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*The listed drawings are included as "General References" only; i.e., refer to the drawings to obtain additional detail or to obtain background information. These drawings are not part of the UFSAR. They are controlled by the Controlled Documents Program.

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6.0 ENGINEERED SAFETY FEATURES

This Chapter is organized as follows:

6.0.1 Identification of Engineered Safety Features (ESFs)

Section 6.0 is the complete listing of ESF systems, structures and components. Discussion of a system, structure, or component elsewhere in Chapter 6 does not imply classification of that item as an engineered safety feature. Conversely, systems listed in Section 6.0 are classified as ESFs, even though the detailed discussion of the system, structure, or component is in another UFSAR Chapter.

This section describes the functional requirements and performance characteristics of the ESFs which have been provided in addition to those safety features included in the design of the reactor, reactor coolant system, reactor control systems, and other instrumentation or process systems described elsewhere in this report. They are included in the plant for the purpose of reducing the consequences of postulated accidents. The following engineered safety features have been provided: [6.0-1]

A. Containment systems;

B. Containment cooling system;

C. Containment isolation;

D. Standby gas treatment system;

E. Emergency core cooling system;

F. Reactor protection system;

G. Main steam line flow restrictors;

H. Control rod velocity limiter; and

I. Control rod housing support.

The following systems, which are not normally defined as ESFs during plant licensing, were also

identified as ESFs in the Quad Cities FSAR.

A. Standby coolant supply system;

B. Standby liquid control system; and

C. Primary containment atmospheric control (inerting).

6.0.1.1 Containment Systems

The containment systems consist of the primary containment system and the secondary containment system. The primary containment system provides a barrier which, in the event of a loss-of-coolant accident (LOCA), will control the release of fission products to the secondary containment, and suppresses the pressure increase in the containment resulting from a LOCA. The secondary containment system limits the release of radioactive materials to the environs. The containment systems are described in Section 6.2. [6.0-2]

6.0.1.2 Containment Cooling System

The containment cooling mode of the residual heat removal (RHR) system consists of the suppression pool cooling subsystem, the suppression chamber spray subsystem, the drywell spray subsystem, and the RHR service water subsystem. The containment spray subsystems provide overpressure protection to the primary containment by quenching steam released to the drywell or torus during a LOCA. The containment cooling systems are described in Section 6.2.2. [6.0-3]

6.0.1.3 Containment Isolation

Isolating the primary containment system from the plant provides protection against the consequences of accidents involving the release of radioactive materials from the RCPB. Sections 6.2.4 and 7.3.2 contain descriptions of the containment isolation system and isolation valves, including the traversing incore probe (TIP) system shear valves. [6.0-4]

6.0.1.4 Standby Gas Treatment System

The standby gas treatment system (SBGTS) removes fission products from the air in the secondary containment following a design basis accident by adsorption in an activated charcoal filter pack before the air is discharged to the environment through the 310-foot chimney. The standby gas treatment system can also be manually aligned to take a suction on the primary containment. The standby gas treatment system is described in Section 6.5. [6.0-5]

6.0.1.5 Emergency Core Cooling System

The emergency core cooling system (ECCS) is automatically placed in operation whenever a loss-of-coolant condition is detected. The subsystems contained in the emergency core cooling system consist of the core spray system, the low pressure coolant injection (LPCI) mode of RHR, the high pressure coolant injection (HPCI) system, and the automatic depressurization system (ADS). The emergency core cooling system is described in Section 6.3. [6.0-6]

6.0.1.6 Reactor Protection System

The reactor protection system (RPS) monitors reactor operation and initiates a reactor trip upon detection of an unsafe condition that might cause damage to the reactor fuel resulting in the release of radioactive materials to the environment. The RPS is described in Section 7.2. [6.0-7]

6.0.1.7 Main Steam Line Flow Restrictors

The main steam line flow restrictor is a simple venturi, welded into each main steam line, for the purpose of limiting the steam discharge through a break in the steam line. A description of the main steam line flow restrictors is provided in Section 5.4.4. [6.0-8]

6.0.1.8 Control Rod Velocity Limiter

The control rod velocity limiter consists of two conical elements which restrict the downward fall of the control rod, yet do not retard the upward motion of the control rod during scram. These conical elements have no moving parts, and are attached to the control rod. A description of the control rod velocity limiter is provided in Section 4.6. [6.0-9]

6.0.1.9 Control Rod Housing Support

The control rod housing support is a gridwork located immediately below the control rod housings. Its purpose is to prevent control rod ejection should the control rod housing fail. A description of the control rod housing support is provided in Section 4.6. [6.0-10]

6.0.1.10 Other Systems Identified as ESFs in FSAR

6.0.1.10.1 Standby Coolant Supply System

The standby coolant supply system is a crosstie between the station service water and the condenser hotwell of each unit to supply water to maintain feedwater flow to the reactor in the event it is needed for core flooding or containment flooding following a postulated loss-of-coolant accident. The crosstie is supplied with double valves to minimize leakage of river water to the condenser. The system is manually actuated from the control room. [6.0-11]

The standby coolant supply system is described in Section 9.2.8.

6.0.1.10.2 Standby Liquid Control System

The standby liquid control system (SBLC) provides an additional and independent means of reactivity control and is capable of making and holding the reactor core subcritical from any hot standby or hot operating condition. The liquid control is a liquid boron solution which can be injected into the reactor vessel at pressures above the vessel design pressure at a constant flow. The standby liquid control system is described in Section 9.3.5. [6.0-12]

In addition, in the event of a design basis LOCA, the required volume of sodium pentaborate is injected into the reactor (and ultimately flushed to the suppression pool via ECCS flow) to maintain the suppression pool pH at a value greater than 7. This action ensures that the iodine deposited into the pool during a DBA LOCA does not re-evolve and become airborne as elemental iodine. This SBLC function is credited in the radiological assessments performed as part of Alternative Source Term (AST) – see UFSAR Section 15.6.5.5.

6.0.1.10.3 Containment Inerting

The inerting system allows the atmosphere in the drywell and torus to be replaced with nitrogen. This is designed to maintain oxygen concentration below flammability limits in order to prevent hydrogen detonation following a LOCA. The inerting system is described in Section 6.2.5.1. [6.0-13]

6.1 ENGINEERED SAFETY FEATURE MATERIALS

The materials used in the Quad Cities Engineered Safety Feature (ESF) systems have to withstand the environmental conditions encountered during normal operation and any postulated accident. The selection of these materials is based on an engineering review and evaluation for compatibility with other materials to preclude interactions that could potentially impair the operation of the ESF systems. The compatibility of service water with the standby coolant supply system is addressed in Section 6.1.1.2.

6.1.1 Metallic Materials

In general, all metallic materials used in ESF systems comply with the 1955 edition of the American National Standards Institute (ANSI) B31.1 Power Piping Code. Some components comply with the 1965 edition of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III and Section VIII. Adherence to these requirements ensures materials of the highest quality for the ESF systems. [6.1.1]

6.1.1.1 Materials Selection and Fabrication

Metallic materials in ESF systems must resist corrosion and cracking under both normal and accident service conditions, including ESF core cooling water and containment spray solutions.

The original design of the ESF systems included 300 series stainless steel safe ends at the reactor vessel. At the time, it was recognized that these safe ends would be furnace-sensitized. Subsequently, these safe ends were replaced during construction of Quad Cities. Section 5.2.3.4.1.1 addresses the replacement of all safe ends. Further information on control of intergranular stress corrosion cracking (IGSCC) of plant components is given in Section 5.2.3. [6.1.2]

Thermal insulation materials for ESF system components are selected based on their ability to withstand expected service and accident conditions of gamma radiation damage, vibration, moisture, or forces from the water deluge of the containment spray system. [6.1.3]

Contaminants in piping insulation can induce stress corrosion cracking of ESF system piping. Such contaminants may include leachable chloride and fluoride ions. However, leachable sodium silicate in asbestos-type insulation will inhibit corrosion, and has a guaranteed concentration greater than 50,000 ppm. Leachable chloride concentration in insulation does not exceed 300 ppm.

6.1.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

The high pressure coolant injection (HPCI) system is supplied with clean water from either the contaminated condensate storage tank or from the suppression pool. The core spray uses the suppression pool as its source of supply. The containment spray cooling and low pressure coolant injection (LPCI) modes of the RHR system are supplied from the

suppression pool. It is possible for the core spray and RHR system to also draw from the contaminated condensate storage tank, if desired. Water in the pool is demineralized water with no special additives present. Water in the condensate storage tanks is also demineralized. Hence, the pH is expected to remain essentially neutral so that neither alkaline nor acidic corrosion should occur. EGC's boiling water reactor (BWR) water chemistry control program is described in Section 5.2.3.2. [6.1.4]

The standby liquid control (SBLC) system uses a sodium pentaborate solution. It is highly unlikely that the SBLC system would be used following a primary system pipe break since the reactivity control function of the borated water would be lost due to dilution with ESF fluids. For this reason, the potential for chloride introduction into the containment by the SBLC system following a design basis accident (DBA) is not a significant safety concern. The SBLC system is described in Section 9.3.5. [6.1-5]

The standby coolant supply system uses plant service water (filtered river water). A description of the standby coolant supply system is contained in Section 9.2.8. It is used only as a manually actuated backup to other core cooling systems for emergency core cooling and containment flooding. Therefore, the use of service water for standby coolant supply is satisfactory for the system to perform its intended function. [6.1-6]

6.1.2 Organic Materials

The likelihood of the protective coatings used inside containment deteriorating in the post-accident environment and contaminating the suppression pool to the extent that ESF operation is affected is negligible. Section 6.2.2.3 contains a discussion of debris generation, transport, and examines its impact on ESF system operation. [6.1-7]

The inside of the Unit 1 torus was originally coated with Plasite 7155H epoxy-polyamide paint, manufactured by the Wisconsin Protective Coating Company of Green Bay, Wisconsin. This material has been used by CECo and other utilities for over 10 years to prevent steel condensate storage tanks (which contain hot condensate at 150°-180° F), and demineralized water reservoirs from corroding. It is one of the few products tested in over 25 years (prior to 1971) that has successfully withstood this type of service exposure.

Plasite was originally sold as a two-component product, with the two components being mixed just prior to application. However, CECo found paint defects called "half-moon cracking," caused by shrinkage. To overcome these defects, the manufacturer began supplying a three-component system in 1967.

In July 1967, test panels were prepared with the three-component coating. After seven days of air curing, the test panels were continuously immersed in demineralized water at 180°F for seven months. At the end of that time, the panels exhibited excellent retention of surface smoothness and gloss. No half-moon cracking, deterioration, or penetration to base metal or rusting was evident, except on panels which were deliberately scored to base metal at the beginning of the test. Although badly rusted in the score marked areas, the scored panels showed no undercutting of the coating in the scored areas when bent. The three-component product was used at Quad Cities.

The Plastic coating on the inside of the Unit 1 torus, including the inside of the vents, but excluding parts of the personnel walkway inside the torus, was removed and the steel re-coated in 1994 with 6548/7107 epoxy primer, manufactured by Keeler & Long Inc. of Watertown, Connecticut. The coating product is manufactured in compliance with ANSI N101.4 "Quality Assurance for Protective Coatings Applied to Nuclear Facilities." It is a

Nuclear Certified Level I coating material. It has been certified to ANSI N101.2 "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities."

The drywell steel is protected against corrosion by a 2-mil thick inorganic zinc-filled coating. The drywell steel has been spot-coated with Carbo Zinc 11 primer and Carboline 305 finish paint. The concrete portions of the drywell have also been touched up with separate Phenoline 305 primer and finish coats. [6.1-8]

The inside of the Unit 2 torus is coated with Phenolic 368 primer and Phenolic 368 finish manufactured by the Carboline Company. The inside surfaces of the vent headers are coated with Plasite 7155H. Minor local repairs were performed with Carboline Carbo Zinc 11 SG inorganic zinc primer in March 1974. In subsequent maintenance and touchup paint repair jobs, the inside of the torus was spot-coated with Carboline 368 primer and finisher.

6.2 CONTAINMENT SYSTEMS

This section presents the design considerations for the containment. The combination of these design aspects provide a conservative basis for overall containment integrity. [6.2-1]

Each Quad Cities unit employs a multi-barrier pressure suppression containment that applies containment-in depth principles. Each primary containment system is located within a common secondary containment.

The Quad Cities primary containment system, depicted in Figure 6.2-1, is commercially known as a General Electric Mark I design. It includes a drywell, which encloses the reactor pressure vessel and the reactor recirculation system; a pressure suppression chamber (or wetwell); and a vent system connecting the drywell to the pressure suppression chamber.

Any leakage from the primary containment system is to the secondary containment, which consists of the reactor building, standby gas treatment system, drywell purge ductwork, main steam isolation valve room, high-pressure coolant injection room, and chimney. The reactor building encloses both reactors and their respective primary containment systems. The reactor building provides secondary containment when the primary containment of either unit is in service. The secondary containment is addressed in Section 6.2.3.

The equipment and evaluation presented in this section are applicable to either unit.

6.2.1 Primary Containment Functional Design

The primary containment system is a steel lined concrete structure which consists of a drywell, a pressure suppression chamber which is partially filled with water, a vent system connecting the drywell and the suppression chamber water pool, isolation valves, ventilating and cooling systems, and other service equipment. The drywell is a steel pressure vessel composed of a spherical lower portion, a cylindrical middle portion, and a hemispherical tophead which houses the reactor vessel, the reactor coolant recirculation system, and other branch connections of the reactor primary system. The pressure suppression chamber is an approximately toroidal steel pressure vessel encircling the base of drywell. Due to its shape the suppression chamber is commonly called the torus. The vent system from the drywell terminates below the suppression chamber water level. [6.2-2]

In the event of a nuclear steam supply system piping failure within the drywell, reactor water and/or steam would be released into the drywell. The resulting increased drywell pressure would force a mixture of noncondensible gases, steam, and water through the connecting vent lines into the pool of water in the suppression chamber. The steam would condense rapidly in the suppression pool, resulting in suppression of the pressure increase in the drywell. Noncondensible gases transferred to the suppression chamber would pressurize the chamber and would eventually be vented back to the drywell through vacuum breaker valves to equalize the pressure between the two vessels. Cooling systems (see Section 6.2.2) would remove heat from the drywell and from the water and gases in the suppression chamber to provide continuous cooling of the primary containment under accident conditions. Appropriate isolation valves would close to ensure containment of radioactive materials which might otherwise be released.

6.2.1.1 Design Bases

The principal design criteria for the containment systems are presented in Section 1.2.1.3. The performance objectives of the primary containment system are: [6.2-3]

- To provide a barrier which, in the event of a loss-of-coolant accident (LOCA), will control the release of fission products to the secondary containment; and
- To limit the pressure increase in the containment resulting from the LOCA.

To achieve these objectives the primary containment system was designed using the following bases:

[6.2-4]

Design Free Volume Drywell (minimum) Suppression Chamber	 158,236 ft^3 117,248 to 113,793 ft^3[a]
Suppression Chamber Water Volume	112,200 to 115,655 ft^3[a]
Design Pressure of Drywell and Suppression Chamber	56 psig
Maximum Allowable Pressure of Drywell and Suppression Chamber	62 psig
Design Leak Rate without Penetrations (preoperational test)	0.5% per day of total contained volume at 56 psig
Design Code	ASME B&PV Code Section III, Class B, 1965 Edition with addenda to and including Winter 1965
Seismic	As specified in Section 3.8

[a]Note: As-built containment volumes are discussed in Section 6.2.1.3.

The design volume of the drywell was dictated by the space required to contain the reactor vessel, the recirculation system, drywell cooling equipment, and reactor auxiliary equipment located in the drywell. The design free volume of the suppression chamber is based on the free volume of the drywell, such that if all of the drywell atmosphere were to be discharged into the suppression chamber, the suppression chamber would remain below its design pressure.

The design pressure was established on the basis of the Bodega Bay pressure suppression tests,[1] with allowance being added for uncertainties (see Section 6.2.1.3.1). Further discussion of the applicable design code, design allowable and test pressures is included in Section 3.8.2.1.3. Preoperational leak rate testing is discussed in Section 6.2.6.1.

The volume of water maintained in the suppression chamber was established by allowing a maximum 50°F rise in the water temperature during a LOCA. Refer to Section 6.2.1.3 for additional information on this basis.

To minimize the release of radioactive gases during accident conditions, the design leak rate of the primary containment was limited to as low a value as could practicably be obtained with the type of construction employed.

The design, fabrication, and inspection of the primary containment was in accordance with the requirements of the ASME Pressure Vessel Code, Section III, Class B, which pertains to containment vessels for nuclear power plants.

6.2.1.2 Design Features

This section describes the design of the major components of the primary containment. It also describes some of the modifications performed as part of the Mark I Program.[2] The Mark I program is described in Section 6.2.1.3.4. Table 6.2-1 summarizes the design parameters of the containment system. Figures 6.2-1 through 6.2-5 show the arrangement and major components of the primary containment. [6.2-5]

6.2.1.2.1 Drywell

The drywell is a steel pressure vessel with a removable steel head. The lower part of the drywell is a sphere with an inside diameter of 66 feet. The upper part of the drywell is a cylindrical shell, 46 feet tall, with an inside diameter of 37 feet. The head and shell of the drywell are fabricated of SA-212 Gr B plate manufactured to A-300 requirements. [6.2-6]

The drywell shell is enclosed in reinforced concrete to provide radiological shielding and additional resistance to deformation. Above the foundation transition zone, the drywell is separated from the reinforced concrete by a gap of approximately 2 inches to accommodate thermal expansion. Shielding in the drywell head area is provided by a concrete vault topped with removable segmented reinforced concrete shield plugs.

Access to the drywell is provided by the drywell head, one personnel airlock, one control rod drive removal hatch, and one bolted equipment hatch. The drywell head is removed during refueling operations. The head is held in place by bolts and is sealed with a double tongue-and-groove seal arrangement which permits periodic checks for leak tightness without pressurizing the entire containment. The head is bolted closed when primary containment integrity is required. [6.2-7]

The locking mechanism on each personnel airlock door is designed so that a tight seal will be maintained under either internal or external pressure. The doors are mechanically interlocked so that a door may be operated only if its companion door is closed and locked. The hatch covers are bolted in place and sealed with a double tongue-and-groove seal. The seals on the hatches can be tested for leakage.

The drywell is not normally entered during power operation, but access is permissible with the reactor in operation following de-inerting and depressurization. Normal environment in the drywell during plant operation is 1.2 to 1.4 psig with a nitrogen atmosphere and nominal bulk temperature of about 150°F. This temperature is maintained by recirculating the drywell atmosphere across forced-air cooling units which, are cooled by the reactor building closed cooling water system. The containment ventilation system is discussed in Section 9.4.

A description of electrical and piping penetrations and their design is provided in Section 3.8. A complete listing of all electrical, instrument, piping, and access penetrations is presented in Table 6.2-7.

6.2.1.2.1.1 Drywell Expansion Gap

The steel drywell shell is largely enclosed within the structural and shielding concrete of the reactor containment building. To accommodate thermal expansion, an expansion gap was provided between the concrete and the drywell shell. [6.2-8]

Although the drywell was designed, erected, pressure tested and N-stamped in accordance with the ASME code using a design pressure of 56 psig, (reference UFSAR Section 3.8.2.1.3) the maximum temperature is the limiting condition for the expansion gap design. The expansion gap size was based upon an ultimate steel shell temperature of 281°F following a postulated reactor LOCA. This temperature corresponds to the temperature of saturated steam at 35 psig, which the Bodega Bay[1] tests and subsequently, the Plant Unique Analysis Report[2] (PUAR), Figure 2-2.2-11, determined to be the suppression chamber pressure following a LOCA. Note that the peak pressure calculated in the PUAR is slightly lower than 35 psig, but the original design remains unchanged to be conservative. [6.2-9]

Both temperature and pressure cause the steel shell to expand. If temperature induced expansion were restrained by interference with the concrete structure, the resulting inward normal component could cause rippling and buckling of the steel. It is essential that sufficient gap exist between the steel shell and the concrete structure to prevent interference due to thermal expansion.

Pressure-induced expansion results from internal forces acting outward and normal to the shell. If the concrete structure were to restrain this type of expansion, the resulting inward normal forces would tend to counterbalance the outward normal pressure-induced forces. A gap larger than that required for temperature-caused expansion is therefore both unnecessary and undesirable, and the expansion gap was designed to accommodate only the temperature-induced growth of the drywell shell. The size of the expansion gap is tabulated in Table 6.2-2 Column (a).

Close proximity of the concrete structure to the shell also provides structural backup in the event of missile or jet impingement against the shell. Tests by the containment designers have shown that the shell can locally deflect 3.0 inches without cracking. Since the maximum gap size is 2.75 inches, it is highly unlikely that the containment shell would fail catastrophically due to local forces such as jet impingement. [6.2-10]

A combination of materials was used to permit pouring the concrete support structure over the steel drywell shell while maintaining the required expansion gap. A 2-inch layer of resilient polyurethane material was placed over the steel drywell shell. The polyurethane was then covered with 1.4-inch thick, shop-contained, polyester reinforced fiberglass shell panels. These panels contained 4 foot x 4 foot, 1/4 inch steel tie plates on 2-foot centers for attachment to the concrete pour. The fiberglass panels were joint-taped together into a rigid shell with epoxy-impregnated fiberglass tape. After the tie plates in the fiberglass were rigidly attached to the outside plywood forms, the fiberglass shell became the inner form for the pouring of the concrete structure.

Drywell penetrations, which extend from the drywell shell through the concrete, were surrounded with concentric pipe sleeves. These pipe sleeves were joined to the fiberglass shell using fiberglass tape and epoxy resins. This technique similarly provided a form for the concrete while maintaining an adequate clearance between the penetrations and the sleeves to accommodate thermal expansion.

Tests were conducted at the site on mockups of the steel/polyurethane foam/fiberglass sections to determine their displacement from a concrete pour. These tests showed the fiberglass was displaced less than 1/4 inch from the pouring and curing of concrete. From Figure 6.2-6, which shows the resilient characteristics of the polyurethane foam, it is apparent that a 1/4 inch compression of the 2-inch blanket of foam results in only a negligible external pressure on the steel drywell shell. Table 6.2-2, Column (b) shows the ASME Code allowable external loadings on the steel shell. These allowable loadings may be compared with the actual external loadings which would result from the thermal expansion of the drywell with concomitant compression of the polyurethane foam. Column (c) of Table 6.2-2 which shows these actual loadings, was based upon the stress-strain curve of Figure 6.2-6 and the thermal growth that would result from a steel shell temperature of 281°F (Column (a) of Table 6.2-2). Column (d) of Table 6.2-2 shows the safety factor which exists between the code allowable loadings and the actual loadings that would result from a LOCA.

The polyurethane foam material was chosen for its resistance to the environmental conditions likely to exist during its service life. In its position outside the drywell, the polyurethane foam will be exposed to a maximum radiation exposure of 2.5 x 10^7 rads, based on 40 full years of reactor operation. Radiation data[3,4,5] show the gamma radiation damage threshold to be between 8 x 10^6 and 4 x 10^7 rads for polyurethane elastomers. Polyurethane foam samples, similar to that used in the gap, were irradiated at various levels from 10^7 to 10^9 rads. There was no detectable change in resilience below 10^8 rads, thus amply confirming the published data. Although the normal in-service temperature will be only 150—180°F, the polyurethane which was used has a temperature rating of 280°F. Further, this material is self-extinguishing in accordance with ASTM-D1692.

The design, materials, and construction of the drywell expansion gap provide sufficient space for thermal expansion of the steel drywell shell. This method of construction prevented concrete, reinforcing bars, and other foreign material from reducing the gap, thereby reducing stress risers. The primary containment can accommodate both normal operating conditions and any postulated accident conditions.

6.2.1.2.1.2 Drywell Corrosion Potential

It is not expected that the lower part of the drywell will be subject to corrosion. The drywell steel is protected against corrosion by a 2-mil thick inorganic zinc-filled coating and is embedded in concrete 19 ft 10 in. above the rock surface. [6.2-11]

The elevation of the bottom of the drywell is 569 feet 10 inches. The normal ground water level is slightly higher than the pool stage of the Mississippi River (572 ft 0 in.), resulting in a negligible driving head of approximately 4 feet.

The concrete plug under the drywell is designed for a thermal gradient of 100°F, from an operating temperature in the drywell of 150°F to a temperature at the rock interface of 50°F. The thermal stress in the concrete of 572 psi is greater than the conservative value of 450 psi at which concrete would crack; therefore, cracking as normally expected with

any concrete structure under tension could occur. However, the heavily reinforced concrete plug would inhibit crack propagation and, in fact, would not permit a thermally-induced crack to open wide enough to act as a water passage. With all these positive factors - protective coating, negligible driving head for water intrusion, low thermal stress which will not develop a continuous crack in the concrete, and the heavily reinforced concrete plug - the potential for corrosion of the drywell is practically nonexistent.

The expansion gap has provisions for drainage of moisture into the basement of the reactor building by means of a sand pocket and drain tube arrangement at the bottom of this space. There are no provisions for ventilation or humidity measurements in this space. [6.2-12]

In response to NRC Inspection and Enforcement Information Notice 86-99 and Generic Letter 87-05 an extensive review was conducted for the potential for drywell steel corrosion in the area of the sand pocket.

This review included:

- inspection of the drain lines,
- initiation of a surveillance program to detect leakage into the annulus, and
- an evaluation of the actual corrosion rates.

The review concluded that although the potential for degradation of the containment could be postulated to exist, in fact, no corrosion problems were determined to exist. The results of the review determined that:

- the water present in the sand pocket or inside the drywell was noncorrosive (based on testing) and
- based on ultrasonic examination, there was no evidence of apparent corrosion.

Also, to ensure active assessment of any future potential problems surveillance procedures were initiated.

6.2.1.2.2 Vent System

Eight large circular vent lines form a connection between the drywell and the pressure suppression chamber. The lines are enclosed with sleeves and are provided with expansion joints to accommodate differential motion between the drywell and suppression chamber. Jet deflectors at the drywell entrance to each vent line prevent possible damage to the vent lines from jet forces which might accompany a pipe break in the drywell. The drywell vent lines are connected to a vent header in the form of a torus which is contained within the air space of the suppression chamber. The vent header has the same temperature and pressure design requirements as the vent lines. [6.2-13]

Projecting outward and downward from the vent header are 96 downcomer pipes which terminate below the water surface of the suppression pool. The downcomers are braced using 3-inch pipe with a 0.281-inch wall thickness to resist expected LOCA forces. A deflector is installed at the bottom of the vent header, supported by connecting plates

which are welded to the vent header collar plates. This deflector helps to reduce loading on the vent header and vent header supports during accident conditions. The deflector and heavier downcomer bracing were installed as part of the Mark I containment modification.

6.2.1.2.3 Pressure Suppression Chamber

The pressure suppression chamber is a steel pressure vessel, roughly in the shape of a torus, symmetrically encircling the drywell. The circular path around its major axis is formed by sixteen cylindrical segments, or bays. Alternate bays (eight in all) are connected to vent lines leading from the drywell. The horizontal centerline of the suppression chamber is located slightly below the bottom of the drywell (see Figure 6.2-2). The suppression chamber is held by supports which transmit dead loads and seismic loads to the reinforced concrete foundation slab of the reactor building. Space is provided outside the chamber for inspection and maintenance.

Vacuum breakers permit flow from the suppression chamber free air space into the drywell to prevent a backflow of water from the suppression pool into the vent header system. As part of the Mark I containment modification, the original vacuum breaker discs were replaced with stronger discs that increased the vacuum breakers' strength and reliability. Additionally, T-quenchers were installed on the safety relief valve (SRV) discharge lines to reduce hydrodynamic loads on the suppression chamber and discharge line supports. The term SRV as used herein refers to both the relief valves and the safety relief valve.

The effect of the T-quenchers is to reduce air clearing loads and promote stable steam condensation in the suppression pool sufficiently which in turn reduces condensation oscillation loads. This design improvement, in conjunction with the installation of SRV discharge line vacuum breakers, reduces the loads on the SRV discharge lines and the hydrodynamic loads in the suppression pool. Refer to Sections 6.2.1.2.4.2 and 6.2.1.3.4 and Figures 6.2-27 through 6.2-29.

Two manholes with double-gasketed bolted covers provide access from the reactor building to the pressure suppression chamber. These access ports are bolted closed when primary containment integrity is required. They are opened only when the primary coolant temperature is below 212°F and the pressure suppression system is not required to be operational. A test connection between the double gaskets on each cover permits checking gasket leak tightness without pressurizing the containment. A drain pipe with double isolation valves provides for suppression chamber cleaning and decontamination. [6.2-14]

Details of the pressure suppression chamber interior coating are discussed in Section 6.1.

6.2.1.2.4 Other Design Features

6.2.1.2.4.1 Primary Containment Vacuum Relief Devices

Automatic vacuum relief devices on the drywell and the suppression chamber prevent the primary containment from exceeding the design external-to-internal pressure differential. The drywell is designed for a maximum external pressure of 2 psi greater than the

concurrent internal pressure. The suppression chamber is designed for a maximum external pressure of 2 psi greater than the concurrent internal pressure based on the original design calculations; however, the overpressure capability of the suppression chamber is conservatively stated to be 1.0 psi. [6.2-15]

The drywell vacuum breakers admit suppression chamber atmosphere into the drywell when the internal drywell pressure drops to about 0.5 psi below that of the suppression chamber. There are a total of 12 vacuum breaker valves installed on the vent header which act to relieve the drywell vacuum relative to the suppression chamber (refer to Figures 6.2-7 in the UFSAR and P&IDs M-34 and M-76). These vacuum breakers are sized on the basis of the Bodega pressure suppression system tests. Their chief purpose is to prevent excessive water level variation in the submerged portion of the vent discharge downcomers prior to a large break LOCA. The Bodega tests regarding vacuum breaker sizing were conducted by simulating a small break LOCA, which tended to cause downcomer water level variation, as a preliminary step in the large break test sequence. The vacuum breaker capacity selected on this test basis is more than adequate (typically by a factor of four) to limit the pressure differential between the suppression chamber and drywell during post-accident drywell cooling operations to below the design limit. [6.2-16]

An analysis[14] of the drywell negative pressure protection requirements was performed as part of the Mark I Containment Program. This analysis confirms that the existing vaccuum breaker system can satisfy the design criteria for the suppression chamber to drywell differential pressure. Three scenarios are considered in the analysis: (1) the inadvertent initiation of drywell spray at normal conditions, (2) the initiation of drywell spray following a LOCA, and (3) a LOCA with no spray actuation where the maximum flow rate into the vessel is modeled, which cascades out of the break and condenses the steam in the drywell atmosphere. The LOCA with maximum vessel overflow results in the most limiting scenario for the evaluation of the vacuum breakers. The analysis concludes that only 7 to 12 vacuum breakers are required, at a setpoint of 0.5 psid and a maximum opening time of 1.8 seconds, to maintain the suppression chamber to drywell differential pressure within the 2 psid design limit for the limiting scenario. [6.2-16a]

The performance of the pressure suppression system can be adversely affected by bypass flow between the drywell and the suppression chamber. Positive closure of the vacuum breaker valves is required. A maximum bypass between the drywell and suppression chamber was determined to be equivalent to the area of an 8-inch diameter pipe. The most critical design case which applies is the break of a pipe with an area of 0.4 ft^2. These issues were analyzed and presented in Quad Cities Special Report 4[6]. [6.2-17]

To ensure closure of the suppression chamber to drywell vacuum breakers, the counterbalance arm of the disc assembly was modified and indicating limit switches installed to alarm in the control room at any time the vacuum breaker valve moves off its seat by more than 1/16 of an inch as measured at all points along the disc. These modifications were performed to meet IEEE-279 standards and effectively limit the bypass area between the drywell and suppression chamber to less than 0.18 ft^2. The drywell is leak tested at the end of each operating cycle by pressurizing it to 1.0 psig. The rate of change of pressure must not exceed 0.25 inches of water per minute as measured over a ten minute period. Monthly tests are conducted to demonstrate the operability of the vacuum breakers (suppression chamber to drywell). If the valves are not shown to be operable, a pressure test must be performed.

The suppression chamber vacuum breakers prevent excessive vacuum in the suppression chamber relative to the reactor building by admitting reactor building air at a preset pressure differential that does not exceed the equivalent of 0.5 psid. Two vacuum breaker valves

in series are used in each of two lines leading from the reactor building atmosphere. One valve is air-operated and actuated by a differential pressure signal, independently of electrical power. The second valve is self-actuating. The combined pressure drop at rated flow through both valves does not exceed the difference between suppression chamber design external pressure and maximum atmospheric pressure. [6.2-18]

6.2.1.2.4.2 Safety/Relief Valve Discharge Line Vacuum Relief Devices

Four relief valves and one safety relief valve are installed on the main steam lines. Refer also to Section 6.2.1.3.4.2. Each SRV discharges through a dedicated discharge line into the suppression pool. The discharge lines are not interconnected. Refer to Figure 6.2-7 in the FSAR for pressure suppression piping, and to FSAR Figure 10.3-1 for main steam [6.2-19]

piping. Each discharge line incorporates vacuum breaker check valves to permit air flow from the drywell to relieve any vacuum which may develop in the discharge line.

For repeated actuations, the SRV is assumed not to reactuate until water level oscillations inside the discharge piping have damped out and the resulting suppression chamber water level increase has stabilized. In-plant SRV tests[7] conducted for Dresden Unit 2 are applicable to Quad Cities Units 1 and 2. Refer to Sections 6.2.1.2.3, 6.2.1.3.4, and 6.2.1.3.4.4, and for further information on SRVs and discharge related load effects.

As part of the Mark I containment modification, an additional SRV discharge line vacuum breaker was installed on each line. The present valves comply with ASME Section III Subsection NC 1977, including Summer 1977 Addendum to meet Class 2 system requirements. [6.2-20]

6.2.1.2.4.3 Drywell Pneumatic System

To facilitate maintaining an inert atmosphere, the drywell pneumatic system takes suction from the drywell atmosphere and supplies compressed air or nitrogen to pneumatically-operated equipment in the containment. The system is crosstied to the instrument air system for use when the containment is not inerted, and to the nitrogen makeup system for use when the containment is inerted. The drywell pneumatic system is described in detail in Section 9.3. [6.2-21]

6.2.1.2.4.4 Drywell to Suppression Pool Differential Pressure Control System

During normal operation, a system consisting of two compressors, a receiver, differential pressure control, and associated piping maintains a pressure differential between the drywell and the suppression chamber (see P&ID M-34). This system is referred to as the pumpback system. The pumpback system maintains drywell pressure slightly above suppression chamber pressure to decrease the amount of water standing in the downcomers and the SRV discharge lines. This decreases the dynamic forces on the suppression chamber during a postulated LOCA or main steam line relief valve discharge. During normal operation, a compressor takes suction from the suppression chamber free air volume and discharges through a moisture separator to an air receiver. Air from the receiver is discharged to the drywell through a differential pressure control valve to maintain a pressure differential. The minimum drywell to suppression chamber differential pressure of 1.0 psi was determined during the Mark I short term program to provide the required safety margin in the suppression chamber design. The drywell to suppression chamber differential is normally maintained at a higher differential pressure as specified in the Technical Specifications. The pumpback system flowrate is monitored to provide a continuous measurement of containment leakage. [6.2-22]

6.2.1.2.4.5 Containment Venting

6.2.1.2.4.5.1 Normal Containment Venting

The drywell may be vented to minimize pressure fluctuations caused by temperature changes during various operating modes. This is accomplished through ventilation purge connections, which are normally closed while the reactor is at a temperature greater than 212°F. The suppression chamber may be vented separately. Containment venting is kept to a minimum during reactor power operation.

The vent discharge may be routed to the standby gas treatment system so that release of gases from the primary containment is controlled, with the effluents being filtered and monitored before discharge through the main chimney.

6.2.1.2.4.5.2 Augmented Primary Containment Vent System

The augmented primary containment vent system (APCVS) is designed to be used for venting the primary containment in the highly unlikely event of a TW sequence. The TW sequence has been postulated by probabilistic risk assessment (PRA) of reactors with Mark I containments. The TW sequence is initiated by a transient event (T) requiring reactor shutdown followed by a complete and sustained failure of decay heat removal (W) capability. The APCVS provides a direct vent path from the pressure suppression chamber and the drywell to the main chimney. The Emergency Operating Procedures define the limiting containment parameters and direct use of APCVS to prevent a possible containment breach and an uncontrolled radioactive release. The valves required to initiate APCVS venting are operated from the main control room.

6.2.1.2.4.5.2.1 Design Basis

The augmented primary containment vent system is non-safety related but seismically supported as related to the secondary containment boundary. APCVS has no active functions during normal plant operation or design basis events. Its only required function under normal operating conditions is that its valves remain in their closed positions, except for the normally open 18" vent and purge prefilter isolation valve, to allow reactor building ventilation operation and provide chimney isolation.

The event for which APCVS was installed, a TW sequence, is beyond the design basis of the plant. In response to Generic Letter 89-16, Quad Cities Station committed to provide capability to vent the pressure suppression chamber. Although not a part of the commitment, APCVS also provides the capability to vent the drywell. Normally the selected vent path would be from the pressure suppression chamber only, to take advantage of the scrubbing effect of the suppression pool.

The system is designed to prevent containment pressure from exceeding the primary containment pressure limit (PCPL).

The design assumes a maximum pressure of 62 psig, measured at the bottom of the pressure suppression chamber coincident with a maximum water level in the pressure suppression chamber.

The vent is sized such that under conditions of constant heat input at a rate equal to 0.85% of rated thermal power and a containment pressure equal to the PCPL, the exhaust flow through the vent is sufficient to prevent the containment pressure from increasing. This vent is capable of operating up to the PCPL. It does not compromise the existing containment design basis.

The hardened vent path is capable of withstanding, without loss of functional capability, expected venting conditions associated with the TW sequence. The design precludes possible sources of ignition for combustible gases.

Existing radiation monitoring capability in the main chimney will alert control room operators of radioactive releases during venting.

Venting from one unit does not compromise the safety of the other unit. System design precludes backflow from the venting unit to the other unit.

Because Quad Cities is a dual unit station, the APCVS for both units will be tied together, and a common line will run to the chimney. It is not postulated that simultaneous TW sequences in both units would require simultaneous venting of both units. Although extremely unlikely, simultaneous venting of both units would be precluded administratively, through procedures and communication between units.

6.2.1.2.4.5.2.2 System Description

Operation of the APCVS would be directed by the Emergency Operating Procedures.

The APCVS is comprised of piping, round duct, square duct, air operated valves, and the associated electrical components for operation and indication. The air operated valves each have an accumulator for a backup air supply. The system piping is shown in P&ID M-34, M-76, and UFSAR Figure 6.2-7.

The piping begins at the suppression chamber main exhaust and the drywell main exhaust lines. It is routed through the reactor building into the turbine building through an 18" diameter vent and purge duct. The APCVS vent valve (AO-1699-6) is located in an 8" diameter branch line connected upstream of the vent and purge system prefilters. This 8" line is routed below the turbine main floor, passes through the turbine building exterior wall, and penetrates the radwaste ventilation exhaust duct which flows to the main chimney.

The controls for the APCVS are located in the main control room. The APCVS mode switch and 3 keylock containment isolation valve (CIV) override switches and annunciation of override of the CIV's are on the 901(2)-5 panel. The APCVS vent valve control switch is on the 901(2)-3 panel.

6.2.1.2.4.5.2.3 System Operation

Initiation of this system requires multiple, deliberate, operator action. By administrative direction, the APCVS mode switch, located on the 901(2)-5 panel in the control room, will be moved from "NORM" to "APCV." The only active function that this switch performs, is to close the AO-1699-7 and AO-1601-63 valves (if they are not already in the closed

position) which isolate the vent and purge system prefilters and standby gas treatment system. The mode switch also provides a permissive for the AO-1699-6 valve to be opened, and a permissive to override the Group 2 primary containment isolation signal for the AO-1601-60, -23, and -24 valves, by use of their respective keylock switches.

After Group 2 isolation signal has been overridden, the outboard CIV and the inboard CIV (torus) can be opened. Finally, the APCVS vent valve can be opened, and the vent path is now established to the main chimney. Subsequent venting sequences are controlled by closing and opening the APCVS vent valve until decay heat removal capability is re-established or until it is assured that primary containment pressure would not exceed PCPL.

In the event that simultaneous venting of both units were required and simultaneous venting was administratively precluded, alternate unit venting could be accomplished.

6.2.1.2.4.6 Suppression Pool Temperature Monitoring System

The suppression pool temperature monitoring system (SPTMS) was installed as part of the Mark I containment modification. The SPTMS is used to measure the suppression pool water temperature (bulk pool temperature). The SPTMS consists of two channels with eight thermocouples each. The thermocouples are placed inside thermowells dispersed circumferentially around the suppression chamber. Four thermowells are located along the inner circumference and four along the outer circumference. Two sensors (one inner and one outer) are located in each of the four quadrants of the suppression chamber. The inputs from the eight sensors are averaged to provide a bulk pool temperature measurement. The design placement of the sensors is on a horizontal plane 5.88 inches below the minimum water level, near the centroid of the water mass to assure an accurate measurement of bulk pool temperature. [6.2-23]

The bulk suppression pool temperature and the individual sensor readings are continuously recorded in the control room. The SPTMS is designed to operate continuously during all modes of reactor operation. It is also designed to operate in the environments expected to follow a LOCA, anticipated transient without scram (ATWS), and safe shutdown earthquake (SSE).

The SPTMS is classified as safety-related and is designed in accordance with IEEE Standard 279-1971. The equipment is qualified to IEEE Standards 323-1974, 344-1971, or 344-1975. The sensors are designed to meet Seismic Category I requirements, refer also to Section 7.5.1.

In the Unit 1 design, the thermowells placed on the inner suppression chamber circumference are in bays connected to vent pipes and the thermowells placed on the outer suppression chamber circumference are in non-vent-pipe bays. The Unit 2 thermowells were placed with the reverse pattern, i.e., the outer circumference thermowells in vent-pipe bays and the inner circumference thermowells in non-vent-pipe bays.

The difference in the thermowell placement can result in slight differences in indicated bulk temperature readings between the Unit 1 and Unit 2 SPTMS under similar steam discharge conditions. The Unit 1 indicated bulk temperature can be 2°F higher than the Unit 2 reading during an extended steam discharge event if steam is discharged into a suppression chamber bay with thermowells. However, little difference between the bulk temperature readings is expected if steam discharges into a suppression chamber bay without a thermowell. The SPTMS bulk temperature is least accurate when a stuck-open relief valve causes steam discharge into a suppression chamber bay without a SPTMS thermowell. When this occurs, the SPTMS may underestimate the actual bulk temperature by as much as 3.1°F on Unit 1 and 3.5°F on Unit 2.

6.2.1.2.4.7 Primary Containment Water Level Indication System

The Primary Containment Water Level Indication System includes pressure transmitters (0 to 100 psig) at the bottom of the torus (X-213A or B) and at the drywell vent (X-25). The signals from the transmitters are converted for processing and subtracting the higher elevation signal from the lower to determine level (0 to 100 feet). Indicators are provided on Control Room panels for containment pressure, torus bottom pressure, and containment level. Signals are also provided to the plant computer. [6.2-23a]

6.2.1.3 Design Evaluation

6.2.1.3.1 Sizing of the Primary Containment

The design parameters for the primary containment system are based on data obtained from the Bodega Bay tests, conducted for Pacific Gas and Electric Company at the Moss Landing steam plant in 1962.[1] Although these tests were run in support of a reactor system differing in size from Quad Cities, the range of parameters investigated covered a system of the size of Units 1 and 2. By juxtaposition of Quad Cities design data and Bodega Bay data, the following design values were determined: [6.2-24]

A. The application of the Bodega Bay pressure suppression test data to the Quad Cities primary containments established as design requirements a drywell pressure of 56 psig and a suppression chamber pressure of 35 psig. To simplify pressure tests of the primary containment, the suppression chamber design pressure was set equal to that of the drywell, at 56 psig. The drywell and connecting vents are designed for an external-to-internal pressure differential of 2 psi at 281°F, and the suppression chamber is designed for an external-to-internal pressure differential of 1 psi at 281°F. The peak drywell (airspace) temperature at 2957 MWt is 291°F, which is above the drywell shell design temperature of 281°F. However, the drywell airspace temperature peaks briefly as shown in Figure 6.2-25a. Because the drywell shell heatup is governed by heat transfer phenomena that require sustained high temperatures in the drywell atmosphere, this brief peak in the drywell airspace temperature results in a drywell shell temperature below 281°F.

B. The drywell is designed to withstand a local hot spot temperature of 300°F with a surrounding shell temperature of 150°F, concurrent with the design pressure of 56 psig.

C. The minimum total vent line cross-sectional area is designed to be equal to the maximum total design accident breakflow area (twice the recirculation pipe area) divided by 0.0194. The entrance area around the jet deflection baffles from the drywell to the vent lines is a minimum of 1.4 times the vent line area in order to minimize entrance losses.

D. The ASME Code impact test requirements for materials used for pressure-containing parts of the primary containment vessel call for the establishment of the lowest metal temperature that will be experienced in service while the unit is in operation. The lowest temperature to which the primary containment vessel pressure-containing parts could actually be subjected while the unit is in service is 50°F, because the primary containment system is housed in a building which is maintained at or above this minimum temperature during reactor operation, and the containment vessel pressure-containing parts would be maintained at or above this temperature while being subjected to post-accident design loadings. To provide an additional factor of safety, the design basis minimum service metal temperature was established as 30°F.

The size of the reactor vessel and associated auxiliary equipment dictated the required drywell dimensions. The volume of the drywell vessel, including connected vent lines, is:

Gross Volume	198,440 ft^3
Occupied Space	40,204 ft^3
Net Free Volume	158,236 ft^3

The total liquid volume of the coolant in the reactor process system, which could be discharged into the drywell and carried over into the suppression chamber during an accident, was calculated to be 10,030 ft^3. This calculation considered the reactor coolant

system, the recirculation system, the main steam system, the feedwater system, the cleanup system, and the shutdown cooling system.

The maximum suppression chamber water temperature that occurred during the Humboldt Bay[8] test was 170°F. This temperature was arbitrarily taken to be the upper limit to achieve complete condensation, although condensation does occur at temperatures above 170°F. The amount of water required to absorb the reactor system sensible heat was based upon a maximum peak temperature rise of 50°F in the suppression chamber water temperature, 10 seconds of original licensed full power operation, and a temperature reduction from 550°F to 212°F for reactor vessel and internals, reactor coolant, recirculation water, main steam system, feedwater system, and cleanup system. The minimum water volume required to meet these criteria was calculated to be 112,200 ft³.

The size of the suppression chamber was calculated using the gas law equation, performing a ratio for initial and final conditions, and solving for V_{2}:

$$V_2 = \frac{P_1 V_1 T_2}{P_2 T_1} \quad (6.2\text{-}1)$$

where:

V_{2} = V_{aw} (gas volume of suppression chamber) - 10,030 (carryover volume)

V_{1} = V_{D} (volume of drywell) + V_{aw} (gas volume of suppression chamber)

P_{1} = 14.7 + 0.5 - 0.8 (vapor pressure of water at T_{1}) = 14.4 psia

P_{2} = 14.7 + 29.0 - 3.3 (vapor pressure of water at T_{2}) = 40.4 psia

T_{1} = 555°R (95°F) (operational temperature limit)

T_{2} = 605°R (145°F)

From this it was determined that:

V_{aw} = 117,000 ft³ [6.2-25]

The design suppression chamber water volume was determined to be 115,600 ft³. The minimum volume required for heat absorption (112,200 ft³) plus 3,400 ft³ for variation level control. The structural material volume, which include structural members within the suppression chamber and the contained volume of vent piping, was determined to be 14,400 ft³. Combining these volumes yielded:

Gross Volume of Suppression Chamber = 247,000 ft³

From this calculated value for the gross volume of the suppression chamber, the dimensions of 109 feet major diameter and 30 feet minor diameter were derived.

Subsequent to the preceding initial design calculations, the following values have been established for the suppression chamber: [6.2-26]

Gross Volume of Suppression Chamber	245,200 ft^3
Downcomer Submergence	3.21 ft to 3.54 ft
Water Volume	111,500 ft^3 to 115,000 ft^3
Air Volume	120,800 ft^3 to 117,300 ft^3
Structural Material Volume - above water level	11,300 ft^3
Structural Material Volume - submerged	900 ft^3
Volume associated with 1.0 psi drywell to suppression chamber differential pressure	700 ft^3

The gross volume of the suppression chamber is calculated based on actual as-constructed dimensions. The water volumes are calculated based on water levels corresponding to a downcomer submergence of 3.21 ft to 3.54 ft, as analyzed in the Mark I Containment Program. The structural material volume is calculated based on the Mark I modifications and the removal of suppression pool baffles. A minimum differential pressure of 1.0 psi between the drywell and the suppression chamber, was established as an operational requirement to mitigate hydrodynamic loads during the Short Term Program in 1973. Each 1.0 psi increment in drywell to suppression chamber DELTA-P results in a 700 ft^3 displacement of suppression pool water. Based on these values, the remaining air volume was established.

These revised suppression chamber parameters have been evaluated in the Mark I Plant Unique Analysis Report and a subsequent analysis. The new suppression chamber parameters have been shown to meet the Mark I Containment acceptance criteria presented in NUREG-0661.

The total vent area is equal to the design accident flow area divided by 0.0194, in accordance with the Bodega Bay test results.[1] As noted in Section 6.2.1.3.2, the equivalent break flow area is 5.62 ft^2, which would result in a vent flow area of 5.62/0.0194 = 290 ft^2. The as-installed design consists of 96 downcomers having a total minimum area of 284 ft^2. This area was factored into the calculation of peak drywell pressure following an accident, which is discussed in Section 6.2.1.3.2.

The entrance area around the jet deflection baffles from the drywell to the vent tubes is a minimum of 1.4 times the vent tube area to minimize entrance losses.

Total Vent (Downcomer) Flow Area284 ft^2

Vent Pipe Entrance Area = 1.4 x 284 = 397.6 ft^2

A plant unique structural analysis was performed based on a operation at full power of 2957 MWt. The suppression chamber water and airspace volumes were 115,000 and 112,800 ft^3 (Dresden airspace volume which bounds the Quad Cities volume). The analysis was compared to loads[24] determined from plant unique tests. The calculated dynamic loads (pool swell, vent thrust, condensation oscillation, and chugging) analyzed at 2957 MWt are bounded by their respective loads already defined.

6.2.1.3.2 Containment Response to a Loss-of-Coolant Accident

In order to identify containment response to a loss of coolant (LOCA) accident, several analyses were performed. These analyses were performed to evaluate the containment short-term and long-term pressure response following the Design Basis Accident (DBA) LOCA, an Intermediate Break Accident (IBA), a Small Break Accident (SBA), as well as minimum NPSH available.

The containment analyses uses the General Electric methodology, which has been reviewed and approved by the NRC. The M3CPT code[15] is used to model the short-term (up to 30 seconds) DBA-LOCA containment pressure and temperature response. The LAMB code[19] is used to generate the break flow rates and break flow enthalpies that serve as inputs to M3CPT. The SHEX code[15][22] is used to analyze the containment pressure and temperature response for other than the short-term DBA-LOCA.

The GE computer code M3CPT is used to analyze the short-term response of pressure suppression containment systems to LOCA events where the primary system rupture occurs within the drywell. The basic containment modeling used in M3CPT is described in Reference 15. The M3CPT code models the containment system as three separate but interrelated models; namely, the vessel blowdown model, drywell model and wetwell model. The code calculates the pressure and temperature histories of the drywell and wetwell and the mass and energy interchange between these volumes and the reactor primary system. The use of the M3CPT code has been accepted by the NRC for calculating the short-term response of the containment system to LOCAs from the start of the transient until operator intervention via Automatic Depressurization System (ADS) or until the reactor blowdown is complete, whichever comes first. The GE containment analysis methods have been reviewed by the NRC.[16][17][18]

For the containment response analysis, these break flows and break enthalpies are calculated with the LAMB code. Reference 19 describes the more detailed LAMB vessel model used to calculate break flow rates used as input to the M3CPT code. For the 2957 MWt analysis, the LAMB blowdown flow rates, used as input to M3CPT, were calculating using Moody's Slip flow model.[20] The Slip flow model is a conservative model and is the same model used in Appendix K calculations.

The use of the LAMB blowdown flow in M3CPT was identified in Reference 21 by reference to the LAMB code qualification in Reference 19. The M3CPT code itself is still used to calculate the drywell pressurization rate, vent clearing time, vent clearing pressure and peak drywell-to-wetwell pressure difference, used in evaluating the DBA-LOCA hydrodynamic loads.

The GE computer code SHEX is used to perform the analysis of the long-term containment pressure and temperature responses to LOCAs and transients until after the suppression pool temperature peaks. The key models used in the SHEX code are described in References 15 and 22. This methodology is consistent with Reference 21. The SHEX code uses a coupled pressure vessel and containment model. The code performs fluid mass and energy balances on the reactor primary system, the suppression pool, and the drywell and wetwell airspace. The Boiling Water Reactor (BWR) primary system, feedwater system, Emergency Core Cooling System (ECCS), and SRVs are also modeled to the extent that their response affects that of the containment system. The code calculates the suppression pool bulk temperature, and the pressures and temperatures in the drywell and wetwell airspaces.

The use of the SHEX code has been accepted by the NRC for calculating the response of the containment during an accident or a transient event and has been applied to the evaluation of containment response for many BWR plants. The SHEX code is used to perform the long-term containment analysis as well as the short-term (defined here as the first 10 minutes when operator action cannot be credited) and long-term containment analyses for the NPSH evaluation. Reference 23 provides NRC's acceptance of the usage of the SHEX code in the analysis of long-term containment pressure and temperature response.

Containment pressure and temperature responses were calculated for Quad Cities Units 1 and 2 for DBA, IBA, and SBA conditions as well as calculations to support assessment of minimum NPSH availability. These calculations were based on operation at full power of 2957 MWt with the operational pressure difference between the drywell and wetwell. Where appropriate, the 2957 MWt results are discussed in the sections below. The containment analyses for 2957 MWt added a 2% margin for uncertainty (i. e., 3016 MWt). The containment analyses for GE14 fuel bound the SVEA-96 Optima2 fuel [Ref. 30], ATRIUM 10XM fuel [Ref. 32] and all legacy fuel types in the Quad Cities reactors [Ref. 26].

6.2.1.3.2.1 Containment Short-Term Response to a Design Basis Accident

The spectrum of postulated break sizes with respect to reactor core response is discussed in Section 6.3.3. The following information covers the effects of a LOCA accident on the containment, with particular emphasis on the most severe break: the doubled-ended rupture of one of the 28-inch-diameter recirculation pump suction lines. The locations of postulated breaks are schematically depicted in Figure 6.2-11. The LOCA involving the recirculation pump suction line would occur upstream of point 1 on Figure 6.2-11. [6.2-27]

For the vessel blowdown, the reactor was assumed to be operating at full power of 2957 MWt. The analysis assumes the suction valve is open.

If the equalizer line valve is closed (the normal operating condition), the flow will choke in the nozzles of the ten jet pumps on the jet pump header of the broken line. The total blowdown flow area in the assumed limiting case results in a break area of 4.261 ft^2.

The reactor was assumed to shut down essentially at time zero due to void formation in the core. A scram initiated from high drywell pressure would occur in less than one second. The difference between shutdown at time zero and at one second is negligible.

Release of the sensible heat stored in the fuel above 545°F and the core decay heat was included in the vessel blowdown calculation. The rate of energy release was calculated using a conservatively high heat transfer coefficient throughout the blowdown. Because of this high energy release rate, the vessel would be maintained at near rated pressure for

almost 10 seconds. The high vessel pressure increases the calculated blowdown flow rates, which is conservative for containment analysis purposes. With the vessel fluid temperature remaining near 545°F; however, the release of sensible energy stored below 545°F is negligible during the first 10 seconds. The later release of this sensible energy does not affect the peak drywell pressure. The small effect of this energy on the end-of-transient pool temperature is included in the calculations.

The main steam isolation valves were assumed to start closing at 0.5 second after initiation of the accident, and were assumed to close at the fastest possible rate (3.0 seconds to full closed). Actually, the isolation signal is expected to come from reactor low-low water level, so these valves may not receive a signal to close for over 4 seconds, and the closing time could be as high as 5 seconds. Assuming rapid closure of these valves in the analysis maintained the reactor vessel at a higher pressure during the blowdown, resulting in a calculated drywell pressure transient more severe than actually expected.

The original drywell pressure response model has been checked against both the Humboldt Bay[9] and Bodega Bay pressure suppression tests for a wide range of break sizes and has been found to be very accurate. The pressure response of the containment is calculated assuming:

A. Thermodynamic equilibrium exists in the drywell and suppression chamber;

B. The composition of the fluid flowing in the vents is based on a homogeneous mixture of the fluid in the drywell;

C. The flow in the vents is compressible except for the liquid phase; and

D. No heat is lost from the contained gases.

Based on assumption A, the following general equilibrium state relationship was used in the analysis: [6.2-28]

where:

$$\frac{E_D}{M_{WD}} = e_f + \frac{e_{fg}}{V_{fg}} + \left[\frac{V_D}{M_{WD}} - V_f\right] + \frac{M_{ad}}{M_{WD}} C_{va} (T_D + 460) \qquad (6.2\text{-}4)$$

E_{D} = Total internal energy in the drywell

M_{WD} = Mass of steam and water in the drywell

M_{ad} = Mass of air in the drywell

V_{D} = Free volume of the drywell

T_{D} = Temperature of the drywell, °F

e_{f}, e_{fg} = Specific internal energies of saturated liquid and vaporization, respectively

v_{f}, v_{fg} = Specific volumes of saturated liquid and vaporization, respectively

C_{va} = Specific heat at constant volume of air

Application of assumption B results in complete liquid carryover into the drywell vents. Realistically, some of the liquid would remain behind in a pool on the drywell floor. Thus, the calculated drywell pressure is conservative.

In the development of the drywell flow model, it was noted that the mass fraction of liquid in the drywell was on the order of 0.60, while the volumetric fraction was only about 0.005. This fact resulted in the following interpretation of the flow pattern. The liquid is in the form of a fine mist that is carried along by the predominantly steam/air flow and does not affect the flow except to add inertia to it. Except for corrections that account for the liquid inertia, flow was treated as compressible flow of an ideal gas in a duct with friction. The loss coefficients of the vent/header/downcomer system were lumped as an equivalent length of pipe.

The accuracy of this interpretation with respect to the effects of liquid carryover is supported primarily by the Humboldt Bay pressure suppression tests[9]. In this series of tests, changes in the drywell geometry resulted in variations in the amount of liquid carryover achieved. The liquid remaining in the drywell at the end of the test was measured and recorded. These tests were performed with a relatively small diameter orifice so that the vessel blowdown could be accurately calculated using Moody's critical flow model. In Figure 6.2-12 the calculated and measured pressure responses for these tests are shown. Note that with 100 percent carryover, the agreement was excellent. In that test, the drywell was preheated to 184°F before the blowdown was started, which prevented any condensation on the drywell walls. A calculated response with no carryover and with the effects of condensation considered is also shown in Figure 6.2-12. Again the agreement with the measured response with no carryover is excellent.

The model was compared against the Bodega Bay test data for two of the smaller orifices tested. As shown in Figures 6.2-13 and 6.2-14, the vessel blowdown was accurately reproduced for these tests. However, the drywell pressure response was slightly overpredicted. The overprediction is believed to be due to a combination of:

A. No condensation assumed in the calculated response ;
B. Slight overprediction of calculated vessel blowdown flow rates ; and
C. Incomplete liquid carryover into the drywell vents during the tests.

As the size of the vessel orifice increases, the vessel blowdown rate is overpredicted and the overprediction of peak drywell pressure increases. This trend is illustrated in Figure 6.2-15, where calculated and measured peak drywell pressures are compared. In no case did the model underpredict the test data.

The pressure and temperature responses of the containment are calculated for 2957 MWt with methodology which has been reviewed and approved by the NRC as documented in Reference 23. The short-term pressure responses are shown in Figure 6.2-22a with a peak drywell pressure of 43.9 psig, which is well below the design pressure of 56 psig. The short-term suppression pool temperatures are shown in Figure 6.2-25a.

Revised analysis of the pressure and temperature response of a similar primary containment (Dresden Unit 2) following an actual LOCA was performed in which peak drywell temperature was calculated to be 320°F. This concern was addressed in Dresden Unit 2 reports entitled "Special Report of Incident of June 5, 1970" and "Supplement to the Special Report of June 5, 1970". The LOCA which caused this peak drywell temperature was a special case small break LOCA (actually a steam leak) which did not have any effect on the design temperature and pressure of the containment (281°F, 56 psig) because the pressure associated with the higher temperature was not a saturation pressure. The resulting combination of slightly higher temperature and significantly lower pressure was less severe than design conditions. [6.2-29]

6.2.1.3.2.2 Containment Long Term Response to A Design Basis Accident

After the blowdown immediately following a postulated recirculation line break, the temperature of the suppression chamber water would approach 130°F and the primary containment system pressure equalizes at about 25 psig. Most of the noncondensible gases would be transported to the suppression chamber during blowdown. As condensation in the drywell began, the drywell pressure would decrease and the gases would redistribute between the drywell and the suppression chamber via the vacuum-breaker system.

The core spray system would remove decay heat and stored heat from the core, thereby minimizing core heatup and limiting metal-water reaction to less than 0.1%. The core spray system would transport core heat out of the reactor vessel through the broken recirculation line in the form of hot water. This hot water would flow from the drywell into the suppression chamber via the connecting vent pipes. Steam flow would be negligible. The energy transported to the suppression chamber water would ultimately be removed from the primary containment system by the residual heat removal (RHR) system heat exchangers.

Prior to activation of the containment cooling mode of RHR (arbitrarily assumed to occur at 600 seconds after accident initiation) the available RHR pumps in the low pressure coolant injection (LPCI) mode would add liquid to the reactor vessel along with core spray. After the reactor vessel was flooded, the excess flow would discharge through the break into the drywell. This flow, in addition to heat losses to the walls, would offer considerable cooling to the drywell and would cause a depressurization of the containment as the steam in the

drywell condensed. At 600 seconds, the RHR system may be transferred from the LPCI mode to the containment cooling mode. The containment spray would not be necessary at all and the transfer to containment cooling mode would not be necessary for several hours. As described in Section 6.2.2, valving permits the operator to obtain a variable division of flow on the RHR system between LPCI and containment cooling. Since the LPCI flow path comes off the containment cooling flow path downstream of the RHR heat exchanger, any flow diverted to LPCI injection is not diverted from the flow through the RHR heat exchanger, and thus would not impact long-term suppression pool cooling.

There is no firm time requirement as to when the containment cooling system must be placed into operation.

To assess the long-term pressure and temperature response of the primary containment after the postulated blowdown, an analysis was made of the recirculation line break accident for the following conditions of containment spray and containment cooling. For all cases, one of the core spray systems is assumed to be in operation with an initial suppression pool temperature of 95°F. The following case was chosen to illustrate the containment response for the limiting availability of equipment:

> Operation of one RHR cooling loop with one RHR pump, one RHR service pump, one RHR heat exchanger, and no containment spray.

The long term pressure and temperature responses of the containment are calculated for the limiting Case at 2957 MWt with methodology that has been reviewed and approved by the NRC as documented in Reference 23. The long-term pressure responses are shown in Figure 6.2-16a. The long term suppression pool temperatures are shown in Figure 6.2-18a.

6.2.1.3.3 Containment Response to a DBA-LOCA for Minimum NPSH

The DBA-LOCA analysis for NPSH is performed for two time periods: short-term (up to 600 seconds) and long-term (after 600 seconds).

The following are the key assumptions for the short-term containment response to DBA-LOCA for minimum NPSH.

For the DBA-LOCA for short-term NPSH evaluation (600 seconds), the analysis is based on a single failure of the loop selection logic. Consequently, the flow from all four LPCI pumps goes into the broken recirculation loop and subsequently discharges into the drywell directly. The maximum runout flow rate is assumed. Both core spray pumps are operating with the maximum flow rate.

Minimum initial drywell and wetwell pressures and maximum initial drywell humidity are assumed. This minimizes the amount of non-condensable gas in the containment, which minimizes the pressure response. The initial suppression pool water volume corresponds to the Low Water Level (LWL) to maximize the suppression pool temperature response.

As a result of the large LPCI injection directly into the drywell during the first 10 minutes, a significant reduction in drywell pressure and temperature produced a reduction of pressure in the suppression chamber. Figure 6.2-16b shows a short-term containment pressure response for NPSH due to DBA-LOCA. Figure 6.2-18b shows the short-term containment suppression pool temperature response for NPSH due to DBA-LOCA.

The assumptions discussed in Section 6.2.1.3.2.2, which are applicable for the long-term DBA-LOCA analysis for peak pool temperature, are used for the minimum NPSH analysis with the following exceptions:

A. Minimum initial drywell and wetwell pressures and maximum initial drywell humidity are assumed. This minimizes the amount of non-condensable gas in the containment, which minimizes the pressure response.

B. Containment cooling is achieved by operating one RHR loop at 600 seconds in the containment spray mode (drywell and wetwell sprays), instead of the pool cooling mode. This will minimize the containment pressure response, since cold water sprays will bring down the pressure.

C. The drywell and wetwell spray flow rates are 4750 gpm and 250 gpm, respectively. The total RHR heat exchanger K-value is 262 Btu/sec-°F.

D. Passive heat sinks in the drywell and wetwell airspace are modeled to minimize the pressure response.

Figures 6.2-16b and 6.2-18b present the containment pressure and temperature response for the short-term DBA-LOCA for NPSH. Figures 6.2-16c and 6.2-18c present the containment pressure and temperature response for the long-term DBA-LOCA for NPSH. It is noted that the early portion (before 600 seconds) of the plots for the long-term DBA-LOCA should not be used. For this time period,the short-term DBA-LOCA results should be used.

6.2.1.3.4 Mark I Program for Re-evaluation of Containment Response to Hydrodynamic Events

Nuclear Regulatory Commission Order 46 FR 9312, which dealt with the suppression chamber hydrodynamic loads defined in NEDO-21888, and NEDO-24583-1, required Quad Cities Station to modify the plant as necessary to assure conformance to Appendix A of NUREG-0661. The resulting modifications, collectively referred to as the Mark I

containment modification, included installation of supports, stiffeners and related items listed in the PUAR Vol. I which have a higher capacity to resist postulated loads due to pool swell, steam condensation and safety/relief valve discharge.

Subsequent to original design, new suppression chamber hydrodynamic loads were identified. The new loads are related to the postulated LOCA and SRV operation. The new loads were identified as a generic open item for utilities with Mark I containments. To determine the magnitude and time characteristics of the dynamic loads and identify the course of action needed to resolve outstanding concerns, the utilities with Mark I containments formed the Mark I Owners Group. The Mark I Owners Group established a short-term program, which was completed in 1976 and approved by the NRC in 1981, and a long-term program, generically resolved in the fall of 1982. The new loads were categorized and defined as part of the short-term program. The Quad Cities Load Definition Report (NEDO 24567) specifically defined the loads for the Quad Cities Station for the suppression pool and its components. [6.2-33]

The analysis of containment response to LOCAs and SRV discharge events, including development of event sequences, assumptions, load definitions, and analysis techniques, are presented in the Plant Unique Analysis Report (PUAR) for Quad Cities issued in May 1983. The PUAR is the primary reference for this section.^[2]^ In February 1986 the NRC approved the Quad Cities Units 1 and 2 PUAR which effectively closed out this phase of the redesign effort.

The loads, methods, and results described in the PUAR demonstrate that the margins of safety which actually existed for the original design loads have not only been restored, but have been increased. The advancements in the understanding of hydrodynamic phenomena and in the structural analyses and modeling techniques have substantially increased since the original design and analysis were completed. This increased understanding and analysis capability is applied to the original loads as well as to those newly defined loads.

The Mark I containment modification program also included testing. The containments for Quad Cities are very similar to those for Dresden, therefore, the subscale and full-scale tests performed for Dresden are applicable to Quad Cities.

Details of the structural analysis, load combinations service levels and other aspects of load characterization are presented in Section 3.8. Suppression pool temperature and pressure response is summarized in this section and detailed in the PUAR.[2]

6.2.1.3.4.1 Summary of Loss-of-Coolant-Related Load Effects

Immediately following a postulated design basis accident (DBA) LOCA, the pressure and temperature of the drywell and vent system atmosphere would rapidly increase. As drywell pressure increased, the water initially present in the downcomers would be accelerated into the suppression chamber until the downcomers were cleared of water. Following downcomer water clearing, the downcomer air, essentially at drywell pressure, would be exposed to the relatively low pressure in the suppression chamber, and would produce a downward reaction force on the suppression chamber shell. The consequent bubble expansion would cause the suppression pool water to swell (pool swell), and the airspace above the pool to compress. This compression would result in an upward reaction force on the suppression chamber shell. Eventually, the bubbles would "break through" to the suppression chamber airspace, equalizing the pressures. An air/water froth mixture

would continue upward (due to the momentum previously imparted to the water), causing impingement loads on elevated structures. The transient associated with this rapid drywell air venting to the suppression pool would last from 3—5 seconds. [6.2-34]

Following air carryover would be a period of high steam flow through the vent system. The discharge of steam into the pool and its subsequent condensation would cause pool pressure oscillations, which would be transmitted to various submerged structures and to the suppression chamber shell. This phenomenon is referred to as condensation oscillation (CO). As the reactor vessel depressurized, the steam flowrate to the vent system would decrease. Steam condensation during this period of reduced steam flow would be characterized by an up-and-down movement of the water-steam interface within the downcomer as the steam volumes condensed and were replaced by surrounding pool water. This phenomenon is referred to as chugging.

Postulated intermediate break accident (IBA) and small break accident (SBA) LOCAs would produce drywell pressure transients that are slow enough that the dynamic effects of vent clearing and pool swell would be negligible. However, some dynamic effects would occur: CO and chugging for an IBA, and chugging for a SBA.

6.2.1.3.4.2 Summary Description of Safety/Relief Valve Discharge-Related Load Effects

Quad Cities Units 1 and 2 are each equipped with one Target Rock Safety Relief Valve (SRV) and four Relief Valves (RV) to control primary system pressure during transient conditions. In the following discussion, the term SRV refers to both SRVs and RVs. The five SRVs are mounted on the main steam lines inside the drywell, with their discharge piping routed down the main vents into the suppression pool. When a SRV is actuated, steam released from the primary system is discharged into the suppression pool. The SRVs are actuated either automatically or manually. See Section 5.2.2 for a presentation of the SRV pressure settings. The lower SRV pressure settings are intended to reduce the frequency of multiple SRV discharges. [6.2-35]

Prior to the initial actuation, the SRV discharge line contains air at drywell pressure and suppression pool water in the submerged portion of the piping. Following SRV actuation, steam would enter the SRV discharge line, compressing the air within the line and expelling the water slug into the suppression pool. During water clearing the SRV discharge line would undergo a transient pressure loading.

Once the water had been cleared from the T-quencher discharge device, the compressed air would enter the pool as high pressure bubbles. These bubbles would expand, resulting in an outward acceleration of the surrounding pool water. The momentum of the accelerated water would result in an overexpansion of the bubbles, causing the bubble pressure to become negative relative to the ambient pressure of the surrounding pool. This negative bubble pressure would slow and reverse the motion of the water, leading to a compression of the bubbles and a positive pressure relative to that of the pool. The bubbles would continue to oscillate in this manner as they rose to the pool surface. The positive and negative pressures developed due to this phenomenon would attenuate with distance and result in an oscillatory pressure loading on the "wetted" portion of the suppression chamber shell and submerged structures.

6.2.1.3.4.3 General Assumptions

Implicit in the LOCA analysis was the assumption that the event would actually occur, although the probability is low. No credit was taken for detection of leaks and subsequent corrective actions to avoid LOCAs. Furthermore, various sizes of pipe breaks were postulated to evaluate a full range of effects. The large, instantaneous pipe breaks were considered to be bounding cases in order to evaluate the initial, rapidly occurring events such as vent system pressurization and pool swell. Smaller pipe breaks were analyzed to maximize prolonged effects such as CO and chugging. Three different LOCAs were analyzed — the DBA LOCA, IBA, and SBA. The DBA LOCA is a double-ended guillotine break in the 28-inch recirculation line (see Figure 6.2-11); the IBA is a 0.1 ft^2 break in a liquid line; the SBA is a 0.01 ft^2 break. [6.2-36]

The LOCAs were assumed to occur coincident with plant conditions that exacerbated the parameter of interest. For example, the reactor was assumed to be at 102% of rated power, a single failure was assumed, and no credit was taken for normal auxiliary power. For the original design bases the initial power condition prior to a design event was 100% of rated power. Operator action to mitigate the effects of a LOCA was assumed to be unavailable for a specified period. Other assumptions were selected to maximize the parameter to be evaluated. This approach resulted in a conservative evaluation, since plant conditions are not likely to be in this worst case scenario if a LOCA were to occur (see Section 6.2.1.3.2 for additional information on LOCAs).

6.2.1.3.4.4 Test Results and Load Definitions

The load definitions utilized in the Quad Cities Units 1 and 2 PUAR were based on conservative test results and analyses. The LOCA steam condensation loads (CO and chugging) were based on tests in the Mark I Full-Scale Test Facility (FSTF). The FSTF, a full-size 1/16 segment of a Mark I torus, was designed and constructed specifically to ensure that conservative results would be obtained on a generic basis. Actual Mark I drywells have piping and equipment which would absorb some of the energy released during a LOCA. The LOCA pool swell loads were developed from similarly conservative tests at the Quarter-Scale Test Facility (QSTF).

The methodology used to develop SRV loads was based on conservative methods and assumptions. Safety/relief valve loads were calculated using a minimum or manufacturer-specified SRV opening time, a maximum steam flow rate, and a maximum steam line pressure. The conservatism in the SRV load definition approach was demonstrated by in-plant tests performed at Dresden Unit 2[7] and at several other plants. All such tests confirmed that actual plant responses are significantly less severe than predicted. The Dresden in-plant SRV discharge tests are directly applicable to Quad Cities Units 1 and 2.

Several loads were classified as secondary loads because of their inherently low magnitudes. The loads include seismic slosh pressure loads, post-pool swell wave loads, asymmetric pool swell pressure loads on the suppression chamber as a whole, sonic and compression wave loads, and downcomer air-clearing loads. Secondary loads were treated as negligible compared to other loads in the analysis, in accordance with Appendix A of NUREG-0661.

The methodology used to develop plant-unique suppression chamber loads for each load defined in NUREG-0661 is discussed in Section 1-4.0 of the PUAR. The results of applying the methodology to develop specific values for each of the governing loads which act on the suppression chamber are discussed in Section 3.8.

The loads acting on the suppression chamber were categorized as follows:

1. Dead weight loads;

2. Seismic loads;

3. LOCA pressure and temperature loads;

4. Pool swell loads;

5. Condensation oscillation loads;

6. Chugging loads;

7. SRV pressure and temperature loads; and

8. Containment interaction loads.

Loads in Categories 1 through 3 were considered in the original containment design. Loads in Categories 1 and 2 are documented in the containment data specifications and loads in Category 2 are documented in the plant design specifications. Additional Category 3 loads would result from postulated LOCA and SRV discharge events. Loads in Categories 4 through 6 would result from postulated LOCA events; loads in Category 7 would result from SRV discharge events; loads in Category 8 are reactions which would result from loads acting on the structures attached to the suppression chamber. Category 3 and Category 7 loads are discussed in this section; the other load categories are discussed in Section 3.8. The sequences of hydrodynamic loads are also discussed in this section as definitions of the blowdown and discharge events. Section 3.8 lists each load category and the resultant effects on major suppression chamber structures.

The following is a breakdown of LOCA pressure and temperature (Category 3) loads.

A. Normal operating internal pressure loads — The suppression chamber shell is subjected to internal pressure loads during normal operating conditions. This loading was taken from the original design specifications. The range of normal operating internal pressure specified is -0.2 — 0.2 psig.

B. LOCA internal pressure loads — The suppression chamber shell would be subjected to internal pressure during a small break accident (SBA), intermediate break accident (IBA), or DBA events. The procedure used to develop LOCA internal pressures for the primary containment is discussed in the PUAR (Section 1-1.1.1).[2] Figures 6.2-20a through 6.2-22a present the resulting suppression chamber internal pressure transients and pressure magnitudes at key times during SBA, IBA, and DBA events.

   The pressure specified for each event was assumed to act uniformly over the suppression chamber shell surface, except during the early portion of a DBA event. The effects of internal pressure on the suppression chamber for the initial portion of a DBA event were included in the pool swell torus shell loads.

The corresponding suppression chamber external or secondary containment pressure for all events was assumed to be 0.0 psig.

C. Normal operating temperature loads — The suppression chamber is subjected to the thermal expansion load associated with normal operating conditions. This loading was taken from the original design specification for the containment.

   Additional suppression chamber normal operating temperatures were taken from the suppression pool temperature response analysis.

D. LOCA temperature loads — The suppression chamber would be subjected to thermal expansion loads associated with the SBA, IBA, and DBA events. The procedure used to develop LOCA containment temperatures is addressed in the PUAR (Section 1-4.1.1). Figures 6.2-23a, 6.2-24a, and 6.2-25a present the resulting suppression chamber temperature transients and temperature magnitudes at key times during the SBA, IBA, and DBA events.

   Additional suppression chamber SBA event temperatures were taken from the suppression pool temperature response analysis. The greater of the temperatures specified in Figure 6.2-23a and that analysis was used in evaluating the effects of SBA event temperatures.

   The temperatures specified for each event were assumed to be representative of pool temperatures, airspace temperatures, and shell metal temperatures throughout the suppression chamber. The ambient temperature for all events was assumed to be equal to the minimum temperature during normal operating conditions.

   As the temperature of the suppression chamber shell began to increase, the temperature difference between it and the suppression chamber vertical supports would result in differential thermal expansion effects. Temperatures in the suppression chamber vertical supports were calculated using a one-dimensional steady-state heat transfer model applying the thermal characteristics of the suppression chamber. Coefficients were then calculated and temperature profiles are derived (Figure 6.2-26).

Transient pressures would act on the submerged portion of the suppression chamber shell during the air clearing phase of a postulated SRV discharge event. The maximum shell pressures and characteristics of the SRV discharge pressure transients were developed using an attenuated bubble model that included the load mitigation effects of the 12-inch diameter T-quenchers.

The SRV actuation cases considered are discussed in Section 1-4.2.1 of the PUAR. The case resulting in maximum suppression chamber shell pressures was an SBA/IBA first actuation with elevated drywell pressure and temperature. This pressure load was

conservatively used for the multiple valve case with actuation occurring in all five SRV discharge load bays simultaneously. Actuation of the automatic depressurization system (ADS) would also create this multiple valve case.

The single valve case was derived from the multiple valve case results. These results were factored by the ratio of the maximum shell pressure for the single valve load profile to that of the multiple valve load profile. When the ratio of 0.669 was applied to the multiple valve load profile, the resulting load was a conservative approximation of the single valve load profile at all locations of the suppression chamber shell. In this manner, the single valve results were conservatively obtained.

Figures 6.2-27 and 6.2-28 show the resulting SRV discharge shell loads for the single valve case and multiple valve case, respectively. The results shown include the effects of the spatial distribution of shell pressures, the absolute summation of multiple valve effects with application of the bubble-induced pressure cut-off criteria, the use of first actuation pressures with subsequent actuation frequencies, and the application of +-25% and +-40% margins to the first and subsequent actuation frequencies, respectively. This methodology is in accordance with the conservative criteria set forth in NUREG-0661.

The distribution of suppression chamber shell pressures for SRV discharge would be asymmetric with respect to the vertical centerline of the containment. The pressure distribution which results in the maximum total vertical and horizontal loads on the suppression chamber would occur for the multiple valve case (Figure 6.2-28). Figure 6.2-29 shows the longitudinal pressure distribution for the multiple valve case.

6.2.1.3.4.5 Suppression Pool Temperature Response to SRV Transients

Quad Cities Units 1 and 2 take advantage of the large thermal capacitance of the suppression pool during plant transients requiring SRV actuation. Steam would discharge through the SRVs into the suppression pool where it would condense, resulting in an increase in the temperature of the suppression pool water. Although stable steam condensation is expected at all pool temperatures, NUREG 0783 imposed a local temperature limit in the vicinity of the T-quencher discharge devices. [6.2-38]

All Quad Cities ECCS suction strainers are located in suppression chamber torus bays that do not contain SRV discharge lines quenchers. This arrangement precludes[25] steam flow from the quenchers being entrained into the ECCS suction. For this reason the local pool temperature limit is eliminated for Quad Cities. Therefore, a local pool temperature limit is not applicable.

6.2.1.3.4.6 Event Sequences

Analysis conditions, load combinations, and service limits are discussed generally in Section 3.8. Event sequences which include only the hydrodynamic loads are discussed in this section. Event sequences that also include nonhydrodynamic loads are discussed in Section 3.8. All hydrodynamic event sequences are discussed in this section in order to more completely define the events.

This section describes the event sequences for the following postulated LOCAs:

A. Design Basis Accident

   The DBA for the Mark I containment design is the instantaneous guillotine rupture of the largest pipe in the primary system (the recirculation line). Figure 6.2-31 presents a bar chart of the DBA sequence of events.

B. Intermediate Break Accident

   The bar chart in Figure 6.2-32 shows the event sequence for a break large enough so that the high-pressure coolant injection (HPCI) system cannot prevent ADS actuation on low-water level, but for break sizes smaller than that which would produce significant pool swell loads. A break size of 0.1 ft^2^ is assumed for an IBA.

C. Small Break Accident

   The bar chart in Figure 6.2-33 shows the event sequence for a break size of 0.01 ft^2. For a SBA, the HPCI system would be able to maintain water level and the reactor would be depressurized by manual initiation of ADS. The SBA break is too small to cause significant pool swell, and CO does not occur during a SBA. The ADS is assumed to be initiated 10 minutes after the SBA begins.

6.2.1.3.5 Containment Capability with Respect to Metal-Water Reactions

6.2.1.3.5.1 Potential for Metal-Water Reactions

If, as the result of a severe transient or accident, zircaloy in the reactor core were to be heated to temperatures above about 2000°F in the presence of steam, an exothermic chemical reaction would occur in which zirconium oxide and hydrogen would be formed. The corresponding energy release would be about 2800 BTU per pound of zirconium reacted, which would be accommodated in the suppression chamber pool. The hydrogen formed, however, would result in an increased containment pressure due simply to the added moles of gas in the fixed volume. Although hydrogen would be produced during a DBA, the containment is inerted during reactor operation and during postaccident conditions to prevent the occurrence of explosive mixtures of gases in the containment. [6.2-39]

6.2.1.3.5.2 Analysis of Expected Metal-Water Reactions

For OPTIMA2 fuel, current analysis of expected metal-water reactions is performed in compliance with 10 CFR 50 Appendix K using the Westinghouse methodology and the GOBLIN/CHACHA codes. For Quad Cities Unit 1 ATRIUM 10XM fuel, this analysis uses the AREVA EXEM BWR-2000 Evaluation Methodology. The previous analysis used the SAFER-GESTR LOCA code. These analyses are further discussed in UFSAR Section 6.3.3. [6.2-40]

Earlier analyses of the metal-water reactions expected to occur during excessive core heatup were performed using a core heatup computer code described in NEDO-20566. The code was also based on requirements in 10 CFR 50 Appendix K. It was used to calculate time and temperature histories for a range of initial average planar segment power values encompassing all expected full power operation conditions. The total amount of zircaloy cladding in the reactor was divided by the amount of cladding in the active fuel region to obtain a percent of cladding available for metal-water reaction. Since inside cladding hydrogen generation in rods calculated to perforate is a localized phenomenon, it is ignored in the calculations. The amount of hydrogen generated due to the reaction of the outer cladding surface having thickness t_R in a given axial segment of a given fuel assembly was modeled as: [6.2-41]

$$W_{H_2} = n \pi D L t_R \rho_c \frac{2 N_{H_2}}{N_{Zr}} \qquad (6.2\text{-}5)$$

where

W_{H_2} = mass of hydrogen gas generated, lb_m

n = number of fuel rods in assembly

t_R = average cladding thickness reacted, ft.

rho_c = density of cladding (lb_m/ft.^{3})

N_{H_2} = molecular weight of hydrogen (2)

N_{Zr} = molecular weight equivalent for zirconium (91.2)

D = fuel rod diameter (ft)

L = assembly segment length (ft)

SVEA-96 Optima2 fuel is evaluated in accordance with Regulatory Guide 1.7 for the purpose of verifying a non-explosive hydrogen mixture in containment post-LOCA. Results of that evaluation show core wide metal water reaction results of less than 4% volumetric hydrogen concentration, based on five times the maximum amount of core-wide oxidation calculated in accordance with 10 CFR 50.46 [Ref. 31]. For Quad Cities Unit 1, a similar AREVA evaluation for ATRIUM 10XM fuel shows a core wise metal water reaction result of 4.01% volumetric hydrogen concentration (Reference 32). The resulting hydrogen concentration would not lead to an explosive mixture in the containment post-LOCA.

An additional consideration with regard to the NCAD analysis is that the primary influence on the nitrogen addition rate is the radiolytic generation of oxygen. The fuel type or extent of hydrogen generation due to metal-water reaction has no impact on the rate of production of oxygen. Since the analysis is primarily focused on maintaining oxygen concentrations below 5%, slight increases in the hydrogen generation due to metal water reaction would actually reduce the oxygen fraction, which would be conservative.

6.2.1.3.5.3 Power Distribution Effect on Hydrogen Generation

The power distribution assumed for all plants in calculating core-wide metal-water reaction is shown in Figure 6.2-34. This distribution was based on 1973 operating data from a large BWR which was operating under severe maximum average planar linear heat generation rate (MAPLHGR) limits as a result of the AEC July 1973 densification model. The distribution is very flat for that reason, which is conservative for calculation of core-wide metal-water reaction. [6.2-43]

The ordinate of Figure 6.2-34 shows the number of six-inch long fuel assembly axial segments whose power was calculated to exceed the value given by the abscissa, expressed as a percentage of the maximum permissible segment power. In doing a plant calculation, Figure 6.2-34 was used to sum up the hydrogen generation in segments with various values of segment power. The "maximum permissible segment power" was defined for a given core as follows:

A. The segment power corresponding to operation at design linear heat generation rate (LHGR) and design local peaking factor was calculated for each fuel type;

B. The segment power corresponding to operation at the MAPLHGR limit (if any) was calculated for each fuel type;

C. The lower (limiting) of the two values in 1 and 2 was selected for each segment; and

D. The "maximum permissible segment power" for the core was defined as the highest value in 3 among all segments in the core.

This definition adds another measure of conservatism in plants with multiple fuel types.

6.2.1.3.5.4 Conclusions

The capability of the containment to tolerate postulated metal-water reactions following a loss of coolant accident was evaluated in the original design phase. [6.2-44]

It was determined that the design integrity of the containment would not be threatened by the pressure increase that would result from a core wide metal water reaction of at least 18%.

For the purposes of combustible gas control the value for metal-water reaction for SVEA-96 Optima2 fuel is less than 4%. Furthermore, for Quad Cities Unit 1, ATRIUM 10XM fuel shows a core wide metal water reaction result of 4.01%.

6.2.1.3.6 Containment Subcompartments — Pipe Break in the Subcompartment Between the Reactor Shield Wall and the Reactor

Section 3.6.2.3.2 provides a discussion of jet impingement forces which could be postulated to act on the concrete reactor shield wall which surrounds the reactor. [6.4-44a]

6.2.1.3.7 Seismic Analysis

Seismic studies of the drywell and the pressure suppression chamber were conducted by John A. Blume and Associates of San Francisco, California. The results of this study are summarized in Sections 3.7.2.1.4 and 3.7.2.1.5. The suppression chamber seismic analysis was updated in the Mark I Plant Unique Analysis Report to incorporate the effect of the Mark I modification.[2]

6.2.2 Containment Heat Removal Systems

Containment cooling is a mode of the residual heat removal (RHR) system and is placed in operation to limit the temperature of the water in the suppression chamber. This section describes the major functional elements and primary components of the containment heat removal system. Included are descriptions of the three functional constituents of containment heat removal: suppression pool cooling, drywell spray, and suppression chamber spray. A description of the equipment in the RHR system is provided in Section 5.4. [6.2-45]

During normal operation, drywell cooling is provided by seven air handling units. Normal drywell cooling is addressed in Section 9.4. [6.2-46]

6.2.2.1 Design Bases

The design bases of the containment cooling mode of the RHR system are: [6.2-47]

1. To limit the suppression pool water temperature during RCIC operation (hot standby condition) so that if a blowdown should occur, the suppression pool water temperature will not exceed that which is necessary to achieve its primary role as the quenching agent in the suppression containment system; and

2. To furnish a spray into the containment to further aid in reducing containment pressure following a LOCA; and

3. To control the temperature of the suppression pool following a LOCA.

6.2.2.2 System Design

The containment cooling mode of RHR is a safety function and consists of two cooling functions: containment spray which consists of drywell spray and suppression chamber spray and suppression pool cooling. [6.2-48]

The RHR containment cooling mode can be initiated after the core is flooded which, for even the largest line break, would be accomplished within a few minutes. [6.2-49]

The RHR containment cooling mode is placed in operation to limit post-LOCA blowdown suppression pool temperature to 170°F. This temperature is based on tests which showed that complete condensation of blowdown steam from the design basis LOCA will definitely occur at temperatures at or below 170°F. The Bodega Bay and Humboldt Bay tests, upon which the pressure suppression design is based, covered the temperature range up to 170°F. Other tests have shown that complete condensation can also be expected at higher suppression pool temperatures. [6.2-50]

During containment spray operation, water pumped through the RHR heat exchangers would be diverted to spray headers in the drywell and above the suppression pool. The spray headers in the drywell would condense steam in the drywell, thereby further lowering containment pressure. The reactor vessel makeup requirement which must be supplied by low pressure coolant injection (LPCI) is approximately 3000 gal/min, which can easily be handled with one RHR pump. Therefore, one of the remaining three RHR pumps can be used to provide flow for operation of containment spray. The drywell spray effluent would collect in the bottom of the drywell until it reached the level of the vent pipes, at which point it would begin to overflow and drain back to the suppression pool. Approximately 5% of the containment spray flow may be directed to the suppression chamber spray ring to cool noncondensible gases collected in the free volume above the suppression pool. The containment spray function is not required for proper performance of the containment pressure suppression system.

Initiation of the containment spray function is prevented when the drywell pressure falls too low. This interlock cannot be overridden. [6.2-51]

During suppression pool cooling operation, the RHR pumps are aligned to pump water from the suppression pool through the RHR heat exchangers, where heat is transferred to the RHR service water, then the water is returned to the suppression pool via the full flow test line. The water in the suppression chamber is thus cooled directly, without using the spray headers. A motor operated valve is used to regulate flow. [6.2-52]

The containment cooling mode of RHR cannot normally be placed into operation unless the core cooling requirements of the LPCI mode have been satisfied. Valving permits the operator to obtain a variable division of flow between LPCI and containment cooling. Since the LPCI flow path comes off the containment cooling flow path downstream of the RHR heat exchanger, any flow diverted to LPCI injection is not diverted from the flow through the RHR heat exchanger, and thus would not impact the heat removal rate of the system or post-accident suppression pool temperature response. Interlocks are provided to ensure containment cooling operation occurs within certain design parameters. For a discussion of the control logic for the containment cooling mode, refer to Section 7.4.1. [6.2-53]

If the reactor water level were to decrease below two-thirds core height, the system flow would return automatically to the LPCI mode, unless the bypass switch was in manual override.

6.2.2.3 Design Evaluation

The possibility of debris contamination of suppression pool water that supplies ECCS has been considered regarding the design of the ECCS suction strainers as required by NRC Bulletin 96-03. [6.2-54]

The potential sources of contaminants considered in the design include containment interior coatings, fibrous insulation, aluminum and stainless steel foil from reflective metal insulation, insulation jacketing, Cal Sil insulation, dirt/dust, rust flakes, suppression pool sludge, and other miscellaneous debris.

The fibrous insulation within the drywell is NUKON blankets used only on parts of the reactor coolant pressure boundary piping that is 2-inch diameter or smaller. Fibrous insulation is also located within flued head penetrations between the process pipe and the guard pipe, see Figure 3.8-38. This insulation is a molded asbestos fiber on carbon steel pipe and NUKON on stainless steel pipe.

Following the accident, the strainers may begin to accumulate debris. To account for this possibility, design calculations have been performed to model the worst case debris generation, transport and accumulation resulting from a DBA-LOCA and the simultaneous operation of ECCS equipment. The design calculations determined the quantity of the debris generated during a LOCA, the quantity of the debris transported to the suppression pool, the transport of the debris within the suppression pool to the strainers, the filtration of the strainers for the transported debris, and the associated head loss. The total strainer head loss is determined based on the mathematical sum of the clean strainer head loss, the calculated head loss contribution due to RMI debris, and the calculated head loss contribution of fibrous insulation including miscellaneous debris. The calculation considers a surface area for each of the four strainers reduced by two square feet and includes an additional 0.5 cubic feet of fibrous material on each of the strainers to account for possible additional foreign material inside containment. The methodology is consistent with the guidance in the BWROG Utility Resolution Guidance for ECCS Strainer Blockage and the associated SER contained therein.[1]

The ECCS strainers are made from perforated stainless steel having perforations of 1/8-inch in diameter with an effective 40% open area. The perforation size has been selected to screen out particles capable of plugging spray nozzles or other ECCS equipment. The strainers are positioned above the bottom of the suppression pool to minimize any risk of plugging from debris. The strainers are also located well below the pool surface to prevent air entrainment due to vortices. The ECCS suction strainers are of the stacked disk design. The outline of the stacked disk ECCS suction strainers is shown on Figure 3.8-24, Section A-A. The strainers have a resistance coefficient of 1.16, which was determined by flow testing of a Unit 1 strainer.

In addition to the design of the ECCS suction strainer, the circuitous flow path from the drywell to ECCS pumps makes it unlikely that damaging debris would actually reach ECCS equipment. The flow path from the drywell leads through the 1 X 1 1/2 foot openings of the jet deflector plates through the 6 ft. 9 in. vent lines (see Figure 6.2-4). Inside the suppression chamber, the vent lines connect to large spherical shells that are interconnected by the 4-foot 10-inch diameter vent header (see Figure 6.2-5). From this header, the path to the suppression pool is through the 96 24-inch diameter downcomers that extend below the water line. The path then proceeds through the large suppression pool volume to the four suction strainers, connected to the ECCS header located about 1/3 of the water level height above the bottom of the suppression chamber. From the strainers the path leads to a 24-inch suction ring header and then to ECCS pump suction lines. The path provides many places to trap foreign objects.

Suppression pool water is demineralized and does not contain special additives. The neutral pH of the pumped fluid would not corrode pump seals or bearings.

In summary, the ECCS suction strainers have been sized to accommodate the debris generated by a pipe break inside the containment. Furthermore, the suction strainers prevent any possibly damaging debris from reaching the ECCS pumps. These considerations have led to the conclusion that the probability of suppression pool contamination creating a safety problem is extremely remote, to the point of being negligible.

6.2.2.4 Tests and Inspections

Since containment cooling is an operating mode of the RHR system, testing performed on the RHR system to verify LPCI operability partially verifies that containment cooling is operable. An operational test of the discharge valves to the containment spray headers is performed by shutting the downstream valve after it has been satisfactorily tested and then operating the upstream valve. Two additional tests are performed to verify that the containment spray function is operable. Once every 10 years, the spray headers and nozzles are water tested in the suppression chamber (in accordance with the Technical Specifications) and air tested in the drywell (in accordance with the Technical Requirements Manual). These tests verify that a flow path exists through the spray header and nozzles and thereby verifies its operational status. [6.2-55]

6.2.3 Secondary Containment Functional Design

The description presented in this section is applicable to both units, since the secondary containment is common to both units. This description includes the design basis and design features of the secondary containment (reactor building) structure, and all interfacing structure/systems needed to ensure the integrity of the secondary containment. A design evaluation is provided which addresses performance characteristics and the impact of an instrument line break. Tests and inspections needed to verify that secondary containment is operable, and instrumentation required to monitor and operate secondary containment, are also described.

6.2.3.1 Design Bases

The safety objective of the secondary containment system, in conjunction with other engineered safeguards and nuclear safety systems, is to limit the release of radioactive materials so that offsite doses resulting from a postulated design basis accident (DBA) will remain below 10CFR100 guideline values. The design bases of the secondary containment system include the following: [6.2-56]

A. The secondary containment system is designed to provide the required level of containment when either Unit 1 or 2 primary containment is open for refueling or maintenance activities.

B. The secondary containment system is designed so that the reactor building inleakage rate is not greater than 4000 ft^3/min under calm wind conditions with an average internal negative pressure equal to or greater than 0.25 in. H_2O gauge. [6.2-57]

C. The secondary containment system is designed with sufficient redundancy so that no single active component failure can prevent the system from achieving its safety objective. [6.2-58]

D. The secondary containment system is designed in accordance with Class I design criteria (see Chapter 3.2.1).

E. The reactor building is designed to contain a positive internal pressure of at least 7 in. H_2O gauge without structural failure and without pressure relief.

F. The secondary containment system has the capability of processing and exhausting air from the reactor building and discharging the treated air from an elevated release point.

G. The secondary containment system is designed so that it may be periodically tested to verify system performance.

H. The secondary containment isolation system and its associated controls are designed to isolate the reactor building in the time required to prevent significant release of fission products through the normal discharge path.

6.2.3.2 System Design

The secondary containment system includes four major parts: [6.2-59]

A. The reactor building;

B. The secondary containment isolation and control system;

C. The standby gas treatment system (SBGTS); and

D. The 310-foot chimney.

The secondary containment system applies four methods to mitigate the consequences of a postulated LOCA (pipe break inside the drywell) and the refueling accident (fuel assembly drop):

A. A negative pressure in the reactor building so that leakage is inward under calm wind conditions, and any exfiltration due to high wind conditions is minimized;

B. A low leakage containment volume to provide holdup time for fission product decay prior to release;

C. Filters and adsorbers to remove radioactive particulates and halogens from the secondary containment atmosphere prior to release; and

D. Discharge of the processed secondary containment atmosphere through an elevated release point.

Design parameters of the secondary containment are presented in Table 6.2-5.

6.2.3.2.1 Reactor Building

A single reactor building completely encloses the reactors and pressure suppression primary containment systems of both units. The reactor building also houses the Unit 1 and 2 refueling and reactor servicing equipment, new and spent fuel storage facilities, and other reactor auxiliary and service equipment. [6.2-60]

The reactor building is a monolithic reinforced concrete structure up to the refueling floor level, with a structural steel framework covered by sealed sheet-metal siding panel walls and a precast concrete roof above the refueling floor level.

The containment barrier function of the reactor building is achieved by design and construction for low leakage through building walls and roof, airlocks, and pipe and electrical penetrations.

The wall panels of the reactor building above the refueling floor level (reactor building superstructure) were designed and installed with special sealing methods. The sheet metal siding employs interlocking joints between panels, and is sealed with vinyl plastic gaskets and caulking compounds (Figure 6.2-36). Other joints are sealed with such materials as rubber strips, adhesive tapes, and caulking compounds. Screw holes are caulked. Blowoff panels are installed as part of the reactor building superstructure siding to relieve pressure and control the damage under short term tornado loadings. These panels are attached by notched bolts, on 6-inch centers, which are designed to fracture at a panel loading of 70 lb/ft^2. Of the approximately 38,200 ft^2 of insulated superstructure siding, approximately 5,400 ft^2 is attached with these bolts. The blowoff panel design was laboratory tested by a commercial testing laboratory to assure conformance with specifications. The remainder of the siding is attached with self-tapping sheet metal screws.

The reactor building roof is comprised of 3 1/2-inch thick precast channel concrete slabs, covered with 1-inch thick fiberboard roof deck insulation, felt, asphalt, and gravel. Corners of the roof slabs are welded to the roof purlins; longitudinal and transverse joints are filled with mastic sealer, and the corner recesses are filled with grout.

On the 595 foot elevation, at both the southwest and northwest corners of the reactor building, a personnel access corridor provides access to the turbine building. As shown on drawing M-5, each corridor includes 3 doors, one to the reactor building, one to the turbine building, and one leading to the exterior area that has been welded shut. [6.2-61] The reactor building and turbine building doors are electrically interlocked.

A personnel airlock located on the east side of the reactor building (595 foot elevation) provides access between the reactor building, the Unit 1/2 diesel generator building, the Unit 1/2 trackway equipment airlock, and the outside. A trackway airlock located adjacent to the personnel airlock provides access for large equipment and rail cars. [6.2-62]

Doors from the reactor building provide access to each MSIV room. Doors between the MSIV rooms and turbine building main access areas can serve as a secondary containment boundary.

Watertight doors provide access from the Unit 1 and Unit 2 sides of the reactor building area to the associated HPCI rooms (554 foot elevation). An airlock in the HPCI access tunnel isolates the HPCI rooms from the remainder of the turbine building. The airlock doors serve as part of the secondary containment boundary. [6.2-63]

On the 647 foot elevation, a door provides access between the reactor building and the turbine building. [6.2-64]

On the 690 foot elevation, an airlock provides access to the turbine building roof. [6.2-65]

Reactor building personnel airlock access control doors have seals and are electrically controlled so that only one door in an airlock can be open at a time. The larger equipment airlock has two gasketed doors which are kept locked except when they are in use. Procedural requirements prevent both doors from being opened at the same time. [6.2-66]

Reactor building pipe and electrical penetrations are sealed to minimize air leakage. Electrical penetrations are typically caulked with inorganic fiber or oakum (historical use) and a soft setting compound. Airflow through pipeways is limited by use of concrete grout or metal collars where pipe movement does not occur. On pipes that move, a silicone rubber sleeve is clamped directly to the pipe at one end with a suitable thermal connection on hot pipes, and to a pipe sleeve embedded in the wall at the other end. [6.2-67]

The structural design features, shielding design, and seismic design requirements are described further in Chapter 3.

6.2.3.2.2 Secondary Containment Isolation and Control

The reactor building ventilation system performs two secondary containment functions. First it automatically controls the reactor building atmosphere at a negative pressure (0.1 - 0.70 in. H_2O) with the exhaust fan dampers, to assure inleakage of air so that exfiltration of airborne radioactive contamination is minimized. Second, it isolates on a secondary containment isolation signal. [6.2-68]

The reactor building ventilation isolation valves for each unit are located adjacent to the reactor building in the turbine building, on the supply and exhaust fan deck above elevation 658 feet. Isolation involves closing two valves in series in the supply duct and two valves in series in the exhaust duct, shutting down the ventilation fans, and activating the SBGTS. Isolations automatically initiated upon instrumentation sensing reactor building ventilation exhaust high radiation or radiation monitor downscale, refueling floor high radiation or radiation monitor downscale, high drywell pressure, reactor low water, or drywell high radiation.

6.2.3.2.3 Standby Gas Treatment System

The SBGTS provides particulate filtration and halogen adsorption from the reactor building atmosphere prior to release. The SBGTS also maintains a negative reactor building pressure after an accident to minimize the release of unprocessed secondary containment atmosphere. As part of this capability, the SBGTS can reduce secondary containment pressure to -0.25 in. H_2O gauge. See Section 6.5 for a detailed SBGTS description. [6.2-69]

6.2.3.2.4 310-Foot Chimney

The 310-foot chimney provides for elevated release of processed secondary containment atmosphere. (Normal reactor building ventilation exhausts through a separate ventilation stack). The chimney may receive inputs from the turbine building ventilation (Units 1 and 2), the off-gas recombiner rooms (Units 1 and 2), the max recycle radwaste building, the off-gas filter building, the resin solidification building, the radwaste building, and the SBGTS trains. Additional discussion of the chimney is provided in Chapter 3 and in Section 11.3. [6.2-70]

6.2.3.3 Design Evaluation

The secondary containment system provides the principal mechanisms for mitigating the consequences of a refueling accident in the reactor building. The primary and secondary containment systems acting together provide the principal mechanisms for mitigating the consequences of a LOCA in the drywell. Since the reactor building leakage rate is low, and the reactor building atmosphere is processed and discharged at an elevated release point (using the SBGTS and the chimney), the offsite radiation doses that would result from postulated design basis accidents are reduced significantly. The reactor building is a Class I structure. The design and construction of the reactor building provides a maximum inleakage rate of 4000 ft^3/min under calm wind conditions with an average internal negative pressure equal to or greater than 0.25 in. H_2O gauge. This results in a low exfiltration rate during high wind conditions. [6.2-71]

In the event of a pipe break inside the primary containment or a fuel handling accident causing an actuation signal, normal reactor building ventilation for both units will shut down and isolate. The motor-operated valve from the train inlet on the unaffected reactor unit to the standby gas treatment system closes. The pre-selected SBGTS primary train will automatically start and operate at a constant flow of 4000 ft^3/min, removing air from all levels of the reactor building and discharging the processed air to the chimney. A high efficiency particulate air filter will remove radioactive particulates and an activated carbon adsorber will remove radioactive halogens from the air stream to reduce the level of radioactive contamination released to the environs. [6.2-72]

After a secondary containment isolation, the SBGTS holds the building at an average negative pressure equal to or greater than 0.25 in. H_2O gauge under calm wind conditions.

A careful determination has been made of the effect of a one inch instrument line break inside a secondary containment. This conservative analysis has led to the conclusion that the consequences of such an event would not be severe, with resulting radiological doses being well within published guideline values. [6.2-73]

The radiological consequence of the one inch instrument line break in the secondary containment is described in Section 15.6.2. An analysis has been performed of the consequences of a 1-inch instrument line break in the Quad Cities plant. Radiation levels in the reactor building ventilation duct would not be high enough to trip Reactor Building (RB) ventilation and start the standby gas treatment system so that all of the radioactive materials escaping to the atmosphere do so via the reactor building ventilation stack. The analysis showed that 70,000 pounds of water and 30,000 pounds of steam are released to the reactor building. Reactor building pressure starts to increase, thereby causing back pressure to be seen by the ventilation supply fan such that essentially no air flows into the reactor building. Concurrently, the exhaust fan on

the ventilation duct increases flow due to increased driving head. As a consequence of this phenomenon, air in the building is exhausted to make room for the expanding steam. Thus, all the steam not condensed in the reactor building is transported out the stack.

The RB internal pressure response analysis is applicable to both units, since a single reactor building completely encloses the reactors and primary containment systems for both units, resulting in a common secondary containment. The most conservative pressure response case with normal ventilation in operation is with RB ventilation isolated on one unit at the time of the accident, thereby minimizing pressure relief from exhaust fan flow and maximizing the pressure transient in the area of the break. For any fan configuration, any single exhaust fan flow rate exceeds any single supply fan flow rate by greater than 4,000 CFM. Additionally, immediately following the accident RB pressure would start to increase, thereby causing back pressure to be seen by the RB ventilation supply fan such that essentially no air flows into the building. Since SBGT rated fan capacity is 4,000 CFM, the secondary pressure response is bounded by analysis Case 5, described below. There was no RB compartment pressure response analysis performed for the small instrument line break, since secondary containment is one building. Analysis Case 5 demonstrates that building pressure remains below the minimum design pressure of 7 in H_2O gauge required to lift the panels, and therefore secondary containment integrity remains intact.

The description that follows was a response to a follow-up question concerning a postulated 1" instrument line break within secondary containment, during initial licensing of Quad Cities Station. The AEC requested Quad Cities Station to specifically provide assurance that the integrity of secondary containment would be maintained and that the building filters (Standby Gas Treatment) would not be bypassed. The second analysis performed as a result of the AEC request is historical from a dose analysis perspective and is not currently relied upon for plant activities, but the pressure response analysis remains valid as a bounding analysis. The assumptions of this evaluation included the original proposed technical specification coolant activity of 20 micro-Curies/cc total Iodine and automatic start of the SBGT system (based on the assumption that RB vents isolate on a vent duct high radiation trip signal). The analysis is historical from a dose perspective because the Technical Specification action limit for required sampling is 0.2 micro-Curies/gram, which would result in RB ventilation duct dose levels that would <u>not</u> be high enough to trip vents and start the SBGT system.

[Start of Secondary Containment bounding pressure analysis]

The second analysis is a bounding pressure response analysis, and does <u>not</u> represent the accident scenario since radiation levels would not be high enough to isolate vents and start the SBGT system. The more conservative analysis for the reactor building internal pressure response as described below shows that under no circumstance will a postulated instrument line break jeopardize the health and safety of the public by degrading the integrity of the secondary containment.

Following the postulated instrument line break, part of the instrument line blowdown flow would flash and enter the reactor building as steam. The remaining blowdown water would descend to the floor and would not strongly influence building pressure. The steam introduced into the secondary containment would cause the pressure to rise. The pressure rise would result in a mass flow through normal building leakage paths, in addition to the SBGTS fan outflow rate. Condensation on relatively cool surfaces in the building would cause further steam mass extraction. Building pressure would adjust to a value such that the volumetric inflow rate of steam would be approximately equal to the combined volume extraction rates of the SBGTS fan, leakage, and steam condensation.

SBGTS Fan Flow Rate

Although it can be shown that the SBGTS fan flow outflow rate would increase with building pressure increase, a continuous removal of 4000 CFM was assumed for the computation. This conservatism leads to slightly higher-than-expected building pressure.

Building Leakage Rate

The building leakage rate is accurately known from normal operational requirements of the SBGTS. The reactor building outflow will correspond to 4000 CFM inflow at 1/4 inch of water vacuum. There is no apparent reason to expect any leakage paths to become plugged or otherwise unavailable for flow during outflow rather than inflow. However, 9 times the flow resistance is arbitrarily considered (or, equivalently, only 1/3 the leakage flow area) for leakage outflow for this worst-case pressure analysis. The effect of higher leakage outflow resistance provides higher-than-expected building pressure.

Condensation Rate

The surface area available for condensation increases as the steam volume increases. Only the concrete exterior surfaces were considered for condensation in the analysis applicable to Section 15.6.2.1. Internal surfaces and numerous other metal equipment surfaces were neglected which would increase the total condensation rate and further reduce building pressure. For the analysis to determine the pressure effects in the secondary containment only one-half the estimated condensation rate is used which also leads to higher-than-expected building pressures.

Outflow Properties

Steam first entering the reactor building would compress air rather than homogeneously mix with it. However, diffusion would occur which would tend to provide a steam-air mixture of varying concentration throughout the building. If air without steam is removed via leakage and the SBGTS fan, less energy removal would occur than if steam or air-steam mixture were removed. The calculated building pressure would be higher. Therefore, it was assumed that only air escaped from the building.

Results

Figure 6.2-37 shows calculated building pressure for Cases 2 and 5 in the following list of considered analysis cases. These analyses were also based on the preceding assumptions and conditions. The maximum building pressure is 6.8 in. H_2O, which is below the reactor building minimum design pressure of 7 in. H_2O gauge and the blow-off panel breakaway loading of 70 lb/ft^2.

Five cases were considered to demonstrate the available margin between the resulting postulated reactor building pressure and the maximum reactor building pressure that could be experienced without coincident panel blowoff.

Case		Assumptions	Maximum Reactor Building Pressure
1.	a.	Expected leakage outflow	0.75 in water
	b.	Rated fan capacity	
	c.	Condensation (on exterior walls only)	
2.	a.	Expected leakage outflow	1.0 in water
	b.	Rated fan capacity	
	c.	No condensation	
3.	a.	Expected leakage outflow	2.1 in water
	b.	No fan	
	c.	No condensation	
4.	a.	1/3 leakage outflow	5.6 in water
	b.	Expected fan capacity	
	c.	1/2 condensation	
5.	a.	1/3 leakage outflow	6.8 in water
	b.	Rated fan capacity	
	c.	1/2 condensation	

Cases 1 — 5 above are based upon no mixing of steam and air.

It is concluded for Case 1 that the expected reactor building pressure of 0.75 in. H_2O following an assumed guillotine instrument line break has a margin which is nearly a factor of ten times expected when compared to the secondary containment design pressure . Even if the assumptions are degraded to a case with no SBGTS fan operating and no condensation (Case 3), there is still more than a factor of three in the margin. Using the conservative assumptions of only one-half the calculated condensation and one-third of the calculated building leakage, the building pressure is still below 7 in.H_2O gauge. For case 4, the building pressure would rise to 5.6 in.H_2O with the expected SBGTS fan flow (accounts for effect of higher building pressure), and even if only rated fan capacity is used (case 5) the building pressure of 6.8 in. H_2O is below the minimum design pressure of 7 in.H_2O gauge.

[End of Secondary Containment bounding pressure analysis].

6.2.3.4 Tests and Inspections

Secondary containment integrity is verified by demonstrating that an air discharge rate of 4000 ft^3/min produces a negative pressure of at least 0.25 in. H_2O. This is accomplished by completely isolating the reactor building and using the SBGTS to exhaust air from the building. Differential pressure measurements are made across each of the four walls with zero flow through the standby gas treatment system to obtain base readings at existing wind conditions and existing internal and external temperature conditions. Similar differential pressure measurements are made at a flow of 4000 ft^3/min. Subtracting the base readings obtained at zero flow from those obtained at 4000 ft^3/min. flow provides differential pressure data corrected to zero wind conditions and zero differential temperature. [6.2-74]

If the reactor building average negative pressure (corrected for zero wind and zero differential temperature conditions) is equal to or greater than 0.25 in. H_2O gauge, the building design basis low leakage requirement is verified. The Technical Specifications require this test to be performed every 24 months. [6.2-75]

The radiation monitors that provide signals to isolate the reactor building can be tested by exposing sensors to appropriate radiation test sources or by simulating high radiation with instrumentation provided in the control room. Similarly, high drywell pressure instruments and reactor low water level instruments that provide signals to isolate primary containment and secondary containment are tested in a manner dictated by primary containment isolation requirements. Testing details for the SBGTS are found in Section 6.5. [6.2-76]

6.2.3.5 Instrumentation Requirements

The instruments required to support secondary containment are those instruments necessary to shut down reactor building ventilation and start SBGTS. These include the vent and area radiation monitors, drywell pressure monitors, and reactor level monitors.

Each parameter is monitored by redundant sensors which actuate redundant logic channels, housed in separate panels, which in turn initiate the redundant SBGTS trains. Radiation sensors are fail-safe such that a loss-of-signal from one sensor will alarm its condition and loss-of-signal from two redundant radiation sensors will initiate secondary containment system operation. Only one radiation sensor is required to initiate secondary containment system operation if an "accident" signal is detected. Pressure and level sensors require one-out-of-two-twice logic indication to initiate secondary containment isolation and start SBGTS. The redundant instrumentation and electrical controls for sensing "accident" signals, initiating the secondary containment isolation system, and operating SBGTS, are provided with separate power sources which can be supplied by separate standby diesel generators. Sufficient redundancy and electrical separation has been provided so that no single active component failure can prevent the system from performing its function. [6.2-77]

6.2.4 Containment Isolation System

The discussion presented in this section is applicable to either unit.

6.2.4.1 Isolation Valves

Isolation valves are provided on lines penetrating the drywell and pressure suppression chamber to assure integrity of the containment during emergency and post-accident periods. Isolation valves which must be closed to assure containment integrity immediately after a major accident are automatically controlled by the primary containment isolation system (PCIS). The controls and logic system are described in Section 7.3. [6.2-78]

Table 6.2-6 lists the of group isolation signals and setpoints for PCIS. Table 6.2-7 lists all penetrations by penetration number; identifies isolation valves with their pertinent modes, characteristics, and closing times; and identifies valves subject to Type C leak testing. For those valves closed by PCIS, Table 6.2-7 identifies the associated isolation group. Table 6.2-7 also lists electrical penetrations and special penetrations such as hatchways and other double gasketed penetrations.

Pipes which penetrate the containment and connect to the nuclear steam supply system, and pipes which open into the free space of the containment are equipped with two isolation valves in series. As a general rule, one of each pair of isolation valves in the series is located inside the containment, the other outside and as close to the containment as practical. [6.2-79]

For each inflowing line, one of two valve arrangements is used. In the first arrangement, both isolation valves in series are self-actuated check valves, one inside and one outside the containment. In the second arrangement, one is a check valve and the other is a power-operated valve (electric motor or air). On lines where flow may be in either direction, both valves are power operated.

On lines such as vacuum relief from atmosphere and suppression chamber water makeup lines, which open to the free space of the containment and have two normally closed valves, the valves are located outside the containment.

Lines forming a closed loop with primary containment (i.e., closed systems) but which, as a result of pipe failure, may carry radioactive fluids outside primary containment are generally provided with one isolation valve outside the containment. This may be either a self-actuating check valve or a remote manually-controlled motor-operated valve.

Systems which connect to the nuclear steam supply system and may be required to have flow after an accident are provided with two check valves, a check valve and a remote manually-controlled valve in series, or two remote manually-controlled valves in series. These include the feedwater, control rod drive hydraulic, standby liquid control, RHR, and core spray systems.

For lines that extend the primary containment boundary, the boundary includes the piping to the last (i.e., outboard) isolation valve. A primary containment pathway must be capable of being isolated. Technical Specification 3.6.1.3 provides the operability requirements for primary containment isolation valves.

Closed systems do not communicate with the primary containment atmosphere; rather they communicate with the suppression pool and are expected to remain submerged during a LOCA. Primary containment isolation valves on closed systems are exempt from 10 CFR Appendix J “Type C” testing because they are not required to isolate containment atmosphere due to the intact piping (inside containment to the outboard isolation valve) and the water seal provided by the suppression pool.

Any containment pathway with a structural flaw is evaluated for operability. Leakage from a through-wall flaw that cannot be isolated is evaluated against the leakage limits specified in Section 15.6.5.5.1 (atmospheric leakage or emergency core cooling system leakage as appropriate). In addition, the structural integrity of the pathway must be evaluated. ASME Code Case N-513 (Temporary Acceptance of Flaws in Moderate Energy Class 2 or 3 Piping) provides a method for evaluating pipe flaws.

In general, the closure time of all isolation valves is such that the release of fission products to the environment is minimized. The closure times of all valves on lines in systems connecting to the nuclear steam supply system are based on the design intent to prevent uncovering the core following pipe breaks outside the primary containment and to contain released fission products following pipe breaks inside the primary containment.

The valve closure time for the main steam line is based on the main steam line break accident discussed in Section 15.6 By keeping the main steam isolation valve (MSIV) closure time less than or equal to 5 seconds, sufficient coolant will remain in the reactor vessel to provide adequate core cooling. The valves are designed to close and to be leak-tight during the worst conditions of pressure, temperature, and steam flow following a break in the main steam line outside the containment. The MSIVs are leak tested in accordance with the 10CFR50 Appendix J program. [6.2-80]

Motive power for each of a pair of power-operated isolation valves in series is from physically independent sources to preclude the possibility of a single malfunction interrupting power to both valves. Air-operated valves which close for the normal containment isolation mode fail closed on loss of motive power. Electric motor-operated valves fail as-is. Main steam isolation valves are discussed in 6.2.4.3.

All containment isolation valves, including their power operators, are designed to operate under the most extreme ambient conditions of pressure, temperature, etc., to which they may be exposed after a major accident. All isolation valves in lines connecting to the nuclear steam supply system and all pipe welded connections were fully radiographed to assure their integrity. They were built to the applicable ASME Codes and all nuclear interpretations of these codes that were applicable at the time of installation. For all containment penetrations that require redundant isolation, all powered valves inside containment are AC. Normally, outside containment, DC powered valves are utilized. For the HPCI turbine exhaust vacuum breaker line, where both isolation valves are located outside the containment/suppression pool, the inboard valve is AC and the outboard valve is DC, to provide diversity in power and control circuits for Division II.

The reactor building serves as secondary containment, and its ventilation system is provided with two isolation valves in series in both the supply and exhaust ducts. These valves automatically close as described in Section 7.3, 11.5, 6.2.3.2.2, and 6.2.3.4.

6.2.4.2 Instrument Lines

Twenty-three penetration assemblies are used for primary system instrumentation. Each of these assemblies is configured to carry multiple instrument lines through the containment shield wall. 96 of the total of 146 penetrating pipes are active lines and 50 are spares. All of the active penetrating lines are equipped with stop valves. Lines penetrating the primary system are also equipped with excess flow check valves located outside the containment, as indicated in Table 6.2-7. [6.2-81]

The penetrating lines are 1-inch schedule 80, type 304 stainless steel pipe. Each of the lines is welded to a stainless steel pipe which is in turn welded to the drywell penetration housing. A typical detail of the multiple pipe instrument penetration is shown in Figure 6.2-38.

Within the secondary containment are 1-inch process stop valves, excess flow check valves, and 1/2-in. schedule 80, type 304 stainless steel piping to the instrument rack. Piping or stainless steel tubing is used within the rack to the instrument sensors. All welds have been dye-penetrant tested. Analyses have been performed to assure that the installations from the penetrations to the instrument rack meet seismic Class I requirements.

Each process stop valve and excess flow check valve is either 304 or 316 stainless steel. The excess flow check valves permit a maximum flow of 2 gal/min. A detail of the penetrating pipe installation is shown in Figure 6.2-39 for Units 1 and 2, and Figure 6.2-39A shows alternate detail for the Process Stop Valve and Excess Flow Check Valve for Unit 1. It was not necessary to provide special protection for any of the lines within the secondary containment.

The vent and instrument line on the No. 1 seal cavity of each of the two reactor recirculation pumps are interconnected with the reactor recirculation pump seal purge lines between the excess flow check valves and the instruments. Redundant, safety-related check valves are installed in each seal purge line in close proximity to the containment penetrations. The piping between the excess flow check valves and the safety-related seal purge line check valves are seismically designed, consistent with containment isolation boundaries.

6.2.4.3 Main Steam Isolation Valves

The purposes of the main steam isolation valves (MSIVs) are:

A. To prevent coolant inventory loss and protect plant personnel in the event of line breakage outside the isolation valves;

B. To complete the containment boundary after a LOCA.

The MSIVs are 20-inch airspring-operated, balanced "Y"-type globe valves mounted inboard and outboard of the containment. The inboard valve air is supplied from the containment drywell pneumatic system. The outboard valve is supplied by the normal instrument air system. Figures 6.2-40 and 6.2-41 show the typical design features for this type valve. This valve type combines full port design with straight-line flow to provide a very good flow pattern. These valves use upstream pressure to aid in closure by tilting the actuator toward the upstream side of the valve. The balancing feature takes advantage of upstream pressure to aid in holding the valve closed. This valve type requires a smaller actuator cylinder to open the valve. This is accomplished by allowing the full upstream line pressure to bleed into the chamber above the plug through the balancing port to exert a force on the plug internals in a direction to hold it against the seat. When the actuator starts to open the valve, the stem lifts the pilot off its seat to vent the steam inside the plug into the downstream line. As the stem travel continues, the plug is lifted off the main valve seat to open the valve port. [6.2-82]

The valve actuator is completely supported by four spring guide shafts. Coil springs located around the spring guide shafts are used for closing the valve in case of air failure. Spring closure of the valve due to loss of supply pressure is assisted by the backup supply from the accumulator attached to the top of the actuator cylinder. [6.2-83]

The valve is opened and held in the open position by compressed air. Operating air is supplied to the valve from the plant air systems through a check valve. An air tank accumulator provides backup operating air. The leak tightness of the check valve is periodically tested to assure sufficient air is available from the accumulator to close the main valve on demand. The valve will close in the specified time with both air and spring action.

On several occasions early in the plant life of US BWRs, MSIVs failed to operate due to sticking pneumatic valves which control the flow of air to the MSIV cylinder operator. The cause of the failure was determined to be excessive heat in the vicinity of the valves and the highly sensitive nature of the small clearance pneumatic valves to oil-contaminated air causing binding due to the build up of deposits within the valves. The air control valves were replaced with "poppet valves." Poppet valves seal with elastomers between the poppet and the metallic valve seat. This design permits the clearance between the valve body and the poppet to be larger, precluding the possibility of deposits forming a mechanical bond. In addition, the instrument air quality has improved with the use of dryers.

For Unit 1, the valve opening and closing times are controlled by a hydraulic (oil) cylinder and two flow control valves, mounted below the main air cylinder. The closing time can be controlled between 3 and 10 seconds by adjusting the large (1 inch) flow control valve. The opening time can be controlled between 5 and 20 seconds by adjusting the small (1/2 inch) flow control valve.[6.2-85]

For Unit 2 the valve closing time can be controlled between 3 and 10 seconds by a hydraulic (oil) dashpot mounted below the main air cylinder and is equipped with an external bypass pipe and flow control valve. Valve opening time cannot be adjusted.

Schematic control diagrams for the Unit 1 and 2 MSIVs are shown in Figures 6.2-42 and 6.2-43 respectively. To open an MSIV, the solenoid on either the dc or ac, both main control solenoid valves (1) and (2) are energized to shift valve (1) into the energized position. This vents air from the upper side of the air cylinder on the main valve and

exhausts the air from valve (2) which supplies air to the top of the cylinder, opening the valve and compressing the springs on the main valve. To close the MSIV, the solenoid on both solenoid valves (1) and (2) are de-energized to shift the solenoid valves and valve (1) into the position shown in Figures 6.2-42 and 6.2-43. This shifts valve (2) to the position shown which exhausts the air below the piston and allows compressed air to enter the top of the cylinder which, with the springs on the main valve, forces the valve closed. Valve (4) also shifts to the position shown to provide a redundant exhaust path for the air below the piston.

To exercise the MSIV, solenoid valves (1) and (2) and valves (1), (2), and (4) are left in the energized position and the solenoid on the solenoid valve (3) is energized to shift valve (3) into the position opposite that shown in Figures 6.2-42 and 6.2-43. This allows the springs on the main valve to force the cylinder downward, exhausting the air through the flow control valve associated with valve (3). The main valve is returned to the open position by deenergizing the solenoid on valve (3) to shift valve (3) back to the position shown on Figures 6.2-42 and 6.2-43 thereby permitting air to enter the lower side of the air cylinder. As a fail-safe feature, the main valve will close on loss of compressed air or loss of both ac and dc voltage to solenoid valves (1) and (2). In both of these cases, valves (2) and (4) shift positions and exhaust the air below the cylinder of the main valve. An accumulator is installed downstream of the control solenoid valves. It provides compressed air to the top of the cylinder to assist the springs on the main valve upon loss of compressed air.

The ability of the MSIVs to close within the times assumed in the DBA analysis under conditions of high pressure differentials and fluid flows, with fluid mixtures ranging from mostly steam to mostly water, was demonstrated prior to plant construction in a series of dynamic tests. A full-size, 20-inch valve produced for actual use in a BWR was tested in a range of steam/water blowdown conditions simulating postulated accident conditions. The test valve was opened and closed more than 400 times (200 cycles) during the test program. Included in the program were 40 flow (shut off) tests which simulated accident conditions up to those more severe than postulated for the DBA.

The variety of steady flow conditions on which the valve was closed covered the following ranges:

Steam Tests:	50 — 1080 lb/sec
Water Tests:	240 — 3490 lb/sec
Mixture Tests:	1530 — 3860 lb/sec (quality 17% - 45%)
Surge Tests:	520 — 2970 lb/sec (quality 1%-33%)

The analysis of valve closing performance with this wide variety of conditions demonstrated that closure is not critically sensitive to fluid temperature, fluid pressure in the valve, or fluid flow through the valve. In every case, the valve opened and closed when signalled and shut off the flow completely and reliably. It was further observed that steam and mixture flows assisted valve closure, with closing speeds up to 20% faster than those obtained under cold station conditions. A detailed description and analysis of this test program is contained in Reference 10.

6.2.4.4 Materials

The containment shell, electrical penetrations, and piping penetrations are metallic components (with a ceramic filler in the electrical penetrations) that are designed to pressure vessel standards (i.e., no degradation will occur from temperature, pressure, or radiation damage). [6.2-86]

Some of the valves use Nordel (EPDM) and Silicone rubber as the elastomer and seat material. These valves are located outside the concrete shield. Thus, the temperature (continuous 250°F) and radiation exposure dose for these locations are less than the service rating for these materials. During an accident, the temperature to which this material is exposed could approach 340°F for about 48 minutes and then drop to less than 250°F for the remainder of the accident. Silicone rubber is good for this temperature range (up to 340°F maximum). The exposure dose approaches the radiation damage threshold for these materials within a short time, but does not exceed their capability (10^8 rads). Nevertheless, the valves and valve seats in question have served their function within a short time; that is, they have prevented bypassing of steam and thus, pressure suppression has been assured.

The manways into the suppression chamber, the two equipment access hatches, the personnel access lock, and the drywell head all have double O-ring seals. The maximum temperature of the primary containment walls has been shown to be 320°F. The time above 250°F will be less than 10 hours; therefore, temperature will not have an effect on these O-rings. The radiation damage limit is greater than 5×10^8 rads; whereas, the maximum calculated exposure doses are less than 5×10^8 rads at 100 days. Thus, there is adequate time to reduce the containment pressure to atmospheric before the radiation damage limit is reached.

All other isolation valves in the primary containment system use metal seats; therefore, the structural integrity and leak-tightness of these valves will remain essentially unchanged following a DBA.

Buna-N rubber, Teflon, and nylon are used in certain applications in the valves discussed above; but, these materials are used only in locations where their failure would not affect the structural integrity or operability of these valves.

6.2.4.5 Traversing In-Core Probe

The traversing in-core probe (TIP) system, described in Section 7.6, has 5 guide tubes which pass from the reactor building through the primary containment. Guide tube penetrations of the primary containment are sealed by brazing which meets the requirements of ASME Boiler and Pressure Vessel Code, Section VIII. Each TIP system guide tube has an isolation valve which closes automatically after the appropriate containment isolation signal retracts the TIP cable and fission chamber. In series with each isolation valve a shear valve provides alternate isolation. The isolation and shear valves are located outside the drywell. The function of the shear valves is to assure integrity of the containment if the other isolation valves fail to close or if the chamber drive cable fails to retract when it is extended in the guide tube during the time that containment isolation is required. The shear valve is a manual, keylock, dc actuated explosive-type valve which will shear the cable and seal the guide tube, if necessary. The position of each isolation and shear valve is indicated in the control room. [6.2-87]

6.2.4.6 Overpressurization Protection Due To Drywell Temperature Increase [6.2-88]

Relief valves have been added between the primary containment valves on the RWCU system for each Unit to prevent the volume between the containment isolation valves from becoming overpressurized during a high-energy line break accident condition. As the drywell temperature increases during an accident, the water within the trapped volume expands. Assuming no leakage from the containment isolation valves, the piping pressure is postulated to rise above the design pressure of the piping and components. Relief valves were also added for Unit 1 on the drywell floor drain and equipment drain systems. The relief valves will vent excess pressure to the drywell and prevent the piping from developing stresses above allowable limits. The relief valves have been installed as part of the response to NRC GL 96-06.

6.2.5 Combustible Gas Control in Containment

The discussion presented in this section is applicable to either unit. Combustible gas mixtures could accumulate in the containment as a result of several mechanisms expected to occur during and after a postulated accident. These mechanisms include fuel cladding metal-water reactions, radiolysis and reactions of other materials in the containment. [6.2-89]

The containment inerting system, described in Section 6.2.5.1, is the primary system for combustible gas control in the containment. The containment atmosphere monitoring (CAM) system provides the ability to monitor post-accident H_2 and O_2 concentration and airborne radioactivity. If H_2 exceeds the flammability limit (6%) by volume and O_2 exceeds 5% by volume, the nitrogen containment atmosphere dilution (NCAD) system could be manually actuated to reduce and maintain the O_2 and the H_2 below the flammability limit.

6.2.5.1 Containment Inerting

Equipment has been installed on both Quad Cities Units to allow the primary containment atmosphere to be inerted with nitrogen to maintain oxygen content below 4.0% by volume during normal operation. This equipment consists of a liquid nitrogen storage tank, electrically powered nitrogen vaporizers, a steam heated nitrogen vaporizer, one atmospheric vaporizer, associated piping, isolation valves, and pressure regulators. Nitrogen is supplied to the drywell through the drywell purge inlet line penetration X-26. A flow regulating valve is installed to limit low nitrogen supply temperatures which could damage the nitrogen piping system. [6.2-90]

The nitrogen inerting system can supply nitrogen to either Unit 1 or 2 containment drywell or suppression chamber from either the electric or steam vaporizers. [6.2-91]

When inerting the containment, nitrogen is supplied to the containment while air is vented to the reactor building ventilation system or the Standby Gas Treatment system (SBGTS). A similar method is used for inerting the suppression chamber. Oxygen content is monitored by an oxygen analyzer at various locations within the containment to ensure the containment is maintained at the desired low oxygen concentration. The

containment is deinerted by admitting air into the containment as the containment atmosphere is vented to the reactor building ventilation system or SBGTS.

Containment inerting is performed to prevent possible explosive mixtures of hydrogen and oxygen in the containment following a postulated LOCA. Hydrogen generation is discussed in Section 6.2.1.3.5. The nitrogen inerting system is not safety-related; however, it can be used for post-LOCA hydrogen control. [6.2-92]

While the containment is inerted, pressure is supplied to pneumatically operated equipment in the containment from the nitrogen system or the drywell pneumatic system (Section 6.2.1.2.4.3). This prevents dilution of the containment nitrogen atmosphere by air leakage from equipment in the containment. [6.2-93]

The nitrogen inerting system is also required to serve as a backup to the pump-back system to maintain the required drywell-to-torus-ΔP. [6.2-94]

6.2.5.2 Containment Atmosphere Monitoring (CAM) and Atmospheric Containment Atmosphere Dilution (ACAD

The containment atmosphere monitoring (CAM) system is a safety-related, fully-redundant system consisting of hydrogen, oxygen, and high gross gamma radiation sensors which monitor the containment atmosphere. The sensors provide signals to redundant control room recorders. The monitoring system is powered from separate electrical divisions. [6.2-95]

The CAM system was originally designed to support the ACAD system. The oxygen and hydrogen recorders are combined units activated when the CAM system is activated.[1] [6.2-96]

During CAM system operation, containment atmosphere is withdrawn through 1/2-inch piping connected to a 1-inch penetration. Hydrogen and oxygen concentration are measured outside the primary containment and the sample returned to the primary containment. The sample withdrawal lines in both cases are heat traced to prevent condensation in the sample lines which would cause measurement inaccuracies. A check valve is installed in the return discharge line for primary containment. In addition, a check valve is installed in each reagent and calibration gas line for primary containment. [6.2-97]

The CAM hydrogen monitors are designed to analyze samples under post-LOCA containment conditions. The monitors were installed to meet NUREG 0737 II.F.1. Attachment 6, Containment Hydrogen Monitor. General environmental qualifications are discussed in UFSAR Section 3.11.

The CAM System automatically initiates upon the occurrence of a loss of coolant accident.

The drywell radiation monitor recorder has an upper scale limit of 1×10^8 R/hr. The alarm contacts on the hi-range drywell radiation monitor are set to alarm at 20 R/hr and to initiate a Group II PCIS isolation at the high-high allowable value of $\leq$ 70 R/hr. The design limit for the hi-range drywell radiation monitor to initiate a Group II PCIS isolation is $\leq$100 R/hr. [6.2-98]

Two redundant radiation sensors are located in the upper half of the containment about 180° apart.

The pressure retaining portion of the CAM system was designed and installed in accordance with the ASME Boiler and Pressure Vessel Code — Section III Division I; Subsections NE-2000, NC-2000, NE-4000, NC-4000, NA-4000, and NE-5000, 1974 edition up to, and including the Summer 1976 Addendum.

The ACAD System once consisted of two subsystems: the dilution air injection subsystem and the pressure bleed subsystem. [6.2-99]

The dilution air subsystem was abandoned in place in June 1996 by cutting and capping the four one-inch diameter piping lines (two drywell lines and two torus lines) that enter the containment. The piping was cut and capped on the outboard side of the containment between the containment penetrations and the air operated containment isolation valves. The pressure bleed subsystem was also permanently removed from service. The subsystem was removed from service because it was only operated in conjunction with the operation of the dilution air injection subsystem. In addition, the volumetric flow rate of the system was too limited for the purge and vent method of operation utilized in the emergency operating procedures. [6.2-100]

The pressure bleed subsystem was removed from service by cutting and capping the one-inch diameter piping lines from the pressure suppression system. The piping was cut and capped on the outboard side of the containment between the containment penetration and the air-operated containment isolation valves.

The ACAD Drywell pressure sensing instrumentation remains in service to provide post-accident containment pressure monitoring as required by Reg. Guide 1.97.

The dilution air subsystem was abandoned in accordance with the recommendations of Generic Letter 84-09 - "Recombiner Capability Requirements of 10CFR50.44(c)(3)(ii) and NRC Safety Evaluation Report, <u>SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION REGARDING POST-ACCIDENT COMBUSTIBLE GAS CONTROL SYSTEM AT DRESDEN, UNITS 2 AND 3, AND QUAD CITIES, UNITS 1 AND 2, COMMONWEALTH EDISON COMPANY DOCKETS NOS. 50-237, 50-249, 50-254, AND 50-265,</u> dated June 29, 1993. The ACAD dilution air subsystem was replaced with the Nitrogen Containment Atmosphere Dilution (NCAD) system.

6.2.5.3 Nitrogen Containment Atmosphere Dilution System (NCAD) [6.2-101]

The NCAD system was installed in June of 1996 in response to Generic Letter (GL) 84-09, "Recombiner Capability Requirements of 10CFR50.44(c)(3)(ii)." The GL stated that the commission has determined that a Mark I BWR type design will not rely upon purge repressurization systems as the primary means of hydrogen control if certain technical criteria were satisfied. With that finding, a Mark I containment facility need not be required to have recombiner capability. The main focus of the GL 84-09 criteria was to assure that there were no additional oxygen sources other than those recognized in the GL supporting technical analyses. The NRC concluded that the NCAD system provided reliable purge-

repressurization capability, and met the GL 84-09 criteria for relief from recombiner requirements.

The nitrogen inerting system is considered the primary system for combustible gas control in the containment. The NCAD system is a backup system to the nitrogen inerting system and is intended for post LOCA operations. The NCAD system was installed to be used in lieu of the ACAD system. The ACAD system injected air into the containment which could have increased the oxygen concentration in the containment.

The NCAD system injects nitrogen, a non-combustible gas, into the containment to purge the containment of oxygen and hydrogen. The primary purpose of NCAD is to maintain the oxygen concentration at or below 5% by volume.

The NCAD system is a variable flow system capable of delivering a maximum flow rate of approximately 312 scfm at a nominal pressure of 160 psig. This maximum flow rate is limited by the flow capacity of one of two electric vaporizers. If both electric vaporizers are unavailable, the atmospheric vaporizer may be utilized at a maximum flow rate of 150 scfm if the outdoor ambient temperature is ≥ 34°F. The maximum flow rate through the atmospheric vaporizer is limited to 50 scfm if the outdoor ambient temperature is below 34°F, in order to prevent approaching the nil-ductility temperature of piping in the containment.

Nitrogen is supplied at a constant pressure from the bulk nitrogen storage tank, located outside on the nitrogen skid. A back up nitrogen source may be connected through two truck connections located near the nitrogen skid. Local instrumentation has been provided to monitor temperature, pressure, and flow for the system.

The NCAD system is a manually operated system that is operated locally at the nitrogen skid by manually throttling a globe valve to achieve the desired flow rate. The system is a non-safety-related system. The piping that is routed through the 1/2 Diesel Generator Room and Reactor Building is seismically qualified.

The NCAD system is made up of two independent redundant flow paths for each unit. Each flow path in turn can supply gaseous nitrogen to either the drywell or suppression chamber. One flow path runs from the units corresponding electric vaporizer and taps back into the nitrogen inerting system piping just upstream of nitrogen purge vaporization valve, AO 1(2)-1601-55, on the non-safety-related side. The other flow path runs from the opposite unit's electric vaporizer and taps back into the normal nitrogen makeup system just upstream of nitrogen makeup valve, MO 1(2)-1601-57. Either flowpath can be supplied by the nitrogen atmospheric vaporizer. The containment purge and vent valves can be aligned to inject nitrogen into the drywell or suppression chamber for either flow path.

Each redundant piping run contains two manual isolation valves. One valve is located in the reactor building and is normally locked open. After a LOCA, this valve will be inaccessible due to high radiation levels. The valve is locked open to ensure that the system will remain in a ready state. The other valve is located outside at the nitrogen skid and is locked closed. After a LOCA, radiation levels will be lower outside and the valve will be accessible. The valve can be unlocked and flow can be manually adjusted. The valve is normally locked closed to prevent inadvertent operation of the system.

The NCAD system is used in a vent and purge mode of operation in accordance with the QGAs.

Venting can be accomplished by either the Standby Gas Treatment System (SBGTS) or the Augmented Primary Containment Vent (APCV) System. If the SBGTS is used, gas could be released through the main line to the SBGTS to the 310-foot chimney intermittently at a rate of about 200 SCFM until the desired volume has been released. Releases would be continued until the containment hydrogen and oxygen concentrations can be maintained below combustible limits.

Changes in containment pressure as a result of containment venting are slow. To reduce containment pressure by one psi, for example, 19,000 SCFM of gas would be released. At a 100 SCFM release rate, this would take 190 minutes. The gas release is started and stopped by the operator. Pressure, hydrogen content, oxygen content, radioactivity in the containment atmosphere, and meteorological information will be available to the operator. Using this information, an operator can safely follow the venting procedure without exceeding the 10 CFR 100 limits following a LOCA. Because it is coordinated with meteorological information, the venting operation is closely supervised and automatic termination is not considered to be necessary. However, in accordance with the QGAs, the operator can vent and exceed the release rate limits of 10 CFR 100 to maintain combustible gas concentrations below combustible levels.

6.2.6 Containment System Leakage Testing

The discussion presented in this section is applicable to either unit. [6.2-102]

The Primary Containment Leakage Rate Testing Program was developed to provide assurance that the primary containment, including those systems and components which penetrate the primary containment, does not exceed the allowable leakage rate values specified in the technical specifications and bases. The allowable leakage rate is determined so that the leakage rate assumed in the safety analysis is not exceeded. This program meets the requirements of Regulatory Guide 1.163, Performance-Based Containment Leak-Test Program and 10 CFR 50 Appendix J.

Table 6.2-7 provides a list of primary containment penetrations and associated isolation valves. Specific leakage testing requirements necessary to implement the requirements of Regulatory Guide 1.163 are included in the Primary Containment Leakage Rate Program.

6.2.6.1 Drywell and Suppression Chamber

Following construction of the drywell and the suppression chamber, each was pressure tested at 70 psig which is 1.25 times its design pressure. Penetrations were sealed with welded end caps. Following the strength test, each vessel was tested for leakage rate at design pressures. Each met the criterion for leakage of less than 0.5 percent of total contained volume per day at design pressure. The suppression chamber was also tested while half filled with water to simulate operating conditions. [6.2-103]

After completing installation of all penetrations, integrated leak rate tests of the drywell, suppression chamber, and associated penetrations were conducted at two test pressures to establish a leak rate curve.

The "design-basis accident" used for determination of allowable containment leak rates was the LOCA as discussed in Section 6.2.1.3.2.

The initial containment conditions, containment pressure transient, percent metal-water reaction and fission product release to the containment assumed for the double-ended recirculation line break were used in this analysis. In addition, the SBGT system was assumed operative such that fission products which leak from the primary containment pass through filters prior to discharge to the environment via the main chimney.

Periodic integrated leak rate tests are conducted in accordance with the requirements of the Primary Containment Leakage Rate Testing Program. The integrated leak rate test is performed at time intervals based on maintaining primary containment leak rate below the permissible leak rate limit, in accordance with 10 CFR 50 Appendix J. An integrated test yielding results above the leak rate limit requires testing to a more frequent test schedule.

6.2.6.2 Containment Penetrations

The major portion of leakage from the containment has been shown at Humboldt Bay[11] and other nuclear power stations to come primarily from valves and penetrations. [6.2-104]

Containment penetrations are tested in accordance with the Primary Containment Leakage Rate Program. Penetration leak rate testing is conducted at test pressures greater than or equal to the design basis accident pressure (43.9 psig, except MSIVs which are tested at greater than or equal to 25 psig). This testing verifies the ability of the penetrations to withstand the peak containment pressure expected as a result of a LOCA. Penetration leak rate testing verifies the capability of the penetrations to maintain overall containment leakage within the limits established by 10 CFR 50, Appendix J.

The access air lock is provided with double doors and is tested by pressurizing the entire access area. Holddown bars are installed on the inside door to prevent damage due to external pressure during testing. These tests are performed on a regular basis in accordance with the requirements of the Technical Specifications. Access to the containment during operation is infrequent, therefore the access locks do not receive excessive use. [6.2-105]

Flanged openings are provided with double "O" rings and are pressure tested to 43.9 psig. Pressure testing is conducted before resuming operation whenever the seal has been broken.

6.2.6.3 Containment Isolation Valve Testing

Isolation valves are tested in accordance with the requirements of the Inservice Testing Program. [6.2-106]

The operational testing of the primary containment isolation valves includes pressure tests, leakage tests, operability tests, and closure timing tests.

During normal operation, each power-operated isolation valve is exercised by fully opening (or closing) at regular intervals. Closure times of all power operated isolation valves are measured on a regular basis. Isolation initiation upon a signal from the primary containment isolation system is also tested for each power operated isolation valve.

6.2.6.3.1 Main Steam Isolation Valve Testing

Main steam isolation valve testing is accomplished both during reactor operation and during shutdowns. Functional performance and leak tests are performed during reactor shutdowns when access to the area of the valves is permitted. In-service exercising is used to demonstrate operability and to check closure times. [6.2-107]

Shutdown tests include actuation and closure time tests to assure: that the valves operate properly, that the sensors are set correctly and cause the proper actuation, that the response speed is correct, and that the fail-safe features are operable. Test taps located between the double isolation valves permit leak testing while the reactor is in the cold shutdown condition by pressurizing the enclosed space between the valves.

The exercising of MSIVs during reactor operation is conducted in a manner to avoid the risk of a high flow PCIS trip and reactor scram. The valve closure scram signal requires less than or equal to a 9.8 percent closure (Technical Specification Allowable Value) of the inboard or outboard valves in three lines; and as a result, in-service testing is limited to one valve at a time. Each MSIV can be exercised partially closed (90% open) at full power or fully closed from a reduced power level. To support exercising at power, each MSIV is equipped with a slow speed exercising circuit and limit switches which provide position indication (i.e., full open, 90% open, full closed). Exercising an MSIV to the 90% open position at full power can be accomplished by momentarily holding the test control switch in the "test" position which will initiate slow closure of the valve. Upon reaching the 90% open position, the test circuitry will return the valve to the fully open position. Exercising an MSIV to verify a closure time of 3 to 5 seconds may be conducted during power operation by reducing reactor power level to less than 75% of reactor power and closing the valve using the normal control switch, and measuring the time to receive the fully closed indication. [6.2-108]

6.2.7 Instrumentation Requirements

To maintain the primary containment within structural load limits, it is necessary to provide measurements of the differential pressure between the drywell and the suppression chamber and atmosphere (or the reactor building). It is also necessary to measure the suppression chamber water level and water temperature to assure appropriate conditions are maintained to respond to a potential accident or event as required. See Section 6.2.1.2.4.4 for further information.

The containment atmosphere must be monitored for oxygen both for combustible gas control and for personnel protection. The capability to measure hydrogen concentration under post-accident conditions is also required. See Sections 6.2.1.3.5 and 6.2.5. Isolation of the containment must be assured by a continuous overall leak rate measurement,

reference Section 6.2.1.2.4.4. Also, it is necessary to be able to remotely monitor containment isolation valve position. The containment bulk air temperature is monitored to maintain an appropriate temperature environment for equipment.

The containment pressure is monitored during leak rate testing under specified conditions, reference Section 6.2.6; and in order to initiate venting when required to assure containment integrity. Containment venting to the SBGTS is described in Section 6.2.3.5. For instrumentation requirements associated with post accident containment cooling refer to Sections 6.2.2. For instrumentation requirements associated with containment cooling during normal operation refer to Section 9.4.

6.2.8 References

6.2.8.1 References for Section 6.2.1

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3. Robert Harrington, Rubber Age 82461 (Dec. 1967).

4. C. S. Schollenberger, et al., "Polyurethane Gamma Radiation Resistance," B. F. Goodrich Co. Research Center, Nobs — 72419 (June l, 1958).

5. J. F. Kircher and R. E. Bowman, "Effects of Radiation on Materials and Components."

6. Quad Cities Special Report #4, Drywell to Suppression Chamber Vacuum Breaker Modifications, October 1973.

7. "Final Report In-Plant SRV Discharge Test," Dresden Unit 2, NUTECH Engineers, Inc., COM-19-142 Rev. 0, June 30, 1982.

8. Moody, F. J., "Maximum Flowrate of a Single Component, Two-Phase Mixture," Journal of Heat Transfer, Trans. ASME Series C, Vol 87, p. 134 (1965).

9. Robbins, C. H., "Tests of a full Scale 1/48 Segment of the Humboldt Bay Pressure Suppression Containment," GEAP-3596, November 17, 1960.

10. Design and Performance of General Electric Boiling Water Reactor Main Steam Isolation Valves, APED 5750, D.A. Rockwell and E.H. Van Zylstra, March 1969.

11. Humboldt Bay, Pacific Gas and Electric Company, Report on Pressure Suppression Containment System Leakage Rate Testing at Humboldt Bay Power Plant Unit No. 3.4

12. Deleted.

13. Deleted .

14. Quad Cities Units 1 an 2, Torus-to-Drywell Vacuum Breaker Requirements, COM-08-018, Rev. 0, August 1981.

15. The GE Pressure Suppression Containment Analytical Model," NEDO-10320, April 1971.

16. “Mark I Containment Program Load Definition Report,” NEDO-21888, Rev. 2, November 1981.

17. NUREG-0800, U. S. Nuclear Regulatory Commission, Standard Review Plan, Section 6.2.1.1.C., “Pressure-Suppression Type Containments,” Revision 6, August 1984.

18. “Safety Evaluation Report – Mark I Containment Program,” NUREG-0661.

19. “General Electric Model for LOCA Analysis in Accordance with 10 CFR 50 Appendix K,” NEDO-20566A, September 1986.

20. Deleted.

21. “Generic Guidelines for General Electric Boiling Water Reactor Power Uprate,” NEDC-31897P-A, May 1992.

22. “The General Electric Mark III Pressure Suppression Containment System Analytical Model.” NEDO-20533, June 1974.

23. “Use of SHEX Computer Program and ANSI/ANS 5.1-1979 Decay Heat Source Term for Containment Long-Term Pressure and Temperature Analysis,” Letter from Ashok Thadani (NRC) to Gary L. Sozzi (GE), July 13, 1999.

24. “Mark I Containment Program Quarter Scale Plant Unique Tests,” NEDE-21944-P, April 1979.

25. NEDO-30832, “Elimination of Limit on Local Suppression Pool Temperature for SRV Discharge with Quenchers,” Class I, December 1984.

26. GE-NE- A22-00103 –08-01, Rev. 1, Project Task Report, Dresden and Quad Cities Extended Power Uprate Task T0400, Containment System Response, December 2000.

27. NEDC-32961P, Rev. 2, Safety Analysis Report for Quad Cities 1 and 2 Extended Power Uprate, August 2001.

28. Letter from USNRC to O. D. Kingsley, Quad Cities Nuclear Power Station Units 1 and 2, Issuance of Amendments for Extended Power Uprate, December 21, 2001.

29. Deleted.

30. NF-BEX-06-6, Task Report for TSD DQW04-027, Containment Loads Analysis for SVEA-96 Optima2 Fuel, Rev. 1 (included in OPTIMA2-TR027-CNMT_LOAD, "Optima2 Containment Loads – Quad Cities").

31. OPTIMA2-TR021QC-LOCA, Revision 5, “Quad Cities 1 & 2 LOCA Analysis for SVEA-96 Optima2 Fuel,” September 2009.

32. ANP-3565P Revision 0, “Quad Cities Unit 1 Cycle 25 Reload Safety Analysis, AREVA, February 2017.

6.2.8.2 References for Section 6.2.2

1. “Utility Resolution Guide for ECCS Suction Strainer Blockage, ” General Electric document NEDO-32686-A, dated October 1998.

6.2.8.3 References for Section 6.2.5

1. "Analysis of Hydrogen Generation and Control in Primary Containment Following Postulated Loss of Coolant Accident," (Including Supplements), Quad Cities Special Report Number 14, Commonwealth Edison Company.

Table 6.2-1

PRINCIPAL DESIGN PARAMETERS OF PRIMARY CONTAINMENT

Vent System	
Vent Pipes	
Number	8
Internal Diameter	6 ft 9 in.
Vent Tubes flow area, total	285 ft^2
Vent Header Internal Diameter	4 ft 10 in.
Downcomer pipes	
Number	96
Internal diameter	2 ft 0 in.
Submergence below suppression pool water level	3.21 min to 3.54 max ft.
Pressure Suppression Chamber	
Water Volume	111,500 ft^3 — 115,000 ft^3
Free air volume	117,300 ft^3 — 120,800 ft^3
Chamber inner diameter	30 ft
Torus major diameter	109 ft
Suppression Chamber To Drywell	
Vacuum Breaker Valves	
Number	12
Vent area, total	2,715 in^2
Actuation set-point	0.5 psi suppression chamber to drywell dp for full open
ΔP	1.0 PSI (minimum ΔP required by NRC)
Service Water Temperature Limits	105° max normal
	85° min normal
General	
Metal Material Design Code	SA212 GR B tested to A300 (ASTM, Section 32) ASME Boiler and Pressure Vessel Code Section III, Class B, 1965 ed including Winter 1965 addenda.
Drywell	
Cylindrical section - diameter	37 ft
Spherical section - diameter	66 ft
Drywell height	111 ft 11 in.
Free Air volume	158,236 ft^3

Table 6.2-1 (Continued)

PRINCIPAL DESIGN PARAMETERS OF PRIMARY CONTAINMENT

Wall Plate Thickness	
Spherical shell	Varies 11/16" to 1-1/8"
Spherical shell to cylindrical neck	2-3/4"
Cylindrical neck	Varies 3/4" to 1-1/2"
Top head	1-1/4" and 1-7/16"
Reactor Building to Suppression Chamber	
Number valves	2
Actuation set-point	0.5 psi, reactor building to suppression chamber dp for full open
Design Conditions	
Design internal pressure and temperature (1)	56 psig @ 281°F
Maximum allowable internal operating pressure and temperature(1)	62 psig @ 281°F
Design external pressure and temperature: Drywell Suppression chamber	 2.0 psid @ 281°F 1 psid @ 281°F
Normal internal pressure and temperature	
Drywell, maximum for normal operation	1.5 psig up to 150°F
Suppression Chamber, normal operating pressure range	+- 0.2 psig
Pool Temperature, normal operating temperature	high T = 95°F low T = 50°F
Scram at suppression pool temperature	>110°F
Maximum Pool Temperature when testing	105°F

Note 1: The peak drywell (airspace) temperature at 2957 MWt is 291°F, which is above the drywell shell design temperature of 281°F. However, the drywell airspace temperature peaks briefly as shown in Figure 6.2-25a. Because the drywell shell heatup is governed by heat transfer phenomena that require sustained high temperatures in the drywell atmosphere, a brief peak in the drywell airspace temperature would result in a drywell shell temperature below 281°F.

Table 6.2-2

DRYWELL THERMAL EXPANSION

Location	(a) Resultant Thermal Growth (inches)	(b) Allowable Loading (psi)*	(c) Resultant Loading (psi)*	(d) Design Margin Safety Factor
A.	0.00	1.55	0.0	---
B.	0.58	1.57	0.7	2.2
C.	0.80	3.05	0.8	3.8
D.	0.99	3.84	1.0	3.8
E.	0.33**	2.77	0.6	4.6

* Code allowable external uniform loading on drywell shell in excess of a 2-psi allowance made for gas pressure (-2 psig pressure in drywell).

** Radial growth only. The vertical growth of the cylindrical portion of the drywell results in a slip/shear in the polyurethane foam which increases the loading on the shell by a negligible amount.

Table 6.2-3

CONTAINMENT RESPONSE SUMMARY FOR A RECIRC LINE BREAK ACCIDENT

Case	RHR Loops	RHR Pumps	RHR Service Water Pumps	Containment Spray (gal/min)	Core Spray (gal/min)	Peak Pool Temperature (F°)	Secondary Peak Pressure (psig)
Rated Power	1	1	1	None	4500	199	36.4

Note: Rated power is 2957 MWt.

TABLE 6.2-4 HAS BEEN DELETED INTENTIONALLY

Table 6.2-5

SECONDARY CONTAINMENT DESIGN

.	Free Volume, ft^3	4,716,000
B.	Pressure, inches of water gauge	
	1. Normal Operation	-0.1 to -0.70
	2. Postaccident	-0.25
C.	Postaccident Inleakage (%/day) of secondary containment volume equal to SBGT flow 4000 SCFM	100
D.	Exhaust Fans	
	Standby Gas Treatment System (Postaccident)	
	1. Number	2
	2. Type	Direct Drive
	Reactor Building Ventilation System (Normal Operation)	
	1. Number	6
	2. Type	Direct Drive Air Flow
E.	Filters	
	Standby Gas Treatment System	
	1. Number	2
	2. Type	HEPA Filter and Activated Carbon Adsorber
	Reactor Building Ventilation System	
	None	

Table 6.2-6

PCIS GROUP ISOLATION SIGNALS

Isolation Groupings	
GROUP 1	The valves in Group 1 are closed upon any one of the following conditions: 1. Reactor low-low water level 2. Main steam line high flow 3. Main steam line tunnel high temperature 4. Main steam line low pressure (with mode switch in RUN)
GROUP 2	The actions in Group 2 are initiated by any one of the following conditions: 1. Reactor low water level 2. High drywell pressure 3. Drywell high radiation
GROUP 3	The actions in Group 3 are initiated by any of the following conditions: 1. Reactor low water level 2. RWCU area high temperature 3. Main steam tunnel high temperatures The following actions cause an automatic initiation of a RWCU system isolation: (NOT GROUP 3) 1. SBLC system initiation 2. RWCU non-regenerative heat exchanger high outlet temperature
GROUP 4	The HPCI steam supply isolation valves are closed upon any <u>one</u> of the following conditions: 1. HPCI steamline high flow 2. High HPCI area temperature (steamline area) 3. Low reactor pressure The HPCI turbine exhaust line vacuum breaker valves are closed upon <u>both</u> of the following signals: 1. Low reactor pressure (HPCI steamline) <u>and</u> 2. High drywell pressure
GROUP 5	RCIC isolation initiated by any one of the following signals: 1. RCIC steam high flow 2. High temperature in the vicinity of the RCIC steam line 3. Low reactor pressure
RHR shutdown cooling isolation	The RHR shutdown cooling suction valves (1001–47 and 50) are closed upon any <u>one</u> of the following conditions: 1. Reactor high pressure 2. Reactor low water level (Group 2) The RHR LPCI/shutdown cooling injection valves (1001–29A, B) are closed upon reactor low water level (Group 2) when in shutdown cooling mode

Table 6.2-7

PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location Ref. to Containment	Normal Status	Actuation on PCIS Signal	Automatic Actuation or Isolation Signal	Power to Close	Power to Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-001	--	Equipment hatchway	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-002	--	Personnel lock	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-004	--	Head access hatch	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-005 A,-H	--	Vent line	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-006	--	CRD removal hatch	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-007 A,B,C,D	203-1 A,B,C,D	Main steam line	AO Globe	A	4/Inside	Open	GC	Group 1	Air & Spring	Air & ac, dc	20	3<=T<5	C	M13, M60
X-007 A,B,C,D	203-2 A,B,C,D	Main steam line	AO Globe	A	4/Outside	Open	GC	Group 1	Air & Spring	Air & ac, dc	20	3<=T<5	C	M13, M60
X-008	220-1	Main steam line drain	MO Gate	A	1/Inside	Closed	SC	Group 1	ac	ac	3	35	C	M13, M60
X-008	220-2	Main steam line drain	MO Gate	A	1/Outside	Closed	SC	Group 1	dc	dc	3	35	C	M13, M60
X-009 A,B	220-62 A,B	From reactor feedwater	Check	A-X	2/Outside	Open	--	Rev. Flow	Process	Fwd. Flow	18	--	C	M15, M62
X-009 A,B	220-58 A,B	From reactor feedwater	Check	A-X	2/Inside	Open	--	Rev. Flow	Process	Fwd. Flow	18	--	C	M15, M62
X-010	1301-16	RCIC-turbine steam supply	MO Gate	A-X	1/Inside	Open	GC	Group 5	ac	ac	3	25	C	M50, M89
X-010	1301-17	RCIC-turbine steam supply	MO Gate	A-X	1/Outside	Open	GC	Group 5	dc	dc	3	25	C	M50, M89
X-011	2301-4	HPCI-turbine steam	MO Gate	A	1/Inside	Open	GC	Group 4	ac	ac	10	50	C	M46, M87
X-011	2301-5	HPCI-turbine steam	MO Gate	A	1/Outside	Open	GC	Group 4	dc	dc	10	63	C	M46, M87
X-012	1001-47	RHR reactor shutdown cooling suction	MO Gate	A Note (4)	1/Outside	Closed	SC	Group 2, I	dc	dc	20	40	C	M39, M81
X-012	1001-50	RHR reactor shutdown cooling suction	MO Gate	A Note (4)	1/Inside	Closed	SC	Group 2, I	ac	ac	20	40	C	M39, M81
X-013 A,B	1001-29 A,B	RHR reactor LPCI/shutdown cooling injection	MO Gate	A-X Note (4)	2/Outside	Closed	SC	B,C Group 2[H]	ac	ac	16	--	C	M39, M81
X-013 A,B	1001-28 A,B	RHR reactor LPCI/shutdown cooling injection	MO Globe	A-X	2/Outside	Open	SO	B	ac	ac	16	--	C[6]	M39, M81
X-013 A,B	1001-68 A,B	RHR reactor LPCI/shutdown ccoling injection	AO Check	A-X Note (4)	2/Inside	Closed	--	Note (3)	Note (3)	Note (3)	16	--	C[8]	M39, M81
X-014	1201-2	Reactor water cleanup supply	MO Gate	A	1/Inside	Open	GC	Group 3, D	ac	ac	6	30	C	M47, M88
X-014	1201-5	Reactor water cleanup supply	MO Gate	A	1/Outside	Open	GC	Group 3, D	dc	dc	6	38	C	M47, M88
X-014	1299-87	Reactor water cleanup supply	Relief	A	1/Inside	Closed	--	--	--	--	3/4	--	C[7]	M-88 M-47
X-015	--	Spare	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-016 A,B	1402-24 A,B	Core spray to reactor	MO Gate	A-X	2/Outside	Open	GC	G	ac	ac	10	--	C	M36, M78
X-016 A,B	1402-25 A,B	Core spray to reactor	MO Gate	A-X Note (4)	2/Outside	Closed	SC	C	ac	ac	10	--	C	M36, M78
X-016 A,B	1402-9 A,B	Core spray to reactor	Check	A-X Note (4)	2/Inside	Closed	--	--	--	--	10	--	C[8]	M36, M78
X-017	--	Spare (old head spray)	--	--	--	--	--	--	--	--	4	--	--	B22, B403
X-018	2001-3	Drywell floor drain discharge	AO Plug	B	1/Outside	Closed	SC	Group 2	Spring	Air/dc	3	20	C	M43, M85
X-018	2001-4	Drywell floor drain discharge	AO Plug	B	1/Outside	Closed	SC	Group 2	Spring	Air/dc	3	20	C	M43, M85
X-019	2001-15	Drywell equipment drain discharge	AO Gate	B	1/Outside	Closed	SC	Group 2	Spring	Air/dc	3	20	C	M43, M85
X-019	2001-16	Drywell equipment drain discharge	AO Gate	B	1/Outside	Closed	SC	Group 2	Spring	Air/dc	3	20	C	M43, M85
X-020	4399-45	Clean demineralizer water in	Hand Globe	--	1/Outside	Closed	--	--	Hand	Hand	3	--	C	M58-3
X-020	4399-46	Clean demineralizer water in	Check	C-X	1/Outside	Closed	--	Rev. Flow	Process	Fwd. Flow	3	--	C	M58-3
X-021	4699-47	Service air to drywell	Check	B	1/Outside	Closed	--	Rev. Flow	Spring	Fwd. Flow	1	--	C	M25, M72
X-021	4699-46	Service air to drywell	Hand Globe	B	1/Outside	Closed	--	--	Hand	Hand	1	--	C	M25, M72
X-022	4799-156	Instrument air to drywell	Check	B	1/Outside	Open	--	Rev. Flow	Spring	Fwd. Flow	2	--	C	M24, M71
X-022	4799-155	Instrument air to drywell	Check	B	1/Inside	Open	--	Rev. Flow	Spring	Fwd. Flow	2	--	C	M24, M71
X-023	3799-31	Reactor building closed cooling water in	Check	C-X	1/Inside	Open	--	Rev. Flow	Spring	Fwd. Flow	8	--	C	M33, M75
X-023	3702	Reactor building closed cooling water in	MO Gate	C-X	1/Outside	Open	SO	G	ac	ac	8	--	C	M33, M75
X-024	3703	Reactor building closed cooling water out	MO Gate	C-X	1/Outside	Open	SO	G	ac	ac	8	--	C	M33, M75
X-024	3706	Reactor building closed cooling water out	MO Gate	C-X	1/Inside	Open	SO	G	ac	ac	8	--	C	M33, M75

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-025	1601-62	Drywell exhaust valve bypass (vent relief)	AO Globe	B-X	1/Outside	Closed	SC	Group 2	Spring	Air/ac	2	15	C	M34, M76
X-025	1601-23	Drywell main exhaust	AO Butterfly	B-X	1/Outside	Closed	SC	Group 2	Spring	Air/ac	18	10	C	M34, M76
X-025 X-203A	1601-24	Main primary containment vent to reactor building exhaust	AO Butterfly	B-X	1/Outside	Closed	SC	Group 2	Spring	Air/ac	18	10	C	M34, M76
X-025 X-203A	1601-63	Drywell exh to standby gas treatment system	AO Butterfly	B-X	1/Outside	Closed	SC	Group 2	Spring	Air/ac	6	10	C	M34, M76
X-025 (U-1) X-203A (U-1)	1699-98	Wetwell exhaust to Hardened Containment Vent System (HCVS)	AO Butterfly	B-X	1/Outside	Closed	SC	None	Spring	HCVS Nitrogen	12	N/A	C	M34
X-026	1601-55	Drywell nitrogen purge inlet	AO Gate	B	1/Outside	Open	GC	Group 2	Spring	Air/ac	4	10	C	M34, M76
X-026	1601-57	Nitrogen makeup	MO Globe	B	1/Outside	Open	GC	Group 2	dc	dc	1	15	C	M34, M76
X-026	1601-21	Drywell purge inlet	AO Butterfly	B	1/Outside	Closed	SC	Group 2	Spring	Air/ac	18	10	C	M34, M76
X-026	1601-22	Drywell purge inlet	AO Butterfly	B	1/Outside	Closed	SC	Group 2	Spring	Air/ac	18	10	C	M34, M76
X-026	1601-59	Nitrogen makeup to Drywell	AO Globe	B	1/Outside	Open	GC	Group 2	Spring	Air/ac	1	15	C	M34, M76
X-026 X-205	8799-214	Nitrogen makeup	Relief	B	1/Outside	Closed	--	Nitrogen Pressure	Spring	Excess Pressure	1- 1/2	--	C	M34, M76
X-026	8803	Oxygen analyzer return	AO Globe	B	1/Outside	Open	GC	Group 2	Spring	Air/ac	2	10	C	M461, M463
X-026	8804	Oxygen analyzer return	AO Globe	B	1/Outside	Open	GC	Group 2	Spring	Air/ac	2	10	C	M461, M463
X-027	--	Instrumentation lines X-27 A thru F	--	--	--	--	--	--	--	--	--	--	--	M34, M76, M78, M35, M77
X-028	--	Instrumentation lines X-28 B,C,E,F	--	--	--	--	--	--	--	--	--	--	--	B-22 B-403 M35, M77
X-028	--	Instrumentation lines X-28 A & D Spares	--	--	--	--	--	--	--	--	--	--	--	B-22 B-403
X-029	--	Instrumentation lines X-29 A thru F	--	--	--	--	--	--	--	--	--	--	--	M13, M60, M35
X-030	_	Instrumentation lines X-30 A,B,C,E,F (Unit 1) A,B,D,E,F (Unite 2)	_	_	_	_	_	_	_	_	_	_	_	M35, M77
X-30	0220-451A 0220-452A	Instrumentation lines X-30D (Unit 1) X-30C (Unit 2)	Check	A	2/Outside	Open	_	Reverse Flow	Spring	Forward Flow	1/2	_	Note 10	M35, M77
X-031	_	Instrumentation lines X-31 A, B, D, E, F	_	_	_	_	_	_	_	_	_	_	_	M35, M77
X-031	0220-451B 0220-452B	Instrumentation lines X-31C	Check	A	2/Outside	Open	_	Reverse Flow	Spring	Forward Flow	1/2	_	Note 10	M35, M77

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-032	--	Instrumentation lines X-32 A,B,C,E,F	--	--	--	--	--	--	--	--	--	--	--	M34,35, M-50 M76,77
X-032	4720	Drywell pneumatic suction X32D	AO Gate	B	1/Outside	Open	GC	Group 2	Spring	Air/ac	1	10	C	M71 M24
X-032	4721	Drywell pneumatic suction X-32D	AO Gate	B	1/Outside	Open	GC	Group 2	Spring	Air/ac	1	10	C	M71 M24
X-033	2499-1 A	CAM/drywell	SO Valve	B	1/Outside	Closed	SC	G	Spring	ac	1/2	--	C	M641 M641
X-033	2499-2 A	CAM/drywell	SO Valve	B	1/Outside	Closed	SC	G	Spring	ac	1/2	--	C	M641 M641
(U-2)X-033	2499-22A	CAM return	Check	B	1/Outside	Closed	--	Rev. Flow	Drywell Pressure	Fwd. Flow	1/2	--	C	M641
(U-1) X-033	--	Instrument lines A, B, C, D	--	--	--	--	--	--	--	--	--	--	--	M-36, M-46
X-035A (U1)	--	Tip drives (Spare)	--	--	--	--	--	--	--	--	--	--	--	M584
X-035A (U2)	743	Traversing in-core probe purge	Check	C	1/Outside	Closed	--	Rev. Flow	Drywell Pressure	Fwd. Flow	3/8	--	C	M584
X-035B-F	737-1B-F	Traversing in-core probe	SO Valve	C	5/Outside	Closed	SC	Group 2	Spring	ac	3/8	--	C	M584 M584
X-035B-F	737-2B-F	Traversing in-core probe	Shear	C	5/Outside	Open	--	--	dc	--	3/8	--	C	M584 M584
X-035G (U1)	743	Traversing in-core probe purge	Check	C	1/Outside	Closed	--	Rev. Flow	Drywell Pressure	Fwd. Flow	3/8	--	C	M584
X-035G (U2)	--	TIP drives (spare)	--	--	--	--	--	--	--	--	--	--	--	M584
X-036	--	Spare (old CRD system return)	--	--	--	--	--	--	--	--	--	--	--	B22, B403
X-037A-D	--	Control rod drive insert	--	--	--	--	--	--	--	--	--	--	--	M41, M83
(U-2)X-37 C	2499-22 B	CAM return	Check	B	1/Outside	Closed	--	Rev. Flow	Drywell Pressure	Fwd. Flow	1/2	--	C	M641
X-038A-D	--	Control rod drive withdraw	--	--	--	--	--	--	--	--	--	--	--	M41, M83
X-039A,B	1001-26 A,B	RHR-containment spray	MO Gate	B-X	2/Outside	Closed	SC	A	ac	ac	10	--	C	M39, M81
X-039A,B	1001-23 A,B	RHR-containment spray	MO Gate	B-X	2/Outside	Closed	SC	A	ac	ac	10	--	C[6]	M39, M81
X-039A	1099-166	RHR-containment spray	Manual Gate	B	1/Outside	Closed	--	--	--	--	6	--	C	M39, M81
X-040A-D	--	Jet pump flow instrumentation penetrations	--	--	--	--	--	--	--	--	--	--	--	M35, M77
X-041	220-44	Reactor water sample	AO Globe	A	1/Inside	Open	GC	Group 1	Spring	Air	3/4	5	C	M35, M77
X-041	220-45	Reactor water sample	AO Globe	A	1/Outside	Open	GC	Group 1	Spring	Air	3/4	5	C	M35, M77

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-042	--	Spare	--	--	--	--	--	--	--	--	--	--	--	B-22 B-403
(U-1) X-043 (U-2) X-044	8800-02 B-V	Particulate sample lines	Hand Globe	B	21/Outside	Closed	--	--	Hand	Hand	1/2	--	C	M461, M463
(U-1) X-043 (U-2) X-044	8800-03 B-V	Particulate sample lines	Hand Globe	B	21/Outside	Closed	--	--	Hand	Hand	1/2	--	C	M461, M463
(U-1) X-043 (U-2) X-044	8801 A,B,C	Drywell oxygen analyzer sample	AO Globe	B	3/Outside	Open	GC	Group 2	Spring	Air/ac	1/2	10	C	M461, M463
(U1) X-043 (U-2) X-044	8802 A,B,C	Drywell oxygen analyzer sample	AO Globe	B	3/Outside	Open	GC	Group 2	Spring	Air/ac	1/2	10	C	M461, M463
(U-1) X-044	1-4799-176 1-4799-489 A thru Z	HVAC instrument penetration	--	--	25/Outside	Closed	--	--	Hand	Hand	1/2	--	--	B-22 B-403 M 24
(U-2) X-043	2-4799-176 2-4799-479 A thru Z	HVAC Inst. Penetration	--	--	25/Outside	Closed			Hand	Hand	1/2			M 71
X-045	--	Spare	--	--	--	--	--	--	--	--	--	--	--	B-22 B-403
X-046	--	Radiation sensor instrument penetration	--	--	--	--	--	--	--	--	--	--	--	B-22 B-403
X-047	1101-16	Standby liquid control	Check	A-X	1/Outside	Closed	--	Rev. Flow	Process	Fwd. Flow	1- 1/2	--	C	M40, M82
X-047	1101-15	Standby liquid control	Check	A-X	1/Inside	Closed	--	Rev. Flow	Process	Fwd. Flow	1- 1/2	--	C	M40, M82
X-048	--	Spare	--	--	--	--	--	--	--	--	--	--	--	B-22 B-403
X-049	--	Instrumentation lines X-49 B,C,E,F	--	--	--	--	--	--	--	--	--	--	--	B-22 B-403
X-049	--	Instrumentation lines X-49 A & D Spares	--	--	--	--	--	--	--	--	--	--	--	B-22 B-403
X-050	--	Instrumentation lines X-50 A thru D	--	--	--	--	--	--	--	--	1	--	--	M-13, M-60
(U-1)X-051	2499-22 A	CAM return (position E)	Check	B	1/Outside	Closed	--	Rev. Flow	Drywell Pressure	Fwd. Flow	1/2	--	C	M641
(U-1) (U-2)X-051	--	Instrumentation penetration A thru D	--	--	--	--	--	--	--	--	1	--	--	M77 M642
X-052	--	Instrumentation penetration A thru D	--	--	--	--	--	--	--	--	1	--	--	M35, M77, M76
X-100A	--	U-1 Electrical U-2 Electrical/Instrumentation	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-100B	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-100C	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
(U-1) (U-2)X-100D	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
(U-2)X-100D	2499-1B	CAM/drywell	SO Valve	B	1/Outside	Closed	SC	G	Spring	Ac	1/2	--	C	M641
(U-2)X-100D	2499-2B	CAM/drywell	SO Valve	B	1/Outside	Closed	SC	G	Spring	Ac	1/2	--	C	M641
(U-2)X-100D	4799-353	SRM/IRM purge	Check	C	1/Outside	Closed	--	Rev. Flow	Spring	Fwd. Flow	1/4	--	C	M71
(U-2)X-100D	4799-354	SRM/IRM purge	Check	C	1/Outside	Closed	--	Rev. Flow	Spring	Fwd. Flow	1/4	--	C	M71

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-100E	--	Electrical	--	--	--		--	--	--	--	--	--	--	B-22, B-403
X-100F	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-101A	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-101B	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-101C	--	Spare	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-101D	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-102A	--	(U-1) Electrical (U-2) Spare	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-102B	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-103	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403 M-34
X-104A	--	(U-2) Electrical (U-1) Spare	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-104B	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-104C	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-104D	1-4799-488 A thru G	Instrumentation Lines	--	--	7/Outside	Closed	--	--	Hand	Hand	1/2	--	--	M-24
(U-2)X-104E	2-4799-477 A thru G	Instrumentation Lines	--	--	7/Outside	Closed	--	--	Hand	Hand	1/2	--	--	M 71
(U-1)X-104E	2499-1B	CAM/drywell	SO Valve	B	1/Outside	Closed	SC	G	Spring	ac	1/2	--	C	M641
(U-1)X-104E	2499-22B	CAM return	Check	B	1/Outside	Closed	--	Rev. Flow	Drywell Pressure	Fwd. Flow	1/2	--	C	M641
(U-1)X-104E	2499-2B	CAM/drywell	SO Valve	B	1/Outside	Closed	SC	G	Spring	ac	1/2	--	C	M641
X-104E	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-104F	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-105A	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
(U-1) X-105B	--	(U-1) Electrical (U-1) Spare	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
(U-2) X-105B	--	U-2 Radiation Sensor Instrument Penetration	--	--	--	--	--	--	--	--	--	--	--	M641
X-105C	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-105D	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-106A	--	(U-1) Spare (U-2) Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
(U-1) X-106B	1-4799-490 A thru D 1-4799-490 E thru G	Instrumentation Line	--	--	7/Outside	Closed	--	--	Hand	Hand	1/2	--	--	M-24
(U-2) X-106B	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-107A	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-107B	--	Electrical	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-108	0263-947A 0263-948A	RVLIS Backfill	Check	A	2/Outside	Open	--	Reverse Flow	Spring	Forward Flow	3/8	--	Note 5	M-35, M-77
	0263-944A 0263-945A	RVLIS Backfill	Check	A	2/Outside	Open	--	Reverse Flow	Spring	Forward Flow	3/8	--	Note 5	M-35, M-77
	0263-2-13A	220X-5 Ref. Leg	Ex. Flow Ck.	A	1/Outside	Open	--	Excess Flow	Diff. Pressure	Spring	1	--	--	M-35, M-77
	0263-2-19A	220X-5 Ref. Leg	Ex. Flow Ck.	A	1/Outside	Open	--	Excess Flow	Diff. Pressure	Spring	1	--	--	M-35, M-77
	0263-2-42A	220X-7 Ref. Leg	Ex. Flow Ck.	A	1/Outside	Open	--	Excess Flow	Diff. Pressure	Spring	1	--	--	M-35, M-77
X-109	0263-947B 0263-948B	RVLIS Backfill	Check	A	2/Outside	Open	--	Reverse Flow	Spring	Forward Flow	3/8	--	Note 5	M-35, M-77
	0263-944B 0263-945B	RVLIS Backfill	Check	A	2/Outside	Open	--	Reverse Flow	Spring	Forward Flow	3/8	--	Note 5	M-35, M-77
	0263-2-13B	220X-6 Ref. Leg	Ex. Flow Ck.	A	1/Outside	Open	--	Excess Flow	Diff. Pressure	Spring	1	--	--	M-35, M-77
	0263-2-19B	220X-6 Ref. Leg	Ex. Flow Ck.	A	1/Outside	Open	--	Excess Flow	Diff. Pressure	Spring	1	--	--	M-35, M-77
	0263-2-42B	220X-8 Ref. Leg	Ex. Flow Ck.	A	1/Outside	Open	--	Excess Flow	Diff. Pressure	Spring	1	--	--	M-35, M-77
X-200A,B	--	Access hatches	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-201A-H	--	Vent lines	--	--	--	--	--	--	--	--	--	--	--	B-22, B-403
X-203A	1601-61	Suppression chamber exhaust valve bypass	AO Globe	B-X	1/Outside	Closed	SC	Group 2[A]	Spring	Air/ac	2	15	C	M34, M76
X-203A	1601-60	Suppression chamber main exhaust	AO Butterfly	B-X	1/Outside	Closed	SC	Group 2[A]	Spring	Air/ac	18	10	C	M34, M76
X-204A-D	--	Header suction	--	--	--	--	--	--	--	--	--	--	--	B-23, B-404
X-205	1601-31 A,B	Vacuum breaker secondary containment to suppression	Check	B	2/Outside	Closed	--	Suppression Chamber Pressure	Gravity/wgt	Suppression Chamber Vacuum	20	--	C	M34, M76

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-205	1601-20 A,B	Vacuum breaker secondary containment to suppression	AO Butterfly	B	2/Outside	Closed	--	G	Air	Spring	20	--	C	M34, M76
X-205	1601-56	Suppression chamber purge inlet	AO Butterfly	B-X	1/Outside	Open	GC	Group 2	Spring	Air/ac	18	10	C	M34, M76
X-205	1601-58	Nitrogen makeup to suppression chamber	AO Globe	B	1/Outside	Closed	SC	Group 2	Spring	Air/ac	1	15	C	M34, M76
X-206A-D	--	Liquid level indicators	--	--	--	--	--	--	--	--	--	--	--	M34, M46
X-207A-H	--	Vent line drain	--	--	--	--	--	--	--	--	--	--	--	B-23, B-404
X-208A-F	--	Relief Valve discharge	--	--	--	--	--	--	--	--	--	--	--	B-23, B-404
X-209A-D	--	Air and water temp	--	--	--	--	--	--	--	--	--	--	--	B-23, B-404
(U-1) X-210A (U-2) X-210B	1402-4A 1402-4B	Core spray test to suppression pool	MO Globe	B	2/Outside	Closed	SC	E	ac	ac	8	--	--	M39, M81
X-210A,B	1001-36 A,B	RHR test line to suppression pool	MO Globe	B-X	2/Outside	Closed	SC	A	ac	ac	14	--	C[6]	M39, M81
(U-1) X-210A (U-2) X-210B	2301-14	HPCI min flow bypass	MO globe		1/Outside	Closed	SC	G	dc	dc	4	--	C[6]	M46, M39 M87, M81
(U-1) X-210A (U-2) X-210B	1301-47	RCIC min flow bypass	Check	B-X	1/Outside	Closed	SC	Rev. Flow	Process	Fwd. Flow	2	--	C[6]	M50 M89
(U-1) X-210A (U-2) X-210B	1402-38A 1402-38B	Core spray min bypass	MO globe		2/Outside	Closed	SC	G	ac	ac	1 1/2	--	C[6]	M-78 M-36
X-210A,B	1001-18A,B	RHR min flow bypass	MO Gate	--	2/Outside	Open	SO	G	ac	ac	3	--	C[6]	M39, M81
X-211A,B X-210A,B	1001-34 A,B	RHR-suppression pool test return	MO Gate	B-X	2/Outside	Closed	SC	A	ac	ac	16	--	C[6]	M39, M81
X-211A,B	1001-37 A,B	RHR to suppression spray header	MO Globe	B-X	2/Outside	Closed	SC	A	ac	ac	6	--	C	M39, M81
X-212	1301-41	RCIC-turbine exhaust	Check	B-X	1/Outside	Closed	--	Rev. Flow	Process	Fwd. Flow	8	--	C	M50, M89
X-212	1301-64	RCIC-turbine exhaust	Stop Check	B-X	1/Outside	Open	--	Rev. Flow	Process	Fwd. Flow	8	--	C	M50, M89
X-213A,B	--	Suppression chamber drain	--	--	--	--	--	--	--	--	--	--	--	M34, M76
(U1) X-214	2399-40	HPCI exhaust vacuum breaker	MO Gate	B	1/Outside	Open	GC	Group 4	ac	ac	4	50	C	M-46
(U1) X-214	2399-41	HPCI exhaust vacuum breaker	MO Gate	B	1/Outside	Open	GC	Group 4	dc	dc	4	50	C	M-46
X-215	--	Spare	--	--	--	--	--	--	--	--	--	--	--	B-23, B-404
X-216	4799-159	Instrument air to suppression chamber	Check	B	1/Outside	Open	--	Rev. Flow	Spring	Fwd. Flow	1/2	--	C	M24, M71

Table 6.2-7 (Continued)

Containment Penetration Number	Valve Part Number	Line Isolated	Valve Type	Class[2]	No. of Valves Location of Ref. to Containment	Normal Status	Actuation On PCIS Signal	Automatic Actuation Or Isolation Signal	Power To Close	Power To Open	Line Size (in.)	Max. Operating Time (sec)	Test Class	Reference Drawings
X-216	4799-158	Instrument air to suppression chamber	Check	B	1/Inside	Open	--	Rev. Flow	Spring	Fwd. Flow	1/2	--	C	M24, M71
X-217	8801D	Torus oxygen analyzer sample	AO Globe	B	1/Outside	Open	GC	Group 2	Spring	Air/ac	1/2	10	C	M463, M76
X-217	8802D	Torus oxygen analyzer sample	AO Globe	B	1/Outside	Open	GC	Group 2	Spring	Air/ac	1/2	10	C	M463, M76
X-218	--	Electrical cable	--	--	--	--	--	--	--	--	--	--	--	B-23, B-404
X-219	--	Electrical cable	--	--	--	--	--	--	--	--	--	--	--	B-23, B-404
X-220	2301-45	HPCI-turbine exhaust	Check	C-X	1/Outside	Closed	--	Rev. Flow	Process	Fwd. Flow	24	--	C[6]	M46, M87
X-220	2301-74	HPCI-turbine exhaust	Stop Check	C-X	1/Outside	Open	--	Rev. Flow	Process	Fwd. Flow	12	--	C[6]	M46, M87
X-221	*2301-34	HPCI-turbine exhaust drain	Check	B-X	1/Outside	--	--	Rev. Flow	Process	Fwd. Flow	2	--	C	M46, M87
X-221	2301-71	HPCI-turbine exhaust drain	Stop Check	B-X	1/Outside	Open	--	Rev. Flow	Process	Fwd. Flow	2	--	C	M46, M87
X-222	1301-55	RCIC-vaccum pump discharge to suppression chamber	Stop Check	B-X	1/Outside	Open	--	Rev. Flow	Process	Fwd. Flow	2	--	C	M50 M89
X-222	1301-40	RCIC-vaccum pump discharge to suppression chamber	Check	B-X	1/Outside	Closed	--	Rev. Flow	Process	Fwd. Flow	2	--	C	M50-1 M89-1
X-223 A,B	1001-7 A,B,C,D	RHR pump suction	MO Gate	B-X	4/Outside	Open	SO	G	ac	ac	14	--	C[6]	M39, M81 M39, M81
X-224 A,B	1402-3 A,B	Core spray pump suction	MO Gate	B-X	2/Outside	Open	SO	G	ac	ac	18	--	C[6]	M36, M78 M39, M81
X-225	2301-36	HPCI pump suction from suppression chamber	MO Gate	B-X	1/Outside	Closed	SC	F	dc	dc	16	--	C[6]	M46, M39 M87, M81
X-226	1301-25	RCIC-pump suction from suppression chamber	MO Gate	B-X	1/Outside	Closed	SC	F	dc	dc	6	--	C[6]	M50, M89 M39, M81
X-227 A,B	2499-3 A,B	CAM/suppression chamber	SO Valve	B	2/Outside	Closed	SC	G	Spring	ac	1/2	--	C	M641
X-227 A,B	2499-4 A,B	CAM/suppression chamber	SO Valve	B	2/Outside	Closed	SC	G	Spring	ac	1/2	--	C	M641
--	1001-20	RHR discharge to radwaste	MO Gate	A	1/Outside	Closed	SC	Group 2	ac	ac	3	25	Note 9	M39, M81
--	1001-21	RHR discharge to radwaste	MO Gate	A	1/Outside	Closed	SC	Group 2	dc	dc	3	25	Note 9	M39, M81
(U2) X-229	2399-40	HPCI Exhaust Vacuum Breaker	MO Gate	B	1/Outside	Open	GC	Group 4	ac	ac	4	50	C	M-87
(U2) X-229	2399-41	HPCI Exhaust Vacuum Breaker	MO Gate	B	1/Outside	Open	GC	Group 4	dc	dc	4	50	C	M-87

Table 6.2-7 (Continued)
NOTES TO TABLE 6.2-7

Additional Isolation and Actuation Signals: (See Table 6.2-6 for a summary of PCIS signals)

A. These valves close and interlock closed on low reactor water level or high drywell pressure. The interlock can be defeated with a keylock switch.

B. The LPCI injection valves are controlled by LPCI loop select logic which isolates the valves on the broken loop. The B loop is preferred and A will isolate if no break is detected.

C. This valve is interlocked closed until reactor pressure decreases below the injection permissive pressure.

D. Closes on injection of standby liquid control.

E. Close and interlock closed on low low reactor water level or high drywell pressure.

F. Suction will switch automatically to the suppression pool on low level in the contaminated condensate storage tank or high level in the suppression pool.

G. Remote manual closure from the control room.

H. These valves close on a Group 2 isolation signal when RHR is in the shutdown cooling mode of operation.

I. Close on high reactor vessel pressure.

Note

1. Basic penetration numbers are shown. Suffix letters that follow the basic number are given on the appropriate piping and instrumentation diagram.

2. Class A Valves are on process lines that communicate directly with the reactor vessel and penetrate the containment.

Class B Valves are on process lines that do no directly communicate with the reactor vessel, but penetrate the primary containment and communicate with the containment free space.

Class C Valves are on process lines that penetrate the primary containment but do not directly communicate with the reactor vessel or with the primary containment free space and are not on lines that communicate with the environs.

A fourth class of valves are exceptions to the preceding definitions.

Their class design notations are followed by an X suffix; for example, A—X. These valves either can be opened after a containment signal or are opened automatically on certain containment signals to permit the operation of the control rods, the standby liquid control system and the various core and containment cooling systems.

Minimum closing rates for each isolation valve shall be:

Class A Valves shall be closed prior to the start of uncovering of fuel caused by blowdown from that line. The main steam isolation valves closing time shall be adjustable between 3 and 5 seconds during specified flow and temperature.

Class B and C

Valves closure times shall be selected to limit radioactivity release from containment to below permissible limits in the event of a loss of coolant accident blowdown within the primary containment.

Table 6.2-7 (Continued)

(The closure rates given are as required for containment isolation only--system operational requirements may be more restrictive).

3. Testable check valves

   are designed for remote opening with approximately zero differential pressure across the valve seat. The valves will close on reverse flow even though the test switches may be calling for open. The valves will open when pump pressure exceeds reactor pressure even though the test switch may be calling for close.

4. Valve performs a Pressure Isolation Valve (PIV) function.

5. These check valves have a critical leakage acceptance criteria for maintaining RVLIS instrumentation operability in the event of CRD drivewater header depressurization. This critical performance leakage has been calculated to be 29.7 cc/hr. To provide additional safety margin, a test acceptance criteria of 3 cc/hr is used. The check valves will be tested in accordance with the IST program and the 10CFR50, Appendix J test program.

6. Valve exempt from type C testing because the line does not constitute a pathway for primary containment atmosphere.

7. Relief valve is a part of the test volume during type C test, but not considered as a component that requires a specific value for contributing to 0.6 La value.

8. Check valve is a part of the test volume during the type C test, but not considered as a component contributing to the 0.6 La total.

9. These are not containment isolation valves but are listed here because they get closed by group 2 isolation.

10. The check valves will be tested in accordance with the IST program.

Miscellaneous definitions of abbreviations used in Table 6.2-7:

AO - air operated
MO - motor operated
GC - goes closed
SC - stays closed
SO - stays open
PCIS Primary Containment Isolation System

6.3 EMERGENCY CORE COOLING SYSTEM

This section covers the design bases, system design, performance evaluation, testing, inspection and instrumentation requirements for the emergency core cooling system (ECCS). The related subject of containment cooling is covered in Section 6.2.2.

All LOCA peak clad temperature evaluations are reported to the NRC per 10 CFR 50.46. Refer to the latest annual or thirty day 10 CFR 50.46 report for details on PCT updates and impact of these evaluations on the limiting licensing basis LOCA analysis results. The 10 CFR 50.46 letter is on file at the site.

6.3.1 Introduction and System Design Bases

The ECCS is designed to provide adequate core cooling across the entire spectrum of line break accidents. This is graphically illustrated by Figure 6.3-1. This figure shows the typical range of effectiveness and redundancy for the various subsystems. The individual subsystems are described in Section 6.3.2, and the integrated performance is evaluated in Section 6.3.3.2. [6.3-1]

Table 6.3-1 summarizes the provisions for emergency cooling of the reactor core under various conditions. A summary description of the ECCS equipment is shown in Table 6.3-2. Both Units 1 and 2 have their own ECCS.

Some information from pre-EPU LOCA analysis (Figures 6.3-1, 31-38, 43-56) has been identified and maintained as historical information.

For operation at 2957 MWt with SVEA-96 Optima2 fuel, the LOCA analysis used the Westinghouse 10CFR50, Appendix K BWR LOCA methodology with bounding input parameters for the Quad Cities units. The significant parameters used in the analysis to support operation at 2957 MWt for SVEA-96 Optima2 fuel types are summarized in Table 6.3-3D.

For AREVA reload cores (starting with Quad Cities Unit 1 Cycle 25), the AREVA EXEM BWR-2000 LOCA Evaluation Methodology was used to analyze ATRIUM 10XM fuel. The significant parameters used in that analysis to support operation at 2957 MWt are summarized in Table 6.3-3E.

Provisions are needed to maintain continuity of core cooling during those postulated accident conditions where it is assumed that mechanical failures occur in the primary system and coolant is partially or completely lost from the reactor vessel, and either normal auxiliary power is unavailable to drive the feedwater pumps or the loss of coolant occurs at a rate beyond the capability of the feedwater system. Under these circumstances, core cooling is accomplished by means of the ECCS. This system consists of the core spray subsystem, the low pressure coolant injection (LPCI) subsystem (an operational mode of the RHR system), the high pressure coolant injection (HPCI) subsystem and the automatic depressurization subsystem (ADS). Each of these subsystems is designed to cover a

specific range of accident conditions and collectively provide a redundancy in kind to avoid undetected common failure mechanisms. The overall ECCS design bases are: [6.3-2]

A. The ECCS is designed to provide adequate core cooling for any mechanical failure of the primary system up to and including a break area equivalent to the largest primary system pipe (see NEDO-20566[2], Section III for further discussion of this design basis).

B. The entire spectrum of line breaks, up to and including this maximum, is designed to be protected against by redundant cooling equipment which is actuated automatically. [6.3-3]

C. The ECCS is required to perform its functions assuming the most limiting single failure of ECCS components. [6.3-4]

D. No reliance is assumed to be placed on external sources of power.

E. The ECCS is capable of fulfilling its performance function under the most adverse of postulated accident conditions, including the combined LOCA and the design basis earthquake.

For a discussion of the integrated ECCS performance analyzed to current regulatory requirements, refer to Section 6.3.3.2. [6.3-5]

The design bases of the subsystems which comprise the ECCS are as follows:

6.3.1.1 Core Spray Subsystem

The following design bases apply to each of the two core spray divisions: [6.3-6]

A. Each core spray division when combined with the remaining ECCS after a single failure will provide adequate core cooling for the various postulated LOCAs for a range of failure sizes up to and including the design basis accident: the instantaneous mechanical failure of a pipe equal in size to the largest coolant/recirculation system pipe.

B. Each core spray division is independent.

C. Either of the two independent core spray divisions meets the preceding design basis requirements without reliance on external power supplies to the core spray or the reactor system.

D. The core spray subsystem is designed so that each component of the subsystem can be tested periodically.

6.3.1.2 Residual Heat Removal System

The design bases of the RHR system are as follows: [6.3-7]

A. To restore the water level in the reactor vessel with at least two LPCI mode RHR pumps combined with one core spray pump and maintain this water level (during a loss-of-coolant accident) so that adequate core cooling is provided. This function is to be performed for the complete break size range. (This function is performed by the LPCI mode of RHR, which is further described in this section.)

B. To limit the pressure suppression pool water temperature during non-accident conditions such as those requiring RCIC operation (e.g., hot standby condition) so that if a LOCA should occur, the suppression pool water temperature will not exceed that which is necessary to achieve its primary role as the quenching agent in the pressure suppression containment system and to limit the post-LOCA suppression pool temperatures as required to maintain ECCS pump suction head required. (This function is performed by the containment cooling mode of RHR, which is described in Section 6.2.2.)

C. To remove decay heat and sensible heat from the primary system so that the reactor can be shut down for a refueling and servicing operation. (This function is performed by the shutdown cooling mode of RHR which is described in Section 5.4.7.)

D. To furnish a spray into the containment as a further aid in reducing containment pressure following a loss of coolant accident. (This function is performed by the containment cooling mode of RHR, which is described in Section 6.2.2.)

To have provisions for periodic testing of each component in the system. [6.3-8]

6.3.1.3 High Pressure Coolant Injection Subsystem

The following design bases were adopted for the HPCI subsystem and serve as the basis for evaluating the adequacy of the system: [6.3-9]

A. The HPCI subsystem when combined with the remaining ECCS after a single failure is provided to ensure that adequate core cooling takes place for all break sizes as directed by 10 CFR 50, Appendix K single failure ECCS analysis requirements.

B. The HPCI subsystem meets the preceding design basis requirement without reliance on an external power source for the injection system or the reactor system.

C. The HPCI subsystem is designed so that each component of the system can be tested on a periodic basis.

6.3.1.4 Automatic Depressurization Subsystem

The automatic depressurization subsystem (ADS) is an alternative to the HPCI subsystem described in Section 6.3.2.3 and performs the function of vessel depressurization for all small breaks. Applicable design bases are the same as for the HPCI subsystem. [6.3-10]

6.3.1.5 Management of Gas Accumulation in Fluid Systems

On January 11, 2008, the NRC issued Generic Letter 2008-01, Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems (Reference 78). NRC SER dated June 19, 2015 (Reference 79), added the suppression pool cooling system. Generic Letter 2008-01 and the SER requested licensees to evaluate the licensing basis, design, testing, and corrective action programs for the Emergency Core Cooling, Decay Heat Removal, Containment Cooling, and Suppression Pool Cooling systems to ensure that gas accumulation is maintained less than the amount that challenges operability of these systems, and that appropriate action is taken when conditions adverse to quality are identified. As a consequence, evaluations have been performed that resulted, in part, in the development of void acceptance criteria, identification of gas susceptible locations in piping, development of periodic gas monitoring procedures for these locations, and the acceptance of some locations that could potentially accumulate voids that were determined to be benign. The piping systems addressed in the response to Generic Letter 2008-01 have the potential to develop voids and pockets of entrained gases. Maintaining the pump suction and discharge piping sufficiently full of water is necessary to ensure that the system will perform properly and will inject the flow assumed in the safety analyses into the Reactor Coolant System or containment upon demand. This will also prevent damage from pump cavitation or water hammer, and pumping of unacceptable quantities of non-condensable gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an ECCS start signal, during shutdown cooling, or during suppression pool cooling. There are some piping locations that cannot be fully vented due to the physical layout and inability to dynamically vent the piping. These locations have been evaluated in accordance with Generic Letter 2008-01 and do not adversely affect the ability of the systems to perform their specified safety functions.

6.3.2 System Design

The following sections describe the design of the core spray, LPCI, HPCI and ADS subsystems.

6.3.2.1 Core Spray Subsystem

6.3.2.1.1 Core Spray Subsystem Interfaces with Other ECCS Subsystems

Each core spray division is designed to operate in conjunction with LPCI and either the ADS or HPCI subsystems to provide adequate core cooling over the entire spectrum of liquid or steam pipe break sizes. Thus, the ADS size and core spray subsystem head and flow requirements are related. [6.3-11]

For small breaks, and without HPCI, the core uncovers while the pressure remains above the core spray pump shutoff head. In this situation, the ADS will be actuated, which will reduce the pressure in time to permit core spray to reach rated flow before significant fuel cladding overheating can occur. Thus, the core spray subsystem with the assistance of the ADS protects the core for all break sizes.

If HPCI is available, the necessary depressurization occurs through the addition of cold feedwater to the vessel. Hence, in combination with HPCI, the core spray subsystem can protect the core for all break sizes.

The core spray system performance was established by heat transfer and flow distribution tests on simulated prototype fuel assemblies. These tests are described in detail in the Oyster Creek Amendment No. 10, Appendix A, Docket No. 50-219, and Topical Report APED 5458,[3] General Electric Docket and in Section 6.3.3.1.1. This was subsequently amended by the SAFER/GESTR - LOCA analysis for Quad Cities reactors. The test results as applied to the Quad Cities Units 1 and 2 cores result in the Core Spray system flow specification of 4500 gal/min. There are several documented existing leakage locations in the CS boundary. CS flow requirement for the current design basis LOCA analysis are described in section 6.3.3. It is small breaks which depressurize the reactor at the slowest rates and therefore require the largest core spray head. Therefore, the head requirements of the core spray subsystem must be determined by a series of analyses of the core spray subsystem in conjunction with either the ADS or HPCI over the small break size spectrum. The size of the ADS or HPCI subsystem plays an important role here also, particularly for the small breaks for which the core spray requires depressurization assistance. As ADS or HPCI capacity is increased, core spray head requirements decrease since the larger the capacity, the faster the vessel will depressurize.

The determination of the flow rate is based on refined prototype testing of a full scale fuel assembly under actual power conditions and actual spray distribution conditions. In order to ensure that the test situations resulted in a limiting case, the test fuel rods were allowed to overheat (1600°F) prior to core spray activation and the channel boxes were allowed to stay at high temperature. The core spray and LPCI divisions have been sized to provide the required flow rate to each assembly in the core.

6.3.2.1.2 Subsystem Characteristics

Two independent core spray divisions are provided for use under LOCA conditions associated with large pipe breaks and reactor vessel depressurization. Each of the two core spray divisions consists of a 4500 gal/min capacity pump, valves, piping and an independent circular sparger ring inside the inner shroud just over the core. Suction water is supplied by the suppression pool. The FSAR single-line drawing for Core Spray Piping is shown on Figure 6.3-2. The P&ID for the core spray subsystem is shown in M-36 and system equipment specifications are given in Table 6.3-4. [6.3-12]

Water injection starts when the injection valve is opened and the reactor vessel pressure drops below pump discharge pressure (325 psig). Rated flow is sprayed over the top of the core at 90 psig in the reactor vessel. Water sprayed into the fuel assemblies runs down the channel walls providing a heat sink for the heat radiated from the fuel rods. Steam produced by evaporation within the fuel assemblies results in some convection cooling of the fuel assemblies prior to the time when reflooding of the core occurs.

The design flow capacity of the pump in each core spray division is approximately 4500 gal/min at a total developed pump head corresponding to a reactor vessel pressure of 90 psig plus system losses, as shown in Figure 6.3-3. The power required for each pump is approximately 850 hp (nameplate rating of 800 hp with a 1.15 service factor). The normal water source for the pump suction is the suppression pool. The condensate storage tank water is used for initial flushing, or as an alternate source of suction for the pumps. [6.3-13] [6.3-14]

For operation at 2957 MWt, the LOCA analysis for SVEA-96 Optima2 fuel types used the Westinghouse GOBLIN methodology using bounding input parameters for the Quad Cities units. For Quad Cities Unit 1, the LOCA analysis for AREVA ATRIUM 10XM fuel types used the AREVA EXEM BWR-2000 Evaluation methodology (Reference 81) using bounding input parameters. The significant parameters used in the analysis to support SVEA-96 Optima2 and the ATRIUM 10XM fuel types are described in Table 6.3-3D and Table 6.3-3E, respectively.

Testing of the amount of spray flow required to keep SVEA fuel rods quenched is described in Reference 75. The LOCA analyses explicitly account for leakage locations affecting core spray effectiveness. Leakage locations are described in Section 6.3.3.1.2.2. Modeling of the leakages is described in Reference 66. The leakage inside the shroud increased the time required to achieve rated spray flow [4500 gpm] through the spray spargers. This affected the cladding heat-up analysis after blowdown period, when the methodology uses the 10CFR50, Appendix K spray heat transfer coefficients, which were confirmed experimentally for Westinghouse fuel. For the system analysis, the core spray liquid entering the upper plenum, including the leakage inside the shroud, may flow into the bypass region or the core based on the countercurrent flow limitation. The liquid flow from both the bypass region and the core assist in filling the lower plenum. For Quad Cities Unit 1, the AREVA LOCA analysis methodology, analysis bases and results for ATRIUM 10XM fuel are documented in References 81, 82 and 83.

Westinghouse has determined that for Optima2 fuel, core spray or core reflooded to the top of active fuel is required for long term cooling [80]. Their conclusions demonstrate that when there is sufficient water from LPCI or core spray to maintain the 2/3 core height

water level, then a core spray of 3620 gpm (based on minimum required 0.4 core spray distribution factor) to the top of the core is essential to meet the fuel safety limits for long term cooling. For Quad Cities Unit 1, the long term cooling criteria are supported for AREVA ATRIUM 10XM fuel with similar conditions (2/3 core height and core spray of 3300 gpm) as presented in Section 8 of Reference 82.

There are several documented existing leakage locations in the Core Spray system. The core spray leakage was included in the LOCA analysis and resulted in a maximum calculated peak cladding temperature less than the 10 CFR 50.46 regulatory limit of 2200°F. Leakage is summarized in Section 6.3.3.1.2.2. Reduction in Core Spray due to minimum flow bypass has been analyzed [66] as described in Table 6.3-3D[66] and Table 6.3-3E.

Internal piping which connects each spray sparger to its reactor pressure penetration is designed and routed to meet the necessary flexibility requirements for thermal expansion and also to accommodate postulated vessel movement, even though such movement is not considered credible.

Monitoring instrumentation and an alarm are provided for detecting loss of integrity of the core spray spargers and associated piping inside the Rx Injection check valves. Design of the piping system external to the reactor vessel reflects considerations for potential damage to the piping. The pipe runs of each system are physically separated and located to take maximum advantage of protection afforded by structural beams and columns. [6.3-15]

A sketch of typical pipe protection provisions is shown on Figure 6.3-4. Drywell penetrations for the core spray pipes are located to achieve minimum length pipe runs within the drywell and to provide maximum circumferential distance between main steam and feedwater lines.

The core spray equipment rooms are located on elevation 554 feet in the northwest and southwest corners of the reactor building. The maximum ambient conditions in each room are estimated to be 150°F at a relative humidity of 100%. The north and south core spray equipment rooms in each unit are provided with room coolers which maintain the compartment temperature below the qualification temperature of the components that are required for safe shutdown of the plant. The room coolers are water-cooled heat exchanger fan units that are designed to maintain qualification temperature when provided with cooling water at a design maximum temperature of 95°F. Cooling water is provided to a unit's core spray room coolers by the respective unit diesel generator cooling water pump or by the 1/2 diesel generator cooling water pump. The diesel generator cooling water system is described in Section 9.5.5. Physical separation of the pumps is achieved by locating pumps in different corners as shown by Figure 6.3-4. Water from the pressure suppression pool to the pumps' suction is taken from a common ECCS ring header that has four suction lines with stainless steel strainers located in the suppression chamber. Additional details of ECCS flow through the strainers is provided in Section 6.2.2.3. [6.3-16]

The piping of the core spray subsystem is fabricated of carbon steel. Relief valves are utilized for overpressure protection of this section of the system. From the outer isolation valves into the reactor, the system is designed for service at 1,250 psig and 575°F. The Class I piping design considerations for this subsystem are addressed in Chapter 3. The spray spargers and spray nozzles are fabricated from Type 304 stainless steel to meet ASME Section III, 1965 Edition. The core structure supporting the spray spargers is also fabricated of Type 304 stainless steel material. The vessel nozzle entry material is Ni-Cr-Mo forging supplied to ASME SA 336 and modified by ASME Code Case 1332. [6.3-17]

The most severe environmental conditions that the isolation valves of the core spray subsystem are expected to encounter result from a postulated event in which a piping failure releases a mixture of steam and water within the drywell. Less than 30 seconds after the break, the drywell pressure would stabilize at about 21 psig. The maximum ambient temperature of the isolation valves following this transient is expected to be less than the drywell design temperature. [6.3-18]

The power source for each core spray subsystem is located on a separate emergency bus that has provisions to protect it from adverse environments such as could be caused by fire or steam line breaks. Power for this emergency bus can be supplied from the diesel generator if off-site power is not available. The core spray subsystem is automatically actuated upon receipt of a reactor low-low water level signal with low pressure signal, or a drywell high pressure signal, or a reactor low-low water level sustained for a maximum of 9 minutes (analytical limit). It can also be manually activated from the control room. The allowable values for the core spray actuation signals and the reactor low-low water level time delay are specified in the Technical Specifications. [6.3-19]

The test lines, each capable of full division flow, are connected from points near the outside isolation valves back to the suppression chamber. Flow can be diverted into these lines to test operability of the pumps and control system during reactor operation.

The control system is arranged to provide two independent and separately isolated control and power circuits for operation of the two independent core spray divisions (refer to Figure 6.3-5).

6.3.2.1.3 Core Spray Operating Sequence

Initiation of the core spray subsystem occurs on signals described in Section 6.3.2.1.2. These signals and their associated logic are discussed in detail in Section 7.3.1.1. [6.3-20]

Opening of the injection valves is accomplished only after the reactor pressure decays to approximately the design discharge pressure of the pump, at which time the permissive signal to open the valves is initiated by two pressure switches connected in a one-out-of-two logic array.

6.3.2.1.3.1 Operating Sequence with Plant on Normal Auxiliary AC Power

Upon receipt of initiation signal, as described in Section 6.3.2.1.2, the core spray pump in each subsystem will start automatically without delay. The injection valves which admit flow from the system to the reactor vessel will remain closed until the reactor pressure decays below the design discharge pressure of the pump, at which time the valves in each division will open to admit flow into the reactor vessel. The pumps are operated on the minimum flow bypass which discharges back to the suppression pool during the period they are running while the injection valves are closed. [6.3-21]

The pump suction valves are automatically opened (if closed) and the test bypass valves are automatically closed (if open) immediately upon receipt of an initiation signal. These suction valves are normally open and the test bypass valves are closed during normal power plant operation.

The system response time is estimated to be as follows:

A. < 3.1 seconds for sensing low-low water level and low reactor pressure, or <1 second for high drywell pressure and initiation of the start signals;

B. 5 seconds for the pumps to accelerate to full speed;

C. Time required for reactor pressure to decay below the pump discharge pressure, plus a 3 second allowance for the injection valves to allow measurable flow; and

D. Up to 53 seconds for injection valves to reach full opening after opening signal is received.

E. Minimum flow bypass valves isolate 32 seconds after reaching 874 gpm flow rate delivered by the Core Spray system.

6.3.2.1.3.2 Operating Sequence With Diesel Generators

A. Receipt of initiation signal; [6.3-22]

B. Diesel generators start;

C. Permissive available to activate pumps and valves of both divisions;

D. Pump suction valves open (if closed) in both divisions;

E. Test bypass valves close (if open) in both divisions;

F. Completion of a time delay (the allowable value for this time delay is specified in the Technical Specifications); and

G. Both core spray subsystem pumps start.

The injection valves in both injection divisions will remain closed until the reactor pressure decays to approximately design discharge pressure of the pumps, at which time the valves will open to admit flow into the reactor vessel. The pumps are operated on the minimum flow bypasses which discharge back to the suppression pool during the period they are running with the injection valves closed.

6.3.2.1.4 Core Spray Pump Discharge Line Fill Provisions

To ensure that the core spray pump discharge piping is not subjected to water hammer during pump starting several provisions are made as follows: [6.3-23]

A. An ECCS fill system is provided as shown in FSAR Figure 6.3-2, P&ID M-36 and M-78, consisting of a "jockey" pump taking suction from the suppression pool via the core spray pump suction line (B Loop for Unit 1 and A Loop for Unit 2). The "jockey" pump discharge lines are normally open to the core spray pump discharge lines as well as those of the LPCI subsystem. The fill system is also connected to the HPCI and RCIC pump discharge lines but valves in these lines are normally closed. The ECCS fill system is backed up by a connection to the condensate transfer system.

B. The ECCS pump discharge lines are provided with high point vent lines located as closely as practicable to the last normally closed valves in the lines. These vent lines are utilized periodically to ensure the discharge piping is filled.

C. Pressure switches are provided to monitor the LPCI and Core Spray pump discharge lines standby pressure, with low and high pressure alarms provided in the main control room.

D. Pressure switches are also provided to alarm high or low pressure in the ECCS "jockey" pump discharge header to assure proper functioning of the fill system.

The single "jockey" pump has a capacity of 50 gpm, is driven by a 11.4 HP motor, and is capable of pressurizing the discharge headers to approximately 70 psig. In the normal core spray system standby lineup (e.g., suction valve open), fill system pressure will not affect the ADS actuation permissive relative to core spray/LPCI operation, as described in Section 6.3.2.4.2. In addition, if the core spray system is not in its normal standby lineup (e.g., suction valve closed), fill system pressure remains low enough to avoid potential overlap between the maximum pressure produced by the fill system and the pressure setting for the ADS actuation permissive.

6.3.2.2 Low Pressure Coolant Injection Subsystem

LPCI is a functional mode of the RHR System. P&IDs M-39 includes diagrams of the RHR System, including LPCI. [6.3-24]

6.3.2.2.1 LPCI Subsystem Interfaces with Other ECCS Subsystems

In general, LPCI operation involves restoring the water level in the reactor vessel to a sufficient height for adequate cooling after a LOCA. The LPCI subsystem operates in conjunction with the HPCI subsystem, the ADS, and the core spray subsystem to achieve this goal. [6.3-25]

The HPCI subsystem is a high-head low-flow system and pumps water into the reactor vessel when the nuclear system is at high pressure. It is described in Section 6.3.2.3. If

the HPCI subsystem fails to deliver the required flow of cooling water to the reactor vessel, the ADS functions to reduce system pressure so that LPCI may inject water into the pressure vessel. The HPCI turbine is shut down after both core spray and LPCI are in operation. All these operations are carried out automatically.

6.3.2.2.2 Subsystem Characteristics

The RHR pumps are sized on the basis of the flow required during the LPCI mode of operation, which is the mode requiring the maximum flow rate. A summary of the design requirements of the RHR pumps is presented in Table 6.3-5. The pump characteristics are shown in Figure 6.3-8.

One division, consisting of a heat exchanger, two RHR pumps in parallel, and associated piping, is located in the northeast corner of the reactor building. The other heat exchanger, pumps, and piping, forming a second division, are located in the southeast corner of the reactor building to minimize the possibility of a single physical event causing the loss of the entire system. The north and south RHR/LPCI rooms in each unit are provided with room coolers which maintain the compartment temperature below the qualification temperature of the components that are required for safe shutdown of the plant. The room coolers are water-cooled heat exchanger fan units that are designed to maintain qualification temperature when provided with cooling water at a design maximum temperature of 95°F. Cooling water is provided to a unit's RHR/LPCI room coolers by the respective unit diesel generator cooling water pump or by the 1/2 diesel generator cooling water pump. The diesel generator cooling water system is addressed in Section 9.5.5. Both divisions are located as close to the ECCS ring header as practical in order to minimize the vulnerability of the piping. Additional details of ECCS flow through the strainers is provided in Section 6.2.2.3. The two divisions of LPCI are cross connected by a single header, making it possible to supply either division from the pumps in the other division. [6.3-26]

LPCI equipment is designed in accordance with Class I seismic criteria (see Chapter 3) to resist sufficiently the response motion within the reactor building from the design basis earthquake. The pumps are designed and constructed in accordance with the Standards of the Hydraulic Institute. The shell side of the heat exchangers is designed in accordance with ASME Section III, Class C vessels, and the tube side is designed in accordance with ASME Section VIII. The provisions of the Winter Addenda of 1966, paragraph N2113 apply.

The RHR pump seals and motor are cooled by the water being pumped. Cooling water is therefore available whenever these pumps are in operation. Two small heat exchangers are provided for each pump, one for the pump seals, and one for the cooling coil located in the motor upper thrust bearing lube oil reservoir. A portion of the RHR pump discharge is diverted through the primary side of the heat exchangers while flow through the secondary side is taken from the discharge of the RHR service water pumps. Both the RHR pump and motor are designed for operation during the accident condition without the use of external cooling water passing through the secondary side of the heat exchangers.

LPCI is designed to reflood the reactor vessel to at least two-thirds core height and one RHR pump is more than sufficient to maintain the level.

During LPCI operation, the pumps take suction from the suppression pool and discharge to the reactor vessel into the core region through one of the recirculation loops. Instrumentation is provided to select an undamaged path for injection of LPCI flow. Any spillage through a break in the lines within the primary containment returns to the suppression pool through the pressure suppression vent lines. [6.3-27]

Power for the RHR pumps normally comes from an auxiliary ac power bus but if this source is not available, power is available from the standby diesel generators supplying these buses.

6.3.2.2.3 Equipment Characteristics

Descriptions of major RHR system equipment items have been located in the UFSAR section in which their performance is evaluated. The RHR service water pumps are described under RHR service water, Section 9.2. The RHR heat exchangers are described under containment cooling, Section 6.2.2. The RHR pumps are described in the following.

6.3.2.2.3.1 RHR Pumps

The RHR pumps are sized on the basis of the flow requirements of the LPCI subsystem. These are the maximum subsystem flow requirements and are determined by calculation of the rate of coolant loss due to the design basis break of a 28 inch recirculation line. This flow rate takes into account the leakage at the jet pump slip joint during the transient when the LPCI flow is established. There are several documented existing leakage locations affecting LPCI effectiveness. These are described in section 6.3.3.1.2.2. The subsystem is required to inject sufficient makeup water to reflood the vessel to the appropriate height before adequate core cooling is compromised, and then maintain the level at 2/3 of core height. Redundancy is provided in that only 2 of the 4 RHR pumps are required to deliver full LPCI flow credited in the DBA LOCA analysis. The pump head characteristic is selected such that sufficient, but less than rated, flow would be provided before reactor vessel pressure decreases to the point where the HPCI turbine trips and HPCI would cease to function. This is done to ensure against significant core overheating over the complete spectrum of breaks up to the design basis break. The specifications for these pumps are shown in Table 6.3-5 and the pump performance curve is shown in Figure 6.3-8. [6.3-28]

6.3.2.2.3.2 Valves

Isolation valves are located on the LPCI subsystem piping since this subsystem is connected into the primary system. Since there are two separate injection points in the primary recirculation loop for the LPCI subsystem flow and since core spray, a parallel ECCS subsystem, is concurrently placed in operation, no special valving redundancy is provided. The isolation valves provide protection against core uncoverage if the piping should break in these systems and also serve to protect the low pressure portion of the RHR system against high reactor pressure in case of a component malfunction. The isolation valves are designed to withstand reactor pressure and temperature and constructed to achieve the highest possible reliability. The speed and response of these isolation valves is such that the injection valves open by the time the pumps are assumed to reach rated speed. (The closing times for the primary recirculation loop valves are compatible with the LPCI subsystem objectives.) Provisions for protection of the high pressure/low pressure interface are described in Section 5.2.5.6. [6.3-29]

The cross-tie line between the two divisions has two motor operated valves. Check valves and stop valves are located in the pump discharge lines, and flow control valves are provided in the lines where flow adjustment is necessary. Check valves in the containment are equipped with pneumatic operators to permit remote exercising and testing when the reactor is depressurized.

Gate and butterfly valves are located where necessary to permit maintenance on the system and are normally locked open.

6.3.2.2.3.3 Piping and Fittings

Two independent pipe lines that are physically separated and protected as much as practical are each sized for full subsystem flow, thereby providing redundancy in flow paths for system operation.

The piping is carbon steel except for the piping from the isolation valves to the reactor system which is stainless steel since it normally contains reactor coolant. Pressure relief valves are employed in the carbon steel section of piping to provide overpressure protection. All system components are designed in accordance with applicable codes for reactor auxiliary systems.

6.3.2.2.3.4 Instrumentation Requirements

The RHR pumps are activated on either a signal of reactor low-low water level with reactor low pressure, or a signal of drywell high pressure, or a reactor water low-low level sustained for a maximum of 9 minutes (analytical limit), from the same instrumentation that activates the core spray subsystem. Power is supplied from the diesel generators if normal auxiliary power fails. The valves in the high pressure part of the system are automatically opened to establish the LPCI flow path when reactor pressure decreases to 300-350 psig (analytical limit). The allowable values for these actuation signals and time delay are specified in the Technical Specifications. [6.3-30]

Instrumentation was provided to establish system reference characteristics during preoperational testing. This information is used for comparison in system tests to determine variations from "normal" operation.

To assure that flow is available in the event that a line in the high pressure portion of the subsystem is broken, loop selection logic instrumentation is provided which causes necessary valves to close or open (as needed) to ensure full LPCI flow will reach the core.

Interlocks are provided to prevent LPCI flow from being diverted to the containment spray subsystem unless the core is flooded. A keylock switch permits this interlock to be overridden, and is administratively controlled by procedure. [6.3-31]

The necessary instrumentation to test the integrity of the major equipment (pumps, valves, and heat exchangers) is also provided.

Additional information on this subject is covered in Section 7.3.1.2.

6.3.2.2.4 Operation Sequence — LPCI

Initiation of LPCI occurs on signals described in Section 6.3.2.2.3.4. Figures 6.3-9 through 6.3-11 are functional control diagrams that show, in block diagram form, the various interlocks in the system. These signals and their associated logic are discussed in detail in Section 7.3.1.2. [6.3-32]

Upon receipt of an initiation signal with normal ac power available the:

A. Diesel generators start;

B. A permissive becomes available to activate pumps and valves;

C. All four RHR pumps start; and

D. RHR service water pumps stop (if running).

The LPCI injection valves in both divisions will remain closed until the reactor pressure decays to approximately the design discharge pressure of the RHR pumps. At this time the injection valves will open to admit flow to the reactor vessel. The RHR pumps are operated on the minimum flow bypasses which discharge back to the suppression pool during the period the pumps are running with the injection valves closed. Should a DBA LOCA occur on the "A" recirculation loop, the A and B pumps' flow will be diverted through a cross-tie by the LPCI loop select logic. In this type of case, the minimum flow bypass valve will not receive an isolation signal because the A flow element would be bypassed. This loss of LPCI flow due to minimum flow bypass not isolating is an analyzed condition.[66] [6.3-33]

If normal ac power is not available, pumps A and B on diesel generator 1/2, and pumps C and D on the unit diesel generator are energized sequentially after a delay to permit the diesel generator to accelerate to operating speed.

If the accident occurs while the RHR system is in the shutdown cooling mode, the RHR system will automatically revert back to the LPCI mode, although operator action is necessary to reset the LPCI injection valves, and to perform other manual actions required by procedures covering termination of shutdown cooling. [6.3-34]

In the design basis LOCA scenario, simultaneous with the diesel generator start signal, an automatic transfer logic is started. This logic described in section 8.3.1.6.4 allows sufficient time for the diesel generators to start and it assures that the bus supplying the LPCI injection valves and recirculation discharge isolation valves are energized in the unlikely event of LOCA concurrent with loss of offsite power and a failure of a diesel generator. Prior to the opening of the injection valves, it is necessary that sufficient information be available to determine if the break has occurred in a recirculation loop, and if so, which loop. If neither loop is broken, a preselected loop will be used for injection. This selection is necessary because the LPCI system injects through the recirculation loops.

The system makes the loop selection by comparing the pressure in the 5 riser pipes on one recirculation loop with the pressure in the corresponding riser pipes on the other recirculation loop. A schematic drawing of the instrument arrangement is shown in Figure 6.3-12. The unbroken recirculation loop will have a higher pressure than the broken loop. Two of the differential pressure instruments indicating higher pressure in one loop than in the other (in a one-out-of-two-twice arrangement) will cause LPCI flow to be injected into the higher pressure loop.

The break detection logic arrangement is shown in Figure 6.3-13. As shown, the logic is actuated by high drywell pressure or low-low reactor water level.

The minimum detectable break size for LPCI Loop Select Logic in the analysis is in Table 6.3-3D for Westinghouse analysis and Table 6.3-3E for AREVA analysis.

The purpose of the checks on recirculation pump differential pressure is to determine whether one pump or two pumps are operating or were operating at the time of the break. These checks assure that for one recirculation pump operation the alternate path through the logic network is used as described in the following sections:

6.3.2.2.4.1 Normal Condition — Both Recirculation Pumps Operating

With both recirculation pumps operating, the path through the logic network is as shown by the solid line in Figure 6.3-13. The short time delay before selection of the injection loop is provided simply to allow momentum effects to establish the full differential pressure across the recirculation loops. [6.3-35]

6.3.2.2.4.2 Alternate Condition — One or No Recirculation Pumps Running

If one or both recirculation pumps are out of service, the logic network will automatically proceed on the alternate path shown by the dotted lines in Figure 6.3-13. To assure that breaks in an operating loop are not masked by the pressure developed by the operating pumps, both recirculation pumps are tripped. Since recirculation system operation in the cross-tied configuration is prohibited during power generating modes, loop isolation is maintained through closure of selected manually operated valves in the equalizer piping. The reactor vessel pressure permissive device acts as a break size gauge, allowing complete recirculation pump coastdown before loop selection for all break sizes for which the operating pump could mask the break. For large breaks, pump coastdown is not required and the reactor vessel pressure permissive device is always satisfied well before the time at which loop selection must be made to assure there is no delay in the start of injection of LPCI flow. When the reactor vessel pressure permissive is satisfied, the network passes through the time delay and selects the unbroken loop for injection in the normal manner. [6.3-36]

All components of the LPCI logic system, including the actuation signals, are designed such that no single failure of the sensing circuitry will preclude proper loop selection.

6.3.2.3 High Pressure Coolant Injection Subsystem

The HPCI subsystem is designed to pump water into the reactor vessel under LOCA conditions which do not result in rapid depressurization of the pressure vessel. The loss of coolant might be due to a loss of reactor feedwater or to a small line break which does not cause immediate depressurization of the reactor vessel. [6.3-37]

The HPCI subsystem consists of a steam turbine driving a multi-stage high-pressure pump and a gear-driven single-stage booster pump, valves, high pressure piping, water sources, and instrumentation. The turbine is driven with extraction steam from the reactor vessel. The HPCI subsystem is shown in FSAR Figure 6.3-14 and P&ID M-46. The HPCI equipment specifications are shown in Table 6.3-6.

6.3.2.3.1 HPCI Subsystem Interfaces with Other ECCS Subsystems

The sizing of the HPCI subsystem is based upon providing adequate core cooling during the time that the pressure in the reactor vessel decreases to a value that the core spray subsystem and/or the LPCI subsystem become effective.

6.3.2.3.2 Subsystem Characteristics

The HPCI subsystem is supplied by water from either the contaminated condensate storage tank (CCST) or the suppression pool. The water from the CCST is the preferred source because it is of a higher quality than the water from the suppression pool. Although the primary function of the HPCI subsystem is small break LOCA mitigation, its most likely use will be in response to transient events, such as loss of offsite power, as an alternative to the RCIC system. For this purpose, the CCST holds approximately 90,000 gallons of water in reserve for supply to RCIC or HPCI. When the water level in the CCST falls below a predetermined level, or when the water in the suppression pool rises above a predetermined level, the pump suction supply would be automatically transferred to the suppression pool. The automatic switchover circuitry would detect a loss of water level in the CCST and open the valves to the suppression pool, then close the valve to the storage tank. This switchover capability assures a Class I source of supply water to the HPCI subsystem. The switchover from the CCST supply to the suppression pool supply may also be made manually by the operator. [6.3-38]

Water from either source would be pumped into the reactor vessel through the feedwater line and flow would be distributed within the reactor vessel through the feedwater sparger to obtain mixing with the hot water in the reactor pressure vessel. Water leaving the vessel through a line break drains by gravity back to the suppression pool. The residual heat removal system is required for cooling of the suppression pool after several hours of HPCI subsystem operation.

The HPCI subsystem is designed to pump 5600 gal/min into the reactor vessel within a reactor pressure range of about 1120 psig — 150 psig. As the pressure decreases, the turbine throttle valves open more to pass the required steam flow to match the pump power which is proportional to pressure.

The HPCI steam supply and vacuum breaker isolation valves are required to be manually opened from the control room to place HPCI in a standby condition ready for automatic initiation. The steam isolation valves are normally open to ensure there is steam pressure to the turbine steam supply valve and the moisture drain pot to eliminate water slugs to the turbine and water hammer of the steam supply piping. This configuration precludes the rapid insertion of high pressure steam into a potentially cold steam line. Turbine speed is controlled by the turbine governor, the motor speed changer and the motor gear unit. Exhaust steam from the unit is discharged to the suppression pool. [6.3-39]

The turbine gland seals are vented to the gland seal condenser and water from the pump is routed through the condenser for cooling purposes. Noncondensible gases from the gland seal condenser are ducted to the reactor building vent system.

Automatic operation of the system is dependent upon reactor water level signals (Figures 6.3-15 through 6.3-17). Either low-low water level or high drywell pressure starts the system, and high water level will stop it. If the HPCI system starts due to a high drywell pressure signal and automatically turns off at reactor high level, then the system will automatically restart at reactor low low level. In addition to the automatic operation, remote manual control for the system is located in the control room. The steam supply valves in the HPCI system must be manually opened in order to place the system in stand-by mode to support automatic operation. This logic was developed to ensure sufficient steam pressure to the 2301-3 turbine supply valve. Slow pressurization of the system via the 2301-4 valve (throttle) precludes rapid insertion of hot steam into a cold steamline. [6.3-40]

The HPCI equipment rooms are located in the turbine building area, immediately adjacent to the reactor building at floor elevation 554 feet 0 inches. Each HPCI equipment room is provided with a room cooler which maintains the compartment temperature below the qualification temperature of the components that are required for safe shutdown of the plant. The room coolers are water-cooled heat exchanger fan units that are designed to maintain qualification temperature when provided with cooling water at a design maximum temperature of 95°F. The respective unit's diesel generator cooling water pump or the 1/2 diesel generator cooling water pump serve as the design basis cooling water supply to the HPCI room coolers. The service water system can also provide a non-safety-related alternate supply of cooling water to the HPCI room emergency coolers. The diesel generator cooling water system is described in Section 9.5.5. [6.3-41]

The piping of the system is designed to USAS B 31.1 and ASME Section 1. The pumps are designed to ASME Section VIII. Arrangement of the piping includes considerations for potential damage. For changes to the system, near-by non-safety related or high energy piping is evaluated. Fabrication, testing and inspection is in accordance with the original code of construction, applicable installation specifications and ASME Section XI. The Class I piping design considerations for this subsystem are discussed in Chapter 3. [6.3-42]

6.3.2.3.3 Operational Sequence — HPCI

Initiation of the HPCI subsystem occurs on signals indicating reactor low-low water level or high drywell pressure. These signals and their associated logic are discussed in detail in Section 7.3.1.3. [6.3-43]

Upon receipt of initiation signal, the HPCI turbine and its required auxiliary equipment will start automatically with simultaneous operation of the following valves:

A. Turbine steam supply and stop valves open;

B. Pump suction valve from a CCST opens (if not already open);

C. Pump discharge valves open (if not already open);

D. Cooling water return to pump valve opens (if not already open);

E. Steam line drain valves close to main condenser and open to drain pot;

F. Stop valve steam line drain valves close;

G. Cooling water return valve to condensate storage tank closes (if not already closed); and

H. Test bypass valves to condensate storage tank closes (if not already closed).

A minimum flow bypass system back to the suppression chamber is provided for pump protection. The bypass valve is automatically opened on low pump flow and closed on high flow whenever the steam supply valve to the turbine is open. The HPCI system performance described in Tables 6.3-3D and Table 6.3-3E is achieved despite the temporary loss of delivered flow until the minimum flow bypass valve is isolated.

In the event of a low water level in the CCST or high level in the suppression pool, the pump suction valves from the suppression chamber open and the suction valve from the CCST closes after both valves from the suppression chamber are full open. The valves are interlocked to prevent automatic opening of the valve from the CCST whenever both valves from the suppression chamber are fully opened. The test bypass valves to the CCST are also interlocked closed when either suction valve from the suppression chamber is fully opened.

6.3.2.3.4 <u>HPCI Automatic Isolation</u>

Automatic isolation of the HPCI steam supply occurs on indication of a large break LOCA accident (HPCI Low Reactor Pressure) <u>or</u> indication of a high energy line break (HELB) within the HPCI system (HPCI High Room Temperature or HPCI High Steamline Flow). Automatic isolation of the turbine exhaust vacuum breaker line occurs on indication of a large line break inside containment (High Drywell Pressure and Low Reactor Pressure existing simultaneously). Closure of the vacuum breaker isolation valves is not required to mitigate the consequences of a HELB in the HPCI system. [6.3-44]

The HPCI (Group 4) isolation logic is divided into 2 trip channels, 1 - DC and 1 - AC circuit. Each trip channel circuit contains its own instrumentation for detecting an isolation condition. Each circuit is functionally independent of the other. Each circuit controls the automatic closure of one of the two isolation valves in the steam supply and vacuum breaker lines. The circuit logic is designed to preclude any "single failure" from preventing an isolation of <u>both</u> valves in a containment leak path and to perform this function without depending on off-site power.

The trip circuit relays are normally de-energized and each trip channel circuit has an indicator light in the Control Room showing that power is available to the circuit. The HPCI system is designed so as to not "rely" on the availability of AC power (both off-site and on-site). A complete loss of the AC trip channel will not prevent HPCI operation in an emergency by causing an isolation or render the isolation function inoperable (since the DC powered isolation valves and their DC trip logic are operable after the failure(s) causing a loss of on-site, emergency AC power to HPCI). Additional details of these isolation functions are contained in the HPCI instrumentation requirements portion of Section 7.3.2.2.

Instrumentation and circuitry is not normally used for both HPCI isolation and HPCI control. The two exceptions are described below:

1) The isolation logic in the DC trip channel (only) is functionally, but not electrically, independent from the DC system control circuitry. Functional independence means that control circuit components are not required to function in order to affect an isolation. The DC trip channel and the DC HPCI control logic (i.e., HPCI initiation logic and turbine trip logic) are in the same electrical circuit. Failure of the control circuit (e.g., causing an electrical trip of the DC circuit due to a ground fault) could prevent one, but not both, of the primary containment isolation valves from functioning in each of the containment leak paths.

2) When a steam supply Group 4 isolation signal in the DC trip channel (only) is received, the HPCI pump suction valves from the suppression pool ECCS ring header automatically close. Since this line is not open to the containment air volume, it is not considered a 10 CFR 50, Appendix J containment leak path. Automatic closure of the pump suction valves is not required to mitigate the consequences of a large break LOCA or a HPCI system HELB, but does preclude any inadvertent or accidental loss of torus water. Group 4 circuit relay contacts are utilized for this control function.

All HPCI containment isolations are sealed-in and each trip channel requires manual reset from the Control Room. Isolated valves will not reopen after a containment isolation (even if a system initiation signal is present) without operator action to open each individual valve (normally with the manual control switch in the Control Room).

6.3.2.3.5 HPCI Turbine Trip

As shown in Figure 6.3-17, initiation for automatic trip of the HPCI turbine occurs (whenever the turbine stop valve is not tripped) on high turbine exhaust pressure, low pump suction pressure, or high reactor water level. The low pump suction pressure trip is delayed by 2.5 seconds to eliminate short-duration, low suction transient trips. The low pump suction and high turbine exhaust pressure trips are blocked when a HPCI auto-initiation signal (reactor water low-low level or high drywell pressure) is present. The pump discharge is prevented from opening automatically whenever any of these turbine trip conditions exist as shown in Figure 6.3-15. In addition to these trips, the turbine can be tripped remotely from panel 901(2)-3, locally with the trip lever, or by a mechanical overspeed trip. The automatic signals and their associated logic are discussed in detail in Section 7.3.1.3. [6.3-45]

6.3.2.3.6 Flow Control

The HPCI turbine has three systems for controlling speed, and the control valve position is governed by the lowest setting of the three: [6.3-46]

1. A speed governor, limiting the turbine speed to approximately 4000 rpm;

2. A motor speed changer, which is a manual power control that is automatically repositioned to its low speed stop (0 rpm) when the turbine stop valve is tripped; and

3. A motor gear unit, which is an automatic speed set point control that is positioned from a demand signal from a flow controller, which maintains a preset subsystem flow of approximately 5600 gpm.

6.3.2.3.7 Standby Water Supply from Suppression Pool

In the event of either low water level in the CCST or high level in the suppression chamber, level switches initiate opening of the two pump suction valves from the suppression pool.

6.3.2.3.8 System Operation

Consistent with the accident analysis, the HPCI sub-system has a safety-function to automatically start once, and inject into the Reactor Vessel in response to a low-low Reactor Vessel level, or high Drywell pressure initiation signal. Following the initial automatic start, the HPCI sub-system will then, by procedure, be controlled manually to prevent steam line flooding and to maintain Reactor core cooling (stop or restart the pump, throttle flow). [6.3-46a]

The HPCI sub-system has a feature that will trip the HPCI sub-system when Reactor Vessel level reaches a high level, and restart the HPCI pump when Reactor Vessel level reaches a low-low level. The HPCI sub-system may also be manually initiated and controlled, by procedure, to provide Reactor Vessel pressure or level control for non-LOCA events.

6.3.2.3.9 Termination of Operation

When the reactor pressure falls below 150 psig, the speed of the turbine-pump unit will begin to decrease and would gradually be slowed to a stop by friction and windage losses at a reactor pressure of about 35 psig; however, turbine isolation occurs at 100 psig (analytical limit). The allowable value for the turbine isolation signal is specified in the Technical Specifications. [6.3-46b]

Core cooling at this time would be accomplished by the core spray subsystem and the LPCI subsystem or, for a small break, maintained by the control rod drive supply pumps if ac power is available. Either the core spray subsystem or the LPCI subsystem is capable of cooling the core independently.

6.3.2.4 Automatic Depressurization Subsystem (ADS)

6.3.2.4.1 Automatic Depressurization Subsystem Interfaces with Other ECCS Subsystems

The ADS is employed as an alternate to the HPCI subsystem to depressurize the reactor pressure vessel for small area breaks. Reactor vessel depressurization is accomplished by blowdown through automatic opening of the relief valves to vent steam to the suppression pool. For small breaks the vessel is depressurized in sufficient time to allow the core spray subsystem or the LPCI subsystem to provide adequate core cooling. For large breaks the vessel depressurizes through the break without assistance. Pressure relief of the reactor vessel may be accomplished manually by the operator, or without operator action by the automatic depressurization circuitry. The ADS functional control diagram is shown in Figures 6.3-18 and 6.3-19. [6.3-47]

6.3.2.4.2 Subsystem Characteristics

Actuation of the ADS requires coincident indication of reactor water low-low level and high drywell pressure. These signals and their associated logic are discussed in detail in Section 7.3.1.4. For additional reliability, each pair of circuits is provided with power from separate dc buses. The instruments in the reactor vessel water level circuit and drywell pressure circuit do not require electrical power to close or open the sensors in the initiation circuits, but the logic circuitry requires 125 VDC power to operate. An additional power source is also available and is automatically switched over upon loss of the primary power source. [6.3-48]

A 2-minute (analytical limit) time delay circuit is located in series with the ADS activation signal to provide time for the HPCI subsystem to achieve proper operation. The timer is activated after the low-low reactor water level signal and the high drywell pressure signal have been received. If the HPCI subsystem fails to deliver sufficient flow, the ADS actuates upon termination of the time delay provided that at least one RHR or core spray pump is running.

The time delay also provides time in which the operator can evaluate possible spurious activation signals. A permissive signal from the time delay circuit serves as the confirming signal to activate the relief valve when the control station switch is in the automatic position. The time delay setting before the ADS is actuated is chosen to be long enough so that the HPCI has time to start, yet not so long that core spray and LPCI are unable to adequately cool the fuel if the HPCI fails to start. After receipt of both initiation signals, and after the 2-minute delay (analytical limit) provided by timers, the solenoid-operated pilot valves are energized if an indication is present of sufficient discharge pressure in any low pressure cooling system (i.e., at least one RHR or core spray pump running). Each of the five ADS valves (4 relief valves and one safety/relief valve) will normally open simultaneously; however two of the valves are equipped with additional control logic and may be subjected to an additional delay to preclude opening in the presence of an elevated water leg in the relief valve discharge piping (see Section 5.2.2.4). Manual depressurization of the reactor vessel is accomplished independently of the automatic circuitry. [6.3-48a]

An additional automatic actuation mode is provided in the circuitry in response to NUREG-0737, Item II.K.3.18. This logic scheme is provided to assure ADS activation when necessary to mitigate events which do not pressurize the drywell, such as a transient or stuck open relief valve with subsequent failure of high pressure makeup (HPCI and RCIC). This actuation sequence is initiated by low-low reactor water level alone, which starts a separate timer set at a maximum of 9 minutes (analytical limit). If reactor level is not recovered within this time, and indication is present of sufficient discharge pressure in LPCI or core spray, depressurization will occur without further operator action. The LPCI and core spray pumps normally start upon low-low level only in conjunction with low reactor pressure. However, the low reactor pressure permissive is bypassed once the 9-minute low level timer times out, permitting the pumps to start and depressurization to occur. [6.3-49]

Subsequent to the 9-minute timer reaching its setpoint, resetting of the 2-minute timer discussed previously will no longer prevent depressurization. However, the operator can prevent automatic ADS actuation by use of a separate ADS inhibit switch if he anticipates level recovery after the 9-minute timer setting is reached. The use of the inhibit switch is alarmed in the control room. Operating procedures allow the operator to inhibit ADS and postpone vessel depressurization until reactor water level reaches the top of active fuel (TAF). The resultant steam cooling following blowdown from TAF is considered to be adequate core cooling during this interval. [6.3-50]

Excessive vessel pressure is automatically relieved by the ADS by circuitry which supplies a direct signal to the auxiliary relay to actuate the valves (see Section 5.2.2). [6.3-51]

The allowable values for the ADS actuation signals and associated time delays (initiation time delay, reactor water low-low level time delay) are specified in the Technical Specifications.

6.3.3 Performance Evaluation

This section discusses the performance evaluation for the ECCS. First, performance evaluations for each of the subsystems that comprise the ECCS are discussed. Then, the performance of the ECCS considered as a whole is discussed.

Analyses supporting Quad Cities operation with feedwater temperature reduction, one ADS out of service, and single loop operation are detailed in References 66 and 80 for Westinghouse SVEA-96 Optima2 fuel. Single loop operation and feedwater temperature reduction is addressed (for Quad Cities Unit 1) by the Reference 82 and 83 LOCA analysis for AREVA ATRIUM 10XM fuel types. However, one ADS out of service is not currently allowed by the Quad Cities Technical Specifications, and is not currently supported by the AREVA fuel analysis.

Westinghouse has evaluated the impact of installation of the adjustable speed drives (ASD) on their respective LOCA analyses (References 76 and 77). The effect of the ASD is a faster pump coastdown, which results in a faster core flow decrease following a postulated LOCA. The Westinghouse evaluation confirms that with the ASD, both the LOCA analyses of record (References 66 and 80) remain applicable. Both References 66 and 80 are current analyses of record, since both support MAPLHGR limits for fuel presently in use.

6.3.3.1 Emergency Core Cooling Subsystem Performance Evaluations

6.3.3.1.1 Core Spray Subsystem

The core spray subsystem is designed to maintain continuity of reactor core cooling for a large spectrum of loss-of-coolant accidents. The core spray subsystem is designed to maintain continuity of reactor core cooling for a large spectrum of loss-of-coolant accidents. The subsystem provides adequate cooling for intermediate and large line break sizes, up to and including the design basis double-ended recirculation line break, with assistance from the LPCI subsystem emergency core cooling subsystem as directed by 10 CFR 50, Appendix K single failure ECCS analysis requirements. The integrated performance of the core spray subsystem, in conjunction with other emergency core cooling subsystems, is described in Section 6.3.3.2. [6.3-52]

As indicated in the original LOCA analysis, for small breaks the core spray subsystem alone cannot protect the core (see Figure 6.3-1) because vessel pressure does not drop rapidly enough to allow sufficient core spray injection before the fuel cladding reaches an excessively high temperature.

Below this break size, either the HPCI or the ADS extend the range of the ECCS to breaks of insignificant magnitude

The minimum flow rate into any fuel assembly in the core is specified as 2.45 gal/min. This is a typical minimum flow rate but not a requirement. The required flow is discussed in Section B.8.3 of Reference 80. This was established from early tests conducted on 36-rod full-length assemblies. In those tests, summarized in Oyster Creek, Amendment No. 10, and APED 5458,[3] flow rates from 1.8 to 2.8 gal/min were tested and no sudden change in fuel cladding temperature with respect to flow was noted over the range tested. Subsequent tests on 49-rod assemblies and at significantly lower flows showed that cooling was possible at reduced flows. In fact, flows as low as 0.7 gal/min per 49-rod assembly did not significantly affect the maximum temperature as shown in Oyster Creek Amendment No. 10, and APED 5458.[3] Therefore, it is concluded that the quantity of flow provided for core spray is greatly in excess of the minimum actually required.

The core spray tests also provided experimental effective heat transfer coefficients, thus enabling calibration of the core heatup code to the actual tests. The fuel rod temperatures were calculated from such experimental correlations. Subsequent testing on an exact prototype at the proper power resulted in volume percentile temperature distributions, as shown in Figure 8, Appendix A, Amendment No. 10, Oyster Creek Unit No. 1. The close correlation between the peak temperature and the analytical curve serves to demonstrate the adequacy of the analytical models employed. Since all water entering the shroud does not go into the fuel assemblies, the total flow to be supplied was based on early flow distribution tests described in Amendment No. 10, Oyster Creek, Appendix A, and APED 5458.[3] These led to the design basis that of the water entering the vessel, the minimum amount into any assembly would be about 0.4 of the amount which could enter if it were evenly distributed among the fuel assemblies.

Core spray distribution tests indicate that with the proper nozzle arrangement, distribution factors approaching 0.6, compared to an ideal of 0.7, may be possible. In any event, a minimum distribution factor of 0.4, the current design criterion, was easily achieved for the Quad Cities Units from full scale tests of the core spray.

The effects of updraft caused by evaporation of water that enters the fuel assemblies has no significant effects on flow distributions. Again, this is based on experimental evidence presented in Amendment No. 10 to the Oyster Creek Docket and APED 5458.

In conclusion, core spray is an effective means of terminating the core heatup transient (in conjunction with HPCI or ADS for small breaks) over the complete spectrum of LOCAs up to the complete rupture of the main recirculation line. Experimental and analytical techniques have shown that steam updrafts expected in the core are in a range which will have little or no effect on the amount of spray flow entering a channel. Section 6.3.3.2 presents a detailed discussion of the integrated performance of the core spray subsystem in conjunction with other ECCS subsystems. [6.3-53]

Westinghouse has determined [66] that for SVEA-96 Optima2 fuel 3620 gpm (based on minimum required 0.4 core spray distribution factor) of core spray flow to the top of the core and 2/3 core height water level or the core reflooded to the top of active fuel is the minimum requirement to assure long term cooling of the fuel. The 3620 gpm requirement can be met with the core spray performance described in Table 6.3-3D by closure of the core spray minimum flow valve. For Quad Cities Unit 1, similar long term cooling criteria are supported for AREVA ATRIUM 10XM fuel. For the AREVA analysis, 3300 gpm core spray to the top of the core is needed (Reference 82, Section 8).

Spray cooling tests for SVEA-96 Optima2 fuel are described in Reference 75.

6.3.3.1.2 Low Pressure Coolant Injection Subsystem

The LPCI subsystem is designed to provide reactor core cooling for a large spectrum of LOCA with assistance from the core spray subsystem emergency core cooling subsystem as directed by 10 CFR 50, Appendix K single failure ECCS analysis requirements. The subsystem provided adequate cooling for intermediate and large line break sizes up to and including the design-basis double-ended recirculation line break with one core spray pump and two LPCI mode pumps. There exists a break size below which the LPCI subsystem requires depressurization assistance to maintain core cooling. For these small breaks, HPCI and ADS provide the necessary depressurization to allow LPCI to protect the core across the entire break spectrum. A detailed discussion of the integrated performance of the LPCI subsystem in conjunction with other ECCS subsystems is given in Section 6.3.3.2. [6.3-54]

The LPCI pumping system is designed with both adequate head and adequate coolant flow capacity to meet flooding requirements for the entire break spectrum, when operating in conjunction with either the HPCI subsystem or the ADS.

The required flow capacity (9,000 gal/min at 20 psi above suppression chamber pressure with two pumps running) is determined by the design basis break (instantaneous break of a recirculation line). This flow, in conjunction with the flow from one core spray pump, will provide adequate core cooling as described in the integrated ECCS performance LOCA analysis required by 10 CFR 50 (Appendix K). This analysis is discussed in Section 6.3.3.2. There are several documented existing leakage locations affecting LPCI effectiveness. These are described in Section 6.3.3.1.2.2. Reduction in LPCI effectiveness due to minimum flow bypass failure to isolate has been explicitly included in the LOCA analysis[66 and 80]. The ECCS pumps are capable of refilling the inner plenum well before significant cladding overheating occurs, even assuming no water remains after the blowdown. The minimum allowable time in which this must be done occurs for the design break, because the least core cooling occurs for this break. Hence, it must be reflooded more quickly than for small breaks. However, the vessel depressurizes very quickly for this break size, and therefore, a greater quantity of water can be pumped due to the pump head-flow characteristic. [6.3-55]

The most limiting break and single failure combination which takes credit for LPCI cooling is the design basis accident (DBA) recirculation suction line break with Diesel Generator or a battery failure.[6.3-56] for Westinghouse analysis. For the AREA analysis, Table 6.3-3E outlines LPCI availability.

For operation at 2957 MWt, the LOCA analysis [66] for SVEA-96 Optima2 fuel types used the Westinghouse GOBLIN methodology using bounding input parameters for the Quad Cities units. The significant parameters used in the analysis to support SVEA-96 Optima2 fuel types are described in Table 6.3-3D. These analyses explicitly account for the leakage locations affecting LPCI effectiveness. Leakage locations are described in Section 6.3.3.1.2.2. Reduction in LPCI effectiveness due to minimum flow bypass failure to isolate has been included in the LOCA analysis·(References 66 and 80 for Westinghouse analyses and Reference 82 for AREVA analysis). The Westinghouse and AREVA LOCA analyses explicitly account for delay in delivery of coolant to the reactor vessel from LPCI by directing the injection downstream of the recirculation discharge valve in the selected recirculation loop. For Quad Cities Unit 1, the Reference 82 LOCA analysis for AREVA ATRIUM 10XM fuel similarly address the same LPCI system characteristics using the parameters in Table 6.3-3E.

The maximum vessel pressure against which the RHR pumps must deliver some flow is determined by the required overlap with HPCI, which has a low pressure cutoff on the HPCI turbine at about 150 psig. [6.3-57]

The ECCS is designed such that after any single failure as identified in Table 6.3-7D, the remaining ECCS will provide adequate core cooling for all postulated LOCAs over the entire pressure range of the event. The pump head characteristics are shown on Figure 6.3-8.

If a recirculation line break occurs and the reactor primary system pressure drops to the shutoff head of the LPCI subsystem, a check valve in LPCI injection line opens. Prior to this time, the LPCI control system would have sensed the loop in which the break has occurred, closed the recirculation pump discharge valve in the broken loop and opened the LPCI injection valves in the unbroken recirculation line. These actions provide an integral flow path for the injection of the LPCI flow into the bottom plenum of the reactor vessel. [6.3-58]

6.3.3.1.2.1 Long-Term Cooling Capability of LPCI

See Section 6.3.3.1.1 for the current post-LOCA long term cooling requirements applicable to all fuel types.

6.3.3.1.2.1.1 Introduction (HISTORICAL INFORMATION)

The following analysis, performed in 1971, describes the ability of the LPCI subsystems alone to provide long-term core cooling in the highly degraded case with both core spray divisions unable to function, i.e. a beyond design basis event. The conclusions of this analysis are still valid; however, specific details contained in the descriptions and associated figures should be used only to understand the analysis and its conclusions. These specific details should not be used as sources of current fuel cycle design information.

This section is concerned with the effectiveness of the LPCI subsystem for long-term cooling without the assistance of the core spray subsystem. Long-term core cooling is defined as the period after the initial transient is terminated and the fuel assembly power becomes too low to maintain the two-phase mixture level above the top of the active fuel. [6.3-59]

This question arises because, for certain size liquid breaks, the core can be flooded only to the two-thirds elevation. For breaks other than liquid, the core can be flooded regardless of the size of the break. Cooling of the upper one-third during a liquid break depends on the level swell within the fuel assembly and the steam generated by the flooded portion. As decay power drops off with time, the level swell resulting from boiling will not be adequate to cover the entire core so that the upper one-third heats up to a temperature consistent with the amount of steam and heat generated. This effect occurs first with the lowest power fuel assemblies and after the initial core temperature has been reduced to saturation by the automatic initiation of the core spray subsystem.

As will be shown in the following sections, the peak temperatures which result are well below those experienced immediately after a LOCA, the number of perforations are not

increased; and therefore, LPCI does not require any additional systems (except ADS for breaks less than the design basis accident) for long-term cooling.

6.3.3.1.2.1.2 Long-Term Reactor Response (HISTORICAL INFORMATION)

During the long-term cooling period, reactor pressure and water level will seek an equilibrium condition such that the LPCI flow is equal to the break flow and all steam generated in the core will be carried away either through the relief valves or through condensation on the cold LPCI water.

The original relief valve design included requirements that the valves would be capable of remote manual opening at any pressure above 100 psig and staying open once opened until pressure decreases to 50 psig. The maximum pressure which can exist during the long-term period is 100 psi plus containment pressure, or approximately 130 psia. This is also true for the HPCI case with no credit for ADS, because the HPCI continues operating down to a reactor pressure of 100 psi. At this pressure, the three-pump LPCI flow is 12050 gal/min, which just equals the flow through a 0.327 $ft.^2$ break with the collapsed water level at the top of the active fuel. Thus, the fuel remains entirely submerged and cooled to saturation for breaks smaller than 0.327 ft^2.

For somewhat larger breaks, the collapsed level will reach the equilibrium condition somewhat below the top of the fuel and pressure will still be fixed at the maximum value of 130 psia. As break area is further increased, the equilibrium water level drops further until the jet pump nozzles become exposed. When this occurs, the high-velocity jets and expulsion of the reverse flow through the broken-side jet pumps will cause rapid steam condensation, which will allow the pressure to drop below the relief valve setting. The pressure must reach the equilibrium level defined by LPCI in-flow equals break flow. The collapsed water level will remain near the top of the jet pumps outside the shroud and somewhat higher inside due to the exit head loss of the water flowing backwards through the jet pump throats. As break area is further increased, pressure continues to decrease until reactor pressure is equal to containment pressure. A value of 30 psia was selected for the worst case long-term containment pressure.

As the break area is increased further, the collapsed water level outside the shroud begins to drop below the top of the jet pumps in order to maintain the inflow equal to outflow. For recirculation suction line breaks, the small additional break area associated with the vessel bottom head drain was incorporated into the current LOCA design basis analysis.

The long-term reactor pressure and level conditions described above are nearly independent of time because the reactor power is changing very slowly with time. Also, the condensation efficiency of the LPCI water is a function of water level above the top of the jet pumps. It should be noted that for times longer than 5 minutes after the start of the accident, a condensation efficiency of less than 20% for LPCI is sufficient to quench all the steam generated in the core, thereby maintaining the pressure at the necessary equilibrium condition. Based on the HPCI depressurization efficiency tests (APED 5447),[5] such an efficiency should be easily achieved. In order to assure a conservative result, no credit is taken for the condensation effect unless the water level outside the shroud is at or below the top of the jet pumps. Figure 6.3-20 shows the equilibrium conditions as a function of break area.

6.3.3.1.2.1.3 Swollen Level Response (HISTORICAL INFORMATION)

As noted previously, the long-term reactor response is determined almost solely by the break area. The swollen water level in the fuel assemblies however is a function of the assembly power level (a function of time) as well as the reactor pressure. These effects have been investigated analytically and experimentally over a wide range of conditions.

The model used for analysis of the level swell phenomenon during the long-term condition is described below.

The fuel assembly is represented by 12 axial nodes. For each node (see Figure 6.3-21)

$$W_N = W_{N-1} + \frac{q_N}{h_{fg}} \qquad (6.3\text{-}1)$$

where :

W_N = steam flow leaving node N,

q_{N} = decay heat for node N, and

h_{fg} = enthalpy change due to vaporization.

The solution to Equation 1 defines the steam flow at any position up the fuel assembly. The void fraction alpha$_{N}$ at each elevation is given by

$$\alpha_N = \frac{\dfrac{W_N + W_{N+1}}{2} V_g}{AV_N} \qquad (6.3\text{-}2)$$

where :

V_{g} = specific volume of steam,

A = channel cross-sectional flow area,

V_{N} = bubble rise velocity.

The bubble rise velocity is a function of pressure, hydraulic diameter and void fraction and is given by the Wilson correlation.[5]

Equations 1 and 2 define the void fraction up the channel. Level is determined by the boundary condition on the collapsed liquid level:

$$\sum_{N=1}^{j}(1-\alpha_N)\,h_N\,\rho_f = C_L\,\rho_L \qquad (6.3\text{-}3)$$

where :

h_{N} = length of node,

ρ_{f} = density of saturated water,

ρ_{L} = density of subcooled water,

C_{L} = collapsed level of subcooled water,

j = node number at top of mixture.

The effect of subcooled rather than saturated water coming into the bottom of the fuel assembly is included by iteration. That is, the amount of fuel assembly power, P_{s}, required to heat the subcooled water to saturation temperature is;

$$P_s = W(h_f - h_s) \qquad (6.3\text{-}4)$$

where:

W = fluid flow

h_{f} = enthalpy of saturated fluid

h_{s} = enthalpy of inlet water.

Equations 1, 2, 3, 4 and the Wilson correlation are solved simultaneously for the five unknowns:

W_{N}, α_{N}, V_{N}, swollen level, and P_{S}.

The above model can be used to predict the duration of level swell cooling by assuming the entire assembly will be cooled to saturation as long as the swollen level covers the top of the active fuel. The model has been verified in this manner by comparison to experimental data[7,8]) as shown in Figure 6.3-22. The excellent agreement verifies the adequacy of the level swell model.

Applying the model results in the swollen level shown in Figure 6.3-23 for the range of reactor pressures and assembly powers of interest. Note that for even the lowest power fuel assembly the entire assembly is covered, and therefore cooled to saturation for 10 minutes to 28 hours, depending upon equilibrium reactor pressure. The exposed portions of the fuel are cooled by convection to the steam generated in the covered portion. An example of the coolant conditions up the fuel assembly is shown in Figure 6.3-24.

The historical GE long-term cooling analysis[2] used to be applicable to the 7x7 and 8x8 arrays of GE fuel. However the analysis and requirements by GE have changed. See Section 6.3.3.1.1 for the current post-LOCA long term cooling requirements applicable to all fuel types. Siemens ATRIUM-9B fuel, which is a 9x9 array, was evaluated[26][31][32] at 2511 MWt for long-term cooling response and found to be consistent with the GE historical analysis[2] swollen level response. Siemens LOCA analysis of the long-term response[26] for the limiting ATRIUM-9B scenario determined that the time to refill the reactor vessel to 2/3 core height was less than 7.5 minutes, i.e., six minutes after the time of rated core spray at 85.5 seconds at 2511 MWt. That limiting scenario is a double-ended guillotine break of the reactor recirculation pump suction line with a single failure of the LPCI injection valve to open. The Siemens analysis at 2511 MWt conservatively assumed 9000 gpm of ECCS flow (two core spray pumps at 4500 gpm per pump). Long-term cooling calculations by Siemens at 2511 MWt also included the effects of leakage as described in Section 6.3.3.1.2.2. Siemens determined that at 2511 MWt once water level reaches 2/3 core height, an ECCS flow rate of 2200 gpm is sufficient to maintain 2/3 core height water level[26]. Subsequent LOCA evaluations[25][34][54] at 2511 MWt did not change the long-term cooling results and conclusions. [6.3-60]

6.3.3.1.2.1.4 Heat Transfer Analysis for Exposed Rods (HISTORICAL INFORMATION)

The portions of the fuel rods not covered by mixture are cooled by convection of the steam generated below the two-phase mixture. Because of the relatively small amount of steam generated at these low powers, the flow is laminar. The nature of laminar flow lends itself to an analytical determination of the heat transfer coefficient in parallel rod array. This was done by Sparrow, et. al.,[9]) who showed that for a given geometry the Nusselt number remained constant.

For the rod-to-rod spacing, the Nusselt number determined from Sparrow's work has a value of 7.2. Therefore, the heat transfer coefficient is determined from:

$$h = \frac{Nu\, k(T)}{d} \qquad (6.3\text{-}5)$$

where:

Nu = Nusselt Number = 7.2

d = hydraulic diameter

$k(T)$ = steam conductivity as a function of temperature

The temperature rise of the steam for node i is given by,

$$(T_{out} - T_{in})_i = \frac{q_i}{WC_p} \qquad (6.3\text{-}6)$$

where:

$T_{\{out\}}$ = Steam temperature leaving node i

$T_{\{in\}}$ = Steam temperature entering node i

$C_{\{p\}}$ = Specific heat of steam

W = Steaming rate

$q_{\{i\}}$ = Heat transferred from node i

The cladding temperature can be determined for node i by:

$$T_{clad} - T_{steam} = \frac{(q/A)_i}{h(T)} \qquad (6.3\text{-}7)$$

where:

$T_{\{steam\}}$ = Average Steam temperature in node i

(q/A) = Heat flux in node i

h(T) = Heat transfer coefficient

Equations 5, 6, and 7 are solved simultaneously in a nodalized fashion for the uncovered portion of the fuel to determine the peak cladding temperature. In this analysis it was conservatively assumed that no fluid mixing occurred within the fuel assembly (i.e., the steam flowing around a rod "channels" up the rod without mixing with the steam flowing by the adjacent rods). This results in a conservative prediction of the peak cladding temperature, since the steam super-heats to higher temperatures.

In Figure 6.3-25 the peak cladding temperatures are shown as a function of fuel assembly power for 130 and 30 psia. These results were determined for collapsed levels of 8.8 and 9.3 feet for 130 and 30 psia, respectively (for which the bases were discussed in Section 6.3.3.1.2.1.2). Figure 6.3-26 shows the long-term peak cladding temperature as a function of break size including the effects of reactor pressure shown in Figure 6.3-20. This vividly shows that, for only a limited spectrum of breaks (0.33 — 0.8 f^2), will significant fuel rod heatup be experienced. It should be emphasized that the maximum containment backpressure should be significantly less than 30 psia and, therefore maximum cladding temperatures would be even lower than shown.

The historical GE long-term cooling analysis[2] used to be applicable to the 7x7 and 8x8 arrays of GE fuel. However, the analysis and requirements by GE have changed. See the current requirements in Section 6.3.3.1.1. Siemens ATRIUM-9B fuel, which is a 9x9 array, was evaluated[26][31][32] at 2511 MWt for long-term cooling and was found to be consistent with the historical GE analysis[2] for the exposed rods heat transfer response. Subsequent LOCA evaluations[25][34][54] at 2511 MWt did not change the long-term cooling results and conclusions. [6.3-61]

To put events in a time perspective following a loss-of-coolant accident, Figure 6.3-27 shows typical peak cladding temperature as a function of time following the design basis accident. This figure shows the temperature response of the original LOCA analysis. The short term temperature response was reanalyzed by the SAFER/GESTR-LOCA analysis for GE fuel (see Figure 6.3-33 and 6.3-34) at 2511 MWt. Siemens LOCA analysis[25][54] short term temperature response for ATRIUM-9B fuel is provided in Figure 6.3-49 at 2511 MWt. The long-term temperature response is not significantly affected due to the approximate flow equivalence of three RHR pumps versus two RHR pumps plus one core spray pump. During the short term (first 3 minutes), the peak temperature is determined by the hot fuel assembly. After the initial temperature transient has been terminated by effectively flooding the core, the individual fuel assembly powers will decrease and at some point in time will not generate enough heat to produce sufficient level swell to cover the fuel. This will first occur in the low power fuel assemblies located on the peripheral regions of the core and then in the high power assemblies (10 minutes to 28 hours) based on GE's historical analysis[2]. The high power fuel assemblies will experience this later (Figure 6.3-23) based on GE's historical analysis[2]. [6.3-62]

6.3.3.1.2.1.5 Fuel Rod Perforations

Because the long-term temperatures are much less than those calculated for the LOCA, it can be concluded that the number of perforations will not be increased. The reason is that, in calculating the perforations, it is assumed that all the fuel rods are at the peak temperature. The possible effect of creep on perforations was also examined and found not to contribute to perforations. At 900°F, the stress rupture properties of zircaloy are such that, at the maximum hoop stress of 9000 psi for the highest internal pressure rod, it would take 3000 hours to rupture—far too long to be of concern here. [6.3-63]

6.3.3.1.2.1.6 Conclusions

It can be concluded from this analysis that:

A. The LPCI subsystem retains its independence from core spray for the long-term when it can reflood the core to the top of active fuel;

B. The LPCI subsystem with core spray is effective in cooling the core for an indefinite period for large breaks when the water level is at 2/3 core height;

C. The combination of ECCS equipment as identified in Table 6.3-7D for Westinghouse analysis and Table 6.3-3E for AREVA analysis are effective in cooling the core for an indefinite period for any postulated LOCAs.

D. The number of fuel rod perforations and amount of metal-water reaction will not increase due to one long-term heatup. [6.3-64]

6.3.3.1.2.2 Leakage Performance Effects of Reactor Internals During Recirculation Line Break

An analysis has been performed to evaluate the potential leakage from within the floodable reactor vessel for the design basis LOCA analysis and during the postulated recirculation line break and subsequent LPCI reflooding. [6.3-65]

The possible sources of leakage are:

1. Jet pump slip joint*
2. Jet pump bolted joint*
3. Jet pump riser cracks at weld and repair holes for clamp (Unit 1 only)*
4. Replacement access hole cover joint*
5. Reactor vessel bottom head drain for recirculation suction breaks*
6. Core shroud horizontal weld flaws*
7. Core shroud repair holes for tie rod assembly*
8. Core spray tee box weld flaws and repair holes for clamp (Unit 1 only)
9. Core spray line flaws
10. Core Spray RPV penetration
11. Vent hole in core spray line T-box
12. Jet Pump flaws (e.g. adapter crack indications)*

* This leakage impacts LPCI.

Specific values for each leakage are documented in the updated LOCA input parameter documents. Each leakage was incorporated into the current licensing basis LOCA analysis. [6.3-66]

The LPCI system capacity was sized to accommodate 3000 gpm leakage at these locations so there is ample margin of conservatism in the design.

6.3.3.1.3 High Pressure Coolant Injection Subsystem

The HPCI subsystem has been evaluated to assure that the design bases are met. This evaluation considers the structural integrity of the system to withstand the effects of an accident for which the system must be available, suitability of valves, pump and turbine sequencing, speed of operation, capacity, and the depressurization efficiency for HPCI flow. [6.3-67]

6.3.3.1.3.1 High Pressure Coolant Injection Subsystem Availability

To inject water at a high pressure, three major active components must operate. A motor-operated valve must open to admit steam to the turbine driving the pump, a motor-operated valve must open to admit the discharge flow from the pump into the reactor feedwater line, and the turbine driven pump itself must be operated. When the supply of water in the contaminated condensate storage tank (CCST) is exhausted, two more motor-operated valves must open and one must close so that the pump draws water from the suppression chamber rather than from the CCST.

The turbine driving the pump is designed especially for this type of service. It operates over a wide range of inlet and exhaust pressures and the construction is such that it can start cold and come to full power operation almost instantaneously. Steam pressure is available to drive this pump whenever high pressure injection is needed. The system can be tested frequently so that any operating deficiencies can be detected early.

The initial HPCI start is automatic and requires no manual intervention. When the CCST is pumped down to a low level, the pump suction is automatically transferred to the suppression chamber. [6.3-67a]

The HPCI subsystem and the core spray subsystem (or the LPCI) complement one another. The HPCI subsystem protects against small breaks and the core spray subsystem and/or the LPCI subsystem protects against large breaks and automatically takes over from the HPCI subsystem before the steam pressure falls below the minimum level required to operate the HPCI subsystem.

There are many actions the operator can take to prevent core damage for moderate size breaks. If normal sources of power are available, he can continue to operate the regular feedwater pumps to provide makeup. He can transfer water from the condensate system to the hotwell so that this type of cooling can be continued indefinitely. Whether or not normal sources of power are available, the operator can manually depressurize the vessel using the relief valves so that core spray and LPCI will provide cooling.

6.3.3.1.3.2 Evaluation of Subsystem Performance

The HPCI subsystem is designed to provide adequate reactor core cooling for small breaks which are below the core cooling capability of the unassisted core spray or LPCI subsystems, and to depressurize the reactor primary system to aid the LPCI and core spray subsystems. A detailed discussion of the performance of the HPCI subsystem in conjunction with the LPCI and core spray subsystems is given in Section 6.3.3.2.

Performance analyses of the HPCI subsystem are conducted in the same manner and with the same basic assumptions as for the core spray subsystem described in Section 6.3.2.1. The detailed model is described in Section 6.3.3.2.1. For information on the current LOCA analysis, refer to References 66 and 80 for Westinghouse analyses and Reference 82 for AREVA analysis. The remaining information in this section is historical and not applicable to the current LOCA analysis.

[START HISTORICAL INFORMATION]

The results of a historical pre-Appendix K licensing basis performance analysis for GE fuel of the HPCI subsystem for a typical small break within the protection range of the unassisted HPCI subsystem are shown in the Figure 6.3-28 at 2511 MWt. During the initial phase of the transient before the HPCI subsystem begins operation, the reactor primary system pressure does not change significantly due to the release of the core stored energy and the action of the turbine initial pressure regulator. The small liquid break cannot remove enough energy from the system to cause a rapid pressure decrease. When the HPCI subsystem begins operation, a significant change in the vessel pressure rate occurs due to the condensation of steam by the cold fluid pumped into the reactor vessel by the HPCI subsystem. The effect of the mass additions by the HPCI are also reflected in the changing slope of the liquid inventory trace. As the reactor vessel pressure continues to decrease, the HPCI flow momentarily reaches equilibrium with the flow through the break. Continued depressurization causes the break flow to decrease below the HPCI flow and the liquid inventory begins to rise. This type of response is typical of the small breaks at 2511 MWt. The core never uncovers and is continuously cooled throughout the transient so that no core damage of any kind occurs for breaks that lie within the range of the HPCI.

The results of a performance analysis at 2511 MWt for Siemens ATRIUM-9B fuel of the HPCI subsystem for a typical small break (0.12 square feet) within the protection range of the unassisted HPCI subsystem are shown in Figures 6.3-28A, B, C, D, and E. The core never uncovers and is continuously cooled throughout the accident so that no core damage of any kind occurs for breaks that lie within the range of the HPCI at 2511 MWt. [6.3-68]

The results achieved for the Siemens unassisted HPCI LOCA analysis at 2511 MWt used the NRC approved Siemens 10 CFR 50, Appendix K model as described in Section 6.3.3.2.1.2. This specific case is not required for 10 CFR 50.46 or 10 CFR 50, Appendix K analysis. However, it demonstrates the continued functional performance of the HPCI system as originally approved by NRC[46][47].[6.3-69]

[END HISTORICAL INFORMATION]

The LOCA analysis by Westinghouse at 2957 MWt for SVEA-96 Optima2 fuel analyzed the entire break spectrum. This analysis included the various combinations of single failures as described in Table 6.3-7D. The LOCA analysis for Quad Cities Unit 1 by AREVA at 2957 MWt for ATRIUM 10XM fuel analyzed the entire break spectrum. This analysis included the various combinations of single failures as described in Table 6.3-7E. The HPCI turbine oil cooler and gland seal condenser are cooled by water from the suppression pool. Since these components are rated at 140 °F, continued operation above a suppression pool temperature of 140 °F is not permitted. Also, operation of HPCI above 140 °F would exceed the current net positive suction head (NPSH) calculations for rated HPCI pump flows. Another limitation on the HPCI system is related to the dependence of the HPCI room cooler on the unit emergency diesel generator (EDG). Therefore, any single failures of the unit EDG need to assume consequential loss of the HPCI system after 10 minutes of operation. As a result of these considerations, the HPCI system is not credited when any of these conditions are exceeded. The results of the analysis show that the HPCI system met its requirements before the 10 minute mission time was exceeded and the suppression pool temperature exceeded 140 °F (see Reference 80) for Westinghouse analysis and Reference 82 for AREVA analysis.

[START HISTORICAL INFORMATION]

Tables 6.3-9A and 9B identified the limiting large break case and a limiting small break case at 2511 MWt. Results from the Siemens LOCA analysis[25][26][54] break spectrum at 2511 MWt showed that the small break case which reached the highest PCT was the 0.5 ft^2 break on the reactor recirculation pump discharge piping with a single failure of the Diesel Generator. Siemens most recent LOCA analysis[25][26][54] at 2511 MWt of small break temperature response for ATRIUM-9B fuel is provided in Figure 6.3-56. System response from this Siemens small break LOCA analysis at 2511 MWt is shown in Figures 6.3-50 to 6.3-55. Important variables from the Siemens LOCA analysis at 2511 MWt of the small break yielding the highest cladding temperature are as follows:

a) Upper plenum pressure as a function of time during blowdown from RELAX.

b) Core inlet flow as a function of time during blowdown from RELAX.

c) Core outlet flow as a function of time during blowdown from RELAX.

d) Lower downcomer mixture level as a function of time during blowdown from RELAX.

e) System pressure as a function of time from FLEX.

f) Lower plenum mixture level as a function of time during refill/reflood from FLEX.

g) Peak cladding temperature as a function of time from HUXY.

This small break case in the Siemens LOCA analysis at 2511 MWt, which relies on HPCI, two core spray pumps and ADS for mitigation, is the most severe challenge to the fuel safety limits of all the small break cases. The PCT results at 2511 MWt for the small break are still well below the licensing basis limiting DBA LOCA results.

[END HISTORICAL INFORMATION]

For operation at 2957 MWt, the following single failures were evaluated for SVEA-96 Optima2 fuel: LPCI injection valve, diesel generator, HPCI, loop select logic, and ADS. A second failure of HPCI was not considered (Reference 80).

The potential problem of the effect of level swell and resultant liquid carryover into the HPCI steam line has been studied extensively; this has been described in detail in Supplement #1 to the Peach Bottom Atomic Power Station Units 2 and 3 Preliminary Safety Analysis Report Docket No. 50-277. It was concluded that a mechanism to cause bypassing of the steam separators, by the swelling steam water mixture, was not available and therefore gross moisture carryover to the HPCI turbine should not occur over the range of steam line breaks of interest in this system.

The HPCI turbine has been designed for high reliability under its design requirements of quick starting. Moreover, the turbine has adequate capacity to accept the small losses in efficiency due to any credible moisture carryover, since HPCI turbine efficiency is not of paramount importance.

No water slugs can reach the inlet to the HPCI turbine; for steam breaks that require HPCI operation (< 0.13 ft.^{2}), the turbine can tolerate the small amount of moisture that might enter the machine. For large steam breaks that do not require HPCI operation, but do result in moisture at the turbine inlet, it was shown that the pressure boundary would not fail and that the most serious consequence would be a failure of the turbine bearings leading to a locked rotor. The steam leaks and consequent doses associated with this condition were shown to be trivial. [6.3-70]

The HPCI steam supply is via a connection to a main steam line and because of the elevation of the main steam lines (7 feet above normal water level), there could be no moisture carryover for breaks less than 1 ft^2. Figure 6.3-1 from the original FSAR pre-Appendix K analysis shows that the largest steam break for which the low pressure ECCS systems (core spray and LPCI) require the assistance of the HPCI is 0.13 ft^2. Steam breaks larger than this do not require HPCI operation in order for the ECCS network to be capable of providing adequate core cooling. It can thus be concluded from the original FSAR pre-Appendix K analysis, that there will be no moisture carryover to the HPCI turbine for the break size range that requires its operation. In the event of a large steam break, there would be some moisture ingested by the turbine but this would in no way jeopardize core cooling or result in a significant release of radioactive materials.

In 1981, a survey was conducted of the HPCI steam lines to determine if any sag in the lines existed which could potentially lead to an accumulation of water in the line. No significant sag in the HPCI steam lines was observed for either unit.

6.3.3.1.3.3 Summary

Based upon performance analysis of equipment provided, it is concluded that the HPCI subsystem combined with the other available ECCS will maintain water inventory sufficient to assure core cooling for small breaks. For larger breaks it will increase vessel depressurization as well as helping to maintain liquid inventory. This depressurization will enable the core spray and/or the LPCI subsystems to function before core damage can occur. [6.3-71]

6.3.3.1.4 Automatic Depressurization Subsystem

The ADS is designed to depressurize the reactor to permit either the LPCI or core spray subsystem to cool the reactor core during a small break LOCA; this size break would result in a loss of coolant without a significant pressure reduction, so neither system alone could provide adequate core cooling. The performance analysis of the ADS is conducted in the same manner and with the same basic assumptions as the core spray subsystem analysis discussed in Section 6.3.2.1. When the ADS is actuated, the critical flow of steam through the relief valves results in a maximum energy removal rate with a corresponding minimum mass loss. Thus, the specific internal energy of the saturated fluid in the system is rapidly decreased, which causes a pressure reduction. Some steam and two-phase cooling would occur during the blowdown phase. Moreover, since the ADS does not provide coolant makeup to the reactor, the ADS is considered only in conjunction with the LPCI or core spray subsystems as a backup to the HPCI. [6.3-72]

All five available ADS valves were assumed operable in the LOCA analysis. One ADS valve from the five valves modeled in the LOCA analyses was assumed to fail for the single failure evaluation resulting in the operation of four valves being credited.

At 2957 MWt for SVEA-96 Optima2 fuel types and the Quad Cities Unit 1 AREVA analysis for ATRIUM 10XM fuel, five of the five available ADS valves were assumed operable in the LOCA analysis. See References 66 and 80 for a discussion and results of small break analyses at 2957 MWt for SVEA-96 Optima2 fuel types with one ADS valve out of service for MAPLHGR reduction requirements.

Design evaluation of the ADS is included in the core spray and LPCI performance analysis discussions in Sections 6.3.3.1.1 and 6.3.3.1.2 on intermediate and Section 6.3.3.1.3 for small breaks.

6.3.3.2 Integrated Emergency Core Cooling System Performance Evaluation

The performance of the ECCS is determined through application of the 10CFR50, Appendix K evaluation models and then showing conformance to the acceptance criteria of 10CFR50.46. A summary description of the loss-of-coolant accident results are provided herein. For a complete description of the LOCA analysis results, see References 66 and 80 for SVEA-96 Optima2 and Reference 82 for ATRIUM 10XM at 2957 MWt.

The information provided herein is applicable to the licensing basis LOCA analyses from References 66 and 80 for SVEA-96 Optima2 fuel types and References 82 and 83 for ATRIUM 10XM fuel types (loaded in Unit 1). Each cycle's specific peak cladding temperature results are typically included in the cycle specific reload reports referenced in the Core Operating Limits Report (COLR), Reference 28. For details for the initial LOCA analysis, refer to the FSAR.

6.3.3.2.1 Description of Loss of Coolant Accident Analysis Model

6.3.3.2.1.1 General Electric Fuel and Methods

[Start of HISTORICAL INFORMATION]

The GE evaluation model used for the LOCA analysis consists of four major computer codes[10]. The LAMB and SCAT models are employed for short-term system response and hot fuel assembly calculations. The long-term water level and inventory calculations and final fuel rod heatup calculations are performed by SAFER, with gap conductance supplied by GESTR-LOCA. Figure 6.3-29 shows a flow diagram of the usage of these computer codes, indicating the major code functions and the transfer of major data variables. [6.3-73]

6.3.3.2.1.1.1 LAMB (Typical GE)

This code is used to analyze the short-term blowdown phenomena for large postulated pipe breaks (breaks in which nucleate boiling is lost before the water level drops and uncovers the active fuel) in jet pump reactors. The LAMB output (most importantly, core flow as a function of time) is input to the SCAT code for calculation of blowdown heat transfer and fuel dryout time.

6.3.3.2.1.1.2 SCAT or TASC (GE)

This code completes the transient short-term thermal-hydraulic calculation for large recirculation line breaks in jet pump reactors. A boiling transition correlation is used to predict the time and location of boiling transition during the period that the recirculation pumps are coasting down. When the core inlet flow is low, SCAT or TASC uses a dryout correlation to predict the resulting time and location of fuel assembly dryout. The calculated fuel dryout time is input to the long-term thermal-hydraulic transient model, SAFER.

6.3.3.2.1.1.3 SAFER (GE)

This code is used to calculate the long-term system response of the reactor for reactor transients over a complete spectrum of hypothetical break sizes and locations. The SAFER model is compatible with the GESTR-LOCA fuel rod model for gap conductance and fission gas release. The SAFER model tracks, as a function of time, the core water level, system pressure response, ECCS performance, and other primary thermal-hydraulic phenomena occurring in the reactor. SAFER realistically models all regimes of heat transfer which occur inside the core during the event, and it provides the outputs as a function of time for heat transfer coefficients and PCT.

6.3.3.2.1.1.4 GESTR-LOCA (GE)

The GESTR-LOCA code is used to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA for input to SAFER. GESTR-LOCA also initializes the transient pellet-cladding gap conductance for input to both SAFER and SCAT.

6.3.3.2.1.1.5 Model Applicability (GE)

The previously described models and computer codes can be used to evaluate all plants. A schematic flow diagram of the LOCA analysis for a typical plant is shown in Figure 6.3-29. [6.3-74]

For operation at 2957 MWt, the LOCA analysis[55] used SAFER/GESTR-LOCA methodology with bounding input parameters from the combination of the Dresden and Quad Cities plants.[56] The significant parameters used in the analysis to support operation at 2957 MWt for GE14, GE9/10, and ATRIUM-9B fuel types are summarized in Table 6.3-3C.

[End of HISTORICAL INFORMATION]

6.3.3.2.1.2 Section Deleted [6.3-75]

6.3.3.2.1.3 Westinghouse SVEA-96 Optima2 Fuel and Methods at 2957 MWt

The Westinghouse BWR LOCA methodology is described in References 67 through 72 and 74. The methodology makes use of the GOBLIN series of computer codes to calculate the BWR transient response to both large and small break LOCAs. The MAPLHGR limits using Reference 66 as the analysis of record use the USA6 evaluation model (EM), and the MAPLHGR limits using Reference 80 as the analysis of record use the USA5 EM. The USA6 Evaluation Model included an update to the modeling of the end of lower plenum flashing.

6.3.3.2.1.3.1 GOBLIN (Westinghouse)

This code performs the analysis of the LOCA blowdown and reflood thermal hydraulic transient for the entire reactor, including the interaction with various control and safety systems. GOBLIN may also be run in the 'DRAGON' mode to perform hot fuel assembly transient calculation using boundary conditions from a previous GOBLIN system analysis. Alternatively, the hot assembly analysis may be performed as a parallel channel in the GOBLIN system analysis. In this case, there is no need to drive the DRAGON analysis with boundary conditions from the system analysis. The GOBLIN code is described in detail in Reference 68.

6.3.3.2.1.3.2 CHACHA (Westinghouse)

This code performs detailed fuel rod mechanical and thermal response calculations at a specified axial level within the hot assembly. All necessary fluid boundary conditions are obtained from the hot assembly thermal hydraulic analysis described above. CHACHA-3D determines the temperature distribution of each rod at the axial elevation analyzed. These results are used to determine the peak cladding temperature and cladding oxidation at the axial plane under investigation. CHACHA-3D also provides input for the calculation of total hydrogen generation. The CHACHA-3D code is described in detail in Reference 72.

6.3.3.2.1.3.3 STAV (Westinghouse)

This code predicts fuel parameters as a function of power history and exposure. For LOCA analysis applications, it is used to develop input to the system performance, hot assembly and cladding heat-up analyses. STAV predicts the fuel stored energy, the pellet-clad gap, the pellet-clad gap heat transfer coefficient and fission gas inventory. For a detailed discussion regarding the LOCA fuel performance inputs, refer to Reference 73.

6.3.3.2.1.4 AREVA LOCA Analysis Methods for Quad Cities Unit 1 at 2957 MWt

The Evaluation Model used for the AREVA LOCA break spectrum analysis and hot channel heatup is the EXEM BWR-2000 LOCA analysis methodology described in Reference 81. The EXEM BWR-2000 methodology employs three major computer codes to evaluate the system and fuel response during all phases of a LOCA. These are the RELAX, HUXY, and RODEX2 computer codes. RODEX2 is used to determine fuel parameters (such as stored energy) for input to the other LOCA codes. RELAX is used to calculate the system and hot channel response during the blowdown, refill and reflood phases of the LOCA. The HUXY code is used to perform heatup calculations for the entire LOCA, and calculates the peak cladding temperature (PCT) and local clad oxidation at the axial plane of interest.

6.3.3.2.2 Plant Specific LOCA Analysis

The purpose of this section is to provide the results of the LOCA analysis. The analysis for SVEA-96 Optima2 fuel was performed using approved Westinghouse BWR LOCA methodology as described in the preceding 6.3.3.2.1.3 sections. For Quad Cities Unit 1, the analysis for AREVA ATRIUM 10XM fuel was performed using approved AREVA BWR LOCA methodology as described in the preceding 6.3.3.2.1.4 section.

6.3.3.2.2.1 Input to Analysis

A list of significant plant-specific input parameters to the LOCA analysis is presented in Table 6.3-3D for SVEA-96 Optima2 fuel and Table 6.3-3E for the Quad Cities Unit 1 analysis for AREVA ATRIUM 10XM fuel. Tables 6.3-7D and 6.3-7E identify the single failure/system available combinations analyzed for Quad Cities 1 & 2, for which the ECCS configuration is depicted in Figure 6.3-30. [6.3-76]

6.3.3.2.2.2 Recirculation Line Break Results

For the Westinghouse analysis of SVEA-96 Optima2 fuel, the recirculation line break spectrum was analyzed using Appendix K assumptions and inputs (see References 66 and 80 for details). For the AREVA analysis of Quad Cities Unit 1 ATRIUM 10XM fuel, the recirculation line break spectrum was analyzed using Appendix K assumptions and inputs (References 81, 82 and 83).

6.3.3.2.2.2.1 Section Deleted

6.3.3.2.2.2.2 Section Deleted [6.3-77]

6.3.3.2.2.2.3 Section Deleted

6.3.3.2.2.2.4 Recirculation Line Breaks at 2957 Mwt

For operation at 2957 MWt, the LOCA analysis for SVEA-96 Optima2 fuel used the Westinghouse BWR LOCA methodology using bounding input parameters for the Quad Cities units. For Quad Cities Unit 1, the analysis for AREVA ATRIUM 10XM fuel was performed using the approved AREVA BWR LOCA methodology of Reference 81.

The recirculation line break spectrum was performed with the hot assembly operating at a constant conservative operating limit and the heat-up analysis at a fixed nodal peaking factor and exposure to ensure that the LOCA response could be compared on the same basis.

The peak cladding temperature (PCT) results for all break sizes analyzed in Reference 66 for Westinghouse SVEA-96 Optima2 fuel and in Reference 82 for AREVA Quad Cities Unit 1 analysis for ATRIUM 10XM fuel were used to establish the limiting break size, location and single failure. The single failure of the LPCI injection valve was the limiting failure for the large recirculation line breaks.

The Westinghouse analysis results in Reference 66 indicate that for the single failure of the loop select logic, the maximum PCT occurs for a break size of approximately 1.0 ft^2. In these cases, the break was placed downstream of the LPCI injection point in the recirculation discharge line.

For Westinghouse analysis of SVEA Optima2 fuel, the limiting small break in the recirculation line occurred for a 0.10 ft^2 break downstream of the LPCI injection point with single failure of HPCI (Reference 66). For recirculation line breaks larger than 0.15 ft^2, the loop select logic is assumed to select the intact loop, in which case none of the coolant injected by LPCI is lost out the break before it enters the reactor vessel. The Reference 82 AREVA analysis for Quad Cities Unit 1 ATRIUM 10XM fuel, the 0.13 ft^2 discharge line split break downstream of the LPCI injection point with HPCI single failure had the highest PCT of all recirculation line break sizes and locations.

6.3.3.2.2.3 Non-Recirculation Line Break Results

For operation at 2957 MWt, the non-recirculation line breaks were analyzed for SVEA-96 Optima2 fuel as part of the break spectrum evaluation. The results of these analyses show that the non-recirculation line breaks are significantly less severe than the postulated recirculation line breaks (Reference 80). The same conclusion resulted from the Reference 82 AREVA analysis of Quad Cities Unit 1 for ATRIUM 10XM fuel.

6.3.3.2.2.4 Alternate Operating Mode Considerations

6.3.3.2.2.4.1 Section Deleted

6.3.3.2.2.4.2 Single Loop Operation LOCA Analysis

The ECCS performance for SVEA-96 Optima2 fuel under single loop operation (SLO) was evaluated using the Westinghouse BWR LOCA methodology [66]. The single loop system performance is performed in the same manner as for two-loop operation with the exception that it is initialized at a different statepoint [72.2% of rated power and 55.1% of rated flow]. The break is placed in the suction line of the active recirculation loop as this reduces the beneficial effect of pump coastdown during blowdown. To ensure that the two-loop licensing basis PCT remains limiting, single loop operation is analyzed to determine if there is a need for reduction, i.e., a multiplier of less than 1.0, on the two-loop MAPLHGR values. The AREVA Reference 82 analysis for single loop operation for Quad Cities Unit 1 for ATRIUM 10XM fuel shows the small recirculation discharge break of 0.1 ft^2 with HPCI single failure to be limiting, and that a multiplier of 0.80 on the two-loop MAPLHGR values was established to assure that the PCT for SLO remains below the two loop PCT result. This analysis supports the rated power and rated flow restrictions outlined in the current cycle's COLR.

6.3.3.2.2.4.3 Section Deleted

6.3.3.2.2.4.4 Maximum Extended Load Line Limit Analysis and Increased Core Flow Effects

The Westinghouse BWR LOCA methodology was used to support operation at 2957 MWt with SVEA-96 Optima2 fuel. The analyses were performed at 102% of rated power and 108% of rated core flow (ICF operation) to establish MAPLHGR limits. Application of the methodology at 95.3% of rated core flow (MELLLA operation at 2957 MWt) showed no adverse effect due to operation at the decreased core flow.

For Quad Cities Unit 1, the AREVA LOCA analyses for ATRIUM 10XM fuel were also performed at both 108% and 95.3% of rated core flow, and therefore support MELLLA and ICF operation.

6.3.3.2.2.5 Core Operating Limits Report MAPLHGR Limits

The MAPLHGR limits are listed in the Core Operating Limits Report (COLR)[28] for the various fuel types loaded in the core for that cycle. The COLR is a cycle-specific document and a new report is generated each reload. [6.3-78]

For all fuel, MAPLHGR specification assures the peak cladding temperature, local oxidation, and hydrogen generation of the fuel following a postulated design basis loss-of-coolant accident will not exceed the peak cladding temperature (PCT), maximum oxidation limits, and hydrogen generation limits specified in 10 CFR 50.46. The calculation procedure used to establish the Average Planar Linear Heat Generation Rate (APLHGR) limits is based on a loss-of-coolant accident analysis.

Although the PCT following a postulated loss-of-coolant accident is strongly influenced by the rod-to-rod power distribution within the assembly, this is accounted for in the determination of MAPLHGR limits.

The Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) limits for two loop and single loop operation are specified in the Core Operating Limits Report (COLR). For a specific cycle, the MAPLHGR limits for each fuel type will appear in the COLR. Also, the requirements for SLO and two-loop LHGR limits are provided in the COLR.

Further discussion on MAPLHGR is provided in Sections 4.2.1.1 and 4.4.2.2.

Exposure dependent MAPLHGR limits were determined for SVEA-96 Optima2 fuel types to support operation at 2957 MWt. The MAPLHGR limits were established using Westinghouse BWR LOCA methodology. LHGR limits based on fuel thermal mechanical design limits are established separately in the Westinghouse BWR reload methodology. Cycle specific MAPLHGR limits for two-loop and single loop operation will be documented in supplements to the reload licensing reports. For Quad Cities Unit 1 AREVA ATRIUM 10XM fuel, the MAPLHGR limits for two-loop and single loop operation are documented in Reference 83, which will be updated as necessary for future ATRIUM 10XM reload fuel designs. The cycle-specific reload licensing reports will also document the applicable MAPLHGR limits for ATRIUM 10XM reload fuel.

6.3.3.2.3 Conclusions of Loss of Coolant Accident Analysis

6.3.3.2.3.1 Section Deleted [6.3-79]

6.3.3.2.3.2 Section Deleted

6.3.3.2.3.3 Section Deleted

6.3.3.2.3.4 Loss of Coolant Accident Analysis Summary Results at 2957 Mwt

Table 6.3-12D summarizes the Westinghouse analysis results for Quad Cities units 1 and 2. The analyses presented are performed in accordance with NRC requirements, conditions and limitations and demonstrate conformance with the ECCS acceptance criteria of 10 CFR 50.46 as shown in Table 6.3-12D. For Quad Cities Unit 1, the AREVA ATRIUM 10XM fuel LOCA analysis results in conformance with 10 CFR 50.46 are provided in Table 6.3-12E.

See the latest 10 CFR 50.46 letter for details regarding the PCT updates associated with the current Westinghouse and/or AREVA assessments of changes affecting the Quad Cities LOCA analyses.

6.3.3.2.4 Single Failure of ECCS Manually Controlled Electrically Operated Valves

The effects of a single failure or operator error that causes any manually-controlled, electrically-operated valve in the ECCS to move to a position that could adversely affect the ECCS has been studied. The purpose of this evaluation is to determine that any such maloperation does not affect the ECCS more than the results of the worst single failure which is reported in the LOCA calculations performed in accordance with Appendix K. [6.3-80]

The results of the break spectrum analysis show the single failure which results in the maximum calculated PCT. For any other single failure to be more significant, its effect on the ECCS must be greater than this single failure. Therefore, a study was made to determine if the malfunction of a manually-controlled, electrically-operated valve by some unknown cause or by an operator improperly positioning a control switch could affect the ECCS more severely than this failure.

In accordance with appropriate IEEE standards as specified in Section 7.3.1, the ECCS valves are electrically assigned to different divisions of power supply. The effect of an operator improperly actuating a single switch on the control panel is to cause only a single valve to move to an incorrect position. For the operator error of actuating a single switch of the ADS, the subsystem valves are not actuated. However, the consequences of a malfunction which causes one ADS valve to inadvertently open has been noted.

The summary of the ECCS Valve Single Failure Analysis is provided in Table 6.3-13. Comparing the effects of the single valve failure noted in Table 6.3-13 with the results of the LOCA analysis, it can be seen that these failure are not more severe than those reported.

6.3.3.2.5 Steam Breaks

Discussion and illustration of the ECCS performance capability has purposely been directed toward the liquid breaks below the core. In general, the ECCS design criterion of no core damage is more easily satisfied for steam breaks than for liquid breaks, because the reactor primary system depressurizes more rapidly with less mass loss for steam breaks than for liquid breaks. Thus, the ECCS performance for a given break size improves with increasing break flow quality. [6.3-81]

The most severe steam pipe break would be one which occurs in the drywell, upstream of the flow limiters. Although the isolation valves would close with the time specified in Reference 56, a break in this location would permit the pressure vessel to continue to depressurize to the drywell. As serious as this accident is, however, it does not result in thermal-hydraulic consequences as severe as the rupture of a coolant recirculation pipe. The results of a typical steam line break are discussed in Section 6.3.3.2.2.3, which concludes that no cladding heatup beyond the initial temperature would occur.

6.3.3.2.6 Summary

6.3.3.2.6.1 Section Deleted

6.3.3.2.6.2 Section Deleted

6.3.3.2.6.3 Section Deleted

6.3.3.2.6.4 Westinghouse Analysis at 2957 Mwt

The Westinghouse BWR LOCA analysis in support of operation at 2957 MWt with SVEA-96 Optima2 fuel was performed using bounding input parameters for the Quad Cities units. The objective of the analysis was to provide assurance that the most limiting break size, break location, and single failure combination have been considered for the plant and that the results for the DBA LOCA meets the acceptance criteria of 10 CFR 50.46. As a result of this analysis, it has been shown that the ECCS meets all the requirements of 10 CFR 50.46, even in the event of the loss of normal station auxiliary power.

Independent of fuel type, additional ECCS cooling capability exists from the feedwater condensate systems in the more probable event that station auxiliary power is available.

6.3.3.2.6.5 AREVA Analysis at 2957 Mwt

The AREVA BWR LOCA analysis in support of operation at 2957 MWt with ATRIUM 10XM fuel was performed using bounding input parameters for Quad Cities Unit 1. The objective of the analysis was to provide assurance that the most limiting break size, break location, and single failure combination have been considered for the plant and that the results for the DBA LOCA meets the acceptance criteria of 10 CFR 50.46. As a result of this analysis, it has been shown that the ECCS meets all the requirements of 10 CFR 50.46, even in the event of the loss of normal station auxiliary power.

6.3.3.2.7 Integrated System Operating Sequence for Design Basis Accident

Since the ECCS is composed of several subsystems that are designed to perform under specific conditions, the operating sequence must be described for alternate operating conditions. [6.3-82]

With normal ac power available all systems are actuated and there is no preferential sequencing. However, when power is supplied by the diesel generators, the pump motor starting loads must be sequenced to prevent overloading of each diesel. The initiating accident for the loading sequence is a complete severance of the largest coolant pipe and no reliance placed on external sources of power. [6.3-83]

For operation at 2957 MWt, the LOCA analysis for SVEA-96 Optima2 fuel used an electrical loading sequence from bounding input parameters for the Quad Cities units. The significant electrical loading parameters used for this analysis are summarized in Table 6.3-14C. For Quad Cities Unit 1 ATRIUM 10XM fuel, the AREVA LOCA analysis used the electrical loading sequence summarized in Table 6.3-14D for the largest recirculation line break with an assumed LPCI injection valve failure; this table also shows the electrical loading sequence for the limiting small recirculation line break with an assumed HPCI failure.

Upon the accident initiation, the LPCI subsystem is initiated first to start the reflooding as soon as possible (see Section 6.3.2.2 for the description of operation of this subsystem).

The core spray subsystem is timed to start after sufficient time has been allowed for the start of the RHR pumps to minimize the diesel starting load. The detailed operating sequence for this subsystem is discussed in Section 6.3.2.1.

The injection valves for the LPCI and core spray subsystems open as soon as the reactor low pressure permissive is cleared provided the emergency electrical power is available. However, in the AREVA and Westinghouse analyses, for the LPCI single failure the LPCI injection valve is assumed to fail in the closed position. Therefore, no coolant is injected by the LPCI subsystem. Two core spray pumps deliver coolant to the spray spargers above the core. The core spray liquid entering the upper plenum, including the leakage inside the shroud, is available to provide coolant to the core and bypass region. The liquid flow from both the bypass region and the core assist in filling the lower plenum. Table 6.3-19C shows the sequence of events for the limiting DBA event based on the methodology of Reference 66. Table 6.3-19D shows the sequence of events for the Reference 82 AREVA Quad Cities Unit 1 ATRIUM 10XM fuel analysis for the limiting recirculation line break with an assumed HPCI failure.

6.3.3.2.8 Availability Analysis

The following analysis was performed in 1971 and remains unchanged since that time. Many modifications have been made in the control systems for the ECCS subsystems since then. The conclusions of the analysis appear to be generally valid; however specific details contained in the descriptions and associated figures should be used only to understand the analysis. These specific details should not be used as sources of current fuel cycle design information.

The availability of the ECCS was calculated for two basic cases: a small line break and a large line break. The analysis for each of these cases is discussed separately. For each case, an availability block diagram was developed showing all of the possible combinations of cooling systems and power sources that could supply the required amount of cooling water to the core under emergency conditions. The main loads in the core spray and LPCI subsystems are the core spray pumps and the RHR pumps respectively. In preparing the block diagrams, due account was taken for the way these pump motors are connected to the 4-kV emergency busses and also the way the 1 (2) and the 1/2 diesel generators are connected to these same buses. Calculated or observed availabilities for components in the ECCS and for the power sources were used to calculate the composite system availability. A computer program, incorporating appropriate logic statements to account for the fact that the same blocks appear in several different success paths of the availability block diagram, was used to calculate ECCS availability and to determine the relative contributions of various components to system unavailability. [6.3-84]

To achieve overall success, the ECCS must survive from the time the last test was conducted until LOCA takes place, then, equipment must start and valves must cycle to provide coolant through the right flow paths and finally equipment must continue to operate for approximately 100 hours after the LOCA in order to remove the residual heat from the core. Prior analysis performed at GE and confirmed by analysis done by Holmes & Narver[14] indicates that the probability of survival and startup dominates the overall probability of success while the probability of continued operation makes a minor contribution. Consequently, the availability analysis results reported here consider only the probability of survival during the standby period and the probability of successful startup.

Availability block diagrams were also developed for the HPCI, ADS, core spray, and LPCI subsystems. The methods used for calculating subsystem availability are described in APED-5496[15], and the component failure rates used in the analyses were obtained from collection of data from similar components now in service and from standard reference sources.[16, 17, 18, and 19] Test intervals and/or repair times used in the analyses reflect operating experience with similar equipment in other nuclear plants.

6.3.3.2.8.1 Small Line Break

For purposes of this analysis, a small line break is defined as a break having a flow area of ≤ 0.6 ft^2. The ECCS availability model is shown in Figure 6.3-39. When auxiliary ac power is available to operate the condensate/condensate booster pumps and the reactor feed pumps, the feedwater system will be used to maintain reactor vessel level. Should either the auxiliary ac power system or the feedwater system fail, several backup cooling systems are automatically started up. The HPCI subsystem is the first alternate for the feedwater system and maintains reactor water level until reactor pressure decays to below 150 psig. The ADS provides an alternate means for reducing reactor pressure to a value where either the core spray subsystem or the LPCI subsystem can take over the core cooling function. [6.3-85]

Auxiliary power must be available to operate the pump motors and valves in the feedwater system. Due to the size of these pump motors (approximately 1750 hp for a condensate/condensate booster pump combination and approximately 9000 hp for a reactor feed pump) these motors are not connected to the diesel generators. The criteria for the normal auxiliary power system requires an availability of at least 0.999, and is the availability used for the auxiliary power system.

The feedwater system is comprised of four sets of condensate/condensate booster pumps, three reactor feed pumps, two main feedwater control valves and associated motor-operated valves, piping, and controls. A condensate pump and a condensate booster pump are mounted on a common baseplate and are both driven by a common double-ended shaft motor. Three out of four of these units are normally in service when the plant is operating at rated power. Each reactor feed pump is driven by a separate motor through a speed increaser. Two out of three of the reactor feed pumps are normally in service when the plant is operating at rated power.

For an emergency condition, the feedwater system availability was calculated on the basis of one out of the four condensate/condensate booster pump units, one out of the three reactor feed pumps, and one out of the two feedwater control valves being available. Due to the high level of redundancy, the calculated feedwater system availability is high, greater than 0.999999; thus, power availability is the limiting factor.

The 125-Vdc station battery system must operate to provide control power to the engineered safety feature cooling systems with 0.99999 availability; this is entirely consistent with past experience.

The HPCI subsystem is started automatically by reactor low-low water level or drywell high pressure sensors. The two-stage HPCI pump is driven by a turbine utilizing steam from the reactor vessel and exhausting to the suppression chamber. The pump can take

suction from either the condensate storage tank or the suppression pool. Calculated availability for the HPCI subsystem is 0.920. The 250-Vdc station battery must operate to provide power for operation of HPCI subsystem valves and the turbine auxiliary and emergency oil pumps. A shaft-driven oil pump takes over as soon as the turbine is in operation. Design criteria and past experience indicate an availability of 0.99999 is appropriate for the 250-Vdc station battery system.

The ADS is automatically initiated by a combination of signals from reactor low-low water level and drywell high pressure maintained for 120 seconds (analytical limit) with evidence of core spray or RHR pump operation. Separate sensors, unique to the ADS, are used for detection of drywell high pressure. Failure rates and test intervals for these sensors are included in the calculation of the availability for the ADS. The reactor low-low water level sensors (but not the electrical contacts) are common to other ECCS subsystems and therefore have been shown separately from the remainder of the ADS. As stated previously, the logic statements in the computer program account for this commonality and produce the correct composite system availability. Relief valves, mounted on the main steam lines, are opened to blow reactor steam into the suppression pool. The calculated availability for this system is 0.920.

Both the core spray pumps and the RHR pumps are started automatically by reactor vessel low-low water level sensors coincident with low reactor pressure sensors or by drywell high pressure sensors. Although the sensors themselves are common to both systems, separate relay contact sets are used for each subsystem. Redundant sensors are provided for each of the functions and together with their associated relays are arranged to provide adequate overall redundancy. The calculated composite availability for the reactor vessel low-low water level sensors in combination with reactor low pressure sensors and the drywell high pressure sensor arrays are 0.99998 and 0.99958 respectively. Due to the high level of redundancy and the low component failure rates involved, this portion of the control logic makes a very small contribution to ECCS unavailability.

Both the core spray and LPCI subsystems require reactor pressure permissive inputs to open injection valves when reactor pressure has decreased to approximately 325 psig. Two reactor pressure sensors in parallel provide a common input to both systems with complete electrical separation by use of separate switches in the sensors themselves. Calculated availability for this parallel sensor array is 0.99988.

Once reactor pressure has decreased to approximately 325 psig, successful core cooling can be achieved in a number of ways depending on availability of normal auxiliary power, power from the unit diesel generator and/or power from the 1/2 diesel generator. These success paths are shown on the right side of Figure 6.3-39 and are discussed by power source in the following paragraphs.

When normal auxiliary power is available to the 4160-V emergency buses both of the pumps in the core spray subsystem and all four of the RHR pumps can be operated. Success is defined as either one of the two core spray pumps and associated core spray subsystem components or three out of four of the RHR pumps and associated LPCI subsystem components. Availability of normal auxiliary power is 0.999 as stated previously and the computer program logic statements recognize that this is the same block as used with the feedwater system. There is common start logic for both core spray divisions with a calculated availability of 0.99999. Calculated availability for a core spray pump is 0.9928 and calculated availability for the remainder of the division associated

with that pump, i.e., valves, piping and control components, is 0.981. Similarly, calculated availability is 0.99999 for the LPCI normal start logic and 0.925 for the remainder of the components in the LPCI subsystem where three out of the four RHR pumps must run and water must be injected into an undamaged recirculation system loop where the recirculation pump discharge valve is cycled closed.

When normal auxiliary power is not available and both diesel generators 1 (2) and 1/2 are used as the source of power the situation is similar to that described above except for the following added logic circuits. There is a logic circuit in the core spray subsystem that delays pumps starting until the diesel can accept a load. There is also a logic circuit for the LPCI subsystem that delays starting of the first pump then sequences the starting of one more pump on each diesel. Observed diesel generator availability of 0.99 is essentially the start probability for similar units based on the manufacturer's user field service records.

When neither normal auxiliary power nor either unit diesel generator are available and the 1/2 diesel generator is used as the source of power, success is defined as operation of core spray pump A and the associated core spray division. Since the swing diesel generator is not connected to the 4-kV emergency bus to which core spray pump B is connected, this could not be defined as a success path. Similarly, although two of the four pumps in the LPCI subsystem are connected to the 4160-volt essential service bus supplied with power from the 1/2 diesel generator and are actually started, no credit was taken for this partial success situation since the basic definition of success required that three out of four of the RHR pumps must operate. Calculated or observed block availabilities previously described were used for evaluation of this success path.

The calculated ECCS availability for this case is 0.999987. The blocks that essentially determine ECCS availability are listed in Table 6.3-15 in order of contribution to system unavailability.

As can be seen from Table 6.3-15 the blocks with low availabilities and those appearing in several success paths make the major contributions to ECCS unavailability.

When auxiliary ac power is not available the calculated ECCS availability for this case is reduced to 0.9943.

As shown in Table 6.3-16 there are also some changes in relative ranking and percent contribution to ECCS unavailability.

As before, those blocks with low availabilities and those appearing in several success paths make the major contributions to ECCS unavailability.

6.3.3.2.8.2 Large Line Break

For the purposes of this analysis, a large line break is defined as a break having a flow area greater than 0.6 ft^2. [6.3-86]

The ECCS availability model is shown in Figure 6.3-40. In this case the line break is large enough to reduce reactor pressure rapidly to the pressure where either a core spray division or the LPCI subsystem can supply the required coolant flow. Thus, only the core spray subsystem or the LPCI subsystem and an appropriate power source must function to provide the required amount of coolant to the core. Thus, the availability block diagram for this case is reduced to the upper right hand portion of Figure 6.3-39. As for the small line break case, the 125-Vdc station battery system must operate to provide control power with criteria availability of at least 0.99999. Comments regarding the function and the calculated or observed availabilities for the other blocks in this diagram are the same as for the small line break case.

The calculated ECCS availability for the large line break case is 0.99972. The blocks that essentially determine ECCS availability are listed in Table 6.3-17 in order of contribution to system unavailability.

As can be seen from Figure 6.3-40 and Table 6.3-17, the main contributors to system unavailability are the series blocks involved in all paths to success and also those blocks having low availabilities. Actually there is redundancy within the composite reactor pressure sensor block, i.e. two sensors in parallel. Also, although contributions to system unavailability are high for both the reactor pressure sensor block and the 125 Vdc battery system, ECCS unavailability is low, i.e., 1 - (0.99972) or 0.00028.

When auxiliary ac power is not available, the calculated ECCS availability is reduced to 0.99968.

6.3.3.2.9 Net Positive Suction Head Availability

The net positive suction head (NPSH) available to the pumps of the ECCS has been evaluated for the entire range of possible operating conditions including various cases with three or four RHR pumps discharging into a broken recirculation loop. It can be concluded that even for severely degraded post-design basis accident conditions, there will always be adequate NPSH for all the pumps. The original plant pipe sizing to ensure NPSH requirements was based on the General Electric process flow diagrams. These diagrams specified the flow, temperature, and pressure conditions and the required NPSH (procurement specified value). NPSH analyses are based on pump vendor certified NPSH curves and include the effects of flow from other systems in the common ring header and suction strainers. [6.3-87]

All the ECCS subsystems can be tested while the plant is operating normally. In the test mode, these subsystems take suction from either the condensate storage tank or the suppression pool. The former is never used as a heat sink and is thus never subject to high temperatures; the subsystems would not be put in the test mode during periods of high pool temperatures. Thus, adequate NPSH will always be available during routine testing of the ECCS subsystems.

Whenever the reactor core isolation cooling (RCIC) system or the HPCI subsystem is automatically activated the reactor will have been scrammed, prior to, or simultaneously with, activation. The HPCI subsystem is an emergency system and thus preaccident operating modes are not applicable to the system. The peak long-term temperature

following a LOCA subsequent to RCIC operation will result in a slightly lower peak pool temperature over the long term than from the LOCA at operating power conditions. In fact, the longer on RCIC operation prior to a LOCA, the lower the peak long term temperature of the suppression pool due to the heat removed from the pool by the RHR heat exchanger plus the increase in pool mass during RCIC operation. The peak pool temperature immediately following blowdown is less than 170°F and the long term peak pool temperature is slightly less than the peak pool temperature from the LOCA at rated power. This latter temperature is not surprising since the decay heat at the time of the accident is based on the time that the reactor was shut down and is considerably lower than if the blowdown was assumed to occur at rated power.

6.3.3.2.9.1 HPCI Pump NPSH Evaluation

The HPCI subsystem normally takes its suction from the condensate storage tank which remains cold and the available NPSH is always adequate. Suction for the HPCI pump can be switched to the suppression pool in the event the condensate storage supply is no longer available; the maximum pool temperature would be less than 140°F and, with 14.7 psia in the suppression pool, the minimum NPSH available would exceed the HPCI pump required NPSH.

The ATWS analysis performed at 2511 MWt results in a maximum pool temperature of 156°F for HPCI operation, slightly higher than during a LOCA. An NPSH evaluation for ATWS at 2511 MWt determined that the minimum NPSH available would exceed the HPCI pumps tested NPSH performance capability of 20 feet. The maximum suppression pool temperature [33] for the ATWS events at 2511 MWt is based on the Loss of Normal AC Power event. The ATWS analysis performed at 2957 MWt credits HPCI suction from the condensate storage tank in accordance with the emergency operating procedures (EOPs). Refer to Section 15.8 for a description of the ATWS events.

6.3.3.2.9.2 RHR/Core Spray Pump NPSH Evaluation (Pre-EPU)

For DBA LOCA long term cooling, assuming the temperature of the cooling water is 95°F and the temperature of the suppression pool water is 165°F, Table 6.3-18 shows how the RHR heat exchanger duty would vary with flow. Note that Case 1 of Table 6.3-18 represents the normal design case and Case 4 represents the degraded case with only one emergency diesel available. (Note: This table is for reference only.)

The peak suppression pool temperature is based on the minimum heat removal capacity of the RHR system. Namely, one RHR heat exchanger with only one RHR service water pump and one RHR pump. The RHR pump flow exiting from the heat exchanger may be injected into the containment as spray, back into the reactor vessel, or back into the suppression pool. Regardless of the choice, the same amount of heat energy would be removed and the temperature response of the pool would be the same.

The most limiting NPSH condition for both the LPCI and core spray subsystems would occur during the transient that would follow a design basis LOCA. In order to demonstrate that adequate NPSH would exist at all times, this transient was analyzed using conservative assumptions that result in a

combination of maximum fluid temperature and minimum pressure which represents the most severe condition for which adequate NPSH must be shown to exist. Refer to Section 8.3.1.6 for a description of the Standby Diesel Generator System design bases.

It was originally shown that the long-term containment pressure required to provide adequate NPSH to the LPCI and core spray pumps is at all times less than the pressure which will actually occur.

There is not enough containment pressure, however, in the short-term to prevent pump cavitation. Cavitation tests were performed on the RHR pump (the core spray pump is the same model) by the vendor at various flow rates. These tests demonstrate that the pumps can operate during the short-term without any damage to the pump internals or any degradation of pump performance. SER dated 1/4/77 for Quad Cities and Dresden accepts that damage will not occur during the short-term when cavitation can be expected.

6.3.3.2.9.3 RHR/Core Spray Pump NPSH Evaluation (Post-EPU)

Containment analysis was performed in support of extended power uprate (EPU) for a DBA-LOCA at 102% of rated thermal power, using ANS 5.1 + two sigma decay heat. The results of this analysis demonstrate adequate NPSH available at the operating RHR and core spray pumps in both the short-term (first 600 seconds) and long-term (after 600 seconds) following a DBA-LOCA. In order to demonstrate that adequate NPSH would exist at all times, the containment temperature and pressure response was modeled following a DBA-LOCA using the following conservative assumptions:

A. Offsite power is lost at the time of the accident and is not restored during the period of interest;

B. Prior to the accident, the maximum temperature of 150°F exists in the drywell together with 100% humidity and an initial suppression pool temperature of 95°F with 100% relative humidity in the atmosphere was assumed;

C. Minimum preaccident drywell and suppression chamber pressure of 1 psig and 0 psig, respectively. (There are no circumstances under which a subatmospheric pressure could exist in the drywell.);

D. Thermodynamic equilibrium exists between the liquids and gases in the drywell. Mechanistic heat and mass transfer between the suppression pool and the suppression chamber air space are modeled to minimize the suppression chamber airspace pressure and temperature;

E. A containment atmospheric leakage rate of 1% per day (at 48 psig).

F. Feedwater flow into the vessel continues until all hot feedwater, which maximizes the suppression pool temperature, is injected into the vessel;

G. All core spray and RHR pumps have 100% of their horsepower converted to a pump heat input, which is added either to the vessel liquid or suppression pool water after the first 10 minutes;

H. The RHR heat exchanger is at its design fouling factor condition with the maximum number of allowed tubes plugged, and the RHR service water temperature remains at its maximum possible value of 95°F through out the transient;

The short term (first 600 seconds) pressure and temperature response of the containment was modeled assuming operation of both core spray pumps and all four RHR pumps with a single failure of LPCI loop select logic resulting in LPCI flow directly into the drywell from the broken recirculation loop. The long-term (after 600 seconds) pressure and temperature response was modeled assuming operation of one RHR and one core spray pump as a result of the limiting single failure of an emergency diesel generator (EDG). These containment analyses determined minimum containment pressure present in the suppression chamber air space for these bounding cases and support the use of the following credited containment pressure values used in the RHR and core spray NPSH analyses:

From (seconds)	To (Seconds)	Credited Containment Pressure (psig)
0	290	8.0
290	5,000	4.8
5,000	44,500	6.7
44,500	52,500	6.0
52,500	60,500	5.5
60,500	75,000	4.7
75,000	95,000	3.8
95,000	115,000	3.0
115,000	155,000	2.3
155,000	Accident End	1.8

These values for credited containment pressure in the RHR and core spray NPSH analyses were evaluated by the NRC and approved in the SER for Amendment 202 to Operating License DPR-29 and Amendment 198 to Operating License DPR-30.

Figure 6.3-42A shows the results of evaluations of the short-term containment parameters and NPSH available to the unthrottled RHR and core spray pumps following a DBA-LOCA with a failure of the LPCI loop select logic that causes all four RHR pumps to inject into the broken reactor recirculation line. As shown in Figure 6.3-42A, sufficient containment pressure is available during the first 290 seconds to provide adequate NPSH for the RHR and core spray pumps; however, pump cavitation may occur for a short-time after 290 seconds until operators throttle the RHR and core spray systems to restore NPSH. While the pumps may cavitate during this time period, they will continue to provide sufficient flow to the vessel, as described below, to ensure core flood up. As described previously, cavitation tests have been performed on the RHR pump, which is the same model as the core spray pump, and these tests demonstrated that the pumps can cavitate in the short-term without any damage to pump internals or any degradation in pump performance.

The required core spray pump flow rate at Quad Cities to cool the core at 2957 MWt operation for the LPCI loop select logic failure case, which is equivalent to the LPCI injection valve single failure case in 10 CFR 50.46 PCT analyses (Reference 55, Figures A-2c and B-2c), is 5,650 gpm[56] for 4 minutes. A pump flow rate to be evaluated for NPSH purposes is the flow measured at the pump, from which all of the minimum flow and leakage flow rates are subtracted to determine the gpm delivered to the top of the core in the 10 CFR 50.46 analysis. This pump flow rate or the core reflooded to the top of active fuel will meet the post-LOCA long term (post-PCT) cooling requirements applicable to all fuel types as described in Section 6.3.3.1.1.

Figure 6.3-41A shows the results of the bounding evaluations for the long-term containment parameters and NPSH available to the throttled RHR and core spray pumps following a DBA-LOCA with an assumed single failure of an EDG. This single failure is assumed for the long-term scenario, because it results in the maximum long-term suppression pool temperature response and the maximum NPSH required for the RHR and core spray pumps. It can be seen from Figure 6.3-41A that sufficient containment pressure is available during this bounding case to ensure adequate NPSH is available at the pumps.

6.3.4 Tests and Inspections

6.3.4.1 Core Spray Subsystem

Provisions have been designed into the core spray subsystem to test the performance of its various components. These provisions and tests are summarized as follows: [6.3-91]

A. Instrumentation

Operational test of entire system.
Periodic system tests using test lines.

B. Valves

Preoperational test of entire system.
Periodic system tests using test lines.

Motor-operated valves are exercised independently, and valves receiving automatic signals are stroke timed periodically.

C. Pumps

Preoperational test of entire system.
Periodic system tests using test lines.
Pump seal leakage is monitored.
Periodic pump vibration data are taken.

D. Spray Sparger

Preoperational test of entire system.

E. Spray Nozzles

Preoperational test of entire system.

F. Relief Valves

Relief valves can be removed and tested for setpoints.

G. Screens

Preoperational test of entire system.
Periodic system tests using test lines.
Pressure indicator on pump suction during above tests.

Each core spray division is tested individually during reactor operation as follows:

A. The pump of the division under test is started by its manual control switch. The test bypass valve is opened to allow the pump to be tested at full flow. Flow and pressure instrumentation is observed for correct response and the system outside the drywell is checked for leaks.

B. The injection valves are tested independently of the pump and flow test as follows:

   1. The normally open maintenance valve upstream of the normally closed injection valve is closed by the control switch. Limit switches on the maintenance valve act as a permissive to open the injection valve which may then be exercised opened and closed by manual actuation of the control switch.

   2. At the end of the test, with the injection valve fully closed, the maintenance valve must be reopened.

In the event that a reactor low-low water level and low reactor pressure, or high drywell pressure actuation signal occurs during a division test, the other division not under test would start automatically.

The pressure differential between each division spray header inside the vessel will be monitored during power operation. Changes in these pressure readings would provide indication of loss of integrity of piping within the reactor vessel. In addition, pipes, pumps, valves, and other working components outside of the primary containment can be visually inspected at any time.

6.3.4.2 Low Pressure Coolant Injection Subsystem

To assure that the LPCI subsystem would function properly, if required, specific provisions are made for testing the operability and performance of the several components of the system. Testing is done periodically. In addition, surveillance features provide continuous monitoring of the integrity of vital portions of the system. [6.3-92]

Testing the sequencing of the LPCI mode of operation and testing operation of the system valves is performed per Technical Specifications.

A design flow functional test of the RHR pumps is performed for each pair of pumps during normal plant operation by taking suction from the suppression pool and discharging through test lines back to the suppression pool. During this functional test, vibration data are recorded for each RHR pump. This enables plant personnel to monitor pump wear and maintain the pumps in proper operating condition.

The discharge valves to the reactor recirculation loops remain closed during this test and reactor operation is undisturbed. An operational test of the discharge valves is performed by shutting the downstream valve after it has been satisfactorily tested and then operating the upstream valve. All these valves can be actuated from the control room using remote manual switches.

The RHR pumps, pump motors, and heat exchangers are periodically inspected in accordance with the manufacturer's recommendations.

6.3.4.3 High Pressure Coolant Injection Subsystem

To assure that the HPCI subsystem will function properly if it is needed, specific provisions are made for testing the operability and performance of the various parts of the subsystem. This testing is done at a frequency that will assure availability of the subsystem. In addition, surveillance features provide continuous monitoring of vital portions of the subsystem. [6.3-93]

The following sections detail the testing and surveillance that have been and can be accomplished during the different modes of operation of the plant.

6.3.4.3.1 Prior to Full-Power Operation

A. When sufficient steam was available from the reactor to drive the HPCI turbine at its rated speed, the system was activated to assure operation of all components at this rated condition.

B. Suction was first taken from the contaminated condensate storage tank and pumped through the complete HPCI system to the reactor. Suction was then taken from the suppression chamber, pumped through the system and returned to the suppression chamber by way of the test return line.

C. Flow, bearing temperatures, and differential pressure measurements were taken during this power test to verify design conditions and to establish reference points for comparison to data from subsequent tests.

D. Taking suction from both the contaminated condensate storage tank and the suppression chamber during the test at rated conditions verified that water from either source is available as needed.

6.3.4.3.2 Subsystem Testing with Unit Operating or at Hot Standby

A. A test of the subsystem up to the isolation valve is conducted with steam from the reactor vessel. The steam admission valve is opened, driving the turbine-pump unit at its rated output. The valves from the suppression chamber and to the feedwater line remain closed and water is pumped from the condensate storage tank, through the subsystem, and returned to the condensate storage tank by way of the test line. Vibration data are recorded periodically when the subsystem is running at rated flow. Trending this information gives an indication of possible pump wear or failure.

B. A periodic testing program is carried out to stroke time all valves that receive an automatic signal during initiation or isolation.

6.3.4.3.3 Pump Testing

The pump may be tested at full flow at any time except when reactor water level is low, the contaminated condensate storage tank water level is low or the pressure suppression suction valves are not closed. The pump testing procedure is as follows:

A. The pump suction valve from the contaminated condensate storage tank and the minimum flow bypass valve to the suppression chamber are opened.

B. The turbine steam supply valve is opened with the remote manual switch to start the pump and establish minimum flow.

C. The test bypass valve is then opened to establish full rated flow from the pump through the bypass line to the condensate storage tank.

D. With the pump off and the HPCI pump discharge valve closed, the HPCI discharge valve may be tested by stroking open and closed with the remote manual switch.

6.3.4.3.4 Reactor Low-Low Water Level Simultaneous With Test

In the event of a HPCI initiation signal when the system is being tested, HPCI equipment will automatically return to the automatic startup configuration, with the exception of the steam supply and vacuum breaker containment isolation valves. These valves will not open automatically, if they have been closed. This design limitation is consistent with NRC NUREG-0737 guidelines for containment isolation logic (Section II.E.4.2). [6.3-94]

6.3.4.4 Automatic Depressurization Subsystem

Testing and inspection requirements for the ADS subsystem are covered in Section 5.2.2.10.

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Table 6.3-1

SUMMARY OF THE OPERATING MODES OF THE EMERGENCY CORE COOLING SUBSYSTEMS

1. Small Line Break Only (Normal Auxiliary Power Available)

Design Provisions*

Feedwater System	or	High Pressure Coolant Injection Subsystem,
	or	ADS plus Core Spray Subsystem or Low Pressure Coolant Injection Mode of the RHR System

2. Small Line Break Only (Normal Auxiliary Power Unavailable - Standby Diesels Available)

Design Provisions*

High Pressure Coolant Injection Subsystem	or	ADS plus Core Spray Subsystem or Low Pressure Coolant Injection Mode of the RHR System

3. Large Line Break Only (With or Without Normal Auxiliary Power Available - Standby Diesels Available)

Design Provisions*

Either Core Spray Subsystem	and	Low Pressure Coolant Injection Mode of the RHR System (2 LPCI pumps)

4. Post Accident Recovery (Long Term)

Design Provisions*

Standby Coolant Supply System	or	Core Spray and RHR or Two Core Spray Pumps.

Sensible heat is removed from the primary containment by operation of the containment cooling mode of the RHR system.

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* Available alternate systems, any one of which will provide the necessary cooling function.

Table 6.3-2

EMERGENCY CORE COOLING SYSTEM

Function	Number of Pumps	Design Coolant Flow	Effluent Pressure Range	Required Electrical Power	Additional Backup Systems
Core spray	2	See Table 6.3-3D and 6.3-3E* for input parameters to the accident analysis and Table 6.3-4 for Core Spray Equipment and specifications.		Normal auxiliary power or standby diesel generator	2nd core spray subsystem or LPCI subsystem
LPCI	4	See Table 6.3-3D and 6.3-3E* for input parameters to the accident analysis and Table 6.3-5 for RHR(LPCI) design parameters.		Normal auxiliary power or standby diesel generator	Either core spray subsystem
HPCI	1	See Table 6.3-3D and 6.3-3E* for input parameters to the accident analysis and Table 6.3-6 for HPCI Equipment specifications.		dc power from 125 and 250 volt station batteries and normal auxiliary power or standby diesel generator	ADS plus core spray or LPCI subsystem

*Parameters in Table 6.3-3E are used in Quad Cities Unit 1 AREVA LOCA Analysis for ATRIUM 10XM Fuel.

TABLE 6.3-3C

(Historical Information)

PLANT PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

Plant Parameters	Nominal	Appendix K
Core thermal Power(1) (MWt)	2957	3016
Corresponding Power (% of 2957 MWt)	100	102
Vessel Steam Output (lbm/hr)	11.71×10^6	11.97×10^6
Rated Core Flow (lbm/hr)(2)	98×10^6	98×10^6
Vessel Steam Dome Pressure (psia)	1020	1020
Maximum Recirculation Suction Line Break Area (ft^2)	4.281(3)	4.281(3)

TABLE 6.3-3C

(Historical Information)

PDLB ECCS PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

1. Low Pressure Coolant Injection (LPCI) System

Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid	250
b. Minimum flow with minimum flow bypass valve open		
• Vessel pressure at which below listed flow rates are quoted	psid (vessel to drywell)	20
• 2 LPCI pumps injecting into the lower plenum	gpm	7690
• 4 LPCI pumps injecting into the lower plenum	gpm	12190
d. Initiating Signals		
• Low-low water level	inches	444
Or		
• High drywell pressure	yes/no	yes(4)
e. Vessel pressure at which injection valve may open	psid	300
f. Time from initiating signal (Item 1.d) to system capable of delivering full flow (power available, pump at rated speed, injection valve fully open, and discharge valve closed)	sec	68
g. Injection valve stroke time-opening(5)	sec	30
h. Recirculation discharge valve stroke time-closing(6)	sec	48
i. Minimum detectable break size	ft^2	0.15

TABLE 6.3-3C

(Historical Information)

PDLB ECCS PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

2. Core Spray (CS) System

Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	314
b. Minimum flow with min. flow valve open		
• Vessel pressure at which below listed flow rate is quoted	psid (vessel to drywell)	90
• Minimum flow to upper plenum	gpm	3850
c. Minimum flow to upper plenum at 0 psid with min. flow valve open	gpm	4740
d. Initiating Signals		
• Low-low water level	inches (above vessel zero)	444
Or		
• High dry well pressure	yes/no	yes(4)
e. Vessel pressure at which injection valve may open	psid	300
f. Injection valve stroke time-opening(7)	sec	53
g. Time from initiating signal (Item 2.d) to system capable of delivering full flow (power available, pump at rated speed and injection valve fully open)	sec	68

TABLE 6.3-3C

(Historical Information)

PDLB ECCS PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

3. High Pressure Coolant Injection (HPCI) System

Variable	**Units**	**Analysis Value**
a. Operating vessel pressure range		
• Minimum pressure	psia	165
• Maximum pressure	psia	1,135
b. Minimum flow required over the entire pressure range	gpm	4400
c. Maximum vessel pressure at which pump can inject flow	psia	1,135
d. Initiating Signals		
• Low-low water level	inches (above vessel zero)	444
Or		
• High drywell pressure	yes/no	yes(4)
e. Maximum allowable time delay from initiating signal (Item 3.d) to system capable of delivering full flow (pump at rated speed and injection valve fully open)	sec	48

TABLE 6.3-3C

(Historical Information)

PDLB ECCS PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

4. **Automatic Depressurization System (ADS)**

Variable	**Units**	**Analysis Value**
a. Number of ADS valves		
• Total number of relief valves with ADS function		5
• Total number of relief valves with ADS function assumed available in the analysis		5
b. Pressure at which below listed capacity is quoted	psid	1,135
c. Minimum flow capacity for one ADS valve	1lb/hr	540,000
d. Initiating Signals		
• Low-low water level	Inches (above vessel zero)	444
and		
• ADS Timer Delay – maximum	sec	121.85

(1) The core thermal power corresponds to 117% of the pre-LPU value of 2527 MWt.
(2) Rated core flow. The limiting LOCA cases were analyzed for a core flow range of 95% to 108% of rated core flow.
(3) Includes area of bottom head drain.
(4) SAFER does not model the drywell pressure, so the drywell pressure is not actually used in the analysis. However, the modeling assumes that the setpoint is reached at the start of the event.
(5) The analysis assumes no LPCI flow until the injection valve is fully open.
(6) The analysis assumes no LPCI flow until the discharge valve is fully closed.
(7) The analysis takes credit for core spray flow with the valve partially open after the pump is at rated speed.

TABLE 6.3-3D [2]

PLANT PARAMETERS USED IN
QUAD CITIES LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 AT 2957 MWt

A. PLANT PARAMETERS (APPENDIX K)		
Variable	**Units**	**Analysis Value**
Core Thermal Power	MWt	3016
% of Rated Core Thermal Power	%	102
Vessel Steam Output	Mlbm/hr	11.95
% of Rated Steam Output	%	102
Core Flow	Mlbm/hr	93.39 – 105.84
% of Rated Core Flow	%	95.3 – 108
Vessel Steam Dome Pressure	psia	1020
Maximum Recirculation Line Break Area	ft^2	3.62 [1]

(1) Pump suction leg pipe area. Bottom head leakage area handled separately.
(2) Table 6.3-3D represents plant parameters utilized in the MAPLHGR analysis performed with the methodology of Reference 66. MAPLHGR analysis for some fuel in the core has been performed with the plant parameters of Reference 80.

TABLE 6.3-3D

PLANT PARAMETERS USED IN
QUAD CITIES LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 AT 2957 MWt

B. EMERGENCY CORE COOLING SYSTEM PARAMETERS		
Low Pressure Coolant Injection System		
Variable	**Units**	**Analysis Value**
System Pressure – Flow Delivery (2 pumps injecting into recirculation loop discharge piping)	gpm/psid	0 / 257 6200 / 150 9000 / 20 9300 / 0
System Pressure – Flow Delivery (4 pumps injecting into recirculation loop discharge piping)	gpm/psid	0 / 257 10200 / 150 15200 / 20 15700 / 0
Maximum Reduction in LPCI due to Minimum Flow Bypass (2 pumps)	gpm	440 (1)
Initiating Signals		
Low-Low Water Level AND Low Reactor Vessel Pressure OR	inch/psig	444 (2) / 300
High Drywell Pressure OR	psig	2.5
Low-Low Water Level AND Time Delay	inch/sec	444 / 540
Reactor Vessel Pressure at Which Injection Valve May Open	psig	300
Injection Valve Stroke Time	sec	28
Recirculation Discharge Valve Stroke Time	sec	48 (3)
Minimum Break Size for Which Loop Selection Logic Assumed to Select Intact Loop	ft^2	0.15
Time for Diesel Generator Output Closure	sec	17
Time to Load Pump A	sec	0
Time to Load Pump B	sec	7
Time for Pump to Reach Rated Speed	sec	7

(1) Minimum flow bypass isolation valve assumed to remain open
(2) Above vessel zero
(3) After closure pressure permissive for loop selection for single or no loop operation (860 – 900 psig) and time delay for loop selection (5.25 sec)

TABLE 6.3-3D

PLANT PARAMETERS USED IN
QUAD CITIES LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 AT 2957 MWt

B. EMERGENCY CORE COOLING SYSTEM PARAMETERS (Continued)		
Core Spray System		
Variable	**Units**	**Analysis Value**
System Pressure – Flow Delivery	gpm / psid	0 / 325 3000 / 200 4500 / 90 5650 / 0
Maximum Reduction in CS Due to Minimum Flow Bypass	gpm	244
Maximum Core Spray Delivery to Initiate Isolation of Minimum Flow Bypass	gpm	874
Maximum Stroke Time for Minimum Flow Bypass Isolation Valve	sec	32
Initiating Signals		
Low-Low Water Level AND Low Reactor Vessel Pressure OR	inch / psig	444 / 300
High Drywell Pressure OR	psig	2.5
Low-Low Water Level AND Time Delay	inch / sec	444 / 540
Reactor Vessel Pressure at Which Injection Valve May Open	psig	300
Injection Valve Stroke Time	sec	53
Time for Diesel Generator Output Closure	sec	17
Time to Load Pump	sec	12
Time for Pump to Reach Rated Speed	sec	5

TABLE 6.3-3D

PLANT PARAMETERS USED IN
QUAD CITIES LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 AT 2957 MWt

B. EMERGENCY CORE COOLING SYSTEM PARAMETERS (Continued)		
High Pressure Coolant Injection System		
Variable	**Units**	**Analysis Value**
Operating Reactor Vessel Pressure Range	psid	150 – 1120
Minimum Rated Flow Over Range	gpm	5000
Initiating Signals		
Low-Low Water Level OR	inch	444
High Drywell Pressure	psig	2.5
Maximum Time Delay from Initiating Signal to Rated Flow Available and Injection Valve Full Open	sec	55
Automatic Depressurization System		
Total Number of Valves Installed	--	5
Number of Valves Used in Analysis	--	5
Valve Capacity		
4 Relief Valves (each)	Mlb/hr	0.546840 at 1120 psig
1 Safety / Relief Valve	Mlb/hr	0.598 at 1080 psig
Initiating Signals		
Low-Low Water Level AND	inch	444
High Drywell Pressure AND	psig	2.5
Timer 1 Delay AND	sec	120
Low Pressure ECCS Pump Running OR		
Low-Low Water Level AND	inch	444
Timer 2 Delay AND	sec	540
Low Pressure ECCS Pump Running		
ADS Reclose Pressure	psig	50
Valve Opening Time	sec	0.4
Valve Closing Time	sec	10

Table 6.3-3E

PLANT PARAMETERS USED IN
QUAD CITIES UNIT 1 AREVA LOCA ANALYSIS
FOR ATRIUM 10XM FUEL AT 2957 MWt

A. PLANT PARAMETERS (APPENDIX K)		
	Units	**Analysis Value**
Core Thermal Power	MWt	3016.14
% of Rated Thermal Power	%	102
Vessel Steam Output	Mlbm/hr	11.98
% Vessel Steam Output	%	102
Core Flow	Mlbm/hr	93.4 – 105.8
% of Rated Core Flow	%	95.3 – 108
Vessel Steam Dome Pressure	psia	1020
Maximum Recirculation Line Break Area (Suction Pipe Area)	ft^2	3.581
B. EMERGENCY CORE COOLING SYSTEM PARAMETERS		
Low Pressure Coolant Injection System		
System Pressure – Flow Delivery (2 pumps injecting into recirculating discharge piping)	gpm/psid	0 / 257 6200 / 150 9000 / 20 9300 / 0
System Pressure – Flow Delivery (4 pumps injecting into recirculating discharge piping)	gpm/psid	0 / 257 10200 / 150 15200 / 20 15700 / 0
Initiating Signals		
Low-Low Water Level AND Low Reactor Vessel Pressure OR	inch/psig	444** / 300
High Drywell Pressure OR	psig	2.5
Low-Low Water Level AND Time Delay	inch/sec	444 / 540
Reactor Vessel Pressure at Which Injection Valve May Open	psig	300
Injection Valve Stroke Time	sec	28
Recirculation Discharge Valve Stroke Time	sec	48*
Minimum Break Size for Which Loop Selection Logic Assumed to Select Intact Loop	ft^2	0.15
Time for Diesel Generator Output Closure	sec	17
Swing Bus Transfer Time	sec	26
Time to Load Pump A	sec	0
Time to Load Pump B	sec	7
Time for Pump to Reach Rated Speed	sec	7

* After closure pressure permissive for loop selection for single or no loop operation (860 – 900 psig) and time delay for loop selection (5.25 sec)

** Above vessel zero

Table 6.3-3E

Low Pressure Core Spray System	**Units**	**Analysis Value**
System Pressure – Flow Delivery	gpm/psid	0 / 325 3000 / 200 4500 / 90 5650 / 0
Maximum Reduction in LPCS Due to Minimum Flow Bypass	gpm	244
Maximum Core Spray Delivery to Initiate Isolation of Minimum Flow Bypass	gpm	874
Maximum Stroke Time for Minimum Flow Bypass Isolation Valve	sec	32
Initiating Signals		
Low-Low Water Level AND Low Reactor Vessel Pressure OR	inch/psig	444 / 300
High Drywell Pressure OR	psig	2.5
Low-Low Water Level AND Time Delay	inch/sec	444 / 540
Reactor Vessel at Which Injection Valve May Open	psig	300
Injection Valve Stroke Time	sec	53
Time for Diesel Generator Output Closure	sec	17
Time to Load Pump	sec	12
Time for Pump to Reach Rated Speed	sec	5
High Pressure Coolant Injection System		
Operating Pressure Range	psid	150 – 1120
Minimum Rated Flow Over Range	gpm	5000
Initiating Signals		
Low-Low Water Level OR	inch	444
High Drywell Pressure	psig	2.5
Maximum Time Delay from Initiating Signal to Rated Flow Available and Injection Valve Full Open	sec	55
Automatic Depressurization System		
Total Number of Valves Installed	--	5
Number of Valves Used in Analysis	--	5
Valve Capacity		
4 Relief Valves (each)	Mlbm/hr	0.558 at 1120 psig
1 Safety / Relief Valve	Mlbm/hr	0.598 at 1080 psig
Initiating Signals		
Low-Low Level AND	inch	444
High Drywell Pressure AND	psig	2.5
Timer 1 Delay AND	sec	120
Low Pressure ECCS Pump Running with Sufficient Discharge Pressure OR		
Low-Low Water Level AND	inch	444
Timer 2 Delay AND	sec	540
Low Pressure ECCS Pump Running with Sufficient Discharge Pressure		

Table 6.3-4

CORE SPRAY EQUIPMENT SPECIFICATIONS

PUMPS	
Number	2 (Appendix K methods were applied for single failure. Either 2 CS or 1 CS & 2 LPCI is required to meet 50.46 criterion)*
Type	single stage — vertical — centrifugal
Speed	3600 rpm
Seals	mechanical
Drive	electric motor
Power source	normal auxiliary or standby diesel generator
Pump casing	cast steel
Impeller	stainless steel
Shaft	stainless steel
Code	ASME Section III C
Flow	4500 gal/min at system head corresponding to 90 psig reactor pressure
Head	see Figure 6.3-3
Power	850 hp @ rated conditions**
NPSH	36 feet
SPRAY HEADERS	
Number	2
Number of flow tubes	64 per header @ alternating pattern
Number of nozzles	66 per header @ alternating pattern
Type of nozzles	1-inch Fulljet — stainless steel
PIPING	
Code	USAS B31.1

* These are the parameters used in the original Quad Cities LOCA analysis. The integrated ECCS performance LOCA analysis required by Appendix K is discussed in Section 6.3.3.2 (SAFER/GESTR). The input parameters to the SAFER/GESTR analysis are provided in Table 6.3-3.

** Nameplate rating is 800 hp with a 1.15 service factor.

Table 6.3-5

RHR PUMP DESIGN PARAMETERS

NUMBER	4 (2 required to meet design basis)
TYPE	Single stage-vertical-centrifugal
Seals	Mechanical
Drive	Electric Motor
Power source	Normal auxiliary or standby diesel generator
Speed	3600 rpm
Pump casing	Cast steel
Impeller	Stainless steel
Shaft	Stainless steel
Code	ASME Section IIIC
PERFORMANCE CHARACTERISTICS	2 pumps running
20 psig above suppression	
chamber pressure	
Flow	4500 gal/min — 9000 gal/min total
Head	400 feet*
Power	600 hp each
NPSH (required)	28 ft.

* Approximately 230 feet is required for pump operability in the LPCI mode (Calculation QDC-1000-M-0587)

Table 6.3-6

HPCI EQUIPMENT SPECIFICATIONS

Turbine

Reactor Pressure (sat. temp)	1135 to 165 psia
Steam Pressure Inlet	1125 to 155 psia
Exhaust (maximum)	65 psia
Steam Temperature	558°F to 360°F
Speed	4000 to 2250 rpm
Power	5000 to 1000 hp
Number stages	2
Emergency starting	45 seconds
Steam Flow	145,000 to 102,500 lb/hr

Pump

Number	1 main - 1 booster
Type (main) (booster)	multi-stage, horizontal, centrifugal single-stage, horizontal, centrifugal, gear driven
Developed Head	2800 ft at 1135 psia rx press 525 ft at 165 psia rx press with a minimum NPSH of 25 ft
Flow	5600 gpm constant
NPSH (min.)	25 ft

Control Power 250/125 Vd-c

Table 6.3-7A
(Historical Information)

QUAD CITIES 1 & 2 SINGLE-FAILURE EVALUATION
FOR GE FUEL AT 2511 MWt ONLY

Assumed Failure*	Recirculation Suction or Discharge Break Systems Remaining**
Battery‡	ADS‡‡, 1 core spray, 2 LPCI (2 into 1 loop)
LPCI injection valve	ADS, HPCI, 2 core spray
Diesel generator^	ADS, HPCI, 1 core spray, 2 LPCI (2 into 1 loop)
HPCI^	ADS, 2 core spray, 4 LPCI (4 into 1 loop)
One ADS Value	(3) ADS##, HPCI, 2 core spray, 4 LPCI (4 into 1 loop)

* Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above assumed failures.

** Systems remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS in which the break is assumed.

‡ Battery failure case assumes two failures (i.e., battery and HPCI). The extra HPCI failure was assumed to facilitate comparisons with the battery failure case in the BWR 3/4 generic analysis.

‡‡ All analyses performed with one non-functioning ADS valve in addition to the single failure. See Table 6.3-3A.

^ This single failure is not specifically analyzed because it is bounded by the battery failure from the ECCS viewpoint.

A single failure of one ADS valve along with one non-functioning ADS valve will result in greater ECCS capacity than the more limiting battery or LPCI injection valve single failures. Therefore, ADS single failure was not analyzed as described in the above footnote*.

Table 6.3-7B
(Historical Information)

QUAD CITIES 1 & 2 SINGLE-FAILURE EVALUATION
FOR SIEMENS FUEL AT 2511 MWt ONLY

Assumed Failure	ECCS System Available			
LPCI Injection Valve (SF-LPCI)		2 LPCS	HPCI*	ADS (4 Valves)**
Diesel Generator (SF-DG)	2 LPCI	1 LPCS	HPCI*	ADS (4 Valves)**
HPCI System (SF-HPCI/DG)	4 LPCI	2 LPCS		ADS (4 Valves)**
One ADS Valve (SF-ADS)	4 LPCI	2 LPCS	HPCI*	ADS (3 Valves)**

* No credit is assumed for HPCI operation in the recirculation piping large break analyses; however, credit for HPCI was assumed in the small break analyses described in the break spectrum analysis report.

** The Quad Cities ADS has five valves. One valve is assumed inoperable to support relief valve out-of-service operation (RVOOS). SF-ADS analyses assume failure of one additional valve.

Table 6.3-7C

(Historical Information)

SINGLE FAILURE EVALUATION USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

Assumed Failure(1)	**Systems Remaining**(2)(3)
Diesel Generator (D/G) or 125-VDC Battery	5 ADS, 1 CS, HPCI, 2 LPCI(4)
LPCI Injection Valve (LPCI IV)	5 ADS, 2 CS, HPCI
HPCI	5 ADS, 2 CS, 4 LPCI
ADS	4 ADS, 2 CS, 4 LPCI, HPCI

(1) Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the assumed failures.

(2) Systems, remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS system in which the break is assumed.

(3) The small break analyses were performed with all ADS valves assumed operable except for when the ADS valve was the single failure.

(4) The D/G failure is analyzed with and without HPCI, although there is no single failure in Dresden/Quad Cities that will fail both the D/G and HPCI. The D/G failure without HPCI has the same systems available as the battery failure in the generic analysis. The large break analysis does not take credit for HPCI, but the small break analysis does not permit a D/G failure without HPCI.

TABLE 6.3-7D

SINGLE FAILURE EVALUATION USED IN
QUAD CITIES LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 FUEL AT 2957 MWt

Assumed Failure [1]	**Systems Remaining** [2]
LPCI Injection Valve	2 LPCS, HPCI, 5 ADS
Diesel Generator or 125-VDC	1 LPCS, 2 LPCI, HPCI, 5 ADS
HPCI	2 LPCS, 4 LPCI, 5 ADS
Loop Select Logic	2 LPCS, 4 LPCI, HPCI, 5 ADS
ADS	2 LPCS, 4 LPCI, HPCI, 4 ADS

1. Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the assumed failures.
2. Systems remaining as identified in this table are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed less the ECCS system in which the break is assumed.

Table 6.3-7E

SINGLE-FAILURE EVALUATION USED IN THE AREVA
QUAD CITIES UNIT 1 LOCA ANALYSIS
FOR ATRIUM 10XM FUEL AT 2957 MWT

Assumed Failure	Systems Remaining[1,2]
LPCI injection valve (SF-LPCI)	2 LPCS + HPCI + 5 ADS
Diesel generator or 125-VDC (SF-DGEN)	1 LPCS + 2 LPCI + HPCI + 5 ADS
HPCI system (SF-HPCI)	2 LPCS + 4 LPCI + 5 ADS
Loop select logic (SF-LSL)	2 LPCS + 4 LPCI + HPCI + 5 ADS
ADS valve (SF-ADS)	2 LPCS + 4 LPCI + HPCI + 4 ADS

[1] Systems remaining, as identified in this table for recirculation line breaks, are applicable to all non- ECCS line breaks. For an ECCS line break, in most cases the systems remaining are those listed less the ECCS system in which the break is assumed. The exception is in the evaluation of small LPCI line breaks. For the evaluation of small LPCI line breaks when the loop selection logic is not able to determine the intact loop, flow through the LPCI injection valve in the broken LPCI line is credited.

[2] With loop selection logic operational, all available LPCI flow is directed to the intact loop for breaks ≥ 0.15 ft^2. All available LPCI flow is directed to the broken loop for breaks < 0.15 ft^2. The limiting condition for a loop selection logic failure would result in all available LPCI flow directed to the broken loop for all break sizes.

Table 6.3-9A
(Historical Information)
SUMMARY OF QUAD CITIES UNIT 1 AND UNIT 2 SPECIFIC BREAK SPECTRUM RESULTS FOR GE FUEL AT 2511 MWt ONLY
(Recirculation Suction Line Break)

		P8X8R		GE8X8EB	
Break Size	Single Failure	1st PCT(°F)	2nd PCT(°F)	1st PCT (°F)	2nd PCT(°F)
NOMINAL:					
DBA	Battery	781	828	692	678
DBA	LPCI/IV	781	784		
80% DBA	Battery	792	717		
60% DBA	Battery	827	632		
1.0 ft^2	Battery	885	702		
0.5 ft^2	Battery	582	548		
0.1 ft^2	Battery	769	825		
0.05 ft^2	Battery	658	701		
APPENDIX K:					
DBA	Battery	1210	1377	967	1343
DBA	LPCI IV	1210	1367		
80% DBA	Battery	1087	1302		
60% DBA	Battery	928	1160		
1.0 ft^2	Battery	903	1057		
0.1 ft^2	Battery	870	900		

Note: (1) 1st PCT is the PCT before ECC systems inject and 2nd PCT is the PCT after ECC systems inject.
(2) Peak local oxidation < 0.3% for all cases.
(3) Core-wide metal water reaction < 0.1% for all cases.
(4) The PCT results here from NEDC-31345 for all break sizes analyzed determined the limiting event for Quad Cities 1 and 2. These PCTs do not represent the current licensing basis LOCA PCT, but were used to define the limiting single failure and break size combination. See section 6.3.3.2.2.2 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

Table 6.3-9B
(Historical Information)

SUMMARY OF QUAD CITIES UNIT 1 AND UNIT 2 SPECIFIC BREAK SPECTRUM RESULTS FOR SPC FUEL AT 2511 MWt ONLY*
(Recirculation Line Break)

Fuel Type: ATRIUM-9B

Break Size	Break Location	Break Type**	Single Failure	PCT(°F)
DBA	Suction	DEG	LPCI	1884
	Suction	DEG	DG	1719
	Discharge	DEG	LPCI	1687
	Discharge	DEG	DG	1722
	Suction	DES	LPCI	1875
	Discharge	DES	LPCI	1685
80% DBA	Suction	DEG	LPCI	1743
	Suction	DES	LPCI	1836
	Discharge	DEG	LPCI	1686
	Discharge	DES	LPCI	1685
60% DBA	Suction	DEG	LPCI	1650***
	Suction	DEG	DG	1525
	Suction	DES	LPCI	1689
	Discharge	DEG	LPCI	1676
	Discharge	DES	LPCI	1641
40% DBA	Suction	DEG	LPCI	1679
	Suction	DES	LPCI	1673
	Discharge	DEG	LPCI	1703
	Discharge	DES	LPCI	1686
20% DBA	Suction	DES	LPCI	1599
	Discharge	DES	LPCI	1593
	Discharge	DES	DG	1540

Table 6.3-9B
(Historical Information)

SUMMARY OF QUAD CITIES UNIT 1 AND UNIT 2 SPECIFIC BREAK SPECTRUM RESULTS FOR SPC FUEL AT 2511 MWt ONLY*
(Recirculation Line Break)

Break Size	Break Location	Single Failure	PCT(°F)
1.4 ft^2	Discharge	LPCI w/HPCI	1604
1.4 ft^2	Discharge	LPCI w/o HPCI	1593
1.0 ft^2	Discharge	LPCI w/HPCI	1646
1.0 ft^2	Discharge	LPCI w/o HPCI	1869
1.0 ft^2	Discharge	ADS w/HPCI	1422
1.0 ft^2	Discharge	ADS w/o HPCI	1663
1.0 ft^2	Discharge	HPCI	1670
1.0 ft^2	Suction	HPCI	1164
1.0 ft^2	Discharge	DG w/o HPCI	1879
1.0 ft^2	Discharge	DG w/HPCI	1674
0.5 ft^2	Discharge	LPCI w/HPCI	1720
0.5 ft^2	Discharge	LPCI w/o HPCI	1814
0.5 ft^2	Discharge	ADS w/HPCI	1494
0.5 ft^2	Discharge	ADS w/o HPCI	1632
0.5 ft^2	Discharge	HPCI	1599
0.5 ft^2	Suction	HPCI	998
0.5 ft^2	Discharge	DG w/o HPCI	1877
0.5 ft^2	Discharge	DG w/HPCI	1736
0.1 ft^2	Discharge	LPCI w/HPCI	706
0.1 ft^2	Discharge	LPCI w/o HPCI	1358
0.1 ft^2	Discharge	ADS w/HPCI	706 #
0.1 ft^2	Discharge	ADS w/o HPCI	1524 #
0.1 ft^2	Discharge	HPCI	1319 #
0.1 ft^2	Suction	HPCI	1287 #
0.05 ft^2	Discharge	ADS w/o HPCI	1579 #
0.05 ft^2	Discharge	HPCI	1002*** #

* Source EMF-96-184(P) (Reference 26) and EMF-96-185(P), Revision 4 (Reference 25)

** For DEG breaks, the discharge coefficient and full break area are used in the analyses. For split breaks (DES), size is the fraction of the twice pipe cross-section area.

*** Mid-peaked power shape results in most limiting PCT for this specific case.

\# Results from these cases below 0.15 ft^2 where LPCI is credited to inject do not include the revised LPCI loop select logic threshold as required by Improved Technical Specifications. See Section 6.3.3.1.3.2.

Table 6.3-12C

(Historical Information)

SAFER/GESTR-LOCA LICENSING RESULTS
FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

	Parameter	**SAFER/GESTR-LOCA RESULTS**			**LICENSING ACCEPTANCE CRITERIA**
1.	Limiting Break	DBA (Recirculation Suction Line)			
2.	Limiting ECCS Failure	Diesel Generator			
3.	Fuel Type	GE14	GE9/10	Atrium 9B	
4.	Peak Cladding Temperature (Licensing Basis)	<2110°F	<1840°F	<2060°F	< 2200°F
5.	Estimated Upper Bound PCT (95% Probability PCT)	<1570°F	<1540°F	<1600°F	< 1600°F
6.	Maximum Local Oxidation	<6%	<2%	<5%	< 17%
7.	Core-Wide Metal-Water Reaction	<0.1%	<0.1%	<0.1%	< 1%
8.	Coolable Geometry	Items 4 & 6			PCT < 2200°F and Local Oxidation < 17%
9.	Long-Term Cooling	Core reflooded or One core spray operating			Long-term decay heat removal

TABLE 6.3-12D

QUAD CITIES LOCA LICENSING RESULTS
WITH SVEA-96 OPTIMA2 FUEL AT 2957 MWt

	Parameter	Results	Acceptance Criteria
1	Limiting Break	DBA (Recirculation Line)	
2	Limiting ECCS Failure	LPCI Injection Valve	
3	Peak Cladding Temperature	< 2179 ˚F	< 2200 ˚F
4	Maximum Local Oxidation	< 9 %	< 17 %
5	Core-Wide Oxidation	< 0.80 %	< 1 %
6	Coolable Geometry	Items 3 and 4	PCT < 2200 ˚F and Local Oxidation < 17%
7	Long term Cooling	Core Reflooded or One Core Spray Pump Operating	Long Term Decay Heat Removal

TABLE 6.3-12E

QUAD CITIES UNIT 1 AREVA LOCA LICENSING RESULTS
WITH ATRIUM 10XM FUEL AT 2957 MWt

	Parameter	Results	Acceptance Criteria
1	Limiting Break	0.13 ft^2 Split Recirculation Discharge Line	
2	Limiting ECCS Failure	HPCI System	
3	Peak Cladding Temperature	2138 ˚F	< 2200 ˚F
4	Maximum Local Oxidation	4.11 %	< 17 %
5	Core-Wide Oxidation	< 1.0 %	< 1 %
6	Coolable Geometry	Items 3 and 4	PCT < 2200 ˚F and Local Oxidation < 17%
7	Long term Cooling	Core Reflooded to the top of active fuel or Core Reflooded to the jet pump suction elevation with One Core Spray Pump Operating	Long Term Decay Heat Removal

Table 6.3-13

ECCS SINGLE VALVE FAILURE ANALYSIS

System	Total Number of Valves at Station	Valves	Position for Normal Plant Operation		Consequences of Valve Failure Assumed Together with Design Basis LOCA
			Closed	Open	
Core spray subsystem	(4)	Suction (MO 1402-3A/B)		X	Negate use of one core spray train
	(8)	Injection (MO 1402-24A/B, 25A/B)	X	X	Negate use of one core spray train
	(4)	Test return (MO 1402-4A/B)	X		Negate use of one core spray train
	(4)	Minimum flow (MO 1402-38A/B)	X		Partial flow loss in one train
High pressure coolant injection subsystem	(2)	Condensate suction (MO 2301-6)		X	Utilize suppression pool water
	(4)	Suppression Pool Suction Valve (MO 2301-35, 36)	X		Utilize Condensate Storage Tank Water
	(4)	Injection (MO 2301-8, 9)	X	X	Negates HPCI
	(6)	Turbine Inlet (MO 2301-3, 4, 5)	X	X	Negates HPCI
	(4)	Turbine Exhaust Vacuum Breaker (MO 2399-40, 41)		X	Degrades HPCI

Table 6.3-13 (Continued)

ECCS SINGLE VALVE FAILURE ANALYSIS

System	Total Number of Valves at Station	Valves	Position for Normal Plant Operation Closed	Open	Consequences of Valve Failure Assumed Together with Design Basis LOCA
	(4)	Test Return (MO 2301-10, 15)	X		No consequences (negates HPCI if both valves fail open)
	(2)	Minimum Flow (MO 2301-14)	X		Partial loss of flow
Low pressure coolant injection subsystem	(8)	Injection (MO 1001-28A/B, 29A/B)	X	X	Negate use of LPCI
	(4)	Minimum flow (MO 1001-18A/B)		X*	Partial flow loss in one train due to flow to suppression pool
	(8)	Test return (MO 1001-34A/B, 36A/B)	X		No consequence (negates train if both valves fail open)
	(4)	Crosstie (MO 1001-19B)		X	Negate one LPCI train (two pumps per train)
	(4)	HX bypass (MO 1001-16B)		X	Reduce flow due to HX pressure drop
	(8)	Pump suction (MO 1001-7A, B, C, D)		X	Negate one out of four pumps

Table 6.3-13 (Continued)

ECCS SINGLE VALVE FAILURE ANALYSIS

System	Total Number of Valves at Station	Valves	Position for Normal Plant Operation		Consequences of Valve Failure Assumed Together with Design Basis LOCA
			Closed	Open	
ADS	(10)	Relief Valve 1(2)-0203A/B/C/D/E	X		Vessel depressurizes faster increases rate of HPCI injection

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* During injection, minimum flow valve is closed only in the selected loop.

Table 6.3-14B

(Historical Information)

SAFER/GESTR-LOCA ECCS ELECTRICAL LOADING
SEQUENCE FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

Sequence	Elapsed TIME (sec)	EVENT	Condition
1	0.0	Break Occurs	1
2	0.0	High Drywell Pressure Occurs (assumed)	
3	1.0 (not to exceed)	High Drywell Pressure Signal to start CS and LPCI and Unit 1(2) and swing Diesel Generator start signal	
4	17.0 (not to exceed)	Diesel Generator at Rated Speed and Bus Powered.	2
		Undervoltage relays reset.	
		LPCI pumps B and D time delay starts.	
		Start LPCI pumps A and C.	
		Core Spray pumps A and B time delay starts.	
		Operate AC powered valves	
5.	24.0	Start LPCI pumps B and D.	2, 3
6	31.0	Starts CS pumps A and B	2, 3
7	31.0 (not to exceed)	All LPCI Pumps at Rated Speed	2
8	36.0 (not to exceed)	All CS Pumps at Rated Speed	2

1. Initiating accident is considered to be 100% DBA suction line break and a diesel generator failure without HPCI, using Appendix K assumptions, i.e., no reliance on external sources of power. Note that with diesel generator failure, only one CS and two LPCI pumps are available.

2. Bypass flow occurs as LPCI or CS pumps start.

3. The start time for the LPCI pumps is based on the analytical limit of 31 seconds minus 7 seconds required for the pumps to reach the rated speed after started. The start time for the CS pumps is determined from the analytical limit of 36 seconds minus 5 seconds required for the pumps to reach the rated speed after started. The LPCI and CS time delays assumed in the analysis bound the Reference 65 values.

TABLE 6.3-14C

QUAD CITIES LOCA ELECTRICAL LOADING SEQUENCE
WITH SVEA-96 OPTIMA2 FUEL AT 2957 MWt

Sequence	Elapsed Time (sec)	Event	Condition
1	0.0	Break / loss of offsite power occurs	1
2	17.0	Unit and swing diesel generators started and bus powered Core spray pumps A and B time delay starts Operate AC power valves	
3	29.0	Start core spray pumps A and B Core spray minimum flow valves start to open	2
4	34.0	Spray pumps A and B at rated speed	3
5	61.0	Core spray minimum flow valve full open	4

1. Initiating accident is assumed to be a 100% DBA suction line break coincident with the loss of off site power. The limiting single failure is the failure of the LPCI injection valve to open.
2. Minimum bypass valves are assumed to be closed initially. They begin to open when the core spray pumps start.
3. Core spray pumps are assumed to reach rated speed 5 seconds after they start.
4. Core spray minimum flow valves are assumed to be full open 32 seconds after they start to open. The valves receive a close signal when core spray flow exceeds 874 gpm or the valve is full open – whichever occurs last.

TABLE 6.3-14D

QUAD CITIES UNIT 1 AREVA LOCA ECCS ELECTRICAL LOADING SEQUENCE
WITH ATRIUM 10XM FUEL AT 2957 MWt

Sequence	Elapsed Time (sec)		Event	Condition
	1.0 DEG Pump Suction SF-LPCI	0.13 ft^2 Pump Discharge SF-HPCI		
1	0.0	0.0	Break / loss of offsite power	
2	17.0	17.0	Unit and swing diesel generators started and bus powered	
3	17.0	49.5	Core spray pumps A and B load sequencing 12 sec. time delay starts	
4	29	61.5	Start core spray pumps A and B Core spray minimum flow valves start to open	
5	34	66.5	Core spray pumps at rated speed	1
6		56.5	Start first LPCI pumps A(C)	
7		63.5	First LPCI pumps A(C) at rated speed Start Second LPCI pumps B(D)	2
8		70.5	Second LPCI pumps B(D) at rated speed	2

1. Core spray pumps are assumed to reach full speed in 5 seconds after they start.
2. LPCI pumps are assumed to reach full speed 7 seconds after they start.

Note: Loading sequence information can be found in the input document used to support Reference 82.

Table 6.3-15

ECCS AVAILABILITY, SMALL BREAK WITH AUXILIARY POWER

Relative Bank	Block of Components	Block Availability	% Contribution to ECCS Unavailability
1	HPCI subsystem	0.920	35.59
2	ADS	0.920	34.38
3	LPCI subsystem	0.925	18.60
4	Core spray train I	0.981	5.06
5	Auxiliary power	0.999	3.02
6	Diesel-gen. #1 (#2)	0.99	1.73
7	Core spray pump A	0.9928	0.79
8	Diesel-gen. #1/2	0.99	0.53
9	Composite reactor pressure sensors	0.99988	0.14
10	125 Vdc station battery system	0.99999	0.15
			Total 99.94%

*Note: See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

Table 6.3-16

ECCS AVAILABILITY, SMALL BREAK WITHOUT AUXILIARY POWER

Relative Bank	Block of Components	Block Availability	% Contribution to ECCS Unavailability
1	HPCI subsystem	0.920	42.30
2	ADS	0.920	40.90
3	LPCI subsystem	0.925	13.00
4	Core spray train I	0.981	2.98
5	Core spray pump A	0.9928	0.35
6	Diesel-gen. #1 (#2)	0.99	0.34
7	Diesel-gen. #1/2	0.99	0.10
			Total 99.97%

*Note: See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

Table 6.3-17

ECCS AVAILABILITY, LARGE BREAK WITH AUXILIARY POWER

Relative Bank	Block of Components	Block Availability	% Contribution to ECCS Unavailability
1	Composite reactor pres. sensors	0.99988	43.08
2	125 Vdc station battery	0.99999	35.90
3	LPCI subsystem	0.925	14.39
4	Core spray train I	0.981	2.95
5	Core spray train II	0.981	2.79
6	Core spray pump A	0.9928	0.39
7	Core spray pump B	0.9928	0.37
8	Diesel-gen. #1 (#2)	0.99	0.06
			Total 99.93

*Note: See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

Table 6.3-18

RHR HEAT EXCHANGER DUTY VARIANCE WITH FLOW

*CASE	HEAT EXCHANGER DUTY (BTU/hr)	HOT SIDE FLOW (lb/hr)	COLD SIDE FLOW (lb/hr)
1	105×10^6	5.35×10^6	3.5×10^6
2	78×10^6	5.35×10^6	1.75×10^6
3	84×10^6	2.7×10^6	3.5×10^6
4	66×10^6	2.7×10^6	1.75×10^6

* Case 1 2 RHR pumps, 1 heat exchanger, 2 RHR SW pumps.
Case 2 2 RHR pumps, 1 heat exchanger, 1 RHR SW pump.
Case 3 1 RHR pump, 1 heat exchanger, 2 RHR SW pumps.
Case 4 1 RHR pump, 1 heat exchanger, 1 RHR SW pump.

This table is for historical information only.

Table 6.3-19B

(Historical Information)

SAFER/GESTR-LOCA EVENT SCENARIO
FOR 100% DBA SUCTION LINE BREAK
AND A DIESEL GENERATOR FAILURE WITHOUT HPCI
USING APPENDIX K ASSUMPTIONS
FOR GE14, GE9/10, AND ATRIUM-9B AT 2957 MWt

EVENT	TIME (sec)
Break Occurs	0.0
High Drywell Pressure Trip (assumed)	0.0
Signal to Start CS	1.0
Signal to Start LPCI	1.0
Signal to Start Diesel Generator	1.0
Low-Low Water Level Trip	3.1
MSIVs Close	3.5
1st Peak PCT (GE14) Occurs	4.8
Top of Jet Pumps Uncovers	4.9
Feedwater Flow Reaches Zero	5.0
Suction Line Uncovers	6.9
Lower Plenum Flashes	7.6
Diesel Generator at Rated Speed and Bus Powered	17.0
PCT Node Uncovers	17.3
CS/LPCI IV Pressure Permissive Reached	23.3
LPCI Pump at Rated Speed	31.0
CS Pump at Rated Speed	36.0
CS Injection Occurs	36.0
CS at Rated Flow	43.7
LPCI Injection Valves Full Open	54.3
Recirc Discharge Valve Closed	69.0
LPCI Injection Starts	69.0
LPCI at Rated Flow	69.0
CS Injection Valves Full Open	77.3
2nd Peak PCT (GE14) Occurs	174.4

TABLE 6.3-19C

QUAD CITIES LOCA TYPICAL SEQUENCE OF EVENTS
WITH SVEA-96 OPTIMA2 FUEL AT 2957 MWt

Event	Time (sec)
Break / loss of off site power occurs	0.0
Turbine stop valve closes on loss of off site power	0.1
High drywell pressure occurs	0.2
Reactor scram signal on high drywell pressure	1.2
Top of jet pumps uncover	3.2
Suction line uncovers	4.9
Reactor low-low water level (L2) reached	5.5
Beginning of lower plenum flashing	6.3
Diesel generators at rated speed and bus powered	17.0
Boiling transition time	17.5
CS pressure permissive reached	23.1
Mid plane uncovers	25.1
CS pumps start	29.0
CS injection occurs	29.0
CS pumps at full speed	34.0
CS pumps deliver rated flow	45.7
Lower plenum flashing ends	57.8
CS injection valves full open	76.2
Peak clad temperature occurs	180.0

TABLE 6.3-19D

QUAD CITIES UNIT 1 AREVA LOCA EVENT SCENARIO FOR 0.13 FT^2 RECIRCULATION LINE DISCHARGE BREAK WITH HPCI FAILURE FOR ATRIUM 10XM FUEL AT 2957 MWt

Event	Time (sec)
Initiate Break	0.0
Initiate Scram	0.6
Diesel Generators Started	17.0
Low-Low Liquid Level, L2	48.5
Power at LPCS Injection Valves	17.0
LPCS Pump at Rated Speed	66.5
LPCS Valve Pressure Permissive	348.5
LPCS Valve Starts to Open	348.5
LPCS Flow Starts	351.2
LPCS Valve Fully Open	401.5
Rated LPCS Flow	549.1
LPCI Pump at Rated Speed	63.5
LPCI Valve Pressure Permissive	348.5
LPCI Valve Starts to Open	348.5
LPCI Flow Starts	366.7
LPCI Valve Fully Open	376.5
Jet Pump Uncovers	139.8
Recirculation Suction Uncovers	414.1
ADS Valves Open	169.5
RDIV Pressure Permissive	207.8
RDIV Closed	255.8
PCT	452.8

6.4 HABITABILITY SYSTEMS

Habitability systems are provided to ensure that control room operators are able to remain in the control room and operate the plant safely under normal conditions and to maintain the plant in a safe condition under accident conditions. The worst-case design basis accident (DBA) for habitability considerations, is postulated as a loss-of-coolant accident (LOCA) with main steam isolation valve leakage at technical specification limits. The control room is included in the control room emergency zone as described in Section 6.4.2.1. [6.4-1]

The habitability systems consist of systems and equipment which protect the control room operators against such postulated releases as radioactive materials, toxic gas, and smoke. Detailed descriptions of the various habitability provisions are discussed in other sections of the UFSAR as follows:

A. Tornado protection is addressed in Section 3.3;

B. Flood protection for the station is discussed in Section 3.4 (since the maximum postulated flood height is 603 feet and the control room is at elevation 623 feet, specific flood protection measures for the control room are not necessary);

C. Lighting systems are described in Section 9.5.3;

D. Protection against dynamic effects associated with the postulated rupture of piping is addressed in Section 3.6; and

E. Plant communications systems are described in Section 9.5.2.

6.4.1 Design Bases

The control room and its supporting systems are designed to ensure that the radiological dose to its occupants does not exceed the limit of 10 CFR 50.67. The supporting radiological analysis is performed in accordance with NRC Regulatory Guide 1.183.

6.4.2 System Design

The Quad Cities station has the following capabilities to ensure habitability of the control room emergency zone under accident conditions: [6.4-3]

A. The control room heating, ventilation, and air conditioning (HVAC) systems are capable of maintaining the control room atmosphere suitable for occupancy throughout the duration of a DBA.

B. The control room does not contain food provisions. Sanitary facilities and an adequate potable water supply are available near the control room. A supply of 1000 130-mg doses of potassium iodide is available in the Operational Support Center (OSC).

C. The HVAC systems are capable of detecting and protecting control room personnel from smoke and toxic gas. NOTE: Smoke isolation is different than toxic gas isolation. See Section 6.4.3 for further information.

D. Emergency breathing air supply, consisting of self-contained air packs and a bottled air reservoir, are provided to protect control room personnel from exposure to air contaminated by smoke, toxic gas, or radioactive material.

E. The control room HVAC system is capable of functioning during and after the DBA, assuming a loss of offsite power. A description of HVAC system instrumentation and control is provided in Section 6.4.6. [6.4-4]

F. The HVAC systems are capable of both automatic and manual transfer from the normal operating mode to the isolation mode. Transfer of the control room HVAC systems to the emergency (pressurization) mode of operation is not a fully automatic operation, since some control room HVAC system components must be manually started to operate the control room HVAC systems in the emergency (pressurization) mode. The manual actions required when placing the Control Room HVAC system into the pressurization mode following an accident include: (1) starting the refrigeration compressor unit; and (2) starting one air filtration unit booster fan. Emergency monitors and control equipment are provided at plant locations as necessary to ensure this capability, as described in Sections 6.4.4.1, 6.4.4.2, and 6.4.4.3. [6.4-5]

The control room is a Seismic Class I structure. Seismic design is addressed in Section 3.7.2.1.2. Seismic qualification of instruments and electrical equipment is addressed in Section 3.10.2. Missile protection is addressed in Section 3.5.2.

6.4.2.1 Definition of Control Room Emergency Zone

The control room envelope includes all instrumentation and controls necessary for safe shutdown of the plant, and is limited to those areas requiring operator access during and after a DBA.

Standard Review Plan 6.4 provides guidance for defining the boundaries for a control room emergency zone. Within this zone, the plant operators are adequately protected against the effects of accidental radioactive gas releases. This zone also allows the control room to be maintained as the center from which emergency teams can safely operate during a design basis radiological release. To accomplish this, the following areas are included in the emergency zone: [6.4-6]

A. The main control room;

B. The cable spreading room;

C. The auxiliary electrical equipment room (AEER), which surrounds the old computer room; and

D. The Train B HVAC equipment room.

Areas outside the emergency zone, which are normally serviced by the Train A HVAC system, are isolated in emergency conditions. Support rooms such as the kitchen, offices, and washrooms are accessible to operators with the aid of breathing equipment. The Train A HVAC equipment room is also not included in the emergency zone. The boundaries of the control room emergency zone envelope are shown on Figure 6.4-1, "Quad Cities Control Room HVAC Schematic." A simplified schematic diagram of the control room HVAC system is included in this figure.

Figure 6.4-3 shows the arrangement of equipment in the control room, and points of entry. Figure 6.4-4 is a plan view showing dimensions, location of radioactive material release points, and location of control room air inlets.

6.4.2.2 Ventilation System Design

The HVAC equipment described in this section is also discussed in section 9.4.1, which explains normal use of the equipment. This section addresses emergency service requirements and the response and operation of control room HVAC equipment under emergency conditions. The control room HVAC system is shown in UFSAR Figure 6.4-2 and P&ID M-725.

The Control Room HVAC System consists of a Train A HVAC system, a Train B HVAC system, an air filtration unit (AFU), a smoke detection system, and a toxic gas analyzer system. The multizone Train A system is the primary train for the control room emergency zone. Since Train A is used primarily during normal operations, it is described in Section 9.4, within the discussion of normal HVAC system operation. [6.4-7]

The Train B system and the AFU were installed to comply with NUREG-0737, item III.D.3.4 (Control Room Habitability Requirements). The Train B system has a capacity of approximately 25,000 cfm. [6.4-8]

The Train B system is a single zone system which provides the cooling required in case of failure of the Train A system. The Train B system only serves those rooms which are a part of the control room emergency zone. Therefore, the Train A HVAC equipment area and stairwell, corridor, Shift Manager office, records room, offices, instrument room, and toilet do not receive any ventilation after failure of Train A. The Train B air handling unit (AHU) is located in the Train B HVAC equipment room which is an enclosure on the turbine building mezzanine level. The supply air from this AHU is independently routed to the areas of the control room emergency zone. The return air is routed to the control room at which point it ties into the Train A return air ductwork. A two-position air-operated balancing damper is located in the return air ductwork to balance the airflows during operation of either train. The air distribution from each AHU is aligned through the use of air operated isolation dampers. These air operated dampers fail to the Train B mode since this train can be powered from the emergency bus during a loss of offsite power. The Train B AHU contains a centrifugal supply air fan, heating coil, direct expansion cooling coil, and medium efficiency filter bank. [6.4-9]

Train B provides cooling through the use of a 90-ton reciprocating compressor and direct expansion cooling coil. The condensing unit is normally cooled with the service water system. However, on loss of service water, the condenser may be cooled with the residual heat removal (RHR) service water system. To assure that the RHR service water cooling water is available, a tie-in is provided from both RHR service water loops of each unit. The cooling water flow rate through the condensing unit is dependent on the heat load and cooling water temperature; however, the design flow rate is 130 gpm. [6.4-9a]

The AFU is sized to accommodate 1800-2200 scfm and is located near the Train B HVAC equipment room. This component consists of a prefilter, electric heating coils, an upstream high-efficiency particulate air (HEPA) filter, charcoal filters, and a downstream HEPA filter. Two full-capacity fans for this unit are located inside the Train B HVAC equipment room. A description of the design, materials, and inspection of the AFU is provided in Section 6.5.1. [6.4-10]

The Train A makeup air intake and exhaust dampers are bubbletight with an area of approximately 9 ft^2 and 13.4 ft^2 respectively. Each has a leakage factor of zero. The Train B makeup air intake damper is a bubble tight damper with an area of approximately 0.5 ft^2, and a leakage factor of zero. The office area 10 x 10-inch duct and the Train A HVAC equipment room 18 x 10-inch duct are isolated with low leakage type dampers for supply and return air. Isolation of the normal makeup air intake takes approximately 10 seconds. [6.4-11]

6.4.2.3 Leak Tightness

Leakage into the control room is negligible because the control room boundary is maintained at a positive pressure with respect to adjacent rooms during both normal and emergency conditions. Backflow infiltration due to ingress and egress through the access doors is assumed to be 10 cfm. [6.4-12]

During normal operation, inleakage to the “A” train HVAC system ductwork has been determined. A bounding value for unfiltered infiltration into the “B” HVAC ductwork has been calculated to be 400 cfm. An analysis of infiltration to the control room HVAC system is included in the radiological assessment presented in Section 15.6.5.5.

6.4.2.4 Interaction With Other Zones and Pressure-Containing Equipment

Potential adverse interactions between the control room ventilation zone and adjacent zones that may allow the transfer of toxic or radioactive gases into the control room are minimized by maintaining the control room at a slightly positive pressure with respect to adjacent areas during normal conditions. During accident conditions, the control room is pressurized to at least 1/8-inch w.g. above the pressure in adjacent areas. In addition, both the intake dampers and the dampers which isolate the emergency zone area actuated automatically by the reactor building ventilation system high radiation alarm, high drywell pressure, low reactor vessel water level high main steam line flow, detection of toxic gas, or high radiation levels in the drywell or refueling floor. [6.4-13]

Steam lines are not routed in the vicinity of any control room wall. Pressurized breathing air cylinders are located outside the control room.

6.4.2.5 Shielding Design

Shielding is provided to protect control room personnel from sources of radiation other than airborne contaminants. Possible sources include the suppression pool water and vapor space, drywell, reactor building, and standby gas treatment system (SBGTS) filters. [6.4-14]

The control room is located at the southend of the turbine building, with part of the turbine building situated between the control room and the reactor building. The path from the control room to the drywell contains a total of 12 feet of concrete shielding. The path from the torus to the control room has 8 feet 8 inches of concrete shielding. The path from the reactor building to the control room has 3 feet 6 inches of concrete shielding.

The path from the SBGTS to the control room has 6 feet of concrete shielding. Figures 6.4-5 through 6.4-7 illustrate the relative location of the control room and radiation sources, and show the paths and shield thicknesses. Figure 6.4-5 is a plan view of the Quad Cities plant. Figure 6.4-6 is an elevation view. Figure 6.4-7 is a sectional elevation view. Section 12.3 describes shielding for other areas of the plant.

6.4.3 System Operational Procedures

The control room HVAC system isolates on high drywell pressure, low reactor vessel water level, high main steam line flow, detection of toxic gas, or high radiation levels in the drywell, reactor building, or refueling floor. The control room can also be isolated by operator action or by detection of smoke in the outdoor air intake. In the event of a LOCA, Train A or Train B is operated and its supply of outdoor air is filtered by the AFU. Train B is operable during a loss of either offsite power or instrument air. Normal operation of the control room HVAC system is discussed in Section 9.4.1. [6.4-15]

Automatic smoke isolation occurs on Train A Control Room HVAC system only. This isolation involves dampers 0-5772-201, 202, and 122. This is a different set of isolation dampers than those used to isolate the system on LOCA and toxic gas signals. In the isolation modes, air is recirculated through the AHU. Detection of smoke in the return air duct will switch the HVAC system to the smoke purge mode.

6.4.4 Design Evaluations

This section evaluates the effectiveness of the HVAC system design in protecting the control room personnel from the postulated hazards of radioactive material, toxic gas, and smoke contaminating the control room atmosphere, and evaluates the impact of the hydrogen water chemistry (HWC) system hydrogen storage facility on control room habitability.

6.4.4.1 Radiological Protection

Radiation protection is provided to allow control room access and occupancy for the duration of a DBA. Satisfactory protection is based on pressurizing the control room emergency zone with filtered outdoor air no later than 40 minutes following a LOCA. In addition, both the intake dampers and the dampers which isolate the non-habitable areas from the emergency zone are isolated automatically by the signals listed in Section 6.4.3. [6.4-16]

The control room HVAC system provides radiation protection by pressurizing the control room emergency zone with filtered air, isolating the normal outdoor air intakes, and isolating the areas not included in the control room emergency zone. This zone isolation with filtered pressurization air provides radiation protection by minimizing the infiltration of unfiltered air into the control room emergency zone. A positive pressure of 1/8-in. H_2O is maintained by passing 1800-2200 scfm of outdoor air through the AFU with an iodide removal efficiency of 99%. The AFU, booster fans, and associated controls can be powered from the emergency bus. In addition, both the intake dampers and the dampers which isolate the non-habitable areas from the emergency zone are isolated automatically by the reactor building ventilation system high radiation alarm. Operator action is required after an accident to verify isolation of the control room emergency zone to activate the AFU. Remote-manual isolation is also available to close the normal outdoor air intakes for both the Train A and Train B air handling units. In the event of a loss of off-site power or instrument air, the isolation dampers fail to the filtration mode. However, AFU unit booster fan discharge dampers fail closed, thereby requiring manual operation prior to activating the booster fans during loss of instrument air. This failure mode is required to protect the emergency zone from a toxic chemical release during a loss of instrument air. [6.4-17]

Section 15.6.5.5 contains an evaluation of the maximum expected dose to the control room during a DBA. This evaluation utilizes the Alternative Source Term (AST) methodology and conforms to NRC Regulatory Guide 1.183. The resulting doses are within the limits specified in 10 CFR 50.67.

6.4.4.2 Toxic Gas Protection

Hazardous chemicals present at the Quad Cities site are identified and discussed in Section 2.2. An analysis of these chemicals was modeled to conform to Regulatory Guide 1.78, which discusses the requirements and guidelines for determining toxicity of chemicals in the control room following a postulated hazardous chemical release. The guidelines for determining the toxicity of a given chemical include shipment frequencies, distance from source to site, and general properties of the chemical such as vapor pressure and toxicity limit. A listing of bulk hazardous chemicals in use at the Quad Cities site, their quantities and locations is provided in Table 6.4-1. An updated list of chemicals will be maintained in the station's annual SARA Title III Report. [6.4-19]

6.4.4.2.1 Analysis Assumptions

Three types of standard limits are considered in defining hazardous concentrations. The first limit is the toxicity limit, which is the maximum concentration that can be tolerated for 2 minutes without physical incapacitation of an average human. If the toxicity limit is not available for a given chemical, a second limit called the short-term exposure limit (STEL) is used. Short-term exposure limit is defined as the maximum concentration to which workers can be exposed for 15 minutes without suffering from irritation, tissue

damage, or narcosis leading to accident proneness or reduction of work efficiency. The third limit is the threshold limit value (TLV), defined as the concentration below which a worker may be exposed eight hours a day, five days a week without adverse health effects.

The models developed to calculate the concentrations of toxic chemicals in the control room in the event of an accidental spill are consistent with the models described in NUREG-0570. These include a consideration of the following factors:

A. There is a failure of one container of toxic chemicals being shipped on a barge, tank car, or tank truck releasing all of its contents to the surroundings. Instantaneously, a puff of that fraction of the chemical which would flash to a gas at atmospheric pressure is released. The remaining chemical is assumed to spread uniformly on the ground and evaporate as a function of time due to the heat acquired from the sun, ground, and surroundings. Further, no losses of chemicals are assumed to occur as a result of absorption into the ground, cleanup operations, or chemical reactions. A postulated failure of a barge is the basis for determining that adequate protection is provided for ammonia gas.

B. From the geography of the area near Quad Cities, a spill from a railroad tank car is assumed to spread roughly over a circular area. Similarly, a spill occurring on the highways is also assumed to spread over a circular area.

C. At an industrial site north of the nuclear plant are three large ammonia tanks. These are refrigerated atmospheric tanks. The closest tank to the control room intake is located 15,000 feet northeast.

D. The initial puff due to flashing, as well as the continuous plume due to evaporation, is transported and diluted by the wind to impact on the control room inlet. The atmospheric dilution factors are calculated using the methodology of Regulatory Guide 1.78 and NUREG-0570, with partial building wake effects conservatively considered.

E. To determine which chemicals need monitoring, the control room ventilation systems were assumed to continue normal operation for the analysis. The chemical concentrations as a function of time were calculated and the maximum levels determined. These were compared to the toxicity limits. Wherever the toxicity limits were not available, STEL values and TLVs published by the American Conference of Governmental and Industrial Hygienists (ACGIH) were used in lieu of toxicity limits.

F. Concentrations were calculated as a function of time following the accident to compare with the published toxicity limits, STEL values, and TLVs.

G. When the concentration in the control room did not exceed the toxicity limit within two minutes after detection by odor, operator action to isolate the control room was assumed. In such cases, monitors are not employed at the control room air intake. Where the toxicity limits are not available, STEL values are used in lieu of toxicity limits.

6.4.4.2.2 Analysis Results

Based on the physical and toxicological properties of the chemicals stored at the Quad Cities site, it is concluded that none of the chemicals are of concern. For these chemicals, the unisolated control room concentrations will not exceed the TLV in the event of a postulated release. [6.4-19a]

Chemicals stored offsite, as well as chemicals transported by pipeline, railroad, river, and highway, were evaluated based on toxic, physical, and chemical properties. Analyses of some were eliminated based on Regulatory Guide 1.78 (Table C-2) criteria. The remaining chemicals were analyzed assuming a fresh air intake of 2000 cfm to the air handling system and no isolation. Under these conditions, the following chemicals exceeded the TLV and the STEL in the control room: ammonia, chlorine, sulfur dioxide, benzene, hydrochloric acid, hydrofluoric acid, and nitric acid.

6.4.4.2.3 Protection Provisions

The control room HVAC system provides toxic gas protection to the control room emergency zone in case of either an onsite or offsite toxic chemical accident. The system provides this protection by either manual isolation through operator action or automatic isolation through the use of a toxic gas analyzer. A monitor is provided for ammonia since the control room concentrations for this chemical reaches the toxicity limits faster than the operator can manually isolate the system after detection of odor. Operator action to isolate the control room is also required for other chemicals whose control room concentrations do not exceed the toxicity limits within two minutes after detection of odor. These chemicals requiring operator action are hydrochloric acid, hydrofluoric acid, nitric acid, benzene, chlorine, and sulfur dioxide. [6.4-20]

The toxic gas analyzer system continuously monitors the outdoor air intake of both air handling units. Upon detection of ammonia, the analyzer system provides a signal which isolates the control room HVAC system outdoor air intakes and annunciates in the control room. The ammonia analyzers have a setpoint that is calculated to assure that a toxicity limit concentration of 300 ppm, per Regulatory Guide 1.78 (Revision 1), is not exceeded for unprotected operators in the control room. The setpoint chosen provides early detection in the outside supply air. The ammonia toxic gas protection system total response time (from presence of ammonia in excess of the allowable value, until the outside ventilation isolation dampers are shut) was calculated to determine the ammonia concentrations reached in the control room with two minutes of infiltration added. Testing requirements for the toxic gas monitoring system are also contained in the Technical Requirements Manual. [6.4-20a]

The toxic gas analyzers sample two locations. Sample point A is located immediately downstream of the Train A outside air inlet damper. Sample point B is located immediately upstream of the Train B and AFU outside air inlet damper. [6.4-21] When the control room HVAC is in isolation/recirculation mode, human smell shall be utilized as a detection method to sense ammonia in-leakage.

6.4.4.3 Fire and Smoke Protection

The control room HVAC system is designed to isolate the control room while maintaining the design conditions within the control room from fires occurring in either the office area, computer room, or a fire outside the emergency zone. The plant fire protection system is discussed in Section 9.5.1. [6.4-22]

Smoke detectors, located in the return air duct system, automatically switch the normal air handling unit (Train A) to the smoke purge mode. During this mode, the unit supplies 100% outdoor air. This prevents the recirculation of smoke into any of the occupied areas during a fire while exhausting 100% of the return air to the outdoors. The smoke purge capability is only available on Train A. [6.4-23]

To comply with Regulatory Guide 1.120, "Fire Protection Guidelines for Nuclear Power Plants", which covers control room breathing air capabilities, the station established an emergency breathing apparatus system, utilizing a bottle reservoir located outside the control room. The system is designed to provide a crew of five men with six hours of air apiece. [6.4-24]

This equipment consists of self-contained breathing apparatus which has an independent supply of fresh air, and allows operators to remain at their positions until the fumes are evacuated. As a backup, the system also has twelve 300-ft^3 bottles located outside the control room and distributed through three manifolds to pressure-demand full face masks. [6.4-25]

6.4.4.4 Hydrogen Storage Facility

As part of the HWC system, liquid hydrogen and liquid oxygen storage facilities are installed at the site. These facilities are described in Section 2.2.3.2 and are located 1500 feet south of the control room. The postulated hazards are failure at the gaseous or liquid storage vessels, which could result in an explosion and/or fireball, and a break in the gaseous or liquid pipeline, which could result in an atmospheric hydrogen concentration which exceeds the lower flammability limit of 4%. The location of these facilities is sufficiently far away from the control room so that these accidents will not affect habitability. [6.4-26]

6.4.5 Testing and Inspection

Requirements for testing of instrumentation which isolates the control room HVAC system are given in Technical Specifications and/or the Technical Requirements Manual. Periodic inspection and testing of the AFU is performed as explained in Section 6.5.1. The balance of the system is used continuously during normal plant operations, therefore no additional testing is required.

6.4.6 Instrumentation Requirement

The isolation mode of the control room HVAC system is initiated automatically by signals received from the reactor pressure vessel (RPV) water level sensors, main steam line flow sensors, drywell pressure sensors, reactor building (including drywell and fuel pool) HVAC system radiation monitors, toxic gas analyzer, and smoke detectors. Reactor building HVAC system instrumentation is addressed in Section 9.4. Toxic gas monitoring instrumentation and smoke detectors were previously addressed in Section 6.4.4. Information about the RPV level sensors, main steam line flow sensors, and drywell pressure sensors is contained in Section 7.3. [6.4-27]

Table 6.4-1

POTENTIALLY HAZARDOUS CHEMICALS STORED WITHIN
THE QUAD CITIES SITE BOUNDARY

Chemical	Quantity*	Location
Acetylene	100 ft^3**	Gas bottle storage rack‡‡
Argon	330 ft^3**	Gas bottle storage rack‡‡
Carbon Dioxide	15,000 lb.	595' turbine building
EHC fluid	2,000 gal.	595' turbine building
Ethylene glycol	24,000 lbs.	Offgas filter building
Freon	1,500 lbs.	Security guardhouse, A and B trains of control room HVAC
Helium	242 ft^3**	Gas bottle storage rack‡‡
Hydrogen	194 ft^3**	Gas bottle storage rack‡‡
Hydrogen, liq	20,000 gal.	South of waste water treatment plant
Nitrogen, liq	918,700 ft^3	North of 1/2 EDG
Nitrogen	224 ft^3**	Gas bottle storage rack‡‡
Oxygen, liq	11,000 gal.	South of waste water treatment plant
P-10 (methane-argon mixture)	200 ft^3**	Gas bottle storage rack‡‡
PCBs (Pyranol)	3,800 gal.	Transformers in turbine building
Sodium bisulfite	6,650 gal.	North of crib house
Sodium hypochlorite	10,000 gal.	North of crib house
Sulfuric acid	1,450 gal.	Battery rooms
Scale inhibitor	6,650 gal.	North of crib house
Silt dispersant	6,650 gal.	North of crib house
Corrosion inhibitor	6,650 gal.	North of crib house

* Wherever multiple containers of the same chemical are stored in close proximity, the quantity of the largest container is provided.
** Standard type gas bottles
‡ Hydrogen at 70F, 2,640 psi
‡‡ Located south of service building
(Gasoline, diesel fuel, oils, etc. not listed)

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

Section 6.5 provides a discussion of fission product removal systems. The filter packs of the standby gas treatment system (SBGTS) and the control room ventilation system are addressed in Section 6.5.1. The remainder of the SBGTS is addressed in 6.5.3, while the control room ventilation system is addressed in Section 6.4.

6.5.1 Off-Normal/Accident Condition Filter Systems

Both the SBGTS and the control room ventilation system have a filter pack used to control radiation exposure during off-normal or accident conditions. The SBGTS filter pack is addressed in Section 6.5.1.1, the control room ventilation system filter pack is addressed in Section 6.5.1.2, and filter pack testing for both systems is addressed in Section 6.5.1.3.

Filter packs, as defined in this section, consist of the housing that contains the filters and adsorber, the filters and adsorber themselves, and any interconnecting ductwork between the filter elements.

6.5.1.1 Standby Gas Treatment System Filter Pack

The SBGTS filter pack treats the intentional release of primary and secondary containment atmosphere to the environs in the unlikely event of a design basis accident (DBA) and thereby reduces exposure to the public and site personnel. [6.5-1]

The filter pack is designed to process the entire 4000 ft^3/min SBGTS flowrate necessary to maintain reactor building pressure at a negative 0.25 in. H_2O. As gas flows through the SBGTS filter pack, it encounters the following components as shown in FSAR Figure 6.5-1 and P&ID M-44.

A. Demister (Dehumidifying Coil)

The demister is provided to remove water particles entrained in the steam-air mixture routed through SBGTS. Water removed from the steam-air mixture is routed to the reactor building equipment drain tank through a loop seal arrangement. [6.5-2]

B. Electric Heater [6.5-3]

The heater is energized whenever flow exceeds a set limit (approximately 2800 ft^3/min) and de-energized whenever flow falls below a set limit (approximately 2500 ft^3/min) as indicated by a flow switch upstream of the heater. This assures the heater and the activated carbon bed are not damaged by excessive heat. The heater raises the temperature of the air entering at least 14°F to result in a relative humidity of less than 70%. The heater is sized at 30 kW and is powered from 480 V MCC 19-4 (Train B) and 480 V MCC 29-4 (Train A). Only about 18 kW is required for the 4000 ft^3/min design air flow.

C. Rough Prefilter [6.5-4]

The rough prefilter is installed to remove dust particles and other debris which may enter the system. This filter increases the usable life of downstream high efficiency particulate air (HEPA) filters. This rough prefilter can be replaced without requiring a retest of HEPA filters when an undesirable dust load has accumulated.

D. High Efficiency Particulate Air Prefilters [6.5-5]

Radioactive particulates entering the SBGTS are removed by the HEPA prefilters. The HEPA filters are designed to have a removal efficiency of not less than 99% for 0.3 micron particles and were factory-tested with thermally generated DOP aerosol or test aerosol equivalent to verify this capability. The filter is designed to withstand 500°F temperatures.

E. Activated Carbon Adsorbers [6.5-6]

A unit-tray (drawer type) activated carbon adsorber is provided for removal of halogens, including radioactive iodine, whether in the elemental or organic form (methyl iodide). The adsorbers consist of a 2-inch thick layer of activated carbon impregnated with potassium iodide.

The standby gas treatment system charcoal adsorber is designed to remove iodine and methyl iodide in accordance with Table 5-1 of ANSI N509-1980. The system design includes high temperature activated carbon (650°F), and metal framing. An overall removal efficiency equal to, or greater than 97.5% (penetration less than 2.5%) is demonstrated periodically in accordance with the laboratory methyl-iodide removal test. Replacement activated carbon shall be purchased qualified according to the guidelines of Regulatory Guide 1.52, Rev. 2 (March 1978), Section C.3.i. [6.5-7]

F. Flow Control Orifice

A flow control orifice is installed between flanges in the mixing section. The orifice will maintain system flow at 4000 scfm ± 10% in the event the flow control valve fails open.

G. Mixing Section [6.5-8]

A section of pipe downstream of the activated carbon adsorber is provided as a mixing section. This mixing section is used to obtain a representative downstream sample when leak testing the activated carbon adsorber or to obtain a representative upstream sample when the HEPA afterfilters are tested.

H. HEPA Afterfilters

The HEPA afterfilters are similar to the HEPA prefilters (see item D.) and are provided to remove any activated carbon particles that may be released by the activated carbon adsorber.

The SBGTS filter packs have instrumentation installed to support the testing outlined in Section 6.5.1.3. Differential pressure is monitored across the demister, rough filter, HEPA prefilter, activated carbon adsorber bed, and HEPA afterfilter. Temperature is monitored at the filter pack inlet, after the rough prefilter, and after the activated carbon adsorber bed. [6.5-9]

6.5.1.2 Control Room Ventilation System Filter Pack

The control room ventilation system filter pack provides protection from radiation exposure to allow control room access and occupancy for the duration of a loss-of-coolant accident (LOCA) with main steam isolation valve leakage at Technical Specification limits as the worst-case DBA. Satisfactory protection is based on pressurizing the control room emergency zone with filtered outdoor air no later than 40 minutes following a LOCA. The filter pack complies with Regulatory Guide 1.52, Rev. 2 (March 1978). [6.5-10]

The filter pack is designed to process the complete 1800-2200 scfm makeup flow of outside air needed to maintain a positive pressure of 1/8 in. w.g. in the control room emergency zone. As gas flows through the control room ventilation filter pack, it encounters the following components: [6.5-11]

A. Rough Prefilter

The rough prefilter is provided for removing dust particles and other debris which may enter the system. This filter is expected to increase the usable life of downstream HEPA filters. This rough prefilter can be replaced without requiring retest of HEPA filters when an undesirable dust load has accumulated. The filter has an efficiency rating of 60-65%.

B. Electrical Heater [6.5-12]

The electrical heater raises the temperature of the entering air to result in a relative humidity of less than 70%. The 12-kW heater is powered from 480 V MCC 18-4.

C. High Efficiency Particulate Air Prefilters [6.5-13]

Radioactive particulates entering the control room ventilation system makeup are removed by the HEPA prefilters. The HEPA filters have a removal efficiency of no less than 99% for 0.3 micron particles.

D. Activated Carbon Adsorber [6.5-14]

The activated carbon adsorber is used to adsorb radioactive iodine and methyl iodide from the atmosphere. The activated carbon is granular, activated coconut shell-based charcoal, impregnated with not more than 5% non radioactive iodine as potassium iodine. Inorganic iodine is readily adsorbed on the activated carbon surface. Organic iodine (methyl iodide) cannot be readily adsorbed and requires an exchange medium. This is provided by the 5% impregnated iodine. The overall removal efficiency of the adsorber is equal to or greater than 99.5% as demonstrated periodically in accordance with the laboratory methyl-iodide removal test.

E. High Efficiency Particulate Air Afterfilter

The HEPA afterfilter is constructed of the same materials as the HEPA prefilter. It filters the activated carbon particles that may be released from the activated carbon adsorber.

The flowpath of the filter pack is shown on P&ID M-725.

This filter pack has a fire protection deluge system which is described in Section 9.5.1. [6.5-15]

The control room ventilation system filter pack has instrumentation installed to support the testing outlined in Section 6.5.1.3. Differential pressure is monitored across the rough filter, the HEPA prefilter, the HEPA post-filter, and the complete filter pack. Temperature is monitored at the filter pack inlet, after the electric heater and after the activated carbon adsorber bed. The temperature element after the activated carbon adsorber provides an interlock to allow the fire protection deluge to be activated.

6.5.1.3 Filter Pack Tests and Inspections

Periodic testing of the filter packs is performed to verify that the filter packs will operate as designed and to provide a heated airflow for drying the activated carbon adsorption bed. This testing is specified in the Technical Specifications and is performed on both the SBGTS and the control room ventilation filter packs. [6.5-16]

The tests performed on these filter packs are as follows:

A. The in-place testing of the activated carbon adsorbers is performed using Freon-11 which is injected into the system upstream of the activated carbon adsorbers. Freon concentration is measured upstream and then downstream of the activated carbon adsorbers. The ratio of inlet to outlet concentrations gives an overall indication of the system's leak tightness. Since the filters have activated carbon of known adsorption efficiency and holding capacity for elemental iodine and/or methyl iodide, the test also gives an indication of the relative efficiency of the installed system. The test procedure is an adaptation of test procedures developed at the Savannah River Laboratory.

B. Appropriate tests are performed to demonstrate that aging, weathering, or poisoning of the activated carbon has not caused unacceptable degradation. The test method used involves the measurement of radioactive methyl iodide removal efficiency using a test developed at Oak Ridge National Laboratory. This is done by removing small test cartridges containing activated carbon representative of that present in the adsorber bed and submitting them for analysis per the Technical Specifications. Additionally, an in-place halogenated hydrocarbon bypass leakage test is demonstrated periodically.

C. Pressure drop tests are conducted on the SBGTS filter packs using differential pressure indication available across each filter element and the adsorber. The pressure drops across the filters and the adsorber are summed in each train to demonstrate that the total pressure drop has not increased significantly. Fan and system design is such that pressure drop can increase substantially without limiting flow. The control room ventilation filter pack pressure drop test is conducted using the total pack differential pressure indicator. Normally, buildup of dust during testing and operation over a period of years will result in a high DELTA-P, particularly on the rough prefilter. When the DELTA-P increases, the rough prefilter will be cleaned or replaced. If the DELTA-P of other filters significantly increases, they will be replaced. [6.5-17]

D. In-place testing to assure that gaskets and seals are properly installed and that the HEPA filters are not damaged, is performed using air-generated dioctylphthalate (DOP) aerosol. Removal efficiency equal to, or greater than 99% for 0.3 micron particles is demonstrated periodically. [6.5-18]

E. Heater performance is demonstrated by calculating heater power or measuring inlet and outlet temperatures of the SBGTS trains using RTDs. Heater current and voltage are measured so that heater power can be calculated. The differential temperatures will be measured and displayed on a differential temperature indicator in the Main Control Room. An annunciator alarm is provided to alert operators should the SBGTS differential temperature drop below the 14°F minimum, which would indicate a possible heater failure. [6.5-19]

6.5.2 Containment Spray Systems

The containment spray systems are part of containment cooling and are not relied upon for fission product removal following a postulated LOCA. [6.5-20]

Refer to Section 6.2, for a discussion of containment cooling.

6.5.3 Fission Product Control Systems

The SBGTS filter pack is discussed in Section 6.5.1. The remainder of the system is discussed below.

The SBGTS, shown in FSAR Figure 6.5-1 and P&ID M-44, is provided to maintain the reactor building at a negative pressure and to filter the exhaust of radioactive matter from reactor building spaces to the environment in the unlikely event of a DBA. It is also instrumental in maintaining the integrity of secondary containment during a primary to secondary containment instrument line break, as discussed in Section 15.6.2. [6.5-21]

The SBGTS was designed to respond to DBAs including the LOCA (Section 15.6.4) and the refueling accident (Section 15.7.2). When SBGTS is in operation and the reactor building is completely isolated, a small average negative pressure is created in the reactor building which minimizes ground level release of airborne radioactivity. Two parallel trains are provided, each of which is capable of producing greater than 0.25 in. H_2O negative pressure required in the reactor building while processing 4000 ft^3 /min of exhaust air. The SBGTS removes radioactive particulate matter and radioactive halogens with the efficiency required to provide sufficient margin between expected offsite doses and 10 CFR 100 (or 10 CFR 50.67 as applicable) guidelines for the postulated LOCA or refueling accident. Any noble gases discharged by the SBGTS are dispersed into the atmosphere when released from the 310-foot chimney. The chimney monitor, discussed in Section 11.5, samples the effluent. [6.5-22]

The system is designed to automatically start a single SBGTS train or start both trains simultaneously. The selector switches for the individual SBGTS trains are arranged so that each train may be placed in the Primary, Standby, Manual Start, or Off positions. In the event of a design basis accident (any size LOCA or fuel handling), both SBGTS trains should not be run simultaneously (or should be minimized), with the Control Room Emergency Air Filtration System operating. The control room habitability analysis assumed the control room emergency air filtration system will be started within 1 hour and 50 minutes, immediately following a design basis accident. The control room habitability analysis also assumed one SBGTS train was operating. [6.5-23]

Normal operation has the 1/2B SBGTS train selected as primary, and the 1/2A SBGTS train as standby. Maintaining the 1/2B SBGTS train as primary, and the 1/2A SBGTS train as standby, ensures the SBGTS meets single failure criteria. Since the 1/2B SBGTS train, and the Unit 1 Primary Containment Isolation (PCI) and Process Radiation Monitoring (PRM) circuits are both supplied from Bus 19, a loss of Bus 19 with the 1/2B SBGTS selected as standby and the 1/2A SBGTS train selected as primary, will prevent the 1/2B SBGTS train from starting, and will inhibit automatic and manual starting of the 1/2A SBGTS train. If the selector switches are in the normal operation positions, and the primary train does not start on an initiation signal within a predetermined time, then the train selected as the standby train will start automatically. Similarly, if the operating SBGTS train should fail, the backup SBGTS train will automatically start. This design will ensure that building negative pressure is maintained. [6.5-24]

If it becomes necessary to shut down a train after it has collected a significant amount of radioactive particulates and iodine, flow may still be required to remove radioisotope decay heat. This flow can be provided by the alternate train fan since the inlet cooling air valve

is always open on the train which is not operating. A restricting orifice is sized to admit at least 300 ft^3/min from the turbine building. This flow is sufficient to maintain maximum temperatures below 200°F, well below the operating temperature limits of all components in the system. [6.5-25]

The transit time from the SBGTS blower to the SBGTS exhaust point inside the chimney is approximately 30 seconds based on a maximum design flow rate of 4000 ft^3/min. In the normal automatic mode, the SBGTS takes suction from the reactor building. As described above, the reactor building will be at a negative pressure whenever the SBGTS is operating and therefore, any leakage will be leakage into the building, thereby preventing release of contamination from building areas which are not in the immediate vicinity of the SBGTS suction inlet. Therefore, all areas within the reactor building are served by the SBGTS. [6.5-26]

The SBGTS is designed with the provision to take suction from the primary containment if required. This mode is operator initiated and is used to reduce excessive containment pressure as directed by the emergency operating procedures. To accomplish this, the containment vent isolation valve signal must be overridden using a keylock bypass switch. Suction for containment venting is supplied from either the drywell or the suppression chamber. Suppression chamber suction is preferred because water scrubbing decontamination can occur in addition to the radiation release reduction achieved by the filter train. The torus can be safely vented through SBGTS at a suppression chamber pressure of 25 psig or lower. The final 6-inch butterfly valve before the SBGTS filter train has been modified to restrict open travel to less than 50°. [6.5-27]

The SBGTS is designed to meet Class I seismic criteria. The equipment is located in the reactor building on the floor at elevation 666 feet 6 inches. One train is on the Unit 1 reactor side and the other is on the Unit 2 reactor side. Additional bracing has been added to the discharge piping as a result of new analyses to assure seismic qualification. [6.5-28]

In the direction of flow, each SBGTS train has the following major features or components:

A. Motor-Operated Inlet Butterfly Valve

This valve automatically opens on initiation of the primary train. Should the primary train inlet valve fail to open on primary train start, the inlet valve for the alternate train will automatically open. This valve automatically closes when its train is shut down. These valves also have manual override to support emergency containment/torus purge. [6.5-29]

B. Cooling Air Line with Motor-Operated Butterfly Valve [6.5-30]

This valve automatically opens whenever a train is not operating. The line provides a source of turbine building air for SBGTS filter decay heat cooling when the alternate train fan is operating. This valve automatically closes when the associated train is operating.

C. Filter Pack

The SBGTS filter pack is addressed in Section 6.5.1.

D. Flow Control Orifice

The flow control orifice is addressed in Section 6.5.1.F.

E. Crosstie Line

A crosstie line, with manual butterfly valve (which is normally locked open), interconnects the two trains so that an operating train fan can provide filter decay heat cooling air at the proper flow through the idle train. The valve allows isolation of the two trains when required for test purposes or when one train is down for maintenance.

F. Flow Control Valve [6.5-31]

An air-operated, butterfly, flow-control valve automatically maintains constant flow through the SBGTS. Using a flow element at the inlet to the train, flow is controlled in a band of 4000 ft^3/min $\pm$10%. The flow control valve fails open on loss of air.

G. Fan [6.5-32]

The SBGTS fan in each train is a direct-drive, high-pressure exhaust fan with a capacity of 4000 ft^3/min.

H. Backdraft Damper

The backdraft damper restricts any backflow that may occur. This damper acts like a check valve and closes whenever air flow into the fan exhaust occurs.

I. Motor-Operated Outlet Butterfly Valve

This valve automatically opens on system initiation of the train selected to operate. This valve automatically closes when the associated train shuts down.

The discharge from the two SBGTS trains are joined together and the discharge from the system is routed to the chimney through a common line.

Shield walls have been installed between the SBGTS trains and their respective control cabinets to isolate the cabinets from the harsh environment caused by the buildup of fission products on the filters and adsorber. These walls will reduce the post accident radiation doses to the control cabinets to below 5 x 10^4 rads. The installation of these walls will not adversely effect the proper operation of SBGTS equipment because the walls are classified as Seismic Category I and are safety-related. These walls ensure equipment will operate in a suitable environment. [6.5-33]

Operating the SBGTS supports secondary containment system integrity testing. This testing is addressed in Section 6.2.3. [6.5-34]

Eight different signals automatically start a SBGTS train. They are: [6.5-35]

1. Low reactor water level using a one-out-of-two-twice logic;

2. High drywell pressure using a one-out-of-two-twice logic;

3. High reactor building ventilation exhaust radiation using a one-out-of-two logic;

4. High refuel floor radiation using a one-out-of-two logic;

5. High-high drywell radiation;

6. Reactor building ventilation radiation monitors downscale using a two-out-of-two logic;

7. Refuel floor radiation monitors downscale using a two-out-of-two logic; and

8. Failure of primary train initial start.

6.6 INSERVICE INSPECTION OF CLASS 2, 3, AND MC COMPONENTS

A summarized inservice inspection program, including information on areas subject to examination, method of examination, and relief requests, is provided in the Quad Cities Inservice Inspection/Inservice Testing Plans. This section addresses inservice inspection (ISI) for ISI Class 2, 3, and MC components. ISI for Class 1 components is addressed in Section 5.2. Inservice inspection and testing of pumps and valves is discussed in Section 3.9. [6.6-1]

The Inservice Inspection Program for Class 1, 2, and 3 components, Quad Cities Units 1 and 2, is based on the requirements of 10 CFR 50.55a(g) and Section XI of the ASME Boiler and Pressure Vessel Code, 2007 Edition through 2008 Addenda and 2001 Edition through the 2003 Addenda for Class MC components. Where these rules are determined to be impractical, specific relief is requested in writing from the Nuclear Regulatory Commission (NRC). 10 CFR 50.55a(g)(6)i authorizes the NRC to grant relief from the requirements of ASME Section XI upon determining that such relief is justified. Relief requests are included in the Quad Cities ISI Plan.

The program for Class 1, 2, and 3 components is currently in the fifth inspection interval for both Quad Cities Units 1 and 2. The program for Class MC components is in the second inspection interval for both Quad Cities Units 1 and 2.

6.6.1 Components Subject to Examination

The construction permits for Quad Cities Units 1 and 2 were issued on February 15, 1967. At that time ASME Section III covered only pressure vessels, primarily nuclear reactor vessels. Piping, pumps, and valves were built primarily to the rules of USAS B31.1, the Power Piping Standard, and so the station has essentially no ASME Section III Class 1, 2, or 3 designed systems. The system classifications used as a basis for the ISI program are based on the requirements given in 10 CFR 50.55a(g) and Regulatory Guide 1.26, and were developed for the sole purpose of assigning the appropriate ISI requirements. The ISI classifications, therefore, are not reflections of ASME Section III design classes. Components within the reactor coolant pressure boundary (RCPB), as defined in 10 CFR 50.2(v), are designated as ISI Class 1 while other safety-related components are designated as ISI Class 2 and 3 in accordance with the guidelines of Regulatory Guide 1.26 for Quality Groups A, B, and C, respectively. Pursuant to 10 CFR 50.55a(g)(1), ISI requirements of ASME Section XI have been assigned to these components, within the constraints of existing plant design. [6.6-2]

A listing of the ISI classification for the plant systems is provided in Table 5.2-3, "List of Systems Included in the ISI Program." Inservice inspection and testing of the RCPB is addressed in Section 5.2.4. Specific testing for intergranular stress corrosion cracking is described in Section 5.2.3.5.

The extent of the Class 1, 2, 3, and MC designations for systems or portions of systems subject to the ISI Program requirements are identified on the Quad Cities Piping and Instrumentation Diagrams (P&IDs) and IWE (MC) program drawings. In accordance with Regulatory Guide 1.26, the ISI boundaries on the P&IDs are limited to safety-related systems that contain water, steam, or radioactive materials. [6.6-3]

ISI Class 2 components at Quad Cities are examined in accordance with requirements listed in ASME Section XI, Table IWC-2500-1. ISI Class 3 components are examined in accordance with ASME Section XI Table IWD-2500-1. ISI Class MC components at Quad Cities are examined in accordance with requirements listed in ASME Section XI, Table IWE-2500-1. [6.6-4]

Inservice testing of snubbers is performed in accordance with Technical Requirements Manual Section 3.7.H and ASME OM Code, Subsection ISTD. [6.6-5]

6.6.2 Accessibility

The as-built configuration of ISI Class 2, 3, and MC system components does not always provide adequate clearance as required by ASME Section XI, Subarticle IWA-1500 to conduct the required inspections. Certain requirements of the ASME Code are impractical to perform on plants of Quad Cities' age because of the plants' design, component geometry, and materials of construction. Where access to components is restricted, specific relief requests are made to the NRC in writing and included in the ISI Plan. [6.6-6]

6.6.3 Examination Techniques and Procedures

ASME Section XI, Tables IWC-2500-1, IWD-2500-1, and IWE-2500-1 specify the type of examination to be performed (visual, surface, or volumetric) within each examination category. Requirements for these examinations are given in ASME Section XI, Subarticle IWA-2200. [6.6-7]

Visual examinations are employed as a basis for reporting the general condition of the part, component, or surface examined. ASME Section XI, Subarticle IWA-2210 gives requirements for visual examination techniques.

Surface examinations are used to detect the presence of surface cracks or discontinuities. ASME Section XI, Subarticle IWA-2220 gives the requirements for surface examination techniques.

Volumetric examination is used to determine the presence of surface and subsurface discontinuities, their size, location, and orientation throughout the volume of material examined. ASME Section XI, Subarticle IWA-2230 gives requirements for volumetric examination methods.

6.6.4 Inspection Intervals

ASME Section XI, Tables IWC-2500-1, IWD-2500-1, and IWE-2500-1 define the inspection frequencies for ISI Classes 2, 3, and MC respectively.

6.6.5 Examination Categories and Requirements

The Quad Cities ISI Program is organized according to the inspection categories defined in ASME Section XI, Tables IWC-2500-1 for ISI Class 2, and IWD-2500-1 for ISI Class 3 and IWE-2500-1 for Class MC. Examination requirements are given in ASME Section V and Section XI. [6.6-8]

6.6.6 Evaluation of Examination Results

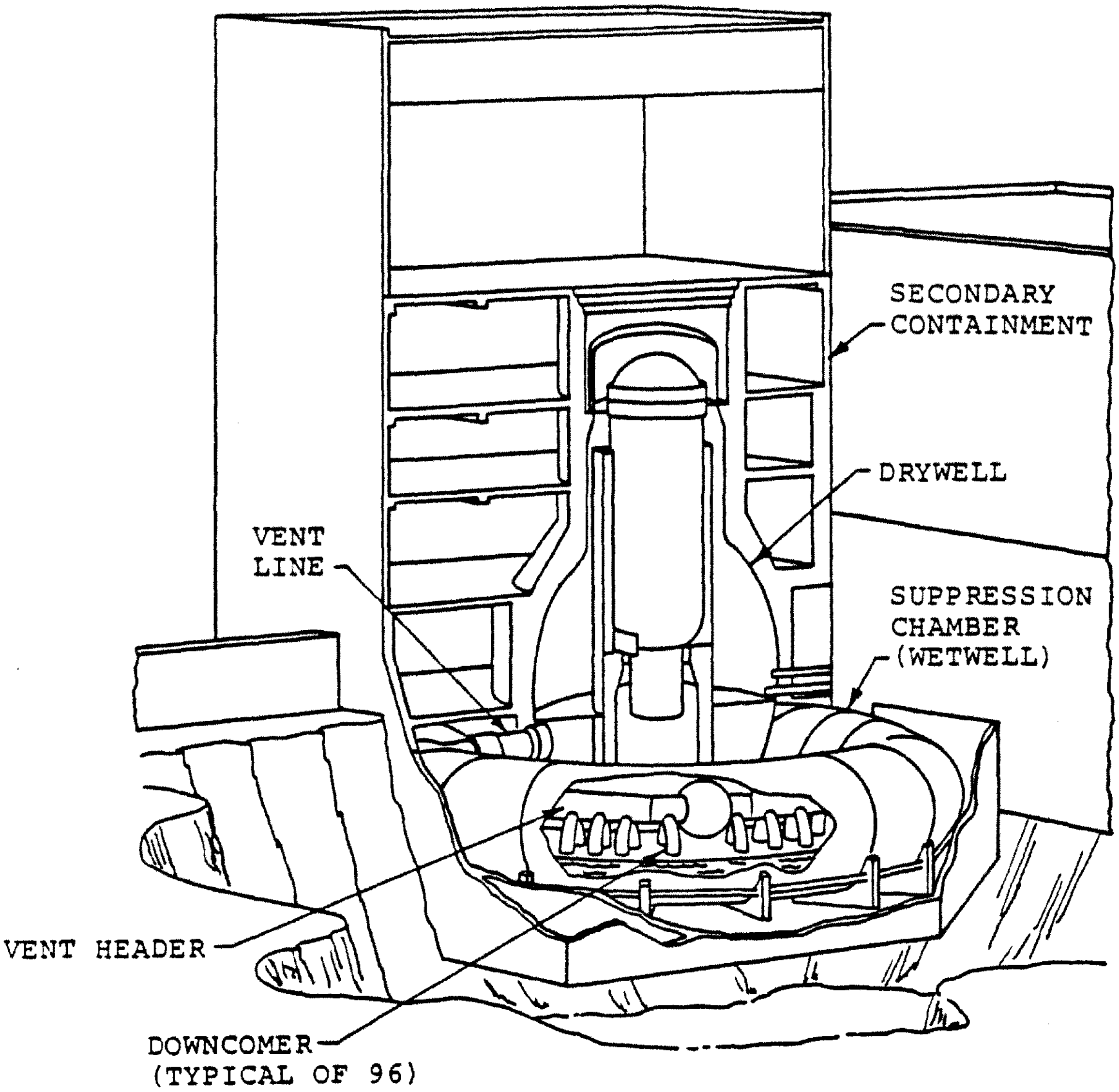
Flaws detected in Class 2, 3, and MC component examinations are evaluated according to the requirements of ASME Section XI as described in the approved ISI Program Plan. Repairs involving welding or metal removal are performed in accordance with ASME Section XI, Article IWA-4000. Replacement of parts and components is performed as specified in ASME Section XI, Article IWA-4000. [6.6-9]

6.6.7 System Pressure Tests

Class 2 systems are pressure tested in accordance with ASME Section XI, Article IWA-5000 and Article IWC-5000. Class 3 systems are pressure tested according to ASME Section XI, Article IWA-5000 and Article IWD-5000. Class MC components are pressure tested according to ASME Section XI Article IWE-5000. [6.6-10]

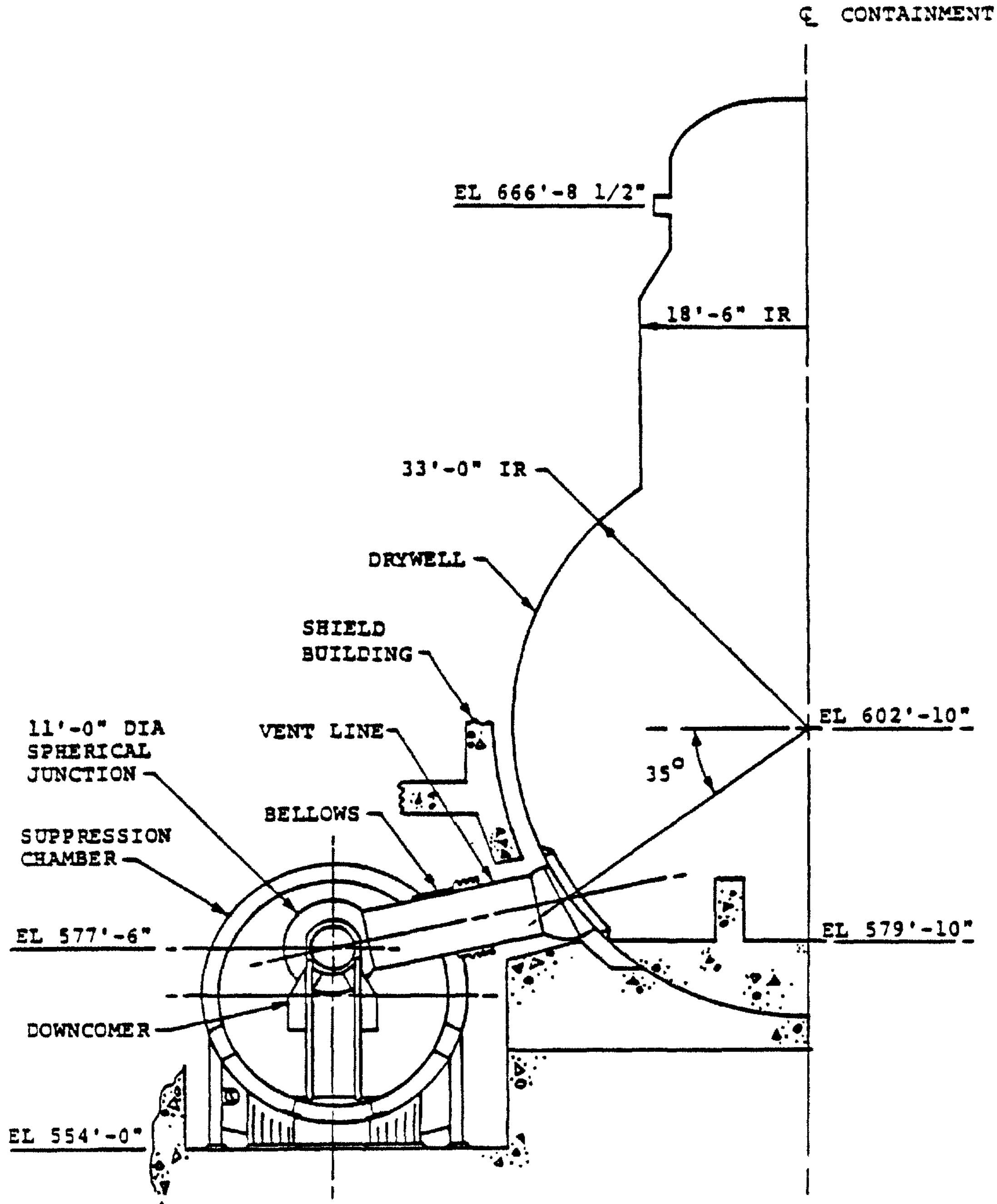
6.6.8 References

1. Deleted



1. THE DRYWELL AND SUPPRESSION CHAMBER FORM THE PRIMARY CONTAINMENT.

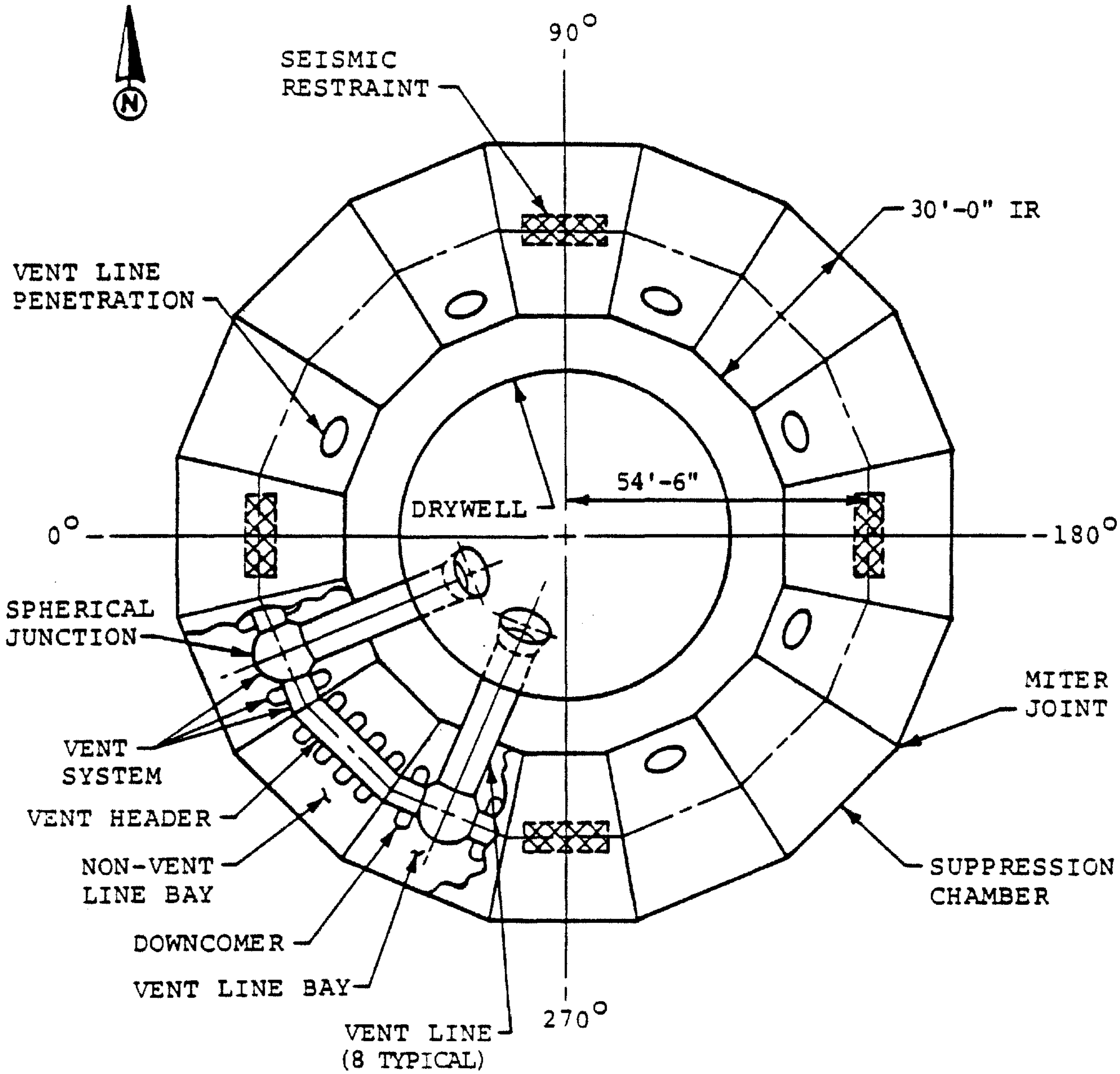
QUAD CITIES STATION UNITS 1 & 2
GENERAL ARRANGEMENT of MK. I CONTAINMENT SYSTEM
FIGURE 6.2-1



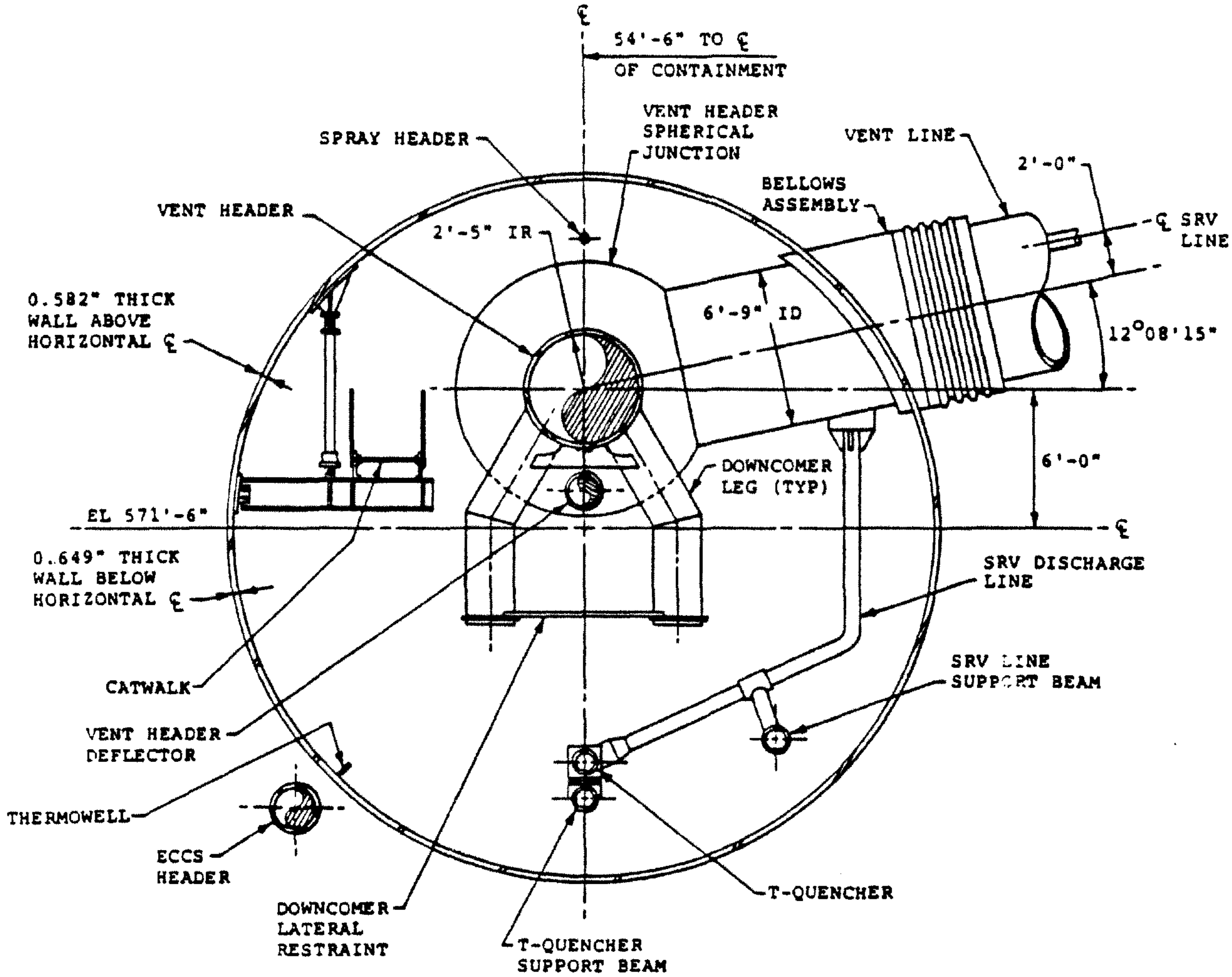
QUAD CITIES STATION
UNITS 1 & 2

ELEVATION VIEW OF CONTAINMENT

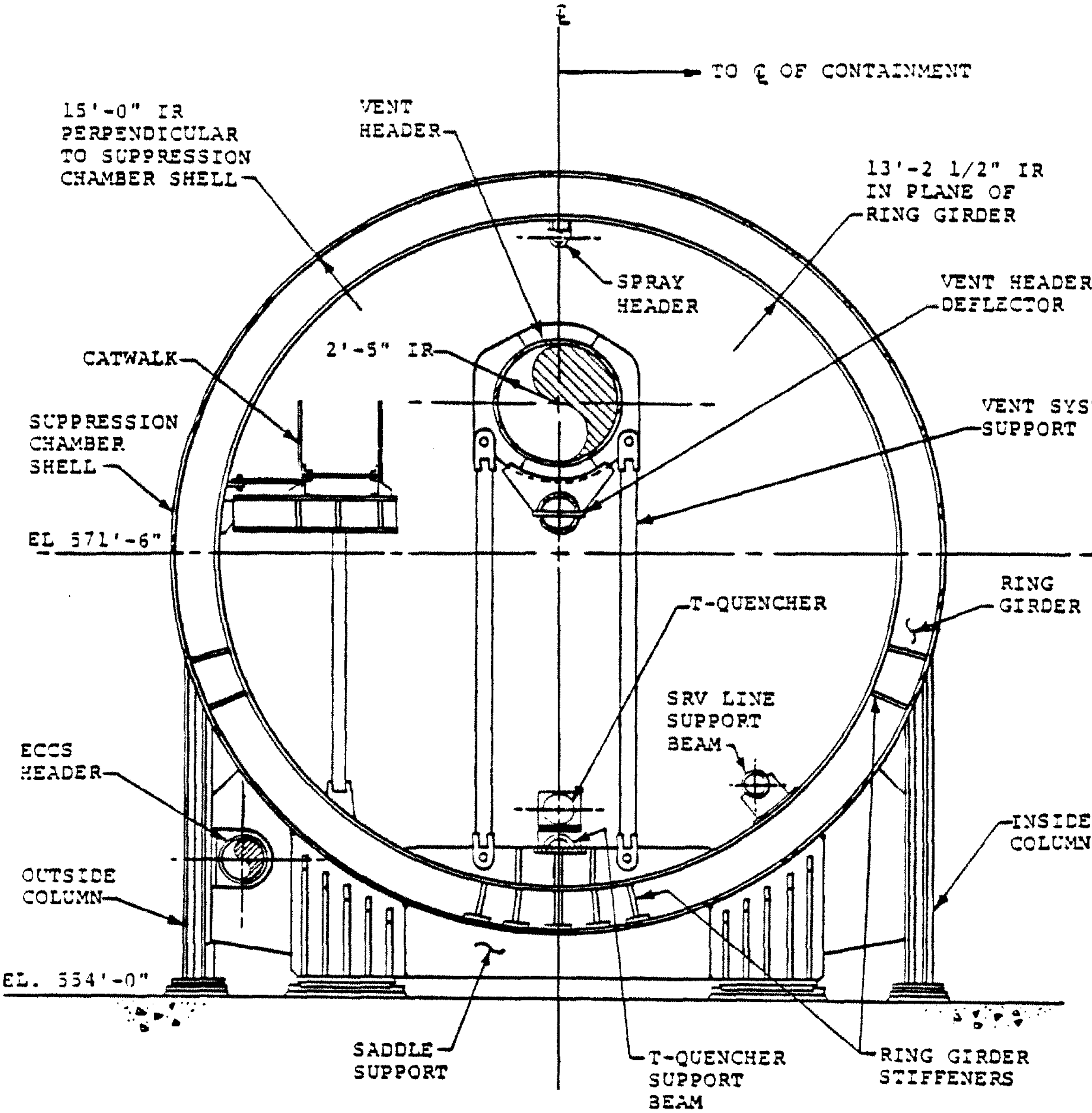
FIGURE 6.2-2



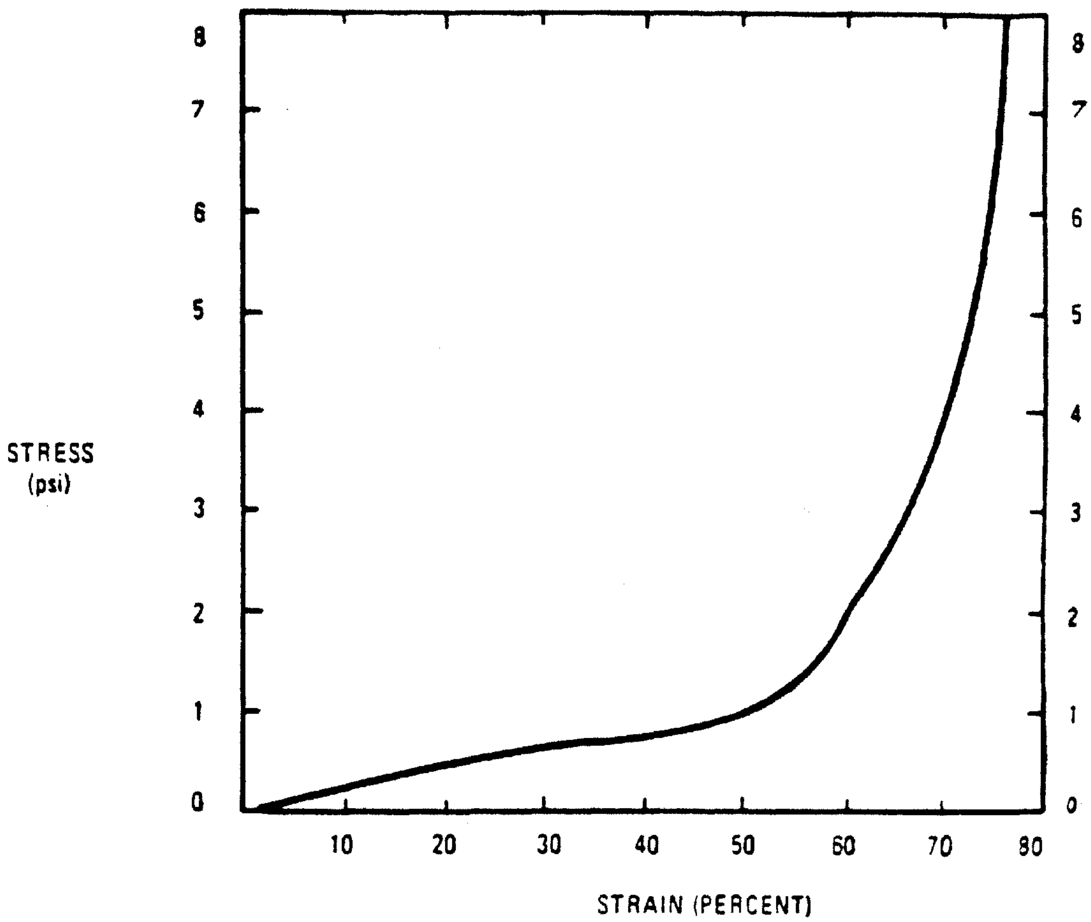
QUAD CITIES STATION UNITS 1 & 2
PLAN VIEW OF CONTAINMENT
FIGURE 6.2-3



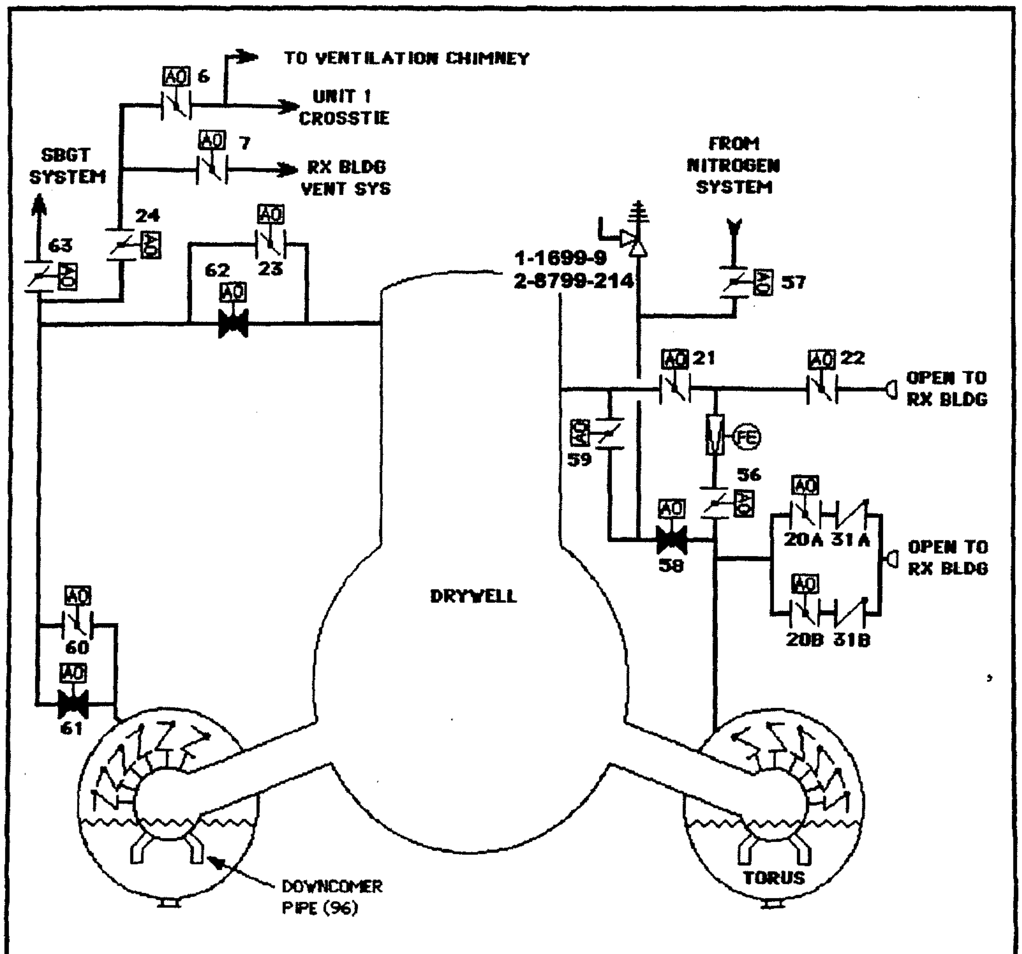
QUAD CITIES STATION UNITS 1 & 2
SUPPRESSION CHAMBER SECTION MIDBAY VENT LINE BAY
FIGURE 6.2-4



QUAD CITIES STATION UNITS 1 & 2
SUPPRESSION CHAMBER SECTION - MITERJOINT
FIGURE 6.2-5



QUAD CITIES STATION UNITS 1 & 2
RESILIENT CHARACTERISTICS OF POLYURETHANE
FIGURE 6.2-6

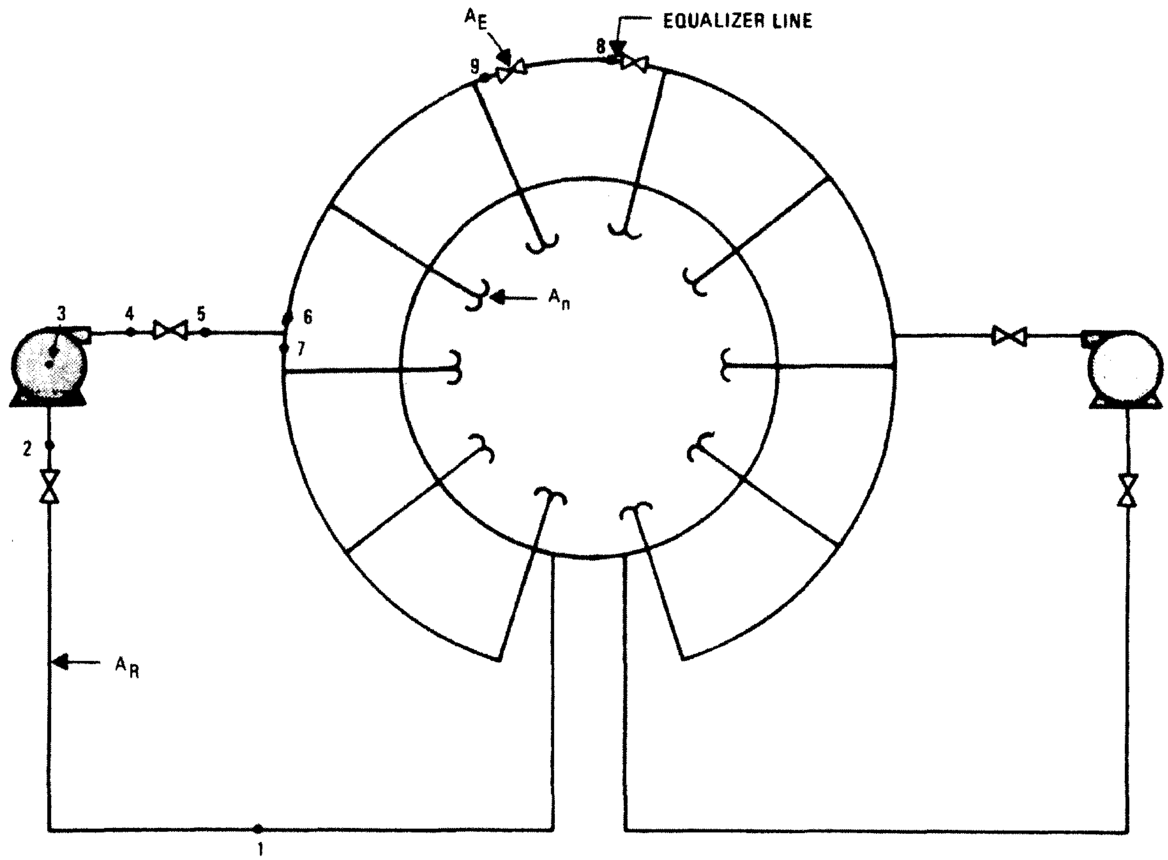


QUAD CITIES STATION UNITS 1 & 2

DIAGRAM OF
PRESSURE SUPPRESSION PIPING

FIGURE 6.2-7

REVISION 7, JANUARY 2003



A_R = Flow area in recirculation line

A_E = Flow area through equalizer line valve

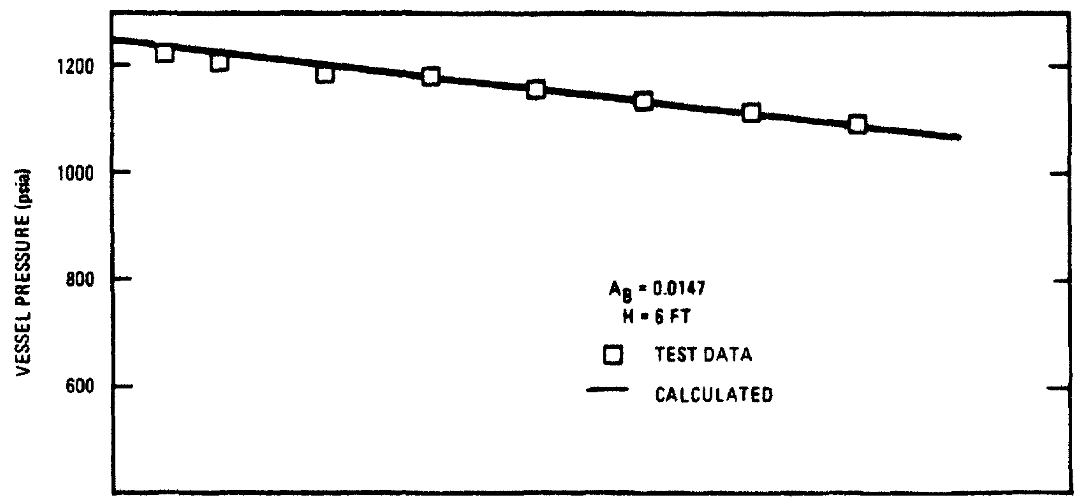
A_n = Flow area of a jet pump nozzle

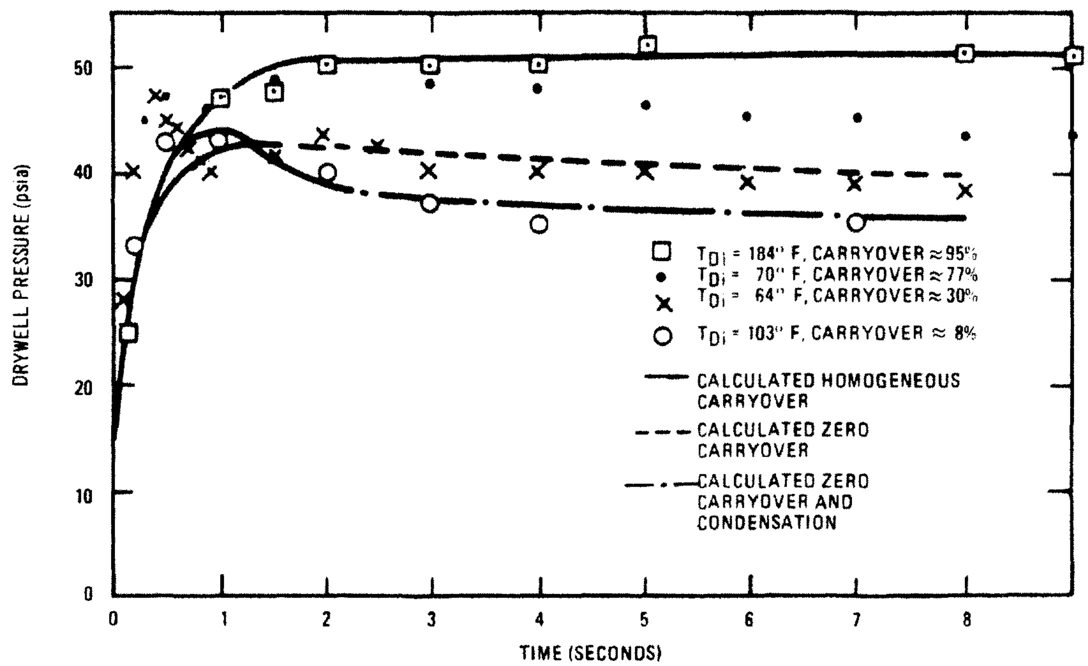
N = Number of jet pumps per header

QUAD CITIES STATION
UNITS 1 & 2

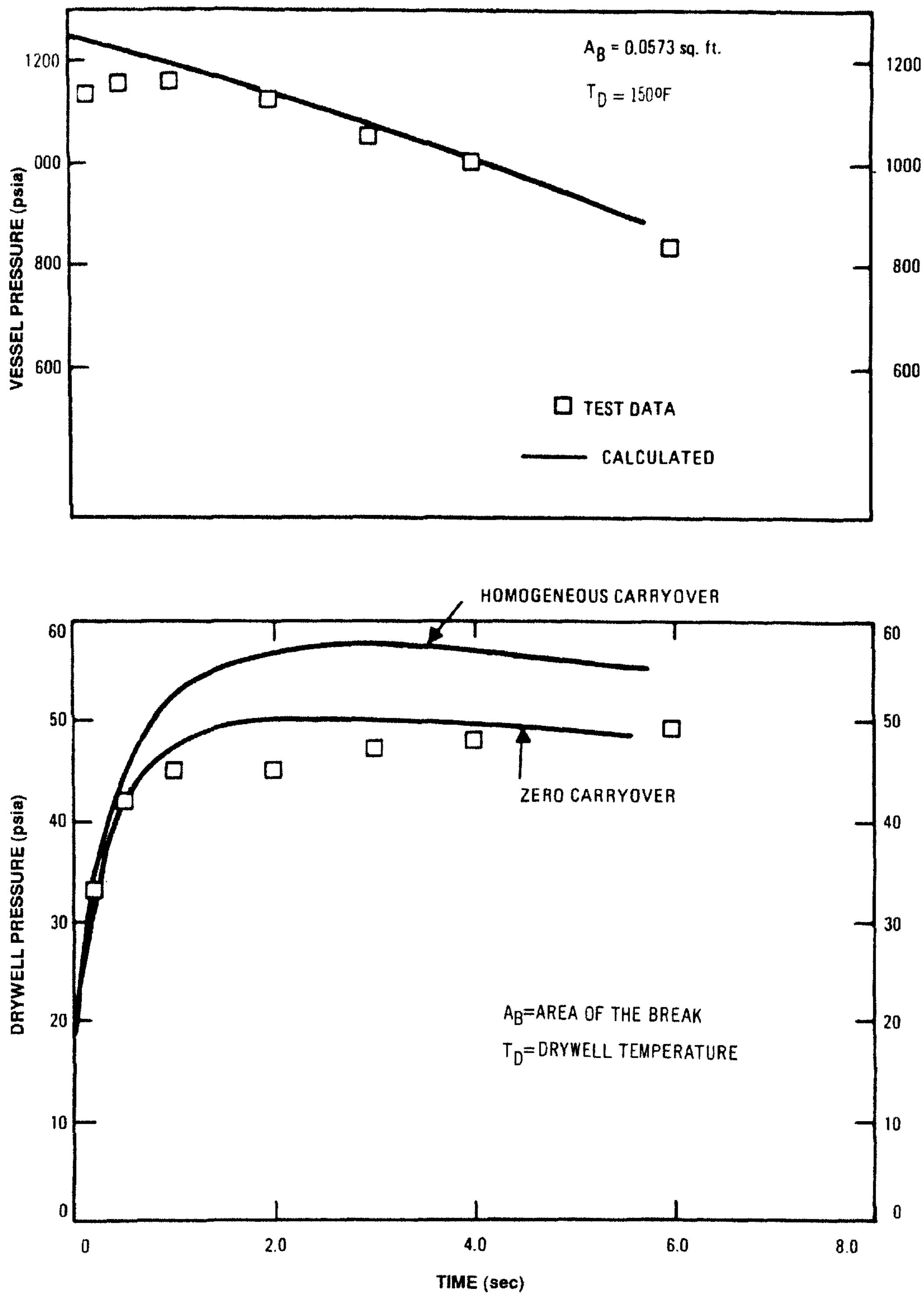
RECIRCULATION LINE BREAK - ILLUSTRATION

FIGURE 6.2-11

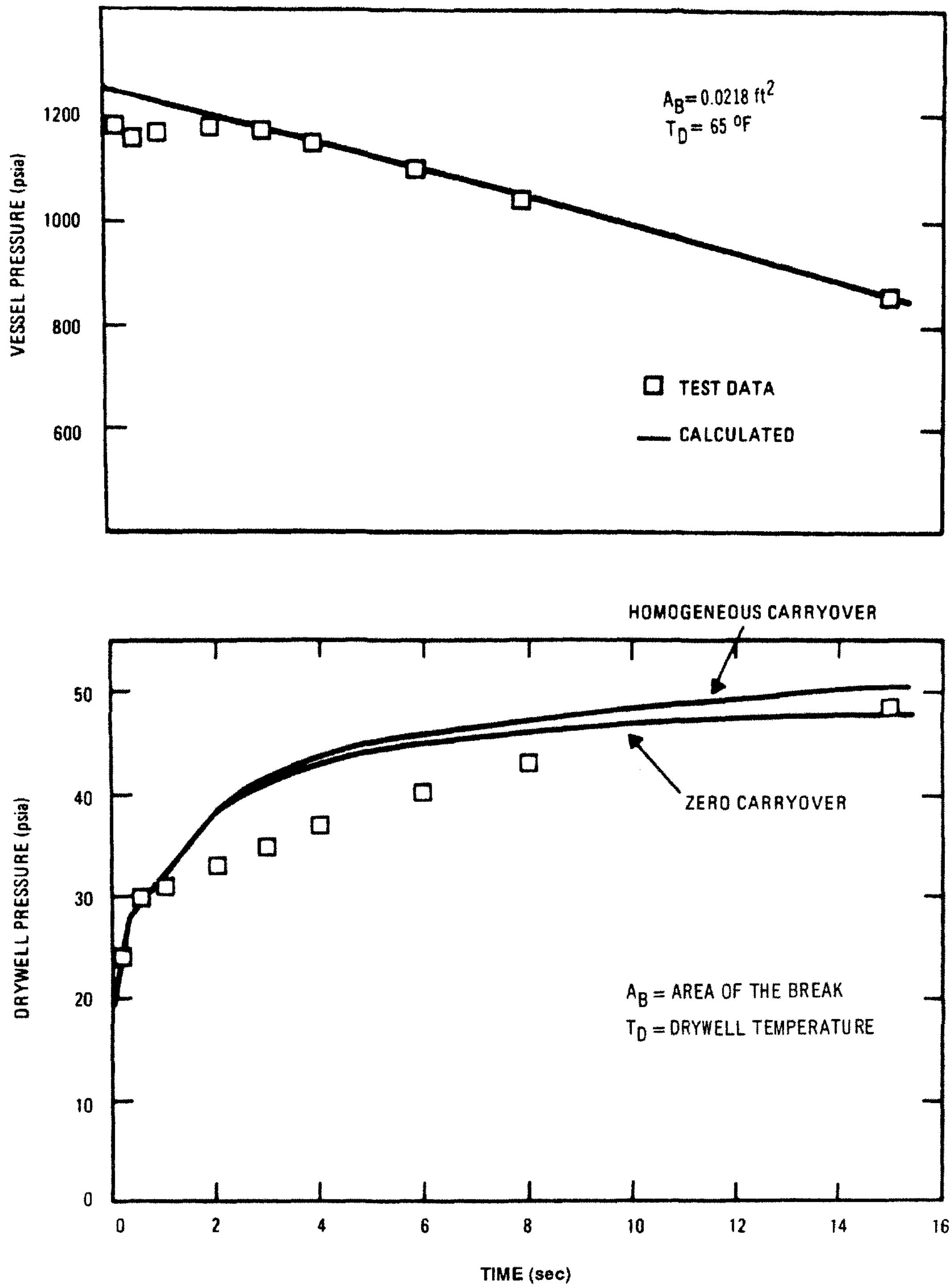




QUAD CITIES STATION UNITS 1 & 2
PRESSURE RESPONSE CALCULATIONS AND MEASUREMENTS
FIGURE 6.2-12



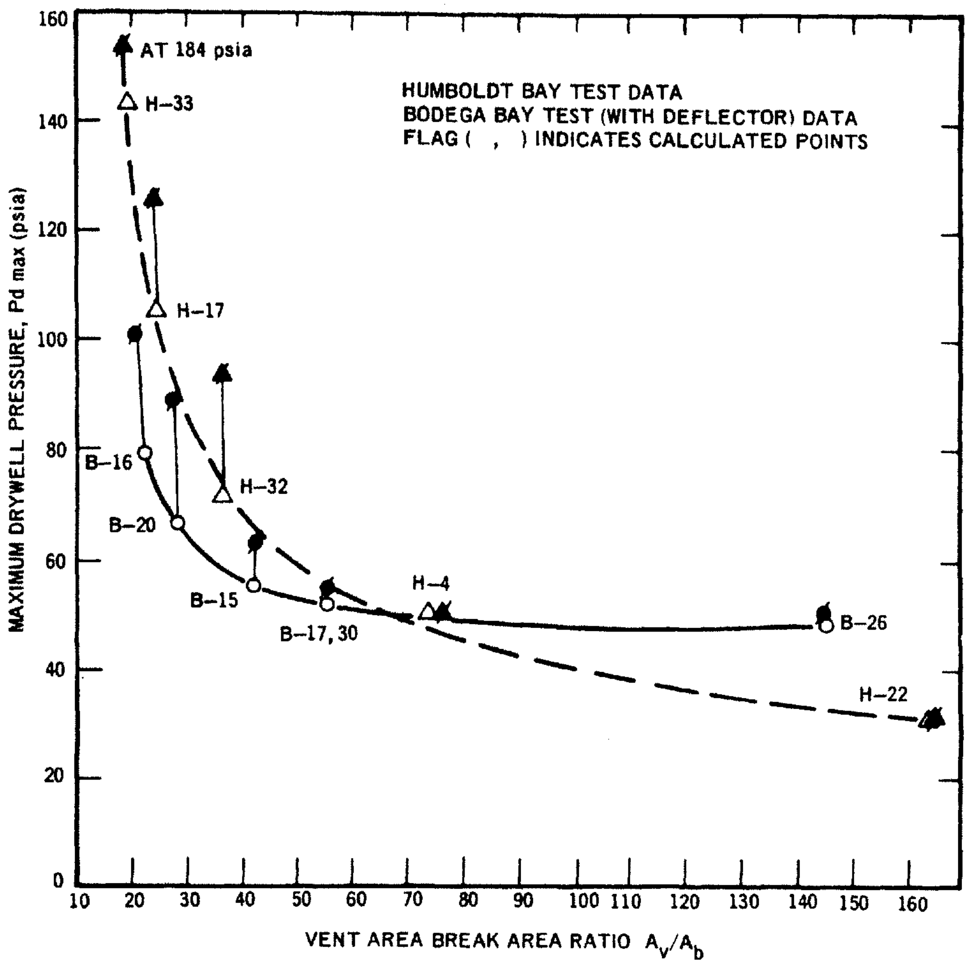
QUAD CITIES STATION UNITS 1 & 2
BODEGA BAY TESTS VESSEL PRESSURE AND DRYWELL PRESSURE
FIGURE 6.2-13



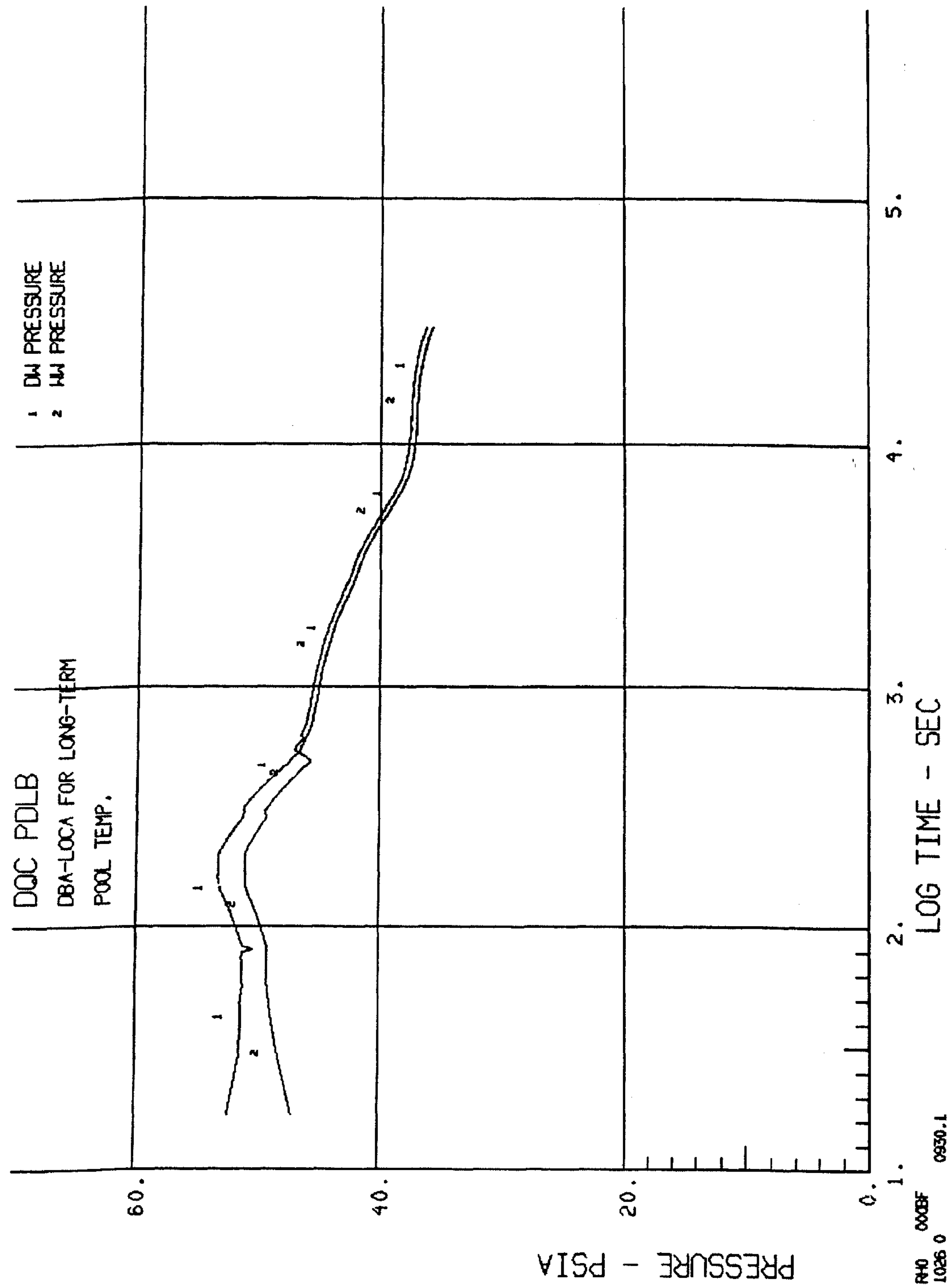
QUAD CITIES STATION
UNITS 1 & 2

BODEGA BAY TESTS
VESSEL AND DRYWELL PRESSURE

FIGURE 6.2-14



QUAD CITIES STATION UNITS 1 & 2
COMPARISON OF CALCULATED AND MEASURED PEAK DRYWELL PRESSURE
FIGURE 6.2-15

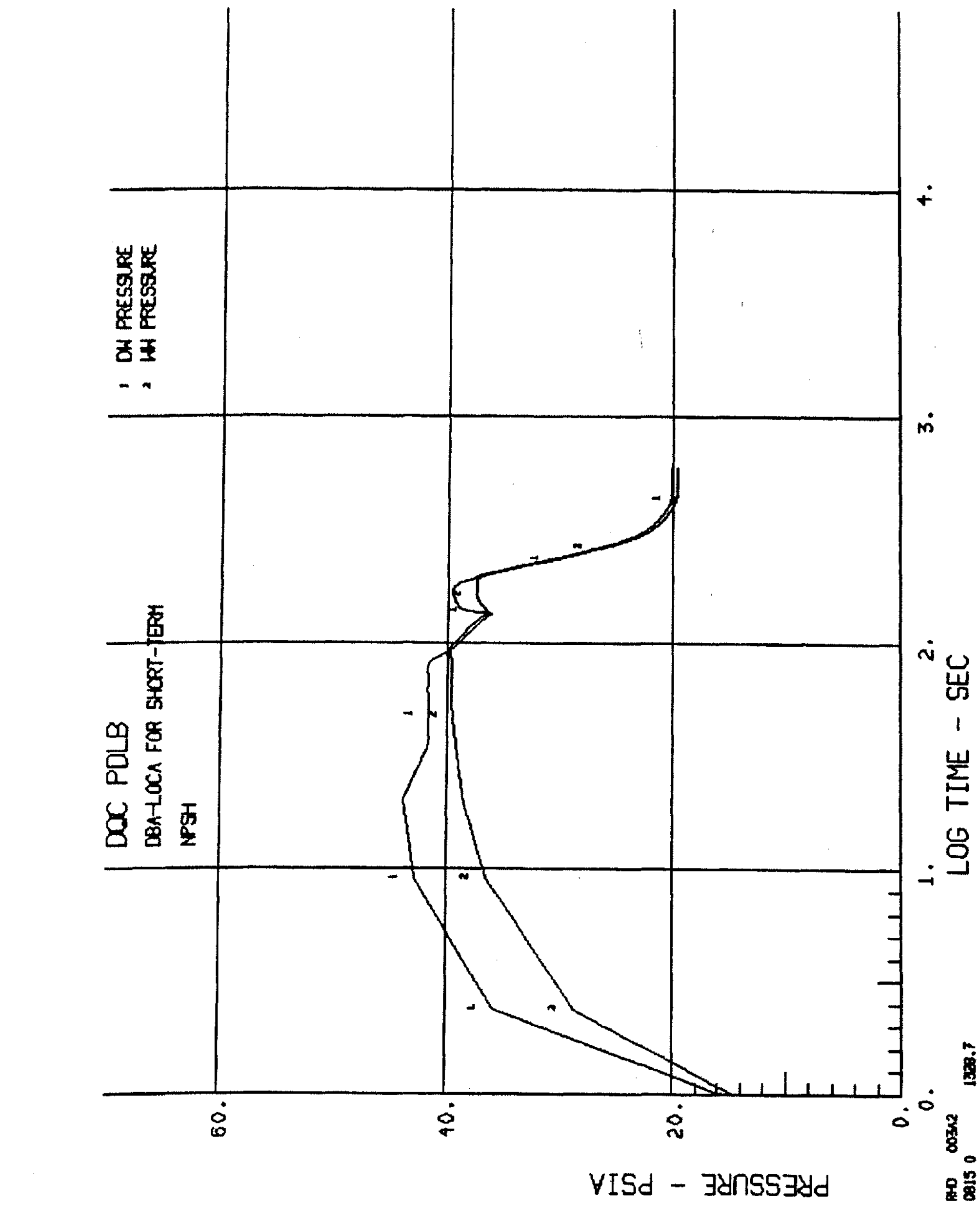


QUAD CITIES STATION
UNITS 1 & 2

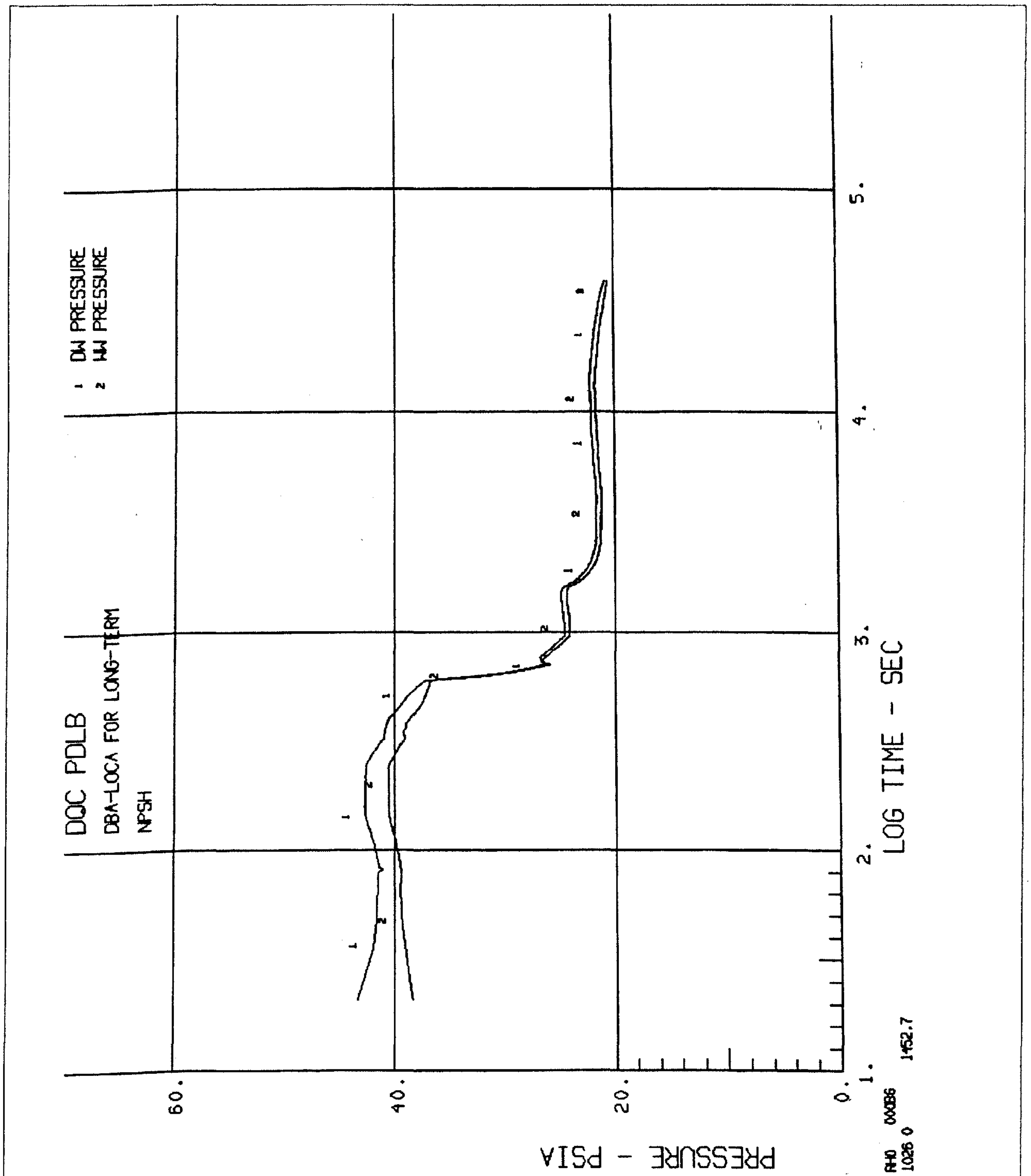
LONG-TERM CONTAINMENT PRESSURE RESPONSE TO DBA-LOCA FOR QUAD CITIES (AT 2957 MWt)

FIGURE 6.2-16a

REVISION 7, JANUARY 2003



QUAD CITIES STATION UNITS 1 & 2
SHORT-TERM CONTAINMENT PRESSURE RESPONSE (FOR NPSH) TO DBA-LOCA FOR QUAD CITIES (AT 2957 MWt)
FIGURE 6.2-16b REVISION 7, JANUARY 2003

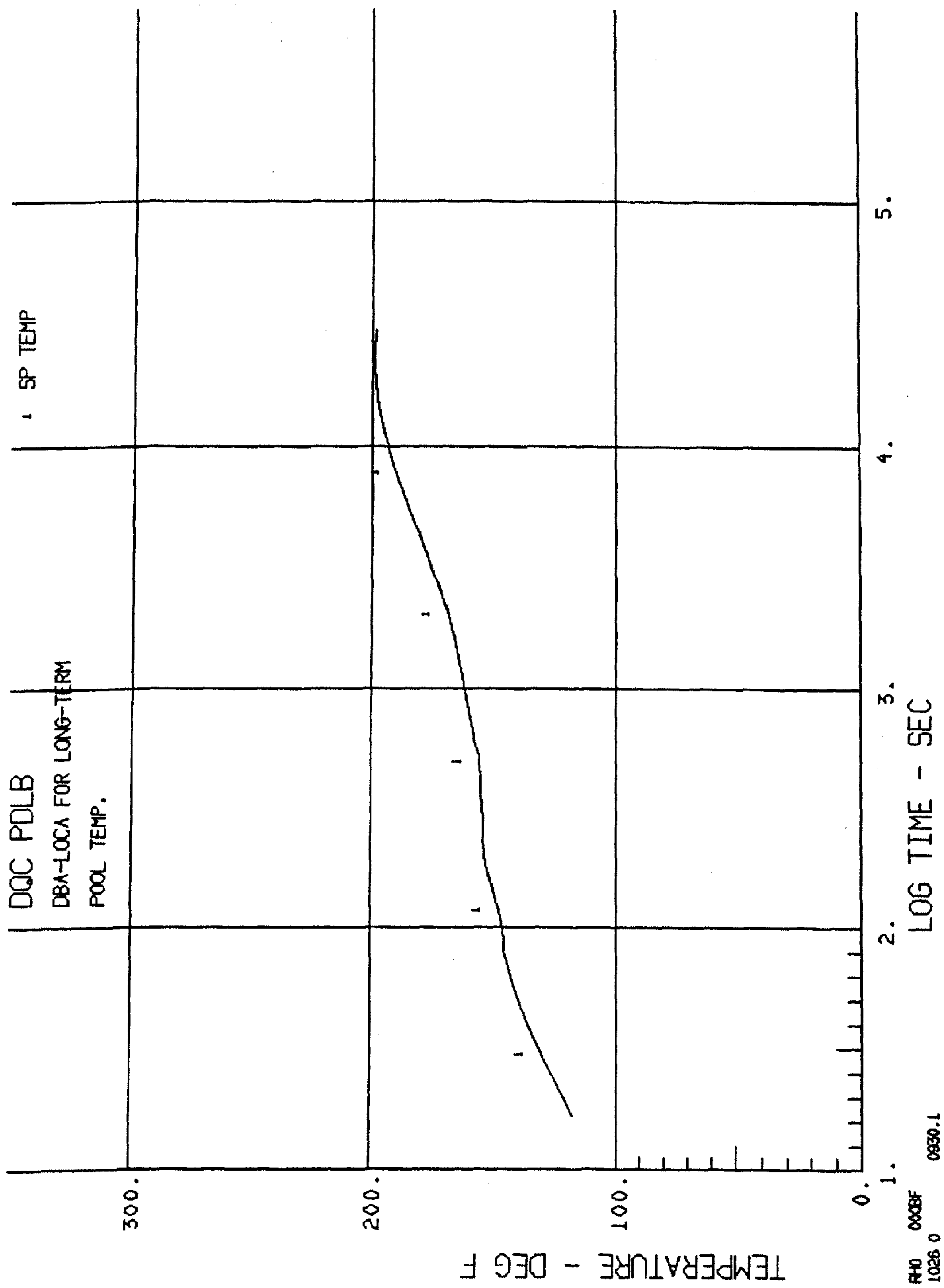


QUAD CITIES STATION
UNITS 1 & 2

LONG-TERM CONTAINMENT PRESSURE RESPONSE (FOR NPSH) TO DBA-LOCA FOR QUAD CITIES (AT 2957 MWt)

FIGURE 6.2-16c

REVISION 7, JANUARY 2003

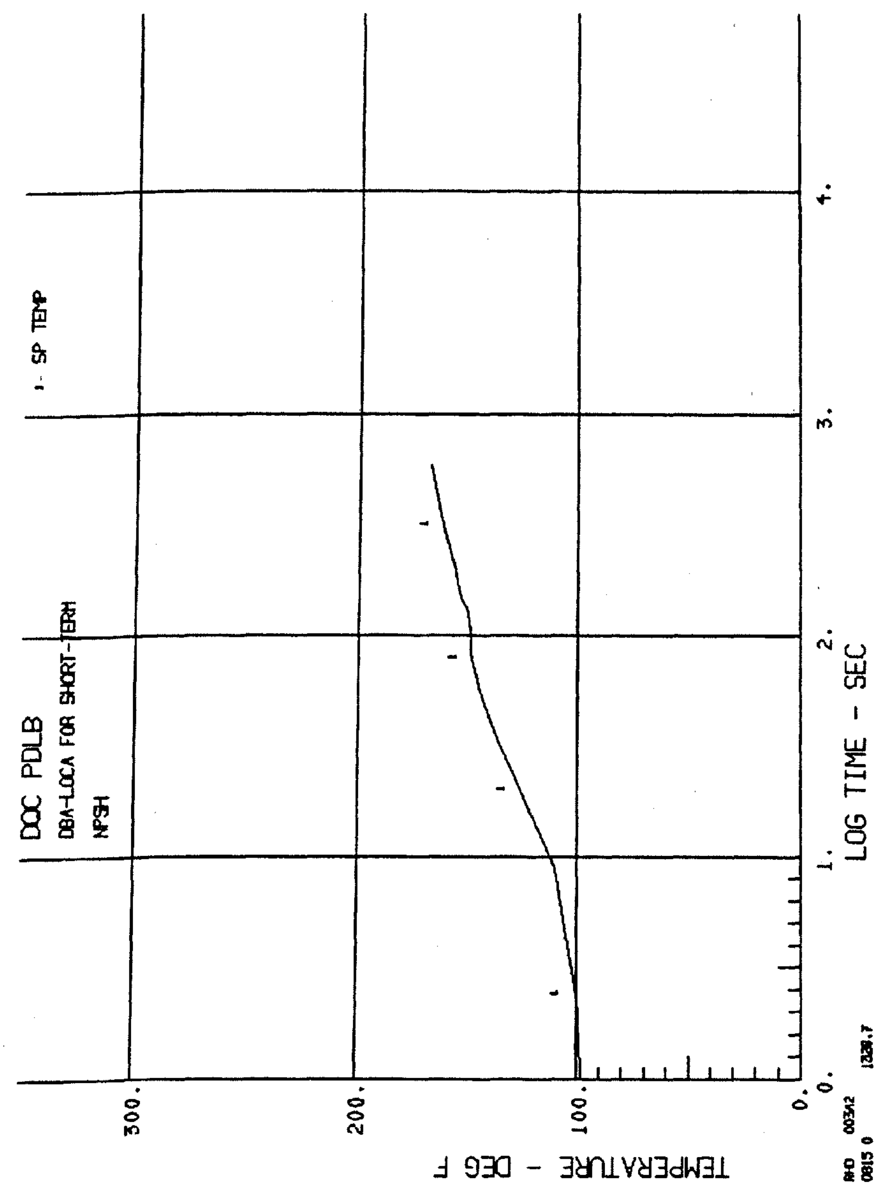


QUAD CITIES STATION
UNITS 1 & 2

LONG-TERM SUPPRESSION POOL TEMPERATURE RESPONSE TO DBA-LOCA FOR QUAD CITIES (AT 2957MWt)

FIGURE 6.2-18a

REVISION 7, JANUARY 2003

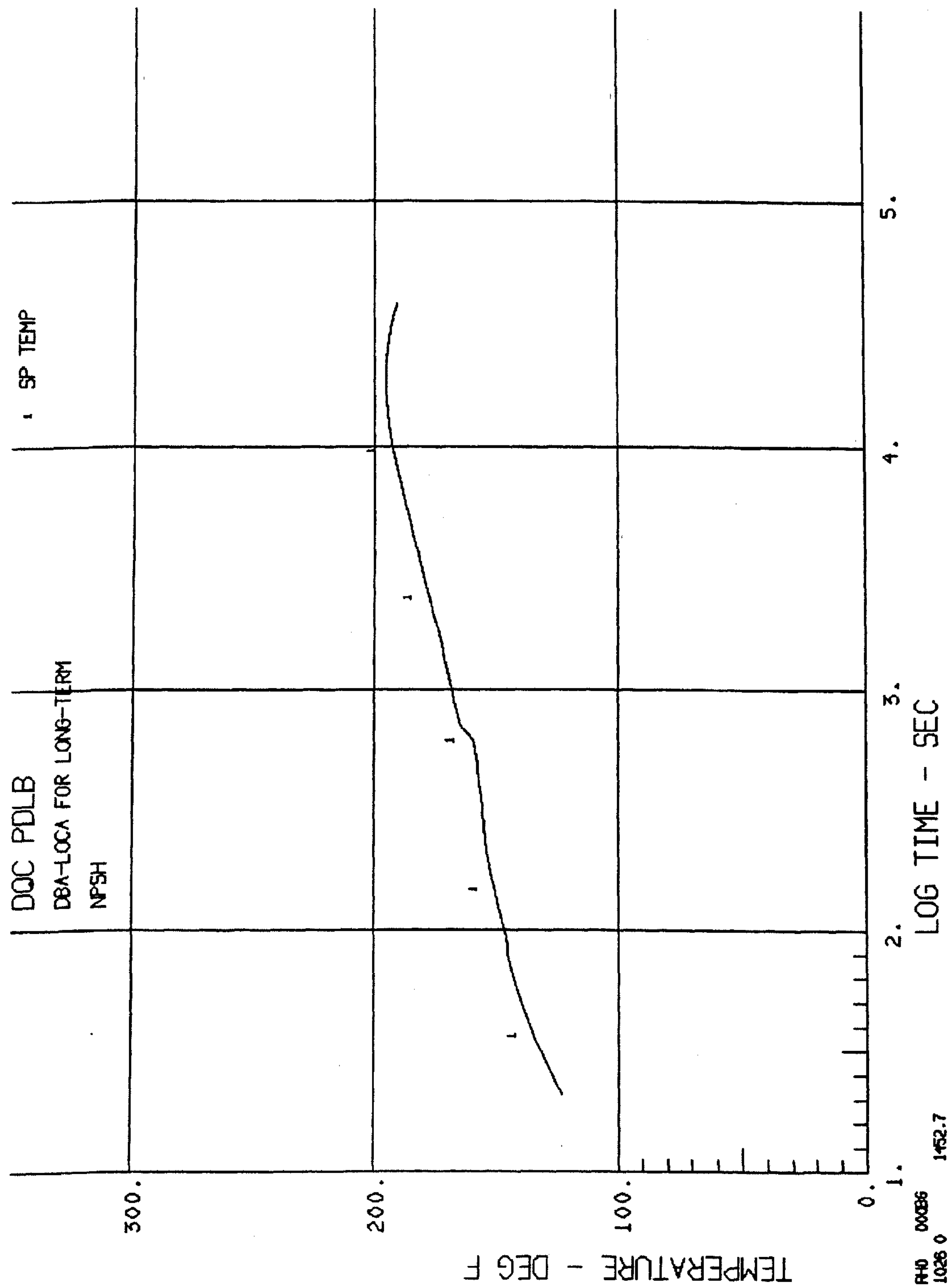


QUAD CITIES STATION
UNITS 1 & 2

SHORT-TERM SUPPRESSION POOL TEMPERATURE RESPONSE (FOR NPSH) TO DBA-LOCA FOR QUAD CITIES (AT 2957 MWt)

FIGURE 6.2-18b

REVISION 7, JANUARY 2003

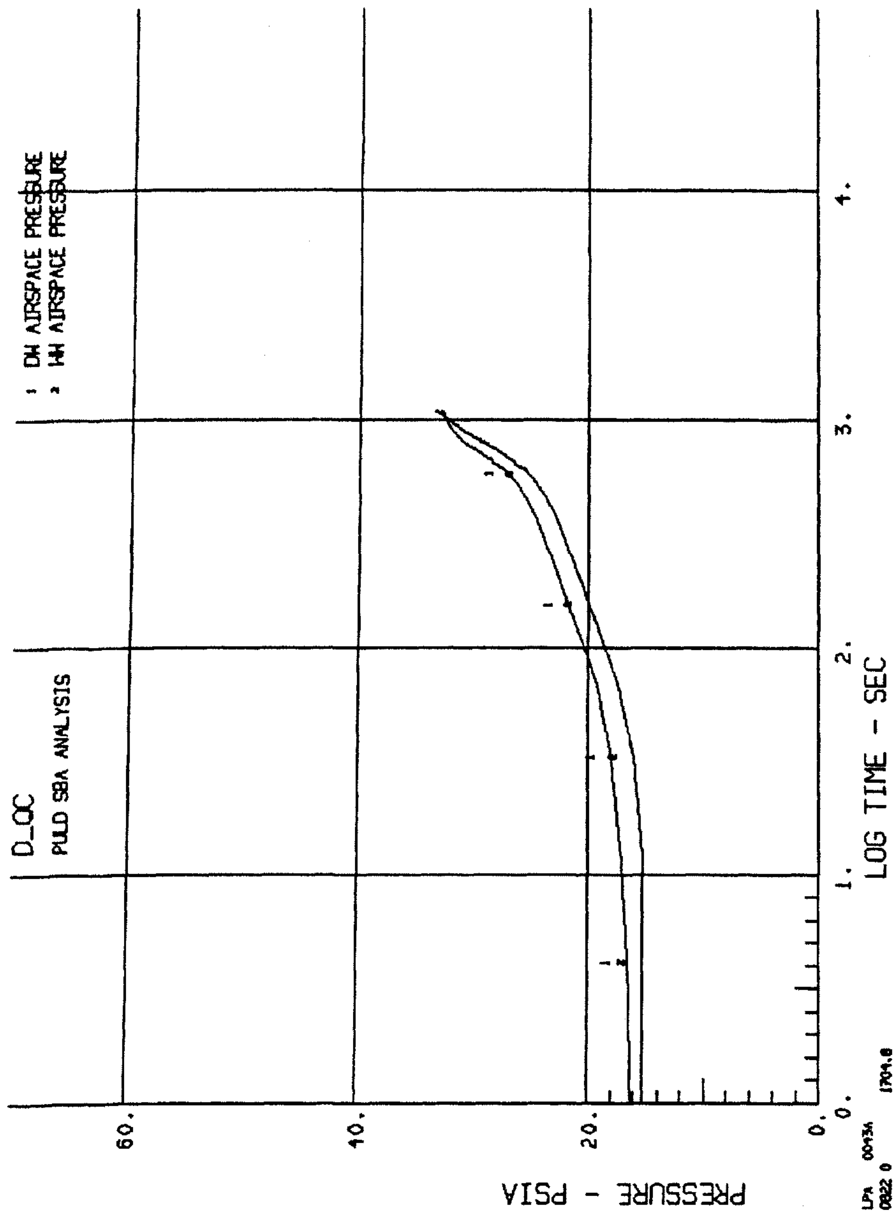


QUAD CITIES STATION
UNITS 1 & 2

LONG-TERM SUPPRESSION POOL TEMPERATURE RESPONSE (FOR NPSH) TO DBA-LOCA FOR QUAD CITIES (AT 2957 MWt)

FIGURE 6.2-18c

REVISION 7, JANUARY 2003



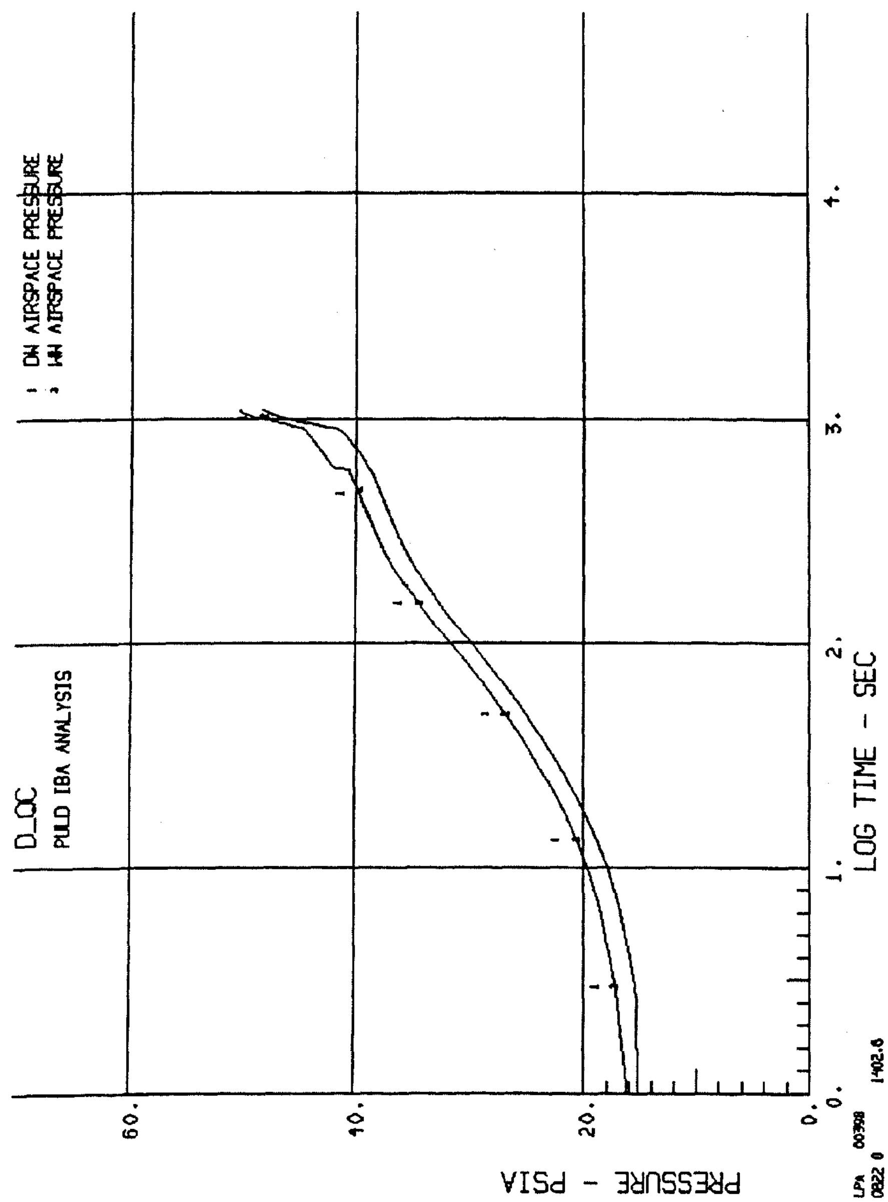
QUAD CITIES STATION

UNITS 1 & 2

CONTAINMENT PRESSURE RESPONSE TO SBA FOR QUAD CITIES (AT 2957 MWt)

FIGURE 6.2-20a

REVISION 7, JANUARY 2003

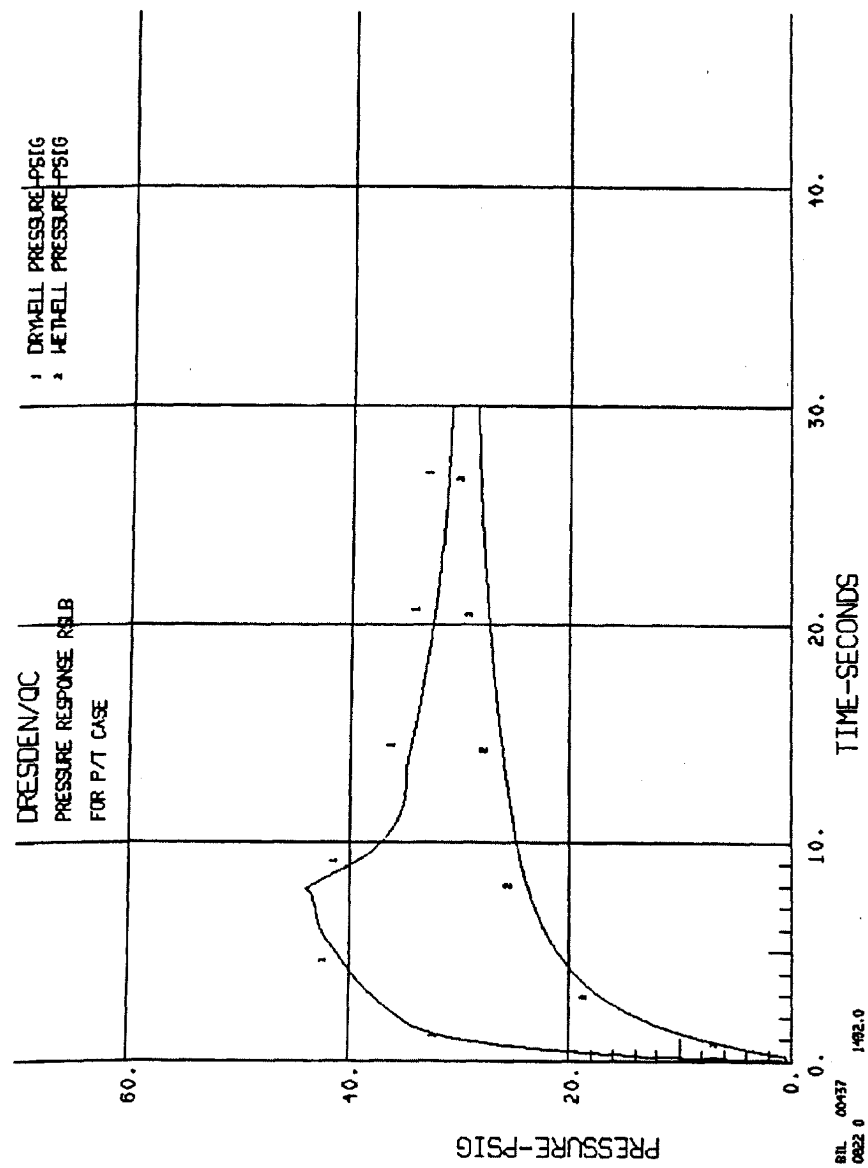


QUAD CITIES STATION
UNITS 1 & 2

CONTAINMENT PRESSURE RESPONSE TO IBA FOR QUAD CITIES (AT 2957 MWt)

FIGURE 6.2-21a

REVISION 7, JANUARY 2003



QUAD CITIES STATION

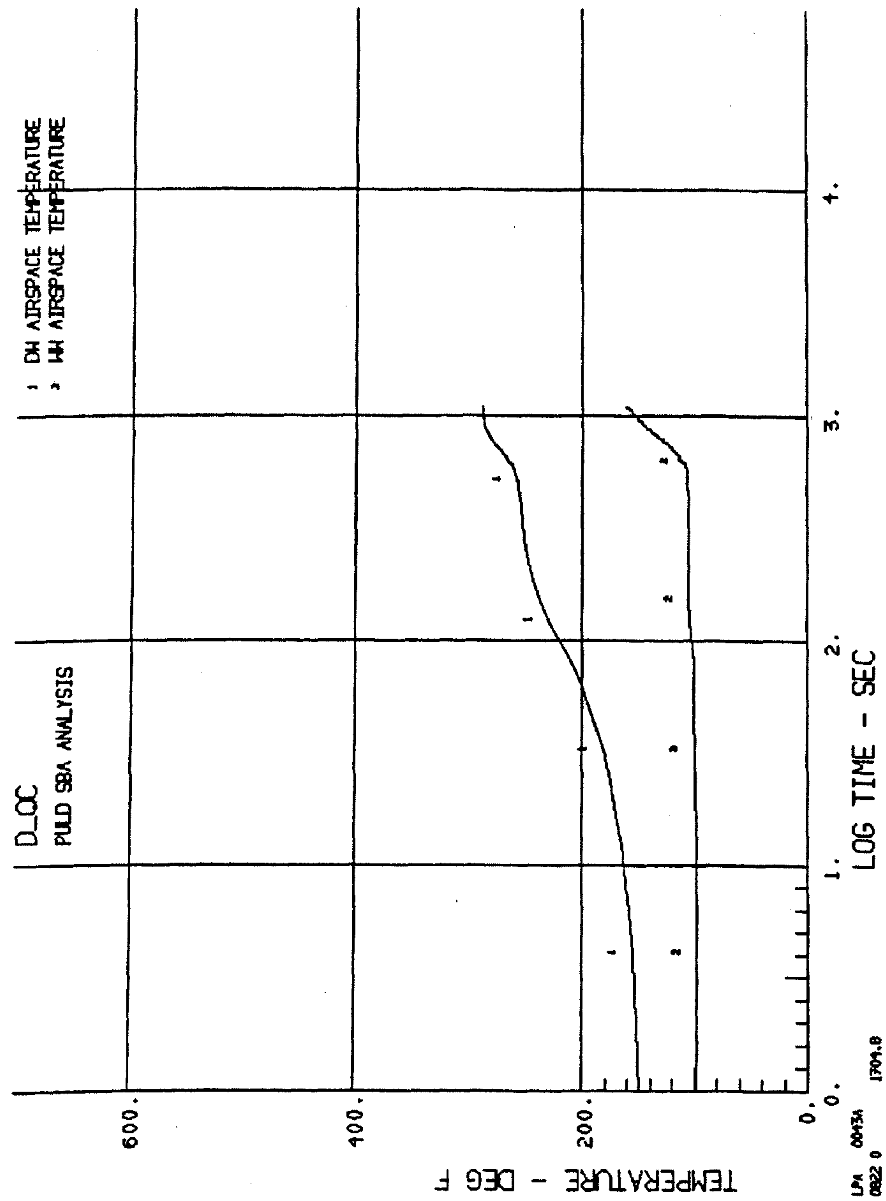
UNITS 1 & 2

SHORT-TERM CONTAINMENT PRESSURE RESPONSE TO

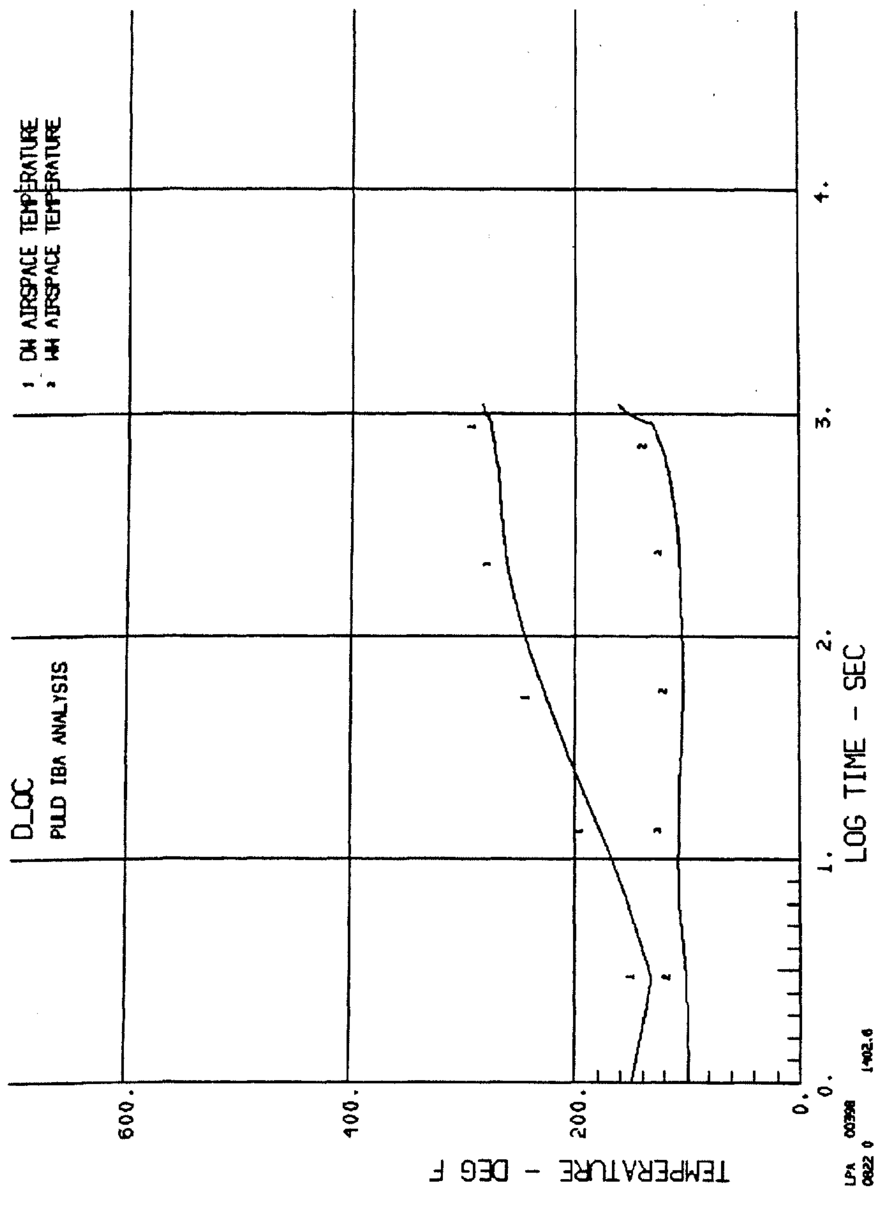
DBA-LOCA FOR QUAD CITIES (AT 2957 MWt)

FIGURE 6.2-22a

REVISION 7, JANUARY 2003



QUAD CITIES STATION UNITS 1 & 2
CONTAINMENT TEMPERATURE RESPONSE TO SBA FOR QUAD CITIES (AT 2957 MWt)
FIGURE 6.2-23a REVISION 7, JANUARY 2003

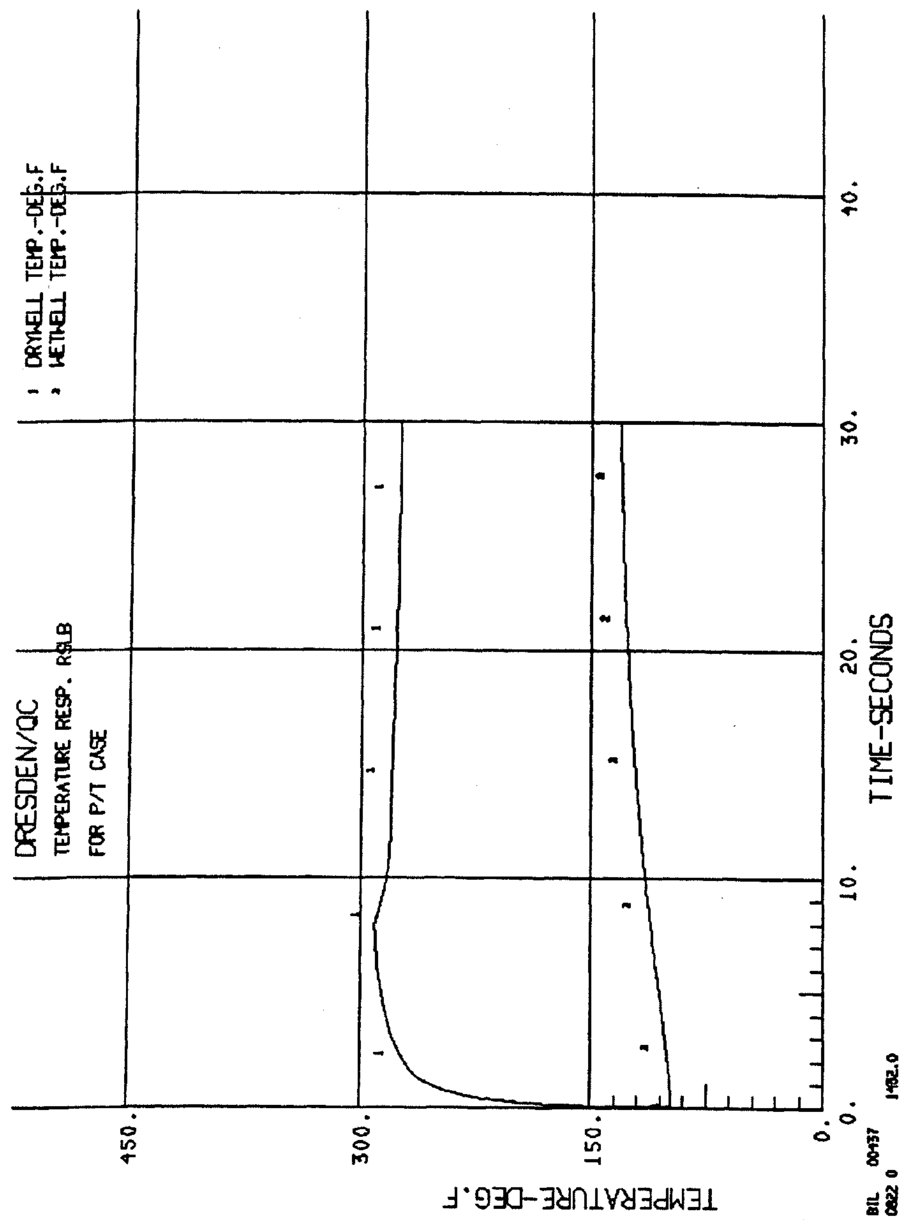


QUAD CITIES STATION
UNITS 1 & 2

CONTAINMENT TEMPERATURE RESPONSE TO IBA FOR QUAD CITIES (AT 2957 MWt)

FIGURE 6.2-24a

REVISION 7, JANUARY 2003

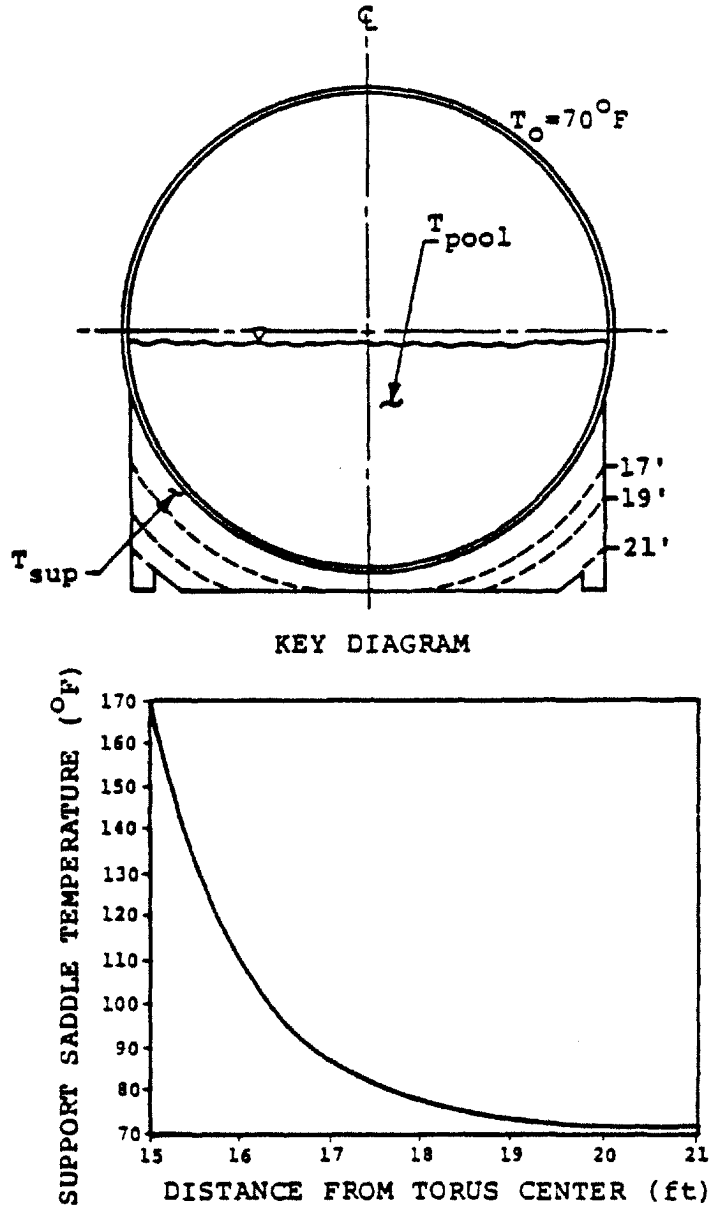


QUAD CITIES STATION
UNITS 1 & 2

SHORT-TERM CONTAINMENT TEMPERATURE RESPONSE TO DBA-LOCA FOR QUAD CITIES (AT 2957 MWt)

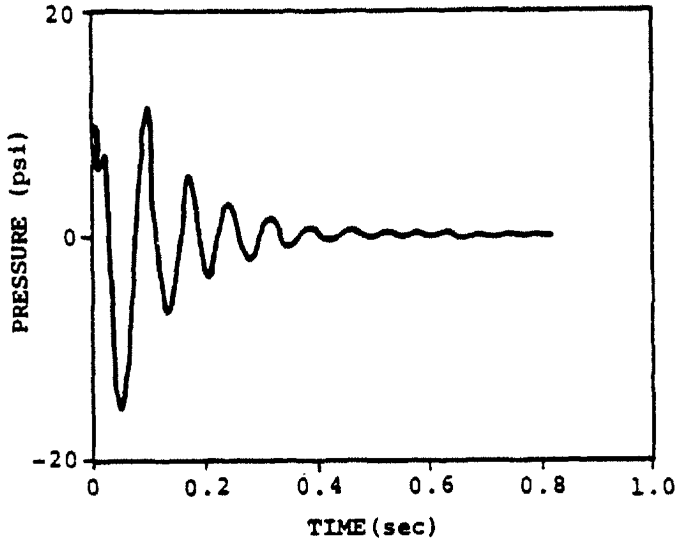
FIGURE 6.2-25a

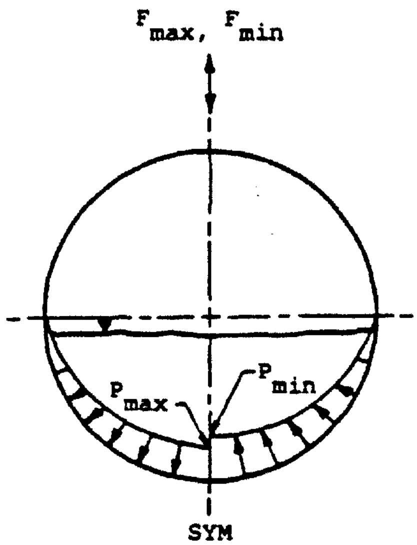
REVISION 7, JANUARY 2003



1. SUPPRESSION POOL TEMPERATURES FOR SBA, IBA, AND DBA EVENTS SHOWN IN FIGURES 6.2-15 THROUGH 6.2-17

QUAD CITIES STATION UNITS 1 & 2
SUPPRESSION CHAMBER SUPPORT DIFFERENTIAL TEMPERATURES
FIGURE 6.2-26





MITERED JOINT SPATIAL DISTRIBUTION

LOADING CHARACTERISTICS

SINGLE VALVE

PRESSURE (psi): LONGEST SRVDL

BUBBLE:

P_{max} = 18.05, P_{min} = -22.05

SHELL:

P_{max} = 11.40, P_{min} = -15.41

TOTAL APPLIED LOAD (kips):

VERTICAL PER MITERED CYLINDER:

DOWNWARD: F_{max} = 763.4

UPWARD: F_{min} = 1031.9

LOAD FREQUENCY (Hz):

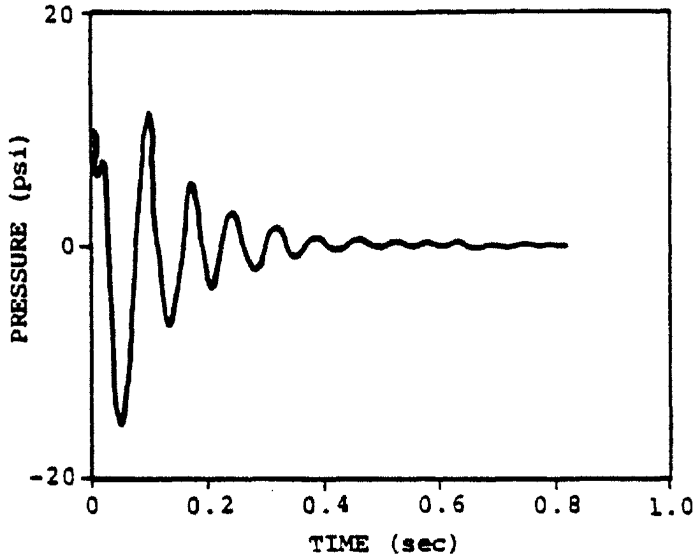
RANGE:

$10.34 \leq f_L \leq 17.24$

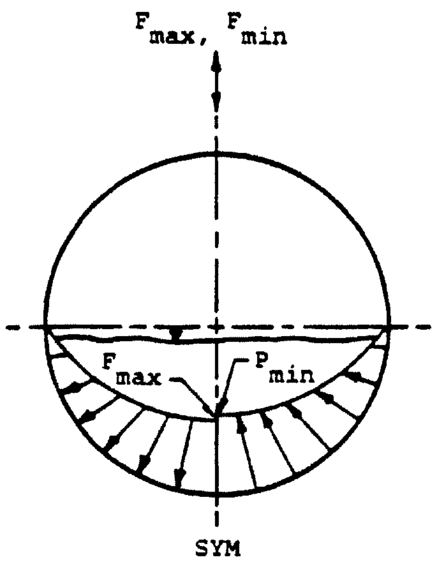
QUAD CITIES STATION
UNITS 1 & 2

SRV DISCHARGE TORUS SHELL LOADS FOR SINGLE VALVE ACTUATION

FIGURE 6.2-27



SHELL PRESSURE FORCING FUNCTION



MITERED JOINT SPATIAL DISTRIBUTION

LOADING CHARACTERISTICS

MULTIPLE VALVE

PRESSURE (psi): LONGEST SRVDL

BUBBLE:

P_{max} = 18.05 P_{min} = -22.05

SHELL: ONE VALVE

P_{max} = 11.40 P_{min} = -12.33

SHELL: ALL VALVES

P_{max} = 17.04 P_{min} = -18.43

TOTAL APPLIED LOAD (kips):

VERTICAL PER MITERED CYLINDER:

DOWNWARD: F_{max} = 1141.0

UPWARD: F_{min} = 1234.1

TOTAL HORIZONTAL
(SEE FIGURE 2-2.2-18):

LATERAL: F_{max} = 649.2

LOAD FREQUENCY (Hz):

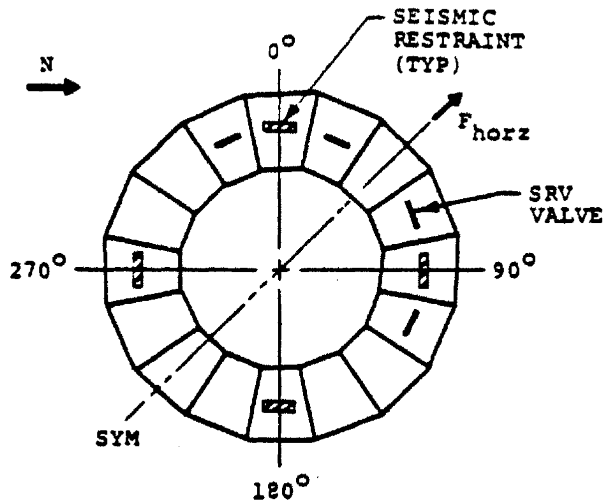
RANGE:

$5.49 \leq f_L \leq 22.11$

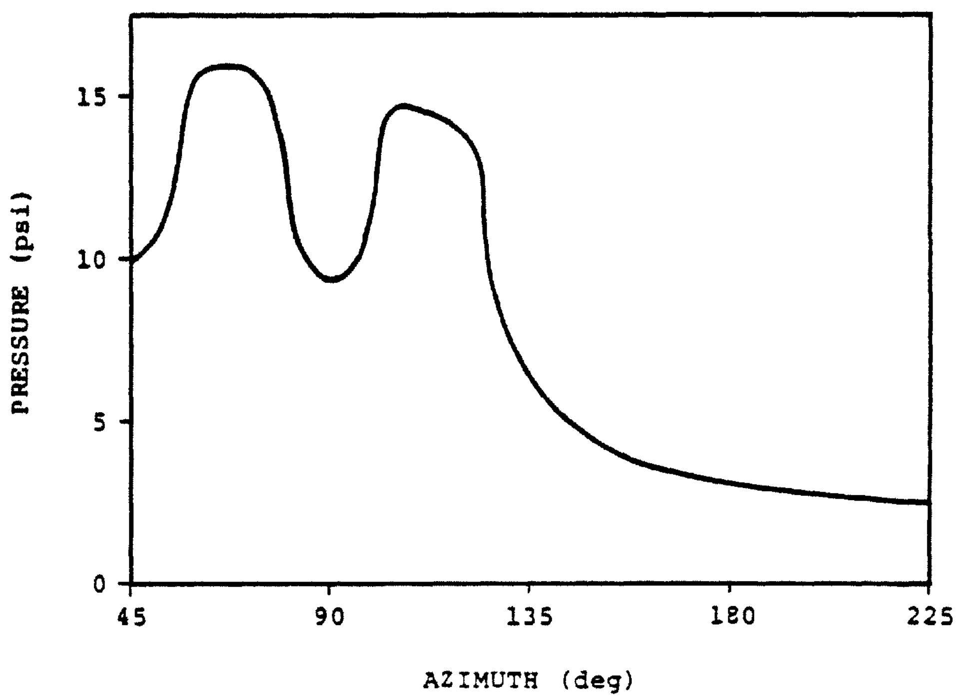
QUAD CITIES STATION
UNITS 1 & 2

SRV DISCHARGE TORUS SHELL LOADS FOR
MULTIPLE VALVE ACTUATION

FIGURE 6.2-28



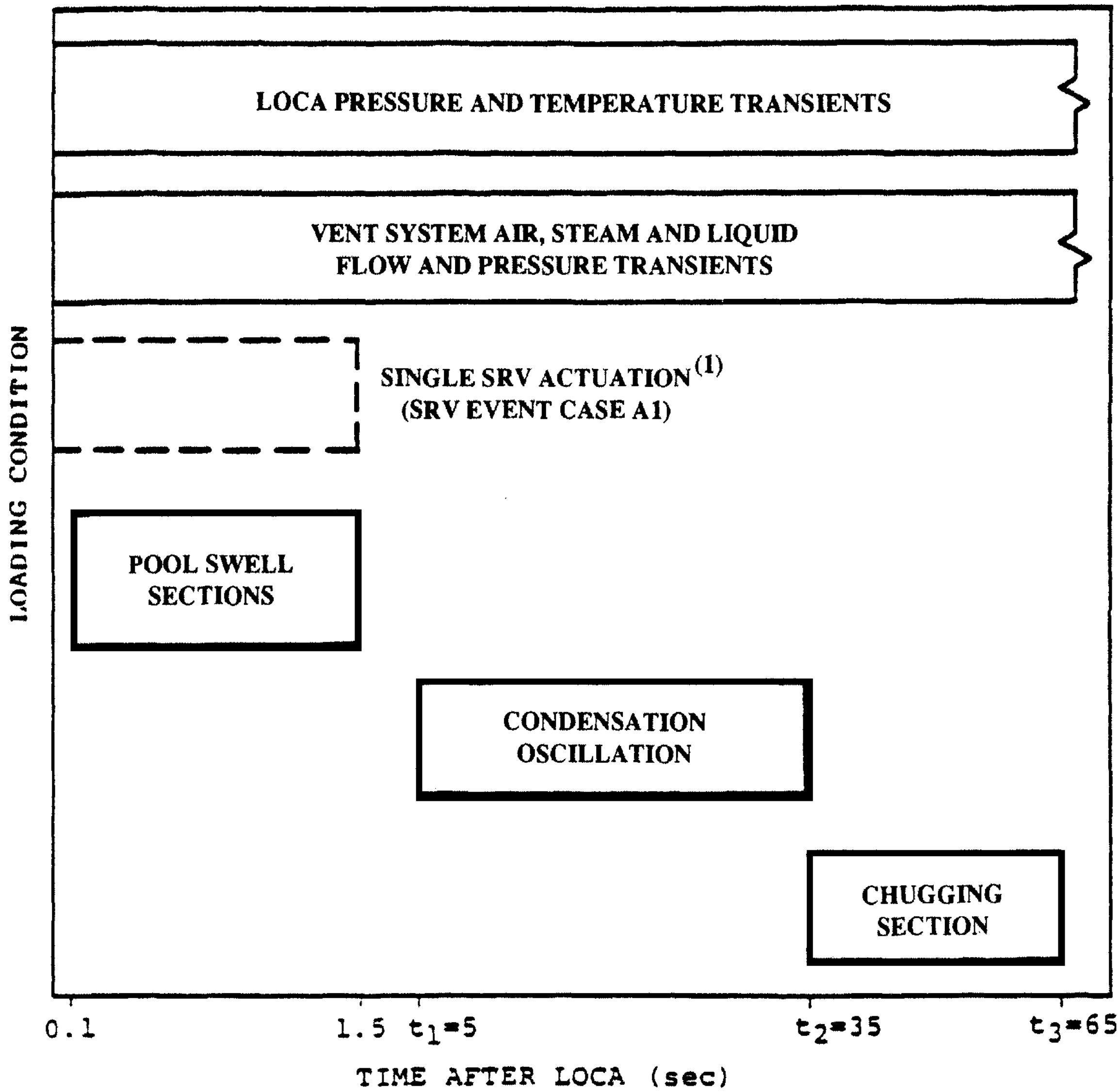
KEY DIAGRAM



QUAD CITIES STATION
UNITS 1 & 2

LONGITUDINAL TORUS SHELL PRESSURE DISTRIBUTION FOR SRV DISCHARGE

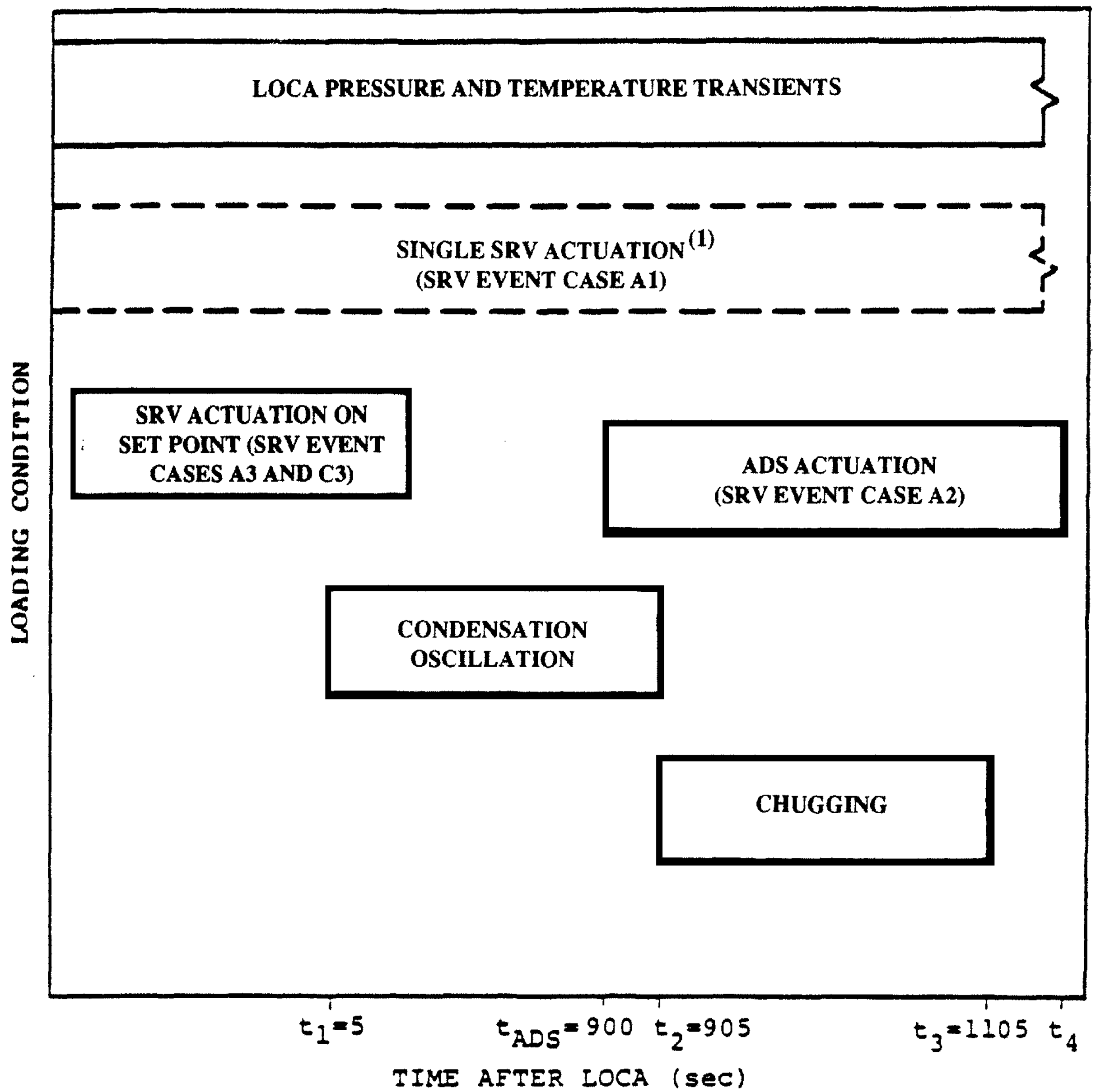
FIGURE 6.2-29



(1) This acutation is assumed to occur coincident with the pool swell event. Although SRV actuation can occur later in the DBA, the resulting air loading on the torus shell is negligible, since the air and water initially in the line will be cleared as the drywell-to-wetwell ΔP increases during the DBA transient.

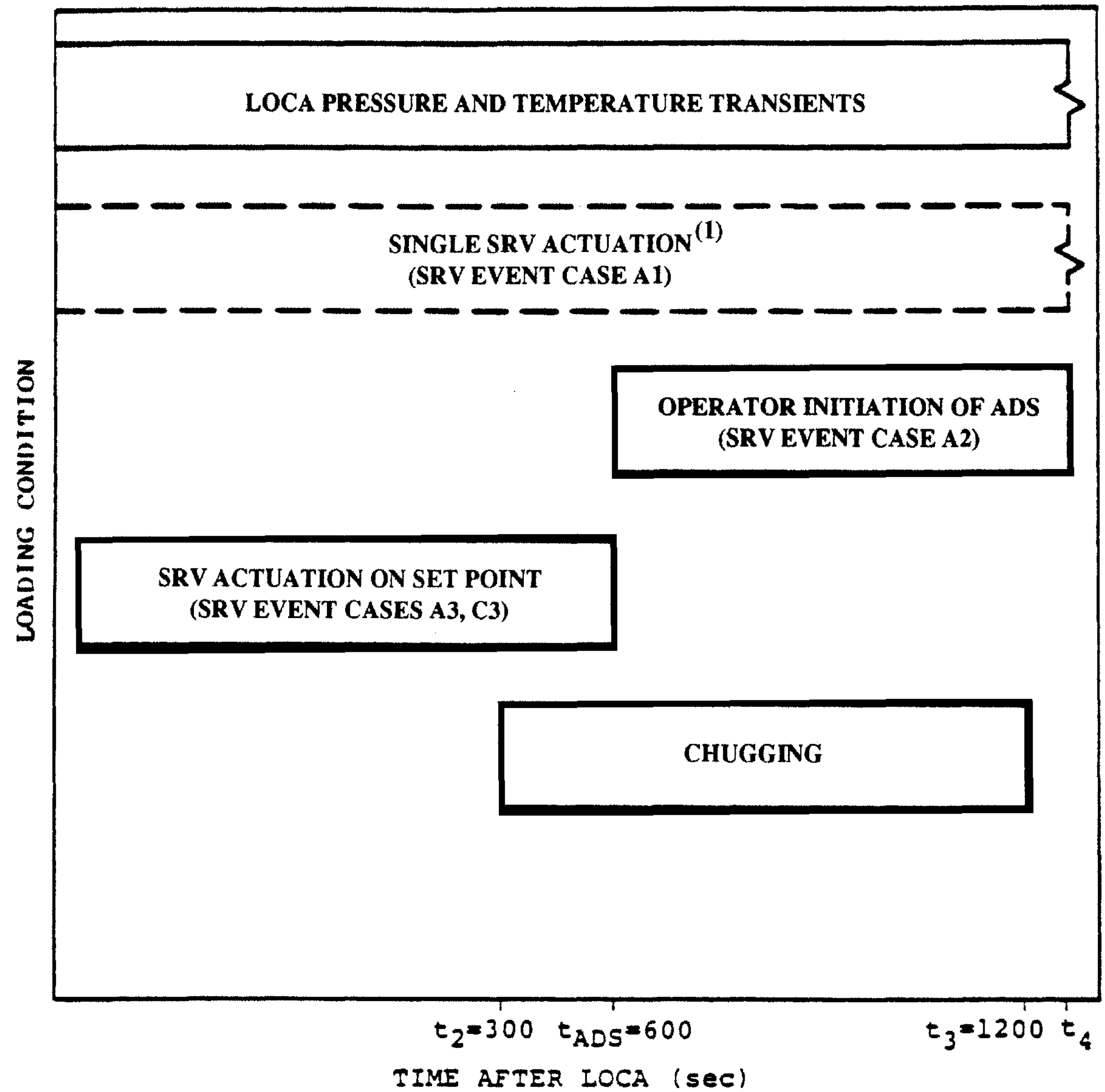
(2) Plant Unique Analysis Report, Volume I, 1-4.1.1

QUAD CITIES STATION UNITS 1 & 2
LOADING CONDITION COMBINATIONS FOR THE VENT HEADER, MAIN VENTS, DOWNCOMERS AND TORUS SHELL DURING A DBA
FIGURE 6.2-31



(1) LOADING NOT COMBINED WITH OTHER SRV CASES.

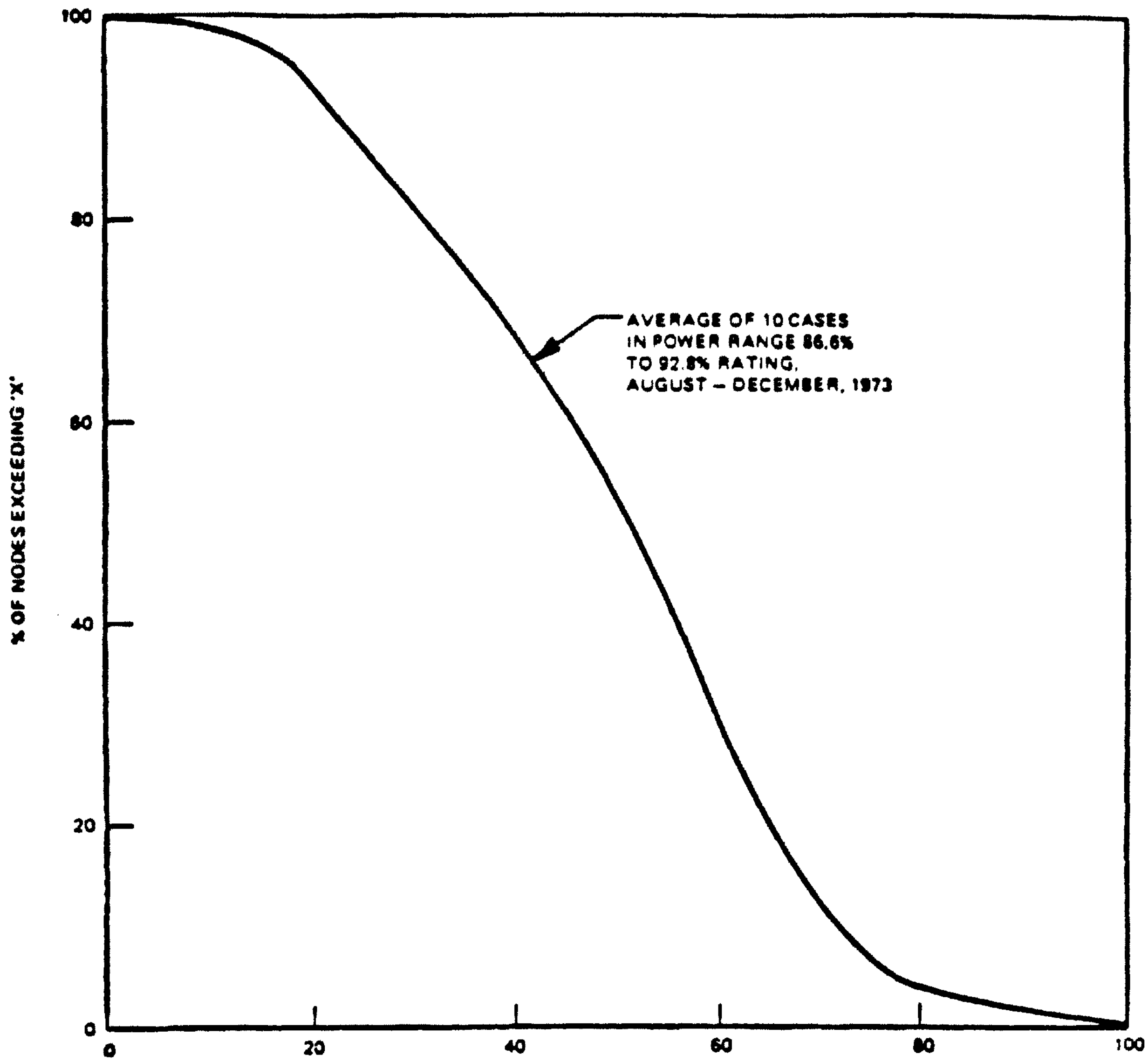
QUAD CITIES STATION UNITS 1 & 2
LOADING CONDITION COMBINATIONS FOR THE VENT HEADER, MAIN VENTS, DOWNCOMERS,TORUS SHELL, AND SUBMERGED STRUCTURES DURING A IBA
FIGURE 6.2-32



(1) LOADING NOT COMBINED WITH OTHER SRV CASES.

(2) Plant Unique Analysis Report, Volume I, 1-4.1.1

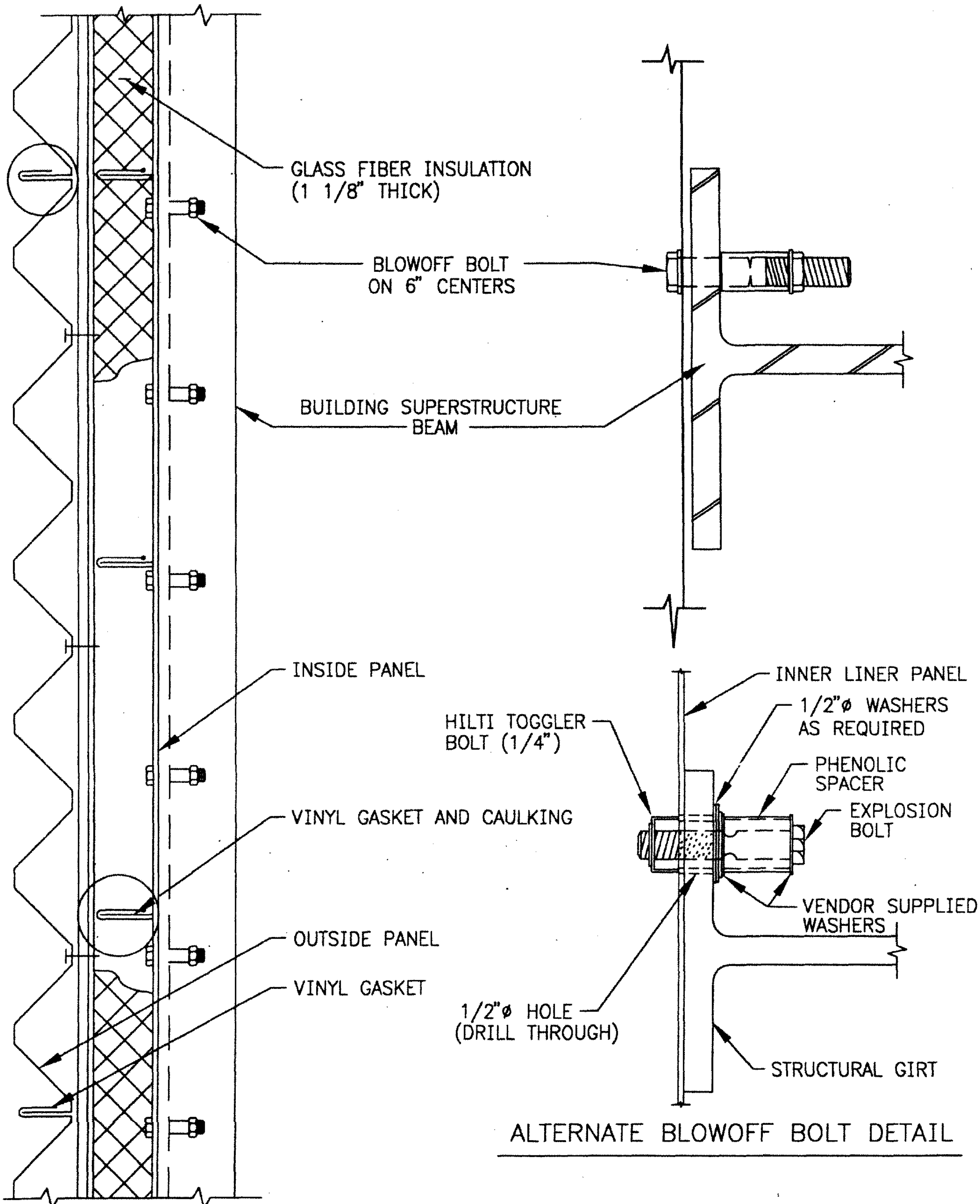
QUAD CITIES STATION UNITS 1 & 2
LOADING CONDITION COMBINATIONS FOR THE VENT HEADER, MAIN VENTS, DOWNCOMERS,TORUS SHELL, AND SUBMERGED STRUCTURES DURING A SBA
FIGURE 6.2-33



'X,' % OF PERMISSIBLE MAPPING

A "NODE" IS A 6-inch BUNDLE SEGMENT

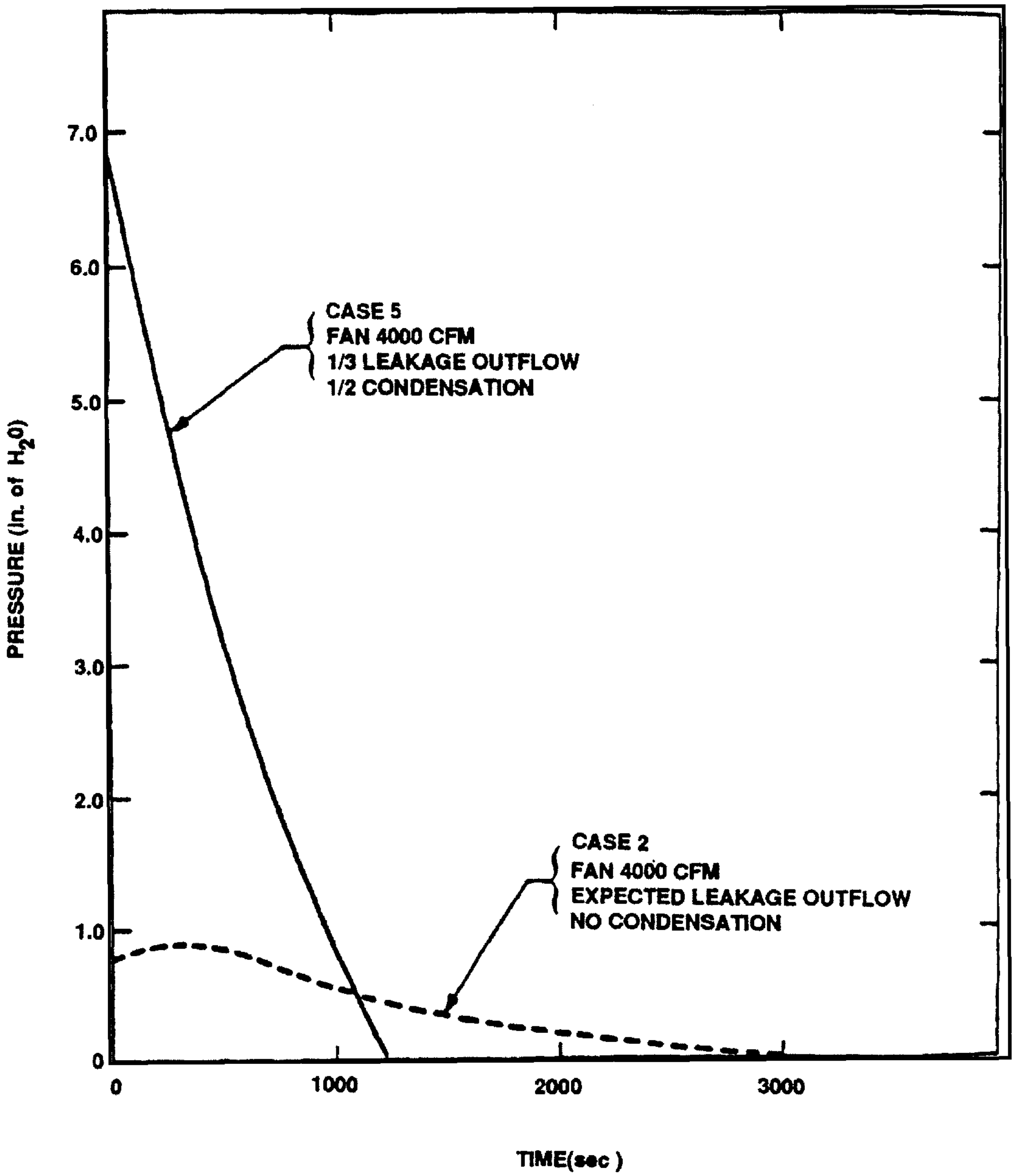
QUAD CITIES STATION UNITS 1 & 2
NODAL AVERAGE POWER EXCEEDANCE DISTRIBUTION BASED ON REACTOR OPERATING DATA
FIGURE 6.2-34



QUAD CITIES STATION
UNITS 1 & 2

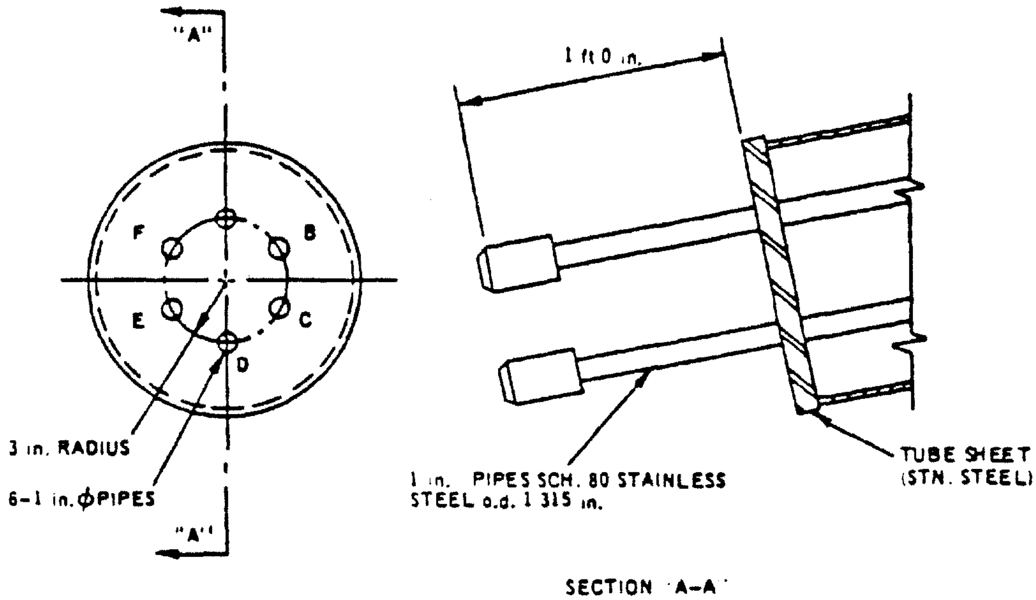
REACTOR BUILDING SUPERSTRUCTURE
PANEL SIDING ASSEMBLY AND BLOWOFF DETAILS

FIGURE 6.2-36
REV. 4, APRIL 1997



Bounding Analysis – Reference
Section 6.2.3.3

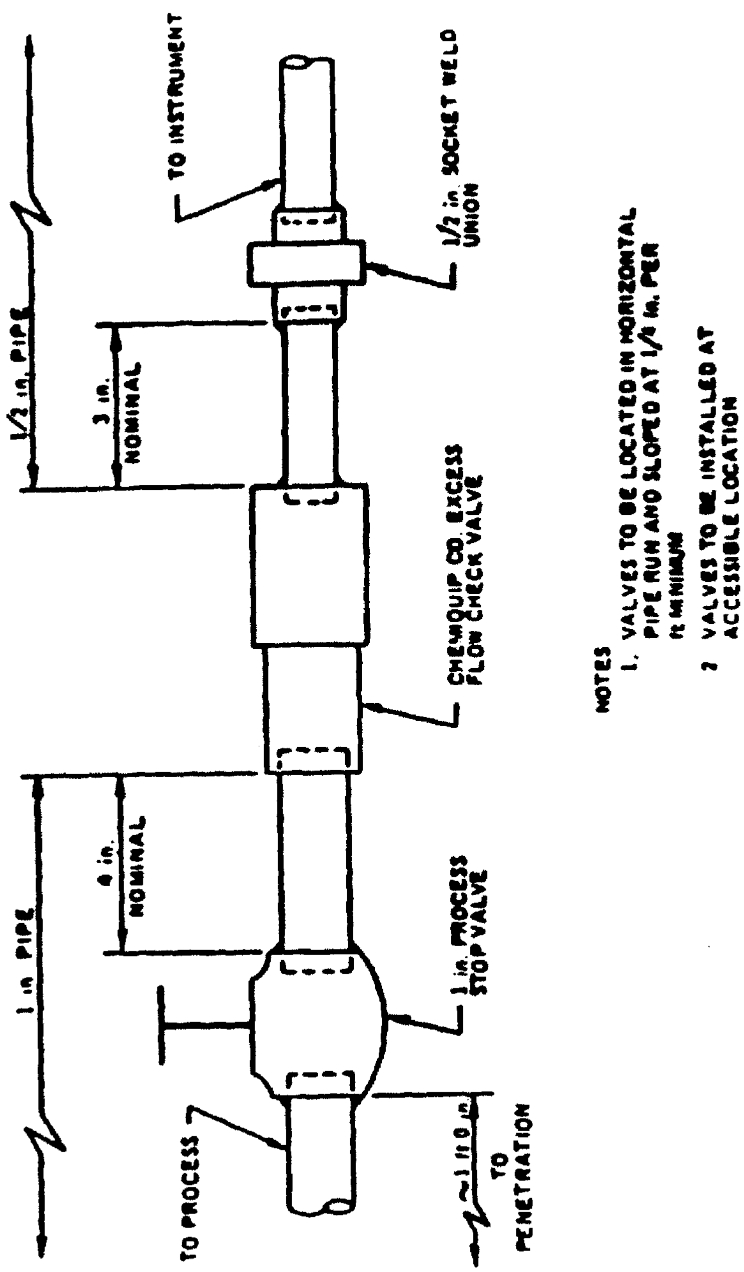
QUAD CITIES STATION UNITS 1 & 2
REACTOR BUILDING PRESSURE (1 - INCH INSTRUMENT LINE)
FIGURE 6.2-37
REVISION 7, JANUARY 2003



QUAD CITIES STATION
UNITS 1 & 2

CONTAINMENT VESSEL PENETRATION

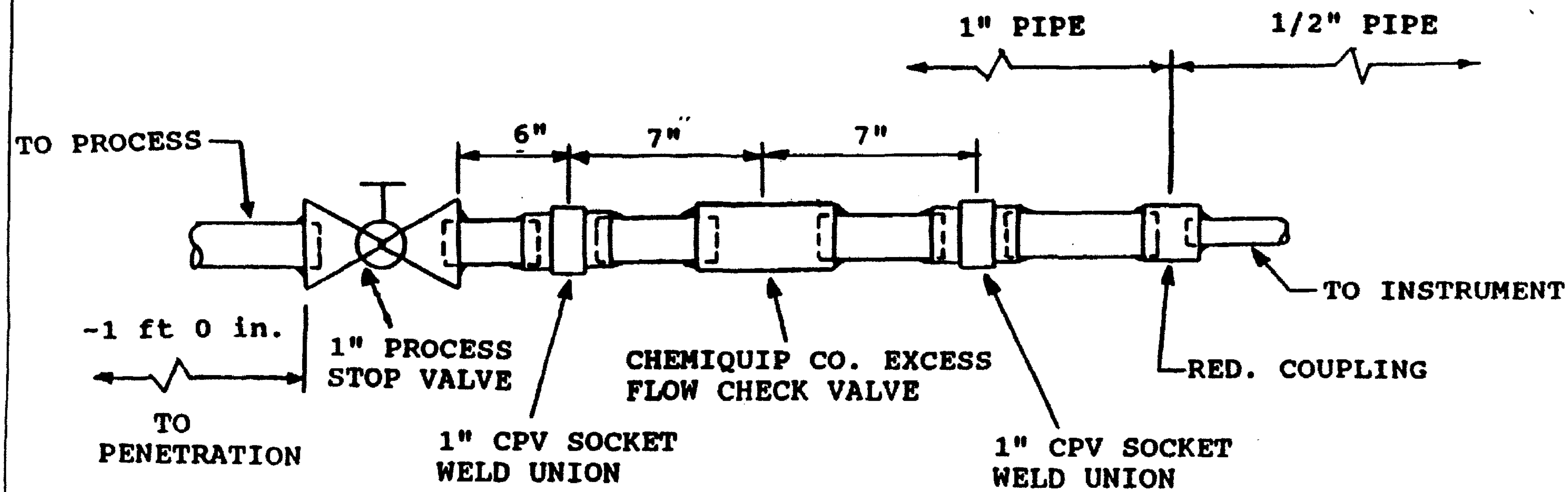
FIGURE 6.2-38



QUAD CITIES STATION
UNITS 1 & 2

PROCESS STOP VALVE AND EXCESS FLOW CHECK VALVE

FIGURE 6.2-39
REV.3, DECEMBER 1995



NOTES:

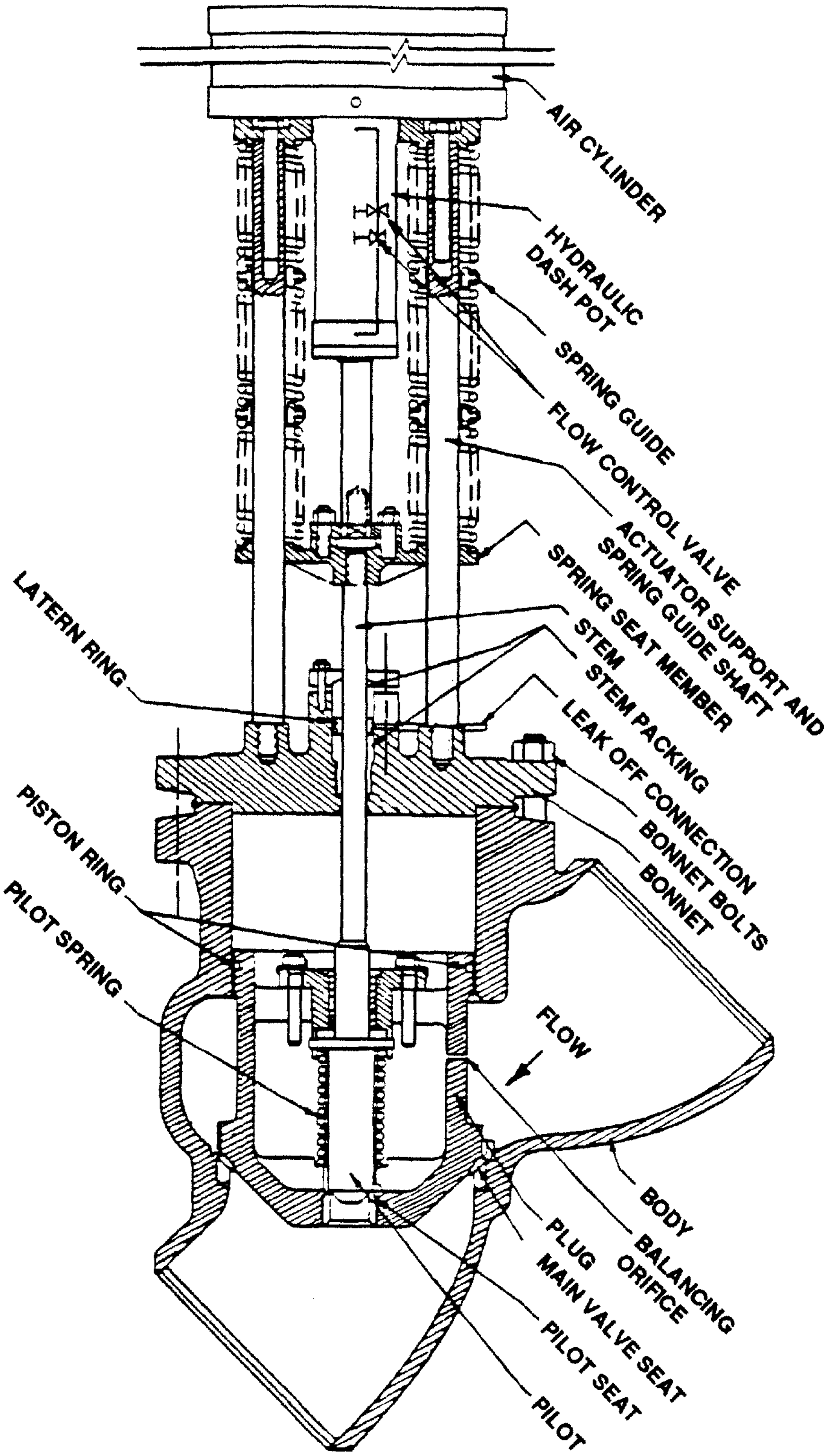
1. VALVES TO BE LOCATED IN HORIZONTAL PIPE RUN AND SLOPED AT 1/4"/FT. MINIMUM.
2. VALVES TO BE INSTALLED AT ACCESSIBLE LOCATION.
3. DIMENSIONS ARE NOMINAL.

QUAD CITIES STATION
UNIT 1

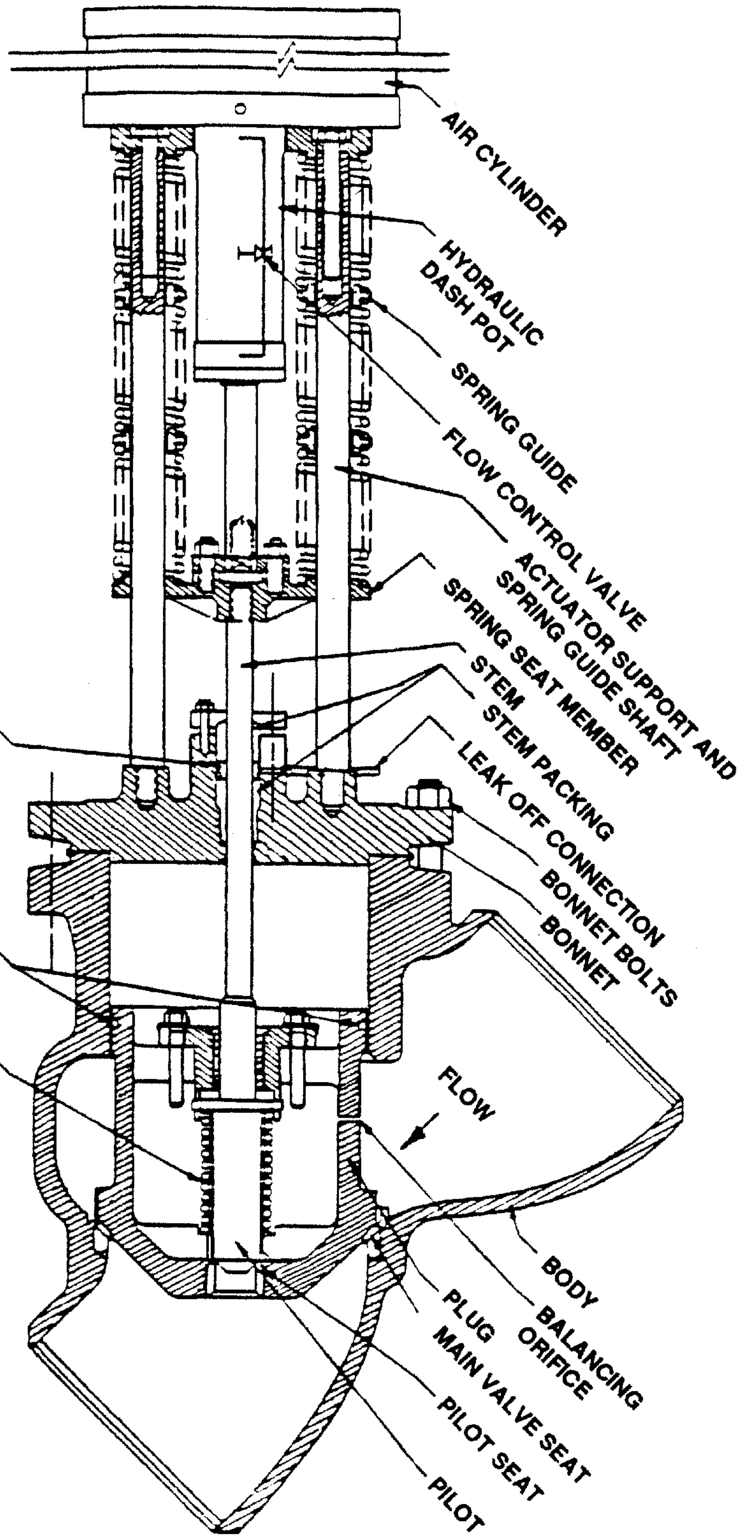
PROCESS STOP VALVE AND EXCESS FLOW
CHECK VALVE - ALTERNATE DETAIL

FIGURE 6.2-39A

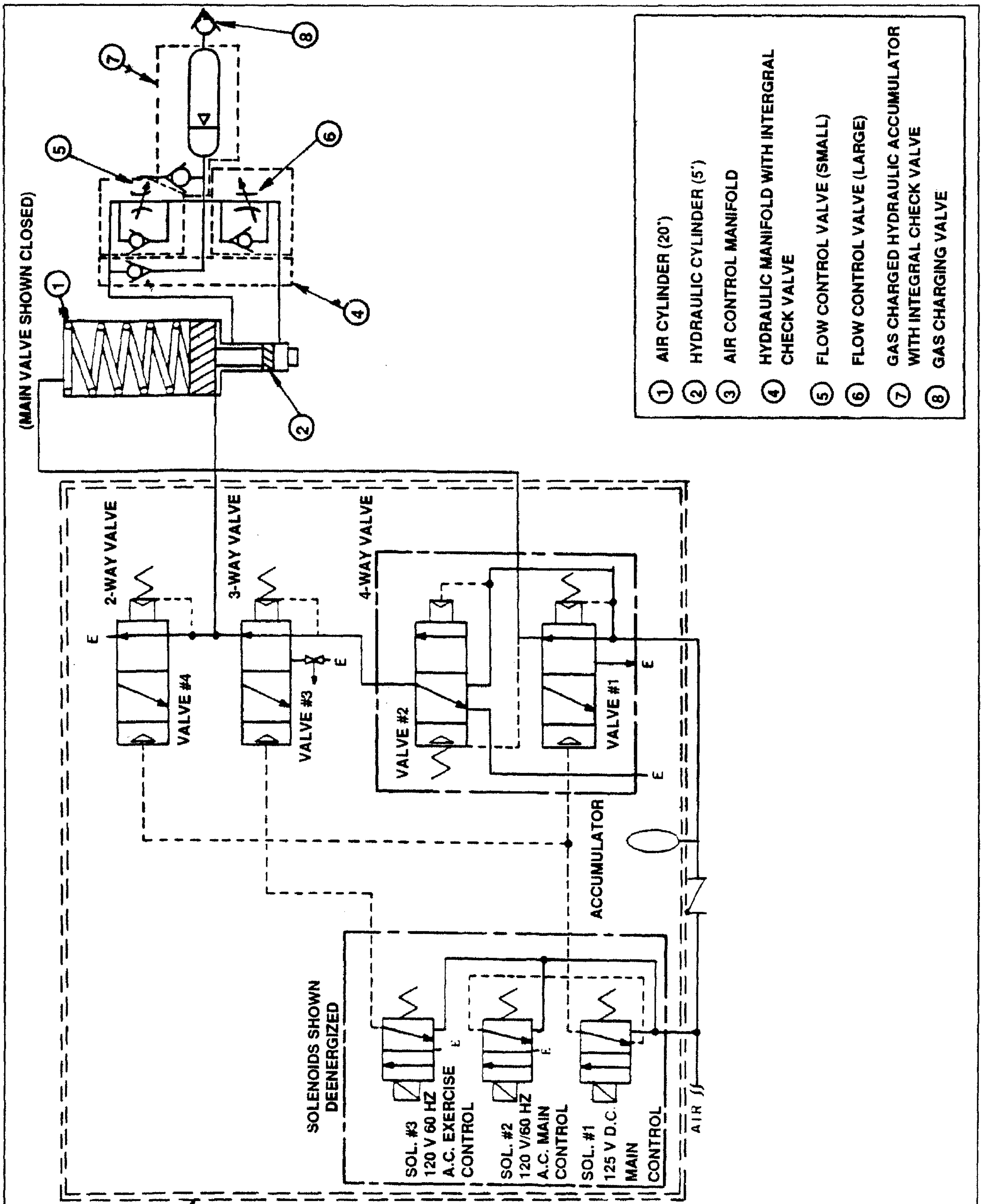
REV. 3, DECEMBER 1995



QUAD CITIES STATION UNITS 1 & 2
UNIT 1 MAIN STEAM ISOLATION VALVE SECTION
FIGURE 6.2-40



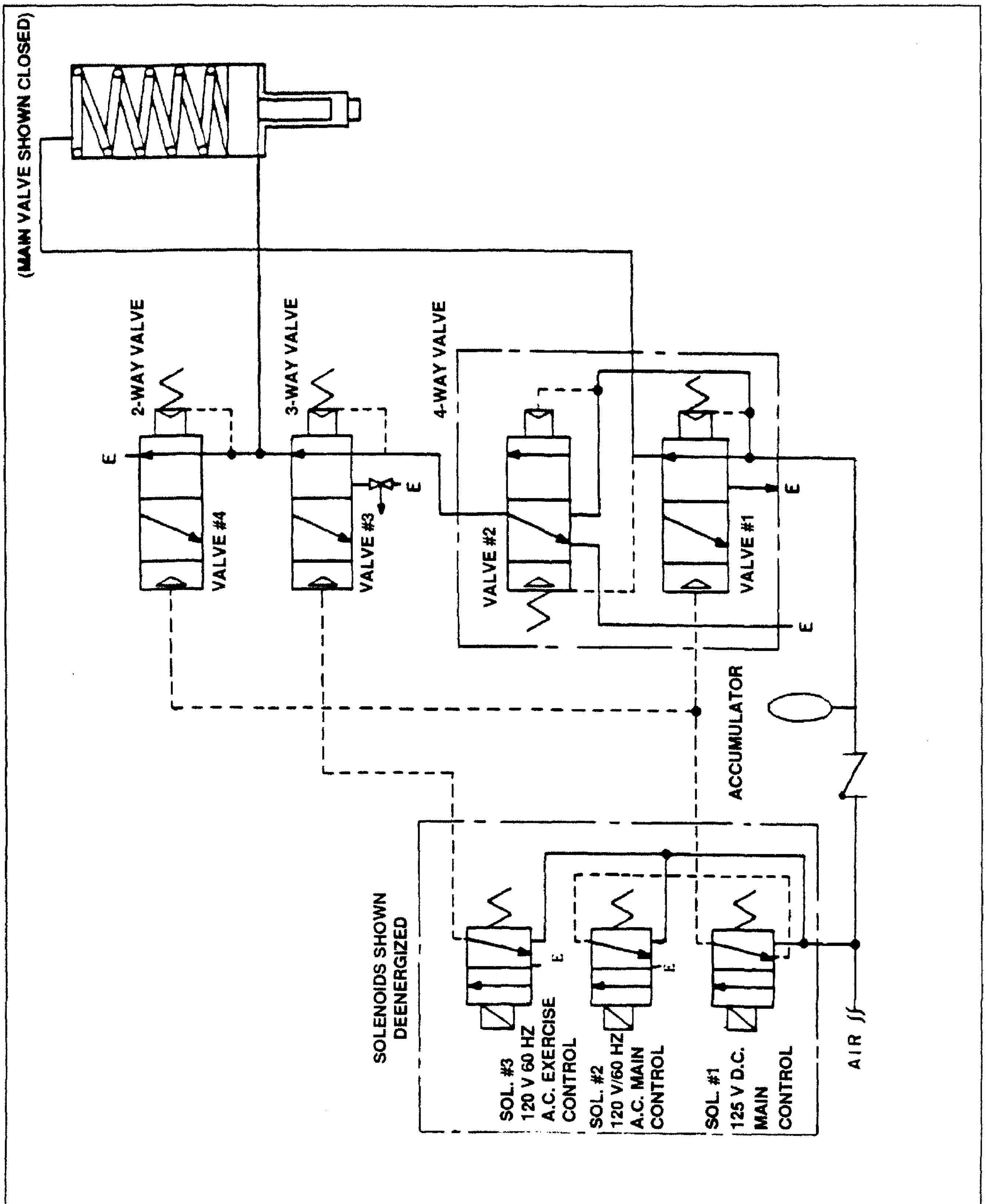
QUAD CITIES STATION UNITS 1 & 2
UNIT 2 MAIN STEAM ISOLATION VALVE SECTION
FIGURE 6.2-41



QUAD CITIES STATION
UNITS 1 & 2

UNIT 1 MAIN STEAM ISOLATION VALVE CONTROL DIAGRAM

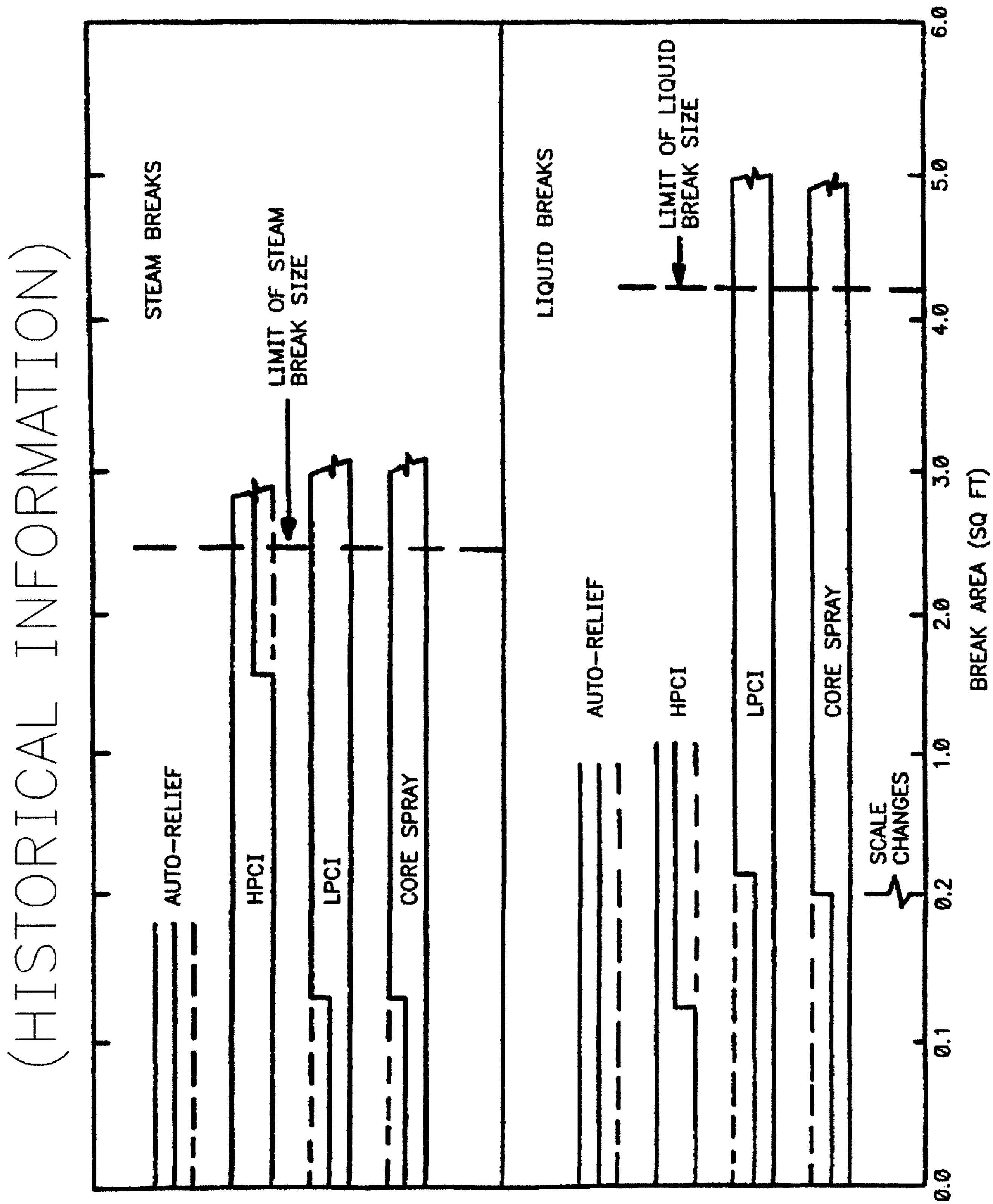
FIGURE 6.2-42



QUAD CITIES STATION
UNITS 1 & 2

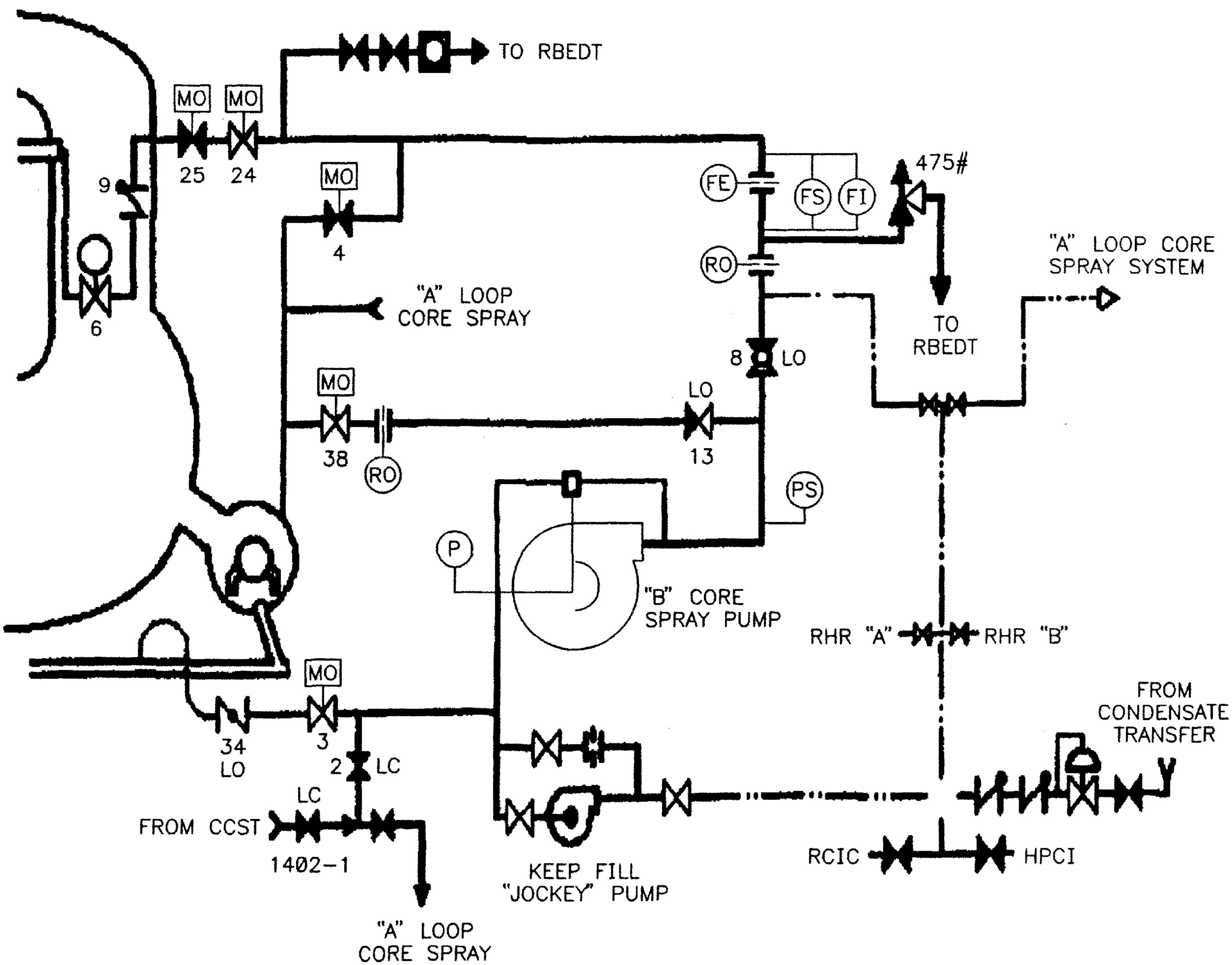
UNIT 2 MAIN STEAM ISOLATION VALVE CONTROL DIAGRAM

FIGURE 6.2-43



NOTE: SEE SECTION 6.3.3.2.2.2 FOR INFORMATION REGARDING THE USE OF DETAILS FROM THIS ANALYSIS WHICH MAY NOT BE APPLICABLE TO THE CURRENT FUEL CYCLE.

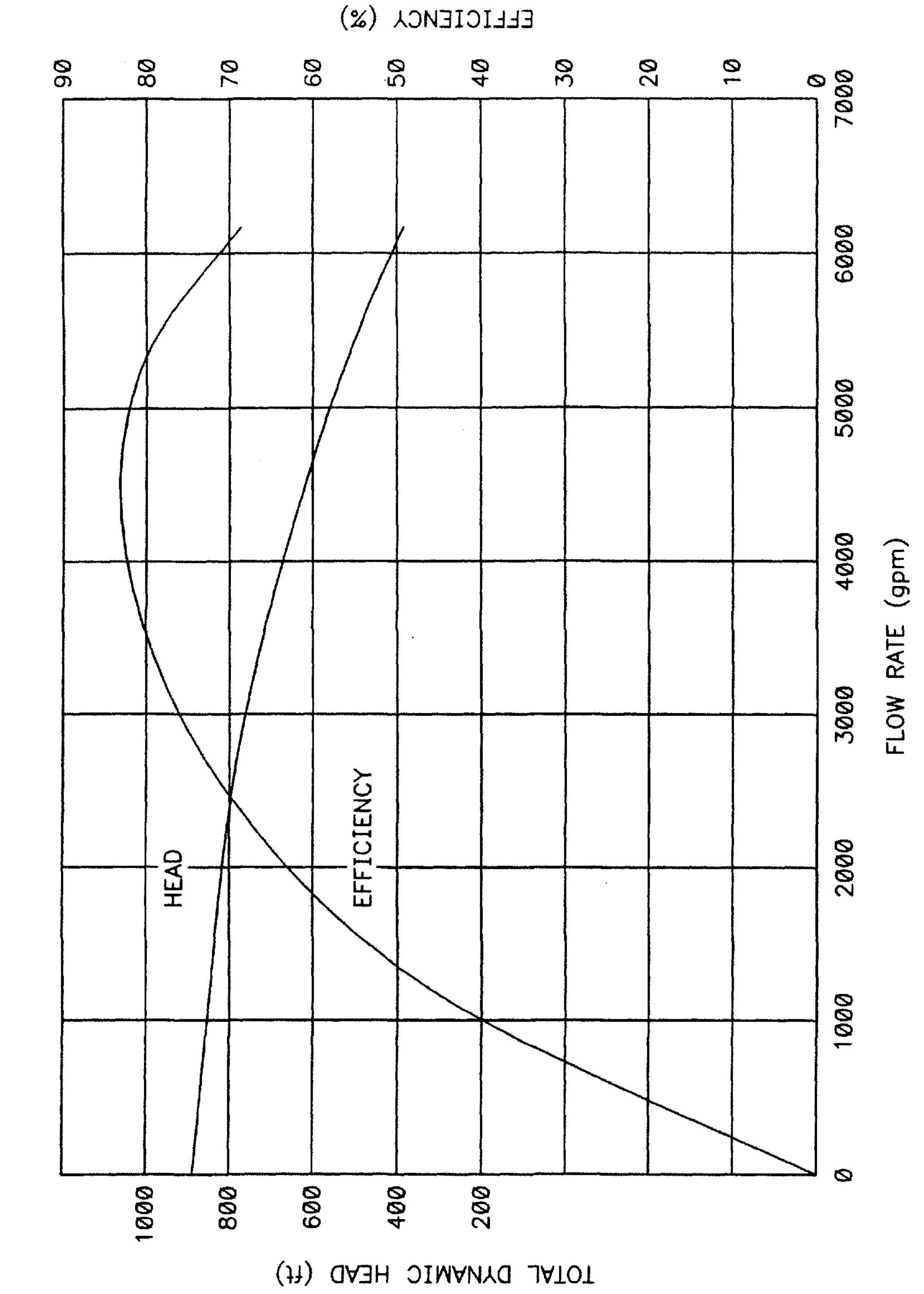
QUAD CITIES STATION UNITS 1 & 2
EMERGENCY CORE COOLING SYSTEM VS. BREAK SPECTRUM AT 2511 MWt
FIGURE 6.3-1 REVISION 8, OCTOBER 2005



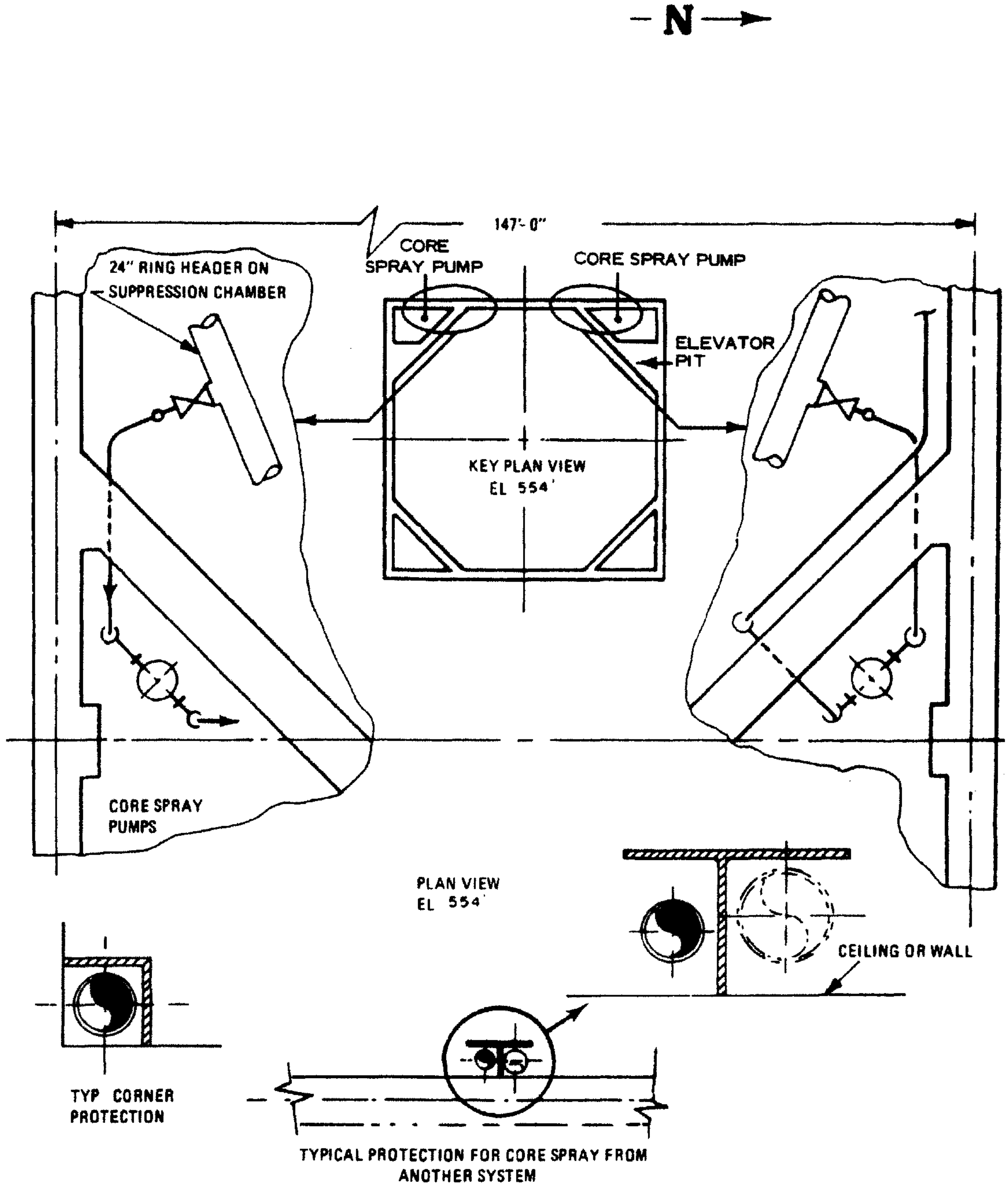
QUAD CITIES STATION
UNIT 1

DIAGRAM OF
CORE SPRAY PIPING

FIGURE 6.3-2
REVISION 5, JUNE 1999



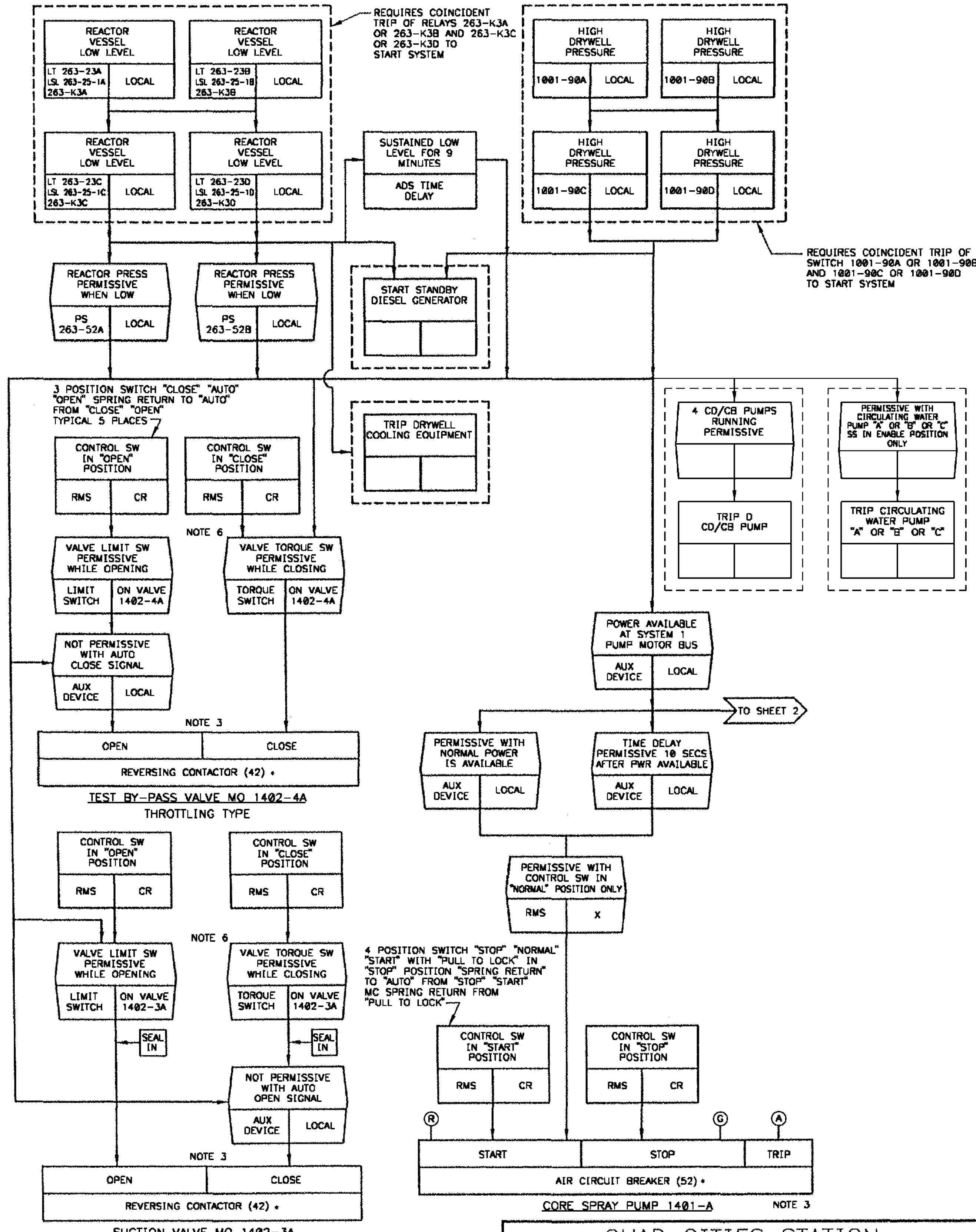
QUAD CITIES STATION UNITS 1 & 2
CORE SPRAY SYSTEM PUMP CHARACTERISTICS
FIGURE 6.3–3 REVISION 5, JUNE 1999



QUAD CITIES STATION
UNITS 1 & 2

CORE SPRAY PIPE PROTECTION

FIGURE 6.3-4

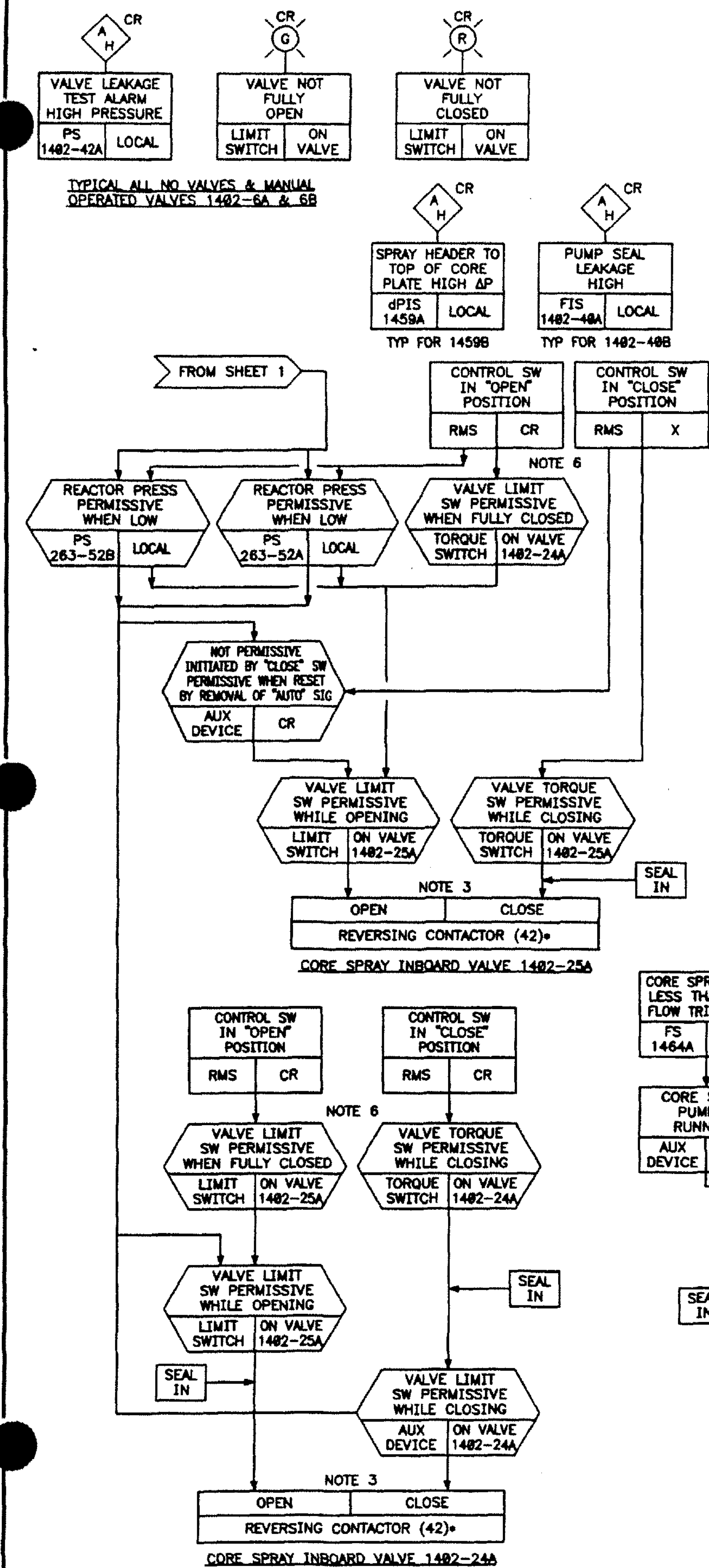


QUAD CITIES STATION
UNITS 1 & 2

CORE SPRAY SYSTEM
FUNCTIONAL CONTROL DIAGRAM

FIGURE 6.3-5
SHEET 1

REVISION 9, OCTOBER 2007



NOTES:

1. THE CONTROL SYSTEM SHOWN IS FOR SYSTEM 1. OPERATING SEQUENCE AFTER SIGNAL INITIATION IS AS FOLLOWS

CONDITION A	PLANT ON NORMAL AUXILIARY POWER
1401-A	SYSTEM I STARTS – NO DELAY
1401-B	SYSTEM II STARTS – NO DELAY
VALVES	
1402-24A	SYSTEM I OPENS AFTER LOW PRESS PERMISSIVE
1402-24B	SYSTEM II OPENS AFTER LOW PRESS PERMISSIVE
1402-25A	SYSTEM I OPENS AFTER LOW PRESS PERMISSIVE
1402-25B	SYSTEM II OPENS AFTER LOW PRESS PERMISSIVE
1402-4A	SYSTEM I CLOSES IF OPEN – NO DELAY
1402-4B	SYSTEM II CLOSES IF OPEN – NO DELAY
1402-3A	SYSTEM I OPENS IF CLOSED – NO DELAY
1402-3B	SYSTEM II OPENS IF CLOSED – NO DELAY

CONDITION B	WITH PLANT ON STANDBY DIESEL POWER
1401-A	10 SEC AFTER POWER AVAILABLE
1401-B	10 SEC
VALVES	SEQUENCE SAME AS CONDITION A

2. SYSTEM II CIRCUIT IDENTICAL TO SYSTEM I EXCEPT COMPONENT PARTS ARE IDENTIFIED AS FOLLOWS

PUMP	SYSTEM I	SYSTEM II
MIN FLOW BYPASS VALVE	1402-38A	1402-38B
OUTBOARD ISOLATION VALVE	1402-24A	1402-24B
INBOARD ISOLATION VALVE	1402-25A	1402-25B
CHECK VALVES	1402-9A	1402-9B
PUMP SUCTION VALVES	1402-3A	1402-3B
TEST BYPASS VALVES	1402-4A	1402-4B

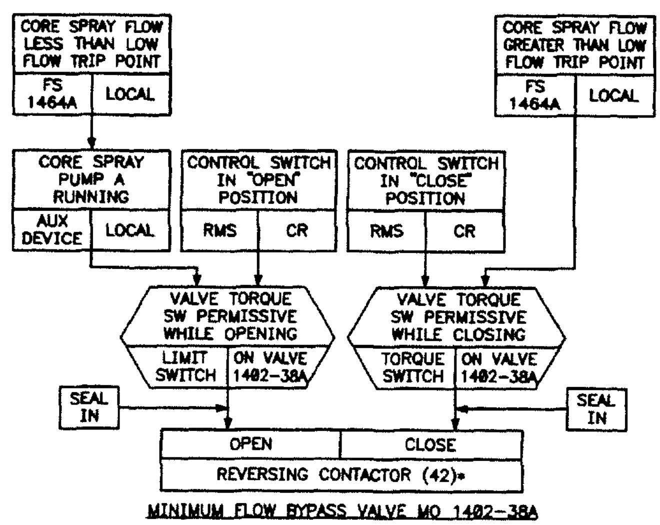
3. PUMP MOTOR CIRCUITS SHALL PROVIDE FOR OVERLOAD & UNDER-VOLTAGE TRIP. UNDER-VOLTAGE TRIP SHALL HAVE A SUFFICIENT TIME DELAY AVAILABLE TO PERMIT POWER TRANSFER FROM AUXILIARY TRANSFORMER TO START-UP TRANSFORMER SOURCE WITHOUT DROPPING OFF THE PUMPS. VALVE MOTOR SHALL BE PROTECTED BY OVERLOAD ALARMS.

4. MOTIVE POWER FOR SYSTEM I PUMPS SHALL ORIGINATE FROM A DIFFERENT EMERGENCY AC BUS THAN POWER FOR SYSTEM II PUMPS. POWER FOR VALVES IN EACH SYSTEM SHALL ORIGINATE FROM THE SAME BUS SUPPLYING BUS POWER.

5. ALL MOTOR OPERATED DEVICES SHALL BE PROVIDED WITH KEYLOCK LOCAL CONTROL SWITCHES FOR "OPEN", "CLOSE", "STOP", POSITIONS PARALLELING THE RMS SHOWN ALL LOCAL CONTROL STATIONS SHALL HAVE POSITION INDICATING LIGHTS.

6. * SWITCHGEAR DEVICE FUNCTION NUMBERS USAS SPEC C372

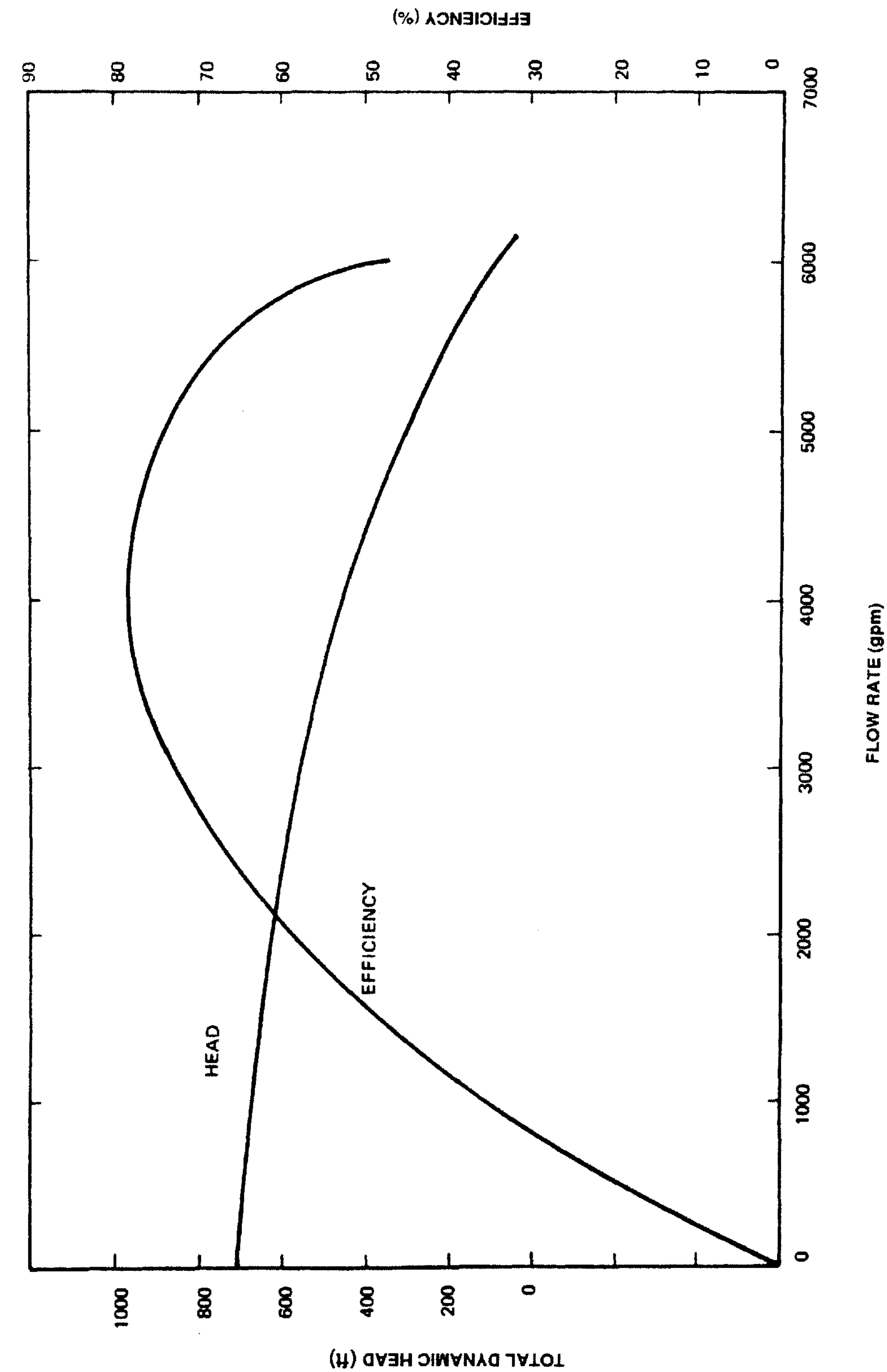
7. MOTIVE PWR SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH "PROPOSED CRITERIA FOR NUCLEAR POWER PLANT PROTECTION SYSTEM IEEE279" TO THE EXTENT PRACTICAL.



QUAD CITIES STATION
UNITS 1 & 2

CORE SPRAY SYSTEM
FUNCTIONAL CONTROL DIAGRAM

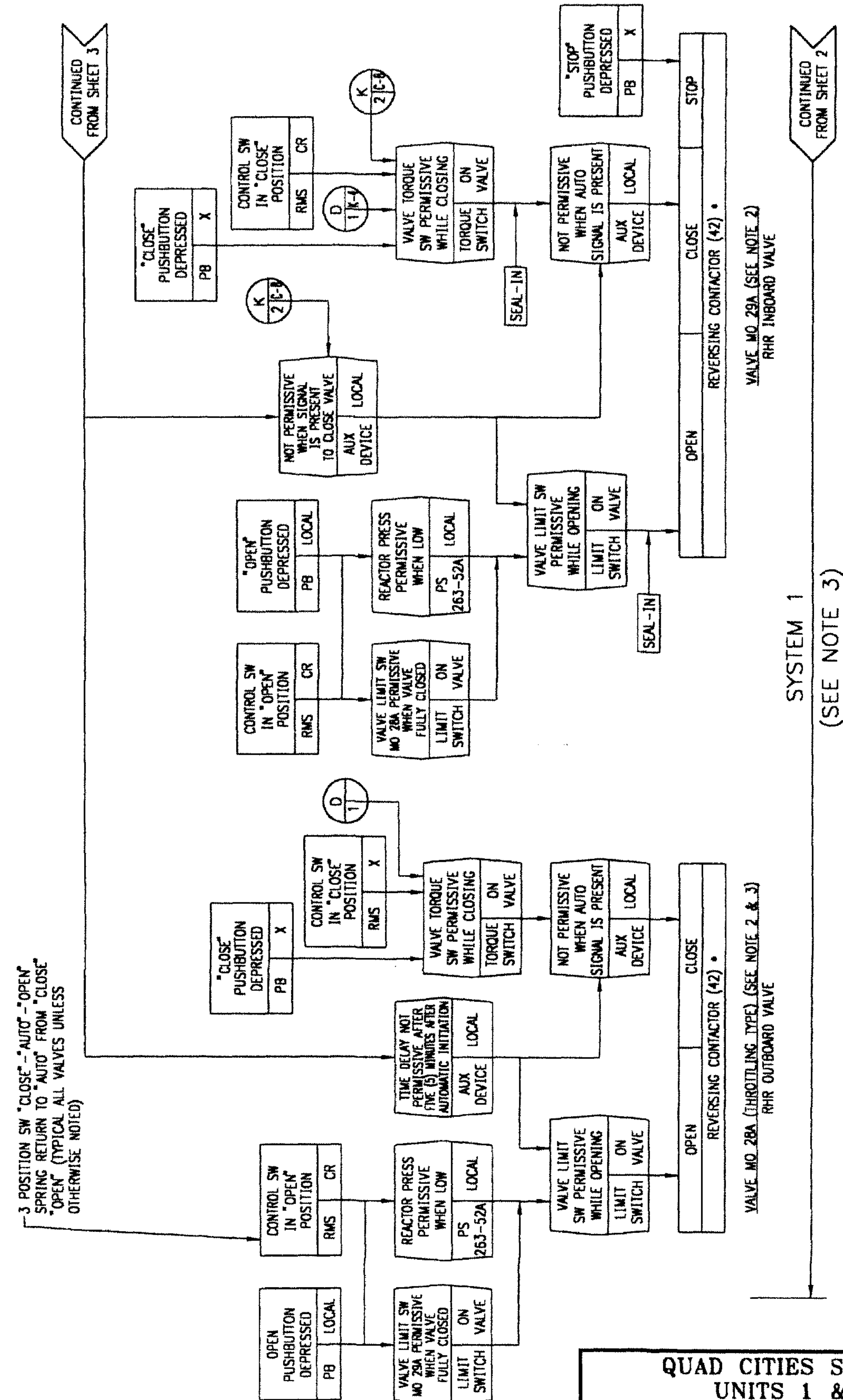
FIGURE 6.3-5 SHEET 2
REVISION 5, JUNE 1999



QUAD CITIES STATION
UNITS 1 & 2

LOW PRESSURE COOLANT INJECTION/CONTAINMENT COOLING SYSTEM PUMP CHARACTERISTICS

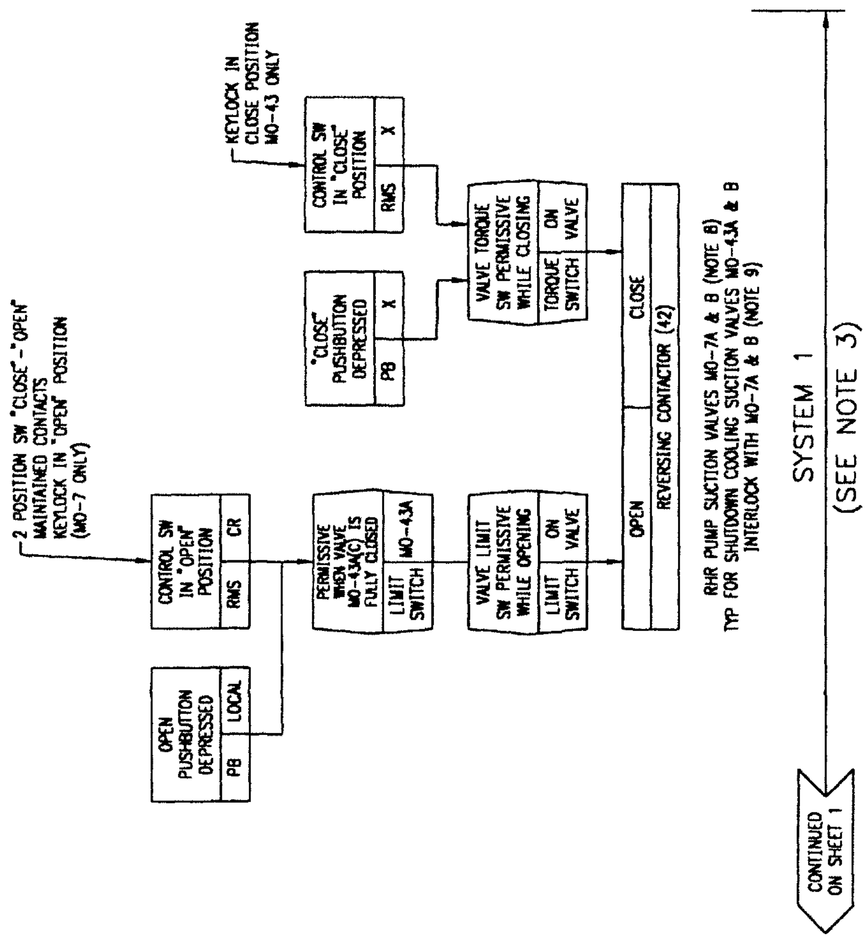
FIGURE 6.3-8



QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

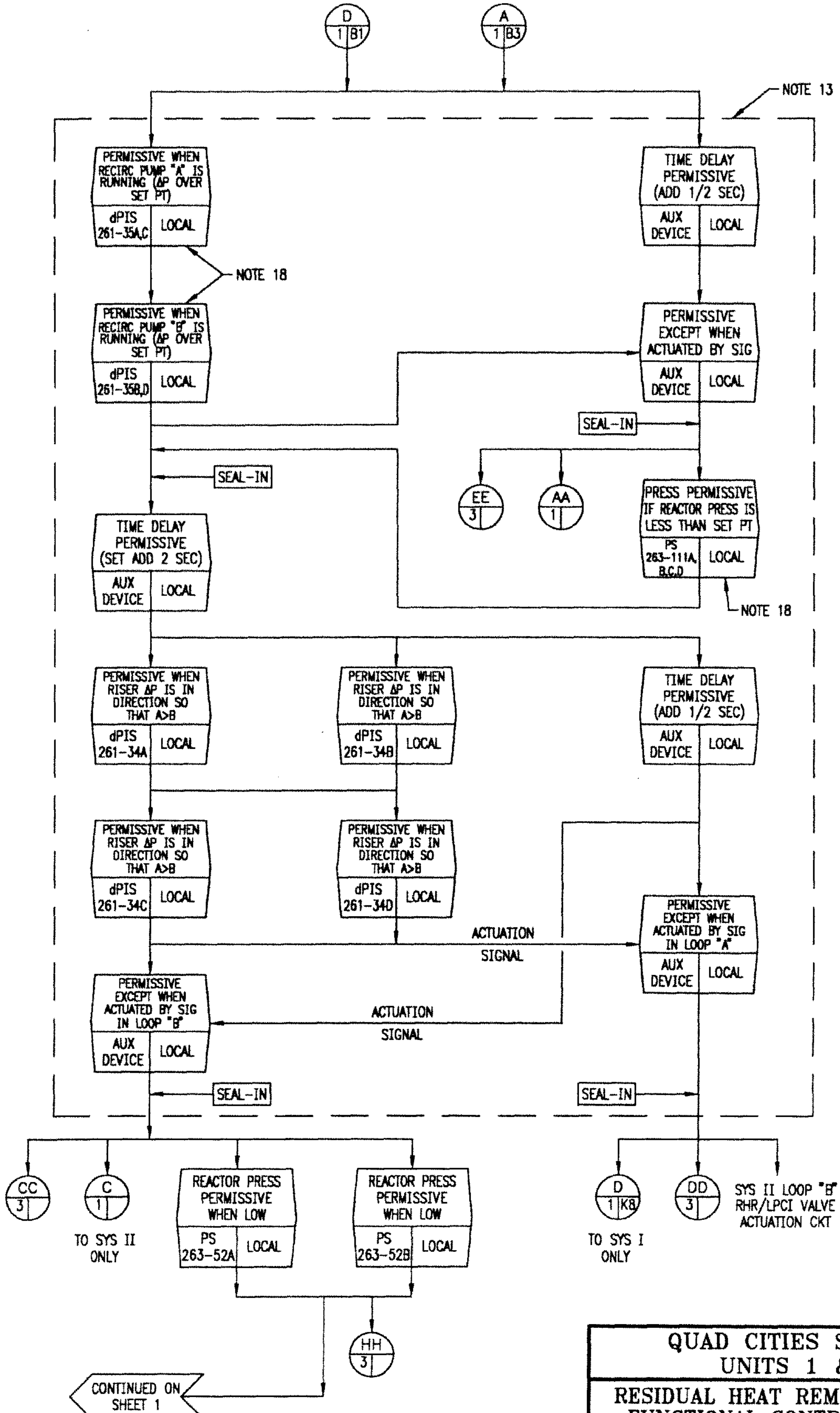
FIGURE 6.3-9 SHEET 1 OF 5
REV. 4, APRIL 1997



QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

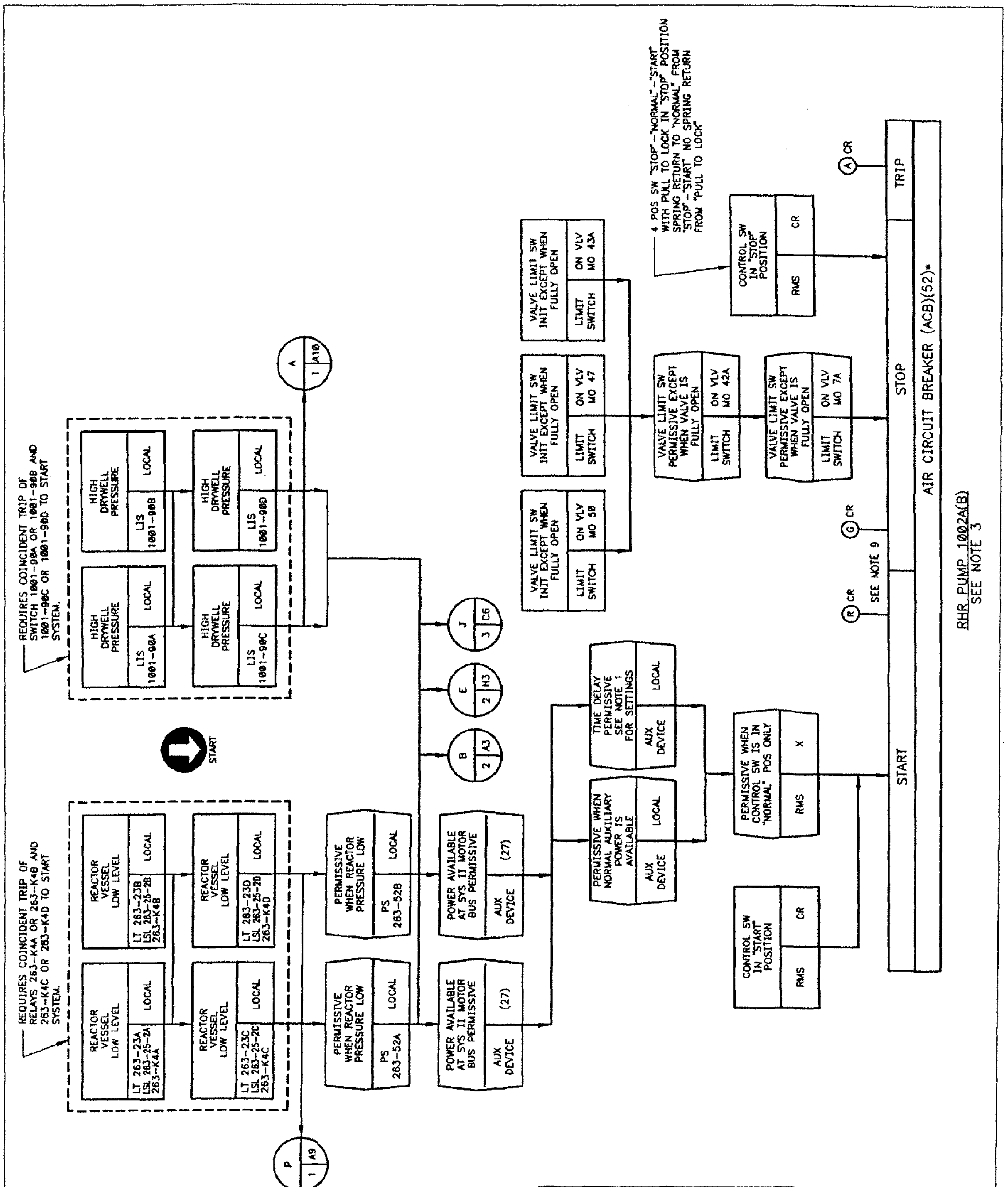
FIGURE 6.3-9 SHEET 2 OF 5
REV. 4, APRIL 1997



QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

FIGURE 6.3-9 SHEET 3 OF 5
REV. 4, APRIL 1997



QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

FIGURE 6.3-9
SHEET 4 OF 5

REVISION 7, JANUARY 2003

NOTES:

1. THE CONTROL SYSTEM SHOWN IS FOR SYSTEM 1. OPERATING SEQUENCE AFTER SIGNAL INITIATION IS AS FOLLOWS:

CONDITION A	PLANT ON NORMAL AUXILIARY POWER
PUMP – 1002A	STARTS NO DELAY
PUMP – 1002B	STARTS NO DELAY
PUMP – 1002C	STARTS NO DELAY
PUMP – 1002D	STARTS NO DELAY

VALVES

28A	OPENS AFTER REACTOR LOW PRESSURE PERMISSIVE
29A	OPENS AFTER REACTOR LOW PRESSURE PERMISSIVE

CONT COOLING 23A)
26A)
34A) CLOSE, IF OPEN (NORMALLY MAINTAINED CLOSED)
36A)
37A)

HEAT EXCHANGER VALVE 5A CLOSES

SERVICE PUMPS 65A, B, C, D STOP IF RUNNING

CONDITION B	PLANT ON STANDBY POWER
PUMP	SET TIME DELAY DEVICE INITIALLY
1002A	0 SECS AFTER POWER AVAIL
1002B	5 SECS AFTER POWER AVAIL
1002C	0 SECS AFTER POWER AVAIL
1002D	5 SECS AFTER POWER AVAIL

VALVES SEQUENCE SAME AS CONDITION A
SERVICE PUMPS SAME AS CONDITION A

2. MANUAL CONTROL SYS FOR THROTTLING TYPE NO VALVE SHALL BE DESIGNED TO ALLOW VALVES TO BE STOPPED AT ANY DESIRED POSITION.
3. SYS I CIRCUITS & EQUIP ARE SHOWN. SYS II CIRCUITS & EQUIP ARE IDENTICAL EXCEPT AS NOTED AND EXCEPT EQUIP NO. SUFFIXES ARE AS SHOWN ON P610.
4. PUMP MOTORS SHALL BE PROTECTED WITH OVERLOAD & UNDERVOLTAGE PROTECTION. VALVE MOTORS SHALL BE PROTECTED BY OVERLOAD ALARMS.
5. AUXILIARY RELAYS AND DEVICES ARE NOT SHOWN ON THE FUNCTIONAL CONTROL DIAGRAM EXCEPT WHERE NEEDED TO CLARIFY THE FUNCTIONAL REQUIREMENTS.
6. MOTIVE POWER FOR SYS I PUMPS SHALL ORIGINATE FROM A DIFFERENT EMERGENCYAC BUS THAN POWER SYS II PUMPS.
7.
8. PANEL LOCATIONS DESIGNATED "CR" ARE LOCATED ON THE CONTROL ROOM PANEL. DEVICES LOCATION DESIGNATED "LOCAL" ARE MOUNTED ON LOCAL PANEL OR MOUNTED DIRECTLY ON PIPE OR WALL WHERE APPROPRIATE.
9. ALL HAND SWITCH LOCAL CONTROL STATIONS SHALL BE KEYLOCK & LOCATED FOR CONVENIENT EQUIP TESTING. EQUIP STATUS LIGHTS SHALL BE INCLUDED AT THE LOCAL STATIONS & ON THE CONTROL ROOM PANEL STATUS LIGHTS SHALL BE AS FOLLOWS:

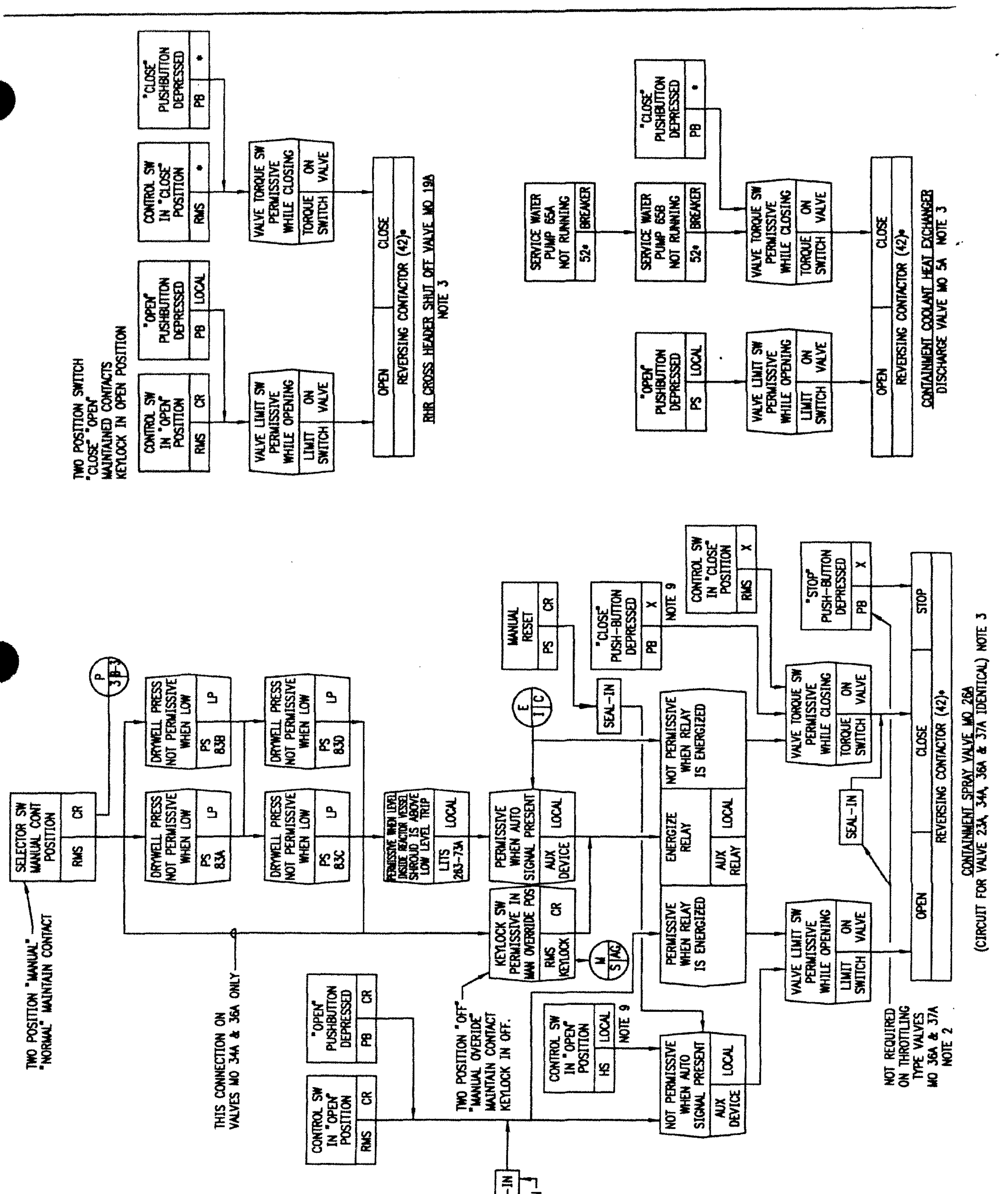
VALVES:	GREEN ON FOR CLOSED POSITION
	GREEN & RED ON FOR INTERMEDIATE POSITION
	RED ON FOR OPEN POSITION
PUMPS:	RED ON FOR PUMP RUNNING
	GREEN ON FOR PUMP STOP
	ALL DARK OR PUMP MANUALLY SHUTDOWN FOR MAINTENANCE
	AMBER FOR PUMP TRIP

10. INTERLOCK FLOW ALARMS WITH PUMPS 1002A, B, C & D SO THAT ALARMS ARE DISABLED UNLESS ANY ONE OF THE PUMPS ARE RUNNING.
11.
12. ALL AUXILIARY TIMING DEVICES SHALL BE ADJUSTABLE FROM 0 TO FULL SCALE. FULL SCALE SHALL BE AT LEAST 1 ½ TIMES GREATER THAN SPECIFIED TIME SETTINGS.
13. THE SENSING CIRCUIT FOR BREAK DETECTION AND VALVE SELECTION IS TO BE ARRANGED SO THAT THE FAILURE OF A SINGLE DEVICE OR CIRCUIT TO FUNCTION ON DEMAND WILL NOT PREVENT CORRECT SELECTION OF LOOP FOR INJECTION.
14. ALL EQUIPMENT & INSTRUMENTS ARE PREFIXED BY A 1001, WHICH IS PART 1001 ON THE MASTER PARTS LIST. UNLESS OTHERWISE NOTED.
15.
16. *SWITCHGEAR DEVICE FUNCTION NUMBERS USAS SPEC C37.2
17. ALL MO VALVES ARE AC OPERATED UNLESS OTHERWISE NOTED.
18. THE FOUR PRESSURE SWITCHES ARE ARRANGED FOR ONE OUT OF TWO TWICE LOGIC SIMILAR TO RISER ΔP LOGIC SHOWN.
19. MOTIVE POWER FOR INJECTION VALVES IN BOTH SYSTEMS SHALL ORIGINATE FROM A COMMON BUS WHICH IS AUTOMATICALLY CONNECTABLE TO TWO ALTERNATE EMERGENCY BUS SOURCES.
20. MOTIVE POWER SYSTEM SHALL BE DESIGNED IN ACCORDANCE WITH "PROPOSED CRITERIA FOR NUCLEAR POWER PLANT PROTECTION SYSTEM IEEE 279" TO THE EXTENT PRACTICAL.

QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

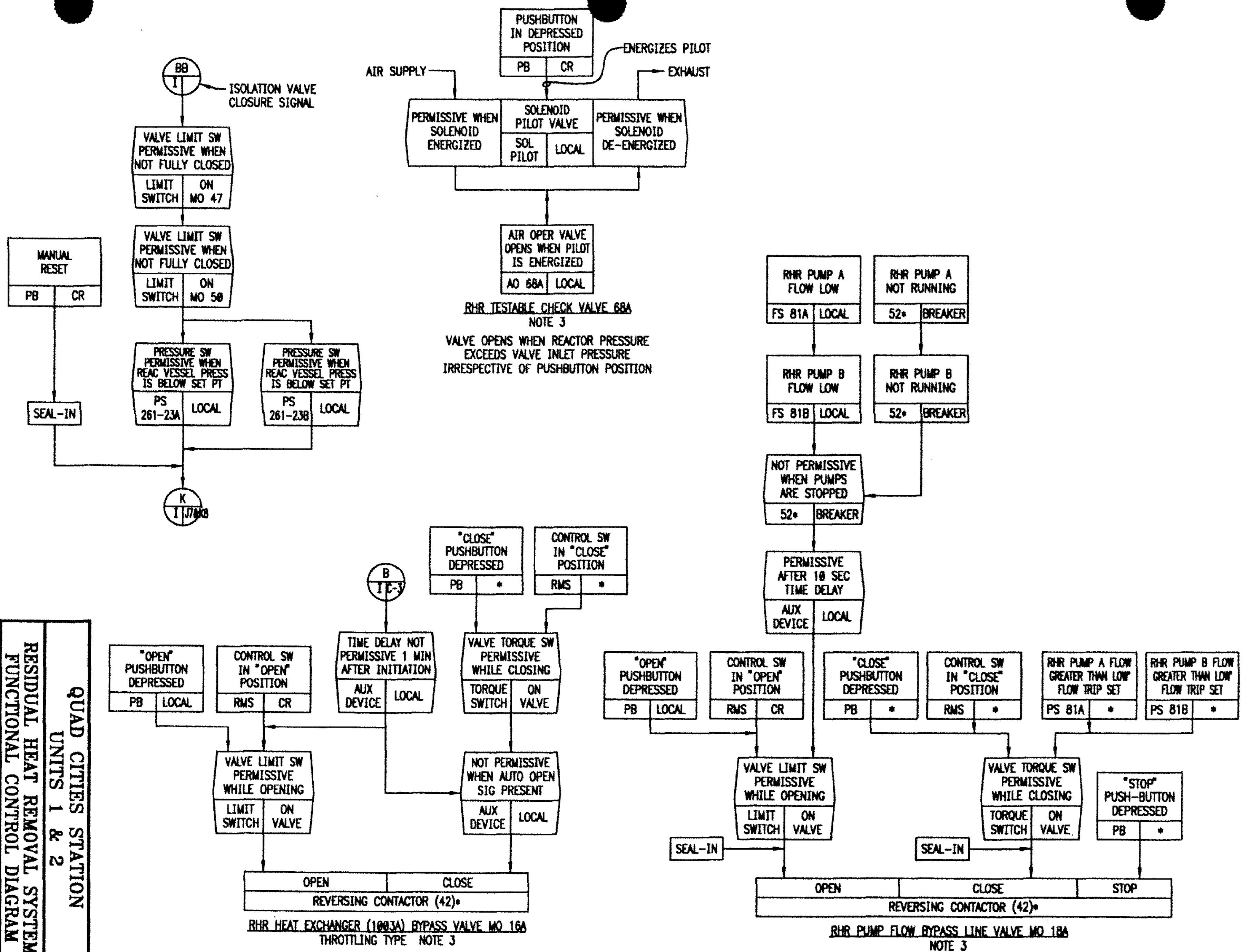
FIGURE 6.3-9 SHEET 5 OF 5
REV. 4, APRIL 1997



QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

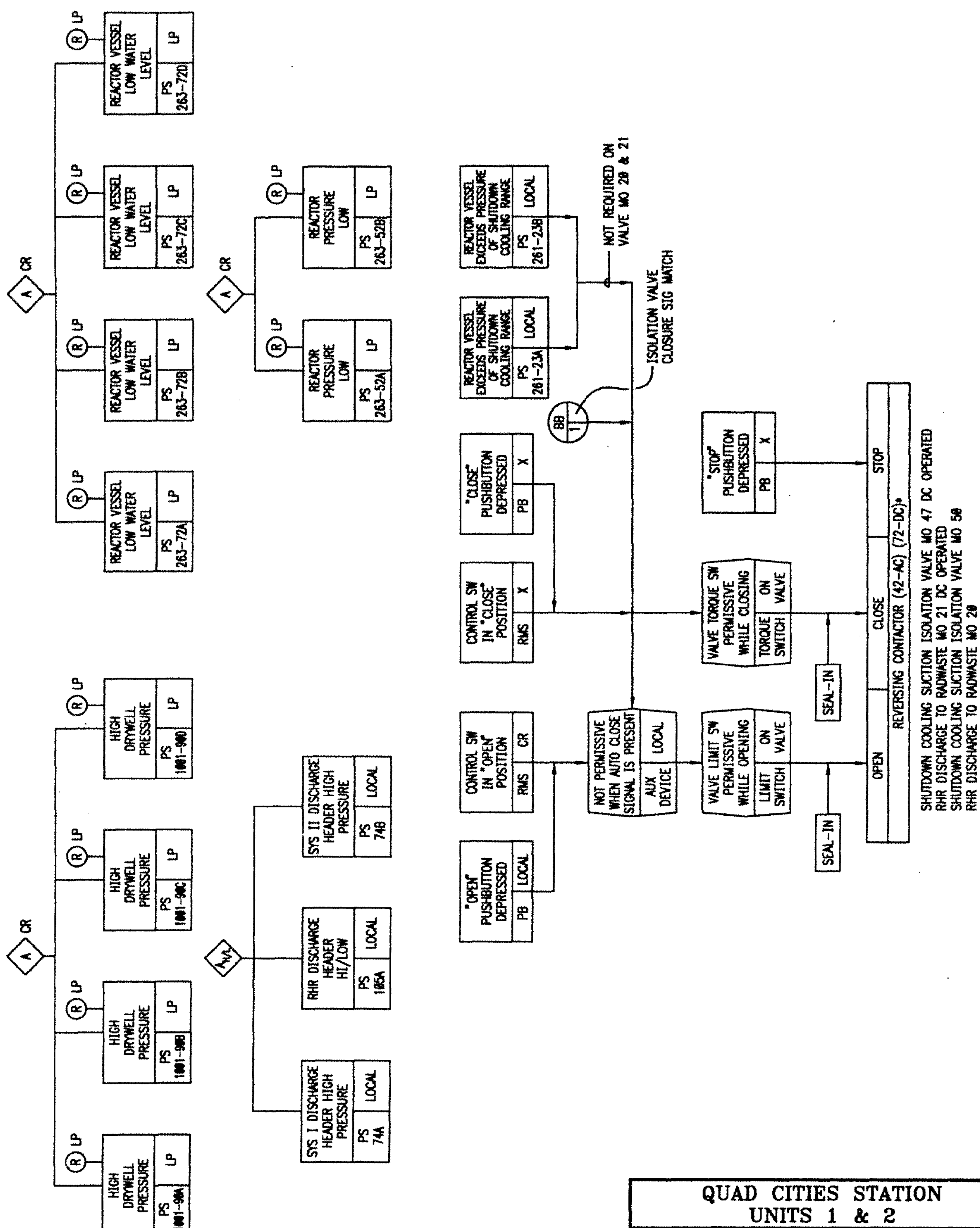
FIGURE 6.3-10 SHEET 1 OF 2
REV. 4, APRIL 1997



QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

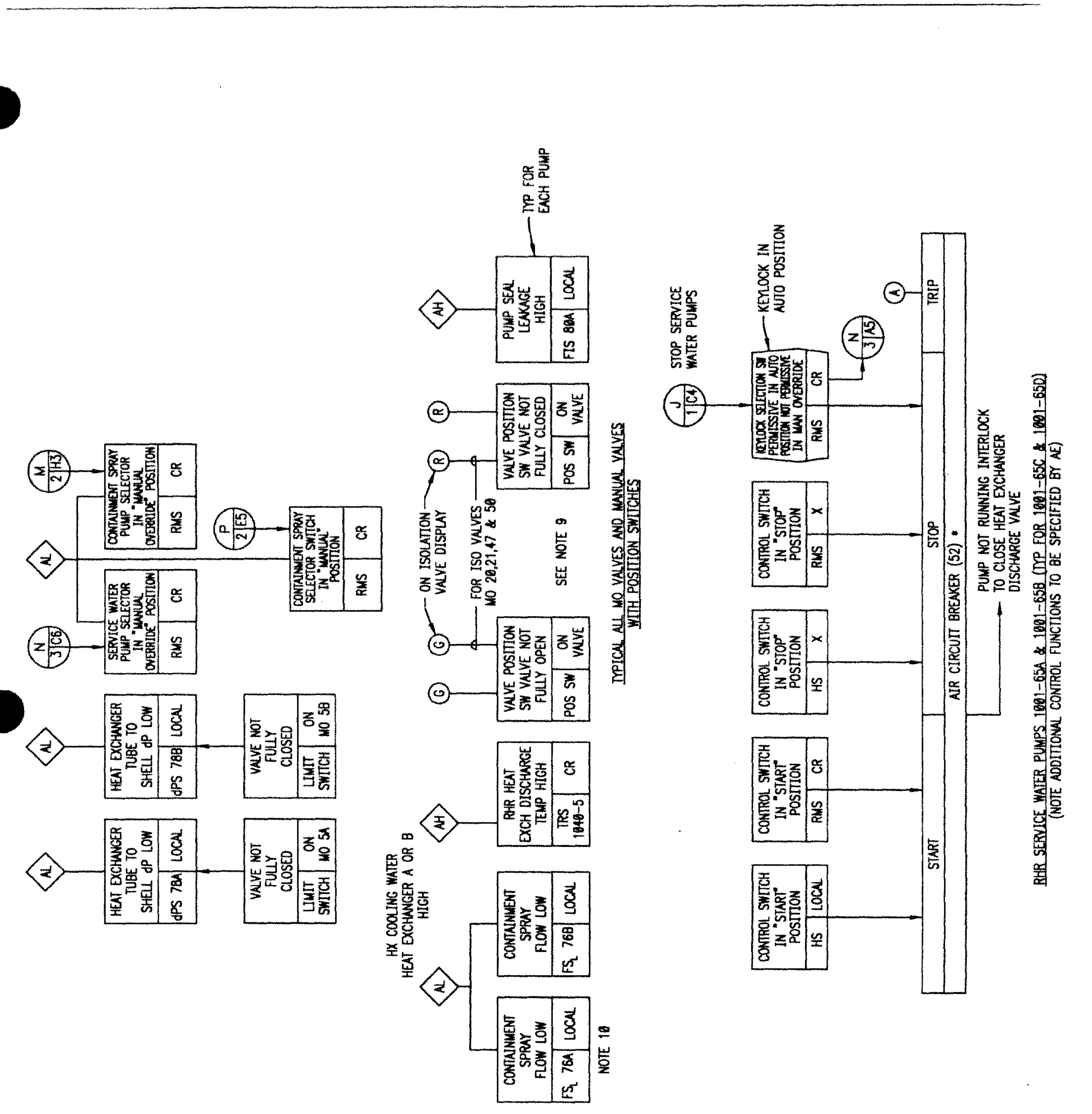
FIGURE 6.3–10 SHEET 2 OF 2
REV. 4, APRIL 1997



QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

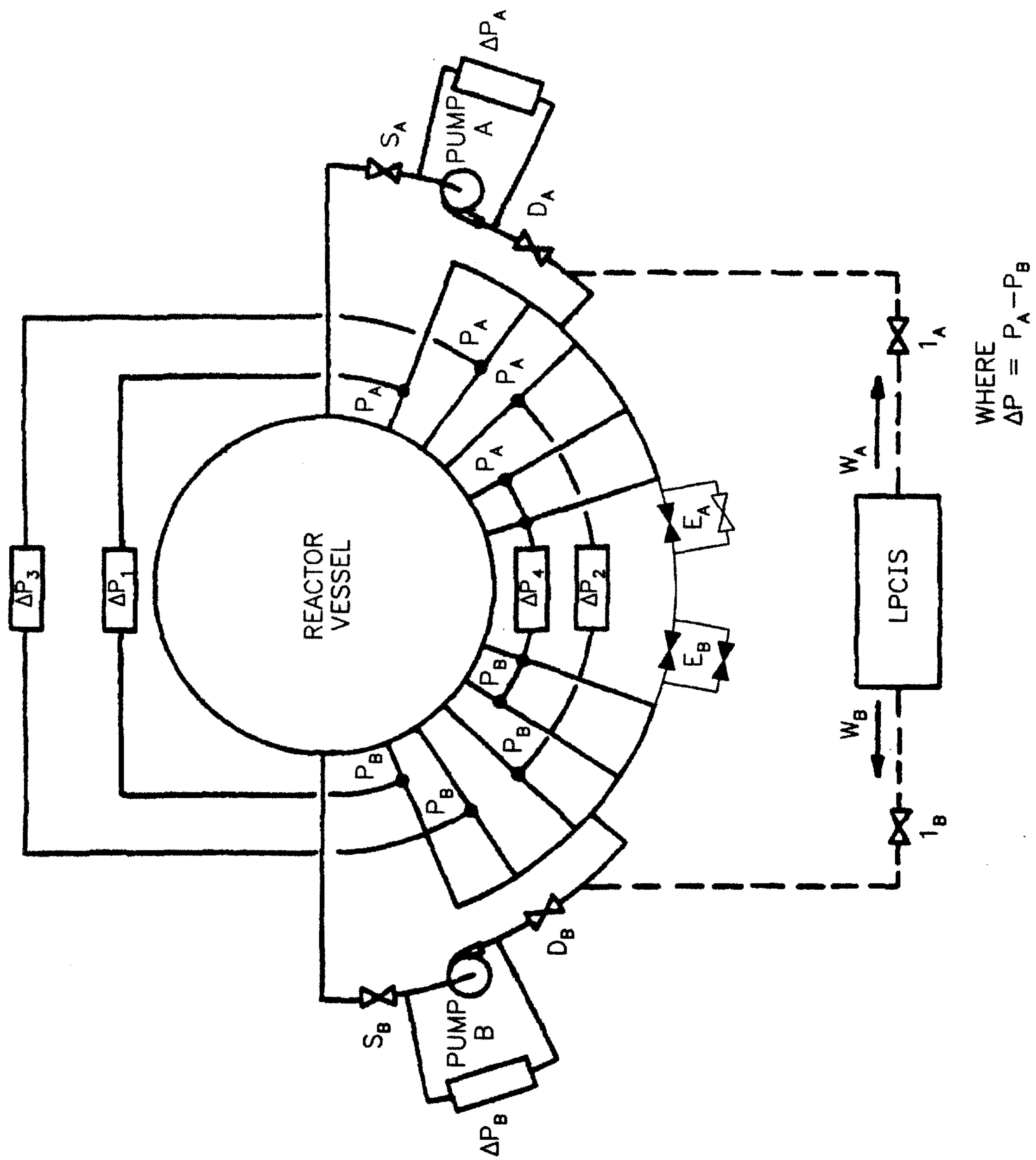
FIGURE 6.3-11 SHEET 1 OF 2
REV. 4, APRIL 1997



QUAD CITIES STATION
UNITS 1 & 2

RESIDUAL HEAT REMOVAL SYSTEM
FUNCTIONAL CONTROL DIAGRAM

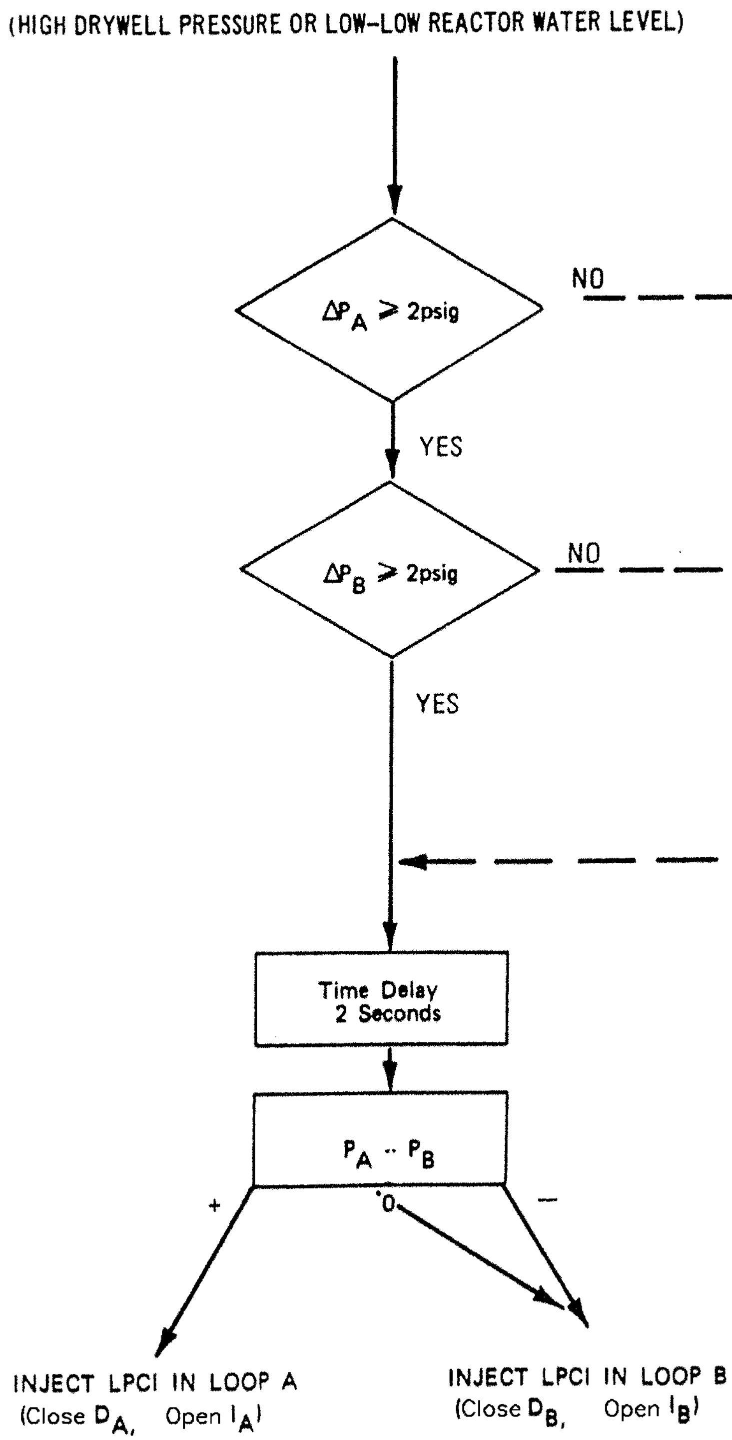
FIGURE 6.3-11 SHEET 2 OF 2
REV. 4, APRIL 1997



QUAD CITIES STATION
UNITS 1 & 2

LPCI – LOGIC CONTROL SYSTEM ARRANGEMENT

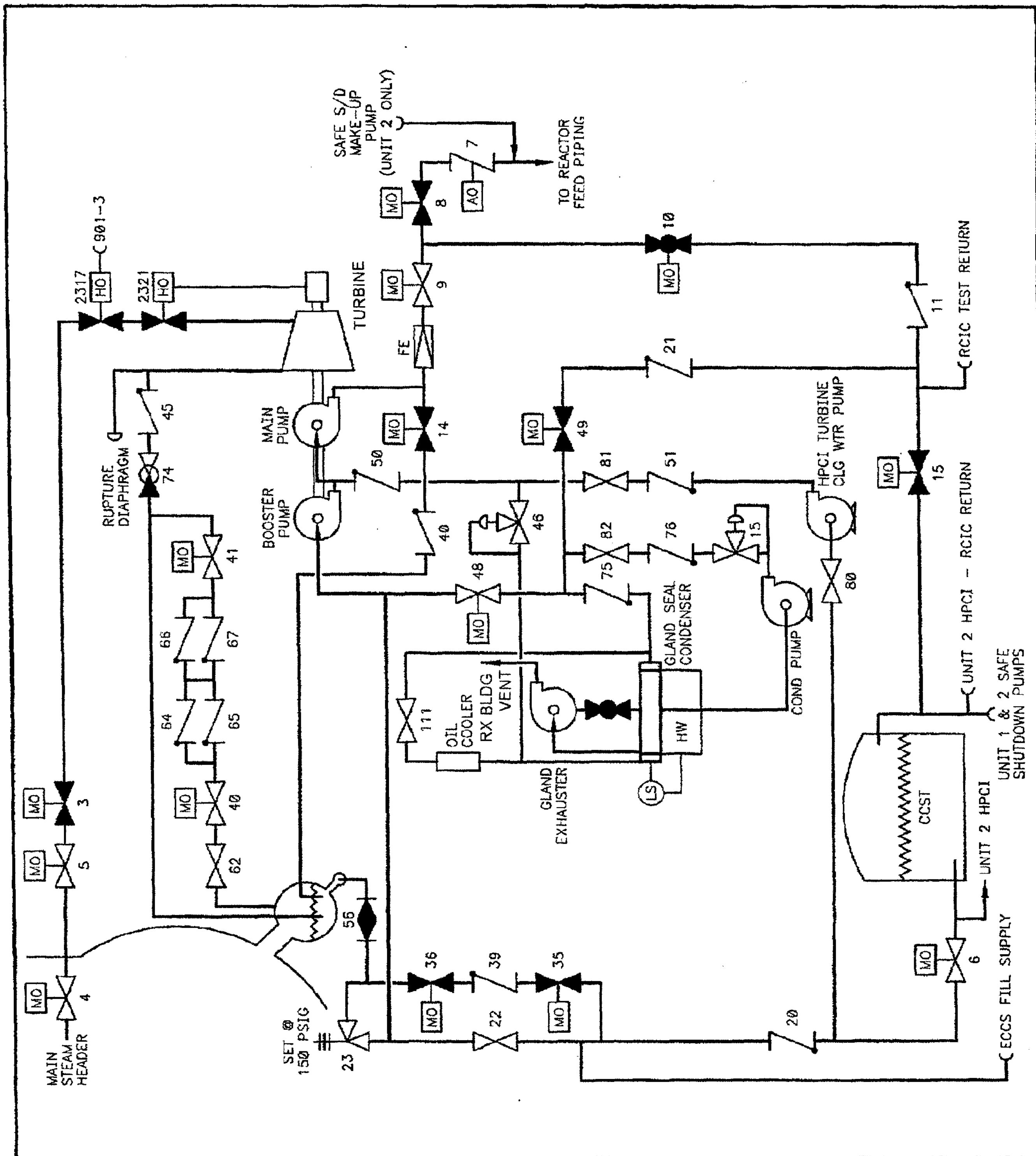
FIGURE 6.3–12
REVISION 5, JUNE 1999



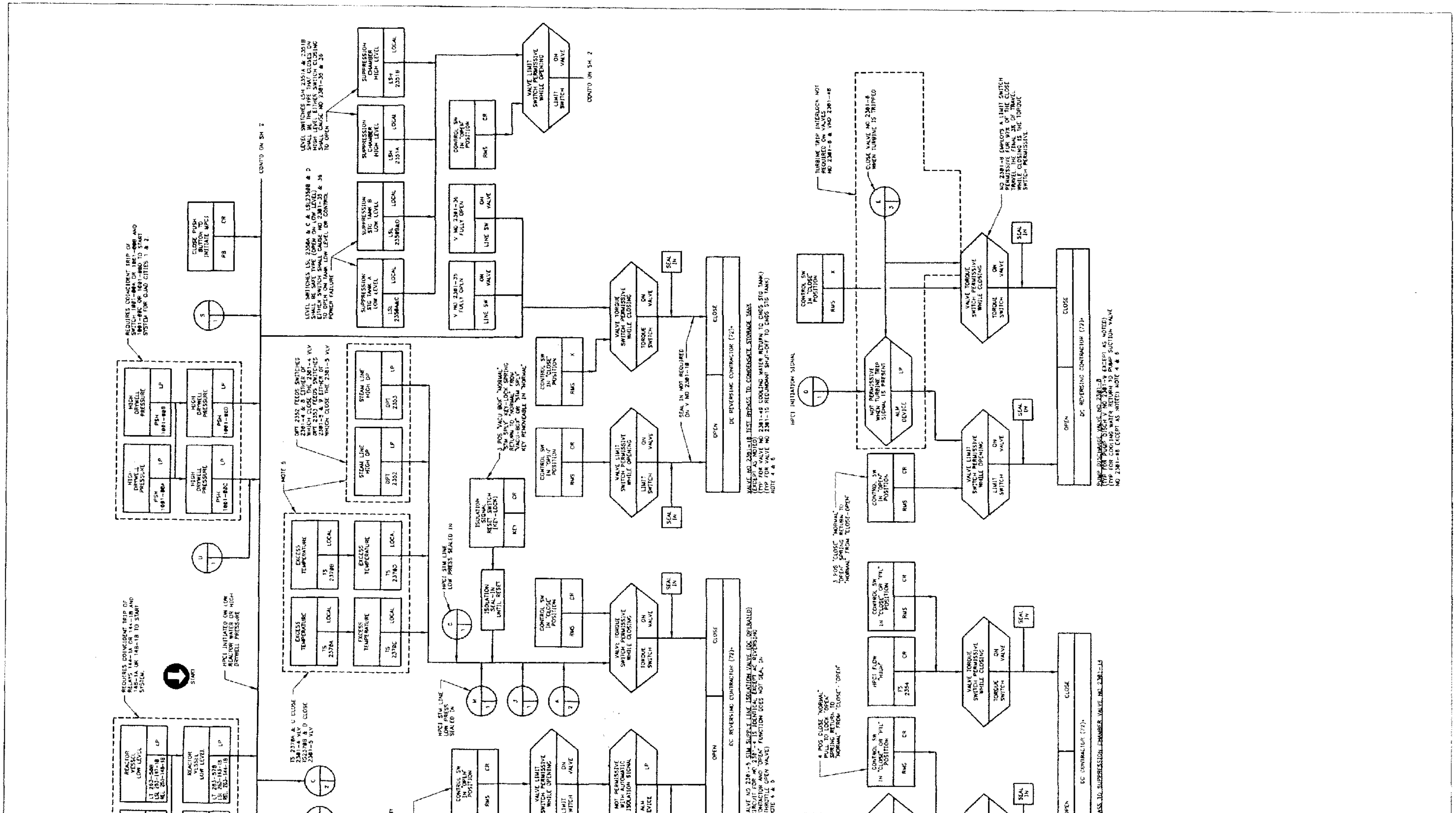
QUAD CITIES STATION
UNITS 1 & 2

LPCI – BREAK DETECTION SYSTEM
LOGIC ARRANGEMENT

FIGURE 6.3–13
REVISION 11, OCTOBER 2011



QUAD CITIES STATION UNIT 1
DIAGRAM OF HIGH PRESSURE COOLANT INJECTION (HPCI) PIPING
FIGURE 6.3-14
REVISION 7, JANUARY 2003



QUAD CITIES STATION
UNITS 1 & 2

HIGH PRESSURE COOLANT INJECTION SYSTEM
FUNCTIONAL BLOCK DIAGRAM

FIGURE 6.3-15
SHEET 1

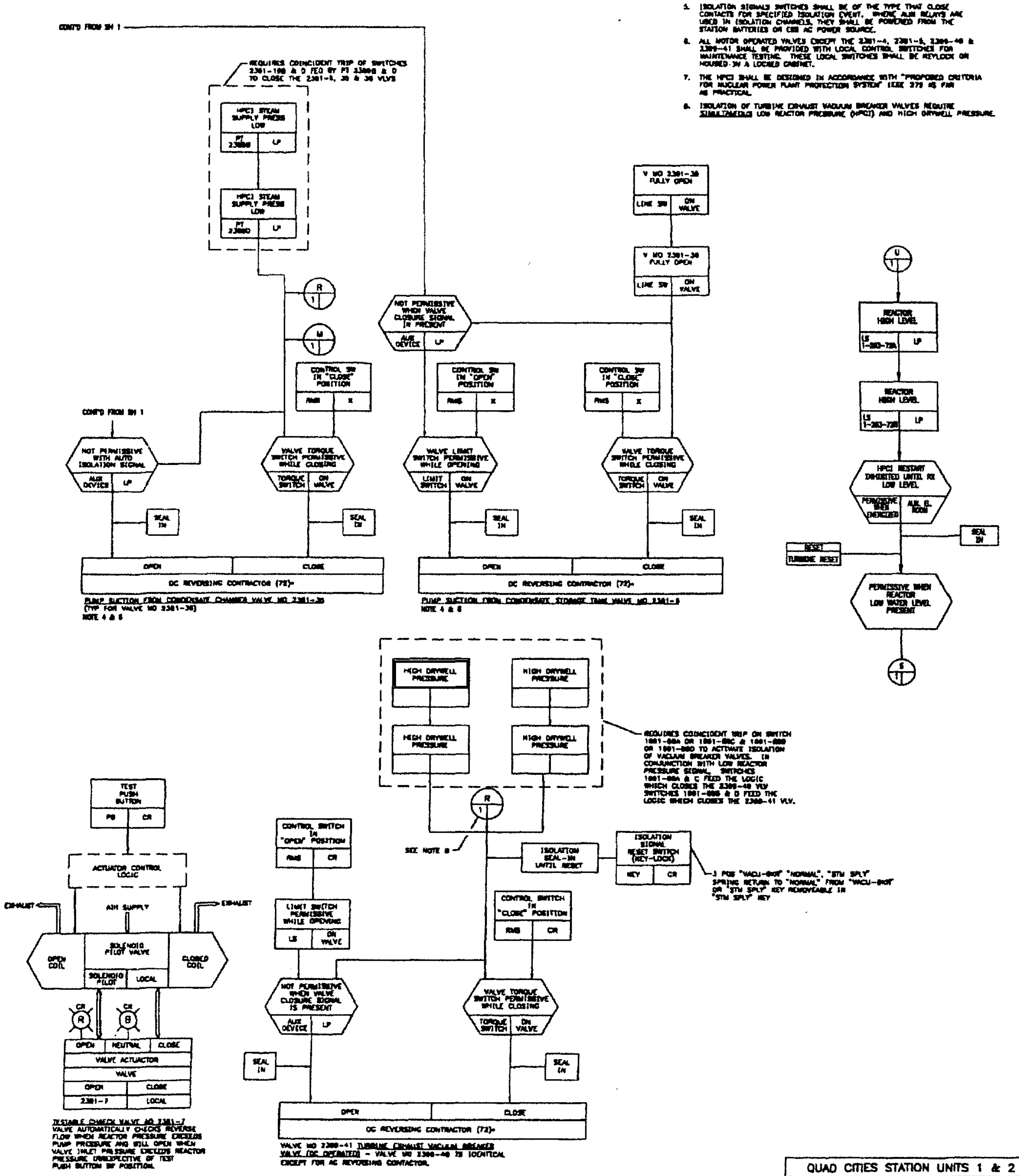
REVISION 7, JANUARY 2003

LEGEND:

** – SWITCH GEAR DEVICE FUNCTION NUMBERS USAS SPEC C37.2
* – FURNISHED WITH TURBINE
CR – LOCATED IN CONTROL ROOM PANEL
LR – MOUNTED ON LOCAL RACK OR PANEL
LOCAL – MOUNTED LOCALLY AT OR NEAR EQUIPMENT OR ON PIPE

NOTES:

1. THE HPCI SYSTEM IS ARRANGED FOR TEST OF PUMP AT FULL FLOW & ALL VALVES FOR OPEN AND CLOSE CAPACITY AT ANY TIME EXCEPT WHEN INITIATION SIGNAL OR AUTO ISOLATION SIGNAL IS ACTIVATED.
2. ALL POWER FOR OPERATION OF DC VALVE MOTORS SHALL ORIGINATE FROM A PLANT DC BUS POWER FOR AC OPERATED VALVES SHALL ORIGINATE FROM ANY EMERGENCY AC BUS.
3. LOCATION NUMBERS FOR RMS, CONTROL SWITCHES AND END TRIP UNITS ARE SHOWN IN ONE POSITION ONLY. AN "X" IN THE LOCATION OF OTHER POSITIONS INDICATES THAT THEIR BLOCKS ARE AN INTEGRAL PART OF THE NUMBERED SWITCH ASSY BUT A DIFFERENT POSITION OF THE SWITCH HANDLE OR A DIFFERENT CONTACT IN THE SWITCH ASSEMBLY.
4. AUXILIARY RELAYS AND DEVICES NOT SHOWN ON FUNCTIONAL CONTROL DIAGRAMS EXCEPT WHERE REQUIRED TO CLARIFY POSITIONS.
5. ISOLATION SIGNALS SWITCHES SHALL BE OF THE TYPE THAT CLOSE CONTACTS FOR SPECIFIED ISOLATION EVENT. WHERE AUX RELAYS ARE USED IN ISOLATION CHANNELS, THEY SHALL BE POWERED FROM THE STATION BATTERIES OR CBB AC POWER SOURCE.
6. ALL MOTOR OPERATED VALVES EXCEPT THE 2301-4, 2301-5, 2399-40 & 2399-41 SHALL BE PROVIDED WITH LOCAL CONTROL SWITCHES FOR MAINTENANCE TESTING. THESE LOCAL SWITCHES SHALL BE KEYLOCK OR HOUSED IN A LOCKED CABINET.
7. THE HPCI SHALL BE DESIGNED IN ACCORDANCE WITH "PROPOSED CRITERIA FOR NUCLEAR POWER PLANT PROTECTION SYSTEM" IEEE 279 AS FAR AS PRACTICAL.
8. ISOLATION OF TURBINE EXHAUST VACUUM BREAKER VALVES REQUIRE SIMULTANEOUS LOW REACTOR PRESSURE (HPCI) AND HIGH DRYWELL PRESSURE.



QUAD CITIES STATION UNITS 1 & 2
HIGH PRESSURE COOLANT INJECTION SYSTEM FUNCTIONAL BLOCK DIAGRAM
FIGURE 6.3-15 SH 2
REVISION 6, OCTOBER 2001

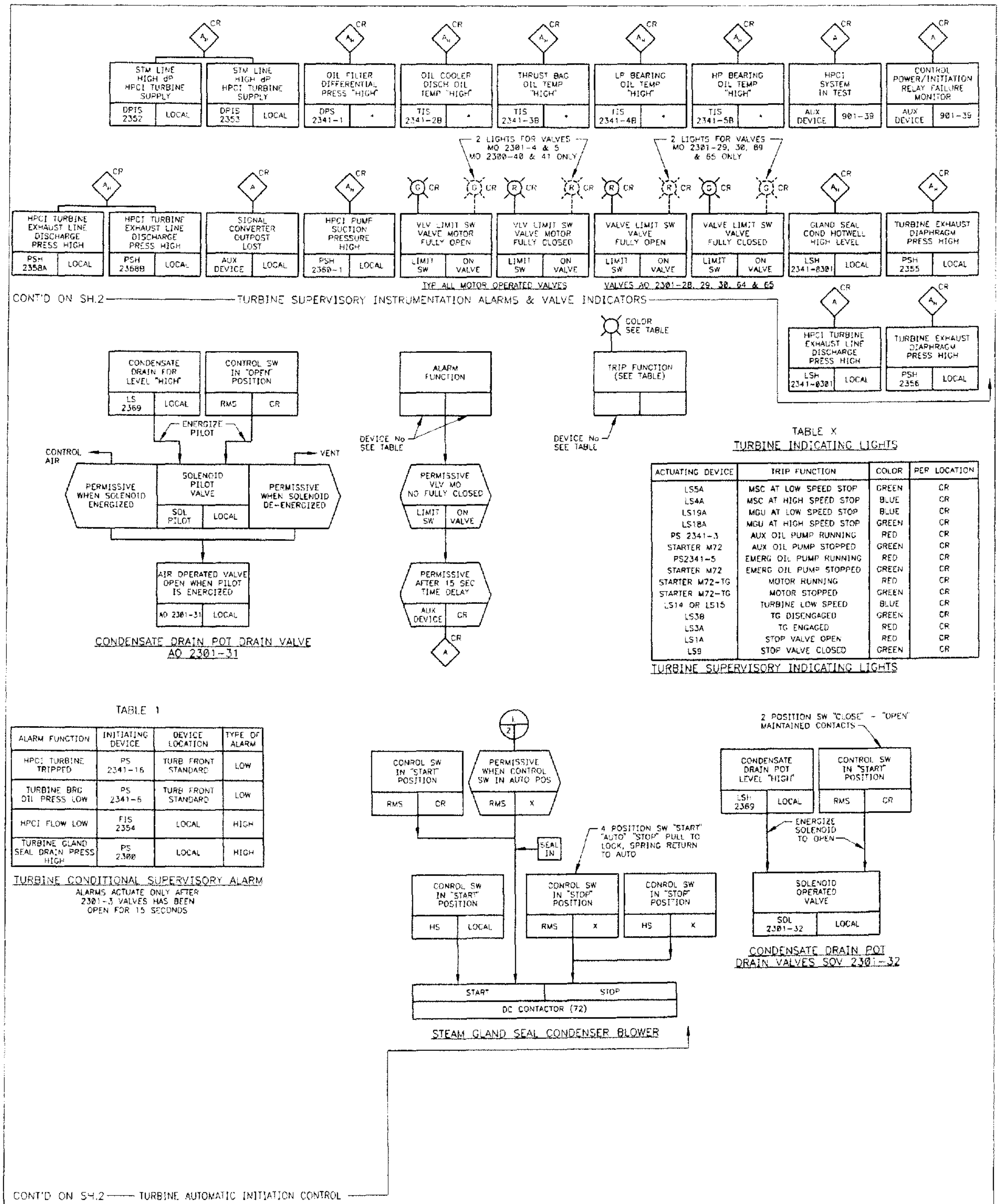


TABLE X
TURBINE INDICATING LIGHTS

ACTUATING DEVICE	TRIP FUNCTION	COLOR	PER LOCATION
LS5A	MSC AT LOW SPEED STOP	GREEN	CR
LS4A	MSC AT HIGH SPEED STOP	BLUE	CR
LS19A	MGU AT LOW SPEED STOP	BLUE	CR
LS18A	MGU AT HIGH SPEED STOP	GREEN	CR
PS 2341-3	AUX OIL PUMP RUNNING	RED	CR
STARTER M72	AUX OIL PUMP STOPPED	GREEN	CR
PS2341-5	EMERG OIL PUMP RUNNING	RED	CR
STARTER M72	EMERG OIL PUMP STOPPED	GREEN	CR
STARTER M72-TG	MOTOR RUNNING	RED	CR
STARTER M72-TG	MOTOR STOPPED	GREEN	CR
LS14 OR LS15	TURBINE LOW SPEED	BLUE	CR
LS3B	TG DISENGAGED	GREEN	CR
LS3A	TG ENGAGED	RED	CR
LS1A	STOP VALVE OPEN	RED	CR
LS9	STOP VALVE CLOSED	GREEN	CR

TURBINE SUPERVISORY INDICATING LIGHTS

TABLE 1

ALARM FUNCTION	INITIATING DEVICE	DEVICE LOCATION	TYPE OF ALARM
HPCI TURBINE TRIPPED	PS 2341-16	TURB FRONT STANDARD	LOW
TURBINE BRG OIL PRESS LOW	PS 2341-6	TURB FRONT STANDARD	LOW
HPCI FLOW LOW	FIS 2354	LOCAL	HIGH
TURBINE GLAND SEAL DRAIN PRESS HIGH	PS 2300	LOCAL	HIGH

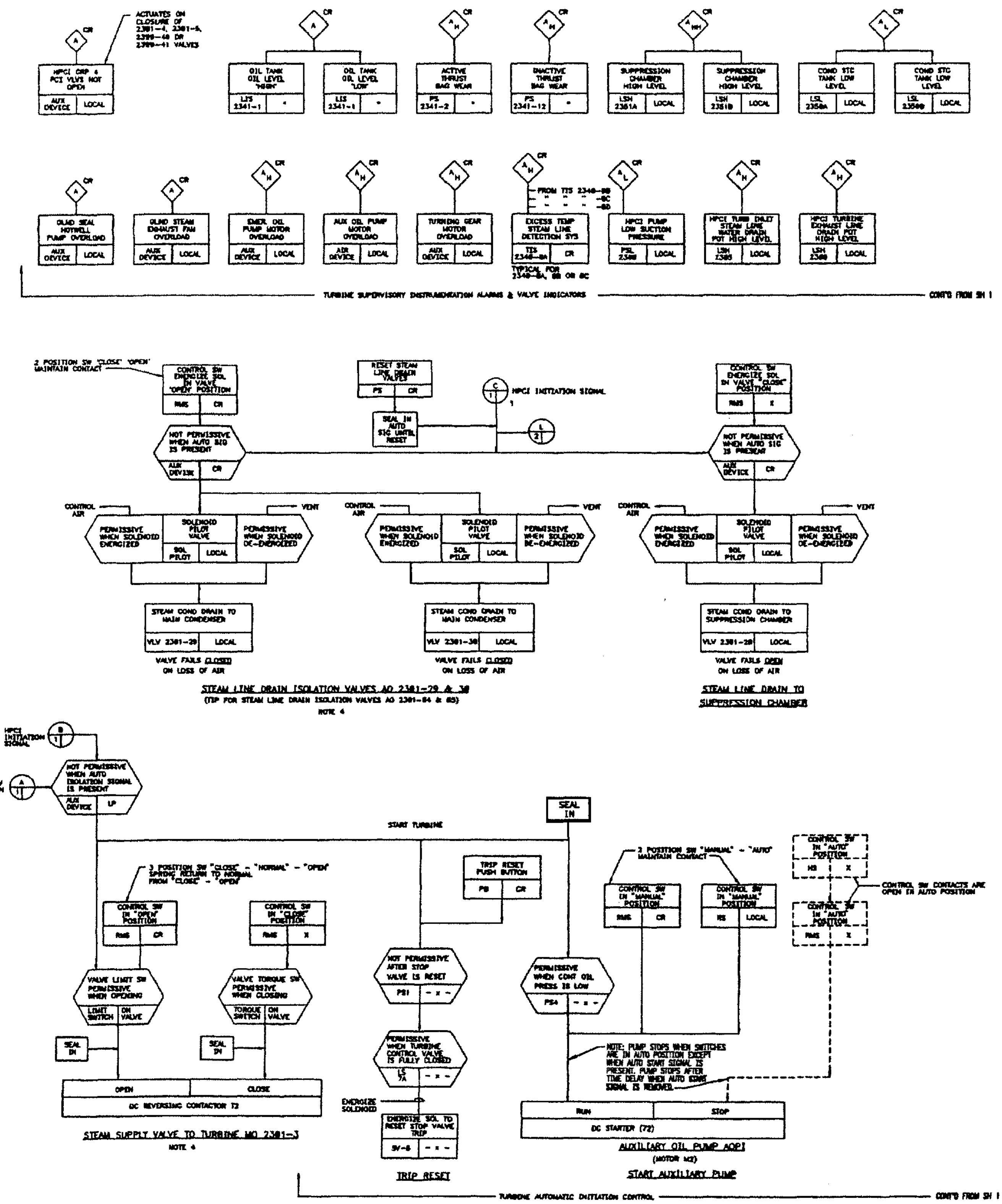
TURBINE CONDITIONAL SUPERVISORY ALARM
ALARMS ACTUATE ONLY AFTER 2301-3 VALVES HAS BEEN OPEN FOR 15 SECONDS

QUAD CITIES STATION
UNITS 1 & 2

HIGH PRESSURE COOLANT INJECTION SYSTEM
FUNCTIONAL BLOCK DIAGRAM

FIGURE 6.3-16
SHEET 1

REVISION 7, JANUARY 2003

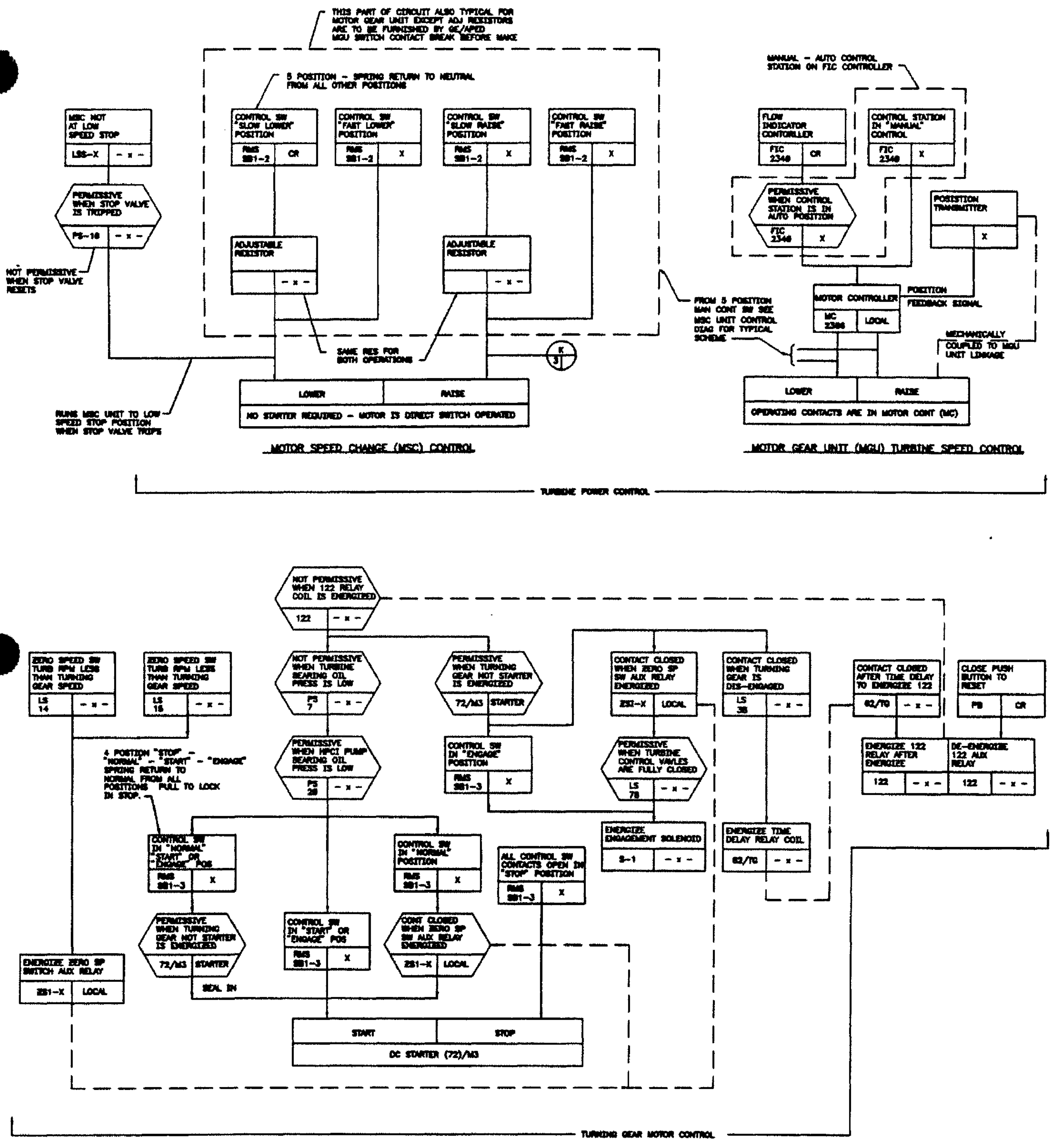


QUAD CITIES STATION UNITS 1 & 2

HIGH PRESSURE COOLANT INJECTION SYSTEM FUNCTIONAL BLOCK DIAGRAM

FIGURE 6.3-16 SHEET 2

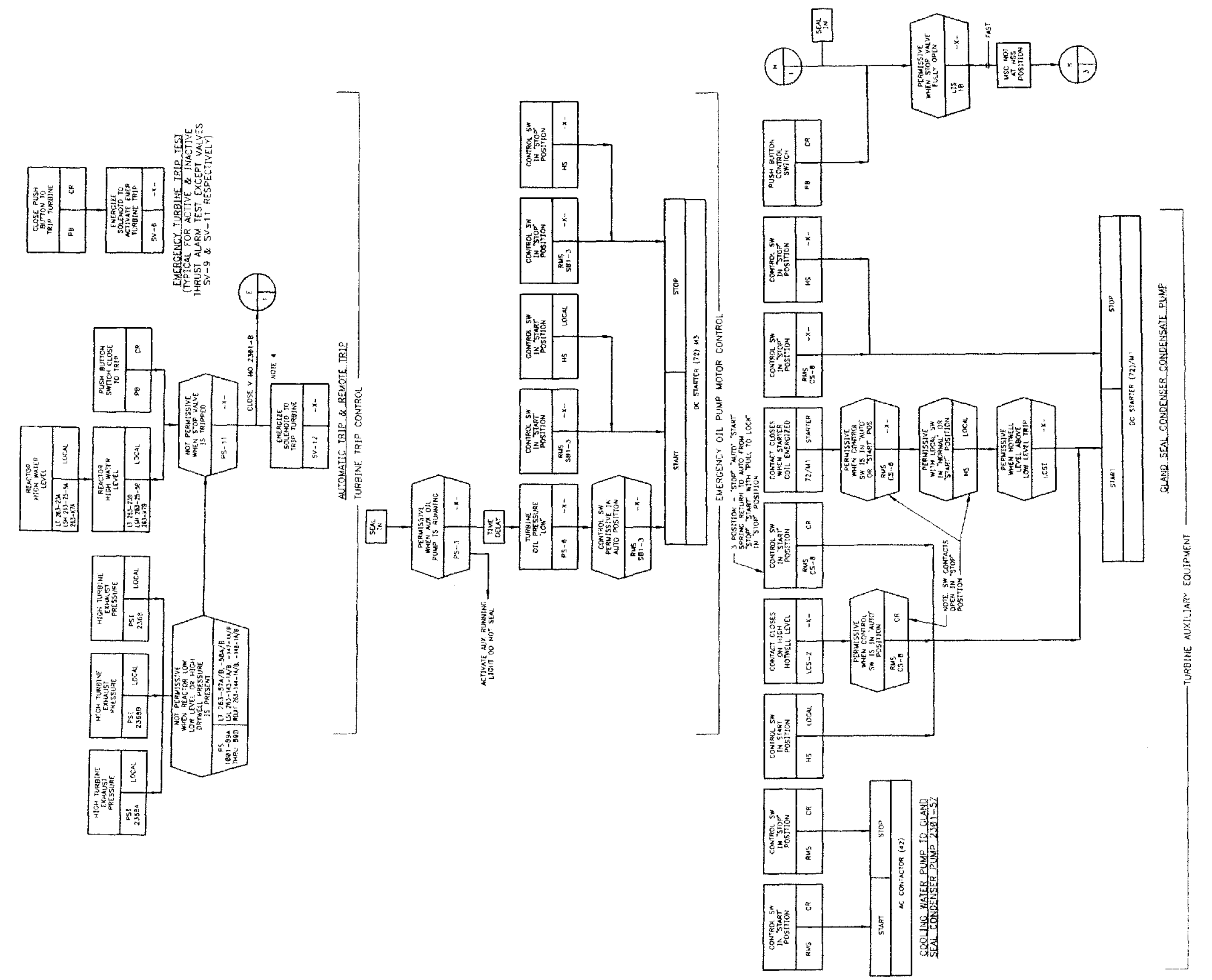
REVISION 6, OCTOBER 2001



QUAD CITIES STATION
UNITS 1 & 2

HIGH PRESSURE COOLANT INJECTION SYSTEM
FUNCTIONAL BLOCK DIAGRAM

FIGURE 6.3–17 SHEET 1
REVISION 5, JUNE 1999

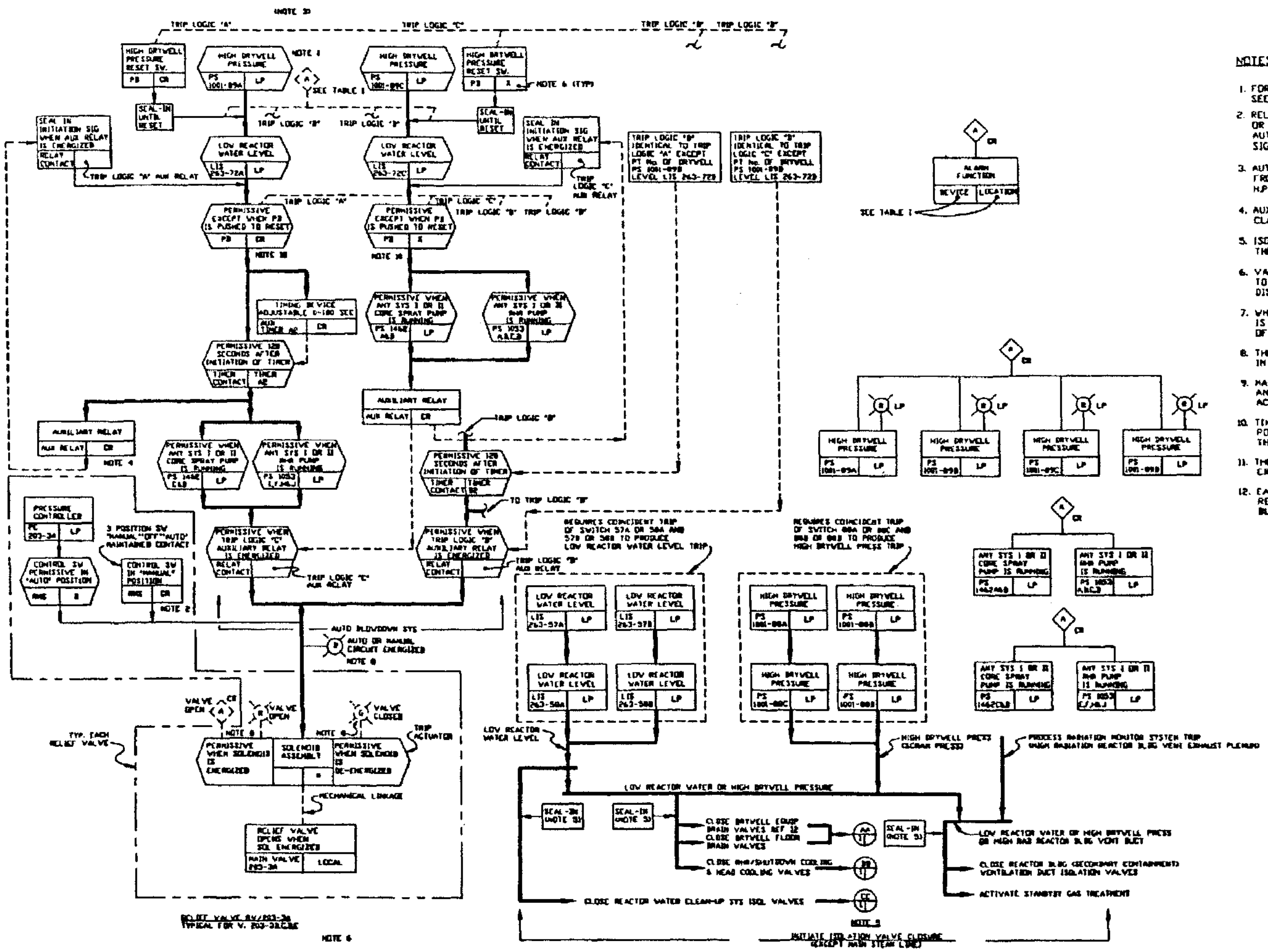


QUAD CITIES STATION
UNITS 1 & 2

HIGH PRESSURE COOLANT INJECTION SYSTEM
FUNCTIONAL BLOCK DIAGRAM

FIGURE 6.3-17
SHEET 2

REVISION 7, JANUARY 2003



NOTES:

1. FOR AUTO BLOWDOWN LOGIC OPERATION WITHOUT HIGH DRYWELL PRESSURE SEE FIGURE 6.3-19
2. RELIEF VALVES MAY BE MANUALLY OPENED AT ANY TIME BY CONTROL SWITCH OR AUTOMATICALLY BY REACTOR HIGH PRESSURE. VALVES CLOSE WHEN SWITCH IS IN AUTO POSITION EXCEPT WHEN AUTOMATIC BLOWDOWN OR REACTOR HIGH PRESSURE SIGNALS ARE PRESENT.
3. AUTOMATIC BLOWDOWN TRIP CIRCUITS A,B,C & D AND TRIP ACTUATORS SHALL BE POWERED FROM STATION BATTERIES AND FROM A SEPARATE CONTROL BUS OTHER THAN WHERE H.P.C.I SYSTEM IS POWERED FROM.
4. AUXILIARY RELAYS AND DEVICES ARE NOT SHOWN ON FCD EXCEPT WHERE REQUIRED TO CLARIFY FUNCTION.
5. ISOLATION VALVE CLOSURE SIGNALS SHALL BE SEALED IN UNTIL MANUALLY RESET FROM THE CONTROL ROOM PANEL.
6. VALVES 308-3B AND 308-3C INCORPORATE A 10-SECOND TIME DELAY IN REPEATED ACTUATION TO PREVENT THE VALVE OPENING WITH AN ELEVATED WATER LEG IN THE RELIEF VALVE DISCHARGE PIPING.
7. WHEN TEST SOLENOID PILOT IS ENERGIZED THE MAIN STEAM ISOLATION VALVE OPERATOR IS SLOWLY EXHAUSTED 160 SECONDS CLOSURE TIME WHILE VALVE IS CLOSED BY ACTION OF THE VALVE SPRING WITHOUT AID OF AIR PRESSURE.
8. THE ALARMS AND VALVE INDICATING LIGHTS SHOWN ON THE FCD ARE SYSTEM REQUIREMENTS IN ADDITION TO THOSE SHOWN ON THE SYSTEM P&ID'S.
9. MAIN STEAM LINE ISOLATION VALVE TRIP LOGIC CIRCUITS A,B,C & D SHALL BE POWERED FROM ANY RELIABLE AC SOURCE. TRIP ACTUATOR CIRCUIT I SHALL BE POWERED FROM ANY RELIABLE AC SOURCE. TRIP CIRCUIT II SHALL BE POWERED FROM STATION BATTERIES.
10. TIMING DEVICES SHALL BE OF THE TYPE THAT AUTOMATICALLY RESETS TO ZERO UPON LOSS OF POWER TO THE TIMING DEVICE, UPON LOSS OF THE INIATIATING SIGNAL OR UPON PUSHING THE PB TO RESET.
11. THE AUTOMATIC BLOWDOWN SYSTEM SHALL BE DEFINED IN ACCORDANCE WITH "PROPOSED CRITERIA FOR NUCLEAR POWER PLANT PROTECTION SYSTEM IEEE 279" TO THE EXTENT PRACTICABLE.
12. EACH AUTO BLOWDOWN VALVE AND AUTO BLOWDOWN CONTROL LOGIC CIRCUIT SHALL HAVE REDUNDANT POWER SUPPLIES SO THAT A SINGLE FAILURE WILL NOT DISABLE THE AUTO BLOWDOWN SYSTEM.

LEGEND

* = SWITCH GEAR DEVICE FUNCTION NO'S USAS SPEC. C37.2
= FURNISHED AS PART OF VALVE OR DEVICE ASSEMBLY

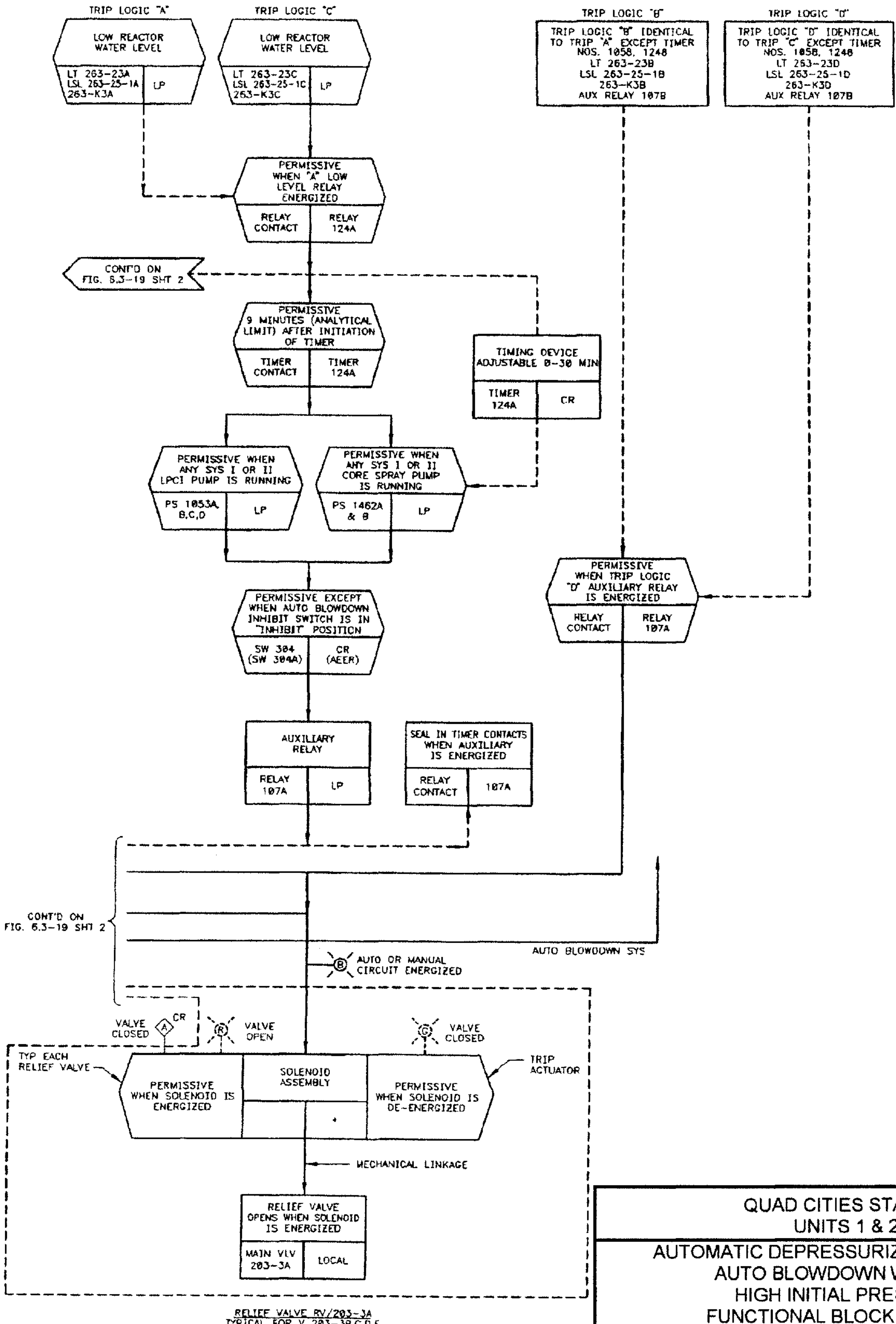
ALARM FUNCTION	INITIATING DEVICE	DEVICE LOCATION
BLOWDOWN TIMERS INITIATED	TIMING DEVICE (A2) OR (B2) TO ONE COMMON ANNUNCIATOR	CR
BLOWDOWN CIRCUIT POWER FAILURE	AUX POWER FAILURE RELAY FOR EACH LOGIC CHANNEL TO ONE COMMON ANNUNCIATOR	CR
HIGH DRYWELL PRESS SIGNAL SEALED IN	EACH DRYWELL PRESSURE SWITCH AUX RELAY TO ONE COMMON ANNUNCIATOR	CR
AUTO BLOWDOWN INHIBIT	SWITCH CONTACT IN INHIBIT POSITION TO ONE ANNUNICIATOR	CR (AEER)

QUAD CITIES STATION UNITS 1 & 2

AUTOMATIC DEPRESSURIZATION SYSTEM FUNCTIONAL BLOCK DIAGRAM

FIGURE 6.3–18

REVISION 6, OCTOBER 2001

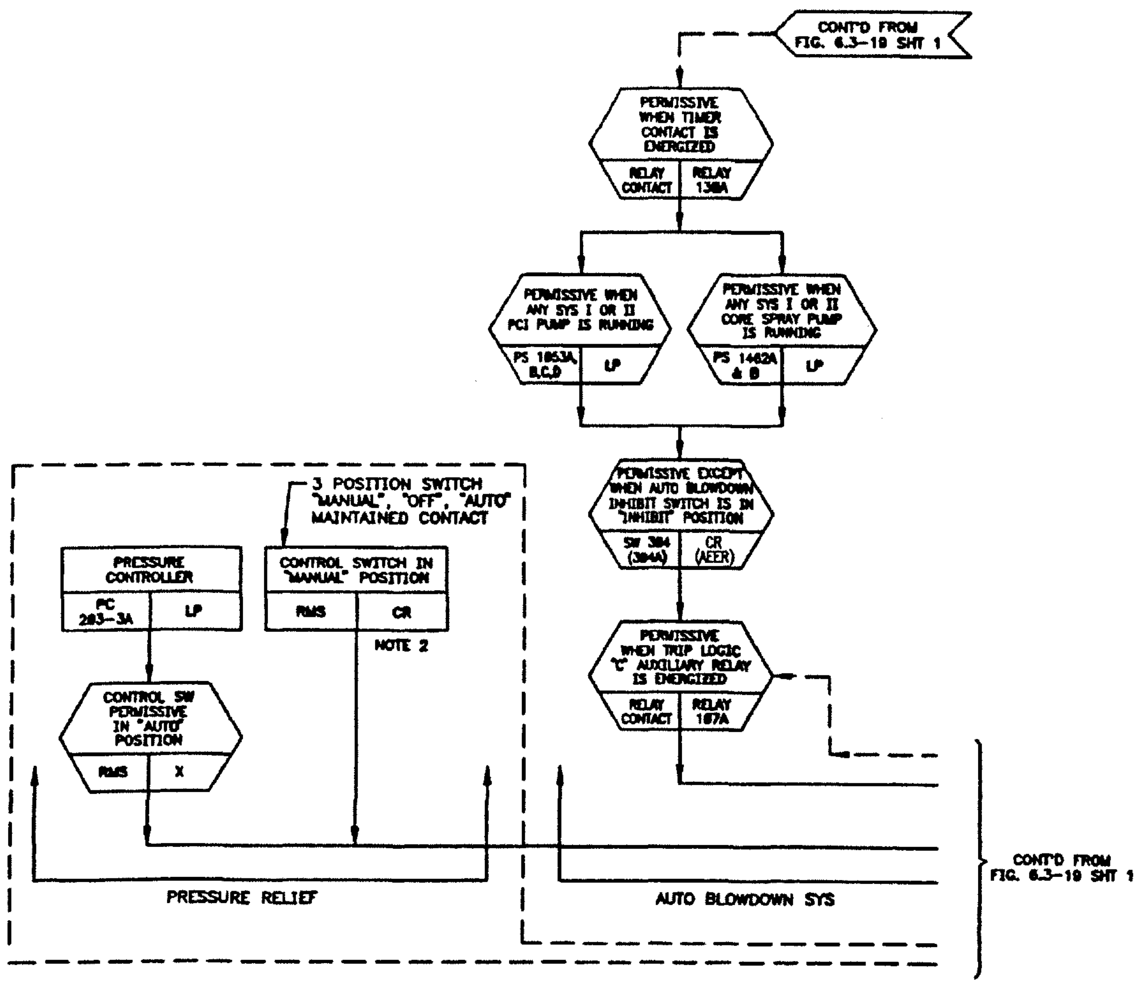


QUAD CITIES STATION
UNITS 1 & 2

AUTOMATIC DEPRESSURIZATION SYSTEM
AUTO BLOWDOWN WITHOUT
HIGH INITIAL PRESSURE
FUNCTIONAL BLOCK DIAGRAM

FIGURE 6.3-19
SHEET 1

REVISION 7, JANUARY 2003

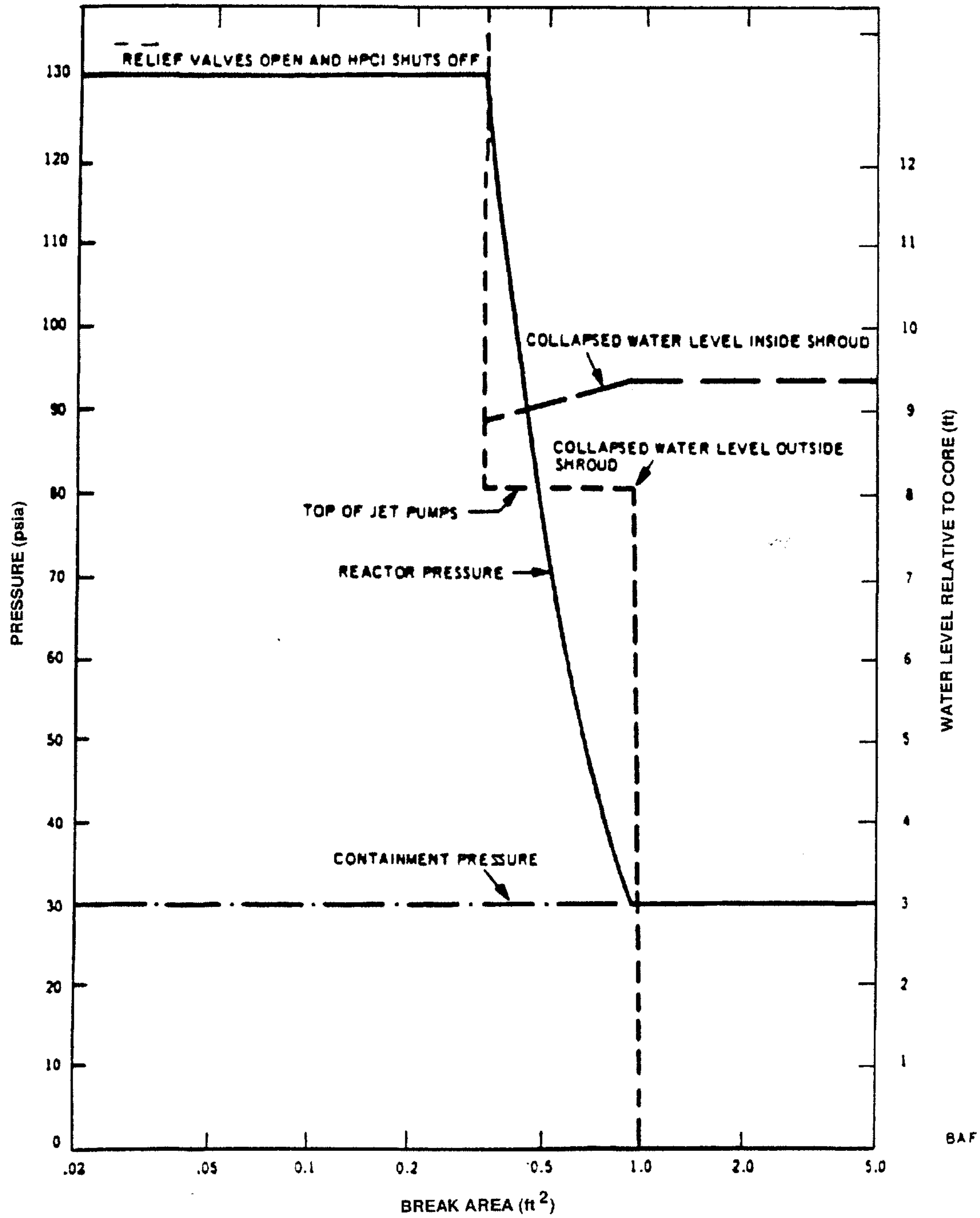


QUAD CITIES STATION UNITS 1 & 2

AUTOMATIC DEPRESSURIZATION SYSTEM – AUTO BLOWDOWN WITHOUT HIGH INITIAL PRESSURE FUNCTIONAL BLOCK DIAGRAM

FIGURE 6.3–19 SHEET 2

REVISION 6, OCTOBER 2001



See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

HISTORICAL ANALYSIS FROM NEDO-20566A

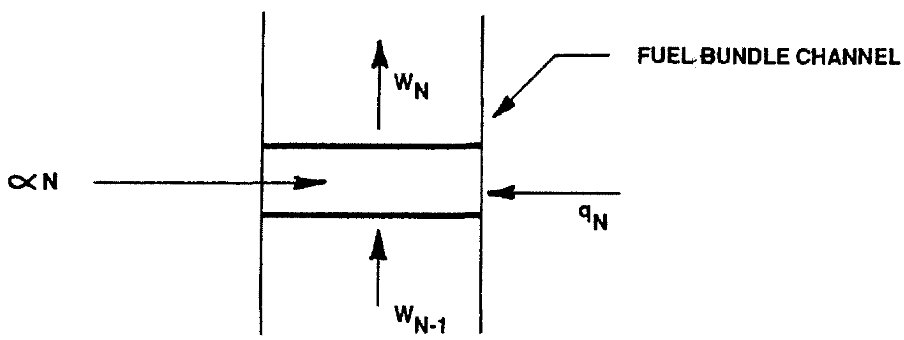
QUAD CITIES STATION

UNITS 1 & 2

LONG TERM REACTOR REPONSE EQUILIBRIUM CONDITIONS (NO CORE SPRAY) AT 2511 MWt

FIGURE 6.3-20

REVISION 7, JANUARY 2003



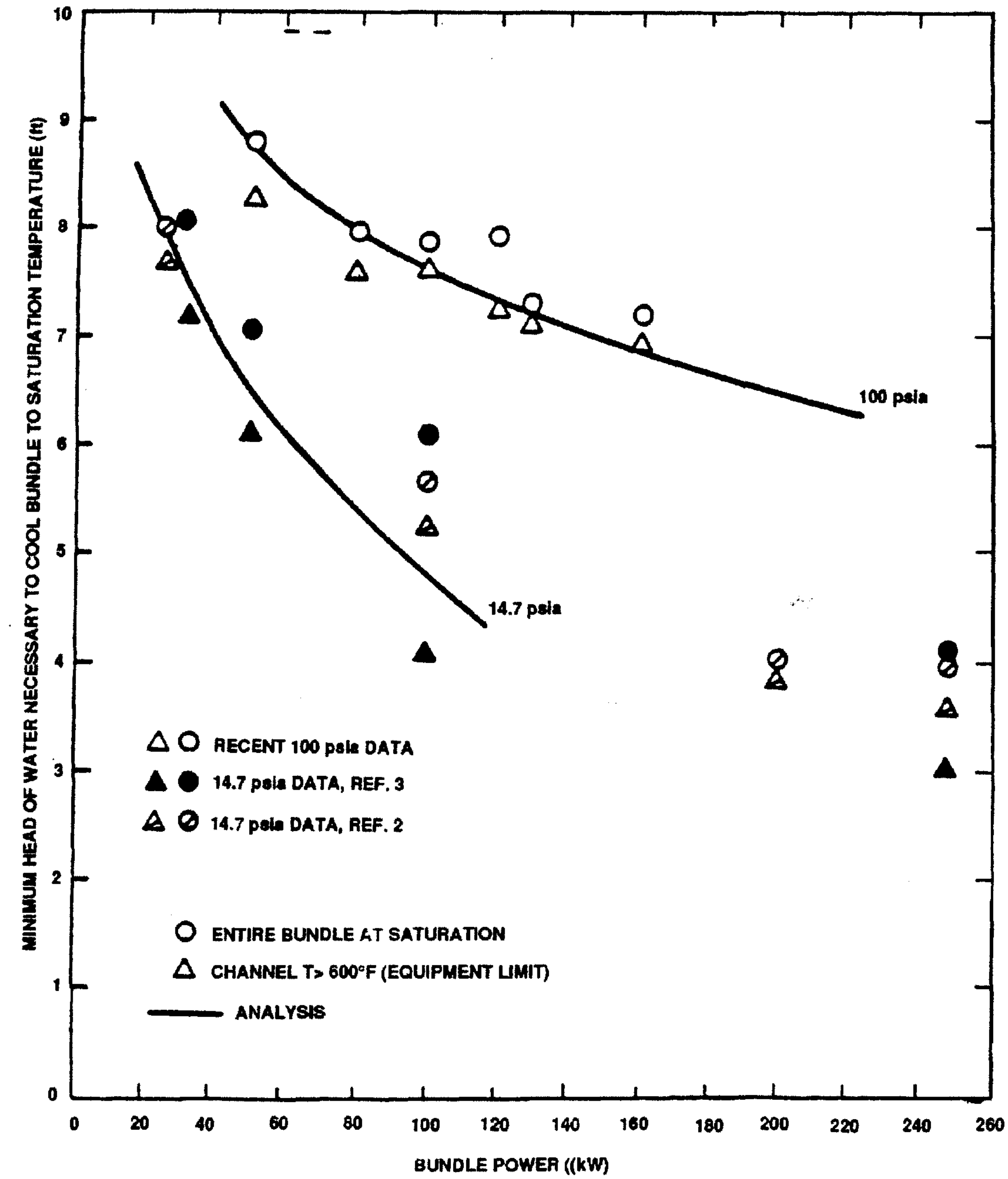
HISTORICAL ANALYSIS FROM NEDO-20566A

QUAD CITIES STATION
UNITS 1 & 2

MODEL USED FOR ANALYSIS OF THE
SWELL PHENOMENON AT 2511 MWt

FIGURE 6.3-21

REVISION 7, JANUARY 2003



See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

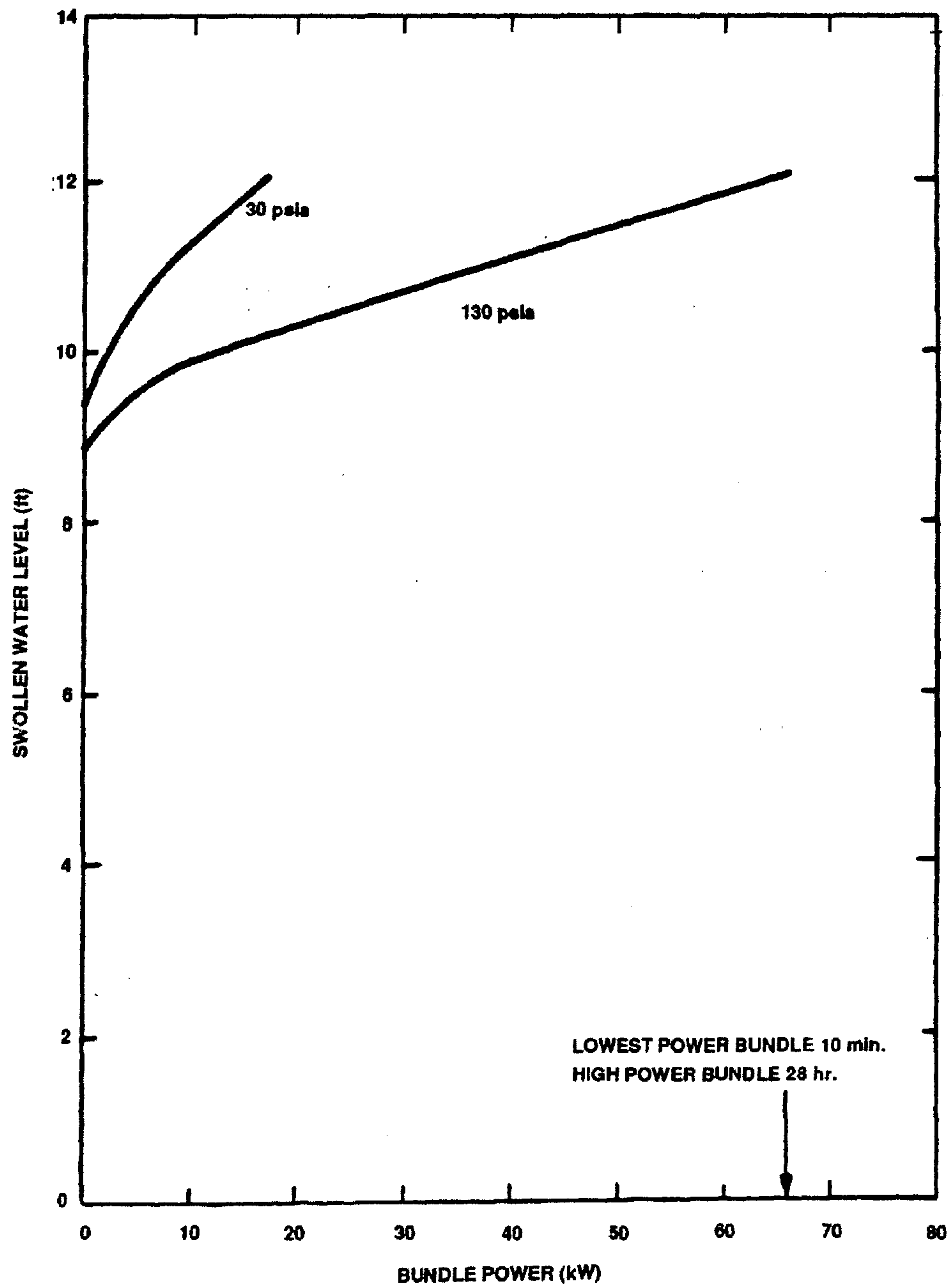
HISTORICAL ANALYSIS FROM NEDO-20566A

QUAD CITIES STATION
UNITS 1 & 2

LONG TERM COOLING LEVEL SWELL MODEL
COMPARISON TO DATA AT 2511 MWt

FIGURE 6.3-22

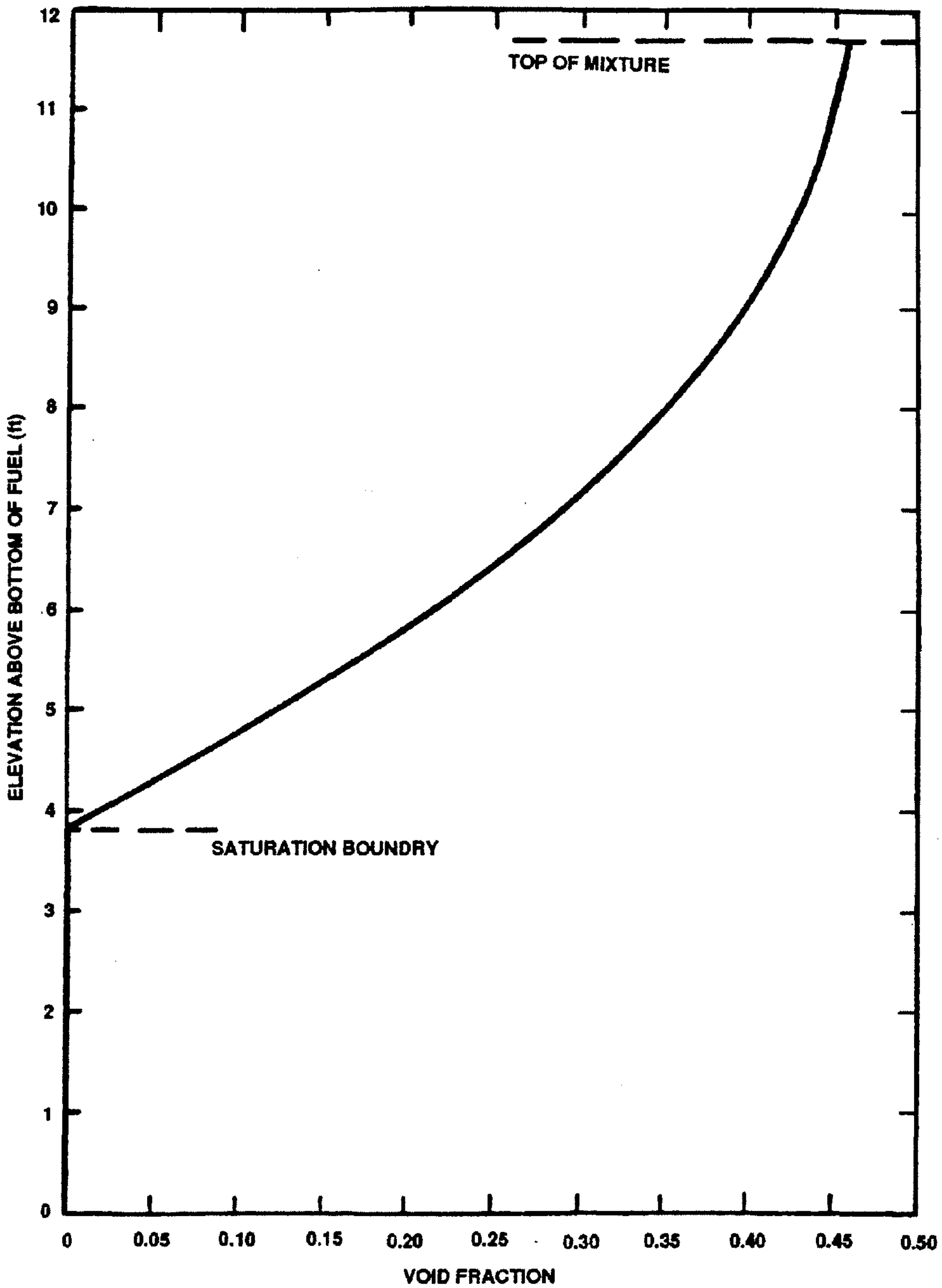
REVISION 7, JANUARY 2003



See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

HISTORICAL ANALYSIS FROM NEDO-20566A

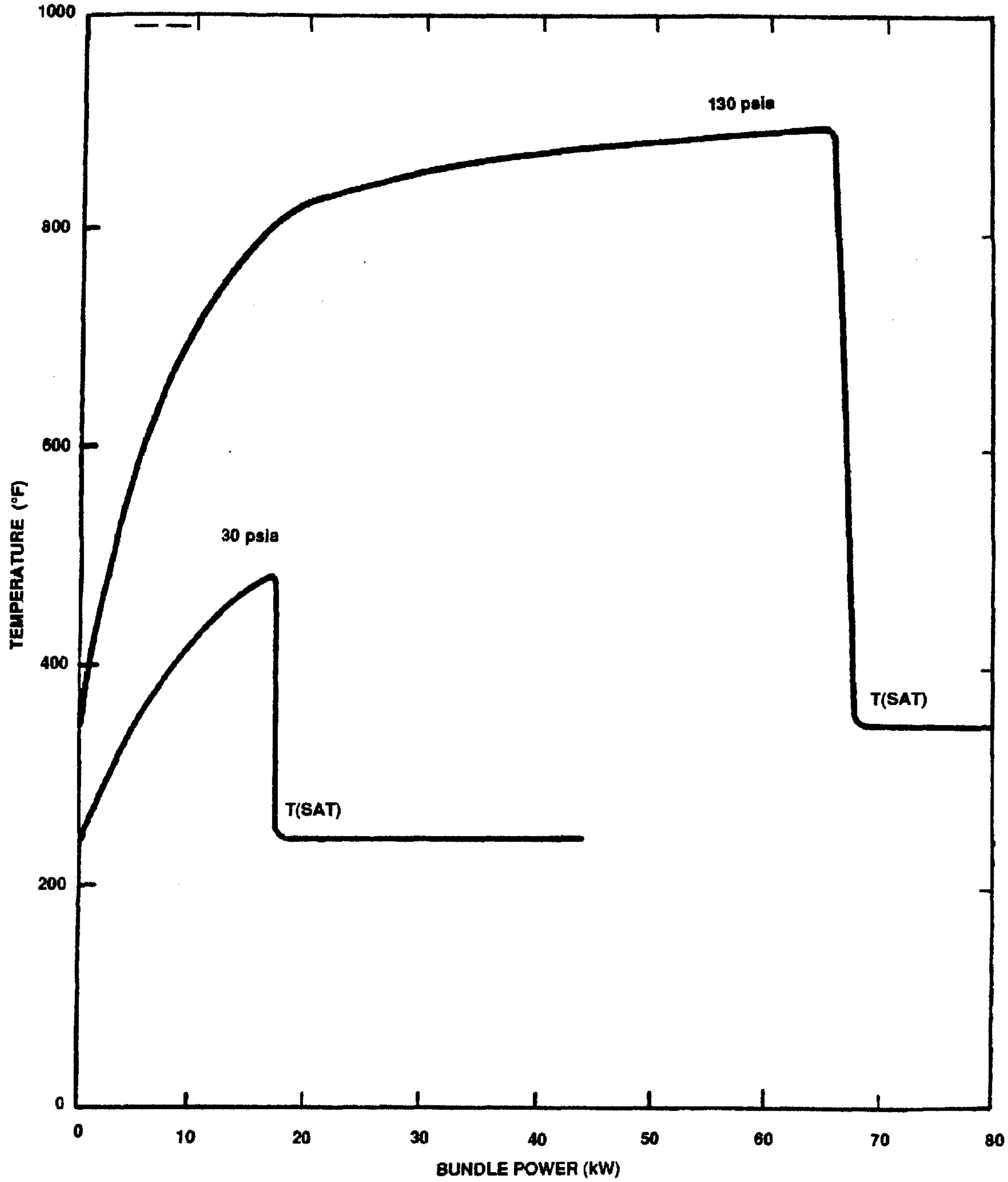
QUAD CITIES STATION UNITS 1 & 2
LONG TERM SWOLLEN WATER LEVEL RESPONSE AT 2511 MWt
FIGURE 6.3-23 REVISION 7, JANUARY 2003



See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

HISTORICAL ANALYSIS FROM NEDO-20566A

QUAD CITIES STATION UNITS 1 & 2
COOLANT DISTRIBUTION (P = 130 PSIA; 60 kW) AT 2511 MWt
FIGURE 6.3-24 REVISION 7, JANUARY 2003



See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

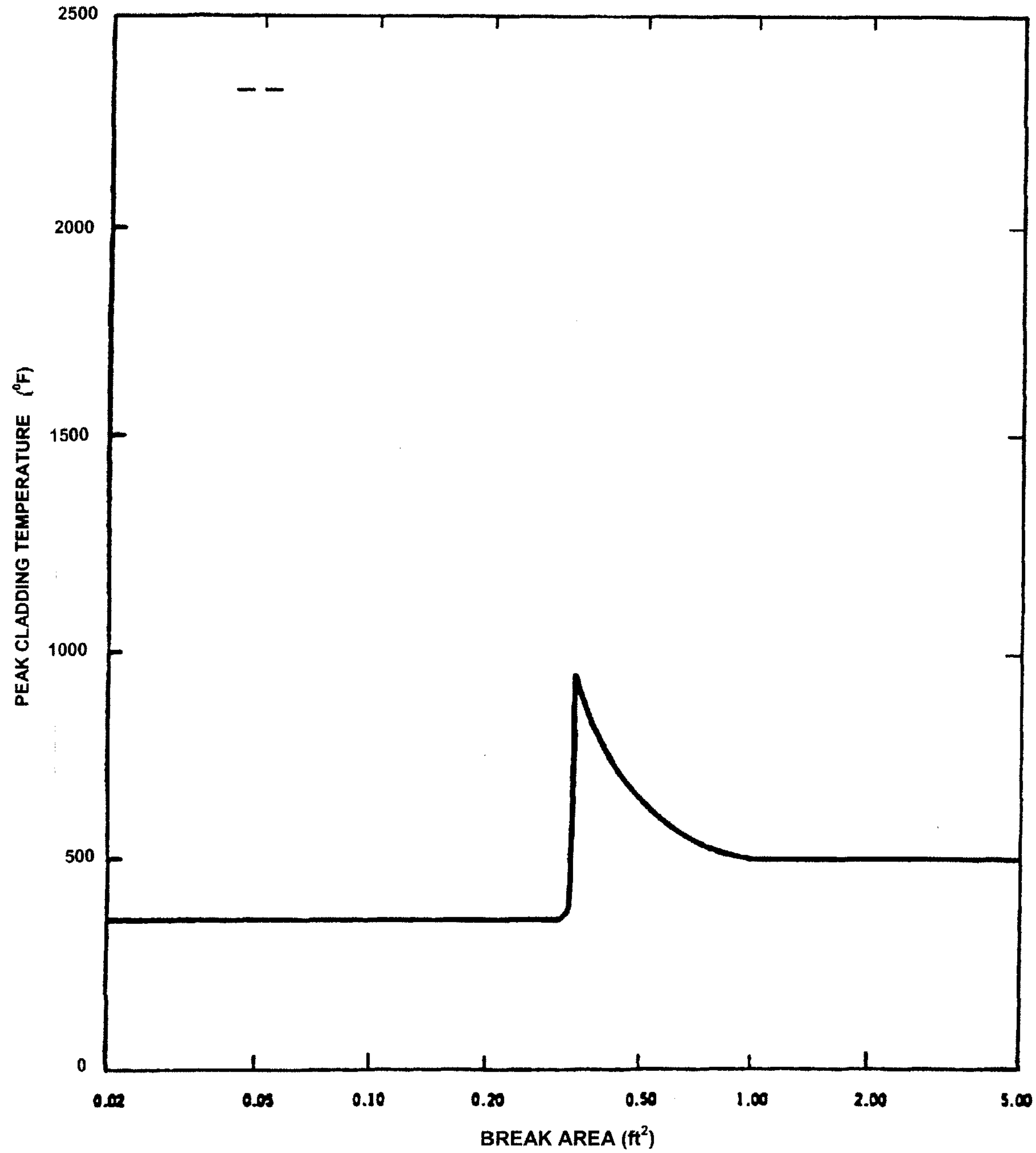
HISTORICAL ANALYSIS FROM NEDO-20566A

QUAD CITIES STATION
UNITS 1 & 2

PEAK CLADDING TEMPERATURES FOR LONG TERM COOLING CONDITIONS AT 2511 MWt

FIGURE 6.3-25

REVISION 7, JANUARY 2003



See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

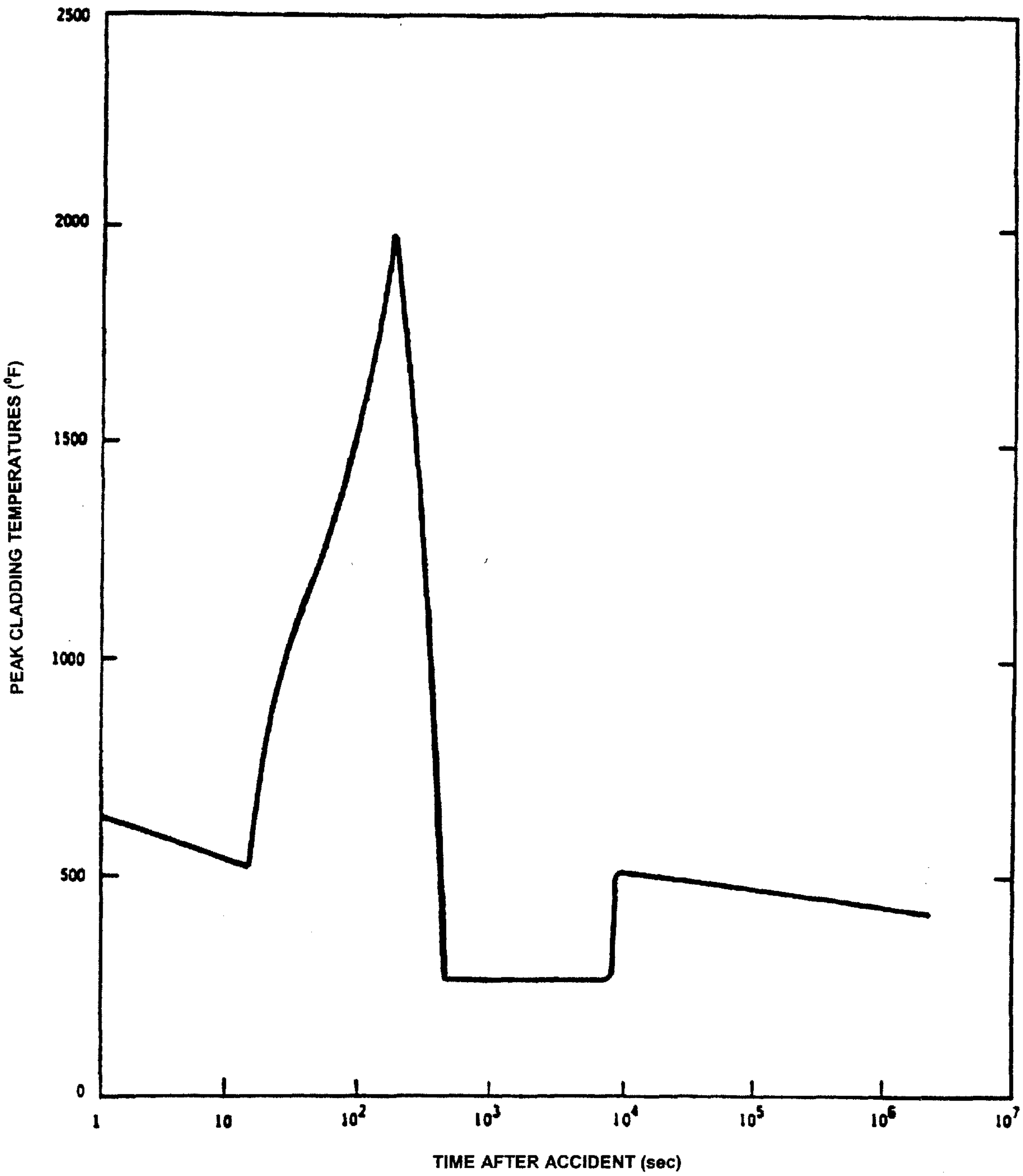
HISTORICAL ANALYSIS FROM NEDO-20566A

QUAD CITIES STATION
UNITS 1 & 2

MAXIMUM CLADDING TEMPERATURE FOR LONG TERM COOLING (LPCI ALONE) AT 2511 MWt

FIGURE 6.3-26

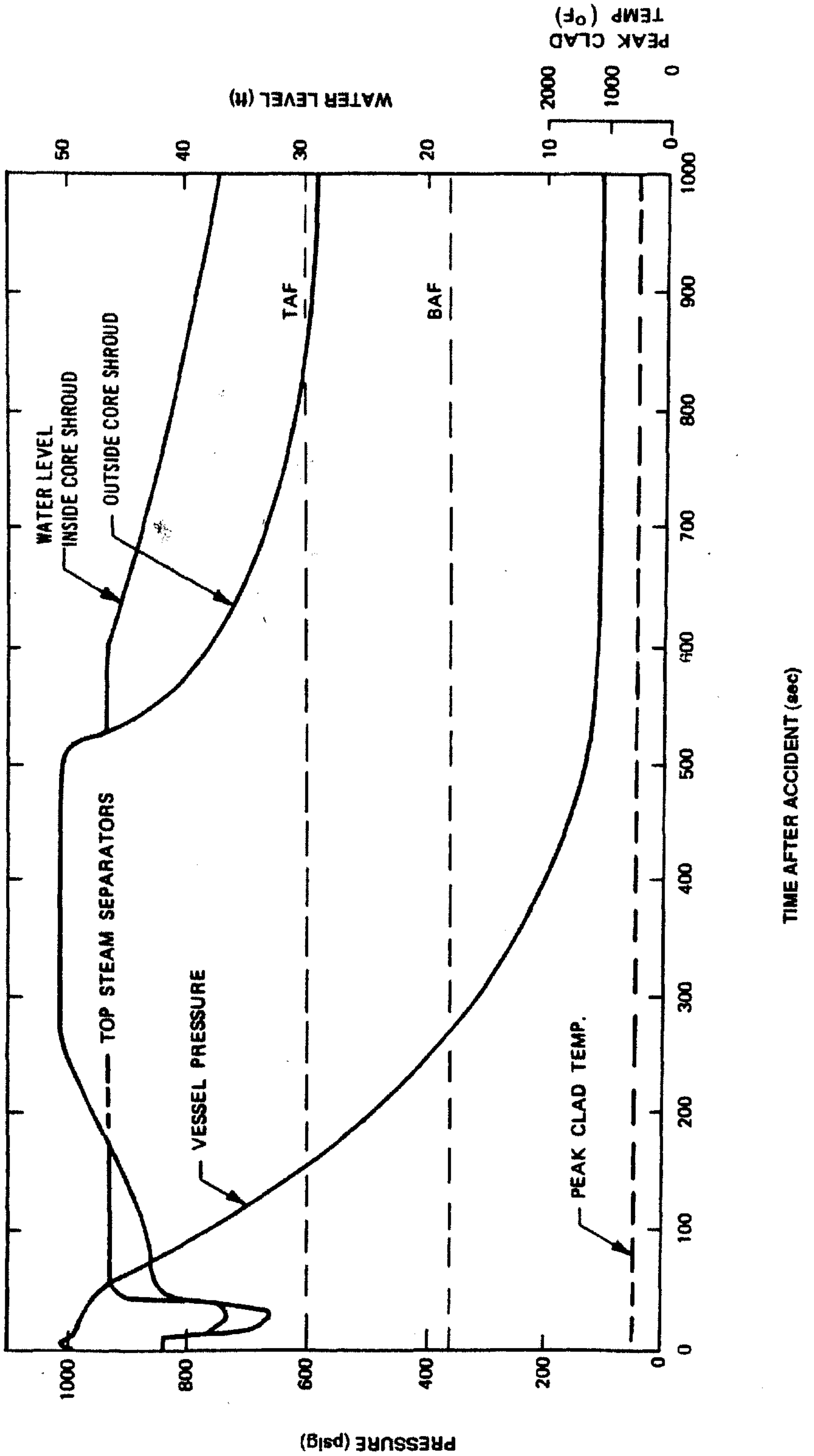
REVISION 7, JANUARY 2003



See the first paragraph of Section 6.3.3.1.2.1.1 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

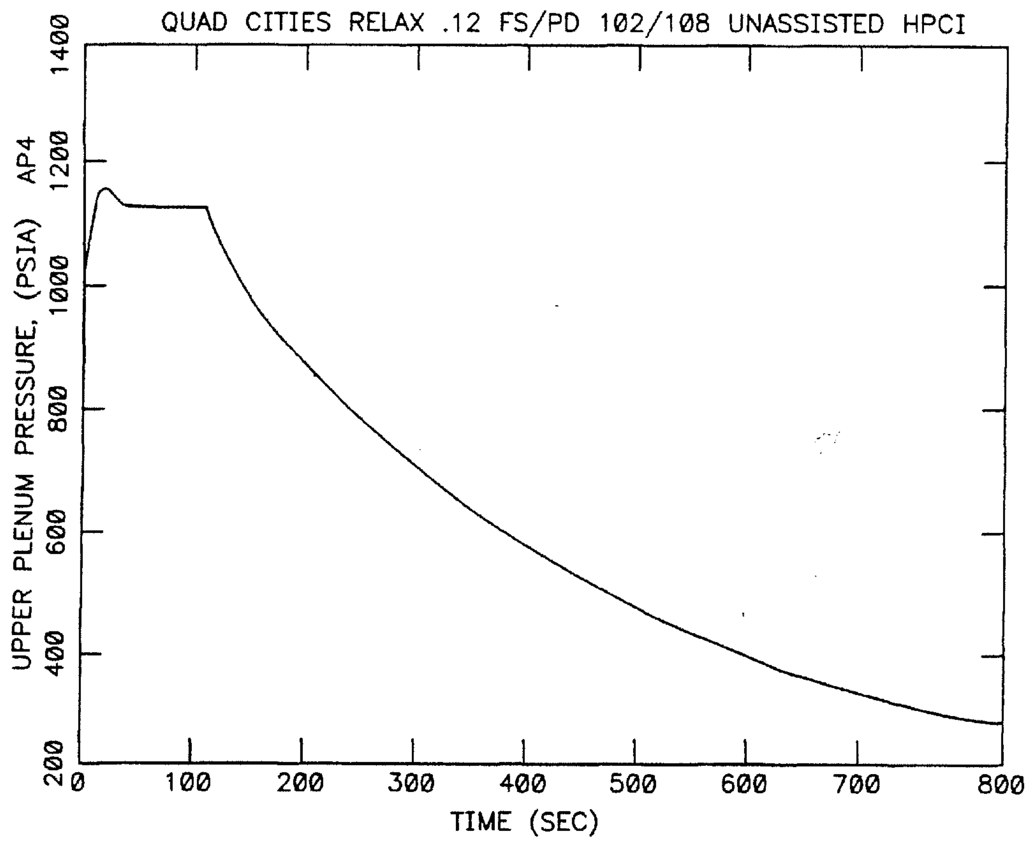
HISTORICAL ANALYSIS FROM NEDO-20566A

QUAD CITIES STATION UNITS 1 & 2
MAXIMUM CLADDING TEMPERATURE FOR THE DESIGN BASIS ACCIDENT (CONTAINMENT P = 30 PSIA) (3 LPCI) AT 2511MWt
FIGURE 6.3-27
REVISION 7, JANUARY 2003



These results are historical and are not required for the current licensing basis under 10 CFR 50.46 and 10 CFR 50 Appendix K requirements.

QUAD CITIES STATION UNITS 1 & 2
UNASSISTED HPCI PERFORMANCE AT 2511 MWt (0.1 FT^2 BREAK AREA)
FIGURE 6.3-28



NOTE: RESULTS ARE HISTORICAL. THESE RESULTS ARE NOT REQUIRED FOR CURRENT LICENSING BASIS UNDER 10CFR50.46 AND 10CFR50 APPENDIX K, SINGLE FAILURE REQUIREMENTS.

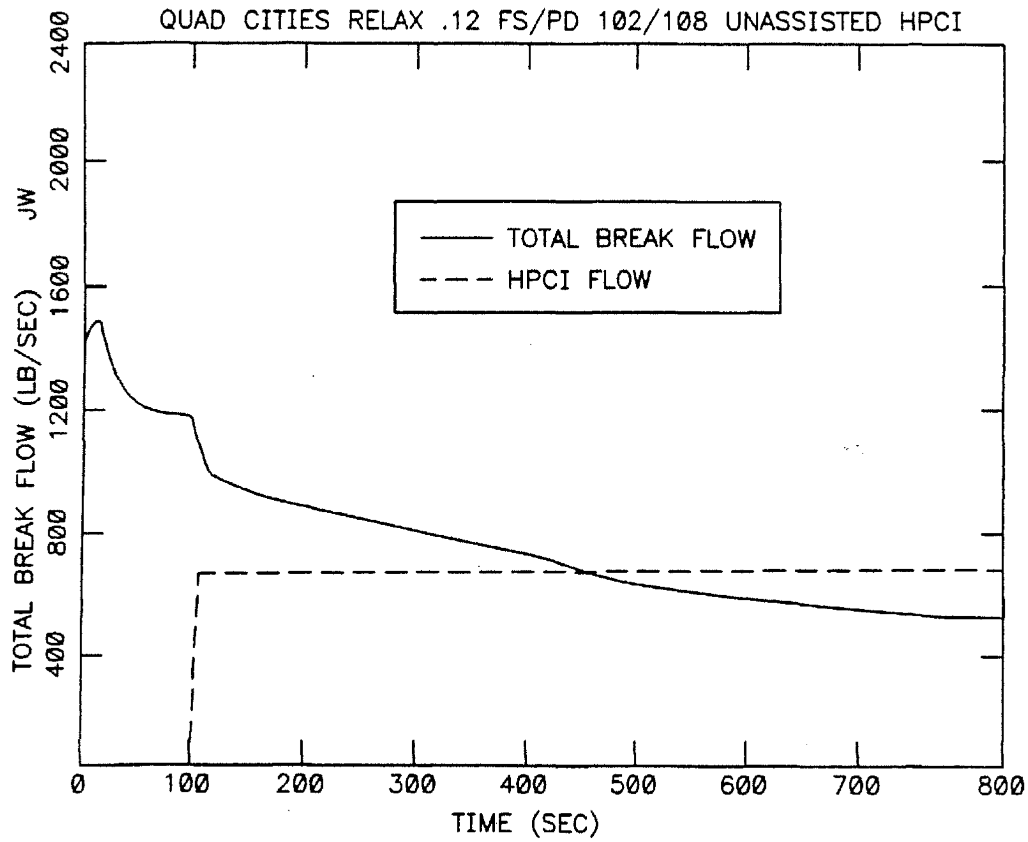
SOURCE: REFERENCES 46, 47

QUAD CITIES STATION UNITS 1 & 2

UPPER PLENUM PRESSURE VS. TIME AFTER BREAK AT 2511 MWt (0.12ft^2 PUMP DISCHARGE BREAK, UNASSISTED HPCI, 102% POWER, 108% CORE FLOW FOR ATRIUM-9B FUEL)

FIGURE 6.3-28A

REVISION 7, JANUARY 2003



NOTE: RESULTS ARE HISTORICAL. THESE RESULTS ARE NOT REQUIRED FOR CURRENT LICENSING BASIS UNDER 10CFR50.46 AND 10CFR50 APPENDIX K, SINGLE FAILURE REQUIREMENTS.

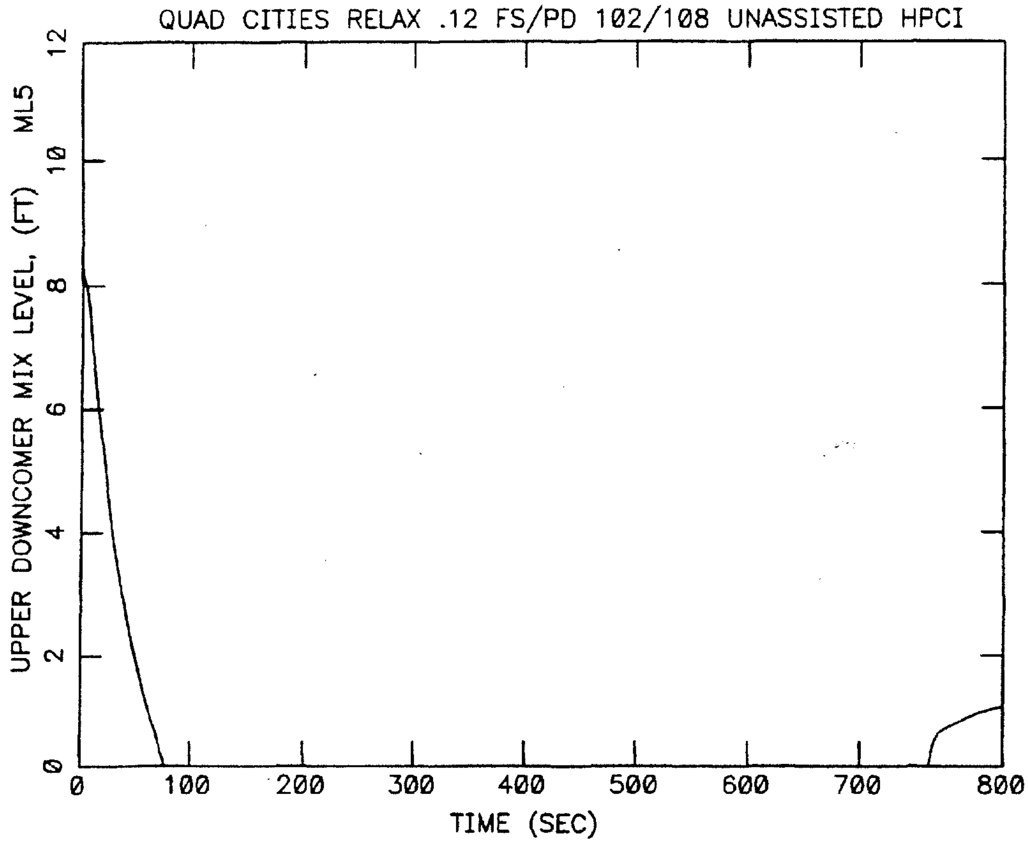
SOURCE: REFERENCES 46, 47

QUAD CITIES STATION UNITS 1 & 2

TOTAL BREAK FLOW AND HPCI FLOW VS. TIME AFTER BREAT AT 2511 MWt (0.12ft^2 PUMP DISCHARGE BREAK, UNASSISTED HPCI, 102% POWER, 108% CORE FLOW FOR ATRIUM-9B FUEL)

FIGURE 6.3-28B

REVISION 7, JANUARY 2003



NOTE: RESULTS ARE HISTORICAL. THESE RESULTS ARE NOT REQUIRED FOR CURRENT LICENSING BASIS UNDER 10CFR50.46 AND 10CFR50 APPENDIX K, SINGLE FAILURE REQUIREMENTS.

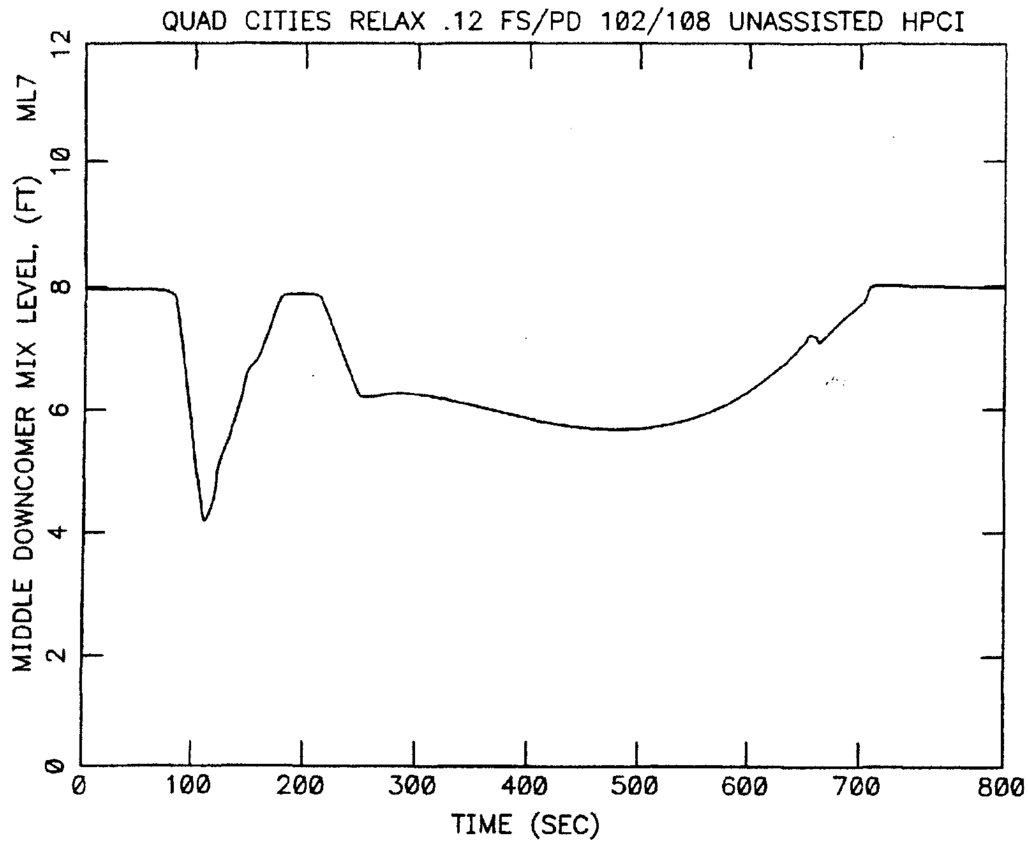
SOURCE: REFERENCES 46, 47

QUAD CITIES STATION UNITS 1 & 2

UPPER DOWNCOMER MIXTURE LEVEL VS. TIME AFTER BREAK AT 2511MWt (0.12FT^2 PUMP DISCHARGE BREAK, UNASSISTED HPCI, 102% POWER, 108% CORE FLOW FOR ATRIUM-9B FUEL)

FIGURE 6.3-28C

REVISION 7, JANUARY 2003



NOTE: RESULTS ARE HISTORICAL. THESE RESULTS ARE NOT REQUIRED FOR CURRENT LICENSING BASIS UNDER 10CFR50.46 AND 10CFR50 APPENDIX K, SINGLE FAILURE REQUIREMENTS.

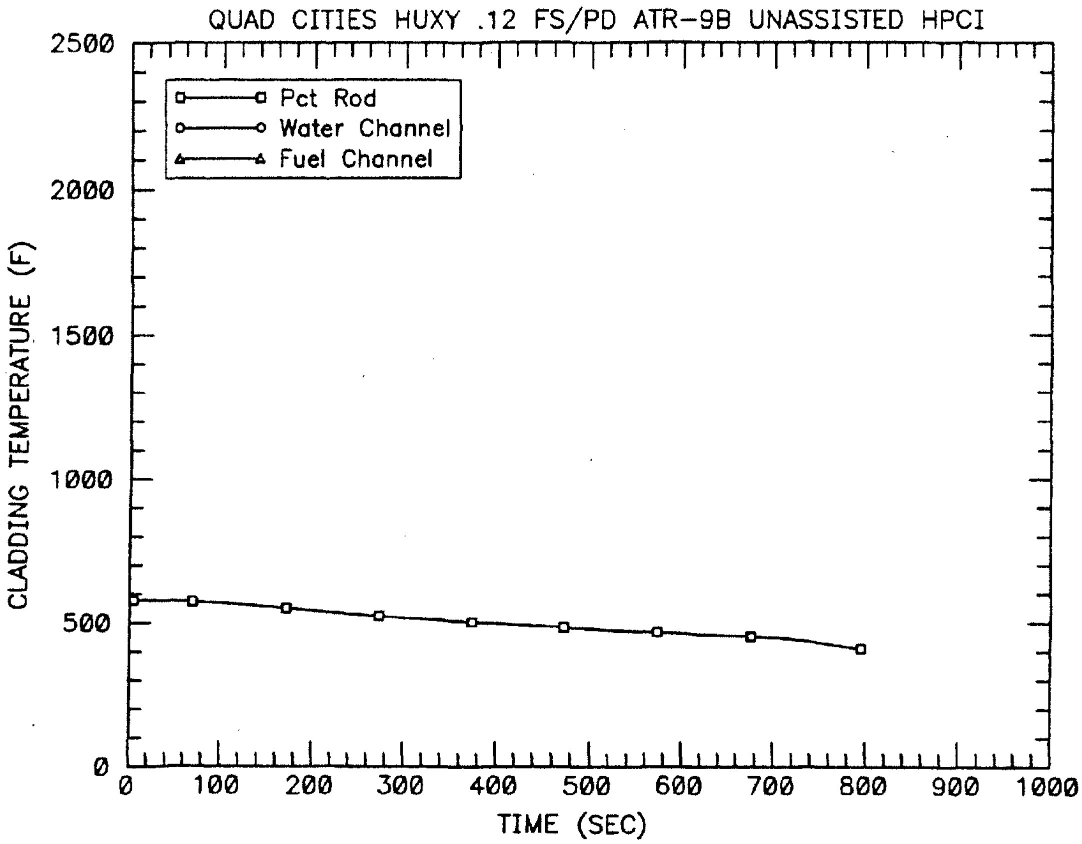
SOURCE: REFERENCES 46, 47

QUAD CITIES STATION UNITS 1 & 2

LOWER DOWNCOMER MIXTURE LEVEL VS. TIME AFTER BREAK AT 2511MWt (0.12FT^2 PUMP DISCHARGE BREAK, UNASSISTED HPCI, 102% POWER, 108% CORE FLOW FOR ATRIUM-9B FUEL)

FIGURE 6.3-28D

REVISION 7, JANUARY 2003



NOTE: RESULTS ARE HISTORICAL. THESE RESULTS ARE NOT REQUIRED FOR CURRENT LICENSING BASIS UNDER 10CFR50.46 AND 10CFR50 APPENDIX K, SINGLE FAILURE REQUIREMENTS.

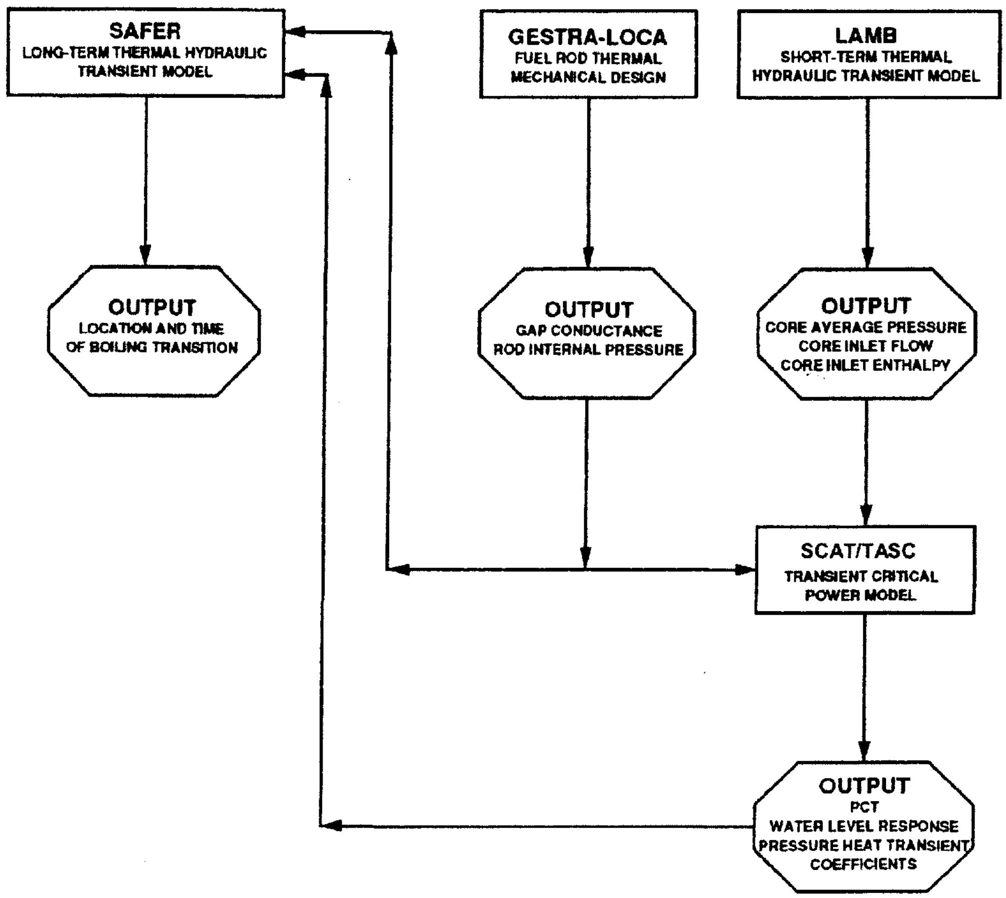
SOURCE: REFERENCES 46, 47

QUAD CITIES STATION UNITS 1 & 2

PEAK CLADDING TEMPERATURE VS. TIME AFTER BREAK AT 2511 MWt (0.12FT^2 PUMP DISCHARGE BREAK, UNASSISTED HPCI, 102% POWER, 108% CORE FLOW FOR ATRIUM-9B FUEL)

FIGURE 6.3-28E

REVISION 7, JANUARY 2003



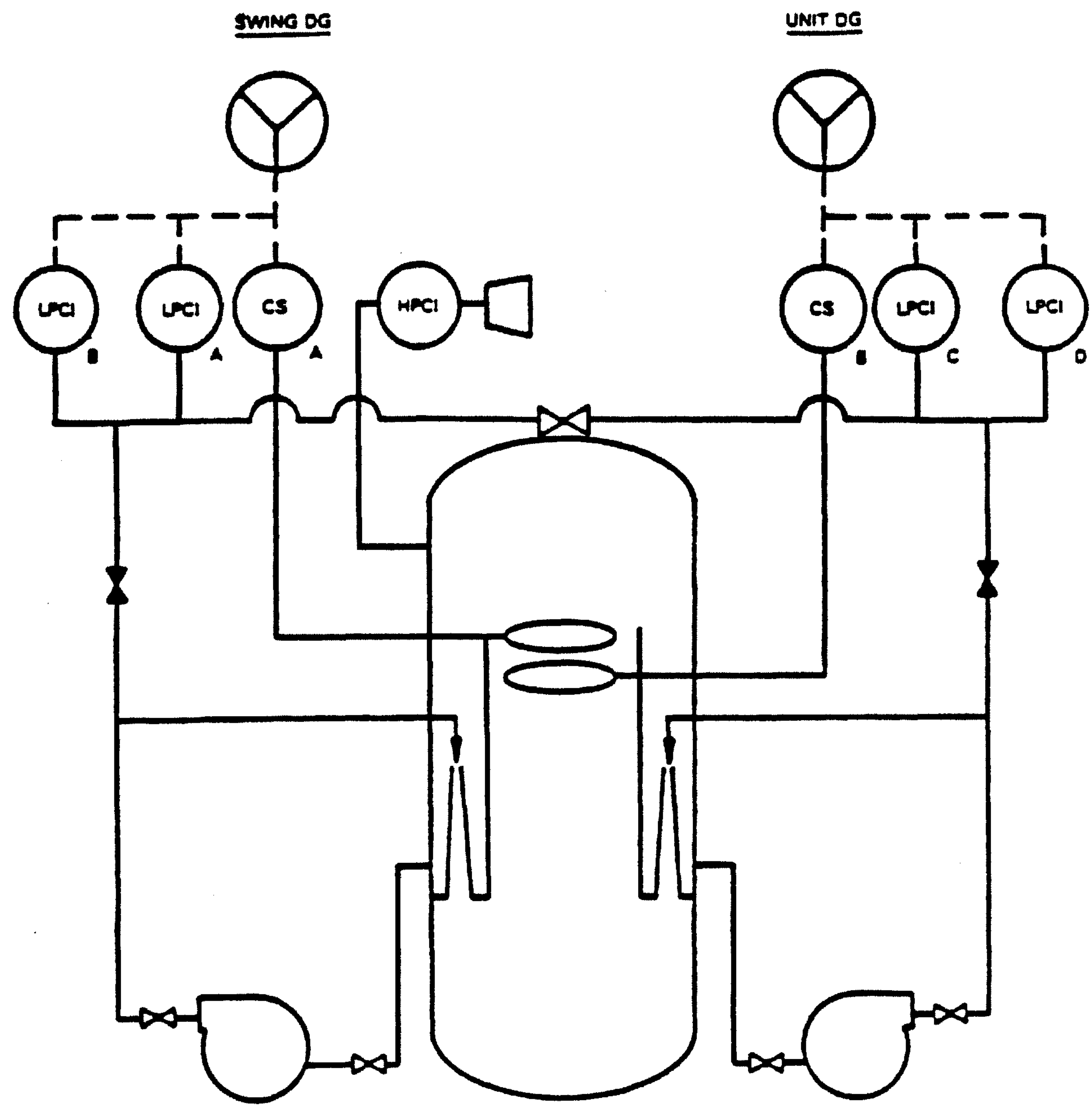
QUAD CITIES STATION

UNITS 1 & 2

FLOW DIAGRAM OF LOCA ANALYSIS USING SAFER

FIGURE 6.3-29

REVISION 7, JANUARY 2003

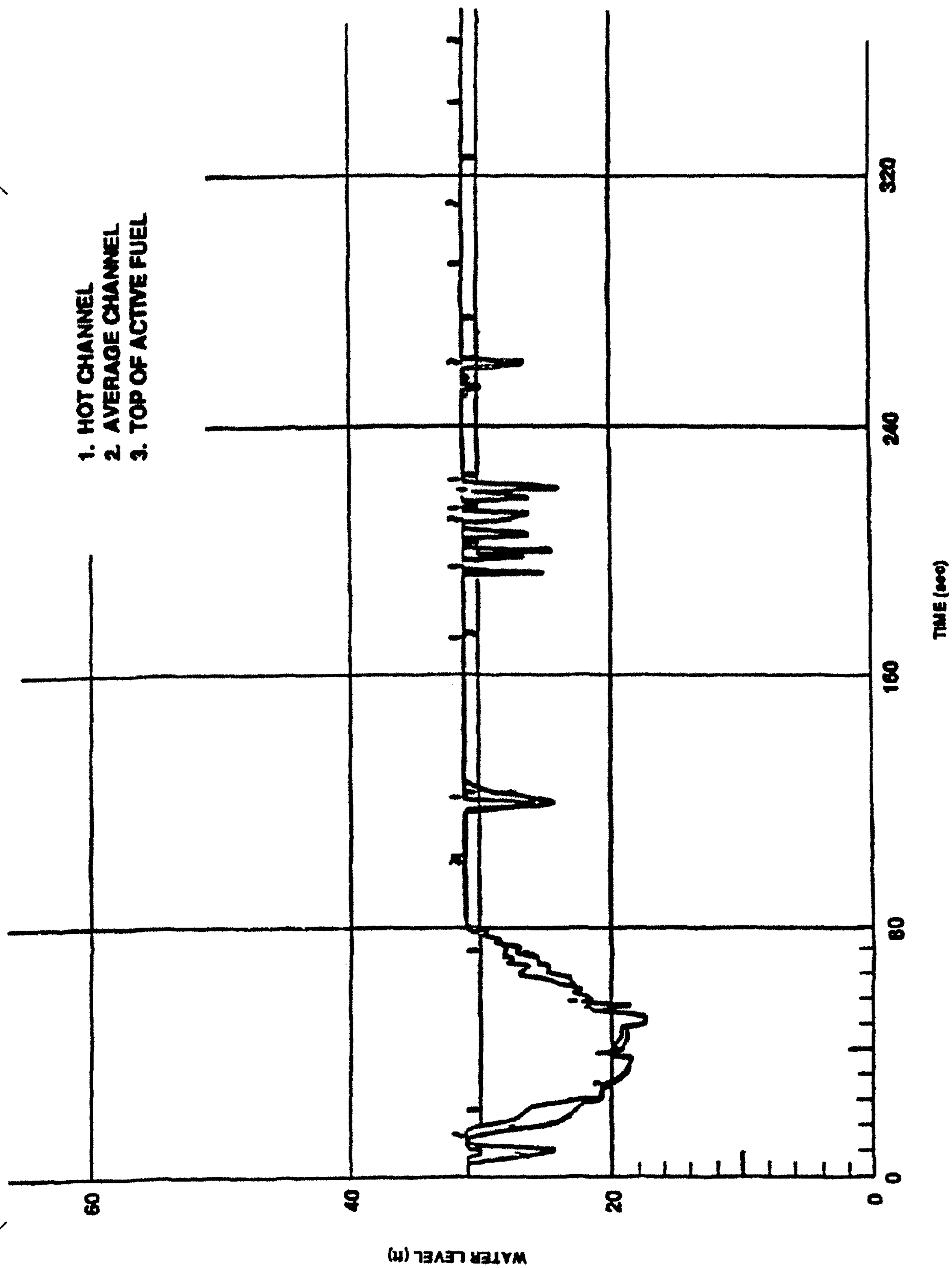


QUAD CITIES STATION
UNITS 1 & 2

ECCS CONFIGURATION

FIGURE 6.3-30

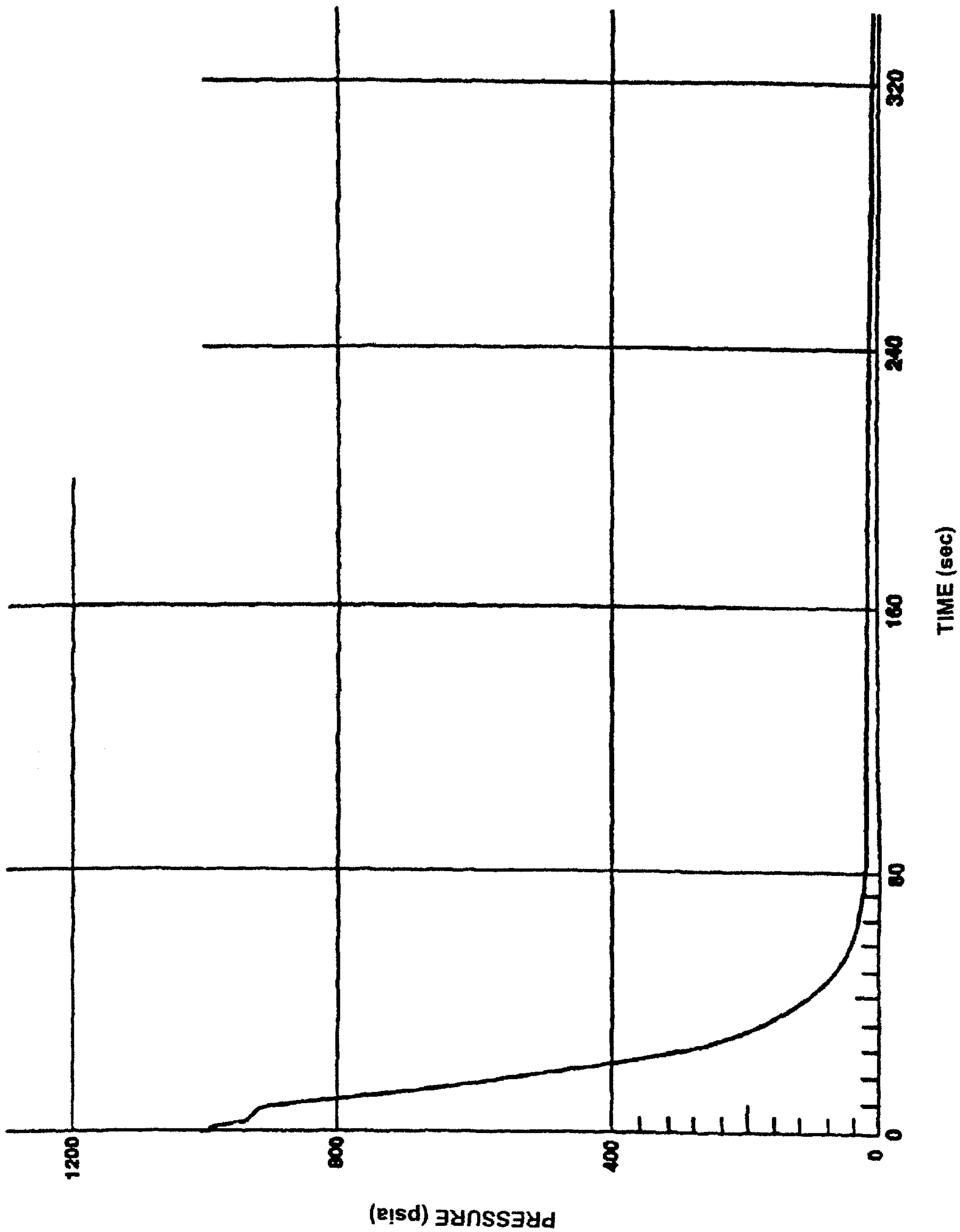
(HISTORICAL INFORMATION)



See Section 6.3.3.2.2.2 for information regarding the use of the details from this analysis which may not be applicable to the current fuel cycle.

QUAD CITIES STATION UNITS 1 & 2
DBA SUCTION-BATTERY FAILURE WATER LEVEL IN HOT AND AVERAGE CHANNEL AT 2511 MWt
FIGURE 6.3-31 REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)



See Section 6.3.3.2.2.2 for information regarding the use of the details from this analysis *which may not be applicable to* the current fuel cycle.

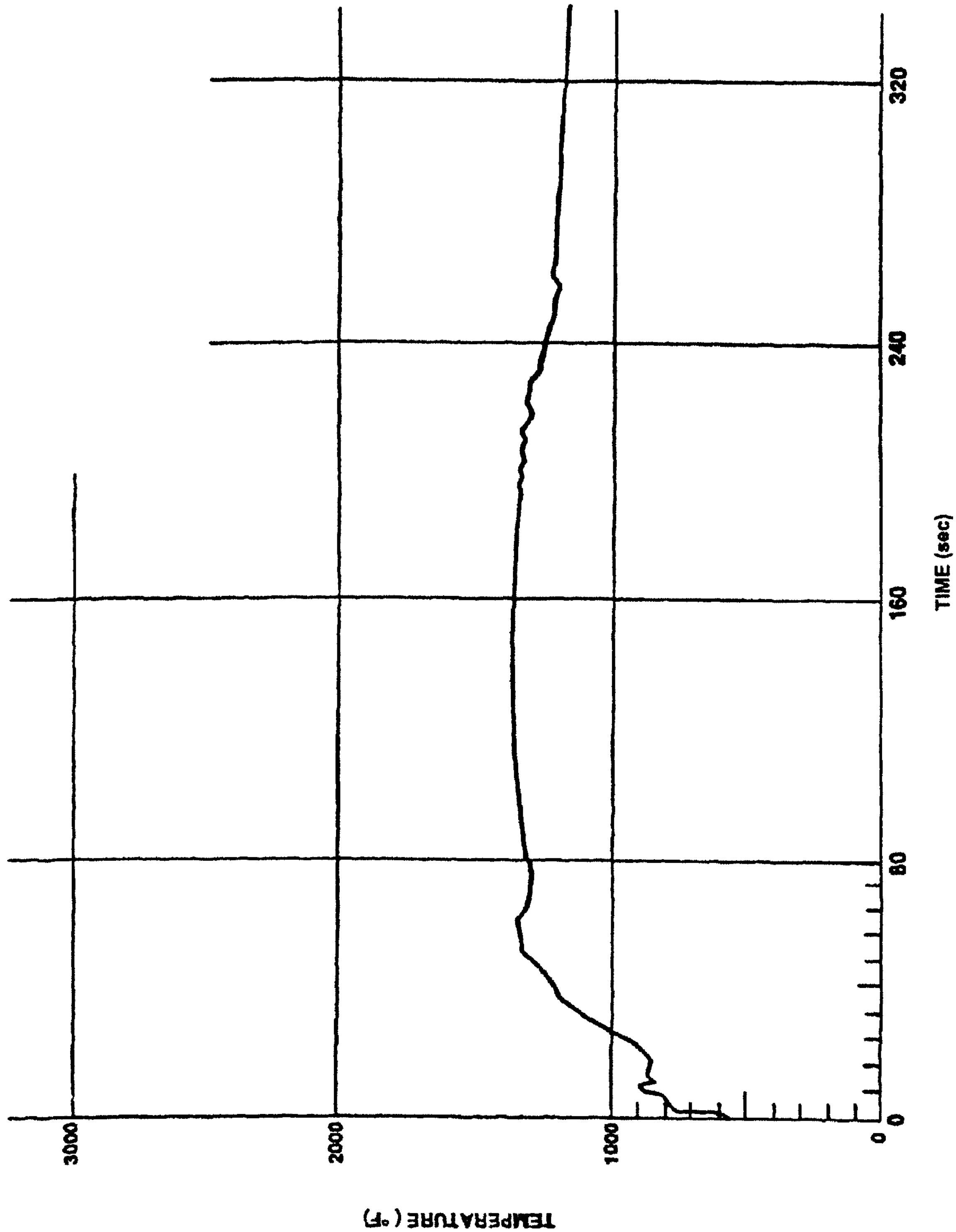
QUAD CITIES STATION
UNITS 1 & 2

DBA SUCTION-BATTERY FAILURE
REACTOR VESSEL PRESSURE AT 2511 MWt

FIGURE 6.3-32

REVISION 8, OCTOBER 2005

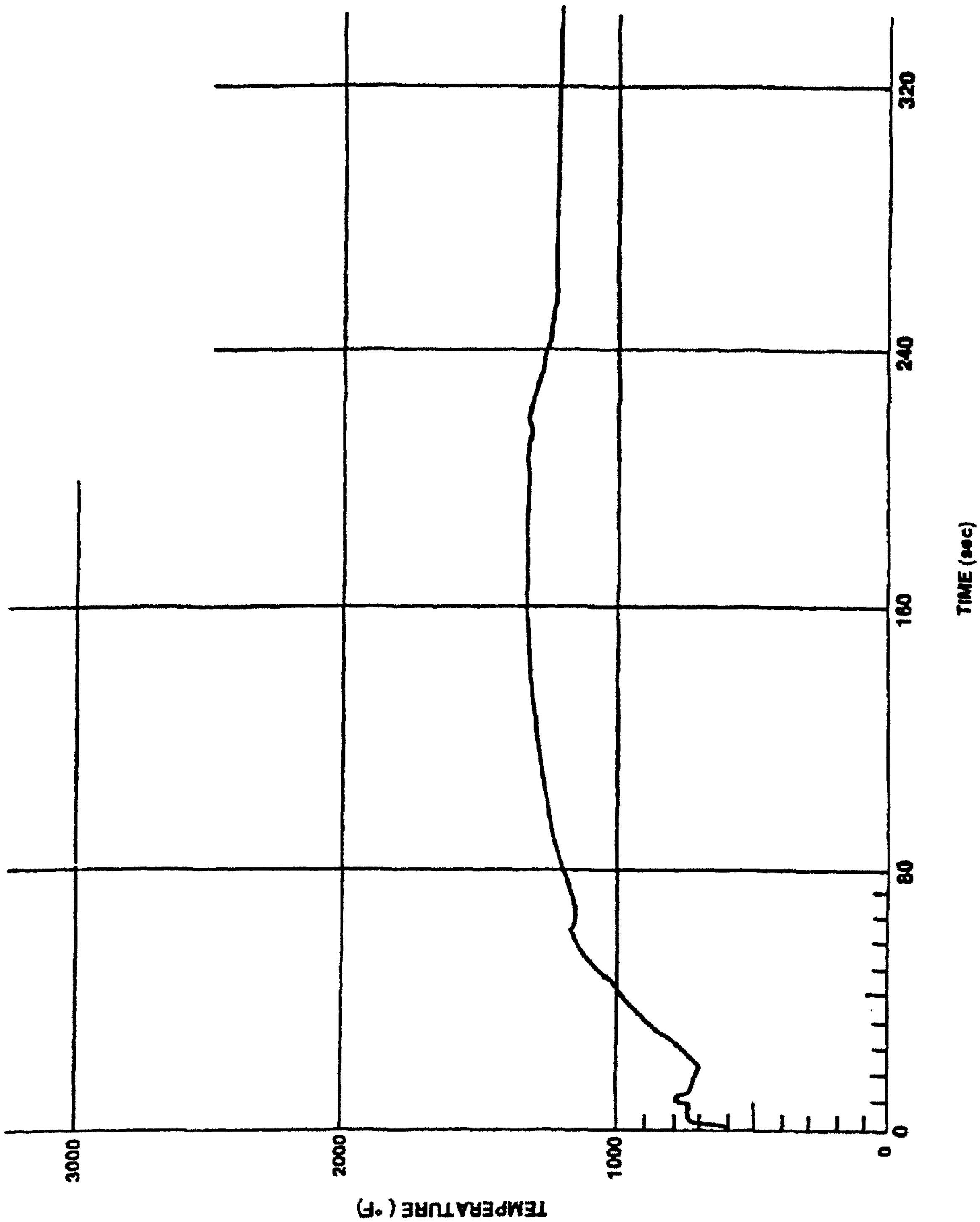
(HISTORICAL INFORMATION)



See Section 6.3.3.2.2.2 for information regarding the use of the details from this analysis which may not be applicable to the current fuel cycle.

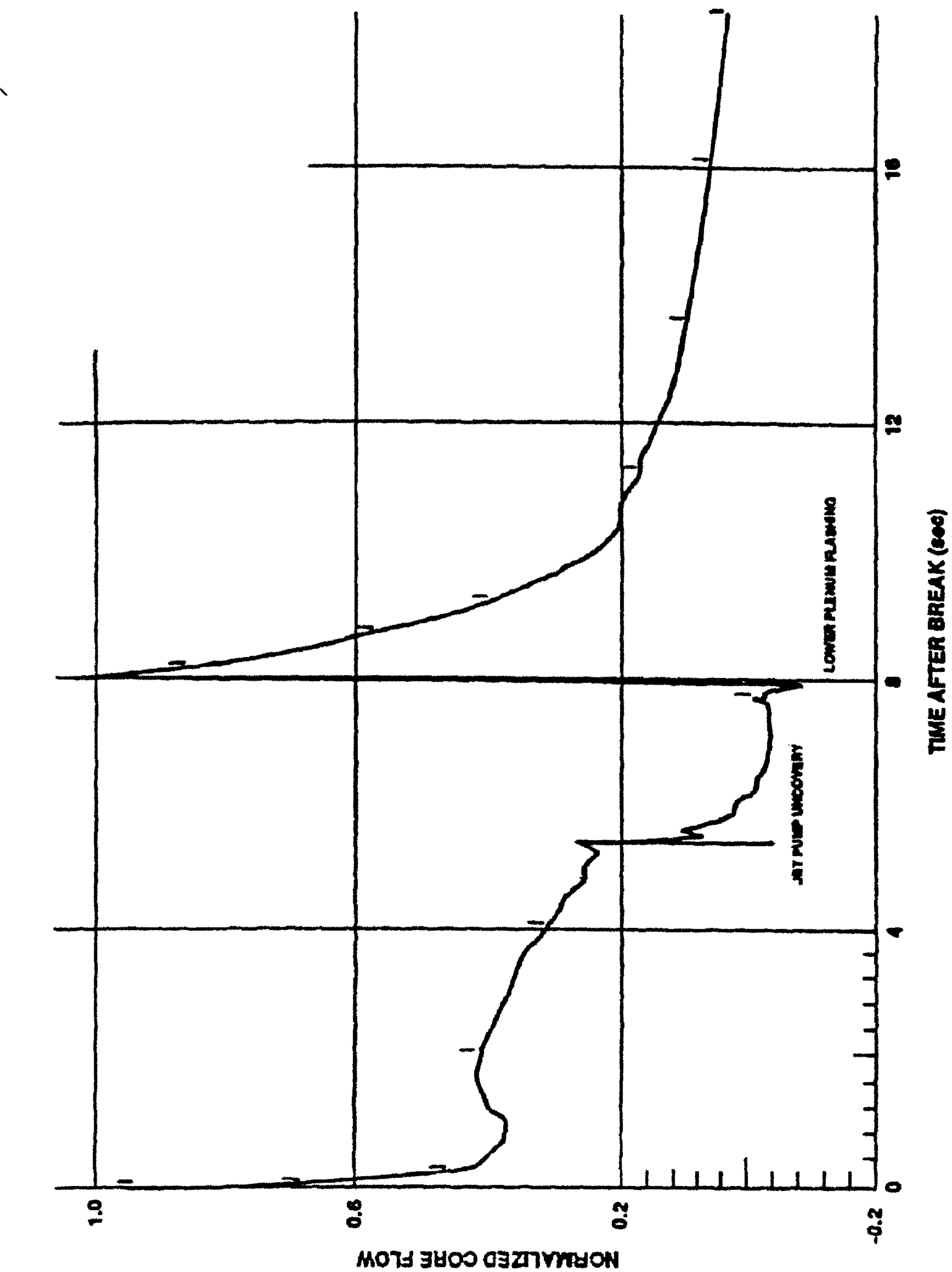
QUAD CITIES STATION UNITS 1 & 2
DBA SUCTION-BATTERY FAILURE PEAK CLADDING TEMPERATURE (P8x8R) AT 2511 MWt
FIGURE 6.3-33
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)



See Section 6.3.3.2.2.2 for *information regarding the use of* the details from this analysis which may not be applicable to the current fuel cycle.

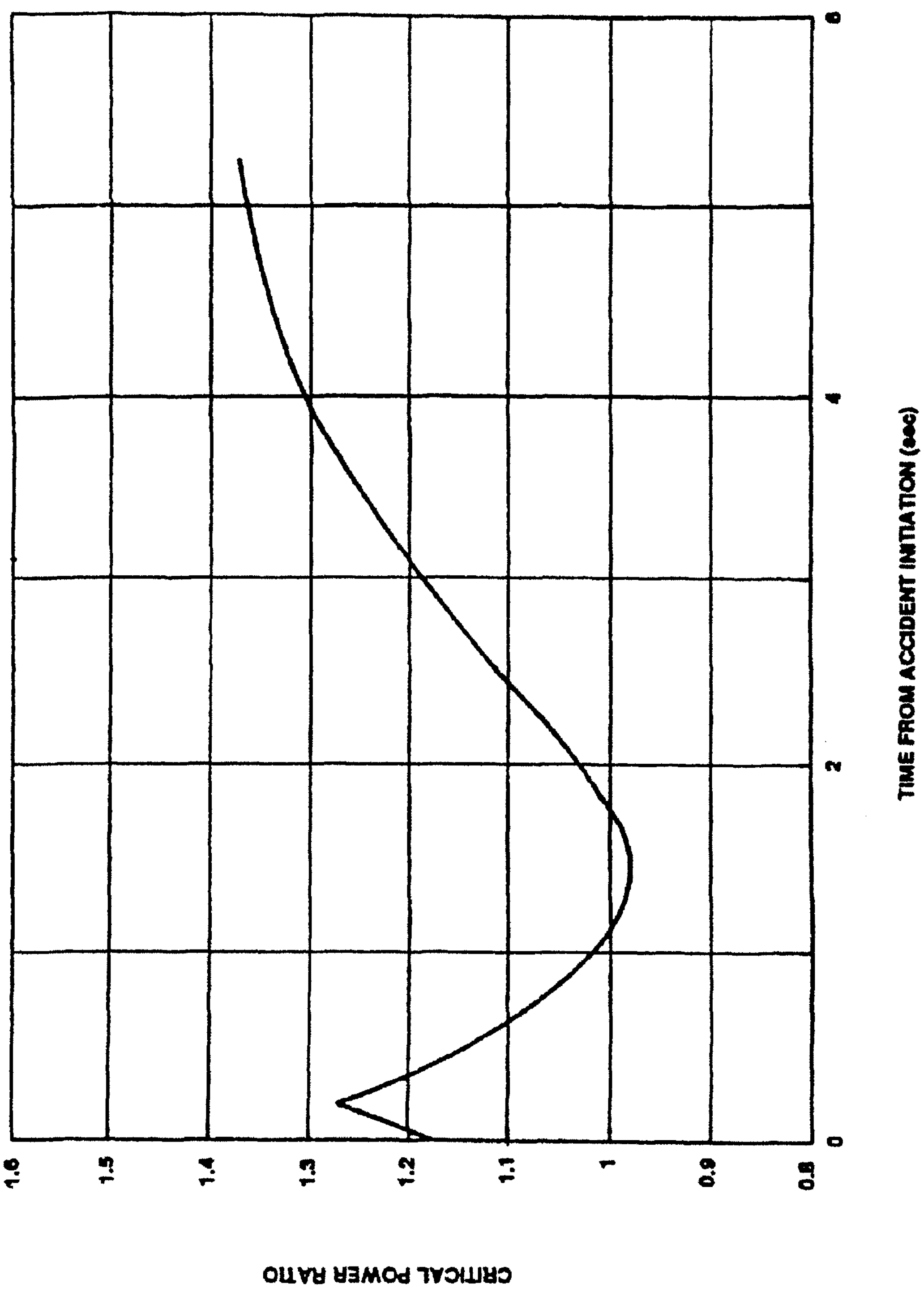
QUAD CITIES STATION UNITS 1 & 2
DBA SUCTION-BATTERY FAILURE PEAK CLADDING TEMPERATURE (GE8x8EB) AT 2511 MWt
FIGURE 6.3-34
REVISION 8, OCTOBER 2005



See Section 6.3.3.2.2.2 for information regarding the use of the details from this analysis which may not be applicable to the current fuel cycle.

QUAD CITIES STATION UNITS 1 & 2
DBA SUCTION-BATTERY FAILURE CORE AVERAGE INLET FLOW AT 2511 MWt
FIGURE 6.3-35 REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)



See Section 6.3.3.2.2.2 for information regarding the use of the details from this analysis which may not be applicable to the current fuel cycle.

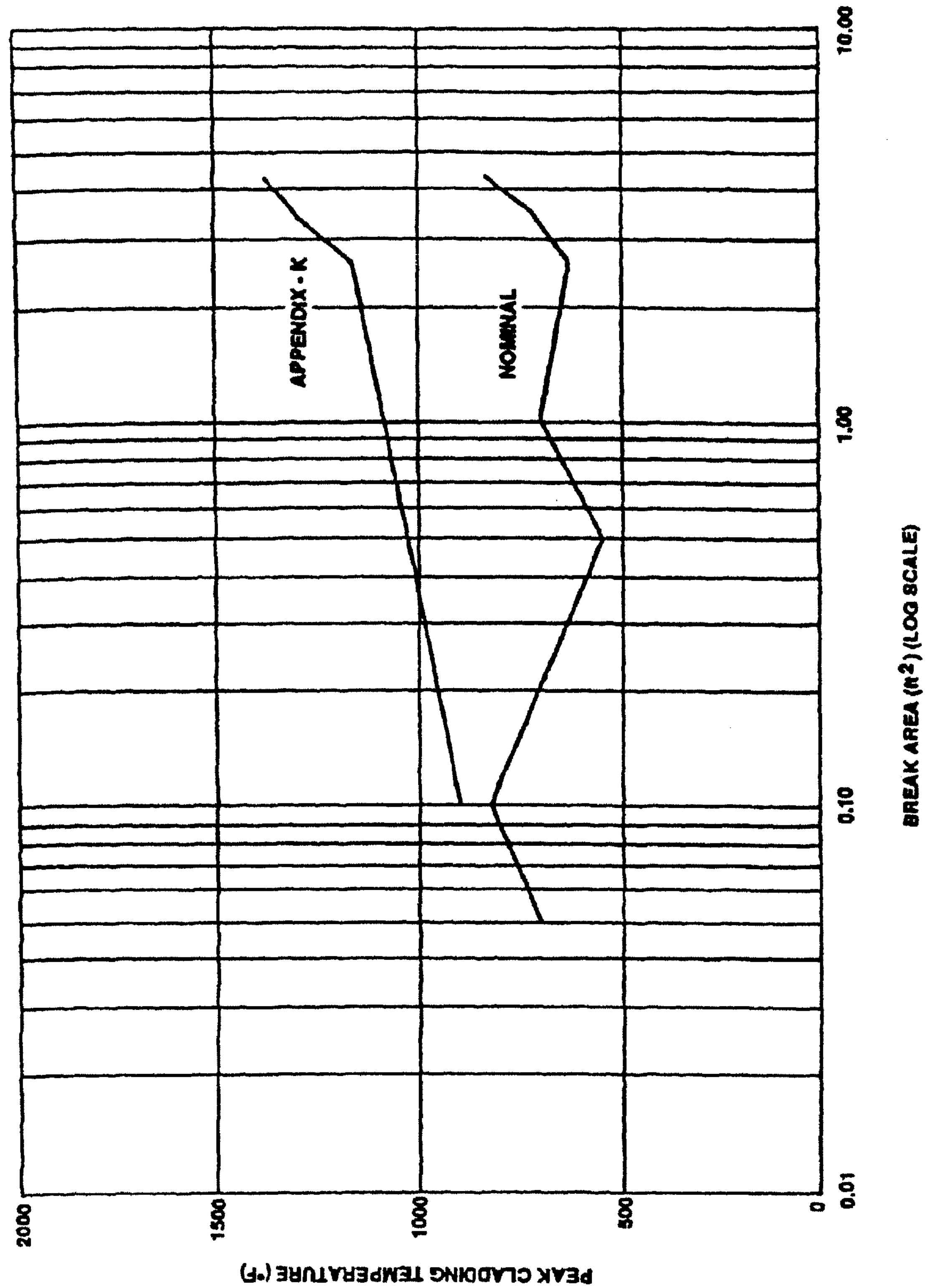
QUAD CITIES STATION
UNITS 1 & 2

DBA SUCTION-BATTERY FAILURE
MINIMUM CRITICAL POWER RATIO AT 2511 MWt

FIGURE 6.3-36

REVISION 8, OCTOBER 2005

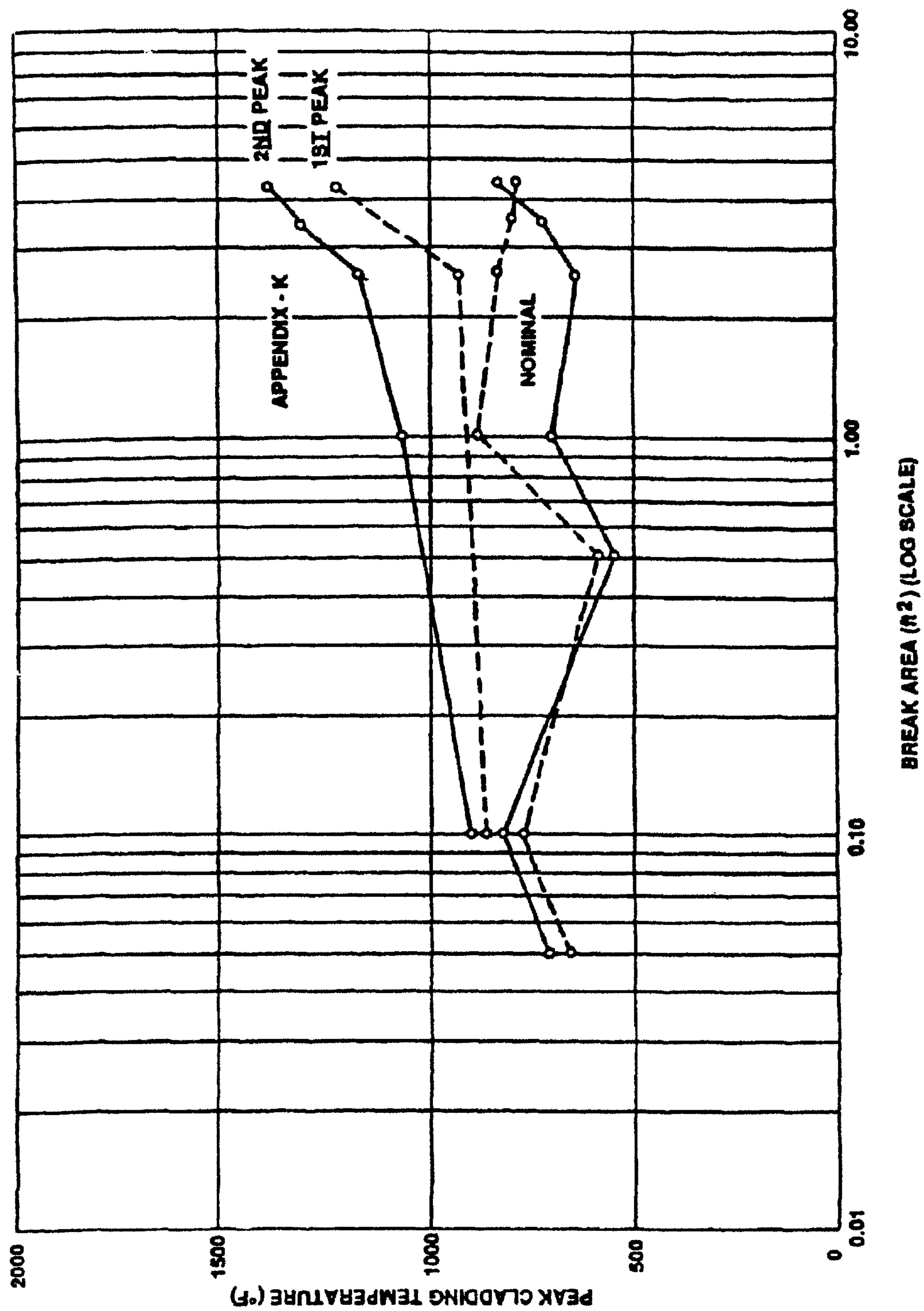
(HISTORICAL INFORMATION)



See Section 6.3.3.2.2.2 for information regarding the use of the details from this analysis which may not be applicable to the current fuel cycle.

QUAD CITIES STATION UNITS 1 & 2
SECOND PEAK CLADDING TEMPERATURE (P8x8R) VS. BREAK AREA AT 2511 MWt
FIGURE 6.3-37 REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

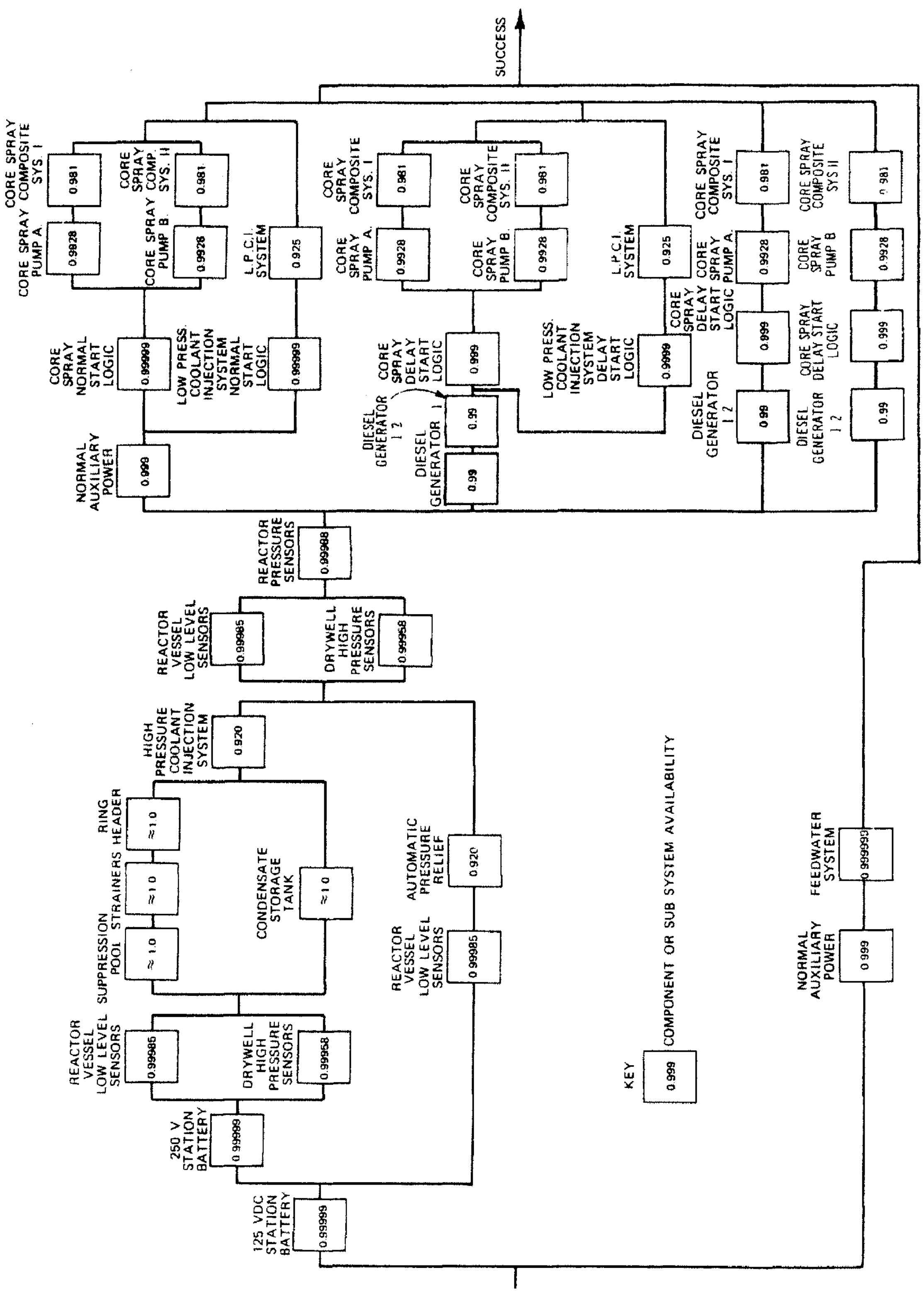


See Section 6.3.3.2.2.2 for information regarding the use of the details from this analysis which may not be applicable to the current fuel cycle.

QUAD CITIES STATION
UNITS 1 & 2

PEAK CLADDING TEMPERATURE (P8x8R)
VS. BREAK AREA AT 2511 MWt

FIGURE 6.3-38
REVISION 8, OCTOBER 2005

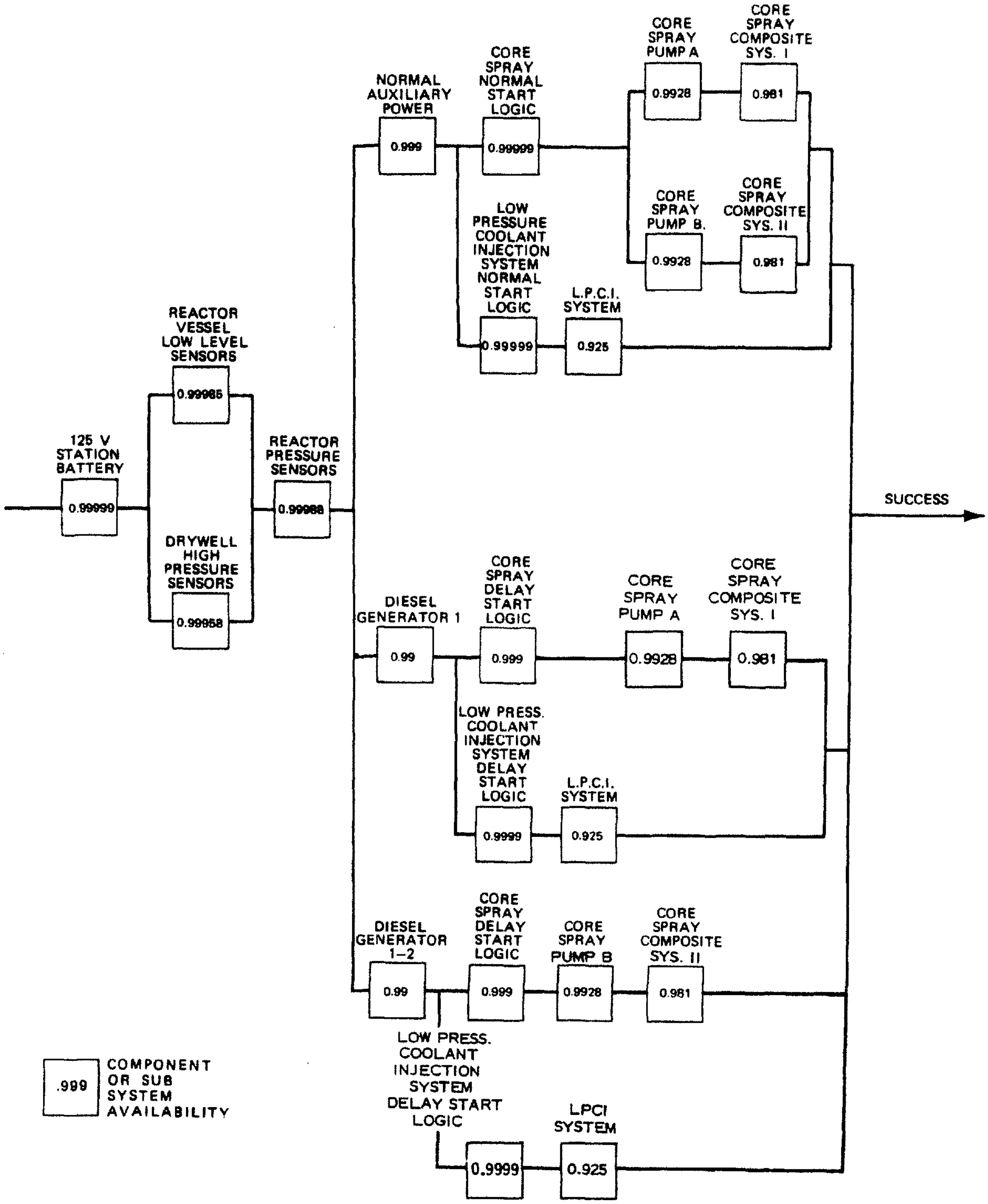


See the first paragraph of Section 6.3.3.2.8 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

QUAD CITIES STATION
UNITS 1 & 2

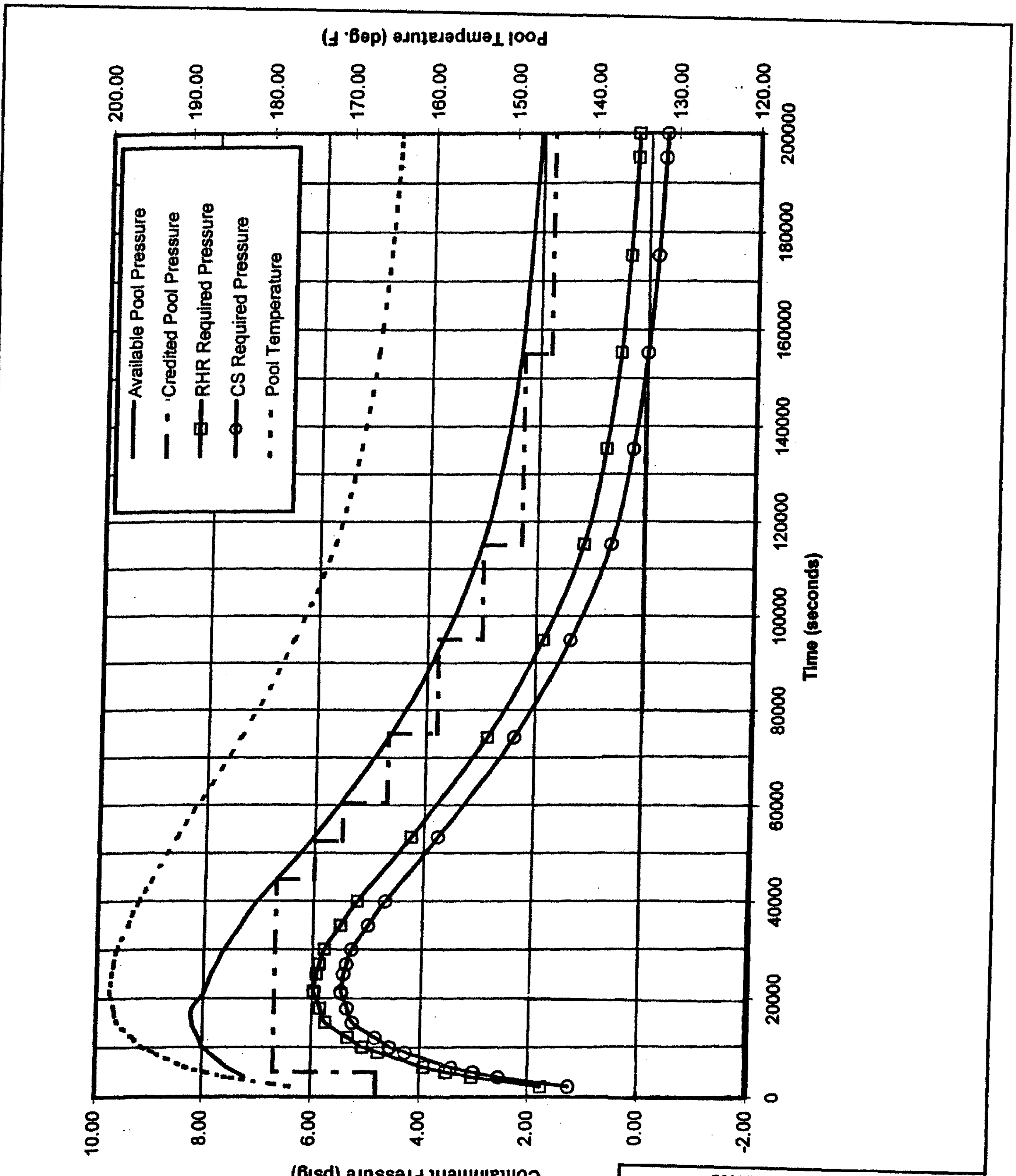
AVAILABILITY ANALYSIS
SMALL LINE BREAK

FIGURE 6.3-39



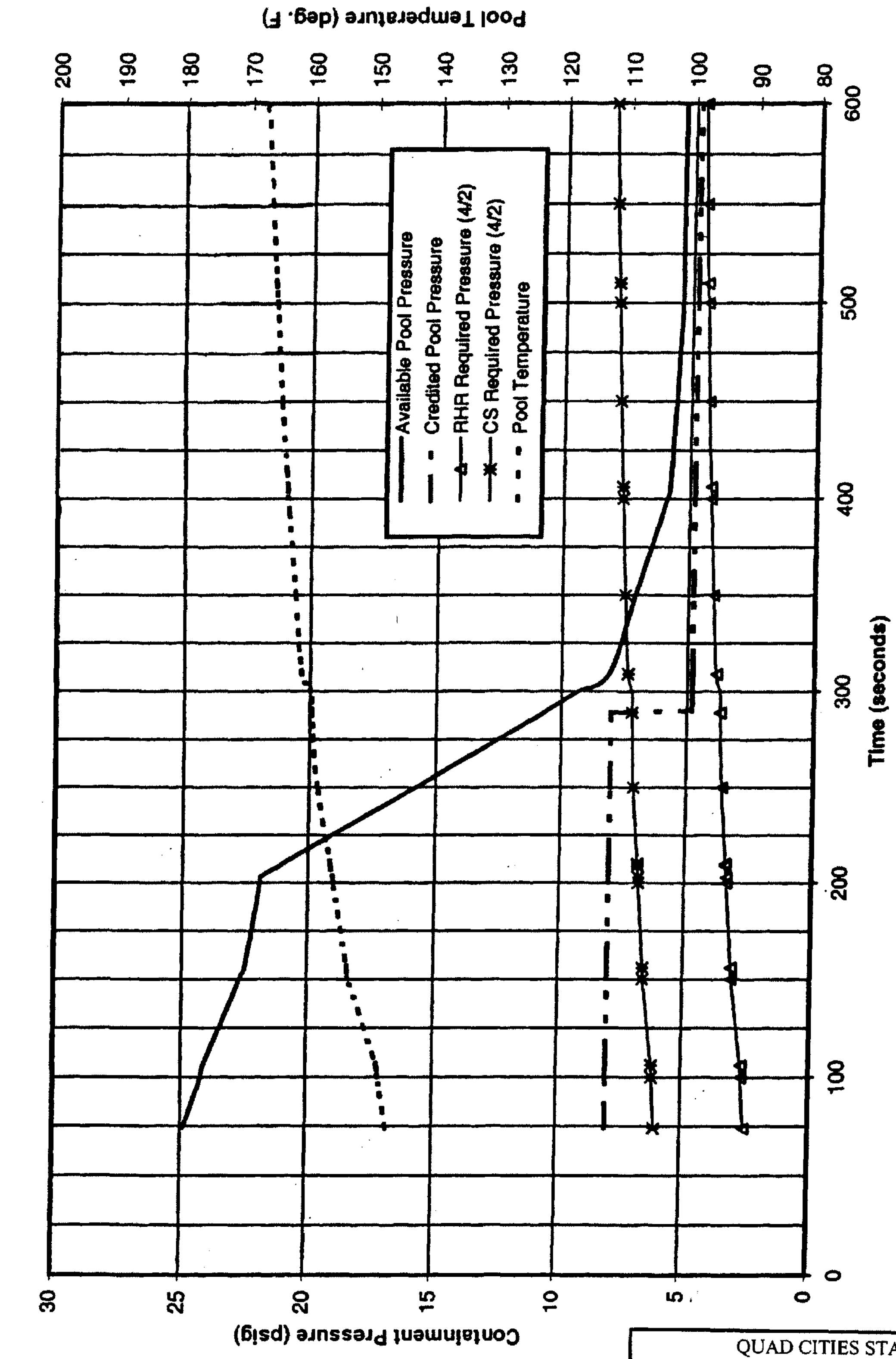
See the first paragraph of Section 6.3.3.2.8 for information regarding the use of details from this analysis which may not be applicable to the current fuel cycle.

QUAD CITIES STATION UNITS 1 & 2
AVAILABILITY ANALYSIS LARGE LINE BREAK
FIGURE 6.3-40



QUAD CITIES STATION UNIT 2
CONTAINMENT PRESSURE REQUIRED AND AVAILABLE IN THE LONG-TERM FOLLOWING A DBA-LOCA
FIGURE 6.3-41A REVISION 7, JANUARY 2003

Figures 6.3-42 is deleted.



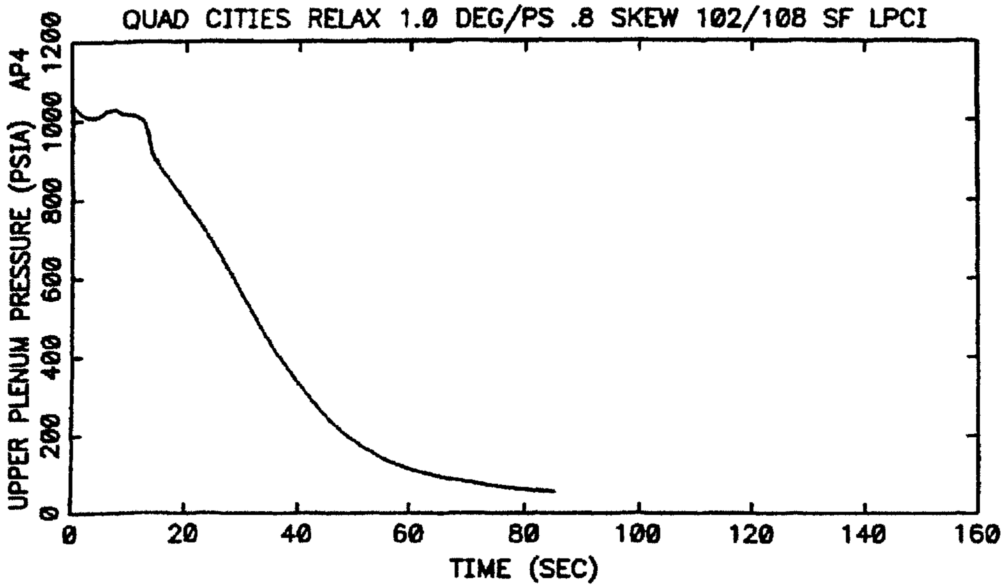
QUAD CITIES STATION
UNIT 2

CONTAINMENT PRESSURE REQUIRED AND AVAILABLE IN THE SHORT-TERM FOLLOWING A DBA-LOCA

FIGURE 6.3-42A

REVISION 7, JANUARY 2003

(HISTORICAL INFORMATION)

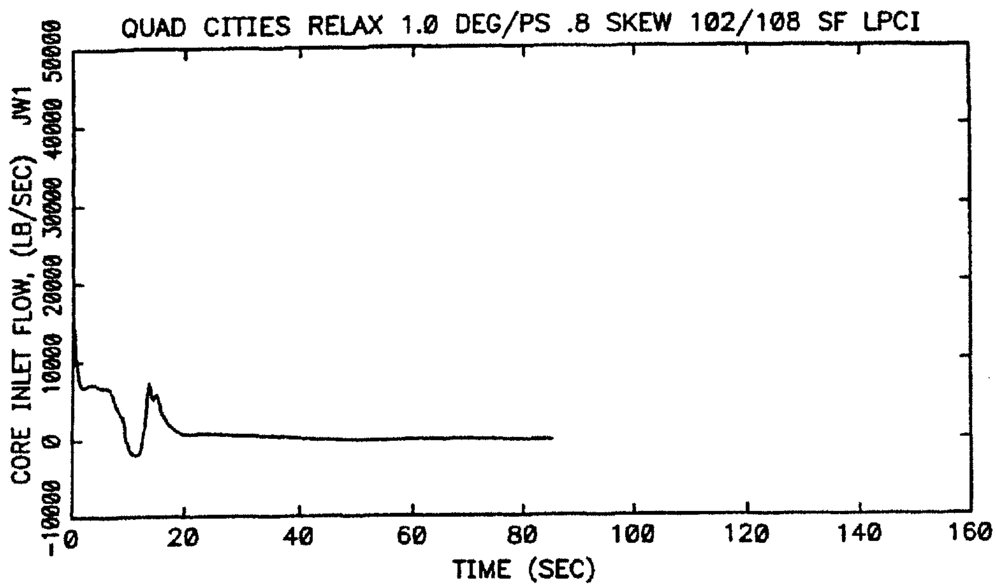


1.0 DEG Pump Suction Break (SF–LPCI)
Upper Plenum Pressure

Source: EMF-2348(P), Rev. 0

QUAD CITIES STATION UNITS 1 & 2
UPPER PLENUM PRESSURE VS. TIME AFTER BREAK AT 2511 MWt (1.0 DEG PUMP SUCTION BREAK, LPCI INJ. VALVE FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-43 REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

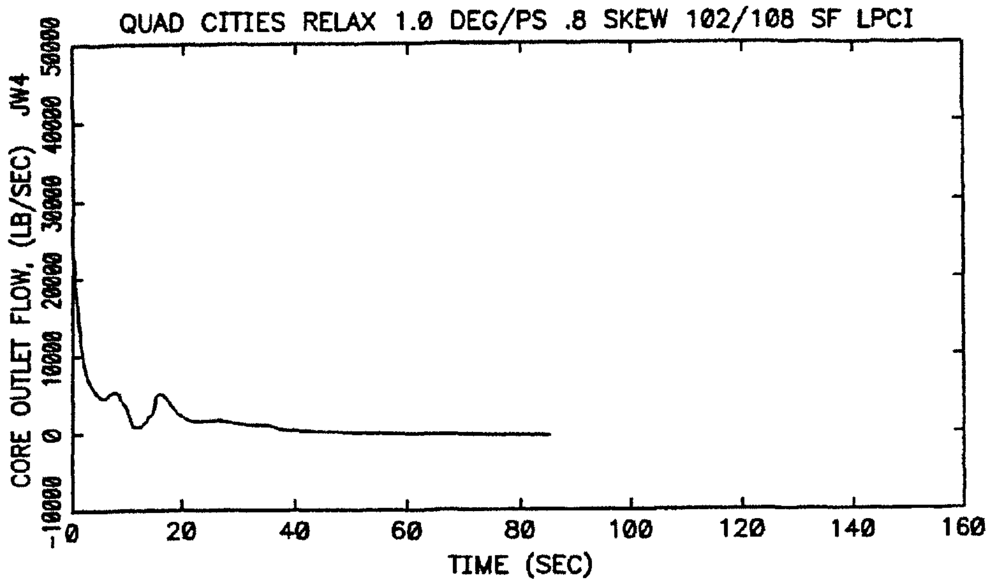


1.0 DEG Pump Suction Break (SF-LPCI)
Core Inlet Flow

Source: EMF-2348(P), Rev. 0

QUAD CITIES STATION UNITS 1 & 2
CORE INLET FLOW VS. TIME AFTER BREAK AT 2511 MWt (1.0 DEG PUMP SUCTION BREAK, LPCI INJ. VALVE FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-44
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

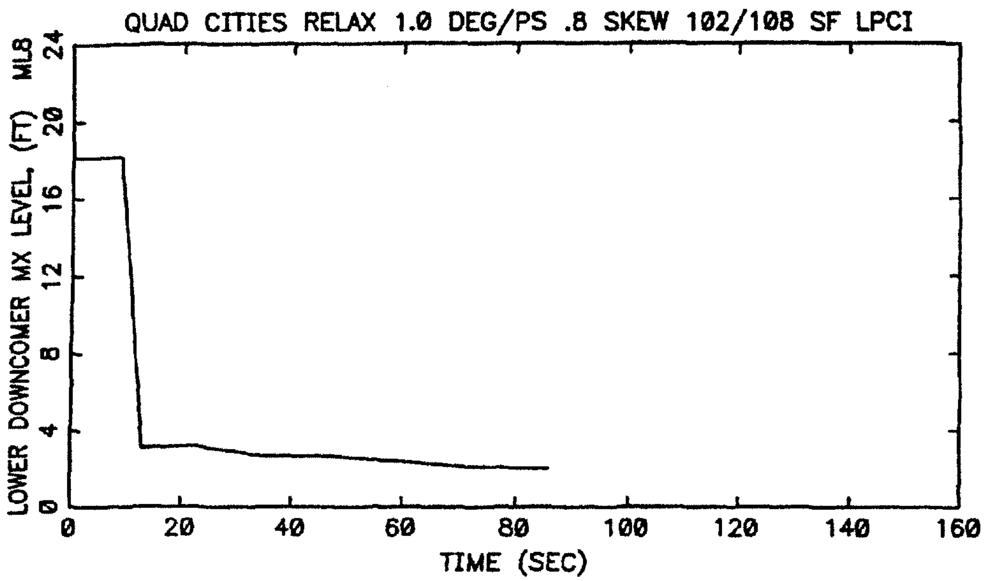


1.0 DEG Pump Suction Break (SF–LPCI)
Core Outlet Flow

Source: EMF-2348(P), Rev. 0

QUAD CITIES STATION UNITS 1 & 2
CORE OUTLET FLOW VS. TIME AFTER BREAK AT 2511 MWt (1.0 DEG PUMP SUCTION BREAK, LPCI INJ. VALVE FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-45
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

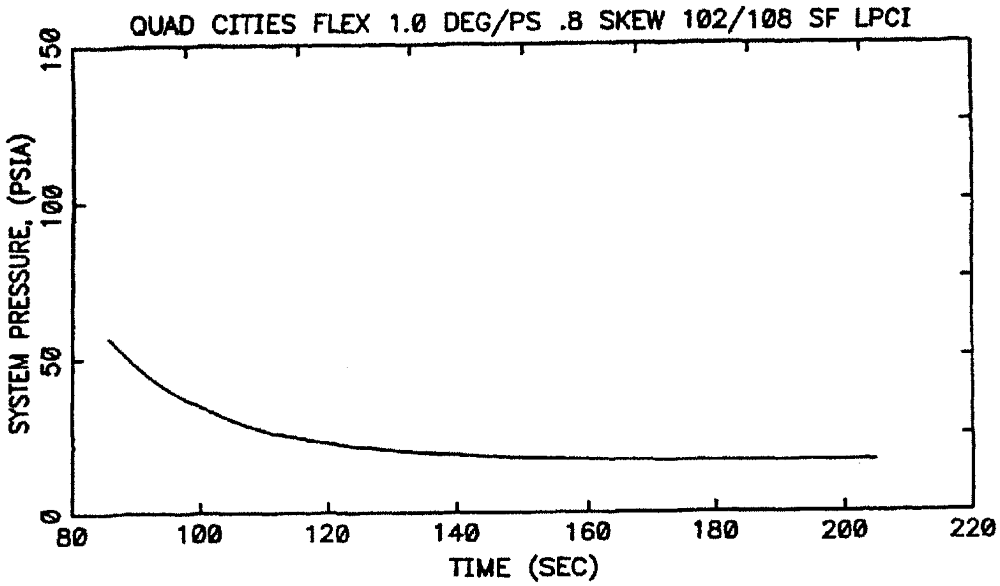


1.0 DEG Pump Suction Break (SF–LPCI)
Lower Downcomer Mixture Level

Source: EMF-2348(P), Rev. 0

QUAD CITIES STATION UNITS 1 & 2
LOWER DOWNCOMER MIXTURE LEVEL VS. TIME AFTER BREAK AT 2511 MWt (1.0 DEG PUMP SUCTION BREAK, LPCI INJ. VALVE FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-46
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

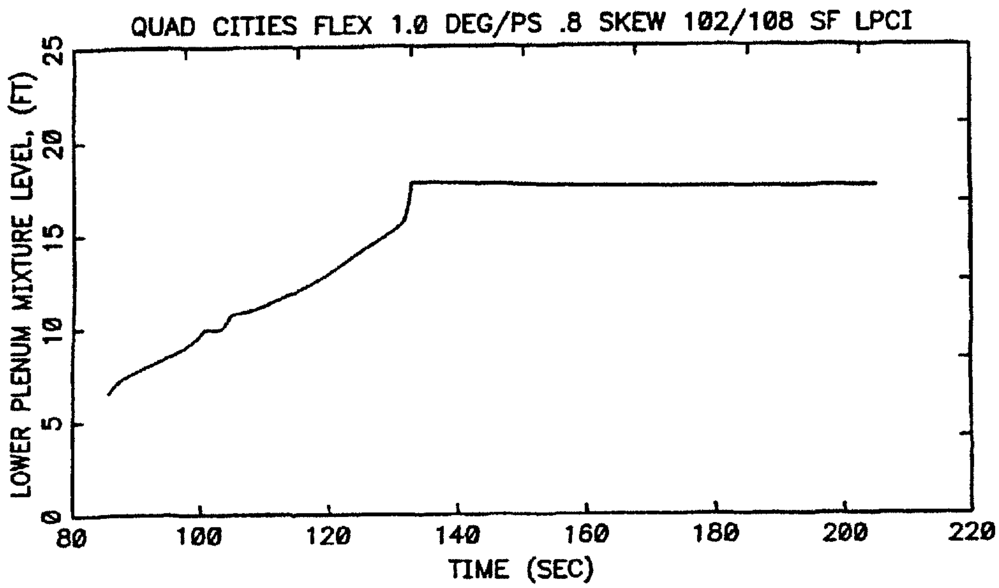


1.0 DEG Pump Suction Break (SF-LPCI)
System Pressure

Source: EMF-2348(P), Rev. 0

QUAD CITIES STATION UNITS 1 & 2
SYSTEM PRESSURE VS. TIME AFTER BREAK AT 2511 MWt (1.0 DEG PUMP SUCTION BREAK, LPCI INJ. VALVE FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-47 REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

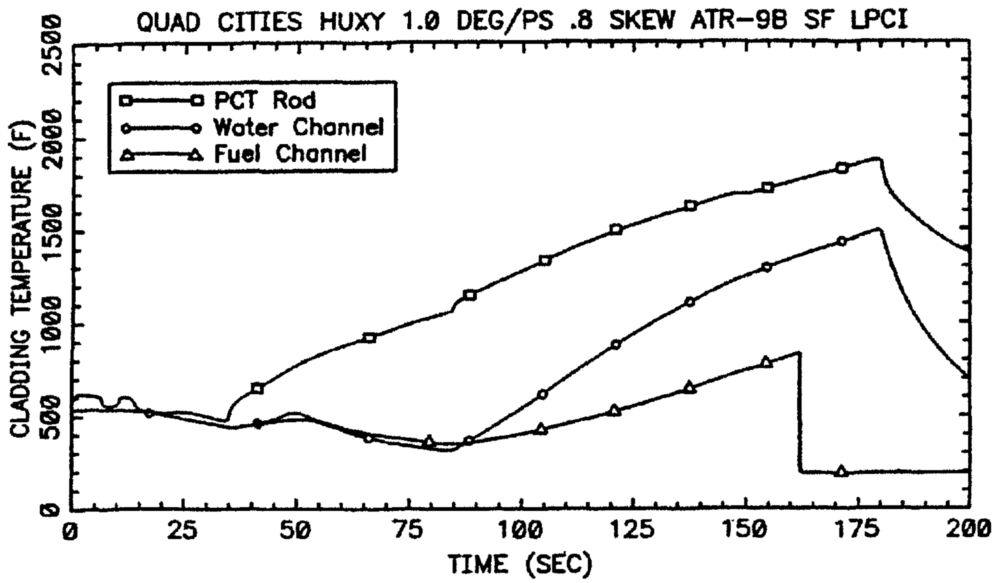


1.0 DEG Pump Suction Break (SF–LPCI)
Lower Plenum Mixture Level

Source: EMF-2348(P), Rev. 0

QUAD CITIES STATION UNITS 1 & 2
LOWER PLENUM MIXTURE LEVEL VS. TIME AFTER BREAK AT 2511 MWt (1.0 DEG PUMP SUCTION BREAK, LPCI INJ. VALVE FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-48
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)



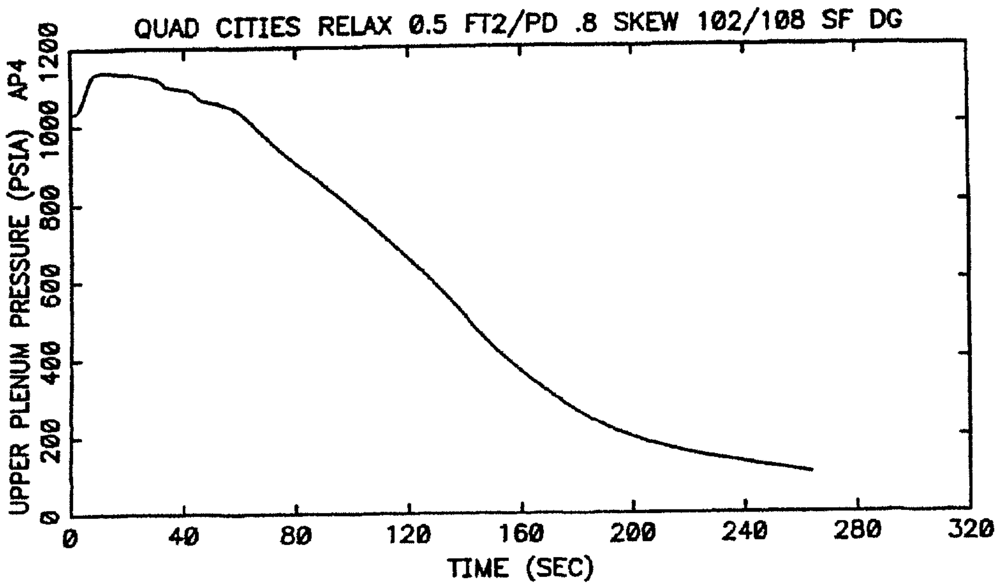
1.0 DEG Pump Suction Break (SF-LPCI)
Cladding Temperature

Note: Cycle specific PCT reported in COLR Reference 28.

Source: EMF-2348(P), Rev. 0

QUAD CITIES STATION UNITS 1 & 2
PEAK CLADDING TEMPERATURE VS. TIME AFTER AT 2511 MWt (1.0 DEG PUMP SUCTION BREAK, LPCI INJ. VALVE FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-49
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

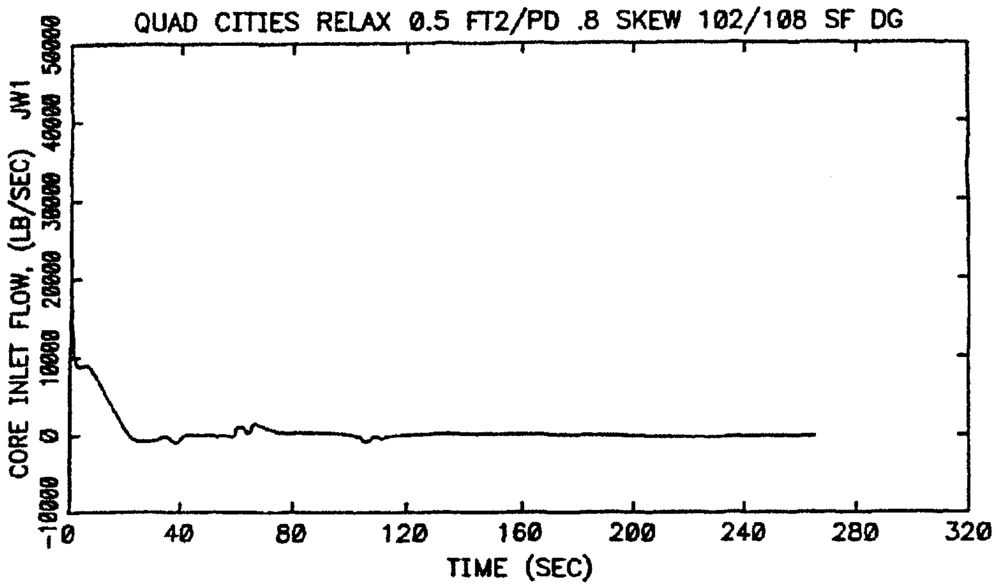


0.5 ft^2 Pump Discharge Break (SF–DG)
Upper Plenum Pressure

Source: EMF-96-185(P), Rev. 4

QUAD CITIES STATION UNITS 1 & 2
UPPER PLENUM PRESSURE VS. TIME AFTER BREAK AT 2511 MWt (0.5ft^2 PUMP DISCHARGE BREAK, DIESEL GENERATOR FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-50 REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)



0.5 ft^2 Pump Discharge Break (SF–DG)
Core Inlet Flow

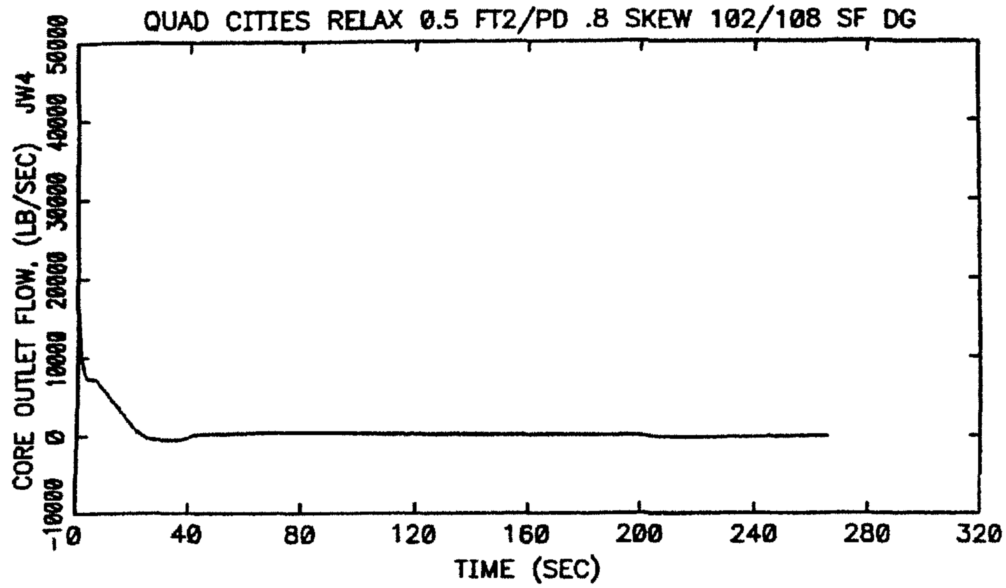
Source: EMF-96-185(P), Rev. 4

QUAD CITIES STATION
UNITS 1 & 2

CORE INLET FLOW VS. TIME AFTER BREAK
AT 2511 MWt ($0.5ft^2$ PUMP DISCHARGE BREAK,
DIESEL GENERATOR FAILURE, ATRIUM-9B FUEL)

FIGURE 6.3-51
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)



0.5 ft^2 Pump Discharge Break (SF–DG)
Core Outlet Flow

Source: EMF-96-185(P), Rev. 4

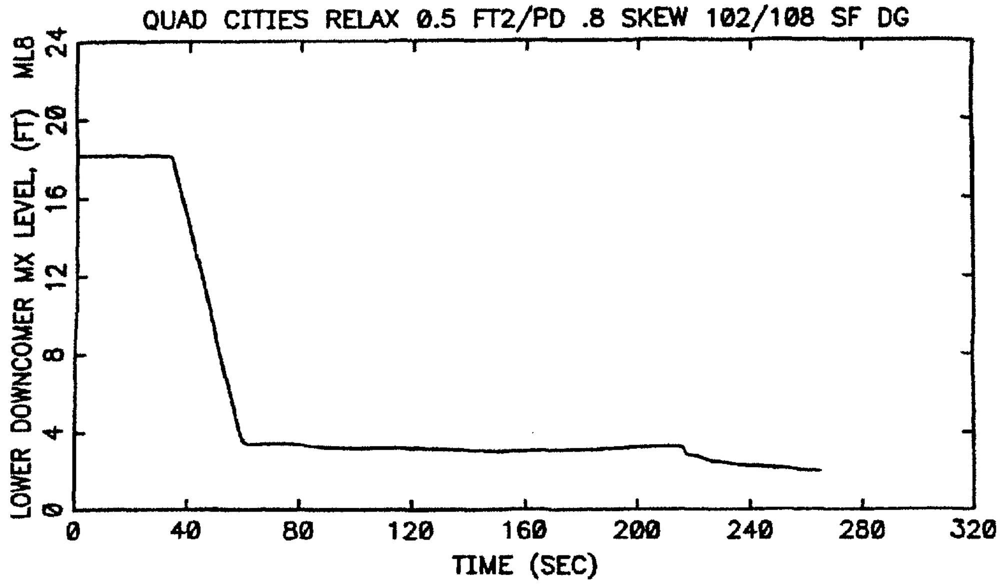
QUAD CITIES STATION
UNITS 1 & 2

CORE OUTLET FLOW VS. TIME AFTER BREAK AT 2511 MWt (0.5ft^2 PUMP DISCHARGE BREAK, DIESEL GENERATOR FAILURE, ATRIUM-9B FUEL)

FIGURE 6.3-52

REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

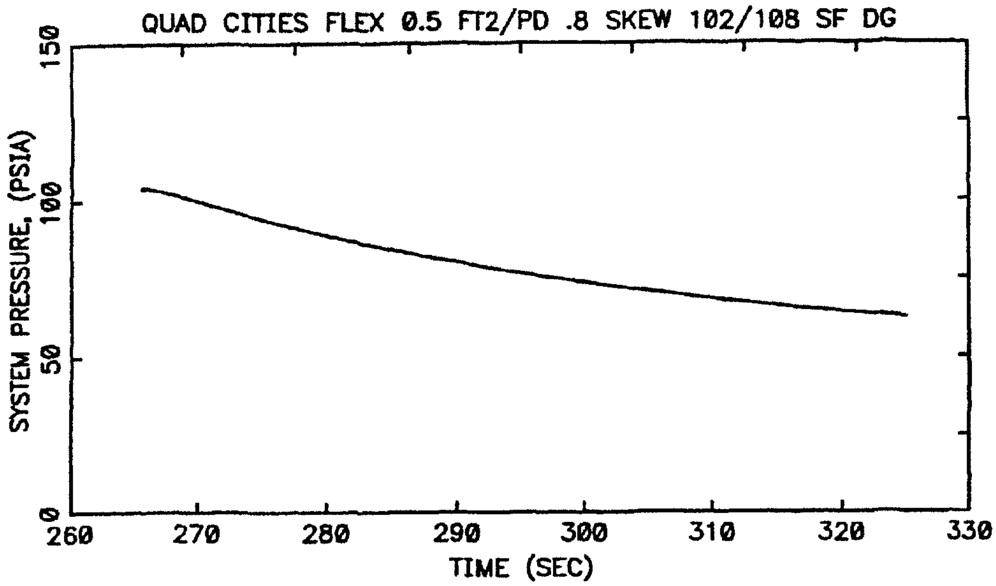


0.5 ft^2 Pump Discharge Break (SF-DG)
Lower Downcomer Mixture Level

Source: EMF-96-185(P), Rev. 4

QUAD CITIES STATION UNITS 1 & 2
LOWER DOWNCOMER MIXTURE LEVEL VS. TIME AFTER BREAK AT 2511 MWt (0.5ft^2 PUMP DISCHARGE BREAK, DIESEL GENERATOR FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-53 REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

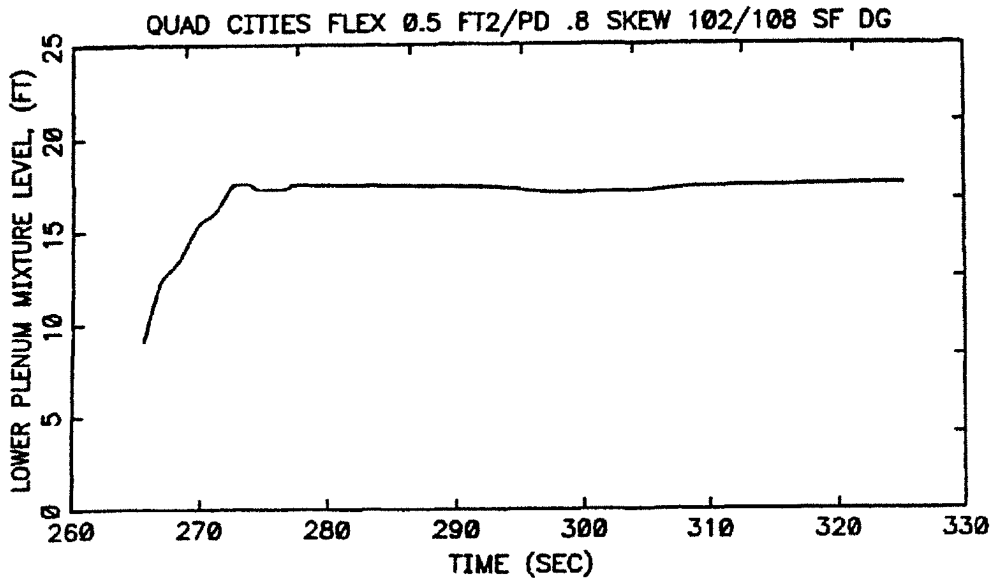


0.5 ft^2 Pump Discharge Break (SF–DG)
System Pressure

Source: EMF-96-185(P), Rev. 4

QUAD CITIES STATION UNITS 1 & 2
SYSTEM PRESSURE VS. TIME AFTER BREAK AT 2511 MWt (0.5ft^2 PUMP DISCHARGE BREAK, DIESEL GENERATOR FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-54
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

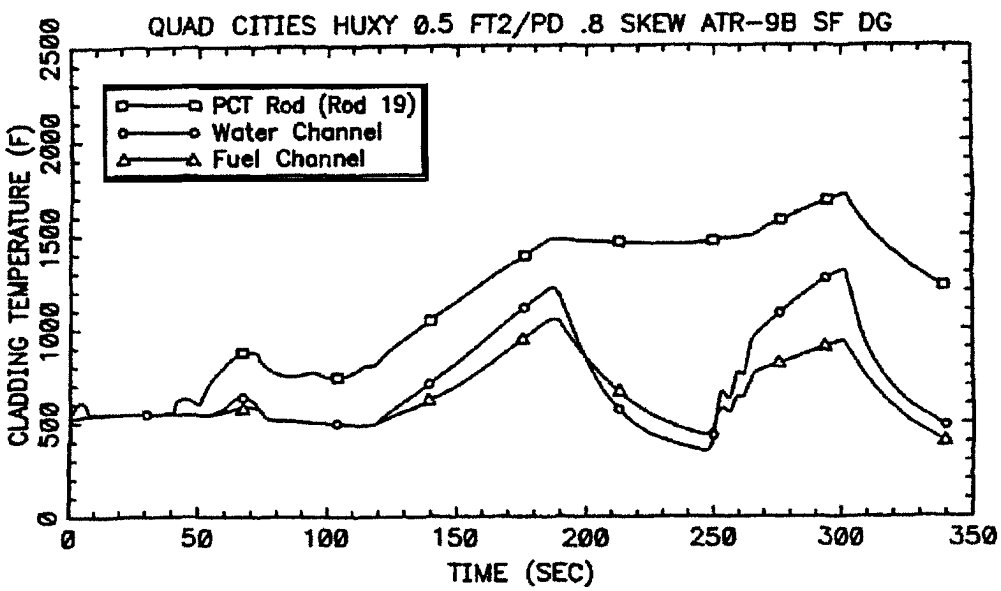


0.5 ft² Pump Discharge Break (SF–DG)
Lower Plenum Mixture Level

Source: EMF-96-185(P), Rev. 4

QUAD CITIES STATION UNITS 1 & 2
LOWER PLENUM MIXTURE LEVEL VS. TIME AFTER BREAK AT 2511 MWt (0.5ft^2 PUMP DISCHARGE BREAK, DIESEL GENERATOR FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-55
REVISION 8, OCTOBER 2005

(HISTORICAL INFORMATION)

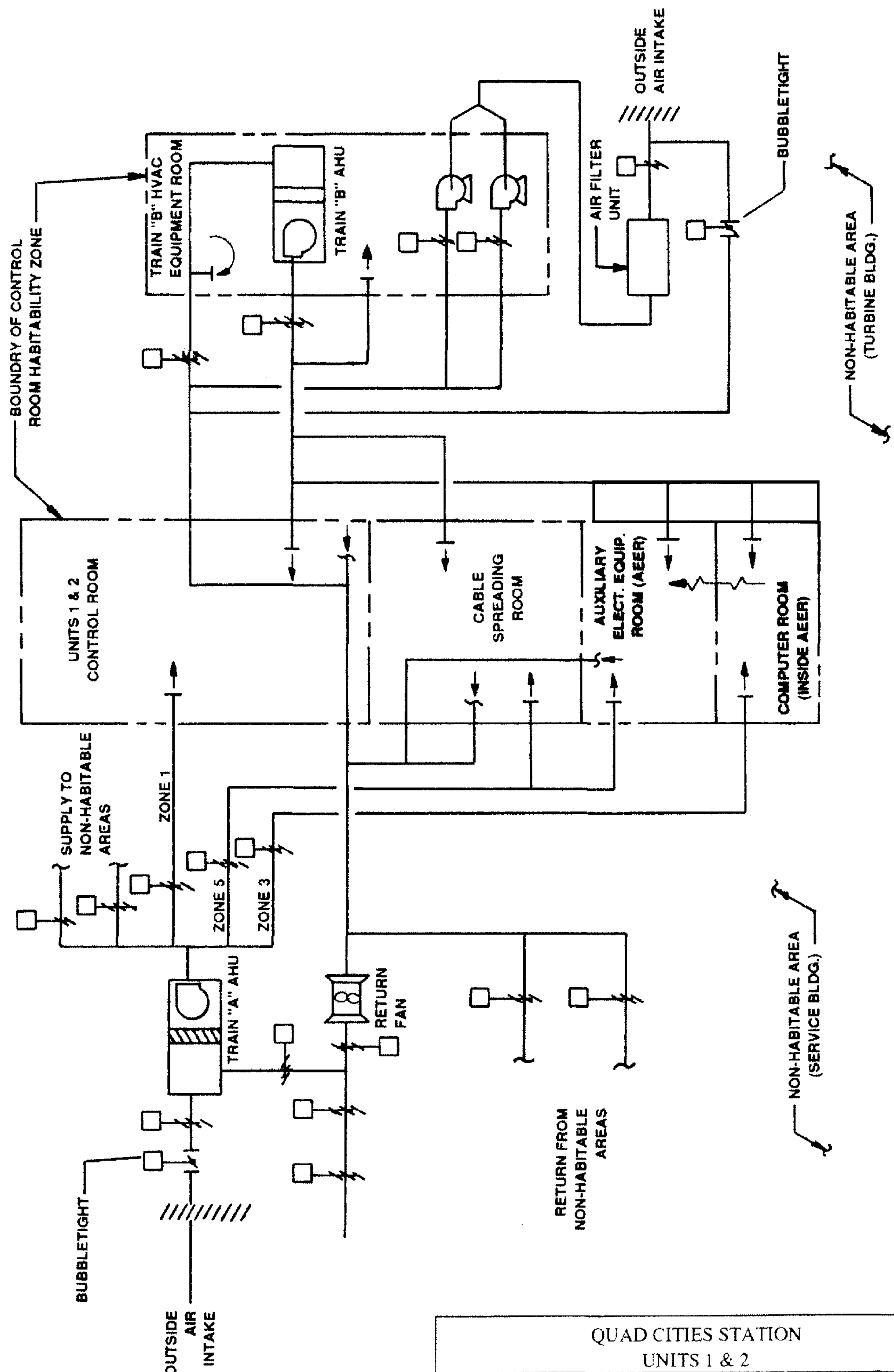


0.5 ft^2 Pump Discharge Break (SF–DG)
Cladding Temperature

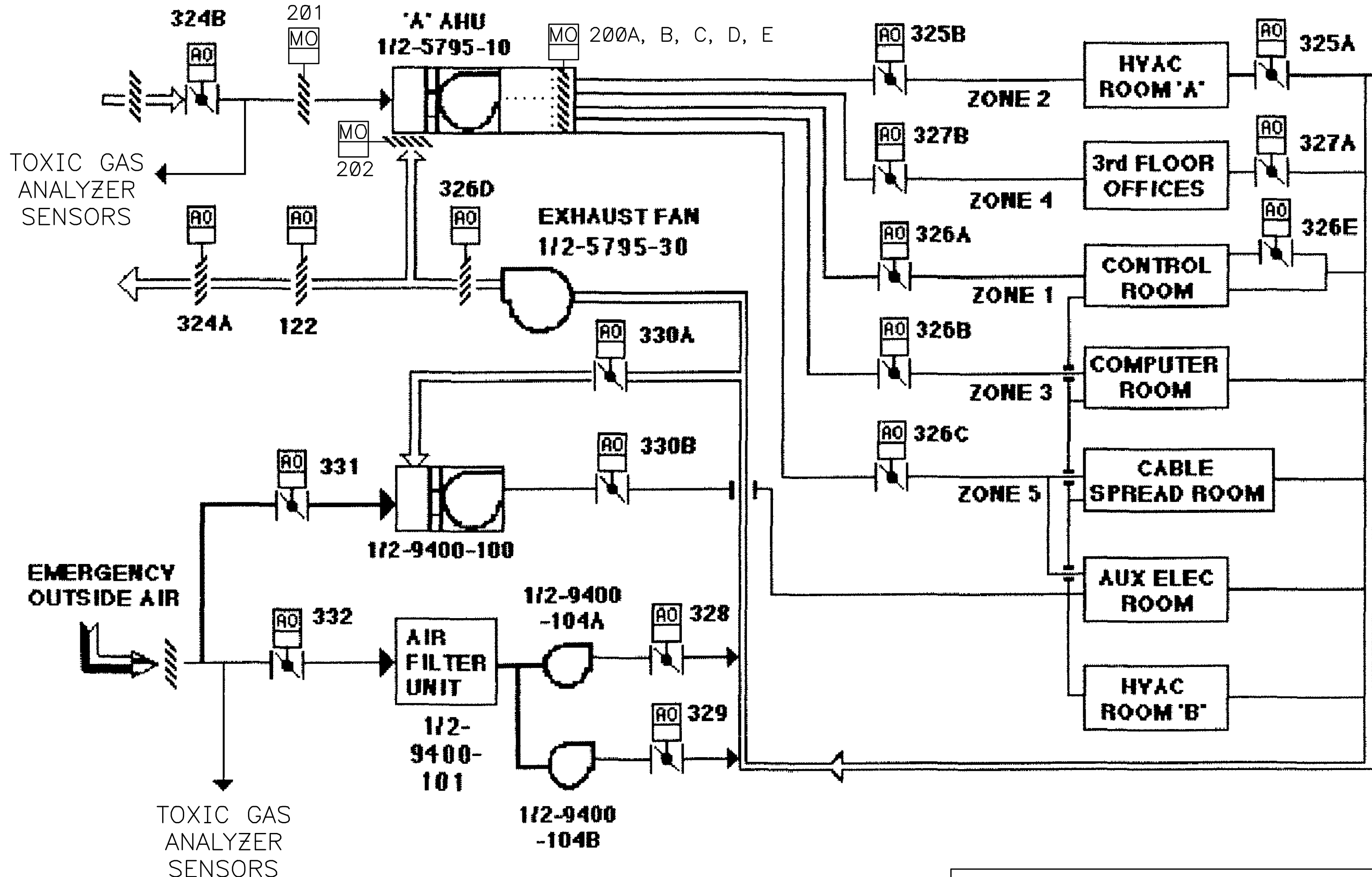
Note: Cycle specific PCT reported in COLR Reference 28.

Source: EMF-96-185(P), Rev. 4

QUAD CITIES STATION UNITS 1 & 2
PEAK CLADDING TEMPERATURE VS. TIME AFTER BREAK AT 2511 MWt (0.5ft^2 PUMP DISCHARGE BREAK, DIESEL GENERATOR FAILURE, ATRIUM-9B FUEL)
FIGURE 6.3-56 REVISION 8, OCTOBER 2005



QUAD CITIES STATION UNITS 1 & 2
QUAD CITIES CONTROL ROOM HVAC SCHEMATIC
FIGURE 6.4-1



QUAD CITIES STATION
UNITS 1 & 2

DIAGRAM OF CONTROL ROOM HVAC SYSTEM

FIGURE 6.4–2
REVISION 12, OCTOBER 2013

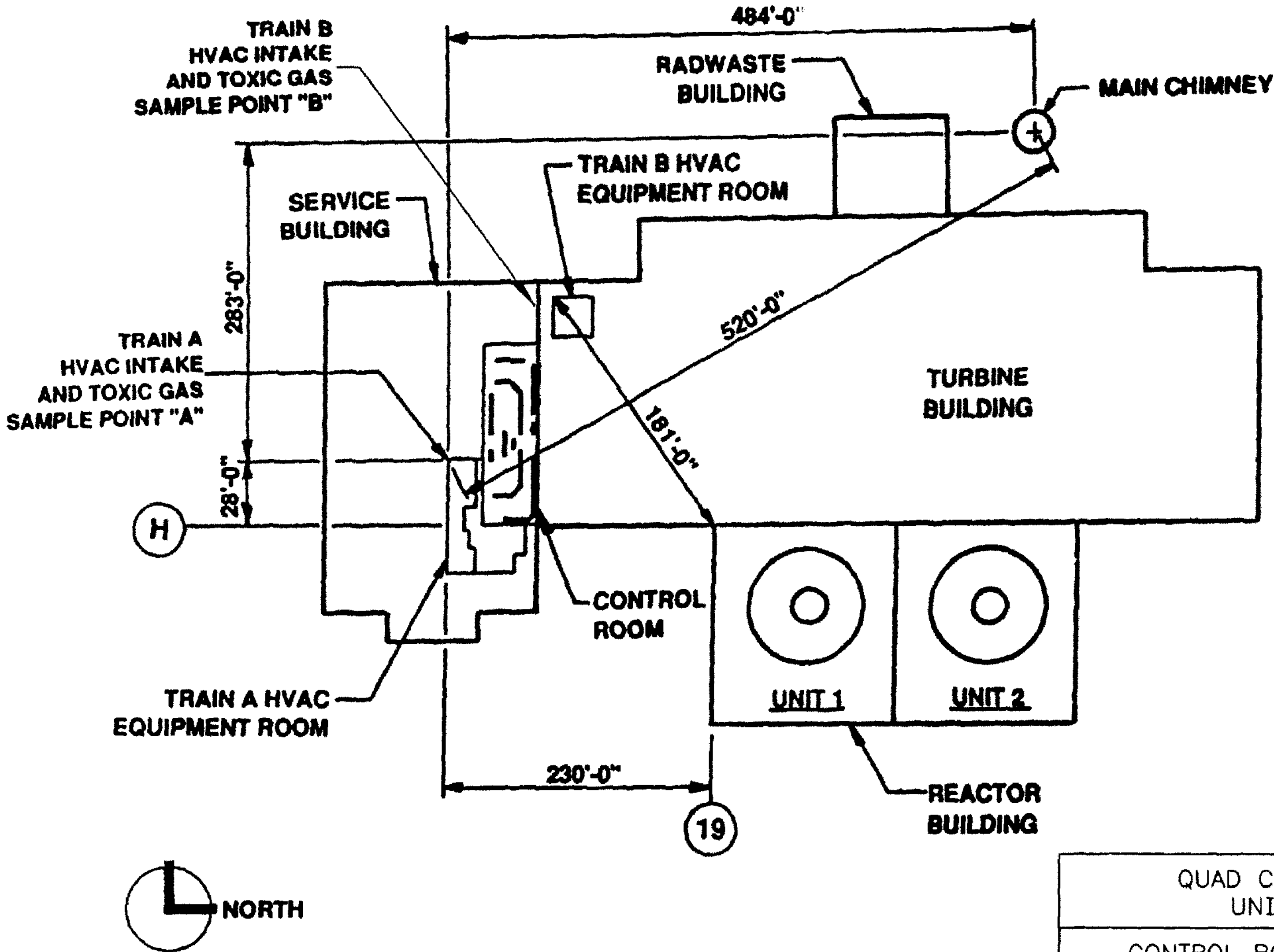
Information withheld in accordance with 10 CFR 2.390

QUAD CITIES STATION
UNITS 1 & 2

QUAD CITIES CONTROL ROOM LAYOUT

FIGURE 6.4-3

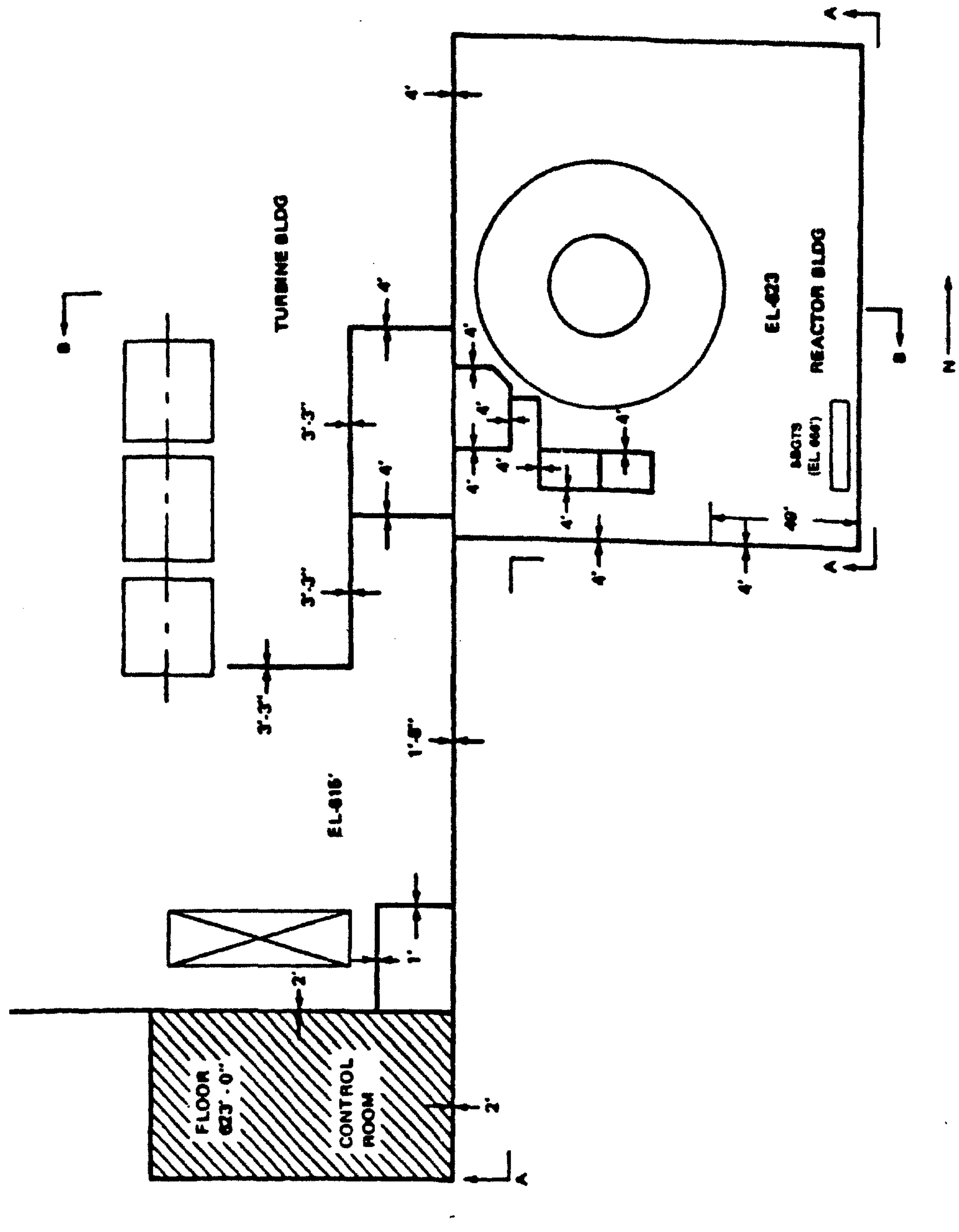
REVISION 14, OCTOBER 2017



QUAD CITIES STATION
UNITS 1 & 2

CONTROL ROOM HABITABILITY
GENERAL PLANT LAYOUT

FIGURE 6.4-4
REVISION 8, OCTOBER 2005

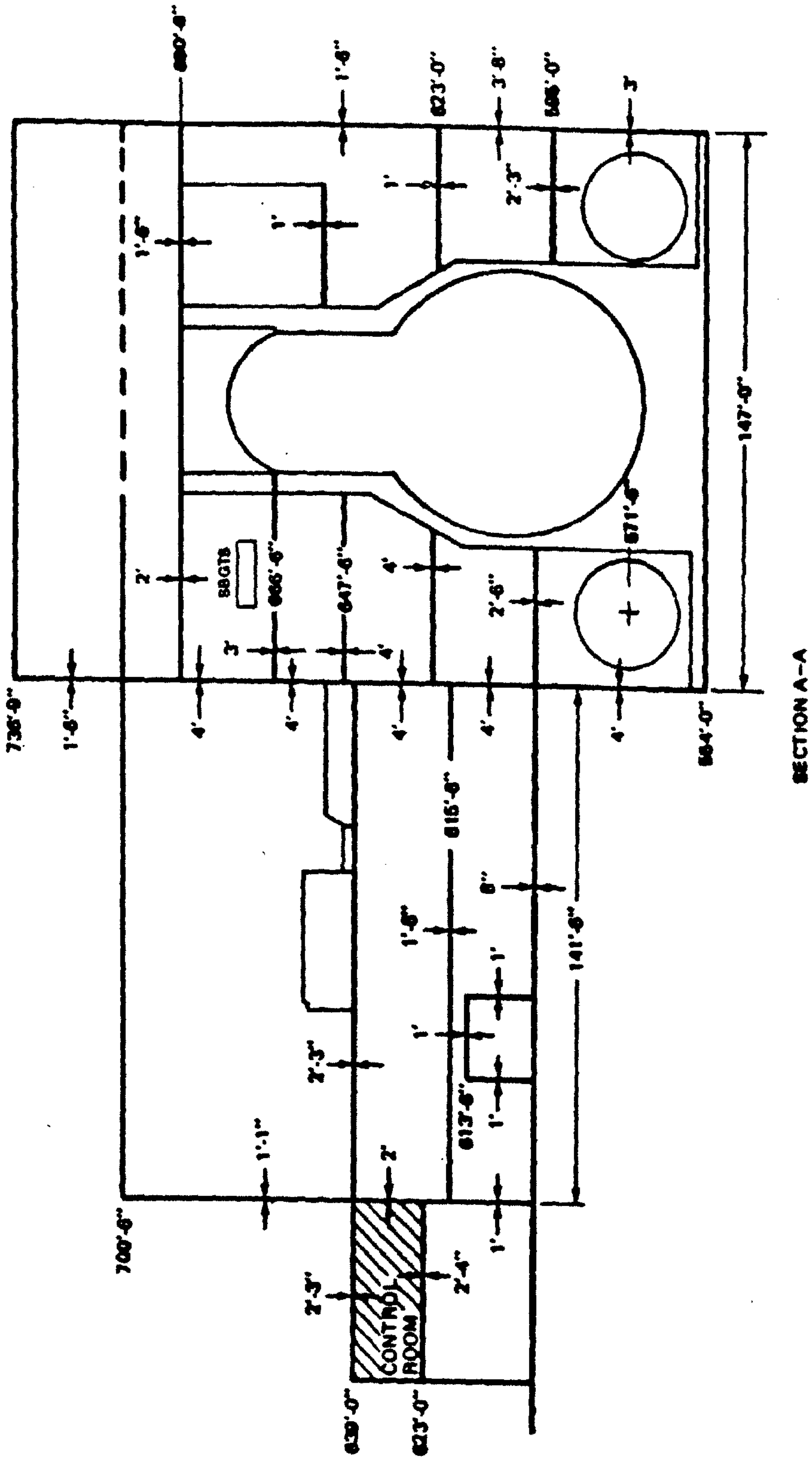


QUAD CITIES STATION
UNITS 1 & 2

CONTROL ROOM LAYOUT AND SHIELDING AT
FLOOR LEVEL OF THE CONTROL ROOM

FIGURE 6.4-5

REV. 3, DECEMBER 1995

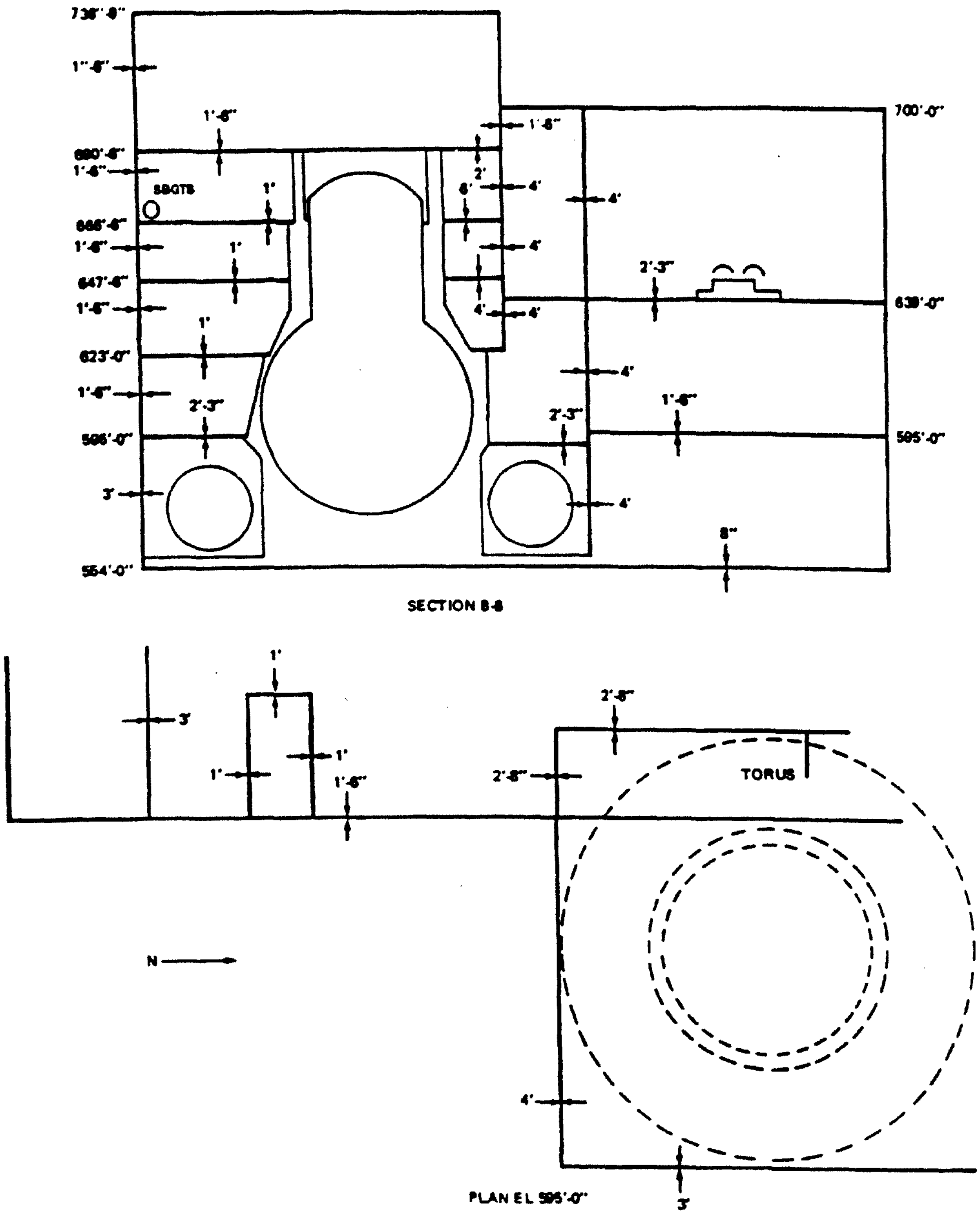


QUAD CITIES STATION
UNITS 1 & 2

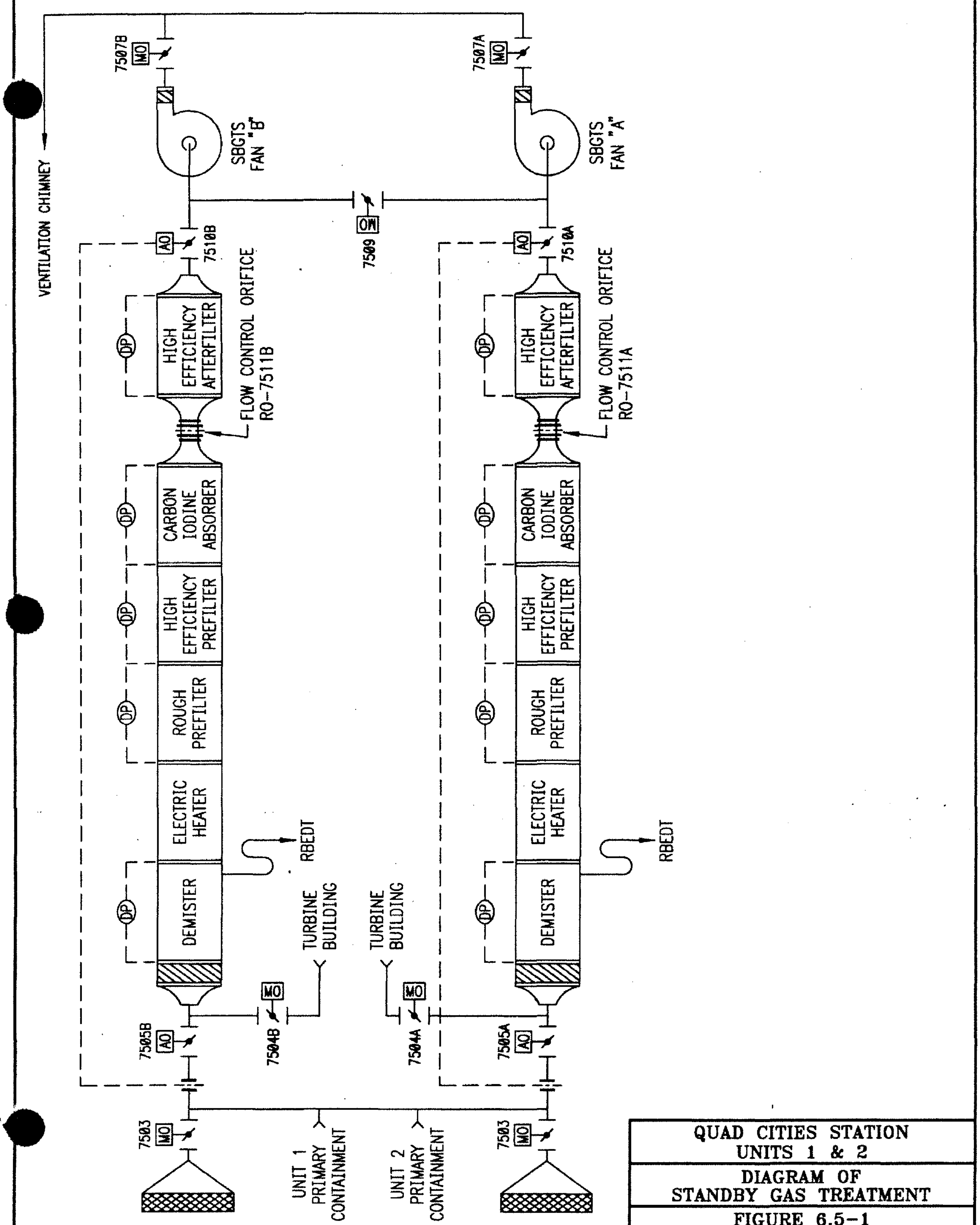
CONTROL ROOM ELEVATIONS WITH RESPECT TO THE TURBINE BUILDING AND REACTOR BUILDING

FIGURE 6.4-6

REV. 3, DECEMBER 1995



QUAD CITIES STATION UNITS 1 & 2
TORUS LAYOUT WITH RESPECT TO THE CONTROL ROOM
FIGURE 6.4-7
REV. 3, DECEMBER 1995



QUAD CITIES STATION
UNITS 1 & 2

DIAGRAM OF
STANDBY GAS TREATMENT

FIGURE 6.5-1
REV. 4, APRIL 1997