conditioning unit containing the steam coil for ventilation heating are installed in the turbine building.

10.3.2.2 Description

Normally, the auxiliary steam supply header receives its steam requirements from the second point extraction lines. During periods of low load operation when second point extraction steam pressure drops below approximately 140 psig, steam is supplied from the main steam header through a pressure-reducing valve. When both reactors are shut down, steam is supplied by the heating boilers.

The containment vacuum system steam ejectors are used only during start-up periods to initially evacuate the containment. During normal operation, two mechanical vacuum pumps maintain the vacuum, as described in Section 5.3.4.

Two heating boilers, each rated at 80,000 lb/hr of steam, are provided for preliminary and shutdown operation. Each boiler is the packaged water tube type and is equipped with motor-driven fuel-oil pumps, deaereator, and feedwater pumps. Number 2 fuel oil is supplied to the boilers from the main oil storage tanks.

10.3.2.3 Performance Analysis

A loss of normal ac power will shut down the heating boilers. No services supplied by auxiliary steam are required to function as part of engineered safeguards during a loss of station power.

10.3.2.4 Tests and Inspections

Routine inspections are performed on a periodic basis.

10.3.3 Turbine Generator

The turbine-generator heat balance for the 100% core power rating of 2546 MWt is shown in Figure 10.2-1 and Reference Drawing 10.

10.3.3.1 Turbine

The turbine is a conventional 1800-rpm tandem compound unit consisting of one double-flow high-pressure cylinder and two double-flow low-pressure cylinders (Building Block 81). The turbine disks are Ni-Cr-Mo-V steel. Periodic inservice inspections are conducted to verify the integrity of the internal components of the turbines. An analysis of turbine missile risk is provided in Section 14.2.13. The inspections are conducted at a frequency consistent with the methodology specified in Reference 7. The inspection interval of the low pressure turbine blading is dictated by Technical Specifications.

The turbine is expected to achieve a maximum capability of 855,408 kW gross with inlet steam conditions of 748 psia and 0.25% moisture exhausting to 1.5 inch Hg (absolute) with a feedwater temperature of 441.1°F and 0.5% makeup. The turbine is provided with six stages of feedwater heating and four moisture-separator reheaters located between the high-pressure and low-pressure cylinders.

Each high-pressure steam line to the high-pressure cylinder contains a stop-trip valve and a governor control valve. Stop valves and intercept valves are provided at the discharge of the moisture-separator reheaters to the low-pressure turbine cylinders.

A gland steam sealing system is provided to prevent air inleakage and steam outleakage along the turbine shaft. All necessary piping, controls, and a gland steam condenser are provided.

The turbine oil systems include a conventionally designed electro-hydraulic-controlled governing-trip system. There is also a low-pressure bearing lubrication system, discussed in Section 10.3.7.

Overspeed protection is provided through use of an overspeed trip mechanism that consists of an eccentric weight mounted in a transverse hole in the turbine rotor extension shaft. Centrifugal force moves the weight outward against spring compression. When the turbine overspeeds to a point at which the mechanism is set to operate, the spring compression is overcome by the centrifugal force of the rotor speed, and the weight moves out to strike a trigger, which trips the overspeed trip valve and releases the auto-stop oil and operating fluid to drain.

Additional turbine overspeed protection utilizes the output of magnetic pickups mounted adjacent to the turbine shaft. A toothed wheel on the shaft provides a fluctuation magnetic coupling for the speed transducer pickups. The speed transducer senses fluctuations and translates them into a sine wave whose frequency is proportional to turbine speed. This signal is fed to the auxiliary governor. If the control subsystem senses an overspeed condition (103% speed), and the generator is not in parallel with the grid or if electrical output is less than 5%, then the auxiliary governor provides a control signal to SOVs in the EHC subsystem which depressurizes the governor valve emergency trip header. This trips the governor and intercept valves closed while the overspeed signal is present in an attempt to limit the overspeed and prevent an overspeed trip. Once the turbine speed decreases below 103% of rated speed, the solenoids close and the intercept valves start to reopen immediately followed by the governor valves after five seconds. When the generator is in parallel with the grid and electrical output is greater than 5% then the auxiliary governor's overspeed function is disabled. This is because this protection is not needed when these conditions are met due to the fact that synchronous generators in parallel must operate at grid frequency and physically can not overspeed.

The Reverse Power protection system provides two forms of turbine protection. Excessive heat damage to the turbine is prevented during generator motoring by tripping the generator breakers 40 seconds after sensing the reverse power condition. Additional turbine overspeed protection is provided by using the reverse power relay to provide sequential tripping.

Sequential tripping is the inclusion of a reverse power relay in series with any trip circuits using steam valve close position switches. This will provide security against possible overspeed by ensuring that all sources of steam to the turbine are reduced below the amount required to produce overspeed before the generator breakers and excitation breakers are tripped. In addition, the reverse power relay provides a time delayed backup trip in the case of failed or misadjusted valve position switches.

This protection will not override the generator or switchyard protection that instantaneously opens the generator breaker when an electrical fault occurs that might cause serious and certain damage to the generator or switchyard equipment.

10.3.3.2 **Generator**

The hydrogen inner-cooled generator rating is 1,055,000 kVA at 75 psig hydrogen gas pressure, 0.90 pf, three-phase, 60 Hz, 22 kV, and 1800 rpm. The Unit 1 generator has a 0.540 SCR, while the Unit 2 generator has a 0.559 SCR. The Unit 1 generator will be operated at 941,700 kVA at 60 psig hydrogen gas pressure and the Unit 2 generator will be operated at 941,700 kVA at 75 psig hydrogen gas pressure as discussed in Section 8.2.

Primary protection of the main generator is provided by differential current and field failure relays. Protective relays automatically trip the turbine stop valves and electrically isolate the generator.

A rotating rectifier (brushless) exciter with a response ratio of 0.5 is provided for both units. The exciter rating is 4700 kW, 570V dc, and 1800 rpm. The exciter consists of an ac alternator coupled directly to the generator rotor. The alternator field winding is stationary, and control of the exciter is applied to this winding. The alternator armature output is rectified by banks of diodes that rotate with the armature. This direct current output is carried through a hollow section of the shaft and is applied directly to the main generator field.

The 22-kV generator terminals are connected to the main step-up transformer and the unit station service transformers by 22-kV aluminum conductors, each rated at 26,000A. Each aluminum conductor is enclosed in a forced-air-cooled, isolated-phase bus duct. Further discussion of the interconnection between the generator and the transmission system is contained in Section 8.3.

Hydrogen seal-oil pumps are furnished to provide seal oil to the generator shaft seals for the prevention of hydrogen leakage from the generator. An ac motor-driven high-pressure hydrogen seal-oil back-up pump and a dc motor-driven, air side seal-oil backup pump are provided. A continuous bypass-type oil purification system removes water and other contaminants from the oil.

Since a mixture of hydrogen and air is explosive over a wide range of proportions (from about 4 to 70% hydrogen by volume), the design of the generator and the specified operating procedures are such that explosive mixtures are not possible under normal operating conditions. In order to provide for some unforeseen condition brought about by the failure to follow the correct operating procedure, it is necessary to design the frame to be explosion-safe. The intensity of an explosion of a mixture of air and hydrogen varies with the proportions of the two gases present. A curve on which the values of intensity are plotted against the proportions of gases will approximate a sine wave, having zero values at 5 and 70% hydrogen and reaching a maximum intensity at a point half way between these limits. The term “explosion-safe” is intended to mean that the frame will withstand an explosion of this most explosive proportion of hydrogen and air at a nominal gas pressure of 2 or 3 psig without damage to life or property external to the machine. This nominal pressure of 2 or 3 psig is that which might be obtained if hydrogen were accidently admitted during the purging operation instead of carbon dioxide, as specified. Such an explosion might, however, result in damage or dislocation of internal parts of the generator. When changing from one gas to another, the generator is vented to the atmosphere, so that a positive pressure of more than 2 or 3 psig will not be built up.

10.3.4 Circulating Water System

The circulating water system, Reference Drawing 4, provides cooling water for the main condensers and the service water systems of both units. A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the circulating water system was found to be adequate.

10.3.4.1 **Design Basis**

To prevent the direct recirculation of the heated circulating water discharge, the system is designed to take water from the James River on the east end of the site and to discharge to the James River on the west end of the site. The shoreline distance between the intake and discharge points is about 5.7 miles, and the overland distance across the peninsula is about 1.9 miles.

Each unit requires 840,000 gpm of river water to supply condensing and service water needs. To provide operational flexibility, system reliability, and station economy, the water requirement for each unit is supplied by four 220,000-gpm pumps. These pumps discharge to the common high-level intake canal that conveys the circulating water to the station area. Coarse trash is removed from the circulating water by trash racks at the river intake structure, and finer trash is removed at the river intake and at the entry-bay and station ends of the intake canal by two sets of traveling water screens. The circulating water flows by gravity from the high-level intake canal through four buried parallel lines to each condenser and then through four separate lines to a concrete tunnel for each unit. The tunnels terminate at seal pits located at the edge of the circulating water discharge canal, which is common to both units.

The discharge canal conveys the flow to the James River. The discharge channel within the river is provided with rock groins along each side to control sedimentation and to maintain exit velocities of the circulating water to achieve desired dilution effects of the heated effluent.

Some components of the circulating water system are used for handling service water, and are therefore designed as Seismic Category I structures and components. These components are:

1. The circulating water intake structure at the river.
2. High-level intake canal.
3. High-level intake structure.
4. Buried circulating water piping and valves between the high-level intake canal and the circulating water discharge tunnel.
5. Circulating water discharge tunnel.
6. Seal pits.
7. Intake canal low-level isolation level switches (1-CW-LS-102 & 103, 2-CW-LS-202 & 203).

10.3.4.2 **Description**

The circulating water is withdrawn from the James River through a channel dredged in the river bed. The original channel invert was 150 feet wide at Elevation -13.3 ft. It extended a distance of approximately 5000 feet to the main river channel. A natural river channel bisects the dredged channel approximately 2000 feet from the shore. This inner portion of the dredged channel is periodically monitored and dredged as necessary to support plant operations. The combination of the natural channel and the dredged channel is also used for shipping materials and equipment to the permanent dock on the east side of the site.

The circulating water intake structure is located at the shore end of the river intake channel and is an eight-bay reinforced-concrete structure. The exposed deck of the structure is at Elevation +12 ft. The invert of the intake structure is at -25.25 feet. Each bay houses one of the eight circulating water pumps for the two units. These pumps are rated 220,000 gpm at 28 feet total dynamic head when running at 220 rpm. Each pump is driven by a vertical, solid-shaft, 2000-hp, induction motor. The pumps are of the nonpullout type and are serviced using mobile hoisting equipment. Before entering the pumps, river water passes through a trash rack and travelling screen at the mouth of each bay. The travelling screens are provided with deflector flaps and screenwash pumps for low-pressure water spray. The deflector flaps ensure that fish dumped from the screens are deflected into a trough for transport via an effluent flume back to the James River. The low pressure spray ensures more efficient washing of fish from the screens into the fish collector trough. The trash rack is serviced by a movable trash rack rake that discharges collected trash to a receptacle where it accumulates until trucked off-site for disposal. In the event of a power failure, accumulated trash can be removed by manual raking. This process could continue indefinitely; however, it is expected that any power failure at the station low-level intake would be of relatively short duration.

Each circulating water pump discharge line is a 96-inch diameter steel pipe that conveys the water over the embankment of and into the high-level intake canal. At the crest of the canal embankment, the crown of the pipe is provided with a pair of active vacuum breakers (valves) and a tap for the vacuum priming system. The vacuum priming system prevents air accumulation in the pump discharge line while the pump is operating. This system is isolated when the circulating water pumps are de-energized. The active vacuum breakers open when the circulating water pump is de-energized. These vacuum breakers prevent loss of water from the high-level intake canal by siphoning through idle pumps. A passive vacuum breaker, designed to conserve intake canal water in the event of a failure of the paired active vacuum breaker valves, is located on the discharge end of each 96-inch diameter pipe. The passive vacuum breaker consists of a 20-inch diameter low profile vertical pipe protection which extends to Elevation +25 ft. of the intake canal. The passive vacuum breakers are designed to interrupt the postulated siphon action prior to reaching the technical specification limitation for canal water level.

The high-level intake canal is about 1.7 miles long and is designed to convey the circulating water flow to the station. The canal is paved with 4.5 inches of reinforced concrete, to allow velocities that would otherwise erode the earthen materials through which the canal is constructed. Since these earthen materials have low permeabilities, significant loss of water through the canal lining and into the substrata is not considered probable. The bottom width along most of the length of the canal is 32 feet, and the canal has side slopes of 1.5 feet horizontal to 1 foot vertical. The invert elevation varies from Elevation +5 ft. at the station end of the canal to Elevation +6.8 ft. at the river end of the canal. The berm along each bank of the canal is at Elevation +36 ft.

The water levels in the canal are controlled by the piping system friction losses within the power station and the prevailing river level. The normal water elevation at the power station end of the canal will vary between Elevation +26 ft. and Elevation +30 ft., depending upon the tide. A minimum freeboard greater than four feet is maintained between the canal water surface and the berm at Elevation +36 ft. during hurricane flooding of the river. This freeboard is adequate to contain surges in the canal that could occur with a loss of station power when the river is in flood and is maintained by progressively reducing the number of pumps in operation by manual control as the James River rises above Elevation +5 ft.

A reinforced-concrete, high-level intake structure is provided in the high-level intake canal at each power station unit. Each structure contains four bays, and each bay contains a trash rack, a traveling screen, and an inlet to a 96-inch-diameter condenser intake line. Steel plates can be placed on the stop log supports to permit dewatering of individual bays of the structure. Screenwash water is supplied by two pumps, each rated at 850 gpm at a 220-feet TDH.

Level sensors (1-CW-LE-102 & 103, 2-CW-LE-202 & 203) are installed in four of the screenwell bays (B & D for Unit 1 and A & C for Unit 2) between the trash rack bars and the travelling screens. Each sensor is positioned at Elevation 23-ft. 6-in. and will initiate a low level isolation channel assigned to two independent trains of 3-out-of-4 actuation logic when the canal level decreases to or below that elevation.

The four 96-inch diameter lines connecting the condenser and the high level intake structure are reinforced concrete in the station yard and welded steel encased in concrete under the station. Service water system taps are made in the steel portion of these lines.

Electric motor-operated butterfly valves are provided at the condenser inlets and outlets. The discharge lines terminate at the reinforced-concrete discharge tunnel, which then carries the water to the common circulating water discharge canal. This tunnel is 12 ft. 6 in. by 12 ft. 6 in. in cross section. The circulating water system total energy gradient in the discharge system is maintained at proper elevation to ensure a full condenser discharge water box by a seal weir at the termination of the discharge tunnel.

On each unit’s discharge tunnel, upstream of the vacuum priming house, is a 12-inch manually operated butterfly valve which is no longer used and has been abandoned in place.

The discharge canal is excavated in earth and is designed to carry the flow of the two units with a velocity of about 2.2 fps at mean low water. The invert of the canal is at Elevation -17.5 ft. and the sides slope at 2 feet horizontal to 1 foot vertical; this slope is stable under the design basis earthquake condition. The bottom width of the canal varies between 20 feet and 65 feet.

The discharge canal extends about 1200 feet into the James River. This extension has rock-filled groins along each side to minimize siltation. The opening between the groins is sized to ensure proper mixing of the discharge water with the James River. A timber pile trestle having five 10-foot-wide bays in which timber gates may be placed extends about half-way across the opening in the groin. The timber gates may be installed in this structure using mobile hoisting equipment to reduce the net area of the opening between groins and increase terminal flow velocity if determined necessary. Since terminal flow velocity is no longer considered a necessary parameter for thermal effluent control and is not required in the existing VPDES permit, the timber gate feature has effectively been abandoned in place.

10.3.4.3 **Performance Analysis**

All four circulating water pumps for each unit should normally be in service. If a circulating water pump is out of service, unit operation can be continued, but the station operator must maintain a satisfactory water level in the high-level intake canal by throttling the condenser outlet valves.

The condenser inlet and outlet valves are normally controlled from the control room. When a consequence-limiting safeguard-initiation occurs and there is a loss of station power, both inlet and outlet valves receive automatic close signals so that if one fails to close, the other will close.

The valves are closed to conserve water in the high-level intake canal for cooling the recirculation spray heat exchangers. When a loss of power occurs without a consequence-limiting safeguard initiation signal, the condenser outlet valves are throttled to conserve water in the intake canal for the bearing cooling heat exchangers and component cooling heat exchangers, and to provide a minimum flow required by the steam dump system. If the water level in the high-level intake canal drops to Elevation 23-ft. 6-in., both the condenser inlet and outlet valves are closed to conserve water in the high-level intake canal for subsequent use. Two air-operated vacuum breaker valves are mounted on each condenser outlet waterbox at the highest point in the circulating water system. These valves are designed to interrupt the siphon action of circulating water flowing through the condenser and conserve intake canal water during a postulated Appendix ‘R’ event which prevents closure of the condenser inlet and outlet valves. As mentioned in Section 10.3.4.1, certain components of the circulating water system are designed as Seismic Category I structures to preclude system failure during an earthquake, and are also designed to withstand a tornado in order to ensure a supply of service water in the event of an accident. The traveling water screens have been sized to prevent trash from plugging critical heat exchangers in the service water system.

Automatic operation of the condenser inlet and outlet valves and the valves in the service water system under various accident or event conditions are listed in Table 9.9-1.

A single-ended rupture of one of the 96-inch diameter main circulating water system lines upstream of the condenser isolation valve will not lead to unacceptable consequences. Within the turbine and service building, the postulated break could only occur at Elevation 5 ft. 6 in. in the valve pit in front of the condensers. In this area, the 96-inch diameter steel pipes are exposed above the concrete encasement for a height of approximately 28 inches. A 96-inch-diameter motor-operated isolation valve and an expansion joint connect this section of the pipe directly to the condenser. The pipelines in question have been analyzed to ensure that failure will not occur as a result of a design-basis earthquake.

The circulating water pipe enters the turbine building through a concrete pipe chase. As it nears the main condenser it makes a 90-degree turn upward and exits the concrete pipe chase adjacent to the main condenser. After the motor-operated isolation valve and expansion joint, the pipe immediately takes a 90-degree turn to the main condenser water box. A break in the circulating water pipe that would permit the equivalent flow of a complete single-ended rupture into the turbine building is not credible. The pipe chase confines the movement of the pipe below the valve, the valve permits stopping flow if the break is after the valve, and the short run of exposed pipe after leaving the pipe chase prohibits side movement of the pipe to clear the break and permit full unrestricted flow.

Because of these restraints on the movement of the circulating water piping, it is not considered likely that a crack will develop in the approximate 28-inch section of exposed pipe. In the unlikely event that a crack as wide as 1/8 inch developed around as much as one half of the circumference of the pipe, the flow through the crack would be approximately 2000 gpm, which would not exceed the capacity of the turbine building floor drain sump pumps. There are three floor drain sumps for both units, each equipped with three pumps rated at 1300-gpm, for an individual sump rated capacity of 3900 gpm.

Stop logs at the inlet end of the intake structure are employed to seal off the circulating water lines upstream from the isolation valves. Long-term cooling water canal integrity provided by installing these stop logs ensures a continued ability to remove decay heat.

There are separate takeoffs from two of the four circulating water lines to supply service water to the equipment needed during an emergency.

Isolation of one of the circulating water lines containing these connections would not result in interruption of emergency service water supply.

Two 300-gpm submersible makeup water pumps for the Gravel Neck Facility have been installed in the intake canal. The supports for these pumps have been designed so that the pumps cannot take suction below the minimum canal level in Technical Specifications. This ensures that design basis calculations for canal level drawdown following a loss of offsite power, are not affected by makeup pump operation. Since these makeup pumps are only rated at 300 gpm, they have an insignificant impact on total circulating water flow during normal station operation.

Automatic operation of the condenser and service water motor-operated valves, as described in Table 9.9-1, are checked during initial operation and at frequent intervals thereafter.

Intake canal level instrumentation calibration and alarm setpoints are checked periodically. The level sensor channels and logic trains are calibrated and tested in accordance with the Technical Specifications.

10.3.5 Condensate and Feedwater Systems

The condensate and feedwater systems are shown on Figures 10.3-8 and 10.3-9 and Reference Drawings 5 and 6, and the heat balance used for station design is shown on Figure 10.2-1 and Reference Drawing 10. A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the following systems were found to be adequate: condensate system, feedwater system, feedwater heaters, moisture separator and high pressure heater drain system, low pressure heater drain system and the extraction steam system.

10.3.5.1 Design Basis

The condenser hotwell is designed to operate at a normal level such that about 4 minutes of condensate flow is available to supply the condensate pumps. A 300,000-gallon condensate storage tank floats on the system. Each of the three vertical barrel-type condensate pumps is rated at 9000 gpm and 1070 feet TDH. Minimum flow through the pumps and gland steam condenser is maintained by an orifice-measuring device downstream of the gland steam condenser. The orifice-measuring device operates the recirculation valve.

Two steam generator feedwater pumps, each rated at 13,800 gpm and 1700 feet TDH, are furnished to supply feedwater to the three steam generators. Each feedwater pump is equipped with two electric motor drivers in tandem. Minimum flow through each pump is maintained by flow nozzles in the discharge lines. The recirculation valve opens when the flow drops to 4300 gpm.

A turbine-driven auxiliary feedwater pump, rated at 700 gpm and 2730 feet TDH, and two motor-driven auxiliary feedwater pumps, rated at 350 gpm and 2730 feet TDH, receive suction from a separate 110,000-gallon-capacity emergency condensate storage tank. The feedwater pumps are located outside the containment in a tornado-missile-protected enclosure near the main steam line and feedwater line containment penetration. The emergency condensate storage tank is also tornado missile protected, as is the suction piping leading from the storage tank to the pumps. The system design is based on the following conditions:

1. Integrated residual heat release from a full-power equilibrium core.
2. Feedwater inventory of the steam generators operating at normal minimum feedwater level.
3. Minimum allowable steam generator feedwater level permitted to prevent thermal shock or other damage.
4. The temperature of the feedwater that is supplied from the condensate storage tank. This temperature was assumed as 32°F when considering thermal shock, and 120°F when considering feedwater enthalpy.

The auxiliary feedwater system has been designed, constructed, and maintained to withstand a design-basis earthquake, utilizing methods and acceptance criteria consistent with those applicable to other safety-grade systems in the plant. All areas of the auxiliary feedwater system (i.e., pumps/motors, piping, valves/actuators, power supplies, water sources, instrumentation and control systems, and structures having and supporting the auxiliary feedwater system) are seismically qualified to the design-basis earthquake level.

The pump discharge piping of the auxiliary feedwater systems installed in Units 1 and 2 is cross-connected to ensure that, in the event of a postulated high energy line break in the Main Steam Valve House or a fire that disables the auxiliary feedwater pumps, the unaffected system will have the ability of maintaining both units in a shutdown condition. The cross-connect line originates downstream of each unit's auxiliary feed pump discharge valve on the auxiliary feed system two main branch lines. Motor-operated valves are installed on each of the two cross-connect branches to provide remote control. A manual valve upstream of the motor-operated valves provides manual control of that specific branch of the cross-connected feed system.

The pumps, drives, piping, and 110,000-gallon emergency condensate storage tank have all been designed as Seismic Category I components (Section 15.2.1).

10.3.5.2 **Description**

The condensate and feedwater systems are shown on Figures 10.3-8 and 10.3-9 and Reference Drawings 5 and 6. Condensate is withdrawn from the condenser hotwells by two of the three half-size motor-driven condensate pumps. The pumps discharge into a common 24-inch header and then through a 24-inch manually operated gate isolation valve to the condensate polishing building. There the water is purified and sent back through another 24-inch manually operated gate isolation valve to the condensate header. From there the condensate continues through two parallel steam jet ejector condensers and through one gland steam condenser. A 24-inch motor-operated gate valve allows for bypassing the gate isolation valves when the system is not in use. The common header divides into two 18-inch lines that carry condensate through a pair of heater drain coolers and the tube side of two parallel trains of five low-pressure feedwater heaters to the suction of two half-size steam generator feedwater pumps. The steam generator feedwater pumps discharge through two parallel No. 1 feedwater heaters to an 18-inch discharge header for distribution to the steam generators through three individual feedwater flow control valves, positioned by the three-element feedwater control system for each steam generator. A remotely operated small bypass valve is provided in parallel with each of the feedwater flow control valves for manual control of feedwater flow to maintain steam generator levels, primarily during low-power operation or hot shutdown. Each bypass line has the capability to provide flow rate indication when aligned to the branch connection downstream of its associated feedwater flow venturi (see Figure 10.3-9).

Drains from the moisture-separators, reheaters, and the No. 1 and No. 2 feedwater heaters are collected in the high-pressure heater drain tank and pumped into the suction of the steam generator feedwater pumps by one of two full-size high-pressure feedwater heater drain pumps.

The principal controls of the condensate and feedwater systems are located in the control room. The system is arranged for automatic or manual control.

Impure condensate in the condenser hotwells is either routed to a condensate polishing system, where it is purified and reused, or is discharged under administrative control through a double-valve connection to the circulating water discharge canal. The double-valved connection with telltale drain prevents inadvertent releases. Planned releases of hotwell condensate to the discharge canal are infrequent, since they are needed only when there has been a major upset in condensate-feedwater chemistry. The condensate is manually sampled to determine if activity levels will permit a safe release. Blowdown line sampling and monitoring is conducted during such releases to ensure that an increase in condensate activity is detected in sufficient time to permit operator action to avoid an uncontrolled release of radionuclides to the environment. Additional indication is provided by radiation monitors installed at the seal pit of the circulating water discharge tunnel.

Two condensate storage tanks, one per unit, are provided for makeup and can be cross connected if necessary. The amount of makeup is controlled by low hotwell level. A recirculation control to the hotwell returns condensate at low generator loads and provides the minimum amount of water for the air ejector condensers and the gland steam condenser.

A condensate cleanup line allows cleaning of the condensate piping and components prior to unit start-up. The condensate pumps can be used to recirculate condensate through the entire condensate system up to the suction of the main feed pumps, through the cleanup line, and back to the condenser hotwell. The condensate is cleaned by filtration through the condensate polishing system demineralizers.

A mixed-bed full-flow condensate polishing system removes dissolved salts and suspended solids from the condensate system. Design and operating information are given in Table 10.3-2.

Each unit's condensate polishing system consists of an independent set of condensate demineralizers supplied from the main condensate header downstream of the condensate pumps. Each set consists of seven demineralizers (six on-line, one spare) with each demineralizer containing mixed resins of cation resin and anion resin. As condensate passes through the resin, impurities are removed by interaction with the resin beads or by the filtration action of the overall resin bed. Each demineralizer discharge then passes through a resin trap, which prevents resin from entering the condensate stream, to an effluent header for return to the condensate system. At the inlet to each trap, an instrumentation penetration supplies a sample source to individual conductivity cells and to local sample valves. A sample is taken before a demineralizer is allowed to supply the condensate stream.

Demineralizer resin is transferred to an external regeneration system for separation and chemical regeneration. Each unit has an independent regeneration system consisting of a separator, separator feed tank, cation regeneration tank, an anion regeneration tank, and a resin mix tank. Air for resin transfer operations is supplied at 40 psig and 100 psig from the service air header of the instrument and service air system. Interlocks are provided to prevent inadvertent operations of influent and effluent valves during resin transfer operations.

Following regeneration, the anion and cation resin is transferred to a resin mix tank in preparation for its eventual return to the condensate demineralizers. Wastes generated by the regeneration process are treated and discharged by the waste neutralization system. Waste is discharged to the settling pond or to the discharge tunnel, and is discharged via waste filters if radiation is present. The waste filters may be bypassed if the total suspended solids have been analyzed to be less than the limits provided in the VPDES permit. Demineralizer and waste systems are remotely controlled from control panels in the condensate polishing building, which is located at the east end of the Unit 2 turbine building.

Condensate polishing system instrumentation is provided to monitor level, pressure, temperature, and flow parameters. This information allows for manual or automatic operation of the system. The instrumentation is tested in accordance with station requirements for existing Category II instrumentation.

Fire protection measures associated with the condensate polishing building are described in Chapter 9. Normal and emergency lighting is provided in the condensate polishing building.

Chemical feed equipment (Figure 10.3-10 and Reference Drawing 7) is provided for chemical treatment of feedwater based on the AVT concept. Hydrazine is added to control residual oxygen content, and ammonium hydroxide, morpholine, ethanolamine, or cyclo-hexylamine can be added to maintain an elevated pH. These chemicals act as corrosion inhibitors to reduce pickup of metal by the feedwater. Solutions are pumped into the main condensate and steam generator recirculation and transfer systems by motor-driven, positive-displacement pumps with manually adjustable strokes.

An auxiliary steam turbine-driven feedwater pump supplies feedwater to the steam generators during a complete loss of station power. During periods of start-up, and for core residual heat removal, two auxiliary feedwater pumps, driven by electric motors connected to the station emergency busses, can be used.

Each of the three pumps discharges into two headers, aligned by manual valves. There are three lines from each header. Each line has a motor-operated valve with a downstream stop-check valve located inside containment. The lines join downstream of the stop-check valves and form a common discharge to supply each steam generator via the associated main feed line. Check valves in the main feedwater lines prevent loss of auxiliary feedwater should a main feedwater line rupture outside containment. The common discharge line to each steam generator has a cavitating venturi installed to restrict flow to the steam generator in the event of a ruptured steam line. A strainer is also installed upstream of each cavitating venturi to prevent blockage of the venturi throat by debris. In the event of failure of one header, the supplies from the pumps may be isolated by manually operated valves to ensure steam generator water flow from the other header. The motor-operated valves required to establish a flow path from the discharge of these pumps to the steam generators are configured such that four of the six valves are left open with the plant between 350°F/450 psig and also receive automatic open signals. The two remaining valves feeding Steam Generator “B” for each unit remain closed between 350°F/450 psig and 535°F and are procedurally opened prior to hot shutdown. The auto-open function for these MOVs has been defeated. This alignment ensures that the turbine driven and motor driven pumps are not damaged by an unanalyzed high flow and potentially inadequate Net Positive Suction Head available (NPSHa) margin condition when a single AFW pump was delivering flow to three low pressure steam generators. The discharge valves fail as-is. Steam generator level is controlled manually from either the control room or the auxiliary shutdown panel by operating the appropriate motor-operated valve in the auxiliary feedwater line.

The steam for the steam-driven auxiliary feedwater pump is supplied from the three main steam lines upstream of the main steam trip valves. Check valves in the steam supply lines prevent steam from flowing into a ruptured main steam line so that an adequate supply of steam will reach the turbine for the steam-driven pump. This steam enters the turbine-driven pump through two parallel air operated valves. These parallel air operated valves are controlled by double acting piston actuators that normally hold the valves closed. On a loss-of-power to the air supply solenoid, the pneumatic double acting piston actuator fails the valves open. A bottled nitrogen system is installed to provide control of the air operated valves for a minimum of 2 hours independent of instrument air.

The auxiliary feedwater system discharge lines of both units are cross connected but are isolated by normally closed motor-operated valves. Operator action will permit the auxiliary feedwater system of one unit to supply water to the steam generators of the other unit. These motor-operated valves are remote manual valves and require operator action to open. They are powered from an emergency bus and are controlled manually from the control room. Check valves are installed in each of the two cross-connect branch lines to the respective auxiliary feedwater header inside each containment to maintain the redundancy of these headers.

Each pump is provided with a full flow recirculation line to facilitate pump periodic testing. The return flow path to the emergency condensate storage tank is normally isolated by two valves in series, with valve position controlled by the plant operating procedures.

10.3.5.3 **Performance Analysis**

The auxiliary feedwater system, as described below, is the portion of the condensate and feedwater systems required for certain accident scenarios. A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the auxiliary feedwater system was found to be adequate.

The auxiliary feedwater system is designed as a safety-related system except for the initiating signals of the reactor coolant buses undervoltage feature, the main feedwater pump breaker trip feature, the loss of reserve station power feature, and the AMSAC feature. The initiating circuitry incorporates both automatic and manual system start capability, including manual initiation of the system from the control room. Manual initiation capability is provided independent of automatic initiation, and the design of the automatic safety-related initiation circuitry is such that a single failure cannot result in total loss of the system function. The design of the safety-related portions of the auxiliary feedwater systems incorporates testability, and the system is powered from reliable emergency buses as specified in NUREG-0578, including automatic actuation of ac motor-driven pumps and valve loads onto the emergency buses. Although the MOVs feeding the B Steam Generator are powered from the emergency buses, the automatic actuation feature for these valves has been defeated. The position of these MOVs are procedurally controlled to ensure proper AFW system operation.

The auxiliary feedwater system consists principally of a turbine-driven auxiliary feedwater pump rated for 700 gpm, two motor-driven auxiliary feedwater pumps rated for 350 gpm, a 110,000-gallon storage tank, and associated piping, valves, and controls. The turbine-driven pump and the electrically-driven pumps represent two diverse pumping systems that operate automatically to supply auxiliary feedwater to the steam generator.

The turbine-driven auxiliary feedwater pump can be used for residual heat dissipation as long as adequate main steam is available. The steam supply lines to the turbine are continuously under main steam pressure to keep them warm and to prevent the formation of water droplets on turbine start-up. Steam traps are provided in lines to ensure that any condensate formed as a result of cooling is removed; however, the turbine is a single-inlet, single-stage unit, and any drops of water forming will not damage or impair its operation.

When main steam pressure is no longer adequate to provide sufficient cooldown, the need for residual heat removal has also been reduced to a level where one of the motor-driven auxiliary feedwater pumps can be used as necessary. The motor-driven pumps are powered from the 4160V emergency buses.

A reduction in the capability of the secondary system to remove the heat generated in the reactor core occurs if a loss of normal feedwater flow (LONF) condition exists. Section 14.2.11, Loss of Normal Feedwater, contains an evaluation of this event for cases with and without the reactor coolant pumps operating and a conservative core residual heat generation. If this event occurs, a reactor trip signal is generated due to a low-low steam generator level. To prevent water relief from the pressurizer and to ensure long-term decay heat removal subsequent to the reactor trip, adequate auxiliary feedwater flow is required. This is provided by use of either the turbine-driven or motor driven auxiliary feedwater pumps. The required amount of auxiliary feedwater depends on the status of the reactor coolant pumps and the core residual heat generation. With the reactor coolant pumps operating, more heat is added to the reactor coolant system which requires slightly more auxiliary feedwater for heat removal. The decay heat in current LONF analyses is based on 100% of the ANS 1979 Decay Heat Standard with 2-sigma uncertainty. Both types of auxiliary feedwater pumps are designed to start within 1 minute, even if a loss of offsite ac power occurs simultaneously with a loss of normal feedwater flow. These pumps ensure that there is adequate capacity to cool down the reactor.

Each unit's auxiliary feedwater pumps take suction from a tornado and missile protected 110,000-gallon emergency condensate storage tank (ECST), which is maintained above 96,000 gallons during unit operation. Each ECST (1/2-CN-TK-1) has redundant level indicators that provide for safety-grade indication, and alarming functions associated with tank level. The transmitters are seismically qualified, and are powered from a safety-related Class 1E vital bus. These components are not subject to harsh environmental conditions. Control room indication is provided with alarms set at or above the minimum Technical Specification limit of 96,000 gallons for tank level and also at a lower level to indicate when there is a 20-minute water supply remaining for the highest volume auxiliary feedwater pump.

Operation of the auxiliary feedwater pumps provides residual heat removal capability for up to 8 hours using the ECST. Each unit also has a non-safety-related emergency condensate makeup subsystem, consisting of a 100,000-gallon in-ground emergency condensate makeup tank (1/2-CN-TK-3) with auxiliary feedwater booster pumps, which can supply additional feedwater for additional heat removal capability. In addition, for Appendix R and environmental qualification considerations, both unit's auxiliary feedwater pumps are cross-connected at the pump discharge. Each unit's ECST is maintained above 60,000 gallons to support cross-tie capability for the opposite unit. An emergency source for necessary feedwater is the fire protection system. The three auxiliary feedwater pumps with redundant means of motive power and associated piping are installed in a tornado-protected area adjacent to the containment so that their use can be relied upon during any loss-of-station power accident.

The automatic initiation signals and circuits for the auxiliary feedwater system comply with the single-failure criterion of IEEE Standard 279-1971, with exceptions. The following signals are used for automatic initiation of the auxiliary feedwater system:

1. Turbine-driven auxiliary feed pump
   a. Low-low steam generator level (two out of three)
   b. Undervoltage on the reactor coolant pump buses (two out of three)
   c. AMSAC initiation
2. Motor-driven auxiliary feed pumps
   a. Low-low level from any one steam generator
   b. Loss of reserve station power (station blackout)
   c. Trip of both main feedwater pumps
   d. Safety injection
   e. AMSAC initiation

The steam generator level signals and the input signals from the safety injection system are both redundant and independent. Undervoltage on the reactor coolant pump buses, main feed pump breaker trip, and loss of reserve station power are considered operational signals for economic (non-public safety) protection and are therefore not required to meet the single failure criterion of IEEE Standard 279-1971.

The AMSAC signal is provided as a means, diverse from the reactor protection system, to automatically initiate the auxiliary feedwater system. This back-up signal was provided in accordance with the requirements of 10 CFR 50.62. The AMSAC logic circuit power supplies are normally powered from non-safety related sources independent of the RPS and are capable of operating on a loss of offsite power. They can be powered from EDG #1 (Unit 1) and EDG #2 (Unit 2) by manual action. (Section 7.2.3.2.7)

The motor-driven auxiliary feedwater pumps are part of the emergency diesel generator sequencing scheme. This feature functions on a loss of offsite power concurrent with or subsequent to a safety injection. The EDG load sequencing scheme will trip the motor-driven auxiliary pumps, if running, and delay the motor-driven auxiliary feedwater pump restart for 10 seconds on SI or 140 seconds on hi-hi CLS (Section 8.5).

The operating bypasses associated with the automatic initiation logic circuitry (including sensors used for automatic initiation) during start-up or operation of the reactor are as follows:

1. The steam generator low-low level initiation circuitry is always active and can be bypassed by placing a particular channel in the test position. This action is restricted by the Technical Specifications. Since these channels are always active, a bypass removal mechanism is not needed.
2. Safety injection initiation circuitry is provided with a bypass for start-up purposes and is separately alarmed in the control room. This bypass (block) is automatically unblocked and requires no operator action.
3. During start-up, the circuit breakers for the motors of at least one main feed pump are closed in the test position to allow the motor-driven auxiliary feedwater pumps to be placed in the automatic mode when required by Technical Specifications. The breakers are procedurally taken out of the test position when the second main feed pump is placed in operation.
4. The auxiliary feedwater pumps may be prevented from starting by placing the pump controls in the PULL-TO-LOCK position. The auxiliary feedwater control is procedurally returned to the AUTO position prior to exceeding RCS temperature and pressure limits of 350°F and 450 psig.
5. Reactor coolant system loop isolation valves provide a signal, when closed, that prevents automatic start of auxiliary feedwater pumps from a steam generator low-low water level signal in the affected loop. This signal is automatically reinstated upon reopening of the valves. In the event this block is initiated, a permissive status light is lit in the control room to alert the operator of the condition. This is, however, not considered an operating bypass, since the plant operation is restricted to three-loop operation and at no time would it be operated with a loop isolated.
6. The reactor coolant pump undervoltage channels that sense the voltage on the station service buses A, B, and C are not provided with bypass capability during start-up or operation.

No bypass capability is provided for the station blackout signal, which senses the voltage on the station transfer buses.

The automatic safety-related initiation circuitry for the auxiliary feedwater pumps originates in the engineered safeguards and reactor protection systems, which are designed in accordance with IEEE 279-1971. Portions of the automatic initiation circuitry, from the reactor coolant buses, main feedwater breakers trip, the loss of reserve station power, and the AMSAC initiation circuitry are not required to completely comply with IEEE 279-1971 because these initiation circuits are needed only as a backup or non-safety-related safeguards feature. Manual capability to initiate auxiliary feedwater operation from the control room has also been retained. Safety-related initiating signals and circuits are powered from emergency buses, with testability an integral feature of the design.

The auxiliary feedwater motor-driven pumps can be locked out by placing pump control in the “pull-to-lock” position. This action prevents automatic initiation of the pump and, therefore, the auxiliary feedwater motor-driven pump overload trip annunciator actuates when the pump control switch is in the “pull-to-lock” position. In addition, a white status light for each auxiliary feedwater pump control switch indicates that its associated breaker is racked into the “connect” position and the breaker has closing control power available.

Safety-grade auxiliary feedwater flow instrumentation is provided in the control room. The instrumentation is powered from the emergency buses and meets regulatory requirements for diversity. Auxiliary feedwater flow to each of the three steam generators is indicated in the control room. Steam generator level instruments back up the flow instruments to satisfy the single-failure criterion. Each steam generator has three narrow-range and one wide-range level instrument loops, which read out in the control room and are energized from vital instrument buses. The auxiliary feedwater flow indication is testable from the transmitter back to the indicator. The total accuracy of the auxiliary feed flow loop is approximately $\pm 1.7\%$ of span for normal operating conditions.

In response to NUREG-0737, it has been confirmed that the ECST has sufficient capacity to provide 700 gpm of auxiliary feedwater flow from the turbine-driven auxiliary feedwater pump for at least 2 hours independent of any AC power source. Auxiliary feedwater pump lube oil cooling is also independent of AC power because the lube oil coolers are cooled by a flow path from the pump discharge back to the pump suction. Emergency dc lighting provides sufficient lighting to manually control the turbine-driven auxiliary feedwater pump and discharge valves. Sound-powered phone communication capability is available in the vicinity of the auxiliary feedwater pumps and discharge valves.

Two parallel, pneumatic valves enable automatic control of the steam supply to the turbine-driven auxiliary feedwater pump, independent of any AC power. Each pressure control valve (PCV) is controlled by a DC-powered solenoid valve. A nitrogen tank with a regulator and a check valve has been added to the instrument air supply line to provide control of the PCVs for a period of 2 hours. The tank and check valve are necessary because the normal instrument air supply would not be available upon loss of all ac power.

Cavitating venturis (flow restrictors) have been installed in the 3-inch auxiliary feedwater lines leading to each steam generator. They are designed to limit the runout flow to approximately 350 gpm for the loop which has been affected by a main steam line break (MSLB) or main feedwater line break (MFLB). Correspondingly, this will permit the minimum required flow to be delivered to the unaffected steam generators.

The venturi design is based on the loss of the turbine driven AFW pump and the availability of two electric driven AFW pumps. Under the design conditions, the minimum required total flow of 350 gpm to the intact loops is met for core residual heat removal requirements.

Procedures are provided to assist the operators in manually starting the auxiliary feedwater system and controlling feed flow to the steam generators under a variety of operating conditions. Since the Surry Power Station has the capability of cross-connecting the two units' auxiliary feedwater systems, procedural guidance is provided on how to utilize the other unit's auxiliary feedwater system, if necessary.

Operability requirements for the auxiliary feedwater system and associated instrumentation are prescribed by the Technical Specifications.

The feedwater piping at the Surry Power Station incorporates several design features to reduce the likelihood of secondary-system fluid flow instability, i.e., water hammer:

1. Loop seals at the feedwater inlets to the steam generators are provided to reduce the length of piping that could be filled with steam if the steam generator feedring were to drain into the steam generator.
2. Top discharge feedwater spargers (J-tubes) reduce the likelihood of feedring drainage. The flow conditions to which the J-tubes are subjected are not severe, and J-tube stiffness is very high. The design has been evaluated for the expected service conditions and the integrity of the attachment weld will be maintained for the expected plant lifetime.
3. A full penetration weld between the steam generator feedwater inlet nozzle and the feedring prevents leakage from the feedring when steam generator water level is below the feedring.
4. The steam generator feedrings are offset approximately 2.5 inches in elevation above the center line of the feed nozzle to further delay draining of the feedwater piping.

During normal operation, the water level in the steam generator is maintained above the feedring and therefore steam cannot enter the feedring to react with cold feedwater. However, in the event of a transient that results in uncovering the feedring, the design features of the feedring and feedwater piping as discussed above will maintain the feedring full of water while flow to the steam generator is interrupted. Therefore, these design features preclude draining of the feedring and reduce the possibility of water hammer in the feedwater system.

10.3.5.4 **Tests and Inspections**

The auxiliary steam generator feedwater pumps and drives are tested in accordance with the Technical Specifications by admitting steam to the turbine drive or energizing the motor drivers. During these tests, verification of flow from the emergency condensate storage tank to the steam generators from each of the auxiliary feedwater pumps verifies proper alignment of the required auxiliary feedwater flowpaths. Periodic testing is staggered to test the motor-driven and steam-driven auxiliary feedwater pumps at different times to reduce the potential for inadvertently leaving closed the discharge valves of all pumps after a test. While a periodic test is being performed, the affected AFW pump is declared inoperable and the applicable Technical Specification limiting condition for operation is placed in effect.

10.3.6 Condenser

Two single-pass, divided water-box condensers are provided. Each condenses steam from one of the two low-pressure turbine exhausts, and steam from the turbine steam bypass valves, as described in Section 10.3.1.

10.3.6.1 **Design Basis**

The design parameters for each condenser are listed in Table 10.3-3.

10.3.6.2 **Description**

The condensers are of conventional design, manufactured by Ecolaire-Rand Company, and have a neoprene-lined rubber belt-type expansion joint in the neck. They also have steam and condensate crossover ducts to equalize pressure, and impingement baffles to protect the tubes. The tubes are made of titanium, which provides relative immunity from tube-end erosion/corrosion and reduces circulating water inleakage. The waterboxes have a 3/16-inch neoprene lining to provide protection and reduce maintenance. The tubesheet material is aluminum-bronze-D, ASTM B171, Alloy 614. In the event that excessive galvanic corrosion is experienced at the tube/tubesheet interface, an epoxy coating can be added to help minimize any corrosive effect of the electrochemical potential between the tubes and tubesheets. The material is a nonaging, nonshrinking, non-hygroscopic, nontoxic, non-water solution that will withstand corrosion, galvanic action, and cavitation. Internal tube support plates are spaced 24 inches apart. One No. 5 feedwater heater and one No. 6 feedwater heater are located in each condenser neck.

The condenser hotwell is of the deaerating type capable of reducing the oxygen content to less than 0.005 cm^3/liter. The deaerating capability is necessary, as there is no deaerating feedwater heater in the feedwater cycle. Hotwell division plates segregate the condensate from each tube bundle, with sample connections provided for each region. Samples are pumped to the turbine building for analysis.

Two twin-element, two-stage, steam jet air ejector units, each complete with tubed inter-condenser and after-condenser, are provided for removing noncondensable gases from the condenser shells. For normal air removal, one element of each ejector unit is operated per condenser shell. The ejectors function by using auxiliary steam and discharge to the atmosphere. A radiation monitor is installed in the common discharge line from the two air ejectors as described in Section 10.3.8. For initial condenser shell-side air removal, a noncondensing priming ejector is provided for each shell. These ejectors function by using steam from the auxiliary steam system (Section 10.3.2).

10.3.6.3 **Performance Analysis**

Loss of normal ac power causes the four 96-inch condenser outlet valves to partially close. This closure permits the minimum flow of circulating water to continue through the condenser for the main steam bypass system, and conserves water in the intake canal for the recirculation spray coolers.

10.3.6.4 **Tests and Inspections**

Circulating water and those service water isolation valves, which are required to close to conserve intake canal inventory following a design basis accident, are periodically verified that the total leakage flow from these sources are limited to less than the leakage assumptions of the canal inventory analysis.

10.3.7 Lubricating Oil System

A pressure lubricating oil system is provided to perform the following functions:

1. Store lubricating oil.
2. Supply oil to and receive oil from the turbine-generator oil reservoir.
3. Purify a side stream of oil from the turbine-generator oil reservoir on a continuous-bypass basis.
4. Clean and reclaim used oil from the storage tanks, pumping it from the used-oil storage tank via the purifier to the clean-oil storage tank.

10.3.7.1 **Design Basis**

The lubricating oil system consists of a 21,000-gallon reservoir, two 22,000-gallon horizontal all-welded steel storage tanks, an oil purifier, and two identical motor-driven transfer pumps. The two gear-type positive displacement transfer pumps are each capable of two-sided operation at 108 and 48 gpm to accomplish the various batch cleaning, transfer, and circulating operations. The variable speed oil conditioner is rated at 1200–1600 gal/hr.

10.3.7.2 **Description**

A turbine shaft-driven oil pump normally supplies all lubricating oil requirements to the turbine-generator unit. An ac motor-driven turning gear oil pump is installed for supplying lubricating oil during start-up, shutdown, and standby conditions. An emergency dc motor-driven oil pump, operated from the black battery, is also available to ensure lubricating oil to the bearings.

Cooling water from the bearing cooling water system (Section 10.3.9) is used for the turbine lube-oil coolers. The two 22,000-gallon storage tanks are normally designated “clean” and “used,” but are interchangeable and are located inside a fireproof room equipped with water sprays and vent fans. The transfer pumps and piping are arranged so that oil can be processed from the oil reservoir or either of the two storage tanks. The processed oil can be returned to either of the other two. A vapor extractor purges oil fumes from the reservoir and exhaust to the atmosphere outside of the turbine building. Piping and valves in the system are of welded steel, and high-pressure bearing oil piping is enclosed in a guard pipe.

10.3.7.3 **Performance Analysis**

The dc motor-driven oil pump is designed to function during a loss of station power to supply lubricating oil to the turbine-generator bearings. The black battery provides an uninterrupted source of power to this pump.

10.3.7.4 **Tests and Inspections**

The dc bearing oil pump is tested periodically.

10.3.8 Secondary Vent and Drain Systems

Because the steam and power conversion system is normally nonradioactive, vents and drains are arranged in much the same manner as those in a fossil-fueled power station. However, because air ejector vents and steam generator blowdown can possibly become contaminated and because they discharge to the environment, they are monitored and discharge under controlled conditions as described in Chapter 11.

The air ejector vent subsystem is shown in Reference Drawing 2. The steam generator blowdown system is shown in Reference Drawing 8.

10.3.8.1 **Design Basis**

Each of the condenser steam jet air ejectors (two per shell) is designed to remove 12.5 cfm of free air. Each ejector normally uses about 800 lb/hr of steam at a 140 to 200 psig from the auxiliary steam header, while using 900 gpm of condensate for cooling. Separate hogging or vacuum priming jets are used to reduce condenser vacuum to 1 to 3 inches Hg absolute during start-up.

10.3.8.2 **Description**

Generally, secondary plant piping drains to the condenser.

Vent gases removed from the condensers by the air ejectors are normally discharged through a radiation monitor (Section 11.3) to the atmosphere. If a steam generator tube ruptures, with subsequent contamination of the steam, the radioactive noncondensable gases would be detected by the radiation monitor located in the air ejector effluent line. The related accident analysis is covered in Section 14.3.1. When the radioactivity level reaches the alarm setpoint of the monitor, trip valves in the air ejector effluent line will automatically actuate to divert the effluent flow to the containment and shut off the vent to atmosphere. Other vents from the turbine generator that handle carbon dioxide, hydrogen, oil vapor, and other nonradioactive gases are discharged directly to the atmosphere outside the turbine building.

As discussed above, the condenser air ejector discharge line is a potentially radioactive release point and is therefore required to have high-range radiation monitoring per the requirements of NUREG-0578, Section 2.1.8.b. For this reason, two manual isolation valves have been installed and the air ejector discharge lines have been rerouted to have connections upstream of ventilation vent no. 2 high-range effluent monitor for use during accident conditions. If a condition were to exist such that a radiation monitor (low range) alarms and the containment is under a phase I isolation mode, the air ejector isolation valves would shut and secure all flow from the air ejector vent. However, this modification provides a method for maintaining condenser vacuum, if necessary, by allowing the operator to manually establish condenser-air ejector flow through the new discharge line and the high-range vent stack monitor, as well as the low-range effluent monitor. Both of the manual isolation valves are under administrative control. The high-range effluent monitor isolation valve is normally shut and the low-range effluent monitor manual isolation valve is open.

10.3.8.3 **Performance Analysis**

Loss of power or air causes both diversion valves in the air ejector line to fail closed, thus preventing possible radioactive contaminants in the condenser steam space from reaching the atmosphere. In addition, the air-operated shut-off valves in the steam supply lines to the air ejectors will also go closed on a loss of power or air.

Radiation monitoring and alarm initiation are unaffected by loss of power, but a signal from the containment isolation system (Section 5.2) causes the trip valves on the outside of the containment wall to close.

10.3.8.4 **Tests and Inspections**

The vent and drain systems are in continual use and require no special testing and inspection. However, the trip valves installed in these systems, which are part of the containment isolation system, are tested in accordance with Section 5.2.

10.3.9 Bearing Cooling Water System

The bearing cooling water system supplies cooling water to the steam and power conversion system equipment and is a closed cycle system using pumped condensate quality water as cooling water. The heat removed by the cooling water is transferred to service water in the bearing cooling heat exchangers, as described in Section 9.9. A review of the effects of the power uprate to a core power of 2546 MWt was conducted and the bearing cooling water system was found to be adequate.

The bearing cooling water system is shown schematically in Figure 10.3-11 and Reference Drawing 9.

10.3.9.1 **Design Basis**

The turbine plant equipment is designed for full load operation with cooling water supplied at a maximum temperature of 105°F. The bearing cooling water heat exchangers consist of three half-size units capable of maintaining the cooling water supply temperature below 105°F at all river water temperatures.

The principal equipment served by the bearing cooling water is listed in Table 10.3-4.

The full-size 13,000-gpm motor-driven pumps circulate the cooling water through the above equipment and the bearing cooling heat exchangers.

10.3.9.2 **Description**

The cooling water flowing through the major equipment coolers, such as the hydrogen and oil coolers, is controlled manually to maintain constant temperature of the cooled fluid.

A head tank is provided to maintain a positive pressure at all points on the system. Makeup to this tank is normally from the water supply and treatment system header; however, when this system is not in operation, makeup is provided from the condensate system (Section 10.3.5).

The bearing cooling water system is chemically treated to inhibit corrosion.

10.3.9.3 **Performance Analysis**

The bearing cooling water system supplies cooling water to steam and power conversion system equipment, including the instrument air compressor, for heat removal. The instrument air compressor is powered from the emergency bus for loss of off-site power events and can be cooled utilizing the fire protection system. The bearing cooling water system is non-safety-related and is not relied upon for accident mitigation or safe-shutdown of the nuclear plant.

10.3 REFERENCES

1. U.S. Nuclear Regulatory Commission, *Seismic Analyses for As-Built Safety-Related Piping Systems,* IE Bulletin 79-14, June 2, 1979.

2. Letter from A. Schwencer, NRC, to W. L. Proffitt, Vepco, Subject: Safety Evaluation of the Steam Generator Repair Program by the Office of Nuclear Reactor Regulation, License Nos. DPR-32 and DPR-37, dated December 15, 1978.

3. U.S. Nuclear Regulatory Commission, *TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendation*, NUREG-0578, July 1979.

4. Revised report on the Reanalysis of Safety-Related Piping Systems. Surry Power Station - Unit 1, August 1979, Stone & Webster Engineering Corporation.

5. Report on the Reanalysis of Safety-Related Piping Systems - Surry Power Station - Unit 2 Rev. 1, April 1980, Ebasco Services, Inc.

6. Report on the I.E. Bulletin 79-14, Analysis for As-Built Safety-Related Piping Systems - Surry Power Station - Unit 2, July 1981, Ebasco Services, Inc.

7. Westinghouse Electric Corporation, *Criteria for Low Pressure Nuclear Turbine Disc Inspection*, Memorandum MSTG-1-P, June 1981 (Westinghouse Proprietary).

10.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11448-FM-064A	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 1
	11548-FM-064A	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 2
2.	11448-FM-066A	Flow/Valve Operating Numbers Diagram: Auxiliary Steam and Air Removal System, Unit 1
	11548-FM-066A	Flow/Valve Operating Numbers Diagram: Auxiliary Steam and Air Removal System, Unit 2
3.	11448-FM-066B	Flow/Valve Operating Numbers Diagram: Auxiliary Steam System, Primary Plant, Unit 1
4.	11448-FM-071A	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 1
	11548-FM-071A	Flow/Valve Operating Numbers Diagram: Circulating and Service Water System, Unit 2
5.	11448-FM-067A	Flow/Valve Operating Numbers Diagram: Condensate System, Unit 1
	11548-FM-067A	Flow/Valve Operating Numbers Diagram: Condensate System, Unit 2
6.	11448-FM-068A	Flow/Valve Operating Numbers Diagram: Feedwater System, Unit 1
	11548-FM-068A	Flow/Valve Operating Numbers Diagram: Feedwater System, Unit 2
7.	11448-FM-123A	Flow/Valve Operating Numbers Diagram: Chemical Feed Systems, Unit 1
	11548-FM-123A	Flow/Valve Operating Numbers Diagram: Chemical Feed System, Unit 2

	Drawing Number	Description
8.	11448-FM-124A	Flow/Valve Operating Numbers Diagram: Steam Generator Blowdown Recirculation and Transfer System, Unit 1
	11548-FM-124A	Flow/Valve Operating Numbers Diagram: Steam Generator Blowdown Recirculation and Transfer System, Unit 2
9.	11448-FM-23A	Flow Diagram: Bearing Cooling Water System, Unit 1
	11548-FM-23A	Flow Diagram: Bearing Cooling Water System, Unit 2
10.	11448-FM-59M	Heat Balance Diagram: 100% Core Power, Unit 1
	11548-FM-59A	Heat Balance Diagram: 100% Core Power, Unit 2

Table 10.3-1
STEAM GENERATOR BLOWDOWN SYSTEMS - CODES AND STANDARDS

Component	Codes and Standards
Heat exchanger	ASME Code, Section VIII, Division 1
Piping and fittings	ANSI B31.1, Code for Pressure Piping, *Power Piping*, 1967
Valves	ANSI B16.5, Flanged Valves, 1973
Instrumentation and controls	ISA Standards and Practices for Instrumentation (1974)

Table 10.3-2
CONDENSATE POLISHER SYSTEM DESIGN AND OPERATING INFORMATION

Design pressure	690 psig
Normal pressure	505-590 psig
Design flow	14,515 gpm
Normal flow per demineralizer	2420 gpm
Design temperature	135°F
Normal temperature	75-125°F
Number of demineralizers	6 (+l standby)
Number of demineralizers used at 100% power	6
Number of regenerations per day	1
Water used per regeneration	Approximately 50,000 gal

Table 10.3-3
CONDENSER DESIGN PARAMETERS

Steam condensed	6,195,000 lb/hr
Circulating water	773,000 gpm
Surface	650,870 ft^2
Number of tubes	71,328
Tube material	22 BWG titanium
Tube o.d.	7/8 in.
Effective length	39 ft. 10 in.
Backpressure	3.29 in. Hg
Heat load, Btu/hr at 90°F	5.807×10^9
Tube water velocity	6.6 ft/sec

Table 10.3-4
EQUIPMENT SUPPLIED BY BEARING COOLING WATER SYSTEM

Equipment	Design Flow, gpm
Generator hydrogen coolers	6048
Hydrogen seal-oil coolers	360
Turbine oil coolers	3380
Exciter cooler	300
Isolated-phase bus duct air coolers	167
Instrument air compressors	21
Condensate, feed, and heater drain pumps	334
Sample coolers and chillers for S/G on line chemistry monitoring system	154 (each unit)
Central chillers	1300 (each)
Vacuum priming sealwater coolers	100 (each)

Figure 10.3-1
MAIN STEAM SYSTEM

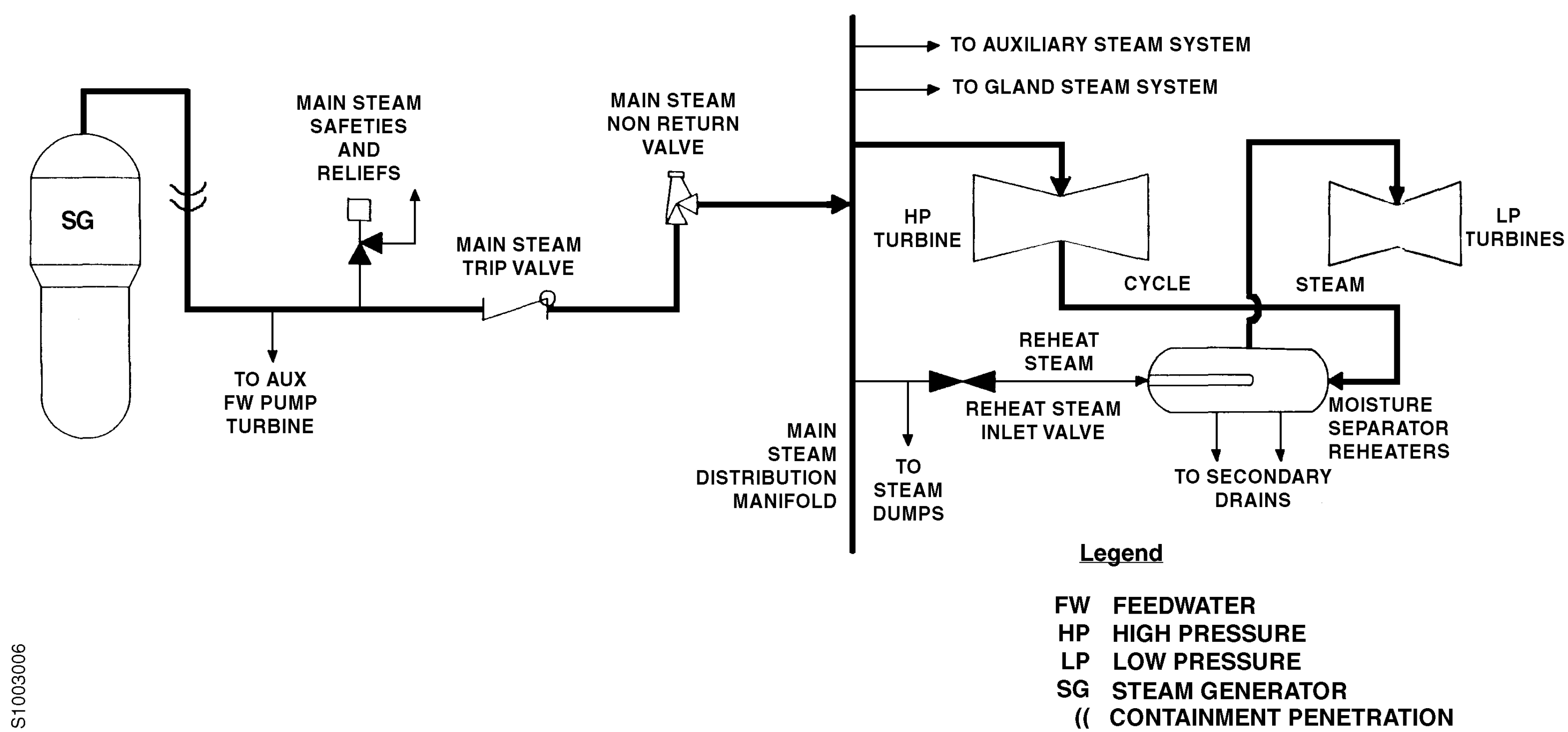
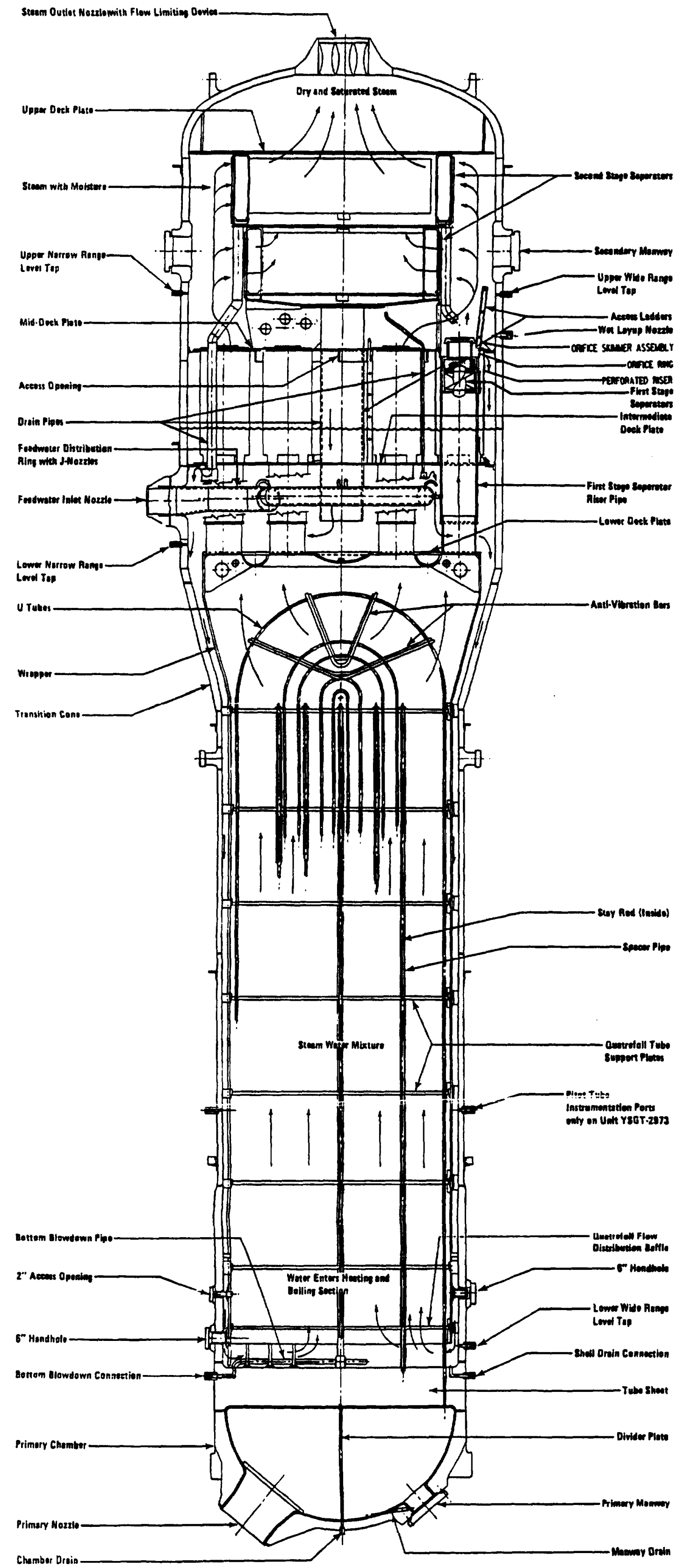


Figure 10.3-2
SERIES 51 STEAM GENERATOR



S1003001

Figure 10.3-3
STEAM GENERATOR LOWER ASSEMBLY

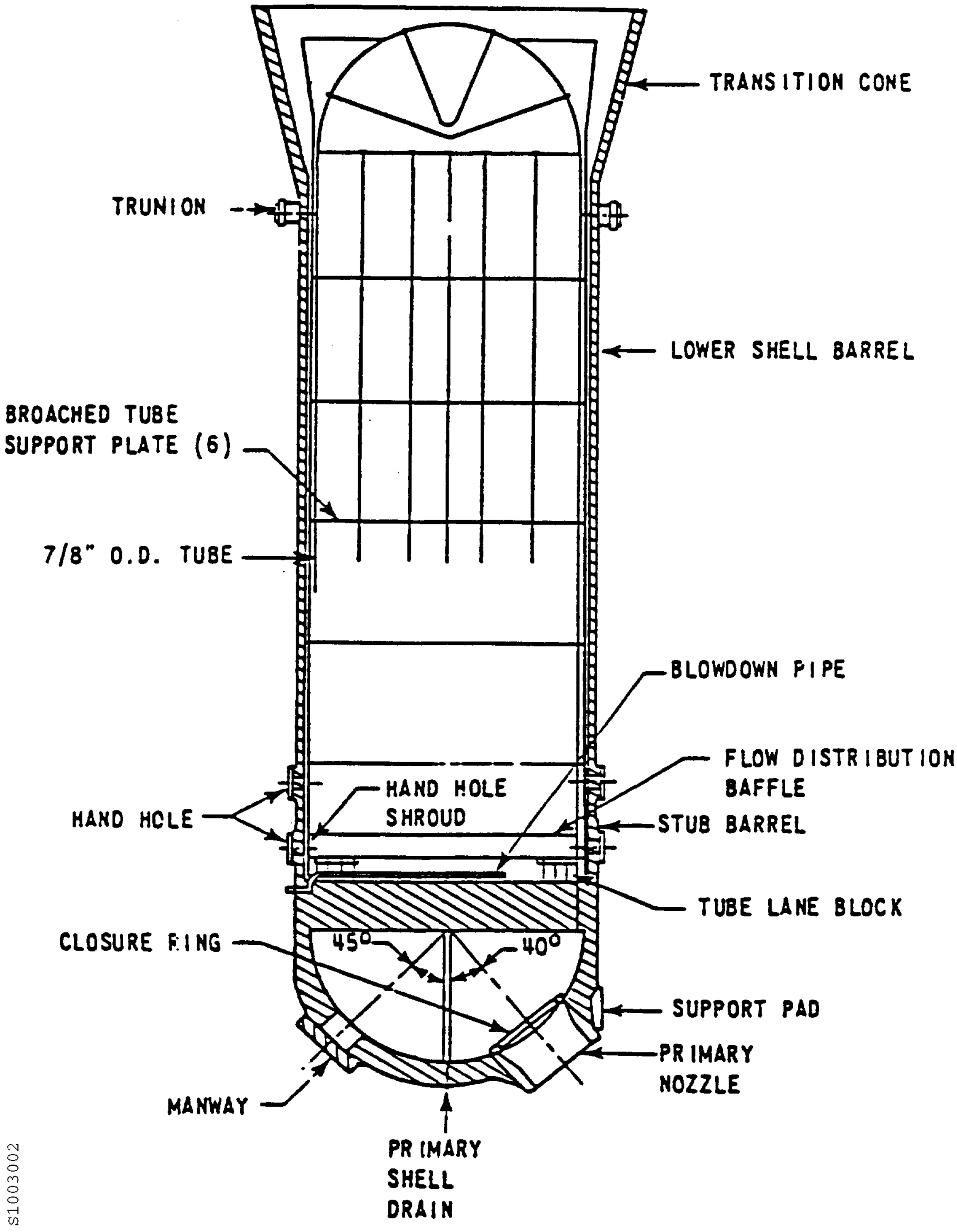


Figure 10.3-4
QUATREFOIL TUBE SUPPORT PLATE

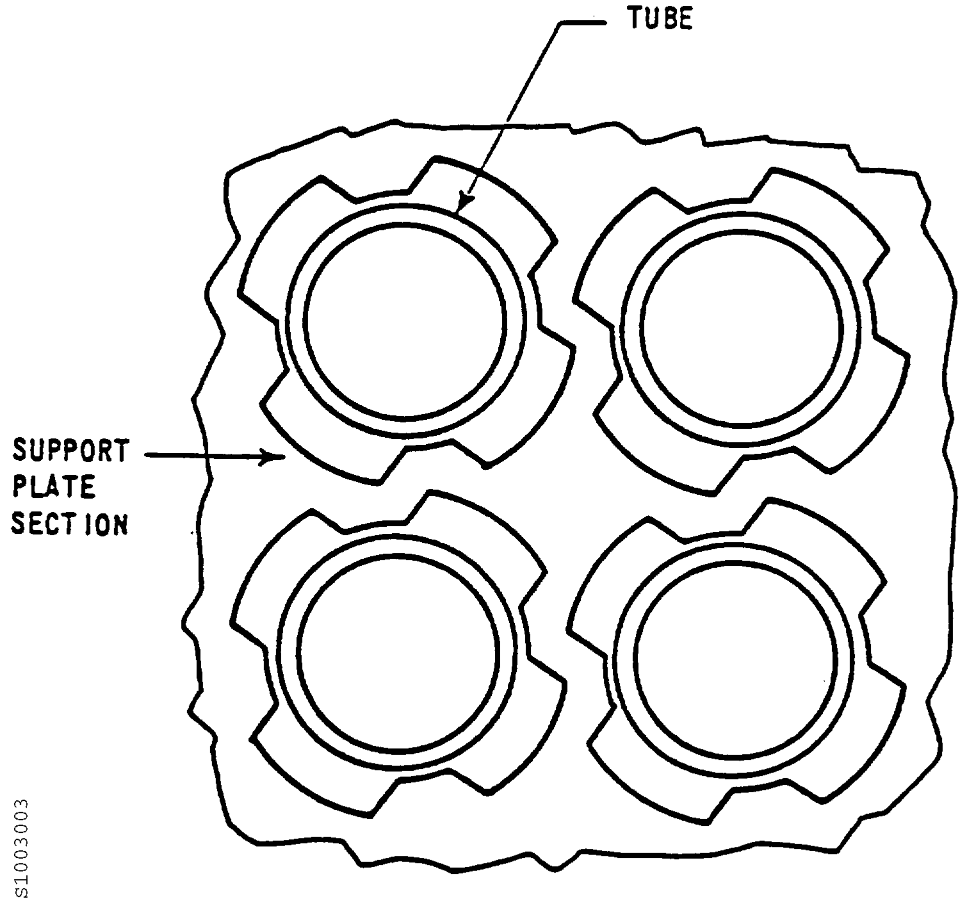


Figure 10.3-5
TYPICAL SLUDGE REMOVAL SYSTEM

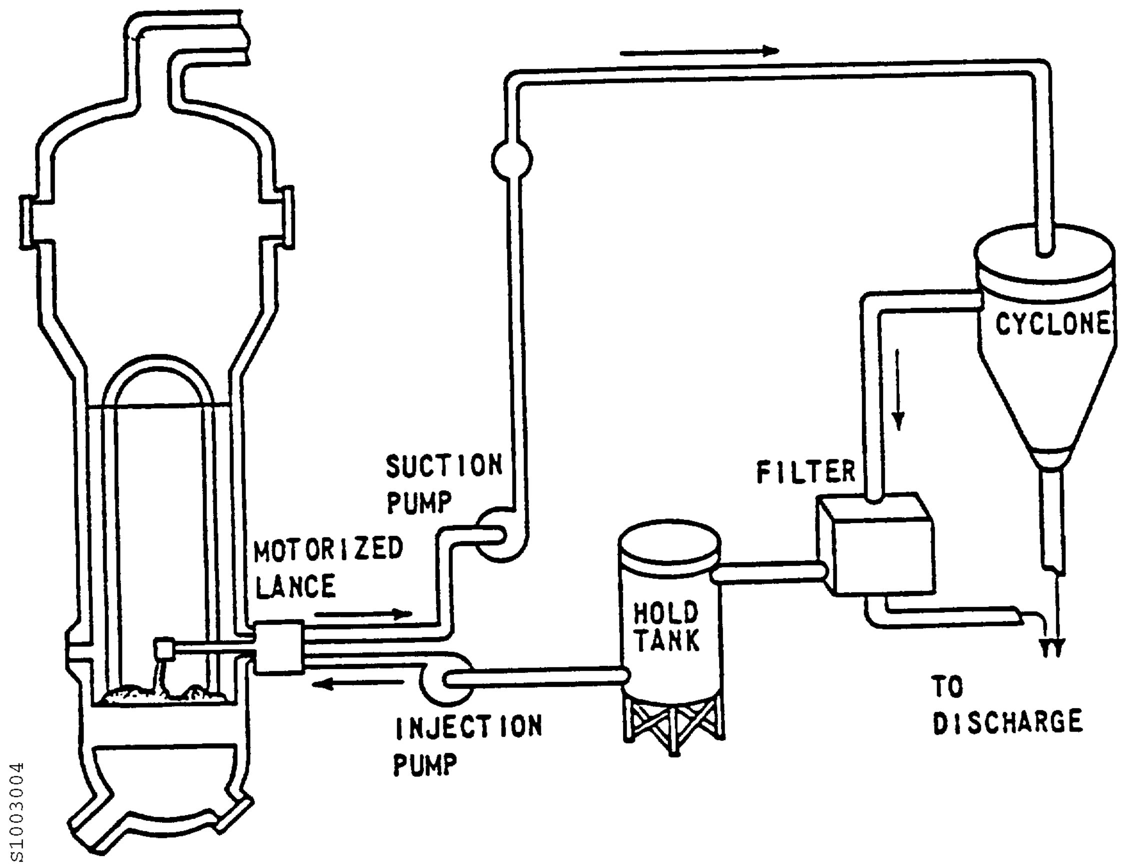


Figure 10.3-6
TYPICAL WET LAYUP SYSTEM

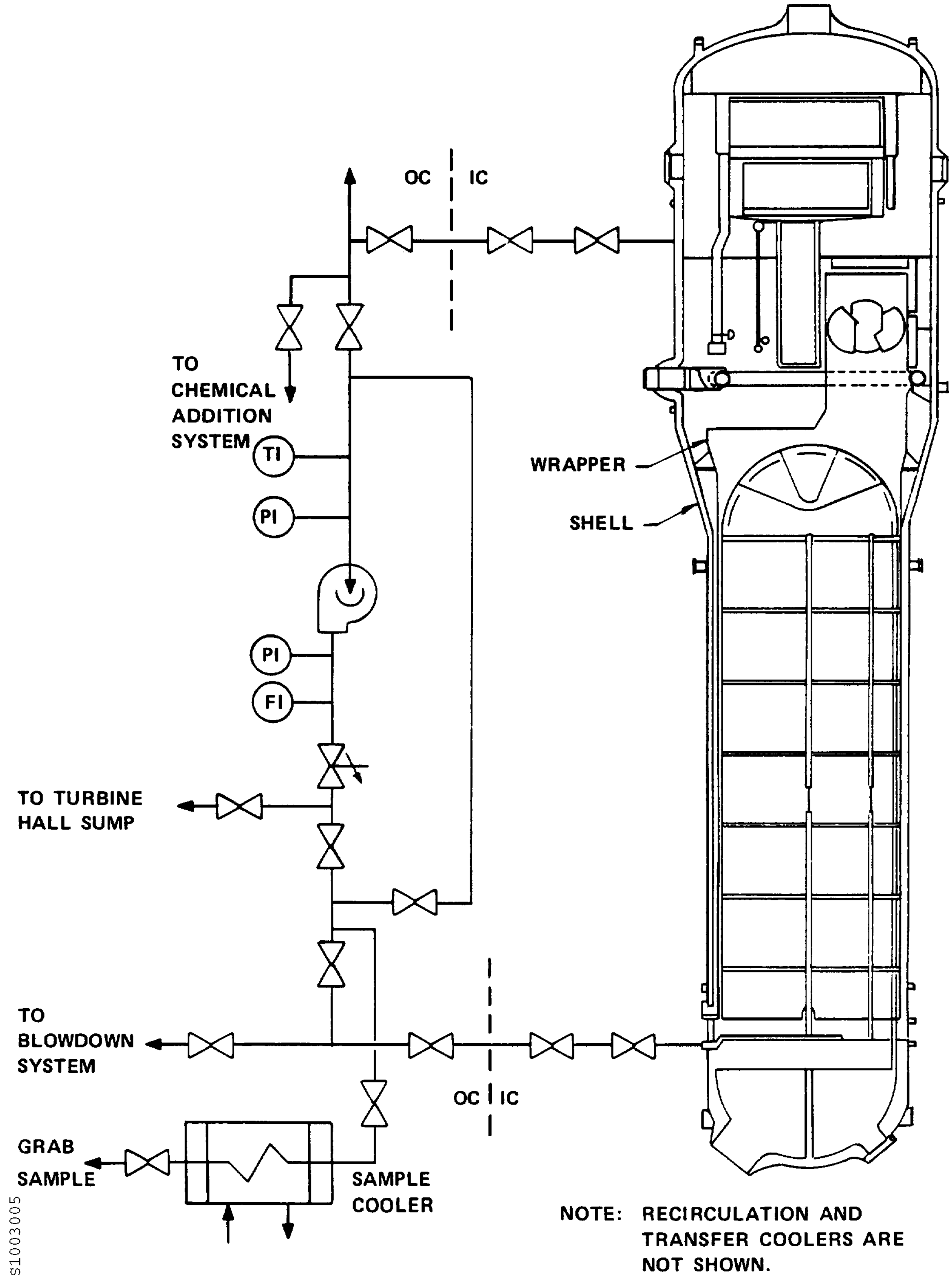
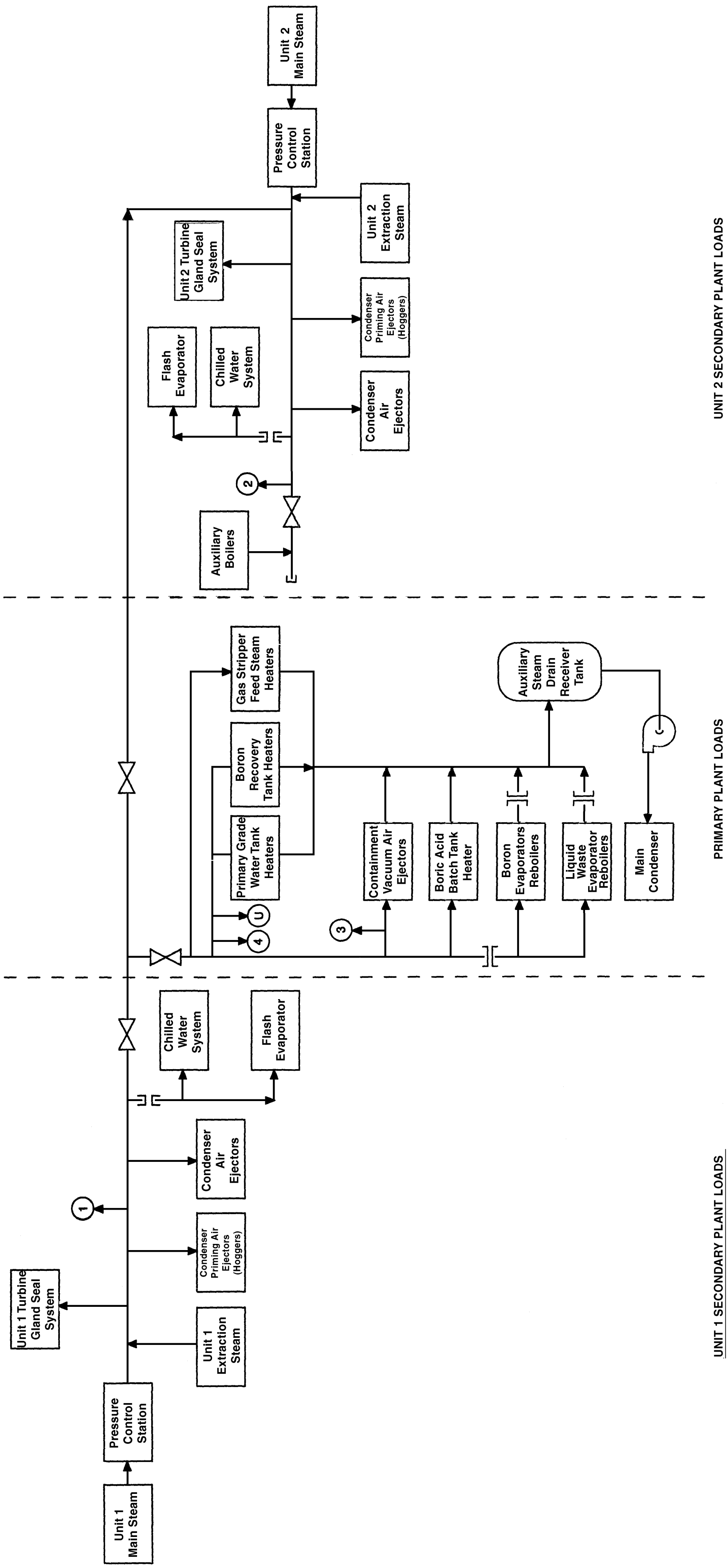


Figure 10.3-7
AUXILIARY STEAM SYSTEM



NOTES:
◯ The circled numbers refer to building heating system stations.
Ⓤ Is the station serving the ultrasonic tanks.

The following equipment is abandoned in place:
Steam Chiller
Boron Evaporators
Flash Evaporators
L. W. Evaporators

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Figure 10.3-8
CONDENSATE SYSTEM

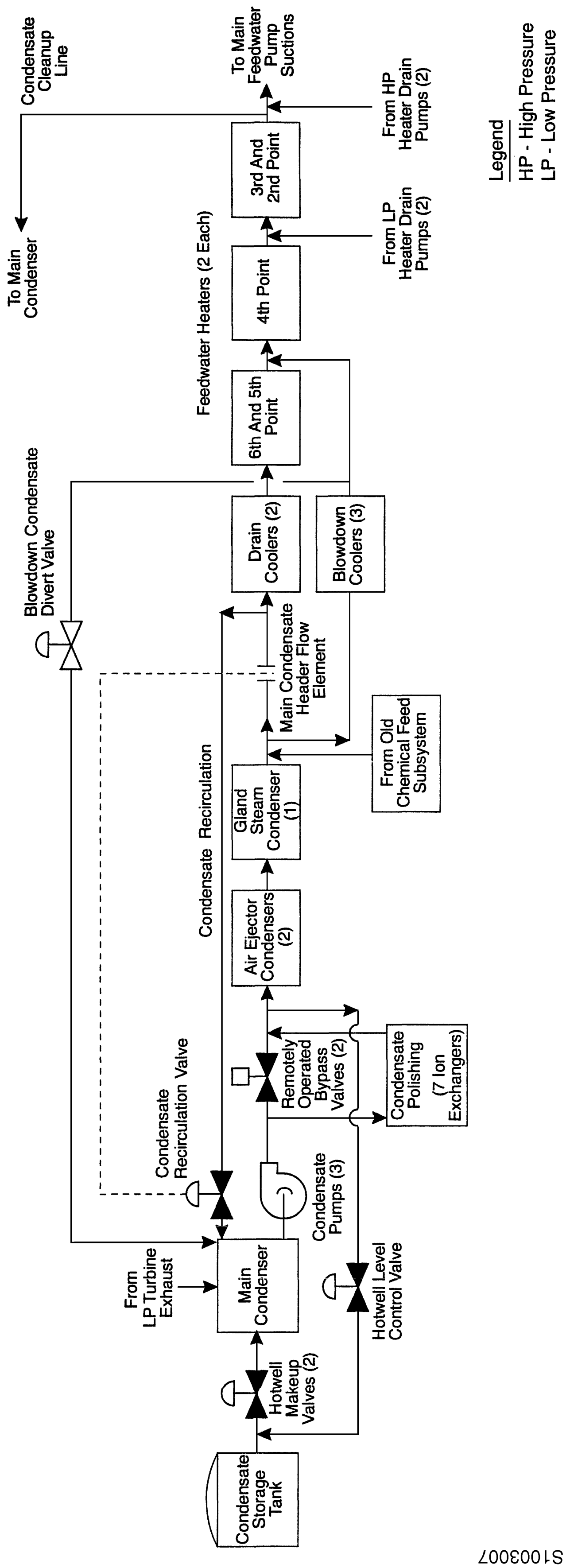
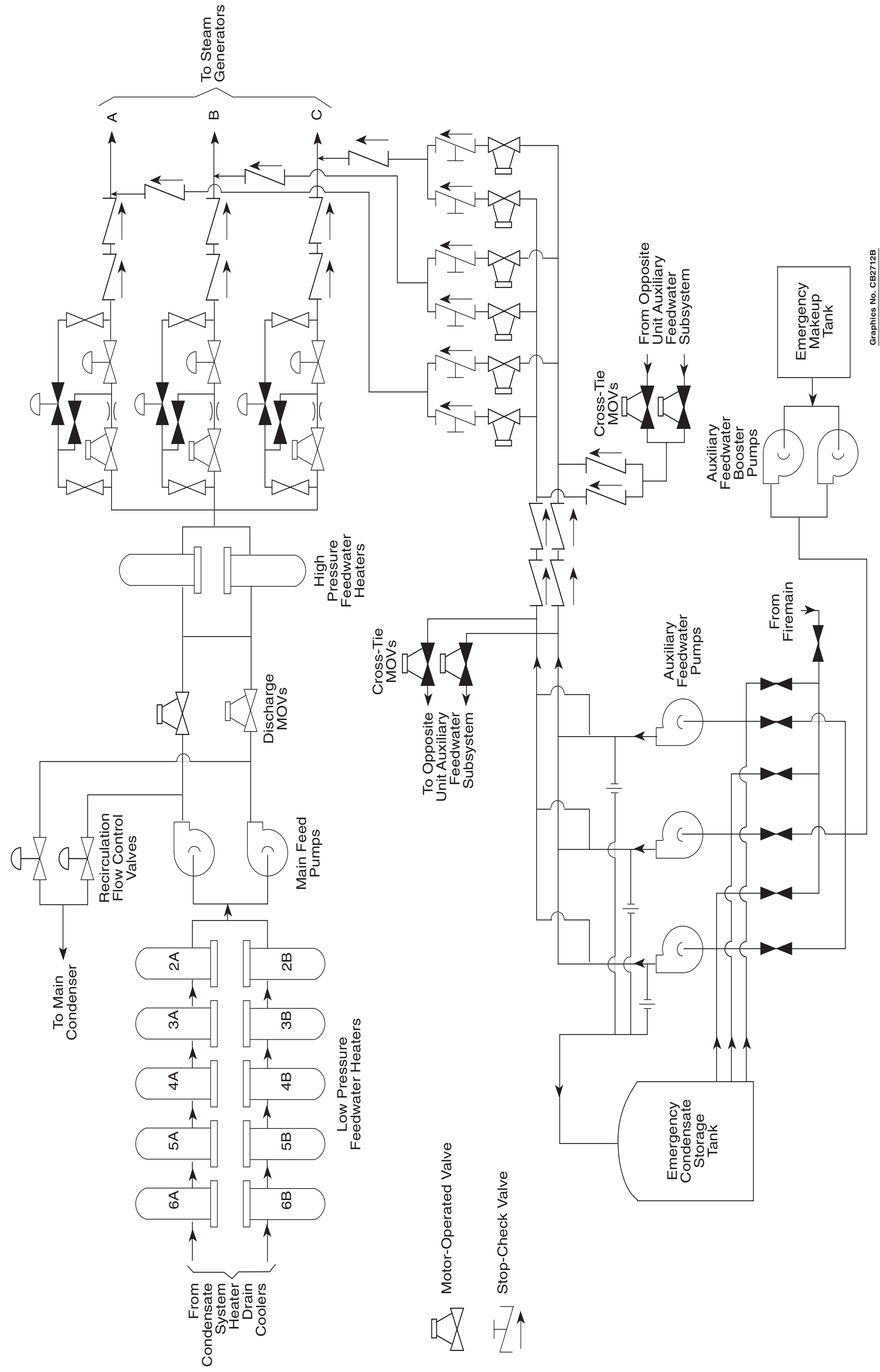


Figure 10.3-9
FEEDWATER SYSTEM



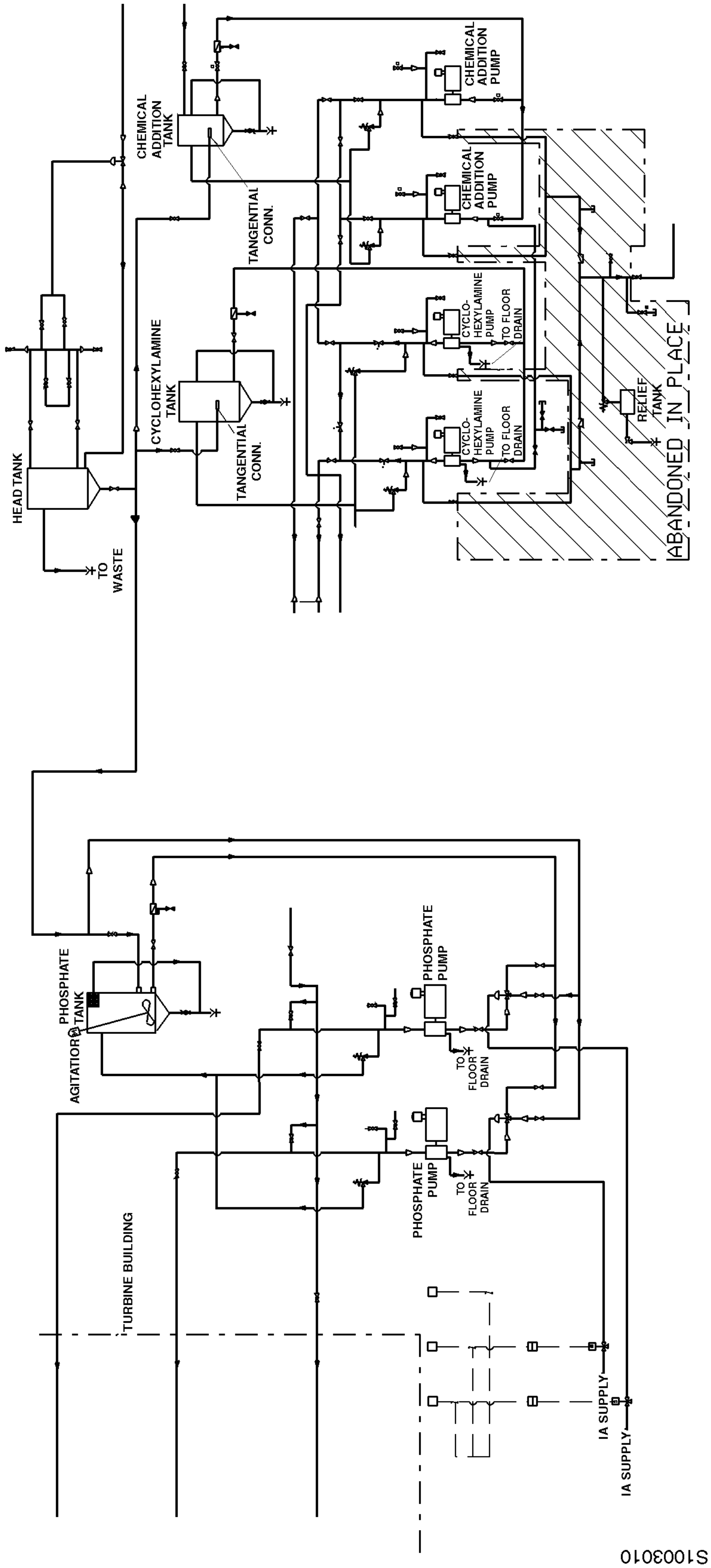


Figure 10.3-10
CHEMICAL FEED SYSTEM

Figure 10.3-11 (SHEET 1 OF 2)
BEARING COOLING SYSTEM

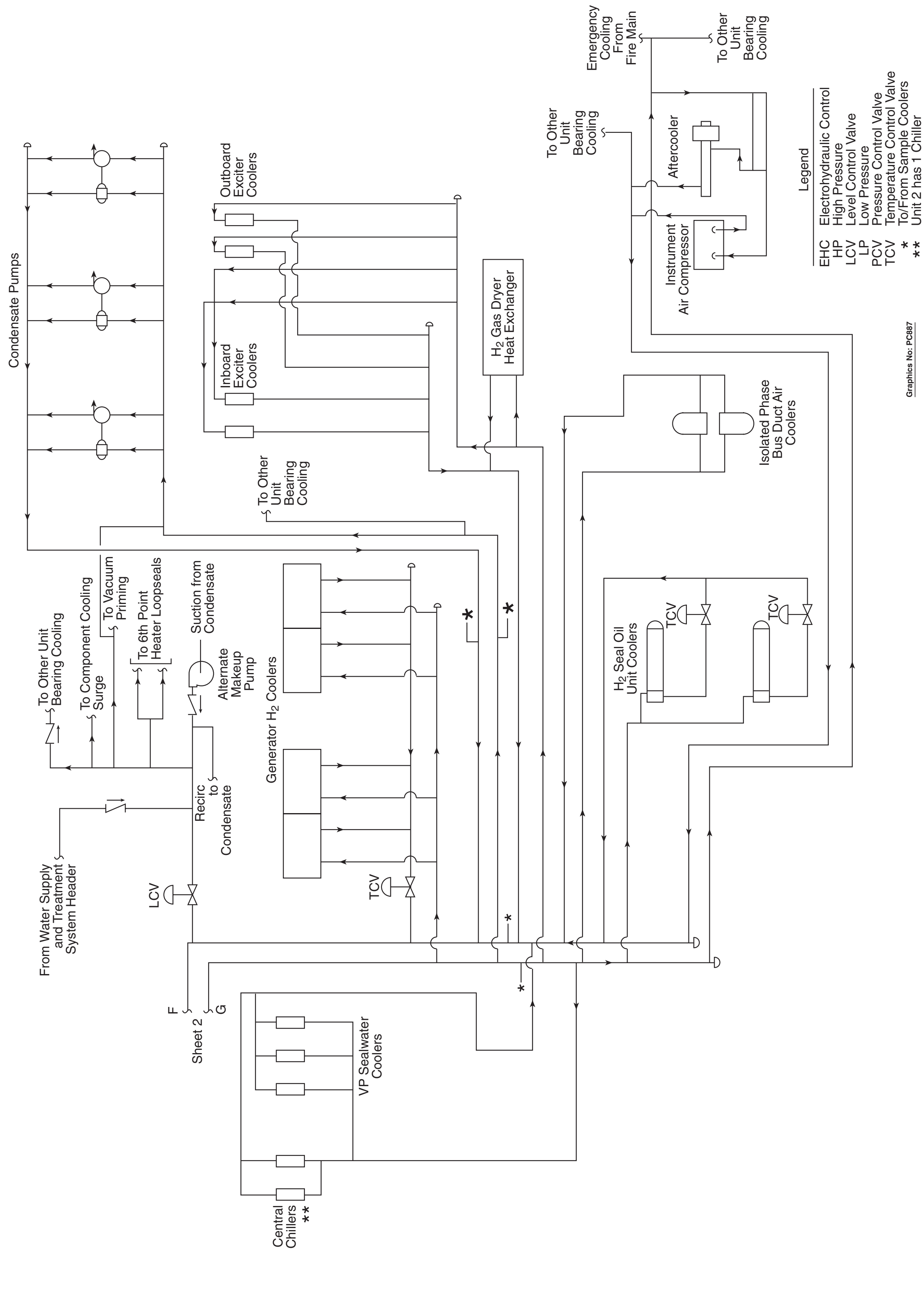


Figure 10.3-11 (SHEET 2 OF 2)
BEARING COOLING SYSTEM