10. STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion system (SPCS) is designed to remove heat energy from the reactor coolant system in the three steam generators and convert it to electrical power via the turbine-generator. The main condenser deaerates the condensate and transfers the heat which is unusable in the cycle to the circulating water system. The regenerative turbine cycle heats the feedwater and returns it to the steam generators.

10.1.1 GENERAL DESCRIPTION

The SPCS receives its steam supply from a pressurized water reactor (PWR) nuclear steam supply system (NSSS). The SPCS generates electrical energy for distribution via the power transmission system. It also provides feedwater to the steam generators of the nuclear steam supply system. A summary of important design features and performance characteristics of the SPCS, assuming no makeup water or losses, is given in table 10.1-1. Heat balances for various power levels are given in figure 10.14. Figure 10.1-2 is an overall flow diagram of the SPCS.

The major components of the SPCS are:

- Turbine-generator
- Condenser
- Condensate pumps
- Turbine steam seal system, including steam packing exhauster
- Turbine bypass steam
- Turbine-driven steam generator feed pumps
- Turbine- and motor-driven auxiliary feedwater pumps
- Feedwater heaters
- High pressure heater drain pumps
- Condensate polishing demineralizer system
- Startup feed pump.

The heat rejected in the condenser is removed by the circulating water system and rejected to the ocean.

The safety-related components included in the SPCS are:

- The main steam isolation valves
- The steam generator power-operated relief valves
- The steam generator safety valves
- The main steam lines extending from the steam generator up to and including the torsional and bending restraints beyond the main steam isolation valves
- The feedwater isolation valves
- The feedwater check valves
- The feedwater lines from the steam generator up to and including the torsional and bending restraints beyond the feedwater isolation valves
- The auxiliary feedwater pumps and supply lines, and the driver and steam supply to the turbine-driven auxiliary feedwater pump.

The SPCS includes a tandem-compound, six-flow exhaust, 1800 r/min
570 turbine with 46-inch last stage buckets (blades). The generator
479 is rated at 1,163,330 kVA for operation at 22,000-volt, 60-hertz
361 frequency, 0.6 short-circuit ratio at 100 percent rated
479 voltage, and 0.90 power factor. Steam produced at 938 psia, 537 °F, and 0.25 percent moisture from the outlets of three steam generators is supplied to drive the turbine-generator. Turbine nameplate rating data are presented on table 10.1-1.

Moisture separation plus two stages of steam reheating are provided between the high pressure and low pressure turbines for all steam entering the low pressure turbines to increase cycle efficiency and to minimize moisture conditions on the last stage turbine blading. Exhaust steam from low pressure turbines is condensed in a surface-type, deaerating, single-pressure condenser consisting of three shells, each with divided water boxes and hotwells. Deaeration of condensate is normally accomplished by the use of the steam jet air ejectors. Condensate is collected in the condenser hotwells.

The condensate and feedwater system returns feedwater to the steam generators through four condensate pumps (three operating and one standby), seven stages of extraction feedwater heating, two heater drain pumps and three steam generator feedwater pumps. A startup feed pump will be used during normal startup, hot standby, and shutdown. Auxiliary feedwater flow is available from one steam-driven auxiliary feedwater pump and two motor-driven auxiliary feedwater pumps (see subsection 10.4.9). Circulating water from the ocean is pumped by the circulating water pumps through the main condenser and returned to the Yellow Sea. through the discharge conduit. A condensate demineralizer system (subsection 10.4.6) is provided to maintain water quality with steam generator water chemistry requirements contained in subsection 10.3.5.

The NSSS has a rated output of 2,912 MWt, consisting of 2,900 MWt net reactor core power plus 12 MWt reactok coolant pump input heat. Overall performance characteristics and component data for the steam and power conversion systems are given in table 10.1-1. 479

The SPCS matches the NSSS load following capability of accepting step load changes of 10 percent and ramp load changes of 5 percent per minute over the load range of 15 to 100 percent of rated output. The turbine bypass system is capable of bypassing II%; 36 percent of rated load main steam flow directly to the main 479
condenser. This bypass capacity, combined with the 10 percent step load change controlled by the NSSS rod control system, provides the capability of accepting a generator step load reduction of up to 46 percent without reactor trip and without steam 479
release to the atmosphere. For load rejections greater than 46 percent, the atmosphere dump valves with a combined capacity of 28 percent rated steam flow will open. Thus, the turbine 479
bypass system valves open automatically to the extent necessary during rapid load reductions to remove excess heat from the reactor coolant system (RCS), and close as operating conditions stabilize at the new lower load. This 64 percent capability combined with the step load change capability of the nsss permit load rejections 479
from full load to 50% load without turbine or reactor trip. Details of 8
the control system are presented in chapter 7, while the turbine bypass system is discussed in subsection 10.4.4.

All auxiliary equipment has the capability to meet the maximum anticipated unit load at rated load heat balance conditions. Design margins are included as required for component wear and system surges to provide dependable service.

During normal operation, main steam is tapped off the main steam line header upstream of the turbine stop valves to supply steam to the second stage reheaters and the auxiliary steam header. During the startup period or low-load operation up to approximately 40 percent load, main steam is used to drive the three steam generator feedwater pump turbines. When operating above approximately 40 percent load, a portion of the reheated steam from the combined moisture separator/reheaters is used to drive the feedwater pump turbines. The changeover from throttle (main) steam to reheated steam is automatic.

The NSSS steam generators are utilized to remove reactor decay heat during the period immediately following reactor shutdown by absorbing heat from the RCS and producing steam. The steam may be bypassed around the main turbine and condensed in the main condenser if circulating water is available; alternatively, the steam may be relieved to the atmosphere. Immediately following a normal reactor shutdown, the condensate pumps and startup feedwater pumps are available to supply feedwater from the main condensers and maintain normal water level in the NSSS steam generators. As long as normal water level is maintained in the steam generators, heat from the primary reactor coolant flowing within the submerged steam generator tubes is transferred to the feedwater steam side of the units. Should a loss of offsite power occur with a turbine trip, two motor-driven auxiliary feedwater pumps powered by the plant standby diesel generators are available to provide feedwater from the condensate storage tanks. A third auxiliary feedwater pump is driven by a steam turbine. The motive steam to drive the steam turbine is produced in the NSSS steam generators from the reactor decay heat. The auxiliary feedwater pump turbine is designed to operate with throttle steam pressures from approximately 1195 psia to 100 psia, the expected steam generator outlet pressure range from reactor trip conditions to the point where the residual heat removal (RHR) system becomes effective.

The steam generator safety valves are provided in accordance with ASME Section III code requirements. Safety valves are provided for the steam side of the feedwater heaters, the moisture separator/reheaters, and the heater drain tank. Diaphragms are provided in the steam exhaust sections of the main turbine for overpressure protection of the low pressure turbine exhaust hoods. Diaphragms are provided also in the exhaust sections of the main feedwater pump turbine drives. Thermal relief valves are provided for sections of the condensate and feedwater system, if necessary.

For upset and/or emergency conditions, certain components and/or systems are tripped out of service by quick-closing isolation valves. Isolation valves outside the containment on the steam outlet of each steam generator close within 5 seconds.

and the main turbine stop valves close in 0.2 second. Quick-closing stop valves in the steam supply lines to the feedwater pump turbine drives close on turbine overspeed signals to shut off steam delivery to the turbines in order to protect the feedwater system from feedwater pump overpressure. Feedwater control valves and stored energy-operated isolation valves are capable of closure in 5 seconds and are.provided outside the containment to isolate the steam generators.

10.1.2 PROTECTIVE AND SAFETY-RELATED FEATURES

10.1.2.1 Turbine Trip

A turbine trip results in an automatic reactor trip when accompanied by a permissive signal from neutron flux level. Excess steam is relieved to the condenser via the turbine bypass valves and/or to the atmosphere through the steam dump valvs. 8 | 31

10.1.2.2 Overpressure Protection

Spring-loaded safety valves are provided on all three main steam lines in accordance with the ASME Boiler and Pressure Vessel (B&PV) Code, Section III. The combined flow capacity of the safety valves is such that pressure cannot exceed 110 percent of the steam generator shell design pressure.

10.1.2.3 Loss of Main Feedwater Flow

The auxiliary feedwater system is designed to provide feedwater to the steam generators for the removal of the sensible and decay heat whenever main feedwater flow is interrupted, such as caused by loss of preferred power supply to the condensate pumps or steam generator feed pumps.

10.1.2.4 Turbine Overspeed Protection

During normal operations, turbine overspeed is precluded by the governing action of the digital electrohydraulic (DEH) control system plus an independent backup mechanical overspeed trip. The turbine DEH control system is further described in section 10.2.

10.1.2.5 Turbine Missile Protection

Missile protection is discussed in section 3.5, Missile Protection.

10.1.2.6 Radioactivity

Under normal operating conditions, there are no detectable radioactive contaminants present in the SPCS. There may be insignificant radioactive contamination due to minor steam generator tube leakage; however, the system is carefully monitored by sampling the effluent from the condenser air removal system and the steam generator blowdown system. It is possible for the system to become contaminated through large steam generator tube leak or failure. In this event, radiological monitoring will detect contamination and alarm high radioactivity concentrations. A discussion of the radiological aspects of primary-to-secondary system leakage during normal plant operation are contained in sections 11.1 and 11.5. Anticipated radioactivity releases are given in section 11.3.

Table 10.1-1

SUMMARY OF IMPORTANT DESIGN FEATURES
AND PERFORMANCE CHARACTERISTICS OF THE
STEAM AND POWER CONVERSION SYSTEM (Sheet 1 of 4)

Nuclear Steam Supply System, Full Power Operation		
Rated NSSS power, MWt	2,912	479
Steam generator outlet pressure, psia	938	
Steam generator inlet feedwater temp, °F	445.9	
Steam generator outlet steam moisture, %	0.25	
Quantity of steam generators per unit	3	
Flow rate per steam generator, 10^6 lb/hr	4.278	479
Turbine-Generator		
Rating, kW	1,057,245[a]	488,570
Turbine type	Tandem-compound, six-flow	
Quantity of turbine elements per unit	1 high pressure 3 low pressure	
Operating speed, r/min	1,800	
Moisture Separator Reheater (MSR)		
Stages of reheat	2	
Stages of moisture separation	1	
Quantity of MSRs per unit	2	
Main Condenser		
Type	Single pressure, three shell	
Quantity, per unit	1	
Condensing capacity, Btu/h [b]	6.3744×10^9	479
Circulating water flow rate, gal/min	858,000	
Circulating water temperature rise, F[b]	15.42	479
Condenser Vacuum Pumps		
Type	2-stage water ring	
Quantity	4	
Hogging capacity, each, standard ft^3/min	800 @ 10 in, HgA	

a. With 3% blowdown and 0.5% system makeup.
b. Based on circulating water inlet temperature of 68.9°F.

Table 10.1-1

SUMMARY OF IMPORTANT DESIGN FEATURES
AND PERFORMANCE CHARACTERISTICS OF THE
STEAM AND POWER CONVERSION SYSTEM (Sheet 2 of 4)

Condenser Vacuum Pumps (con't)	
Motor hp, each Speed, motor/pump, r/min	150 1,800/435
Steam Jet Air Ejectors	
Quantity	Two 50% first-stage One 100% second-stage
Motive fluid source	Main steam
Holding capacity	75 cfm at 1.0 in. HgA
Condensate Pumps	
Type	Vertical, canned motor-driven
Rated conditions	
Flow, gal/min	6,235
Total head, ft	1,260
Motor hp	3,000
Quantity per unit	4 (one standby)
Feedwater Heaters	
High pressure	
No. 7	
Quantity per unit	2
Duty, Btu/h	224×10^6
No. 6	
Quantity per unit	2
Duty, Btu/h	412.94×10^6 per heater
No. 5	
Quantity per unit	2
Duty, Btu/h	189.032×10^6 per heater

Table 10.1-1

SUMMARY OF IMPORTANT DESIGN FEATURES
AND PERFORMANCE CHARACTERISTICS OF THE
STEAM AND POWER CONVERSION SYSTEM (Sheet 3 of 4)

Feedwater Heaters (con't)		
Low pressure		
No. 4		
Quantity per unit	3	
Duty, Btu/h	131.2×10^6 per heater	
No. 3		
Quantity per unit	3	
Duty, Btu/h	129.2×10^6 per heater	
No. 2		
Quantity per unit	3	
Duty, Btu/h	133.1×10^6 per heater	404
No. 1		
Quantity per unit	3	
Duty, Btu/h	167.6×10^6 per heater	404
Steam Generator Feedwater Pumps		
Pump type	Horizontal, centrifugal	
Turbine type	multi-stage condensing	
Quantity per unit	3	
Rated conditions, pump		
Flow, gal/min	9,125	
Total head, ft	2,070	
Turbine hp @ 4,600 r/min	4,823	
Heater Drain Pumps		
Type	Vertical, centrifugal, motor-driven	
Rated conditions		
Flow, gal/min	5,895	
Total head, ft	925	
Motor hp	1,750	
Quantity per unit	2	

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2008.12.19

Table 10.1-1

SUMMARY OF IMPORTANT DESIGN FEATURES AND PERFORMANCE CHARACTERISTICS OF THE STEAM AND POWER CONVERSION SYSTEM (Sheet 4 of 4)

Startup Feed Pump (Motor-Driven)	
Type	Horizontal, centrifugal
Quantity	1-100%
Rated flow, gal/min	920
Rated head, ft.	1,800
Design pressure, psig	2,000
Design temperature, °F	350
Steam Generator Blowdown Regenerative Heat Exchangers	
Duty, Btu/h	35.6 x 10^6 per pair
Quantity per unit	4 (two pairs)
Steam Generator Blowdown Nonregenerative Heat Exchangers	
Duty, Btu/h	12.1 x 10^6 per heater
Quantity per-unit	2
Steam Generator Blowdown Flash Tank	
479 Steaming rate, lb/h	66.746
Outlet steam pressure, psia	312
Quantity per unit	1
Heater Drain Tank	
Quantity per unit	1
Design pressure, psig	400 and full vacuum

Amendment 479
2007. 8. 3

Drawn: RTC	KHNP	HEAT BALANCE DIAGRAM YONGGWANG 1 and 2 Upgraded Reactor Power Level	TSRTG
Checked:		Figure 10.1-1 (Sheet 1 of 6)	2010-02-10/15:56
Approved:		2912 MWt 63.14 bar 1800 rpm	TS30130C
Doc F L E Sh.No. N.o.Sh.		Post HP Retrofit - 3% throttle margin	

Drawn: RTC	KHNP	HEAT BALANCE DIAGRAM YONGGWANG 1 and 2 2912MWt (1% S.G. Blow down, 0.5% SYS Make up)	TSRTG 2010-04-14/14:11
Checked:		Figure 10.1-1 (Sheet 2 of 6)	
Approved:		2912 MWt 63.14 bar 1800 rpm	TS90591C
Doc F L E Sh.No. N.o.Sh.		Post HP Retrofit - 3% throttle margin	

Drawn: RTC	KHNP	HEAT BALANCE DIAGRAM YONGGWANG 1 and 2 2912MWt (3% S.G. Blow down, 0.5% SYS Make up)	TSRTG
Checked:		Figure 10.1-1 (Sheet 3 of 6)	2010-04-14/14:11
Approved:		2912 MWt 63.14 bar 1800 rpm	TS90592C
Doc F L E Sh.No. N.o.Sh.		Post HP Retrofit - 3% throttle margin	

Drawn: RTC	KHNP	HEAT BALANCE DIAGRAM YONGGWANG 1 and 2 75% Load (Based on 2912MWt as 100%)	TSRTG
Checked:		Figure 10.1-1 (Sheet 4 of 6)	2010-04-14/14:11
Approved:		2912 MWt 63.14 bar 1800 rpm	TS90593C
Doc F L E Sh.No. N.o.Sh.		Post HP Retrofit - 3% throttle margin	

Drawn: RTC	KHNP	HEAT BALANCE DIAGRAM YONGGWANG 1 and 2 50% Load (Based on 2912MWt as 100%) Figure 10.1-1 (Sheet 5 of 6)	TSRTG 2010-04-14/14:11
Checked:			
Approved:		2912 MWt 63.14 bar 1800 rpm	TS90594C
Doc F L E Sh.No. N.o.Sh.		Post HP Retrofit - 3% throttle margin	

Drawn: RTC	KHNP	HEAT BALANCE DIAGRAM YONGGWANG 1 and 2 25% Load (Based on 2912MWt as 100%)	TSRTG
Checked:		Figure 10.1-1 (Sheet 6 of 6)	2010-04-14/14:12
Approved:		2912 MWt 63.14 bar 1800 rpm	TS90595C
Doc F L E Sh.No. N.o.Sh.		Post HP Retrofit - 3% throttle margin	

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PROCESS FLOW DIAGRAM STEAM AND POWER CONVERSION SYSTEM

Figure 10.1-2

10.2 TURBINE-GENERATOR

10.2.1 DESIGN BASES

Criteria for the selection of design bases are stated in paragraph 1.1.2.2.

10.2.1.1 Safety Design Bases

The turbine-generator has no safety design basis.

10.2.1.2 Power Generation Design Bases

10.2.1.2.1 Power Generation Design Basis One

479

The turbine-generator is designed to receive steam from the steam generators and convert the thermal energy into electric power in a base-loaded or load-following mode of operation.

10.2.1.2.2 Power Generation Design Basis Two

The turbine-generator load change characteristics are compatible with the restrictions imposed by or on the nuclear steam supply system (NSSS).

The steam turbine is compatible with the following loading capabilities of the NSSS:

A. To accept ramp-load changes of 5 percent rated power per minute and step-load change of 10 percent rated power from steady-state condition between 15 to 100 percent rated load.

B. This capability is based on the ability of the system to accept 64 percent steam dump (i.e.,36 percent steam dump to condenser and 28 percent 479
steam dump to atmosphere) and to maintain adequate feedwater supply to the steam generator. The 8
turbine bypass system is discussed in subsection 10.4.4.

C. To follow load changes automatically when these load changes occur within the automatic control range of 15 to 100 percent rated load; manual control is required below 15 percent load.

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2007. 8. 3

10.2.1.2.3 Power Generation Design Basis Three

The turbine-generator is designed to trip automatically under emergency conditions.

10.2.1.3 Codes and Standards

The turbine-generator and accessories are manufactured in accordance with the turbine-generator vendor's standards and specifications.

10.2.2 SYSTEM DESCRIPTION

10.2.2.1 General Description

The turbine-generator (designated TC6F-13.9sqm) is a four-casing,
570 full arc admission, tandem-compound, six-flow exhaust, 1800
rpm unit with 46-inch last stage blades.

361 The ac generator is connected directly to the turbine shaft
and the generator is equipped with a digital static excitation system.

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

Accessories for the turbine-generator include a complete
bearing lubrication oil system, digital electrohydraulic
control system, turbine steam seal system, protective valve
system, turning gear, crossunder and crossover piping, moisture
separator/reheaters, hydrogen system, seal oil system, stator
361 cooling system, digital static excitation system, control equipment,
and supervisory instruments.

10.2.2.2 Component Description

The turbine-generator system design features and performance characteristics are given in table 10.2-1.

10.2.2.2.1 Turbine

The main turbine consists of.one double-flow high pressure element in tandem with three double-flow low pressure elements. Steam from the three steam generators is supplied to the turbine-generator unit. The steam enters the high pressure turbine element through four steam lines. Two steam lines supply steam to the right-hand steam chest, and two steam lines supply steam to the left-hand steam chest. Each steam chest has two stop valves at each end and two control valves between the stop valves forming a single assembly. Each control valve (four) feeds steam to the turbine cylinder through their respective pipe. After expanding through the high pressure turbine element, the steam flows through two moisture separator/ reheat units, each consisting of a moisture separator and two-stage reheater within one vessel. Reheated steam from the moisture separator/ reheat vessels flows to the three low pressure turbine elements through six 42-inch crossover steam lines, each equipped with a separate reheat stop valve and a separate intercept valve. Each low pressure turbine element is fed by two steam lines.

Turbine extraction steam used for seven stages of feedwater heating is taken from seven extraction points (see figure 10.1-1), two on the HP turbine casing, one from the exhaust of the HP turbine, and four from the LP turbine casing. Motor-operated block valves and power assisted nonreturn valves in the third, fourth, fifth, sixth and seventh point extraction piping protect against the possibility of turbine water induction or overspeed due to energy storage in the extraction systems. Anti-flashback baffles are used in the first and second stages to protect the turbine against overspeed.

The exhaust from the three LP turbines passes to the condenser where it is condensed by the circulating water system (see subsection 10.4.5).

No radiation shielding is required for the turbine-generator and related steam handling equipment. Continuous access to the components of the system is possible during normal conditions. The steam generated in the steam generator is not normally radioactive. However, in the event of primary-to-secondary system leakage due to a steam generator tube leak, it is possible for the main steam to become radioactively contaminated. A discussion of radiological aspects of primary-to-secondary leakage is included in chapter 11.

10.2.2.2.2. Generator and Exciter

The generator is a 1,163,330 kVA unit designed for 22,000 volt, 3-phase, 60-hertz operation, at a power factor of 0.90. The generator stator is water cooled, and the rotor is hydrogen cooled. The generator hydrogen system includes all necessary controls and regulators for hydrogen cooling. A seal oil system is provided to prevent hydrogen leakage through the generator shaft seals. The service gas system, which is located outside the turbine building, provides hydrogen makeup 361 479 to replace any hydrogen leakage from the generator. Escaping hydrogen is vented from the turbine building to the atmosphere. Carbon dioxide provided from the liquified carbon dioxide storage cylinders is used for purging the hydrogen supply line and/or the generator, and ensures that no explosive mixture can be formed. Controls and pressure regulators are provided for the supply of carbon dioxide used in purging the generator.

361 The excitation system is of the digital static type directly supplying the generator rotor field. Its power source is derived from an excitation transformer connected to the generator side via isolated phase bus. The excitation system consists of silicon controlled rectifiers, digital triple voltage regulator, exciter and AVR control cubicles and excitation transformers.

10.2.2.2.3 Moisture Separator/Reheater

Two horizontal-axis, cylindrical-shell, combined moisture separator and reheater assemblies are installed between the high pressure and low pressure turbine elements. The water removed from the steam passing through the moisture separators is drained to the moisture separator drain tanks and from there to the feedwater heater drain tank.

Extraction steam from the high pressure turbine is supplied to the first-stage reheater tube bundles in each reheater. Condensate from these bundles drains via reheater drain tanks to the shell side of feedwater heater No. 6 in the appropriate train. Main steam is supplied to the second-stage reheater tube bundles, which drain via reheater drain tanks to the shell side of feedwater heater No. 7 in the appropriate heater train.

10.2.2.2.4 Turbine Steam Seal System

A full description of the turbine steam seal system is given in subsection 10.4.3.

10.2.2.2.5 Lube Oil System

The turbine-generator shaft bearings are lubricated by a conventional pressurized lube oil system. For normal operation, bearing oil is provided from the discharge of a high pressure centrifugal pump mounted on an extension of the turbine-generator shaft. During startup or shutdown, an ac motor-driven bearing oil pump supplies bearing oil to the shaft. A dc motor-driven emergency oil pump is also provided for lubrication during coastdown following lbss of normal ac power. Bearing lift pumps are also provided for each low pressure element bearing.

10.2.2.2.6 Digital Electrohydraulic Control System

The turbine-generator unit is equipped with a digital electro-hydraulic (DEH) control system to control steam flow through the turbine. The DEH control system is a programmable redundant digital controller, and consists of three major subsystems: 154

- Speed control unit.
- Load control unit.
- Control valve positioning unit.

The speed control unit compares actual turbine speed with a reference speed or actual turbine acceleration with a reference acceleration to provide a speed error signal for the load control unit. The load control unit combines the speed error signal with the load reference signal and determines desired steam flow signals for the control valve positioning units of the main control valves. The control valve positioning units in turn position the steam admission valves to obtain required steam flow through the turbine.

10.2.2.3 <u>System Operation</u>

10.2.2.3.1 Cycle Description

As shown in figures 10.1-2 and 10.2-1, the steam from the three steam generators is supplied to the turbine-generator. The steam enters the high pressure turbine element through four stop valves followed by four governing control valves. After expanding through the high pressure turbine element, the exhaust steam flows through the moisture separator and two-stage reheater. The drying and reheating processes, which take place between the high pressure turbine exhaust and low pressure turbine inlets, improve the cycle efficiency. A portion of the reheated steam is directed into the turbines which drive the steam generator feedwater pumps. The remainder of the reheated steam is conducted equally to the three low pressure turbine elements.

Steam extracted from the turbine at various stages of expansion is used for feedwater heating. There are a total of seven stages of feedwater heating. Two extractions from the high pressure turbine element are used to heat the No. 7 and No. 6 feedwater heaters, and part of the exhaust steam from the high pressure turbine element is used to heat the No. 5 feedwater heater. Extractions from the low pressure turbine elements are used to heat the No. 4, No. 3, No. 2, and No. 1 feedwater heaters

Extraction steam from the high pressure turbine is also used as heating steam for the first-stage reheater. Heating steam for the second-stage reheater is supplied from the main steam lines. Moisture-removal from the cycle is achieved by both external moisture separators and stage moisture removal in the low pressure turbine element.

10.2.2.3.2 Operation of the Turbine-Generator System

A description of control provided by bypassing main steam to the condenser and/or atmosphere in case of sudden load rejection by the turbine-generator is included in subsection 10.4.4.

During normal power generation, the main steam supply is delivered to the turbine for the generation of electrical energy. The DEH control system regulates the steam flow through the turbine to satisfy load demands.

The turbine-generator is designed to utilize the load-following capability designed into the reactor and the reactor control system. The NSSS has the capability of accepting a step load change of 10 percent and a ramp load change of 5 percent/min over the load range of 15 to 100 percent. Operation of the turbine bypass system will permit, without utilizing the main steam safety valves:

8 A. A reactor and turbine trip from full power

In the event of a sudden large load rejection that could lead to turbine overspeed, the load drop anticipator (LDA) function
154 of the overspeed protection controller (OPC) rapidly closes both the governor and interceptor valves at 105 percent rated speed. The primary objective of the OPC is to prevent excessive turbine overspeed such that a turbine trip is avoided. This is achieved by an overspeed function and load drop anticipator function.

154 The overspeed function of the OPC uses 2-out-of-3 logic to detect a speed channel failure. Above 105 percent rated speed the overspeed protection controller closes both the governor valves and interceptor valves. The reference is reset to rated speed. The interceptor valves are modulated by the speed in order to remove the entrapped steam in the reheater.

In automatic control, the governor valves stay closed due to the speed error until the speed has decreased to synchronous speed. At this point the digital system takes over control and maintains synchronous speed. The turbine-generator is ready for resynchronizing.

In manual control, the governor valves stay closed until the operator takes speed control by adjusting the appropriate governor valve position.

For further protection the load drop anticipator function will also be initiated if the reheat pressure transducer is in a failed-low condition and the main generator breaker opens. Emergency turbine overspeed protection is provided by two separate systems:

A. Mechanical Hydraulic Overspeed Protection

The turbine mechanical overspeed protective system is interfaced with the auto-stop and overspeed protection controller trip system. The mechanical overspeed trip signal initiates closure of all steam admission valves at 111 percent rated speed during normal operation. Appropriate orificing of the high pressure lubricating oil operated trip system establishes the overspeed and manual trip header which physically interfaces with the auto-stop system trip header. Either manual trip action or turbine overspeed, as detected by the overspeed trip device, will cause a loss of pressure in the overspeed and manual trip header. The loss of pressure in the auto-stop trip header results in closing of all the steam valves by diverting all actuator. motive fluid into the drain system, and is reflected by means of the diaphragm interface valve.

The diaphragm valve associated with the mechanical overspeed trip is mounted on the governor pedestal near the trip block. Under normal conditions, oil pressure keeps the diaphragm valve closed. This oil is lube oil supplied from the main bearing oil pump. If the mechanical overspeed trip should function, this pressure will collapse, unseating the diaphragm valve, sending the header oil to drain and thereby tripping the turbine.

B. Electric Overspeed Protection

The backup electrical overspeed trip initiates closure of all steam admission valves at 115 percent of rated turbine speed. The electrical trip system operates directly on the AST header by means of 4 AST solenoids. It uses signals obtained from magnetic pickups which monitor turbine rotor speeds, and opens a solenoid valve which dumps the fluid holding the steam admission valves open when the turbine speed reaches the trip point.

Complete on-line test capabilities are provided by the trip system without compromising protection. While one of two trip channels is being tested, the other trip channel provides trip protection.

There is a series of protective turbine-generator trips provided in the turbine-generator control system that cause tripping of all turbine steam admission valves when initiated.

The most significant design features of the governor control system, related to overspeed prevention, are presented in table 10.2-2.

10.2.2.3.2.1 Turbine Trips. The following turbine trips are provided:

- Emergency trip pushbutton
- Low vacuum
- Lubrication oil pressure low
- Low pressure turbine exhaust temperature high
- Reactor initiated turbine trip
- Thrust bearing wear
- Overspeed trip
- Low electrohydraulic fluid pressure.
- Steam generator level Hi-Hi
- 181 Loss of DEH power
- Mech Trip Lever
- Safety injection system

10.2.2.3.2.2 Generator Trips. The following generator trips are provided:

- Generator differential protection

- ○ Accidental energization 534
- ○ Negative phase sequence
- ○ Unit differential protection
- ○ First zone distance
- ○ Reverse power
- ○ Volts per hertz high
- ○ Generator stator ground fault
- ○ Under Frequency 534
- ○ Main transformer differential protection
- ○ Main transformer sudden pressure
- ○ Loss of excitation
- ○ Unit auxiliary transformer differential protection
- ○ Unit auxiliary transformer overcurrent
- ○ Unit auxiliary transformer neutral ground (4.16 kV and 13.8 kV)
- ○ Loss of generator field
- ○ Unit auxiliary transformer sudden pressure.
- ○ Excitation system trouble.
- ○ Excitation transformer differential protection. 361
- ○ Excitation transformer overcurrent protection.

In addition to the foregoing trips, the turbine-generator is equipped with the following protective devices:

A. Safety valves on the shell side of the moisture separator reheaters (MSR) to protect the MSRs shells from overpressure in the event of a turbine trip.

B. Nonreturn valves in the steam extraction lines to No. 3, 4, 5, 6 and 7 feedwater heaters to prevent reverse extraction line flow from overspeeding the turbine in the event of a turbine trip and to minimize water induction into the turbine.

C. Exhaust casing rupture diaphragms to protect the low pressure turbine elements from overpressure in the event of a loss of condenser vacuum.

Under normal operating conditions, there are no detectable radioactive contaminants present in the steam produced in the three steam generators. However, in the event of large primary-to-secondary system leakage due to a steam generator tube leak, it is possible for the secondary system to become radioactively contaminated. A discussion of the radiological aspects of primary-to-secondary leakage, including anticipated operating concentrations of radioactive contaminants, means of detection of radioactive contamination, and anticipated releases to the environment is included in chapter 11.

10.2.3 TURBINE DISC INTEGRITY

A full discussion of turbine missiles, including the probabilities of genesis and damage, is given in section 3.5.

10.2.3.1 Materials Selection

A. LP Disc Forgings

Forgings produced for nuclear turbine discs comply with Siemens AG specifications. More general ASTM specifications for disc (A-471 cl. 1-9) exist and may be used for guidance. The material used for the disc is a nominal 3.5 percent Ni, 1.5 percent Cr, 0.4 percent Mo, 0.1 percent V composition. These materials are melted in basic electric furnaces and are vacuum carbon deoxidized to minimize the level of objectionable gases such as hydrogen and also to keep the Si content at a low level which improves toughness. | 570 | 570

Sufficient discard is taken from the top and bottom of each ingot to remove pipe and the most heavily segregated material. Several forging operations are performed which usually include blocking and upsetting operations. The axial center of the ingot is kept in common with the center of the forging during these operations. The as-forged dimensions of each forging are made as close as possible to the finished machined dimensions.

The forgings are then given a preliminary heat treatment consisting of a single or double normalize and temper to refine the structure. After rough machining to heat treating dimensions, the forgings are austenitized, quenched, and tempered to produce the desired properties. For discs, the tensile and impact properties are then determined as both the rim and the bore of the forgings. A minimum of six impact specimens are used to determine the fracture appearance transition temperature (FATT) in comparable with ASTM A-370. | 570

After heat treatment, all discs are completely ultrasonically inspected to insure freedom from harmful internal defects. Because the disc is contoured before heat treatment, certain areas cannot be reliably tested using ultrasonic techniques. In a typical disc these areas are the radii in the contour areas as are shown in figure 10.2-2. All ultrasonic indications are evaluated by the Steam Turbine Division Engineering Department. After finish machining of the disc forging in the Westinghouse shops, the disc is 100 percent surface inspected (excluding the blade grooves) using a fluorescent magnetic particle technique. Magnetic particle indications on surfaces exposed to a steam environment are not permitted.

B. HP Rotor Forgings

Forgings produced for nuclear turbine rotors are made to comply with Alstom specification STV M22024(Rev. B). The material used for the rotor is 3.00 to 3.75 percent Ni, 1.30 to 1.80 percent Cr, 0.30 to 0.50 percent Mo, 0.07 to 0.15 percent V composition.
Sufficient discard is taken from the top and bottom of each ingot to remove the most heavily segregated material. Several forging operations are performed which usually include stretching and upsetting operations. Immediately after forging operations, the forgings are given a preliminary heat treatment consisting of a single or double normalize and temper to refine the structure. 368

After rough machining to heat treating dimensions, the forgings are austenitized, quenched, and tempered to produce the desired properties. Rotor tensile and impact properties are determined at both ends and the middle of the forgings. A minimum of ten impact 368
specimens are used to determine the fracture appearance transition temperature (FATT) in the central part of the 368
forgings in accordance with ASTM A-370.

After heat treatment for properties, the rotors are ultrasonically inspected to insure freedom from harmful internal defects. After finish machining at factory, the external surfaces (excluding blade grooves) are magnetic particle inspected. 368

Delete

C. Mechanical Properties

The disc material property requirements are listed in table 10.2-4 along with the comparable ASTM requirement for ASTM A-471. The high pressure rotor material property requirements are listed in table 10.2-5. 368

Delete

The fracture appearance transition temperature (50 percent FATT) is obtained from Charpy tests performed in accordance with specification ASTM A-370. Siemens AG
570 requires that the FATT be no higher than -80 ℃ for the
368 low pressure disc. Alstom requires that the FATT
be no higher than +10℃ for HP rotor material.

Charpy V-notch (Cv) energy at room temperature of each
570 low pressure disc is at least 130 J. The Cv
368 energy of high pressure rotor materials at 0℃ is at least 54J.

10.2.3.2 Fracture Toughness

A. The ratio of K_{IC} to maximum tangential stress for discs and rotors at speeds from normal speed to design overspeed is not utilized because this ratio may assume a minimum value at a stress below the maximum due to temperature dependency of K_{IC}.

Delete

At steady-state temperature conditions at normal and design
570 overspeeds, the ratio K_{IC}/σ max ≥ 2.0 for the smooth bores within
the discs of Siemens AG nuclear turbines.

Delete

The largest flaw that can escape inservice detection is dependent on the inspection method. The present state of the art for inspection if disc bores without disassembly is not developed to the point that there is assurance that flaws will not escape detection.
570 Siemens AG has an inservice inspection procedure
actively and successfully in use.

570 Siemens AG has the technical capability to make a
fracture mechanics analysis based on appropriate conservative assumptions to calculate the critical flaw size at speeds from normal speed to design overspeed
570 (115 percent rated speed). As noted above, Siemens AG
has an inservice inspection in active and successful use.

B.

Delete

570

Delete

570

C. K_{IC} values are explained in Siemens AG Missile Probability Anaysis report SU-EN-MO-M-10-11947.

D. Current specification limits include centrifugal, interference, and thermally induced stress where applicable.

E. The maximum FATT values of low pressure discs of -80 ℃ and high pressure rotors of 10℃ ensure that the metal temperature of the discs and rotors during operation is adequately above the FATT. 570 368

10.2.3.3 High Temperature Properties

Since the steam at the turbine stop valve only has a temperature of approximately 535.7°F for YGN 1 and 2, it is not considered that creep processes will occur on the HP rotors and, therefore, stress rupture properties are not relevant.

10.2.3.4 Turbine Disc Design

A. Design Overspeed

The highest anticipated speed resulting from a loss of load is less than 110 percent of rated speed. The rotor is spin tested at 120 percent of rated speed.

B. LP Disc and HP Rotor Stresses

At a speed of 115 percent, the maximum tangential stress in low pressure discs or high pressure rotors due to centrifugal force, interference fit and thermal gradients should not exceed 0.75 of the maximum specified yield strength of the material.

The rotors are designed so that the response levels at the natural critical frequency of the turbine shaft assemblies are controlled between zero speed and 20 percent overspeed so as to cause no distress to the unit during operation.

368 Delete

The rims of the low pressure discs can also be inservice
570 inspected. As previously noted, Simens AG has inservice inspection procedures.

10.2.3.5 Preservice Inspection

A. Discs are rough machined as close as practical to the forging drawing dimensions prior to heat treatment for properties. After heat treatment, the forgings are machined to the dimensions of the forging drawing and stress relieved.

Rotors are rough machined with minimum stock allowance prior to heat treatment and stress relieved.

B. After heat treatment, the rough machined disc is ultrasonically inspected on the flat surfaces of the hub and the rim (see figure 10.2-2). If ultrasonic indications are detected in the hub or the rim sections, additional ultrasonic testing may be required in the web section. These ultrasonic tests are defined by a
570 Siemens AG specification, which is similar to the requirements of ASTM A-418.

The rotors are ultrasonically tested after heat treatment and rough machining. The sonic indications are either removed or evaluated to assure that they will not grow to a size that will compromise the integrity of the component during its service life.

368 Delete

C. The finished machined discs are fluorescent magnetic particle inspected including blade grooves. The disc is shrunk onto the shaft. After the disc is cooled,
570 equally spaced round bottomed holes are drilled and reamed and are inspected using dye penetrant techniques. No indications are allowed in the bore regions.

D. Each fully bladed rotor assembly is spin tested at 120 percent of rated speed. The maximum speed anticipated following a turbine trip from full load is less than 110 percent of rated speed.

10.2.3.6 Inservice Inspection

A. The timing of the inservice inspection program will be determined later by KHNP. The disassembly of the turbine at approximately 10 years is acceptable to Siemens AG. However, Siemens AG feels that in the future the inspection interval should be determined not by a time interval but by a probabilistic approach, where fracture mechanics criteria determine the time for an inspection, based on the number of cycles of operation during which the discs may have experienced high stress. 479 570

When the turbine is disassembled, a visual and magnetic particle examination is made externally on accessible areas of the high pressure rotor, low pressure turbine blades and low pressure discs. The coupling and coupling bolts are visually examined.

B. Westinghouse recommends a schedule of valve inspection for throttle, governor, reheat stop and interceptor valves at 15, 17, and 39 months after initial startup of a turbine. In this program, some valves are inspected 12-15 months after startup, others 24-27 months, and the remainder 36-39 months so that all valves are inspected at least once in the 39 months of operation following initial startup, and throttle and reheat stop valves are inspected twice in this period. After this initial inspection program is completed, inspection of all valves at least once every 36-39 months is suggested.

C. Westinghouse recommends that a functional test of the turbine steam inlet valves be performed weekly. This test can be made while the unit is carrying load. The purpose of the test is to ensure proper operation of throttle, governor, reheat stop and interceptor valves. Westinghouse recommends that the operation of these valves be observed during the test by an operator stationed at the valves. Movements of the valves should be smooth and free. Jerky or intermittent motion may indicate a buildup of deposits on shafts. As proper operation of these valves is vital, prompt remedial action is imperative if difficulty of any type is indicated during these tests. The functional testing requirements for nuclear turbines are as follows:

1. Once Each Week (A complete check of valve stem freedom)

   a. Throttle valves

   b. Governor valves

c. Reheat stop valves

d. Interceptor valves

e. Extraction nonreturn valves

2. Once Each Month

a. Overspeed trip - oil trip test

b. Low vacuum trip

c. Low bearing oil trip

d. Thrust bearing trip

e. Electrical overspeed trip

f. Low EH fluid tripe

3. Once Every Six Months

a. Overspeed emergency trip by overspeeding the unit

b. Remote trip

c. Initial pressure regulator

d. Auxiliary governor (overspeed protection controller)

4. Once Each Startup

Check the overspeed protection controller once each startup at any speed up to rated speed. Check visually to be sure governor and interceptor valves close up.

10.2.4 EVALUATION

The turbine-generator has no safety-related design basis. Subsection 10.2.2 provides an assessment of design and operation. Significant features of the turbine-generator system are summarized as follows:

A. As determined in chapter 15, failure of the system will not impair the capability of the reactor for safe shutdown and cooldown.

B. No shielding is necessary to meet 10 CFR 20 standards, and no control of access is required under operating conditions. The radiological evaluation of the secondary coolant system is discussed in section 11.2.

C. The turbine-generator interfaces with the NSSS under all operating conditions in a manner which does not impair the capability of the reactor for safe shutdown and cooldown.

D. The turbine-generator interfaces with the NSSS under all operating conditions in such a manner that the permissible operating restraints on the turbine are not exceeded.

E. Major interfacing systems with the turbine-generator, particularly the main steam supply, the extraction steam system, and the main condenser system, are designed in a manner consistent with maintaining the mechanical integrity of the turbine-generator unit.

F. The turbine-generator and the auxiliary equipment are manufactured, erected, preoperationally tested, started up, and will be operationally maintained to ensure the continued operational reliability of all systems and the mechanical integrity of the main turbine-generator unit.

G. Radiation exposure levels resulting from accidents are developed in chapter 15.

H. The design of the reinforced concrete pedestal supporting the main generator minimizes pockets on the underside in which escaped hydrogen could collect. The potential for an explosion is considered nil, since there is no high pressure gas within the building and the ventilation system prevents accumulation of any minor leakage that may occur.

Table 10.2-1

TURBINE-GENERATOR DESIGN FEATURES
AND PERFORMANCE CHARACTERISTICS
(Manufacturer : Turbine-Siemens AG& ALSTOM, 570
Generator-Doosan Heavy Industries & Construction Co., Ltd.) 368 361

Turbine		
Type	TC6F-13.9sqm	570
Number of elements	1 HP, 3 LP	
Last stage blade length, in.	46	570
Operating speed, rpm	1800	
Condenser pressure, in. HgA	1.5	
Turbine cycle heat rate, Btu/kWh	9,308 (100% load)(a)	479,570
Generator		
Net generator output, kW	1,063,016 (100% load)(a)	488,570
Generator rating, kVA	1,163,330	479
Power factor, pf	0.90	
Voltage, kV	22	
Hydrogen pressure, psig (maximum)	75	
Combined Moisture Separator/Reheater (a)		
Type	Shell and tube	
Number	Two	
Steam flow, lb/h		
Moisture Separator	9,759,768	479
1st Stage Reheater	591,934	479
2nd Stage Reheater	514,325	479

a. With 1% blowdown and 0.5% system makeup

Table 10.2-2
TURBINE GENERATOR CONTROL SYSTEM DESIGN FEATURES

Governor Control and Emergency Overspeed Protection	Control Function	Physical Sensor Type and Number	Control Channel Type and Number	Final Control Elements	Control Channel Redundancy	Control Channel Independence	Point of Independency Termination	Control channel Physical separation
Trubine electric governor	Normal speed-acceleration control	Three independent magnetic speed pickups	Three independent speed-acceleration computing channels	Three independent control signal transmission lines (highways)	Triplicate speed computing channel redundancy	Three independent channels with independent control lines	Valve controller	Three physically separate and isolated speed computing control channels
Electro-hydraulic actuators control system	Speed con-trol and overspeed protection	Valve controller with dual control channel	Fourteen hydraulic servo con-trol valve actuators, six solenoid controlled valve actuators	Dual channel valve controller	Dual control channels valve control module	Dual control channels	Hydraulic ram	Two separate control channels in each actuator
Governor alarm and trip module	Turbine protection and over-Speed prevention	Central electrical alarm moni-tor for emergency detection and control	One elec-trical alarm malfunction signal processor	One solenoid dump valve per hydraulic actuator	Governor alarm mon-itor and protective circuits	Independent lines for transmission of alarms and isolation	Turbine trip protective circuits	Separate alarm signal from each control module
Emergency overspeed protection	Prevent turbine overspeed in case of governor failure	Two inde-pendent mechanical overspeed sensing devices Four inde-pendent electronic speed mea-suring channels	Two mechani-cal actuated emergency overspeed trip channels Four elec-trical independent emergency trip channels	One solenoid dump valve per hydraulic actuator Two sole-noids on emergency overspeed trip	Dual emergency mechanical overspeed protection channels Four emer-gency elec-trical overspeed protection channels	Two inde-pendent channels with individual final control elements	Turbine trip protective circuits	Two physically separate isolated mechanical overspeed emergency control channels Four electri-cal overspeed emergency control channels

Table 10.2-3

TURBINE VALVE RESPONSES (Seconds)

Valve	Closing	Opening
High pressure stop valve	0.2	2.5
High pressure governing valves	1.5	2.5
Low pressure stop valves	1.5	60
Low pressure intercept valves	1.5	60

Table 10.2-4

REQUIRED PROPERTIES OF SIEMENS AG TURBINE DISCS
COMPARED WITH ASTM A-471

	.2% YS (N/mm²)	UTS (N/mm²)	Elong. (%)	RA (%)	FATT (℃)	At Room Temper-ature CVN Energy (J)
Disc-1	780-850	≤1,010	≥15	≥50	≤-80	≥130
Disc-2	820-890	≤1,060	≥15	≥50	≤-80	≥130
Disc-3	820-890	≤1,060	≥15	≥50	≤-80	≥130

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Amendment 570
2013. 4. 10

Table 10.2-5

REQUIRED PROPERTIES OF ALSTOM TURBINE HP ROTORS

368

.2% YS (MPa)	UTS (MPa)	Elong. (%)	RA (%)	FATT (℃)	At 0℃ CVN Energy (J)
540 min 640 max	640 min	14 min	45 min	10 max	54 min

KOREA HYDRO & NUCLEAR POWER COMPANY
YGN 1 & 2 FSAR

FDEO P & I DIAGRAM
MAIN TURBINE SYSTEM
(SHEET 1 OF 4)
FIGURE 10.2-1

Amendment 462
2010.03.18

KOREA HYDRO & NUCLEAR POWER COMPANY
YGN 1& 2 FSAP

FDED P & I DIAGRAM
MAIN TURBINE SYSTEM
(SHEET 2 OF 4)
FIGURE 10.2-1

Amendment 400
2008.10.30

KOREA HYDRO & NUCLEAR POWER COMPANY
YGN 1& 2 FSAR

FDEO P & I DIAGRAM
MAIN TURBINE SYSTEM
(SHEET 3 OF 4)
FIGURE 10.2-1

Amendment 154
2001.10.16

KOREA HYDRO & NUCLEAR POWER COMPANY
YGN 1 & 2 FSAR

FDEO P & I DIAGRAM
MAIN TURBINE SYSTEM
(SHEET 4 OF 4)
FIGURE 10.2-1

KOREA ELECTRIC POWER CORPORATION
KOREA NUCLEAR UNITS 7 & 8
FSAR

ULTRASONIC INSPECTION-
LP TURBINE DISC FORGINGS

Figure 10.2-2

10.3 MAIN STEAM SUPPLY SYSTEM

The function of the main steam supply system (MSSS) is to convey steam generated in the steam generators by the reactor coolant system to the turbine-generator system and auxiliary systems for power generation.

10.3.1 DESIGN BASES

10.3.1.1 Safety Design Bases

The portion of the MSSS from the steam generator outlet to and including the first seismic anchor following the main steam isolation valves (MSIV) is safety-related, and is required to function following a design basis accident (DBA) and to achieve and maintain the plant in a safe shutdown condition.

10.3.1.1.1 Safety Design Basis One

The safety-related portion of the MSSS is protected from the effects of natural phenomena, such as earthquakes, typhoons, floods, and external missiles.

10.3.1.1.2 Safety Design Basis Two

The safety-related portion of the MSSS is designed to remain functional both during and after an SSE, or to perform its intended function following postulated hazards of fire, internal missile, or pipe break.

10.3.1.1.3 Safety Design Basis Three

Component redundancy is provided so that safety functions can be performed, assuming a single active component failure coincident with the loss of offsite power.

10.3.1.1.4 Safety Design Basis Four

The MSSS is designed so that the active components are capable of being tested during plant operation. Provisions are made to allow for inservice inspection of components at appropriate times, as specified in the ASME Boiler and Pressure Vessel (B&PV) Code, Section XI.

10.3.1.1.5 Safety Design Basis Five

The MSSS uses design and fabrication codes consistent with the quality group classification assigned by Regulatory Guide 1.26 and the seismic category assigned by Regulatory Guide 1.29. The power supply and control functions are in accordance with Regulatory Guide 1.32.

10.3.1.1.6 Safety Design Basis Six

The MSSS provides for isolation of the secondary side of the steam generator to deal with leakage or malfunctions, and to isolate nonsafety-related portions of the system.

10.3.1.1.7 Safety Design Basis Seven

The MSSS provides means to dissipate heat generated in the reactor coolant system during reactor cooldown following any abnormal plant condition.

10.3.1.1.8 Safety Design Basis Eight

The MSSS provides an assured source of steam to operate the turbine-driven auxiliary feedwater pump for reactor cooldown under emergency conditions and for shutdown operations.

10.3.1.1.9 Safety Design Basis Nine

Safety-related instrument air will be used to back up non safety-related instrument air to PORVs for their safety functions.

10.3.1.2 Power Generation Design Bases

10.3.1.2.1 Power Generation Design Basis One

The MSSS is designed to deliver steam from the steam generators to the turbine-generator system for a range of flows and pressures varying from warmup to rated conditions. The system provides means to dissipate heat during plant step load reductions and during plant startup. It also provides steam to:

A. The turbine-generator system second stage reheaters

B. The main feed pump turbines and auxiliary feed pump turbine

C. The steam seal system

D. The turbine bypass system (TBS)

E. The auxiliary steam system

F. The process sampling system.

10.3.1.3 Codes and Standards

Codes and standards applicable to the MSSS are listed in table 3.2-1. The MSSS is designed and constructed in accordance with ASME B&PV Code, Section III, Safety Class 2 and Quality Group B requirements from the steam generator out to the first seismic anchor following the main steam isolation valve. The remaining piping out to the turbine-generator and auxiliaries meets ANSI B31.1 requirements.

10.3.2 SYSTEM DESCRIPTION

10.3.2.1 General Description

The MSSS is shown in figure 10.3-1. The system conveys steam from the steam generators to the turbine-generator system. The system consists of main steam piping, power-operated relief valves, safety valves, main steam isolation valves, atmospheric dump valves, and turbine bypass valves. The turbine bypass system is discussed in detail in subsection 10.4.4.

The MSSS instrumentation, as described in table 10.3-1 and chapter 7, is designed to facilitate automatic operation and remote control of the system, and to provide continuous indication of system parameters. As described in chapter 7, instrumentation is provided to provide protection against potential accidents involving the secondary system.

10.3.2.2 Component Description

Design data for MSSS components are listed in table 10.3-2.

10.3.2.2.1 Main Steam Piping

Saturated steam from the three steam generators is conveyed to the turbine generator by three 29.25-inch ID lines. The lines are sized for a pressure drop of less than 35 psi from the steam generators to the turbine stop valves at turbine manufacturer's guaranteed conditions. Refer to figure 10.2-1.

Each of the lines is anchored at the containment penetration, and has sufficient flexibility to provide for movement of the steam generators due to thermal expansion. The main steam line between the containment penetration and the Seismic Category I pipe restraints downstream of the MSIV are designed to meet the no-break zone criteria of NRC BTP MEB 3-1, as described in section 3.6.

Each line is equipped with:

A, Two power-operated atmospheric relief valves

B. Five spring-loaded safety valves

C. One main steam isolation valve

D. One low point drain, which is piped to the condenser through a drain valve

E. One flow restrictor.

All main steam branch process line connections are made downstream of the isolation valves, with the exception of the line to the power-operated atmospheric relief valve, connections for the safety valves, lines to the auxiliary feedwater pump turbine, and low-point drains and high-point vents.

Each steam generator outlet nozzle contains a flow restrictor assembly with equivalent throat diameter of 16 inches to limit flow in the event of an MSLB.

Each main steam line contains five spring-loaded safety valves, two power-operated atmospheric relief valves, and an MSIV, all of which are located outside of the containment. All other main steam connections are made downstream of the isolation valves with the exception of the auxiliary feedwater pump turbine steam supply takeoffs and low-point drains.

The main steam piping is cross-connected downstream of the isolation valves, with four 28-inch main steam lines from the header to the main turbine stop valves. Branch piping from the cross-connection header provides steam to the reheaters, auxiliary steam system, main feedwater pump turbines, turbine bypass piping to the condensers, and steam dump to atmosphere.

Drain lines are connected to the low points of each main steam line. These drains are connected to the condenser, and the lines are sloped to promote adequate drainage. Orificed valves or steam traps are installed in the drain lines to permit continuous drainage from the main steam line low points.

10.3.2.2.2 Power-Operated Relief Valves (PORVs)

Two power-operated, atmospheric, relief valves are installed in each main steam line upstream of the safety valves, with one of the two valves being a spare. The PORVs are provided for cooldown following any abnormal plant condition. The PORVs are also used to provide for controlled removal of reactor decay heat during normal reactor cooldown when the main steam isolation valves are closed or the turbine bypass system is not available. The valves will pass sufficient flow at all pressures to achieve a 50°F per hour plant cooldown rate. The maximum actual capacity of the relief valve at design pressure is limited to reduce the magnitude of a reactor transient if one valve would inadvertently open and remain open.

The PORVs are air-operated. A nonsafety-related air supply is available during normal operating conditions. In case that non safety-related air supply is not available, safety-related air will automatically back up the supply. The capability for remote manual valve operation is provided in the main control room and at the auxiliary shutdown panel. The valves are opened by pneumatic pressure and closed by spring action. In addition, provisions are made for local manual operation of the PORVs by using reach rods.

The two PORVs on each steam line are powered by separate safety trains. Each PORV is provided with an upstream, active, motor-operated isolation valve with Class 1E operator to be controlled by the same train as the PORV.

10.3.2.2.3 Safety Valves

The spring-loaded main steam safety valves provide overpressure protection in accordance with the ASME Section III code requirement for the secondary side of the steam generators and the main steam piping. There are five valves installed in each main steam line. Table 10.3-2 identifies the valves, their set pressure, and capacities. The valves discharge directly to the atmosphere via vent stacks. The maximum actual capacity of the safety valves at the design pressure is limited to reduce the magnitude of a reactor transient if one of the valves would open and remain open.

10.3.2.2.4 Main Steam Isolation Valves (MSIV)

One MSIV is installed in each of the three main steam lines outside the containment and downstream of the safety and relief valves. The MSIVs are installed to prevent uncontrolled blowdown from more than one steam generator in the event of a pipe failure. The valves isolate the nonsafety-related portions from the safety-related portions of the system. The valves are bidirectional, double-disc, parallel slide gate valves. Stored energy for closing is supplied by accumulators that contain a fixed mass of high pressure nitrogen gas and a variable mass of high pressure hydraulic fluid. For emergency closure, the train A or B, or both train A and B pilot valves are de-energized causing the high pressure hydraulic fluid to be admitted to the top of the valve stem driving the piston closed, and also causing the fluid stored below the piston to be dumped to the fluid reservoir. Two separate pneumatic/hydraulic power trains are provided. Electrical solenoids for the separate pneumatic/ hydraulic power trains are energized from separate Class 1E sources. The valves are designed to close within 5 seconds against the flows associated with line breaks on either side of the valve, assuming the most limiting normal operating conditions prior to occurrence of the break. Valve closure capability is tested in the manufacturer's facility by pressurizing the valve body and closing the valve twice, each time with a different setting of actuator controls. Preservice and inservice tests are also performed as discussed in paragraphs 10.3.4.2 and 10.3.4.3, respectively.

10.3.2.2.5 Main Turbine Steam Bypass Valves

A total of 16 steam dump valves provides capability to dump 64 percent of rated main steam flow following generator load
479 rejection. Of this, 36 percent of rated main steam flow is bypassed to the condenser and 28 percent of rated main steam flow is dumped to the atmosphere. The turbine bypass system is discussed in detail in subsection 10.4.4.

10.3.2.3 System Operation

During plant startup, the vacuum pumps are used to establish condenser vacuum. The condenser evacuation system is discussed in subsection 10.4.2.

Main steam from the cross-connection header is then applied to the main feedwater pump turbine driver and the feedwater system is placed in operation. When the plant is operating above approximately 40 percent load, the steam supply for the main feedwater pump is shifted to the outlet of the steam reheater. The main feedwater system is discussed in subsection 10.4.7.

At low power levels, the main steam supply system provides steam to the turbine steam seal system via the auxiliary steam header. This prevents leakage of air into the condenser via the turbine steam seal system. The turbine steam seal system is described fully in subsection 10.4.3.

Main steam is supplied to the second-stage reheaters and extraction steam to the first-stage reheaters during power operation to raise the plant efficiency. The reheaters are described in section 10.2.

If a large rapid reduction in turbine-generator load occurs, steam is bypassed (36 percent of the rated capacity) directly to the condenser and 28 percent of the rated capacity) to atmosphere via the turbine bypass system. If the turbine bypass system is not available, steam is vented to the atmosphere via the PORVs and the safety valves, as required. 479 8

During certain emergency conditions, steam from the main steam supply system is provided automatically to the auxiliary feedwater pump turbine driver. Thus, it is possible to feed the steam generators to produce steam and thereby remove decay heat from the reactor core. The auxiliary feedwater system is described fully in subsection 10.4.9.

In the event that a main steam line break occurs that results in a main steam isolation signal (MSIS), the MSIVs automatically close. Steam is automatically provided to the auxiliary feedwater pump turbine from one of two steam lines upon low-low level in two steam generators or loss of offsite power. Redundant check valves are installed in the lines to the turbine to ensure that only one steam generator will feed a ruptured-main steam line. The closure of two out of three MSIVs will ensure that no more than one steam generator can supply a postulated break.

The coordinated operation of the main steam supply system, the safety valve/relief valve system, the turbine bypass system, and the auxiliary feedwater system during a large generator load rejection, or loss of offsite power situation as described above, may also be employed to remove decay heat during normal shutdown operations.

Radioactive leakage into the main steam supply system is detected by the radiation monitor located in the condenser air removal exhaust line and by the steam generator blowdown radiation monitor. The radiological aspects of a major secondary system pipe rupture are discussed in section 15.1.

Minor steam leakage from the main steam supply system is detected by visual inspection. Major leakage is detected by temperature sensors located on each of the main steam lines.

10.3.3 SAFETY EVALUATION

Safety evaluations are numbered to correspond to the safety design bases of paragraph 10.3.1.1.

10.3.3.1 Safety Evaluation One

The safety-related portions of the MSSS are located in the reactor and auxiliary buildings. These buildings are designed to withstand the effects of earthquakes, typhoons, floods, external missiles, and other appropriate natural phenomena. Sections 3.3, 3.4, 3.5, 3.6, and 3.11 provide the bases for the adequacy of the structural design of these buildings.

10.3.3.2 Safety Evaluation Two

The safety-related portions of the MSSS are designed to remain functional both during and after an SSE. Sections 3.7 and 3.9 provide the design loading conditions that were considered. Sections 3.5 and 3.6 provide the hazards analyses to assure that a safe shutdown, as outlined in section 7.4, can be achieved and maintained.

10.3.3.3 Safety Evaluation Three

As indicated by table 10.3-3, no single failure will compromise the system's safety functions. All vital power can be supplied from either onsite or offsite power systems, as described in chapter 8.

10.3.3.4 Safety Evalution Four

The MSSS is initially tested with the program given in chapter 14. Periodic inservice functional testing is done in accordance with subsection 10-3.4.

Section 6.6 discusses the ASME B&PV Code, Section XI inservice inspection requirements that are appropriate for the MSSS.

10.3.3.5 Safety Evaluation Five

Section 3.2 delineates the quality group classification and seismic category applicable to the safety-related portion of this system and supporting systems. Table 10.3-2 indicates the design and fabrication codes for MSSS components. All the power supplies and controls necessary for safety-related functions of the MSSS are Class 1E, as described in chapters 7 and 8.

10.3.3.6 Safety Evaluation Six

Redundant power supplies and power trains operate the MSIVs to isolate safety and nonsafety-related portions of the system. Branch lines upstream of the MSIV contain normally closed power-operated relief valves that modulate open and closed on steam line pressure. The power-operated relief valves fail close on loss of air, and the safety valves provide the overpressure protection.

Accidental releases of radioactivity from the MSSS are insignificant due to negligible amount of radioactivity in the system under normal operating conditions. Additionally, the main steam isolation system provides controls for reducing accidental releases, as discussed in chapter 15, following a steam generator tube rupture.

Detection of radioactive leakage into and out of the system is facilitated by process radiation monitoring (discussed in section 11.5) and steam generator blowdown sampling (discussed in subsections 9.3.2 and 10.4.8).

10.3.3.7 Safety Evaluation Seven

Each main steam line is provided with two power-operated relief valves to permit reduction of the main steam line pressure, and remove stored energy to achieve an orderly cooldown following any abnormal plant condition. The auxiliary feedwater system, which is described and evaluated in subsection 10.4.9, provides makeup to the steam generators consistent with the steaming rate.

The PORVs are air-operated and supplied from a safety and nonsafety-related air supply. The capability for remote valve operation is provided in the main control room and at the auxiliary shutdown panel.

The PORVs are capable of manual operation. Reach rods are provided for local manual operation of PORVs.

10.3.3.8 Safety Evaluation Eight

The steam line to the auxiliary feedwater pump turbine is connected to a cross-connecting header upstream of the MSIV. This arrangement ensures a supply of steam to this turbine when the steam generators are isolated. Redundant check valves are provided in ach supply line from the main steam lines to preclude any potential backflow during a postulated main steam line break. The auxiliary feedwater system is described in subsection 10.4.9.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

10.3.4.1 Preservice Valve Testing

The safety valves located in the main steam piping at the outlet from each steam generator are individually tested during initial-startup or shutdown operation by checking the actual lift and reseating point of the valve, as indicated by pressure gauges mounted on the main steam piping.

The lift-point of each PORV is checked against pressure gauges mounted in the main steam piping.

The MSIVs are checked for closing time prior to initial startup.

10.3.4.2 Preservice System Testing

Preoperational testing is described in chapter 14.

The MSSS is designed to include the capability for testing through the full operational sequence that brings the system into operation for reactor shutdown and for MSLB accidents, including operation of applicable portions of the protection system and the transfer between normal and standby power sources.

The safety-related components of the system, i.e., valves and piping, are designed and located to permit preservice and inservice inspections to the extent practicable.

10.3.4.3 Inservice Testing

The performance, structural, and leaktight integrity of all system components are demonstrated by continuous operation.

The closure time and the operability of the actuator for the redundant
203 actuator power trains of each MSIV are checked by fully closing the
valve every reactor cold shutdown pursuant to In-Service Test Plan.

Additional discussion of inservice inspection of ASME Code Class 2 and 3 components is contained in section 6.6.

10.3.5 SECONDARY WATER CHEMISTRY

10.3.5.1 Chemistry Control Basis

Steam generator secondary-side water chemistry control is accomplished by :

A. A close control of the feedwater chemistry to limit the amount of impurities that can be introduced into the steam generator

B. The capability of a continuous blowdown of the steam generators to reduce concentrating effects of the steam generator

C. Chemical addition to establish and maintain an environment that minimizes system corrosion

D. By post-construction cleaning of the feedwater system

E. Minimizing feedwater oxygen content prior to entry into the steam generator by deaeration in the hotwell

F. The capability of continuous demineralization and filtration of the condensate system through partial flow, deep bed condensate demineralizers.

Secondary water chemistry is based on the all volatile treatment (AVT) method. This method employs the use of volatile additives to maintain system pH and to scavenge dissolved oxygen present in the feedwater. 132
ETA is added, to establish and maintain alkaline conditions in the feedtrain. Although ETA is volatile and will not concentrate in the steam generator, it will reach an equilibrium level that will establish an alkaline condition in the steam generator.

Hydrazine is added to scavenge dissolved oxygen present in the feedwater. Hydrazine also tends to promote the formation of a protective oxide layer on metal, surfaces by keeping these layers in a reduced chemical state.

Both ETA and hydrazine can be injected continuously at the discharge headers of the condensate pumps and are added, as necessary, for chemistry control. 132

Operating chemistry guidelines for secondary steam generator water are given in table 10.3-4. Water chemistry monitoring is discussed in subsection 9.3.2. The requirements of BTP MTEB 5-3 are met.

The condensate demineralizer system is discussed in subsection 10.4.6. Alkaline conditions in the feed train and the steam generator reduce general corrosion at elevated temperatures and tend to decrease the release of soluble corrosion products from metal surfaces. These conditions promote formation of a protective metal oxide film, and thus reduce the corrosion products released into the steam generator.

10.3.5.2 Corrosion Control Effectiveness

Hydrazine also promotes formation of a metal oxide film by the reduction of ferric oxide to magnetite. Ferric oxide may be loosened from the metal surfaces and be transported by the feedwater. Magnetite, however, provides an adhesive, protective layer on carbon steel surfaces. Removal of oxygen from the secondary waters is also essential in reducing corrosion. Oxygen dissolved in water causes general corrosion that can result in pitting of ferrous metals I particularly carbon steel. Oxygen is removed from the steam cycle condensate in the main condenser deaerating section. Additional oxygen protection is obtained by chemical injection of hydrazine into the condensate stream. Maintaining a residual level of hydrazine in the feedwater ensures that any dissolved oxygen not removed by the main condenser is scavenged before it can enter the steam generator.

The presence of free hydroxide(OH) can cause rapid corrosion (caustic stress corrosion) if it is allowed to concentrate in a local area. Free hydroxide is avoided by maintaining proper pH control and by minimizing impurity ingress into the steam generator.

AVT control is a technique whereby both soluble and insoluble solids are kept at a minimum within the steam generator. This is accomplished by maintaining strict surveillance over the possible sources of feedtrain contamination (e.t., circulating water system leakage, air in leakage, and subsequent corrosion product generation in the low pressure drain system, etc.). Solids are also excluded, as discussed above, by injecting only volatile chemicals to establish conditions that reduce corrosion and therefore, reduce transport of corrosion products into the steam generator.

In addition to minimizing the sources of contaminants entering the steam generator, condensate demineralizers are used, and a continuous blowdown from the steam generators is employed to limit the concentration of contaminants. With the low solids level that results from employing the above procedures, the accumulation of scale and deposits on steam generator heat transfer surfaces and internals is limited. Scale and deposit formations can alter the thermal hydraulic performance in local regions which creates a mechanism that allows impurities to concentrate and thus possibly cause corrosion. The effect of this type of corrosion is reduced by limiting the ingress of solids into the steam generator and limiting their buildup.

The chemical additives, because they are volatile, do not concentrate in the steam generator and do not represent chemical impurities that can themselves cause corrosion.

10.3.6 STEAM AND FEEDWATER SYSTEM MATERIALS

10.3.6.1 Fracture Toughness

Compliance with fracture toughness requirements of ASME III, Articles NC-2300 and ND-2300, is discussed in section 6.1.

10.3.6.2 Material Selection and Fabrication

All pressure-retaining material in the steam and feedwater systems conforms to the corresponding material specification permitted by ASME B&PV Code, Section III, Division 1. In addition, the pressure-retaining material meets the requirements of Article NC/ND-2000, as applicable, of ASME B&PV Code, Section III.

All pipe, flanges, fittings, valves, and other standard products comply with the standards and specifications listed in Table NC/ND-3132-1, Dimensional Standards.

The following ASME material specifications apply:

ASME SA-155, Gr KCF70, Class 1

ASME SA-106, Gr C

ASME SA-106, Gr B

ASME SA-234, Gr,WPB

ASME SA-234, Gr WPBW

ASME SA-234, Gr WPC

ASME SA-105

ASME SA-193, Gr B7

ASME SA-194, Gr 2H

ASME SA-216, Gr WCB

ASME SA-333, Gr 6

ASME SA-182, F-304

ASME SA-312, TP 304

The preheat temperatures are in accordance with Section III, Article D-1000, of the ASME Boiler and Pressure Vessel Code.

The nondestructive examination procedures used for the examination of tubular products conform to the requirements of the ASME Boiler and Pressure Vessel Code.

For material fabrication, compliance with applicable Regulatory Guides is discussed in appendix 3A of this FSAR.

Table 10.3-1

MAIN STEAM SUPPLY SYSTEM
CONTROL, INDICATING, AND ALARM DEVICES

Device	Control Room	Local	Emergency Shutdown Panel	Control Room Alarm
Flow Rate indication[(a)]	Yes	–	–	Yes[(e)]
Pressure indication[(b)(c)]	Yes	–	Yes	Yes
Pressure control	Yes[(d)]	–	Yes	–

a. Two per steam line

b. For each generator, three devices are involved in two-out-of-three logic to generate input to reactor protection system, MSIS, and ESFAS.

c. Total of five per steam line.

d. Two per steam line (power-operated relief valves).

e. Steam flow-feedwater flow mismatch.

Table 10.3-2

MAIN STEAM SUPPLY SYSTEM DESIGN DATA
(Sheet 1 of 2)

Main Steam Piping (Safety-related portion)	
479 Rated flow rate at 938 psia and 0.25% moisture, lb/hr	12.95×10^6
Number of lines	3
O.D., in.	32
Minimum wall thickness, in.	1.320 (inside containment) 1.973 (inside main steam support structure)
Design pressure, psia	1,200
Design temperature, °F	600
Design code	ASME Section III, Class 2
Seismic design	Seismic Category I
479 Calculated pressure drop from steam generator to main turbine stop valve, psi	24
Main Steam Isolation Valves	
Number per main steam line	1
Closing time, seconds	Less than 5
Design code	ASME Section III, Class 2
Seismic design	Seismic -Category I
Atmospheric Relief Valves (PORVs)	
Number per main steam line	2
Normal set pressure, psig	1,125
Capacity (each) at 100 psia, lb/hr	64,000
Required minimum relieving capacity per valve, lb/hr at 1200 psia	684,000
Total required minimum receiving capacity of two valves, lb/hr at 1200 psia	1,368,000
Design code	ASME Section III, Class 2 *
Seismic design	Seismic Category I

Table 10.3-2

MAIN STEAM SUPPLY SYSTEM DESIGN DATA
(Sheet 2 of 2)

Main Steam Safety Valves	
Number per main steam line	5
Orifice area, in^2.	16
Size, in.	$6^* \times 10$ 99
Design code	ASME Section III, Class 2
seismic design	Seismic Category I.
Performance data	

Number	Set Pressure (psig)	Capacity at 3% Accumulation (lb/hr)
1	1,185	889,380
2	1,204	903,470
3	1,204	903,470 460
4	1,223	917,560
5	1,223	917,560

Turbine Bypass Valves	
Number of valves	9
Normal capacity (each) lb/hr	546,000
Size in	8
Design code	ASME B&PV Sect. VIII
Seismic design	Seismic Category II
Atmospheric Dump Valves	
Number of valves	7
Normal capacity (each) lb/hr	527,000
Size in	8
Design code	ASME B&PV Sect. VIII
Seismic design	Seismic Category II

* Main Steam Safety Valve Inlet Pipe : 6 in.ID, 1 5/8 in. Thickness 99

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Table 10.3-3

MAIN STEAM SYSTEM
SINGLE ACTIVE FAILURE ANALYSIS (Sheet 1 of 2)

Component	Failure	Comments
1. Main steam line isolation valves	Loss of power from one power supply	Independent power supply provided to redundant pneumatic/hydraulic power trains for the valve actuator.
	Valve fails to close upon receipt of automatic signal (MSIS)	Closure of two-out-of-three isolation valves is adequate to meet requirements.
2. Power-operated relief valves (PORV)	Loss of power or air to valve fails to modulate upon high pressure	Safety valves provide overpressure protection for the associated line. PORVs can be locally operated using reach rods. Redundant PORV will be available for operation

Table 10.3-3

MAIN STEAM SYSTEM
SINGLE ACTIVE FAILURE ANALYSIS (Sheet 2 of 2)

Component	Failure	Comments
3. Pressure transmitters	No signal generated for protection logic	For each generator 2-out-of-3 logic reverts to 1-out-of-2 logic, and protection logic is generated by other devices. Refer to table 7.3-1.
4. Main steam line drain line isolation valve	Valve fails to close upon receipt of automatic signal (MSIS)	Negligible steam lost from generator.
5. Steam supply valve to auxiliary feed pump turbine	Valve fails to open upon receipt of automatic signal (AFS)	Redundant valve provides 100% of flow requirements to the auxiliary feed pump turbine.

Table 10.3-4
STEAM GENERATOR STEAM-SIDE AND FEEDWATER
ETHANOL AMINE CHEMISTRY GUIDELINES
(Sheet 1 of 5)

Chemistry Parameter[a]	Cold Hydro/Cold Wet Layup[b]	Hot Functional/Hot Shutdown/Hot Standby[c]	
	Blowdown	Blowdown	
	Control[j]	Control	Expected
pH @ 25℃	< 9.8	NA	≥ 9.0
Cation conductivity µmhos/cm @ 25℃	NA	NA	< 2.0
Sodium, ppm	> 0.1	> 0.1	≤ 0.1
Chloride, ppm	> 0.1	> 0.1	≤ 0.1
Sulfate, ppm	> 0.1	> 0.1	≤ 0.1
ETA, ppm	As pH requires	NA	≥ 1.0
Hydrazine, ppm	〈 75[h]	Detectable	NA
Dissolved oxygen, ppb	NA	NA	< 5
SiO_2, ppm	NA	NA	< 1.0
Fe, ppb	NA	NA	NA
Cu, ppb	NA	NA	NA
Suspended solids, ppm	NA	NA	≤ 0.1[j]
Blowdown rate, gal/min/SG	NA	NA	As required

Table 10.3-4
STEAM GENERATOR STEAM-SIDE AND FEEDWATER
ETHANOL AMINE CHEMISTRY GUIDELINES
(Sheet 2 of 5)

Chemistry Parameter[a]	Startup From Hot Standby			
	Blowdown		Blowdown	
	Expected	Control	Control	Expected
pH @ 25℃	9.3 - 10.0[e]	< 9.0	NA	9.0 - 10.0[e]
Cation conductivity μmhos/cm @ 25℃	NA	NA	NA	< 2[g]
Sodium, ppm	NA	NA	> 0.1	≤ 0.1
Chloride, ppm	NA	NA	> 0.1	≤ 0.1
Sulfate, ppm	NA	NA	> 0.1	≤ 0.1
ETA, ppm	NA	NA	NA	≥ 1.0
Hydrazine, ppm	≥ 8 × $[O_2]$[i] and ≥ 0.1	< 8 × $[O_2]$[i] or < 0.1	NA	NA
Dissolved oxygon, ppb	≤ 100	> 100	NA	< 5
SiO_2, ppm	NA	NA	NA	< 5
Fe, ppb	< 100	NA	NA	NA
Cu, ppb	< 50	NA	NA	NA
Suspended solids, ppm	< 0.1	NA	NA	NA
Blowdown rate, gal/min/SG	NA	NA	Maximum	Maximum

Table 10.3-4
STEAM GENERATOR STEAM-SIDE AND FEEDWATER
ETHANOL AMINE CHEMISTRY GUIDELINES
(Sheet 3 of 5)

Chemistry Parameter[a]	Normal Power Operation			
	Feedwater		Blowdown	
	Expected	Control	Control	Expected
pH @ 25℃	≥ 9.1[f]	NA	NA	≥ 9.2[f]
Cation conductivity μmhos/cm @ 25℃	NA	NA	≥ 2.0	< 2.0
Total conductivity μmhos/cm @ 25℃	NA	NA	NA	NA
Sodium, ppm	NA	NA	> 0.02	≤ 0.02
Chloride, ppm	NA	NA	> 0.02	≤ 0.02
Sulfate, ppm	NA	NA	> 0.02	≤ 0.02
ETA, ppm	1 - 5	< 1.0	NA	≥ 1.5
Hydrazine, ppm	> 8 × [O_2]	≤ 8 × [O_2]	NA	NA
Dissolved oxygon, ppb	≤ 5	> 5	NA	< 5
SiO_2, ppm	NA	NA	NA	NA
Fe, ppb	< 10	> 10	NA	NA
Cu, ppb	< 5	> 1	NA	NA
Suspended solids, ppm	NA	NA	NA	≤ 0.1

Table 10.3-4
STEAM GENERATOR STEAM-SIDE AND FEEDWATER
ETHANOL AMINE CHEMISTRY GUIDELINES
(Sheet 4 of 5)

Chemistry Parameter[a]	Normal Power Operation[d]			
	Feedwater		Blowdown	
	Expected	Control	Control	Expected
Blowdown rate, gal/min/SG	NA	NA	As required to maintain control parameters	

Table 10.3-4

STEAM GENERATOR STEAM-SIDE AND FEEDWATER
ETHANOL AMINE CHEMISTRY GUIDELINES

(sheet 5 of 5)

a. Process sampling techniques are discussed in sub-section 9.3.2.

b. Condensate quality makeup water shall be used exclusively in achieving these condition.

c. Feedwater(auxiliary feedwater) shall be of condensate makeup quality to which ETA and hydrazine are added at the inlet into the steam generator
132 for pH and dissolved oxygen control. the hydrazine shall be added at a rate to achieve a hydrazine concentration equivalent to 8[O_2]

d. Operation outside the control parameters specified for normal power operation is governed by the limiting conditions specifications.

e. Departure from the normal 9.1 - 9.6 pH range allows for increased NH3 resulting from decomposition of hydrazine used for feedwater
132 system lay up.

f. If the fluid in the condensate, feedwater, and steam systems does not
125 come in contact with copper or its alloys, the allowable feedwater pH may be increased above 9.3

g. During startup up to 48 hours from the initiation of plant loading, additional latitude from normal operating specifications is provided because increased levels of contaminants are anticipated.

h. During cold hydro some decomposition of hydrazine is anticipated. Sufficient hydrazine should be added with the makeup to re-establish the cold wet lay up conditions at completion of the test.

132 i. Hydrazine level should exceed oxygen level by eight times.

132 j. Control chemistry spec. is the value to initiate an action an action to improve the water quality.

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P & I DIAGRAM
MAIN STEAM SYSTEM
FIGURE 10.3-1
(SHEET 1 OF 2)

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KOREA HYDRO & NUCLEAR POWER COMPANY
YGN 1 & 2 FSAR

FDEO P & I DIAGRAM
MAIN STEAM SYSTEM
(SHEET 2 OF 2)
FIGURE 10.3-1

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

This section provides discussions of each of the principal design features of the steam and power conversion system.

10.4.1 MAIN CONDENSER

The main condenser is the steam cycle heat sink. During normal operation, it receives and condenses main turbine exhaust steam, steam generator feedwater pump turbine exhaust steam, and turbine bypass steam. The main condenser is also a collection point for other miscellaneous steam cycle flows, drains, and vents.

The main condenser is utilized as a heat sink in the initial phase of reactor cooldown during a normal plant shutdown.

10.4.1.1 Design Bases

10.4.1.1.1 Safety Design Bases

The main condenser serves no safety function and has no safety design basis.

10.4.1.1.2 Power Generation Design Bases

10.4.1.1.2.1 Power Generation Design Basis One. The main condenser is designed to function as the steam cycle heat sink and miscellaneous flow collection point.

10.4.1.1.2.2 Power Generation Design Basis Two. The main condenser accommodates up to 36 percent of the rated main steam flow which is bypassed directly to the condenser by the turbine bypass system. 479

10.4.1.1.2.3 Power Generation Design Basis Three. The main condenser releases noncondensable gases from the condensing steam through the condenser evacuation system, as described in subsection 10.4.2. This minimizes the occurrence of erosion and corrosion within the secondary system.

10.4.1.1.2.4 Power Generation Design Basis Four. The main condenser provides the surge volume required for the condensate and feedwater system.

10.4.1.1.2.5 Power Generation Design Basis Five. The main condenser provides for deaeration of the condensate, such that
186 condensate oxygen content will not exceed 7 ppb under any normal operating condition.

10.4.1.2 System Description

10.4.1.2.1 General Description

The main condenser is a single pressure, three-shell, deaerating unit. Each shell is located beneath its respective low pressure turbine. The tubes in each shell are oriented transverse to the turbine generator longitudinal axis.

The condenser shells have divided water boxes. Each shell has two tube bundles, each of which is connected through the water boxes. Each shell is divided to two hotwells longitudinally by a vertical partition plate. The condensate pumps take suction from these hotwells, as shown in figure 10.1-2.

The condenser shells are located in pits below the turbine building operating floor and are supported above the turbine building foundation. Expansion joints are provided in the condenser necks. The three shells are interconnectied by steam equalizing lines in the steam regions. Four low pressure feedwater heaters are located in the steam dome of each shell.
Piping is installed for hotwell level control and condensate sampling. Rupture diaphragms are provided to protect the condenser and turbine exhaust hoods against overpressure.

10.4.1.2.2 Component Description

The condenser is a three-shell, single pressure, single pass unit with titanium tubes. The condenser is equipped with intergral groove tube sheets to reduce seawater leakage into the condensate. The condenser neck for each shell houses one train of four low pressure feedwater heaters and also contains one rubber expansion joint. The expansion joints have a water seal to prevent air in-leakage.

Steam spargers are provided for condensate deaeration during startup and low load operation. These spargers are located in each hotwell just above the condensate level for scrubbing the condensate falling from the tube bundles. The auxiliary steam system (subsection 9.5.11) provides steam required for the spargers.

Table 10.4-1 provides the design data for the condenser.

10.4.1.2.3 System Operation

During normal operation, exhaust steam from the low pressure turbines is directed into the main condenser shells. The condenser also receives auxiliary system flows, such as feedwater heater vents and drains, feedwater pump turbine exhaust, and turbine gland sealing system drains.

Hotwell level controls provide automatic makeup or rejection of condensate to maintain a normal level in the condenser hotwells. On low water level in a hotwell, the makeup control valves open and admit condensate to the hotwell from the condensate storage tank. When the hotwell is brought to within normal operating range, the valves close. On high water level in the hotwell, the condensate reject control valve opens to divert condensate from the condensate pump discharge (downstream of the demineralizers) to the condensate storage tank; rejection is stopped when the hotwell level falls to within normal operating range. Rejection of hotwell condensate to the condensate storage tank may be manually overriden upon an indication of high hotwell conductivity. Operator action can therefore prevent transfer of contaminants into the condensate storage tank in the event of a, condenser tube failure.

The main condenser deaerates the condensate so that dissolved 186
oxygen does not exceed 7 ppb over the entire load range. Both the air inleakage and the noncondensable gases contained in the turbine exhaust are collected in the condenser and removed by the condenser evacuation system (subsection 10.4.2).

During the initial cooling period after plant shutdown, the main condenser removes decay heat from the reactor coolant system via the turbine bypass system. The main condenser receives up to
36 percent of the rated main steam flow through the turbine 479
bypass valves. The bypassed steam is distributed over the condenser tubes by spray headers. If the condenser is not available to

receive steam via the turbine bypass system, the reactor coolant system can be safely cooled down by discharging steam into the atmosphere through the atmospheric dump valves or the power-operated relief valves (PORVs).

The condenser is provided with integral-grooved tube sheets to minimize seawater inleakage. However, in the event of seawater inleakage into the main condenser, the condenser may remain in operation, provided the feedwater chemistry is maintained within acceptable limits. Thus the condenser can be operated at rated flow if the amount of leakage is within the capability of the condensate polishing demineralizer to remove the impurities and maintain the feedwater chemistry.

If the inleakage is beyond the capability of the demineralizer, the affected hotwell is isolated by closing the condensate hotwell isolation valve as well as the circulating water inlet and outlet valves supplying cooling water to the affected hotwell. All exhaust steam is drawn to the active hotwell side, as cooling water is provided to the active hotwell only. The condensate from the isolated hotwell can be pumped by opening the appropriate overboard pump inlet valve and starting the overboard pump and
187 discharging to the neutralizing tank. The isolation of any one condenser hotwell will necessitate reduced load operation.

Circulating water leakage occurring within the condenser is detected and alarmed in the control room by monitoring the condensate leaving each hotwell. This information permits determination of which tube bundle has sustained the leakage. Steps may then be taken to isolate and dewater that bundle and its water boxes and, subsequently, repair or plug the leaking tubes.

During normal operation and shutdown, the main condenser has a negligible inventory of radioactive contaminants which may enter through a steam generator tube leak. A discussion of the radiological aspects of primary-to-secondary leakage, including anticipated operating concentrations of radioactive contaminants, is included in chapter 11. No hydrogen buildup in the main condenser is anticipated.

The failure of the main condenser and the resulting flooding will not preclude operation of any essential system. Refer to subsection 10.4.5 for a description of the effects of a circulating water expansion joint failure.

10.4.1.3 Safety Evaluation

The main condenser serves no safety-related function.

10.4.1.4 Tests and Inspections

The condenser shells are hydrostatically tested after erection. The condenser waterboxes, tube sheets, and tubes are hydrostatically tested as a unit.

10.4.1.5 Instrument Applications

The main condenser hotwells are equipped with level control devices for automatic control of condensate makeup and rejection. Local and remote indicating devices are provided for monitoring the water level in the condenser shells. High, low, and low-low hotwell water level alarms are provided in the control room.

A sensor is provided to monitor condenser backpressure. A high backpressure alarm is activated at approximately 5.5 in.HgA and turbine trip is activated at 8.5 in.HgA.

Conductivity and sodium content of the condensate from each condenser shell is monitored to provide an indication of condenser tube leakage.

Turbine exhaust hood temperature is monitored and controlled with water sprays supplied from the condensate pump discharge.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The main condenser evacuation system (MCES) removes noncondensable gases and air from the main condenser during plant startup, cooldown, and normal operation.

10.4.2.1 Design Bases

10.4.2.1.1 Safety Design Bases

The MCES serves no safety function and has no safety design bases.

10.4.2.1.2 Power Generation Design Bases

10.4.2.1.2.1 Power Generation Design Basis One. The MCES is designed to remove air and noncondensable gases from the condenser during plant startup, cooldown, and normal operation, and discharge the gases to the environment. Radiation monitoring in the discharge vent in the turbine building detects primary-to-secondary leakage in the steam generators.

10.4.2.1.2.2 Power Generation Design Basis Two. The MCES uses mechanical vacuum pumps to initially attain main condenser vacuum during plant startup and steam jet air ejectors to maintain condenser vacuum during normal power operations.

10.4.2.1.3 Codes and Standards

Codes and standards applicable to the MCES are listed in table 3.2-1.

10.4.2.2 System Description

10.4.2.2.1 General Description

The MCES, as shown in figure 10.61, consists of four 33-1/3 percent capacity mechanical vacuum pumps each with its own seal water cooler, two 50 percent first-stage and one 100 percent second-stage steam jet air ejectors with the corresponding intercondenser and aftercondenser. During holding operation, gases and vapors from the condenser pass successively through the first-stage steam jet ejectors to the intercondenser. Only the noncondensible portion of the first-stage capacity passes on to the aftercondenser through the second-stage jet ejector. Finally, the noncondensable gases, primarily air, leave the aftercondenser to the atmosphere. The air ejectors, however, can also be used for hogging operation, if required. The mechanical vacuum pumps take suction from the condenser and discharge noncondensable gases to the atmosphere during hogging operation. The vacuum pumps, however, can also be used for holding operation, if necessary.

The noncondensable gases and vapor mixture discharged to the atmosphere from the system is not normally radioactive. It is possible however, for the mixture discharged to become contaminated in the event of primary-to-secondary system leakage. The mixture removed from the condenser is monitored for radioactivity prior to discharge to the atmosphere.

Should the air removal system fail completely, a gradual reduction in condenser vacuum would result from the buildup of noncondensable gases. This reduction in vacuum would cause a lowering of turbine cycle efficiency which requires an increase in reactor power to maintain the demanded electrical power generation level. The reactor power is limited by the reactor control system, as described in section 7.7. The reactor protection system, described in section 7.2, independently guarantees that the reactor is maintained within safe operation limits.

If the MCES remains inoperable, condenser vacuum decreases to the turbine trip set point and a turbine trip is initiated. A loss of condenser vacuum incident is discussed in section 15.2.

10.4.2.2.2 Component Description

Design data for major components of the main condenser evacuation system are listed in table 10.4-2.

10.4.2.2.2.1 Mechanical Vacuum Pumps. The four motor-driven mechanical vacuum pumps remove air and noncondensable gases from the condenser for condenser hogging during startup. The mechanical vacuum pump package consists of a two-stage liquid ring, centrifugal pump, and separator tank. During hogging operation, the four pumps are capable of evacuating the condenser from 14.7 psia to 10 in.HgA in approximately 30 minutes.

10.4.2.2.2.2 Seal Water Coolers. The seal water coolers are shell-and-tube heat exchangers. Mechanical vacuum pump seal water flows through the shell side of the coolers, and turbine plant open cooling water flows through the tubes.

10.4.2.2.2.3 Steam Jet Air Ejectors. Two 50 percent first-stage air ejectors and one 100 percent second-stage air ejector remove air and noncondensable gases from the condenser during normal holding operation. The air ejectors are provided with inter and after condensers. Air ejector motive steam is from the main steam line.

10.4.2.2.3 System Operation

Noncondensable gases are initially removed from the main condenser shells by four mechanical vacuum pumps during turbine-generator startup. All four pumps are capable to lower the condenser shell pressure from atmospheric pressure to 10 in.HgA in approximately 30 minutes.

During normal plant power generation operation, the air ejectors remove noncondensables from the condenser, and the vacuum pump in automode is started upon demand as the condenser backpressure rises with increased turbine generator load and warmer circulating water temperatures. Cold circulating water and low exhaust steam flow, such as may occur during a winter startup, induce low condenser backpressure while high circulating water temperatures and full rated steam flow, such as may occur during summer operating conditions, induce condenser backpressures higher than those experienced during normal operation.

If the condenser backpressure increases, due to excessive air inleakage, to 4 in.HgA during normal operation, all four mechanical vacuum pumps may be required to run until manually switched to standby. A high condenser pressure alarm at 5.5 in.HgA is annunciated in the control room. If inleakage continues to be greater than the capacity of the evacuation system, a gradual increase in condenser pressure may occur, resulting in lower turbine efficiency. If condenser pressure increases to 8.5 in.HgA, a turbine trip is initiated. (This is considered a main condenser evacuation system failure; safe shutdown of the reactor in such an event is discussed in section 15.2.)

The main condenser evacuation system is also used during reactor cooldown when main steam is being bypassed to the condenser. Malfunction of the condenser evacuation system will not impair the capability to remove heat from the reactor coolant system (RCS), as the main steam power-operated relief valves, the atmospheric dump valves and safety valves are designed to provide this capability in the event of condenser unavailability.

The mixture of water vapor and noncondensable gases is monitored continuously for radioactivity as it is discharged to the atmosphere. Normally, the water vapor and noncondensable gases discharged to the atmosphere from the main condenser evacuation system during normal power generation are not radioactive. However, in the event of primary-to-secondary system leakage due to a steam generator tube leak, it is possible for the mixture discharged to become radioactive. Radiation detectors located in the exhaust lines from the evacuation system monitor the system effluent for both noble gas and particulate contamination. A radiation alarm annunciates high radioactivity concentrations in the evacuation system discharge. A full discussion of the radiological aspects of primary-to-secondary system leakage is contained in section 11.1. The presence of activity in the main condenser evacuation system is indicative of steam generator tube leakage. Depending upon the severity of the leak, the operator may immediately shut down the unit and depressurize the primary side, thereby terminating the leakage.

10.4.2.3 Safety Evaluation

In as much as the main condenser evacuation system has no safety design basis, no safety evaluation is provided. An assessment of system design and operation is given in paragraph 10.4.2.2. An evaluation of potential radiological releases is provided in section 11.1.

10.4.2.4 Tests and Inspections

Testing and inspection of the system is performed prior to plant operation. Refer to chapter 14 for additional information.

Components of the system are continuously monitored during operation to ensure satisfactory operation. Periodic inservice tests and inspections of the evacuation system are performed in conjunction with the scheduled maintenance outages.

10.4.2.5 Instrumentation Applications

Local indicating devices such as pressure, temperature, and flow indicators are provided as required for monitoring the system operation. Pressure switches are provided for automatic operation of the standby mechanical vacuum pump during normal operation. High condenser pressure alarm is provided in the control room.

Radiation detectors are provided to monitor the discharge of the MCES. The radiation detection is indicated and alarmed in the control room. Refer to section 11.5 for additional information.

10.4.3 TURBINE GLAND SEALING SYSTEM

The turbine gland sealing system (TGSS) prevents the escape of steam from the main turbine shaft/casing penetration, the steam generator feedwater pump turbines and valve stems and prevents air inleakage to the turbine glands under vacuum conditions.

10.4.3.1 Design Bases

Criteria for the selection of design bases are stated in paragraph 1.1.2.2.

10.4.3.1.1 Safety Design Basis

The TGSS serves no safety function and has no safety design basis.

10.4.3.1.2 Power Generation Design Bases

10.4.3.1.2.1 Power Generation Design Basis One. The TGSS is designed to prevent atmospheric air leakage into the turbine casings and to minimize steam leakage out of the casings of the turbine-generator and steam generator feedwater pump turbines.

10.4.3.1.2.2 Power Generation Design Basis Two. The TGSS returns the condensed steam to the condenser and exhausts the noncondensable gases to the atmosphere.

10.4.3.1.3 Codes and Standards

Codes and standards applicable to the TGSS are listed in table 3.2-1. The system is designed and constructed in accordance with the requirements of ANSI Standard B.31.1.

10.4.3.2 System Description

10.4.3.2.1 General Description

The TGSS, shown in figure 10.4-2, consists of a gland sealing steam condenser, two 100 percent capacity motor-driven exhausters, steam supply and spillover regulating and isolating valves, plus the associated piping and instrumentation.

10.4.3.2.2 System Operation

The annular space through which the turbine shaft penetrates the casing is sealed by steam supplied to labyrinth packings. Where the packing seals against positive pressure, the sealing steam connection acts as a leakoff. Where the packing seals against vacuum, the sealing steam either is drawn into the casing or leaks outward to a vent annulus that is maintained at a slight vacuum. The vent annulus also receives air leakage from the outside. The air-steam mixture is drawn to the gland sealing steam condenser.

Sealing steam is distributed to the turbine shaft seals by the steam seal header. Steam flow to the header is controlled by a steam seal pressure regulator which maintains specified steam seal header pressure. In case of high pressure, the steam seal spillover valve opens to bypass excess steam directly to the main condenser. In case of low steam seal header pressure, the pressure regulator opens a pressure -reducing valve to admit steam from the auxiliary steam header or the main steam line.

During turbine-generator startup, sealing steam is supplied from the auxiliary steam header. During low-power operation, sealing steam is supplied from the high pressure (HP) leakoff connections of the main steam control valves and the main steam system for both the HP and low pressure (LP) turbines glands. As the turbine generator load is increased, the steam required to seal the HP turbine glands will decrease and the steam from the main steam control valve HP leakoffs will be terminated by the backseating of the valve stems when the control valves are fully opened. As the turbine load continues to increase, the HP glands will begin leaking steam instead of requiring it. This excess steam will be diverted to the condenser to maintain a constant HP gland steam pressure. The LP glands will continue to be supplied from the main steam system at all turbine loads with the gland pressure controlled individually at each LP turbine gland.

The outer ends of all seals are provided with collection piping which routes the mixture of air and excess seal steam to the gland sealing steam condenser. The gland sealing steam condenser is a shell and tube heat exchanger; the steam-air mixture passes into the shell side and condensate flows through the tube side. The gland sealing steam condenser is maintained at a slight vacuum by two 100 percent redundant motor-driven exhauster blowers mounted in parallel. Condensate from the steam-air mixture drains to the main condensers, while noncondensables are passed through radiation monitors and then are exhausted to the atmosphere.

The mixture of noncondensable gases discharged to the atmosphere by the motor-driven exhauster blower is not normally radioactive; however, in the event of significant primary-to-secondary system leakage due to a steam generator tube leak, it is possible for the mixture discharged to be radioactively contaminated. Primary-to-secondary system leakage is detected by the radiation monitors in either the main steam sample system or the condenser air removal system. A full discussion of the radiological aspects of primary-to-secondary system leakage is included in chapter 11.

In the absence of primary-to-secondary leakage, failure of the turbine gland seal system will result in no leakage of radioactivity to the atmosphere. A failure of this system would, however, result in a drop of condenser vacuum.

10.4.3.3 Safety Evaluation

The TGSS has no safety-related function.

10.4.3.4 Tests and Inspections

Since the TGSS is in constant use during normal plant operation, the satisfactory operation of the system components will be evident.

10.4.3.5 Instrumentation Applications

A pressure regulator is provided to maintain steam seal header pressure.

A transmitter is supplied in the main supply header used for all glands and the supply and leakoff header from the HP turbine. This permits the remote adjustment of the sealing steam pressure in these headers in case of the regulator control valve failure.

Supplied at each LP gland is a gauge with alarm contact which is being used to signal the operator of high or low gland sealing steam pressure.

A pressure transmitter and motor-operated spillover bypass valve are provided for remote control of the gland header pressure in case of failure of high pressure spillover valve.

10.4.4 TURBINE BYPASS SYSTEM

The turbine bypass system (TBS) has the capability to bypass main steam from the steam generators to the main condenser in a controlled manner to minimize transient effects on the reactor coolant system (RCS) during startup, hot shutdown and cooldown, and step load reductions in generator load. The TBS is also called the steam dump system.

10.4.4.1 Design Bases

10.4.4.1.1 Safety Design Bases

The TBS serves no safety function and has no safety design basis.

10.4.4.1.2 Power Generation Design Bases

10.4.4.1.2.1 Power Generation Design Basis One. The TBS has the capacity to bypass 36 percent of the rated main steam flow to the main condenser. 479

10.4.4.1.2.2 Power Generation Design Basis Two. The TBS is designed to bypass steam to the main condenser during plant startup and to permit a normal manual cooldown of the RCS from a hot shutdown condition to a point consistent with the initiation of residual heat removal system operation.

10.4.4.1.2.3 Power Generation Design Basis Three. The TBS is designed to bypass 36 percent of the rated steam flow to the condenser and 28 percent of the rated steam flow to the atmosphere. 8 479

10.4.4.2 System Description

10.4.4.2.1 General Description

The TBS is shown on figure 10.3-1, main steam system. The system consists of piping connected to the main steam header upstream of the turbine stop valves and lines with regulating valves to each condenser shell and to the atmosphere.

There are 16 turbine bypass valves. Nine valves discharge in to the condenser, three per shell. Seven valves discharge to the atmosphere. 8

The steam bypassed is not normally radioactive. In the event of primary-to-secondary leakage, it is possible for the bypassed steam to become radioactively contaminated. A full discussion of the radiological aspects of primary-to-secondary leakage is contained in chapter 11.

10.4.4.2.2 Component Description

The TBS contains 16 air-actuated, globe valves. The valves are pilot-operated, spring-opposed, and fail closed upon loss of air or loss of power to the control system. Sparger piping distributes the steam within the condenser. Isolation valves permit maintenance of the bypass valve while the plant is in operation.

10.4.4.2.3 System Operation

The TBS reduces the probability of a turbine or reactor trip during a large load rejection at rated load. The bypass system provides a means of stabilizing the NSSS during rapid reduction of steam demand from the main turbine by passing steam directly to the condenser and/or to the atmosphere. It also provides a means of controlled cooldown of the RCS after reactor shutdown by operating cooldown bank (first three condenser dump valves) only.

The TBS takes steam from the main steam line upstream of the
turbine stop valves and discharges it to the condenser and/or
the atmosphere. The system is designed to discharge up to
479 64 percent of NSSS rated output steam flow. The control
sequence for the TBS is arranged for preferential operation of
condenser dump to conserve condensate and to minimize steam
release to the atmosphere. During modulating service, three
turbine bypass valves open at a time, one valve for each of
the three condenser shells. This maintains equal steam flow
to each condenser shell and an even heat distribution throughout
the condenser. Condenser dump valves are prevented from
opening by interlock when condenser pressure rises to 5.5 inches
182 HgA or more, and when the circulating water pump breakers are
closed less than 4 of 6.

The atmospheric dump valves open automatically if the required relief is more than the relieving capacity of the condenser dump valves or if the condenser is not available.

The TBS, during normal operating transients for which the plant is designed, is automatically regulated by the reactor coolant temperature control system to maintain the programmed coolant temperature. The programmed coolant temperature is derived from the high pressure turbine first-stage pressure, which is a load reference signal. The difference between programmed reactor coolant average temperature and measured reactor coolant average temperature is used to activate the steam dump system under automatic control.

When the plant is at no load and there is no turbine load reference, the system is operated in a pressure control mode. The measured main steam system pressure is compared against the pressure set by the operator in the control room. The pressure control mode is also used for plant cooldown,

The turbine bypass control system can malfunction in either the open or closed mode. The effects of both these potential failure modes on the NSSS and turbine system are addressed in chapter 15. If the bypass valves fail open, additional heat load is placed on the condenser. If this load is great enough, the turbine is tripped on high-high condenser pressure. Ultimate overpressure protection for the condenser is provided by rupture diaphragms located in the low pressure turbine hoods.

All atmospheric dump valves and turbine bypass control valves are air-operated modulating valves. Upon a large step load reduction, the valves go full open in 3 seconds. The valves are modulated closed as the reactor output is reduced to match the turbine-generator load. 8

In the event of condenser unavailability combined with a load rejection requiring steam release in excess of the relieving capacity of the atmospheric dump valves, the atmospheric relief valves and spring-loaded safety valves open in response to system pressure increases to vent the excess steam flow to the atmosphere. If a load rejection of a magnitude greater than the capacity of the relief valves occurs concurrently with unavailability of the turbine bypass system, the spring-oaded safety valves sequentially open as pressure increases and discharge the required amount of steam to the atmosphere, thus preventing system pressure from exceeding the maximum allowable pressure of the main steam system.

The turbine bypass valves close automatically or are blocked from opening during high condenser pressure. All bypass system valves fail closed upon loss of air.

10.4.4.3 Safety Evaluation

The TBS serves no safety function and has no safety design basis.

10.4.4.4 Inspection and Testing Requirements

Before the system is placed in service, all turbine bypass valves are tested for operability. The steam 'fines are hydrostatically tested to confirm leaktightness. The bypass valves may be tested while the unit is in operation. All system piping and valves are accessible for inspection.

10.4.4.5 Instrumentation Applications

The turbine bypass control system is described in section 7.7. Hand switches in the main control room are provided for selection of the system operating mode. Pressure controllers and valve position lights are also located in the main control room.

10.4.5 CIRCULATING WATER SYSTEM

The circulating water system (CWS) provides cooling seawater for the removal of the waste heat from the main condenser and rejects this heat to the Yellow Sea, the ultimate heat sink.

10.4.5.1 Design Bases

Criteria for the selection of design bases are stated in paragraph 1.1.2.2.

10.4.5.1.1 Safety Design Bases

The CWS serves no safety%elat&d function.

10.4.5.1.2 Power Generation Design Bases

10.4.5.1.2.1 Power Generation Design Basis One. The CWS supplies cooling water at a sufficient flow rate to remove heat from the main condenser under all conditions of power plant loading.

10.4.5.1.2.2 Power Generation Design Basis Two. The CWS is designed to supply the condenser with an adequate amount of sea-water to maintain design backpressure.

10.4.5.1.2.3 Power Generation Design Basis Three. The CWS will be automatically isolated in the event of gross leakage into the condenser pit to limit flooding of the turbine building.

10.4.5.1.2.4 Power Generation Design Basis Four. The CWS is designed to operate safely and reliably with variations in sea-water level

10.4.5.1.3 Codes and Standards

Codes and standards applicable -to the CWS are listed in table 3.2-1. The system is designed and constructed in accordance with Quality Group R specifications.

10.4.5.2 System Description

10.4.5.2.1 General Description

The CWS, shown schematically in figure 10.4-3, consists of the circulating water pumps with associated piping, valves and instrumentation. In addition, the following auxiliary systems are provided:

- Water Box Scavenging System
- Condenser Tube Cleaning System (Amertap)
- Circulating Water Pump Bearing Lubrication System
- Condenser Integral Grooved Tube Sheet Pressurization System.

10.4.5.2.2 Component Description

Table 10.4-3 provides the design parameters for major components in the CWS.

10.4.5.2.2.1 Circulating Water Pumps. The six 16-2/3 percent capacity circulating water pumps per unit are vertical, wet pit, single-stage, centrifugal pumps driven by solid shaft electric motors. The pumps are mounted in a sump connected to the intake structure, and discharge into concrete conduits leading to the main condenser. The pumps are provided with motor-operated valves at their discharge to permit isolation of a pump out of service.

10.4.5.2.2.2 Piping. The circulating water piping is constructed of coal-tar epoxy lined carbon steel piping and reinforced concrete conduits. The inlet concrete conduit is located between the intake structure and the turbine building wall, where it is connected to the 960inch diameter steel piping on the condenser inlet side. On the condenser outlet, the steel pipe connects to the concrete conduit which is routed back to the ocean. The steel piping is embedded in the concrete using a thimble, to ensure perfect sealing at the interface. Piping 4 inches and smaller is Monel (70Ni-30Cu). Piping, 6 inches through 24 inches, is rubber-lined carbon steel.

10.4.5.2.2.3 Valves. Motor-operated butterfly valves are pro-
vided at each circulating water pump discharge, in the inter-
6 connecting header and in each of the circuiting water lines at
their exit from the condenser shells to allow isolation of a
faulted line. Shutoff valves are provided upstream and down-
stream of all major components of the system to enable isolation
of specific components.

10.4.5.2.2.4 Water Box Scavenging System. A condenser water box scavenging subsystem using two 100 percent capacity mechanical vacuum pumps and a vacuum control tank is provided to assist in maintaining siphon in the system and to remove noncondensable gases from the water boxes.

10.4.5.2.2.5 Condenser Tube Cleaning System and Debris Filter.
The Amertap condenser tube cleaning system is provided to ensure
78 condenser cleanliness by periodically removing any type of fouling
that may be deposited in the condenser tubes. In addition, self-
cleaning debris filters are provided at the water box inlet lines.

10.4.5.2.2.6 Circulating Water Pump Bearing Lubrication System.
The circulating water pump bearings are water lubricated. Each
pump is supplied with an independent seawater bearing lubrica-
79 tion system consisting of a Turbine Plant Open Cooling Water (TPOCW)
pump, a duplex strainer, plus piping and valves. Provisions are
included for fresh water lubrication during initial operation and
shutdown.

10.4.5.2.2.7 <u>Condenser Integsal Grooved Tube Sheet Pressurization System.</u> The condenser is provided with integral-grooved tube sheets which are pressurized with condensate to prevent seawater in leakage through the tube-to-tube sheet joint. Pressurization is accomplished by the use of static head tanks.

10.4.5.2.3 System Operation

The circulating water pumps take suction from the intake structure located on the Yellow Sea, discharge into the intake concrete conduits and branch out at the turbine building to the six condenser water boxes; the water is then returned to the ocean by the discharge network. The system incorporates means of conserving power by reducing the number of pumps in operation during periods of low water temperature. During normal plant operation, chlorination of the circulating water is continuos and condenser tube cleaning is periodical. The chlorine is used to control biological growth inside the condenser tubes and the growth of marine organisms in the intake structure. Amertap condenser tube cleaning systems maintain condenser efficiency at design levels by removing bio-fouling, sediment, corrosion products, and scaling. Specially engineered oversized, sponge rubber balls periodically circulate throughout the condenser, wiping the tube inner wall clean. 78

The water box scavenging system will remove air and noncondensable gases from the condenser water boxes. Water carry-over to the vacuum pumps is precluded by an automatic control which shuts off flow in the riser in response to high water level. The pumps run continuously and are protected from over-vacuum and dead-ending by vacuum relief valves. The water Vapor and noncondensable gases removed from the condenser water boxes are discharged to the atmosphere as they are not radioactive during plant operation.

The CWS is designed to prevent inflow of radioactive material into the circulating water. Since the circulating water is at a higher pressure than the condensing steam, ally leakage between the two sides would be from the circulating water into the condenser shell.

Small leaks around valves and fittings are detected by level alarms in the condenser pit and condenser pit sump pump operation. Large leaks due to pipe or expansion joint failure would be indicated in the control room by both a gradual loss of vacuum and by level alarms with high-high condenser pit water level switches provided to trip all circulating water pumps under these conditions. Table 10.4-4 lists the instrumentation available to alert the operator and to mitigate the consequences of an expansion joint failure.

10.4.5.3 Safety Evaluation

Inasmuch as the CWS has no safety design basis, no safety evaluation is provided.

10.4.5.4 Tests and Inspections

Preoperational testing is described in chapter 14. The performance and structural and leaktight integrity of all system components are demonstrated by continuous operation.

All active components of the CWS are accessible for inspection during plant power generation. The circulating water pumps are tested in accordance with standards of the Hydraulic Institute. Performance, hydrostatic, and leakage tests are performed on the CWS butterfly valves in accordance with the American Water Works Association Code 504-74 for rubber-seated butterfly valves.

10.4.5.5 Instrumentation Applications

Indicating lights actuated by position switches are provided in the control room to indicate open and closed positions of motor-operated butterfly valves in the circulating water piping. The motor-operated valve at each pump discharge is interlocked with the pump such that the pump will not start until the discharge valve has opened a minimum of 20 degrees. The interlock also closes the valve when the pump stops operating.

Local pressure indicators and pressure transmitters with indication in the control room are provided on the circulating water pump discharge lines. Local pressure indicators axe provided at the inlet and outlet of each condenser shell. Local and remote indicators are provided for circulating water temperature at the inlet and outlet of each condenser shell.

297 A level transmitter with a remote indicator , a low and a low-low level alarm in the control room is provided In the intake structure to provide indication of water level in the structure.

10.4.6 CONDENSATE DEMINERALIZER SYSTEM

The condensate demineralizer system (CDS) is designed to maintain the required purity of feedwater to the steam generators by filtering out corrosion product accumulation, and by ion exchange to remove condenser leakage impurities.

10.4.6.1 Design Bases

10.4.6.1.1 Safety Design Bases

The condensate demineralizer system has no safety design basis.

10.4.6.1.2 Power Generation Design Bases

10.4.6.1.2.1 Power Generation Design Basis One. The CDS removes dissolved and suspended solids from the condensate and feedwater system prior to startup to remove corrosion products or foreign materials from the secondary system.

10.4.6.1.2.2 Power Generation Design Basis Two. The CDS removes impurities entering the secondary cycle from condenser leaks that would otherwise concentrate in the steam generator.

10.4.6.1.2.3 Power Generation Design Basis Three. The CDS removes corrosion products from the condensate system and any drains returned to the hotwell so as to limit corrosion product accumulation which is difficult to remove from the steam generator by the steam generator blowdown system.

10.4.6.1.2.4 Power Generation Design Basis Four. 'The CDS limits the entry of dissolved solids into the feedwater system from large condenser leaks, to permit an increased amount of time for plant shutdown. Table 10.4-5 shows the quality of the influent to the condensate demineralizers during startup, normal operation and with a condenser leak of 0.2 gal/min. Table 10.4-6 shows the effluent quality of the condensate demineralizers.

10.4.6.1.2.5 Power Generation Design Basis Five. The CDS is designed to process up to 100 percent of the condensate system flow.

10.4.6.1.3 Codes and Standards

Codes and standards applicable to the CDS system are listed in table 3.2-1.

10.4.6.2 System Description

10.4.6.2.1 General Description

The CDS consists of five deep bed demineralizers, an automated regeneration system, and all necessary controls and instruments and associated tanks, piping, valves, and strainers, as shown schematically in figures 10.4-4 and 10.4-5.

10.4.6.2.2 Component Description

The CDS consists of five 25 percent of full condensate flow demineralizer units (one on standby) containing regenerable mixed strong acid cation-strong base anion resins. Each vessel maximum capacity is 6100 gpm.

Design maximum pressure for all vessels and piping, except for regeneration equipment, is the shutoff head of the condensate pump. Vessel internals are capable of withstanding this head as a differential pressure.

Service runs terminate on reaching a limiting differential pressure of 50 psi or a limiting conductivity or effluent sodium or silica limit on ionic loading. The limiting values are given in table 10.4-6. Six conductivity cells are provided to monitor the conductivity of the effluent lines of the polisher units. Surface flow rate is approximately 50 gal/min/ft2 of bed area. Resin requirement is at least a 36-inch bed depth.

10.4.6.2.2.1 Regenerant Bulk Storage System. The bulk storage system is made up of two tanks for storage of sulfuric acid and caustic, required for regeneration of the resins in the demineralization train.

10.4.6.2.2.2 Neutralizing Tank. The neutralizing tank is a cylindrical vertical tank where the regenerant waste is neutralized. Samples from this tank are analyzed to determine pH and radioactivity. The Unit 2 tank has 60,000 gallons capacity, and the Unit 1 tank has 120,000 gallons capacity.

10.4.6.2.2.3 Sump Pumps. The sump pumps transfer the regenerant from the waste sump to the neutralizing tank. The pumps are rated 450 gal/min at 65 feet differential head.

10.4.6.2.2.4 Sluice and Regenerant Water Pumps. The sluice and regenerant water pumps are horizontal, centrifugal type pumps that transfer water from the condensate storage tank for use in the regeneration system. These pumps have a capacity of 396 gal/min @ 130 feet differential head.

10.4.6.2.2.5 Chemical Regeneration Pumps. The chemical regeneration pumps transfer sulfuric acid and caustic to the anion, cation, and mixed bed regeneration vessels. The acid pump is a diaphragm type, rated at 3.5 gal/min at 65 psi. The caustic pump is a diaphragm type rated at 4.7 gal/min at 65 psi.

10.4.6.2.2.6 Sulfuric Acid and Caustic Transfer Pumps. These pumps transfer the regeneration chemicals from the chemical bulk storage tanks to the acid day tank and caustic day tank, respectively. They are all positive displacement, diaphragm type, with manual stroke control, and rated at 7 gal/min minimum at 100 feet differential head.

10.4.6.2.2.7 Regenerant Waste Recirculation and Transfer Pumps. These pumps are horizontal, centrifugal type with a capacity of 440 gal/min at 148 ft. differential head. These pumps recirculate the regenerant waste through the neutralization tank for homogeneous mixing and transfer the neutralized waste to the liquid radwaste discharge header.

10.4.6.2.2.8 Cation Regeneration Vessel. This vessel is a cylindrical, vertical vessel of 596 ft^3 capacity.

10.4.6.2.2.9 Resin Addition Hopper. This hopper is a 11 ft^3 capacity cylindrical and conical bottom tank.

10.4.6.2.2.10 Anion Regeneration Vessel. This vessel is a cylindrical, vertical vessel of 365 ft^3 capacity.

10.4.6.2.2.11 Resin Mixing and Storage Vessel. This vessel is a cylindrical, vertical vessel of 464 ft^3 capacity.

10.4.6.2.2.12 Acid Day Tank. This tank is a cylindrical tank of 58 ft^3 capacity.

10.4.6.2.2.13 Caustic Day Tank. This tank is a cylindrical tank of 57 ft^3 capacity

10.4.6.2.2.14 Caustic Solution Hot Water Tank. This tank is a cylindrical vessel of 285 cubic feet capacity.

10.4.6.2.2.15 ETA Bulk Storage Tank.
132 The ETA is used for pH control of condensate. The ETA is transferred from ETA Bulk Storage Tank at 100 feet to the metering cylinder of the ETA feed tank at 75 feet by differential head(see subsection 10.4.10).

10.4.6.2.3 System Operation

132 The set of five demineralizers (including one on standby) are capable of operating in the hydrogen or ETA cycle to deionize and filter the flow of condensate from the main condenser hotwell and maintain low levels of suspended and dissolved impurities. Condenser leak detection methods are described in subsection 10.4.1.

Conductivity cells are provided for monitoring each drain line of each cation and anion regeneration vessel, resin storage tank, and preservice rinse recycle line, to the condenser hotwell. Conductivity is continuously monitored during the rinse cycle of the regeneration process nd during the preservice rinse cycle.

Effluent from the condensate demineralizers is continuously monitored for conductivity and sodium concentration during system operation. An improperly regenerated bed will show an abnormally high cation conductivity and sodium concentration.

The improperly regenerated bed will be taken out of service and the required regeneration steps will be repeated again.

Once a condensate demineralizer has been removed from service, the exhausted resin charge is hydraulically transferred to the cation regeneration and resin separation tank. If the end point was due to crud loading, an air scrub and water rinse cycle is initiated to clean the resins. If the end point was ionic exhaustion, a resin separation and chemical regeneration, cleaning and remixing cycle is initiated to restore ion exchange capacity. These cycles are manually initiated but are carried out according to an automatic program sequence. The regeneration system holds an additional bed volume of resin in the final mix and storage tank which is sluiced to the out of service vessel as soon as its contents have been removed to the resin cleaning and separation tank. At the end of the cleaning or regeneration procedure the restored resin is held in the final mixing tank until the next service vessel is taken out of service.

Regenerant waste is discharged to the neutralizing tank. From this tank, the waste water is discharged to the waste water treatment plant. If radioactivity is detected, in the waste water, the discharge should be diverted to the liquid radwaste holdup tank. 97

It is anticipated that the steam generator blowdown demineralizers will capture most of the radioactivity in the event of a steam generator tube leak. The activity level of the regenerants is expected to be low enough to allow the waste water to be discharged into the yellow Sea. The regeneration rinse water is sampled to verify that bed rinsing is complete.

The system includes all isolation valves, piping for vessels, basket strainers, and piping for resin transfer and for rinsing resins to the hotwell.

10.4.6.3 <u>Safety Evaluation</u>

In as much as there is no safety design basis for the CDS, no safety evaluation is provided.

10.4.6.4 <u>Tests and Inspections</u>

Preoperational testing of the CDS, as described in chapter 14, assures proper functioning of the equipment and instrumentation. The system is checked functionally during power generation operation.

10.4.6.5 <u>Instrumentation Applications</u>

Continuous, inline operation of sensor monitors equipment performance in service or during the regeneration cycle. Local and control room alarms annunciate trouble in components of the system. Systematic manual analysis of local samples must be performed to monitor the accuracy of the automatic equipment and for calibration purposes. Flow and differential pressure are continually monitored along with ionic concentration and suspended solids content of th influent and effluent streams.

10.4.7 CONDENSATE AND FEEDWATER SYSTEM

The function of the condensate and feedwater system(CFS) is to receive condensate from the condenser hotwells and deliver feedwater at the required pressure and temperature to the three steam generators.

10.4.7.1 Design Bases

10.4.7.1.1 Safety Design Bases

The portion of the CFS from the steam generator to the main feedwater isolation valves (MFIVs) is safety-related, and is required to function following a design basis accident (DBA) and to achieve and maintain the plant in a safe shutdown condition.

10.4.7.1.1.1 Safety Design Basis One. The safety-related portion of the CFS is protected from the effects of natural phenomena such as earthquakes, typhoons, tornadoes, hurricanes, floods, and external missiles.

10.4.7.1.1.2 Safety Design Basis Two. The safety-related portion of the CFS is designed to remain functional after a safe shutdown earthquake (SSE), or to perform its intended function following postulated hazards of fire, internal missiles, or high energy line breaks.

10.4.7.1.1.3 Safety Design Basis Three. Safety functions can be performed, assuming a single active component failure coincident with the loss of offsite power.

10.4.7.1.1.4 Safety Design Basis Four. The CFS is designed such that the active components are capable of being tested during plant operation. Provisions are made to allow for inservice inspection of components at appropriate times specified in the ASME Boiler and Pressure Vessel (B&PV) Code, Section XI.

10.4.7.1.1.5 Safety Design Basis Five. The CFS is designed and fabricated to codes consistent with the quality group classification assigned by Regulatory Guide 1.26 and the seismic category assigned by Regulatory Guide 1.29. The power supply and control functions are in accordance with Regulatory Guide 1.32.

10.4.7.1.1.6 Safety Design Basis Six. For a main feedwater line break inside the containment or a main steam line break (MSLB), the CFS is designed to limit high energy fluid to the broken loop, and to provide a path for addition of auxiliary feedwater to the two intact loops.

10.4.7.1.1.7 Safety Design Basis Seven. For a main feedwater line break upstream of the MFIV (outside of the containment), the CFS is designed to prevent the blowdown of any steam generator and to provide a path for the addition of auxiliary feedwater.

10.4.7.1.1.8 Safety Design Basis Eight. The CFS is designed to provide a path to permit the addition of auxiliary feedwater for reactor cooldown under emergency shutdown conditions.

10.4.7.1.2 Power Generation Design Bases

10.4.7.1.2.1 Power Generation Design Basis One. The CFS is designed to provide a continuous feedwater supply to the three steam generators at required pressure and temperature under anticipated steady-state and transient conditions, from zero load to rated power.

10.4.7.1.2.2 Power Generation Design Basis Two. The CFS is designed to control the dissolved oxygen content and pH in the turbine cycle and the steam generators.

10.4.7.1.2.3 Power Generation Design Basis Three. The CFS is designed to maintain feedwater flow following a loss of all external loads.

10.4.7.1.2.4 Power Generation Design Basis Four. The feedwater heaters and steam extraction lines are designed to minimize the possibility of water induction to the turbine in accordance with the guidelines of ASME Standard TWDPS, Part 2, and to limit turbine overspeed due to entrained energy in the extraction system.

10.4.7.1.2.5 Power Generation Design Basis Five. The CFS is designed to permit continued operation of the plant at rated power without reactor trip with three of the four condensate

479 pumps available, or one of the three feedwater pumps. Loss of one of the two heater drain pumps will permit continued operation at reduced power.

10.4.7.1.2.6 Power Generation Design Basis Six. The CFS provides feedwater of the required chemical composition and quality to minimize steam generator tube failures.

10.4.7.1.2.7 Power Generation Design Basis Seven. The CFS is designed to operate at approximately 75 percent of rated load with one of the two HP feedwater heater trains out of service.

10.4.7.1.2.8 Power Generation Design Basis Eight. The CFS includes one motor-driven startup feedwater pump to be used during startup, shutdown, hot standby, and refueling operations.

10.4.7.2 System Description

10.4.7.2.1 General Description

The CFS, as shown in figure 10.4-6, consists of four 33-1/3 percent capacity condensate pumps, three 50 percent capacity steam generator feedwater pumps with turbine drivers, four stages of low-pressure feedwater heaters, three stages of high-pressure feedwater heaters, gland steam condenser, air ejector, heater drain tank, and two 50 percent capacity heater drain pumps, piping, valves, and instrumentation. The condensate pumps take suction from the condenser hotwells and discharge the condensate into one common header that feeds the condensate demineralizers. Downstream of the condensate demineralizers the header branches into three parallel trains. Each train contains four stages of low-pressure feedwater heaters. The trains join together at a common header that branches into three lines that go to the suction of the steam generator feedwater pumps. The turbine-driven feedwater pumps discharge the feedwater into two cross-connected parallel trains. Each of the two trains contains three stages of high-pressure feedwater heaters. The trains are then joined into a common header, which divides into three lines that connect to the steam generators. Each of the three lines contain6 a main feedwater control valve and main feedwater bypass control valve, a feedwater flow element an MFIV, a controlled closure check valve, an auxiliary feedwater connection, and a chemical injection connection.

The condensate and feedwater chemical injection system, as shown in figure 10.4-7, is provided to inject hydrazine and ETA into the condensate pump discharge downstream of the condensate demineralizers, and additional hydrazine and ETA into the three main feedwater lines connecting with the three steam generators. Injection points are shown in figure 10.4-7. This condensate and feedwater chemical injection system is described in subsection 10.4.10. 132

During normal power operation, the continuous addition of hydrazine and ETA to the condensate system is under automatic control, with manual control optional. As discussed in subsection 10.3.5, the addition of ETA and hydrazine establishes the design pH according to the condensate and feedwater system chemistry requirements, and establishes a constant initial hydrazine residual in the feedwater system so that oxygen inleakage can be scavenged. 132

The following measures have been taken to protect personnel from any toxic effects of chemicals :

A. ETA and hydrazine solution and measuring tanks are provided with outside vents to minimize ammonia and hydrazine vapors in the general atmosphere of the turbine building. 132

B. Concentrated chemicals are diluted to less than a 5 percent solution strength in hydrazine solution tank and 10 percent solution strength in ETA solution tank.

C. Corrosion resistant construction materials (stainless steels) are used throughout the storage and injection equipment.

D. Chemical mixing is accomplished by the tank mixer used to agitate tank contents.

E. Chemical drum unloading is accomplished with air driven drum bung pumps, which are nonsparking and pose no electrical hazard to personnel.

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ETA and hydrazine are injected under manual control for special plant conditions such as hydrostatic test, hot standby, layup, etc. These conditions require high levels of pH and hydrazine residual to minimize corrosion in the steam generators.

Component failures within the CFS that affect the final feedwater temperature or flow have a direct effect on the reactor coolant system and are listed in table 10.4-8. Occurrences that produce an increase in feedwater flow or a decrease in feedwater temperature, result in increased heat removal from the reactor coolant system, which is compensated for by the reactor control system action, as described in section 7.7. Events that produce the opposite effect, i.e., decreased feedwater flow or increased feedwater temperature, result in reduced heat transfer in the steam generators. Normally, automatic control action is available to adjust feedwater flow and reactor power to prevent excess energy accumulation in the reactor coolant system, and the increasing reactor coolant temperature provides a negative reactivity feedback that tends to reduce reactor power. In the absence of normal control action, either the high outlet temperature or high-pressure trips of the reactor by the reactor protection system are available to assure reactor safety. Loss of all feedwater, the most severe transient of this type is examined in section 15.2.

Refer to section 5.4 for a discussion of steam generator design features to preclude fluid flow instabilities such as water hammer. The feedwater connection on each of the steam generators is the highest point of each feedwater line downstream of the MFIV to preclude high point pockets which, if present, could trap steam and lead to water hammer. The horizontal run length from the feedwater nozzle of each steam generator is minimized.

10.4.7.2.2 Component Description

Codes and standards applicable to the CFS are listed in table 3.2-1. The CFS is designed and constructed in accordance with Quality Group B and Seismic Category I requirements from the steam generator out to the first weld outside of the main steam support structure. This pipe contains the feedwater isolation valves as well as upstream bending and torsional pipe restraints. The remaining piping of the CFS meets ANSI B31.1 requirements. Branch lines out to and including isolation valves for the auxiliary feedwater and chemical injection are designed and constructed in accordance with Quality Group B and Seismic Category I requirements. Refer to table 10.1-1 for design data. Safety related feedwater piping materials are discussed in subsection 10.3.6.

10.4.7.2.2.1 Main Feedwater Piping. Feedwater is supplied to the three steam generators by three 18 inch carbon steel lines. Each of the lines is anchored at the containment wall, and has sufficient flexibility to provide for relative movement of the steam generators due to thermal expansion. The main feedwater lines between the containment penetration and the torsional restraint upstream of the MFIV are designed to meet the no-break zone criteria, as described in NRC BTP MEB 3-1 (refer to section 3.6).

10.4.7.2.2.2 Main Feedwater Isolation Valves. One MFIV is installed in each of the three main feedwater lines outside the containment and downstream of the feedwater control valve. The MFIVs are installed to prevent uncontrolled blowdown from more than one steam generator in the event of a feedwater pipe rupture in the turbine building. The main feedwater check valve provides backup isolation. The MFIVs isolate the non-safety-related portions from the safety-related portions of the system. In the event of a secondary cycle pipe rupture inside the containment, the MFIV limits the quantity of high-energy fluid that enters the containment through the broken loop, and provides a pressure boundary for the controlled addition of auxiliary feedwater to the two intact loops. The valves are bidirectional, double disc, parallel wedge gate valves. Stored energy for closing is supplied by accumulators that contain a fixed mass of high pressure nitrogen gas and a variable mass of high pressure hydraulic fluid. For emergency closure, a solenoid is deenergized, which causes the high pressure hydraulic fluid to be admitted to the top of the valve stem driving piston, and also causes the fluid stored below the piston to be dumped to the fluid reservoir. Two separate pneumatic/hydraulic power trains are provided for each MFIV. Electrical solenoids are energized from separate Class 1E sources.

10.4.7.2.2.3 Main Feedwater Control Valves and Control Bypass Valves. The MF control valves are air-operated angle valves that automatically control feedwater between 20 percent and full power. The bypass control valves are air-operated globe valves, which are used during startup up to approximately 15 to 20 percent power. The MF control valves and bypass control valves are located in the turbine building.

In the event of a secondary system pipe rupture inside the containment, the main feedwater control valve(and associated bypass valve) provide a diverse back-up to the MFIV to limit the quantity of high-energy fluid that enters the containment through the broken loop. For emergency closure, either of two separate train solenoid valves 136
(main and back-up), when main and solenoid valves de-energized in train, will result in valve closure. Electrical solenoids are energized from separate Class 1E sources.

10.4.7.2.2.4 Main Feedwater Flow Elements. One feedwater flow element is provided in each of the three main feedwater lines outside the containment between the main feedwater control valve and the MFIV. The signals from these elements are used for flow control of the feedwater to the steam generators, and as an input to the reactor protection system.

The flow elements are venturi type. In order to assure feed-water flow accuracy, the elements are located with a minimum of 18 diameters of straight pipe upstream and 2 diameters downstream.

10.4.7.2.2.5 Main Feedwater Check Valves. The main feedwater check valves are located immediately downstream of the main feedwater isolation valves. In the event of a secondary system pipe rupture inside the containment, the main feedwater check valves provide a diverse backup to the MFIV to assure the pressure boundary for the controlled addition of auxiliary feedwater to the two intact loops.

10.4.7.2.2.6 Chemical Addition Line Check Valves and Isolation Valves. The check valves are located downstream of the isolation valves in the chemical addition lines. The check valves provide a diverse backup to the isolation valves to assure the pressure boundary. The normally-closed isolation valves are air-operated valves that fail closed.

10.4.7.2.2.7 Condensate Pumps. Four motor-driven condensate pumps are provided and three pumps will operate in-parallel. Valving is provided to allow individual pumps to be removed from service. Pump capacity is sufficient to meet full power requirements with three of the four 'pumps in operation.

10.4.7.2.2.8 Low-Pressure Feedwater Heaters. Parallel strings of closed feedwater heaters are located in the condenser necks. The No. 1, 2, 3, and 4 heaters have integral drain coolers, and their drains are cascaded to the next lower stage feedwater heaters. The drains from No. 1 heaters are dumped to the condenser. FeedWater leaves the No. 4 heaters from a header and is routed to the steam generator feed pumps. The heater shells are carbon steel, and the tubes are stainless steel.

10.4.7.2.2.9 High-Pressure Feedwater Heaters. Parallel strings of three high-pressure feedwater heaters with integral drain coolers in heater No. 6 and 7 are used. The drains of the No. 7 heater shellside cascade to the No. 6 heater. The No. 5 and 6 heaters are drained to the heater drain tank. The heater shells are carbon steel, and the tubes are stainless steel.

Isolation valves and bypasses are provided that allow each string of high-pressure and low-pressure heaters to be removed from service. In case one string of high-pressure heaters is out of service, the system operability is maintained at reduced power by using parallel high-pressure heater string and bypass line.

Provisions are made in all heater drain lines except No. 5, which drains via the heater drain tank, to allow direct discharge to the condenser in the event the normal drain path is blocked.

10.4.7.2.2.10 Heater Drain Tank. A single heater drain tank drains the shells of No. 5 and 6 feedwater heaters and provides reservoir capacity for drain pumping. The heater drain tank is installed in such a way that the No. 5 heaters drain freely by gravity flow. The drain level is maintained within the tank by a level controller in conjunction with the heater drain pumps.

The heater drain tank is provided with an alternate dump line to the main condenser for automatic dumping upon high level. The alternate dump line is also used during startup and shutdown when it is desirable to bypass the drain piping for feedwater quality purposes.

10.4.7.2.2.11 Heater Drain Pumps. Two motor-driven heater drain pumps operate in parallel, taking suction from the heater drain tank and discharging it into the suction of the steam generator feed pumps.

The piping arrangement allows each heater drain pump to be individually removed from service while operating the remaining pump.

10.4.7.2.2.12 Steam Generator Feedwater Pumps. The three steam generator feedwater pumps (SGFP) operate in parallel and discharge to the high-pressure feedwater heaters. The pumps take suction from the No. 4, low-pressure feedwater heaters and discharge through the high-pressure feedwater heaters. Each pump is turbine-driven with variable speed. Steam for the turbines is supplied from the main steam header at low loads, and from the moisture separator reheater outlet during normal operation.

Isolation valves are provided that allow each steam generator feed pump to be individually removed from service, while con-
479 tinuing operations with two operating pumps at reduced power level.

10.4.7.2.2.13 Pump Recirculation Systems. Minimum flow control systems are provided to allow all pumps in the main condensate and feedwater trains to pump at the manufacturer's recommended minimum flow rate to prevent damage.

10.4.7.2.2.14 Startup Feed Pump. During normal startup a motor-driven startup feed pump supplies feedwater to the steam generators. This maintains steam generator water level until sufficient steam is generated to allow startup of the main feedwater pumps. This pump will also be used during normal plant hot standby, shutdown, and refueling operations.

10.4.7.2.3 System Operation

10.4.7.2.3.1 Normal Operation. Under normal operating conditions, system operation is automatic. Automatic level control systems control the levels in all feedwater heaters, except No. 5 heaters, the heater drain tank, and the condenser hotwells. Feedwater heater levels are controlled by modulating the drain valves. Control valves in the discharges of the heater drain pumps control heater drain pump flows in reaction to the level in the heater drain tank. Six valves, one in each of the six makeup lines to the condenser from the condensate storage tank, and one valve in the return line to the condensate storage tank, control the level in the condenser.

At very low power levels, feedwater is supplied by the startup feed pump. Once sufficient steam pressure has been established, an SGFP turbine is started, and from this low-power level to approximately 20 percent power, feedwater flow is under the control of the feedwater bypass control valves and their control system. The SGFP turbine speed is under manual control.

At approximately 20 percent power, feedwater flow is controlled by the main feedwater control valves, and SGFP turbine speed is automatically controlled. The steam generator feedwater pump turbines are controlled by a speed signal from the feed pump speed control system. The control system utilizes measurements of steam generator steam flow, feedwater pressure, and steam pressure to produce this signal. The pump speed is increased or decreased in accordance with the speed signal by modulating the flow of steam admitted to the pump turbine drivers.

The feedwater flow to each steam generator is controlled by a three-element feedwater flow control system to maintain a programmed water level in the steam generator. The control system regulates the feedwater control valves by continuously comparing steam generator water level with the programmed level, and feedwater flow with the pressure-compensated steam flow signal.

The system is capable of accepting a 10 percent step load, a 5 percent per minute ramp change, and a load rejection from full load to 50% load without major effect in the CFS. Under this 479
transient, heater drain pump flow is lost. The condensate pumps pass 96 percent of feedwater flow until heater drain pump flow is restored.

10.4.7.2.3.2 Emergency Operation. In the event that the plant must be shut down and offsite power is lost, or a DBA occurs that results in a feedwater isolation signal, the MFIV and other valves associated with the main feedwater lines are closed. Coordinated operation of the auxiliary feedwater system (refer to subsection 10.4.9) and the main steam supply system (refer to section 10.3) is employed to remove decay heat.

10.4.7.3 Safety Evaluation

Safety evaluations are numbered to correspond to the safety design bases of subparagraph 10.4.7.1.1.

10.4.7.3.1 Safety Evaluation One.

The safety-related portions of the CFS are located in the reactor and auxiliary buildings. These buildings are designed to withstand the effects of earthquakes, typhoons, hurricanes, floods, external missiles, and other appropriate natural phenomena. Sections 3.3, 3.4, 3.5, 3.7 and 3.8 provide the bases for the adequacy of the structural design of these buildings.

10.4.7.3.2 Safety Evaluation Two

The safety-related portions of the CFS are designed to remain functional after an SSE. Subsection 3.7.2 and section 3.9 provide the design loading conditions that were considered. Sections 3.5, 3.6, and subsection 9.5.1 provide the hazards analyses to assure that a safe shutdown, as outlined in section 7.4, can be achieved and maintained.

10.4.7.3.3 Safety Evaluation Three

The CFS safety functions are accomplished by redundant means, as indicated by table 10.4-9. No single failure will compromise the system's safety functions. All vital power can be supplied from either onsite or offsite power systems, as described in chapter 8.

10.4.7.3.4 Safety Evaluation Four

Preoperational testing of the CFS is performed as described in chapter 14. Periodic inservice functional testing is done in accordance with paragraph 10.4.7.4.

Section 6.6 provides the ASME B&PV Code, Section XI requirements that are appropriate for the CFS.

10.4.7.3.5 Safety Evaluation Five

Section 3.2 delineates the quality group classification and seismic category applicable to the safety-related portion of this system and supporting systems. Table 10.4-7 shows that the components meet the design and fabrication codes given in section 3.2. All the power supplies and controls necessary for the safety-related functions of the CFS are Class 1E, as described in chapters 7 and 8.

10.4.7.3.6 Safety Evaluation Six

For a main feedwater line break inside the containment or an MSLB, the MFIVs located in the auxiliary building and the main feedwater control valves located in the turbine building are automatically closed upon receipt of a feedwater isolation signal. For each intact loop, the main feedwater check valve and MFIV and associated redundant isolation of the chemical addition line will close, forming a pressure boundary to permit auxiliary feedwater addition. The auxiliary feedwater system is described in subsection 10.4.9.

10.4.7.3.7 Safety Evaluation Seven.

For a main feedwater line break upstream of the MFIV, the MFIVs are supplied with redundant power supplies and power trains to assure their closure to isolate safety- and nonsafety-related portions of the system. Branch lines downstream of the MFIVs contain normally closed, power-operated valves that close on a feedwater isolation signal. These valves fail closed on loss of power.

Releases of radioactivity from the CFS due to the main feed-water line break are minimal because of the negligible amount of radio-activity in the system under normal operating conditions. Additionally, following a steam generator tube rupture, the main steam isolation system provides controls for reducing accidental releases, as discussed in section 10.3 and chapter 15. Detection of radioactive leakage into and out of the system is facilitated by area radiation monitoring (discussed in subsection 12.3.4), Process Radiation Monitoring (discussed in section 11.5), and Steam Generator Blowdown Sampling (discussed in subsections 10.4.8 and 9.3.2).

10.4.7.3.8 Safety Evaluation Eight.

In the event of loss of offsite power, loss of the steam generator feedwater pumps, or other situations that may result in a loss of main feedwater, the feedwater isolation signal will automatically isolate the feedwater system and permit the addition of auxiliary feedwater to allow a controlled reactor cooldown under emergency shutdown conditions. The auxiliary. feedwater system is described in subsection 10.4.9.

10.4.7.4 Tests and Inspections

10.4.7.4.1 Preservice Valve Testing

The MFIVs and feedwater control valves are checked for closing time prior to initial startup.

10.4.7.4.2 Preoperational System Testing

Preoperational testing of the CFS is performed as described in chapter 14.

10.4.7.4.3 Inservice Inspections

The performance, structural, and leaktight integrity of all system components are demonstrated by continuous operation.

203 The closure and the operability of the actuator system for the redundant actuator power trains of each MFIV are checked by fully closing the valve every reactor cold shutdown pursuant to In-service Test plan.

Additional discussion of inservice inspection of ASME Code Class 2 and 3 components is presented in section 6.6.

10.4.7.5 Instrumentation Applications

The main feedwater instrumentation, as described in table 10.4-10, is designed to facilitate automatic operation, remote control, and continuous indication of system parameters. As described in chapter 7, certain devices are involved in the secondary system protection system.

The feedwater flow to each steam generator is controlled by a three-element feedwater flow control system to maintain a programmed water level in the steam generator. The three-element feedwater controllers regulate the feedwater control valves by continuously comparing the feedwater flow and steam generator water level with the programmed level and the pressure-compensated steam flow signal (refer to section 7.7).

The steam generator feedwater pump turbine speed is varied to maintain a programmed pressure differential between the steam header and the feed pump discharge header. The pump speed is increased or decreased in accordance with the speed signal by modulating the steam pressure at the inlet of the pump turbine drivers.

All SGFP turbines are tripped automatically upon any one of the following:

A. High-high level in any one steam generator

B. Safety injection signal

C. Low feedwater pump suction header pressure

183 D. High feedwater pump discharge pressure.

A or B signals above generates ESFAS - Feedwater Isolation Signal (refer to section 7.3).

Each SGFP turbine trip occurs on any one of the following signals:

A. Low lube oil pressure

B. Turbine overspeed

C. Low vacuum

D. Low main feedwater pump suction NPSH 183

A flow element with a flow controller is installed on the condensate and heater drawn pumps. The flow controller provides the automatic modulating signals to open the minimum flow valves for the pumps.

A flow element with a flow controller is installed on the suction of each of the steam generator feedwater pumps to provide the modulating control signal to open the minimum recirculation valves for the steam generator feedwater pumps.

A pressure transmitter is located in the main feedwater header to provide feedwater system pressure to the speed-control system for the steam generator feedwater pump turbines. A flow element with two flow transmitters is located on the inlet to each of the three steam generators to provide signals for the three-element feedwater control system.

The total water volume in the condensate and feedwater system is maintained through automatic makeup and rejection of condensate to the condensate storage tank. System makeup and rejection are controlled by the condenser hotwell level controllers.

The system water quality is automatically maintained through the injection of hydrazine and ammonia into the condensate system. The ammonia and hydrazine injection is controlled by pH and the hydrazine residual in the system, which is continuously monitored by the process sampling system.

Non-Class 1E pressure switches are installed in each MFIV actuator accumulator for the monitoring of the air pressure. These pressure switches activate control room alarms upon low actuator accumulator pressure.

Instrumentation, including pressure indicators, flow indicators, and temperature indicators required for monitoring the system is provided in the control room.

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

The steam generator blowdown system (SGBS) is used in conjunction with the chemical feed portion of the feedwater system (subsection 10.4.7). and the condensate polishing system (subsection 10.4.6) to control the chemical composition and solids concentration in the steam generators. The design of this system allows for heat recovery by use of a flash
2 tank that returns steam to sixth point feedwater heaters and condensate to the condenser hotwell. The steam generator blowdown system is shown in figure 10.4-8.

10.4.8.1 Design Bases

Criteria for the selection of design bases are stated in paragraph 1,1.2,2,

10.4.8.1.1 Safety Design Bases

10.4.8.1.1.1 Safety Design Basis One, The system from the steam generators up to and including the containment isolation valves is designed to remain functional after a safe shutdown earthquake (SSE),

10.4.8,1,1,2 Safety Design Basis Two, The blowdown system downstream of the containment isolation valve is designed according to the provisions of Branch Technical Position ETSB 11-1 (Revision 1).

10.4.8.1.2 Power Generation Design Bases

10.4.8.1.2.1 Power Generation Design Basis One. The SGBS in conjunction with the condensate polishing demineralizer and the condensate and feedwater chemical injection system is capable of maintaining the chemical purity of the steam generator shell water within limits discussed in subsection 10.3.5.

During normal operation, the steam generators collectively blow down liquid continuously to the SGBS. Equipment is designed for the temperatures associated with maximum blowdown pressure.

10.4.8.1.2.2 Power Generation Design Basis Two. The SGBS provides a means of removing radioactive material from the secondary side water inventory in the event of a primary to secondary

leak in order to maintain the secondary radioactivity level below the technical specification limit. In the event of condenser water in leakage, the increase of cation conductivity and 2
sodium content in the blowdown effluent from the demineralizers is monitored and alarmed in the control room. The blowdown rate is then increased by remote/manual adjustments of the control valves to satisfy the limits of steam generator water chemistry requirements.

10.4.8.L.2.3 Power Generation Design Basis Three. The SGBS is designed to recover a portion of the heat energy contained in the blowdown fluid and return it to the condensate 2
while recovering all the blowdown fluid.

10.4.8.1.3 Codes and Standards

Codes and standards applicable to the SGBS are listed in table 3.2-1. The portions of the system extending from the steam generators to the containment isolation valves are designed and constructed in accordance with Quality Group B requirements. Those portions of the system downstream of the containment isolation valve are designed and constructed in accordance with requirements of the USNRC Branch Technical Position ETSB No. 11-1, Revision 1.

10.4.8.2 System Description

10.4.8.2,1 General

The SGBS is shown schematically in figure 10.4-8. The system consists of a flash tank, heat exchangers, filters, demineralizers, and associated piping, controls, and instrumentation.

10.4.8.2.2 Component Description

10.4.8.2.2.1 Flash Tank. The flash tank is a vertical, carbon steel pressure liquid effluent vessel equipped with a level controller that regulates the flow rate. The tank pressure is monitored in the control room by a pressure transmitter. This pressure transmitter and associated controller also control the steam outlet control valve set at 298 psig in order to provide the differential pressure necessary for transport of the flash steam to the number 6 feedwater heater shell.

10.4.8.2.2.2 Regenerative Heat Exchangers. The regenerative heat exchangers are shell and U-tube exchangers; unprocessed blowdown water passes through the tubes and condensate is used as the cooling water which passes through the shell. Blowdown water temperature is controlled by modulating the condensate cooling water return valves.

10.4.8.2.2.3 Nonregenerative Heat Exchangers. The non-regenerative heat exchangers are shell and U-tube exchangers; unprocessed blowdown water passes through the tubes, and turbine building closed cooling water passes through the shell.

10.4.8.2.2.4 Steam Generator Blowdown Inlet Filters. Each of the two steam generator blowdown (SGB) inlet filters is a
2 100 percent capacity, vertical, stainless steel pressure vessel with a replaceable filter cartridge. The filters are designed for 323,116 lbs/hr at △P of 5 psi when clean and △P of 20 psi when fouled.

2 10.4.8.2.2.5 Demineralizers. Each of the two demineralizers is a 100 percent capacity, vertical, stainless steel pressure vessel with a mixed-bed, nonregenerable resin charge.

10.4.8.2.3 System Operation

During plant operation, blowdown from the steam generators flow continuously at a preset rate to the flash tank. The
2 expected normal continuous blowdown rate is approximately 1 percent of the rated feedwater flow.

479 During normal operation, a blowdown of 43,522 lb/hr is maintained from each steam generator, or 130,567 lb/hr total. During periods 2 of condenser inleakage or steam generator primary to secondary leakage, the blowdown increases to a maximum of 132,799 lb/hr from each steam generator (398,396 lb/hr total) to maintain the water quality within limits given in sub-section 10.3.5.

The blowdown flow from each steam generator is individually routed to the steam generator flash tank, with the flow rate ljeing adjusted by a manual remote operated control valve in each line located as close as possible to the flash tank. This minimizes the length of the piping subject to the severe erosion effects caused by the flashing liquid downstream of the valve. The steam line from the flash tank is automatically throttled to maintain a constant flash tank pressure.

Downstream of blowdown flash tank, the system splits into two trains each with three heat exchangers and one filter. Each train is designed to handle 168,737 lbs/hr of condensate, 479 which is 50 percent of the maximum liquid blowdown from the flash tank Either train can be used during normal blowdown while during maximum blowdown both trains are utilized in parallel. Part of the blowdown is flashed into steam and is returned to the feedwater cycle. The flashed liquid is cooled in the regenerative heat exchangers, cooled further in a nonregenerative heat exchanger, filtered, demineralized, and returned, to the condenser.

The blowdown from each steam generator is monitored as needed to comply with water chemistry requirements of subsection 10.3.5. Operator action required to maintain the water chemistry requirements with a condenser leak will consist of the following, depending on the size of the leak:

A. Increase the steam generator blowdown rate to meet the steam generator chemistry as given in table 10.3-4.

B. Discard the water in the affected hotwell, if condenser leakage is detected. Isolate the leaking condenser half and repair while continuing operation at reduced power.

If the above corrective measures prove unsuccessful in controlling the steam generator chemistry, the unit must be shut down and repairs made to eliminate the condenser leakage.

If the total dissolved solids (TDS) in the steam generator feedwater should increase, the blowdown rate can be increased accordingly.

If the radioactivity in the treated blowdown from a steam generator exceeds acceptable limits due to steam generator tube leakage, the containment isolation valves close to shut off the blowdown flow from that steam generator. A safety injection signal will also result in isolation valve closure. This ensures that in the event that the normal feedwater supply is lost and operation of the auxiliary feedwater system is initiated, blowdown flow will be stopped so that no additional feedwater will be lost from the steam generators through the blowdown lines.

In the event the piping between the containment isolation valve and the flash tank were to rupture, temperature switches in the appropriate auxiliary building compartments would respond to the heat of escaping steam from the ruptured pipe and close the isolation valve.

10.4.8.3 Safety Evaluation

The safety evaluations are numbered to correspond to the Safety Design Bases. Criteria for the selection of safety design bases are stated in subparagraph 1.1.2.2.1.

10.4.8.3.1 Safety Evaluation One

The system from the steam generators up to and including the containment isolation valves is designed in accordance with Seismic Category I requirements as specified in section 3.2. The components (and supporting structures) of any system, equipment, or structure which is not Seismic Category I and whose collapse could result in loss of required integrity of the SGBS through impact are supported to ensure that they will not collapse when subjected to seismic loading resulting from the SSE.

10.4.8.3.2 Safety Evaluation Two

Containment isolation valves are open during normal operation and close on loss of air, on a containment isolation signal (CIS), on an auxiliary feedwater actuator signal (AFAS), or on a high temperature in certain auxiliary building compartments. A failure analysis of the system components is presented in table 10.4-11.

10.4.8.4 Tests and Inspections

Periodic tests and recalibration will be performed on the radiation monitors in the blowdown processing system. Periodic tests of the blowdown processing system isolation valve functioning will be performed to check operability and leaktightness. Periodic visual inspections and preventive maintenance can be conducted as necessary as all components are accessible for inspection and maintenance.

10.4.8.5 Instrumentation Applications

Redundant radiation monitoring of the sample from each blowdown line is provided as discussed in section 11.5. Level control is provided for the blowdown tank. Temperature control is provided for the outlet of the regenerative heat exchanger. A temperature alarm is initiated in the control room when the temperature of the blowdown fluid leaving the nonregenerative SGB heat exchanger reaches 140°F. The filters and demineralizers are each provided with local differential pressure indications. Temperature switches in certain auxiliary building compartments would detect the temperature increase resulting from steam released by a blowdown line rupture and would close the containment isolation valves. The effluent from the blowdown dem-
2 inerlizers is monitored for sodium concentration, specific conductivity, and cation conductivity.

10.4.8.6 Steam Side Water Chemistry

10.4.8.6.1 Introduction

Condenser leakage, makeup water contaminants, or condensate and feedwater system corrosion products are the sources of chemical agents that have the potential for accumulating as sludge on the steam generator tube sheet, producing deposits on steam generator heat transfer surfaces, and for being deleterious to the steam generator materials of construction. The feedwater is the means by which these chemical agents are transported to the steam generator. Recognition must be given to the fact that an all volatile treatment (AVT) chemistry provides no buffer against the effects of condenser leakage; that it is incapable of preventing the formation of scale should the chemical agents that have the propensity for scale formation be present, and that the ammonium hydroxide or the amines added to the system for feedwater pH control have minimum effectiveness as steam generator pH control agents at the operating temperature in the steam generator. Therefore, to accomplish the goal of maintaining a steam generator steam-side, all-volatile chemistry environment which is innocuous to the steam generator materials, it is necessary, through a rigorously controlled chemistry program, to minimize the introduction of contaminants to the system and to minimize corrosion of the materials of construction of the condensate and feedwater systems. In addition to providing the proper environment for the steam generator, a well-maintained AVT chemistry program will accomplish the following:

A. Maintain the high integrity of all systems components

B. Avoid or minimize turbine deposits due to carryover and volatility from the steam generator

C. Minimize sludge at its point of concentration, the steam generator

D. Minimize scale deposits on the steam generator heat transfer surfaces

E. Minimize feedwater oxygen content prior to entry into the steam generator

F. Minimize corrosion of the condensate/feedwater systems materials

These objectives will be achieved by proper selection of system materials and by exercising careful chemistry control over the systems, including comprehensive sampling and analysis (inline and laboratory), chemical injection at selected points, continuous system lowdown from the steam generator and effective protection of the steam generator and feedwater train internals during periods of inactivity.

10.4.8.6.2 General Treatment Requirements

The steam system AVT chemistry specifications are addressed to the concerns of:

A. Minimizing metal corrosion

B. Limiting the accumulation of sludge in the steam generator

C. Minimizing scale formation (Ca-Mg) on the heat transfer surfaces

D. Minimizing the potential for the formation of acid

E. Maintaining zero dissolved oxygen level (particularly at points of contact with carbon steel and the steam generator heat transfer surfaces, such as the Inconel 600 tubing).

The above concerns will be minimized by meeting the three steam generator control parameters identified in table 10.3-4; the blowdown pH, cation conductivity, and the free hydroxide.

Protection of the steam generators during inactive periods of maintenance, refueling, etc., will require placing the steam generators in a lay-up condition. To ensure the long term performance of the steam system, the same degree of chemical control will be exercised during these idle periods as that exercised during normal plant operation.

Periods of hot shutdown -and hot standby operations require that steam be released from the steam generators to provide heat release from the reactor coolant system due to heat input from core decay and reactor coolant pump heat. Chemistry control will be applied during such operations similar to that exercised during normal operating conditions. Feedwater addition to the steam generators during this period may be from the condenser hotwell (if the condenser is being used as the heat sink and condenser is being maintained under adequate vacuum), or from the condensate storage tank. Testing procedures will be exercised to check the steam generator water chemistry during hot shutdown and hot standby operation periods to maintain the required water chemistry requirements specified in subsection 10.3.5.

10.4.9 AUXILIARY FEEDWATER SYSTEM

The auxiliary feedwater system supplies feedwater to the steam generators during hot standby conditions and reactor cooldown to the point where the residual heat removal (RHR) system starts operation, whenever the main feedwater system fails to supply feedwater following any accident.

10.4.9.1 Design Bases

Criteria for selection of design bases are stated in paragraph 1.1.2.2.

Protection of the auxiliary feedwater system from wind and typhoon effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

10.4.9.1.1 Safety Design Bases

10.4.9.1.1.1 Safety Design Basis One. The auxiliary feed-water system provides feedwater for the removal of reactor core decay heat in order to ensure that: (a) there shall be no damage to the reactor following a loss of main feedwater from a condition of full power and (b) the reactor may be brought to the point at which the RHR system is placed in operation.

10.4.9.1.1.2 Safety Design Basis Two. The auxiliary feedwater and supporting systems ensure the required flow to the steam generators with a single active failure following any accident entailing a loss of main feedwater. The operational requirements during normal and accident conditions are given in table 10.4-12.

10.4.9.1.1.3 Safety Design Basis Three. In the unlikely event that the control room must be evacuated, the auxiliary feedwater system is operated as the primary means of feedwater supply.

10.4.9.1.1.4 Safety Design Basis Four. The auxiliary feed-water system and condensate storage tanks are designed to remain functional during and after a safe shutdown earthquake (SSE). The condensate storage tanks have sufficient water capacity for the auxiliary feedwater system to bring the reactor to an RHR initiaton temperature in 36 hours.

10.4.9.1.1.5 Safety Design Basis Five. The auxiliary feed-water system is designed with diversity of power sources to remain operable with the loss of both offsite and onsite ac power.

10.4.9.1.1.6 Safety Design Basis Six. The auxiliary feedwater system is designed to avoid the effects of water hammer.

10.4.9.1.2 Power Generation Design Basis

10.4.9.1.2.1 Power Generation Design Basis One. The auxiliary feedwater system may be used to supply feedwater to the steam generators during startup, cooldown, and hot standby conditions, when the condensate and feedwater system is inoperative.

10.4.9.1.3 Codes and Standards

Codes and standards applicable to the auxiliary feedwater system are listed in table 3.2-1. The auxiliary feedwater system is designed and constructed in accordance with Quality Group C requirements.

10.4.9.2 System Description

10.4.9.2.1 General Description

The auxiliary feedwater system is shown schematically on figure 10.4-9. Major system components include one steam turbine-driven and two motor-driven auxiliary feedwater pumps, auxiliary feedwater control/isolation valves, auxiliary feedwater pump turbine with lube oil cooler, associated piping, miscellaneous valves, instrumentation, and controls. The auxiliary feedwater system components are located in the auxiliary building. The normal water supply to all three auxiliary feedwater pumps is gravity fed from the Seismic Category I condensate storage tanks. Additional supplies are available from the demineralized water storage tank and the raw water reservoir. To satisfy separation criteria, separate pump discharge headers are provided for the motor-driven and steam turbine-driven auxiliary feedwater pumps, with means provided to permit any pump to supply feedwater to any or all steam generators. A flow limiting orifice is installed in each feed line to each steam generator to limit the loss of auxiliary feedwater in the event of a feed line or steam line break, to limit containment pressurization during a steam line break, and to provide pump runout protection. Each of the three auxiliary feedwater pumps is provided with a locked open minimum flow recirculation line back to the condensate storage tank. All auxiliary feedwater lines discharge into the main feedwater lines (subsection 10.4.7) outside of the containment. Operation of the auxiliary feedwater system during normal and emergency conditions is discussed in subparagraph 10.4.9.2.3. The condensate storage tanks are discussed in subsection 9.2.6.

10.4.9.2.2 Component Description

Table 10.4-13 shows component data for the auxiliary feedwater system.

10.4.9.2.2.1 Motor-Driven Pumps. The two 50 percent Seismic Category I motor-driven pumps are powered from independent Class 1E essential switchgear buses. During transient or accident conditions, the auxiliary feedwater system is designed to provide a minimum required total flow (listed in table 10.4-12) to at least two of the three steam generators plus the flow through the break in the event of a main feedwater or a main steam line break.

Each motor-driven auxiliary feedwater pump is rated to supply 554 gal/min at a total head of 3450 ft, including minimum flow for pump protection and design margins.

10.4.9.2.2.2 Turbine-Driven Pump. A steam turbine-driven, horizontal centrifugal Seismic Category I auxiliary feedwater pump provides 100 percent redundancy of auxiliary feedwater supply and diversity of pump motive power. This pump is sized to provide 1082 gal/min at a total head of 3550 feet, including minimum flow for pump protection and design margins. Steam supply to the turbine driver is taken from two of the three main steam lines between the containment penetrations and the main steam isolation valves as shown in figure 10.3-1. Each of the takeoffs from the main steam lines is equipped with a normally closed air-operated globe valve and two check valves in series. These steam lines join to form a single steam supply line to the turbine through a normally closed air-operated steam isolation valve, a motor-operated normally open trip/throttle valve, and hydraulically-operated turbine governor valve all in series. The turbine driver is rated at inlet steam pressures ranging from 1195 to 100 psia. Turbine exhaust steam is vented to the atmosphere above the auxiliary building roof. The steam lines and exhaust duct have low point drain piping to remove condensate. The high condensate level in the steam supply line to the turbine is alarmed in the control room and the backup drain isolation valve automatically opens to help control accumulation of condensate.

The steam isolation valves from each of the two steam generators are provided with small bypass lines. In order to avoid thermal shock and steam hammer upon system actuation, these bypass lines keep the auxiliary turbine piping pressurized at nearly steam generator pressure up to the normally closed steam supply stop valve in the common line. The drain control system for the common line upstream of the stop valve drains this line so that water slug jetting into the auxiliary turbine on system actuation can be avoided.

10.4.9.2.2.3 Piping and Valves. All auxiliary feedwater system piping is seamless stainless steel. Welded joints are used throughout the system except for where flanged connections are required, such as at the pumps. Check valves are provided as required to prevent backflow. Each of the auxiliary feedwater lines from the pumps is equipped with a pneumatic-operated control valve which can also be used to isolate a faulted steam generator. Two lines supply water from the condensate storage tanks to all three auxiliary feedwater pumps through a two header arrangement. The auxiliary feedwater control/isolation valves from the motor-driven pumps are provided with safety-related instrument air from the compressed air system (subsection 9.3.1) for their safety function if the normal instrument air supply fails or is not available. The safety-related air supply is adequate for a period of 12-hour operation. Each auxiliary feedwater control/isolation valve from the turbine-driven pump is provided with an air accumulator. Upon loss of normal air supply these accumulators act as a backup source of air supply and provide for a minimum of two cycles of valve operation.

10.1.9.2.3 System Operation

10.4.9.2.3.1 Plant Startup. In the unlikely event of the startup feedwater pump being inoperable during startup, the auxiliary motor-driven feedwater pumps may be used under manual control to supply feedwater from the condensate storage tanks to the steam generators until sufficient steam is available to operate the turbine-driven main feedwater pumps.

10.4.9.2.3.2 Normal Plant Operation. The auxiliary feedwater system is not required during normal power generation. The pumps are lined up with the condensate storage tanks, and are available if needed.

10.L9.2.3.3 Normal Plant Cooldown. In the unlikely event of the startup feedwater pump being inoperable during cooldown, the auxiliary feedwater pumps may be used under manual control to supply water from the condensate storage tanks to the steam generators. Auxiliary feedwater flow to each steam generator is manually regulated by the isolation/control valves. Steam generated in this manner is bypassed to the main condenser. The auxiliary feedwater pumps are used until reactor coolant temperature and pressure drop to 350°F and 400 psig at which point the residual heat removal system is placed in service and further cools the reactor.

10.4.9.2.3.4 Emergency Operation. The auxiliary feedwater system starts automatically without operator action with an actuation signal following an accident. The auxiliary feedwater pumps automatic actuation is described in section 7.3. Manual actuation is also provided. The condensate storage tanks are normally aligned to provide feedwater to the auxiliary feedwater pumps. To start the turbine-driven pump, the air-operated isolation valve in the steam supply line to the turbine driver is opened. The turbine is designed to start immediately without warmup. The operator can remotely manipulate the position of any of the auxiliary feedwater control valves in order to control the auxiliary feedwater addition rate and thereby control the steam generator water level. Provision for local manual operation is also provided and is discussed in section 7.4. Additional water supply is also available from the non-Seismic Category I demineralizer water storage tank, if required. A switchover to the demineralizer water storage tank is manually accomplished by the operator. In addition to the above water sources, the auxiliary feedwater pumps can also be manually aligned to take suction from the non-Seismic Category I raw water reservoir through removal spool pieces, if ultimately necessitated. These non-Seismic Category I water sources could be used in order of preference in addition to the condensate storage tanks.

Heat is removed from the reactor by boiling the feedwater in the steam generators and venting steam to the atmosphere through the main steam power-operated valves. If the main condenser is available, the steam may be discharged via the turbine bypass system to the condenser. When reactor coolant temperature and pressure drop to 350°F and 400 psig, respectively, cooldown is shifted to the RHR system.

Actuation of the auxiliary feedwater system is not expected to result in water hammer induced by condensing steam.

10.4.9.3 Safety Evaluation

Safety evaluations are numbered to correspond to the safety design bases. Criteria for selection of safety design basis are started in paragraph 1.1.2.2.

10.4.9.3.1 Safety Evaluation One

The auxiliary feedwater system, in conjunction with the condensate storage tanks, provides a means of pumping sufficient feedwater to prevent damage to the reactor following a loss of main feedwater incident as well as to cool down the reactor coolant system to the condition of 350°F and 400 psig during normal shutdown at which point the RHR system can operate. Pump discharge head is sufficient to establish the minimum required flow rate against a steam generator pressure corresponding to the accumulation pressure of the lowest pressure set main steam safety valve. The system supplies the minimum required feedwater to at least two steam generators within 60 seconds following automatic actuation signals, which activate the auxiliary feedwater pumps and position the valves, following an accident. This 60-second delivery time includes all time delays from the time the process variable set point is reached until the pumps are running at full speed and includes the time required to start the emergency diesel generators and supply power to any necessary motors, valves, and controls.

All three auxiliary feedwater pumps are normally lined up with the two Seismic Category I supply lines coming from the condensate storage tanks so that water is always available at the suction side of the pumps. Pressure indicators and low pressure alarms are provided in the control room for each pump suction to identify pipe failures. The condensate storage and transfer system is described in subsection 9.2.6.

10.4.9.3.2 Safety Evaluation Two

The auxiliary feedwater system provides redundant and diverse means of supplying feedwater to the steam generators for cooling the reactor coolant system under emergency conditions. Without the occurrence of a main steam or feedwater line break, each of the motor-driven pumps has the capability of supplying 100 percent of the feedwater requirements for cooldown of the reactor coolant system. The turbine-driven auxiliary feedwater pump is also capable of providing 100 percent of the minimum required feedwater flow for reactor decay heat removal. The auxiliary feedwater system can also perform its safety-related function assuming a postulated failure in the feedwater piping to one steam generator concurrent with a single active component failure in the auxiliary feedwater system. The minimum flow is delivered assuming the following failure modes:

A. One motor-driven pump operative with no main steam or feedwater line break.

B. Both motor-driven pumps operative, or the turbine-driven pump operative with spillage from a main steam or feedwater line break.

Complete physical and electrical separation is maintained throughout the pump controls, control signals, electrical power supplies, and instrumentation for each auxiliary feedwater Pump Redundancy and diversity are provided in the type and number of pumps and arrangement of piping and of pump and valve controls so that any single failure will not negate the auxiliary feedwater system's ability to perform its safety function. The auxiliary feedwater system is shown in figure 10.4-9 and the single failure analysis is presented in table 10.4-14. Minimum auxiliary feedwater system flow rates for various normal and abnormal plant conditions are given in table 10.4-12.

10.4.9.3.3 Safety Evaluation Three

Instrumentation and controls are provided at the emergency shutdown panel which enable placing the plant at hot shutdown and operating of the auxiliary feedwater system in the event of evacuation of the control room. Instruments provided at the auxiliary shutdown panel are described in section 7.4. Indications are provided for steam generator pressure and water level, auxiliary feedwater flow, and auxiliary feedwater control valve position along with condensate storage tank water level. Controls include auxiliary feedwater flow control valves and start/stop of motor driven feedwater pumps (see table 10.4-15).

10.4.9.3.4 Safety Evaluation Four

All components of the auxiliary feedwater system required for safe plant shutdown are designed and constructed to Seismic Category I requirements. The auxiliary feedwater system can be supplied through redundant headers from the Seismic Category I condensate storage tanks, which are the normal water source.

The amount of water (approximately 600,000 gallons) is reserved in the condensate storage tanks for the auxiliary feedwater system so that the plant can be brought to an RHR initiation temperature within 36 hours (see subsection 9.2.6).

The components (and supporting structures) of any system, equipment, or structure which are not Seismic Category I and whose collapse could result in loss of a required function of the auxiliary feedwater system through either impact or flooding are supported to ensure that they will not collapse when subjected to seismic loading resulting from the SSE.

10.4.9.3.5 Safety Evaluation Five

Diversity is provided in the type and number of pumps, power supplies, and arrangement of piping and of pump and valve controls so that any single failure will not negate the auxiliary feedwater system's ability to perform its safety function. The features which provide this capability are shown in figure 10.4-9 and table 10.4-14. Details of these features are found in paragraph 10.4.9.2 and section 7.3. Whereas the motor-driven pumps and associated equipment are powered by separate Class 1E 4,160V power supplies, the turbine-driven pump receives steam drawn from two main steam lines between the containment penetrations and the main steam isolation valves.

All valves and controls necessary for the function of the turbine-driven pump and motor-driven pump trains and their associated equipment are energized by redundant Class 1E 125V dc system or have pneumatic-operated valves which fail to the safe position and/or provided with Seismic Category I air accumulators (capable of 2 cycles of valve operation) and safety-related instrument air to assure their intended operation following loss of the normal instrument air supply. This ensures that the auxiliary feedwater system can provide the minimum required feedwater to the steam generators with the most restrictive single active failure in the safety grade components that adversely affect the system performance.

10.4.9.3.6 Safety Evaluation Six

Actuation of the auxiliary feedwater system is not expected to result in water hammer induced by condensing steam with the use of model F steam generator. Main feedwater system piping is designed to withstand transients associated with the isolation of main feedwater on the auxiliary feedwater system starting.

10.4.9.4 Test and Inspections

Each of the auxiliary feedwater pumps is hydrostatically tested in accordance with ASME Boiler and Pressure Vessel Code Section III, Class 3. The turbine driver is given a quick start test, a performance test, and an overspeed trip test prior to shipment. The entire auxiliary feedwater system is hydrostatically tested after assembly is completed. The system is capable of being tested periodically, while the plant is at power, in accordance with the frequency specified
343 in the technical specifications, ITS Chapter 1 3.7 and ITS Chapter 3 4.4. During the testing period,. the backup water sources are not permitted to contaminate the main feedwater system or the steam generators.

10.4.9.5 Instrumentation Applications

Safety-related display instrumentation related to the auxiliary feedwater system is discussed in section 7.5. Information indicative of the readiness of the auxiliary feedwater system prior to operation and the status of active components during system operation is displayed for the operator in the main control room (see table 10.4-15).

10.4.10 CONDENSATE AND FEEDWATER CHEMICAL INJECTION SYSTEM

The condensate and feedwater chemical injection system injects hydrazine and ETA into the condensate and feedwater systems for continuous maintenance of the oxygen and pH in the feedwater and steam generators under all modes of operation and shutdown. 132

10.4.10.1 Design Bases

Criteria for the selection of design bases are stated in paragraph 1.1.2.2.

10.4.10.1.1 Safety Design Bases

The condensate and feedwater chemical injection system has no safety design basis.

10.4.10.1.2 Power Generation Design Bases

10.4.10.1.2.1 Power Generation Design Basis One. The chemical injection system supplies hydrazine to the condensate in an amount required to scavenge oxygen.

10.4.10.1.2.2 Power Generation Design Basis Two. The chemical injection system supplies ETA to the condensate to control the pH of the condensate and feedwater system in order to meet the steam generator water chemistry requirements.

10.4.10.1.2.3 Power Generation Design Basis Three. In addition to continuous treatment for normal power operation, the chemical injection system can supply hydrazine and ETA Solution to the feedwater for individual steam generators for corrosion control during hydrostatic testing, wet lay up, and standby of any steam generators not in normal operation. 132

10.4.10.1.3 Codes and Standards

Codes and standards applicable to the chemical injection system are listed in table 3.2-1. The system is designed and constructed in accordance with requirements of the Power Piping Code, ANSI Standard B 31.1.0.

10.4.10.2 System Description

10.4.10.2.1 General Description.

The condensate and feedwater chemical injection system is shown schematically in figure 10.4-7.

The condensate and feedwater chemical injection system consists of one stainless steel hydrazine solution feed tank and one stainless steel ETA solution feed tank. A stainless steel metering cylinder is provided with each feed tank. In the condensate chemical injection system, two pumps are provided. One pump is provided for hydrazine, one for ETA. In the feedwater chemical injection system two metering pumps are provided to feed hydrazine or ETA into the steam generator. A spare pump can be used to supply ETA or hydrazine for feedwater or condensate chemical injection.

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These pumps are intended for intermittent duty and they service each individual steam generator. The condensate hydrazine and ETA feed pumps are equipped with automatic stroke adjustment for individual control by condensate flow, residual hydrazine analyzers and conductivity meter. The feedwater chemical injection pumps are equipped with manual adjustment. Solution lines are equipped with suction strainers, discharge relief valves, and necessary valves and instrumentation. ETA and hydrazine feed solutions are prepared by the addition of the concentrated solution and condensate to the appropriate solution feed tank.

10.4.10.2.2 Component Description

10.4.10.2.2.1 Feedwater Hydrazine Feed Pump. The hydrazine pumps for injection to the steam generators and main feedwater lines are manually throttled, proportioning type pumps, driven by electric motors. These pumps are rated at 0 to 60 gal/h.

10.4.10.2.2.2 Condensate Chemical Feed Pumps.

132 The hydrazine, ETA, and standby pumps for injection into the condensate system, are variable stroke controlled, proportioning

type Pumps, driven by electric motors. These pumps are rated at 0 to 15 gal/h.

10.4.10.2.2.3 Hydrazine Feed Tank.

The hydrazine feed tank is a stainless steel cylindrical tank of 400 gallons capacity, equipped with level indicators and motor driven agitators.

10.4.10.2.2.4 ETA Feed Tank.

The ETA feed tank is a vertically skid mounted tank of approximately 400 gallons capacity, equipped with level indicators and motor-driven agitators.

10.4.10.2.2.5 Hydrazine and ETA Metering Cylinders. 132

Both tanks have stainless steel metering cylinders with a capacity of 25 gallons each.

10.4.10.2.3 System Operation

The condensate hydrazine feed pump injects solution from the feed tank to a point in the main condensate flow downstream of the condensate demineralizer. Capacity is automatically controlled by the condensate flow and the hydrazine analyzer controller. To protect operators from hazardous vapor, the hydrazine metering cylinder is filled from shipping drums by means of a small dispensing pump fitted to the drum.

The ETA feed pump injects solution through separate line to a point downstream of the hydrazine injection point. Its capacity is automatically controlled by a condensate flow and conductivity meter controller, measuring condensate conductivity downstream of the chemical injection point. ETA feed solution is prepared manually in the same manner as for hydrazine. Morpholine or cyclohexylamine may be used in place of ETA for pH control. 132

Condensate chemical injection pumps can be operated by manual or local control, if desired, for startup or other reasons. The feed-water chemical injection system feeds an excess of chemical to a steam generator feedwater line just outside containment downstream of the auxiliary feedwater connection for special lay up or standby procedures. One or more steam generators can be treated simultaneously, as required, to meet the required steam generator water chemistry.

10.4.10.3 Tests and Inspections

The condensate and feedwater chemical injection system is operationally checked before plant startup to ensure proper functioning of the feed systems and chemical makeup sensors. The system is used intermittently during power generation operation.

10.4.10.4 Instrumentation Applications

Instrumentation is provided for manual and automatic control of the chemical injection system. Conductivity meters and hydrazine analyzers provide indication of water quality and provide signal input to the automatic mode chemical injectors. Local and remote alarms are provided to monitor the performance and protect components of the system.

Table 10.4-1

CONDENSER DESIGN DATA

Type	Single Pressure, Three Shells
Duty, total, Btu/h	6.3744×10^9 479
Shell pressure with 68.9°F circulating water, in.HgA	1.5
Tubeside circulating flow, total, gal/min	858,000
Tubeside temperature rise, °F	15.42 479
Design pressure, psig, shell , tube	15 and full vacuum 50
Hotwell storage capacity - total at normal water level, gallons	117,585
Applicable codes and standards	ASME B&PV Code, Sect VIII, Div. 1; HEI Standards for Steam Surface Condensers
Effluent oxygen content, ppb	7

Table 10.4-2

MAIN CONDENSER AIR REMOVAL SYSTEM
DESIGN DATA (Sheet 1 of 2)

Component Description		
Condenser Mechanical Vacuum Pump		
Quantity	4	
Type	Two-stage water ring centrifugal	
Hogging capacity, time required to evacuate condenser and turbine from 14.7 psia to 10 in.HgA with 4 pumps running	Approximately 30 minutes	
Speed	435 rpm	
Driver type	Electric motor	
Horsepower	150 hp	
Speed, rpm	1,800	
Electrical requirements	460V ac, 60 Hz, 3 phase	
Seal Water Coolers		
Quantity	4	
Type	Straight tube	
Duty	965,000 Btu/hr	
Fluid Data :	Shell side	Tube Side
Fluid	Seal water	Turbine plant open cooling water
Flow rate	90	800 gpm
Design pressure	150 psig	150 psig
Design temperature	300°F	300°F
Test pressure	225 psig	225 psig

Table 10.4-2

MAIN CONDENSER AIR REMOVAL SYSTEM
DESIGN DATA (Sheet 2 of 2)

Component Description		
Fluid Data: (Con't)	Shell Side	Tube Side
Inlet temperature	107.7	83.0
Outlet temperature	85.5	85.5
Material	Carbon steel	Titanium
Steam Jet Air Ejectors		
Quantity	Two 50% first-stage One 100% second-stage	
Motive Fluid Source	Main steam	
Pressure at ejector nozzle (minimum)	225 psig	
Flow		
First-stage	3128 lb/hr	
Second-stage	1282 lb/hr	
Holding capacity	75 cfm @ 1 in.HgA	
Inter- and After-Condensers		
Type	Shell and Tube	
	Tube Side	Shell Side
Flow (Intercond)	1000 gpm	4208 lb/hr
(Aftercond)	650 gpm	1854 lb/hr
Temperature In		
(Intercond)	101°F	400°F
(Aftercond)	101°F	400°F
Temperature Out		
(Intercond)	109°F	125°F
(Aftercond)	108°F	130°F
Design temperature	200°F	400°F
Design pressure	700 psig	50 psig & Vac
Material	Stainless steel, Type 304L	Carbon steel

Table 10.4-3

CIRCULATING WATER SYSTEM
COMPONENT DESCRIPTION (Sheet 1 of 3)

Circulating Water Pumps	
Quantity (per unit)	6
Type	Vertical, wet pit, centrifugal
Capacity (each), gal/min	143,000
Head at rated flow, Unit 1/Unit 2, ft.	31.7/30.5
Driver	Electric motor
Motor, hp	1,500
Motor, rpm	323
Electrical requirements	13,200 Vac, 60 Hz, 3 phase
Materials:	
Impeller	Ni-Al-Bronze
Bell and casing	Ni-Al-Bronze

Main Circulating Water Piping		
	Pipe	Conduit
Material	Carbon steel, coal tar epoxy lined	Concrete conduit
Size	96-inch	8 ft-6 in. sq (inlet) 10 ft-9 in. sq (outlet)
Design pressure, psig	75	+30/-6 (inlet) +21/-6 (outlet)
Design temperature, °F	150	150

Table 10.4-3

CIRCULATING WATER SYSTEM
COMPONENT DESCRIPTION (Sheet 2 of 3)

Circulating Water Expansion Joints	
Type	Rubber
Design pressure, psig	75
Design temperature, °F	150
Condenser Water Box Scavenging Pumps	
Type	Rotary vacuum pumps
Quantity (per unit)	2
Capacity, standard ft^3/min	280 at 8 inches HgA
Driver	Electric motor
Motor, hp	75
Motor, rpm	900
Electrical requirements	460 Vac, 60 Hz, 3 phase
Cooling water flow to seal water coolers	70 gal/min

Condenser Tube Cleaning System (Amertap)		
	Recirculating Pump	Reinjection Pump
Quantity (per unit)	6	6
Type	Nonclogging-centrifugal	Nonclogging-centrifugal
Capacity, gal/min	250	250
Head at rated flow, ft	40	15
Driver	Electric motor	Electric motor
Motor, hp	7.5	3
Motor, rpm	1,800	1,200
Electrical requirements	460 Vac, 60 Hz, 3 phase	460 Vac, 60 Hz, 3 phase

Table 10.4-3

CIRCULATING WATER SYSTEM
COMPONENT DESCRIPTION (Sheet 3 of 3)

Condenser Tube Cleaning System (Amertap) (Cont.)	
	Debris Filter
Quantity (per unit)	6
Type	Self-cleaning
Screen	Stainless steel, 3/8 inch diameter perforations
Maximum capacity, gal/min	179,000
Maximum differential pressure across filter, inch H_2O	20

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Table 10.4-4

INSTRUMENTATION TO IDENTIFY THE OCCURRENCE OF A
CIRCULATING WATER SYSTEM EXPANSION JOINT FAILURE

Instrument	Instrument Response	Control Room Indication/Alarm	Automatic Actuation
Condenser pressure	Loss of vacuum in condenser shell	Yes/yes	None 184
Hotwell temperature	Temperature rise in hotwell	Yes/no	None
Hotwell water level	Low level in hotwell	Yes/yes	None
Circulating water discharge temperature	Temperature rise/decline response to inlet/discharge expansion joint failure	Yes/no	None
Water box level	Low level in water box	No/yes	None
High condenser pit level	High level in condenser pit	No/yes	None
High-high condenser pit level switch (2 out of 3 logic)	Trips pumps on high-high level in condenser pit	No/no	Trips CWS pumps and closes pump discharge valves.

Table 10.4-5

INFLUENT-QUALITY TO THE CONDENSATE DEMINERALIZERS

	Constituent	Startup	Normal Operation	Condenser Leakage [a]
	Sodium, ppb	20	10	130
	Chloride, ppb	20	10	215
	Iron, total, ppb	1,000[b]	10	10
186	Ammonia, ppb	N/A	300-1,000	300-1,000
	Hydrazine, ppb	N/A	10-100	10-100
	Silica, as SiO_2, ppb	100	10	10
	Total dissolved solids, ppb	4,000	100	500
	Total suspended solids, ppb	3,000	50	250
	Conductivity, micromhos/cm at 25℃	15	3.0-8.5	3.0-8.5
186	pH at 25℃	9.2-9.7	9.0-9.5	9.0-9.5
	ETA, ppb	N/A	500-1,500	500-1,500

a. Assuming a 0.2 gal/min condenser leak.
b. Total iron will be 4,000 ppb for several hours at initial plant startup.

Table 10.4-6

CONDENSATE DEMINERALIZERS EFFLUENT QUALITY

Constituent	
Sodium, ppb	<0.1
Chloride, ppb	<0.15
Silica, ppb	<1
Suspended solids, ppb	≤1
Conductivity, micromhos/cm at 25℃	≤0.1
PH[(a)] at 25℃	7.0 ± 0.2 (Hydrogen cycle)

a. Condensate demineralizers operating in the hydrogen cycle. For operation beyond the ammonia breakthrough, the pH is maintained at 9.2 to 9.5.

Table 10.4-7

CONDENSATE AND FEEDWATER SYSTEM DESIGN DATA

Main Feedwater Piping (Safety-Related Portion)	
479 Rated flow rate, lb/h, total	13.12 x 10^6
Number of lines	3
Nominal size, in.	18
Schedule	80
Design pressure, psig	1,185
Design temperature, °F	600
Design code	ASME Section III, Class 2
Seismic design	Category I
Feedwater Isolation Valves	
Number per main feedwater line	1
Closing time, sec	5
Body design pressure, psig	2,000
Design temperature, °F	450
Design code	ASME Section III, Class 2
Seismic design	Category I
Feedwater Control Valves	
Number per main feedwater line	1
Closing time, sec	5
Design code	ASME Section III, Class 3
Seismic design	None

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Table 10.4-8

CONDENSATE AND FEEDWATER SYSTEM COMPONENT FAILURE ANALYSIS (Sheet 1 of 2)

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS	
Condensate Pump	None. Condenser hot-wells are inter-connected for condensate pumps suction.	The turbine control sys-tem will initiate a 10 percent load reduction.	Reactor control sys-tem will initiate reduction in reactor power necessary to match turbine load.	
No. 1,2,3, or 4 Feedwater Heater	One train of No. 1, 2, 3, and 4 feedwater heaters is isolated. Remaining two trains continue to operate.	LP tcedwater heaters bypass valve opens automatically Limiting the flow through the operating trains. Operation continues at reduced capacity.	Rcactor control system reduces reactor power to compensate for reduced feedwater temperature.	479
Heater Drain Tank	Extraction steam to No. 5 feedwater heaters must be isolated. Drains from No. 6 feedwater dumped to condenser.	Operation continues at reduced capacity. heaters are	Reactor control sys-tem reduces reactor power to compensate for reduced feed-water temperature.	
Heater Drain Pump	None. conden-sate pumps have suffi-cient capacity to handle additional flow.	Up to 50 percent of the heater drain tank flow is dumped to condenser.	Reactor control sys-tem adjusts reac-tor power to compensate for reduced feedwater temperature.	479 479

Table 10.4-8

CONDENSATE AND FEEDWATER SYSTEM COMPONENT FAILURE ANALYSIS (Sheet 2 of 2)

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
Steam Generator Feedwater Pump	None. Remaining two operating pumps increase flow rates to retain required feedwater flow.	Operations con-tinue at full capacity with two pumps. Until operator action reduces the reactor power level to 90%. Reduction in power level assures that the operating pumps can handle any system surge	None.
No. 5, 6 or 7 Feed-water Heater	One train of No. 5, 6 and 7 heaters is shut down. The parallel train is designed to provide 75 percent of the rated flow.	CFS operation continues at reduced load, using parallel train and bypass line.	Reactor control sys-tem adjusts reac-tor output power to compensate for reduced feedwate temperature.

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Table 10.4-9

FEEDWATER ISOLATION SINGLE FAILURE ANALYSIS (Sheet 1 of 2)

Component	Failure	Comments
Main Feedwater Control Valve (MFCV)	Valve fails to close upon receipt of automatic signal (FIS).	MFIV will close, providing adequate isolation to limit high energy fluid addition.
	Loss of one power supply.	Valve fails closed upon loss of either train of power.
Main Feedwater Bypass Control Valve (MFBCV)	Same as MFCV.	Same as MFCV.
Main Feedwater Isolation Valve (MFIV)	Valve fails to close upon receipt of automatic signal (FIS).	MF control valve and MF check valve close as required to isolate. The MF check valve provides a pressure boundary for auxiliary feedwater addition for any secondary side pipe rupture. The MF control valve (and bypass control valve) serve to limit the addition of high energy fluid into the containment following a main feedwater line rupture inside the containment or a main steam line break.

Table 10.4-9

FEEDWATER ISOLATION SINGLE FAILURE ANALYSIS (Sheet 2 of 2)

Component	Failure	Comments
	Loss of one power supply.	Valve fails closed upon loss of either train of power.
Main Feedwater Check Valve	Valve fails to close.	MFIV, MFCV, and MFBCV will close, providing isolation.
Chemical Addition Isolation Valve	Valve fails to close upon receipt of automatic signal (FIS).	Associated check valve will close, providing isolation.
	Loss of power for valve operation.	Valve fails closed.
Chemical Addition Check Valve	Valve fails to close.	Chemical addition isolation valve will close, providing isolation.
Steam Generator Narrow Range Level (four per steam generator; but three per steam generator are used for Feedwater Isolation Signal)	No signal generated for protection logic from one transmitter.	2-out-of-3 logic reverts to 2-out-of-2 logic for affected channel; the protection logic for other channels remains 2-out-of-3 logic.
	Loss of one of three logic channels.	The other two logic channels remain intact and Feedwater Isolation can be achieved if either 2 logic channels are activated.

Table 10.4-10

MAIN FEEDWATER SYSTEM
CONTROL, INDICATING, AND ALARM DEVICES

Device	Control Room Indication/ Control	Local Indication	Emergency Shutdown Panel Indication	Control Room Alarm
Flow Rate	Yes	No	No	Yes [a]
Steam Generator Level (narrow[b] range)	Yes	No	Yes	Yes
Steam Generator Level (wide range)	Yes	Yes	Yes	No
Feed pump Speed	Yes	Yes	No	Yes

a. Steam flow - Feedwater flow mismatch.

b. Four per steam generator - Involved in 2-out-of-4 logic to generate input to reactor trip, auxiliary feed pump start, turbine trip, and feedwater isolation signals.

TABLE 10.4-11

CONSEQUENCES OF COMPONENT FAILURES IN THE
STEAM GENERATOR BLOWDOWN SYSTEM

Components	Malfunction	Consequences and Comments
Valves of the system	Loss of air or electric power	All air-operated valves fail closed on loss of air or electric power.
Flash tank	Rupture	Relief valves prevent tank overpressure and, therefore, rupture.
Pump	Failure	Pump operation is only required during plant shutdown to drain the shell side of the steam generators. A Pump failure, therefore, will not affect the safe operation or shutdown of the plant.
Piping	Rupture	Blowdown line rupture would be less severe than a feedwater line leak due to its smaller size. Consequences of feedwater line l&ak are discussed in subsection 6.2.1 and chapter 15. Rupture of the blowdown piping between the containment isolation valves and the flash tank would result in automatic closure of the isolation valves.

Table 10.4-12
AUXILIARY FEEDWATER SYSTEM MINIMUM FLOW REQUIREMENTS

Transient or Accident Condition	Minimum Flow Requirement	Maximum Time to Enter SG	No. of TD[a] Pumps Req'd (assuming no MD pumps operable)		No. of MD[a] pumps Req'd (assuming no TD pumps available)	
			No. Pumps	gal/min	No. Pumps	gal/min
1. Normal plant cooldown	380 gal/min (total) to at least two SGs	–	1	803 [b]	1	532 [b]
2. Loss of main FW with or without offsite power	500 gal/min (total) to at least two SGs	See subsection 15.2.6	1	803 [b]	1	532 [b]
3. Loss of main FW with RCP operating	500 gal/min (total) to at least two SGs	See subsection 15.2.7	1	803 [b]	1	532 [b]
4. Main FW line break	380 gal/min (total) to two unaffected SGs	See subsection 15.2.8	1	464 [c]	1	445 [c]
5. Steam line break	380 gal/min (total) to two unaffected SGs	See subsection 15.1.5	1	480 [c]	1	460 [c]
6. Small LOCA	380 gal/min (total) to at least to SGs	See subsection 15.6.5	1	803 [b]	1	532 [b]

a. TD = turbine-driven pump, MD = motor-driven pump
b. total flow to three steam generators
c. total flow to two steam generators

Table 10.4-13

AUXILIARY FEEDWATER SYSTEM COMPONENT DATA (Sheet 1 of 2)

Motor-Driven Auxiliary Feedwater Pump (per pump)	
Quantity	2
Type	Horizontal centrifugal, multistage, split case with packing
Capacity, gal/min (each)	554
TDH, ft	3,450
NPSH required, ft	16 at a maximum flow of 750 gpm
NPSH available, ft (min)	26 at a maximum flow of 750 gpm
Material	
Case	Alloy steel
Impellers	Stainless steel
Shaft	Stainless steel
Design code	ASME B&PV Code, Section III, Class3
Seismic design	Category I
Driver	
Type	Electric motor
Horsepower, hp	800
rpm	3560
Power supply	4,160V, 60 Hz, 3-phase Class 1E
Design code	NEMA
Seismic design	Category I

Table 10.4-13

AUXILIARY FEEDWATER SYSTEM COMPONENT DATA (Sheet 2 of 2)

Turbine-Driven Auxiliary Feedwater Pump	
Quantity	1
Type	Horizontal centrifugal, multistage, split case with packing
Capacity, gal/min	1082
TDH, ft	3550
NPSH required, ft	21 at a maximum flow of 1430 gpm
NPSH available, ft (min)	26 at a maximum flow of 1430 gpm
Material	
Case	Alloy steel
Impellers	Stainless steel
Shaft	Stainless steel
Design code	ASME B&PV Code, Section III, Class 3
Seismic design	Category I
Driver	
Type	Noncondensing, single stage, mechanical-drive steam turbine
rpm (rated)	3550
Horsepower, hp (rated)	1241
Design code	NEMA
Seismic design	Category I

Table 10.4-14

FAILURE ANALYSIS OF AUXILIARY FEEDWATER SYSTEM

Component	Failure	Comments
One motor-driven auxiliary feedwater pump	Fails to start on automatic signal	Two motor-driven pumps are provided. One pump is sufficient to meet normal decay heat removal requirements. Following a main steam or feedwater line break, the turbine-driven pump will supply feedwater to meet decay heat removal requirements.
Turbine-driven pump steam supply valve from main steam header	Fails to open on automatic signal	Parallel connections are provided on two main steam lines. One of the two valves will supply 100 percent of the turbine steam requirements.
Suction line from condensate storage tanks	Loss of function	Two separate lines are provided from the condensate storage tanks. The remaining line will supply feedwater to meet decay heat removal requirements.
Auxiliary feedwater pump discharge line	Failure in pressure boundary	The motor-driven pumps supply feedwater to all three steam generators. A discharge line failure will still provide feedwater to two steam generators. The failed piping can be isolated at the local control valve station or the main control room.
Electrical power supply	Failure of power supply bus to components associated with one motor-driven pump	Motor-driven pumps are separate and redundant, including power supplies. One pump is sufficient to meet normal decay heat removal requirements. Following a main steam or feedwater line break, the turbine-driven pump will supply feedwater to meet decay heat removal requirements.
	Failure of one power supply bus to components associated with any one pump	Single failure of one power supply can not affect more than one auxiliary feedwater train out of total of three trains (two motor-driven and one turbine-driven pump trains).
Turbine-driven pump	Failure resulting in loss of function	The two motor-driven pumps will provide 100 percent of the feedwater requirements.
Motor-driven pump control valve	Failure to open or loss of flow control	The motor-driven pumps can still provide feedwater to two steam generators, or the turbine-driven pump will provide the required flow to all three steam generators for normal decay heat removal through separate control valves. Following a main steam or feedwater line break, the turbine-driven pump will supply feedwater to meet decay heat removal requirements.
Turbine-driven pump control valve	Failure to open or loss of flow control	The two motor-driven pumps will supply 100 percent of the required feedwater flow through separate control valves.

Table 10.4-15
AUXILIARY FEEDWATER SYSTEM
INDICATING, ALARM, AND CONTROL DEVICES

Parameter	Control Room		Auxiliary Shutdown Panel		Local Indication	Control Room Alarm
	Indication	Control	Indication	Control		
Steam generator water level-wide range	×		×			
Steam generator water level-narrow range	×		×			×
Steam generator pressure	×	×	×	×		×
Auxiliary feedwater flow rate[(a)]	×	×	×	×		
Main feedwater pressure	×	×			×	
Condensate storage tank supply to Auxiliary feedwater pumps isolation valve	×	×				
Auxiliary feedwater pump turbine trip switch	×	×			×	
Auxiliary feedwater pump suction pressure[(a)]	×		×		×	×
Auxiliary feedwater pump discharge header train	×	× (Separation valve)				
Auxiliary feedwater pump discharge pressure[(a)]	×		×		×	×
Auxiliary feedwater pump discharge temperature [(a)]	Computer					
Auxiliary feedwater pump turbine driver steam inlet pressure					×	
Auxiliary feedwater pump turbine speed	×	×			×	
Auxiliary feedwater pump thrust and radial bearing temperature[(a)]	Computer				×	
Auxiliary feedwater pump turbine journal bearing temperature	Computer					
Condensate storage tank level	×	×	×		×	×
Motor-driven auxiliary feedwater pump start/stop	×	×	×	×		
Turbine-driven auxiliary feedwater pump start/stop	×	×	×	×		
Auxiliary feedwater pumps supply isolation valve position	×	×				

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FDEO P & I DIAGRAM
CONDENSER AIR REMOVAL SYSTEM
FIGURE 10.4-1

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FDEO P & I DIAGRAM
TURBINE GLAND STEAM
SEALING SYSTEM
FIGURE 10.4-2

Amendment 424
2009.06.12

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P & I DIAGRAM
CIRCULATING WATER SYSTEM
(SHEET 1 OF 4)
FIGURE 10.4-3

Amendment 274
2005.05.27

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FDEO P & I DIAGRAM
CIRCULATING WATER SYSTEM
(SHEET 2 OF 4)
FIGURE 10.4-3

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FDED P & I DIAGRAM
CIRCULATING WATER SYSTEM
(SHEET 3 OF 4)
FIGURE 10.4-3

Amendment 462
2010.03.18

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P&I DIAGRAM CIRCULATING
WATER SYS.
(SHEET 4 OF 4)
FIGURE10.4-3

Amendment 470
2010.04.22

KOREA HYDRO & NUCLEAR POWER COMPANY
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FDEO P & I DIAGRAM
CONDENSATE DEMINERALIZER AND
REGENERATION SYSTEM
FIGURE 10.4-4

Amendment 450
2010.02.04

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P & ID DIAGRAM CONDENSATE
POLISHING SYSTEM
FIGURE 10.4-5

dment 61
5. 28

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FSAR

P&ID DIAGRAM CONDENSATE &
FEEDWATER SYSTEM
(SHEET 1 OF 8)
FIGURE 10.4-6

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Amendment 462
2010.03.18

KOREA HYDRO & NUCLEAR POWER COMPANY
YGN 1& 2 FSAR

FDEO P & I DIAGRAM
CONDENSATE SYSTEM
(SHEET 2 OF 8)
FIGURE 10.4-6

Amendment 462
2010.03.18

KOREA HYDRO & NUCLEAR POWER COMPANY
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FDEO P & I DIAGRAM
CONDENSATE SYSTEM
(SHEET 3 OF 8)
FIGURE 10.4-6

Amendment 483
2010.09.08

KOREA HYDRO & NUCLEAR POWER COMPANY
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FDEO P&I DIAGRAM CONDENSATE SYSTEM
(SHEET 4 OF 8)
FIGURE10.4-6

Amendment 324
2006.7.21

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P & I DIAGRAM FEEDWATER SYSTEM
(SHEET 5 OF 8)
FIGURE10.4-6

Amendment 497

2011. 2.10

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P&I DIAGRAM CONDENSATE & FEEDWATER SYSTEM
(SHEET 6 OF 8)
FIGURE10.4-6

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FDEQ P & I D DIAGRAM
FEEDWATER SYSTEM
(SHEET 7 OF 8)
FIGURE 10.4-6

Amendment 273
2005.05.27

KOREA HYDRO & NUCLEAR POWER COMPANY
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P & I DIAGRAM FEEDWATER SYSTEM
(SHEET 8 OF 8)
FIGURE10.4-6

Amendment 132
2001.02.09

KOREA ELECTRIC POWER CORPORATION
YGN 1 & 2 FSAR

P & I DIAGRAM CONDENSATE AND
FEED WATER CHEMICAL CONTROL
FIGURE 10.4-7

Amendment 462
2010.03.18

KOREA HYDRO & NUCLEAR POWER COMPANY
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P & I DIAGRAM
STEAM GENERATOR BLOWDOWN SYSTEM
(SHEET 1 OF 2)
FIGURE10.4-8

Amendment 441
2009.08.21

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FDEO P & I DIAGRAM
STEAM GENERATOR BLOWDOWN SYSTEM
(SHEET 2 OF 2)
FIGURE10.4-8

Amendment 126
2000.11.20

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FDEO P & I DIAGRAM
AUXILIARY FEEDWATER SYSTEM
(SHEET 1 OF 2)
FIGURE 10.4-9

Amendment 428
2009.06.12

KOREA HYDRO & NUCLEAR POWER COMPANY
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P & ID DIAGRAM AUXILIARY
FEEDWATER SYSTEM
(SHEET 2 OF 2)
FIGURE10.4-9