CHAPTER 10

STEAM AND POWER CONVERSION SYSTEM

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10. STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion systems for each unit at PVNGS are identical. Therefore, the summary description provided in this section is on a per-unit basis.

10.1.1 DESIGN BASES

The steam and power conversion system is designed to remove heat energy from the reactor coolant in two steam generators and to convert it to electric power via the turbine-generator. The main condenser transfers heat that is not utilized in the cycle to the circulating water system and deaerates the condensate. The closed regenerative turbine cycle heats the condensate and returns it as feedwater to the steam generators.

A full-flow condensate demineralizer system is available to maintain feedwater quality. A blowdown system operates to maintain steam generator water chemistry. The condenser air removal system provides a filter and charcoal adsorber and is monitored for radioactive contamination. The Seismic Category I redundant auxiliary feedwater pumps, one motor-driven and one steam turbine-driven, provide feedwater during loss of offsite power and during design basis accident conditions. A non-Seismic Category I, motor-driven auxiliary feedwater pump provides feedwater for startup, hot standby, and normal shutdown.

10.1.2 SYSTEM DESCRIPTION

Components of the steam and power conversion system are of types that have been extensively used in fossil fuel plants and in other nuclear power plants. Instruments, controls, and protective devices are provided to ensure reliable and safe operation, as described in paragraph 10.2.2.3.

A system flow diagram is shown in figure 10.1-1. A summary of design basis information and performance specifications is given in table 10.1-1. Also, the cycle heat balances, at turbine rated (guaranteed) power and at stretch power (valves wide open-VWO), are shown on figures 10.1-2 and 10.1-3, respectively, and are summarized in table 10.2-2. Safety-related components include the main steam isolation valves, the atmospheric steam dump valves, the feedwater isolation valves, the Seismic Category I portion of the auxiliary feedwater system, and the main steam safety valves. The steam and power conversion system provides steam for the feedwater pump turbines, the turbine gland sealing system, condensate and feedwater heating, and main turbine reheat steam as required.

The condenser air removal system is described in subsection 10.4.2. The condensate cleanup system is described in subsection 10.4.6. The auxiliary feedwater system is described in subsection 10.4.9.

10.1.3 SAFETY-RELATED FEATURES

10.1.3.1 Loss of External Electrical Load and/or Turbine Trip

Upon loss of load the turbine control system provides for fast closing of turbine valves. Depending on the magnitude of the load reduction, a turbine bypass system will dump excess steam into the condenser and, if required, to atmosphere. If the load reduction is large, i.e., greater than approximately 55% of full load, an automatic reactor power cutback will be initiated provided the turbine power level is greater than 75%. The turbine control and bypass equipment is not safety grade.

Table 10.1-1
STEAM AND POWER CONVERSION SYSTEM DESIGN AND PERFORMANCE SPECIFICATIONS (Sheet 1 of 4)

Design and Performance Characteristics	Original Design Value(1)	Power Uprate/Rotor Replacement Value(2)
Main steam system minimum required design pressure/temperature, psia/F	1270/575	1270/575
Main steam system operating pressure/ temperature, at 100% power, psia/F (at guar. load 3817/3990 MWt)	1070/552.9	1012/546.1
Main steam system operating pressure/ temperature, at 100% power, psia/F (VWO)	1000/544.6	1007/545.4
Main steam flow, guar./VWO, 10^6 lb/h	17.2/18.1	17.96/18.36
Main turbine throttle flow, guar./VWO, 10^6 lb/h	15.9/17.05	16.87/17.28
Main condenser pressure, in.Hg abs	3.5	3.5
Feedwater temperature, guar./VWO, F	442.5/449.5	448.5/450.9
Main turbine-generator output, guar./VWO, MWe	1304/1375	1411/1443
Guaranteed generator rating, MVA	1559.1	1559.1
No./normal capacity/runout capacity at 65% of each feedwater pump, lb/hr x 10^6 at VWO	2/9.2/11.3	2/9.2/11.3
No./design capacity/runout capacity of each condensate pump, lb/hr x 10^6	3/4.4/6.2	3/4.4/6.2
Turbine gland seal system, normal flow air/steam, lb/h	2855/9025	2855/9025
Steam generator blowdown system, flowrate, normal/abnormal/high rate	0.2%/1%/8% of maximum steam rate	0.2%/1%/8% of maximum steam rate

Table 10.1-1

STEAM AND POWER CONVERSION SYSTEM DESIGN AND PERFORMANCE SPECIFICATIONS (Sheet 2 of 4)

System Component	Performance Characteristics
Main steam system (section 10.3)	
Main steam piping	From each steam generator up to and including the main steam isolation valves: ASME III, Code Class 2. (design pressure 1255 psig, design temperature 600F, Seismic Category I) Balance of the main steam piping: ANSI B31.1
Main steam isolation valves (one per steam line)	Maximum closing time 4.6 seconds after receipt of signal. ASME III, Code Class 2 valves. (design pressure 1270 psia, design temperature 575F, Seismic Category I)
Main steam safety valves (five per steam line)	Required flow capacity equal to 19 x 10^6 lb/hr (105% of the maximum calculated steam generator stretch power flow 18.0 x 10^6 lb/hr) at setpoint pressure: ASME III, Code Class 2 valves. (design pressure 1375 psig, design temperature 575F, Seismic Category I) (See CESSAR Table 5.4.13-2).
Atmospheric dump valves (one per steam line)	Required flow capacity equal to 950,000 lb/hr (min): ASME III, Code Class 2 valves. (design pressure 1333 psia, design temperature 575F, Seismic Category I)
Turbine bypass system (subsection 10.4.4)	
Bypass valves down- stream of main steam isolation valves (six piped to condenser, two piped to atmosphere)	Flow capacity equal to at least 55% of design steam flow: Piping ANSI B31.1 (design pressure 1255 psig, design temperature 600F, non-Seismic Category I)

Table 10.1-1

STEAM AND POWER CONVERSION SYSTEM DESIGN AND PERFORMANCE SPECIFICATIONS (Sheet 3 of 4)

System Component	Performance Characteristics
Condenser	See subsection 10.4.1
Condenser air removal system	See subsection 10.4.2
Circulating water system	See subsection 10.4.5
Turbine gland seal system	See subsection 10.4.3
Condensate and main feedwater system (subsection 10.4.7)	Piping in main steam support structure (MSSS) to upstream economizer feedwater isolation valves - ASME III, Code Class 2. Design pressure 1875 psig, 450F downcomer feedwater piping to upstream isolation valve - ANSI B31.1, design pressure - 1600 psig, design temperature - 450F. From downstream feedwater isolation valves to steam generators - ASME III, Code Class 2. Design pressure 1255 psig, 600F, Seismic Category I. Balance of system piping: ANSI B31.1
Auxiliary feedwater system (subsection 10.4.9)	See subsection 10.4.9.

Table 10.1-1
STEAM AND POWER CONVERSION SYSTEM DESIGN AND PERFORMANCE SPECIFICATIONS (Sheet 4 of 4)

System Component	Performance Characteristics
	All piping from the condensate storage tank to the Seismic Category I auxiliary feedwater pumps and containment isolation valves is ASME III, Code Class 3; piping from and including the isolation valves to the steam generators is ASME III, Code Class 2, design pressure 1255 psig, design temperature 600F, Seismic Category I All piping associated with the non-Seismic Category I motor-driven auxiliary feedwater pump, excluding upstream of the condensate tank isolation valve and downstream of the containment isolation valves, is ANSI B31.1 Code for pressure piping.
Secondary chemistry control system (subsection 10.4.6)	Full flow condensate demineralization. Continuous hydrazine additions for oxygen scavenging and continuous ammonia additions for pH control. Continuous monitoring of significant chemical parameters. Steam generator blowdown at a rate up to 8% of the maximum steaming rate

NOTE 1: The parameters listed in Table 10.1-1 for Original Design are nominal parameters obtained from GE Heat Balance 449HB673 (13-M400-0301-00029) and Specification 13-MM-0004/010 for the original rated performance at 3800 MWt and VWO conditions of the plant secondary system, respectively. The Heat Balance and specification are applicable for original operation, stretch power to 3876 MWe and T_{hot} Reduction. For the actual design parameters and predicted performance at various power levels see calculation 13-MC-MT-0200.

NOTE 2: The parameters listed in Table 10.1-1 for Power Uprate are nominal parameters obtained from GE Thermal Kit 91LR0297 (13-M400-0303-01570) to determine the effect of Replacement Steam Generators, Power Uprate to 3990 MWt and Low Pressure Turbine Rotor Replacement on the plant secondary system. For the actual design parameters and predicted performance at various power levels see calculation 13-MC-MT-0200.

In the event the condenser is not available to receive steam, ASME Code safety and atmospheric dump valves are provided on the main steam piping.

The atmospheric dump valves are remotely operated from the control room and can be modulated to control the steam flow.

The turbine control system is capable of controlling the speed of the turbine generator upon full load rejection so as not to activate the overspeed trip of the emergency governor system.

10.1.3.2 Overpressure Protection

Safety valves are provided on the main steam lines in accordance with the ASME Boiler and Pressure Vessel Code, Section III. The pressure relief capacity of all safety valves is such that the flow capacity is equal to 19×10^6 lb/hr (105% of maximum calculated steam generator stretch power mass flow, 18.0×10^6 lb/hr) at setpoint pressure.

10.1.3.3 Loss of Normal Electric Power

The auxiliary feedwater system is designed to provide feedwater to the steam generators for the removal of decay heat when the feedwater pumps are not available following a loss of normal electric power. In the event of reactor trip with loss of offsite power, two Seismic Category I auxiliary feedwater pumps, one motor-driven and one steam turbine-driven, are available to provide feedwater to the steam generators. The motor-driven pump and its associated isolation valves receive power from a separate standby diesel generator bus. In addition, the steam turbine-driven auxiliary feedwater pump with dc powered controls is available. Refer to subsection 10.4.9.

10.1.4 TESTS AND INSPECTIONS

Pumps and controls are given preoperational tests. Functional operational checks are made on essential valves, control systems, and protective equipment.

10.1.5 INSTRUMENTATION APPLICATIONS

Operating instrumentation is provided to permit the operators to monitor equipment and plant performance. Equipment, instruments, and controls are inspected regularly and are monitored during operation to ensure proper functioning of systems.

Checking and recalibration of instruments and controls continue during operating periods as well as during standby and shutdown periods.

10.2 TURBINE-GENERATOR

The function of the turbine-generator is to convert thermal energy into electric power.

10.2.1 DESIGN BASES

10.2.1.1 Safety Design Bases

The turbine-generator serves no safety function and has no safety design bases.

10.2.1.2 Power Generation Design Bases

The following is a list of the principal design bases:

A. The turbine-generator load change characteristics are compatible with the restrictions imposed by or on the nuclear steam supply system (NSSS). The NSSS is capable of accepting a step load change of 10% and ramp load change of 5% per minute over the load range of 15 to 100%. These load change rates can be accomplished without the operation of the turbine bypass system (TBS) described in subsection 10.4.4. With operation of the TBS, the reactor can accept step load rejections of up to 55% of the rated power of 3817 MWt without causing a reactor trip by bypassing steam to the condenser and, if required, to atmosphere. With the reactor power cutback system and TBS, the reactor can accept a step load rejection of 100% without causing a reactor trip. However, the steam bypass control system (SBCS) and reactor power cutback system (RPCS) are not capable of handling step load rejections for turbine power level between 57% and 75% due to limitations on condenser pressure.

B. The turbine-generator is designed to trip automatically under abnormal conditions as designated in paragraph 10.2.2.4.

C. The turbine-generator is intended to operate base loaded.

10.2.1.3 Codes and Standards

System components are designed in accordance with the requirements of ANSI B31.1.0 Code for pressure piping, TEMA and HEI standards for heat exchangers, NEMA standards, IEEE standards, Hydraulic Institute standards, and regulations of the National Board of Fire Underwriters.

10.2.2 DESCRIPTION

The General Electric turbine-generator (engineering drawings 01, 02, 03-M-MTP-001, -002 and -003) is designated TC6F-43 and consists of turbines, a generator, moisture separator-reheaters, exciter, controls, and auxiliary subsystems. The major design parameters of the turbine-generator are presented in tables 10.2-1 and 10.2-2. Details of system components are presented in this section. The location of the turbine-generator is shown in engineering drawings 13-P-OOB-002 through -011.

10.2.2.1 Turbine-Generator Description

The turbine is an 1800 revolutions per minute, tandem-compound, six-flow, reheat unit with 43-inch, last-stage buckets (blades). The turbine includes one double-flow, high-pressure turbine; three double-flow, low-pressure turbines; and four moisture separator-reheaters with two stages of reheating. The direct-driven generator is conductor-cooled and rated at 1559.1 MVA at 24 kV, three phase, 60 Hz. Other related system components include a complete turbine-generator bearing lubrication oil system, an electrohydraulic control (EHC) system with supervisory instrumentation, a turbine gland sealing system (refer to subsection 10.4.3), overspeed protective devices, turning gear, a generator hydrogen and seal oil system, a stator cooling system, an exciter cooler, a rectifier section, and a voltage adjuster.

Table 10.2-1

TURBINE-GENERATOR DESIGN DATA

Supplier	General Electric
Unit designation	TC6F-43" LSB
Last-stage bucket length, in.	43
Design condenser backpressure (average for three shells), in. Hg abs	3.50
Stages of reheating	2
Stages of feedwater heating	7
Rotational speed, r/min	1,800
Guaranteed generator rating, MVA	1,559.1
Generator voltage, kV	24
Power factor	0.9
Short circuit ratio	0.5

10.2.2.2 Turbine-Generator Cycle Description

Steam from the main steam system enters the high-pressure turbine through four stop and governing control valves. Crossties are provided both upstream and downstream of the stop valves to provide pressure equalization with one or more stop valves closed. A portion of the main steam is used for second-stage reheat of the steam supply to the low-pressure turbines.

There are two steam extraction points in the high-pressure turbine. Steam from the first (higher pressure) extraction point is used for seventh-point feedwater heating and first-stage reheat of the two-stage reheater. Steam from the second extraction point is used for sixth-point feedwater heating. (Refer to subsection 10.4.7 for discussion of the condensate and feedwater system.) After expansion in the high-pressure turbine, the steam flows through the moisture separator-reheaters to remove entrained moisture and to superheat the steam, thus improving cycle efficiency. A portion of the cold reheat steam is used for fifth-point feedwater heating. (Feedwater heaters are numbered sequentially in order of increasing extraction pressure.)

Table 10.2-2
TURBINE-GENERATOR PERFORMANCE DATA

Parameter	Guaranteed Load (a)(b) Original/Pur & Rotor Replacement	Valves Wide Open (a)(b) Original/Pur & Rotor Replacement
NSSS thermal output, MWt	3,911/4,013	4,030/4,030
Steam generator outlet pressure, psia	1,020/1,030	1,010/1,025
Throttle pressure, psia	1,002/1,012	993/1,007
Throttle temperature, °F	544.8/546.1	543.7/545.4
Main steam flow, 10^6 lb/h	17.5/17.96	18.1/18.36
Gross electrical output, MWe	1,333/1,411	1,375/1,443

a. For turbine-generator design purposes only.

b. The parameters listed for Original Design are nominal parameters obtained from GE Heat Balance for the original rated performance and Valves Wide Open conditions of the plant secondary system. This data is applicable for original operation at 3800 MWt, stretch power to 3876 MWe and T_{hot} reduction. The parameters listed for Power Uprate (PUR) are nominal secondary system parameters based upon implementation of Replacement Steam Generators, Power Uprate to 3990 MWt and Low Pressure Turbine Rotor Replacement.

Hot reheat steam leaving the moisture separator-reheaters is used to power the feedwater pump turbine. Hot reheat steam also is distributed equally to the three low-pressure turbines through combined reheat stop and intercept valves. In each low-pressure turbine, there are four steam extraction points for the remaining four stages of feedwater heating (one heater train per low-pressure turbine). After expansion in the low-pressure turbines, the steam is discharged to the main condensers.

In addition to the external moisture separators, the last three low-pressure turbine stages are designed to remove any condensed moisture and drain it to the next lowest extraction. The moisture from the external moisture separators is drained to moisture separator drain tanks and from there to the high-pressure heater drain tank and subsequently is pumped into the feedwater system. Similarly, the condensate in the reheaters is drained to the heater drain tank and is pumped into the feedwater system.

10.2.2.3 Automatic Controls

Automatic controls provide control of turbine speed and acceleration through the entire speed range, with several discrete speed and acceleration rate settings. The automatic control system includes control of load and loading rate from no load to full load, with continuous load adjustments and discrete loading rates. Should it become necessary to remove the generating unit from the primary automatic controls, the standby manual control of speed and load takes over, thus allowing continued operation of the turbine generator.

10.2.2.3.1 Electrohydraulic Control Systems

The turbine-generator is equipped with an EHC system that combines the principles of solid-state electronics and high-pressure hydraulics to control steam flow through the turbine. The control system has three major subsystems: speed control unit, load control unit, and valve flow control units.

10.2.2.3.1.1 Speed Control Unit. The speed control unit produces the speed error signal for input to the load control unit. This error signal is determined by comparing the desired speed with the actual speed of the turbine at steady-state conditions, or the desired acceleration with the actual acceleration during startup. Because of the importance in safeguarding against overspeed, the speed control unit has two redundant channels. If the primary channel fails, the backup channel takes over automatically. If both channels should fail, the turbine-generator will trip.

The above two speed channels generate three error signals during the period between turbine roll and synchronization. Two of these error signals are from a deviation between the actual speed as measured by the primary and backup speed sensors and a reference speed. The third error signal is a deviation between the actual acceleration as measured by the primary and backup speed sensors and a reference acceleration. These signals combine with signals from the load control unit to generate a flow reference signal to the control valves and intercept valves.

10.2.2.3.1.2 Load Control Unit. The load control unit develops flow reference signals that are used to proportion the steam flow to the control valves and intercept valves. Signal outputs are based on a proper combination of the speed error signals and load reference signals. The generator does not strictly follow load, but is controlled through a ramped, predetermined straight-line function. Power/load imbalance is discussed in paragraph 10.2.2.3.1.4.

10.2.2.3.1.3 Valve Flow Control Units. The valve flow control unit regulates the steam flows as directed by the load control unit. Compensation circuits are introduced to ensure linear steam flow response with respect to steam flow reference signals. The bypass valve in the No. 2 main stop valve, control valves, and the intercept valves each have a control loop which consists of electronic circuitry, an electrohydraulic servo valve, a hydraulic actuator, and a linear position transducer. By use of valve position feedback control, the valve control units position the bypass valve in the No. 2 main stop valve, the control valves, and the intercept valves according to the flow demand signal from the load control unit, the standby control unit, or directly from the control panel (valve test).

Only the No. 2 main stop valve has an internal bypass valve. The control loop operates the internal bypass valve and is used only for prewarming the turbine.

The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four governing control valves. Each stop valve is controlled by an electrohydraulic actuator so that the stop valve is either fully open or fully closed. The function of the stop valves is to shut off the flow of steam to the turbine, when required. The stop valves are closed within 0.2 second or less when steam pressure is present, and are closed in 0.3 second or less when no steam pressure is present, by actuation of the emergency trip system devices. These devices are independent of the electronic flow control unit (see paragraph 10.2.2.3.1.5).

The turbine control valves are positioned by electrohydraulic servo-actuators in response to signals from their respective flow control unit. The flow control unit signal positions the control valves for long range speed control through the normal turbine operating range and for load control after the turbine-generator unit is synchronized.

The combined reheat valves located in the hot reheat lines are stop and intercept valves in one casing and control steam flow to the low-pressure turbines. During normal operation of the turbine, the stop and intercept valves are wide open. The intercept valve flow control unit positions the valve during startup and normal operations and closes the valve rapidly on loss of turbine load. The reheat stop valves close completely on turbine overspeed and trip.

10.2.2.3.1.4 Power/Load Unbalance. Associated with the load control unit is a rate sensitive power/load unbalance circuit whose purpose is to initiate control valve fast closing action under load rejection conditions that might lead to rapid rotor acceleration and consequent overspeed.

Valve action will occur when the power exceeds the load by at least 40% and generator current is lost in a time span of 35 ms or less with an additional 150 ms time delay. Cold reheat pressure is used as a measure of power, and generator current is used as a measure of load to provide discrimination between loss of load incidents and occurrences of electric system faults.

The power/load unbalance circuitry includes an approximate 150 ms time delay between the detection of a power/load unbalance condition and actuation of turbine control. This time delay will allow the turbine control to ride out transient electrical grid disturbances. The 150 ms delay is based on a three-phase bolted fault a PVNGS 525 kv switchyard as a worst case scenario.

Following the detection of a power/load unbalance condition and the 150 ms time delay, all control valves are closed in 0.2 second or less when steam pressure is present, and are closed in 0.3 second or less when no steam pressure is present, by a fast acting solenoid for each control valve. Simultaneously, the load reference signal is grounded and the load reference motor begins to run back toward the no-load flow point. Should the condition disappear quickly, the power/load unbalance circuit will reset automatically, and the load reference signal will be reestablished near its value prior to the loss of load. Should the condition persist and the load does not return within approximately 45 seconds, the load reference runback will be completed. The power/load unbalance circuit will clear automatically when the cold reheat pressure drops below 40%. However, after a power/load unbalance circuit actuation, a positive turbine trip occurs with no subsequent re-opening of the control valves and intercept valves.

10.2.2.3.1.5 Overspeed Protection. Two means of overspeed trip protection are provided; a mechanical overspeed trip (OST) and a backup overspeed trip (BOST). The OST is a conventional eccentric ring that actuates a trip latch to operate a pilot valve that operates the mechanical trip valve. The mechanical trip valve releases the hydraulic fluid pressure in the steam valve actuator, allowing the springs to close the steam valves. The OST trip is set at 110% of rated turbine speed. (Refer to protection system block diagram, figure 10.2-2.)

The BOST is an electric trip normally set to operate at a slightly higher speed than the OST. Three independent BOSTs are provided by magnetic pickups from toothed wheels on the turbine shaft. The signals are amplified through electronic circuitry and are compared to trip speed reference voltage signals. Exceeding the trip speed will cause each BOST voltage to energize its master trip relay. The master trip relays, through a two-out-of-three logic, deenergize both pilot solenoids of the master (electric) trip solenoid valve. This releases the hydraulic fluid pressure in the steam valve actuators, causing the turbine main valves to close. The overspeed trip logic is shown in figure 10.2-1.

The BOST electric trip also results in a "cross trip" by actuating, also through two-out-of-three relay logic, the mechanical trip, the mechanical trip solenoid, and the trip latch system described above. The BOST trip is set at 111% of rated turbine speed.

When in the standby mode, the automatic speed control and load control subsystems are out of service. If it is necessary to operate the turbine in the standby mode, added overspeed protection is provided by automatically lowering the setpoint of the backup overspeed governor to 105% of rated turbine speed. The mechanical governor then becomes the backup governor since its trip setpoint remains at 110% of rated speed. (See table 10.2-3 for turbine overspeed sensors and trip signals.) Each of the two means of overspeed tripping may be independently tested online at any desired load. During these tests,

Table 10.2-3

TURBINE OVERSPEED SENSORS AND TRIP SETPOINTS (Sheet 1 of 2)

Sensors	Type	Function	Setpoints in Percent of Turbine Rated Speed			
			HP Stop Valve	HP Throttle Valve	LP Stop Valve	LP Intercept Valve
MTNST-160	Magnetic pickup	Normal speed control and overspeed protection	None	100	None	102
MTNST-161	Magnetic pickup	Normal speed control and overspeed protection	None	100	None	102
MTNZS-145	Mechanical eccentric ring	Emergency overspeed protection	110	110	110	110
MTNST-162	Magnetic pickup	Backup emerg. overspeed protection (2/3 logic)	111	111	111	111
MTNST-163	Magnetic pick up	Backup emerg. overspeed protection (2/3 logic)	111	111	111	111
MTNST-164	Magnetic pickup	Backup emerg. overspeed protection (2/3 logic)	111	111	111	111
MTNST-165	Magnetic pick up	Backup emerg. overspeed protection (2/3 logic)	111	111	111	111
MTNST-169	Magnetic pickup	Backup emerg. overspeed protection (2/3 logic)	111	111	111	111

Table 10.2-3

TURBINE OVERSPEED SENSORS AND TRIP SETPOINTS (Sheet 2 of 2)

Sensors	Type	Function	Setpoints in Percent of Turbine Rated Speed			
			HP Stop Valve	HP Throttle Valve	LP Stop Valve	LP Intercept Valve
MTNPT-9	Cold RH press transmitter	Power/load unbalance turbine power	None	100	None	102
1 PUE-A004(a)	KW transducer	Power/load unbalance anticipatory O/S protection	None	(b)	None	(b)

a. Turbine supplier identification number.

b. Control valves and intercept valves all close in 0.2 second or less following a 150 ms delay when power/load unbalance detects loss of generator load. This could occur before turbine speed starts to increase. This is not a trip.

overspeed protection will be provided by the device not being tested.

Finally, because the turbine-generator overspeed protection system is not a safety system (other than for equipment protection), a single failure analysis per IEEE-279 is not required.

10.2.2.4 Turbine Protective Trips

Turbine protective trips are independent of the electronic control system and, when initiated, cause tripping of all turbine stop and control valves. The protective trips are:

- Overspeed trip (mechanical): 110% of normal
- Backup overspeed trip (electrical): 111% of normal
- Low vacuum trip
- Excessive thrust bearing wear trip
- Electric solenoid trip actuated by:
    - Reactor trip
    - Generator trip
    - Manual trip from control room
- Excessive vibration trip
- Manual trip handle located at the turbine front standard
- High exhaust hood temperature trip
- Moisture separator drain system high level trip
- Prolonged loss of stator coolant trip
- Low hydraulic fluid pressure trip
- Loss of both speed signals or backup overspeed trip
- Low bearing oil pressure trip
- Loss of main shaft oil pump discharge pressure trip

The EHC system employs five electric and one mechanical speed inputs. Signals are redundantly processed in both electronic and hydraulic logic channels. Valve opening actuation is provided by a 1600 psig hydraulic system that is totally independent of the bearing lubrication system. Valve closing actuation is provided by springs and steam forces upon the reduction or relief of fluid pressure. The system is designed so that loss of fluid pressure for any reason leads to valve closing and consequent shutdown.

To help prevent turbine overspeed, a sequential tripping system isolates all steam to the high-pressure turbine and low-pressure turbines, and must detect no load on the generator before the main generator breaker is opened. (See figure 10.2-3.) This system provides for an orderly shutdown from a single tripping signal and prevents a rapid rise in speed that would occur if the generator breaker were opened before the turbine valves closed. All turbine protective trips are done by sequential tripping logic including the manual trip from the control room or by the trip handle at the turbine front standard. In a sequential trip, the interval between the closure of the turbine valves and the opening of the generator breaker is at least 3 seconds. Refer to calculation 13-EC-MA-232. In some electrical faults which would do serious damage to the generator, sequential tripping is not permissible. In these cases the generator and turbine are tripped simultaneously.

It is possible for the operator, in an emergency, to open the main generator breaker from the control room switch instead of using the turbine trip button. This action at or near full load, coupled with transient steam conditions from the steam generator, could cause serious turbine damage and excessive overspeed. To help prevent the above, the operator is required to hold a breaker bypass switch in "trip" as a permissive before operating the main breaker switch to trip the generator. Limit switches on the main stop valves, control valves, reheat stop valves, and intercept valves are used in the sequential tripping logic. A reverse power relay is used to detect reverse current flow for the no load condition on the generator. A time delay, which is adjustable in the reverse power relay, is credited for a portion of the 3 second interval between a turbine trip and the loss of power to the RCPs assumed in certain accident analyses. Refer to section 8.3.4 and table 15.0-0. In a sequential trip, the unit auxiliary transformer continues to supply power to the non-Class 1E distribution system during the relay timeout period. Refer to section 8.3.5 and calculation 13-EC-MA-232.

All steam valves are arranged in series pairs such as a main stop valve and associated control valve or a reheat stop and associated intercept valve. There are four pairs of valves for the high-pressure turbine and two pair of valves for each low-pressure turbine making a total of ten pairs of steam admission valves. Each stop valve, control valve, and intercept valve (20 total) is actuated by either of two overspeed trip systems. Four control valves on the high-pressure turbine and one intercept valve on each low-pressure turbine is modulated by the speed governing system. Closure of either valve in a pair stops the steam flow from that source and therefore a single valve failure would not disable the turbine overspeed trip from functioning. The backup overspeed trip and the trip caused by loss of the primary and backup speed signals are initiated by the 24 volt dc trip logic shown on figure 10.2-2.

The 24 volt trip system is used for turbine vital trips which includes the backup overspeed trip. A 125 volt dc trip system is also used for trips from related equipment and several turbine protective trips. As further protection, there is a "cross trip" logic employed which allows all trips originating in the 24 volt dc logic to initiate a trip by the 125 volt dc system. Conversely all trips originating in the 125 volt dc logic will initiate a trip in the 24 volt dc system. The output trip signals from these two voltage levels energize separate and individual solenoid valves which, in turn, dump the pressure off the high-pressure fluid connected to all the turbine steam admission valves.

10.2.2.5 Other Protective Systems

In addition to the previously mentioned devices, other protective features of the turbine and steam system are:

A. Safety valves on the moisture separator-reheater to protect the high-pressure turbine cylinder from overpressure in the event of a turbine trip

B. With the exception of the last two low-pressure heaters, each steam extraction line is equipped with a nonreturn valve to protect the turbine from overspeed due to reverse flow in case of a turbine trip. Each nonreturn valve will be exercised once per week using a hand air test valve which is located at the nonreturn valve. Movement of the nonreturn valve shaft and counter weight extension will be noted during testing.

C. Exhaust casing rupture diaphragms to protect the low-pressure turbine cylinders from overpressure in case of loss of condenser vacuum.

10.2.2.6 Plant Loading and Load Following

The turbine-generator is intended to be base loaded, but is designed to match or exceed the transient load following capabilities of the NSSS. The reactor regulating system (RRS) automatically adjusts reactor power to follow turbine load transients. The RRS senses turbine first-stage pressure as a linear indication of load and generates signals that regulate control element assembly (CEA) drive direction and speed. As a combined unit consisting of turbine-generator and reactor, the system accepts step load changes of ±10% and ramp load changes of ±5%/min over the range of 15 to 100% full power. It also accepts, with the aid of the turbine bypass system, a load rejection of approximately 55% of full load power without reactor trip. For load rejections greater than approximately 55% of full load, reactor power is cut back as described in subsection 10.4.4, and steam is dumped to the condenser as needed. In the event of complete loss of load, the system automatically runs back to house load. If the condenser is not available, concurrent with a load rejection, the reactor is tripped.

The turbine control system is designed to provide protection to the turbine by tripping the turbine for certain predetermined conditions as discussed in paragraph 10.2.2.3. The turbine is tripped upon reactor trip. The reactor protective system provides two separate signals of reactor trip to the turbine control system.

10.2.2.7 Inspection and Testing Requirements

Major system components are readily accessible for inspection and are available for testing during normal plant operation. Controls and protective devices associated with each turbine-generator component will be tested on a regularly scheduled basis. Various turbine trips will be tested in sequence prior to unit startup.

The schedules for testing and inspection of the various system components are developed as part of the plant operating procedures presented in section 13.5.

10.2.3 TURBINE DISK INTEGRITY

10.2.3.1 Materials Selection

The originally installed General Electric turbine wheels and rotors are made from vacuum melted or vacuum degassed Ni-Cr-Mo-V alloy steel by processes that minimize flaw occurrence and provide adequate fracture toughness. Tramp elements are controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long life fracture toughness for the environment in which the parts operate. The turbine wheel and rotor materials have the lowest fracture appearance transition temperatures (FATT) and highest Charpy V-notch energies obtainable, on a consistent basis, from water quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Since actual levels of FATT and Charpy V-notch energy vary depending upon the size of the part and the location within the part, etc., these variations will be taken into account in accepting specific forgings for use in turbines for nuclear application. Charpy tests essentially in accordance with Specification ASTM A370 are included.

The replacement General Electric Low Pressure Rotors are manufactured as a monoblock forging and do not have shrunk on wheels to preclude brittle failure at the wheel bore region. The monoblock forging material chemistry is optimally balanced to achieve high hardenability, good fracture toughness at the required tensile strength, low tramp elements to minimize temper embrittlement and low sulfur to minimize harmful segregation. This material is similar to ASTM 470 Class 6 but with more restrictive quality requirements.

The rotor forging is semi-machined to provide suitable surface for a periphery ultrasonic inspection. After final heat treatment a series of NDT testing is performed to ensure rotor structural integrity. Specimen testing of the rotors is performed to assure the rotors meet the supplier's material specifications. Charpy tests essentially in accordance with Specifications ASTM A370 and ASTM A470 are included. A copy of all these test records and inspections for each rotor are submitted by GE and included in SDR log 13-M400-0303-1036.[1]

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in paragraph 10.2.3.1 to produce a balance of adequate material strength and toughness to ensure safety while simultaneously providing high reliability, availability, and efficiency during operation. For the original General Electric turbines, bore stress calculations include components due to centrifugal loads, interference fit, and thermal gradients where applicable. The ratio of material fracture toughness, K_{IC} (as derived from material tests on each wheel or rotor) to the maximum tangential stress for wheels and rotors at speeds from normal to 115% of rated speed[(a)] will be at least $2\sqrt{\text{inches}}$. Adequate material fracture toughness needed to maintain this ratio is assured by destructive tests on material taken from the wheel or rotor using correlation methods which are more conservative than that presented in reference 1.

Turbine operating procedures are employed to preclude brittle fracture at startup by ensuring that the metal temperature of wheels and rotors (a) is adequately above the FATT, and (b) as defined above is sufficient to maintain the fracture toughness to tangential stress ratio at or above $2\sqrt{\text{inches}}$. For original General Electric turbines details of these startup procedures are contained in reference 2.

10.2.3.3 High-Temperature Properties

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

10.2.3.4 Turbine Disk Design

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

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

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a. The highest anticipated speed resulting from a loss of load is 110%.

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

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

GE, in the course of designing the new turbine for Palo Verde #1, 2 and 3, has evaluated tensile stresses in rotating components. All of the rotating components have sufficient margin to tensile strength at design component temperatures to support operating speeds well in excess of 120% of normal. For example, the overspeed capability of the un-bucketed HP and LP rotors is over 200%. The most limiting components, per design, for the bucketed rotors are the LP L-0 buckets which have a minimum overspeed capability of 170%. The design of some of the most critical parts of the monoblock rotor assembly meet the following criteria:

A. The new monoblock rotors utilize tangential entry “pinetree” dovetails to attach the first five stages of buckets and radial entry “finger” dovetails to attach the last two stages. The wheel tangential entry dovetails are shot peened to introduce a compressive stress layer for protection against Stress Corrosion Cracking (SCC). In addition, the critical areas that are susceptible to SCC are designed such that the peak stresses do not exceed 55 percent of the material yield strength.

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

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

10.2.3.5 Preservice Inspection

The preservice inspection program is as follows:

A. The original wheel and rotor forgings and the new monoblock forgings are rough machined with minimum stock allowance prior to heat treatment.

B. Each original rotor and wheel forging and new monoblock forging is subjected to a 100% volumetric (ultrasonic) examination. Each finish-machined original rotor and wheel and new monoblock forging is subjected to a surface magnetic particle and visual examination. Results of the above examination will be evaluated by use of General Electric acceptance criteria. These criteria are most restrictive than those specified for Class 1 components in the ASME Boiler and Pressure Vessel Code, Sections III and V, and include the requirement that subsurface sonic indications are either removed or evaluated to assure that they do not grow to a size which compromises the integrity of the unit during the service life of the unit.

C. Finish-machined surfaces are subjected to a magnetic particle examination. No magnetic particle flaw indications are permissible in bores, holes, keyways, and other highly stressed regions.

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

10.2.3.6 Inservice Inspection

The inservice inspection program for the turbine assembly and valves includes the following:

A. Disassembly of the turbine is conducted during selected plant shutdowns. Inspection of parts that are normally inaccessible when the turbine is assembled for operation, such as couplings, coupling bolts, turbine shafts, low-pressure turbine buckets, low-pressure wheels, and high-pressure rotors, is conducted. This inspection consists of visual, surface, and volumetric examinations.

B. Dismantle at least one main steam stop valve, one main steam control valve, one reheat stop valve, and one reheat intercept valve during selected refueling or maintenance shutdowns, and conduct a visual and surface examination of valve seats, wheels, and stems. If unacceptable flaws or excessive corrosion are found in a valve, other valves of its type are inspected. Valve bushings are inspected and cleaned, and bore diameters are checked for proper clearance.

C. Main steam stop, reheat stop, and intercept valves will be exercised at least once a week by closing each valve and observing by the valve position indicator that it moves smoothly to a fully closed position. The control valves will be exercised monthly. At least once a month, this examination will be made by direct observation of the valve motion.

D. Extraction steam valves will be exercised once per week using a hand air test valve which is located at the nonreturn valve. Movement of the nonreturn valve shaft and counterweight extension will be noted during testing.

10.2.4 EVALUATION

10.2.4.1 Power Generation

Components of the turbine-generator are conventional and are types that have been extensively used in other nuclear power plants. Instruments, controls, and protective devices are provided to ensure reliable and safe operation. Redundant, fast actuating controls are installed to prevent any damage resulting from overspeed and/or full load rejection. The control system ensures turbine trip upon reactor trip. Automatic low-pressure exhaust hood water sprays prevent excessive hood temperatures. Exhaust casing rupture diaphragms prevent low-pressure cylinder overpressure in the event of loss of condenser vacuum.

Since the steam generated in the steam generators is not normally radioactive, no radiation shielding is provided for the turbine-generator and associated components. Thus, radiological considerations do not affect access to system components during normal conditions. In the event of a primary-to-secondary system leak due to a steam generator tube leak, it is possible for the main steam to become radioactively contaminated. Discussions of the radiological aspects of primary-to-secondary leakage are presented in chapters 11 and 12.

10.2.4.2 CESSAR Interface Evaluation

Refer to subsections 5.1.5 and 7.2.4.

10.2.5 INSTRUMENTATION APPLICATIONS

The turbine-generator is provided with a full complement of turbine supervisory instruments mounted in the control room, complete with sensors and/or transmitters mounted on the associated equipment, which indicate and record the following:

- Speed
- Stop valve position
- Control valve position
- Intercept valve position
- Temperatures as required for controlled starting, including:
  - Steam chest
  - Nozzle bowl
  - First-stage steam and drain
  - High-pressure casing drain
  - High-pressure exhaust
  - First-stage reheater outlet
  - Second-stage reheater outlet

- Casing expansion
- Casing and shaft differential expansion
- Vibration at each bearing
- Shaft eccentricity
- Bearing oil drain, shaft bearing sleeve, and thrust bearing plate temperatures
- Shaft axial position

Control room alarms are provided to warn the operators of the following abnormal conditions:

- High vibration
- High eccentricity
- High differential expansion
- High bearing temperature
- High exhaust hood temperature alarm
- Turbine trip (for each independent redundant channel)
- Low vacuum
- Thrust bearing wear
- Low bearing oil pressure
- Low steam seal pressure
- High gland seal condenser pressure (or low vacuum)
- Overspeed trip (for each independent redundant channel)
- High-low level in moisture separator drain tank

Local and control room indication of the following miscellaneous parameters are provided:

- Main steam chest pressure
- Steam seal header pressure
- Gland seal condenser vacuum
- Bearing oil header pressure
- Hydraulic header pressure
- Crossover pressure
- Moisture separator drain tank level (local only)
- First-stage pressure
- High-pressure turbine exhaust pressure
- Extraction steam pressure, each extraction point (via computer)
- Exhaust hood spray water flow
- Exhaust hood temperature, each exhaust

Instrumentation and controls are provided in the control room for the generator equipment as follows:

A. Generator supervisory instruments with sensors and/or transmitters mounted on the associated equipment, indicating or recording the following:

   1. Multiple generator stator winding temperatures. The detectors are built into the generator, fully protected from the cooling medium, and suitably distributed around the circumference in positions having the highest temperature.

2. Multiple stator winding cooling coil outlet temperature detectors
3. Stator coolant inlet and discharge temperatures
4. Hydrogen cooler inlet gas temperature (two detectors at each point)
5. Field temperature
6. Hydrogen gas pressure
7. Hydrogen gas purity
8. Generator winding over temperature.

B. Alarms are provided for high stator, hydrogen, stator coil coolant, and field temperature. An alarm is provided from a core monitoring system to indicate a local core overheating condition.

10.2.6 REFERENCES

1. Begley, J. A., and Logsdon, W. A., Westinghouse Scientific Paper 71-1E7-MSLRF-P1.
2. Spender, R. C., and Timo, D. F., Starting and Loading of Turbines, General Electric Company, presented at the 36th Annual Meeting of the American Power Conference, Chicago, Illinois, April 29-May 1, 1974.
3. Turbine Generator Final Report 105% core Thermal Uprate Study, SDR log 13-M400-0303-01036.

10.3 MAIN STEAM SUPPLY SYSTEM

The function of the main steam supply system is to deliver steam from the steam generators to the high-pressure turbine over a range of flows and pressures covering the entire operating range from system warmup to valves-wide-open (VWO) conditions. The system also provides steam to the moisture separator/reheaters, the feedwater pump turbines, the auxiliary steam system, and the steam seal system for the main and the feedwater pump turbines.

Under certain conditions the Auxiliary Steam condensate cross connection header may be connected to the Secondary Chemistry Condensate Cleanup System in order to transfer water from the steam generators to the Chemical Waste Neutralization Tanks. This capability is discussed further in Section 10.4.6.

10.3.1 DESIGN BASES

10.3.1.1 Safety Design Bases

Pertinent safety design bases are as follows:

A. Safety Design Basis One

The system provides a means of dissipating heat generated in the nuclear steam supply system (NSSS) during normal power operation, plant startup, hot shutdown, hot standby, and cooldown, even if the main condenser is unavailable. Atmospheric dump valves are provided to allow cooldown of the steam generator when the condenser is not available.

B. Safety Design Basis Two

The system is provided with automatically operated isolation valves on the main steam lines. These valves are located outside of and as close as possible to the containment in accordance with the requirements of Criterion 57 of 10CFR50.

C. Safety Design Basis Three

The system, from the secondary side of the steam generators and up to and including the main steam isolation valves (MSIVs) and the main steam isolation valve bypass valves, is designed to withstand the effects of a safe shutdown earthquake (SSE). The safety-related portions of the system are capable of withstanding the effects of natural phenomena.

D. Safety Design Basis Four

Main steam system components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, testing, and postulated accidents, including loss-of-coolant accidents (LOCAs), in accordance with 10CFR50, Appendix A, General Design Criterion 4.

E. Safety Design Basis Five

The main steam piping and supports are designed so that a single failure in the main steam system will have no contributory effects on:

- Initiation of a LOCA
- Integrity of other steam lines
- The capability of the engineered safety features system to effect a safe reactor shutdown
- Transmission of excessive loading to the containment pressure boundary

F. Safety Design Basis Six

The portion of the main steam system that is constructed in accordance with ASME Section III, Class 2, requirements is provided with access to welds and removable insulation as required for inservice inspection in accordance with ASME Section XI, Rules for Inservice Inspection of Nuclear Reactor Coolant Systems.

G. Safety Design Basis Seven

Flow restrictors are installed in the steam generator steam nozzles to limit flow in the event of a main steam line break.

H. Safety Design Basis Eight

Provide steam to the auxiliary feedwater pump turbine.

10.3.1.2 <u>Power Generation Design Basis</u>

The main steam supply system delivers the steam from the steam generators to the high-pressure turbine for a range of flows and pressure varying from system warmup to maximum operating conditions. It also provides steam to the moisture separator reheater, the feedwater pump turbines, the auxiliary steam system, and the turbine gland steam seal system.

10.3.1.3 <u>Environmental Design Bases</u>

Refer to section 3.11 and CESSAR Section 3.11 for a discussion of environmental design bases.

10.3.1.4 <u>Codes and Standards</u>

The main steam supply is designed in accordance with the codes and standards identified in table 3.2-1.

10.3.1.5 CESSAR Interface Requirements

Refer to subsection 5.1.4.

10.3.2 DESCRIPTION

10.3.2.1 General Description

The main steam supply system, shown in engineering drawings 01, 02, 03-M-SGP-002 and -001, includes the following major components:

- Main steam piping from the steam generator nozzles to the main turbine stop valves
- One main steam isolation valve per main steam line
- Main steam safety valves, 5 per main steam line
- Atmospheric dump valves, 1 per main steam line

Table 10.3-1 lists the design data covering the major components of the main steam supply system.

10.3.2.2 Component Description

10.3.2.2.1 Main Steam Piping

The main steam lines deliver the required steam flow from the secondary side of the two steam generators to the high-pressure turbine; while brunch lines deliver steam to the moisture separator/reheater, feedwater pump turbines, steam seal system, and the auxiliary steam system. Each of the main steam lines from the steam generators is anchored at the containment wall and has sufficient flexibility to accommodate thermal expansion. Design of the attachment of the main steam piping to the steam generators includes design considerations that incorporate the allowable nozzle loading moments and stresses for both steam generators operating, or with one of them out of service. The design of all piping and supports considers all static and dynamic loadings, stresses, and moments arising from normal operation, pressure transients, or pipe rupture. The design of Seismic Category I piping and supports considers the loads discussed in subsection 3.9.3.

Each main steam line contains five spring-loaded safety valves, one atmospheric dump valve, and one isolation valve. All of these valves are located outside the containment and are installed as close as possible to the containment wall. Containment penetrations are discussed in subsection 6.2.4.

Turbine bypass valves are provided between the main steam isolation valves and turbine generator stop valves as discussed under the turbine bypass system (refer to subsection 10.4.4). Connections are provided for nitrogen pressurization of the steam generators. Also, sample connections are provided downstream of the steam generator nozzles for determination of steam quality. Branch piping provides steam to moisture separator reheaters, main and feedwater pump turbine gland steam sealing systems, the feedwater pump turbines, the auxiliary feedwater pump turbine, and the bypass steam to the condenser and to atmosphere.

The main steam lines are designed to permit preoperational cleaning to remove foreign material and rust. The design is such as to prevent entry of foreign material into either the steam generators or turbine-generator. The main steam piping drops several feet immediately downstream of the steam generators prior to being routed to the turbine stop valves. The lines are sloped in the direction of the turbine, and drains are provided at all low points to provide for flushing and drainage.

Pertinent design parameters for the main steam piping out to the main steam isolation valve are presented in table 10.3-2.

Table 10.3-1

MAIN STEAM SUPPLY SYSTEM DESIGN DATA

(Sheet 1 of 2)

Component	Parameter
Main steam piping	
Steam flow at Rated power (Reactor Power of 3800 MWt), 10^6 lb/hr	17.2
at rated Power (Reactor Power of 3990 MWt), 10^6 lb/hr	17.96
at VWO power, (Reactor Power of 3800 MWt), 10^6 lb/hr	18.1
at VWO power, (Reactor Power of 3990 MWt), 10^6 lb/hr	18.45
Number of main steam lines	4
Pipe size, OD in.	28
Design pressure, psig	1255
Design temperature, °F	600
Pipe material	ASME SA-155 grade KCF 70, class I carbon steel
Pressure drop from steam generator to stop valve at VWO, psi	39
at Rated Power (Reactor Power of 3880 MWt), psi	33
at Rated Power (Reactor Power of 3990 MWt), psi	19.8
at Turbine Guarantee, psi	33
Main steam isolation valves	
Number per main steam line	1
Total number required	4
Atmospheric dump valves	
Number per main steam line	1
Total number required	4
Design relieving capacity per valve 100% open, lb/h (at 1000 psia)	1.47×10^6
Controllable capacity per valve, lb/h (at 1170 psia)	63,000
Main steam safety valves	
Number per main steam line	5
Total number required	20

Table 10.3-1

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

Component	Parameter
Main steam safety valves (Cont.)	
Set pressure, psig	
No. 1	1250
No. 2	1290
No. 3	1315
No. 4	1315
No. 5	1315
Orifice size, in^2	
No. 1	16.0
No. 2	16.0
No. 3	16.0
No. 4	16.0
No. 5	16.0
Inlet/Outlet size, in./in.	
No. 1	6 x 10
No. 2	6 x 10
No. 3	6 x 10
No. 4	6 x 10
No. 5	6 x 10
Minimum rated relieving capacity, per valve, at 3% accumulation, 10^5 lb/h:	

VALVE NUMBER

	S/G No. 1	S/G No. 2	Parameter
a.	SGE PSV 572	SGE PSV 554	9.415
b.	SGE PSV 579	SGE PSV 561	9.415
c.	SGE PSV 573	SGE PSV 555	9.713
d.	SGE PSV 578	SGE PSV 560	9.713
e.	SGE PSV 574	SGE PSV 556	9.899
f.	SGE PSV 575	SGE PSV 557	9.899
g.	SGE PSV 576	SGE PSV 558	9.899
h.	SGE PSV 577	SGE PSV 559	9.899
i.	SGE PSV 691	SGE PSV 694	9.899
j.	SGE PSV 692	SGE PSV 695	9.899
	Total (20 valves), 10^6 lb/h		19.53
	Total maximum actual relieving capacity (20 valves), 10^6 lb/h		22.258

[Editing Note: The truncated "parameter" value bounds the CTS Value]

The main steam piping out to the first isolation valve is inspected and tested in accordance with ASME Code, Sections III and XI. ANSI B31.1 piping is inspected and tested in accordance with Paragraphs 136 and 137 of ANSI B31.1.

10.3.2.2.2 Main Steam Isolation Valves

Each of the main steam lines is equipped with one quick acting main steam isolation valve (MSIV). Each valve has an actuation time of 4.6 seconds or less and operates automatically in the event of rupture in the main steam piping or associated components either upstream or downstream of the MSIV. They prevent blowdown of more than one steam generator (assuming a single active failure of an MSIV to close coincident with rupture) based on the MSIV’s ability to close against maximum design differential pressure in either direction. The valves are designed to close upon loss of electric power. Once isolation is initiated, in response to a main steam isolation signal (MSIS), the valves continue to close and cannot be opened until the initiating MSIS is reset or overridden manually by the operator in the control room.

Table 10.3-2

MAIN STEAM ISOLATION VALVE EXPECTED LEAKAGE

Differential Pressure (psi)	Pressurized (Upstream/Downstream)	Seat Leakage
1400	Downstream (after steam line break)	0.1% VWO steam flow
1400	Upstream (after steam line break)	0.001% VWO steam flow

Each valve has two physically separate and electrically independent solenoid actuators in order to provide redundant means of valve operation. Refer to table 10.3-2 for valve leakage.

The main steam isolation valves are installed in the straight piping runs outside the containment. Table 10.3-3 tabulates all flow paths that branch off the main steam lines between the MSIVs and the turbine stop valves and provides information, including valve positions, to determine performance in the event of steam line break upstream of the MSIV. For those valves which remain open, the total steam flow through these valves is approximately 251,200 lbm/hr. The auxiliary feedwater pump (AFW) delivers at least 316,000 lbm/hr (650 gpm @ 180F.), to the intact steam generator at 1270 psia. Therefore, in the event of a postulated MSLB on one steam generator, and one MSIV failure to close on the intact steam generator, an auxiliary feedwater pump can provide sufficient make-up to the intact steam generator. The maximum stress level does not exceed the criteria specified in subsection 3.9.3. As noted in UFSAR Sections 15.1.5 and 15.1.6, however, the single failure of a HPSI pump to start on demand is more limiting for postulated MSLBs, than the single failure of an MSIV to close.

A mechanistic main steam line pipe rupture is not postulated to occur between the containment penetrations and the MSIVs nor between the MSIVs and the double concrete wall (designed as a pipe whip restraint) downstream from the MSIVs. However, the main steam support structure and safety-related equipment within are designed to withstand the temperature and pressure effects of a single area pipe break.

The bending moment resulting from a main steam line rupture downstream of the pipe whip restraint is absorbed by the pipe whip restraint and the MSIV nozzle has no bending moment transmitted to it.

The steady-state discharge thrust load from such a break does not cause nozzle bending or torsion. Axial thrust is resisted and balanced at the penetration.

Table 10.3-3

FLOW PATHS ORIGINATING AT MAIN STEAM LINES (Sheet 1 of 2)

System Identification	Max. Steam Flow (LB/HR)	Type of Shut-off Valves	Size of Valve	Quality of Valve	Design Code of Valve	Closure Time of Valve (Seconds)	Actuation Mechanism	Motive or Power Source	Closure Signal (Sensor)	Quality of Power Source	Quality of Air Supply	Positive Status of Valve After MSIV Isolation	Comment
SG-V093 (or AS-V004)	82,600	Gate (Gate)	6"	Non-Q	ANSI B31.1	15	Manual	N/A	N/A	N/A	N/A	Open	Aux. steam supply to control valves PV-5A/B,PV-6 (13-M-ASP-001) (13-M-SGP-001)
SG-V094 (or AS-V012)	82,600	Gate (Gate)	6"	Non-Q	ANSI B31.1	15	Manual	N/A	N/A	N/A	N/A	Open	
SG-V095 (or AS-V013)	50,000	Globe (Gate)	3"	Non-Q	ANSI B31.1	10	Manual	N/A	N/A	N/A	N/A	Open	
MT-UV-1004 (or UV-1005)	4.25 X 10^6	Globe	28"	Non-Q	ANSI B31.1	0.2	Hydraulic	Trip of turbine speed control system (actuated on MSIS parameters)	MSIS Actuation Signal (Low S/G Pressure)	Non-IE	N/A	Closed	
MT-UV-1006 (or UV-1007)	4.25 X 10^6	Globe	28"	Non-Q	ANSI B31.1	0.2	Hydraulic	Trip of turbine speed control system (actuated on MSIS parameters)	MSIS Actuation Signal (Low S/G Pressure)	Non-IE	N/A	Closed	Main steam supply to main turbine (13-M-MTP-001)
MT-UV-1002 (or UV-1001)	4.25 X 10^6	Globe	28"	Non-Q	ANSI B31.1	0.2	Hydraulic	Trip of turbine speed control system (actuated on MSIS parameters)	MSIS Actuation Signal (Low S/G Pressure)	Non-IE	N/A	Closed	
MT-UV-1000 (or UV-1003)	4.25 X 10^6	Globe	28"	Non-Q	ANSI B31.1	0.2	Hydraulic	Trip of turbine speed control system (actuated on MSIS parameters)	MSIS Actuation Signal (Low S/G Pressure)	Non-IE	N/A	Closed	
SG-UV-031	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	Non-IE	N/A	Non-IE	N/A	Closed	
SG-UV-032	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	480V	N/A	Non-IE	N/A	Closed	Bleed off line between MSIV's and turbine stop valves closes on turbine trip (normally closed MOVs) (13-M-SGP-001)
SG-UV-033	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	3 Phase	N/A	Non-IE	N/A	Closed	
SG-UV-034	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	60 Cycle	N/A	Non-IE	N/A	Closed	
SG-UV-035	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	Non-IE	N/A	Non-IE	N/A	Closed	
SG-UV-036	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	480V	N/A	Non-IE	N/A	Closed	
SG-UV-037	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	3 Phase	N/A	Non-IE	N/A	Closed	
SG-UV-038	50,000	Globe	2"	Non-Q	ANSI B31.1	10	Motor	60 Cycle	N/A	Non-IE	N/A	Closed	

Table 10.3-3

FLOW PATHS ORIGINATING AT MAIN STEAM LINES (Sheet 2 of 2)

System Identification	Max. Steam Flow (LB/HR)	Type of Shut-off Valves	Size of Valve	Quality of Valve	Design Code of Valve	Closure Time of Valve (Seconds)	Actuation Mechanism	Motive or Power Source	Closure Signal (Sensor)	Quality of Power Source	Quality of Air Supply	Positive Status of Valve After MSIV Isolation	Comment
SG-PV-1007	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic	Instrument Air	Solenoid permissive to open (Non-ie 120V dc) SGBD permissive signal logic (Non-IE 120V ac	Non-IE	ANSI B31.1	Closed	Main steam blow-down at atmos vent restrictor (13-M-SGP-001)
SG-PV-1008	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
SG-PV-1002	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	Main steam blow down to condenser (13-M-SGP-001)
SG-PV-1001	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
SG-PV-1003	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
SG-PV-1004	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
SG-PV-1005	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
SG-PV-1006	1,240,000	Globe	12"	Non-Q	ANSI B31.1	15	Pneumatic			Non-IE	ANSI B31.1	Closed	
FT-HV-65	120,000	Globe	5"	Non-Q	ANSI B31.1	0.3	Hydraulic	MFW Pump Turgine Speed Control System	MFW pump trip logic (MSIS)[a]	Non-IE	N/A	Closed	Main steam supply to MFW pump turbine
(or HV-67)	120,000	Globe	5"	Non-Q	ANSI B31.1	0.3	Hydraulic			Non-IE	N/A	Closed	
FT-HV-66	120,000	Globe	5"	Non-Q	ANSI B31.1	0.3	Hydraulic			Non-IE	N/A	Closed	
(or HV-68)	120,000	Globe	5"	Non-Q	ANSI B31.1	0.3	Hydraulic			Non-IE	N/A	Closed	
MT-UV-328B	262,500	Globe	10"	Non-Q	ANSI B31.1	75	Motor	Electrical (Non-IE, 480V 3 phase 60 cycle	Load sensing logic on main turbine, (i.e., pressure switch PSL 512) Control room hand switch	Non-IE	N/A	Closed	Main steam supply to moisture separator reheater
MT-UV-328A	262,500	Globe	10"	Non-Q	ANSI B31.1	75	Motor			Non-IE	N/A	Closed	
MT-UV-328D	262,500	Globe	10"	Non-Q	ANSI B31.1	75	Motor			Non-IE	N/A	Closed	
MT-UV-328C	262,500	Globe	10"	Non-Q	ANSI B31.1	75	Motor			Non-IE	N/A	Closed	
GS-HV-005	36,000	Gate	4"	Non-Q	ANSI B31.1	10	Motor	Electrical (Non-IE, 480V 3 phase 60 cycle		Non-IE	N/A	Open (closed by plant operator)	Main steam supply to gland seal

The bending and axial loads resulting from a postulated main steam line break inside the containment are absorbed by the containment penetration which is designed to withstand pipe collapsing moments and axial thrust.

The operability of the MSIVs is thus unaffected by the above postulated main steam line breaks.

The MSIVs are designed, manufactured, inspected, tested, and certified in accordance with the requirements of the ASME Code, Section III.

The supplier of the MSIVs has designed the valve body to the specified design pressure and temperature and designed the disc, piston, cylinder, connecting shaft, and all other valve and operational components subject to the closing and opening loads within the specified operational time limits to the design differential pressure (in either direction). Disc load and disc assembly inertia load are safely transferred to the valve body.

Total load combinations and stress limits (including pressure load and disc assembly inertia load acting on the valve seat) meet the requirements of table 3.9-3.

The maximum disc stress due to differential pressure and the inertia load due to the moving disc assembly do not exceed 75% of the yield strength in bending and 50% of the yield strength in shear of the disc material at the operating temperature.

The MSIVs are qualified for operability in conformance to paragraph 3.9.3.2.1.2.

10.3.2.2.3 Main Steam Safety Valves

Each main steam line is provided with five ASME Code, spring loaded safety valves located upstream of the main steam isolation valves but outside the containment. The total relieving capacity of these valves is divided equally between the main steam lines and is sufficient to pass the steam flow equivalent to 105% of the plant's maximum steam flow. Design data for the main steam safety valves are included in table 10.3-1. The safety valve pressure accumulation does not exceed 3% and the maximum pressure while relieving is below the maximum allowable of 10% above the steam generator design pressure, in accordance with Article NC-7000 of ASME Section III, Nuclear Power Plant Components Code. The design pressure-temperature rating of the main steam piping is 1270 psia and 600F, which are more conservative than the design conditions for the steam generator secondary side.

10.3.2.2.4 Atmospheric Dump Valves

Atmospheric dump valves, one per main steam line, are provided to allow cooldown of the steam generators when the main steam isolation valves are closed, or when the main condenser is not available as a heat sink. Each atmospheric dump valve is sized to hold the plant at hot standby while dissipating core decay heat or to allow a flow of sufficient steam to maintain a controlled reactor cooldown rate. No automatic control capability is required or provided. Refer to section 7.4 for discussion of the control of the atmospheric dump valves. A nitrogen accumulator is provided for each valve. The accumulator is designed to Seismic Category I standards and is sized for 4 hours at hot standby plus 9.3 hours of operation to reach cold shutdown(1) under natural circulation conditions in the event of failure of the normal control air system, with a minimum nitrogen accumulator pressure of 615 psig indicated. Refer to subsection 9.3.6 for a discussion of the nitrogen supply for the atmospheric dump valve accumulators.

10.3.2.3 Radiological Considerations

Because the steam from the steam generator is not normally radioactive, no radiation shielding is required for the main steam system and associated components. Thus, radiological considerations will not affect access to system components during normal conditions. In the event of a primary-to-secondary system leak caused by a steam generator tube leak, it is possible for the steam to become radioactively contaminated. Discussions of the radiological aspects of primary-to-secondary leakage are presented in chapters 11 and 12.

10.3.3 EVALUATION

Table 10.3-4 covers the failure mode and effects analysis of the main steam supply system.

10.3.3.1 Safety Evaluation

Safety evaluations are numbered to correspond to the safety design bases and are as follows:

A. Safety Evaluation One

Under the following conditions, with the steam generators in service, the power-operated atmospheric dump valves are used to dissipate reactor coolant system energy and core decay heat into the atmosphere:

1. When the turbine generator or main condenser is not in service
2. When the plant is being started up or shut down
3. During core physics testing
4. Following a turbine-generator trip on loss of main condenser vacuum

Table 10.3-4

MAIN STEAM SYSTEM FAILURE MODE AND EFFECTS ANALYSIS (Sheet 1 of 3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision
1	Main steam isolation valve	a) Fails open	Solenoid failure	None, redundant solenoid will close valve	Valve Position Indicator, S. G. Pressure and Level Indicators, and steam line flow recorders	Each MSIV has redundant trip circuits, solenoid valves, accumulators, and position indicators.
		b) Fails closed	Actuator failure	Decrease in steam flow to the turbine generators, about 25%	Valve Position Indicator and steam line flow recorders	None
2	MSIV bypass valve	a) Fails closed	Mechanical binding Pneumatic operator failure	Main steam isolation valves can't be opened if there is a pressure drop across them	Valve position indication in control room	Either of two valves can be used to equalize pressure in all four steam lines.
		b) Fails open	Mechanical binding	None, if MSIV is open. If MSIV is shut, then bleedoff of steam generator	Valve position indication in control room	Affects only one steam generator.

Table 10.3-4

MAIN STEAM SYSTEM FAILURE MODE AND EFFECTS ANALYSIS (Sheet 2 of 3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision
3	Valve, atm dump	a) Fails closed	Failure of seals or air supply	No effect unless coupled with some other failure	Valve position indication in control room	Backup nitrogen supply. Also, other steam generator atmospheric dump valves provide full capability for steam release
		b) Fails open	Mechanical binding	About 16% of one steam generator's steam output would be dumped to atmosphere. A stuck open ADV will result in both a reactor trip and a MSIS.	Noise level increase, and a decrease in steam generator pressure indicated in control room	Blowdown of only one steam generator
4	Main feedwater isolation valve	a) Fails open	Mechanical binding	No effect	Periodic tests	Two valves in series in each line are available for isolation. Auxiliary feed flow is available via alternate path
		b) Fails closed	Operator failure	Loss of 90% of flow to one section of the steam generator. Decrease in steam generator efficiency	Low flow indicated on flow indicator	Feed to steam generator still available to other sections

Table 10.3-4

MAIN STEAM SYSTEM FAILURE MODE AND EFFECTS ANALYSIS (Sheet 3 of 3)

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failure	Methods of Detection	Inherent Compensating provision
5	Main feedwater check valve	a) Fails closed	Mechanical binding	No flow to one portion of the economizer in one steam generator. Decrease in efficiency of the steam generator	Flow indicator in control room	Steam generator feed still available to other sections Feedwater control system will automatically compensate
		b) Fails open	Mechanical binding	No effect unless coupled with some other failure	Periodic test	Closing of containment isolation valve
6	Auxiliary feedwater check valve	a) Fails closed	Mechanical binding	Temporary low feedwater flow to one steam generator	Low flow indication in control room	Alternate flow paths available. Feedwater control system compensates automatically
		b) Fails open	Mechanical binding	No effect unless coupled with some other failure	Periodic test	None required

5. Loss of electric power to plant auxiliaries

Controlled cooldown can be accomplished by use of the dump valves.

B. Safety Evaluation Two

Isolation valves are included in the system design. These valves are described in paragraph 10.3.2.2.2 and their performance under the accident conditions is discussed in chapter 15.

C. Safety Evaluation Three

The main steam system is designed in accordance with seismic criteria set forth in chapter 3. The design of the main steam system with respect to natural phenomena is also discussed in chapter 3.

D. Safety Evaluation Four

All safety-related components in the main steam system are designed to perform their intended function in the normal and accident temperature, pressure, humidity, chemical, and radiation environment in which they will operate. Environmental design bases and qualifications are discussed in section 3.11.

E. Safety Evaluation Five

The main steam lines are routed from the containment to the turbine building with separations provided so that the failure of steam lines or components associated with one steam generator cannot damage the main steam lines, the isolation valves, and atmospheric dump valves associated with the other steam generator, or damage any component required to effect a safe reactor shutdown. Refer to sections 3.5 and 3.6 for the discussion of missile and pipe rupture effects.

F. Safety Evaluation Six

Removable insulation and access to welds, in accordance with ASME Section XI requirements, are provided in the main steam supply system.

G. Safety Evaluation Seven

Each steam generator steam outlet nozzle is equipped with a flow limiting device to limit steam flow in the event of a downstream pipe break. Refer to CESSAR Section 5.4.4 for a description of the flow limiting device.

H. Safety Evaluation Eight

A branch connection upstream of the MSIVs from each steam generator provides steam to operate the auxiliary feedwater pump turbine. Refer to subsection 10.4.9.

10.3.3.2 CESSAR Interface Evaluation

Refer to subsection 5.1.5.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

Refer to section 14.2 for preoperational testing requirements. Refer to section 3.9 and to the Technical Specifications for inservice testing and inspection requirements.

10.3.5 WATER CHEMISTRY (PWR)

10.3.5.1 Chemistry Control Basis

Steam generator secondary side water chemistry control is accomplished by:

A. Close control of the feedwater to limit the amount of impurities which can be introduced into the steam generator;

B. Blowdown of the steam generator to reduce the concentrating effects of the steam generator;

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

D. Preoperational cleaning of the feedwater system;

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

Chemistry limits for secondary steam generator water and feedwater are established in accordance with EPRI PWR Secondary Water Chemistry Guidelines as endorsed by NEI 97-06, Steam Generator Program Guidelines. The EPRI guidelines and their bases represent the industry best practice, as developed from evaluation of the most recent experimental data and plant operating experience. Exceptions are fully evaluated and documented prior to implementation.

Secondary water chemistry is based on all volatile treatment to maintain system pH, ensure a reducing environment, and to scavenge dissolved oxygen present in the feedwater. Boric acid may be added to minimize SCC of the steam generator tubes.

A neutralizing amine such as ammonia, ethanolamine (ETA) and/or dimethylamine (DMA) is added to establish and maintain alkaline conditions in the feed train.

A reducing agent/oxygen scavenger, such as hydrazine is added to establish a reducing environment and to scavenge dissolved oxygen present in the feedwater. The reducing agent/oxygen scavenger also tends to promote the formation of a protective oxide layer on metal surfaces by keeping these layers in a reduced chemical state (lower electrochemical potential).

Both the pH agent and the reducing agent/oxygen scavenger can be injected continuously downstream of the condensate polishing demineralizers. These chemicals are added for chemistry control, and can also be added to the upper steam generator feed line when necessary.

Molar Ratio chemistry is monitored and may be controlled to provide additional assurance that aggressive species are not concentrated above their respective molar concentration ratio (anion to cation ratio). Ammonium chloride injection may be utilized as a method to control Molar Ratio within a prescribed band.

Implementation of Boric Acid Treatment per NSSS Vendor recommendations and EPRI BAT Application guidelines is site specific and is controlled by the station chemistry control program. Boron is maintained at very low concentrations in wet layup to minimize excessive use of pH control agent.

pH is dependent on the pH agent used, the implementation of Boric Acid Treatment (BAT), which may be used to mitigate IGA/SCC of steam generator tubes (alloy 690 tubes, and the use of condensate polishing demineralizes. Alternate amine pH agents can be utilized to provide better pH control at the normal operating temperature of PWR steam generators. Implementation of BAT will require adjustment in the pH and boron specifications.

The normal chemistry conditions can be maintained by any plant operating with little or no condenser leakage. The steam generator limits permit operations with minor system fault conditions until the affected component can be isolated and/or repaired.

Secondary water chemistry monitoring is described in section 9.3.2.

Procedures will require prompt corrective action for out of specification secondary water chemistry conditions.

If condenser leakage is indicated, leak isolation procedures are instituted.

The abnormal limits permit operation with minor system fault conditions until the affected component can be isolated and/or repaired. If the abnormal limits are exceeded, plant shutdown procedures are considered.

Sampling of the steam generator water is done on a continuous basis; parameters monitored include pH, conductivity and radiation.

Out of specification chemical conditions are alarmed in the auxiliary building chemistry laboratory, with a common system trouble alarm in the control room.

In addition, recording and management of secondary water chemistry data will be covered by administrative procedures. These procedures will include the following requirements:

A. The composition, quantities, and addition rates of additives shall be recorded initially and thereafter whenever a change is made;

B. The electrical conductivity and the pH of the bulk steam generator water and feedwater shall be measured continuously (with provision for alternate sampling methods in case of equipment failure);

C. The electrical conductivity and sodium ion concentration of the condensate is measured continuously. An administrative procedure will specify responsibilities for interpretation of secondary water chemistry data, initiation of corrective action, maintaining secondary water chemistry conditions within specifications, and taking such action as is needed to correct out of specification or off control point conditions. The Shift Manager is responsible for initiating corrective action for out of specification chemical parameters. The Shift Manager is advised in these corrective actions by the senior chemistry technician. Chemistry data sheets and reports are reviewed on a routine basis by unit chemistry management. Procedures will provide guidance for correcting out of specification and off control point conditions and will require prompt action to correct out of specification conditions.

Procedures for secondary water chemistry control and monitoring were available onsite for NRC review 60 days prior to filling the secondary side of a steam generator.

10.3.5.2 Corrosion Control Effectiveness

Alkaline conditions in the feedtrain 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 the formation of a protective metal oxide film and thus reduce the corrosion products released into the steam generator.

The reducing agent/oxygen scavenger also promotes the 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 adherent protective layer on carbon steel surfaces. The reducing agent/oxygen scavenger also promotes the formation of protective metal oxide layers on copper surfaces.

The removal of oxygen from the secondary waters is also essential in reducing steam generator corrosion mechanisms. Low levels of oxygen dissolved in water causes general corrosion that can result in pitting of ferrous metals, 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 a reducing agent/oxygen scavenger into the condensate stream. Maintaining a residual level of the reducing agent/oxygen scavenger 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 in the steam generator.

Zero solids treatment is a control technique whereby both soluble and insoluble solids are excluded from the steam generator. This is accomplished by maintaining strict surveillance over the possible sources of feed train contamination (e.g.,: Main Condenser cooling water leakage, air in leakage and subsequent corrosion product generation in the Low Pressure Drain System, etc.). Solids (with the exception of boric acid, if used) are also excluded, as discussed above, by injecting only volatile chemicals to establish conditions which reduce corrosion and, therefore, reduce the transport of corrosion products into the steam generator. Reduction of solids in the steam generator can also be accomplished through the use of full flow condensate demineralization.

In addition to minimizing the sources of contaminants entering the steam generator, continuous blowdown of one and/or both steam generators is employed to minimize their concentration. These systems are discussed in Section 10.4.6. With the low solid levels which result 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 to such an extent that they create a mechanism which allows impurities to concentrate to high levels, and thus could possibly cause corrosion. Therefore, by limiting the ingress of solids into the steam generator, the effect of this type of corrosion is reduced.

Because they are volatile, the chemical additives will not concentrate in the steam generator, and do not represent chemical impurities which can themselves cause corrosion.

10.3.5.3 Chemistry Control Effects on Iodine Partitioning

The partition factor assumed for the condenser vacuum pump outlet is discussed in subsection 11.1.8.

10.3.6 STEAM AND FEEDWATER SYSTEM MATERIALS

10.3.6.1 Fracture Toughness

The materials are in compliance with the ASME Boiler and Pressure Vessel Code, Sections II and III, 1974 Edition through the Winter, 1975 Addenda. The fracture toughness properties meet the requirements of the Code, Section III, Paragraphs NB-2300, NC-2300, and ND-2300.

10.3.6.2 Material Selection and Fabrication

All pipe, flanges, fittings, valves, and other piping material conform to the latest referenced ASME, ASTM, ANSI, or MSS-SP code, including addenda and supplements.

The following code requirements apply:

	Stainless Steel	Carbon Steel
sPipe	ANSI B36.19	ANSI B36.10
Fittings	ANSI B16.9, B16.11 or B16.28	ANSI B16.9, B16.11 or B16.28
Flanges	ANSI B16.5	ANSI B16.5

The following ASME material specifications apply specifically:

ASME SA-155 GR KCF 70 Class 1 (impact tested)
ASME SA-106 GR C (impact tested)
ASME SA-106 GR B
ASME SA-234 GR WP-22
ASME SA-234 GR WPB
ASME SA-234 GR WPBW (manufactured from ASME SA-516 GR 70 plate)
ASME SA-234 GR WPC (impact tested)
ASME SA-105
ASME SA-182
ASME SA-193 GR B7
ASME SA-194 GR 2H
ASME SA-333 GR 6 (impact tested)
ASME SA-335 GR P22
ASME SA-420 GR WPL6 (impact tested)
ASME SA-420 WPL6-W (manufactured from ASME SA-516 GR 70 plate) (impact tested)
ASME SA-350 LF 2 (impact tested)
ASME SA-403

ASME SA-312

ASME SA-376

For austenitic stainless steel components, consistency with the recommendations of Regulatory Guide 1.44, Control of the Use of Sensitized Stainless Steel; Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel; and Regulatory Guide 1.31, Control of Ferrite Content in Metal, is discussed in section 1.8.

For cleaning and handling of Class 1, 2, and 3 components, the recommendations of Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants, and ANSI-N45.2.1-73, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Plants, are followed as discussed in section 1.8.

With regard to preheat temperatures used for welding of Class 1, 2, and 3 low-alloy steel, the recommendations of Regulatory Guide 1.50, Control of Preheat Temperatures for Welding of Low-Alloy Steel, were followed.

All piping of the main steam system with pipe sizes larger than 2-1/2 inches is grit blasted.

Materials for use in Class 1, 2, and 3 components have been specified to conform to Appendix I of Section III of the Code and to Parts A, B, and C of Section II of the Code. Regulatory Guide 1.85, Code Case Acceptability ASME Section III Materials, has been used in conjunction with the above specifications.

For a discussion of conformance to Regulatory Guide 1.71, Welder Qualification for Areas of Limited Accessibility, refer to section 1.8.

10.3.7 REFERENCES

1. Scherer, A. E., Director, Nuclear Licensing, Combustion Engineering, letter to Eisenhut, D. G., Director, Division of Licensing, USNRC, August 12, 1983 (LD-83-074).

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10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

The main condenser is designed to condense and deaerate exhaust steam from the turbine generator and the feedwater pump turbines.

10.4.1.1 Design Bases

10.4.1.1.1 Safety Design Bases

The main condenser has no safety function.

10.4.1.1.2 Power Generation Design Bases

Power generation design bases are as follows:

A. Power Generation Design Basis One

The main condenser provides a heat sink for the exhaust steam from the turbine-generator and the feedwater pump turbines, as well as for turbine bypass steam and other cycle flows.

B. Power Generation Design Basis Two

The main condenser provides hotwell storage for surge capability and retention of condensate in the event of a condenser tube leak.

C. Power Generation Design Basis Three

The main condenser provides required deaeration of the condensate.

D. Power Generation Design Basis Four

The main condenser is designed to minimize air inleakage into the steam thermal cycle.

E. Power Generation Design Basis Five

The chemistry of the condensate and feedwater is maintained by the secondary chemical system under all normal operating and allowable upset or abnormal conditions.

10.4.1.1.3 Codes and Standards

The main condenser is designed in accordance with the applicable codes and standards identified in table 3.2-1.

10.4.1.2 System Description

The main condenser is a multi-pressure, three-shell, single-pass, deaerating type of surface condenser with divided waterboxes. The condenser is floor supported and is located beneath the low-pressure turbines. Expansion joints are provided between each turbine exhaust opening and steam inlet connection of the condenser shells. Main condenser design data are given in table 10.4-1. During normal operation, exhaust steam from the low-pressure turbines is directed downward into the condenser shells through exhaust openings in the bottom of turbine casings and is condensed. The condenser also receives vents and drains from feedwater heaters, miscellaneous equipment, valves, and piping. During transient conditions, the main condenser serves as a heat sink for feedwater heater and drain tank high-level dumps and for the turbine bypass steam. The main condenser is designed to accept up to 41% of the rated steam flow through the turbine bypass system described in subsection 10.4.4. The bypassed steam flow is distributed between the three condenser shells. These conditions are accommodated without increasing the condenser backpressure to the turbine trip setpoint or exceeding the allowable turbine exhaust temperature. Provision is made to reduce the bypass steam pressure before exhausting into the condenser distribution manifold. Special considerations were given to the design of the condenser to avoid steam impinging on the tubes. The condenser has titanium tubes conforming to ASTM B388 which eliminate corrosion/erosion problems.

The condenser is cooled by the circulating water system that removes the heat rejected to the condenser. The use of divided water boxes, lined with repairable protective coating to minimize corrosion/erosion, on each shell permits isolation of one-half of the total circulating water flow through each shell. This permits access to the isolated water box on each shell for repair and/or inspection while one-half of the circulating water flows through the other water box. The circulating water system is described in subsection 10.4.5. The condenser hotwells provide 100,000 gallons of water storage, equivalent to that required for 4 minutes of operation at valves wide open load. The hotwells of each of the condenser shells are interconnected. In addition to struts and braces, the first, second, third, and fourth point low-pressure feedwater heaters are installed in the steam dome of each condenser shell.

In the event that a condenser hotwell ruptures, the flooding will not jeopardize the safe shutdown of the plant. At no time would the water enter the auxiliary building, control building, or diesel generator building. The only access to any of these buildings from the turbine building is sufficiently above the turbine building basemat elevation. Since there is no safety-related equipment in the turbine building, none could be affected.

Table 10.4-1

MAIN CONDENSER DESIGN DATA (Sheet 1 of 2)

Design Factor	Value
Exhaust steam to condenser at VWO load, (Reactor Power of 3800 MWt/3990 MWt), lb/h	9,303,000/ 9,361,830
Total condensate outflow, (Reactor Power of 3800 MWt/3990 MWt), lb/h	12,864,000/ 12,752,876
Total condenser duty, Btu/h	9.04×10^9
Maximum expected condenser operating pressure, in.Hg abs	5.0
Condenser high operating pressure alarm, in.Hg abs	5.5
Condenser loss of vacuum setpoint for bypass valves to close, in.Hg abs	5.5
Turbine trip vacuum setpoint, in.Hg abs	7.5
Circulating water design flow to condenser gal/min	560,000
Physical Characteristics	**Value**
No. of condenser tubes	76,278
Condenser tube material	Titanium
Total heat transfer surface, ft^2	1,122,860
Overall dimensions	
High pressure (HP)	90'-4" L; 30'-11" W; 67'-2" H
Intermediate pressure (IP)	87'-10" L; 30"-11" W; 67'-2" H
Low pressure (LP)	87'-10" H; 30'-11" W; 67'-2" H
No. of passes	One
Total hotwell capacity	100,000 gal

Table 10.4-1

MAIN CONDENSER DESIGN DATA (Sheet 2 of 2)

Physical Characteristics	Value
Special design features	3 pressure deaerating type condenser
Minimum heat transfer, Btu/h°F sq ft	
High-pressure stage	533
Intermediate pressure stage	546
Low-pressure stage	560
Steam flow from main turbine	
Guaranteed power, (Reactor Power of 3800 MWt/3990 MWt)lb/h	9,002,000 9,191,086
Vwo power, (Reactor Power of 3800 MWt/3990 MWt)lb/h	9,303,000 9,361,830
Circulating water temp., °F (Typical)	
Normal	87.3
Maximum	94.0
Exhaust steam temperature, °F	
Normal	
Without bypass flow	127
With bypass flow	133.8
Maximum	
Without bypass flow	131
With bypass flow	133.8
Condensate oxygen content cc/liter (at normal circulating water temp.)	
Above 24% load	0.005
Below 24% load (circulating water flow is divided)	>0.005

Air and noncondensable gases contained in the turbine exhaust steam are collected in the condenser and passed through the air removal section. Here, the noncondensable gases are removed by the condenser air removal system described in subsection 10.4.2. The maximum total condenser air inleakage is 60 standard cubic feet per minute, as calculated in accordance with Heat Exchange Institute Standard. Buildup of noncondensable gases is precluded since the air removal system is in continuous operation. The condenser reduces oxygen concentration in the condensate to 5 ppm or less by deaeration while the final oxygen content is reduced to 0.01 ppm or less by hydrazine injection at the discharge side of the condensate polishing system. The hydrazine injection system is discussed in subsection 10.4.6.

The internal steam dump fittings for the turbine bypass steam consist of double pressure reduction critical flow orifices. The steam exits in a horizontal direction away from both the turbine and the condenser tubes. In addition, the condenser tubes are protected from high temperature drains by austenitic stainless steel baffles that direct the flow away from the condenser tubes.

Loss of main condenser vacuum, as evidenced by the condenser pressure reaching or exceeding the setpoint of 7.5 in.Hg abs, trips the turbine. However, a standby vacuum pump having 100% capacity for one condenser shell is provided to prevent loss of vacuum. The pump is on automatic control to assist or take over the service of the operating pump. If the turbine is tripped because of high backpressure, the steam bypass valves close to prevent additional steam from entering the condenser.

Two of the eight bypass valves are directed to atmosphere and open only on high condenser pressure.

Rupture diaphragms on the main turbine exhaust hood are provided to protect the condenser and turbine exhaust hoods against overpressure. Exhaust hood overheating protection is provided by an exhaust hood spray system that uses condensate from the condensate pumps.

In the event of primary-to-secondary tube leakage, radioactive contaminants are present in the steam generator. Radioactive concentrations in the hotwell are given in section 11.1. During normal operation, there is no gaseous hydrogen going to the main condenser. In the event of a steam generator tube leak, minute quantities of gaseous hydrogen are carried over to the main condenser. As noted in subsection 10.4.2, the condenser air removal system removes the hydrogen.

The reactor coolant system (RCS) is independent of the condenser circulating water system and the condensate and feedwater systems; therefore, the influence of condenser control functions on RCS operation is negligible. Minute changes in reactor power level occur as a result of changes in main turbine cycle efficiency caused by variations in condenser vacuum. However, these reactor power level variations are slight and are limited by the reactor regulating system. Each occurrence that leads to a loss of function of the condenser is accompanied by a loss of condenser vacuum, which is analyzed in section 15.2.

The operating chemistry limits for condensate and feedwater are discussed in section 10.3.5. Excessive leakage of coolant from the circulating water system into the condensate causes the condensate demineralizer to be placed in service. This system is also used to maintain water chemistry during startup, shutdown, and other conditions requiring the polishing of the condensate to maintain the required chemistry. The secondary chemistry control system, which controls and monitors the condensate chemistry, is discussed in subsection 10.4.6.

10.4.1.3 Safety Evaluation

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

10.4.1.4 Tests and Inspections

Acceptance testing of the main condenser will be performed in accordance with section 14.2.

The condenser shells, hotwells, and waterboxes are provided with access openings to permit inspection and/or repairs.

During unit outages, the condenser shells can be completely filled with water and tested by the fluorescent tracer method for leaks in accordance with ASME Power Test Code 19.21, before returning the condenser to operation.

10.4.1.5 Instrument Application

Hotwell level and pressure indications are provided locally and associated alarms are provided in the control room for each condenser shell. The condenser hotwell in each shell contains conductivity cells to provide a means of detecting and locating condenser tube leaks. Rejection of hotwell condensate to the condensate tank is blocked automatically upon an indication of high hotwell cation conductivity. This feature prevents transfer of impurities into the condensate tank in the event of a condenser tube leakage. The condensate level in the main condenser hotwell is maintained within proper limits by automatically transferring condensate to or from the condensate tank. Condensate temperature is measured in the suction lines of the condensate pumps. Turbine exhaust hood temperature is monitored and automatically controlled by use of the water sprays. A high condenser backpressure alarm also is provided.

Turbine trip is activated on loss of main condenser vacuum when condenser pressure reaches or exceeds the setpoint. Monitoring of circulating water temperature, pressure, and differential pressure from waterbox to waterbox is provided.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The main condenser evacuation system for PVNGS is the condenser air removal system (CARS) which establishes and maintains vacuum in the shell side of the condenser and provides for continuous removal of air and noncondensable gases from the condenser during normal power operation and plant startup.

10.4.2.1 Design Bases

10.4.2.1.1 Safety Design Bases

The CARS has no safety function.

10.4.2.1.2 Power Generation Design Bases

Applicable power generation design bases are as follows:

A. Power Generation Design Basis One

The CARS is designed to remove air and noncondensable gases from the condenser and turbine gland sealing system and exhaust them to the atmosphere via the plant vent or through the effluent filtration system to atmosphere via the plant vent when radioactivity is detected.

B. Power Generation Design Basis Two

The CARS establishes and maintains vacuum in the condenser during startup and normal operation.

10.4.2.1.3 Codes and Standards

The CARS is designed in accordance with the codes and standards identified in table 3.2-1.

10.4.2.2 System Description

The CARS, shown schematically in engineering drawings 01, 02, 03-M-ARP-001, consists of four two-stage mechanical vacuum pumps, a moisture separator, post-filter, charcoal bed adsorber, blower, and associated valves and piping. The design parameters of the system are shown in table 10.4-2.

Operation of the vacuum pumps is initiated from the main control room. These pumps establish a vacuum of approximately 5 inches Hg abs, prior to buildup of steam generator pressure during plant startup.

During normal plant operation, three mechanical vacuum pumps evacuate air and noncondensables from the condenser.

Noncondensable gases, air, and water vapor are drawn from the three condenser shells to the vacuum pumps. The air and noncondensables from the vacuum pumps are directed to the filtration system whenever radioactivity is detected and prior to discharge to the plant vent stack.

Table 10.4-2

CONDENSER AIR REMOVAL AND TREATMENT SYSTEM

DESIGN DATA

Design Factor	Value
Vacuum pumps	
Design air removal capacity, std ft^3/min	180
Number	4
Capacity, each pump, std ft^3/min	60
High efficiency particulate air filters	
Number	1
Design Noncondensable gas flow, std ft^3/min[a]	1,664
Charcoal bed adsorber	
Number	1
Vessel material	Carbon Steel
Bed depth, in.	2
Design temperature, °F	165
Design Noncondensable gas flow, std ft^3/min[a]	1,664

a. Includes noncondensable gas flow from turbine gland steam seal exhausters.

b. All values shown in the table that have units of std ft^3/min are based on standard temperature and pressure conditions of 60°F and 14.7 psia, respectively.

If the steam generators develop a primary to secondary leak, the CARS effluents will contain radioactive nuclides. A radiological evaluation of the discharge from the CARS and the basis for this evaluation are discussed in section 11.3. The average and maximum steam generator tube leaks are given in section 11.1. The CARS effluents, after passing through the moisture separators, are treated in the effluent treatment system. The post-filter removes particulate radioactivity.

The charcoal adsorber removes iodine. Effluents from the treatment system are monitored for radioactivity by plant vent monitors before being released to the atmosphere via the plant vent stack. The effluent treatment system also treats effluent from the turbine gland sealing system (TGSS).

As long as the CARS is functional, its operation does not affect the RCS. Should the CARS fail completely, a gradual reduction in condenser vacuum would result from the buildup of noncondensable gases. The reduction in vacuum would cause a lowering of turbine cycle efficiency that requires an increase in reactor power to maintain the demanded electric power generation level. The reactor power is limited by the reactor regulating system as described in section 7.7. If the CARS remains inoperable, condenser vacuum decreases to the turbine trip setpoint and a turbine trip is initiated. Loss of condenser vacuum is discussed in section 15.2.

10.4.2.3 Safety Evaluation

The CARS has no safety function.

10.4.2.4 Tests and Inspections

Tests and inspections of the equipment and piping are performed in accordance with applicable codes and standards prior to operation. CARS standby equipment is cycled periodically to ensure availability. Periodic inservice tests and inspections of the CARS are performed in conjunction with the scheduled maintenance outages.

10.4.2.5 Instrumentation Applications

Radioactivity of the effluent from the CARS is indicated and monitored in the main control room. In addition, high activity levels are alarmed.

10.4.3 TURBINE GLAND SEALING SYSTEM

The TGSS prevents air leakage into and steam leakage out of the main turbine and feedwater pump turbines.

10.4.3.1 Design Bases

10.4.3.1.1 Safety Design Bases

The TGSS has no safety function.

10.4.3.1.2 Power Generation Design Bases

Power generation design bases applicable to this system are as follows:

A. Power Generation Design Basis One

The TGSS prevents air leakage into, and steam leakage out of, the turbine through the turbine shaft glands and through various steam valve stems.

B. Power Generation Design Basis Two

The TGSS returns the air-steam mixture to the turbine gland steam packing exhauster (GSC), condenses the steam, returns the drains to the main condenser, and exhausts the noncondensable gases to the atmosphere, via the effluent filtration system whenever radio-activity is detected.

10.4.3.1.3 Codes and Standards

The TGSS is designed in accordance with the applicable codes and standards identified in table 3.2-1.

10.4.3.2 System Description

The TGSS, shown schematically in engineering drawings 01, 02, 03-M-GSP-001, consists of steam seal supply and exhaust headers, gland steam regulators (GSRs), gland steam packing exhauster, steam packing exhauster drain tank, and the associated piping and valves. For the system to function satisfactorily from startup to full load, a fixed positive pressure in the steam seal supply header and a fixed vacuum in the outer ends of all the turbine glands (refer to table 10.4-3) must be maintained at all loads.

On cold startup of the steam generators or during emergencies when the normal steam supply is not available, sealing steam is provided by the auxiliary boiler. The steam discharge ends of all glands are routed to the GSC that is maintained at a slight vacuum by the redundant motor-driven blowers. The GSC is a shell and tube heat exchanger. Water supplied from the turbine cooling water system is used to condense the steam from the mixture of air and steam drawn from the shaft packings. Drains from the GSC are returned to the main condenser, and the noncondensables are discharged to the atmosphere via the effluent filtration system of the MCES.

PVNGS operates with Auxiliary Steam as the preferred source to provide added protection to the main condenser in case of a main steam isolation signal. As the turbine is brought up to load, steam leakage from the high-pressure packings enters the steam-seal header becoming a steam source to the gland steam header. At higher loads, when more steam is leaking from the HP packings than is required by vacuum packings, the excess steam is discharged to the main condenser.

Table 10.4-3

TURBINE GLAND SEALING SYSTEM

Design Data	Value
Pressure in steam-seal header, psig	3 to 5
Vacuum in gland steam packing exhauster, in.WG	10 to 20
Number of gland steam packing exhausters	1
Number of blowers mounted on gland steam packing exhausters	2

In case of a malfunction of the GSR, a motor-operated bypass valve is opened and manually controlled to maintain steam-seal header pressure. Vacuum in the GSC can be maintained with one or both blowers in operation. Loss of both blowers may cause sufficient steam to blow through the seals into the turbine area and thus necessitate shutdown of the turbine. The radiological evaluation for the turbine gland sealing system is included in section 11.3. Relief valves on the steam-seal header prevent excessive steam seal pressure. The valves are vented to atmosphere. The potential effects of high-energy pipe breaks are covered in section 3.6.

10.4.3.3 Safety Evaluation

The TGSS has no safety function.

10.4.3.4 Tests and Inspection

Tests and inspection on the TGSS equipment are performed in accordance with applicable codes and standards.

10.4.3.5 Instrumentation Applications

Local and control room displays consist of indicating and alarm devices of steam seal header pressure, temperature, and flow.

10.4.4 TURBINE BYPASS SYSTEM

The turbine bypass system removes heat from the NSSS and transfers it to the condenser or atmosphere following load rejections and during plant cooldown, plant startup, and hot standby.

For a discussion of environmental conditions for equipment qualification, refer to section 3.11.

10.4.4.1 Design Bases

10.4.4.1.1 Safety Design Bases

The turbine bypass system has no safety function.

10.4.4.1.2 Power Generation Design Bases

Power generation design bases applicable to the turbine bypass system are as follows:

A. Power Generation Design Basis One

   Operate in conjunction with the reactor power cutback system (refer to CESSAR Section 7.7.l.l.6) to prevent reactor trip or opening of the pressurizer or main steam safety valves following load rejections provided the condenser is available.

B. Power Generation Design Basis Two

Remove heat from the NSSS and reject it to the condenser or atmosphere during plant cooldown, plant startup, and hot standby conditions.

C. Power Generation Design Basis Three

Control NSSS thermal conditions to prevent the opening of safety valves following a unit trip.

D. Power Generation Design Basis Four

Control NSSS thermal conditions when it is desirable to have reactor power greater than turbine power, e.g., during turbine synchronization.

E. Power Generation Design Basis Five

Provide pressure-limiting control during the loss of one out of two feedwater pumps.

F. Power Generation Design Basis Six

Provide a CEA automatic motion inhibit (AMI) signal when turbine power and reactor power fall below selected thresholds; provide AMI signal below 15% reactor power to block automatic control of the reactor below this power level.

G. Power Generation Design Basis Seven

Provide a means for manual control of RCS temperature during NSSS heatup or cooldown.

H. Power Generation Design Basis Eight

Provide for operation of the turbine bypass valves in a manner that minimizes valve wear and maintains controllability.

I. Power Generation Design Basis Nine

Provide for the operation of the turbine bypass valves in a manner to maximize thermal efficiency of the condenser.

J. Power Generation Design Basis Ten

Include redundancy in the design so that neither a single component failure nor a single operator error result in excess steam releases.

K. Power Generation Design Basis Eleven

Provide a condenser interlock which will block turbine bypass flow when unit condenser pressure exceeds a preset limit.

10.4.4.1.3 Codes and Standards

All components of the turbine bypass system are designed and constructed in accordance with the applicable codes and standards identified in section 3.2.

10.4.4.2 System Description

The turbine bypass system is shown schematically in figure 10.4-1.

The turbine bypass system consists of eight air-operated globe valves and associated instruments and controls. These valves branch from each main steam line downstream of the main steam isolation valve.

Six of these valves direct steam to the condenser and the remaining two vent directly to the atmosphere.

The valves are designed to quick open within approximately 1 second and quick close within approximately 5 seconds or modulate full open or closed within approximately 15 seconds. The valves are equipped with remote-operated handwheels to permit manual operation at the valve location.

The two valves which exhaust to the atmosphere are the last to open and the first to close during load rejections, thus minimizing the quantity of steam discharged to the environment. The valves and piping for the system are located in the turbine building.

The valves in the turbine bypass system are designed to fail closed to prevent uncontrolled bypass of steam. Should the bypass valves fail to open on command, the main steam safety valves provide main steam line overpressure protection, and the power-operated atmospheric dump valves provide a means for controlled cooldown of the reactor. The main steam safety valves and power-operated atmospheric dump valves are described in paragraph 10.3.2.2.

In the event of a turbine trip, the amounts of radioactivity released and the resultant offsite doses are those stated in section 15.2. The main steam safety valves and power-operated atmospheric dump valves are used to control the load transient, if the bypass valves are disabled. Because the ASME Code safety valves provide the ultimate overpressure protection for the steam generators, the turbine bypass system is defined as a control system and is designed without consideration for the special requirements applicable to protection systems. Failure of this system will have no detrimental effects on the RCS.

The turbine bypass system removes heat from the NSSS following load rejections and during startup, plant cooldowns, and hot standby. The system removes heat by modulating bypass steam flow. The modulation of the bypass steam is performed by the turbine bypass valves, which receive signals from the steam bypass control system. Refer to section 7.7 for a discussion of the steam bypass control system.

The turbine bypass system provides a design steam dump capacity of at least 55% of the rated main steam flow. This amount of bypass steam capacity in conjunction with the reactor power cutback feature of the steam bypass control system will dissipate enough energy from the NSSS to permit load rejection of any magnitude without lifting the main steam or pressurizer safety valves or tripping the reactor provided the condenser remains available. The effects of postulated system piping failure on safety-related equipment are given in section 3.6.

10.4.4.3 Tests and Inspections

A. Prior to initial operation, the complete turbine bypass system receives a field hydrostatic test and inspection in accordance with ANSI B31.1.

B. The turbine bypass system is tested under the requirements of the preventative maintenance program on a minimum frequency of every 18 months.

10.4.4.4 Instrumentation Applications

The control system for the turbine bypass system is discussed in CESSAR Section 7.7.

10.4.4.5 CESSAR Interface Requirements

Refer to subsection 5.1.4.

10.4.4.6 CESSAR Interface Evaluation

Refer to subsection 5.1.5.

10.4.5 CIRCULATING WATER SYSTEM

The circulating water system (CWS) removes heat from the main condensers and rejects it to the atmosphere using the plant cooling towers.

10.4.5.1 Design Bases

10.4.5.1.1 Safety Design Bases

The CWS has no safety function.

10.4.5.1.2 Power Generation Design Bases

The power generation design bases are as follows:

A. Power Generation Design Basis One

The circulating water receives the heat rejected by the turbine cycle.

B. Power Generation Design Basis Two

The plant cooling towers in the CWS dissipate waste heat from the turbine thermal cycle and from the plant cooling water system. The plant cooling water system is discussed in subsection 9.2.10.

10.4.5.1.3 Codes and Standards

The CWS is designed in accordance with codes and standards specified in table 3.2-1.

10.4.5.2 System Description

The CWS consists of the main condenser, cooling towers, circulating water pumps, a chemical injection system, and a makeup and blowdown system. The CWS is shown schematically in engineering drawings 01, 02, 03-M-CWP-001. Table 10.4-4 lists design data of the major components in the system.

The circulating water pumps are motor-driven, vertical, wetpit type, each rated at 25% capacity. The total design flow rate is 560,000 gallons per minute. These pumps take suction from the intake structure of the CWS and pump the circulating water through the main condensers. The CWS cooling water is returned from the main condensers through a common line to the cooling towers. The system is designed with cross-connected discharge piping from the circulating water pumps. The pump discharge lines are equipped with butterfly valves that permit any circulating water pump to be isolated individually.

Each circulating water path is provided with a butterfly valve at the low-pressure shell inlet and at the high-pressure shell outlet. In case of a condenser tube leak in any water box, the system will remain operable at reduced capacity.

The main condenser is discussed in subsection 10.4.1.

The cooling towers are designed for an ambient wet bulb temperature that will not be exceeded more than 5% of the time during the year. The design cooling range, design approach to ambient wet bulb temperature, and the unit data of the towers are shown in table 10.4-4.

In the event of flooding due to a failure in the portion of the circulating water system in the yard area (such as cooling towers, intake structure, buried pipe), the yard is graded in a direction to provide drainage of the water away from the power block and spray ponds. Therefore, the safe shutdown capability will not be compromised by flooding of the yard area.

A postulated failure in the circulating water system in the turbine building would flood the turbine building floor. The water would flow out of the building doors and side panels. The condenser area sumps and the oily waste sump would be filled to overflowing, but they are not safety-related. The condensate demineralizer sump, which is a sealed sump, would not be affected.

Assuming that 684,000 gallons per minute are available at the riser butterfly valve and considering the closing characteristics of the valve, it has been determined that 520,200 gallons would escape through the rupture with a valve closing time of 60 seconds. This amount of water would tend to flood the turbine building floor; however, as previously stated, the water would flow out of and away from the building. There are no passageways, pipe chases, cableways, or any other flow paths joining the turbine building floor. There are no essential electrical systems in the turbine building floor. These conclusions are based on the following conditions:

A. Low-pressure alarms in the circulating pumps discharge line will alert the operators.

B. Each pump is capable of delivering 171,000 gallons per minute at maximum runout conditions.

C. The circulating water line crosstie is initially open.

D. Valve closing time is 60 seconds.

Table 10.4-4
CIRCULATING WATER SYSTEM DESIGN DATA FOR ONE TURBINE UNIT

Design Factor	Values
Circulating water pumps	
Number	4
Type	Vertical, wet-pit
Capacity each, gal/min	140,000
Head, ft (TDH)	103
Cooling tower	
Number	3 Round, mechanical draft
Design ambient temperatures	
Wet bulb temperature, °F	75
Dry bulb temperature, °F	116
Design range, °F	31.5
Design approach, °F	12.3
Unit tower data, VWO	
Makeup flow, gal/min	19,651
Blowdown flow, gal/min	1,284
Evaporation, gal/min	18,341
Drift, gal/min	26
Cooling tower circulating water flow, gal/min	587,000
Total turbine plant heat load, Btu/h	9.1×10^9
Chlorination facilities	
Chlorine injection rate (yearly average), lb/d	3,490 average

It is estimated that the operator action time to shut the valves and stop the circulating water pumps would be 20 seconds based on multiple indications of low circulating water pump discharge pressure and high condenser pressure. At 80 seconds, 748,200 gallons of water would have escaped. If the operator should fail to act, then the water would continue to flow out of the turbine building through doors and sidings at grade level 100 feet.

In the event of a failure of the circulating water system in the turbine building, at no time would the water enter the auxiliary building, control building, main steam support structure, or diesel generator building. Finish grade of 0.5% is established to permit flood water from a break in the circulating water system to spread and flow away from safety-related structures (reference Bechtel drawings 01-C-ZVC-400 through 01-C-ZVC-407). This flow pattern occurs whether the break is in the yard area or within the turbine building. The at-grade door sills in the auxiliary building and main steam support structure (MSSS) are sufficiently above expected water levels resulting from any postulated flooding source. An opening in the MSSS at the 81-foot elevation (a stairwell from the roof of the condensate tunnel) will have a waterproof door installed.

A makeup system is provided to replace water losses due to evaporation, blowdown, and drift from the unit cooling towers. Makeup water for the CWS is pumped from the water storage reservoirs to the CWS pump intake structure as required. Plant water requirements are covered in paragraph 2.4.11.5.

Salinity buildup in the CWS is controlled by blowing down to the evaporation ponds. Blowdown is taken from the circulating water system condenser discharge. Periodic samples are analyzed for dissolved solids, pH, temperature, and radioactivity.

The CWS is designed to prevent any injection of radioactive material into the circulating water. Circulating water passing through the main condenser is at a higher pressure than the steam on the condensing side. Therefore, any leakage, such as from the main condenser tubes, will be from the circulating water into the shell side of the main condenser.

Chemical injection systems add chlorine as sodium hypochlorite, sulfuric acid, and dispersant. The hypochlorite is used to control biological growth and the sulfuric acid adjusts pH in order to minimize corrosion and scaling from calcium carbonate. A flow diagram of the chemical injection system is shown in engineering drawings 01, 02, 03-M-CWP-001.

Sodium hypochlorite is received into storage from a chemical production system for chlorination. Upon initiation of a timed cycle, hypochlorite is fed to each unit CWS for biological control. The hypochlorite system serves all units, and includes, at each unit, adjustable program control with a residual chlorine analyzer.

In addition to chlorination, a non-oxidizing biocide is used for control of aerobic slime forming bacteria and anaerobic corrosive bacteria, which are relatively unaffected by chlorine alone. The biocide is one which will hydrolyze to less toxic components with time.

10.4.5.3 Tests and Inspections

All active components of the system are accessible for inspection during station operation. Performance, hydrostatic, and leakage tests are conducted on the CWS butterfly valves in accordance with applicable codes and standards.

10.4.5.4 Instrumentation Application

Temperature and pressure in the CWS lines are measured at the main condensers. In addition, level alarms are provided at the CWS pump intake structure and high discharge pressure is alarmed in the control room.

10.4.6 CONDENSATE CLEANUP SYSTEM

Condensate cleanup is performed by the secondary chemistry control system (SCCS) which is an integrated system comprised of the condensate demineralization and blowdown processing subsystem and the chemical monitoring and addition subsystem.

These two subsystems, operating concurrently, provide the capability to maintain the proper operating chemistry of the condensate feedwater and steam generator secondary side water. The SCCS is shown schematically in engineering drawings 01, 02, 03-M-SCP-002, -003, -001 and -004.

An interconnection exists between Secondary Chemistry (SC) and Auxiliary Steam (AS) condensate piping which permits the condensate cross connection header (APASNL107) to transfer warm (212 °F or less) condensate drained from the steam generators of a unit in operational mode 5 (when the primary system pressure is less than or equal to the secondary system pressure), mode 6, or defueled, to either or both of the other unit’s Chemical Waste Neutralization Tanks for disposal or processing. The following conditions and restrictions apply to the use of this interconnection.

1. The unit discharging secondary coolant is in either Mode 5 and the primary system pressure is less than or equal to the secondary system pressure, or Mode 6, or in a defueled operating condition.
2. The specific activity of the secondary coolant in both the discharging and the receiving units is less than or equal to PVNGS Technical Specification LCO 3.7.16.
3. Radiological surveys and controls of ASNL107 will be performed as directed by the Radiation Protection Program.
4. Prior to transferring water, radiological conditions in the secondary system will be evaluated to ensure the transfer will not have a significant impact on operations in the receiving unit.
5. ASNL107 should be flushed after the draining of the steam generators to minimize the potential build-up of non-soluble particulates in the line. The flush may be waived if an evaluation of the radiological conditions determines it is not required.
6. Administrative controls (such as procedures) shall be in place to isolated the flow in the event of a large leak or pipe rupture.
7. Since flow rate from this modification may approach TDS sump pump capacity, monitor the sump as needed to ensure that is does not overflow.

8. During Operational Modes 1 through 4, valves 13PSCNV955 and 13PSCNV956 are to be verified closed and locked if not in use.
9. After use of pipe 13PSCNL479 and closure of 13PSCNV955 and 13PSCNV956, 13PSCNL479 must be drained.

10.4.6.1 Design Bases

The condensate cleanup system has no safety function.

10.4.6.1.1 Condensate Demineralization and Blowdown Processing Design Bases

The following design bases apply to the condensate demineralization and blowdown processing subsystem:

A. Maintain the purity and chemistry of the condensate, feedwater, and steam generator secondary side water. When feeding the steam generators, the chemistry of the main feed train shall be in accordance with subsection 10.3.5.

B. Be capable of continuously purifying the full condensate flow. Full flow condensate demineralization systems shall be capable of continuous operation with 1 ppm total dissolved solids in the influent.

C. Continuously purify and recycle the steam generator blowdown. Blowdown flow for each steam generator may be used to maintain the steam generator chemistry within the limits outlined in subsection 10.3.5.

D. In order to minimize the consequences of a blowdown line rupture, each steam generator shall be equipped with an independent blowdown line.

10.4.6.1.2 Chemical Monitoring and Addition Design Bases

The following design bases apply to the chemical monitoring and addition subsystem:

A. Continuously monitor significant secondary side chemical parameters and alarm any fault conditions.

B. Continuously add volatile chemicals to the secondary side water to maintain pH and oxygen levels within the specified limits.

C. Inject boric acid into the secondary system as needed to mitigate denting and intergrannular attack/stress corrosion cracking (IGA/SCC) in the SGs.

D. Add chemicals to the feed train and steam generators prior to wet layup to minimize corrosion during long outages.

10.4.6.2 System Description and Operation

10.4.6.2.1 Condensate Demineralization

A full flow condensate demineralization subsystem capable of continuous service maintains feedwater purity during startup and periods of condenser leakage. In the condensate demineralizers, dissolved solids are removed by ion exchange, and suspended solids are removed by filtration.

The Condensate demineralization subsystem is comprised of six mixed bed ion exchangers in the hydrogen-hydroxide form. The demineralizers are normally in standby unless condenser leakage dictates that they be in service. If full flow service is needed, five of the demineralizers are required to be in service to support full power (approximately 26,000 gallons per minute), leaving one vessel in standby where it is available when one of the other beds becomes exhausted. This extra vessel allows the system to remain in continuous operation without reducing the process capability. The effluent from each condensate demineralizer is continuously monitored for conductivity and specific ions. This will assure that the quality of the effluent is within the specified limits for feedwater (subsection 10.3.5).

The condensate demineralizer subsystem is designed to have sufficient capacity to continuously process condensate contaminated by small condenser leaks, and will permit an orderly shutdown if a larger leak occurs. The size of the leak that is able to be tolerated will depend partly on the pH at which the secondary system is being maintained. It takes approximately 24 hours to perform a regeneration of both the cation and anion resin. The secondary pH may be lowered slightly to allow sufficient time to perform full regenerations if the condenser leakrate exceeds the capacity of the resin to maintain acceptable effluent chemistry.

The operation of the CDS during plant startup is described in paragraph 10.4.6.2.5.

In order to ensure that a condensate demineralizer is always on standby, and to minimize the possibility of introducing regenerant chemicals into the feed train, the exhausted resin from the condensate demineralizers is externally regenerated.

Resin regeneration is performed in one of the two modes:

- Full regeneration, including backwash, anion resin chemical regeneration, and cation resin chemical regeneration
- Partial regeneration, including backwash and cation resin chemical regeneration.

Wastes produced by resin regeneration are minimized by reusing those which are acceptably low in TDS. Low TDS rinse water is recycled to the condenser hotwell. Low TDS regenerant waste is recycled to the circulating water system for use in condenser cooling. Condensate polisher Pre-Service Rinse water can be diverted directly to the Retention Tank for ultimate onsite disposal. High TDS regenerant waste is unacceptable for reuse and is processed through the chemical waste system. From here the waste is sent either to the retention tank for ultimate onsite disposal or, if radioactivity exceeds the release limits stated in the Offsite Dose Calculation Manual (ODCM), to the liquid radwaste system for further processing and eventual recycle.

10.4.6.2.2 Steam Generator Blowdown Processing

Steam generator blowdown controls the concentration of impurities in the steam generator secondary side water. Each steam generator will be equipped with its own blowdown processing line with the capability of blowing down either the primary inlet or primary outlet regions of the steam generator. In addition to a hot leg blowdown line, the steam generators are also equipped with a blowdown line that allows blowdown from the downcomer region, and an additional downcomber blowdown line.

The blowdown will be directed into a flash tank operating at 225 psig where the flashed steam is returned to the cycle via the heater drain tanks. The liquid portion then flows to a heat exchanger where it is cooled by condensate to 140F (Blowdown Demineralizer in use) or 165F (Blowdown Demineralizer bypassed). It is then directed through a blowdown filter where the major portion of the suspended solids are removed. It can also be directed to the retention tank for ultimate onsite disposal. After filtration, the blowdown fluid is processed by the blowdown demineralizer or directed straight to the condenser hotwell (Blowdown Demineralizer bypassed).

In the event of malfunction of the blowdown processing equipment, the flow can be directed to the condenser, thus maintaining the steam generator chemistry. During this mode of operation, the condensate polishing demineralizers would be placed in service.

10.4.6.2.3 Chemical Monitoring

The chemical monitoring subsystem is designed to provide continuous indication of significant chemical parameters in the secondary system and to alert the operator of faulty chemistry or equipment malfunction. Continuous online samples are taken from each section of the main condenser, the condensate demineralizer system inlet and outlet, the main feed lines, and the steam generator blowdown lines or downcomer sample, feedwater lines, and circulating water lines.

Samples taken from each section of the main condenser are analyzed for sodium ion concentration and intensified conductivity. Besides providing indications of condenser tube leakage, these monitors can be used in locating the section of the condenser that is leaking.

Upon indication of a condenser tube leak by the sampling system, the condensate polishing demineralizer may be placed into service and the polishing demineralizer bypass valve closed. The condensate polishers will handle a maximum circulating water inleakage of 1 gallon per minute on a continuous basis. If this leakage is exceeded, the affected condenser hotwell half may be isolated by motor-operated valves in the condensate pump suction and discharge lines. The remaining condenser hotwell storage and the makeup rate will provide enough condensate for reduction to 50% power by utilizing a 10% step and then a 5% per minute ramp down to a 50% power level. The respective circulating water path is isolated and the condenser half is drained. The leaking tubes can be plugged and the contaminated hotwell can be pumped out by one condensate pump to the condenser circulating water outlet.

Leakage from the condensate demineralizers will allow contaminants to enter the steam generators (SGs). To detect for this possibility, the condensate demineralizers' influent and effluent will be monitored. Sodium, specific conductivity, cation conductivity, sulfates, and chlorides will be measured on the demineralizer effluent.

Hydrazine monitors are used to measure the hydrazine content in the main feed lines.

The main feed lines will be analyzed for pH, and samples taken from the steam generator blowdown lines are monitored for pH, conductivity, and radiation. Continuous pH measurements will ensure that the specified alkaline conditions exist in the system. This will ensure an alkaline environment which minimizes corrosion. Conductivity measurements on the steam generator blowdown will verify that dissolved solids are not concentrating in the steam generators. A steam generator sample is measured for radioactivity in order to detect primary to secondary leakage.

10.4.6.2.4 Chemical Addition

The function of the chemical addition subsystem is to establish and maintain the proper chemistry within the condensate, feedwater, and steam generator secondary side water. During normal operation, volatile chemicals are added to the feed train downstream of the condensate demineralizers. These additives serve to control the pH, establish a reducing environment, and to scavenge any dissolved oxygen. In addition, the chemical addition subsystem is also used to provide the proper chemical environment during wet layup.

Since these additives are volatile, they will not concentrate in the steam generators. This characteristic is desirable for several reasons. First, the concentration of solids in the steam generators will be minimized. This will lessen the dangers associated with solids attack of Inconel 690. In addition, the volatile nature of these additives will allow for some corrosion protection throughout the steam system. This is especially important in protecting the large metal surface areas of the feedwater heater shells.

A pH controlling additive, usually ammonia, is used to raise the feedwater pH to within normal limits. This pH range is effective in slowing the corrosion rate of carbon steel.

Continuous ammonia additions are required during operations because the volatile ammonia will be scrubbed from the condensing steam in the air removal section of the main condenser or be removed by the condensate demineralizers if it redissolves in the condensate.

An inventory of a reducing agent/oxygen scavenger, usually hydrazine, is maintained in the feed train as a means of scavenging dissolved oxygen and to ensure a reducing environment is maintained in the steam generators. Hydrazine also contributes to the formation of an adherent metal oxide film on system surfaces that reduces corrosion product release. Ammonia is a by-product of Hydrazine once it volatilizes.

Boric acid, a non-volatile chemical, may be injected into the secondary system for mitigating denting and Intergranular Attack/Stress Corrosion Cracking (IGA/SCC) in the steam generator. Boric acid reduces pH in the steam generator crevices by reacting with sodium hydroxide (NaOH) to form a borate complex. Also, boric acid dilutes the hydroxide (OH^-) concentration, thereby lowering the chemical activity and reducing the probability that OH^- is present at the actively corroding grain boundary of the steam generator crevices. The small affect that boric acid has on lowering the secondary plant pH can be offset by increasing the pH controlling chemical additive.

Chemical additions necessary for wet layup will be accomplished through the use of the auxiliary feedwater system. The chemical additions will be made at the suction of the non-Seismic Category I auxiliary feed pump. This will ensure that each steam generator receives adequate protection during long outages.

Chemical additions are typically made by metering pumps, two high-pressure and four low-pressure. The high-pressure pumps inject into the steam generator main feedwater, one pump taking hydrazine from the two hydrazine tanks and the other taking ammonia from the two ammonia tanks. The low-pressure pumps inject hydrazine and ammonia to the demineralized condensate, blowdown condensate, or auxiliary feedwater. The low-pressure pumps are duplicated.

10.4.6.2.5 System Operation During Plant Startup

While the secondary plant is in a cold shutdown condition, it is possible for air to enter the system. Use of nitrogen blankets and a reducing agent/oxygen scavenger, such as hydrazine will minimize, but not eliminate, the corrosion of metal surfaces. This corrosion results in loose oxide layers being formed on the surfaces of the feed train. Before returning to power, it is necessary to reduce the concentration of the reducing agent/oxygen scavenger in the secondary system, remove the corrosion products generated during layup, and reduce the dissolved oxygen concentration to within the normal operating specifications.

Reduction in the reducing agent/oxygen scavenger concentration is accomplished by draining the steam generators and refilling them with auxiliary feedwater containing the correct hydrazine concentration. In addition, the draining of the steam generators serves to remove any suspended solids which might be present in the generators.

Once the steam generators have been refilled with water, the primary plant temperature will be raised and the steam generators warmed up.

Next, feed train recirculation is started by initiating flow through the presteam generator cleanup line.

The concentration of suspended solids is reduced by draining a portion of the circulating flow prior to entering the hotwell or by circulating through the condensate demineralizers. Make-up at a rate of approximately 500 gallons per minute is supplied from the condensate storage tank.

Oxygen will be removed from the recirculating feedwater by using the vacuum that has been established in the main condenser. Since the feedwater has been heated to 175F, a condenser vacuum to 6 inches of Hg (abs) is sufficient to remove dissolved oxygen from the feedwater.

Once main feed has been initiated, the reactor power can be increased.

10.4.6.3 Safety Evaluation

The secondary chemistry control system serves no safety-related functions. Therefore, no safety evaluation is performed.

Each of the steam generator blowdown lines is equipped with two remotely operated containment isolation valves that automatically close on a main steam isolation signal (MSIS), auxiliary feedwater actuation signal (AFAS), or safety injection actuation signal (SIAS).

The sample lines from the steam generator blowdown lines are each equipped with two remotely operated containment isolation valves which automatically close on an AFAS, MSIS, or SIAS.

10.4.6.4 Tests and Inspections

Preoperational testing will include a test of the system instrumentation. Automatic control features will be tested to ensure proper operation. Piping, valves, and components will be checked for proper installation. Pumps will be tested for head and capacity. Valves will be operated and checked for function. The system will be operated automatically to ensure that the system will function as designed. Heat exchangers will be checked for proper performance and flow rates adjusted where necessary to establish proper conditions.

During normal plant operations, testing, inspection, and calibration will be conducted on a regular schedule to ensure proper system operation. Data taken during operating periods will be used to evaluate the performance of the secondary chemistry control system.

10.4.6.5 Instrumentation Requirements

Flow and conductivity of the demineralized condensate are continuously recorded.

Local instrumentation is provided for the demineralizer regeneration system including temperature control of the dilute caustic and level control of acid and rinse tanks.

Conductivity of the demineralized condensate is recorded continuously. Local conductivity indication is provided for the resin regenerant solutions and rinses.

Local instrumentation is provided for the chemical addition and monitoring subsystem. The sampling instruments are protected from a high temperature sample by a bypass valve operated by a temperature controller.

10.4.7 CONDENSATE AND FEEDWATER SYSTEM

The condensate and feedwater system provides heated feedwater to the steam generators. The system has the capability of maintaining the proper feedwater inventory in the steam generator during startup and normal operation.

10.4.7.1 Design Bases

10.4.7.1.1 Safety Design Bases

Pertinent safety design bases are as follows:

A. Safety Design Basis One

The feedwater lines are designed so that failure in this piping will have minimal effects on the reactor coolant pressure boundary (RCPB).

B. Safety Design Basis Two

The feedwater lines are designed so that the failure of any feedwater supply piping will not prevent safe shutdown of the reactor.

C. Safety Design Basis Three

The containment feedwater isolation valves and piping from the valves to the steam generator nozzles are designed to withstand the effects of a safe shutdown earthquake (SSE).

D. Safety Design Basis Four

Components and piping shall be designed, protected from, or located to protect against the effects of high and moderate energy pipe rupture, whip, and jet impingement.

E. Safety Design Basis Five

This system will be designed such that adverse environmental conditions such as tornados, floods, and earthquakes will not impair its safety function.

F. Safety Design Basis Six

The loss of offsite power to the system will not prevent the safe shutdown of the reactor.

10.4.7.1.2 Power Generation Design Bases

Power generation design bases applicable to this system are as follows:

A. Power Generation Design Basis One

The condensate and feedwater system is designed to provide feedwater to the steam generator at the required temperature and pressure during all phases of operation.

B. Power Generation Design Basis Two

Extraction lines and feedwater heaters are designed to minimize the possibility of water slug induction to the main turbine and to limit main turbine overspeed due to entrained energy in the extraction system.

10.4.7.1.3 Codes and Standards

Components of the condensate and feedwater systems are designed and constructed in accordance with the applicable codes and standards identified in table 3.2-1.

10.4.7.2 System Description

The condensate and feedwater system is shown schematically on engineering drawings 01, 02, 03-M-CDP-001, -002, -003, -004 and 01, 02, 03-M-FWP-001. The condensate and feedwater system supplies the steam generators with heated feedwater in a closed steam cycle using regenerative feedwater heating. The main turbine cycle heat balance at guaranteed load is given in section 10.1. Extraction steam is covered in subsection 10.2.2.

The main condenser hotwells receive condensate makeup from the condensate tank. Refer to subsection 9.2.6 for a discussion of the condensate storage system.

The main portion of the feedwater flow is deaerated condensate pumped from the main condenser hotwells by the condensate pumps.

This stream passes in sequence through the condensate cleanup system; the three trains of low-pressure heaters, each train consisting of No. 1, No. 2, No. 3, and No. 4 low-pressure heaters; the steam generator feedwater pumps; the two trains of high-pressure heaters, each train consisting of No. 5, No. 6, and No. 7 high-pressure heaters; control and isolation valves; and on into the two steam generators of the NSSS. The balance of the feedwater flow is provided by the drains from the moisture separator reheaters and No. 7, No. 6, and No. 5 heaters that are collected into a drain tank and pumped into the feedwater pump suction stream by the heater drain pumps.

To allow feedwater and condensate system startup recirculation, a cleanup system called "long path recirculation" is provided. This system allows condensate from the hotwell to be pumped by a condensate pump through all major feedwater/condensate piping and components up to the economizer crosstie line. From this point the recirculation flow is returned to the hotwell. The system is sized to allow a flow velocity of up to 2 ft/sec in the largest portion of the main flow path, thereby ensuring shearing and entrainment of pipe scale and other system impurities. A drain connection is provided upstream of the return nozzle to the hotwell.

In addition to the long path recirculation system, a connection to the shell side of a low-pressure feedwater heater from the auxiliary boiler is provided. This connection is capable of admitting sufficient steam to raise the feedwater temperature to 175F.

Transients within the condensate and feedwater system that affect the final feedwater temperature or flow have a direct effect on the RCS. Occurrences that produce an increase in feedwater flow or a decrease in feedwater temperature result in excessive heat removal from the RCS, which is compensated for by control system action as described in section 7.7. These occurrences are considered in section 15.1 in conjunction with the failure of compensatory control actions, and are shown to be safely terminated by the reactor protective system. 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 system action is available to adjust feedwater flow and reactor power to prevent excess energy accumulation in the RCS, and the increasing reactor coolant temperature provides a negative reactivity feedback that tends to reduce reactor power. In the absence of control action, the high outlet temperature and high-pressure trips of the reactor protective system are available to assure reactor safety. Loss of all feedwater, the most severe transient of this type, is examined in section 15.2.

Nitrogen accumulators are provided on the feedwater control and isolation valves in the feedwater line to the steam generator downcomer nozzle. These accumulators allow the operator to remotely operate these valves without normal instrument air. In conjunction with the non-Seismic Category I auxiliary feedwater pump described in subsection 10.4.9, this provides a third flow path for auxiliary feedwater to the steam generators. This use of the non-essential AFS train is provided to improve the overall availability of the AFS system and is not required for Chapters 6 and 15 accident mitigation.

10.4.7.2.1 Component Description

Refer to table 10.4-5 for design data.

10.4.7.2.1.1 Condensate Pumps. The condensate pumps are motor-driven, of the vertical mixed-flow type, and operate in parallel. Valving is provided to allow removal of individual pumps and maintain system operability.

10.4.7.2.1.2 Condensate Cleanup System. Refer to subsection 10.4.6 for a discussion of the condensate cleanup system.

Table 10.4-5

MAIN FEEDWATER/CONDENSATE SYSTEM REQUIREMENTS
FOR MAJOR COMPONENTS DESIGN DATA

Equipment	Number	Capacity
Condensate pumps	3	50%
No. 1 to No. 4 feedwater heaters	4/train 3 trains	33%/train
Steam generator feedwater pumps	2	65%
No. 5, No. 6, and No. 7 HP feedwater heaters	3/train 2 trains	50%/train [(a)]
Heater drain tank	1/train 2 trains	50%/train
Heater drain pumps	1/train 2 trains	50%/train

a. Approximately 40%/train and 20% bypass in feedwater temperature reduction mode of full power operation.

10.4.7.2.1.3 Low-Pressure Feedwater Heaters. The low-pressure heaters are of the closed type and are installed in the main condenser necks. Low-pressure feedwater heaters have integral drain coolers. The No. 4 drains to No. 3 heater, No. 3 drains to No. 2, and No. 2 drains to No. 1 and from there to the main condenser. The condensate, after passing from the main condenser through the low-pressure heaters (three trains), is routed to a header and fed to the steam generator feedwater pumps.

Low-pressure feedwater heaters have main condenser drain lines to allow direct discharge to the main condenser.

10.4.7.2.1.4 Feedwater Pumps. The feedwater pumps operate in parallel and discharge to the high-pressure feedwater heaters. The pumps take suction from the No. 4 low-pressure feedwater heaters of the three parallel low-pressure heater trains and discharge through the two parallel trains of high-pressure feedwater heaters. Each pump is turbine-driven with independent variable speed control units. Steam for the turbines is supplied from the main steam header at low loads, and from the hot reheat line during normal operation.

Isolation valves are provided to allow each steam generator feedwater pump to be individually removed from service, while continuing operations at reduced capacity with the parallel pump.

10.4.7.2.1.5 High-Pressure Feedwater Heaters. The feedwater system contains two parallel trains of high-pressure feedwater heaters. High-pressure feedwater heaters Nos. 6 and 7 are provided with integral drain coolers. High-pressure heater No. 7 drains to high-pressure heater No. 6. High-pressure heaters Nos. 6 and 5 drain to the high-pressure heater train drain tank.

Isolation valves and bypasses are provided to allow each train of high-pressure heaters to be removed from service. System operability is maintained with the remaining train. The bypass line may also be used in conjunction with flow through both heater trains when operating the plant in the feedwater temperature reduction mode of full power operation.

Provisions are made in heater drain lines to allow direct discharge to the main condenser.

10.4.7.2.1.6 Heater Drain Tank. A single heater drain tank for each high-pressure heater train receives the drains from the shells of high-pressure feedwater heater Nos. 5 and 6 and moisture separator reheater drain tank and provides reservoir capacity for drain pumping into the feed pump suction header. Each high-pressure heater train drain tank is installed beneath the No. 5 feedwater heater so that high-pressure heaters drain freely. The drain level is maintained within the train drain tank by a level controller in conjunction with the heater drain pump discharge flow control valve.

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

10.4.7.2.1.7 Heater Drain Pumps. The high-pressure heater drain pumps operate in parallel, each taking suction from its high-pressure heater train drain tank and discharging to the suction header of the feedwater pumps. Each high-pressure heater drain tank pump is a motor-driven, multistage, centrifugal pump located below the heater drain tank and is designed for the available suction conditions.

10.4.7.2.1.8 Pump Recirculation Systems. Minimum flow control systems are provided to allow all pumps in the main condensate and feedwater trains to operate at a sufficient rate to prevent damage.

10.4.7.2.1.9 Containment Feedwater Line Isolation Valves. The containment feedwater isolation valves discussed in subsection 6.2.4 are designed to isolate the feedwater system from the steam generator in the event of a steam line break, feedwater line break, or loss-of-coolant accident (LOCA). This isolation precludes any possibility of radioactivity release from the containment due to a condensate or feedwater pipe break. The isolation valves in the feedwater line to the steam generator downcomer nozzle are provided with nitrogen accumulator to allow manual remote control with a loss of offsite power to supply auxiliary feedwater to the steam generators from the non-Seismic Category I auxiliary feedwater pump described in subsection 10.4.9. Note that the backup nitrogen accumulator for the feedwater control and isolation valves was not credited during a normal loss of offsite power event.

10.4.7.2.2 System Operation

10.4.7.2.2.1 Prestartup Feedwater Cleanup Procedure. The condensate pumps circulate condensate from the condenser hotwells, through the condensate cleanup system, through all feedwater heater trains through the recirculation valve, and back to the hotwell. This procedure is repeated until the condensate cleanup system has yielded feedwater quality equivalent to that specified in section 10.3.5.

10.4.7.2.2.2 Power Generation Operation. Feedwater is supplied to the steam generator from the steam generator feedwater pumps. Feedwater flow is controlled through the main feedwater control valves that establish steam generator feedwater balancing in conjunction with the variable speed feedwater pump turbine drives. The feedwater system may be operated either with the high pressure feedwater bypass valve open or closed in conjunction with both feedwater heater trains being in service. When the plant is operated at the licensed reactor power with the bypass valve closed, additional plant thermal efficiencies are achieved. When the plant is operated at the licensed reactor power with the bypass valve open in the feedwater temperature reduction mode, both plant thermal efficiencies and steam generator thermal stresses are reduced. Extended operation in either configuration is within the system and plant design and licensing basis.

10.4.7.3 Safety Evaluation

Safety evaluations, numbered to correspond to the safety design bases, are as follows:

A. Safety Evaluation One

The main feedwater lines are restrained or are separated to the extent necessary to prevent damage to the RCPB in the event of a feedwater pipe rupture. Refer to section 3.6 for additional discussion on this subject.

B. Safety Evaluation Two

Main feedwater lines are designed and routed so that a failure will not prevent a safe shutdown of the reactor. Refer to section 3.6 for information on this subject.

C. Safety Evaluation Three

The containment feedwater isolation valves and piping between them and the steam generators are designed to meet Seismic Category I criteria in accordance with requirements given in sections 3.7 and 3.9.

D. Safety Evaluation Four

Components and piping are designed to protect against the effects of high and moderate energy pipe rupture as discussed in section 3.6.

E. Safety Evaluation Five

Adverse environmental conditions do not impair the safety function of this system. Wind and tornado loadings are discussed in section 3.3. Flood design is covered in section 3.4. Seismic design is discussed in section 3.7.

F. Safety Evaluation Six

The loss of offsite power does not prevent the safe shutdown of the reactor as discussed in sections 7.4 and 8.3.

10.4.7.4 Tests and Inspections

ASME Code, Section III, Class 2, piping is inspected and tested in accordance with ASME Code, Sections III and XI and the ASME OM Code. ANSI B31.1.0 piping is inspected and tested in accordance with Paragraphs 136 and 137. ASME Code, Section III, Class 2, valves are periodically inservice-tested for exercising and leakage in accordance with ASME OM Code. Isolation valves, vent and drain valves, and test connections required in the system to effect these tests are included in engineering drawings 01, 02, 03-M-CDP-001, -002, -003, -004 and 01, 02, 03-M-FWP-001.

Each feedwater heater, heater drain tank, pump, and valve is shop-tested by hydrostatic pressure tests performed in accordance with applicable codes. Tube joints of feedwater heaters are shop leak-tested. Prior to initial operation, the completed condensate and feedwater system receives a field hydrostatic test and inspection in accordance with the applicable code. Periodic tests and inspections of the system are performed in conjunction with scheduled maintenance outages. In addition, PVNGS agrees to perform a steam generated feedwater water hammer test in accordance with NUREG/CR-1606. PVNGS will perform the test according to a standard operating procedure (SOP). PVNGS will run the plant at approximately 15% of full power by using feedwater through the downcomer nozzle. The feedwater will then be switched from the downcomer nozzle to the economizer nozzle and the following transient will be observed and recorded. Inservice inspections are not required unless there is an indication of malfunction somewhere in the system.

10.4.7.5 Instrumentation Applications

Feedwater flow control instrumentation measures the feedwater flowrate from the condensate and feedwater system. This flow measurement, transmitted to the feedwater control system, regulates the feedwater flow to the steam generators to meet system demands. Refer to section 7.7 for a description of the feedwater control system.

Instrumentation and controls are provided for regulating minimum pump flowrates for the condensate pumps, high-pressure heater drain pumps, and steam generator feedwater pumps.

Sampling means are provided for monitoring the quality of the final feedwater, as described in subsection 10.4.6.

In the feedwater heating portion of the system, temperature measurements are provided for each stage of heating. These measurements include the temperature into and out of each feedwater heater for the water side and out of each heater for the steam side of the system except that steam temperature is determined by its saturation pressure in feedwater heater Nos. 1, 2, 3, and 4. Steam pressure measurements are provided at each feedwater heater. Liquid pressure measurements are provided at appropriate locations throughout the system.

Instrumentation and controls are provided to maintain the proper condensate level in the feedwater heater or heater drain tank. High level alarm and automatic dump action on high level also are provided.

Appropriate instrumentation displays and alarms are provided in the control room.

10.4.8 STEAM GENERATOR BLOWDOWN SYSTEM

The steam generator blowdown system is an integral part of the secondary chemistry control system of the condensate cleanup system, and is discussed in subsection 10.4.6.

10.4.8.1 CESSAR Interface Requirements

Refer to subsection 5.1.4.

10.4.8.2 CESSAR Interface Evaluations

Refer to subsection 5.1.5.

10.4.9 AUXILIARY FEEDWATER SYSTEM

The auxiliary feedwater system (AFS) is designed to provide steam generator feedwater during startup, hot standby, normal shutdown, and emergency conditions.

The AFS reliability analysis (formally appendix 10B) has been archived as historical information only in PVNGS engineering calculation 13-NC-AF-200, "Auxiliary Feedwater System (AFS) Reliability Analysis." Refer to appendix 5A, Question 5A.17, for additional discussion.

10.4.9.1 Design Bases

10.4.9.1.1 Safety Design Bases

The following safety design bases are applicable to the essential portions of the AFS only:

A. Safety Design Basis One

The AFS shall provide feedwater for the removal of decay heat from the RCS following reactor shutdown from any power level until such time as cooling by the shutdown cooling system may be initiated.

B. Safety Design Basis Two

One motor-driven AFS pump and one steam turbine-driven AFS pump and associated valves and piping shall be designed to Seismic Category I requirements. In addition, the isolation valves and piping connections to this Seismic Category I piping shall be designed to Seismic Category I requirements.

C. Safety Design Basis Three

The turbine-driven Seismic Category I AFS pump shall be available in the event of a loss of all ac power.

D. Safety Design Basis Four

The Seismic Category I motor-driven AFS pump and its associated power-operated valves shall be connected to one onsite (diesel generator) power bus as discussed in subsection 8.3.1. In addition, the turbine-driven AFS pump's turbine control system and its associated power-driven valves are connected to the dc power system as discussed in subsection 8.3.2.

E. Safety Design Basis Five

Redundancy shall be provided throughout the AFS and supporting systems to ensure the supply of feedwater to either or both steam generators in the event of an accident plus one active failure.

F. Safety Design Basis Six

The AFS shall be designed to maintain water level in the steam generators under the following operating modes and accident conditions:

1. Reactor coolant system cooldown at a maximum rate of 75F per hour from hot standby to a temperature of 350F with a loss of offsite power and normal onsite power.
2. Hot standby for 8 hours with a loss of offsite power and normal onsite power.
3. Reactor coolant system cooldown using the intact steam generator following a main steam line break

or main feedwater line break inside the containment with a loss of offsite power and normal onsite power.

G. Safety Design Basis Seven

Each of the two Seismic Category I AFS pumps shall be designed to provide 100% of the required flow (see Table 10.4-6) for decay heat removal. The head generated by each pump is sufficient to deliver feedwater into the steam generators at 1270 psia or equivalent at the entrance of the steam generators.

H. Safety Design Basis Eight

In the unlikely event that the control room must be evacuated, the AFS shall be capable of being operated for shutdown from a remote shutdown station.

I. Safety Design Basis Nine

The Seismic Category I, motor-driven AFS pump shall be located in a separate room designed to Seismic Category I requirements in the main steam support structure. The Seismic Category I, steam turbine-driven AFS pump shall also be located in a separate room designed to Seismic Category I requirements in the main steam support structure.

J. Safety Design Basis Ten

The components, including piping for each AFS pump safety train, shall be separated from each other and are either enclosed by a Seismic Category I structure or installed underground.

K. Safety Design Basis Eleven

The combination of motor-driven and steam turbine-driven pumps shall provide diversity of power sources to assure delivery of feedwater under an emergency condition.

L. Safety Design Basis Twelve

All components and piping shall be designed, protected from, or located to protect against the effects of high and moderate energy pipe rupture, pipe whip, and jet impingement.

M. Safety Design Basis Thirteen

This system shall be designed such that adverse environmental conditions such as tornados, floods, and earthquakes will not impair its safety function.

10.4.9.1.2 Power Generation Design Basis

The non-Seismic Category I, motor-driven AFS pump is used as the feedwater pump during startup, hot standby, and normal shutdown conditions.

10.4.9.1.3 CESSAR Interface Requirements

Refer to subsection 5.1.4.

10.4.9.1.4 CESSAR Interface Evaluation

Refer to subsection 5.1.5.

10.4.9.1.5 Codes and Standards

The AFS is designed to codes and standards identified in table 3.2-1.

10.4.9.1.6 Reliability/Availability Bases

The bases contained within this section represent the major design features of the non-essential AFS train which were added to improve the original AFS design from a reliability/availability perspective or are major assumptions which have been credited in performing risk related analyses for PVNGS. These bases reflect the most relevant features of the non-essential AFS train design from a reliability/availability perspective and are not intended to be all encompassing. The PVNGS Individual Plant Examination (IPE) provides a complete description of the reliability/availability assessments that were completed for the AFS. The following bases are only applicable to the non-essential AFS trains:

A. Reliability/Availability Bases One

The non-essential AFS train is not required to perform a safety function for the mitigation of the design basis accidents presented in Chapters 6 and 15. The emergency operating procedures provide instructions for using the non-essential AFS train, if available, in addition to the essential AFS trains as a defense-in-depth measure that assists in mitigating plant events. The non-essential AFS train is not required to mitigate accidents, but provides additional reliability/availability to the AFS. Risk related analyses shall consider operator actions (including human errors) in assessing the reliability or availability of the AFS.

B. Reliability/Availability Bases Two

The following bases have been credited in the risk assessments performed on the non-essential portion of the AFS as part of the IPE:

1. The non-Seismic Category I AFS pump minimum flow recirculation path back to the condensate storage tank does not need to be isolated to meet the IPE performance as described in Table 10.4-6, note c. In addition, the IPE does not require the flow path to remain open in situations where the minimum flow requirements for the pump are met with the minimum flow path isolated.
2. Periodic full-flow testing of the non-Seismic Category I AFS pump is not required.
3. The downcomer feedwater isolation valves are designed to fail open on a loss of power.
4. The backup nitrogen accumulator for the downcomer feedwater control and isolation valves was not credited during a normal loss of offsite power event.
5. The AFS flow to the steam generators is controlled in accordance with the standard post trip actions as defined in the emergency operating procedures (see Table 10.4-6, note c, for IPE credited performance for the AFS pumps).

C. Reliability/Availability Bases Three

The AFS overall reliability is enhanced by including the non-essential AFS pump in each unit's Technical Specifications.

D. Reliability/Availability Bases Four

The non-Seismic Category I motor driven AFS pump and associated power-operated valves shall have the capability to be powered by the Train A diesel generator when connected by manual action to the load group 1 bus as described in Section 8.3.1. The non-Seismic Category I motor driven AFS pump may be controlled from the main control room.

E. Reliability/Availability Bases Five

The non-Seismic Category I motor driven AFS pump is located within the Turbine Building. This structure and the non-essential AFS train components contained within this structure are not designed to withstand adverse environmental conditions resulting from earthquakes, tornadoes, floods or hazards for which the essential AFS trains are required to be designed to withstand.

F. Reliability/Availability Bases Six

The design and performance requirements for the non-Seismic Category I motor driven AFS pump are provided in Table 10.4-6.

10.4.9.2 System Description

10.4.9.2.1 General Description

The AFS consists of one Seismic Category I, motor-driven AFS pump; one Seismic Category I, steam turbine-driven AFS pump; and one non-Seismic Category I, motor-driven AFS pump, associated piping, controls, and instrumentation. Engineering drawings 01, 02, 03-M-AFP-001 show the piping and instrumentation diagram of the system.

The primary source of auxiliary feedwater is the condensate storage tank. The condensate storage tank provides a reserve capacity (see Table 9.2-21) for the AFS during emergency shutdown conditions. This provides an orderly RCS cooldown to shutdown cooling initiation conditions as addressed in safety design basis six of paragraph 10.4.9.1.1 and provides sufficient feedwater to maintain the plant as hot standby for 8 hours.

Both motor-driven auxiliary feedwater pumps and their motor-operated valves can receive power from both onsite and offsite power sources. In the event of a loss of offsite power, power is supplied to these motor-driven pumps by their standby diesel generators. The Seismic Category I, motor-driven pump and its motor-operated valves are connected to the train B power source by automatic initiation or by operator action. The non-Seismic Category I pump and its valves can be connected to the train A power source by operator action only. The two Seismic Category I auxiliary feedwater pumps are separated by a physical barrier. Piping and components for the Seismic Category I pumps are located, separated, or protected to preclude damage from any missile effects.

The turbine-driven AFS pump is supplied with steam from the main steam lines of either steam generator upstream of the main steam isolation valves. The turbine controls and associated valves are powered from the dc bus.

10.4.9.2.2 Component Description

Principal components are listed in table 10.4-6.

10.4.9.2.3 System Operation

For emergency operation, normal flow is from the condensate tank to either the Seismic Category I, motor-driven AFS pump or to the steam turbine-driven, Seismic Category I AFS pump which are located in the main steam support structure. An alternate supply of water is provided by cross-connections to the reactor makeup tank.

A minimum flow recirculation system is provided on each pump discharge with recirculation to the condensate tank and supports pump testing. Each pump can supply either steam generator with feedwater.

One auxiliary feedwater path to the steam generators is provided for the non-Seismic Category I, motor-driven auxiliary feedwater pump through the feedwater header, with manual operation of feedwater valves possible during emergency operation. This feature of the non-essential AFS train is provided to improve the overall availability of the AFS system and is not required for Chapters 6 and 15 accident mitigation.

Table 10.4-6

AUXILIARY FEEDWATER SYSTEM DESIGN DATA

Design Factor	Value	Notes
Auxiliary feedwater pumps		
Quantity		
Motor-driven, non-Seismic Category I	1	
Motor-driven, Seismic Category I	1	
Steam turbine-driven, Seismic Category I	1	
Flow, Seismic Category I, gal/min, net	750	a, b
Miniflow, Seismic Category I, gal/min, maximum	260	b
Flow, non-Seismic Category I, gal/min, net	710	a, c
Miniflow, non-Seismic Category I, gal/min, maximum	300	c
Head, ft - Seismic Category I at 750 gal/min plus 260 gal/min miniflow	3,280	b
Head, ft - non-Seismic Category I at 710 gal/min plus 300 gal/min miniflow	2,960	c

a. Net flow delivered to steam generators.

b. The values shown are for the design performance specifications of the auxiliary feedwater pumps. The safety analysis credits delivery of 650 gpm at a steam generator pressure of 1270 psia or equivalent at the steam generator entrance for design basis accidents.

c. The values shown in this Table are based on the design performance specifications for the non-Seismic Category I AFS pump. The power generation design bases for this pump assumes a minimum performance of 650 gpm delivered to the steam generator(s) at a design no load pressure of 1170 psia. The IPE credits a AFS flow of approximately 500 gpm to the steam generator(s) when steam generator conditions are maintained in accordance with the standard post trip actions as defined in the emergency operating procedures.

The two Seismic Category I auxiliary feedwater pumps only provide flow to the downcomer feedwater nozzles on each steam generator. Either Seismic Category I auxiliary feedwater pump can supply the necessary feedwater for reactor decay heat removal and reactor cooldown to 350F.

At a reactor coolant temperature of 350F, the shutdown cooling system is placed in operation.

A minimum flow path is provided for each pump. Approximately 26% of the Seismic Category I pump capacity and 30% of the non-Seismic Category I pump capacity is recirculated back to the condensate tank whenever a pump is operating. The minimum flow line is provided to prevent pump overheating in the event the pump discharge line is isolated.

The Seismic Category I pump motor driver is powered from a separate engineered safety features (ESF) bus which is powered by the load group 2 diesel generator. The Seismic Category I, steam turbine-driven pump's associated valving is powered from the dc bus as discussed in subsection 8.3.2. The turbine for this pump is supplied with steam from either of the steam generators. The turbine controls are powered from the dc bus.

Auxiliary feedwater control for the essential trains is normally from the control room, but instrumentation is provided for operation from the remote shutdown panel in the unlikely event that the control room must be evacuated.

Signals from the auxiliary feedwater actuation signal (AFAS) start the Seismic Category I, motor-driven auxiliary feedwater pump and the Seismic Category I, steam turbine-driven auxiliary feedwater pump, shut all steam generators' blowdown and blowdown sample isolation valves, and open the associated isolation valves to the downcomer nozzles of the intact steam generator(s). The non-Seismic Category I, motor-driven pump is started manually and its associated valves are opened manually from the control room.

Assuming a pipe break in either steam generator lower feedwater supply line in the containment, a single electrical failure will not prevent the system from accomplishing its function. Either Seismic Category I pump can supply the flow required for safe shutdown. Table 10.4-7 lists the Seismic Category I valves in the AFS.

10.4.9.3 Safety Evaluation

Safety evaluations, numbered to correspond to the safety design bases, are as follows:

A. Safety Evaluation One

The AFS, in conjunction with the condensate tank described in subsection 9.2.6, provides a means of pumping feedwater to maintain the plant at hot standby for 8 hours, with a subsequent cooldown at a maximum rate of 75F per hour to a reactor coolant temperature of 350F.

B. Safety Evaluation Two

The two Seismic Category I AFS pumps and their associated valves and piping are designed to Seismic Category I requirements. The isolation valves and piping connections to the Seismic Category I piping are also designed to Seismic Category I requirements.

C. Safety Evaluation Three

During normal operation, the two Seismic Category I AFS pumps are each available in the event of loss of off-site power and normal onsite power.

D. Safety Evaluation Four

The Seismic Category I, motor-driven AFS pump and its associated line valves are connected to the load group 2 onsite power bus as discussed in subsection 8.3.1. The turbine-driven AFS pump control system and the associated line valves are connected to the dc power system as discussed in subsection 8.3.2.

E. Safety Evaluation Five

Redundancy is provided throughout the AFS and associated systems to ensure the supply of feedwater to either or both steam generators in the event of an accident plus one active failure. Table 10.4-8 presents a single failure analysis for the AFS.

F. Safety Evaluation Six

The AFS is designed to maintain an adequate water level in the steam generators under the following operating modes and accident conditions:

1. Reactor cooldown at a maximum administratively controlled rate of 75F per hour from hot standby to 350F with a loss of offsite power and normal onsite power.
2. Hot standby for 8 hours with a loss of offsite power and normal onsite power.

3. Reactor coolant system cooldown using the intact steam generator following a main steam line break or main feedwater line break inside the containment with a loss of offsite power and normal onsite power.

Table 10.4-7

SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM[a] (Sheet 1 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actu-ator Type	Valve Classifi-cation[b]
V002	Main steam to AFW PP A turbine isolation valve	Gate	6	None	N
V005	AFW PP A suction check valve from reactor makeup water tank	Check	8	None	A
V006	AFW PP A suction isolation valve from condensate storage tank	Gate	8	None	N
V007	AFW PP A suction check valve from condensate storage tank	Check	8	None	A
V009	AFW PP B suction check valve from reactor makeup water tank	Check	8	None	A
V015	AFW PP A discharge check valve after recirculation	Check	6	None	A
V016	AFW PP A discharge isolation valve after recirculation	Gate	6	None	N
V017	AFW PP A miniflow recirculation	Gate	3	None	N
V021	AFW PP B suction isolation valve from condensate storage tank	Gate	8	None	N

Table 10.4-7

SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM[a] (Sheet 2 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actuator Type	Valve Classification[b]
V022	AFW PP B suction check valve from condensate storage tank	Check	8	None	A
V024	AFW PP B discharge check valve after recirculation line	Check	6	None	A
V025	AFW PP B discharge isolation valve (manual)	Gate	6	None	N
V026	AFW PP B miniflow recirculation valve	Gate	3	None	N
V028	AFW PP B suction isolation valve from reactor makeup water tank	Gate	8	None	N
HV30	AFW regulating valve PP B to SG 1	Globe	6	Motor	A
HV31	AFW regulating valve PP B to SG 2	Globe	6	Motor	A
HV32	AFW regulating valve PP A to SG 1	Globe	6	Motor	A
HV33	AFW regulating valve PP A to SG 2	Globe	6	Motor	A
UV34	AFW isolation valve PP B to SG 1	Gate	6	Motor	A
UV35	AFW isolation valve PP B to SG 2	Gate	6	Motor	A
UV36	AFW isolation valve PP A to SG 1	Gate	6	Motor	A

Table 10.4-7

SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM[(a)] (Sheet 3 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actu-ator Type	Valve Classifi-cation[(b)]
UV37	AFW isolation valve PP A to SG 2	Gate	6	Motor	A
HV54	AFW turbine steam trip and throttle valve	Globe	4	Motor	A
VO55	AFW turbine auxiliary steam isolation valve	Gate	4	None	N
VO58	AFW PP A reactor makeup water tank isolation valve	Gate	8	None	N
VO77[(c)]	AFW PP A recirculation isolation valve to condensate tank	Gate	6	None	N
VO78[(c)]	AFW PP B recirculation isolation valve to condensate tank	Gate	6	None	N
VO79	AFW check valve to SG 1 FW header (in-containment)	Check	6	None	A
VO80	AFW check valve to SG 2 FW header (in-containment)	Check	6	None	A
VO96	Auxiliary steam check valve to AFW turbine	Check	4	None	N

Table 10.4-7
SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM[a] (Sheet 4 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actuator Type	Valve Classification[b]
V137	AFW PP A discharge check valve before recirculation	Check	6	None	A
V138	AFW PP B discharge check valve before recirculation	Check	6	None	A
UV134[d]	SG 1 steam supply to AFW PP turbine	Gate	6	Motor	A
UV138[d]	SG 1 steam supply to AFW PP turbine	Gate	6	Motor	A
UV134A[d]	SG 1 steam bypass to AFW PP turbine	Globe	1.5	Motor	A
UV138A[d]	SG 2 steam bypass to AFW PP turbine	Globe	1.5	Motor	A
V234[d]	SG 1 steam bypass line isolation valve for UV134A	Globe	2[f]	None	N
V238[d]	SG 2 steam bypass line isolation valve for UV138A	Globe	2[f]	None	N
V885[d]	SG 1 steam bypass isolation valve to AFW PP turbine	Globe	2	None	N
V886[d]	SG 2 steam bypass isolation valve to AFW PP turbine	Globe	2	None	N
V887[d]	SG 1 steam bypass check valve to AFW PP turbine	Check	2	None	A
V888[d]	SG 2 steam bypass check valve to AFW PP turbine	Check	2	None	A

Table 10.4-7

SEISMIC CATEGORY I VALVES IN MAJOR FLOW PATHS FOR THE AUXILIARY FEEDWATER SYSTEM(a) (Sheet 5 of 5)

Valve No.	Service Description	Valve Type	Valves Size, Inches	Actuator Type	Valve Classification(b)
V889(d)	Steam bypass to AFW PP turbine isolation valve	Globe	2	None	N
V043(d)	SG 1 steam check valve to AFW PP turbine	Check	6	None	A
V044(d)	SG 2 steam check valve to AFW PP turbine	Check	6	None	A
V994(e)	SG 2 FW recirculation isolation valve	Gate	4	None	N
V995(e)	SG 2 FW recirculation isolation valve	Gate	4	None	N
V996(e)	SG 1 FW recirculation isolation valve	Gate	4	None	N
V997(e)	SG 1 FW recirculation isolation valve	Gate	4	None	N

a. Seismic Category I valves listed below are omitted from the list:

- Instrument isolation valves
- Vent valves
- Drain valves
- AFW PP turbine cooling subsystem valves
- AFW PP bearing cooling and gland seal injection subsystem valves

b. A = active; N = nonactive; Note that “A” and “N” are related to the component’s movement during performance of its safety function and not to the application of single failure criteria.

c. Valves in AFW system shown in condensate transfer and storage system (CT)

d. Valves in AFW system shown in main steam system (SG)

e. Valves isolate downcomer feedwater (an AFW flow path) from recirculation lines.

f. Valve size in Unit 2 is 1½ inches

Table 10.4-8

SINGLE FAILURE MODE ANALYSIS--AUXILIARY FEEDWATER SYSTEM (Sheet 1 of 2)

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Isolation valve to reactor makeup water tank	Fails closed/ mechanical failure or inadvertent misposition	Loss of secondary source of water for the auxiliary feedwater pumps	Valve stem position	Redundant lines from condensate tank	
	Fails open/ mechanical failure or inadvertent misposition	None	Valve stem position		Valve is normally closed.
Check valves from reactor makeup water tank	Fails closed/corrosion	None	None	Redundant lines available to condensate tank	Only used in case condensate tank not available.
	Fails open/ contamination	None	None		
Isolation valves to condensate tank	Fails closed/ mechanical binding	None	Handle position	Redundant line available from condensate tank	Valve is normally locked open.
	Fails open/locking mechanism jams	None	Handle position	None	Valve is locked open.
Check valves from condensate tank	Fails closed/corrosion	None	None	Redundant line available from condensate tank	
	Fails open/ contamination	None	None		
Auxiliary feedwater pump (Seismic Category I)	Fails to pump/ mechanical electrical failure	No effect on system performance	Low pressure indication from pump	Redundant 100% capacity Seismic Category I auxiliary feedwater pump available. A 100% capacity non-Seismic Category I pump is also available	

Table 10.4-8

SINGLE FAILURE MODE ANALYSIS--AUXILIARY FEEDWATER SYSTEM (Sheet 2 of 2)

Component	Failure Mode/Cause	Effects on System	Method of Detection	Inherent Compensating Provision	Remarks
Pump discharge check valves	Fails closed/ corrosion	Loss of one auxiliary feedwater pump	High-pressure indication from pump	Redundant 100% capacity auxiliary feedwater pump available.	
	Fails open/ contamination	No effect other than causing trouble if maintenance of valve is required while system is operating.	None		
Discharge valves, auxiliary feedwater pumps	Fails open/ mechanical or electrical failure	None	Handle position		Valve is normally locked open
	Fails closed/ mechanical binding	Effective loss of one auxiliary feedwater pump	Handle position	Redundant 100% capacity auxiliary feedwater pump	Valve is normally locked open
Isolation valves to feedwater header	Fails open/ mechanical or electrical failure	Loss of double isolation between the main feedwater supply and auxiliary feedwater supply to one steam generator	Valve position indicator in control room	Redundant valves	
	Fails closed/ mechanical or electrical failure	Slight decrease in flexibility of feedwater system	Valve position indicator in control room	None required	
Check valves to feedwater header	Fails open/ contamination	No serious effect	Periodic test	None required	
	Fails closed/ corrosion	Slight decrease in flexibility of feedwater system	Periodic test	None requried	
Overpressure Relief Valves for Outboard AF Containment Isolation Valves	Fails open/ mechanical failure	Slight decrease in amount of water delivered to Steam Generator(s)	Periodic test	Both auxiliary feedwater pumps remain available such that their total combined Technical Specification required flow is met.	
	Fails closed/ mechanical failure or corrosion	Effective loss of one auxiliary feedwater pump	Periodic test	Redundant 100% capacity auxiliary feedwater pump	
FW recirculation isolation valve[(a)]	Fails open/inadvertent position	None	Handle position	Redundant valve	Valves are locked closed and administratively controlled

a. Valves isolate downcomer feedwater (an AFW flow path) from recirculation lines.

Only the Seismic Category I pumps are started on an AFAS. The Seismic Category I AFS pumps are not routinely used for normal plant operations. The non-Seismic Category I AFS pump is utilized for startup, hot standby and normal shutdown of the plant.

G. Safety Evaluation Seven

Each of the essential AFS pumps is capable of delivering 650 net gallons per minute at 1270 psia or equivalent at the entrance of the steam generator.

H. Safety Evaluation Eight

The AFS can be operated from either the control room or from a remote shutdown station.

I. Safety Evaluation Nine

Each Seismic Category I AFS pump is installed in a separate room designed to Seismic Category I requirements. These rooms are in the main steam support structure.

J. Safety Evaluation Ten

The components and piping for each Seismic Category I AFS pump train are separated from each other in that no credible hazard within either train pump room can affect both trains. Where complete physical separation is not met as a result of design constraints, separation criteria are satisfied because sufficient protection is provided to assure an inherently reliable and safe design configuration which ensures essential AFS train redundancy. In general, the components and piping of both Seismic

Category I AFS trains are either enclosed by a Seismic Category I structure or are installed underground. Those components and piping of both Seismic Category I AFS trains which are not contained within a Seismic Category I structure or installed underground (e.g., portions of the AFS recirculation lines and AFS Turbine Exhaust Stack), have been analyzed to show that the probability of being struck by a tornado missile postulated in section 3.5, is sufficiently low ($<10^{-7}$ per year) to not be a credible event for the design basis of the AFS and do not require tornado missile protection.

K. Safety Evaluation Eleven

The combination of the one Seismic Category I, motor-driven pump and the one Seismic Category I, steam turbine-driven pump utilizes a diversity of power sources to assure delivery of feedwater under emergency conditions.

L. Safety Evaluation Twelve

All components and piping are designed to protect against the effects of high and moderate energy pipe ruptures as discussed in section 3.6.

M. Safety Evaluation Thirteen

Adverse environmental conditions will not impair the safety function of this system. Wind and tornado loadings are discussed in section 3.3. Flood design is covered in section 3.4. Seismic design is discussed in section 3.7.

10.4.9.4 Inspection and Testing Requirements

The system is capable of being tested while the plant is in normal operation. Each of the essential and non-essential AFS pumps is provided with a minimum flow recirculation line back to the condensate storage tank. This line ensures that the minimum flow requirements for each pump are met and allows for periodic testing required by the applicable codes that are identified in Section 3.9.6. This design allows the AFS to be operationally tested up to the steam generator auxiliary feedwater isolation valves. Full flow testing of the essential AFS pumps is performed in accordance with the Technical Specifications. These tests ensure the operability of the essential AFS by taking a supply from the condensate storage tank and injecting auxiliary feedwater into the steam generators. Successful performance of these full flow tests ensure that the essential AFS meets the minimum performance requirements credited in the safety analyses (Table 10.4-6, note b) for Chapter 6 and 15 events. Full flow testing of the non-essential AFS pump is not required to be performed since this pump is not credited in the safety analyses for Chapter 6 and 15 events.

Power Operated Containment isolation valves can be tested by either remote or local operation during normal plant operation.

The system is inspected as required by the applicable codes as identified in table 3.2-1.

Temperature monitoring of both the Seismic Category I and Non-Seismic Category I Auxiliary Feedwater pump is conducted in accordance with the recommendations of Generic Letter 88-03, Steam Binding of Auxiliary Feedwater Pumps.

10.4.9.5 Instrumentation Requirements

Instrumentation and controls are provided as described in paragraph 10.4.9.3. Control room instrumentation includes auxiliary feedwater flow and pump discharge pressure, steam generator level, control hand switches, and position indication for all power-operated valves, and auxiliary feedwater pump, turbine speed control, and indication.

Control logic for the AFS is addressed in section 7.3.

APPENDIX 10A

RESPONSES TO NRC REQUESTS FOR INFORMATION

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QUESTION 10A.1 (NRC Question 430.37) (10.1)

Provide a general discussion of the criteria and bases of the various steam and condensate instrumentation systems in section 10.1 of the FSAR. The FSAR should differentiate between normal operation instrumentation and required safety instrumentation.

RESPONSE: The response is given in subsection 10.1.3 and amended paragraph 10.4.9.5.

QUESTION 10A.2 (NRC Question 430.38) (10.2)

Expand your discussion of the turbine speed control and overspeed protection system. Provide additional explanation of the turbine and generator electrical load following capability for the turbine speed control system with the aid of system schematics (including turbine control and extraction steam valves to the heaters). Tabulate the individual speed control protection devices (normal emergency and backup), the design speed (or range of speed) at which each device begins operation to perform its protective function (in terms of percent of normal turbine operating speed). In order to evaluate the adequacy of the control and overspeed protection system provide schematics and include identifying numbers to valves and mechanisms (mechanical and electrical) on the schematics. Describe in detail, with references to the identifying numbers, and sequence of events in the turbine trip including response times, and show that the turbine stabilizes. Provide the results of a failure mode and effects analysis for the overspeed protection systems. Show that a single steam valve failure cannot disable the turbine overspeed trip from functioning. (SRP 10.2, Part III, Items 1, 2, 3, and 4).

RESPONSE: Expanded discussion of turbine speed control and overspeed protection system is given in amended subsection 10.2.2 and table 10.2-3.

QUESTION 10A.3 (NRC Question 430.39) (10.2)

The FSAR discusses the main steam stop and control, and reheat stop and intercept valves. Show that a single failure of any of the above valves cannot disable the turbine overspeed trip functions. (SRP 10.2, Part III, Item 3).

RESPONSE: The turbine overspeed protection system is an equipment protection system and is not required for plant safety.

Nevertheless, as described below and in section 10.2, the turbine overspeed protection system provides a highly reliable system to trip the turbine in the event of a turbine overspeed condition.

The function of the turbine overspeed trip sensors is to provide signals to the turbine trip system which, in turn, actuates the solenoid valves in the emergency trip systems. The emergency trip actuates the disk dump valve for each stop, control, reheat stop, and intercept valve to depressurize hydraulic fluid in trip system. This allows spring to close the valves to terminate the flow of steam to the turbine.

Each of the main steam and reheat lines supplying steam to the high-pressure and low-pressure cylinders of the turbine has two valves (stop and control) in series. Failure of one valve to close will not prevent tripping the turbine since the second valve in the same line will close, thus terminating the flow of steam to the turbine.

(Figure 10.1-1, sheet 1, indicates the approximate location of the turbine main steam stop, control, reheat stop, and intercept valves.)

QUESTION 10A.4 (NRC Question 430.40) (10.2)

Expand your discussion of the inservice inspection program for throttle-stop, control, reheat stop, and interceptor steam valves to include inspection times and the capability for testing essential components during turbine generator system operation. (SRP 10.2, Part III, Items 5 and 6).

RESPONSE: The response is given in amended paragraph 10.2.3.6.

QUESTION 10A.5 (NRC Question 430.41) (10.2)

Discuss the effects of a high and moderate energy piping failure or failure of the connection from the low pressure turbine to condenser on nearby safety-related equipment or systems. Discuss what protection will be provided the turbine overspeed control system equipment, electrical wiring, and hydraulic lines from the effects of a high or moderate energy pipe failure so that the turbine overspeed protection system will not be damaged to preclude its safety function. (SRP 10.2 Part III, Item 8).

RESPONSE: High and moderate energy piping failure within the turbine building, or failure of the connection between the low-pressure turbine to the condenser will not adversely affect plant safety since there is no safety-related equipment located within the turbine building. Further response is given in paragraph 3.6.1.2. The turbine overspeed protection system is for equipment protection only.

Nevertheless, the turbine overspeed protection system provides a highly reliable system to trip the turbine in event of a turbine overspeed condition. Aside from providing two redundant channels of speed control, two additional means of overspeed protection are provided as discussed in paragraph 10.2.2.3.1.5. Because of the redundancy in the mode of operation and the physical separation of components, a high or moderate energy pipe failure will not preclude protective function of the turbine overspeed control system.

QUESTION 10A.6 (NRC Question 430.42) (10.2)

In paragraph 10.2.3.6 you discuss inservice inspection and exercising of the main steam turbine stop and control and reheater stop and intercept valves. You do not discuss the inservice inspection, testing and exercising of the extraction steam valves. Provide a detail description of: 1) the extraction steam valves, and 2) your inservice inspection and testing program for these valves. Also provide the time interval between periodic valve exercising to assure the extraction steam valves will close on turbine trip.

RESPONSE: The extraction steam valves are described in amended paragraph 10.2.2.5.

QUESTION 10A.7 (NRC Question 430.43) (10.2)

Describe with the aid of drawings, the bulk hydrogen storage facility including its location and distribution system. Include the protective measures considered in the design to prevent fires and explosions during operations such as filling and purging the generator, as well as during normal operations.

RESPONSE: The following drawings (sent under separate cover) show the location of the bulk hydrogen storage facilities and the hydrogen distribution system:

- 13-P-ZYA-958, Rev. 0
- 01-C-ZVC-305, Rev. 7
- 01-C-CVC-306, Rev. 7
- 13-P-GAF-201, Rev. 4
- 13-P-GAF-401, Rev. 2
- 13-P-ZYA-015, Rev. 6
- 13-M-GAP-001, Rev. 4
- 13-M-GAP-002, Rev. 2
- 13-M-GHP-001, Rev. 4
- 13-M-CHP-002, Rev. 6
- 13-P-CHF-218, Rev. 5

Further response is given in paragraph 9.3.6.2.2.

QUESTION 10A.8 (NRC Question 430.44) (10.2)

Paragraph 10.2.1.3 references the CESSAR turbine generator interface requirements of subsections 5.1.4 and 7.2.3 The CESSAR FSAR sections 5.1.4 and 7.2.3 do not contain any turbine generator interface requirements. Clarify this inconsistency, provide the CESSAR interface requirements and an evaluation of how you are meeting those requirements.

RESPONSE: The response is given in amended paragraph 10.2.1.3.

QUESTION 10A.9 (NRC Question 430.45) (10.3)

As explained in issue No. 1 of NUREG-0138, credit is taken for all valves downstream of the main steam isolation valve (MSIV) to limit blowdown of a second steam generator in the event of a steam line break upstream of the MSIV. In order to confirm satisfactory performance following such a steam line break provide a tabulation and descriptive text (as appropriate) in the

FSAR of all flow paths that branch off the main steam lines between the MSIVs and the turbine stop valves. For each flow path originating at the main steam lines, provide the following information:

a) System identification

b) Maximum steam flow in pounds per hour

c) Type of shutoff valve(s)

d) Size of valve(s)

e) Quality of the valve(s)

f) Design code of the valve(s)

g) Closure time of the valve(s)

h) Actuation mechanism of the valve(s) (i.e., solenoid-operated, motor-operated, air-operated diaphragm valve, etc.)

i) Motive or power source for the valve actuating mechanism

In the event of the postulated accident, termination of steam flow from all systems identified above, except those that can be used for mitigation of the accident, is required to bring the reactor to a safe cold shutdown. For these systems describe what design features have been incorporated to assure closure of the steam shutoff valve(s). Describe what operator actions (if any) are required.

If the systems that can be used for mitigation of the accident are not available or decision is made to use other means to shut down the reactor describe how these systems are secured to assure positive steam shutoff. Describe what operator actions (if any) are required.

If any of the requested information is presently included in the FSAR text, provide only the references where the information may be found.

RESPONSE: NUREG-0138 page 1-9 states that the probability of occurrence of the above scenario is quite low. Page 1-10 states that the scenario is not analyzed by the staff and need not be considered as a design basis accident. This scenario should, therefore, not be a design basis accident for Palo Verde Units 1, 2, and 3.

Refer to the following P&IDs:

- 13-M-SGP-001
- 13-M-SGP-002
- 13-M-FTP-001
- 13-M-CDP-001
- 13-M-MTP-001
- 13-M-MTP-002
- 13-M-ASP-001
- 13-M-GSP-001

Further response is given in paragraph 10.3.2.2.2.

QUESTION 10A.10 (NRC Question 430.46) (10.4.1)

Provide a tabulation in your FSAR showing the physical characteristics and performance requirements of the main condensers. In your tabulation include such items as: 1) the number of condenser tubes, material and total heat transfer surface, 2) overall dimensions of the condenser, 3) number of passes, 4) hot well capacity, 5) special design features, 6) minimum heat transfer, 7) normal and maximum steam flows, 8) normal and maximum cooling water temperature, 9) normal and maximum exhaust steam temperature with no turbine bypass flow and with maximum turbine bypass flow, 10) limiting oxygen content in the condensate in cc per liter, and 11) other pertinent data. (SRP 10.4.1, Part III, Item 1).

RESPONSE: The response is given in amended paragraph 10.4.2.2 (table 10.4-1).

QUESTION 10A.11 (NRC Question 430.47) (10.4.1)

Discuss the measures taken; 1) to prevent loss of vacuum, and 2) to prevent corrosion/erosion of condenser tubes and components. (SRP 10.4.1, Part III, Item 1).

RESPONSE: The response is given in paragraph 10.4.1.2.

QUESTION 10A.12 (NRC Question 430.48) (10.4.l)

Indicate and describe the means of detecting and controlling radioactive leakage into and out of the condenser and the means for processing excessive amounts. (SRP 10.4.1, Part III, Item 2).

RESPONSE: The response is given in paragraphs 10.4.5.2, 11.3.3.4, and 11.5.2.1.3.2, and subsection 10.4.6.

QUESTION 10A.13 (NRC Question 430.49) (10.4.1)

Discuss the measures taken for detecting, controlling and correcting condenser cooling water leakage into the condensate stream. (SRP 10.4.1, Part III, Item 2)

RESPONSE: The response is given in amended paragraph 10.4.6.2.3.

QUESTION 10A.14 (NRC Question 430.50) (10.4.1)

In paragraph 10.4.1.4 you have discussed tests and initial field inspection but not the frequency and extent of inservice inspection of the main condenser. Provide this information in the FSAR (SRP 10.4.1, Part II).

RESPONSE: The response is given in amended paragraph 10.4.1.4.

QUESTION 10A.15 (NRC Question 430.51) (10.4.1)

Indicate what design provisions have been made to preclude failures of condenser tubes or components from turbine bypass blowdown or other high temperature drains into the condenser shell (SRP 10.4.1, Part III, Item 3).

RESPONSE: The condenser and its tubes are protected from turbine bypass blowdown steam flow by a manifold having two stages of pressure reduction orifices that direct the steam flow away from the condenser tubes.

Further response is given in paragraph 10.4.1.2.

QUESTION 10A.16 (NRC Question 430.52 (10.4.1)

Discuss the effect of loss of main condenser vacuum on the operation of the main steam isolation valves (SRP 10.4.1, Part III, item 3).

RESPONSE: As discussed in subsection 10.4.1, the main condenser has no safety function. However, the main steam isolation valves will shut indirectly because of loss of main condenser vacuum as explained in paragraph 15.2.2.1.

QUESTION 10A.17 (NRC Question 430.53) (10.4.4)

Provide additional description (with the aid of drawings) of the turbine bypass valves and associated instrumentation and controls. In your discussion include the number, size, principle of operation, construction, setpoints, and capacity of each valve and the malfunctions and/or modes of failure considered in the design of the turbine bypass system. (SRP 10.4.4, Part III, Item 1.)

RESPONSE: The response is given in subsection 10.4.4 and section 7.7, figure 10.4-1, CESSAR Sections 10.4.4 and 7.7.1.1.5, and CESSAR Figure 7.7-6.

QUESTION 10A.18 (NRC Question 430.54) (10.4.4)

Provide the results of an analysis indicating that failure of the turbine bypass system high energy line will not have an adverse effect or preclude operation of the turbine speed control system or any safety-related components or systems located close to the turbine bypass system. (SRP 10.4.4, Part III, Item 4).

RESPONSE: See response to Question 10A.5 (NRC Question 430.41.)

QUESTION 10A.19 (NRC Question 430.55) (10.4.4)

In paragraph 10.4.4.4 you have discussed tests and initial field inspection but not the frequency and extent of inservice testing and inspection of the turbine bypass system. Provide this information in the FSAR. (SRP 10.4.4, Part II).

RESPONSE: The response is given in amended paragraph 10.4.4.3, listing B.

QUESTION 10A.20 (NRC Question 430.56) (10.4.4)

Subsection 10.4.4 of your FSAR refers to Section 10.4.4 of CESSAR for additional discussion of the turbine bypass system. Your turbine bypass system differs from the one discussed in CESSAR, in that two of your bypass valves dump to atmosphere while in CESSAR they do not. Provide a discussion to show that your system meets the 11 design bases stated in Section 10.4.4.1 of CESSAR.

RESPONSE: The response is given in amended subsection 10.4.4.

QUESTION 10A.21 (NRC Question 282.2) (10.3.5)

Provide the steam generator secondary water chemistry control and monitoring program, addressing the following:

1. Sampling schedule for the critical parameters and of control points for these parameters for each mode of operation: normal operation, hot startup, cold startup, hot shutdown, cold wet layup;
2. Procedures used to measure the values of the critical parameters;
3. Process sampling points;
4. Procedure for the recording and management of data;
5. Procedures defining corrective actions(a) for off-control point chemistry conditions; and
6. The procedure identifying (a) the authority responsible for the interpretation of the data and (b) the sequence and timing of administrative events required to initiate corrective action.

Verify that the steam generator secondary water chemistry control program incorporates technical recommendations of the NSSS. Any significant deviations from NSSS recommendations should be noted and justified technically.

In addition to the secondary water chemistry monitoring and control program, we require monitoring of the steam condensate at the effluent of the condensate pump. The monitoring of the condensate is for the purpose of detecting condenser leakage.

RESPONSE: (Item numbers correspond to those of the question.)

1. The response is given in paragraph 10.3.5.1.

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a. Branch Technical Position MTEB 5-3 describes the acceptable means for monitoring secondary side water chemistry in PWR steam generators, including corrective actions for off-control point chemistry conditions. However, the staff is amenable to alternatives, particularly to Branch Technical Position B.3.b(9) of MTEB 5-3 (96-hour time limit to repair or plug confirmed condenser tube leaks).

2. Procedures for measuring the values of critical parameters will reflect C-E technical recommendations or exceptions will be technically justified in subsection 10.3.5.

   The following industry procedures reflect the most recent C-E technical recommendations for measuring the respective parameters.

Parameter	Procedure
pH	ASTM, Part 31, Procedure D1293, Method B
Conductivity	ASTM, Part 31, Procedure D1125, Method B
Suspended Solids	Standard Methods, Procedure 208D or ASTM, Part 31, Procedure D1888
Silica	ASTM, Part 31, D859, Method B

3. Process sampling points are listed in paragraph 10.4.6.2.3.

4. The response is given in paragraph 10.3.5.1.

5. The response is given in paragraph 10.3.5.1.

6. The response is given in paragraph 10.3.5.1.

   The steam generator secondary water chemistry control program is described in paragraph 10.3.5.1, which reflects C-E's technical recommendations. Technical recommendations are met by the existing design. There are no significant deviations from NSSS steam generator chemistry recommendations.

Paragraph 10.4.6.2.3 describes the method of continuously monitoring for indication of condenser leaks, which is to continuously monitor each section of the condenser hotwell, instead of monitoring condenser pump discharge.

QUESTION 10A.22 (NRC Question 410.25) (10.3)

In order to prevent blowdown of more than one steam generator, verify that the main steam isolation valves are designed to stop full main steam flow at the maximum design differential pressure in both directions in the event of a main steam line break in one steam line upstream of an MSIV and corresponding single failure (to close) in an MSIV to the other steam generator.

RESPONSE: The response is given in subsection 10.3.2.2.2.

QUESTION 10A.23 (NRC Question 410.26) (10.4.5)

The evaluation of potential flooding of essential plant areas as a result of a circulating water system failure indicates that the water level would eventually reach plant grade at which point the water leaves the turbine building. Verify that this water can not enter safety-related structures through openings at grade or describe the protection provided for safety-related equipment from such an occurrence.

RESPONSE: The response is given in paragraph 10.4.5.2.

QUESTION 10A.24 (NRC Question 410.27) (10.4.7)

It is our position that you commit to perform a steam generator/feedwater water hammer test in accordance with the guidance for preheat type steam generators as identified in NUREG/CR-1606, "An Evaluation of Condensation-Induced Water Hammer in Preheat Steam Generators." The following procedure should be followed:

"Run the plant at approximately 15% of full power by using feedwater through the downcomer nozzle at the lowest feedwater temperature that the plant Standard Operating Procedure (SOP) allows. Switch the feedwater at that temperature from the downcomer nozzle to the economizer nozzle by following the SOP. Observe and record the transient that follows."

RESPONSE: The response is given in paragraph 10.4.7.4.

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APPENDIX 10B

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