# 10 STEAM AND POWER CONVERSION SYSTEM

# 10.1 INTRODUCTION

## *10.1.1 SUMMARY DESCRIPTION*

### 10.1.1.1 Functional Description

The conversion of the heat produced in the reactor to electrical energy is accomplished by the steam and power conversion system.

Steam from each of the two steam generators supplies the turbine where the steam expands through the high-pressure turbine, and then flows through moisture separators, reheaters, and intercept valves 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.

The steam that leaves the exhaust of the low-pressure turbine enters the main condenser as saturated steam. The steam is condensed by the circulating water, which passes through the tubes of the condenser.

Condensate is taken from the condenser hotwell through the condensate pumps, condensate demineralizers and bypass valve to the suction of the condensate booster pumps. The condensate booster pumps flow condensate through the condensate cooler, hydrogen coolers, air ejector condensers, gland steam condenser, and low-pressure heaters to the suction of the feedwater pumps. The feedwater pumps send feedwater through the high-pressure heaters to the steam generators.

Drains from the high-pressure heater are cascaded together with drains from the four reheaters to the No. 4 low-pressure heater and then to a drain tank. The moisture separators also drain to this tank. The heater drain pump discharges to the feedwater pump suction. Drains from the first three low-pressure heaters cascade to the condenser.

The main steam lines have four safety valves on each line, which provide pressure relief to the atmosphere for the steam generators. There are also two steam dump lines with four relief valves each to the condenser and one atmospheric steam dump valve (power-operated relief valve) on each line for long term plant cooldown by atmospheric steam discharge if condenser steam dump is not available. Each steam line is equipped with a fast closing Main Steam Isolation Valve (MSIV) and a Main Steam non-return check valve. The isolation and non-return valves are located outside of the containment. These valves prevent reverse flow in the steam lines which would result from an upstream steam line break or they isolate a downstream steam line break at the common header.

The feedwater lines are equipped with a non-return check valve and an air operated isolation valve in each line. The non-return valve is the boundary between Seismic Category I and non-seismic feedwater piping and prevents the steam generator from blowing back through the feedwater lines if damage occurs to the non-seismic portion.

#### 10.1.1.2 Radioactivity

Radiation shielding is not required for the components of the steam and power conversion system. Continuous access to the components of the system is possible during normal conditions.

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 offgas will detect any contamination.

The limiting conditions to meet the guidelines of 10 CFR 20 for MODES 1 and 2 with leaks through the steam generator tubes are established in the Technical Specifications.

Corrosion protection for the system is discussed in Section 10.7.7.

#### 10.1.1.3 Major Systems

The major systems within the steam and power conversion system are as follows:

A. The main steam system produces dry saturated steam in the steam generators and directs it to the main turbine and auxiliary equipment. The system is discussed in Section 10.3.

B. The main turbine acts to convert the thermal energy of the steam into mechanical energy. The mechanical energy drives the main generator for the production of electrical energy. The turbine generator and the turbine generator control systems are discussed in Section 10.2.

C. The condensate and feedwater systems function to condense the steam exhausted from the low-pressure turbines, collect and store this condensate, and then send it back to the steam generator for reuse. The systems are discussed in Section 10.4.

D. The preferred auxiliary feedwater system supplies water to the steam generators when the normal feedwater system is not available. The system is discussed in Section 10.5.

E. The standby auxiliary feedwater system supplies water to the steam generators in the event of a loss of preferred auxiliary feedwater flow, and thus provides a reliable means of residual heat removal in the event that all other sources of feedwater are lost. The system is discussed in Section 10.5.

F. The circulating water system provides the means for condensing the steam exhausted from the low-pressure turbines in the main condensers. It also provides a reliable supply of water for the service water (SW) system and the fire protection system. The system is discussed in Section 10.6.

In addition to the major systems listed above, the steam and power conversion system includes systems with supporting or interfacing functions. They are discussed in Section 10.7 and include

- The steam dump system (Section 10.7.1).
- The heater drain system (Section 10.7.2).

- The extraction steam system (Section 10.7.3).
- The condensate storage system (Section 10.7.4).
- The steam generator blowdown system (Section 10.7.5).
- The turbine and generator auxiliary systems (Section 10.7.6).
- The secondary chemistry control systems (Section 10.7.7).

The design parameters of some of the major components used in the steam and power conversion system are listed in Table 10.1-1.

## *10.1.2 DESIGN BASES*

### 10.1.2.1 System Design

The turbine generator system consists of components of conventional design, acceptable for use in large central power stations. The equipment is arranged to provide the best possible thermal efficiency without compromising safety.

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

All of the equipment in the turbine generator systems was originally designed to produce a maximum calculated gross output of 516,739 kW. With plant uprate to 1775 MWt the equipment was verified as being capable to support a gross electrical output of 612,855 kW.

The system design provides means to monitor and restrict radioactivity migration to the normal heat sink or environment such that, considering all controlled plant discharges, 10 CFR 20 limits are not exceeded under conditions of MODES 1 and 2 and under anticipated system malfunctions or failures.

The system design provides sufficient feedwater under conditions of loss of power and loss of normal heat sink to maintain flow, as required, to the steam generators until power is restored or the reactor heat load is accommodated by other systems.

The electric transmission system directs the power conversion system to provide load changes up to generation step load increases of 10% of full power and ramp increases of 5% of full power per min within the load range of 12.8% to 100% of full power without reactor trip subject to possible xenon limitations late in core life. Similar step and ramp load reductions are possible within the range of 100% to 12.8%. Turbine trip from 50% of full power can be sustained without a reactor trip with the supplemental use of steam dump to the condenser. Complete loss of load, when operating above 50%, will cause a reactor trip.

The system design incorporates backup means of heat removal (modulating relief valves and safety valves) under any loss of normal heat sink (e.g., main steam stop valves trip, condenser isolation, recirculating water loss of flow) to accommodate reactor shutdown heat rejection requirements. Planned system atmospheric discharges under MODES 1 and 2 are made only

if atmospheric releases are acceptable under considerations of 10 CFR 20. All such discharges are monitored for acceptable radiation levels. Technical Specifications on secondary side activity ensure that releases are minimized during transients.

The steam and power conversion system provides steam for driving the turbine driven auxiliary feedwater pump (TDAFW) and for turbine gland steam, reheater steam, and air ejector operation in addition to supplying the turbine generator.

#### 10.1.2.2 Codes and Classifications

The codes and classifications used in the design of the main steam system, the feedwater system, the preferred auxiliary feedwater system, and the standby auxiliary feedwater system appear in Table 3.2-1. The table lists the systems and components along with the current code requirements, the codes and standards used when the plant was built, the seismic classification in accordance with Regulatory Guide 1.29, and the seismic classification used in the plant design.

As part of the Systematic Evaluation Program (SEP) the codes, standards, and classifications to which the station was built were compared to current code requirements. It was generally concluded that changes between original and current code requirements do not significantly affect the safety functions of the systems and components reviewed. Details of the review of codes and classifications at Ginna Station are discussed in Section 3.2.2.

### *10.1.3 SYSTEM EVALUATION*

#### 10.1.3.1 Variables Limits Functions

Trips, automatic control actions, and alarms will be initiated by deviations of system variables within the steam and power conversion system. In the case of automatic corrective action in the steam and power conversion system, appropriate corrective action will be taken to protect the reactor coolant system. The more significant malfunctions or faults which cause trips, automatic actions, or alarms in the steam and power conversion system are:

1. <u>Turbine trips.</u>
   a. Generator/electrical faults.
   b. Loss of both circulating water pumps.
   c. Low condenser vacuum.
   d. Thrust bearing failure.
   e. Low lube-oil pressure.
   f. Loss of both main feedwater pumps.
   g. Turbine overspeed.
   h. Reactor trip.
   i. Manual trip.
2. <u>Automatic control actions.</u>

a. High level in steam generator stops feedwater flow.

b. Normal and low level in steam generator modifies feedwater flow by continuous proportional control.

3. Principal alarms.

a. Low pressure at feedwater pump suction.

b. Low vacuum in condenser.

c. Low water level in condenser hotwell.

d. High water level in condenser hotwell.

e. High temperature in low-pressure turbine exhaust hood.

f. Low NPSH margin at feedwater pump suction (shown on Plant Process Computer System PPCS).

### 10.1.3.2 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 bypass to the condensers. Thereafter, core decay heat can be continuously dissipated via the steam bypass to the condenser as feedwater in the steam generator is converted to steam by heat absorption. Normally, the capability to return feedwater flow to the steam generators is provided by operation of the turbine cycle feedwater system. One motor-driven auxiliary feedwater pump (MDAFW) can supply sufficient feedwater for removal of decay heat from the plant.

In the unlikely event of complete loss of offsite electrical power to the station, decay heat removal would continue to be ensured by the availability of one steam-driven, and/or one of two motor-driven auxiliary (MDAFW) or standby auxiliary feedwater pumps (SAFW), and steam discharge to the atmosphere via the main steam safety valves (MSSV) and/or the atmospheric relief valves (ARV). The preferred auxiliary feedwater system utilizes the two motor-driven pumps with each pump delivering feedwater into an associated steam generator and a steam-driven pump to deliver flow to both steam generators. In this case feedwater is available from two condensate storage tanks (CST) by gravity feed to the preferred auxiliary feedwater pumps. Each condensate storage tank (CST) has a nominal capacity of 30,000 gal of water for a total nominal capacity of 60,000 gallons. Actual usable volume is less than 60,000 gallons. The minimum amount of water in the condensate storage tanks (CST), given in the Technical Specifications (24,350 gal), is the amount needed to remove reactor decay heat for 2 hrs of operation after reactor trip at full power. If the need is more than a 2-hr supply and additional water is not available in the condensate storage tanks (CST), additional sources can be made available. These include the condenser hotwell and the all-volatile-treatment storage tank. Further, Lake Ontario water could be used. This water supply is available from the lake via the service water (SW) system for an indefinite time period. Finally, water could be made available from the yard fire hydrant system.

In the event of a high energy line break or other event that would render inoperable the three preferred auxiliary feedwater pumps, the standby auxiliary feedwater system can provide the necessary feedwater for removal of decay heat from the plant. Each standby auxiliary feed water pump (SAFW) delivers feedwater into an associated steam generator. Feedwater is available from the service water (SW) system, a 160,000 gallon DI water storage tank, or

from the yard fire loop.

#### 10.1.3.3 Secondary-Primary Interactions

Following a turbine trip, from power levels above 50% full power, the control system reduces reactor power output immediately by a reactor trip. The steam bypass to the condenser together with the action of the control rods can handle all the steam relief without lifting the main 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 motor-driven auxiliary feedwater pumps (MDAFW) will start automatically. If the reactor is operating above 50% of full power at this time, the reactor will trip.

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

| | |
|---|---|
| Turbine generator | |
| Turbine type | Three-element, tandem-compound, four-flow exhaust |
| Turbine capacity | |
| Maximum guaranteed, kW | 585,000 @ 1775MWt |
| Maximum gross output, kW | 613,640 |
| Turbine speed, rpm | 1800 |
| Generator rating, kVA | 667,000 |
| Condensers | |
| Number | Two |
| Type | Radial flow, semi-cylindrical water boxes, deaerating |
| Condensing capacity, lb of steam/hr | 4,235,070 |
| Condensate pumps | |
| Number | Three |
| Type | Multistage, vertical, pit-type, centrifugal |
| Design capacity (each), gpm | 6600 |
| Motor type | vertical |
| Motor rating, hp | 1500 |
| Feedwater pumps | |
| Number | Two |
| Type | Single stage, double flow, centrifugal |
| Design capacity (each), gpm | 8800 |
| Motor type | Horizontal |
| Motor rating, hp | 5500 |

| | |
|---|---|
| Condensate booster pumps | |
| Number | Three (50% capacity each) |
| Type | Horizontal single stage, centrifugal |
| Design capacity, gpm | 5400 |

NOTE: Pump PCD01A has a higher capacity to accommodate future EPU requirements.

| | |
|---|---|
| Motor rating, hp | 500 |
| Auxiliary feedwater | |
| Sources | 30,000 gal in each of two condensate storage tanks<br>28,000 gal in each of two condenser hotwells<br>100,000 gal all-volatile-treatment storage tank<br>Unlimited service water<br>Yard fire hydrant system |
| Auxiliary feedwater pumps | |
| Number | Three (one steam-driven and two motor-driven) |
| Design capacity (each), gpm | 400 (steam-driven)<br>200 (motor-driven) |
| Standby auxiliary feedwater (SAFW) | |
| Sources | Service water<br>Yard fire hydrant system<br>160,000 gallon DI water storage tank |
| Standby auxiliary feedwater (SAFW) pumps | |
| Number | Two (motor-driven) |
| Design capacity (each), gpm | 215 |
| Main steam isolation valves | |
| Number | 2 |
| Type | Atwood and Morrill |
| Flow design capacity, lb/hr | $3.29 \times 10^6$ at 770 psia |
| Closure time (without flow), sec | 5 |

| | |
|---|---|
| Main steam safety valves | |
| Number | 8 |
| Type | Crosby |
| Capacity (each), lb/hr | 797,689: two valves at 1085 psig +3% accumulation<br>837,600: six valves at 1140 psig +3% accumulation |
| Condenser steam dump valves | |
| Number | 8 |
| Type | Copes Vulcan |
| Capacity, lb/hr | 302,500 at 695 psig |
| Atmospheric steam dump valves | |
| Number | 2 |
| Type | Masoneilan |
| Capacity (each), lb/hr | 329,000 at 1005 psig (normal) |

# 10.2 TURBINE GENERATOR AND CONTROLS

## *10.2.1 MAIN TURBINE*

### 10.2.1.1 Description

The main turbine is made up of one high-pressure and two low-pressure turbines, all mounted on a common shaft. The steam flow path is first through the high-pressure turbine, then in a parallel path to the two low-pressure units via the four moisture separator reheaters. The main turbine is a three-element, tandem compound, four-flow exhaust, 1800 rpm unit with 40-in. last row blades. Both the high- and low-pressure elements are of the double flow design. As a part of the plant uprate to 1775 MWt, the HP Turbine was modified from a partial arc design to a full arc design; and the rotating and stationary blading of the HP Turbine was replaced with a new design. Additionally, the four HP Turbine control valves were replaced with larger valves to decrease throttling losses in control valves.

The turbine has a maximum guaranteed gross rating of 496,322 kW when operating with inlet steam conditions of 730 psia, 508°F full throttle temperature, exhausting at 1.35 in. of mercury absolute, 0% makeup, and with five stages of feedwater heating in service.

High-pressure steam is admitted to the high-pressure turbine through two stop and four governing control valves. These valves are controlled by the electro-hydraulic control system discussed in Section 10.2.3. The flow guide is made up of a single nozzle chamber to allow full 360-degree steam entry at full power. Steam flows axially in both directions through 11 stages of pressure reaction blading.

The high-pressure turbine exhaust steam is directed through the preseparators to four combination moisture separator reheaters where the steam is superheated. This is accomplished by:

A. Moisture separation.

B. Reheating the relatively dry steam.

The moisture is removed as the high-pressure exhaust steam rises through the multi-vane chevron-configuration separators. The steam then flows over the reheater tube bundle where it is superheated by steam from the main steam header. Entry into the low-pressure turbines is through the reheater stop and intercept valves. Flow through the low-pressure turbines is double axial flow through 11 stages of pressure reaction blading to exhaust into two single-pass condensers.

### 10.2.1.2 Turbine Controls

#### 10.2.1.2.1 Description

High-pressure steam enters the turbine through two stop valves and four governing control valves. One stop and two control valves form a single assembly which is anchored to the foundation above the turbine room floor line. An electrohydraulic servo-actuator controls each stop valve so that it is either in the wide-open or fully closed position. The control signal for this servo-actuator comes from the mechanical-hydraulic overspeed trip portion of the electrohydraulic control system. The major function of these 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 control valves are positioned by a similar electrohydraulic servo-actuator acting in response to an electrical signal from the main governor portion of the electrohydraulic control system. Upon loss of load resulting in a high rate of acceleration, the auxiliary governor portion of the electrohydraulic control unit will act to close the control valves rapidly.

The steam, after passing through the stop and control valves, passes through the high-pressure turbine and the preseparators, then through the moisture separator and reheater. The reheater stop valves and reheater intercept valves are located between the reheater and the low-pressure turbine inlet. Their purpose is to control the steam flow to the low-pressure turbines in the event of turbine overspeed. The reheater stop valve is an open-closed type valve that is closed upon operation of the overspeed trip, similar to the operation described above for the main stop valves. The reheater intercept valve is a positioned valve controlled from the auxiliary governor portion of the electro-hydraulic control system. The use of intercept valves provides the capability for the turbine generator to accept a 50% loss of external electrical load without turbine trip; in this event, electrical power is maintained to the plant auxiliaries.

Figure 10.2-1 illustrates the control of the steam admission valves (electrohydraulic governing 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 lube-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 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 initiates a reactor trip to prevent excessive reactor coolant temperature and/or pressure.

#### 10.2.1.2.2 Automatic Load Reduction

Automatic turbine load runback is initiated by two-of-four coincidence overpower delta T channels or two-of-four coincidence overtemperature delta T channels (see Section 7.7.1.2.8).

### 10.2.1.3 Turbine Disk Integrity

Turbine disk cracking was investigated and analyzed by Westinghouse Corporation in a proprietary report submitted to the NRC in June 1981. The report recommended criteria for scheduling disk inspections that provide a very low probability of disk failure prior to inspection. A safety evaluation report on these criteria was issued by the NRC on August 28, 1981. (*Reference 1*) Rochester Gas and Electric Corporation committed to inspect and reinspect the low-pressure rotor disks on a schedule consistent with the Westinghouse criteria as outlined in *Reference 1* (see Section 3.5.1.2). The impact of the uprate (1775 MWt) operating conditions on LP Turbine disk cracking was evaluated and no changes to the normal disk inspection frequency was required.

#### 10.2.1.4 Turbine Supervisory Instrumentation

Turbine supervisory instrumentation is provided to monitor turbine vibration, eccentricity, and differential thermal expansion and provide alarms in the control room in the case of abnormal conditions.

The turbine supervisory instrumentation system includes a proximity transducer system, which uses non-contacting pickups for measuring the gaps of the following sensors: radial vibration, key phasor reference, eccentricity, and thrust position. The proximity transducer system consists of a proximeter, which is supplied with dc voltage from the system power supply. The proximeter produces a radio frequency signal, which is supplied to the 8-mm proximity probes through an extension cable. The radio frequency signal sets up an eddy current signal across the air gap being measured. This eddy current reduces the return signal to the proximeter, which conditions the signal for display on a digital monitor.

Thermal case expansion of the turbine is measured with a linear variable differential transformer (LVDT) transducer assembly. The LVDT is supplied with dc voltage by the case expansion analog indicator to which it is connected.

Differential expansion of the turbine shaft is measured at the shaft ends by 25-mm probes connected to 25-mm proximeters through 25-mm extension cables. The output from the differential expansion proximeters is transmitted to differential expansion monitors in the turbine supervisory instrument rack in the control room.

Digital monitors are provided to display the outputs of the following proximeters: nine x-y radial vibration monitors, one eccentricity monitor, one thrust position monitor, one case expansion monitor, and two differential expansion monitors.

Relay modules are provided to actuate control room annunciators for high vibration, rotor eccentricity, differential expansion, and rotor position.

The system automatically receives alarms for an abnormal condition. Readings of vibration, eccentricity, etc., may either be read in the rear of the main control board on the individual monitors, on the recorder, or may be called up on a CRT monitor available to both maintenance and engineering personnel.

### *10.2.2 MAIN GENERATOR*

The main generator is a totally enclosed, pressurized, hydrogen gas cooled, four pole, three-phase ac generator. The generator at full load is rated to produce 613.64 MW at an 0.92 power factor. The generator rating is 667 MVA at 0.92 power factor and 60 Hz at 1800 rpm, with 60 psig hydrogen pressure. The generator has sufficient capability to accept the gross kilowatt output of the steam turbine with its control valves wide open at rated steam conditions.

The generator uses a brushless generator exciter system and voltage regulator. Direct current voltage to the field windings of the generator is supplied by the brushless exciter system. Three-phase power is supplied to the voltage regulator circuit through the exciter field breaker by the permanent magnet generator. The permanent magnet generator is mounted on

the end of the exciter shaft and consists of 28 permanent magnets, which induce a voltage in the stator windings. Automatic and manual control of the generator field voltage is provided by the voltage regulator circuit. The voltage regulator provides control during normal and transient system operations by receiving power from the permanent magnet generator stator windings. The rotating bridge rectifier assembly supplies regulated dc voltage to the generator field windings. In the event of a generator trip, whether automatic or manual, a rapid deexcitation circuit is energized for 3 seconds to collapse the generator field before the generator field breaker opens. The generator exciter is totally enclosed. Air flow from a blower attached to the generator shaft is cooled by an installed cooler.

## *10.2.3 ELECTROHYDRAULIC CONTROL SYSTEM*

### 10.2.3.1 Function

The electrohydraulic control system performs the following functions:

A. Controls the position of the valves that admit steam to the high-pressure turbine (four control valves).

B. Positions the valves that isolate the steam supply to the high-pressure and low-pressure turbines (two high-pressure turbine stop valves, four reheater stop valves, and four reheater intercept valves).

C. Responds automatically to an operator input.

D. Allows direct operator control.

E. Responds to automatic protective signals and devices.

F. Alerts the operator to malfunctions of the component parts of its system.

The function of the high-pressure fluid control system is to provide a motive force which positions the turbine steam valves in response to electronic commands from the electronic controller, acting through the servo-actuators. The fluid control medium is a fireproof triarylphosphate ester base fluid. The fluid is stored in a stainless steel reservoir assembly on which is mounted a duplicate system of fluid pumps, controls, filters, and heat exchangers. The system is so arranged that one pump and one set of the various control components function while the duplicate set serves as a standby system.

### 10.2.3.2 Components

The electrohydraulic control system has a 200-gal stainless steel reservoir tank which provides the suction for the pumps and storage for the returned fluid. Inside the reservoir is a common filter suction which is constructed of 140-micron wire screen.

Two positive displacement pumps, 27.2 gpm each, with a design pressure of 4000 psig, supply the force for fluid circulation. Each pump discharges through a double section filter. The pump discharge filters are steel-backed 10-micron cartridge filters with a differential pressure switch set at 100 psid to warn the operator of filter clogging.

There are two pilot-operated unloader valves on the discharge side of the pumps, which regulate electrohydraulic control fluid pressure between 1600 to 2200 psig. The unloader valves

"unload" the pump discharge back to the reservoir when fluid pressure reaches 2200 psig. The unloader shuts when header pressure drops to 1600 psig and redirects the pump discharge to the high-pressure header.

System overpressure protection is provided by a relief valve actuation at 2350 psig. The relief valve returns the fluid to the reservoir.

A control block manifold mounted on the reservoir top is machined for the assembly of the following:

- Two differential switches.
- Four metal mesh 10-micron pump discharge filters.
- Two unloading valves.
- Two check valves from discharge.
- One relief valve.
- Two manual shutoff valves to the unloading valves.

There are four high-pressure accumulators mounted in a supporting rack. They are connected through manual isolation valves to the manifold block. Each accumulator consists of a cylinder that encloses a free piston fitted with ring seals. Hydraulic fluid pressure on the lower side of the piston is opposed by a 1250-psig pressure charge of nitrogen gas on the upper side.

Fluid from valve operation or trip functions enters a common drain line, and is directed to a three-way valve. This valve permits the operator to select one of two heat exchangers and return filters for service or to bypass the filters and heat exchangers. There are two heat exchangers mounted on the side of the reservoir. Fluid returning to the reservoir flows in the shell side while service water flows through the tube bundle. Also mounted on the side of the reservoir are two disposable cotton-cellulose cartridge-type filters. Upon leaving the heat exchangers or bypass line, the fluid is returned to the reservoir.

A bypass filter system provides the capability for continuous circulation of approximately 1 gpm of high-pressure fluid to the reservoir via a fuller's earth filter which is mounted in series with a corrugated cellulose filter. This assembly is located in an orificed line from the high-pressure fluid header (manual isolation provided). The fuller's earth filter is used for acid and water removal control of the fluid and the cellulose filter is used for contaminant control of the fluid.

#### 10.2.3.3 Alarms and Controls

The alarms for the electrohydraulic control system on the main control board are the electrohydraulic reservoir level and the electrohydraulic system reservoir pressure temperature alarms.

A. Electrohydraulic reservoir level-high level alarm, low level alarm, low-low level alarm, and low-low level pump trip.

B. Electrohydraulic system pressure-return pressure greater than 30 psig, low pressure 1450 psig, discharge filter discharge pressure greater than 100 psig, and temperature greater than 140°F.

C. EH System stand-by pump auto start is set at 1400 psig.

The controls for the two electrohydraulic control pumps are start/stop switches located on the main control board.

The valves controlled by the electrohydraulic control system are:

- High-pressure turbine stop valves.
- High-pressure turbine control (governing) valves.
- Reheater stop valves.
- Reheater interceptor valves.

The high-pressure turbine stop valves are two hydraulically opened, spring-closed valves that isolate the high-pressure turbine inlet from the high-pressure steam supply. They are designed to close rapidly when the unit trips to remove the source of motive power from the turbine.

The high-pressure control (governing) valves are four hydraulically opened, spring-closed valves that control the steam flow into the flow guide for the high-pressure turbine. They must do this in order to control unit speed when the generator is not connected to the grid and to control generator load when connected to the grid.

The reheater stop valves are four hydraulically opened, spring-closed valves which are used to isolate the steam supply to the low-pressure turbine. They close rapidly on a unit trip and prevent the stored steam contained in the moisture separator reheater unit and interconnecting piping from reaching the low-pressure turbine causing a possible overspeed condition.

The reheater interceptor valves are four hydraulically opened, spring-closed valves used to limit the steam flow to the low-pressure turbine following a partial or complete load rejection.

#### 10.2.2.1 Turbine Trip Devices

##### 10.2.3.4.1 **Overspeed Trip Mechanism**

The overspeed trip mechanism consists of an eccentric weight mounted on the turbine rotor extension shaft. The weight is offset from the center so that centrifugal force tends to move it outward. The weight is normally held in place by the compression of a spring. The valve trigger normally holds the trip valve closed by oil pressure being opposed by spring tension.

When the turbine overspeeds, the spring compression is overcome by centrifugal force. The weight moves out to strike a trigger, which trips the overspeed trip valve and releases the auto stop oil which trips the turbine. This trip is set at a value less than 109.3% of design speed. A manual means of testing the trip mechanism while at load is provided.

#### 10.2.3.4.2 **Auxiliary Governor**

If the auxiliary governor senses an overspeed condition at 103% of 1800 rpm, high-pressure fluid from the top of the dump valve pistons of the reheater intercept valves will be dumped through the stop valve emergency trip line in the drain header. This action will close the reheater intercept valves. As soon as the overspeed condition clears, backpressure will be restored to the check valve in the emergency trip line and the reheater intercept valves will reopen.

The overspeed condition will also dump fluid from the dump valves associated with the turbine control valves, causing them to modulate closed until the overspeed condition clears.

#### 10.2.3.4.3 **Protective Trip Devices**

Protective trip devices are included in a separate assembly. These devices include:

A. Low bearing oil pressure trip - On a low bearing oil pressure trip, a spring-loaded diaphragm at 6-psig bearing oil pressure will move downward and raise the protective trip dump relay, dumping auto stop oil pressure. An alarm will sound at 10 psig decreasing.

B. Solenoid trip - On a solenoid trip signal, the solenoid energizes and raises the protective trip dump relay, dumping the auto-stop oil and tripping the turbine. The solenoid is energized by the following:

   1. Reactor trip (from trip breakers).
   2. Manual pushbutton on the operator's console.
   3. Trip of all main feedwater pumps.
   4. Generator trip on a fault condition.
   5. Trip of all circulating water pumps.

C. Thrust bearing trip device - The thrust bearing trip device consists of two small nozzles which have discharge openings close to the thrust collar faces. Oil is supplied to each nozzle through orifices, and the pressure in the line is piped through ball check valves to a spring-loaded diaphragm in the protective trip block. Should excessive wear occur, the thrust bearing collar will move toward one of the nozzles and the pressure in the line will increase. When pressure reaches 35 psig, a pressure switch will sound an alarm. If it continues to rise to 75-80 psig, the diaphragm will move, raising the protective trip dump relay dumping the auto-stop oil to the drain.

   An electrical thrust bearing trip will trip the protective trip dump relay without time delay if the turbine trips and if the thrust bearing trip pressure is greater than 35 psig.

D. Low vacuum trip - On a low vacuum trip, a spring-loaded diaphragm will raise the protective trip dump relay, dumping oil to the drain when vacuum decreases to 20 in. of mercury. A latch is provided to permit starting the unit when vacuum is low. The latch falls out automatically when vacuum reaches a value of 20 to 24 in. of mercury. Even if latched below this value, the trip will function if a positive pressure of 2.5 to 4.5 psig is developed during the starting cycle.

#### 10.2.3.4.4 Testing and Inspection

There are three different tests of the turbine overspeed protection system performed on a routine basis. At every turbine overhaul and at each refueling outage the following two tests are performed:

A. Overspeed protective test - The turbine is oversped to the trip setpoint to close the stop, governing, and interceptor valves. This test is only performed during power descent and not repeated during power escalation unless problems are encountered.

B. As turbine is brought up to speed, the stop and governing valves are tested as a normal part of the startup.

On a periodic basis the following two tests are performed:

A. One at a time the solenoid valves (20/ET, 20-1/AG, and 20-2/AG) are isolated from the electrohydraulic control system and electrically actuated to verify operability.

B. The turbine stop, governing, and interceptor valves are tested (stroked) every 535 days (*References 2 and 3*).

## REFERENCES FOR SECTION 10.2

1. Letter from D. M. Crutchfield, NRC, to J. D. Maier, RG&E, Subject: Turbine Disc Cracking (Ginna), dated August 28, 1981.

2. 0236-0076-CALC-001, Rev. 0, MPR Calculation - Risk Assessment of Steam Turbine Valve Test Interval Extension, dated November 23, 2016.

3. ECP-16-000732, Rev. 0000, Modify Main Turbine Valve Testing Frequency, dated January 13, 2017.

# 10.3 MAIN STEAM SYSTEM

## *10.3.1 DESIGN BASIS*

The function of the main steam system is to produce dry saturated steam in the steam generators and to direct it to steam-driven components and auxiliary systems. Most of the steam is used by the main turbine.

The main steam system is designed to generate and contain saturated steam and transport it from the steam generators to the main turbine during power operation. When the unit is in the MODE 3 (Hot Shutdown) mode, the main steam system operates to maintain no-load $T_{AVG}$ (547°F) or it can be used to perform a plant cooldown.

The steam piping is designed to ensure correct steam distribution and pressures to all steam operated equipment for all turbine loads. The steam and feedwater lines with their supports and structures from the steam generators to their respective isolation valves are Seismic Category I.

## *10.3.2 SYSTEM DESCRIPTION*

### 10.3.2.1 Flow Path

The main steam flow diagram is shown in Drawings 33013-1231 and 33013-1232.

Feedwater entering the steam generator mixes with recirculated fluid and flows downward around the tube bundle wrapper and enters the tube bundle where heat is transferred from the reactor coolant to the feedwater producing steam. This wet vapor is then dried to a near moisture-free condition as it exits the steam generator. The steam exits the steam generator through an integral flow restrictor which limits excessive flow after which it passes through a flow venturi to measure steam flow. It then enters the main steam line where it passes by the main steam safety valves (MSSV) and an atmospheric relief valve (ARV), then through an isolation valve (MSIV) and non-return check valve to the equipment it serves.

Steam supplied to the high-pressure turbine passes through a turbine stop valve (normally open) and a control valve which is used to control the steam flow into the turbine. Some of the steam supplied to the high-pressure turbine is extracted from various turbine stages and sent to preheat the feedwater returning to the steam generator via the feedwater heaters which are located in both the feedwater and condensate systems. Steam exiting from the high-pressure turbine is directed through the pre-separators to the moisture separator reheaters where the moisture is removed and the steam is superheated prior to entering the low-pressure turbines. The steam leaving the moisture separator reheaters passes through a reheater stop valve and an intercept valve and then enters the low-pressure turbines. Some of this steam is extracted from various turbine stages and used for feedwater preheating.

The total steam flow is approximately $7.7 \times 10^6$ lbm/hr with steam generator blowdown flow ranging from 40-100 gpm per steam generator as needed to maintain secondary side water chemistry within plant water chemistry requirements. This corresponds to a core power of 1775 MWt and an approximate 590 MWe net rating.

#### 10.3.2.2 Steam Generators

The steam generators form the boundary between the radioactive primary and the nonradioactive secondary. There are two steam generators, each capable of delivering 3.9 x $10^6$ lbm/hr saturated steam at 810 psig, at the steam generator outlet nozzle with an RCS $T_{AVG}$ of 576°F. The steam generator shells are constructed of carbon and low alloy steels with the primary side divider plate being Alloy 690 and Alloy 600-clad tubesheet on the primary side. The major components of the steam generator include the feed ring, blowdown connections, tube bundle wrapper, moisture separators, and a steam flow restrictor. A detailed discussion of the steam generators as part of the reactor coolant pressure boundary is in Section 5.4.2.

**Feed Ring**

The replacement steam generator’s feedwater distribution system is a split ring design connected via a T-section to a “goose-neck” assembly which is welded to the thermal sleeve in the feedwater nozzle. Feedwater is distributed axisymmetrically around the downcomer through Alloy J-tubes which discharge from the top of the feed ring. The use of Alloy J-tubes, the all welded design, the thermal sleeve and the "goose-neck" design satisfy all current NRC recommendations with respect to waterhammer, provide flow stratification mitigation and address industry concerns regarding corrosion, corrosion cracking, thermal fatigue, and material erosion.

**Tube Bundle Wrapper**

The tube bundle wrapper encloses the tube bundle of 4765 Inconel tubes and forms the inner wall of the annular downcomer passage.

**Blowdown Connections**

The tubesheet surface blowdown is performed at the tube-free lane which contains an integral blowdown header consisting of two (2) holes down the tube-free lane connected to the secondary surface by means of several vertically-drilled connecting holes. This draws a flow of liquid from the no tube-lane. The two blowdown nozzles are prepared for 3" Sch. 160 pipe.

**Moisture Separator Assemblies**

Two stages of moisture separators maintain the moisture content of the steam at, or less than, 0.1% moisture. Most of the water is removed from the steam/water mixture by the primary separators before entering the secondary separators. The steam/water mixture exiting the tube bundle enters the primary riser at the bottom of the separator support deck. The mixture is separated into water and steam by centrifugal action returning the separated water into the downcomer to mix with the feedwater and providing a steam/water mixture to the secondary separators at greater than 80% quality. The secondary separators use centrifugal separation to further dry the steam to a moisture content of less than 0.1% by weight.

**Steam Flow Venturis**

The steam line leaving each steam generator has a steam flow venturi in a horizontal section of the 30" main steam piping. During MODES 1 and 2, the venturi provides a differential

pressure signal that is used for steam flow indication. Two differential pressure cells are connected to the venturi to measure that parameter. In the event of a steam line break, there is an integral flow restrictor in the replacement steam generator outlet nozzles which will limit the steam flow from the steam generators.

#### 10.3.2.3 Steam Piping

The steam piping from the steam generators to the main steam isolation valves (MSIV) is Seismic Category I and is designed to ensure the correct distribution and pressure to all steam loads at any turbine power.

The steam line from steam generator A leaves the containment and goes directly into the intermediate building. The steam line from steam generator B leaves the containment on the northeast side, goes around the containment building, and enters the intermediate building from the east end. Inside the intermediate building, tapping off each steam line, is a steam supply line to the turbine-driven auxiliary feedwater pump (TDAFW), the four main steam safety valves (MSSV), and an atmospheric relief valve (ARV).

#### 10.3.2.4 Main Steam Safety Valves (MSSV)

There are four main steam safety valves (MSSV) for each steam line. The first valve lifts at 1085 psig and the remaining three valves are set to lift at 1140 psig. The minimum total relieving capacity is 6.58 x $10^6$ lbm/hr which is equal to the full load steam flow for the original 1520 MWt licensed power level. Although these safety valves do not relief 100% steam capacity at 1775 MWt, the UFSAR Chapter 15 analyses demonstrates that sufficient relief capacity is available to prevent over-pressurization of the steam generators and main steam systems. The valves, therefore, are able to relieve the required steam flow.

#### 10.3.2.5 Atmospheric Relief Valves (ARV)

One atmospheric relief valve (ARV) is provided on each steam line. The valve has two functions. It offers overpressure protection to the steam generator at a setpoint below the main steam safety valves (MSSV) setpoints and it can be used to maintain no-load $T_{AVG}$ or perform a plant cooldown in the event the steam dump to the condenser is not available. The relief valves are air-operated valves with 329,000 lbm/hr normal relief capacity. The maximum ARV flow from a stuck open ARV is less than the flow from a stuck open MSSV. They can be operated automatically or remotely from the control room. The valves can also be operated manually by a handwheel mounted on each valve and they can be isolated by a manual valve located upstream of the valves.

The atmospheric relief valve (ARV) controls are integrated into the advanced digital feedwater control system (Section 7.7.1.5). The atmospheric relief valve (ARV) control system consists of microprocessor-based controllers with dedicated manual/auto stations on the control room main control board. The control stations have steam pressure setpoint increase/decrease pushbuttons, valve position pushbuttons, and valve demand indication meters. Input to the control system is from validated median signal selected steam pressure channels (six channels, three per loop). The advanced digital feedwater control system and atmospheric relief valve (ARV) control system use median signal selection of input signals, as explained in Section 7.7.1.5, to reduce the probability of a failed sensor disturbing the control systems. The median steam pressure signal is used as input to the atmospheric relief valve (ARV) control system. The steam pressure setpoint (set by the operator) is subtracted from the median selected steam pressure for the loop, and the difference signal is applied to

the steam generator pressure controller to develop a modulation signal to control the loop atmospheric relief valve (ARV). If two or three steam pressure channels are lost for one loop, that loop's atmospheric relief valve (ARV) control automatically switches to manual operation and the feedwater control remains in automatic. If two or three steam pressure signals for both loops are lost, both atmospheric relief valves (ARV) switch to manual and the feedwater control also switches to manual. In manual operation the operator uses the pushbuttons to control valve position, and thus, the steam pressure. In the event of failure of the automatic and remote manual controls to control steam generator pressure, backup solenoid valves will energize to open the atmospheric relief valves (ARV) at 1060 psig. When the pressure decreases to 1005 psig, the backup solenoid will deenergize causing the valves to close.

The atmospheric relief valves (ARV) are Seismic Category I as part of the main steam line pressure boundary. The piping and restraints necessary to ensure functioning of the valves after a seismic event are also Seismic Category I. Air supply to the valves is provided by the nonseismic instrument air system. Backup supply is provided by two nonseismic nitrogen supply systems in the event that a loss of offsite power causes loss of the instrument air system. Therefore, the atmospheric relief valves (ARV) cannot be expected to operate after the seismic event.

#### 10.3.2.6 Main Steam Isolation Valves

The main steam isolation valves (MSIV) are 30-in. pipe size, 24-in. seat diameter, ANSI 600-lb rating, Atwood and Morrill Company, Inc., swing-disk check valves. The open position of the disk is at full horizontal, held open against the flow of steam by an air cylinder. The valves have stainless steel disks and disk arms. The stiffness of the disk arms is designed to reduce valve strains developed during closure following a postulated downstream pipe break. The disks and disk arms are also designed to uniformly transfer the kinetic energy from the disk to the valve body during impact. The valve disks and disk arms are stainless steel in order to better withstand the local strains in the contact region. The design of the valves reduces the likelihood of damage due to spurious closure and prevents excessive degradation of the valves during normal service.

The valves are designed to shut in less than 5 sec during no-flow conditions and are tested at each MODE 6 (Refueling) outage. Other design parameters are listed in Table 10.1-1. Main steam isolation is discussed and evaluated in Section 5.4.4.

#### 10.3.2.7 Main Steam Non-Return Check Valves

Downstream of the main steam isolation valves (MSIV) are the main steam non-return check valves. They are free swinging gravity closing type check valves. The check valves protect the main steam header against reverse flow from one generator to another in the event of a steam line rupture. The main steam non-return check valves are free fall closed with no steam flow or differential pressure across the seat. The valve disc and disc arm assemblies are similar to those installed in the MSIVs.

### 10.3.2.8 Main Steam Header

Downstream of the main steam isolation and non-return check valves, the 30-in. steam lines combine to form a 36-in. steam header that runs from the intermediate building into the turbine building. Inside the turbine building the 36-in. steam header splits into two 12-in. steam headers to the condenser steam dump valves; four 8-in. steam headers to the moisture separator reheaters; a 4-in. header supplying the gland seal system and air ejectors, and two 24-in. steam headers supplying the main turbine.

The two 12-in. headers feeding the steam dump system supply four steam dump valves to each header. Each header has an isolation valve that can be used to isolate the entire header.

A 4-in. steam line supplies the gland seal system to provide sealing steam to the turbine glands where the rotor extends out of the casing. At low power this sealing steam is supplied to the glands to prevent air leakage into the condenser through the turbine glands. At high power operation, sufficient steam leaks from the high-pressure turbine glands to supply the gland seal header for the low-pressure turbines.

Pressure taps installed on the main steam header provide vibration monitoring.

### 10.3.2.9 Main Turbine Stop Valves and Control Valves

The two 24-in. steam headers directing steam to the high-pressure element of the main turbine have one stop valve and two control valves each. The stop valves are swing disk stop valves keyed to a shaft that is actuated by high-pressure fluid off the electrohydraulic control system. The function of the stop valves is to provide overspeed protection for the turbine and to isolate the turbine from the steam header for maintenance. The stop valves cannot be opened against main steam pressure; therefore, stop valve bypass valves must be used to equalize pressure across the stop valve prior to opening.

Downstream of the stop valves the two steam lines each split into two headers providing four steam lines to supply the high-pressure element of the main turbine. Each of these four steam lines has a control valve. The control valves are single-seat plug type valves controlled by high-pressure fluid of the electrohydraulic control system. The function of the control valves is to control steam flow to the turbine.

Steam that exhausts from the high-pressure turbine contains up to 15% moisture. To prevent low-pressure turbine blade damage due to erosion from low quality steam, the steam exhausted from the high-pressure turbine is reconditioned by the moisture separator reheaters.

### 10.3.2.10 Moisture Separator Reheaters

The exhaust steam from the high-pressure turbine is passed through moisture preseparators, which are located at the exhaust plane of the high-pressure turbine. Up to 70% of the moisture is removed from the exhaust steam before entering the moisture separator section of moisture separator reheaters. Remaining moisture is removed, and the cycle steam enters the reheaters dry and saturated. The steam is then reheated to become super-heated to ensure no moisture is carried over to the low-pressure turbines. To reheat the high-pressure turbine exhaust, main steam is supplied to the moisture separator reheater tube bundle (Drawing

33013-1918, Sheets 1 and 2). From the 36-in. steam header four 8-in. headers supply one moisture separator reheater each. The steam admission valves are controlled by a timed opening controller to limit differential expansion during low-pressure turbine heatup. Water from the condensed reheating steam drains to the feedwater heaters 5A and 5B as extraction heating (Drawing 33013-1919, Sheets 1 and 2). The steam that is not condensed is returned to the high-pressure turbine exhaust piping. During unit startup, purging steam for the moisture separator reheater shells is supplied to each moisture separator reheater through 0.25-in. orifices tapping off the supply line to reheater 2A. The four moisture separator reheater shells have overpressure protection provided by a common header with one safety valve and five rupture disks. The safety valve setpoint is 175 psig, whereas all five rupture disks are set at 183 psig.

Condensate from the moisture separator section is drained to the heater drain tank. This drain system also includes emergency dump capability to the condenser.

Reheater tube bundles have been modified from two-pass systems to four-pass systems to improve tube bundle reliability and to ensure stable operation of drain systems.

The moisture separator reheaters 1A and 1B supply the No. 1 low-pressure turbine while moisture separator reheaters 2A and 2B supply the No. 2 low-pressure turbine. The steam lines from the moisture separator reheaters to the low-pressure turbine are 44-in. headers. Each header has one reheater stop valve and one intercept valve.

Each moisture separator reheater is provided with separate level control tanks and separate condensate lines for better control of level in all the drain systems.

#### 10.3.2.11 Reheater Stop and Intercept Valves

The intercept valves provide overspeed protection for the main turbine by isolating steam to the low-pressure turbines. These valves are necessary due to the volume of steam remaining in the high-pressure turbine and moisture separator reheaters after the main turbine stop valves trip closed. The reheater stop valves provide backup protection for the turbine in the event the intercept valves fail. Both the reheater stop valve and intercept valve are 44-in. butterfly valves that are controlled by the electrohydraulic control system. From the reheater stop and interceptor valves, the steam from the moisture separator reheaters is supplied to the low-pressure turbines.

### *10.3.3 INSTRUMENTATION REQUIREMENTS*

The main steam system uses instrumentation at various points to provide protection, control, and indicating functions. Points monitored in the main steam system include steam generator pressure, temperature, level, and steam flow, as well as steam header pressure and high-pressure turbine inlet and HP Turbine first stage pressures. Three pressure transmitters per steam generator located in the 30" main steam piping in the Intermediate Building, provide signals for steam generator level control, reactor protection circuits, atmospheric relief, and indication on the main control board and auxiliary feedwater pump station. The instruments provide an alarm function on high pressure and a protective function on low pressure. In the

event of a main steam line break, safety injection is initiated when two-out-of-three pressure transmitters from either steam generator reach the low pressure setpoint.

There are three narrow-range level channels for each steam generator used for steam generator level control, reactor protection circuits, and indications at the main control board and MODE 3 (Hot Shutdown) panel. There are also three wide-range level channels for each steam generator to monitor level from the tubesheet to the separators. The wide-range level channels are used for steam generator level control and indication. See Section 7.7.1.5 for a discussion of the steam generator level control system.

Two channels of steam flow indication from each steam generator are used for steam generator level control, reactor protection circuits, and indication at the main control board. A third steam flow channel for each steam generator has been added for steam generator level control and plant process computer system indication only. Remote indicators provide median signal selected wide-range level indication near the auxiliary feedwater pumps and the main feedwater regulating valves (MFRV).

Steam header pressure at the crossover header is used for main control board indication and for condenser steam dump system control, while high-pressure turbine inlet pressure provides main control board indication only.

Two channels of high-pressure first stage impulse pressure indication are used for steam generator level control, rod control system, electrohydraulic controller, reactor protection circuits, steam dump control system, anticipated transient without scram (ATWS) mitigation actuation circuitry (AMSAC), and indication on the main control board.

# 10.4 CONDENSATE AND FEEDWATER SYSTEMS

## *10.4.1 DESCRIPTION*

The condensate and feedwater systems function to condense the steam exhausted from the low-pressure turbines, collect and store this condensate, and then send it back to the steam generator for reuse.

## *10.4.2 FLOW PATH*

The steam that leaves the exhaust of the low-pressure turbines enters the main condenser as saturated steam with low moisture content (9% to 11% moisture). This steam is condensed by the circulating water, which passes through the tubes of the condenser. The condensed steam collects in the condenser hotwell from which the condensate pumps take suction. The condensate pumps increase the pressure of the water and provide suction head for the condensate booster pumps (see Drawing 33013-1252).

The condensate booster pumps in turn provide sufficient suction head for the main feedwater pumps. Between the condensate pumps and the condensate booster pumps is the condensate demineralizer system, which maintains condensate water purity (see Section 10.7.7.4).

Between the condensate booster pumps and the main feedwater pumps are:

A. The air ejector condensers, which condense air ejector exhaust steam and preheat the condensate water (Drawing 33013-1235).

B. Gland steam condenser, which condenses the gland sealing steam and preheats the condensate water (Drawing 33013-1235).

C. Generator hydrogen coolers, which cool the hydrogen from the main generator and preheat the condensate water (Drawing 33013-1235).

D. Two trains of low-pressure feedwater heaters, which condense turbine extraction steam and preheat the condensate water (Drawing 33013-1233).

In addition to the condensate system, the heater drain system provides condensate to the suction of the main feedwater pumps. The main feedwater pumps increase the pressure of the water and provide water supply to the steam generators. Between the main feedwater pumps and the steam generators are:

AA. The high-pressure feedwater heaters, which condense turbine extraction steam, and the moisture separator reheater drains which both preheat the feedwater (Drawing 33013-1236, Sheets 1 and 2).

BB. Main Feedwater Regulating Valves (MFRV) and bypass valves that control the proper amount of feedwater to the steam generators. (These control valves are controlled by the steam generator water level control system, see Section 7.7.1.5.)

## *10.4.3 MAIN CONDENSERS*

The main condensers are the radial flow type with semicylindrical water boxes bolted at both ends. The hotwell is the deaerating type with storage sufficient for 2 1/2 minutes of operation

at maximum throttle flow with an equal free volume for surge protection. The hotwell has manholes, a water gauge glass to indicate the condensate level, four condensate outlets with coarse strainers, and anti-swirl devices. The hotwell is split in half by baffles with provisions for separate conductivity measurements in each half. Expansion joints are provided for all circulating water inlet and outlet connections.

The condenser is a two-shell, single-pressure, deaerating type surface condenser. Each shell is located below its low-pressure turbine and is connected to the low-pressure turbine outer casing by a skirt. This skirt contains a water-filled expansion joint and water-supplied by the gland sealing system that dampens turbine vibrations.

Each condenser has a heat transfer area of 125,000 $ft^2$ of 1-in. O.D. No. 22 BWG type 316 stainless steel tubes. The tubes are 40 ft long and are rolled to the 1-in. metal tubesheets. The condensers are designed for a circulating water temperature of 50°F with an approximate 24.5°F temperature rise to minimize the discharge temperature back into Lake Ontario. The condensers contain a total of 24,004 tubes.

Three of the four low-pressure heaters per train are located in the upper portion (neck) of each condenser shell.

Below the neck is the tube space. The condenser tubes run perpendicular to the centerline of the low-pressure turbines. The tubes are arranged in two bundles per condenser shell. Circulating water flows inside the tubes and provides the cooling medium for the main condenser.

In the centerline of each tube bundle a space is provided for air collection. Air is drawn from this space by the air ejectors. This maintains condenser vacuum.

The condensed steam falls into a collecting area in the condenser shell (hotwell). Each hotwell has two penetrations in its floor for the condensate pump suction header. Hotwell water level is controlled by either rejecting water when the level is high or making up water when the level is low. Control can be automatic or manual. During rejection, the condensate system pressure causes water to flow into the two condensate storage tanks. During makeup, the condenser vacuum and the level head in the condensate storage tanks produce water flow into the condenser hotwell. High and low hotwell levels produce alarms in the main control room. Hotwell level is displayed in the main control room and locally.

## *10.4.4 CONDENSATE SYSTEM*

### 10.4.4.1 Condensate Pumps

The condensate pumps provide the initial flow energy to transport the water in the condenser hotwells to the steam generators. In doing so they supply sufficient suction pressure to the condensate booster pumps.

There are three 50%-capacity condensate pumps. Each pump is a seven-stage, vertical, centrifugal pump, powered by a 1500-hp electric motor. The pumps are controlled from the main control board. Each pump is rated at 6600 gpm with a discharge pressure of 285 psig.

The condensate pumps take suction on a common header through a suction strainer and a manual isolation valve. They discharge to a common header through a check valve and a manual isolation valve. Discharge header pressure is indicated on the main control board and will alarm on low pressure.

From the discharge header, water may be recirculated back to the condenser or sent through the condensate demineralizer system to the suction of the condensate booster pumps. The gland sealing system for miscellaneous gland seals taps off of the discharge of the condensate pumps. This supplies gland sealing water to the condensate pumps, heater drain pumps, condensate booster pumps, condenser skirt expansion joints, and other miscellaneous components. (See Drawing 33013-1905.)

#### 10.4.4.2 Condensate Booster Pumps

The condensate booster pumps provide the second stage of flow energy addition to the condensate. They boost the flow supplied by the condensate pumps and consequently supply sufficient suction pressure to the main feedwater pumps.

There are three 50%-capacity condensate booster pumps (PCD01A, PCD01B, and PCD01C). Each is a horizontal single-stage centrifugal pump powered by a 500-hp induction motor. These motors were installed during the 2005 refueling outage in preparation for the extended power uprate modifications (EPU). The condensate booster pumps were modified to accommodate the EPU requirements. The pumps are controlled from the main control board.

The water leaving the condensate demineralizer system enters the condensate booster pump common suction header. Each pump takes a suction on the header via a manual isolation valve and discharges to a common discharge header via a check valve and a manual isolation valve. During condensate system startup, the condensate booster pumps are secured and are bypassed to recirculate water in the system through the demineralizers for system cleanup. When a condensate booster pump is started a check valve in the bypass line is forced shut.

From the discharge header of the condensate booster pumps, lines are tapped off to feed the feedwater pump gland seals and the condensate booster pump gland seals. The line that feeds the feedwater pump gland seals contains two parallel seal booster pumps that boost seal-water pressure during low load conditions when the pressure drop from the condensate booster pump to the main feedwater pump suction is small.

#### 10.4.4.3 Low-Pressure Heaters

After leaving the air ejector and gland steam condensers, the condensate passes sequentially through four low-pressure heaters which extract heat from the steam discharged from the low-pressure and high-pressure turbines to heat the condensate and thereby increase system efficiency. Low-pressure heaters No. 1, 2, and 3 are located in the neck of the main condenser and extract heat from steam entering the condenser from the low-pressure turbines. Low-pressure heater No. 4 receives heat from the extraction steam from the high-pressure turbine.

#### 10.4.4.4 Condensate Bypass Valve

The condensate bypass valve is in a line from the discharge of the condensate pumps to the suction of the main feedwater pumps. This bypass valve is operated from the main control board or automatically. The function of this valve is to maintain net positive suction head (NPSH) on the main feedwater pumps in the event that the heater drain pump flow is lost, e.g., during a load decrease. In automatic, the valve will open on a low main feedwater pump suction pressure and low main feedwater pump net positive suction head (NPSH), to provide the needed suction conditions to the main feedwater pumps to prevent cavitation. The opening of the bypass valve reduces the feedwater pump suction line resistance and hence increases the available NPSH. The valve must be closed manually when the low NPSH condition clears.

The main feedwater pump NPSH instrumentation computes the NPSH for each feedwater pump as a function of feedwater pump suction pressure, flow, and temperature. The main feedwater pump positive suction head system will open the condensate bypass valve and actuate a control room main control board annunciator when the available NPSH is less than the required minimum. Additionally, a plant computer point for NPSH margin will alarm prior to reaching a condition where available NPSH is less than required NPSH.

### *10.4.5 FEEDWATER SYSTEM*

#### 10.4.5.1 Main Feedwater Pumps

The main feedwater pumps supply the condensate and heater drain water to the steam generators. The system contains two 50% capacity feedwater pumps. Each pump is a single-stage centrifugal pump that operates nominally at 6811 rpm and has a capacity of 8800 gpm. The common feedwater header discharge pressure is nominally 1054 psig. Each is driven by a 5500-hp, 1800-rpm electric motor. A geared speed increaser enables the pump to operate at 6811 rpm. Each pump has its own lubrication system including two ac pumps, one dc auxiliary pump, oil reservoir, oil coolers, and filters. The feedwater pumps are provided with high-pressure gland seal-water from the discharge header of the condensate booster pumps.

The main feedwater pumps are controlled from the main control board. The line from the condensate system taps into the common feedwater suction header. Each feedwater pump takes a suction on this header through a manual isolation valve. The pumps discharge to a common header via a check valve and the motor operated Main Feedwater pump discharge valve (MFPDV). The discharge valve closes automatically when the respective pump trips.

Between each main feedwater pump and the discharge check valve, an 8-in. recirculation line taps off. The recirculation lines return to the feedwater pump suction header and contain a control valve. A small part of the recirculation flow is directed to the main condenser where it is then pumped back to the main feedwater pump. The recirculation valve controller is on the main feedwater pump and feedwater pump seal panel outside the feedwater pump room. The valves will open whenever a main feedwater pump continuous flow falls below approximately 33% full flow without recirculation. Feedwater flow is measured at the suction of each feedwater pump. The recirculation lines are sized to allow a minimum of 25% of full pump

flow to be recirculated. Full pump flow is defined as the best efficiency pump flow for the feedwater pump.

#### 10.4.5.2 High-Pressure Heaters

The main feedwater pump discharge splits to pass through high-pressure heaters 5A and 5B. These heaters preheat the feedwater prior to its entry into the steam generators to increase plant efficiency.

High-pressure heaters 5A and 5B receive heat from the high-pressure turbine steam extraction and moisture separator reheater drains. Heater levels can be read locally or on the main control board. Heater temperatures and differential pressures are provided from the plant computer.

Downstream of the high-pressure heaters, the main feedwater lines join together into a header and an 8-in. recirculation line to the main condenser taps off.

This recirculation line contains a manual isolation valve and is used for cleanup operations during system startup.

#### 10.4.5.3 Feedwater Flow Control

After the recirculation line taps off, the main feedwater header splits into two 14-in. lines that feed the steam generators. Located in each line is a 12" Main Feedwater Regulating Valve (MFRV) (FCV 4269 and 4270) and a 4-in. Main Feedwater bypass valve (FCV 4271 and 4272). These valves regulate the amount of feedwater sent to the steam generators. They are controlled by the steam-generator water level control system termed the advanced digital feedwater control system and described in Section 7.7.1.5. The valves are equipped with valve position sensors and their positions are displayed in the control room on the main control board.

The Main Feedwater bypass valve is used at low power levels to prevent erosion damage to the Main Feedwater Regulating Valve (MFRV). At highest power, the Main Feedwater Regulating Valve (MFRV) is in operation while the bypass valve is shut.

Hydraulic stabilizer operators are provided for the Main Feedwater Regulating Valve (MFRV) to dampen valve stem vibrations.

The feedwater lines leave the turbine building and enter the intermediate building penetration area where flow is measured and the auxiliary feedwater system taps into the main feedwater system. A check valve and an air operated isolation valve are located between the flow transmitters and the auxiliary feedwater piping. After the auxiliary feedwater connections, the main feedwater line penetrates containment and enters the steam generators.

#### 10.4.5.4 Feedwater Flow Measurement

A feedwater flow measurement system, consisting of a single piping spool piece with eight ultrasonic transducers and an electronics package, can be used to determine the absolute feedwater flow rate for the plant calorimetric. The spool piece is installed in the 20-in.O.D. common feedwater line between the No. 5 feedwater heaters and the feedwater regulating valves in the turbine building.

The ultrasonic transducers generate a signal through the feedwater. A feedwater flow processor converts the transducer signals into rate of flow. The feedwater flow measurement system is designed to operate with an accuracy of ±0.75% or better. The ultrasonic flow measurement data can be used only for calorimetric calculations.

Feedwater flow measurement required for safeguards protection actuation and steam generator level control is obtained from the feedwater flow venturi nozzles. These feedwater flow venturi nozzles are also used to perform plant calorimetric power calculations. In the 1980's and 1990's Ginna experienced venturi fouling with these nozzles. Since feedwater venturi nozzle fouling results is masking true feedwater flow, it results in an artificially high indicated feedwater flow rate and causes actual thermal power to be depressed relative to indicated thermal power. The ultrasonic system does not experience this degradation. However, since the late 1990's, Ginna no longer experienced feedwater venturi fouling. Therefore, the feedwater venturi nozzles are the preferred flow indication for performing plant calorimetric power calculations.

# 10.5 AUXILIARY FEEDWATER SYSTEMS

## *10.5.1 INTRODUCTION*

The auxiliary feedwater systems consist of a preferred auxiliary feedwater system and a standby auxiliary feedwater system (SAFW). The preferred system consists of two motor-driven pumps and one turbine-driven pump. Normally, each motor-driven pump supplies one steam generator, but the alignment can be altered to allow either motor-driven pump to supply either or both steam generators. The turbine-driven pump normally supplies feedwater to both steam generators. Each pump supplies the steam generators through a normally open, motor-operated, discharge valve.

The standby auxiliary feedwater system (SAFW) was installed to provide an independent system capability following a high-energy line break event which could render inoperable the three preferred auxiliary feedwater pumps. The standby auxiliary feedwater (SAFW) system consists of two motor-driven pumps located in a plant area separate from the preferred auxiliary feedwater system. The standby auxiliary feedwater system (SAFW) is manually actuated and aligned so that each pump supplies one steam generator.

## *10.5.2 DESIGN BASES*

### 10.5.2.1 Functional Requirements

The main function of the auxiliary feedwater system is to maintain the steam generator water inventory when the normal feedwater system is not available. The auxiliary feedwater system is an engineered safety feature because it provides a secondary heat sink for residual heat removal and therefore provides core protection and prevention of reactor coolant release through the pressurizer safety valves.

The reactor plant conditions which impose safety-related performance requirements on the design of the auxiliary feedwater system are as follows:

A. Loss of main feedwater transient.
    1. Loss of main feedwater with offsite power available.
    2. Loss of main feedwater without offsite power available.
    3. Rupture of feedwater line.

B. Rupture of a main steam line.

C. Loss of all ac power (offsite and onsite).

D. Loss-of-coolant accident.

E. Cooldown.

The above transients are discussed in Chapter 15 and *References 1* and *2*.

Following a reactor trip, decay heat is dissipated by evaporating water in the steam generators and venting the generated steam either to the condensers through the steam dump or to the atmosphere through the Main Steam Safety Valves (MSSV) or the Atmospheric Relief Valves

(ARV). Steam generator water inventory must be maintained at a level sufficient to ensure adequate heat transfer and continuation of the decay heat removal process. The water level is maintained under these circumstances by the preferred auxiliary feedwater system which delivers an emergency water supply to the steam generators. The preferred auxiliary feedwater system is capable of functioning for extended periods, allowing time to proceed with an orderly cooldown of the plant to the reactor coolant temperature where the residual heat removal system can assume the burden of decay heat removal. The preferred auxiliary feedwater system flow and the emergency water supply capacity are sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant cooldown. The preferred auxiliary feedwater system can also be used to maintain the steam generator water level following a loss-of-coolant accident, in order to facilitate additional decay heat removal as necessary.

#### 10.5.2.2 Preferred Auxiliary Feedwater System

The preferred auxiliary feedwater system is designed to provide high-pressure flow using two motor-driven pumps with a capacity of 200 gpm each or one turbine-driven pump with a capacity of 400 gpm.

The water supply source for the preferred auxiliary feedwater system is redundant. The main source is by gravity feed from the condensate storage tanks (CST) and the backup supply is provided by the service water (SW) system with pumps which can be powered by the diesel generators. An additional supply of feedwater can be provided through the yard fire hydrant system to the condensate storage tanks (CST).

The turbine-driven auxiliary feedwater pump (TDAFW) can supply 200% of the required feedwater and one motor-driven auxiliary feedwater pump (MDAFW) can supply 100% of the required feedwater for removal of decay heat from the plant. The minimum amount of water in the condensate storage tanks (CST) (24,350 gal) is the amount needed to remove decay heat for 2 hr after reactor scram from full power. An unlimited supply is available from the lake via either leg of the plant service water (SW) system for an indefinite time period.

The preferred auxiliary feedwater system is designed to Seismic Category I and Class 1E criteria and the automatic initiation signals and circuits are designed to comply with the requirements of IEEE 279-1971.

#### 10.5.2.3 Standby Auxiliary Feedwater System (SAFW)

The purpose of the standby auxiliary feedwater system is to provide auxiliary feedwater backup in the event the preferred auxiliary feedwater system is inoperable due to a high-energy line break or other event. The standby auxiliary feedwater system (SAFW) is capable of being brought into service by operator action in the control room if the preferred auxiliary feedwater pumps, which start automatically, are not operative. The standby auxiliary feedwater system (SAFW) can deliver emergency feedwater to each steam generator via two motor-driven pumps of 215-gpm flow capacity each.

Seismic Category I sources of water are available for use by the standby auxiliary feedwater system (SAFW) via connections to both loops of the service water (SW) system. In addition, a 160,000 gallon DI water storage tank is available for periodic tests of the system and serves as an additional source of water. Connections to utilize the yard fire hydrant loop have been installed and procedures put in place to use this source if the service water (SW) supply from the screen house is lost. A line from the yard fire loop to a hose connection in the standby auxiliary feedwater building is run underground and thus protected from tornado and missile damage. A fire hose mounted in a hose cabinet in the building is used to supply the standby auxiliary feedwater pumps (SAFW) from the yard fire loop hose connection.

Essential components of the standby auxiliary feedwater system (SAFW) are designated Seismic Category I. The structure housing the pumps and the system piping also meet Seismic Category I criteria. The pump motors are powered by two redundant Class 1E electrical systems. The system is designed to sustain a single active failure and still deliver 215 gpm flow to either steam generator.

## *10.5.3 SYSTEMS OPERATION AND DESCRIPTION*

### 10.5.3.1 Preferred Auxiliary Feedwater System

#### 10.5.3.1.1 Normal Lineup

The flow diagram of the preferred auxiliary feedwater system is shown in Drawing 33013-1237.

The preferred auxiliary feedwater system is normally lined up when the reactor is at power to respond to any situation that could cause a loss of normal feedwater flow to the steam generators. Two motor driven AFW (MDAFW) trains, one turbine driven AFW (TDAFW) train, and two standby AFW (SAFW) trains shall be operable in MODES 1, 2 and 3. The turbine-driven auxiliary feedwater pump (TDAFW) must be shown to be operable prior to exceeding 5% power. (See the Technical Specifications.) The normal lineup is for each motor-driven auxiliary feedwater pump (MDAFW) to supply one steam generator; however, the pumps can be cross-connected to feed either or both steam generators. The turbine-driven pump discharges in a common header, then to either or both steam generators. A cross-connect between the motor-driven and turbine-driven pumps is provided to allow for continuous makeup to the steam generators during extended MODE 3 (Hot Shutdown) conditions by using the motor-driven auxiliary feedwater pumps (MDAFW). All pumps have recirculation lines back to the condensate storage tanks (CST).

#### 10.5.3.1.2 Startup and Cooldown Operations

The system is used to maintain steam generator level during startup because a certain loading is required prior to starting a main feedwater pump. After reactor power is at about 2% to 4% and a main feedwater pump has been started, the system is shut down and set up for automatic start operations.

The preferred auxiliary feedwater system also supplies feedwater to the steam generators when the reactor is shut down. Steam, after being heated by residual heat from the reactor, is drawn from the steam generator and sent to the condenser steam dump system (or atmospheric relief) at a controlled rate for cooldown. The preferred auxiliary feedwater pumps are used to maintain levels in the steam generators.

Pneumatically operated valves installed around the motor-operated valves in the discharge piping of the motor-driven auxiliary feedwater pumps (MDAFW) provide a means of controlling preferred auxiliary feedwater flow from the motor-driven pumps during startup and cooldown without opening the cross-tie to the turbine-driven auxiliary feedwater pump (TDAFW) piping.

Both motor-driven preferred auxiliary feedwater pumps (MDAFW) are not normally operated with the crossover valve(s) open as a precaution against the potential for pump overheating due to a strong/weak pump interaction which may exist.

#### 10.5.3.1.3 **Transient Operations**

The motor-driven preferred auxiliary feedwater system pumps will start if one steam generator level decreases to a low-low level of 17%. A positive 13.9% error has been included in the setpoint to account for errors which may be introduced into the steam generator level measurement system at a containment temperature of 286°F as determined by an evaluation performed on temperature effects on level systems as required by IE Bulletin 79-21. The turbine-driven auxiliary feedwater pump (TDAFW) will automatically start if the level in both steam generators decreases to a low-low level of 17%. Additional information is provided in Section 7.3.

All three preferred auxiliary feedwater pumps will start on loss of offsite power. However, if power is lost to the engineered safety features bus supplying power to an preferred auxiliary feedwater pump, the motor will not start until the associated emergency diesel generator supplies power to that bus. The turbine-driven pump has the added feature of starting immediately on loss of power (undervoltage) to both 4.16-kV service buses. In this situation, the preferred auxiliary feedwater pumps will supply water to each steam generator to maintain level and the atmospheric relief valves will be used to maintain MODE 3 (Hot Shutdown) temperatures or for cooling the reactor coolant system.

Upon receipt of a safety injection signal, the two motor-driven preferred auxiliary feedwater pumps will start and feed the steam generators to maintain their inventory of water to be used for control of reactor coolant system temperature or cooldown.

#### 10.5.3.1.4 **System Description**

The two motor-driven preferred auxiliary feedwater pumps (MDAFW) are driven by 460V three-phase, 300 hp, 1780 rpm motors, and are capable of pumping 200 gpm at 1085 psig. Each pump contains an auto-start oil pump which will start when the auxiliary feedwater pump starts. The feedwater pumps have splash lubricated gears, and the motors are of an open, drip proof design. They are powered from the engineered safety features bus with an emergency diesel backup. The turbine-driven auxiliary feedwater pump (TDAFW) receives steam from either or both steam generators and is capable of pumping 400 gpm at 1085 psig. It has both ac and dc oil pumps. If oil pressure drops below 25.0 psig sensed at the trip and throttle valve, the turbine will trip. If oil pressure drops below 3.0 psig sensed at the low oil pressure drip device, the turbine will trip. A steam line branches off from the main steam line from each

steam generator and joins to supply steam to the turbine-driven auxiliary feedwater pump (TDAFW). See Drawing 33013-1231. Motor-operated valves 3504A and 3505A are opened to supply steam to the auxiliary feedwater pump turbine. The steam admission check valves in each branch line (valves 3504B and 3505B) isolate one steam generator from the other in the event of a steam line break.

Water is supplied to the pumps by means of gravity feed from the two 30,000-gal nominal capacity condensate storage tanks (CST). For system operation, a minimum of 24,350 gal total is required (see Section 10.7.4). The service water (SW) system provides backup water supply to the preferred auxiliary feedwater pumps. Alternate water supply to directly fill the condensate storage tanks can be provided by alignment of the fire water system (via valve 5158C) or the city water system. Water from the condenser hotwells and the all-volatile-treatment storage tank can also be made available to these pumps (see Table 10.1-1).
The condensate storage tanks (CST) are significant to safety for pressure boundary integrity to maintain sufficient inventory for the preferred auxiliary feedwater pumps. The tanks are nonseismic. The backup service water (SW) system supplying the preferred auxiliary feedwater pumps is safety-related and Seismic Category I.

Condensate (blocking water) is supplied to the suction side of the motor driven auxiliary feedwater (MDAFW) pumps, and available to the turbine driven auxiliary feedwater (TDAFW) pump but normally isolated from the TDAFW pump. Pressure regulated blocking water, higher than SW pressure, prevents leakage of service water (SW) into the auxiliary feedwater system. In addition, the system provides pressurization of the MDAFW pump instrument tubing connections.

Redundant level indications and low level alarms in the control room are provided for the condensate storage tanks (CST). This allows the operator to anticipate the need to make up water or transfer to an alternate supply and prevent a low suction pressure at the auxiliary feedwater pumps.

Safety-grade flow indication instrumentation is provided for each steam generator. The individual steam generator auxiliary feedwater flow circuitry is powered from separate battery-backed instrument buses. For each preferred auxiliary feedwater pump, there is a primary and secondary flow instrumentation channel. The primary channel indicates flow and, for the motor-driven pumps, controls the individual discharge valves. The secondary flow instrumentation indicates flow only. The primary and secondary channels are powered from opposite instrument buses. The primary and secondary flow indication is provided on the main control board by a dual-movement vertical-scale indicator.

The motor-driven and turbine-driven pumps each have an automatically controlled minimum flow recirculation system sized and periodically tested to ensure that sufficient minimum flow will be provided under all conditions, during which the pump flow would be either automatically or manually throttled to the air-operated control valve setting, to prevent pump damage from overheating.

Chemistry control for the preferred auxiliary feedwater system is provided through a connection to the chemical addition tanks.

#### 10.5.3.2 Standby Auxiliary Feedwater System (SAFW)

The flow diagram of the standby auxiliary feedwater system (SAFW) is shown in Drawing 33013-1238. The standby auxiliary feedwater system (SAFW) is manually started and controlled from the control room. In the event that an existing preferred auxiliary feedwater pump fails to function properly after a high-energy pipe break outside containment, or all means of feedwater are lost, the operator would be alerted by existing control room indication. The operator would manually remove the affected preferred auxiliary feedwater pump from the diesel generator and place the standby pump (SAFW) into operation on the same diesel. Flow is controlled by throttling the discharge valve. For operational tests, manually operated valves in the supply line from the DI water storage tank must be verified to be opened and adequate tank level verified before starting the pump or pumps.

The system consists of two motor-driven pumps capable of 215 gpm at 1085 psig. Water is supplied by the respective service water (SW) loop of the pumps. Cross-connecting the system is possible; however, the usual lineup is for two separate, independent sources of water. A hose connection from the fire water system to the standby auxiliary feedwater pumps (SAFW) provides a means for decay heat removal in the event of a loss of service water (SW). A fire hose from a yard fire loop hose connection located inside the standby auxiliary feedwater pump (SAFW) building can be attached to fittings on the suction piping to the standby auxiliary feedwater pumps (SAFW) (see Section 10.5.2.3). The motor-driven pumps are supplied by engineered safety features buses for reliable power supplies.

Condensate (blocking water) is supplied to the suction side of the standby auxiliary feedwater (SAFW) pumps. Pressure regulated blocking water, higher than SW pressure, prevents leakage of service water (SW) into the auxiliary feedwater system. In addition, the system provides pressurization of the SAFW pump instrument tubing connections.

The pumps each have a minimum flow recirculation system similar to the preferred auxiliary feedwater pumps to prevent pump damage from overheating.

A DI water storage tank with a 160,000-gal capacity is provided to store condensate quality water as a source of supply for periodic testing of the system.

### *10.5.4 DESIGN EVALUATION*

#### 10.5.4.1 System Evaluation

The design and qualification of the auxiliary feedwater systems has been reviewed by the NRC both as part of the NUREG 0737 requirements review and the Systematic Evaluation Program (SEP).

The NRC concluded in the safety evaluation related to Amendment No. 29 to the Ginna Provisional Operating License (*Reference 3*) that the standby auxiliary feedwater system (SAFW) is an acceptable backup to the preferred auxiliary feedwater system for maintaining the plant in a safe shutdown condition, and in evaluations under NUREG 0737, Items II.E.1.1 and II.E.1.2 (*References 4 through 6*), that the preferred and standby auxiliary feedwater systems (SAFW) meet NRC requirements.

#### 10.5.4.2 Alternating Current Independence of the Turbine-Driven Auxiliary Feedwater Pump (TDAFW)

As part of the review for NUREG 0737, Item II.E.1.1, Ginna Station was evaluated to determine if there was an essential dependence of the turbine-driven auxiliary feedwater pump (TDAFW) system on ac power. It was determined that the only ac dependence was the need for service water (SW) cooling of the lube-oil for the turbine-driven pump. The turbine-driven auxiliary feedwater pump (TDAFW) has an ac lube-oil pump and a dc lube-oil pump. The DC Lube Oil Pump can be powered by a portable DC generator during a loss of both AC and DC plant power. These pumps direct the oil through a heat exchanger, which depends on the ac-powered service water (SW) system pumps to cool the oil. The outboard (thrust) bearing of the pump is also provided directly with service water cooling through a water jacket within the bearing housing. The inboard pump radial bearing is cooled by an oil bath without an external source of cooling water. In the event of a total loss of ac power, lube-oil cooling capability for the turbine-driven pump will be lost due to the loss of ac power to the service water (SW) pumps.

An NRC criterion (Recommendation GL-3 of NUREG-0737 Action Item II.E.1.1) was that the as-built plant should be capable of providing the required preferred auxiliary feedwater flow for at least 2 hr from one preferred auxiliary feedwater pump train independent of any ac power source. As part of the 48 hour Endurance Test conducted on March 6-8, 1981, RG&E performed a test with service water (SW) secured to the turbine’s lube oil cooler and the pump outboard (thrust) bearing. The pump was run for a duration of 3 hours 55 minutes in one sequence without any service water cooling and for 15 hours in a later sequence without service water cooling to the turbine lube oil cooler. During the first sequence, excessive steaming from the floor drains with service water secured caused the reinitiation of service water (SW) to the pump thrust bearing. The Endurance Test was run in the recirculation mode with 70 gpm passing through the recirculation line back to the condensate storage tanks (CST). This flow rate is found by plotting the measured pump head on a degraded pump curve. The degraded pump curve was derived in response to NRC CDBI Request number 2007-0243. Throughout the testing without service water supplied, the pump outboard (thrust) bearing, which is service water cooled, and the inboard pump radial bearing (oil bath) were within manufacturer’s limits of 165°F. The turbine governor bearing return oil temperature and turbine inboard bearing return oil temperature, as well as the turbine lube oil reservoir temperature, stabilized well within the manufacturer’s limit of 180°F.

In addition to the Endurance Test, another test was performed on April 17, 1981, for a period of 2 hours without service water cooling to the outboard pump bearing and turbine lube oil cooler, this sequence with the pump delivering 200 gpm (100 gpm to each steam generator). This test was performed to simulate accident conditions. This test also confirmed that oil temperature, as well as pump and turbine bearing temperatures stabilized within acceptable limits.

In a letter dated June 8, 1981 (*Reference 7*) RG&E submitted the test results for these tests. In a letter dated June 16, 1982 (*Reference 5*) the NRC concluded that, based on the results of the recirculation flow test and the 2 hour test on April 17, 1981, RG&E has shown that the turbine-driven auxiliary feedwater system (TDAFW) does not have an essential ac power dependence.

To protect against a total loss of service water or fire water backup cooling to the TDAFW

pump lube oil cooler and thrust bearings, a modification (PCR 2004-0021) was installed on 10/06/2004 to provide TDAFW pump self-cooling. This alignment is outside the design basis of the plant and is procedurally driven.

### *10.5.5 INSTRUMENTATION*

#### 10.5.5.1 Motor-Driven Auxiliary Feedwater Pump (MDAFW) Controls

Both the preferred and standby auxiliary feedwater motor-driven pumps are powered by independent ac emergency buses. The loading of the preferred auxiliary feedwater motor-driven pumps onto their respective 480-V ac emergency buses is part of the postaccident automatic load sequencing. The standby auxiliary feedwater pumps (SAFW) are manually started and controlled from the control room. The standby auxiliary feedwater (SAFW) motor-driven pumps are interlocked with the preferred auxiliary feedwater motor-driven pumps so that a standby pump can only be energized when its associated preferred auxiliary feedwater pump is deenergized. The primary purpose of the interlocks is to prevent both pumps from being energized simultaneously and overloading the emergency diesel generator on loss of offsite power. Also, the standby auxiliary feedwater pumps (SAFW) supply service water (SW) to the steam generators and are intended to be used only when the preferred auxiliary feedwater pumps, which supply condensate to the steam generators, are not available.

The actual interlocks are formed by using switches from the breakers supplying the preferred auxiliary feedwater pumps as permissives to close the breakers supplying the standby auxiliary feedwater pumps (SAFW). The main breakers are equipped with cell switches to provide the permissives when the main breakers are removed for testing or repair.

#### 10.5.5.2 Preferred Auxiliary Feedwater System Initiation

The following signals are used for automatic initiation of the main auxiliary feedwater system:

**Motor-driven pumps.**

1. Low-low steam generator level (two-out-of-three channels on either steam generator).
2. Trip of both main feedwater pumps.
3. Safety injection.
4. Anticipated transient without scram mitigation system actuation circuitry (AMSAC) actuation.

**Turbine-driven pump.**

1. Low-low steam generator level (two-out-of-three channels on both steam generators).
2. Loss of voltage on both 4-kV buses. (11A and 11B)
3. AMSAC actuation.

The preferred auxiliary feedwater system may be manually initiated from the control room by starting the motor-driven auxiliary feedwater pumps (MDAFW) individually. Upon pump start, the associated discharge valve opens and is automatically throttled to less than 230 gpm (See Section 7.4.1.2.)

The automatic open signals to the steam admission valves of the turbine-driven pump can be overridden by the operator to prevent excessive cooldown of the primary system. Indication in the form of an annunciator will alert the operator to the fact that the pump automatic start signals have been overridden.

The system design allows one channel to be bypassed for maintenance, testing, and calibration during power operation without initiating a protective action. When a channel is bypassed for testing, the bypass is accompanied by a single channel alert and channel status light actuation in the control room.

The automatic start of the preferred auxiliary feedwater motor-driven pumps resulting from the tripping of both main feedwater pumps may be defeated during startup or shutdown when the turbine generator is off the line. The defeat switch is automatically bypassed when the turbine is latched. This bypass is alarmed in the control room.

The only interaction between the preferred auxiliary feedwater system automatic initiation circuits and normal system control functions occurs in the narrow-range steam generator level instrumentation. These level instruments are used for both protection (reactor trip and preferred auxiliary feedwater initiation) and normal control functions in the main feedwater system. The control signals are separated from the protection signals by isolation transformers so that a malfunction in the control circuits will have no effect on the protection signals. The steam generator level control system is discussed in Section 7.7.1.5.

#### 10.5.5.3 Auxiliary Feedwater System Alarms

The following individual alarms are provided on the main control board to alert the operator concerning the operation of the auxiliary feedwater system:

1. Low-low steam generator level (three channels each).
2. Two-out-of-three low-low steam generator levels (one channel each).
3. Three-out-of-three low-low steam generator levels (one channel each).
4. Emergency shutdown equipment local control.
5. Engineered safety features breaker trip.
6. Engineered safety features equipment lock-off.
7. Preferred auxiliary feedwater bypass in defeat lockout.
8. Single channel alert.
9. Standby auxiliary feedwater pump (SAFW) C or D trip.
10. Standby auxiliary feedwater pump (SAFW) transfer or test switch off normal (one channel each).

11. Standby auxiliary feedwater pump (SAFW) high discharge flow (one channel each).
12. Standby auxiliary feedwater pump (SAFW) high discharge pressure (one channel each).
13. Standby auxiliary feedwater heating, ventilation, and air conditioning trouble.

### 10.5.5.4 Auxiliary Feedwater Performance Indications

The capability to evaluate the performance of the preferred and standby auxiliary feedwater systems at Ginna Station is provided by the following indications:

1. preferred auxiliary feedwater motor-driven pump flow to each steam generator (two channels each).
2. preferred auxiliary feedwater turbine-driven pump discharge flow (two channels).
3. preferred auxiliary feedwater turbine-driven pump flow to each steam generator (two channels each).
4. Standby auxiliary feedwater motor-driven pump flow (one channel each).
5. Preferred auxiliary feedwater pump discharge pressure.
6. Standby auxiliary feedwater pump (SAFW) discharge pressure.
7. Narrow-range steam generator level (three channels each).
8. Wide-range steam generator level nominal (three channels each).
9. Preferred and standby auxiliary feedwater pump status indication.
10. Preferred and standby auxiliary feedwater valve position indication.
11. Condensate storage tank levels (one channel per tank).

Since the discharge header from the turbine-driven pump branches to supply both steam generators, an additional channel of safety-grade flow instrumentation is provided in each line. Safety-grade wide-range steam generator level indication is provided as a backup. The standby auxiliary feedwater system (SAFW) provides a single channel of safety-grade flow instrumentation for each pump. The flow indication channels are tested in accordance with the Technical Specifications.

### 10.5.5.5 Control From Outside the Control Room

For the purpose of achieving safe shutdown in the event of an unmitigated fire, the turbine-driven auxiliary feedwater pump (TDAFW) is dependent only upon dc power for operation of the turbine auxiliary oil pump. A manual start/stop switch and a manual local/remote switch with a control room alarm for the local position are included on the intermediate building emergency local instrument panel (IBELIP) (see Section 7.4.3.7) that permits transfer of control from the control room to the panel when local control of the dc-lube-oil pump is required.

The IBELIP and the TDAFW Pump DC Lube Oil Pump can be powered by a portable DC generator during a loss of both AC and DC plant power. A manual open/close switch and a manual local/remote switch with a control room alarm for the local position are also included on the intermediate building emergency local instrument panel (see Section 7.4.3.7) that permits transfer of control from the control room to the panel when local control of the discharge valve is required.

## REFERENCES FOR SECTION 10.5

1. Letter from L. D. White, Jr., RG&E, to D. M. Crutchfield, NRC, Subject: NRC Requirements for Auxiliary Feedwater Systems, dated July 14, 1980.

2. Letter from K. W. Amish, RG&E, to J. F. O'Leary, NRC, Subject: Effects of Postulated Pipe Breaks Outside Containment, dated May 24, 1974.

3. Letter from D. L. Ziemann, NRC, to L. D. White, Jr., RG&E, Subject: Amendment No. 29 to Provisional Operating License No. DPR-18, dated August 24, 1979.

4. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: Safety Evaluation Report, Implementation of Recommendations for Auxiliary Feedwater Systems, dated January 29, 1981.

5. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: Auxiliary Feedwater System Evaluation, NUREG 0737 Item II.E.1.1, dated June 16, 1982.

6. Letter from D. M. Crutchfield, NRC, to J. E. Maier, RG&E, Subject: Auxiliary Feedwater System Automatic Initiation and Flow Indication (TMI Action Plan Item II.E.1.2), dated August 18, 1982.

7. Letter from J. E. Maier, RG&E, to D. M. Crutchfield, NRC, Subject: NRC Requirements for Auxiliary Feedwater Systems, dated June 8, 1981.

# 10.6 CIRCULATING WATER SYSTEM

## *10.6.1 DESIGN BASES*

The function of the circulating water system is to provide a reliable supply of water to condense the steam exhausted from the low-pressure turbines. The water source and sink for the circulating water system is Lake Ontario.

The circulating water system is a nonseismic piping system whose primary function is to remove heat from the steam cycle via the main condensers. To achieve this end, the system consists of an intake structure specially designed to minimize the possibility of clogging, an inlet tunnel, four traveling screens, two circulating water pumps, and a discharge canal.

## *10.6.2 SYSTEM DESCRIPTION*

The flow diagram of the circulating water system is shown in Drawing 33013-1885, Sheets 1 and 2.

### 10.6.2.1 Intake Structure

The circulating water system is designed to provide a reliable supply of Lake Ontario water, regardless of weather or lake conditions, to the suction of the screen house pumps. The Lake Ontario intake is designed to withstand, without loss of function, ground accelerations of 0.2g, acting in the vertical and horizontal planes simultaneously. To meet these high reliability requirements, the intake structure is 3100 ft out from shore and is completely submerged below the surface of the lake. Even an occurrence of historical low water level will result in no less than 15 ft of water over the inlet structure. The probability of water stoppage due to plugging of the inlet has been reduced to an extremely low value by incorporating certain design features in the system. The intake structure is an octagonal-shaped structure containing electrically-heated screen racks in six of the eight faces. Three separate circuits (A, B, & D) provide electrical power to the intake structure screen racks. The ‘C’ circuit that supplied power to the fourth circuit has been removed from service. Each of the three remaining circuits provides electrical power to two (2) adjacent faces of the structure. Heavy screen racks with bars spaced 14-in. apart, center to center, will prevent large objects from entering the system on six of the eight sides.

At conditions of full flow (354,600 gpm) the velocity at the intake screen racks is 0.8 ft/sec. Plant cooling requirements during accident conditions would only be 10,000 gpm with an inlet velocity of 0.02 ft/sec. In addition, water enters the screen racks in a 360circle, protecting against stoppage by a single large piece of material. The low velocity plus the submergence provides assurance that floating ice will not plug the intake. The only phenomenon that might contribute to the plugging would be the accumulation of frazil ice on the screen racks. Frazil ice is a type of lumpy, crystallized ice that forms on objects in a turbulent stream of supercooled water. The electric heaters keep the metal bars above 32°F, thus minimizing the adhesive characteristics of frazil ice to the cylindrical bar metal surfaces. To minimize such a formation, the bars are separated 14-in. on center, making it unlikely that frazil ice could support itself over a span of this distance; however, bridging of accumulated frazil ice from unheated portions of the metal heater racks to the rest of the surface area of the rack has still proven to be a credible scenario. Consequently, heater racks were removed to create 68-in. x 112-in. openings on two sides of the octagonal structure to prevent plugging of the intake structure as a whole and

provide an open, reliable flow path for plant cooling water.

The bars are also equipped with dual voltage electric heaters which may be transferred between voltages via a double throw transfer switch.

#### 10.6.2.2 Inlet Tunnel

To meet the high reliability requirements, the intake system is completely submerged below the surface of the lake as shown in Figures 10.6-2 and 10.6-3. A 10-ft diameter, reinforced-concrete-lined tunnel driven through bedrock extends 3100 ft in a northern direction from the shore line. The tunnel slopes downward over its 3100-ft length for a total elevation decrease of 10 ft. From underneath the screen house, the tunnel rises vertically and connects to a reinforced-concrete inlet plenum in the screen house. Warm water recirculation is provided in the screen house inlet plenum to melt any ice that might reach this point.

#### 10.6.2.3 Traveling Screens

Before the inlet plenum water reaches the pump suctions, the water passes through the four parallel traveling screens (see Figure 10.6-3). The four installed traveling screens are fitted with 3/16 in. x 1 in. smooth top, stainless steel mesh, and are similar in concept to vertical conveyor belts. As debris collects on the screens, they rotate carrying the debris. Service water pump discharge or electric-driven fire pump discharge is used to periodically flush the debris off the screens into a collecting trough where it is carried away. The screens can operate at two speeds, slow and fast, and in two modes, automatic and manual.

#### 10.6.2.4 Circulating Water Pumps

The station has two (2), centrifugal type, vertical, circulating water pumps. Each pump has a rated flow of 178,000 gpm at 212 rpm with a 33.3 ft. head and 12 ft. submergence. Nominal flow with both pumps operating is approximately 333,000 gpm when driven by 208 rpm, 2000 hp induction motors.

#### 10.6.2.5 Condenser Inlet and Outlet Valves

The condenser inlet and outlet valves, two sets per pump, are 72-in. butterfly type valves with rubber seats. The valves can be operated via switches on the back of the main control board or manually operated. They are interlocked with the circulating water pumps. The main condensers are described in Section 10.4.3.

#### 10.6.2.6 Condensate Cooler

The circulating water system also contains a condensate cooler that is used to cool condensate to the hydrogen coolers and air ejectors. The cooler has 9551 $ft^2$ of heat transfer area and condensate flow is adjusted for desired temperature control.

#### 10.6.2.7 Screen House

The screen house is located 115 ft north of the turbine building and 80 ft south of the lake shore. It contains the traveling screens, circulating water pumps, service water pumps, fire water pumps, plant heating boiler, the chlorination system, engineered safety features buses 17 and 18, and safety-related 480-V ac motor control center G (MCCG).

#### 10.6.2.8 Piping and Discharge Canal

Water leaves the circulating water pumps via 90-in. carbon steel, pipe lines which run southward 63 ft where they have a common valveless cross-tie pipe. The lines continue then divide into two 72-in. wyes and enter the two condensers through the condenser inlet butterfly valves. The 72-in. lines exit the condensers where the water passes through the condenser outlet butterfly valves and discharges into the respective condenser discharge tunnel. These two discharge tunnels are each 8-ft wide and 7-ft high and are rectangular in shape. They run west 95 ft and then turn north towards the discharge canal. Six feet north of the turbine building the two tunnels direct flow into two 96-in. prestressed, reinforced-concrete pipes (96-in. I.D. and 8-in. thick). These two pipes run 160 ft and enter the discharge canal at the bottom of a seal well. The purpose of a seal well is to provide a water seal and prevent air from entering the condensers via the discharge lines.

The discharge canal is on the north side of the screen house and is 40-ft wide. It contains a fish screen to prevent small fish from entering the discharge tunnel or the screen house. The canal then turns north and extends another 35-ft where it enters Lake Ontario. This last 35 ft is lined with armor stones. The canal is rectangular and is constructed of reinforced concrete. The floor rises gradually from the seal well (231.5 ft) to an elevation of 238 ft. This elevation is maintained throughout the rest of the canal. The canal has recirculation lines that can direct warm discharge water into the screen house inlet plenum for ice melting.

#### 10.6.2.9 Flooding Protection

Protection of safety-related equipment from flooding due to a break or leakage in the circulating water system is provided. This protection consists of tripping the circulating water pumps when a leak is detected and the existence of a dike around areas containing safety-related equipment of sufficient height to accommodate a maximum calculated water level.

The tripping of the circulating water pumps is accomplished by redundant two-out-of-three logic receiving level information from the circulating water pump pit in the screen house and from the condenser pit in the turbine building. Three mechanically protected float switches have been installed at each end of the two pits at a height of 2 ft off their respective floor elevations. The switches feed into a fail-safe group of logic relays in the relay room which in turn trip both circulating water pumps whenever water reaches a level of 2 ft at any of the four level switch locations. The logic circuit has been designed to the IEEE Standard 279-1971 to the greatest degree practicable.

The second part of the protection system is a permanently installed, non-movable Seismic Category I dike in the screen house, and elevated doorways between the turbine building and the control building, which have been built to contain the water that may escape from the circulating water system.

For the purposes of calculating the maximum water level a different approach was used for the turbine building and the screen house.

In the turbine building three contributions can be made to the maximum water height. The first contribution is the volume of water that could flow onto the turbine hall floor before a

water buildup would be seen by the level switches and cause a trip of the circulating water pumps. Assuming that there is an unrestricted flow from all pipes in the turbine building, the volume of water that would flow from the break would result in a water height of 5.32 in. After the circulating water pumps are tripped, more water would flow onto the floor because of the kinetic energy stored in the pump rotor and in the water moving in the circulating water piping. The highly conservative maximum contribution to the level from this source is 3.12 in. The third contribution would come from possible wave action caused by a safe shutdown earthquake. The level contribution from this source would be 0.48 in. and when added to the other contributions results in a total of 8.92 in. The elevated doorways in the turbine building are 18 in. tall.

In the screen house, based on the unrealistically conservative assumption that the two pumps do not trip, the maximum water level that could occur would be 10.8 in. This level is based on the idea that water flowing from the pumps would flow north for a short distance and drop into the circulating water system intake bay. Wave action in the screen house generated by the safe shutdown earthquake would add a height of 16.08 in. to this value for a total of 26.9 in. The dikes in the screen house are 30 in. in height and are situated to prevent water from reaching safety-related equipment.

In analyzing the water buildup in the turbine building, the assumption was made that no water escaped from that area either through open doors or through floor drains. If this water were to escape from the floor but be restricted from draining into the discharge canal, the water level buildup would reach a steady-state height of 4 in. around the screen house. Maximum wave action here because of the safe shutdown earthquake would be only 4 in. for a total of 8 in. In order to prevent this water from draining into the basement of the screen house, 9-in. curbs were installed around the entrances to this area.

### *10.6.3 INSTRUMENTATION AND CONTROL*

The main control board has the circulating water pump switches, circulating water pump discharge pressure and valve position indication, screen house water level indication, traveling screen status lights, and the switches to operate the condenser inlet/outlet valves (on the back of the main control board). In addition, several annunciators would alert the operators to a problem with the circulating water system including high water alarms for the screen house and turbine building condenser pit.

### *10.6.4 INSERVICE INSPECTION*

The inservice inspection program for the condenser and water control structures at Ginna Station is incorporated into the Ginna Station preventive maintenance program. It includes provisions for continuous washing of the traveling screens and periodic maintenance of the screens; periodic monitoring of the intake water for chemical conditions and aquatic life; periodic inspection of the forebay by divers to evaluate pump wear, silt buildup, zebra mussel buildup, and general conditions; periodic checking of the intake structure by divers; and checking of the revetment annually for adverse erosion or other deterioration. Since 1975, condenser inservice inspection has utilized the eddy current examination method to ensure the integrity of the tubing. From 1975 to 1995, this typically included approximately 100% inspection of one water box with a random sampling of tubes in the other three water boxes

each year. This sample included areas where previous damage or leaks were found in the air removal sections. Since the total retubing of the condenser in 1995, the sampling group is approximately 10%.

This normal maintenance program at Ginna Station serves to ensure that water control structures remain in good condition.

## 10.7 OTHER FEATURES OF THE STEAM AND POWER CONVERSION SYSTEM

### *10.7.1 STEAM DUMP SYSTEM*

The purpose of the steam dump system is to minimize the stresses on the nuclear steam supply system induced by disturbances in secondary plant steam loads. It does this by acting as an artificial steam load itself via eight steam dump valves that are capable of passing up to approximately 28% rated steam flow from the common steam header directly to the main condenser. In conjunction with the rod control system, the design of the steam dump system allows the plant to accommodate a 50% load rejection without inducing a reactor trip. In addition to limiting reactor coolant system temperature and pressure transients on reductions in steam loads, the steam dump system also serves to minimize the undesirable possibility of lifting the pressurizer and Main Steam Safety Valves (MSSV) and aids in conducting and controlling reactor coolant system cooldowns and heatups.

Basically, the steam dump system can operate in three modes: Manual, Automatic (Loss of Load), and Automatic (Plant Trip). Each of these modes uses different inputs and programs, and all require certain permissive conditions to exist prior to steam dump actuation being possible.

The flow diagram of the steam dump system is shown in Drawings 33013-1918 and 33013-1232.

The system flow path starts with two 12-in. lines which tap off of the common 36-in. main steam header downstream of the main steam isolation valves. Each of these 12-in. lines has a manual isolation valve with a bypass valve around it. Each line has four steam dumps with manual isolation valves that tap into one of the two condensers. Thus, each condenser can receive this discharge of four steam dump valves via a 12-in. steam line. Drain line taps upstream of the steam dumps drain any condensate in the upstream piping to a steam trap header to prevent erosion and water hammer in the downstream lines.

All eight steam dump valves are identical in construction. They are 5-in., reverse acting, air-operated valves that open on air pressure acting against a spring. Thus, on a loss of air pressure, these valves fail shut. They are modulating valves, as determined by the air pressure signal converter via a valve positioner. On large temperature errors, provision is made for rapid opening of the dump valves by bypassing the positioner with full upstream air pressure (maximum open signal). The valve positioner can stroke a valve fully open in 3 to 20 sec while the trip open mode can stroke a valve open within 5 sec. Each valve is capable of passing 302,500 lbm/hour of steam with a steam inlet pressure of 695 psig.

The eight steam dumps are separated for control purposes into four groups of two valves each. For finer control of operation, the four group operating setpoints are staggered sequentially. Each steam generator also has a 6-in., air-operated, atmospheric steam dump valve located upstream of the main steam isolation valves that is capable of relieving 4.25% of rated steam flow, for 1775 MWt full power conditions, directly to the atmosphere. These valves are discussed in Section 10.3.2.5.

### *10.7.2 HEATER DRAIN SYSTEM*

The heater drain system collects drains from various components and injects the water to the main feedwater pump suction to supplement the condensate system and increase system efficiency. The main components of the system are the heater drain tank and two heater drain pumps (see Drawings 33013-1922 and 33013-1923).

The heater drain tank collects the drainage from the high-pressure heaters (5A, 5B), the low-pressure heaters (4A, 4B), and the drains from the moisture separator reheaters (1A, 1B, 2A, 2B). The heater drain tank is located at the east end of the turbine building. It has a capacity of 3600 gallons. It is designed to contain water at 380°F at a pressure of 175 psig.

The heater drain tank has a level control system that indicates on the main control board. It controls the heater drain pump discharge valve and a condenser dump valve to maintain heater drain tank level.

Cool condensate water from the discharge of the condensate pumps is used to maintain the temperature at the bottom of the heater drain tank 10°F lower than the temperature at the normal operating level. This ensures the net positive suction head requirements of the heater drain pumps during rapid power transients. The temperature difference is controlled automatically by a temperature controller, located on the main control board, and a modulating valve in the condensate line.

The heater drain pumps take a suction from the heater drain tank through individual headers and a manual isolation valve and deliver the water to the condensate system just before it enters the suction header of the main feedwater pumps.

There are two 50%-capacity heater drain pumps. Each heater drain pump is rated at 2400 gpm at a discharge pressure of 244 psig. They are driven by 400-hp motors that receive power from the 4160-V ac buses. The controls for the heater drain pumps on the main control board are identical with the condensate pumps.

A recirculation line is provided for each heater drain pump. These lines merge and return to the heater drain tank via a control valve. This valve is controlled by heater drain pump discharge header pressure. The valve will modulate to maintain a minimum flow of 500 gpm per pump.

### *10.7.3 EXTRACTION STEAM SYSTEM*

To improve the efficiency of the steam cycle, extraction steam is taken from several stages of the main turbine to preheat the feedwater prior to entering the steam generators. This involves routing some of the steam to the feedwater heaters that would normally continue through the turbine (see Drawings 33013-1903 and 33013-1924). Cycle efficiency is improved by adding the latent heat of condensation to the feedwater instead of the circulating water system.

Extraction points from the main turbine are as follows:

A. Between the fifth and sixth stage blade rows for the high-pressure turbine to supply steam to the No. 5 feedwater heaters.
B. Steam from the high-pressure turbine exhaust is supplied to the No. 4 feedwater heaters.
C. Fourth stage extraction from the low-pressure turbines supplies the No. 3 feedwater heaters.
D. Seventh stage extraction from the low-pressure turbine supplies the No. 2 feedwater heaters.
E. Ninth and tenth stage extraction from the low-pressure turbines supplies the No. 1 feedwater heaters.
F. The No. 4 feedwater heaters also receive steam from the preseparators.
G. The No. 5 feedwater heaters also receive heating from the moisture separator reheat steam.

Installed in each of the extraction steam lines from the high-pressure turbine are two counter weighted air-operated nonreturn or check valves. The valves are installed to prevent overspeeding of the turbine due to backflow of steam from the feedwater heaters after a turbine trip, and to protect the turbine from high water level in a feedwater heater in the case of feedwater heater tube leaks.

On a turbine trip the air operators are vented on both valves in each line allowing them to close in the event steam does flow back from the feedwater heaters.

On a high water level on the shell side of either No. 4 or No. 5 feedwater heater, one of the two valves in the steam line supplying the affected feedwater heater will shut. This prevents water from backing up into the turbine casing and causing damage.

### *10.7.4 CONDENSATE STORAGE SYSTEM*

There are three storage tanks in the condensate storage system. Two of the tanks (condensate storage tanks (CST) A and B) are identical and provide water to the suction of the preferred auxiliary feedwater pumps, water for hotwell makeup, and storage capacity for rejected hotwell water. The third tank (all-volatile-treatment condensate storage tank) functions to provide demineralized water to the other two condensate storage tanks and also for condensate demineralizer regeneration. The arrangement of the tanks is shown in Drawing 33013-1234.

The two identical tanks are vertical cylindrical tanks located in the service building. Each has a nominal capacity of 30,000 gallons. Redundant level instrumentation and low level alarms in the control room are provided for the condensate storage tanks (CST). A condensate storage tank (CST) level alarm is generated if the level of either tank reaches either 18 ft 4 in or 22 ft 4 in. The tanks are cross-connected by two headers. One header supplies the preferred auxiliary feedwater pump suctions and is used for steam generator makeup operations. The other header is used for hotwell rejection or makeup.

The Technical Specifications require that there be a minimum of 24,350 total gallons of water available in these two tanks whenever the reactor is above MODE 4 (Hot Standby), for use by the preferred auxiliary feedwater system. This is the minimum amount of water needed to remove decay heat for 2 hours after a reactor trip from full power. Should more water be needed, additional sources are available. An unlimited supply from Lake Ontario via the service water (SW) system. Alternate water supply to directly fill the condensate storage

tanks can be provided by alignment of the fire water system (via valve 5158C) or the city water system.

Makeup lines and drain lines are provided to and from the condensate storage tanks (CST) A and B. Water can be drained from the tanks and replaced with demineralized makeup water in order to purify the condensate storage water if necessary.

Condensate storage tanks A and B were designed to the American Water Works Association Standard (AWWA) D100, 1965 edition. The tanks are located in the service building, which is a nonseismic structure. The tanks are significant to safety for pressure boundary integrity to maintain sufficient inventory for the preferred auxiliary feedwater pumps. The tanks are nonseismic. They have the potential for being rendered inoperable by the effects of several postulated hazards including the safe shutdown earthquake, tornadoes, floods, and missiles. These hazards are accommodated by the availability of the service water (SW) system as a Seismic Category I source of water to the preferred auxiliary feedwater pumps.

The all-volatile-treatment condensate storage tank is located outside of the all-volatile-treatment building and has a capacity of 100,000 gallons. This is adequate for two regenerations. The water is kept from freezing by a heating system.

A condensate transfer pump is used to supply makeup to the all-volatile-treatment condensate storage tank from the condensate storage tanks (CST) A and B. It is also used to pump down the hotwells to any of the condensate storage tanks (CST) for maintenance.

Demineralized water from the GE Betz Water Treatment System is sent to the all-volatile-treatment condensate storage tank. This water is then normally transferred to condensate storage tanks (CST) A and B using the A or B regeneration sluice pumps. The sluice pumps are also used to take water from the all-volatile-treatment condensate storage tank for condensate demineralizer regeneration.

## *10.7.5 STEAM-GENERATOR BLOWDOWN AND BLOWDOWN RECOVERY SYSTEM*

### 10.7.5.1 Steam Generator Blowdown System

Continuous blowdown is used to reduce the quantities of solids that accumulate in the steam generators as a result of the boiling process. The all-volatile-treatment for the secondary water uses steam generator blowdown to optimize water chemistry conditions. The quantity of blowdown fluid ranges from 40-100 gpm per steam generator as needed to maintain secondary side water chemistry within plant water chemistry requirements.

The blowdown system is designed to surge from the continuous flow rate to a periodic surge blowdown rate of 150 gpm for each steam generator for a period of three to five minutes nominally at a frequency of once a week. However, the blowdown flow rate is procedurally limited to 125 gpm. The exact surge flow rates, time period, and frequency are determined as a function of steam generator corrosion product removal and plant operating condition.

The steam generator blowdown system is shown in Drawing 33013-1277, Sheets 1 and 2.

Each steam generator has a blowdown header drilled integral to the tubesheet. Both steam generator A and steam generator B are equipped with independent blowdown piping from the connecting steam generator nozzles to a common header located in the Turbine Building just upstream of the blowdown flash tank.

The piping transports the removed fluid and entrapped debris away from the steam generator, through containment penetrations, to a common flash tank in the turbine building basement.

To reduce the erosion-corrosion potential and permit periods of increased blowdown flow rates, the blowdown pipe size was increased from 2 in. to 3 in. throughout each blowdown system outside of containment. The common 2 in. piping inside containment associated with steam generator A was also replaced with 3 in. piping. The only remaining 2 in. piping is located in the steam generator B blowdown system from the steam generator nozzles to a point just downstream of the containment penetration.

Each blowdown line and each blowdown sample line are provided with a containment isolation valve just outside containment. These pneumatic isolation valves will automatically shut on a containment isolation signal or on receipt of a signal from a blowdown radiation detector. Two flow control valves (V-5725A and V-5725B), just upstream of the blowdown flash tank inlet, are used to set the individual blowdown rates. Two isolation valves (V-5709 and V-5710) located upstream of the flow control valves will close on high blowdown flash tank level or turbine trip. A cross-tie line is located upstream of the isolation valves to allow blowing down both steam generators through one line while the flow control valve in the other line is being maintained.

The blowdown flash tank also receives blowdown sample water via the nuclear sample room.

### 10.7.5.2 Blowdown Recovery System

The blowdown recovery system is designed to recover both the blowdown water and heat.

Flashed steam is vented from the blowdown flash tank to low-pressure feedwater heater 3A for heat recovery. The vented steam condenses in the feedwater heater and returns to the condenser through the feedwater heater drain system. The remaining condensate in the blowdown flash tank is drained directly to condenser 1B through a level control valve. All blowdown flow can thus be recovered and returned to the condensate system through the condensate demineralizers.

The Condensate demineralizers can also be bypassed, which requires the blowdown flash tank condensate to be overboarded via the condenser waterboxes to the circulating water discharge canal tunnels. This is done using the same level control valve as used to recover the condensate to the 1B Condenser.

### 10.7.5.3 Blowdown System Operation

The blowdown system startup, shutdown, and blowdown flow rate modulation are manual operations. The level in the flash tank is automatically controlled.

During initial startup the steam generator blowdown is normally aligned to the flash tank, and the flash tank is drained to the discharge canal tunnel, and vented to the atmosphere. Once the turbine load is approximately 25%, the flash tank drain is realigned to the waterboxes, and the steam is recovered by the low-pressure feedwater heater 3A. Normal blowdown flow ranges from 40-100 gpm per steam generator as needed to maintain secondary side water chemistry within plant water chemistry requirements. The blowdown flow rate is procedurally limited to 125 gpm.

### *10.7.6 MAIN TURBINE AND GENERATOR AUXILIARY SYSTEMS*

The main turbine is supported by a number of auxiliary systems that improve the efficiency and safety of its operation.

First and second stage air ejectors remove air and noncondensable gases from the condenser and maintain it under a vacuum, improving the efficiency of the main turbine by reducing the backpressure seen by the turbine exhaust.

The gland sealing and exhaust system applies steam to a labyrinth seal around the rotor shaft to preclude air inleakage into the turbine casings and condenser and to prevent steam leakage into the turbine building.

The vacuum priming system uses mechanical vacuum pumps to prevent air buildup in the condenser water boxes or tubes a condition that would reduce condenser efficiency.

The exhaust hood spray system prevents overheating of the last stage low-pressure blading under low steam flow conditions.

The turbine lube-oil system provides lubrication and cooling of the turbine bearings and supplies oil to the auto-stop header for turbine protection. It also provides backup oil to the seal-oil system to prevent hydrogen leakage into the turbine building. A purification system is an adjunct to the turbine lube-oil system to remove water and contaminants from the lube-oil, as well as to provide storage space for makeup oil.

The generator auxiliary systems are required to ensure that the main generator will operate at its maximum rated output safely and efficiently. This is accomplished by cooling the generator rotor, stator, exciter, main output bushings, and the isophase bus ducts.

Pressurized hydrogen is circulated by the internal ventilation of the generator to remove heat produced in the rotor and stator. The hydrogen then transfers this heat to hydrogen coolers which are supplied with cooling water from the condensate system.

To prevent the escape of hydrogen along the generator shaft and out of the casing, a seal-oil system is utilized. The air-side seal-oil pump and the hydrogen-side seal-oil pump provide oil for sealing at approximately 12 psig higher than generator hydrogen pressure. The main turbine oil system can provide a backup source of pressurized seal oil.

### 10.7.6.1 Gland Sealing Steam and Exhaust System

The gland sealing steam system shown in Drawing 33013-1904 prevents air leakage into the turbine casing that could increase turbine windage losses and reduce condenser vacuum. It also prevents steam leakage from the turbine casing into the turbine building.

The rotor glands are a labyrinth type consisting of a number of seal strips to minimize steam leakage. The leakage steam is removed from a chamber through a connection in the lower half of the gland case to the gland seal condenser. The condenser maintains a partial vacuum in the chamber which prevents steam leakage past the chamber to the turbine room. The labyrinth seals are steam throttling devices consisting of alternating rows of stationary and rotating rings arranged around the shaft with a small radial clearance. They provide a high resistance to steam or air flow along the shaft.

Sealing steam is admitted to the chamber through a connection in the gland case. A pressure of about 3 psig is automatically maintained on the chamber under all operating conditions by the gland steam controller. The gland steam controller is an air-operated diaphragm control valve and during starting of the turbine supplies steam to the gland header. As load is increased, the steam pressure inside the high-pressure turbine increases and the steam leakage path is outward toward the rotor ends, reducing or eliminating the need to supply sealing steam to the glands. When this occurs, leakage from the high-pressure turbine glands and steam from the regulator valve will supply steam sealing requirements for the low-pressure glands. A safety valve and safety head protect against excessive pressure in the gland sealing system. Due to increased HP Turbine exhaust pressure from the plant uprate to 1775 MWt, a manual spillover system was installed. This system allows operators to manually bypass gland steam header steam flow to the condenser if high gland steam header pressures are observed.

The gland steam condenser maintains a pressure slightly below that of atmosphere (5 in. to 10 in. of mercury vacuum) in the gland leakoff system to prevent the escape of steam from the ends of the glands and to remove and condense the vapor. It eliminates dripping and accumulation of moisture caused by slight gland leakage to the atmosphere. The gland seal steam is admitted into the condenser section via the steam inlet and then passes among the tubes. The air and other noncondensable vapors are discharged to an atmospheric vent by an air exhauster. The condensate formed in the gland steam condenser shell is removed via the drain. Cooling of the condenser is provided by the condensate system.

Supplementing the gland sealing steam system, two diaphragm operated valves, each under control of a differential pressure controller, introduce throttled steam into the inner glands at both the governor and generator ends of the high-pressure turbine at a pressure of 5 psig higher than that existing in the high-pressure exhaust. This will create a flow of steam into the turbine and also into the 3 psig zone. Since this is throttled steam, the temperature at maximum load will be approximately 500°F. When this is throttled down to 3 psig in the gland area, the resulting temperature will be approximately 310°F with 90°F superheat. As a result, the temperature gradient will be reduced between the gland area of the cylinder and the cylinder end wall.

#### 10.7.6.2 Air Ejectors

There are four first-stage and two second-stage air ejector nozzles provided to remove air and noncondensables from the two single pass condensers. There are also two priming ejectors (hoggers) supplied in the system.

Main steam is supplied to a reducing station where the steam pressure is reduced to approximately 145 psig. The first-stage air ejector is lined up to take a suction on the main condenser and discharge to the air ejector inner condenser. The second-stage ejector takes a suction on the inner condenser and discharges to the after condenser. Any air and noncondensables are then directed out the ventilation stack. The inner and after condensers are cooled by condensate flow. The condensed steam collected by the air ejectors is returned to the main condensers.

The condenser air removal arrangement is shown in Drawing 33013-1921.

#### 10.7.6.3 Vacuum Priming System

The vacuum priming system, shown in Drawing 33013-1921, removes air and noncondensable gases from the condenser water boxes. By ensuring air-free water boxes, condenser cooling becomes more efficient.

The vacuum priming system utilizes two vacuum pumps and a vacuum priming tank to accomplish water box degasification. The vacuum priming tank is maintained at 25 in. mercury vacuum by the vacuum pumps and the condenser water boxes are connected to the priming tank through float valves. The condensate cooler is also connected to the vacuum priming tank through a float valve.

Under MODES 1 and 2, the preferred method of operation is to have BOTH vacuum priming pumps in service. This removes as much air as possible from the inlet and outlet condenser waterboxes, as well as the discharge tunnel. This reduces air buildup in the system and provides a small increase in MW output during the summer months. An additional benefit is that it reduces back pressure on the Circulating Water System, providing additional margin for Operations to maintain circulating water flow upon trip of a circulating water pump. One vacuum priming pump may be operated if the opposite train is out of service for maintenance. During any other scenario where one pump is in operation, logic exists where the standby pump will start if the vacuum priming tank decreases to 12 in. mercury vacuum to aid in restoring vacuum.

To start the vacuum priming pump, service water (SW) must be available to seal the priming pump. A pressure switch on the seal-water line will close at 10 psig, allowing the vacuum priming pump to start. An interlock is also provided which requires that a circulating water pump be running before starting the vacuum priming pump. The status of the vacuum priming pumps is indicated at the main control board.

#### 10.7.6.4 Exhaust Hood Spray System

During low load operation there is insufficient steam flow to provide cooling for the turbine blades. Wind friction (windage) will cause the long blades to overheat. The result is that the exhaust load temperature reaches an exceptionally high level. This high temperature affects the mechanical characteristics of the turbine last-stage brackets, inner casings, and exhaust hoods. To control this temperature, a water spray system with nozzles installed downstream

of the eleventh-stage buckets is provided.

The water supply to the spray system is taken from the condensate system downstream of the condensate polishers. Although provisions exist for automatic operation of the system controlled by exhaust hood temperatures, the system is normally operated on a manual bypass. The spray nozzles direct the water away from the blades, cooling by absorbing radiant heat. Temperatures in the exhaust hood are normally maintained below 160°F.

#### 10.7.6.5 Turbine Lube-Oil System

The turbine lube-oil system shown in Drawing 33013-1901, has three main functions:

A. Provide lubrication and cooling for the turbine bearings.

B. Supply lube oil to the turbine trip devices.

C. Provide cooling, purification, and storage facilities for the oil.

The main oil pump, located on the front end of the high-pressure turbine, is driven from the turbine rotor shaft and supplies oil at 320 to 380 psig with 10 to 45 psig suction pressure. This pump is not self-priming and must have pressure applied to the suction. At turbine operating speed, the suction is supplied by a suction ejector which uses high-pressure oil from the main oil pump impeller as the operating medium. During startup, the suction is supplied by the turning gear oil pump.

The main oil pump supplies lubrication to all nine journal bearings and the thrust bearing, provides normal makeup to the seal-oil system, and supplies oil to the auto-stop oil header and turbine trip devices. The main oil pump is backed up by the turning gear oil pump which starts on a turbine trip or a low lube-oil bearing pressure of 8 psig. As a backup to the seal-oil system, a high-pressure seal-oil backup pump which takes suction from the turbine oil reservoir is provided. It also starts on a turbine trip or a low bearing oil pressure of 8 psig. As an emergency backup, a dc emergency oil pump is provided should the turning gear oil pump fail. This pump will start on a low lube-oil pressure of 6 psig.

Oil is supplied to the bearings through one of two oil coolers. The oil is cooled to 110-120°F by service water (SW) which is automatically throttled on the outlet of the cooler. The oil coolers may be shifted at any time by opening the service water (SW) to the idle cooler, then filling and venting the oil cooler. The selector valve is then shifted. The oil supplied to the bearings passes to and from them through double-walled pipe. Return to the turbine oil reservoir is by gravity drain.

High-pressure oil from the main oil header is directed to the auto-stop oil header, to the overspeed trip valve, and to the thrust bearing trip. The turbine will be tripped when the auto-stop oil header is depressurized by dumping the oil back to the reservoir. Trip devices for the turbine include:

- Overspeed (108%).
- Low vacuum (20 in. of mercury).
- Low oil pressure (6 psig).
- Thrust bearing failure (75 to 80 psig).
- Electrohydraulic fluid trip.
- Manual.

Provisions are made for cleaning and conditioning the oil. The purifying component is the turbine oil conditioner unit, referred to as the "Bowser" type. It removes free water and solid particles from the oil, then polishes it and strips all moisture and cloud vapor from it. The oil conditioner consists of a three-section segmented tank, a fiberglass filter, and associated pumps.

#### 10.7.6.6 Generator Hydrogen Cooling System

Hydrogen gas cooling is provided for the turbine generator based on the "inner-cooling" principle.

The functions of the hydrogen gas system are to:

A. Provide a means for safely putting hydrogen in or taking hydrogen out of the generator, using carbon dioxide as a scavenging medium.

B. Maintain the gas pressure in the generator at the desired value.

C. Indicate to the operator at all times the condition of the generator with regard to gas pressure, temperature, and purity. The presence of liquid in the generator is also indicated by an alarm on the hydrogen supervisory panel.

D. Dry the gas and remove any water vapor, which might get into the generator from the seal oil.

The hydrogen gas supply provides the necessary valves, pressure gauges, regulators, and other equipment to permit introducing hydrogen into the generator. It also provides a means of controlling the gas pressure within the generator housing either manually by means of valves or by means of pressure regulators which are manually adjustable to give the desired gas pressure.

The carbon dioxide supply provides a means of admitting carbon dioxide to the generator during the gas purging operation.

The gas, either hydrogen or carbon dioxide, is distributed uniformly to the various compartments of the generator by means of perforated pipe manifolds located in the top and bottom of the generator housing.

A gas dryer consisting of a chamber filled with activated alumina absorbent material is connected across the generator blower, so that gas is circulated through the dryer whenever the machine is running.

The purity of the gas in the generator is determined by use of the hydrogen purity indicating transmitter and the purity meter blower. Gas purity can be read on the hydrogen panel or on a remote indicator on the control board.

A thermostat is located in the generator to provide an alarm in case the temperature of the hydrogen in the generator becomes excessive.

The hydrogen is cooled by passing it through coolers where the gas gives up its heat to the condensate.

Float-operated switches are provided under the generator frame and under the main lead box to indicate the presence of any liquid in the generator which might be due to leakage or condensation from the cooler.

Temperature detectors are provided in the generator and gas passages to measure the various internal temperatures in the gas passages.

All generators are equipped with a hydrogen pressure control, which has a supply pressure switch and two pressure gauges. A pressure switch is located on the supply side of the hydrogen pressure control manifold and gives an alarm when the supply pressure is low.

#### 10.7.6.7 Generator Seal-Oil System

The function of the seal-oil system is to lubricate the seals and prevent hydrogen escaping from the generator. The same oil is used in the turbine bearing system and the gland seal-oil system.

Contaminating air and moisture are kept out of the generator by separating the air side of the seal-oil system from the hydrogen side of the seal-oil system. When this is done, the hydrogen-side oil is returned to the hydrogen side of the seal ring in the generator, thus preventing the escape of absorbed hydrogen to the outside atmosphere. The air-side seal oil is returned to the air side of the seal ring, thus preventing the release of absorbed air or moisture into the hydrogen-side compartment of the generator.

#### 10.7.6.8 Generator Exciter Cooling

The exciter is totally enclosed within the exciter housing. An attached fan on the exciter shaft circulates the air within the exciter enclosure. The air circulates through the exciter and then passes through a heat exchanger cooled by service water (SW).

### *10.7.7 SECONDARY CHEMISTRY CONTROL*

#### 10.7.7.1 All-Volatile-Treatment Chemistry

##### 10.7.7.1.1 Background

Chemistry control reduces the corrosion of equipment in the secondary system and minimizes the fouling of heat transfer surfaces.

Westinghouse adopted all-volatile-treatment chemistry for use in steam generators in August 1974 when inservice inspection of steam generators operating with phosphate chemistry revealed excessive corrosion of the heat transfer tubes. Ginna Station shifted to all-volatile-treatment chemistry control during a shutdown for this purpose in November 1974.

##### 10.7.7.1.2 All-Volatile-Treatment Chemistry Control

The basis for all-volatile-treatment chemistry control is that only volatile chemicals are added to the system as chemical control agents.

In all-volatile-treatment chemistry control, system pH is controlled by the addition of ammonium hydroxide and ethanolamine (ETA), while hydrazine is added to the system to scavenge oxygen. Drawing 33013-1909 shows the chemical control system used to maintain

all-volatile-treatment chemistry control. The all-volatile-treatment chemistry method also minimizes the solids content of the steam generator water, thus reducing the presence of those elements which cause corrosion or induce scale and sludge formation. This is accomplished by ensuring high-quality makeup water, a continuous steam generator blowdown, and operation of an on-line condensate demineralizer system (if needed). Typically, at full power, it is not necessary to operate the demineralizers to maintain the desired plant chemistry.

The all-volatile-treatment chemistry system accomplishes the following:

A. Minimizes corrosion in the steam generator and the condensate and feedwater systems.

B. Minimizes the deposit of sludge in the steam generators.

C. Minimizes scale deposits on the steam generator heat transfer surfaces.

D. Avoids turbine deposits due to carryover from the steam generator.

In conjunction with the all-volatile-treatment system, the condensate polishing demineralizer system removes soluble and insoluble impurities from the condensate stream, and the steam generator blowdown system continuously removes solids from the steam generators.

The oxygen content of the feedwater is of particular concern since it has a strong influence on system corrosion. Some of the oxygen entering the system is contained in makeup water from the condensate storage tanks (CST). Diaphragms on condensate storage tanks (CST) minimize the oxygen increase but do not eliminate it. Air leaks into the sub-atmospheric portions of the turbine cycle also contribute to the feedwater oxygen concentration. Hydrazine is added to the system to react with and scavenge the oxygen before it enters the steam generator.

Hydrazine is pumped into the system at the suction of the condensate booster pumps during MODES 1 and 2. During shutdown and startup operations, it is added at the turbine-driven auxiliary feed pump. Alternatively, hydrazine can be added upstream of the condensate pumps by utilizing the condenser vacuum to draw hydrazine into the condensate system. Hydrazine reacts with dissolved oxygen to remove it from the system as follows:

$$N_2 H_4 + O_2 \rightarrow N_2 + 2H_2O$$

To ensure the removal of all oxygen from the feedwater, hydrazine is maintained at a concentration well above the oxygen concentration.

The addition of hydrazine also tends to raise the pH of the system:

$$2\ N_2H_4 \rightarrow 2\ NH_3 + H_2 + N_2$$

This reaction is encouraged by heat, so that nearly all of the hydrazine has reacted by the time it reaches the steam generator. The $NH_3$ is so highly soluble that it is not removed by the air ejectors and tends to raise the entire secondary system pH.

The steam generator pH is established and maintained, when necessary, by ammonium hydroxide and ethanolamine (ETA) additions to the feedwater stream.

In addition to pH and hydrazine level, several other parameters are monitored to give indication of the results of the chemical additions. The secondary all-volatile-treatment chemistry specifications for normal power operations are based on the current revision of the industry standard, EPRI TR-102134, "PWR Secondary Water Chemistry Guidelines".

Steam generator secondary side wet layup, with chemically treated water, is used below MODE 4 (200°F) and minimizes corrosion and oxidation. Each steam generator has a wet layup recirculation system that mixes steam generator bulk water, preventing chemical stratification and providing representative chemistry samples.

Secondary Water Chemistry Program requirements are included in the Technical Specifications.

### 10.7.7.2 Nonnuclear Sampling System

To ensure that the established chemistry parameters are maintained, a non-nuclear sampling system is provided (see Section 9.3.2.2). This system allows for both continuous and periodic sampling of a variety of points throughout the secondary side to provide analysis necessary for plant operation, corrosion control, and the monitoring of equipment and plant performance. The system includes a computerized system for on-line monitoring of secondary water chemistry. The system accepts continuous inputs from individual sensors and in-line chemistry analyzers in the secondary water system and provides data to the chemistry laboratory for use in controlling secondary water chemistry. The inputs are shown in Table 10.7-1.

### 10.7.7.3 Water Chemistry Monitoring Program

Ginna Station has an established water chemistry monitoring program directed at maintaining chemistry control in the secondary circuit. That program continues to be reviewed and revised based on plant and industry experience. This program, in conjunction with the general philosophy of operation, limits corrosion damage and helps ensure the long-term integrity of the steam generators. Secondary chemistry limitations are established for all plant modes. A chemistry monitoring procedure includes sections that identify (1) critical steam generator blowdown parameters, (2) action level objectives, (3) limiting control specifications that become progressively more stringent and can result in plant shutdown, (4) schedular requirements for sampling and analysis, (5) data recording requirements, and (6) the sequence of reporting out-of-normal chemistry conditions to specific individuals. The procedure incorporates the steam generator blowdown Action Levels and limitations identified in EPRI TR-102134, "PWR Secondary Water Chemistry Guidelines." One of the Level 1 objectives is to identify and correct the cause for a parameter value that is "out-of-the-historical-normal". Action Level 1 steam generator blowdown limitations include values specified in EPRI TR-102134 for cation conductivity, sodium, chloride, and sulfate.

### 10.7.7.4 Catalytic Oxygen Removal System

The catalytic Oxygen removal system was used in conjunction with the IONICS water treatment system. The IONICS water treatment system was replaced by the GE Betz water treatment system and the catalytic Oxygen removal system was isolated per PCR 2004-0081. The remaining description is retained for historical purposes only.

The catalytic oxygen removal system reduced dissolved oxygen by mixing hydrogen with the condensate and reducing the free oxygen to water by exposure of the mixture to a metal catalyst surface. The system was designed to reduce oxygen concentration in the condensate storage system to less than 100 ppb. The catalytic oxygen removal system was controlled automatically by a central processing unit and operated on demand. Hydrogen was supplied from dedicated hydrogen cylinders in the hydrogen supply shed. The catalytic oxygen removal system interfaced with the condensate system and with the primary water makeup system through the primary water treatment system. The catalytic oxygen removal system took suction from the condensate storage tank and/or the primary water treatment system and discharged to the condensate storage tank and/or the primary water treatment system. A hydrogen leak would have resulted in a shut down the catalytic oxygen removal system.

### 10.7.7.5 Condensate Polishing Demineralizer System

#### 10.7.7.5.1 **System Description**

Condenser in-leakage provides the major source of dissolved solids in the condensate. Other solids are introduced with the makeup water or are contributed from steam lines, turbine, or condenser as corrosion products. Moisture carryover also introduces a low level of solids into the condensate.

The condensate polishing demineralizer system provides for the removal of soluble and insoluble impurities in the condensate. It consists of four inline mixed-bed demineralizers that take full flow from the condensate pumps, remove the impurities, and discharge the purified condensate to the condensate booster pumps (see Drawing 33013-1911, Sheets 1 and 2).

The condensate polishing demineralizer units are separate vessels that remove the impurities in the condensate through regenerable ion exchange resins. The resins are regenerated in separate vessels. The resin regenerants are stored in concentrated form and diluted for regeneration service.

Each vessel is provided with a resin trap to prevent gross transport of resin to the steam generators in case of demineralizer underdrain failure. Differential pressure across each resin trap is indicated and alarmed.

The four demineralizers are in parallel with each other and a bypass allows for the use of any number, depending upon plant conditions. The original design basis for the demineralizer system assumed that one bed is lined up for startup, a second bed is placed in service at about 35% power, a third at 70%, and the fourth bed is normally left on standby. The fourth bed allows rotation of the beds, with one at a time being taken off the line for regeneration by the regeneration facilities. Indications that a bed is due for regeneration are:

- High effluent sodium.
- High conductivity in the demineralizer effluent.
- Low flow (high-pressure drop).
- Preset number of gallons put through the bed (not normally used).

Based upon existing secondary side chemistry, the demineralizers are not required to operate continuously when the plant is operating at full power.

The demineralizers, resin regeneration tanks, and tanks for the regenerate wastes are located in a separate, shielded building (all-volatile-treatment building). The building has a 2-ft-thick concrete wall and roof to minimize operator exposure in case of radioactivity buildup when a steam generator tube leak occurs. The system is operated from a control panel in one end of the building.

The all-volatile-treatment building is located adjacent to the all-volatile-treatment condensate storage tank, which contains sufficient water for two regeneration cycles. The 100,000-gallon tank has a layer of polyethylene balls floating on the surface of the water to limit oxygen interaction with the condensate. It is maintained above 35°F by a 15-kW, 100-gallon heater which cycles on at 35°F and off at 39°F.

#### 10.7.7.5.2 **Resin Transfer**

Upon the exhaustion of a demineralizer, which is signaled by high-pressure drop (low flow), totalizer count alarm, high conductivity alarm, or high sodium effluent alarm, the operator initiates resin transfer operations.

The resin in the exhausted demineralizer is hydraulically transferred to the resin separation/ cation regeneration tank. The regenerated, ammoniated, mixed, and rinsed resins in the resin mix rinse tank are then transferred to the empty demineralizer and the demineralizer is placed in standby. New resin is introduced into the system through the separately located resin addition hopper in the turbine building. Bags or drums of resins are manually dumped into the hopper and hydraulically educted from the hopper to the resin separation/cation regeneration tank.

The water for resin transfer, regenerant dilution, and resin rinsing is supplied from the 100,000allon condensate storage tank.

#### 10.7.7.5.3 **Regeneration (Drawing 33013-1910, Sheets 1 and 2)**

Plant procedures control the Condensate Polishing System resin regenerations as follows:

- Transfer exhausted resin from service vessel to resin separation/cation regeneration vessel.
- Clean resins in resin separation/cation regeneration vessel by Air Bump and Rinse Operations (ABROs).
- Backwash resins in resin separation/cation regeneration vessel to separate cation and anion resins.
- Transfer anion resins from resin separation/cation regeneration vessel to anion regeneration vessel.
- Regenerate anion resins with caustic and then rinse.
- Regenerate cation resins mixed with anion resins by ammonium hydroxide rinse followed by ammonium hydroxide recycle treatment and then rinse.
- Regenerate cation resins with acid and then rinse.

- Transfer anion resins to resin separation/cation regeneration vessel.
- Mix regeneration cation and anion resins.
- Transfer mixed resin to mixed resin storage vessel.

Cation resin removal of secondary water treatment amines determines bed exhaustion. Anion resins use little capacity during service. Anion resin regeneration caustic and ammonium hydroxide steps are eliminated in an alternative regeneration procedure that reduces sodium ingress to secondary systems.

Installed chemical reclaim equipment is not used since using reclaimed chemicals in regenerations would not result in regeneration quality meeting current secondary chemistry impurity limits.

##### 10.7.7.5.4 Waste Disposal (Drawing 33013-1912)

The high conductivity regeneration wastes are collected in the neutralization tank. The wastes are adjusted to a neutral pH at the completion of a regeneration cycle. The neutralized wastes are discharged to the plant circulating water discharge under normal operating conditions. Should unacceptable amounts of radioactivity be detected in the neutralization tank, the contents are discharged to radwaste disposal. A blanked connection is provided outside the east wall of the all-volatile-treatment building for connecting to portable, shielded waste treatment equipment. This provides a second alternative for disposing of regeneration wastes not suitable for discharge to the lake.

The low conductivity regeneration wastes are collected in the low conductivity waste tank. The contents of this tank are used to supplement the regeneration water supply to the condensate polishing demineralizer system. Should unacceptable amounts of radioactivity be detected in the low conductivity waste tank the contents would be drained into the building sump via the trench. This waste is then transferred to the 25,000-gallon holding tank and monitored for radiation before discharge.

#### 10.7.7.6 Chemical Dispersant

One type of chemical dispersant is Polyacrylic Acid (PAA). It is an organic chemical that affixes itself to corrosion product particles and keeps them suspended in solution so that they do not affix to the Steam Generator tube walls. These corrosion product particles can subsequently be removed from the Feedwater System (and Steam Generators) via the Steam Generator Blowdown System. By continually injecting PAA into the Feedwater, while the plant is on-line, the life of the Steam Generators is expected to be prolonged. This is achieved by improving the iron removal efficiency during blowdown. The PAA is expected to reduce the amount of iron oxide deposition on the Steam Generator tubes, which may better maintain the heat transfer from the Primary Loop to the Secondary Loop.

A chemical injection skid injects PAA into the Feedwater System while the plant is on-line. As shown on P&ID 33013-3124, the chemical injection skid contains three lines. Each line can receive PAA from one of two five gallon carboys or an external tote. Each line is equipped with a positive displacement pump that provides the energy to inject the PAA into the Feedwater System. The ‘A’ and ‘B’ line are normally used to inject into the Feedwater

System. The ‘C’ line is the swing line that is normally closed, but can be utilized to inject PAA through either the ‘A’ line or the ‘B’ line. This would be utilized if the ‘A’ or ‘B’ line would ever have to be shutdown for maintenance.

In addition to on-line application, PAA may also be added during wet layup and long path during outages.

### *10.7.8 EROSION/CORROSION MONITORING PROGRAM*

Ginna Station has developed an erosion/corrosion program for single and two-phase systems consistent with the requirements of NUREG 1344 and the NUMARC erosion/corrosion report, dated June 11, 1987. The program is designed to ensure that erosion/corrosion does not result in unacceptable degradation of the structural integrity of high energy carbon steel piping systems. The program is documented in the Ginna Station Erosion/Corrosion Program Manual and includes the following:

- Frequency of Inspection Criteria.
- Acceptance Criteria.
- Inspection/Expansion Criteria.
- Repair/Replacement Criteria.
- Corrective Action.

The main steam, condensate, feedwater, steam generator blowdown, extraction steam, turbine gland steam, gland sealing water, and moisture separator reheater system piping systems are included in the program.

## Table 10.7-1
## COMPUTERIZED SECONDARY WATER CHEMISTRY MONITORING SYSTEM

| Source | Inputs |
|---|---|
| 1. | 1B hotwell sodium |
| 2. | 1A hotwell sodium |
| 3. | 1A steam generator sodium |
| 4. | 1B steam generator sodium |
| 5. | Condensate dissolved oxygen |
| 6. | Feedwater dissolved oxygen |
| 7. | 1A steam generator pH |
| 8. | 1B steam generator pH |
| 9. | Condensate pH |
| 10. | Feedwater pH |
| 11. | Feedwater hydrazine |
| 12. | Spare |
| 13. | Feedwater conductivity |
| 14. | A steam generator conductivity |
| 15. | B steam generator conductivity |
| 16. | Condensate cation conductivity |
| 17. | Feedwater cation conductivity |
| 18. | A hotwell cation conductivity |
| 19. | B hotwell cation conductivity |
| 20. | Heater drain tank cation conductivity |
| 21. | A steam generator cation conductivity |
| 22. | B steam generator cation conductivity |
| 23. | A main steam cation conductivity |
| 24. | B main steam cation conductivity |
| 25. | A steam generator blowdown rate |
| 26. | B steam generator blowdown rate |
| 27. | Sample cooling water temperature |