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SECTION 10

10.0 STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

10.1.1 Design Bases

The steam and power conversion system is designed to remove heat energy from the reactor coolant in two steam generators and convert it to electrical energy via the turbine generator. The condenser transfers the heat which is unusable in the cycle to the condenser circulating water and deaerates the condensate. The closed regenerative turbine cycle heats the condensate and returns it to the steam generators. The entire system is designed for the maximum expected energy from the Nuclear Steam Supply System.

10.1.2 System Description

The components of the steam and power conversion system are conventional and of a type that has been extensively used in fossil fuel plants and in other nuclear power plants. Adequate instruments, controls and protective devices are provided to ensure reliable and safe operation.

The system functional drawings are identified in their respective subsections of this chapter. A summary of the important design and performance characteristics is shown in Table 10.1-1.

The steam and power conversion system provides steam for driving the main feed pump turbines. Steam is also used for the auxiliary feed pump turbines, gland sealing, condenser inventory heating, steam jet air ejector, turbine reheater steam heating, building heating (steam supplied unit heaters), station heating heat exchangers, and outdoor tank heating, as required.

10.1.3 Safety-Related Features

10.1.3.1 Loss of Full Load

Upon loss of full load, the system is capable of dissipating all of the energy existent or produced in the Reactor Coolant System through turbine bypass valves to the condenser and atmospheric vent valves and code safety valves to the atmosphere. The analysis of the effects of the loss of full load on the unit is discussed in Section 15.2.7.

10.1.3.2 Turbine Trip

Following a turbine trip, the ARTS will automatically trip the reactor. The safety valves will relieve excess steam until the output is reduced to the point at which the steam bypasses to the condenser. If the condenser is unavailable, the atmospheric vent valves can handle all the steam generated.

10.1.3.3 Overpressure Protection

Pressure relief is required at the system design pressure of 1050 psig, and two main steam safety valves per steam generator are set to relieve at this pressure. The remainder of the safety valves are set at pressures up to 1100 psig, as allowed by the ASME Code. See Section 5.2.2.3.

The pressure relief capacity is such that the energy generated at the reactor high-power level trip setting can be dissipated through this system.

10.1.3.4 Turbine Overspeed Protection

See Subsection 10.2.4.

10.1.3.5 Turbine Missile Protection

See Subsection 10.2.5.

10.1.3.6 Radioactivity

Under normal operating conditions, there are no radioactive contaminants present in the steam and power conversion system. It is possible for this system to become contaminated only through steam generator tube leaks. In this event, monitoring of the steam generator main steam lines and the steam air ejector discharge will detect any contamination.

10.1.4 Tests and Inspections

As is essential in successful operation of any modern power station, frequent functional operational checks are made on vital valves, control systems and protective equipment.

10.1.5 Instrumentation and Controls

Operating instrumentation is adequate to permit the operators to monitor equipment and station performance. Equipment, instruments and controls are regularly inspected and monitored to ensure proper functioning of all systems.

Checking and recalibration of instruments and controls will continue during operating periods as well as during shutdown periods.

10.1.5.1 Design Bases for Steam, Feedwater, and Condensate Instrument Systems

The design bases for those steam, feedwater, and condensate instrument systems required to provide safety-related indication in the main control room and also on the Auxiliary Shutdown Panel are identified and discussed in Section 7.5.

The main steam and feedwater isolation instrument systems are designated as safety-related. These systems provide pipe rupture protection to the feedwater system and are designed to operate after the maximum possible earthquake that would result in a steam line break and loss of outside power. The design bases for these systems are listed below:

1. Main steam isolation valve instrumentation is designated essential and provides redundant, isolated signals in accordance with IEEE Standard 279-1971.

   The instruments used in this system were “Q” listed and are manufactured under approved quality control procedures providing seismic qualification.

2. Main feedwater line isolation instrumentation is designated essential and provides redundant, isolated signals in accordance with IEEE Standard 279-1971. The

instruments used in this system were manufactured under approved quality assurance procedures providing seismic qualification.

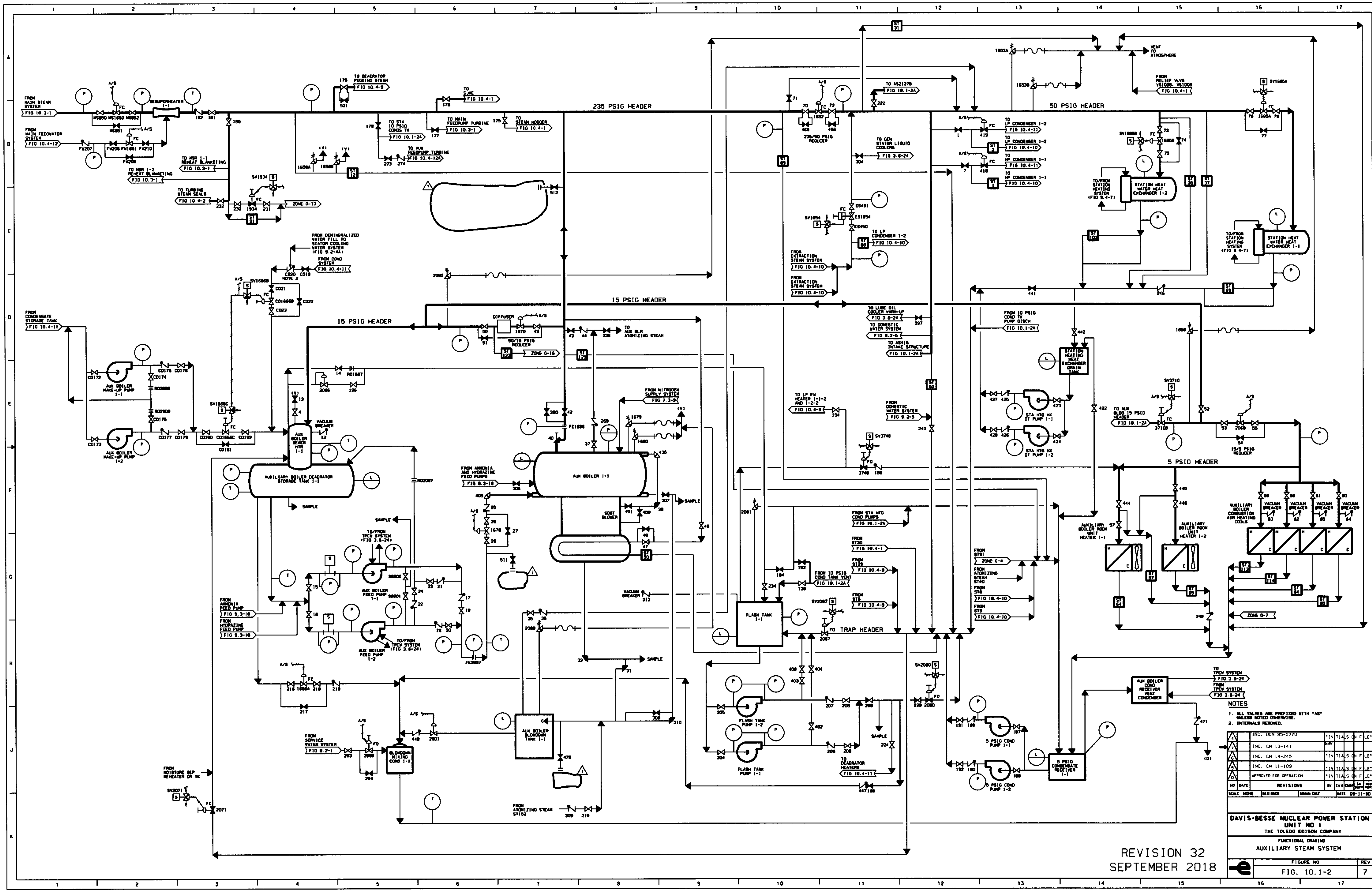
3. The essential power supply is discussed in Chapter 8.

4. The design bases for those instruments that are required for normal operation were to use good quality instruments of proven operation and reliability to provide accuracy and speed of response necessary for efficient control and operator information.

TABLE 10.1-1

Design and Performance Characteristics

Main steam system design/operating pressure	1050 psig/910 psig
Main steam system design/operating temperature	600°F/593°F
Turbine inlet steam conditions, press./temp.	885 psia/588.5°F
Turbine design throttle flow	11,410,110 lb/hr
Turbine expected VWO throttle flow	11,654,180 lb/hr
Condenser design pressure H.P./L.P.	2.66 inches HqA/2.04 inches HqA
Expected VWO feedwater flow	12,135,700 lb/hr
Expected VWO feedwater temperature	459.8°F
Main feed pump turbine maximum power ea.	10,395 hp
Turbine generator rating	1,068,794 kVA



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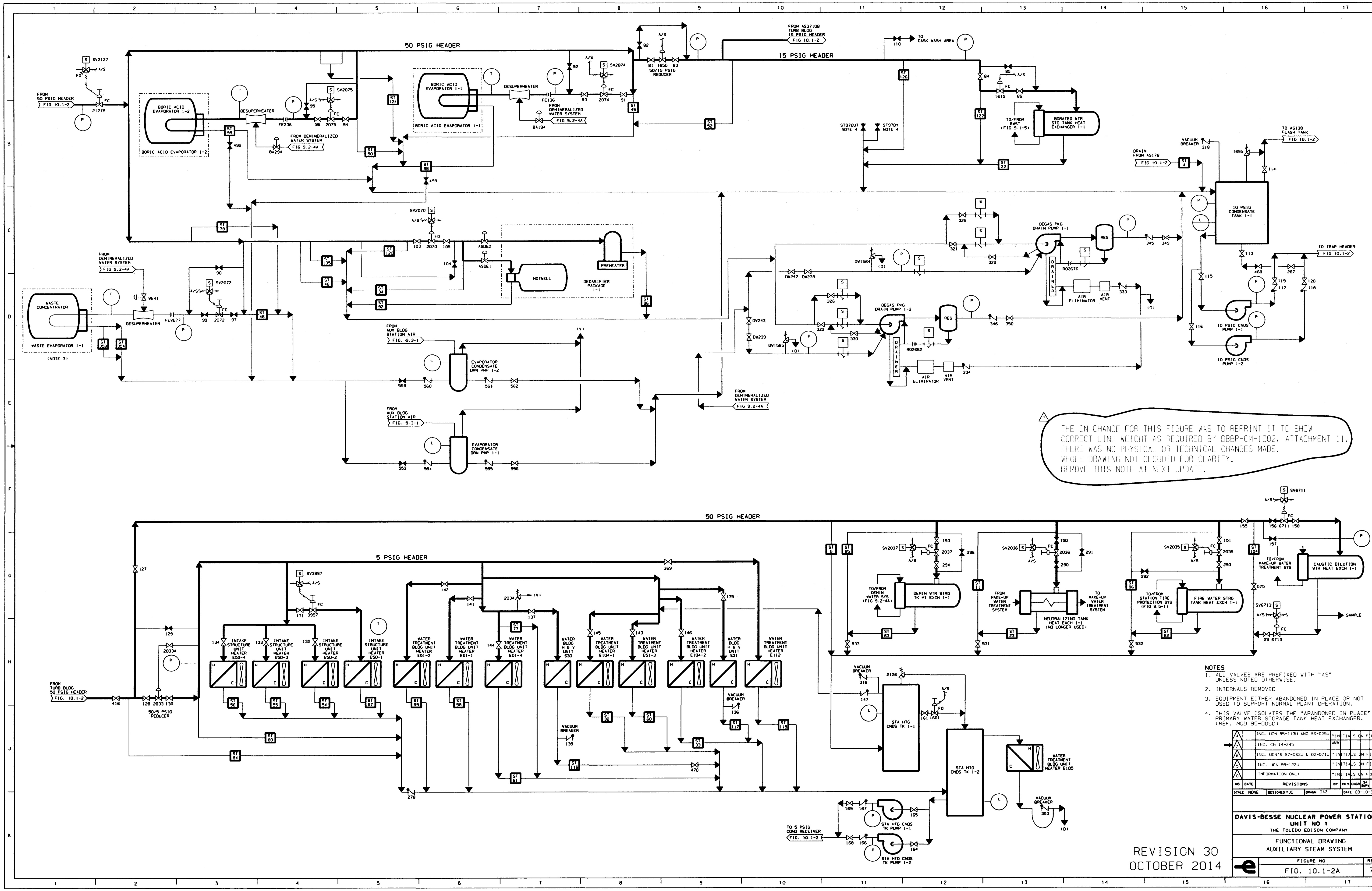

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10.2 TURBINE GENERATOR

10.2.1 Design Bases

The turbine-generator maximum capacity is sufficient for the Nuclear Steam Supply System capability for up to a 2817 megawatts thermal rating.

The turbine-generator is operated in an “integrated-control” mode with the steam generators and reactor. The turbine header pressure setpoint is varied in proportion to megawatt error. The turbine control valves change position to change load and steam pressure. By limiting the effect of megawatt error on the steam pressure setpoint, the system can be adjusted to permit controlled variations in steam pressure to achieve any desired rate of turbine response to megawatt demand.

The analysis of the effects of loss of full load on the Reactor Coolant System is discussed in Chapter 15.

The rate of change of reactor power as limited to values consistent with the characteristics of the Reactor Coolant System, its control system, and the turbine control system. Further limitation in the steam and power conversion system may reduce the Reactor Coolant System functional limits as given in Chapter 5.

The nuclear steam system, when under automatic control, imposes the following limitations on manual changes to electric load:

a. Step load changes — increasing load steps of 10% of full power in the range between 20% and 90% full power, decreasing load steps of 10% full power in the range between 100% and 20% full power.

b. Ramp load changes — increasing or decreasing load ramps of 5%/min. in the range between 15-20% full power, increasing load ramps of 10%/min. between 20-90% full power and 5%/min. between 90-100% full power, and a decreasing load ramp of 10%/min. between 100-20% full power.

The system is designed to accept 10 percent step load rejection without safety valve action or turbine bypass valve action. The combined actions of the control system and the turbine bypass valve are expected to permit a 40 percent load reduction or a turbine trip from 40 percent load without safety valve action.

The turbine-generator equipment conforms to the applicable ANSI, ASME and IEEE Standards.

10.2.2 Description

The turbine is a General Electric 1800 rpm, M-7 design tandem-compound unit. It consists of a double flow high-pressure section and two double flow low-pressure sections, two-stage reheat with 43-inch last stage buckets. It is an indoor unit with a design flow rating of 11,410,110 lbm/hr at 2.04 inch Hg for the low-pressure section and 2.66 inch Hg for the high-pressure section. A back pressure and zero makeup. The initial steam condition is 885 psia at 1252.7 Btu/lb. The turbine provides the extraction steam for six stages of feedwater heating and two steam generator feed pump drive turbines. Steam leaving the high pressure turbine is passed through two moisture separator-reheater units in parallel where the steam is dried and

superheated. The steam then enters two low pressure turbines. A portion of the main steam and the first point extraction steam is bypassed to the two-stage reheaters as the heat source.

The generator is a direct driven, three-phase, 60 cycle, 25,000 volt, conductor cooled wye-connected synchronous unit. It is rated 1,068,794 kVA at 60 psig hydrogen pressure, 0.90 power factor and 0.58 short circuit ratio. The exciter is direct-driven and is of the silicon diode rectifier type. It is rated at 500 volts and 2180 kW. The generator shaft glands are oil sealed to prevent hydrogen leakage.

Accessories for the turbine generator include complete bearing lubrication oil system, electro-hydraulic control system, steam seal system, protective valve system, turning gear, moisture separator-reheaters, crossover piping, supervisory instruments, hydrogen supply and seal oil systems, stator cooling system, exciter air cooler, rectifier section, generator field breaker and voltage adjuster.

10.2.3 Control Functions

Trips, automatic control actions, and alarms are initiated by deviations of system variables within the steam and power conversion system. In the case of the turbine-generator system, appropriate corrective action is taken to protect the Reactor Coolant System. The more significant malfunctions or faults which cause turbine trips are as follows:

a. Generator faults.

b. Main and auxiliary transformer faults.

c. Low condenser vacuum.

d. Excessive thrust bearing wear.

e. Low bearing oil pressure.

f. Turbine overspeed.

g. Turbine protection for generator motoring.

h. Reactor trip.

i. Manual trip.

j. Low hydraulic oil pressure.

k. Prolonged loss of generator stator coolant.

l. High moisture separator level.

m. Emergency overspeed.

n. SFRCS actuation.

o. Loss of all turbine control system controllers

p. Loss of 2/3 primary or 2/3 emergency speed signals

The turbine trip rapidly closes the main stop valves; this action supports the unit response to an SFRCS actuation.

The turbine stop and control valves, reheat intercept valves and extraction line non-return valves are periodically tested while the turbine is in operation. Overspeed testing is periodically performed prior to turbine operation.

The interface between the turbine-generator Trip and the reactor protection system is described in USAR Section 7.4.1.4.

10.2.4 Turbine-Generator Overspeed Protection

10.2.4.1 Turbine Steam Flow Control

The following devices are provided to control the flow of steam into the turbines:

a. Main steam inlets have the following valves in series:

   1. Main turbine stop valves – actuated by the primary overspeed trip and emergency overspeed trip.

      Valves of this design have been used on General Electric steam turbines of 10,000 kW and larger since 1948. During this period there has been no report of the main stop valve failing to close when required to protect the turbine. Impending sticking has been disclosed by means of a periodic full closed test so that a planned shutdown could be made to make the necessary correction. This almost always involves the removal of the oxide layer which builds up on the stem and bushing which would not occur on a low temperature nuclear application.

      Combined stop and intercept valves in the cross around system to the L.P. turbines – controlled by the flow control program and fast acting solenoid, and tripped closed by the primary overspeed trip and emergency overspeed trip. These valves are also tested periodically as described above.

   2. Control valves – controlled by the flow control program and fast acting solenoid and tripped closed by the primary overspeed trip and emergency overspeed trip. These valves are tested closed within a six month interval (Reference 6, Subsection 10.2.5.6).

b. Uncontrolled extraction lines to feedwater heaters - If the energy in an uncontrolled extraction line is sufficient to cause a dangerous overspeed, one or two positive closing non-return valves are close assisted upon a turbine trip. These are designed for periodic manual tests to ensure freedom to operate. The station piping, feedwater heater, and check valve systems are designed to ensure that entrained steam cannot overspeed the unit beyond safe limits.

c. Overspeed Protection – The primary overspeed protection trip and emergency overspeed protection trip de-energize trip solenoids on the trip manifold; this reduces the hydraulic fluid pressure that results in closing the main stop valves,

control valves, intermediate stop valves, and intercept valves. These trips use diverse electronic speed detection in a triple modular redundant (TMR) configuration to separately control the trip solenoids. The trip solenoids are testable under load. The emergency overspeed protection trip is in service when testing the primary overspeed protection trip. The primary overspeed protection trip setpoint is adjusted to provide backup protection during the emergency overspeed protection trip test. The primary overspeed protection trip actuates at approximately 109.5% of rated speed and the emergency trip actuates at approximately 110%.

General Electric personnel have reviewed the number and type of non-return valves to confirm that design recommendations have been followed. Reviews were also made of techniques for inspection and maintenance of governing and protective valves prior to initial startup and at subsequent inspections. Analysis for the plant performance with the Mark VIe control system found that the Mark VIe system is superior to the original Mark I control system for limiting overspeed probability.

10.2.4.2 Turbine Overspeed Control

10.2.4.2.1 Overspeed Monitoring

Monitored parameters are as follows:

1. Turbine-generator speed (six speed probes).

2. Generator load and turbine power

3. Turbine hydraulic fluid system pressure

10.2.4.2.2 Components Associated with Overspeed Control

Components which function to prevent or limit turbine overspeed are as follows:

1. Speed control.

   There are six independent pulse signals obtained from magnetic pickups located at a toothed wheel on the turbine shaft. Three signals are used for primary overspeed trip and normal speed control, and three are used for emergency overspeed trip. Two of the three signals in each TMR group are needed for the system to function. If two probes in the same group fail simultaneously, the turbine will trip. The overspeed protection system is single failure proof.

   During steady-state speed operation, the speed control program compares the speed reference signal with the actual speed signal. The obtained speed error signal is sent to the load control program. The speed error signal in the load control program positions the control valves and intercept control valves for loading the turbine. The primary overspeed protection system uses this actual speed signal to initiate a turbine trip if the actual speed exceeds the primary overspeed setpoint of approximately 109.5%.

   The emergency overspeed protection trip uses separate speed pickup probes, processing hardware, and firmware to independently access turbine speed. It

compares the measured speed to the emergency overspeed trip setpoint of approximately 110%, and it will trip the turbine if the setpoint speed is exceeded.

2. Generator load and turbine power.

   A rate sensitive power load unbalance (PLU) function initiates control and intercept valve fast closure under load rejection conditions that might lead to rapid rotor acceleration and consequent overspeed. The PLU function looks for an unbalance between mechanical power and electrical load. The PLU action actuates the control valve and intercept valve fast acting solenoids, resets the load reference value to zero, and ramps the load target down to the load reference value.

   The mechanical power is measured by a steam pressure signal from the cold reheat pressure.

   The generator electrical load is measured by a signal derived from the three current transformers. The object is to detect a sudden large PLU when at a power of 40% or more.

3. Turbine hydraulic fluid trip signal.

   When the turbine is tripped by one of the two trip manifolds, the extraction relay dump valve is actuated by the hydraulic fluid trip system. This valve controls the air to the air-operated non-return valves in the uncontrolled extraction lines to the feedwater heaters. The dump valve is spring actuated to cut off the air supply to the non-return valves. Air in the non-return valve operators is discharged to the atmosphere, resulting in a power-assisted closure of these valves.

10.2.4.2.3 DELETED

10.2.5 Turbine Missile Protection

The low pressure turbine rotors were replaced in 14 RFO with new monoblock turbine rotors. Monoblock rotors consist of the shaft with the turbine wheels as one forging. The previous low pressure turbine rotors were a built-up design utilizing a shaft with shrunk-on wheels with axial keys. The high pressure turbine rotor is also a monoblock design.

High stresses in the shrunk-on wheel keyways and the potential for stress corrosion cracking due to a condensation mechanism which resulted in an enrichment of oxygen levels in the location of the highly stressed keyway allowed for the possibility of a brittle wheel burst. A 120° segment of the last stage wheel was the largest possible missile predicted to be generated by this design.

General Electric in the course of designing the new low pressure turbine rotors for Davis-Besse has evaluated the stresses in rotating components. The limiting components, per design are the last stage buckets, which have an overspeed capability of 174%. The maximum attainable overspeed for the turbine is 190% with two arc admission. A complete failure of the control system would be required to achieve this overspeed. The minimum overspeed capacity of the rotor is at least 217% assuming that all the buckets stay intact, however the failure of the individual buckets would occur before such overspeeds could be obtained. A bucket does not have sufficient energy to exit the turbine casing and produce a missile. Due to the loss of torque energy of the failed buckets, vibration and mechanical obstructions associated with a

bucket loss, the maximum attainable speed of the rotors is reduced. Therefore, the speed capability of the monoblock rotors is higher than the maximum attainable speed of the turbine and the probability of missiles being generated from a monoblock rotor is not present. The missile probability of the built-up rotor design is bounding for the monoblock design and therefore the following USAR discussion on turbine missile protection for the built-up rotor design has not been changed.

10.2.5.1 Low Pressure Turbine 43 Inch Wheel

Experience and tests have shown that turbine missiles could be generated only from the rotating parts of the low pressure turbine.

The wheel capable of producing the largest missile is the last stage wheel of the low pressure turbine. Using the analysis techniques described in G.E.'s Report TR67SL211, "An Analysis of Turbine Missiles Resulting from Last Stage Wheel Failure," it has been concluded that a 120° wheel fragment is the largest possible missile. The physical properties of the 120° wheel fragment are summarized in Table 10.2-1.

10.2.5.2 Analysis

The penetration analysis of the low pressure turbine missile was carried out using the following modified Petry formulas:

$$D = K\,A_p\,V^1 \qquad \text{(Equation 1)}$$

$$V^1 = \log_{10}\left[1 + \frac{v^2}{215000}\right] \qquad \text{(Equation 2)}$$

$$D^1 = D\left[1 + e^{-4(\alpha^1 - 2)}\right] \qquad \text{(Equation 3)}$$

$$\alpha^1 = \frac{T}{D} \qquad \text{(Equation 4)}$$

For explanation of symbols, see Subsection 10.2.5.5. Table 10.2-2 contains a summary of missile penetration calculations.

10.2.5.3 Missile Energy Losses

Along the projectile path, there is a certain amount of energy loss due to air drag, which is proportional to the square of the velocity.

$$F_D = C_D \frac{\rho A V^2}{2} \qquad \text{(Equation 5)}$$

Upward Flight:

$$dv = -g\,dt - \frac{C_D \rho A V^2}{2}\,dt \qquad \text{(Equation 6)}$$

Downward Flight:

$$dv = g\,dt - \frac{C_D \rho A V^2}{2} dt \qquad \text{(Equation 7)}$$

For explanation of symbols, see Subsection 10.2.5.5.

The turbine manufacturer has stated that 64% of the total energy of the turbine missile will be absorbed by the casing (see Figure 10.2-1). This has been adopted as the best estimate of absorption and has been used in the analysis.

10.2.5.4 Conclusion

It is concluded that the 43 inch wheel fragment (see Figures 10.2-2 and 10.2-3), which is the largest possible turbine missile, will not penetrate the shield building, control room, or spent fuel pool area (see Table 10.2-2). The penetration values have been calculated without considering the energy lost in penetrating the turbine building. The probability of formation of a turbine missile is remote. However if it should occur, the vertical trajectory must be between 89° and 90° to land on the Shield Building or Auxiliary Building roofs. In order to make a direct hit on the Shield Building wall, the trajectory must be between 16° and 50° from the horizontal.

The designs are such that a missile will not cause a LOCA or prevent shutdown of the reactor.

The spent fuel pool roof has 4 1/2 inches of ribbed roof decking below the reinforced concrete slab. Beams, 6 feet 2 inches center to center, are used to support the ribbed roof decking. The total thickness of roof, including ribbed roof decking, is 22 1/2 inches at the center and the thickness increases to 2 feet 6 inches at the north side of the wall and 2 feet 9 inches at the south side of the wall. The ribbed roof decking will restrain any spalled concrete from the under side from falling into the pool.

The missile projectile study shows that if the turbine missile has a projectile of around 89 degrees from the horizontal position then it will go up in the air and probably land on the Shield Building or Auxiliary Building roofs. The vertical downward velocity of the missile will vary according to the height of the building roof. See Table 10.2-2. In calculating the striking velocities for various roof heights, the turbine roof (see Figures 3.6-21 and 3.6-22) was not accounted for in calculating the energy absorption in penetrating the roof structure. The Turbine Building roof has heavy trusses at El. 694 feet 4 inches, approximately 69 feet 4 inches above the turbine operating floor. The trusses are made up of 14 WF 111 top and bottom members and cross members of double angles L5x5x3/4. The spacing between the trusses is 25 feet center to center. The cross-beams of 16 WF 40 at 6 feet 3 inches center to center are used to support the roof and the ribbed roof decking. The roof has 3 5/8 inches thick concrete over the ribbed roof decking.

On the west side of the turbine generator, there are three floors at EL 643 feet-0 inches, 657 feet-3 inches and 692 feet-4 inches, respectively, including the roof that the turbine missile has to penetrate (see Figures 10.2-4, 10.2-5, and 10.2-6).

Our as-built reports from the field show that the type of concrete used for the Shield Building dome, Auxiliary Building roof, and spent fuel pool roof is of 5,000 psi strength. The design calculations were made based on 4,000 psi concrete. The turbine missile penetration calculations shown on Table 10.2-2 are based on our design assumptions of 4,000 psi concrete.

However, because of the pump-ability and the concrete slump requirements, a 5,000 psi concrete was used for the Shield Building dome, Control Building roof, and spent fuel pool roof.

The results of the concrete test reports from Pittsburgh Testing Laboratory have been summarized in Table 10.2-3.

The 90-day cylinder break reports for the Shield Building dome show that there is a 75 percent safety margin in concrete strength over and above the 4,000 psi value used in the missile penetration calculations.

The 28-day cylinder break reports for Auxiliary Building and spent fuel pool roofs show an average safety margin of 56 percent over and above the 4,000 psi value used in the missile penetration calculations.

Safety-related systems in the Auxiliary Building are below the turbine operating deck elevation (Elevation 623 feet). In order to penetrate into the lower areas of the Auxiliary Building, turbine missiles would have to impact the turbine operating deck at an extremely shallow angle of incidence. This is considered as a ricochet shot at the Auxiliary Building. Penetration of the Auxiliary Building by a ricocheting turbine missile is not postulated to occur.

The control room is outside the postulated low trajectory missile strike zones (Reference 4, Subsection 10.2.5.6).

Turbine missiles may also be produced at high trajectories; however, the probability of impacting a safety-related structure is substantially less from a high trajectory missile. Therefore, risks of radiological releases from a destructive overspeed are dominated by low trajectory missiles (Reference 4, Subsection 10.2.5.6).

The NRC staff evaluated the probability of ejecting a massive high velocity turbine missile that could impact and penetrate the containment, cause a failure of safety-related equipment, and result in a subsequent release of radioactivity sufficient to exceed 10CFR100 limits. The staff estimate of the probability of this event is 1.4×10^{-6} per turbine year. This value was derived assuming the probability of a destructive overspeed to be 4×10^{-5} per year; the probability of a massive, high energy missile striking the containment to be 1.7×10^{-1}; the probability of that missile penetrating the containment be 1.0: and the probability of impacting safety-related equipment to be 2×10^{-1} (Reference 3 and 6, Subsection 10.2.5.6).

The probability of generating a turbine missile is calculated for each low pressure turbine rotor based on periodic volumetric inspections of the keyway and bore. The primary wheel failure mode is assumed to be fracture due to the presence of a stress corrosion crack in the keyway near the bore of the shrunk-on wheel. A second, independent wheel failure mode due to simple ductile failure during overspeed is also included. This calculation depends on the testing interval of the main turbine stop valves, control valves, and combined intercept valves. The results of these calculations are used to establish re-inspection intervals for rotor volumetric inspections. The re-inspection intervals are used to ensure that the total unit missile generation probability is maintained within acceptable limits and less than the original NRC staff estimate.

10.2.5.5 Symbols

D = Depth of penetration in a slab of infinite thickness, feet

D^1 = Penetration in a slab of a finite thickness, T, feet

T = Thickness of slab, feet

A_p = Sectional pressure obtained by dividing the weight of missile by its cross-sectional area, lbs/ft^2

V = Velocity of missile, ft/sec

K = Penetration material coefficients experimentally determined

V^1 = Velocity coefficient factor

α^1 = Ratio of slab thickness to penetration thickness

F_D = Drag force, lbs

C_D = Drag coefficient (dimensionless) used as 1.0

ρ = Air density, $lbf\text{-}sec^2/ft^4$

w = Air density, lbm/ft^3, used as 0.074 lb/ft^3

A = Projected area, ft^2

W = Weight of missile, lbs

M = Missile mass, $lbf\text{-}sec^2/ft$

g = Acceleration due to gravity, ft/sec^2

10.2.5.6 References

1. General Electric Report, TR67SL211, “An Analysis of Turbine Missiles Resulting from Last-Stage Wheel Failure.”

2. “Design of Protective Structures” by Arsham Amirikian “NavDocks P-51.”

3. Safety Evaluation Report by the Office of Nuclear Reactor Regulation, United States Nuclear Regulatory Commission in the matter of Toledo Edison Company, Cleveland Electric Illuminating Company, Davis-Besse Nuclear Power Station, Unit 1, Docket No. 50-346; December, 1976; NUREG-0136; pp. 3-5 and 3-6.

4. Stenographic transcript of the proceedings of the United States Nuclear Regulatory Commission’s Advisory Committee on Reactor Safeguards 201st General Meeting; January 6, 1977; pp. 104-117.

5. General Electric Statement, “Turbine Missile Analysis Statement, First Energy Davis-Besse, Turbine 170X495;” March 20, 2013

6. MPR Associates, Inc., Effect of Extending Turbine Valve Test Intervals on Davis-Besse OPS Reliability, 0200-0207-CALC-001, December 17, 2019.

10.2.6 Radioactivity

No radiation shielding is required for the turbine generator and related steam handling equipment. Continuous access to the components of this system is possible during normal conditions. Monitoring of the main steam supply from the steam generators will determine if the safe operating limits are exceeded.

TABLE 10.2-1

120° Wheel Fragment Missile Properties

Wheel fragment weight	8264 lbs.
Fragment angle	120°
Minimum projected area	5.17 ft^2
Maximum projected area	11.7 ft^2
Failure speed	3190 rpm
Initial translational velocity	676 ft/sec
Translational energy	58.7×10^6 ft-lbs
Rotational energy	34.1×10^6 ft-lbs
Estimated velocity after leaving casing	409 ft/sec
Estimated energy after leaving casing	21.5×10^6 ft-lbs

NOTE: The estimated velocity of 409 ft/sec was considered as an escape velocity leaving the casing. The missile striking velocities for calculating various penetrations as given in Table 10.2-2 are calculated by using a computer program for upward and downward flights, including the drag coefficient.

TABLE 10.2-2

Summary of Penetration Calculations

Exposed Surface of Shield Building	Thickness inches	% of Best Estimate of Energy Absorption* by Turbine Casing: 0 V fps	0 D[1] inches	25 V fps	25 D[1] inches	50 V fps	50 D[1] inches	100 V fps	100 D[1] inches
Shield Building Containment Dome	24	581	27.2	543	24.9	499	17	375	7.4
Control Room 18 in. roof & 12 in. ceiling	30	670	32.5	621	29.75	560	25.9	400	10.9
Spent Fuel Pool Roof	22 ½ (center) 30 and 33 at sides	670	32.5	621	29.75	560	25.9	400	10.9

* NOTE: The percentage of best estimate of energy absorption are interpreted as follows:

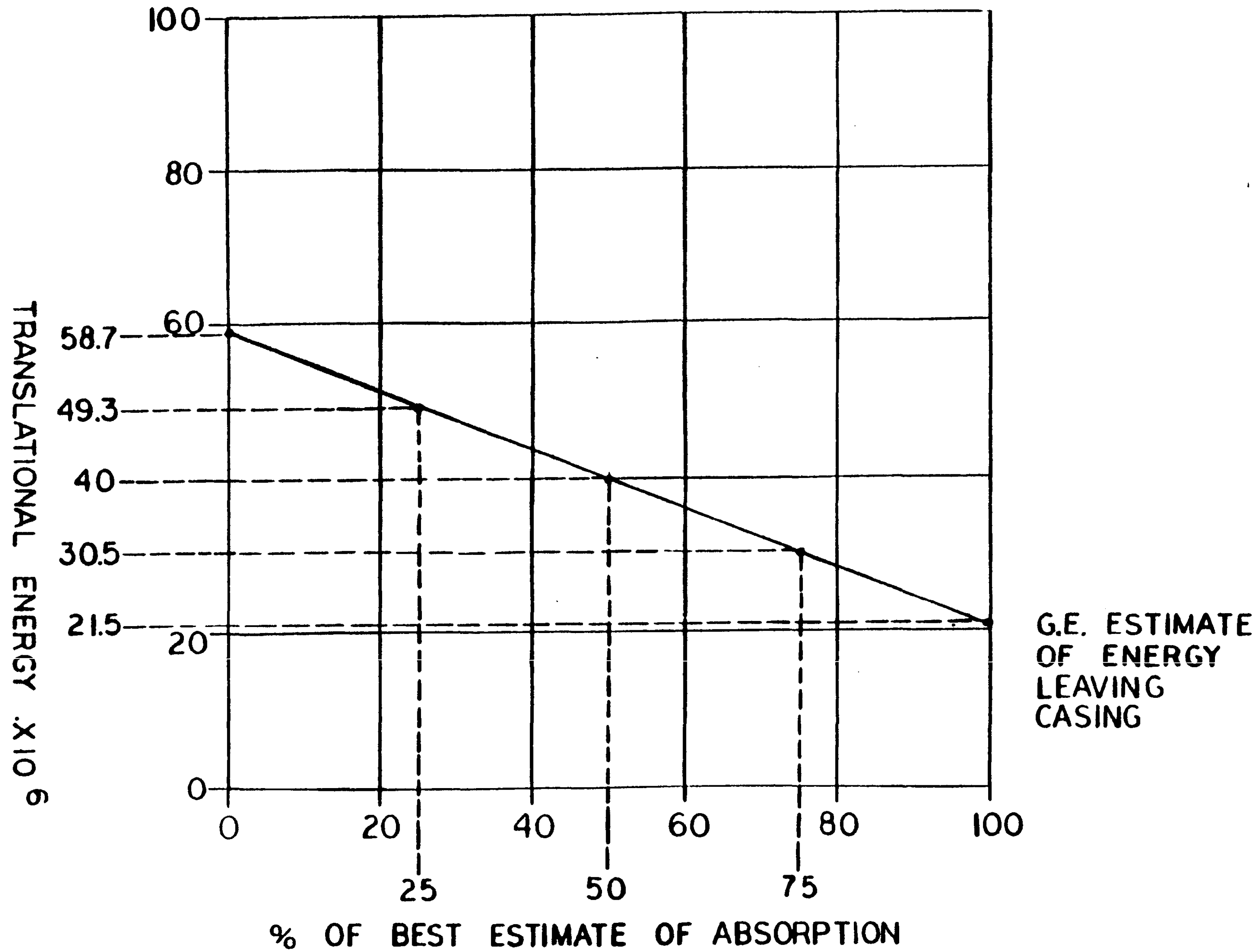
100 percent, 50 percent, and 25 percent of best estimate of energy absorptions are equivalent to 64 percent, 32 percent, and 16 percent respectively, of energy absorption by casing as recommended by General Electric.

The average projected area of contact $\frac{5.17 + 11.7}{2}$ = 8.44 sq. ft. is used in calculating the depth of penetrations. The type of concrete used for calculating the penetrations is 4000 psi.

TABLE 10.2-3

Concrete Report

Building	Concrete Used in Design	Strength as Built	Tested Cylinder Break Strength
Shield Bldg. Dome	4000 psi	5000 psi	Avg 28 Days = 6026 psi Avg 90 Days = 7002 psi
Control Bldg. Roof	4000 psi	5000 psi	Avg 28 Days = 6185 psi
Spent Fuel Bldg. Roof	4000 psi	5000 psi	Avg 28 Days = 6213 psi



DAVIS-BESSE NUCLEAR POWER STATION
TURBINE MISSLE ENERGY ABSORPTION
FIGURE 10.2-1

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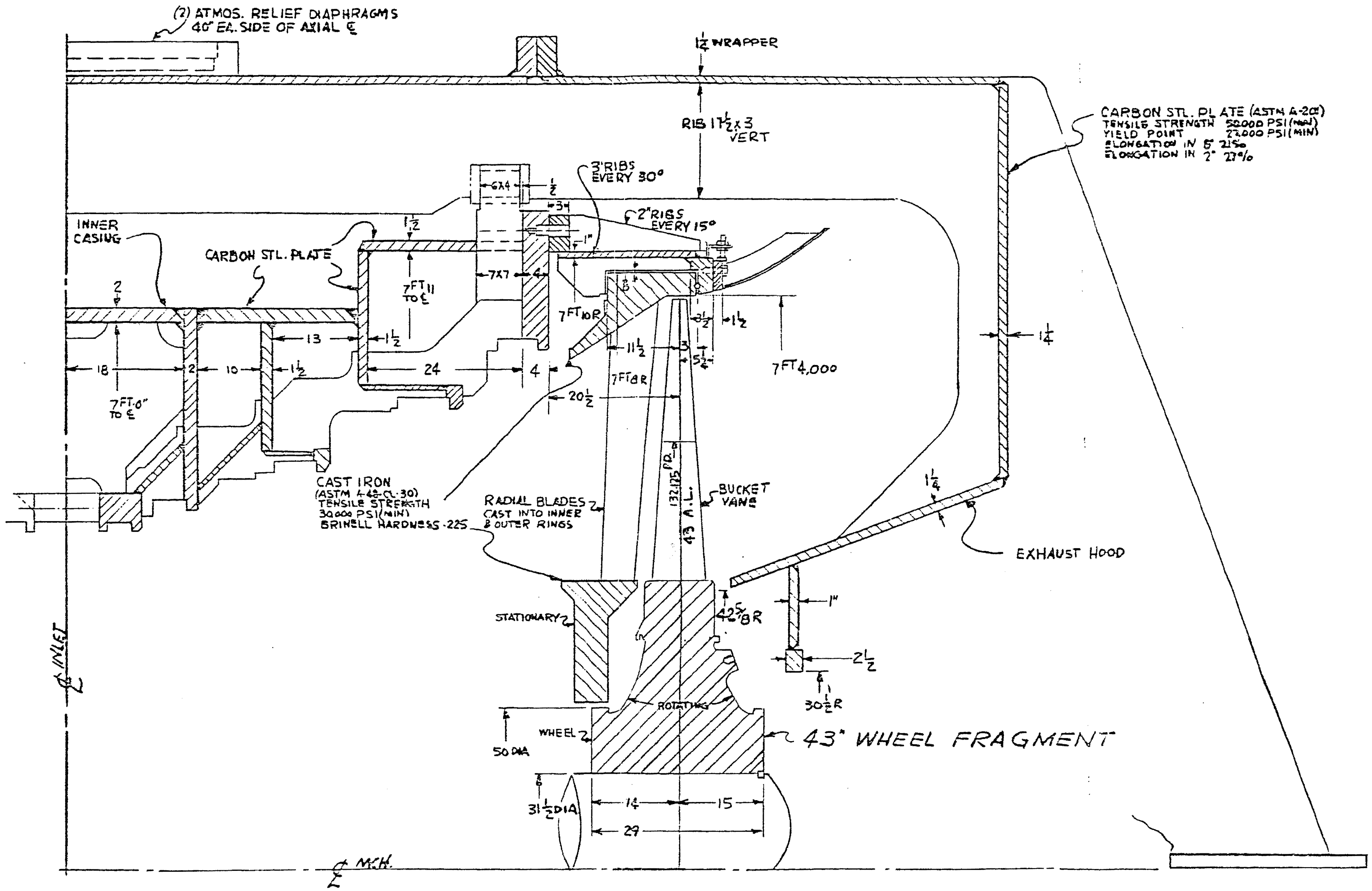
JULY 1982



SECTION SHOWING TURBINE CASING

DAVIS-BESSE NUCLEAR POWER STATION
TURBINE SECTION
FIGURE 10.2-2

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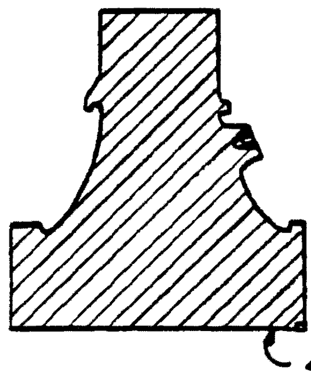
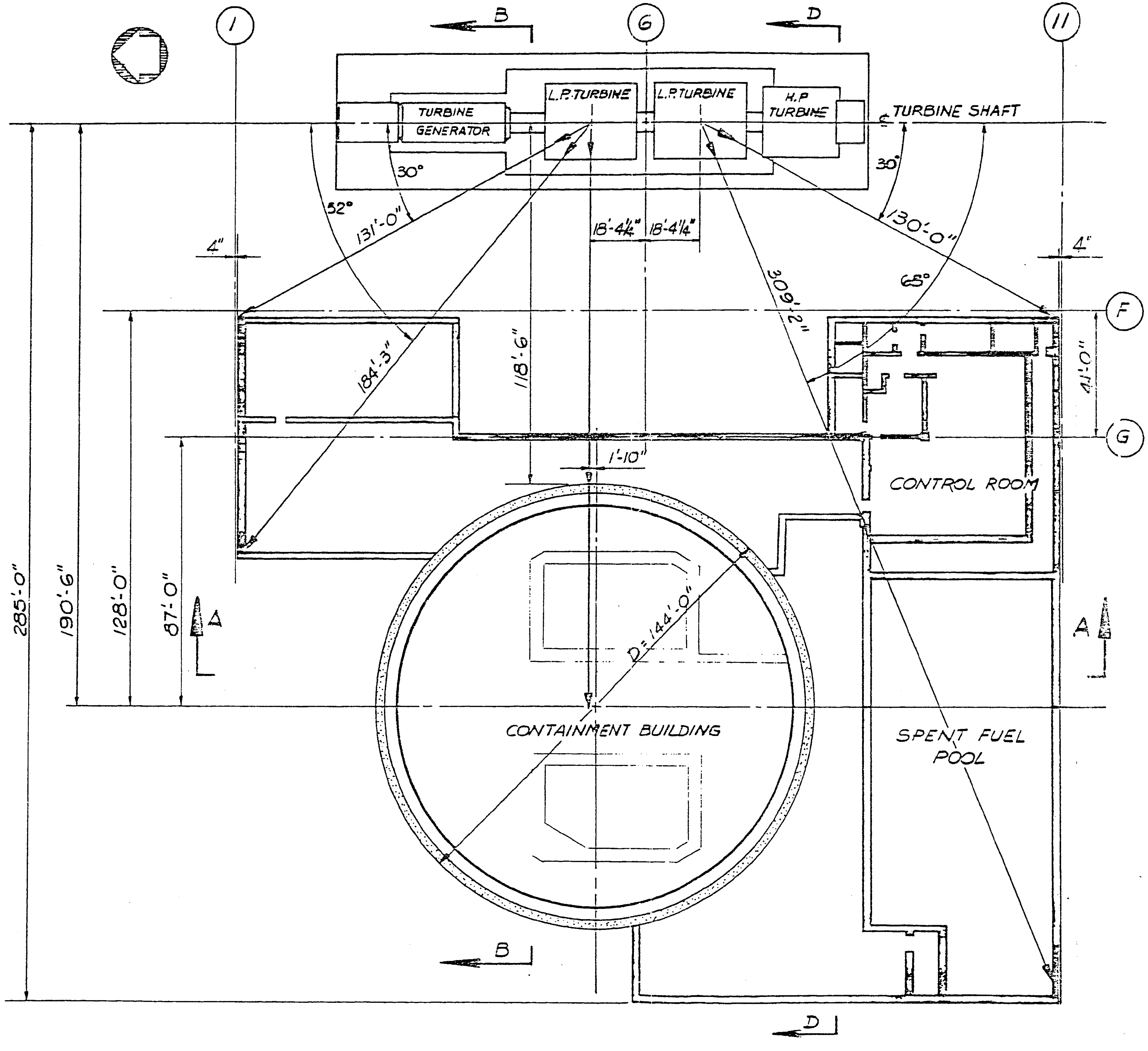
JULY 1982

TURBINE MISSILE



DAVIS-BESSE NUCLEAR POWER STATION
43 INCH TURBINE WHEEL FRAGMENT
FIGURE 10.2-3



DAVIS-BESSE NUCLEAR POWER STATION
PLAN LP TURBINE ORIENTATION
FIGURE 10.2-4

REVISION 0
JULY 1982

Removed in Accordance with RIS 2015-17

DAVIS-BESSE NUCLEAR POWER STATION
TURBINE MISSILE PROJECTILE
FIGURE 10.2-5

Removed in Accordance with RIS 2015-17

DAVIS-BESSE NUCLEAR POWER STATION
TURBINE MISSILE PROJECTILE STUDY
FIGURE 10.2-6

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 Design Bases

The main steam line takes steam from each of the two steam generators and conducts it through the main steam isolation, main steam non-return, turbine stop, and control valves to the H.P. turbine. There are several taps off the main steam header.

The atmospheric vent valve, safety valves, and auxiliary feed pump turbine lines tap off of the high pressure header between the steam generator and the Main Steam Isolation Valves (MSIVs). This design ensures overpressure protection of the steam generator even with the MSIVs shut. This design also allows for cooldown of the primary plant using auxiliary feed and the atmospheric vents when the condenser is not available for cooldown.

The main feed pump turbine, turbine bypass system, and Moisture Separator Reheater (MSR) second stage reheating steam lines tap off of the high pressure header between the non-return valves and the H.P. turbine stop valves. The auxiliary steam system supply taps off the H.P. Header from Steam Generator 1-1 in the same location. This design allows for primary system cooldown using the turbine bypass system and the main feed system. Steam Generator 1-2 can also supply the gland seal system from a tap on the main steam line to the No. 1 H.P. turbine stop valve. The main feed pump turbines also receive low pressure main steam from between the MSR and L.P. turbines. Steam is extracted from the second stage of the H.P. turbine and used for first stage reheating steam in the MSR. See Figure 10.3-1 for the Main Steam and Reheat System and Figures 10.1-2 and 10.1-2A for the Auxiliary Steam System.

10.3.1.1 Design Parameters

10.3.1.1.1 Temperature and Pressure Limits

The main steam piping design rating is 1050 psig at 600°F. It meets the requirements of ASME Section III for Nuclear Class 2 piping from the steam generators through the containment penetrations up to and including the isolation valves. Downstream of the isolation valves, the piping meets the requirements of ANSI B31.1.0 and is upgraded for inspection and documentation requirements.

Each 600-pound ANSI main steam isolation valve serves to isolate its respective steam generator from the main steam line upon a steam and feedwater rupture control system signal. The valves are designed in accordance with the requirements of Section III, Nuclear Power Plant Components of the ASME Boiler and Pressure Vessel Code. The valves are designed to fail closed. Upon closure due to a downstream break, the valves are designed for zero leakage. Upon a steam line break upstream (reversed flow), the affected valve is signaled to close. Complete closure occurs when line pressure is less than 80 psig at which time leakage is not greater than 0.2 pounds per hour.

Main steam non-return valves serve to close in the event of reversed flow. They are designed, manufactured, examined, tested, and inspected in accordance with ANSI B31.1.0.

The steam generators' spring-loaded safety valves discharge to the atmosphere and are in accordance with the requirements of the ASME Boiler and Pressure Vessel Code, Section III, 1968. License Amendment No. 278 increased rated thermal power to 2817 MWt. With an additional 17 MWt input from the RC pumps, this results in a total Nuclear Steam Supply System power output of 2834 MWt. The spring-loaded safety valves have sufficient capacity for

the increase in thermal rating. The capacity is 14,175,000 lb/hr at 1155 psig. (See section 5.2.2.3)

The piping and valves are designed for maximum ambient conditions of 120°F and 100% relative humidity.

10.3.1.2 Seismic Evaluation

Piping from the steam generators to the main steam line isolation valves has been analyzed for thermal flexibility and imposed Seismic Class I loads Piping from the isolation valves to the turbine stop valves has been analyzed for thermal flexibility. Loads imposed on the steam generators and turbine stop valves are below the allowable forces and moments.

10.3.2 Description

Two separate steam lines penetrate the Containment Vessel and Shield Building. The steam lines are anchored at the Shield Building wall and have the flexibility to take the relative movement (expansions) of the steam generators. Spring loaded steam generator safety valves are located outside of the containment in each line. In addition, there is an atmospheric vent valve and turbine bypass valve system (Subsection 10.4.4) on each steam line. These valves are set to open at a lower pressure than the spring-loaded safety valves.

Steam line isolation valves are located downstream of the code safety valves, the atmospheric vent valves, and the lines to the auxiliary feed pump turbines. The isolation valves are air operated, balanced disc type stop valves which, when shut, prevent flow from the steam generators into the headers. Non-return valves downstream of the isolation valves are provided to prevent reverse flow. The non-return valves are equipped with pneumatic operators in order that the valves may be opened during plant startup when steam flow is low. When steam flow is sufficient to keep the non-return valves open, air is removed. Failure to remove air does not impair non-return valve closure following a main steam line break upstream of the valve.

The turbine bypass valves and connections to main feedpump turbines steam reheaters and auxiliaries are downstream of the isolation valves.

Each of the steam generator leads feeds two steam turbine stop valves. There are four steam turbine leads starting at the control valves. There is an equalizing pipe between the turbine leads at the stop valve discharge, close-coupled to the turbine control valves.

Interconnecting pipe is shown on Figure 10.3-1.

10.3.3 Accident Analysis

The main steam line non-return valves are located in the Turbine Building to reduce the amount of energy which would flow out of a double-ended steam line rupture if it occurs in the Auxiliary Building or containment structure.

Following a postulated double-ended rupture of a main steam line inside the Containment Vessel, low pressure switches located in the main steam line outside containment will actuate the Steam and Feedwater Rupture Control System (SFRCS). The reactor trips on low Reactor Coolant System pressure. SFRCS will trip the turbine-generator, initiate closure of the main steam isolation valves in both main steam lines, initiate main feedwater isolation for both steam generators, and will start the Auxiliary Feedwater System.

SFRCS will determine which is the affected steam generator. No auxiliary feedwater will be added to the affected steam generator, as SFRCS will align both auxiliary feedwater pumps to supply water only to the unaffected steam generator.

Following main steam and main feedwater isolation of the steam generator, the unaffected steam generator will re-pressurize while the affected steam generator will continue to blow down and will not re-pressurize. The redundant SFRCS pressure switches on the main steam lines of each steam generator (set at > 591.6 psig) are the means of detecting the affected generator. These pressure switches are interlocked with the valves in the auxiliary feedwater system to prevent the addition of auxiliary feedwater to the affected steam generator. Because the Auxiliary Feedwater System only supplies water to the unaffected steam generator, there is no runout of the auxiliary feedwater pumps and their continued availability is not affected.

During the period of time required to detect a Main Steam Line Break (MSLB) and close the main steam and feedwater valves, main feedwater will continue to flow to both the affected and the unaffected steam generators. This feedwater addition has been considered in the MSLB analysis in Chapter 15. The analysis has shown that the values of feedwater addition used as data were conservative.

Figure 10.3-1 shows isolation valves MS-100 and MS-101 in the main steam lines. In the event of a failure upstream of the isolation valve, if the non-return valve fails to close, it cannot be assumed that the main steam isolation valve will maintain the required tightness, i.e., cannot be given credit for closing. If the same event occurs in the containment, an analysis in Chapter 15 has illustrated that Containment Vessel pressure rating is adequate.

If a steam line rupture occurs in the Auxiliary Building taking credit for the non-return valves, the following analysis applies.

An instantaneous break using an orifice coefficient of 1.0 was assumed to occur at the Auxiliary Building wall nearest the check valve. This break causes a sudden depressurization, which propagates through the system as a decompression wave. The resulting depressurization produces a flow reversal through the valve in about 5 milliseconds. Impact of the disc on the valve seat occurs 45 milliseconds after the break; the centerline velocity at impact is 117 feet per second, corresponding to an impact energy of 2.05×10^5 ft-lbf. About 3 milliseconds after the valve closes, the steam pressure at the valve outlet peaks at 854 psia as a result of a steamhammer effect; this pressure is 672 psia at the moment the disc impacted on the seat.

The manufacturer of the Davis-Besse non-return valves, Atwood & Morrill Co., used the report prepared by Teledyne Materials Research for Millstone Point Unit 2, entitled “Dynamic Analysis of 34 Main Steam Isolation Valves for Faulted Conditions,” E-1975-50, September 5, 1975, to evaluate the performance of the non-return valves. Atwood & Morrill determined that since the internals in the Davis-Besse check valve had been modified to conform to the design used in the Millstone main steam isolation valve, the Teledyne analysis was applicable to Davis-Besse. Atwood & Morrill concluded that since the disc centerline velocity at impact was 117 feet per second for Davis-Besse as compared to 129.5 feet per second for Millstone, the actual shear stress on the shaft was well within the ultimate shear stress for the shaft material, and the problem of radial growth was accounted for by removing material in the Davis-Besse valve bodies to eliminate any possible interference. Consequently, the Davis-Besse non-return valve internals are structurally adequate for the faulted condition.

10.3.4 Inspection and Tests

All piping, isolation valves, atmospheric vent valves, and code safety valves are readily available for inservice inspection. Periodic visual inservice inspection is performed on piping welds, valve stem packings, and vent and safety valve discharge leakage.

Main Steam line isolation valves (MSIV) and MSIV bypass valves were shop tested as described below prior to service:

> The main steam line isolation valves were hydrostatically tested in accordance with the requirements of Article NC-6000 of ASME Section III. Valve seat tests are in accordance with MSS-SP-61, except seat leakage which is not allowed to exceed 2 cc/hr per inch of diameter across the valve seat.
>
> The main steam isolation valves and MSIV bypass valves were given an air seat leakage test. Conditions of this test are 40 psi across the valve assembly with upstream and downstream temperatures of 60°F. The test duration is one hour and the maximum leakage rate is 34.3 cc per inch of diameter across the valve seats at standard conditions.

Provisions for periodic inservice testing of the main steam isolation valves are outlined in Technical Specifications.

The following preoperational tests were performed to demonstrate that the main steam line isolation, check, relief, bypass, atmospheric vent, and high pressure feedwater valves function in accordance with design:

1. An isolation signal to the main steam isolation valves was initiated during the hot functional testing period to ensure that the valves close within their allotted time.

2 During the hot functional testing period, the check valves were individually cycled to ensure proper operation under full pressure and temperature.

3. During the hot functional period, each relief valve was tested at full temperature and pressure to ensure that each valve functions at its required lifting pressure.

4. During the hot functional testing period, each bypass valve was individually cycled to verify its operation over the required pressure and temperature range.

5. Atmospheric vent valves were tested to ensure proper maintenance of steam generator pressure during initial plant heatup.

6. The high-pressure feedwater regulating valves (main feedwater control valves) were stroked from fully open to fully closed by initiation of feedwater isolation at design feedwater pressure.

Periodic functional tests or exercising are performed to demonstrate that the main steam line isolation, relief, bypass, main steamline non-return check valves, main feedwater control valves, and atmospheric vent valves function in accordance with design. Periodic functional tests or exercising for each type of valve are as follows:

1. Main steam line isolation valves are tested for closing times in accordance with Technical Specifications.

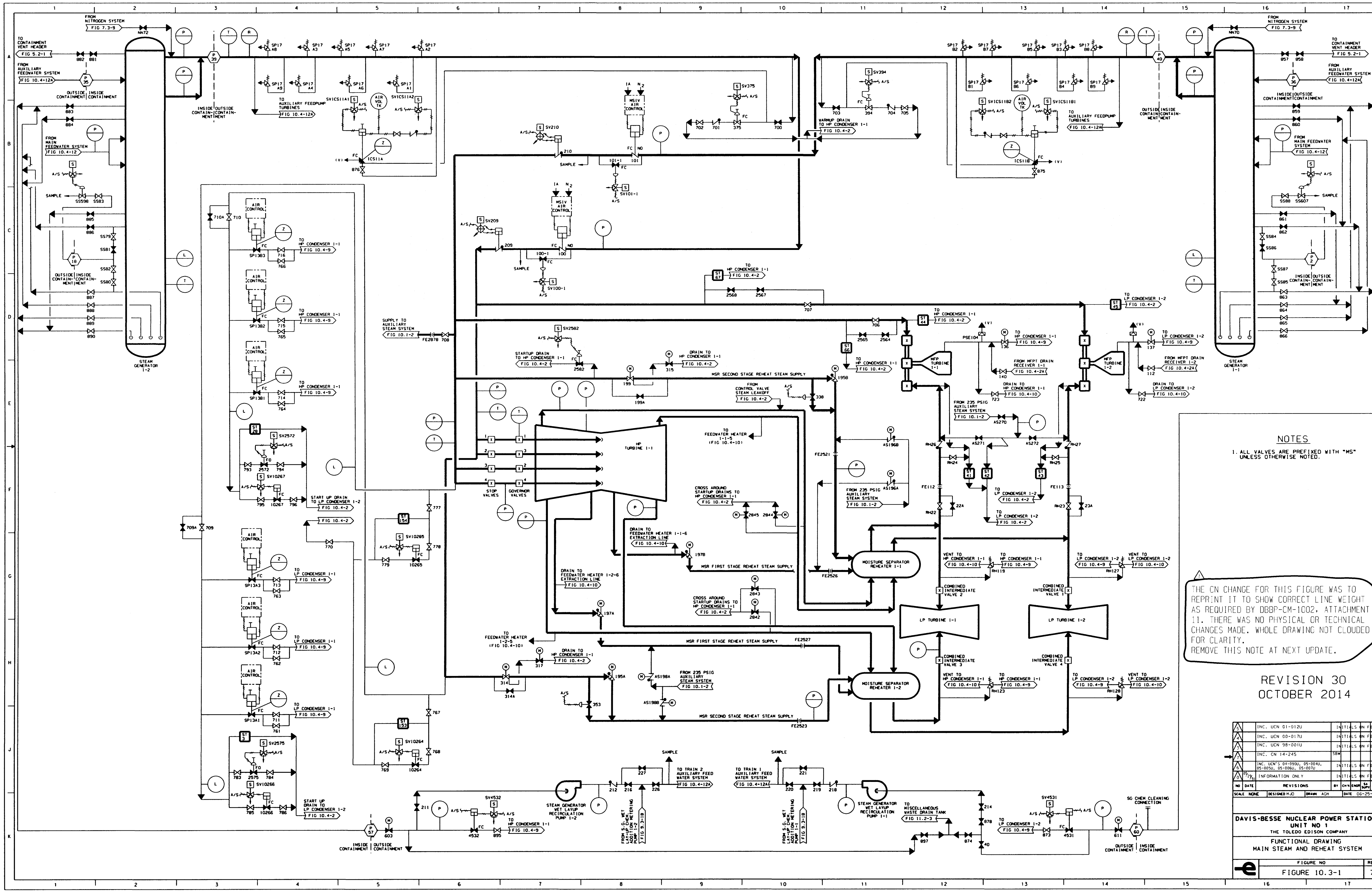
2. Periodic functional tests are performed on the main steam line non-return check valves.

3. Relief valves are functionally tested as per the Technical Specification.

4. Bypass valves are exercised during each plant startup.

5. Atmospheric vent valves are tested in accordance with Technical Specifications.

6. Main feedwater control valves are tested in accordance with Technical Specifications.



NOTES

1. ALL VALVES ARE PREFIXED WITH "MS" UNLESS OTHERWISE NOTED.

THE CN CHANGE FOR THIS FIGURE WAS TO REPRINT IT TO SHOW CORRECT LINE WEIGHT AS REQUIRED BY DBBP-CM-1002, ATTACHMENT 11. THERE WAS NO PHYSICAL OR TECHNICAL CHANGES MADE. WHOLE DRAWING NOT CLOUDED FOR CLARITY.
REMOVE THIS NOTE AT NEXT UPDATE.

REVISION 30
OCTOBER 2014

NO	DATE	REVISIONS	BY	CH'K	ENGR	SA SUPV	NED MGR
5		INC. UCN 01-012U	INITIALS ON FILE				
4		INC. UCN 00-017U	INITIALS ON FILE				
3		INC. UCN 98-001U	INITIALS ON FILE				
7		INC. CN 14-245	SBW				
6		INC. UCN'S 04-090U, 05-004U, 05-005U, 05-006U, 05-007U	INITIALS ON FILE				
0	05/29/91	INFORMATION ONLY	INITIALS ON FILE				

SCALE NONE | DESIGNED MJD | DRAWN AGM | DATE 06-25-90

DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
MAIN STEAM AND REHEAT SYSTEM

FIGURE NO: FIGURE 10.3-1 | REV: 7

DFN=G:/USAR/UFIG1031.DGN
DB 10-01-14

10.4 STEAM AND POWER CONVERSION SUBSYSTEMS

10.4.1 Main Condenser

10.4.1.1 Design Bases

The condenser maintains a design pressure in the H.P./L.P. shells of 2.66 inches HgA and 2.04 inches HgA, respectively, at a circulating water temperature of 75°F and flow of 480,000 gpm.

It is designed, in addition to the main turbine exhaust, to condense exhaust steam from the main feed pump turbines under full load conditions. It also provides for condensing bypass steam from the steam generators and the collection of the steam generator blowdown effluent and miscellaneous turbine cycle drains.

The condenser is designed to the following codes and standards:

a. Heat Exchange Institute Standards for Steam Surface Condensers, Sixth Edition, 1970.

b. ASTM Specification for Welded/Austenitic Steel Boiler, Superheater, Heat Exchanger and Condenser Tubes, ASTM A-249.

10.4.1.2 Description

The main condenser is a dual pressure, series flow, twin shell, deaerating surface type unit with tubes arranged perpendicular to the turbine spindle. The condenser shells are connected to the turbine exhaust hoods through expansion joints. Each condenser shell neck accommodates two low pressure feedwater heaters. Condenser tubing is made of 304 stainless steel. A manually operated sampling system is installed on the main condenser to detect condenser tube leakage.

The condenser hotwell is a storage reservoir for the deaerated condensate which supplies the condensate and main feedwater pumps, and normally contains five minutes storage at full load. This supply of condensate is backed up by two 250,000 gal. condensate storage tanks from which condensate may be admitted by gravity and vacuum drag into the condenser for deaeration.

The condenser hotwell supplies the necessary suction head for the condensate pumps. The condensate pumps supply condensate to the deaerators, through the Condensate Demineralizer System.

There are four sampling lines located at the low pressure condenser shell which permit taking grab samples of the condensate in each of the four cross-over lines between the low pressure and high pressure condenser shells. In addition, the condensate pump common discharge is connected to the sampling system, permitting monitoring of the conductivity of the condensate downstream of the condensate pumps but upstream of the condensate demineralizers. Condenser inleakage of circulating water is indicated by high conductivity of the condensate. The location of the leakage can be further identified by taking grab samples of the condensate in the cross-over lines.

10.4.1.3 Safety Evaluation

There is no potential for hydrogen buildup in the condenser.

During normal or shutdown operation, no radioactive contaminants are anticipated in the condenser. However, in the event that steam generator tube leakage occurs at the same time that a failed fuel condition exists, contamination could occur in the main condenser hotwell.

Chloride ions in sufficient concentration and at elevated temperatures can crack austenitic stainless steels. They normally do not cause stress-corrosion cracking at temperatures below 140°F and/or at levels below 1000 ppm of chloride ion. These temperature and concentration conditions are not exceeded in the Circulating Water System during normal operation of the station (see Subsection 10.4.5.2.2). Stress concentrations in the stainless steel condenser tubes have been minimized during tube manufacture by stringent quality control and subsequent tube-rolling operations through control of dimensional tolerances of tubes and tube holes.

It is expected that the precautionary measures described above prevent stress-corrosion cracking of the Type 304 stainless steel condenser tubes.

10.4.1.4 Instrumentation

Operating instrumentation to permit adequate monitoring of condenser performance includes the following:

a. Hotwell level indication and high/low alarms.

b. Vapor pressure and temperature.

c. Hotwell temperature.

d. Hotwell water chemistry (hand extracted samples).

e. Condensate pump discharge chemistry.

10.4.1.5 Tests and Inspection

The condenser water boxes were pressure tested during construction. Condenser leak testing is performed as needed.

10.4.2 Main Condenser Vacuum System

10.4.2.1 Design Bases

The main condenser vacuum system is designed to evacuate the condenser, turbine main steam piping, and steam generators prior to NSSS warm-up and assist in holding a vacuum during turbine startup and normal station operation.

Vacuum equipment design is based on the standards of the Heat Exchanger Institute, the American Society for Testing and Materials, and the Hydraulic Institute,

10.4.2.2 System Description

The vacuum equipment removes air from the deaerating sections of the main condenser and discharges it to the station vent. A functional drawing of this system is shown in Figure 10.4-1.

One motor driven mechanical vacuum hogger and one steam jet hogger are provided for evacuation of the condenser and steam system for NSSS warm-up and turbine startup. They are also available for holding condenser vacuum in the event that the main steam jet air ejectors are out of use. Each hogger is capable of evacuating the main condenser from atmospheric pressure to 3 inches HgA.

The steam jet hogger is designed for a maximum evacuation time of 90 min. from atmospheric pressure to 10 inches HgA (steam generator vacuum at startup). The mechanical hogger is designed for a maximum evacuation time of 180 minutes.

One twin-element steam jet air ejector is provided for condenser vacuum holding during normal station operation. The ejector has a total minimum capacity of 50 scfm dry air, taking its suction from 1.0 inch HgA at 71.5°F saturation temperature.

Motive steam is obtained from the 235 psig auxiliary steam header and condensed in a combined inter and after condenser. Condensate from the condensate pumps passes through the stainless steel tubes of the unit, and the condensed steam is returned to the condenser. Non-condensables and a small quantity of water vapor are discharged to the station vent.

The discharge to the station vent is continuously monitored by at least one of two off-line detectors for Xe-133 in order to detect a primary to secondary leak in the steam generators. There are a gamma detector and a beta detector that alarm. Alarm setpoints are set according to the Offsite Dose Calculation Manual.

If there is a radiation problem, the vacuum system discharge line has a vent filter that may be valved into operation to remove the radioactive material in the discharge prior to discharge to the station vent.

Each of the L.P. and H.P. condenser shells has a motor operated valve attached to it. The motor operated valve vents the condenser to atmosphere to break vacuum and quickly slow down the turbine.

10.4.2.3 Safety Evaluation

An offgas monitoring system continuously monitors for the presence of radioactivity in the non-condensable gases, which would indicate a primary to secondary leak in the steam generators. The sampler is located in the air ejector vent line. Loss of the steam jet air ejector during normal operation automatically brings the mechanical vacuum hogger into operation. An alarm is initiated in the event that the radioactivity exceeds a preset limit The radiological evaluation is provided in Chapter 11.

10.4.2.4 Instrumentation

Operational parameters, for which instrumentation is provided, include the following:

a. Orifice air leakage

b. Evacuation pressure at hogger or air ejector inlet

c. Off-gas temperatures

d. Off-gas radioactivity

10.4.2.5 Tests and Inspection

Pressure containing parts have been hydrotested. Performance tests were conducted per the ASME Power Test Codes and HEI Standards. This equipment is available for inservice inspection at all times. All major components are periodically tested to insure reliable performance.

10.4.3 Turbine Gland Sealing System

10.4.3.1 Design Bases

The turbine gland sealing system provides steam to the shaft seals to provide sealing of the turbine shaft between the turbine shells or exhaust hood and the atmosphere. The sealing system prevents leakage of air into the condenser and prevents steam from blowing into the turbine room. This system provides these functions from startup to full load. All piping meets the requirements of ANSI B31.1.0.

10.4.3.2 System Description

Functional drawings of this system are shown in Figures 10.4-2 and 10.4-2A.

On cold startup of the steam generators, sealing steam is provided by the auxiliary boiler. Steam flow to the shaft seals is controlled by a steam feed control valve and unloading valves. A small quantity of steam leaks into the turbines while the remainder is exhausted through an exhauster system. The exhauster is a shell and tube heat exchanger with two motor driven blowers which maintain a pressure slightly below atmospheric on the low pressure side of the packings. Condensate from the discharge of the condensate pumps condenses the steam. Drains from the exhauster are returned to the main condenser, while the non-condensable and some vapor are discharged to atmosphere. Excess steam from the unloading header is returned to the main condenser or the lowest pressure feedwater heater. When the steam generator has been brought up to full pressure, the auxiliary steam source may be closed and main steam provides sealing. As the turbine is brought up to load, steam leakage past the H.P. turbine H.P. seals enters the steam seal header.

When this leakage is sufficient to maintain seal header pressure, the main steam feed valve closes, and sealing steam to all turbine seals is maintained from the H.P. turbine. The main feed pump turbine sealing steam requirements are also maintained by the main turbine sealing system.

10.4.3.3 Safety Evaluation

During normal operation, sealing steam is continually unloaded to the lowest pressure feedwater heaters. Steam is bypassed to the condenser if both heaters are out of service, as during either turbine trip or startup. In case of a malfunction of one or both of the unloading valves, a motor operated bypass valve may be opened and manually controlled to maintain

steam seal header pressure. During startup operation, a motor operated bypass feed valve can be manually operated to bypass a malfunction of the automatic feed valve.

Exhauster vacuum on the low pressure side of the seals can be maintained with either one blower or both blowers in operation. Loss of both blowers will cause steam to blow through the seals into the turbine room and will necessitate shutdown of the turbine if radioactive leakage into the secondary system has been detected. Otherwise the system may be operated without damage.

A failed steam packing exhauster tube can be plugged during turbine operation by isolating and bypassing the exhauster water side. The blower will continue to operate during this time.

Four relief valves on the steam seal header prevent excessive steam seal pressure. The valves are vented to atmosphere.

10.4.3.4 Instrumentation and Controls

Operating instrumentation to permit adequate monitoring of the turbine steam seal system includes the following:

a. Steam Seal Header Pressure Instrumentation

b. Low Seal Header Pressure Alarm

c. Seal Steam Temperature Instrumentation

d. Steam Packing Exhauster High Level Alarm

e. Seal Steam Return Header High Pressure Alarm

f. Loss of Blower Motor Alarm

g. High and Low Exhauster Drain Tank Alarm

10.4.3.5 Tests and Inspections

The entire steam seal system is readily available for inservice Inspection.

The tube side of the exhauster is designed for the shutoff pressure of the condensate pumps and was hydrostatically tested to 1.5 times this pressure. The shell side is always open to atmosphere.

10.4.4 Turbine Bypass System

10.4.4.1 Design Basis

The turbine bypass system is used during heatup, startup and hot standby of the NSSS to control main steam pressure. Additionally, the system functions to control pressure during load swings as a part of the reactor turbine control system and to remove decay heat and stored heat from NSSS equipment during cooldown.

The turbine bypass system has a nominal capacity of 35% of steam flow at rated NSSS ouput.

The system is composed of an atmospheric vent valve on each steam line between the containment and the main steam isolation valve, and three turbine bypass valves on each steam line downstream of the main steam isolation valves. This system is shown in Figure 10.3-1.

The atmospheric vent valves are used to control cooldown of the steam generator by controlling steam discharge to the atmosphere when the main condenser is not available as a heat sink due to loss of condenser vacuum or main steam isolation valve closure. Each atmospheric vent valve has a nominal capacity of 5% of total steam flow at rated NSSS output. The atmospheric vent valves meet the requirements of ASME Section III for Nuclear Class 2 valves and are designed to operate in maximum ambient conditions of 120°F and 100% relative humidity. The valves are shown in Figure 10.3-1.

The turbine bypass valves are used to control cooldown of the steam generator by controlling steam discharge to the condenser. The turbine bypass valves are capable of discharging a nominal 25% of steam flow at rated NSSS output (total for all 6 turbine bypass valves). The turbine bypass valves are not required for engineered safety features; therefore, the single failure criterion is not applicable. Evaluations have been performed that show turbine bypass valves may be removed from service during normal power operations. The total steam bypass/relief capacity shall remain above the ARTS arming setpoint. Refer to Section 7.4.1.4.2. The turbine bypass valves meet the requirements of MSS-SP-61 and ANSI B16.5. The valves are designed to operate in maximum ambient conditions of 120°F and 100% relative humidity.

Neither the atmospheric vent valves nor the turbine bypass valves are used to meet the code requirements for overpressure protection.

10.4.4.2 System Description

During normal operation, the turbine bypass valves are under control of the Integrated Control System (ICS). During cooldown or hot shutdown, they are manually controlled from the control room.

The atmospheric vent valves operate automatically at a point lower than the normal code valve setting, and the setpoint is adjustable downward in case they need to be used for cooldown. They are controlled by the ICS steam pressure control instrumentation.

When the condenser is available, the turbine bypass valves are the first to relieve excess pressure in the steam generators, followed by the atmospheric vent valves, and then the code safety valves.

10.4.4.3 Safety Evaluation

The effects of inadvertent steam relief or steam bypass are covered by the analysis of the steam line failure given in Chapter 15. The effects of an inadvertent rapid throttle valve closure are also covered by the discussion of loss of full load in Chapter 15.

The consequences of the reactor system transient expected to occur assuming all power operated relief valves in the secondary system fail to open are discussed below.

The secondary system is protected from overpressure by:

a. Spring-Loaded Safety Valves

b. Turbine Bypass Valves

c. Atmospheric Vent Valves

The turbine bypass valves and the atmospheric vent valves are power operated valves. The turbine bypass valves have a relieving capacity of 25% steam flow and the atmospheric vent valves have a relieving capacity of 10% of rated steam flow.

During normal operation, failure of these power operated valves may result in a turbine trip; however, overpressure protection is provided by the spring-loaded safety valves. The spring-loaded safety valves are sized to handle the projected steam release following a turbine trip which is expected to impose the maximum pressure transient on the secondary system. The particulars of the spring-loaded safety valves are included in Subsection: 10.3.1.1.1. The turbine bypass valves are not essential to safe shutdown.

10.4.4.4 Instrumentation

Steam pressure and temperature in this system are monitored by the instrumentation in the main steam system. Valve open indicating lights and position alarming are provided for all bypass and vent valves.

10.4.4.5 Tests and Inspection

The turbine bypass valves and atmospheric vent valves may be tested while the turbine is in operation. All piping and valves are readily available for inservice inspection. Seat leakage through the turbine bypass valves is sensed by thermocouples downstream of the valves. Atmospheric vent valve leakage is monitored visually and via downstream thermocouples. For turbine bypass valves, inservice testing is only performed as required for maintenance purposes. Atmospheric vent valves are tested as part of the Inservice Testing Program.

10.4.5 <u>Circulating Water System</u>

10.4.5.1 Design Bases

The circulating water system is designed to remove 6.69×10^9 BTU/hr lbm the power cycle. The condenser is designed to operate efficiently with circulating water over the range of 50°F to 100°F. The circulating water system is a closed cycle system consisting of the condenser, cooling tower, circulating water pumps, makeup pumps, and water chlorination system and chemical feed system.

System structural integrity and functional capability design is based on a computerized hydraulic transient analysis for the open canal and closed conduits.

10.4.5.2 System Description

10.4.5.2.1 General

Four equal capacity, motor driven, horizontal split-case circulating water pumps take suction from the common discharge channel from the cooling tower basin and supply cooling water to the two halves of the low pressure shell of the dual pressure condenser. Each half is supplied by two pumps. The circulating water leaves the condenser at the two high pressure shell outlet

waterboxes in two independent steel pipes and returns to the cooling tower. A provision is made for cross-connecting the inlet low pressure shell waterboxes to equalize flow through each tube bundle and allow for less than four pump operation.

A natural draft hyperbolic cooling tower rejects the heat from the circulating water. Circulating water loss from the cooling tower occurs by evaporation and blowdown. A makeup water system replaces these losses.

Blowdown is accomplished downstream of the circulating water pumps and is controlled to maintain a dissolved solids concentration ratio. Slime and algae control is achieved by a chlorination system, which includes the addition of a Sodium Bromide solution to the Sodium Hypochlorite (NaOCl) to enhance the biocidal effectiveness of the water treatment without increasing the level of chlorine. Should the Sodium Bromide portion of the system not be available, Sodium Hypochlorite solution may be used alone.

The primary source of makeup water is the Service Water System which is connected to the circulating water pump suction lines. Also, two vertical turbine pumps, located on the intake structure, can supply lake water as an alternate source of makeup water. Blowdown is not accomplished from a circulating water line when the same line is supplied with makeup.

The following is a description of the Sodium Hypochlorite (NaOCl) and Sodium Bromide (NaBr) addition system for the circulating water system:

a. A dike enclosed 7500-gallon NaOCl storage tank is used for supplying the station chlorination system.

b. A dike enclosed 4500-gallon NaBr storage tank is used for supplying the station chlorination system.

c. NaOCl was selected for station chlorination to replace the chlorine gas supply system. NaOCl is not considered to be a hazard to site personnel and therefore eliminates the requirement of control room monitoring of chlorine gas.

d. NaBr is not considered to be a hazard to site personnel.

Circulating water system ruptures are described in Section 3.6.2.7.2.13.

In the event of a circulating system rupture, no essential equipment will be adversely affected, and a safe shutdown is possible.

A functional drawing is shown in Figure 10.4-4.

10.4.5.2.2 Water Chemistry

A typical analysis of Lake Erie water based on a mathematical average of samples taken 50 to 100 feet from shore from November 1968 to October 1970 is given below (all constituents expressed as ppm $CaCO_3$).

Cations

Calcium 113

Magnesium	45
Sodium	25

Anions

Chloride	31
Sulfate	39
Nitrate	10
Phosphate	2
Bicarbonate	89
Carbonate	12

A concentration factor of 2 was chosen for the cooling tower system, which requires a blowdown approximately equal to the evaporative losses. The resulting concentration of dissolved solids is approximately twice that of the makeup water from the lake. This concentration factor was chosen to reduce the problems of scale formation on condenser tubes and to keep the dissolved solids in the blowdown water within reasonable levels. The amount of makeup water required at this concentration factor also permits the Service Water System discharge to serve as makeup, since these quantities are approximately equal, and thereby reduces the amount of discharge to the lake.

Chlorination of the Circulating Water System is done on a periodic basis to prevent algae growth within the system. Sodium Hypochlorite and a Sodium Bromide solution are mixed to enhance the biocidal effectiveness of the water treatment without increasing the level of chlorine and together are injected into those circulating pump suctions whose discharges are not providing blowdown water. Should the Sodium Bromide portion of the system not be available, Sodium Hypochlorite may be used alone. In this way, blowdown water contains essentially nofree chlorine residual and the chloride content is unchanged. A chemical feed system is used to reduce scaling tendencies of the circulating water and disperse silt. Treatment increases the sulfate content of the water to more than 80 ppm.

Since the system water, in passing through the cooling tower, is in intimate contact with air to accomplish the cooling, the outlet water contains an oxygen content which is essentially at the saturation level corresponding to the cold water outlet temperature. The oxygen content for the highest tower outlet temperature will be 7 ppm.

10.4.5.3 Safety Evaluation

There is no dependence on this system for any engineered safety feature.

The cooling tower is located a considerable distance from the Containment, Auxiliary, and Turbine Building complex. The tower is 493 feet high, constructed of noncombustible material, and its base is located about 700 feet from the closest structure, the Emergency Diesel Generator fuel oil storage tanks. These tanks are tornado missile protected as described in Section 9.5.4.2. In addition, since it is smaller at the top, the tower would tend to collapse inwardly. Therefore, the probability for debris damaging any station structure is extremely small.

For elevation drawings showing the water level in the Turbine Building at various times after a complete rupture of the main condenser circulating water rubber expansion joint, refer to Subsection 3.6.2.7.2. Included in the discussion are passageways, pipe chases, cableways, and all other possible flow paths joining the flooded space to other spaces containing essential electrical systems and components is also discussed.

The means are provided to detect a failure in the Circulating Water System. Refer to Subsection 3.6.2.7.2.13. Also described is how flow will be stopped.

10.4.5.4 Instrumentation

Operating instrumentation provided to monitor performance of this system includes the following:

a. Circulating water temperature and pressure to and from the condenser

b. Differential pressure across each condenser shell half

c. Screen structure low level alarm

d. Makeup and blowdown water flow

e. Cooling tower basin level and low and high alarms

f. Traveling water screens' high level differential alarms

10.4.5.5 Tests and Inspections

All active components of the system are accessible for inspection during station operation.

The cooling tower has been tested in accordance with the ASME Power Test Code for Atmospheric Water Cooling Equipment, PTC-23.

The circulating water pumps and makeup pumps have been hydrostatically tested. Performance tests are conducted in accordance with the standards of the Hydraulic Institute.

Performance, hydrostatic, and leakage tests have been conducted on the circulating water system butterfly valves in accordance with AWWA C-504.

10.4.6 Condensate Demineralizer System

10.4.6.1 Design Bases

To meet the rigid limitations on impurities entering the steam generators, condensate flow is processed through a polishing demineralizer system. The demineralizers are designed to process full condensate flow and maintain a high degree of effluent purity as required by the steam generators.

Of the total feedwater flow to the steam generators, only Nos. 4, 5 and 6 feedwater heater drains and heating steam to the deaerators, or 32% of flow at rated load, are not processed through the demineralizers.

The demineralizers remove dissolved ionic species and suspended solids from the influent.

The design of the demineralizers is based on the applicable standards of ANSI, ASME, ASTM, and the Hydraulic Institute.

10.4.6.2 System Description

A functional drawing is shown in Figure 10.4-8.

The system consists of the following major items:

a. Polishing demineralizer service units with resin retaining elements and individual holding pumps.

b. A precoat tank and a resin tank with precoat pump.

c. A backwash system.

d. A backwash receiving tank and two sump pumps.

e. Two holdup tanks and one transfer pump.

f. A master control panel.

The demineralizers are set up for parallel operation for processing condensate flow upstream of the No. 2 low-pressure feedwater heaters. The condensate flow is divided among the units in operation. When resin replacement is required, the affected unit or units are placed on hold with the condensate flow bypassed. Spent resin from exhausted units may be backwashed either to the Backwash Receiving Tank or directly to the Condensate Polisher Demineralizer Holdup Tanks. If backwashed to the Backwash Receiving Tank, it may be sampled for radioactivity before being pumped to either the settling basin or the Condensate Polisher Demineralizer Holdup Tanks.

10.4.6.3 Safety Evaluation

If radiation is detected in the main steam line and steam jet air ejector exhaust, the demineralizers are monitored for radioactivity level. Backwashes are transferred to the condensate polishing demineralizer holdup tanks and then processed as low level radwaste.

The maximum limits for demineralizer effluent water quality are as follows:

pH @ 25°C	≥ 9.3
Corrected cation conductivity	0.2 μS/cm
Sodium	3 ppb
Chloride	5 ppb
Fluoride	5 ppb
Sulfate	3 ppb
Silica (as SiO_2)	10 ppb
Iron (membrane)	10 ppb

There is no contribution to the reactor coolant system activity levels from the secondary system impurity levels.

10.4.6.4 Instrumentation

Condensate samples are taken before and after the demineralizers at various locations of the condensate and feedwater system.

Operating instrumentation provided to monitor performance of this system includes the following:

a. Differential pressure across each unit, including a high differential pressure alarm

b. Condensate flow to each unit, including low and high flow alarms

c. Deleted

d. Deleted

e. High differential pressure alarm across the entire demineralizer package

f. Backwash pump flow

g. Precoat pump flow

h. Precoat tank low level alarm

i. Backwash receiving tank high alarm

j. Deleted

k. Holdup tanks level indicators

Controls are provided for automatic flow balancing between units on stream. Remote manual operation is also available. Valve position and operating status of each demineralizer unit are indicated on the control panel, providing indication as to which automatic sequence is in progress.

10.4.6.5 Tests and Inspections

During normal operation, all of the equipment is readily available for inspection. The holdup tanks are located in a separate enclosed room which is isolated during periods when radioactivity has been detected in the secondary system and a backwash has been transferred to the tanks.

All pressure-containing components of the condensate polishing demineralizer system were hydrostatically tested before installation. Tests were performed after installation to verify performance requirements.

10.4.7 <u>Condensate and Feedwater Systems</u>

10.4.7.1 Design Bases

The design, materials, and details of construction of the feedwater heaters are in accordance

with both the ASME Code, Section VIII, Unfired Pressure Vessels and Heat Exchange Institute standards for open and closed feedwater heaters.

All piping meets the requirements of ANSI B31.1.0 except as follows:

a. All feedwater piping from the main feed pumps to the containment isolation valves is upgraded for critical service.

b. All piping into the containment structure from and including the isolation valves meets the requirements of ASME, Section III, Class 2 Piping.

Criteria for the main feedwater and steam generator drain isolation valves is given in Subsection 6.2.4.

All piping and equipment are designed for environmental temperatures of 60-130°F at 100 percent relative humidity.

10.4.7.2 System Description

The condensate and feedwater functional drawings are shown in Figures 10.4-8, 10.4-11, 10.4-12 and 10.4-12A.

The condensate pumps take suction from the condenser hotwell and discharge through the steam jet air ejector and steam packing exhauster. Two or three condensate pumps may be operated to satisfy system flow requirements. The condensate then goes through two No. 1 heaters in the condenser necks, condensate polishing demineralizers, and two No. 2 heaters in the condenser necks. The condensate continues into two No. 3 heaters downstream of the No. 2 heaters. These two No. 3 deaerating heaters heat and deaerate the condensate using steam from the fourth extraction point at loads above 25 percent. At lower loads steam comes from an auxiliary steam header. During a cold startup, steam from the auxiliary boiler is used in the deaerator. The deaerator storage tanks hold slightly more than four minutes of feedwater requirement at rated NSSS capacity.

The feedwater cycle is a closed system with deaeration accomplished in the main condenser and two one-half capacity deaerators. Six stages of feedwater heating (including the deaerators) are incorporated. Chemical injection is provided for pH control and oxygen removal. Condensate polishing demineralizers provide impurity control.

The feed pump system takes suction from the deaerators through two low speed booster pumps driven through gear reduction units from the feed pump driving turbines. The booster pumps discharge into the full speed feed pumps direct-connected to the driving turbines. These turbines are variable speed units controlled by the Integrated Control System, which controls feedwater flow to the two steam generators. There are individual control valves to each steam generator to divide flow between the steam generators.

The feed pump turbines take motive steam from the main turbine system downstream of the reheaters and ahead of the low pressure turbine sections. For low load operation, steam is supplied directly from the main steam lines. These feed pump turbines exhaust into the main condenser. The two feed pumps discharge in parallel trains through the No. 4, No. 5 and No. 6 high pressure feedwater heaters.

All drains from the high pressure heaters are cascaded to the next lower pressure heater at

normal loads ending in the deaerator (No. 3 heater). The moisture separators and the first stage reheat drain to the No. 5 heaters. The second stage reheater section drains to the No. 6 feedwater heaters. The No.2 feedwater heaters drain to the No. 1 heaters, and the combined drains are either pumped forward or drained via loop seal to the condenser.

All feedwater heaters have stainless steel tubes, and the deaerators have stainless steel internals.

In addition to the two turbine driven main feedwater pumps a motor driven feedwater pump is installed to provide feedwater to the steam generators during plant startup and shutdown and for oxygen removal during feedwater cleanup. During plant operation when reactor power is less than 40%, the motor driven feedwater pump may be aligned to supply feedwater from the deaerator storage tanks via the main feedwater system to the steam generators. Above 40% power the turbine driven main feedwater pumps supply the normal feedwater requirement and the motor driven feedwater pump is re-aligned as a backup auxiliary feedwater pump (see Section 9.2.8). These original alignment considerations for the Motor Driven Feedwater Pump (MDFP) only allowed the pump to be aligned in the main feedwater mode or the auxiliary feedwater mode. An evaluation was done to allow aligning the MDFP suction to the main feedwater system while aligning the discharge to the auxiliary feedwater system during Mode 4. This alignment is not intended for plant cooldown to Mode 5 or plant heat up to Mode 3. The startup feed pump has been repowered and may be used as a backup to the motor driven feedwater pump in Modes 4, 5, and 6 (see Section 3.6.2.7.2.12). It can also be used in Modes 1, 2, or 3 in the event that the main feedpumps, auxiliary feedpump, and motor driven feed pump are unavailable.

A separate and independent chemical feed system is provided for the turbine cycle condensate and feedwater system. One ammonia (or pH control chemical) feed tank and feed pump to control pH and one hydrazine (or other oxygen scavenging chemical) feed tank and feed pump to minimize oxygen concentration are provided for direct chemical injection into the feedwater system. A spare chemical injection pump is on standby for manual startup.

10.4.7.3 Safety Evaluation

System transients or malfunctions include the following automatic control actions:

a. Feedwater flow lagging feedwater demand results in a reduction in power demand

b. Low feedwater temperature results in a reduction in flow demand

c. High level in the steam generators results in a reduction in feedwater demand

d. Low level in the steam generators results in an increase in feedwater demand

e. Loss of one main feedwater pump results in station runback to 55 percent full power

f. Loss of two main feedwater pumps starts the turbine driven auxiliary feedwater pumps (to maintain minimum steam generator level)

There is a high water level control on each feedwater heater to divert drains from any heater to the condenser, in case of high water level.

When the feedwater heaters experience a high high level, interlocks close the valves permitting steam to flow to the feedwater heaters while simultaneously opening those which permit the excess steam to flow to the condenser. At lower loads some of the heaters are drained to the condenser. The operator may want to bypass all heater drains to the condenser for purification at loads below 30 or 40 percent when starting up and shutting down the unit.

There are feedwater bypasses around each low pressure heater and around each train of high pressure heaters to allow removal of heaters from service while the others continue to function.

The station can carry more than half load with one string of the feedwater heaters out of service and entirely isolated from the system.

The worst case transient conditions resulting from feedwater flow increase are discussed in Subsection 15.2.10.

During power operation, the startup valve is in the full open position after about 15% load.

Rupture of a feedwater pipe outside of the containment releases radioactivity to the environment only if primary-to-secondary leakage exists. Any radioactive releases of this type would be limited to a small fraction of 10CFR100 limits, assuming prior operation at the Technical Specification limits for secondary coolant system specific activity and primary-to-secondary leakage. See Subsection 3.6.2.7 for the environmental effects of a main feedwater line rupture.

The location, physical separation, or protective barriers provided for the main and auxiliary feedwater pumps to ensure their operation, if flooding or gross failure of adjacent components or structures were to occur, are as follows:

The main feed pumps are located in the Turbine Building and are not essential equipment. Therefore, no provisions are made for physical separation and protective barriers. Discussion pertaining to the auxiliary feedwater pumps is located in Section 3.6.

Subsection 3.6.2.7.2 provides a description and discussion of the potential for and consequences of a condensate line rupture in the Turbine Building or other structures housing portions of the system. The discussion includes the effects of condensate line rupture on safety related systems.

A comprehensive secondary water chemistry monitoring and control program is employed to inhibit potential steam generator tube degradation. The program includes:

(a) sampling schedule and control points for critical parameters

(b) procedures for quantifying critical control point parameters

(c) numerous process sampling points

(d) procedures for the recording and management of data

(e) procedures defining corrective actions for off-control point chemistry conditions

(f) a clear delineation of organizational authority and responsibility for the interpretation of data

(g) procedures detailing the administrative actions required for initiation of corrective actions for off-control point chemistry conditions.

Maintaining the steam generator feedwater within the specified limits will control the introduction of potentially corrosive impurities into the steam generators and thereby minimize tube degradation.

Secondary water chemistry control chemicals stored in the station are controlled in accordance with EPA and OSHA requirements to prevent becoming a personnel or environmental hazard.

Should a failure occur in the supply piping from the tanks, there are no adverse effects since the concentrations of the chemicals in the piping as well as in the feed tanks are very low.

10.4.7.4 Instrumentation

Operating instrumentation to permit adequate monitoring of the condensate and feedwater system includes the following alarms:

a. Low pressure at each booster feedwater pump suction

b. High or low water level in the steam generators

c. High or low pressure in the steam generators (alarmed through the station computer)

d. Low or high deaerator storage tank level

e. Maximum load limit, feedwater pumps limits, reactor coolant pump limits, or steam generator high level limit

f. Feedwater flow limited by reactor power or reactor power limited by feedwater flow.

10.4.8 Steam Generator Blowdown System

10.4.8.1 Design Bases

All steam generator blowdown piping meets the requirements of ANSI B31.1.0 except as follows:

a. All piping from the steam generators to and including the containment isolation valves meets the requirements of ASME Section III, Class 2-piping

b. All piping from the containment isolation valves to the turbine building wall anchors is upgraded for seismic considerations

Criteria for the blowdown system containment isolation valves is given in subsection 6.2.4.

All piping and equipment are designed for environmental temperatures of 60-130°F at 100 percent relative humidity.

10.4.8.2 System Description

The steam generator blowdown system (SGBS) functional drawing is shown in Figure 10.3-1.

During startup, shutdown, and at low power levels, steam generator water chemistry is stabilized by blowing down through the four 1 ½" lower tube sheet drains at each steam generator. These drain lines are tied to a 4" header, one for each steam generator, and are routed inside containment to enter the auxiliary building in Room 236. Both 4" lines then run into Room 314 where they exit the auxiliary building through the wall into the turbine building. A drag valve has been installed in each line at the condenser inlet to take the required pressure drop from steam generator operating pressure to condenser vacuum. During all modes of power operation, these lines are either left full and pressurized up to the drag valves or they can be depressurized from the containment isolation valves to the drag valves and these lines will be filled before the containment isolation valves are opened. This will preclude the possibility of water hammer resulting from voids developing in the lines due to condenser vacuum.

The drag valves are pneumatically operated and flow rates are regulated from the control room feedwater panel.

Automatic closure of valves MS 603 and MS 611 for the two steam generator blowdown lines is provided through an isolation trip of the steam and feedwater line rupture control system (SFRCS). See subsection 7.4.1.3 for a description of the SFRCS.

10.4.8.3 Safety Evaluation

There is no dependence on this system for any engineered safety feature with the exception of containment isolation. See subsection 6.2.4 for a discussion of containment isolation.

Rupture of the SGBS piping outside of the containment releases radioactivity to the environment only if primary-to-secondary leakage exists. Any radioactive releases of this type would be limited to a small fraction of 10CFR100 limits, assuming prior operation at the Technical Specification limits for secondary coolant system specific activity and primary-to-secondary leakage. See subsection 3.6.2.7 for the environmental effects of a SGBS line rupture.

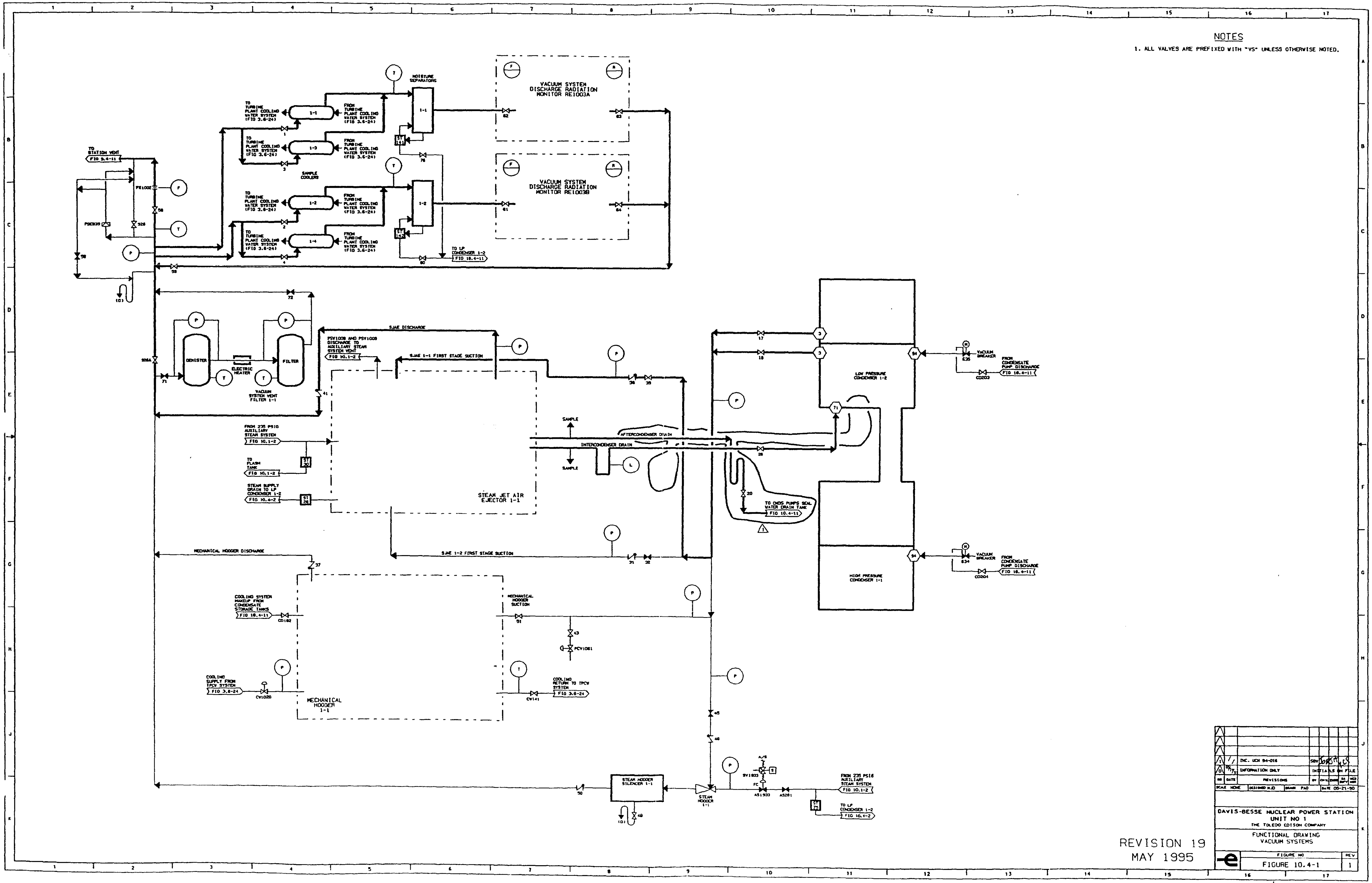
10.4.8.4 Instrumentation

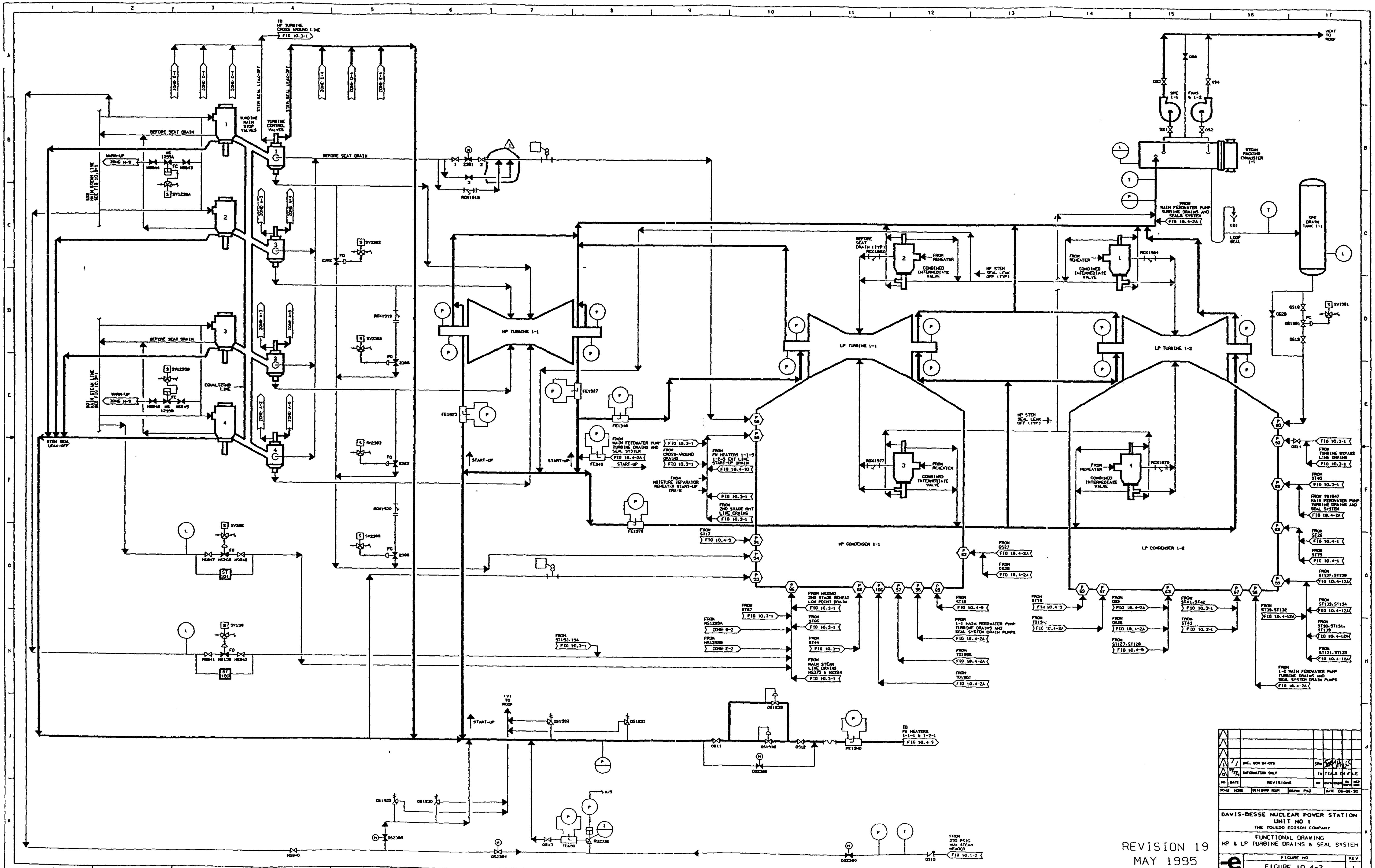
Hand controllers and valve position indicators for the drag valves are located in the control room on the feedwater control panel.

10.4.8.5 Tests and Inspections

All active components of the system are accessible for inspection during station operation.

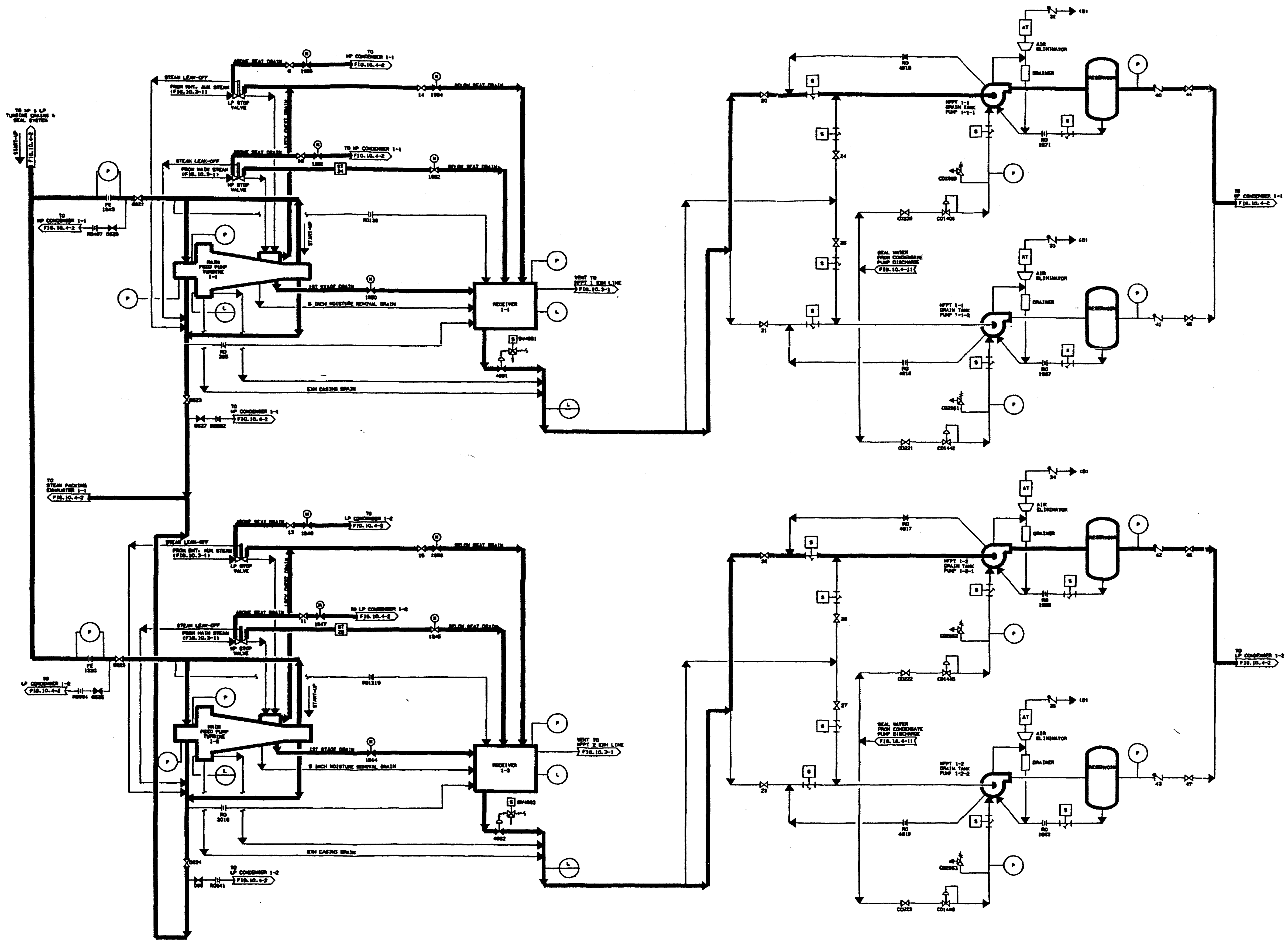
Applicable sections of the piping system are under the auspices of the Inservice Inspection Program per ASME Section XI.


NOTES
1. ALL VALVES ARE PREFIXED WITH "VS" UNLESS OTHERWISE NOTED.
MOISTURE SEPARATORS
VACUUM SYSTEM DISCHARGE RADIATION MONITOR RE1003A
VACUUM SYSTEM DISCHARGE RADIATION MONITOR RE1003B
TO STATION VENT FIG 9.4-11
SAMPLE COOLERS
TO LP CONDENSER 1-2 FIG 10.4-11
DEMISTER
FILTER
ELECTRIC HEATER
VACUUM SYSTEM VENT FILTER 1-1
SJAE DISCHARGE
PSV1008 AND PSV1009 DISCHARGE TO AUXILIARY STEAM SYSTEM VENT FIG 10.1-2
SJAE 1-1 FIRST STAGE SUCTION
FROM 235 PSIG AUXILIARY STEAM SYSTEM FIG 10.1-2
TO FLASH TANK FIG 10.1-2
STEAM SUPPLY DRAIN TO LP CONDENSER 1-2 FIG 10.4-2
STEAM JET AIR EJECTOR 1-1
SAMPLE
AFTERCONDENSER DRAIN
INTERCONDENSER DRAIN
TO CWDS PUMPS SEAL WATER DRAIN TANK FIG 10.4-11
LOW PRESSURE CONDENSER 1-2
HIGH PRESSURE CONDENSER 1-1
VACUUM BREAKER
FROM CONDENSATE PUMP DISCHARGE FIG 10.4-11
SJAE 1-2 FIRST STAGE SUCTION
MECHANICAL HOGGER DISCHARGE
COOLING SYSTEM MAKEUP FROM CONDENSATE STORAGE TANKS FIG 10.4-11
MECHANICAL HOGGER SUCTION
COOLING SUPPLY FROM TPCW SYSTEM FIG 3.8-24
COOLING RETURN TO TPCW SYSTEM FIG 3.8-24
MECHANICAL HOGGER 1-1
STEAM HOGGER SILENCER 1-1
STEAM HOGGER 1-1
FROM 235 PSIG AUXILIARY STEAM SYSTEM FIG 10.1-2
TO LP CONDENSER 1-2 FIG 10.1-2
REVISION 19
MAY 1995
DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY
FUNCTIONAL DRAWING
VACUUM SYSTEMS
FIGURE NO
FIGURE 10.4-1



REVISION 19
MAY 1995

DFN-/USR2/USAR/UFIG1042.DGN
DR 02-16-95



NOTES

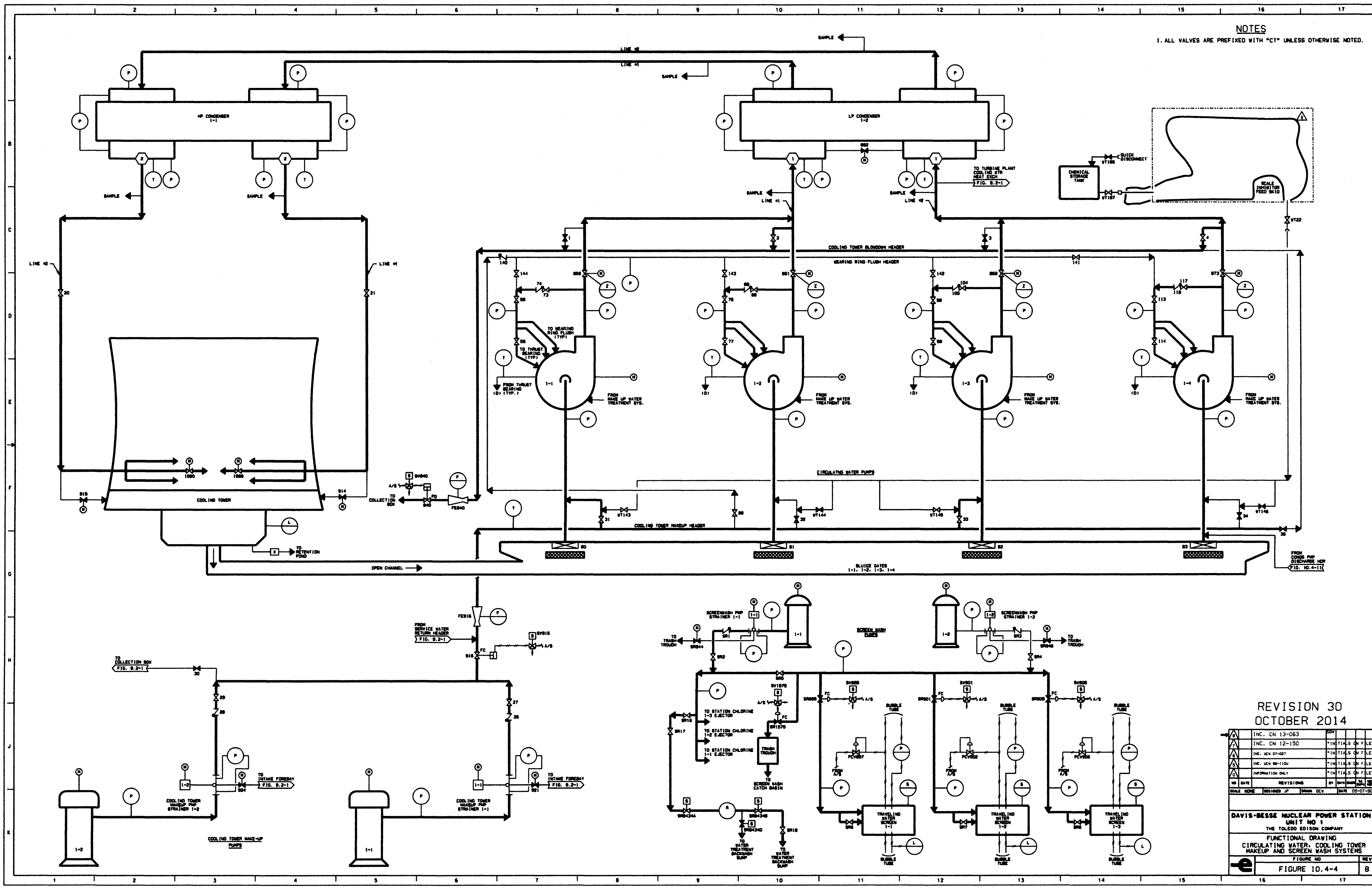
1. ALL VALVES ARE PREFIXED WITH "TO" UNLESS OTHERWISE NOTED.

REVISION 14
JULY 1991

DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
MAIN FEEDWATER PUMP
TURBINE DRAINS AND SEAL SYSTEM

FIGURE 10.4-2A



REVISION 30
OCTOBER 2014

NO	DATE	REVISIONS	BY	CHK	ENGR	SA SUPV	MED MGR
8		INC. CN 13-063	SBW				
7		INC. CN 12-150	"INITIALS ON FILE"				
6		INC. UCN 07-027	"INITIALS ON FILE"				
5		INC. UCN 98-110U	"INITIALS ON FILE"				
0		INFORMATION ONLY	"INITIALS ON FILE"				

SCALE NONE | DESIGNED JP | DRAWN BEV | DATE 05-07-90

DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

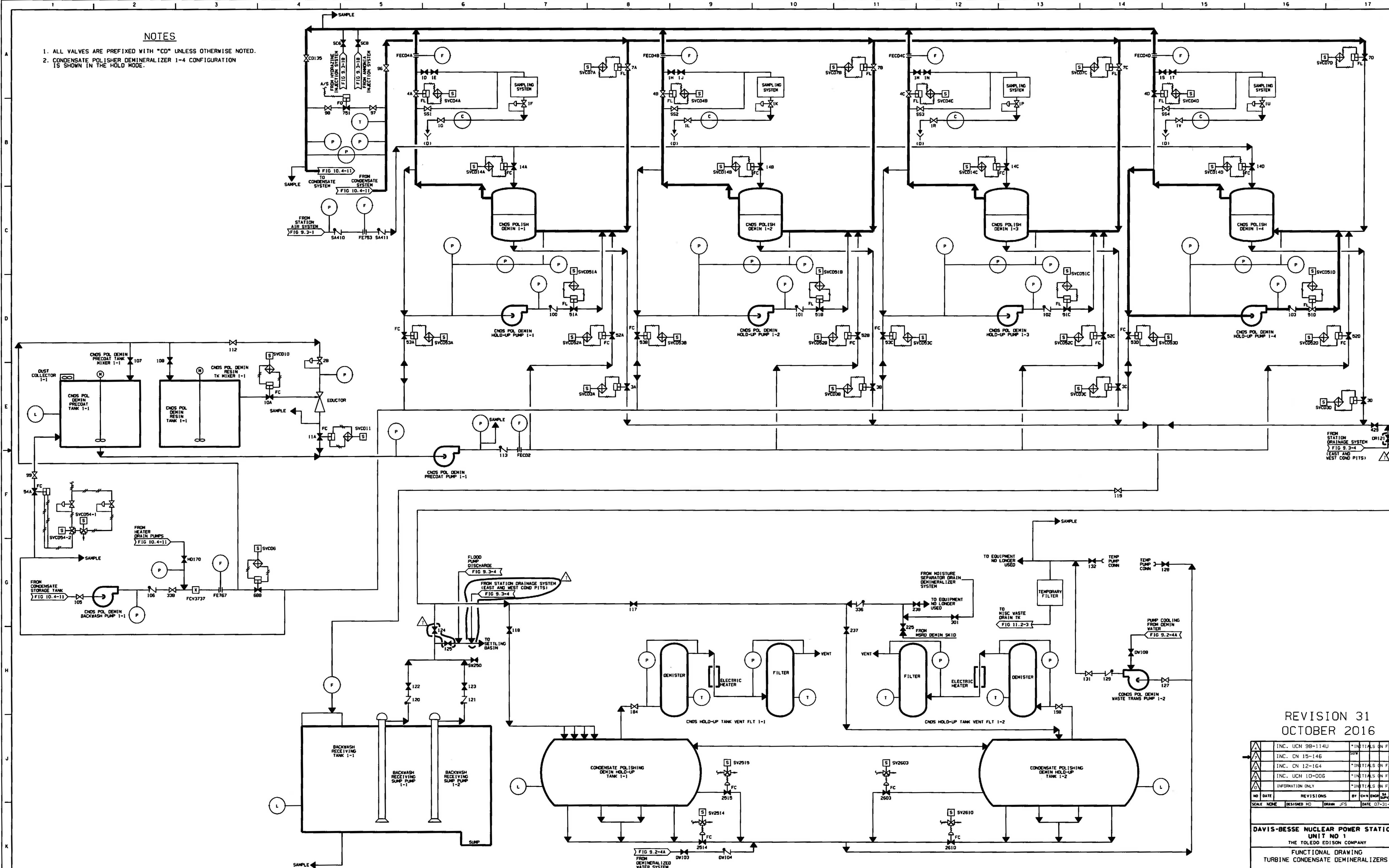
FUNCTIONAL DRAWING
CIRCULATING WATER, COOLING TOWER MAKEUP AND SCREEN WASH SYSTEMS

FIGURE NO: FIGURE 10.4-4 | REV: 8

DFN=/G/USAR/UFIG1044.DGN
DB 02-12-14

NOTES

1. ALL VALVES ARE PREFIXED WITH "CO" UNLESS OTHERWISE NOTED.
2. CONDENSATE POLISHER DEMINERALIZER 1-4 CONFIGURATION IS SHOWN IN THE HOLD MODE.



REVISION 31
OCTOBER 2016

NO	DATE	REVISIONS	BY	CHK	ENGR	SA SUPV	NED MGR
4		INC. UCN 98-114U	"INITIALS ON FILE"				
7		INC. CN 15-146	SBW				
6		INC. CN 12-164	"INITIALS ON FILE"				
5		INC. UCN 10-006	"INITIALS ON FILE"				
0		INFORMATION ONLY	"INITIALS ON FILE"				

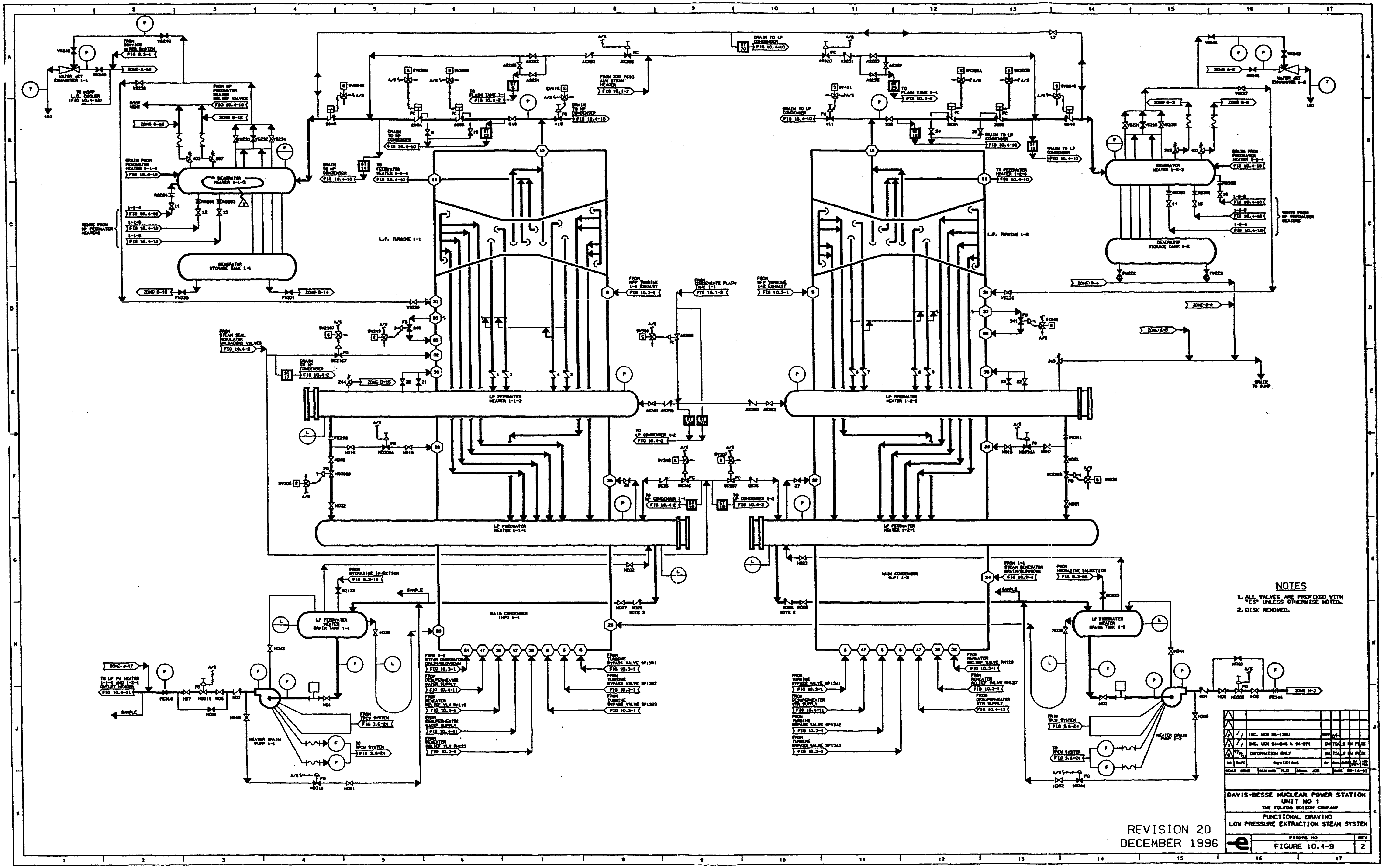
SCALE NONE | DESIGNED MD | DRAWN JFS | DATE 07-31-90

DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
TURBINE CONDENSATE DEMINERALIZERS

FIGURE NO	REV
FIGURE 10.4-8	7

DB: 03-15-16
DFN-/USAR/UFIG1048.DGN



NOTES

1. ALL VALVES ARE PREFIXED WITH "ES" UNLESS OTHERWISE NOTED.
2. DISK REMOVED.

2	/ /	INC. UCN 96-132U					
1	/ /	INC. UCN 94-046 & 94-071	INITIALS ON FILE				
0		INFORMATION ONLY	INITIALS ON FILE				
NO	DATE	REVISIONS	BY				

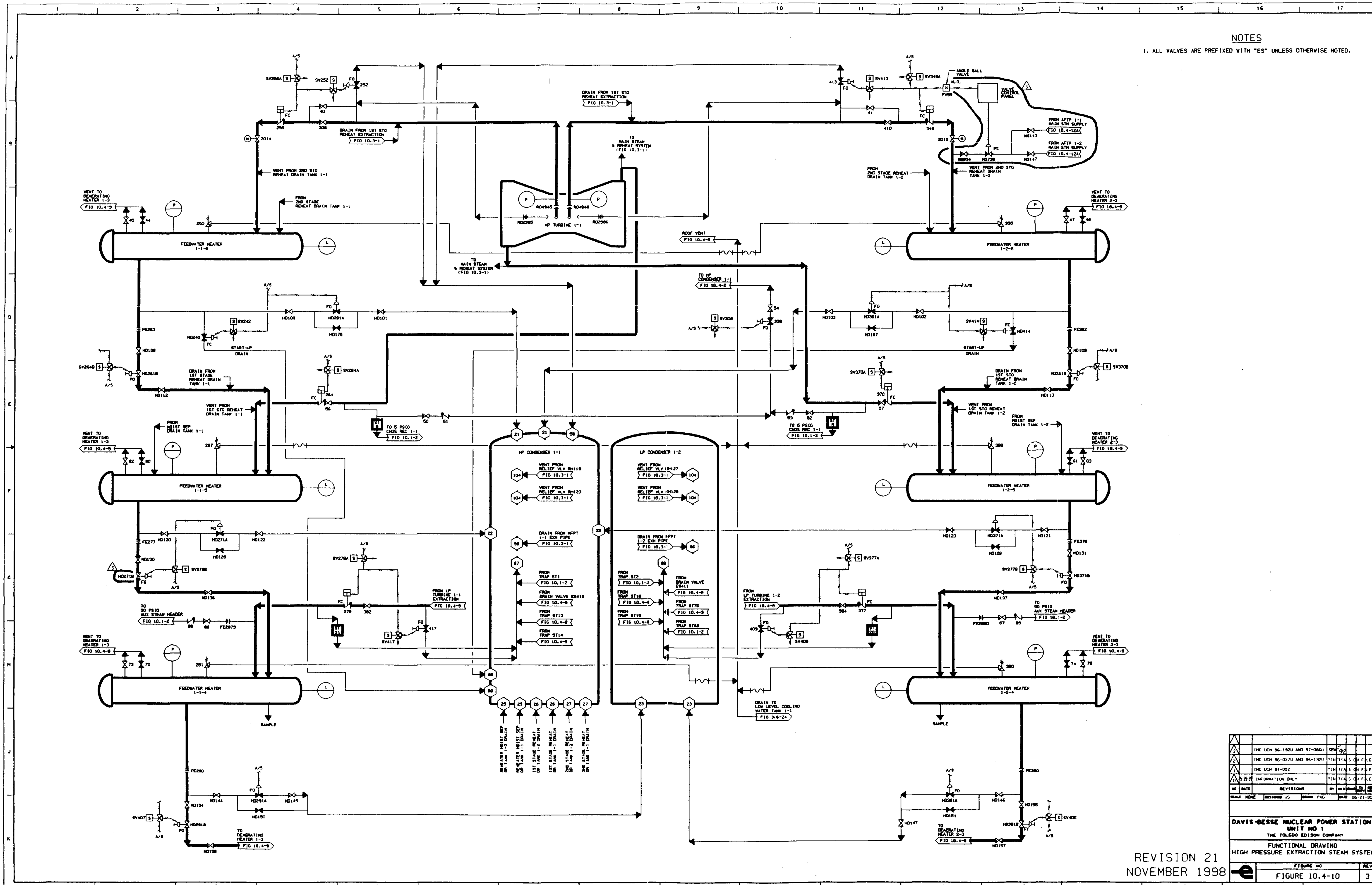
SCALE NONE | DESIGNED HJD | DRAWN JDR | DATE 08-14-80

DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
LOW PRESSURE EXTRACTION STEAM SYSTEM

REVISION 20
DECEMBER 1996

FIGURE NO: FIGURE 10.4-9 | REV: 2



NOTES

1. ALL VALVES ARE PREFIXED WITH "ES" UNLESS OTHERWISE NOTED.

NO	DATE	REVISIONS	BY
3		INC UCN 96-192U AND 97-086U	
2		INC UCN 96-037U AND 96-132U	*INITIALS ON FILE*
1		INC UCN 94-052	*INITIALS ON FILE*
0	5-29-92	INFORMATION ONLY	*INITIALS ON FILE*

SCALE NONE DESIGNED JS DRAWN PAC DATE 06-21-90

DAVIS-BESSE NUCLEAR POWER STATION UNIT NO 1

THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING

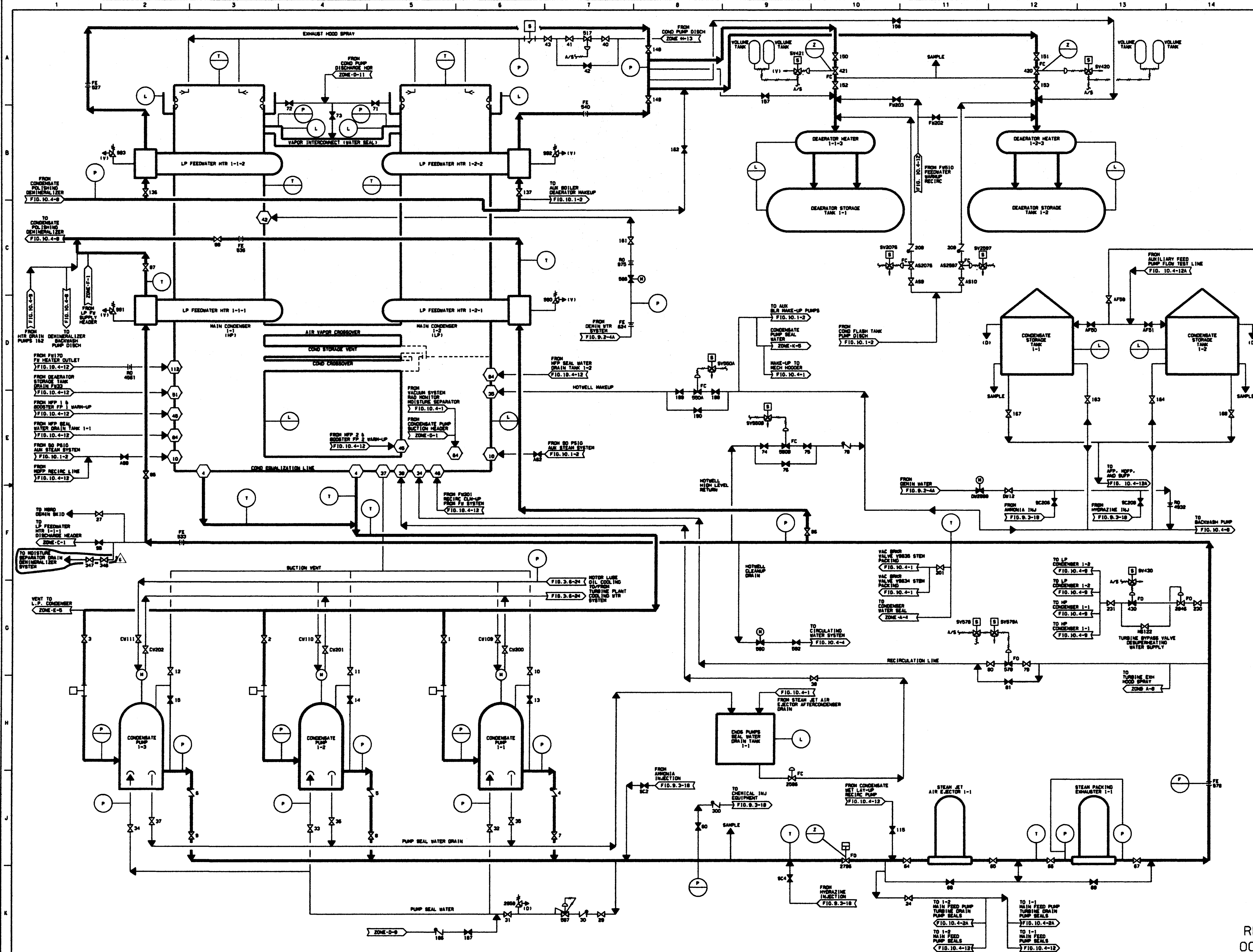
HIGH PRESSURE EXTRACTION STEAM SYSTEM

REVISION 21

NOVEMBER 1998

FIGURE NO: FIGURE 10.4-10 REV 3

DFN=G/USAP/UF110410.DGN
DB 08-04-98



NOTES

1. ALL VALVES ARE PREFIXED WITH "CD" UNLESS OTHERWISE NOTED.

NO	DATE	REVISIONS	BY	CHK'D	ENGR	SA SUPV	MGR
5		INC. UCN 10-064 AND UCN 10-085	"INITIALS ON FILE"				
4		INC. UCN 03-041U	"INITIALS ON FILE"				
3		INC. UCN'S 95-018U AND 95-080U	"INITIALS ON FILE"				
2		INC. UCN'S 94-018, 94-055, 94-087, 94-102 AND 94-154	"INITIALS ON FILE"				
6		INC. CN 12-163	SBW				
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SCALE NONE | DESIGNED JP | DRAWN BEV | DATE 05-08-90

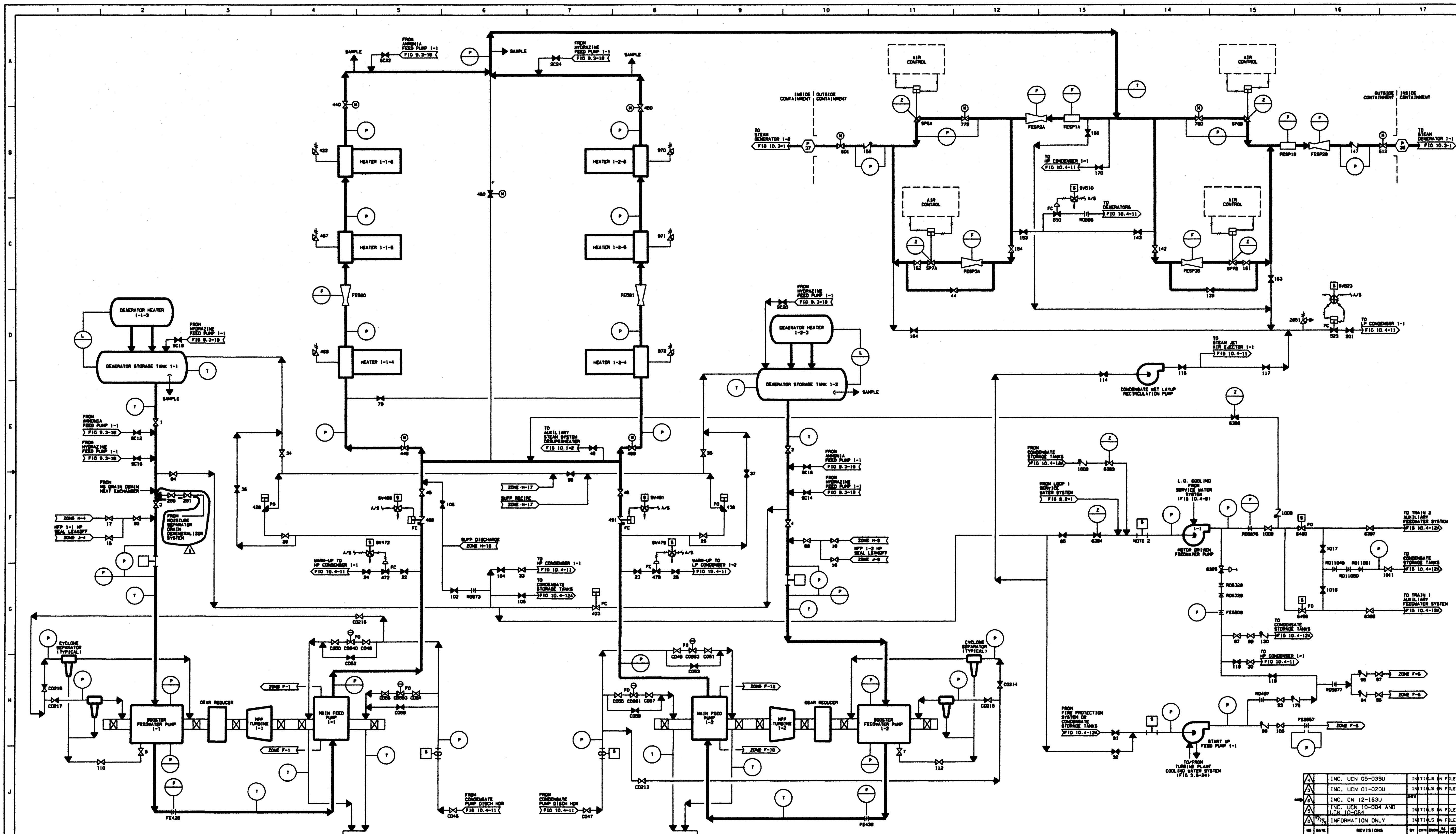
DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
CONDENSATE SYSTEM

REVISION 30
OCTOBER 2014

FIGURE NO: FIGURE 10.4-11 | REV: 6

DFN=/DBNPS2/USAR/UF110411.DGN
DB 02-12-14



NOTES

1. ALL VALVES ARE PREFIXED WITH "FW" UNLESS OTHERWISE NOTED.
2. SCREEN REMOVED.

REVISION 30
OCTOBER 2014

NO	DATE	REVISIONS	BY	CHK'D	ENGR	SA SUPV	NED MGR
4		INC. UCN 05-039U	INITIALS ON FILE				
3		INC. UCN 01-020U	INITIALS ON FILE				
6		INC. CN 12-163U	SBW				
5		INC. UCN 10-004 AND UCN 10-064	INITIALS ON FILE				
0	05/24/91	INFORMATION ONLY	INITIALS ON FILE				

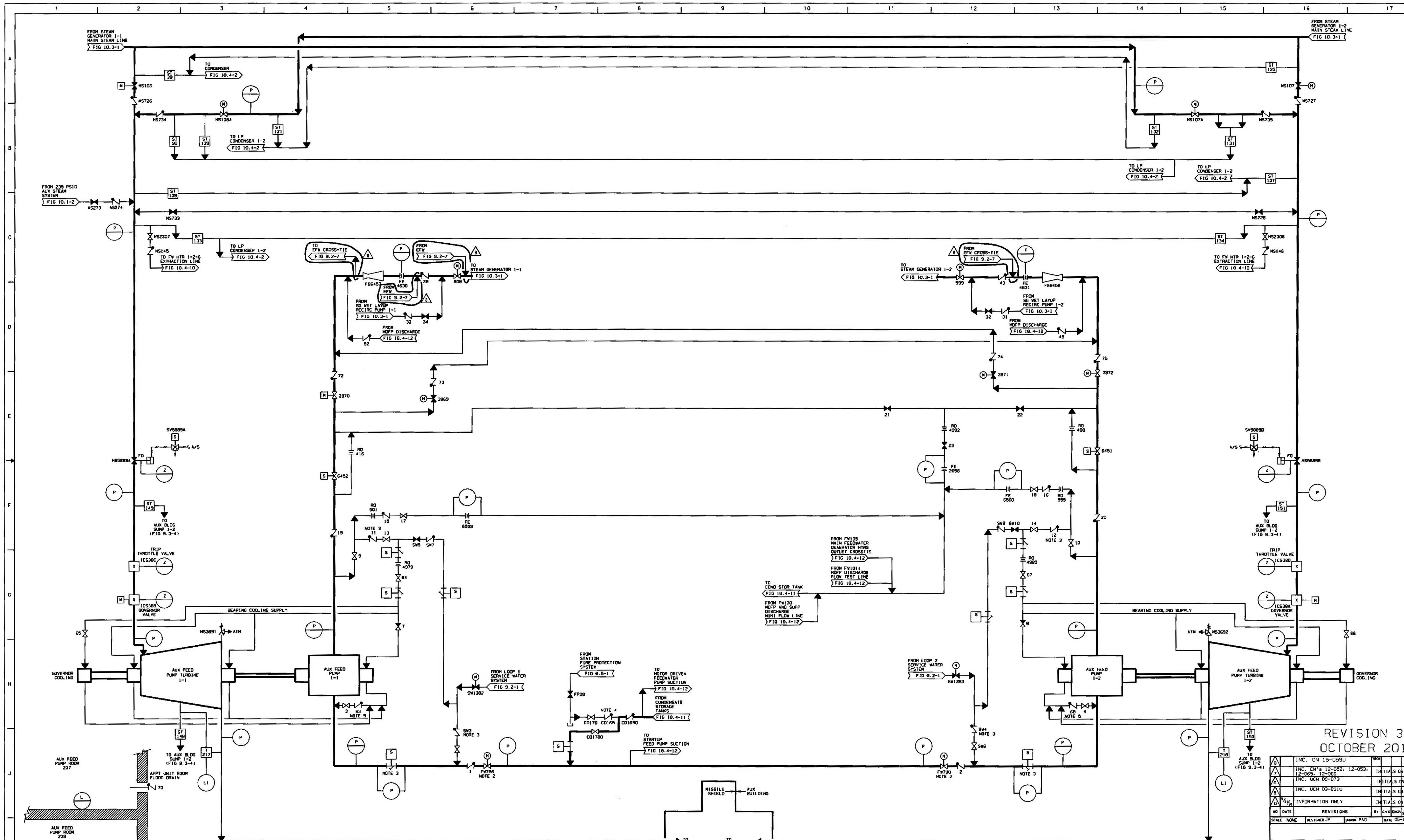
SCALE NONE | DESIGNED JVP | DRAWN HHB | DATE 05-22-90

DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
MAIN FEEDWATER SYSTEM

FIGURE NO: FIGURE 10.4-12 | REV: 6

DFN=/USR2/USAR/UFI10412.DGN
DB 02-12-14



REVISION 31
OCTOBER 2016

NOTES

1. ALL VALVES ARE PREFIXED WITH "AF" UNLESS OTHERWISE NOTED.
2. MOTOR AND INDICATION DISCONNECTED, OPERATED AS A MANUAL VALVE.
3. INTERNALS REMOVED.
4. CHECK VALVE CD169 INTERNALS REMOVED.
5. CHECK VALVES AF63 AND AF68 INTERNALS REMOVED.

NO	DATE	REVISIONS	BY	CH'K	ENGR	SA SUPV	NED MGR
8		INC. CN 15-059U	SBW				
7		INC. CN's 12-052, 12-053, 12-065, 12-066	INITIALS ON FILE				
6		INC. UCN 09-073	INITIALS ON FILE				
5		INC. UCN 03-031U	INITIALS ON FILE				
0	5/29/91	INFORMATION ONLY	INITIALS ON FILE				

SCALE NONE | DESIGNED JP | DRAWN PAG | DATE 05-10-90

DAVIS-BESSE NUCLEAR POWER STATION
UNIT NO 1
THE TOLEDO EDISON COMPANY

FUNCTIONAL DRAWING
AUXILIARY FEEDWATER SYSTEM

FIGURE NO: FIGURE 10.4-12A | REV: 8

DFN=/G/USAR/UF10412A.DGN
DB 06-06-16