CHAPTER 10

STEAM AND POWER CONVERSION SYSTEM

10.1 DESIGN BASIS

10.1.1 Performance Objectives

The turbine-generator system consists of components of conventional design, acceptable for use in large power stations. The equipment is arranged to provide high thermal efficiency with no sacrifice to safety. The component design parameters are given in Table 10.1-1.

The equipment in the turbine-generator system under the Stretch Power Uprate Project conditions produces a gross output of approximately 1,065,000 KWe. The calculated maximum gross output is 1,093,500 KWe. Heat balance diagram at 1,093,500 KWe, maximum calculated is shown on Figure 10.1-1.

The Steam and Feedwater System is designed to remove heat from the reactor coolant in the four steam generators, producing steam for use in the turbine generator. The Steam and Feedwater System can receive and dispose of, in its cooling systems and through power operated relief valves, the total heat existent or produced in the Reactor Coolant System following an emergency shutdown of the turbine generator from a full load condition.

The system design provides means to monitor and restrict radioactivity discharge to normal heat sinks or the environment such that the limits of 10 CFR 20 are not exceeded under normal operating conditions nor in the event of anticipated system malfunctions.

One turbine and two motor driven auxiliary feed pumps are provided to ensure that adequate feedwater is supplied to the steam generators for reactor decay heat removal under all circumstances, including loss of power and normal heat sink. Auxiliary feedwater flow can be maintained until either loss of power is restored, or reactor decay heat removal can be accomplished with emergency power sources. Auxiliary feedwater pumps and piping are designed as Class I seismic components.

10.1.2 Load Change Capability

The Reactor Control System can handle transmission system disturbances that cause electrical generation step load increases of 10% and ramp increases of 5% per minute within a power range from 15% to 100% without reactor trip, subject to possible Xenon limitations late in core life. Similar step and ramp load reductions are possible for the changes from 100 to 15% of full load (maximum guaranteed load). The Reactor Coolant System can sustain a complete loss of load from full power with reactor trip (see Section 7.2). In addition, the turbine bypass and steam dump systems make it possible to accept a turbine load decrease of 10% to 50% of full power at a maximum turbine unloading rate of 200% per minute without reactor trip (see Section 7.3.2).

The 10% to 50% of full power at a maximum unloading rate of 200% per minute without reactor trip (depending on full power Tavg) is handled by the steam bypass, condenser, and reactor rod control systems. The reactor control system handles 10% of the load decrease while the remainder of the load decrease is handled by the steam bypass and the condenser systems.

10.1.3 Functional Limits

The system design incorporates backup means (power relief and code safety valves) of heat removal under any loss of normal heat sink (e.g., condenser failure, containment isolation, circulating water loss of flow) to accommodate turbine trip steam rejection requirements. Condenser isolation occurs automatically with the existence of high pressure (low vacuum). In such a case the turbine trips and heat removal capability is provided by atmospheric dump valves and code safety valves. Also, in case of condenser tube leaks, one side of any condenser may be manually isolated and the hotwell dumped without reducing the condenser heat removal capability.

The Steam and Power Conversion System environmental discharges under normal operations are made through the condenser air ejector or the steam generator blowdown system. All such discharges to the environment are monitored for secondary radioactivity. The monitors ensure that any radioactivity discharged will be within 10 CFR 20 limits.

10.1.4 Secondary Functions

The Steam and Power Conversion System provides steam for the auxiliary steam driven feedwater pump and for the operation of the air ejector. The turbine bypass system is designed to dissipate the heat in the reactor coolant following a full load trip. This heat is removed by means of the steam bypass through the condenser to the circulating water and by steam dump through the power operated relief and safety valves in the event of loss of vacuum in the condenser.

TABLE 10.1-1

STEAM AND POWER CONVERSION SYSTEM COMPONENT
DESIGN PARAMETERS

Turbine-Generator	
Turbine Type	Four element, tandem-compound six-flow exhaust
Turbine-Generator Capacity (kW)	
Nominal SPU Value	1,065,000
Maximum calculated	1,093,500
Generator Rating (kVA)	1,125,600
Turbine Speed (rpm)	1800
Condensers	
Type	Radial flow, single pass, divided water box
Quantity	3
Condensing Capacity (lbs of steam/hr)	7,230,000
Condensate Pumps	
Type	8 stage, vertical pit type, centrifugal
Quantity	3
Design Capacity (each-gpm)	7860
Motor Type	Vertical Induction
Motor Rating (hp)	3000

TABLE 10.1-1
(Cont.)

STEAM AND POWER CONVERSION SYSTEM COMPONENT
DESIGN PARAMETERS

Feedwater Pumps	
Type	High Speed, barrel coring, single stage, centrifugal
Quantity	2
Design Capacity (each-gpm)	15,300
Pump Drive	Horizontal steam turbine
Drive Rating (hp)	8350
Auxiliary Feedwater Source	360,000 gallons assured reserve in 600,000 gallon condensate tank. Alternate supply from city water system.
Auxiliary Feedwater Pumps	3 (one steam turbine driven, two electric motor driven)
Design Capacity (each-gpm)	800 (turbine driven) 400 (motor driven)

10.2 SYSTEM DESIGN AND OPERATION

The Steam and Power Conversion System Process Flow Diagram is shown on Figure 10.2-1. Process and Instrumentation Diagrams for the following systems: Main Steam; Condensate and Boiler Feed Pump Suction; Condensate Polishing; Boiler Feedwater; Extraction Steam; Heater Drains and Vents; Moisture Separator and Reheater Drains and Vents; Condenser Air Removal and Water Box Priming; Circulating Water; Chemical Feed,; Auxiliary Steam and Condensate for Nuclear Equipment; Auxiliary Steam Supply and Condensate Return; and Steam Generator Blowdown and Blowdown Recovery Systems are shown on Plant Drawings 9321-F-20173, -20183 Sh. 1 & 2, -20193, -20203, -20223, -20233, -20253, -20263, -20383, -27273, -40573, -27293, and -24063 [Formerly Figures 10.2-2 through 10.2-13, and 10.2-47 and 4].

Heat Balance diagrams at loads of 1,068,701 kW(e); 1,021,793 kW(e); 1,000,630 kW(e); 766,350 kW(e); 510,897 kW(e); and 255,448 kW(e) are shown on Figures 10.2-14 through 10.2-19.*

> *NOTE: These figures are based on original plant equipment and are provided for historical purposes only.

10.2.1 Main Steam System

The Main Steam System conducts steam in a 28 inch pipe from each of the four steam generators within the reactor containment through a swing disc type isolation valve (referred to henceforth as Main Steam Isolation Valve or MSIV) and a swing disc type non-return valve (referred to henceforth as Main Steam Check Valve or MSCV) to the turbine stop and control valves. The Main Steam Isolation and (non-return) Check Valves are located outside of the Containment. The four lines are interconnected near the turbine. The design pressure of this system is 1085 psig at 600 F. A steam flow-meter (flow venturi) is provided upstream of the Main Steam Isolation and (non-return) Check Valves in the line from each steam generator to measure steam flow. Steam flow signals are used by the automatic feed-water flow control system (see Chapter 7). The flow venturi also limits the steam flow rate in the event of a steam line break downstream of the venturi. Steam pressure is measured upstream of the Main Steam Isolation and (non-return) Check Valves.

The MSIV's contain free swinging discs that are normally held out of the main steam flow path by an air piston. They are designed to close in less than five seconds. Air receiver tanks are provided in the instrument air piping to the MSIV operators to compensate for pressure transients in the instrument air system in order to prevent spurious MSIV closure. The MSIV's are automatically closed (closure of the valves initiates unit trip) on receipt of the following signals from the steam line break protection system:

1) After delay (maximum of 6 seconds) High steam flow in any two out of the four steam lines, coincident with low steam line pressure or low T_{avg}; or
2) Two sets of two-of-three high-high containment pressure signals [energize to actuate]; or
3) Manual actuation (one at a time).

Tests on the Main Steam Isolation Valves and the Main Steam Check Valves performed by the manufacturer were:

1) Tight seating at 1200 psi maximum and 50 psi minimum differential pressures
2) Stem gland leakage not to exceed 1 cc of water per hour per inch of stem diameter when subjected to a hydrostatic leak test pressure of 1100 psig, or not to exceed 0.03 SCFH of air per inch of stem diameter with a differential pressure of 80 psi
3) Non-destructive testing.

The basis for the Main Steam Isolation Valves' and the Main Steam Check Valves' design leakage rates was the Manufacturer's Standardization Society Specification MSS-SP-61 and standard industry criteria for steam leakage rates. The acceptance criteria for shop tests and stem leakage rates were that steam valve glands be designed and packed so that leakage along the stem does not exceed 1 cc of water per hour per inch of stem diameter when subjected to a hydrostatic leak test pressure of 1100 psig, or 0.03 SCFH of air per inch of stem diameter with a differential pressure of 80 psig. The basis for this criterion was sound, up-to-date engineering practice, and was acceptable to valve manufacturers and used by them in the design and fabrication of their products.

The air operated Main Steam Isolation Valves are tested at refueling intervals to verify their ability to close within the specified time upon receipt of a closure signal. See Section 3.7.2 of the Technical Specifications.

Testing of Main Steam Isolation Valves under steam flow conditions is not justified. This testing would cause a severe transient and the collapse of steam bubbles in the steam generator shell side resulting in a low-low water level plant trip. Also, because of the valve design, the valves cannot be reopened against any differential pressure across the valve. The valve operator was designed only to close the valve during steam flow conditions. Thus a valve test at steam flow conditions would necessitate bringing the plant to shutdown conditions after each valve test.

The Main Steam Check Valve, as any swing type check valve, closes upon reverse flow of steam in case of accidental pressure reduction in any steam generator or its piping.

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

Design criteria for the steam line flow restrictors were:

1) Provide plant protection in the event of a steam line rupture downstream of the restrictor. In such an event, the flow restrictor reduces steam flow rate from the break, which in turn reduces the cooling rate of the primary system. This increases the margin to DNB and fuel clad damage.
2) Minimize unrecovered pressure loss across the restrictor during normal operation (less than 5 psi at approximately 120% of rated steam flow).
3) Withstand the number of pressure and thermal cycles experienced during the life of the plant.
4) Maintain restrictor integrity in the event of double-ended rupture of a main steam line immediately downstream of the restrictor.

In addition to meeting these criteria, the restrictors also:

1) Reduce thrust forces on the main steam piping in the event of a steam line rupture, thereby minimizing the potential for pipe whip.
2) Serve as a flow element for steam flow measurement.
3) Limit containment pressurization in the event of a main steamline break inside containment.

Each restrictor is a 304 SS venturi. The complete restrictor assembly was fitted inside a length of main steam pipe and attached to the pipe by a circumferential weld at the discharge end as shown in Figure 10.2-20. Materials, welding and inspection requirements applied in fabrication of the restrictors conform to USAS B31.1 requirements.

Being fitted inside a length of main steam pipe, a flow restrictor is not a pressure boundary component except for flow element throat pressure taps that are similar to other small branch connections on the main steam lines. In addition, component integrity was assured by satisfaction of B31.1 requirements. Approved weld procedures, welders test qualifications, inspection procedures and materials, and a quality assurance program were used in the design and fabrication of the venturi nozzle.

The main steam flow restrictors are not a part of the main steam system boundary. However, all tests or inspections of the restrictors required by USAS B31.1 were performed in the fabricator's shop.

The system is classified as Class I for seismic design up to and including the Main Steam Check Valves.

The steam break incident is analyzed in Chapter 14.

<u>Turbine Steam Bypass</u>

Excess steam generated by the Reactor Coolant System is bypassed during conditions described below, from the four 28-in main steam lines ahead of the turbine stop valves directly to the condensers by means of two 20-in main steam bypass lines. One bypass line runs on either side of the turbine. From each 20-in line six 8-in lines are taken, each with an 8-in bypass control valve installed. Each bypass valve discharges into a 10-in pipe that is connected by a manifold with one other 8-in bypass valve and discharges into a 12-in manifold. Each 12-in manifold is taken to a separate section of the condenser where it discharges into the condenser through a perforated diffuser. Each bypass valve has a capacity of 500,000 lb/hr at an inlet pressure of 650 psia. The bypass values, in conjunction with the NSSS Control Systems, can accommodate a 50% load rejection from 100% power without reactor trip for full power Tavg values of 564^{o}F and above (see Section 7.3). The turbine bypass steam capacity is nominally 40% of full-load steam flow at full-load steam pressure. The large number of small valves is installed to limit the maximum steam flow should one valve stick open. A potential uncontrolled plant cooldown is thus eliminated. Local manually operated isolation valves are provided at each control valve.

The local manually operated isolation valves at each turbine steam bypass control valve are locked open. Since the dump valves are required to open wide in approximately three seconds, it would not be feasible to attempt to open the subject valves. These valves are provided for maintenance purposes and for isolation of a failed open valve.

On a turbine trip with reactor trip, the pressure in the steam generators rises. To prevent overpressurization without main steam safety valve operation, the twelve turbine steam bypass valves open and discharge to the condenser for several minutes. The operation of the valves is initiated by a signal from the reactor coolant average temperature. In the event of a turbine trip, all valves open fully in three seconds. After the initial opening, the valves are modulated by the T_{avg} signal to reduce the average temperature and to maintain it at the no-load valve. This operation is described further in Chapter 7.

With loss of offsite power, the plant can be put in the hot shutdown condition in accordance with plant operating procedures and held there safely until outside power is restored, at which time a normal cooldown may be performed in accordance with operating procedures.

In the unlikely event that cold shutdown must be achieved before outside power is restored, this can still be accomplished. During the period of holding hot shutdown, the operator will manually load all equipment necessary for plant cooldown; all equipment and systems used for normal cooldown will be available except reactor coolant pumps and steam dump to condenser.

The cooldown would follow the same sequence of events as in the normal operating procedure for cooldown to cold conditions, with the following exceptions:

1) Circulation in the Reactor Coolant System is via natural circulation rather than by one reactor coolant pump.
2) Steam is dumped to the atmosphere rather than to the condenser. Cooldown rate will be slightly less than if steam were being dumped to the condenser due to the lower rate of steam dump.
3) When reactor coolant temperature and pressure are low enough to permit operation of the residual heat removal loop, cooldown rate would be maintained at less than 50 F/hr to reduce temperature differences between loops.

After a normal orderly shutdown of the turbine generator leading to plant cooldown, the operator may select pressure control for more accurate maintenance of no-load conditions using the bypass valves to release steam generated by the residual heat. Plant cooldown, programmed to minimize thermal transients and based on residual heat release, is achieved by a gradual manual adjustment of this pressure setpoint until the cooldown process is transferred to the Residual Heat Removal System.

During startup, hot standby service, or physics testing, the bypass valves may be controlled manually from the pressure controllers located on the main control board.

The twelve temperature controlled bypass valves open on turbine trip or large load reduction. The valves are interlocked to prevent opening unless the following conditions are established:

1) The circulating water pump for the particular condenser section is running
2) The condenser vacuum must be above the allowable set point
3) Loss of load interlock

The reason for condenser vacuum allowable setpoint is not based on the condenser shell and tubes but on the main turbine design. This setpoint has been established on information from the turbine manufacturer. The automatic vacuum trip for the main turbine is 18" Hg. In conjunction with this trip, the condenser dump valves are blocked when condenser pressure rises to 25" Hg. Therefore, the trip is provided for turbine protection. The condenser tubes are protected from steam impingement by an interlock with the circulating water pump breakers. The variation in steam flow from the dump system with increased condenser pressure to 25" Hg is not significant. Critical pressure drop exists from the main steam line to the condenser. With critical pressure drop, the steam flow rate is independent of downstream pressure and is only dependent on upstream pressure.

The loss of load interlock prevents actuation of the steam dump system for small load variations. The interlock allows steam dump for load reductions greater than 10%. This channel is independent of the steam dump control system.

The steam bypass system was designed to prevent spurious opening of the bypass valves by requiring more than one actuating signal (as in noted in Chapter 7). This will be the case only on those instances where bypass would be desirable, such as: (a) turbine trip or loss of load greater than approximately 10% and (b) cooldown, heatup and maintenance of hot shutdown via header pressure control.

Steam Relief to Atmosphere

If the condenser is not available during a turbine trip, excess steam, generated as a result of Reactor Coolant System sensible heat and core decay heat, is discharged to the atmosphere by the code safety and power operated relief valves.

There are five code safety valves and one power operated relief valve on each of the main steam lines located outside of the Reactor Containment and upstream of the MSIV's and MSCV's.

The five code safety valves per steam main consist of four 6-inch by 10-inch and one 6-inch by 8-in. These valves are set to open at 1065, 1080, 1095, 1110 and 1120 psig, respectively. The total relieving capacity of all 20 code safety valves is 15,108,000 lb per hr or 108% of the rated steam flow, according to Tech Spec Basis, Amendment #91. Discharge from each of these 20 valves is carried to the atmosphere through individual vent stacks.

The single power operated relief valve on each steam main is 6 in. Together, these valves are capable of releasing the sensible and core decay heat to the atmosphere. The valves are automatically controlled by pressure or may be manually operated from the main control board. Two indicating lights located above the relief valve controllers confirm their respective positions. The total relief capacity of the four valves is 2,467,000 lb per hour at 1020 psig. This capacity exceeds 10% at the rated steam flow. Discharge from each of these four valves is carried to the atmosphere through individual vent stacks. Functionally, these valves are part of the Auxiliary Feedwater System and are necessary to go from hot to cold shutdown.

The power operated relief valves may be used to release the steam generated during reactor physics testing, operator license training, and plant hot standby operation if the Turbine Bypass System is not available.

The design and installation criteria for mounting of the main steam safety and relief valves was similar to that described for pressure relieving devices in Section 4.2.3. At the main steam safety and relief valves specific provisions include: extra strong weldolet type header connections reinforced with weld build-up at the junction point, the weldolet size is two pipe sizes larger than the valves inlet size, a double extra strong reducer is used between the weldolet and the valve inlet, and the valve discharge is oriented to minimize reaction loads. Main steam pipe whip restraints were designed to allow their use as thrust restraints where required.

The following highlighted information is deemed to be "Historical" in nature and is not meant to be used or updated. It refers to, and utilizes, a methodology that is no longer applicable to Indian Point 3. The Alternate Source Term methodology that is currently applied to dose assessment at IP3 does not require the type of evaluation contained in the highlighted section below.

[Historical Information] Detailed piping stress analysis has been performed, taking into consideration the cumulative effect of all valves relieving simultaneously. This analysis has proven stresses to be within allowable code limits in all cases.

During any year of normal operation, it is not expected that there will be any necessity for steam relief to the atmosphere. The plant can be taken through most transients without need for atmospheric relief. The only credible cause for atmospheric relief would be the loss of the condenser. This could be caused by loss of air removal capacity or loss of cooling water. Both of these occurrences are unlikely and would require minimal time to correct. For a two- hour repair time and the plant maintained in a hot shutdown condition, the amount of steam dumped to the environment would be roughly 400,000 pounds.

If there is a loss of offsite power requiring that the plant be brought to a cold shutdown condition, the amount of the steam dump would be 1.4×10^6 pounds from the time power is lost to the time the Residual Heat Removal System is brought into operation 6 hours later. This includes the two hours at hot shutdown conditions.

The maximum quantity of radioactivity calculated to be released during each of the above postulated occurrences is given in Table 10.2-2. Releases were calculated for two cases:

a) The case in which the secondary side water contains an I-131 activity of 0.35 uCi/cc

b) The case in which the maximum expected fuel defects (0.2%) and steam generator tube leakage (20 gpd) are present. These anticipated levels of fuel defects and steam generator tube leakage were based on operating experience at Westinghouse plants employing Zircaloy-4 fuel rod cladding and Inconel steam generator tubes. A blowdown rate of 12.5 gpm per steam generator was used in the analysis for both the design case and the expected case.

Based on 1 percent fuel defects, the amount of radioactivity that would be released during either the 2-hour steam dump of 400,000 lb or the 6-hour steam dump of 1,400,000 lb is given in Figures 10.2-21 and 10.2-22 as a function of primary-to-secondary leak rate.

For the case when the reactor is operating at the design limit of 1% defective fuel, and using accident meteorology, site boundary thyroid doses of 3.7 rem and 5.7 rem and site boundary total body doses of 0.47 rem and 0.90 rem for the 2-hour and 6-hour steam dumps, respectively, have been calculated. The whole body dose (due to gamma radiation) would be much less than this total body dose.

With the simultaneous occurrence of approximately 0.2% fuel defects and steam generator tube leakage of approximately 20 gpd, and using average meteorology, the anticipated doses for the steam dumps would be:

	2-hour steam dump	**6-hour steam dump**
Thyroid dose	0.02 mrem	0.03 mrem
Total Body Dose	0.0004 mrem	0.0007 mrem

The Indian Point 3 steam dump system is arranged to avoid steam dump to the atmosphere in all cases with the exception of the loss of the main condenser. The plant can heat up, cooldown, trip, and take a load reduction without steam dump to the atmosphere as long as the main condensers are available. The plant was designed as practically as possible to avoid steam release to the atmosphere.

Under expected plant operating conditions, the doses at the site boundary are only a small fraction of those specified in 10 CFR 20 for the cases in which steam dump is necessary.

Neither the steam bypass valves nor the power operated relief valves are required for safety. A typical response of the Reactor Coolant System to a condition in which all power operated relief valves, both on the Reactor Coolant System and the Main Steam System, are assumed to be inoperative is given in Section 14.1.8. These analyses show, both for beginning and end of core life, that no hazard is presented to the integrity of the Reactor Coolant System or the Main Steam System and that the minimum DNBR remains well above 1.30, indicating no fuel clad damage, even assuming that the Reactor Coolant System and Main Steam System power operated relief valves, as well as the pressurizer spray and steam dump system, are inoperative. Operation of the power operated relief valves, pressurizer spray, and steam dump system are not required for safety. The Main Steam System safety valves provide a limiting device to the transient and are sized to take a minimum of 100% at the maximum calculated steam flow without exceeding 110% of design pressure. The pressurizer safety valves are conservatively sized to take the maximum flow resulting from a loss of external load, assuming no direct reactor trip, without Reactor Coolant System pressure exceeding permissible ASME code valves.

Steam for Auxiliaries

The steam for the turbine driven auxiliary feedwater pump is obtained from two of the 28-in steam generator outlet mains, upstream of the Main Steam Isolation Valves. The steam pressure is reduced to 600 psig for the turbine by a pressure control valve.

Auxiliary steam for the turbine gland steam supply control valve, the three steam-jet air ejectors, the heater section of the six moisture separator reheaters, the three priming ejectors and supplementary steam for the main feed pump turbines is obtained from branches on the steam lines upstream of the turbine stop valves. Pressure reducing stations are used for the priming and main air ejectors. Temperature control valves are provided in the steam line to the reheaters.

The design pressure and temperature for this system are 1085 psig and 600^{o}F, respectively.

Four combination moisture, Preseparators/Special Cross Under Pipe Separators (MOPS/SCRUPS) were installed to improve cycle efficiency.

The preseparator is a concentric chamber in the crossunder pipe whose upper end is open, constituting a cyclindrical gap. The preseparators are located directly at each HP turbine exhaust. Together with transport steam, the moisture flowing along the wall of the HP turbine exhaust is forced into the gap of the preseparator.

This moisture is drained within the apparatus to the SCRUPS. The transport steam is separated from the moisture and flows through a channel to the SCRUPS. The SCRUPS consists of turning vanes on which moisture droplets form a film that is removed together with transport steam through slots in the turning vanes. The turning vanes are hollow, and the separated moisture and transport steam flow through them to an outer chamber. There the steam separates from the moisture and leaves the MOPS/SCRUPS together with the transport steam from the MOPS.

The steam flows as extraction steam to feedwater heaters No. 35. The separated moisture is drained together with the moisture from the MOPS through a drain nozzle. Each MOPS/SCRUPS has a separate drain line equipped with a check valve. The four drain lines are routed via a common header to the heater drain tank. The drain piping is provided with a loop seal to prevent steam from flowing back to the MOPS/SCRUPS or to the heater drain tank.

The MOPS/SCRUPS reduces the moisture content of the wet steam exhausting from the HP turbine. This reduction results in lower pressure loss in the crossunder pipe with subsequent decrease in station heat rate and a reduction in the erosion-corrosion rate of the crossunder pipe walls.

There are six horizontal-axis, cylindrical shell, combined moisture separator steam reheater assemblies. Partially dried steam from the outlet of the moisture preseparators enters each assembly at one end. Internal manifolds in the lower section distribute the steam. The steam then rises through a moisture separator where most of the remaining moisture is removed and is drained to a drain tank. The steam leaving the separator flows over a tube bundle where it is reheated. This reheated steam leaves through nozzles in the top of the assemblies and flows to LP turbine elements. The tube bundle is supplied with main steam from upstream of the turbine throttle valves, which condenses in the tubes and leaves as condensate. Condensate from the reheater assemblies flows to the heater drain tank and is directed to the suction line of the boiler feedwater pumps together with the drains from the moisture preseparators and from feedwater heaters Nos. 35 and 36.

Steam from six extraction openings in the turbine casings is piped to the shells of the three parallel strings of feedwater heaters. The first point extraction originates at the high pressure turbine casing and supplies steam to the shell of feedwater heaters No. 36 (high pressure). The second point extraction originates at the high pressure turbine exhaust (cross under) piping and the moisture preseparator units, upstream of the moisture separator reheaters, and supplies steam to high pressure feedwater heaters No. 35.

The third, fourth, fifth, and sixth point extractions all originate at the low pressure turbine casings and supply steam to feedwater heaters Nos. 31, 32, 33, and 34 (all low pressure), respectively.

Non-return valves are provided in all but the two lowest pressure steam lines corresponding to feedwater heaters No. 31 and 32, which are mounted at the neck of the turbine.

To prevent turbine overspeed from backflow of flashed condensate remaining in the heaters after a turbine trip, these reverse-current, air cylinder operated valves are equipped with balancing counterweight. They close automatically upon a signal from the turbine trip circuit. Since the low pressure fifth and sixth point extraction lines to feedwater heaters Nos. 31 and 32 are located entirely in the condenser shells, they are not provided with non-return valves.

To prevent low pressure turbine overspeed, low pressure steam dump valves are provided in the high pressure turbine exhaust to the moisture separators. These valves discharge to the condenser on turbine trip.

Testing of the low pressure steam dump system was performed at plant power levels of 50% and 85-100% of the license application rating. This testing was accomplished in conjunction with the loss of load trip tests listed in Table 13.3-1. The test was performed by measuring the peak turbine speed achieved following an immediate and total loss of electrical load with the plant operating at full licensed power. The design condition for the loss of load was based on the turbine trip being delayed until functioning of the mechanical or IEOPS (Independent Electrical Overspeed Protection System) trips (IEOPS was abandoned in 3R19 2017). However, turbine trip actually occurs at an earlier time due to operation of the turbine trip solenoid valves triggered by the loss of load. Since it would not be prudent to disable the turbine trip solenoid valves for testing, the measured peak speed was mathematically corrected to the speed that would have been achieved had the solenoid trip failed. These corrected speeds were then compared to the predicted turbine responses. All test results were satisfactory.

<u>Steam Generator Blowdown</u>

Each steam generator is provided with a drain connection at the bottom and two 2.5 inch blowdown connections to control the concentration of solids in the shell side of the steam generator. The two blowdown connections are at the same level, but on opposite sides of the shell. Each of the three connections contains a manual isolation valve. Piping from the three connections join to form a 4 inch stainless steel blowdown header for each steam generator. (See Plant Drawing 9321-F-27293 [Formerly Figure 10.2-47A].)

Four individual blowdown headers are routed from the respective steam generators to the PAB. Each header contains two air operated containment isolation valves. Each blowdown header downstream of the containment isolation valves contains a venturi flowmeter, and a tee connection allowing flow to be diverted to either the blowdown flash tank or the blowdown recovery system.

Steam generator flow is measured using a venturi flowmeter (FE-545 through 548) with split range local dP transmitters (FT-545 A & B through 548 A & B) installed downstream of the isolation valves in the PAB.

These transmitters provide a signal to the totalizer (FY-545 through 548) and controller (FIC-545 through 548) units that calculates a true flow in each SGBD line using instantaneous changes in process flow and temperature. All four totalizers and controllers are mounted on the SGBD panel, located at elevation 15' -0" of the Turbine Building. The RTDs (TE-545 through 548) installed downstream of the venturi flowmeter in each SGBD line, provide instantaneous temperature input to the totalizers in the SGBD panel.

An interconnection between the 4" SGBD lines and the 3/8" SGBD Sample tubing was installed during RO9. This interconnection allows for the 4" SGBD lines to be filled from the Sample System. This modification was installed to prevent water hammer during SGBD restart above cold shutdown. There are two paths for each of the four blowdown lines: to recovery system or to flash tank. Manually / locally operated isolation valves located in PAB, control the path to the flash tank. Remotely / manually air operated flow control valves control the path to the recovery system from the steam generator blowdown panel. These valves are procedurally controlled to be operated selectively to prevent simultaneous blowdown to both the flash tank and the recovery system.

The steam from the blowdown flash tank is vented directly to the atmosphere. The condensate in the flash tank is routed to the main service water return header where it is ultimately discharged to the Hudson River. Flow elements are installed in the vent piping, blowdown discharge piping and city water supply piping for monitoring and heat balance calculations. FT-538 instrument loop meets the requirements of Regulatory Guide 1.97 and is used for radiation dose assessment in the event of a steam generator tube leak or rupture. A drain at the bottom of the blowdown flash tank will allow draining of potentially contaminated fluid to sump tank #31 and subsequently to the liquid waste processing system.

The blowdown flow from each steam generator to the recovery system is remotely/manually controlled from the steam generator blowdown recovery panel by means of an air-operated flow control valve in each of the four blowdown lines. The Steam Generator Blowdown Recovery System (Plant Drawing 9321-F-24063 [Formerly Figure 10.2-48]) consists of two heat exchangers, a filter and demineralizer package, and associated piping, valves and instrumentation. During normal system operation, the blowdown flow from all four steam generators is routed to the recovering heat exchanger (SGBDHX-3) in the Turbine Building.

The recovering heat exchanger (SGBDHX-3) utilizes condensate flow from the discharge of the No.32 feedwater heaters to cool the blowdown flow and recover as much heat as possible. This heat exchanger is designed to recover approximately 65% of the maximum theoretically recoverable heat during the period of nominal continuous blowdown (1% of feedwater flow) at 100% power.

The blowdown flow exiting this heat exchanger is routed through a non-recovering heat exchanger (SGBDHX-4) also located in the Turbine Building. This heat exchanger utilizes service water to cool the blowdown flow to 120 F for subsequent treatment in the filter and demineralizer package and final discharge to the drains collecting tank.

The pressure in the blowdown piping system upstream of and including SGBDHX-4 is maintained by means of a pressure control valve located at the outlet of SGBDHX-4. This back pressure minimizes flashing and enhances flow control. Immediately downstream of the pressure control valve the flow path divides. One path routes the flow to the blowdown demineralizer package.

The other path bypasses demineralizer and diverts the blowdown flow to the drains collecting tank for treatment of the blowdown by the condensate polisher during periods when the polisher is operating. Additionally, the air-operated isolation valves for these flow paths permit a pressure and temperature declassification in the downstream piping.

The total blowdown flow rate can be maintained between 0.2% and 1.0% of the total feedwater flow rate. For operation at 100% power this corresponds to volumetric blowdown rates between 48 and 240 gpm from all four steam generators. The blowdown recovery system design basis is 300 gpm for four steam generators. This provides for occasionally higher blowdown rates should they be required to reduce solids concentration. The replacement steam generator design permits up to 230 gpm continuous blowdown flow to be drawn from any single blowdown nozzle over the entire design life of the steam generators, or up to 335 gpm through a single nozzle over a cumulative one year period. There are two blowdown nozzles on each steam generator.

Redundant area temperature sensors are provided at three selected locations in the PAB in the vicinity of the blowdown recovery piping for detection and mitigation of a high energy line break. Specifically, two RTDs are located in each of the three following areas:

1) 55' -0" elevation of the piping penetration area,
2) 35' -0" piping tunnel (mini-containment area), and
3) 18' -0" elevation of the Heat Exchanger Room.

These RTDs are electrically interlocked with the actuation circuitry for the blowdown containment isolation valves and will automatically close these valves upon detection of high temperature in any of these areas. In addition, these RTDs will initiate an alarm in the Control Room upon high temperature detection.

Steam generator sample lines are taken from the blowdown headers inside the containment (see Plant Drawing 9321-F-27293 [Formerly Figure 10.2-47A]). Small flows from the sample lines are combined and monitored for radiation (See Plant Drawing 9321-F-27293 [Formerly Figure 10.2-47B]). In the event of a high radiation signal, both diaphragm valves in the sample and blowdown liens will close automatically prior to Blowdown Flow being released to the environment. If significant radioactivity is present in the steam generator blowdown from Indian Point 3, this flow could be routed to Indian Point 1 for treatment (see Section 11.1 for details on this intertie).

Sources of radioactivity releases from the Steam and Power Conversion System (SPCS) of Indian Point 3 are shown in Figure 10.2-23.

Isolation of Steam Generator Blowdown from event initiation is assumed for both Loss of Normal Feedwater (Section 14.1.9) and Loss of All A.C. Power to the Station Auxiliaries (Section 14.1.12).

10.2.2 Turbine Generator

The Turbine Generator Building General Arrangement Drawings are shown in Plant Drawings 9321-F-20043, -20053, -20063, -20093, -20083, -20073, and –20103 [Formerly Figures 10.2-40 to 10.2-46]. The original turbine generator had a guaranteed capability of 1,021,793 kW at 1.5" Hg absolute exhaust pressure with zero percent makeup and six stages of feedwater heating. The unit operates at 1800 rpm with steam supplied ahead of the main stop valves at 720 psia, 506^{o}F and enthalpy of 1,200 BTU/lb. Steam is admitted to the turbine through four stop valves and four control valves. The expected throttle flow at 1,093,500 kW is 13,136,870 lb of steam per hour.

The turbine is a four-casing, tandem compound six-flow exhaust unit with 44-inch last row blades. It consists of one double flow High Pressure (HP) element in tandem with three double flow Low Pressure (LP) elements. Steam, after passing through the stop and control valves, passes through the high pressure element, exhausts through the moisture preseparators, flows through the moisture separator reheaters and then to the LP elements.

WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," provides the methodology used to determine the frequency of testing for the turbine stop and control valves. Westinghouse report WOG-TVTF-93-17 (8/6/93), "Update of BB-95/96 Turbine Valve Failure Rate and Effect on Destructive Overspeed Probabilities," revised the valve failure data in WCAP-11525 requiring a decrease in the stop valve test interval to satisfy regulatory approved overspeed probability criteria.

High Pressure Turbine

The Indian Point 3 turbine generator is rated and guaranteed to a steam flow equal to the licensed thermal power of the NSSS. The turbine is designed to pass 5% additional flow.

The HP turbine rotor was replaced during the 2004 Refueling Outage (2R16) in order for the HP turbine to be able to accommodate the increase in steam flow caused by the power uprate. The original nozzle block design was removed and replaced with an inner cylinder design with directional inlet vanes. The new design also incorporated an all Rateau blade designed rotor.

In the large size turbine that is applied to the nuclear cycle, the reaction type stage is inherently more efficient. For this reason, it is desirable to maximize the work performed in the reaction stages. Therefore, in order to increase the proportion of work performed by the reaction stages, the impulse chamber pressure must be increased.

The desired increase in impulse chamber pressure was accomplished by installing new stationary blading and by adjusting the gauging of the proper number of stationary rows in the HP blade path.

In summary, the HP Optimization Program included:
1) Two new nozzle blocks
2) Two new rows of triple pin control stage blades
3) Ten new rows of stationary blades (five (5) GVN and five (5) GNN)
4) Four new rows of reaction blades (two (2) GVN and two (2) GNN)

Based upon HP turbine optimization calculations, the anticipated heat rate improvements were set at 10 btu/kw-hr for the new steam generators and 63 btu/kw-hr for the HP turbine optimization program for a total improvement of 73 btu/kw-hr plus or minus the test tolerance of 18 btu/kw-hr. The HP turbine optimization modification acceptance test was successfully carried out in July 1989. This test demonstrated the heat rate decrease equal to or larger than the minimally acceptable 73 – 18 = 55 btu/kw-hr.

Low Pressure Turbine

During the 1990 Refueling outage, the existing three low pressure turbines (stationary and rotating components) were replaced with three (3) ASEA Brown Boveri (ABB) low pressure turbines.

The ABB turbines incorporate design improvements that significantly reduce stresses and utilize materials of lower yield strength. This results in a turbine that is resistant to stress corrosion cracking and low cycle fatigue. Additionally, several performance-related design features have been incorporated to improve the overall efficiency of the turbines. These design features will result in an increase in the power output of the unit.

Turbine Oil System

The turbine oil system consists of a high pressure hydraulic control system and a low pressure lubrication system. Oil is also used to seal the generator shaft seals to prevent hydrogen leakage form the generator into the Turbine Building. The oil pump mounted on the main turbine shaft normally supplies all oil requirements. A motor driven auxiliary oil pump supplies the oil required during turbine startup and whenever there is low pressure in the bearing oil header. The auxiliary unit is a centrifugal pump driven by a 150 hp motor. Oil is supplied to the hydraulic control mechanism at 300 psig. A motor driven bearing oil pump is also provided to supply oil whenever there is low pressure in the bearing oil header. This is a centrifugal type pump with a 75 hp motor. During startup, these auxiliary oil pumps supply all the oil while the main pump acts against a closed check valve. An AC motor driven oil pump is provided for turning gear and emergency operation. A DC motor driven oil pump operated from a station battery provides additional backup to ensure a supply of lubricating oil to the machine. An AC motor driven generator seal oil pump is furnished for normal operation with a DC motor driven backup pump to ensure confinement of the hydrogen within the generator.

A continuous bypass turbine oil purification system removes contaminants from the oil.

To maintain shaft alignment while the unit is down, a motor driven turning gear is provided.

The turbine is coupled to a single, hydrogen inner cooled generator and rotating rectifier exciter. The generator is rates at 1,125,600 kVA, 3 phase, 60 cycles, 22 kV, 90 percent power factor, and 75 psig hydrogen pressure. It has sufficient capability to accept the gross kilowatt output of the steam turbine with its control valves wide open at 720 psia, saturated, 1,200 BTU/lb enthalpy steam conditions.

Bulk Hydrogen Storage

Hydrogen truck is connected to system as primary supply.

A removable section of pipe is provided between the pressure control station and the stator. This piping section is supplied as a safety precaution to avoid an explosive hydrogen-air mixture in the generator. Ventilation piping is provided with isolation valves to ensure correct purging of gases from the stator.

Before maintenance work is performed on the generator, the hydrogen gas must be evacuated from the system. Since hydrogen and air form an explosive mixture, air cannot be used to purge the system. Inert carbon dioxide gas is used for the purpose of purging the generator.

The Indian Point 3 purging requirements are satisfied with a carbon dioxide gas vaporizing system, and can also be satisfied by the Indian Point 2 CO_2 gas vaporizing system through a 2.5-inch supply line from the Indian Point 1 intake structure area.

Downstream of HS-PCV-1002 where hydrogen pressure has been reduced to an intermediate 125 psig, there is an emergency crossover connection with Indian Point 2. This crossover may be used to transfer quantities of low-pressure hydrogen to or from Indian Point 3 during generator-filling applications, or as an emergency source of supply.

Pressure gauges and vents are provided to facilitate this operation. Additional operating notes are listed on the Hydrogen-CO_2 system flow diagrams. (See Plant Drawings 9321-F-20403, 20443, and -20453 [Formerly Figures 10.2-24, 10.2-25 and 10.2-26].)

Turbine Generator Inservice Inspection Program

Base loaded units are normally operated for 5 to 6 years before overhauling, unless there is specific intelligence from operating parameters (such as unusual vibration, pressure and temperature variations throughout the steam path, or bearing temperature indications) that indicates the need for an earlier inspection. An outline of procedures for performing turbine and generator inspection is included in their operating and maintenance manuals.

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

Depending upon the physical arrangement of the blading and the contour surfaces that are to be inspected, any of the following non-destructive techniques might be used: magnaflux, magnaglo, and red dye penetrant.

A detailed and very careful ultrasonic inspection of all turbine components was performed in the preassembly and assembly stages. Turbine operating experience indicates the occurrence of a turbine originated missile to be highly unlikely, however, the plant has been designed to withstand the consequences of a turbine missile.

10.2.3 Turbine Controls

High pressure steam enters the turbine through four stop valves and four governing control valves. The four main stop valves were designed for the specific operating conditions. Each stop valve is a single seated, oil operated, spring closing valve controlled primarily by the turbine overspeed trip device. The turbine overspeed trip pilot is actuated by one of the following to close the stop valves:

1) Turbine thrust bearing trip
2) Low bearing oil pressure trip
3) Low condenser vacuum
4) Solenoid trip
5) Overspeed trip
6) Hand trip.

Each stop valve has limit switches that operate position lights on the main control board. There are similar limit switches in the electrical interlock system that operate the turbine trip auxiliary relay and the reactor trip breakers.

Test switches on the main control board permit test closure of each valve. The valve operation can be observed from within the turbine front-end enclosure. Periodic tests exercise the stop valves and ensure their ability to close during an emergency.

Before a stop valve can be opened, the pressure across the valve must be equalized. This is done by opening a small bypass valve around each of the stop valves.

Four hydraulically operated control valves of the single seated plug type open and close in sequence to control steam admission to the turbine. They are actuated by the turbine speed governor, which is responsive to turbine speed. It includes:

1) A speed changer or synchronizing device
2) A load limit device that must be reset after operation of the over-speed trip before the control valves can be opened
3) A second load limit device without reset is added for redundancy [Deleted]
4) The governing emergency trip valve, actuated when the stop valves are tripped, to close the control valves
5) An auxiliary governor, responsive to the rate of turbine speed increase, to close the control valves.

Each control valve has a motor controlled hydraulic pilot valve to test the operation of the control valve. Test switches with indicating lights are provided on the main control board turbine section. Removable strainers are located in each control valve body to protect the valves and turbine from foreign material in the steam.

The normal governing devices that operate through hydraulic relays to operate the control valves are as follows:

1) The governor handwheel at the unit
2) The governor synchronizing motor, which is controlled by a switch on the electrical section of the main control board and is used for raising or lowering turbine speed or load
3) The load limit handwheel at the unit
4) The load limit motor, which is controlled by a switch on the turbine section of the main control board and by a reactor control rod drop run back signal. This is described further in Chapter 7.

The pre-emergency device functions similar to the normal governing devices by operating the control valves in case of abnormal operating conditions in the auxiliary governor. This pre-emergency device closes the control valves on rapid increase in turbine speed. The control valves will be actuated by either the speed governor or load limit. The device delivering the lowest oil pressure will be in control. Pressure gauges on the main control board indicate the oil pressure from these devices.

The emergency devices that will trip the stop valves, the control valves, and the air relay dump valve are as follows:

1) Overspeed emergency governor
2) Solenoid trip (actuated by reactor trip breakers opening, electrical faults and a manual push button)
3) Low condenser vacuum trip
4) Low bearing oil trip
5) Thrust bearing trip
6) Hand trip at unit.

The mechanical overspeed trip mechanism consists of an eccentric weight mounted in the end of the turbine shaft that is balanced in position by a spring until the speed reaches the tripping speed. Its centrifugal force overcomes the restraining spring and the eccentric weight flies out striking a trigger that trips the overspeed trip valve and releases the autostop fluid to drain. The resulting decrease in autostop pressure causes the governing emergency trip valve to release the control oil pressure. This closes the main stop and control valves. An air pilot valve used to control the extraction line non-return valves is also actuated by the autostop pressure.

The autostop valve is also tripped when any one of the protective devices is actuated. The protective devices include a low bearing oil pressure, solenoid, thrust bearing, and low vacuum trips. These devices are all included in a separate assembly, but are connected hydraulically to the over-speed trip valve. An additional protective feature includes a turbine trip following a reactor trip.

When unit load is greater than the P-8 setpoint, trip of the turbine generator initiates a reactor trip to prevent excessive reactor coolant temperature and/or pressure.

[Deleted]

10.2.4 Circulating Water System

Hudson River water is used for the condenser circulating water. River water flows under the floating debris skimmer wall into six separate screen wells. The water flows through Ristroph travelling screens where fish and debris are collected and returned to the river. Modified baskets employing bucket features collect and lift fish to be returned to the river. Additionally, the head section of the screen employs five (5) spray wash headers; three (3) low pressure fish sprays, and two (2) high pressure debris sprays for debris removal. Each screen well is provided with the ability to install stop logs to allow dewatering of any individual screen well for maintenance purposes.

The water from each individual screen well flows to a variable speed motor driven, vertical, circulating water pump. Each of the six condenser circulating water pumps provides 140,000 gpm at 29 ft TDH when operating at 360 rpm and is located in an individual pump well, thus tying a section of the condenser to an individual pump. The circulating water is piped to the condensers and is discharged back into the river through a thermal discharge dispersion arrangement designed to minimize recirculation and thermal effects. A temperature recorder has been installed in the discharge canal to monitor temperature and provide a record of plant thermal effluents. Radiant heaters are also supplied for the screens but are no longer in service. The extreme low level conditions for the river at the intake structure is 4'-5" below the mean sea level at the site. With the circulating water pump suctions at 20.5 feet below the mean sea level at the site, sufficient submergence for the circulating water pump suctions is provided. (See Plant Drawings 9321-F-20123, and -20113 [Formerly Figures 10.2-27 and 10.2-28].)

From the study in response to IE Bulletin No. 81-03, the Authority has concluded that neither Corbicula sp. nor Mytilus sp. is present in the Hudson River in the vicinity of Indian Point 3 (see IPN-81-36, May 21, 1981). The Authority performs an inspection of various circulating water system inlet boxes at least once per refueling cycle and monitors circulating water system temperatures on a regular basis. These activities and the close monitoring of the spread of these aquatic species in the Hudson River will serve to prevent blockage or degradation of the plant's cooling system as a result of aquatic species intrusion.

To prevent disabling the vital 480 Volt electrical switchgear in the adjoining Control Building in the event of flooding due to circulating water system line or expansion joint failure, a four foot high dike is erected around the entrance to the elevation 15' of the Control Building from the Turbine Hall. Based on one circulating water pump operating at rated flow discharging into the

Turbine Hall with no water escaping from the building, it would take approximately twenty minutes before the water level would reach the top of the dike.

In addition to this, redundant level alarm switches are installed in the pipe tunnel at Elevation 3' 3" of the Turbine Hall. These switches will sense high water in the pipe tunnel and give an indication in the Control Room.

These two features allow the operator at least twenty minutes to investigate a problem and take appropriate action by shutting down the circulating water pumps.

10.2.5 Condenser and Auxiliaries

Three surface type, single pass, radial flow condensers with bolted divided water boxes at both ends are provided. Fabricated steel water boxes and shell construction is used. Hotwell design is for four-minute storage while operating at maximum turbine throttle flow with free volume for condensate surge protection. The hotwells are longitudinally divided to facilitate the detection of condenser tube leakage. Each half is provided with separate conductivity measurement devices. In the event of high conductivity (high salinity) in a hotwell, it will be manually isolated. The condensate will be dumped overboard instead of being used to provide suction for the condensate pumps described below. The Titanium metal tubes are rolled and welded into solid titanium tube sheets. Water box manholes are provided for access. Provision is made for condensing the main feedpump drive turbine exhaust. The condensers have steam turbine bypass condensing arrangements to condense turbine bypass steam for controlled startups and to condense residual and decay heat steam following a shutdown.

Condenser level instrumentation consists of:

1) Hotwell level transmitter with electronic transmitter and impulse piping
2) Separate hotwell level alarms
3) Extreme low level alarm

Three motor driven, eight-stage, one-third capacity, vertical, pit type, centrifugal condensate pumps are provided, each taking suction from the condenser hotwells. The condensate pumps discharge into three separate parallel strings of feedwater heaters and provide the suction supply to the feedwater pumps.

For each condenser, one four element, two-stage air ejector with separate inter-condenser and common after-condensers is provided. For normal air removal, one air ejector unit is required per condenser. The ejectors function by using steam from the main steam system supplied through a pressure reducing valve. The air ejector exhaust is monitored for radioactivity. In the event of a steam generator leak and the subsequent presence of radioactive contaminated steam in the secondary system, the radioactive non-condensable gases that concentrate in the air ejector effluent will be detected by this radiation monitor. A high activity level signal automatically diverts the exhaust gases from the vent stack to the Containment.

For initial condenser shell side air removal, three non-condensing priming ejectors are provided. Each has a capacity of 900 cfm. This apparatus may be used during periods of plant shutdown where decay heat is involved. The main ejectors will also be operated at the same time to ensure that the effluent is monitored for radioactivity.

10.2.6 Condensate and Feedwater System

The Condensate and Feedwater System is designed to supply a total of approximately 13,283,282 lb of feedwater per hour to the four steam generators at a turbine load of 1022 MW(e). This system, as shown on Figure 10.2-1 is composed of:

1) A condensate system that collects and transfers condensed steam and the drains from four stages of feedwater heaters through five stages of feedwater heating to the suction of the main feedwater pumps.
2) A condensate makeup and surge system that maintains a normal water level in the condenser hot wells.
3) A heater drain system that collects and transfers the drains from feedwater heaters No. 35 and No. 36 and the six moisture separator-reheaters to the suction of the main feedwater pumps.
4) A feedwater system that delivers the condensate and heater drains through the final stage of feedwater heating to the steam generators.
5) An Auxiliary Feedwater System that provides a flow of water from the condensate storage tank to the steam generators when the main feedwater pumps are unavailable. The flow is equivalent to that required from makeup because of reactor core decay heat removal requirements.

The main steam and feedwater lines are protected from reaction forces caused by a failure in the Reactor Coolant system pressure boundary by the steam generator support system, which is designed to resist reactor coolant blowdown loads combined with seismic and normal loads without exceeding yield strength of the structural steel.

The steam generator support structures are box sections with each vertical side made up of structural steel sections to form a vertical truss. These structures are designed to withstand longitudinal and guillotine breaks in the Reactor Coolant System boundary.

Condensate System

The condensate system transfers condensate and low pressure heater drains from the condenser hotwell through the condensate polisher and five stages of feedwater heating to the suctions of the main feedwater pumps.

Three 1/3 size condensate pumps, arranged in parallel, take suction from the bottom of the condenser hotwells. The pumps discharge into a common header that carries a portion of the condensate through three steam jet air ejector condensers, arranged in parallel, and through one gland steam condenser. The remaining portion flows in parallel with the first flow-path, bypassing the steam jet air ejectors and the gland steam condenser. The second flow-path rejoins the first in the condensate header downstream of the gland steam condenser.

The condensate pumps are eight stage, vertical, pit-type pumps. Each pump is rated at 7860 gpm and 1150 ft TDH when operating at 1170 rpm. A split mechanical seal is used for shaft sealing. The pump bearings are lubricated by the pumped liquid. Each pump is driven through a solid coupling by a 3000 hp, vertical, solid shaft, induction motor that has an open drip-proof enclosure. The performance characteristic of the pump is given in Figure 10.2-29. The condensate pumps are operated by manual controls on the main control board.

An 8-in condensate recirculation line, containing a diaphragm operated valve, is provided to maintain minimum flow through the air ejector condensers and gland steam condenser. This recirculation will maintain condenser vacuum and turbine steam seals during startup, shutdown, and at very low loads. The recirculation line originates at the condensate header downstream of the gland steam condenser and terminates at the condenser hotwell. The diaphragm operated recirculation valve is automatically controlled by the minimum flow required by the air ejector condensers. The diaphragm operated recirculation valve may also be controlled manually from the local control panel.

The 24-inch condensate header divides into three 14-in lines downstream of the gland steam condenser. These lines carry the condensate through the tube sides of three parallel strings of two LP feedwater heaters. The flow to the remaining three strings of three LP heaters is through a common 24-in pipe. After the No. 35 feedwater heaters, the three condensate lines join into a common header. The heater drain pump discharge enters this header and then continues on to the suction of the main feedwater pumps.

Each parallel string of feedwater heaters may be taken out of service by closing manual gate valves at the inlet and outlet of the string of heaters.

The condensate makeup and surge systems operate to maintain normal water level in the condenser hotwell.

The makeup system connects the 600,000 gallon capacity condensate storage tank to a diffusing pipe in the condenser shell. This line contains an air operated valve that automatically opens on low level in the condenser hotwell to pass makeup water from the tank to the condenser. Two redundant isolating valves will close to the condenser makeup when the condensate storage tank level reaches 360,000 gallons. This will ensure a reserve of condensate for the auxiliary feedwater pumps that will hold the plant at hot shutdown for 24 hours following a trip at full power.

The condensate surge system connects the condenstate pump discharge header to the condensate storage tank. This line contains a diaphragm operated valve that automatically opens on high level in the condenser hotwell to pass excess condensate from the condensate pump discharge header to the condensate storage tank.

Hotwell levels are indicated on the main control board. Should the automatic makeup valve or the surge valve become inoperative, it may be isolated from its respective system and the hotwell level controlled from the Control Room by remote manual positioning. The condenser hotwells contain 114,000 gallons, which is equal to approximately 5.5 minutes condensate flow at 1022 MW(e) load.

The drains from the No. 36 feedwater heater flow to the heater drain tank. Normal condensate level is maintained in the No. 36 heaters by diaphragm operated level control valves.

The drains from the No. 35 feedwater heaters flow by gravity directly to the heater drain tank. There are no level control valves in the drains from these heaters.

The heater drain tank receives gravity drains directly from the four moisture preseparators via a single drain header. Check valves are provided in the drain lines just before they are manifolded into the common drain header.

The heater drain tank also receives drains from the shells of moisture separators through separate gravity flow drain lines. Air cylinder operated swing check type non-return valves in these drain lines close on turbine trip.

Two half-size heater drain pumps pump the drains from the drain tank into the condensate header upstream of the main feedwater pumps. Both pumps discharge through diaphragm operated level control valves.

The heater drain pumps are fourteen-stage, vertical, enclosed suction-type pumps. Each pump is rated at 4150 gpm and 720 ft TDH when operating at 1170 rpm. Each pump is driven through a solid coupling by a 1000 hp, vertical, solid shaft, induction motor that has an open drip proof enclosure.

The heater drain pumps are operated by manual controls on the main control board. A heater drain pump is automatically stopped on low drain tank level or if the flow falls below a set minimum. After the pump has stopped, the water level in the heater drain tank will increase. An alarm sounds in the Control Room on both tank low level and pump low flow.

When a high level occurs in the heater drain tank, a diaphragm operated valve opens to discharge the excess condensate from the heater drain tank directly to the shell of a condenser. A spare condenser connection and control valve is provided. An alarm sounds in the Control Room. The alarm is to alert the operator that inflow is greater than outflow at the heater drain tank and/or that the automatic level controls have failed. The cable runs direct via conduit and tray to Supervisory Panel SD. The heater drain tank has a 5660 gallon storage capacity at normal water level or approximately ¾ minute storage of drains at a load of 1022 MW(e).

Drains from the No. 32, No. 33, and No. 34 feedwater heater strings normally flow through diaphragm operated level control valves to the shells of the next lowest pressure feedwater heater. On high level in any heater, a separate high level drain from the heater discharges directly to the condenser. Heater Nos. 33 and 34 are equipped with an alternate high level drain that discharges from the condensing zone of the heaters. This is to eliminate the high flow velocities and accompanying flashing experienced in the subcooling zones of these heaters during plant power transients.

Drains from the No. 31 feedwater heater normally flow through diaphragm operated level control valves to the condenser. When a high level occurs in the heaters, a separate high level drain for each heater discharges to the condenser.

A high level drain to the condenser is provided for No. 31 and No. 32 feedwater heaters in the event of a tube break.

Condensate Polishing System

The Condensate Polishing System (CPS) is designed to remove dissolved and suspended solids from the condensate in order to maintain the feedwater quality required for the steam generators.

The Condensate Polishing System is not required for safe shutdown of the reactor, has no safety-related function, and is designed as non-nuclear safety equipment. The system was tested and inspected in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code.

The CPS, as shown in Plant Drawing 9321-F-20183, Sh. 2 [Formerly Figure 10.2-3B], is installed within the existing condensate system between the condensate pumps and the first stage of feedwater heaters. The system is designed for a maximum capacity of 19,745 gpm with an inlet maximum pressure of 700 psi at 140°F. The system consists of six Service Vessels, six condensate post filters, an external resin regeneration system, and piping, valves, instrumentation and controls for proper operation.

Normally, five service and five condensate post filter vessels are in service, and one service and one condensate post filter vessel are on standby.

During normal operation, 100 percent of the condensate flow is passed through the service vessels and filtered through the condensate post filters. Although all the condensate passes through the service vessels, individual service vessels may or may not contain ion exchange resin, based on the condensate and feedwater pH control program in use. Condensate that passes through a service vessel that contains no ion exchange resin will allow filtering of the condensate through the condensate post filters. The reason for this is that none is bypassed around the service vessel.

The service vessels are arranged for parallel flow operation. Any one vessel can be removed from service for the regeneration of resin or for maintenance at any time. The regeneration system consists of the resin separation and cation regeneration vessel, an ion regeneration vessel and resin mix and hold vessel. The service vessel effluent is sent to the condensate post filters to remove any resin fines or crud that is carried out into the effluent. After that, condensate post filter effluent is pumped to the feedwater heaters using the condensate booster pumps. When plant conditions permit, the condensate booster pumps can be secured or placed in standby if desired

The high and low total dissolved solids (TDS) sumps in the condensate polisher building collect the wastewater generated by the condensate polisher facility. Waste with a high conductivity is directed to the high TDS sump while wastes with a low conductivity are directed to the low TDS sump. The waste in the tank is neutralized by the addition of acid or caustic until a pH in the range of 6-9 is reached. When the proper pH is obtained, the waste is discharged through the plant discharge canal. If high radioactivity is detected, the discharge is automatically terminated.

The Condensate Polishing System is designed to allow for semi-automatic operation and/or remote manual operation from a main control panel in the condensate polisher facility. Instrumentation to monitor conductivity, differential pressure, and flow are provided to determine system operation status. Specific conductivity, and cation conductivity are monitored and recorded at the effluent of each of the polisher vessels. pH monitoring is provided on the auxiliary panel for the waste treatment facility.

Condensate Polisher System chemistry is designed to the limits given in Table 10.2-8.

Condensate Storage Tank

The condensate storage tank supplies water to the Auxiliary Feedwater System, main condenser hotwell, and to the Seal Injection System for pumps and valves exposed to the condenser vacuum. Two redundant level controllers and level indication in the Control Room are provided for the condensate storage tank. The tank is provided with a nitrogen blanket in the air space above the liquid to reduce the amount of dissolved oxygen in the condensate.

The head space of the tank will be maintained at a nominal positive pressure of 0.5 inches Water Column (WC) by the nitrogen atmosphere. To ensure the condensate storage tank is operated within its analyzed pressure limits, the tank is equipped with two QA Category 1 safety-related 100% capacity breather valves on the dome. The breather valves are set to open at nominal pressure on both the vacuum side and positive pressure side.

The Nitrogen Supply System (NSS) is classified as QA Non-Category 1 since it does not perform any safety-related function. However, a QA Category 1 restriction orifice is installed in the nitrogen supply piping downstream of the NSS to protect the condensate storage tank from excessive ingress in the event of a failure of the NSS control station.

Main Feedwater System

Two half-size steam driven main feedwater pumps increase the pressure of the condensate for delivery through the final stage of feedwater heating and then the feedwater regulating valves to the steam generators.

The main feedwater pumps are single-stage, horizontal, centrifugal pumps with barrel casings. Each pump is rated at 15,300 gpm and 1830 ft TDH when operating at 4875 rpm. Seal water injection is used for shaft sealing. Bearing lubrication for each feedpump and its turbine drive, as well as turbine control, is accomplished by an integral oil system mounted on the pump base. Normal circulation of the oil is by a motor driven pump. The lubricating/control oil system includes a reservoir, a cooler, and two motor driven oil pumps. Low lubricating oil pressure, sensed by three pressure switches per pump and having 2-out-of-3 logic, trips the turbine/pump combination. Surges in the control oil portion of the system are dampened by the 80 gallon oil accumulators. Each main feedwater pump is driven through a flexible gear type coupling by an 8350 hp horizontal steam turbine using steam from the discharge of the three reheater moisture separators on one side of the Turbine Hall. The main feedwater pumps are operated automatically by the feed control system. Manual controls are also provided on the main control board for remote operation and testing during normal operation. During normal startup of the plant, these pumps are started locally. A minimum flow control system is provided to ensure that each pump is handling at least a 3000 gpm flow at all times. See Figure 10.2-37 for the pump characteristic curve.

Low suction pressure reduces the turbine speed to maintain suction pressure. Normal speed is regained when the suction pressure and flow is reestablished. High discharge pressure reduces turbine speed to prevent excessive pressure in the feed piping. Hi-hi discharge pressure causes the boiler feedpump turbines to trip.

High main feedwater pump bearing temperatures are alarmed in the Control room but do not, however, automatically stop the pump.

The two parallel main feedwater pumps operate in series with the condensate pumps, and discharge through check valves and motor operated gate valves into a common header. The feedwater then flows through the three parallel, high pressure feedwater heaters into a common header. Four parallel 18-in lines containing the feedwater metering and regulating stations feed the four steam generators. A pre-startup treatment (filtering) system capable of removing corrosion products from the feedwater/condensate system piping and components accumulated during plant shut-downs is connected to the 30" common feedwater header downstream of the high pressure heaters. The filtrated water is recirculated to the condenser hotwells.

Shutoff valves at the inlets and outlets of the feedwater heaters permit a heater train to be taken out of service. Bypass lines are provided around the heaters to allow operation when a heater is out of service for maintenance.

Steam Generator Internal Feed Ring and Regulator Modifications

A cross section of the feedwater ring is shown in Figure 10.2-30. The design includes features to preclude the rapid drainage of the feedwater ring when the water level in a steam generator falls below the ring. This prevents a cold water-steam interface from forming in either the feedwater ring or the connected 18-inch feedwater piping, and should preclude the initiation of water hammer type shocks due to steam condensation. Plan and elevation views of the feedwater ring are shown on Figure 10.2-32.

The design consists of 36 flow holes (2-inch diameter) located in the top of the ring. Short J-bend pipes were welded to each flow hole to direct the feedwater vertically downward. As an additional measure against water hammer and thermal stratification, the feed ring is elevated several inches above the feedwater inlet to the steam generator.

The steam generator feedwater metering and regulating stations measure, indicate, record and control the water level in each of the four steam generators. Figure 10.2-34 shows the Feedwater Regulating System (one of four typ.) which, in turn, shows the low flow bypass regulator. A conventional three element system receives flow and load signals from the Reactor Protection System through isolation amplifiers and compares the difference between steam and feedwater flows to adjust the level set point.

The deviation of level measurement from this set point positions the feedwater control valve accordingly. Totalized steam flow controls the speed of the main feedwater pump turbines.

Piping restraints were installed on two of the feedwater lines to the steam generators that have the longest horizontal radial run inside the Containment Building to limit pipe movement in the vicinity of the containment penetration. Figure 10.2-33 shows the feedwater piping to the steam generator. Clearances in the penetration whip restraints on all four feedwater lines are sited to prevent "rebound" type stressing of the pipe in the event of water hammer shock.

Hydraulic dampers were installed on the main feedwater regulators to preclude rapid closure of these valves which might cause water hammer. These dampers will not, however, adversely affect the closing time of the valves during normal operation. In addition, the plug trim on the main feedwater regulator valves was designed to provide improved low flow control characteristics.

Reactor Trip

A reactor trip is actuated on a coincidence of steam flow-feedwater flow mismatch coupled with low level in the corresponding steam generator. A reactor trip is also initiated on a coincidence of two-out-of-three low-low water level signals from any one steam generator.

Whenever this reactor trip occurs, the feedwater valves move to the fully opened position to provide an additional heat sink for the reduction of reactor coolant temperature to the no-load average temperature value. The valves remain fully open until average Tavg temperature reaches a predetermined setpoint value equal to or greater than 554 ^{o}F.

The feedwater control system is an electronic analog instrumentation system. Readout and control equipment are as follows:

1) A wide range level recorder (one two-pen recorder for each of two pairs of steam generators), calibrated for cold conditions in the steam generator, permits observation of one level essentially over the full height of each steam generator shell. In addition, a level indicator is provided at various local control stations for safe shutdown of the plant in the event the Control Room is uninhabitable.

2) A direct reading, three-pen recorder in the Control Room records steam generator level and the steam and feedwater flows (in pounds per hour) for each steam generator.

3) Each flow channel and each narrow range level channel is indicated on the main control board.

4) Each feedwater controller has one manual control station. This unit consists of an auto/manual transfer switch and an analog output control that serves as the valve position signal when in "Manual." The "Automatic" set point is pre-set but adjustable in the instrument rack.

Other manual control stations are used to position auxiliary feedwater regulating valves.

Auxiliary Feedwater System

The Auxiliary Feedwater System (AFS) is used for manual plant startup. It also supplies high pressure feedwater to the steam generators. This feedwater supply is needed to maintain sufficient water inventory in the steam generators to allow removal of decay heat from the Reactor Coolant System by secondary steam releases in the event that the Main Feedwater System is inoperable. To achieve this, the AFS is designed to remove decay and other residual heat by delivering water to the steam generators at least at the minimum required flow rate at pressures corresponding to the lowest steam generator safety valve set pressure plus accumulation. Redundancy of auxiliary feedwater supply is provided by utilizing two pumping loops using two different types of motive power to the pumps.

One auxiliary feedwater loop utilizes a steam turbine driven pump and the other utilizes two motor driven pumps. The capacity of each loop is sufficient to ensure that at least two of the four steam generators will not boil dry and that the Primary Coolant System will not relieve water through the pressurizer relief/safety valves following a loss of main feedwater flow.

The two motor driven pumps receive automatic start signals from the engineered safeguards circuits. All three pumps receive start signals from the low-low steam generator level circuitry. Steam flow to the turbine for the steam driven pump must be throttled manually in order to bring the unit up to speed and prevent damage to the pump. In addition, the steam driven pump discharge flow control valves are manually opened as necessary to provide adequate auxiliary feedwater flow.

The steam turbine-driven pump was designed with the capability to supply 800 gpm of auxiliary feedwater to the steam generators. This pump, although automatically actuated, requires manual operation to deliver flow and is therefore not assumed to be available until 10 minutes after reactor trip. In accordance with the relevant Chapter 14 analyses, due to operator action at this later time, at least an additional 343 gpm of auxiliary feedwater flow is delivered to the steam generators. The design performance characteristic of the pump is shown in Figure 10.2-35. Steam to drive the turbine is supplied from two of the main steam lines from a point upstream of the main stream isolation valves. Each supply line is provided with a stop check valve, suitable for manual isolation. Downstream of the stop check valves the lines merge into a single supply line to the turbine of the steam driven pump. This single supply line is provided with two isolation valves in series. Main steam is at steam generator outlet pressure, which is reduced to the pressure of the steam driven pump turbine (approximately 600 psig, as necessary to achieve the required pump flow rate) by a pressure control valve.

The steam supply for the auxiliary feedwater pump turbine is ensured under all conditions, except in the event of:

1) Failure in the single supply line to the auxiliary feedwater pump turbine anywhere downstream of the stop check valves
2) Failure of the auxiliary feedwater pump pressure relief valve at low pressure in the steam generator
3) Closure of the two automatic isolation valves from a high temperature signal in the building

The system design ensures a steam supply to the auxiliary feedwater pump turbine in the event of:

1) Failure of one main steam line upstream of the stop check valve. The stop check valves prevent flow to the broken main.

2) Failure of the pressure reducing valve. This valve fails open on loss of control (either through the loss of electrical power or air supply); the turbine pressure relief valve ensures that sufficient steam flows to the turbine while maintaining a safe pressure at the turbine. This applies at safety valve set pressure plus accumulation in the steam generator.

Protection of the Main Steam System has been provided in the event of a failure downstream of the stop check valves by limiting the take off points at the steam main to 3-inch nominal pipe size. This restricts the consequences of the rupture of this pipe to a release of steam less severe than that resulting from the sticking open of a safety valve.

Protection of the AFS from lack of water to pump suctions is provided by operator action. If it is discovered that one or both of the valves in the single auxiliary feedwater supply from the CST are closed in MODES 1, 2, or 3, then the AFS is immediately placed in manual mode. The AFS is returned to automatic mode once a water supply has been restored.

Feedwater is supplied by the steam turbine driven pump to all four steam generators through individual feedwater regulating valves that are controlled either from the main control board or locally at the valves. The drive unit is a single stage turbine, capable of quick starts from cold standby, and is connected directly to the pump. This turbine is started by opening the pressure reducing valve between the turbine supply steam header and the main steam lines. The turbine sleeve journal bearings are ring oil lubricated water cooled. The pump uses oil slinger lubricated ball bearings.

The motor driven pump loop utilizes two pumps with ring lubricated ball bearings. Each pump has a design capacity of 400 gpm, but conservatively assumed to be 340 gpm (343 gpm for

Loss of Normal Feed/Loss of AC Power events), and their discharge piping is arranged so that each pump supplies two steam generators. Upon automatic start of a motor driven AFW pump, the flow distribution may be asymmetrical in the individual branch lines to the associated steam generators. The Chapter 14 safety analyses have evaluated branch line asymmetry up to 150 gpm difference between steam generators under limiting accident conditions. The design performance characteristics for these pumps is given in Figure 10.2-36.

The motors are of open drip-proof design. In the event of complete loss of power, electrical power is restored automatically from the diesel generators.

The three auxiliary feedwater pumps are located in an enclosed room in the Auxiliary Feedwater Building that houses the area of the main steam and feedwater penetration, immediately outside of the Reactor containment (see Figures 10.2-30 and Plant Drawing 9321-F-20143 [Formerly Figure 10.2-38]). The distribution piping is seismic Class I throughout. The piping was designed to ensure that a single failure will not compromise the system function.

All components within the AFS boundary were designed to seismic Class I criteria, as noted in Section 16.1. This includes designing for the Design Basis Earthquake and pipe breaks (pipe whip). The AFS has tornado protected pumps and redundant water supplies, as discussed in Section 16.2.

The possibility of internally generated missiles from the auxiliary feedwater steam driven pump turbine has been evaluated. The evaluation findings note that missiles generated at destructive overspeed could penetrate the turbine casing and that there are possible targets that require protection from such a missile. In view of this, a shield around this turbine was designed. The system is otherwise protected from a main turbine missile by incorporation of redundant water supplies, missile protected pumps and redundant, separate pipes feeding the four steam generators.

Protection of the AFS from excessive vibration and overheating is provided by means of a 2-in recirculation line without flow restricting fixed orifices. Pressure reducing control valves, shut-off isolation valves and check valves were sized to minimize vibration and pipes were routed to minimize bends. The control valves are designed to fail closed.

Single Failure Criteria

Redundant auxiliary feedwater supply is provided by using two pumping systems with independent motive power sources. In the event of a complete loss of offsite power, electrical power to the motor driven pumps is supplied by the diesel generators. The turbine driven pump is completely independent of the motor driven pumps and there are redundant power supplies to the motor driven pumps.

The three auxiliary feedwater pumps can be started remotely-manually from the Control Room or locally at the pump room. Thus, provision exists for manual initiation on the component level, but no such provisions exist for initiating the system as a whole.

The water supply source for the AFS is also redundant. The main source is by gravity feed from the condensate storage tank. This tank is sized to meet the normal operating and maintenance needs of the main turbine cycle systems; however, a minimum water level is maintained that is sufficient to remove residual heat generation for 24 hours at hot shutdown conditions.

An alternate supply of water to the pumps is provided by a connection to the 1.5 million gallon city water storage tank. The city water storage tank shall have a minimum volume of 360,000 gallons of water to provide alternate supply to the AFS.

Various isolation devices were provided to ensure separation of the instrumentation and control circuits to assure that single failure criteria are met. The control and protection circuitry involves steam generator level, safety injection initiation, main boiler feed pump controls, blackout initiation and breaker controls.

Actuation

The motor driven pumps are actuated by any one of the following:

1) Low-low level in any steam generator
2) Loss of 480 VAC bus voltage on bus 3A (ABFP 31) or bus 6A (ABFP 33) (non-SI blackout)
3) Safeguards loading sequence
4) Trip of either main boiler feed pump
5) Manual actuation from the Control Room
6) Manual actuation locally at the pump room.
7) AMSAC

The steam turbine driven pump is actuated by any one of the following:

1) Low-low level in two of the four steam generators
2) Non-SI blackout signal
3) Manual actuation from the Control Room
4) Manual actuation locally at the pump room.
5) AMSAC

The AFS is able to remain in operation should evacuation of the Control Room become necessary.

The pneumatically powered flow control valves associated with the three AFW pumps are supplied by instrument air with a nitrogen supply as backup (for accident analyses the non-safety grade instrument air is not credited). Lack of the nitrogen backup supply (and instrument air) would cause the motor driven and turbine driven pump flow control valves to fail open and the turbine governor control valve to fail open. The nitrogen backup supply is adequate to permit remote (CCR) positioning of the flow control valves for 30 minutes, following which local manual operator action would be taken. If AFW was actuated due to an event such as a Loss Of Normal Feedwater (LONF) when the backup nitrogen supply is not available, the AFW function is available for the following reasons:

- With offsite electrical power supplying the motor driven pumps, they would start on low-low steam generator level in any generator (see above start signals). However, the overcurrent protection logic could result in breaker amptector* actuation if there is a reduced bus voltage and the pumps are providing high flow because the flow control valves are full open. These pumps are considered unavailable in this condition. The turbine driven pump would be in idle until a start signal on low-low steam generator signals from two steam generators (see above start signals). Calculations have shown that the pump would provide adequate flow from that point to maintain steam generator level.

- With the loss of offsite power, the motor driven and turbine driven AFW pumps would get a start signal. The two motor-driven AFW pumps will provide their required function since they would be loaded on the emergency diesel generators but would not trip on breaker amptector* operation since the low voltage condition would not exist on the diesels. The turbine-driven AFW pump will perform its required AFW function when the flow control valves and the turbine governor control valve fails open since the pump design speed at the nominal mechanical governor setting is adequate to provide the required flow.

* Note that the amptector may be replaced with the equivalent Westinghouse device, 'Westector'

Posting of the operator dedicated to pump control will restore operability to all pumps and allow maintenance on the nitrogen backup system.

Flow Monitoring Instrumentation

Flow measurement devices are installed in the discharge lines to each of the four steam generators with indication in the Control Room. The functioning of the pumps may also be monitored locally by direct visual observation. Auxiliary feedwater flow information and valve position indication in the Control Room allow the operators to properly route the discharge flow from the pumps through two remote, manual discharge valves.

Testability

Periodic testing requirements of the Auxiliary Feedwater System are discussed in Section 10.4 and in the Technical Specifications.

System Chemistry

Steam generator water chemistry is maintained within the limits given in plant procedures based on EPRI PWR secondary water chemistry guidelines. A Secondary Side Water Chemistry Monitoring System has been installed for this purpose. Hydrazine, morpholine and/or ethanolamine are added to the condensate for oxygen control and to maintain the pH, respectively. Boric acid is added into the steam generators via the main and auxiliary feedwater headers.

Radiation Levels

No radiation shielding is required for the components of the Steam and Power Conversion System. During normal operation, continuous access to the components of this system outside containment is possible.

Under normal operating conditions, no radioactive contaminants are present in the Steam and Power Conversion System. It is possible, however, for this system to become contaminated through steam generator tube leaks. In this event, any contaminant is detected by monitoring the steam generator shell side blowdown sample points and the condenser air ejector discharge.

Anticipated long term continuous operation of the plant is expected to include operations with fuel rod clad defects in the equivalent of 0.2% of the fuel rods, coincident with a primary to secondary leak rate of 20 gpd. For these expected conditions, the radiation levels at various locations in the Steam and Power Conversion System were calculated at the time of the initial license application (1975) on the basis of the assumptions listed in Table 10.2-3. The shielding design data and the estimated isotopic strengths for the various steam and power conversion system components are provided in Tables 10.2-3 and 10.2-5, respectively.

Table 10.2-6 lists the calculated radiation levels around various components of the Steam and Power Conversion System during operation with 0.2% equivalent fuel rod defects and a primary to secondary leak rate of 20 gpd. Assuming continued operation with primary system activity based on defects in 1% equivalent fuel rods, the maximum allowable primary to secondary leakage would be 0.9 gpm. This leak rate is not a maximum allowable short-term primary to secondary leak rate but a calculated maximum based on continued operation for one year with 1% equivalent fuel defects and the maximum allowable Xe-133 air concentration at the site boundary. The radiation levels at various locations for the Steam and Power Conversion System components were calculated in a like manner to that previously described for expected conditions for the assumed 1% equivalent fuel rod defects and a 0.9 gpm leak, and are presented in Table 10.2-7.

10.2.7 Codes and Classifications

The pressure retaining components or compartments of components comply, at a minimum, with the codes detailed in Table 10.2-1.

TABLE 10.2-1

CODES AND CLASSIFICATIONS

System Pressure Vessels and Pump Casing	ASME Boiler and Pressure Vessel Code, Section VIII
Steam Generator Vessel	ASME Boiler and Pressure Vessel Code, Section III*
System Valves, Fittings, and Piping	USAS Section B31.1 Pressure Piping Code * *

NOTE:
* The shell side of the steam generator conforms to the requirements for Class 1 vessels and is so stamped as permitted under the rules of Section III.

** Portions of Non-Safety Related pipe systems may be exempted from the mandatory post weld heat treatment requirements of ANSI B31.1 by NSE-98-3051. This NSE applies to P11 and P22 material with component wall thickness 0.625" and less.

TABLE 10.2-2

ACTIVITY RELEASE DURING STEAM DUMP

	Activity Release (Curies)	
	2 Hour Steam Dump	6 Hour Steam Dump
Case 1: 0.35 μCi/cc of I-131 in secondary side water (Technical Specifications limit)		
I-131	7	10.7
Xe-133 equivalent	1060	2023
Case 2: Anticipated release based on 0.2% fuel defects and 20 gpd steam generator tube leakage		
I-131 equivalent	0.0017	0.0025
Xe-133 equivalent	0.4	0.7

TABLE 10.2-3

ASSUMED SYSTEM PARAMETERS

Core thermal power (maximum calculated)* - MW(t)	3216
Equivalent fuel rod defects - %	0.2
Primary to secondary leak rate – gpm	0.014 (20 gpd)
Steam flow rate – lbs per hour	1.395×10^{7}
Steam quality - %	99.75
Continuous blowdown rate (total 4 steam generators) – gpm	12.5 each
Mass of secondary water in 4 steam generators – lbs	3.21×10^{5}
Volumetric source geometry used	Equivalent cylinder
Steam generator iodine decontamination factor	100
Steam generator noble gas decontamination factor	1.0
Steam Generator decontamination factor for Mo and Cs	400

*NOTE: The license application core thermal power rating was 3025 MW(t). Thus any radiation levels experienced will be slightly less than those indicated.

TABLE 10.2-4

COMPONENT SHIELDING DESIGN DATA

Item	Self Absorption Media	Wall Thickness	Material
Steam Piping	Steam (0.039 gms/cc)	0.912 inches	Carbon Steel
Turbine	Steam (0.039 gms/cc)	3.0 inches	Carbon Steel
Condenser Air Ejector	Air (ρ=1.3 x 10^{-3} gms/cc)	0.375 inches	Carbon Steel
Condenser	Water (ρ=1.0 gm/cc)	0.75 inches	Carbon Steel
Feedwater Piping	Water (ρ=1.0 gm/cc)	0.938 inches	Carbon Steel
Blowdown Tank	Water (ρ=1.0 gm/cc)	0.50 inches	Carbon Steel

TABLE 10.2-5

ESTIMATED ISOTOPIC SOURCE STRENGTHS FOR
STEAM AND POWER CONVERSION SYSTEM COMPONENTS

Isotope	Steam Piping & Turbine μCi/cc	Condenser Air Ejector μCi/cc	Condenser & Feedwater Systems μ Ci/gm	Blowdown System μ Ci/gm
Kr-85	2.6×10^{-8}	4.2×10^{-5}	---	---
Kr-85M	7.5×10^{-9}	1.2×10^{-5}	---	---
Kr-87	4.4×10^{-9}	7.1×10^{-7}	---	---
Kr-88	1.3×10^{-8}	2.1×10^{-5}	---	---
Xe-133	1.0×10^{-6}	1.6×10^{-3}	---	---
Xe-133M	1.1×10^{-8}	1.8×10^{-5}	---	---
Xe-135	2.2×10^{-8}	3.5×10^{-5}	---	---
Xe-135M	6.8×10^{-10}	1.1×10^{-6}	---	---
Mo-99	2.5×10^{-8}	---	6.0×10^{-7}	2.4×10^{-4}
I-131	4.8×10^{-8}	---	1.2×10^{-6}	1.2×10^{-4}
I-132	3.8×10^{-9}	---	9.6×10^{-8}	9.4×10^{-6}
I-133	5.6×10^{-8}	---	1.4×10^{-6}	1.4×10^{-4}
I-134	1.0×10^{-9}	---	2.6×10^{-8}	2.6×10^{-6}
I-135	1.9×10^{-8}	---	4.8×10^{-7}	4.7×10^{-5}
Cs-134	1.5×10^{-9}	---	3.7×10^{-8}	1.5×10^{-5}
Cs-137	7.4×10^{-9}	---	1.8×10^{-7}	7.4×10^{-5}

TABLE 10.2-6

STEAM AND POWER CONVERSION SYSTEM COMPONENTS
GENERAL RADIATION LEVELS BASED ON EXPECTED PLANT OPERATION*

Equipment	Dose Rate On Contact mr/hr	100 mr/week Access Time Hrs/week
Steam Piping	<0.01	Unlimited
Turbine	<0.01	Unlimited
Condenser Air Ejector	0.05	Unlimited
Condenser	<0.01	Unlimited
Feedwater Systems	<0.01	Unlimited
Blowdown Systems	0.02	Unlimited

*NOTE: 0.2% equivalent fuel defect
20 gpd primary to secondary leakage

TABLE 10.2-7

STEAM AND POWER CONVERSION SYSTEM COMPONENTS
GENERAL RADIATION LEVELS BASED ON MAXIMUM PERMISSIBLE LIMITS*

Equipment	Dose Rate On Contact mr/hr	100 mr/week Access Time Hrs/week
Steam Piping	<0.05	Unlimited
Turbine	<0.05	Unlimited
Condenser Air Ejector	16.	6
Condenser	<0.05	Unlimited
Feedwater Systems	<0.05	Unlimited
Blowdown Systems	3.6	28

*NOTE: 1% equivalent fuel defects
0.9 gpm primary to secondary leakage

TABLE 10.2-8

INFLUENT AND EFFLUENT QUALITY OF THE CONDENSATE POLISHING SYSTEM

	INFLUENT TYPICAL VALUES	EFFLUENT TYPICAL VALUES
		H:OH cycle
	ppb	ppb
Sodium as Na	1.0	0.5
pH control amine	4500(1)	5.0
CO_2 as $CaCO_3$	40	10
Iron as Fe	10	-
Copper as Cu	1.0	-
Total Iron & Copper	-	1
Chloride as Cl	20	0.1
Sulfate as SO_4	1.0	-
Hydrazine	100	-
Conductivity µmho/cm @ 25°C	4 to 10	-
pH @ 25°C	6.0 to 9.0	-

(1) Typical for morpholine. Other pH control amines will require different concentrations.

10.3 SYSTEM EVALUATION

10.3.1 Safety Features

Trips, automatic control actions and alarms will be initiated by deviations of system variables within the Steam and Power Conversion System. Appropriate corrective action is taken as required to protect the Reactor Coolant System. The more significant malfunctions or faults that cause trips, automatic actions or alarms in the steam and power conversion system are:

a) Turbine Trip
   1. Generator/electrical faults.
   2. Low condenser vacuum.
   3. Turbine thrust bearing failure.
   4. Turbine low lubricating oil pressure.
   5. Turbine overspeed.
   6. Reactor trip.
   7. Manual turbine trip.
   8. High steam generator water level.
   9. Safety injection actuation.
   10. Main Steam Isolation Valve not fully open.

   The Independent Overspeed Protection System (IEOPS) has been abandoned and is out of service. IEOPS is not required by the Technical Specifications (removed under License Amendment 93 based on WCAP-11525), is redundant to the Turbine Mechanical Overspeed Protection and is not credited for turbine overspeed protection.

b) Automatic Control Actions
   1. High level in steam generator stops feedwater flow.
   2. Normal and low level in steam generator modifies feedwater flow by continuous proportional control.

c) Principal Alarms
   1. Low pressure at feedwater pump suction.
   2. Insufficient vacuum in condenser.
   3. Turbine thrust bearing failure.
   4. Turbine low lubricating oil pressure.
   5. Turbine overspeed.
   6. Low level in steam generator.
   7. High level in steam generator.
   8. Steam flow – feed flow mismatch coincident with low steam generator level.

A reactor trip from power requires subsequent removal of core decay heat. Immediate decay heat removal requirements are satisfied by the steam bypass to the condensers. Thereafter, core decay heat can be continuously dissipated via the steam bypass to the condenser as feedwater in the steam generator is converted to steam by heat absorption.

Normally, the capability to return feedwater flow to the steam generators is provided by operation of the turbine cycle feedwater system. In the unlikely event of a complete loss of offsite electrical power to the station, and concurrent reactor trips, decay heat removal would continue to be assured by the steam-driven, and two motor-driven (via diesel generator) auxiliary feedwater pumps, and steam dumped to atmosphere via the main steam safety and atmospheric dump valves. In this case feedwater is available from the condensate storage tank by gravity feed to the auxiliary feedwater pumps. The minimum 360,000 gallons of water in the condensate storage tank is adequate for decay heat removal for a period of at least 24 hours. A back-up source of feedwater is available from the city water system.

The analysis of the effects of loss of full load on the Reactor Coolant System is discussed in Chapter 14.

10.3.2 Secondary-Primary Interactions

Following a turbine trip, the control system reduces reactor power output immediately by a reactor trip. Steam is bypassed to the condenser and there is no lifting of the main safety valves. In the event of failure of a main feedwater pump, the motor driven auxiliary feedwater pumps are automatically started. The second main feedwater pump remaining in service will carry approximately 65 percent of full load feedwater flow when operated at full speed. If both main feedwater pumps fail, the reactor will be tripped, as a result of steam generator low-low level or steam- feedwater flow mismatch and the auxiliary feedwater pumps started. If Reactor Coolant System conditions reach trip limits, the reactor will trip.

Main Steam pressure relief is required at the system design pressure of 1085 psig. The number of safety valves, their operation and settings are discussed in Section 10.2.1. The pressure relief capacity is equal to the steam generation rate at maximum calculated conditions (116% of the rated steam flow).

The evaluation of the capability to isolate a steam generator to limit the release of radioactivity in the event of a steam generator tube leak is presented in Chapter 14. The steam break accident analysis is also presented in Chapter 14.

10.3.3 Single Failure Analysis

A single failure analysis has been made for all active components of the system that have an emergency function. The analysis, which is presented in Table 10.3-1, shows that the failure or malfunction of any single active component will not reduce the capability of the system to perform its emergency function.

For those spaces containing safety related systems, the Turbine Generator Building is designed to withstand a 360 mile per hour tornado or the O.B. or D. B. earthquake. Collapse of any portion of the remainder of this building will therefore have no effect on any safety related systems and structures.

TABLE 10.3-1

SINGLE FAILURE ANALYSIS

Component or System	Malfunction	Comments and Consequences
Auxiliary Feedwater System	Auxiliary feedwater pump fails to start (following loss of main feedwater)	The Auxiliary Feedwater System comprises one turbine driven and two motor driven pumps. The rated design flow of the turbine pump is twice the rated flow of a motor driven pump, and one motor driven has sufficient capacity to prevent relief of fluid through the primary side relief valves. Thus adequate redundancy of auxiliary feedwater pumps is provided.
Steam Line Isolation System	Failure of steam line isolation valve to close (following a main steam line rupture)	Each steam line contains an Isolation Valve and a Check Valve in series. Hence a failure of an Isolation or Check Valve will not permit the blowdown of more than one steam generator irrespective of the steamline rupture location.
Turbine Bypass System	Bypass valve sticks open (following operation of the bypass system resulting from a turbine trip)	The turbine bypass system comprises 12 bypass valves. Hence one valve can only pass <4% of the steam generator steam flow and there is no hazard in the form of an uncontrolled plant cooldown if a bypass valve sticks open.

10.4 TEST AND INSPECTIONS

The Main Steam Isolation Valves are tested at regular intervals as established in the Technical Specifications. Closure time of 5 seconds has been and will be continually verified.

These valves serve to limit an excessive reactor coolant system cooldown rate and resultant reactivity insertion following a main steam line break incident. Their ability to close upon signal is verified at periodic intervals. A closure time of 5 seconds from receipt of closing signal was selected as being consistent with expected response time for instrumentation as detailed in the steam line break incident analysis.

The two motor driven auxiliary feedwater pumps can be tested at any time. The steam driven auxiliary feedwater pump may be tested when the plant is above cold shutdown and steam at 600 psi is available. Each pump will deliver water from the condensate storage tank through its feedwater control valves to the feedwater lines to the steam generators. Verification of correct operation is made both from instrumentation within the main control room and by direct visual observation of the pump. The frequency of testing is specified in the Technical Specifications.