GE NUCLEAR ENERGY

TIER 1 DESIGN CERTIFICATION MATERIAL

FOR

THE GE ABWR DESIGN

STAGE 2 SUBMITTAL

MARCH, 1992

EXECUTIVE SUMMARY

GE is currently seeking certification of the Advanced Boiling Water Reactor (ABWR) design under the provisions of 10 CFR Part 52. As endorsed by the NRC commission, the design certification process is proceeding on the basis of a tiered approach. Tier 1 will be the certified Rule and will include a description of the principal design bases and principal design features of the certified design. Tier 1 will also include the inspections, tests, analyses and acceptance criteria (ITAAC) called for by 10 CFR Part 52. Tier 2 will encompass the larger body of design material submitted as part of the certification application as documented in the plant Safety Analysis Report (SAR).

This report presents the Tier 1 material proposed by GE for approximately 40 of the ABWR systems. It also includes Tier 1 entries for generic issues such as Equipment Qualification. In a limited number of areas, ABWR design certification will be based on approval of design acceptance criteria; examples of Tier 1 entries utilizing this concept are also presented.

Plans for GE submittal of ABWR Tier 1 material are based on a staged approach. This report represents fulfillment of the GE commitment to submit Stage 2 at the end of March 1992. Stage 2 is intended to cover approximately 50% of ABWR systems which require Tier 1 treatment. Stage 3 will be the final submittal and will cover all proposed Tier 1 material for the ABWR; this is scheduled for submittal May 31, 1992.

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1.0 Introduction

The GE Advanced Boiling Water Reactor (ABWR) is in the process of obtaining a design certification under the provisions of 10 CFR Part 52. The material in this report supports this process by providing Stage 2 of the proposed Tier 1 material for the ABWR. The complete set of ABWR Tier 1 material (Stage 3) is scheduled for submittal in mid-1992.

Tier 1 is information which will be included in the Certification Rule and includes a brief description of the ABWR design features (the design description), together with the inspections, tests, analyses and acceptance criteria (ITAAC) called for by 10 CFR Part 52.

The form, content and scope of the Tier 1 material required to support the design certification is described in Reference 1 and is the basis for the information in this report. Reference 1 was prepared after extensive GE/industry/NRC interactions on Tier 1 requirements and summarizes what GE believes to be the consensus that was reached on Tier 1 form, scope and content.

This report is structured as follows:

Section 1.1 — A top-level General Plant Description intended to be a Tier 1 design description entry. This material will provide a broad overview of the plant and will address general features and characteristics not covered by the more detailed system material which forms the bulk of the proposed Tier 1 design descriptions. Examples of issues addressed in Section 1.1 are the site plot plan, facility thermal and electrical power output, and major plant thermal-hydraulic parameters. No ITAAC are proposed for the technical entries in Section 1.1.

Section 2 — System-by-system material for the Tier 1 design description and ITAAC entries. This version of the report represents completion of Stage 2 and contains entries for approximately 40 of the ABWR systems which will ultimately receive Tier 1 treatment. Publication of information for the remaining ABWR systems (Stage 3) is scheduled for mid-1992.

Section 3 — Tier 1 entries that fall into the category of generic. This type of entry addresses technical issues that span multiple ABWR systems and is most appropriately handled in a single Tier 1 location. Section 3 includes a matrix showing which generic entries apply to each of the ABWR systems. In selected areas of the plant for which design details are unavailable, Design Acceptance Criteria (DAC) are being prepared. The DAC approach involves certification of the design process and is being applied to areas of the plant design for which design details are not available at the time of design certification. Section 3 includes Tier 1 material that is in this category. Reference 1 discusses the criteria which guide selection of plant features which should be handled by the DAC process.

Section 4 — 10 CFR Part 52 requires that the ITAAC include methods for verifying interface requirements. The latter are defined in 10 CFR Part 52 as the technical requirements to be met by those portions of the plant for which design certification is not being sought. Section 4 contains ITAAC entries required for compliance with this provision.

1.1 General Plant Description

The following is a summary of the Advanced Boiling Water Reactor (ABWR) Standard Plant principal design features and principal design criteria.

1.1.1 ABWR Standard Plant Scope

The ABWR Standard Plant includes all buildings which are dedicated exclusively or primarily to housing systems and the equipment related to the nuclear system or controls access to this equipment and systems. There are five such buildings within the scope of the ABWR Standard Plant:

(1) Reactor Building (including containment)

(2) Service Building

(3) Control Building

(4) Turbine Building

(5) Radwaste Building

In addition to the buildings and their contents, the ABWR Standard Plant provides the supporting facilities shown in Figure 1.1.

The principal plant structures include the following:

(1) Reactor Building — includes the containment, drywell, and major portions of the Nuclear Steam Supply System (NSSS), steam tunnel, refueling area, diesel generators, essential power, non-essential power, Emergency Core Cooling Systems (ECCS), Heating, Ventilation and Air Conditioning System (HVAC), and supporting systems.

(2) Service Building — personnel facilities, and portions of the non-essential HVAC.

(3) Control Building — includes the control room, the computer facility, the cable tunnels, some of the plant essential switchgear, some of the essential power, reactor building water system and the essential HVAC System.

(4) Turbine Building — houses all equipment associated with the main turbine generator. Other auxiliary equipment is also located in this building.

(5) Radwaste Building — houses all equipment associated with the collection and processing of solid and liquid radioactive waste generated by the plant.

(5) Radwaste Building — houses all equipment associated with the collection and processing of solid and liquid radioactive waste generated by the plant.

1.1.2 Number of Plant Units

For the purpose of this design certification, a single standard plant is described.

1.1.3 Type of Nuclear Steam Supply

This plant will have a boiling water reactor (BWR) nuclear steam supply system (NSSS) designed by GE and designated as the Advanced Boiling Water Reactor (ABWR).

1.1.4 Type of Containment

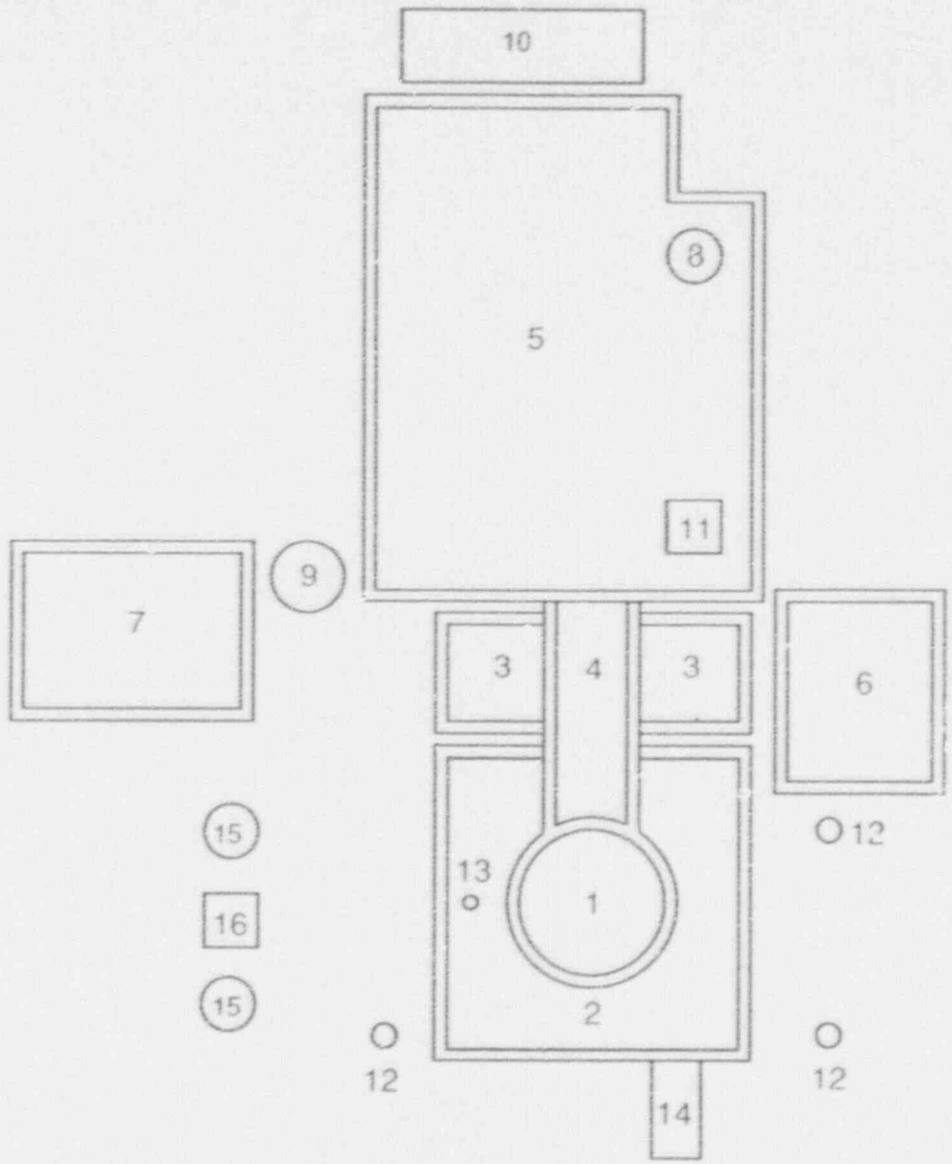
The ABWR will have a low-leakage containment vessel comprised of the drywell and pressure suppression chamber. The containment vessel is a cylindrical steel-lined reinforced concrete structure integrated with the Reactor Building.

1.1.5 Core Thermal Power Levels

The information presented in this design certification pertains to one reactor unit with a rated power level of 3926 MWt and a design power level of 4005 MWt. The station utilizes a single-cycle, forced-circulation BWR designed to operate at a gross electrical power output of approximately 1356 MWe and an electrical power output of approximately 1300 MWe.

1.1.6 Principal Design Parameters

Rated power (MWt)	3,926
Design power (MWt) (ECCS design basis)	4,005
Rated steam flow rate, Kg/hr at 215.6°C (FW temp)	$7.64x10^6$
Rated core coolant flow rate (Kg/hr)	$52.2x10^6$
RCPB design pressure (Kg/cm^2g)	87.9
RCPB design temperature (°C)	302
Containment internal design pressure (Kg/cm^2g)	3.16
Number of fuel assemblies	872
Number of control rods	205
Number of internal pumps	10



No.	FACILITY
1	REACTOR CONTAINMENT
2	REACTOR BUILDING
3	CONTROL BUILDING
4	MAIN STEAM/FEEDWATER TUNNEL
5	TURBINE BUILDING
6	SERVICE BUILDING
7	RADWASTE BUILDING
8	HOUSE BOILER
9	CONDENSATE STORAGE TANK
10	MAIN TRANSFORMER
11	NORMAL SWITCHGEAR
12	DIESEL OIL STORAGE TANK (3)
13	STACK
14	EQUIPMENT ENTRY LOCK
15	FIRE PROTECTION WATER STORAGE TANK (2)
16	FIRE PROTECTION PUMPHOUSE

Figure 1.1 Site Plan

2.0 Tier 1 Material for ABWR Systems

This section provides Tier 1 material for each of the ABWR systems within the scope of the certified design. As a minimum, each system has a Tier 1 design description which is intended to be the technical description of the facility that will appear in Tier 1 of the Certification Rule. Most systems also have entries defining the inspections, tests, analyses and acceptance criteria (ITAAC) called for by 10 CFR Part 52.

Notice

For a number of ABWR systems addressed in this document, the Tier 1 design description is accompanied by a schematic diagram of the system configuration. The diagrams include simplified system piping and instrumentation diagrams for hydraulic/pneumatic systems; simplified one-line diagrams for electrical systems; and simplified outline drawings for selected equipment items.

These diagrams are for the purpose of illustrating the principal design features of the ABWR systems and their relationship to each other. The simplified figures are not to scale and are not intended to be exact representations of the detailed system configurations that will be utilized in any facility referencing the certified design.

The proposed ABWR Tier 1 material includes numerical information for aspects of the design such as equipment performance, material compositions, structural dimensions and system configurations. Where appropriate, this numerical information includes the allowable range and/or tolerances. In those cases where allowable variations are not specifically quantified, the stated value should be considered nominal with tolerances based on accepted industry practices as they apply to the parameter being considered.

2.1 Nuclear Steam Supply

2.1.1 Reactor Pressure Vessel System

Design Description

The Reactor Pressure Vessel (RPV) System consists of (1) the reactor pressure vessel and its appurtenances, supports and insulation, and (2) the reactor internals enclosed by the vessel, excluding the core, in-core nuclear instrumentation, reactor internal pumps, and control rod drives.

The reactor coolant pressure boundary (RCPB) portion of the RPV System retains integrity as a radioactive material barrier during normal operation and following abnormal operational transients and design basis accidents (DBAs).

Certain RPV internals support the core, flood the core during a DBA, and support instrumentation utilized during a DBA. Other RPV internals direct coolant flow, separate steam, hold material surveillance specimens, and support instrumentation utilized for normal operation.

The RPV System provides guidance and support for the control rod drives (CRDs). It also admits and distributes the sodium pentaborate from the Standby Liquid Control (SLC) System.

The RPV System restrains the CRD in order to prevent the ejection of the control rod connected with the CRD in the event of a postulated failure of the RCPB associated with the CRD housing. A restraint is also provided for the reactor internal pump (RIP) in order to prevent it from becoming a missile in case of a postulated failure of the RCPB associated with the reactor internal pump.

The major plant design parameters are listed in Section 1.1. The configuration of the RPV System is shown on Figure 2.1.1a, with key dimensions presented in Table 2.1.1b, and the tolorances for these dimensions in Table 2.1.1c.

Reactor Pressure Vessel, Appurtenances, Supports and Insulation

The reactor pressure vessel (RPV), as shown schematically in Figure 2.1.1a, consists of a vertical, cylindrical pressure vessel of welded construction, removable top head and head closure bolting and seals. The vessel includes the cylindrical shell, flange, bottom head, reactor internal pump (RIP) casings, penetrations, brackets, nozzles, venturi shaped flow restrictors in the steam outlet nozzles, and the shroud support, which includes the pump deck forming the partition between the RIP suction and discharge. The shroud support is an assembly consisting of a short vertical cylindrical shell, a horizontal annular pump deck plate and vertical stilt legs. This support carries the weight of peripheral fuel assemblies, neutron sources, core plate, top guide, shroud, and shroud head with steam separators. It also laterally supports the fuel assemblies and the pump diffusers. The shroud support also sustains the differential pressures.

The control rod drives are mounted into the control rod drive housings. Sodium pentaborate solution from the SLC System enters the vessel via one of the two high pressure core flooding (HPCF) lines and is distributed through the sparger connected to the line.

The CRD housings are inserted through and connected to the CRD penetrations (stub tubes) in the reactor vessel bottom head. The in-core neutron flux monitor housings are inserted through and connected to the bottom head.

A flanged nozzle is provided in the top head for bolting of the flange associated with the instrumentation for vibration test of internals.

The integral reactor vessel skirt supports the vessel on the RPV pedestal. Steel anchor bolts extend through the pedestal and secure the flange of the skirt to the pedestal. RPV stabilizers are provided in the upper portion of the RPV to resist horizontal loads. Lateral supports among the CRD housings and in-core housings are provided by restraints which, at the periphery, are supported off the CRD housing restraint beams.

A restraint consisting of a pair of energy absorbing rods is provided to prevent a RIP from being a missile in case of a failure in the casing weld with the bottom head penetration. The restraint is connected to lugs on the RPV bottom head and the RIP motor cover.

The RPV insulation is supported from the biological shield wall surrounding the vessel. Insulation for the upper head and flange is supported by a steel frame independent of the vessel and piping. Insulation access panels and insulation around penetrations are designed for ease of installation and removal for vessel inservice inspection and maintenance operation.

The RCPB portion of the RPV and appurtenances and the supports (RPV skirt, stabilizer and CRD housing/in-core housing restraints and beams) are classified as Quality Group A, Seismic Category I. The design, materials, manufacturing, fabrication, testing, examination, and inspection used in the construction of these components meet the requirements of ASME Code Class 1 vessel and supports, respectively. The shroud support is classified as Quality Group C, Seismic Category I, and designed and fabricated to ASME Code Class CS (core support structures). Hydrostatic test of the RPV is performed in accordance with the requirements for ASME Code Class 1 vessels. The components are code-stamped according to their code class.

The materials used in the RCPB portion of the RPV and appurtenances (or their equivalents) will be used: ASME SA-533, Type B, Class 1 (plate); SA-508, Class 3 (forging); SA-508, Class 1 (forging); SB-166, Type 600 (UNS 06600, forging); SA-182, F316L (maximum carbon 0.020%) or F316 (maximum carbon 0.020% and nitrogen from 0.060 to 0.120%, forging); and SA-540, Grade B23 or B24 (bolting).

The materials of the low alloy plates and forging used in construction of the RPV are melted to fine grain practice and are supplied in quenched and tempered condition. Vacuum degassing is performed to lower the hydrogen level and improve the cleanliness of the low-alloy steels.

Electroslag welding is not applied for structural welds. Preheat and interpass temperatures employed for welding of low alloy steel meet or exceed the values given in ASME, Section III, Appendix D. Post-weld heat treatment at 593°C minimum is applied to all low-alloy steel welds.

Pressure boundary welds are given an ultrasonic examination in addition to the radiographic examination performed during fabrication. The ultrasonic examination method, including calibration, instrumentation, scanning sensitivity, and coverage, is based on the requirements imposed by ASME, Section XI, Appendix I. Acceptance standards are equivalent or more restrictive than required by ASME, Section XI.

A stainless steel weld overlay is applied to the interior of the cylindrical shell and the steam outlet nozzle. Other nozzles and the RIP motor casing do not have cladding. The bottom head is clad with Ni-Cr-Fe alloy. The RIP penetrations are clad with Ni-Cr-Fe alloy or, alternatively, stainless steel.

The fracture toughness tests of pressure boundary ferritic materials, weld metal and heat-affected zone (HAZ) are performed in accordance with the requirements for ASME Code Class 1 vessel. Both longitudinal and transverse specimens are used to determine the minimum upper shelf energy (USE) level of the core beltline materials. Separate, unirradiated baseline specimens are used to determine the transition temperature curve of the core beltline base materials, weld metal, and HAZ.

For the vessel material surveillance program, specimens are manufactured from the material actually used in the reactor beltline region and weld typical of those in the beltline region, thus representing base metal, weld material, and the weld HAZ material. The plate and weld specimens are heat treated in a manner which simulates the actual heat treatment performed on the core region shell plates of the completed vessel. Each in-reactor surveillance capsule contains Charpy V-notch specimens of base metal, weld metal, and HAZ material, and tensile specimens from base metal and weld metal. Brackets are welded to the vessel cladding in the core belt region for retention of the detachable holders, each of which contains a number of the specimen capsules. Neutron dosimeters and temperature monitors are located within the capsules.

Access for examinations of the installed RPV is incorporated into the design of the vessel, biological shield wall, and vessel insulation.

Reactor Pressure Vessel Internals

The major reactor internal components included in the RPV System are:

(1) Core Support Structures

Shroud, shroud support (integral to the RPV and including the internal pump deck), core plate, top guide, fuel supports (orificed fuel supports and peripheral fuel supports), and control rod guide tubes.

(2) Other Reactor Internals

Control rods, feedwater spargers, RHR/ECCS low pressure flooding spargers, ECCS high pressure core flooding spargers and coupling, in-core guide tubes and stabilizers, core plate differential pressure (DP) lines, surveillance specimen holders, shroud head and steam separators assembly, and steam dryer assembly.

A general assembly drawing of these reactor internal components is shown in Figure 2.1.1a. The core support structures locate and support the fuel assemblies, form partitions within the reactor vessel to sustain pressure differentials across the partitions, and direct the flow of the coolant water.

The shroud support, shroud, and top guide make up a stainless steel cylindrical assembly that provides a partition to separate the upward flow of coolant through the core from the downward recirculation flow. This partition separates the core region from the downcomer annulus.

The core plate consists of a circular stainless steel plate with round openings and is stiffened with a rim and beam structure. The core plate provides lateral support and guidance for the control rod guide tubes, in-core flux monitor guide tubes, peripheral fuel supports and startup neutron sources. The last two items are also supported vertically by the core plate.

The top guide consists of a circular plate with square openings for fuel and with a cylindrical side forming an upper shroud extension. Each opening provides lateral support and guidance for four fuel assemblies or, in the case of peripheral fuel, less than four fuel assemblies. Holes are provided in the bottom, where the sides of the openings intersect, to anchor the in-core instrumentation detectors and start-up neutron sources.

The fuel supports are of two types: 1) peripheral and 2) orificed. The peripheral fuel supports are located at the outer edge of the active core and are not adjacent to control rods. Each peripheral fuel support supports one peripheral fuel assembly and contains an orifice to provide coolant flow to the fuel assembly. Each orificed fuel support supports four fuel assemblies vertically upward and horizontally and contains four orifices to provide coolant flow distribution to each fuel assembly. The orificed fuel supports rest on the top of the control rod guide tubes (CRGTs), which are supported laterally by the core plate. The control rods pass through cruciform openings in the center of the orificed fuel support.

The CRGTs located inside the vessel extend from the top of the CRD housings up through holes in the core plate. Each guide tube is designed as the guide for the lower end of a control rod and as the support for an orificed fuel support. This locates the four fuel assemblies surrounding the control rod. The lower end of the guide tube is supported by the CRD housing, which, in turn, transmits the weight of the guide tube, fuel supports, and fuel assemblies to the reactor vessel bottom head. The CRGTs also contain holes, near the top of the CRGT and below the core plate, for coolant flow to the orificed fuel supports.

The CRGT base is provided with a device for coupling the CRD with it. The CRD is restrained from ejection, in the case of a stub tube weld failure, by the coupling of the CRD with the CRGT base; in this event, the flange at the top of the guide tube will contact the core plate and restrain the ejection. The coupling will also prevent ejection if the housing fails at the stub tube weld; in this event, the guide tube remains supported on the intact upper housing.

The control rods are cruciform-shaped neutron absorbing members that can be inserted or withdrawn from the core by the CRD to control reactivity and reactor power.

Each of the two feedwater lines is connected to three spargers via three RPV nozzles. The feedwater spargers, which also function as ECCS high or low pressure flooding spargers (depending upon their connection to the line designated to receive high pressure or low pressure coolant flooding supply, respectively), are stainless steel headers located in the mixing plenum above the downcomer annulus. Each sparger, in two halves, with a tee connected in the middle, is fitted to each feedwater nozzle with the tee. The sparger tee inlet is connected to the RPV nozzle safe end by a double thermal sleeve arrangement. Feedwater flow enters the center of the spargers and is discharged radially inward to mix the cooler feedwater with the downcomer flow from the steam separators and steam dryer.

The design feature of the two residual heat removal (RHR) shutdown cooling system spargers, which also function as ECCS low pressure flooding (LPFL) spargers, is similar to that of the feedwater spargers. Two lines of RHR shutdown cooling system enter the reactor vessel through the two diagonally opposite nozzles and connect to the spargers. The sparger tee inlet is connected to the RPV nozzle safe end by a thermal sleeve arrangement.

The two ECCS high pressure core flooding (HPCF) spargers and couplings are the means for directing high pressure ECCS flow to the upper end of the core. Each of the two HPCF lines enters the reactor vessel through a diagonally opposite nozzle with a thermal sleeve arrangement. The curved sparger, including the connecting tee, is located around the inside of and is supported by the cylindrical portion of the top guide. The sparger tee is connected to the thermal sleeve by the HPCF coupling.

In-core guide tubes (ICGTs) protect the in-core flux monitoring instrumentation from flow of water in the bottom head plenum. The ICGTs extend from the top of the in-core housing to the top of the core plate. The local power range monitoring (LPRM) detectors for the Power Range Neutron Monitoring (PRNM) System and the detectors for the Startup Range Neutron Monitoring (SRNM) System are inserted through the guide tubes.

Two levels of stainless steel stabilizer latticework of clamps, tie bars, and spacers give lateral support and rigidity to the guide tubes. The stabilizers are connected to the shroud and shroud support.

The core plate differential pressure (DP) lines enter the reactor vessel through reactor bottom head penetrations. Four pairs of the core plate DP lines enter the head in four quadrants through four penetrations and terminate immediately above and below the core plate to sense the pressure in the region outside the bottom of the fuel assemblies and below the core plate during normal operation.

Surveillance specimen capsules, which are held in capsule holders mentioned earlier, are located at three azimuths at a common elevation in the core beltline region. The capsule holders are non-safety-related internals. The capsule holders are mechanically retained by capsule holder brackets welded to the vessel cladding in order to allow their removal and reattachment.

The shroud head and steam separators assembly includes the connecting standpipes and forms the top of the core discharge mixture plenum. The steam dryer assembly removes moisture from the wet steam leaving the steam separators. The extracted moisture flows down the dryer vanes to the collecting troughs, then flows through tubes into the downcomer annulus. The shroud head and steam separators assembly and the steam dryer assembly are non-safety-related internals.

The core support structures are classified as Quality Group C, Seismic Category I. The design, materials, manufacturing, fabrication, examination, and inspection used in the construction of the core support structures meet the requirements of ASME Code Class CS structures. These structures are code-stamped accordingly. Other reactor internals are designed per the guidelines of ASME Code NG-3000 and are constructed so as not to adversely affect the integrity of the core support structures as required by NG-1122.

Special con[illegible] exercised when austenitic stainless steel is used for constructio[illegible] V internals in order to avoid cracking during service.

Design and construction of the RPV internals assure that the internals can withstand the effects of flow-induced vibration (FIV).

Inspection, Test, Analyses and Acceptance Criteria

Table 2.1.1a provides a definition of the instructions, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the Reactor Pressure Vessel System.

Table 2.1.1a: Reactor Pressure Vessel System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. System configuration of the Reactor Pressure Vessel (RPV) System is shown on Figure 2.1.1a. Key dimensions are presented in Table 2.1.1b, with design details of RPV lower plenum and core arrangement in Figures 2.1.1b and 2.1.1c, respectively.	1. Visual field inspections will be conducted of the installed RPV System key components identified in Section 2.1.1 and Figure 2.1.1a.	1. The installed configuration of the RPV System will be considered acceptable if it complies with Figures 2.1.1a, b, and c, Tables 2.1.1b and c, and Section 2.1.1.
2. The reactor coolant pressure boundary (RCPB) portion of the RPV and appurtenances and their supports are classified as Quality Group A, Seismic Category I. These components are designed, fabricated, examined, and hydrotested in accordance with the rules of ASME Code Class 1 vessel or component support, and are code stamped accordingly. The core support structures are Quality Group C, Seismic Category I, and are designed, fabricated, and examined in accordance with the rules of ASME Code Class CS structures, and are code-stamped accordingly.	2. Inspections will be conducted of ASME Code required documents and the Code stamp on the components.	2. Existence of necessary ASME Code required documents and the Code stamps on the components confirm that the components in the RCPB portion of the RPV and the supports, and the core support structures are designed, fabricated and examined as ASME Code Class 1 and CS, respectively. This also confirms that the RPV is hydrotested per the ASME Code Class 1 requirements.
3. The RCPB of the RPV System retains its integrity under internal pressure that will be experienced during the service.	3. A hydrostatic test of the RCPB will be conducted in accordance with ASME Code requirements.	3. The results of the hydrostatic test must conform with the requirements in the ASME Code.
4. The materials used for the RCPB portion of the RPV and appurtenances are low and high alloy steels with certain additional requirements for construction (Section 2.1.1). Special controls are exercised when austenitic stainless steel is used for construction of RPV internals in order to avoid cracking during service.	4. Inspection will be conducted of the records of materials, fabrication, and examination used in construction of the RCPB and austenitic stainless steel reactor internals.	4. Records of the materials and processes must confirm that the requirements specified for the RCPB in Section 2.1.1 are satisfied and that the manufacture and fabrication of the RPV internals made of austenitic stainless steel avoid potential for cracking in service.

Table 2.1.1a: Reactor Pressure Vessel System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The ferritic materials used in the RCPB portion of the RPV and appurtenances are not susceptible to brittle fracture under pressure during the service.	5. Fracture toughness tests of the ferritic base, weld and heat-affected zone (HAZ) metal used in the RCPB will be conducted in accordance with the requirements for ASME Class 1 components.	5. Records of the fracture toughness data of the RCPB ferritic materials must confirm that 1) the requirements of the ASME Code are met, and 2) the reactor vessel beltline materials will not be susceptible to brittle fracture during the service.
6. Specimens for the surveillance program are selected from the vessel base metal and weld metal.	6. Inspection will be conducted of the records of the specimens selected from the reactor beltline region.	6. The specimens, with respect to location and orientation, types (tensile or Charpy V-notch), and quantities, must meet the requirements of ASTM E-185.
7. Analysis for vibration prediction is performed to assure that design and construction of the RPV internals can withstand the effects of flow-induced vibration (FIV). The design analysis is based on predicted values of FIV loads. The vibration prediction analysis may be upgraded by available test data.	7. A vibration test will be conducted of the reactor internals to verify the adequacy of the internals design, manufacture, and assembly with respect to the potential effects of FIV. The first-of-a-kind prototype internals will be flow tested by vibration instrumentation followed by inspection for damage. The internals in subsequent plants will be flow tested, but without vibration instrumentation, followed by inspection for damage.	7. Reactor vessel internals vibration is considered acceptable when results of the vibration measurement are compared with results of the vibration prediction analysis to verify compliance with design limits, and when inspection of the internals indicate no sign of damage, loose parts, or excessive wear in the prototype test. The vibration of reactor internals in subsequent plants is considered acceptable when inspection of the internals indicate no sign of damage, loose parts, or excessive wear.

Table 2.1.1a: Reactor Pressure Vessel System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. Access for examinations of the RPV is incorporated into the design of the vessel, biological shield wall and vessel insulation.	8. Visual inspection will be conducted of accessibility for examinations of the vessel and welds.	8. Provisions for access in the design of the vessel, biological shield wall, and vessel insulation shall be, in the minimum, as follows: The shield wall and vessel insulation behind the shield wall must be spaced away from the RPV outside surface. Access for the insertion of automated devices must be provided through removable insulation panels at the top of the shield wall and at access ports at reactor vessel nozzles. Access to the RPV welds above the top of the biological shield wall must be provided by removable insulation panels. The closure head must have removable insulation to provide access for manual ultrasonic examinations of its welds. Access to the bottom head to shell weld must be provided through openings in the RPV support pedestal and removable insulation panels around the lower cylindrical portion of the vessel. Access must be provided to partial penetration nozzle welds (i.e., CRD penetrations, instrumentation nozzles and recirculation internal pump penetration welds) for performance of visual examinations. Access must be provided for examination of the attachment weld between the support skirt knuckle (forged integrally on the shell ring) and the RPV support skirt. Access must be provided to the balance of the support skirt for performance of visual examination.

Table 2.1.1b: Key Dimensions of RPVS Components

Description	Elevation/ Dimension (Figure 2.1.1a)	Nominal Value (mm)
RPV inside diameter (inside cladding)	G	7112.0
RPV wall thickness in beltline (without cladding)	H	174.0
RPV bottom head inside invert	A	0.0
Top of RPV flange	F	17703.0
RPV support skirt bottom	B	3200.0
RPV stabilizer connection	E	13766.0
Shroud outside diameter	L	5550.0
Shroud wall thickness	M	50.8
Steam nozzle ID at pipe connection	K	642.0
Steam nozzle flow element throat diameter	J	353.8
Core plate support/Top of shroud middle flange	C	4695.2
Top guide support/Top of shroud top flange	D	9351.2
Shroud support legs (Fig. 2.1.1b)	NxO	153.0x662.0
Control rod guide tube OD	P	273.05

Table 2.1.1c: Acceptable Variations of Dimensions and Elevations

Description	Elevation/ Dimension (Figure 2.1.1a)	Variation (mm)
RPV inside diameter (inside cladding)	G	±50.0
RPV wall thickness in beltline (without cladding)	H	+14.0/-3.0
RPV bottom head inside invert	A	Reference 0.0
Top of RPV flange	F	±25.0
RPV support skirt bottom	B	+50.0/-10.0
RPV stabilizer connection	E	±15.0
Shroud outside diameter	L	±20.0
Shroud wall thickness	M	±2.0
Steam nozzle ID at pipe connection	K	+8.0/-0.0
Steam nozzle flow element throat diameter	J	±1.0
Core plate support/Top of shroud middle flange	C	±10.0
Top guide support/Top of shroud top flange	D	±13.1
Shroud support legs (Fig. 2.1.1b)	N×Q	±6.0 (for N and Q)
Control rod guide tube OD	P	±2.5

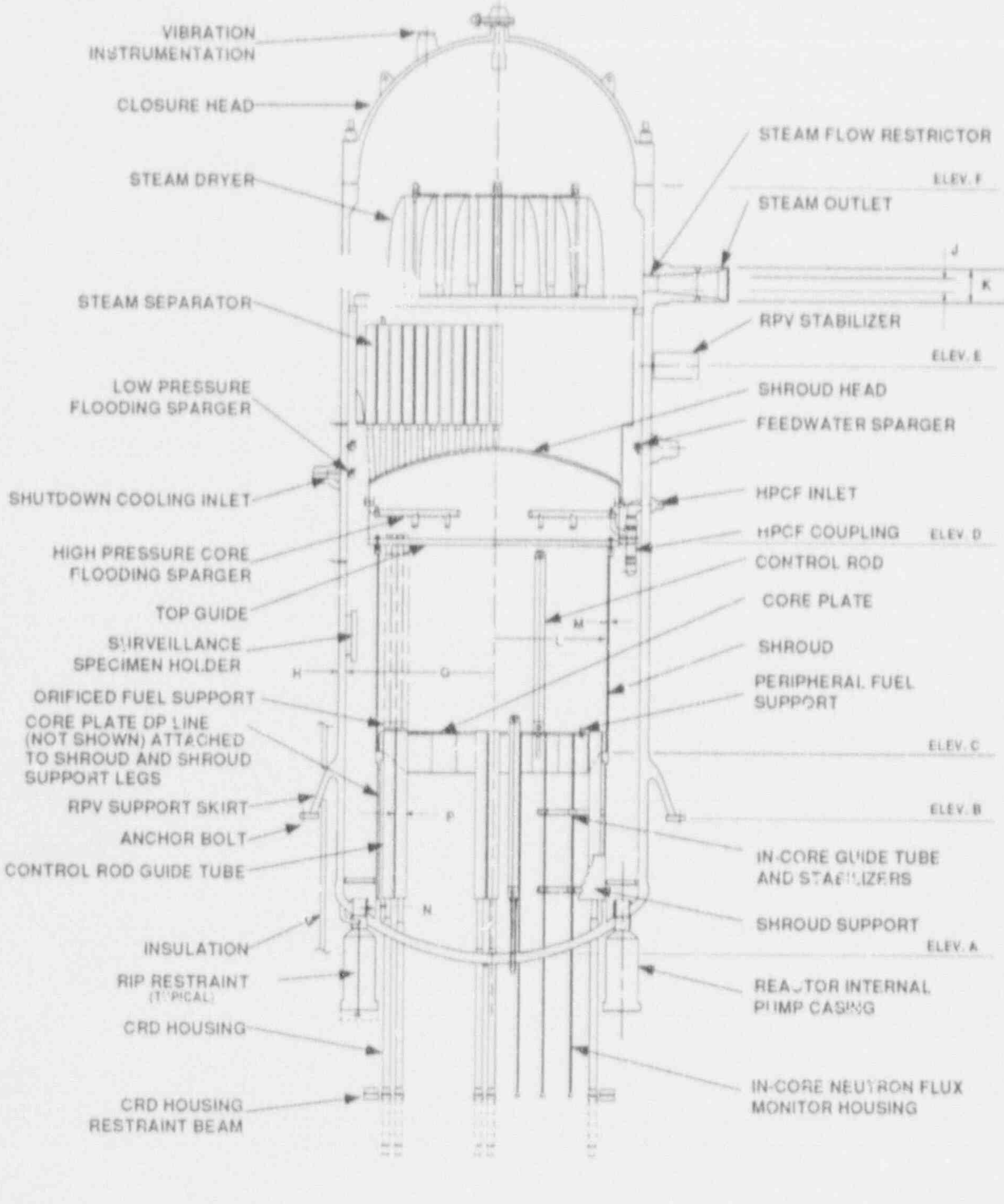


Figure 2.1.1a Reactor Pressure Vessel System Key Features

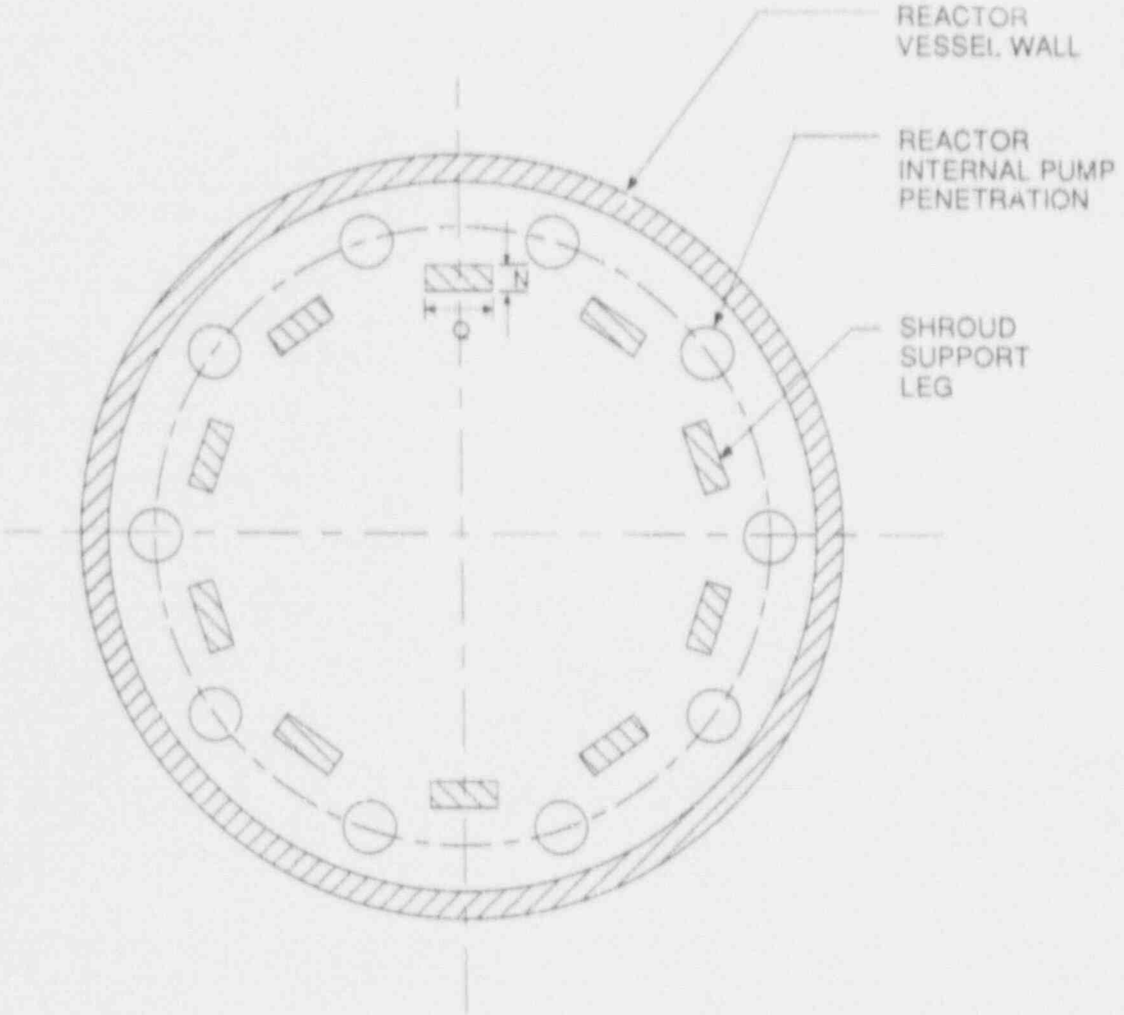


Figure 2.1.1b Pump and Shroud Support Leg Arrangement

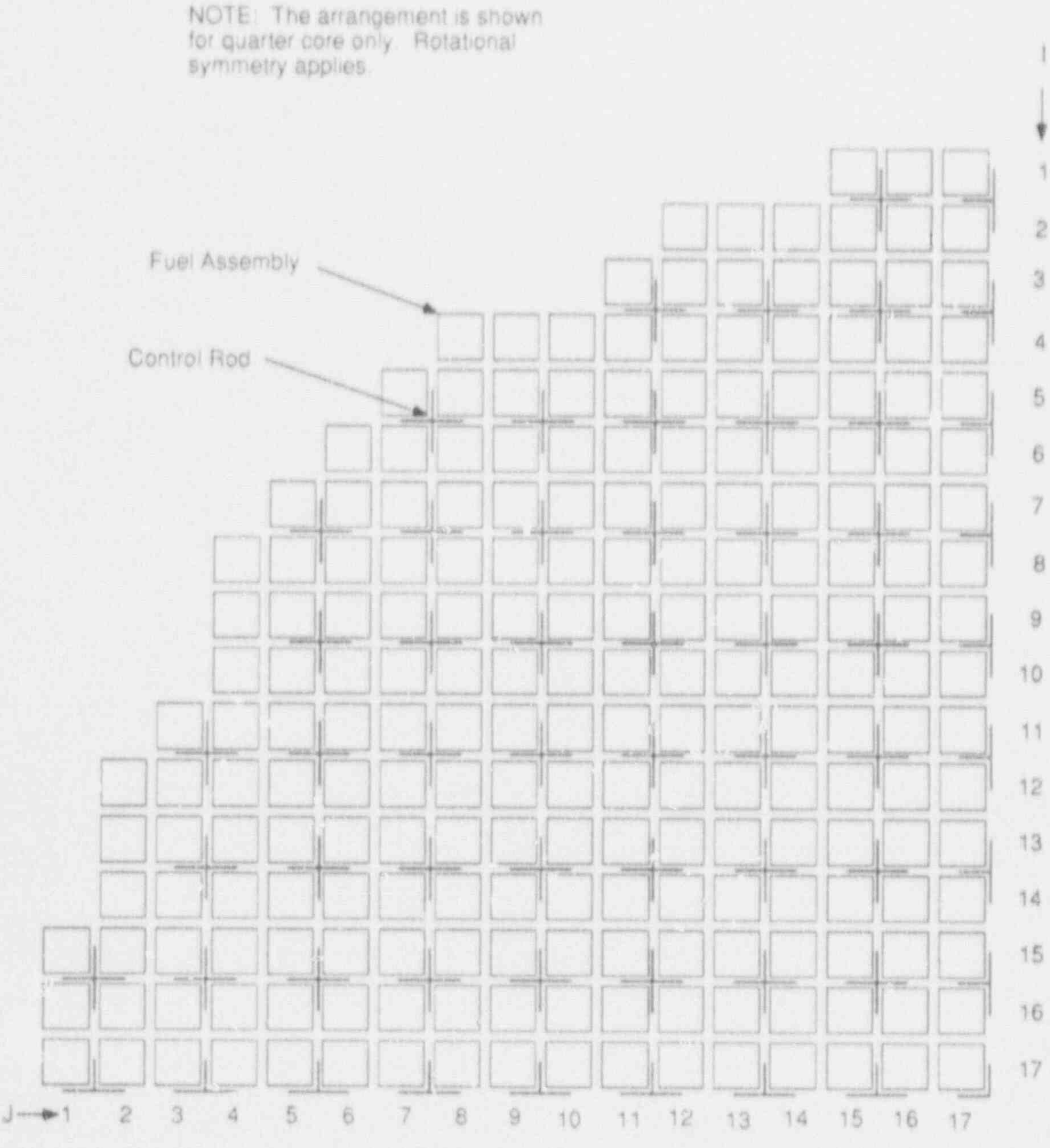


Figure 2.1.1c Core Arrangement

2.1.2 Nuclear Boiler System

Design Description

Later. Stage 3 Item.

2.1.3 Reactor Recirculation System (RRS)

Design Description

The RRS includes an arrangement of 10 Reactor Internal (Seal-less) Pumps (RIP) with wet motors mounted in the bottom of the RPV as shown in Fig. 2.1.3. The RIPs circulate coolant through the reactor core at variable flow rates, which varies reactor power approximately 70-100% power.

Core coolant flow rate is controlled by the Recirculation Flow Control System (RFCS). The RFCS includes the Adjustable Speed Drive (ASD), RIP trip (RPT) function and core flow measurement. Tier 1 information for the RFCS is found in Section 2.2.8.

In addition to providing core coolant flow during normal reactor operation, the RIPs and associated equipment are designed to (1) have flow coastdown characteristics that provide an adequate fuel thermal margin during plant transients and (2) maintain Reactor Coolant Pressure Boundary (RCPB) integrity during adverse combinations of loading during abnormal, accident and special event conditions.

The only safety related portion of the RRS, is the bottom motor cover bolted to the RIP motor housing. The RIP motor housing is part of the RPV described in Section 2.1.1. The motor cover is part of the Reactor Coolant Pressure Boundary (RCPB) and is designed to Seismic Category I and Quality Group A (similar to the RPV). The design, materials, manufacturing, fabrication, testing, examination, and inspection used in the construction of the cover and cover bolts and nuts meet requirements of ASME Code Class 1 vessels. The motor cover and cover bolt materials are low or high alloy steels.

Hydrostatic test of the covers and bolts after fabrication and in the plant is performed in accordance with the requirements for ASME Code Class 1 vessels.

The RIP design parameters are:

RIP Motor Cover Design Pressure (kg/cm^2 g)	87.9
RIP Motor Cover Design Temperature (°C)	302
Individual RIP rated Flow (M^3/hr)	≥6912
RIP rated TDH (M)	≥32.6

The RIP and core flows are measured in various plant operating modes with the RFCS described in the RFCS Section 2.2.8.

The Recirculation Motor Cooling (RMC) subsystem (Fig. 2.1.3) provides forced circulation with an auxiliary combination thrust bearing-impeller mounted on the bottom of the motor rotor, inside the motor housing. The impeller forces cooling water through the motor radial bearings and windings and to the motor cooling heat exchanger. The RMC heat exchangers are located under the RPV close to the RIP motors.The RMC is classified as Quality Group D. For plant availability the RMC is designed to the same parameters as the RPV.

The RIPs receive power through their individual ASDs from the plant non essential power system.

As shown in Figure 2.1.3 the RIPs are mounted in the RPV bottom head. The motor cooling heat exchangers are located inside the RPV pedestal adjacent to the RIP motors.

Each RIP instrumentation includes speed, vibration, and RMC temperature, which are indicated in the Main Control Room.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.1.3 provides a definition of the instructions, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the RRS.

Table 2.1.3: REACTOR RECIRCULATION SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. System configuration of the reactor recirculation system (RRS) as described in Section 2.1.3 is shown on Figure 2.1.3	1. Visual field inspections will be conducted of the installed RRS key components identified in Section 2.1.3 and Figures 2.1.3.	1. The installed configuration of the RRS will be considered acceptable if it complies with Figure 2.1.3 and Section 2.1.3
2. RIPs flow coastdown provide adequate reactor fuel thermal margin during plant transients.	2. During preop testing, RIPs will be tripped at less than rated speed and temperature to obtain in-plant RIP flow coastdown characteristics.	2. Preliminary inertia measurements confirm RIP flow coastdown is within design limits.
3. The reactor coolant pressure boundary (RCPB) motor cover are classified as Quality Group A, Seismic Category 1. The covers and bolts are designed, fabricated, examined and hydrotested in accordance with the rules of ASME Code Class 1 vessels and are code stamped accordingly.	3. Inspections will conducted of ASME Code required documents and the Code stamp on the cover and bolts.	3. Existence of necessary ASME Code required documents and the code stamps on the components confirm that the RCPB cover and bolts are designed, fabricated and examined as ASME Code Class 1.
4. The RCPB cover and bolts retain their integrity under internal pressure that will be experienced during the service.	4. A hydrostatic test of the RCPB including the covers and their bolts will be conducted in accordance with the ASME Code requirements.	4. The hydrostatic test results must conform with the ASME requirements.
5. The materials used for the RCPB motor covers and bolts are proven low and high alloy steels with certain additional requirements for construction, as identified in Section 2.1.1.	5. Inspection will be conducted of the RCPB motor covers and bolts records of materials, fabrication, and examination used in construction of the covers and bolts.	5. Records of the materials and processes must confirm that the requirements specified for the RCPB covers and bolts are satisfied.
6. The RCPB covers and bolts ferritic materials are not susceptible to brittle fracture under pressure during service.	6. Fracture toughness tests of the ferritic materials will be conducted in accordance with the requirements for ASME Class 1 components.	6. Records of the fracture toughness data of the RCPB ferritic materials must confirm that the ASME Code requirements are met.
7. The Recirculation Motor Cooling (RMC) forced circulation transfers the heat from each RIP motor to its heat exchanger.	7. Factory or Preop tests will be performed to determine whether the RMC will adequately remove the motor heat within the RMC design limits.	7. Detectors in the RMC subsystems confirm the temperatures of the RMC water and motor temperatures are acceptable.

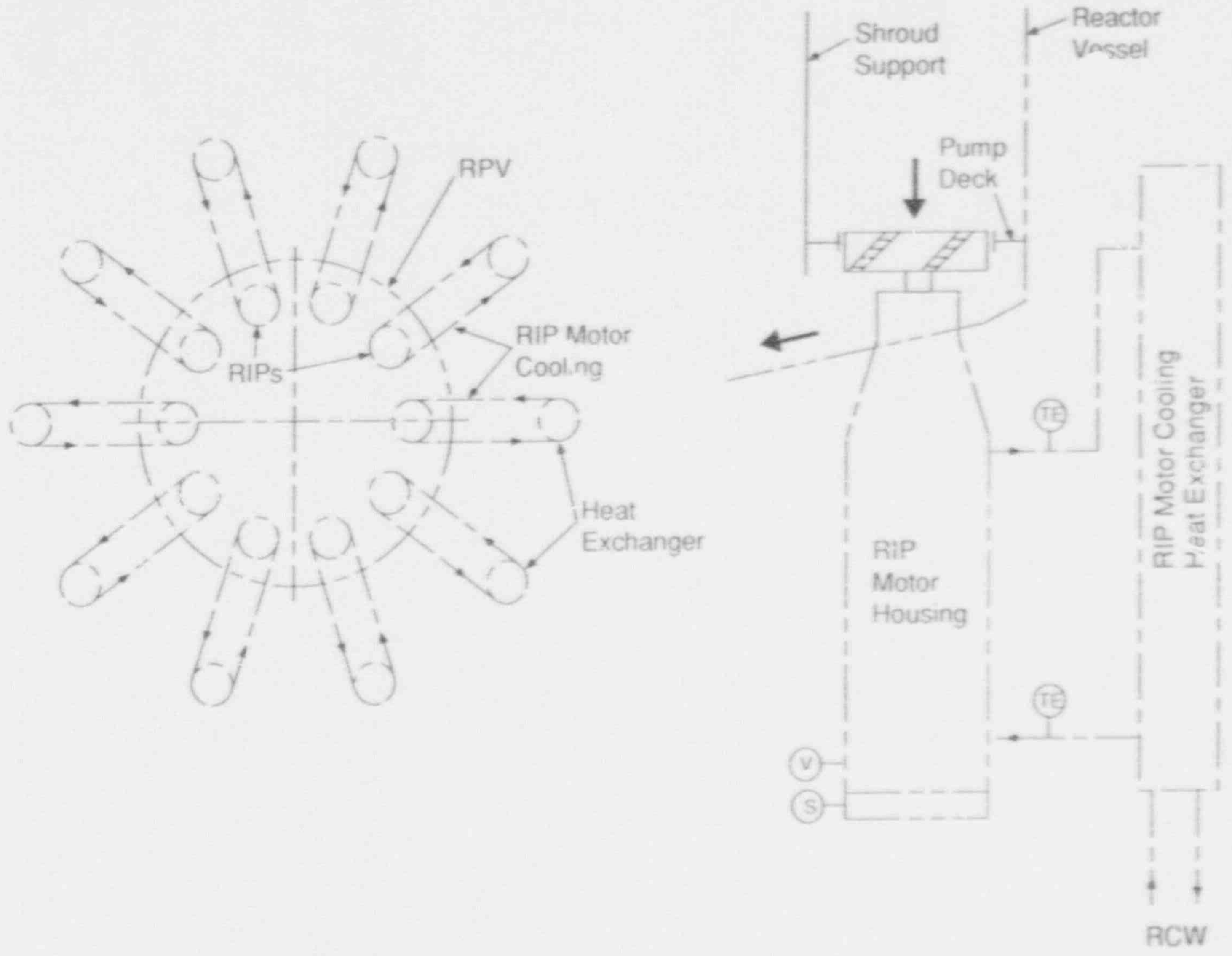


Figure 2.1.3 Reactor Recirculation System (RRS) Arrangement

2.2 Control and Instrument

2.2.1 Rod Control and Information System

Design Description

Later. Stage 3 Item.

2.2.2 Control Rod Drive System

Design Description

The CRD System is composed of three major elements: (1) the electro-hydraulic fine motion control rod drive (FMCRD) mechanisms, (2) the hydraulic control unit (HCU) assemblies, and (3) the control rod drive hydraulic system (CRDHS). The FMCRDs provide electric-motor driven positioning for normal insertion and withdrawal of the control rods and hydraulic-powered rapid control rod insertion (scram) for abnormal operating conditions. The hydraulic power required for scram is provided by high pressure water stored in the individual HCUs. Each HCU is designed to scram two FMCRDs. The HCUs also provide the flow path for purge water to the associated drives during normal operation. The CRDHS supplies high pressure demineralized water which is regulated and distributed to provide charging of the HCU scram accumulators and purge water flow to the FMCRDs.

During power operation, the CRD System controls changes in core reactivity by movement and positioning of the neutron absorbing control rods within the core in fine increments via the FMCRD electric motors, which are operated in response to control signals from the Rod Control and Information System (RCIS).

The CRD System provides rapid control rod insertion (scram) in response to manual or automatic signals from the Reactor Protection System (RPS), so that no fuel damage results from any plant transient.

There are 205 FMCRDs mounted in housings welded into the reactor vessel bottom head. A schematic of the drive is shown in Figure 2.2.2a. Each FMCRD has a movable hollow piston tube that is coupled at its upper end, inside the reactor vessel, to the bottom of a control rod. The piston is designed such that it can be moved up or down, in fine increments over its entire range, by a ball nut and ball screw driven by the electric stepper motor. In response to a scram signal, the piston rapidly inserts the control rod into the core hydraulically using stored energy in the HCU scram accumulator. The scram water is introduced into the drive through a scram inlet connection on the FMCRD housing, and is then discharged directly into the reactor vessel via clearances between FMCRD parts. The FMCRD scram time requirements with the reactor steam dome at a pressure of 1085 psig are:

Percent Insertion	Time (sec)
10	≤ 0.42
40	≤ 1.00
60	≤ 1.44

The FMCRD design includes an electro-mechanical brake on the motor drive shaft and a ball check valve at the point of connection with the scram inlet line. These features prevent control rod ejection in the event of a failure of the scram insert line. An internal housing support is provided to prevent ejection of the FMCRD and its attached control rod in the event of a housing failure. It utilizes the outer tube of the drive to provide support. The outer tube, which is welded to the drive middle flange, attaches by a bayonet lock to the control rod guide tube base. The guide tube, being supported by the lower core plate, in turn prevents any downward movement of the drive.

The FMCRD is designed to detect separation of the control rod from the drive mechanism. Two redundant and separate Class 1E switches detect separation of either the control rod from the hollow piston or the hollow piston from the ball nut. Actuation of either switch will cause an immediate rod block and initiate an alarm in the control room, thereby preventing the occurrence of a rod drop accident.

There are 103 HCUs, each of which provides sufficient volume of water stored at high pressure in a pre-charged accumulator to scram two FMCRDs at any reactor pressure. Figure 2.2.2.b shows the major HCU components. Each accumulator is connected to its associated FMCRDs by a hydraulic line that includes a normally-closed scram valve. The scram valve opens by spring action but is normally held closed by pressurized control air. To cause scram, the RPS provides a de-energizing reactor trip signal to the solenoid operated pilot valve that vents the control air from the scram valve. The system is fail safe in that loss of either electrical power to the solenoid pilot valve or loss of control air pressure causes scram. The HCUs are housed in secondary containment at the basemat elevation. This is a Seismic Category I structure, and the HCUs are protected from external natural phenomena such as earthquakes, tornados, hurricanes and floods as well as from internal postulated accident phenomena. In this area, the HCUs are not subject to conditions such as missiles, pipe whip and discharging fluids.

The CRDHS design provides the pumps, valves, filters, instrumentation and piping to supply the high pressure water for charging the HCUs and purging the FMCRDs. Figure 2.2.2.b shows the major system equipment. Two 100% capacity pumps (one on standby) supply the HCUs with water from the condensate treatment system and/or condensate storage tank for charging the accumulators and for supplying FMCRD purge water. The CRDHS equipment is housed in the Seismic Category I reactor building to protect the system from floods, tornadoes and other natural phenomena.

The CRD System includes Control Room indication and alarms to allow for monitoring and control during design basis operational conditions. This includes system flows, temperatures and pressures as well as valve position indication and pump on/off status for those instruments and components shown in Figure 2.2.2.b, with the exception of simple check valves. Class 1E pressure instrumentation is provided on the HCU charging water header to monitor header performance. The pressure signals from this instrumentation are provided to the RPS which will initiate a scram if the header pressure degrades to a predetermined low pressure setpoint. This feature assures the capability to scram and safely shut down the reactor before HCU accumulator pressure can degrade to the level where scram performance is adversely affected following the loss of charging header pressure.

The FMCRD electric motors are powered from a dedicated non-divisional 480VAC power center fed by the Division I 6.9-kV Class 1E bus as the first source of standby power and by the non-divisional combustion turbine generator as the second backup source.

The CRD pumps, valves and controls are powered from two separate trains of 6.9-kV offsite power with automatic transfer to the combustion turbine generator upon loss of preferred power.

Components of the system which are required for scram are classified Seismic Category I. This includes the FMCRDs, HCUs and scram piping. The balance of system equipment (pumps, valves, filters, piping, etc.) is classified as non-Seismic Category I, with the exception of the Class 1E charging water header pressure instrumentation which is Seismic Category I. The major mechanical components are designed to meet ASME Code requirements as shown below:

	ASME	Design Conditions	
Component	Code Class	Pressure	Temperature
FMCRD (RCPB parts)	1	87.9 kg/cm^{2}g	302°C
Scram Piping	2	190 kg/cm^{2}g	66°C
HCU (scram related parts)	2	190 kg/cm^{2}g	66°C
CRD Pumps	non-Code	190 kg/cm^{2}g	66°C
CRDHS Piping, Valves	non-Code	190 kg/cm^{2}g	66°C

The CRD System is separated both physically and electrically from the Standby Liquid Control System (SLCS).

Inspection, Test, Analyses and Acceptance Criteria

This section provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the CRD System.

Table 2.2.2: Control Rod Drive System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. A simplified configuration of the Control Rod Drive (CRD) System as described in Section 2.2.2 is shown in Figure 2.2.2.b.	1. Visual field inspections will be conducted to confirm that the installed CRD System equipment is in compliance with the design configuration defined in Figure 2.2.2.b.	1. The system configuration is in accordance with Figure 2.2.2.b.
2. The reactor coolant pressure boundary (RCPB) portions of the FMCRD (middle flange, spool piece, mounting bolts, seal housing) are classified as ASME Code Class 1. They are designed, fabricated, examined and hydrotested per the rules of ASME Code, Section III.	2. Inspections will be conducted of ASME Code required documents and the Code stamp on the actual components to verify that they have been manufactured per the relevant ASME requirements.	2. The components have appropriate ASME Code, Section III, Class 1 certifications and Code stamps.
3. The scram related parts of the HCU and the scram piping are classified as ASME Code Class 2. They are designed, fabricated, examined and hydrotested per the rules of ASME Code, Section III.	3. Inspections will be conducted of ASME Code required documents and the Code stamp on the actual components to verify that they have been manufactured per the relevant ASME requirements.	3. The components have appropriate ASME Code, Section III, Class 2 certifications and Code stamps.
4. The installed FMCRDs and HCUs shall be capable providing control rod scram time performance within specified limits.	4. Scram tests will be conducted during the preoperational testing program to confirm proper operation of HCUs and associated valves, including scram timing demonstrations with the reactor at atmospheric pressure.	4. The observed/measured scram times meet the requirements specified in Section 2.2.2.
5. The FMCRD electro-mechanical brake and ball check valve shall be capable of performing their rod ejection prevention functions as identified in Section 2.2.2.	5. Functional tests of the brake and check valve will be performed for each FMCRD during the preoperational testing program.	5. The brake holding torque is within specified limits. The ball check valve actuates to seal the scram inlet port under conditions of reverse flow.
6. The FMCRD outer tube, which is welded to the drive middle flange, shall bayonet lock to the control rod guide tube base to form the internal housing support for prevention of rod ejection in the event of a CRD housing failure.	6. Visual inspection of the actual installed equipment shall confirm the FMCRD is in compliance with the design commitment.	6. Inspection confirms that a bayonet lock is provided.

Table 2.2.2: Control Rod Drive System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. The FMCRD separation switches shall detect separation of the control rod from the drive mechanism and initiate a control room alarm.	7. The separation switch operation shall be tested as part of the drive functional testing conducted during the preoperational testing program.	7. The switches actuate the control room alarm when exercised.
8. The pressure instrumentation on the HCU charging water header for monitoring HCU accumulator charging pressure shall signal the RPS to initiate a scram if charging pressure is low.	8. Logic and instrument functional testing shall be performed to demonstrate that low charging header pressure will generate a scram by the RPS.	8. The pressure instrumentation functions as required to generate low pressure scram signals to the RPS.
9. CRD System equipment can be powered from the standby AC power supplies as described in Section 2.2.2.	9. System tests will be conducted after installation to confirm that the electrical power supply configurations are in compliance with design commitments.	9. The installed equipment can be powered from standby AC power supplies.
10. CRD System components which are required for scram are classified Seismic Category I and qualified for the appropriate environment for locations where installed.	10. See Generic Equipment Qualification verification activities (ITA).	10. See Generic Equipment Qualification Acceptance Criteria (AC).

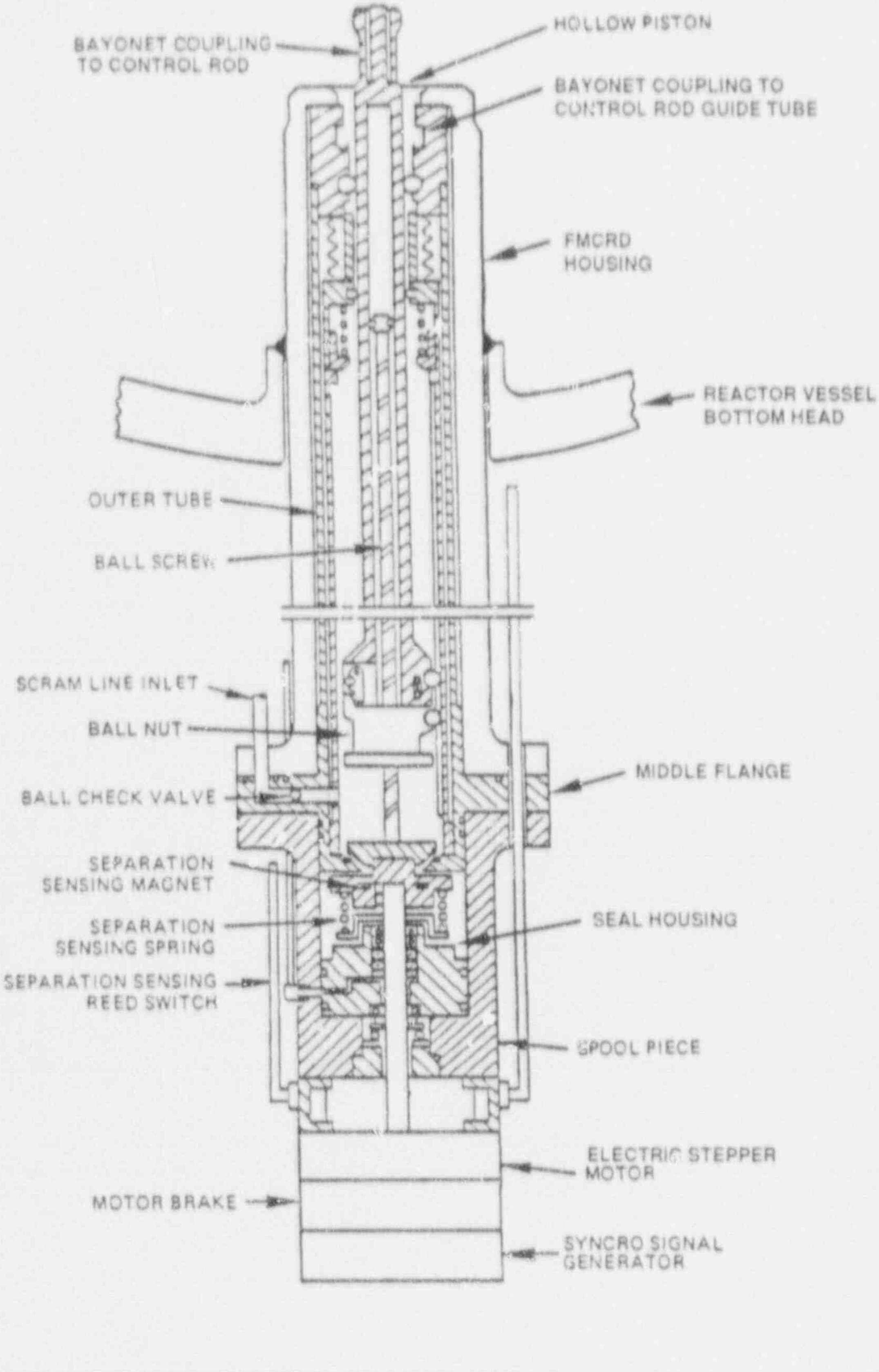


Figure 2.2.2a Fine Motion Control Rod Drive Schematic

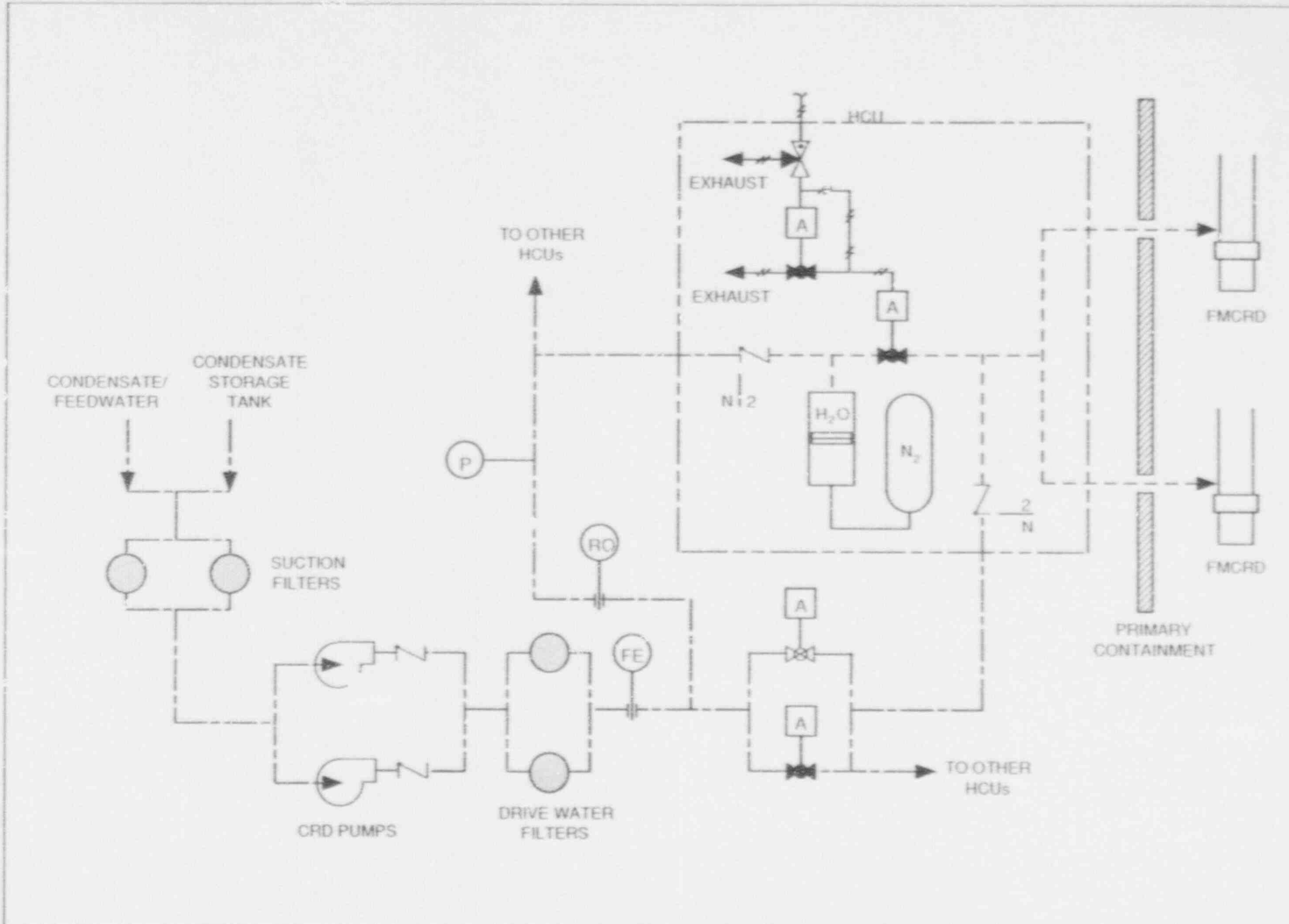


Figure 2.2.2b Control Rod Drive System

2.2.3 Feedwater Control System

Design Description

The feedwater control (FDWC) system controls the flow of feedwater into the reactor pressure vessel to maintain the water level in the vessel within predetermined limits during all plant operating modes. The FDWC system may operate in either single or three element control modes. At low reactor powers (when steam flow is either negligible or else measurement is below scale), the FDWC system utilizes only water level measurement in the single element control mode. When steam flow is negligible, the reactor water cleanup (CUW) system dump valve flow can be controlled by the FDWC system in single element mode in order to counter the effects of density changes during heatup and purge flows into the reactor. At higher powers, the FDWC system in three element control mode uses water level, main steam line flow, main feedwater line flow, and feedpump suction flow measurements for water level control. The FDWC system control structure is shown in Figure 2.2.3.

The FDWC system is a power generation (control) system with operation range between high water level and low water level trip setpoints. It is classified as nonsafety-related. This system is not required for safety purposes, nor is it required to operate after the design basis accident. This system is also required to operate in the normal plant environment for power generation purposes only.

Reactor vessel narrow range water level is measured by three identical, independent sensing systems. For each level measurement channel, a differential pressure transmitter senses the difference between the pressure caused by a constant reference column of water and the pressure caused by the variable height of water in the reactor vessel. The FDWC fault tolerant digital controllers (FTDC's) will determine one validated narrow range level signal using the three level measurements as inputs to a signal validation algorithm. The validated narrow range water level is indicated on the main control panel and is continuously recorded in the main control room.

The steam flow in each of four main steam lines is sensed at the reactor pressure vessel nozzle venturi's. The MUX system signal conditioning algorithms process the venturi differential pressures and provide steam flow rate signals to the FTDC's for validation. These validated measurements are summed in the FTDC's to give the total steam flow rate out of the vessel. The total steam flow rate is indicated on the main control panel and recorded in the main control room.

Feedwater flow is sensed at a single flow element in each of the two feedwater lines. The MUX system signal conditioning algorithms process the flow element differential pressure and provide feedwater flow rate signals to the FTDC's. These validated measurements are summed in the FTDC's to give the total feedwater flow rate into the vessel. The total feedwater flow rate is indicated on the main control panel and recorded in the main control room.

Feedpump suction flow is sensed at a single flow element upstream of each feedpump. The MUX system signal conditioning algorithms process the flow element differential pressure and provide the suction flow rate measurements to the FTDC's. The feedpump suction flow rate is compared to the demand flow for that pump and the resulting error is used to adjust the actuator in the direction necessary to reduce that error. Feedpump speed change and low flow control valve position control are the flow adjustment techniques involved.

Three modes of feedwater flow control and thus level control are provided: 1) Single element control; 2) Three element control; and 3) Manual control. Each FTDC will execute the control software for all three of the control modes. Actuator demands from the redundant FTDC's will be sent over the MUX system to field voters which will determine a single demand to be sent to each actuator. Each feedpump speed or control valve position demand may be controlled either automatically by the control algorithms in the FTDC's or else manually from the main control panel through the FTDC's.

Three element automatic control is provided for normal operation. Three element control utilizes water level, feedwater flow, steam flow, and feedpump flow signals to determine the feedpump demands. The total feedwater flow is subtracted from the total steam flow signal yielding the vessel flow mismatch. The flow mismatch summed with the conditioned level error from the master level controller provides the demand for the master flow controller. The master flow controller output provides the demand for the feedpump flow loops which send a pump speed demand signal to the adjustable speed drive (ASD) for the feedpump.

In the single element control mode, which is employed at lower feedwater flow rates, only conditioned level error is used to determine the feedpump demand. The master level controller conditions the level error and sends it directly to the feedpump ASDs, and/or low flow control valve actuator. When the reactor water inventory must be decreased, during very low steam flow rate conditions the CUW system dump valve is controlled by the FDWC system in single element control. Reactor water is dumped through the CUW system to the condenser.

Each feedpump flow control actuator can be controlled "manually" from the main control panel by selecting the manual mode for that feedpump. In manual mode, the operator may increase or decrease the demand that is sent directly to the ASD of the chosen feedpump.

The FDWC system also provides interlocks and control functions to other systems. When the reactor water level reaches the high level trip setpoint, the FDWC system simultaneously annunciates a control room alarm, sends a trip signal to the turbine control system to trip the turbine generator, sends trip signals to all feedpumps and closes the main feedwater discharge valves. This interlock is enacted to protect the turbine from damage from high moisture content in the steam caused by excessive carryover while preventing water level from rising any higher.

The FDWC system will send a signal to the main steam line condensate drain valves to open when steam flow rate is below a pre-determined setpoint. This also protects the turbine from damage caused by excessive moisture in the steam line.

The FDWC system will send a trip signal to the recirculation flow control (RFC) system when reactor water level reaches this low level setpoint. The RFC system will runback the reactor internal pumps (RIP's) if this low level signal coincides with a feedpump trip signal provided to the RFC system by the feedwater and condensate system. The RIP runback will aid in avoiding a low water level scram by reducing the reactor steaming rate.

Feedwater flow is delivered to the reactor vessel through a combination of three adjustable speed turbine-driven feedpumps and a low flow control valve. Each adjustable speed drive can also be controlled by its manual/automatic transfer station which is part of the feedwater and condensate system. A low flow control valve (LFCV) is also provided in parallel to a common discharge line from the feedpumps. The LFCV can also be controlled by the manual/automatic transfer station which is part of the feedwater and condensate system.

The FDWC system is not required for safety purposes, nor is it required to operate after the design basis accident. This system is required to operate in the normal plant environment for power generation purposes only.

The FDWC system is powered by redundant uninterruptable power supplies (UPS). No single power failure will result in the loss of any FDWC system functions.

Controllers to be used for the FDWC System shall be triplicated, fault tolerant digital type with self-test and diagnostic capabilities.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.2.3 provides definition of the inspection, tests, and/or analysis together with associated acceptance criteria which will be undertaken for the Feedwater Control System.

Table 2.2.3: Feedwater Control System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. This system automatically maintains reactor water level within operational limits, by regulating feedwater flow and reactor water cleanup system dump flow. This system shall use single element control (level only) or three element control, (level, steam flow and feedwater flow), or manual control.	1. Perform tests to confirm that the system can maintain reactor water level in all control modes. Operate system in each mode of controls: Single Element Three Element Manual	1. The FDWC must maintain water level between high and low trip setpoints. (See Figure 2.2.3)
2. This system must be powered by redundant uninterruptable power supplies.	2. Loss of power tests shall demonstrate no loss in FDWC function.	2. There is no loss of FDWC function by loss of any power supply.
3. The water level shall be measured by three identical, independent sensing systems.	3. Inspection and testing will show the three identical and independent sensing systems.	3. The system conforms to Figure 2.2.3, and the input signal is independent of the output signal response.
4. Triplicated, fault tolerant digital controllers with self test and diagnostic capabilities shall be used.	4. Inspect FTDC's and perform validation testing.	4. The fault tolerant digital controllers, FTDC self test and on-line diagnostics test features are capable of identifying and isolating failures of process sensors, I/O cards, buses, power supplies, processors and inter-processors communication paths down to the machine level.
5. This system shall monitor reactor water level, and in the event that high water level is reached, it shall issue trip signals to the Turbine Control System to trip turbine generator, Feedwater and Condensate Systems to trip feedpumps and close discharge valves.	5. Perform test to confirm high water level trip signal is properly issued.	5. High water level trip signal is issued to Turbine Control System and Feedwater and Condensate System when reactor water reaches high level.
6. This system shall monitor reactor water level and in the event that low water level is reached, shall issue trip signal to Recirculation Flow Control System (RFC System logic determines need for RIP runback).	6. Perform test to confirm low water level trip signal is properly issued.	6. Low level trip signal is issued to Recirculation Flow Control System when reactor water reaches low level.

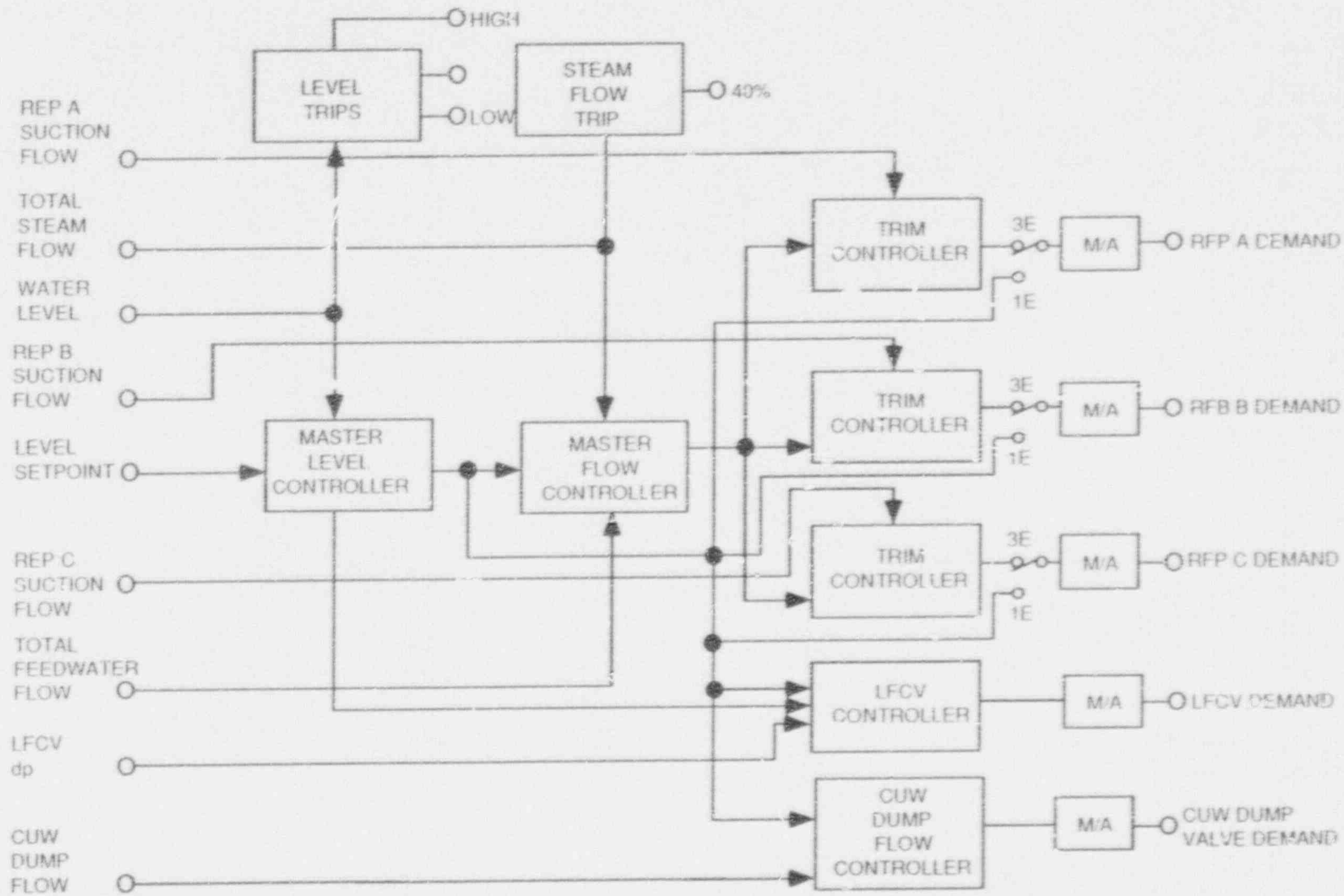


Figure 2.2.3a FWC Control Algorithm

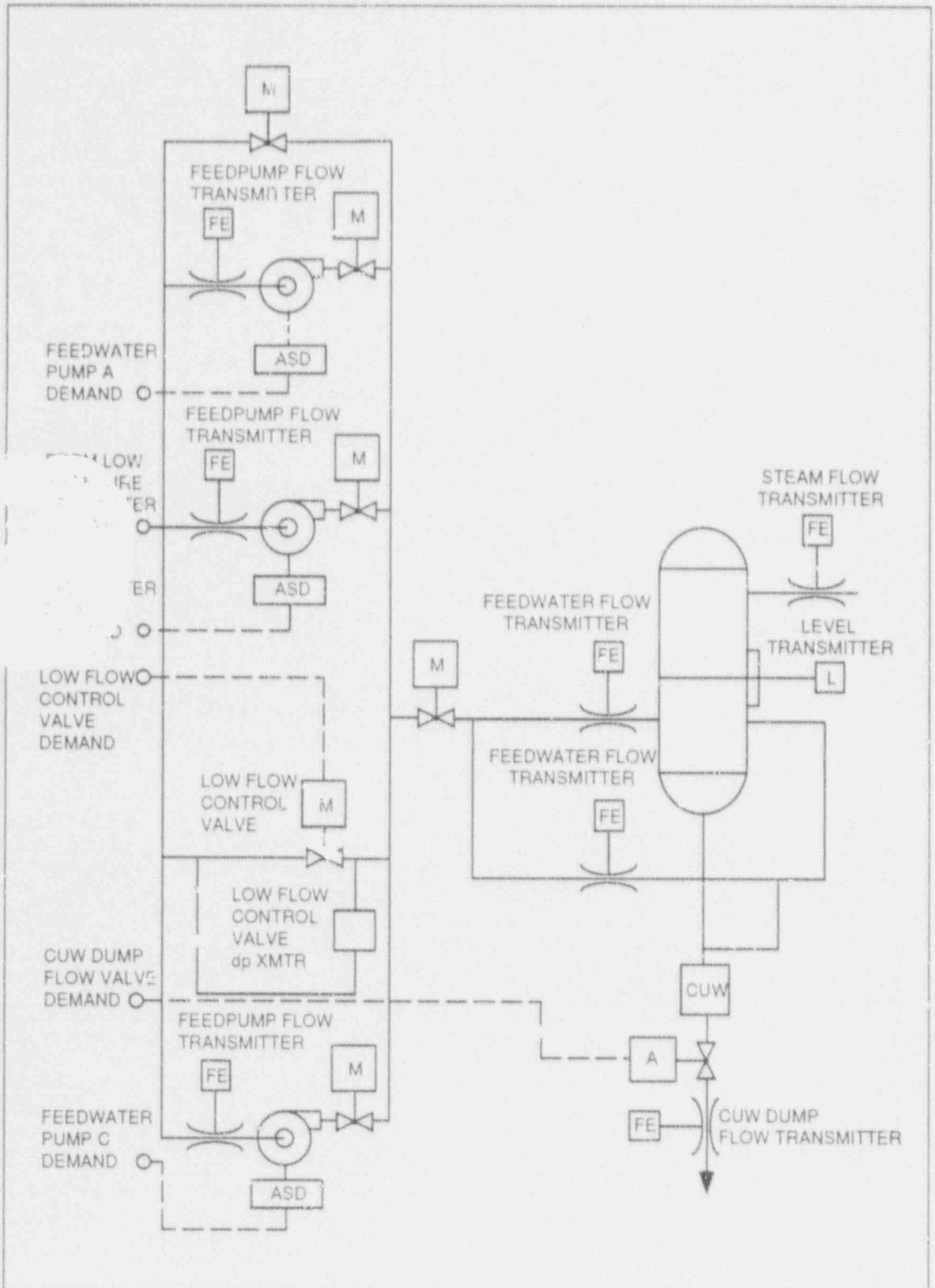


Figure 2.2.3b FWC Piping and Instrumentation

2.2.4 Standby Liquid Control System

The standby liquid control system (SLCS) is designed to inject neutron absorbing poison using a boron solution into the reactor and thus provide back-up reactor shutdown capability independent of the normal reactivity control system based on insertion of control rods into the core. The system is capable of operation over a wide range of reactor pressure conditions up to and including the elevated pressures associated with an anticipated plant transient coupled with a failure to scram (ATWS).

The standby liquid control system (SLCS) is designed to provide the capability of bringing the reactor, at any time in a cycle, from full power and at all conditions to a subcritical condition with the reactor in the most reactive xenon-free state without control rod movement. The system will complete the injection of the boron solution in 50 to 150 minutes.

The SLCS consists of a boron solution storage tank, two positive displacement pumps, two motor operated injection valves which are provided in parallel for redundancy and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged through the 'B' high pressure core flooder (HPCF) subsystem sparger. Figure 2.2.4 shows major system components. Key equipment performance requirements are:

a.	Pump flow (minimum)	100 gpm with both pumps running
b.	Maximum reactor pressure (for injection)	1250 psig
c.	Pumpable volume in storage tank (minimum)	6100 U.S. gal

The required volume of solution contained in the storage tank is dependent upon the solution concentration and this concentration can vary during reactor operations. A required boron solution volume/concentration relationship is used to define acceptable SLCS storage tank conditions during plant operation.

The SLCS is automatically initiated during an ATWS. An ATWS condition exists when either of the following occurs:

a. High RPV pressure (1125 psig) and Average Power Range Monitor (APRM) not down scale for 3 minutes, or

b. Low RPV level (Level 2) and APRM not down scale for 3 minutes.

When the SLCS is automatically initiated to inject a liquid neutron absorber into the reactor, the following devices are actuated:

a. the two injection valves are opened;

b. the two storage tank discharge valves are opened;

c. the two injection pumps are started; and

d. the reactor water cleanup isolation valves are closed.

The SLCS can also be manually initiated from the main control room. When the SLCS is manually initiated to inject a liquid neutron absorber into the reactor, the following devices are actuated by each switch:

a. one of the two injection valves is opened;

b. one of the two storage tank discharge valves is opened;

c. one of the two injection pumps is started; and

d. one of the reactor water cleanup isolation valves is closed.

The SLCS provides borated water to the reactor core to compensate for the various reactivity effects during the required conditions. These effects include xenon decay, elimination of steam voids, changing water density due to the reduction in water temperature, Doppler effect in uranium, changes in neutron leakage and changes in control rod worth as boron affects neutron migration length. To meet this objective, it is necessary to inject a quantity of boron which produces a minimum concentration of 850 ppm of natural boron in the reactor core at 70°F. To allow for potential leakage and imperfect mixing in the reactor system, an additional 25% (220) is added to the above requirement. The required concentration is achieved accounting for dilution in the RPV with normal water level and including the volume in the residual heat removal shutdown cooling piping. This quantity of boron solution is the amount which is above the pump suction shutoff level in the tank thus allowing for the portion of the tank volume which cannot be injected.

The pumps are capable of producing discharge pressure to inject the solution into the reactor when the reactor is at high pressure conditions corresponding to the system relief valve actuation (1560 psig) which is above peak ATWS pressure.

The SLCS includes sufficient Control Room indication to allow for the necessary monitoring and control during design basis operational conditions. This includes pump discharge pressure, storage tank liquid level and temperature as well as valve open/close and pump on/off indication for those components shown on Figure 2.2.4 (with the exception of the simple check valves).

The SLCS uses a dissolved solution of sodium pentaborate as the neutron-absorbing poison. This solution is held in a storage tank which has a heater to maintain solution temperature above the saturation temperature. The heater is capable of automatic operation and automatic shutoff to maintain an acceptable solution temperature. The SLCS solution tank, a test water tank, the two positive displacement pumps, and associated valving is located in the secondary containment on the floor elevation below the operating floor. This is a Seismic Category I structure, and the SLCS equipment is protected from phenomena such as earthquakes, tornados, hurricanes and floods as well as from internal postulated accident phenomena. In this area, the SLCS is not subject to conditions such as missiles, pipe whip, and discharging fluids.

The pumps, heater, valves and controls are powered from the standby power supply or normal offsite power. The pumps and valves are powered and controlled from separate buses and circuits so that single active failure will not prevent system operation. The power supplied to one motor operated injection valve, storage tank discharge valve, and injection pump is powered from Division I, 480 VAC. The power supply to the other motor-operated injection valve, storage tank outlet valve, and injection pump is powered from Division II, 480 VAC. The power supply to the tank heaters and heater controls is connectable to a standby power source. The standby power source is Class 1E from an on-site source and is independent of the off-site power.

Components of the system which are required for injection of the neutron absorber into the reactor are classified Seismic Category I. The major mechanical components are designed to meet ASME Code requirements as shown below.

Component	ASME Code Class	Design Conditions Pressure	Temperature
Storage Tank	2	Static Head	150°F
Pump	2	1560 psig	150°F
Injection Valves	1	1560 psig	150°F
Piping Inboard of Injection Valves	1	1250 psig	575°F

Piping and components not required for the injection of the neutron absorber (e.g. test tank, sampling system line and storage tank vent) are classified NNS.

Design provisions to permit system testing include a test tank and associated piping and valves. The tank can be supplied with demineralized water which can be pumped in a closed loop through either pump or injected into the reactor.

The SLCS is separated both physically and electrically from the control rod drive system.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.2.4 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the SLCS.

Table 2.2.4: STANDBY LIQUID CONTROL SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The minimum average poison concentration in the reactor after operation of the SLCS shall be equal to or greater than 850 ppm.	1. Construction records, revisions and plant visual examinations will be undertaken to assess as-built parameters listed below for compatibility with SLCS design calculations. If necessary, an as-built SLCS analysis will be conducted to demonstrate the acceptance criteria is met. **Critical Parameters:** a. Storage tank pumpable volume b. RPV water inventory at 70°F c. RHR shutdown cooling system water inventory at 70°F	1. It must be shown the SLCS can achieve a poison concentration of 850 ppm or greater assuming a 25% dilution due to non-uniform mixing in the reactor and accounting for dilution in the RHR shutdown cooling systems. This concentration must be achieved under system design basis conditions. This requires that SLCS meet the following values: Storage tank pumpable volume range 6100-6800 gal. RPV water inventory $\leq 1.00 \times 10^6$ lb RHR shutdown cooling system inventory $\leq .287 \times 10^6$ lb
2. A simplified system configuration in shown in Figure 2.2.4.	2. Inspections of installation records together with plant walkdowns will be conducted to confirm that the installed equipment is in compliance with the design configuration defined in Figure 2.2.4.	2. The system configuration is in accordance with Figure 2.2.4.

Table 2.2.4: STANDBY LIQUID CONTROL SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. SLCS shall be capable of delivering 100 gpm of solution with both pumps operating against the elevated pressure conditions which can exist in the reactor during events involving SLCS initiation.	3. System preoperation tests will be conducted to demonstrate acceptable pump and system performance. These tests will involve establishing test conditions that simulate conditions which will exist during an SLCS design basis event. To demonstrate adequate Net Positive Suction Head (NPSH), delivery of rated flow will be confirmed by tests conducted at conditions of low level and maximum temperature in the storage tank, and the water will be injected from the storage tank to the RPV.	3. It must be shown that the SLCS can automatically inject 100 gpm (both pumps running) against a reactor pressure of 1250 psig with simulated ATWS conditions. It must also be shown that the SLCS pumps can pump the entire storage tank pumpable volume.
4. The system is designed to permit in-service functional testing of SLCS.	4. Field tests will be conducted after system installation to confirm, in-service system testing can be performed.	4. Using normally installed controls, power supplies and other auxiliaries, the system has the capability to: a. Pump tests in a closed loop on the test tank and b. Reactor pressure vessel injection tests using demineralized water from the test tank.
5. The pump, heater, valves and controls can be powered from the standby AC power supply as described in Section 2.2.4.	5. System tests will be conducted after installation to confirm that the electrical power supply configurations are in compliance with design commitments.	5. The installed equipment can be powered from the standby AC power supply.
6. SLCS components which are required for the injection of the neutron absorber into the reactor are classified Seismic Category I and qualified for appropriate environment for locations where installed.	6. See Generic Equipment Qualification verification activities (ITA).	6. See Generic Equipment Qualification Acceptance Criteria (AC).

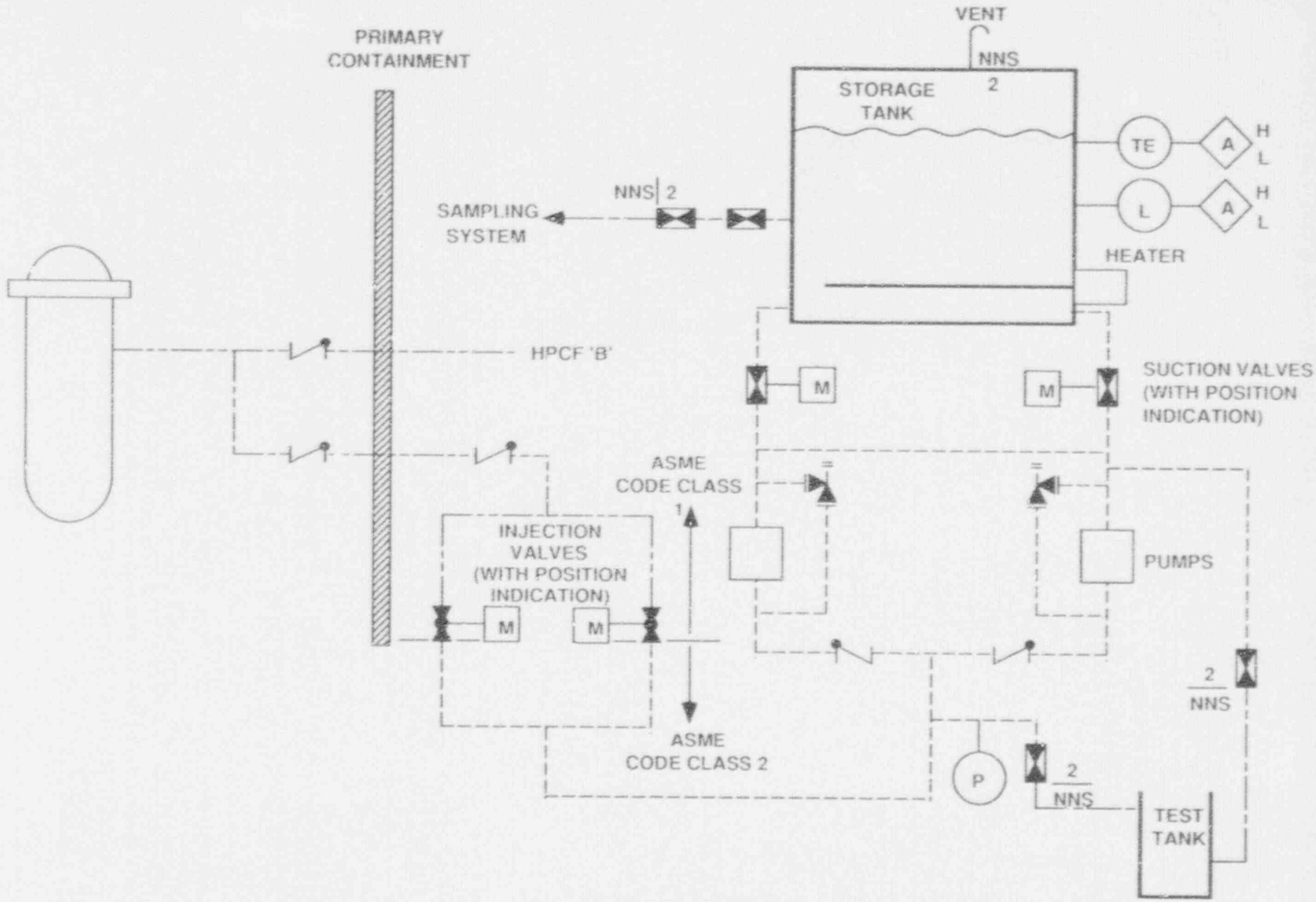


Figure 2.2.4 STANDBY LIQUID CONTROL SYSTEM (STANDBY MODE)

2.2.5 Neutron Monitoring System

Design Description

Later. Stage 3 Item.

2.2.6 Remote Shutdown System

Design Description

Later. Stage 3 Item.

2.2.7 Reactor Protection System

Design Description

The reactor protection system (RPS) for the Advanced Boiling Water Reactor (ABWR) is a warning and trip system where initial warning and trip decisions are implemented with software logic installed in microprocessors. The primary functions of this system is to provide prompt protection against the onset and consequences of events or conditions that threaten the integrity of the fuel barrier. To accomplish this, the system is designed to: (1) make the logic decisions related to warning and trip conditions of the individual instrument channels, and (2) make the decision for system trip (emergency reactor shutdown) based on coincidence of instrument channel trip conditions.

The RPS is classified as a safety protection system (i.e., as differing from a reactor control system or a power generation system). The functions of the RPS and its components are safety-related. The RPS and the electrical equipment of the system are also classified as Safety Class 3, Seismic Category I and as IEEE electrical category Class 1E.

Basic System Parameters are:

a.	Number of independent divisions of equipment	4
b.	Minimum number of sensors per trip variable (at least one per division)	4
c.	Number of automatic trip systems (one per division)	4
d.	Automatic trip logic used for plant sensor inputs (per division)	2-out-of-4
e.	Separate automatic trip logic used for division trip outputs	2-out-of-4
f.	Number of separate manual trip systems	2
g.	Manual trip logic	2-out-of-2

The RPS consists of instrument channels, trip logics, trip actuators, manual controls and scram logic circuitry that initiates rapid insertion of control rods (scram) to shut down the reactor for situations that could result in unsafe reactor operating conditions. The RPS also establishes the required trip conditions that are appropriate for the different reactor operating modes and provides status and control signals to other systems and annunciators. The RPS related equipment includes detectors, switches, microprocessors, solid state logic circuits, relay type contactors, relays, solid-state load drivers, lamps, displays, signal transmission routes, circuits and other equipment which are required to execute the functions of the system. To accomplish its overall function, the RPS utilizes the functions of the essential multiplexing system (EMS) and of portions of the safety system logic and control (SSLC) system.

As shown in Figure 2.2.7a, the RPS interfaces with the neutron monitoring system (NMS), the process radiation monitoring (PRRM) system, the nuclear boiler system (NBS), the control rod drive (CRD) system, the rod control and information system (RC&IS), the recirculation flow control (RFC) system, the process computer system and with other plant systems and equipment. RPS components and equipment are separated or segregated from process control system sensors, circuits and functions such as to minimize control and protection system interactions. Any necessary interlocks from the RPS to control systems are through isolation devices.

The RPS is a four division system which is designed to provide reliable single-failure proof capability to automatically or manually initiate a reactor scram while maintaining protection against unnecessary scrams resulting from single failures in the RPS. The RPS remains single-failure proof even when one entire division of channel sensors is bypassed and/or when one of the four automatic RPS trip logic systems is out-of-service. Equipment within the RPS is designed to fail into a trip initiating state or other safe state on loss of power or input signals or disconnection of portions of the system. The system also includes trip bypasses and isolated outputs for display, annunciation or performance monitoring. RPS inputs to annunciators, recorders and the computer are electrically isolated so that no malfunction of the annunciating, recording, or computing equipment can functionally disable any portion of the RPS. The RPS related equipment is divided into four redundant divisions of sensor (instrument) channels, trip logics and trip actuators, and two divisions of manual scram controls and scram logic circuitry. The automatic and manual scram initiation logic systems are independent of each other and use diverse methods and equipment to initiate a reactor scram. The RPS design is such that, once a full reactor scram has been initiated automatically or manually, this scram condition seals-in such that the intended fast insertion of control rods into the reactor core can continue to completion. After a time delay, the design allows operator action to return the RPS to normal.

Figure 2.2.7b shows the RPS divisional separation aspects and the signal flow paths from sensors to scram pilot valve solenoids. Equipment within a RPS related sensor channel consists of sensors (transducers or switches), multiplexers and digital trip modules (DTMs). The sensors within each channel monitor for abnormal operating conditions and send either discrete bistable (trip/no trip) or analog signals directly to the RPS related DTM or else send analog output signals to the RPS related DTM by means of the remote multiplexer unit (RMU) within the associated division of essential multiplexing system (EMS). The RPS related bistable switch type sensors, or, in the case of analog channels, the RPS software logic, will initiate reactor trip signals within the individual sensor channels, when any one or more of the conditions listed below exist within the plant during different conditions of reactor operation, and will initiate reactor scram if coincidence logic is satisfied.

a. Turbine Stop Valves Closure (above 40% power levels) [RPS]

b. Turbine Control Valves Fast Closure (above 40% power levels) [RPS]

c. NMS monitored SRNM and APRM conditions exceed acceptable limits [NMS]

d. High Main Steam Line Radiation [PRRM System]

e. High Reactor Pressure [NBS]

f. Low Reactor Water Level (Level 3) [NBS]

g. High Drywell Pressure [NBS]

h. Main Steam Lines Isolation (MSLI) (Run mode only) [NBS]

i. Low Control Rod Drive Accumulator Charging Header Pressure [CRD]

j. Operator-initiated Manual Scram [RPS]

The system monitoring the process condition is indicated in brackets in the list above. The RPS outputs, the NMS outputs, the PRRM system outputs and the MSLI and manual scram outputs are provided directly to the RPS by hard-wired or fiber-optic signals. The NBS and the CRD system provide other sensor outputs through the EMS. Analog to digital conversion of these latter sensor output values is done by EMS equipment. The DTM in each division uses either the discrete bistable input signals, or compares the current values of the individual monitored analog variables with their trip setpoint values, and for each variable sends a separate, discrete bistable (trip/no trip) output signal to the trip logic units (TLUs) in all four divisions of trip logics. The DTMs and TLUs utilized by the RPS are microprocessor components within the SSLC system.

RPS related equipment within a RPS division of trip logic consists of manual control switches, bypass units (BPUs), trip logic units (TLUs) and output logic units (OLUs). The manual control switches and the BPUs, TLUs and OLUs are components of the RPS portions of the SSLC system. The various manual switches provide the operator means to modify the RPS trip logic for special operation, maintenance, testing and system reset. The bypass units perform bypass and interlock logic for the single division of channel sensors bypass function and for the single division TLU bypass function. The TLUs perform the automatic scram initiation logic, normally checking for two-out-of-four coincidence of trip conditions in any set of instrument channel signals coming from the four division DTMs or from isolated bistable inputs from all four divisions of NMS equipment, and outputting a trip signal if any one of the two-out-of-four coincidence checks is satisfied. TLU trip decision logic in all four RPS

TLUs becomes a check for two-out-of-three coincidence of trip conditions if any one division of channel sensors has been bypassed. The OLUs perform the division trip, seal-in, reset and trip test functions. Trip signals from the OLUs within a single division are used to trip the trip actuators, which are fast response, bistable, solid-state load drivers for automatic scram initiation, and are trip relays for air header dump (back-up scram) initiation. Load driver outputs toggled by a division OLU interconnect with load driver outputs toggled by other division OLUs into two separate arrangements which results in two-out-of-four scram logic, i.e., reactor scram will occur if load drivers associated with any two or more divisions receive trip signals.

The isolated ac load drivers are fast response time, bistable, solid-state, high current interrupting devices. The operation of the load drivers is such that a trip signal on the input side will create a high impedance, current interrupting condition on the output side. The output side of each load driver is electrically isolated from its input signal. The load driver outputs are arranged in the scram logic circuitry, between the scram pilot valves' solenoids and the solenoids ac power source, such that when in a tripped state the load drivers will cause deenergization of the scram pilot valve solenoids (scram initiation). Normally closed relay contacts are arranged in the two back-up scram logic circuits, between the air header dump valve solenoid and air header dump valve dc solenoid power source, such that when in a tripped state (coil deenergized) the relays will cause energization of the air header dump valve solenoids (air header dump initiation). Associated dc voltage relay logic is also utilized to effect scram reset permissives and scram-follow (control rod run-in) initiation.

The RPS design for the ABWR is testable for correct response and performance, in over-lapping stages, either on-line or off-line (to minimize potential of unwanted trips). Access to bypass capabilities of trip functions, instrument channels or a trip system and access to setpoints, calibration controls and test points are under administrative control.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.2.7 provides a definition of the visual inspections, tests and/or analyses, together with associated acceptance criteria, which will be used by the RPS.

Table 2.2.7: REACTOR PROTECTION SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. RPS components and equipment are kept separate from equipment associated with process control systems.	1. Visual field inspections and analyses of relationship of installed RPS equipment and of installed equipment of interfacing process control systems (and/or tests of interfaces) to confirm appropriate isolation methods used to satisfy separation and segregation requirements.	1. RPS equipment installation acceptable if inspections, analyses and/or tests confirm that any failure in process control systems can not prevent RPS safety functions.
2. Fail-safe failure modes result upon loss of power or disconnection of components.	2. Field tests to confirm that trip conditions and/or bypass inhibits result upon loss of power or disconnection of components.	2. Acceptable if safe state conditions result upon loss of power or disconnection of portions of the RPS.
3. Provisions exist to limit access to trip setpoints, calibration controls and test points.	3. Visual field inspections of the installed RPS equipment will be used to confirm the existence of appropriate administrative controls.	3. The RPS hardware/firmware will be considered acceptable if appropriate methods exist to enforce administrative control for access to sensitive areas.
4. The four redundant divisions of RPS equipment and the four automatic trip systems are independent from each other except in the area of the required coincidence of trip logic decisions and are both electrically and physically separated from each other. Similarly, the two manual trip systems are separate and independent of each other and of the four automatic trip systems.	4. Inspections of fabrication and installation records and construction drawings or visual field inspections of the installed RPS equipment will be used to confirm the quadruple redundancy of the RPS and the electrical and physical separation aspects of the RPS instrument channels and the four automatic trip systems as well as their diversity and independence from the two manual trip systems.	4. Installed RPS equipment will be determined to conform to the documented description of the design as depicted in Figure 2.2.7b.

Table 2.2.7: REACTOR PROTECTION SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. It is possible to conduct verifications of RPS operations, both on-line and off-line, by means of a) individual instrument channel functional tests, b) trip system functional tests and c) total system functional tests.	5. Preoperational tests will be conducted to confirm that system testing such as channel checks, channel functional tests, channel calibrations, coincident logic tests and paired control rods scram tests can be performed. These tests will involve simulation of RPS testing modes of operation. Interlocks associated with the reactor mode switch positions, and with other operational and maintenance bypasses or test switches will be tested and annunciation, display and logging functions will be confirmed.	5. The installed reactor protection system configuration, controls, power sources and installations of interfacing systems supports the RPS logic system functional testing and the operability verification of design as follows: a. Installed RPS hardware/firmware initiates trip conditions in all four RPS automatic trip systems upon coincidence of trip conditions in two or more instrument channels associated with the same trip variable(s). b. Installed system initiates full reactor trip and emergency shutdown (i.e., deenergization of both solenoids associated with all scram pilot valves) upon coincidence of trip conditions in two or more of the four RPS automatic trip systems. c. Installed system initiates trip conditions in both RPS manual trip systems if both manual trip switches are operated or if the reactor mode switch is placed in the "shutdown" position. d. Trip system (automatic and manual) trip conditions seal-in and protective actions go to completion. Trip reset (after appropriate delay for trip completion) requires deliberate Operator action.

Table 2.2.7: REACTOR PROTECTION SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
		5. (Continued) e. Installed system energizes both air header dump (back-up scram) valves of the CRD hydraulic system, and initiates CRD motor run-in, concurrent only with a full scram condition. f. When not bypassed, trips result upon loss or disconnection of portions of the system. When bypassed, inappropriate trips do not result. g. Installed system provides isolated status and control signals to data logging, display and annunciator systems. h. Installed system demonstrates operational interlocks (i.e., trip inhibits or permissives) required for different conditions of reactor operation.
6. The RPS design provides prompt protection against the onset and consequences of events or conditions that threaten the integrity of the fuel barrier.	6. Preoperational tests will be conducted to measure the RPS and supporting systems response times to: (1) monitor the variation of the selected processes; (2) detect when trip setpoints have been exceeded; and, (3) execute the subsequent protection actions when coincidence of trip conditions exist.	6. The RPS hardware/firmware response to initiate reactor scram will be considered acceptable if such response is demonstrated to be sufficient to assure that the specified acceptable fuel design limits are not exceeded.

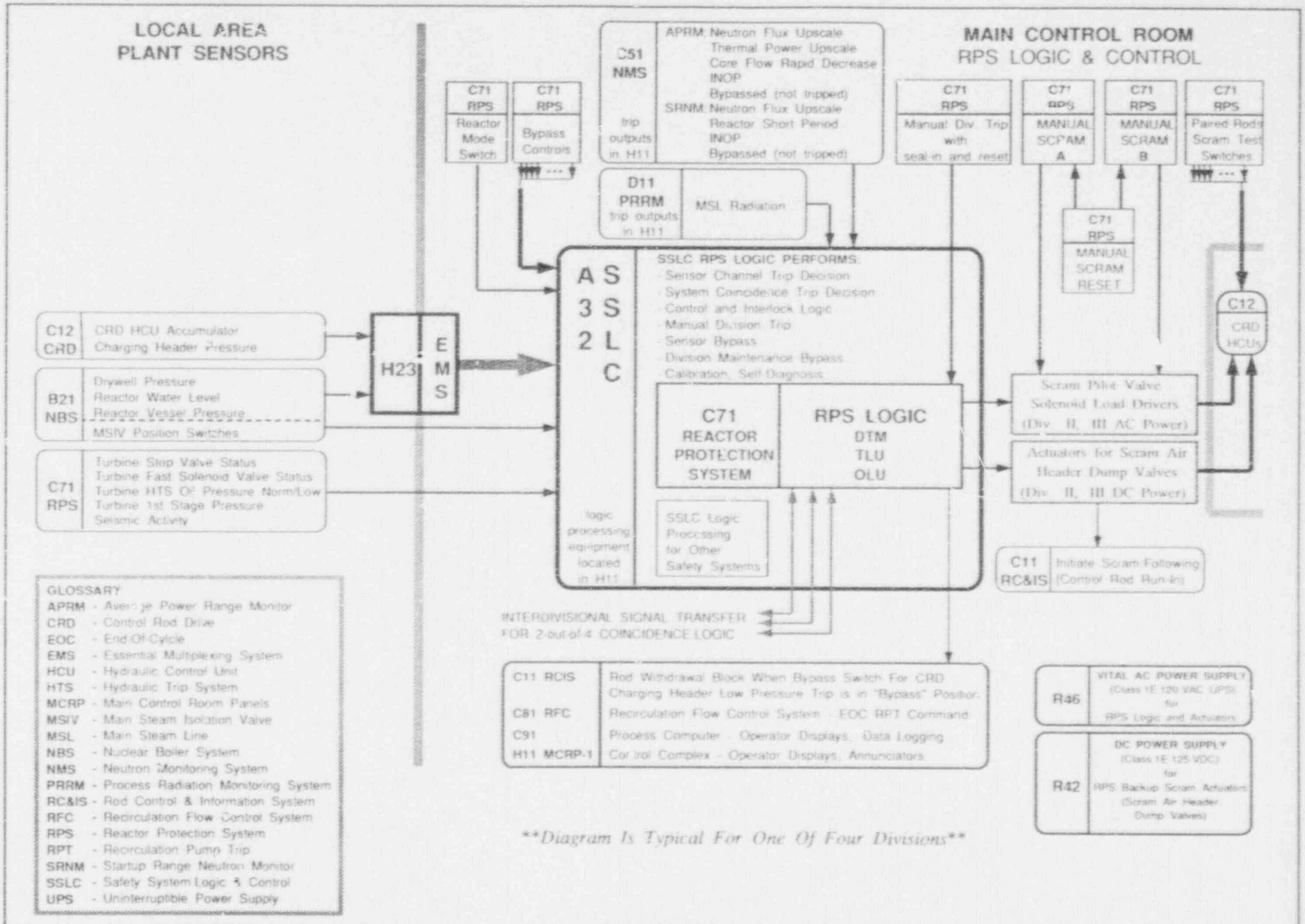


Figure 2.2.7a REACTOR PROTECTION SYSTEM

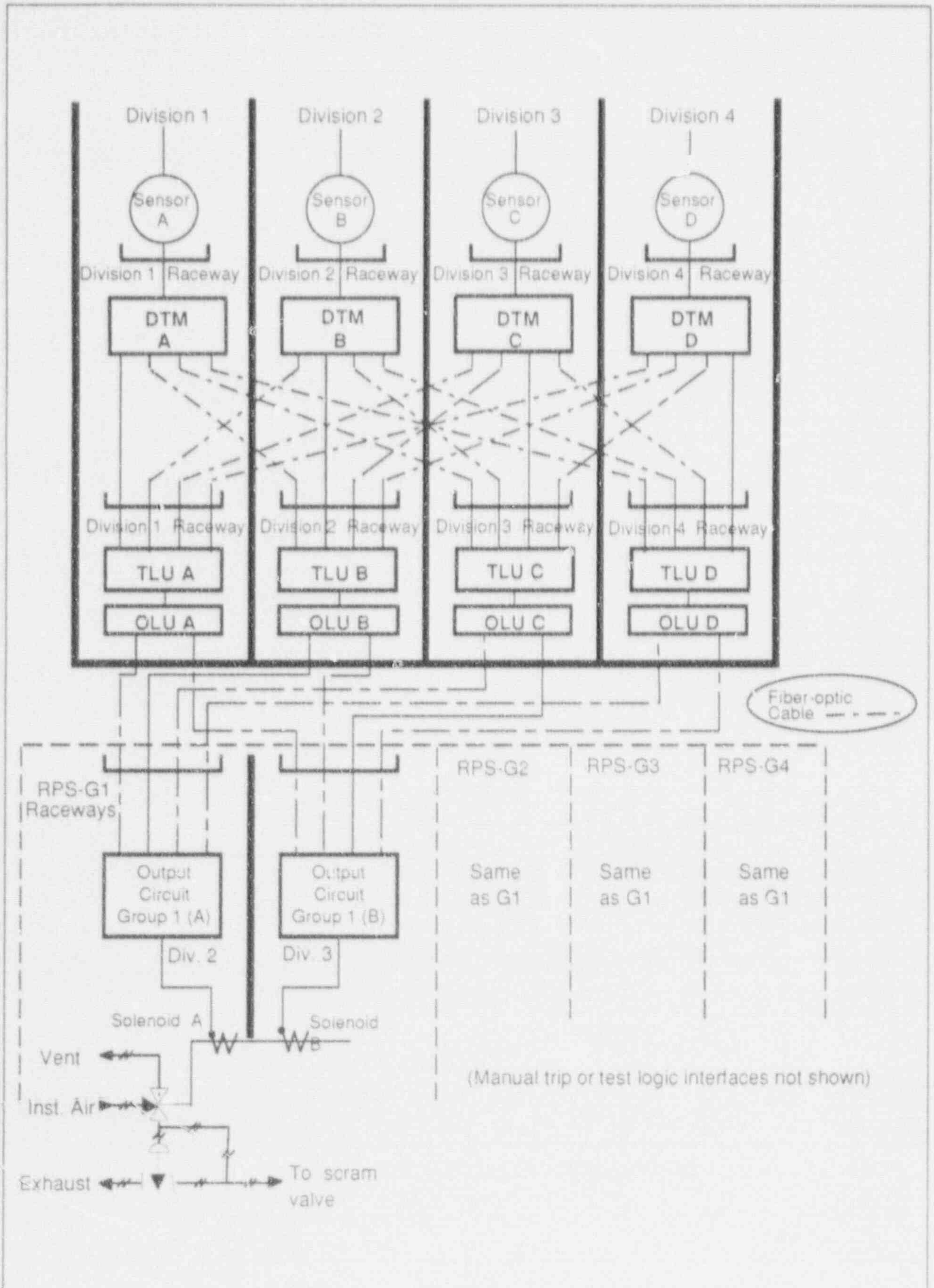


Figure 2.2.7b REACTOR PROTECTION SYSTEM

2.2.8 Recirculation Flow Control System

Design Description

Later. Stage 3 Item.

2.2.9 Automatic Power Regulator System

Design Description

Later. Stage 3 Item.

2.2.10 Steam Bypass and Pressure Control System

Design Description

The Steam Bypass and Pressure Control (SB&PC) System is a non-safety related system. It is a control system only, and consists of three redundant fault tolerant digital controllers (FTDC) for control algorithms and logic along with indicators and alarms for operator information and the non-safety related power supplies to power each FTDC. Because of the systems triple redundancy, it is possible to lose one logic channel without impacting the system functions. In addition, each FTDC is equipped with self-test and on-line diagnostic capabilities for identifying and isolating failure of input/output signals, buses, power supplies, processors and interprocessor communications. These on-line tests and diagnostics can be performed without interrupting the normal control operation of the SB&PC System. The SB&PC system receives input signals from other systems and sensors as shown in Figure 2.2.10 and as follows:

a. Steam bypass valve position switches,

b. Steam bypass valve servo current sensors,

c. The TCS turbine trip sensors,

d. The TCS power/load unbalance relay operation,

e. The Turbine Bypass System (TBS) hydraulic power supply trouble sensors,

f. The Nuclear Boiler System (NBS) Main Steam Isolation Valve (MSIV) position switches,

g. NBS narrow and wide range dome pressure transmitters

h. Steam Extraction System main condenser low vacuum sensors

i. Operator manual commands and manual switch positions

The SB&PC system provides output signals to:

a. The Turbine Control System (TCS),

b. The Automatic Power Regulation (APR) System,

c. The Recirculation Flow Control System,

d. Various related control room indicators and alarms, and

e. The process computer.

The primary function of the pressure control portion of the SB&PC system is to efficiently control the reactor system pressure during plant startup/shutdown, power generation, and load following modes of plant operation, through control of turbine control and/or steam bypass valves. The system maintains plant stability during pressure setpoint changes.

The system also has several secondary functions used during non-emergency situations and plant transients, none of which are safety related.

Additional reactor system pressure control functions are provided by other systems when the main steam isolation valves are closed.

The function of the steam bypass portion of the system is to control steam pressure by sending steam directly to the main condenser whenever reactor steam production exceeds main turbine steam flow demand. The system provides transfer capability between steam bypass valves and turbine control valves, and can accommodate load rejection.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.2.10 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the SB&PC system.

Table 2.2.10: Steam Bypass and Pressure Control System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Each FTDC is equipped with self-test and on-line diagnostic capabilities for identifying and isolating failure of input/output signals, buses, power supplies, processors and interprocessor communications. These on-line tests and diagnostics can be performed without interrupting the normal control operation of the SB&PC System.	1. Perform a on-line self-test with complete diagnostics based on the parameters shown in the design description (2.2.10).	1. The results of the self-test confirms system operation.
2. The system responds to setpoint changes while maintaining plant stability.	2. A response test shall be performed.	2. Testing results conform to system response and stability requirements.
3. The system incorporates redundant control channels.	3. The system shall be tested by simulating failure of one operating controller.	3. The system continues to function during loss of one operating controller.
4. The system provides successful transfer capability between steam bypass valves and turbine control valves.	4. Pressure setpoint step tests shall be performed.	4. Successful transition of opening bypass valves is observed.
5. Steam bypass capacity is sufficient to accommodate load rejection.	5. A load rejection test shall be performed with the turbine load reference set just above the initial pressure regulation demand.	5. Steam bypass capacity is demonstrated.

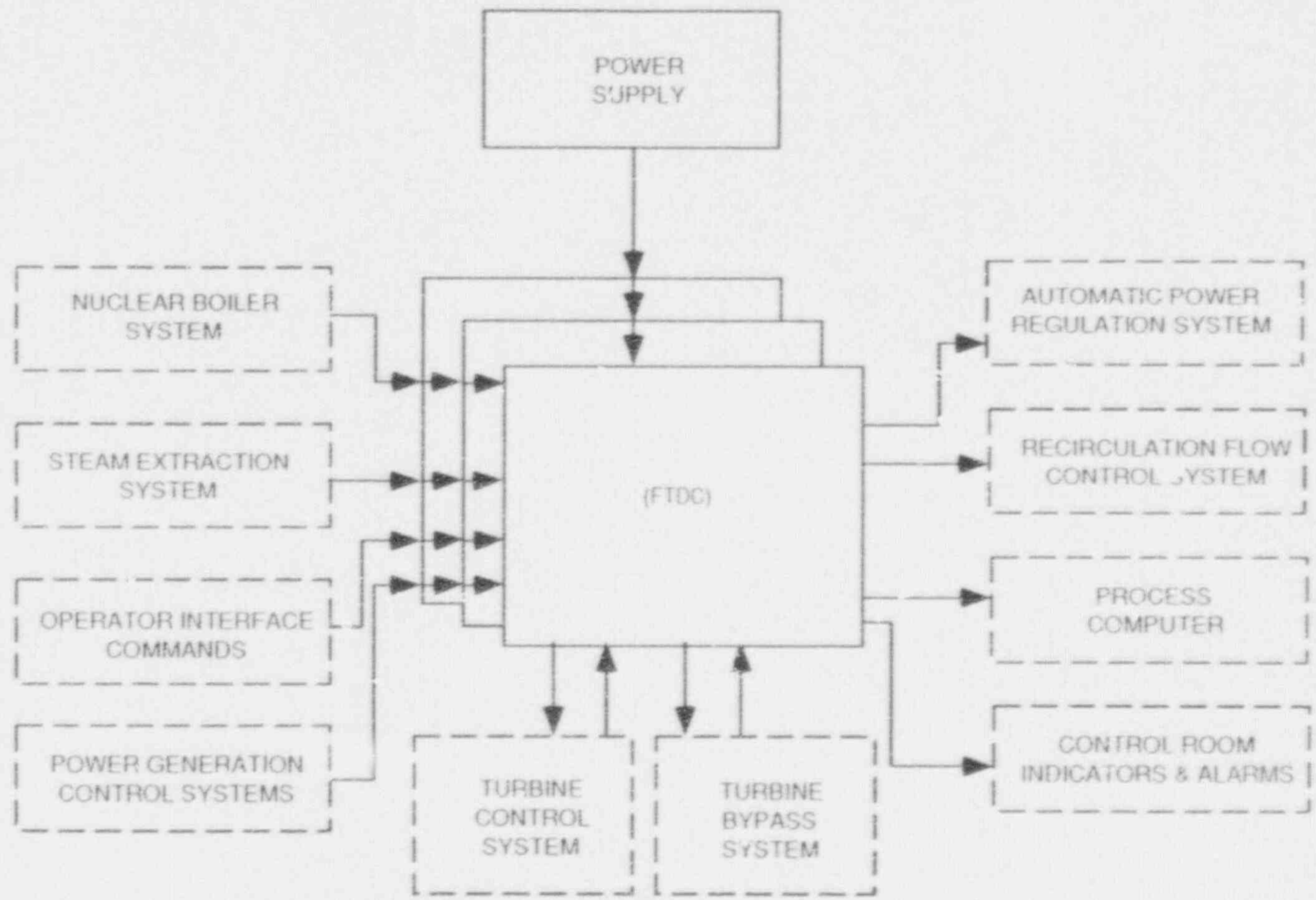


Figure 2.2.10 Steam Bypass and Pressure Control System

.2.11 Process Computer

Design Description

Later. Stage 3 Item.

2.2.12 Refueling Platform Control Computer

Design Description

Later. Stage 3 Item.

2.2.13 CRD Removal Machine Control Computer

Design Description

No Tier 1 entry for this system.

2.3 Radiation Monitoring

2.3.1 Radiation Monitoring System

Design Description

Later. Stage 3 Item.

2.3.2 Area Radiation Monitoring System

Design Description

Later. Stage 3 Item.

2.3.3 Dust Radiation Monitoring System

Not an ABWR system. No entry.

2.3.4 Containment Atmospheric Monitoring System

Design Description

The primary function of the Containment Atmospheric Monitoring (CAM) system is to monitor the atmosphere in the primary containment for excessive gamma radiation levels and for high concentration of oxygen and hydrogen levels during normal reactor operations and under post accident conditions. CAMS is classified as a safety system, seismic Category I, and provides no control function.

The safety function of CAMS is to identify if a potentially explosive mixture of hydrogen and oxygen is building up in the primary containment during post accident monitoring and provide concentration measurements to the operator for use in flammability control. Also, the use of gamma monitors with high-range are provided for post accident monitoring.

CAM consists of two independent but redundant divisional subsystems, (I and II), which are electrically and physically separated. Each CAM division provides measurement of the total gamma-ray dose rate and of the concentration of hydrogen and oxygen levels in the drywell and/or the suppression chamber during normal plant operation and following a LOCA event. The system is configured as shown in Figure 2.3.4.

The operation of each CAM subsystem can be activated manually by the operator during reactor operations or it will be automatically activated by the LOCA signal, either on high drywell pressure or on low reactor water level. In either mode, sampling is selected for the designated area.

Two high-range radiation monitoring channels are provided per division, one for monitoring the radiation level in the drywell and the other for monitoring the radiation level in the suppression chamber. Each channel provides continuous dosage rate measurements for display and recording in the control room. Alarms are activated on high radiation levels and when the monitors fail and become inoperative. Each monitor has a measurement and display range of 1 to 10^7R/hr.

Each divisional hydrogen/oxygen monitoring channel consists of a gas sampling rack used to extract samples of the atmosphere in the drywell (DW) or the suppression chamber (SC) and feeds the sample to a local gas analyzer for measurement and display in the control room. Alarms are activated on high gas content levels and for abnormal flow sampling. Each gas sampling rack is provided with gas calibration sources to verify operability of the individual gas monitors and for periodic calibration. Each hydrogen and oxygen monitor is capable of measuring gas contents up to 30% of volume and displays digitally the readout.

Power to each CAM subsystem is provided from the uninterruptable Class 1E 120 VAC vital divisional source.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.3.4 provides definition of the inspections, tests, and/or analysis together with associated acceptance criteria which will be undertaken for the Containment Atmospheric Monitoring System.

Table 2.3.4: Containment Atmospheric Monitoring System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Each CAM subsystem is designed to be operated manually. Air sampling and radiation monitoring are performed to check and analyze the air in the primary containment for high levels of gas concentrations and radiation.	1. Manually activate each subsystem and verify operational readiness of the radiation monitors and the sampling equipment. Select an air sample from the DW and SC, verify alignment of the sample lines control valves, and check for normal air flow.	1. Equipment readiness will be verified when each radiation monitor and each sampling rack correctly indicates no failure and are ready for operation. Correct valve alignment and normal air sampling will be indicated by the instrumentation.
2. Each CAM subsystem is designed to be activated automatically by a LOCA signal for post accident monitoring of the same parameters as identified under item #1 above.	2. In the auto mode, use simulated LOCA signals to initiate operation of each CAM subsystem and verify the sampling and monitoring operations for the conditions stipulated in item #1 above.	2. Equipment readiness will be verified when the same conditions stipulated under item #1 above are satisfied.
3. Each radiation channel monitors and displays the gamma dosage rate in the MCR in R/hr, and activates alarms on high radiation levels or when the monitor fails.	3. Each channel shall be tested to verify channel response and measurement by using a portable gamma radiation source. Tests shall be performed at least one point at low end of the monitor range to verify channel response and sensitivity. Perform trip tests to validate the setpoints.	3. Successful channel operation will be verified when each monitor provides the required response and displays the sensed radiation level and initiates the appropriate alarms.
4. Each CAMS gas sampler extracts an air sample from the DW or the SC, analyzes the hydrogen contents and displays the measurement in MCR in percent volume. High gas levels and abnormal sampling will be alarmed in the MCR.	4. Each hydrogen monitor shall be tested at least 2 known H_2 concentration levels from 1 to 5 percent content using a hydrogen gas calibrated source. The channel response and readout shall be verified. Perform trip tests for setpoint verification.	4. Monitor operability will be verified when the response and display are compatible with the tested gas levels. Confirmation that the MCR alarms are initiated.
5. Each CAMS gas sampler extracts an air sample from the DW or the SC, analyzes the contents for oxygen and displays the results in the MCR in percent volume. High gas levels and abnormal sampling will be alarmed.	5. Each oxygen monitor shall be tested at least 1 known O_2 concentration level from 1 to 5 percent content using an oxygen gas calibration source. The channel response and readout shall be verified. Perform trip tests to verify the setpoints.	5. Monitor operability will be verified when the response and display are compatible with the tested gas levels. Confirmation that the MCR alarms are initiated.

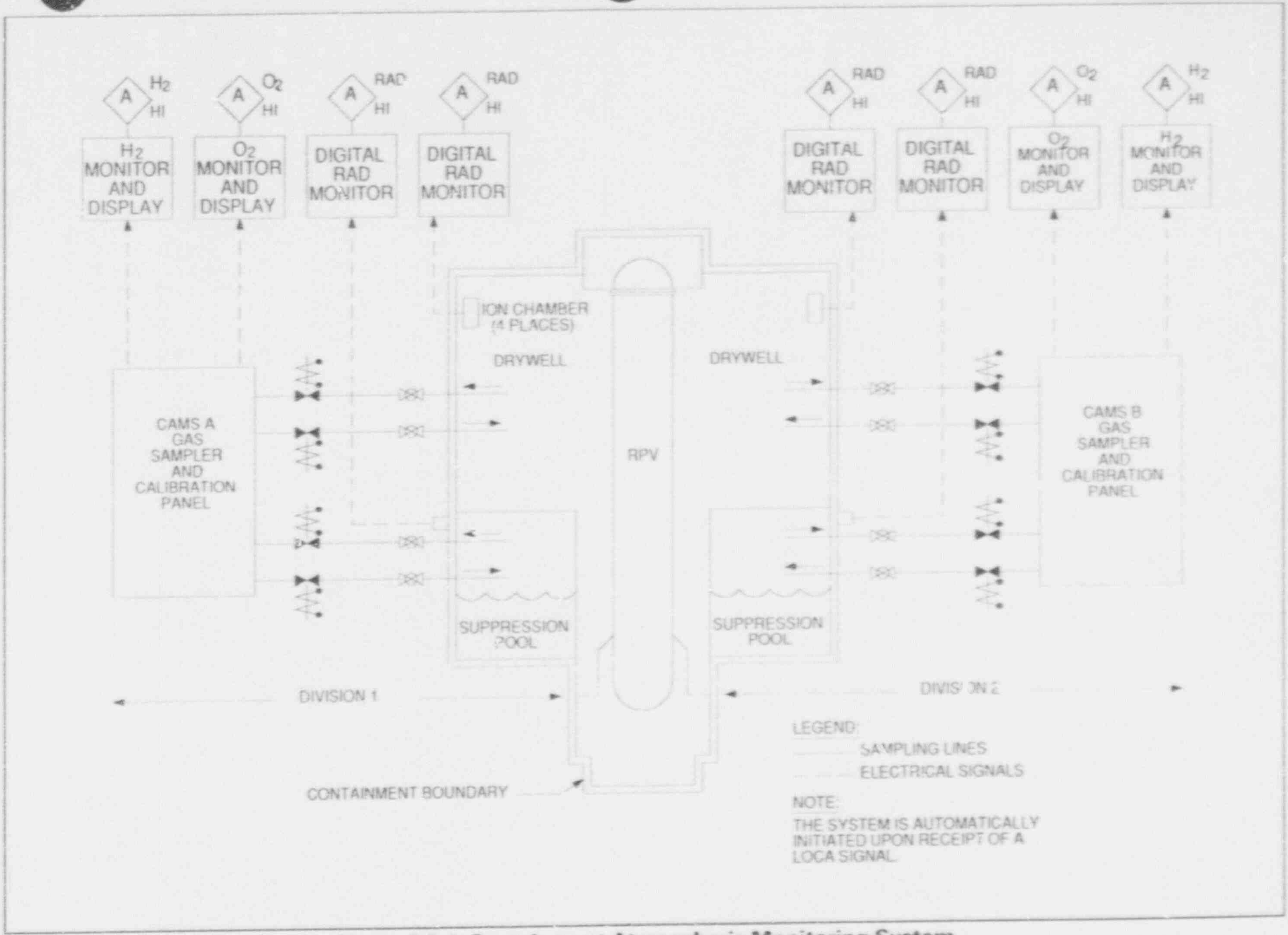


Figure 2.3.4 Containment Atmospheric Monitoring System

2.4 Core Cooling

2.4.1 Residual Heat Removal (RHR) System

Design Description

The RHR system is comprised of three divisionally separate subsystems that perform a variety of functions utilizing the following six basic modes of operation: (1) shutdown cooling, (2) suppression pool cooling, (3) wetwell and drywell spray cooling, (4) low pressure core flooder (LPFL), (5) fuel pool cooling, and (6) ac independent water addition. The configuration of each loop is shown on its P&ID in Figure 2.4.1 (aligned in the standby mode). The major functions of the various modes of operation include containment heat removal, reactor decay heat removal, emergency reactor vessel level makeup and augmented fuel pool cooling. In line with its given functions, portions of the system are a part of the ECCS network and the containment cooling system. Additionally, portions of the RHR system are considered a part of the reactor coolant pressure boundary (RCPB).

The entire RHR system is designed to safety related standards although it performs some non-safety functions, i.e. those that are not taken credit for when evaluating design basis accidents. The safety related modes of operation include low pressure flooding, suppression pool cooling, wetwell spray cooling and shutdown cooling. Non-safety related modes of operation include drywell spray cooling, AC independent water addition and augmented fuel pool cooling. RHR also provides a back-up, safety-related fuel pool make-up capability. Ancillary modes of operation include minimum flow bypass and full flow testing.

The ECCS function of the RHR system is performed by the LPFL mode. Following receipt of a LOCA signal (low reactor water level or high drywell pressure) the RHR system automatically initiates and operates in the LPFL mode, in conjunction with the remainder of the ECCS network, to provide emergency makeup to the reactor vessel in order to keep the reactor core cooled such that the criteria of 10 CFR 50.46 are met. The LPFL mode is accomplished by all 3 loops of the RHR system by transferring water from the suppression pool to the RPV, via the RHR heat exchangers. Although the LPFL mode is automatically initiated , it may also be initiated manually. The system will also automatically revert to the LPFL mode of operation from any other test or operating mode upon receipt of a LOCA signal. Each RHR loop's RPV injection valve requires a low reactor pressure permissive signal whether being opened manually or automatically in response to a LOCA signal.

The containment heat removal function in the ABWR is performed by the containment cooling system which is comprised of the low pressure core flooder (LPFL), suppression pool cooling, and wetwell and drywell spray cooling modes of the RHR system. Following a LOCA the energy present within the reactor primary system is dumped either directly to the suppression pool via the SRVs, or indirectly via the drywell and connecting vents. Subsequently, fission product decay heat continues to add energy to the pool. The containment cooling system is designed to limit the long-term bulk temperature of the suppression pool, and thus limit the long term peak temperatures and pressures within the wetwell and drywell regions of the containment to within their analyzed design limits, with only 2 of the 3 loops in operation (i.e. worse case single failure). The cooling requirements of the containment cooling function establish the necessary RHR heat exchanger heat removal capacity.

The LPFL mode, along with its primary function of cooling the core, also serves to cool the containment as the heat exchanger is designed to always be in the loop. The dedicated suppression pool cooling mode is made available in each of the 3 loops of the RHR system by circulating suppression pool water through the respective RHR heat exchanger and then directly back to the suppression pool. This mode of RHR is usually initiated manually but will also initiate automatically in response to high suppression pool temperature. The wetwell and drywell spray modes of RHR are each available in only 2 of the 3 subsystems (loops B & C). These functions are performed by drawing water from the suppression pool and delivering it to a common wetwell spray header and/or a common drywell spray header, both via the associated RHR heat exchanger(s). These containment spray modes of the RHR system are typically initiated manually, with the exception of automatic initiation of wetwell spray coincident with automatic suppression pool cooling. However, the drywell spray inlet valves can only be opened if there exists high drywell pressure and the RPV injection valves are fully closed. Wetwell and drywell sprays serve as an augmented method of containment cooling. Wetwell spray also serves to mitigate the consequences of steam bypassing the suppression pool.

The normal operational mode of the RHR system is in the shutdown cooling mode of operation which is used to remove decay heat from the reactor core. This mode provides the required safety related capability needed to achieve and maintain a cold shutdown condition, including consideration of the worst case system single failure. The RHR heat exchanger heat removal capacity requirements in this mode are bounded by containment cooling requirements. Shutdown cooling is initiated manually once the RPV has been depressurized below the system low pressure permissive. In this mode each loop takes suction from the RPV via its dedicated suction line, pumps the water through its respective heat exchanger and returns the cooled water to the RPV. Two loops (B & C) discharge water back to the RPV via dedicated spargers while the third loop (A) utilizes the vessel spargers of one of the two feedwater lines (FW-A). The heat removed in the RHR heat exchangers is transported to the ultimate heat sink via the respective division of reactor cooling water and service water. Each shutdown cooling suction valve is interlocked with that loop's suppression pool suction and discharge valves and wetwell spray valve to prevent draining of the reactor vessel to the suppression pool. Also, each shutdown cooling suction valve is interlocked with and automatically closes on low reactor water level.

The augmented fuel pool cooling mode of RHR supplements/replaces the normal fuel pool cooling system during infrequent conditions of high heat load.

This mode is accomplished manually in one of two ways. When the reactor vessel head is removed, the cavity flooded and the fuel pool gates removed, the RHR system cools the fuel pool in the normal shutdown cooling mode. When the fuel pool is otherwise isolated from the reactor cavity, two loops (B & C) of the RHR system can directly cool the pool by taking suction from and discharging back to the normal fuel pool cooling system. This connection also provides for emergency fuel pool make-up capability by supplying a safety related make-up path to the fuel pool from a safety related source, i.e. the suppression pool.

One loop (C) of the RHR system also functions in an AC independent water addition mode. This mode provides a means of cross connecting the reactor building fire protection system header to the RHR system just outside containment in the absence of the normal ECCS network and independent of the normal essential AC power distribution network.. The connection is accomplished by the manual opening of two in-series valves on the cross connection piping just upstream of its tie-in to the normal RHR piping. Fire protection system water can be directed to either the RPV or the drywell spray sparger by manual opening of the respective RHR injection valve. The fire water is supplied via the system's reactor building distribution header by either the direct diesel driven fire pump or from an external source utilizing a dedicated connection just outside the reactor building.

Each loop of RHR also has both a minimum flow mode and a full flow test mode. The minimum flow mode assures that there is pump flow sufficient to keep the pump cool by opening a minimum flow valve that directs flow back to the suppression pool anytime the pump is running and the main discharge valve is closed. Upon sensing that there is adequate flow in the pump main discharge line, the minimum flow valve is automatically closed. In the full flow test mode the system is essentially operated in the suppression pool cooling mode, drawing suction from and discharging back to the suppression pool.

The RHR system is comprised of three separate loops or subsystems, each of which includes a pump and a heat exchanger, takes suction from either the RPV or the suppression pool, and directs water back to either the RPV or the suppression pool. Two of the three loops can divert a portion of the suppression pool return flow to a common wetwell spray sparger or direct the entire flow to a common drywell spray sparger. The divisional subsystems of the RHR system are separated both mechanically and electrically as well as being physically located in different areas of the plant to address requirements pertaining to fire protection and other separation criteria. Each of the three subsystems is powered from a separate divisional power distribution bus that can be supplied from either an on-site or off-site source. Cooling water to each division of RHR equipment (heat exchanger as well as pump and motor coolers) is supplied by the respective division of the reactor cooling water (RCW) system. The RHR system also includes provisions for containment isolation and RCPB pressure isolation.

The RHR system will maintain the capability to perform its intended safety related functions either following a Safe Shutdown Earthquake or during the environmental conditions imposed by a LOCA, and in each case assuming the worst case single failure. The system will also accommodate calculated movement and thermal stresses. The system is designed so that the pumps will have necessary head/flow characteristics and available NPSH greater than required NPSH for operating modes. The system can be powered from either normal off-site sources or by the emergency diesel generators. The RHR system is Seismic Category 1 and is housed in the Seismic Category 1 reactor building to provide protection against tornados, floods, and other natural phenomena.

The RHR pumps are motor-driven centrifugal pumps each capable of supplying at least 4200 gpm at 40 psid (drywell to RPV). The pumps are ASME Code Class 2 components with a design pressure of 500 psig and a design temperature of 360 °F. The pumps are interlocked from starting without an open suction path. The RHR pumps are protected from possible pump run-out conditions during operation. The RHR heat exchangers are horizontal U-tube/ shell type each sized to provide a minimum effective heat removal capacity (K-coefficient) of 195 Btu/sec°F. The primary and secondary sides of the heat exchangers are ASME Code Class 2 and 3, respectively. The primary side design temperature and pressure are 500 psig and 360 °F, respectively. The secondary side design temperature and pressure are consistent with that of the RCW system. Each loop of RHR has its own jockey pump to act as a keep fill system for that loop's pump discharge piping. The jockey pumps are ASME Code Class 2.

The RHR system piping and valves are ASME Code Class 1 or 2 as shown on the P&ID (Figures 2.4.1). The design pressure and temperature of piping and valves varies across the system. For that piping attached to the RPV, from the RPV out to and including the outboard containment isolation valves, the design pressure and temperature are 1250 psig and 575 °F, respectively. For other piping open to the containment atmosphere, out to and including the outboard containment isolation valves, the design pressure and temperature are 45 psig and 219 °F, respectively. For piping and valves outside the containment isolation valves, the design pressure and temperature depends on whether it is located on the suction or discharge side of the main pump. Those portions on the suction side are rated at 300 psig and 360 °F, while those portions on the discharge side are rated at 500 psig and 360 °F, respectively. The low pressure portions of the shutdown cooling piping are protected from full reactor pressure by automatic pressure isolation valves that are interlocked with reactor pressure. High reliability of this interlock is assured by utilizing 4 separate and divisionally independent pressure sensors in a 2-out-of-4 logic. Additionally, in-series inboard and outboard containment/pressure isolation valves in each loop are powered from separate electrical divisions. Relief valves are also provided for protection from overpressure.

The RHR system includes Control Room indication to allow for monitoring and control during design basis operational conditions, i.e., system flows, temperatures and pressures as well as valve open/close and pump on/off indication for those instruments and components shown on Figures 2.4.1.a, b and c, with the exception of simple check valves and overpressure relief valves (of the check valves shown only the testable check valves downstream of each loop's RPV injection valve has control room status indication).

Inspection, Test, Analyses and Acceptance Criteria

This section provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the RHR system.

Table 2.4.1: Residual Heat Removal System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the RHR system is shown in Figures 2.4.1.a, b and c.	1. Inspections of the as-built RHR configuration shall be performed.	1. Actual RHR system configuration, for those components shown, conforms with Figures 2.4.1.a, b and c.
2. The RHR system operates in the LPFL mode as part of the overall ECCS network.	2. The ECCS LOCA performance analysis for assuring core cooling shall be validated by RHR system functional testing, including demonstration that the LPFL mode (of each RHR loop) is capable of automatically initiating and operating in response to a LOCA signal.	2. RHR system actuation and operation is consistent with the ECCS performance analysis as follows: a) RHR Flow (each loop) .....≥ 4200 gpm (at 40 psid) b) Time to Rated Flow (each loop) .....≤ 36 seconds
3. The RHR system operates in the suppression pool cooling mode to limit the long term temperature and pressure of the containment under post-LOCA conditions.	3. The primary containment performance analysis for long term peak pressure and temperature shall be validated by RHR system functional testing demonstrating the required flowrate through the heat exchanger and by inspection of vendor test data demonstrating the heat exchanger's effective heat removal capability. Automatic initiation in the suppression pool cooling mode will also be demonstrated	3. RHR system automatically actuates in the suppression pool cooling mode as designed and RHR heat exchanger performance is consistent with the containment cooling system analysis as follows: a) Effective heat removal capability of each RHR Heat Exchanger (K coefficient; includes effects of RCW, RSW and UHS) .....≥ 195 Btu/sec°F. b) Tube side flow of each RHR Heat Exchanger .....≥ 4200 gpm
4. A portion of the RHR system return flow (in loops B & C) can be diverted to the wetwell spray header.	4. RHR system functional tests shall be performed to demonstrate wetwell spray flow capability.	4. RHR loops B & C each separately are capable of providing wetwell spray flow consistent with the suppression pool bypass analysis as follows: a) Wetwell spray flow (each loop individually) ....≥ 500 gpm.

Table 2.4.1: Residual Heat Removal System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The RHR system operates in the shutdown cooling mode to remove reactor core decay heat and bring the reactor to cold shutdown conditions.	5. RHR system functional tests shall be performed to demonstrate operation in the shutdown cooling mode of operation.	5. RHR system (each loop) is capable of taking suction from and discharging back to the reactor pressure vessel. [Heat exchanger heat removal capability in this mode is bounded by containment cooling requirements - ITAAC # 3]
6. The RHR system (loops B & C) operates in the augmented fuel pool cooling mode to supply supplemental or replacement cooling to the spent fuel storage pool under abnormal conditions.	6. RHR system functional tests shall be performed to demonstrate operation in the augmented fuel pool cooling mode of operation.	6. RHR system (loops B & C) is capable of taking suction from and discharging back to the normal fuel pool cooling system. [Required cooling capability in this mode bounded by containment cooling requirements - ITAAC #3]
7. The RHR system (loop C) provides an AC independent water addition function.	7. RHR systems functional testing shall be performed to demonstrate operation in the AC independent water addition mode of operation.	7. Flow capability exists for directing water from the fire protection system to the RPV and drywell spray sparger, via the RHR system (loop C), without power being available from the essential AC distribution system.
8. The RHR system operates when powered from both normal off-site and emergency on-site sources.	8. RHR system functional tests shall be performed to demonstrate operation when supplied by either normal off-site power or the emergency diesel generator(s).	8. RHR system is capable of operating when supplied by either power source.
9. If already operating in any other mode, the RHR system automatically reverts to the LPFL mode in response to a LOCA signal.	9. Using simulated inputs, logic and functional testing shall be performed to demonstrate the RHR systems ability to automatically revert to the LPFL mode from any other mode.	9. RHR logic functions to automatically reconfigure the system to the LPFL mode of operation in response to a LOCA signal.
10. Pressure isolation valves are provided to protect low pressure RHR piping from being subjected to excessively high reactor pressure.	10. Using simulated inputs, logic and functional testing shall be performed to demonstrate operation of automatic isolation and interlock functions of pressure isolation valves.	10. Automatic isolation and interlock features function upon receipt of input signals.

Table 2.4.1: Residual Heat Removal System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
11. Each RHR loop operates automatically in a minimum flow mode to protect the pump from overheating.	11. Logic and functional testing shall be performed to demonstrate operation of the minimum flow mode for each loop (including extended minimum flow operational conditions).	11. RHR system logic functions automatically to assure a pump minimum flow path exists and no deleterious affects are observed during extended operation in the minimum flow mode.
12. The RHR system automatically isolates shutdown cooling suction valves to prevent draining of the reactor vessel.	12. Using simulated inputs, logic and valve functional testing shall be conducted to demonstrate operation of the shutdown cooling mode isolation function.	12. The shutdown cooling suction isolation valves automatically isolate on a low reactor water level signal.
13. RHR system valve interlocks prevent establishment of a drainage path from the reactor vessel to the suppression pool.	13. Using simulated inputs, logic and functional testing shall be conducted to demonstrate operation of interlocking between RPV suction valves and other RHR valves providing potential flow paths to the suppression pool.	13. RHR system valve interlock logic functions upon receipt of input signal
14. The drywell spray inlet valves can only be opened if there exists high drywell pressure and the RPV injection valves are fully closed.	14. Using simulated inputs, logic and functional testing shall be conducted to demonstrate operation of drywell spray permissive logic.	14. RHR drywell spray permissive logic functions to prevent drywell spray inlet valves from opening in the absence of either a high drywell pressure signal or a signal indicating RHR RPV injection valve(s) not fully closed.
15. The RHR pumps are interlocked from starting without an open suction path.	15. Logic tests shall be conducted to demonstrate that the RHR pumps will not start without an open suction path being available.	15. An RHR pump start signal is not generated in the absence of indication of an open suction path.
16. The RHR system utilizes jockey pumps (1 in each loop) to keep the pump discharge lines filled.	16. Functional tests will be performed to demonstrate the ability of the jockey pump (in each loop) to keep its respective RHR pump discharge line full while in the standby mode.	16. Each jockey pump performs its keep fill function.

Table 2.4.1: Residual Heat Removal System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
17. The RHR system full flow test mode allows periodic demonstration of RHR capability during normal power operation.	17. Functional tests will be performed to demonstrate operation in the full flow test mode.	17. Each RHR subsystem demonstrates full flow functional capability while approximating actual vessel injection conditions during operation in the full flow test mode.
18. The RHR pumps have sufficient NPSH during postulated operating conditions.	18. Pump vendor records will be inspected and as-procured pump NPSH compared with design basis analysis assumptions. Actual system installation will be inspected, and appropriate measurements taken, to determine available pump NPSH.	18. Minimum pump NPSH available, as determined based on as-built conditions and the results of vendor tests and/or analyses, exceeds as-procured pump requirements and is consistent with design basis analyses requirements.
19. The RHR pumps have adequate head/flow characteristics.	19. Pump vendor test records and calculations will be inspected, and as-installed system flow testing conducted, to establish pump head/flow characteristics.	19. RHR pumps, in as-installed system configuration, demonstrate head/flow characteristics consistent with design basis analyses assumptions.
20. Control room indications are provided for RHR system parameters defined in Section 2.4.1.	20. Inspections will be performed to verify presence of control room indication for the RHR system as described in 2.4.1.	20. The instrumentation is present in the control room as defined in Section 2.4.1.

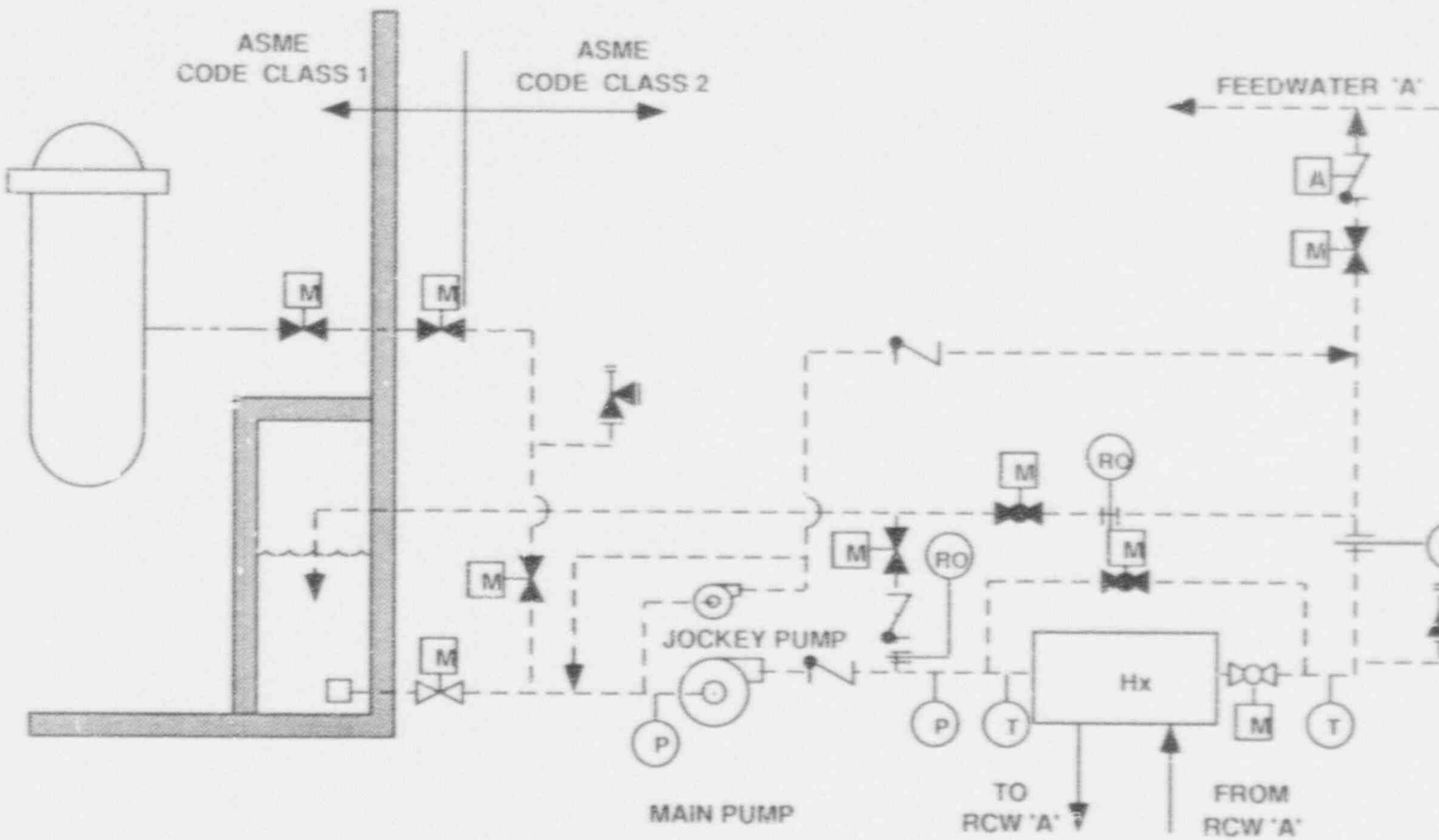


Figure 2.4.1a RESIDUAL HEAT REMOVAL (RHR-A) SYSTEM

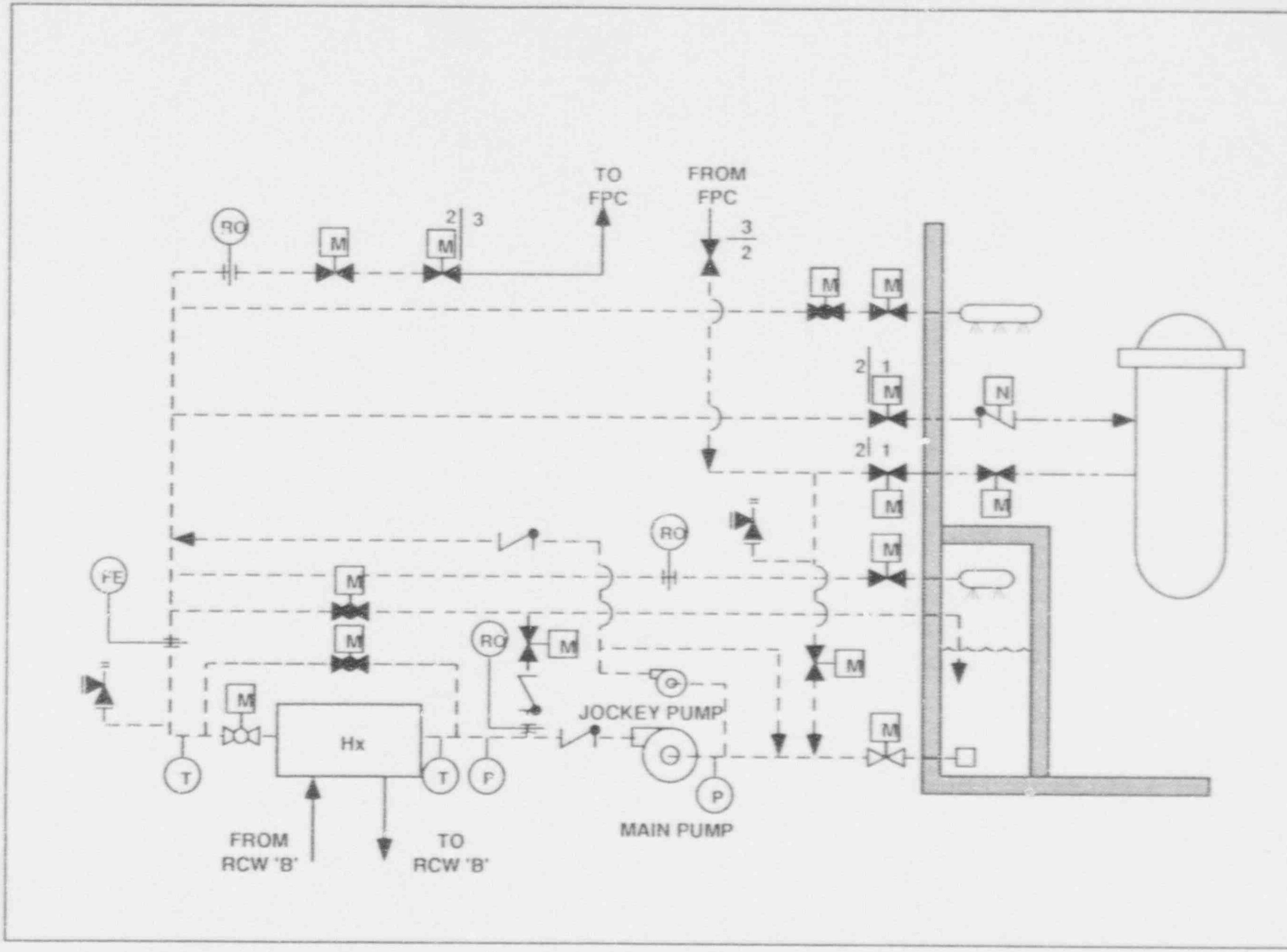


Figure 2.4.1b RESIDUAL HEAT REMOVAL (RHR-B) SYSTEM

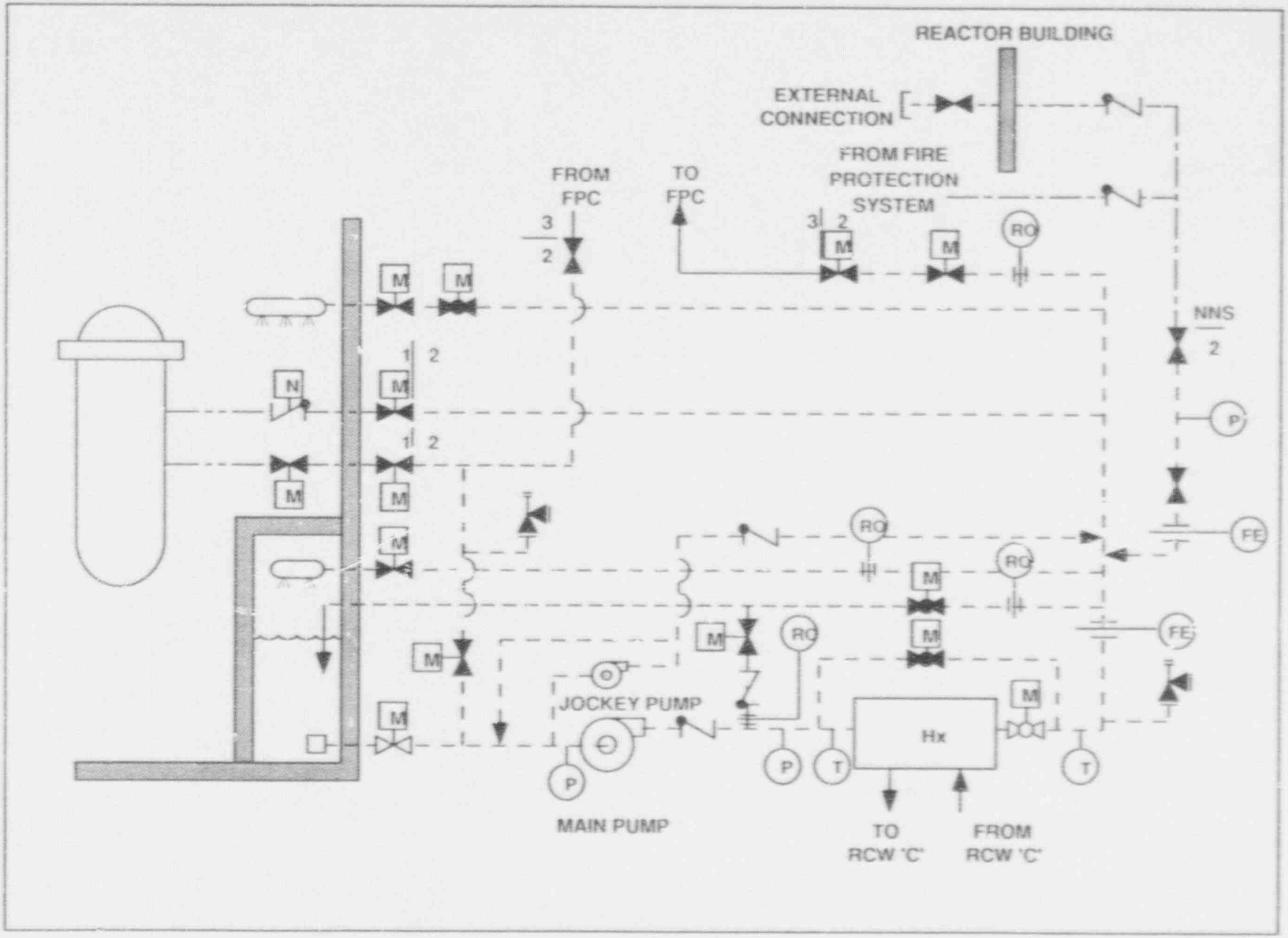


Figure 2.4.1c RESIDUAL HEAT REMOVAL (RHR-C) SYSTEM

2.4.2 High Pressure Core Flooder (HPCF) System

Design Description

The HPCF system is comprised of two divisionally separate subsystems that provide emergency make up water to the reactor for transient or LOCA conditions. The configuration of each loop is shown on its P&ID in Figure 2.4.2 (aligned in the standby mode). The HPCF system is a part of the ECCS network and portions of the system are considered a part of the reactor coolant pressure boundary (RCPB).

The entire HPCF system is designed to safety related standards. The ECCS function of the HPCF system is performed by the high pressure flooder mode, which floods the core region of the reactor for any reactor pressure condition when an initiation signal is received. Ancillary modes of operation include minimum flow bypass and full flow testing.

Following receipt of an initiation signal (low reactor water level or high drywell pressure) the HPCF system automatically initiates and operates in the flooder mode in conjunction with the remainder of the ECCS network. This emergency makeup to the reactor vessel contributes to keeping the reactor core cooled such that the regulatory requirements governing fuel performance during a LOCA are met by the ECCS network. The flooder mode is accomplished by both loops of the HPCF system by transferring water from the condensate storage tank (CST) or the suppression pool (S/P) to the RPV. The flooder mode is the only automatically initiated mode of HPCF, but it may also be initiated manually. The system will automatically revert to the flooder mode of operation from the test mode upon receipt of an initiation signal.

Each loop of the HPCF system also has both a minimum flow mode and a full flow test mode. The minimum flow mode assures that there is pump flow sufficient to keep the pump cool by opening a minimum flow valve that directs flow back to the S/P anytime the pump is running and the main discharge valve is closed. Upon sensing that there is adequate flow in the pump main discharge line, the minimum flow valve is automatically closed. In the full flow test mode the system draws suction from the S/P and discharges back to the S/P.

The HPCF system is comprised of two separate loops or subsystems, each of which includes a pump and takes suction from either the CST or the S/P, and directs water back to either the RPV or the S/P. The preferred suction source is the CST. Automatic suction transfer from the CST to the S/P occurs with a CST low water level signal or with a S/P high water level signal. The divisional subsystems of the HPCF system are separated both mechanically and electrically as well as being physically located in different areas of the plant to address requirements pertaining to fire protection and other separation criteria. Each of the two subsystems is powered from a separate Class 1E divisional power distribution bus that can be supplied from either an on-site or off-site source. Cooling water to each division of the HPCF pump and motor coolers is supplied by the respective division of the reactor cooling water (RCW) system. The HPCF system also includes provisions for containment isolation and RCPB pressure isolation.

The HPCF system will maintain the capability to perform its intended safety related functions either following a Safe Shutdown Earthquake or during the environmental conditions imposed by a LOCA, and in each case assuming the worst case single failure. The system will also accommodate calculated movement and thermal stresses. The system is designed so that available NPSH exceeds required NPSH for the pumps in all operating modes. The system can be powered from either normal offsite sources or by the emergency diesel generators. The HPCF system is Seismic Category I and is housed in the Seismic Category I reactor building to provide protection against tornados, floods, and other natural phenomena.

The HPCF pumps are motor-driven centrifugal pumps capable of supplying pressure at flow conditions at least equal to or greater than the value corresponding to a straight line between a reactor pressure of 1177 psid at 800 gpm and at a reactor pressure of 100 psid at 3200 gpm. The 1177 and 100 psid pressures are taken between the vessel and the air space of the compartment containing the source water for the pump. The pumps are ASME Code Class 2 components with a design pressure of 1565 psig and a design temperature of 212 °F. The pumps are interlocked from starting without an open suction path. The HPCF pumps are protected from possible pump run-out conditions in all operating modes. Each loop of HPCF utilizes a connection from the Make Up Water System (Condensate) (MUWC), that remains open throughout plant operation, to serve as a keep fill system for that loop's pump discharge piping.

The HPCF system piping and valves are ASME Code Class 1 or 2 as shown on the P&ID (Figure 2.4.2). The design pressure and temperature of piping and valves varies across the system. For that piping attached to the RPV, from the RPV out to the containment side (downstream side) of the outboard containment isolation valves, the design pressure and temperature are 1250 psig and 576 ° F, respectively. The design pressure and temperature for the outboard containment isolation valves are 1565 psig and 576 deg F, respectively. For other piping open to the containment atmosphere, out to and including the outboard containment isolation valves, the design pressure and temperature are 45 psig and 219 ° F, respectively. For piping and valves outside the containment isolation valves, the design pressure and temperature depends on whether it is located on the suction or discharge side of the main pump. Those portions on the suction side are rated at 200 psig and 212 ° F, while those portions on the discharge side are rated at 1565 psig and 212 ° F, respectively. The low pressure portions of the shutdown cooling piping are protected from full reactor pressure by two check valves in series or combinations of normally closed valves. Relief valves are also provided for protection from overpressure resulting from high pressure valve leakage or water thermal expansion.

The HPCF system includes Control Room indication to allow for the monitoring and control during design basis operational conditions, i.e., system flows and pressures as well as valve open/close and pump on/off indication for those instruments and components shown on Figure 2.4.2, with the exception of simple check valves and overpressure relief valves (of the check valves shown only the testable check valves downstream of each loop's RPV injection valve has control room status indication).

Inspection, Test, Analyses and Acceptance Criteria

Table 2.4.2 provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the HPCF system.

Table 2.4.2: High Pressure Core Flooder System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the HPCF system is shown in Figures 2.4.2.	1. Inspections of the as-built HPCF configuration shall be performed.	1. Actual HPCF system configuration, for those components shown, conforms with Figures 2.4.2.
2. The HPCF system operates in the flooder mode as part of the overall ECCS network.	2. The ECCS LOCA performance analysis for assuring core cooling shall be validated by HPCF system: a) demonstration that the flooder mode (of each HPCF loop) is capable of automatically initiating and operating in response to an initiation signal, and b) analyses to demonstrate compliance with acceptance criteria using as-built functional performance test data and construction dimensions.	2. HPCF system actuation and operation is consistent with the ECCS performance analysis as follows: a) HPCF pump developed pressures of at least 1177 psid and 100 psid for flow rates no less than 800 gpm and 3200 gpm respectively, where the pressure difference is between the RPV and the air space of the compartment containing the source water for the pump, and where the water temperature is valued at 50 deg F. b) 36 seconds maximum allowed delay time from the initiating signal to rated flow available and the injection valve fully open.
3. The HPCF system operates when powered from both normal off-site and emergency on-site sources.	3. HPCF system functional tests shall be performed to demonstrate operation when supplied by either normal off-site power or the emergency diesel generator(s).	3. HPCF system is capable of operating when supplied by either power source.
4. If already operating in any other mode, the HPCF system automatically reverts to the flooder mode in response to an initiation signal.	4. Using simulated inputs, logic and functional testing shall be performed to demonstrate the HPCF systems ability to automatically revert to the flooder mode from any other mode.	4. HPCF logic functions to automatically reconfigure the system to the flooder mode of operation upon receipt of an initiation signal.

Table 2.4.2: High Pressure Core Flooder System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Pressure isolation valves are provided to protect low pressure HPCF piping from being subjected to excessively high reactor pressure.	5. Using simulated inputs, logic and functional testing shall be performed to demonstrate operation of automatic isolation and interlock functions of pressure isolation valves.	5. Automatic isolation and interlock features function upon receipt of an initiation signal.
6. Each HPCF loop operates automatically in a minimum flow mode to protect the pump from overheating.	6. Logic and functional testing shall be performed to demonstrate operation of the minimum flow mode for each loop (including extended minimum flow operational conditions).	6. HPCF system logic functions automatically to assure a pump minimum flow path exists and no deleterious affects are observed during extended operation in the minimum flow mode.
7. The HPCF pumps are interlocked from starting without an open suction path.	7. Logic tests shall be conducted to demonstrate that the HPCF pumps will not start without an open suction path being available.	7. An HPCF pump start signal is not generated in the absence of indication of an open suction path.
8. The HPCF system utilizes a continuously open connection from the Make-Up Water (Condensate) system (MUWC) to keep the pump discharge lines filled.	8. Functional tests will be performed to demonstrate the ability of the MUWC system to keep its respective HPCF pump discharge line full while in the standby mode.	8. The MUWC system performs its keep fill function.
9. The HPCF system full flow test mode allows periodic demonstration of HPCF capability during normal power operation.	9. Functional tests will be performed to demonstrate operation in the full flow test mode.	9. Each HPCF subsystem demonstrates full flow functional capability while approximating actual vessel injection conditions during operation in the full flow test mode.
10. The RHR pumps have sufficient NPSH during all postulated operating conditions.	10. Actual system installation will be inspected, and appropriate measurements taken, to verify adequate pump NPSH.	10. Minimum pump NPSH available, as determined based on as-built conditions, exceeds pump required NPSH.
11. HPCF mechanical equipment is built in accordance with ASME Code, Section III requirements.	11. Procurement records and actual equipment shall be inspected to verify applicable HPCF system components have been manufactured per the relevant ASME requirements.	11. HPCF equipment has appropriate ASME, Section III, Class 1 or 2 certifications in accordance with its proper classification (as described in Section 2.4.2).

Table 2.4.2: High Pressure Core Flooder System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
12. Control room indications are provided for HPCF system parameters as specified in Section 2.4.2.	12. Inspections will be performed to verify presence [illegible] control room indication for the HPCF [illegible]m as described in 2.4.2.	12. The instrumentation is present in the control room as specified in Section 2.4.2.

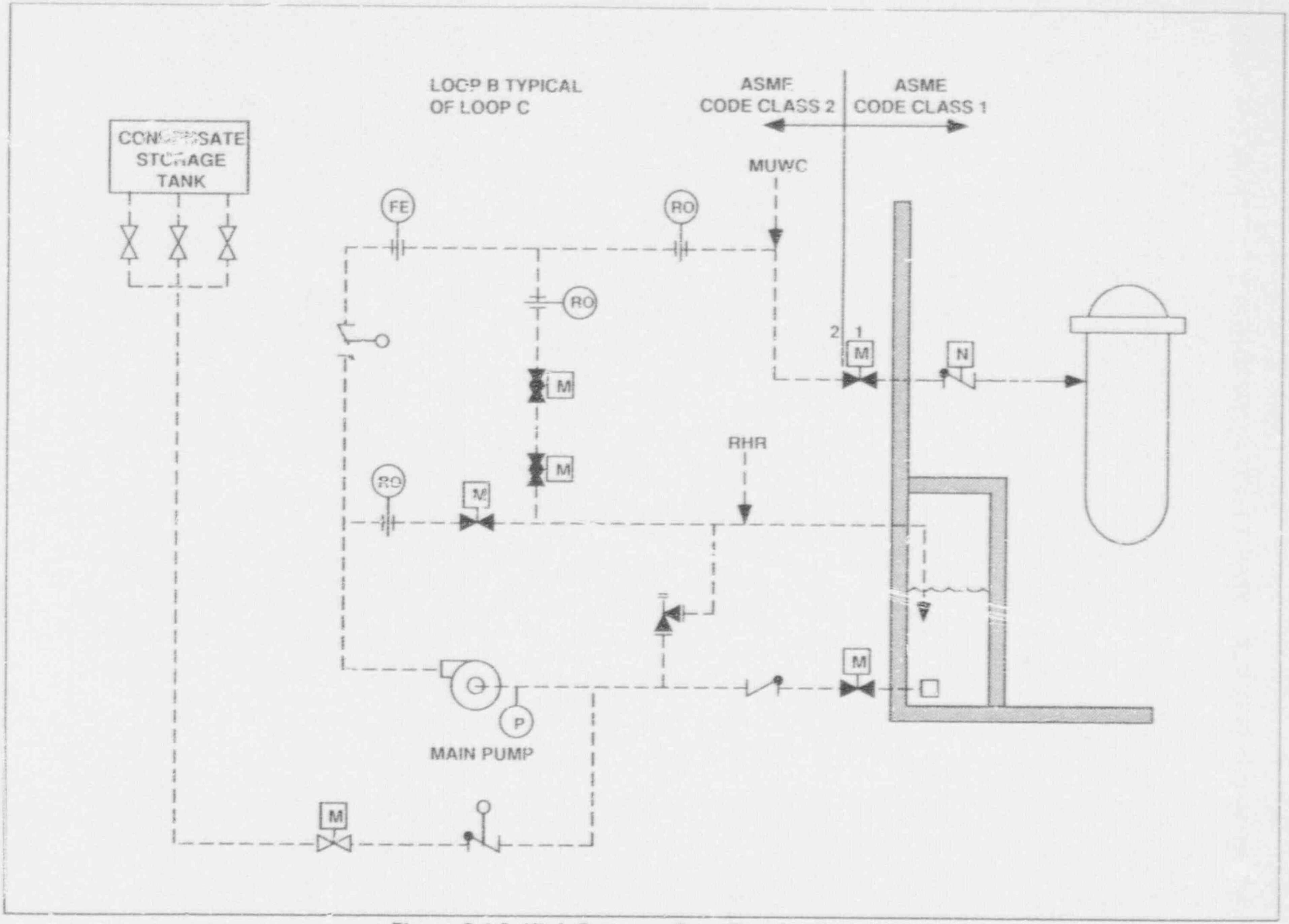


Figure 2.4.2 High Pressure Core Flooder System

2.4.3 Leak Detection and Isolation System

Design Description

Later. Stage 3 Item.

2.4.4 Reactor Core Isolation System

Design Description

The reactor core isolation cooling (RCIC) system, in conjunction with other systems, supplies makeup water to the reactor pressure vessel to assure that sufficient water inventory is maintained to permit adequate core cooling to take place during the following events:

a. a loss-of-coolant accident

b. vessel isolated and maintained at hot standby

c. vessel isolated and accompanied by loss offeedwater flow

d. complete plant shutdown with loss of normalfeedwater system before the reactor isdepressurized to a level where the shutdowncooling mode of RHR system can be placed inservice

e. loss of all AC power.

The RCIC system consists of a 100% capacity steam-driven turbine which drives a 100% capacity pump assembly and the pump accessories. The system also includes piping, valves, and instrumentation necessary to provide several flow paths for system operation. The RCIC steam supply branches off from main steam line "B" (leaving the reactor pressure vessel) and goes to the RCIC turbine with drainage provision to the main condenser. The turbine exhausts to the suppression pool with vacuum breaking protection. The primary source of RCIC suction supply is from the Condensate Storage Tank (CST). The suppression pool water is the secondary source of RCIC supply. Automatic switch-over of makeup water source from CST to the suppression pool (with override provision) is integrated in the system logic. CST and suppression pool suction valves are interlocked, and check valves are provided to safeguard accidental drainage of CST water to the suppression pool . RCIC pump discharge lines include the main discharge to the feedwater line, a test return line to the suppression pool, a pump minimum flow bypass line to the suppression pool, and a cooling water supply line to auxiliary equipment. The piping configuration and instrumentation is shown in Figure 2.4.4

The RCIC system is a part of the ECCS network and is designed to safety-related standards. It is powered from Class 1E DC sources (except the inboard steam supply isolation valve which has Class 1E AC) and is designed to perform its function deprived of all AC sources. Although RCIC system design is safety related, it also performs some non-safety related functions. The safety related function includes emergency core cooling, in conjunction with the High Pressure Core Flooder (HPCF) system, Automatic Depressurization System (ADS) and the Residual Heat Removal (RHR) system. As part of this network, the RCIC system can provide reactor makeup in the period while the reactor is still at high pressure after a small break has occurred. The non-safety related functions include providing makeup water to the reactor pressure vessel (1) during transient events accompanied by loss of feedwater, and (2) during a complete loss of all AC power (Station Black Out).

During normal operation, the RCIC system is in its standby condition with the motor-operated valves in their normally open or normally closed position as shown in Figure 2.4.4. In this mode, the pump discharge line is kept filled with water supplied by the system head of the Condensate Makeup system to prevent water hammer in the discharge piping system when RCIC system is initiated. Full flow functional testing may be performed with the RCIC pump taking suction from and returning flow to the suppression pool. Should an initiation signal were to occur during test mode, the system configuration will automatically realign to the vessel injection mode.

During transient and LOCA events, RCIC system is automatically initiated upon receipt of low reactor water level or high drywell pressure signal. The steam turbine-driven pump delivers water from the CST or from the suppression pool to the reactor vessel via the feedwater line "B" and distributes it through the feedwater sparger to promote mixing with hot water or steam within the reactor vessel. The RCIC turbine is driven by the portion of the decay heat steam from the reactor vessel, and exhausts through a discharge sparger below the suppression pool water level. The turbine exhaust line penetrates the containment at a location about 1 meter above the suppression pool maximum water level. Two vacuum breakers in series are connected to the exhaust line (above the suppression pool water level) in the wetwell air space. A check valve and a remote manually operated motorized valve installed in series outside the containment provides containment isolation function for the turbine exhaust line.

When high reactor water level in the reactor vessel has been established, the vessel injection valve, and the steam supply admission valve to the turbine will close causing the turbine to shutdown. When the low reactor water level initiation signal re-occurs, RCIC will automatically restart to provide core cooling function.

The RCIC turbine is automatically tripped (turbine trip and throttle valve isolated) upon receipt of any signal indicating turbine overspeed, low pump suction pressure, high turbine exhaust pressure, or an auto isolation signal from the Leak Detection System. Once tripped, the spring closing mechanism latches and must be manually reset if the turbine needs to be re-started. This very same isolation signal (LDS) also isolates the RCIC steam supply isolation valves to provide primary containment isolation. The Leak Detection System isolation signals are as follow:

a. a high pressure drop across a flow device in the steam supply line equivalent to 300 percent of the steady-state steam flow

b. a high RCIC area temperature

c. a low reactor pressure (low steamline pressure)

d. a high pressure between the RCIC turbine exhaust rupture diaphrams

RCIC system can also be manually initiated and shutdown from the main control room as long as permissive interlocks are present.

In the event that all AC power sources are not available (Station Black Out), RCIC is designed to perform its core cooling function for at least 8 hours. Station batteries and CST water inventory are sized to support the 8-hour RCIC operation. RCIC room is designed such that room temperature does not reach the equipment maximum environmental limit for at least 8 hours without room cooling. The RCIC steam supply isolation valves are normally open motor-operated valves. These valves fail as-is (open) on loss of AC power thereby providing steam supply flow path to the turbine. During this event, the reactor pressure is controlled and maintained at the main steam safety relief valve set pressure to assure an 8-hour steam supply to the RCIC turbine.

The RCIC system is designed to Seismic Category I requirements and is housed in a Seismic Category I reactor building structure to provide protection from tornadoes, floods, and other natural phenomena.

The RCIC system also includes provision for primary containment and RCPB pressure isolation. The RCIC piping system and valves are Seismic Category I, Quality Group B except for the steam supply piping which is Seismic Category I, Quality Group A up to and including the outermost primary containment isolation valve. The inboard and outboard isolation valves are powered from independent Class 1E sources. The steam supply piping up to and including the turbine has a design pressure of 87.9 kg/cm^{2}g and a design temperature of 302°C while the turbine exhaust piping is designed to 10 kg/cm^{2}g and 184°C. The RCIC pump discharge piping up to the injection valve is designed to 120 kg/cm^{2}g and 77°C. The injection valve itself is rated at 120 kg/cm^{2}g and 302°C. Beyond the injection valve, the discharge piping portion that connects to the feedwater line is rated at 87.9 kg/cm^{2}g and 302°C. The pump suction piping is rated at 21 kg/cm^{2}g and 77°C. Protection of the low pressure suction piping from potential high reactor pressure is accomplished by three valves in series (testable check valve, injection valve and pump discharge check valve) at the pump discharge line.

The RCIC turbine which drives the pump is a safety-related component although not covered by ASME Code. The gland seal however, is not safety-related but it is not essential for RCIC operation. The turbine and its accessories are seismically designed and analyzed to withstand a design basis earthquake. The turbine is designed to operate at both high and low pressure conditions. The minimum steam inlet pressures at high pressure condition is 82.8 kg/cm^{2}abs, and 10.5 kg/cm^{2}abs for the low pressure condition.

The RCIC pump is designed to Seismic Category I, Quality Group B. The pump is a constant flow centrifugal type capable of providing an injection flow into the reactor vessel of at least 182 m^3/hr against a differential pressure of 82.8 kg/cm^2d (drywell to RPV) within 30 seconds following receipt of initiation signals. The suction piping configuration is designed such that adequate NPSH is always available on all RCIC operating modes. Pump developed head is about 900 meters at 83.8 kg/cm^2abs and 186 meters at 11.6 kg/cm^2abs reactor pressure.

The RCIC system includes control room indications and alarms to allow for the monitoring and control during the design basis operational conditions, i.e., system flows, temperatures, pressures, valve open/close and pump on/off conditions, bypassed, override or inoperative status conditions.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.4.4 provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the RCIC system.

Table 2.4.4: Reactor Core Isolation Cooling System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the RCIC system is shown in Figure 2.4.4.	1. Inspection of the as-built RCIC configuration shall be performed.	1. Verification of the as-built system is in conformance with the as-designed configuration (Figure 2.4.4).
2. RCIC system automatically re-aligns to vessel injection mode if LOCA signal occurs while the system is in test mode.	2. Using simulated LOCA signal, functional testing of the system logic shall be performed to demonstrate systems capability to revert to the vessel injection mode while in test mode.	2. RCIC system automatically re-aligns to vessel injection mode upon receipt of LOCA signal.
3. RCIC pump capable of delivering flow rate of $\geq$182 m^3/hr against 82.8 kg/cm^2d.	3. Vendor to conduct shop tests relating to pump performance.	3. Verification of certified documentation demonstrating that the pump will meet $\geq$182 m^3/hr against 82.8 kg/cm^2d.
4. Steam supply isolation valves are capable of closure against the maximum design basis differential pressure.	4. Vendor to conduct shop tests relating to valve operation during design basis events	4. Valve closure occurs against design basis differential pressure.
5. RCIC pump suction automatically switches over from CST to the suppression pool on low CST or high suppression pool water level with override provision.	5. System logic testing shall be performed to demonstrate auto switch-over of suction source and override.	5. Suction auto transfer occurs on low or high suppression pool water level.
6. RCIC steam supply isolation valves fail as-is (open) on loss of AC power.	6. Field testing shall be performed to demonstrate that the steam supply isolation valves (normally open motorized valves) will stay in the open position when AC power is lost.	6. Valves remain open upon removal of AC power.
7. RCIC steam supply isolation valves isolate upon receipt of auto isolation signals from Leak Detection System in $\leq$ 30 seconds.	7. Functional testing shall be performed on the system logic by simulating the automatic isolation signal from LDS.	7. Valves isolate within $\leq$30 seconds from receipt of auto isolation signals.
8. RCIC system auto shutdown on high reactor water level and auto re-start capability.	8. Functional testing shall be performed on the system logic to demonstrate RCIC systems capability to automatically shutdown on high reactor water level, and automatically re-start when low water level re-occurs.	8. RCIC auto shutdown on high reactor water level, and auto re-start on low reactor water level.

Table 2.4.4: Reactor Core Isolation Cooling System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. RCIC mechanical equipment (except the turbine) is built in accordance with ASME Code Section III requirements.	9. Procurement records and actual equipment shall be inspected to verify applicable RCIC system components have been designed, manufactured and installed per relevant ASME Code.	9. Certified documentation demonstrates compliance with the appropriate ASME Code.
10. Provision for control room alarms, and indications vital for RCIC system operation.	10. Inspection will be performed to verify presence of control room alarms and indications.	10. The control room alarms and indications specified in Section 2.4.4.

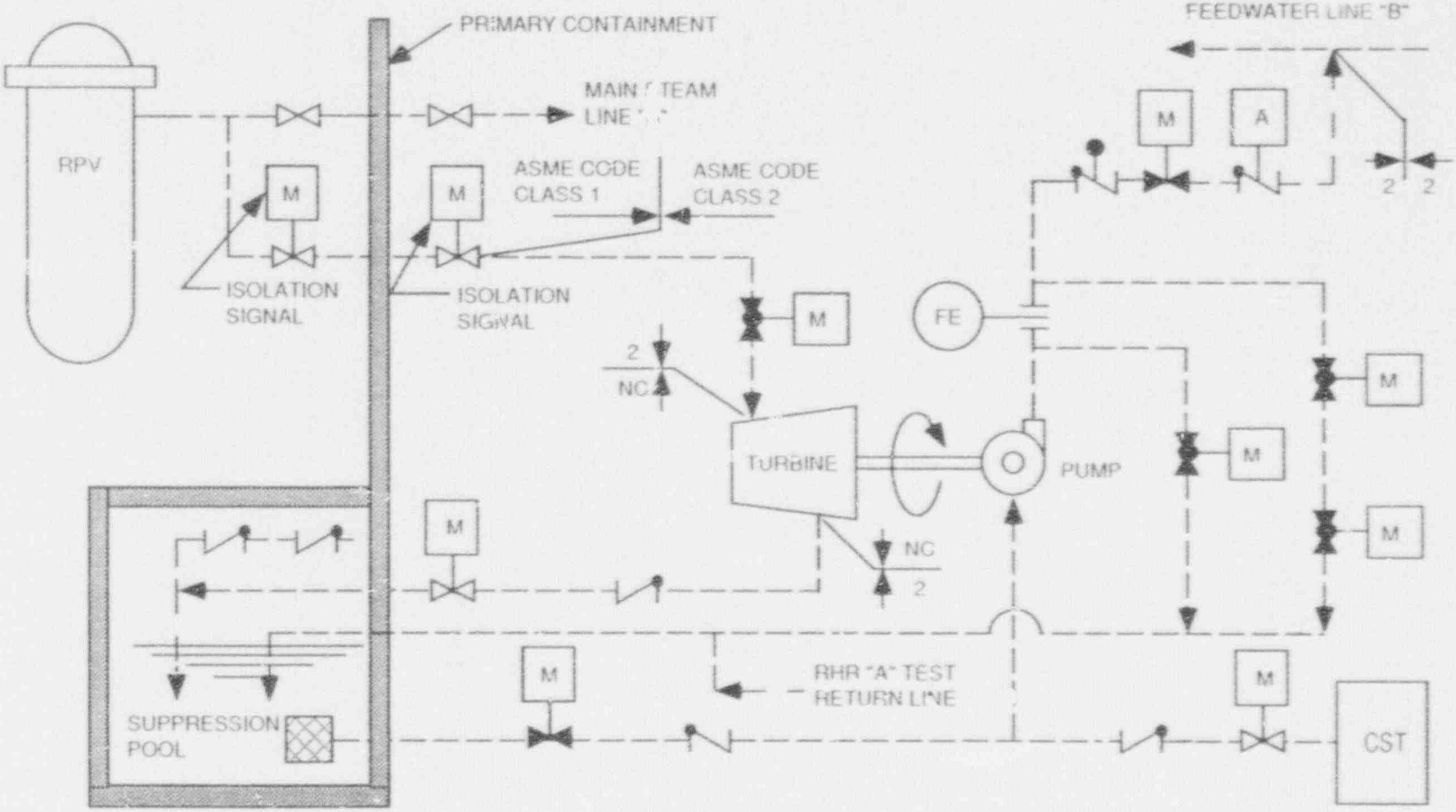


Figure 2.4.4 Reactor Core Isolation Cooling (RCIC) System P&ID

2.5 Reactor Servicing Equipment

2.5.1 Fuel Service Equipment

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.5.2 Miscellaneous Servicing Equipment

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.5.3 Reactor Pressure Vessel Servicing Equipment

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.5.4 RPV Internal Servicing Equipment

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.5.5 Refueling Equipment

The Reactor Building is supplied with a Refueling Platform for fuel movement and servicing plus an Auxiliary Platform for servicing operations from the Vessel Flange level.

Design Description — Refueling Platform

The refueling platform is a gantry crane, which spans the reactor vessel and the storage pools on bedded tracts in the refueling floor. A telescoping mast and grapple suspended from a trolley system is used to lift and orient fuel bundles for placement in the core and/or storage racks. Control of the platform is from an operator station on the refueling floor.

A position indicating system and travel limit computer is provided to locate the grapple over the vessel core and prevent collision with pool obstacles. Two auxiliary hoists, one main and one auxiliary monorail trolley-mounted, are provided for incore servicing.The grapple position provides sufficient water shielding over the active fuel during transit. The mast grapple has a redundant load path so that no single component failure will result in a fuel bundle drop. Interlocks on the platform: (1) prevent hoisting a fuel bundle over the vessel with a control rod removed; (2) prevent collision with fuel pool walls or other structures; (3) limit travel of the fuel grapple; (4) interlock grapple hook engagement with hoist load and hoist up power; and (5) ensure correct sequencing of the transfer operation in the automatic or manual mode.

Design Description — Auxiliary Platform

The auxiliary platform provides a reactor flange level working surface for in-vessel inspection and reactor internals servicing, and permits servicing access for the full vessel diameter. No hoisting equipment is provided with this platform, as this function can be performed from the refueling platform. The platform operates on tracks at the reactor vessel flange level and is lowered into position by the reactor building crane using the dryer/separator strongback. The platform power is supplied by a cable from the refueling floor elevation.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.5.5 provides definition of the inspection, test, and/or analyses together with associated acceptance criteria which will be undertaken for the Refueling Platform. No entries are proposed for the Auxiliary Platform.

Table 2.5.5: Refueling Platform

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The Refueling Platform has two auxiliary hoists having the capacity of 500 kg each.	1. Perform load tests on both auxiliary hoists.	1. Both auxiliary hoists shall be load tested and hold 125% of rated load.
2. The platform is provided with controls and interlocks which: a. Maintain water shielding over fuel when grappled on mast. b. Allow no fuel movement over vessel when control rod is removed. c. Provide fuel grapple travel limit. d. Prevent collision with fuel pool walls and other structures. e. Interlock grapple hook engagement with hoist load and hoist up power. f. Insure automatic sequencing control for transfer operation.	2. Review of as-installed equipment and field tests will be conducted after the platform has been installed.	2. Using normal installed controls and power, the platform meets required operating characteristics.

2.5.6 Fuel Storage Facility

Storage Racks are required for the temporary and long term storage of fuel and associated equipment. Storage may be either wet or dry depending upon the item being stored.

Design Description — Fuel Storage Racks

Racks provide storage for spent fuel in the Spent Fuel Storage Pool in the Reactor Building. The racks are top loading, with fuel bail extended above the rack, and shall have a minimum capacity of 270% of the reactor core. The rack design preclude the possibility of criticality under normal or abnormal conditions and maintain a subcriticality of at least 5% Δk. The racks arrangement and design prevents accidental insertion of fuel between adjacent racks and provide adequate water flow to prevent the water from exceeding 212°F. The racks are structurally able to maintain a Safety Class 2 and Seismic Category I. The racks are an Essential component performing a passive safety function.

Design Description — New Fuel Storage Rack

The new fuel and spent fuel storage racks are the same type rack in design, construction and height. The new fuel storage racks are located in a vault. The vault is a pit in the refueling floor that is fitted with a special cover which is in place when ever fuel is not being processed. The depth of the pit is such that when fuel is racked the bail is below the cover's plane. The pit is constructed the same as the spent fuel pool except that it contains a drain and is maintained dry. The new fuel storage racks store approximately 40% of one full core fuel load.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.5.6 provides a definition of the inspection, tests, and/or analyses and associated acceptance criteria which will be undertaken for the fuel storage racks.

Table 2.5.6: Fuel Storage Racks

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. A full rack is subcritical by at least 5% Δk, which includes uncertainty value and associated probability and confidence level.	1. Design documentation and records will be reviewed to confirm that required criticality margin has been provided. As-installed equipment will be compared to design documentation; reconciliation analyses will be performed if necessary.	1. The calculated k_{eff}, including biases and uncertainties will not exceed 0.95 under normal and abnormal conditions.
2. The cooling water in the spent fuel storage pool shall be under 212°F when all storage positions are full.	2. Documentation for the as-installed racks will be reviewed to confirm that adequate cooling will occur.	2. The combination of storage racks and support structure provides adequate flow to prevent water from exceeding 212°F.
3. The structure, its appurtenances and its supports, shall satisfy the ASME Class, Seismic Category and Quality Group requirements commensurate with its classification.	3. Inspections will be conducted of ASME Code required documents and the code stamp on the components.	3. Existence of ASME Code required documents and the Code stamps on the components confirms that the structure and components have been designed, analyzed, fabricated and examined in accordance with the applicable requirements.

2.5.7 Under-Vessel Servicing Equipment

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.5.8 CRD Mainenance Facility

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.5.9 Internal Pump Maintenance Facility

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.5.10 Fuel Cask Cleaning Facility

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.5.11 Plant Startup Test Equipment

Design Description

No Tier 1 entry for this system.

2.5.12 Inservice Inspection Equipment

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.6 Reactor Auxiliary

2.6.1 Reactor Water Cleanup System

Design Description

The CUW system removes particulate and dissolved impurities from the reactor coolant by recirculating a portion of the reactor coolant through a filter-demineralizer. The CUW system is designed to process a nominal flow of 2% of rated feedwater flow. The CUW is designed for 87.9 kg/cm^{2}g and 302°C.

The CUW system removes excess coolant from the reactor system during startup, shutdown and hot standby. The excess water is directed to the radwaste or suppression pool. The CUW system also provides processed water to the reactor head spray nozzle for RPV cooldown.

The CUW system reduces RPV temperature gradients by maintaining circulation in the bottom head of the RPV during periods when the reactor internal pumps are unavailable.

The suction line through the PCPB contains two motor operated isolation valves which automatically close upon receipt of auto isolation signal from leak detection system and upon actuation of the SLCS. The auto isolation signal from LDS consists of the following signals:

a. Low reactor water level

b. High ambient temperature in CUW equipment room

c. High temperature differential between the air conditioning duct and in the CUW equipment room

d. High flow differential between CUW system suction and discharge flows

The suction valves (containment isolation valves) are designed to isolate against a maximum differential pressure of 87.9 kg/cm2d within 30 seconds. The inboard valve is powered from Class 1E Division 1 AC, while the outboard is fed from Class 1E Division 2 AC bus.

The CUW system is classified as a nonsafety system with a major portion of the system located outside of the primary containment pressure boundary (PCPB) and automatically isolatable. System piping and components within the PCPB, including the suction piping up to and including the outboard suction isolation valve, and containment isolation valves including interconnecting piping, are ASME Section III, Seismic Category I, Quality Group A. Nonsafety equipment is designed as Nonseismic, Quality Group C. Low pressure piping in the filter-demineralizer area, downstream of the high pressure block valves, is designed to Quality Group D.

The CUW system is a single closed loop system that takes suction from the reactor vessel bottom head drain line or the shutdown cooling suction line connection to RHR loop "B". CUW flow passes through a regenerative heat exchanger (RHX) and two parallel nonregenerative heat exchangers (NRHX) to two pumps in parallel . The flow is discharged to two filter-demineralizers and returned, through the regenerative heat exchanger to feedwater lines "A" and "B". Each pump, NRHX and filter-demineralizer is capable of 50% system capacity operation. See Figure 2.6.1 for system arrangement.

Each filter-demineralizer vessel is installed in an individual shielded compartment with provisions for handling filter material. Inlet, outlet, vent, drain and other process valves are located outside the filter-demineralizer compartment in a separate shielded area together with the necessary piping and associated equipment.

Process equipment and controls are arranged so that normal operations are conducted at a panel from outside the vessel or valve and pump compartment shielding walls.

Penetrations through compartment walls are designed so that they preclude direct radiation shine.

A remote, manually operated valve on the return line to the feedwater lines in the steam tunnel provides long term leakage control and reverse flow isolation is provided by a check valve in the CUW piping.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.6.1 provides a definition of the instructions, tests, and/or analyses together with associated acceptance criteria which will be undertaken for CUW.

Table 2.6.1: REACTOR WATER CLEANUP SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitments	Inspections, Test, Analysis	Acceptance Criteria
1. The configuration of the CUW system is shown in Figure 2.4.1.	1. Inspection of the as-built CUW configuration shall be performed.	1. As-built CUW system configuration conforms with Figure 2.6.1.
2. Suction line isolation valves automatically isolate CUW upon SLCS actuation, and receipt of auto isolation signal from Leak Detection system within 30 seconds.	2. Field test will be conducted to confirm that CUW will isolate upon SLCS actuation and receipt of leak detection signal by applying a simulated signal to the isolation logic circuit.	2. CUW isolates within 30 seconds when SLCS is actuated or when leak detection limit is sensed by closing the primary containment pressure boundary isolation valves.
3. CUW suction valves are designed to close against the maximum design basis differential pressure.	3. Procurement records shall be reviewed and vendor to conduct shop test relating to valve operability during design basis condition.	3. Certified documentation demonstrates that the valves can close against a maximum differential pressure of 87.9 kg/cm^2d within 30 seconds.

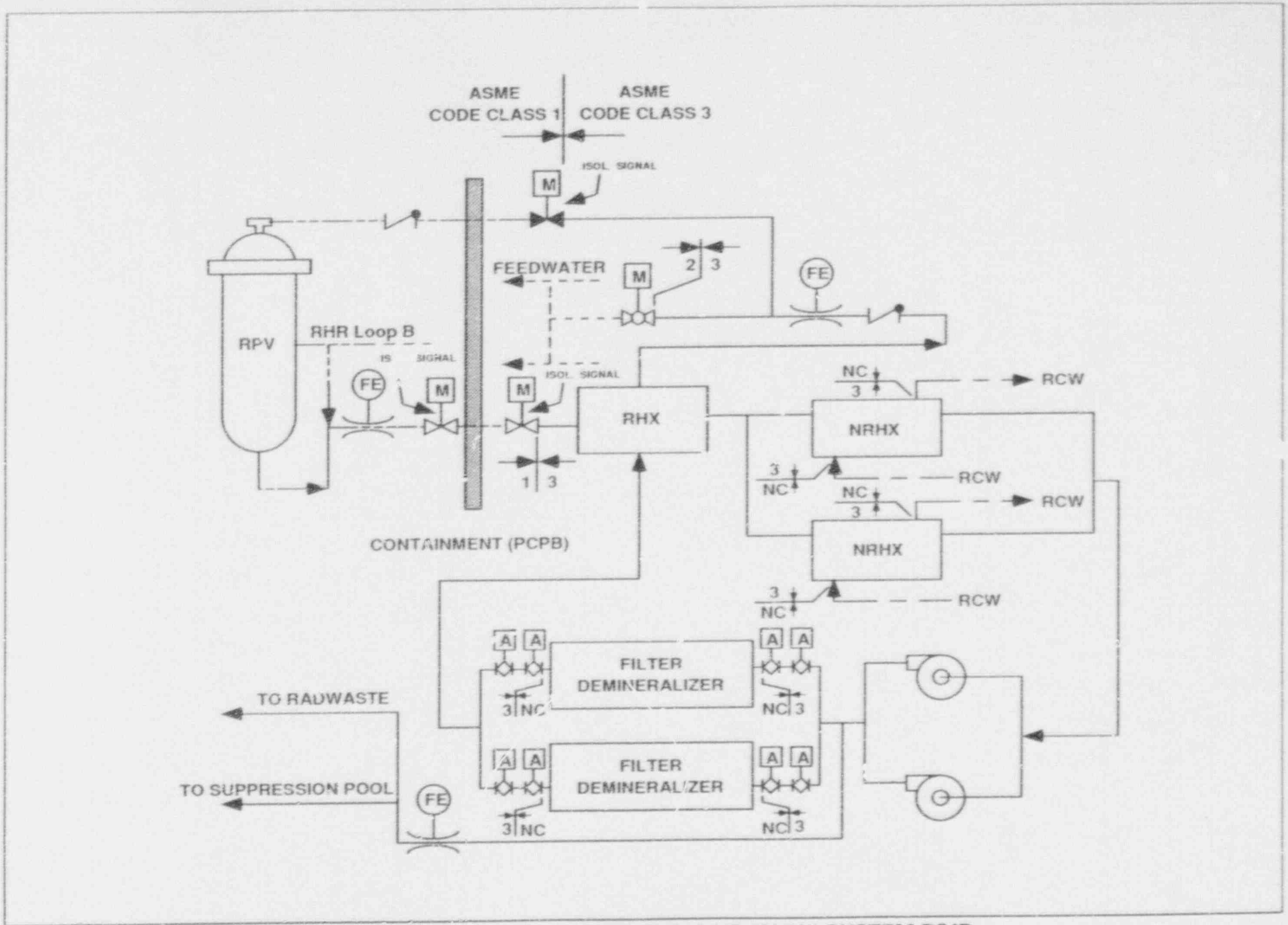


Figure 2.6.1 REACTOR WATER CLEANUP (CUW) SYSTEM P&ID

2.6.2 Fuel Pool Cooling and Cleanup System

Design Description

The fuel pool cooling and cleanup (FPC) system removes decay heat generated by the spent fuel assemblies in the spent fuel storage pool. It also maintains the water quality and clarity by removing corrosion products, fission products, and other impurities from the pool. The system also monitors fuel pool water level and maintains a water level above the fuel sufficient to provide shielding for normal building occupancy.

The FPC system process water flows from spent fuel storage pool through skimmer weirs into two surge tanks. It is drawn from the surge tanks by two circulating pumps arranged in parallel, and is subsequently discharged through a common header to two filter/demineralizer units arranged in parallel. The discharge water than flows through a common header to two heat exchangers arranged in parallel and cooled by reactor building cooling water system, and then returns to the spent fuel storage pool. A bypass line is provided around the filter/demineralizer portion of the system. Check valves are provided in the pool return lines to prevent the pools from siphoning in the event of pipe rapture. The system configuration is shown in Figure 2.6.2.

The primary operational mode of the FPC system is cooling of the spent fuel pool under normal heat load conditions after normal refueling operation. In this mode, initially both pumps, both heat exchangers, and both filter/demineralizer units are used. However, as fuel decay heat decreases, only one pump and one filter/demineralizer is used. The filter/demineralizer units may be bypassed in this mode. The pool temperature is kept at or below 52°C during this operating mode.

When the fuel pool is loaded with more than the normal fuel batch, the system operates in the maximum heat load operating mode. Since the decay heat in this mode exceeds the exchanged heat capacity of the FPC system heat exchangers, RHR system heat exchangers are used to supplement the FPC system heat exchangers. The FPC system operates with both pumps, both heat exchangers and both filter/demineralizer units along with two RHR heat exchangers. The pool temperature is kept at or below 60°C during this operating mode.

After an earthquake the system is operated with the filter/demineralizer units bypassed.

Normal makeup water to the spent fuel storage pool is provided by the non-safety related condensate (MUWC) makeup system. A backup to the normal makeup system is also available from the nonsafety-related suppression pool cleanup (SPCU) system. Additionally, an emergency safety-related, seismic category I makeup water to the spent fuel pool is provided via the FPC system connections to the residual heat removal (RHR) system which draws water from the suppression pool-a safety related water source. The segment of the FPC system piping from the RCW system interface to the discharge of the fuel pool is safety-related.

The entire FPC system with the exception of the filter/demineralizers is designed to seismic category I and quality group C standards.

The system can be powered from either normal off-site sources or by the on-site power source.

The FPC system is located in the reactor building, a seismic category I, flood and tornado-missile protected structure.

The FPC system pumps are motor-driven centrifugal pumps supplying at least 250 m^3/hr at a head of 80m. A low suction pressure at the pump inlet will automatically stop that pump. The pump is also protected by an interlock for a low pump discharge flow. The FPC system heat exchangers are horizontal U-tube/shell type, each sized to provide a minimum heat transfer rate of $1.65x10^6$ kcal/hr with a cooling water inlet temperature (shell side) of 35°C maximum, and the process water inlet temperature (tube side) of at least 52°C. The filter/demineralizer subsystem consists of filter and demineralizer units and supporting facilities for precoating of resin, backwashing and waste removal.

The FPC system includes Control Room indication to allow for the monitoring and control during design basis operational conditions, i.e., system flows, temperatures, pressures, pool water level as well as valve open/close and pump on/off indication for these instruments and components shown on Figure 2.6.2, with the exception of check valves and manual valves.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.6.2 provides a definition of the inspections, tests and/or analyses together with associated acceptance criteria which will be undertaken for the FPC system.

Table 2.6.2: Fuel Pool Cooling and Cleanup System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the FPC system is shown in Figure 2.6.2.	1. Inspection of the as-built FPC system configuration shall be performed.	1. As-built FPC system configuration for those components shown, conforms with Figure 2.6.2.
2. FPC pump capable of delivering flow rate of ≥ 250 m^3/hr against 80m differential head.	2. Review of vendor design documents and test results relating to pump performance.	2. Installed pump meets design flow requirements.
3. The FPC system operates when powered from both normal off-site and on-site sources.	3. FPC system functional test shall be performed to demonstrate operation when supplied by either normal off-site power or from the on-site power source.	3. FPC system is capable of operating when supplied by either power source.
4. The FPC system mechanical equipment, excepting filter/demineralizer is built as seismic category I and Quality Group C standards.	4. Procurement records and actual equipment shall be inspected to verify applicable FPC system components have been designed, manufactured and installed per the relevant standards.	4. Installed equipment meets the seismic category I requirements and quality group C standards.
5. Control room indications are provided for FPC system parameters.	5. Inspections shall be performed to verify presence of control room indication for the FPC system as described in 2.6.2.	5. The instruments are present in the control room as specified in Section 2.6.2.
6. RHR system provides a safety-related makeup water source to the fuel pool.	6. The FPC and RHR systems combined functional test shall be performed by aligning the system such that RHR draws water from the suppression pool and discharges into the fuel pool.	6. The combined system operation transfers makeup water from suppression pool to the fuel pool.

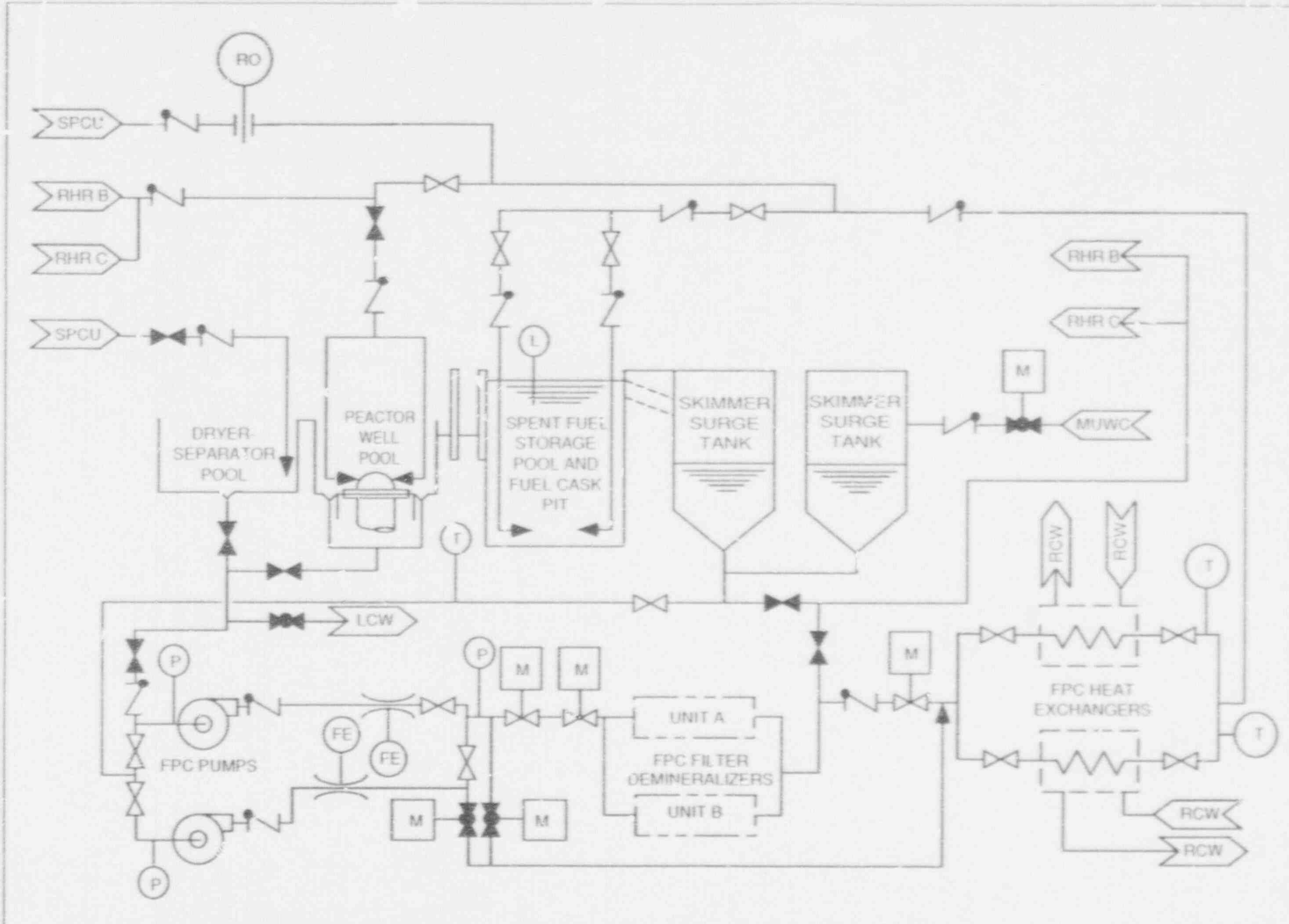


Figure 2.6.2 Fuel Pool Cooling and Cleanup (FPC) System

2.6.3 Suppression Pool Cleanup System

Design Description

Later, Stage 3 Item.

2.7 Control Panels

2.7.1 Main Control Room Panel

Design Description

The Main Control Room Panel is comprised of separate stand alone modules (e.g. Main Control Panel, Large Display Panel). Each panel module is seismically qualified and provides grounding, and electrical independence and physical separation between safety divisions and between safety divisions and non-essential components and wiring.

Electrical power to divisional "Vital" components is from the Vital AC Control Power or battery of the same electrical division. Power to the non-essential "Vital" components is from the non-essential Vital AC Control Power or non-essential battery. Divisional, non-vital components are powered from the respective divisional AC Instrument Power and non-divisional, non-vital components are powered from non-essential AC Instrument Power.

The Main Control Room Panel and other main control room operator interfaces are designed to provide the operator with information and controls needed to safely operate the plant in all operating modes, including startup, refueling, safe shutdown, and maintaining the plant in a safe shutdown condition. The process to be used during the implementation stage will incorporate accepted Human Factor Engineering (HFE) principles in implementing the Main Control Room Human-System Interface (HSI).

Inspection, Test, Analyses and Acceptance Criteria

Table 2.7.1 together with the Design Acceptance Criteria (DAC) in Table 3.4 defines the design process to be used for the Main Control Room Panel and other main control room operator interfaces.

Table 2.7.1: Main Control Room Panels

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The Main Control Room Panels are seismically qualified.	1. Inspection of the as-built design documentation and installed equipment will be performed.	1. Panels are seismically qualified and installed.
2. The Main Control Room Panels design provides grounding and electrical independence and physical separation between divisions and between divisions and non-divisional components and wiring.	2. Inspection of the as-built design documentation and installed equipment will be performed.	2. Electrical Independence, and physical separation, and grounding of components and wiring is provided.
3. The Main Control Room Panel components identified as "Vital" are powered from their respective division or non-essential Vital AC Control Power or battery. Non-vital components are powered from their respective divisional or non-essential AC Instrument Power Supplies.	3. Inspections of installed equipment will be performed. be performed.	3. Panel components are powered from power supplies consistent with component classification and divisional assignment.
4. A Design and Implementation Process, directed by a dedicated Man Machine Interface System (MMIS) Design Team, will govern the implementation of the Main Control Room Panel and other main control room operator interfaces. Human Factors Engineering principles will be employed to provide a Human-System Interface (HSI) for the Main Control Room Panels.	4. See Table 3.6.	4. Design and Implementation of the Main Control Room Panels and other main control room operator interfaces comply with the criteria defined in Section 3.6.

2.7.2 Radioactive Waste Control Panel

Design Description

No entry. Covered by Item 2.9.1.

2.7.3 Local Control Panels

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.7.4 Instrument Racks

Design Description

Later, Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.7.5 Multiplexing System

Design Description

Later. Stage 3 Item.

2.7.6 Local Control Box

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.8 Nuclear Fuel

2.8.1 Nuclear Fuel

Fuel design for the ABWR is not within scope of the certified design. It is intended that the specific fuel to be utilized in any facility which has adopted the certified design be in compliance with U.S. NRC approved fuel design criteria. This strategy is intended to permit future use of enhanced/improved fuel designs as they become available. However, this approach is predicated on the assumption that future fuel designs will be extensions of the basic fuel technology that has been developed for boiling light water reactors. Key characteristics of this established BWR fuel technology are:

a. Sintered uranium oxide fuel pellets

b. Zirconium-based (or equivalent) fuel cladding

c. All material selected on the basis of BWR operating conditions

d. Multi-rod fuel bundles in an N lattice

e. Zirconium-based (or equivalent) fuel channels which preclude cross-flow in the core region

f. Fuel bundle inlet orificing to control bundle flow rates, core flow distribution, and reactor coolant hydraulic characteristics

The following is a summary of the principal requirements which must be met by the fuel supplied to any facility utilizing the certified design.

General Criteria

a. NRC-approved analytical models and analysis procedures are applied.

b. New design features are included in lead test assemblies.

c. The generic post-irradiation fuel examination program approved by NRC is maintained.

Thermal-Mechanical

The fuel design thermal-mechanical analyses are performed for the following conditions:

a. Either worst tolerance assumptions are applied or probabilistic analyses are performed to determine statistically bounding results (i.e., upper 95% confidence).

b. Operating conditions are taken to bound the conditions anticipated during normal steady-state operation and anticipated operational occurrences.

The fuel design evaluations are preformed against the following criteria:

a. The fuel rod and fuel assembly component stresses, strains, and fatigue life usage do not exceed the material ultimate stress or strain and the thermal fatigue capacity.

b. Mechanical testing is performed to ensure that loss of fuel rod and assembly component mechanical integrity will not occur due to fretting wear.

c. The fuel rod and assembly component evaluations include consideration of metal thinning and any associated temperature increase due to oxidation and the buildup of corrosion products to the extent that these influence the material properties and structural strength of the components.

d. The fuel rod internal hydrogen content is controlled during manufacture of the fuel rod consistent with ASTM standards.

e. The fuel rod is evaluated to ensure that fuel rod or channel bowing does not result in loss of fuel rod mechanical integrity due to boiling transition.

f. Loss of fuel rod mechanical integrity will not occur due to excessive cladding pressure loading.

g. The fuel assembly (including channel box), control rod and control rod drive are evaluated to assure control rods can be inserted when required. These evaluations consider the effect of combined Safety Shutdown Earthquake (SSE) and Loss-of-Coolant Accident (LOCA) loads.

h. Loss of fuel rod mechanical integrity will not occur due to cladding collapse into a fuel column axial gap.

i. Loss of fuel rod mechanical integrity will not occur due to pellet-cladding mechanical interaction.

Nuclear

a. A negative Doppler reactivity coefficient is maintained for any operating condition.

b. A negative core moderator void reactivity coefficient resulting from boiling in the active flow channels is maintained for any operating conditions.

c. A negative moderator temperature coefficient is maintained above hot standby.

d. For a super prompt critical reactivity insertion accident originating from any operating conditions, the net prompt reactivity feedback due to prompt heating of the moderator and fuel is negative.

e. A negative power coefficient, as determined by calculating the reactivity change, due to an incremental power change from a steady-state base power level, is maintained for all operating power levels above hot standby.

f. The plant meets the cold shutdown margin requirement.

g. The effective multiplication factor for fuel designs stored under normal and abnormal conditions is shown to meet fuel storage limits by demonstrating that the peak uncontrolled lattice k-infinity calculated in a normal reactor core configurations meets the limits for the storage racks.

Hydraulic

Flow pressure drop characteristics are included in the calculation of the Operating Limit MCPR.

Because of the channeled configuration of BWR fuel assemblies, there is no bundle-to-bundle cross -flow inside the core, and the only issue of hydraulic compatibility of various bundle types in a core is the bundle inlet flow rate variation and its impact on margin-to-thermal limits. The coupled thermal-hydraulic-nuclear analyses performed to determine fuel bundle flow and power distribution uses the various bundle pressure loss coefficients to determine the flow distribution required to maintain a total core pressure drop boundary condition to be applied to all fuel bundle. The margin to the thermal limits of each fuel bundle is determined using this consistent set of calculated bundle flow and power.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.8.1 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the fuel that will be proposed for the facility.

Table 2.8.1: Nuclear Fuel

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The proposed fuel design will meet the general, thermal-hydraulic, nuclear and hydraulic criteria approved for the certified design.	1. The fuel design process and documentation will be reviewed for evidence of compliance with design criteria.	1. Fuel design is compatible with the design criteria approved for the certified design.

2.8.2 Fuel Channel

Design Description

Later. Stage 3 Item.

2.8.3 Control Rod

Design Description

Control rod design for the ABWR is not within scope of the certified design. It is intended that the specific control rod to be utilized in any facility which has adopted the certified design be in compliance with U.S. NRC approved control rod design criteria. This strategy is intended to permit future use of enhanced/ improved control rod designs as they become available. However, this approach is predicated on the assumption that future control rod designs will be extensions of the basic technology that has been developed for light water reactors. Key characteristics of this established BWR control rod technology are:

a. Control rods perform dual functions of power distribution shaping and reactivity control.

b. The control rod has a cruciform cross sectional envelope shape.

c. The control rod has a coupling at the bottom for attachment to the control rod drive.

d. The control rod has an upper bail handle for transporting.

e. The cruciform cross section contains neutron poison materials which are either contained within or as part of the control rod structure.

The following is a summary of the principal requirements which must be met by the control rod supplied to any facility utilizing the certified design.

General Criteria

a. The control rod stresses, strains, and cumulative fatigue shall be evaluated to not exceed the ultimate stress or strain of the material.

b. The control rod shall be evaluated to be capable of insertion into the core during all modes of plant operation within the limits assumed in the plant analyses.

c. The material of the control rod shall be shown to be compatible with the reactor environment.

d. The reactivity worth of the control rod shall be included in the plant core analyses.

e. Lead Surveillance program shall be implemented if a change in design features such as new absorber material or structural material not previously used in reactor cores could impact the function of the control rod.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.8.3 provides a definition of the inspection, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the control rod that will be proposed for the facility.

Table 2.8.3: Control Rod

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Control rod design is compatible with the design criteria approved for the certified design.	1. The control rod design process and documentation will be reviewed for evidence of compliance with design criteria.	1. Control rod design is compatible with the design criteria approved for the certified design.

2.9 Radioactive Waste

2.9.1 Radwaste System

Design Description

Later. Stage 3 Item.

2.10 Power Cycle

2.10.1 Turbine M.ain Steam System

Design Description

The main steam (MS) system supplies steam generated in the reactor to the turbine. This Tier 1 entry addresses that portion of the MS that ranges between, but does not include, the outermost containment isolation valves and the turbine stop valves.

The MS is not required to effect or support safe shutdown of the reactor or to perform in the operation of rector safety features; however, the MS is designed:

a. To comply with applicable codes and standards in order to accommodate operational stresses such as internal pressure and dynamic loads without risk of failures and consequential releases of radioactivity in excess of the established regulatory limits.

b. To accommodate normal and abnormal environmental limits.

c. To assure that failures of nonseismic category I equipment or structures, or pipe cracks or breaks in high or moderate piping in the MS will not preclude functioning of safety related equipment or structures in the plant

d. With suitable access to permit in-service testing and inspections.

The basic MS configuration is shown in Figure 2.10.1. The main steam piping consists of four lines from the outboard main steam line isolation valves to the main turbine stop valves. The header arrangement upstream of the turbine stop valves allows them to be tested on-line with minimum load reduction and also supplies steam to the power cycle auxiliaries, as required.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.1 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which sill be undertaken for the MS system.

Table 2.10.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Failures of nonseismic category I equipment or structures, or pipe cracks or breaks in high or moderate piping in the MS will not preclude functioning of safety related equipment or structures in the plant.	1. Visual inspection of MS will be performed.	1. Confirmation that related systems or structures are in the vicinity or they are protected from failures in the nonseismic portions of the MS.
2. Access is provided for inservice testing and inspections.	2. Visual inspection of MS will be performed.	2 Confirmation that required inservice inspections can be accomplished.

Figure 2.10.1 Main Steam System

2.10.2 Condensate Feedwater and Condensate Air Extraction System

Design Description

The condensate feedwater and condensate air extraction system (CFDWA) consists of two subsystems, the condensate and feedwater system and the main condenser evacuation system (MCES).

Condensate and Feedwater System

Design Description

The function of the condensate and feedwater system (CFS) is to receive condensate from the condenser hotwells, supply condensate to the cleanup system, and deliver high purity feedwater to the reactor, at the required flow rate, pressure and temperature. Condensate is pumped from the main condenser hotwell by the condensate pumps, passes through the feedwater heaters to the feedwater pumps, and then is pumped through the high pressure heaters to the nuclear steam supply system.

The CFS boundaries considered here extend from the main condenser outlet to (but not including) the second isolation valve outside the containment. The CFS consists of the piping, valves, heat exchangers, controls and instrumentation, and the associated equipment and subsystems which supply the reactor with heated feedwater in a closed steam cycle utilizing regenerative feedwater heating.

The CFS does not serve or support any safety function and has no safety design basis. System analyses show that failure of this system cannot compromise any safety-related systems or prevent safe shutdown.

Portions of the system that are radioactive during operation are shielded with access control for inspections.

Leakage is minimized with welded construction used wherever practicable.

Relief discharges and operating vents are channeled through closed systems.

Operational system redundancy is provided with respect to feedwater heaters, pumps, or control valves by using multi-string arrangements and provisions for isolating and bypassing equipment and sections of the system.

The majority of the condensate and feedwater piping considered in this section is located within the turbine building which contains no safety-related equipment or systems. The portion which connects to the second isolation valve outside the containment is located in the steam tunnel between the turbine and reactor buildings. This portion of the piping is analyzed for dynamic effects from postulated events and safety-relief valve discharges.

The entire system piping is analyzed for water hammer loads that could potentially result from anticipated flow transients.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.2a provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the CFS s em.

Table 2.10.2a: Condenser Feedwater System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The CFS will be analyzed to show that system failure will not compromise plant safety.	1. Review failure analysis design assumptions with respect to as-built condition.	1. As-built conditions are same as the design assumptions used in the analysis.
2. The CFS will be provided with shielding and access control.	2. Visual inspection of CFS will be performed.	2. The as-built CFS provides shielding and access control.
3. CFS leakage will be minimized by use of welded construction wherever practicable.	3. Visual inspection of CFS will be performed.	3. Welded construction utilized as designed.
4. CFS relief valve discharges and operating vents will be channeled through closed systems.	4. Visual inspection of CFS will be performed.	4. Relief valve discharges and operating vent lines are routed as required by certified design.
5. The CFS will operate with a feedwater heater, pump or control valve out-of-service.	5. Simulated signals to verify operational status maintained.	5. CFS remains operational.
6. Failures of nonseismic category I equipment or structures, or pipe cracks and breaks in high- or moderate piping in the CFS will not preclude functioning of safety related equipment or structures in the plant.	6. Visual inspection of CFS will be performed.	6. No safety related systems or structures are in the vicinity or are protected from failure in the nonseismic portions of the CFS.
7. The CFS will be analyzed for potential water hammer loads.	7. Review water hammer analysis design assumptions with respect to as-built condition.	7. As-built conditions are same as the design assumptions used in the analysis.

Main Condenser Evacuation System

Design Description

Noncondensable gases are removed from the power cycle by the main condenser evacuation system (MCES). The MCES removes the hydrogen and oxygen produced by the radiolysis of water in the reactor, and other power cycle noncondensable gases, and exhausts them to the offgas system during plant power operation, and to the turbine building compartment exhaust system at the beginning of each start up.

The MCES does not serve or support any safety function and has no safety design basis.

The MCES is designed to quality group D.

The MCES is illustrated in Figure 2.10.2. The system consists of two 100% capacity, double stage, steam jet air ejectors (SJAE) units (complete with intercondenser) for power plant operation, and a mechanical vacuum pump for use during startup. The last stage of the SJAE unit is normally in operation and the other is on standby.

Steam supply to the second stage ejector is maintained at a minimum specified flow rate to ensure adequate dilution of the hydrogen and prevent the offgas from reaching the flammable limit of hydrogen.

Steam pressure and flow is continuously monitored and controlled in the ejector steam supply lines. Redundant pressure controllers sense steam pressure at the second stage inlet and modulate the steam supply control valves upstream of the air ejectors. The steam flow transmitters provide inputs to logic devices. These logic devices provide for isolating the offgas flow from the air ejector unit on a two-out-of-three logic, should the steam flow drop below acceptable limits for offgas stream dilution.

The vacuum pump exhaust stream is discharged to the turbine building compartment exhaust system which provides for radiation monitoring of the system effluents prior to their release to the monitored vent stack and the atmosphere.

The vacuum pump is tripped and its discharge valve is closed upon receiving a main steam high-high radiation signal.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.2b provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the MCES system.

Table 2.10.2b: Main Condenser Evacuation System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The offgas will be prevented from reaching a flammable limit of hydrogen.	1. Tests will be conducted using simulated signals to the SJAE flow control system.	1. Confirmation that the system isolates before flammability limits are reached.
2. Radioactive releases will be maintained within established limits.	2. Tests will be conducted using simulated signals to the vacuum pump isolation system.	2. Confirmation that the system isolates as required to limit releases.

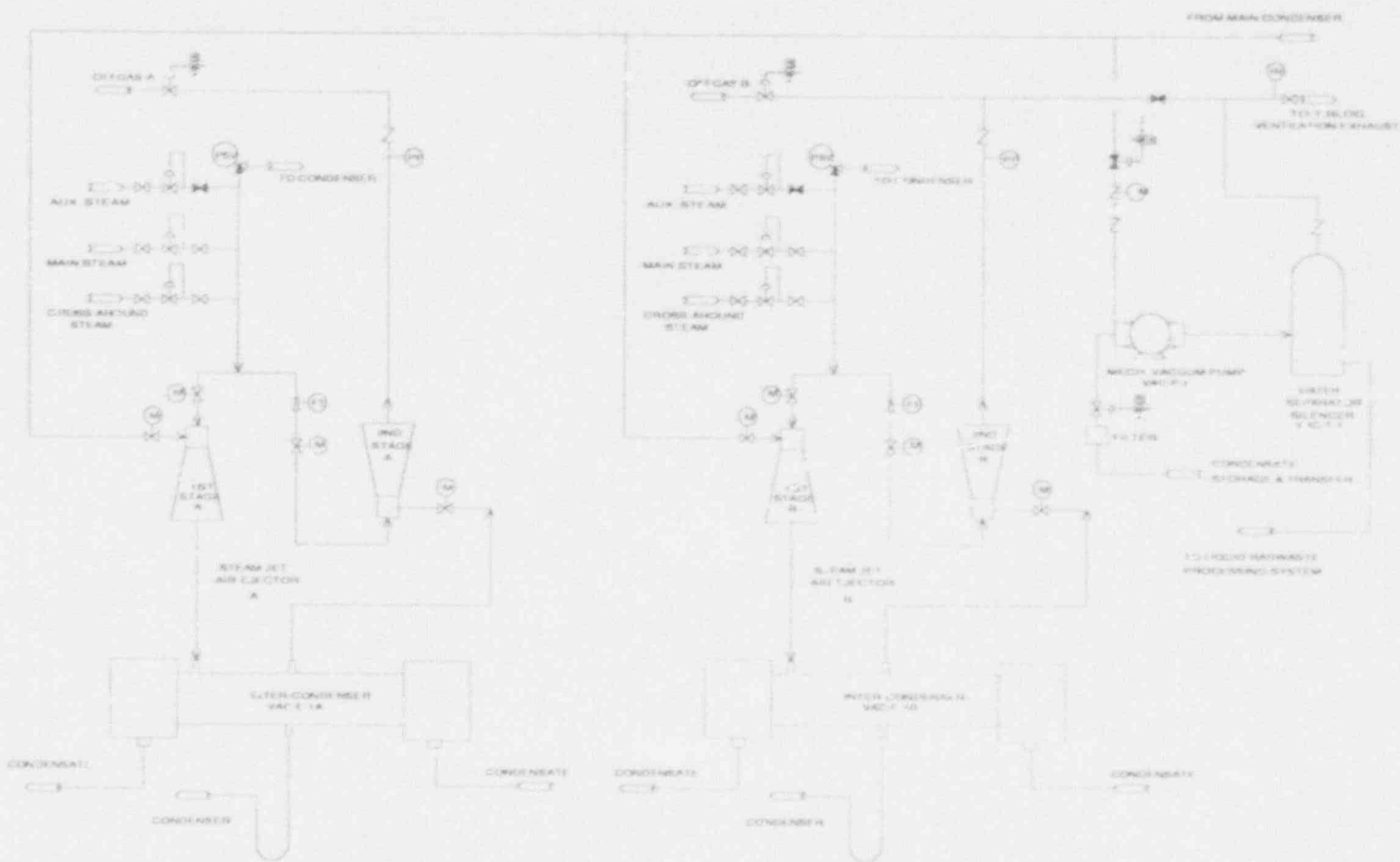


Figure 2.10.2 Main Condenser Evacuation System

2.10.3 Heater Drain and Vent System

Design Description

No Tier 1 entry for this system.

2.10.4 Condensate Purification System

Design Description

The condensate purification system (CPS) purifies and treats the condensate as required to maintain reactor feedwater purity, using filtration to remove corrosion products, ion exchange to remove condenser leakage and other impurities, and water treatment additions to minimize corrosion/erosion releases in the power cycle.

The CPS does not serve or support any safety function and has no safety design basis.

The CPS is designed to quality group D.

The CPS consists of full flow high efficiency particulate filters followed by full flow deep bed demineralizers.

Shielding is provided for the CPS.

Vent gases and other wastes from the CPS are collected in controlled areas and sent to the radwaste system for treatment and/or disposal.

The CPS is located in the turbine building and piping or equipment failures will not effect plant safety.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.4 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the CPS system.

Table 2.10.4: Condensate Purification System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Shielding will be provided for the CPS.	1. Visual inspection of the as-built CPS will be performed.	1. Installed equipment is shielded in accordance with certified design.
2. NO safety related equipment will be in the vicinity of the CCS.	2. Visual inspection of the as-built CPS will be performed.	2. Equipment is located as specified by certified design.
3. CCS wastes will be collected in controlled areas.	3. Visual inspection of the as-built CPS will be performed.	3. Compliance with certified design commitment.

2.10.5 Condensate Filiter Facility

Design Description

No entry. Covered by Item 2.10.4.

2.10.6 Condensate Demineralizer

Design Description

No entry. Covered by Item 2.10.4.

2.10.7 Main Turbine

Design Description

The main turbine generator system (TGS) converts the energy in steam from the nuclear steam supply system into electrical energy.

The TGS does not serve nor support any safety function and has no safety design basis. The TGS is, however, a potential source of high energy missiles that could damage safety related equipment or structures.

The TGS is designed to prevent overspeed and thus minimize the possibility of high energy missile generation from TGS moving parts.

The following component redundancies are employed to guard against overspeed:

a. Main stop valves/Control valves

b. Intermediate stop valves/Intercept valves (CIVs)

c. Primary speed control/Backup speed control

d. Fast acting solenoid valves/Emergency trip fluid system (ETS)

e. Speed control/Overspeed trip/Backup overspeed trip.

The TGS is enclosed within the turbine building which contains no safety related equipment or structures. The turbine generator is orientated within the turbine building to be inline with the reactor and control buildings to minimize the potential for any high energy TGS generated missiles from damaging any safety related equipment or structures.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.7 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the TGS.

Table 2.10.7: Main Turbine Generator System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The TGS will be designed to prevent the turbine generator rotor from exceeding the design overspeed with redundant instrumentation, controls and valving such that a single failure of any component will not cause the rotor speed to exceed its design value.	1. Visual inspection of the installed equipment together with simulated testing of the as-built overspeed protection system.	1. Design provisions to prevent overspeed are in place.
2. The turbine building will contain no safety related equipment or structures. The turbine generator will be orientated to minimize the potential for low trajectory high energy TGS missiles from damaging safety related equipment or structures.	2. Visual inspection of the as-built turbine building and plant arrangements.	2. Turbine generator arrangements per approved plant design.

2.10.8 Turbine Control System

Design Description

No entry. Covered under Item 2.10.7.

2.10.9 Turbine Gland Steam System

Design Description

The turbine gland sealing system (TGSS) prevents the escape of radioactive steam from the turbine shaft/casing penetrations and valve stems and prevents air inleakage through subatmospheric turbine glands.

The turbine gland sealing system consists of a sealing steam pressure regulator, sealing steam header, a gland steam condenser, with two full capacity exhaust blowers, and the associated piping, valves and instrumentation.

The TGSS does not serve or support any safety function and has no safety design basis.

The TGSS is designed to quality group D.

The outer portion of all glands of the turbine and main steam valves are connected to the gland steam condenser which is maintained at a slight vacuum by the exhauster blower. During plant operation, the gland steam condenser and one of the two installed 100% capacity motor-driven blowers are in operation. The exhauster blower to the turbine building compartment exhaust system effluent stream is continuously monitored prior to being discharged.

During normal operation the steam seal header is supplied from the main steam path. The auxiliary steam system provides a 100% steam supply backup when high radiation levels are detected in the blower exhaust or the main steam path source(s) are unavailable.

Relief valves on the seal steam header prevent excessive seal steam pressure.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.9 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the TGSS.

Table 2.10.9: Turbine Gland Steam System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Radiological releases will be maintained within established limits.	1. Visual inspection of the installed equipment coupled with a site specific radiological analysis and simulated signals to verify that system switches to auxiliary steam on high radiation levels.	1. System switches to auxiliary steam as required to limit radiological releases.

2.10.10 Turbine Lubricating Oil System

Design Description

No Tier 1 entry for this system.

2.10.11 Moisture Separator Heater

Design Description

No Tier 1 entry for this system.

2.10.12 Extraction System

Design Description

No Tier 1 entry for this system.

2.10.13 Turbine Bypass System

Design Description

The turbine bypass system (TBS) provides capability to discharge main steam from the reactor directly to the condenser to minimize step load reduction transients effects on the reactor coolant system. The system is also used to discharge main steam during reactor hot standby and cooldown operations.

The TBS does not serve or support any safety function and has no safety design basis.

There is no safety-related equipment in the vicinity of the TBS. All high energy lines of the TBS are located in the turbine building and no failure of high energy lines in the TBS will affect safety related equipment.

The TBS consists of a three valve chest that is connected to the main steam lines upstream of the turbine stop valves, and of three dump lines that connect separately each regulating valve outlet to one condenser shell. The system is designed to bypass nominally 33% of the rated main steam flow directly to the condenser.

The TBS, in combination with the reactor systems, provides the capability to shed 40% of the turbine-generator rated load without reactor trip.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.13 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the TBS.

Table 2.10.13: Turbine Bypass System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Failure of high energy lines in the TBS will not affect safety related equipment.	1. Visual inspection of the installed TBS will be conducted.	1. Confirmation that high energy line breaks will not jeopardize any safety-related equipment.

2.10.14 Reactor Feedwater Pump Driver

Design Description

No entry. Covered under Item 2.10.2.

2.10.15 Turbine Auxiliary Steam System

Design Description

No Tier 1 entry for this system.

2.10.16 Generator

Design Description

No entry. Covered under Item 2.10.7.

2.10.17 Hydrogen Gas Cooling System

Design Description

No Tier 1 entry for this system.

2.10.18 Generator Cooling System

Design Description

No Tier 1 entry for this system.

2.10.19 Generator Sealing Oil System

Design Description

No Tier 1 entry for this system.

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

2.10.20 Exciter

Design Description

No Tier 1 entry for this system.

2.10.21 Main Condenser

Design Description

The main condenser (MC) is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system.

The main condenser does not serve or support any safety function and has no safety design basis. It is however, designed with necessary shielding and controlled access to protect plant personnel from radiation.

The main condenser is a multi-shell type deaerating unit with a shell located directly beneath each of the low pressure turbines. Each shell has tube bundles through which circulating water flows. The condensing steam is collected in the condenser hotwells (the lower shell portion) which provide suction to the condensate pumps.

Since the main condenser operates at a vacuum any leakage is into the shell side of the main condenser. Tubeside or circulating water inleakage is detected by measuring the conductivity of sample water extracted beneath the tube bundles. In addition, conductivity is continuously monitored at the discharge of the condensate pumps and alarms provided in the main control room.

In all operational modes the condenser is at vacuum and consequently no radioactive releases can occur. Loss of vacuum sequentially leads to control room alarm, turbine trip and eventually bypass and main steam isolation valve closure to prevent condenser overpressurization. Additionally, to avoid a turbine trip on high condenser back pressure reactor recirculation runback is automatically initiated and, on a site specific basis setting, on a combination of high condenser backpressure and loss of a circulating water pump.

Ultimate overprotection is provided by rupture diaphragms on the turbine exhaust hoods.

The instrumentation and control features that monitor the performance to ensure that the condenser is in the correct operating mode include:

a. Hotwell water level.

   Automatically controlled within preset limits. During normal full load operation with nominal hotwell levels that main condenser provides a 4 minute active condensate storage volume and has a two minute surge capacity. At minimum normal operating hotwell water level, and normal full load condensate flow rate, the condenser provides a 2 minute minimum hold-up time for N-16 decay.

b. Condenser pressure.

Key overall performance indicator that initiates alarms and trips at preset levels.

c. Low pressure turbine exhaust hood temperature.

Automatically initiates turbine exhaust water sprays to protect the turbine.

d. Inlet and outlet circulating water temperature.

Monitors performance only.

e. Conductivity within the condenser and at the discharge of the condensate pumps.

Initiates alarms at preset levels.

The main condenser potential for flooding is less than the CWS and consequently flooding protection is the same as the circulating water system (CWS) (2.10.23). Condenser pressure indicators are located above any potential flood level.

Spray pipes and baffles are designed to protect the main condenser internals from high energy flow inputs.

Hydrogen buildup during operation is provided by continuous evacuation of the main condenser. Hydrogen sources are excluded during shutdown.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.21 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the MC.

Table 2.10.21: Main Condenser

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Overpressurization of the condenser will be prevented by condenser isolation from high energy sources.	1. Tests will be performed using simulated signals to verify that the system isolates.	1. System isolation occurs.
2. Condenser pressure indicators and transmitters will be located above any potential flood levels.	2. Visual inspections of the as-built system will be conducted.	2. Installed equipment is in compliance with the design commitment.
3. Shielding and controlled access shall be provided for the main condenser system.	3. Visual inspections of the as-built system will be conducted.	3. Installed equipment meets the shielding and access control provisions of the certified design.

2.10.22 Off-Gas System

Design Description

Later. Stage 3 Item.

2.10.23 Circulating Water System

Design Description

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems.

The CWS does not serve or support any safety function and has no safety design basis.

To prevent flooding of the turbine building, the CWS is designed to automatically isolate in the event of gross system leakage. The circulating water pumps are tripped and the pump and condenser valves are closed in the event of a system isolation signal from the condenser area high-high level switches. A condenser area high level alarm is provided in the control room.

A reliable logic scheme will be adopted to minimize potential for spurious isolation trips (e.g. 2 out of 3 logic).

The CWS is designed and constructed in accordance with Quality Group D specifications.

The CWS consists of the following components:

a. Intake screens located in a screen house

b. Pumps

c. Condenser water boxes

d. Piping and valves

e. Tube-side of the main condenser

f. Water-box fill and drain subsystem

Figure 2.10.23 is a simplified system diagram showing major system components.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.10.23 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the CWS.

Table 2.10.23: CIRCULATING WATER SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Flooding of the turbine building will be prevented by CWS isolation in the event of gross system leakage.	1. Visual inspection of the installed equipment coupled with the analyses of the leakage/flooding characteristics of the as-built CWS will be performed using simulated signals to verify system isolates on high level.	1. System isolates upon receipt of an isolation signal.

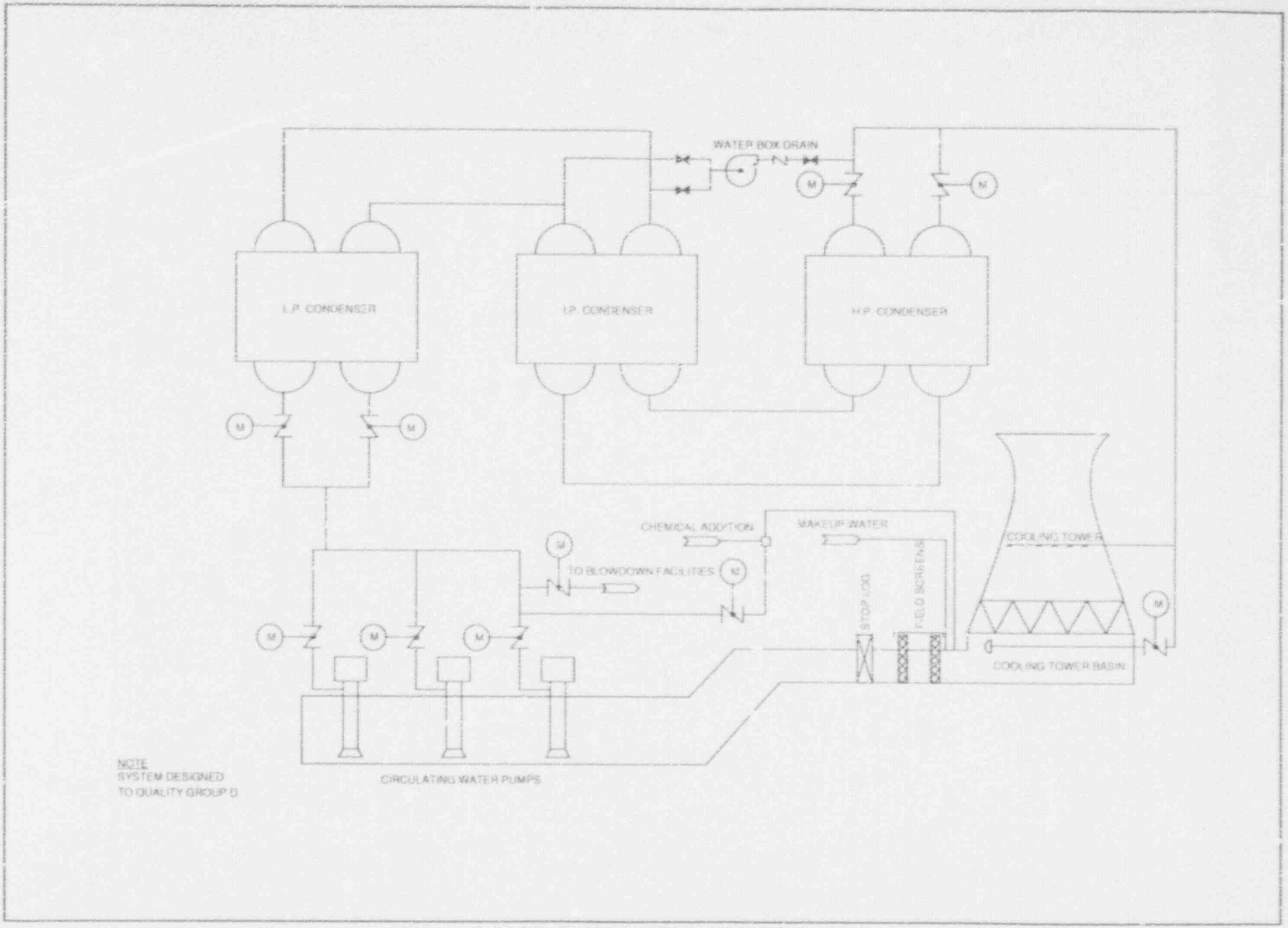


Figure 2.10.23 CIRCULATING WATER SYSTEM

2.10.24 Condenser Cleanup Facility

Design Description

No Tier 1 entry for this system.

2.11 Station Auxiliary

2.11.1 Makeup Water System (Purified)

Design Description

Later. Stage 3 Item.

2.11.2 Makeup Water System (Condensate)

Design Description

Later. Stage 3 Item.

2.11.3 Reactor Building Cooling Water System

Design Description

The reactor building cooling water RCW system distributes cooling water during various plant operating modes, as well as during shutdown, and during post-LOCA operation of the various safety systems. The system removes heat from plant auxiliaries and transfers it to the ultimate heat sink (UHS) via the reactor service water (RSW) system. The RCW removes heat from the ECCS equipment including the emergency diesel generators during a safe reactor shutdown cooling function.

The RCW system is designed to perform its required safe reactor shutdown cooling function following a postulated loss of coolant accident/loss of offsite power (LOCA/LOOP), assuming a single active failure in any mechanical or electrical RCW subsystem or RCW support system. In case of a failure which disables any one of the three RCW divisions, the other two divisions meet plant safe shutdown requirements, including a LOCA or a loss of offsite power, or both.

Redundant isolation valves are able to separate the essential portions of the RCW cooled components from the nonsafety-related RCW cooled components during a LOCA, to assure the integrity and safety functions of the safety related parts of the system. The isolation valves to the nonessential RCW system are automatically or remote-manually operated and their positions are indicated in the main control room.

Each RCW division includes two pumps which circulate RCW through the various equipment cooled by RCW and through three heat exchangers which transfers the RCW heat to the UHS via the RSW.

Each RCW division Main Control Room (MCR) instrument indication includes main loop surge tank level, main loop radiation and RHR HX flow and temperature. MCR control includes all MOV's and AOV's shown on Fig. 2.11.3. Normal surge tank MUWP makeup is automatic or MCR controlled.

The three RCW train configurations are shown on Figure 2.11.3. The RCW system provides three similar complete trains, A, B and C which are mechanically and electrically separated. The RCW pumps and valves for each RCW division is supplied electrical power from a different division of the ESF power system.

The RCW ASME code classifications for different portions of the system are indicated on Figure 2.11.3a-c. The safety related portions of the RCW divisions are designed to Seismic Category I and Quality Group C, and are located Seismic Category I structures.

During various plant operating modes, one RCW water pump and two heat exchangers are normally operating in each division. Flow balancing provisions are included within each RCW division.

Pump design parameters are:

	RCW A/B	RCW C
Design pressure (psig)	200	200
Design temperature (°F)	158	158
Discharge flow rate (gpm/pump)	≥ 5,700	≥ 4,800
Pump total head (psig)	≥ 80	≥ 75
Heat exchanger capacities are each:	≥ 45E^6 Btu/h	≥ 42E^6 Btu/h

Connections to a radiation monitor are provided in each division to detect radioactive contamination resulting from a tube leak in one of the RHR exchangers, fuel pool exchangers, or other exchangers.

The RCW pumps and heat exchangers are located in the lower floors of the control building. The equipment cooled by the RCW divisions are located in the reactor building, turbine building, and radwaste building, as stated on Figure 2.11.3a-c. Tables 2.11.3.2b,c,d show which equipment receives RCW flow during various plant operating and emergency modes. The tables also indicate how many heat exchangers are in service in each mode.

During normal plant operation, RCW flows through equipment which is normally operating and requires cooling and all ECCS equipment, except RHR heat exchangers and ESF diesel generators as shown by open or closed valves in Figure 2.11.3.

If a LOCA occurs, a second RCW pump and third heat exchanger in each loop are placed in service. Automatic or remote operated isolation valves will separate the RCW for the LOCA required safety equipment from the nonsafety-related equipment, if a RCW surge tank low water level signal occurs. The primary containment RCW isolation valves automatically close if a LOCA occurs.

After a LOCA, the following sequence will be followed:

a. If the nonsafety portion of RCW is available to the instrument air/service air (IA/SA) compressors, the CRD pumps and CUW pumps, RCW flow to these nonsafety components shown on Figure 2.11.3 is maintained. Flow is automatically shutoff to other non-essential equipment after the LOCA.

b. If the operator determines after the LOCA, from essential RCW instrumentation, that the integrity of the non-safety RCW system to the above mentioned compressors and pumps has been lost he can shut the remote operated nonessential isolation valves shown in Figure 2.11.3.

If the surge tank water level reaches a low level, with or without LOCA, indicating loss of water out of the RCW system, isolation valves in the supply and return piping to the nonessential equipment will automatically close, including the compressors and pumps mentioned above. Without LOCA and with low surge tank standpipe water level, all running RCW pumps trip. For post LOCA, both RCW pumps continue running with low surge tank standpipe water level.

The RCW/RSW heat exchanger design basis condition occurs during post-LOCA cooling of the containment via the RHR heat exchangers.

The RCW pumps have the flow capacity to deliver required flow to the ECCS equipment in each division and the above mentioned compressors and pumps if the isolation valves cannot be closed.

After a LOOP, the RCW pumps isolation valves and their control logic are automatically powered by the emergency diesel generators.

A separate surge tank is provided for each RCW division. Normal makeup water source to the surge tank is the makeup demineralized water system (MUWP). For LOCA conditions, the suppression pool cleanup system (SPCU) provides a backup surge tank water supply.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.11.3a provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be and undertaken for the RCW.

Table 2.11.3a: REACTOR COOLING WATER (RCW) SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. System configuration including key components and flow paths are shown in Figure 2.11.3.	1. Inspection of construction records will be performed. Visual inspection (VI) will be performed based on Figure 2.11.3.	1. The system configuration conforms with Figure 2.11.3.
2. Three RCW trains are mechanically and electrically independent.	2. Tests and VI of the three independent trains will be conducted which will include independent and coincident operation of the three trains to demonstrate complete divisional separation.	2. Plant tests and VI confirm proper independence of three RCW divisions.
3. During various modes of operation, RCW has adequate hydraulic capability for plant auxiliaries and the primary containment required for safe shutdown following a design accident or transient. These safe shutdown requirements are satisfied with only any 2 of 3 RCW divisions operating.	3. Limited system hydraulic tests will be conducted according to available nonnuclear heat plant conditions. The tests will demonstrate a safe plant shutdown with one RCW division out of service.	3. The results confirm the RCW has the water flow capability specified by the certified design commitment, including safe shutdown operation with 1 RCW division out of service.
4. Isolation valves as shown in Figure 2.11.3 can automatically or remote manually separate the RCW for the essential equipment from the RCW for the nonessential equipment.	4. VI of the installed RCW system and RCW preoperational tests as follows will be completed: a. Remote manual operation of the isolation valves from the main control room. b. During simulated LOCA conditions, a simulated LOCA condition will be combined with a simulated RCW surge tank water level signal to automatically close the isolation valves. c. A LOCA signal will shut RCW isolation valves which will shut off RCW flow to all nonessential equipment except the IA/SA compressors, CRD pumps and CUW pumps.	4. Isolation valves are properly located as shown in Figure 2.11.3 and are demonstrated to operate automatically or remote manually to isolate RCW for nonessential from RCW for essential equipment cooled by RCW.

Table 2.11.3a: REACTOR COOLING WATER (RCW) SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Without LOCA and with low surge tank standpipe water level, both RCW pumps in that division trip. For post LOCA, both RCW pumps will operate with low surge tank standpipe water level.	5. RCW system preoperational tests will be performed as follows: a. Simulate a surge tank standpipe low water level in the standpipe and confirm the running pump(s) trip. b. During a simulated LOCA condition and a simulated surge tank standpipe low water level signal, confirm both RCW pumps will operate. c. During low surge tank standpipe water level condition, a simulated LOCA signal starts both divisional RCW pumps.	5. The RCW pumps will trip or operate as follows: a. The running pump(s) will trip on surge tank standpipe low water level. b. With a LOCA condition signal, both RCW pumps will continue to operate with a simulated surge tank standpipe low water level signal. c. Both RCW pumps start on simulated LOCA signal.
6. A LOCA will result in the automatic start of the second RCW pump in each division and start flow through the third RCW/RSW Hx in each division. During LOCA/LOOP (loss of coolant accident/loss of off-site power) conditions, RCW pumps and valves are powered by the emergency diesel generators (D/G).	6. Tests simulating LOCA/LOOP conditions will be conducted for the RCW system which confirm the RCW and it's support systems will perform it's function under those conditions. Tests will be conducted for the RCW, which confirm that after the LOOP, each division of RCW pumps and valves operate with the same division of emergency D/G power and associated DC control power sources.	6. LOCA/LOOP signal successfully starts second RCW pump and initiates RCW/RSW Hx flow in each division including the following confirmations: a. Regardless of which RCW pump was operating during normal operation before the LOCA, after the LOAC/LOOP simulation occurs, the first and second RCW pump will start automatically, powered by the emergency diesel generator. b. Regardless of which two RCW/RSW Hx's were operating before the LOCA, after the LOCA/LOOP occurs, the RCW motor operated valve on the third Hx discharge will open automatically.

Table 2.11.3b: REACTOR BUILDING COOLING WATER CONSUMERS

DIVISION A

Operating Mode/ Components	Normal Operating Conditions	Shutdown at 4 hours	Shutdown at 20 hours	Hot Standby (no loss of AC)	Hot Standby (loss of AC)	Emergency (LOCA) (Suppression Pool at 97°C
RCW/RSW Heat Exchangers In Service	2	3	3	2	3	3
ESSENTIAL	Note 1					
Emergency Diesel Generator A	-	-	-	-	X	X
RHR Heat Exchanger A	-	X	X	-	X	X
FPC Heat Exchangor A	X	X	X	X	X	X
Others (essential) (Note 2)	X	X	X	X	X	X
NON-ESSENTIAL						
RWCU Heat Exchanger	X	X	X	X	X	-
Inside Drywell (Note 3)	X	X	X	X	X	-
Others (non-essential) (Note 4)	X	X	X	X	X	X

NOTES:

(1) (X) = Equipment receives RCW in this mode.
(-) = Equipment does not receive RCW in this mode.

(2) HECW refrigerator, room coolers (FPC pump, RHR, RCIC, SGTS, FCS, CAMS), RHR motor and seal coolers.

(3) Drywell (A & C) and RIP coolers.

(4) Instruments and service air coolers; RWCU pump cooler, CRD pump oil, and RIP Mg sets.

Table 2.11.3c: REACTOR BUILDING COOLING WATER CONSUMERS

DIVISION B

Operating Mode/ Components	Normal Operating Conditions	Shutdown at 4 hours	Shutdown at 20 hours	Hot Standby (no loss of AC)	Hot Standby (loss of AC)	Emergency (LOCA) (Suppression Pool at 97°C
RCW/RSW Heat Exchangers In Service	2	3	3	2	3	3
ESSENTIAL	Note 1					
Emergency Diesel Generator B	–	–	–	–	X	X
RHR Heat Exchanger B	–	X	X	–	X	X
FPC Heat Exchanger B	X	X	X	X	X	X
Others (essential)(Note 2)	X	X	X	X	X	X
NON-ESSENTIAL						
RWCU Heat Exchanger	X	X	X	X	X	–
Inside Drywell (Note 3)	X	X	X	X	X	–
Others (non-essential) (Note 4)	X	X	X	X	X	X

NOTES:

(1) (X) = Equipment receives RCW in this mode
(-) = Equipment does not receive RCW in this mode

(2) HECW refrigerator, room coolers (FPC pump, RHR, RCIC, SGTS, FCS, CAMS), RHR motor and seal coolers

(3) Drywell (B) and RIP coolers

(4) Reactor Building sampling coolers; LCW sump coolers (in drywell and reactor building); RIP MG sets and RWCU pump coolers

Table 2.11.3d: REACTOR BUILDING COOLING WATER CONSUMERS

DIVISION C

Operating Mode/ Components	Normal Operating Conditions	Shutdown at 4 hours	Shutdown at 20 hours	Hot Standby (no loss of AC)	Hot Standby (loss of AC)	Emergency (LOCA) (Suppression Pool at 97°C
RCW/RSW Heat Exchangers In Service	2	3	3	2	3	3
ESSENTIAL	Note 1					
Emergency Diesel Generator C	--	--	--	--	X	X
RHR Heat Exchanger C	--	X	X	--	X	X
Others (essential)(Note 2)	X	X	X	X	X	X
NON-ESSENTIAL						
Others (non-essential) (Note 3)	X	X	X	X	X	X

NOTES:

(1) (X) = Equipment receives RCW in this mode
(-) = Equipment does not receive RCW in this mode

(2) HECW refrigerator, room coolers motor coolers, and mechanical seal coolers for RHR and HPCF.

(3) Instrument and service air coolers, CRD pump oil cooler, radwaste components, HSCR condenser, and turbine building sampling coolers.

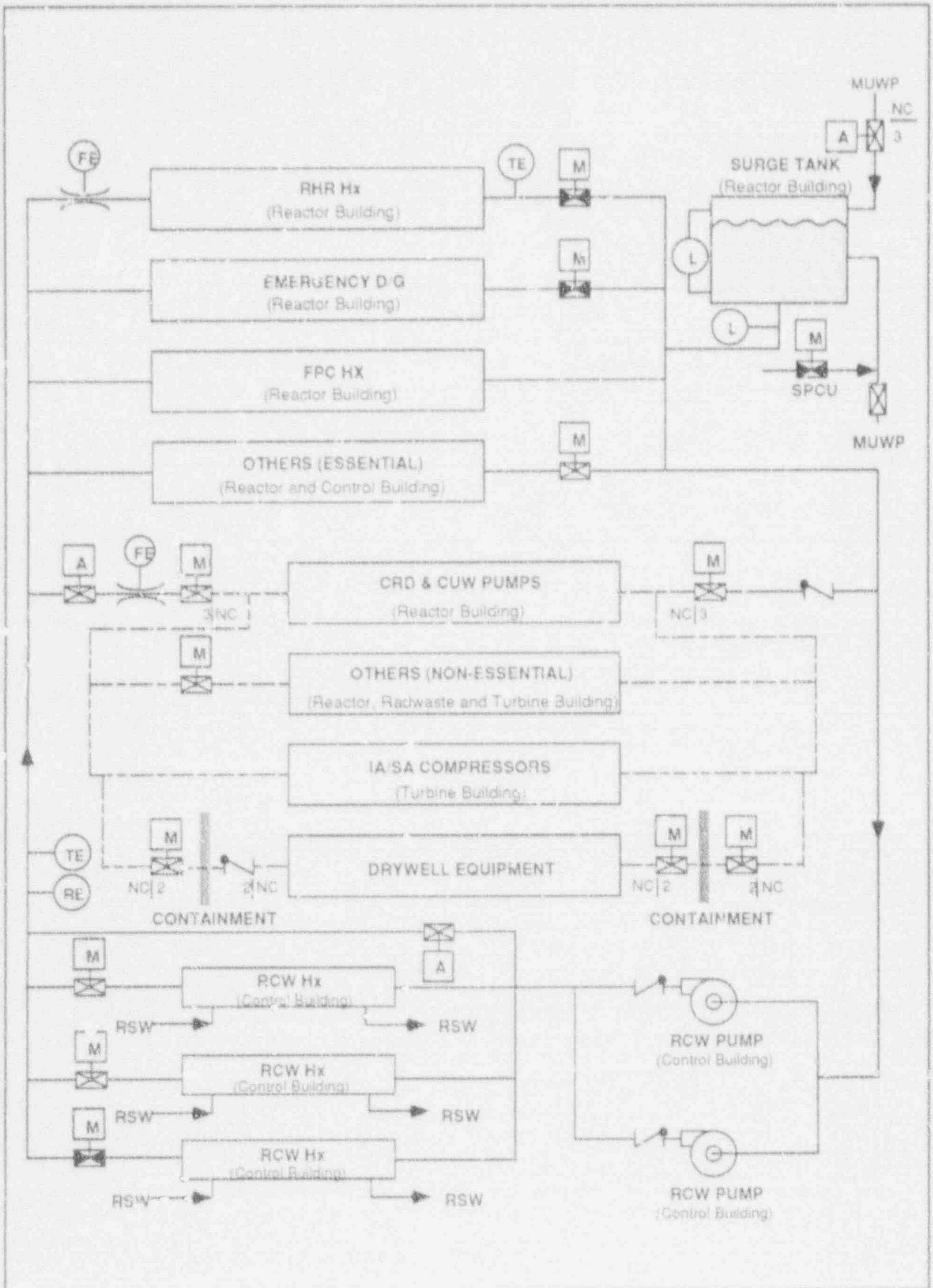


Figure 2.11.3a RCW DIVISION - A

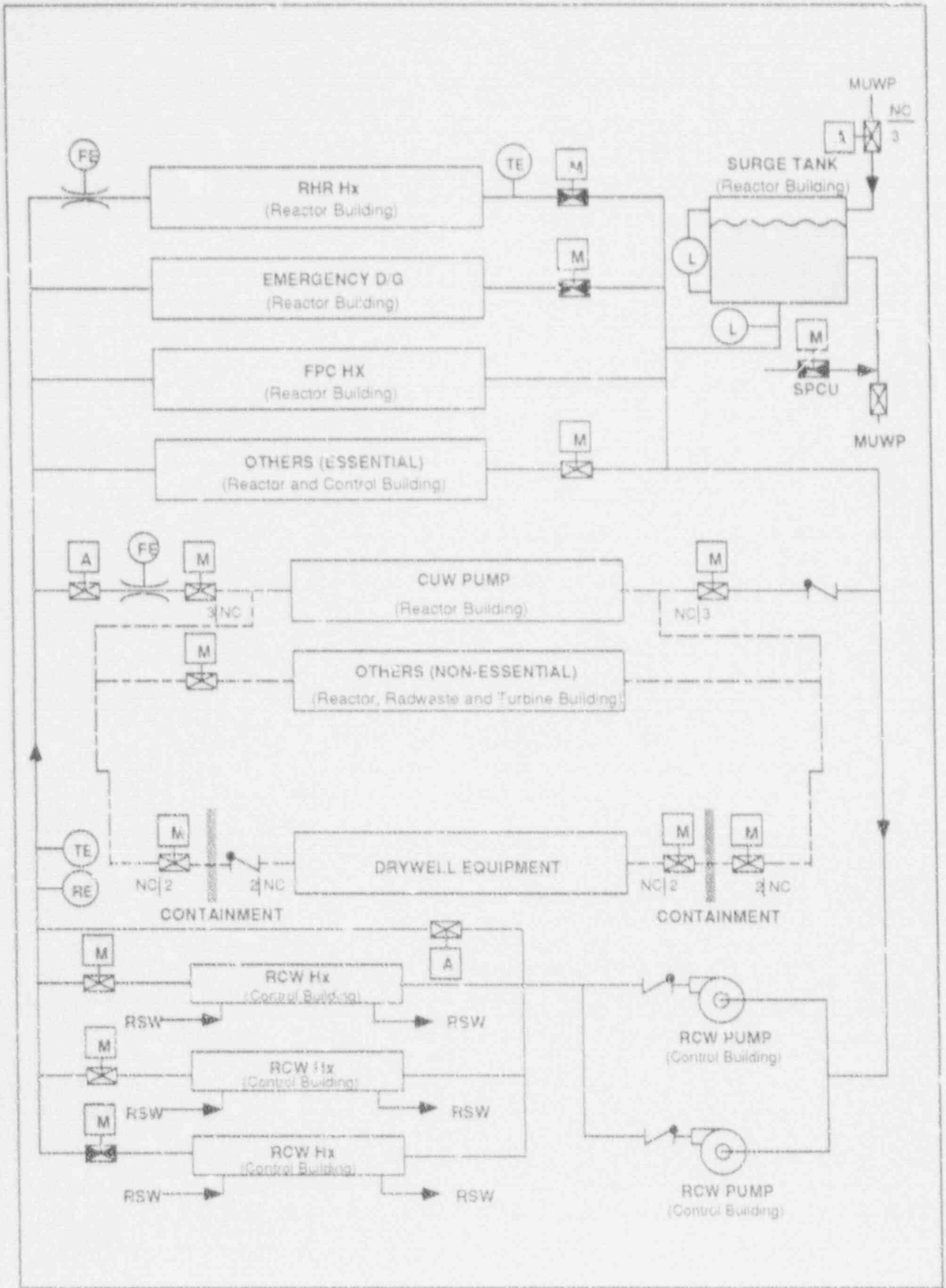


Figure 2.11.3b RCW DIVISION - B

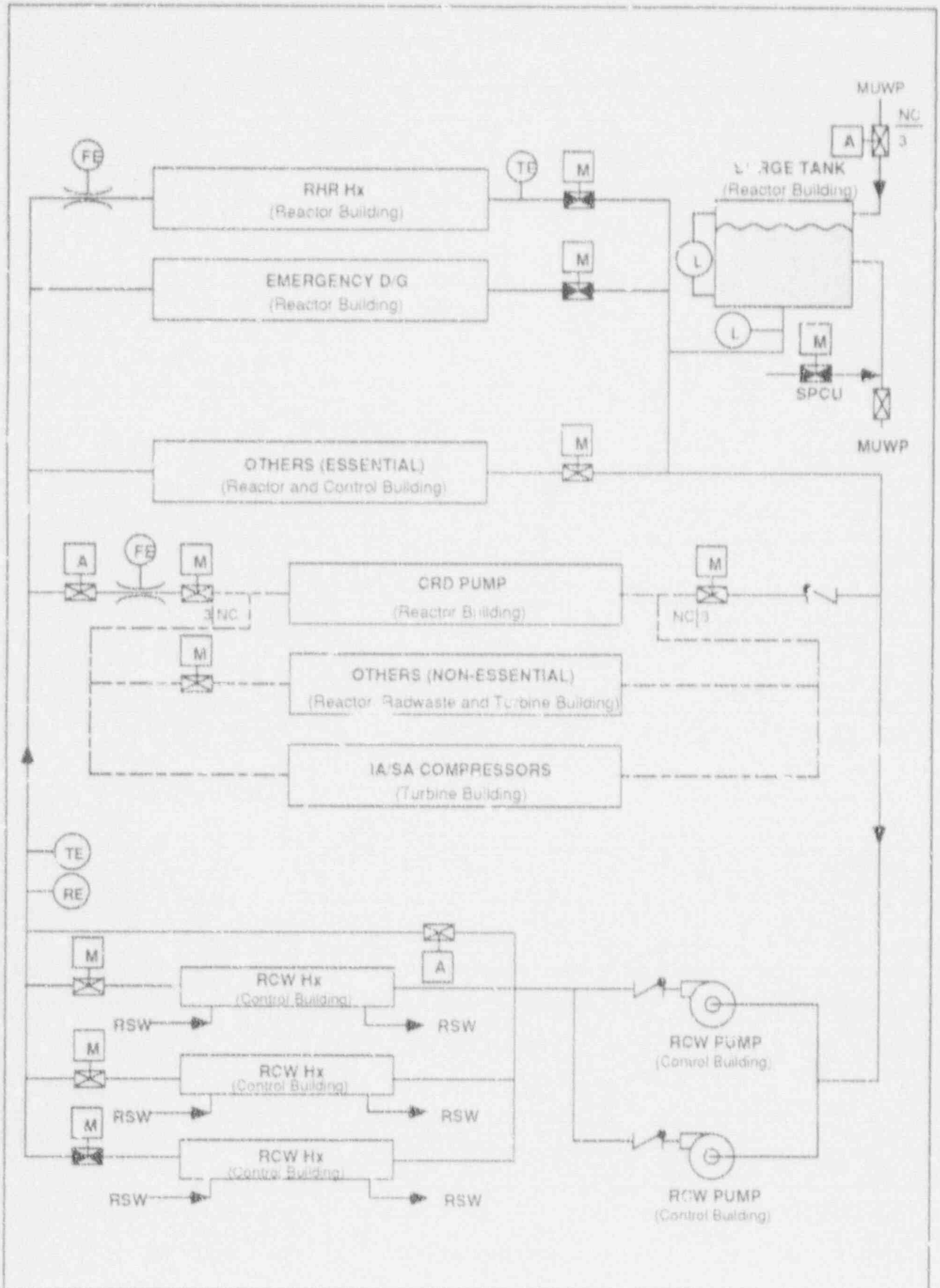


Figure 2.11.3c RCW DIVISION - C

2.11.4 Turbine Building Cooling Water System

Design Description

Later. Stage 3 Item.

2.11.5 HVAC Normal Cooling Water System

Design Description

Later. Stage 3 Item.

2.11.6 HVAC Emergency Cooling Water System

Design Description

The HVAC emergency cooling water system (HECW) delivers chilled water to the control building essential electrical equipment room coolers, the diesel generator zone coolers, and the main control room coolers during shutdown of the reactor, normal operating modes and abnormal reactor conditions including LOCA.

The HECW system consists of three mechanically separated divisions. Each division provides cooling to one control building essential electrical equipment room and one diesel generator zone. Either division "B" or "C" also provides cooling to the main control room. Power is supplied to each division from independant Class 1E sources.

HECW division "A" consists of one pump, one refrigeration unit, instrumentation, and distribution piping and valves to the cooling coils. Divisions "B" and "C" are similar except that two parallel pumps and refrigeration units are used. Surge tanks and condenser coolant flow are provided by the corresponding division of the RCW system. A chemical addition tank is shared by all HECW divisions. The system configuration is shown in Figure 2.11.6.

The refrigeration and pump units are designed to meet the following requirements:

Refrigerator Capacity (BTU/h)	2.3×10^6
Pump Capacity (gpm)	256

All major system components are located in the control building except for the diesel generator zone cooling coils in the reactor building. There are no primary or secondary containment penetrations within the system.

Piping and valves for the HECW system, as well as the cooling water lines from the RCW system,are designed to ASME Code, Section III, Class 3 and Quality Group C requirements. The classification extends up to and including the block valves for the chemical feed tank.

The HECW system is capable of removing all heat loads with one of the four pump and refrigerator units from division "B" and "C" in standby. The standby refrigerator is equipped with an interlock which automatically starts the unit upon failure of the operating refrigerator. Flow switches prohibit the refrigerators from operating unless there is water flow through the evaporator and condenser. The refrigerator units can be controlled individually from the main control room by a remote manual switch.

The HECW system is designed to perform its required safe reactor shutdown cooling function following a postulated loss of coolant accident/loss of offsite power (LOCA/LOOP), assuming a single active failure in any mechanical or electrical division. In case of a failure which disables any one of the three HECW divisions, the other two divisions meet plant safe shutdown requirements.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.11.6 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the HECW.

Table 2.11.6: HVAC Emergency Cooling Water (HECW) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The system configuration includes key components and flow paths as shown in Figure 2.11.6.	1. Inspection of construction records will be performed. Visual inspection (VI) will be performed based on Figure 2.11.6.	1. The system configuration conforms with Figure 2.11.6.
2. The HECW divisions are mechanically and electrically independent. The HECW divisions are powered by independent Class 1E sources.	2. Tests and VI of the divisions will include independent and coincident operation of the three divisions to demonstrate complete divisional separation. VI will check for independent Class 1E power sources.	2. Plant tests and VI confirm proper independence of each HECW division. VI confirm Class 1E power sources for each HECW division
3. The standby refrigerator and pump units automatically start upon high temperature cooling water or failure of the operating units. The refrigerator units can be controlled individually from the main control room.	3. Tests simulating high temperature cooling water and operating pump failure will be conducted for each refrigerator and pump unit in divisions "B" and "C". Tests simulating main control room switch signals will be conducted for all refrigerator units in.	3. All refrigerator and pump units acting as standby units successfully start upon a high temperature cooling water or operating pump failure signal. Refrigerator and pump units are operable from main control room signals.
4. The HECW cooling capacity is capable of removing the heat loads on the system.	4. Inspections of vendor documentation will include refrigeration and pump capacities. Flow tests will confirm that adequate flow is available to the system	4. Each refrigeration unit shall have an effective heat removal capacity of 2.3E6 BTU/h at 256gpm. Each pump is capable of delivering 256 gpm to the system.

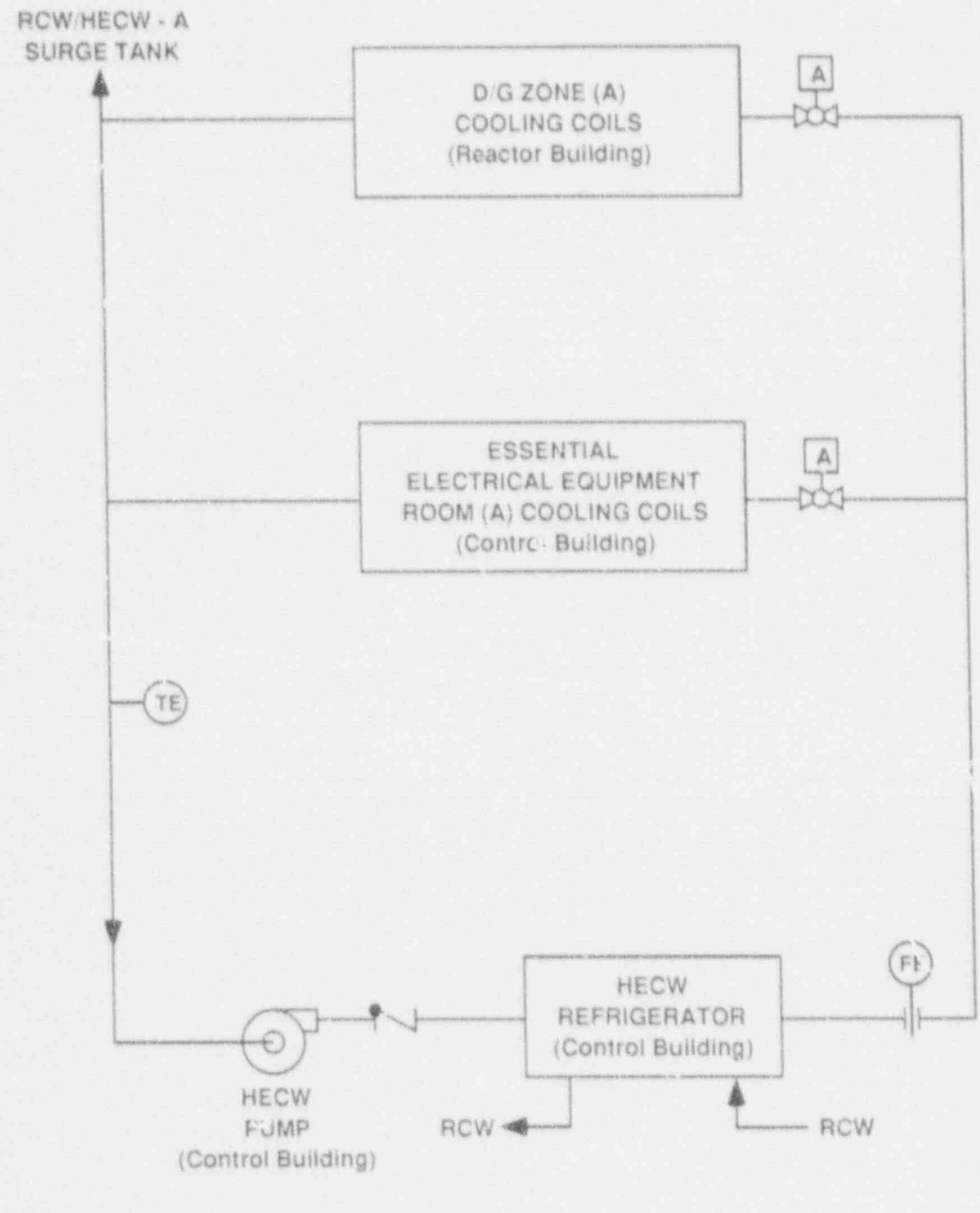


Figure 2.11.6a HECW Division - A

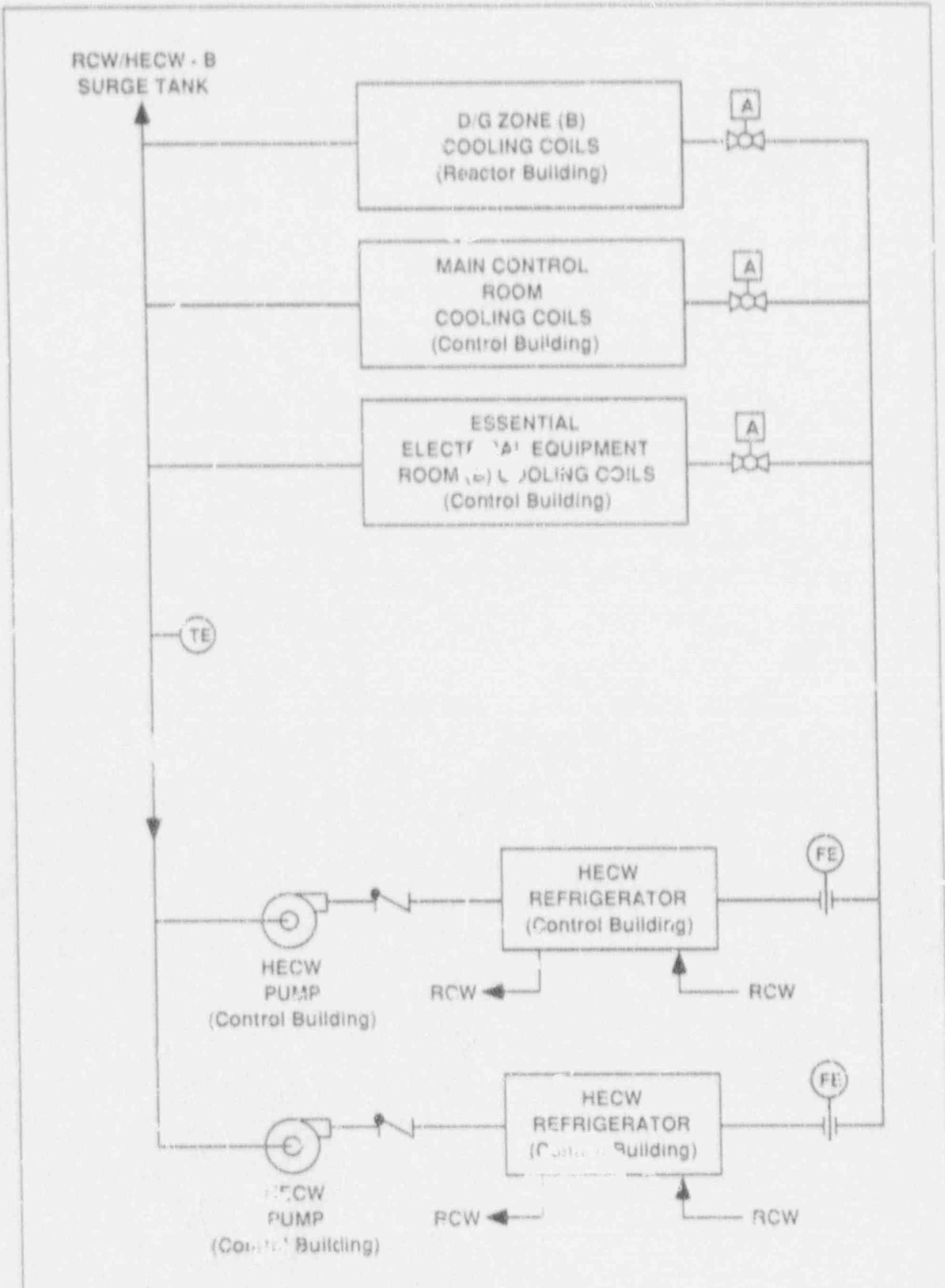


Figure 2.11.6b HECW Division - B

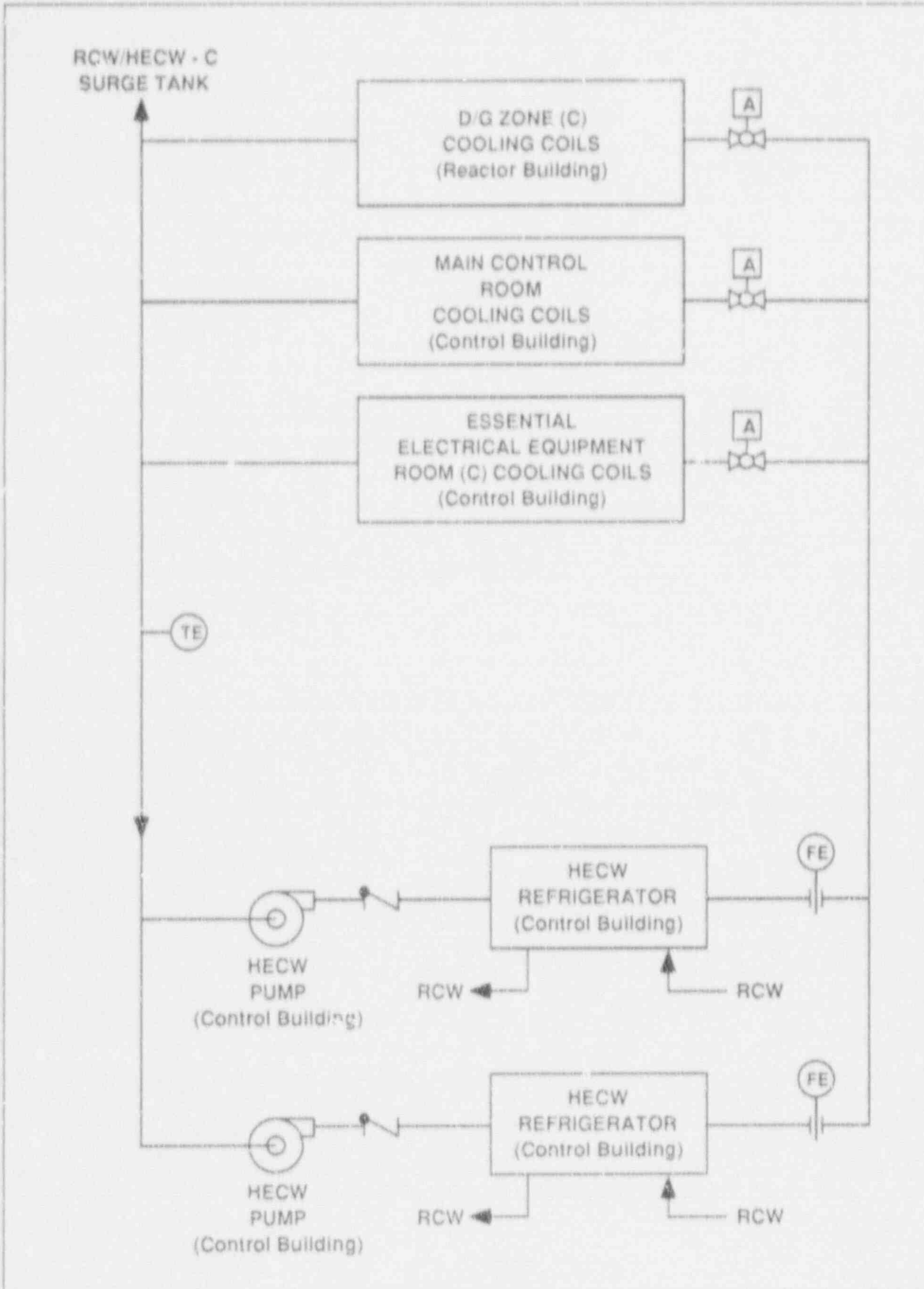


Figure 2.11.6c HECW Division - C

2.11.7 Oxygen Injection System

Design Description

No Tier 1 entry for this system.

2.11.8 Ultimate Heat Sink

Design Description

Interface item. Covered by Item 5.1.

2.11.9 Reactor Service Water System

Design Description

The function of the reactor service water (RSW) system is to remove heat from the Reactor Building Cooling Water (RCW) system and reject this heat to the Ultimate Heat Sink (UHS). The system is classified as safety related and has three separate divisions.

The reactor service water system is designed to perform its functions taking into consideration site specific factors. These factors include: adequate NPSH for the RSW pumps under all water level fluctuations in the ultimate heat sink (UHS), tendency for organic or macrobial fouling and means for their control and component and piping materials compatible with the UHS water. Measures to prevent flooding the control building after a pipeline break will be included.

The total heat removal capacity of the RCW, RSW and UHS is sufficient to remove heat loads associated with emergency shutdown and post-LOCA core and containment cooling. The system also removes heat during normal plant operation and shutdown.

The RSW system is designed to Seismic Category I and ASME Code Section III, Class 3, Quality Group C, and applicable IEEE requirements. The divisions of the RSW system are separated and protected from flooding, spraying, steam impingement, pipe whip, jet forces, missiles, fire and the effect of failure of any non-Seismic Category I equipment. This is accomplished by locating the pumps, valves, their power supplies and controls in the UHS pump house which is a Seismic Category I structure and away from high energy piping systems.

If a loss of preferred power occurs, all RSW system pumps and heat exchangers will automatically be placed in service using diesel generator power.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.11.9 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria for the RSW system.

Table 2.11.9: Reactor Service Water System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Adequate pump NPSH is available for the RSW pumps under all anticipated water level conditions in the UHS.	1. Available NPSH and requirements will be determined by analysis and compared to the NPSH of the as-built pumps.	1. Adequate NPSH is available under all anticipated conditions.
2. Provisions will be made to prevent organic and macrobial fouling.	2. Analyses of potential fouling problems in the UHS water source shall be performed and compared to the as-built provisions to prevent fouling.	2. Design provisions are in place to preclude unacceptable fouling or degradation of the RSW system performance.
3. Proper materials for RSW components and piping will be selected.	3. Analysis of potential corrosion problems in the UHS water source shall be performed and compared to the capabilities of the as-built equipment.	3. The design has appropriate anti-corrosion features.
4. Provisions will be made to prevent control building flooding if a pipeline break occurs in or near the control building.	4. An analysis will be performed of a pipe break in the control building using conservative assumptions. The extent of flooding will be estimated based on as-built component characteristics and site-specific UHS.	4. The control building flooding shall not affect any other RCW division or any other safety related equipment or areas.
5. RSW system can remove the heat from RCW system following a LOCA.	5. The heat removal capacity of the RSW divisions will be compared with the heat removal requirements of the RCW system divisions by evaluation of the as-built components.	5. The heat removal capacity of the RSW divisions is adequate to remove the heat from the divisions of the RCW system.
6. The RSW divisions are separated mechanically and electrically and are protected from the events listed in the Design Description.	6. Inspections and analyses will be performed of the mechanical and electrical separation and the measures to protect the RSW components and piping.	6. The RSW divisions are separated mechanically and electrically and are protected against events.

2.11.10 Turbine Service Water System

Design Description

Later. Stage 3 Item.

2.11.11 Station Service Air System

Design Description

Later. Stage 8 item.

2.11.12 Instrument Air System

Design Description

Later. Stage 3 Item.

2.11.13 High Pressure Nitorgen Gas Supply System

Design Description

Later. Stage 3 Item.

2.11.14 Heating Steam and Condensate Water Return System

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.11.15 House Boiler

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.11.16 Hot Water Heating System

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.11.17 Hydrogen Water Chemistry System

Design Description

Later. Stage 3 Item.

2.11.18 Zinc Injection System

Design Description

No Tier 1 entry proposed for this system.

2.11.19 Breathing Air System

Design Description

Later. Stage 3 Item

2.11.20 (This section not used)

2.11.21 Process Sampling System

Design Description

The process sampling system (PSS) is designed to provide sampling of all principal fluid process streams associated with plant operation. Representative samples are taken for analysis and provide the analytical information required to monitor plant and equipment performance.

The PSS consists of:

a. Permanently installed sampling nozzles and sample lines

b. Sampling panels with analyzers and associated sampling equipment

c. Provisions for local grab sampling

d. Permanent shielding

e. Casks for storing and transporting samples

The seismic design and quality group classifications of sample lines and their components shall conform to the classification of the system into which they are connected, up to and including the block valve (or valves), or, in the case of the reactor water sampling lines, the second isolation valve. The downstream sampling lines are Quality Group D.

Sampling is available from the post accident sampling station (PASS) following a LOCA or ATWS event. All PASS sampling valves are operated remotely. The PASS isolation valves are operated from the main control room using Class 1E power sources. All other valves are operated from the local control panel with two offsite power supplies.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.11.21 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be used by the PSS.

Table 2.11.21:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The system has the capability to perform post-accident sampling	1. Visual inspection (VI) will confirm that a post-accident sampling station (PASS) is provided.	1. The post-accident sampling station is provided.
2. The PASS isolation valves are connected to Class 1E sources. The PASS isolation valves may be opened for sampling during an accident without removing the LOCA signal.	2. VI will include the isolation valve electrical connections. Tests simulating a LOCA signal will be performed while the isolation valves are operated.	2. Plant tests and VI confirm Class 1E power sources and proper isolation valve operation under LOCA signals.
3. The PASS provides shielding and sample transporting casks.	3. VI of the PASS will review the presence of sample shielding	3. Shielding and transporting casks are provided at the PASS

2.11.22 Freeze Protection System

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.11.23 Iron Ion Injection System

Design Description

No Tier 1 entry for this system.

2.12 Station Electrical

2.12.1 Electrical Power Distribution System

Design Description

The plant Electrical Power Distribution System is a complete three load group distribution system with two independent off-site power sources (Normal Preferred and Alternate Preferred), the Main Turbine Generator, three on-site Standby Power Sources (Emergency Diesel Generators), and a Combustion Turbine Generator (CTG) located on-site. This three load group configuration, with multiple power sources, reduces the challenge to plant safety systems by increasing plant reliability. Any one of the three load groups can safely shutdown the plant and maintain safe shutdown. The CTG provides an additional diverse power supply to back up safety system power supplies, if needed. (See Figure 2.12.1a)

During normal plant operation, the main generator supplies power to the Main Power Transformer (MPT) and the three Unit Auxiliary Transformers (UAT) through a main generator output breaker and an Isolated Phase Bus. When the main generator is off-line, power is supplied to the Unit Auxiliary Transformers from the Main Power Transformer (Normal Preferred Power).

Each of the three Unit Auxiliary Transformers supplies power to a separate load group. One winding of each transformer supplies power to one non- essential medium voltage (6.9 KV) Power Generation (PG) switchgear and through a bus tie breaker to a Plant Investment Protection (PIP) switch- gear. The second winding supplies power to a second non-essential Power Generation medium voltage switchgear and to an Essential Safety System medium voltage switchgear. Power from the Unit Auxiliary Transformers to the medium voltage switchgear of the three non-essential load groups and to the first set of medium voltage circuit breakers feeding the three essential medium voltage switchgear is supplied through Non- Segregated Phase Buses.

The Reserve Auxiliary Transformer (RAT) is the Alternate Preferred Power source and is preferably lined up to supply power to one of the three Essential Safety System switchgear. One winding of the transformer can supply power directly to three non-essential Power Generation (PG) and three non-essential Plant Investment Protection (PIP) medium voltage switchgear and through bus tie circuit breakers to the other three non- essential Power Generation medium voltage switchgear. The second winding can supply power to all three Essential Safety System medium voltage switchgear (Div. 1,2,3). Power from the Reserve Auxiliary Transformer to all of the medium voltage switchgear of the three essential and non- essential load groups is provided through Non-Segregated Phase Buses.

Each Essential Safety System (Div. 1,2,3) medium voltage switchgear is normally supplied power from its associated Unit Auxiliary Transformer or from the

Reserve Auxiliary Transformer. In addition to these power sources, each Essential Safety System medium voltage switchgear is provided with its own dedicated Standby Power Supply. In the event of low voltage on the switchgear bus (e.g. loss of off-site power), the associated emergency diesel generator automatically starts, and after assuring that all other input feeder breakers are open, automatically connects to the bus to supply emergency power. Each emergency bus can also be supplied power from the combustion turbine generator. All bus transfer operations to the Class 1E buses, except for the automatic connection of each dedicated emergency diesel generator, are manual only.

Each load group of non-essential medium voltage switchgear is supplied power from its associated Unit Auxiliary Transformer with an alternate supply from the Reserve Auxiliary Transformer. In addition to these power sources, the three non-essential Plant Investment Protection medium voltage switchgear can be connected directly to the combustion turbine generator. On loss of voltage to a pre-selected Plant Investment Protection bus, the combustion turbine generator will automatically start, and after assuring that all other input feeder and bus tie breakers are open, automatically connects to the affected bus. However, only the two preselected buses of the three buses will connect automatically to the combustion turbine generator. All other non-essential bus transfers are manual only.

Medium voltage Metal Clad Switchgear (M/C) supply power to large loads (typically larger than 300KW) and one or more medium voltage (6.9 KV) to low voltage (480 V) Power Center Switchgear (P/C) transformers in the same non-essential load group or safety division. Power Center Switchgear supply power to medium size loads (typically between 100 to 300 KW) and multiple low voltage (480 V) Motor Control Centers (MCC) in the same non-essential load group or safety division. Motor Control Centers supply power to smaller loads (typically less than 100 KW), including lighting, 120 VAC instruments, power, and control equipment.

With one exception, Essential Safety System switchgear and Non-essential system switchgear are not interconnected except by common non-essential medium voltage power supplies. The one exception is the Fine Motion Control Rod Drive Power Center Switchgear. One of the Essential medium voltage switchgear supplies the preferred power to the non-essential Power Center through a series of one feeder circuit breaker and one transfer switch. The feeder breaker is Class 1E. The feeder cable, transfer switch, Power Center transformer, and interconnecting cable to the Power Center bus input breaker are classified as Associated 1E. One of the non- essential medium voltage Plant Investment Protection switchgear supplies the alternate power to the non-essential Power Center through a series of one feeder circuit breaker and the transfer switch. The feeder breaker, feeder cable (to the contacts of the transfer switch), transformer output breaker and Power Center are non-essential. Automatic transfer of the transfer switch is only from the essential to the non-essential power source on loss of essential bus voltage. Transfer back is manual only. (See Figure 2.12.1b)

Unit Auxiliary Transformers (UAT):

The size of each Unit Auxiliary Transformer is selected such that it will provide the full power requirements of its associated load group without exceeding its air/oil rating during normal 100% plant operation (e.g. all three load groups available) and will not exceed its forced air/oil rating with one load group out of service during 100% plant operation. Each transformer has two secondary windings as described above and will provide power at 6.9 KV with a nominal input voltage of 27 KV. Transformer impedance is selected to limit the output voltage decrease to a maximum of 20% during the starting of large motors and to limit the fault current to less than the maximum interrupting capacity of the circuit breakers while maintaining the required bus voltage regulation. The three Unit Auxiliary Transformers are separated from each other and from the Main Power Transformer by shadow fire walls. The Unit Auxiliary Transformers are also separated from the Reserve Auxiliary Transformer by a minimum of 50 feet. Each Unit Auxiliary Transformer is provided with its own oil pit and drain. Grounding and lightning protection is provided.

Reserve Auxiliary Transformer (RAT):

The size of the Reserve Auxiliary Transformer is selected such that one of the secondary windings will provide the power requirements of the loads on one full non-essential load group at 100% plant power operation and the second winding will provide the power requirements of all three divisions of Essential Safety System loads without exceeding its air/oil rating. The transformer ratio and impedance is selected to provide 6.9 kv (+/-10%) with a maximum frequency variation of +/-2% at a .9 power factor load and a maximum voltage decrease of 20% during the starting of large motors, assuming nominal input voltage and frequency. A frequency variation of 2 cycles is acceptable during periods of instability of the input. Impedance is also selected to limit the fault current to less than the maximum interrupting capacity of the circuit breakers while maintaining the required bus regulation. The Reserve Auxiliary Trans- former and its input feeders are separated from the Main Power Transformer and its input feeders and from the Unit Auxiliary Transformers by a minimum of 50 feet. The Reserve Auxiliary Transformer is provided with its own oil pit and drain. Grounding and lightning protection is provided.

Switchgear and Breakers:

The Main Generator Circuit Breaker is sized to handle the main generator full load output at a nominal voltage of 27 KV and to interrupt the maximum calculated fault current occurring at the breaker. It is equipped with redundant trip coils supplied from separate non-essential on-site 125 VDC batteries and is located approximately midway between the Main Generator and the Main Power Transformer.

Each feeder from a Unit Auxiliary Transformer to its respective Essential Safety System switchgear is provided with a stub bus and circuit breaker to facilitate the transition from the Non-Segregated Phase Bus to cable.

All Metal Clad and Power Centers switchgear, and Motor Control Centers are identified according to their Essentiality, Load Group or Division and their voltage level (6.9 KV, 480 V) and are physically separated accordingly. Divisional switchgear are qualified Essential Class 1E and are located in Seismic Category I structures and in their respective divisional electrical equipment rooms or fire areas. Essential equipment rooms and fire areas are separated by three hour fire barriers. Non-essential switchgear are separated by appropriate distances between non-essential load groups. Switchgear and associated transformers (e.g. Power Centers) are selected for their intended service and load requirements and are rated to sustain the maximum calculated fault current under all modes of operation until the fault is cleared. Feeder and load circuit breakers are sized and rated to provide the load requirements under all expected operating modes and are capable of interrupting their maximum calculated fault currents. Both switchgear and associated transformers are grounded. In addition, each medium voltage Metal Clad switchgear is provided with a Safety Ground Circuit Breaker which is racked-out during normal operation and is interlocked with bus voltage and its related bus feeder breakers to prevent inadvertent closure. The breaker is annunciated in the main control room when it is in the racked-in position.

Switchgear and motor control centers are provided with the manufactures recommended fault current and protective devices as required by the fault current and breaker coordination analysis performed during the implementation stage of the design. Fault current and breaker coordination analysis for Class 1E equipment is coordinated with the non-essential equipment load groups. Analyses consider the impedance of interconnecting cables and buses, and load cables. Control and instrumentation power for each switchgear is provided from the associated divisional or non-essential power train 125 VDC battery. For power circuits providing power through primary containment penetrations, a redundant overcurrent protective device is provided in series with the circuit breaker if the calculated fault current could exceed the maximum continuous current rating of the penetration. In addition to the normal protective features, zone-select interlocks are provided on the input feeder breakers to the essential switchgear supplying power to the Fine Motion Control Rod Drive (FMCRD) Power Center. The interlocks are provided to delay tripping the essential switchgear input feeders until the normal overcurrent device on the feeder to the non-essential FMCRD Power Center has had time to trip and clear any fault.

Electrical power generation and distribution parameters needed to assure plant reliability and safe shutdown are provided in the Main Control Room and to the Remote Shutdown System. These parameters include power distribution system breaker positions, voltages, amperes, KVA, KW, and power factor. In addition, remote control of selected power generation circuit breakers including synchronizing capability, is provided in the control room.

Phase Buses and Cables:

The Isolated Phase Bus is selected to carry the Main Generator full load output at a nominal 27 KV and rated to sustain the maximum calculated fault current until the fault is cleared. Disconnect links are provided in the feeds to each of the Unit Auxiliary Transformers to facilitate maintenance and isolate a faulty transformer. A main generator breaker is also provided as described above. The Isolated Phase Bus housing is grounded at both the Main Generator and the Main Power Transformer ends of the bus.

The Non-Segregated Phase Buses are selected to carry the full load at 6.9 KV to which they will be subjected under all modes of operation and are rated to sustain the maximum calculated fault current until the fault is cleared. Buses are identified according to voltage level and load group and are grounded at the same point as the switchgear to which they connect.

Power distribution system cables are selected for size and insulation based on their voltage, service load, routing, and environmental conditions, including temperature, humidity, and radiation, to which they may be exposed. Ratings and loading of the selected cables assures that they can sustain the maximum calculated fault currents to which they may be subjected until the fault is cleared. Cable impedance is considered in the overall distribution system protection analysis which will be performed during the implementation stage of the design. Selection and application of cables is intended to assure a life expectancy of 60 years. Cables are identified according to voltage levels, non-essential load center, essential division, and function.

Independence and Separation:

Electrical independence of equipment is provided by three separate load groups which are functionally redundant and capable of supporting plant operation at 50% of its rated output. There are no automatic connections between the load groups. Each load group is supplied by a separate power source unless connected to the combustion turbine generator. Electrical independence of Essential Safety Systems is provided by three separate safety divisions with their own dedicated emergency diesel generator. There are no automatic bus ties or power supply transfers between divisions. Normal Preferred Power to each division is from a separate non-essential power transformer. The only on line connection between a safety division and a non-essential load is the divisional power feed (as described above) to the Fine Motion Control Rod Drive Power Center.

Transformer and switchgear separation is described above. Essential Safety division cables are routed in Seismic Category 1 structures and dedicated divisional raceways which are separated from each other such that tolerance is provided for a complete burnout of a single fire area. Non-essential cables, if routed with divisional cables, are treated as Class 1E Associated. Cables of different divisions are not routed through a common hostile area except where justified by analysis (e.g. primary containment).

Separation of non-essential Normal Preferred and Alternate Preferred Power feeders is maintained by routing through different areas of the turbine and reactor buildings and by distance when routing across the control building. Non-essential load group separation between feeders from the Unit Auxiliary Transformers to the divisional switchgear is provided by routing cables in separate raceways.

A separate Combustion Turbine Generator feeder cable is provided to each of the three divisional and three non-essential switchgear to facilitate maintenance and fault clearance. Combustion Turbine Generator feeders to the reactor building follow a similar routing scheme to that used for the Alternate Preferred Power feeders.

In addition to the above separation, raceways are separated according to voltage levels and functions within divisions and load groups (e.g. low voltage control cables are routed separate from medium voltage power cables). Raceway are provided with grounding connections.

Grounding:

The electrical grounding system is comprised of 1) an instrument grounding network for grounding of instrumentation and computer systems, 2) an equipment grounding network for grounding electrical equipment (e.g. switchgear, motors, distribution panels, cables, etc.) and selected mechanical components (e.g. fuel tanks, chemical tanks, etc.), 3) a lightning protection network for protection of structures, transformers and other equipment located outside buildings, 4) a plant grounding grid. All grounding networks are insulated from each other and separately grounded to the plant grounding grid outside the structures. All grounding networks and equipment are low resistance grounded except the main generator, the emergency diesel generators, and the combustion turbine generator, which are high resistance grounded to maximize availability. All components requiring grounding are identified and provided with grounding connections.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.12.1 provides a definition of the inspection, test, and/or analysis together with associated acceptance criteria which will be undertaken for the electrical power distribution system.

Table 2.12.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The electrical power distribution system is a three- load group distribution system with two off-site power supplies, three on-site emergency generators, a combustion turbine generator located on site, and the main generator with its output circuit breaker.	1.a Inspections of the distribution system configuration will be performed to confirm each load group is supplied by a separate Unit Auxiliary Transformer.	1.a Each of the three load groups is supplied power from a separate Unit Auxiliary Transformer.
An Isolated Phase Bus connects the Main Generator to the Main Power Transformer and Unit Auxiliary Transformers through the Main Generator Breaker and through disconnect links to the Unit Auxiliary Transformers.	1.b Inspections of the Isolated Phase Bus and Non-segregated Phase Bus Installations, including the main generator breaker and disconnect links to the Unit Auxiliary Transformer, will be performed.	1.b Isolated and Non-segregated Phase Buses, with associated main generator breaker and disconnect links, are provided.
Non-segregated Phase Buses connect the Unit Auxiliary and the Reserve Auxiliary Transformers to their associated switchgear breakers and the first in-line breakers providing power to the Essential Safety System switchgear.	1.c Inspections of the transformer and other power sources and their power feeders will be performed to confirm their location and connections to the specified switchgear.	1.c The transformers, emergency diesel generators, and combustion turbine generator are located in accordance with the certified design and connect to the specified switchgear.
Each Unit Auxiliary Trans- former connects to two nonessential Power Generation switchgear and one Essential Safety System switchgear in its own load group.		
The Reserve Auxiliary Transformer connects to three Power Generation, three Plant Investment Protection, and three Essential Safety System switchgear.		
The Combustion Turbine Generator connects to the three nonessential Plant Investment Protection and the three Essential Safety System switchgear. (See Figure 2.12.1a and 1b)		

Table 2.12.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. Unit Auxiliary Transformers are sized to provide full load requirements within their air/oil rating for 100% plant operation (with all three load groups available) and will not exceed their forced air/oil rating with one load group out of service.	2.a Inspection of load assignments will be performed to assure transformer nameplate ratings will not be exceeded with all expected loads operating during either the two or three load group operating mode.	2.a Transformer nameplate ratings will not be exceeded during two and three load group operating modes.
Unit Auxiliary Transformers have two secondary windings and will provide a nominal voltage of 6.9 kV with a nominal input voltage of 27 kV. Output voltage will not exceed a 20% decrease from nominal during motor starting to assure at least the required minimum voltage at connected motor terminals.	2.b Inspections and tests will be conducted to confirm transformer ratios provide output voltages on both windings that are consistent with the input voltage.	2.b Transformer ratios provide output voltages that are consistent with input voltages and output voltages do not decrease below 20% of nominal voltage when motors with the largest starting currents are started during expected load conditions.
3. The Reserve Auxiliary Transformer is sized to provide the full load requirements of one complete nonessential load group and all three Essential divisions without exceeding its air/oil rating.	3.a Inspection of load assignments will be performed to assure transformer nameplate ratings will not be exceeded with all expected loads operating.	3.a Transformer nameplate ratings will not be exceeded when supplying power to one nonessential load group and three Essential divisions.
The Reserve Auxiliary Transformer has two secondary windings and will provide a nominal output voltage of 6.9 kV +/-10% with the nominal input voltage provided. Output voltage will not exceed a 20% decrease from nominal during motor starting to assure at least the required minimum voltage at the connected motor terminals.	3.b Inspections and tests will be conducted to confirm transformer ratios provide output voltages on both windings that are consistent with the input voltage.	3.b Transformer ratios provide output voltages that are consistent with input voltages and output voltages do not decrease below 20% of nominal voltage when motors with the largest starting currents are started during expected load conditions.

Table 2.12.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Breakers are capable of interrupting the maximum fault current to which they may be subjected. Switchgear, Motor Control Centers, Isolated and Non-segregated Phase Buses, and cables are selected to sustain the maximum fault currents to which they may be subjected until the fault is cleared.	4.a Inspection of the connected load requirements and breaker coordination scheme will be performed to confirm the selection of the electrical power distribution system components and cables and their capability to limit and clear faults.	4.a Transformers, switchgear, motor control centers, phase buses, and cables are capable of sustaining the maximum fault currents to which they may be subjected until the fault is cleared. Circuit breakers are rated to interrupt the maximum fault currents to which they may be subjected.
Transformers are sized to limit maximum fault currents while maintaining required voltage regulation. Cables are sized and insulation selected to accommodate the load requirements, type of service, and environmental conditions to which they may be subjected.	4.b Inspection of the distribution system cable selection criteria will be performed to assure that sizing and insulation selection of cables is consistent with the load and environment to which they may be subjected.	4.b Cable selection is consistent with the cable selection criteria and will perform their intended service.
Switchgear and motor control center protection devices and breaker control power is provided from the 125 VDC battery of the same division or load group or the power is internal to the switchgear. The main generator breaker control power is provided from two separate, on-site, nonessential 125 VDC batteries.	4.c Inspection of power distribution system protective devices and control power supplies will be performed.	4.c Power distribution system protective devices and control power sources are either internal to the switchgear or from the 125 VDC battery of the same division or nonessential load group. The main generator breaker control power is supplied from two separate on-site, nonessential 125 VDC batteries.
Redundant overcurrent devices are provided for cables entering primary containment through penetrations, when required.	4.d Inspection of the redundant overcurrent devices on cables penetrating the primary containment will be performed.	4.d Redundant overcurrent devices are provided, when required, on all electrical cables penetrating the primary containment.

Table 2.12.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Electrical independence is maintained between Essential Safety Systems.	5.a Inspections of the Essential Safety Systems will be performed to confirm their independence.	5.a There are no bus ties between Essential Safety Systems.
Electrical independence is maintained between nonessential load groups.	5.b Inspections of the nonessential load groups will be performed to confirm their independence.	5.b There are no automatic bus ties between nonessential load groups.
Electrical independence is maintained between Essential Safety Systems and nonessential load groups. The one exception is the two power supplies to the Fine Motion Control Rod Drive (FMCRD) Power Centers.	5.c Inspection of the configuration and protection scheme employed for the two power sources providing power to the FMCRD Power Center will be performed.	5.c The configuration and protection employed on the essential and nonessential feeders to the FMCRD Power Center provide the required electrical independence and separation.

Table 2.12.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. All switchgear, phase buses, and cables are identified according to Essential Safety Division, Divisional Association, Nonessential load group, voltage level and, when required, function; and are separated accordingly.	6.a Inspections of switchgear, phase buses, power distribution and control cables will be performed to confirm that they are identified according to their Essential division, divisional association, nonessential load group, voltage levels, and functions.	6.a Power distribution system components and cables are identified according to division, association, load group, voltage level, and function.
Essential Safety System divisional equipment are Class 1E and are located in Seismic Category 1 structures and divisional equipment areas which are physically separated by three hour fire barriers. Divisional cables are Class 1E and are routed in Seismic Category 1 structures and dedicated raceways which are separated such that tolerance is provided for complete burnout of a single fire area. Cables of different divisions are not routed through a common hostile area except where justified. Nonessential cables, if routed with Essential cables are Class 1E Associated.	6.b Inspection of the locations, separation, and identification of Essential power distribution system components and raceways will be performed. 6.c Inspections will be performed to identify all associated circuits. 6.d Inspections of the separation provided for the Normal Preferred Power, Alternate Preferred Power, and Combustion Turbine Generator feeders will be performed.	6.b Essential power distribution system components are located in Seismic Category 1 structures and separated divisional raceways and fire areas. Separation is provided between divisions, voltage levels, and functions. 6.c Class 1E Associated circuits are identified and comply with Class 1E requirements. 6.d Separation is provided between the Normal Preferred Power feeders and the Alternate Preferred Power and Combustion Turbine Generator feeders and between the Normal Preferred Power feeders of the three load groups.
Nonessential load group equipment are nonessential and separated by distance. The Normal Preferred Power and Alternate Preferred Power feeders are routed through different areas of the Turbine and Reactor Buildings and by distance when crossing the Control Building.		
The three Normal Preferred Power feeders are separated by routing in separate raceways.		

Table 2.12.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. (Cont.) Combustion Turbine Generator feeders follow a similar routing scheme as that used for the Alternate Preferred Power feeders to separate them from the Normal Preferred Power. Unit Auxiliary Transformers are separated from each other and from the Main Power Transformer by shadow fire walls and from the Reserve Auxiliary Transformer by a minimum of 50 feet. The Main Power Transformer and its feeders are separated from the Reserve Auxiliary Transformer and its feeder by a minimum of 50 feet. Essential division and nonessential load group raceways are separated according to voltage levels and functions, when required. Medium voltage power cables are not routed in the same raceway as control cables.	6.e Inspection of the separation between the Main Power Transformer, the Unit Auxiliary Transformers, and the Reserve Auxiliary Transformer will be performed.	6.e A minimum 50 foot separation is provided between the Main Power and Reserve Auxiliary Transformers and between the Unit Auxiliary Transformers and the Reserve Auxiliary Transformers. The Main Power and Reserve Auxiliary Transformer transmission lines are separated by a minimum of 50 feet. Shadow fire walls separate the Unit Auxiliary Transformers from each other and from the Main Power Transformer.

Table 2.12.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. The electrical grounding system is comprised of separate grounding and lightning protection networks. These networks are instrument, equipment, lightning protection, and a plant grounding grid. The instrument, equipment, and lightning protection networks are insulated from each other and separately connected to the plant grounding grid outside the structures.	7.a Inspection and tests will be performed on the grounding networks and lightning protection system to confirm that they are insulated from each other and low resistance grounded and that all equipment requiring grounding are identified.	7.a Grounding networks and lightning protection systems are insulated from each other and connected to the plant grounding grid outside structures. Equipment requiring grounding is identified and low resistance grounded except for the Main Generator, the Emergency Diesel Generators, and the Combustion Turbine Generator, which are high resistance grounded.
All electrical and mechanical components requiring grounding are identified and low resistance grounded to the appropriate grounding network. The Main Generator, Emergency Diesel Generators, and Combustion Turbine Generator are high resistance grounded to maximize availability. Equipment located outside structures are grounded locally and provided with lightning protection, when required. Medium voltage switchgear are provided with a Safety Ground Circuit Breaker which is interlocked with the bus voltage and the bus input feeder breakers and is annunciated in the control room when in the racked-in position.	7.b Inspection and test of the Safety Ground Circuit Breakers protection scheme will be performed.	7.b Safety Ground Circuit Breakers are interlocked with the bus voltage and bus input feeder breaker positions to prevent inadvertent closure. Annunciation is provided in the main control room when a breaker is in the racked-in position.
8. Power distribution system remote control, parameter information, and annunciators are provided in the Main Control Room and to the Remote Shutdown System for required plant operation and safety shutdown of the plant.	8. Inspections of the controls and information provided to the Main Control Room and Remote Shutdown System will be performed to assure plant control and information needs are provided for plant operation and safe shutdown.	8. Necessary controls and information are provided in the Main Control Room for safe operation and Safety Shutdown of the plant.

Table 2.12.1:

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. All Bus transfer operations are manual only, except for automatic bus transfer on the divisional buses form their normal power supplies to their respective Emergency Diesel Generators, automatic bus transfer on the Plant Investment Protection buses from their normal power supplies to the Combustion Turbine Generator, and the automatic bus transfer from the Essential divisional bus to the Plant Investment Protection bus for the Fine Motion Control Rod Drive Power Center. All automatic bus transfers are dead bus transfers and are initiated on bus low voltage.	9. Testing will be performed to confirm that all bus transfers are manual only, except for the specified automatic bus transfers on the Emergency, Plant Investment Protection, and Fine Motion Control Rod Drive Power Center switchgear when bus low voltage occurs.	9. Bus transfers are automatic for Safety System transfers to the Emergency Diesel Generators, PIP bus transfers to the Combustion Turbine Generator, FMCRD Power Center transfer to the nonessential power source. Bus transfers occur on bus low voltage. All other bus transfers are by manual operation only.
10. Essential Class 1E valve motors fed from the Motor Control Centers are provided with thermal overload protection which is bypassed during a Loss of Coolant Accident (LOCA) only. The thermal overload bypass is separately testable.	10. Testing will be performed to assure Class 1E valve motor thermal overloads will be bypassed when a LOCA signal is received and are operable under all other conditions.	10. Class 1E valve motor thermal overloads are bypassed on receiving a LOCA signal and are operable under all other conditions.

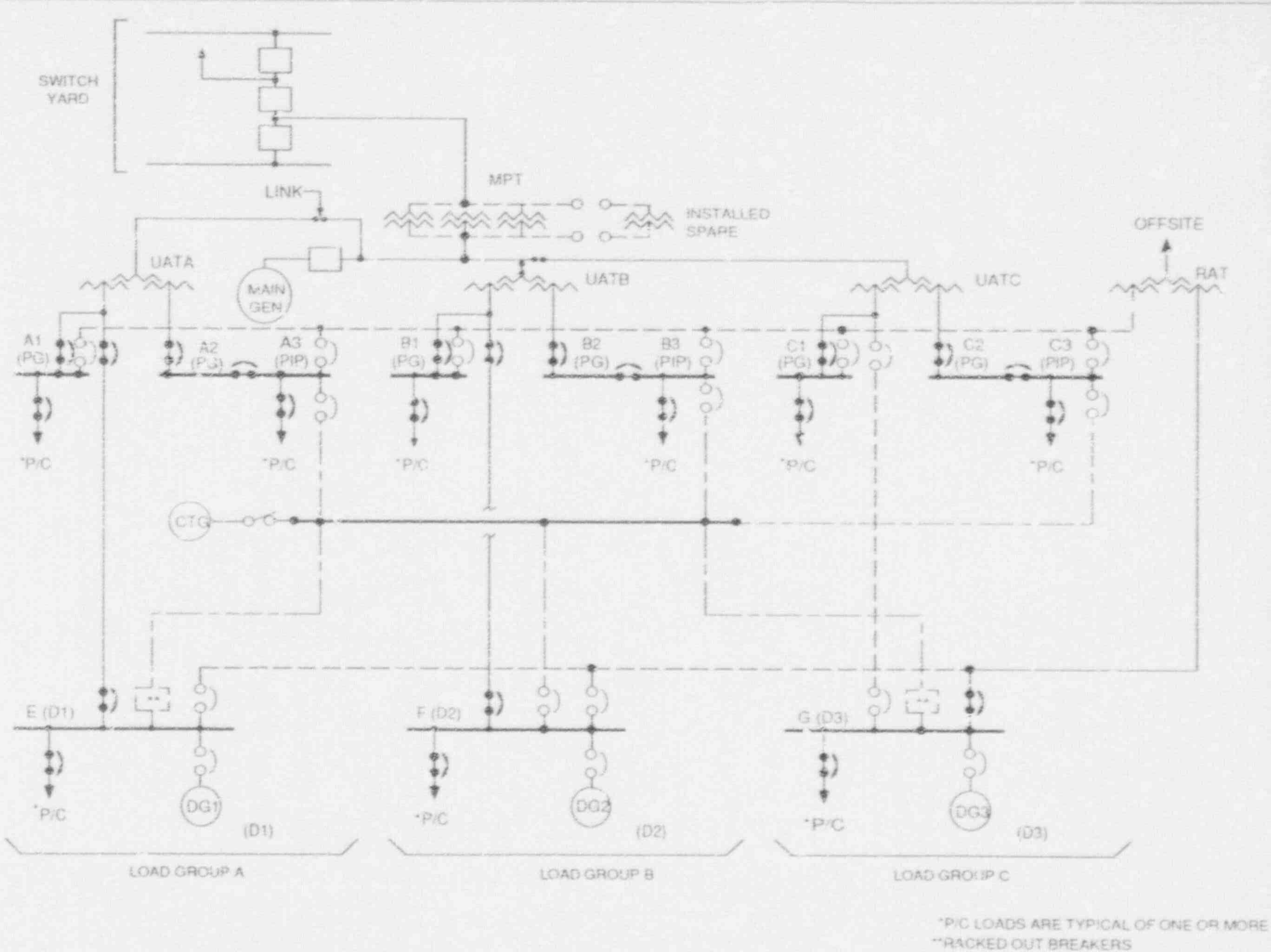


Figure 2.12.1a Electrical Power Distribution System

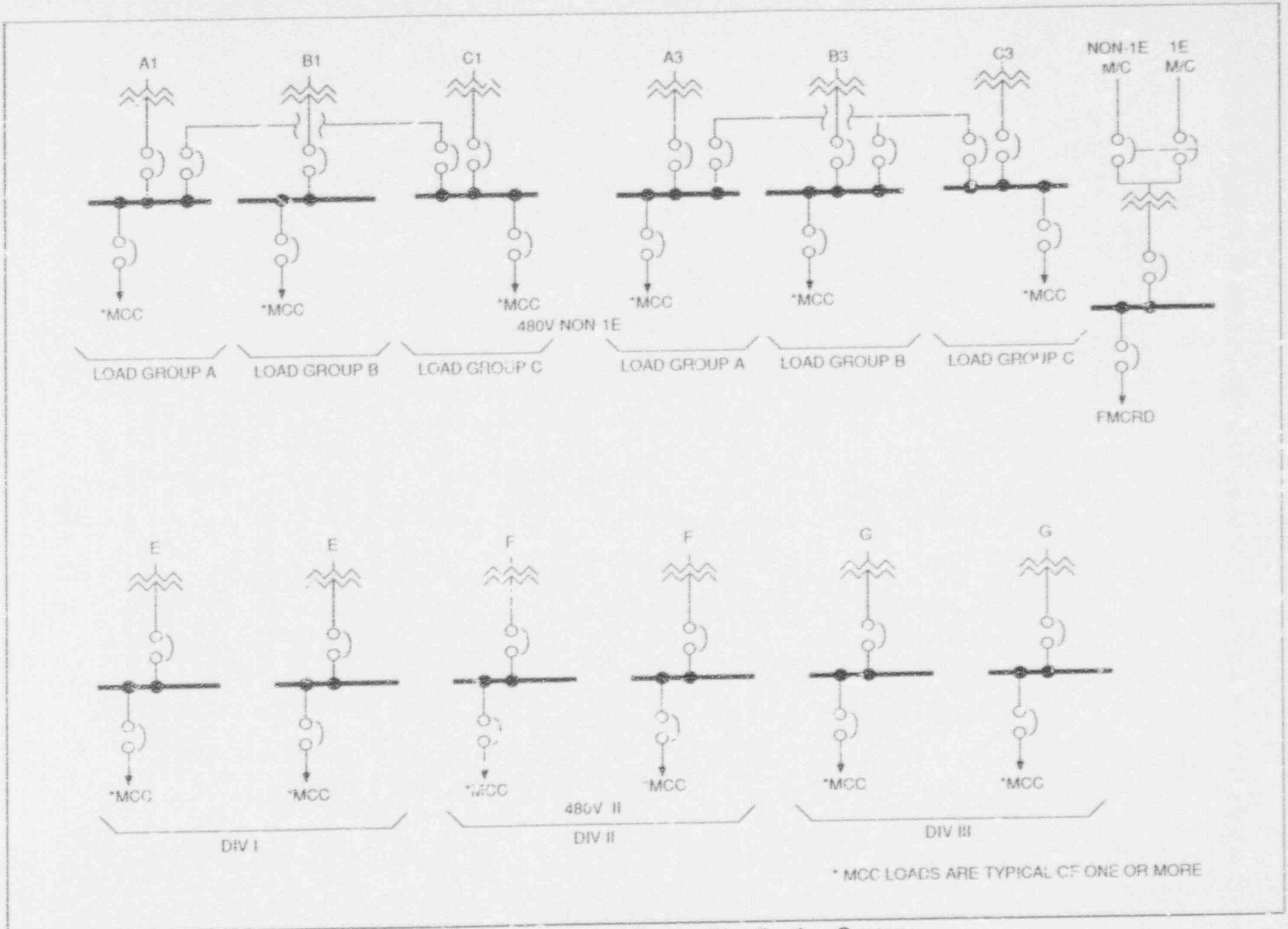


Figure 2.12.1b Electrical Power Distribution System

2.12.2 Unit Auxiliary Transformer

Design Description

No entry. Covered by item 2.12.1.

2.12.3 Isolated Phase Bus

Design Description

No entry. Covered by item 2.12.1.

2.12.4 Nonsegregated Phase Bus

Design Description

No entry. Covered by item 2.12.1.

2.12.5 Metal Clad Switchgear

Design Description

No entry. Covered by item 2.12.1.

2.12.6 Power Center

Design Description

No entry. Covered by item 2.12.1.

2.12.7 Motor Control Center

Design Description

No entry. Covered by item 2.12.1.

2.12.8 Raceway System

Design Description

No entry. Covered by item 2.12.1.

2.12.9 Grounding Wire

Design Description

No entry. Covered by item 2.12.1.

2.12.10 Electrical Wiring Penetration

Design Description

No entry. Covered by item [Later].

2.12.11 Combustion Turbine Generator

Design Description

The Combustion Turbine Generator (CTG) is a Non-essential standby power source located on-site within the turbine island. The turbine generator unit is sized to provide standby electrical power to any two of the non-essential plant investment protection (PIP) buses or one PIP bus and one Essential Safety System (Div.) bus and their associated loads at a nominal voltage of 6.9 KV and 60 cycles during loss of off-site power to the bus. The combustion turbine generator is not required for safe shutdown or maintenance of safe shutdown of the plant under any condition. Transfer to the CTG power supply is automatic for either or both of a preselected pair of PIP buses on loss of bus voltage. Transfer of the CTG power supply to any one of the divisional safety buses is manual and only performed after assuring that the safety-related power source has failed and no more than one PIP bus is being powered by the CTG.

The CTG is provided with an output disconnect switch for maintenance and feeds a stub bus where individual cables are connected to provide power to any of the three non-essential PIP buses or three essential divisional buses. In the unlikely event of multiple power source failures, this configuration also provides, with appropriate controls, the capability of using the CTG feeder cables as a vehicle for connecting any power source to any load. (See Figure 2.12.11)

The CTG unit is a skid mounted unit. It is equipped with its own auxiliary control and support systems (e.g. hydraulic start, excitation, lubrication, cooling, intake and exhaust, control and protective systems, control panel, etc.). Fuel is provided from an external fuel storage tank similar to that provided for an emergency diesel generator. Fuel is the same type and quality as that used by the diesel generators.

The Combustion Turbine Generator is designed to automatically start on a decrease of bus voltage to 70% of nominal, on either of the two preselected PIP buses, and be up to rated conditions and ready to load within a specific start time after receiving a start signal. The CTG will automatically provide power to the preselected PIP buses only.

CTG voltage and frequency regulation is the same as that provided by the non-essential 6.9 KV power distribution system. Sudden applications of large loads will not result in a voltage decrease from nominal voltage greater than 25%. Analysis to determination the need, if any, for load sequencing will be performed during the implementation stage of the design.

Controls, instrumentation, and alarms are provided in the control room to manually control and monitor the performance of the CTG.

The GTG is high resistence grounded to maximize availability.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.12.11 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria that will be undertaken for the CTG.

Table 2.12.11: Combustion Turbine Generator

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The Combustion Turbine Generator is capable of supplying full load power to any two Plant Investment Protection (PIP) buses or any one plant investment protection bus and any one essential safety bus. (See Figure 2.12.11)	1.a Inspection will be performed to confirm that the maximum expected combined loads on the two heaviest loaded buses are within the load rating of the combustion turbine generator.	1.a The combined maximum operating load of the two heaviest loaded buses do not exceed the rated power output (according to the nameplate rating) of the combustion generator.
	1.b Testing will be conducted by sychronizing the combustion generator to the off site system and increasing its output to its full load condition.	1.b The unit produces rated output at rated voltage and frequency for a minimum of 24 hours. (momentary transients excepted).
2. Sudden applications of large loads will not result in more than a 25% voltage decrease from nominal voltage.	2. Testing will be conducted by sudden application of the largest load block.	2. The sudden application of the largest load block to the unit does not cause a voltage decrease in excess of 25% from nominal voltage.
3. Controls, instrumentation, and alarms are provided in the control room to operate and monitor performance of the combustion generator.	3. Inspection of instrumentation and testing will be conducted by operation of the Combustion Turbine Generator from the main control room.	3. The unit can be controlled, loaded, and monitored from the main control room.

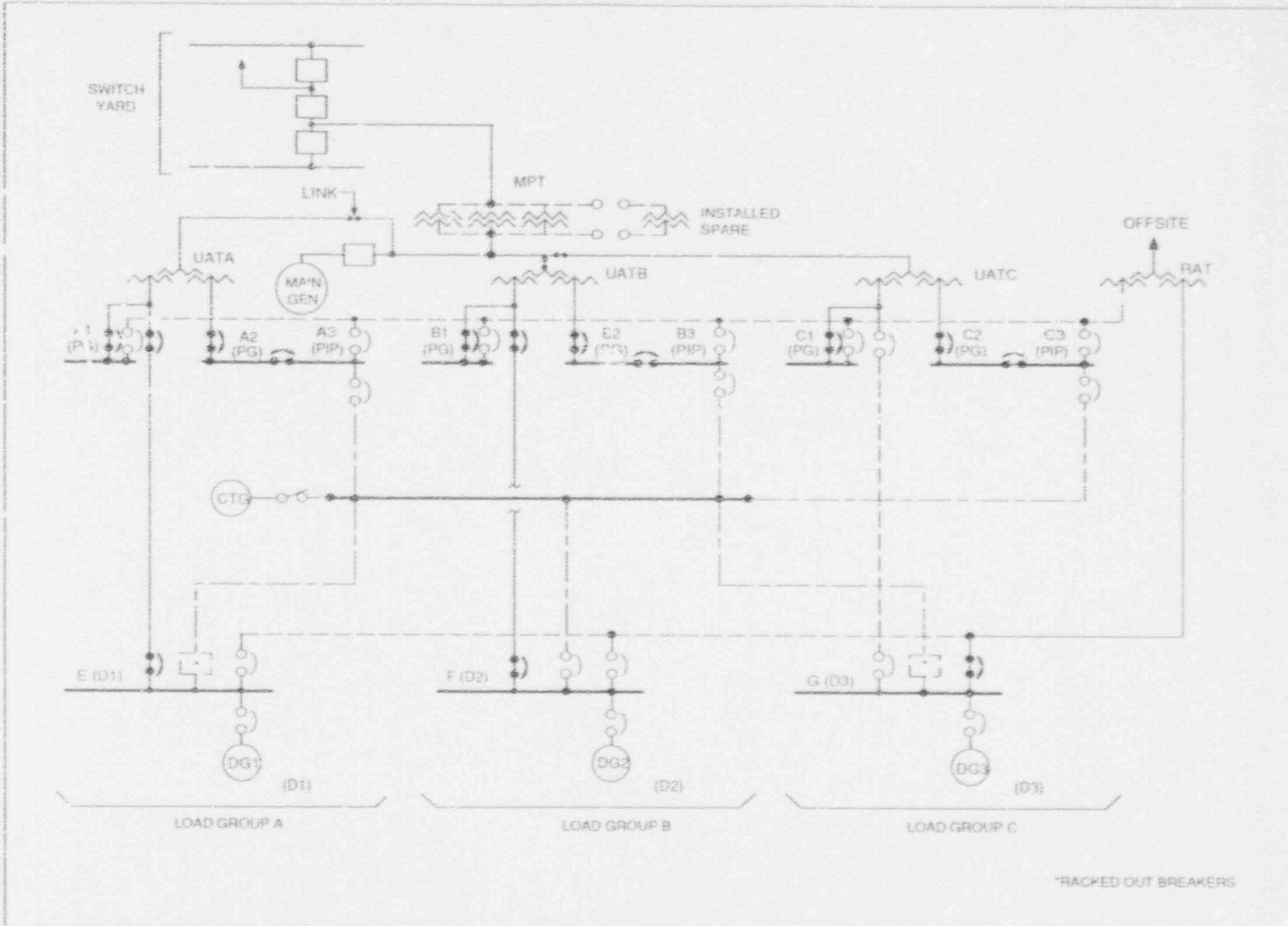


Figure 2.12.11 Combustion Turbine Generator

2.12.12 Direct Current Power Supply

Design Description

Later. Stage 3 Item.

2.12.13 Emergency Diesel Generator System (Standby AC Power Supply)

Design Description

The Class 1E diesel generators comprising the Divisions I, II, and III standby AC power supplies are designed to restore power to their respective Class 1E distribution system divisions as required to achieve safe shutdown of the plant and/or to mitigate the consequences of a loss-of-coolant accident (LOCA) in the event of a coincident loss of normal electrical power. Each of the three divisions of the AC power system has its own diesel generator.

The major loads consist of the following systems for all three divisions: Residual Heat Removal (RHR) System, Reactor Building Cooling Water (RCW) System, HVAC Emergency Cooling Water (HECW) System, and Reactor Service Water (RSW) System. In addition, Divisions II and III include the High Pressure Core Flooder (HPCF) System loads. (The Division I RCIC system is also part of the ECCS network, but is steam-driven and therefore does not present a significant load to the diesel generator.)

Each Class 1E diesel generator, with its auxiliary systems (i.e, Fuel Oil Storage and Transfer System, Jacket Cooling Water System, Starting Air System, Lubrication System, and Combustion Air Intake and Exhaust System), supplies standby AC power to various Class 1E loads through the 6.9 kV and 480 V systems. The 480 V system, in turn, supplies power to the UPS and battery charger for the division's 120 VAC and 125 VDC safety loads. (The low voltage portion does not significantly contribute to diesel generator loading, but is included with "other 480 V loads" per Figure 2.12.13.) Each is physically and electrically isolated from the other divisions. No automatic interconnection is provided between the Class 1E divisions. Each diesel-generator set is operated independently of the other sets, and is connected to the utility power system by manual control only during testing or for bus transfer. A failure of any component of one diesel generator set will not jeopardize the capability of either of the two remaining diesel generator sets to perform their functions. The diesel generators and their essential support equipment are classified Seismic Category 1, and are qualified for the environments where located. All components except for the fuel storage tanks and fuel transfer equipment are located within the Reactor Building.

Each diesel generator unit is rated at 6.9 kV, 60 Hz; and is capable of automatically starting, accelerating, attaining rated frequency and voltage within 20 seconds, and supplying its loads in the sequence and timing specified in the plant design documents. In addition, each diesel generator is capable of starting, accelerating and running its largest motor at any time after the automatic loading sequence is completed, assuming that the motor had failed to start initially. Each diesel generator unit is also reliability tested by the manufacturer.

The diesel generators start automatically on loss of bus voltage. Under-voltage sensors are used to start each diesel engine in the event of a sustained drop in bus voltage below 70% of the nominal 6.9 kV rating of the bus. Low-water-level sensors and drywell high-pressure sensors in each division are also used to initiate the respective diesel start under accident conditions. However, the diesels will remain on standby (i.e., running at rated voltage and frequency, but unloaded) unless the bus under-voltage sensors trigger the need for bus transfer to the diesel supply. Manual start capability (without need of DC power) is also provided.

Each diesel is supplied by its own independent fuel storage tank, which is located in an area protected from natural phenomena. This tank has a fuel capacity sufficient to operate its diesel for a period of 7 days while the diesel generator is supplying maximum post-LOCA load demand. A day tank is also provided for each diesel, and is located in the Reactor Building. The day tank has a fuel capacity sufficient for approximately 8 hours of full-load operations. Low-level sensors on the day tank actuate dual motor-driven transfer pumps to replenish the day tank supply from the storage tank.

The standby AC power supplies are designed such that testing and inspection of equipment is possible during both normal and shutdown plant conditions.

Each standby AC power supply is composed of a three-phase synchronous generator and exciter, the diesel engine, the engine auxiliaries (including the fuel tanks), and the control panels. Figure 2.12.13 shows the emergency diesel generator system interconnections between the offsite power supplies and the Divisions I, II, and III diesel-generator standby AC power supplies.

The transfer of each Class 1E bus to its standby power supply is automatic, should this become necessary, on loss of its offsite power. After the circuit breaker connecting the bus to the preferred power supply is open, large motors are kept on the bus for parallel coastdown and optimal residual voltage decay. When the voltage decays to an acceptable level, major loads are tripped from the Class 1E bus, except for the Class 1E 480 V unit substation feeders. Then the diesel-generator breaker is closed when the required generator voltage and frequency are established. The large motor loads are later re-applied sequentially and automatically to the bus after closing of the diesel-generator breaker.

Each diesel generator is capable of being started or stopped manually from the main control room. Start/stop control and bus transfer control may be transferred to a local control station in the diesel generator room. Control room indications are provided for system parameters.

Each diesel generator, when operating other than in test mode, is independent of the preferred power supply. Additional interlocks to the LOCA and loss-of-power sensing circuits terminate parallel operation tests and cause the diesel generator to revert and reset to its automatic control system if either signal appears during a test. A lockout or maintenance mode removes the diesel generator from service. The inoperable status is indicated in the control room.

Devices monitor the conditions of the diesel generators, and effect action in accordance with one of the following categories: 1) Conditions to trip the diesel engine even under LOCA, 2) Conditions to trip the diesel engine except under LOCA, 3) Conditions to trip the generator breaker but not the diesel, and 4) Conditions which are only annunciated.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.12.13 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the emergency diesel generators and their auxiliary systems.

Table 2.12.13: EMERGENCY DIESEL GENERATOR SYSTEM

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The three diesel generator trains are mechanically and electrically independent.	1. Tests and verification inspection will be conducted which will include independent and coincident operation of the three trains to demonstrate complete divisional separation.	1. Plant tests and verification inspection for physical location confirm proper independence of three diesel generator divisions.
2. All components essential to the operation of the diesel generators are Seismic Category I and qualified for the appropriate environment for locations where installed.	2. See Generic Equipment Qualification verification activities (ITA).	2. See Generic Equipment Qualification Acceptance Criteria (AC).
3. The three diesel generators are capable of supplying sufficient AC power to achieve safe shutdown of the plant and/or to mitigate the consequences of a LOCA in the event of a coincident loss of normal power. (See Figure 2.12.13.)	3a. Confirmatory inspection will be performed to assure the maximum design loads expected to occur for each division are within the ratings of the corresponding diesel generator.	3a. The maximum loads expected to occur for each division (according to nameplate ratings) shall not exceed 90% of the rated power output of the diesel generator.
	3b. Testing will be conducted by synchronizing each diesel generator to the plant offsite power system and increasing its output power level to its fully rated load condition.	3b. Each of the three units shall produce rated power output at ≥0.8 PF for a period of ≥24 hours (momentary transients excepted). Each unit will then experience full load rejection by tripping the load and verifying the unit does not trip.
4. Each diesel generator is rated at 6.9 kV, three phase, 60 [illegible] nd is capable of attaining rated freq[illegible]ncy and voltage within 20 seconds after receipt of a start signal.	4. Perform a test of each diesel generator to confirm its ability to attain rated frequency and voltage.	4. Each diesel generator attains a voltage of 6.9 kV±10%, and a frequency of 60 Hz±2% within 20 seconds after application of a start signal.

Table 2.12.13: EMERGENCY DIESEL GENERATOR SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. In the event of a loss of normal power, each diesel generator unit is capable of starting (both manually and automatically), accelerating, and supplying its loads in the proper sequence and timing specified in the plant design documents. It is also capable of recovery following trip and restart of its largest load.	5. The automatic and manual start sequences will be tested for each diesel generator unit.	5. Each of the three units starts from each automatic and remote manual signal, then accelerates and properly sequences its loads. Each local manual signal also starts the corresponding unit, but does not initiate load sequencing. The automatic load sequence begins at ≤20 seconds and ends ≤65 seconds. Following application of each load, the bus voltage will not drop more than 25% measured at the bus. Frequency restored to within 2% of nominal, and voltage restored to within 10% of nominal within 60% of each load-sequence time interval. In addition, the unit's largest motor load shall be tripped and restarted after the unit has completed its sequence, and the bus voltage shall recover to 6.9 kV±10% at 60±2% Hz within 10 seconds.
6. Each diesel generator unit is capable of manually starting without the need for external electrical power. The air receiver tanks have sufficient capacity for five starts without recharging.	6. Each unit will be tested and the air receiver tank capacities shall be analyzed to assure its black-start capability is f[illegible]al.	6. Black-start capability is demonstrated following one successful manual start, acceleration, and bus energization for each of the three units without assist from any external electric power. Following black start, each unit's receiver tanks shall have sufficient air remaining for four more starts.
7. Interlocks to the LOCA and loss-of-power sensing circuits terminate parallel operation tests and cause the diesel generator to revert and reset to its automatic control system if either signal appears during a test.	7. Interlocks for the standby AC power system will be tested.	7. While in a parallel test mode, each unit will revert and reset to its automatic control system following individual application of a simulated LOCA signal and a simulated loss-of-power signal.

Table 2.12.13: EMERGENCY DIESEL GENERATOR SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
8. Devices monitor the conditions of the diesel generators, and effect action in accordance with one of the following categories: 1) Conditions to trip the diesel engine even under LOCA, 2) Conditions to trip the diesel engine except under LOCA, 3) Conditions to trip the generator breaker but not the diesel, and 4) Conditions which are only annunciated.	8. Using simulated signals, protective interlocks and annunciations will be tested to assure they perform their functions, in accordance with the four categorical conditions described.	8. Successful circuit testing will be confirmed for the individual diesel generator protective sensors according to the following: <u>Category 1 sensors:</u> Annunciations and diesel engine trip signals will be confirmed in combination with a simulated LOCA signal. <u>Category 2 sensors:</u> Annunciations and diesel engine trip signals will be confirmed without a LOCA, but trips will be bypassed when a simulated LOCA signal is present. <u>Category 3 sensors:</u> Annunciations and generator circuit breaker trip signals will be confirmed. <u>Category 4 sensors:</u> Annunciation signals will be confirmed.
9. Each diesel has its own 7-day fuel storage tank, and its own 8-hour capacity day tank which is replenished by the storage tank.	9a. Visual inspection and calculation of capacities for each tank shall be performed.	9a. Tank inspections and calculations confirm proper capacities of the storage and day tanks. These shall be sufficient for full-load operation of each respective diesel generator for 7 days, and 8 hours, respectively.
	9b. The fuel transfer system shall be tested.	9b. Transfer system operation for each division will be confirmed by actuating both pumps from the day tank level sensors and observing proper flow into the day tanks.

Table 2.12.13: EMERGENCY DIESEL GENERATOR SYSTEM (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10. The manufacturer has conducted reliability testing on the units.	10. The manufacturer's test documents shall be visually inspected.	10. Visual inspection of manufacturer's test documents confirms the required reliability testing has been performed, and that the diesel generator has passed the test requirements.
11. Control indications are provided for D/G system parameters.	11. Inspections will be performed to verify presence of control room indication for the D/G system.	11. The designated instrumentation is present in the control room.

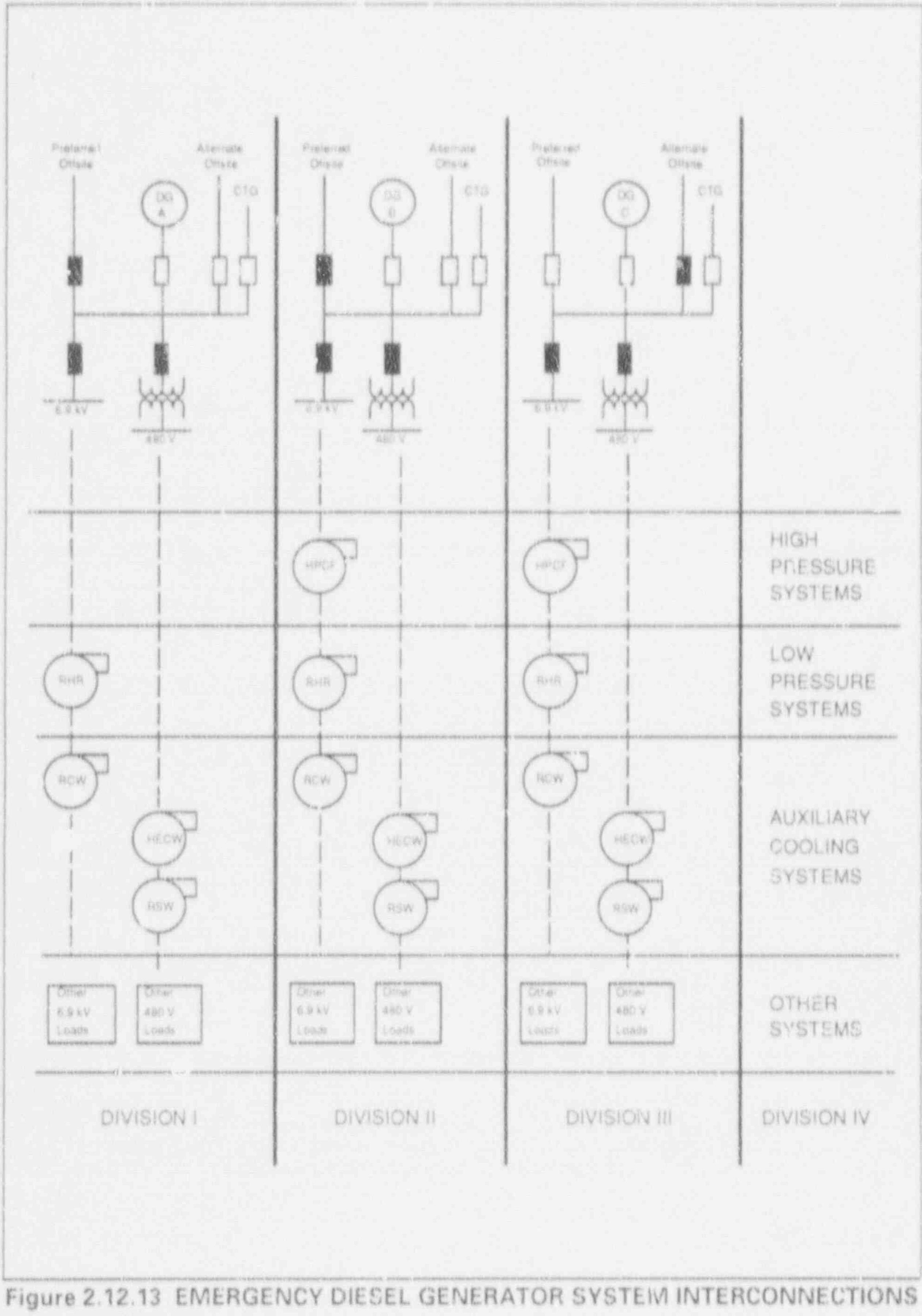


Figure 2.12.13 EMERGENCY DIESEL GENERATOR SYSTEM INTERCONNECTIONS

2.12.14 Reactor Protection System Alternate Current Power Supply

Design Description

Not an ABWR system. No entry.

2.12.15 Vital AC Power Supply And AC Instrument and Control Power Supply Systems

Design Description

Vital AC Power Supply System

The Vital AC Power Supply System as shown in Figure 2.12.15a is comprised of a Class 1E, Safety-Related system, a Non-Class 1E, Non Safety-Related system, and a Non-Class 1E, Non Safety-Related Computer system. Each system provides power to those "vital" instrument and control circuits for which continuity of power is desirable.

The Safety-Related Vital AC Power Supply system provides uninterruptable, regulated 120 VAC power to the four divisions of the Class 1E Safety System Logic and Control (SSLC) system. Each of the four divisions contains its own Constant Voltage Constant Frequency (CVCF) static inverter power supply. Normal Power to each CVCF is supplied from a 480 VAC Motor Control Center (MCC) in the same division, except for the Division IV CVCF, which is supplied power from the Division I MCC. Backup Power for each CVCF is supplied from the 125 VDC battery of the same division. Each CVCF output is provided to distribution panels local to the circuits powered. Divisional CVCFs and their respective distribution panels are electrically independent and physically separated between divisions and are appropriately identified. The Class 1E Vital AC Power Supplies and their distribution panels are located in Seismic Category I structures. Divisional CVCF power distribution is arranged such that the loss of a single CVCF power supply will not result in an inadvertent reactor shutdown.

The Non-Safety-Related Vital AC Power Supply system provides uninterruptable, regulated 120 VAC power to the non-safety-related logic and control circuits important to the continuity of power plant operation. There is a Constant Voltage Constant Frequency (CVCF) static inverter power supply in each of the three nonessential load groups. Normal Power to each CVCF is supplied from a 480 VAC Motor Control Center (MCC) in its associated load group. Each MCC receives power from the Plant Investment Protection (PIP) bus in the associated load group. Backup Power to each CVCF is supplied from the nonessential 125 VDC battery of the same load group. CVCF output is provided to distribution panels local to the circuits powered. Each load group CVCF and its respective distribution panels are electrically independent from the other load groups and are appropriately identified.

The Non-Safety-Related Vital AC Computer Power Supply system provides uninterruptable, regulated 120 VAC power to the non-safety-related plant computers. This system contains two nonessential Constant Voltage Constant Frequency (CVCF) static inverter power supplies. Normal Power to each CVCF is supplied from a different load group 480 VAC Power Center (P/C). Each P/C receives power from the Plant Investment Protection (PIP) bus in its associated load group. Backup Power to both CVCFs is from the nonessential 250 VDC battery. CVCF output is provided to distribution panels local to the circuits powered. Each load group CVCF and its respective distribution panels are electrically independent from the other load groups and are appropriately identified.

Each CVCF contains an Alternate Power supply for maintenance of the inverter or to supply power in the event of inverter failure. The Alternate Power supply is a voltage regulating stepdown transformer, which is supplied power from the same 480 VAC power source as the Normal Power supply. Each inverter is synchronized in both frequency and phase with its alternate power supply to avoid unacceptable voltage spikes during transfer from the inverter to the alternate supply. Automatic transfer between the three CVCF power sources within a load group occurs as necessary to maintain a regulated output. Manual transfer between each CVCF power source is also provided.

AC Instrument and Control Power Supply System

The AC Instrument and Control Power System is shown in Figure 2.12.15b and is comprised of both a Class 1E Safety-Related system and a Non Class 1E, Non-Safety Related system. Both systems provide 120 VAC power to "non-vital" instrument and control power loads which can sustain a power interruption during a Loss of Offsite Power (LOOP).

The Class 1E Safety-Related AC Instrument and Control Power Supply system is comprised of a transformer and distribution panels in each of the three Safety-Related divisions. Each transformer is supplied power from a 480 VAC Motor Control Center (MCC) within its division and provides power to distribution panels local to the circuits powered. The transformers and distribution panels within each division are electrically independent and physically separated from each other and are appropriately identified. The Class 1E power supply system components are located in Seismic Category I structures.

The Non-Class 1E, Non-Safety-Related AC Instrument and Control Power Supply system is comprised of a transformer and distribution panels local to the circuits powered. The transformer is supplied power from either of two 480 VAC Motor Control Centers (MCC) through a manual transfer switch. Each MCC is powered from a different nonessential load group Plant Investment Protection (PIP) bus.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.12.15 provides a definition of the inspections, tests and/or analyses, together with associated acceptance criteria which will be undertaken for the Vital AC Power Supply System and Instrument and Control Power Supply System.

Table 2.12.15: Vital AC Power Supply and AC Instrument and Control Power Supply Systems

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. A Class 1E Vital AC Constant Voltage Constant Frequency (CVCF) Power Supply and associated distribution panels are provided in each of the four Instrument and Control Safety Divisions. The CVCFs and associated distribution panels are located in Seismic Category I structures, identified, and electrically independent and physically separated from each other.	1. Inspections will be performed to confirm that the four Class 1E CVCFs and their associated distribution panels are located in Seismic Category I structures, identified, and that each division is electrically independent and physically separated from the other divisions.	1. Each of the four divisional Class 1E CVCFs and associated distribution panels are located in Seismic Category I structures, identified, and electrically independent and physically separated.
2. Each Class 1E CVCF receives power from the MCC and 125 VDC battery in the same division, except Division IV, which is supplied AC power from the same division that provides the battery charger for the Division IV battery.	2. Inspections will be performed to confirm that the AC and DC power sources for each Class 1E CVCF is from its associated division, except the CVCF in division IV which is supplied AC power from the same division that provides the battery charger for the Division IV battery.	2. Each Class 1E CVCF receives power from the MCC and 125 VDC battery in the same division, except the CVCF in division IV which is supplied AC power from the same division that provides the battery charger for the Division IV battery.
3. Each Class 1E CVCF inverter provides a 120 VAC regulated voltage and frequency output and its alternate power supply within the same division provides a regulated voltage output. The CVCF automatically transfers between power sources within the same division to maintain the required output. Manual transfer is also provided	3. Inspections and tests will be conducted to confirm the automatic transfer within the same division and output regulation of the Class 1E CVCFs. Manual transfer will be tested.	3. Each Class 1E CVCF provides the required output regulation during normal operation, automatic and manual transfer operations.
4. A Non-Class 1E Vital AC Constant Voltage Constant Frequency (CVCF) Power Supply and associated distribution panels are provided in each of the three nonessential load groups for Instruments and Controls important to the continuity of power plant operation. The CVCFs and associated distribution panels are identified and electrically independant from each other.	4. Inspections will be performed to confirm that the three Non-Class 1E CVCFs and their associated distribution panels are identified and are electrically independent from each other.	4. Each of the three Non-Class 1E CVCFs and associated distribution panels are identified and electrically independent from each other.

Table 2.12.15: Vital AC Power Supply and AC Instrument and Control Power Supply Systems (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Each Non-Class 1E CVCF receives power from the MCC and 125 VDC battery in the same load group.	5. Inspections will be performed to confirm that the AC and DC power sources for each Non-Class 1E CVCF is from its associated nonessential load group.	5. Each Non-Class 1E CVCF receives power from the MCC and 125 VDC battery in the same non-essential load group.
6. Each Non-Class 1E CVCF inverter provides a 120 VAC regulated voltage and frequency output and its alternate power supply provides a regulated voltage output. The CVCF automatically transfers between power sources to maintain the required output. Manual transfer is also provided.	6. Inspections and tests will be conducted to confirm the automatic transfer and output regulation of the Non-Class 1E CVCFs. Manual transfer will be tested.	6. Each Non-Class 1E CVCF provides the required output regulation during normal operation, automatic and manual transfer operations.
7. Two Non-Class 1E Vital AC Constant Voltage Constant Frequency (CVCF) Power Supplies and associated distribution panels are provided for the nonessential plant computers. The CVCFs and associated distribution panels are identified and electrically independent from each other.	7. Inspections will be performed to confirm that the two Non-Class 1E computer CVCFs and their associated distribution panels are identified and are electrically independent from each other.	7. Each of the two Non-Class 1E computer CVCFs and associated distribution panels are identified and electrically independent from each other.
8. Each Non-Class 1E computer CVCF receives power from the P/C in the same load group and from the nonessential 250 VDC battery.	8. Inspections will be performed to confirm that the AC power sources for each Non-Class 1E computer CVCF is from its associated nonessential load group and from the nonessential 250 VDC battery.	8. Each Non-Class 1E computer CVCF receives power from the P/C in the same non-essential load group and from the nonessential 250 VDC battery.
9. Each Non-Class 1E computer CVCF inverter provides a 120 VAC regulated voltage and frequency output and its alternate power supply provides a regulated voltage output. The CVCF automatically transfers between power sources to maintain the required output. Manual transfer is also provided. (See Figure 2.12.15a.)	9. Inspections and tests will be conducted to confirm the automatic transfer and output regulation of the Non-Class 1E computer CVCFs. Manual transfer will be tested.	9. Each Non-Class 1E computer CVCF provides the required output regulation during normal operation, automatic and manual transfer operations.

Table 2.12.15: Vital AC Power Supply and AC Instrument and Control Power Supply Systems (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
10. Three Class 1E 120 VAC instrument and Control Power Supplies and associated distribution panels are provided for the "non-vital" essential safety-related instrument and control circuits which can sustain a power interruption on Loss of Offsite Power (LOOP). The Instrument and Control Power Supplies and associated distribution panels are located in Seismic Category 1 structures, identified, and electrically independent and physically separated from each other.	10. Inspections will be performed to confirm that the three Class 1E instrument and Control Power supplies and their associated distribution panels are located in Seismic Category 1 structures, identified, and are electrically independent and physically separated from each other.	10. Each of the three Class 1E Instrument and Control Power Supplies and associated distribution panels are located in Seismic Category 1 structures, identified, and electrically independent and physically separated from each other.
11. Each Class 1E Instrument and Control Power Supply receives power from the MCC in the same division.	11. Inspections will be performed to confirm that the power sources for each Class 1E Instrument and Control Power Supply is from the MCC of the same safety division and that the transformer ratio provides a nominal 120 VAC output.	11. Each Class 1E Instrument and Control Power Supply receives power only from the MCC in the same safety division and the transformer ratio provides a nominal 120 VAC output.
12. The Non-Class 1E 120 VAC Instrument and Control Power Supply and associated distribution panels is provided for the "non-vital", nonessential instrument and control circuits which can sustain a power interruption a Loss of Offsite Power (LOOP). The Power Supply receives input power from either of two 480 VAC nonessential MCCs through a manual transfer switch. The MCCs are powered from Plant Investment Protection. (PIP) buses in separate load groups. (See Figure 2.12.15b.)	12. Inspections and test will be conducted to confirm that the two power sources for the Non-Class 1E 120 VAC Instrument and Control Power Supply are from separate load groups and that the manual transfer switch will transfer power between sources.	12. The Non-Class 1E 120 VAC Instrument and Control Power Supply is powered from two MCCs in different nonessential load groups and the manual transfers power between the two power sources.

Table 2.12.15: Vital AC Power Supply and AC Instrument and Control Power Supply Systems (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
13. Each Vital AC Power Supply and AC Instrument and Control Power Supply is sized to supply the full load requirements of its connected loads.	13. Inspections will be performed to confirm that each Vital AC Power Supply and AC Instrument and Control Power Supply is sized (as determined by the nameplate rating) to supply the full load requirements of its connected loads.	13. Each Vital AC Power Supply and AC Instrument and Control Power Supply is sized (as determined by the nameplate rating) to supply the full load requirements of its connected loads.

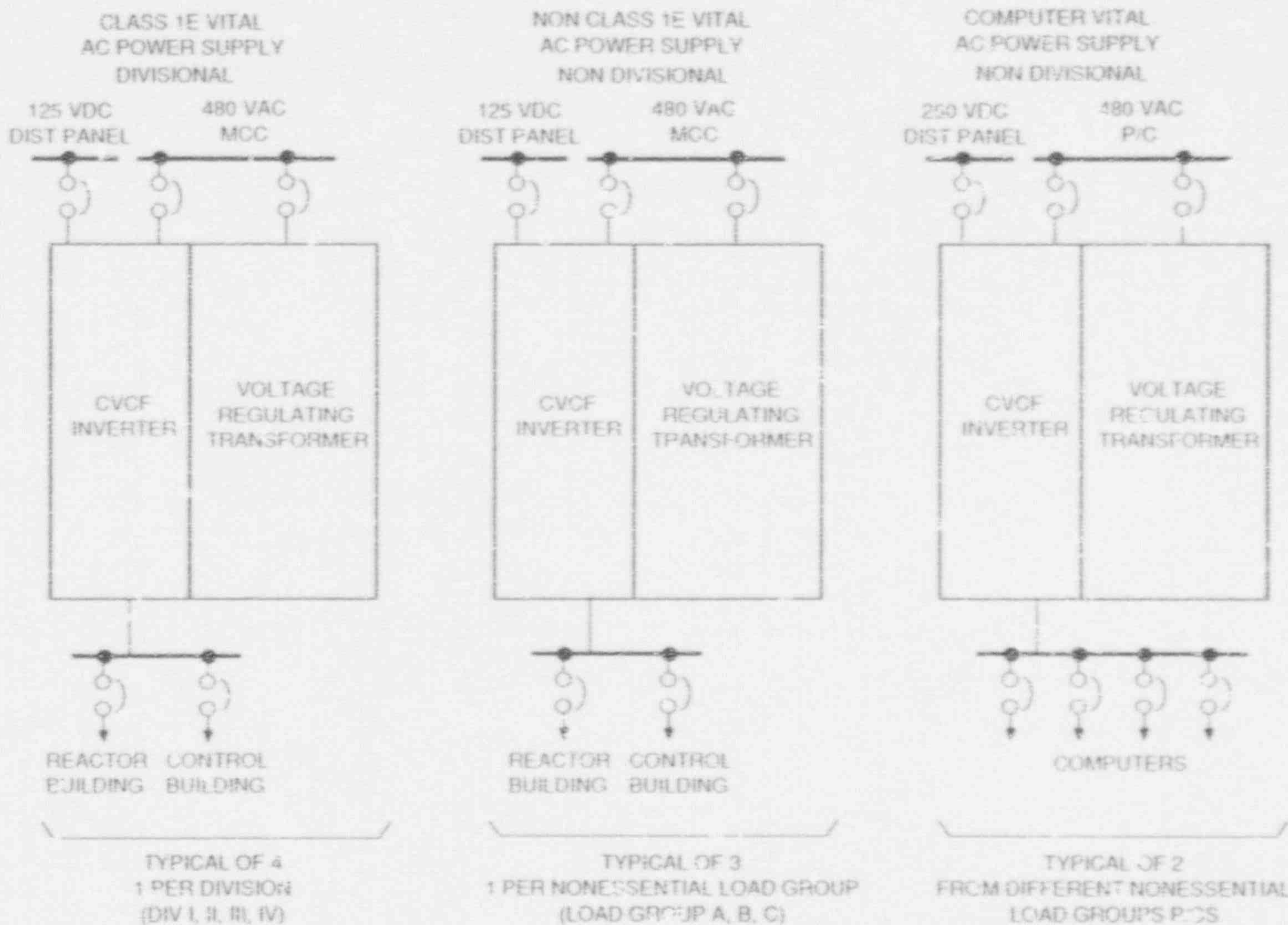


Figure 2.12.15a Vital AC Power Supply

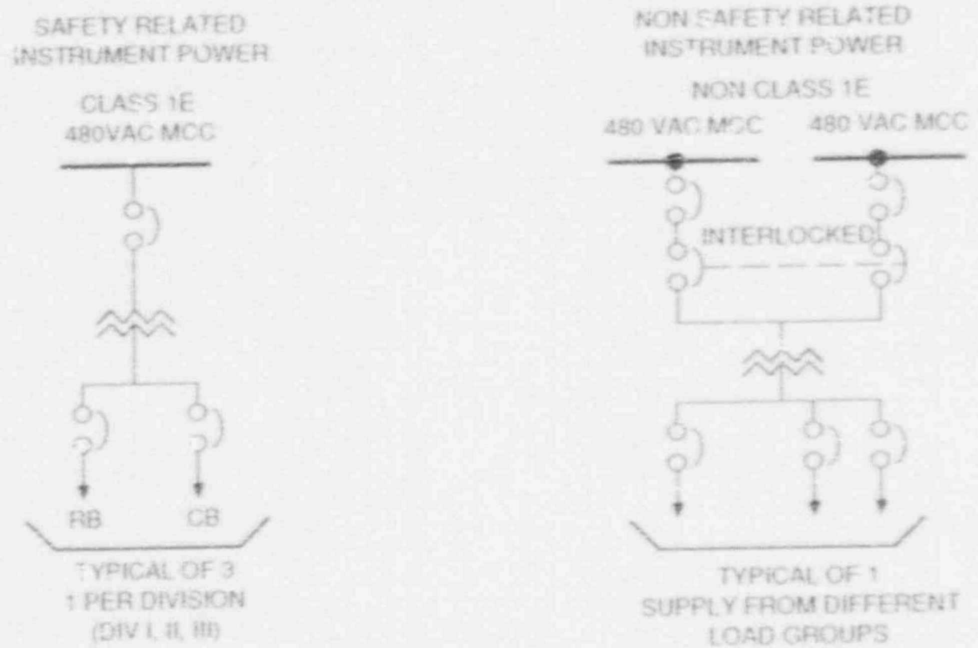


Figure 2.12.15b AC Instrument and Control Power

2.12.16 Instrument and Control Power Supply

Design Description

No entry. Covered under item 2.12.15.

2.12.17 Communication System

Design Description

Later. Stage 3 Item.

2.12.18 Lighting and Service Power Systems

Design Description

The plant lighting system is comprised of four independent lighting systems. They are the Normal Lighting system, the Standby Lighting system, the Emergency Lighting system, and the Guide Lamp Lighting system. The Normal Lighting system is non-Class 1E. The other three lighting systems are comprised of both Safety-Related and Non-Safety-Related subsystems.

The Normal Lighting system is AC and nonessential and provides up to 50% of the lighting needed for operation, inspection, and repairs during normal plant operation and is installed throughout the plant in nonessential equipment areas, except for the passageways and stairwells. Normal Lighting is generally supplied from the nonessential Power Generation (PG) buses. In the nonessential equipment areas, the Normal Lighting is supplemented (a minimum of 50%) by the Non-Safety-Related Standby Lighting system. Lighting from a single load group is acceptable for localized high intensity lighting and lighting in small rooms where only a limited number of fixtures are needed. Nonessential service outlets and internal lighting for nonessential panels is provided by the Normal Lighting system. In passageways and stairwells leading to nonessential equipment areas, the lighting is supplied from two different load groups of the Non-Safety-Related Standby Lighting system. With this configuration, nonessential equipment areas receive 100% of their lighting from two different power sources.

The Non-Safety-Related AC Standby Lighting system is comprised of lighting from three nonessential load groups. Each load group is supplied from a different Plant Investment Protection (PIP) bus which is connectable to the nonessential Standby Power Supply (Combustion Turbine Generator (CTG)). The Non-Safety-Related Standby Lighting system supplies a minimum of 50% of the lighting needs of the nonessential equipment areas and 100% of the lighting in passageways and stairwells leading to nonessential equipment areas (as described above). In addition, the Non-Safety-Related Standby Lighting system supplies up to 50% of the lighting needs in essential equipment areas and in passageways and stairwells leading to essential equipment areas. The remainder of the lighting (a minimum of 50%) in the essential equipment areas and in passageways and stairwells leading to them is supplied from the Safety-Related Standby Lighting system. The Non-Safety-Related Lighting in the essential equipment areas and the passageways and stairwells leading to them is supplied from the same nonessential load group as the essential load group (Safety Division) in the same area.

The Safety-Related AC Standby Lighting system is comprised of lighting from three essential Safety Divisions. Each of the three essential divisions is supplied power from the Class 1E divisional bus, which is connectable to the essential Standby Power Supply (Emergency Diesel Generator (DG)) in its respective division. Each Safety-Related Standby Lighting system supplies a minimum of

50% of the lighting needs of the essential equipment areas in its respective division and of the passageways and stairwells leading to its respective equipment areas. The essential lighting in the Battery room and other Instrument and Control areas of Division IV is supplied from the Safety-Related Standby Lighting system of the same division as other divisional equipment supplying the areas (e.g., battery chargers). The Main Control Room lighting is supplied from the same two divisions of the Safety-Related Standby Lighting system as the divisions supplying the Main Control Room Heating, Ventilation, and Air Conditioning (HVAC). The remainder of the lighting (up to 50%) in the essential equipment areas and the passageways and stairwells leading to them is supplied from the Non-Safety-Related Standby Lighting system in the same load group as the Safety-Related Lighting system. With this configuration, essential equipment areas receive 100% of their lighting needs from two different Standby Lighting power supplies.

The above described AC lighting configuration permits retaining approximately 50% of the lighting illumination in all passageways, stairwells and essential equipment areas during lighting maintenance or loss of a load group. Illumination from 50% of the lighting is adequate to observe equipment and support personnel movement. (See Figure 2.12.18a)

The Emergency Lighting systems provide DC powered backup lighting to prevent total blackout in areas which are occupied or may be occupied during periods when AC lighting is lost until the Normal or Standby Lighting systems are energized. Therefore, the Emergency Lighting systems are not required to provide the same lighting illumination levels as the normal/standby systems.

The Non-Safety-Related Emergency Lighting system provides the emergency lighting needs to the Radwaste Building control room (RWB), the Combustion Turbine Generator (CTG) area and control room, and the nonessential electrical equipment areas (both AC and DC). Lighting power for the RWB control room is supplied from the nonessential 250 VDC battery. Lighting power for the nonessential electrical equipment rooms is supplied from the 125 VDC battery in the same nonessential load group as the equipment in the room. Lighting power for the nonessential CTG is supplied from one of the nonessential 125 VDC batteries.

The Safety-Related Emergency Lighting system provides the emergency lighting needs to the Main Control Room, the Remote Shutdown Panel room, the Emergency Diesel Generator areas and control rooms, and the essential electrical equipment rooms (both AC and DC). Lighting power for the identified essential areas is supplied from the 125 VDC battery in the same divisions as the area. The lighting power to the Main Control Room is supplied from the two 125 VDC batteries in the same division as the Safety-Related Standby Lighting sources for the control room. (See Figure 2.12.18b.)

Guide Lamps are provided for stairways, exit routes, and major control areas such as the main control room, radwaste control room and remote shutdown panel areas. The Guide Lamps are self contained, battery pack units, suitable for operation in the environment of the areas in which they are located. The units contain a rechargeable battery with a minimum 8 hour capacity and a battery charger supplied from the Standby Lighting system of the area in which they are located. Guide Lamps are Seismic Category I and are Class 1E when located in Safety-Related areas.

All lighting systems are designed to provide lighting intensities consistent with the lighting needs of the areas in which they are located, and with their intended purpose. The lighting design considers the effects of glare and shadows on control panels, video display devices, and other equipment, and the mirror effects on glass and pools. Lighting and other equipment maintenance, in addition to the safety of personnel, plant equipment, and operation is considered in the design. Areas containing flammable materials (e.g., battery rooms, fuel tanks) have explosion-proof lighting systems. Areas subject to high moisture have water-proof installations (e.g. drywell, wash-down areas). Plant AC lighting systems are generally of the fluorescent type, with mercury lamps provided for high ceiling and yard lighting, except where breakage could introduce mercury into the reactor coolant system. Incandescent lamps are used for DC lighting systems and above the reactor, fuel pools, and other areas where lamp breakage could introduce mercury into the reactor coolant.

Lighting systems and their distribution panels and cables are identified according to their essentiality and type. Safety-Related Lighting systems are Class 1E, located in Seismic Category I structures and are electrically independent and physically separated. Cables are routed in their respective divisional raceways. Normal Lighting is separated from Standby Lighting. DC lighting cables are not routed with any other cables.

Plant Service buses supply power and heavy duty service outlets to equipment not generally used during normal plant power operation (e.g., turbine building and refueling floor cranes, welding equipment). Service outlets have grounded connections and the outlets in wet or moist areas are supplied from breakers with ground current detection.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.12.18 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the lighting and service power systems.

Table 2.12.18: Lighting and Service Power System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The AC lighting in nonessential equipment areas is supplied from two different lighting power sources. AC Normal Lighting supplies up to 50% of the lighting and Non-Safety- Related AC Standby Lighting supplies the remainder of the lighting needs (a minimum of 50%). The lighting in passageways and stairwells to nonessential equipment areas is supplied from two Non-Safety-Related Standby Lighting systems from different nonessential load groups. High intensity lighting and lighting in small rooms may be from a single lighting system.	1. Inspections and tests will be conducted to confirm that two different AC lighting systems supply 100% of the lighting needs in nonessential equipment areas and in the passageways and stairwells leading to them, and at least 50% of the lighting is supplied from a Non-Safety- Related AC Standby Lighting system.	1. Two different AC lighting systems supply 100% of the lighting needs in the nonessential equipment areas and in the passageways and stairwells leading to them. At least 50% of the lighting is supplied by a Non-Safety-Related AC Standby Lighting system. Localized high intensity lighting and lighting in small rooms is from a single source.
2. The AC lighting in essential equipment areas and the lighting in passageways and stairwells to essential equipment areas is supplied from two AC Standby Lighting systems. AC Safety- Related Standby Lighting supplies a minimum of 50% of the lighting and Non-Safety-Related AC Standby Lighting supplies the remainder of the lighting needs (up to 50%). Both the Safety-Related and the Non-Safety-Related Standby Lighting systems are in the same divisional or nonessential load group as the essential divisional area being supplied lighting.	2. Inspections and tests will be conducted to confirm that two different AC Standby Lighting systems in the same load group supply 100% of the lighting needs in essential equipment areas and in the passageways and stairwells leading to them, and at least 50% of the lighting is supplied from the Safety-Related AC Standby Lighting system in the same division as the essential equipment area.	2. Two different AC Standby Lighting systems in the same load group supply 100% of the lighting needs in the essential equipment areas and in the passageways and stairwells leading to them. At least 50% of the lighting is supplied by the Safety-Related AC Standby Lighting system in the same division as the essential equipment area.

Table 2.12.18: Lighting and Service Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The three Non-Safety-Related AC Standby Lighting systems are connectable to the Combustion Turbine Generator (CTG) and the three Safety-Related AC Standby Lighting systems are connectable to their respective Emergency Diesel Generators (DG). Generally, the Normal Lighting system is supplied from the nonessential Power Generation (PG) buses (see Figure 2.12.18a).	3. Inspections will be performed to confirm that the three Non-Safety- Related AC Standby Lighting systems are connectable to the Combustion Turbine Generator (CTG) and that the three Safety-Related AC Standby Lighting systems are connectable to their respective Emergency Diesel Generators (DG).	3. The three Non-Safety-Related AC Standby Lighting systems can be supplied by the Combustion Turbine Generator (CTG) and that the three Safety-Related AC Standby Lighting systems can be supplied by their respective Emergency Diesel Generators (DG).
4. The Non-Safety-Related DC Emergency Lighting system supplies lighting, at reduced illumination levels, to nonessential areas which are occupied during periods when AC lighting is lost. These areas include the Radwaste Building (RWB) control room, the Combustion Turbine Generator (CTG) area and control room, and the nonessential AC and DC electrical equipment areas. The nonessential 250 VDC battery supplies the DC lighting for the Radwaste Building and Combustion Turbine Generator. The lighting for the nonessential AC and DC electrical equipment areas is supplied from the nonessential 125 VDC of the same load group as the equipment in the room.	4. Inspections and tests will be conducted to confirm that the nonessential 250 VDC battery supplies DC Emergency Lighting to the Radwaste Building control room and Combustion Turbine Generator area and control room, and that the nonessential 125 VDC batteries supply DC Emergency Lighting to the AC and DC nonessential electrical equipment areas in their respective load groups.	4. The nonessential 250 VDC battery supplies DC Emergency lighting to the Radwaste Building control room. The nonessential 125 VDC batteries supply DC Emergency lighting to the nonessential AC and DC electrical equipment areas in their respective load groups, the Combustion Turbine Generator area and control room. Lighting is supplied from a nonessential 125 VDC battery.

Table 2.12.18: Lighting and Service Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. The Safety-Related DC Emergency Lighting system supplies lighting, at reduced illumination levels, to essential areas which are occupied during periods when AC lighting is lost. These areas include the Main Control room, the Emergency Diesel Generator areas and control rooms, and the essential AC and DC electrical equipment areas. Each essential 125 VDC battery supplies the DC Emergency Lighting for the Emergency Diesel Generator area and control room, and the essential AC and DC electrical equipment area within its safety division. The Main Control room is supplied DC Emergency Lighting from the two essential 125 VDC batteries in the same division as the Safety-Related Standby Lighting source for the control room. (See Figure 2.12.18b.)	5. Inspections and tests will be conducted to confirm that the essential 125 VDC battery supplies DC Emergency Lighting to the Emergency Diesel Generator area and control room, and the essential AC and DC electrical equipment areas in the same safety division. Two essential 125 VDC batteries, in the same division as the AC Standby Lighting systems, supply DC Emergency Lighting to the Main Control Room.	5. An essential 125 VDC battery supplies DC Emergency Lighting to the Emergency Diesel Generator area and control room, and the essential AC and DC electrical equipment areas in the same safety division. Two essential 125 VDC batteries, in the same divisions as the AC Standby Lighting systems, supply DC Emergency Lighting to the Main Control Room.
6. Guide Lamps are provided for stairways, exit routes, and major control areas, such as the Main Control room and the Radwaste Building Control room. They are self contained units with a minimum 8 hour battery pack and a battery charger supplied from the AC Standby Lighting system in the same area in which they are located. Guide Lamps are qualified Seismic Category I and are Class 1E when located in a Safety-Related area.	6. Inspections and tests will be conducted to confirm that Guide Lamps are located in stairways, exit routes, and major control areas and that they contain 8 hour batteries, rechargeable from the AC Standby Lighting system in the same area. Seismic Category I and, when in Safety-Related areas, Class 1E status will also be confirmed.	6. Guide Lamps are located in stairways, exit routes, and major control areas and contain 8 hour batteries, rechargeable from the AC Standby Lighting system in the same area. They are qualified Seismic Category I and are Class 1E in Safety-Related areas.

Table 2.12.18: Lighting and Service Power System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. All lighting systems are designed to provide the lighting intensities consistent with the lighting needs of the area and the intended purpose of the lighting system. The effects of the lighting, such as glare and shadows on equipment, and the mirror effects on glass and pools, are considered in the design. Lighting and other equipment maintenance, in addition to environmental conditions (e.g., areas containing flammable materials, wet or moist areas, areas above the reactor and fuel pools) are considered in the selection and installation of lighting equipment.	7. Inspection and tests will be conducted to confirm that lighting intensities are consistent with the lighting needs of the area and intended purpose of the lighting system. Inspection of the selected lighting equipment and its installation will be performed to confirm that it satisfies the requirements of its intended application.	7. The lighting intensities are consistent with the lighting needs of the area and intended purpose of the lighting system. Selected lighting equipment as installed satisfies the requirements of its intended application.
8. Lighting equipment, including distribution panels and cables, are identified according to essentiality and type. Safety-Related lighting systems are Class 1E, electrically independent and physically separated, and are located in Seismic Category I structures. Cables are routed in the respective divisional raceways. Normal Lighting is separated from Standby Lighting. DC lighting cables are not routed with any other cables.	8. Inspections will be performed to confirm that lighting equipment and cables are identified, electrically independent, and physically separated between safety divisions and between the Normal and Standby Lighting systems. The location of Class 1E equipment and cables in Seismic Category I structures and the separation between AC and DC cables will also be confirmed.	8. Lighting equipment and cables are identified, electrically independent, and physically separated between safety divisions and between the Normal and Standby Lighting systems. Class 1E equipment and cables are located in Seismic Category I structures and DC cables are routed separate from ac cables.
9. Heavy duty service outlets (e.g., welding outlets) are supplied from plant services buses and have grounded connections. Service outlets in wet or moist areas are supplied from breakers with ground fault detection.	9. Inspections will be performed to confirm that heavy duty service outlets are supplied from plant service buses and have grounded connections, and that outlets in wet or moist areas are supplied from breakers with ground fault protection.	9. Heavy duty service outlets are supplied from plant service buses and have grounded connections. Outlets in wet or moist areas are supplied from breakers with ground fault detection.

2.13 Power Transmission

2.13.1 Reserve Auxiliary Transformer

Design Description

No entry. Covered by item 2.12.1.

2.14 Containment and Environmental Control

2.14.1 Primary Containment System

Design Description

Later. Stage 8 Item.

2.14.2 Containment Internal Structures

Design Description

Later. Stage 3 Item.

2.14.3 Reactor Pressure Vessel Pedestal

Design Description

Later. Stage 3 Item.

2.14.4 Standby Gas Treatment System

Design Description

Later. Stage 3 Item.

2.14.5 PCV Pressure and Leak Testing Facility

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.14.6 Atmospheric Control System

Design Description

Later. Stage 3 Item.

2.14.7 Drywell Cooling System

Design Description

Later. Stage 3 Item.

2.14.8 Flammability Control System

Design Description

The flammability control system (FCS) is provided to control the potential buildup of oxygen in the containment from design-basis radiolysis of water. The primary containment during normal operation is purged with nitrogen and maintained in an oxygen deficient condition (≤3.5 volume percent) by the atmospheric control system (ACS). The objective of these two systems together (ACS and FCS) is to preclude combustion of hydrogen and damage to essential equipment and structures.

The FCS consists of two identical thermal hydrogen recombiners, with associated piping, valves, controls and instrumentation. The recombiner units are located in the secondary containment and controlled from the main control room. Each recombiner removes gas from the drywell, recombines the oxygen with hydrogen, and returns the gas mixture, along with the condensate to the suppression chamber. After a LOCA, the system is manually actuated from the control room when high oxygen levels are indicated by the containment atmospheric monitoring system (CAMS). Once placed in operation the system continues to operate until it is manually shut down when an adequate margin below the oxygen concentration design limit is reached.

Operation of either recombiner will provide effective control over the buildup of oxygen generated by radiolysis after a design-basis LOCA. Independent drywell and suppression chamber penetrations are provided for the two recombiners. Each penetration has two normally closed isolation valves; one air or nitrogen operated and one motor operated.

Each recombiner unit is an integral package. All pressure containing equipment, including piping between components, is considered an extension of the containment and therefore is designed to ASME Section III, Safety Class 2 requirements. The entire package is designed to meet Seismic Category I requirements. The recombiners are in separate rooms in the secondary containment and are protected from damage by flood, fire, tornadoes and pipe whip.

The recombiner unit consists of a blower, electric heater, reaction chamber, water spray cooler, a water separator, piping, valves, controls and instrumentation. During operation of the system, gas is drawn from the drywell by the blower, and heated. Hydrogen and oxygen in the gas will be recombined into steam in the reaction chamber and condensed in the spray cooler. The condensate and spray water, along with some of the gas, are returned to the wetwell. The rest of the gas is recycled through the blower.

The operation of the system can be tested from the control room. The test consists of energizing the blower and heaters and observing system operation to see if components are performing properly. Flow and pressure measurement devices are periodically calibrated.

Cooling water required for operation of the system after a LOCA is taken from the RHR system. Demineralized water is used for functional testing of the recombiner units. The cooling water is used to cool the water vapor and the residual gases leaving the recombiner prior to returning them to the containment.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.14.8 provides a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the FCS.

Table 2.14.8: Flammability Control System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The simplified system configuration of the FCS is shown in Figure 2.14.8.	1. Inspections of installation records together with plant walkdowns will be conducted to confirm that the installed equipment is in compliance with the design configuration defined in Figure 2.14.8.	1. The as-built FCS configuration is in accordance with Figure 2.14.8.
2. Two recombiners are mechanically and electrically independent.	2. Operational tests and visual inspection will be conducted which will include independent and coincident operation of the two recombiners to demonstrate complete divisional separation.	2. Plant test and visual inspection confirm proper independence of the two recombiner divisions.
3. FCS equipment and piping is built to Safety Class 2 and Quality Group B requirements.	3. Procurement records and actual equipment shall be inspected to verify that system components have been manufactured per the relavant requirements.	3. Records and inspections verify that FCS equipment and piping meets Safety Class 2 and Quality Group B requirements.
4. The RHR system provides cooling water to the exhaust flow from the FCS.	4. With the RHR system operating in the LPFL mode, perform a test to verify that spray cooling water is supplied to both recombiners	4. Tests confirm that the RHR system supplies cooling water to the FCS spray coolers of the recombiners.
5. The FCS is manually operated from the control room.	5. Perform an operational test in which the containment isolation valves are opened, both recombiners are started and operated (including blower, heater, spray cooler and instrumentation), shut down and the system isolated.	5. Tests confirm that all FCS functions required for post LOCA oxygen control can be performed from the control room.

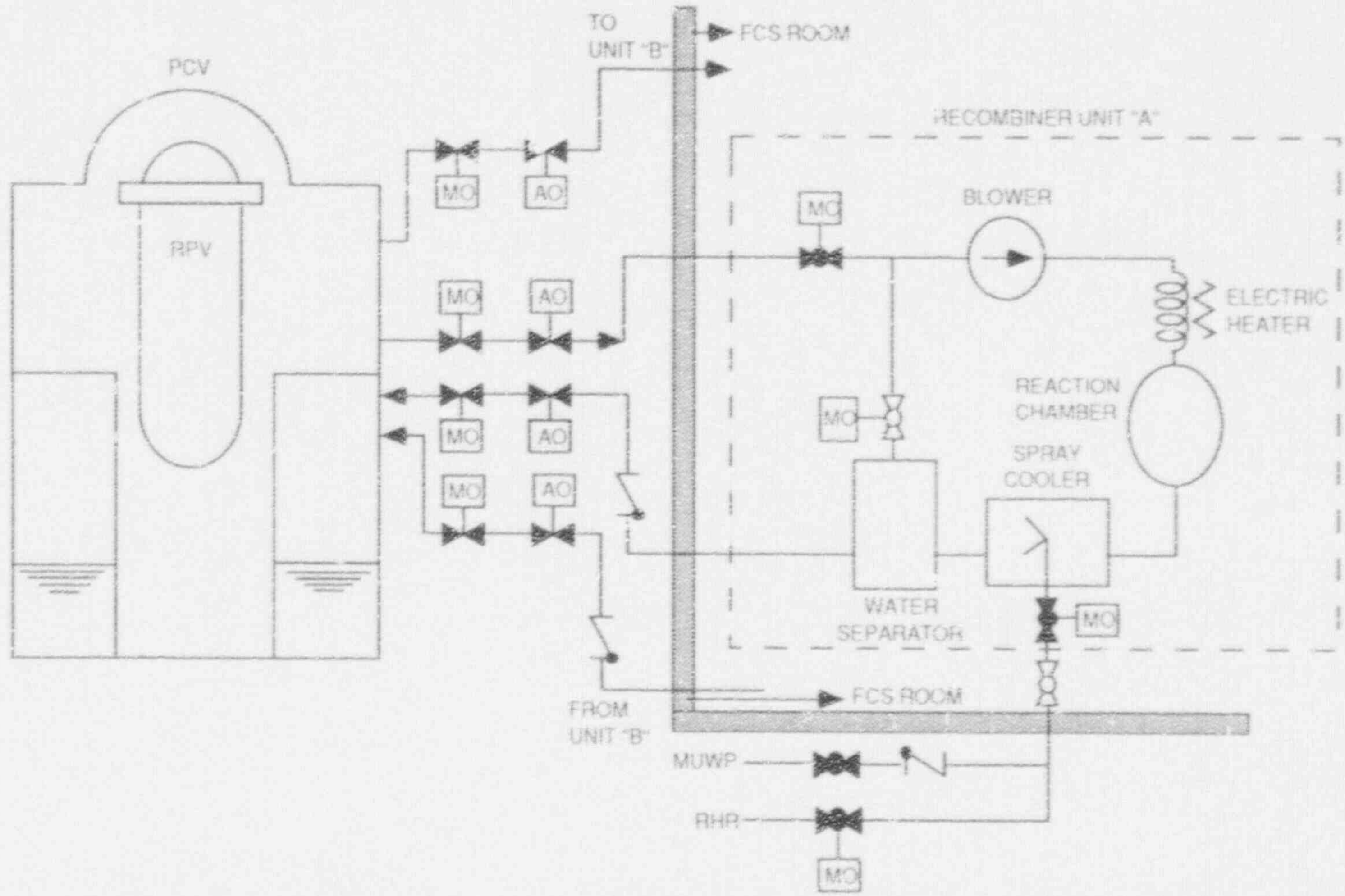


Figure 2.14.8 Flammability Control System

2.14.9 Suppression Pool Temperature Monitoring System

Design Description

Later. Stage 3 Item.

2.15 Structures and Servicing

2.15.1 Foundation Work

Design Description

No entry. Covered by item 2.15.10.

2.15.2 Turbine Pedestal

Design Description

No Tier 1 entry for this system.

2.15.3 Crane and Hoist

Design Description

Later. Stage 3 Item.

2.15.4 Elevator

Design Description

Later, Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.15.5 Heating, Ventilating and Air Conditioning

Design Description

Design Descriptions are provided for each of the following HVAC Systems: Control Building, Control Room Habitability Area, Reactor Building, Turbine Building, Electrical Building, Service Building and Radwaste Building. Tables for the Inspection, Test, Analyses and Acceptance Criteria are included with ten HVAC System Figures.

Control Building HVAC Systems

Control Building safety related air conditioning systems other than the Control Room Habitability Area, are designed to maintain 85°F, 50% RH at a slight positive pressure to provide efficient work environments for the operators and proper environments for structures and equipment to insure it has the capability to perform every safety function considering the worst case single failure for all normal and abnormal reactor operating conditions and accident conditions.

Major equipment consists of redundant supply fans, prefilters, 80% efficiency filters, hot water heating coils, chilled water cooling coils, and recirculation/exhaust fans, backdraft dampers, fire dampers, and air distribution ducts and accessories. Bird screens, dust and insect filters are provided to protect heating and cooling coil efficiency. Corrosion resistant materials are used in the fabrication of fans, coils, cabinets, plenums, air ducts and accessories. Refer to Figure 2.15.5a Control Building HVAC Systems for simplified design configuration.

All safety related HVAC systems are served from Class 1E power from either normal off-site sources or on-site emergency diesel generators.

Electrical equipment rooms are maintained at a positive pressure and air movement is designed to flow to the battery rooms maintained at a negative pressure by the exhaust fans.

Rooms housing the motor-generator (MG) sets, which provide power to the reactor internal pumps, are cooled by individual fan coil cooling units. These non-safety related cooling units are powered from the same electrical source as the MG set served. The HVAC Normal Cooling Water System connects to each fan coil unit cooling coil.

Smoke detectors are provided to initiate an alarm to close the return air dampers, open the fire zone damper bypassing the exhaust fans and start the supply fans to pressurize the Control Building compartments and discharge smoke through the exhaust louvers. The supply fans are located in mechanical rooms separate from the remainder of the Control Building compartments. The supply and exhaust fans can be started from the Control Room or the hand-off-automatic switches on the motor control center. These fans are powered from Class 1E Electrical Divisions 1,2 or 3.

Control Room Habitability Area HVAC System

The Control Room is maintained at a positive pressure for most events, 76°F., 42% Relative Humidity (RH) and is continuously habitable during LOCA, chemical release, fire, safe shutdown earthquake, tornado, flood, and other natural phenomena to insure the operators can safely shutdown the reactor and keep it in a safe shutdown condition.

Major equipment consists of redundant supply fans, prefilters, 80% efficiency filters, hot water heating coils, chilled water cooling coils, and recirculation/exhaust fans, backdraft dampers, fire dampers, and air distribution ducts and accessories. Bird screens, dust and insect filters are provided to protect heating and cooling coil efficiency. Corrosion resistant materials are used in the fabrication of fans, coils, cabinets, plenums, air ducts and accessories. The Control Room habitability equipment consists of redundant HEPA and charcoal filtration units designed to meet regulations addressing Control Room habitability during LOCA and other abnormal events. These units treat air from one of two widely separated air intakes with radiation monitors controlled to select the air intake with the non-contaminated air or isolate both in the event contaminants are present at both locations. Provisions are included for the future installation of site dependent toxic chemical monitors with controls capable of actuating the Control Room isolation dampers. The Control Room Habitability HVAC system is Seismic Category I, located in a Seismic Category I structure with air intakes and exhausts designed for protection from the effects of wind, rain, snow, tornados and tornado missiles. Refer to Figure 2.15.5b Control Room Habitability Area HVAC Systems for simplified design configuration.

All safety related HVAC components are served from Class 1E power from either normal off-site sources or on-site emergency diesel generators

Smoke detectors are provided to initiate an alarm to close the return air dampers, open the fire zone damper bypassing the exhaust fans and start the supply fans to pressurize the Control Room Habitability areas and discharge smoke through the exhaust louvers. The supply and exhaust fans are located in mechanical rooms separate from the remainder of the Control Room Habitability Area and can be started from the Control Room or the hand-off-automatic switches on the motor control center. These fans are powered from Class 1E Electrical Divisions 2 or 3.

Reactor Building HVAC Systems

Reactor Building Secondary Containment is served from non-safety related HVAC equipment located in the Turbine Building and is designed to maintain temperatures between 65 to 104°F, 50% RH and hold a negative 0.25 inch water gauge pressure. Air supply and exhaust duct systems are balanced to cause air movement from clean areas to areas with potential airborne radioactive contamination. Redundant Secondary Containment isolation dampers in series are provided in the main air supply and exhaust ducts where they enter the Reactor Building. These isolation dampers close whenever high airborne radiation is detected in the exhaust duct or in the Refueling Floor exhaust air intake, or when the fans fail or are not operating. These isolation dampers are safety related, Seismic Category I with Seismic Category I supports and have normally open, fail closed air operators powered from Class 1E Electrical Divisions 1 or 2.

Secondary Containment air conditioning and heating equipment consists of three 50% air supply fans moving 100% outdoor air which is filtered with bag type filters, heated with hot water coils or cooled with chilled water coils before the air is distributed through air ducts to and within the Secondary Containment. Exhaust air from the Reactor Building Secondary Containment compartments is collected in ducts, monitored for radiation and drawn to three 50% exhaust fans discharging into the plant stack. Seismic Category I duct supports are provided where air ducts could fall on safety related equipment. The Primary Containment supply fan, filter and purge exhaust fan are not safety related and serve the Primary Containment Atmospheric Control System. Refer to Figure 2.15.5c Reactor Building Secondary Containment HVAC Systems for simplified design configuration.

Essential Equipment HVAC System is safety related and consists of cabinet cooling (HVH) units containing fans and cooling coils connected to the Reactor Cooling Water System. Individual HVH coolers are provided for each compartment housing the following safety related equipment: Emergency Core Cooling System (ECCS) consisting of three Residual Heat Removal (RHR) pumps and heat exchangers, two High Pressure Core Flooding (HPCF) pumps, one Reactor Core Injection Cooling (RCIC) steam turbine pump, Flammability Control System (FCS) two recombiners, Standby Gas Treatment System (SGTS) two filter/dryer units and the Containment Atmospheric Monitoring System (CAMS) two equipment rooms. Each room cooler is controlled to start when the equipment served starts or when the respective space thermostat calls for cooling.

Main Steam Tunnel has a nonsafety related cabinet cooler (HVH) containing cooling coils served from the HVAC Normal Cooling Water System. Two fans distribute air to the main steam (MS) and feedwater (FW) isolation valve areas. These units are manually started from the main Control Room and are designed to keep the temperature below 140°F.

Other non-safety related cabinet coolers (HVH) containing fans and cooling coils connected to the HVAC Normal Cooling Water System are provided for the Refueling Machine Control Room, the Inservice Inspection (ISI) Rooms and the Suppression Pool Cleanup System (SPCU) Equipment Room. These cabinet cooling units are controlled to start when the space thermostat calls for cooling.

Radiation monitors are provided in the air environment of the refueling floor and in the main air exhaust duct in the Reactor Building to cause closure of the main air supply and exhaust duct automatic isolation dampers whenever high airborne radiation occurs. This high radiation signal will also activate the Standby Gas Treatment System to maintain the negative 0.25 inch water gauge pressure within the Secondary Containment.

Smoke removal from any compartment of the Secondary Containment is accomplished by operating all three air supply fans and all three air exhaust fans with their filter bypass dampers opened. Air exhaust flow limiting dampers are actuated within the fire zones not experiencing the fire to pressurize these fire zones to limit smoke intrusion.

The remaining areas of the Reactor Building outside of Secondary Containment are served by individual HVAC supply and exhaust systems designed to keep the temperatures below 104°F.

Electrical Equipment HVAC consists of three safety related systems, Seismic Category I, Safety Class 3, Quality Group C and are powered from their respective Class 1E Electrical Divisions 1, 2 or 3. Outdoor air and return air is mixed, filtered, cooled, and distributed to maintain a slightly positive pressure in the electrical equipment rooms and a slightly negative pressure in the Diesel Generator and Day Tank Rooms except when the diesel generators are running and their two emergency cooling fans operate to keep the temperature below 110°F. Smoke removal is accomplished by stopping the exhaust fans, closing the return air damper and opening the exhaust fan by-pass damper. Continuing to operate the supply fans pressurizes the areas served and releases the smoke through the exhaust bypass duct to the outdoors. Refer to Figure 2.15.5d Reactor Building Electrical Equipment HVAC Systems for a simplified design configuration.

Reactor Internal Pump (RIP) Rooms are supplied recirculated air cooled by HVAC normal cooling water coils and distributed by fans and air ducts. The return air is drawn into the RIP power supplies and control panels before being recooled. This RIP HVAC System is non-safety related and non-seismic except the air duct supports where safety related equipment is located. Refer to Figure 2.15.5e Reactor Building RIP HVAC System for a simplified design configuration.

Fine Motion Control Rod Drive (FMCRD) Auto Exchanger Control Panel Rooms are served by three fan coil units (FCU) with cooling water supplied by the HVAC Normal Cooling Water System. These FCU's are not safety related.

Turbine Building HVAC Systems

Turbine Building is served from non-safety related HVAC equipment located within the building to maintain less than 104°F, 50% RH and a slightly negative pressure except in electric switchgear rooms. Air supply and exhaust duct systems shall be balanced to cause air movement from clean areas to areas with potential airborne radioactive contamination.

Turbine Building air conditioning and heating equipment consists of three 50% ventilation system air supply fans moving 100% outdoor air which is filtered with bag type filters, cooled with chilled water coils or heated with hot water coils before the air is distributed through air ducts to and within the Turbine Building. General exhaust air from the Turbine Building is collected in ducts connected to three 50% ventilation system exhaust fans with bag filters discharging into the plant vent stack. Heat from the Turbine Operating Floor is removed by roof exhaust ventilating fans. Refer to Figures 2.15.5f and 2.15.5g Turbine Building HVAC Systems for the simplified design configurations.

Separate Lube Oil Area exhaust fans and ducts are provided to serve the LO storage and pump rooms to remove lubricating oil (LO) fumes and discharge them from the plant vent stack.

Compartments with potential radioactive contamination are collected in separate exhaust ducts and moved by the compartment exhaust fans with bag filters and radiation monitors to the plant vent stack.

Compartments housing heat releasing equipment are provided with multiple fan recirculation fan coil unit coolers with cooling coils and filters to keep temperatures below 104°F.

Smoke removal is accomplished with operation of the Turbine Building roof power exhaust ventilators, supply fans with the return air damper closed, exhaust fans with their exhaust filter bypass dampers opened and fire zone smoke dampers positioned to create a positive pressure in the areas adjacent to the zone experiencing the fire. The Turbine Building supply and exhaust fans can be started from the Control Room or the on-off-automatic switches on the motor control center in the Electrical Building.

Electrical Building HVAC Systems

Redundant air supply units with filters, cooling coils and fans are provided to maintain a positive pressure in the non-safety related Electrical Switchgear Rooms. Return/exhaust fans and air ducts provide the ventilation. Recirculating fan coil unit coolers help maintain the temperature below 104°F in the Electrical Switchgear Rooms and the Air Compressor Room. A negative pressure in the Auxiliary Boiler Rooms and Combustion Gas Turbine Generator Room is accomplished with roof exhausters. Refer to Figure 2.15.5h Electrical Building HVAC Systems for a simplified design configuration.

Smoke removal is accomplished by closing the return air dampers and circulating all outdoor air within the Electrical Building. The Heating Boiler Room and Combustion Turbine Generator Room are maintained at a negative pressure relative to the Electrical Switchgear Rooms, Chiller Room, Air Compressor Room and the stair towers which are maintained at a positive pressure. Equipment rooms position their fire zone smoke dampers to increase pressurization when the fire is in an adjacent area. Supply and exhaust fans can be started and dampers aligned from the Control Room or the hand-off-automatic switches on the motor control center.

Service Building HVAC Systems

Service Building is served from non-safety related HVAC equipment located within the building to maintain 72°F, 50% RH and a slightly negative pressure except in corridors and electrical equipment rooms. Refer to Figure 2.15.5i Service Building HVAC Systems for a simplified design configuration.

Service Building air supply to the non-radioactive area is provided with a mixture of outdoor and return air which is filtered, cooled, dehumidified or humidified and distributed by redundant fans through air ducts and diffusers to three reheat zones controlled by zone thermostats. Cooling is provided by the HVAC Normal Cooling Water System and reheat by the Hot Water Heating System. Air supply and exhaust duct systems are balanced to cause air movement from clean areas to areas with potential airborne radioactive contamination.

Service Building air supply to the potentially radioactive area is provided with 100% outdoor air which is filtered, cooled and distributed by redundant fans and air ducts to a single reheat zone controlled by a thermostat. The potentially radioactive area is maintained at a negative pressure by redundant exhaust fans which draw the exhaust air through filters before discharge to the vent stack. The exhaust air flow is controlled by a variable air operated damper with signals from a flow meter and radiation monitor.

Room cooling is supplemented by fan coil units with filters and cooling coils provided with HVAC normal cooling water. The Chemical Counting Room, Computer Room and Technical Support Center are provided with cooling units having redundant fans. The space temperature is controlled by thermostats modulating the HVAC normal cooling water valves.

Smoke removal can be accomplished by closing the non-radioactive controlled area return air damper to pressurize this area and positioning the fire zone smoke damper in the exhaust duct to by-pass the exhaust fans and remove the smoke through the exhaust louvers. The radioactive controlled area supply and exhaust fans circulate all outdoor air and normally maintain this area at a negative pressure compared to the non-radioactive controlled area. The radioactive controlled area exhaust fans can remove smoke from both the non-radioactive controlled area and the radioactive controlled area. Supply and exhaust fans and return air and fire zone dampers can be controlled from the Control Room or from the hand-off-automatic switches on the motor control center.

Radwaste Building HVAC Systems

Radwaste Building is served from non-safety related HVAC equipment located within the building to maintain 65 to 104°F, 50% RH and a slightly negative pressure except in the Radwaste Control Room. Air supply and exhaust duct systems are balanced to cause air movement from clean areas to areas with potential airborne radioactive contamination. Refer to Figure 2.15.5j Radwaste Building HVAC Systems for a simplified design configuration.

Radwaste Building air supply to potentially radioactive areas is provided with 100% outdoor air which is filtered, cooled and distributed by redundant fans and air ducts to several reheat zones each controlled by a thermostat. The potentially radioactive area is maintained at a negative pressure by redundant exhaust fans which draw the exhaust air through filters before discharge to the vent stack. The exhaust air flow is controlled by a variable air operated damper with signals from a flow meter and radiation monitor.

Radwaste Building process tanks are connected to a tank vent transfer system that equalizes air outflow from tanks being filled with air inflow needed for tanks being emptied. Any excess air is exhausted through a filter, radiation monitor and redundant exhaust fans to the plant vent stack.

The Radwaste Control Room is maintained at a positive pressure by varying the air flow to the redundant exhaust fans by a variable position damper.

Smoke removal is accomplished by opening the exhaust fan by-pass damper to enable the dual Radwaste Building air supply fans to be started to pressurize all areas. Smoke is discharged to the stack. The supply and exhaust fans can be controlled from the Radwaste Building Control Room or the hand-off-automatic switches on the motor control center.

Inspection, Test, Analyses and Acceptance Criteria

The following tables provide the Inspections, Tests, Analyses and associated Acceptance Criteria which are to be accomplished for the plant HVAC systems.

Table	System
2.15.5a	Control Building HVAC Systems
2.15.5b	Control Room Habitability Area HVAC System
2.15.5c	Reactor Building HVAC Systems
2.15.5d	Turbine Building HVAC Systems
2.15.5e	Electrical Building HVAC Systems
2.15.5f	Service Building HVAC Systems
2.15.5g	Radwaste Building HVAC Systems

Table 2.15.5a: Control Building HVAC System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Control Building HVAC Systems are shown in Figure 2.15.5a	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration shall be accomplished.	1. As-built Control Building HVAC System installations conform to the configuration for all components shown in Figure 2.15.5a.
2. Three Control Building HVAC trains are mechanically and electrically independent.	2. Tests and visual inspection of the three independent trains will be conducted which will include independent and coincident operation of the three trains to demonstrate complete divisional separation.	2. As-built operational tests and visual inspection shall confirm independence of the three electrical divisions.
3. Exhaust fan bypass dampers are designed to enhance smoke removal from the Control Building in the event of a fire inside or outside the Control Building. Refer to Table 3.2b, Ventilation and Airborne Monitoring.	3. Demonstrate and visually inspect the capability of each exhaust fan bypass damper to open, return air damper to close and the exhaust fans to be stopped from the Control Room or aligned and positioned from outside the Control Room with their hand-off-automatic (H-O-A) switches in the motor control center (MCC) to remove smoke from the Control Building.	3. Confirm the Control Building exhaust fan bypass dampers are capable of being aligned and operated from inside or outside the Control Room and able to remove smoke from the Control Building.
4. Control Building HVAC equipment is designed to Safety Class 3, Quality Group C, Seismic Category I requirements and is powered from Class 1E Electrical Divisions 1, 2 or 3.	4. Review documentation of the installed equipment, instruments, ducts, piping and supports for compliance, and (if applicable) the Code Stamp on the hardware.	4. Confirm the system equipment is designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements. Visually inspect the electrical installation to confirm Class 1E Electrical Divisions 1, 2 and 3.

Table 2.15.5b: Control Room Habitability Area HVAC System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Control Room HVAC and Habitability System is shown in Figure 2.15.5b	1. Inspections of the as-built HVAC and Habitability System construction records shall be performed. Visual inspection of the configuration shall be accomplished.	1. As-built configuration of the HVAC and Habitability System installation conforms with those components shown in Figure 2.15.5b.
2. Two Control Room HVAC and Habitability trains are both mechanically and electrically independent.	2. Tests and visual inspection of the two independent trains will be conducted which will include independent and coincident operation of the two trains to demonstrate complete divisional separation.	2. As-built operational tests and visual inspection shall confirm independence of the two electrical divisions.
3. During abnormal and accident conditions the Control Room HVAC and Habitability trains are capable of responding to high radiation levels at one or both of the two air intakes.	3. Tests and visual inspection of each train operating in the abnormal or accident mode and using a simulated high radiation signal at one of the outdoor air intakes. confirm the logic will open the alternate air intake dampers and close the dampers at any intake detecting high airborne radiation.	3. As-built operational tests and visual inspections shall confirm that a simulated high radiation signal at one of the two outdoor air intakes will open the outdoor air damper at the alternate air intake. Also confirm that dampers at both air intakes close with simulated high airborne radiation signals at both outdoor air intakes.
4. Isolation valves are designed to isolate the Control Room during onsite or offsite chemical releases	4. Demonstrate with a simulated signal from the chemical release sensor that the Control Room HVAC and Habitability isolation valves close to isolate the Control Room.	4. Confirm the isolation valves are in their design locations and are capable of completely isolating the Control Room and Habitability Areas from the outside environment upon receipt of an isolation signal.

Table 2.15.5b: Control Room Habitability Area HVAC System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Exhaust fan bypass dampers are designed to enhance smoke removal from the Control Room in the event of a fire inside or outside the Control Building.	5. Demonstrate and visually inspect the capability of each exhaust fan bypass damper to be opened, each return air damper to be closed and the exhaust fans to be stopped by their remote manual switches (RMS) in the Control Room or the hand- off-automatic switches in the motor control center (MCC) outside the Control Room. All outdoor air pressurization of the Control Room removes the smoke through the exhaust louvers.	5. Confirm the Control Room smoke removal equipment is capable of being aligned and operated outside the Control Room and able to remove smoke from the Control Room.
6. Habitability air treatment equipment is designed to meet the requirements of applicable regulations and standards. Refer to Table 3.2b Ventilation and Airborne Monitoring.	6. Test and visually inspect the air treatment equipment to demonstrate that all of the components are ready to perform their function in accordance with applicable standards.	6. Confirm treatment equipment is in compliance with acceptance criteria of applicable standards relating its functional performance.
7. Control Room Habitability Area HVAC equipment is designed to Safety Class 3, Quality Group C, Seismic Category I requirements and are powered from Class 1E Electrical Divisions 2 or 3.	7. Review documentation of the installed equipment, instruments, ducts, piping and supports for compliance, and (if applicable) the Code Stamp on the hardware.	7. Confirm the system equipment is designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements. Visually inspect the electrical installation to confirm the Class 1E Electrical Divisions 2 and 3.

Table 2.15.5c: Reactor Building Heating, Ventilating And Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Reactor Building Secondary Containment HVAC System is shown in Figure 2.15.5c.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Reactor Building Secondary Containment HVAC installation conforms to the configuration shown in Figure 2.15.5c.
2. Secondary Containment dual isolation dampers of the main air supply and exhaust ducts are designed to Safety Class 2, Quality Group B, Seismic Category I and are powered from Class 1E Electrical Divisions 1 or 2.	2. Review the documentation of the as-installed isolation dampers to verify compliance with the required standards and (if applicable) visually inspect the Code Stamp on the hardware.	2. Confirm by visual inspection the isolation dampers are designed, fabricated, installed and tested in compliance with codes and regulatory requirements.
3. Secondary Containment dual isolation dampers close in less than 30-seconds due to a LOCA signal or detection of high airborne radioactivity upstream of these isolation dampers or at the exhaust air intake duct in the Refueling Area or failure of system fans. Refer to Table 3.2b Ventilation and Airborne Monitoring.	3. Test the closure of the Secondary Containment HVAC main dual supply and exhaust isolation dampers with simulated isolation signals. Verify that closure of each isolation valves occurs in less than 30-seconds. Also test the fail close actuation of each damper on loss of power or instrument air supply.	3. Confirm by visual inspection that each Secondary Containment HVAC main supply and exhaust isolation damper closes in less than 30 seconds after receipt of each isolation signal.
4. Leakage through each Secondary Containment isolation damper is designed to be compatible with the Secondary Containment leakage requirements established for the Standby Gas Treatment System.	4. Inspect the damper position switch capability and verify each secondary containment isolation damper reaches the fully closed position when automatic closure actuation occurs.	4. Confirm by visual inspection the Secondary Containment isolation dampers and their position switches comply with regulation requirements calling for an acceptable secondary containment barrier when fully closed.
5. Secondary Containment HVAC System exhaust fans are designed to be started before the supply fans start and be stopped in the event the supply fans fail.	5. Inspect the configuration of the controls and test the interlock of the supply fans with the exhaust fans to verify the supply fans cannot be started before the exhaust fans are operating and upon failure of the exhaust fans, the supply fans stop automatically.	5. Confirm by visual inspection that the supply fans do not start before the exhaust fans are operating and the supply fans stop when the exhaust fans are not operating.

Table 2.15.5c: Reactor Building Heating, Ventilating And Air Conditioning (HVAC) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. Secondary Containment Essential Equipment HVAC system configuration is shown on Figure 2.15.5c and consists of safety related room coolers in each of the following rooms: Residual Heat Removal (RHR) System's three pump and heat exchanger rooms, High Pressure Core Flooding(HPCF) System's two pump rooms, Reactor Core Injection Cooling (RCIC) System turbine driven pump room, Standby Gas Treatment System (SGTS) two fan rooms, Flammability Control System (FCS) two recombiner rooms, Fuel Pool Cooling (FPC) System's two pump rooms, and Containment Atmospheric Monitoring System (CAMS) two equipment rooms.	6. Inspect the configuration of the room coolers and verify their cooling coils are connected to the HVAC Emergency Cooling Water (HECW) System.	6. As-built Secondary Containment HVAC installation conforms to the design documentation and the configuration of the components as shown in Figure 2.15.5c. Confirm by visual inspection that each cooling unit starts when the equipment to be cooled starts or the space thermostat calls for cooling.
7. Reactor Building HVAC equipment is designed to Safety Class 3, Quality Group C, Seismic Category I requirements.	7. Review documentation of the installed equipment, instruments, ducts, piping and supports for compliance, and (if applicable) the Code Stamp on the hardware.	7. Confirm the system equipment is designed, fabricated, installed and tested in compliance with applicable codes and regulatory requirements.
8. Reactor Building HVAC safety related equipment room cooling units are powered from Class 1E Electrical Divisions 1, 2 or 3 and each unit is connected to the same electrical division as equipment served. Equipment Room cooling units are designed to start when the equipment served starts or the room thermostat calls for cooling.	8. Test each cooling unit fan to verify they are powered from the same Class 1E Electrical Division that serves the equipment being cooled. Visually inspect each cooling unit to verify the cooler starts when the equipment served starts or the space thermostat is calling for cooling.	8. Based on visual inspection of actual operational tests confirm independence of the three electrical divisions and verify equipment room cooling unit starts when equipment served starts. Confirm the room cooling unit will also start when the room thermostat calls for cooling.

Table 2.15.5c: Reactor Building Heating, Ventilating And Air Conditioning (HVAC) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. Exhaust fans are designed to remove smoke from the Reactor Building Secondary Containment Rooms in the event of a fire. Fire zone dampers are designed to close to pressurize all areas adjacent to the zone with the fire and enable the exhaust filter bypass dampers to be opened and the exhaust fans establish and maintain a negative pressure in the zone and remove the smoke.	9. Demonstrate and visually inspect the capability of each fire zone damper to be positioned, each Reactor Building air exhaust filter to be bypassed and the exhaust fans started from the Control Room or from the hand-off- automatic (H-O-A) switches in the motor control center (MCC) outside the Reactor Building and remove the smoke.	9. Confirm the Reactor Building HVAC fire zone dampers partially close, exhaust bypass dampers open and each exhaust fan is capable of being started from outside the Reactor Building and able to remove smoke from the Reactor Building compartments.
10. The configuration of the Reactor Building Electrical Equipment HVAC System is shown in Figure 2.15.5d.	10. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	10. As-built Reactor Building Electrical Equipment HVAC installation conforms to the configuration shown in Figure 2.15.5d.
11. Three Reactor Building Electrical Equipment HVAC trains are mechanically and electrically independent.	11. Tests and visual inspection of the three independent trains will be conducted which will include independent and coincident operation of the three trains to demonstrate complete divisional separation.	11. As-built operational tests and visual inspection shall confirm independence of the three Class 1E Electrical Divisions 1.2 or 3.
12. Exhaust fan bypass dampers are designed to enhance smoke removal from the Reactor Building Electrical Equipment Rooms in the event of a fire inside these Reactor Building rooms. The exhaust fans are designed to remove smoke from the Diesel Day Tank Rooms and the Diesel Generator Rooms.	12. Demonstrate and visually inspect the capability of each exhaust fan bypass damper to open, return air damper to close and the exhaust fans to be stopped from the Control Room or aligned and positioned from outside the Reactor Building Electrical Equipment Rooms with their hand-off-automatic (H-O-A) switches on the motor control center to remove smoke from these Reactor Building Rooms. Demonstrate the capability of the exhaust fans to remove smoke from the Diesel Day Tank Rooms and the Diesel Generator Rooms.	12. Confirm by visual inspection the Reactor Building Electrical Equipment Rooms' exhaust fan bypass dampers are capable of being opened, return air dampers closed and the exhaust fans stopped from the Control Room or aligned and operated from outside the Reactor Building Electrical Equipment Rooms to remove smoke from the Electrical Equipment Rooms. Also confirm by inspection that the exhaust fans are also capable of removing smoke from the Diesel Day Tank Rooms and the Diesel Engine Rooms.

Table 2.15.5c: Reactor Building Heating, Ventilating And Air Conditioning (HVAC) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
13. DG Emergency Supply Fans are safety related and are designed to provide additional diesel generator room cooling when the diesel is operating and also remove smoke from the Diesel Generator Room in the event of fire.	13. Inspections of the as-built HVAC System shall determine that one DG Emergency Supply Fan is controlled to start when the diesel engine starts, and the second fan starts when the room thermostat calls for additional cooling. High and low temperature alarms in the Control Room when the temperature is high. Both fans can be manually controlled, locally or from the Control Room. In the event of a fire these fans can also remove smoke from the Diesel Generator Room	13. As-built Reactor Building DG Emergency Supply Fan installation conforms to the design documentation and visual inspection shall confirm the controls will start one of the two fans when the diesel engine is started or start the second fan when the room thermostat calls for additional cooling. Also confirm these fans can remove smoke from the Diesel Generator Room.
14. Reactor Building non-safety related RIP Panel and Power Supply Rooms are designed to be cooled by the RIP HVAC dual fan recirculating air system with cooling coils served from the HVAC normal cooling water (HNCW) system as configured on Figure 2-15-5e. This is in addition to the supply and return/exhaust air cooling and smoke removal provided by the Electrical Equipment HVAC System configured on Figure 2.15.5d.	14. Inspections of the as built RIP HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	14. As-built Reactor Building RIP Panel and Power Supply Rooms RIP HVAC installation conforms to the configuration shown in Figure 2.15.5e.

Table 2.15.5d: Turbine Building Heating, Ventilating and Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Turbine Building HVAC System is shown in Figures 2.15.5f and 2.15.5g.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Turbine Building HVAC installation conforms to the configuration shown in Figures 2.15.5f and 2.15.5g.
2. Exhaust fans and roof power ventilators are designed to remove smoke from the Turbine Building rooms in the event of a fire. Fire zone dampers are designed to pressurize all areas adjacent to the zone with the fire and enable the exhaust filter bypass dampers to be opened and the exhaust fans and roof power ventilators started to establish and maintain a negative pressure in the zone and remove the smoke.	2. Demonstrate and visually inspect the capability of each fire zone damper to partially close and each Turbine Building air exhaust filter to be bypassed and the exhaust fans started from the Control Room or from the hand-off- automatic (H-O-A) switches in the motor control center (MCC) outside the Turbine Building fire zone and remove the smoke.	2. Confirm the Turbine Building HVAC fire zone dampers partially close and pressurize the areas adjacent to the zone with the fire, the exhaust filter bypass dampers open and each exhaust fan is capable of being started from outside the Turbine Building fire zone and able to remove smoke.
3. The Turbine Building Compartment Exhaust System is designed to establish and maintain a negative pressure in rooms with potential airborne radioactivity. Adjacent areas are pressurized to move air from clean areas to potentially contaminated areas. Refer to Table 3.2b Ventilation and Airborne Monitoring.	3. Demonstrate and visually inspect the performance of the Turbine Building Compartment Exhaust System to create a negative pressure in the rooms having the potential for radioactive contamination and observe the movement of air from the pressurized clean areas to the potentially contaminated rooms.	3. Confirm that the Turbine Building Compartment Exhaust System has the capability to maintain a negative pressure in the rooms having the potential for airborne radioactive contamination. Verify by visual inspection the movement of air from clean areas to potentially contaminated rooms.
4. The Turbine Building Lube Oil Exhaust System is designed to remove oil vapors from lube oil reservoir, condenser and pump rooms.	4. Visually inspect the lube oil exhaust system to demonstrate it maintains a negative pressure in the lube oil condenser and pump room and the room housing the lube oil reservoir.	4. Confirm that the Turbine Building Lube Oil Exhaust System actually maintains a negative pressure in the lube oil condenser and pump room and the room housing the lube oil reservoir.
5. Various Turbine Building spaces are provided with supplemental fan coil cooling units with coils connected to the HVAC Normal Cooling Water System. Space thermostats control the cooling water flow valves.	5. Visually inspect the supplemental fan coil units to verify their operation and control.	5. Confirm that the Turbine Building supplemental cooling units are capable of removing operating equipment heat releases to the spaces and are controlled by space thermostats.

Table 2.15.5e: Electrical Building Heating, Ventilating and Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Electrical Building HVAC System is shown in Figure 2.15.5h. The equipment in this building is not safety related.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Electrical Building HVAC installation conforms to the configuration shown in Figure 2.15.5h.
2. Fan coil cooling units supplement the equipment room cooling with coils connected to the HVAC Normal Cooling Water System. Room thermostats control the cooling water flow control valves.	2. Visually inspect the supplemental fan coil units to verify their operation and control.	2. Confirm that the Electrical Building supplemental cooling units are capable of removing operating equipment heat releases to the spaces and are controlled by space thermostats.
3. Smoke removal is accomplished by closing the return air damper and circulating all outdoor air within the Electrical Building spaces. The Heating Boiler Room and the Combustion Turbine Generator Room are normally maintained at a negative pressure relative to the remaining equipment rooms maintained at a positive pressure. Equipment rooms are designed with zone fire dampers in their exhaust ducts to increase the pressurization when the fire is in an adjacent area.	3. Visually inspect the damper alignment to utilize all outdoor air and adjacent room pressurization to accomplish smoke removal. Demonstrate the capability to start each exhaust fan and align the dampers for smoke removal locally or from the hand-off-automatic (H-O-A) switches at each of the motor control centers.	3. Confirm by visual inspection that all supply and exhaust fans can be started from local or remote panels. Also confirm the return air dampers can be closed and the fire zone dampers positioned to accomplish pressurization in the areas adjacent to a fire. Verify that the Heating Boiler Room and the Combustion Turbine Generator Room is maintained at a negative pressure relative to the adjacent equipment rooms which are maintained at a positive pressure.

Table 2.15.5f: Service Building Heating, Ventilating and Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Service building HVAC System is shown in Figure 2.15.5i. The HVAC equipment in this building is not safety related.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Service Building HVAC installation conforms to the configuration shown in Figure 2.15.5i.
2. The Service Building HVAC System consists of two trains, one serving the non-radioactive controlled areas and the other serving the radioactive controlled areas. The non-radioactive controlled areas are pressurized by redundant supply fans. The radioactive controlled areas are maintained at a negative pressure by redundant supply and exhaust fans to insure that air moves from the clean areas to the potentially contaminated areas. Refer to Table 3.2b Ventilation and Airborne Monitoring.	2. Visually inspect the equipment serving each area and demonstrate that air moves from the clean areas to the potentially contaminated areas. Demonstrate that the flow controls and low flow alarm are functioning to maintain the radioactive controlled area at a negative pressure as the pressure drop across the exhaust filters increase with time.	2. Visually confirm that air moves from the clean areas toward the potentially contaminated areas. Confirm that the HVAC equipment and flow control serving the radioactive controlled areas establishes and maintains a negative pressure relative to the environment. Confirm that the non-radioactive controlled areas are pressurized.
3. Smoke removal is accomplished by closing the non-radioactive controlled area return air damper and positioning the fire zone damper in the exhaust duct to pressurize the area. The radioactive controlled area exhaust fans remove smoke from both the clean areas and the potentially contaminated areas.	3. Inspect and visually demonstrate the return air damper can be closed and the radioactive controlled area fire zone damper can be positioned to pressurize the non-radioactive controlled areas. The exhaust fans of the radioactive controlled areas can be started locally or from their hand-off-automatic (H-O-A) switches on the motor control center to remove smoke from all areas of the Service Building.	3. Visually confirm that for smoke removal the return air damper closes, the fire zone damper is positioned to pressurize the non-radioactive controlled areas and the radioactive controlled area redundant exhaust fans start from the local panel or the H-O-A switches on the motor control center. Verify that smoke is removed from all areas of the Service Building.

Table 2.15.5g: Radwaste Building Heating, Ventilating and Air Conditioning (HVAC) System

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The configuration of the Radwaste building HVAC System is shown in Figure 2.15.5j. The HVAC equipment in this building is not safety related.	1. Inspections of the as-built HVAC System construction records shall be performed. Visual inspection of the configuration components shall be accomplished.	1. As-built Radwaste Building HVAC installation conforms to the configuration shown in Figure 2.15.5j.
2. The Radwaste Building HVAC System consists of a dual fan supply unit with bag filters and cooling coil connected to the HVAC Normal Cooling Water System. The radioactive controlled areas are maintained at a negative pressure by redundant exhaust fans to insure that air moves from the clean areas to the potentially contaminated areas. The Radwaste Control Room is maintained at a positive pressure with volume control on the room's redundant exhaust fans. Refer to Table 3.2b Ventilation and Airborne Monitoring.	2. Visually inspect the equipment serving each area and demonstrate that air moves from the clean areas to the potentially contaminated areas. Demonstrate that the flow controls function to maintain the Radwaste Control Room at a positive pressure.	2. Visually confirm that air moves from the clean areas toward the potentially contaminated areas. Confirm that the Radwaste Control Room flow control establishes and maintains a positive pressure relative to the environment and confirm that the potentially radioactive areas are maintained at a negative pressure.
3. Smoke removal is accomplished by opening the exhaust fan bypass damper to enable the dual supply fans to be started to pressurize all areas and remove smoke from the Radwaste Building. The supply and exhaust fans can be controlled from the Radwaste Control Room panel or the hand-off- automatic switches in the motor control center.	3. Inspect and visually demonstrate the exhaust fan bypass damper can be opened, the exhaust fans stopped and both supply fans started from the Radwaste Control Room panel or from the hand-off-automatic (H_O_A) switches in the motor control center. Both exhaust fans of the Radwaste Control room can be started locally or from their hand-off-automatic (H-O-A) switches on the motor control center to remove smoke from all areas of the Radwaste Building.	3. Visually confirm that for smoke removal the exhaust fan bypass damper opens, the exhaust fans stop and both supply fans start when their controls are actuated from the Radwaste Control Room panel or the H-O-A switches on the motor control center to remove smoke from the Radwaste Building. Similarly confirm that the Radwaste Control Room exhaust fans can both be started to remove smoke from the Radwaste Building

Table 2.15.5g: Radwaste Building Heating, Ventilating and Air Conditioning (HVAC) System (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Radwaste Building Tank Exhaust System is designed to control air released from tanks being filled and permit this air to be drawn into tanks being simultaneously pumped out or being drained. Excess air is passed through a bag filter before the tank exhaust fan discharges it along with Radwaste Building exhaust to the stack.	4. Inspect and visually determine that the Radwaste Building Tank Exhaust System limits the release of tank air to the Radwaste Building Exhaust System and the stack.	4. Confirm that the Radwaste Building Tank Exhaust System controls the release of tank air and filters it before the tank exhaust is discharged to the stack. Verify the exhaust air is monitored for radioactivity before it is discharged to the stack.
5. Radwaste Building Incinerator Exhaust is designed to be treated by cooling the gas and passing it through a HEPA filter and fan before release to the stack.	5. Inspect and visually determine that the Radwaste Building Incinerator System functions to cool the exhaust gas before passing it through a HEPA filter and fan to the stack.	5. Confirm the Incinerator exhaust gas is cooled and passes through a HEPA filter and fan before the gas is discharged to the stack.

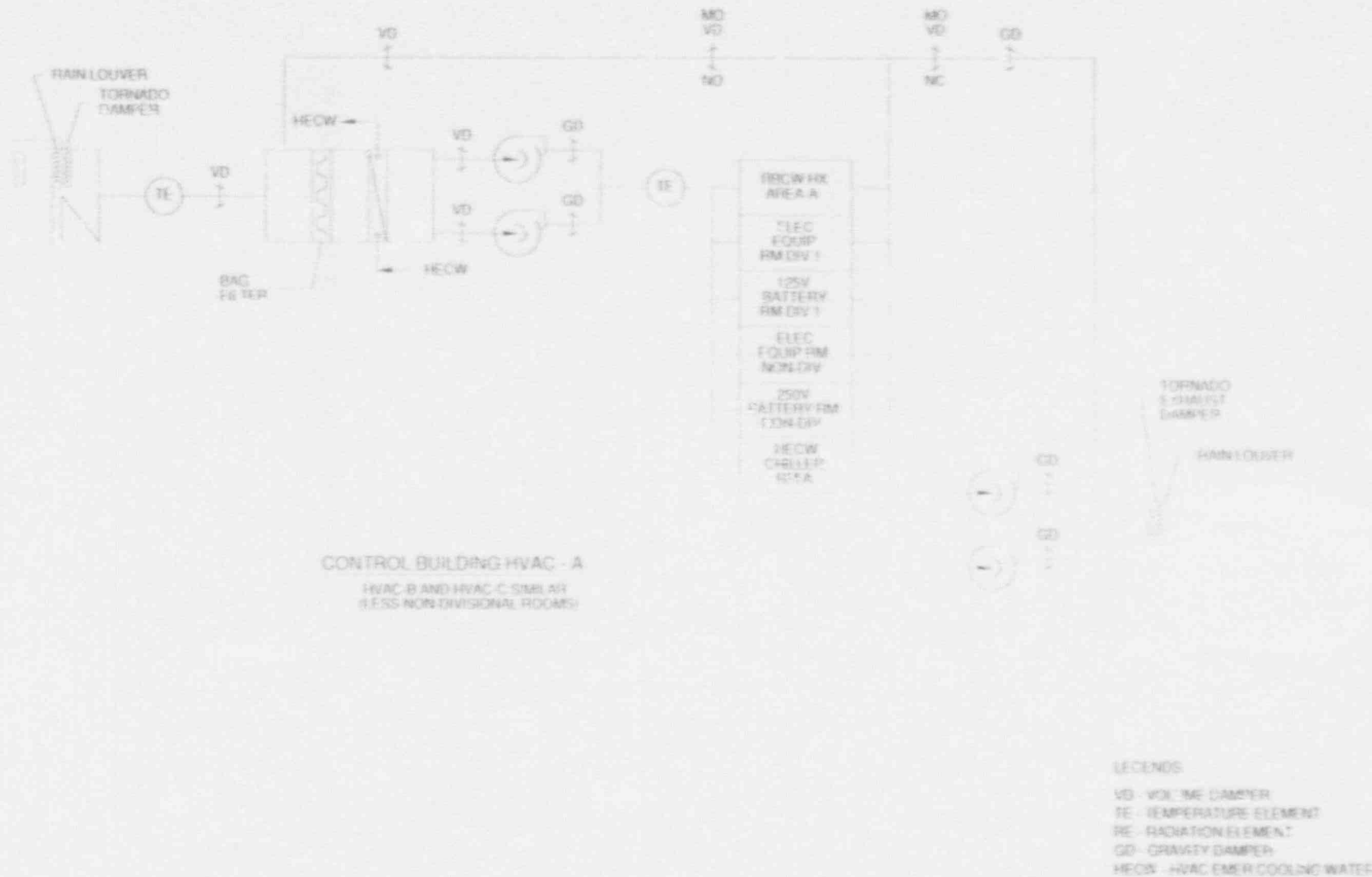


Figure 2.15.5a Control Building HVAC System

Figure 2.15.5b Control Room and Habitability Area HVAC System

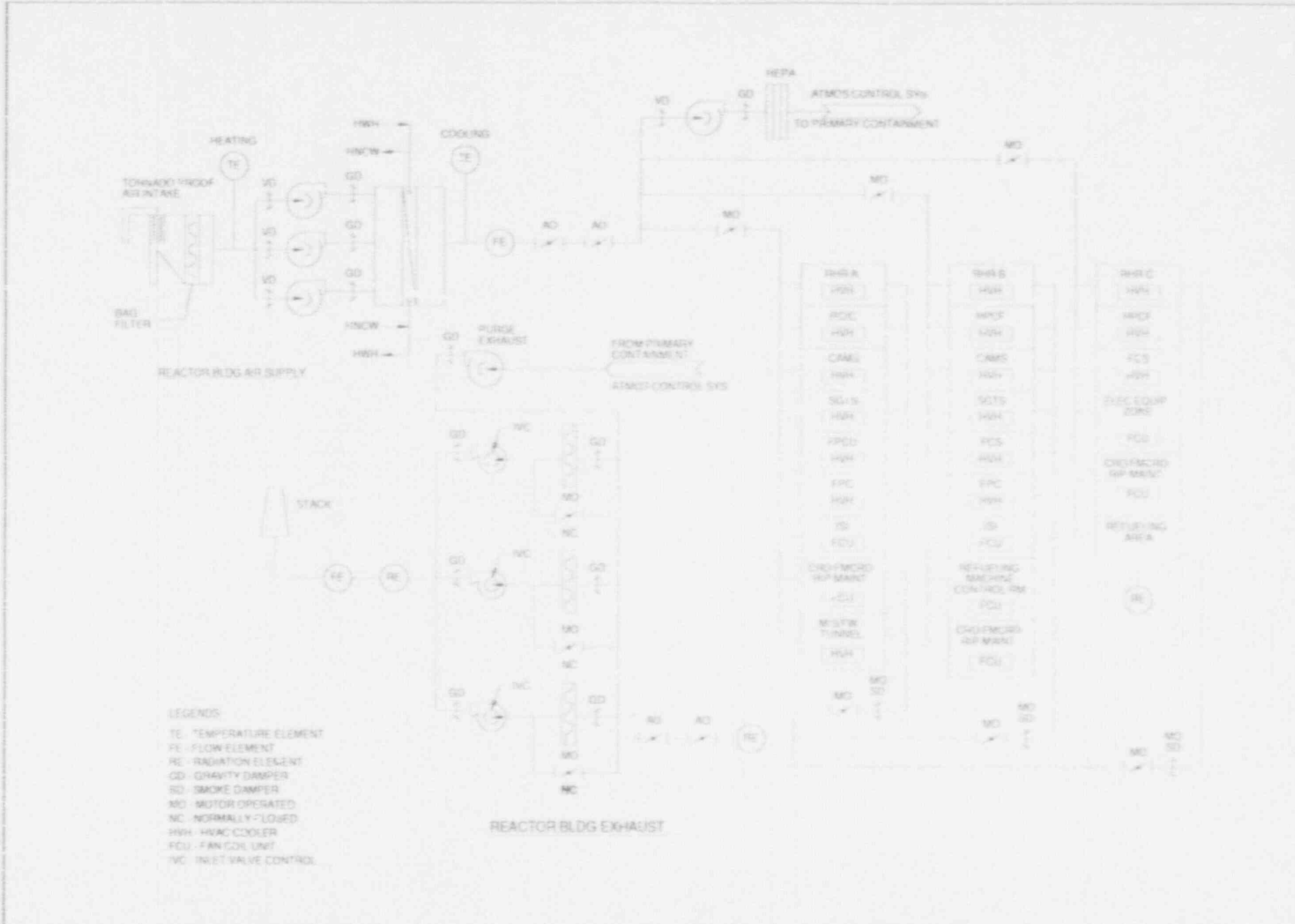


Figure 2.15.5c Reactor Building Secondary Containment HVAC System

Figure 2.15.5d Reactor Building Electrical Equipment HVAC System

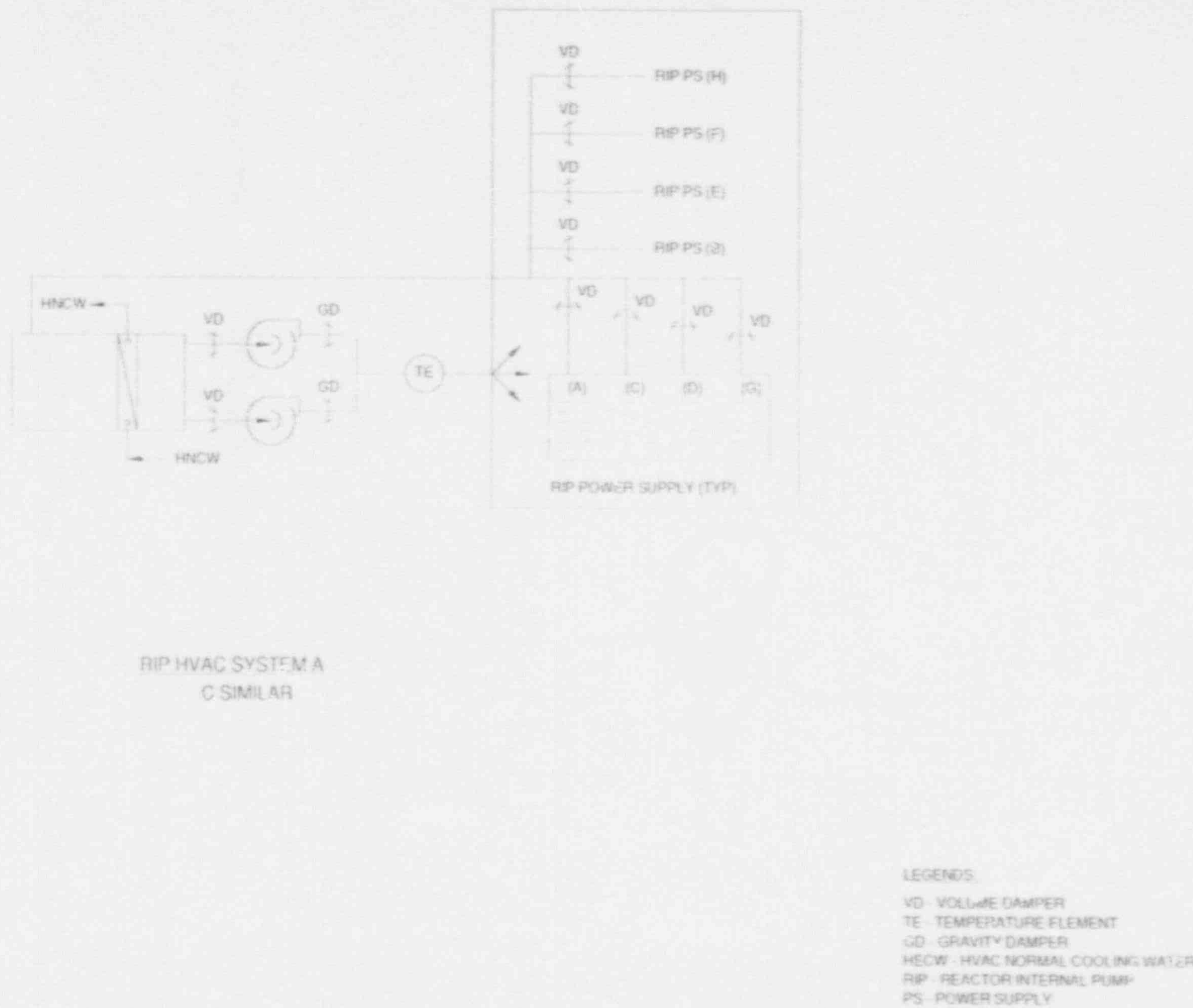


Figure 2.15.5e Reactor Building RIP HVAC System

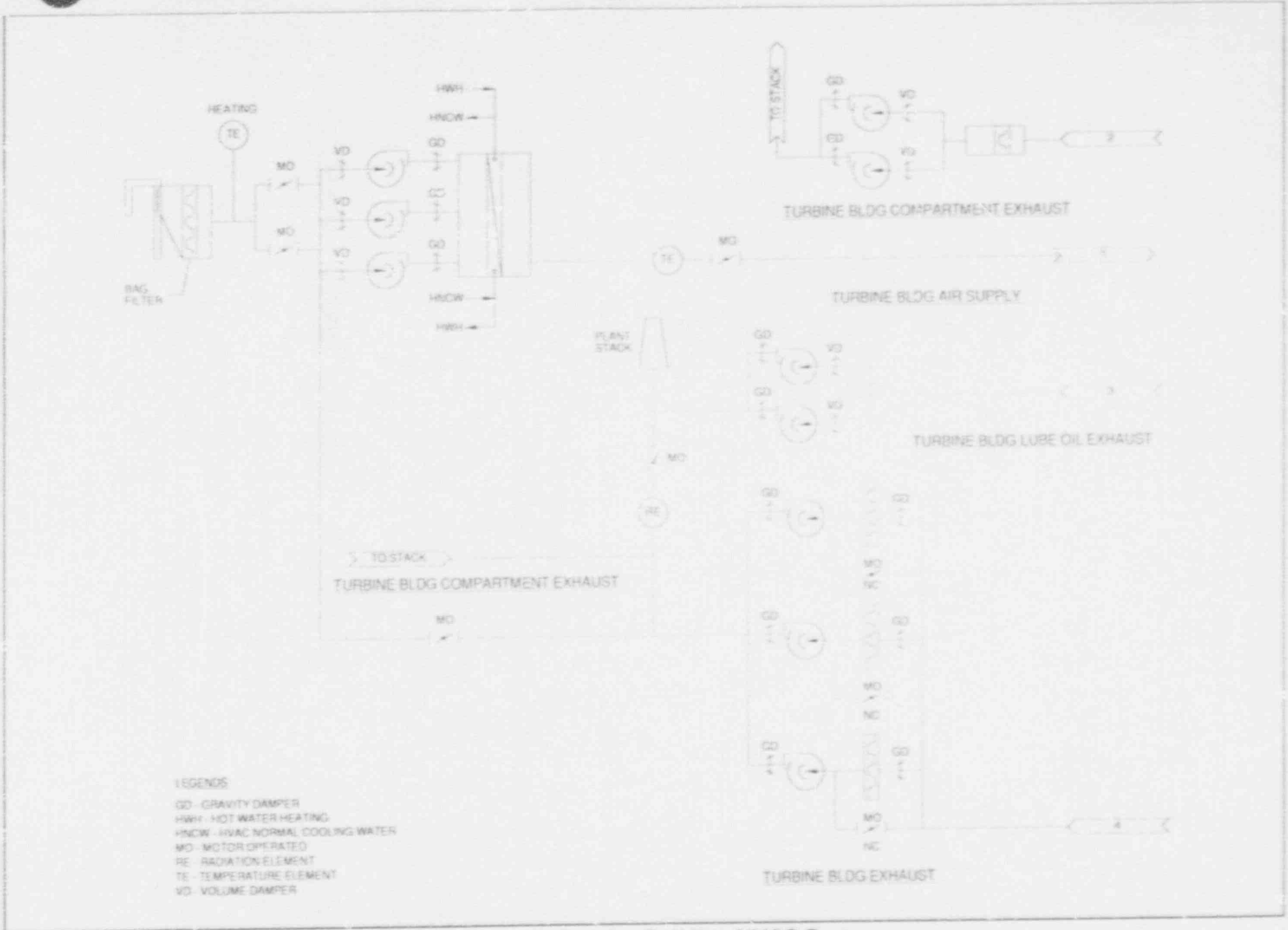


Figure 2.15.5f Turbine Building HVAC System

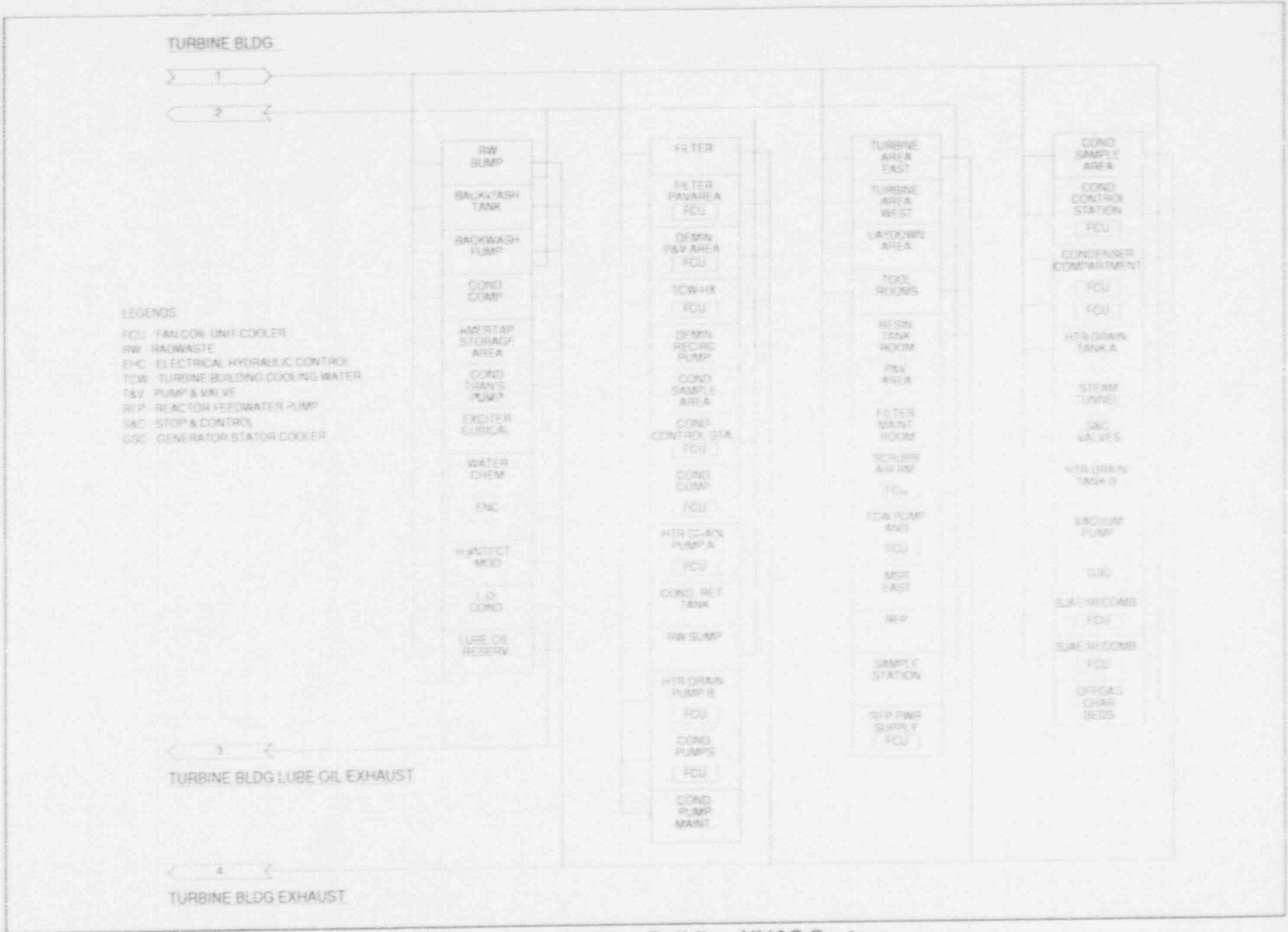


Figure 2.15.5g Turbine Building HVAC System

Figure 2.15.5h Turbine/Electrical Building HVAC System

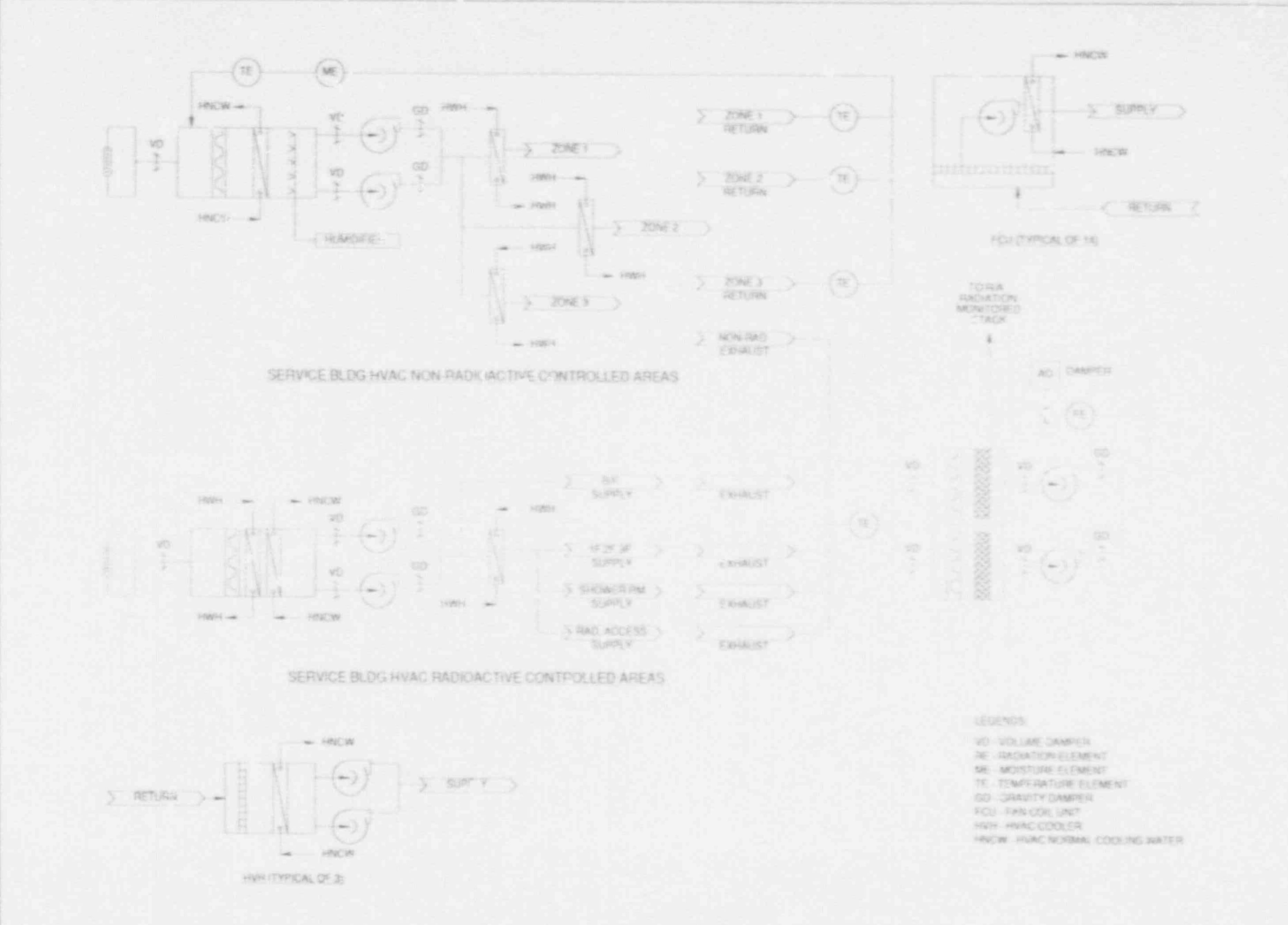


Figure 2.15.5i Service Building HVAC System

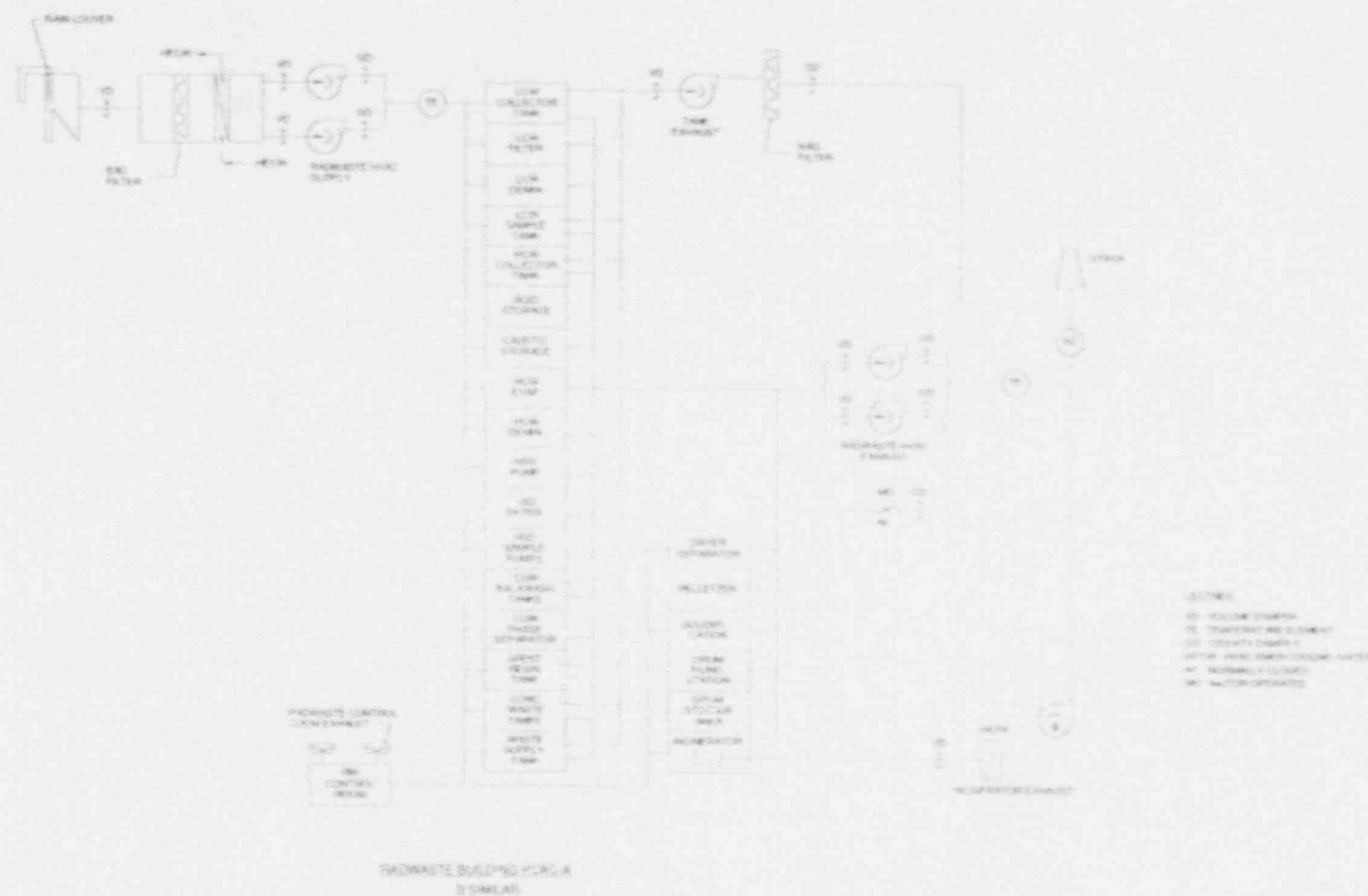


Figure 2.15.5j Radwaste Building HVAC System

2.15.6 Fire Protection System

Design Description

Later. Stage 3 Item.

2.15.7 Floor Leakage Detection System

Design Description

Later. Stage 3 Item.

2.15.8 Vacuum Sweep System

Design Description

Later. Stage 3 Item.

Inspection, Test, Analyses and Acceptance Criteria

No Tier 1 ITAAC are proposed for this system.

2.15.9 Decontamination System

Design Description

Later. Stage 3 Item.

2.15.10 Reactor Building

Design Description

[Later]

2.15.11 Turbine Building

Design Description

Later. Stage 3 Item.

2.15.12 Control Building

Design Description

The control building (CB) is the building that houses the main control room, control equipment and operations personnel for the Reactor and Turbine Islands. The control building is located between the reactor and turbine buildings.

In addition to the control room and operations personnel, this building houses the essential electrical, control and instrumentation equipment, essential switch gear, essential battery rooms, the CB heating and air conditioning (HVAC) equipment, reactor building component cooling water pumps and heat-exchangers, and the steam tunnel.

The general building arrangement including watertight doors and sills for doorways where needed for flood control is found in Figures 2.15.12a through 2.15.12g.

The CB is a Seismic Category I structure designed to provide missile and tornado protection.

The CB is constructed of reinforced concrete with steel truss roof. The CB has two stories above the grade level and four stories below. The building shape is rectangle. Major nominal dimensions are as follows:

Overall height above top of basemat	30.5 m
Overall planar dimensions (outside)	
0 deg-180 deg direction	24.0 m
90 deg-270 deg direction	56.0 m
Thickness of Outer Wall	
from -8.2m TMSL to 17.15m TMSL	1.0m
from 17.15m TMSL to 22.2 m TMSL	0.6m
Thickness of Steam Tunnel	
Walls, Floors, and Ceiling	1.6m
Thickness of Walls supporting Steam Tunnel	1.6m

The CB is a shear wall structure designed to accommodate all specified seismic loads with its perimeter walls. Therefore, frame members such as beams or columns are designed to accommodate deformations of the walls in case of earthquake condition. Column sized and floor slab thicknesses are also provided in the general building arrangement figures. With major dimensions defined as listed above for specified reinforced concrete materials and design procedures, the dynamic characteristic of the CB structure is defined. Seismic adequacy of the detailed site-specific control building design will be evaluated using the dimensional characteristics noted above and approved analytical procedures and methodology for dynamic analysis of structures. This work will be in compliance with the ACI and AISC codes governing design of reinforced concrete structures for nuclear power plants. Detailed analyses of the site specific control building design will utilize appropriate site data for seismic events, floods, tornados, winds and other loading conditions.

To protect against external flood damage, the following design features are provided:

a. wall thickness below flood level greater than 0.6m.

b. water stops provided in all construction joints below grade.

c. watertight doors and piping penetrations installed below flood level.

d. waterproof coating on exterior walls.

e. foundations and walls of structures below grade are designed with water stops at expansion and construction joints.

f. roofs are designed to prevent pooling of large amounts of water.

To protect against internal flood damage, the following design features are provided:

a. elevation differences and divisional separations from remainder of the CB.

b. drainage system to divert water to assigned floor and location.

c. sills for doorways as needed to provide flood control.

d. watertight doors installed below internal flood level.

e. wall thickness below internal flood level greater than 0.6m.

Inside the steam tunnel is the mainsteam piping, the mainsteam drain line, and the feedwater piping. The steam tunnel has no penetrations from the steam tunnel into the control building. Any high energy line breaks inside the steam tunnel will vent out to the turbine building. All standing water will collect in the large volumes in the lower portions of the steam tunnel at the reactor building or turbine building ends.

On Floor B1F, there are fire hose stands and reactor cooling water (RCW) piping. It is designed that any rupture of the fire hose stand will leak onto the floor and drain to the -8200 level by floor drains. Sills will be provided at doorways to prevent the entry of standing water into the control room complex. The RCW piping runs vertically in a concrete pipe chase. No flooding outside this pipe chase is possible.

On the floor where computer room located, there are fire hose stands, RCW piping, and other piping systems. A limited amount of standing water is expected upon a rupture of any of these systems. Sills will be provided at doorways to prevent water from crossing divisional boundaries. Similar arrangements and designs are also provided for other floors for floods protection.

During normal operation, the concrete surrounding the steamline tunnel provides shielding so that operator doses are below the value associated with uncontrolled, unlimited access. The outer walls of the control building are designed to attenuate radiation from radioactive materials contained within the reactor building and from possible airborne radiation surrounding the control building following a LOCA. The walls provide shielding to limit the direct-shine exposure of control room personnel following a LOCA. Shielding for the outdoor air cleanup filters also is provided to allow temporary access to the mechanical equipment area of the control building following a LOCA, should it be required.

The control building is not a vented structure. The exposed exterior roofs and walls of the structure are designed for the required pressure drop. Tornado dampers are provided on all air intake and exhaust openings. These dampers are designed to withstand the specified negative pressure.

Inspection, Test, Analyses and Acceptance Criteria

Table 2.15.12 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the control building.

Table 2.15.12: CONTROL BUILDING

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Control building general arrangement is shown in Figures 2.15.12a through 2.15.12g.	1. Plant walk through to check and verify requirements are met.	1. Per Figure 2.15.12a through 2.15.12 g.
2. Design features are provided to protect against design basis internal and external floods.	2. Review construction records and perform visual inspections of the flood control features.	2. For external flooding: a. Exterior wall thickness below flood level greater than 0.6m. b. Water stop c. Watertight door and piping penetrations below flood level d. Water proof coating on exterior walls e. Foundations and walls of structures below grade are designed with water stops at expansion and construction joints f. Roofs are designed to prevent pooling of large amounts of water. For internal flooding: a. Elevation differences and divisional separation of the mechanical functions from the remainder of the CB b. Drainage system to divert water to assigned floor and location c. Sills for doorways as needed to provide flood protection d. Watertight doors installed below internal flood level e. Wall thickness below internal flood level greater than 0.6m. f. Steam tunnel has no penetrations from the steam tunnel into the control building. Any high energy line or feedwater piping breaks inside the steam tunnel will vent out to the Turbine Building.

Table 2.15.12: CONTROL BUILDING (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The control building is designed to have adequate radiation shielding to protect operating personnel during operation and following a LOCA.	3. Performed dimensional inspections of the Control Building walls, ceiling, floors, and other structural features.	3. The concrete thickness for the steam tunnel wall, floor and ceiling shall be greater than 1.6m. The steam tunnel interface structure and control building wall below the steam tunnel should have a combined thickness of 1.6m.
4. The CB is designed to protect against design basis tornado and tornado missiles.	4. Review construction records and perform visual inspections of the tornado protection features.	4. For tornado a. Roof and walls above grade designed greater than 0.5m b. HVAC dampers designed for differential pressure > 1.46 psi. c. HVAC dampers have tornado missile barriers.
5. The CB is designed as a Seismic Category I structure and has major dimensions defined in the certified design.	5. Plant walk through to check and verify CB building major dimensions including column sizes and floor slab thickness. Review final design record for material properties site input data and analytical procedures and methodology for seismic analysis. Visual inspections of structures and review of as-built documentation will be conducted to asses compliance with the certified design commitments.	5. Structures have dimensions compatible with data in the certified design. (Figures 2.15.12a through 2.15.12g)
6. The detail structural design will be based on ACI and AISC codes and will use site data for seismic events, floods, tornadoes winds and other loading conditions.	6. The control building design documentation will be reviewed.	6. Confirmation that the as-built design is in compliance with ACI and AISC requirements and is based on appropriate site design data.

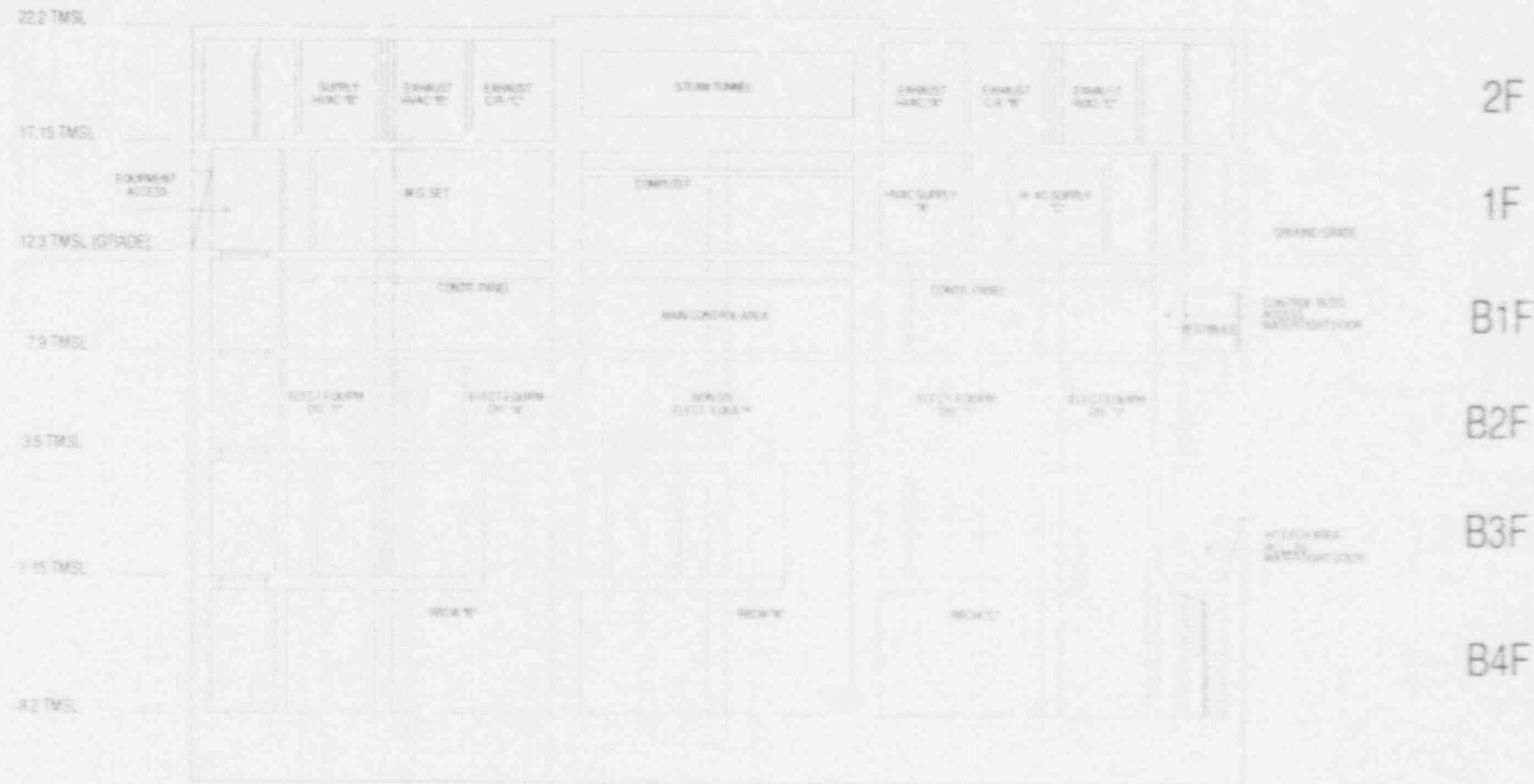
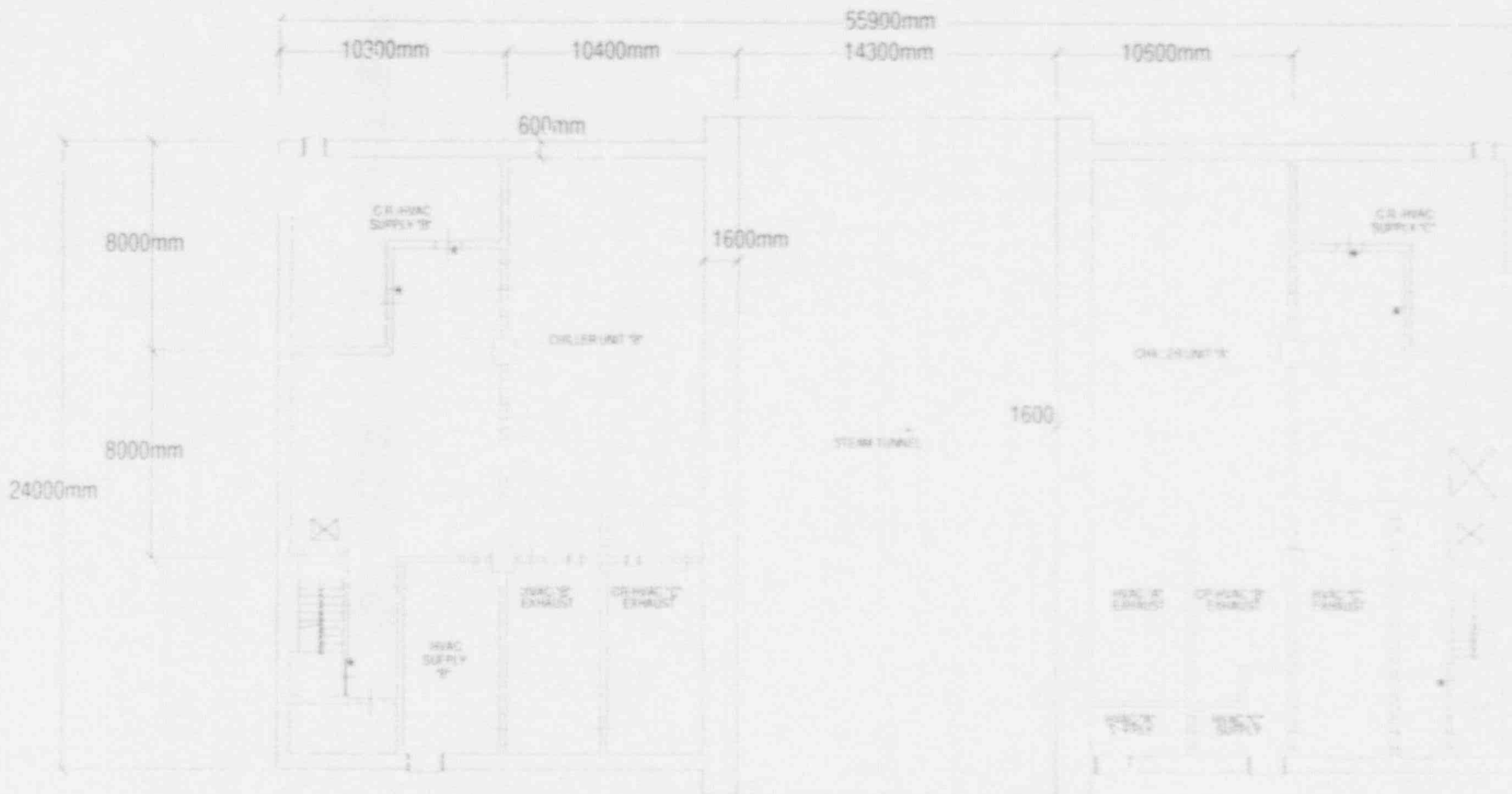


Figure 2.15.12a CONTROL BUILDING ELEVATION (90° - 270°)

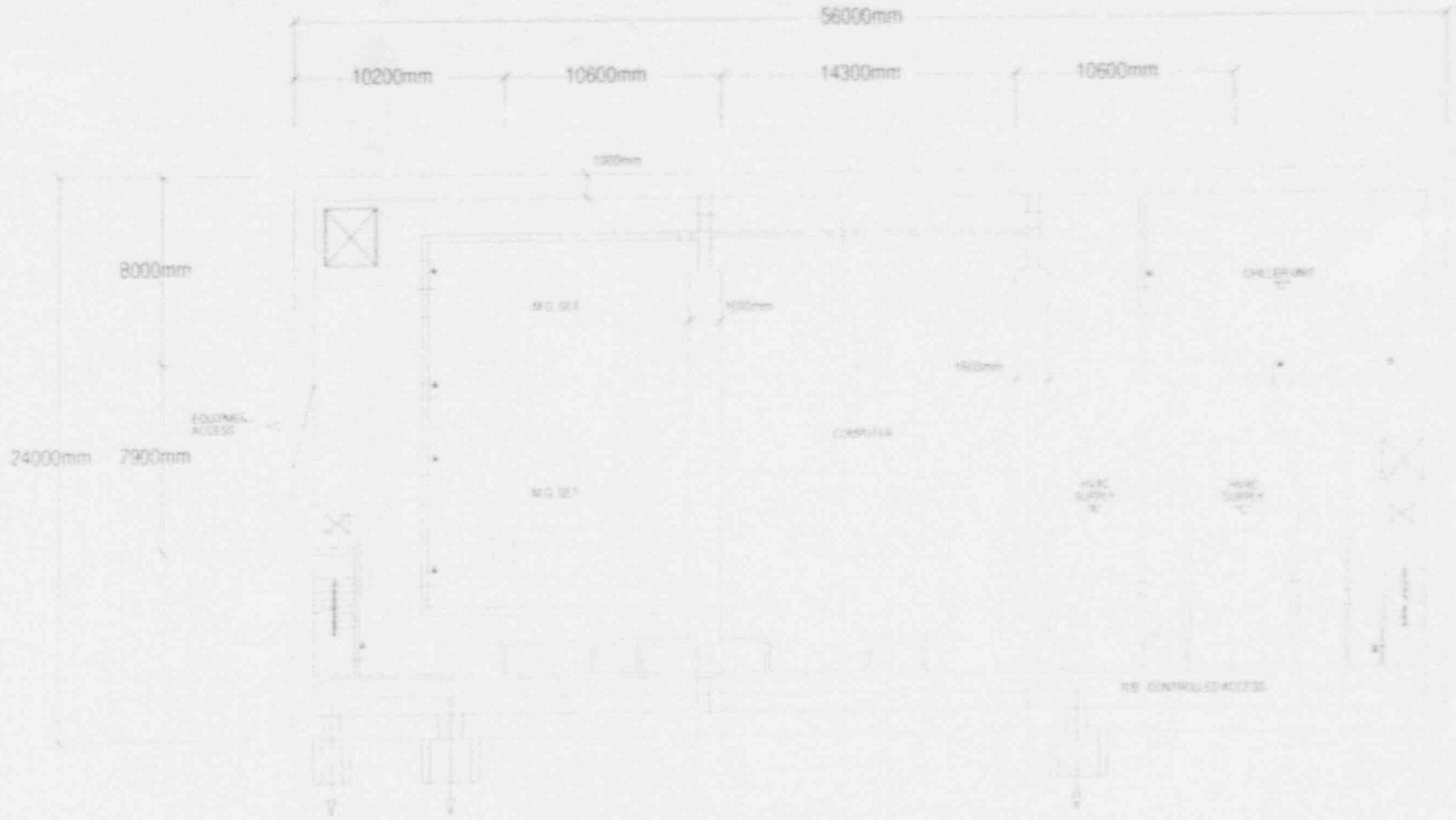
ELEVATION 17150mm TMSL



Notes: Doors marked with a * have raised sills
Floor slab is 400mm thick
Columns are 1000x1000mm typical

Figure 2.15.12b CONTROL BUILDING - FLOOR 2F

ELEVATION 12300mm TMSL



Notes: Doors marked with a * have raised sills
Columns are 1000x1000mm typical
Floor slab is 400mm thick

Figure 2.15.12c CONTROL BUIDING FLOOR 1F - GROUND GRADE

ELEVATION 7900mm TMSL

Notes: Floor slab is 400mm thick
Columns are 1000x1000mm typical

Figure 2.15.12d CONTROL BUILDING FLOOR B1F

ELEVATION 3500mm TMSL

Notes: Doors marked with a * have raised sills
Floor slab is 400mm thick
Columns are 1000x1000mm typical

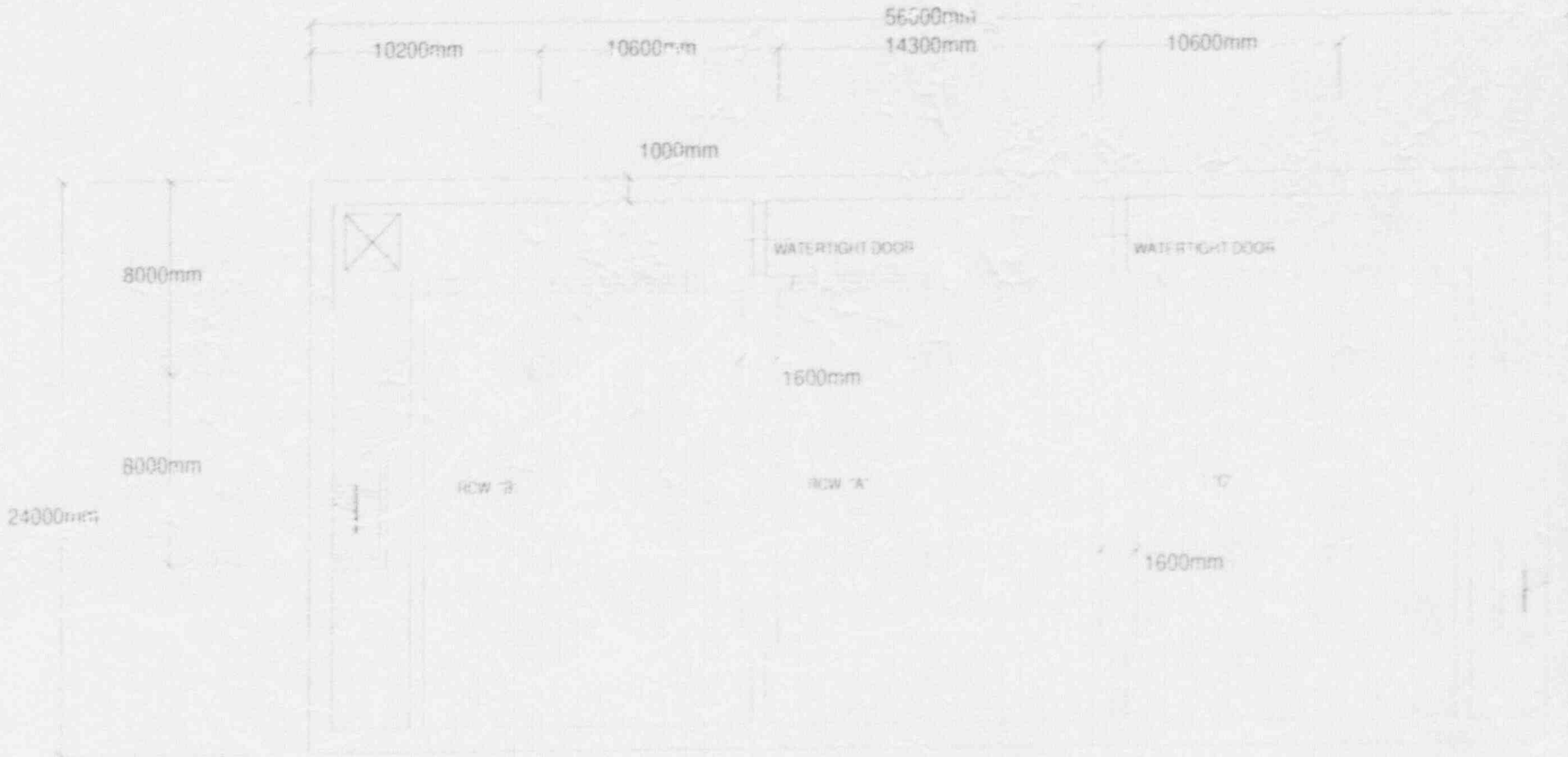
Figure 2.15.12e CONTROL BUILDING FLOOR B2F

ELEVATION -2150mm TMSL

Notes: Columns are 1000x1000mm typical
Floor slab is 400mm thick

Figure 2.15.12f CONTROL BUILDING FLOCR B3F

ELEVATION -8200mm TMSL



Notes: Columns are 1000x1000mm typical
Basemat is 2600mm thick (min)

Figure 2.15.12g CONTROL BUILDING FLOOR B4F

2.15.13 Radwaste Building

Design Description

Later. Stage 5 Item.

2.15.14 Service Building

Design Description

Later. Stage 3 Item.

2.16 Yard Structures and Equipment

2.16.1 Stack

Design Description

Later. Stage 3 Item.

2.16.2 Oil Storage and Transfer Systems

Design Description

Later. Stage 3 Item.

2.16.3 Site Security

Design Description

Later. Stage 3 Item.

3.0 Non-System Based Tier 1 Material

In addition to the system-based Tier 1 material presented in Section 2, separate Tier 1 entries are proposed for subjects not conveniently covered by the system-by-system approach. In general, these non-system Tier 1 entries address subjects that are more generic in nature. That is, they cover technical issues that are relevant to many of the systems addressed in Section 2. An example of a generic technical issue is qualification of safety-related equipment for the environmental conditions that will occur during normal operation and accident conditions. This issue of equipment qualification (EQ) is relevant to many ABWR Systems having a safety function; treatment in a single generic EQ Tier 1 entry avoids repetitious EQ-related entries for multiple systems. Table 3.0 provides a matrix defining the relationship between generic material and the ABWR Systems covered in Section 2.

For selected areas of the ABWR design, there are (for legitimate reasons) insufficient design details available at this time upon which the NRC staff can base a safety finding. Under these circumstances, it has been agreed that the Tier 1 entries for these technical subjects can include some items addressing the detailed design process. For issues in this category, some of the proposed inspections, tests, analyses and acceptance criteria (ITAAC) will be aimed at verifying implementation of the design process, i.e., will utilize design acceptance criteria (DAC). The remaining ITAAC entries will still focus on confirming the as-built facility is in compliance with the certified design. Reference 1 contains a more detailed discussion of the DAC concept and the criteria which will be used to govern application of the concept. ABWR technical issues which will have elements of a design acceptance approach in their Tier 1 treatment are:

(1) Instrumentation and control design issues including Human Factors Engineering (HFE)

(2) Radiation protection

(3) Piping

In summary, this section provides Tier 1 material that is generic in nature and is more efficiently handled outside the system-by-system approach being used for the bulk of the ABWR Tier 1 material. Furthermore, to the extent that it is being used for the ABWR design certification, this section also includes material that will achieve design verification utilizing the DAC process.

Table 3.0: Generic ITAAC Application

[LATER]

3.1 Equipment Qualification (EQ)

Design Description

Mechanical and electrical equipment that is important to safety is qualified for the full range of environmental conditions that will exist up to and including the time the equipment has finished performing its safety-related function. Equipment used for the certified design will be in full compliance with the regulatory requirements and industrial standards governing qualification methodology to be used for safety equipment in nuclear power plants.

The scope of this generic material is to address the complete spectrum of environmental conditions that may occur in the facility. Not all safety equipment will experience all of these conditions; the intent is that qualification be performed by selecting the conditions applicable to each particular piece of equipment and performing the necessary qualification using acceptable methods.

Inspection, Test, Analyses and Acceptance Criteria

Table 3.1 provides a definition of the inspections, tests, and/or analyses (together with associated acceptance criteria) which will be performed to demonstrate compliance with the equipment qualification commitments for the certified design.

Table 3.1: Equipment Qualification

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Mechanical and electrical equipment important to safety will be qualified for the environmental conditions that exist up to and including the time the equipment has finished performing its safety-related function. Conditions that exist during normal, abnormal and design basis accident events will be considered in terms of their cumulative effect on equipment performance. These conditions will be considered for the time period up to the end of components refurbishment interval or end of equipment life. These conditions include number and/or duration of equipment functional and test cycles/events; process fluid conditions (where applicable); the voltage, frequency, load, and other electrical characteristics of the equipment; the dynamic loads associated with seismic events, containment response to hydrodynamic conditions, system transients, and other vibration inducing events, and the pressure, temperature, humidity, chemical and radiation environments, aging and submergence (if any) that can affect or degrade equipment performance. Other environmental conditions that will be considered are those included within environmental compatibility (EMC). These conditions are electromagnetic interference (EMI), electrostatic discharge (ESD), radio-frequency interference (RFI) and surge withstand capability (SWC).	1. Documentation relating to EQ issues will be completed for all equipment items important to safety and reviewed on a selected basis for compliance with requirements. This documentation will be in the form of the equipment qualification list and the device specific qualification files. The review will include review of specified environmental conditions, qualification methods (e.g., analyses or testing), and documentation of qualification results.	1 It will be confirmed that a comprehensive list of equipment important to safety has been prepared. The following information for this equipment shall be provided in a qualification file and subject to audit: a. The performance specifications under conditions existing during and following design basis accidents. For electrical items, this will include the voltage, frequency, load and other electrical characteristics for which the performance specified above can be ensured. b. The environmental conditions, including temperature, pressure, humidity, radiation, electromagnetic compatibility, chemicals and submergence at the location where the equipment must perform as specified above. This will include environmental conditions defined in 10 CFR 50.49, for electrical items and shall include consideration of synergistic effects and margins for unquantified uncertainty. c. The testing method used to qualify the equipment. Each item of equipment important to safety must be qualified by one (or a combination) of the following methods: 1) Testing an identical item of equipment under identical conditions or under similar conditions with a

Table 3.1: Equipment Qualification (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
		1.c (cont.) supporting analysis to show that the equipment to be qualified is acceptable 2). Testing a similar item of equipment with a supporting analysis to show that the equipment to be qualified is acceptable. 3) Experience with identical or similar equipment under similar conditions with a supporting analysis to show that the equipment to be qualified is acceptable. 4) Analysis in combination with partial type test data that supports the analytical assumptions and conclusions. e. The results of the qualification have been documented to permit verification that the item of equipment important to safety: 1) Is qualified for its application; and 2) Meets its specified performance requirements when it is subjected to the conditions predicted to be present when it must perform its safety function up to the end of its qualified life.

Table 3.1: Equipment Qualification (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. The installed condition of mechanical and electrical equipment important to safety will be compatible with conditions for which it was qualified.	2. An inspection will be performed of installed safety equipment to assess compatibility with the methods and assumptions used to qualify the equipment.	2. The installed configuration is bounded by the test configuration and conditions. No physical interferences exist with adjacent plant feature which have not been addressed by the qualification process.

3.2 Instrument Setpoint Methodology

Design Description

A disciplined approach is used when establishing allowable values and nominal trip setpoints for instruments having safety-related trip functions. The following is a generic treatment of the processes which will be used to verify that this is accomplished.

The determination of nominal trip setpoints (NTSP)* must include a consideration of many factors. In the case of setpoints which are directly associated with an abnormal plant transient or accident analyzed in the safety analysis, a design basis analytical limit is established as part of the safety analysis. The design basis analytical limit is the value of the sensed process variable prior to or at the point where a desired action is to be initiated. The design basis analytical limit is set so that appropriate licensing safety limits (LSL) are not exceeded, as confirmed by plant design basis performance analysis. An allowable value** is determined from the analytical limit by providing allowances for the specified or expected calibration capability and accuracy of the instrumentation and the measurement errors. The nominal trip setpoint value is calculated from the analytical limit by taking into account instrument drift in addition to the instrument accuracy, calibration and the measurement errors.

Not all parameters have an associated design basis analytical limit (e.g., main steam line radiation monitoring). An allowable value may be defined directly based on plant licensing requirements, previous operating experience or other appropriate criteria. The nominal trip setpoint is then calculated from this allowable value, allowing for instrument drift. Where appropriate, a nominal trip setpoint may be determined directly based on operating experience or engineering judgment.

Procedures will be used that provide a consistent and repeatable method for establishing instrument nominal trip setpoint and allowable value. Because of the general characteristics of the instrumentation and processes involved, three different methods are used. These are:

(1) Computational

(2) Engineering Judgment

(3) Historical Data

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* The limiting value of the sensed process variable at which a trip action will be set to operate at the time of calibration.

** The limiting value of the sensed process variable at which the trip setpoint may be found during instrument surveillance.

Inspection, Test, Analyses and Acceptance Criteria

Table 3.2 provides a definition of the inspections, tests, and/or analyses, together with associated acceptance criteria which will be undertaken for the instrumentation to which this methodology must be applied.

Table 3.2: Instrument Setpoint Methodology

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Instrumentation having safety-related trip functions will have nominal trip setpoints (NTSP) and allowable values (AV) established by approved methodology.	1. A review will be conducted of the NTSP and AV specified for the installed instrumentation and associated equipment. This review will include the methods used to develop the NTSP and AV.	1. NTSP and AV have been established using acceptable methodologies and are compatible with the plant-specific safety analysis. Acceptable methodologies are: a. Computations b. Engineering Judgment c. Historical Data

3.3 Piping Design

Design Description

Piping associated with hydraulic and pneumatic systems is categorized as either nuclear safety related or non-safety related. Piping systems that must remain functional following a safe shutdown earthquake (SSE) are designated as Seismic Category I. Depending on the intended service conditions and system design functions, piping is further classified as ASME Code Class 1, 2, 3, or non-Code Class. NRC regulations govern piping designations and piping in the certified design may further be classified as Quality Group A, B, C, or D.

All ABWR piping components will be designed, fabricated, installed and examined to confirm full compliance with all applicable regulatory requirements and industrial codes and standards.

Inspection, Test, Analyses and Acceptance Criteria

Table 3.3 provides a definition of the inspections, tests and analyses, together with the acceptance criteria, which will be performed for ABWR piping in order to demonstrate compliance with the certified design commitments. The information in Table 3.3 is intended to be generic and to apply to all safety related piping governed by Quality Group A, B, or C and ASME Code Class 1, 2, or 3 designations. Not all of the entries in Table 3.3 apply to all piping classifications. Appropriate applicability, based on designation, will be incorporated at the time the inspections, tests, and analyses are implemented.

Table 3.3: Generic Piping Design

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The piping shall be designed for a fatigue life of 60 years. This design shall account for the cyclic stresses resulting from the expected pressure/temperature cycles and loads in the required combinations. For ASME Class 1 piping systems, a fatigue analysis will be performed in accordance with ASME Code, Section III requirements. For ASME Class 2 & 3 piping, ASME Code, Section III rules will be followed using a stress range reduction factor of 1.0, based on fewer than 7000 cycles. These fatigue analyses results shall be documented in a certified stress report.	1. An inspection of the certified stress report will be conducted to assure that the fatigue evaluation is consistent with the ASME Code, Section III requirements and with the 60 year design life.	1. ASME Code, Section III requirements shall be satisfied, including the cumulative fatigue usage factor, which shall be less than or equal to 1.0. The applied subsections of ASME Code shall be contained in the approved editions documented in 10CFR50.55a.
2. Pipe mounted equipment allowable loads and attachment interface (for example, the interface between a snubber and its embedment plate) allowable loads, accelerations and stresses shall be satisfied. The loads, accelerations, and stresses that the piping system imposes on its pipe mounted equipment and on its interfaces shall be determined by analyses of the piping systems and compared to the allowable values. The results of these analyses shall be documented as interface requirements to assure design compatibility with the equipment and interfaces.	2. Inspections of stress reports, design specifications, and design drawings will be conducted to confirm that the as-designed interface loads, accelerations and stresses are consistent with the interfacing vendor's / constructor's specified hardware allowables.	2. The allowables for pipe mounted equipment and interfacing equipment shall be met. The allowables at attachment interfaces shall be met.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. Analytical methods for the dynamic and static analysis of piping systems and the corresponding component stress analysis shall be specified in a certified design specification for each piping system. The dynamic analysis of piping systems shall use a suitable dynamic method, such as time history or response spectrum method, or an equivalent static load method. Linear-elastic analysis or nonlinear-plastic analysis shall be used. For the applied method, the key analysis parameters shall be addressed. For example, for the response spectrum method, the following shall be defined: a. Combination of group responses when multiple response spectra are used. b. Combination of modal responses. c. Combination of response spectra analysis results with differential building movement analysis results. d. Damping coefficients. e. Cut-off frequency. f. High frequency modes.	3. Inspection (review) of the certified design specification and the certified stress report will be conducted to confirm that the piping was designed and analyzed in compliance with all regulatory (and other applicable) requirements.	3. Methods shall be in compliance with all applicable regulatory requirements.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Essential piping systems, including required pipe whip restraints, shall be designed to protect against the dynamic effects associated with the postulated rupture of high energy and moderate energy fluid systems. A pipe break analysis report shall be generated to confirm that the piping system is acceptable for all postulated breaks. Piping systems that are qualified for the optional leak-before-break design approach may exclude design against the dynamic effects from the postulation of breaks in high energy piping.	4. Inspections of ASME Code III required documents and the pipe break analysis report, or leak-before-break justification report, will be conducted to confirm that the piping system was designed/analyzed in compliance with requirements that assure postulated pipe breaks will not unduly impact the safety of the plant.	4. The essential functions of structures, systems, and components shall not be precluded by the postulated pipe breaks. For those components required for safe shutdown, limits to meet the ASME Code requirements for faulted conditions and limits to ensure required operability shall be met.
5. All ASME Code Safety Class 1, 2, and 3 piping systems which are essential for safe shutdown, shall be designed to assure that they will maintain sufficient dimensional stability to perform their required function following application of all loads to which they will be subjected during postulated events requiring their safety function.	5. An inspection of the certified stress report will be conducted to assure that none of the stresses or deflections of the piping system exceed values which could lead to large reductions in the cross-sectional flow area.	5. ASME Code, Section III limits that protect the piping and pipe supports against primary stress failures will be compared with allowable values that preclude impairment of functional capability. In no case will stresses exceed values allowed for Service Level D in ASME Code, Section III.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
6. When performing static and dynamic analysis of piping systems, the mathematical model of the piping system shall be constructed to realistically reflect the dynamic and static characteristics of the piping system. The following parameters shall be addressed: a. The model shall adequately account for modes up to the analysis cut-off frequency. b. The appropriate stiffness and mass of piping, pipe supports, and pipe mounted equipment shall be included in the piping system model. c. The appropriate stiffnesses for anchors and intermediate supports shall be included in the piping system model.	6. An inspection (verification) of the mathematical model will be performed to confirm that the boundary conditions and dynamic and static characteristics have been adequately technically addressed.	6. Analytical modeling practices shall be in compliance with all applicable regulatory requirements. The methods used for modeling will be applied to NRC benchmark problems and the results of the corresponding analyses shall be compared to the NRC benchmark and consistency shall be confirmed.
Construction items:		
7. The piping, its appurtenances, and its supports, shall satisfy the ASME Class, Seismic Category, and Quality Group requirements commensurate with its classification.	7. Inspections will be conducted of ASME Code required documents and the Code stamp on the components.	7. Existence of ASME Code required documents and the Code stamps on the components confirms that the piping and components have been designed, analyzed, fabricated, and examined in accordance with the applicable requirements.
8. For those piping systems using ferritic materials, the ferritic materials shall not be susceptible to brittle fracture under pressure during the expected service conditions. Only intrinsically tough grades of ferritic materials conforming to the ASME Code, Section III SA specifications shall be used.	8. Fracture toughness tests will be performed in accordance with ASME Code, Section III.	8. Records of the fracture toughness tests must confirm that the requirements of ASME Code, Section III are satisfied.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. For those piping systems using austenitic stainless steel materials, the stainless steel piping shall be selected to minimize the possibility of cracking during service. Special chemical, fabrication, handling, welding, and examination requirements that minimize cracking shall be met.	9. Inspections of ASME Code required documents and other pertinent records will be conducted to confirm that manufacture, fabrication, welding, and examination were performed in accordance with the committed requirements.	9. Records of the materials and processes must confirm that the committed requirements to avoid the potential of stainless steel to crack in service are satisfied.
10. For essential systems, the as-built piping system shall be confirmed to be consistent with the as-designed piping system. All deviations shall be shown to not invalidate the design.	10.	10.
	a. Pipe routing will be confirmed by inspecting isometric drawings containing verification stamps from field visual inspections. This documentation will also confirm that no interferences exist.	a. The as-built pipe routing is within the tolerances allowed on the as-designed drawings. The piping system has the minimum specified clearance from neighboring hardware. Deviations shall be addressed in compliance with c below.
	b. The exact location, orientation, and size of snubbers and struts; the location and size of hangers; the location and weight of valves, pumps, and heat exchangers; the location and configuration of anchors; the location of guides and pipe whip restraints; and the specified clearances, will be confirmed by reviewing isometric drawings containing quality control verification stamps, or by taking the as-built measurements.	b. The location, size, orientation of pipe mounted components are within the tolerances allowed on the as-designed drawings. Deviations shall be addressed in compliance with c below.
	c. Deviations from the as-designed condition will be documented and evaluated. If acceptance limits are not satisfied in the reevaluation, a reanalysis of the as-built condition will be performed, the stress report and design drawings will be revised, and the final stress report will be certified.	c. For Safety Class 1, 2, & 3 piping, the required allowables in the applicable subsections of ASME Code, Section III shall be satisfied. The applied subsections of ASME Code, Section III shall be contained in the approved editions documented in 10CFR 50.55a.

Table 3.3: Generic Piping Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
Combination Design and Construction Items:		
11. ASME Code Safety Class 1, 2, and 3 piping shall retain its pressure integrity under all internal pressures that will be expected during its design lifetime. Piping and piping components shall be designed and analyzed to show compliance with the pressure integrity requirements of ASME Code.	11. Inspections of ASME Code required documents will be conducted to confirm that the piping system was designed/ analyzed in compliance with requirements that assure pressure integrity. A hydrostatic test of the Safety Class 1, 2, and 3 piping will be conducted as required by, and in accordance with, the ASME Code.	11. For safety class 1, 2, & 3 piping, the required allowables in the applicable subsections of ASME Code, Section III shall be satisfied. The applied subsections of ASME Code, Section III shall be contained in the approved editions documented in 10CFR 50.55a. The results of the hydrostatic test must conform with the requirements in the ASME Code.
12. Piping shall be designed (and installed) to provide adequate clearance to prevent interference with other piping, structures, and components as the piping moves or deflects due to the thermal, dynamic, and/ or static loads which it experiences in service. Stress analyses shall be performed to calculate piping movements. These calculated movements shall be used to develop and document minimum required clearances.	12. An inspection of the certified stress report will be conducted to assure that the calculated pipe deflection values do not result in the piping exceeding its design allowables for the specified load combinations and that the minimum specified clearances adequately encompass these deflections. A field walkdown will be performed on all essential piping to measure the "As-installed" piping clearances and confirm the actual clearances are within allowable values	12. The design allowables for piping clearance in both the axial and lateral directions shall be met.

3.4 Safety System Logic and Control

Later. Stage 8 Item.

3.5 Software Development

Design Description

The certified design uses microprocessor-based digital equipment to perform selected safety-related functions. Development of the necessary software is dependent upon the as-procured hardware and is thus not part of the certified design. The process to be used for software development and implementation will be in full compliance with the regulatory requirements and industrial standards governing these activities. These requirements will apply to: a) each ABWR safety system that uses the safety-related software functions of the Safety System Logic and Cont.: l (SSLC) equipment and b) other safety-related equipment that contains software to perform safety functions.

Inspection, Test, Analyses and Acceptance Criteria

Table 3.5 together with Appendices A, B, and C provide a definition of the processes that will be used to demonstrate compliance with the requirements governing development and implementation of software for safety-related functions. This material is structured as follows:

Table 3.5:	Generic inspections, tests, analyses, and acceptance criteria (ITAAC) material for the overall software development process. Key elements of this process are a Software Management Plan, Configuration Management Plan, and a Verification and Validation (V&V) Plan.
Appendix A:	Design Acceptance Criteria (DAC) for the Software Management Plan
Appendix B:	Design Acceptance Criteria (DAC) for the Configuration Management Plan
Appendix C:	Design Acceptance Criteria (DAC) for the Verification and Validation (V&V) Plan

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. A plan shall be developed for software used in microprocessor-based equipment that performs safety-related functions. The plan shall describe the organizational and procedural aspects of software development and shall comprise the following elements: - Software Management Plan - Configuration Management Plan - Verification and Validation (V&V) plan	1. Review: - Software Management Plan - Configuration Management Plan - Verification and Validation Plan	1. The overall development plan documents the requirements and methodology for achieving the software attributes of consistency, accuracy, error tolerance and modularity. The plan includes the methodology for assuring the software is both auditable and testable during the design, implementation and integration phases. Each element of the plan contains the following items as a minimum: a. Software Management Plan establishes standards, conventions and design processes for the design, development, and maintenance of safety-related software. The plan meets the design acceptance criteria described in Appendix A. b. Configuration Management Plan establishes a formal set of standards and procedures to provide visible status and control of software documentation. The following basic elements are addressed: 1) Unique identification of each software documentation item 2) Management of software documentation change control 3) Accounting methods to provide visibility and traceability for all changes to baseline product software 4) Verification steps required to assure proper adherence to software design requirements

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
		1. (Continued) The plan meets the design acceptance criteria described in Appendix B. c. Verification and Validation Plan establishes verification reviews and validation testing procedures with the following components: 1) Independent design verification 2) Baseline reviews 3) Testing a) Unstructured testing b) Formal validation testing 4) Firmware issue and validation procedure 5) Procedure for future revisions The plan meets the design acceptance criteria described in Appendix C.
2. The software design documentation shall meet the requirements of each element of the software development plan described in Item 1.	2. Review design documentation: - Hardware/Software System Specification - Software Requirements Specification - Software Design Specification - Hardware Requirements Specification - Hardware Design Specification	2. The documentation complies with the requirements of the software development plan. The design documentation generated by the definition and planning process described in Appendix A allows correlation of the design elements with each specific software requirement as determined by the V&V process described in Appendix C. The computer system hardware documentation identifies the hardware requirements that impact software.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
3. The generation of documentation for: 1) software implementation and 2) the integration of hardware and software into the final product shall follow the process described in the elements of the software development plan.	3. Review the software development plan.	3. The documentation for software implementation and hardware/software integration testing meets the requirements of the software development plan, as shown in Appendices A, B, and C.
4. The assembled, final production computer system shall be exercised through static and dynamic simulations of input signals present during normal operation and design basis event conditions requiring computer system action. The validation test plan shall identify the validation tests for each software-based system component of Safety System Logic and Control (SSLC) . The plan shall also include tests that validate correct operation for each safety system requirement of the systems that interface with SSLC. The requirements are those stated in the System Design Specification of each interfacing safety system.	4. Review formal (verified) validation test report.	4. The test report summarizes the results of the computer system validation testing and shows how the system is in compliance with the requirements. The test report identifies the validation tests for each computer system and safety system requirement. In addition, the required input signals and their values, the anticipated output signals, and the acceptance criteria are stated. The test report identifies the hardware and software used, test equipment and calibrations, simulation models used, test results, and discrepancies and corrective actions. The test plan was developed, the tests executed, and the test results evaluated by individuals who did not participate in the design or implementation phases.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix A: Design Acceptance Criteria for Software Management Plan

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The standards, conventions, and design processes to be followed during the design, development, and maintenance of safety-related software shall be established in the software management plan.	1. A review shall be performed of the contents of the software management plan.	1. A software management plan has been issued.
2. The software management plan shall define and document the following major design phases of the software engineering process: a. Definition and Planning b. Product Performance Definition c. High Level Software Design d. Detailed Design/Code/Module Test e. Integration Test f. Validation and Firmware Issue g. Firmware Release	2. A review shall be performed of the contents of the software management plan.	2. The plan contains a description of each specified phase of the software engineering process. A particular design phase shall be verified with respect to the set of documents produced for that phase. These documents are listed in the design commitments in the following sections. See Appendix C for details of, and acceptance criteria for, the verification and validation process.
3. Definition and Planning Phase. This phase comprises the identification of applicable requirements (contractual or from design specifications) and confirmation of suitability of the software planning documents. The documents required to be baselined at the completion of this design phase are: a. Design Requirements b. Software Configuration Management Plan c. Software Management Plan d. Software Verification and Validation Plan e. Baseline Review Record	3. A review shall be performed of the contents of the software management plan. Definition of baseline: A set of documents, assumptions, and open items that reflect the current state of a design phase and define the design input for the next design phase.	3. The plan states that the committed documents are the baseline of the Definition and Planning Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix A: Design Acceptance Criteria for Software Management Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. <u>Product Performance Definition</u>. Defines the general product design and the split between hardware and software. The documents required to be baselined at the completion of this design phase are: a. Product Schematic b. Product Performance Specification, including Software Requirements c. Product User's Manual d. Communications Protocols e. Baseline Review Record	4. A review shall be performed of the contents of the software management plan.	4. The plan states that the committed documents are the baseline of the Product Performance Definition Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record.
5. <u>High Level Software Design</u>: This phase comprises the design of the software architecture and structure and the determination of general module functions. The documents required to be baselined at the completion of this design phase are: a. Software Design Specification b. Baseline Review Record	5. A review shall be performed of the contents of the software management plan.	5. The plan states that the committed documents are the baseline of the High Level Software Design Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record.
6. <u>Detailed Design/Code/Module Test</u>: This phase comprises detailed design of the software and testing of individual software modules by the designer. The documents required to be baselined at the completion of this design phase are: a. Source Code b. Module Testing Report c. Baseline Review Record	6. A review shall be performed of the contents of the software management plan. <u>Definition of module</u>: Executable computer code that implements a functional requirement or part of a functional requirement; normally the smallest segment of code controlled by the operating system.	6. The plan states that the committed documents are the baseline of the Detailed Design/Code/Module Test Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record. Someone other than the designer reviews the software modules.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix A: Design Acceptance Criteria for Software Management Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. Integration Test: This phase comprises the testing that evaluates performance and adequacy of the software when installed in its destined hardware. The documents required to be baselined at the completion of this design phase are: a. Integration Test Report b. Baseline Review Record	7. A review shall be performed of the contents of the software management plan.	7. The plan states that the committed documents are the baseline of the Integration Test Phase. The plan also states that all required verification reviews are to be completed before the design moves to the next phase, as attested to in the Baseline Review Record.
8. Validation and Firmware Issue: This phase comprises the generation and use of the procedures necessary to perform final testing on a production instrument and to assure the quality of the delivered software. The documents required to be baselined at the completion of this design phase are: a. Validation Test Plan and Procedure b. Validation Test Report c. Firmware Release Description d. Issued Firmware (object code) e. Baseline Review Record	8. A review shall be performed of the contents of the software management plan. Definition of firmware: Object (machine) code contained in non-volatile memory, typically PROM or EPROM.	8. The plan states that the committed documents are the baseline of the Validation and Firmware Issue Phase. The Firmware Release Description contains the following information: a. The means by which the source code was compiled, linked, and located. b. The means by which the master PROMs were generated. c. A record of hardware and software tools used to develop the firmware. The plan also states that all required verification reviews are to be completed before release of the firmware for production, as attested to in the Baseline Review Record.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix B: Design Acceptance Criteria for Configuration Management Plan

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Development of software for the microprocessor-based safety systems shall be controlled according to a configuration management plan	1. A review shall be performed of the contents of the configuration management plan.	1. A configuration management plan has been issued.
2. The configuration management plan will define the purpose and scope of the plan with emphasis on the groups to which it applies and the specific product which is to be developed. The product description shall include both executable and non-executable material.	2. A review shall be performed of the contents of the configuration management plan.	2. The configuration management plan identifies each group which develops and/or maintains software for safety systems. The plan includes both executable and non-executable portions of the design.
3. The configuration plan shall describe the organizational responsibilities. The organizational independence or dependence of the groups responsible for the software configuration shall be specifically described. The plan shall describe a function independent of the software designers that is responsible for verifying that the software is maintained under this plan. The plan shall detail the relationships of the configuration control with the software QA, development, and other groups.	3. A review shall be performed of the contents of the configuration management plan.	3. The configuration plan describes the organizational independence and responsibilities.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix B: Design Acceptance Criteria for Configuration Management Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
4. Applicable procedures, such as standards for the designation of software versions, shall be described in the plan or specifically referenced. All software shall be identified such that the version can be verified directly, either embedded in the software if in a non-programmable/erasable format or permanently inscribed directly on the component.	4. A review shall be performed of the contents of the configuration management plan.	4. The plan describes the procedures for implementation of the plan.
5. The plan shall describe the audits and reviews that are to be performed to verify that the software is being maintained under configuration management. The plan shall describe a procedure for corrective actions if any problems are discovered.	5. A review shall be performed of the contents of the configuration management plan.	5. The plan describes audits and reviews and describes a procedure for corrective actions.
6. The configuration management of tools, techniques, and methodologies shall be specifically delineated. The plan shall address control of development methods to be used (such as formal specification) and tools (such as compilers).	6. A review shall be performed of the contents of the configuration management plan.	6. The plan describes control of tools and methodologies.
7. The plan shall describe the method of records collection and retention.	7. A review shall be performed of the contents of the configuration management plan.	7. The plan describes the record storage plan.
8. The plan shall address control of the final user documentation and the information to be supplied. The method of informing the user of each product of known faults, failures, and changes shall be specifically described.	8. A review shall be performed of the contents of the configuration management plan.	8. The plan identifies the method by which faults, failures, and changes are identified to the affected user.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix B: Design Acceptance Criteria for Configuration Management Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
9. The configuration management plan shall be in place and approved by the implementor prior to the first concept development phases of software development.	9. A review of this plan shall be conducted during a product's Definition and Planning design phase (see Appendix A).	9. The configuration management plan will be approved and in place at the beginning of the project.
10. The configuration management plan shall require that the design documents (such as software requirements specifications) shall provide specific reference to the applicable configuration management plan. The plan shall define procedures for change control, including change request, evaluation, approval, and implementation.	10. A review shall be performed of the contents of the configuration management plan.	10. The plan requires that the design documents reference the configuration management plan.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix C: Design Acceptance Criteria for Verification and Validation Plan

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Verification reviews and validation testing shall be used to assure software quality. The methodology and requirements for these techniques are described in the Verification and Validation (V&V) Plan.	1. A review of this plan shall be conducted during a product's Definition and Planning design phase (see Appendix A).	1. The review assures the suitability of the plan and notes any needed modifications. The V&V plan will be approved and in place at the beginning of the project.
2. The V&V process shall comprise a combination of the following activities: a. Informal reviews b. Independent design verifications c. Baseline reviews d. Layered testing (unstructured testing and validation testing)	2. A review shall be performed of the contents of the V&V plan.	2. The plan contains a description of the committed activities. The activities are defined in the following sections.
3. Informal Reviews: Informal reviews shall be used to resolve problems, evaluate alternate approaches, tentatively confirm adequacy of a solution or processing approach, or other design evolution activity.	3. A review shall be performed of the contents of the V&V plan.	3. The plan describes the uses and limitations of informal reviews and their methodology. This activity does not confirm compliance with any external requirements.
4. Independent Design Verification: The product assurance process shall provide controlled, independent, documented confirmation that the design meets requirements. The process shall address the following aspects of the design as a minimum: a. Quality b. Safety c. Reliability d. Performance	4. A review shall be performed of the contents of the V&V plan.	4. The plan describes the independent design verification process. Confirmation of design adequacy is performed by knowledgeable individuals other than those responsible for the design.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix C: Design Acceptance Criteria for Verification and Validation Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
5. Baseline Reviews: Formal, independent evaluations of the design process, and the effectiveness and completeness of the process to specified points in the design, shall be performed. Baseline reviews are required during the following software development phases: a. Definition and Planning b. Product Performance Definition c. High Level Software Design d. Detailed Design/Code/Module Test e. Integration Test f. Validation and Firmware Issue g. Firmware Release	5. A review shall be performed of the contents of the V&V plan.	5. The plan describes the baseline review process. As a minimum, each review evaluates the following areas: a. Adequacy of documentation b. Adequacy of design process c. Adequacy of test methods d. Adherence to software management plan, configuration management plan and V&V plan Baseline reviews are performed by knowledgeable individuals other than those directly responsible for the design.
6. Unstructured Testing: No formal test plan or procedure shall be required. The following unstructured tests shall be performed during the design process: a. Exploratory testing evaluates implementation ideas of the designer. b. Module testing confirms the performance of individual software modules via emulation of hardware components c. Integration testing is performed on prototype hardware and confirms that all instrument functions, including self-test (if applicable), work properly	6. A review shall be performed of the contents of the V&V plan.	6. The plan describes the testing processes, which are documented as follows: a. Exploratory testing requires no formal certification, but may be documented by design notes. b. Module testing is documented in the Module Test Report. c. Integration test results are documented in the Integration Test Report. Concurrence on test adequacy is achieved during the Integration Test Baseline Review.

Table 3.5: Software for Programmable Digital Computers in Safety-related Applications

Appendix C: Design Acceptance Criteria for Verification and Validation Plan (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
7. Validation Testing: This process confirms that the final version of the software (firmware) loaded in the production (or fully equivalent) hardware performs all required functions. In addition, displays (if any) are confirmed to be consistent with the final version of the User's Manual.	7. A review shall be performed of the contents of the V&V plan.	7. The plan describes the validation testing process. Validation testing is performed as specified in a formal documented procedure which is written by an individual not responsible for software design and is verified against requirements and performance specifications to confirm that all functions are tested. Results of the test are documented, along with a resolution of anomalies, in a Validation Test Report. Validation testing shall be performed by individuals other than the instrument software designers.
8. Firmware Verification and Issue: The final software (firmware) shall be verified prior to issue.	8. A review shall be performed of the contents of the V&V plan.	8. The plan describes the final verification process for firmware. The process includes structured confirmation that the design has been tested or verified by formal review, shows compliance with all requirements, and all testing has been completed and open items resolved.
9. Software Changes: Changes to the software after release shall be handled in accordance with the software management plan and authorized change control provisions.	9. A review shall be performed of the contents of the V&V plan.	9. The plan describes the software change process and required V&V tests. Steps of the V&V process will be repeated as applicable, including repeat of all or part of the Validation Test.

3.6 Human Factors Engineering

Design Description

[Later]

3.7 Radiation Protection

Design Description

The ABWR design provides radiation protection features that will keep exposures for both plant personnel and the general public well below allowable limits. These low exposure conditions are achieved by an integrated approach that recognizes the contribution of both shielding provisions and ventilation system designs that control airborne contaminants. Monitoring of radiation levels is an integral part of the plant radiation protection strategy.

The plant design provides radiation shielding for rooms, corridors and operating areas commensurate with their occupancy requirements and thus maintains radiation exposures to plant personnel as low as reasonably achievable. Maintenance of plant components is achieved without significant radiation exposure from adjacent plant systems or equipment by use of shielded cubicles, labyrinth access and provisions for temporary shielding. Under accident conditions, plant shielding designs permit operators to perform required safety functions in vital areas of the plant. In addition to protection of operating personnel, the plant design provides radiation shielding which maintains radiation exposure to the general public as low as is reasonably achievable.

Plant ventilation systems insure that concentrations of airborne radionuclides are maintained at levels consistent with personnel access requirements. In addition, airborne radioactivity monitoring is provided for those normally occupied areas of the plant in which there exists a significant potential for airborne contamination.

Inspection, Test, Analyses and Acceptance Criteria

Tables 3.7a and 3.7b provide a definition of the inspections, tests, and/or analyses together with associated acceptance criteria which will be undertaken for the ABWR plant shielding, ventilation and airborne monitoring equipment.

Table 3.7a: Plant Shielding Design

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. The plant design shall provide radiation shielding for rooms, corridors and operating areas commensurate with their occupancy requirements to maintain radiation exposures to plant personnel as low as reasonably achievable.	1. An analysis of the expected radiation levels in each plant area will be performed to verify the adequacy of the shielding design. This analysis shall consider the following: a. Confirmatory calculations shall consider all significant radiation sources (greater than 5% contribution) for an area. Radiation source strength in plant systems and components will be determined based upon an assumed source term of 100,000 μCurie/second offgas release rate (after 30 minutes decay), a 200 μCurie/gram steam N-16 source term at the vessel exit nozzle, and a core inventory commensurate with a 4005 MWT equilibrium core at 51.6 kwatt/liter. All source terms shall be adjusted for radiological decay and buildup of activated corrosion and wear products. b. Commonly accepted shielding codes, using nuclear properties derived from well known references (such as Vitamin C and ANSI/ANS-6.4) shall be used to model and evaluate plant radiation environments. 1) For non-complex geometries, point kernal shielding codes (such as QAD or GGG) shall be used. 2) For complex geometries, more sophisticated two or three dimensional transport codes (such as DORT or TORT) shall be used.	1. Maximum expected radiation levels are well within (25% or less) of the radiation zone designation, for each plant area, as indicated in Figures [Later].

Table 3.7a: Plant Shielding Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	1. (Cont.) c. In any calculation, a safety factor shall be applied based upon benchmark comparisons of the code and data collected from known and measured environments.	
2. The plant design shall provide shielded cubicles, labyrinth access, and space for temporary shielding to allow for maintenance of plant components without significant radiation exposure from adjacent plant systems or equipment.	2. Using the methods identified in (1) above, radiation levels present in areas where maintenance is performed shall be evaluated for the contribution from adjacent high radiation areas and equipment.	2. Shielding design (with temporary shielding installed, where appropriate) is such that radiation from adjacent areas shall contribute no more than a small fraction (10% or less) of the radiation field intensity or less than 0.05mrem/hr whichever is larger, in plant areas where maintenance is performed.
3. The plant radiation shielding design shall permit operators to perform required safety functions in vital areas of the plant (including access and egress of these areas) under accident conditions.	3. An analysis of the expected high radiation levels in each area which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident (vital area) shall be performed to verify the adequacy of the plant shielding design. This analysis shall use calculational methods consistent with (1.b) above and a radiation source term (adjusted for radioactive decay) based on the following: a. Liquid containing systems: 100% of the core equilibrium noble gas inventory, 50% of the core equilibrium halogen inventory and 1% of all others are assumed to be mixed in the reactor coolant and recirculation liquids recirculated by the residual heat removal system (RHR), the high	3. Under accident conditions, radiation shielding design allows access, occupancy and egress of vital areas such that personnel radiation exposures do not exceed 5 rem to the whole body, or its equivalent, for the duration of the accident (based on the required frequency of access to each vital area). For areas requiring continuous occupancy (such as the control room), local radiation hot spots shall not exceed 15 mrem/hr (averaged over 30 days).

Table 3.7a: Plant Shielding Design (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
	3. (Cont.) pressure core flooder (HPCF), and the reactor core isolation cooling (RCIC) systems. b. Gas containing systems: 100% of the core equilibrium noble gas inventory and 25% of the core equilibrium halogen activity are assumed to be mixed in the containment atmosphere. For vapor containing systems (such as the main steam lines) these core inventory fractions are assumed to be contained in the reactor coolant vapor space.	
4. The plant design shall provide radiation shielding to maintain radiation exposure to the general public as low as is reasonably achievable.	4. Using the methods identified in (1) above, the radiation dose to the maximally exposed member of the general public from direct and scattered shall be determined.	4. The radiation dose to the maximally exposed member of the public is a small fraction (10% or less) of the dose limit to a member of the public listed in 40CFR190.

Table 3.7b: Ventilation And Airborne Monitoring

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
1. Plant design shall provide adequate containment of airborne radioactive materials and the ventilation system will ensure that concentrations of airborne radionuclides are maintained at levels consistent with personnel access requirements.	1. Expected concentrations of airborne radioactive material shall be calculated by nuclide for normal plant operations, anticipated operational occurrences for each equipment cubicle, corridor, and operating area requiring personnel access. Calculations shall consider: a. Design ventilation flow rates for each area. b. Typical leakage characteristics for equipment located in each area, and c. A radiation source term in each fluid system shall be determined based upon an assumed offgas rate of 100,000 Curie/second (30 minute decay) appropriately adjusted for radiological decay and buildup of activated corrosion and wear products.	1. Calculation of radioactive airborne concentration shall demonstrate that: a. For normally occupied rooms and areas of the plant (i.e. those areas requiring routine access to operate and maintain the plant) equilibrium concentrations of airborne nuclides will be a small fraction (10% or less) of the occupational concentration limits listed in 10 CFR 20 Appendix B. b. For rooms that require infrequent access (such as for non-routine equipment maintenance), the ventilation system shall be capable of reducing radioactive airborne concentrations to (and maintaining them at) the occupational concentration limits listed in 10CFR20 Appendix B during the periods that occupancy is required. c. For rooms that seldom require access (such as tank rooms), plant design shall provide sufficient containment and ventilation to ensure airborne contamination does not spread to other areas.

Table 3.7b: Ventilation And Airborne Monitoring (Continued)

Inspections, Tests, Analyses and Acceptance Criteria

Certified Design Commitment	Inspections, Tests, Analyses	Acceptance Criteria
2. Airborne radioactivity monitoring shall be provided for those normally occupied areas of the plant in which there exists as significant potential for airborne contamination (greater than 0.1 per year)	2. An analysis shall be performed to identify the plant areas that require airborne radioactivity monitoring.	2. Airborne radioactivity monitoring system shall: a. Have the capability of detecting the time integrated change in concentrations of the most limiting particulate and iodine radionuclides in each area equivalent to the occupational concentration limits in 10CFR20, Appendix B for 10hours. b. Provide a calibrated response, representatvie of the concentrations within the area (i.E. air sampling monitors in ventilation exhaust streams shall collect and isokinetic sample). c. Provide local audible alarms (visual alarms in high noise areas) with variable alarm set points, and readout/ annunciation capability in the control room.

Appendix A Legend for Figures Included in Tier 1

For a number of the systems, presented in Section 2, simplified figures have been included to help facilitate the design description. The figures contain information that uses the following conventions:

Line classification:

	Figure Designation
ASME Code Class 1	1
ASME Code Class 2	2
ASME Code Class 3	3
Non ASME code	NC

Classification Boundaries:

The following is a self-explainatory exapmle of how Code Class change are identified on the schematic diagrams.

1 | NC

Instrumentation:

Flow element	FE
Restricting orifice	RO
Temperature element	T
Radiation element	RE
Level detector	L
Pressure element	P
Vibration detector	V
Speed detector	S
Moisture element	ME

Equipment:

Gate valve
Globe valve
Check valve
Valve type not specified
Relief valve
Open cirucit breaker
Closed circuit breaker
Annunciator
(H=high, L=low)

Valves are shown on the figures in their normal postition.

Valve Operators:

Motor	M
Nitrogen	N
Air	A

Appendix B Tier 2 ITAAC Correlation Matrices

In response to NRC requests, GE intends to prepare indexes which will identify the relationship between Tier 2 (the SAR) entries and the Tier 1 ITAAC material. The intent of this index material is to provide a "road map" which will indicate which ITAAC entries are being used to verify key parameters defined in the SAR. For example, it has been agreed there will be a matrix for SAR Chapters 6 and 15 indicating which ITAAC will be used to verify the key safety system performance parameters assumed in the safety analyses described in these chapters. Other subjects that are candidates for such treatment are plant ATWS response and severe accident mitigation features.

It has yet to be decided how much of the Tier 2 SAR material is to be included in this road map effort and how the information is to be documented. Options under consideration include:

a. Keeping the indexes as an informal guide to assist NRC Staff in their review of the ITAAC development effort and ultimately in their development of the Tier 1 material required by the Rule.

b. Formally integrating the indexes into the SAR.

It is clear that this material is not intended to become part of Tier 1 since this would necessarily involve Tier 1 references to SAR (Tier 2) sections and thus undesirable elevation of Tier 2 material to Tier 1 status.

Appendix B1 presents the proposed index for the Chapter 6 and 15 safety analyses discussed above. Appendix B2 contains a preliminary assessment of the index that could be prepared for the PRA/severe-accident-related ABWR design features.

Appendix B1 ABWR Design Certification ITAAC Preparation For Safety Analysis Verification

Background

During recent GE/NRC meetings on ITAAC, the concept of safety analysis verification was discussed. The approach would be to use ITAAC entries as a mechanism for confirming that the as-built plant has attributes compatible with values used in important SSAR safety analyses. As an example, the drywell-to-wetwell venting area is an important input to the containment LOCA analyses. An entry in the set of containment system ITAAC would call for field confirmation that sufficient vent area had, in fact, been provided.

As a result of these discussions, GE agreed to identify which SSAR safety analysis assumptions should be selected for ITAAC treatment and to prepare an index indicating which system, generic or DAC, ITAAC should be used to accomplish verification of each individual safety analysis assumption. The purpose of this Appendix is to summarize the GE proposals on this subject.

Discussion

The GE ABWR SSAR contains a variety of plant safety evaluations covering the full spectrum of transient events, design basis accidents and conditions beyond the design bases (e.g., ATWS and severe accidents). The following table summarizes the most important SSAR safety analyses:

SSAR Section	Safety Analyses
Chapter 15	Plant transient analyses
Section 6.2.1	Containment LOCA performance
Section 6.3.1	Reactor core LOCA performance

The SSAR contains other analysis results in Chapter 6 and elsewhere; however, these analyses are viewed (by GE) as being of lesser importance than the major items identified above and are not currently being included in the proposed ITAAC-based safety analysis verification effort.

The SSAR contains extensive information on the input values of parameters used in the plant safety analyses. Only the most significant parameters will be subject to verification through ITAAC entries. Parameter selection will be made using criteria which reflect the tiered approach to design certification and the Tier 1 status of ITAAC. Table B1a summarizes the selection criteria.

Safety Analysis Verification

The safety analysis input parameters that will be verified through the ITAAC process.

Chapter 15, Transient Analysis
Section 6.2.1, Containment LOCA Performance
Section 6.3.1, Reactor Core LOCA Performance

Table B1b summarizes the SSAR safety analysis assumptions which will be verified by ITAAC and identifies the proposed set of system ITAAC which will include the entry for a particular assumption.

Table B1a:
Criteria For Selecting Safety Analysis Parameters To Be Confirmed By Itaac Entries

A parameter will be selected for ITAAC treatment if it has the following characteristics.

CHARACTERISTIC	BASES
The parameter has a primary influence on the safety analysis results such that small variations could possibly result in changes to analysis results of some safety significance.	Self-evident compatibility with the tiered approach to design certification. Example: Primary containment post-LOCA leakage rate of 0.5% per day.
The parameter is a measurable characteristic of the plant which can be verified prior to fuel loading.	As defined in the Part 52 regulations, the ITAAC process must be completed prior to fuel load. Example: Area of steam-venting flow path between drywell and wetwell.
The parameter is a plant design characteristic and not an operating condition.	By definition, the ITAAC process does not encompass plant operating conditions. (These items are covered by Technical Specifications.) Example: The assumed pre-LOCA reactor pressure conditions <u>would not</u> be a candidate for ITAAC treatment.

Intent

The following points summarize GE's understanding of the intent of the proposed safety analysis verification effort.

a. The index of SSAR safety analysis assumptions and the list of ITAAC which will verify each particular assumption will be retained in Tier 2. It will serve as a "road map" for SSAR review to clarify the linkage to Tier 1 ITAAC. The latter will not include a comparable reference back to the Tier 2 SSAR material. This is because any such reference would elevate the SSAR material to Tier 1 status.

b. The safety analysis verification process only summarizes and cross-correlates ITAAC entries which would have been selected anyway, using the existing criteria for ITAAC selection. In other words, preparing the safety analysis verification ITAAC index does not add to or substitute from the plant ITAAC material.

c. Final disposition of the safety analysis verification table has yet to be decided. It may be incorporated into the body of the SSAR; where and how this will be accomplished has yet to be decided.

Table B1b: Safety Analysis Verification Using ITAAC

SSAR Entry	Parameter	Value (1)	Verifying ITAAC	
6.2.1	**Containment Functional Design**			
6.2.1.1.4.1	**Vacuum Breakers**			
	Diameter (inches)	20	2.14.1	Primary Containment System
	Quantity	8	2.14.1	Primary Containment System
Table 6.2-2	**Drywell**			
	Volume (ft^3)	259,563	2.14.1	Primary Containment System
	Leak Rate, Drywell and Wetwell (%/Day)	0.5	2.14.1	Primary Containment System
	Wetwell			
	Volume (ft^3)	210,475	2.14.1	Primary Containment System
	Minimum Suppression Pool Water Volume (ft^3)	126,427	2.14.1	Primary Containment System
	Total Vent Area (ft^2)	125	2.14.1	Primary Containment System
	Vent Centerline Submergence (Low Water Level), (ft):			
	Top Row	11.48	2.14.1	Primary Containment System
	Middle Row	15.98	2.14.1	Primary Containment System
	Bottom Row	20.48	2.14.1	Primary Containment System
Table 6.2.2-a	**RHR System**			
	Pump Capacity (gpm/pump)	4200	2.4.1	Residual Heat Removal System
	Heat Transfer Area (ft^2/unit)		2.4.1	Residual Heat Removal System
	Heat Transfer Coefficient (Btu/sec-F)	195	2.4.1	Residual Heat Removal System
	Service Water Flow (lbm/hr)	2.63×10^6	2.4.1	Residual Heat Removal System
Table 6.2-2d	**Secondary Containment**			
	Free Volume (ft^3)	3.0×10^6	2.15.10	Reactor Building
	Pressure (inch H_2O)	-0.25	2.15.10	Reactor Building
	Leak Rate (%/day)	50	2.15.10	Reactor Building

Table B1b: Safety Analysis Verification Using ITAAC (Continued)

SSAR Entry	Parameter	Value (1)	Verifying ITAAC	
Table 6.3-1	**Low Pressure Flooder System**			
	Minimum Vessel Pressure to Initiate Flow (psid)	225	2.4.1	Residual Heat Removal System
	Minimum Rated Flow (gpm/unit) at Vessel Pressure (psid)	4200 40	2.4.1	Residual Heat Removal System
	Initiating Signals Low Water Level (ft above TAF)	<0.6	2.1.2	Nuclear Boiler System
	Maximum Time from Signal to Pumps at Rated Speed (sec)	29	2.4.1	Residual Heat Removal System
	Maximum Time from Low Pressure Permissive signal to Injeciton Valve Fully Open (sec)	36	2.4.1	Residual Heat Removal System
	RCIC System			
	Minimum Vessel Pressure to Initiate Flow (psid)	1177	2.4.4	Reactor Core Isolation Cooling
	Minimum Rated Flow (gpm/unit) at Vessel Pressure (psid)	800 1177-150	2.4.4	Reactor Core Isolation Cooling
	Initiating Signals Low Water Level (ft above TAF)	<8.1	2.1.2	Nuclear Boiler System
	Maximum Time from Signal to Injection Valve Fully Open (sec)	29	2.4.4	Reactor Core Isolation Cooling
	HPCF System			
	Minimum Vessel Pressure to Initiate Flow (psid)	1177	2.4.2	High Pressure Core Flooder System
	Minimum Rated Flow (gpm/unit) at Vessel Pressure (psid)	800-3200 1177-100	2.4.2	High Pressure Core Flooder System
	Initiating Signals Low Water Level (ft above TAF)	<3.4	2.1.2	Nuclear Boiler System
	Maximum Time from Signal to Injection Valve Full Open (sec)	36	2.4.2	High Pressure Core Flooder System
	ADS			
	Minimum Flow Capacity (lbs/hr) at Vessel Pressure (psig)	6.4×10^6 1125	2.1.2	Nuclear Boiler System
	Initiating Signals Low Water Level (ft above TAF)	<0.6	2.1.2	Nuclear Boiler System
	Maximum Time from Signal to Valves Fully Open (sec)	<29	2.1.2	Nuclear Boiler System

Table B1b: Safety Analysis Verification Using ITAAC (Continued)

SSAR Entry	Parameter	Value (1)	Verifying ITAAC	
Table 6.3-4	**LOCA Break Sizing**			
	Steamline (ft^2)	1.06	2.1.1	Reactor Pressure Vessel System
	Feedwater Line (ft^2)	0.903	2.1.1	Reactor Pressure Vessel System
	RHR Shutdown Cooling Suction Line (ft^2)	0.852	2.1.1	Reactor Pressure Vessel System
	RHR Injection Line (ft^2)	0.221	2.1.1	Reactor Pressure Vessel System
	High Pressure Core Flooder (ft^2)	0.099	2.1.1	Reactor Pressure Vessel System
	Bottom Head Drain Line (ft^2)	0.0218	2.1.1	Reactor Pressure Vessel System
Table 6.3-9	**Design Parameters for RHR System Components**			
	Pump Flow Rate (gpm)	4200	2.4.1	Residual Heat Removal
Table 15.0.1	**Input Parameters and Initial Conditions for System Response Analysis Transient**			
	Safety/Relief Valve Capacity at 80.5 kg/cm^2 (%NBR)	91.13	2.1.2	Nuclear Boiler System
	Recirculation Pump Trip Inertia Time Constant (sec)	0.62	2.1.3	Reactor Recirculation System
	Steamline Volume (m^3)	113.2	2.1.2	Nuclear Boiler System
Table 15.0-6	**FMCRD Scram Time**			
	100% Rod Insertion (sec)	3.719	2.2.2	Control Rod Drive System
15.2	Increase in Rx Pressure			
15.2.2.3.1	TCV Full Stroke Closure (sec)	0.15	2.10.8	Turbine Control System
15.2.3.3.1	Turbine Stop Valve Full Stroke Closure (sec)	0.10	2.10.9	Turbine Control System
15.2.4.3.1	MSIV Closure (sec)	3-5	2.1.2	Nuclear Boiler System
15.2.5.3.1	Same as 15.2.3.3.1			
15.4	**Reactivity and Power Distribution Anomalies**			
15.4.1.2.3.2	FMCRD Withdrawal (mm/sec)	30	2.2.2	Control Rod Drive System

Table B1b: Safety Analysis Verification Using ITAAC (Continued)

SSAR Entry	Parameter	Value (1)	Verifying ITAAC	
15.8	**ATWS Events**			
15.8.2	Manual SLCS Capacity	100	2.2.4	Standby Liquid Control System
Table 15E.3-1	**Initial Operating Conditions**			
	Suppression Pool Volume (m^3)	3580	2.14.1	Primary Containment System
Table 15E.3-2	**Equipment Performance Characteristics**			
	Relief Valve Capacity (%NBR Steam Flow/No. Valves)	91.3/18	2.1.2	Nuclear Boiler System
	RHR Pool Cooling Capacity (Kcal/sec-C)/(%NBR at 38-C)	265/1.57	2.4.1	Residual Heat Removal System

Notes:
1. This table is a summary of data presented in the SSAR. Margins and/or ranges may be added when these values are incorporated into specific ITAAC entries.

Appendix B2 ABWR PRA Studies
Examples Of Plant Features Added As A Result Of PRA Studies

	TIER 1 TREATMENT		
PLANT FEATURE	DESIGN DESCRIPTION ENTRY		ITAAC SCOPE
Containment over-pressure protection	2.14.6	Atmospheric Control System	1. Equipment in place 2. Rupture disc setpoint
Lower drywell flooder	2.14.1	Primary Containment System	1. [illegible]uipment in place 2. Valve opening characteristics
AC independent water addition	2.4.1	Residual Heat Removal	1. Equipment in place 2. Flow-heat characteristics for injection to RPV or spray header
Combustion turbine generator	2.12.11	Combustion Turbine Generator	1. Equipment in place 2. Auto load pickup capability

References

1. Guidelines for Preparation of Inspections, Tests, Analyses and Acceptance Criteria (ITAAC), A. J. James, December 1991 (GE Memorandum).