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10.0 STEAM AND POWER CONVERSION

The steam and power conversion systems of Units 1 and 2 are essentially identical. For each unit, the turbine generator systems consist of components of conventional design, designed for use in large central power stations. The equipment is arranged to provide high thermal efficiency with no sacrifice to safety. The component design parameters are given in Table 10.1-1.

The steam and feedwater system is designed to remove heat from the reactor coolant in the two steam generators, producing steam for use in the turbine generator. The steam and feedwater system can receive and dispose of, in the cooling systems and through atmospheric relief valves, the total heat existent or produced in the reactor coolant system following an emergency shutdown of the turbine generator from a full load condition.

Each unit has undergone a low pressure turbine retrofit which replaced the original Westinghouse BB80 low pressure turbine rotors with newly designed Westinghouse BB80R (Ruggedized) monoblock rotors. The replacement included rotors, inner cylinders and all stationary and rotating blading. The design incorporated state-of-the-art turbine technology to improve reliability and thermal performance.

All of the equipment in the turbine generator systems was originally designed to produce a maximum calculated gross output of 537,960 kWe. Significant modifications to secondary plant equipment were necessary as a result of the increase in reactor thermal power to 1800 MWt for the Extended Power Uprate (EPU).

The original Westinghouse double flow BB95 high pressure (HP) turbine was modified by replacing the rotor and internals such that the HP turbine is equivalent to a BB95A design. Similar to the previous low pressure (LP) turbine rotor retrofit, the inner cylinders and all stationary and rotating blading were replaced. The HP casings have been retained but modified to accommodate a higher exhaust pressure. In addition the LP turbine blowout panels have been replaced to accommodate the increase in steam flow at EPU conditions.

Significant modifications to the condensate and feedwater system for EPU included higher capacity main feedwater pumps, higher capacity condensate pumps, higher capacity condensate coolers, replacement of all feedwater heaters, new valve trim and actuators for the main feedwater regulating valves and installation of new main feedwater isolation valves.

10.1 STEAM AND POWER CONVERSION SYSTEM

10.1.1 DESIGN BASIS

Load Change Capability

The plant has the capability to provide load changes up to step load increase of 10% and ramp increases of 5% per minute within the load range of 15% to 100% of full load without reactor trip subject to possible xenon limitations late in core life. Similar step and ramp load reductions are possible within the range of full power to 15% nominal power. The reactor coolant system will accept a complete loss of load from full power with reactor trip. In addition, the steam dump system makes it possible to accept a rapid load decrease of 50% at a rate up to 200%/minute without reactor trip providing condenser vacuum is maintained (Reference 1).

Functional Limits

The system design incorporates backup means (Atmospheric Steam Dump Valves and Main Steam Safety Valves) for heat removal under any loss of normal heat sink (i.e., main steam isolation valves trip, condenser isolation, loss of circulating water flow) to accommodate reactor shutdown heat rejection requirements.

Secondary Functions

The steam and power conversion system also provides steam for driving the turbine-driven auxiliary feedwater pump and for turbine gland steam, reheater steam, the two-stage steam-jet air ejectors, the two priming ejectors, blowdown evaporator, waste evaporator, letdown gas strippers and tank, and building heating.

Codes And Classifications

The pressure retaining components (or compartment of components) comply with the codes given in Table 10.1-2.

10.1.2 SYSTEM DESIGN AND OPERATION

Schematic Flow Diagrams

The main and reheat steam, the condensate and feedwater, the extraction steam, the feedwater heater drains, the auxiliary feedwater, the circulating water, the feedwater heater vents and reliefs, and the gland steam and drains flow diagrams are given in Figure 10.1-1 through Figure 10.1-8, respectively.

Design Features - Steam and Feedwater System

Steam from each of the two steam generators supplies the turbine, where the steam expands through the double flow high pressure turbine, and then flows through moisture separator reheaters (MSRs) to two, double flow, low pressure turbines, all in tandem. Five stages of extraction are provided, two from the high pressure turbine, one of which is the exhaust, and three stages from the low pressure turbines as shown in Figure 10.1-3. The feedwater heaters for the lowest three stages are located in the condenser neck. All feedwater heaters are horizontal, half-size units. The feedwater string is the closed type with deaeration accomplished in the condenser.

Condensate is taken from the condenser hotwell by the condensate pumps and pumped through the hydrogen coolers, air ejector condensers, gland steam condenser, and low pressure heaters to the suction of the feedwater pumps. The feedwater pumps then send feedwater through the high-pressure heaters to each steam generator.

The four MSRs drain to the high pressure heaters. Drains from the high pressure heaters are cascaded through No. 4 feedwater heaters to the heater drain tank. The moisture separators also drain to this tank. The heater drain pumps take suction from the drain tank and discharge to the feedwater pump suction. Drains from the three lower pressure heaters cascade to the condenser.

The steam and feedwater lines from the steam generators up to and including the steam line non-return check valves and the main feedwater isolation valves are seismic Class I. A failure of any Class I main steam or feedwater line or malfunction of a valve installed therein will not impair the reliability of the auxiliary feedwater system, render inoperative any engineered safeguard feature, initiate a loss of coolant condition, or cause failure of any other steam or feedwater line.

The main steam system conducts steam in a 30 in. pipe from each of the two steam generators within the reactor containment through a swing disc-type isolation valve and a swing-disc type nonreturn valve to the turbine stop and control valves. The main steam isolation and nonreturn valves are located outside of the containment. The two lines are interconnected locally to the turbine. The design pressure of this system is 1085 psig at 555°F. Steam pressure is measured upstream of the main steam isolation and non-return valves. A steam flowmeter is provided in the line from each steam generator upstream of the main steam isolation and nonreturn valves to measure steam flow from each steam generator. Steam flow signals are used by the automatic feedwater flow control system (see Section 7.0). The flow venturi also serves to limit steam flow rate in the event of a steam line break downstream of the venturi. In addition to this venturi, the steam generators have a steam flow limiter located in the steam nozzle.

Each main steam isolation valve contains a swing disc which is normally held out of the main steam flow path by an air piston. This valve is closed by a spring when the air supply is shut off by a signal from the steam line break protection system, and the piston is vented by redundant valves actuated by the same signal, as described in Section 7.0. The main steam isolation valve is designed to close in less than five seconds.

The nonreturn valves prevent reverse flow of steam. If a steam line ruptures between a main steam isolation valve and a steam generator, the affected steam generator will blow down. The nonreturn valve in the line will prevent blowdown (reverse flow) from the other steam generator. The steam break incident is analyzed in Section 14.0.

<u>Steam Dump to Atmosphere</u>

If the condenser heat sink is not available during a turbine trip or during a unit startup, excess steam, generated as a result of reactor coolant system sensible heat and core decay heat, is discharged to the atmosphere.

There are four 6 in. by 10 in. Main Steam Safety Valves (MSSVs) located on each of the two 30 in. main steam lines outside the reactor containment and upstream of the main steam

isolation and nonreturn valves. Discharge from these safety valves is carried to atmosphere through individual vent stacks. The lift settings for the main steam safety valves are specified in Technical Specification 3.7.1. The MSSVs have sufficient relieving capacity so that the main steam pressure does not exceed 110 % of the steam generator shell-side design pressure for the worst-case loss-of-heat sink event (Reference 1).

In addition, one 6 in. Atmospheric Steam Dump Valve (power operated relief valve) is provided in each main steam line which is capable of releasing the sensible and core decay heat to the atmosphere. These valves are automatically controlled by pressure or may be manually operated from the main control board. Combined, the valves will be capable of passing no less than 10% of the maximum calculated steam flow at no-load steam pressure. Discharge from each atmospheric steam dump valve is carried to atmosphere through an individual vent stack. In addition, the atmospheric steam dump valve may be used to release the steam generated during reactor physics testing and plant hot standby operation if the condenser is not available.

The atmospheric steam dump lines are relied upon, following a steam generator tube rupture coincident with a loss of A.C. power, to cool down the reactor coolant system to RHR entry conditions. Further discussion of this event can be found in FSAR Section 14.2.4, “Steam Generator Tube Rupture.”

Condenser Steam Dump System

Excess steam generated by the reactor coolant system is bypassed, during conditions described below, to the condenser by means of two 16 in. main steam dump lines, one for each condenser. From each 16 in. line four 6 in. lines are taken, each with a 6 in. control valve installed. Each valve discharges through a 10 in. pipe into the condenser through a perforated diffuser. The capacity of the condenser dump system (as a percentage of full-load steam flow) decreases as full-load steam pressure decreases and full-load steam flow increases. The steam dump system capacity is adequate to prevent reactor trip for a steep ramp load reduction of 50% over 15 seconds from the EPU power level and is adequate to prevent exceeding MSSV setpoints following a reactor trip from full EPU power. This capacity also exceeds that necessary for prompt cooldown to RHR system operation entry conditions (Reference 1, Reference 2 and Reference 3). The smaller size valves are provided to limit the maximum steam flow should one valve stick open. A potential hazard in the form of an uncontrolled plant cooldown is thus minimized. Manual isolation valves are provided at each control valve.

The operation of the condenser steam dump valves is initiated by the error signal from the reactor coolant average temperature or header pressure. After initial opening, the valves are modulated by the T_{avg} signal to reduce the average temperature to the correct value. This is further described in Section 7.0. The valves are designed to rapidly open and fail in a closed position.

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

During startup, hot standby service or physics testing, the condenser steam dump valves may be remotely controlled from the main control board. The steam dump valves are prevented from opening on loss of condenser vacuum; they are also blocked on trip of both circulating water pumps that supply water to that unit.

Steam for Auxiliaries

The steam for the turbine-driven auxiliary feedwater pump is obtained from both main steam lines, upstream of the main steam isolation valves. Each steam supply is through a motor- operated stop check valve which prevents reverse flow between the steam generators.

Main steam for the turbine gland steam supply control valve, the two stage air ejectors, the reheater section of the four moisture-separator-reheaters and the two priming ejectors is obtained from branches on the main steam lines ahead of the turbine stop valves. Pressure reducing stations are used for the priming and main air ejectors. Temperature control valves are located in the main steam lines to the reheaters.

Steam from the five stages of extraction is piped from the turbine casings to the shells of the two parallel strings of feed water heaters. The first point extraction originates at the high pressure turbine casing and supplies steam to the shell of the No. 5 (high pressure) feedwater heater. The second point extraction originates in the high pressure turbine exhaust piping ahead of the moisture separators, and supplies steam to the No. 4 (low pressure) feedwater heater. The third, fourth, and fifth point extractions all originate at the low pressure turbine casings and supply steam to the No. 3, No. 2, and No. 1 (all low pressure) feedwater heaters, respectively.

To prevent turbine overspeed from backflow of flashed condensate from the heaters after a turbine trip, bleeder trip valves are provided in the extraction lines to heaters No. 4 and 5 and in the moisture separator drain lines. The bleeder trip valves are air-cylinder operated valves which are closed automatically upon a signal from the turbine trip circuit.

Steam Generator Blowdown

Each steam generator is provided with two 2½ in. bottom blowdown connections for shell-side solids concentration control. The two connections are at the same level, but on opposite sides of the shell. Piping from the two connections join to form a 2 in. blowdown header for each steam generator. The bottom of each steam generator is also provided with a drain connection which discharges into the blowdown line.

Each blowdown line is provided with a hand shutoff valve and an air operated trip valve. Each blowdown line includes, in addition to these shutoff valves, a manually-operated needle-type flow control valve for blowdown flow adjustment. A steam generator sample line, also provided with a trip valve, is taken from the blowdown line inside containment. A slip stream from each sample line is monitored for radiation. In the event of a high radiation signal, the trip valves in the sample and blowdown lines, and a trip valve in the blowdown tank drain line will close.

Downstream of the blowdown line trip valves, the blowdown from each steam generator can be aligned to pass through the blowdown heat exchangers. Each heat exchanger is composed of two shell and tube heat exchangers connected in series. The blowdown passes through the tube side of the heat exchangers and is cooled by water from the main condensate system. The blowdown then passes to the blowdown tank. It is also possible to align the blowdown from each steam generator directly to the blowdown tank, or to both the blowdown tank and the blowdown heat exchangers.

In order to reduce the iodine quantity leaving in the flashed steam from the steam generator blowdown tank vent, a situation which could occur with a high secondary water activity due to potential primary to secondary steam generator tube leakage, vent condensers have been added to condense most of the steam which would otherwise leave the tank vent. The water from the blowdown tanks may then be concentrated by a 35 gpm evaporator and further processed (see Chapter 11).

Turbine Generator

Each turbine is a three-element, tandem-compound, four-flow exhaust, 1800 rpm unit, and has moisture separation and live steam reheat between the HP and LP elements. Steam is admitted to the turbine through two stop valves and four control valves. The A.C. generator and rotating rectifier exciter are direct-connected to the turbine shaft. The turbine consists of one double flow, HP element in tandem with two double flow, LP elements. Four combination moisture-separator, live-steam reheater assemblies are located along side the turbine.

Each turbine is designed to operate with inlet steam conditions of 802 psia/518.5 F (Unit 1) / 806 psia/519.1 F (Unit 2), exhausting at 1.47 in. of Hg absolute, and with five stages of feedwater heating in service. Operating at design conditions with 8,111,883 lbm/hr inlet steam flow, 0% makeup flow, and 75°F circulating water temperature, the calculated gross output of each unit is ~607,000 kWe at a reactor power of 1806 MWt (1800 MWt reactor power plus 6 MWt pump heat).

High-Pressure Turbine

The high-pressure turbine has full arc steam admission and a double flow element, consisting of 11 stages of reaction blading in each end of the element. The steam enters the high pressure element from two main stop-control valve assemblies. The control valve outlets are connected to the high pressure casing through four inlet pipes. Two of these inlet connections are in the base and two are in the cover. The steam flows axially in both directions through the flow guide and reaction blading to the moisture separator reheaters, through four exhaust openings in the casing base. Crossover pipes return the steam to the two low pressure turbines.

The high pressure cylinder consists of an outer casing of carbon steel and is split at the horizontal centerplane to form a base and cover. The high pressure blading is carried in blade rings or guide blade carriers which are separate elements supported in the casing at the horizontal joint. They are guided at the top and bottom by dowel pins to retain correct position with respect to the turbine axis, while allowing free expansion and contraction in response to temperature changes. The high pressure turbine rotor is machined from an alloy steel forging. A separate extension shaft is bolted to the governor end of the rotor to carry the main oil pump and overspeed trip weight.

Low-Pressure Turbine

The double flow low pressure turbine incorporates high efficiency blading, diffuser type exhaust and liberal exhaust hood design. The low pressure turbine cylinders are fabricated from steel plate to provide uniform wall thickness thus reducing thermal distortion to a minimum. The entire outer casing is subjected to low temperature exhaust steam. The temperature drop from the cross-over steam temperature to the exhaust steam temperature is taken across the inner cylinder and thermal shield. The inner cylinder is surrounded by the thermal shield. This precludes a large temperature drop except across the thermal shield (which is not a structural element) thereby virtually eliminating thermal distortion. The fabricated inner cylinder is supported by the outer casing at the horizontal centerline and is fixed transversely at the top and bottom and axially at the centerline of the steam inlet, thus allowing freedom of expansion independent of the outer casing. The steam leaving the last row of blades flows into the diffuser where the velocity energy is converted to pressure energy, thus improving efficiency and reducing the excitation forces on the last rotating row of blades.

As part of a LP Turbine retrofit on each unit, the original LP turbine rotors (Westinghouse BB80) and low pressure turbine sections have been replaced with newly designed Westinghouse BB80R (Ruggedized) low pressure turbine rotors and low pressure turbine sections. The replacement ruggedized monoblock rotors have integrally forged “discs” made of highly corrosion-resistant material which eliminates the primary risk for stress corrosion cracking. The last 3 rows of the bladepath incorporate interlocking blades. The number of blade rows has been reduced from11 to 10 with the last stage blade length increased from 40 inches to 47 inches due to the added structural capability of the interlocking blades. The replacement low pressure equipment was manufactured to fit within the dimensions of the existing outer cylinders, bearing housings, coupling guards and hood sprays.

The hydrogen inner cooled generator is rated at 684,000 KVA at 0.94 power factor and 75 psig hydrogen gas pressure.

There are four, horizontal-axis, cylindrical-shell, combined moisture-separator, live-steam reheater assemblies. Steam from the exhaust of the HP turbine element enters the shell side of each assembly at one end. The steam is deflected down to the lower section of the vessel from which it rises through chevron type moisture separators. The moisture is collected from the chevrons in a trough and drained to the heater drain tank. Live steam from the steam generators enters at the other end of each assembly, passes through the tubes and leaves as condensate. Condensate from the reheater assemblies drains to the high pressure heaters. The lower pressure steam leaving the chevron separators flows over the tube bundle where it is reheated. This reheated steam leaves through openings in the top of the assemblies and flows to the LP turbines.

The crossover steam dump system is located on the crossover piping between the moisture separator reheaters and the LP turbines. The purpose of the system is to provide a means of energy removal from the turbine in the event of a unit trip and is designed to assure that the maximum overspeed of 132% will not be exceeded. The system consists of four air pilot-operated dump valves located in the HVAC equipment room. Discharge from these dump valves is carried to the atmosphere through individual vent stacks. The system is armed at 540 MW equivalent load and actuated upon turbine trip at 104% of design speed (Reference 11).

The dump valves are reseated by applying reseat steam pressure following a time delay after the required blowdown. Service air may be used as an alternative administrative pressure source to assist in closing a stuck open dump valve. Any three of the four dump valves will provide the design capacity to prevent exceeding the turbine maximum overspeed.

Turbine Oil System

The turbine oil system is of a conventional design. It consists of three parts: 1) a high pressure oil system, 2) lubrication system, and 3) Electro-Hydraulic (E/H) control system. The E/H control system is completely separate from the other two parts. Lube oil is also used to seal the generator glands to prevent hydrogen leakage from the machine. The fluid used for the E/H control system is a fire-resistant synthetic oil. The maximum available steam temperature is not capable of initiating a fire in the E/H oil system.

The turbine oil system supplies all of the oil required for the emergency trip and lubrication system during normal operation. A “Bowser” type oil conditioner is used for purifying oil in the reservoir and all makeup oil before it is added to the system.

The turbine has low speed, motor-driven, spindle-turning gear equipment which is mounted outboard of the No. 2 low pressure turbine generator end bearing (No. 6 bearing).

Condensate and Feedwater

The feedwater train is the closed type with deaeration accomplished in the condenser. Condensate is taken from the condenser hotwell by the condensate pumps and pumped through the condensate cooler, hydrogen coolers, air ejectors, gland steam condenser, and low pressure heaters to the suction of the feedwater pumps. The feedwater pumps then send feedwater through the high pressure heaters to the steam generators.

The main condenser is in two sections, one under each LP turbine. Each section is a single pass, radial flow condenser with semicylindrical water boxes at both ends. Each main condenser section has two condensate outlets with coarse strainers and antiswirl devices. Each hotwell is baffled with provisions for separate conductivity measurements on each half to locate leaking tubes.

There are two multistage, vertical pit-type, centrifugal condensate pumps with vertical motor drives. Each pump is half capacity with the turbine operating at the maximum calculated rating. The pumps deliver condensate to the system at approximately 11,064 gpm, including up to 3280 gpm of condensate to the generator hydrogen coolers. Oil in the upper motor bearing reserviour is cooled by condensate supplied from the pump discharge. The condensate pumps are started and stopped by manual controls on the main control board.

The steam jet air ejector maintains a vacuum in the condenser. The steam jet air ejector has four first stage elements and two second stage elements mounted on the shells of the intermediate and after condensers. The ejector is supplied with steam from the main steam line. During startup, one priming ejector of the low-head high-flow type is used to evacuate the condenser. A second originally installed priming ejector has been disabled to allow the option to use a mechanical vacuum pump to evavuate the condenser during startup when main steam is unavailable (Reference 12).

The reheaters, the moisture separators and all feedwater heaters (except the No. 4 heaters) are provided with duplex level controls. The Nos. 1 and 2 low-pressure heaters are combined into one heater shell. The level controllers also operate the emergency dump valves which dump the drains directly to the condenser in case of abnormally high level. There are no level controls for the No. 4 heaters which drain to the heater drain tank by gravity flow.

Three half-capacity, multistage, vertical, centrifugal heater drain tank pumps are provided for pumping the heater drainage into the suction line of the feedwater pumps. The pumps are started and stopped from the main control board. Heater drain tank level is controlled by a control valve in the discharge line.

A gland steam condenser maintains a pressure slightly below atmospheric in the turbine gland leakoff system. Sealing steam and air leakage along the shaft at each turbine gland is fed to this condenser, thus preventing any leakage of steam into the turbine room. A motor-driven exhauster is mounted on the gland condenser to remove noncondensable gases.

The Containment Pressure Condensate Isolation (CPCI) circuit trips the two condensate pumps and the three heater drain tank pumps upon sensing a high pressure in containment. The circuit trips the pumps on high containment pressure (2/3 logic). The purpose of this circuit was to prevent overpressurization of containment assuming one of the main feedwater regulating valves fails to close during a steamline break inside containment. However, this function is no longer credited in the steamline break analysis (FSAR 14.2.5) due to installation of the main feedwater isolation valves (MFIVs).

Main Feedwater System

Two motor-driven main feedwater pumps increase the pressure of the condensate for delivery through one stage of feedwater heating, the feedwater regulating valves and the feedwater isolation valves to the steam generators. The pumps have capacity to deliver 50% each of combined condensate discharge flow from the number 4 feedwater heaters and heater drain tank pumps for 100% power (1806 MWt). Each pump is capable of supplying 60% of feedwater flow during single pump operation.

The main feedwater pumps are single-stage, centrifugal pumps. Shaft sealing is accomplished by seal water injection with flow regulated by temperature control valves based on seal water leakoff temperature. Bearing lubrication for the motor and pump is accomplished by an integral lubricating oil system mounted on the pump base. Normal circulation of the lubricating oil is by a shaft-driven pump. The lubricating oil system includes a reservoir, two 100% capacity heat exchangers cooled by condensate, an AC motor-driven auxiliary oil pump and an immersion heater. Main feedwater pump bearing temperatures are recorded in the main control room. The steam generator feedwater pumps are started and stopped from the main control board. A modulated minimum flow control system is provided to ensure 4000 gpm flow during low system flow conditions. Sustained low suction pressure sounds an alarm on the main control board and trips the feedwater pumps after two minutes.

An automatic bypass is provided around the low-pressure heaters to ensure sufficient suction pressure at the feed pumps during a transient when flashing may occur in the heater drain tank and affect the drain pumps performance.

The two main feedwater pumps operate in series with the condensate and the heater drain pumps, discharging through check valves and motor operated gate valves into a common header. The feedwater then flows through the two parallel, high-pressure feedwater heaters and flows into a common header. Two 16 in. lines containing the feedwater control stations feed the two steam generators from the header. The control station consists of one main feedwater control valve and one bypass feedwater control valve in parallel.

The steam generator feedwater control system measures, indicates, records and controls the water level in each of the two steam generators. A conventional three element system is used.

Bypass valves together with shutoff valves at the inlets and outlets of the feedwater heaters are provided to permit heaters to be taken out of service.

Reactor trip is actuated either on a coincidence of sustained steam flow - feedwater flow mismatch, coupled with low level in any steam generator or by a low-low steam generator water level. These trips are discussed in further detail in Section 7.2.

The sizing and control capability of the main feedwater regulating valves (MFRVs), together with the hydraulic operation of the condensate pumps and feedwater pumps, provides sufficient flexibility to accommodate plant load rejection transients by providing 95% of rated flow with a steam generator pressure increase of 100 psi. This is based on the limiting normal condition transient of a 50 % load rejection which causes a decrease in steam generator water level concurrent with an increase in steam pressure.

The MFRVs fail closed on loss of control power or air and close on a reactor trip, safety injection or steam generator High-High water level. The minimum specified valve closure time of 3 seconds was considered in the EPU dynamic valve closure analysis and the maximum closure time of 10 seconds was considered for the EPU main steam line break analysis (FSAR 14.2.5). The bypass feedwater control valves also fail closed on loss of power or air and close on safety injection or an abnormally high steam generator water level.

A three-element primary and secondary programmable indicating controller is provided for each main feedwater control valve and a single-element controller is provided for each bypass feedwater control valve. See Section 7.7.4, Steam Generator Level Control, for additional information on the control systems.

The MFRVs and associated bypass valves are credited for isolation of condensate and feedwater flow for a faulted steam generator, but are considered the backup means rather than the primary means of isolation. The MFRVs are the primary device for feedwater isolation on steam generator High-High water level and reactor trip. The bypass feedwater control valves are a primary isolation device for Feedwater Isolation on steam generator High-High water level.

The MFRVs and bypass valves are classified as non-safety-related because the valves are not considered the primary means of feedwater isolation for a faulted steam generator. The solenoid valves required to trip the main feedwater control and bypass valves for feedwater isolation are safety-related, powered from a safety-related DC power source and receive a safety-related SI signal from both train A and B.

The main feedwater isolation valves (MFIVs) are located downstream of the feedwater control valves (closer to containment) and are credited as the primary means of isolating main feedwater flow to a faulted steam generator. The MFIVs are pnuematically operated and each have two redundant solenoid valves which energize to close the associated MFIV on a safety injection signal. See Section 9.7 for a description of the pneumatic system used to operate the MFIVs. The MFIVs fail as-is on loss of air and are safety-related, seismic Category I. They are designed to close in greater than 3 seconds and less than 5 seconds. The 3 second closure time was used in the dynamic valve closure analysis for both the MFIVs and MFRVs. The maximum closure time of 5 seconds satisfies the assumptions of the containment steam line break safety analysis (Section 14.2.5).

A venturi is installed in each main feedwater line and an acoustic leading edge flowmeter (LEFM) is installed in the common main feedwater line downstream of the number 5 feedwater heaters for flow measurement. The LEFM is more accurate and allows operation at higher power level. See Section 7.5.1.4 and TRM 3.2.2 for additional information.

Circulating Water System

The circulating water system circulates water from Lake Michigan through the main condensers to condense the steam exhausting from the turbines. The water is discharged back to the lake through discharge flumes. Two circulating water pumps per unit are used to circulate the water (see Figure 10.1-6). Travelling screens and a screen wash system remove debris from the water (see Figure 10.1-6B). The circulating water system also supplies cooling water to the condensate cooler for maintaining the main generator hot gas temperature.

The circulating water intake system, common to both units, is designed to provide a reliable supply of Lake Michigan water, regardless of weather or lake conditions, to the suction of four circulating water pumps, six service water pumps, two fire water pumps, two screenwash pumps, and one jockey fire pump. The pumphouse is Class I. The intake crib is located 1750 ft. from the shore in a water depth of 22 ft. The structure consists of two annular rings of 12 in. structural steel H pile driven to a minimum depth of 23 ft. below lake bed and reinforced with walers fabricated from 12 in. structural steel H pile. The annulus is filled with individually placed limestone blocks having two approximately parallel surfaces and weighing between 3 and 12 tons. The structure has an outside diameter of 110 ft., an inside diameter of 60 ft. and a top elevation of approximately -11′-0″. Water enters the intake crib primarily through the 60 ft. opening above the intake cones. The 60 ft. opening is covered with a trash rack having approximately 7 in. x 18 in. openings. The intake crib has been designed to reduce the likelihood of ice blockage during the wintertime.

Water flows from the intake crib to the pumphouse forebay through two 14 ft. diameter, corrugated, galvanized, structural plate pipes buried to a minimum depth of 3 ft. below lake bed. Flow through either pipe can be reversed during winter operation to recirculate warm condenser discharge water to the intake to prevent freezing in the system. Water flows from the forebay through bar grates and through travelling screens having 3/8 in. mesh to the suction of the pumps.

The circulating water is periodically treated to control biological fouling in system piping and in the condensers. Sodium hypochlorite is currently added to the system intermittently to prevent the buildup of slime and algae in the system and to minimize zebra mussel colonization. Sodium

bisulfite is simultaneously injected at the outlet end of the condensers to dechlorinate the discharge circulating water. Other treatments may be considered in the future and will be evaluated prior to implementation. All treatments must be performed within the requirements of our Department of Natural Resources (DNR) Discharge Permit under the Wisconsin Pollutant Discharge Elimination System (WPDES).

Plant internal flooding due to postulated loss of circulating water system integrity in the turbine building is discussed in Appendix A.7.

Turbine Controls

High-pressure steam enters the turbine through two turbine stop valves and four governing valves. One turbine stop and two governing valves form a single assembly which is anchored above the turbine room floor line. An electro-hydraulic servo-actuator controls each turbine stop valve so that it is either in the wide open or closed position. The control signal for this servo-actuator comes from the mechanical hydraulic overspeed trip portion of the electro-hydraulic control system. The major function of these turbine stop valves is to shut off the flow of steam to the turbine in the event the unit overspeeds beyond the setting of the overspeed trip. These valves are also tripped when the protective devices function. The governing valves are positioned by a similar electro-hydraulic servo-actuator acting in response to an electrical signal from the main governor portion of the electro-hydraulic control system. Upon loss of load, the auxiliary governor portion of the electro-hydraulic control will act to close the governor valves rapidly.

The electro-hydraulic turbine control system combines a solid state electronic controller with a high pressure fire resistant fluid supply system which is independent of the lubricating oil. The design features and response characteristics of the system increase the reliability and availability of the power plant.

The electro-hydraulic control system includes the following features:

1. Governor valve controller
2. Load limit controller
3. Auxiliary governor
4. Speed controller
5. Load controller
6. Operators panel on the RTG control board
7. High pressure hydraulic fluid pumping unit
8. Turbine protective devices, including function limits trips, and extraction line nonreturn valves closing signal.

The mechanical overspeed trip mechanism consists of an eccentric weight mounted in the end of the turbine shaft, which is held in position by a spring until the speed reaches approximately 105% of rated speed. Its centrifugal force then overcomes the spring and the weight strikes a trigger which trips the overspeed trip valves and causes the autostop fluid to drain. The resulting decrease in autostop pressure causes the governing emergency trip valve to release the control oil pressure, closing the turbine stop and governing control valves. An air pilot valve is used to close the nonreturn valves in the H.P. turbine extraction lines and in the moisture separator drain lines.

The auxiliary governor provides overspeed protection via the overspeed protection circuitry (OPC) and the EH high pressure fluid system. It will close the governor valves by energizing the OPC solenoid valves if the turbine speed, as sensed from the auxiliary speed tachometer, exceeds

103% of rated speed. By means of the load drop anticipator, it will shut the governor valves by energizing the OPC solenoid valves following a complete load separation. The load drop anticipator measures the mismatch (~30%) between the reheat pressure and the megawatt signals provided the reheat pressure is above a preset value.

The independent overspeed protection system (IOPS) monitors speed electronically and causes a trip signal to be generated should turbine speed exceed 104%. There are 3 identical independent speed channels. The signal for each channel originates from a magnetic pickup mounted adjacent to the shaft turning gear. AC pulses, whose frequency is dependent on turning gear RPM, are generated by the magnetic pickup as the teeth of the turning gear pass. These pulses are transmitted to the speed circuit. The speed circuit generates a fixed-width filtered pulse which is proportional to turbine speed. For reliability, trip signals are generated only when any 2 of 3 channels sense overspeed. Also built into the speed measuring circuitry is a failure detection system which detects failure of the speed pickup, speed wiring or speed amplifier. Failure detection in 2 of 3 speed channels will also trip the turbine. The overspeed trip signals and failure detection signals operate 2 independent relay trains which in turn operate turbine-mounted solenoid valve fluid dump systems, closing the stop and governor valves. Thus failure of one of the 2 relay trains to operate will not prevent this device from tripping the turbine. Test circuitry is provided to test operation of all components without actually tripping the turbine.

In the steam admission system, any steam path has two valves in series which are controlled by completely independent systems. Furthermore, the high pressure oil system that actuates the steam valves is completely independent of the low pressure lubrication oil. The turbine control and protection system is fail-safe. Any loss of oil pressure or voltage causes closure of the steam valves.

The autostop drain valve is also tripped when any one of the protective trip devices is actuated. The protective devices are all included in a separate assembly, but connected hydraulically to the overspeed trip relay.

Trip of the turbine generator when operating above the permissive P-9 setpoint initiates a reactor trip to prevent excessive reactor coolant temperature and/or pressure.

On each unit, two relays have been connected in parallel with the green open light on each main steam line isolation valve (MSIV). One relay on each valve will trip the autostop trip solenoid on the turbine and the other relay will trip the emergency turbine trip solenoid whenever a steam line isolation valve leaves the full open position.

These trip relays function to reduce the closure shocks and frequency of main steam line stop valve closing by:

1. Causing a sudden turbine trip and cessation of main steam flow whenever either main steam line isolation valve moves away from the wide open position. Therefore, if a valve air piston starts to lose air by air failure, or solenoid valve unlatching, the trip signal rapidly acts and can cause turbine trip even before air pressure is so reduced as to allow "wipe in" closure of the main stop valve.

2. Causing a sudden turbine trip and cessation of rapidly increasing flow in the second steam line, when for some reason the first steam line stop has suddenly closed. This trip circuit then prevents much greater than 100% flows from occurring in the second steam line and the wipe in of the second stop valve under conditions of aggravated stress at abnormally high flows.

Chemistry And Radioactivity

Chemistry control specifications for the steam generators, condensate, and feedwater are listed in Table 10.1-3.

Under normal operating conditions, there are no radioactive contaminants present in the steam and power conversion system unless steam generator tube leaks develop. In this event, monitoring of the steam generator shell side sample points and the air ejector off-gas will detect any contamination. A radioactivity monitor is provided for both steam generator blowdown sample lines. A high activity signal initiates closure of remotely operated stop valves in both the blowdown and sample lines. Refer to Chapter 11 for the radiation monitoring system description. The combined air ejector off-gas discharges through the auxiliary building vent stack. A radioactivity monitor in the off-gas line initiates an alarm in the control room in the event that high activity is present.

Shielding

No radiation shielding is required for the components of the steam and power conversion system. Continuous access to the components of this system is possible during normal conditions, except for the steam generator and flow nozzle located inside the containment.

10.1.3 SYSTEM EVALUATION

Safety Features - Variables Limit Functions

Trips, automatic control actions and alarms will be initiated by deviations of system variables within the steam and power conversion system. The more significant malfunctions or faults which cause trips or automatic actions in the steam and power conversion system are:

Turbine Trips

1. Generator/electrical faults;
2. Low condenser vacuum;
3. Thrust bearing failure;
4. Low lubricating turbine bearing oil pressure;
5. Turbine overspeed;
6. Reactor trip;
7. Manual trip;
8. Loss of both main feedwater pumps via AMSAC;
9. Closure of either the main feedwater regulating valve or feedwater isolation valve in both main feedwater lines via AMSAC;
10. Loss of EH system internal power; and
11. Either steam line isolation valve leaves the full open position.

Transient Effects

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

In the unlikely event of complete loss of offsite electrical power to the station and concurrent reactor trip, decay heat removal would continue to be assured by the availability of the auxiliary feedwater system, and steam discharge to atmosphere via the main steam safety valves and the atmospheric steam dump valves.

The analysis of the effects of loss of full load on the reactor coolant system is discussed in Section 14.0. Analysis of the effects of partial loss of load on the reactor coolant system is discussed in Section 14.1.10.

Secondary-Primary Interactions

The automatic condenser steam dump system has been included to increase the transient capability of the plant to provide a means for an orderly reactor power reduction in the event the load is suddenly decreased. The time for a return to full power operation is therefore minimized. The condenser steam dump capacity is discussed in Section 10.1.2. Condenser steam dump is initiated by coincidence of a large rapid load change together with a large error signal between T_{avg} (reactor coolant system average temperature) and T_{ref} (program reference average coolant temperature which is based on turbine power) at the new load condition. As the control group is inserted by the reactor control system, reactor power is reduced thereby reducing T_{avg}. The steam dump modulation is proportional to the difference between measured T_{avg} and T_{ref} and is thus reduced as rapidly as the rods are able to reduce core power. The transient is terminated with the plant at equilibrium the new load conditions and there is no further steam dump to the condenser. The transient response to a 50% rapid load reduction would consist of the full condenser steam dump actuated in a few seconds and fully closing in about 10 minutes.

If the condenser heat sink is not available during a turbine trip, excess steam, generated as a result of reactor coolant system sensible and core decay heat, is discharged to the atmosphere.

If the atmospheric steam dump valves should fail to dump steam, the loss of load transient will be accommodated by steam discharge through the main steam safety valves. If a valve would operate to dump steam inadvertently, the result would be a load increase equivalent to a small steam break. In either case, the reactor control and protection system precludes unsafe operation. These protection systems are provided to trip the reactor in the event of a sustained load mismatch between the reactor and turbine.

Normal turbine overspeed protection and the main steam safety valves provide protection for these systems completely independent of any steam dump valve operation.

Following a turbine trip from power levels above the P-9 setpoint, the control system reduces reactor power output immediately by a reactor trip. The steam dump can handle all the steam generated without lifting the main steam safety valves.

In the event of failure of one feedwater pump, the feedwater pump remaining in service will carry approximately 60% of full load feedwater flow. If both main feedwater pumps fail, the turbine will be tripped, and the auxiliary feedwater pumps start automatically. If reactor coolant system conditions reach trip limits, the reactor will trip.

Pressure relief is required at the system design pressure of 1085 psig, and the first main steam safety valve is set to relieve at this pressure. Additional main steam safety valves are set at pressures up to 1105 psig, as allowed by the ASME Code. In addition to the main steam safety valves, one atmospheric steam dump valve is installed for each steam generator which can be manually operated from the control room. The atmospheric steam dump valves are set to open at a pressure slightly below that of the main steam safety valves. The pressure relieving capacity of the main steam safety valves is equal to the steam generation rate at maximum calculated conditions.

Single Failure Analysis

A single failure analysis has been made for all active components of the system which have an emergency function. The analysis, which is presented in Table 10.1-4 shows that the failure or malfunction of any single active component will not reduce the capability of the system to perform its emergency function.

10.1.4 REQUIRED PROCEDURES AND TESTS

The main steam isolation valves, main steam safety valves, atmospheric dump valves, main feedwater isolation valves and main feedwater regulating valves are tested and/or inspected in accordance with the Technical Specifications to ensure proper operation.

The turbine stop and governor valves are tested for proper operation in accordance with the TRM section 3.7.6.

A review of the turbine valve failure-rate data will be conducted at least once every three years to determine if the testing frequency requires modification. A review of the turbine valve failure-rate data will be conducted whenever major changes to the turbine system are made or a significant upward trend in turbine valve failure rate is identified, to determine if the testing frequency requires modification.

10.1.5 REFERENCES

1. NRC SER, “Point Beach Nuclear Plant- Units 1 and 2, Issuance of License Amendments Regarding Extended Power Uprate,” dated May 3, 2011.

2. Westinghouse letter WEP-08-173, Point Beach Units 1 and 2-Westinghouse NSSS/BOP Interface System Evaluations-Steam Generator Blowdown System & Turbine Bypass/ Steam Dump System, dated December 23, 2008. (Accepted per PBNP letter PB-EPU-08-2370)

3. Westinghouse internal letter SEE-111-08-095, Point Beach Units 1 and 2- NSSS/BOP Interface System Evaluations-Steam Generator Blowdown System & Turbine Bypass/ Steam Dump System, dated June 6, 2008. (submitted by Reference 2 above)

4. Screening 2010-0120-01, Engineering Design Changes EC 12042, “Replacement of Unit #2 Steam Generator Main Feedwater Pumps and Motor Sets” & EC 09998 “Replacement of Unit #2 Steam Generator Main Feedwater Pumps Minimum Flow Recirculation System,” May 26, 2011.

5. Screening 2010-0147, Engineering Design Changes EC 12052 (2558480), “Feedwater Isolation Valve Addition,” dated May 7, 2011.

6. Screening 2010-0002, Engineering Design Change EC 12054, Rev 2, “Feedwater Regulating Valve Upgrade,” May 9, 2011.

7. Unit 1 SCR 2011-0153, Engineering Design Change 11954 (258382) “Feedwater Isolation Valve Addition,” July 26, 2011.

8. SCR 2009-0189, Engineering Design Changes EC 12041,”Replacement of Unit #1 Steam Generator Main Feedwater Pumps and Motor Sets” and EC 09997, “Replacement of Unit #1 Steam Generator Main Feedwater Pumps Minimum Flow Recirculation System,” July 7, 2011.

9. Unit 1 SCR 2010-0001, “EC 258481 (12053) Rev 2 Feedwater Regulating Valve Upgrade Unit 1s,” August 25, 2011.

10. SCR 2011-0060-01, CN-CPS-08-20, Rev 3, “Plant Operability Margin to Trip and EOC Coastdown Analysis for Point Beach Units 1 and 2 Extended Power Uprate Program,” July 13, 2011.

11. Siemens Letter TL-SPG-FPLE PB 0120, Steam Dump System Arming Setpoint, dated June 8, 2009.

12. Modification Request MR 83-70, “2HB7B-6” Tie Line Between Existing 2HB7A-12” Heating Building Steam Piping and Tuirbine Gland Seal Steam,” approve August 7, 1985.

Table 10.1-1 STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS

Turbine-Generator	
Turbine	Three element, tandem-compound four-flow exhaust
Turbine Capacity (KW)	
Maximum calculated @ 1806 MWt	641,600
Generator Rating (KVA)	684,000
Turbine Speed (rpm)	1800
Main Condenser	
Type	Single pass, radial flow, semicylindrical water boxes, deaerating
Number of Sections	2
Rated Capacity (lbs of steam/hr)	3,545,820 @ 999.7 BTU/lb
Circulating Water Pumps	
Type	Single stage, vertical centrifugal
Number	2
Design Capacity (each gpm)	178,000 @ 29.9 ft. TDH
Motor Type	Vertical
Motor Rating (hp)	1750
Condensate Pumps	
Type	Multi-stage, vertical, pit-type, centrifugal
Number	2
Design Capacity (each-gpm)	5700 @ 760 ft. TDH
Motor Type	Vertical
Motor Rating (hp)	1500
Feedwater Pumps	
Type	Single stage, centrifugal
Number	2
Design Capacity (each gpm)	9300 @ 2200 ft. TDH
Motor Type	Horizontal
Motor Rating (hp)	6200

Table 10.1-2 STEAM AND POWER CONVERSION SYSTEM CODE REQUIREMENTS

Steam Pressure Vessels	ASME VIII*
Steam Generator Vessel	ASME III, Class A, tube side**
	ASME III, Class C, shell side***
System Valves, Fittings and Piping	USAS B31.1****

* American Society of Mechanical Engineers, Boiler and Pressure Vessel Code. Section VIII.

** American Society of Mechanical Engineers, Boiler and Pressure Vessel Code. Section III, Nuclear Vessels.

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

**** Code for Pressure Piping.

Table 10.1-3 AVT CONTROL, SECONDARY CHEMISTRY CONTROL GUIDELINES[1]
Sheet 1 of 2

Steam Generator Blowdown Control

Parameter	Power Operation Normal Value	Hot Standby[3] Normal Value	Cold Shutdown (Wet Layup)[2] Normal Value
pH at 25ºC[4]	----	----	9.8 - 10.5
Organic Corrected Cation Conductivity, µS/cm, at 25ºC	≤0.8	≤2.0	----
Sodium, ppb Na	≤20	≤100	≤1000
Chloride, ppb Cl	≤20	≤100	≤1000
Sulfate, ppb SO_4	≤20	≤100	≤1000
Dissolved Oxygen, ppb O_2	----	----	≤100
Oxygen Scavenger[6]	----	----	----
Ammonia[4]	----	----	----
Corrosion Control Additive(s)[5]	----	----	----

(1) These chemistry control guidelines have been formulated to minimize steam generator tube degradation and secondary system corrosion while maintaining operating flexibility. The normal values are based on the current understanding of corrosion behavior, chemical transport, impurity concentrations, materials, and chemical analysis methods; on industry practices; and on plant-specific experience. Because the steam generator is most susceptible to corrosion from impurity ingress while at power, the power operation normal values are the most stringent. In the event the monitored parameters are observed and confirmed to be outside normal operating values, action levels are implemented and corrective actions are executed in accordance with plant procedures.

(2) The steam generator is placed in a cold wet layup condition with chemically treated water whenever practical during outages to minimize surface corrosion. Impurity levels introduced from hideout return during power reduction to shutdown are reduced by feed and bleed, flushing, or drain and refill.

(3) When not at power with the reactor coolant system hot, the steam generator is maintained in the hot standby condition. The steam generator is essentially ready for steaming and power operation while in hot standby. Impurity inventories are reduced prior to proceeding to power by feed and bleed (blowdown and makeup).

(4) Values for these parameters are listed in NP 3.2.3, "Secondary Water Chemistry Monitoring Program."

(5) The corrosion control additive(s) and values are listed in NP 3.2.3, "Secondary Water Chemistry Monitoring Program."

(6) The oxygen scavenger additive(s) and values are listed in NP 3.2.3, "Secondary Water Chemistry Monitoring Program."

Table 10.1-3 AVT CONTROL, SECONDARY CHEMISTRY CONTROL GUIDELINES
Sheet 2 of 2

Feedwater

	Power Operation	Hot Standby	Cold Shutdown (Wet Layup)
pH at 25ºC[1]	---		
Dissolved Oxygen, ppb O_2	≤5	<100[3]	<100[3]
Oxygen Scavenger[2, 5]	---		
Total Iron, ppb	≤5		
Total Copper, ppb	≤1		
Ammonia[1]	---		
Corrosion Control Additive(s)[4]	---		

(1) Values for these parameters are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

(2) As measured at the feed pump suction or equivalent feed pump discharge sample point.

(3) As measured at the condensate storage tanks (CST's) or auxiliary feed pump suction.

(4) The corrosion control additive(s) and values are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

(5) The oxygen scavenger additive(s) and values are listed in NP 3.2.3, “Secondary Water Chemistry Monitoring Program.”

Condensate

Dissolved Oxygen, ppb O_2	≤10

Table 10.1-4 STEAM AND POWER CONVERSION SYSTEM SINGLE FAILURE ANALYSIS

Component or System	Malfunction	Comments and Consequences
Steam Line Isolation System	Failure of steam line isolation valve to close (following a main steam line rupture)	Each steam line contains an isolation valve and a nonreturn valve in series. Hence, a failure of an isolation (or non-return) valve will not permit the blowdown of more than one steam generator irrespective of the steam line rupture location.
Steam Dump System	Steam dump valve sticks open (following operation of the system resulting from a turbine trip)	The steam dump system is comprised of 8 bypass valves. Hence, one valve passes less than 5% of the steam generator steam flow and there is a reduced potential for a hazard in the form of an uncontrolled plant cool-down if a steam dump valve sticks open.
Feedwater Isolation System	Failure of Feedwater Isolation Valve to close (following a main steam line rupture)	Main feedwater regulating valve closes to stop flow. Two trains of containment fan coolers and spray credited for containment response (Reference Section 14.2.5 C).
	Failure of main feedwater regulating valve to close (following a main steam line rupture)	Feedwater isolation valve closes to stop flow. Feedwater, condensate, and heater drain pumps trip on high containment pressure to stop flow.

Figure 10.1-1 UNITS 1 & 2 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-1 UNIT 1 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-1 UNIT 1 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-1A UNIT 2 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-1A UNIT 2 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-1A UNIT 2 MAIN AND REHEAT STEAM FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-2 UNIT 1 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-2 UNIT 1 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-2 UNIT 1 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-2A UNIT 2 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-2A UNIT 2 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-2A UNIT 2 CONDENSATE AND FEEDWATER FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-3 UNIT 1 EXTRACTION STEAM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-3 UNIT 1 EXTRACTION STEAM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-3A UNIT 2 EXTRACTION STEAM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-3A UNIT 2 EXTRACTION STEAM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-4 UNIT 1 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-4 UNIT 1 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-4 UNIT 1 FEEDWATER HEATER DRAINS (Sheet 3)

[redacted]

Figure 10.1-4A UNIT 2 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.1-4A UNIT 2 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.1-4A UNIT 2 FEEDWATER HEATER DRAINS FLOW DIAGRAM (Sheet 3)

[redacted]

Figure 10.1-6 UNIT 1 CIRCULATING WATER CONDENSER AIR REMOVAL

[redacted]

Figure 10.1-6A UNIT 2 CIRCULATING WATER CONDENSER AIR REMOVAL

[redacted]

Figure 10.1-6B UNITS 1 & 2 CIRCULATING WATER SYSTEM SCREEN WASH (Sheet 2)

[redacted]

Figure 10.1-7 UNIT 1 FEEDWATER HEATER VENTS AND RELIEFS FLOW DIAGRAM

[redacted]

Figure 10.1-7A UNIT 2 FEEDWATER HEATER VENTS AND FLOW DIAGRAM

[redacted]

Figure 10.1-8 UNIT 1 GLAND STEAM AND DRAINS FLOW DIAGRAM

[redacted]

Figure 10.1-8A UNIT 2 GLAND STEAM AND DRAINS FLOW DIAGRAM

[redacted]

10.2 AUXILIARY FEEDWATER SYSTEM (AF)

Due to required increase in pump capacity for the EPU LAR and the unitization of the AFW system, new 100 % capacity motor-driven AFW Pumps (1(2)P-53) replaced the shared motor-driven AFW Pumps (P-38A/P-38B) as the credited motor-driven pumps (Reference 19). P-38A/B were then renamed Standby Steam Generator (SSG) Feedwater Pumps. The SSG pumps no longer have automatic start circuitry and are only available by manual operator action at Main Control Board C-01 and local control panels N-01 (N-02).

Previous automatic actuation signals to the P-38A/B pumps from safety injection, AMSAC, and steam generator A/B low-low level were removed. The SSG pump start circuits consist solely of manual control switch manipulation between "Normal" and "Override" positions on Main Control Board C-01. If running, the SSG pumps will be stripped by an automatic start signal for 1P-53 or 2P-53 or an automatic or manual SI signal from either unit. This feature is used to control loading on the EDG and 480V buses and to prevent excess flow to a faulted steam generator in a main steam line break or steam generator tube rupture event. To prevent inadvertent starting of an SSG pump while the new MDAFW pumps are operating, restart of a tripped SSG pump requires administrative controls and manual action by the operator.

Service water suction valves AF-4009 for P-38A and AF-4016 for P-38B remain unchanged in the transition to SSG pumps. P-38A AFW discharge valves AF-4023 for Steam Generator (SG) 1HX-1A and valve AF- 4022 for SG 2HX-1A as well as P-38B AFW discharge valves AF-4021 for SG 1HX-1B and valve AF-4020 for SG 2HX-1B have their respective automatic open and close functions removed from their control circuits. All other functionality and terminations remain unchanged in the transition to SSG pumps.

The SSG pumps are normally used during plant startup and shutdown and during hot shutdown or hot standby conditions when chemical additions or small feedwater flow requirements do not warrant the operation of the main feedwater and condensate systems.

NOTE: Unless indicated otherwise, the remaining portion of Section 10.2 applies only to portions of the AFW system credited for safety related functions.

10.2.1 DESIGN BASIS

The Auxiliary Feedwater System consists of one full-capacity MDAFW pump system and one full-capacity TDAFW pump system for each unit to ensure that adequate feedwater is supplied to the steam generators for heat removal under all circumstances, including loss of offsite power and normal heat sink. Feedwater flow can be maintained until power is restored or reactor decay heat removal can be accomplished by other systems. The auxiliary feedwater system is designed as a seismic Class I system and normally takes suction from the condensate storage tanks (CSTs). A backup supply of auxiliary feedwater is provided by automatic or manual switchover to the seismic Class I portion of the service water system (see Figure 10.2-1). The MDAFW pump discharge piping for each unit can be cross-tied by opening normally closed manual valves to feed the SGs on the opposite unit (Reference 16). The MDAFW cross-tie performs a safety-related function to provide pressure boundary and separation between the two pumping systems (Reference 23).

Each auxiliary feedwater pump system is required to supply 275 gpm high-pressure feedwater to the steam generators in order to maintain a water inventory for removal of heat energy from the reactor coolant system by secondary side steam release in the event of inoperability or unavailability of the main feedwater system. Redundant supplies are provided by two 100% capacity pump systems using different sources of power for the pumps and different trains of DC for valve and control power. DC power for the Unit 1 and 2 TDAFW pumping systems are also from different trains. The design capacity of each pump system is set so that the steam generators will not boil dry nor will the primary side relieve fluid through the pressurizer relief or safety valves, following a loss of main feedwater flow with a reactor trip (Reference 16).

The AF system performs the following safety-related functions:

The AF system shall automatically start and deliver adequate AF system flow to maintain adequate steam generator levels during accidents which may result in main steam safety valve opening. Such accidents include; Loss of Normal Feedwater (LONF), FSAR Chapter 14.1.10, and Loss of All AC Power To The Station Auxiliaries (LOAC), FSAR Chapter 14.1.11, events. LONF and LOAC are time-sensitive to AF system start-up.

The AF system shall automatically start and deliver sufficient system flow to maintain adequate steam generator levels during accidents where AF flow is credited to cool down the reactor coolant system to RHR initiation conditions within the limits of the analysis assumptions. Such accidents include; steam generator tube rupture (SGTR), FSAR Chapter 14.2.4, and Rupture of a Steam Pipe (MSLB), FSAR Chapter 14.2.5.

The AF system shall be capable of isolating the AF steam and feedwater supply lines from the ruptured or faulted steam generator following a SGTR or MSLB event. Steam to the TDAFW pump can be isolated by closing the steam supply MOVs or manually tripping the overspeed trip throttle valve. Each AF pumping system has two diverse ways to stop auxiliary feedwater flow when required. Flow from the MDAFW can be stopped by closing the flow control valve (FCV) to the affected steam generator via 120 VAC power or tripping the pump via 125V DC control power. Flow from the TDAFW pump can be isolated by closing the pump's discharge MOV for the affected steam generator using 125V DC control power or by tripping the pump via a diverse 125 VDC supply to the trip throttle valve (Reference 16).

The safety-related portions of the AFW system are designed as Seismic Class I, and are capable of withstanding design basis earthquake accelerations without a loss of system performance capability.

The AF system also performs the following augmented quality functions related to regulatory commitments:

In the event of a station blackout (prolonged loss of offsite and onsite AC power), the AF system is capable of automatically supplying sufficient feedwater to remove decay heat from both units without any reliance on AC power for one hour. This independence from AC power was initially two hours as documented in the NRC safety evaluation dated April 21, 1982 (Reference 8). This was subsequently superseded by the re-licensing of PBNP via acceptance of the Station Blackout Coping Analysis in NRC safety evaluation dated October 3, 1990 (Reference 9), which concluded that PBNP is a one-hour coping plant.

While this subsequent safety evaluation did not explicitly supersede the requirement from NUREG-0737, the submittal of a one-hour coping assessment for a loss of all AC power under the requirements of 10 CFR 50.63 (the station blackout rule) was reviewed and approved by the NRC. The subject is discussed in the Point Beach FSAR, Appendix A.1.

In the event of plant fires, including those requiring evacuation of the control room, the AF system shall be capable of manual initiation to provide feedwater to a minimum of one steam generator per unit at sufficient flow and pressure to remove decay and sensible heat from the reactor coolant system over the range from hot shutdown to cold shutdown conditions. The AF system shall support achieving cold shutdown within 72 hours (Reference 2). The MDAFW pumps and TDAFW pumps are located in separate fire areas. Power and control cables are routed and associated motor control centers are located to ensure adequate separation of the TDAFW and MDAFW systems (Reference 16).

In the event of an Anticipated Transient Without Scram (ATWS), the AF system shall be capable of automatic actuation by use of equipment that is diverse from the reactor trip system. This is accomplished by the AMSAC system described in FSAR Section 7.4. An AFW pump start delay time of less than or equal to 90 seconds is assumed in the ATWS analysis. This delay time consists of a 30 second AMSAC time delay plus a 60 second AF system pump start response time (Reference 4).

The safety related auxiliary feedwater system has no functional requirements during normal, at power, plant operation. It may be used during plant startup and shutdown and during hot shutdown or hot standby conditions when small feedwater flow requirements do not warrant the operation of the main feedwater and condensate systems.

10.2.2 SYSTEM DESIGN AND OPERATION

The safety related auxiliary feedwater system consists of one electric motor-driven pump and one steam turbine-driven pumps per unit, pump suction and discharge piping, and the controls and instrumentation necessary for operation of the system. Redundancy is provided by utilizing two 100% capacity pumping systems, two different sources of power for the pumps, and two sources of water supply to the pumps. The system is categorized as seismic Class I and is designed to ensure that a single active failure will not obstruct the system function.

The system utilizes a steam turbine-driven pump (1/2P-29) with the steam capable of being supplied from either or both steam generators. This system is capable of supplying 275 gpm combined flow to both steam generators through normally throttled MOVs AF-4000 and AF-4001. The feedwater flowrate from the turbine-driven auxiliary feedwater pump depends on the throttle position of these DC powered MOVs. Check valves are provided to help prevent backflow when the pumps are not in service. The pump drive is a single-stage turbine, capable of quick starts from cold standby and is directly connected to the pump. The turbine is started by opening either one or both of the isolation valves (MS-2019 and MS-2020) between the turbine supply steam header and the main steam lines upstream of the main steam isolation valves. These valves are DC powered motor operated stop check valves which prevent reverse flow between the steam generators. The turbine is cooled via AFW, drawn through the pump via a first stage tap connection, and returned to the pump suction. The pump does not require cooling water.

Alternate DC power is provided for the manual trip capability of the TDAFW pump by means of its redundant trip control switch 1(2) MS-2082S-CS located in the main control room. The switch provides a means of transferring the overspeed trip valve 1(2) MS-2082 solenoid power from its normal supply, battery D105(D106), to its alternate supply, battery D05 (D06), to manually trip the pump from either power supply in case a single failure prevents stopping flow by closing the steam generator inlet isolation MOV(s) or the pump steam inlet MOVs (Reference 16).

The electric-motor driven auxiliary feedwater pumps (1/2P-53) are 350 horsepower, 4160 volt and powered from safeguards buses 1A-06 and 2A-05 for Unit 1 and 2 respectively. The pumps are designed to supply a total of 275 gpm to their associated units' steam generators through fail-open discharge flow control valves (FCVs) 1(2) AF-4074A and 1(2) AF-4074B. The FCVs will maintain flow approximately split between the two SGs regardless of SG pressure. This limits the flow to a ruptured SG in a main steam line break (MSLB) accident, thereby limiting the uncontrolled cooldown. Cavitating venturis (1/2 RO 4088A(B)) are installed downstream of each of the flow control valves. The cavitating venturis are designed to prevent excessive flow to a faulted steam generator in the event of a failure of the associated flow control loop. During a steam generator tube rupture the venturis allow feeding up to approximately 230 gpm to the intact steam generator for decay heat removal (Reference 20 and Reference 21).

The MDAFW pumps have a shaft mounted cooling fan, eliminating the need for any external fluid to provide shaft or seal cooling, or motor cooling. The pump motors are not environmentally qualified (EQ) because they are not needed for a large break LOCA and are located in a mild environment for small break LOCA, SG tube rupture, MSLB, loss of normal feedwater and loss of AC events (Reference 16).

The water supply source for the auxiliary feedwater system is redundant. The normal source is by gravity feed from two nominal capacity 45,000 gallon condensate storage tanks while the safety-related seismic Class I (Reference 3) supply is taken from the plant service water system whose pumps are powered from the diesel generators if station power is lost. The turbine driven and motor driven pumps take suction from the CSTs through separate headers (Reference 16).

It is possible that a loss of normal feedwater initiated by a seismic event could also result in the interruption of the normal source of auxiliary feedwater from the condensate storage tanks because the condensate storage tanks are not classified as seismic Class I. The plant operators would be alerted to this problem by receipt of low suction pressure alarms on the auxiliary feedwater pumps. Seperate and redundant level instrumentation including both alarms and indication for both condensate storage tanks is available in the control room (Reference 8 and Reference 13). Missile shielding is provided on certain AFW pump suction piping from the CST to ensure sufficient water volume for AFW pump suction prior to low suction pressure trip (Reference 12).

Automatic switchover of AFW pump suction from the CSTs to Service Water is initiated by low pump suction pressure to restore suction pressure prior to consumption of the available condensate water in the protected section of suction piping upstream of the service water supply connection. The low pump suction pressure circuit includes a time delay to ensure that the suction transfer will not be inadvertently initiated due to temporary low suction pressure that occurs during normal pump start-up transients.

The time delay to initiate tripping of the operating AFW pumps on low suction pressure has been selected to ensure the pumps are secured prior to depletion of the condensate inventory in the protected section of suction piping if the SW transfer were to fail. Adequate safety margin is provided by making allowance for the maximum opening time of the SW supply valve, uncertainty in the timing circuits for both initiation of suction transfer and AFW pump trip, and the time for the pump trip time delay relay to reset after full opening of the SW supply valve and associated restoration of suction pressure. Therefore, adequate margin will remain between the maximum time to restore suction pressure and the minimum time for initiation of the AFW pump trip, and an inadvertent AFW pump trip would be unlikely with SW available to the suction of the pumps (Reference 16).

The AFW pump suction also automatically transfers to service water upon low-low-low CST level. This circuitry is not credited in the safety analyses. See Sections 7.3.2.2.h and 7.4.3.

The TDAFW pump has a single minimum flow recirculation line, isolated by a fail-closed AOV (1/2AF-4002) and the MDAFW pump has two parallel minimum flow recirculation lines, each isolated by a fail-closed AOV (1/2 AF 4073 A(B)). The recirculation lines direct recirculation flow to the CSTs. Each of the MDAFW recirculation lines is designed to ensure the minimum flow rate to protect the pump is provided in the event of a failure of one of the recirculation valves to open. The minimum flow recirculation AOVs have a safety-related function to close to ensure the required AFW flow is not diverted away from the steam generators. These valves also have a safety-related function to open to ensure that a minimum flow is maintained through the pumps to prevent damage due to hydraulic instabilities or increased temperature (Reference 16).

Safety-related backup pneumatic systems are provided for the system's air operated valves. The pneumatic systems permit operation at hot shutdown for at least four hours followed by cooldown to the RHR cut-in temperature from the control room with only safety grade equipment, assuming the worst-case single failure in accordance with Branch Technical Position (BTP) 5-4. Although designed for 24 hours of operation, these backup air supplies are only credited for four hours of minimum recirculation AOV operability if instrument air is lost. Manual gags permit operators to open the recirculation AOVs and throttle the MDAFW pump flow control valves consistent with decay heat requirements prior to depletion of the backup pneumatic supply (Reference 16 and Reference 17).

Flow- restricting orifices (1/2RO-4003, 1/2RO-4075 A(B)) installed in the pump recirculation lines facilitate pressure reduction for pumping back to the CSTs (at atmospheric pressure). These orifices have a safety function to restrict the flow to an appropriate value to ensure pump operability. A recirculation flow larger than what is assumed in the AFW pump coastdown analysis for a seismic-induced loss of CSTs (Reference 7 and Reference 18) could result in one or both units having no auxiliary feedwater capability. Additionally, a recirculation flow that is too high could reduce forward flow to a point that the recirculation AOVs may not shut, and the pump will not be capable of delivering the required 275 gpm flow to the steam generators. These orifices also have a safety function to pass the minimum flow required to prevent pump damage. 1/2 P-29 require 75 gpm and 1/2 P-53 require 55gpm for 60 total accumulated hours and 75 gpm for 1500 accumulated hours. The orifices are sized so as to not be susceptible to clogging by service water debris. This debris size is limited by the size of the service water strainers (Reference 10, Reference 11 and Reference 16).

The minimum flow recirculation lines are safety-related up to the flow restricting orifices, but are considered augmented-quality downstream of the orifices to the CSTs, even though the recirculation lines have a safety function to provide a recirculation flowpath as described above. Operability of the AFW pumps is dependent upon a recirculation flowpath being available. The augmented-quality classification is appropriate since failure could result in a loss of water from the CST that is essential to mitigate station blackout (SBO).

During normal plant operations, the auxiliary feedwater system is maintained in a standby condition ready to be placed in operation automatically when conditions require. The turbine-driven and motor-driven auxiliary feedwater pumps are automatically started on receipt of any of the following signals (Reference 16):

1. Low-low water level in either steam generator.

2. Loss of voltage on both 4.16 kv buses supplying the main feedwater pump motors.

3. Trip or shutdown of both feedwater pumps or closure of either a feedwater isolation valve or a feedwater regulating valve in both main feedwater lines. These signals are processed through AMSAC at reactor power levels above 40% (Reference Section 7.4).

4. Automatic or manual safety injection. In conjunction with a loss of AC the MDAFW pump start is sequenced a nominal 32.5 seconds after EDG breaker closure. The MDAFW pump will also start anytime the corresponding 4.16 kv bus is islanded on EDG power, but will run on minimum recirculation until a valid AFW start signal is initiated.

The steam generator blowdown isolation valves are configured to close automatically based upon start of the associated unit's steam driven or motor-driven auxiliary feedwater pump. A bypass switch allows defeating this function for testing and normal operation of the auxiliary feedwater pump.

Operator action is required to maintain proper steam generator levels and control auxiliary feedwater flow. In the event that both auxiliary feedwater pumps start and run as designed, the initial auxiliary feedwater flow will be significantly greater than the design basis flow. Auxiliary feedwater pump flow and direct flow indication for each steam generator is provided in the control room. Flow indication is also available locally at the discharge of each motor-driven pump. Auxiliary feedwater flow instrumentation is powered from highly reliable battery backed Class 1E power sources. Alarms are available in the control room to indicate that the automatic initiation of the auxiliary feedwater system is disabled (Reference 14).

Both the MDAFW pump and TDAFW pump have local control stations located near the pumps, so that auxiliary feedwater can be supplied to the steam generators from outside the control room. Local control panels 1(2)N-05 are installed just outside of the MDAFW pump rooms and provide controls for starting and stopping the MDAFW pumps. Local control panels 1(2) RK-38 and 1(2) C-205 are located in the vicinity of the TDAFW pumps and include steam generator level indication for local control of AFW flow. Operators for the steam supply valves to the TDAFW pump, steam generator flow control valves and minimum recirculation valves are provided with hand wheels to allow local manual positioning as necessary (Reference 16).

10.2.3 SYSTEM EVALUATION

In the event of complete loss of offsite electrical power to the station, decay heat removal would continue to be assured for each unit by the availability of either the turbine-driven auxiliary feedwater pump or the motor-driven auxiliary feedwater pump, and discharge to the atmosphere via the main steam safety valves or atmospheric relief valves. Either AFW pump is capable of

supplying sufficient feedwater for removal of decay heat from a unit operating at 100.6% of 1806 MWt Core Power (includes 6 MWt pump heat). In this case, feedwater is available from the condensate storage tanks by gravity feed to the auxiliary feedwater pumps. When the water in the condensate storage tanks is depleted, suction for the pumps automatically shifts to the service water system to provide makeup water from the lake for an indefinite time period.

During a Station Blackout (SBO) event, only the turbine-driven pumps would be available for decay heat removal. The turbine-driven pumps are capable of supplying feedwater to the steam generators without an AC power source. Each of the two steam supply valves and each of the two auxiliary feedwater discharge valves are powered from diverse sources of vital 125V DC, i.e., two different buses on the same DC train. The Technical Specification minimum amount of water in the condensate storage tanks provides adequate makeup to the steam generators to maintain each unit in a hot shutdown condition for at least one hour concurrent with a loss of all AC power. Further information on the SBO event is provided in Appendix A.1 (Reference 1).

In order to meet the design basis, the Loss of Normal Feedwater (Section 14.1.10) and Loss of All AC Power to Station Auxiliaries (Section 14.1.11) accident analyses assume that the auxiliary feedwater system provides 275 gpm of flow split between two steam generators. If limited to the MDAFW pump, the maximum flow that can be delivered to a single steam generator is approximately 230 gpm due to the presence of the cavitating venturis (Reference 20 and Reference 21). The Loss of Normal Feedwater analysis assumes flow starts within 30 seconds following receipt of a low-low steam generator water level setpoint signal and reaches 100% within 120 seconds. The Loss of AC Power to Station Auxiliaries analysis assumes flow starts within 60 seconds following receipt of a low-low steam generator water level setpoint signal and reaches 100% within 150 seconds. These minimum parameters are met or exceeded by system design and verified by required testing (see Section 10.2.4).

The loss of main feedwater due to a seismic/tornado event (Reference 7) is not equivalent to the Loss of Normal Feedwater (LONF) and Loss of All AC Power to Station Auxiliaries (LOAC) events discussed above. The purpose of the seismic/tornado event analysis is to ensure the AFW pumps are not damaged by low suction pressure resulting from damage to the suction supply piping from the CSTs. In the case of the LONF/LOAC analyses, conservative initial conditions and assumptions are used to ensure that a bounding analysis results. These conservative conditions and assumptions include conservative decay heat rates, credit for only 275 gpm of AFW flow, no credit for the automatic reactor trip on steam flow / feedflow mismatch coincident with a low steam generator level and no credit for a manual reactor trip.

The two other accident analyses which assume auxiliary feedwater system operation are Steam Generator Tube Rupture (Section 14.2.4) and Rupture of a Steam Pipe (Section 14.2.5). For the Steam Generator Tube Rupture analysis auxiliary feedwater is isolated to the affected steam generator and used for RCS cooldown using the unaffected steam generator. The core power and reactor coolant system transient portion of the Rupture of a Steam Pipe analysis assumes a conservatively high auxiliary feedwater flow rate to the affected steam generator that continues for the duration of the transient. The containment response portion of the Rupture of a Steam Pipe analysis assumes auxiliary feedwater flow is manually realigned to prevent further water addition to the faulted steam generator.

Although the auxiliary feedwater system may be initiated during a Small Break LOCA (Section 14.3.1) or a Loss of External Electrical Load (Section 14.1.9), the events have been analyzed with no credit for auxiliary feedwater.

The system is categorized primarily as safety related, Seismic Class I and is designed to ensure that a single active failure will not adversely affect the reliability or function of the system. The AFW system is designed so a single active failure will not disable more than one pump system in each unit. Each of the two AFW pump systems (i.e., a TDAFW pump and a MDAFW pump) in each unit has some shared discharge piping with instrumentation and controls necessary for operation of the pump system. The two MDAFW pumps (one per unit) share a CST suction header. The two TDAFW pumps (one per unit) share the second CST suction header.

A system level Failure Modes and Effects Analysis for the AFW System has been performed and the results are shown in Table 10.2-1. A component level Failure Modes and Effects Analysis for the new components installed in the EPU AFW Margin Improvement Modification was also performed and verified that no individual component (or connection of system components) results in a common mode failure between redundant pump systems.

10.2.4 REQUIRED PROCEDURES AND TESTS

The AF system components are tested and inspected in accordance with Technical Specification 3.7.5 surveillance criteria and surveillance frequencies by the Surveillance Frequency Control Program (Reference 22). Testing verifies motor-driven pump operability, turbine-driven pump operability including a cold start and operability of all required automatic valves. Control circuits, starting logic, and indicators are verified operable by their respective functional test.

Procedures provide guidance for recognizing steam binding of the AFW pumps and for restoring the AFW system to operable status should steam binding occur. The AFW pump discharge piping temperature is monitored shiftly for temperatures in excess of ambient which may be indicative of potential steam binding of an AFW pump (Reference 15).

Isolation valves for the MDAFW and TDAFW pump discharge flow transmitters and the steam generator flow transmitters are locked per the Auxiliary Feedwater valve lineup checklists which require independent operator verification (Reference 13).

10.2.5 Generic Letter 81-14

Generic Letter 81-14, “Seismic Qualification of Auxiliary Feedwater Systems,” was issued to evaluate the seismic qualifications of AFW systems and to correct deficiencies, where practical, such as to provide reasonable assurance that the AFW system is able to function following the occurrence of earthquakes up to and including the design Safe Shutdown Earthquake (SSE). In response to GL 81-14, PBNP provided existing design information, performed additional evaluations, and performed plant modifications to correct identified deficiencies.

NOTE: Check valves 1/2AF-191, manual valves 1/2AF-190 and the automatic suction transfer feature mentioned in the following paragraph were installed later by the AFW capacity upgrade modification for EPU.

The AFW system pumps, motors, safety related piping, valves and actuators, power supplies, initiation and control systems are all qualified to withstand a SSE. The condensate storage tank (CST), which is the primary water source of the AFW system, is not seismically qualified. The Service Water system is the safety related, seismic Class I water source for the AFW system. Protection of the Service Water system source from failure of non-seismic branch piping in the supply from the CST, is provided by a safety related, seismically qualified check valve (1/2AF-0111, AF-0112, AF-0113, and 1/2AF-191) in the CST supply piping to the pump suctions. A normally open, seismically qualified manual valve in series with the check valve (1AF-0026, 2AF-0064, AF-0039, AF-0052, and 1/2-AF-190) provides for additional isolation capabilities. The AFW pump low suction pressure trip and automatic transfer to service water is described in Section 10.2.2. Flooding concerns related to postulated CST failure during a seismic event are discussed in Appendix A.7 (Reference 5).

The major portions of the AFW system reside within seismic Class I structures. Portions of the steam supply lines to the turbine driven AFW pumps run through the facades and portions of the PAB steel frame superstructure. Neither the facades, nor the PAB steel frame superstructures, are seismic Class I structures (Reference 5).

The facade structures were designed for loads which can be reasonably expected to envelope the SSE loads. The auxiliary building central superstructure was analyzed for seismic loads and found capable of withstanding an SSE. At least three sides of the PAB north/south wing superstructures have been analyzed for SSE or designed for loads which can be reasonably expected to envelope SSE loads. However, even if the wing superstructures would not withstand an SSE, at least one steam supply line to the turbine driven AFW pump for each unit is routed through structures capable of withstanding SSE loads. Should the steam supply line in the north/south PAB wing be lost, the failed line can be isolated from the control room by closing the associated steam supply motor operated valve which is located in the seismic Class I portion of the PAB. Further, there is no loss of available steam to the surviving supply lines considering loss of main steam lines located in the north/south PAB wings since the main steam isolation valves (MSIV) are located upstream in the facade structures (Reference 5).

Portions of the AFW system are located in the turbine building. The turbine building is not a seismic Class I structure but was seismically analyzed during original design and found capable of withstanding SSE loads (Reference 5).

The NRC concluded that the AFW system design provides reasonable assurance that the AFW system will perform its required safety function following a SSE (Reference 6).

10.2.6 REFERENCES

1. FSAR Appendix A.1, Station Blackout.
2. PBNP Fire Protection Evaluation Report (FPER).
3. NRC Safety Evaluation “Safety Evaluation on the Resolution of Unresolved Safety Issue A-46 at Point Beach Nuclear Plant Units 1 and 2,” Enclosure Page 3 of 10, dated July 7, 1998.
4. NRC Safety Evaluation “ATWS RULE (10 CFR 50.62),” August 4, 1988.

5. Wisconsin Electric Letter to the NRC dated April 26, 1985, "Final Resolution of Generic Letter 81-14 Seismic Qualification of Auxiliary Feedwater System Point Beach Nuclear Plant, Units 1 and 2."

6. NRC Safety Evaluation, "Seismic Qualification of the Auxiliary Feedwater System at Point Beach Nuclear Plant, Units 1 and 2." dated September 16, 1986.

7. Calculation 97-0215, "Water Volume Swept by all Four AFW Pumps Following a Seismic/ Tornado Affecting Both Units."

8. NRC Safety Evaluation, "NUREG-0737 Item II.E.1.1, Auxiliary Feed Water System Evaluation for Point Beach Nuclear Plant Units 1 and 2," dated April 21, 1982.

9. NRC Safety Evaluation, "Safety Evaluation of the Point Beach Response to the Station Blackout Rule," dated October 3, 1990.

10. NMC Letter to NRC dated January 12, 2004, "Reply to Notice of Violation EA-03-057 NRC Inspection Report No. 50-266/02-15 (DRP); 50-301/02-15 (DRP)."

11. NMC Safety Evaluation SE 2003-001, dated October 1, 2003, "Crediting of Auxiliary Feedwater Pump Minimum Flow Recirculation Line Flow Restricting Orifices Installed by MR 02-039*A/B/C/D and OPR000031 Compensatory Action Removal."

12. LER 266/97-031-00, "Non-conservative Setpoint for Auxiliary Feedwater Pump Low Suction Pressure Trip," July 21, 1997

13. NRC Safety Evaluation, "Point Beach Nuclear Plant, Units 1 and 2 Implementations of Recommendations for Auxiliary Feedwater Systems," dated January 27, 1981.

14. NRC Safety Evaluation, "NUREG-0737 Item II.E.1.2 Auxiliary Feedwater Automatic Initiation and Flow Indication," dated May 3, 1982.

15. NRC letter to C. W. Fay, "Response To Generic Letter 88-03," dated April 12, 1988.

16. NRC Safety Evaluation, "Point Beach Nuclear Plant Units 1 and 2-Issuance of License Amendments Re: Auxiliary Feedwater System Modification," dated March 25, 2011.

17. NRC Letter NRC 2009-0116, "License Amendment Request 261, Extended Power Uprate, Response to request for Additional Information, dated November 21, 2009.

18. Calculation 2009-06582, Rev 0, "Available Water Volume of Piping in the Protected Portion of Motor Driven Auxiliary Feedwater Pump Suction," dated May 17, 2011.

19. Engineering Change (EC) 259835, Transition to Replacement MDAFW Pump Train.

20. NextEra Energy letter, NRC 2011-0086, "Clarification/Comments on NRC Safety Evaluation Report Amendment Nos. 238 (Unit 1) and 242 (Unit 2) Auxiliary Feedwater System Modification," dated September 16, 2011.

21. NRC Letter to NextEra Energy, "Point Beach Nuclear Plant, Units 1 and 2 - NRC Staff Response to Clarification/Comments Related to the Safety Evaluation Report Associated with the Auxiliary Feedwater System Modification License Amendment," dated December 6, 2011.

22. NRC Safety Evaluation, "Point Beach Nuclear Plant Units 1 and 2 - Issuance of Amendments Regarding Relocation of Surveillance Frequencies to Licensee Control (TAC NOS. MF4379 and MF4380)," dated July 28, 2015.

23. AR 02073664, "AFW Cross-tie Piping Evaluation," dated September 14, 2015.

Table 10.2-1 AFW SYSTEM LEVEL FAILURE MODES AND EFFECTS ANALYSIS

Component	Failure Mode	Effect
Isolation valve for AFW safety related suction supply	Fails to open	Two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
Auxiliary feedwater pump	Failure to start	Two AFW pumps provided; either one of the two AFW pumps provide the required feedwater flow to remove sufficient decay heat.
Auxiliary feedwater pump	Failure to trip on low suction pressure	Two AFW pumps provided; each AFW pump is provided with low suction pressure protection; separate suction supply headers for two pumps; either one of the two AFW pumps provide the required feedwater flow to remove sufficient decay heat.
MDAFW Pump Recirculation Valve	Fails to open	Two recirculation paths provided per MDAFW pump; either recirculation path has sufficient capacity to support short term pump operation.
MDAFW Pump Recirculation Valve	Fails to close	Two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
MDAFW pump discharge control valve on either of the steam generator supply lines	Fails to control flow	Redundant flow path from TDAFW pump is available; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
MDAFW pump discharge control valve on line leading to faulted steam generator	Fails to close	Operator to trip pump; two AFW pumping systems provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
TDAFW Pump Recirculation Valve	Fails to open	Two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
TDAFW Pump Recirculation Valve	Fails to close	Two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.
TDAFW pump discharge throttle valve on line leading to faulted steam generator	Fails to close	Operator to trip pump; two AFW pumps provided; either one of the two AFW pump systems provide the required feedwater flow to remove sufficient decay heat.

Figure 10.2-1 UNITS 1 & 2 AUXILIARY FEEDWATER SYSTEM FLOW DIAGRAM (Sheet 1)

[redacted]

Figure 10.2-1 UNITS 1 & 2 AUXILIARY FEEDWATER SYSTEM FLOW DIAGRAM (Sheet 2)

[redacted]

Figure 10.2-1 UNIT 1 AUXILIARY FEEDWATER SYSTEM FLOW DIAGRAM (Sheet 3)

[redacted]