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Chapter 10 - Steam Power Conversion Systems

Chapter 10 - Steam and Power Conversion Systems

10.1 STEAM AND POWER CONVERSION SYSTEMS SUMMARY DESCRIPTION

The Steam and Power Conversion Systems consist of the following systems, auxiliary systems, and selected components:

Turbine Generator System (TGS)
Turbine Bypass Valve
Turbine Bypass Isolation Valve
Main Steam System (MSS)
Feedwater System (FWS)
Air Ejector System (AES)
Seal and Lube Oil System (SLO)
Condensate System (CDS)
Circulating Water System (CWS)
Make-Up Demineralizer and Demineralizer Transfer System (DMW)
Resin Regeneration System (RGS)
Main Condenser

The Main Steam System (MSS) provides a flow path for steam from the Nuclear Steam Supply System (NSSS) to the main condenser, which is the main heat sink for the reactor. Under normal power operation this is accomplished through the turbine via the turbine admission valves. A second flow path is through the turbine by-pass valve to the main condenser. During startup or abnormal conditions, flow can be through both paths.

A single Main Steam Isolation Valve (MSIV), located inside containment, provides isolation between the steam drum and the turbine.

Normal reactor operating pressure is maintained by the positioning of the turbine admission valves. In the event of a load rejection or any other event which causes rapid closure of the turbine control valves, it is the function of the turbine by-pass valve control system to take command and attempt to maintain the reactor pressure.

The system controlling the reactor and turbine generator is normally one in which the turbine is slave to the reactor.

10.1.1 TURBINE AND MAIN STEAM CONTROL

The turbine control mechanism includes a conventional governor and an initial pressure regulator. During normal operation the turbine admission valves are controlled by the initial pressure regulator. The turbine speed control is set at some amount above the pressure regulator. The steam by-pass valve is normally closed, and all reactor steam flow is through the turbine. On abnormal conditions such as turbine trip, the bypass valve opens to dump steam directly to the condenser.

With the control system set up in this manner, the turbine follows the reactor output rather than system load changes. Turbine overspeed control is maintained in the conventional manner.

10.1.2 TURBINE PROTECTION DEVICES

If the turbine should overspeed due to sudden loss of electrical load, the speed governor signal will override the initial pressure regulator signal which normally controls the turbine admission valves. The admission valves close sufficiently to maintain satisfactory turbine speed. This causes the reactor pressure and reactivity to rise. The turbine bypass valve is opened by means of a pressure signal and dumps steam to the condenser.

A turbine emergency overspeed governor is provided as a backup for the speed governor. Other conventional turbine protective devices include a low vacuum trip, thrust bearing failure trip, generator protective relay trip and manual trip. Each device will initiate closure of the turbine stop valve.

Control and supervisory equipment for the turbine-generator are conventional and are arranged for remote operation from the control board located in the control room. Turbine lubrication oil and steam extraction pressures are transmitted to receivers on the control board, as are turbine throttle steam, first stage and the exhaust pressures.

The turbine steam bypass valve is also arranged for operation from the control room console.

Turbine extraction bleeder trip valves of the conventional type are furnished on the high pressure and intermediate pressure feedwater heater extraction lines. These valves are arranged to close on a turbine trip and/or high level in the heaters and are provided with remote manually operated test valves. These control functions are shown in Drawing 0740G40241.

10.1.3 HEAT BALANCE

System Heat Balance

System Heat Balance at 1350 psia pressure; at one or two inch condenser pressures; and at 50, 60, and 75 Mw loads are provided on Drawings 0740G40112; 40114; and 40117 A and B.

Heat Balance Calculations

Procedural controls provide the basis for calibrating the out-of-core Neutron Monitoring System (NMS) power range monitor channels to ensure the steady reactor power output will not exceed Technical Specification nuclear, thermal, or hydraulic limits. These controls provide for calculated heat balance at specified intervals during periods of steady state conditions, power changes, escalations, ascents following refueling, and following specified major maintenance on selected NMS components.

10.2 TURBINE-GENERATOR SYSTEM (TGS)

10.2.1 TURBINE-GENERATOR DESIGN BASES AND DESCRIPTION

The turbine is a 3600 rpm, tandem-compound, double flow, condensing unit directly connected to a hydrogen cooled generator which in turn is connected through a reduction gear to an air-cooled exciter. Three points of extraction for feedwater heating are provided. The turbine-generator unit, including its controls and auxiliaries, are designed for operation with saturated steam.

The initial rating of the turbine was 54,500 kw at 1000 psig, 0 degrees final superheat and 3 1/2 inches of mercury absolute exhaust pressure with 3 percent makeup allowance and three feedwater heaters in service. The turbine is capable of operating continuously at 1450 psig, 0 degrees final superheat and 2 inches Hg back pressure with a maximum expected output of 75,000 kw.

The current nameplate rating of the turbine is 75,000 kw at 1450 psig, 593 degrees final superheat and 1 1/2 inches of mercury absolute exhaust pressure.

The 13,800 volt, wye-connected generator initial rating was 70,588 kva, 0.85 power factor, 0.80 short circuit ratio at 30 psig hydrogen cooling pressure. Based upon the output of the nuclear steam supply system, the generator nameplate rating was increased to 88,235 kva, 0.85 power factor, 0.64 short circuit ratio at 30 psig hydrogen cooling pressure.

Besides conventional design criteria, all modifications necessary due to use of saturated steam from a boiling water reactor are incorporated in the turbine design. Particular attention is given in the design of the machine to the elimination of pockets or crevices in which radioactive material might lodge. Each turbine stage is drained, either internally or externally. The turbine is provided with moisture removal buckets ahead of each extraction point; in addition, two external moisture separators are provided in the cross-over between the high-pressure and low-pressure sections. Materials used in the construction of the turbine are selected to minimize the wear caused by wet, oxygenated steam.

The flow paths through the turbine are shown in Drawing 0740G40106, which also shows the extraction drains and vents.

10.2.2 TURBINE GENERATOR CONTROL

The turbine is arranged for two modes of control:

a. Initial Pressure Regulation (Base Loaded Operation).

b. Speed Control (House Unit Operation).

Normally, the turbine-generator is base loaded, and to avoid swings with accompanying transients being felt by the reactor, the steam line pressure is maintained at a constant value by the initial pressure regulator (IPR). This pressure regulator positions the turbine admission valves to maintain a constant steam line pressure without regard to the generator or the transmission line system loads. The speed control is normally backed off above the IPR control band, but overrides the IPR on increasing speed to keep the unit below the high speed (emergency) trip.

During turbine start-up and shutdown, and for short periods of time during normal operation, operation on speed control shall be permitted. During such operation, the turbine load limiter shall be set to limit turbine output to correspond to the planned reactor output.

During normal power operation, the initial pressure regulator shall maintain the reactor pressure at its rated value by operating the turbine admission valves. The turbine-generator load shall be established by the control rod positions.

Upon a sudden load loss, protective relaying separates the unit from the line, automatically transfers control from the initial pressure regulator to the speed control through two solenoid transfer and reset devices, and at the same time repositions the governor outer bushing to a predetermined set point at about the value of the house load. This causes a rapid closure of the turbine admission valves with the turbine speed remaining below trip speed. The turbine levels out close to synchronous speed and the turbine bypass valve opens to dump excess steam to the condenser and attempts to maintain correct reactor pressure.

The generator 138Kv line breaker was originally fitted with an automatic reclosing feature and time delay following reclosure which were eliminated via Facility Change FC-62 in November 1965.

10.2.2.1 Controls at Cold Start-Up and Hot Start-Up

The turbine shaft sealing system will be placed in service as soon as sufficient steam pressure is available. (Approximately 150 psig.)

The condenser will be evacuated with the mechanical vacuum pump and the air ejector will be placed in service.

Turbine heating will be started at any convenient time during this operational sequence. After turbine heating is completed it is brought up to speed. Upon reaching rated speed the generator is synchronized and connected to the line. During this time the turbine is under speed control.

The mode of turbine control is next transferred to the initial pressure regulator, and the solenoid transfer and reset devices are latched in their standby positions.

The speed control is then run up to its high-speed stop. The bypass valve pressure controller is then backed off 10 psi above desired reactor operating pressure.

10.2.2.2 Controls for Extended Shutdown

Reactor power and main generator load will be decreased simultaneously. The turbine-generator will be separated from the system. The removal of reactor decay heat and the reduction of reactor pressure will be accomplished by controlling reactor steam flow to the main condenser through the turbine by-pass line. (This steam will be condensed, and returned to the reactor vessel by the reactor feed pumps.) The rate of cooling of the reactor is controlled. When the condenser ceases to be an effective heat sink, the steam bypass valve will be closed. (NOTE: Rarely is the bypass valve open. Steam through the air ejectors and gland seal regulator are enough for cooldown once the turbine is off-line.)

10.2.2.3 Controls for Short Duration Shutdown

A shutdown of short duration may be accomplished while maintaining system pressure. The turbine-generator will be unloaded and separated from the system. Reactor heat will be accommodated by system losses or bypassing steam to the main condenser while maintaining condenser vacuum with the air ejectors and gland seals.

10.2.3 TURBINE BYPASS VALVE AND CONTROL SYSTEM

The turbine bypass valve limits transient pressure increases in the main steam line by opening in response to two independent pressure sensors located near the turbine stop valve which are set slightly above the normal IPR setting. The bypass valve is hydraulically actuated and electronically controlled to provide the rapid response necessary for load-loss transients.

The turbine bypass control system is designed to operate a high-speed 100% capacity bypass valve connected between the reactor and the turbine-generator condenser to maintain an essentially constant reactor pressure. Normally, the bypass valve will remain closed and the turbine control valves will maintain reactor pressure as determined by the turbine-generator initial pressure regulator. In the event of a load rejection or other event which will cause closure of the turbine control valves, it is the function of the bypass valve and its control system to take command and attempt to maintain reactor pressure. It should be noted, however, that the turbine bypass valve system is not designed to maintain reactor pressure in the pressure control mode upon rapid closure of the turbine control valves or main stop valve without load rejection due to the time lags built into the control system. For load rejection requirements, a separate input to the control system provides for rapid turbine bypass valve opening proportional to the amount of steam flow to the turbine at the time of the rejection.

The basic principle of the operation of the turbine bypass valve system in the pressure control mode is that of measuring turbine throttle pressure and comparing it with desired pressure in a controller and then utilizing the controller output to operate the control valve through a servo-operated system. The servo-operated system compares the signal representing desired valve opening with a signal representing actual valve opening and applies the output of the servo-amplifier to a servo-valve which, in turn, controls oil pressure to the bypass valve. Actual position of the bypass valve is fed back to the servo-amplifier by the valve position transducer.

To prevent inadvertent opening of the bypass valve, each controller and servo-amplifier (and transducer) are duplicated and in each case, the signal which desires the valve to be more nearly closed is selected and utilized. Upon loss of condenser vacuum, valve opening permissive is lost by direct application of a close signal to the servo-valve (in addition, a mechanical close bias is applied to the servo-valve to ensure closure upon loss of power).

Manual operation of the servo-valve is available through the use of the manual/automatic selector station located on the operating console adjacent to the controller setpoint modules.

10.2.3.1 Turbine Bypass Valve Control Design Features

The bypass valve design features are as follows:

Flow Capacity at 1015 Psia, Pounds per Hour	739,000
Flow Capacity at 1465 Psia, Pounds per Hour	963,000
Maximum Speed, Full Valve Stroke, Seconds	Approximately 0.2

Other Features

When the 138 kv transmission line breaker is tripped as a result of a transmission line fault, the generator load falls to approximately plant auxiliary level (upon sensing the fault, the speed reset solenoid trips, positioning the admission valves to a predetermined setpoint of approximately 5 MWe, this is higher than house load, thus, the frequency will require adjustment) and the turbine starts to speed up. Upon reaching the speed limit, the turbine admission valve starts to close under the influence of the turbine speed control. As the admission valve closes, the pressure in the main steam line starts to rise and increases rapidly if corrective action is not taken in time.

The bypass valve control system attempts to handle the load drop from full to auxiliary load level. An anticipatory valve opening signal (after the 138Kv breaker opens) has been programmed to provide opening proportional to the steam flow to the turbine.

An auxiliary relay and circuitry were installed to provide actuation of the turbine bypass auxiliary when the 138Kv circuit breaker is tripped open manually by the console control switch. This auxiliary relay will provide an opening signal to the bypass valve.

In the past, the opening signal was generated only on the loss of a tone relay signal to the 138Kv circuit breaker between Emmet Substation and Big Rock Point. This change was completed via Facility Change FC-122 and reported to the NRC June 24, 1968.

A condenser vacuum control to override the control system and close the bypass valve if condenser pressure rises to a preset level, is also provided.

Some of the features incorporated in the bypass valve system are the accumulator to provide stable hydraulic power, duplicate hydraulic pumps and servo valves, along with automatic standby pump start on low pressure. The loss of hydraulic power and bypass valve starting open are annunciated in the control room. All the controls for the bypass system are located in the control room.

The plant has demonstrated it can accommodate a 138Kv transmission line trip at reactor power up to about 160 Mwt without a reactor scram based upon the automatic opening of the turbine bypass valve. (Reference CPCo letter dated June 2, 1982 for Systematic Evaluation Program - SEP Topic XV-3, Loss of External Load.

10.2.3.2 Turbine Bypass Valve Testing

The turbine bypass valve control system circuitry is tested periodically during normal plant operation. The test will not result in any disturbance in the reactor system. During refueling shutdown, a turbine bypass valve system functional test is performed to test features and associated components.

10.2.3.3 Pressure Regulator Set-Point Changing

Fast changes in the initial pressure regulator set point may cause a pressure and resultant flux transient within the reactor. With a sufficiently rapid change in set point, a flux transient would result, which could be large enough to scram the reactor at 125% of rated power. The rate of change will be limited by operating procedures to a value that will not cause such a flux transient.

Increasing the set point of the initial pressure regulator causes the turbine admission valve to close momentarily; this results in increasing the pressure of the system, and the turbine admission valve then reopens to stabilize the pressure at the new set point.

10.2.3.4 Turbine Bypass Isolation Valve

A direct current motor-operated isolation valve was installed in the bypass line between the main steam line and ahead of the turbine bypass valve. Installation was completed in March of 1968. The turbine bypass isolation valve provides the ability to terminate blowdown caused by inadvertent bypass valve opening and failure to reclose. This valve is one of several valves which provides backup isolation for the main steam isolation valve.

Vacuum interlocks as part of the valve control system close the valve on loss of condenser vacuum.

Valve closure is also automatic on complete loss of Reactor Protection System Motor Generator Power and on Reactor Protection System Containment Isolation from High Containment Pressure or Low Reactor Water Level.

The isolation valve installation and low vacuum closure features were reported in the Eighth Semi-Annual Report dated June 24, 1968.

10.2.3.5 Turbine Bypass Valve Electrohydraulic System

As part of the Integrated Plant Safety Assessment Report (IPSAR) NUREG 0828, Final Report dated May 1984, Section 5.3.3.1, a study of the reliability of the Turbine Bypass Valve Control System electrohydraulic control (EHC) system was proposed. Based upon this study, the servo-amplifier gain for the control system was reduced to provide a slightly overdamped valve signal to eliminate oscillation in valve control. Following valve testing, it was determined that the valve stroke for 0 to 90% opening would occur in equal to or less than 0.2 seconds. This revised gain setting still meets the Technical Specification opening time requirement for maximum speed of full valve stroke of approximately 0.2 seconds.

The Turbine Bypass Valve opening speed is a function of the flow, pressure, and reactor power condition calling for its operation. Original Transient Analyses submitted in General Electric (Atomic Power Equipment Department) APED-4093 in October 1962 calculations assumed a bypass valve opening speed of approximately 0.7 seconds to match the admission valve closure.

Start-up testing reported in General Electric APED-4230, May 1963 reported Bypass Valve stroke rate of approximately 0.5 seconds.

Subsequent modifications to the valve control system and the re-installation of the four inch valve actuator via Facility Change FC-132 to decrease the time response and increase the flow capacity, resulted in an optimum bypass valve opening stroke on full load rejection of approximately 0.2 seconds in order to limit the pressure rise.

10.2.3.6 Turbine Bypass Valve Hydraulic Oil System

The Hydraulic System is designed to operate the by-pass valve with one pump running. The system is designed so that if oil pressure drops, the second pump will start and restore system pressure.

The Hydraulic System also has an accumulator on the high pressure line to the servo valves. The accumulator is designed to full line pressures, and has a capacity which should allow for five complete strokes of the valve. The accumulator is charged with nitrogen and then to full system pressure by the hydraulic pumps. The accumulator will provide pressure in case of power failure to the hydraulic pumps.

The Turbine Bypass Valve Hydraulic Oil System is shown on Drawing 0740G40109.

10.2.4 SECONDARY SYSTEM INSTABILITIES

An evaluation of the effects of load rejection was completed as part of the Systematic Evaluation Program (SEP) Integrated Plant Safety Assessment Report (IPSAR), NUREG 0828, Final Report dated May 1984, Section 5.3.3.2, Secondary System Instabilities was addressed.

This issue stems from the observed phenomena that when the turbine bypass valve opens with the turbine at or near full load, condenser hotwell level can swell sufficiently to cause the condensate reject valve to fully open, such that the reactor feedwater pumps trip on low suction pressure.

An analysis of condenser hotwell/feedwater system characteristics has been completed. Recommendations along with further analysis are currently being evaluated to improve system performance.

10.2.5 TURBINE ROTOR DISC INTEGRITY AND OVERSPEED PROTECTION

An evaluation of the turbine-generator was completed as part of the Systematic Evaluation Program (SEP) Topic III-4.B - Turbine Missiles. Results and conclusions in regard to turbine rotor integrity and adequacy of overspeed protection are provided in Section 3.5 of this Updated FHSR along with the turbine rotor surveillance schedule basis.

10.2.6 TURBINE STOP VALVE

The turbine emergency stop valve is an oil operated, spring closed valve controlled from the following devices:

1. Mechanical Low Vacuum Trip
2. Electrical Trips
   a. Turbine Thrust Bearing Failure
   b. Hand Trip in Control Room
   c. Low Vacuum Switch
   d. Reactor Scram Auxiliary
   e. Generator Lockout Relay
3. Emergency Trip Mechanism

A turbine trip circuit was installed to automatically close the turbine stop valve on the occurrence of a reactor scram. This automatic trip was completed via Facility Change FC-108 and reported to the NRC in the sixth Semi-Annual Report May 23, 1967.

The valve is of the quick closing type and functions primarily by being tripped either by hand or by an emergency trip device.

The passage of steam through the stop valve is dependent upon the hydraulic oil pressure forcing the valve open against spring energy. So long as the turbine operates normally, the sustaining hydraulic oil pressure is maintained. However, if an unsafe condition occurs which endangers the machine, the hydraulic oil pressure holding the stop valve open is dumped and spring energy closes the valve.

The turbine stop valve closes in approximately 0.7 seconds.

10.3 MAIN STEAM SYSTEM (MSS)

10.3.1 MAIN STEAM SYSTEM DESIGN BASES

a. Piping Design Pressures, Temperatures, and Materials Specifications. (Reference CPCo letter dated March 12, 1975)

Main Steam

Steam Drum to First Valve 1700 psig, 625 F, ASTM A-106, Grade B (Seamless)
First Valve to Turbine & Condenser 1470 psig, 600 F, ASTM A-106, Grade B (Seamless)

b. Closing times on motor-operated isolation valves are as follows:

Description	Closing Time (Seconds)
Main Steam (MO-7050)	60
Main Steam Drain (MO-7065)	60

Operability and leak testing intervals for these valves are prescribed in the Technical Specifications. The Main Steam Drain valve is disabled in the closed position and testing is required only if the valve is opened for use.

c. Piping Analyses

The piping flexibility analysis of the main steam system was performed by Bechtel. All calculations were made on an IBM computer.

The support system (hangers, guides and anchors) was designed by Bechtel and included in the flexibility calculation.

The thermal pipe stresses are well below the code allowable stresses, and the end reactions on equipment meet the equipment manufacturers' criteria. (Reference CPCo May 1, 1962 Amendment 10 Addenda to Final Hazards Summary Report Technical Qualifications Amendment 8. Portions resubmitted to the NRC March 12, 1975.)

10.3.2 MAIN STEAM SYSTEM DESCRIPTION

The Main Steam System provides a flow path for steam from the Nuclear Steam Supply System to the Main Condenser. Associated Piping and Instrument Drawings 0740G40106 and G40121 depict the flow paths for the steam.

The Main Steam System consists of 12" piping from the steam drum to the "turbine stop valve" and 10" piping through the turbine by-pass valve to the condenser, together with the turbine by-pass valve, "main steam isolation valve," (MO-7050) and associated instruments and drains. Piping is all carbon steel, and is rated for 1700 psi at 625 F through the isolation valve MO-7050. From the isolation valve to the turbine stop and by-pass valves, the rating is 1470 psi at 600 F. Piping after the by-pass valve is rated for 1100 psi at 625 F.

The Main Steam Isolation Valve (MSIV) MO-7050 and main steam drain isolation valve MO-7065 (which is disabled closed) have been addressed in Section 6.2 of this Updated FHSR. The turbine bypass valve and turbine bypass isolation valve are addressed in Section 10.2 above.

The motor associated with the main steam isolation valve receives its dc power from the Alternate Shutdown System Battery in the Alternate Shutdown Building and in the event operation is not possible from the Control Room, the MSIV may be closed only from the Alternate Shutdown Building. (Reference Facility Change FC-462J-1.)

Closure of Main Steam Isolation Valve

This valve is automatically operated and will go closed with all conditions requiring penetration closure as indicated below.

High pressure in enclosure
Low water level in reactor
Loss of auxiliary power supply

A control console manual hand switch is provided to enable the operator to initiate closure of all automatically operated open enclosure penetrations. Such action initiates closing of the main steam line isolation valve, and when this valve is 50% closed, a signal initiates a scram of the reactor.

10.3.3 MSIV Closure at Power

If the MSIV was closed simultaneously with power operation, all steam flow would be cut off and reactor pressure would rise. To avoid such a pressure increase, the safety circuit is set to scram the reactor on partial closure of this valve. This valve closes in about 40 seconds which allows sufficient time for initiation of the scram before the reactor pressure can rise significantly. A signal from very high reactor pressure initiates diversion of steam flow from the steam drum to the emergency condenser. If a scram does not occur due to failure of the initiating signal (valve closing), a high flux scram will subsequently occur, as reactor flux will rise to the neutron flux scram level. If this in turn fails, another signal is provided by a pressure scram when the high pressure scram level is reached. If none of these devices operate, the steam safety valves on the steam drum would operate to limit pressure rise. The size of these valves is large enough to pass the steam generated in such a case with the reactor operating initially at rated power.

10.3.4 RUPTURE OF MAIN STEAM LINE

The automatically actuated Main Steam Isolation Valve (MSIV) and the system pressure controlled valves (ie, turbine control and bypass line valves) would act to protect against the radiological effects of a main steam line rupture. In the event such a rupture occurred in the portion of line inside the containment vessel, both isolation valves (MSIV and Main Steam Drain) would act to confine the released water and steam to within the containment vessel. In the event the steam line ruptured outside the containment vessel, these valves would act to limit the total release of steam-water and fission products which may be included.

The radiological effects on the plant environment of a steam line rupture accident occurring inside or outside the containment vessel have been evaluated in Chapter 15 and High Energy Line Breaks are addressed in Chapter 3, Subsection 3.6 of this Updated FHSR. In comparing the effects between the two rupture locations, the "outside" break would be the more severe, since the radioactive materials would be free to move into the turbine building and from there, a portion would be free to flow through the turbine building ventilation louvers to the outside.

<u>Analyses</u>

By letters dated June 29, 1973 and February 7, 1974 CPCo provided the results of the stress analysis performed for the main steam and feedwater lines which reveals that total stresses are in all cases less than 50% of the value allowed by the evaluation criteria (from the NRC December 18, 1972 and January 16, 1973 letters) and in many cases less than 25% of the criteria allowed values. Based on these stress levels, a break in the lines is not considered to be credible and it has been concluded that certain modifications for High Energy Line Break are not required. In addition to the low stress levels; the determination that the nil ductility transition temperature for the type of material used in the main steam and feedwater lines (ASTM A-106 GrB) is approximately 70°F; the piping system design is such that these lines are not pressurized during plant operations to full operating pressures unless the temperatures are several hundred degrees above this temperature; thus, essentially no potential exists for brittle type failures.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEMS

10.4.1 MAIN CONDENSER

10.4.1.1 Main Condenser Design and Operation

The main turbine condenser is designed to perform the following functions: (a) Condense the steam exhausted from the turbine to obtain the desired heat utilization and vacuum; (b) De-aerate the condensate and water from heater drains and other returns; (c) Serve as a heat sink for excess reactor steam dumped through the turbine bypass valve; and (d) Detain condensate in the hotwell to permit decay of shortlived radioactivity.

a. Design Features

Type	Radial Flow Surface Condenser With Deaerating Hot Well
Condenser Surface Area, Square Feet	27,500
Design Condensing Pressure, Inches Hg Absolute	1.5
Condensing Capacity, Pounds per Hour @1.5 Inches Hg Absolute	460,000
Condensing Capacity During Full Load Rejection, Pounds per Hour	948,000
Air Ejector Capacity	10 Cubic Feet per Minute of Free Dry Air (72 lbs/hr) Plus 1.1 Pounds per Hour of Hydrogen Plus 8.3 Pounds per Hour of Oxygen

b. Shell and Tube Design at a Service Duty of 428 x 10^6 BTU/HR at 1-1/2 Inches Hg. (Note, Duty is 526 x 10^6 BTU/HR at 2 Inches Hg)

Shell Design

Flow Lb/Hr	Psia	°F	Temp °F In & Out
460,000	30 & 1-1/2" Hg	92	92@ 1-1/2" Hg

Tube Design			
Flow Lb/Hr	Psia	°F	Temp °F In & Out
51,600 Gpm	35	50	50 - 70

c. Operating Requirements

(1) The following condenser pressure trips will be operative during reactor power operations:

Low Vacuum Alarm

Low Vacuum Turbine Trip and Bypass Valve Closure

(2) The following condenser pressure trip will be operable during reactor power operations when steam drum pressure is at least 500 psig or higher:

Low Vacuum Reactor Scram

The purpose of the low vacuum alarm and trips are to insure the main condenser is available as a heat sink for reactor power operation. The high condenser pressure (low vacuum) reactor trip is automatically bypassed any time steam drum pressure is below a setpoint maximum of 500 psig. The basis and margin for the 500 psig setpoint are provided in CPCo letter dated September 10, 1975 which lead to Technical Specification Amendment 14, dated June 24, 1977. This low vacuum scram bypass is provided to allow warm-up of the main steam lines and the condenser so the plant may be started up.

10.4.1.2 Main Condenser Description

The main turbine condenser is a fabricated steel, horizontal, single pass, divided water box de-aerating type unit of conventional construction. It is spring supported and solidly connected to the turbine exhaust flange. The unit has an effective condensing surface of 27,500 square feet. The condenser is located directly beneath the low pressure turbine with its tubes perpendicular to the turbine centerline. Provisions are made for accepting 948,000 #/Hr of saturated steam at 1450 psig and 1170 BTu/lb from the turbine bypass valve. This steam will be reduced in pressure through the muffler orifice and desuperheated with condensate. Since this heat load will occur only when the turbine heat load is decreased by a similar amount, additional heat exchange surface for this purpose is not required.

Admiralty metal tubing with Muntz metal tube sheets are used. Tube material originally was ASTM Specification B-111-58 and approximately 75% of the tubes were replaced in 1982 utilizing ASTM Specification B 111-80 which is an equivalent substitution. Tube sheets are ASTM Specification B-171-58.

A 6000 gallon minimum capacity oversized, baffled, storage-type hotwell is provided to allow decay of short-lived radioactivity. The hotwell is divided by a partition plate parallel to the tubes to facilitate location of tube leaks.

A single twin-element, two-stage steam-jet ejector with surface type inter- and after-condenser is provided. Each element is capable of removing 10 cfm of free air (72 lbs/hr) leakage plus 1.1 lbs/hr of hydrogen and 8.3 lbs/hr of oxygen gas from the reactor.

A motor-driven, wet-type, rotary vacuum pump with a capacity of approximately 600 cfm of air at 15" Hg absolute pressure is provided for rapid evacuation of the condenser steam space at startup.

The air and gas removal equipment discharges to the main exhaust stack through oversize piping systems which provide holdup time enroute for decay of short-lived radioactivity.

10.4.1.3 High Main Condenser Pressure and Loss of Vacuum

High condenser pressure (ie, low vacuum) is used as an indication that:

a) The low pressure turbine casing is in danger of being overheated; and

b) That the main condenser is no longer available as a heat sink for the reactor output. The low vacuum trip system consists of the following devices: two pressure switches for each reactor safety channel; the turbine mechanical low vacuum trip valve which trips the turbine stop valve; a pressure switch which closes or prevents opening of the main steam bypass valve; and a backup pressure switch which actuates both the turbine trip solenoid and the bypass valve. These devices are all actuated by loss of condenser vacuum and are provided to give duplicate and independent initiation for scramming the reactor and isolating the main condenser. The reactor is scrammed at a lower setting before the turbine is tripped.

Loss of vacuum is caused by:

a) Loss of power to the circulating water pumps.

b) Excessive air inleakage.

c) Original FHSR described automatic closing of the off-gas valve from high activity signal as being a cause for loss of vacuum which was thought to be provided in initial plant design. Difficulties with this system were described in CPCo letter dated May 26, 1976, Request for Technical Specification Change, which provides the basis for administrative controls for the off-gas release rate. These controls, which include reduction of reactor power levels on off-gas alarm limits are addressed in Technical Specification Amendment 14 dated June 24, 1977. This reduction of reactor power levels allow for an orderly reactor shutdown to stay below stack gas release limits.

In the event that the condenser becomes unavailable for reactor heat dissipation, the condenser is isolated from the reactor by the indicated action of the turbine stop and bypass valves. The subsequent pressure rise in the reactor places the emergency condenser in service to serve as a backup heat sink.

Loss of Condenser Vacuum (ie, High Pressure)

If the condenser vacuum is lost, the main reactor heat sink is lost. If no action were taken by the automatic system protection circuit, condenser pressure and temperature would increase to a point where the turbine or condenser would be damaged. To eliminate this possibility, vacuum-sensing devices are used to transmit a scram signal to the reactor and to trip the turbine upon loss of vacuum. An independent signal will initiate closure of the bypass valve to prevent turbine damage. When condenser vacuum decreases to the Technical Specification setpoint, the reactor is scrammed. If the cause of the incident was loss of circulating flow due to power failure, the power failure will initiate automatic shutdown signals from the entire safety system which is designed to be normally energized. Thus, loss of condenser vacuum should have initially produced a reactor shutdown. If this does not occur, closure of the stop and bypass valves will produce a reactor scram through the mechanism of high reactor pressure, and very high reactor pressure signal will initiate cooling via the emergency condenser.

Analyses

In the event that the air ejectors fail, the pressure in the main condenser will rise. When the condenser vacuum starts to decrease, the reactor is tripped at a preset condenser pressure. The setting for turbine trip is somewhat higher and thus the loss of condenser vacuum is expected to be a milder transient than the turbine trip without bypass. CPCo has not analyzed the loss of condenser vacuum, but has identified the turbine trip without bypass as a bounding event.

Evaluation

In the extreme case of sudden loss of condenser vacuum or in the case of failed reactor trip at increased condenser pressure, the transient is identical to the turbine trip without bypass. Otherwise loss of condenser vacuum is a less severe event. (Reference Chapter 15, Section 15.2 for Turbine Trip Without Bypass Analyses.)

10.4.2 MAIN CONDENSER EVACUATION SYSTEM/AIR EJECTOR SYSTEM (AES)

The main condenser is evacuated by the Air Ejector System (AES) which consists of the air ejectors and the mechanical vacuum pump. Components of the system are depicted on Drawing 074G40106 and 44016.

The air ejectors remove the air and noncondensable gases during normal operation.

The mechanical vacuum pump is provided for the rapid evacuation of air from the main condenser during start-up.

The addition of a vacuum pump on the condenser waterbox to assist in removing air from the system was reported October 9, 1963 in the Annual Report of Changes, Tests, and Experiments.

10.4.2.1 Steam Jet Air Ejectors and Turbine Gland Sealing

The evacuation system contains a twin-element, two stage air ejector unit for removing air and noncondensable vapors from the main condenser during normal operations. The rated capacity of each element is ten cubic feet per minute of free dry air (72 lbs/hr) plus 1.1 pounds per hour of hydrogen and 8.3 pounds per hour of oxygen gas and entrained moisture. The ejector unit consists of two first stage ejectors and two second stage ejectors mounted on a single shell containing the inter- and after-condenser sections in separate compartments.

The ejectors operate on steam pressure, supplied from the main steam supply through a control valve, which is controlled from the control room console. The steam seal regulator is also supplied by this same line.

The air and noncondensable gases removed by the air ejectors are discharged into the 24 inch holdup line, which provides a 30 minute delay for the decay of short lived radioactive gases, before being discharged to the main stack through the off-gas isolation valve. The Off-gas System is described in Chapter 11 and the Off-gas Isolation valve operation is addressed in Section 6.2.10 of this Updated FHSR.

10.4.2.2 Mechanical Vacuum Pump

The mechanical vacuum pump is a positive displacement wet type rotary pump which takes its suction from a line between the air ejectors and the main condenser. This line is equipped with a valve which is normally closed when the pump is not in operation. The discharge line from the pump passes to a 20 inch holdup line for the air discharge to the stack. This 20 inch line provides approximately 90 seconds holdup time for radioactive decay of the gases.

10.4.2.3 Inter- and After-Condenser

The surface inter-and after-condenser is cooled by main condensate flow and provided with suitable loop seals. The condensate then flows to the gland seal condenser. A vacuum is maintained on the gland seal condenser by two mechanical exhausters. The gases from the gland seal condenser flows to the stack through the 20 inch holdup line.

10.4.2.4 Evacuation Systems Gaseous Radioactive Wastes

The normal sources of gaseous radioactive wastes from turbine operation are:

a) Main condenser air ejector off-gas.

b) Gland seal condenser and condenser mechanical vacuum pump exhaust.

The gaseous radwaste system consists of a delay line for condenser offgas which provides approximately 30 minutes of decay time prior to release via the stack.

Condenser offgas represents more than 95% of the total gaseous source term. The other minor sources are gland seal condenser exhaust, containment ventilation, radwaste system vents and miscellaneous turbine building system leakage. All these sources are ducted to the stack for release.

The air ejector off-gas monitoring system audits continuously the level of radioactivity in the gases released from the main turbine condenser to the off-gas hold up pipe and 240 ft stack. During normal operation, these levels are very low compared with the allowable Technical Specification limits. The time delay between the off-gas system radiation monitor at the air ejector exhaust and the stack permits off-gas system isolation and reactor shutdown before high radioactivity levels can reach the stack and environment. In addition to providing a continuous measurement of the radiation in the controlled release of gases from the main turbine condenser to the off-gas piping and stack, the off-gas monitoring system is also a fuel failure detection system. The system therefore provides an alarm at the control room to alert the operator if there is a significant increase in off-gas radioactivity. The alarm set point can be no higher than allowed in the Technical Specification. Before the radiation levels reach the limits stated in the Technical Specification, the isolation valve in the off-gas system will close automatically.

A stack gas monitoring system is provided. In the event the release rate rises, the alarm setpoint allows time for corrective actions. Operator action might include load reduction, isolation of the source of radioactivity, orderly plant shutdown, or reactor scram depending on the conditions.

Further information on the off-gas and stack gas monitoring system is provided in Chapter 11 of this Updated FHSR.

10.4.2.5 Evacuation Systems Explosion Hazard

A potential hazard in the off-gas system may exist due to the presence of a stoichiometric mixture of hydrogen and oxygen. Actually, the probability of a hydrogen-oxygen reaction occurring is very low, since the off-gas system is closed and no source of ignition or spark is present, and the gas is saturated with water vapor so no static spark should result. However, the system is designed to withstand the calculated pressures encountered due to such a reaction.

CPCo by letter dated April 11, 1978 provided the results of a review and analysis of the off-gas system potential for accumulation of explosive gas mixtures.

This review of the design of the off-gas system at Big Rock Point indicates that there are two potential areas that could possibly be affected by off-gas release. These areas are the pipe tunnel and the radwaste area. Both areas are well ventilated; the pipe tunnel having a flow of 5,000 cfm to 14,100 cfm (design) and the radwaste area from 1,500 cfm to 4,000 cfm (design). In order to reach an explosive concentration in these areas, the hydrogen concentration would have to exceed 4% and, based on the ventilation flow rates, this would correspond to a hydrogen escape rate of 60 cfm and 200 cfm for the radwaste area and pipe tunnel, respectively. Since these are significantly higher flow rates than nominally exist in the off-gas holdup line (10 cfm), it is highly unlikely that the limit(s) can be exceeded.

Note: The analysis deriving these flow rates assumes minimum design ventilation flow and uniform mixing.

Analysis has shown that off-gas pressure is nominally one to two ounces per square inch, necessitating a four-inch loop seal to ensure sealing integrity. Since all off-gas loop seals at Big Rock Point are approximately two feet or longer, the possibility of seal failure is remote. If a loop seal should fail however, it would automatically refill via moisture collection from within the system and without any procedural action required.

The NRC staff provided a review of the BRP off-gas system and provided an evaluation in NUREG/CR-0727, by letter dated August 22, 1979, which determined the off-gas system has been judged to have features which give reasonable assurance that the potential for external off-gas detonations is minimized.

10.4.3 TURBINE SEAL AND LUBE OIL SYSTEM (SLO)

The turbine Generator Bearing and Seal Oil System; Lube Oil Storage and Purifier; By-pass Valve Hydraulic Oil System; and Feedwater System Feed Pump Lube Oil System are shown on Drawing 0740G40109.

10.4.4 CIRCULATING WATER SYSTEM (CWS)

Condenser cooling water is drawn from Lake Michigan through a submerged line extending out approximately 1450 feet from the shore. This line (about 1500 feet long) empties into the intake structure on the shore, where the water passes through bar racks and screens and is then pumped through underground lines to the condenser by two half-capacity, vertical, axial flow, wet-pit type pumps. The circulating water is carried from the condenser through an underground line to the discharge headworks at the shoreline. The circulating water discharges through an adjustable weir chamber at its terminus.

The intake structure consists of two compartments, each with a sloping bar rack, a traveling water screen, and a circulating water pump. A third center compartment supplied with screened water from either or both of the two other compartments forms the pump well for the two service water pumps, the screen wash pump, the electric and diesel engine driven fire pumps and the fire system jockey pump. Provision for stop logs for dewatering either of the two principal compartments is also included. Pumps and screens are removed for maintenance through roof hatches in the enclosing structure. The emergency diesel generator is housed immediately adjacent to the intake structure.

The Circulating Water System is shown on Drawing 0740G40111 and G44015. The Intake Line and Discharge Canal are depicted on the Site Plan Drawing 0740G20003. Equipment locations within the screen, well, and pump house are provided on Drawing 0740G40141.

10.4.4.1 Circulating Water Pumps

Circulating water flow is provided by two 24,500 gpm capacity pumps with a total head of 25 feet of water. The pumps will produce a head of 22.3 feet at the inlet nozzle of each water box with a flow of 25,800 gpm per pump as determined from pump and system head curves.

10.4.4.2 Flooding Potential From CWS

Chapter 3, Subsection 3.6 of this Updated FHSR addresses failures of the expansion joints utilized in the piping system in the screen, well and pump house.

10.4.4.3 Circulating Water Chlorination

As part of the Sewage and Chlorination System (SEC) shown on Drawing 0740G40118, chlorination is provided to prevent and/or kill organics in the Service Water or Condenser Circulating Water Systems by injecting sodium hypochlorite. This system is not used on a routine basis because the Lake Michigan water is so cold. Chlorination may be utilized when organic fouling is suspected or indicated by a decrease in heat exchanger or condenser efficiency.

10.4.5 CONDENSATE AND MAKE-UP WATER DEMINERALIZERS

Condensate water purity is provided by the Condensate Demineralizer; the Resin Regeneration System (RGS); and the Make-Up Demineralizer and Demineralizer Water Transfer Systems (DMW). Refer to Drawing 0740G40110. Associated Demineralizers are the Radwaste System (RWS) Demineralizer Drawing 0740G40108 and the Reactor Cleanup System (RCS) Demineralizer shown on Drawing 0740G40107. The Clean-Up System is addressed in Chapter 5, and the Radwaste System in Chapter 11 of this Updated FHSR.

10.4.5.1 Condensate Demineralizer

Three half-capacity mixed-bed ion exchangers (sized for 965 gpm each vessel) designed for a maximum flow rate of 50 gpm/ft^2 of surface area are provided for removal of reactor solids carry-over and turbine-condenser system corrosion products from the full condensate flow.

All three are normally in service, while one may be taken out of service for resin change while on standby.

Instrumentation for the condensate demineralizer system is provided on a local control panel.

Each demineralizer is arranged for manual start and shutoff. The differential pressure head across all demineralizers is indicated with high pressure head annunciated on the local panel. The maximum pressure drop across the demineralizer system shall not exceed 50 psig immediately prior to regeneration or resin replacement when operating at 965 gpm flow rate.

Each condensate demineralizer outlet contains a temperature compensated effluent conductivity cell which displays locally and provides input for a trouble alarm in the control room. In-stream laboratory-type conductivity cells allow comparison of the installed conductivity cells.

Pressure Vessel Design

Pressure vessels for this system are designed and fabricated in accordance with the 1959 edition of the ASME Boiler and Pressure Vessel Code, section VIII for 300 psig at 120°F.

10.4.5.2 Resin Regeneration System (RGS)

The original plant design provided for a Resin Regeneration System that was utilized as follows:

> An external resin regeneration system consisting of cation resin regeneration tanks and a combination anion regeneration tank and regenerated resin storage tank. Spent resins may be hydraulically sluiced from the demineralizers to this system, where they may be separated, individually regenerated and stored. Refer to Drawing 0740G40110.
>
> Spent resins are monitored for radiation level after removal from the ion exchangers before classification and potential regeneration. If resin is found to contain a concentration of radioactive material as to pose unwarranted handling and disposal problems with the regeneration waste solution, the resin is sluiced directly to the radwaste system resin storage tank and replaced with a fresh resin charge. Resin of low activity level may be regenerated and returned to service. Because of the potential radiation levels associated with this equipment, the ion exchangers and resin regeneration tanks are shielded with 2 inches of lead. The regeneration system is connected with the cleanup demineralizer and waste demineralizer so that this system may serve as the source of resin supply for the cleanup and waste demineralizers. It was also possible to return used resins from the cleanup demineralizer for back-wash and regeneration. However, as reported in CPCo Special Report Number 5, dated August 15, 1963, it is no longer practical to regenerate cleanup resins.

Currently the plant does not regenerate resins, choosing instead to replace the resin when certain criteria for replacement are met. The reason for replacement, vice regeneration, is that Big Rock Point is cooled by Lake Michigan, a fresh water source containing only 10 ppm chloride with conductivity levels of 200-240 umho/cm. Such a relatively pure water is not expected to cause resin exhaustion for a long period of time, thus making regeneration, with its attendent large amounts of acid, base, and fresh water, an unnecessary expense in equipment, time, and expendables.

10.4.5.3 Makeup Water System

Makeup water to the steam and condensate system, and demineralized water for the reactor cooling water system and other requirements are supplied by a single mixed-bed ion exchanger of standard commercial design. Operation of the demineralizer may be manually initiated as determined by demineralized water requirements. The final design of the makeup demineralizer was changed as reported in the October 9, 1963 Annual Report to provide for automatic operation as determined by levels in the demineralized water storage tank. A sand filter was installed ahead of the makeup demineralizer to reduce the iron content of the well water supply. Facility Change FC-152 was completed in 1970 and reported in the February 15, 1971 Semi-Annual Report Number 13. This change added an interlock to the makeup demineralizer outlet valves to allow opening of these valves only when the demineralizer feed pump is in operation. This change will prevent mixed bed drainage when the demineralizer is not in use and will permit fully automatic control on tank level.

The primary function of the system is to provide makeup water of minimum conductivity and minimum solids content for the Nuclear Steam Supply System and for the following reactor auxiliaries:

1. Emergency condenser

2. Spent fuel pool and refueling shield tanks

3. Reactor Cooling Water System

4. Reactor Building Heating and Cooling System

5. Heating boiler

The system original design was to be capable of producing about 30,000 gallons net of treated water per 24 hour day with not more than two complete regenerations to meet this rated capacity. Thus, the system capacity of approximately 15,000 gallons (well water quality dependent) between regenerations.

The system as installed has not performed up to specification. Corrective measures taken to improve the capability were reported in the August 15, 1963 Special Report and included:

a. Sand filters were installed ahead of the demineralizer for iron removal.

b. Additional diffusers were added so that backwash rates can be maintained and diffusers will not be plugged up by fines in the resin.

c. The original demineralizer resin was replaced with specially classified resin to eliminate fines.

d. Additional anion resin was added to improve length of each run.

e. An additional air sparger was installed to obtain better mixing in order to improve the low pH of the effluent.

Demineralizer Resin Carryover

The December 24, 1965 Semi-annual Report Number 3 stated that in an effort to eliminate all possible avenues for inadvertent entry of demineralizer resins into the primary system, the following strainers were installed (Reference Facility Changes FC-33, 34, 35 & 36):

a. A "Y" strainer in the demineralized waterline to the clean-up demineralizer.

b. A "Y" strainer in the inlet line to the clean-up demineralizer.

c. A strainer in the demineralized water supply line to the sphere.

d. A strainer in the "treated waste" line to the sphere.

Make-up Water Control System

The water levels in the demineralized water and the condensate storage tanks are indicated locally and in the control room with abnormally high or low level annunciated on the main annunciator panel. High level in the demineralized water tank also closes the raw water supply to the make-up demineralizer.

The make-up demineralizer system is arranged for manual or automatic start with automatic shutoff at high level in the storage tank, as noted above. Automatic shutoff also occurs at high effluent conductivity or completion of a preset flow cycle, either of which indicates a requirement for regeneration of the demineralizer bed.

Instrumentation for the make-up demineralizer system is provided on a local control panel, on the turbine operating floor. Regeneration is arranged for manual start with automatic regeneration cycle shutoff and employs a conventional technique using sulfuric acid and caustic soda as regenerants. Full flow regulation in the make-up water to the demineralizer is accomplished by remote manual control from the local demineralizer control panel.

Pressure Vessel Design

Pressure vessels for this system are designed in accordance with the ASME Boiler and Pressure Vessel Code for 75 psig at 90°F.

10.4.6 CONDENSATE DEMINERALIZER RESIN REPLACEMENT

As part of Systematic Evaluation Program (SEP) Topic V-12.A - Water Purity of BWR Primary Coolant, an evaluation of the adequacy of the Condensate Treatment System Administrative Controls was completed.

As a result of this review, a revised NRC Safety Evaluation Report issued October 9, 1979 identified two issues to be resolved during the Integrated Assessment. These issues were subsequently summarized in NUREG 0828, May 1984 - Integrated Plant Safety Assessment, Section 4.18.

The NRC recommended that CPCo provide new limiting conditions for operation of the Condensate Demineralizers unless it could be demonstrated that such changes are not necessary.

In response to the NRC recommendations, CPCo by letter dated February 28, 1983 committed to submittal of an evaluation of the adequacy of existing Administrative Controls to ensure that a sufficient capacity margin exists in the condensate treatment system in which to conduct an orderly and safe reactor shutdown.

The CPCo evaluation was provided in a letter dated June 14, 1983 which maintained that 20 years of operating experience at Big Rock Point (which includes condenser tube failures) and the ongoing inservice inspection (ISI) program have demonstrated the adequacy of the existing limits and Technical Specifications.

Within the June 14, 1983 evaluation, CPCo established the resin replacement frequency required to maintain adequate capacity margin in the condensate treatment system as follows:

10.4.6.1 Resin Replacement Criteria

1. Number of days inservice on a resin bed and number and extent of condenser leaks (if any) during that period of service.

2. Expected future operation of the plant - this may result in replacement in advance of that required by the other criteria and allows scheduling of the resin bed replacement when it is least likely to interfere with other planned activities.

3. Differential pressure across each bed - retention of crud (corrosion products) on the resin beds will cause an increase in differential pressure and necessitate resin replacement in advance of that dictated by resin exhaustion alone.

4. Resin bed effluent conductivity.

10.4.6.2 Condensate Demineralizer Resin Replacement Controls

The administrative controls for condensate demineralizer resin replacement to ensure adequate resin capacity margin in the condensate treatment system for postulated condenser cooling water in-leakage consist of the following:

Resin in the three condensate demineralizers is replaced based on either an instream maximum conductivity measurement of approximately 0.1 micromho per centimeter (umho/cm), low demineralizer flow, high system differential pressure or need for resins in the radwaste demineralizer. The resin from the affected demineralizer is sluiced to a holding tank for eventual use in the radwaste demineralizer or, at times, sluiced directly from the condensate demineralizer to the radwaste demineralizer.

If the radwaste demineralizer requires resin change-out due to exhaustion and the resin holding tank is empty, the resin from the condensate demineralizer with the longest service life is sluiced to the radwaste demineralizer and new "factory regenerated" resin is then added to the empty condensate demineralizer and placed in service or new resins may be added directly to radwaste demins. Resin replacement in each condensate demineralizer normally occurs based on the demineralizer with the longest elapsed service time.

During plant shutdown, the radwaste demineralizer resin is replaced more frequently due to the increased volume of water generated during shutdown. This results in condensate demineralizer resin replacement on a more frequent basis unless new resins are added directly to the radwaste demineralizers.

Controls for condensate demineralizer resin bed replacement have been implemented to assure ion-exchange capacity margin exists to ensure adequate capacity is always on hand for the purpose of orderly plant shutdown.

In addition, the operating history at Big Rock Point indicates that if a main condenser tube leak was to occur, sawdust (pine or any softwood), if dumped by the slug-feed method into the inlet water bays, would immediately reduce the hotwell conductivity to near normal levels. Experience has shown that sawdust can reduce or stop inleakage for a period of a few days to several months if properly applied. Several saw mills are within ten miles of the plant allowing quick purchase if necessary. The probability of inleakage of relatively pure northern Lake Michigan water is very small, however, since approximately 75% of the main condenser tubes were replaced in 1982 based on the results of eddy-current testing.

NRC Staff Resolution

In the Integrated Plant Safety Assessment, NUREG 0828, May 1984, Section 4.18.2, the NRC staff concluded that CPCo's procedures are adequate and incorporating these procedures into the Technical Specifications is not warranted.

CPCo Clarification

Subsequent to the May 1984 Assessment, BRP adopted Electric Power Research Institute (EPRI) Guidelines on Chemistry. These guidelines address the level of conductivity in the hotwell at 0.08 micro mho per centimeter (BRP normal is less than 0.07). Postulating a full power operation at 0.08 micro mho per centimeter conductivity, it would take approximately fifteen (15) months to reach 50% capacity in the Condensate Demineralizers. Controls for the condensate demineralizer resin bed replacement, although changed from those discussed above, still assure sufficient capacity is always on hand for the purpose of orderly plant shutdown. The use of EPRI Guidelines was docketed within NRC Inspection Report 87-019 dated September 14, 1987.

10.4.7 CONDENSATE SYSTEM (CDS) AND FEEDWATER SYSTEM (FWS)

The Condensate System serves to remove condensed steam from the condenser hotwell, remove impurities contained in the condensate and preheat this water before it enters the reactor feed pumps. The system is shown on Drawing 0740G40106, 40110 and 44011.

The Feedwater System serves to deliver high pressure, preheated water to the steam drum maintaining constant drum level. Feedwater pump piping is shown on Drawing 0740G40106 with piping to the drum and level instruments shown on Drawings 0740G40121 and 44013. Feedwater Heaters and Heater Extraction - Water Drains (HED) System is shown on Drawing 0740G44012.

Condensate from the condensate demineralizers (refer to Section 10.4.5 above) is piped through the Low Pressure (LP) feedwater heater and the Intermediate Pressure (IP) feedwater heater to the suction of the reactor feed pumps.

10.4.7.1 Condensate and Feedwater Systems Piping

Piping Design Pressures, Temperatures, and Materials Specifications are as follows:

Condensate

200 psig, 300 F, ASTM A-106, Grade B (Seamless)

Feedwater

Steam Drum to Second Valve 2000 psig, 375 F, ASTM A-106, Grade B (Seamless)

Second Valve to Feed Pumps 2000 psig, 375 F, ASTM A-106, Grade B (Seamless)

The design and fabrication information for these piping systems was submitted to the NRC March 23, 1962 and resubmitted March 12, 1975.

10.4.7.2 Condensate and Feedwater System Auxiliaries

Extraction Drains and Vents

Extraction steam for feedwater heating is taken from three points off the turbine to the respective heaters. The IP and HP heater pressure extraction lines are provided with automatic bleeder trip valves to protect the turbine from flooding, in the event of a heater tube break, or over-speed from steam flashing out of the heater after a turbine trip.

Water collected from the turbine moisture removal stages is piped to the drain cooling section of either the high intermediate or low pressure heaters. Heater drains are cascaded to the condenser where they are deaerated and added to the condensate flow.

Condensate Pumps

Two 1000 gpm half-capacity, vertical, multi-stage centrifugal pumps, pump the condensate from the hotwell through the condensate system to the suction of the reactor feed pumps. Pump design pressure is 265 psia.

The condensate pumps deliver condensate through the air ejector inter- and after-condenser, turbine gland seal condenser, condensate demineralizers, low pressure feedwater heater, and intermediate pressure feedwater heater, in series.

Facility Change FC-005 added an auto-start scheme to the starting circuits of the condensate pumps to provide automatic starting of the stand-by pump upon low reactor feed pump suction pressure. This change was reported in the Semi-Annual Report Number 2 June 25, 1965.

Based upon Westinghouse Electric Corporation shop testing results, the condensate pumps delivered 537 feet Total Differential Head (TDH) at 1000 gpm, 180 Brake Horse Power (BHP), 74.0% efficiency and a shutoff head of 670 feet. The motor is rated at 200 horsepower and 1790 RPM at full load.

10.4.7.3 Condensate Control System

Main condenser controls are conventional and include a vacuum trip arranged to close the turbine stop valve and trip the reactor safety system. Level control of demineralized water make-up to the condenser and condensate rejection from the condensate pump discharge downstream of the demineralizers is also provided. Condensate hotwell level and condenser temperature and vacuum are recorded on the control board. Abnormally high or low hotwell level and low condenser vacuum, ie, high back pressure, are annunciated on the main annunciator panel. Conductivity measurement of the condensate from each half of the condenser hotwell monitors condenser cooling water leakage. A sample connection in the condensate header upstream of the demineralizer allows for laboratory determination of dissolved oxygen as a guide to the performance of the gas removal system and de-aerating section of the condenser.

Condensate recirculation to the condenser, actuated from low feedwater flow, insures minimum flow requirements of condensate through the air ejector and gland seal condensers.

10.4.7.4 Feedwater System (FWS)

Description

The feedwater system is designed to deliver high pressure, preheated water, to the steam drum maintaining a constant steam drum level. The system is shown on Drawing 0740G40106, 44012 and 44013.

The feedwater system consists of two reactor feed pumps, two feedwater control valves, two minimum flow valves, a high pressure heater, a level control system, and various manual and check valves, to properly perform its design function. The system is designed for 2000 psig at 375°F as described in 10.4.7.1 above.

Condensate from the demineralizers passes through the Low-Pressure and Intermediate-Pressure feedwater heaters to the suction of the reactor feed pumps. The feed pumps return feedwater to the steam drum through a high pressure feedwater heater, feedwater control valve and check valves.

10.4.7.4.1 Feedwater Pumps

Two feedwater pumps, taking suction directly from the condensate system, discharge feedwater through the high pressure heater and through a common header to the reactor steam drum. They are horizontal, multistage, centrifugal, motor driven 1600 gpm reactor feed pumps.

Reactor Feedwater Pump Recirculation

Each reactor feed pump is provided with a solenoid valve, actuated air diaphragm control valve and multiple orifices which recirculate feedwater to the condenser to maintain minimum flow through the pumps. The actuating signal is provided by a low flow switch in the feedwater line to the reactor. When the total feedwater flow falls below the minimum required to prevent overheating of the pumps, both recirculation valves open and remain open until the flow demand of the reactor increases sufficiently to protect the pumps.

Feed Pump Recirculation Valves

These valves had originally been arranged for snap action operation in both the opening and closing directions. They opened faster than the condensate recirculation valve could close. The solenoid exhaust on each recirculation valve was fitted with a volume chamber and a bleed valve. These valves still snap closed, but require approximately 5 seconds to open wide.

10.4.7.4.2 Feedwater Heaters

Three feedwater heaters are located in the condensate circuit. The low pressure and intermediate pressure heaters are of the horizontal-mounted U-tube type with removal tube bundles, integral drain coolers, and bolted head covers.

The high pressure heater is of the horizontal U-tube type with integral drain cooler. Channel connections are welded and tube maintenance is performed by cutting and removing a skirt section on the shell.

As reported in Semi-Annual Report Number 8, June 24, 1968 new stainless steel tube bundles were installed in each of the three feedwater heaters (LP, IP and HP). Previous experience with these heaters during operation indicated the following:

1. Exfoliation and oxygen attack occurred on the 70%-30% copper-nickel tube material in the original HP heater. The tube bundle was physically removed from service and bypassed for months after many tubes ruptured.

2. Chemical tests showed oxygen attack in all heaters, thus causing many of the corrosion products noted in the feedwater system as well as the reactor.

The new tube bundles were installed to ASME Section VIII 1959 Edition, FHMA, and State of Michigan requirements. The U-tubes are now SA-249T-304 stainless steel material.

The heat balance conditions shown on Drawings 0740G40112 through 40117B provide updated performance under varying loads for the retubed heaters.

Feedwater Heater Control System

Controls on the feedwater heaters are conventional, utilizing level controllers on each heater shell for normal cascading of drains to the lower pressure heater or condenser, and for high level dump to the condenser.

Further increase in the condensate level in any heater past the dump level is annunciated on the main annunciator panel, while a still higher level in both the intermediate and high pressure heaters will close the respective turbine extraction bleeder trip valves to prevent back flow of water to the turbine. Pressure and temperature test points are provided on each feedwater heater condensate inlet and outlet nozzle and on each heater drain nozzle. Local heater shell pressure gages are provided for use during maintenance.

Bleeder Trip Valves

Bleeder trip valves are located on the turbine steam extraction lines to the IP and HP feedwater heaters to protect the turbine. The air operated valves prevent reversal of flow and are equipped with a side closing cylinder to give positive closing when the air is released from the cylinder. The spring loaded cylinder closes the valve on loss of air initiated by turbine overspeed trip or high level in the heaters. As long as air pressure is established, the internal disc is free to swing open or closed as with any ordinary check valve.

Upon release of air pressure from below the cylinder piston, (from overspeed trip or high heater level) the closing spring forces the piston downward, which in turn pulls down the closing lever on the shaft and by means of engaging dogs, closes and holds the disc in its seat in the event of reverse flow or loss of extraction steam forward flow. The valve will remain in this position until air pressure is again established and the piston moved upwards.

10.4.7.4.3 Feedwater and Reactor Water Level Control System

The water level in the steam drum is controlled by a three element level control system. This control system uses the measurement of steam flow, feedwater flow and steam drum water level. Signals proportional to each of these measurements feed into the control system. Normally, the steam flow signals equal that of the feedwater. Any mismatch in these results in a correcting signal to the feedwater control valve. The water level measurements adds or subtracts from this signal to the control valve, if the detected level varies from the designed range.

The water level, steam flow and water flow rates are recorded and indicated in the control room. The water level indication is a completely independent level system from the level recording system and by a switch located on the console, either one can be used for controlling. Both level systems are independently pressure-compensated for accurate reading throughout the range. Both feedwater and steam flow are integrated. A manual automatic switch is provided on the console so the control valve may be operated manually if desired.

In addition to the two level systems used in the feedwater control, there are two independent steam drum level indicator systems that read-out in the control room which are not considered part of the FWS.

10.4.7.4.4 Loss of Feedwater or Feedwater Heaters Analyses

Loss of Feedwater Heaters

Sudden loss of all the feedwater heaters would cause an immediate but smooth rise in flux. It is expected that the flux will reach the scram value within a few minutes with no significant overshoot or damage to the fuel. Analyses for loss of feedwater heating are provided in Chapter 15, Subsection 15.1.1 of this Updated FHSR.

Loss of Feedwater

Loss of feedwater will result in gradual lowering of the water level in the steam drum and if continued, will automatically initiate reactor shutdown. Analyses for loss of feedwater are provided in Chapter 15, Subsection 15.2.7 of this Updated FHSR.

10.4.7.4.5 Feedwater Flow Control Evaluation

The NRC staff, by letter dated February 1, 1978 requested CPCo to provide an evaluation of the feedwater control system to determine the need for an automatic high reactor water level trip for the reactor feedwater pumps.

This evaluation was submitted to the NRC by CPCo letter dated March 7, 1978 and excerpts from the evaluation are provided below: (It should be noted that at the time of the evaluation the feedwater system was required to perform an "Interim" high pressure coolant injection function during fuel Cycle 15 for certain design basis LOCA events. Currently, the feedwater system may be utilized for high pressure coolant injection functions for certain events described in the Emergency Operating Procedures which are considered beyond design basis.)

CPCo has concluded that the installation of this trip is inappropriate and unnecessary for Big Rock Point. This evaluation is based upon the following considerations: (1) The high reliability of the feedwater control system, (2) the existence of a steam drum at Big Rock Point and the large feed volume it affords, and (3) the unusually high availability required of the reactor feedwater system under specific LOCA conditions.

The Big Rock Point feedwater control system has operated reliably with no known problems relating to inadvertent flooding of the primary steam drum. In general, the feedwater control system is a three-element controller utilizing steam flow, feed flow, and steam drum water level signals. The system is designed to maintain drum level during steady state operation, and to handle all normal plant load swings without resulting in reactor trip on low drum level. Steam flow is the primary element in the controller. A mismatch between steam flow and feed flow is anticipatory of an impending drum level deviation and will result in appropriate controller action. For example, a step increase in steam flow, and the resulting reduction in drum pressure, causes an immediate swelling of the drum level due to flashing. The controller, however, will cause an increase in feedwater flow in anticipation of the eventual fall in drum level as the primary system fluid inventory is depleted based upon the steam flow/feed flow mismatch. In the unlikely event of a large reduction in steam flow (ie, caused by a turbine trip without bypass, for example) the drum level would rapidly fall due to the collapse of voids in the primary system. The operation of the controller would be to initially reduce feedwater flow in response to the high steam flow/feed flow mismatch and thus avoid overfilling of the drum. The controller would then continue to supply some water to the drum until normal level was reached.

Due to the high free volume of the primary steam drum, the potential for completely filling the drum and overpressurizing the primary system is remote. The steam drum which contains the steam separators and dryers, as well as the feedwater spargers, has a free volume of about 1,100 cf. During normal operation the drum is about half full. Failure of the control system could result in filling of the drum beyond the normal water level. Assuming such a failure, high drum level alarms would be initiated. The second high level alarm is part of the reactor depressurization system, is four-channel redundant, and the transmitter is environmentally qualified. Under the worst conditions, with the reactor tripped and assuming a very high feedwater flow rate of 2,200 gpm, the operator would have at least 2.4 minutes after the first alarm to terminate the transient before the drum would fill. However, if the amount of available condensate is considered, the feed pumps can be shown to trip on low suction pressure before the drum fills. For other cases, the drum would fill more slowly, thus allowing adequate time for operator action to terminate the transient.

It should be noted that aside from the primary safety valves, no safety-related equipment or equipment required for the orderly shutdown of the reactor would be affected by the filling of the steam drum and that the filling of the drum cannot inhibit initiation of any required safety features. A solid drum condition would inhibit the actuation of the reactor depressurization system (required for small break LOCAs), however, the availability of feedwater can only improve the consequences of the LOCA (ie, core uncovery is not possible if water remains in the steam drum). Filling of the drum may result in damage to the primary safety relief valves. However, as noted above, there will exist adequate time after the high drum level alarm is actuated before operator action is required to terminate the level rise. Thus, the possibilities of this even occurring is considered remote.

In summary, based upon the proven reliability of the feedwater control system, the excess capacity of the steam drum when compared to the normal feedwater flow rate, and the availability of the reactor feedwater system for high pressure injection water as part of the Emergency Operating Procedures, Consumers Power Company concluded that the installation of an automatic high reactor water level trip for the reactor feedwater pumps is an unnecessary and undesirable modification.

Increase In Feedwater Flow Analysis

An analysis for "Increase in Feedwater Flow," has been included in Chapter 15, Subsection 15.1.2 of this Updated FHSR. The analysis assumptions are somewhat different than the above evaluation based upon the input parameters involved. The results of the Chapter 15 analysis supplements the results of the evaluation performed above.