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STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The power conversion system (turbine generator) produces electrical energy through conversion of a portion of the thermal energy contained in the steam supplied from the reactor. The steam passes through the turbine to the condenser where it is condensed and returned to the reactor as heated feedwater. A major portion of its gaseous, dissolved, and particulate impurities is removed in the condenser, condensate prefilters in the condensate filtration system (CFS), and condensate demineralizers (CND).

The power conversion system is based on a Rankine steam cycle with a closed, regenerative feedwater heating cycle and pumped forward heater drains (Figure 10.1-1). It is capable of accepting and supporting reactor operation at 100 percent of reactor rated output. The turbine is a tandem-compound turbine generator having a double-flow, high-pressure shell, an external moisture-separator reheater (MSR) (single stage), and three double-flow, low-pressure shells each with internal moisture separation. At reactor rated conditions (3,988 MWt), steam leaves the reactor at 1,035 psia with 0.1 percent moisture and enters the turbine stop valve at 991 psia with 0.35 percent moisture. It is exhausted into a triple-shell, single-zone condenser designed for a maximum backpressure of 5.9 in Hg. It is condensed with circulating water cooled by a single natural-draft cooling tower. Six stages of regenerative feedwater heating are provided with the cycle drains from the top three stages being pumped forward into the feedwater stream. The design final feedwater temperature is 440.5°F. The evaluation for each power level allows a range of 20°F feedwater temperature below the rated value (e.g., 3,988 MWt power operation is acceptable with final feedwater temperature between 420.5°F and 440.5°F).

The major components of the steam and power conversion system are the turbine generator, main condenser, condensate pumps, air ejectors, turbine gland seal system, turbine bypass system, CNDs, condensate prefilters, condensate booster pumps, feedwater heaters, feedwater heater drain coolers, reactor feed pumps, heater drain pumps, circulating water pumps, and cooling tower, most of which are shown on Figure 10.1-1.

Table 10.1-1 presents a summary of important design and performance characteristics of the steam and power conversion systems at reactor rated conditions. The unit heat balance at reactor rated conditions is shown on Figure 10.1-2.

The saturated steam produced by the reactor is passed through the high-pressure turbine where it is expanded and then exhausted to the moisture separator/reheaters (Figures 10.1-3 and 10.1-4).

The moisture separators reduce the moisture content of the steam, and the reheaters superheat it before it enters the low-pressure turbines where the steam is expanded further (Figure 10.1-4). From the low-pressure turbines, the steam is exhausted into the main condenser where it is condensed and deaerated. Condensate then collects in the hotwells. A portion of the main steam is fed to the reheaters where it transfers heat to the low-pressure turbine inlet steam, condenses, and drains to the highest pressure heater (Figure 10.1-4).

The condensate pumps take suction from the condenser hotwell and deliver the condensate to the condensate booster pumps by way of the CFS system, CND system, the air ejector intercondensers, and the steam packing exhausters. The condensate booster pumps supply condensate through two separate drain coolers and five stages of low-pressure feedwater heaters to the reactor feed pumps (Figure 10.1-5). The reactor feed pumps supply feedwater through the feedwater control valves and one stage of high-pressure feedwater heaters to the reactor (Figure 10.1-6).

Feedwater is heated with steam from one extraction in the high-pressure turbine, one extraction in the high-pressure turbine exhaust, four extractions in the low-pressure turbines (Figure 10.1-7), and hot drains from the reheaters and moisture separators (Figure 10.1-4). The cascaded drains for the reheaters, moisture separator, and top three stages of feedwater heaters are deaerated in the fourth-point feedwater heater and pumped forward by the heater drain pumps into the condensate stream between the fourth- and fifth-point feedwater heaters (Figures 10.1-5 and 10.1-7).

Heat is removed from the condenser by the circulating water system (CWS). The circulating water pumps, which take suction from the basin of the counterflow natural-draft cooling tower, pump the circulating water through the main condenser and discharge it to the top of the cooling tower fill.

Normally, the turbine utilizes most of the steam being generated by the reactor. However, an automatic pressure-controlling turbine bypass system capable of discharging approximately 18.5 percent of the turbine valves wide open (VWO) steam flow directly to the main condenser is provided (Section 10.4.4). This turbine bypass system is designed to control pressure by dumping excess steam during startup, shutdown, and for short periods during power operation when the reactor steam generation exceeds the turbine transient steam requirements.

Reactor steam is also used as auxiliary steam and is provided to the steam jet air ejectors (SJAEs), clean steam reboilers, building heating heat exchangers, and offgas system. This steam

is provided from the extraction steam system and/or the main steam system as appropriate for the required pressure and demand (Figures 10.1-3, 10.1-7, and 10.1-8).

Clean steam is produced in the clean steam reboilers for use by the turbine seal system and radioactive waste processing systems. Auxiliary steam is used by the clean steam reboilers to evaporate high-quality condensate taken downstream from the CND (Figure 10.1-9) to produce the clean steam.

The steam and power conversion system is not required to effect or support safe shutdown of the reactor or to function during operation of reactor safety features, with the following exceptions. The portions of the feedwater system from the reactor to the manually-actuated long-term isolation valve outside the primary containment, and the main steam system from the reactor to the outboard main steam isolation valve (MSIV), are part of the reactor coolant pressure boundary (RCPB) and are discussed in detail in Chapters 3 and 5. Several pressure switches on the condenser, main steam lines (MSLs), and the turbine generator are safety-related and provide signals to the MSIVs and reactor trip system. This instrumentation is discussed in the description of the particular safety system to which it belongs.

Section 3.2 indicates the specific safety classes, quality group classification, and seismic categories of the components of the steam and power conversion system.

TABLE 10.1-1

IMPORTANT PERFORMANCE CHARACTERISTICS OF THE POWER CONVERSION SYSTEM AT REACTOR RATED CONDITIONS

1. Turbine/Generator Data	
Manufacturer	GE
Type - last-stage blade length, in	TC6F-38LSB
Number of casings	1-HP, 3-LP
Generator rating at 75 psig H_2 pressure, 0.9 pf, KVA	1,399,220
2. Cycle Performance	
Gross generator output, MW	1,368.9
Net unit heat rate (best point), Btu/kW-hr	9,941
Backpressure, in Hga	2.00
Final feedwater temperature, °F	440.5*
3. Steam Conditions at Turbine Throttle Valve	
Flow, lb/hr	16,121,000
Pressure, psia	991
Temperature, °F	543.5
Enthalpy, Btu/lb	1,191
Moisture content, %	0.35
4. Turbine Cycle Arrangement	
Steam reheat, stages	1
Number of feedwater stages	6
Heater drain system	Drains from 3 highest pressure stages pumped forward
Feedwater heating stages in condenser neck	2
5. Type of condensate demineralizer	Deep bed
6. Main steam bypass capacity lb/hr @991 psia	3,260,000
7. Type of feedwater pump drive	Motor, constant speed

* The evaluation for each power level allows a range of 20°F feedwater temperature below the rated value (e.g., 3,988 MWt power operation is acceptable with final feedwater temperature between 420.5°F and 440.5°F).

10.2 TURBINE GENERATOR

10.2.1 Design Bases

10.2.1.1 Safety Design Basis

The turbine generator is not required to effect or support safe shutdown of the reactor or to perform in the operation of reactor safety features. The turbine generator is, however, designed to minimize the possibility of a rotor failure that might produce a high-energy missile that could damage a safety-related component.

10.2.1.2 Power Generation Design Bases

The turbine generator is designed for the conditions listed in Table 10.1-1. The turbine generator is designed to receive approximately 16,121,000 lb/hr of steam at 991 psia at an enthalpy of 1,191.0 Btu/lb, and convert this energy into approximately 1,368.9 MWe at the generator terminals at warranteed conditions, based on a turbine exhaust pressure of 2.00 in Hg abs, 0-percent makeup, a single stage of reheat in operation, and normal steam extraction for feedwater heating. In addition, the maximum expected flow for which the turbine is designed at rated steam conditions and VWO is 16,927,050 lbs/hr. The maximum expected output for this flow is 1,424.6 MWe.

There are no requirements for turbine generator trips for nuclear steam supply system (NSSS) upset, emergency, or faulted conditions. The turbine generator will trip to protect itself from conditions that may cause damage.

The turbine generator is designed for a base-loaded mode of operation. To meet functional limitations imposed by design or operational characteristics of the reactor coolant system (RCS):

1. The turbine control valves (TCVs) are capable of full stroke openings and closures within 7 sec.

2. Turbine stop valve fast closure will not reduce turbine steam flow faster than is shown on Figure 10.2-1.

3. TCV fast closure will not reduce turbine steam flow faster than is shown on Figure 10.2-2.

4. The turbine is capable of responding to a load demand step change as follows:

   a. 0.9x in 10 sec for |x| less than or equal to 10 percent.

   b. 0.9x in x sec for |x| greater than 10 percent.

   Where: x is in percent of power at rated core flow on the rod line in which the transient takes place.

The turbine generator unit, a General Electric Company (GE) design, is built in accordance with GE standards, codes, and quality assurance (QA) program. The moisture separator/reheaters are built in accordance with ASME Section VIII.

10.2.2 Description

10.2.2.1 Turbine Generator Unit

The turbine generator consists of the turbine, generator, exciter, controls, and required subsystems. Specifically, this includes all steam path valves, piping, and equipment from the main stop and control valves, through the main steam leads to the high-pressure turbine, through the high-pressure turbine, the cross-around piping, the moisture separator/reheaters, the low-pressure turbine combined intercept valves, and the low-pressure turbines to the exhaust hood connection to the condenser. The required subsystems include the turbine lubricating oil system, the electrohydraulic control (EHC) system, the stator cooling system, the hydrogen cooling system, and other miscellaneous instruments and controls. The turbine gland seal system and turbine steam bypass system are discussed in Sections 10.4.3 and 10.4.4, respectively.

Turbine arrangement and location with respect to safety-related structures and equipment is discussed in Section 3.5.1.3.1.

The turbine is a tandem-compound, single-stage reheat unit with 38-in last-stage, low-pressure buckets. It consists of a double-flow, high-pressure turbine and three double-flow, low-pressure turbines. Exhaust steam from the high-pressure turbine passes through a moisture separator/reheater before entering the three low-pressure turbines. The moisture separators mechanically remove the entrained moisture in the steam. The reheaters reheat the dried steam to a temperature near the initial steam temperature. The reheaters use high-pressure steam from the MSLs as a heating medium and drain the condensed steam, along with some scavenging steam, to the highest pressure (sixth-point) feedwater heaters. The moisture separator drains are diverted to the fourth-point feedwater heaters. Additional steam for feedwater heating and auxiliary steam uses is supplied from the turbine extraction steam system (Figure 10.1-7 and Section 10.4.10).

The generator is a direct-coupled, three-phase, 60-Hz, 25-kV, 1,800-rpm synchronous generator with a hydrogen-cooled rotor and a water-cooled stator. The generator is rated at 1,399,220 kVa, 0.90 power factor (p.f.), with a short-circuit ratio of 0.58 and a rated hydrogen pressure of 75 psig.

The exciter system is the Alterrex type. The alternator exciter is a three-phase, 1,800-rpm, 60-Hz, air-cooled machine rated at 3,385 kW, 555 V, with a response ratio of 0.5.

The turbine utilizes an EHC system consisting of conventional governing devices (two initial pressure regulators, speed governor, startup control devices), emergency devices for turbine and plant protection (overspeed governor, backup overspeed, master trip, low-vacuum trips, motoring protection, thrust bearing wear detector, electrical fault protection relays), and special control and test devices. The EHC system operates the main stop valves, main control valves, turbine bypass valves, combined intermediate valves (CIVs), and other protective devices. The EHC system utilizes solid state control techniques in combination with a high-pressure hydraulic system that is completely independent of the turbine lubricating system. The high-pressure fluid supply is a dual pump system in which one pump is a complete backup to the other. The hydraulic fluid is a fire-resistant, synthetic phosphate ester fluid.

The turbine generator has an emergency trip system (ETS) that closes the main stop valves, control valves, and low-pressure turbine CIVs (turbine steam admission valves), shutting down the turbine on any of the following signals:

1. Overspeed:

    a. Turbine approximately 9.5 percent above rated speed (mechanical trip).

    b. Turbine approximately 10.5 percent above rated speed (electrical trip).

2. Low condenser vacuum.

3. Excessive thrust bearing wear.

4. Prolonged loss of generator stator coolant at loads in excess of 314,825 kVA.

5. External trip signals (customer-supplied), including remote manual trip from the control room.

6. Loss of hydraulic fluid supply pressure (loss of ETS fluid pressure automatically closes the turbine valves and then actuates the master trip relay to prevent a false restart).

7. Shaft pump low lubrication oil pressure.

8. Loss of both primary and backup speed signals.

11. Loss of both primary and secondary EHC power supplies.

12. Operation of the manual mechanical trip at front standard.

13. High level in moisture separators.

14. High reactor water level.

15. Reactor core isolation cooling (RCIC) initiation.

16. Unit electrical protection.

17. Main generator protection.

For overpressure protection of the low-pressure turbine exhaust hoods and the condenser shells, two rupture diaphragms that rupture at approximately 5 psig are provided in each low-pressure turbine exhaust hood. The moisture separator/reheaters, cross-around piping, and high-pressure turbine exhaust casing are protected from overpressurization by six relief valves located on the cross-around piping between the reheaters and the combined intercept valves.

In the event of high backpressure on the turbine low-pressure units and the actuation of the rupture diaphragms, the turbine building heating, ventilating, and air conditioning (HVAC) system is designed to accommodate radioactive steam.

The turbine lubricating oil system supplies oil for lubricating the bearings. A bypass stream of turbine lubricating oil flows continuously through an oil conditioner to remove water and other impurities.

The generator stator windings are cooled by an independent skid-mounted cooling water unit. This system provides for automatic regulation of flow and temperature of clean, low-conductivity water. A closed loop cooling system using hydrogen gas as the coolant is used to cool all the generator internals except the stator winding. Gas is circulated by a radial flow fan at each end of the generator, mounted on and driven by the generator rotor. The hydrogen is cooled by two duplex heat exchangers mounted in the plenum chambers above the stator core. Both the hydrogen coolers and the stator cooling water unit are cooled by the turbine building closed loop cooling water (TBCLCW) system (Section 9.2.7).

Figure 1.2-2 shows the location of the bulk hydrogen storage facility. The system consists of several preassembled modules located about 50 ft northwest of and external to the turbine building with interconnecting piping. The storage bank is composed of seven storage cylinders, designed to ASME VIII requirements, manifolded in active and reserve banks. The active bank consists of three cylinders and the reserve bank consists of four cylinders. Each storage cylinder is mounted in supporting frames restrained from movement. Shutoff valves, a bursting disc assembly, and a vent are provided for each storage cylinder.

The bulk storage area is completely enclosed by protective fencing. Administrative and safety procedures are enforced to prevent fires or explosions. Access by unauthorized personnel is controlled by permanent warning placards and a locked gate.

A pressure control station is installed at the end of bulk storage cylinders. Its function is to control pressure within the distribution system to approximately 100-110 psig. The control cabinet contains two parallel pressure-reducing regulators; normally one regulator will function for normal hydrogen supply with the second regulator being available for reserve hydrogen supply.

Two safety valves at the pressure control station, vented to atmosphere within the fenced area, protect low-pressure piping. A vent line piped to atmosphere through the turbine building roof is also provided at the hydrogen use point.

Hydrogen feed to the generator is automatically controlled to maintain hydrogen pressure at the rated pressure of 75 psig. A normally-open shutoff valve is provided at the bulk storage facility and at the local hydrogen control panel. Each shutoff valve is manually controlled from the local hydrogen control panel by means of an individual control switch. Additional control switches for closing the valves are provided on the fire protection panel in case the local hydrogen control panel becomes inaccessible. This system limits the release of uncontrolled amounts of hydrogen into the turbine building if the piping system should fail.

Provisions are included for purging the system, and flammable gas safety precautions are used for this procedure. Initial purging of the bulk hydrogen storage system is achieved with carbon dioxide (CO_2) following evacuation of the storage bank and dead-end piping legs. The system is hydrogen-charged only after repeated purgings with CO_2 from the low-pressure CO_2 fire protection system (Section 9.5.1), and when the oxygen concentration is reduced to within the permissible 0.5 percent by volume.

10.2.2.2 Turbine Overspeed Protection

Design Bases

Safety Design Basis The turbine generator overspeed protection controls are not required to effect or support the safe shutdown of the reactor or to perform in the operation of reactor safety features.

Power Generation Design Basis The turbine generator controls are designed to prevent overspeed that may result from a turbine generator trip or a large reduction in load. The mechanical overspeed trip is set at about 110 percent of rated turbine speed. The mechanical overspeed trip will prevent the rotor from

exceeding the maximum transient speed of 120 percent (design overspeed) of rated turbine speed. An electrical backup overspeed trip, which is set at about 112 percent of rated turbine speed, provides overspeed protection when the mechanical overspeed trip is locked out for testing. At rated turbine load, the electrical backup overspeed trip will not limit turbine overspeed to less than 120 percent of rated turbine speed. However, the electrical backup overspeed trip will provide protection against catastrophic, destructive overspeed.

The turbine overspeed protection system is designed to fail safe upon damage to electrical wiring or hydraulic lines such as would result from a moderate or high-energy line break (HELB). The fail-safe action is a turbine trip.

Description

Figure 10.2-3 is a schematic diagram of the overspeed protection system. Turbine speed is normally controlled by the EHC system. The speed control unit of the EHC system produces a speed/acceleration error signal that is determined by comparing the desired speed with the actual turbine speed at steady state conditions, or the desired acceleration with the actual acceleration during startup. When the speed reference signal is increased in a step, the acceleration control will take over and accelerate the turbine at the selected rate up to the new speed reference, at which point the speed control will automatically take control. Upon decrease of the speed reference, the turbine will coast down with the valves closed. The valves will reopen only when the new set speed has been reached. There is no deceleration limit. During normal operation at rated speed, the speed error signal is essentially zero, regardless of the load.

Because of the extreme importance of safeguarding against overspeed, the speed control unit has two redundant channels. Loss of both speed signals will shut down the turbine. In the event of an overspeed, the EHC system normal speed-load control and power load unbalance relay start to close the main TCVs to reduce speed. If speed continues to rise to about 102 percent of rated speed, the reheat intercept valves start to close, and at 105 percent the main turbine control and reheat intercept valves fully close. This completely blocks the flow of steam to both the high- and low-pressure turbines. If speed reduces to 102 percent, the intercept valves reopen.

All turbine steam valves are hydraulically operated. The hydraulic fluid is supplied at 1,600 psig from the hydraulic power unit (HPU) to all valves in three modes:

1. Hydraulic Fluid to Operating Devices (EHC) This fluid keeps the valves open against spring and process steam forces.

2. Emergency Trip System (ETS) Fluid This fluid maintains pressure on the disk dump valve in each steam valve. When ETS fluid is drained by actuating the fast-acting valve, the piston actuating the valve disk is depressurized and the EHC fluid is drained, allowing the valves to fail closed by spring force.

3. Fluid Actuator System (FAS) Fluid This fluid is the input to the servo valves and is used for throttling.

All valves except the bypass valves have the ETS feature. FAS is used for all main control valves, main stop valve no. 2, and CIVs 1, 2, and 3. All valves have EHC fluid actuation. The tripping action occurs when the ETS fluid is drained. The trip signal can be an electrical input to a solenoid-operated fast-acting valve for an electrical emergency trip or a mechanical trip via the emergency trip valves.

The emergency trip valves are three valves connected in series to supply or interrupt the supply of ETS fluid to the steam valves. The first valve in the string, the mechanical trip valve (MTV), can be operated either mechanically or electrically. The MTV is connected by linkages to the manual mechanical trip and the mechanical overspeed trip. Electrically, the MTV is actuated by the mechanical trip solenoid which is one of the system backups. The mechanical overspeed trip device is located in the front standard and acts to prevent damage in case the turbine overspeeds due to failure of the EHC speed control loop.

The mechanical overspeed trip device is an unbalanced ring that is held concentric with the shaft by an adjustable spring. When the speed reaches the trip speed, the centrifugal force on the ring overcomes the force on the spring and the ring snaps to an eccentric position. In so doing, it strikes the trip finger to operate the MTV, which closes all turbine steam admission valves.

The backup emergency speed trip is an electrical trip originated by a toothed wheel that is mounted on the turbine shaft. A magnetic speed sensor pickup converts the mechanical signal to an electrical signal, which is processed through a megacycler and a voltage comparator and then operates a 112-percent speed trip relay. The signal from the speed trip relay will energize the master trip relay, which will de-energize the master trip solenoid valve, and open the lockout valve circuit and operatethe MTV. Both of these actions independently trip the energizing trip fluid system. Should the Station control system power source fail, a permanent magnet generator geared to the turbine shaft supplies power to all necessary systems.

The ETS has a lockout solenoid valve to permit quarterly testing of the mechanical overspeed trip device without tripping the unit. The mechanical overspeed trip device is tested at normal speed by application of oil through the oil trip valve. The supporting sleeve for the overspeed trip device has an oil

catcher into which the oil is directed by a nozzle. From this catcher the oil empties into a chamber formed by the closed side of the ring. The weight of the oil moves the ring, causing the overspeed trip device to trip. After the overspeed trip device trips and the valve in the nozzle is closed, the oil chamber is emptied through two small holes in the ring by centrifugal force, and the overspeed trip device resets itself. During testing of the mechanical overspeed trip, the turbine is protected by the backup overspeed trip device.

Turbine generator overspeed protection is provided in the extraction steam lines in accordance with the turbine manufacturer's requirements. These take the form of testable, power-assisted nonreturn valves in the extraction lines to the sixth-, fourth-, and third-point feedwater heaters and in the feeds to the auxiliary steam system. These valves are swing check valves with external counterweighted lever arms and air cylinders. The air cylinders use air pressure to maintain a spring in compression. Upon release of the air pressure, the spring provides enough force at the start of the stroke to overcome sticking and to place the swing disc in the flow stream.

The spring will not close the valve against flow, but will provide sufficient motion to confirm operability for nonreturn valves that are full open during normal operating conditions. For nonreturn valves that are not full open during normal operating conditions, an acceptable method of verifying that the disc is attached and free to move is to observe valve movement during power changes and/or manually moving the counterweight arm. When the turbine trips, the extraction relay dump valve loses ETS fluid pressure and changes position, interrupting the air supply to and venting the air in the air operator for each nonreturn valve. The valves close on reverse flow with or without the air supply. Also closed are a group of air-operated valves (AOVs) whose failure to operate could contribute to turbine overspeed. All these valves move to their overspeed safe positions upon loss of supply air. These valves are the reheating steam loading valves to the reheaters and reheater scavenging steam valves to the sixth-point heaters.

The extraction steam system is designed so that the total unrestrained energy in the piping and equipment volume is less than the turbine manufacturer's maximum value limit. Nonreturn valves are not supplied in the extraction lines to the fifth-point feedwater heaters since the steam is prevented from expanding through any turbine stages by the CIVs. Nonreturn valves are not needed on the extraction lines to the second- and first-point heaters, since they contain insufficient stored energy to produce an unacceptable overspeed event.

To show that a single steam valve failure cannot disable the turbine overspeed trip from functioning, the following discussion is offered.

Main Stop and Control Valves - The main stop and control valves are arranged in series, four sets in parallel. On a turbine generator trip all stop and control valves close. If, for example, a stop valve was not to close, the corresponding control valve would interrupt steam flow. Likewise, if a control valve fails to close, the corresponding stop valve would interrupt steam flow. The valves close in 0.2 sec on a turbine generator trip. Thus, a single valve failure cannot contribute to an overspeed trip.

Combined Intermediate Valves - The CIVs are arranged six in parallel; however, each CIV has a stop valve function and a control valve function powered by separate actuators and control loops effectively making each CIV a stop valve and a control valve in series. As such, the overspeed protection system is not disabled based on the discussion above. The closing time for the CIVs is 0.15 sec.

Bypass Valves - There are five bypass valves arranged in parallel capable of passing approximately 18.5-percent VWO flow. The opening time for a bypass valve is 0.25 sec. If one bypass valve fails to open on a turbine generator trip, approximately 14.8 percent of VWO flow can still be bypassed to the condenser, and so not adversely affect overspeed protection.

The above discussion is necessary for generator-related trips only. On all other trips the main generator breaker remains closed after the trip initiation, keeping a load on the turbine thus acting to "brake" it. The main breaker remains closed until the generator begins to motor.

<u>Testing</u>

Turbine overspeed trip testing is performed according to the schedule in Table 10.2-1. Testing during plant operation of the mechanical trip system is accomplished by the use of the lockout valve in the ETS. The lockout valve allows the trip mechanisms to be manipulated without taking the turbine off-line while the backup overspeed trip remains armed. The backup overspeed trip is tested at reduced loads and uses an electrical lockout.

The main stop valves, control valves, and CIVs are tested quarterly by cycling each through at least one complete cycle from the running position. Valve testing is based on the manufacturer's recommendations and calculations of turbine missile generation and damage probabilities. The main stop valves, control valves and CIVs are also tested every 24 months by direct observation of the movement of each valve through at least one complete cycle from the running position. The performance of a channel calibration of the turbine overspeed protection system is conducted once per 24 months. Testing requirements, including internal inspection and maintenance, for

critical and noncritical ESS check valves will be determined based on performance established by the preventive maintenance program. Inservice inspection (ISI) of the main steam valves is discussed in Section 10.2.3.6.

At least one turbine overspeed protection system shall be operable in Operational Conditions 1 and 2. The turbine overspeed system is not required to be operable prior to the initial opening of the MSIVs in Operational Condition 2. If one TCV or one turbine throttle stop valve per high pressure turbine steam lead becomes inoperable and/or one turbine combined intercept valve per low-pressure turbine steam lead becomes inoperable, the inoperable valve(s) will be restored to operable status within 72 hr, or at least one valve in the affected steam lead(s) will be closed, or the turbine steam supply will be isolated within the next 6 hr. If the above-required overspeed protection system otherwise becomes inoperable, the turbine will be isolated from the steam supply within 6 hr.

10.2.3 Turbine Rotor Integrity

10.2.3.1 Materials Selection

The turbine rotors are made of vacuum-melted or vacuum-degassed Ni-Cr-Mo-V alloy steel by processes that minimize flaw occurrence and provide adequate fracture toughness. Trace impurities are controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long-life fracture toughness for the environment in which the parts operate. The turbine rotor materials have the lowest fracture appearance transition temperatures (FATT) and the highest Charpy V-notch energies obtainable on a consistent basis from water-quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Since actual levels of FATT and Charpy V-notch energy vary depending with the size of the part and the location within the part, etc., these variations are taken into account in accepting specific forgings for use in turbines for nuclear application. Charpy tests were performed in accordance with specification ASTM A-370.

The FATTs are no higher than 0°F for the low-pressure rotors and 50°F for the high-pressure rotor. V-notch energies are no lower than 60 ft-lb for the low-pressure rotors and 50 ft-lb for the high-pressure rotor.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described above to produce a balance of adequate material strength and toughness to ensure safety, while simultaneously providing high reliability, availability, and efficiency during operation. Bore stress calculations are for components subject to centrifugal loads, interference fit, and thermal gradients, where applicable. The ratio of material

fracture toughness K_{IC} (as derived from material tests on each disc or rotor) to the maximum tangential stress for rotors at speeds from normal to 120 percent of rated speed is at least 2 $\sqrt{in}$. (The highest anticipated speed resulting from a loss of load is 112 percent.) Adequate material fracture toughness needed to maintain this ratio is assured by destructive tests on material taken from the rotor using conservative correlation methods[1].

Turbine operating procedures are employed to preclude brittle fracture at startup by ensuring that the metal temperature of discs and rotors is adequately above the FATT and sufficient to maintain the fracture toughness to tangential stress ratio at or above 2 $\sqrt{in}$[2].

10.2.3.3 High-Temperature Properties

The operating temperatures of the high-pressure rotor in turbines with light-water reactors are below the creep rupture range. Creep rupture is, therefore, not considered to be a significant factor in assuring rotor integrity over the lifetime of the turbine. Basic data are obtained from laboratory creep rupture tests.

10.2.3.4 Turbine Rotor Design

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

1. Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

2. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20-percent overspeed are controlled in the design and operation so as to cause no distress to the unit during operation.

3. The maximum tangential stress in rotors resulting from centrifugal forces, interference fit, and thermal gradients does not exceed 0.75 of the yield strength of the materials at 115 percent of rated speed.

10.2.3.5 Preservice Inspection

The preservice inspection program includes:

1. Rotor forgings are rough machined with minimum stock allowance prior to heat treatment.

2. Each finish machined rotor is subjected to 100-percent volumetric (ultrasonic), surface, and visual examinations using GE acceptance criteria. These criteria are more restrictive than those specified for Safety Class 1 components in the ASME Boiler and Pressure Vessel Code, Sections III and V, and include the requirement that subsurface sonic indications are either removed or evaluated to assure that they will not grow to a size that will compromise the integrity of the unit during the service life of the unit.

3. All finish machined surfaces are subjected to a magnetic particle test with no flaw indications permissible.

4. Each fully bucketed turbine rotor assembly is spin tested at or above the maximum speed anticipated following a turbine trip from full load.

5. Operation at or near critical speeds may be avoided by readjusting the speed reference.

10.2.3.6 In-service Inspection

The following turbine system maintenance program is based upon the manufacturer's recommendations and calculations of missile generation probabilities.

1. The ISI program for the turbine assembly requires disassembly of the turbine in stages over a 6- to 10-yr interval during plant shutdowns such that the turbine is completely inspected within the interval. This includes complete inspection of all normally inaccessible parts, such as couplings, coupling bolts, high- and low-pressure turbine shafts, and turbine buckets. This inspection consists of visual, surface, and volumetric examinations, as follows:

    a. A thorough volumetric examination of all low- and high-pressure rotors.

    b. Visual and surface examination of all accessible surfaces of rotors and buckets.

    c. Surface examination of couplings and coupling studs excluding threads.

The ISI of main steam and reheat valves includes the following: Dismantling at least one main steam stop valve, one main steam control valve, one reheat stop valve, and one reheat intercept valve at approximately 3 1/3-yr intervals during refueling or maintenance shutdowns, and conducting a visual and surface examination of valve seats, discs, and stems. If unacceptable

flaws or excessive corrosion are found in a valve, all valves of its type will be inspected. Valve bushings will be inspected and cleaned and bore diameters will be checked for proper clearance.

10.2.4 Safety Evaluation

The turbine generator is not nuclear safety related and is not needed to effect or support a safe shutdown of the reactor.

The turbine is designed, constructed, and inspected to minimize the possibility of a turbine rotor failure. The turbine has a redundant, testable overspeed trip system to minimize the possibility of a turbine overspeed event. Unrestrained stored steam energy in the extraction steam system has been reduced to an acceptable minimum by the addition of nonreturn valves in these extraction lines.

The turbine generator equipment shielding requirements and the method of access control for all areas of the turbine building ensure that the dose criteria specified in 10CFR20 for operating personnel are not exceeded. All areas in proximity to turbine generator equipment are zoned according to expected occupancy times and radiation levels anticipated under normal operating conditions. Specification of the various radiation zones in accordance with expected occupancy is listed in Chapter 12. If deemed necessary during unusual operational occurrences, the occupancy times for certain areas will be reduced by administrative controls by Health Physics personnel.

The design basis operating concentrations of N-16 in the turbine cycle are indicated in Chapter 12.

The connection between the low-pressure turbine exhaust hood and the condenser is made by means of a rubber expansion joint. Since there is no nuclear safety-related mechanical equipment in the turbine area and since the condenser is at subatmospheric pressure during all modes of turbine operation, failure of the joint will have no adverse effects on nuclear safety-related equipment.

10.2.5 References

1. Begley, J. A. and Logsdon, W. A. Westinghouse Electric Corporation, Scientific Paper 71-1E7-MSLRF, July 26, 1971.

2. Spencer, R. C. and Timo, D. P. Starting and Loading of Turbines. General Electric Company, presented at the 36th Annual Meeting of the American Power Conference, Chicago, IL, April 29 - May 1, 1974.

TABLE 10.2-1

TESTING OF THE OVERSPEED TRIP SYSTEM

Test Designation	Devices Tested	Schedule	Test Conditions	Test Procedure	Indications
A	Overspeed trip Mechanical trip valve (MTV) (steam valves remain open)	Determined based on performance established by the preventive maintenance program or during startup	Rated speed on-line As soon as rated speed is reached, off-line	1. Push "LOCKOUT" 2. Push "OIL TRIP" until MTV trips (a few seconds) 3. Push "RESET" until MTV is reset (a few) seconds 4. Push "NORMAL" to manually release the lockout valve approximately 12 sec after the "RESET" button has been released	"LOCKOUT" light on MTV "TRIPPED" light on MTV "RESETTING" light off-on-off "RESET" light on "NORMAL" light on "LOCKOUT" light off
B	Overspeed trip (trip speed) Mechanical trip valve (MTV) (steam valves remain open)	After maintenance on the trip system or once a refueling outage (time interval not to exceed 24 months of continuous operation)	Off-line ROTOR HOT OVERSPEED	1. Push "LOCKOUT" 2. Push "FAST" startup rate 3. Push "OVERSPEED" and keep depressed 4. At 50 rpm below trip speed push "MEDIUM" startup rate keep "OVERSPEED" depressed 5. At trip speed record trip speed, release "OVERSPEED" 6. Let unit slow down to rated speed; it will hold speed there 7. Push "RESET" (not master reset) 8. Push "NORMAL" to manually release the lockout valve approximately 12 sec after the "RESET" button has been released	"LOCKOUT" light on "FAST" light on "OVERSPEED" and "ACCELERATING" light on "MEDIUM" light on (5%/min rate) MTV "TRIPPED" light on "AT SPEED" light on rated speed on speed indicator MTV "RESETTING" light off-on-off "RESET" light on "NORMAL" light on, "LOCKOUT" light off
C	Overspeed trip system (trip speed) All steam valves	At startup after maintenance work on trip system or valves	Off-line Rotor hot Overspeed	1. Push "FAST" startup rate 2. Push "OVERSPEED" and keep depressed 3. At 50 rpm below rated trip speed push "MEDIUM" startup rate keep "OVERSPEED" depressed	"FAST" light on "OVERSPEED" and "ACCELERATING" light on "MEDIUM" light on (5%/min rate)

TABLE 10.2-1 (Cont'd.)

Test Designation	Devices Tested	Schedule	Test Conditions	Test Procedure	Indications
				4. At trip speed record trip speed Release "OVERSPEED" Check valve closures 5. Let unit slow down to rated speed or less 6. Push "MASTER RESET" until ETS "RESET" light comes on 7. Push RATED TRIP SPEED 8. Push "FAST" startup rate 9. Let unit accelerate to rated speed	MTV "TRIPPED" light on ETS "TRIPPED" light on Speed set "VALVES CLOSED" on rated speed MTV "RESETTING" off-on-off MTV "RESET" on ETS "RESET" on Rated speed set light on "ACCELERATING" light on "FAST" light on "AT SPEED" light on rated speed on speed indicator
D	Backup overspeed trip (BUOT) circuits	Determined based on performance established by the preventive maintenance program or during startup	Rated speed on-line (or off-line if desired)	1. Place keylock switch in test position 2. Push "BUOT TEST" on monitor panel. Keep depressed for a few seconds	None "BUOT TEST" light on (indicates test successful)
E	Backup overspeed trip system (trip speed) All steam valves	12 to 24 months	Off-line Rotor hot Load set at 40% OVERSPEED*	1. Push loading rate "10" 2. Put load set to 40% (push "INCREASE" long enough) 3. Push "FAST" startup rate 4. Push "LOCKOUT" 5. Push "OVERSPEED" and keep depressed 6. At trip speed of mechanical overspeed trip, keep "OVERSPEED" depressed	"10"%/min light on Load set 40%, unit will accelerate approximately 4% in 4 min "FAST" light on "LOCKOUT" light on "OVERSPEED" and "ACCELERATING" light on Mechanical trip valve "TRIPPED" light on

TABLE 10.2-1 (Cont'd.)

Test Designation	Devices Tested	Schedule	Test Conditions	Test Procedure	Indications
			For value of trip speed see lineup diagram or BUOT schematic	7. At trip speed of BUOT release "OVERSPEED," record trip speed. Check valve closure. 8. Same as 5 through 9 of Test C	"LOCKOUT" light off MTV light "TRIPPED" ETS light "TRIPPED" Speed set "VALVES CLOSED" Load set running back to zero

* Load set must be increased because "OVERSPEED" top limit is generally set below trip speed of BUOT.

10.3 MAIN STEAM SUPPLY SYSTEM

The main steam supply system discussed in this section consists of the MSLs from the outermost containment isolation valves (MSIVs) up to but not including the turbine stop valves, bypass valves, and all lines 2 in or smaller in diameter. The main steam supply system includes all connecting pipes that feed the auxiliary equipment and the MSRs. The main steam supply system from the reactor pressure vessel (RPV) to the outermost MSIVs is part of the RCPB and is discussed in Section 5.4. The turbine stop valves, bypass valves, and other turbine equipment are discussed in Section 10.2.

10.3.1 Design Bases

10.3.1.1 Safety Design Bases

Although the main steam supply system is not required to effect or support the safe shutdown of the reactor or to function during the operation of reactor safety features, it was designed and constructed as described in Section 10.3.3.

The main steam supply system is:

1. Designed in accordance with ANSI B31.1.

2. Analyzed to meet the requirements for a design basis earthquake (DBE) and an operating basis earthquake (OBE) (Section 3.2.1), hydrodynamic vibration loads resulting from safety/relief valve (SRV) actuation and loss-of-coolant accident (LOCA), and pipe whip stresses (Section 3.6A).

3. Designed to limit the release of radioactive steam in the event of a steam line break (Section 5.4.4).

4. Designed to allow for testing of the turbine stop valves with no load reduction at full-power operation.

The MSIVs, shutoff valves in connecting piping, turbine stop valves, and bypass valves are designed to close against maximum steam flow and differential pressure.

10.3.1.2 Power Generation Design Bases

The main steam supply system is designed to:

1. Deliver steam from the reactor to the turbine from warmup to reactor rated flow and pressure. The design pressure is 1,250 psig at 575°F design temperature.

2. Deliver steam from the reactor to the reheating side of the MSR.

3. Deliver approximately 18.5 percent of the turbine VWO throttle flow to the turbine bypass valve manifold (Section 10.4.4).

4. Deliver steam to the following auxiliary steam system components:

   a. Steam jet air ejectors.

   b. Offgas preheaters.

   c. Clean steam reboiler.

   d. Building heating intermediate heat exchanger.

   e. Turbine gland seal system, when the steam supply from the clean steam reboiler is not available.

10.3.2 System Description

The main steam supply system is shown on Figure 10.1-3. The main steam piping consists of four 28-in diameter lines from the outermost MSIVs to a 48-in diameter main steam equalizing header. Four 28-in diameter lines from the equalizing header lead to the turbine generator stop valves. The use of four MSLs and the equalizing header permit the testing of the turbine stop valves and the MSIVs during operation without a need for a load reduction when the high steam flow scram setpoint is at 140-percent reactor rated flow. (See Chapter 7 for additional information on the high flow setpoint.) Two 16-in diameter lines from the main steam equalizing header supply steam for the two single-stage MSRs. Two 18-in diameter lines from the main steam equalizing header supply steam to the turbine bypass valve manifold. The turbine bypass valves are connected to the condenser by five 10-in diameter lines (Section 10.4.4).

A 4-in line from one of the two 18-in lines to the bypass manifold supplies emergency steam to the turbine gland seal system (Section 10.4.3). A 6-in line from the other 18-in line supplies auxiliary steam to the SJAEs, offgas preheaters, clean steam reboilers, and building heating intermediate heat exchangers.

Drain lines are provided at low points where condensed steam could collect. All drains from the same pressure source are headered wherever possible. All drains discharge to the condenser (Figure 9.3-12). A main steam drain header from inside the containment is used as a source of warming steam for the MSLs beyond the outermost MSIVs. This header permits the equalization of pressure across the MSIVs following a steam line isolation.

The classification of the components and piping of the main steam supply system is given in Sections 3.1 and 3.2.

The design pressure of the main steam system is 1,250 psig. Overpressure protection is provided by the main steam relief valves (Section 5.2.2). Branch lines having a different design pressure are provided with their own relief valves, all of which discharge to the condenser.

10.3.3 Safety Evaluation

The following items provide an additional safety margin to preclude an uncontrolled leakage of radioactive steam:

1. The main steam supply system up to and including the piping through the jet impingement wall, located about 16 ft beyond the outermost MSIV, is stress analyzed in accordance with the requirements of ASME Section III, Safety Class 1. In addition, piping between the outermost MSIV and the jet impingement wall (break exclusion area) was evaluated in accordance with Class 2 requirements and found to be acceptable. The main steam supply system beyond the jet impingement wall, plus the turbine stop valves, and lines 2 1/2 in and larger up to and including the first valve (including restraints) that leads to the moisture separator and reheater, turbine gland seal system, and auxiliary steam header, are stress analyzed in accordance with the requirements of ASME Section III, Safety Class 2. This meets the requirements of Regulatory Guide (RG) 1.29 for seismic classification. See Table 3.2-1, Notes 13 and 14, for further discussion regarding seismic design and quality group classification.

2. The MSLs (26-, 28-, and 48-in lines) are all located in the steam tunnel and/or the shielded area of the turbine building. The structure which contains the main steam piping up to main steam (turbine) stop valves is a Category I structure. Nonsafety-related components in the main steam tunnel whose failure could compromise Category I components are seismically supported.

3. Isolation of the MSLs is accomplished by closing the MSIVs. All instrumentation and control systems required to close the MSIVs during or following an accident are safety related (Section 5.4.5). These valves have very low leakage characteristics and the leakage requirements of RG 1.96 are met without a seal system.

4. The piping is designed in accordance with postulated high-energy pipe failure criteria noted in Section 3.6A.

The MSLs and the main steam tunnel area are continuously monitored to detect steam leaks and high radiation indications of fuel failures. Main steam system failure analysis is described in Section 15.6.4.

10.3.4 Inspection and Testing Requirements

All components and piping for the main steam supply system are inspected and tested in accordance with the requirements of the codes, standards, and classifications listed in Section 3.2. Welds are tested nondestructively according to the requirements in Section 3.2. The MSLs and all branch lines are hydrostatically tested prior to initial operation. Further discussion of inservice inspection and inservice testing of the piping and components analyzed to ASME Class 2 requirements is found in Sections 3.9A.6 and 6.6.1.

10.3.5 Water Chemistry

This section is not applicable to a boiling water reactor (BWR). See Section 10.4.6 for reactor coolant water chemistry considerations.

10.3.6 Steam and Feedwater System Materials

10.3.6.1 Fracture Toughness

ASME Class 1 portions of the main steam and feedwater systems are impact tested in accordance with Subarticle NB-2300 of ASME Section III. Impact testing is not specified for the other portions of the main steam and feedwater systems since it is not required by ANSI B31.1. The materials used in the main steam piping described in Section 10.3.3 and Safety Class 4 feedwater systems are ASTM A155 Grade KCF70, A106 Grade B and Grade C, A335-P22, A105, and A216 Grade WCB. These materials are the same as used in ASME Class 1 piping, and would meet the impact testing requirements of Subarticle NB-2300 of ASME Section III if testing were performed.

10.3.6.2 Materials Selection and Fabrication

All materials used in the steam and feedwater systems are listed in Appendix I to the 1974 Edition of ASME Section III, and in parts A and C of ASME Section II.

Austenitic stainless steel is used only in the tubes in the high-pressure feedwater heaters in the feedwater system. The tubes are supplied in the solution-annealed condition, and the bent area is resolution annealed after U-bending. The ferrite

content in the stainless steel weld metal is in accordance with RG 1.31. The feedwater heaters are constructed in accordance with ASME Section VIII.

Cleaning of the steam and feedwater systems during construction was in accordance with ANSI N45.2.1. Construction flushing and cleaning in accordance with RG 1.37 will ensure that cleanliness is maintained.

The control of preheat temperatures used for welding low-alloy steel is in accordance with RG 1.50. Fabrication and installation of these piping systems are in accordance with the applicable codes and RG 1.71.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 Main Condenser

The purpose of the main condenser is to provide a heat sink for the turbine exhaust steam, turbine bypass steam, and other turbine cycle flows and drains. It also provides deaeration, noncondensable gas removal, and storage of condensate which is returned to the condensate system after a period of radioactive decay.

10.4.1.1 Design Bases

10.4.1.1.1 Safety Design Bases

The main condenser is not required to effect or support safe shutdown of the reactor or to perform in the operation of reactor safety features. It is, however, designed with the necessary shielding and controlled access to protect plant personnel.

10.4.1.1.2 Power Generation Design Bases

The main condenser design parameters are shown in Table 10.4-1. The main condenser is designed to accept a maximum of approximately 25 percent of the turbine VWO throttle steam flow from the turbine bypass system (Section 10.4.4). This steam flow is accommodated without increasing the condenser backpressure to the turbine trip setpoint or exceeding the allowable turbine exhaust temperature.

The main condenser deaerates the condensate and provides an oxygen content in the condenser effluent not exceeding 20 ppb over the entire load range.

The condenser hotwell is designed to contain a reserve quantity of condensate to provide for 5 min of full-power operation. Baffling in the hotwell provides a minimum of 5-min holdup time, which permits the decay of short-lived radioactive isotopes. The baffling is designed to minimize radiation levels at the east and west sides of the condenser.

Condenser construction is designed in accordance with requirements of the Heat Exchange Institute, Standards for Steam Surface Condensers (1970). Piping associated with the condenser is designed, fabricated, inspected, and erected in accordance with ANSI B31.1. The detection of leakage from the main condenser to the turbine building and its effects are described in Section 3.4.1.1.3.

10.4.1.2 System Description

Steam from the low-pressure turbine is exhausted directly downward into the condenser shells, through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several other flows such as feedwater heater drains, air ejector drains, gland seal steam condenser drains, and feedwater heater shell vents. Other flows to the condenser originate from the startup vents of the condensate pumps, startup and minimum flow from condensate, booster and reactor feed pumps, low-point drains, and condensate makeup.

During transient conditions, the condenser is designed to receive turbine bypass steam and feedwater heater and drain tank high level discharges. The condenser is also designed to receive relief valve discharges from moisture separators, feedwater heater shells, steam seal regulators, and various steam supply lines.

Steam from the bypass valves is dispersed into the condenser by stainless steel spray pipes. The sprays are directed away from impinging on the tubes or other important areas of the condenser.

A divider is provided above the hotwell (condenser false bottom) to separate the drains from each tube bundle. Individual collection trays are also provided under each tube sheet. An in-leakage for 6 hr at 88 gpm is permitted based upon the design of the CND.

The main condenser consists of three shells, one under each low-pressure turbine. Each shell contains two tube bundles, each bundle divided into three sections. Periphery sections (70-30 Cu-Ni tubes) are located around the outside of the bundle where there is the potential for impingement from flashing water and steam. An air cooler section (70-30 Cu-Ni tubes) is located in the center of the bundle. The remainder of each bundle is Admiralty tubes. Support plates are provided to limit the tubes' midspan deflection under load due to local steam velocity.

The tube bundle is designed so that steam enters at the top, sides, middle, and bottom, and from there flows through the tube array until it reaches a common area near the center of the bundle before entering the air cooler. This arrangement allows the steam to effectively feed all the tubes. It creates a decreasing cross-sectional area of steam lanes, so that the volume of steam is decreased (by condensation) as it penetrates the tubes to the air removal section, thus maintaining constant velocity. This design assures maximum efficiency of condensation and complete removal of noncondensable gases.

The condenser is cooled by the CWS described in Section 10.4.5. Air in-leakage and noncondensable gases are removed by the main condenser evacuation system (Section 10.4.2). The condensate leaving the condenser is deaerated resulting in an oxygen level of less than 20 ppb. The minimum oxygen concentration level of 30 ppb in the condensate and feedwater systems is maintained by

the oxygen in feedwater injection system (Section 10.4.11), which injects oxygen into the suction side of the condensate pumps.

Air in-leakage is minimized by the reversing of all globe valves subject to vacuum, where possible. Thus, when the valve is closed (such as the PX valves at the end of the condenser headers), the valve stem will not be subject to vacuum and will not be a potential leak source. (See Section 10.4.1.4.)

10.4.1.3 Safety Evaluation

During operation, radioactive steam, gases, and condensate are present in the shell of the main condenser. The inventory of radioactive contaminants during operation is discussed in Section 12.2.1. Shielding for and controlled access to the main condenser are discussed in Section 12.3.

Hydrogen concentration is maintained below the explosive limit during operation by continuous evacuation of the main condenser (Section 10.4.2). During shutdown, there are no hydrogen sources to the condenser.

The main condenser is not required for safe shutdown of the reactor and does not perform a safety function. Due to the distance of the main condenser from safety-related equipment, there would be no damage to safety equipment from flooding caused by failure of the condenser (Section 3.4.1). The low-pressure turbine is directly connected to the condenser. Exhaust hood overheating protection is provided by sprays located downstream of the last-stage blades of the turbine.

Degradation of the main condenser takes two forms:

1. Air in-leakage.

2. Circulating water in-leakage.

Air in-leakage is addressed in Section 10.4.2. Excessive air in-leakage will result in high condenser backpressure and loss of vacuum in the offgas system. Both conditions alarm in the main control room. There is a fixed and a power-dependent variable alarm in the main control room. The fixed alarm point for high condenser backpressure is 5.8 in Hg abs. The variable alarm setpoint ranges from 5.0 in Hg abs at low power to 6.5 in Hg abs at high power. If air in-leakage increases, the following will occur.

The turbine will trip and the reactor will scram upon loss of main condenser vacuum, at a pressure greater than 7.9 in Hg abs. When the reactor pressure is less than 600 psia, this trip feature can be bypassed to allow discharge to the condenser during reactor startup. Should the turbine stop valves, control valves, or bypass valves fail to close upon loss of condenser vacuum, rupture diaphragms are provided on each turbine exhaust

hood. This protects the condenser and turbine exhaust hood against overpressurization. In this event, steam would exhaust to the turbine building. Loss of main condenser vacuum, at a pressure greater than 23 in Hg abs, will close the turbine bypass valves (Section 10.4.4) and the MSIVs. The amount of steam exhaust to the turbine building is within technical limits and monitored at its release point (the main stack).

Circulating water in-leakage is monitored through the use of the condensate demineralizer inlet conductivity instrumentation. High sample conductivity will initiate a manual repair if the limits stated in Section 10.4.6.2.1 are exceeded.

10.4.1.4 Tests and Inspections

The condenser shell receives a field hydrostatic test prior to initial operation. This test consists of filling the condenser shell with water and inspecting the entire tube sheet and shell welds and surfaces for visible leakage and/or excessive deflection. The tubeside of the condenser is given an operational leak test as part of the CWS. The acceptance criterion is no visible leaks.

There are no ISI attributes associated with the condenser. The condenser is monitored for air in-leakage and circulating water in-leakage as stated in Section 10.4.1.3.

10.4.1.5 Instrumentation Requirements

Indicators for condenser vacuum are located in the main control room and are shown on Figure 10.4-10. For a description of condenser hotwell level controls and monitors, refer to Section 9.2.6.5.

10.4.2 Main Condenser Air Removal System

10.4.2.1 Design Bases

10.4.2.1.1 Safety Design Bases

The main condenser air removal system is not required to effect or support the safe shutdown of the reactor or to perform in the operation of reactor safety systems. The system is designed to maintain hydrogen concentration below the lower explosive limit in the condenser.

All piping and components from the main condenser to the offgas system are designed to be capable of withstanding the effects of a hydrogen explosion. For the design basis for the hydrogen explosion pressure spike, refer to Section 11.3.1.

10.4.2.1.2 Power Generation Design Bases

The main condenser air removal system is designed to remove air from the condenser during plant startup and maintain the condenser vacuum by continually removing any noncondensable gases from air in-leakage or gases generated in the reactor by the radiolytic decomposition of reactor coolant. The air removal equipment has a design capacity in accordance with the Standards for Steam Surface Condensers, Sixth Edition, published by the Heat Exchange Institute, 1970 Edition. The piping system is designed, fabricated, and erected in accordance with the requirements of ANSI B31.1. The heat exchangers associated with the system are designed and fabricated in accordance with ASME Section VIII, Division 1. The components of the entire main condenser air removal system have been designed to meet all the requirements of Quality Group D as defined in RG 1.26.

10.4.2.2 System Description

The main condenser air removal system consists of two subsystems, a hogging system and a holding system (Figure 10.4-2). These systems are capable of establishing and maintaining condenser pressure of 4.41 in Hg abs or lower by removing air from the main condenser while the turbine shafts (Section 10.4.3) are steam sealed against in-leakage of air into the condenser.

The electrically-driven, mechanical vacuum pumps are used when the reactor steam is unavailable and the turbine is sealed with steam from the auxiliary boiler. When the condenser pressure is less than 5 in Hg abs, the SJAEs are placed in service with auxiliary boiler steam also. Once the jets are stabilized, the mechanical vacuum pumps are secured and their block valves are shut. The jets continue to use auxiliary boiler steam until main steam is available.

10.4.2.2.1 Hogging System

During hogging or startup, the air and associated water vapor are drawn from the air cooler sections of the main condensers by two motor-driven water ring-type vacuum pumps. Each pump discharges the air and water mixture into its own separator, where air is separated from water and discharged directly to the main stack. Little or no gaseous activity is expected during this phase of the startup operation. However, radiation levels are monitored at the main stack prior to release to the environment. A recirculation pump takes suction from the separator and discharges the liquid back into the vacuum pump after it has been cooled by the seal water cooler. Service water (Section 9.2.1) cools the seal water cooler. Any overflow from the separator is directed to the turbine building equipment drain system (Section 9.3.3).

Little or no radioactivity is expected during the hogging operation. The hogging system can be isolated automatically by tripping the vacuum pumps and closing a block valve in the pump suction upon a high MSL radiation signal.

10.4.2.2.2 Holding System

The holding system is composed of two full-capacity SJAEs, each consisting of a precooler, a first-stage double jet, an intercondenser, and a second-stage double jet. The auxiliary steam system supplies motive steam to the SJAEs from the main steam system except when the pressure is too low (i.e., during startup and shutdown evolutions); then motive steam is supplied from the auxiliary boilers. The auxiliary steam system is discussed in Section 10.3.2. Air, other noncondensables, and the associated steam from the condenser pass through the precooler where a portion of steam is removed by condensing on tubes cooled by the service water system. The first-stage jets draw the remaining steam and noncondensables from the precooler and discharge to the intercondenser at approximately 5 in Hg abs. The intercondenser, using main condensate as the cooling medium, condenses most of the steam. The second-stage jets draw the remaining effluent from the intercondenser and discharge to the offgas system at approximately 1 psig. The condensed steam from the precooler and intercondenser is returned to the main condenser.

10.4.2.3 Safety Evaluation

The main condenser air removal system is not safety related. During power operation, noncondensable gases from the main condenser are a major source of radioactive gas from the plant. An inventory of radioactive contaminants in the effluent from the SJAE is discussed in Section 12.2. The offgas system, which treats the noncondensable gases prior to discharge, is discussed in Section 11.3.

10.4.2.4 Test and Inspection

The main condenser air removal system equipment was inspected and hydrostatically tested by the vendor. The vacuum pumps were also given normal performance tests. The system is tested during the preliminary and preoperational test phase of the test program for proper operation. The startup test program is discussed in Section 14.2.1.

10.4.2.5 Instrumentation Requirements

Description

Instruments and controls are provided for automatic and manual control of the main condenser vacuum system. The controls and monitors described below are located in the main control room. The control logic is shown on Figure 10.4-1. Specific requirements for monitoring hydrogen concentrations are provided in Technical Requirements Manual (TRM) Section 3.7.8.

Operation

The condenser air removal vacuum pumps are started manually. The pumps trip automatically when MSL radiation level is high-high, seal recirculation water flow is low after preset time, or pump motor sustained bus undervoltage. The pumps can also be stopped manually.

The seal recirculation water pumps are interlocked to start or stop automatically when the associated air removal vacuum pump is started or stopped.

The air removal vacuum pumps isolation valve opens automatically when an air removal vacuum pump is running, provided a MSL radiation level is not high-high. The valve closes automatically when neither air removal vacuum pump is running or when a MSL radiation level is high-high. The valve can also be controlled manually.

The air ejector isolation valve opens automatically when neither air removal pump is running and the control switch is in the automatic position.

The air ejector isolation valve closes automatically when either air removal pump is running and the control switch is in the automatic position.

The air ejector isolation valve can be manually opened or closed by placing the control switch in the open or closed position.

The air removal recovery tank isolation valve opens automatically and 2ARC-P4 starts when the catch tank level is high and the control switch is in the automatic position. The isolation valve closes automatically and 2ARC-P4 stops when the catch tank level is low and the control switch is in the automatic position.

The isolation valve can be open or closed and the pump started and stopped by placing the control switch in the open or closed position. The control switch is locally mounted.

The precooler inlet valves, air take-off valves, and condenser vacuum breaker valves are controlled manually.

The strainer blowdown valves are manually controlled by locally-mounted switches.

Monitoring

Alarms are provided for:

1. Condenser air removal pump auto trip/fail to start.

2. Condenser air removal pump seal recirculating water flow low.

3. Condenser air removal pump seal water recirculating temperature high.

4. Condenser air removal pump separator silencer tank level high and low.

5. MSL radiation high-high.

6. MSL radiation downscale.

7. Condenser air removal pump motor electrical fault.

8. Seal recirculation water pump motor overload.

9. Air removal recovery catch tank 2ARC-TKI level low-low.

10. Air removal recovery catch tank 2ARC-TKI level high-high.

10.4.3 Turbine Gland Sealing System

10.4.3.1 Design Bases

10.4.3.1.1 Safety Design Bases

The turbine gland sealing system is not nuclear safety related. The piping from the main steam system up to the first block valve is designed to a seismic consideration as described in Section 3.2.

The system is designed to provide clean sealing steam from the clean steam reboilers to the turbine seals to minimize the potential for release of radioactive gas to the environment.

10.4.3.1.2 Power Generation Design Bases

The turbine gland sealing system is designed to provide clean sealing steam for the turbine shaft and turbine steam control valves and to exhaust air that is drawn into the system to the stack. The sealing steam prevents steam leakage out through the high-pressure turbine shaft and turbine steam control valves (i.e., stop valves, control valves, bypass valves, and CIVs), and prevents air in-leakage through the low-pressure turbine shaft.

The clean steam reboilers and the steam packing exhauster drain tank are designed and fabricated in accordance with Section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code, and the Standards of the Tubular Exchanger Manufacturers Association, Class R. Piping and equipment supplied by the turbine manufacturer are fabricated to standards discussed in Section 10.2.1.2 and the remaining piping is designed and fabricated in accordance with ANSI B31.1.

10.4.3.2 System Description

The turbine gland sealing system is shown on Figure 10.1-8. During startup, the steam seal system minimizes in-leakage of air into the condenser through the turbine glands, thus aiding the condenser hogging operation. The system also protects the hot turbine shaft from a thermal shock.

Each of the two full-capacity clean steam reboilers can produce clean steam at 50 psig for the steam seal system and radwaste reboilers. The shellside of each reboiler is supplied with demineralized water from the condensate system. The tubeside of each reboiler is provided with heating steam via the auxiliary steam system, from either the auxiliary boiler (prior to MSL pressurization or after MSIV closure), the main steam system (below approximately 55-percent turbine load), or the extraction steam system (above approximately 55-percent turbine load). The condensate from the tubeside of each reboiler is drained to individual drain tanks and then routed to either the third-point feedwater heater shells or the condenser. Steam is routed to the turbine manufacturer's steam seal feed valve and from there, at approximately 7 psig, to the high- and low-pressure turbine shaft packings, and to the stem packings of turbine stop valves, TCVs, turbine bypass valves, and turbine CIVs. Backup sealing steam from the main steam system is supplied through an auxiliary feed valve in the event that the normal seal steam source fails.

The exhaust steam from the outermost turbine packings is drawn into either of the two full-capacity steam packing exhauster coolers. The steam is condensed by the main condensate flowing through the tubes and returns to the condenser via an atmospheric pressure drain tank. The noncondensables are discharged directly to the stack by one of the two full-capacity blowers on each cooler. The discharge from the steam packing exhauster unit is sampled by the turbine plant sampling system. Leakoffs from the TCV stems (stop valves, control valves, CIVs, and bypass valves) and high-pressure turbine packings are directed to: 1) the main condenser, 2) the high-pressure turbine exhaust, or 3) the extraction steam system (Figure 10.1-7).

10.4.3.3 Safety Evaluation

Turbine gland sealing is not nuclear safety related. The system is designed to provide a continuous supply of clean steam during normal operation. In the event of total failure of normal supply, steam from the MSL to the turbine bypass chest will be used for shaft sealing. This will avoid potential turbine damage caused by pulling cold air across the hot turbine shaft. The system is equipped with all necessary SRVs for overpressure protection. Any radioactive materials processed by the system are monitored at the discharge of the stack.

10.4.3.4 Test and Inspection

All the items of equipment associated with the turbine gland seal system are tested by their vendors. Preoperational tests of the equipment will be performed in accordance with the program described in Section 14.2. Refer to Table 3.2-1 for quality group status.

10.4.3.5 Instrumentation Requirements

Description

Instruments and controls are provided for automatic and manual control of the turbine gland sealing system. The controls and monitors described below are located in the main control room. The control logic is shown on Figure 10.4-3.

Operation

The water level of each clean steam reboiler shell is controlled automatically by the associated makeup control valve. The makeup control valve closes when the reboiler shell water level is high-high.

Each reboiler shell outlet isolation valve may be opened or closed manually. The outlet isolation valve closes automatically when the associated reboiler shell water level is high-high.

The reboiler shell condensate inlet isolation valves and the reboiler shell blowdown valves are controlled manually.

The gland seal steam auxiliary supply motor-operated valve is maintained normally open. The valve can also be controlled manually (remote).

The gland seal steam auxiliary supply isolation valve opens automatically when the gland seal steam supply pressure or the gland seal steam header pressure is low. The valve can also be controlled manually (remote).

The steam seal supply pressure is controlled automatically by the steam seal supply header control valves.

The gland seal steam header pressure is controlled automatically by the gland seal feed control valve.

The gland seal steam feed bypass valves and the gland seal steam feed supply valve are controlled manually.

The steam packing exhauster blowers are controlled manually. The associated steam packing exhauster suction valve must be open to start each blower.

The steam packing exhauster drain tank outlet valve opens or closes automatically when the drain tank level is high or low, respectively. The valve can also be controlled manually.

Monitoring

Indicators are provided for:

1. Reboiler outlet steam pressure.
2. Gland seal steam supply pressure.
3. Gland seal steam header pressure.
4. Steam packing exhauster vacuum.
5. Clean steam reboiler water level.

Alarms are provided for:

1. Clean steam reboiler water level low, high, and high-high.
2. Clean steam reboiler header pressure low.
3. Gland seal steam header pressure low.
4. Gland seal auxiliary steam supply isolation valve open.
5. Gland seal exhaust cooler loop seal overflow.
6. Steam packing exhauster pressure high.
7. Steam packing exhauster blower auto trip/fail to start.
8. Steam packing exhauster drain tank level low-low and high-high.
9. Steam packing exhauster blower motor overload.
10. Steam packing exhauster blower motor temperature high.

10.4.4 Turbine Bypass System

The purpose of the turbine bypass system is to bypass approximately 18.5 percent of turbine VWO throttle flow around the turbine to the condenser. In so doing, a comparable turbine load change can be accommodated without disturbing the NSSS.

10.4.4.1 Design Bases

10.4.4.1.1 Safety Design Bases

The turbine bypass system is not required to effect or support safe shutdown of the reactor or to perform in the operation of any reactor safety features.

10.4.4.1.2 Power Generation Design Bases

The turbine bypass system is designed to control reactor pressure:

1. During reactor heatup and while the turbine generator is brought up to speed and synchronized.

2. During power operation when the reactor steam generation exceeds the transient turbine steam requirements.

3. During reactor cooldown.

The turbine bypass system is designed to bypass approximately 18.5 percent of the turbine VWO throttle flow to the main condenser. The bypass system works in conjunction with the turbine EHC system. The turbine bypass valves are capable of remote manual operation in their normal sequence, during plant startup and shutdown, and individually for verification that the valves are operable.

The turbine bypass system, in conjunction with the reactor recirculation flow control system, is designed to accommodate a maximum 35-percent reactor power step change increase (up to rated reactor power) with no reactor or turbine trip.

The system, in conjunction with the recirculation flow control system, is designed to accommodate a maximum 35-percent turbine load step-down with intermittent bypass flow and no control rod motion, and a maximum 10-percent turbine load step-down with no bypass flow or control rod motion. The relationship between the turbine bypass valves and the main steam SRVs is discussed in Section 15.2.

10.4.4.2 System Description

The turbine bypass system controls primary system pressure by sending excess steam flow directly to the main condenser. This permits independent control of reactor pressure during reactor vessel heatup to rated pressure, and as the turbine is brought up to speed and synchronized under turbine speed-load controls. Following main turbine generator trips, hydraulic pressure is maintained to the turbine bypass valves which will be signaled to open to control reactor overpressure. Upon failure of the EHC system coincident with a turbine generator trip, and a resultant loss of system pressure to the bypass valves, the valves will open using the energy stored in the nitrogen-charged accumulators for a short period of time (approximately 1 min).

The turbine bypass system consists of five hydraulically-operated control valves mounted on a valve manifold. These valves are operated automatically and in sequence. The manifold is connected to the main steam header, which is upstream of the

turbine main stop valves. The bypass valve outlets are piped to the main condenser via individual pressure breakdown assemblies. Each assembly reduces pressure by successive throttlings through a series of multiple orificed plates to the condenser nozzles. Each of the five condenser nozzles is designed for a flow of 683,800 lb/hr at an inlet pressure of 250 psia. Steam enters the condenser by way of five carbon steel spray pipes, one for each bypass valve, which disperse the flow. The spray pipes direct the steam away from the turbine steam lanes and important areas of the condenser. The design internal pressure of the spray pipes is 1250 psig.

The bypass valves automatically trip closed whenever pressure in the main condenser exceeds approximately 23 in Hg abs; in addition, the 23 in Hg abs pressure signals the MSIVs to close. If steam flow exceeds the capacity of the turbine and bypass valves, the reactor pressure will increase until the main steam relief valves open (Section 5.4.13). The bypass system accommodates about 18.5-percent turbine load rejection without causing a significant change in reactor steam flow. The turbine bypass system valves and piping conform to the applicable codes (Section 3.2).

The turbine bypass valve assembly is shown on Figure 10.4-4. A single valve chest containing five parallel valves is provided. Each valve has a capacity of approximately 3.7 percent of turbine VWO throttle flow.

The bypass valve disk is of the globe type, and the stem is arranged to reach the outside through the discharge chamber of the valve. This arrangement minimizes the steam leakage when the valve is closed. It is necessary only to seal the stem against condenser vacuum.

Each bypass valve has its actuator arranged underneath the valve chest and fastened to the valve chest by a yoke-type structure. The actuator for each bypass valve is a double-acting hydraulic cylinder moved by 1,600 psig EHC fluid from the power unit controlled by a servo valve. Attached to the cylinder is a spring that opposes the opening motion so that the valves fail closed upon loss of hydraulic fluid pressure.

To supply hydraulic fluid during fast opening of the bypass valves, or for a limited time in case of failure of the hydraulic pumping system, gas-charged hydraulic accumulators are connected to the hydraulic supply lines on the bypass valve assembly (Figure 10.4-5).

10.4.4.3 Safety Evaluation

The turbine bypass system is not safety related. The turbine bypass valves are designed to fail closed on loss of main condenser vacuum (a pressure greater than 23 in Hg abs) or loss

of the turbine EHC system. The effects of a HELB in the bypass system are discussed in Section 15.6.4.

The effects of a turbine bypass system valve malfunction, as well as the effects of such failures on other systems and components, are evaluated in Chapter 15 and Appendix A. The effects of postulated piping failures in the turbine bypass system are evaluated in Section 3.6 and Appendix 3C.

10.4.4.4 Tests and Inspections

Testing of the turbine bypass valves by full stroking of the valves is not scheduled, except during refueling outages. Quarterly full-stroke testing causes wear of both the valves and the condenser internals, leading to leaks and reduced efficiency. Based on previous experience, stroking of the bypass valves during startups, shutdowns, or scrams should provide adequate assurance that the valves will function during subsequent trips.

10.4.4.5 Instrumentation Requirements

Description

Instruments and controls are provided to automatically adjust bypass steam flow and thereby control reactor pressure. The controls and monitors described below are located in the main control room.

Operation

The turbine bypass valves are controlled automatically by a signal from the bypass control unit (Figure 10.4-6). The bypass control unit compares the total reactor steam flow signal to the TCV flow signal. The resulting error signal is biased slightly to prevent continuous opening and closing of the bypass valves. This biased error signal is the total flow error signal. The total flow error signal is the bypass valve flow signal unless overridden by the limit circuits or the bypass valve jack.

The bypass valve jack is a motor-operated device used for setting a bypass valve position reference during startup and shutdown of the reactor. The bypass jack reference signal is compared with the total flow error signal in a high-value gate so that the one calling for the more open valve position is dominant.

Limit signals are produced in the limit circuits by the maximum combined flow limit and the TCV flow to position the bypass valve. This can be canceled by loss of condenser vacuum, causing closure of the bypass valve and preventing the valve from reopening.

Upon turbine trip or generator load rejection, the start of the bypass valve flow is delayed no more than 0.1 sec after the start of the main turbine stop valve or the main TCV closure. A

minimum of 80 percent of the bypass system capacity is established within 0.3 sec after the start of the stop valve or the control valve closure. These values are also described in TRM Section 3.7.5.

The turbine bypass valves fail closed on loss of main condenser vacuum or if the turbine EHC system loses its electric power or hydraulic system pressure (Section 7.7.1.5).

Manual controls are provided for setting the bypass valve opening jack.

Monitoring

Indicators are provided for bypass valve opening jack position and bypass valves positions. Alarms are provided for turbine bypass valve outlet temperature high and the main turbine bypass valves position.

10.4.5 Circulating Water System

The function of the CWS is to provide the main condenser with a continuous supply of cooling water. The water is used to remove the heat rejected from the turbine exhaust and turbine bypass steam as well as from other equipment (Section 10.4.1) over the full range of operating loads. The CWS is not required after unit shutdown.

10.4.5.1 Design Bases

10.4.5.1.1 Safety Design Bases

The CWS is not required to effect or support safe shutdown of the reactor or to perform in the operation of reactor safety features.

10.4.5.1.2 Power Generation Design Bases

The CWS is designed to convey 580,000 gpm of cooling water between the main condenser and the natural-draft cooling tower. The cooling tower is designed to reject a heat load of 7.875 x 10^9 Btu/hr from the main condenser to the atmosphere.

10.4.5.2 System Description

The major components of the closed loop CWS consist of the tubeside of the main condenser, the cooling tower, and six circulating water pumps (Figure 10.4-7). Water leaves the cooling tower cold water basin through a discharge flume that contains six bays of stationary screens. The screens are located within a closed cooling tower screenhouse with hoists and facilities available for removing and cleaning the screens.

The cooling water is conveyed from the discharge flume through two 120-in diameter pipes approximately 1,250 ft to the circulating water pumps. The two pipes manifold into six 72-in diameter pipes, each of which is equipped with a motor-operated butterfly valve and expansion joint. Each of the six vertical dry-pit pumps takes suction from one of the 72-in diameter pipes and is individually connected to one of the six condenser inlets with a 72-in diameter pipe. Expansion joints are located at each pump discharge and each condenser inlet. An expansion joint and motor-operated butterfly valve are located on each of the six 72-in diameter condenser outlet pipes.

The six condenser outlet pipes manifold into two 120-in diameter pipes that carry the heated water approximately 1,000 ft to the cooling tower. At the cooling tower, the 120-in pipes connect to the riser pipes and distribution piping. After passing through the distribution piping and the tower fill, the cooled water falls into the tower basin where the cooling cycle is repeated.

Makeup water for the CWS is obtained from the service water system (SWP) (Section 9.2.1). After passing through the SWP, a variable (circulating water makeup) flow of generally less than 25,000 gpm of service water is discharged into either 120-in diameter pipe upstream of the circulating water pumps. The remaining service water flow, called the service water system discharge, is directed to the screenwell discharge bay. The quantity of makeup flow is maintained by two sets of flow control valves (FCV) located within the SWP.

A vacuum priming system provides a keep-full provision for the CWS to preclude voiding the condenser when starting a circulating water pump during system startup. The priming system consists of a vacuum pump, separator, silencer, seal water heat exchanger, piping, and valves, as shown on Figure 10.4-7c.

The design basis water quality of the CWS is listed in Table 10.4-2. Actual operating constituent concentrations in the closed loop are maintained at less than about four times the actual lake water concentrations as a result of makeup and blowdown flow control. Blowdown is taken from the discharge lines of the circulating water pumps and is regulated by a FCV. The blowdown is routed to the screenwell discharge bay, where it is mixed with the SWP discharge and returned to the lake (Section 9.2.5).

During the winter months, warm water from the CWS is used to temper the lake intake water. The tempering water is taken from the circulating water pipe downstream of the condenser outlet and is piped to the screenwell intake bays where it is mixed with the lake intake flow. A FCV regulates the tempering flow as governed by the restrictions or limitations in the facility's Environmental Protection Plan (Nonradiological).

In order to maintain clean heat exchanger surfaces, acid, scale inhibitor, dispersant, corrosion inhibitor, sodium hypochlorite, and sodium bromide are added to the CWS. Sodium hypochlorite and sodium bromide are used for the prevention of biological growth within the CWS condenser.

Onsite generation of hypochlorite has been abandoned in place. Sodium hypochlorite and sodium bromide products are commercially supplied and are added to the CWS as necessary using administrative controls. The commercially supplied sodium hypochlorite and sodium bromide products are stored in the flume house. Grab samples are used to monitor for chlorine against limits established by the State Pollution Discharge Elimination System (SPDES). A liquid solution of sodium hypochlorite combined with the sodium bromide product is fed into the CWS upstream of the condenser in a controlled manner to inhibit biological fouling in the condenser.

The water chemistry of the CWS is controlled by the chemical feed systems which maintain the appropriate chemistry to inhibit mineral salt deposition (primarily calcium carbonate) by adding a scale inhibitor and dispersant into the CWS. In addition, a corrosion inhibitor is added when needed to reduce leaching of copper from heat exchanger surfaces. The equipment and piping used to inject the chemical regimen described above are located in the flume house and chemical injection building.

The cooling tower is a single-cell, wet-evaporative, hyperbolic, natural-draft cooling tower utilizing a counter-flow type design. The cooling tower design point is at an atmospheric condition of 74°F wet-bulb temperature and 50-percent relative humidity. During these conditions, the tower is designed to operate at a 16°F approach with a 27°F range. Depending on meteorological conditions, the cooling tower is designed to supply water ranging between 45°F and 90°F to the main condenser. The maximum expected water drift emitted from the cooling tower is 0.002 percent of the circulating water flow (Section 2.3.2.3).

Ice formation on the cooling tower is prevented by the flow of warm water through the ice prevention ring which restricts the amount of cooling tower inlet air. Twelve motor-operated valves (MOV) and their sectionalizing gates are provided to control the flow of warm water through the ice prevention ring.

10.4.5.3 Safety Evaluation

The CWS does not perform a safety-related function. No flooding of safety-related equipment or safety-related areas affecting safe shutdown will occur due to the CWS failure as described below. Each of the six circulating water pumps is designed for 105,000 gpm (at 75 ft total dynamic head). The pump size is determined by the quantity of heat to be rejected by the main condenser at all loads up to and including the maximum expected load. Each pump discharge is individually connected to six

condenser inlets. Expansion joints with metal jackets are located at each pump discharge and each condenser inlet. A MOV is located at the suction side of each pump. An expansion joint, with a protection jacket, and a MOV are located on each of the six 72-in condenser outlet pipes. The metal jackets minimize leakage in the event of an expansion joint failure. Telltale drain lines indicate expansion joint failure.

The condenser outlet valves are interlocked with their respective pumps and automatically open or close when the circulating water pumps are started or stopped. If a condenser outlet valve is closed while the pump is running, its respective circulating water pump automatically stops, preventing an abnormal increase of pressure before cutoff. These valves can also be operated by a switch from the control room and locally by means of a handwheel.

If a rupture occurred at a condenser expansion joint, the escaping water would first fill the jacket, then accumulate in the retention pit around the condenser. This pit is provided with a sump and level alarm. A deluge of water immediately activates the high-level alarm of the sump. The metal jacket protecting the expansion joint will allow approximately 17 gpm to discharge into the surrounding retention pit. The sump pump is of adequate size to prevent overflowing from the retention pit. Furthermore, once a rupture is determined, the Operator can manually stop the circulating water pumps and close the pump suction and condenser outlet valves. The circulating water pump pit is physically separated by elevation from any essential safety-related equipment necessary for safe shutdown. Therefore, no essential safety-related equipment would be affected, and safe shutdown could be accomplished.

If a circumferential rupture occurred simultaneously in a condenser expansion joint and jacket or a break occurred in the circulating water piping, up to 100,000 gpm could be discharged into the turbine building at el 250'-0". A loss of condenser cooling water of this magnitude could cause a vacuum loss, activating alarms in the main control room. Sump alarms would also activate. As described above, Operator action could limit the flooding into the building. However, if the leakage continues, the water would spill over the turbine building floor and seek the lowest possible level. Tunnels running below the turbine building floor (el 250'-0") would experience flooding; however, no safety-related equipment necessary for safe shutdown would be affected.

The control and reactor buildings' tunnel interfaces are sealed by a watertight door and penetrations to protect safety-related equipment in these areas.

As the tunnels fill up and the water level rises in the turbine building, an equilibrium level of el 257 ft will be reached between the water level in the cooling tower basin and the flood

level within the turbine generator building. All safety-related equipment necessary for safe shutdown in the affected buildings is located above el 257 ft and would not be affected.

In conclusion, a complete circumferential expansion joint or pipe break in the CWS inside the turbine generator building would have no effect on safety-related equipment.

10.4.5.4 Testing and Inspection Requirements

All active components of the CWS are accessible for inspection and testing during Station operation. The expansion joint metal jackets are equipped with a 3/8-in diameter telltale-type hole providing indication of a ruptured expansion joint.

10.4.5.5 Instrumentation Requirements

Description

Instruments and controls are provided for automatic and manual control of the CWS. The controls and monitors described below are located in the main control room. The control logic is shown on Figure 10.4-8.

Operation

Circulating water pumps are started manually. Interlocks prevent starting a pump when the suction valve is not fully open, the seal water pressure is low, or the condenser discharge valve is not fully closed. The pumps trip automatically when the suction valve is not fully open, or the condenser discharge valve is greater than 90-percent closed. The pumps can also be stopped manually.

The circulating water pump suction valves are controlled manually.

The circulating water condenser discharge valves open or close automatically when the associated pump is running or is not running, respectively. The valves can also be controlled manually with jogging capability.

The water level in the cooling tower basin is controlled automatically by the cooling tower basin level control valve. The cooling tower basin water temperature is controlled by the cooling tower bypass valves. The valves open automatically when the cooling tower basin temperature switches are actuated on low temperature. The normal control scheme incorporates a two-out-of-four logic using all four of the basin thermal detectors. Alterations to the logic are incorporated in accordance with temporary modification procedures based on detector availability. The acceptable alternate logic configurations include two-out-of-three and two-out-of-two. De-energizing the gate motor starters provides an additional

means of overriding the automated logic, thereby maintaining the gates in the desired position. Control switches in the control room provide the ability to manually open the valves.

The cooling tower ice prevention valves are controlled manually. Each of the valves can be opened or closed individually, and all valves can be opened simultaneously.

Monitoring

Indicators are provided for:

1. Cooling tower flume water temperature.

2. Cooling tower blowdown flow.

3. Cooling tower basin water level.

A recorder is provided for blowdown water pH.

Alarms are provided for:

1. Circulating water pump suction pressure low, seal water pressure low, and auto trip/fail to start.

2. Circulating water system trouble.

3. Circulating water cooling tower flume water temperature high.

4. Effluent liquid radiation monitor activated (cooling tower blowdown).

5. Circulating water cooling tower trouble.

10.4.6 Condensate Demineralizer System

10.4.6.1 Design Bases

10.4.6.1.1 Safety Design Bases

The CND system is not required to effect or support safe shutdown of the reactor or to perform in the operation of reactor safety features. However, the system is required to limit the conductivity and total dissolved solids content of the reactor feedwater. Shielding and access control are used to protect plant personnel from exposure to radiation.

10.4.6.1.2 Power Generation Design Bases

The CND system is designed to maintain high purity of the condensate to assure high-quality feedwater to the reactor by removal of the following contaminants:

1. Corrosion products from piping and components.

2. Suspended and dissolved solids that may be introduced by small leakage of circulating water through the condenser tubes.

3. Fission and activation products that are entrained in reactor steam and retained in condensate leaving the condenser hotwell.

4. Other solids carried in by makeup water.

The CND system is designed to maintain the following condensate water quality:

Specific conductivity at 77°F (25°C)	0.1 umho/cm
Silica (as SiO_2)	5.0 ppb max
Metallic impurities (as metal)	10.0 ppb, of which copper does not exceed 2 ppb
Lead (as Pb)	Not detectable by acceptable ASTM referee method
Hardness (as $CaCO_3$)	0
pH	6.5-7.5

The system design is based on the following influent concentrations as described in the Nuclear Boiler Vendor's Design Specification for Water Quality.

	Concentration	
Impurity	Startup	Normal Operation
Iron (as Fe)		
Soluble, ppb	40	5
Insoluble, ppb	1,000*	25
Copper (as Cu)		
Soluble and insoluble, ppb	50	7
Other metals (as metal)		
Soluble and insoluble, ppb	40	3
Soluble silica (SiO_2), ppb	500-2,000	20-40
Specific conductivity		

* Insoluble iron may be as much as 4,000 ppb for several hours at initial plant startup.

at 25°C, umho/cm	0.5	0.2
pH	6-8	6.5-7.5

The CND system has nine ion exchanger units, one of which is a spare. The units have sufficient capacity to treat the total normal condensate flow based on a nominal design flow rate of 50 gpm/sq ft of resin (maximum of 55 gpm/sq ft). The CND system is designed to treat ~122 percent of design condensate flow from the condensate pumps. A partial flow bypass line is provided around the condensate demineralizers as shown on Figure 10.1-5a. This provides for full condensate flow during off-normal conditions such as heater drain pump out of service and/or multiple demineralizers out of service. An air-operated valve is provided to secure bypass flow from the control room should condensate, feedwater or reactor water chemistry indicate adverse impurity concentrations. The total feedwater flow consists of this rated condensate flow, as well as flow from heater drains that bypass the CNDs. This results in treatment of approximately 68 percent of the total feedwater flow to the reactor vessel.

The CND system is sized to continuously process condensate with peak impurity concentrations resulting from plant startup operation of 1-wk duration or from condenser leaks. The ion exchangers are sized to handle cooling water condenser leaks of up to 88 gpm for 6 hr with a maximum chloride concentration of 472 ppb (as CaCO3). This condition assumes a resin capacity of 0.4 meq/ml and produces an effluent conductivity of 0.1 umho/cm. The CND system is designed in accordance with RG 1.56, June 1973 (Section 10.4.6.3).

The method used to verify initial total capacity of new demineralizer resins will be based upon methods recommended by the resin manufacturer, ASTM D2187-77 F and H or Federal Specification No. 0-1-1279.

10.4.6.2 System Description

10.4.6.2.1 Condensate Demineralizers

The CND system is shown on Figure 10.1-9. The CNDs are in the direct flow path of condensate flow to the reactor vessel and are located downstream of the condensate pump before the SJAE intercondenser. Each demineralizer has an effluent resin strainer to prevent resin carryover with the condensate. The system controls are designed to preclude improper operation of the system in its various modes.

The reactor chemistry limits outlined in RG 1.56 Rev. 1, Table 1, will be met. These chemistry limits, as well as corrective action, will be established in the TRM. The following methods of chemical analyses will be used.

Parameter	Analysis Method*
Chloride	ASTM D512-81C or Ion Chromatographic
pH	ASTM D1293-84B
Conductivity	ASTM D1125-82B

The water chemistry control program to assure maintenance of conductivity will be based upon the limits described in RG 1.56 Rev. 1, Table 2.

	Micromho/cm	
	Limit	Maximum Limit
Conductivity system inlet	0.5	10
Conductivity individual demineralizer outlet	0.2	0.5
Conductivity combined demineralizer outlet	0.1	0.2

Corrective action for the case when the limit is met at the system inlet will require determination of which waterbox is leaking, isolation and repair within 72 hr. When the maximum limit is met, immediate isolation and repair is required.

Corrective action for the case when the limit is met at the demineralizer outlet will require removal from service of the demineralizer with the high alarm within 72 hr. When the maximum limit is met, immediate removal from service of the demineralizer with high alarm is required.

See Section 10.4.6.5 for control room alarm setpoints.

10.4.6.2.2 External Regeneration System

A resin regeneration system external to the demineralizers is provided. Facilities are provided for the separation and mixing of resin and for ultrasonic cleaning. Ultrasonic resin cleaning (URC), air scrubbing, backwashing, or any combination of these are used to prevent the excessive buildup of crud on resin as may be indicated by a decreasing trend in flow through a particular vessel, an increasing trend in final feedwater metals, or an increasing trend in demineralizer effluent conductivity.

The regeneration system consists of a cation regeneration vessel, an anion regeneration vessel, a mix-and-hold vessel, day storage

* The method used will provide adequate sensitivity to ensure that the limits described in RG 1.56 Rev. 1, Table 1, will be met. Alternative methods are acceptable provided adequate analytical sensitivity is ensured.

tanks designed for acid and caustic, a hot water tank, and positive displacement metering pumps designed for acid and caustic. The regeneration system also includes a waste recovery system.

The CND resin regeneration tanks and URC receiving and storage tanks meet the design requirements of ASME Section VIII, Division 1. All piping and valves in the system are designed in accordance with ANSI B31.1.

The acid and caustic day tanks and recovered acid and caustic tanks are removed from service in accordance with New York State regulations for tank closures. The demineralizer resin is replaced on a maintenance interval and the resin is no longer chemically regenerated. All domestic BWRs have discontinued the practice of chemically regenerating condensate resin due to IGSCC concerns.

Resin Cleaning

As necessary, resin beds are cleaned based on operating history. The bed is taken out of service depending on operating history. The bed is taken out of service for URC and/or air scrub and backwash cleaning after it has been replaced by a standby bed. The resin is sluiced with water and air to the cation regeneration tank, where the resin is air scrubbed and backwashed. The crud removed is sent to radwaste. Multiple air scrub and backwash cleanings may be performed or the resin can be transferred to the URC. During URC cleaning the resin is transferred via an eductor to the URC cleaned resin storage tank, while the URC wastewater, with the crud removed during cleaning, is discharged to radwaste. After the whole bed has been cleaned, it is transferred to the cation tank where it is backwashed and air scrubbed and the resin levels are checked. The resin is then transferred to the mix-and-hold vessel where it is remixed and rinsed down to an acceptable conductivity.

The bed may then be transferred to a demineralizer vessel, or retained for standby service.

The condensate filtration system (CFS) upstream of the CND system relieves iron loading on the demineralizers and helps to achieve optimal final feedwater iron levels consistent with the BWR Water Chemistry Guidelines. The CFS system includes the filter vessels, piping, valves, and associated controls and indication necessary to filter full condensate flow for normal plant operation, and to perform automated or manual backwash evolutions used to remove the captured iron particles from the filter septa. The backwash provisions include a primary blowdown line from the CFS filters to a remote backwash waste receiving tank (BWRT), a dedicated backwash air receiver and compressor to support the blowdown cycles, and a local distribution cabinet and remote control center. The CFS system is shown on Figures 10.1-5f and 10.1-5g.

Resin Replacement

Actual resin replacement frequency will be based upon resin conditions during operation. Resins will be discarded and replaced when their capacity falls below 0.4 meq/ml.

The resin replacement frequency is estimated based on a remaining capacity for anion resin of 0.4 meq/ml, thereby assuring that the capacity of the system will not fall below that necessary to maintain condensate purity during a postulated condenser in-leakage. The postulated condenser in-leakage is 88 gpm with the circulating water composition given in Table 10.4-2, and 6 hr for orderly shutdown. Based upon normal condensate flow of 21,000 gpm, 0.1 micromho/cm influent conductivity, seven resin beds in service, 220 cu ft of resin per bed, 1:1 cation to anion resin ratio, 1.2 meq/ml anion capacity, and 1.6 meq/ml cation capacity, it is estimated that a new resin bed will have a service life of 10,000 effective full-power operation hours without chemical regeneration.

The condition of each demineralizer bed is determined by subtracting the ionic loading in each bed from the initial total capacity of the new demineralizer resin. The ionic loading on each bed is monitored using the condensate demineralizer inlet conductivity, the flow rate throughput, and the time in service. The initial capacity is measured as described in Section 10.4.6.1.2.

1. Conductivity meter readings will be electronically calibrated in accordance with approved plant procedures by using calibrated resistors in place of the conductivity cells.

2. The influent conductivity is resolved into ion concentrations based on in-leakage of circulating water with the composition given in Table 10.4-2. The ionic loading is calculated by integrating the influent ionic concentration and flow of water into each unit over time. The result is the percent ionic loading based on the total capacity of the anion resin, which is limiting. The total capacity is the original value for the new anion resin adjusted for the loss of anion resin sites by thermal decomposition over time.

3. The flow rates through each demineralizer vessel are measured by a flow transmitter located at the inlet to each demineralizer vessel and recorded at the local control panel.

4. The accuracy of the resin capacity calculations may be confirmed by measurements of the residual capacity using samples of resin withdrawn from service during

resin transfer between demineralizer vessels and regeneration equipment.

Purified condensate is sampled monthly during steady state operation using a millipore filter and cation and anion paper. Based upon 0.1 micromho/cm conductivity, the total dissolved solids are expected to be limited to 50 ppb. Suspended solids limits are expected to be within the fuel warranty limits.

10.4.6.3 Safety Evaluation

The CND system is not safety related. Since the CND system also removes corrosion products, including radioactive material, adequate shielding is provided around the CNDs, URC vessels, and regeneration facilities. Remote operation is accomplished from the CND control room, adjacent to the equipment area.

Radioactive waste is held only temporarily within the CND system prior to transfer to the liquid waste management system (Section 11.2). Backup tanks and pumps, including an overflow sump, preclude difficulties in handling radioactive waste.

In accordance with RG 1.56, the CND system provides the capability of monitoring resin capacity and electrical conductivity by establishing limits for operation and demineralizer capacity, both new and residual, as follows:

1. Conductivity is continuously monitored at several points within the condensate and feedwater systems and the reactor by a combination of continuous monitors and grab samples. High-conductivity alarms are provided to alert plant Operators to an abnormal condition. These abnormal conditions include conductivity levels that indicate breakthrough in one or more demineralizers.

2. The depletion of resin capacity is monitored by instrumentation measuring the influent conductivity (converted to concentration of the principal ions) and flow through each demineralizer as a function of time. The loss of anion exchange resin sites by thermal decomposition is also monitored by measuring the operating temperature and calculating the loss of sites based on the first order reaction. A bed is removed from service when the remaining capacity of anion resin reaches 62 kg (as $CaCO_3$), thereby assuring that sufficient capacity will be present to handle a main condenser leak of 88 gpm. Based on 220 cu ft of resin per bed and 1:1 cation to anion resin ratio, a remaining anion bed resin capacity of 62 kg (as $CaCO_3$) is equivalent to 0.4 meq/ml for the anion resin. Removal at this point is prior to any rise of effluent conductivity, thereby assuring high water quality. The results of samples taken to check the accuracy of this calculation may be used to adjust the calculated value

of residual demineralizer capacity. Due to the water quality required and the use of high flow rate demineralizers, a change in conductivity of the demineralizer effluent is a more significant factor than ion breakthrough.

Conductivity cells are provided at the effluent of each demineralizer to alarm at 0.2 umho/cm. The effluent strainer in the piping from each ion exchanger protects the feedwater system against a massive discharge of resin in the event of an underdrain failure.

Concentrations of impurities in the primary coolant are kept low by maintaining condenser integrity and optimal CND and reactor water cleanup (RWCU) system performance. The minimum oxygen level in the incoming feedwater is maintained at 30 ppb.

10.4.6.4 Test and Inspection

Field tests are performed after equipment installation to check satisfactory operation and function of control equipment. The CND, regeneration and URC storage vessels, and other related tanks and equipment, are hydrostatically tested to 1.5 times design pressure by the vendor. Component redundancy and routine inspection and maintenance provide for enhanced reliability.

10.4.6.5 Instrumentation Requirements

Description

Instruments and controls are provided for automatic and manual control of the CND system. The controls are located on a local panel in the CND room. The monitors are located in the main control room and CND control room. The control logic is shown on Figure 10.4-9.

Operation

After manual mode selection and manual placement of the individual resin bed in and out of service, the regeneration of the demineralizers may be controlled automatically.

The low-conductivity waste pumps are started manually. Interlocks prevent starting a pump when the low-conductivity waste tank level is low. A pump trips automatically when the low-conductivity waste tank level is low, or the discharge header pressure is sustained low. The pumps can also be stopped manually.

The normal and backup discharge valves for the low-conductivity waste pumps are opened manually. Interlocks prevent opening the backup discharge valve unless the normal discharge valve is closed. The normal discharge valve cannot be opened unless the waste tank conductivity is sustained low. A sustained high waste

tank conductivity closes the normal discharge valve automatically and diverts the discharge from the radwaste system to the anion regeneration tank.

The waste neutralizing recirculation and transfer pumps are controlled automatically by the neutralizing tank level. The running pump will trip and the standby pump will start automatically when the recirculation flow is sustained low. The pumps can also be controlled manually.

The waste neutralizing tank discharge valve is opened manually. Interlocks prevent opening the valve unless the neutralizing tank pH is within the prescribed range and either transfer pump is running. The valve closes automatically when the neutralizing tank pH is not within the prescribed range or neither transfer pump is running. The valve can also be closed manually.

The waste neutralizing tank recirculation valve opens automatically when the neutralizing tank discharge valve is closed and either recirculation pump is running. The valve closes automatically when the neutralizing tank discharge valve is opened or both recirculation pumps are stopped. The valve can also be controlled manually.

The chemical waste sump pumps are started manually. Interlocks prevent starting a pump when the neutralizing tank level is high-high or the sump water level is low. The pumps trip automatically when the sump water level is low or the neutralizing tank level is high-high. The pumps can also be stopped manually.

<u>Monitoring</u>

Alarms are provided in the main control room for:

1. Each CND outlet conductivity high.

2. CND system trouble.

3. CND(s) flow low.

All other system monitors are located in the CND control room.

The control room alarm setpoints for the conductivity meters at the inlet and outlet of the CND system are as follows:

Inlet umho/cm	Outlet umho/cm
0.5 at system inlet	0.2 at each vessel outlet
	0.2 at system outlet

These alarm points will indicate off-normal status of the system or noticeable breakthrough of one or more demineralizers.

10.4.7 Condensate and Feedwater System

This section describes the condensate and feedwater system from the condenser to the outboard manually-initiated long-term isolation valve. The condensate and feedwater system from the outboard manually-initiated long-term isolation valve to the reactor is discussed in Section 5.4.9.

10.4.7.1 Design Bases

10.4.7.1.1 Safety Design Bases

The condensate and feedwater system is not required to effect or support the safe shutdown of the reactor or to perform in the operation of reactor safety systems. However, in the event that the condensate and feedwater system is available after an accident, it can supply feedwater to the reactor. System quality groups are discussed in Section 3.2.2.

10.4.7.1.2 Power Generation Design Bases

The condensate and feedwater system provides a reliable supply of feedwater to the reactor at the temperature, pressure, quality, and flow rate required by the reactor. The condensate and feedwater system has sufficient capacity to provide approximately 105-percent nuclear boiler rated (NBR) flow against rated reactor feedwater sparger inlet pressure. The condensate and feedwater system is designed to the requirements of ANSI B31.1 for piping and ASME Section VIII for pressure vessels, except for integral attachments to the feedwater and condensate system where the preheat and postweld heat treatment meet either ANSI B31.1 or ASME Section III.

10.4.7.2 System Description

The condensate and feedwater system consists of the piping, valves, pumps, heat exchangers, controls, instrumentation, associated equipment, and subsystems that supply the reactor with heated feedwater in a closed steam cycle using regenerative feedwater heating. The condensate system is shown on Figure 10.1-5. The feedwater system is shown on Figure 10.1-6. Evaluation of feedwater lines against General Design Criterion (GDC) 55 is discussed in Section 6.2.4.

Three 50-percent capacity condensate pumps are provided. The condensate pumps are canned suction, 3-stage, vertical mixed turbine pumps. Each pump is driven by a 1,750-hp air-cooled electric motor. The discharge of the condensate pumps flows through the CND system (Section 10.4.6). The condensate then provides cooling to the SJAE intercondensers and the turbine gland steam exhausters. A recirculation line to the condenser is provided downstream of the gland steam exhausters to maintain minimum flow through the condensate pumps, air ejectors, and gland steam exhausters during startup and low load operation.

Three 50-percent capacity condensate booster pumps are provided. Each condensate booster pump is a constant speed, single-stage, horizontal, centrifugal pump driven by a 3,000-hp air-cooled electric motor. Each condensate booster pump has a minimum flow recirculation line to the condenser. The discharge of the condensate booster pumps flows through three independent nominal 33-percent capacity low-pressure closed feedwater heater strings.

Each string of low-pressure feedwater heaters consists of five feedwater heaters and two drain coolers. The first- and second-point feedwater heaters are located inside the condenser neck. The drains from each fourth-point feedwater heater are pumped forward into the condensate stream after the fourth-point feedwater heater by a separate heater drain pump. The closed feedwater heaters and the heater drain pumps are discussed in Section 10.4.10. A clean source of demineralized water from the suction side of the condensate booster pumps is available. The ZIP system is discussed in Section 9.5.11.

Normally, two of three reactor feed pumps are operating. The pumps are horizontal, 2-stage, 50-percent nominal capacity, 3,400-rpm constant speed centrifugal pumps. Each pump is capable of providing approximately 73-percent NBR flow at runout conditions. Each pump is driven through a step-up gear by a 16,500-hp, 1,800-rpm electric motor. Minimum flow is maintained through each pump by a recirculation line to the condenser. Connections from the zinc injection passivation (ZIP) system are provided on both the suction and discharge to the reactor feed pumps.

The discharge from the reactor feed pumps flows through three one-third-capacity high-pressure feedwater heaters. The final feedwater temperature out of these heaters is 440.5°F.

Feedwater flow control is provided by a control valve in the discharge line of each reactor feed pump. Low-flow feedwater control valves, each capable of maintaining controlled flow down to 0.5-percent NBR flow, are provided in the discharges of two of the pumps for startup. The feedwater control system is discussed in Section 7.7.1.3.

The condensate and feedwater system can recirculate flow back to the condenser from downstream of the high-pressure heaters for corrosion product cleanup.

1. A low-energy section returns water to the hotwell and allows recirculation up to full demineralizer capacity before reactor startup without operation of the reactor feed pumps.

2. A high-energy section, which sprays the water in the condenser upper shell, allows recirculation of up to one-third NBR flow with the feed pumps operating at limit loads limited to 50-percent NBR.

The quality of the water in the condensate and feedwater system is monitored through appropriately located sample points (Section 9.3.2).

Oxygen is injected on the suction side of the condensate pumps to maintain the minimum oxygen concentration of 30 ppb. The oxygen in feedwater injection system is described in Section 10.4.11.

The hydrogen water chemistry (HWC) system injects hydrogen into the condensate system at the suction side of the condensate booster pumps. The hydrogen injection system is used in conjunction with NobleChem™ in order to mitigate IGSCC of the stainless steel reactor vessel components and recirculation piping.

For mitigation of IGSCC of susceptible reactor vessel components and recirculation piping (refer to Appendix 4A for additional details), an on-line noble metal injection (ONI) system provides a means to inject noble metals into the feedwater system. The system consists of an injection skid containing pumps to inject the metals into the feedwater stream, with the plant operating at power using the makeup water system (MWS) as a carrier source. Refer to Figures 10.1-6b and 9.2-6a.

The condensate and feedwater system is designed with welded connections wherever practicable to minimize leakage. The closed feedwater heaters have stainless steel tubes with rolled tube joints, and in the case of the high-pressure heaters, rolled and welded tube joints.

10.4.7.3 Safety Evaluation

The condensate and feedwater system is not safety related and is not required for the safe shutdown of the reactor. In the event of individual component failures, the multipath design of the system permits components to be isolated or bypassed and other equipment to maintain system operation. In the event of multiple or complete system failure, a unit trip results. Chapter 15 discusses the effects of major system failures on the NSSS. The protection against the dynamic effects associated with the rupture of condensate and feedwater piping in the proximity of essential systems, components, or structures is discussed in Section 3.6. The seismic design of the section of the condensate and feedwater system located in essential structures is discussed in Section 3.7.

During operation, radioactive water is present in the system. Radiation sources from the condensate and feedwater system are discussed in Section 12.2.

10.4.7.4 Tests and Inspections

The condensate and feedwater system pumps were extensively shop tested to ensure reliable operation. All pumps were given normal performance tests, including noncavitating performance and determination of net positive suction head (NPSH) required. The condensate booster and the reactor feed pumps were given severe cavitation tests and a reactor feed pump was given a thermal transient test.

The condensate and feedwater system components are hydrostatically tested as required by the appropriate codes or standards. The system is tested during the preliminary test phase of the test program for leaks and proper operation. The startup test program is discussed in Section 14.2.

10.4.7.5 Instrumentation Requirements

10.4.7.5.1 Condensate System

Description

Instruments and controls are provided for manual and automatic control of the condensate system. The controls and monitors described below are located in the main control room. The control logic is shown on Figure 10.4-10.

Operation

The condensate pumps are controlled automatically or manually. In the auto mode, a standby pump will start automatically on an electrical fault in another pump circuit, low-condensate booster pump suction pressure, or two of three heater drain pumps not running.

The condensate pump recirculation FCV opens automatically to control recirculation flow whenever a pump is running, and closes when all pumps are stopped. Its setpoint is adjusted automatically in accordance with the number of pumps running.

The condensate booster pumps are controlled automatically or manually. In the auto mode, a standby pump will start automatically on an electrical fault in another pump circuit, low reactor feed pump suction pressure, or two of three heater drain pumps not running. A running pump trips automatically when the suction pressure is sustained low.

A condensate booster pump recirculation valve opens automatically to control recirculation flow when the associated pump is started, and closes when the pump is stopped.

The low-pressure heater string inlet and outlet isolation valves and the condensate heater bypass valve are opened and closed manually. The heater bypass and the CND bypass valve will be opened automatically on a turbine trip when turbine first-stage pressure is greater than 71 percent turbine load. Interlocks

prevent opening block valves, and initiate closure of open block valves when a first- or second-point heater water level is high-high.

The reactor feed pump suction valves and bypass valves are opened and closed manually.

Monitoring

Indicators are provided for:

1. Condenser vacuum.

2. Condensate pump discharge header pressure, discharge header flow, recirculation valve position, and motor current.

3. Condensate low-pressure system flow.

4. Condensate booster pump suction header pressure, suction flow, discharge header pressure, recirculation valve position, and motor current.

5. Feedwater low FCV flow.

6. Reactor feed pump suction pressures.

7. Local differential pressure across the condensate pump suction strainers.

Alarms are provided for:

1. Condensate pumps auto trip/fail to start, auto start, discharge header pressure high, motor overload, and bearing/winding temperature high.

2. Condensate system trouble and no backup pump available.

3. Condensate booster pumps auto trip/fail to start, auto start, suction pressure low, suction pressure low-low, suction flow low, suction header pressure low, bearing/winding temperature high, motor overload, and bearing vibration high.

4. Condensate booster pumps system trouble and no backup pump available.

5. Condensate system flow low.

10.4.7.5.2 Feedwater System

Description

Instruments and controls are provided for manual and automatic control of the feedwater system. The controls and monitors described below are located in the main control room. The control logic is shown on Figure 10.4-11. See Section 7.7.1.3 for a description of the feedwater control system.

Operation

Reactor feed pumps are started and stopped manually. Interlocks prevent operation of a pump when reactor water level is high, pump suction pressure is low, bearing oil pressure is low, the pump recirculation valve is not open, or the fire disconnect switch is in actuated position. Sustained low-low suction pressure will stop a running pump.

A reactor feed pump recirculation valve opens automatically to modulate recirculation flow when the associated pump is started and the pump lube oil pressure is normal, and closes when the pump is stopped.

The reactor feed pump seal injection lines are supplied with manual throttle valves to modulate flow to maintain seal water temperature in conjunction with the seal coolers.

The sixth-point heater feedwater inlet, outlet, and bypass valves, reactor feed pump discharge block valves, and the high-energy feedwater cycle cleanup shutoff valve are opened and closed manually.

The feedwater high-point vent valves are opened and closed manually and locally.

The low-energy feedwater cycle cleanup shutoff valve is controlled manually. Interlocks prevent opening, or trip closed, the valve when the low-energy feedwater cycle cleanup pressure is high.

The low- and high-energy feedwater cycle cleanup control valves are modulated by hand-indicating controllers. The low-energy feedwater cycle cleanup valves close automatically when the pressure in the associated lines before the valves is high.

Monitoring

Indicators are provided for:

1. Reactor feed pump discharge pressures.

2. Feedwater cycle cleanup flow.

3. Reactor feed pump suction flow.

4. Reactor feed pump recirculation valve position.

5. Reactor feed pump seal water temperature.

Alarms are provided for:

1. Reactor feed pump auto trip.
2. Reactor feed pump suction pressure low/low-low.
3. Reactor feed pump bearing vibration high.
4. Reactor feed pump bearing/winding temperature high.
5. Reactor feed pump step-up gear bearing vibration high.
6. Reactor feed pump step-up gear bearing temperature high.
7. Reactor feed pump seal water temperature high.
8. Low-energy feedwater cycle cleanup system trouble.
9. Reactor feed pump suction flow low.
10. Reactor feed pump motor overload.
11. Reactor feed pump motor electrical fault.

10.4.8 Steam Generator Blowdown System

Not applicable to BWR.

10.4.9 Auxiliary Feedwater System

Not applicable to BWR.

10.4.10 Extraction Steam and Feedwater Heater Drain System

10.4.10.1 Design Bases

10.4.10.1.1 Safety Design Bases

The extraction steam and feedwater heater drain system is not required to effect or support the safe shutdown of the reactor or to perform in the operation of reactor safety features. The system is designed to minimize the possibility of water induction into the turbine and to limit the amount of energy stored in the system that can flow back to the turbine after a trip or sudden load rejection.

10.4.10.1.2 Power Generation Design Bases

The system is designed to heat the reactor feedwater to meet reactor inlet requirements. The system also provides heating steam to the building heating intermediate heat exchangers and

clean steam reboilers. The systems are designed to the requirements of ANSI B31.1 for piping, ASME Section VIII for pressure vessels, and Hydraulic Institute Standards for pumps. Exceptions to this are integral attachments to the extraction steam system where the preheat and postweld heat treatment meet either ANSI B31.1 or ASME Section III.

10.4.10.2 System Description

The extraction steam system is shown on Figure 10.1-7. The feedwater heater drain system is shown on Figure 10.1-7. The extraction steam and feedwater heater drain systems consist of the piping, valves, heat exchangers, pumps, drain receivers, controls, instrumentation, and associated equipment required to heat the reactor feedwater and remove the feedwater from the heater drains.

The low-pressure section of the system consists of three independent strings of feedwater heaters, each containing two drain coolers and five closed feedwater heaters. The high-pressure section consists of three strings each with one closed feedwater heater. The feedwater heaters are horizontal, U-tube heat exchangers with stainless steel tubes. The drain coolers are horizontal straight-tube, single-pass, heat exchangers with stainless steel tubes. The tubes are rolled into the tube sheets except in the case of the high-pressure heaters where they are rolled and welded.

The sixth-point high-pressure feedwater heaters receive fourth-stage extraction steam, reheater drains, and reheater scavenging steam. They normally drain to the fifth-point feedwater heaters.

The fifth-point heaters receive extraction steam from the high-pressure turbine exhaust (cold reheat) and sixth-point heater drains and, normally, drain to the fourth-point feedwater heaters.

The fourth-point feedwater heaters receive eighth-stage extraction steam from the low-pressure turbine, moisture separator drains, and cascaded fifth-point heater drains. The drains from the fourth-point feedwater heaters are normally pumped forward by heater drain pumps into the condensate system upstream of the fifth-point feedwater heaters.

The third-point feedwater heaters receive extraction steam from the ninth stage of the low-pressure turbine, drains from the clean steam reboiler, and high-pressure turbine gland seal leakoff steam. The drains normally flow through separate drain coolers to the condenser.

The second-point feedwater heaters, located in the condenser neck, receive extraction steam from the eleventh stage of the low-pressure turbine. The drains from each heater collect in a

drain receiver and normally drain through separate drain coolers to the condenser.

The first-point feedwater heaters, also located in the condenser neck, receive extraction steam and moisture removal stage drips from the thirteenth stage of the low-pressure turbine. The first-point heaters drain directly to the condenser through a loop seal.

The fourth-point feedwater heaters are of the closed deaerating type. They are designed so that the oxygen content of the drains is less than 70 ppb at the turbine VWO load condition.

The extraction steam and heater drain systems are designed in accordance with ASME Standard No. TWDPS-1, Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation, Part 2 - Nuclear Fueled Plants. In general this means that, except when drained by a loop seal, all feedwater heaters have two independent, full-capacity drain systems and an automatic means of detecting water accumulation from a heater tube leak and subsequent isolation of the heater or the water source from the turbine. The second- through sixth-point heaters have independent, high-level drain systems draining directly to the condenser. The third- through sixth-point heaters have automatic motor-operated block valves in their extraction lines that close on a high water level in the source heater. High water level in the first- or second-point heater closes that string's condensate inlet and outlet valves to block the incoming water flow. This precludes the possibility of a heater tube failure from causing water induction and turbine damage.

The extraction steam system protects the turbine from excessive overspeed by the use of nonreturn valves in the extraction lines. These valves prevent the stored energy in the extraction lines and feedwater heaters from entering the turbine after a turbine trip or sudden load rejection. The valves are of the power-assisted, check type and are designed in accordance with the requirements of the turbine generator manufacturer.

Normally, three 33 1/3-percent capacity heater drain pumps are operating. The heater drain pumps are eight-stage, vertical-mixed turbine, constant-speed pumps. Each pump is driven by a 1,750-hp direct-coupled electric motor. The pumps can operate under all plant loads from 40 to 100 percent and adequate NPSH is provided over the full range of required operating flows including off-normal conditions. Minimum flow is maintained through each pump by a recirculation line to the suction source. A debris strainer with a slotted wedge wire screen is provided on the discharge line of each heater drain pump to prevent particles larger than 0.040 in from entering the feedwater system and reactor. Sample points are provided in the discharge line of each heater drain pump to monitor water quality. The sample system is discussed in Section 9.3.2.2.

During unit operation, noncondensable gases are removed from each feedwater heater through an orificed vent to the condenser. The third-point feedwater heaters are protected against shell overpressurization with SRVs that discharge to the main condenser.

During normal operation, cold reheat extraction steam lines supply steam to the building heating intermediate heat exchangers, while eighth-stage extraction steam is supplied to the clean steam reboilers.

10.4.10.3 Safety Evaluation

The extraction steam and feedwater heater drain system is not safety related and is not required for the safe shutdown of the reactor. The protection of the turbine generator against excessive overspeed from the effects of stored energy returning to the turbine after a tripout or sudden load rejection through the extraction steam system is discussed in Section 10.2. The turbine is protected against water induction via the extraction lines. During operation, radioactive water and steam are present in the system. The descriptions for shielding and controlled access are provided as necessary in Sections 12.3.1 and 12.3.2.

10.4.10.4 Tests and Inspection

The heater drain pumps have been extensively shop tested to ensure reliable operation. The pumps have been given normal performance tests including determination of required NPSH.

The system components are hydrostatically tested as required by the appropriate codes or standards. The system is tested during the startup test program for leaks and proper operation (Section 14.2).

Preoperational and operational tests are conducted in accordance with approved procedures for maintenance and preventive maintenance programs.

10.4.10.5 Instrumentation Requirements

<u>Description</u>

Instruments and controls are provided for automatic and manual control of the extraction steam and feedwater heater drain system. The monitors and controls described below are located in the main control room. The control logic is shown on Figures 10.4-12 and 10.4-13.

<u>Operation</u>

The condensate level of each feedwater heater and drain receiver is controlled automatically by the normal and high-water level drain control valves.

The fourth-point heater drain pumps are controlled manually. A pump trips automatically when the pump suction pressure is low; the first-point, second-point, or fourth-point heater water level is high-high; the fourth-point heater water level is low; an electrical fault in the pump motor or the turbine master trip bus is energized. Minimum flow is maintained through each drain pump by a recirculation control valve.

The heater extraction steam block valves are controlled manually. The valves close automatically when the heater feedwater inlet or outlet valve closes, or the heater level is high-high.

Monitoring

Indicators are provided for:

1. Fourth-point heater water level.

2. Fourth-point heater drain pump recirculating valve position.

3. Fourth-point heater drain pump discharge flow and pressure.

Alarms are provided for:

1. First-, second-, third-, fourth-, fifth-, and sixth-point heaters water level high and high-high.

2. Second-point heater drain receivers water level low.

3. Third-, fourth-, fifth-, and sixth-point heaters water level low.

4. Second-, third-, fourth-, fifth-, and sixth-point heater emergency drain valves open.

5. Fourth-point heater drain pumps suction pressure low.

6. Fourth-point heater drain pumps auto trip/fail to start.

7. Fourth-point heater drain pumps bearing/winding temperature high.

8. Fourth- and fifth-point heaters extraction steam supply header pressure low.

9. Fifth-/sixth-point heaters steam supply header drain level high.

10. Extraction steam system trouble.

10.4.11 Oxygen Feedwater Injection System

10.4.11.1 Design Bases

10.4.11.1.1 Safety Design Bases

The oxygen feedwater injection (OFI) system is not required to effect or support safe shutdown of the reactor or to perform in the operation of reactor safety features.

10.4.11.1.2 Power Generation Design Bases

The OFI system is designed to allow the Operator to maintain an oxygen concentration of 30 ppb to 200 ppb in the condensate and feedwater systems. However, the upper ceiling for oxygen for long-term plant operation must also consider the impact of electro-chemical potential (ECP) on corrosion, as described in the EPRI BWR Water Chemistry Guidelines. The injected oxygen reduces the release of corrosion products from the carbon steel piping of the feedwater system by oxidizing on the pipe surface and reducing rust buildup. Reduction of the potential spreading of irradiated corrosion products improves the plant's capability to comply with as low as reasonably achievable (ALARA) requirements.

Piping components are designed and fabricated in accordance with ANSI B31.1, and materials are selected in accordance with ASTM A-213, Type 316, or ASTM A-269 and ASTM B-75. The system is installed in accordance with Compressed Gas Association (CGA) Standards G-4.1, Cleaning Equipment for Oxygen Service, and G-4.4, Industrial Practices of Gaseous Oxygen Transmission and Distribution Piping Systems. Electrical enclosures are fabricated in accordance with the National Electrical Manufacturers Association (NEMA) Publication No. 250.

10.4.11.2 System Description

The OFI system consists of two parts. The first part is the oxygen supply, which consists of six oxygen cylinders, an oxygen control manifold, excess flow check valve and relief valve. The oxygen supply system supplies oxygen to the oxygen injection control skid at a maximum pressure of 150 psig. The oxygen cylinders are each 300 cu ft nominal size at 2640 psig. The oxygen pressure is reduced through the automatic duomatic manifold control section. A relief valve is included to prevent overpressurization of the system in case of a regulator failure, and an excess flow check valve is also included.

The second part is the injection portion, which is composed of isolation and bypass valves, flow controller, solenoid and check

valves, backpressure regulator, and oxygen and condensate flow indicators.

Oxygen flow is manually set with reference to oxygen analyzer readings to maintain the required concentration level. The system can be operated in either a manual or manual bypass mode. The oxygen is injected on the suction side of the condensate pumps. Oxygen flow will only occur if one or more condensate pumps are in operation. The injection portion of the system operates with gaseous oxygen at temperatures between 50°F and 115°F, and pressure between 8 psig and 12 psig, with a maximum flow rate capability of 5 standard l/min.

The backpressure regulator keeps the control system at the predetermined pressure so it will not be subject to the pressure variations of plant operation. A low-point drain line is provided for maintenance and can also be used as a calibration port.

10.4.11.3 Safety Evaluation

The OFI system is not safety related and is not required for the safe shutdown of the reactor. In the event of the system failure, the oxygen level in the feedwater flow will drop, resulting in a potential increase in corrosion products generation rate. Protection from fire hazards is provided by physical separation of electrical equipment from oxygen-containing equipment, minimizing leakage by using valves with soft-seats, the use of oil-free nitrogen or oil-free compressed air for calibration, and proper identification of all piping used to transfer oxygen. In addition, all power-operated valves are designed to fail in the closed position.

10.4.11.4 Testing and Inspection Requirements

The control system is checked electrically prior to installation in the plant to verify proper operation. The piping portion of the system is pneumatically leak tested in accordance with paragraph 137.5 of ANSI B31.1.

Under normal operation, the system is essentially maintenance free except for periodic leak checks to verify seal integrity, and regular calibration of the system's components. The OFI system can be tested under simulated operating conditions using inert gas.

10.4.11.5 Instrumentation Requirements

Instruments and controls are provided for the OFI system. The controls are located in instrument racks located in the turbine building. Indicating lights on the instrument racks provide the energized/de-energized status for the system's valves.

The system can be operated in either a manual or manual bypass mode. In the manual mode, the opening of the flow controller is controlled by an electrical signal. The magnitude of the electrical signal is manually controlled by the Operator via the positioning of the potentiometer. In the manual bypass mode, the flow controller is isolated and the injection of oxygen is controlled by the positioning of the metering valve.

During the manual mode, the Operator has digital indication for condensate flow, and both digital and mechanical indication for oxygen flow.

In the manual bypass, the Operator has digital condensate flow indication and only mechanical oxygen flow indication.

TABLE 10.4-1

MAIN CONDENSER DESIGN PARAMETERS

1.	Total duty, Btu/hr	7.83×10^9
2.	Surface area total for Condensers A, B, and C, ft^2	671,714
3.	Total circulating water flow, gpm	580,000
4.	Circulating water inlet temperature, °F	90
5.	Circulating water outlet temperature, °F	117
6.	Total condensate effluent, lb/hr	10,266,983
7.	Average condensate outlet temperature normal, °F	128
8.	Average condenser pressure for the three shells, in Hg Abs	4.41
9.	Cleanliness factor, %	76.2
10.	Circulating water velocity in tubes, ft/sec	6.16
11.	Number of passes	1
12.	Total main turbine exhaust steam flow, lb/hr	8,095,108
13.	Hotwell storage capacity normal, gal	160,200
14.	Hotwell minimum delay time, min	5
15.	Air in-leakage flow rate limit, scfm	52.5

TABLE 10.4-2

CHEMICAL ANALYSIS OF CIRCULATING WATER

Constituent	Concentration[1]
pH	8.8[2]
Calcium (Ca)	133[3]
Magnesium (Mg)	31[3]
Sodium	60[3]
Potassium	6.4[4]
Chloride (Cl)	140[5]
Iron (Fe)	0.72
Ortho-P as P	0.10[6]
Ortho-P as PO_4	0.30[6]
Sulfate (SO_4)	356[3]
Suspended solids	106
Silica as Si	10
Silica as SiO_2	21.4
Conductivity	1594[5]
Copper	1.14
Zinc	1.39

[1] All values are in ppm except pH and conductivity.
[2] The pH is based on scale inhibitor and dispersant addition for scaling control. Permissible range is governed by New York State Discharge Permit.
[3] Typical circulating water concentration.
[4] Four times the typical lake water concentration.
[5] Maximum value expected during normal CWS operation.
[6] Does not include contribution from chemical additives.