SECTION 11

PLANT POWER CONVERSION SYSTEM

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SECTION 11 POWER PLANT CONVERSION SYSTEM

11.1 SUMMARY DESCRIPTION

The Steam and Power Conversion Systems of Units 1 and 2 are identical except as noted.

11.1.1 Performance Description

The steam and power conversion system consists of a closed, regenerative cycle in which steam from the main turbine is condensed and returned to the steam generators as heated feedwater.

The turbine-generator system consists of components of conventional design, designed for use in large central power stations. The equipment is arranged to provide high thermal efficiency with no sacrifice in safety. The component design parameters are given in Table 11.1-1.

The Main Steam and Feedwater Systems are designed to remove heat from the reactor coolant in the two steam generators, producing steam for use in the turbine-generator. The Main Steam System can receive and dispose of the total heat existent or produced in the Reactor Coolant System following a turbine-generator trip at full load.

Two auxiliary feedwater pumps, one turbine-driven and one electric-driven are provided for each unit to ensure that adequate feedwater is supplied to the steam generators for heat removal under all circumstances, including loss of power and normal heat sink. Feedwater flow can be maintained until power is restored or reactor decay heat removal can be accomplished by other systems. The Auxiliary Feedwater System is designed as a Class I system, and is described in Section 11.9.

11.1.2 Load Change Capability

The plant can accommodate step load changes of 10% or ramp load changes of 5% per minute without reactor trip as described in USAR Sections 4 and 7. The Reactor Coolant System will accept a complete loss of load from full power with reactor trip. In addition, both units are designed to accept a step decrease of 40.0% of nominal full load with the combined operation of the Reactor Rod Control System and the Steam Dump System. 04--024

11.1.3 Functional Limits

The system incorporates backup means (power operated relief valves and code safety valves) for heat removal under any loss of normal heat sink (i.e., main-steam stop valves trip, condenser isolation, loss of circulating water flow) to accommodate reactor shutdown heat rejection requirements.

11.1.4 Secondary Functions

The Steam and Power Conversion System also provides steam for driving the turbine-driven auxiliary feedwater pump and for turbine gland steam, reheater steam, condenser and water box steam-jet air ejectors, hogging ejectors, waste evaporator, boric acid evaporator packages and building heating.

11.1.5 Codes and Classifications

The pressure boundary components comply with the codes given in Table 11.1-2.

11.1.6 Schematic Flow Diagrams

The Main, Auxiliary Steam and Steam Dump, Condensate, Feedwater, Bleed Steam and Heater Vents, Feedwater Heater, Moisture Separator and Reheater Drains, Air Removal, Turbine Building Traps and Drains, Feedwater Pump Injection and Gland Seal Piping, Circulating Water, and Condensate Polishing Flow Diagrams are given in Figures 11.1-1 through 11.1-20, respectively.

11.1.7 Single Failure Analysis

A single failure analysis has been made for all active components of the system which have an emergency function. The analysis, which is presented in Table 11.1-3, shows that the failure or malfunction of any single active component will not reduce the capability of the system to perform its emergency function.

11.1.8 Shielding

No radiation shielding is required for the components of the Steam and Power Conversion System. Continuous access to the components of this system is possible during normal conditions, except for the components located inside the containment.

11.2 TURBINE-GENERATOR SYSTEM

11.2.1 Design Basis

The turbine is designed to produce a maximum calculated gross rating of 591,988 KW when operating with inlet steam conditions of 702 psia and 503.4°F, exhausting at 1.6 in. Hg absolute, zero percent makeup, and with five stages of feedwater heating in service. The expected throttle flow at 591,988 KW is 7,370,720 lb/hr of steam. See Figures 11.2-1 through 11.2-5 for various turbine/condenser/reheat heat balance gross loads.

The Unit 1 hydrogen inner-cooled generator is designed to produce rated 659,000 KVA at 1800 RPM and 60 psig hydrogen gas pressure. The Unit 2 hydrogen inner-cooled generator is designed to produce rated 730,000 KVA at 1800 RPM and 60 psig hydrogen gas pressure. 01435983

11.2.2 Description

The turbine is a three-element, tandem-compound, four-flow exhaust, 1800 rpm unit that has moisture separation and reheating between the HP and LP elements. The a-c generator and rotating rectifier exciter are direct-connected to the turbine shaft. The turbine consists of one double-flow HP element in tandem with two double-flow LP elements. Four combination moisture-separator reheater assemblies are located alongside the turbine.

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

The turbine oil system supplies all of the oil required for the emergency trip and lubrication system during normal operation. A turbine lube oil purification and filtration system purifies the lube oil for the turbine.

A gland steam condenser maintains a pressure slightly below atmospheric in the Turbine Gland Leakoff System. Sealing steam and air leakage along the shaft at each turbine gland is fed to this condenser, thus preventing any leakage of steam into the turbine room. Two motor-driven exhausters are mounted on the gland condenser to remove noncondensable gases, as shown in Figure 11.1-11.

The turbine has low speed, motor-driven spindle turning gear equipment which is side mounted on the outboard bearing of the low-pressure turbine nearest the generator.

11.2.3 Performance Analysis

11.2.3.1 Turbine Controls

High-pressure steam enters the turbine through two turbine stop valves and four governing valves. One turbine main steam stop and two main steam governing valves form a single assembly which is anchored above the turbine room floor line. An electro-hydraulic (E-H) actuator controls each turbine stop valve so that it is either in the wide-open or closed position. One of the control signals for this actuator comes from the mechanical-hydraulic overspeed trip portion of the Electro-Hydraulic Control System. The safety function of these turbine stop valves is to shut off the flow of steam to the turbine in the event the unit overspeeds beyond the setting of the overspeed trip. These valves are also tripped when the other protective devices function. The main steam governing valves are positioned by an electrical signal from the main governor portion of the Electro-Hydraulic Control System.

Additionally, there are Reheat Steam Stop Valves (at the outlet of each reheater) and reheat steam intercept valves (in each reheat steam line just ahead of the low pressure turbine inlet). These reheat stop and intercept valves limit the reheated steam flow available to the low pressure turbine.

The Electro-Hydraulic Turbine Control System combines triple modular redundant controller with a high-pressure fire-resistant fluid supply system which is independent of the lubricating oil. The design features and response characteristics of the E-H control system increase the reliability and availability of the power plant.

The Electro-Hydraulic Control System includes the following features:

a. Governor valve controller

b. Load limit controller

c. Overspeed Protection Controller

d. Load Controller

e. Operator’s touch screens on the control room control panel

f. High-pressure hydraulic fluid pumping unit

g. Turbine protective devices, including function limit trips, automatic load reference runback upon receipt of the OTΔT and OPΔT signal, and extraction line non-return valves closing signal.

In the steam admission system, each steam path has two valves in series which are controlled by the high pressure E-H oil system. Loss of hydraulic fluid pressure or power supply causes closure of the steam valves.

The auto-stop oil is dumped to drain, directly and indirectly via the interface valve, when any one of the protective trip devices is actuated. Independent reactor trip signals will actuate the EH controller trip logic to dump ET, OPC, and auto-stop oil to drain.

Automatic turbine load reference runback is initiated as described in Section 7.2.

11.2.3.2 Turbine Overspeed Control

Turbine overspeed, upon loss of electrical load, is prevented by the rapid cut-off of steam admission to the high pressure turbine, and to the low pressure turbine. Main steam admission to the high pressure turbine is controlled by a series array of main steam stop and governor valves; and reheat steam admission to the low pressure turbine is controlled by a series array of reheat steam stop and reheat steam intercept valves. All these valves are held open against strong spring pressure by high-pressure hydraulic fluid.

Should loss of electrical load occur, the turbine will tend to accelerate, and the E-H control automatically switches from load follow to speed follow and calls for the maintaining of a turbine synchronous speed of 1800 rpm such that the main E-H governor calls for modulated closing of the main steam governor valves.

(Should the loss of load be from maximum calculated load to zero load, the E-H overspeed protection controller alone limits turbine speed to a maximum of 108% of synchronous speed.)

Overspeed control is accomplished by trip-valve release of hydraulic fluid pressure. Redundant shaft-speed sensors and trip-valving systems assure a highly reliable prevention of turbine overspeed and prevention of resultant turbine missiles.

The Electro-Hydraulic Control System contains turbine shaft speed probes. At 103% of rated shaft speed the E-H controller releases actuating hydraulic fluid pressure to close the main steam governor and the reheat steam intercept valves, which cut off both high pressure and low pressure turbine steam admission.

(Should this trip be from maximum calculated load to zero load, the 103% E-H overspeed trip function alone limits the turbine speed to a maximum of 111% of synchronous speed.)

In addition to the two protective functions already described, the turbines are provided with three emergency overspeed trip functions which are activated at less than 111% of rated shaft speed.

The first of these emergency overspeed trip functions is the conventional back-up control consisting of an overspeed trip valve and mechanical overspeed mechanism which consists of a spring-loaded eccentric weight mounted in the end of the turbine shaft. At 110% of rated speed, centrifugal force moves the weight outward to mechanically actuate the overspeed trip valve which dumps auto-stop oil pressure and in turn releases the actuating hydraulic fluid pressure to close the main steam stop valves, the main steam governor valves, the reheat steam stop valves, and the reheat steam intercept valves. The supply steam pressure and the spring force act to hold the stop valves closed.

Upon loss of the actuating hydraulic fluid pressure, an air pilot valve closes the extraction non-return valves to heaters No. 14 and 15. Baffles in feedwater heaters No. 11, 12, and 13 minimize flashback of water in these heaters.

The secondary emergency overspeed control is provided by the Electro-Hydraulic Control system if the turbine speed exceeds 108% of rated speed by 10 rpm. At this point ET, OPC, and AST solenoids are actuated to dump the auto-stop oil which in turn dumps the actuating hydraulic fluid pressure to ensure closing of the main steam stop valves, the main steam governor valves, the reheat steam stop valves and the reheat steam intercept valves.

The third emergency overspeed control is provided by the Electro-Hydraulic Control system if the turbine speed exceeds 109% of rated speed. At this point the independent Protech system actuates the ET and OPC solenoids to dump ET oil header pressure, thereby depressurizing the AST header via the interface valve which in turn dumps the actuating hydraulic fluid pressure to ensure closing of the main steam stop valves, the main steam governor valves, the reheat steam stop valves and the reheat steam intercept valves. The Protech also provides trip input to the main EH controller to actuate the ET, OPC, and AST solenoids.

The reheat steam stop valves and reheat steam intercept valves stop the steam flow to the low pressure turbine, such that assuming a single failure of one reheat steam intercept valve, the 111% overspeed trip point limits turbine shaft speed to less than the 120% of synchronous speed which was used as a design basis for the turbine-generator.

Thus a 100% maximum calculated load rejection (with no in-plant load) cannot result in destructively excess overspeed.

The overspeed trip function is tested periodically. The turbine valves function to control and protect the main turbine. They must be capable of moving freely in response to control and protection signals. In an effort to develop a reasonable basis for frequency of turbine valve testing, a probabilistic study of turbine valve failure mechanisms was undertaken by the Westinghouse Owners Group. This work was reported in WCAP-11525: “Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency” (Reference 7). This study concluded that the Prairie Island turbine valves could be tested at a reduced frequency not exceeding one year while not exceeding NRC guidance for acceptable turbine missile ejection probability. A change to the Prairie Island Technical Specifications allowing the interval between turbine valve tests to be up to, but not exceeding one year, was approved by NRC SER dated February 7, 1989. (Reference 8). IT.S. has subsequently relocated these requirements to the TRM.

In accordance with the program plan for tracking turbine valve failure rates, the Westinghouse Owners Group performed evaluations and updates of turbine stop and control valve failure rates. The evaluation is an ongoing process and the most recent study results set the requirements for turbine valve testing.

The turbine valve failure rates through January 1998 were reevaluated in March 1999 (reference 13) in accordance with the program plan established in WCAP 11525. This reevaluation resulted in conservative missile ejection probabilities relative to previous studies. WCAP-16054 was commissioned to re-check WCAP-11525. WCAP 16054 confirmed WCAP-11525 with the inclusion of recent valve failure data and increasing the valve exercise surveillance interval to 6 months. The total probability continues to be maintained at less than $1x10^{-5}$.

11.2.3.3 Variables Limit Functions

Trips, automatic control actions and alarms will be initiated by deviations of system variables within the Steam and Power Conversion System. The more significant malfunctions or faults which cause trips, or automatic actions in the Steam and Power Conversion System are listed below.

Turbine Trips

a. Generator electrical faults

b. Low condenser vacuum

c. Thrust bearing failure

d. Low turbine bearing lubricating oil pressure

e. Turbine overspeed

f. Reactor trip

g. Manual trip

h. Loss of both main feedwater pumps

i. Loss of E/H system internal power

j. Low auto-stop oil pressure

k. Steam generator High-High level.

l. MSIV closure initiated turbine trip

m. AMSAC actuation

11.3 MAIN CONDENSER SYSTEM

11.3.1 Condenser

The condenser is the double-flow, dual-pressure, single-pass vertically divided surface type with fabricated steel water boxes at both ends. The hotwell has sufficient storage for three minutes operation at maximum throttle flow with an equal free volume for surge protection.

There are two air coolers built integral with each condenser shell, located in the center of each tube bundle, extending from face to face of the tube sheets. The coolers are subdivided by the main support plates.

The “direct steam flow” type tube bundle in each shell is arranged so that steam will enter at the top, outboard and inboard sides, and bottom where it flows through the tubes until reaches a common area at the center of the tube nest before entering the air coolers.

The arrangement of the tubes in the tube bundle allows the steam to effectively feed to all the tubes. This tube arrangement creates decreasing cross-sectional area, and as the volume of steam is decreased by being condensed as it penetrates the depth of the tube bank, a brisk velocity is maintained at all times, assuring maximum condensation at maximum efficiency.

In its passage through the tube bundle most of the steam is condensed and when the flow reaches the air cooler there remains only a mixture of air, non-condensible vapor and water vapor.

The air and non-condensible vapors are cascaded from the outlet end to the inlet end of each condenser. This is accomplished by having each section of the condenser arranged so that the air and non-condensible vapors from preceding sections will be forced to pass over cooler tubes in every section of each condenser.

In passing through the air coolers, the air and non-condensible vapors are cooled and a large part of the water vapor is condensed. This reduces the partial vapor pressure of the mixture which is analogous to shrinking what was originally a large volume of rarefied air into a small volume of dense air. In this state it is drawn into the air removal equipment where it is compressed to atmospheric pressure with a minimum expenditure of energy.

Each condenser is divided into two sections by means of separate water boxes. This construction for practical purposes may be considered as two condensers placed side by side, having a common steam inlet and condensate outlet, but with separate air-vapor outlets. This construction also makes it possible to open the water boxes on one section of the condenser to clean and inspect the tubes while there is vacuum on the condenser and the turbine is operating.

11.3.2 Main Condenser Air Removal System

The steam-jet air ejector maintains a vacuum in the condenser. This ejector has three first-stage elements and three second-stage elements mounted on the shells of the intermediate and after-condensers. Only two of the three stages are required during normal operation. During startup, a separate hogging ejector is used to evacuate the condenser. The ejectors are supplied with steam from the main steam line, as shown in Figures 11.1-1,-2,-11, or from the plant heating boiler. They are used in parallel with the second stage of the steam jet air ejectors which are also started at the same time. After a vacuum of 20″ to 25″ Hg. has been established, the first stage jets of the air ejector are started automatically. Operation of the first and second stages of the air ejector will lower the turbine condenser steam space to its operating vacuum. The hogging ejectors are removed from service by closing, first, the suction valves, and second, closing their steam supply valves.

The discharge of the hogging ejectors is not monitored for radioactivity because this parameter can be measured by the radiation monitor in the discharge of the normal steam jet air ejector which discharges to the Auxiliary Building Ventilation System.

11.3.3 Condenser Spray System

The condenser spray system, as shown in Figures 11.1-3, -4, consists of a pump, filters, strainers, and spray nozzles. The system is designed to eliminate stratification which causes vacuum problems during unit startup. When steam dump and other steam sources enter the condenser, the steam in the process of going to a low pressure condition goes to a superheated condition. Since the superheated steam has a higher specific volume the steam rises to the top of the condenser. To prevent this steam from reaching the top of the condenser, the condenser spray system blankets the condenser with a water spray below the feed water heater level. 01-003

Hydrazine is injected into the condenser spray system to start the O_2 scavenging sooner in the condensate and feed water cycle. This will help reduce the dissolved O_2 in the condensate pump suction. In this way the quantity of iron oxides produced in the condenser and carried to the steam generators is reduced.

11.4 STEAM SAFETY, RELIEF AND DUMP SYSTEMS

11.4.1 Design Basis

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

There are five 6-in. by 10-in. code safety valves located on each of the two 30-in. main steam lines outside the reactor containment and upstream of the main steam isolation and non-return valves. Discharge from these safety valves is carried to the atmosphere through individual vents. The total relieving capacity of all 10 valves is 7,745,470 lb/hr at 1194 psig. The five safety valves on each main steam line are set to relieve at 1077, 1093, 1110, 1120, and 1131 psig. The main steam safety valve Technical Specification originally required lift setpoints to be within ± 1% of the specified setpoint. The Specification was difficult to meet when test instrument error and repeatability were considered. A License Amendment Request justified increasing the as-found setpoint tolerance to ± 3%, provided the setpoint was returned to ± 1% following testing. License Amendments 123 and 116 approving the request were issued May 21, 1996.

In addition, one 5-in. power-operated relief valve is provided in each main steam line which is capable of releasing the sensible and core decay heat to the atmosphere. These valves are automatically controlled by pressure or may be manually operated from the main control board and have a total capability of ten per cent of the maximum calculated steam flow (405,000 lb/hr each at 1100 psia). Discharge from each power relief valve is carried to the atmosphere through an individual vent stack. In addition, the power-operated relief valves may be used to release the steam generated during reactor physics testing, operator license training, plant cooldown, and Mode 2, Startup, if the condenser is not available. Two steam dump systems, the condenser steam dump system and the atmospheric steam dump system, are available to remove energy for the steam generators downstream of the mainsteam isolation and non- return valves. The condenser steam dump system taps off one main steam line (downstream of the 20″ bypass/equalizing line connecting the two lines) with a 16″ then to 12″ line. From the 12-in. line two valves are installed in parallel (one 8-in. and one 4-in.). These valves discharge through a 16-in. pipe into the condenser through a perforated diffuser.
The 8-in. valve has a capacity of 590,000 lb/hr, at an inlet pressure of 722 psia. The 4- 01183316
in. valve has a capacity of 200,000 lb/hr. However, the 4-inch valve receives no automatic control signals and can only be operated by manipulating it locally, intended to be used only if the 8-inch valve is out of service (i.e., unavailable for cooldown).
Therefore, the effective capacity is only that of the 8-inch valve, at least 7.0% of full load 01183316
steam flow.

The atmospheric dump system provides two atmospheric dump valves on each steam generator main steam line. Each 8-in. valve is capable of dumping 590,000 lb/hr at an inlet pressure of 721 psia. Total capacity of all four atmospheric dump valves is at least 28.6% of full load steam flow. Two valves were installed to limit the maximum steam flow from one valve stuck open to 890,000 lb/hr at 1100 psia. A potential hazard in the form of an uncontrolled plant cooldown is thus eliminated. Manual isolation valves are provided at each control valve. 01183316

11.4.2 Description

The relief, safety and steam dump system is shown in Figures 11.1-1 and 11.1- 2.

The atmospheric dump valves and the condenser dump valve are controlled by a servoloop. Either a Tavg error signal or a main steam pressure error signal may be selected as the loop error signal. The Tavg error signal is used for normal at power operation. Under this condition, the loop provides the capability for rejecting a minimum 40.0% of nominal full load without reactor trip. 01183316

During a normal orderly shutdown of the turbine generator leading to plant cooldown, the operator may select pressure control for more accurate maintenance of no-load conditions using the steam dump valves to release steam generated by the residual heat. Plant cooldown, programmed to minimize thermal transients and based on residual heat release, is effected by a gradual manual adjustment of this pressure setpoint or by controlling the valve position in “Manual” until the cooldown process is completed or transferred to the Residual Heat Removal System.

During start-up, Mode 2, Startup, or physics testing, the steam dump valves are remotely controlled from the main control board.

The automatic condenser steam dump valve is prevented from opening on loss of condenser vacuum; it is also blocked on trip of both circulating water pumps that supply water to the Unit.

11.4.3 Performance Analysis

The condenser and atmospheric Steam Dump System has been included to increase the transient capability of the plant to provide a means for an orderly reactor power reduction in the event the load is suddenly decreased. The time for a return to full power operation is therefore minimized. The minimum dump capacity is equal to 35.6% of full load steam flow. Dump is initiated by a large rapid load change. Steam Dump Control is described in section 7.2.2.3. 01183316

Table 4.1-8 lists the number of these type transients expected during the plant lifetime.

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

The amount of steam that will be dumped to atmosphere during load reduction is as follows:

Load Reduction of 10%	no steam released
Load Reduction of 20%	no steam released
Load Reduction of 30%	7000 lbs.
Load Reduction of 40%	30,000 lbs.
Load Reduction of 50%	75,000 lbs.

Based on a 50% load loss and the subsequent release of 75,000 lbs. of steam, the total radioactivity release to atmosphere would be 1.4 curies of I-131 equivalent. Using the yearly average X/Q, the site boundary thyroid inhalation dose associated with this release would be less than 0.5 mrem. This value additionally assumes that the secondary system radioactivity level is at 0.1 μCi/gm and only 10% of the activity contained in the steam generator secondary side is available for dispersion to atmosphere. The analysis neglected any plate-out or condensation effects on the release plume.

The requirement for monitoring the secondary coolant water chemistry is specified in the PINGP Chemistry Procedures. 01193402

If the control valves should fail to dump steam, the result is a loss-of-load transient. If they operate to dump steam inadvertently, the result would be a load increase equivalent to a small steam break. In either case, the Reactor Control and Protection System precludes unsafe operation. These protection systems are provided to trip the reactor in the event of a sustained load mismatch between the reactor and turbine.

Continuous radioactive monitoring of the secondary loops of the steam generators is provided by the Steam Generator Blowdown System Liquid Sample Monitor and the Condenser Air Ejector Gas Monitor as discussed in Sections 7.5.2.13 and 7.5.2.6.

Once there is an indication of tube leakage in a steam generator, the affected unit's steam generators will be sampled and actual release documentation will be based on the known isotopic inventory and ODCM requirements. Isotopic analyses will quantify activity of the individual nuclides and total nuclide activity. Partitioning Factors will be applied to the steam generator bulk water particulate and iodine concentrations, to adjust activity results for a steam release, based on the differences in the volatility of individual isotopes. Radiation monitors will provide confirmation that no change in the system activity has taken place during the release.

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

In the event of failure of one feedwater pump, the feedwater pump remaining in service will carry approximately 65% of full load feedwater flow. If both main feedwater pumps fail, the turbine and the reactor will be tripped, and the auxiliary feedwater pumps start automatically.

Pressure relief is required at the system design pressure of 1085 psig. The first safety valve is set to relieve at 1077 psig. Additional safety valves are set at pressures up to 1131 psig, as allowed by the ASME Code. In addition to the safety valves, one power-operated relief valve is installed for each steam generator which can be manually operated from the control room. The power-operated relief valves are set to open at a pressure slightly below that of the main steam safety valves.

The original Westinghouse sizing criteria for the code safety valves was a flow rate equal to the original maximum calculated steam generation rate. 01183316

11.5 CIRCULATING WATER SYSTEM

11.5.1 Design Basis

The circulating water system provides the heat sink for the generating plant. Excess heat from the steam leaving the turbine is transferred to circulating water flowing through the condenser tubes. Based on seasonal limitations heat is transferred to the environment either by the use of the cooling towers, discharge to the river, or a combination of cooling towers and river discharge. Operating restrictions are governed by National Pollutant Discharge Elimination System (NPDES).

During startup and shutdown of the steam plant, the Circulating Water System removes the heat of steam dumped to the condenser at low power.

The Circulating Water System is designed to supply 294,000 gpm to each Unit in normal operation. Each Unit has two condenser circulating water pumps, each rated at 147,000 gpm at a TDH of 45 ft. The system is designed for condenser heat rejection of 3.88×10^9 BTU/hr from each Unit with a temperature rise across the condensers of 27°F. Total plant heat rejection by the Circulating Water System is 8.09×10^9 BTU/hr.

01-009

The Circulating Water System also supplies the water for the Cooling Water System and Fire Protection System. Water flows from the Intake Bay into the Plant Screenhouse. The Cooling Water pumps draw water from the screenhouse, pump it through the system and discharge to the warm circulating water leaving the condensers. Thus, the Circulating Water System indirectly cools the plant auxiliary equipment. The Intake Bay is required to remain intact during and after a design basis seismic event. The Intake Bay is classified as a Class I* structure. Refer to Section 12.2 for more discussion on classification of structures and components. Refer to Section 10.4 for more discussion on the cooling water system response to a seismic event.

The circulating water system flow diagrams are shown in Figures 11.1-16 and 17. The general plan of the system external to the plant is shown in Figure 11.1-18. 01-009

11.5.2 Description

Circulating water for the generating plant is taken from the Mississippi River and directed to the plant site by the intake canal. The quantity of river water which may be appropriated for use in the Circulating Water System is specified in Water Appropriations Permit #69-072 (issued by the Minnesota Department of Natural Resources). 01-015

Circulating water flows through the intake screenhouse to the intake canal and into the Screenhouse. Trash racks and traveling water screens located in the intake screenhouse collect fish, fish larvae and debris from the intake stream and return these organisms to the river to prevent them from entering plant systems.

Two circulating water pumps for each unit individually pump circulating water through one side of each condenser for the associated unit. As the circulating water passes through the condenser tubes, it absorbs the heat of vaporization from the low pressure turbine exhaust system.

The heated circulating water leaving the condenser is directed to the discharge basin through 102-in. concrete piping. From the discharge basin the water is directed to the river or to the cooling towers (see Section 11.6). From the cooling tower, the water flows through the cooling tower return canal to the distribution basin.

A recycle canal is provided to recycle circulating water from the distribution basin back to the intake canal. Recycle control gates between the distribution basin and the recycle canal control the recycle flow rate. Guide walls and submerged mixing blocks are located in the intake canal to mix the warm recycle and cool river water to prevent large temperature differences between the four circulating water pumps. Water returned to the river is dispersed through pipes into the main body.

The exterior circulating water system is operated to NPDES Permit MN0004006.

11.5.3 Performance Analysis

The design of the circulating water system allows for a variety of operating conditions that are governed by power levels and NPDES Permit requirements. In the open cycle mode the cooling towers are not used and the system acts as a once through design. In the closed cycle mode the cooling towers are in operation and there is limited return flow to the river. Depending on cooling requirements the system may be operated with cooling towers on line in addition to substantial blowdown to the river.

System discharge to the river, blowdown, is measured in cubic feet per second (CFS)
and is restricted by environmental impact considerations. The system can be operated 01-015
with complete reliance on the cooling towers and a nominal (150 cfs) blowdown, as a
once through system with maximum allowed blowdown, or at any desired blowdown
rate in between in order to meet environmental impact based restrictions. Operations
that exceed NPDES permit limits are reported to the appropriate state officials in 01-015
accordance with the NPDES permit.

Limitations are placed on the discharge flow rates by the NPDES permit April through June.

During other periods of the year the intake flow rate may vary to provide maximum plant efficiency provided the thermal criteria of the NPDES permit are not exceeded.

11.6 COOLING TOWER SYSTEM

11.6.1 Design Basis

The cooling tower system is designed to dissipate to the atmosphere the heat rejected to the cooling water system and the entire circulating water flow passing through the condensers.

11.6.2 Description

The cooling tower system is comprised of four towers, fans, water distribution headers and basins as shown in Figure 11.1-17. Each tower has one cooling tower pump. Each tower is made up of 12 cells grouped together (a bank).

The cooling tower pumps intake water from the discharge basin and discharge into individual distribution pipes to the top of the cooling towers. The pumps are vertical, dry pit pumps mounted so that the casing will be flooded with the water in the discharge basin at normal level. The pump motors are mounted on, and supported by, the pump. The intakes to the pumps are submerged to prevent the intake of air from any cause.

Spray nozzles at the top of the cooling towers break-up the water stream into small streams which drop by gravity through a maze of “fill” to a basin at the base of the towers. Fans draw air up through the streams of water and the heat of the water is carried into the atmosphere by the airstream. From the cold water basin at the bottom of the towers, the water flows through the cooling tower return canal to the distribution basin.

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11.7 MAIN STEAM SYSTEM

11.7.1 Design Basis

The Main Steam System is designed to remove heat from the reactor coolant in the two steam generators, producing steam for use in the turbine generator. The system can receive and dispose of the total heat existent or produced in the Reactor Coolant System following a turbine generator trip at full load.

The steam and feedwater lines from the steam generators to their respective isolation valves are Class I. A failure either of the main steam or feedwater lines, or malfunction of a valve installed therein, will not impair the reliability of the Auxiliary Feedwater System, render inoperative any engineered safety feature, initiate a loss-of-coolant condition, or cause failure of any other steam or feedwater line.

11.7.2 Description

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

The four reheaters drain to the No. 5 high-pressure heaters. The No. 5 heaters drain to the No. 4 feedwater heaters. The No. 4 heaters and the moisture separators drain to the heater drain tank. The heater drain pumps take suction from the drain tank and discharge to the feedwater pump suction. Drains from the three lower pressure heaters cascade to the condenser.

The Main Steam System conducts steam in a 30-in. pipe from each of the two steam generators within the reactor containment through a swing-disc type isolation valve and a swing-disc type non-return valve to the turbine stop and control valves. The isolation and non-return valves are located outside of the containment. The two lines are cross-connected by a 20-in. equalizing line downstream of the isolation valves. The design pressure of the system is 1085 psig at 600°F. A steam flow nozzle is provided in the line from each steam generator upstream of the isolation and non-return valves, to meter steam flow from each steam generator and to limit the rate of steam release in the event of a main steam line break. Steam flow signals are used by the Automatic Feedwater Flow Control System as discussed in Section 7.

The steam for the turbine-driven auxiliary feedwater pump is obtained from both main steam lines, upstream of the main steam isolation valves, as shown in Figures 11.1-1 and 11.1-2.

Main steam for the turbine gland steam supply control valve, the air ejectors, the reheater section of the four moisture separator reheaters, and the priming ejector, is obtained from branches on the main steam lines ahead of the turbine stop valves.

Steam from five extraction points in the turbine casings is piped to the shells of the two parallel strings of feedwater heaters. The first point of extraction originates at the high-pressure turbine casing and supplies steam to the shell of the No. 5 high-pressure feedwater heater. The second point of extraction originates in the high- pressure turbine exhaust piping ahead of the moisture separators, and supplies steam to the No. 4 low-pressure feedwater heater. The third, fourth, and fifth point extractions all originate at the low-pressure turbine casings and supply steam to the No. 3, No. 2, and No. 1 low-pressure feedwater heaters, respectively, as shown in Figures 11.1-7 and 11.1-8.

To prevent turbine overspeed from backflow of flashed condensate from the heaters after a turbine trip, non-return valves are provided in the extraction lines to heaters No. 4 and 5. The non-return valves are air-cylinder operated valves which are closed automatically upon a signal from the turbine trip circuit and on high level in the feedwater heater.

11.7.3 Performance Analysis

The main steam line isolation and check valve assemblies have been modified by changing valve disc material to 410 stainless steel and by adding a rupture disc assembly to the isolation valve air-cylinder actuator. An extensive design analysis has shown that disc, linkage and valve body will perform as required for the entire range of valve closure incidents.

In both the check and the isolation valve, the disc has been designed to withstand the maximum energy impact from closure. Separate valve models were made for the analysis of isolation valve and check valve. In order to determine the flow parameters of the fluid passing through the valve, a blowdown computer program was used. The relevant equations required to determine the angular acceleration, angular velocity and angular position of the valve disc are incorporated into the program. Valve flow coefficients were employed to calculate the frictional pressure drop across the valve at the various angular positions of the disc. Using appropriately conservative conditions, the highest closure energy calculated was 1.252×10^6 in.-lb. 01406854

However, an additional margin was arbitrarily added to the closure energy (raising it to 1.35×10^6 in.lb.) for design.

Details of the closure energy analysis are presented in a topical report PI0- 02-03 (Reference 15) titled: “Analysis Report - Maximum Energy of Disc Impact - Main Steam Check and Isolation Valves for Kewaunee Unit 1,” submitted to the Regulatory Staff on Kewaunee Docket 50-305. Because the main steam isolation and check valves for the Prairie Island and Kewaunee plants are identical, a jointly sponsored program was undertaken by Northern States Power Company and Wisconsin Public Service Corporation to determine disc closure energies. Due to the locations of postulated breaks relative to the valves, the Kewaunee plant has the highest disc closure energies. Therefore, in the analysis, the Kewaunee values were used; and the report, PI0-02-03 (Reference 15), not only applies to Prairie Island but also gives a margin of safety. Due to changes in the full power operating characteristics the MS check and isolation valve disc impact energies were updated in 09Q4836-CAL-002 (Reference 11); however, the Hot-Zero Power condition disc impact energies for the check and isolation valves of PI0-02-03 (Reference 15) remains applicable. 01406854 01406854

A finite element model of the disc linkage and valve body was developed and an elastic plastic analysis was made to determine deformations. The elastic plastic design of the valve allows for permanent deformation of the disc upon spurious valve closure at full load steam flow conditions. A detailed presentation of the stress analysis was presented in a topical report PI0- 01-06 (Reference 9) titled: “Analysis Report - Structural Analysis of Main Steam Check and Isolation Valves for Prairie Island Unit 1.” An updated structural analysis of the main steam check and isolation valves is presented in 09Q4836-CAL-003 (Reference 10). 01406854

The non-return valves prevent reverse flow of steam. If a steam line ruptures between a non-return valve and a steam generator, the affected steam generator will blow down. The non-return valve in the line eliminates blowdown from the other steam generator. The steam break incident is analyzed in Section 14.5.

11.7.4 Inspection and Testing

The main steam line valves can be tested at regular intervals.

The main steam isolation valves serve to limit an excessive reactor coolant system cooldown rate and resultant reactivity insertion following a main steam break incident. Their ability to close upon signal within a specified time interval is verified each refueling outage or when work has been performed on the valves.

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11.8 CONDENSATE POLISHING SYSTEM

11.8.1 Design Basis

The condensate polishing system is typically used during unit start-up and is designed to remove suspended and dissolved impurities from the condensate so that the secondary water chemistry is maintained within specified limits. The system is designed to accommodate a maximum condenser tube leak of 0.5 gpm. The system was originally sized to process approximately 10,000 gpm of condensate. The peak flow capacity of the system is 11,000 gpm.

The system is designed with 50% redundant capacity to provide for continuous operation when portions of the system are shutdown for maintenance or repair.

The system also provides storage, handling and processing of waste solids with interfaces to the ultimate means of disposal via the plant waste solidification system, portable onsite solidification equipment, offsite solidification or offsite landfill.

The system is provided with a process air supply which is designed with sufficient excess capacity to supplement the plant station air system. Chemistry sampling and monitoring is provided to ensure proper system operation. Shielding is provided for the protection of plant personnel. The design of the shielding is based on the maximum primary-to-secondary leakage allowed by the Technical Specifications.

11.8.2 Description

The condensate polishing system (Figures 11.1-19 through 11.1-20) consists of the following subsystems:

a. filter/demineralizer

b. backwash and flush water

c. spent resin disposal

d. backwash air supply

e. resin disposal building sump

All system functions are controlled locally. System malfunctions are alarmed locally and in the control room.

11.8.2.1 Filter/Demineralizer System

The filter/demineralizer (F/D) system is shown in detail in Figure 11.1-20 and consists of three 50%-capacity, precoat-type F/D vessels per unit arranged in parallel in the condensate pump discharge header. Each F/D vessel is rated at 5500 gpm and 30 psi max ΔP across the filter elements. During normal operation two vessels are online while the third is in backwash, precoat, shutdown or standby.

One full-capacity bypass is provided for all three F/D vessels. The bypass valve is automatically actuated by F/D differential pressure to maintain a maximum total system ΔP of 45 psid. Full capacity manual bypass is provided in parallel with the automatic bypass.

A holding pump is provided for each vessel to retain the precoat on the filter elements. The holding pump maintains a 750 gpm flow through the F/D vessel and is automatically actuated on low F/D vessel effluent flow.

Backwash air and water are supplied to each vessel for the purpose of dislodging precoat from the filters by pressurizing and then rapidly depressurizing the vessel. Separate precoating equipment is provided for each F/D train. The vessels are individually precoated via cross-ties to the precoat equipment.

Adequate shielding is provided in the vicinity of the F/D vessels to allow personnel access through the area during design basis primary-to-secondary leakage conditions.

11.8.2.2 Backwash and Flush Water System

Backwash and flush water is stored in the backwash water storage tank (BWST) which is manually supplied from the condensate storage tank (CST). A cross- tie is provided so that the BWST for one unit may be supplied from the CST of the other unit. Backwash waste water and resin from the F/D vessels dumps by gravity to the backwash waste receiving tank (BWRT). The slurry is then transferred to the resin disposal building (RDB). After dewatering via clamshell filters, the spent resin is diverted to the spent resin disposal system, and the backwash waste water is filtered and directed to the turbine building sump. The backwash waste water may be directed to the BWST should circumstances warrant. Each Unit's BWST and BWRT have capacity for two backwashes. Cross-ties are provided such that the dewatering equipment for each unit is interchangeable with the other unit.

11.8.2.3 Spent Resin Disposal System

Dewatered, spent resin from backwash system operations of both units is transferred, via the drain diverters and spent resin disposal chutes, to the spent resin transfer tank (SRXT) in the resin disposal building, or to barrels or to other containers, depending on ultimate disposal. Flush water is also supplied to the SRXT for disposal and/or processing of spent resins.

Flush water or resin slurry in the SRXT can then be pumped under manual control to one of the following places for further processing and/or disposal:

a. Atcor waste metering tank for solidification via the plant waste solidification system in the radwaste building

b. Normally-closed, blind-flanged line in the resin disposal building for transfer to truck or portable solidification equipment

c. backwash system for further reprocessing

d. recirculation line to SRXT

11.8.2.4 Backwash Air Supply System

Compressed air for resin backwashing operations is supplied from the Compressed Air System. The Compressed Air System is discussed in Section 10.3.10. 01284959

11.8.2.5 Resin Disposal Building Sump System

The resin disposal building sump system consists of two sumps, each equipped with a redundant set of sump pumps.

Sump "A" handles the RDB floor drains and may be discharged to either the miscellaneous drains collection tank or the waste holdup tanks.

Sump "B" handles the truck loading enclosure floor drains and discharges to the aerated drains sump tank.

11.8.3 Performance Evaluation

The condensate polishing system is designed to maintain the EPRI PWR Secondary Water Chemistry Guidelines (Reference 1). During normal power operation, sampling of steam generator blowdown, condensate and feedwater is performed in accordance with these guidelines per plant chemistry procedures.

System high conductivity is annunciated at local control panels and actuate the system trouble alarms in the main control room.

The volume of spent powdered resin throughput from the plant is conservatively estimated at 3525 cubic feet annually for both units. Almost all of the spent powdered resin contains negligible radioactivity and can be safely disposed of by landfill burial.

The annual volume of radioactive spent powdered resin depends on the amount of primary-to-secondary leakage. In general, the annual volume of radioactive spent powdered resin is extremely small and has sufficiently low activity to be disposed of as low level waste in accordance with applicable federal regulations.

11.9 CONDENSATE, FEEDWATER AND AUXILIARY FEEDWATER SYSTEMS

11.9.1 Design Basis

11.9.1.1 Condensate and Feedwater Systems

The Condensate and Feedwater System design is based on removing condensate from the hotwell of the condenser and supplying heated feedwater to the steam generators at all load conditions.

There are three multi-stage, vertical, pit-type, centrifugal condensate pumps with vertical motor drives. Each pump is half capacity with the turbine operating at the maximum calculated rating.

Two half-capacity, high speed, centrifugal, vertically-split case, motor-driven main feedwater pumps increase the pressure of the condensate for delivery through one stage of feedwater heating and the feedwater regulating valves to the steam generators.

The main feedwater pumps are single-stage, horizontal, centrifugal pumps with barrel casings. Each feedwater pump is rated at 8600 gpm and 2100 ft. TDH. Shaft sealing is accomplished by a pressure breakdown style arrangement cooled with seal water injection. Bearing lubrication for the motor, the pump, and its step-up gear is accomplished by an integral Lubrication Oil System mounted on the pump base. Normal circulation of the lubrication oil is by shaft-driven pump. The Lubricating Oil System includes a reservoir, a cooler, and an ac motor-driven back-up oil pump. Feedwater pump bearing temperatures are available on ERCS. The feedwater pumps are started and stopped from the main control board. A minimum flow control system is provided to ensure 925 gpm flow during low system flow conditions.

Should there be a loss of suction pressure, an automatic bypass around the low-pressure feedwater heaters ensures sufficient suction pressure at the feedwater pumps.

11.9.1.2 Auxiliary Feedwater System

The Auxiliary Feedwater System supplies feedwater following interruption of the main feedwater supply. Feedwater must be provided for the removal of residual heat from the core by heat exchange in the steam generators if the main feedwater pumps cease to operate for any reason.

The Auxiliary Feedwater System delivers feedwater from the condensate storage tank (or from the cooling water system) to the main feedwater piping at a location near the steam generator inlet. The system consists of the auxiliary feedwater pumps, associated valves and piping, and control systems. The entire system is redundant.

The Auxiliary Feedwater System provides three essential functions during abnormal conditions:

a. prevents thermal cycle of the steam generator tube sheet upon loss of main feedwater pump;

b. removes residual heat from the reactor coolant system until the RCS temperature drops below 300-350°F and the RHR system is capable of providing the necessary heat sink;

c. maintains a head of water in the steam generator following a loss of coolant accident.

The feedwater flow rate required to prevent thermal cycling of the tube sheet and for removing residual heat is the same and is about 160 gpm (historical) per Unit (or 80 gpm per steam generator). 01491637 A 200-gpm flow is therefore sufficient to fulfill all the three functions stated above. However, since the Auxiliary Feedwater System is a safety features system, an additional 200-gpm pump is provided as a backup for the first for each Unit. 200 gpm is the design sizing of the AFW Pumps and not a minimum flow requirement.

In other 2-loop plants (R.E. Ginna, Point Beach, etc.) prior to Prairie Island, the inventory of secondary side water in the steam generator versus secondary side water level was such that the pump size required to prevent thermal cycling was larger than the pump size required for removing the residual heat in the core (almost twice as big).

As a result of this difference in capacity requirement between the two functions, these plants used the turbine driven pump to meet the larger capacity since it was not a safeguards requirement and therefore did not require redundancy. Smaller motor driven pumps are used for the safeguards requirements of removing fission product decay heat so as not to unnecessarily increase the diesel-generator size. The recent designs use a large steam generator with a different dimensional configuration. This reduces the pump size required to prevent thermal cycling, such duty being about the same as for removing residual heat, 160 gpm (historical) per unit or 80 gpm per steam generator. 160 gpm (historical) minimum flow rate is based on normal SG water levels 01491637 at the time of the event (Reference 2). [Only one steam generator is required to remove all decay heat in the core.]

11.9.2 Description

11.9.2.1 Condensate and Feedwater Systems

Condensate is taken from the condenser hotwell by the condensate pumps and pumped through the filter/demineralizer system or its bypass line, the air ejector condensers, gland steam condenser, and low-pressure heaters to the suction of the feedwater pumps. The feedwater pumps then send feedwater through the high-pressure heaters to each steam generator. The condensate and feedwater systems flow diagrams are shown in Figures 11.1-3 to 11.1-6.

The two main feedwater pumps operate in series with the condensate and the heater drain pumps, discharging through check valves and motor-operated gate valves into the No. 5 heaters. The feedwater flows through the two parallel, high-pressure feedwater heaters and flows into a common header. Two 16-in. lines containing the feedwater control stations feed the two steam generators from the header.

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

The steam generator feedwater control system indicates, records and controls the water level in each of the two steam generators.

Reactor trip is actuated by low-low steam generator water level. These trips are discussed in further detail in Section 7.

The main feedwater control valves are closed when any one of the following conditions occurs:

Abnormally high steam generator level

Safety injection signal

Reactor trip in coincidence with low Tavg

Any safety injection signal will isolate the main feedwater lines by closing all control valves (main and bypass valves) and tripping the main feedwater pumps, which causes the discharge valves to close.

One manual control station is provided for each feedwater valve. This unit consists of auto/manual transfer capability and analog output control. When in automatic, flow is adjusted as necessary to maintain narrow range steam generator level at its set point, which is programmed as a function of load.

The reheater and moisture separator are housed in one pressure vessel. Reheaters are provided with drain tanks and level controls. The moisture separators are also provided with level control, while feedwater heater No. 15 is equipped with a duplex level control. All the low-pressure feedwater heaters, No. 11, 12, and 13, are located in the condenser neck. Feedwater heaters No. 11 & 12 are combined into one shell (duplex) with bolted-head construction. Feedwater heater No. 11 is provided with a separate Feedwater Heater Drain Cooler (No. 11). Drain from moisture separator and Feedwater heater No. 14 are drained directly to the Heater Drain Tank, as shown in Figures 11.1-9, 10.

The level controllers operate the emergency drain dump valves which dump the various drains directly to the condenser in case of abnormally high level. Three half-capacity, vertical, centrifugal heater drain pumps are provided for pumping the heater drainage into the condensate line ahead of the feedwater pumps. The pumps are started and stopped from the main control board. Tank level is controlled by variable-speed pump drives. An emergency dump valve to the condenser is sized to pass all condensate from Feedwater Heater No. 14.

11.9.2.2 Auxiliary Feedwater System

The Auxiliary Feedwater System is the most reliable system for decay heat removal following any reactor shutdown. Full flow capability is reached within a maximum response time of one minute when the pump drives are automatically energized from an open-valve standby status, when the normal coolant source is available. As discussed below, response time to other scenarios such as seismic events and tornadoes may take longer if there is a need to realign pump suction to the backup coolant source. Redundancy of flow paths, valving, pumps, and redundancy and diversity of coolant sources, and pump energy sources assures a high degree of system reliability.

The Auxiliary Feedwater System consists of one steam turbine-driven pump and one motor-driven pump per operating unit, with each capable of delivering coolant to either or both steam generators of the same operating unit. Check valves are provided to prevent a rupture in either pump’s discharge from negating the other pump’s effectiveness. Welded construction is used where possible throughout the Auxiliary Feedwater System piping, valves, and equipment to minimize the possibility of leakage. The Auxiliary Feedwater System is shown on the Main Steam System and Feedwater System flow diagrams, Figures 11.1-1, 11.1-2, 11.1-5 and 11.1-6. Pump characteristic curves are shown on Figure 11.9-1.

There is no interconnection between the two turbine-driven pumps, and there is no sharing of the Auxiliary Feedwater System components by the two operating units during normal operations. However, a cross-connection between the discharge lines of the motor-driven pumps is provided to achieve greater flexibility during operational emergencies. By incorporating two valves in this cross-connection, the Auxiliary Feedwater System has the capability to take an active or passive failure and still fulfill its functional requirements.

The turbine-driven auxiliary feedwater pumps operate independent of all plant AC power sources and are supplied steam from both main steam lines of their associated operating unit. The two steam lines join together downstream of motor-operated isolation valves (one per line) to supply steam to the turbine through a single air-operated, fail open, steam admission valve.

The air-operated steam admission valve has two safety related functions:

1) Open: To allow passage of steam to start the associated turbine-driven auxiliary feedwater pump.

2) Close: Tripping the pump on low turbine-driven auxiliary feedwater pump suction or discharge pressure.

The steam admission valve safety related air pressure boundary is from the safety related check valve to the air-operated steam admission valve actuator. The instrument air system supplies air to the steam admission valve air pressure boundary. The air supply to the steam admission valve is controlled by a three-way DC powered solenoid. The air-operated steam admission valve opens automatically on a turbine-driven auxiliary feedwater pump start signal. Additionally, the turbine-driven auxiliary feedwater pump may also be started locally using a 3-way manual valve to locally bleed air pressure from the steam admission valve air pressure boundary.

Failure of control power to the three-way DC powered solenoid valve causes the air pressure boundary to be vented, which results in the steam admission control valve to open, starting the associated pump. On failure of the instrument air system, the accumulator is capable of maintaining sufficient air pressure for the steam admission valve. The steam admission valve will remain closed until accumulator pressure is lost or an automatic start signal is received. In the case of loss of instrument air, the most likely start signal will be from Low-Low Steam Generator Water Level.

The motor-driven auxiliary feedwater pumps are fed by separate safeguard buses, one each per operating unit, and are included in the load restoration sequencing onto the emergency buses. Motor-operated valves are not stripped from the emergency buses. A failure in the automatic circuitry will not affect the capability to manually initiate auxiliary feedwater from the control room.

Instrumentation and logic circuits for starting both the motor- and turbine-driven pumps meet the single failure criterion (except for AMSAC) for actuation and are capable of being tested at power.

Instrumentation power supplies are from the site's four vital 120 VAC buses, each supplied by an inverter connected to the associated 480 VAC emergency bus and 125 VDC power system. Motor-driven pump breaker controls are powered by the respective train of the 125 VDC system. Control power for the turbine-driven pumps' steam admission control valves is also supplied from the Safeguards 125 VDC battery systems.

The following signals automatically start the pump motors and open the steam admission control valve to the turbine-driven pumps:

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

b. Trip of both main feedwater pumps (bypassed during startup and shutdown operation).

c. Safety injection.

d. Loss of both 4.16 KV normal buses (turbine-driven pump only).

e. AMSAC actuation.

In addition, the motor-driven pumps and the turbine-driven pumps can be manually started locally or remotely.

Each auxiliary feedwater pump has a pressure switch on its suction and on its discharge piping. If a low pressure setpoint is reached on either switch, the pump will trip either by closing the air-operated steam admission control valve on the turbine-driven auxiliary feedwater pumps, or by opening the motor breaker on the motor-driven auxiliary feedwater pumps. The low discharge pressure trip protects the pump from damage due to runout. The low suction pressure trip prevents damage to the pump from loss of suction. In either case, the pump will be protected so it can be restarted once the cause of low pressure is corrected.

On 11 and 22 Turbine-Driven Auxiliary Feedwater Pumps, the low discharge pressure trip is blocked when in AUTO and the Reactor Trip Breakers are closed (RTA for relay contact for 11 TD AFW pump and RTB relay contact for 22 TD AFW pump). This circuit ensures that following the completion of the AMSAC initiation of Auxiliary Feedwater during an ATWS transient, the TD AFW pump will continue to run.

During reactor operation, all pumps are on standby, and the isolation valves and pump suction and discharge valving are open. Start of an auxiliary feedwater pump causes the steam generator blowdown flow control valves in the associated operating unit to auto close.

Auxiliary feedwater system coolant sources are redundant and diverse. The normal source is by gravity feed from the three cross-connected 150,000 gallon condensate storage tanks. The safety related (backup) water supply is provided by the Design Class I Cooling Water System. If an external event such as a tornado or seismic event were to cause flow disruption from the condensate storage tanks, the auxiliary feedwater pumps would likely trip on low suction pressure. Piping connecting the three condensate storage tanks has been evaluated against failure under seismic loads. 01427085

An auxiliary feedwater reliability study [Ref. 14] was performed after the Three Mile Island accident and in response to NUREG-0611. This study determined steam generator dryout times with no auxiliary feedwater flow available. For a loss of normal feedwater event, the dryout time is approximately 30 minutes. For a loss of offsite power event, the dryout time is approximately 60 minutes. (Additional reliability study information follows near the end of this section.) Additional analysis (NSP-07-33, Reference 5) has determined that additional time is available for reinitiating of A.F. flow based on the effect on the primary system for a loss of offsite power due to an external event.

PINGP has standing operating procedures for realigning the auxiliary feedwater pump suction from the condensate storage tanks to the Cooling Water System and for flow restoration after a low suction/low discharge pressure auxiliary feedwater pump trip. These procedures have been time-validated and can be accomplished within the SG dryout time frames listed above.

In the normal cooldown procedure, after programmed reactor shutdown or trip, steam generator levels may be maintained by control of the feedwater flow control valves. If the Main Feedwater System is inoperable or its flow is too great, steam generator levels are controlled by local or remote manual operation of the auxiliary feedwater flow control valves for the turbine- and motor-driven pumps.

When reactor containment isolation is initiated, the normally-open auxiliary feedwater containment isolation valves receive an “open” signal.

Following blowdown in the loss-of-coolant accident, the Auxiliary Feedwater System maintains a positive pressure differential from the secondary side to the primary side of the steam generators, providing a barrier to prevent possible fission product escape to the Main Steam System.

The SI actuation circuits which initiate auxiliary feedwater addition are safety grade, separated and trained. The SI actuation contacts which trip the normal feedwater pumps off are also safety grade, using additional relays to maintain separation even though both pumps are tripped off by both Train A and Train B SI signals. In addition, either Train A or Train B SI Signal causes closure of the parallel flow control valves downstream of the feedwater pumps. The SI signal causes closure of the containment isolation valves downstream of the normal feedwater flow control valves through the containment isolation signals.

A cycle timer control circuit automatically runs the auxiliary motor-driven lube oil pump on each auxiliary feedwater pump for approximately 10 minutes twice per week. The minimum requirement is 5 minutes once per week. If the proper lube oil pressure is not reached following the lube oil pump start, an alarm is sounded in the control room. This ensures that sufficient auxiliary feedwater pump oil film for pump start is maintained at all times. Thus, the auxiliary motor-driven lube oil pump is not required for auxiliary feedwater pumps starting.

The bearing oil coolers are cooled by recirculation flow from the discharge of the auxiliary feedwater pumps back to the condensate storage tanks. Oil cooling is thus available whenever the pump is running.

As a result of the Three Mile Island accident, reliability of the auxiliary feedwater system received additional attention. The NRC issued Generic Letter 81-14, “Seismic Qualification of AFW Systems”. Several responses to the NRC were made from which the NRC concluded in a letter dated June 16, 1983 that, following a number of minor modifications, the auxiliary feedwater system had sufficient capability to withstand a safe shutdown earthquake and accomplish its safety function.

Generic Issue No. 124, “Auxiliary Feedwater System Reliability” was also identified as a result of the Three Mile Island accident. The Prairie Island Auxiliary Feedwater System was determined to be in the low reliability range based on an NRC reliability analysis reported in NUREG-0611. As a result of Generic Issue No. 124, Northern States Power Company performed a probabilistic risk assessment study on the auxiliary feedwater and supporting systems, Prairie Island Units 1 and 2 Auxiliary Feedwater System Reliability Study [Ref 14]. Based on the NSP study, and an NRC staff audit of plant variables affecting the Auxiliary Feedwater system, Generic Issue No. 124 was closed out by an NRC Safety Evaluation Report transmitted by letter dated November 26, 1986.

The following is a list of actions that were taken as a result of the NSP study and remaining NRC concerns expressed in the NRC Safety Evaluation to close out Generic Issue 124.

a. Lube Oil Cooling - AFW pump discharge recirculation flow was rerouted to supply cooling water for pump lube oil coolers. This action removed the AFW dependency on cooling water for lube oil cooling.

b. Manual Control of TDAFW Pump - A three way solenoid valve has been added to the air supply line to the TDAFW pump steam inlet supply control valve. This valve allows the pump to be run manually by locally opening the control valve by venting diaphragm air. A procedure has been written for manual auxiliary feedwater pump operations. All operations crews have been trained in use of the procedures.

c. Eliminate Auto Open Signal to MV-32041 & MV-32042 - The auto open signal to the “Condensate Emergency Supply Valve,” MV-32041 (Unit 1) and MV-32042 (Unit 2), has been removed.

d. Drain Valves from AFW Steam Lines to the Main Condenser - All drain valves from the AFW steam lines to the main condenser have been blocked open using safeguards hold cards.

e. Proceduralize Bypass of Control/Actuation Faults - The subject procedures have been written as subsections of the Auxiliary Feedwater System procedure.

f. AFW System Valve Integrity - Check valve integrity is assured by monitoring the temperature of AFW discharge lines during each shift.

g. Trip/Throttle Leakoff - Both the high and low pressure leakoff for the TDAFW pump trip/throttle valves have been rerouted to discharge into the turbine exhaust lines. This modification was completed to eliminate the potentially for creating a steam environment in the auxiliary feedwater pump room during operation of the turbine-driven auxiliary feedwater pump.

h. Condensate Header Valve C-41-1 - Condensate header valve C-41-1 was installed during plant construction to facilitate isolation and testing of systems. This valve was not used after plant startup and represented a potential for loss of AFW pump suction supply, it was removed from service and replaced by a spoolpiece.

i. Actions Taken to Eliminate Final NRC Concerns:

   1. Administratively locked open the condensate storage tank isolation valves to ensure AFW pumps suction supply.

   2. A step ladder is located in each AFW pump room to aid operators in manipulating overhead AFW valves in emergency situations.

   3. Installed additional emergency lighting in the area of the TDAFW pumps.

   4. Work toward maintaining similarity between Unit 1 and Unit 2 AFW surveillance and maintenance procedures.

11.9.3 Performance Analysis

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 upon 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 atmospheric steam dump valves, steam generator safety valves or the power-operated relief 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 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.

The reactor plant conditions which impose performance requirements on the design of the Auxiliary Feedwater System are as follows for the Prairie Island plants.

Loss of Main Feedwater Transient
- Loss of main feedwater with offsite power available (*)
- Loss of main feedwater without offsite power available (*)

Secondary Pipe Ruptures
- Feedline rupture
- Steamline rupture (*)

Loss of All AC Power (station blackout)

Loss of coolant Accident (LOCA) (*)

Cooldown

a. Loss of Main Feedwater Transients

The design loss of main feedwater transients are those caused by:

– Interruptions of the Main Feedwater System flow (LONF) due to a malfunction in the feedwater or condensate system

– Loss of offsite power (LOOP) with the consequential shutdown of the system pumps, auxiliaries, and controls

(*) Impose safety related performance requirements

Loss of main feedwater (LONF) transients are characterized by a rapid reduction in steam generator water levels which results in a reactor trip, a turbine trip, and auxiliary feedwater actuation by the protection system logic. Following reactor trip from high power, the power quickly falls to decay heat levels. The water levels continue to decrease, progressively uncovering the steam generator tubes as decay heat is transferred and discharged in the form of steam either through the steam dump valves (to the condenser or atmosphere) or through the steam generator safety or power-operated relief valves to the atmosphere. The reactor coolant temperature increases as the residual heat in excess of that dissipated through the steam generators is absorbed. With increased temperature, the volume of reactor coolant expands and begins filling the pressurizer. Without the addition of sufficient auxiliary feedwater, further expansion will result in water being discharged through the pressurizer safety and relief valves. If the temperature rise and the resulting volumetric expansion of the primary coolant are permitted to continue, then (1) pressurizer safety valve capacities may be exceeded causing overpressurization of the Reactor Coolant System and/or (2) the continuing loss of fluid from the primary coolant system may result in core uncovering, loss of natural circulation, and core damage. If such a situation were ever to occur, the Emergency Core Cooling System would be ineffectual because the primary coolant system pressure exceeds the shutoff head of the safety injection pumps, the nitrogen over-pressure in the accumulator tanks, and the design pressure of the Residual Heat Removal Loop. Hence, the timely introduction of sufficient auxiliary feedwater is necessary to arrest the decrease in the steam generator water levels, to reverse the rise in reactor coolant temperature, to prevent the pressurizer from filling to a water solid condition, and eventually to establish stable hot standby conditions. Subsequently, a decision may be made to proceed with plant cooldown if the problem cannot be satisfactorily corrected.

The LOOP transient differs from a simple loss of main feedwater in that emergency power sources must be relied upon to operate vital equipment. The loss of power to the electric driven condenser circulating water pumps results in a loss of condenser vacuum and condenser dump valves. Hence, steam formed by decay heat is relieved through the atmospheric steam dump valves, steam generator safety valves or the power-operated relief valves. The calculated transient would be similar for both the loss of main feedwater and the LOOP, except that reactor coolant pump heat input is not a consideration in the LOOP transient following loss of power to the reactor coolant pump bus.

The LONF transient serves as the basis for the minimum flow required for the smallest capacity single auxiliary feedwater pump for the Prairie Island plants due to the additional heat from Reactor Coolant Pump operation. The pump is sized so that any single pump will provide sufficient flow against the steam generator safety valve set pressure (with accumulation) to prevent water relief from the pressurizer. For decay heat removal using the safety valve(s), actual accumulation is a function of the steam flow rate required for the decay heat load and if the decay heat load is being removed by one or both Steam Generators.

b. Secondary System Pipe Ruptures

The feedwater line rupture accident not only results in the loss of feedwater flow to the steam generators but also results in the complete blowdown of one steam generator within a short time if the rupture should occur downstream of the last nonreturn valve in the main or auxiliary feedwater piping to an individual steam generator. Another significant result of a feedline rupture may be the spilling of auxiliary feedwater out the break as a consequence of the fact that the auxiliary feedwater branch line may be connected to the main feedwater line in the region of the postulated break. Such situations can result in the spilling of a disproportionately large fraction of the total auxiliary feedwater flow because the system preferentially pumps water to the lowest pressure region in the faulted loop rather than to the effective steam generator which is at a relatively high pressure. The system design must allow for terminating, limiting, or minimizing that fraction of auxiliary feedwater flow which is delivered to a faulted loop or spilled through a break in order to ensure that sufficient flow will be delivered to the remaining effective steam generator. The concerns are similar for the main feedwater line rupture as those explained for the loss of main feedwater transients.

Main steamline rupture accident conditions are characterized initially by plant cooldown and, for breaks inside containment, by increasing containment pressure and temperature. Auxiliary feedwater is not needed during the early phase of the transient but flow to the faulted loop will contribute to the release of mass and energy to containment. Thus, steamline rupture conditions establish the upper limit on auxiliary feedwater flow delivered to a faulted loop. Eventually, however, the Reactor Coolant System will heat up again and auxiliary feedwater flow will be required to be delivered to the unfaulted loop, but at somewhat lower rates than for the loss of feedwater transients described previously. Provisions must be made in the design of the Auxiliary Feedwater System to allow limitation, control, or termination of the auxiliary feedwater flow to the faulted loop as necessary in order to prevent containment overpressurization following a steamline break inside containment, and to ensure the minimum flow to the remaining unfaulted loops.

c. Loss of All AC Power

The loss of all AC power is postulated as resulting from accident conditions wherein not only onsite and offsite AC power is lost but also AC emergency power is lost as an assumed common mode failure.

Battery power for operation of protection circuits is assumed available. The impact on the Auxiliary Feedwater System is the necessity for providing both an auxiliary feedwater pump power and control source which are not dependent on AC power and which are capable of maintaining the plant in Mode 3, Hot Standby until AC power is restored.

d. Loss-of-Coolant Accident (LOCA)

The loss of coolant accidents do not impose on the auxiliary feedwater system any flow requirements in addition to those required by the other accidents addressed in this response. The following description of the small LOCA is provided here for the sake of completeness to explain the role of the auxiliary feedwater system in this transient.

Small LOCA's are characterized by relatively slow rates of decrease in reactor coolant system pressure and liquid volume. The principal contribution from the Auxiliary Feedwater System following such small LOCAs is basically the same as the system's function during Mode 3, Hot Standby or following spurious safety injection signal which trips the reactor. Maintaining a water level inventory in the secondary side of the steam generators provides a heat sink for removing decay heat and establishes the capability for providing a buoyancy head for natural circulation. The auxiliary feedwater system may be utilized to assist in a system cooldown and depressurization following a small LOCA while bringing the reactor to Mode 5, Cold Shutdown.

e. Cooldown

The cooldown function performed by the Auxiliary Feedwater System is a partial one since the reactor coolant system is reduced from normal zero load temperatures to a hot leg temperature of approximately 350°F. The latter is the maximum temperature recommended for placing the Residual Heat Removal System (RHRS) into service. The RHR system completes the cooldown to Mode 5, Cold Shutdown conditions.

Cooldown may be required following expected transients, following an accident such as a main feedline break, or during a normal cooldown prior to refueling or performing reactor plant maintenance. If the reactor is tripped following extended operation at rated power level, the AFWS is capable of delivering sufficient AFW to remove decay heat and reactor coolant pump (RCP) heat following reactor trip while maintaining the steam generator (SG) water level. Following transients or accidents, the recommended cooldown rate is consistent with expected needs and at the same time does not impose additional requirements on the capacities of the auxiliary feedwater pumps, considering a single failure. In any event, the process consists of being able to dissipate plant sensible heat in addition to the decay heat produced by the reactor core.

Table 11.9-1 summarizes the criteria which are the general design bases for each event. Specific assumptions used in the analyses to verify that the design bases are met are discussed below.

The primary function of the Auxiliary Feedwater System is to provide sufficient heat removal capability for heatup accidents following reactor trip to remove the decay heat generated by the core and prevent system overpressurization. Other plant protection systems are designed to meet short term or pre-trip fuel failure criteria. The effects of excessive coolant shrinkage are bounded by the analysis of the rupture of a main steam pipe transient. The maximum flow requirements determined by other bases are incorporated into this analysis, resulting in no additional flow requirements.

Analyses have been performed for the limiting transients which define the AFWS performance requirements. Specifically, they include:

- Loss of Main Feedwater (LONF)
- Rupture of a Main Feedwater Pipe
- Rupture of a Main Steam Pipe Inside Containment

The analyses described below are for determining the performance requirements of the AFWS; for example, sizing of the AFW Pumps. The description below, the criteria in Table 11.9-1, and the inputs and assumptions in Table 11.9-2 may be different than those used for the accident and transient analyses described in Section 14. In addition, the accidents and transients evaluated for AFW sizing may be different than those analyzed in Section 14. For example, the rupture of Main Feedwater Line (cannot be isolated from the associated SG) is evaluated for AFW sizing, but is not an analyzed accident in Section 14. That is, the Main Feedwater Line Break is not a design basis accident for Prairie Island.

In addition to the above analyses, calculations have been performed specifically for the Prairie Island plants to determine the plant cooldown flow (storage capacity) requirements. The Loss of All AC Power is evaluated via a comparison to the transient results of a LOOP, assuming an available auxiliary pump having a diverse (non-AC) power supply. The LOCA analysis, as discussed in Item (d) above, incorporates the system flow requirements as defined by other transients, and therefore is not performed for the purpose of specifying AFWS flow requirements. Each of the analyses listed above are explained in further detail below.

Loss of Main Feedwater (LONF)

A loss of feedwater (LONF) transient assuming a single auxiliary feedwater pump delivering flow to both steam generators was evaluated to show that this event does not result in filling the pressurizer, that the peak RCS pressure remains below the criterion for Condition II transients and that no fuel failures occur (refer to Table 11.9-1). As previously discussed, for determining AFW flow requirements, maintaining off-site power is more conservative than losing off-site power. Table 11.9-2 summarizes the assumptions used in this analysis. The transient analysis begins at the time of the loss of main feedwater. The analysis assumes that the plant is initially operating at the power shown on the table, a very conservative assumption in defining decay heat and stored energy in the RCS. The reactor is assumed to be tripped on low-low steam generator level. Steam generator level at the time of reactor trip was assumed to be 0% NRS for additional conservatism; to that, allowance for level uncertainty was also accounted for. The analysis shows that there is a considerable margin with respect to filling the pressurizer.

This analysis establishes the capacity of the smallest single pump and also establishes train association of equipment so that this analysis remains valid assuming the most limiting single failure.

Rupture of Main Feedwater Pipe

The double ended rupture of a main feedwater pipe inside of containment is analyzed for determining AFW performance requirements (Reference 3). Table 11.9-2 summarizes the assumptions used in the analyses. Reactor trip is assumed to occur as a result of a safety injection signal based on high containment pressure. This is a conservative time assumption which increases the stored heat prior to reactor trip and minimizes the ability of the steam generator to remove heat from the RCS following reactor trip due to a conservatively small total steam generator inventory. As in the loss of normal feedwater analysis, the initial power rating was assumed to be 1683 MWt. The analysis allows for 180 gpm auxiliary feedwater delivered to the intact loop within 10 minutes of the reactor trip (10 minutes for operator action to reroute flow paths and to start the auxiliary feedwater pumps). The criteria listed in Table 11.9-1 are met.

The outside of containment main feedwater line break and subsequent blowdown of a steam generator is precluded by the closing of the check valve inside containment. However, the Turbine Building or Auxiliary Building would experience the break flow from the feedwater pump discharge. The reactor coolant system would experience an event which would be similar to the loss of normal feedwater transient.

This analysis establishes the capacity requirements for a single pump, establishes requirements for layout to preclude indefinite loss of auxiliary feedwater to the postulated break, and establishes train association requirements for equipment so that the AFWS can deliver the minimum flow required in 10 minutes following operator actions assuming the worst single failure. Primary system heat removal due to blowdown is included in our analytical code model and is correctly simulated during the feedline rupture analysis.

Rupture of a Main Steam Pipe Inside Containment

Because the steamline break transient is a cooldown, the AFWS is not needed to remove heat in the short term. Furthermore, addition of excessive auxiliary feedwater to the faulted steam generator will affect the peak containment pressure following a steamline break inside containment. This transient is performed for several break sizes. Auxiliary feedwater is assumed to be initiated at the time of the break, independent of system actuation signals to provide the most conservative analysis with respect to containment pressure.

Table 11.9-2 summarizes the assumptions used in this analysis. The criteria stated in Table 11.9-1 are met.

This transient establishes auxiliary feedwater flow rate to a single faulted steam generator assuming one pump operational and establishes layout requirements so that the flow requirements may be met considering the worst single failure. Primary system heat removal due to blowdown is included in our analytical code model and is correctly simulated during the steamline rupture analysis.

Plant Cooldown

Maximum and minimum flow requirements from the previously discussed transients meet the flow requirements of plant cooldown. This operation, however, defines the basis for tankage size, based on the required cooldown duration, maximum decay heat input and maximum stored heat in the system. As previously discussed above the auxiliary feedwater system partially cools the system to the point where the RHRS may complete the cooldown, i.e., 350°F in the RCS. Table 11.9-2 shows the assumptions used to determine the cooldown heat capacity of the auxiliary feedwater system.

The cooldown is assumed to commence at the maximum rated power, and maximum trip delays and decay heat source terms are assumed when the reactor is tripped. Primary metal, primary water, secondary system metal and secondary system water are all included in the stored heat to be removed by the AFWS. See Table 11.9-3 for the items constituting the sensible heat stored in the NSSS.

This operation is analyzed to establish minimum tank size requirements for auxiliary feedwater fluid source which are normally aligned. This analysis is documented in Reference 6.

11.9.4 Inspection and Testing

11.9.4.1 Auxiliary Feedwater System

The auxiliary feedwater pumps can be periodically operated to verify their operability, as discussed in Section 11.9.1.

Proper functioning of the steam admission valve and subsequent starting of the steam-driven pump demonstrates the integrity of the system. Verification of correct operation can be made both from instrumentation within the main control room and direct visual observation of the pump.

The actions required to provide a head of water in the steam generator after a loss of coolant accident are exactly the operations required to fill a tank with fluid using a pump.

The test for the auxiliary feedwater system is to confirm the operability of the pumps, valves, and flow paths. The operability of the Auxiliary Feedwater System will be proven by starting any one of the pumps and demonstrating that steam generator water level is controlled using auxiliary feedwater during startup operations. Testing requirements are specified in Prairie Island Technical Specifications. If these operate, the ability of the system to maintain a water level in the steam generators is confirmed.

The Auxiliary Feedwater System is operated during reactor shutdown until the reactor conditions permit use of the Residual Heat Removal System. The active components (valves, pumps and pump drives, lube-oil pumps) of the system can be tested at any other time.

NRC IE Bulletin 85-01 presented a concern over the operability of a steam driven auxiliary feedwater pump due to steam binding (Generic Issue 89). Steam binding incidents have been observed as a result of back leakage through check valves from steam generators to the auxiliary feedwater pump casing. To alleviate concerns over auxiliary feedwater pump steam binding, Prairie Island has implemented procedures to monitor the temperature of pump discharge piping each shift. Procedures have also been implemented to recognize steam binding and for restoring the Auxiliary Feed System to operable status. 01429750

11.9.4.2 Wall Thickness Monitoring of High-Energy Piping

An Erosion/Corrosion program or Flow-Accelerated Corrosion program as referred to by EPRI to survey high-energy pipe wall thickness was begun at Prairie Island in 1983 and expanded following a feedwater pump suction line rupture event at the Surry plant in December 1986.

The Prairie Island program incorporates guidelines from NRC Bulletin 87-01 (Reference 4), NRC Generic Letter 89-08 (Reference 12), and EPRI NSAC-202L to evaluate piping components susceptible to erosion/corrosion.

Sample size and inspection frequency are adjusted based on engineering review of the operating conditions, previous inspection results, experience gained, and results of an analytical program.

Non-Destructive Examination (NDE) methods such as: Ultrasonic Testing (UT) or Radiography Testing (RT) are used to determine pipe wall thickness for run/repair/replace decision.

Run/repair/replace decisions are made by the plant system engineers following evaluation of the inspection data.

11.10 REFERENCES

1. EPRI PWR Secondary Water Chemistry Guidelines

2. “Westinghouse Letter PIW-N-50, Auxiliary Feedwater System,” dated Sept. 4, 1968. [Film Loc. 7497-No Blip]

3. NSP NAD-98006, “Analysis of a Feedwater Line Break for Prairie Island,” dated September 1998. [NAD Files]

4. NRC Bulletin 87-01, “Thinning of Pipe Walls in Nuclear Power Plants,” July 9, 1987. (1400/0304)

5. NSP-07-33, “Loss of Offsite Power with Delayed AFW Analysis Results” 01477171

6. Calculation ENG-ME-443, latest Rev, Condensate Storage Tank Sizing

7. WCAP-11525, “Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency”, June, 1987. (1729/0009)

8. Letter, D C DiIanni (NRC) to D M Musolf (NSP) “Amendment Nos. 86 and 79 to Facility Operating Licenses Nos. DPR-42 and DPR-60: Turbine Valve Test Frequency Reduction (TACS Nos. 66867 and 66868)”, February 7, 1989. (1664/2491)

9. PI0-01-06, Analysis Report - Structural Analysis of Main Steam Check and Isolation Valves for Prairie Island Unit 1, September 14, 1973 (7346/515)

10. 09Q4836-CAL-003, Updated Structural Analysis of Main Steam Check and Isolation Valves

11. 09Q4836-CAL-002, Updated Disc Impact Analysis of Main Steam Check and Isolation Valves

12. NRC Generic Letter 89-08, “Erosion/Corrosion–Induced Pipe Wall Thinning,” May 2, 1989. (1771/0376)

13. Westinghouse Owners Group Report, “Update and Evaluation of BB-95/96 Turbine Valve Failure Data Base,” March 1999 (Westinghouse Letter WOG-TVTF-99-007, March 24, 1999) (see PI copy of WCAP 11525).

14. NSPNAD-8606, Auxiliary Feedwater System Reliability Study, Rev. 0, April 1986, [Location: Library Manual and film at 1270-645].

15. PI0-02-03, Analysis Report Maximum Energy of Disc Impact Main Steam Check and Isolation Valves for Kewaunee Unit 1, dated December 23, 2009.

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TABLE 11.1-1 STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS

Turbine–Generator	
Turbine	Three element, tandem–compound four-flow exhaust
Turbine Capacity KW	
Maximum guaranteed	583,722 (Unit 1); 575,642 (Unit 2) (Note 1)
Maximum calculated	591,988
Generator Rating (Kva) - Unit 1	659,000
Generator Rating (Kva) - Unit 2	730,000
Turbine Speed (rpm)	1800
Condensers	
Type	Double flow, single pass deaerating
Number	2
Steam Load, Lb./hr.	4,111,711
BTU Rejected per hour (total condenser “A” & “B”)	3,873,616,764
Absolute Pressure, Ins. Hg.	Cond. A - 1.82 Cond. B - 1.28
Percent Cleanliness	85
Circulating Water Temperature, °F	60
Circulating Water Quantity, gpm	294,000
Water Velocity, fps	8.49
Friction in Water Circuit, ft.	35.7
Guaranteed 0_2 Content, CC/liter	0.003

Notes:

(1) For various turbine / condenser / reheat heat balance gross loads see Figures 11.2-1 through 11.2-5.

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TABLE 11.1-1 STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS

(Page 2 of 3)

Condensate Pumps

Type	Multi-stage, vertical, pit-type, centrifugal
Number	3
Design Capacity (each–gpm)	5250
Motor Type	Vertical
Motor Rating (hp)	1750

Feedwater Pumps

Type	High speed, vertically split single stage, double suction centrifugal
Number	2
Design Capacity (each–gpm)	8600
Motor Type	Horizontal
Motor Rating (hp)	5000

Heater Drain Pump

Type	Multi–stage, vertical, can-type centrifugal
Number	3
Design Capacity (each–gpm)	2800
Motor Type	Vertical
Motor Rating (hp)	500

TABLE 11.1-1 STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS

Emergency Feedwater Source	Three 150,000 gallon condensate storage tanks. Alternate supply from the cooling water system.
Auxiliary Feedwater Pumps	2 total. One steam turbine-driven pump and one electric motor-driven pump.
Design Capacity (gpm)	200 (turbine driven) 200 (motor driven)

TABLE 11.1-2 STEAM AND POWER CONVERSION SYSTEM CODE REQUIREMENTS

System Pressure Vessels	ASME VIII*
Steam Generator Vessel	See USAR Table 4.1-11 01-010
System Valves, Fittings and Piping	USAS B31.1, 1967**

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* American Society of Mechanical Engineers, Boiler and Pressure Vessel Code. Section VIII. (The Code version applicable to that which was in effect at the date of placement of order for each individual component).

** Code for Pressure Piping. 01-010

TABLE 11.1-3 STEAM AND POWER CONVERSION SYSTEM SINGLE FAILURE ANALYSIS

Component or System	Malfunction	Comments and Consequences
Auxiliary Feedwater System	Auxiliary feedwater pump fails to start (following loss of main feedwater)	One full-capacity steam driven pump and one full-capacity motor-driven auxiliary feedwater pumps are provided. Hence either of the two auxiliary feedwater pumps provide the required flow of feedwater.
Steam Line Isolation System	Failure of steam line isolation valve to close (following a main steam line rupture)	Each steam line contains an isolation valve and a non-return valve in series. Hence a failure of an isolation (or non-return) valve will not permit the blowdown of more than one steam generator regardless of the steam line rupture location.
Bypass and Atmospheric Steam Dump System	Steam dump valve sticks open (following operation of the system resulting from a turbine trip)	This steam dump system comprises one steam bypass valve and four atmospheric dump valves. One valve will only pass 12% of the maximum calculated steam flow and there is no hazard in the form of an uncontrolled plant cool down if a steam dump valve sticks open.

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TABLE 11.9-1
CRITERIA FOR AUXILIARY FEEDWATER SYSTEM DESIGN BASIS CONDITIONS[3]

Condition or Transient	Classification[1]	Criteria[1]	Additional Design Criteria	
Loss of Main Feedwater	Condition II	Peak RCS pressure not to exceed design pressure. No consequential fuel failures	Pressurizer does not fill with 1 single motor driven aux. feed pump feeding 2 SGs.	05-002
Loss of Offsite Power (LOOP)	Condition II	(same as LMFW)	Pressurizer does not fill with 1 single motor driven aux. feed pump feeding 2 SGs.	05-002
Feedline Rupture	Condition IV	10CFR100 dose limits. Containment design pressure not exceeded	Core does not uncover	
Steamline Rupture	Condition IV	10CFR100 dose limits. Containment design pressure not exceeded		
Loss of all A/C Power	N/A	Note[2]	Same as LOOP assuming turbine driven pump	
Loss of Coolant	Condition III	10CFR100 dose limits 10CFR50 PCT limits		
	Condition IV	10CFR100 dose limits 10CFR50 PCT limits		
Cooldown	N/A		100°F/hr 547°F to 350 OF	

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[1] Ref: ANSI N18.2

[2] Note: Although this Transient establishes the basis for AFW pump powered by a diverse power source, this is not evaluated relative to typical criteria since multiple failures must be assumed to postulate this transient

[3] Note: These criteria and conditions/transients were used for determining the performance capabilities for AFW and may be different than those used to analyze design basis accidents and transients in Section 14.

TABLE 11.9-2
SUMMARY OF ASSUMPTIONS USED IN AFWS MINIMUM FLOW EVALUATION
(Page 1 of 2)

Input	Loss of Normal Feedwater or Loss of Off Site Power	Cooldown	Main Feedwater Line Break (Not isolated from SG)	Main Steam Line Break (Containment)
Initial Reactor Power (%)	1683 MWt	1683 MWt	1683 MWt	Most limiting as determined in the analysis
Time Delay from event to Rx Trip	15 seconds after Lo-Lo SG Level signal	N/A	Time for containment pressure to reach 4 psig + time delay for rod insertion	Time for containment pressure to reach 4 psig + time delay for rod insertion.
AFWS Actuation Signal	Lo-Lo SG Level	N/A	SI	SI
Time Delay for AFWS flow (after initiating signal)	60 seconds	N/A	10 minutes	None (for containment pressure response)
Initial SG liquid level	55% Narrow Range Level	Nominal	Nominal	Greater than maximum operational band
# of SGs which receive AFW flow	2	2	1 *	1 *
AFW Temperature	100°F	100°F	100°F	100°F
AFW flow rate	190 gpm	Variable (as necessary for plant cooldown)	180 gpm	AFW flow is initially maximized for core and containment pressure analyses. Minimum AFW flow is variable and corresponds to the flow rate used for decay heat removal.

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TABLE 11.9-2
SUMMARY OF ASSUMPTIONS USED IN AFWS MINIMUM FLOW EVALUATION
(Page 2 of 2)

Input	Loss of Normal Feedwater or Loss of Off Site Power	Cooldown	Main Feedwater Line Break (Not isolated from SG)	Main Steam Line Break (Containment)
MFW Purge Volume/Temp.	Included in Computer Model	N/A	Included in Computer Model	Included in Computer Model
Operator Action	N/A (immediately)	Control Cooldown Rate	Start Pump and Realign AFW flow path within 10 minutes	Start Pump and Realign AFW flow path within 10 minutes
RCP Status**	Running for LONF/ secured for LOOP	Secured	Running	Running
Sensible Heat	See Cooldown	Table 11.9-3	See Cooldown	See Cooldown
Decay Heat	ANS 5.1-1979 + 2 Sigma	Reference 6	120% of ANS 5.1-1971	120% of ANS 5.1-1971 or ANS 5.1-1979 + 2 Sigma
Time at standby/time to cooldown to RHR	See Cooldown	2 hours/6 hours	See Cooldown	See Cooldown

* Initially the faulted SG receives the AFW flow. Following the system flow path realignment, the intact SG receives the AFW flow.

** Availability of RCPs is a function of whether or not off-site power is available. For each transient, it is determined if it is worse to maintain off-site power or loss off-site power.

TABLE 11.9-3 SUMMARY OF SENSIBLE HEAT SOURCES

Primary Water Sources (initially at rated power temperature and inventory)

- RCS fluid
- Pressurizer fluid (liquid and vapor)

Primary Metal Sources (initially at rated power temperature)

- Reactor coolant piping, pumps and reactor vessel
- Pressurizer
- Steam generator tube metal and tube sheet
- Steam generator metal below tube sheet
- Reactor vessel internals

Secondary Water Sources (initially at rated power temperature and inventory)

- Steam generator fluid (liquid and vapor)
- Main feedwater purge fluid between steam generator and AFWS piping.

Secondary Metal Sources (initially at rated power temperature)

- All steam generator metal above tube sheet, excluding tubes.

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FIGURE 11.1-1 REV. 34

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FIGURE 11.1-2 REV. 34

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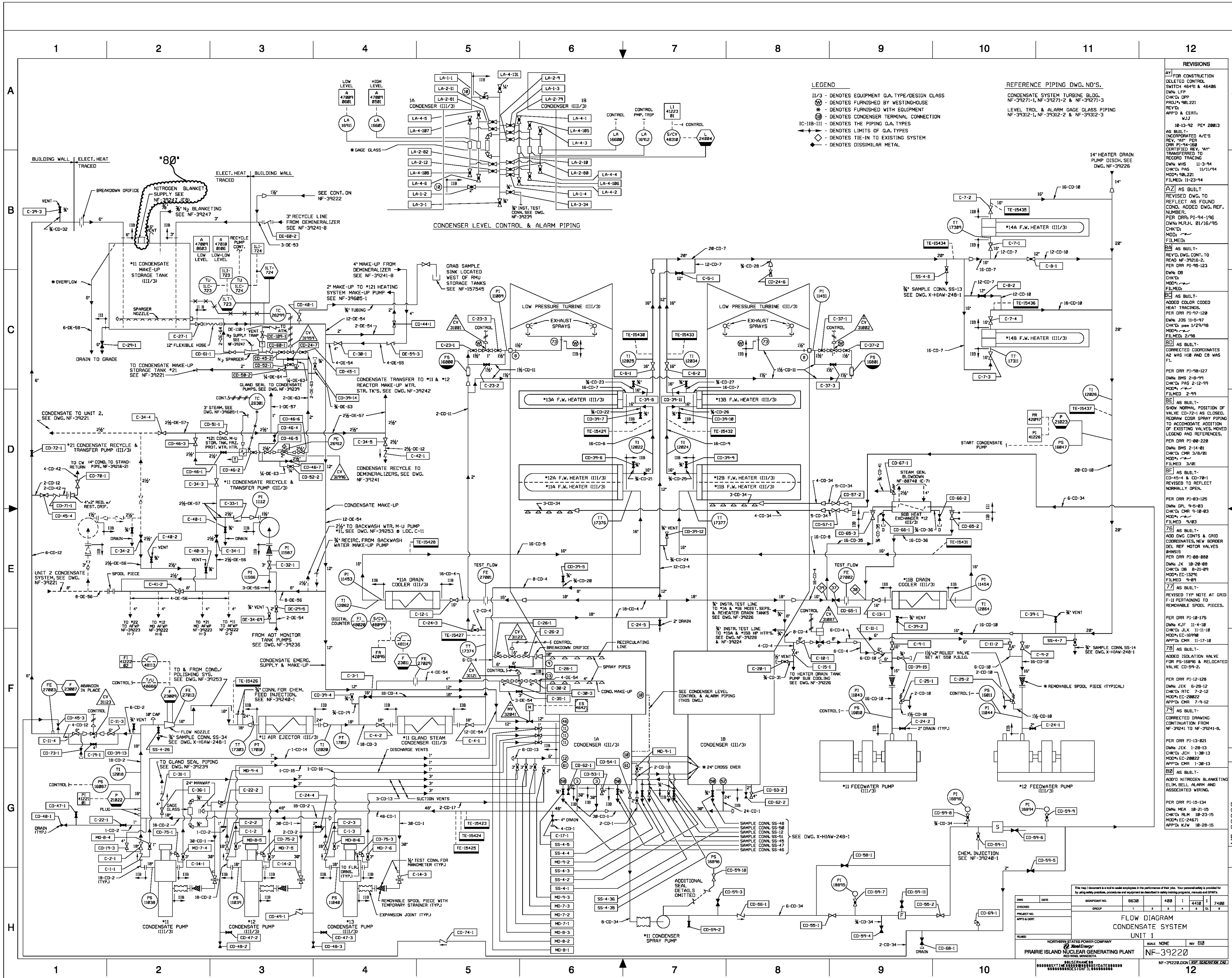

FIGURE 11.1-3 REV. 34

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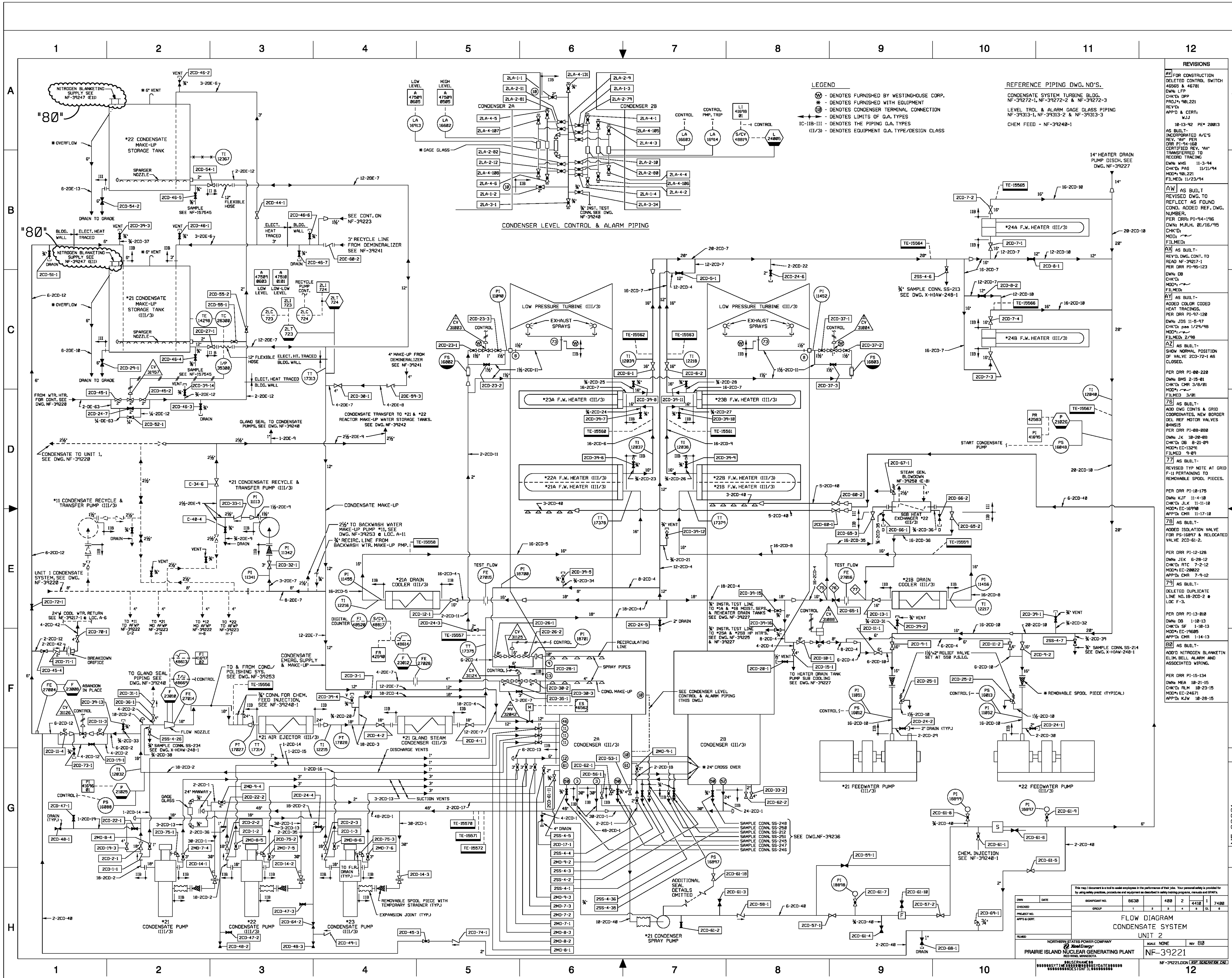

FIGURE 11.1-4 REV. 34

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FIGURE 11.1-5 REV. 34

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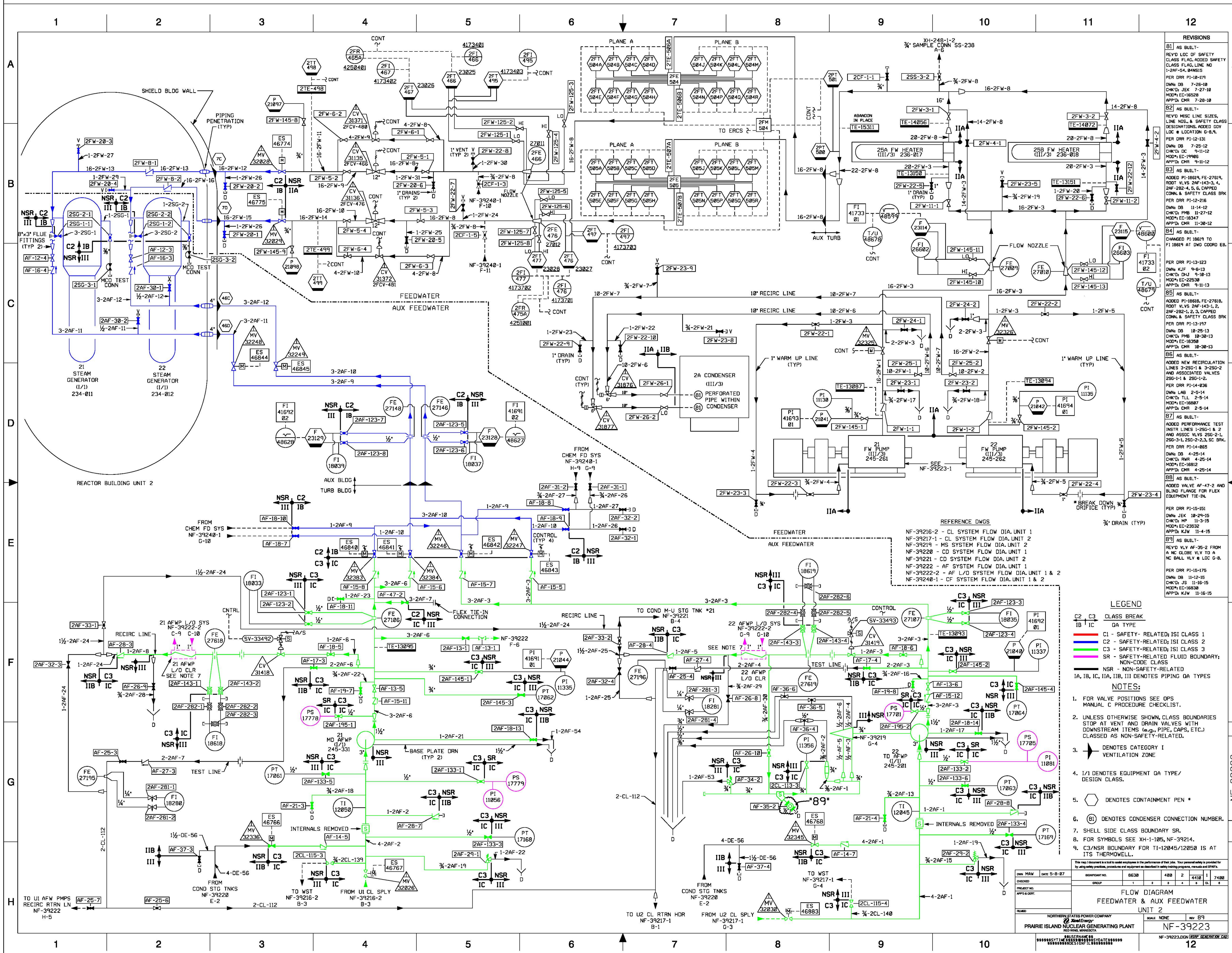

FIGURE 11.1-6 REV. 34

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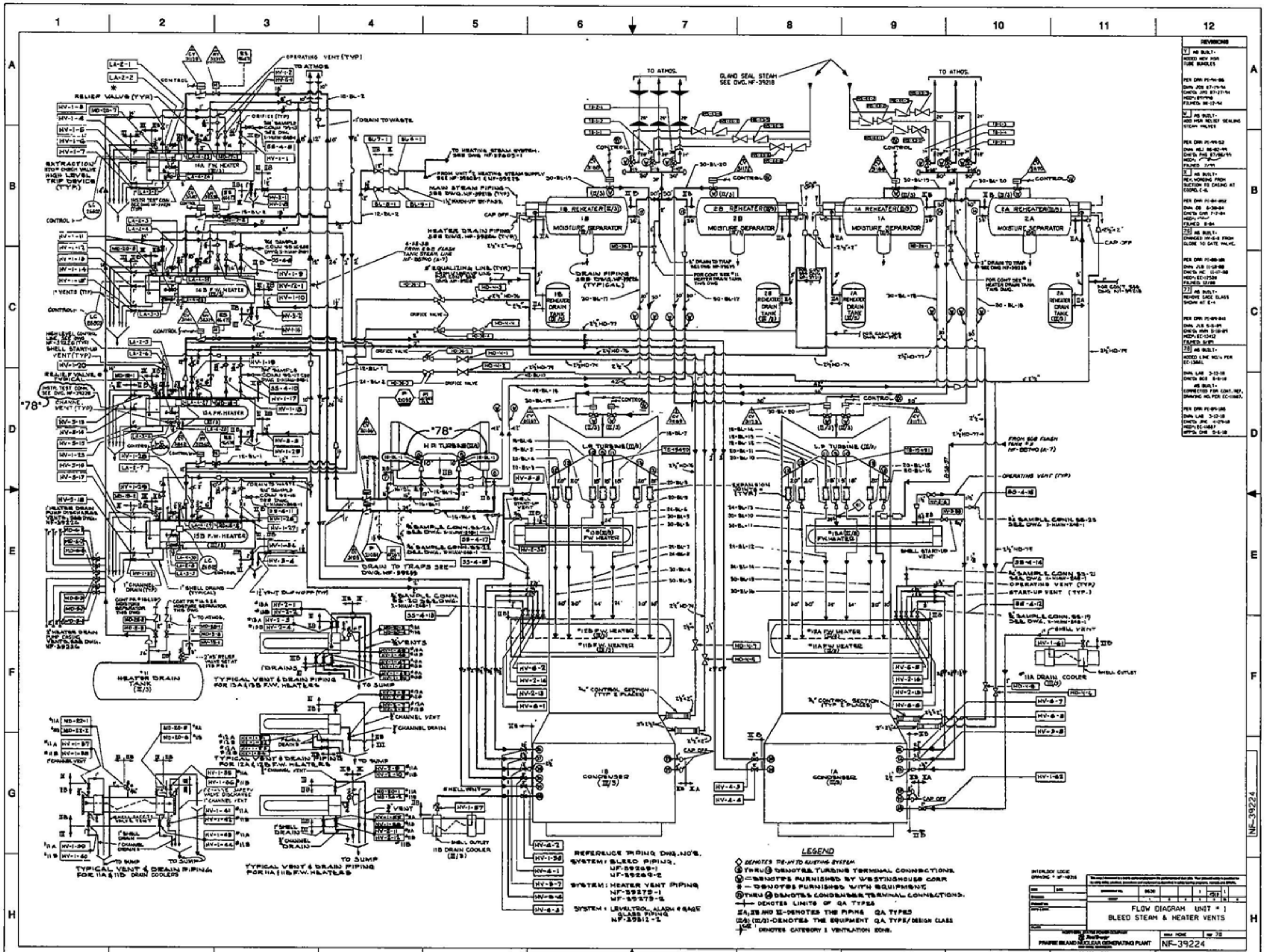

FIGURE 11.1-7 REV. 31

01248495

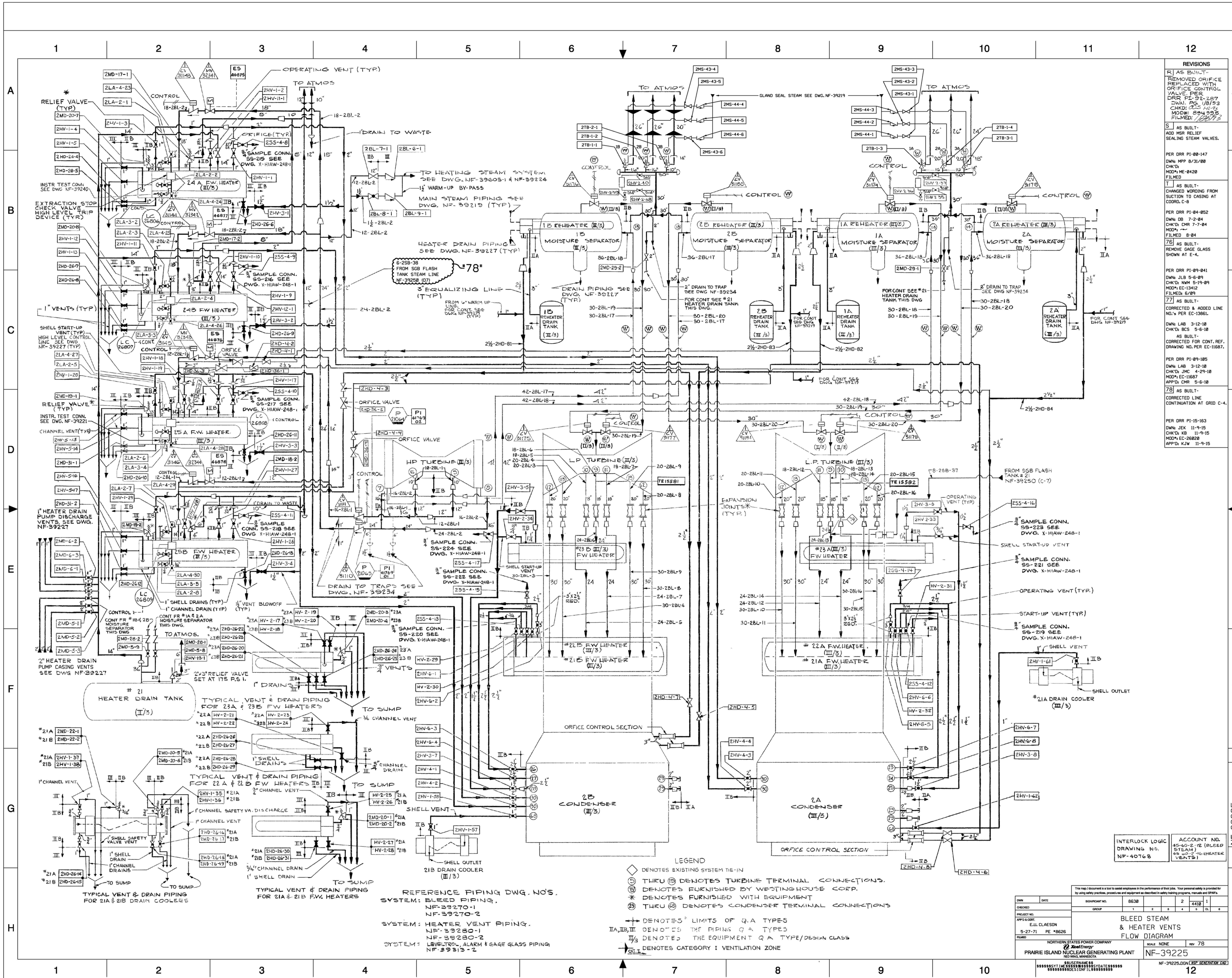

FIGURE 11.1-8 REV. 34

01516979

CAD FILE: U11108.DGN

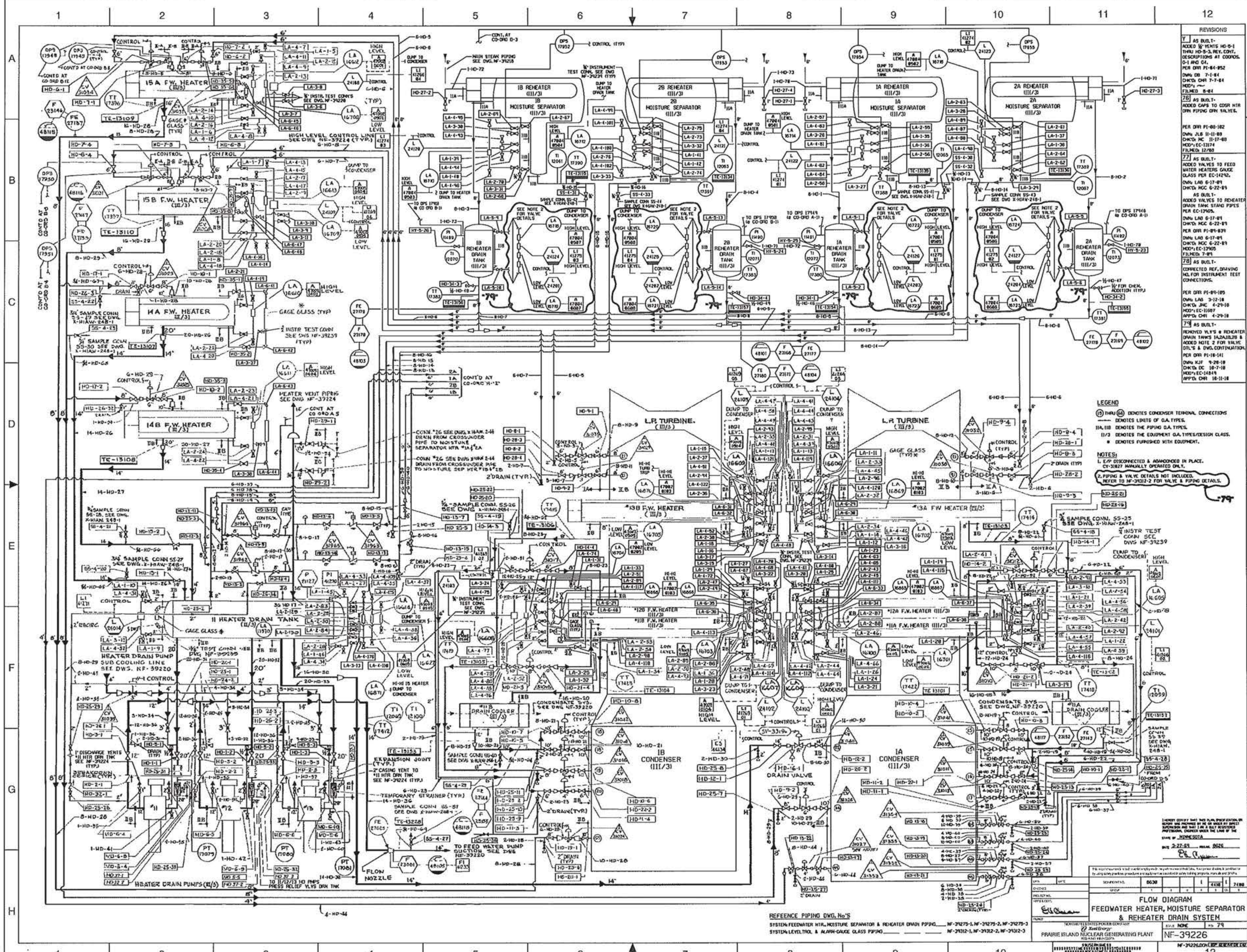

FIGURE 11.1-9 REV. 32

CAD FILE: U11109.DGN

01352784

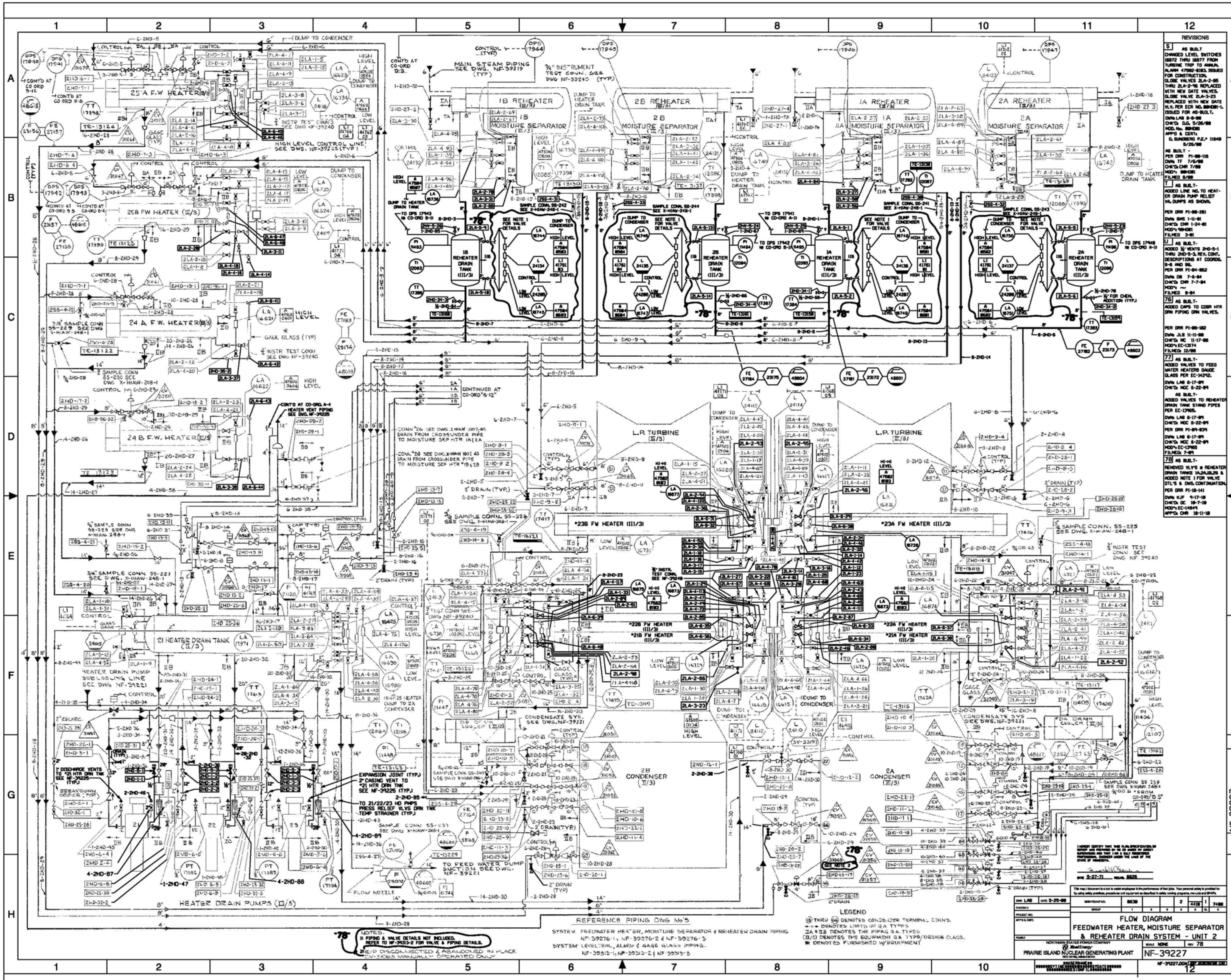

FIGURE 11.1-10 REV. 32

CAD FILE: U11110.DGN

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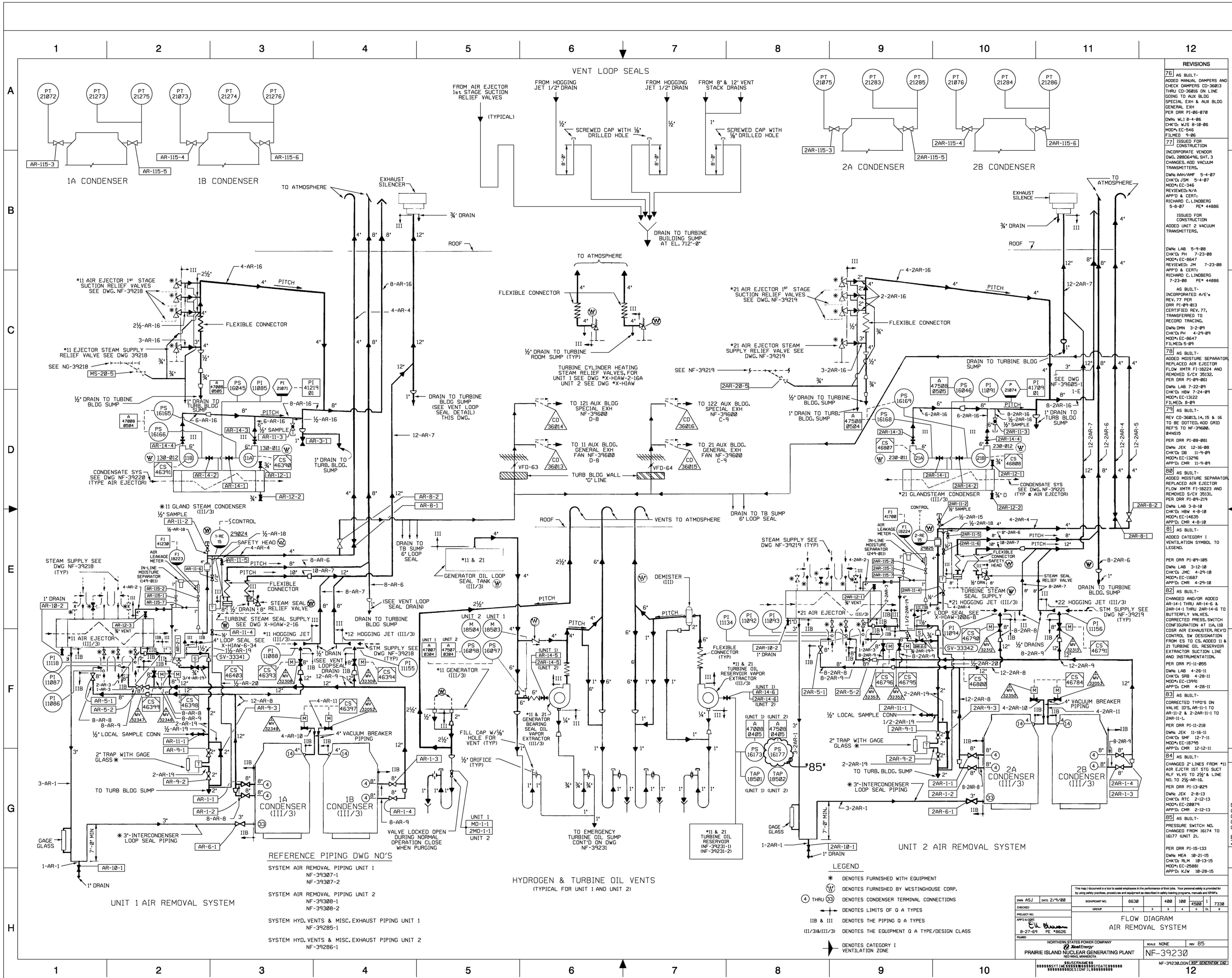


FIGURE 11.1-11 REV. 34

CAD FILE: U11111.DGN

01516979

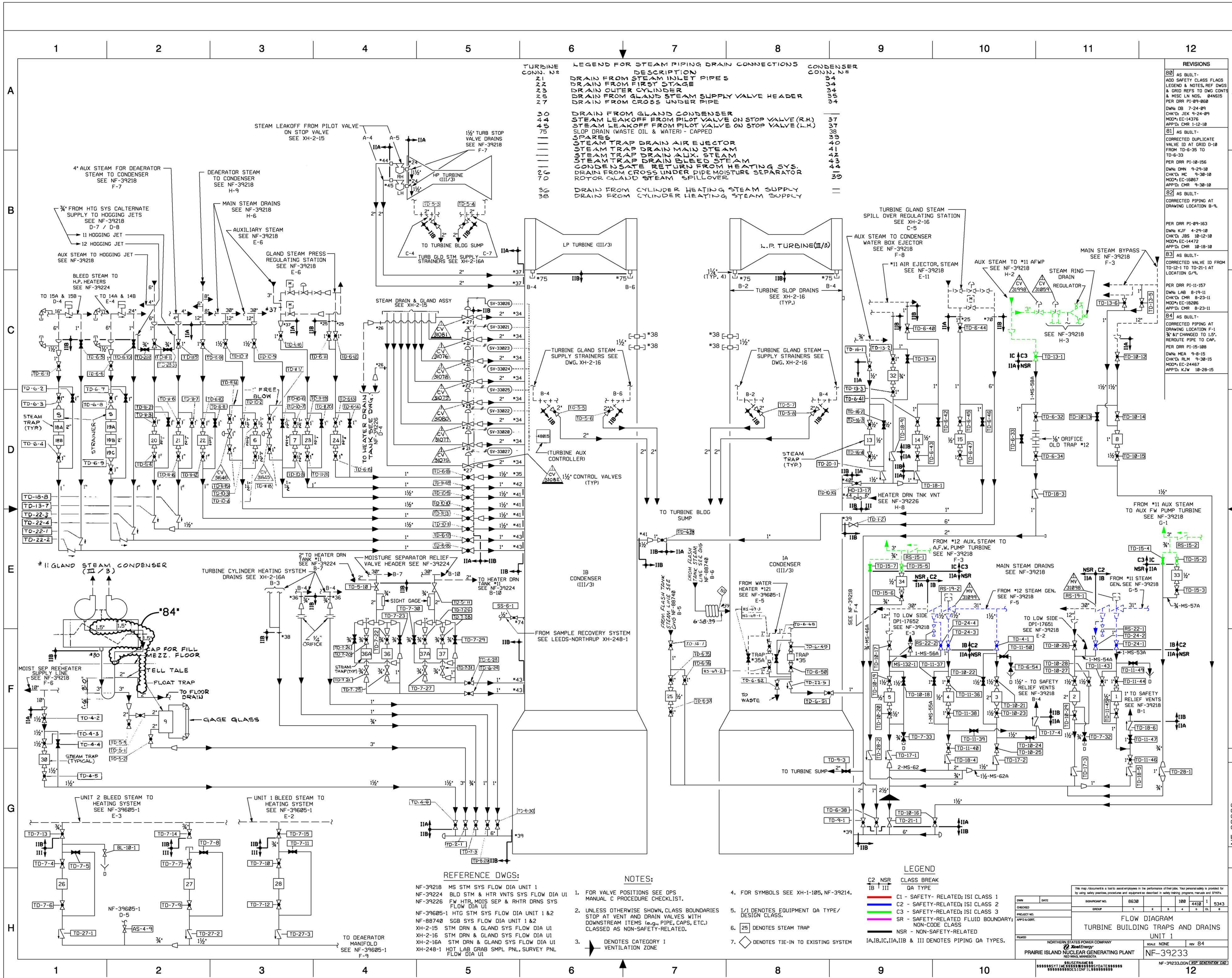


FIGURE 11.1-12 REV. 34

01516979

CAD FILE: U11112.DGN

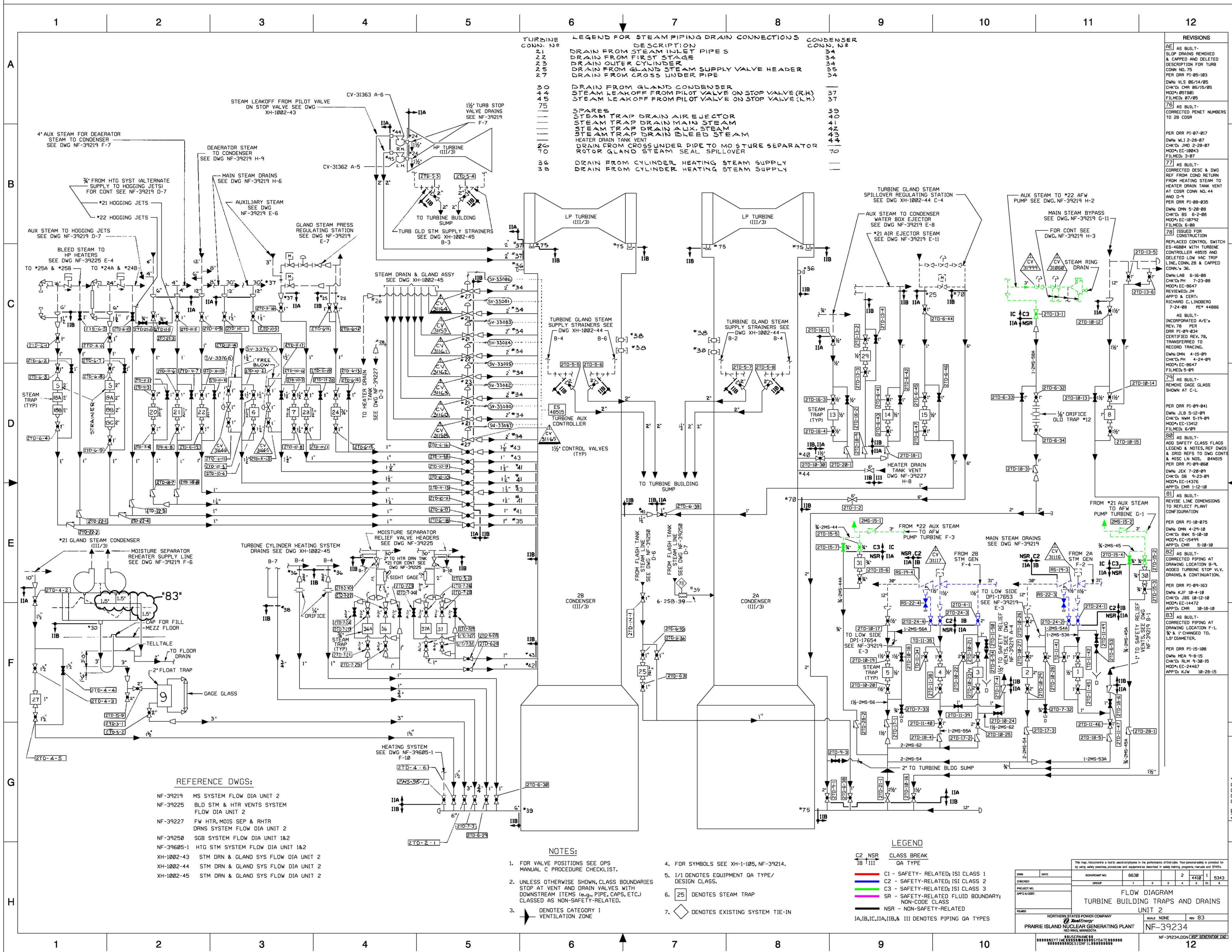


FIGURE 11.1-13 REV. 34

01516979

CAD FILE: U11113.DGN

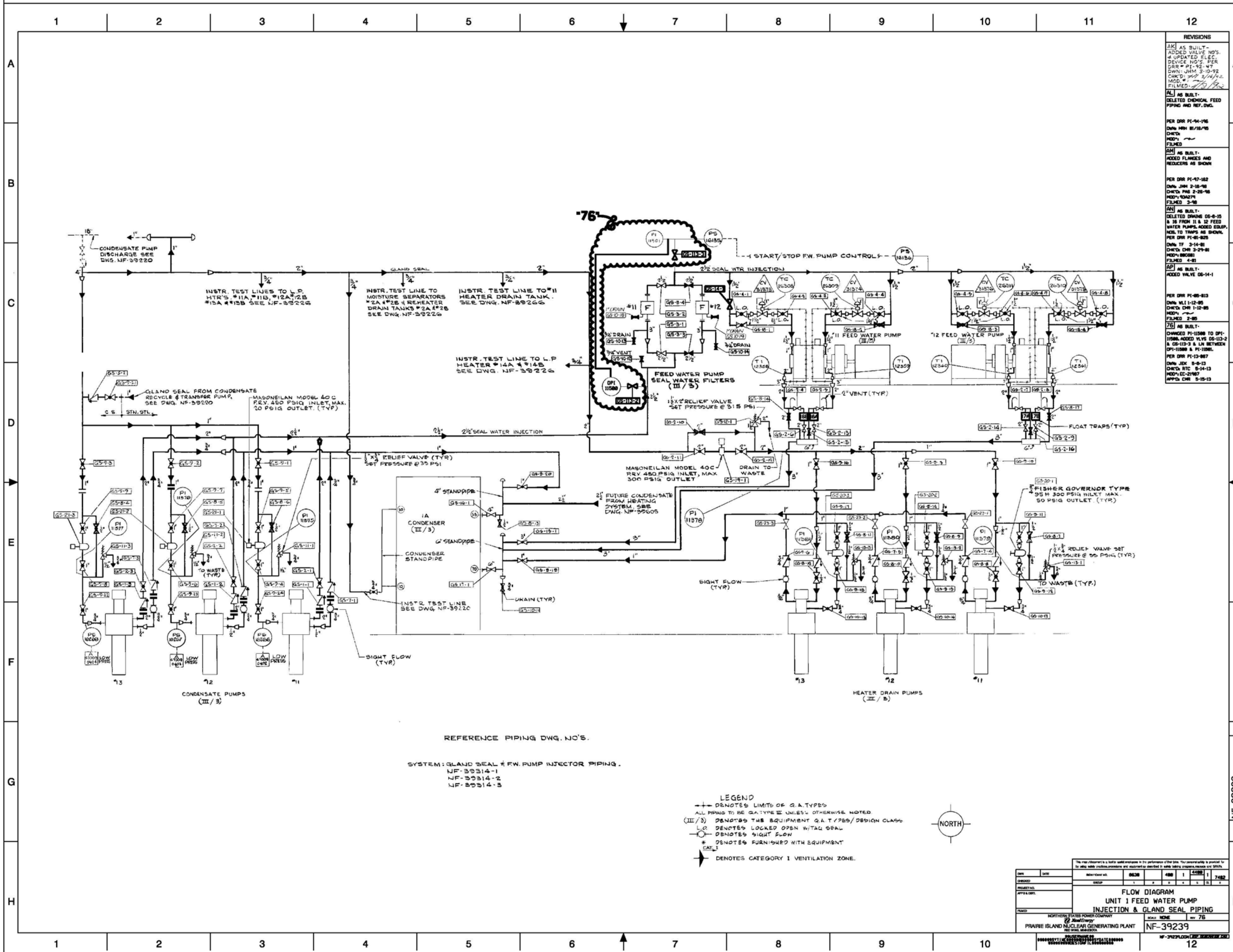
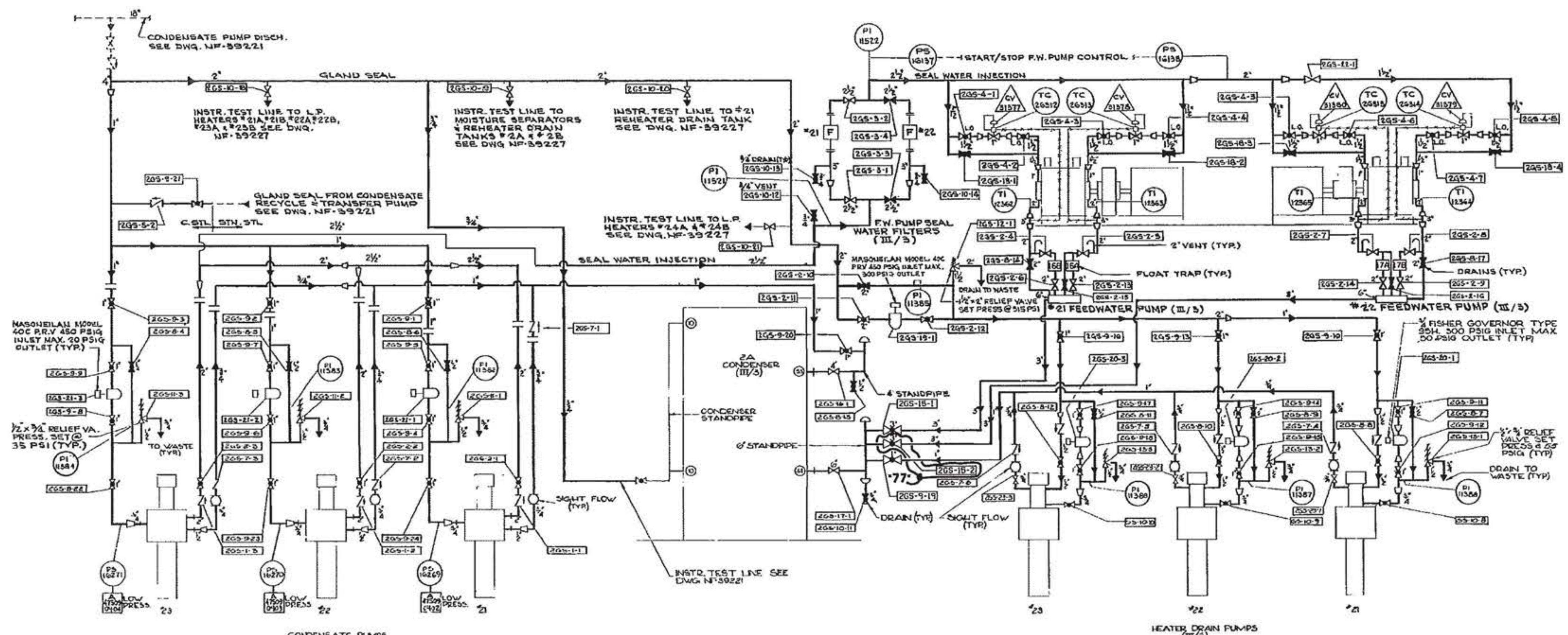


FIGURE 11.1-14 REV. 33

01429088

CAD FILE: U11114.DGN



REFERENCE PIPING DWG NO'S.

SYSTEM: GLAND SEAL & F.W. PUMP INJECTOR PIPING. NF-39315-1 NF-39315-2 NF-39315-3

LEGEND:
- DENOTES LIMITS OF QA. TYPES
- ALL PIPING TO BE QA TYPE III UNLESS OTHERWISE NOTED.
- (III/3) DENOTES THE EQUIPMENT QA TYPES/DESIGN CLASS
- LO. DENOTES LOCKED OPEN W/TAG SEAL
- DENOTES SIGHT FLOW
- DENOTES FURNISHED W/ EQUIPMENT
- DENOTES CATEGORY I VENTILATION ZONE.

UNIT 2 FEED WATER PUMP INJECTION AND GLAND SEAL PIPING

PRAIRIE ISLAND NUCLEAR GENERATING PLANT

NF-39240

FIGURE 11.1-15 REV. 32

CAD FILE: U11115.DGN

01352784

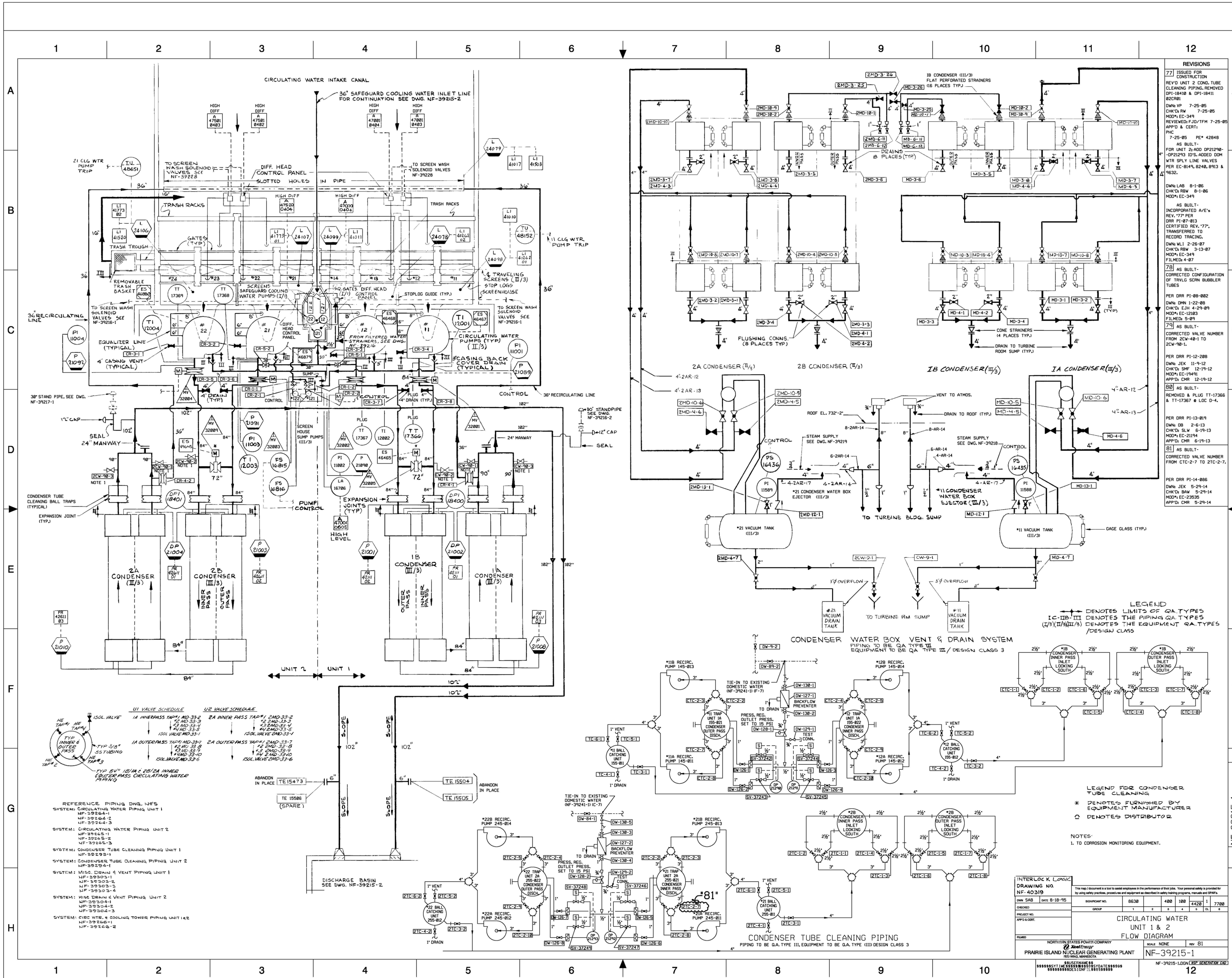


FIGURE 11.1-16 REV. 34

01516979

CAD FILE: U11116.DGN

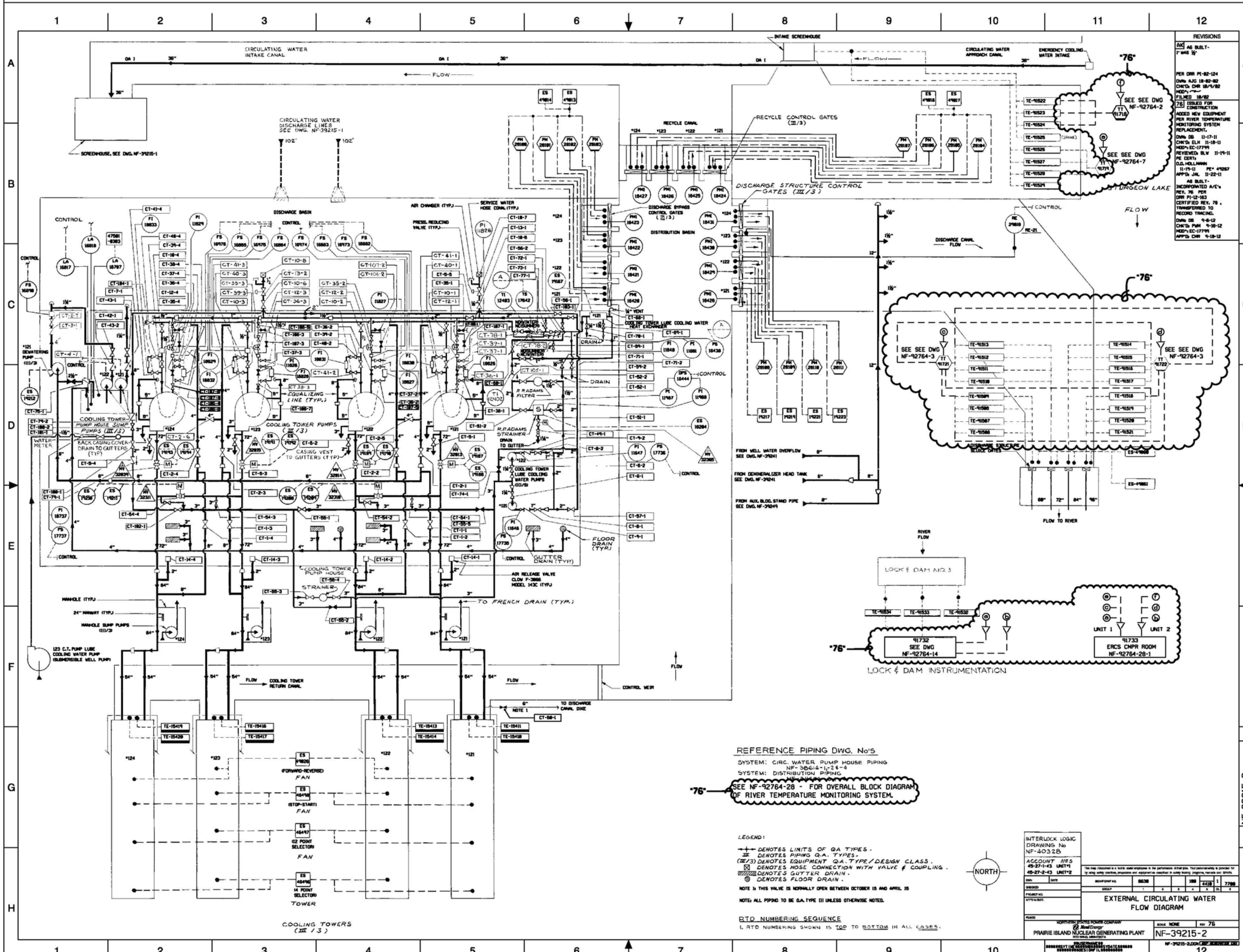


FIGURE 11.1-17 REV. 32

01352784

CAD FILE: U11117.DGN

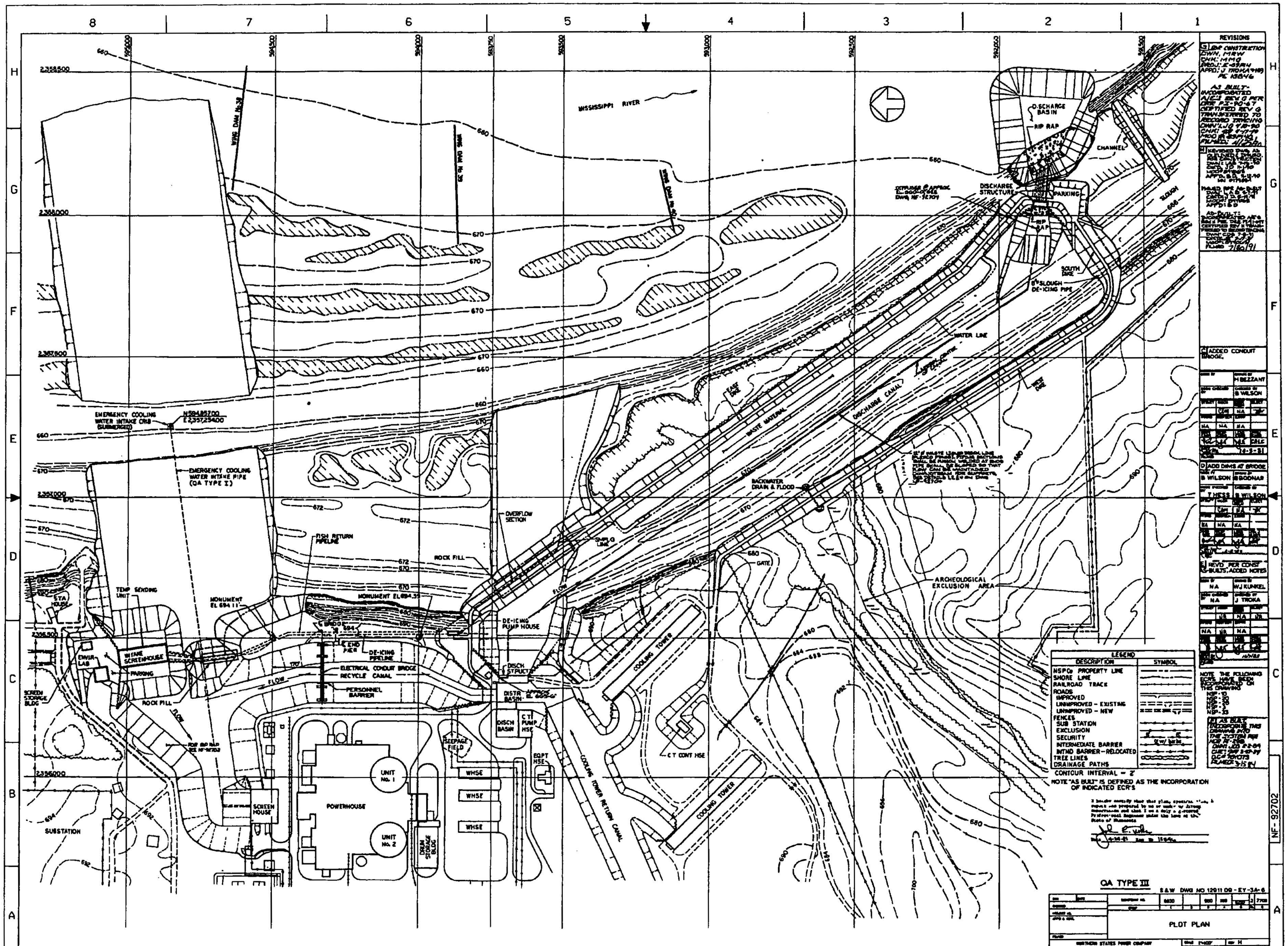


FIGURE 11.1-18 REV. 18

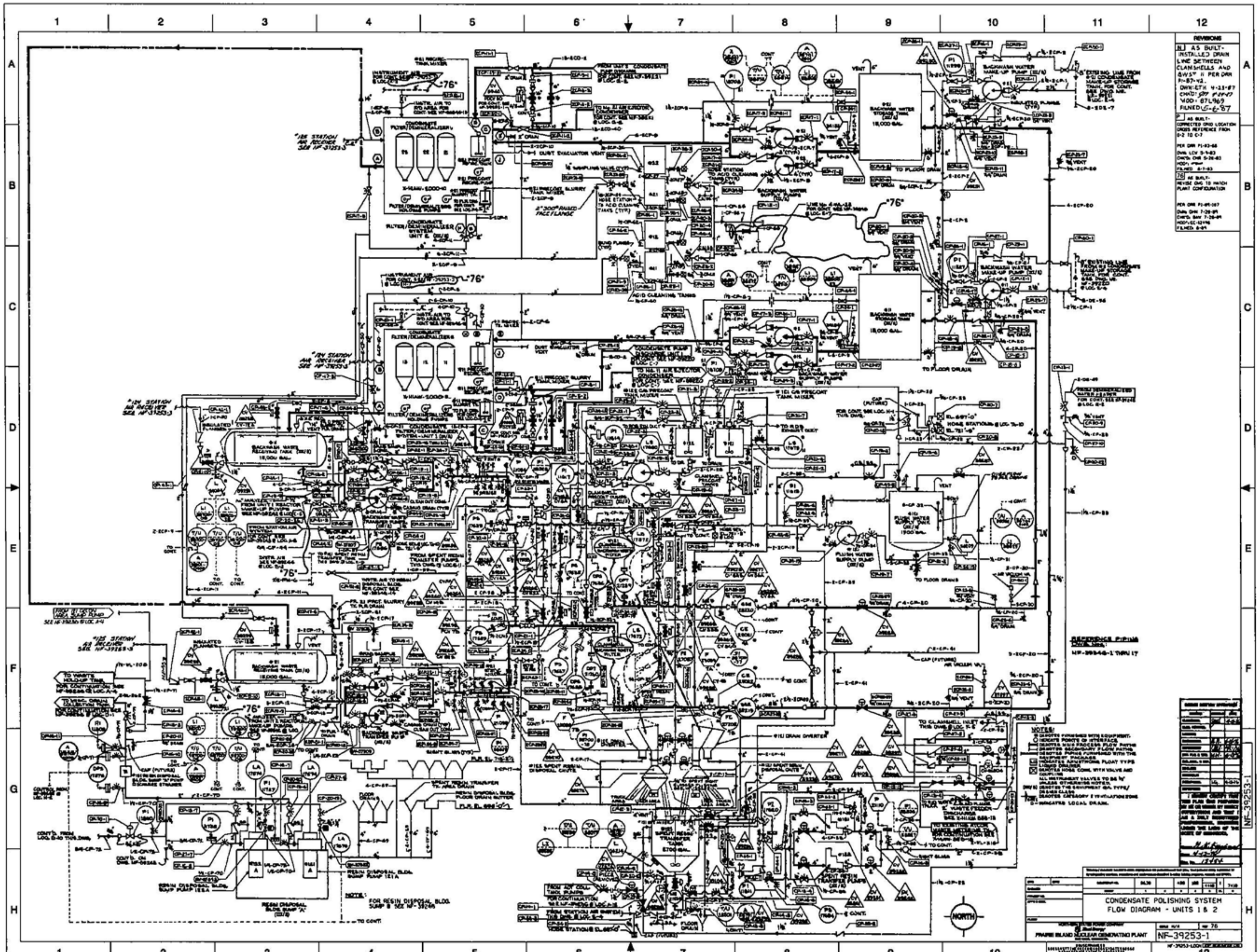


FIGURE 11.1-19 REV.31

01248495

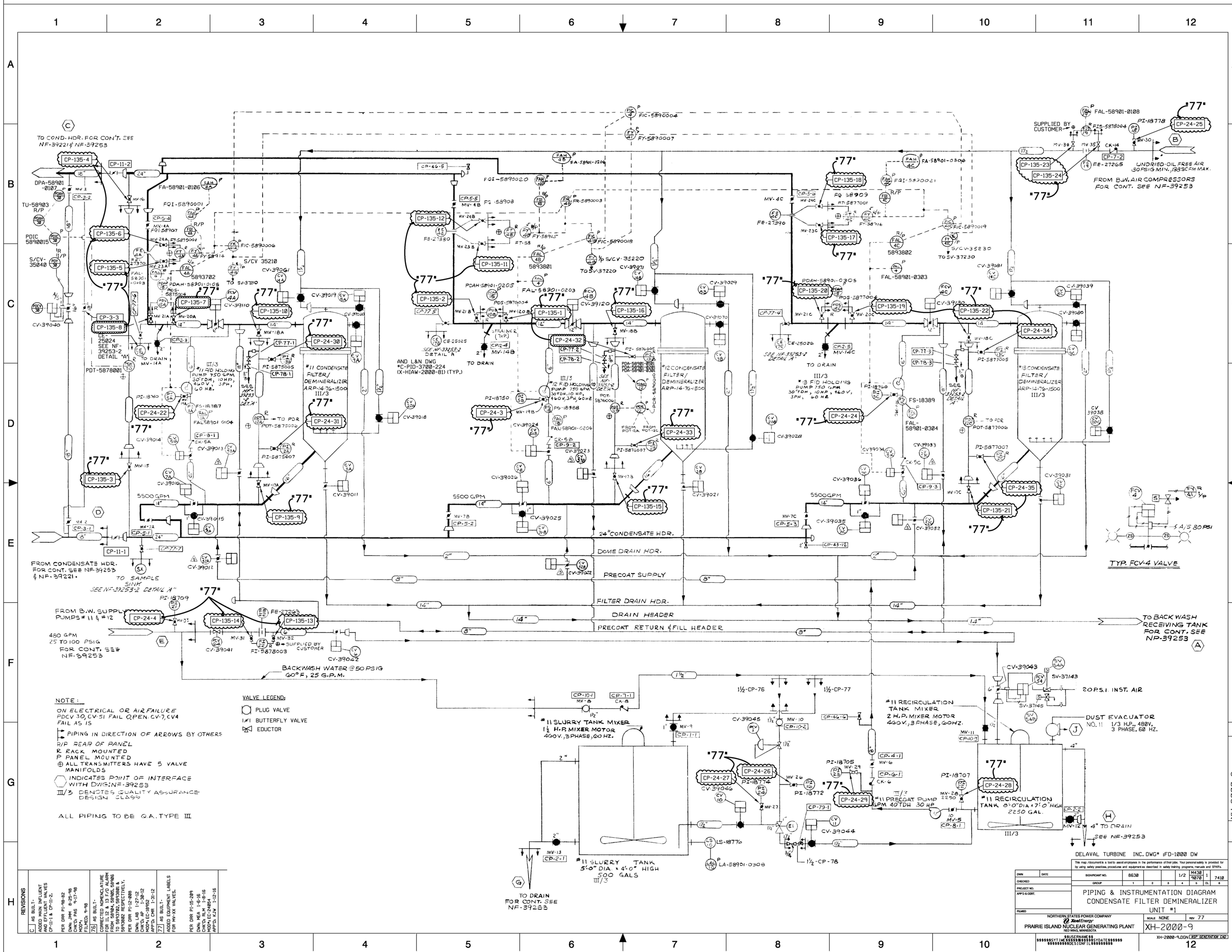


FIGURE 11.1-20 REV. 34

01516979

CAD FILE: U11120.DGN

FIGURE 11.2-1
DELETED

01406854

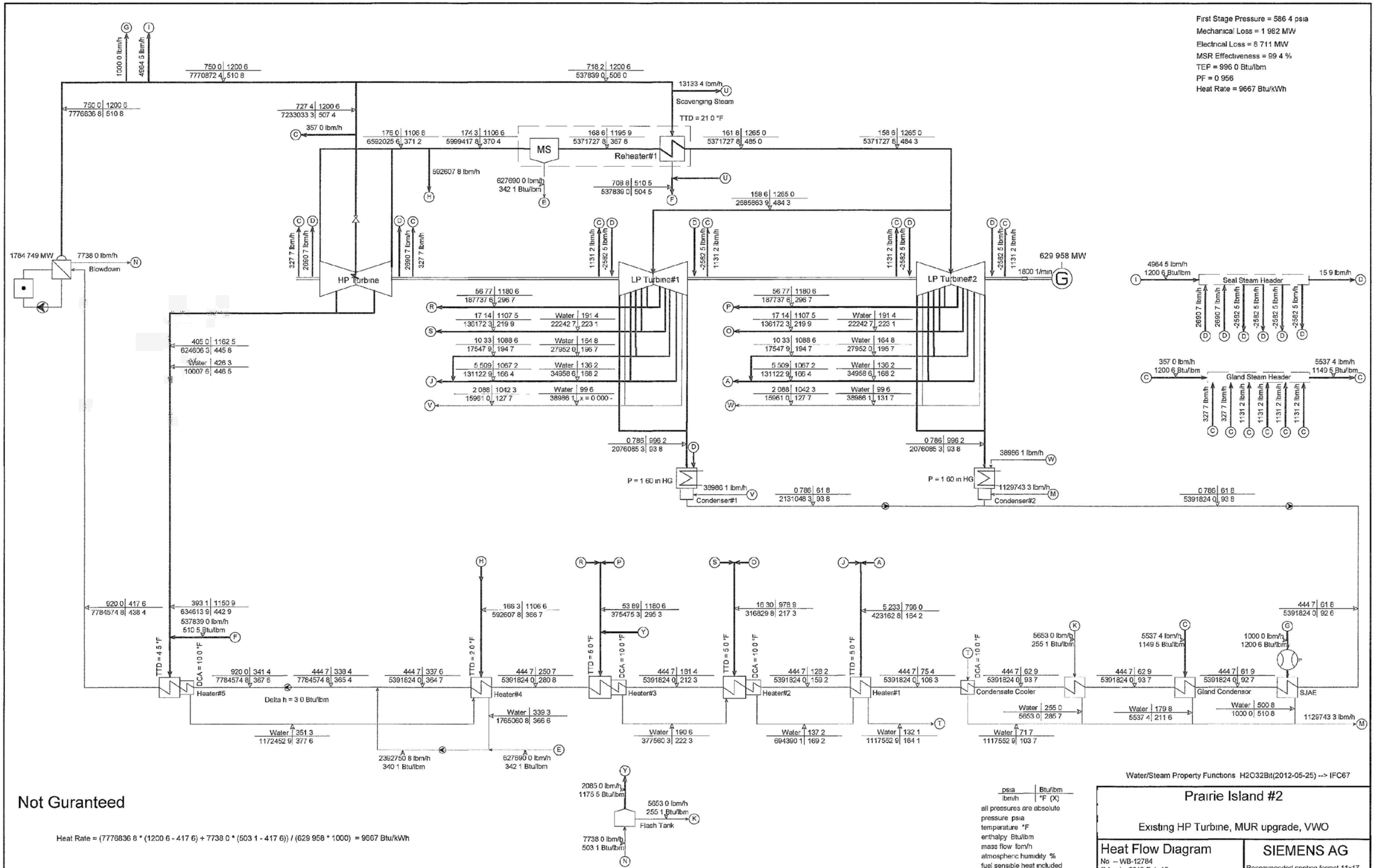


FIGURE 11.2-2 REV. 33

CAD FILE: U11202.DGN

01406854

FIGURE 11.2-3
DELETED

01406854

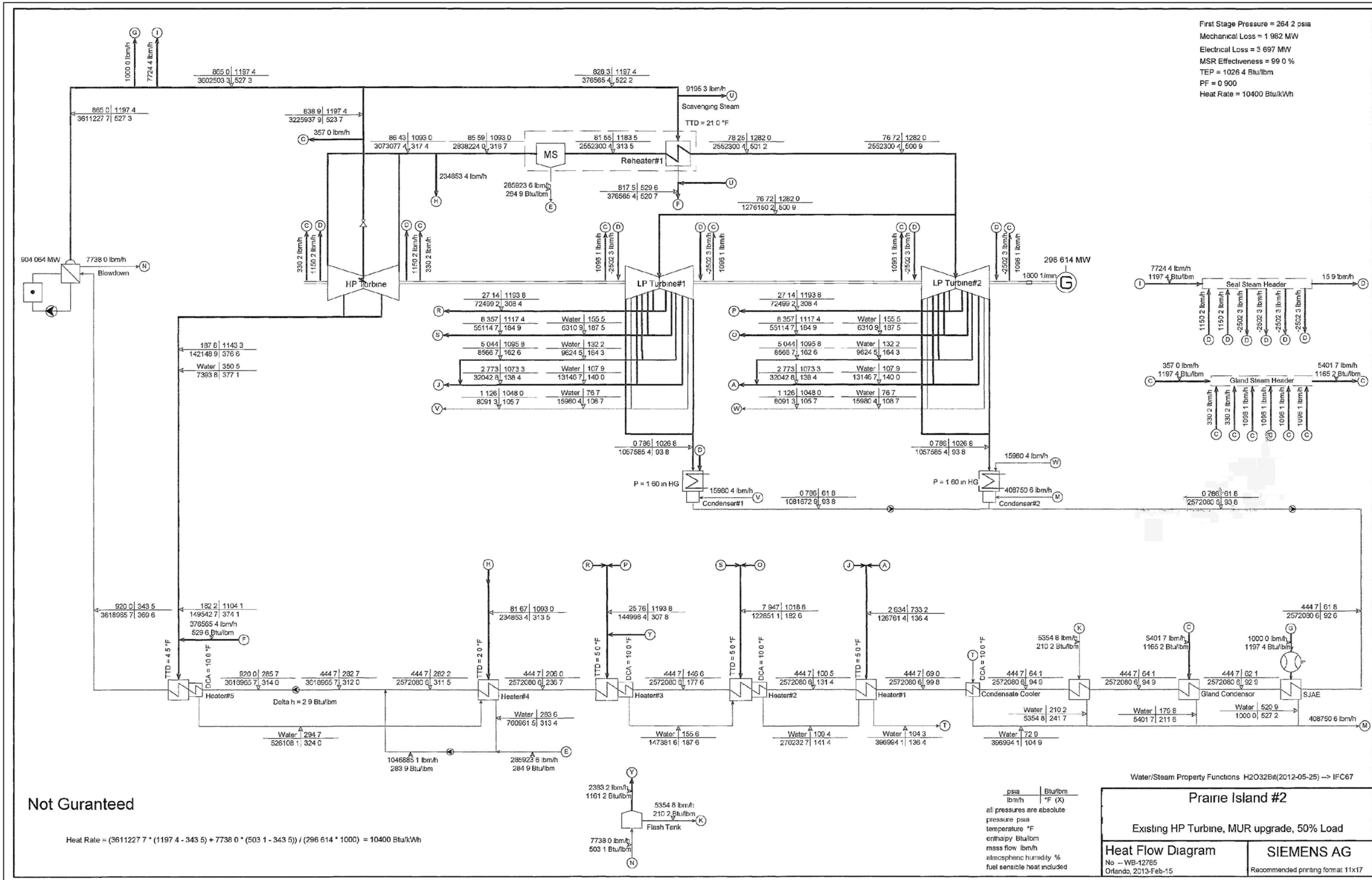


FIGURE 11.2-4 REV. 33

CAD FILE: U11204.DGN

01406854

FIGURE 11.2-5
UNIT 1 – TURBINE GENERATOR HEAT BALANCE – 100% POWER - VALVES WIDE OPEN AT 1.60 IN HGA CONDENSER VACUUM

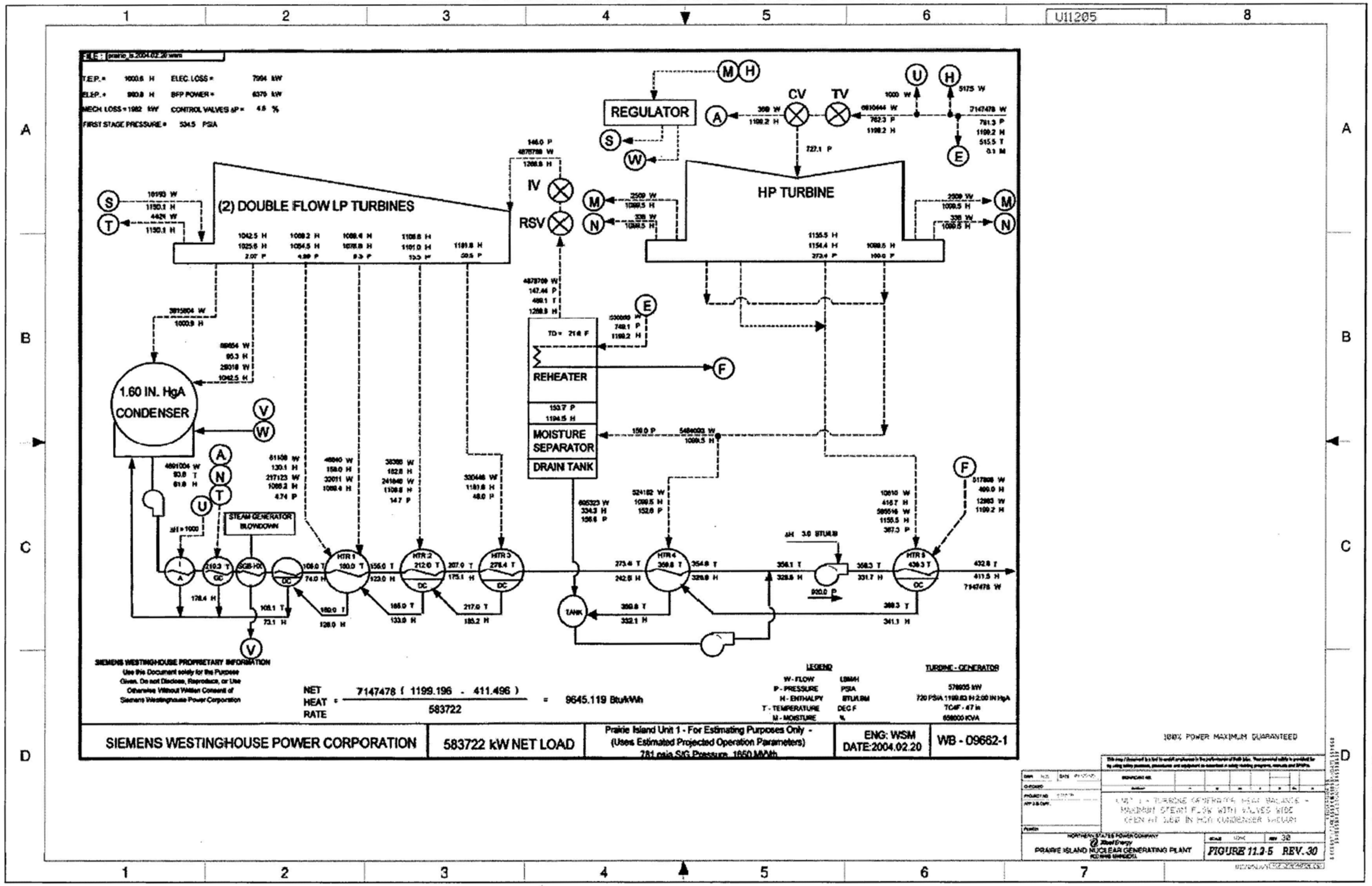
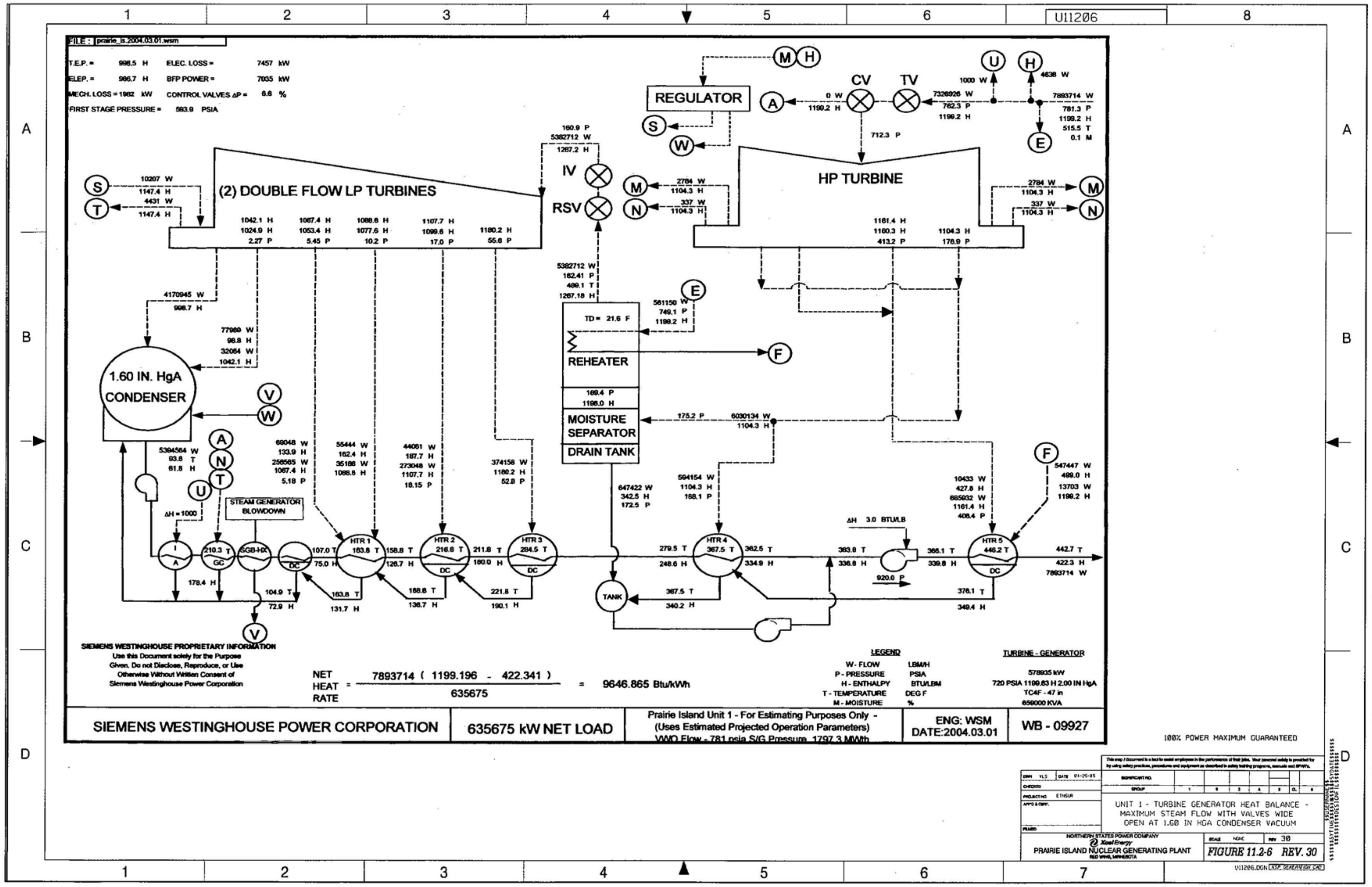


FIGURE 11.2-5

01086710

FIGURE 11.2-6
UNIT 1 – TURBINE GENERATOR HEAT BALANCE – MAXIMUM STEAM FLOW WITH VALVES WIDE OPEN AT 1.60 IN HGA CONDENSER VACUUM



01086710

FIGURE 11.2-6

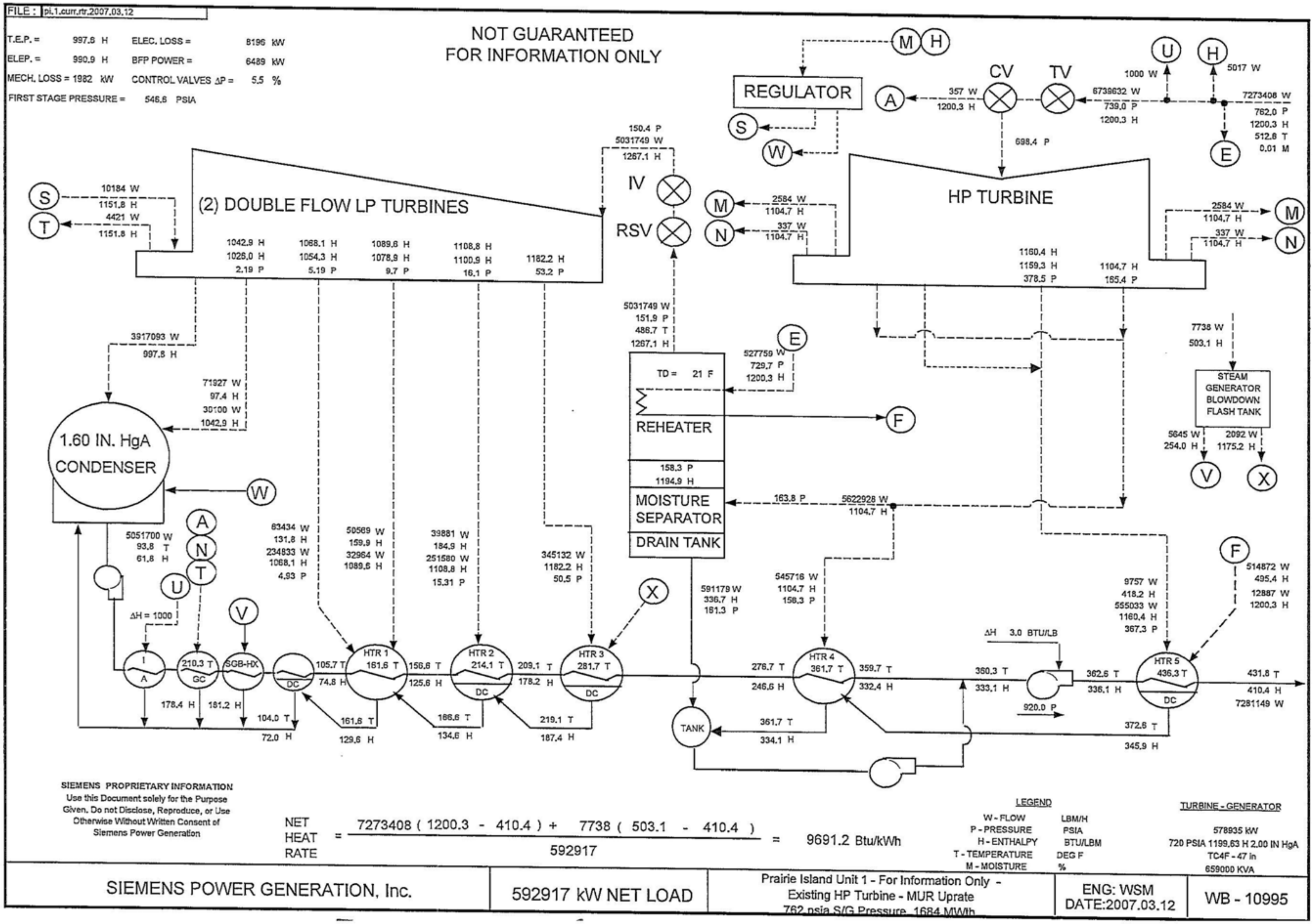


Figure 11.2-7 PRAIRIE ISLAND UNIT 1 HBD-MUR

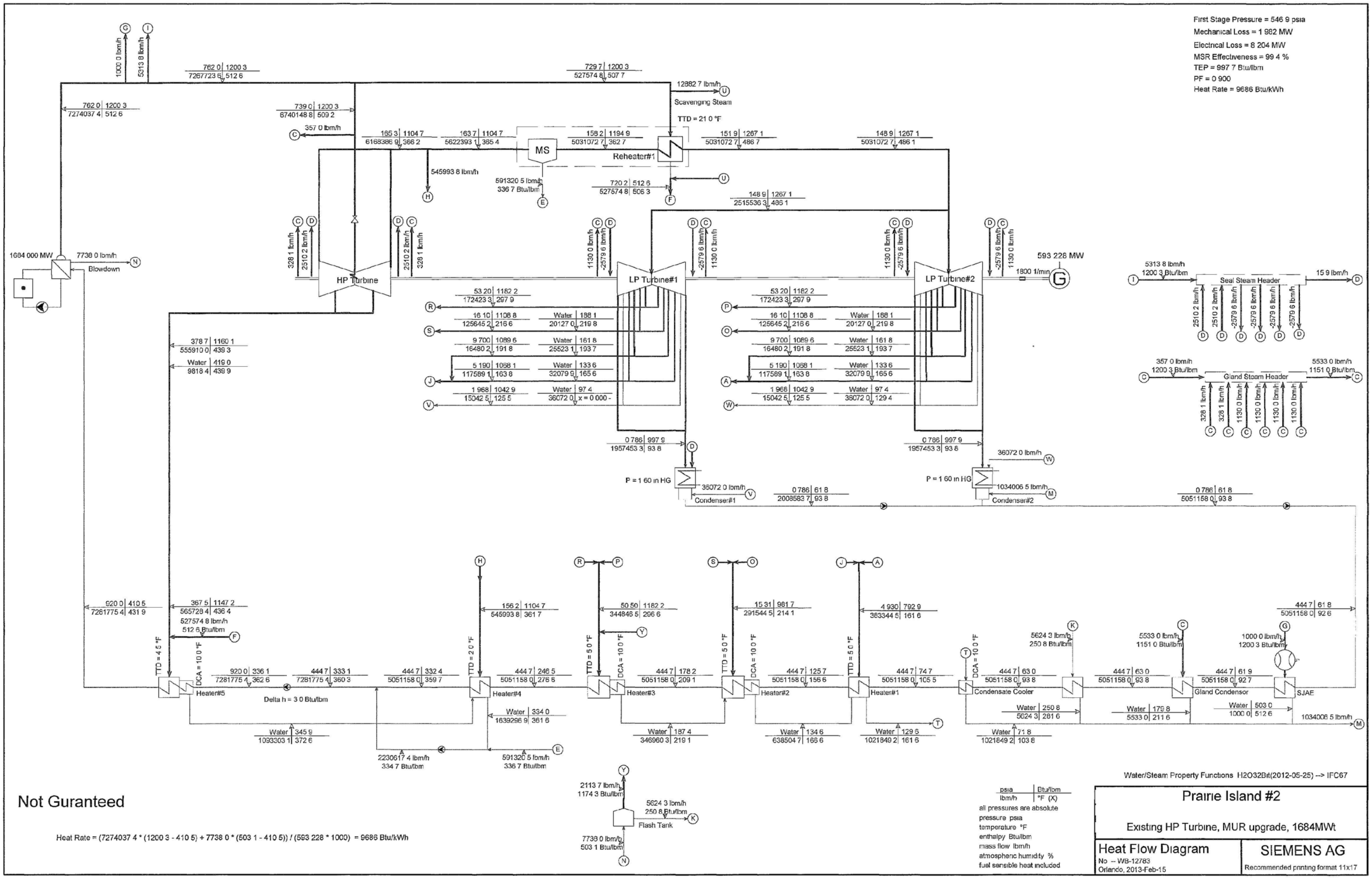
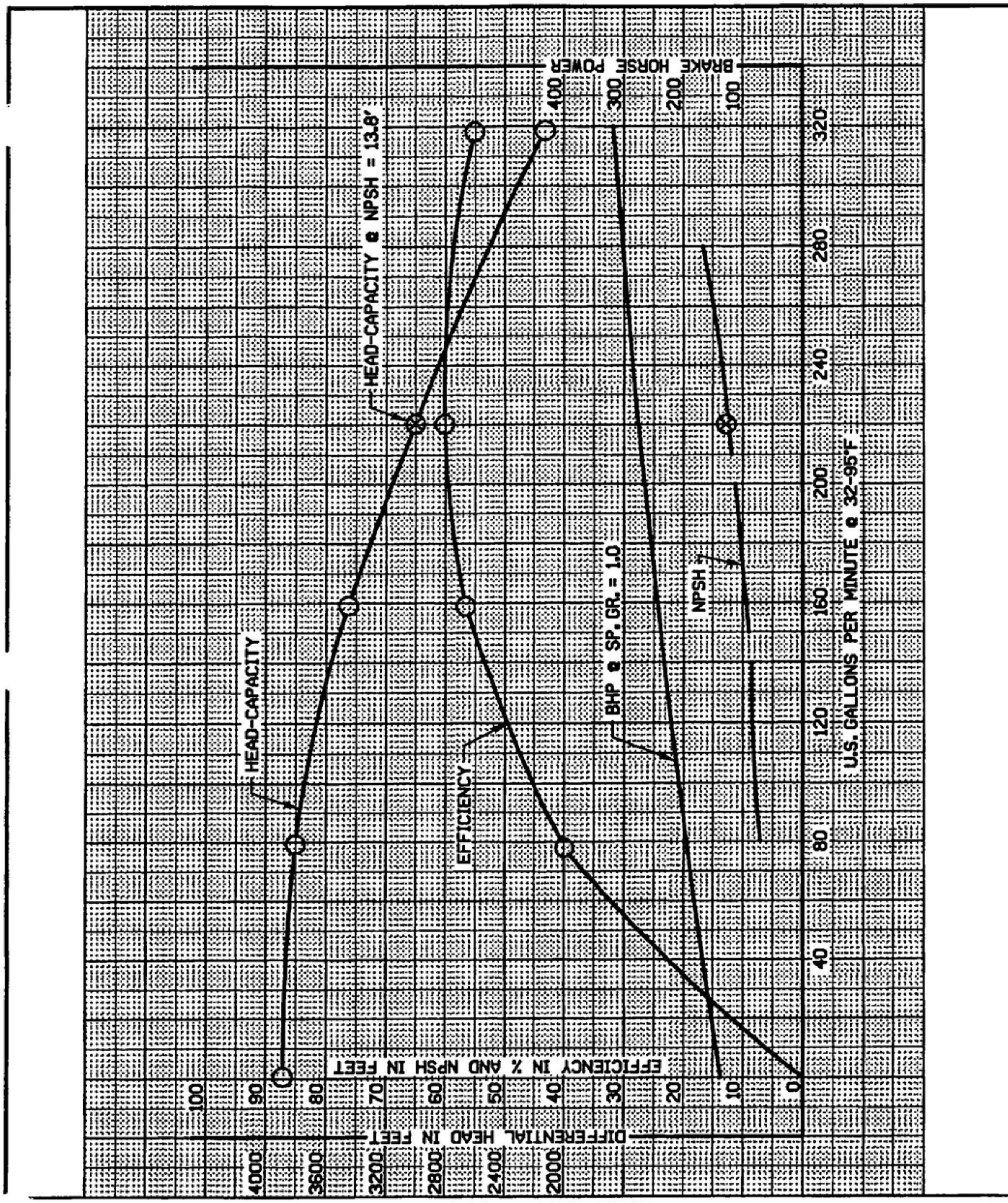


FIGURE 11.2-8 REV. 33

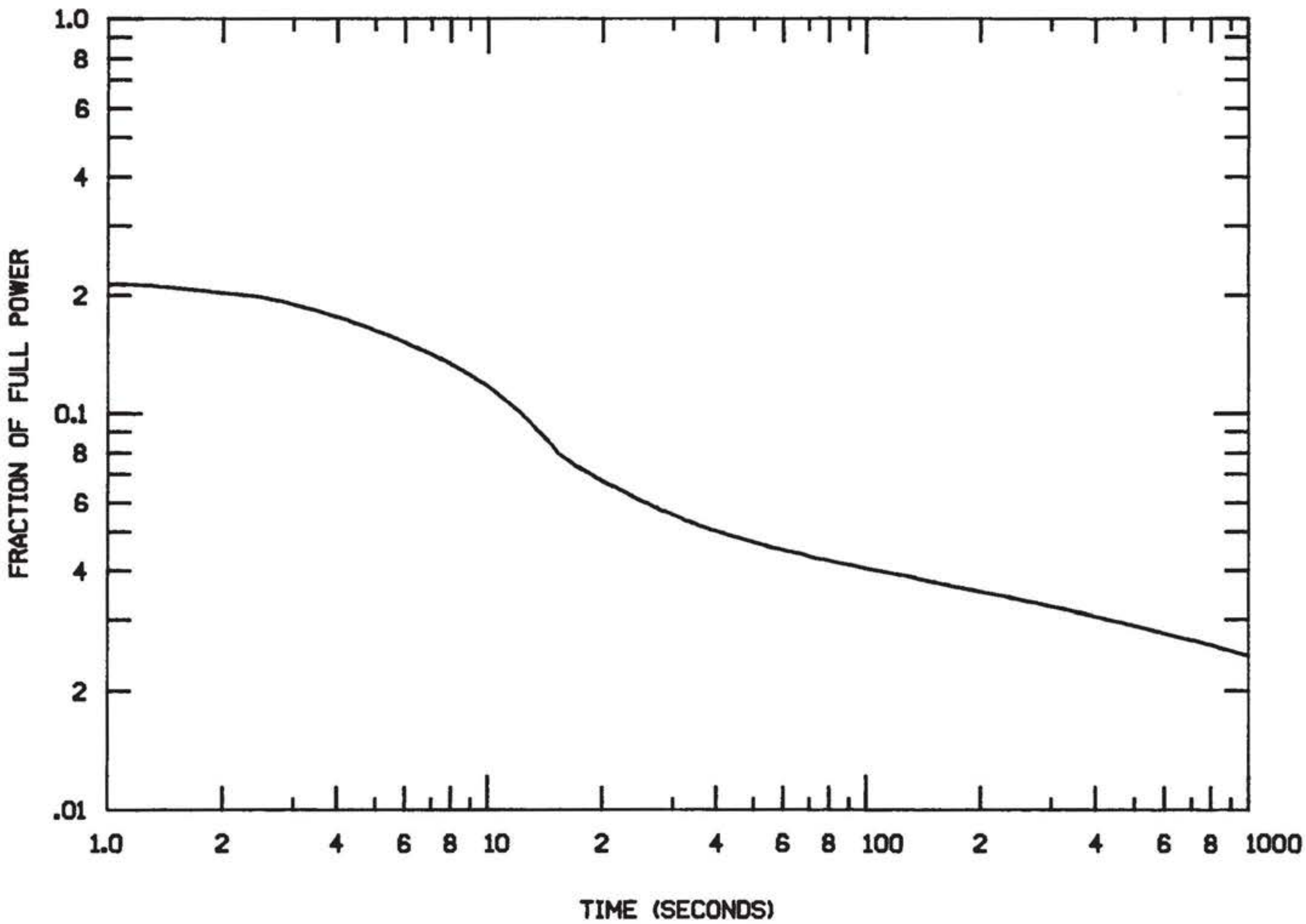
CAD FILE: U11208.DGN

01406854



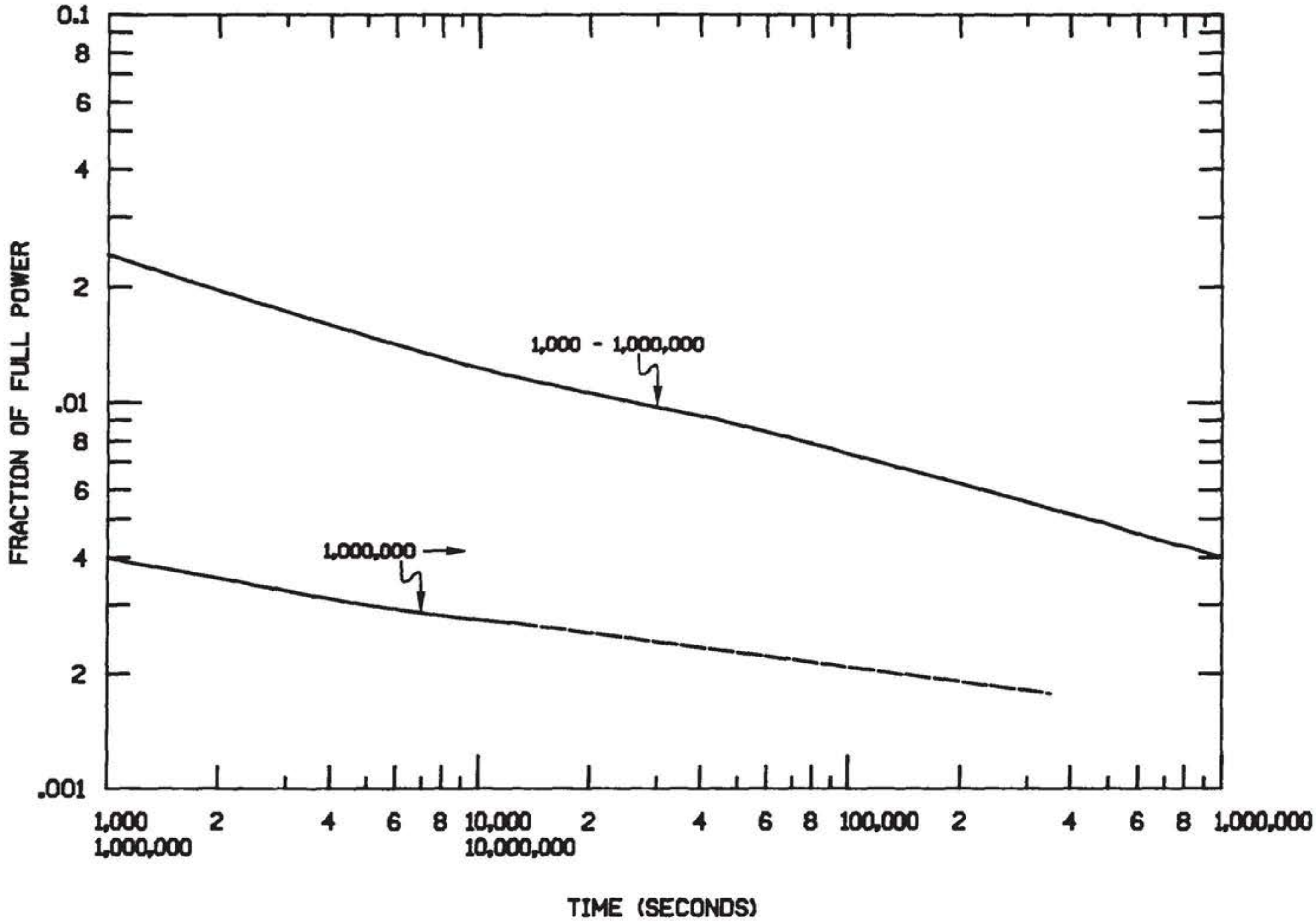
AUXILIARY FEEDWATER PUMP
CHARACTERISTIC CURVES

DWN L. BORCHARDT	DATE 6-23-99	NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	SCALE: NONE
CHECKED	CAD FILE U11901.DGN		FIGURE 11.9-1 REV. 18



DECAY HEAT CURVE
1 TO 1000 SECONDS

DWN L. BORCHARDT	DATE 6-23-99	NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	SCALE: NONE	
CHECKED	CAD FILE U11904A.DGN		FIGURE 11.9-4A REV. 18	



DECAY HEAT CURVE
GREATER THAN 1000 SECONDS

DWN	L. BORCHARDT	DATE	6-23-99	NORTHERN STATES POWER COMPANY	SCALE: NONE
CHECKED		CAD FILE	U11904B.DGN	PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	FIGURE 11.9-4B REV. 18