SECTION 10

STEAM AND POWER CONVERSION SYSTEM

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SECTION 10

STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The power conversion system is designed to convert thermal energy, which is contained in the steam supplied by the reactor, into mechanical energy in the turbine, and then into electrical energy in the generator.

After the steam has expanded through the turbine, it is exhausted to the condenser. The condensate returns to the reactor as heated feedwater with unacceptable impurities removed.

The major components of the power conversion system are:

1. Turbine generator with auxiliaries
2. Main condensers
3. Turbine Bypass System
4. Primary condensate pumps
5. Steam jet air ejectors (SJAEs)
6. Secondary condensate pumps
7. Condensate demineralizers
8. Reactor feed pumps, including reactor feed pump turbines (RFPTs) and their auxiliaries
9. Feedwater heaters and drain coolers

10. Condensate storage system

11. Makeup demineralizer system

12. Interconnecting piping and valves.

Steam generated in the reactor is supplied to the high pressure turbine through the main stop and control valves. After expanding through the high pressure turbine, the steam exhausts to the moisture separators through the crossaround piping, where any entrained moisture is removed. The dried steam leaves the moisture separators and enters the low pressure turbines through the six combined intermediate valves. After expanding through the low pressure turbines, the steam exhausts to the condensers, where it is condensed by rejecting heat to the Circulating Water System (CWS), which is discussed in Section 10.4.5. The condensate collects in the condenser hotwell.

The primary condensate pumps take condensate from the condenser hotwell and discharge it through the SJAE condensers, the steam packing exhauster condenser, and the condensate demineralizers to the suction side of the secondary condensate pumps. The secondary condensate pumps discharge the condensate through three feedwater heater strings (A, B, and C) that consist of five feedwater heaters in each string to the reactor feedpumps. The reactor feedpumps discharge to the reactor through feedwater heaters 6A, B, and C in parallel. Feedwater heaters 2A, B, and C each have an external drain cooler.

Steam is extracted from five stages of the high and low pressure turbine and is used to heat the condensate as it passes through the feedwater heaters. The extraction steam condenses in each heater and cascades to the next lower pressure heater, and finally the total cascaded flow drains to the condenser.

Steam is also extracted from the crossaround piping, for the low pressure supply to the RFPTs.

The condensate collected in the moisture separator is drained to feedwater heater 5, where it mixes with the condensed extraction steam and eventually drains to the condenser. If the water level in the moisture separator becomes too high, and the normal control valve is not able to drain it, then the dump valve opens, and the water is drained directly to the condenser. If the level continues to rise, the turbine trips, and the combined intermediate valves shut, protecting the turbine from water induction.

If the water level in any feedwater heater becomes too high, and the normal control valve is not able to drain it, the dump valve opens to automatically control the level, draining the water directly to the condenser. If the water level continues to rise, then for heaters 3 through 6, the heater extraction isolation valves automatically close, and for heaters 1 and 2, the tube side isolation valves close, preventing turbine water induction.

If the reactor is producing more steam than the turbine can use, the excess flow (up to 22 percent of rated flow) is discharged directly to the condenser by the Turbine Bypass System, which is discussed in Section 10.4.4.

Except for portions of the main steam lines from the reactor pressure vessel (RPV) to the main steam stop valves (MSSVs) and the feedwater lines from the RPV to the last power assisted check valves, along with selected instruments listed in Section 7 used for the Reactor Protection System (RPS), no portions of the steam and power conversion systems are nuclear safety-related.

Because of the high radioactivity of the main steam, nuclear radiation shielding is provided to protect operating personnel from exposures to high radiation levels. The main steam lines that are routed from the drywell to the turbine building are shielded by the main steam pipeway. The condensers, feedwater heaters, moisture separators, steam seal evaporators, and any other area housing equipment and piping carrying main steam are

surrounded by heavy concrete shield walls. Concrete and steel shield walls also surround the high and low pressure turbines to protect the turbine operating floor from direct radiation shine. See Section 12.3 for further discussion.

Instrumentation is of commercial quality, designed to meet process requirements and GE turbine-generator requirements. See Section 7.7.1 for further discussion.

Design conditions for the power conversion system are summarized in Table 10.1-1 and are shown on Figure 10.1-2 "Valve Wide Open (VWO) Heat Balance".

TABLE 10.1-1

ORIGINAL DESIGN CONDITIONS OF THE POWER CONVERSION SYSTEM FOR VALVES WIDE OPEN

Steam Conditions at Main Stop Valve

Flow (lb/h)	14,847,525
Pressure (psia)	965.0
Temperature (°F)	540.3
Enthalpy (Btu/lb)	1191.5
Moisture content (%)	0.41

Feedwater Conditions

Flow (lb/h)	14,824,025
Temperature (°F)	424.5

Condenser

Air inleakage (cfm)	75
Hotwell retention capacity (min)	3

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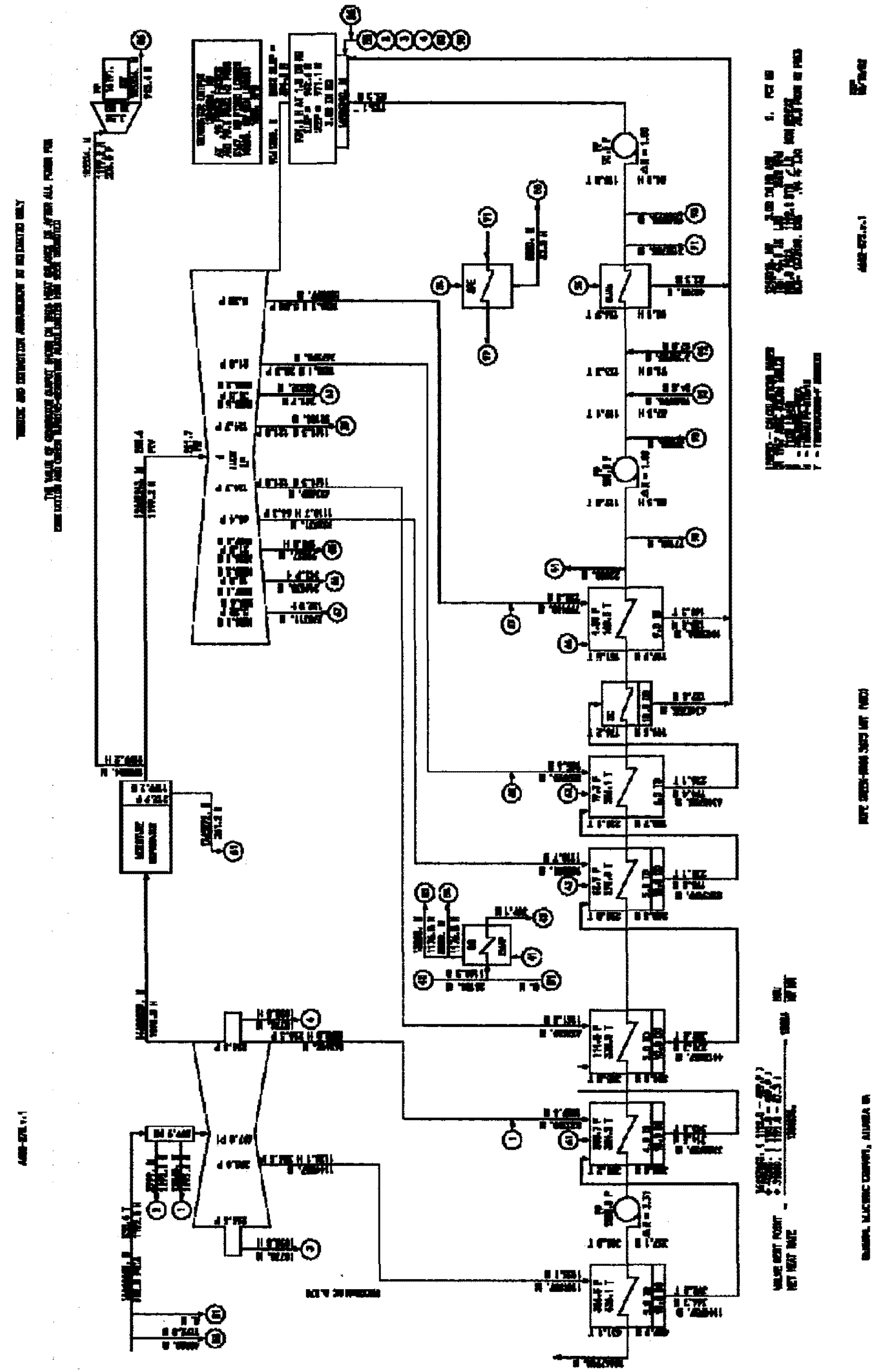
4.3 Attachment C: 10% CLTP VWO Heat Balance AA02-075 v.1



Revision 17, June 23, 2009

PSEG Nuclear, LLC HOPE CREEK NUCLEAR GENERATING STATION	Hope Creek Nuclear Generating Station VALVES WIDE OPEN (VWO) HEAT BALANCE
	Updated FSAR Figure 10.1-2

10.2 TURBINE GENERATOR

The turbine generator is designed to convert thermal energy contained in the Nuclear Steam Supply System (NSSS) supplied steam into mechanical energy in the turbine and then into electrical energy in the generator. The turbine supplies extraction steam for feedwater heating and for driving the reactor feed pump turbines (RFPTs). The turbine generator is not safety-related.

10.2.1 Design Bases

The turbine is a tandem compound, six flow, nonreheat steam turbine. It is rated at 1,248 MWe when operating with 3.0 inches of mercury absolute exhaust pressure, 0 percent makeup, with steam conditions of 950 psia and 1192 Btu/lb. It is designed to operate at VWO conditions as shown in Figure 10.1-2.

The generator has a capacity of 1,373.1 MVA at a 0.9375 power factor.

The turbine generator is supplied by General Electric (GE) and is designed to their standards and codes. The moisture separator and steam seal evaporator vessels are designed, fabricated, and tested in accordance with ASME B&PV Code, Section VIII, Division 1.

The Turbine Generator Control System is designed to maintain constant reactor pressure during normal operation and to operate the steam bypass system at up to 22.18 percent of full load to maintain constant reactor pressure during plant startup, operational transients, and shutdown.

The turbine control valves are capable of allowing turbine steam flow rate changes of at least 10 percent nuclear boiler warranted flow per second in both the opening and closing directions for adequate pressure control performance. During any event resulting in turbine control valve fast closure, turbine inlet steam flow must not be reduced faster than permitted by Figure 10.2-2.

10.2.2 System Description

10.2.2.1 Turbine

The turbine is a tandem compound arrangement, consisting of one double flow high pressure turbine and three double flow low pressure turbines. The turbine operates at 1800 rpm. The low pressure turbines have 43-inch last stage buckets.

Two horizontal nonreheat moisture separator vessels are located on the operating floor, one on each side of the turbine. The moisture separators remove moisture in the steam from the high pressure turbine exhaust before it enters the low pressure turbine.

Steam from the reactor enters the Power Conversion System through four main steam lines. Each of the four main steam lines to the high pressure turbine is connected to a main stop valve and a control valve. The four stop valves and four control valves are combined to form a single valve chest. A pressure equalizing line connects the stop valves together just below the valve seats. Six combined intermediate valves (CIVs), each composed of an intercept valve and an intermediate stop valve, are located in each line between the moisture separator vessels and the low pressure turbines. A nine valve bypass valve chest is connected to each of the main steam lines just upstream of the main stop valves to divert excess flow to the condenser.

Extraction steam is taken from the fourth and seventh stages of the high pressure turbine and from the eighth, ninth, eleventh, and thirteenth stages of each low pressure turbine to heat the feedwater as it passes through the six feedwater heaters.

Low pressure driving steam for the reactor feed pump turbines (RFPTs) is taken from the crossaround piping downstream of the moisture separators.

10.2.2.2 Generator and Exciter

The generator is synchronous, direct connected, 3 phase, 60 hertz, 25,000 volt, and is rated at 0.94 power factor and a 0.5 short circuit ratio at a maximum hydrogen pressure of 75 psig.

The generator has a water cooled stator and a hydrogen cooled rotor.

The Alterrex excitation system consists of an air cooled alternator, rated at 3268 kVA, and a series of water cooled rectifiers with a total output of 3080 kW at 530 V.

Bulk makeup hydrogen used for cooling the generator is stored in the yard, approximately 65 feet due south of the Turbine Building as shown on Plant Drawing C-0001-0. The piping from the makeup storage area to the Turbine Building is buried. To prevent a potentially hazardous air-hydrogen mixture, carbon-dioxide is used as an intermediate agent for purging air from the generator during startup and for purging hydrogen from the generator during shutdown. A seal oil system prevents hydrogen leakage along the generator shaft to the Turbine Building. The hydrogen purity inside the generator is continuously monitored. For more details of the Generator Gas Control System, see Plant Drawing M-28-1. Protective measures to prevent fires and explosions during purging and normal operations consist of hydrogen pressure control stations, excess flow shutoff valves, alarms, and pressure safety devices. Test connections are provided to analyze the air/CO_2 and H_2/CO_2 concentrations during purging. Hydrogen analyzing equipment is provided to continuously monitor hydrogen purity during normal operations. Removable spool pieces provide additional isolation, assuring that hydrogen does not leak into the generator during maintenance activities.

Automatic water deluge Fire Protection Systems (FPSs) protect the turbine and generator bearings, the area below the generator, and the Hydrogen Seal Oil System. In addition, portable fire extinguishers and fire hoses are provided.

10.2.2.3 Protective Valve Functions

The primary function of the main stop valves is to quickly shut off steam to the turbine under emergency conditions. The stop valve discs are totally unbalanced and cannot open against full pressure drop. An internal bypass valve in one of the four stop valves permits slow warming of the combined valve chest and pressurization below the stop valve seat area to allow valve opening.

The function of the control valves is to throttle steam flow to the turbine. The valves are partially balanced because they are large and operate against a high pressure differential. A small internal valve is opened first to decrease the pressure in a balance chamber. The valves are opened by individual hydraulic cylinders.

The function of the turbine bypass valves is to pass steam directly from the reactor to the condenser without going through the turbine. The bypass valve chest is connected to the main steam lines and is composed of nine valves operated by individual hydraulic cylinders. When the valves are open, steam flows from the chest, through the valve seat, out the discharge casing, and through connecting piping to the pressure breakdown assemblies, where, as discussed in Section 10.4.4, a series of orifices is used to further reduce the steam pressure before the steam enters the condenser.

Two of the functions of the CIVs are to protect the turbine against overspeed from stored steam in the crossaround piping and in moisture separators following turbine trip and to throttle and balance steam flow to the low pressure turbines. Each valve is composed of an intercept valve and an intermediate stop valve incorporated into a single casing. The two valves have separate operating mechanisms and controls. The intercept valve is a positioning valve and the intermediate stop valve is an open-closed valve. Both valves, however, are capable of fast closure. The valves are located as close to the turbine as possible to limit the amount of uncontrolled steam available as an overspeed source.

During normal plant operation, the intercept valves are open. The intercept valves are capable of opening against maximum crossaround pressure and of controlling turbine speed during blowdown following a load rejection. The intermediate stop valves also remain open for normal operation, and they trip closed by actuation of the digital EHC system or by operation of the master trip. They provide backup protection if the intercept valves or the normal control devices fail.

10.2.2.4 Extraction System Check Valves

The energy contained in the extraction and feedwater heater system can be of sufficient magnitude to cause overspeed of the turbine generator following an electrical load rejection or turbine trip. Check valves are installed where necessary to prevent high energy steam from entering the turbine under these conditions.

After a turbine trip, power assisted (spring to close) check valves (bleeder trip valves) protect the turbine from excessive overspeed by preventing flashing condensate in the extraction lines and feedwater heaters from entering the high and low pressure turbines. These check valves are provided in the extraction lines from the low pressure turbines to feedwater heaters 3 and 4, and the steam seal evaporator, and in the extraction lines from the high pressure turbine to feedwater heater 6.

The power assisted check valves to feedwater heaters 3 and 4 are also provided with motor operators that may be used to provide positive closure if required. These motor operators have no automatic functions and are not required for turbine overspeed protection. When not required, these motor operators may be disabled.

The source of extraction steam to feedwater heater 5 is the exhaust of the high pressure turbine, so check valves are not required in the extraction piping to these feedwater heaters.

The small amount of low energy steam contained in the short run of extraction piping to feedwater heaters 1 and 2, which are located in the condenser neck, does not contain enough energy to overspeed the turbine. Thus, check valves are not required in the extraction piping to these feedwater heaters. The extraction system check valves are shown on Plant Drawing M-02-1.

10.2.2.5 Control System

The Turbine Generator Control System is a GE Mark VI digital Electrohydraulic Control (DEHC) System. The Mark VI DEHC system is a triple modular redundant (TMR) design consisting of three redundant microprocessor based controllers for normal turbine control and independent TMR controllers for turbine protection. Turbine control and protection are achieved via a combination of speed control, load control, flow control and overspeed protection (see Section 10.2.2.6 for Overspeed Protection). The speed control algorithm develops servo positioning demand signals for control valves and intercept valves to control the turbine speed and rate of acceleration.

Upon generator breaker closure, the load control algorithm is used to develop a steam flow signal representing the desired turbine load, up to and including maximum turbine load. The flow control algorithms determine the main stop valve, control valve, and intercept valve flow references, which include considerations to obtain the desired linear effect on the total steam flow through the turbine. The combination of the three control types, speed, load, and flow, ensure that turbine control is highly reliable during plant startup, steady state operation, transient/trip conditions and shutdown.

The speed control algorithm modulates the turbine control valves to affect turbine speed while off-line. Its action covers the entire normal speed range, 0 to 1800 rpm, up to the speeds needed to test the protective overspeed settings. The speed control algorithm resides in the turbine controllers and ensures control of the off-line turbine speed.

The operator interfaces with the EHC system touchscreen control panel, located on control room panel 10C651 (with a backup panel located on 10C650) human machine interface (HMI) to set both the desired speed command (or target) and acceleration rate. The HMI is configured to accept either preprogrammed speed command and acceleration rate values or values that have been manually entered by the turbine operator. The HMI transfers the most recent set point entries to the controllers.

Upon generator breaker closure, the turbine speed reference is commanded to rated speed and the speed deviation integrator functionality is turned off. At this point, the turbine is on-line and the load control function begins; the turbine shaft speed is governed by the frequency of the power transmission system.

The purpose of the load control algorithm is to generate the load reference signal used to bias the turbine control valve position during synchronizing and, upon generator breaker closure, to set the turbine control valve position corresponding to the desired megawatt output. It accepts inputs from other control functions and combines these inputs to calculate the appropriate load reference signal.

Similar to speed control, the HMI becomes the point of entry to control both the turbine load set command and the desired loading rate. With the turbine on-line, the HMI operator interface is configured to accept pushbutton controlled load set raising or lowering pulses and/or manually entered load set command and loading ramp rate set points.

The flow control algorithm is used to position main stop valves, turbine control valves, intermediate stop valves, and the intercept valves via the servo valves or solenoids by regulating the motive force applied to their actuators by the high pressure hydraulic fluid supply system. The flow control algorithms determine the above valves' flow references, which includes considerations to obtain the desired linear effect on the total steam flow through the turbine. The flow and load control algorithms ensure that the turbine runs optimally during all on-line steady state and transient conditions.

The Mark VI digital EHC system will also utilize the turbine bypass valves as necessary to maintain turbine and reactor pressure control. This is achieved by tight coordination between the turbine control valve positioning and the bypass valve positioning algorithms. The pressure control will open the bypass valves to reduce reactor pressure and close the turbine control valves to increase pressure. The bypass valve control algorithm also offers a manual feature that can be used to operate the bypass valves by setting a positioning demand set point via the HMI interface.

Because of the importance of overspeed protection, the speed control signal has two independent redundant circuits. Detail of overspeed protection is discussed in Section 10.2.2.6.

10.2.2.5.1 Emergency Control Operation

A number of conditions may exist during turbine operation that cause a turbine trip. The EHC system trips the unit, shutting the turbine down, on the following signals:

1. Turbine approximately 8 percent above rated speed (primary overspeed) and at approximately 10 percent above rated speed (emergency overspeed)

2. If a Power/Load Unbalance condition exists

3. Condenser pressure reaches 7.5 inches of mercury absolute

4. Excessive thrust bearing wear (axial position) (2/3 logic)

5. Low bearing oil pressure (2/3 logic)

6. Exhaust hood temperature in excess of 225 degrees F (2/3 logic)

7. Loss of generator stator coolant without a successful load runback (2/3 logic)

8. External trip signals due to generator and unit protection lock-out relay trips. They are as follows:

    a. Generator regular and backup lock-out relay trip

    b. Unit protection regular and backup lock-out relay trip

    c. 500 kV generator breaker BS2-6 and BS6-5 flashover failure and ground protection relay trip

    d. Generator breaker BS2-6 and BS6-5 current transformer module ground protection lock-out relay trip

9. Loss of hydraulic fluid supply pressure

10. Low shaft driven oil pump discharge pressure trip (2/3 logic)

11. Loss of two out of three speed signals in either the primary speed control or emergency overspeed trip control

12. Loss of both the primary and secondary power supplies

13. Manual trip pushbutton at operator console in the main control room

14. High level in a moisture separator (2/3 logic)

15. High water level in reactor.

16. Excessive Acceleration/Deceleration

Rapid closure of the control valves or stop valve closure initiates an input signal to the Reactor Protection System (RPS) to initiate reactor shutdown.

10.2.2.6 Overspeed Protection

Although the turbine generator overspeed protection system is not safety related and consequently not subject to all of the separation and redundancies required in systems which are safety-related, it is part of a high energy system central to the overall protection of the plant. Such protection from turbine excessive overspeed is required since excessive overspeed of the turbine could generate potentially damaging missiles which could impact and damage safety related components, equipment or structures. Critical to the system is operability of the turbine overspeed protection system instrumentation and the turbine valves (i.e., main stop valves, control valves, or combined intermediate valves).

To protect the turbine generator against overspeed, when the turbine speed begins increasing, the EHC system will rapidly throttle the control valves and the intercept valves. If the speed continues to rise, the main stop valves and the intermediate stop valves will be closed by one of the following trip devices:

1. A primary electrical overspeed trip that is initiated if the turbine speed reaches approximately 8 percent above rated speed.

2. An emergency electrical overspeed trip that serves as a backup to the primary trip that is initiated at approximately 10 percent above rated speed.

The primary overspeed system is part of the normal speed control system and uses magnetic pickups to sense turbine speed, speed-detection software, and associated logic circuits. The primary overspeed protection algorithm uses the same three speed pickups as the speed control algorithm. When the turbine speed exceeds a predetermined overspeed setting, a turbine trip command is issued. The primary overspeed protection algorithm resides in the normal turbine controllers.

The emergency overspeed system consists of an independent 2-out-of-3 voting electronic overspeed protection which is independent from the normal overspeed protection system, discussed above, in the turbine protection controllers.

The emergency overspeed protection design consists of a Triple Modular Redundant (TMR) controller arrangement. Each independent controller has its own power supply, processor, and magnetic speed sensor input. When two of the controllers detect an overspeed condition, a turbine trip will be initiated. A trip will occur if the median value of three speed signals exceeds the emergency overspeed set point (approximately 110% of rated speed).

This trip acts upon the electrical trip solenoids located on the hydraulic trip manifolds to quickly close the steam valves. The emergency overspeed set point is set slightly above the primary overspeed set point to provide backup overspeed protection.

As the control system utilizes 2-out-of-3 voting logic, a single controller can be tested on-line while still providing overspeed protection. The test function generates a soft speed signal that raises the generated signal through the overspeed set point and confirms the controller has submitted a trip signal.

When an overspeed condition is detected, the trip signal is sent to the emergency trip system (ETS) dual two-out-of-three trip manifold assemblies. This system consists of two identical hydraulic trip manifolds, each with the capability to completely dump the hydraulic trip header to the hydraulic tank reservoir. The design is based on the two-out-of-three voting logic for a trip to occur; i.e., two of the three controlling solenoids and valves on a single manifold must move to the trip position in order to depressurize the hydraulic trip header and complete the turbine trip process.

The diversity of the overspeed detection system is designed to mitigate the chances that a single disruption will cause a malfunction in both the primary and the emergency electrical overspeed trip systems. This is due to the physical and functional independence of the primary overspeed detection hardware, which is associated with the normal turbine controllers, and the emergency overspeed detection hardware, which is associated with the turbine protection controllers. In the event that the speed signals from both of the overspeed detection systems are lost, the Mark VI digital EHC system is designed to trip the turbine. This conservative action ensures that the turbine will be safely shutdown and thus prevent a turbine overspeed failure.

When the primary overspeed trip is being tested, the emergency overspeed trip protects the turbine against overspeed.

An additional feature of the protective system that will minimize the likelihood of an overspeed condition is the power/load unbalance circuitry. The rate sensitive PLU algorithm is provided to initiate a turbine trip under high load rejection conditions that might lead to rapid rotor acceleration and subsequent overspeed.

The PLU function is armed at loads above 40%. The PLU turbine trip occurs when turbine power exceeds the generator load by at least 40% and generator current is decreasing (at a rate equivalent to approximately 1500%/sec or is lost in a time span of 35 milliseconds or less). The DEHC utilizes intermediate steam pressure as a measure of load to provide discrimination between loss of load incidents and occurrences of electrical system faults while the PLU function is active.

The DEHC system includes a periodic on-line test feature that tests the PLUY logic using a simulated loss of load. The test is conducted under load without affecting the turbine output.

There are four steam lines at the high pressure stage. Each line is provided with one stop valve in series with one control valve. Steam from the high pressure stage flows to the moisture separators and then to the three low pressure stages. Each of the six low pressure lines has a combined intercept valve that consists of a stop valve in series with a control valve, in one housing. All of the above valves close within 0.2 seconds on turbine trip. Assuming a single failure within the above system of 20 valves in case of a turbine overspeed trip signal, the turbine will be successfully tripped.

The diversity of devices shown on Table 10.2-1 ensures that stable operation following a turbine trip proceeds from the requirement that both the stop valves and the combined intercept valves close in a turbine trip, thereby preventing steam from the main steam line from entering the turbine and preventing the expansion of steam already in the high pressure stage and in the moisture separator. An additional provision is made to automatically isolate the major steam extraction lines from the turbine by power assisted check valves. Closure times of the check valves have been calculated at less than two seconds, and are in accordance with the turbine manufacturer's recommendations.

Any postulated accident, including the effects of high or moderate energy pipe failures, that results in a loss of hydraulic pressure or loss of the electrical signal to the dual 2/3 trip manifold solenoids will result in the closure of the main stop valves, control valves, and combined intermediate valves, thereby preventing a turbine overspeed condition.

As documented in the Hope Creek Safety Evaluation Report, the discussion provided in this section has been reviewed and found acceptable in lieu of an analytical failure mode and effect analysis of the turbine overspeed protection system. The diversity of devices shown on Table 10.2-1, along with the addition of Table 10.2-2, illustrates that a minimum of two independent lines of defense is employed for protection against overspeed and that no single failure of any device or steam valve can disable the turbine overspeed trip from functioning.

10.2.3 Turbine Rotor Integrity

The LP rotors on the Hope Creek turbine generator set are mono-block rotor forgings. Therefore the missile analysis issued previously considering an SCC failure mechanism no longer applies. In the mono-block rotor, the stress levels at the design point are conservative and the stress concentration associated with wheel keys no longer exists. If the unit trips, valves fail to operate and full flow steam remains, the maximum possible speed the rotors can attain is about 220% running speed, assuming that all steam path components on the rotor remain in place. This is the point at which the driving forces are countered by drag forces and can no longer accelerate the rotors. The rotor overspeed capability, with the assumption all buckets remain in place, is 225% for typical rotor strengths. Therefore, rotor missiles will not be generated. A complete failure of the control and safety systems is required for this to occur and is very unlikely. The probability of a control failure of this nature is approximately 1×10^{-8} per year. In conclusion, given the low stress levels of mono-block rotors and the elimination of the wheel SCC mechanism, the probability of generating rotor missiles is not present.

10.2.3.1 <u>Inservice Inspection</u>

The following turbine system maintenance program 1.S based upon the manufacturer's recommendations and calculations of missile generation probabilities:

1. The in-service inspection program for the low pressure turbine assembly includes disassembly of the turbine in stages over a ten year interval during plant shutdowns such that the turbine is inspected within ten years. This includes complete inspection of all normally inaccessible parts, such as couplings, coupling bolts, turbine shafts, and low pressure turbine buckets. This inspection consists of visual, surface, and volumetric examinations, as indicated below:

a. Visual examination of all accessible surfaces of rotors.

b. Visual and surface examination of all low pressure buckets.

c. 100 percent surface examination of couplings and coupling bolts.

2. The main stop valves, control valves, and combined intermediate valves are inspected and nondestructively tested at a frequency based upon their operation, operational tests, industry experience, and good industry practices. Critical areas such as the valve stem, seats, valves, bushings, and casings receive an ultrasonic test, liquid penetrant test, or magnetic particle test, and a thorough visual inspection. At least one valve of each type will be dismantled for inspection at approximately 3-1/3-year intervals. If unacceptable flaws or excessive corrosion are found in a valve, all valves of its type are inspected. Valve bushings are inspected and cleaned and bore diameters are checked for proper clearance.

3. Main stop valves are exercised at least once every three months by closing each valve and observing by the valve position indicator that it moves smoothly to a fully closed position. High pressure turbine control valves are exercised at least once a quarter through at least one complete cycle from the running position. High pressure turbine combined intermediate valves are exercised at least once every three months through at least one complete cycle from the running position. Proper valve motion is verified by observing the valve position indicator.

10.2.4 Safety Evaluation

The turbine generator has no safety related function. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

Results of the radiological evaluation of the turbine-generator and the related steam systems are described in Section 12.

10.2.5 References

10.2-1 J.A. Begley, W.A. Logsdon, "Westinghouse Scientific Paper," 71-1E7-MSLRF-P1, July 2, 1971.

10.2-2 R.C. Spencer, D.P. Timo, "Starting and Loading of Turbines," General Electric Company, 36th Annual Meeting of American Power Conference, Chicago, Illinois, April-May 1974.

10.2-3 GE letter dated October 4, 1995, S. P. Campbell to R. Masten.

TABLE 10.2-1

TURBINE OVERSPEED PROTECTION

DEVICE	DESCRIPTION/FUNCTION	TRIP SETTING	ACTUATING DEVICE INTERMEDIATE	ACTUATING DEVICE FINAL	ACTUATED VALVE	ACTUATED POSITION
Primary Overspeed Trip	Toothed Wheel Electronic Probe Speed Sensor Close Emergency trip sys. Vlv. & remove electro-hyd control oil press	108 percent of rate speed	Digital EHC Turbine Controller	Emergency Trip System VLVs	All SV's All CV's All CIV's	Close
Emergency Overspeed Trip	Toothed wheel Electronic Speed Sensor Close Emergency trip sys. Vlv. & remove electro-hyd control oil press	110 percent of rated speed	Digital EHC Protection Controller	Emergency Trip System VLVs	All SV's All CV's All CIV's	Close
Power/Load Unbalance	Gen current & steam pressure transducers, Digital EHC Turbine Controller Algorithms Turbine Trip Energize CV fast closing Solenoids & remove electro-hydraulic control oil press. from the CV's.	40 percent unbal.			All CV's All SV's All CIV's (see Description)	Fast Close (see Description)

NOTE: SV = Stop Valve
CV = Control Valve
IV = Intercept Valve
CIV = Combined Intercept Valve

TABLE 10.2-2

TURBINE OVERSPEED PROTECTION

For protection against overspeed, a minimum of two independent lines of defense are employed. The following redundancies are used:

1. Main stop valves - backup: Control valves

2. Intercept valves - combine both stop and control function

3. Speed control unit with three redundant circuits

4. Emergency Trip System - dual two-out-of-three trip manifold assembly

5. Primary Overspeed trip - backup: Emergency Overspeed trip

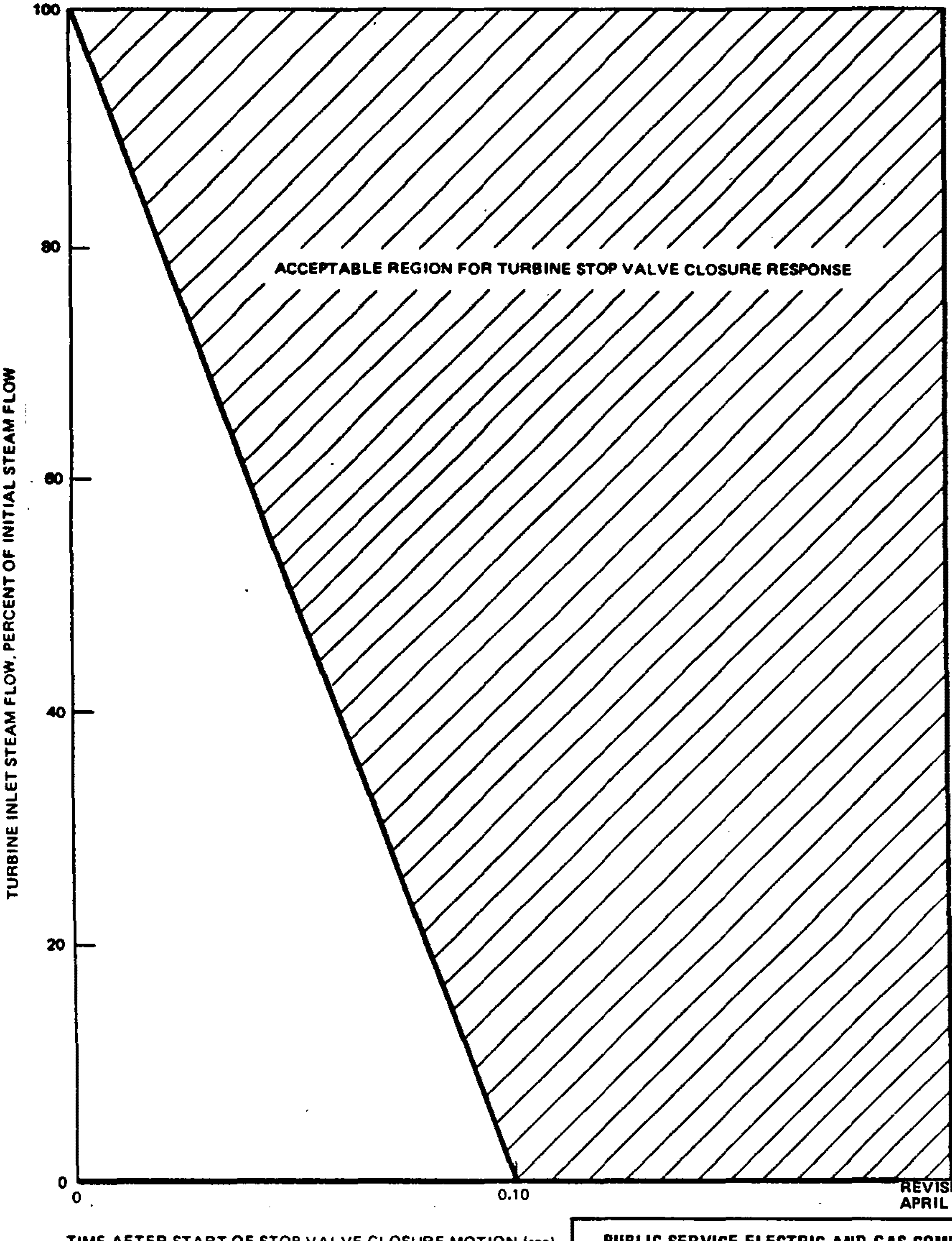
6. Fast acting solenoid valves - backup: Hydraulic fluid trip system

In addition, these features are used:

"FAIL SAFE" mode of operation of all valves. If hydraulic pressure is lost, all turbine valves will close.

Power/load unbalance to reduce overspeed on loss of high loads.

Power assisted extraction check valves.



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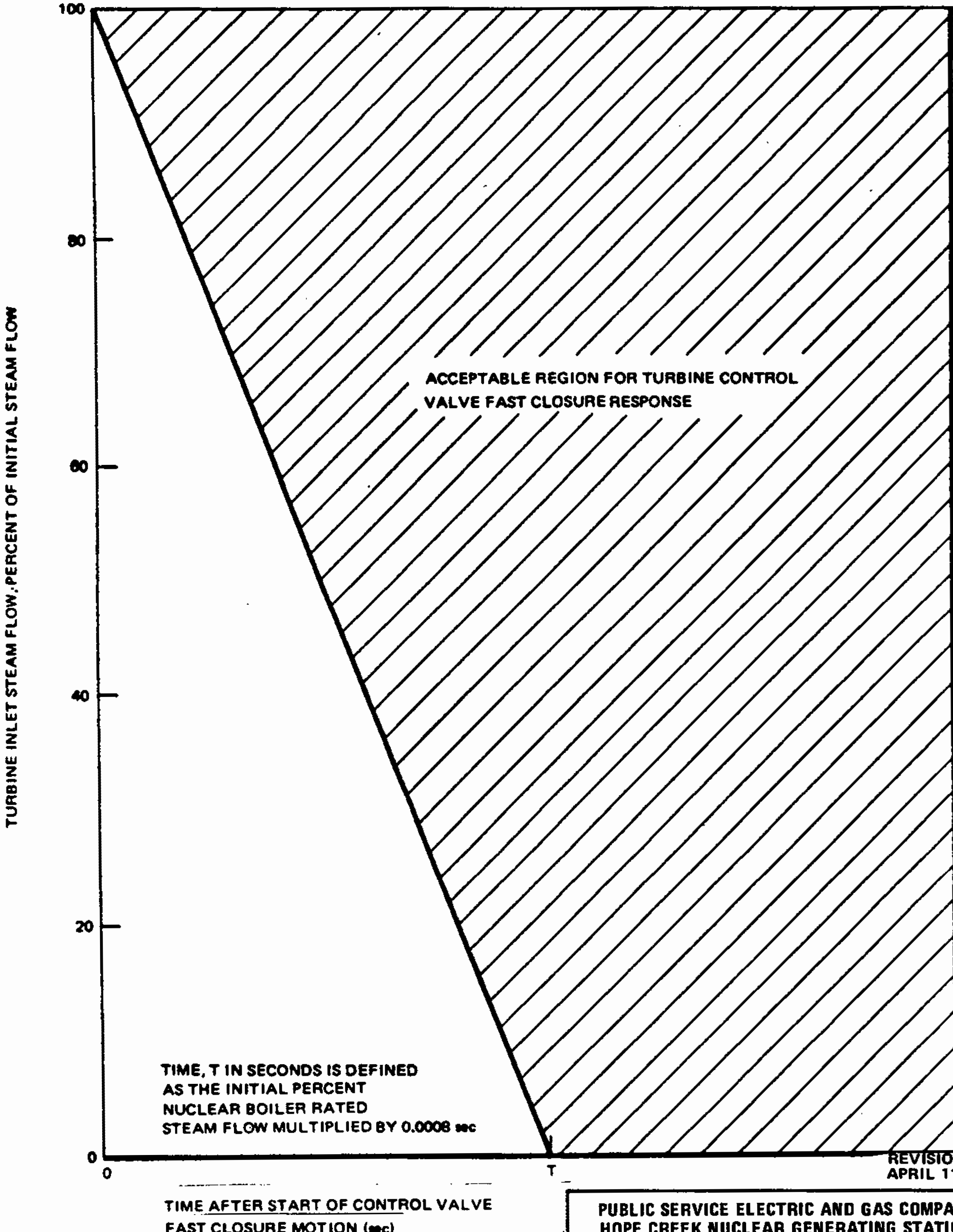
TURBINE STOP VALVE
CLOSURE CHARACTERISTIC

UPDATED FSAR

FIGURE 10.2-1



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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
HOPE CREEK NUCLEAR GENERATING STATION

TURBINE CONTROL VALVE
FAST CLOSURE CHARACTERISTIC

UPDATED FSAR

FIGURE 10.2-2

Figure F10.2-3 intentionally deleted.

Refer to Plant Drawing M-28-1 in DCRMS

Figure F10.2-4 intentionally deleted.

Refer to Plant Drawing M-02-1 in DCRMS

THIS FIGURE HAS BEEN DELETED

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HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F10.2-5

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HOPE CREEK UFSAR - REV 14 SHEET 1 OF 1

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HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
July 26, 2005	F10.2-8

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HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14 SHEET 1 OF 1

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HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14	SHEET 1 OF 1
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HOPE CREEK GENERATING STATION

HOPE CREEK UFSAR - REV 14 SHEET 1 OF 1

July 26, 2005 F10.2-12

10.3 MAIN STEAM SUPPLY SYSTEM

The Main Steam Supply System transports steam from the Nuclear Steam Supply System (NSSS) to the Power Conversion System and to various types of auxiliary equipment.

10.3.1 Design Bases

The design bases ensure that the Main Steam Supply System will:

1. Deliver the expected steam flow from the reactor to the turbine at reactor operating temperature and pressure over the full range of operation from turbine warmup to full power operation with turbine valves wide open (VWO)

2. Provide motive steam to the steam jet air ejectors (SJAEs)

3. Provide steam to the steam seal evaporator and the reactor feed pump turbines (RFPTs)

4. Provide steam to the gaseous radwaste off-gas recombiner preheaters and the condenser hotwell steam spargers

5. Bypass reactor steam to the condenser during startup and at any time the quantity of steam produced by the reactor is more than the turbine generator requires.

6. Provide a deposition surface to limit the release of fission products after a postulated loss-of-coolant accident.

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the Main Steam Supply System are discussed in Section 3.2. Environmental design is discussed in Section 3.11. Inservice inspection is discussed in Section 6.6.

10.3.2 Description

The Main Steam Supply System is shown on Plant Drawings M-41-1 and M-01-1, and the design parameters are listed in Table 10.3-1. The system extends from the outboard main steam isolation valves (MSIVs), up to but not including the main stop valves, and includes connecting piping of 2-1/2-inch nominal diameter or larger, up to and including the first valve that is either normally closed or is capable of automatic or remote manual closure during all modes of reactor operation.

The main steam isolation valves (MSIVs), main stop valves (MSVs, turbine stop valves) and shutoff valves in connecting piping, can close against maximum steam flow. The main steam shutoff valves (main steam stop valves, MSSVs) are not designed to, and cannot close against maximum steam flow. The MSSVs perform no active safety function and are located within the reactor building which is a Seismic Category I structure. The main stop valves (MSVs) located downstream of the MSSVs are in the turbine building which is not Seismic Category I.

The Main Steam Supply System consists of four main steam lines capable of supplying the original 14,847,525 lb/h of saturated steam to the turbine with the turbine VWO. The section of pipe between the outboard MSIVs, up to but not including the main stop valves (MSVs), performs a passive safety function. This function is to provide a deposition surface to limit the release of fission products after a postulated loss-of-coolant accident. In the accident analysis, leakage through the MSIVs flows through the main steam lines to the non-seismic piping boundary at the MSVs. A large fraction of the fission products deposit on the piping surface before being released to the turbine building as discussed in Section 15.6.5.

The portion of the main steam supply system downstream of the MSSVs consists of four 28-inch outside diameter lines up to, but

not including, the main stop valves. The use of four main steam lines permits testing of the MSSVs, main stop valves, and MSIVs during normal plant operation with only minimum load reduction. A 28-inch pressure equalizing line connects to the four main steam lines.

There is a 1-inch connection to each main steam line, just upstream of the main stop valves, which leads to a 4-inch pressure averaging manifold. The main steam line pressure controller senses the average steam line pressure from the pressure averaging manifold instead of sensing the pressure of a single main steam line. This arrangement, when coupled with the main steam pressure equalizing line, allows for testing of the main stop valves at higher power levels without scramming the reactor because of high neutron flux and/or high steam line flow.

Each main steam line is provided with a drain pot just upstream of the main stop valves. Condensate collected in the drain pot flows through a locked open valve and then into a common 2-inch header with a restricting orifice. A motor-operated valve, HV-1026, which bypasses the restricting orifice to provide maximum drainage, opens automatically on turbine trip. It is also opened during startup and closed at 15 percent of turbine rated speed by a handswitch in the main control room.

A 14-inch nominal diameter line branches from each of the four main steam lines. The 14-inch lines from main steam lines A and B then flow together into one 18-inch line, and the 14-inch lines from main steam lines C and D flow together into another 18-inch line. These two 18-inch lines connect to opposite ends of the bypass valve chest. The 8-inch main steam supply to the steam seal evaporator originates from the 14-inch line that branches from main steam line A. The 8-inch main steam supply to the reactor feed pump turbines (RFPTs) originates from the 14-inch line that branches from main steam line B. The 3-inch main steam supply to the steam jet air ejectors (SJAEs) and the 6-inch main steam supply to the condenser hotwell steam spargers originate from these 18-inch lines.

10.3.3 Evaluation

The main steam lines from the main steam stop valve (MSSV), up to but not including the main stop valve, all branch lines 2-1/2 inches in diameter or larger, up to and including the first valve that is either normally closed or is capable of automatic or remote manual closure during all modes of reactor operation, are ASME B&PV Code, Section III, Class 3, non-Seismic Category I.

The piping and piping supports on these lines are analyzed and designed to withstand the same seismic loads as those for Seismic Category I lines. ASME B&PV Code, Section III, Class 3 piping rules were used in the analysis and evaluation performed to faulted limits. Higher damping values up to 5 percent may be considered for this analysis.

The seismic analysis is performed using the response spectra superposition method. The response spectra at the point of connection of the piping to the supporting structure are generated by the time-history method.

For the criteria used in the design of the main steam lines between the outboard main steam isolation valves (MSIVs) up to and including the MSSVs, refer to Section 5.4.9.

For details of the analysis of postulated high energy line failure, refer to Section 3.6.

10.3.4 Inspection and Testing Requirements

The main steam lines between the main steam stop valves (MSSVs) and the main stop valves are fabricated, examined, and tested in accordance with ASME B&PV Code, Section III, Class 3.

The system is preoperationally tested in accordance with the requirements of Section 14 and periodically tested in accordance with the requirements of Section 16.

The inspection and testing requirements of the portion of the main steam piping between the MSSVs and the main steam isolation valves (MSIVs) are addressed in Section 5.4.

10.3.5 Water Chemistry (PWR)

This section is not applicable to Hope Creek Generating Station (HCGS).

10.3.6 Steam and Feedwater System Materials

With the exception of the section of pipe between the outboard main steam isolation valve (MSIV), up to and including the main steam stop valve (MSSV), the materials used in the fabrication of the steam and feedwater systems are discussed below. For the portion between the outboard MSIV and the MSSV, a discussion of the materials used can be found in Section 5.4.9.

10.3.6.1 Fracture Toughness

Design specifications for Class 3 piping do not require impact testing.

10.3.6.2 Material Selection and Fabrication

1. All materials used in the main steam lines are included in Appendix I to Section III of the ASME B&PV Code.

2. Austenitic stainless steel is not used in the main steam supply system; therefore, Regulatory Guide 1.31, Control of Stainless Steel Welding, Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel, and Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel, are not applicable.

3. The cleaning procedures for the main steam supply system are based on ANSI N45.2.2, Class C criteria. A discussion

of compliance with Regulatory Guide 1.37 is included in Section 1.8.

4. Regulatory Guide 1.50, Control of Preheat Temperature for Welding of Low Alloy Steel, is not applicable, since no low alloy steel is used in this system.

5. Regulatory Guide 1.71, Welder Qualification for Areas of Limited Accessibility, is not applicable, since no low alloy or high alloy material is installed in the main steam supply system as described in this section.

6. Preheat temperatures for the welding of carbon steel components are in accordance with Section III, Article D-1000, of the ASME B&PV Code.

7. Butt welded pipe receives 100 percent radiography. All nondestructive examination procedures conform to the ASME B&PV Code.

TABLE 10.3-1

ORIGINAL MAIN STEAM SUPPLY SYSTEM DESIGN PARAMETERS

Main Steam Supply System

Valve wide open flow rate	14,847,525 lb/h
Number of lines	4
Size, outside diameter	28 inches
Design pressure	1250 psig
Design temperature	575°F

Figure F10.3-1 intentionally deleted.

Refer to Plant Drawing M-01-1 in DCRMS

10.4 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

10.4.1 Main Condenser

The Main Condenser System is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the Turbine Bypass System. The Main Condenser System is not safety-related.

10.4.1.1 Design Bases

The Main Condenser System is designed to:

1. Condense and deaerate the exhaust steam from the main turbine and reactor feed pump turbines (RFPTs).

2. Deaerate the drains from the feedwater heaters and other components in the heat cycle.

3. Serve as a heat sink for the turbine bypass system, extraction steamline dump drains, and heat cycle relief valve and equipment discharges.

4. Assist in deaeration of the condensate during startup by admitting auxiliary steam into the hotwell.

5. Retain, for a minimum of 3 minutes, the condensate formed during full load operation, to allow radioactive decay prior to returning the condensate to the cycle.

10.4.1.2 Description

The main condenser is a single pressure deaerating type that includes three separate low pressure shells connected by an equalizing duct. Each of these shells is connected to the exhaust of one of the three low pressure turbines by a rubber expansion joint. The expansion joint is secured by bolted keeper segments

attached to two steel frames, one welded to the turbine exhaust and the other to the condenser. The general plant arrangement of equipment is shown on Plant Drawings N-1011, P-0012-1, P-0013-1 and P-0014-1. Although it is not required for operation, the expansion joint is surrounded by a water seal to preclude air leakage.

During normal operation, steam from each low pressure turbine is exhausted directly downward into its condenser shell through exhaust openings in the bottom of the turbine casings. The condenser also serves as a heat sink for several other flows, such as exhaust steam from the RFPTs cascading heater drains, the steam jet air ejector (SJAE) intercondenser drain, condensate and reactor feed pump recirculation lines, feedwater heater shell operating vents, crossaround piping relief valves, and primary condensate pump suction vents. The steam exhausted to the condenser is condensed by cooling water circulated through the condenser tubes, as discussed in Section 10.4.5.

At startup, two mechanical vacuum pumps are used to draw a vacuum on the condenser to a pressure of 5 inches of mercury, as discussed in Section 10.4.2. Once vacuum has been established, the SJAEs are put into service. During normal operation, the SJAEs draw the vacuum down to 2.5 inches of mercury.

The condensers are provided with an air removal system that removes noncondensable gases that include air inleakage as well as hydrogen and oxygen formed in the turbine steam due to the radiolytic disassociation of water in the reactor. These noncondensable gases are concentrated in the air cooling sections of each condenser shell, where they are removed by the SJAE, as discussed in Section 10.4.2, and discharged to the gaseous waste management system discussed in Section 11.3. The oxygen content of the condensate at the discharge of the primary condensate pumps ranges from 20 to 200 ppb, with an air inleakage of up to 75 scfm.

Each shell has two tube bundles, two inlet/outlet waterboxes, and two reversing end waterboxes. A butterfly valve is provided at

the inlet nozzle and the outlet nozzle of each inlet/outlet waterbox. Therefore, any tube bundle can be isolated during operation.

Design parameters for the condensers are shown in Table 10.4-1. The condenser is designed and built to the standards of the Heat Exchange Institute; ASME B&PV Code, Section VIII; and the manufacturer's standard practice.

The tube side of the condenser is designed for a pressure of 100 psig. The waterboxes are made of carbon steel and are lined to resist erosion and corrosion. Provisions are made for a cathodic protection system, which can be added if it is deemed necessary. The condenser tubes are titanium, and the tubesheets are aluminum bronze.

All high velocity or flashing steam and water mixtures such as drains, dumps, and turbine bypass blowdown connections are provided with suitable chrome moly perforated distribution pipes or impingement plates to prevent tube erosion. Spray pipes and plates are oriented to preclude cutting of structural members and condenser tubes.

Steam spargers are located in the bottom of each hotwell. During startup, auxiliary steam is injected into the hotwell to heat and deaerate the condensate.

10.4.1.3 <u>Safety Evaluation</u>

The Main Condenser System is not safety-related. Failure of the system will not compromise any safety-related system or component or prevent safe shutdown of the plant.

10.4.1.3.1 Radioactive Gases

Under normal operation, radioactive and noncondensable gases are removed by the SJAE and delivered to the gaseous radwaste

system. To prevent an excessive release of radioactivity to the environment in case of an accident, the Turbine Building Ventilation System maintains a slight vacuum in the condenser area. Radiation monitors are provided in the Turbine Building exhaust to alarm at high radiation level.

Safety-related main steam line radiation monitors are installed downstream of the outboard MSIVs in the main steam tunnel. These monitors provide a means of determining if high radiation is present in the main steam entering the turbine/condenser. In addition, radiation monitors are provided downstream of the offgas system charcoal decay tanks and HEPA filters to continuously monitor activity released from the offgas. A discussion of main steam radiation monitoring system, including detection and control is included in Section 7.3.1.1.2. A discussion of the radiation monitoring in the offgas system including its processing is included in Sections 11.3.1 and 11.3.2.

Fission and activation products that are entrained in reactor steam and are retained in the condensate leaving the condenser are detected by samples taken upstream and downstream of the condensate demineralizers. As discussed in Section 10.4.6 these products are removed by the condensate demineralizer system.

There is no free hydrogen in the main condenser during shutdown because it is isolated from potential sources of hydrogen. The Condenser Evacuation System, Turbine Building Ventilation System, and gaseous radwaste system are discussed in Sections 10.4.2, 9.4.4, and 11.3, respectively.

The anticipated inventory of radioactive contaminants during normal operation and shutdown is discussed in Sections 11.1 and 11.3. The shielding and controlled access arrangement for the main condenser is described in Section 12.3.

10.4.1.3.2 Condenser Leakage

If a condenser tube develops a leak at a tubesheet, or if a tube to tubesheet joint should fail, a drip tray under each tubesheet and a conductivity cell associated with each tray detects the leak. If leakage is detected, a local alarm annunciates, and the leak is indicated on the computer in the main control room.

Condenser tube leakage is detected by conductivity cells located in the hotwell of each condenser. High conductivity at these cells also alarms locally and indicates on the computer in the main control room.

The measuring point location indicates which of the six flow paths (3 shells, each with 2 tube bundles), contains the leaking tube(s). This tube bundle section can then be isolated and dewatered allowing the necessary tube plugging corrective measure, to be implemented.

The effect of condenser tube leakage on condensate water quality and reactor operation is discussed in Section 10.4.6. The condensate system sustains an effluent conductivity of 0.1 micromho with a maximum condenser tube leak rate of 1.5 gpm when the circulating water contains 27,000 ppm (as $CaCO_3$) of total dissolved solids.

To prevent loss of vacuum, the condenser shell and piping is of welded construction wherever practicable. The condenser is hydrostatically tested after it is installed to verify leak tightness. During plant operation, measures to prevent loss of vacuum include:

1. Maintaining adequate flow in the Circulating Water System

2. Completely filling and maintaining level in the condenser waterboxes by periodically purging the air to prevent air blanketing.

In addition the SJAE systems and the off-gas system are provided with two 100 percent capacity redundant trains to evacuate and process the noncondensable gases from the condenser.

10.4.1.3.3 Circulating Water System Rupture

Reactor Protection System (RPS) sensors are mounted on the turbine to monitor first stage pressure, main control valve fast closure, and stop valve closure and on the main condenser to measure condenser vacuum. These sensors are all located above the 102-ft elevation. This is the only safety-related equipment located in the Turbine Building. The building is designed to withstand flooding up to the 102-foot elevation.

The failure of the expansion joint in the Circulating Water System could result in essentially the entire contents of the cooling tower basin plus the circulating water piping being transferred to the Turbine Building. Station Service Water System (SSWS) is assumed to continue supplying makeup water to the cooling tower basin until the circulating water pumps lose suction due to low level in the pump pit. Free communication exists between the Unit 1 areas and the unoccupied areas that were formerly Unit 2 (See Plant Drawing P-0001-0). The equilibrium water level in this condition would be below Elevation 72-ft. This is well below the design flood elevation of 102 ft. No credit is taken for operator action or isolation valve closure, doors or barriers to flooding in the turbine building or for distance from the turbine building. There are no safety-related systems or components in the turbine building below flood level nor are there any paths by which this flood water could reach areas of the plant containing safety-related systems or components.

Instrumentation to annunciate a postulated Circulating Water System rupture includes low level in the cooling tower basin, high levels in the Turbine Building sumps, loss of condenser vacuum and turbine trip.

10.4.1.4 Tests and Inspections

The steam side of each condenser is hydrostatically tested in the field by completely filling each shell with water and inspecting all accessible welds and surfaces for leakage and/or excessive deflection. The tubesheets are also inspected for leaks at the tube to tubesheet joints.

The circulating water side of each condenser is hydrostatically tested in the field to a pressure of 150 psig, and all joints and surfaces are inspected for leaks. In addition, at the tube manufacturer's shop all tubes were subjected to a pneumatic test in accordance with ASTM B 338 at 150 psig minimum. Also, nondestructive tests were performed by the eddy current method in accordance with ASTM E 426, and ultrasonic examination in accordance with ASTM E 213.

The system is tested before operation in accordance with the requirements of Section 14.

Main Condenser Inspection shall be performed in accordance with station procedures every 18 months during a refueling or maintenance outage. The inspection shall include:

1. visual inspection of the condenser tube sheets.
2. visual inspection of condenser anodes.
3. eddy current testing of a sample of condenser tubes.
4. visual inspection of condenser shell side structures and piping.

10.4.1.5 Controls and Instrumentation

10.4.1.5.1 Condenser

To prevent the shell side of the condenser from exceeding recommended turbine pressures while it is in operation, a variable alarm notification

is provided by CRIDS to alarm between 5 and 6 inches of mercury absolute and pressure switches trip the turbine at 7.5 inches of mercury absolute. In addition, separate switches are installed that prevent the bypass valves from opening if the condenser backpressure exceeds 22.9 inches of mercury absolute. The accuracy of these switches is ±1/2 percent. Pressure switches are provided to close the main steam isolation valves (MSIVs) in the event that condenser pressure rises to approximately 21 inches of mercury absolute. Each condenser shell has four rupture diaphragms set at 5 psig.

To ensure that the level of the condensate in the hotwell remains within acceptable limits, level transmitters are installed to regulate the condensate makeup and reject control valves. When the condensate in the hotwell reaches a preset high level, valve LV-1657-2, as shown on Plant Drawing M-05-1, opens, bypassing condensate from the secondary condensate pump discharge to the condensate storage tank (CST). When the level in the hotwell reaches preset low level, valve LY-1657-1 opens and allows condensate to flow by gravity and vacuum drag into the condenser hotwell from the CST. During normal operation, both valves are closed. Whenever the condensate level reaches high-low levels, an alarm in the main control room alerts the operator. If either the makeup or reject control valve fails, the process is regulated remotely.

10.4.2 Main Condenser Evacuation System

The Main Condenser Evacuation System, shown on Plant Drawing M-07-1, establishes a vacuum in the condenser and removes noncondensable gases during normal operation. The system is not safety-related.

10.4.2.1 <u>Design Bases</u>

The Main Condenser Evacuation System is designed to perform the following functions:

1. Establish a vacuum in the condenser during startup and maintain it during normal operation.

2. Remove the noncondensable gases from the main condenser during normal operation and discharge these gases to the gaseous radwaste system.

3. Condense the motive steam for the first two ejector stages from the noncondensable gases and return the condensate to the condensate system.

The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the main condenser evacuation system are discussed in Section 3.2.

10.4.2.2 <u>System Description</u>

The Main Condenser Evacuation System consists of two 50 percent capacity vacuum pump systems and two redundant 100 percent capacity steam jet air ejector (SJAE) trains, with associated valves, piping, and controls as shown on Plant Drawing M-07-1. System design parameters are listed in Table 10.4-2.

Hydrogen is produced in the reactor due to radiolytic disassociation of water in the reactor and carried over to the condenser via main steam. Approximate rate of production of hydrogen at full power operation is 132 scfm.

Hydrogen and other noncondensible gases are concentrated in the air cooling sections at a high elevation of the condenser shell where they are removed by the SJAE.

10.4.2.2.1 Mechanical Vacuum Pumps

Two 50 percent capacity mechanical vacuum pumps are used during startup to establish a vacuum in the condenser. Both pumps are actuated after the turbine glands are sealed with auxiliary steam. Mechanical vacuum pumps may be used to maintain condenser vacuum following a plant shutdown/scram. The air drawn out of the condenser is discharged to the south plant vent.

The mechanical vacuum pumps and their suction valves are actuated remotely from the main control room. If high radiation is detected in the main steam lines (detectors are located in the main steam tunnel between the outboard main steam isolation valves and the main steam stop valves) the pumps are tripped, and the suction valves automatically close. If the seal water flow drops below acceptable limits, the vacuum and seal water pumps are tripped and a low flow pump trouble alarm actuates in the main control room. A water separator removes any water droplets from the noncondensable gases before discharging the gases to the south plant vent. A seal water pump removes water from the separator and cycles the water through the seal water cooler and back to the vacuum pump.

If the Low Pressure Turbine is being pre-warmed, or if it is desired to control the flow rate from the main condenser, the suction valves may be throttled manually to maintain proper vacuum. When the suction valves are manually throttled, closure involves manual action on a mechanical vacuum pump trip.

When working in parallel, the vacuum pumps are designed to evacuate the main condenser from atmospheric pressure to 5 inches of mercury absolute in 120 minutes.

10.4.2.2.2 Steam Jet Air Ejectors

After condenser vacuum is established by the mechanical vacuum pumps, and the air flow from the condenser has diminished to 75 scfm, one SJAE is placed in service to maintain the vacuum. The mechanical vacuum pumps are shut down. The mechanical vacuum pumps cannot be run during plant operation due to the radioactive gases that accumulate in the main condenser.

The SJAE train is a full capacity three stage unit, including three 33 percent capacity first stage ejectors, an intercondenser, one 100 percent capacity second stage ejector, an aftercondenser, and one 100 percent capacity third stage ejector. A redundant SJAE train is provided to maintain condenser vacuum if the first train is not available. The three first stage ejectors continuously remove noncondensable gases and entrained steam and discharge them to the SJAE intercondenser. The intercondenser condenses the ejector motive steam and the carryover steam. The condensate is returned to the main condenser. The second stage ejector draws the

noncondensable gases and entrained steam from the intercondenser and discharges them to the aftercondenser. The condensate from the aftercondenser is returned to the main condenser. A third stage ejector is provided to boost the discharge pressure to 11 psig maximum before discharging the noncondensable gases and third stage motive steam to the Gaseous Radwaste System.

The noncondensable gases include condenser air inleakage, disassociated hydrogen and oxygen from the reactor coolant, activation products, and noble gases along with their daughter products. The largest contributor to the main condenser's offgas activity is N^{16}. For an inventory of radioactive contaminants in the effluent from the SJAE, the associated doses, and a description of the Gaseous Radwaste System, see Section 11.3.

The steam and gas mixture is discharged at 11 psig maximum from the third stage SJAE. The percentage of hydrogen by volume is less than 4 percent; therefore, the possibility of an inline explosion is eliminated.

The SJAEs require motive steam at 125 psig to operate. Under normal operation, main steam at 950 psig is throttled through a control valve to reduce the pressure to the SJAE operating pressure. During shutdown and startup, when main steam is not available and a condenser vacuum is required, auxiliary steam is used. See Section 9.5.9 for more details.

Condensate pumped by the primary condensate pumps is used as the cooling medium in the intercondenser and aftercondenser.

10.4.2.3 Safety Evaluation

The Main Condenser Evacuation System has no safety-related function. Failure of the system does not jeopardize the function of any safety-related system or component or prevent a safe shutdown of the plant.

The radiological consequences of a failure of the SJAE are evaluated in Section 15.

10.4.2.4 Tests and Inspections

The main condenser evacuation system is tested prior to operation in accordance with the requirements of Section 14.

10.4.2.5 Controls and Instrumentation

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and protect system components.

Increases in the third stage discharge pressure that are above acceptable limits are sensed by a pressure switch and indicated in the main control room via the plant computer. In the event that the flow rate through the charcoal filters recombiner discussed in Section 11.3 approaches the maximum design conditions, a pressure transducer actuates a flow control valve to bypass the excess flow to the main condenser.

Decreases in the third stage steam flow rate that are below acceptable limits are sensed by a flow switch, alarmed in the main control room, and displayed by the plant computer. The flow rate of noncondensable gases and associated vapor to the third stage ejector is recorded in the main control room.

10.4.3 Steam Seal System

The Steam Seal System seals the turbine shafts and selected valves to prevent air from being drawn into the low pressure turbines and nuclear steam from leaking out of the high pressure turbine into the Turbine Building. The Steam Seal System has no safety-related functions.

10.4.3.1 Design Bases

The Steam Seal System is designed to provide a continuous supply of slightly radioactive sealing steam to:

1. Main turbine shaft seals

2. Stem packings of the main stop, control, bypass, and combined intermediate valves

3. Shaft seals of the reactor feed pump turbines (RFPTs)

4. Stem packings of the reactor feed pump stop and control valves.

The steam seal evaporator is designed, fabricated, and tested in accordance with the ASME B&PV Code, Section VIII, Division 1.

The seismic category and quality group classification for the steam seal system are discussed in Section 3.2.

10.4.3.2 Description

The Steam Seal System, as shown on Plant Drawing M-29-1, consists of a steam seal evaporator; a steam seal header; two 100 percent capacity steam packing exhausters (SPE) mounted on the SPE condenser; and associated piping, valves, and controls.

The steam seal evaporator is a horizontal shell and tube heat exchanger. It generates sealing steam by passing nuclear steam through the tube bundle, which is totally immersed in condensate on the shell side. The condensate is from the discharge of the secondary condensate pumps. The normal steam source is the extraction steam to feedwater heaters 4A, 4B, and 4C. During low load operation, the steam is supplied from the line connecting the bypass valve chest to the main steam lines.

The backup source of sealing steam is auxiliary steam from the auxiliary boilers. Because this backup source is nonradioactive, it is admitted directly to the steam seal header. The Auxiliary Boiler System is described in Section 9.5.9.

The condensate level in the steam seal evaporator is maintained by a level control valve. Sealing steam generated in the steam seal evaporator is admitted to the system through a pressure control valve that maintains a pressure of 4 psig in the steam seal supply header. If either the level control valve or the pressure control valve fails, it can be bypassed by a motor operated globe valve, which is normally closed. Each globe valve is capable of maintaining the respective level and pressure through remote manual throttling.

From the steam seal supply header the steam travels to various valve stems and turbine shafts. When the sealing steam enters the main turbine shaft seals, some steam flows inward toward the turbine and discharges to the main condenser. The rest of the steam flows outward to an annulus that is maintained at a slight vacuum by the SPE. This steam, and any air drawn inward along the shaft is removed through the SPE condenser.

The SPE condenser is a shell and tube heat exchanger. Sealing steam on the shell side condenses by rejecting heat to the tube side cooling medium, which is condensate from the discharge of the primary condensate pump. The resultant condensed steam flows from the bottom of the SPE condenser to the main condensers. The remaining air and noncondensable gases are discharged through the Turbine Building Ventilation System.

The Turbine Building ventilation is monitored for radioactivity. For further information on the radiation monitoring system, see Section 11.5.

The first stem leakoff from the bypass valves and the control valves goes to the crossaround piping upstream of the moisture separators. The second stem leakoff from the bypass valves and the control valves combines with the sealing steam and goes to the main condensers. Stem leakoffs from the main stop valves and the combined intermediate valves mix with the sealing steam and go to the main condensers.

All relief valves in the Sealing Steam System discharge to the main condensers.

With this arrangement, all nuclear steam is completely contained within the turbine loop.

10.4.3.3 Safety Evaluation

The steam seal system does not have any safety-related function. Its failure does not compromise any safety-related system or component or prevent safe shutdown of the plant. Clean steam from the auxiliary boiler is available for sealing in the event of a steam seal system failure, such as an SPE or steam seal evaporator tube break.

The SPE condenser has two 100 percent capacity exhauster fans. Failure of one fan does not prevent normal operation of the steam seal system.

The steam seal header and the steam seal evaporator on the shell side and the tube side are protected from overpressure by relief valves that discharge to the main condensers.

10.4.3.4 Tests and Inspections

The steam seal evaporator is tested in accordance with ASME B&PV Code, Section VIII, Division 1.

The system is preoperationally tested in accordance with the requirements of Section 14.

10.4.3.5 Controls and Instrumentation

Condensate level in the shell side of the steam seal evaporator is monitored by level switches and is alarmed in the main control room on high-high level. Steam pressure in the sealing steam supply header is monitored by pressure switches and is alarmed in the main control room if it falls below 1.5 psig. Pressure at the sealing steam inlet to the SPE is also sensed and alarmed in the main control room upon high pressure.

During low load operation, startup, and shutdown, heating steam for the steam seal evaporator is taken directly from the main steam lines ahead of the main stop valves. A pressure switch on the steam seal evaporator controls two throttling valves, PV-1992A and PV-1992B that reduce the main steam pressure.

When the pressure in the extraction line to feedwater heater 4 is 5 psi or more above the tube side pressure in the steam seal evaporator, air is applied to the cylinders of the bleeder trip valves, XV-2012A and XV-2012B, opening them and admitting extraction steam to the steam seal evaporator. When the extraction steam maintains the pressure in the steam seal evaporator, the valves in the main steam supply lines close.

Pressure in the steam supply header is monitored, and whenever the pressure drops below 4 psig, a low pressure switch opens a throttling valve that admits clean auxiliary steam directly to the steam seal header from the auxiliary boilers.

10.4.4 Turbine Bypass System

The Turbine Bypass System dissipates the energy of the main steam produced by the reactor that cannot be used by the turbine.

10.4.4.1 Design Bases

The Turbine Bypass System has no safety-related functions.

The Turbine Bypass System is designed to discharge main steam directly to the condenser to control the pressure in the reactor pressure vessel (RPV) during the following modes of operation:

1. RPV heatup to rated pressure

2. Bringing the turbine up to speed and synchronizing it

3. Power operation when the quantity of steam generated by the reactor exceeds that required by the turbine. (Refer to Section 10.4.4.2 for the Turbine Bypass System capacity.)

4. RPV cooldown.

The piping that connects the main steam lines to the inlet of the bypass valve chest is described in Section 10.3. The piping connecting the discharge of the bypass valves to the condenser is designed to ANSI B31.1 requirements.

10.4.4.2 System Description

The Turbine Bypass System is shown on Plant Drawing M-01-1 and consists of the:

1. Bypass valve chest assembly

2. Piping downstream of the bypass valves to the condensers

3. Pressure reducer assemblies

The bypass valve chest consists of nine separate bypass control valves mounted in individual compartments of a common valve chest. The valves are globe type, with the stems arranged so that they extend to the outside of the chest through the discharge chamber of the respective valve. This stem arrangement minimizes leakage when the valves are closed, since it is necessary to seal the stem only against condenser vacuum.

Each bypass valve has a discharge line routed directly to the condenser. To reduce the pressure at which the bypassed steam enters the respective condenser, a pressure reducer assembly is installed in each bypass valve discharge line.

The valves open sequentially. When used during normal startup and shutdown, only the number 1 and number 2 bypass valves are used. However, in the event of a full load rejection, such as would occur if the generator circuit breakers were opened, it is necessary that all nine valves open to bypass 25 percent of the original turbine valves wide open (VWO) flow, which is the maximum design flow of the bypass valves. Each individual bypass valve has a capacity to pass 2.78 percent of the VWO flow.

10.4.4.3 Safety Evaluation

The Turbine Bypass System has no safety-related function. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

Failure of the bypass valves to open for any reason, such as a mechanical malfunction or insufficient vacuum in the condenser, causes the pressure in the reactor to increase, ultimately shutting down the reactor and lifting the main steam safety/relief valves (SRVs) that discharge the excess steam to the suppression pool.

There are no safety-related components in the vicinity of the bypass system piping. A high energy line failure in the turbine bypass system could cause a turbine trip due either to high condenser pressure caused by increased air inleakage at the condenser or to a possible break in the turbine's Electrohydraulic Control (EHC) System piping caused by steam impingement. Loss of EHC causes a turbine trip but does not cause overspeed.

The bypass valves fail closed upon loss of hydraulic fluid system pressure. In this case a turbine trip will result. Hydraulic fluid in accumulators at the bypass valves will hold them open for approximately one minute following the turbine trip. During this time reactor steam will be bypassed to the condenser.

In-service testing of the turbine bypass valves is performed in accordance with Technical Specification Surveillance requirements. Turbine bypass valves will be tested monthly and every 18 months a system functional test which includes a simulated automatic actuation and verification that each automatic valve actuates to its correct position.

Maintenance procedure MD-CM.AC-007(Z), Turbine Bypass Valve Overhaul and Inspection requires visual inspection of the turbine bypass valve internals. This inspection includes the valve seat, disk and stem. One turbine bypass valve will be inspected every 40 months.

The failure mode of the bypass valves is closure of the valves. The effects of this malfunction on the operation of the reactor are summarized in Table 15.0-1 and discussed in Sections 15.2.2 and 15.2.3.

The effects of a malfunction of the turbine bypass valve due to a faulty control signal to the fully open position are also bounded by Section 15 analyses. The following consequences would occur due to this malfunction:

1. The bypass valves would move to full open position causing reactor pressure to decrease; the consequent increase in coolant voids would cause the vessel water level to increase.

2. The pressure regulation system, sensing the pressure reduction, would cause movement of the turbine control valves to reduce turbine steam flow so as to maintain the pressure.

3. Then, there are two possible scenarios:

   a. If the water level swell were large enough to cause a high water level (L8) turbine trip, then the remainder of the event would be similar to - and the consequences would not be worse than - the transient caused by "Pressure Regulatory Failure - Open," as described in Section 15.1.3.

   b. If the pressure regulation system can gain control soon enough to prevent the L8 turbine trip, then the turbine control valves would settle to a position corresponding to about 78% NBR steam flow through turbine control valves and 22% NBR steam flow through turbine bypass valves, with no appreciable effect on the reactor. If the turbine bypass misoperation cannot be readily corrected, the reactor operator would take appropriate action, which could include reactor shutdown.

10.4.4.3.1 High Energy Line Failure in the Turbine Bypass System

Damage to nearby safety-related equipment or systems or to the turbine overspeed equipment from a high energy or moderate energy piping failure (including failure of the connection from the low pressure turbine to the condenser, or a failure of the turbine

bypass line) would not affect the capability to achieve safe shutdown, to trip the reactor, or to initiate a turbine trip.

Safety-related equipment located in the turbine enclosure includes:

1. PT-C71-N052 A, B, C and D
2. PT-B21-NO75 A, B, C and D
3. PT-B21-NO76 A, B, C and D
4. ZS-C71-N006 A, B, C and D
5. PS-C71-N005 A, B, C and D

The function of ZS-C71-N006 and PS-C71-N005 are described in Section 7.2.1.1.4 and 7.2.1.1.5 respectively. PT-C71-N052 monitors first stage pressure on the high pressure turbine. When the turbine first stage pressure is less than a certain percentage of the pressure at rated load the reactor trip signal, which would result from a turbine stop or a control valve closure, is bypassed.

PT-B21-N075 initiates MSIV closure on loss of main condenser vacuum, while PT-B21-N076 initiates MSIV closure because other instruments are available to perform these function. For example, a pipe break involving the main steam lines outside containment would cause automatic closure of the MSIVs due to any of the following signals:

1. low pressure in the main steam lines
2. high flow in the main steam lines, and
3. high temperature in the vicinity of the main steam lines.

MSIV closure would in turn generate a reactor trip signal. Section 10.2.2.6 has been changed to state that the effects of high or moderate energy piping failure on the turbine overspeed control system would not prevent closure of the main stop valves, control valves or the combined intermediate valves and that failure of the normal turbine speed control system will not prevent the turbine overspeed control system from shutting down the turbine.

10.4.4.4 Tests and Inspections

The piping downstream of the bypass valve chest, i.e., between the bypass valves and the condenser nozzles, is inspected and tested according to ANSI B31.1.

For testing and inspection requirements of the piping upstream of the bypass valve chest, see Section 10.3.

The system is preoperationally tested in accordance with the requirements of Section 14.

During normal plant operation, each bypass valve can be tested from the controls on the EHC panel in the main control room to ensure that it is functioning correctly.

Inservice testing of the turbine bypass valves is performed in accordance with Technical Specification surveillance requirements. Turbine bypass valves will be tested monthly, and every 18 months a system functional test will be performed which includes a simulated automatic actuation and verification that each automatic valve actuates to its correct position.

Maintenance procedure MD-CM.AC-007(Z), Turbine Bypass Valve Overhaul and Inspection, requires visual inspection of the turbine bypass valve internals. This inspection includes the valve seat, disk, and stem. One turbine bypass valve will be inspected every 40 months.

10.4.4.5 Controls and Instrumentation

The bypass valves and the associated control circuitry are designed so that the bypass valves' steam flow is shut off if the control system loses its electric power or hydraulic system pressure. For testing the bypass valves during operation, the stroke time of the individual valves is increased during testing to limit the rate of bypass flow increase and decrease to approximately 1 percent per second of reactor rated flow.

Upon turbine trip or generator load rejection, the start of the bypass valve steam flow is not delayed more than 0.10 second after the start of the main stop valve or control valve fast closure motion. A minimum of 80 percent of the rated bypass capacity is established within 0.3 second after the start of the main stop valve or control valve closure motion. Bypass valve position is indicated in the main control room. For more details on pressure regulators and turbine generator controls, refer to Section 7.7.1.

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10.4.5 Circulating Water System

10.4.5.1 Design Bases

The Circulating Water System (CWS) is designed to remove the bulk of the plant heat load using a hyperbolic natural draft cooling tower. Some heat may be rejected to the Delaware estuary from the cold water side of the cooling tower in the form of blowdown.

10.4.5.2 System Description

The CWS consists of one counterflow hyperbolic natural draft cooling tower with a blowdown and fill bypass system; four single stage, vertical, wet pit, circulating water pumps; a three shell, two pass, surface condenser with water box vents and drains; and a closed loop circulating water piping arrangement. Additional components include various isolation valves, condenser dewatering pumps, and associated instrumentation.

The system is shown schematically on Plant Drawing M-09-1. The design parameters for the circulating water pumps and the cooling tower are given in Tables 10.4-3 and 10.4-4, respectively. Plant general arrangement is shown on Plant Drawings C-0001-0, P-0016-1, P-0031-0, P-0032-0 and P-0033-0.

Circulating water from the cooling tower basin is pumped by each circulating water pump through an 84-inch discharge pipe and shutoff valve to a 144-inch diameter header. This underground header branches into six 78-inch lines that penetrate the Turbine Building. Each of the six lines connects to an individual condenser waterbox. The condenser has a single pressure, two pass, deaerating, three shell design. The circulating water then flows through the condenser into six 72-inch discharge lines. These combine outside the Turbine Building into a 144-inch header that leads to the cooling tower.

Motor operated butterfly valves are provided in each of the condenser inlet and outlet lines. These permit each of the six flow paths on the circulating water side of the condenser to be isolated. Rubber expansion joints are provided at each circulating water inlet and outlet connection to the condenser.

The vertical, wet pit circulating water pumps are driven by electric motors. They are located in the circulating water pump structure near the cooling tower. Motor operated butterfly valves are provided in the discharge line from each pump to avoid undesirable hydraulic transients. Rubber expansion joints are also provided at the outlet connections of the pumps.

The circulating water is periodically chlorinated to prevent formation of biological growth. To comply with the NJPDES permit limitations of no chlorine discharge for more than two hours per day, a dechlorination system has been installed in the cooling tower blowdown. Caustic is added to the system to control pH and keep the water from becoming aggressive toward the cooling tower, yet maintain scale forming compounds below their solubility limits to minimize scaling of the condenser tubes.

The Station Service Water System (SSWS) provides makeup water to the circulating water system to replace the water lost due to evaporation, to drift from the cooling tower, and to blowdown from the system. The blowdown limits buildup of dissolved solids in the circulating water. The SSWS is discussed further in Section 9.2.1.

Single stationary screens, which are removable for cleaning, are located in the circulating water pump bay to prevent debris from entering the pumps, piping, and condensers.

10.4.5.3 Safety Evaluation

The CWS is used during the normal shutdown of the plant.

Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant. The CWS has no safety-related function and is not required to be operable following a LOCA.

A postulated complete rupture of one of the expansion joints in the system does not adversely affect any safety-related system. Nonsafety-related Turbine Building equipment in the flooded area is mounted on 3-foot high pedestals.

The opening and closing rates of the circulating water pump discharge valves have been arranged to minimize system transients when a pump is started, stopped, or tripped.

10.4.5.4 Tests and Inspection

The condenser is tested as described in Section 10.4.1. The pumps, butterfly valves, and expansion joints are all tested by their respective manufacturers before shipment. The performance of the pumps is tested after installation. Circulating water piping sections are shop tested by their manufacturers in accordance with American Water Works Association (AWWA) standards.

The system is preoperationally tested in accordance with the requirements of Section 14.

10.4.5.5 Controls and Instrumentation

Pressure relief valves, local and remote indicators, and alarms are provided to monitor the system performance and protect system components. Level elements are located upstream and downstream of the screens in the pump bay. These initiate high and low level alarms. A differential level switch alarms upon high level differential across the screens, indicating that they require cleaning. These alarms are displayed in the main control room.

The cooling tower is provided with a Gravity Blowdown System to the estuary. Basin water level is controlled by the use of a weir. The cooling tower has a deicing control system to prevent freezing in the cooling tower fill. The tower also has the capability to bypass 60 percent of the design flow directly into its basin.

Pump motor bearing and stator temperatures, pump and motor vibrations, and lube water supply are monitored. Any irregularity is alarmed in the main control room by means of a common system trouble alarm.

Temperature elements are installed at the inlet and outlet of each condenser pass to monitor the circulating water temperature.

10.4.6 Condensate Cleanup System

10.4.6.1 Design Bases

The Condensate Demineralizer System has no safety-related functions and is designed to maintain the condensate at the required purity by removal of the following contaminants:

1. Corrosion products that occur in the main steam and turbine extraction piping, feedwater heater shells, drains, condenser, and condensate piping.

2. Suspended and dissolved solids that can be introduced by small condenser leaks.

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

4. Solids carried into the condenser by makeup water and miscellaneous drains.

The system design is based on the influent concentrations given in Table 10.4-5.

At 5000 gpm per service vessel, and with the influent quality listed in Table 10.4-5, ion exchangers' effluent does not exceed the following concentrations during operation:

Iron, total (Fe)	5 ppb
Chloride (Cl)*	20 ppb
Silica (SiO_2)*	500 ppb
pH at 25°C	6.5 to 7.5
Conductivity at 25°C	0.1 micromho/cm
Total metallic impurities (Total metallic impurities retained on a 0.45-micron filter)	10 ppb

*Chloride and silica measured in the reactor water after concentration.

The bases for these limits are the prevention of crud buildup on fuel heat transfer surfaces, the need to minimize the transport of active corrosion products outside the core, and the protection of the reactor coolant pressure boundary.

Piping is furnished in accordance with ANSI B31.1. Demineralizer vessels that fall within the jurisdiction of ASME B&PV Code, Section VIII, are furnished in accordance with that Code. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the condensate demineralizer system are discussed in Section 3.2. Protection against dynamic effects associated with the postulated rupture of piping is discussed in Section 3.6.

Water quality and resin regeneration requirements comply with Regulatory Guide 1.56.

10.4.6.2 System Description

The Condensate Demineralizer System shown on Plant Drawing M-16-1 purifies condensate continuously at a nominal temperature of 124°F and a nominal pressure range of 160 - 175 psig at the design flow rate of 35,000 gpm. Each demineralizer vessel has a design flow capacity of 5000 gpm and is capable of operating at flow rates up to 6000 gpm for short periods.

10.4.6.2.1 Condensate Demineralizer System

The Condensate Demineralizer System consists of a bank of seven ion exchangers, each containing a bed of mixed resin and optionally, an underlay of anion resin. The cation to anion stoichiometric ratio is maintained between 0.6 and 1.0. A stoichiometric value between 0.6 and 1.0 allows the option of maintaining a large anion underlay, which has resulted in a significant decrease in reactor coolant sulfate levels. Seven exchangers are normally in service during power operation, but six can process 100% of the condensate flow allowing one to be isolated for maintenance. The condensate demineralizers are part of the feedwater cycle and receive condensate under pressure from the primary condensate pumps via the condensate pre-filter system.

Iron is removed from the condensate through the condensate pre-filter system discussed in section 10.4.6.6 before proceeding to the condensate demineralizer system. Upon completion of reactor refueling, the water from the reactor well is returned to the condensate storage tank (CST) via condensate demineralizer vessel AF106 or BF106.

The condensate demineralizer system is sized to keep the level of impurities in the primary coolant low and not to exceed the preset values indicated in Sections 10.4.6.1 and 10.4.1.2. The system is provided with proper instrumentation to monitor the level of impurities and the oxygen concentration. Provisions have been made to allow future addition of a deaerator to control the oxygen level during shutdown and startup. See also Section 6.1.1 for a discussion of other measures taken to prevent IGSCC.

The Condensate Demineralizer System has been designed for differential pressure or conductivity endpoint as an indication of when to regenerate, clean, or replace a demineralizer resin bed. Hope Creek uses a calculation method to determine when to replace a bed.

The Condensate Demineralizer System produces high purity water with impurities well below the detection levels of conventional chemical analysis methods. Therefore, the performance of this system is best analyzed by measuring conductivity. The conductivity of the purified condensate is monitored and continuously recorded at the discharge of each individual demineralizer vessel. In addition, the common discharge header is monitored and continuous recordings are made of O_2 concentration and conductivity. Corrosion product samplers are provided to ensure that appropriate condensate quality limits are maintained as discussed in Section 10.4.6.1. The control room alarm set points for conductivity at the inlet and outlet of the condensate demineralizers are 0.2 µmho/cm and 0.1 µmho/cm, respectively. Demineralizer vessels with effluents exceeding 0.15 µmho/cm will be isolated to allow the appropriate actions to be taken prior to reaching the effluent conductivity limits of 0.5 µmho/cm (individual vessel) or 0.2 µmho/cm (common discharge) established by Regulatory Guide 1.56, Revision 1. Conductivity cells will be standardized using a standard potassium solution. Accuracy of the conductivity meters will be checked periodically by calibrating in accordance with approved plant procedure and the manufacturer's recommendations.

HCGS recommends monitoring condensate demineralizer exhaustion by means of conductivity measurements. Although unlikely since the addition of the condensate pre-filter system, resin would be cleaned, regenerated, or replaced due to a buildup of suspended solids, indicated by a high differential pressure, and a conductivity increase beyond a specified limit.

The major concern with ionic exhaustion of the deep bed demineralizer is the intrusion of sodium chloride (NaCl) present due to condenser leakage. The conductivity readings of the influent will be converted to ppm of NaCl by a chart constructed for the operator. Flow through each demineralizer vessel is integrated and totalized on a volumetric counter for each unit.

The initial total capacity of new demineralizer resins will be checked in accordance with the guidelines set forth in Regulatory Guide 1.56. The operating capacity will be determined by multiplying the initial total capacity of the new resins by an appropriate industry established factor (estimated to be 0.6 - 0.7). By knowing the total expected capacity of the resin the operator can determine if any vessel is approaching the exhaustion level by determining the NaCl equivalent load based on influent conductivity and the appropriate vessel flow rate.

Very small condenser tube leaks ($\leq$0.1 gpm) only require that the condensate demineralizers be regenerated or replaced with reasonable frequency in an orderly fashion. Leaks above 0.1 gpm must be considered more carefully. Based on a cation anion stoichiometric ratio of between 0.6:1 and 1:1 and assuming the resin is already loaded to 40%, sufficient capacity still remains to maintain the hour's action of a large leak (50 gpm).

These conditions are alarmed on the remote control panel. Each vessel is capable of treating 140,000,000 gallons of condensate under normal conditions before any of these conditions arise. The flow rate through each demineralizer vessel is measured by a flow element and transmitter on the suction line of the vessel.

Flow indication is provided both locally and in the main control room.

After exhaustion, the resin beds can be replaced with new resin or transferred from the ion exchangers to the external regeneration system for cleaning and/or chemical regeneration.

10.4.6.2.2 External Regeneration System

Because of the condensate pre-filter system, the amount of suspended solids build up in the resin bed has been significantly reduced. Capability for the removal of suspended solids remains in place and is available should it be determined this is necessary or desirable.

The system provided for cleaning and chemical regeneration of the resins used in the condensate demineralizer is shown on Plant Drawing M-05-1. It consists essentially of an ultrasonic resin cleaner, resin separation and cation regeneration vessel, anion regeneration vessel, and a resin mix and hold vessel. The cation vessel also serves as a resin receiving and separation tank, through which exhausted resins are transferred from the ion exchanger to the regeneration system. Interlocks are provided so that an offline demineralizer cannot detect condensate pressure unless it is isolated from the External Regeneration System. The maximum operating conditions of the regeneration system are 100 psig and 135°F.

Crud accumulation on the resin is removed by:

1. In situ cleaning, using air scrubbing and water rinsing operations

2 External cleaning, using ultrasonic resin cleaning tank. The cleaned resins are then transferred back to the original service vessel for further service.

If the resins need a complete regeneration, they are transferred to the cation vessel and cleaned as described above. The anion and cation resins are separated by gravity, and then the anion resin is transferred to the anion regeneration vessel. At the end of the

regeneration, the resins are mixed and stored in the resin mix and hold vessel, until needed in any ion exchanger.

10.4.6.2.3 Acid and Caustic Dilution Systems

HCGS has elected to operate the Condensate Demineralizer System with the resins in a non-regenerable mode. Capability for regeneration remains in place and is available should it be determined this is necessary or desirable.

Solutions of acid and caustic required for regeneration of the cation and anion resins are prepared by in-line dilution of 66° Baume sulfuric acid and a 50 percent sodium hydroxide solution pumped from bulk storage tanks situated below the regeneration equipment.

A 10.4 percent sulfuric acid solution is required to regenerate the cation resins. The strong acid is mixed in a mixing tee with clean condensate as needed. Water is supplied at a constant rate by condensate transfer pumps through a pressure control valve.

A 4 percent concentration of caustic solution at 120°F is required to regenerate the anion resins. Strong caustic is mixed with dilution water at 120°F in a mixing tee as needed. Dilution water is produced by blending 150°F water from the caustic dilution hot water tank with cool water.

10.4.6.2.4 Waste System

The condensate regeneration wastewater resulting after regeneration is subdivided as high conductivity and low conductivity.

High conductivity wastewater (conductivity above 100 micromhos) is routed to the waste neutralizer tanks in the liquid radwaste system, where it is neutralized and pumped to the radwaste evaporators for evaporation.

Low conductivity wastewater is routed to the liquid radwaste collection tanks for treatment by filtration and demineralization.

10.4.6.3 Safety Evaluation

The Condensate Demineralizer System has no safety-related function, and is not required to be operable following an accident. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

The Condensate Demineralizer System is designed to maintain the effluent water quality as stated in Section 10.4.6.1, with a condenser tube leak not exceeding 1 gpm. The system is designed to sustain an effluent conductivity of $\leq$0.1 micromho with a maximum 1.5 gpm condenser tube leak when the circulating water contains 27,000 ppm of total dissolved solids. The circulating water quality used in the design of the condenser is given in Table 10.4-6. Conductivity is recorded for the following locations:

1. In the condenser

2. At analysis stations located on the common influent and effluent of the condensate demineralizer system

3. At the discharge of each ion exchange vessel

4. At the discharge header of the reactor feed pumps.

High conductivity alarms are provided to alert the plant operators of an abnormal condition.

Tables 12.2-117 through 12.2-123 provide the design bases for radiation shielding in the condensate demineralizer area.

The effluent strainer in the discharge from each ion exchanger protects the feedwater system against a massive discharge of resins in the event of an underdrain failure.

10.4.6.4 Tests and Inspections

Piping is inspected and tested in accordance with ANSI B31.1. All demineralizer vessels are tested in accordance with Section VIII of the ASME B&PV Code.

The system will be preoperationally tested in accordance with the requirements of Section 14.

Sampling frequency and chemical analysis will be in accordance with Regulatory Guide 1.56, Rev.1, Regulatory Position C-1 and Hope Creek UFSAR section 5.2.3.2.2.2. Limits for dissolved and suspended solids, and the basis for these limits has been provided in Section 10.4.6.1.

10.4.6.5 Controls and Instrumentation

The condensate demineralizer and the regeneration systems are controlled from a local control panel for all modes of operation, including transfer of resins for cleaning and returning these resins to the exchange vessel, or transfer of resins for cleaning and regeneration and transferring the previously regenerated and stored resins to the exchanger for standby.

Operating efficiency is monitored by a multipoint conductivity recorder, which measures the conductivity in the inlet and outlet of the system and at the outlet of each vessel.

The system influent is continuously monitored for conductivity and dissolved oxygen.

In addition, conductivity alarms are provided to alert the operator to abnormal conditions. The accumulation of suspended solids is monitored by a differential pressure indicator switch, which measures the differential pressure across the Condensate Demineralizer System. Flow transmitters, recorders, and a flow totalizer are provided in the inlet line of each condensate polishing demineralizer.

10.4.6.6 Condensate Pre-filter System

A. Design Bases

The Condensate Pre-filter System has no safety-related functions and is designed to remove insoluble impurities from the condensate upstream of the deep bed demineralizers. The primary impurity of interest is insoluble iron. The filter system is designed to operate at 100% condensate flow with a filter flux flow of less than 0.32 gpm/ft^2 with all four filter vessels in service. The Condensate Pre-filter System is designed to remove iron to less than 1 ppb.

Piping is furnished in accordance with ANSI B31.1.

Additional design requirements for the Condensate Pre-filter System are identified in GE Nuclear Energy Design Specification 24A5881 and Control System Requirements 24A5706.

B. System Description

The Condensate Pre-filter System shown on Plant Drawing M-102-1 removes insoluble iron from the condensate continuously at a maximum temperature of 150 degrees F and a nominal pressure range of 160 – 175 psig. The system design flow is 35,000 gpm (8,750 gpm per filter vessel with four vessels in service).

C. Condensate Pre-filter System

The Condensate Pre-filter System is placed between the Primary Condensate Pumps and the Steam Packing Exhauster/Steam Jet Air Ejector Condensers in the condensate system flow stream. The Condensate Pre-filter System consists of four vessels operated in parallel with a 33% bypass valve. Automatic valves operated by the condensate pre-filter control system remove the individual filter vessels from the process stream and backwash the filter media. Backwash water is collected in a header and directed to the Backwash Receiving Tank (BWRT). The BWRT is pumped to the radwaste system.

The condensate pre-filters are backwashed using a high pressure air-water pulse in the reverse direction. The high pressure air is stored in an air receiver. Upon backwash demand, the fast acting air inlet valve opens to provide a high energy pulse to the filter vessel and elements.

The four vessel system is designed to operate at 100% condensate system flow with a filter flux flow of less than 0.32 gpm/ft^2, assuming all four vessels are in service. Backwash operations, which nominally are accomplished in one hour, take place with the three remaining filter vessels in operation at 100% condensate system flow. During infrequent or abnormal periods when a vessel is out of service for maintenance and a second vessel requires backwash, the system is provided with a 0 – 33% air operated modulating valve to permit continued plant operation at 100% condensate flow. The impact of bypass operation on demineralizer crud loading during these short periods is considered inconsequential. The porosity rating of the filters is one micron absolute. This rating removes insoluble iron such that the effluent of the Condensate Pre-filter System is well less than 1 ppb.

Additional system description of the Condensate Pre-filter System is contained in GE Nuclear Energy Design Specification 24A5881 and Control System Requirements 24A5706.

D. Safety Evaluation

The Condensate Pre-filter System has no safety-related function, and is not required to be operable following an accident. Failure of the system does not compromise any safety-related system or component or prevent a safe shutdown of the plant.

The Condensate Pre-filter System is designed to remove insoluble impurities from the condensate upstream of the deep bed demineralizers. The primary impurity of interest is insoluble iron. The filter system is designed to operate at 100% condensate flow with a filter flux flow of less than 0.32 gpm/ft^2 with all four filter vessels in service. The Condensate Pre-filter System is designed to remove iron to less than 1 ppb.

E. Test and Inspections

Piping is inspected and tested in accordance with ANSI B31.1. All pressure vessels are tested in accordance with Section VIII of the ASME B&PV Code. The condensate Pre-filter System will be preoperationally tested in accordance with GE Nuclear Energy Design Specification 24A5881 and Control System Requirements 24A5706.

F. Controls and Instrumentation

The Condensate Pre-filter System is controlled using digital microprocessor controls and screen technology. Operator system access is obtained through the use of tw0 touchscreens located on the CPF system Main Control Panel. A remote PC with similar Main Control Panel capability is also included as part of the CPF system.

Status of system operations is indicated by means of multiple selectable screens on the CPF system Main Control Panel. Information such as system flows, filter vessel differential pressures, alarms, fault/failures, setpoints and flow balancing is accessed through touchscreen technology.

The CPF system has three subsystems, System Bypass, Filter Vessels and Backwash Collector System. Each of these subsystems can be operated in either manual or semi-automatic modes. In the manual mode the operator must manually manipulate valve positions and system equipment to perform system functions. The semi-automatic mode requires the operator to initialize system operations. Once this has occurred, the balance of system functions is executed automatically by the PLC.

The Backwash Receiving Tank (BWRT) discharges water to the condensate demineralizer waste header. Provisions are provided for sampling the condensate filtration system influent and each condensate vessel effluent. Control Room annunciators will alert Operators of CPF system abnormalities.

Additional Controls and Instrumentation description of the Condensate Pre-filter System is contained in GE Nuclear Energy Design Specification 24A5881 and GE Nuclear Energy Control System Requirements 24A5706.

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10.4.7 Condensate and Feedwater

The condensate and feedwater systems recycle the condensate from the condenser hotwells to provide the required feedwater to the reactor.

10.4.7.1 <u>Design Bases</u>

1. The condensate and feedwater systems are designed to return condensate from the condenser hotwells to the reactor at the required flow, pressure, temperature, and quality.

2. The systems are designed to automatically maintain the water levels in the reactor and the condenser hotwells during steady state and transient conditions.

3. The condensate and feedwater systems from the condenser hotwells up to, but not including, the outermost primary containment isolation valve are not safety-related. The feedwater system from the outermost primary containment isolation valve to the reactor is safety-related. For the isolation criteria between this system and the reactor coolant boundary, see Section 6.2.4.

4. Inservice inspection is performed in accordance with ASME B&PV Code, Section XI for that portion of the feedwater system furnished in accordance with ASME B&PV Code, Section III, Classes 1 and 2.

5. The condensate and feedwater systems are designed to permit continued operation of the plant at reduced power without reactor trip on loss of one of the three primary condensate pumps, one of the three secondary condensate

pumps, one of the three reactor feed pumps, or one of the three strings of feedwater heaters.

6. The seismic category, quality group classification, and corresponding codes and standards that apply to the design of the condensate and feedwater systems are discussed in Section 3.2.

7. The condensate and feedwater systems are stress analyzed for the forces and moments that result from thermal movement.

10.4.7.2 System Description

The condensate and feedwater systems are shown on Plant Drawings M-05-1 and M-06-1, respectively. The systems' design parameters are shown in Tables 10.4-7 and 10.4-8.

10.4.7.2.1 Condensate System

Three one-third capacity, vertical, canned suction, constant speed, motor driven, centrifugal primary condensate pumps take suction from a common header that is connected to each condenser hotwell for flow equalization. The primary condensate pumps discharge into a common header, and the condensate is then directed and balanced through the parallel array of the steam packing exhauster (SPE) condenser, steam jet air ejector (SJAE) condensers, and the SPE/SJAE bypass regulating valve.

Condensate is cleaned up through the Condensate Pre-filter System and the Condensate Demineralizer System discussed in Section 10.4.6 before proceeding to the suction of the secondary condensate pumps.

At low load, the main turbine exhaust hood cooling is accomplished by automatically spraying with effluent from the condensate demineralizer. During normal operation, condensate demineralizer

effluent also provides the makeup water to the Control Rod Drive (CRD) System.

The Condensate Recirculation System is provided downstream of the SPE/SJAE condensers to maintain a minimum flow required for the primary condensate pumps during the initial startup period when the secondary condensate pumps are not yet operating.

The sealing water for the primary condensate pumps is taken from the condensate storage tank (CST). The leakoff from the seals is piped to the Liquid Radwaste System. Any break in the seal water piping will not degrade the CST since the tank supply nozzle is located above the minimum CST level that is required for Emergency Core Cooling System (ECCS) operation, as discussed in Section 9.2.6.

Three one-third capacity, horizontal, constant speed, motor driven, centrifugal secondary condensate pumps deliver reactor quality condensate effluent from the demineralizer through the low pressure feedwater heaters to the suction of the reactor feed pumps.

Condensate from the secondary condensate pump common discharge header divides and passes through three parallel strings (A, B, and C), each with five stages of low pressure feedwater heaters where condensate is progressively heated by extraction steam. In each string of heaters, either heaters 1 and 2 with an external drain cooler, or heaters 3, 4, and 5 may be isolated from the system. Upon removal of one of these strings of heaters from service, each of the two remaining parallel strings can operate continuously at 150 percent of their normal flow rating. A throttle valve in the bypass line around heaters 3, 4, and 5 can be used to reduce final feedwater temperature.

The extraction steam lines from the turbine to each of the stages as well as the feedwater piping to each of the stages is arranged to provide balanced operation of the turbine, resulting in minimum load reductions due to feedwater heater outage. Source of extraction steam is shown in Tables 10.4-7 and 10.4-8.

Drains from the high pressure feedwater heater 6 sequentially cascade to the next lower pressure stage, and from the drain cooler of heater 2 to the condenser. Heater 1 drains directly to the condenser through a loop seal.

During low load operation, minimum flow through the primary and secondary condensate pumps is ensured by the individual recirculation lines on each secondary pump discharge. The minimum recirculation control valve is modulated by a flow element installed at the suction line of the secondary condensate pump. When system flow is below a predetermined setpoint, condensate is automatically recirculated back to the condenser.

A hotwell makeup and reject system maintains the condenser hotwell level during steady state and transient conditions, as discussed in Section 10.4.1.

The condensate supply to the steam seal evaporator for the Turbine Sealing System is taken from the secondary condensate pump discharge.

The secondary condensate pumps also provide the required net position suction head (NPSH) for the reactor feed pumps.

The Hydrogen Water Chemistry system is provided to inject gaseous hydrogen into the secondary condensate pumps (A,B&C) suction side at an injection rate necessary to provide intergranular stress corrosion cracking (IGSCC) protection of the recirculation piping. The addition of hydrogen reduces the oxygen content in the reactor water and reduces the corrosion potential of the water. Although the hydrogen concentration is reduced in the steam, the hydrogen/oxygen ratio increases. To ensure that sufficient oxygen is present in the gaseous radwaste system to combine with the excess hydrogen, air is injected upstream of the offgas recombiners to maintain the stoichiometric balance of oxygen and hydrogen. In order to maintain the desired dissolved oxygen level in the feedwater, a supplemental oxygen injection system (oxygen gas bottles) is also installed to inject oxygen, as needed basis, upstream of the primary condensate pumps.

10.4.7.2.2 Feedwater System

Three one-third capacity, horizontal, variable speed, steam turbine driven reactor feed pumps receive feedwater from a common header downstream of the low pressure feedwater heaters. The reactor feed pumps discharge feedwater to the three high pressure feedwater heaters (6A, 6B, and 6C) in parallel, where the feedwater is further heated to 420.6°F by extraction steam. The heater discharge lines join into a common header to ensure uniform feedwater temperature before branching into two lines that enter the primary containment for distribution into the reactor. The 6A, B and C heaters can be isolated when lower feedwater temperature is desired. The 6A, B and C heater drains can be directed as follows; the 6A and B heater drains return to their respective condenser. The 6C heater drain is returned to the A condenser.

Primary containment isolation in each branch is provided by a motor operated stop check valve, an air assisted check valve outside the containment, and a check valve and a motor operated gate valve inside the containment, as discussed in Section 5.4.9 and shown on Plant Drawing M-41-1. The motor operated stop check valve, which is capable of being remotely closed from the main control room, is provided for long term leakage protection upon operator judgment that continued makeup from the feedwater source is unnecessary.

The outermost motor operated stop check valves, HV-F032A (AE-V005) and HV-F032B (AE-V001), are connected to Class 1E power channels A and B respectively, as shown in Plant Drawing M-41-1 and Table 6.2-16 (p. 1 of 30).

The second of the three check valves in each of the two feedwater supply headers has a spring loaded actuator for positive seating. These are air assisted check valves, HV-F074A (AE-V006) and HV-F074B (AE-V002), and are shown in Plant Drawing M-41-1 and Table 6.2-16 (p. 1 of 30). During normal operation, the spring loaded piston operator will be held open by air pressure. Upon accidental loss of operator air pressure, the valve will remain open due to water flow.

However, upon a loss of water flow incident, the valve will shut as a normal check valve. In addition, the control room operator can assist in starting valve closure by remote manual opening of the two fail open solenoid valves releasing air pressure from the operator cylinder.

The feedwater system intertie with the Reactor Core Isolation Cooling (RCIC) and the High Pressure Coolant Injection (HPCI) Systems is described in Sections 5.4.6 and 6.3, respectively.

Injection water for the reactor feed pump seals is taken from the secondary condensate pump discharge header and is drained to the main condenser.

Each high pressure heater can be isolated individually from the system. The other two heaters can operate at 150 percent of their normal feedwater flow.

Each reactor feed pump has a recirculation line connected to the main condenser. This recirculation line branches off the discharge line between the reactor feed pump and its discharge check valve and is used to maintain a minimum flow through the feed pump at startup and low load operation to avoid pump vibration and high running temperatures. The minimum recirculation control valve opens automatically to establish the required minimum recirculation pump flow in response to an analog control signal from flow elements located in the pump discharge and minimum recirculation lines. The control valve is closed automatically on pump/turbine stop signal.

The reactor feed pumps are driven by variable speed, nine stage turbines that receive steam from either the main steam header or the crossaround piping downstream of the moisture separators. During normal full power operation, the turbine drivers use low pressure crossaround steam. High pressure main steam is used during startup, low load, or transient conditions, when crossaround steam is either not available or is of insufficient pressure. The exhaust steam from each turbine driver is piped to the main condenser, as shown on Plant Drawing M-31-1.

Before starting the reactor, the feedwater lines between the condensate demineralizer and the reactor are flushed to remove any crud present. The flow is pumped through these lines by the primary condensate pumps, bypassing the secondary condensate pumps, reactor feed pumps, and high and low pressure heaters and recirculating the flow to the condenser through the startup recirculation line. This ensures proper reactor water quality during startup.

Normally, the three primary condensate, three secondary condensate, and three reactor feed pumps are in service, together with all three strings of feedwater heaters. The system is designed so that it can operate with any two primary condensate

pumps, two secondary condensate pumps, two reactor feed pumps, or two feedwater heater strings in service without a reactor trip.

The primary condensate pumps, secondary condensate pumps, and reactor feed pumps are designed to provide the maximum required design flows plus adequate margins to account for both transients and pump wear. Adequate margin is provided in the NPSH requirements to ensure noncavitating performance under operating and runout conditions.

The low pressure feedwater heaters and drain coolers have 20 BWG, 304 stainless steel tubes installed, whereas the high pressure feedwater heaters have 18 BWG, 304 stainless steel tubes installed.

10.4.7.3 Safety Evaluation

The condensate and feedwater systems are not safety-related and are not required to be operable following a LOCA, other than containment isolation. Failure of the systems does not compromise any safety-related system or component, or prevent a safe shutdown of the plant.

Feedwater system primary containment penetrations, isolation valves, and piping inside containment are designed to Seismic Category I and ASME B&PV Code Section III, Class 1 requirements as discussed in Sections 3.2, 3.7, 5.4.9, and 6.2.

In the event of a reactor feed pump trip (RFPT) coincident with a low reactor water level, the recirculation pumps will run back to a predetermined percentage of flow. This run back, which promptly reduces reactor power, averts a reactor trip and allows continued operation at reduced power. Recirculation pump run-back is also initiated due to a loss of one primary condensate pump or one secondary condensate pump, or to a loss of vacuum in the main condenser when a circulating water pump trips.

If it is necessary to remove a component such as a feedwater heater, pump, or control valve from service, continued operation of the system is possible by use of the three string arrangement and the provisions for removing from service and bypassing equipment and sections of the system.

During operation, steam and condensate are present in the feedwater heating portion of the system, which includes the extraction steam piping, feedwater heater shells, heater drain piping, and heater vent piping. Thus, the RFPTs and feedwater heaters are compartmentalized to localize radiation. Shielding and access requirements are provided where necessary, as discussed in Section 12.3. The condensate and feedwater systems are designed to minimize leakage, with welded construction used where practicable. Relief valve discharges and operating vents are handled through closed systems.

The probability of releasing radioactivity to the environment due to a pipe break outside the primary containment is minimized by the containment isolation valves. The primary containment prevents the release of radioactivity to the environment should a feedwater line break occur inside the containment.

Protection against dynamic effects associated with the postulated rupture of piping is discussed in Section 3.6.

An abnormal operational transient analysis of the loss of feedwater heater string is included in Section 15.

10.4.7.4 <u>Tests and Inspections</u>

That portion of the feedwater system designed to ASME B&PV Code, Section III, Class 1 or 2, is inspected and tested in accordance with ASME B&PV Code, Section XI.

The primary condensate, secondary condensate, and reactor feed pump performance is verified by shop testing. The casings of the

condensate and reactor feed pumps are hydrostatically tested to 1.5 times their shutoff discharge pressures. The shell and tube sides of all feedwater heaters and drain coolers are hydrostatically tested to 1.5 times their design pressure in accordance with ASME B&PV Code, Section VIII.

Before initial operation, the completed condensate and feedwater system receives a field hydrostatic test and inspection in accordance with the applicable code.

The system is preoperationally tested in accordance with the requirements of Section 14.

10.4.7.5 Controls and Instrumentation

Local and remote indicators, alarms, and pressure relief valves are provided to monitor the system process and protect system components.

Controls are provided to maintain the condenser hotwell level so that on high level the excess condensate is transferred to the CST, while on low level makeup from the storage tank is admitted to the system. Controls are also provided to maintain the correct levels in the feedwater heaters (shell side), drain coolers (shell side), and drain tank.

During startup and low power operation, feedwater flow to the reactor is regulated by a startup control valve located in the high pressure feedwater heater bypass line. The startup control valve regulates feedwater flow and control reactor water level in response to an analog level control signal from the reactor feedwater control system. During normal operation, the RFPT speed regulates the reactor level. The turbine speed signal is generated by the three element Feedwater Control System that monitors feedwater flow, steam flow, and reactor level. The Feedwater Control System is discussed in Section 7.7.

Monitoring equipment, including pressure indicators, flow and temperature indicators, vibration input to the computer, and alarms for abnormal conditions, is provided in the main control room to ensure the proper operation of system components. Sampling means are provided for monitoring the quality of the condensate and feedwater as described in Section 9.3.2.

TABLE 10.4-1

MAIN CONDENSER DESIGN PARAMETERS

Main Condenser	Low Pressure Shell
Quantity	3 shells
Type	Shell and tube
Duty	7.726×10^9 Btu/h at 2.5 inch Hg abs
Normal cooling water temperature	80°F
Design cooling water temperature	92°F
Overall dimensions of each shell	
Width	29 feet-0 inches
Height	61 feet-9 inches
Length	39 feet-2 inches
Minimum heat transfer rate	441.08 Btu/h/°F/sq.ft.
Shell design	
Fluid	Steam
Flow rate from turbine	7,936,587 lb/h *
Maximum flow rate	8,292,671 lb/h *
Operating pressure	4.0 inch Hg abs
Design pressure	15 psig and full vacuum
Hotwell storage volume at maximum level	174,752 gallons
Hotwell storage at minimum level	124,221 gallons
Tube design	
Fluid	Circulating water
Flow rate	552,000 gpm
Operating pressure	50 psig
Tube velocity	7.5 feet/s
Number of passes	2

TABLE 10.4-1 (Cont)

<u>Main Condenser</u>	<u>Low Pressure Shell</u>
Main Condenser Tube Specifications	
Material	Titanium ASTM B 338, gr 2
OD	0.875 inch
Gauge	22 BWG
Total effective surface area	821,430 square feet
Design pressure	100 psi
Length	40 feet
Total number of tubes	89,652
Exhaust Steam Temperature w/o Bypass	
Normal	125.42°F **
Maximum	149.62°F **
Exhaust Steam Temperature w/ Bypass	
Normal	NA
Maximum	146.85°F **

* Values at EPU conditions: Flow rate from turbine - 8,699,153 lb/h
Maximum flow rate - 9,061,380 lb/h

** These values are Condenser Shell Design values and are affected at EPU conditions

EPU Target Power Uprate (3673 MWt)

TABLE 10.4-2

MAIN CONDENSER EVACUATION SYSTEM DESIGN PARAMETERS

Mechanical Vacuum Pump

Quantity	2
Type	Rotary water ring
Capacity, each	1900 scfm
Design suction pressure	3.53-inch Hg abs
Motor power rating	150 hp

Seal Water Cooler

Quantity	2
Type	Horizontal, two-pass, U-tube
Duty	317,300 Btu/h
Shell side design	
Fluid	Water
Flow rate	60 gpm
Design pressure	150 psig
Design temperature	300°F
Tube side design	
Fluid	Condensate
Flow rate	64 gpm
Design pressure	150 psig
Design temperature	300°F

Seal Water Pump

Quantity	2
Type	Centrifugal, single stage
Capacity	60 gpm

<u>Seal Water Pump</u>	
Discharge pressure	35 psig
Motor power rating	1.5 hp
<u>Steam Jet Air Ejectors</u>	
Quantity	2 trains (100 percent capacity each) 3 first stage elements per train (33 percent capacity each element) 1 second stage element per train (100 percent capacity) 1 third stage element per train (100 percent capacity)
Design first stage suction pressure	1.0-inch Hg abs
Design second stage suction pressure	9.5-inch Hg abs
Design third stage suction pressure	30-inch Hg abs
Noncondensable gas flow rate	
Dry air	337 lb/h
Hydrogen	49 lb/h
Oxygen	383 lb/h
Motive steam operating pressure	125 psig
<u>Air Ejector Intercondenser</u>	
Quantity	2 (100 percent capacity each)
Type	Horizontal, single pass, single shell
Duty	20.96×10^6 Btu/h

TABLE 10.4-2 (Cont)

Air Ejector Intercondenser

Shell side design	
Steam flow rate	20,741 lb/h
Noncondensable gas flow rate	769 lb/h
Design pressure	50 psig & full vacuum
Design temperature	600°F
Tube side design	
Fluid	Condensate
Flow rate	2,103,500 lb/h
Design pressure	300 psig
Design temperature	150°F

Air Ejector Aftercondenser

Quantity	2 (100 percent capacity each)
Type	Horizontal, single-pass, Single-shell
Duty	13.11×10^6 Btu/h
Shell side design	
Steam flow rate	13,443 lb/h
Noncondensable gas flow rate	769 lb/h
Design pressure	50 psig & full vacuum
Design temperature	600°F
Tube side design	
Fluid	Condensate
Flow rate	1,327,000 lb/h
Design pressure	300 psig
Design temperature	150°F

TABLE 10.4-3

CIRCULATING WATER PUMPS DESIGN PARAMETERS

Number of pumps	4, with 25 percent capacity each
Type	Vertical, wet pit, single stage
Rated flow	138,000 gpm
Rated head	97 feet
Rated speed	396 rpm
Motor type	Induction
Motor size	4500 hp
Voltage/phase/frequency	4000 V/3-phase/60 Hz

TABLE 10.4-4

ORIGINAL COOLING TOWER DESIGN PARAMETERS

Total duty	7.972×10^9 Btu/h
Flow rate	552,000 gpm
Inlet water temperature	119°F
Outlet water temperature	90°F
Ambient wet bulb temperature	76°F
Relative humidity	60%
Range	29°F
Approach	14°F
Tower height	512 feet
Basin diameter	432 feet
Basin capacity	8.5×10^6 gallons
Drift rate	0.0005 percent circ water flow rate

TABLE 10.4-5

SYSTEM DESIGN BASIS
INFLUENT CONCENTRATIONS TO THE
CONDENSATE DEMINERALIZER SYSTEM

Constituents	Normal Operation	Startup
Iron (Fe)		
Soluble, ppb	5	40
Insoluble, ppb	50	1000 (1)
Nickel (Ni)		
Soluble, ppb	5	30
Insoluble, ppb	5	100
Chloride (Cl), ppb	20 (2)	20
pH at 25°C	6.5 to 7.5	6 to 8
Conductivity at 25°C, μmho/cm	0.2	0.5
Radioactivity, μCi/g	10^{-4} to 10^{-3}	10^{-4} to 10^{-3}

(1) Soluble iron is at a concentration of 4000 ppb during plant startup.

(2) For equipment specification only because, without condenser tube leak, chlorides are much lower.

TABLE 10.4-6

CIRCULATING WATER QUALITTY DESIGN PARAMETERS
USED FOR THE CONDENSATE DEMINERALIZER SYSTEM

Calcium as $CaCO_3$, ppm	1,170
Magnesium $CaCO_3$, ppm	3,870
Sodium $CaCO_3$, ppm (by difference)	17,550
Hardness $CaCO_3$, ppm	5,040
Bicarbonates as $CaCO_3$ [(1)], ppm	70
Carbonates $CaCO_3$ [(1)], ppm	40
Sulphates $CaCO_3$ [(1)], ppm	2,200
Chlorides $CaCO_3$ [(1)], ppm	20,300
Phosphates $CaCO_3$, ppm	4
Nitrates $CaCO_3$, ppm	16
Iron as Fe, ppm	11.2
Copper as Cu, ppm	0.54
Manganese as Mn, ppm	1
Total dissolved solids, ppm	27,000
Suspended solids, ppm	1,400
pH	7
Total ammonia [(1)], ppm	20
Sulfides as S, ppm	0.2
Reducing substances as H_2S, ppm	4
Total organic carbon, ppm	28

(1) The circulating water is treated with caustic to prevent cooling tower fill degradation. To prevent bacteria growth, the circulating water is chlorinated by addition of sodium hypochlorite to maintain residual chlorine at the condenser inlet.

TABLE 10.4-7

ORIGINAL CONDENSATE SYSTEM DESIGN PARAMETERS

Primary Condensate Pumps

Quantity	3 (33-1/3 percent capacity each)
Tag numbers	1AP102, 1BP102 and 1CP102
Type	Two stage, vertical, canned, centrifugal
Capacity, each	12,300 gpm
Head	365 feet
Motor power rating	1500 hp

Secondary Condensate Pumps

Quantity	3 (33-1/3 percent capacity each)
Tag numbers	1AP137, 1BP137, and 1CP137
Type	Single stage, horizontal, centrifugal
Capacity, each	11,400 gpm
Head	1000 feet
Motor power rating	3650 hp

Condensate Drain Tank

Quantity	1
Tag number	10T108
Type	Horizontal, cylindrical
Volume	1000 gallons
Design pressure	Atmospheric
Design temperature	200°F

Feedwater Heaters

Quantity	3 (33-1/3 percent normal capacity each)
Tag numbers	1A1E101, 1B1E101, and 1C1E101 (1A, 1B, and 1C)
Type	Low pressure, horizontal, two pass, U-tube, mounted in condenser neck, removable tube bundle
Duty, each	187.117 x 10^6 Btu/h
Shell side design	
Fluid/flow rate, each	Extraction steam and moisture/190,934 lb/h
Design pressure	50 psig and full vacuum
Design temperature	300°F
Tube side design	
Fluid	Feedwater
Flow rate, each	4,941,341 lb/h
Design pressure	850 psig
Design temperature	300°F

Drain Coolers

Quantity	3 (33-1/3 percent normal capacity each)
Tag numbers	1A2E107, 1B2E107, and 1C2E107
Type	Low pressure, horizontal, two pass, fixed tubesheet, mounted in condenser neck
Duty, each	111.180 x 10^6 Btu/h

Drain Coolers

Shell side design	
Fluid/flow rate, each	Drains/1,902,760 lb/h
Design pressure	50 psig and full vacuum
Design temperature	300°F
Tube side design	
Fluid	Feedwater
Flow rate, each	4,941,341 lb/h
Design pressure	850 psig
Design temperature	300°F

Feedwater Heaters

Quantity	3 (33-1/3 percent normal capacity each)
Tag numbers	1A3E102, 1B3E102, and 1C3E102 (2A, 2B, and 2C)
Type	Low pressure, horizontal, two pass, U-tube, mounted in condenser neck, removable tube bundle
Duty, each	209.019×10^6 Btu/h
Shell side design	
Fluid/flow rate, each	Extraction steam and moisture/214,600 lb/h Cascading drains/ 1,649,139 lb/h
Design pressure	50 psig and full vacuum
Design pressure	300°F

Feedwater Heaters

Tube side design	
Fluid	Feedwater
Flow rate, each	4,941,341 lb/h
Design pressure	850 psig
Design temperature	300°F

Feedwater Heaters

Quantity	3 (33-1/3 percent normal capacity each)
Tag numbers	1A1E103, 1B1E103, and 1C1E103 (3A, 3B, and 3C)
Type	Low pressure, horizontal, two pass, U-tube, removable shell
Duty, each	348.364×10^6 Btu/h
Shell side design	
Fluid/flow rate, each	Extraction steam and moisture/279,947 lb/h Cascading drains/1,357,000 lb/h
Design pressure	75 psig and full vacuum
Design temperature	320°F
Tube side design	
Fluid	Feedwater
Flow rate, each	4,941,341 lb/h
Design pressure	850 psig
Design temperature	320°F

Feedwater Heaters

Quantity	3 (33-1/3 percent normal capacity each)
Tag numbers	1A2E104, 1B2E104, and 1C2E104 (4A, 4B, and 4C)
Type	Low pressure, horizontal, two pass, U-tube, removable shell
Duty, each	208.285×10^6 Btu/h
Shell side design	
Fluid/flow rate, each	Extraction steam/ 169,105 lb/h Cascading drains/1,187,896 lb/h
Design pressure	125 psig and full vacuum
Design temperature	340°F
Tube side design	
Fluid	Feedwater
Flow rate, each	4,941,341 lb/h
Design pressure	850 psig
Design temperature	350°F

Feedwater Heaters

Quantity	3 (33-1/3 percent normal capacity each)
Tag numbers	1A3E105, 1B3E105, and 1C3E105 (5A, 5B, and 5C)
Type	Low pressure, horizontal, two pass, U-tube, removable shell
Duty, each	224.895×10^6 Btu/h

TABLE 10.4-7 (Cont)

Feedwater Heaters

Shell side design	
Fluid/flow rate, each	Crossaround steam/ 236,575 lb/h Cascading drains/ 386,854 lb/h
Design pressure	260 psig and full vacuum
Design temperature	380°F
Tube side design	
Fluid	Feedwater
Flow rate, each	4,941,341 lb/h
Design pressure	850 psig
Design temperature	400°F

TABLE 10.4-8

ORIGINAL FEEDWATER SYSTEM DESIGN PARAMETERS

Reactor Feed Pumps

Quantity	3 (33-1/3 percent capacity each)
Tag numbers	1AP101, 1BP101, and 1CP101
Type	Single stage,double suction, centrifugal, variable speed, horizontal
Capacity, each	13,000 gpm
Head	2530 ft
Driver	Dual admission steam turbine rated at 10,500 hp

Feedwater Heaters

Quantity	3 (33-1/3 percent normal capacity each)
Tag numbers	1AE106, 1BE106, and 1CE106 (6A, 6B, and 6C)
Type	High pressure, horizontal, two pass, U-tube, removable shell
Duty, each	299.732×10^6 Btu/h
Shell side design	
Fluid/flow rate, each	Extraction steam/ 386,854 lb/h
Design pressure	425 psig and full vacuum
Design temperature	440°F
Tube side design	
Fluid	Feedwater
Flow rate, each	4,941,341 lb/h
Design pressure	1800 psig
Design temperature	450°F

Figure F10.4-1 intentionally deleted.

Refer to Plant Drawing M-07-1 in DCRMS

Figure F10.4-2 intentionally deleted.

Refer to Plant Drawing M-29-1 in DCRMS

Figure F10.4-3 SH 1-2 intentionally deleted.

Refer to Plant Drawing M-09-1 for both sheets in DCRMS

Figure F10.4-4 SH 1-2 intentionally deleted.

Refer to Plant Drawing M-16-1 for both sheets in DCRMS

Figure F10.4-5 SH 1-3 intentionally deleted.

Refer to Plant Drawing M-05-1 for all sheets in DCRMS

Figure F10.4-6 intentionally deleted.

Refer to Plant Drawing M-06-1 in DCRMS

Figure F10.4-7 SH 1-2 intentionally deleted.

Refer to Plant Drawing M-31-1 for both sheets in DCRMS

Figure F10.4-8 intentionally deleted.

Refer to Plant Drawing M-102-1 in DCRMS