Chapter 10: Steam and Power Conversion System

Table of Contents

Chapter 10: Steam and Power Conversion System
Table of Contents (continued)

Chapter 10: Steam and Power Conversion System
Table of Contents (continued)

Chapter 10: Steam and Power Conversion System

List of Tables

Chapter 10: Steam and Power Conversion System

List of Figures

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Chapter 10
STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

Note: As required by the Renewed Operating Licenses for North Anna Units 1 and 2, issued March 20, 2003, various systems, structures, and components discussed within this chapter are subject to aging management. The programs and activities necessary to manage the aging of these systems, structures, and components are discussed in Chapter 18.

This section describes that category of systems and equipment that are required to convert steam energy to electrical energy. The following sections describe separate equipment and systems required for each unit:

10.2 Turbine Generator

10.3 Main Steam System

10.4.1 Auxiliary Steam System

10.4.2 Circulating Water System

10.4.3 Condensate and Feedwater System

10.4.4 Main Condenser

10.4.5 Lubricating Oil System

10.4.6 Secondary Vent and Drain Systems

10.4.7 Bearing Cooling Water System

10.4.8 Condensate Polishing System

The following system design features are safety related:

1. Main steam lines from the steam generators up to and including the main steam line nonreturn valves (Section 10.3).
2. Feedwater lines from the steam generators up to and including the isolation valves outside the containment (Section 10.4.3).
3. All components of the auxiliary feedwater system (Section 10.4.3).
4. Screen wash pump and discharge piping providing makeup to the Service Water Reservoir (Section 10.4.2).
5. Steam generator blowdown lines from the steam generators up to and including the isolation valves outside the containment (Section 10.4.6).

6. That portion of main air ejector discharge piping from the check valve inside containment, and penetrating the reactor containment outward to the second isolation valve outside the containment.

The design bases of the steam and power conversion equipment and systems are largely derived from past design experience with fossil-fueled stations and have evolved over a long period of time. Specifically, the design bases are oriented to a high degree of operational reliability at optimal thermal performance. The performance of the collective equipment and systems is a function of environmental conditions and the selection of design options. All auxiliary equipment was designed for the maximum expected unit capability.

The conventional design bases have been modified in order to provide suitability for nuclear application. These modifications include provisions for specific earthquake, tornado, and missile protection, as further described in other sections.

Figures 10.1-1 and 10.1-2 show the heat balance for the current core rating equivalent to 2905 MWt for each unit.

These heat balances show the overall steam and power conversion system and indicate the performance requirements of the major equipment. More detailed system diagrams and design data are presented in succeeding sections.

The steam generated by the nuclear steam supply system (NSSS) is distributed to the turbine generator by the main steam system. The turbine is an 1800-rpm tandem-compound, four-flow machine coupled to a hydrogen-cooled generator. Four combination moisture separator-reheaters are installed to remove any moisture from the steam as it passes between the high- and low-pressure turbines.

Six stages of feedwater heating are provided. All heaters are of the closed type and consist of two shells resulting in a two-train condensate and feedwater piping system.

The turbine exhausts to a two-shell, single-pass steam surface condenser. Three half-size condensate pumps are provided. During normal operation, two of these pumps pump the condensate through the air ejector condensers, gland steam condenser, flash evaporator, fifth-point drain coolers, and the sixth-, fifth-, fourth-, third-, and second-point feedwater heaters to the suction side of the steam generator feed pumps.

Three half-size steam generator feed pumps are provided. During normal operation, two of these pumps pump the condensate through the first-point heater and the feedwater regulating valves to the steam generators. Drains from the reheaters drain to the first-point heater shells. The first-point heater shells drain to the second-point heater. Drains from the second-point heater shells are collected in individual high-pressure heater drain receivers. Drains from the moisture separators are collected in another high-pressure heater drain receiver. Three full-size, high-pressure heater drain pumps pump the condensate from these high-pressure heater drain receivers to the suction side of the steam generator feed pumps. Drains from the third-point heater shells drain to the fourth-point heater. Two full-size, low-pressure heater drain pumps pump fourth-point heater drains to the condensate stream between the third- and fourth-point heaters. The drains from the fifth-point heater cascade to an external fifth-point heater drain cooler. The drains from this drain cooler and the sixth-point heater drain to the condenser.

Figure 10.1-1
UNIT 1 HEAT BALANCE DIAGRAM - 2905 MWT LOAD

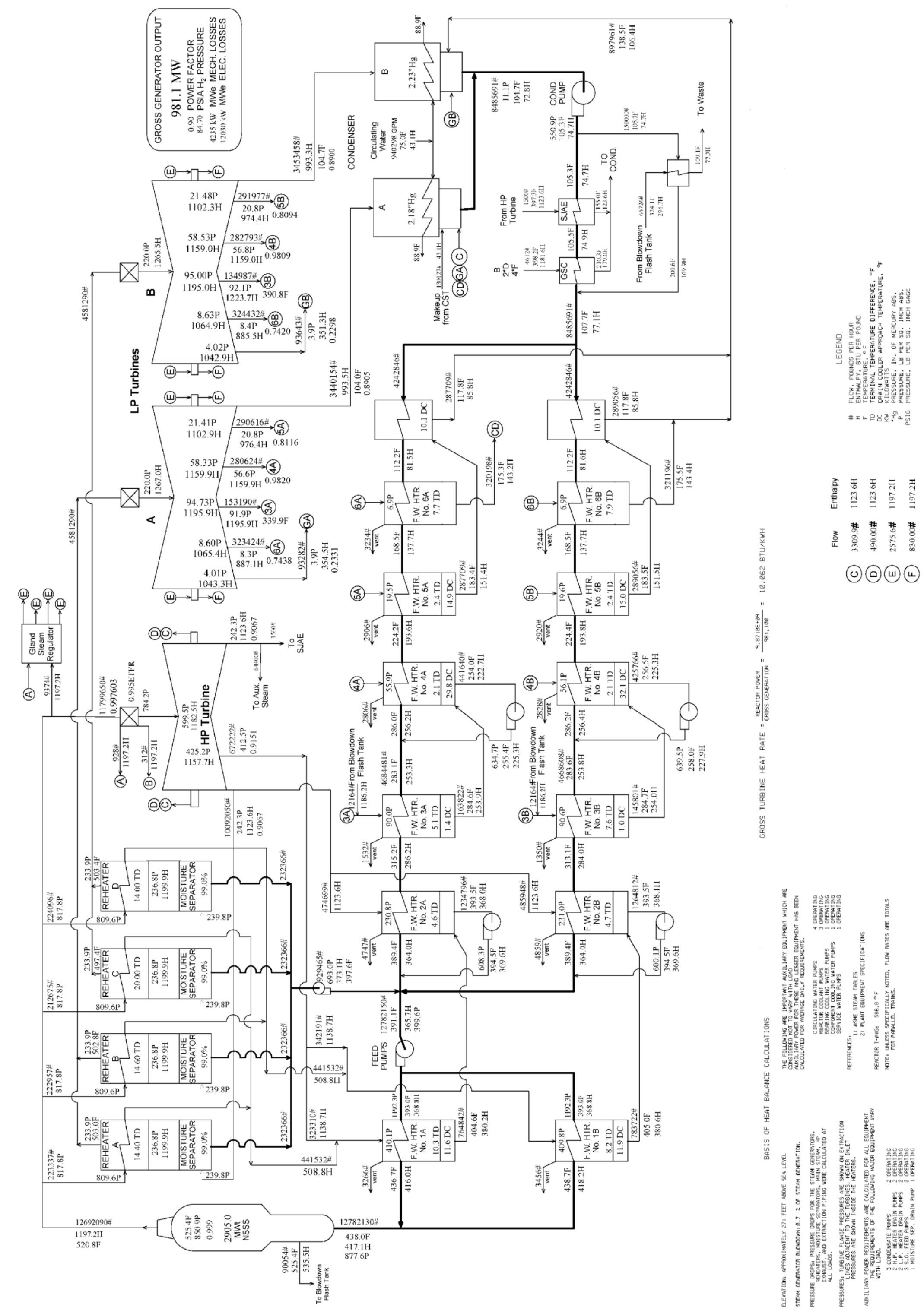
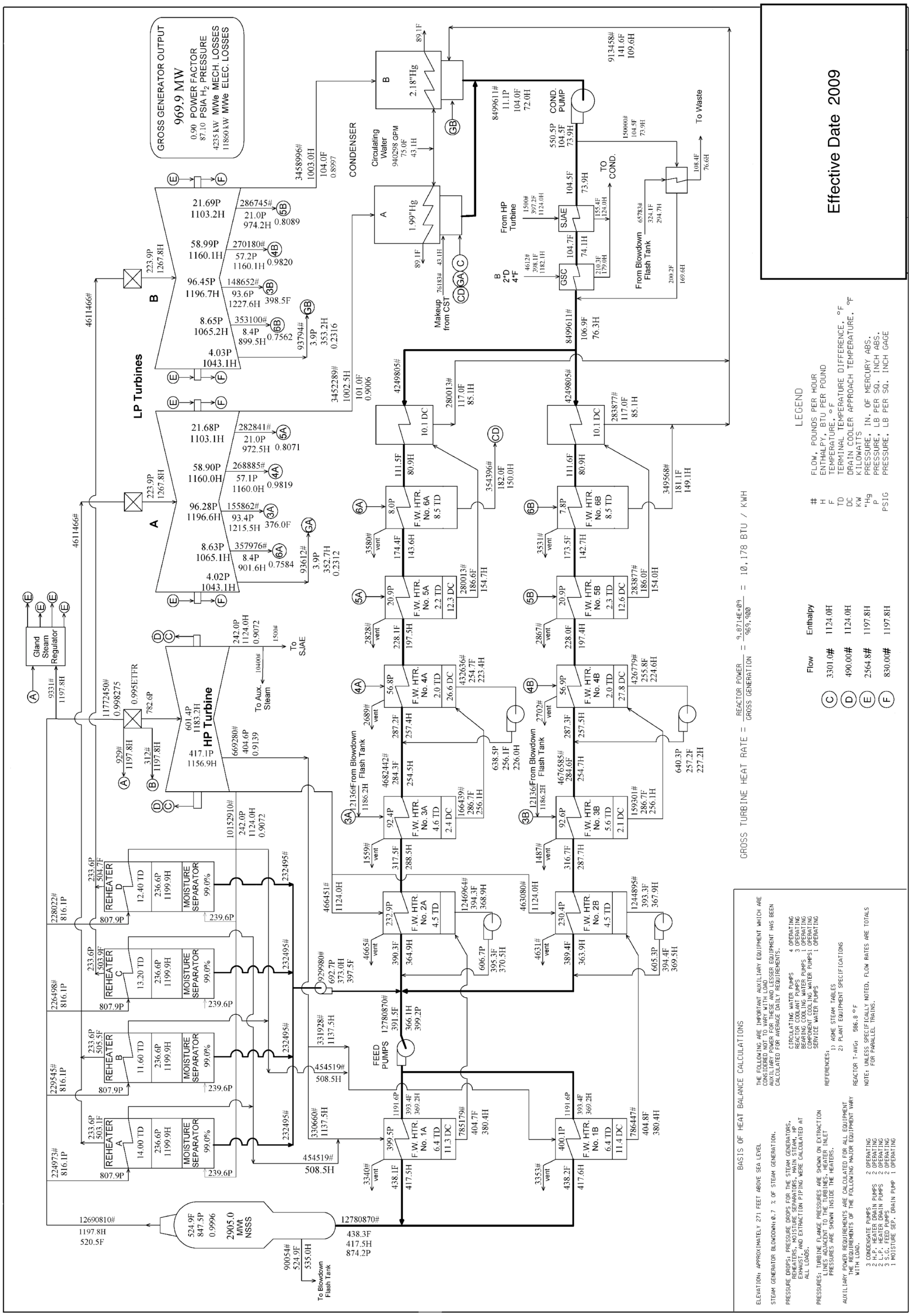


Figure 10.1-2
UNIT 2 HEAT BALANCE DIAGRAM - 2905 MWT LOAD



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10.2 TURBINE GENERATOR

The turbine is a conventional 1800-rpm, tandem-compound unit (Westinghouse Model BB-281), consisting of one double-flow, high-pressure cylinder and two double-flow, low-pressure cylinders. The turbine can achieve a maximum capability of 983,917 kW gross with 11,946,287 lb/hr of steam at inlet conditions of 828 psia and 0.38% moisture exhausting to 2.07 in. Hg abs. The turbine is provided with four moisture separator-reheaters, located between the high-pressure and low-pressure cylinders. Turbine extraction connections supply steam to six stages of feedwater heaters.

Each high-pressure steam line to the high-pressure cylinder contains a stop-trip (throttle) valve and a governor control valve. A stop valve and an intercept valve are provided in the crossover piping between each moisture separator and the low-pressure turbine cylinders.

The nuclear steam supply system is designed to follow turbine load changes not exceeding a 10% step or 5%/minute ramp without a reactor trip.

A gland steam sealing system is provided to prevent air inleakage and steam outleakage along the turbine shaft. The turbine gland steam system consists of a main supply valve that reduces high-pressure steam to 140 psia and supplies gland supply valves that maintain 16 psia at the turbine shaft glands. A high-pressure spillover valve is designed to limit pressure buildup to 21 psia in the gland supply lines to the high-pressure turbine. Higher pressures can be accepted provided that the gland sealing function, i.e. no steam leakage from the glands, is maintained. All necessary piping and controls and a gland steam condenser are provided. Steam condensed in the gland steam condenser is drained to the main condenser. Noncondensibles are removed by an exhauster on the condenser and are discharged to the atmosphere. The radiological evaluation of these releases is discussed in Chapter 11. A failure analysis of the gland steam sealing system is provided in Table 10.2-1.

The turbine control system is of the electrohydraulic type, ensuring rapid speed of response and close control of turbine operation. The control system includes an overspeed protection controller, which acts to hold unit speed in case of a load rejection. If the Overspeed Protection Controller senses an overspeed condition (103%), and the generator is not in parallel with the grid or if electrical output is less than 5%, then the Auxiliary Governor provides a control signal to solenoids in the EHC subsystem which depressurizes the governor valve emergency trip header. This trips the governor and intercept valves closed while the overspeed signal is present in an attempt to limit the overspeed condition and prevent an overspeed trip. Once the turbine speed decreases below 103% of rated speed the solenoids close and the intercept valves start to re-open immediately followed by the governor valves after five seconds. When the generator is in parallel with the grid and electrical output is greater than 5%, the Auxiliary Governor's overspeed function is disabled because this protection is no longer needed. Synchronous generators in parallel must operate at grid frequency and physically can not overspeed.

The valves are then automatically reopened. The protective devices for the turbine include a low bearing oil pressure trip, a solenoid trip, overspeed trips, a thrust bearing trip, and a low vacuum trip. Solenoid trip will be actuated on malfunctions of the steam and power conversion system, such as reactor trip, generator trip, AMSAC initiation, loss of feedwater flow, and loss of electrohydraulic governor power. A solenoid trip can also be actuated manually from the main control room. Nonreturn valves are installed in the turbine extraction steam lines, as required, to minimize turbine overspeed following a trip.

The turbine trip signals are sensed locally at the turbine via three pressure switches in the turbine auto-stop oil system and via limit switches on the four turbine stop valves. The pressure switches send trip signals via channels as do the limit switches on the turbine stop valves to the Westinghouse solid-state logic protection system (see Section 7.2). Should two out of three pressure switches or four out of four limit switches indicate a turbine trip condition, signals will be sent via channels to the redundant Westinghouse cabinets. Two-position, key-lock switches (“normal-trip”) installed locally at the turbine such that if a failure of a pressure switch or limit switch occurred the appropriate channel would be placed in the “trip” position. This is in compliance with the requirements of the Technical Specifications.

Motoring occurs when the steam supply to the turbine is shut off while the generator is still on line. Because there is insufficient steam energy available to overcome the turbine generator losses, the generator will act as a synchronous motor and drive the turbine. Although the condition is generally described as generator motoring, the protection is not for the generator but to prevent overheating the low-pressure turbine of high-pressure turbine blading. This protection consists of one reverse power relay which provides anti-motoring protection for the turbine generator upon loss of the prime mover. Motoring of the generator is annunciated in the Control Room and after forty seconds will initiate a generator and unit trip. Sequential tripping is the inclusion of a second reverse power relay in series with any trip circuits using steam valve closed position switches, turbine trip oil pressure switches or high pressure steam differential switches. The Sequential tripping ensures that the generator has started motoring before the main breakers are allowed to open. A static Basler relay is installed into a separate control circuit and provides a trip input to the following independent lockout relays: stop valve differential, 86V, turbine intercept and reheat valve differential, 86V1, and turbine anti-motoring (timer), TD. These lockout relays will trip the main generator thirty seconds after a motoring condition begins.

The mechanical overspeed trip system will stop the flow of all steam into the turbine, should the speed increase a predetermined amount above normal. The mechanism consists of a trip weight that is carried in a transverse hole in the rotor body, with its center of gravity offset from the axis of rotation, so that centrifugal force tends to move it outward at all times. The trip weight is held in position by a compression spring. If the speed of the turbine increases to a speed above the setpoint, the centrifugal force overcomes the compression of the spring, and the weight moves outward and strikes the trip trigger. This causes the draining of the auto-stop oil and the loss of pressure in the chamber above the diaphragm of the interface emergency trip valve. This opens the valve and drains the operating fluid beneath the hydraulic piston system, closing all valves capable of admitting steam to the turbine.

After the mechanism has tripped, it must be manually reset. It is impossible to reset the trip until the trip weight returns to its normal position (at 2% above normal speed). This trip device can also be tripped manually. The mechanical trip device will function at 111% of rated turbine speed.

The second method of tripping the turbine on overspeed using the auto-stop oil system is provided by the primary speed channel, which receives a continuous turbine speed signal from a variable reluctance transducer mounted at the turbine shaft. The transducer output is a series of pulses whose frequency is proportional to turbine speed. This signal is converted to a precise dc signal with a level proportional to turbine speed. At 111% of turbine speed, this system operates the emergency trip solenoid valve located on the emergency trip control block. The actuation of the emergency trip solenoid valve will cause the auto-stop oil to drain and the opening of the interface emergency trip valve to open, as described above, subsequently closing all valves capable of admitting steam to the turbine.

An auxiliary speed channel provides a separate overspeed trip system, sharing none of the same components as the above-described systems. It receives frequency pulses generated by a separate reluctance pickup and converts them to a proportional analog signal for the control of overspeed. If the Overspeed Protection Controller senses an overspeed condition (103%), and the generator is not in parallel with the grid or if electrical output is less than 5%, the Auxiliary Governor provides a control signal to solenoids in the EHC subsystem which depressurizes the governor valve emergency trip header. This trips the governor and intercept valves closed while the overspeed signal is present in an attempt to limit the overspeed condition and prevent an overspeed trip. Once the turbine speed decreases below 103% of rated speed the solenoids close and the intercept valves start to re-open immediately followed by the governor valves after five seconds. When the generator is in parallel with the grid and electrical output is greater than 5%, then the Auxiliary Governor's overspeed function is disabled because this protection is no longer needed. Synchronous generators in parallel must operate at grid frequency and physically can not overspeed.

Detailed procedures for the turbine overspeed trip system tests can be found in the Westinghouse instruction book for the operation and control of the North Anna Power Station Westinghouse steam turbine. These procedures were part of the North Anna preoperational test program. The frequency of tests below will be increased if operating experience indicates that more frequent testing is advisable:

1. A thorough check of the throttle and governor valve stem freedom will be made once per 184 days, except during end of cycle power coastdown between 835 MWe and 386 MWe when testing of the governor valves may be suspended.

2. A thorough check of the reheat stop and interceptor valve stem freedom will be made once per 18 months.
3. Motor-driven oil pumps and controls will be tested once each month. During normal operation, this procedure involves testing the bearing oil pump pressure switch by reducing the pressure by the use of the bleed-off valve to a point where the switch makes contact, completing the circuit to the ac pump motor. The emergency oil pump pressure switch can be tested by continuing to reduce the pressure to the point where this switch makes contact, thus operating the emergency oil pump. The actual pressure at which each switch operates is compared to the prescribed setting.
4. The following oil trip test devices located at the governor end pedestal will be tested before each turbine start-up:
    a. Overspeed trip oil test device.
    b. Low vacuum trip.
    c. Low bearing oil pressure trip.
    d. Thrust bearing oil trip.
5. The overspeed trip will be tested by overspeeding the turbine-generator unit during each refueling.
6. The auxiliary speed channel trip is checked during normal unit start-up.

A turbine shaft-driven main oil pump normally supplies all lubricating-oil requirements to the turbine-generator unit. An ac motor-driven bearing oil pump is installed for supplying lubricating oil during start-up, shutdown, and turning gear operation. An ac motor-driven bearing lift pump is also provided to supply high-pressure oil to the turbine-generator bearings before shaft rotation to reduce the starting load on the turning gear motor. A dc motor-driven emergency oil pump, operated from the station battery, is also available to ensure lubricating oil to the bearings. Cooling water from the bearing cooling water system (Section 10.4.7) is used for the turbine lube-oil coolers.

A continuous bypass-type lubricating oil system (Section 10.4.5) removes water and other contaminants from the oil. All piping and valves in the lube oil system are of welded steel, and high-pressure bearing oil piping is enclosed in a guard pipe.

The emergency oil pump starts on low bearing oil pressure, which may be the result of the failure of the ac bearing oil pump to start or provide adequate oil pressure. The emergency oil pump is the only lubricating oil pump required to function, as this is the last backup to supply adequate lubrication to allow the turbine generator to coast down to a stop after a trip. Pump operation will be required during a loss of ac power, and possibly during a loss-of-coolant accident. The dc emergency oil pump is tested monthly.

To allow turning gear operation after a loss of off-site power and thereby reduce to a minimum rotor distortion on the cooling of turbine parts, the bearing oil pump, bearing lift pump, and turning gear motor are powered from the emergency bus.

The hydrogen inner-cooled generator is rated at 1,105,000 kVA (Unit 1), 1,200,000 kVA (Unit 2) at 75-psig hydrogen gas pressure, 0.90 power factor, three phase, 60 Hz, 22 kV, 1800 rpm. Generator rating, temperature rise, and insulation class are in accordance with the latest ANSI standards, at the time of manufacture.

Primary protection of the main generator is provided by differential current and field failure relays. Protective relays automatically trip the turbine stop valves and electrically isolate the generator.

A rotating rectifier brushless exciter with a response ratio of 0.5 is provided. The exciter is rated at 4600 kW, 570V dc, 1800 rpm. The exciter consists of an ac alternator coupled directly to the generator rotor. The alternator field winding is stationary, and control of the exciter is applied to this winding. The alternator armature output is rectified by banks of diodes that rotate with the armature. This dc output is carried through a hollow section of the shaft and is applied directly to the main generator field.

The 22-kV generator terminals are connected to the main step-up transformer and the unit station service transformers by means of 22-kV aluminum conductor enclosed in an isolated-phase bus duct. This bus duct is rated 30,500A, cooled by forced air.

Hydrogen-side and air-side ac, motor-driven, seal oil pumps are furnished to provide seal oil for the prevention of hydrogen leakage from the generator. A dc air-side seal oil backup pump, powered from the station battery, is also provided. Backup is also provided from the turbine-generator lubricating oil system from a variety of sources. Backup is normally provided by the main oil pump. During periods of start-up, shutdown, or turning gear operation, backup is provided by an ac motor-driven seal oil backup pump or the bearing oil pump. During a loss-of-station-power incident, seal oil is provided by the dc air-side seal oil backup pump, and backup is provided by the dc emergency oil pump.

A malfunction of the main generator hydrogen system will not result in an explosion. Since a mixture of hydrogen and air is explosive over a wide range of proportions (from about 4% to 70% hydrogen by volume), the design of the generator and the specified operating procedures are such that explosive mixtures are not possible under normal operating conditions. To provide for some unforeseen condition brought about by the failure to follow the correct operating procedure, it has been deemed necessary to design the frame to be explosion-safe. The intensity of an explosion of a mixture of air and hydrogen varies with the proportion of the two gases present. A curve on which the values of intensity are plotted against the proportions of gases will approximate a sine wave, having zero values at 5% and 70% hydrogen and reaching a maximum intensity at a point halfway between these limits. The term “explosion-safe” referred to earlier is intended to mean that the frame will withstand an explosion of this most explosive proportion of hydrogen and air at a nominal gas pressure of 2 or 3 psig without damage to life or property external to the machine. This nominal pressure of 2 or 3 psig is that which might be obtained if hydrogen were accidentally admitted during the purging operation instead of carbon dioxide, as specified. Such an explosion might, however, result in damage or dislocation of internal parts of the generator.

When changing from one gas to another, the generator is vented to the atmosphere so that a positive pressure of more than 2 or 3 psig will not be built up. It is necessary in fixing the design features and operating procedure of hydrogen-cooled turbine generators to follow conservative and safe practices. The four principal requirements of the hydrogen gas control and alarm system are determined by the "running," "standstill," "gas filling," and "gas scavenging" conditions. In filling or scavenging the generator housing with gas, it is necessary to use an inert gas such as carbon dioxide to make the displacement so that there will not be any mixing of hydrogen and air. It is, of course, the oxygen in the air that represents the potential hazard in conjunction with hydrogen. The primary functions of the hydrogen gas control and alarm system equipment are to provide for scavenging and filling the generator housing with gas, to maintain the gas in the generator housing within predetermined limits of purity, pressure, and temperature, to maintain the gas in a moisture-free condition, and to give warning of improper operation of the generator or failure of the gas control and alarm system.

10.2.1 Turbine Missiles

Postulated turbine missiles have been evaluated by considering the probabilities of missile generation and of impact to safety-related items.

The probability (P4) of damage to plant structures, systems, and components important to safety is:

$$P4 = P1 \times P2 \times P3 \tag{10.2-1}$$

where:

P1 = the probability of generation and ejection of a high-energy missile

P2 = the probability that a missile strikes a critical plant region, given its generation and ejection

P3 = the probability that the missile strike damages its target in a manner leading to unacceptable consequences. Unacceptable consequences are defined here as the loss of the capacity to shut down the plant, maintain it in a safe-shutdown condition, and/or limit offsite radiation exposures.

10.2.1.1 **Probability of Generation and Ejection (P1)**

A turbine missile can be caused by brittle fracture of a rotating turbine part at or near turbine operating speed, or by ductile fracture upon runaway after extensive, highly improbable, control system failures. The calculation of this probability (P1) is the responsibility of Westinghouse. Turbine operating speed and two overspeed conditions, 120% and 190% of rated speed, have been used by Westinghouse in the calculation of this probability (P1). The resulting missile generation probabilities are provided in References 1, 2, and 3.

Additional information on P1 is provided in References 4, 5, and 6.

10.2.1.1.1 Effect of Extending Reheat Stop and Intercept Valve Test Interval

Westinghouse performed an evaluation of the effects of extending the test interval of the reheat stop and intercept valves to 18 months at North Anna Power Station (Reference 12) using fault free models and methodology from the Westinghouse report WCAP-11525 (Reference 13). The NRC staff accepted the methodology of WCAP-11525 for use in determining the probability of turbine missile generation in a supplemental safety evaluation issued under a cover letter dated November 2, 1989.

The Westinghouse evaluation (Reference 12) was performed to determine the turbine missile ejection probability resulting from an extension of reheat stop and intercept valve test intervals. Based upon the results of the evaluation, it was determined that the total turbine missile generation probability meets applicable acceptance criteria with an 18-month reheat stop and intercept valve test interval.

10.2.1.1.2 Effect of Extending Main Turbine Throttle and Governor Valve Test Interval

Westinghouse performed an evaluation of the effects of extending the test interval of the turbine throttle and governor valves to 6 months at North Anna Power Station (Reference 15) using fault free models and methodology from the Westinghouse report WCAP-11525 (Reference 13). The NRC staff accepted the methodology of WCAP-11525 for use in determining the probability of turbine missile generation in a supplemental safety evaluation issued under a cover letter dated November 2, 1989.

The Westinghouse evaluation (Reference 15) was performed to determine the turbine missile ejection probability resulting from an extension of turbine throttle and governor valve test intervals. This is consistent with the approach used in WCAP-14732 (Reference 14). Based upon the results of the evaluation, it was determined that the total turbine missile generation probability meets applicable acceptance criteria with a semi-annual turbine throttle and governor valve test interval.

10.2.1.2 **Probability of Missile Strike (P2)**

In the event of missile ejection, the probability of a strike on a plant region (P2) is a function of the energy and direction of an ejected missile and of the orientation of the turbine with respect to the plant region. The orientation of the turbine is shown on the plot plan, Reference Drawing 1. The energy, physical properties, and range of ejection angles associated with each postulated missile are provided by Westinghouse (References 7 & 8).

The selection of plant regions as targets was limited to those areas containing systems essential to shut down the plant, maintain it in a safe-shutdown condition, and/or limit offsite radiation exposures. The set of selected targets was further reduced to exclude those protected by redundancy (see Section 10.2.1.5). Those target areas included in the probability calculation are listed below and further defined in Figures 10.2-1 and 10.2-2:

1. Reactor containment.
2. Main steam valve area.
3. Control room.
4. Relay room.
5. Auxiliary building.
6. Fuel building (portions only).
7. Cable vault.
8. Cable tunnel.
9. Fuel-oil pump house and tanks.
10. Decay tanks - waste gas.
11. Condensate storage tank.
12. Auxiliary feedwater pipe tunnel.

The probability of striking a particular region is calculated by using a solid-angle approach as follows. The turbine spins about the z-axis of the reference system shown in Figure 10.2-3. A postulated missile is thrown from the turbine with initial velocity V_o as shown. The variable angles required to describe the resulting motion are displayed in Figure 10.2-3. Deflection angles δ_1 and δ_2, provided by Westinghouse, limit θ to the range:

$$\frac{\pi}{2} - \delta_1 \leq \theta \leq \frac{\pi}{2} + \delta_2$$

The probability that a single disk fragment strikes a critical area A_o is defined as:

$$P(A_o) = \int_{\Omega_o} f(\Omega)\, d\,\Omega \qquad (10.2\text{-}2)$$

where:

Ω_o = the solid angle that must be subtended by the initial velocity vector for a missile to strike A_o

$d\Omega$ = the differential solid angle, and

$f(\Omega)$ = the probability density function

From Figure 10.2-3,

$$d\Omega = \cos\phi \; d\phi \; d\psi \tag{10.2-3}$$

Given V_o, the elevation angle ϕ necessary to hit any point on A_o (described by r, y, and ψ in Figure 10.2-3) is determined from classical trajectory theory as:

(10.2-4)

$$\phi = \left[\frac{1 \pm \left[1 - \left(rg/v_o^2\right)^2 - 2\left(yg/v_o^2\right)\right]^{1/2}}{\left(rg/v_o^2\right)}\right]$$

In Equation 10.2-4, air resistance is neglected and the ± refers to high- and low-trajectory missiles, respectively.

The probability density function $f(\Omega)$ is determined by assuming:

$f(\Omega)$ = constant = f_o for $0 \le \beta \le 2\pi$ and $\pi/2 - \delta_1 \le \theta \le \pi/2 + \delta_2$

$f(\Omega)$ = 0, for all other θ

From probability theory it is required that:

$$\int_{all\,\Omega} f(\Omega) d\Omega = 1$$

Therefore,

$$f_o = \frac{1}{2\pi(\sin\delta_1 + \sin\delta_2)} \tag{10.2-5}$$

The probability that n disk fragments strike a critical area A_o is, then:

$$P2\ (A_o) = \frac{n}{2\pi(\sin\delta_1 + \sin\delta_2)}\ \Omega_o \int d\,\Omega \tag{10.2-6}$$

A computer program has been developed to calculate the strike probability using Equation 10.2-6. Following Bush (Reference 9), the analysis considers high- trajectory hits on the tops of critical targets and low-trajectory hits on the sides of critical targets. Figures 10.2-4 and 10.2-5 represent the top and side views of an idealized target. The strike probability of the target is found by numerically integrating Equation 10.2-6, which gives:

$$P2 = \frac{n}{2\pi(\sin\delta_1 + \sin\delta_2)} \sum_{i=1}^{n_\psi} (\cos\phi_i)(\Delta\phi_i)\Delta\psi \tag{10.2-7}$$

for:

$\pi/2 - \delta_1 \leq \theta_i \leq \pi/2 + \delta_2$

and:

$P2 = 0$

for:

$0 \leq \theta_i < (\pi/2 - \delta_1),\ (\pi/2 + \delta_2) < \theta_i \leq \pi$

where

$\theta_i = \cos^{-1}(\cos\phi_i \cos\psi_i)$

n_ψ = number of ground angle increments taken through the target

From Figures 10.2-4 and 10.2-5,

$$\Delta\Psi = \frac{\Psi_{max} - \Psi_{min}}{n_\Psi} \tag{10.2-8}$$

$$\psi_i = \psi_{min} + (i - 1/2)\Delta\psi \tag{10.2-9}$$

$$\Delta\phi_i = \left|\phi_2^i - \phi_1^i\right| \tag{10.2-10}$$

$$\phi_i = \frac{1}{2}\left(\phi_1^i + \phi_2^i\right) \tag{10.2-11}$$

Equation 10.2-4 is used to determine ϕ_1^i and ϕ_2^i. The low- and high-trajectory probabilities are calculated separately and added to obtain the final probability.

10.2.1.3 **Probability of Damage (P3)**

The probability (P3) is a function of the energy of the missile, its angle of impact on the affected structure, and the ability of that structure to prevent unacceptable damage to the essential systems it protects. The following criteria are used:

1. For unprotected systems, a strike is considered unacceptable (P3 = 1.0).
2. For systems protected by a steel-lined concrete barrier:
   a. The target is modeled as a discrete area in both the horizontal and vertical plane. The target size is based on the projected area of all essential systems within the cubicle determined by estimating the fraction of the total area occupied by these systems.
   b. If a missile can perforate the concrete barrier and strike the target, it is considered unacceptable. The perforation protection of the liner is neglected to provide conservatism.
   c. The conservative modified National Defense Research Council (NDRC) perforation formula (Reference 10) is used.

   (This portion of the analysis was completed before the publication of Reference 10 and, since the use of this equation is conservative, it was not revised to use the more accurate CEA-EDF formula.)
3. For systems protected by an unlined concrete barrier:
   a. The entire cubicle area is modeled as a target.
   b. The CEA-EDF perforation formula (Reference 10) is used to establish perforation potential of each missile. If a missile perforates the final barrier, damage probability (P3) is considered as 1.0.
   c. If a missile does not perforate but produces backface scabbing, the damage probability (P3) is considered to be some intermediate value between 0.0 and 1.0. The actual calculation of damage potential due to scabbing is nearly impossible, especially since there is the possibility of numerous scabbing fragments of various energies. However, since the total kinetic energy of all scabbed material is only 1% to 2% of the striking missile's energy, it is reasonable to use a value on the low end of this range.

To allow flexibility in the damage probability associated with backface scabbing, the following approach was used. An analysis using the probability equation described earlier was performed twice using two different criteria for unacceptable missile damage due to backface scabbing.

1. Criterion A: Uses the conservative modified National Defense Research Council (NDRC) formula for scabbing (Reference 10), and the extreme position that the initiation of scabbing constitutes a damage potential of 1.0.
2. Criterion B: Uses the other extreme position that the damage potential of scabbing fragments resulting from nonperforating impacts is 0.0.

By using the results of these two extreme analyses, the total probability for any intermediate scabbing damage probability value (P_S) can be calculated.

$$\text{Total Probability} = \text{Prob. B} + P_S\,(\text{Prob. A} - \text{Prob. B})$$

The probability P_S is the sum of the damage probabilities for each of the scabbing fragments. Since these fragments are not very energetic, the number of essential components endangered is not great, so the best-estimate total probability is likely closer to criterion B than to criterion A.

10.2.1.4 **Assumptions Used for North Anna Turbine Evaluations**

1. The failure of a disk from the low-pressure hood is assumed to create three or four equal segments with the properties defined in References 7 and 8. The probability of generating either 90-degree or 120-degree segments is assumed to be equal.
2. The only targets of high-trajectory missiles are the roofs of structures, and the only targets of low-trajectory missiles are the walls of structures. (Since the containment dome has a projected area in both plan and elevation views, it is a target for both types of missiles.)
3. Interior disks (disks 1 through 4) may have trajectories up to 5 degrees off the plane of rotation. End disks (disk 5) may have trajectories from 5 degrees to 25 degrees off the plane of rotation, but only in the direction of the hood end.
4. For the purpose of calculating strike probabilities, the missile is assumed to be a point object.
5. The origin of interior disk missiles is located at the center of the hood, and the origins of the end disk missiles are assumed to be 6 ft. to either side of the hood center.
6. If a missile perforates a barrier, it is assumed to follow the same trajectory it had before striking the barrier, but the kinetic energy is reduced (i.e., the barrier is not a scattering source). If the missile does not perforate a barrier, ricochets are not considered.
7. In a barrier perforation analysis, only the velocity normal to the barrier surface is relevant.
8. The selection of targets assumed that no earthquake or pipe rupture occurs concurrently with the postulated failure of the turbine.

9. The column 9 line as shown on the site plan, Reference Drawing 1, is the divider between Units 1 and 2.
10. For the destructive overspeed case, it is assumed that the failure rate of any one of the 20 low-pressure turbine disks is 1/20 of the total.
11. It is assumed that for every fragment created by a low-pressure disk failure, there will be corresponding cylinder and blade ring fragments as detailed in References 7 and 8.
12. When using the modified NDRC formula for calculating missile perforation, it is sufficient to use the average missile "diameter," since the perforation equation is reasonably insensitive to this parameter in the normal range of turbine missile diameters.

10.2.1.5 **Targets Eliminated Based on Redundancy**

Standard Review Plan (SRP) Section 3.5.1.3, *Turbine Missiles*, provides the following position on redundancy.

> Adequate protection will also be identified with targets which are redundant and sufficiently independent (e.g., by separation distance, barriers) such that a turbine failure could not comprise two or more members of a redundant train.

This position was employed in the North Anna systems review to eliminate the following essential systems as potential targets of turbine missiles:

1. Emergency diesel generators
   a. Protected from low-trajectory missiles by the turbine pedestal.
   b. Only one of the two diesel generators provided for each unit is required to meet all safety requirements.
   c. A vertical concrete wall separates each diesel generator and provides adequate protection against multiple failures or secondary missiles due to a single high-trajectory missile.
2. Service water system and auxiliary service water system

   These two systems exit the service building at 180 degrees to each other and are both independent and redundant. Either system acting alone can handle all safety-related service water requirements.

10.2.1.6 Intermediate Barriers

In addition to the protection provided by the structures housing essential systems, the following intermediate structures and components were evaluated for their shielding potential.

1. *Turbine Support Pedestal*: The turbine support consists of 8 feet of reinforced concrete in the area of the low-pressure hoods. This barrier was judged adequate to stop all turbine missiles, thereby making it impossible for any missile ejected below the horizontal to present a hazard. They are either directed into the turbine support or more sharply downward where there are no essential systems.
2. *Turbine Room Floor*: This floor acts as a deflecting shield for those missiles ejected within 1 or 2 degrees of horizontal. These missiles will slide along the operating floor but will not perforate it because of the extremely shallow angle of impact.
3. *Moisture Separators*: The moisture separators are close to the turbine and must be penetrated by some postulated low-trajectory missiles. These separators will stop some missiles and significantly reduce the kinetic energy of others. The following method is used to evaluate missiles striking the moisture separators:
   a. The Ballistic Research Laboratory (BRL) formula (Reference 11) is used to define the required perforation energy. This energy is assumed equal to twice the energy required to perforate the 1.25-inch-thick shell of the moisture separator (i.e., perforation must occur on entering and exiting).
   b. If the striking missile's energy exceeds that required for perforation, it is assumed to continue on its original path with its energy reduced by an amount equal to its perforation energy from step (a).

10.2.1.7 Overall Probability Calculation

Turbine missile information provided by Westinghouse (References 1-3, 7, & 8) was applied to the two units shown in Reference Drawing 1 using the previously detailed procedure. The resulting total damage probability (P4) for each unit/trajectory case is summarized in the tables as follows:

1. Table 10.2-2: Gives breakdown of total damage probability (P4) associated with each postulated failure speed for 1 year of continuous operation using criterion A.[1]
2. Table 10.2-3: Gives breakdown of total damage probability (P4) associated with each postulated failure speed for 1 year of continuous operation using criterion B.[1]
3. Table 10.2-4: Gives breakdown of total damage probability (P4) associated with each postulated failure speed for 2 years of continuous operation using criterion A.[1]

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1. Criteria A and B, as used in Tables 10.2-2 through 10.2-5, are discussed in Section 10.2.1.3. Criterion A is the present conservative NRC approach that equates the initiation of scabbing within a safety-related cubicle with a damage probability of 1.0, and criterion B neglects scabbing damage if missile perforation is presented.

4. Table 10.2-5: Gives breakdown of total damage probability (P4) associated with each postulated failure speed for 2 years of continuous operation using criterion B.[2]
5. Table 10.2-6: This table combines the results of Tables 10.2-2 through 10.2-5 with two possible realistic scabbing damage probabilities (P3S) of 0.05 and 0.10. P3S is the probability for ensuing damage to safety-related equipment if a missile strike results in scabbing without perforation.
6. Table 10.2-7: This table contains a listing of the critical plant regions for the Unit 1 turbine for the postulated high- and low- trajectory missiles.
7. Table 10.2-8: Same as Table 10.2-7 for the Unit 2 turbine.

10.2.1.8 **Conclusion**

The following conclusion can be made from the values given in Table 10.2-6 and the use of Westinghouse Turbine Disk Inspection Criteria (deterministic) for operating reactors. The probability (P4) of significant damage to critical plant regions due to a postulated turbine failure is sufficiently low that design changes of the plant against turbine missile effects need not be considered.

Vepco will inspect the turbine disk for cracking by performing an ultrasonic inspection on the low-pressure turbine at North Anna Units 1 and 2 on a schedule calculated by Reference 6. Vepco will base its inspection intervals on the disk that gives the shortest interval for the unit involved, regardless of whether or not that disk would be contained by the casing, in the event of a turbine missile generation.

10.2 REFERENCES

1. Westinghouse Electric Corporation, *Analysis of the Probability of the Generation and Strike of Missiles from a Nuclear Turbine*, 1974.
2. Westinghouse Electric Corporation, *Results of Probability Analyses of Disc Rupture and Missile Generation, North Anna 2*, CT-24860, Revision 1, 1981.
3. Westinghouse Electric Corporation, *Results of Probability Analyses of Disc Rupture and Missile Generation, North Anna 1*, CT-24822, Revision 1, 1981.
4. Westinghouse Electric Corporation, *Procedures for Estimating the Probability of Steam Turbine Disc Rupture from Stress Corrosion Cracking*, WSTG-1-NP, 1981.
5. Westinghouse Electric Corporation, *Missile Energy Analysis Methods for Nuclear Steam Turbines*, WSTG-2-NP, 1981.

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2. Criteria A and B, as used in Tables 10.2-2 through 10.2-5, are discussed in Section 10.2.1.3. Criterion A is the present conservative NRC approach that equates the initiation of scabbing within a safety-related cubicle with a damage probability of 1.0, and criterion B neglects scabbing damage if missile perforation is presented.

6. Westinghouse Electric Corporation, *Criteria for Low Pressure Nuclear Turbine Disc Inspection* (Westinghouse proprietary), 1981.
7. Westinghouse Electric Corporation, *Turbine Missile Report, North Anna 1*, CT-24821, 1980.
8. Westinghouse Electric Corporation, *Turbine Missile Report, North Anna 2*, CT-24859, 1980.
9. S. H. Bush, *Probability of Damage to Nuclear Components Due to Turbine Failures*, Nuclear Safety, Vol. 14, No. 3, 1973.
10. G. E. Sliter, *Assessment of Empirical Concrete Impact Formulas*, Journal of Structural Division, May 1980.
11. Department of the Army, *Fundamentals of Protection Design*, TM-5-855-1, July 1965.
12. Westinghouse Electric Corporation evaluation report, *Evaluation of Turbine Missile Ejection Probability Resulting from Extending the Test Interval of Interceptor and Reheat Stop Valves at North Anna Units 1 and 2*, dated December 1994.
13. Westinghouse Electric Corporation report, WCAP-11525, *Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency*, dated June 1987.
14. Westinghouse Electric Corporation, WCAP-14732, *Probabilistic Analysis of Reduction in Turbine Valve Test Frequency for Nuclear Plants with Westinghouse BB-296 Turbines with Steam Chests,* dated September 1996.
15. Westinghouse Electric Corporation, WCAP-16501-P, *Extension of Turbine Valve Test Frequency Up to 6 Months for BB-296 Siemens Power Generation (Westinghouse) Turbines with Steam Chests,* Revision 0, dated February 2006.

10.2 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11715-FY-1A	Plot Plan, Units 1 & 2
2.	11715-FM-4D	Machine Location: Turbine Area, Sections, Sheet 1

Table 10.2-1
FAILURE ANALYSIS OF GLAND STEAM SEAL SYSTEM COMPONENTS

Component	Malfunction	Remarks
Main supply valve	Failure of diaphragm or air supply	Valve opens. The pressure in the header system increases to 300 psig, at which point the safety valve would open, limiting the maximum pressure buildup to 485 psig. The gland supply valves and the high-pressure spillover valve would continue to maintain the prescribed pressure at each gland. A pressure transmitter and motor-operated bypass and isolation valves are provided to permit manual or remote correction of this situation. No adverse effect is anticipated.
Gland supply valve	Failure of diaphragm or air supply	Valve opens. These valves are sized so that when they are fully open and with 140-psia steam pressure maintained in the supply header, the pressure in the gland case will only increase to 21 psia. This condition will not cause any steam leakage to the atmosphere since the gland suction piping is sized to accommodate the resulting leakage. No adverse effect is anticipated.
High-pressure spillover valve	Failure of diaphragm or air supply	Valve closes. If the failure should happen at starting or at low loads, the pressure in the gland will increase, but the gland will continue to function properly. If failure occurs at a turbine load point in excess of 10% to 15%, the glands will leak steam to the turbine building atmosphere At high loads, the pressure in the gland header will increase to a point that will result in the opening of a safety valve. A pressure transmitter and motor-operated shutoff and bypass valves are supplied for manual or remote control in the event of this failure. The effects and consequences of this occurrence are the same as discussed in Section 15.3.2 for minor secondary pipe breaks.

Table 10.2-1 (continued)
FAILURE ANALYSIS OF GLAND STEAM SEAL SYSTEM COMPONENTS

Component	Malfunction	Remarks
Steam supply pressure	Supply line rupture	Steam would be released to the turbine building. Loss of supply steam would also cause eventual loss of vacuum and subsequent turbine trip. The consequences of a break in the supply line to the gland seal system are discussed in Section 15.3.2. A supply line break would be indicated in the main control room by a pressure indicator. A loss of supply steam causes eventual loss of condenser vacuum and subsequent turbine trip, which is discussed in Section 15.2.7.

Table 10.2-2
TOTAL DAMAGE PROBABILITY FOR 1 YEAR OF CONTINUOUS OPERATION USING CRITERION A

Unit Trajectory	Percentage of Rated Speed 100	120	191	Total
		Unit 1		
Low trajectory	2.33×10^{-7}	4.002×10^{-9}	5.710×10^{-7}	8.080×10^{-7}
High trajectory				
Due to Unit 1 turbine	1.446×10^{-7}	8.855×10^{-10}	5.595×10^{-8}	
Due to Unit 2 turbine	6.978×10^{-9}	2.085×10^{-10}	2.447×10^{-9}	
Total high trajectory	1.516×10^{-7}	1.094×10^{-9}	5.84×10^{-8}	2.111×10^{-7}
		Unit 2		
Low trajectory	1.90×10^{-7}	3.293×10^{-9}	5.579×10^{-7}	7.514×10^{-7}
High trajectory				
Due to Unit 1 turbine	1.257×10^{-8}	2.349×10^{-10}	2.326×10^{-9}	
Due to Unit 2 turbine	7.224×10^{-8}	9.002×10^{-10}	2.793×10^{-8}	
Total high trajectory	8.481×10^{-8}	1.135×10^{-9}	3.026×10^{-8}	1.162×10^{-7}

Note: P1 values from References 1, 2, and 3.

Table 10.2-3
TOTAL DAMAGE PROBABILITY FOR 1 YEAR OF
CONTINUOUS OPERATION USING CRITERION B

	Percentage of Rated Speed			
Unit Trajectory	100	120	191	Total
		Unit 1		
Low trajectory	1.937×10^{-14}	4.835×10^{-15}	4.763×10^{-7}	4.763×10^{-7}
High trajectory				
Due to Unit 1 turbine	1.197×10^{-9}	9.744×10^{-11}	1.588×10^{-9}	
Due to Unit 2 turbine	2.861×10^{-10}	7.128×10^{-11}	1.641×10^{-9}	
Total high trajectory	1.483×10^{-9}	1.687×10^{-10}	3.229×10^{-9}	4.881×10^{-9}
		Unit 2		
Low trajectory	1.026×10^{-11}	6.8322×10^{-13}	4.686×10^{-7}	4.686×10^{-7}
High trajectory				
Due to Unit 1 turbine	2.617×10^{-9}	8.705×10^{-11}	1.243×10^{-9}	
Due to Unit 2 turbine	4.867×10^{-9}	1.258×10^{-10}	1.841×10^{-9}	
Total high trajectory	7.484×10^{-9}	2.128×10^{-10}	3.084×10^{-9}	1.078×10^{-8}

Note: P1 values from References 1, 2, and 3.

Table 10.2-4
TOTAL DAMAGE PROBABILITY FOR 2 YEARS OF CONTINUOUS OPERATION USING CRITERION A

Unit Trajectory	Percentage of Rated Speed: 100	120	191	Total
		Unit 1		
Low trajectory	1.26×10^{-5}	1.619×10^{-7}	1.142×10^{-6}	1.390×10^{-5}
High trajectory				
Due to Unit 1 turbine	8.225×10^{-6}	3.720×10^{-8}	1.119×10^{-7}	
Due to Unit 2 turbine	3.493×10^{-7}	8.603×10^{-9}	4.894×10^{-9}	
Total high trajectory	8.574×10^{-6}	4.580×10^{-8}	1.168×10^{-7}	8.737×10^{-6}
		Unit 2		
Low trajectory	1.086×10^{-5}	1.384×10^{-7}	1.116×10^{-6}	1.211×10^{-5}
High trajectory				
Due to Unit 1 turbine	7.348×10^{-7}	1.004×10^{-8}	4.652×10^{-9}	
Due to Unit 2 turbine	4.010×10^{-6}	3.715×10^{-8}	5.586×10^{-8}	
Total high trajectory	4.745×10^{-6}	4.719×10^{-8}	6.051×10^{-8}	4.853×10^{-6}

Note: P1 values from References 1, 2, and 3.

Table 10.2-5
TOTAL DAMAGE PROBABILITY FOR 2 YEARS OF CONTINUOUS OPERATION USING CRITERION B

Unit Trajectory	Percentage of Rated Speed 100	120	191	Total
		Unit 1		
Low trajectory	1.686×10^{-11}	3.166×10^{-12}	9.526×10^{-7}	9.560×10^{-7}
High trajectory				
Due to Unit 1 turbine	7.036×10^{-8}	4.084×10^{-9}	3.176×10^{-9}	
Due to Unit 2 turbine	1.632×10^{-8}	2.936×10^{-9}	3.282×10^{-9}	
Total high trajectory	8.668×10^{-8}	7.020×10^{-9}	6.458×10^{-9}	1.002×10^{-7}
		Unit 2		
Low trajectory	2.415×10^{-9}	1.047×10^{-10}	9.372×10^{-7}	9.397×10^{-7}
High trajectory				
Due to Unit 1 turbine	1.528×10^{-7}	3.687×10^{-9}	2.486×10^{-9}	
Due to Unit 2 turbine	2.730×10^{-7}	5.167×10^{-9}	3.684×10^{-9}	
Total high trajectory	4.258×10^{-7}	8.854×10^{-9}	6.170×10^{-9}	4.408×10^{-7}

Note: P1 values from References 1, 2, and 3.

Table 10.2-6
TOTAL PROBABILITY FOR EACH UNIT-TRAJECTORY CASE

	P3S = 5%			P3S = 10%	
	1 Year[a]	2 Year[a]	3 Year[a]	1 Year[a]	2 Year[a]
Unit 1					
High trajectory	1.519×10^{-8}	5.320×10^{-7}	3.746×10^{-6}	2.550×10^{-8}	9.639×10^{-7}
Low trajectory	4.929×10^{-7}	1.600×10^{-8}	5.883×10^{-6}	5.095×10^{-7}	2.247×10^{-6}
Unit 2					
High trajectory	1.605×10^{-8}	6.614×10^{-7}	3.574×10^{-6}	2.132×10^{-8}	8.820×10^{-7}
Low trajectory	4.827×10^{-7}	1.498×10^{-6}	5.378×10^{-6}	4.969×10^{-7}	2.057×10^{-6}

a. Inspection interval based on actual operating hours assuming the inspection intervals for both units coincide.

Table 10.2-7
TURBINE TARGET DISTANCES AND IMPACT AREAS - UNIT 1 TURBINE

		Low-Pressure Hood 1		Low-Pressure Hood 2		
Critical Plant Region	Impact Area (ft^2)	r min. (ft)	r max. (ft)	r min. (ft)	r max. (ft)	Y (ft)
High-trajectory missiles						
Reactor containment, Unit 1	11,457	202	303	204	335	36
Reactor containment, Unit 2	11,457	321	452	295	426	36
Main steam valve house, Unit 1	1546	169	706	119	205	22
Main steam valve house, Unit 2	1546	304	362	273	331	22
Fuel building	1899	297	359	282	339	-15
Auxiliary feedwater pump house, Unit 1	2241	260	335	276	350	-20
Auxiliary feedwater pump house, Unit 2	2241	449	511	418	482	-20
Auxiliary building	6259	171	335	154	312	12
Fuel-oil pump house and tanks	3144	557	630	535	609	-30
Gaseous waste decay tanks	688	328	364	318	352	-35
Auxiliary feedwater pipe tunnel, Unit 1	770	190	258	207	270	-35
Auxiliary feedwater pipe tunnel, Unit 2	770	398	438	365	408	−35
Cable tunnel, Unit 1	871	147	194	144	187	-33
Cable tunnel, Unit 2	871	273	314	242	284	-33
Cable vault, Unit 1	1500	186	245	189	253	-8
Cable vault, Unit 2	1500	269	302	298	325	-8
Control room and emergency switchgear/relay room	17,702	75	261	75	293	-13

Notes:
1. All r values are taken from the center of the low-pressure hood.
2. Refer to Figure 10.2-3 for the definitions of r and y.
3. "Min." and "max." refer to minimum and maximum distances, respectively.

Table 10.2-7 (continued)
TURBINE TARGET DISTANCES AND IMPACT AREAS - UNIT 1 TURBINE

Critical Plant Region	Impact Area (ft^2)	LP1 r (ft)	LP2 r (ft)	Y min. (ft)	Y max. (ft)
Low-trajectory missiles					
Reactor containment, Unit 1	9185	200	200	-6	80
Reactor containment, Unit 2	9185	--	--	--	--
Main steam valve house, Unit 1	1825	169	169	-17	22
Main steam valve house, Unit 2	1825	--	--	--	--
Condensate storage tank, Unit 1	1000	317	331	-33	-2
Condensate storage tank, Unit 2	1000	--	--	--	--
Ventilation in auxiliary building	146	--	198	-14	19

Notes:
1. All r values are taken from the center of the low-pressure hood.
2. Refer to Figure 10.2-3 for the definitions of r and y.
3. “Min.” and “max.” refer to minimum and maximum distances, respectively.

Table 10.2-8
TURBINE TARGET DISTANCES AND IMPACT AREAS - UNIT 2 TURBINE

		Low-Pressure Hood 1		Low-Pressure Hood 2		
Critical Plant Region	Impact Area (ft^2)	r min. (ft)	r max. (ft)	r min. (ft)	r max. (ft)	Y (ft)
High-trajectory missiles						
Reactor containment, Unit 1	11,457	310	441	337	468	36
Reactor containment, Unit 2	11,457	202	333	204	335	36
Main steam valve house, Unit 1	1546	290	349	322	380	22
Main steam valve house, Unit 2	1546	169	204	169	210	22
Fuel building	1899	282	326	293	343	-15
Auxiliary feedwater pump house, Unit 1	2241	436	498	468	528	-20
Auxiliary feedwater pump house, Unit 2	2241	266	341	253	328	-20
Auxiliary building	6259	163	325	184	349	12
Fuel-oil pump house and tanks	3144	450	521	446	516	-30
Gaseous waste decay tanks	688	338	374	355	392	-35
Auxiliary feedwater pipe tunnel, Unit 1	770	381	419	415	450	-35
Auxiliary feedwater pipe tunnel, Unit 2	770	196	267	182	257	−35
Cable tunnel, Unit 1	871	260	285	292	315	-33
Cable tunnel, Unit 2	871	145	190	154	201	-33
Cable vault, Unit 1	1500	285	315	315	340	-8
Cable vault, Unit 2	1500	187	249	194	259	-8
Control room and emergency switchgear/relay room	17,702	81	334	101	369	-13

Notes:
1. All r values are taken from the center of the low-pressure hood.
2. Refer to Figure 10.2-3 for the definitions of r and y.
3. “Min.” and “max.” refer to minimum and maximum distances, respectively.

Table 10.2-8 (continued)
TURBINE TARGET DISTANCES AND IMPACT AREAS - UNIT 2 TURBINE

Critical Plant Region	Impact Area (ft^2)	LP1 r (ft)	LP2 r (ft)	Y min. (ft)	Y max. (ft)
Low-trajectory missiles					
Reactor containment, Unit 1	9185	--	--	--	--
Reactor containment, Unit 2	9185	200	200	-6	80
Main steam valve house, Unit 1	1825	--	--	--	--
Main steam valve house, Unit 2	1825	169	169	-17	22
Condensate storage tank, Unit 1	1000	--	--	--	--
Condensate storage tank, Unit 2	1000	322	310	-32	-2
Ventilation in auxiliary building	146	--	--	--	--

Notes:
1. All r values are taken from the center of the low-pressure hood.
2. Refer to Figure 10.2-3 for the definitions of r and y.
3. “Min.” and “max.” refer to minimum and maximum distances, respectively.

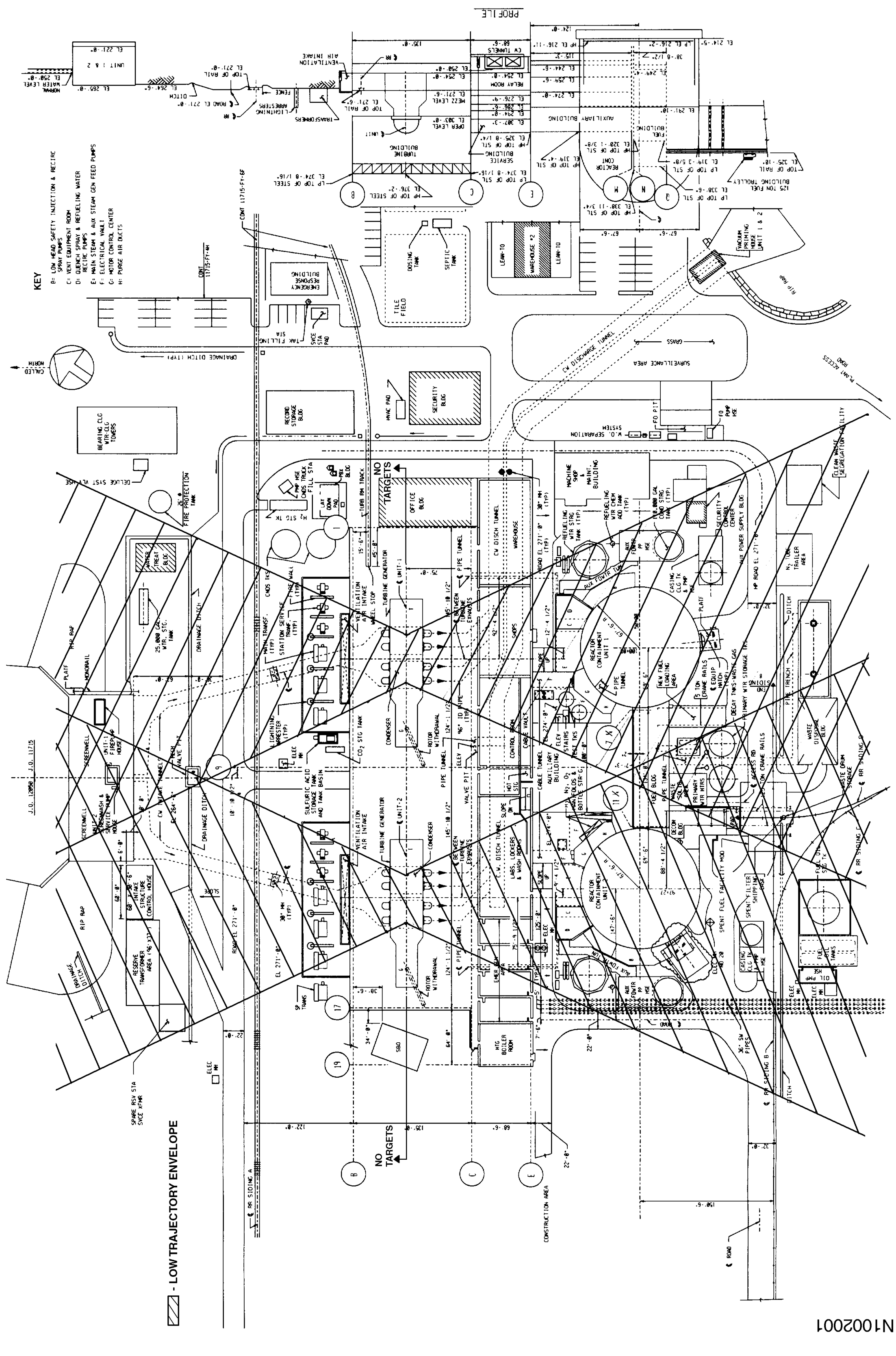


Figure 10.2-1
TOTAL LOW TRAJECTORY TURBINE MISSILE ENVELOPE

Figure 10.2-2
TURBINE MISSILES

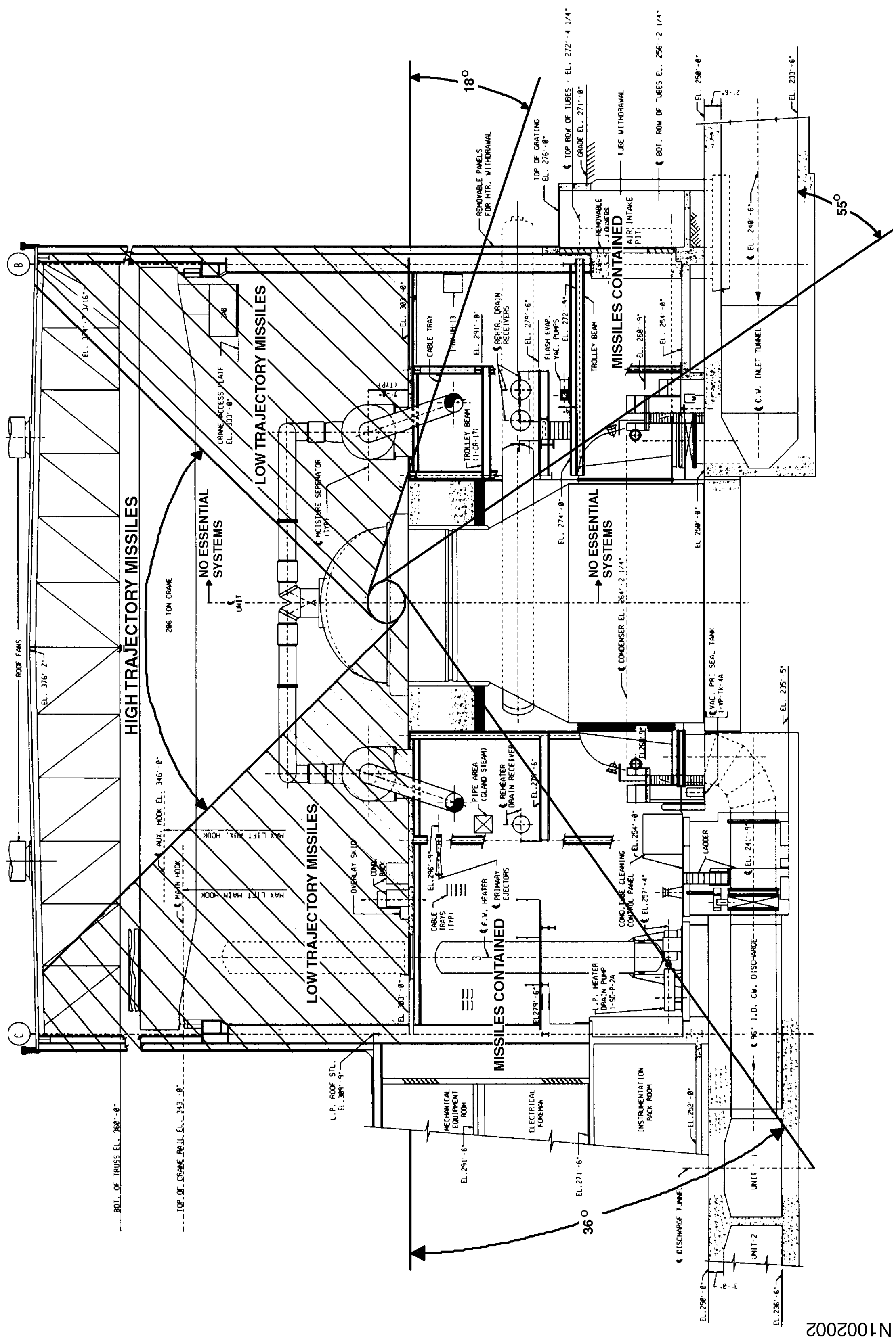


Figure 10.2-3
TURBINE MISSILE REFERENCE SYSTEM

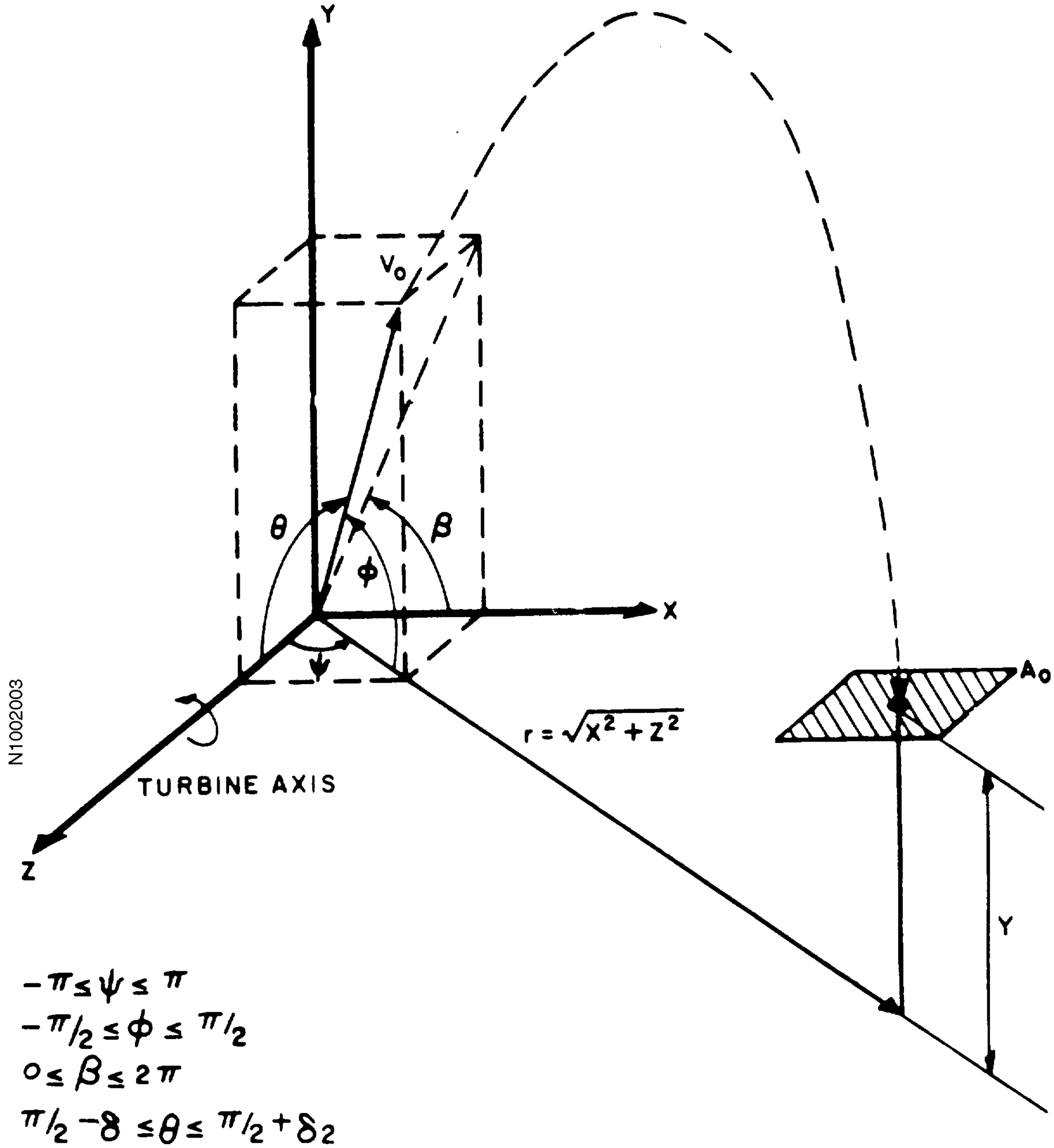


Figure 10.2-4
TOP VIEW OF IDEALIZED TARGET

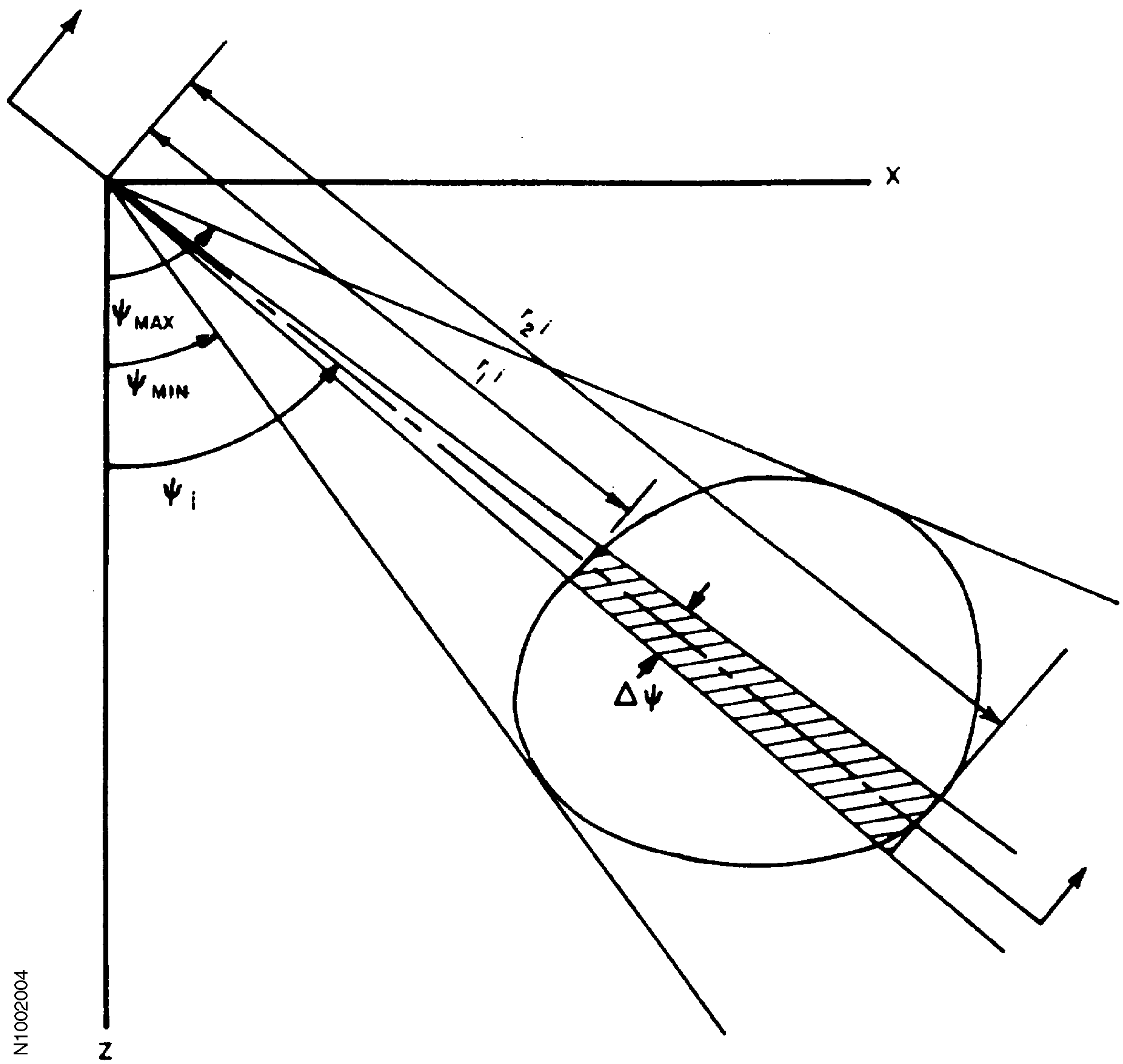
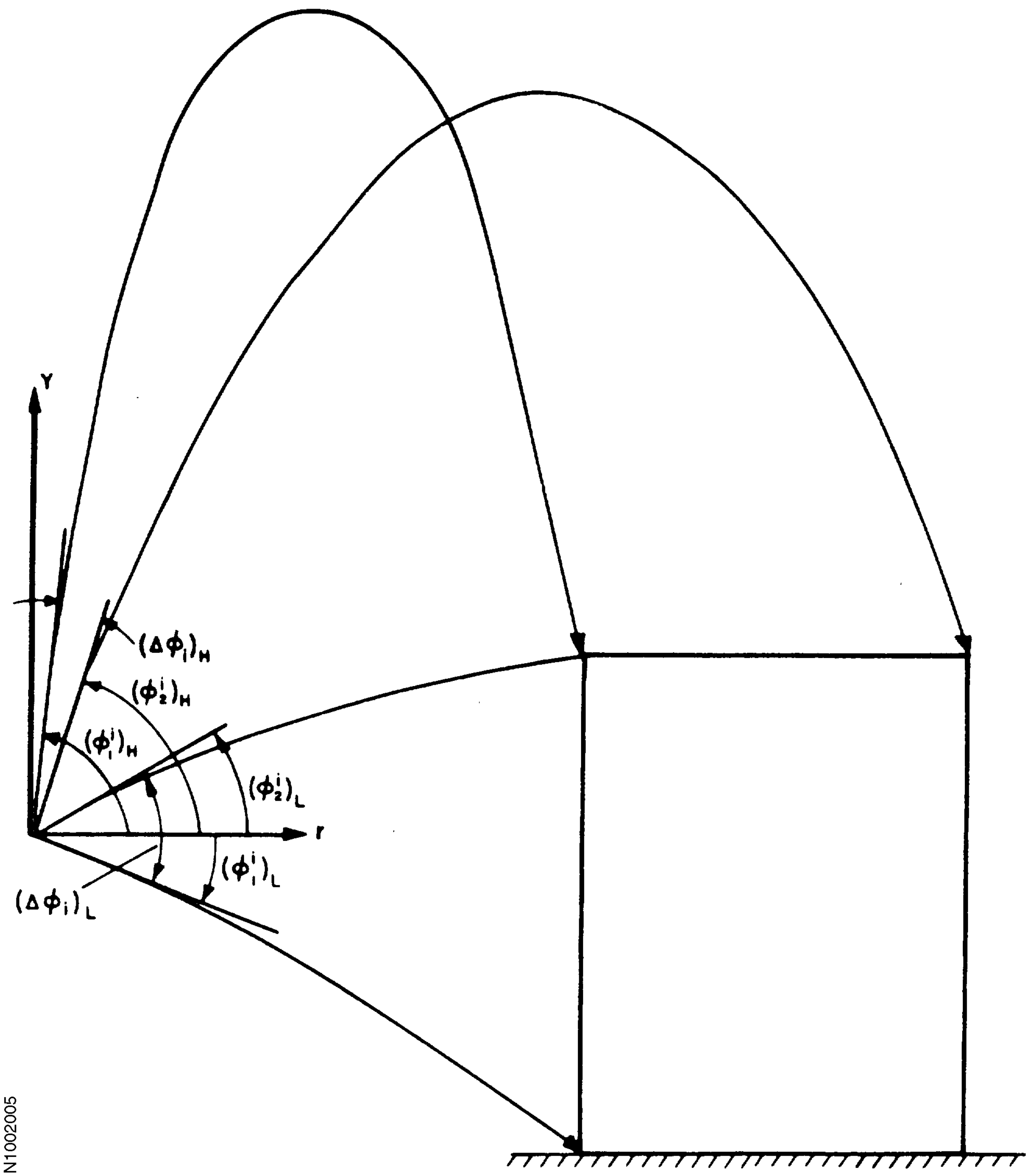


Figure 10.2-5
SIDE VIEW OF IDEALIZED TARGET



10.3 MAIN STEAM SYSTEM

10.3.1 Design Basis

See Section 10.1 for a general description of the design basis for the steam and power conversion system. Additional relevant information is contained in Section 5.5, which discusses the steam generator.

Each of the three main steam pipes is designed in accordance with the ASME Code for Pressure Piping, ANSI B31.1-1967, except for that portion designated as Seismic Class I piping, which is designed in accordance with the Code for Nuclear Power Piping, ANSI B31.7 (see Section 3.2.2).

The main steam safety valves are designed in accordance with the functional requirements of ASME III-1968 Edition with Addenda through Winter 1970.

The steam dump system is designed to take the excess steam generated from load changes exceeding 10% step or 5%/minute and is sized to take the flow resulting from a 50% load rejection. A 50% load rejection results in a 40% steam dump to the condenser with the remaining portion of the load rejection accommodated by the nuclear steam supply system. This flow is divided equally through eight steam dump valves. An uncontrolled plant cooldown caused by a single valve sticking open is minimized by the use of a group of valves installed in parallel instead of a single valve. The steam dump system will also permit a turbine and/or reactor trip from full load without lifting the steam generator safety valves.

Each steam generator is provided with one safety-grade, seismically supported, atmospheric dump valve. The atmospheric dump valves are each sized to pass approximately 10% of the maximum calculated steam flow from each steam generator. The design function of the atmospheric dump valves is to provide controlled relief of the main steam flow. Each valve is capable of being fully opened and closed, either remotely or by local manual operation.

The main steam piping supports have been analyzed for turbine trip forces as well as for seismic forces. In addition, the system has been stress analyzed for the forces and moments that result from thermal expansion. The main steam piping within the containment annulus has been reviewed for possible pipe rupture, and sufficient supports and guides have been provided to prevent damage to the containment liner and adjacent piping.

10.3.2 System Description

The main steam system is shown in Figure 10.3-1 and Reference Drawings 1 and 2.

Steam is conducted individually from each of the three steam generators within the reactor containment through a steam flow meter (venturi) interconnected with its three-element feedwater control system, a swing-disk-type trip valve and an angle-type nonreturn valve into a common header. Figures 10.3-2 and 10.3-3 show an outline of these valves, including material identification, dimensions, steam conditions, and flows. The steam passes from the header to the turbine throttle stop valves and governor valves.

Each steam generator is provided with a flow limiting device that is installed integral to the steam outlet nozzle. The steam nozzle flow limiting devices were installed during the steam generator replacement modification to limit the blowdown rate of steam from the steam generator in the unlikely event of a main steam line rupture. A venturi tube flow restrictor is located in the main steam line downstream of each steam outlet nozzle. These flow restrictors were installed during original construction of the plant and, prior to the installation of the steam nozzle flow limiting devices, functioned both as the flow limiters during a postulated main steam line rupture downstream of the venturis and as flow elements for steam flow measurement during normal operation of the unit. The venturi currently functions only as a flow element for steam flow measurement, since the steam nozzle flow limiting device is upstream of and has a slightly smaller total throat cross sectional area.

Design bases for the main steam flow restrictors are as follows:

1. To provide plant protection in the event of a main steam line rupture. In such an event, the flow restrictor limits steam flow rate from the break, which in turn limits the cooling rate of the primary system. This precludes departure from nucleate boiling (DNB) and minimizes fuel clad damage, as discussed in Chapter 15.
2. To reduce thrust forces on the main steam piping in the event of a steam line rupture, thereby minimizing the potential for pipe whip.
3. To minimize unrecovered pressure loss across the restrictor during normal operation.
4. To withstand the number of pressure and thermal cycles experienced in the life of the plant.
5. To maintain flow restrictor integrity in the event of a double-ended severance of a main steam line immediately downstream of the flow restrictor.

The main steam line flow element has the additional design requirement of providing the pressure differential necessary for steam flow measurement.

Each steam nozzle flow limiting device consists of an assembly of seven bundled venturis, each having a nominal throat diameter of 6 inches, installed integral to the main steam outlet nozzle of each steam generator. The steam nozzle flow limiting device does not restrict steam flow under normal conditions, but would prevent a rapid depressurization of the steam generator by choking the steam flow, should a main steam line break (MSLB) accident occur.

Each main steam line flow element is composed of a nominal 16-inch diameter throat venturi nozzle section and a carbon steel discharge cone and is permanently welded inside a length of main steam piping by a circumferential weld at the discharge end of the venturi. The main steam line flow elements provide the pressure differential necessary for steam-flow measurement using upstream and venturi throat pressure taps.

The swing-disk-type trip valves in series with the nonreturn valves contain swinging disks that are normally held up out of the main steam flow path by air cylinder operators. If a steam line pipe rupture occurs, as discussed in Section 15.4.2, downstream of the trip valves, an excess flow signal from the steam flow meter, combined with low T average or low steam line pressure in two out of three matrices, will release the air pressure on the air cylinders and spring action will cause these valves to trip closed, thus stopping the flow of steam through the steam lines. Valve closure checks the sudden and large release of energy that is in the form of main steam, thereby preventing rapid cooling of the reactor coolant system and ensuing reactivity insertion. Trip valve closure also ensures a supply of steam to the turbine drive of the auxiliary steam generator feed pump described in Section 10.4.3.

The nonreturn valves prevent reverse flow of steam in the case of accidental pressure reduction in any steam generator or its piping and also provide a motor-operated manual shutoff of steam from the respective steam generator.

If a steam line breaks between a trip valve and a steam generator, the affected steam generator will continue to blow down. The nonreturn valve in the line prevents blowdown from the other steam generators. This would be the worst steam-break accident and is discussed in Section 15.4.2. The main steam trip valves provide backup for the nonreturn valve, by ESF actuation, to prevent blowdown from intact loop steam generators through a ruptured pipe between the affected steam generator and its trip valve.

A total of five ASME Code safety valves are located on each main steam line outside the reactor containment and upstream of the nonreturn valves. The five valves provide each header with a total relieving capacity of 4,275,420 lb/hr. The setpoints, setpoint tolerances, and relieving capacities of each safety valve are given as follows:

Mark Number	Setpoint Pressure (psig)	Capacity, Each at Setpoint Pressure	Capacity, Each at Setpoint 1135 psig	Setpoint Pressure Tolerance
SV-MS101A,B,C	1085	817,883	855,084	±1% [a]
SV-MS102A,B,C	1095	825,323	855,084	±1%
SV-MS103A,B,C	1110	836,483	855,084	±1%
SV-MS104A,B,C	1120	843,924	855,084	±1%
SV-MS105A,B,C	1135	855,084	855,084	±1%

a. Technical Specifications allow a ±3% “as-found” lift setpoint tolerance and a ±1% “as-left” setpoint tolerance. The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

Actual total capacity for five valves	4,275,420 lb/hr
Required total capacity for five valves	4,255,542 lb/hr
Excess capacity	19,878 lb/hr

In the case of one or more inoperable main steam safety valve(s) (MSSVs), the Technical Specifications allow operation of Units 1 and 2 at reduced power levels. The reduction in reactor power (and associated reduction in neutron flux) is required to ensure MSSV capacity is sufficient to prevent secondary side pressure from exceeding 110% of the design.

The steam dump system dumps excess steam generated by the sensible heat in the core and the reactor coolant system directly to the condensers by means of two main steam bypass lines, each of which contains a bank of four steam dump valves arranged in parallel.

All or several of the dump valves open under the following conditions provided the various permissive interlocks are satisfied:

1. On a large step-load decrease, the steam dump system creates an artificial load on the steam generators, thus enabling the nuclear steam supply system to accept a 50% load rejection from the maximum capability power level without reactor trip or atmospheric dump through the main steam safety valves. An error signal exceeding a set value of reactor coolant T_{avg} minus T_{ref} fully opens all valves in less than 5 seconds. T_{ref} is a function of load and is set automatically. The valve closes automatically as reactor coolant conditions approach their programmed setpoint for the new load.
2. On a turbine trip with reactor trip, the pressures in the steam generators rise. To prevent overpressure without main steam safety valve operation, the steam dump valves open, discharging to the condenser for several minutes to dissipate the thermal output of the reactor without exceeding acceptable core and coolant conditions.
3. After a normal orderly shutdown of the turbine generator leading to unit cooldown, the steam dump valves are used to release steam generated from the sensible heat for several hours and are controlled from main steam header pressure. Unit cooldown, programmed to minimize thermal transients and based on sensible heat release, is effected by a gradual manual closing of the dump valves until the cooldown process can be transferred to the residual heat removal system (Section 5.5).
4. During start-up, hot standby service, or physics testing, the steam dump valves are actuated remote manually from the main control board and are operated in the steam pressure control mode.

All condenser steam dump valves are prevented from opening on a loss of condenser vacuum or when an insufficient number of circulating water pumps are running. In this event, excess steam pressure is relieved to the atmosphere through the atmospheric steam dump valves or the main steam safety valves. Interlocks are provided to reduce the probability of spurious opening of the steam dump valves.

An atmospheric steam dump valve with a manually adjustable setpoint is provided on each main steam header upstream of the nonreturn valve outside the containment. Control air is supplied to the atmospheric dump valves from the instrument air system. Air is delivered to the valves through a seismically qualified 2-inch header from the auxiliary building. The 2-inch header is reduced to a 3/4-inch seismically qualified header in the main steam valve house. The 3/4-inch header splits and supplies each of the valves through individual check valves. Located between the check valve and the respective atmospheric dump valve is a connection to a backup supply tank for each of the dump valves. The seismically qualified tanks each have a volume of 16.7 ft^3 at 110 psig. The tanks are maintained at pressure by the instrument air header. The check valves prevent a loss of air from the tanks back through the instrument air header should the instrument air system become depressurized. Electrical power to the electropneumatic controller, which controls the valve position, is provided to each valve from separate channels of uninterruptible safety-grade power from independent station batteries. The control cables providing electrical signals to all three atmospheric dump valves are designated as non-safety related and routed in the same non-safety related cable tray and conduit, which reflects the original control grade design of this system. The relieving pressure of these valves (normally 1035 psig) is individually controlled from the main control board. Each valve has a capacity of 425,244 lb/hr of saturated steam at 1025 psig. The valve is normally set to discharge at a pressure lower than that of the lowest set main steam safety valve to avoid opening the safety valves.

The atmospheric steam dump valves (steam generator PORVs) can also be used to achieve a controlled cooldown of the reactor by reducing steam generator pressure. This capability is particularly important for recovery from a steam generator tube rupture accident. For the event to be terminated in a timely manner, the operators must depressurize the reactor coolant system (RCS) to a value at or below the secondary side of the ruptured generator. To support this depressurization, the RCS must first be cooled by dumping steam from the non-ruptured generators. This is done via the condenser steam dump valves, if available. If a loss of offsite power or other upset renders the condenser or condenser steam dump valves unavailable, then cooldown is achieved using the steam generator PORVs. See Section 15.4.3, Steam Generator Tube Rupture, for further details.

In addition, a decay heat release control valve (HCV-MS104) is provided that, approximately 1/2 hour after reactor shutdown, is capable of releasing the sensible and core residual heat to the atmosphere via the decay heat release header. This valve is manually positioned from the main control board by remote control. This one valve, which is mounted on the common decay heat release header, serves all three steam generators through 3-inch connections on each main steam line upstream of the nonreturn valve. In addition, this valve can be used to release the steam generated during reactor physics testing and unit hot standby conditions. The decay heat release valve (HCV-MS104) is a 4-inch, Seismic Class I, Quality Assurance Category I valve located in the main steam valve house (see Reference Drawing 2). The valve fails in the closed position on a loss of air. A 3-inch stop-check valve is provided in each line connecting the main steam lines to the common residual heat release header. These valves are located in the main steam valve house (see Reference Drawing 2), where they are protected from adverse environmental effects such as freezing. These stop-check valves ensure that steam may flow to the header, but prevent reverse flow of steam.

Steam leaving the main high-pressure turbine passes through four moisture separator-reheater units in parallel to the inlets of the low-pressure turbine cylinders. Each of the four steam lines between the reheater outlet and low-pressure turbine (crossover piping) are provided with a stop valve and an intercept valve in series. These valves, operated by the turbine control system, function to prevent turbine overspeed. ASME Code safety valves are installed on each moisture separator to protect the separators and crossover piping from overpressure. The valves are designed to pass the flow resulting from the closure of the crossover stop and intercept valves with the main steam inlet valves wide open. Although this event is highly unlikely, the function of the valves that discharge to the condenser is to prevent equipment damage.

For fine control of steam flow to the moisture-separator reheater (MSR) during startup, a 3-inch warm-up line and a 1-inch warm-up line, each with a manually operated valve, are installed in parallel around the 8-inch MSR flow control valve. A 1-inch drain line attaches upstream of the flow control valve and drains to a header for condenser penetration 55. The drain line enables water to be removed from the steam line prior to placing the line in service. In addition, an annubar flow element has been installed in the 8-inch reheater steam supply line upstream of the flow control valve FCV-MS104A, B, C, or D. Attached to the flow control valve is a 1-¼-inch branch line to provide valving and piping for the local flow indicator. This provides a means of monitoring moisture separator-reheater steam supply flow.

10.3.3 Performance Analysis

The main steam line trip valves will close within 5 seconds on the receipt of a signal, and the main steam-line nonreturn valves will close instantaneously on steam-flow reversal. These valves are not required to open for plant safety.

Under accident conditions, the main steam-line trip valves will close as long as back pressure is equal to or less than the inlet pressure. The failure of the nonreturn valves will have no effect on the ability of the trip valves to function. The nonreturn valves can also serve as stop valves and are designed to close in 120 seconds by motor operation.

The atmospheric steam dump valves are fail-safe by going closed and staying closed on a loss of instrument air supply.

The maximum capacity of any single atmospheric steam dump valve, main steam safety valve, or condenser steam dump valve does not exceed 1.02×10^6 lb/hr at a pressure of 1100 psia. This limits the steam flow for any stuck-open valve to the value analyzed in Section 15.2.13.

In the event of an accident such as a main steam-line rupture either upstream or downstream of the valves, the maximum design steam-flow rates, minimum steam quality, and pressure differentials for the main steam isolation valves and main steam nonreturn valves are as follows.

Main Steam Trip Valves (TV-MS-101A, B, C)	
Maximum flow	14.7×10^6 lb/hr
Minimum steam quality	94%
Maximum pressure differential	1005 psig

Main Steam Nonreturn Valves (NRV-MS-101A, B, C)	
Maximum flow	16.9×10^6 lb/hr
Minimum steam quality	93%
Maximum pressure differential	1005 psig

10.3.3.1 **Potential for Unisolable Blowdown of All Three Steam Generators**

A break in the decay heat release line (see Reference Drawing 2) between the decay heat release valve and the stop check valves upstream, or the inadvertent opening of the decay heat release valve could result in the unisolable blowdown of all three steam generators.

The inadvertent opening of the decay heat release valve is bounded by the analysis of the inadvertent opening of a single steam dump, relief, or safety valve, presented in Section 15.2.13.2. These valves are larger than the decay heat release valve, resulting in a larger blowdown rate and a faster reactor coolant system cooldown rate. The stop-check valves permit the isolation of flow from the decay heat release valve.

A break in the decay heat release line could result in a break opening area slightly larger than the opening of a single steam dump, relief, or safety valve. Thus, the analysis presented in Section 15.2.13.3 is applicable to this situation.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

10.3.3.2 **Tests Ensuring Steam System Valve Integrity**

In order to support assumptions that certain valves in the steam system could reliably prevent simultaneous blowdown of more than one steam generator, the construction tests performed on the valves are provided in Tables 10.3-1 through 10.3-4. These tests are provided "For Information Only" for the main steam trip valves, main steam nonreturn valves, steam dump valves, and turbine throttle and governor valves.

10.3.4 Tests and Inspections

The main steam-line trip valves are tested periodically in accordance with the Technical Specifications.

Inservice inspection for the main steam-line trip valves is not required by ASME Code, Section XI.

The nonreturn valves will be tested during unit shutdown to verify that they are functional.

Since the decay heat release valve does not perform a safety-related function, there is no need to perform periodic in-plant testing.

The condenser steam dump valves are normally used in station operation and do not perform a safety-related function. There is no need to perform periodic in-plant testing.

The main steam-line flow elements and the steam nozzle flow limiting devices are not a part of the steam system pressure boundary. No in-plant tests or inspections of these components are anticipated.

10.3 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11715-FM-070A	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 1
	12050-FM-070A	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 2
2.	11715-FM-070B	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 1
	12050-FM-070B	Flow/Valve Operating Numbers Diagram: Main Steam System, Unit 2

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 10.3-1

TESTS ENSURING STEAM SYSTEM INTEGRITY MAIN STEAM TRIP VALVES

The main steam trip valves were supplied by the Schutte & Koerting Company of Cornwells Heights, Pennsylvania. The main steam trip valves have had the following quality control requirements performed satisfactorily:

1. Radiographic examination of critical body areas (valve ends and bonnet).
2. Magnetic particle examination of body in areas not radiographed.
3. The valves were hydrostatically and seat leak tested.
4. A functional performance test was performed on the valves.
5. Welding and nondestructive test procedures were reviewed.
6. Welder and nondestructive test operators' qualifications were reviewed.
7. Valve body-wall thickness was checked ultrasonically.
8. Mill test reports have been obtained for all pressure-retaining parts.
9. Valve rockshafts were liquid penetrant inspected.
10. Valve disk and pin materials were ultrasonically tested prior to machining.
11. Valve disk and pin assemblies were liquid penetrant examined.
12. Magnetic particle examination was performed on the valve tail links.

Dynamic analyses were performed on the valves by Schutte & Koerting and Stone & Webster in 1972 and resulted in the following modifications:

1. The valve disk was changed to 410 stainless steel and increased in thickness to 3 inches.
2. The valve rockshaft was changed to 410 stainless steel and its connections changed to splined.
3. Rupture disks were added to the air cylinders to prevent overstressing the rockshaft during a valve trip.

The main steam trip valves have been seismically analyzed by the vendor and the analysis reviewed by Stone & Webster.

The main steam trip valves have been protected from the effects of pipe breaks and jet impingement as described in Section 3C.5. The valves are functionally qualified for the environment.

A summary of a similar analysis on similar valves for the Beaver Valley Unit 1, Docket No. 50-334, was provided to the NRC on July 17, 1975.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 10.3-2

TESTS ENSURING STEAM SYSTEM INTEGRITY MAIN STEAM NONRETURN VALVES

The main steam nonreturn valves (MSNRVs) were supplied by Rockwell International Flow Control Division (Rockwell) of Pittsburgh, Pennsylvania.

These valves have had the following quality control requirements performed satisfactorily.

1. Radiographic examination of critical body areas (valve ends).
2. Magnetic particle examination of body in areas not radiographed.
3. Body hydrostatic and seat leakage tests.
4. Functional performance test.
5. Review of welding and nondestructive test procedures.
6. Review of welding and nondestructive test operators' qualifications.
7. Ultrasonic checking of valve body-wall thickness.
8. Receipt of mill test reports for all pressure-retaining parts.

Dynamic analyses were performed on the valves by Rockwell and Stone & Webster, and the valves were found to be satisfactory.

The main steam nonreturn valves have been seismically analyzed by the vendor and the analysis reviewed by Stone & Webster.

The main steam nonreturn valves have been protected from the effects of the pipe breaks and jet impingement, as stated in Section 3C.5.1.5. Environmental considerations are discussed in Section 3C.5.1.6.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 10.3-3

TESTS ENSURING STEAM SYSTEM INTEGRITY STEAM DUMP VALVES

The valve bodies, bonnet assemblies, and blind heads of these valves are designed in accordance with the applicable requirements of USAS B16.5 (e.g., a nominal 600 lb pressure rating that provides 1030 psig at the 650°F design). The general design conditions include the following:

1. Design life of 40 years
2. 500 open-shut cycles per year for the 40-year design life.
3. Valve assemblies designed to withstand seismic loadings equivalent to 3.0g in the horizontal direction and 2.0g in the vertical direction.
4. Bolting and nuts conforming to ASTM A193 and A194, respectively, except for the bolts and nuts in the packing gland area.
5. Hydrostatic shell tests in accordance with MSS-SP-61.
6. Pressure-retaining components surface inspected and checked by volumetric inspection of the body and bonnet.

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 10.3-4
TESTS ENSURING STEAM SYSTEM INTEGRITY
TURBINE THROTTLE AND GOVERNOR VALVES

The following nondestructive tests were performed on components of the steam chest assemblies, including the throttle and governor valves:

Component	Test
q	Magnetic particle inspection
Steam chest support fabrication	a. Radiographic inspection of the welded joint of the barrel support to the body b. Radiographic inspection of welds of inlet pipe to body c. Magnetic particle inspection of weld joints in flexible support d. Magnetic particle inspection of barrel support vertical seam weld, barrel support to base plate weld, and the welds for the jacketing lugs.
Inlet pipe for fabricating to steam chest body	Hydrotest (≈2100 psig) by pipe supplier
Throttle valve seat stellited overlay	Liquid penetrant inspection
Throttle valve pilot valve seat insert stellited overlay	Liquid penetrant inspection
Weld joining throttle valve guide to bonnet	Magnetic particle inspection
Weld joining throttle valve strainer to bonnet	Liquid penetrant inspection
Weld joining leak-off pipe connections to throttle valve bonnet	Magnetic particle inspection
Throttle valve bonnet	Magnetic particle inspection
Plate for governor valve insert ring (parent metal) and subsequent assembly to governor valve plug	Ultrasonic inspection
Stellited overlay on governor valve insert ring that assembles on governor valve plug	Liquid penetrant inspection
Governor valve seat	Ultrasonic inspection by forging supplier
Weld joining leakoff pipe connections to governor valve bonnet	Magnetic particle inspection
Seal welding of pins that assemble muffler to governor valve bonnet subassembly	Magnetic particle inspection

The following information is HISTORICAL and is not intended or expected to be updated for the life of the plant.

Table 10.3-4 (continued)
TESTS ENSURING STEAM SYSTEM INTEGRITY
TURBINE THROTTLE AND GOVERNOR VALVES

Component	Test
Governor valve bonnet	Magnetic particle inspection
Fabricated spring housing welds	Magnetic particle inspection
Cast throttle valve support for linkage	a. Ultrasonic inspection of vicinity of linkage pinhole areas b. Magnetic particle inspection of surfaces
Valve springs (compression type)	Magnetic particle inspection by supplier
Steam chest bodies	Hydrotest (≈600 psig)

The steam chests have been analyzed for seismic loads as have the throttle valve and governor valve components. The chest supports were analyzed for 1.0g vertical and 1.5g horizontal applied at the center of the chest. Throttle valves and governor valves were analyzed for 1.0g vertical and l.5g horizontal applied to various components.

The valves are designed to close under full pressure. The throttle valves are fully unbalanced to close; the governor valves are partially unbalanced. Flow and pressure drop for each valve are in the direction of spring closing action. Therefore, the larger the pressure drop, the larger the force to close the valves.

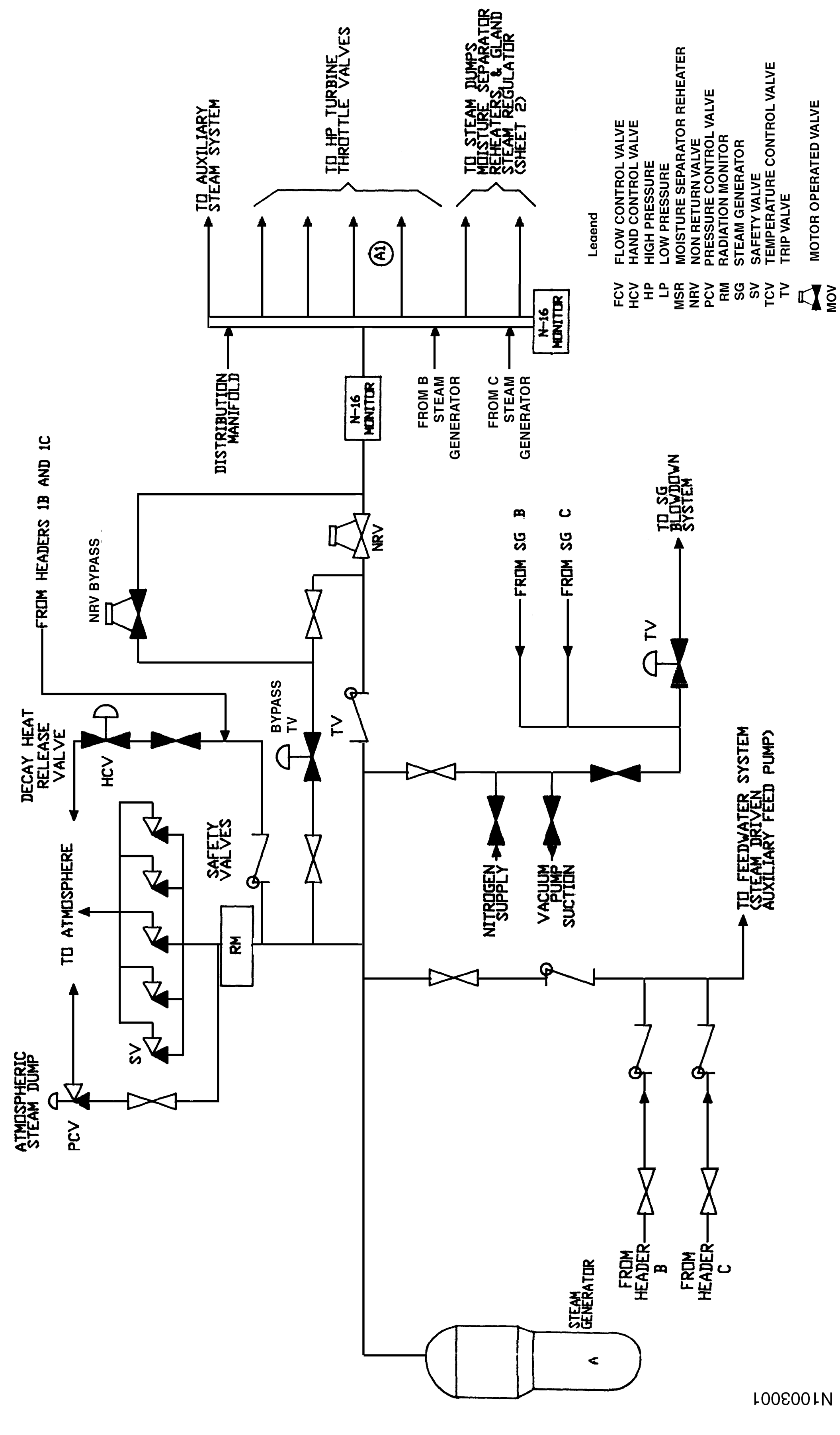


Figure 10.3-1 (SHEET 1 OF 2)
MAIN STEAM SYSTEM

Figure 10.3-1 (SHEET 2 OF 2)
MAIN STEAM SYSTEM

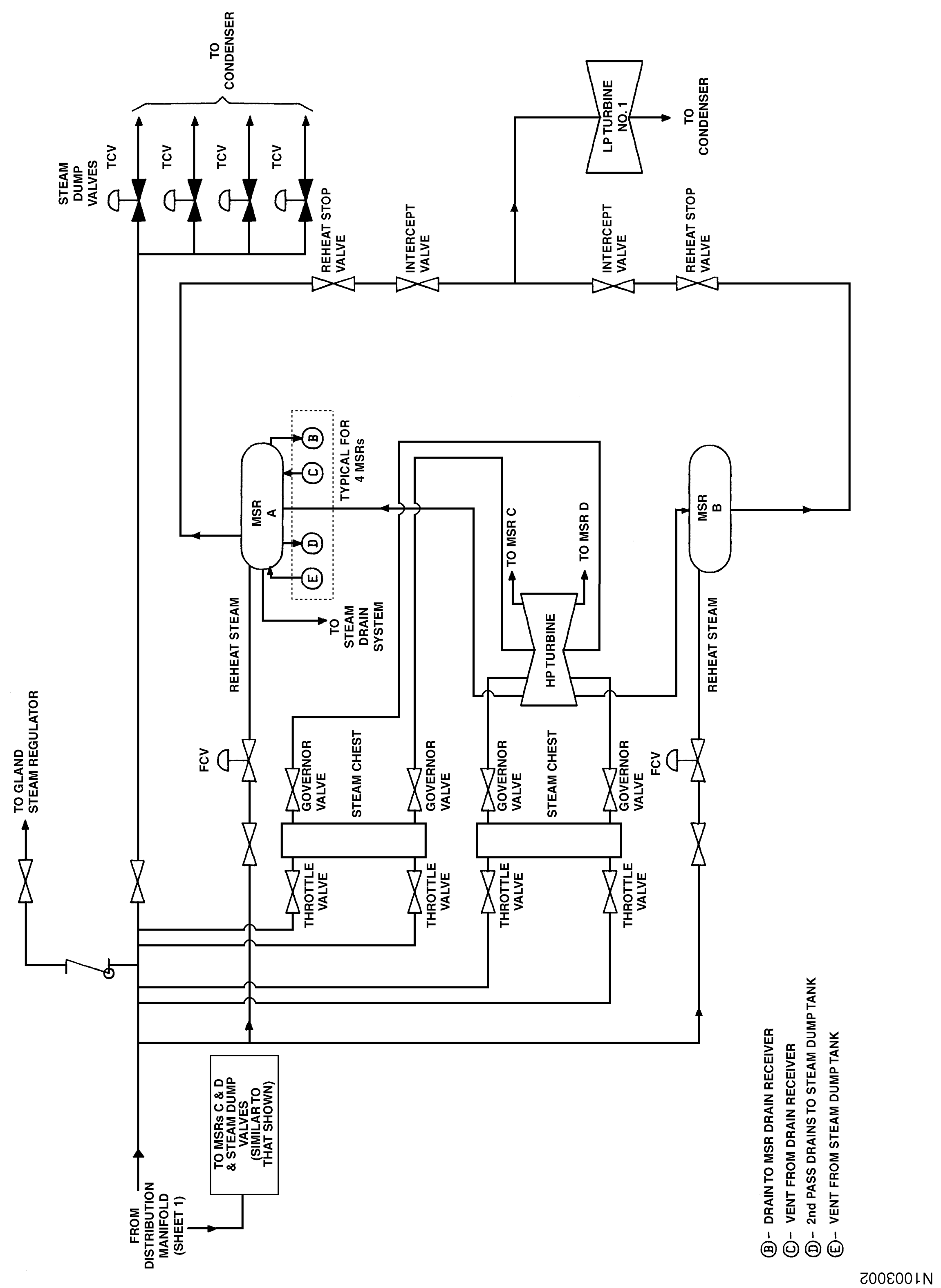


Figure 10.3-2
MAIN STEAM LINE TRIP VALVE

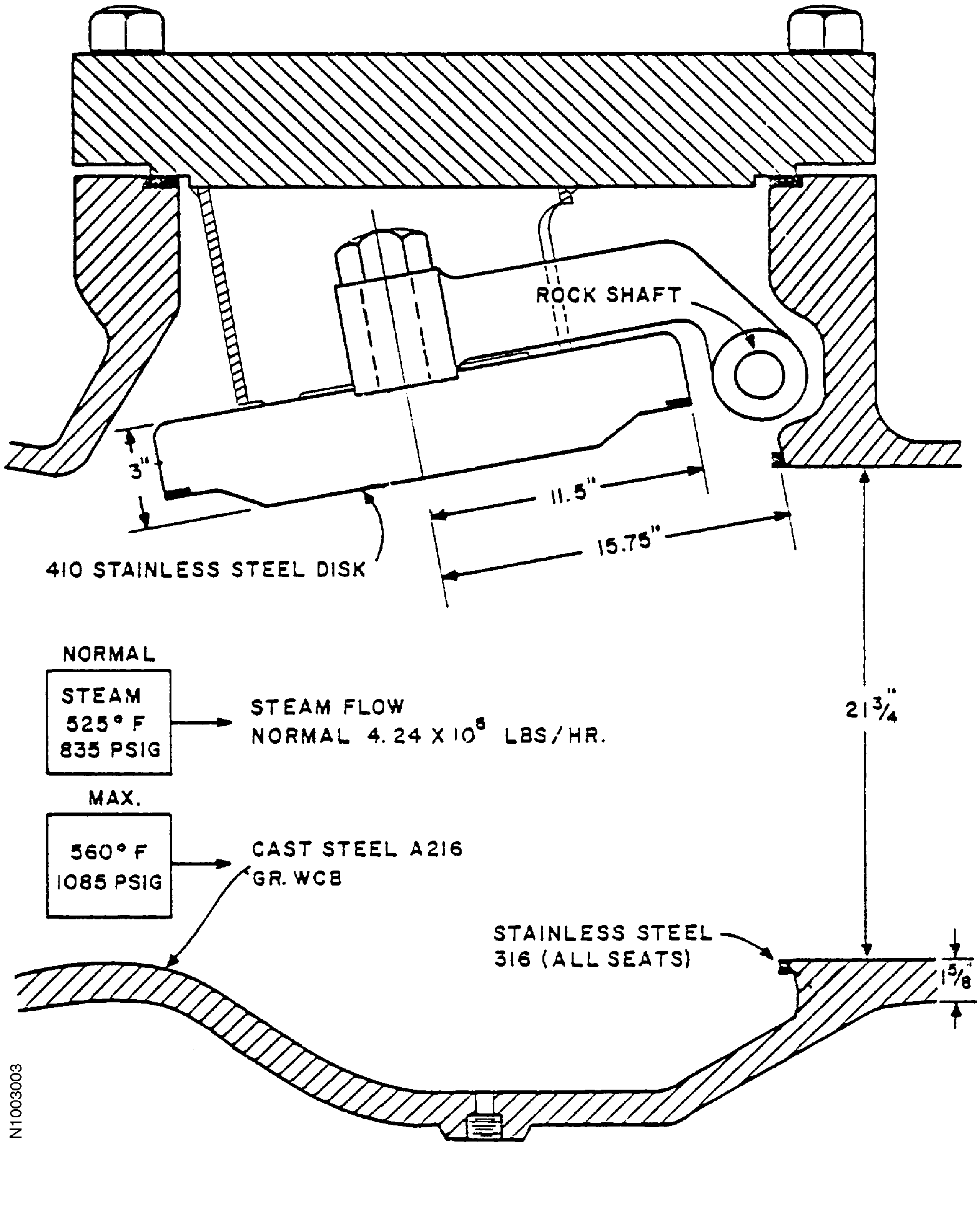
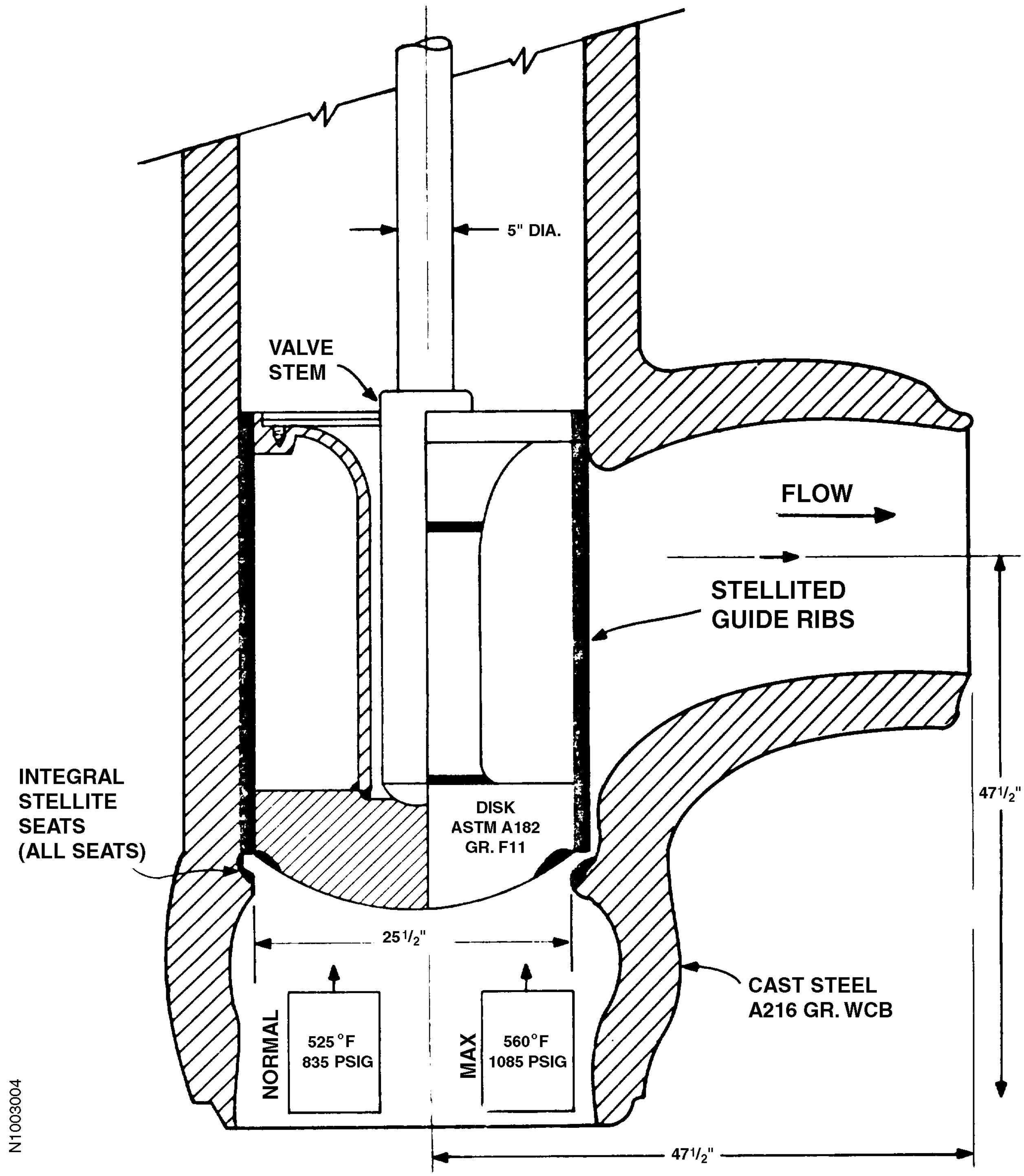


Figure 10.3-3
MAIN STEAM LINE NON-RETURN VALVE



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10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 Auxiliary Steam System

10.4.1.1 Design Basis

See Section 10.1.

All piping is designed in accordance with the ASME Code for Pressure Piping, ANSI B31.1-1967.

10.4.1.2 System Description

An auxiliary steam system is provided as shown in Reference Drawing 1 and 2. The auxiliary steam supply header distributes 150 psig to 225 psig steam throughout the station for auxiliary services, including the following:

1. Boric acid batch tank.
2. Condenser air ejectors.
3. Chilled water units.
4. Flash evaporator (not used).
5. Primary-water tank heaters.
6. Gas stripper feed heaters.
7. Boron evaporator reboilers.
8. Containment vacuum ejectors.
9. Building heating.

Pressure-reducing valves at the inlet to the above items provide lower pressure where required.

Auxiliary steam is supplied from either the main steam or extraction steam systems, depending on turbine-generator load, or the auxiliary boilers. The steam from main steam or extraction steam contains no detectable radioactivity unless there has been gross leakage between the primary and secondary sides of the steam generator.

As discussed in Section 11.4, radioactive contamination of this steam will be detected by either the condenser air ejector monitor or the steam generator blowdown monitors. These monitors will warn personnel of increasing radioactivity levels and therefore provide early indication of system malfunctions. Complete severance of a steam generator tube and the effects and consequences of such an accident on this function are discussed in detail in Section 15.4.3.

Normally, the auxiliary steam supply header receives its steam from the second-point extraction lines. During periods of low-load operation, when extraction steam pressure drops below approximately 150 psig, steam is supplied from the main steam header through a pressure-reducing valve. When both reactor units are shut down, steam is supplied to the auxiliary steam header by the auxiliary boilers.

Condensate returning from the primary plant systems collects in a 300-gallon auxiliary steam drain receiver, which is vented to the atmosphere. A portion of the condensate returning to the receiver will flash to steam and be released to the atmosphere. Details of the radiological evaluation of this release are discussed in Chapter 11. The remaining portion of the condensate returns is pumped to the condensate storage system. Condensate returns from the building heating system are returned to the condensate storage system via separate receivers as discussed in Section 9.4.

The containment vacuum system steam ejectors are used only during start-up periods to initially evacuate the containment. During normal operation, two mechanical vacuum pumps maintain the vacuum, as described in Section 6.2.6.

The condenser vacuum priming ejectors are used during start-up to draw the initial condenser vacuum. During normal operation, the steam jet air ejectors maintain condenser vacuum, as described in Section 10.4.6.

Two heating boilers, each rated at 80,000 lb/hr of steam, are provided for shutdown operation. Each boiler is of the packaged-water-tube type. The boilers are furnished with deaerator and feed and condensate pumps. Fuel oil is supplied to the boilers from the main oil storage tank through motor-driven fuel-oil pumps.

10.4.1.3 **Performance Analysis**

A loss of normal ac power will shut down the auxiliary boilers. No services supplied by auxiliary steam are required to function as part of the engineered safety features during a loss of station power.

10.4.1.4 **Tests and Inspections**

The usage of the system during plant operation provides a continuing check of system functionality status; specific periodic testing is not required.

10.4.1.5 **Instrumentation Application**

Auxiliary steam header pressure is monitored in the main control room.

Control switches for the auxiliary steam drain receiver pumps are local. Alarms are provided in the main control room for auxiliary boiler trouble. More specific alarms are provided locally.

Local instrumentation and controls are provided as required.

10.4.2 Circulating Water System

10.4.2.1 Design Basis

See Section 10.1.

To supply condensing and cooling water needs each unit requires 940,300 gpm of water at 95°F. To provide operational flexibility, system reliability, and station economy, the water requirements for each unit are supplied by four pumps. Design data for these pumps (CW-P-1A, B, C, and D) are presented below:

Capacity	238,200 gpm
Head	25 ft
Design temperature	93°F
Design pressure	45 psig
Suction bell material	ASTM-A48, Cl. 30
Impeller	ASTM-B143-2A-M
Shaft	AISI 416 SS

The temperature of the water pumped will vary between 35°F and 95°F.

10.4.2.2 System Description

The circulating water system, as shown in Figure 10.4-1 and Reference Drawing 3, is supplied from the North Anna Reservoir and provides cooling water for the main condenser. Circulating water is taken from the North Anna Reservoir on the north side of the station and after passing through the condenser is discharged into the Waste Heat Treatment Facility to dissipate a large portion of the heat before returning to the reservoir.

The circulating water intake structure is an eight-bay reinforced-concrete structure. Each bay houses one of the eight circulating water pumps for the two units. These pumps are rated at 238,200 gpm at 25-foot total dynamic head when running at 250 rpm. Each pump is driven by a vertical, solid-shaft, 2000-hp induction motor. Before entering the pumps, North Anna Reservoir water passes through a trash rack at the mouth of each bay. This trash rack is serviced by a movable rake that discharges trash to a basket. A trolley beam is provided to handle the basket and its contents for dumping into collection trucks.

Trash that is less coarse is removed from the circulating water by traveling water screens upstream of each circulating pump.

The intake structure also contains two screen wash pumps for each unit and two bearing pumps common to both units. The latter provide lubricating water for the circulating water pumps and are common for both units. One of the screen wash pumps for each unit is designed to Seismic Class I criteria. A three-way valve located in the discharge piping of this pump provides makeup to the Service Water Reservoir and water to the screens when required.

A dedicated vertical pump located on the intake structure near the fire pump house is designed to provide the raw water supply for the reverse osmosis system and it also provides a backup to the screen wash pump through a normally isolated cross-connecting line.

The circulating water pumps discharge to the common concrete intake tunnel, which conveys the circulating water to the station area, from which four buried steel pipes convey the water to the condensers. Steel pipes convey the discharge water to a common concrete discharge tunnel, which terminates at a seal pit located at the entrance to the Waste Heat Treatment Facility. Each intake tunnel has provisions to measure circulating water flow. A manhole is also provided in the intake and discharge tunnels for maintenance, inspection, or repair. Taps located in the condenser water boxes and discharge tunnel are provided for the vacuum priming system. The vacuum priming system maintains vacuum assisted flow conditions by removing noncondensible gases while the circulating water pumps are operating. This system is isolated when the circulating water pumps are de-energized.

10.4.2.3 **Performance Analysis**

Three or four circulating water pumps for each unit will normally be in service depending on the circulating water temperature. The flow resulting from four pumps inservice promotes self cleaning of condenser tubes, but in winter months, when circulating water temperature is low, may cause excessive condenser vacuum.

Motor-operated butterfly valves are located at the condenser inlet and discharge downstream of the condenser tube cleaning system strainer. The controls for the inlet and discharge valves are arranged for full travel service. The intake tunnel, main condenser, discharge tunnel, and circulating water pumps are initially primed before starting the circulating pumps. This procedure is required as a means to prevent a hydraulic transient in this system. Controls are located in the main control room.

Motor-operated butterfly valves at the discharge of each circulating water pump are interlocked with the motor circuits and open automatically on pump start-up and close on pump shutdown.

A loss of normal ac power causes the four circulating water pumps to shut down.

An analysis of the complete rupture of a main condenser circulating water expansion joint has been performed to assess the effect of subsequent flooding on safety-related systems and components. Figure 10.4-2 indicates turbine building flood levels at various times following such a rupture. The limited flooding conditions possible from a rupture of a condensate line in the turbine building (or in other structures housing portions of the system) are less severe than those of the postulated circulating water expansion joint rupture mentioned above, because of the slower flooding rate and the ability of the operator to take action to limit the amount of flooding. The protection of essential systems described below also applies for a condensate line rupture.

Complete protection of essential systems and components has been provided by locating watertight barriers up to Elevation 257 ft. 0 in. around equipment rooms and pipe chases important to safety. The three doors connecting the turbine building and safety-related equipment rooms, emergency switchgear rooms, and air conditioning chiller rooms (Units 1 and 2) have been provided with 3-foot-high flood barriers. Where necessary, vital electrical cable duct openings have been sealed. There are no passageways, pipe chases, or cableways below Elevation 257 ft. that can connect the flooded space to other safety-related areas except for drain lines, which have been provided with backflow preventers.

The circulating water pumps will be automatically tripped in the event that the water level in the turbine building is greater than 1 foot above the 254-foot elevation floor level. The control system is based on a total of six level switches. The level switches are arranged in three sets of two. Each set is distributed about the turbine building 254-foot elevation. A matrix of two out of three switches, one switch from each of the three sets, trips the four circulating water pumps. On a pump trip signal the pump discharge valves will close due to a pump valve interlock. A matrix of two-out-of-three signals from the other group of three switches will result in a direct signal to the discharge valves to close. The closing of the discharge valves will prevent additional flow from getting to the point of rupture, even should the pumps continue to run. The automatic trip of the pumps and a high-water-level alarm will be shown on annunciator displays on the main control board. The control arrangement was designed to permit on-line testing of each individual level switch, its output signal, and the matrix output trip signal. These level instruments, though not a part of the safety-related protection system, meet the single failure and testability requirements of IEEE-279.

In addition, there are two level switches in the condenser tube cleaning pit that are at a lower level than the turbine building floor. The signal from either one of the two switches will alert the operator to an abnormal water level in the turbine building as excess water from the floor will flow into these pits. The control room operator, on seeing the three alarms occur in rapid succession, will check to see if the circulating water pumps are still running. If the pumps are still running, as indicated by the lights or ammeters on the intake structure control board, the operator will then close the condenser inlet or outlet water box valves, which will shut in 80 seconds, stopping flow, and will also shut down all four circulating pumps as soon as valve travel starts. The condenser inlet and outlet valves are designed to shut against full pump flow.

If the pumps were to continue to run, the operator would trip the main bus feeder breaker from the control room, securing power to the bus serving all four pumps.

Most of the components used to trip the circulating water pumps and/or the associated valves are safety-grade or equivalent to safety-grade components. This provides added assurance that the water flow will be secured. These components and related design features are summarized below:

1. All breakers associated with the circulating water pump motor circuits and bus feeder are identical to seismically qualified, safety-grade breakers.
2. All relays associated with the turbine building level alarms and circulating pump trip circuits are seismically qualified and safety-grade, and are mounted in the emergency switchgear room.
3. Trip control relay and alarm relay power is from the vital bus and is redundant.
4. Normal pump controls are identical to seismically qualified and safety-grade controls.
5. Water box inlet and outlet valve controls are mounted on the main control board and are identical to seismically qualified and safety-grade equipment.

Subsequent to tripping all of the circulating water pumps, the maximum flood elevation in the affected Turbine Building as a result of a failed CW outlet expansion joint is 256 ft or 1 foot below the protective watertight barriers.

10.4.2.4 **Tests and Inspections**

Tests and inspections are performed periodically.

10.4.2.5 **Instrumentation Application**

Control switches are provided in the main control room for the circulating water pumps, condenser water box valves, vacuum priming pumps, and the Class I screen wash pumps.

Local control switches are provided for the bearing lubricating water pumps, screen wash pumps, and traveling water screen drives.

The principal alarms provided in the main control room are as follows:

1. Circulating water pump—electrical fault.
2. Lubricating water—low flow.
3. Vacuum priming tank—low vacuum.
4. Traveling water screen—high-level differential.
5. Condenser vacuum breaker valve—valve open.
6. Circulating water pump auto trip—loss of pump.
7. Condenser water box level control—electrical fault.
8. Turbine building sump alarms—high water level.

Local instrumentation is provided where required.

10.4.3 Condensate and Feedwater Systems

10.4.3.1 Design Basis

See Section 10.1.

The pumps, drives, piping, and 110,000-gallon condensate storage tank of the auxiliary feedwater system have all been designed to Seismic Class I criteria (Section 3.2.1). The auxiliary feedwater system meets the guidelines of Branch Technical Position ASB No. 10-1. The system uses a diversity of power sources and redundant equipment and does not rely on any one source of energy.

The auxiliary feedwater pumps are designed, fabricated, and tested in accordance with Class III requirements of the Draft ASME Code for Pumps and Valves for Nuclear Power, November 1968. The applicable requirements of the Draft ASME Code for Pumps and Valves (Nov. 1968) are invoked in the design/procurement specification for those pumps.

The turbine-driven auxiliary feedwater pump is rated at 735 gpm and 2806-foot TDH at 4200 RPM. The two motor-driven auxiliary feedwater pumps are each rated at 370 gpm and 2806-foot TDH. These ratings include recirculation flow. The design is based on the following conditions:

1. Integrated residual heat release from a full-power equilibrium core.
2. Water inventory of the steam generators operating at normal minimum feedwater level.
3. Minimum allowable steam generator feedwater level permitted to prevent thermal shock or other damage.
4. Automatic starting of auxiliary feedwater pumps to deliver full flow within 1 minute of signal.
5. The temperature of the feedwater, supplied from the emergency condensate storage tank, was assumed to be 35°F when considering thermal shock and 120°F when considering feedwater enthalpy.
6. The pumps have continuous minimum flow recirculation whenever operating. Pump net ratings after recirculation losses are 700 gpm and 350 gpm for the turbine-driven and motor-driven pumps, respectively.

Design-basis flow requirements for the auxiliary feedwater system are summarized in Table 10.4-1.

10.4.3.2 System Description

The condensate and feedwater systems are shown in Figure 10.4-3, Reference Drawings 4, 5, and 7, and Figure 10.4-4. Table 10.4-2 presents design data for the major components of the condensate and feedwater system.

Condensate is normally withdrawn from the condenser hotwells by two of the three half-size motor-driven condensate pumps. The pumps discharge into a common 24-inch header that carries the condensate through two parallel steam jet air ejector condensers and through one gland steam condenser.

A condensate recirculation line is provided to return condensate to the condenser at low turbine-generator loads to provide the minimum required flow of water for the condensate pumps, air ejector condensers, and the gland steam condenser. Downstream of the gland steam condenser and upstream of the chemical feed injection points, flow is passed through the condensate polishing demineralizer. The common header divides into two 18-inch lines that carry condensate through a pair of heater drain coolers and the tube side of two parallel trains of five feedwater heaters to the suction of three half-size steam generator feed pumps. Two of the steam generator feed pumps discharge through two parallel first-point feedwater heaters to a common 26-inch discharge header for distribution to the steam generators through three 16-inch lines with individual feedwater flow control valves, positioned by the three-element feedwater control system and through feedwater isolation valves for each steam generator. A remotely operated small bypass valve is provided in parallel with each feedwater flow control valve for manual or automatic control of feedwater flow to maintain steam generator levels during low-power operation or hot shutdown.

Shell-side drains from the four moisture separators are collected in one high-pressure feedwater heater drain receiver and pumped into the suction of the steam generator feed pumps by one full-size high-pressure feedwater heater drain pump. Drains from the second-point feedwater heaters are collected in two high-pressure heater drain receivers and pumped into the suction of the steam generator feed pumps by individual full-size high-pressure feedwater heater drain pumps.

Chemical feed equipment is provided to ensure proper chemistry control of the secondary system during all modes of operation. Secondary system chemical additives include either morpholine or ethanolamine for pH control, hydrazine for dissolved oxygen control and ammonia, if needed, for further pH control. The primary objective is to minimize the corrosion of the steam generators, steam piping, turbines, and condensate and feedwater systems, with secondary objectives being (1) to prevent or minimize turbine deposits due to carryover from the steam generator, (2) to minimize sludge deposits in the steam generator, (3) to prevent scale deposits on the steam generator heat transfer surfaces and in the turbine, (4) to minimize feedwater oxygen content by the use of hydrazine, and (5) to minimize the potential for the formation of free caustic or acid in the steam generators.

These objectives are met by controlling system chemistry by sampling, including both continuous sampling and laboratory analysis, chemical injection at selected points, continuous blowdown from each steam generator, and chemical protection of the steam generator and feedwater train internals during outages.

Excessive chloride concentrations and free caustic in combination with other water conditions are generally considered to be the causes of steam-generator-tube stress corrosion cracking. The Inconel steam generator tubes are not subject to stress corrosion cracking with low chloride concentrations. The steam generator chlorides are monitored by the analysis of samples. The chloride concentration is kept below the maximum limits recommended by the nuclear steam supply system (NSSS) vendor by blowdown and condensate polishing.

The concentration of dissolved oxygen and electrolytic conductivity are monitored by continuous in-line instrumentation. In each case, the respective concentrations are kept well below the maximum limits recommended by the NSSS vendor.

Chemicals for oxygen scavenging and pH control are added to the condensate system downstream of the condensate polishing demineralizer. This allows good mixing in the condensate and feedwater system before the entrance of the feedwater into the steam generator.

Chemicals for oxygen scavenging and pH control can be manually added to the feedwater and/or the auxiliary feedwater systems, thus allowing the addition of chemicals to the steam generators during start-up and shutdown conditions when the condensate system is not flowing. For example, addition to auxiliary feedwater may be required during plant start-up and during wet layup of the steam generators. Chemical solutions are mixed and stored in tanks on the 259-foot elevation of the turbine building. The solutions are pumped from the tanks into the appropriate system by motor-driven, positive-displacement pumps with manually adjustable strokes. See Figure 10.4-5 and Reference Drawing 6.

Chemicals may be added directly to the steam generators during layup or shutdown conditions through the blowdown system by means of a steam generator transfer pump. Demineralized water may be added directly to the steam generator in this manner, or the contents of a steam generator may be transferred to another steam generator. There is also provision for pumping the steam generators to the liquid waste system using the steam generator transfer pump. See Reference Drawing 8.

The steam generator wet layup circulation system (Reference Drawing 8) provides forced circulation capabilities to the steam generators during wet layup periods. The forced circulation enhances the mixing of oxygen and pH-control chemicals, thus minimizing corrosive attack on the steam generator components. Circulation is provided by centrifugal pumps rated at 100 gpm at 85 feet. The pumps are located in the auxiliary building. The containment isolation valves of the system are shown in Table 6.2-36.

The auxiliary feedwater system serves as a backup system for supplying feedwater to the secondary side of the steam generators at times when the feedwater system is not available, thereby maintaining the heat sink capabilities of the steam generator. As an engineered safeguards system, the auxiliary feedwater system is directly relied on to prevent core damage and system overpressurization in the event of transients such as a loss of normal feedwater or a secondary system pipe rupture and to provide a means for plant cooldown following any plant transient.

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 steam generator safety valves or the atmospheric steam dump valves. 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 auxiliary feedwater system, which delivers an emergency water supply to the steam generators. The auxiliary feedwater system must be capable of functioning for extended periods, allowing time either to restore normal feedwater flow or 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 auxiliary feedwater system flow and the emergency water supply capacity must be sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant cooldown. The auxiliary feedwater system can also be used to maintain the steam generator water levels above the tubes following a loss-of-coolant accident (LOCA). In the latter function, the water head in the steam generators serves as a barrier to prevent leakage of fission products from the reactor coolant system into the secondary plant should the LOCA involve a leaky steam generator tube.

Two motor-driven and one steam-turbine-driven auxiliary feedwater pumps supply feedwater to the steam generators during a complete loss of offsite electric power, for core heat removal. Steam to the turbine-driven auxiliary feedwater pump is available through parallel air-operated valves (MS-TV-111A & B and -211A & B). The automatically actuated solenoid valves for each are powered from redundant dc power sources. In addition, supply valves MS-TV-111A & B and -211A & B can be manually positioned using selector switches at the main control board or at the auxiliary shutdown panel. MS-TV-111A & B and -211A & B are designed to fail open.

Each motor-driven auxiliary feedwater pump driver is powered from redundant 4.16-kV emergency buses, as described in Section 8.3. Control power for the pump-motor circuit breakers is supplied from redundant batteries.

All three pumps are manifolded into two main headers. Both manifolded headers may supply any steam generator but are normally aligned so that one manifold carries flow to a particular generator. A third header provides a flow path from the turbine-driven pump to the “A” steam generator. This third header provides the flexibility required to dedicate a pump to each steam generator.

The three auxiliary feedwater headers tie into the main feedwater headers downstream of the feedwater containment isolation valves.

Both manifolded headers are provided with either an air-operated valve or a motor-operated valve and manual isolation valves at their connections to the auxiliary feedwater headers. The header from the turbine-driven pump to the “A” steam generator contains a motor-operated and a manual isolation valve.

The motor-operated valves FW-MOV-100A, B, C, & D, and -200A, B, C, & D receive 480V ac power from an emergency bus. These valves are designed to fail in an “as-is” position.

The hand-control valves FW-HCV-100A, B, & C and -200A, B, & C can be remotely controlled from the manual station at the main control board or from a similar station at the auxiliary shutdown panel. These hand-control valves and the backpressure-control valves FW-PCV-159A & B and -259A & B are supplied by seismically designed air lines with individual air storage capacity as discussed in Sections 9.3.1.3.1 through 9.3.1.3.3. The hand-control valves are designed to fail open.

FW-MOV-100B & D and -200B & D and FW-HCV-100C & -200C are normally open to provide independent flow paths between each auxiliary feed pump and its respective steam generator. All the remaining valves (FW-MOV-100A & C and -200A & C and FW-HCV-100A & B and -200A & B) are normally closed.

Pressure control valves FW-PCV-159A & B and -259A & B control the associated AFW pump FW-P-3A & B discharge header pressure to prevent FW-P-3A or FW-P-3B pump runout during the worst case scenario of a main steam line break.

In the normal lineup, flow to the individual steam generators from the auxiliary feed pumps is controlled from the main control room by remotely operating hand-control valves (FW-HCV-100C & -200C) and two motor-operated valves (FW-MOV-100B & D and -200B & D). Local control is also provided by manual backup valves. Steam to drive the auxiliary feed pump turbine is supplied from the main steam header.

The turbine-driven auxiliary pump is started immediately on a loss of power by opening the steam valve automatically on a loss of reserve station power or on low-low level in any generator or on a trip of all main feed pumps. The motor-driven pumps are started automatically on a loss of reserve station power, low-low level in any steam generator, or a trip of all main feed pumps. The motor-driven pumps have a delayed start after either a safety injection signal or a simultaneous safety injection/loss of offsite power signal. These time delays do not impact the pumps’ ability to attain full speed and flow within 60 seconds of these events. These delays are part of the load sequencing design intended to provide acceptable offsite voltage profiles to meet GDC-17 requirements and acceptable EDG transient responses. Section 7.3.1.3.5.3 provides the description of AFW auto starts.

10.4.3.3 **Design Evaluation**

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

1. Loss-of-main-feedwater transient.

   a. Loss of main feedwater with offsite power available.

   b. Station blackout (i.e., loss of main feedwater without offsite power available).

2. Secondary system pipe ruptures.
   a. Feedline rupture.
   b. Steam-line rupture.
3. Loss of all ac power.
4. LOCA.
5. Cooldown.

Table 10.4-3 summarizes the criteria used for the above design-basis conditions. Specific assumptions used in the limiting transient analysis (see Section 15.4.2.2) to verify that the design bases are met are shown in Table 10.4-4.

The auxiliary feedwater system has been designed to meet single-failure criteria as defined in Appendix A to 10 CFR 50. Sufficient redundancy has been provided to meet a single active failure in the short term or a single active or passive failure in the long term. A detailed failure analysis of the individual components is discussed in Table 10.4-5.

A failure in the feedwater control system could lead to one of two possible events. The first event is an abnormal increase of water inventory within a steam generator and the second event is an abnormal decrease of water inventory within a steam generator. An abnormal increase is terminated by the steam generator high-high level function. Two out of 3 level channels at the high-high level setpoint in 1 out of 3 steam generators will cause a turbine trip, main feedwater pump trip, and closure of the main feedwater isolation valves.

An abnormal decrease of water inventory is terminated by the steam generator low feedwater flow or low-low water-level functions. Should one of two low-water-level bi-stables in any steam generator indicate an abnormally low water inventory within the steam generator and one-out-of-two flow bi-stables indicate a mass flow mismatch between feedwater input and steam output of the steam generator, a reactor and turbine trip will occur. It is conceivable that a slight flow mismatch could develop that lacks the magnitude to trip the mismatch flow bi-stable but would have a time-integrated value that would reduce the water inventory. In this case, the low-water-level bi-stables would trip; however, no reactor trip would occur because the flow bi-stables would remain in the untripped state. Thus, the water inventory would be further reduced. It should be noted that when a low-water-level bi-stable is tripped, an alarm is actuated within the main control room.

In the event that this trend was not reversed by operator action, two out of three low-low-water-level bi-stables would indicate a low-low water inventory within any one steam generator and would cause the reactor to trip and initiate the start-up of the auxiliary feedwater system. The motor-driven auxiliary feedwater pumps will start automatically. The turbine-driven auxiliary feedwater pump will also start immediately by opening the steam supply valve to the turbine. Thus, there is no operator action necessary to initiate operation of the auxiliary feedwater system (see Figures 7.3-1, 7.3-12 & 10.4-6, and Reference Drawings 13 & 14).

For the case of low-low level in any one, two, or all three steam generators, the amount of feedwater delivered to the steam generators is adjusted by the operator by means of remotely operated hand-control valves FW-HCV-100C or -200C or FW-MOV-100B or D or -200B or D, as shown in Reference Drawing 7. The valves are maintained in a normally open position so operator action is not a requirement for system functioning.

The operator has the following instrumentation available to properly determine what flow adjustments may be necessary: individual steam generator level indicators, individual auxiliary feedwater flow indicators, individual steam generator high-high-level alarms, individual steam generator low-level alarms, and individual steam generator low-low-level alarms.

Following any reactor trip, all main feedwater control valves are closed on a low T_{avg} signal. The low T_{avg} signal has a setpoint above the no-load temperature. The interlock circuitry used for this function is redundant. Redundant signals operate redundant solenoid valves that activate the operator on the feedwater control valve by venting. One of the redundant signals energizes the closing coils of the motor-operated feedwater isolation valves. These interlocks meet the requirements of IEEE-279. The low T_{avg} signal is generated with two out of three reactor coolant loops below approximately 554°F.

In conclusion, a single failure within the feedwater control system would not cause an activation of the emergency core cooling system (ECCS), although it is not a design requirement that ECCS actuation be prevented for a control system failure in the feedwater system.

The auxiliary feedwater pumps are located outside the containment in the auxiliary feedwater pump house, a tornado missile-protected enclosure. They take suction of 35°F to 100°F water from a missile-protected, 110,000-gallon emergency condensate storage tank through individual pipes. Piping and valves at the storage tank are also protected from missiles. The contents of the tank may be recirculated to prevent freezing. In the event further condensate is required, it can be supplied by means of gravity from the 300,000-gallon condensate storage tank. Emergency sources of water supply are provided from the fire protection or service water systems. Pressure transmitters in the suction and discharge piping of the pumps provide indication of the status of the system on the control board. The analysis presented in Sections 15.2.8.1 and 15.2.8.2 shows that two auxiliary feedwater pumps are necessary to maintain a unit in a safe condition following a loss of normal feedwater with offsite power available. However, the auxiliary feedwater pumps are only required to bring the unit to hot shutdown. The two motor-driven auxiliary feedwater pumps are connected to independent buses of the emergency power system, as described in Section 8.3.

Operation of the auxiliary feedwater pumps provides residual heat removal for up to 8 hours using the emergency condensate storage tank. The turbine-driven pump can be used for residual heat dissipation as long as adequate main steam is available. During normal operation, the turbine steam supply lines are pressurized to the trip valves in the main steam valve house. The remaining section at the supply line is supplied with drain collectors with trapped drains to collect the condensate formed by the introduction of hot steam into the cold pipe. The turbine is a single-inlet, single-stage, solid rotor unit and any drops of water forming do not damage or impair its operation. When main steam pressure is no longer adequate to operate the turbine-driven auxiliary feedwater pump, the need for residual heat removal is reduced to a level wherein a motor-driven pump can be used if necessary. In the event that only one pump is available to supply feedwater following a loss of offsite power, there is adequate capacity to cool down the reactor. The effect of this transient on the overall steam generator fatigue usage factor, as stipulated in Section III of the ASME Code, is that the allowable fatigue usage factor of 1.0 is not to be exceeded. The emergency condensate storage tank is maintained with at least 110,000 gallons at all times.

Cooling water to the oil coolers of the auxiliary feedwater pumps is supplied from the individual pump first-stage leakoff lines with the cooling water returning to the 110,000-gallon emergency condensate storage tank via the minimum recirculation line. Each pump is provided with a full flow recirculation line to facilitate pump periodic testing in order to verify head capacity curves. This line is normally isolated by locked closed valves.

The complete loss of redundant ac power sources to the auxiliary feedwater system components is highly improbable. The redundancy of onsite ac power supplied from the diesel generators, along with redundancy of offsite ac power supplied from the switchyard, ensures that at least one source of ac power will be available.

Notwithstanding, the auxiliary feedwater system can be operated independently of ac power. MOV-FW-100B and D and HCV-FW-100C are the valves used to control flow to the steam generators. These valves are open when the system is put into operation. If ac power were unavailable, manual backup valves would be used to decrease flow into the steam generators by manually throttling the valves. The capacity of the turbine-driven feedwater pump is such that it would not cause the steam generator, to which it is aligned, to fill in the 30 minutes conservatively assumed for operator action.

In the event of a feedwater line break downstream of the check valve and the single failure (in the closed position) of the backpressure control valve or a motor-operated discharge valve, or the failure of an auxiliary feedwater pump aligned to one intact steam generator, the remaining intact steam generator will be supplied with adequate flow from its respective supply line and auxiliary feedwater pump. Flow to the unaffected steam generator and flow out the broken line will result in a loss of approximately one third of the condensate storage tank inventory during the first 30 minutes after the pipe break. At that time, it is conservatively assumed that operator action takes place to isolate flow out the broken line to prevent excessive drawing down of the condensate storage tank.

In the event of a pipe rupture in the steam supply line to the turbine-driven auxiliary feedwater pump and the single failure of any valve in the discharge line of the other two pumps, or the single failure of one of the two pumps, one auxiliary feedwater pump (providing adequate flow to one steam generator) would still be available.

10.4.3.3.1 Potential for Water Hammer in Steam Generator Feedlines

The installation of J-tubes to the steam generator feedwater sparger ring precludes the water-hammer mechanism, which has been identified as water-steam slugging occurring as a result of a steam bubble collapse. The J-tubes prevent rapid draining of the feedwater sparger and adjacent feedwater piping. On the initiation of auxiliary feedwater flow, they serve to ensure that the sparger ring is filled prior to recovery and act as a large positive vent for any trapped steam bubble.

All steam generator orifice holes on the bottom side of the sparger have been plugged, and J-tubes installed on the upper side. This has been done to avoid water-hammer events caused by steam bubble collapse following the initiation of auxiliary feedwater flow to recover the feedwater sparger ring.

Extensive in-plant tests conducted at Trojan and Indian Point Unit 2 have shown that the feedwater hammer experience has been effectively precluded by the J-tube modification and that no operating restrictions on auxiliary feedwater flow are necessary to ensure the safe operation of the plant.

Since the occurrence of water hammer has been precluded, there is no need to consider either the stress effects or the resulting loads to the system piping supports or equipment design.

Stone & Webster has developed two major computer programs, WATHAM (for water hammer) and STEHAM (for steam hammer), for developing forcing functions due to flow-induced transients.

WATHAM is a general-purpose computer program used for developing time-dependent forcing functions required in the water-hammer analysis of characteristics with finite difference approximations for one-dimensional homogeneous fluid flows. The time-dependent initial and boundary conditions of piping components, which include valves and pumps, influence the fluid motion. Also, the effect of pipe friction, vapor collapse, and entrapped air has been considered.

STEHAM is a general-purpose computer program used for developing time-dependent forcing functions required in the steam-hammer analysis of piping systems. This program has been developed and is based on the method of characteristics with finite difference approximations for one-dimensional homogeneous fluid flows. It is also dependent on piping component characteristics with the allowance of pipe friction and heat transfer for one-dimensional steam flow. Influences of flow control valves, steam reservoirs, and pipe connections on the behavior of flow response are studied in detail.

The following systems have been analyzed for steam-hammer and water-hammer occasional mechanical loadings:

1. Feedwater.
2. Main steam and main steam bypass.
3. Pressurizer safety/relief.
4. Moisture separator crossover.
5. Quench and recirculation spray.
6. Service water.

These systems analyzed for water hammer and steam hammer have been selected on the basis of past experience in the power industry (Industrial Accident Report) and on the basis of component characteristics for North Anna Unit 1 and 2 systems that generate significant flow-induced forcing functions.

First, the flow-induced, time-dependent forcing functions are developed based on the piping system characteristics and the time-dependent initial and boundary conditions of the components (pumps, valves, etc.).

These time-dependent forcing functions are then applied to the applicable piping system in order to perform time-history dynamic analysis on these systems. The calculated occasional mechanical loading stresses are then combined with other primary stresses and held within piping allowables with the use of pipe supports and restraints. Peak occasional mechanical loading stresses are combined with peak seismic stresses by the square root of the sum of the squares method, and the combination is then added to other primary loading stresses absolutely.

Testing was performed on Units 1 and 2 to demonstrate that the occurrence of water hammer associated with recovering the steam generator feedwater sparger ring was precluded by J-tube installation and feedwater loop seal arrangement. The test procedure added auxiliary feedwater to the steam generators with the water level below the sparger ring and observed the response of the system. The test conditions were points representative of the full range of operating and accident conditions, that is, no load, 100% power, and reduced pressure (accident) conditions. Accelerometers were mounted on feedwater piping in proximity to the steam generators to detect water and auxiliary feedwater pressure during sparger recovery.

10.4.3.4 **Tests and Inspections**

Testing of the auxiliary feedwater system is conducted in accordance with Technical Specifications.

10.4.3.5 Instrumentation Application

The principal controls of the condensate and feedwater systems are located in the main control room.

In addition, an auxiliary shutdown panel in the emergency switchgear room provides control for the auxiliary feedwater system.

The turbine-driven feedwater pump has, as part of its controls, a locally mounted throttle trip valve. In order to increase the control room operator's awareness of auxiliary feedwater system availability, an alarm will notify the control room operator whenever the throttle trip valve is in the trip position, as could be done locally with the overspeed trip lever. The alarm has been added via a position switch on the throttle trip valve wired to the main control board annunciator.

To further increase the control room operator's awareness of auxiliary feedwater system availability, the turbine-driven feedwater pump lube oil reservoir level will be monitored. An alarm will notify the control room operator whenever a low lube oil level condition occurs. This alarm is wired in parallel to the throttle trip valve position alarm and utilizes the common alarm point on the main control board annunciator.

An alarm will notify the control room operator when either of the auxiliary feedwater system discharge motor-operated valves and hand-control valves is out of its normal position, and when either auxiliary feedwater system discharge pressure-control valve is closed after the associated motor-driven pump has started. This will be accomplished by control room annunciation from limit switch contacts of each of the above-mentioned auxiliary feedwater system discharge valves. Annunciating for closed position after pump start-up for each pressure-control valve will be delayed for 20 seconds by the addition of a timing relay to allow sufficient time for the valves to open after the pump has started.

Redundant safety-grade level indication and low-level alarm capability have been installed in the main control room for the auxiliary feedwater system emergency condensate storage tank (1-CN-TK-1). Both level loops are composed of seismically and environmentally qualified transmitters, with power supply from safety-related Class 1E vital buses. One safety-grade alarm indicator is on each loop, set to alarm at 20 minutes of water level left in the tank for the highest-volume auxiliary feed pump operation.

Each indicator will relay the input to a common annunciator window, which will alarm at the same setpoint.

10.4.4 Main Condenser

10.4.4.1 Design Basis

The condensers are designed in accordance with the Heat Exchange Institute standards for steam surface condensers.

The design parameters for each condenser are as follows:

Steam condensed	7,096,000 lb/hr
Circulating water	940,300 gpm
Surface	618,000 ft^2
Number of tubes	53,856
Tube material	SS 304
Tube outside diameter	1 in.
Effective length	43 ft. 10 in.
Backpressure	3.5 in. Hg
Temperature	120°F

10.4.4.2 **System Description**

The condenser is a conventional, two-shell, single-pass unit with divided water boxes. The condenser is supported from the basement floor of the turbine building and is provided with a rubber belt-type expansion joint at the turbine exhaust connections. Steam and condensate equalizing lines are provided between the condenser shells. Half-size fifth- and sixth-point heaters are mounted in each condenser neck.

For initial condenser shell-side air removal, a noncondensing priming ejector is provided for each shell. These ejectors function by using steam from the auxiliary steam system (Section 10.4.1).

Two twin-element, two-stage, steam jet air ejector units, each complete with inter- and after-condensers, are provided for removing noncondensible gases from the condenser shells during normal operation. For normal air removal, one element of each ejector unit is operated per condenser shell. The ejectors function by using auxiliary steam and normally discharge to the ventilation vent. The air ejector discharge is diverted to the reactor containment on high radioactivity in the discharge.

The condenser air removal equipment is discussed in more detail in Section 10.4.6.

The condenser hotwell normally contains 71,000 gallons of condensate. Provisions have been made for detecting circulating water inleakage by sampling condensate at the condensate pump discharge.

The condenser tubes are continuously cleaned on-line by an Amertap tube cleaning system complete with controls, piping, reinjection and recirculation pumps, collector, and sponge rubber balls.

10.4.4.3 Design Evaluation

The condenser hotwell is of the deaerating type capable of reducing the oxygen content of the condensate to less than 0.005 ppm. The deaerating capability is necessary as there is no deaerating feedwater heater in the feedwater cycle.

10.4.4.4 Tests and Inspections

During preoperational testing, unit trips are simulated to check the ability of the condenser to handle the maximum bypass steam dump flow as discussed in Section 10.3.1.

10.4.4.5 Instrumentation Application

The condenser tube cleaning equipment is designed to operate in automatic or manual mode. Once it is put into operation, the equipment can be operated either locally (automatic or manual) or from the main control room (automatic only). Local or MCR operation is determined by a control transfer switch on the system mimic control panel located in the turbine building basement.

Condenser hotwell level is monitored both locally and in the main control room.

Alarms are provided in the main control room for condenser tube cleaning equipment trouble and condenser hotwell high and low levels.

Local instrumentation is provided as required.

10.4.5 Lubricating Oil System

10.4.5.1 Design Basis

See Section 10.1.

All piping is designed in accordance with the ASME Code for Pressure Piping, ANSI B31.1-1967.

10.4.5.2 System Description

The lubricating oil system, shown in Figure 10.4-7 and Reference Drawing 9, is provided to perform the following functions:

1. Store lubricating oil.
2. Supply oil to and receive oil from the turbine-generator oil reservoir.
3. Purify a side stream of oil from the turbine-generator oil reservoir on a continuous bypass basis.
4. Clean and reclaim used oil from the storage tanks, pumping it from the “used oil” storage tank via the conditioner to the “clean oil” storage tank.

The lubricating oil system consists of a 10,000-gallon turbine oil reservoir, two 16,000-gallon storage tanks, a lube-oil conditioner, a combination fill/batch cleaning pump, and a combination circulating/drain pump. The combination fill/batch cleaning pump and the two 16,000-gallon storage tanks are common to both units.

The combination fill/batch cleaning pump is a two-speed pump that is operated at its higher speed for draining purposes and at its lower speed for circulating the lube-oil through the system.

The pumps and piping are arranged so that oil can be processed from the oil reservoir or either of the two storage tanks. The process oil can be returned to the oil reservoir or to either of the storage tanks.

The two 16,000-gallon storage tanks are normally designated “clean” and “used,” but are interchangeable.

A lubricating oil purifier is provided to supplement the turbine lube-oil conditioner.

The turbine lube-oil reservoir is the source of lubricating oil for the turbine generator.

10.4.5.3 **Design Evaluation**

The pumps and piping are arranged so that oil can be processed from the oil reservoir or either of the two storage tanks. The process oil can be returned to the oil reservoir or to either of the storage tanks.

The lube-oil tanks and lube-oil fill pump are located in a fireproof room equipped with a fire-protection sprinkler system (Section 9.5.1), and vent fans.

The lube-oil reservoir, lube-oil conditioner, and lube-oil circulating pumps are also protected by a sprinkler system.

The lube-oil conditioner is surrounded by a sump to accommodate a loss of oil in case of a rupture of the conditioner.

Vapor extractors purge oil fumes from the oil conditioner and reservoir and exhaust to the atmosphere outside the turbine building.

10.4.5.4 **Tests and Inspections**

The lube-oil piping is hydrostatically tested before initial operation. Other tests and inspections are performed on a periodic basis.

10.4.5.5 **Instrumentation Application**

Control switches for the lube-oil circulating and lube-oil fill pumps are local only.

An alarm is provided in the main control room for low level in the lube-oil conditioner.

Local instrumentation is provided where required.

10.4.6 Secondary Vent and Drain Systems

10.4.6.1 Design Basis

See Section 10.1.

Because the steam and power conversion system is normally nonradioactive, vents and drains are arranged in much the same manner as those in a fossil-fueled power station. However, because air ejector vents and steam generator blowdown can possibly become contaminated and because they discharge to the environment, they are monitored and discharged under controlled conditions.

All piping penetrating the containment is designed in accordance with the Code for Nuclear Power Piping, ANSI B31.7-1969, up to and including the containment isolation valves.

All other piping is designed to the Code for Pressure Power Piping, ANSI B31.1-1967.

10.4.6.2 System Description

Vents from the turbine generator, which handle carbon dioxide, hydrogen, oil vapor, and other nonradioactive gases, are discharged directly to the atmosphere outside the turbine building.

Generally, secondary plant piping drains to the condenser.

The condenser air ejector vent is shown in Reference Drawing 1.

There are two priming ejectors and two twin-element, two-stage steam jet air ejectors serving both main condensers. The priming ejectors are used to evacuate large air quantities from the condensers during start-up. The two-stage steam jet air ejectors are used during normal operation to remove accumulated noncondensibles from the condensers.

The priming ejectors take suction from the air suction headers leading from the condensers and discharge to the atmosphere.

The twin-element, two-stage steam jet air ejectors take suction from the air suction headers leading from the condensers and discharge to the atmosphere, but the discharge is diverted to the reactor containment if the radiation monitoring system (Section 11.4) detects radioactivity in the discharge stream. The air ejector vapors and motive steam are condensed by condensate being circulated through the tube side of the inter- and after-condensers of the air ejectors. A loop seal automatically drains the intercondenser back to the main condenser. The after-condensers drain to the turbine building sump through a loop seal.

If a steam generator tube leak develops with subsequent contamination of the steam, the radioactive noncondensible gases would be detected by the radiation monitor located in the air ejector discharge line. When the radioactivity level reaches the setpoint of the monitor, trip valves in the air ejector discharge lines will automatically divert the discharge to the reactor containment. Details of the radiological evaluation for normal operation are discussed in Chapter 11.

Each steam jet air ejector is designed to remove 25 cfm of free air at 1 inch Hg abs when supplied with 1600 lb/hr of saturated steam at 140 psig. During normal operation, it is anticipated that 12.5 scfm of air and 41.5 lb/hr of steam per unit will be released to the atmosphere and that 1800 lb/hr of condensate will be drained to the turbine building sump.

Each steam generator is provided with blowdown connections for the control of the ionic impurity concentrations on the shell (secondary) side of the steam generator. The steam generator blowdown system is shown in Figure 10.4-8 and Reference Drawing 10.

Each blowdown line contains three normally open trip valves, two inside the containment and one outside. The steam generator blowdown system is divided into two parallel systems. Either can be isolated from the other or both can be operated simultaneously.

The first of these systems is the high-capacity steam generator blowdown system. This system is normally aligned to receive blowdown. The rate of blowdown is controlled by flow control valves and uses blowdown flash tank BD-TK-2. The normal blowdown rate for the high-capacity blowdown system is approximately 90,000 lb/hr with a system design rate of 100,000 lb/hr. The design of this system allows for heat recovery by two means: (1) by use of a flash tank that returns steam to the third-point feedwater heaters, and (2) by use of a flash tank drains cooler that transfers heat from the drains to the main condensate system.

During steam generator blowdown, the liquid passes to the flash tank, where the steam is drawn off to the third-point feedwater heaters, and the liquid is drained to the blowdown flash tank drain cooler, then discharged to the circulating water discharge tunnel. A continuous radiation monitor and a sampling line for manual grab sampling are located in the cooled flash tank drain line upstream of their point of discharge to the circulating water discharge tunnel.

A pair of pressure-control valves on the flash tank vent line keep a minimum backpressure on the tank to limit the amount of flashing during reduced load operation.

The blowdown from each steam generator is individually monitored for radioactivity as described in Section 11.4. If the radiation monitor detects contamination exceeding a set limit in the blowdown sample, an alarm is initiated in the main control room. Details of the radiological evaluation are discussed in Chapter 11. The radiation monitor in the high-capacity blowdown system effluent line does not perform a safety function, but is included in the design for added protection against release of radiation to the environment.

The high-capacity blowdown system is automatically terminated, after a short time delay to prevent spurious trips, for any of the following abnormal conditions:

1. High-high flash tank level
2. Low-low flash tank level

3. High flash tank pressure
4. High condenser pressure (no time delay)
5. High effluent discharge radiation
6. High-high drains cooler outlet temperature
7. Low-low inlet flow (2 out of 3 trip matrix)
8. High-high inlet flow
9. High-high discharge flow
10. Loss of power to either the control cabinet or radiation monitor

The high-capacity blowdown system has an automatic feature that trips the pressure control valve (BD-PCV-100) should either extraction steam non-return valve trip closed (ES-NRV-103A, ES-NRV-103B). The non-return valves are tripped closed on high-high feedwater heater level and turbine trip. This action will close BD-PCV-100 and the blowdown flash tank pressure will be controlled by BD-PCV-101 which diverts steam to the condenser. The high-capacity steam generator blowdown system is isolated automatically on a containment isolation signal.

The second steam generator blowdown system is the low-capacity blowdown system, in which the rate of blowdown is manually regulated by hand-control valves, and uses blowdown tank BD-TK-1. This system is a backup to the high-capacity steam generator blowdown system.

When the low-capacity blowdown system is in operation, blowdown from any or all of the three steam generators passes to and flashes in the blowdown tank. The blowdown tank is equipped with a vent condenser that condenses vapor discharge from the tank. Condensate from the blowdown tank and vent condenser is drained to the liquid waste disposal system (Section 11.2). Noncondensibles are vented to the atmosphere.

Using the low-capacity system, the three steam generators can blow down normally 10,900 lb/hr, to a maximum of approximately 40,000 lb/hr, of water to the blowdown tank and subsequently to the liquid waste disposal system.

The low-capacity steam generator blowdown system is isolated automatically on a containment isolation signal.

10.4.6.3 **Design Evaluation**

Loss of power or air causes the trip valve in the air ejector line to the ventilation vent to fail closed, thus preventing possible radioactive contaminants in the condenser steam space from reaching the atmosphere. In addition, the air-operated shutoff valve in the steam supply lines to the air ejectors also fails closed on a loss of power or air.

The trip valves leading to the containment are part of the containment isolation system (Section 6.2.4). A containment isolation signal will over-ride any other signal the valves receive.

Loss of power or air will cause the three blowdown trip valves for each steam generator to fail closed. Two of these valves are part of the containment isolation system (Section 6.2.4) and will also close automatically on an auxiliary feedwater pump auto start signal (Section 10.4.3), or by AMSAC activation. The two valves inside containment close automatically in the event of excess flow, as described in Section 3C.5.4.6.2.1.

10.4.6.4 **Tests and Inspections**

Vent and drain lines are hydrostatically tested before initial operation.

Valves that are part of the containment isolation system are tested in accordance with Technical Specifications.

10.4.6.5 **Instrumentation Application**

Push buttons are provided in the main control room for opening and closing the control valves admitting steam to the air ejectors. Push buttons are also provided for opening and closing the containment isolation blowdown trip valves.

An air leakage meter is provided with each main condenser air ejector to make checks of system air leakage during normal operation.

The position of the trip valves that open the air ejector discharge to the containment is indicated in the main control room.

Alarms are provided in the main control room for high radioactivity in the air ejector air discharge and steam generator blowdown.

The steam generator blowdown system includes two containment isolation trip valves per steam generator. Containment isolation trip valves TV-BD-100A, B, C, D, E, and F are normally open and fail closed on a loss of air or loss of electrical power to the associated solenoid valve. A flow switch contact in the control circuitry for trip valves TV-BD-100B, D, F, G, H, and J is present for the intended functioning of isolating a high-flow condition caused by possible downstream pipe break. Circuitry has been installed to prevent high-flow trips on the steam generator blowdown lines during initial pressurization of the steam generator. The flow switch trip signal is blocked during the initial pressurization of the blow-down lines. Once pressurized, the blocking signal will automatically be cleared and thus will not defeat the intended function of the high-flow trip for downstream pipe breaks.

10.4.7 Bearing Cooling Water System

10.4.7.1 **Design Basis**

See Section 10.1.

The turbine plant equipment is designed for full-load operation with bearing cooling water supplied at a maximum temperature of 95°F.

All piping is designed in accordance with the ASME Code for Pressure Piping, ANSI B31.1-1967 except effective March 2005, non-metallic chemical addition piping is designed in accordance with ASME B31.3, 2002 Edition, Process Piping.

10.4.7.2 System Description

The bearing cooling water system is shown schematically in Figure 10.4-9 and Reference Drawings 11 and 12. Table 10.4-6 presents design data for the major system components. The bearing cooling water system supplies cooling water to the steam and power conversion system equipment. The bearing cooling water system is normally a closed-loop cooling system that uses an induced-draft cooling tower. The cooling tower consists of four cells (two cells for each unit), which are erected over a common cold-water basin. Provision has been made in the system to switch operation from the cooling tower to Lake Anna as discussed below.

With the cooling tower placed in service, the bearing cooling water pumps take suction through a header common to both units from the cooling tower's cold-water basin, and discharge through fine mesh self-cleaning strainers before circulating through the equipment and returning to the cooling tower via a header common to both units. The system is also provided with a chemical addition system and sample points for corrosion control.

As an alternate cooling source when the cooling tower is not in service, the bearing cooling water pumps take suction from the circulating water intake tunnel in the turbine building and discharge through fine mesh self-cleaning strainers before circulating through the equipment and discharging to the circulating water discharge tunnel.

Two 100%-capacity mechanical chiller condenser pumps are installed in parallel with the Unit 2 bearing cooling water pumps and associated system components. This arrangement permits the mechanical chiller condenser pumps to take suction from and discharge back to the same source as the bearing cooling water pumps. The mechanical chiller condenser pumps are designed to supply cooling water to the condenser of the mechanical chilled water unit described in Section 9.2.2 (see Figure 10.4-9 and Reference Drawing 11).

The principal equipment served by the bearing cooling water is as follows:

Equipment	Design Flow (gpm)
Generator hydrogen coolers	4500 (U1), 4000 (U2)
Hydrogen seal-oil coolers	360
Turbine oil coolers	2934
Exciter cooler	300
Isolated phase bus duct air coolers	276 (U1) 130 (U2)
Sample coolers	50

Equipment	Design Flow (gpm)
Condensate, feed, and heater drain pumps	300
Flash evaporator (during unit shutdown) (not used)	9280
Central station air conditioner (Unit 1 only)	710
Chiller condenser	4000
Chiller condenser air ejector	100
HP fluid reservoir oil coolers	20
Vacuum priming pumps	45
Mechanical chiller (Unit 2 only)	1500
Mechanical chiller - Unit 1 (SG on-line chemistry)	42
Mechanical chiller - Unit 2 (SG on-line chemistry)	25 each, quantity of 2
Primary sample coolers (6/unit) (SG on-line chemistry)	7 each
Primary sample coolers (6/unit) (SG on-line chemistry)	12 each
Main generator breaker (Unit 1 only)	50

As an alternate source of cooling water, the chilled water subsystem can supply the Unit 1 isolated phase bus duct cooler. The flash evaporator is obsolete and no longer used. The bearing cooling makeup line between Units 1 and 2 that used to provide makeup water to the flash evaporator has been removed from service. The cooling water flowing through the major equipment coolers, such as the hydrogen and air coolers, is controlled automatically to maintain constant temperature of the cooled fluid.

10.4.7.3 **Design Evaluation**

To provide operational flexibility and system reliability, provision has been made to transfer system operation from the cooling tower to Lake Anna (via the intake and discharge tunnels). Each unit is also provided with two full-size bearing cooling water pumps, cooling tower makeup pumps, and self- cleaning strainers to increase system reliability. Normally, only one set of pumps and strainers would be operating, with the remaining pumps and strainers for backup service.

Units 1 and 2 share a common suction line and return between the cooling tower and the bearing cooling water pumps.

A loss of bearing cooling water would require a unit shutdown.

10.4.7.4 **Tests and Inspections**

All piping is hydrostatically tested before initial operation. The usage of the system during plant operation provides a continuing check of system functionality status; specific periodic testing is not required.

10.4.7.5 **Instrumentation Application**

Control switches from the bearing cooling water pumps, cooling tower makeup pumps, and cooling tower fan motors are provided in the main control room. Control switches are also provided in the main control room for the cooling tower bypass line valves, the circulating water tunnel isolation valves, and the cooling tower isolation valves. Local control switches are provided for the bearing cooling water self-cleaning strainers.

The principal alarms provided in the main control room are as follows:

1. Bearing cooling water pumps low discharge pressure.
2. Bearing cooling water pumps low suction pressure.
3. Bearing cooling water pump auto trip/system misaligned.
4. Cooling tower makeup pump low discharge pressure.
5. Mechanical chiller condenser pump low discharge pressure (Unit 2).
6. Loss of power to cooling tower fan motor.
7. Cooling tower basin high/low temperature.
8. Cooling tower basin high/low water level.
9. High cooling tower fan vibration.

Local instrumentation is provided where required.

10.4.8 Condensate Polishing System—Powdered-Resin Type

The function of the condensate polishing system is to remove impurities from the condensate stream that result from condenser tube leakage and to produce a high-quality effluent within the feedwater and steam generator chemistry specifications. The condensate polishing system is shown in Reference Drawing 5.

10.4.8.1 **Design Basis**

The design bases of the condensate polishing system are the following:

1. The system, in conjunction with continuous steam generator blowdown, shall maintain the condensate water chemistry in accordance with the requirements of the NSSS vendor.

2. Sufficient demineralizer redundancy shall be provided to allow demineralizer precoating while the system retains its normal polishing capacity.
3. The system shall be sized to accommodate 100% condensate flow.

10.4.8.2 **System Description**

The condensate polishing system consists of five powdered-resin filter demineralizers in the condensate stream between the gland steam condenser and the chemical feed injection point. The system is capable of polishing the full condensate flow while one of the demineralizers is being backwashed and precoated or is on standby. Anion resin is operated in the hydroxide cycle and cation resin is operated in the ammonia, hydrogen morpholine, or ethanolamine cycle. The cation/anion resin ratio can be varied over a wide range, with various mixtures determined by condensate chemistry. Each vessel contains approximately 350 lb of resin. The demineralizer design includes the provision for operation of the vessels without a resin precoat, during which time they function as a mechanical filter. Each of the five 6-foot-diameter cylindrical vertical filter demineralizers has a flanged removable head that allows internal assemblies to be easily removed if required. Each vessel contains filter elements sized to hold the resin. The 60- to 400-mesh ion-exchange resin is used as a thin precoat (1/16-inch to 1/2-inch thick) on the filter elements. The vessels' hold pump will automatically start in the event that flow falls below that required to retain the resin coat on the filter element. Powdered resin in this system is disposed of after its capacity is expended. When a vessel needs new resin, the exhausted filter demineralizer is isolated and a combination of condensate and air is admitted to remove the resin by backwashing. The backwash slurry is transferred to the backwash recovery tanks for separation and settling. Air used in the backwash operation is filtered by HEPA filters before being discharged. Each backwash will require up to 15,000 gallons of condensate.

New resin, which is received fully regenerated by the manufacturer, is placed in the precoat tank along with condensate quality water. The resin is mixed in the condensate water using an agitator to form a slurry. The slurry is then pumped by the precoat pumps through the previously backwashed demineralizer until the filter elements are completely coated.

The expended resin in the backwash recovery tanks is transferred to the phase separator for further settling before being drained by gravity flow for waste resin disposal. Excess water is returned to the backwash recovery tanks. When another filter demineralizer vessel requires a new precoat, the water contained in the backwash recovery tank can be pumped through the vessel requiring the precoat.

All piping is constructed to ANSI B31.1-1967. Pressure vessels are fabricated, inspected, tested, and stamped in accordance with the ASME Code, Section VIII, Division 1, 1974.

Radioactivity would be concentrated in the condensate polishing system only if primary to secondary leakage occurs in a steam generator.

10.4.8.3 **Safety Evaluation**

Normally, condensate polishing will be used to control inleakage during short periods of time or until the inleakage can be repaired.

In the event of high primary to secondary leakage, the vessels can be backwashed should the radiation level reach an unacceptable value. The resin can be sent to the liquid waste system for solidification and disposal with other wastes (See Section 11.2.3).

10.4.8.4 **Tests and Inspections**

The condensate polishing system can be in continuous operation whenever the condensate system is operating. Even with no condenser inleakage, each filter demineralizer may be precoated and backwashed periodically, if required by system chemistry. The conductivity of the condensate leaving the condenser hotwells is monitored continuously during plant operation, thus providing a method of evaluating system performance and determining the need for resin replacement.

10.4.8.5 **Instrumentation Application**

The condensate polishing control panel contains two redundant programmable logic controllers (PLC), power supplies, communication modules, and operator interface units (CRT based). This redundancy results in a high level of system reliability and flexibility.

The PLC performs the automatic control functions and modulation of control variables for the CP System. Display of equipment status, indications of process variables, and alarm status is provided on the CRT. All of the operator actions are initiated through programmable function keys, the keyboard, or icon type graphical symbols.

The conductivity of the effluent condensate from any of the five Powdex Vessels is monitored by the PLC when a resin precoat is present. Each of the vessel sample lines contains two conductivity probes and a cation chamber. The conductivity measurements from the vessel and cation chamber discharge are monitored by the PLC and will provide an alarm on high conductivity.

A differential pressure transmitter is provided to monitor the differential pressure across each filter demineralizer and a differential pressure transmitter is provided for the entire condensate polishing system. A trouble alarm signal is provided at the main control board. A high differential pressure alarm is logged on the CRT screen. The polishing system will automatically be bypassed on high system differential pressure.

All system alarms are provided and indicated on the CRT screen at the local control panel to warn operators of faulty and/or out of specification system parameters. In turn, a general trouble alarm is provided at the main control board to notify operators to investigate system operating conditions.

10.4 REFERENCE DRAWINGS

The list of Station Drawings below is provided for information only. The referenced drawings are not part of the UFSAR. This is not intended to be a complete listing of all Station Drawings referenced from this section of the UFSAR. The contents of Station Drawings are controlled by station procedure.

	Drawing Number	Description
1.	11715-FM-072A	Flow/Valve Operating Numbers Diagram: Auxiliary Steam and Air Removal System, Unit 1
	12050-FM-072A	Flow/Valve Operating Numbers Diagram: Auxiliary Steam and Air Removal System, Unit 2
2.	11715-FM-16B	Flow Diagram: Auxiliary Steam, Primary Plant
3.	11715-FM-077A	Flow/Valve Operating Numbers Diagram: Circulating Water System, Unit 1
	12050-FM-077A	Flow/Valve Operating Numbers Diagram: Circulating Water System, Unit 2
4.	11715-FM-17A	Flow Diagram: Condensate
	12050-FM-17A	Flow Diagram: Condensate
5.	11715-FM-17B	Flow Diagram: Condensate Polishing Demineralizer
	12050-FM-17B	Flow Diagram: Condensate Polishing Demineralizer
6.	11715-FM-102A	Flow/Valve Operating Numbers Diagram: Chemical Feed Systems, Unit 1
	12050-FM-102A	Flow/Valve Operating Numbers Diagram: Chemical Feed Systems, Unit 2
7.	11715-FM-074A	Flow/Valve Operating Numbers Diagram: Feedwater System, Unit 1
	13075-FM-102C	Flow/Valve Operating Numbers Diagram: Chemical Feed System, Unit 1
	12050-FM-074A	Flow/Valve Operating Numbers Diagram: Feedwater System, Unit 2
8.	11715-FM-102B	Flow/Valve Operating Numbers Diagram: Chemical Feed Systems, Unit 1
	12050-FM-102A	Flow/Valve Operating Numbers Diagram: Chemical Feed Systems, Unit 2

	Drawing Number	Description
9.	11715-FM-083A	Flow/Valve Operating Numbers Diagram: Lube Oil Lines, Unit 1
10.	11715-FM-098A	Flow/Valve Operating Numbers Diagram: Steam Generator Blowdown System, Unit 1
	12050-FM-098A	Flow/Valve Operating Numbers Diagram: Steam Generator Blowdown System, Unit 2
11.	11715-FM-24A	Flow Diagram: Bearing Cooling Water
	12050-FM-24A	Flow Diagram: Bearing Cooling Water
12.	11715-FM-24B	Flow Diagram: Bearing Cooling Water
13.	11715-LSK-5-13B	Turbine Driven, Steam Generator, Auxiliary Feedwater Pumps
	12050-LSK-5-13B	Turbine Driven, Steam Generator, Auxiliary Feedwater Pumps
14.	11715-LSK-5-13C	Auxiliary Feedwater Control Valves
	12050-LSK-5-13C	Auxiliary Feedwater Control Valves

Table 10.4-1
AUXILIARY FEEDWATER SYSTEM DESIGN BASIS

AFW Pump Mark Number	Design Basis Delivered Flow to S/G Required by Accident Analysis (gpm)	Comments
1/2-FW-P-2	400	Turbine Driven AFW Pumps
1/2-FW-P-3A, 3B	300	Motor Driven AFW Pumps

Note: The main feedline break analysis requires a minimum auxiliary feedwater flow of 300 gpm delivered to an intact steam generator at the steam generator safety valve setpoint (with allowance for uncertainties). See Section 15.4.2.2. The turbine driven AFW pump minimum required flow, 400 gpm, exceeds the required flow for the main feedline break analysis and provides adequate flow for analyses which assume the motor driven AFW pumps are unavailable. The AFW system minimum delivered flow calculation determines the minimum delivered AFW flow for each AFW pump, with mini-flow recirculation and oil cooler flows included, to its respective steam generator at the minimum MSSV setpoint pressure plus uncertainty and presents resulting flow margins over minimum required accident analysis flows.

Table 10.4-2
DESIGN DATA FOR MAJOR COMPONENTS
OF CONDENSATE AND FEEDWATER SYSTEMS

Surface condenser (CN-SC-1A and B)	
Duty (total)	6,594,900,000 Btu/hr
Tube side design pressure	20 psig
Shell and tube support plates	ASTM A285-C
Tube sheets	304 stainless steel
Tubes	304 stainless steel
Shell material	ASTM A285-C
Shell design pressure	15 psig to full vacuum
Shell design temperature	250°F

Air ejector after/intercondenser (CN-EJ-1A and B)	
Duty	3,208,697 Btu/hr
Tube side design pressure	700 psig
Steam chest material	ASTM-A285-C
Shell material	ASTM-A285-C
Tube material	304 stainless steel
Shell design pressure	15 psig to full vacuum
Shell design temperature	250°F

Condensate pumps (CN-P-1A, B, and C)	
Capacity (each)	8500 gpm (1 backup)
Design pressure	550 psig (casing)
Casing material	ASTM A48
Impeller material	ASTM B143
Design temperature	120°F
Head	1230 ft

Condensate storage tank (1-CN-TK-2)	
Capacity	300,000 gal
Design temperature	115°F
Design pressure	atmospheric
Shell material	ASTM-A285
Head material	ASTM-A285-C
Bottom plate	ASTM-A285-C

Table 10.4-2 (continued)
DESIGN DATA FOR MAJOR COMPONENTS
OF CONDENSATE AND FEEDWATER SYSTEMS

Condensate storage tank (1-CN-TK-1)	
Maximum Capacity	119,568 gal
Normal Operating Capacity	110,000 gal
Design temperature	120°F
Design pressure	atmospheric
Shell material	ASTM A285-C
Head material	ASTM-A285-C
Bottom plate	ASTM-A285-C
Tank is missile protected by surrounding concrete structure	

Gland steam condenser (1 & 2 CN-SC-2)	
Duty (each)	4,221,821 Btu/hr
Tube design pressure	700 psig
Tube design temperature	650°F
Tube	304 SS, 28 fins/inch
Tube plates, tube support plates, shell, and water box	carbon steel
Shell design pressure	14 psig
Shell design temperature	210°F

Flash evaporator makeup pumps (1-WT-P-12A,B; 2-WT-P-12A) (NOT USED)	
Capacity	340 gpm
Design temperature (casing)	35-95°F
Design pressure (casing)	100 psig
Head	60 ft
Casing material	cast iron
Impeller	bronze

Second-point heater drain receiver (1 & 2 SD-TK-2A, B)	
Capacity	400 ft^3
Design temperature	400°F
Design pressure	250 psig
Shell material	ASTM A516-70
Head material	ASTM A516-70

Table 10.4-2 (continued)
DESIGN DATA FOR MAJOR COMPONENTS
OF CONDENSATE AND FEEDWATER SYSTEMS

Flash evaporator (condenser section) (NOT USED)

Duty	61.6 x 10^6 Btu/hr
Shell design pressure	15 psig to full vacuum
Shell design temperature	325°F
Tube design pressure	700 psig
Tube design temperature	410°F
Shell material	carbon steel
Tube material	304 stainless steel
Tube sheet material	carbon steel

Flash evaporator recycle pumps (1,2-WT-P-2A, B) (Unit 1 abandoned in place)

Capacity	5800 gpm
Design temperature (casing)	130-165°F
Design pressure (casing)	150 psig
Head	55 ft
Casing material	cast iron
Impeller	bronze

Flash evaporator distillate pumps (1,2-WT-P-1A, B)

Capacity	465 gpm
Design temperature (casing)	165°F
Design pressure (casing)	300 psig
Head (NAS-39)	240 ft
Casing material	316 stainless steel
Impeller	316 stainless steel

Steam generator feed pumps (FW-P-1A, B, C)

Capacity (1 backup)	16,250 gpm
Head	1980 ft
Design temperature	400°F
Design pressure	1200 psig
Casing material	ASTM CA-6NM 13-4 chrome
Impeller (11-13 chrome)	ASTM A296-CA15

Table 10.4-2 (continued)
DESIGN DATA FOR MAJOR COMPONENTS
OF CONDENSATE AND FEEDWATER SYSTEMS

First-point heater (FW-E-1A, B)

Duty (both heaters)	678,178,530 Btu/hr
Design pressure, tube	1650 psig
Design temperature, tube	525°F
Shell material	SA516-70
Tube material	SA688 TP 304
Tube sheet material	SA350-LF2 w/304 SS overlay
Shell-side design pressure	vacuum to 475 psig
Shell-side design temperature	525°F

Second-point heater (FW-E-2A, B)

Duty (both heaters)	704,609,200 Btu/hr
Design pressure, tube	700 psig
Design temperature, tube	425°F
Shell material	SA516-70
Tube material	SA688 TP304
Tube sheet material	SA350-LF2 w/304 SS overlay
Shell design pressure	vacuum to 250 psig
Shell design temperature	425°F

Third-point heater (FW-E-3A, B)

Duty (both heaters)	310,914,960 Btu/hr
Design pressure, tube	700 psig
Design temperature, tube	395°F
Shell material	SA-285-C
Tube material	SA688 TP304
Tube sheet material	SA350-LF2 w/304 SS overlay
Shell design pressure	vacuum to 110 psig
Shell design temperature	395°F

Table 10.4-2 (continued)
DESIGN DATA FOR MAJOR COMPONENTS
OF CONDENSATE AND FEEDWATER SYSTEMS

Fourth-point heater (FW-E-4A, B)	
Duty (both heaters)	479,352,919 Btu/hr
Design pressure, tube	700 psig
Design temperature, tube	320°F
Shell material	SA-285-C
Tube material	SA688 TP304
Tube sheet material	SA350-LF2 w/304 SS overlay (4A) SA266-CL2 w/304 SS overlay (4B)
Shell design pressure	vacuum to 75 psig
Shell design temperature	320°F

Fifth-point heater (FW-E-5A, B)	
Duty (both heaters)	420,400,000 Btu/hr
Design pressure, tube	700 psig
Design temperature, tube	300°F
Shell material	ASTM-285C
Tube material	SA688 TP 304
Tube sheet material	SA105-N w/SS 304 overlay
Shell design pressure	vacuum to 50 psig
Shell design temperature	300°F

Sixth-point heater (FW-E-6A, B)	
Duty (both heaters)	725,379,000 Btu/hr
Design pressure, tube	850 psig
Design temperature, tube	300°F
Shell material	ASTM-285C
Tube material	SA688 TP304 (0.03mc)
Tube sheet material	SA350-LF2
Shell design pressure	vacuum to 50 psig
Shell design temperature	300°F

Table 10.4-2 (continued)
DESIGN DATA FOR MAJOR COMPONENTS
OF CONDENSATE AND FEEDWATER SYSTEMS

Fifth-point external drain cooler (CN-DC-1A, 1B)

Duty (both heaters)	40,200,000 Btu/hr
Design pressure, tube	700 psig
Design temperature, tube	300°F
Shell material	ASTM-285C
Tube material	SA688 TP304
Tube sheet material	ASTM A516-70
Shell design pressure	vacuum to 50 psig
Shell design temperature	300°F

High-pressure heater drain pumps (SD-1A, B, C)

Capacity	3120 gpm
Design temperature (casing)	393°F
Design pressure (casing)	675 psi
Head	650 ft
Bowl material	ASTM-A217-C5
Impeller	ASTM A-217-C5

Low-pressure heater drain pumps (SD-P-2A, B)

Capacity	1380 gpm
Design temperature (casing)	277°F
Design pressure (casing)	1200 psig
Head	1150 ft
Casing material	ASTM-A217-C5
Impeller material	ASTM-A20-C5

Moisture separator-reheaters

Duty (total)	6.7×10^8 Btu/hr
Shell design pressure	265 psig
Shell design temperature	600°F
Tube-side design pressure	1125 psig
Tube-side design temperature	600°F
Tubes	SA- 268 (TP439) Stainless Steel
Tube plates, tube support plates, shell, and water boxes	carbon steel

Table 10.4-3

CRITERIA FOR AUXILIARY FEEDWATER SYSTEM DESIGN-BASIS CONDITIONS

Condition or Transient	Classification[a]	Criteria[a]	Additional Design Criteria
Loss of main feedwater	Condition II	Peak reactor coolant system pressure not to exceed 110% of design pressure. No consequential fuel failures.	Pressurizer does not become water solid
Station blackout	Condition II	Peak reactor coolant system pressure not to exceed 110% of design pressure. No consequential fuel failures.	Pressurizer does not become water solid
Steamline rupture	Condition IV	Regulatory Guide 1.183 dose limits. Containment design pressure not exceeded.	
Feedline rupture	Condition IV	10 CFR 100 dose limits. Containment design pressure not exceeded.	Core does not uncover
Loss of all ac power	N/A	(b)	Same as blackout assuming turbine driven pump
Loss of coolant	Condition III	10 CFR 100 dose limits. 10 CFR 50 peak clad temperature limits.	
	Condition IV	10 CFR 50.67 dose limits. 10 CFR 50 peak clad temperature limits.	
Cooldown	N/A		100°F/hr 547° to 350°F

a. ANSI N18.2 (this information provided for those transients performed in the FSAR).

b. Although this transient establishes the basis for auxiliary feedwater pump powered by a diverse power source, this is not evaluated relative to typical criteria since multiple failure must be assumed to postulate this transient.

Table 10.4-4

SUMMARY OF ASSUMPTIONS USED IN AUXILIARY FEEDWATER SYSTEM DESIGN VERIFICATION ANALYSES

Transient	Loss of Feedwater (With and Without Offsite Power)	Cooldown	Main Feedline Break	Main Steam Line Break (Containment)
Max. reactor power	102% of rated thermal power (102% of 2893 MWt)	2968 MWt	102% rated thermal power (102% of 2893 MWt)	0% (of rated) - worst case
Time delay from event to reactor trip	2 sec (delay after trip)	2 sec	2 sec	0 sec
AFWS actuation signal/time delay	(Low-low/steam generator level) 1 min	NA[a]	(Low-low steam generator level) 1 min	Feedwater isolation actuation signal: safety injection signal 0 sec (no delay); flow to steam generator: 17 sec after main steam line break (which is time of feedwater isolation)
Steam generator water level at time of reactor trip	(Low-low steam generator level) 0% NR span	NA	(Low-low steam generator level) 0% NR span	Same as initial level before event
Initial steam generator inventory	103,839 lbm/steam generator	104,500 lbm/steam generator at 525.2°F	89,055 lbm/steam generator (intact) 94,148 lbm/steam generator (faulted)	151,000 lbm/steam generator
Rate of change before and after actuation	See Figures 15.2-31 and 15.2-32	NA	Turnaround greater than 2000 sec	NA
Decay heat	ANS 1979 Standard		ANS 1973 Standard	120% of ANS 1973 Standard

a. Not applicable.

Table 10.4-4 (continued)
SUMMARY OF ASSUMPTIONS USED IN AUXILIARY FEEDWATER SYSTEM DESIGN VERIFICATION ANALYSES

Transient	Loss of Feedwater (With and Without Offsite Power)	Cooldown	Main Feedline Break	Main Steam Line Break (Containment)
Auxiliary feed-water pump design pressure	1133 psia	1133 psia	1133 psia	1025 psig [c]
Minimum number of steam generators that must receive auxiliary feedwater flow	2 of 3	NA[a]	1 of 3	NA
Reactor coolant pump status	All operating (With Offsite Power) Tripped at reactor trip (Without Offsite Power)	Tripped	All operating	Tripped
Maximum auxiliary feedwater temperature	120°F	110°F	120°F	120°F
Operator action	None	NA	30 min	30 min
Main feedwater purge volume/temperature	336.9 ft^3/440°F	NA	203.1 ft^3/440°F	218 ft^3/441°F
Normal blowdown	None assumed	None assumed	None assumed	None assumed
Sensible heat	See cooldown	(b)	See cooldown	See cooldown

a. Not applicable.
b. Sources of sensible heat are conservatively determined for each transient. Sensible heat sources that are considered include the following: primary water sources, initially at rated power temperature and inventory (RCS fluid and liquid and vapor pressurizer fluid); primary metal sources, initially at rated power temperature (reactor coolant piping, pumps and reactor vessel, pressurizer, steam generator tube metal and tubesheet, steam generator metal below tubesheet, and reactor vessel internals); secondary water sources, initially at rated power temperature and inventory (liquid and vapor steam generator fluid and main feedwater purge fluid between steam generator and AFW system piping); and secondary metal sources, initially at rated power temperature (all steam generator metal above tubesheet, excluding tubes).
c. The maximum steam generator pressure is the initial steady state pressure, since this is a cooldown transient.

Table 10.4-4 (continued)

SUMMARY OF ASSUMPTIONS USED IN AUXILIARY FEEDWATER SYSTEM DESIGN VERIFICATION ANALYSES

Transient	Loss of Feedwater (With and Without Offsite Power)	Cooldown	Main Feedline Break	Main Steam Line Break (Containment)
Time at standby/time to cooldown to residual heat removal	2 hr/4 hr	2 hr/4 hr	NA[a]	NA [a]
Auxiliary feedwater flow rate	600 gpm (with power) 600 gpm (without power)	Variable	300 gpm - 1 min after trip	900 gpm to broken steam generator, 350 gpm to each intact steam generator [b]

a. Not applicable

b. The impact for increasing this auxiliary feedwater flow rate to 970 gpm was subsequently evaluated. That evaluation confirmed that with this increase in auxiliary feedwater flow, the results of the analysis for main steam line break in containment would still be within the acceptance criteria. The auxiliary feedwater flow rate to the intact steam generators is among the less significant secondary parameters. Expected variations in auxiliary feedwater flow to the intact steam generators do not invalidate the results of the analysis, so flow is conservatively modeled as a constant flow rate.

Table 10.4-5
FAILURE ANALYSIS OF AUXILIARY FEEDWATER COMPONENTS

Component	Malfunction	Remarks
Auxiliary feedwater pumps		All of the auxiliary feedwater pumps can be started manually as well as automatically. They are used to supply the steam generators with feedwater in the event of a loss of outside electric power to the plant and are essential for safe plant cooldown. All are designed as Seismic Class I. All three of the auxiliary pumps are started automatically when certain requirements are met (e.g., loss of station power, or steam generator low-low level indicators).
Motor-driven pump	Fails to start	No manual action is required. Turbine-driven pump is automatically started as shown above.
Turbine-driven pump	Fails to start	Under this situation, no pump manual action is required. Motor-driven pumps are automatically started as shown above.
Turbine-driven pump	Fails during operation	No manual action is required. If this pump fails, it will not influence the operation of the two motor-driven pumps.
Piping		All piping in this system complies with the seismic classification system of ANSI B31.7.
	Break between the 110,000-gallon emergency condensate storage tank and steam generator feed pumps	There are three independent lines from the tank to the auxiliary pumps. The two motor-driven pumps are fed by 6-inch headers, while the turbine-driven pump is supplied by an 8-inch line. This water supply is backed up by a 6-inch line to the plant fire main. (Water can also be obtained from the plant service water system as well as the 300,000-gallon condensate storage tank.)
	Break between the auxiliary feed pumps and steam generator	The three steam generators are independently supplied by a separate auxiliary feedwater pump. The turbine-driven pump supplies one steam generator through a 4-inch line while the remaining steam generators are each supplied by one of the motor-driven pumps through the 6-inch headers. The 4-inch header and the two 6-inch headers are isolated by valves to ensure independent flow paths. This system ensures flow to one steam generator for any combination of a high-energy pipe break and a single active failure (see Chapter 15 for additional information).

Table 10.4-5 (continued)
FAILURE ANALYSIS OF AUXILIARY FEEDWATER COMPONENTS

Component	Malfunction	Remarks
Valves		There are various valves that will isolate the respective feedlines and the corrective action taken is the same for many of them (i.e., if the 6-inch line breaks, the line will be closed off at the storage tank). The major valves are discussed below.
Pressure-control valves in the two 6-inch headers from the auxiliary feedwater pumps	Fail Closed	The two pressure-control valves in the two 6-inch headers and an orifice in the 4-inch line from the turbine-driven pump control backpressure to prevent pump runout due to a downstream pipe break. If any of the pressure-control valves fail closed, the pump can be shut down without affecting flow to the remaining steam generator.
	Fail Open	If any one of the pressure control valves fails open, the corresponding motor driven auxiliary feedwater pump will deliver a maximum flow of 845 gpm to its steam generator. This flow rate is below the 900 gpm which was assumed in the safety analysis. Therefore, the flow rate satisfies the requirements of the safety analysis, The pump can be shut down without affecting flow to the remaining steam generators.
Air-operated and motor-operated hand control valves for steam generator lines	Fail	One steam generator supply has an air-operated hand-control valve and two steam generator supplies have motor-operated valves. The motor-operated valves are set in the open position. Any active failure of hand- control valves can only affect the flow to the respective steam generator. The flow of feedwater to the remaining two steam generators is unaffected. It should also be noted that the entire steam generator auxiliary feedwater system is provided with a tornado- and missile-protected enclosure.

Table 10.4-6
DESIGN DATA FOR MAJOR COMPONENTS OF THE
BEARING COOLING WATER SYSTEM

Bearing cooling water pumps (1BCP-1A and B)	
Capacity	12,500 gpm
Head	185 ft
Operating temperature	33°F to 94°F
Design temperature	94°F
Design pressure	80 psig
Casing material	ASTM A48 C1. 30
Impeller	ASTM B143 C1.1A

Bearing cooling water system cooling tower (1 & 2-BC-CT-1)	
Flow per tower	12,500 gpm
Flow per cell	6250 gpm
Design inlet water temperature	115°F
Design outlet water temperature	92°F
Design ambient dry bulb	95°F
Design ambient wet bulb	78°F
Structural members	Fiber Reinforced Plastic (FRP)
Fill and drift eliminator	Polypropylene/PVC
Outer wall sheathing	16 oz/ft^2 FRP

Cooling tower makeup pumps (BC-P-3A & B)	
Capacity	850 gpm
Design temperature (casing)	32-95°F
Design pressure (casing)	150 psig
Head	150 ft
Casing material	B-62-4A (bronze)
Impeller	B-62-4A (bronze)

Mechanical chiller condenser pumps (2-BC-P-5A & B)	
Capacity	1500 gpm
Design temperature	32-95°F
Design pressure (casing)	250 psig
Head	180 ft
Casing material (cast iron)	A-48CL30B
Impeller material (bronze)	CDAC83500

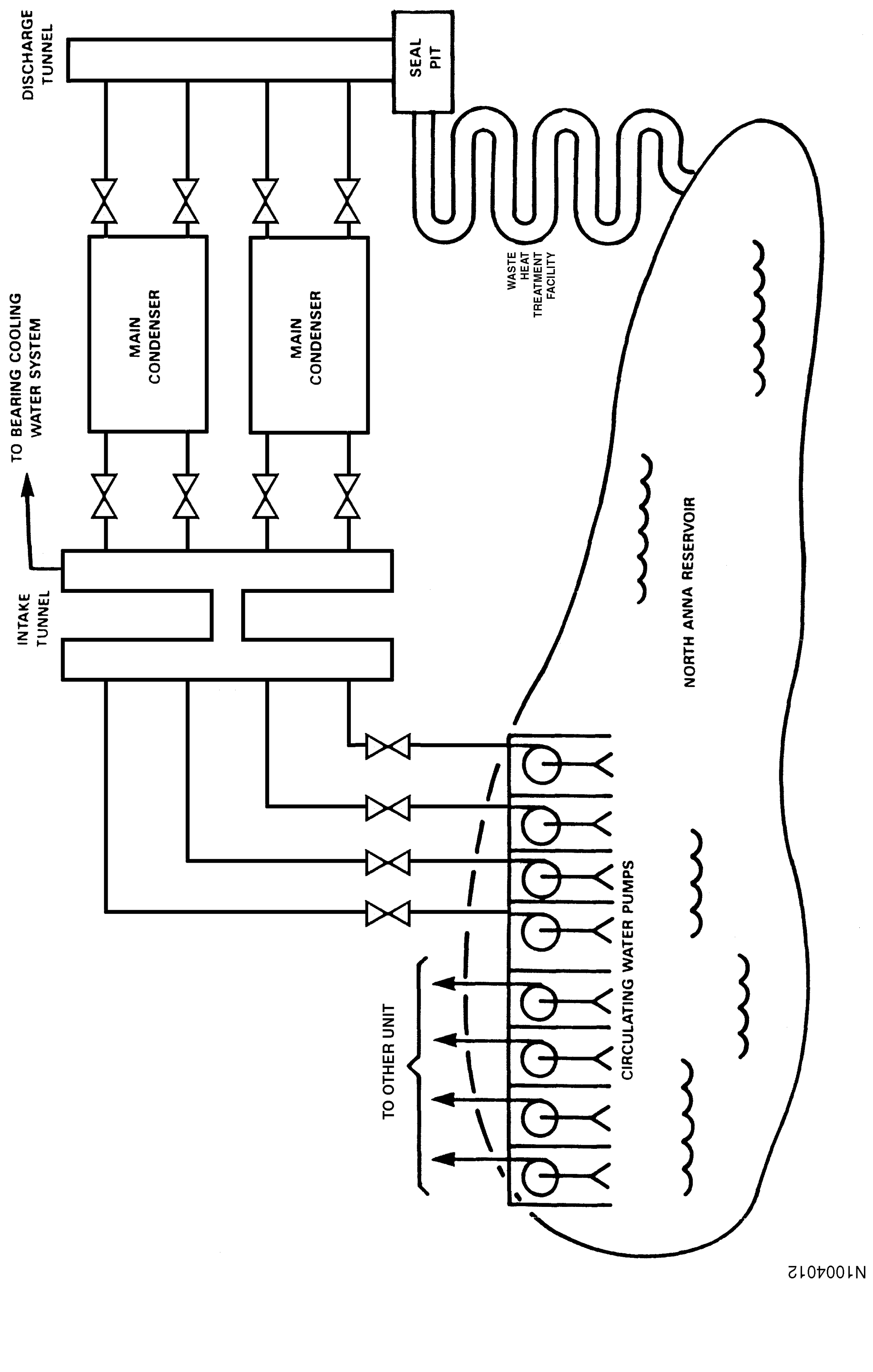
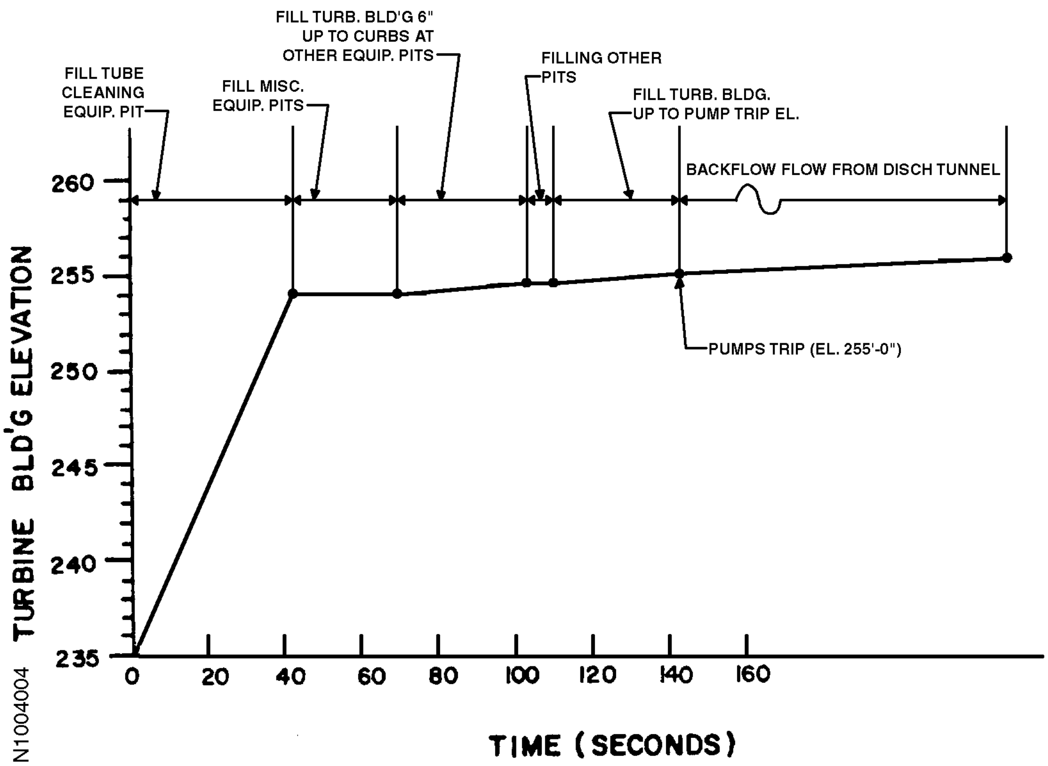


Figure 10.4-1
CIRCULATING WATER SYSTEM

Figure 10.4-2
TURBINE BUILDING FLOODING
AFTER CIRCULATING WATER EXPANSION JOINT RUPTURE [a]



a. Figure presented is based on the failure of a condenser outlet expansion joint. An inlet expansion joint failure would result in a change in the order of the filling of the tube cleaning equipment pit and miscellaneous equipment pits.

Figure 10.4-3 (SHEET 1 OF 4)
CONDENSATE SYSTEM

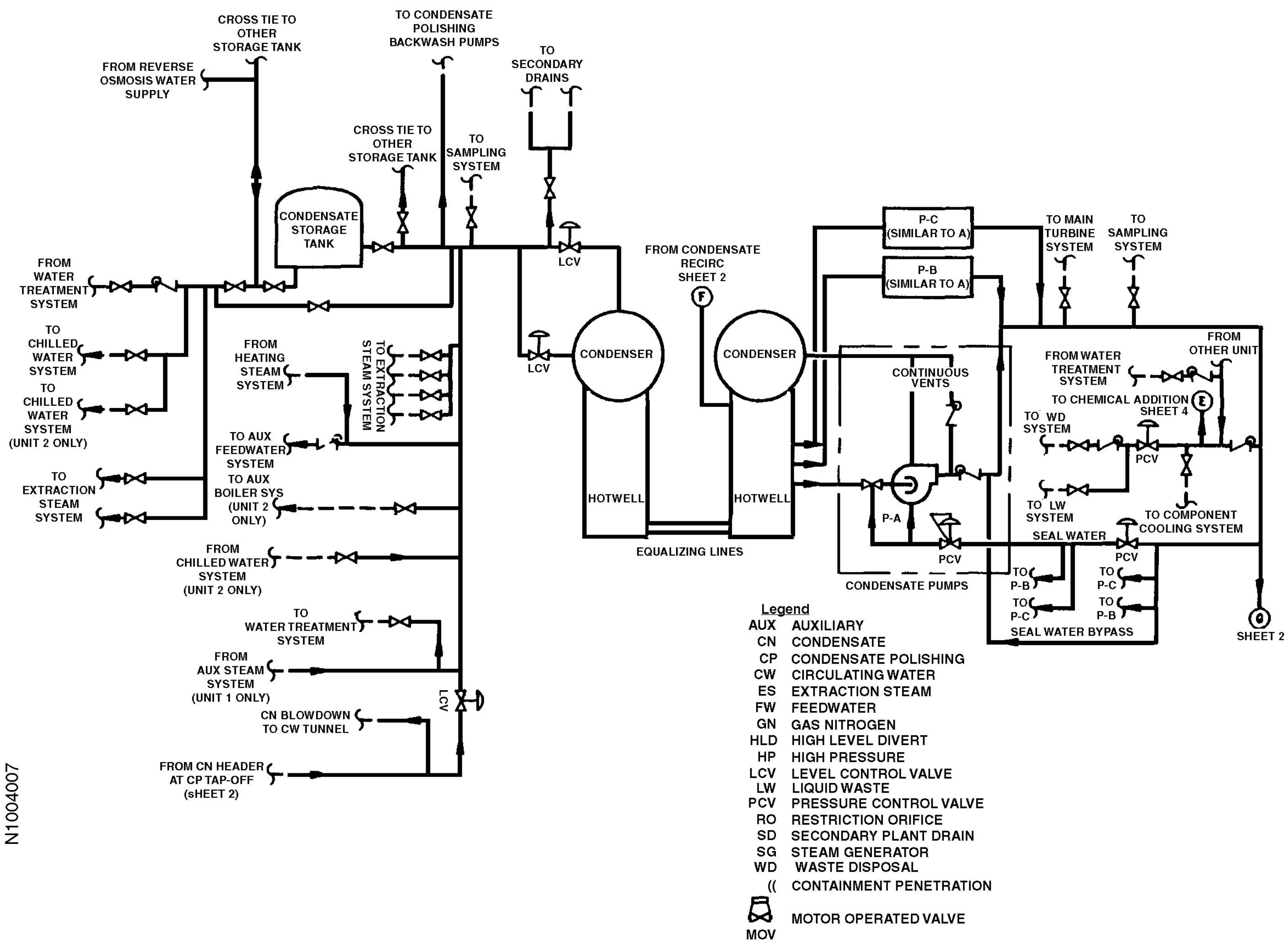


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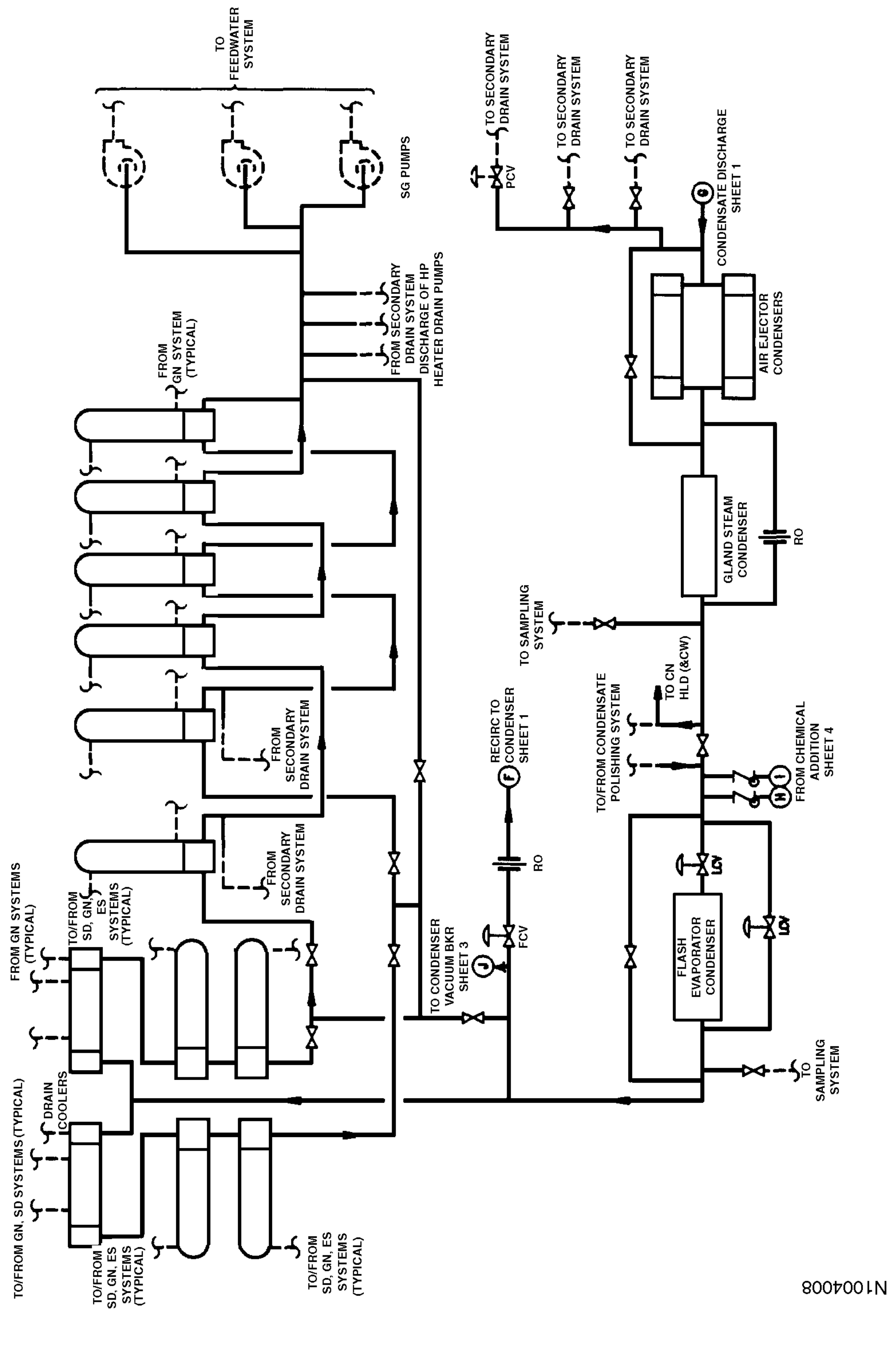
Figure 10.4-3 (SHEET 2 OF 4)
CONDENSATE SYSTEM



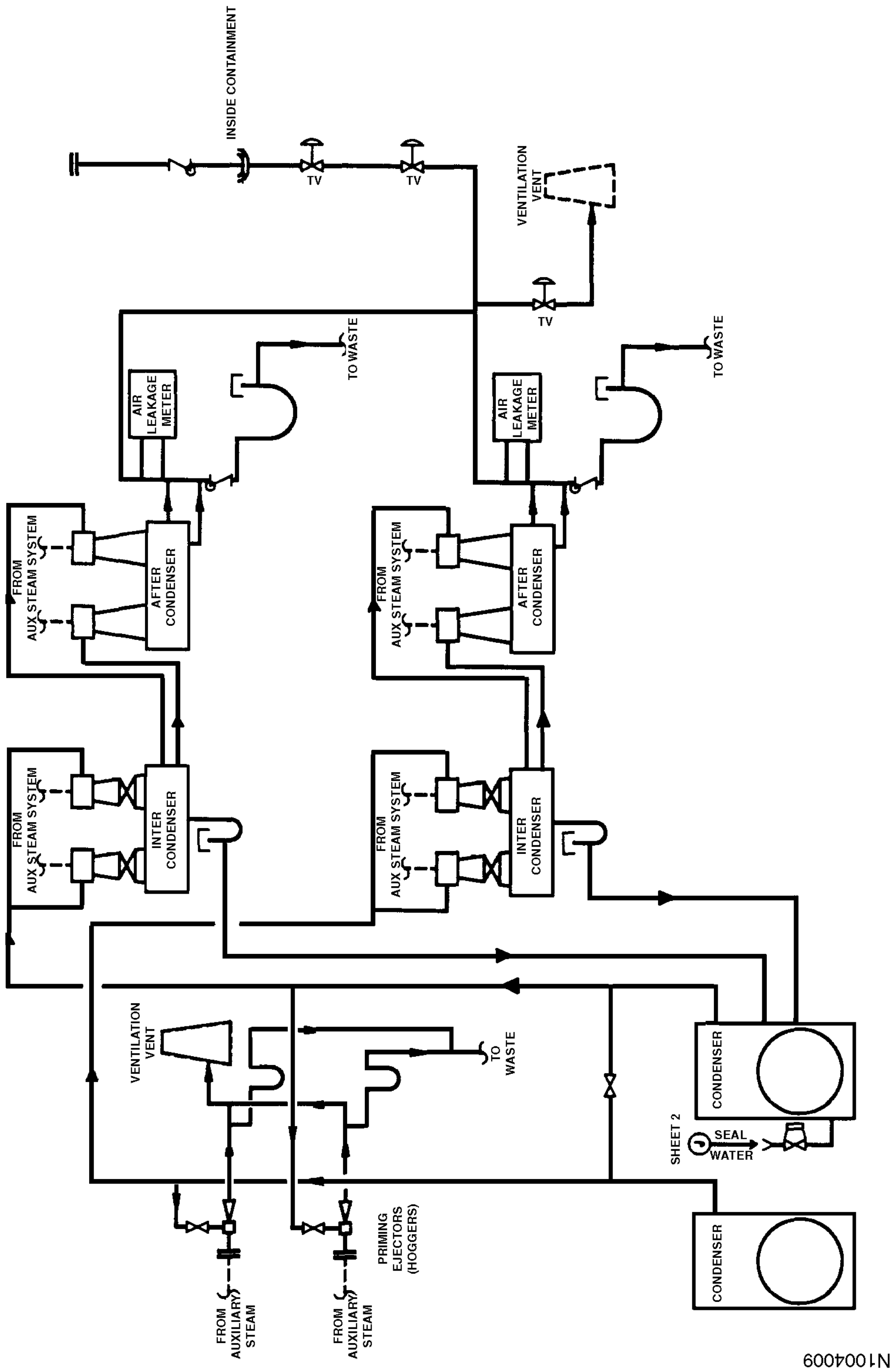


Figure 10.4-3 (SHEET 3 OF 4)
CONDENSATE SYSTEM

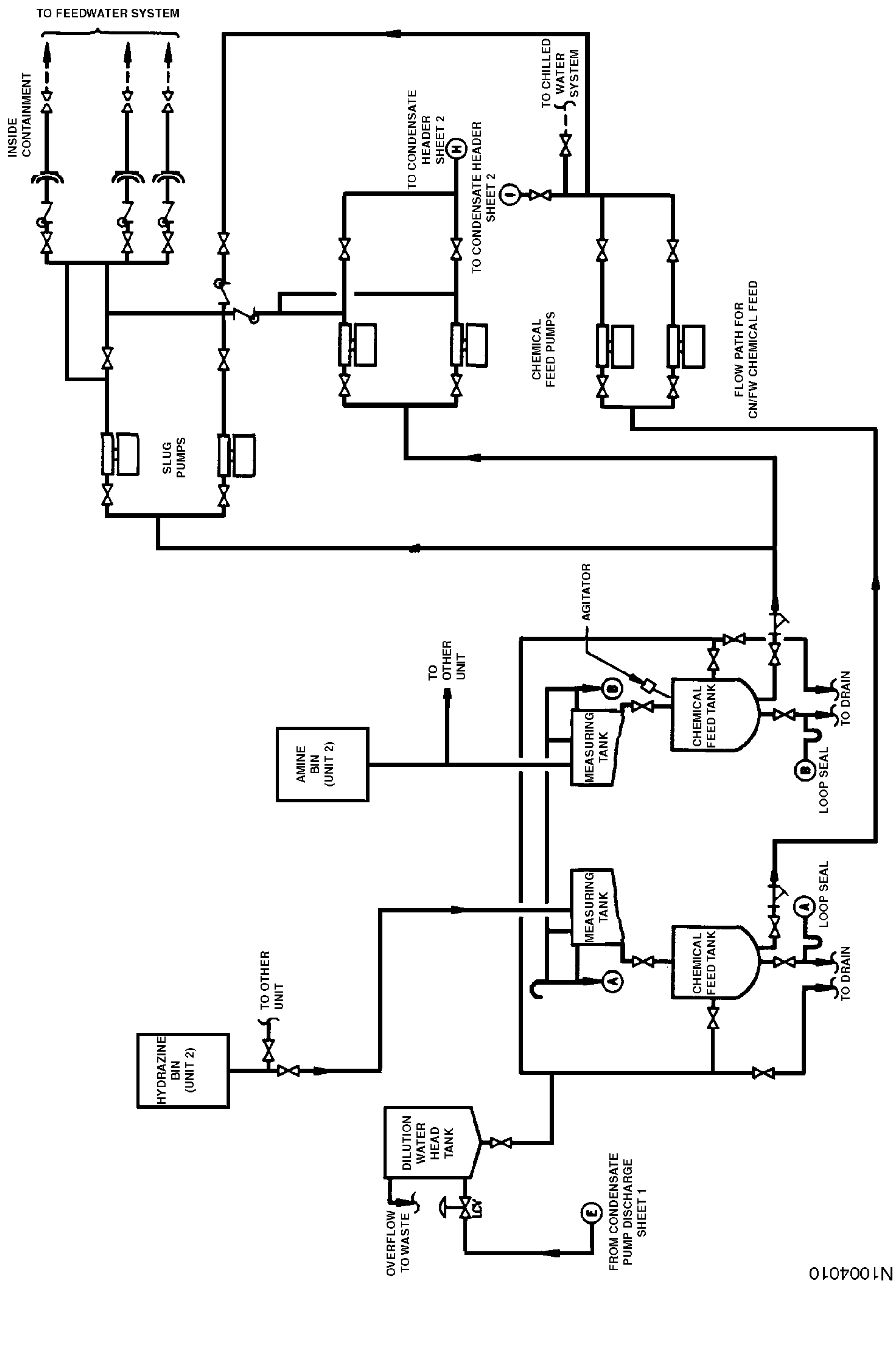


Figure 10.4-3 (SHEET 4 OF 4)
CONDENSATE SYSTEM

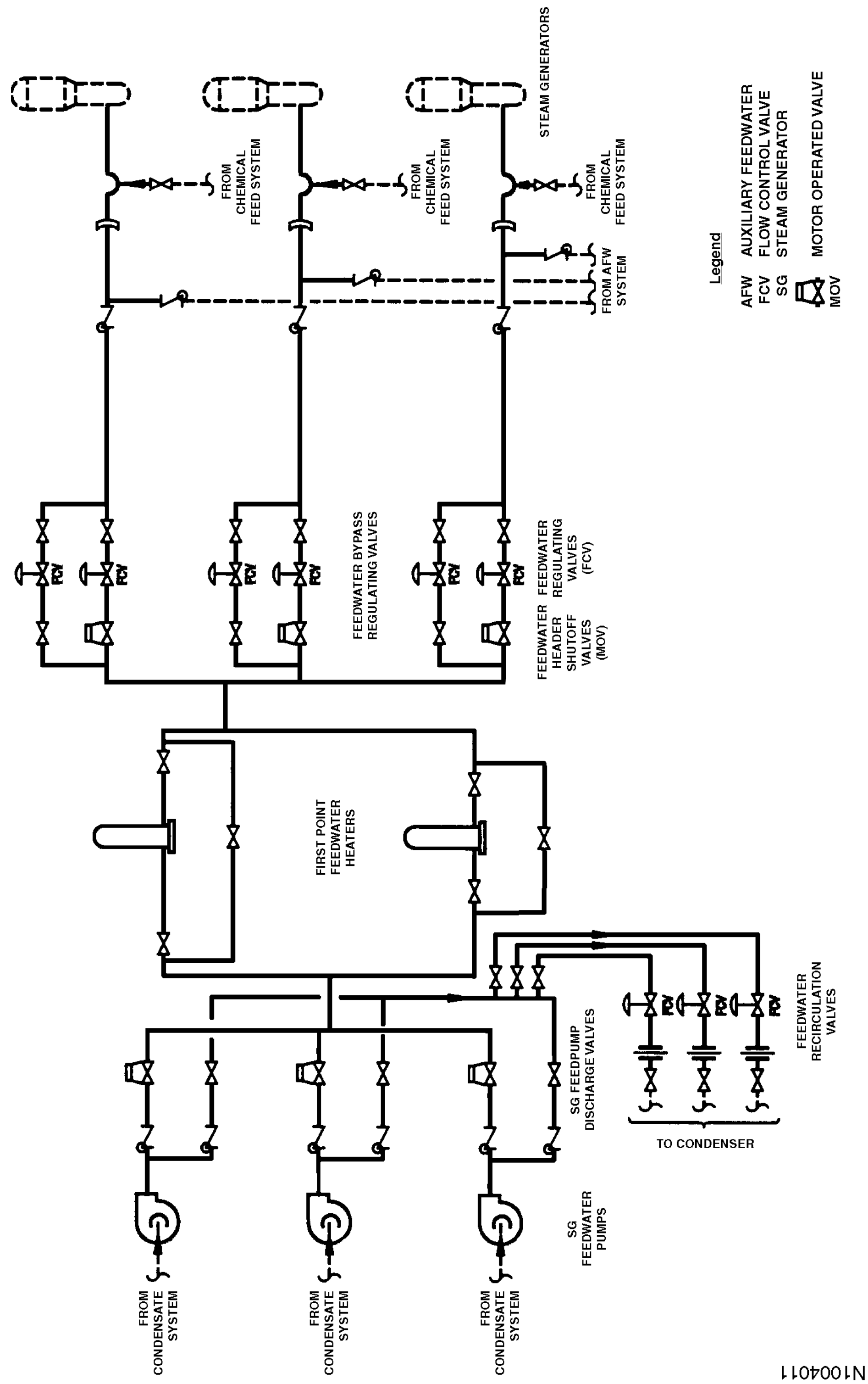
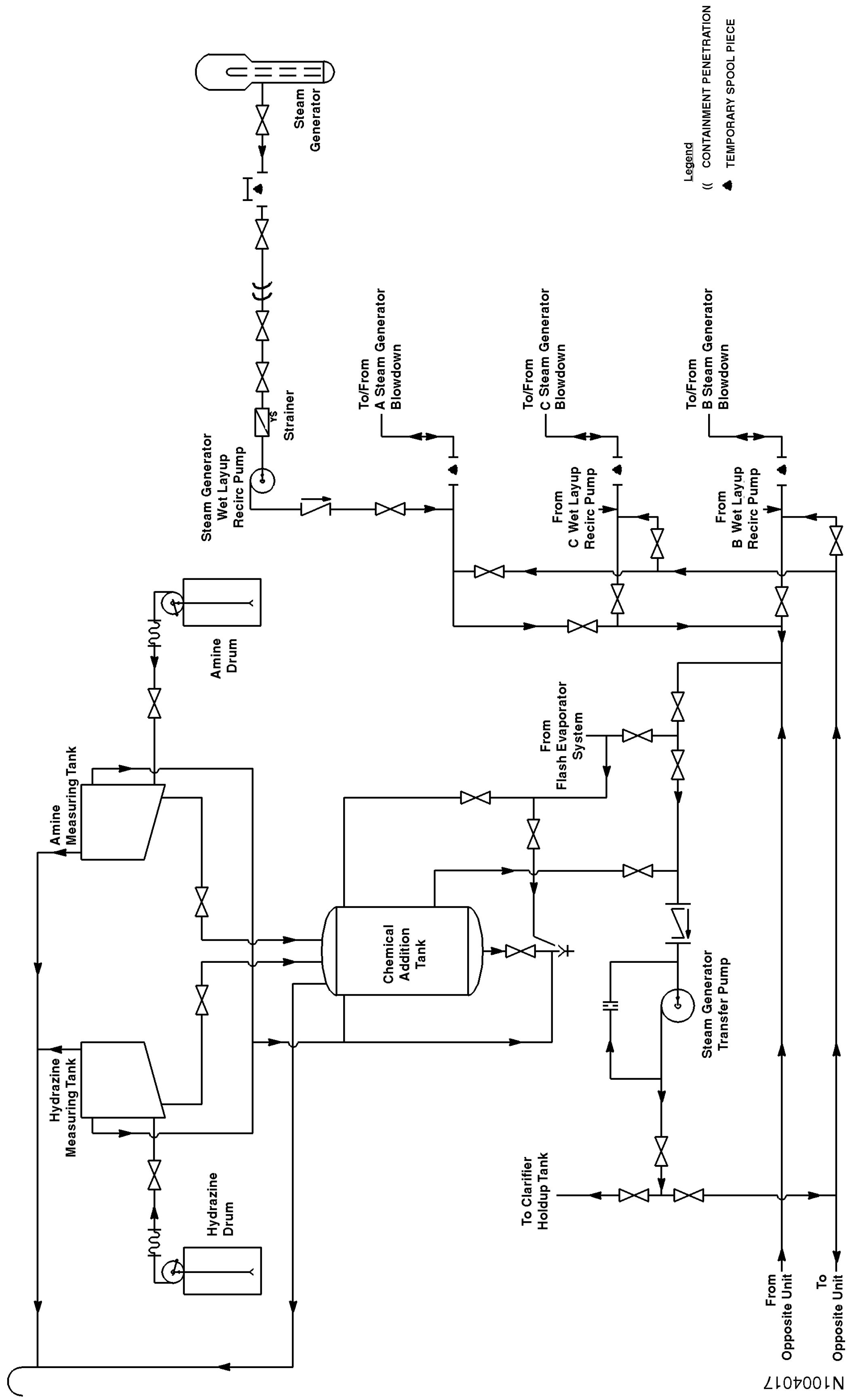


Figure 10.4-4
FEEDWATER SYSTEM

Figure 10.4-5
CHEMICAL FEED SYSTEM



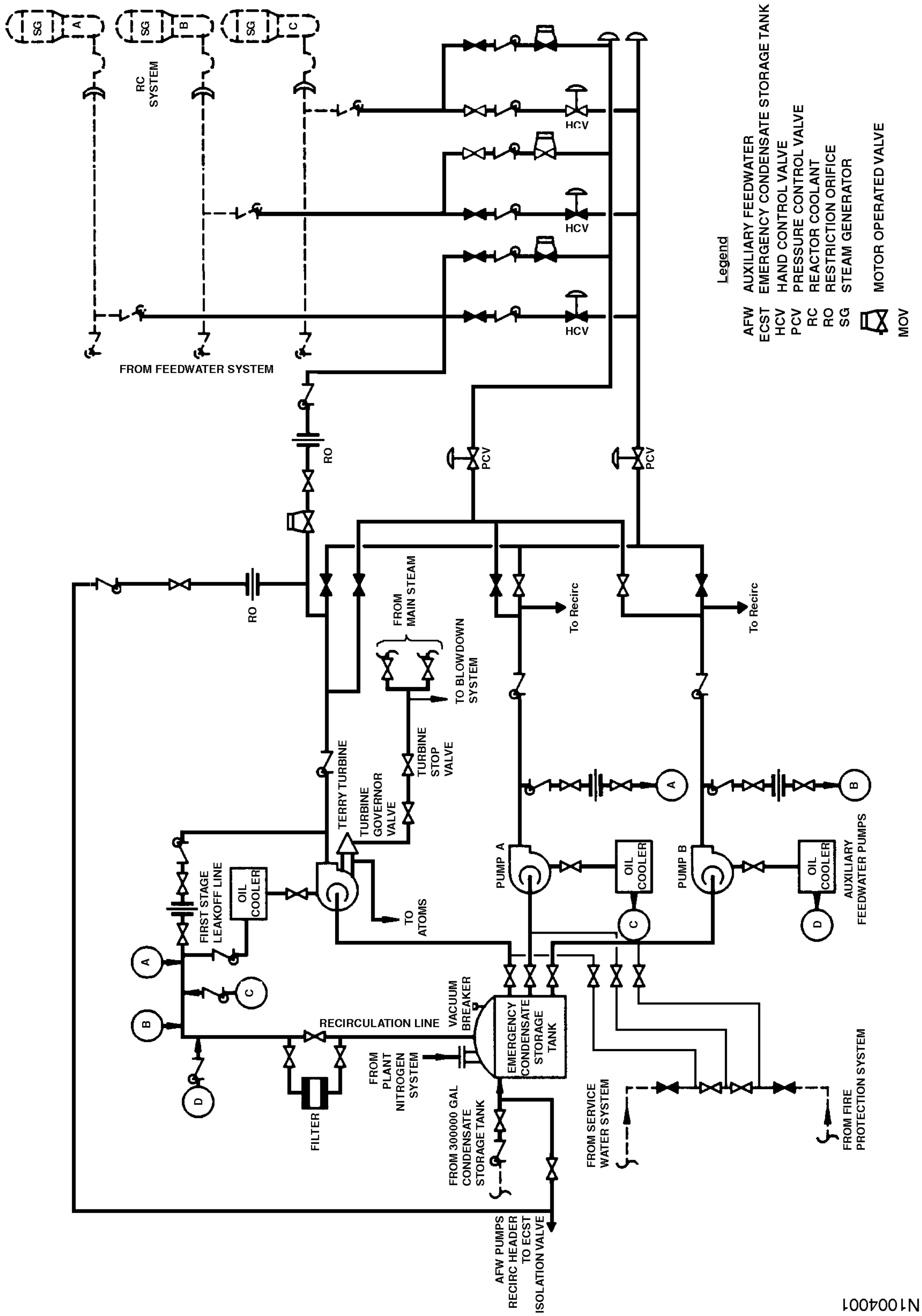


Figure 10.4-6
AUXILIARY FEEDWATER SYSTEM

Figure 10.4-7
LUBRICATING OIL SYSTEM

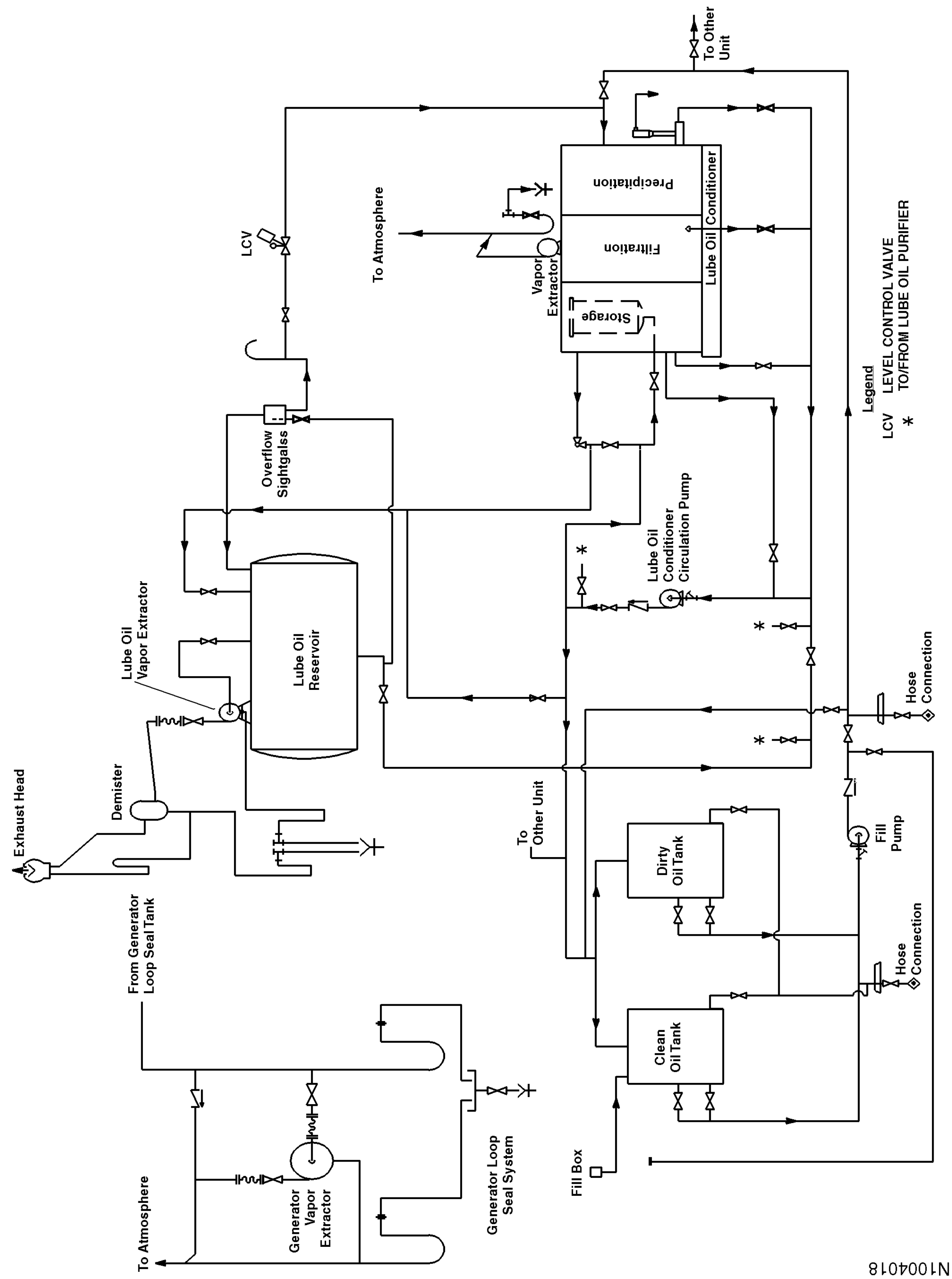


Figure 10.4-8
STEAM GENERATOR BLOWDOWN SYSTEM

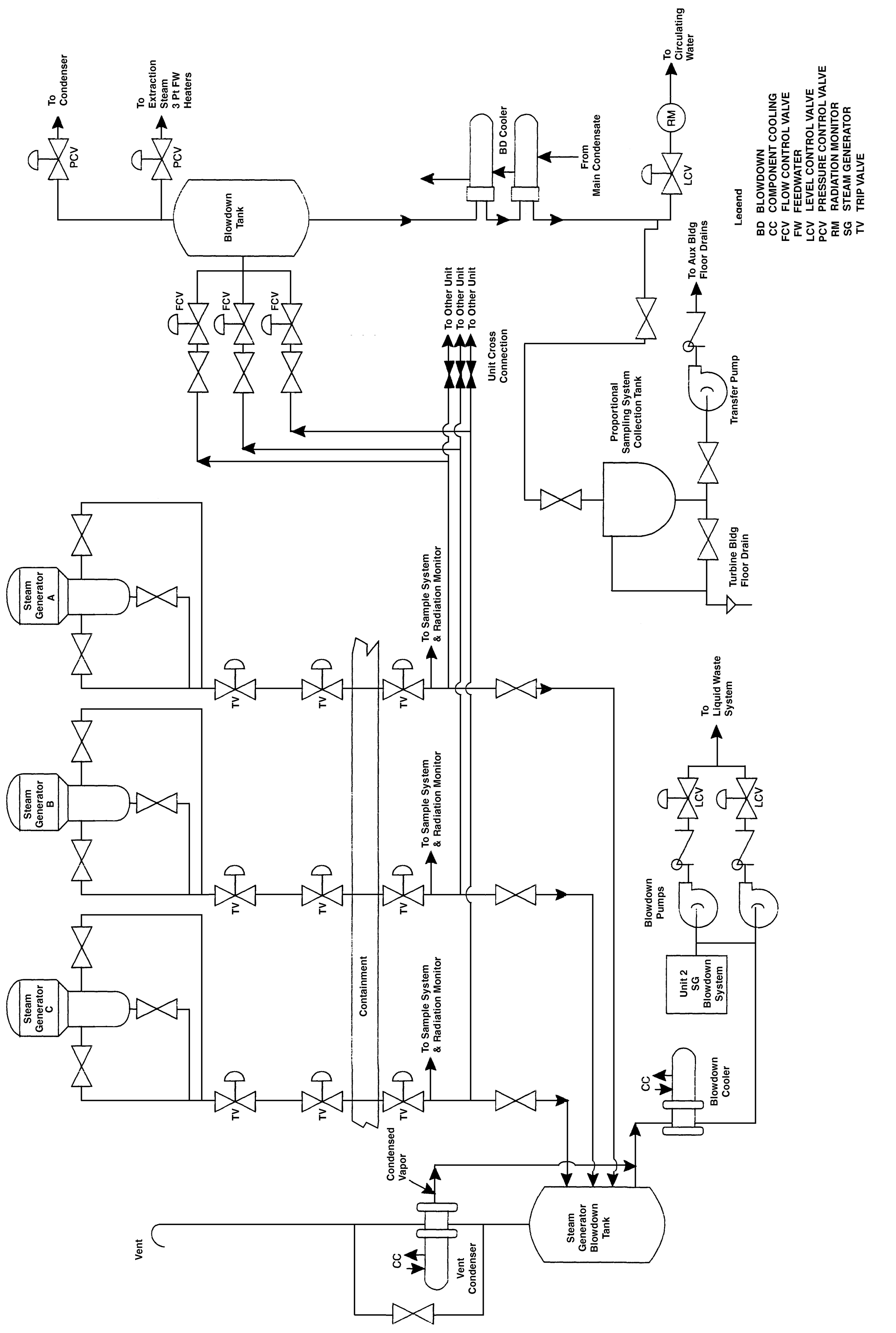


Figure 10.4-9 (SHEET 1 OF 4)
BEARING COOLING SYSTEM

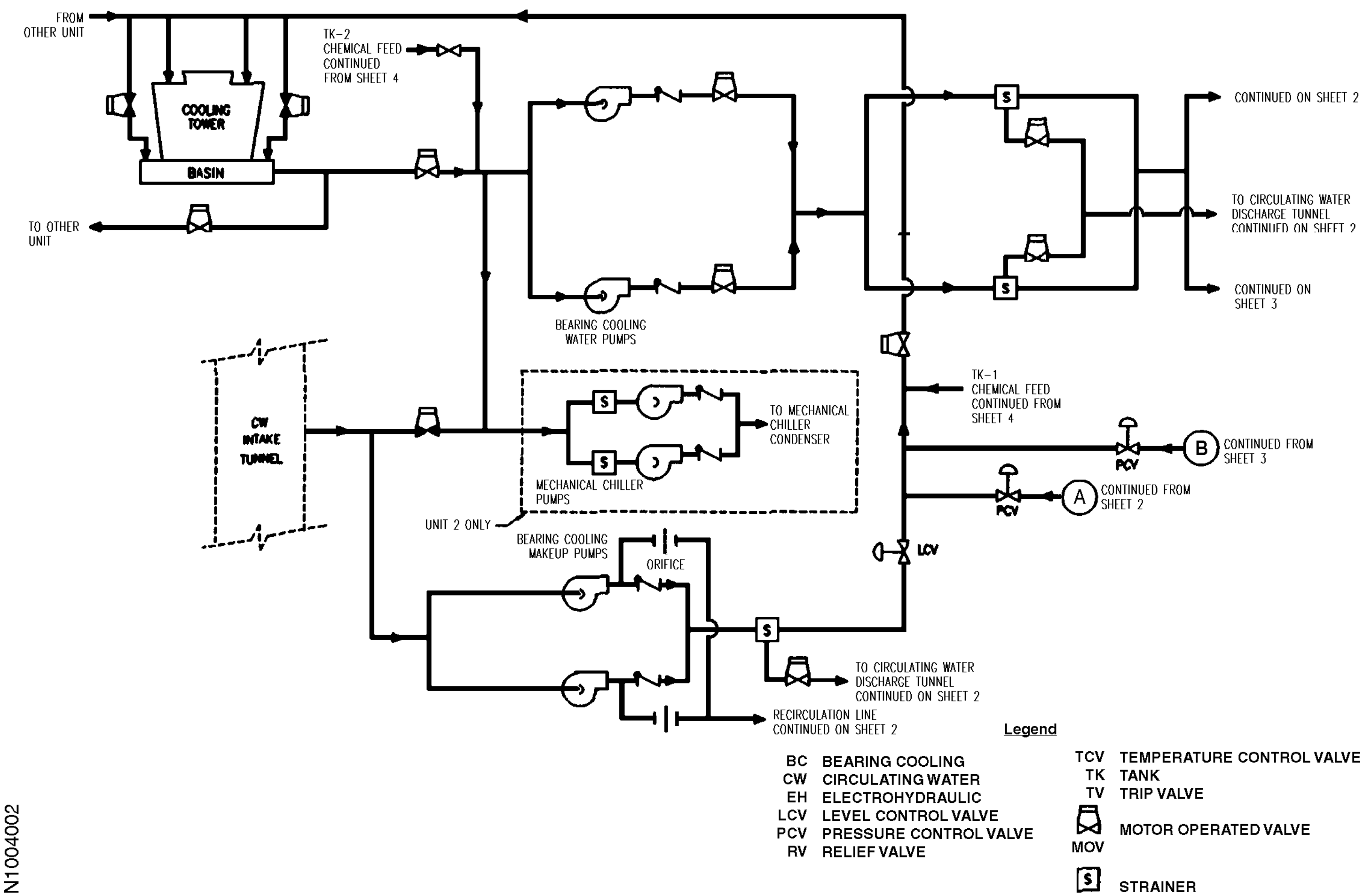


Figure 10.4-9 (SHEET 2 OF 4)
BEARING COOLING SYSTEM

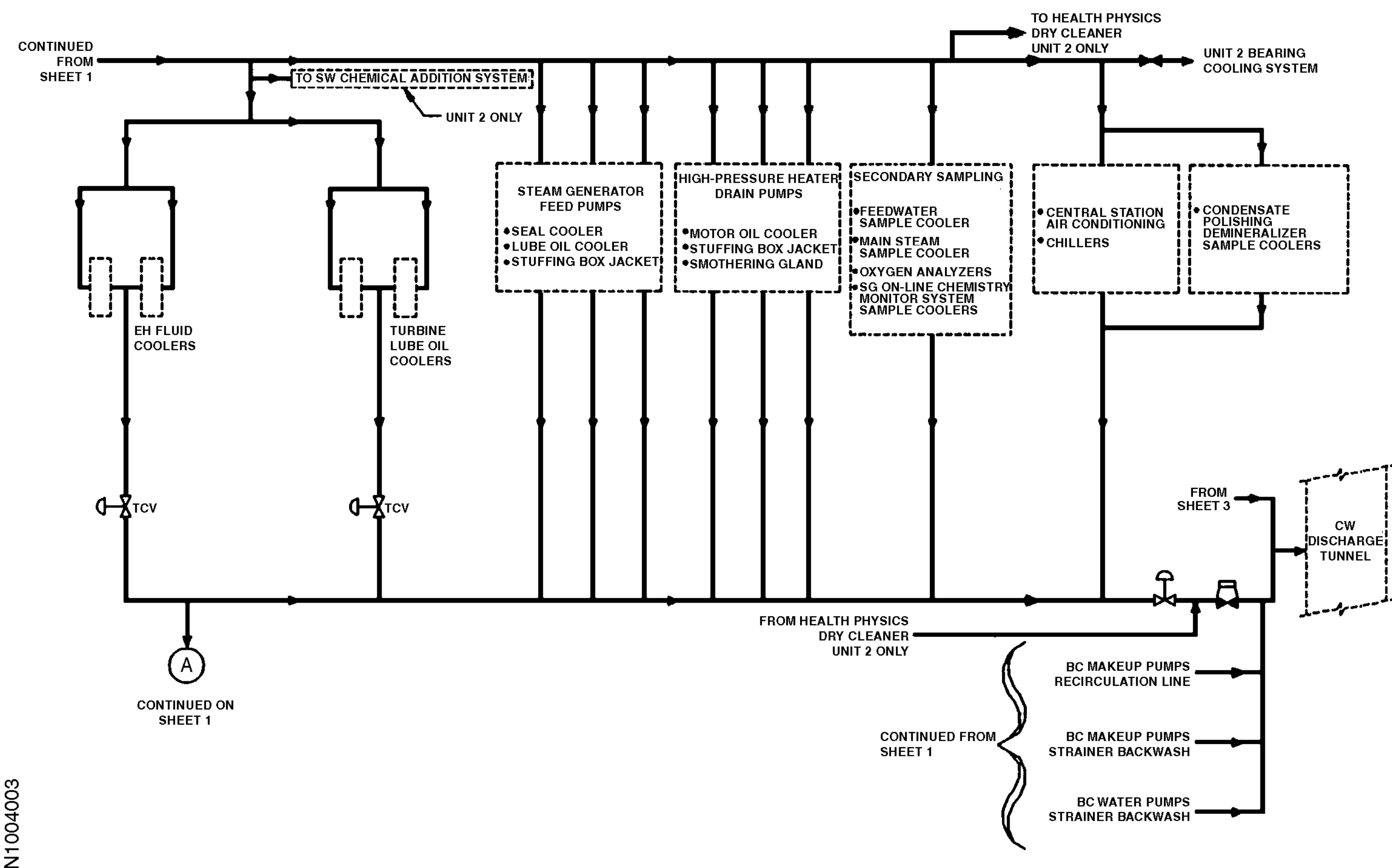


Figure 10.4-9 (SHEET 3 OF 4)
BEARING COOLING SYSTEM

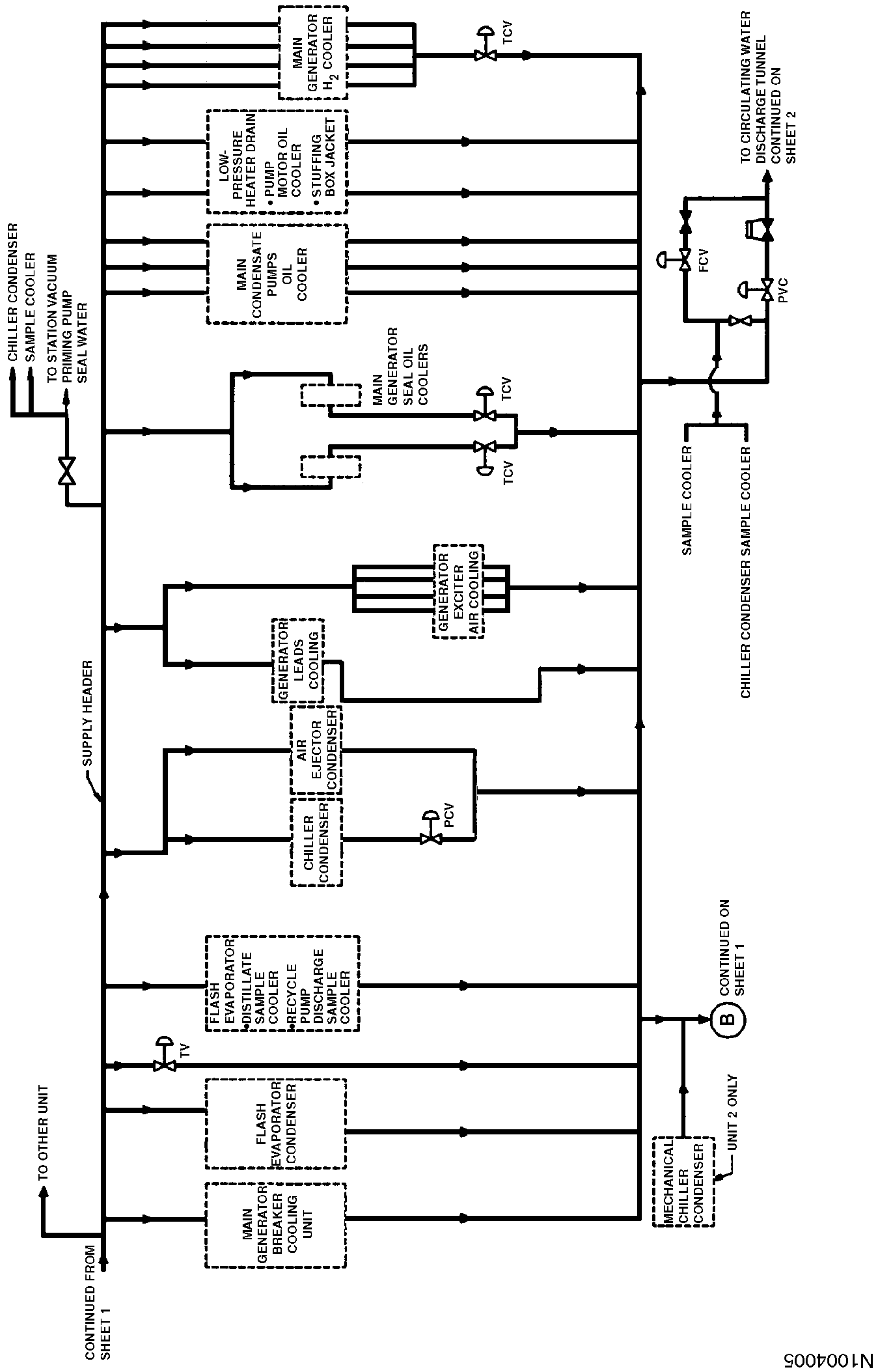


Figure 10.4-9 (SHEET 4 OF 4)
BEARING COOLING SYSTEM