Dresden Station

Updated Final Safety Analysis Report

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6.3 EMERGENCY CORE COOLING SYSTEM

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

All LOCA PCT evaluations performed are reported to the NRC per 10 CFR 50.46. The UFSAR is marked up for updates within 90 days of the submittal. The 10 CFR 50.46 letter is on file at the site. Between UFSAR updates the latest PCT is tracked by Nuclear Fuel Management or the cognizant equivalent.

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. It consists of the core spray (CS) subsystem, the low pressure injection (LPCI) subsystem, the high pressure coolant injection(HPCI) subsystem, and the automatic depressurization (ADS) subsystem. The individual subsystems are described in Sections 6.3.2.1 through 6.3.2.4, and the integrated performance is evaluated in Section 6.3.3.2.

The primary principle of coolant system design is to provide core cooling continuity over the entire range of operating and postulated accident conditions. When normal auxiliary power is available, core cooling is achieved by removing heat using the steam turbine-condenser cycle or using the shutdown cooling system.

In the absence of any loss of coolant from the primary system, the core is cooled by relief valve action followed by use of the isolation condenser system under the following conditions:

A. When the reactor is isolated from the main condenser and the shutdown cooling system, or

B. When electrical power is unavailable to the pumps which provide cooling water to the main condenser and shutdown cooling heat exchangers.

However, other means are needed to provide 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. 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. Figure 6.3-1 shows the typical range of effectiveness and redundancy for the various subsystems as they were originally designed (see Section 6.3.3.3.1 for more detail). The overall ECCS design bases are as follows:

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;

B. The entire spectrum of line breaks, up to and including this maximum, is designed to be protected by at least two automatically actuated, independent cooling methods; and

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

Refer to Section 7.3 for a definition of auto-initiation of appropriate action per IEEE 279-1968. For a discussion of integrated ECCS performance analyzed to current regulatory requirements, refer to Section 6.3.3.2.

The design bases of the subsystems which comprise the overall ECCS are provided in the following sections.

6.3.1.1 Core Spray Subsystems

The following design bases have been adopted for each of the two core spray subsystems and aid in evaluating the adequacy of the subsystems:

A. Each core spray subsystem is provided to ensure adequate core cooling when operated with other available ECCS systems determined from the Appendix K single failure criterion.

B. The two independent core spray subsystems shall meet the above design basis requirements without reliance on external power supplies to either core spray subsystem or the reactor system.

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

6.3.1.2 Low Pressure Coolant Injection Subsystem

The design bases of the LPCI subsystem are as follows:

A. The LPCI subsystem is provided to ensure adequate core cooling when operated with other available ECCS systems determined from the Appendix K single failure criterion.

B. The LPCI subsystem is provided with redundancy in critical components to meet reliability requirements.

C. The LPCI subsystem operates without reliance upon external sources of power.

D. The LPCI subsystem is designed so that each component can be tested and inspected periodically to demonstrate availability of the subsystem.

In addition to its ECCS design bases, the LPCI subsystem also provides the capability to achieve cold shutdown - during the Systematic Evaluation Program (SEP) review of SEP topic VII-3, the NRC determined that General Design Criteria 19 and 34 require the capability of achieving cold shutdown from normal operating conditions using safety grade systems. The containment cooling service water (CCSW) system and pressure relief system are used in conjunction with the LPCI subsystem to provide this capability.

6.3.1.3 High Pressure Coolant Injection Subsystem

The following design basis was adopted for the HPCI subsystem and served as the basis for evaluating the adequacy of the system:

A. The HPCI subsystem is provided to ensure adequate core cooling when operated with other available ECCS systems determined from the Appendix K single failure criterion.

B. The HPCI subsystem shall meet the above design basis requirement without reliance on an external power source. Thus, condenser hotwell inventory is considered unavailable.

C. The HPCI subsystem is designed so that each component of the subsystem can be periodically tested.

6.3.1.4 Automatic Depressurization Subsystem

The ADS subsystem is provided to ensure adequate core cooling when operated with other available ECCS systems determined from the Appendix K single failure criterion. Applicable design bases are the same as for the HPCI subsystem (refer to Section 6.3.1.3). The ADS is provided with power from two separate divisional dc power supplies.

6.3.2 System Design

The following sections discuss the design of the ECCS subsystems.

6.3.2.1 Core Spray Subsystem

6.3.2.1.1 Core Spray Subsystem Interface with Other Emergency Core Cooling Subsystems (Historical)

Under current regulatory requirements, the function of the core spray subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. Table 6.3-21 lists the ECCS equipment available under different postulated single active failure considered in Appendix K ECCS performance evaluation (see Section 6.3.3). This section presents historical information on the interface between the CS subsystem and other ECCS subsystems under the original design. The information is historical and is not needed to support the current design basis.

Each core spray subsystem is designed to operate in conjunction with the LPCI subsystem 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.

For small breaks without either feedwater or HPCI availability, the core would uncover while reactor pressure remains above the core spray pump shutoff head. Hence, ADS is actuated to reduce reactor pressure to permit core spray and LPCI to reach rated flow in time to ensure adequate core cooling. Two core spray subsystems or one core spray subsystem and two LPCI pumps, with the assistance of the ADS, provide adequate cooling for all break sizes.

If feedwater or HPCI is available, the necessary depressurization occurs through the addition of cold feedwater to the vessel. Hence, in combination with feedwater or HPCI, two core spray subsystems or one core spray subsystem and two LPCI pumps provide adequate core cooling for all break sizes.

The core spray flow requirement for the current design basis LOCA analysis is given in Table 6.3-20. The following paragraphs contain information on how the core spray flow requirement was determined in the original design. This information is historical and is not needed to support the current design basis.

The core spray flow requirement was established by heat transfer and flow distribution tests on simulated prototype fuel assemblies. These tests are described in detail in References 1 and 2. The head requirements of the core spray subsystem were determined by a series of analyses of the core spray subsystem in conjunction with either the ADS or HPCI subsystem over the small break size spectrum, since small breaks depressurize the reactor at the slowest rates and, therefore, require the largest core spray head. The size of the ADS or HPCI subsystem plays an important role here also, particularly for the small breaks for which core spray subsystem 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 flowrate was based on refined prototype testing of a full scale fuel assembly under actual power and spray distribution conditions. 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 subsystems were sized to provide the minimum required flowrate to each assembly in the core. Flow distribution in the upper plenum and leakage flow available to fuel rods were also taken into account in establishing the core spray flow requirements.

6.3.2.1.2 Subsystem Characteristics

Each of the two independent core spray loops consists of a pump, valves, piping, and an independent circular sparger ring inside the core shroud just above the core. The normal water source for the pump suction is the suppression pool. Condensate storage tank water is used for initial flushing and for system testing when using suppression pool water is either undesirable or not feasible. The core spray subsystem is shown in Drawings M-27 and M-358. Core spray subsystem equipment specifications are tabulated in Table 6.3-3.

The core spray subsystem pumps are started by initiation signals which are described in Sections 6.3.2.1.4 and 7.3.1.1. The injection valves will open when the reactor pressure decreases below the pressure permissive to open. Core spray flow is sprayed over the top of the core. Water sprayed into the fuel assemblies runs down the channel walls providing a heat sink for the heat radiated from the fuel rods.

The discharge piping of the core spray subsystem is required to be filled and vented for the subsystem to be considered operable. The vent pathway for core spray is through vent valves and a sightglass to the reactor building equipment drain tank. A fill system is used to ensure that the core spray discharge lines remain pressurized. This fill system consists of a pump which takes suction from the suppression pool via a core spray pump suction line and discharges to the core spray and LPCI pump discharge lines. A control room alarm is provided to indicate faulty fill system performance.

The core spray pumps and motors are located in the corners at the lowest level of the reactor building where maximum ambient conditions are estimated to be at 150°F at a relative humidity of 100%. Physical separation of the pumps is achieved by locating pumps in different corners of the reactor building as shown by Figure 6.3-3. Each of the two pump rooms contains a room cooler and associated fan as described in Section 9.2.2.

Each core spray pump takes suction from a common ring header that has four suction lines with stainless steel screens located in the torus. These screens are positioned above the bottom of the suppression pool but well below the pool surface to minimize any risk of plugging from debris. Sufficient flow area is available to meet the flow requirements of the combined use of the core spray, LPCI, and HPCI subsystems with four partially plugged suction screens. The screen size ($^1/8$-inch openings) was selected to screen out particles capable of plugging spray nozzles. Additional details of ECCS flow through the strainers are provided in Section 6.2.2.

The core spray pump motors are cooled with core spray pump discharge water. The water flows through a 1-inch line in the pump motor casing and returns to the suction side of the pump. The pump motor cooling system uses no external power source. The pump motors are ac-driven. When normal power is not available, one of the two pumps will receive power from the unit diesel generator and the other from the 2/3 diesel generator. These diesels will automatically start upon loss of normal ac power.

The piping of each core spray subsystem is fabricated of carbon steel from the suppression chamber to the outer isolation valve. Relief valves are utilized for overpressure protection for this section of the piping. From the outer isolation valves into the reactor, the subsystem is fabricated of stainless steel and designed for service at 1250 psig and 575°F. The spray spargers and spray nozzles are fabricated from Type 304 stainless steel to meet the requirements of ASME Section III. 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 fabricated to ASME SA 336 and modified by ASME Code Case 1332.

The most severe environmental conditions that the core spray isolation valves are expected to encounter is 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 27 psig. The maximum ambient temperature of the isolation valves following this transient is expected to be less than the drywell design temperature of 281°F.

The power sources for the core spray subsystems are located on separate emergency buses that have provisions to protect them from adverse environments such as could be caused by fire or steam line breaks. Power for these emergency buses can be supplied from the diesel generators if offsite power is not available.

A test line capable of full system flow is connected from a point near the outside isolation valve back to the suppression chamber. Flow can be diverted into this line to test operability of the pumps and control system during reactor operation.

Each core spray pump is equipped with a four-position control switch provided with START, AUTO, STOP and PULL-TO-LOCK positions. The control switch has a spring return to AUTO position from both the START and STOP positions. The PULL-TO-LOCK position permits the pump to be stopped by pulling the switch and placing it in the PULL-TO-LOCK position. This four-position control switch arrangement permits the operator to override the automatic start signal, which is necessary during long-term cooling of the reactor core following an accident. In such a case, the operator would secure one core spray pump after assuring that adequate core cooling capability exists by the remaining ECCS components.

Administrative procedures restrict the operation of these control switches. Since each pump has its own control switch, no single failure could preclude operation of both core spray loops.

6.3.2.1.3 Equipment Characteristics

6.3.2.1.3.1 Core Spray Pumps

The design flow capacity of each core spray pump is approximately 4500 gal/min at a total developed pump head of 640 ft, as shown in Figure 6.3-4. The core spray pump motors are rated at 800 hp each with a service factor of 1.15. A service factor (or use factor) is used to define the operating limits beyond which deleterious effects to the motor can be expected. Thus, if a pump is rated at 800 hp with a service factor of 1.15, then deleterious effects to the motor can be expected if the motor is operated beyond 920 hp. Table 8.3-1 indicates the nameplate rating of the pump motors.

6.3.2.1.3.2 Piping

Core spray piping internal to the reactor which connects each spray sparger to its reactor pressure vessel 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.

The core spray nozzle arrangement consists of sixty-five 1HH12 full jet nozzles and sixty-five 1-inch open elbows. The spray outlets are equally spaced with the full jets and open elbows alternating around the sparger. The core spray sparger ring is actually two 180° sections with flow entering each section 15° from the midpoint. Uniform distribution of flow around the sparger was obtained by the use of orifices placed in the entrance of the spray branches around the sparger. The effect of inclination angle is shown in Figure 6.3-5 for the open elbows of the lower header. Variation of the full jet inclination angle has even less effect and is not shown. The effect of azimuth setting is shown in Figure 6.3-6. The design value for azimuth for all nozzles is 0°. As a result of these sensitivity tests, an allowable tolerance of ±1° has been set for all angle settings.

During D3R14, IGSCC flaws were identified at two downcomers elbows and three collars (shroud thermal sleeves) welds. These flaws were evaluated (S&L Report SL-5130, June 1997) and it was determined that the design basis for Core Spray would not be affected for up to forty-eight months of hot operation. The impact of projected increasing leakage at the elbow welds on the fuel manufacturer's LOCA-ECCS Analysis of peak cladding temperature must be evaluated at the beginning of each fuel cycle. Other core spray line leakages are considered in LOCA-ECCS analysis (see Section 6.3.3.3.2).

Concern over possible oxygen accumulation in the core spray piping and nozzles was addressed by making an opening at the top of the core spray line divider end plate. The opening is sized to provide a flow in the line of approximately 8 gal/min per loop.

Design of the piping system external to the reactor vessel reflects considerations for potential damage to the piping. The piping runs of each subsystem are physically separated and located to take maximum advantage of protection afforded by structural beams and columns. A sketch of pipe protection provisions is shown on Figure 6.3-3. 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.

6.3.2.1.3.3 Instrumentation

To provide detection of a core spray line guillotine break in the annulus region between the vessel wall and the core shroud during normal reactor power operation, a differential pressure switch in each of the core spray loops was included in the design. Calibrated to read zero at cold shutdown (reactor and instrument legs cold), this instrumentation provides guillotine break detection while reactor power is greater than 80%.

Other local instrumentation provided for monitoring core spray subsystem operation include core spray pump suction pressure, core spray pump discharge pressure, and core spray loop flow (% rated flow).

6.3.2.1.4 Core Spray Operating Sequence

Initiation of each core spray subsystem occurs on any of the following signals:

A. High drywell pressure;

B. Low-low reactor water level coincident with low reactor pressure;

C. Low-low reactor water level coincident with timeout of the ADS high drywell pressure bypass timer.

The core spray system can also be started manually. Refer to Section 7.3 for a complete description of the core spray logic.

During a core spray subsystem test, the test bypass valve is opened to the suppression pool and the pump is started using the remote switch in the control room. The only difference between test and normal standby operation of the core spray subsystem is the use of the pump switch and the test valve.

Upon receipt of a LOCA initiation signal, the test bypass valve is automatically closed. The signal to close the test bypass valve is initiated by the same instrumentation used to activate the core spray system, as shown in Figure 7.3-1. The core spray pump in the test loop remains running unless there is a loss of voltage, in which case the pump will be tripped by undervoltage protective devices. The pump is restarted upon the restoration of power. Other valves in the core spray subsystem will operate as designed on a LOCA initiation signal.

6.3.2.1.4.1 Operating Sequence with Plant on Normal Auxiliary AC Power

Upon receipt of an initiation signal, the core spray pump in each subsystem starts automatically without delay. The injection valves, which admit core spray flow to the reactor vessel, remain closed until the reactor pressure decays below the discharge valve opening interlock pressure. At that time, the valves in each subsystem open to admit flow into the reactor vessel. During the period when the injection valves are closed, pumps are operated on minimum flow bypass to the suppression pool.

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. The suction valves are normally open and the test bypass valves are normally closed during normal power plant operation. The suction valve control logic permits the control room operator to override the automatic opening feature and close the valve if required to isolate a system leak.

The estimated core spray subsystem response time for a DBA LOCA is as follows:

A. Less than six seconds for reaching reactor low-low water level.

B. Five seconds for the pump to accelerate to full speed;

C. Less than 41 seconds for the reactor pressure decay below the permissive pressure for the injection valve to start open.

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

6.3.2.1.4.2 Operating Sequence with Diesel Generator

Upon receipt of an initiation signal coincident with a loss of normal ac power, the following sequence occurs:

A. Diesel generators start (see Table 6.3-4 and Section 8.3.1.5.3 for the ECCS loading sequence)

B. Permissive available to activate pumps and valves of both subsystems;

C. Pump suction valves open (if closed) in both subsystems;

D. Test bypass valves close (if open) in both subsystems;

E. Ten seconds after power is available on the respective bus, both core spray subsystem pumps receive start permissives.

Separate timers are used to start each core spray subsystem to improve system reliability.

The injection valves in both core spray loops will remain closed until the reactor pressure decays to the permissive pressure, at which time the valves will open to admit flow into the reactor vessel. The pumps are operated on minimum flow bypass which discharges back to the suppression pool during the period they are running with the injection valves closed.

6.3.2.2 Low Pressure Coolant Injection Subsystem

The LPCI subsystem includes the equipment for coolant injection and containment cooling. Refer to Section 6.2.2 for a description of the containment cooling subsystem. Refer also to Section 9.2.1 for a description of the containment cooling service water pumps. The LPCI subsystem is further subdivided into two functional loops. The LPCI subsystem equipment includes two heat exchangers, four containment cooling service water pumps, four LPCI pumps, two drywell spray headers, and a suppression chamber spray header. The LPCI subsystem is shown in Drawings M-29, Sheet 1 and M-360, Sheet 1).

6.3.2.2.1 Low Pressure Coolant Injection Subsystem Interface with Other ECCS Subsystems (Historical)

Under current regulatory requirements, the function of the LPCI subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. Table 6.3-21 lists the ECCS equipment available under different postulated single active failure considered in Appendix K ECCS performance evaluation (see Section 6.3.3). This section presents historical information on the interface between the LPCI subsystem and other ECCS subsystems under the original design. The information is historical and is not needed to support the current design basis.

The LPCI subsystem operates in conjunction with the HPCI and core spray subsystems to achieve its core cooling function. During a loss-of-coolant accident, coolant is lost from the core with a corresponding decrease in reactor vessel pressure. The HPCI subsystem operates initially during the high-pressure phase of the accident to supply a small amount of coolant at high pressure.

As the pressure in the reactor vessel decreases, the HPCI subsystem flow ceases and the core spray and LPCI subsystems automatically begin operation to take over the core cooling function. When the pressure in the reactor vessel equals the pressure in the suppression chamber, the LPCI subsystem is capable of delivering maximum capacity. LPCI delivers rated flow with reactor pressure equal to 20 psid (differential pressure between the reactor vessel dome and the drywell). After the core has been flooded to two-thirds height, only one LPCI pump is required to maintain this level.

6.3.2.2.2 Subsystem Characteristics

The LPCI subsystem is required to inject sufficient makeup water to reflood the vessel to the appropriate core height to provide adequate core cooling and is later required to maintain the level at two-thirds core height. Although redundancy is provided in that only three of the four LPCI pumps are required to deliver full capacity LPCI flow, the DBA LOCA analyses take credit for a maximum of two operable LPCI pumps. These analyses also require operation of at least one core spray subsystem to ensure adequate core cooling. The pump head characteristic was selected such that sufficient but less than rated flow is provided before the HPCI turbine is tripped by low vessel pressure. This approach provides core cooling 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 performance curve for the LPCI subsystem is shown in Figure 6.3-8.

The two LPCI pumps for each LPCI subsystem are located on the basement floor in shielded rooms in each of two corners of the reactor building. Each LPCI pump room has the necessary piping and instrumentation to perform in any LPCI or containment cooling mode of operation (refer to Section 6.2.2 for a description of containment cooling functions by the LPCI subsystem). A crosstie header between the otherwise separate subsystems makes it possible for the LPCI pumps in one room to deliver their flow through the second loop's piping. This crosstie is located in a well-protected basement floor area and has two normally keylocked open, motor-operated valves. The valves may be closed from the control room if loop isolation is necessary. Separation of the piping provides protection against missiles in the vicinity of the reactor in that only one of the two flow paths must be assumed to be incapacitated by missiles. Missile protection shielding is provided by routing piping along the reactor building structure walls as much as possible.

Each of the two LPCI pump rooms contains its own room cooler and associated fan. Cooling water is normally provided by the service water system, with the containment cooling service water system as a backup, as described in Section 9.2.

The LPCI room cooler fan motors are seismically supported from rod hangers in a pendulum fashion from the ceiling of the reactor building at elevation 517'-6".

The LPCI subsystem is protected from plugging (due to the presence of foreign material which may find its way into the suppression chamber) by the use of multiple suction header connections with strainers. An evaluation of the strainers is provided in Section 6.2.2.

The LPCI pump motors are cooled by use of the LPCI pump discharge water which is routed through a 1-inch line to the pump motor oil coolers and returned to the suction side of the pump. The pump discharge water cools the oil that in turn lubricates and cools the motor. Hence, no external power source is required other than that used to power the pump motors.

During post-accident operation one or more of the LPCI pumps may be used for containment spray mode. The containment long-term response analysis for a DBA LOCA assumes that a minimum of 5000 gal/min is provided by LPCI to cool the containment (refer to Section 6.2.1.3.2.3). Additionally, to meet two-thirds core coverage requirements, continued post-LOCA ECCS flow is required to make up shroud leakage as described by Section 6.3.2.2.3.1. Therefore, post-DBA LOCA operation of the ECCS system must address both core coverage and containment spray requirements. The long term post-LOCA analysis employed the containment spray mode in order to yield the lowest containment pressure over the long term. Note that containment spray mode is not the preferred method of long term cooling, but was assumed in the analysis since it yields the lowest containment pressures and is therefore conservative in determining ECCS pump NPSH requirements.

After a period not exceeding 2 hours, the operator can manually stop one LPCI pump and start the two containment cooling service water pumps (460 bhp each) powered by the same diesel generator (assuming offsite power is not available). Operating procedures have the operator start the two CCSW pumps in less than this period of time. This pump sequencing serves to limit the load imposed on a diesel generator. Utilization of the LPCI subsystem in conjunction with containment cooling service water would achieve the containment cooling capability as specified in Section 6.2.1.3.2.3.

During LPCI subsystem operation, water is normally taken from the suppression pool and is pumped into the core region of the reactor vessel via one of the two recirculation loops. There is also a connection to the condensate storage tanks to make condensate available as a backup supply. In the event of a recirculation line break, instrumentation is provided to select the undamaged flow path for injection of the required LPCI flow into the reactor vessel. This instrumentation also causes appropriate valves to close which could otherwise result in spillage of the LPCI flow from the shroud region. The sensing circuit for break detection and loop selection is arranged so that failure of a single device or circuit to function on demand will not prevent correct selection of the loop for injection. All components of the loop selection network are operated from dc power sources so that loop selection can take place irrespective of the availability of ac power. LPCI loop selection logic and instrumentation is described in Section 7.3.

calculated from the rate of coolant loss due to a maximum credible break in the primary system piping. This flowrate calculation considered shroud leakage.

The shroud and jet pumps form an inner vessel which must be sufficiently leaktight, despite thermal expansion allowances, to permit reflooding the core to a level adequate for core cooling following a DBA LOCA. The expected leakage is a function of time and water level in the core. The first leakage path is the bolted joint at the top of the jet pump riser, and the second is the slip fit between the jet pump throat and diffuser sections. A potential leakage path at the jet pump to the baffle plate joint is precluded by a completely seal welded joint. A third leakage path exists on Unit 2 at the access hole cover joints in the shroud support baffle plate. The Unit 2 access holes have been modified to a bolted design versus the original welded configuration.

The leakage path at the bolted joint at the top of the jet pump riser is a function of time because the force holding the mating parts together is a function of the differential thermal expansion in the holddown bolt relative to the jet pump "rams head." Early in the transient the bolts will be extended relative to the rams head because the bolts will tend to remain at about 545°F while the rams head will cool off rapidly during LPCI injection. The bolt will cool within a few minutes, however, thereby retightening the joint. The jet pump bolted joint by analysis has been shown to leak no more than 582 gal/min for the 10 pumps through which the vessel is being flooded. The leakage path between the jet pump throat and diffuser sections is a function of water level only since the level is the only driving force for the leakage. This leakage path is not a function of time since both parts of the joint will thermally expand and contract together. The slipjoints for all 20 jet pumps will leak no more than 225 gal/min. Leakage through the Unit 2 access hole covers is a function of water level only since the differential level is the only driving force for the leakage. The leakage is not a function of time since the access hole cover and shroud support baffle plate expand and contract together. The bolted joints for the two access hole covers in the Unit 2 shroud support plate have been analyzed and shown to leak no more than 78 gal/min total for both covers.

Although the LPCI system capacity was sized to accommodate 3000 gal/min leakage at these three locations, the calculated maximum combined leakage is 885 gal/min for Unit 2 and 807 gal/min for Unit 3.

The 3000 gal/min leakage rate from inside the shroud through the jet pumps is a design number for all BWR jet pump plants for the purpose of sizing the LPCI pumps. This design basis is based on early estimates of the shroud leakage rate when the water level is at two-thirds core height. These estimates were performed in a most conservative fashion to arrive at a jet pump leakage rate which could be applied to any BWR jet pump system without exceeding the actual expected leakage rate of any particular plant. Thus, the basis for the assumption of 3000 gal/min leakage from the jet pumps during LPCI operation with the water level at the two-thirds core height is simply to provide a conservative allowance for leakage which may be applied in the design of any LPCI system, allowing "decoupling" of the LPCI pump design and the jet pump component design.

Table 6.3-6 summarizes the maximum calculated leakage rates for the Dresden design as a function of water level in the core and for the two end points of maximum holddown bolt extension (early in transient) and minimum holddown bolt extension (after several minutes).

Breaks in the LPCI injection line between the check valve and the recirculation loop would be detected as a loss-of-coolant accident. These breaks are equivalent to recirculation discharge line breaks of the same size in the same loop. Since the LPCI injection line is smaller than the recirculation discharge line, the LPCI line break is bounded by the DBA LOCA. The drywell sump pump method is capable of detecting leakage in the LPCI line. Unidentified leakage in excess of 5 gal/min would result in plant shutdown within 24 hours to determine the cause of the leak.

Because the low pressure ECCS piping outside the drywell up to the first outside isolation valve is considered an extension of the primary containment, the LPCI subsystem piping must meet the same design, surveillance, and testing criteria as the primary containment. Rupture of this low pressure piping is, therefore, extremely unlikely. The location and identification of such leaks would be through room temperature alarms, reactor building floor drain sump activity, and visual inspection (since these lines are accessible).

All leakage in the ECCS outside the primary containment can be isolated from the suppression chamber and the primary system itself.

The discharge piping of the LPCI subsystem is required to be filled and vented in order for the subsystem to be considered operable. The vent pathway for LPCI is through vent valves and a sight glass to the reactor building floor drains. The fill system is used to ensure that the LPCI discharge lines remain pressurized. This fill system consists of a core spray jockey pump described in Section 6.3.2.1.2. If the jockey pump is removed from service for maintenance, the condensate transfer system can be used as an alternate fill system.

During the In-Vessel Visual Inspection of D2R15, a flaw was identified on the jet pump riser between jet pumps 15 and 16 at the reactor vessel nozzle thermal sleeve to elbow weld. An evaluation was performed that calculated LPCI system leakage that would be lost through the flaw (11 gpm) during the DBA LOCA and the effects of that leakage on the peak fuel cladding temperature. The evaluation concluded that this piping is safe and acceptable to operate until D2R17 when a re-inspection and disposition will be necessary.

6.3.2.2.3.4 Instrumentation

The LPCI subsystem is initiated on any of the following signals as discussed in Section 7.3:

A. High drywell pressure;

B. Low-low reactor water level coincident with low reactor pressure; or

C. Low-low reactor water level coincident with timeout of the ADS high drywell pressure bypass timer.

Logic is provided to ensure the LPCI flow is injected into the unbroken recirculation loop. A detailed description of LPCI subsystem loop selection instrumentation, logic, and minimum flow valve operation is provided in Section 7.3.

Interlocks are provided to prevent LPCI flow from being diverted to the containment cooling subsystem piping unless the core is flooded to at least two-thirds of its height. Sections 6.2.2 and 7.4 provide a more detailed description of containment cooling interlocks.

Instrumentation provided for monitoring LPCI subsystem operation includes LPCI pump suction and discharge pressure, LPCI flow to recirculation loop, LPCI minimum flow (% rated flow), and LPCI loop select logic jet pump riser differential pressure.

6.3.2.2.4 LPCI Operating Sequence

6.3.2.2.4.1 LPCI Operating Sequence with Plant on Normal Auxiliary AC Power

Upon receipt of an initiation signal with normal ac power available, the following sequence automatically occurs:

A. Diesel generators start;

B. Permissive available to activate pumps and valve;

C. All four LPCI pumps start without delay;

D. Pump suction valves open (if closed). The pump suction valve opening signal can be overridden such that the valves can be closed if necessary to isolate a leak; and

E. Containment cooling service water pumps stop (if running).

When the reactor primary system pressure drops to the shutoff head of the LPCI pumps, a check valve in the 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 line pump discharge valve in the unbroken loop, and opened the LPCI injection valve to the unbroken recirculation line.

6.3.2.2.4.2 LPCI Operating Sequence with Diesel Generator

Upon receipt of an initiation signal coincident with a loss of normal ac power, the following sequence occurs:

A. Diesel generators start;

B. Permissive available to activate pumps and valves;

C. Pump suction valves open (if closed);

D. After the diesel generators restore power to their respective buses, LPCI pumps A and C receive a start signal;

E. Five seconds after the diesel generators restore power to their respective buses, LPCI pumps B and D receive a start signal. (See Table 6.3-4.)

LPCI flow to the vessel is established as previously described in Section 6.3.2.2.4.1.

6.3.2.3 High Pressure Coolant Injection Subsystem

The HPCI subsystem is designed to pump water into the reactor vessel under those LOCA conditions which do not result in rapid depressurization of the reactor 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.

The HPCI subsystem includes a steam turbine driving a two-stage high pressure pump and a gear-driven, single-stage booster pump, valves, high pressure piping, water sources, and instrumentation. The HPCI subsystem is shown in Drawings M-51 and M-374. The HPCI equipment specifications are shown in Table 6.3-7.

The subsystem piping was designed to USAS B31.1 and ASME Section I. The pumps were designed to ASME Section III. The piping arrangement includes considerations for potential damage, and open piping runs are protected by structural steel. Fabrication, testing, and inspection of this piping was equal to that required for the primary containment system.

Operation of the HPCI system in the emergency mode is completely independent of ac power with the exception of the HPCI room cooler fans, and requires only dc power from the station battery to operate the controls.

Operation of the HPCI subsystem is dependent upon reactor water level signals (Figures 7.3-8A, 8B, and 8C). Either low-low water level or high drywell pressure starts the subsystem and high water level stops it.

6.3.2.3.1 High Pressure Coolant Injection Interface with Other Emergency Core Cooling Subsystems (Historical)

Under current regulatory requirements, the function of the HPCI subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. Table 6.3-21 lists the ECCS equipment available under different postulated single active failure considered in Appendix K ECCS performance evaluation (see Section 6.3.3). This section presents historical information on the interface between the HPCI subsystem and other ECCS subsystems under the original design. The information is historical and is not needed to support the current design basis.

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 where the core spray subsystem and/or the LPCI subsystem become effective.

6.3.2.3.2 Subsystem Characteristics

Suction for the HPCI pump is normally taken from both condensate storage tanks, where 90,000 gallons of water are reserved by administrative control for HPCI. On low-low level in the condensate storage tank or high level in the torus, the HPCI suction will automatically switch to the suppression pool.

The discharge piping of the HPCI subsystem is required to be filled and vented for the subsystem to be considered operable. With HPCI suction aligned to a condensate storage tank (CST), keep fill is provided by the head of the CST. If HPCI suction is aligned to the torus, ECCS keep fill must be aligned to the HPCI discharge line.

The water from either source is pumped into 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 to the suppression pool. The LPCI subsystem in conjunction with the containment cooling service water 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 1135 psia to 165 psia. However, the HPCI flow assumed in the LOCA analysis is 5000 gal/min. The turbine is driven with steam from the reactor vessel. As reactor pressure decreases, the control valves throttle to pass the required steam flow to maintain the set pump flowrate. Turbine speed is controlled by the motor speed changer (MSC) and the motor gear unit (MGU) described in Section 7.3.1.3.2.

The HPCI flowrate is measured in the pump discharge line. A conventional flow controller compares this measured flowrate with a preset flow requirement of 5600 gal/min. The output of the flow controller will vary from 4 to 20 milliamps, depending on where (i.e., at what speed) the flow demand is satisfied. The controller output is fed to the turbine control (MGU) logic for turbine-pump speed control and, therefore, ultimate flow control.

The controlling design condition for the turbine steam path is the low pressure operation point, i.e., developing the required horsepower (1350 hp at 2250 rpm) with 155 psia inlet steam pressure and 65 psia exhaust pressure. This operating condition (maximum volume flow) dictates the required turbine stage areas. All other operating conditions require less volume flow and, therefore, result in throttling the turbine control valves. This control function is no different than that encountered in boiler feed pump drive systems.

Exhaust steam from the unit is discharged to the suppression pool. The turbine exhaust line is provided with a vacuum breaker system. The vacuum breakers were added to improve turbine low-load operation, to minimize pressure fluctuations, and to prevent suppression pool water rise in the exhaust line which would result in unacceptable back pressure during the turbine startup transient.

The turbine gland seals are vented to the gland seal condenser, and water from the HPCI booster pump discharge is routed through the gland seal condenser for cooling purposes. Noncondensible gases from the gland seal condenser are ducted to the standby gas treatment system.

Moisture removal systems are provided both in the steam supply line near the turbine, in the turbine exhaust line, and in the turbine casing. The systems use conventional equipment consisting of collection drain pots and steam traps.

However, for preoperational warmup in the test mode using a controlled startup procedure rather than an emergency auto startup, the subsystem has a cooling water pump which can be used only when normal ac power is available.

A minimum flow bypass system returns a portion of the pump discharge flow back to the suppression chamber 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 pump suction valves are interlocked to prevent opening the valve from the condensate storage tank whenever both valves from the suppression chamber are fully open. The test return valves to the condensate storage tank are also interlocked closed when either suction valve from the suppression chamber is not fully closed.

Instrumentation provided for monitoring HPCI operation includes main pump discharge temperature, turbine oil temperature, booster pump suction pressure, main pump discharge pressure, turbine inlet and outlet pressure, gland seal pump discharge pressure, turbine lube oil and hydraulic oil pressures, steam supply pressure, HPCI flow (% rated water flow), and HPCI steam line flow ΔP.

6.3.2.3.3 High Pressure Coolant Injection Operational Sequence

6.3.2.3.3.1 High Pressure Coolant Injection Automatic Initiation

Initiation of the high pressure coolant injection 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.

Upon receipt of the initiation signal, the HPCI turbine and its required auxiliary equipment such as the auxiliary oil pump and gland seal leakoff blower, automatically start. The automatic HPCI turbine trip due to low booster pump suction pressure is bypassed if an initiation signal is present. In addition, the following valves assume or maintain the following positions:

A. Steam supply line containment isolation valves open, if closed (these are normally open valves);

B. Turbine steam supply and stop valves open;

C. Pump suction valve from the condensate storage tank opens if closed (normally open);

D. Pump discharge valves open (one valve is normally open);

E. Cooling water return valve to the HPCI booster pump suction opens;

F. Steam line drain valves to the main condenser close and the steam line drain valve to the suppression chamber opens;

G. Turbine stop valve drain valves close;

H. Cooling water return valve to condensate storage tank closes; and

I. Test return valves to condensate storage tank close (if open). Note: the 2301-10 test bypass valve closing logic includes an interposing relay which delays the closing of the valve by approximately 40 milliseconds to limit loading on the battery system.

6.3.2.3.3.2 High Pressure Coolant Injection Automatic Isolation and Shutdown

Shutdown of the HPCI subsystem may occur in either of two ways: isolation of the steam supply to the turbine or tripping the turbine stop valve closed. It should be noted that with the turbine stop valve leaving the full open position, the turbine control valves close automatically. A description of the HPCI subsystem shutdown signals and logic is provided in Section 7.3.

The steam supply isolation will occur upon receipt of a high steam line flow, high area temperature, or low steam line pressure. Turbine stop valve closure will occur upon receipt of a turbine overspeed trip, low booster pump suction pressure, high turbine exhaust pressure, or reactor vessel high water level.

A steam leak from the HPCI line, outside the primary containment, in the HPCI room would result in high room temperature which would then result in HPCI isolation and an alarm in the control room. A steam leak of sufficient magnitude would result in a high HPCI steam flow isolation and annunciation. If HPCI does not automatically isolate due to high steam flow then, upon detection of the leak, the operator may close the HPCI steam line isolation valves to terminate the leak.

Leakage from the HPCI subsystem discharge line which leads to the feedwater line would be condensate storage tank water and, as such, the leakage does not constitute a hazard.

LOCA analyses assuming the additional failure of HPCI for each of the single failure scenario in Table 6.3-21 have been performed. The results meet the 10 CFR 50.46 acceptance criteria.

6.3.2.3.3.3 High Pressure Coolant Injection - Continuous Operation

Operation of the HPCI turbine continues as long as reactor pressure is above 165 psia and reactor water inventory has not returned to normal. Components are designed to maintain constant flow as the pressure is reduced. The HPCI subsystem automatically maintains reactor water level between low-low level and high level if the break size is within the capacity of the pump and the reactor is not depressurized below 165 psia.

6.3.2.3.3.4 High Pressure Coolant Injection - Termination of Operation

When the reactor pressure falls below 165 psia, the speed of the turbine-pump unit will begin to decrease and will gradually be slowed to a stop by friction and windage losses at a reactor pressure of about 65 psia; however, HPCI isolation will automatically occur on low reactor pressure of 100 psig. This isolation setpoint occurs at or above the pressure at which the turbine would stop due to friction and windage losses.

Core cooling at this time will be accomplished by the core spray subsystem and the LPCI subsystem. For a small break, core cooling will be maintained by the control rod drive pumps if ac power is available.

6.3.2.4 Automatic Depressurization System

6.3.2.4.1 Automatic Depressurization Subsystem Interface with Other Emergency Core Cooling Systems (Historical)

Under current regulatory requirements, the function of the ADS subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. Table 6.3-21 lists the ECCS equipment available under different postulated single active failure considered in Appendix K ECCS performance evaluation (see Section 6.3.3). This section presents historical information on the interface between the ADS subsystem and other ECCS subsystems under the original design. The information is historical and is not needed to support the current design basis.

The ADS is an ECCS subsystem which is employed as a backup to the HPCI subsystem to depressurize the reactor pressure vessel for small area breaks. The HPCI subsystem provides primary depressurization and core cooling for small breaks. In the event that HPCI is not effective, the ADS reduces pressure 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 core spray or LPCI 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 ADS circuitry. Additional ADS logic information is provided in Section 7.3.

6.3.2.4.2 Subsystem Characteristics

The ADS is designed to automatically actuate to depressurize the reactor vessel if the following conditions A and B and C are met for 120 seconds or if conditions C and D are met:

A. Low-low reactor water level,

B. High drywell pressure,

C. At least one LPCI or one core spray pump with discharge pressure exceeding 100 psig.

D. Low-low reactor water level (continuous for 8.5 minutes), in conjunction with Condition C.

The 120-second ADS time delay prevents unnecessary blowdowns resulting from transient conditions and provides an opportunity for HPCI to restore reactor water level. The ADS timer logic is discussed in Section 7.3.

The time delay also provides surveillance 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 valves when the control station switch is in the automatic position. The delay time 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 the core spray and LPCI are unable to adequately cool the fuel if the HPCI fails to start. All of the five relief valves (four electromatic relief valves and one Target Rock safety/relief valve) normally open simultaneously; however, two of the electromatic relief valves are equipped with additional control logic and are subjected to an additional 10-second valve reopening delay to preclude immediate automatic reopening of valves that were previously opened. This delay will prevent excessive loading as a result of an elevated water leg in the relief valve discharge piping (see Section 5.2.2.2). An ADS inhibit switch is provided to prevent ADS

6.3.3 Performance Evaluation

6.3.3.1 Emergency Core Cooling Subsystem Performance Evaluation

The original design basis of the ECCS subsystems was to prevent fuel clad melting over the entire spectrum of postulated primary coolant leaks. The range of break sizes for which each of the emergency core cooling systems was deemed capable of protecting the core against clad melting is shown in Figure 6.3-1. Figure 6.3-1 shows the range of break sizes for which an ECCS subsystem was deemed capable of preventing clad melting without assistance from the in conjunction with any other subsystems (See Section 6.3.3.3.1 for further discussion).

Under current regulatory requirements, the function of each ECCS subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. The integrated performance of the ECCS system is evaluated using an approved Appendix K ECCS evaluation model (see Section 6.3.3.3). A system by system performance evaluation is no longer needed. This section provides the historical performance evaluation of each ECCS subsystem. Tables 6.3-1 and 6.3-2 list the ECCS parameters used in the evaluation. The information in this section is historical and is not needed to support the current design basis.

6.3.3.1.1 Core Spray Subsystem (Historical Information)

Each core spray subsystem is designed to maintain continuity of reactor core cooling for a large spectrum of loss-of-coolant accidents. Each subsystem provides adequate cooling for intermediate and large line break sizes; however, either two core spray subsystems or one core spray subsystem and two LPCI pumps are required to ensure adequate core cooling following a DBA LOCA. The integrated performance of a core spray subsystem in conjunction with other emergency core cooling subsystems is provided in Section 6.3.3.3.

As indicated previously, there exists a break size below which the core spray subsystem alone cannot protect the core (see Figure 6.3-1). Vessel pressure does not drop rapidly enough to allow sufficient core spray injection to occur before the fuel cladding reaches an excessively high temperature. Below this break size either HPCI or ADS extends the range of the core spray subsystem to breaks of insignificant magnitude.

The core spray heat transfer tests were completed and are reported in Reference 2. These tests covered fuel bundles having an initial power level of 6.5 MWt, well in excess of the peak bundle power for the units. The test fuel rods were allowed to overheat (1600°F) prior to core spray activation. Actual core spray operating temperatures of 2350°F were tested, well in excess of the 10 CFR 50.46 allowable PCT of 2200°F.

Further decreases in level inside the shroud are the result of flashing due to depressurization and boiloff. As the level outside the shroud drops below the suction side vessel penetration of the recirculation loop, the level is held up in the unbroken loop. As the broken recirculation loop is completely drained of liquid, the break flow changes to steam which causes an increase in the vessel depressurization rate. When the vessel pressure decreases to below the shutoff head of the core spray subsystem, core spray injection begins. For a short time the core spray flow is in equilibrium with the flashing rate and the water level inside the shroud is constant. As core spray flow increases due to the decreasing pressure, the water level inside the shroud increases. When the water level in the jet pumps reaches the top of the jet pumps, water spills over from inside the shroud to outside the shroud slowly raising the water level in the unbroken loop. The water level inside the shroud is slightly above the jet pump inlet due to the higher void fraction in the core compared to that in the jet pumps. The water level inside the shroud continues to rise slowly due to the decreasing pressure and corresponding increase in core void fraction.

In conclusion, the core spray subsystem provides an effective means of terminating the core heatup transient (in conjunction with HPCI or ADS for small breaks) over a wide spectrum of loss-of-coolant accidents. Note, however, the two core spray subsystems or one core spray subsystem and two LPCI pumps are required to ensure adequate core cooling following a DBA LOCA. 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 6.3.3.3 presents a detailed discussion of the integrated performance of the core spray system in conjunction with other emergency core cooling subsystems.

6.3.3.1.2 Low Pressure Coolant Injection Subsystem (Historical Information)

The LPCI subsystem is designed to provide reactor core cooling for a large spectrum of loss-of-coolant accidents. The LPCI subsystem is capable of providing adequate cooling for intermediate and large line break sizes; however, either two core spray subsystems or one core spray subsystem and two LPCI pumps are required to ensure adequate core cooling following a DBA LOCA. A detailed discussion of the integrated performance of the LPCI subsystem in conjunction with other emergency core cooling subsystems is given in Section 6.3.3.3.

The LPCI pumps are designed to have both adequate head and adequate coolant flow capacity to meet flooding requirements, when operating in conjunction with either the HPCI or ADS system.

The maximum LPCI flow capacity (14,500 gal/min at a differential pressure between the suppression pool and the reactor pressure vessel of 20 psid with three pumps running) is determined by the design basis break (instantaneous break of a recirculation line). The pumps are capable of refilling the inner plenum in time to ensure adequate core cooling, assuming no water remains after blowdown. The minimum allowable time in which this must be done is based on the design basis break because the least core cooling occurs for this break. Hence, the core 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 to the vessel due to the LPCI pump head-flow characteristic.

through the minimum flow line. The 10 CFR 50 Appendix K analysis assumes a two pump LPCI flowrate of 9000 gal/min for the DBA LOCA with a diesel generator failure. The minimum flow of the non-selected loop is subtracted from this assumed flow rate. Based on actual station test data obtained with the minimum flow valves open, the minimum LPCI flowrate assumed by the current accident analysis was verified.

6.3.3.1.3 High Pressure Coolant Injection Subsystem

The high pressure coolant injection subsystem has been evaluated to assure that the design bases are met. This evaluation considers the structural integrity of the HPCI subsystem to withstand the effects of an accident for which the subsystem must be available. The suitability of valves, pump and turbine sequencing, speed of operation, capacity, and the depressurization efficiency for HPCI flow were also evaluated.

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 operate. Section 6.3.2.3.3.1 identifies additional HPCI components required to ensure proper HPCI system operation.

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. The HPCI turbine is essentially identical to numerous units in service as boiler feed pump drives. Steam pressure is available to drive this pump whenever high pressure injection is needed. The HPCI subsystem can be tested frequently so that any operating deficiencies can be detected early.

Operation of the HPCI subsystem is automatic and requires no manual intervention.

LOCA analyses assuming the additional failure of HPCI for each of the single failure scenario in Table 6.3-21 have been performed. The results meet the 10 CFR 50.46 acceptance criteria.

There are many actions the operator can take to prevent core damage for moderate size breaks. If normal sources of power are available, the operator can continue to operate the regular feedwater pumps to provide makeup. The operator 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 electromatic relief valves so that core spray and LPCI will provide adequate core cooling.

6.3.3.1.3.2 Evaluation of HPCI Subsystem Performance (Historical Information)

The HPCI subsystem is designed to provide adequate reactor core cooling for small breaks and to depressurize the reactor primary system to enable cooling water injection by 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 6.3.3.3.

Performance analyses of the HPCI subsystem were conducted in the same manner and with the same basic assumptions as for the core spray subsystem described previously. The detailed model is described in Section 6.3.3.2.2.

The results of a performance analysis of the HPCI subsystem for a typical small break within the protection range of the unassisted HPCI subsystem are shown in the Figure 6.3-14. 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 main turbine 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 depressurization 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 addition by HPCI is 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. 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 HPCI subsystem is designed to deliver full rated flow down to a reactor pressure of 165 psia. For lower pressures, the estimated flow decreases linearly to zero at 65 psia reactor pressure. If reactor pressure drops below the low pressure isolation setpoint, a later pressure buildup above the setpoint would automatically restart the turbine if a HPCI initiation signal were present. Thus, slow pressure changes may occur depending on the level in the core and the fraction of decay heat released to the fluid. If the HPCI subsystem decreases reactor pressure below the low pressure isolation and shuts off while the level is below the top of the core, subsequent level rise would cause enough energy to be added from core heat to raise the pressure which would reactuate the HPCI turbine. However, this discussion is focused on the operation of HPCI acting alone, a scenario that is not in the design basis. The integrated operation of all ECCS subsystems is discussed in Section 6.3.3.4.

An evaluation was made to evaluate the combined performance of the HPCI and LPCI subsystems, considering a 0.3 square foot break area, a 100 psig low reactor pressure HPCI isolation, and a HPCI restart (with a delay of 30 seconds) after reactor pressure rises above 100 psig. It should be noted that the evaluation was intended to address the performance capabilities of the HPCI and LPCI subsystems under one specific break size. However, this evaluation was not intended to establish the design basis for either system. Refer to Section 6.3.3.4 for a discussion of integrated system operating sequences, under various design basis accident scenarios.

During the HPCI restart time the water level inside the shroud is restored and the addition of decay heat causes pressure to seek an equilibrium value so that the energy absorbed by the HPCI flow plus that leaving through the break is equal to decay heat. Spillage of LPCI flow from inside the shroud to outside the shroud is important at this point because the LPCI flow which spills would absorb energy from the primary system flow as it passes through the annulus and the recirculation loop to the break. However, this depressurization effect is conservatively ignored in the analysis. As the LPCI spillage flow passes through the break, it reduces the area available for saturated blowdown thereby tending to hold pressure constant.

The model used for ECCS evaluations accounted for restart of HPCI, compression of saturated fluid by LPCI water, and ramp down of HPCI flow. The model did not take credit for the effect of depressurization by LPCI.

The automatic depressurization system operates completely independently of HPCI or feedwater and is provided as a backup to the HPCI subsystem. If HPCI and/or feedwater cannot maintain reactor water level the ADS will actuate in accordance with initiation logic described in Section 6.3.2.4.2. Additional HPCI performance analysis information is provided in Section 6.3.3.3.

Calculations performed since the current ECCS were first conceived indicated that ADS combined with HPCI or ADS alone will not impose intolerable stresses on either the pressure vessel or the internals. Allowing the ADS to operate simultaneously with HPCI will not lead to the core thermal behavior or pressure transients more severe than with HPCI alone.

Figures 6.3-15 and 6.3-16 show the peak clad temperature and depressurization rates respectively for the cases of the ADS operating simultaneously with HPCI.

6.3.3.1.3.2.1 HPCI Subsystem Response to Reactor Vessel Level Swell (Historical Information)

Potential level swell and resultant liquid carryover into the HPCI steam line has been studied extensively. Gross moisture carryover to the HPCI turbine should not occur over the range of breaks of interest for this subsystem. The following is a summary of the results of the more detailed discussions which are included later:

A. For breaks below the water surface, the depressurization rate is much less than that for steam breaks. Because the depressurization rate is relatively slow for liquid breaks, the level swell phenomenon will not occur. Even for the maximum liquid break, the level does not rise above its initial value.

B. For breaks above the water surface, the ECCS bar chart (Figure 6.3-1) shows that the HPCI subsystem is required only for breaks smaller than 0.13 square feet. The minimum break size which could cause a swell condition sufficient to ultimately flood the HPCI steam line is 0.35 to 0.40 square feet. Thus, a steam break large enough to cause sufficient swelling to flood the steam line would depressurize the vessel fast enough such that only LPCI and/or core spray would be required for adequate core cooling.

C. Even if a slug of water were to enter the HPCI steam line, evidence indicates that moisture entrainment and turbulent mixing would occur, and slugging would not occur.

D. If the HPCI turbine were to ingest a slug of water, failure of the casing would not occur and no release of radiation could occur by this mechanism. Some leakage might occur through the gland seal.

The isolation signals which serve to ensure isolation of the HPCI in the event that a water slug damages the turbine (and also fails the gland seal condenser) are generated as follows:

A. The water slug will produce a high differential pressure signal in the steam line which will isolate the HPCI turbine in approximately 50 seconds;

B. In the event of shaft seal steam leakage from the damaged turbine, the high temperature area monitors located in the HPCI turbine room would produce a signal to isolate the HPCI turbine in less than 2 minutes; and

C. Steam flowing through the locked rotor would produce a high exhaust pressure also isolating the HPCI turbine in less than 2 minutes.

As a backup signal to all of the signals mentioned above, the reactor low pressure signal would isolate the HPCI turbine. Based on a main steam line break of sufficient size to produce a water slug in the HPCI line (0.4 square feet), the reactor depressurization rate would produce an isolation signal in less than 15 minutes. The 15-minute time interval for depressurization of the reactor vessel was determined based on a steam line break of 0.4 square feet, no HPCI cooling, no automatic blowdown, and depressurization from 1000 psig to 100 psig. This postulated depressurization cannot possibly occur, because if HPCI were available during this time, depressurization would occur in 8 minutes. If HPCI were not available, automatic blowdown of the reactor vessel would occur, depressurizing the vessel at an even greater rate.

6.3.3.1.3.2.1.1 Model for Level Swell Analysis (Historical Information)

The analysis of moisture carryover to the HPCI turbine was based upon a break size of 0.2 square feet which is conservative with respect to the expected level rise corresponding to a steam break of 0.13 square feet. The phenomenon was modeled as described below:

Following a primary system break, the level in the separation region outside the core shroud was determined from the volume of mixture in this region at any time. At the start of the transient, the total mixture volume was known from the position of the water level and the separation region geometry (free surface region around separators). This volume was continuously integrated in the model simulation of reactor blowdown so that level could be tracked.

The rate of change of mixture volume at any time was evaluated from the various flows to and from the separation region. These flows were as follows:

A. Separator flow,

B. Flow to the downcomer, and

C. Free separation of steam from the surface.

The ability of the steam separators to perform their function is dependent on level. When tracking the level after a steam break, it was assumed that separator efficiency becomes zero whenever the level reaches the top of the separators. This minimizes the quality of any two-phase blowdown. This is doubly conservative in that the model ignored steam tunneling, which occurs when the level is only slightly above the separators, and that the steam flow from the upper plenum is injected into the entire mixture volume.

Both the total separator flow and the flow to or from the downcomer were calculated from the current pressure differences. Each of these regions was a pressure node in the overall reactor model; internodal flow calculations included momentum effects.

During the transient, the rate at which steam is separated from the surface of the mixture was determined from the current surface area, the surface quality, and the bubble rise velocity. To maximize any level swell and to minimize the quality of any two-phase carryover to the steam line, it was assumed that the mixture was of uniform quality. In fact, the surface quality would be higher than the average and the free separation rate thus greater than the calculated rate.

A bubble rise velocity of 1 ft/s was used. This was conservative because it resulted in a faster and higher level rise than if a faster bubble rise velocity had been used.

6.3.3.1.3.2.1.2 Moisture Carryover to HPCI - Breaks Smaller than 0.13 Square Feet (Historical Information)

The ECCS performance bar chart (Figure 6.3-1) shows that for pipe breaks above the water surface, the HPCI subsystem is required only for breaks smaller than 0.13 square feet. However, analysis of moisture carryover to the HPCI turbine was based on the original value of 0.2 square feet which was presented in the "old" core cooling model. Therefore, the following analysis is conservative with respect to the expected level rise corresponding to 0.13 square feet. The level rise transient for a 0.2 square foot break inside the drywell is shown in Figure 6.3-17. The break inside the drywell would result in a more severe transient level response than the break which is outside the drywell because ADS would be initiated by the combined reactor low-low level and high drywell signals maintained for 2 minutes. A break outside the drywell would not result in a high drywell pressure; therefore, ADS would not be initiated until after an 8.5-minute delay, if other conditions are met (refer to Section 6.3.2.4.2). However; the ADS initiation with the 8.5-minute logic is not addressed by this analysis.

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.

6.3.3.1.3.2.1.3 Moisture Carryover to HPCI - Breaks Larger than 0.2 Square Feet (Historical Information

For breaks above the water level larger than 0.2 square feet, the level rise would be higher and the moisture content at the HPCI turbine would be greater. If it is postulated that the mixture level is above the steam line elevation when the turbine admission valves are open, as might be the case for steam line breaks above 0.2 square feet, it would still not be possible to form solid water slugs in the steam line. Flashing due to the static pressure drop at the inlet and other local losses would tend to increase the mixture quality and provide turbulent mixing. The nature of two-phase mixture blowdown flow was discussed in Reference 4, and it was demonstrated that slugs will not occur.

6.3.3.1.3.2.1.4 Pressure Rise at HPCI Turbine Due to Moisture Carryover (Historical Information)

It has been experimentally demonstrated that the pressure rise caused by sudden deceleration of a two-phase mixture, such as might occur in the HPCI turbine, is not significantly higher than the pressure rise for steam.[5] The pressure rise was measured following closure of a fast-acting valve (typically 50 milliseconds). Since the acoustic transmission time to the vessel and back to the valve was 70 milliseconds, the valve closure was essentially instantaneous. Thus it is concluded that even if a two-phase mixture did enter the HPCI steam line, no significant pressure rise would occur at the turbine since this deceleration would be less severe than the instantaneous deceleration used in the experiment.

Additional experimental data were also provided by the main steam isolation valve test which was reported in Reference 6. The transition flow tests were started with an established steam/water interface. Even so, the measured pressure rise at the valve indicates that the interface had dispersed by the time it reached the valve. Furthermore, the experimentally measured pressure rise was only about one-third of the analytically calculated value which was based on a discrete steam/mixture interface. It is concluded that even if a water slug did enter the HPCI steam line, it would disperse before reaching the HPCI turbine.

6.3.3.1.3.2.1.5 Evaluation of Effects of Gross Carryover on the HPCI Turbine (Historical Information)

For postulated break sizes where water swell could occur, it is difficult if not impossible to predict whether the HPCI turbine is capable of continued operation while ingesting slugs of water. Based on historic information of similar turbine applications (on naval quick start units), the most detrimental effect of a water slug accident would be thrust bearing failure, resulting in axial interference between rotating and stationary parts. This worst condition would not result in casing failure or any material leaving the turbine casing.[7] Since failure of the turbine casing is not possible, no calculation of radiation release has been made for this hypothetical situation. Gland seal leakage might be possible however.

With the gland seal condenser equipment functioning, a slight vacuum (14.5 psia) is maintained at the turbine shaft seals, and there is no leakage external to the turbine casing. Assuming ultimate failure of the gland seal condenser (with a locked turbine rotor, there will be no cooling water flow to the condenser), it would be possible to have turbine shaft seal leakage external to the machine, assuming the steam supply valves to the turbine remain open. The seal leakage would be 0.6 lb/s or less.

Calculation of radiation release for shaft seal leakage was based on the following source terms:

A. Total coolant activity of 2.4 μCi/cc;

B. A release to the secondary containment of 550 pounds of steam which was assumed to have associated with it the total activity consistent with 550 pounds of liquid;

C. Release of activity to the environment via the standby gas treatment system (filter efficiency for iodine of 99%) and the 310-foot chimney; and

D. In addition to the activity associated with the vaporized liquid, 0.01 curies of noble gas activity are also released to the environment.

Assuming the steam line low pressure signal successfully isolates the turbine loop, a maximum period of 15 minutes will have elapsed, with a maximum external leakage quantity of less than 550 pounds of steam. This total leakage would result in the following released radiation doses:

A. Cloud gamma dose of 3.9×10^{-8} rem, compared with an allowable limit of 25 rem, per 10 CFR 100, and

B. Thyroid inhalation dose of 8.7×10^{-6} rem, compared with an allowable limit of 300 rem, per 10 CFR 100.

It is concluded that even with the most pessimistic combinations of water slug damage (i.e., locked turbine rotor, failed gland seal condenser, and steam isolation not occurring until 15 minutes after scram), the radiation dose rates from external shaft seal leakage are significantly less than the allowable quantities as given in 10 CFR 100.

6.3.3.1.3.2.1.6 Evaluation of HPCI Operation with Fuel Damage (Historical Information)

Radiation monitors are not required on the HPCI turbine gland seal discharge line. The only time the discharge from the HPCI turbine gland seals will be of special concern will be during an accident which involves the perforation of fuel rods. Since rupture of a main steam line will not result in any fuel rod perforations, this type of accident is of no special interest as far as gaseous discharge from the HPCI turbine gland seal condenser is concerned.

The spectrum of break sizes which could result in fuel damage and, hence, transport of activity to the gland seal condenser, have been investigated as a function of location, total rod perforations, and HPCI turbine run time. The results of this investigation have shown that a 0.3 square foot liquid break is the break size of major interest and would result in the perforation of 3.5% of the total fuel rods. For rupture sizes less than 0.3 square feet, no fuel damage occurs. For larger rupture sizes, while the number of perforations may be greater than for a 0.3 square foot break, the actual run time of the HPCI turbine is less, resulting therein in a smaller amount of activity being transferred to the turbine gland seal condenser.

The analysis considers a 0.3 square foot break, perforations of 3.5% of the fuel rods, a HPCI turbine run time of 3 hours, associated flow to the HPCI turbine gland seals and gland seal condenser, and the release rate from the gland seal condenser to the standby gas treatment system and then to the stack. The total amount of activity calculated to be released to the environment would be 6.3×10^{-2} curies of iodine and 3.0×10^{2} curies of noble gases. The release of this activity would result in a thyroid dose of 3×10^{-4} rem and a cloud gamma dose of 3.0×10^{-5} rem.

6.3.3.1.3.3 Summary of HPCI Subsystem Performance (Historical Information)

Based upon performance analysis of equipment provided, it is concluded that the HPCI subsystem will maintain water inventory sufficient to ensure core cooling for small breaks. For larger breaks it will increase vessel depressurization and help maintain liquid inventory. This depressurization will enable the core spray subsystem and/or the LPCI subsystem to provide adequate core cooling.

6.3.3.1.4 Automatic Depressurization Subsystem (Historical Information)

The automatic depressurization subsystem is designed to depressurize the reactor to permit the LPCI and core spray subsystems to cool the reactor core during a small break loss-of-coolant accident; this size break would result in a loss of coolant without a significant pressure reduction, so neither low pressure system could provide adequate core cooling without ADS. 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 6.3.3.1.1. 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. Although some steam cooling would occur during the blowdown phase, no credit was taken for this in the analysis. Moreover, since the ADS does not provide coolant makeup to the reactor, the ADS is considered only in conjunction with the core spray or LPCI subsystems as a backup to the HPCI.

Analyses have shown that full ADS capability can be provided with only four ADS valves operable. To ensure peak clad temperatures do not exceed 2200°F as specified by 10 CFR 50.46, core thermal limits will be adjusted as necessary. Refer to Section 4.2 for a description of the core thermal limits. It has also been determined that the long term (100 days) functional requirements of ADS valves decreases with time, a point will eventually be reached where the energy additions from decay heat will no longer be sufficient to maintain the required operating pressure for the HPCI turbine. However, this point is well below the pressure at which either the LPCI subsystem and/or the core spray subsystem is sufficient to keep the core cooled after the HPCI subsystem shuts off.

Note, however, that the ECCS acceptance criteria are now based on the requirements of 10 CFR 50.46 and the ECCS evaluations are performed in accordance with 10 CFR 50, Appendix K. LOCA break spectrum analysis is performed to determine the characteristics of the pipe break and ECCS performance that result in the highest calculated peak cladding temperature (PCT) during a postulated LOCA. The break characteristics addressed are the break location, break type and break size. The ECCS performance is determined by applying the Appendix K single active failure criterion.

6.3.3.3.2 Large Break Analysis for ATRIUM-9B and 9x9-2 Fuel

A LOCA-ECCS break spectrum[66] applicable to Dresden Units 2 and 3 using NRC approved methodology (EXEM BWR [64]) was performed by Siemens Power Corporation. The worst or limiting break determined from this break spectrum during normal operation is the double-ended guillotine break of the recirculation suction piping with a discharge coefficient of 1.0 coincident with a single failure of the LPCI injection valve. The conditions of the reactor as well as the ECCS capacities and setpoints assumed in the LOCA-ECCS break spectrum analysis are shown in Table 6.3-20. The ECCS leakages and uncertainties accounted for in both Unit 2 and 3 limiting analyses are shown in Tables 6.3-19a, 6.3-19b and 6.3-23 respectively.

As stated above the most limiting single failure assumed in this LOCA analysis is the failure of the LPCI injection valve to open for the intact loop. Table 6.3-21 lists the single failure considered in performing the LOCA-ECCS break spectrum analysis shown in Table 6.3-22.

The LOCA-ECCS analyses taken from Reference 65 for Unit 3 and Reference 67 for Unit 2 and contained in this section were performed for 9x9-2 and ATRIUM-9B fuel designs for the limiting LOCA break identified in Reference 66. The analyses were performed at the expected worst points bounding the operating power-flow map for both Unit 2 and Unit 3.

Analyses previously performed for the Dresden reactors (Reference 68, Section 6.6) have shown very little difference in the peak cladding temperatures (PCTs) calculated for different core flows. It was shown that higher core flows produce slightly higher PCTs. Based on these conclusions the Reference 65, 66 and 67 analyses for 9x9-2 and ATRIUM-9B fuel designs were performed at a core flow corresponding to 100% of rated core flow.

Calculated event time results and LOCA-ECCS results for the limiting break and worst case conditions are given in Tables 6.3-12a, 6.3-12b, 6.3-12c, 6.3-12d, 6.3-13a, and 6.3-13b. The results shown in Tables 6.3-12a and 6.3-12b (metal-water reaction and peak cladding temperature) are for Unit 2. The results shown in Tables 6.3-12c and 6.3-12d (metal-water reaction and peak cladding temperature) are for Unit 3. Representative system blowdown results are presented in Figures 6.3-33 through 6.3-53b.

Representative system refill and reflood results are given in Figures 6.3-54 through 6.3-57. These system conditions are used as boundary conditions for a series of exposure dependent maximum power assembly heatup calculations. Typical calculated temperatures are shown in Figures 6.3-58a and 6.3-58b for ATRIUM-9B and 9x9-2 fuel designs respectively.

The MAPLHGR limits for 9x9-2 and ATRIUM-9B fuel designs during normal operation as a function of exposure were determined based on the limiting operating conditions for the limiting LOCA break identified in Reference 66. The MAPLHGR limits are set high enough such that the fuel design (LHGR) limits are more limiting than the MAPLHGR limits. This is the case for 9x9-2 and ATRIUM-9B fuel at Dresden Unit 2 and Unit 3. The exposure dependent MAPLHGR limits are shown in Figures 6.3-59a through 6.3-59c, and the computed points used to determine these curves are given in Tables 6.3-12a through 6.3-12d. The MAPLHGR limits apply to 9x9-2 and ATRIUM-9B fuels as specified in the Tables for Dresden Unit 2 and Unit 3 during normal operation for both the initial and subsequent reloads of the 9x9-2 and ATRIUM-9B fuel designs.

All calculations were performed with the NRC-approved EXEM/BWR ECCS Evaluation Model in accordance with 10 CFR 50, Appendix K. Operation of the Dresden reactors with 9x9-2 and ATRIUM-9B fuel at or below the MAPLHGR limits of Figures 6.3-59a through 6.3-59c as applicable satisfies the criteria specified by 10 CFR 50.46, and assures that the emergency core cooling system for Dresden reactors will meet the NRC criteria for LOCA breaks up to and including the double-ended severance of a reactor coolant pipe. The acceptance criteria are as follows:

A. The calculated peak fuel element clad temperature does not exceed the 2200°F limit.

B. The amount of fuel element cladding which reacts chemically with water or steam does not exceed 1% of the total amount of Zircaloy in the reactor.

For much larger breaks, the HPCI subsystem has less effect on core spray or LPCI performance, and the results are more like those shown in Sections 6.3.2.1 and 6.3.2.2, respectively.

The integrated performance of the ADS in conjunction with the LPCI subsystem or core spray subsystem for the intermediate break sizes is very similar to the performance of these same combinations for the small break sizes, except depressurization is more easily accomplished with increasing break size. For this reason, the integrated performance of these subsystem combinations is shown in the next section.

6.3.3.5 Small Break Loss-of-Coolant Accident Analysis

6.3.3.3.5.1 Siemens Power Corporation Small Break Analysis for ATRIUM-9B and 9x9-2 Fuel

The SPC LOCA methodology as described in section 6.3.3.2 describes that small breaks (i.e. breaks approximately 1.4 ft2 and smaller) are not limiting with respect to the large breaks. Only split breaks are considered in the small break LOCA analysis; a DEG break is a large break by definition. The most limiting small break is determined by varying the break area and performing a series of LOCA analyses. The range of small break sizes considered in the LOCA ECCS break spectrum[66] extends from the minimum large break size down to a 0.05 ft^2 break. The limiting break size and limiting single failure were analyzed for both suction and discharge recirculation pipe breaks. The potentially limiting single failures that are analyzed for small break LOCAs are the HPCI single failure, the failure of an ADS valve, and the limiting single failure determined from the large break LOCA analysis - LPCI injection valve.

6.3.3.3.5.2 Historical Small Break Analysis

For small breaks the core is protected by the HPCI subsystem (up to point E for liquid breaks and point F for steam breaks on Figure 6.3-1), and by the core spray subsystem or LPCI subsystem in conjunction with the ADS. With normal auxiliary power available, the feedwater-condensate systems will never permit core uncovering for these break sizes.

The performance of the HPCI subsystem for these small break sizes was described in Section 6.3.3.1.3.

Generally the ADS/core spray or ADS/LPCI combinations will not prevent core uncovering as the HPCI subsystem or feedwater-condensate systems do for the small break sizes. However, the ADS is designed to allow the LPCI or core spray subsystems to prevent clad melting for all break sizes down to and including a zero break size.

An example of the ADS/core spray subsystem performance for a typical small break is shown in Figure 6.3-69. The sequence of events during the initial phase of the transient is similar to that discussed in Section 6.3.2.3 for the HPCI subsystem performance. The important difference in the system response for the automatic depressurization case is that vessel pressure hovers near rated for a much longer period of time since the HPCI is assumed to be inoperable and the ADS is not actuated until 120 seconds after the low-low trip level is reached. An additional obvious difference is the more rapid loss of liquid inventory due to the higher vessel pressure and absence of HPCI makeup. When the ADS is actuated, a marked increase in the vessel pressure reduction rate occurs due to the critical steam flow through the relief valves. This increased depressurization rate causes a corresponding increase in water levels inside and outside the shroud. When the water level inside the shroud drops to the top of the jet pumps the water level is sustained except for flashing due to depressurization and boiloff.

C. The first 10 seconds of this accident are similar to the break outside the drywell discussed in Section 15.6.4. However, for the break inside the drywell, closure of the isolation valves reduces the blowdown rate but does not prevent the vessel from depressurizing. The vessel would continue depressurizing through the pipe from the pressure vessel to the break.

During a steam line break, the reactor would be shut down immediately by the voids which would result from the depressurization. A mechanical scram would be initiated by position switches in each main steam isolation valve (MSIV) at approximately 10% valve closure so control rod insertion would begin within 1.5 seconds after the break. Low water level, which would occur later in the blowdown, would also initiate a scram.

The reactor coolant loss through blowdown consists of three intervals: steam blowdown; then mixture blowdown; and finally steam blowdown again. After the accident, steam in each end of the break is accelerated to critical flow. In the short pipe from the pressure vessel, the steam flow will be accelerated to about 3800 lb/s. At the other end of the break, flow would be critical at the steam flow restrictor with a maximum steam flow of 1400 lb/s.

As the reactor vessel depressurizes, the water level rises due to flashing. When the level reaches the steam pipes, the break flow changes from steam blowdown to mixture blowdown. Mass flowrate through the break increases sharply to 12,000 lb/s, at this time, as shown in Figure 6.3-71. At 10.5 seconds the isolation valves are closed, which reduces the blowdown rate. As coolant is expelled and the pressure decreases, the water level in the pressure vessel will drop below the steam pipe elevation and steam blowdown will begin again at approximately 50 seconds. The system depressurization rate would increase, but the mass flowrate through the break would decrease. The long-term pressure transient and water level transient are shown in Figures 6.3-72 and 6.3-73 for the cases of one core spray pump and three LPCI pumps operating.

The reactor core inlet flow transient was calculated with an analytical digital computer code model which simulates the entire vessel. Included in the model is the reactor core heat addition, pump momentum, distributed pressure drops, critical flow, and the effect of water level movements in the vessel. A vapor bubble to liquid relative velocity of 1 ft/s is used in the model.[54,11] The calculated core inlet flow transient is shown in Figure 6.3-74. The initial rapid reduction in core inlet flow is due primarily to the vessel rapid depressurization rate and the corresponding larger pressure differential across the recirculation drive pumps. The assumed simultaneous loss of the normal ac power supply with the postulated accident would cause a loss of the electrical power to pumps thereby resulting in pump coastdown.

The thermal hydraulic transient performance of the reactor fuel was evaluated using a digital computer code transient model which simulates a fuel bundle. Included as input are the dimensions of the bundle, thermal properties of the coolant and the fuel, and time varying pressure and flow, thereby allowing for the evaluation of the condition of the fuel throughout the accident.

The primary purpose of the thermal hydraulic performance analysis of the fuel bundle is to determine if adequate core cooling exists during the blowdown to prevent an overtemperature condition and possible perforation of the fuel rod

The no clad melt criterion was selected for the purpose of designing and sizing ECCS equipment in a consistent manner. The sizing of the ECCS equipment to this criterion of no clad melt necessitated the thermal performance analysis of the core following the postulated break. In order to provide a consistent design approach for ECCS sizing, simplified models and grossly conservative assumptions were used to calculate the core heatup transient. Some basic assumptions included:

A. Dryout cooling during blowdown for the design (recirculation line) break;

B. Core insulated when half uncovered for small break;

C. No steam cooling; and

D. 100% steam availability for metal-water reaction.

Having sized the ECCS equipment in this manner, more refined models have been used to evaluate the actual performance. Instead of simply neglecting cooling phenomena known to exist, a conservative estimate has now been included for most of the important phenomena. Using these more refined models, the performance of the Unit 2 ECCS across the complete break spectrum has been evaluated.

These evaluations demonstrate that the ECCS design criterion of no clad melting is satisfied across the entire spectrum of possible liquid or steam line break sizes by at least two separate and independent systems and by two different modes of core cooling, even in the event of the loss of normal station auxiliary power.

6.3.3.3.10 Appendix K Criterion

The original ECCS design basis of no fuel clad melting was used to size ECCS equipment. In 1974, 10 CFR 50, Appendix K, "ECCS Evaluation Models," was implemented reducing the allowed peak clad temperature to 2200°F.

The Dresden Appendix K analysis does not address the original design basis of fully redundant, diverse, low pressure ECCS systems. The analysis does prove, as required, that the integrated ECCS provides adequate core cooling for the design basis accident assuming a limiting single active failure (e.g., for LPCI injection valve failure, two core spray pumps provide adequate cooling; for diesel generator failure, one core spray and two LPCI pumps provide adequate cooling).

The LOCA Appendix K analysis cases envelope all remaining design basis events with a single failure (see Table 6.3-21).

Additional emergency core cooling capability exists from the feedwater-condensate systems in the more probable event that station auxiliary power is available.

6.3.3.4 Integrated System Operating Sequence

6.3.3.4.1 Design Basis Accident

Since the emergency core cooling system is composed of several subsystems that are designed to perform under specific conditions, the operating sequence must be described for alternate operating conditions.

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 each diesel. The design basis accident (complete severance of the largest coolant pipe) represents the most severe time/load conditions. Therefore, the event sequence shown in Table 6.3-13 is based on this accident condition.

Upon receipt of the accident initiation signal, the LPCI subsystem is initiated first to start the flooding effort as soon as possible (see Section 6.3.2.2 for the description of operation). Because the LPCI admission valves are still closed, the LPCI pumps are started with minimum bypass flow to prevent a dead headed pump condition.

Both core spray subsystems are timed to start after sufficient time has been allowed for starting all LPCI pumps. The core spray subsystems are started with 3% bypass flow to minimize the diesel starting load. The detailed operating sequence for the core spray subsystem is discussed in Section 6.3.2.1.

The LPCI injection valve and each core spray system's injection valves open as soon as the reactor low pressure permissive is cleared.

After 10 minutes, at least one LPCI pump and two containment cooling service water pumps are needed for suppression pool cooling. One LPCI pump or one core spray pump is adequate to maintain two-thirds core coverage, and at least one LPCI pump must operate to provide containment spray cooling. The loads on the diesel under these conditions can be carried indefinitely. Diesel generator 2/3 can then be made available to the non-accident unit.

6.3.3.4.3 Net Positive Suction Head for ECCS Pumps

The evaluation of post LOCA NPSH for core spray and LPCI pumps was divided into two portions:

1. Short Term (less than 600 seconds - no operator action credited-vessel injection phase)

2. Long Term (greater than 600 seconds - operator action credited-containment cooling phase)

It should be noted that the 600 second mark for operator action was established per UFSAR Sections 6.2.1.3.2.3 as the time in which credit for manual initiation of containment cooling can be taken.

6.3.3.4.3.1 CS/LPCI Pump Post-LOCA Short Term Evaluation

A calculation was performed to evaluate LPCI and core spray NPSH requirements in the short-term post-DBA LOCA. Short-term is considered the time period from initiation of the design basis LOCA until 10 minutes post-accident when operator action is credited.

The most limiting single failures (SFs) relating to Peak Clad temperature (PCT) were considered:

1. SF-LPCI: Failure of a LPCI injection valve

   This case results in two (2) core spray pumps injecting at maximum flow with four (4) LPCI pumps running on minimum flow only.

2. SF-DG: Loss of Diesel Generator

   This case results in two (2) LPCI pumps and one (1) core spray pump injecting at maximum flow.

The most limiting failure with regards to LPCI/CS pump NPSH, however, is failure of the LPCI Loop Select Logic (SF-LSL). This scenario involves the LPCI pumps injecting into a broken reactor recirculation loop and is discussed in detail in GE SIL 151. From a PCT perspective, this case is identical to the SF-LPCI case since the net result of each scenario is two core spray pumps injecting into the core with no contribution from the LPCI pumps. SF-LSL is the NPSH limiting scenario due to the LPCI/CS pumps operating at the highest achievable flow rates, resulting in the maximum pump suction losses and NPSH requirements. Additionally, the LPCI water escaping to the containment results in reduced containment and suppression pool pressures, which limit the available NPSH, see Section 6.2.1.3.2.2. Both the SF-LSL and SF-DG single failure cases were evaluated in the calculation. The SF-LPCI case is bounded by the SF-LSL case.

The calculations use the following inputs:

1. Maximum LPCI and core spray pump flow conditions (un-throttled system, reactor pressure at 0 psid), maximizing suction friction losses and NPSH required.

    a. Maximum LPCI and core spray pump flows-case SF-LSL

CS	1-Pump Maximum Injection Flow:	5800 gpm
LPCI	3-Pump Maximum Injection Flow:	16,750 gpm [5,610/11,140]
LPCI	4-Pump Maximum Injection Flow:	20,600 gpm

b. Maximum LPCI and core spray pump flows-case SF-DG

CS	1-Pump Maximum Injection Flow:	5800 gpm
LPCI	2-Pump Maximum Injection Flow:	11,600 gpm

2. Increased clean, commercial steel suction piping friction losses by 15% to account for potential aging effects, thus maximizing suction losses.

3. To account for strainer plugging, each of the four torus strainers is assumed partially plugged.

4. Containment conditions used in the analysis are given in UFSAR Section 6.2.1.3.2.3 which minimize the NPSH available.

5. Initial suppression pool temperature is 95°F which is the maximum allowable pool temperature under normal operating conditions. This value is used as the initial pool temperature to maximize pool peak temperature, and is used as a minimum temperature during the LOCA to maximize piping friction losses (maximum viscosity).

6. The minimum suppression pool level elevation using a maximum drawdown of 2.1 ft. is 491'5", (491.4 ft). LPCI and core spray pump centerline elevation is 478.1 ft.

7. The suppression pool strainers have a head loss of 5.8 ft. @ 10,000 gpm, for each of the four partially plugged strainers.

8. NPSHR values at various LPCI/CS pump flows are taken from the vendor pump curves.

The minimum suppression pool pressure required to meet LPCI/CS pump NPSH requirements was determined for both the SF-LSL and SF-DG single failure cases. The minimum pool pressure required was compared to the minimum pool pressure available post-LOCA for two cases:

- Case 6a2 with 60% thermal mixing used for SF-LSL containment conditions.

- Case 2a1 with 100% thermal mixing used for the SF-DG containment conditions.

If the pressure available is greater than the pressure required, then adequate NPSH exists. If the available pressure is less than the pressure required, then the potential exists for the pumps to cavitate, resulting in reduced flows.

For the SF-LSL case, no cavitation is expected to occur for the first 240 seconds post-LOCA. During this time, the LPCI and CS pumps will deliver maximum flow of 5800 gpm per pump. Since PCT occurs at about 170 seconds, the CS pumps will deliver adequate flow to ensure no impact on PCT. After 240 seconds, the LPCI and CS pumps may cavitate, resulting in reduced flows. The CS pump NPSH deficit reaches a maximum of 6.87 feet at 600 seconds. Under these conditions for NPSH, core spray pump flow will reduce from 11,600 gpm (5800 gpm per pump) at 240 seconds to about 10,560 gpm (5280 gpm per pump). This represents the minimum expected flow from the core spray pump for the 240 to 600 second interval.

As stated above, a potential exists for the LPCI and CS pumps to cavitate after the first 240 seconds post-LOCA. However, as part of the original design of the plant, the pump vendor performed a cavitation test on a LPCI pump (a Quad Cities (RHR) pump was actually used). The Cavitation Test Report for Bingham 12x14x14x1/2 CVDS pump demonstrated no evidence of any damage to the pump components from cavitation with up to one hour of operation at the cavitating condition.

This analysis was reviewed with respect to the core spray pump and the results determined to be applicable. The rationale for this determination is the following:

- Core spray and LPCI are the same make and model pump (only impeller diameter is different).
- LPCI and core spray utilize the same impeller pattern, and therefore the same overall characteristics.
- All LPCI and core spray pumps have tested NPSHR curves that are essentially identical (within 1%).

For the SF-DG case, adequate suppression pool pressure is available to satisfy LPCI/CS pump NPSH requirements for the entire 10 minute period. That is, no LPCI/CS pump cavitation will occur, nor will any reduction take place from 5800 gpm for core spray and 11,600 gpm for LPCI (5800 gpm per pump).

LPCI/CS pump flow requirements are as follows:

- For the SF-LSL and SF-LPCI cases, a two-pump core spray flow of ≥ 11,300 gpm up to the 200 second mark results in a PCT of ≤ 2030 °F.
- For the SF-DG case, a two-pump LPCI flow of at least 9000 gpm and a single core spray pump flow of at least 5650 gpm are required for PCT considerations.
- Only a constant nominal total pump flow of 9000 gpm is required to achieve 2/3 core reflood in less than 5 minutes.

Therefore, under the most limiting single failures, the ECCS will still perform its function in the short term with no credit for operator action.

6.3.3.4.3.2 CS/LPCI Pump Post-LOCA Long Term Evaluation

The evaluation examined the net positive suction head (NPSH) available to the Dresden LPCI and core spray (CS) pumps after the first 600 seconds following a DBA LOCA for several pump combinations.

If the suppression pool pressure available is greater than the pressure required for adequate NPSH to the LPCI and CS pumps, then these pumps have adequate NPSH for operation. If the suppression pool pressure available is less than the pressure required by the pumps, then there is inadequate NPSH for operation and there is a potential for pump cavitation. In these situations, LPCI pump flows were reduced below nominal values and new cases were run to establish the ability of the operator to throttle the pumps to an acceptable condition.

A spectrum of pump combinations was explored to determine the bounding NPSH case for the LPCI and core spray pumps. It will be shown that the 4 LPCI/2 CS pump case is bounding for NPSH.

The calculation uses the following inputs:

1. Various LPCI and core spray pump flow conditions are evaluated (See Table 6.3-18).

2. Increased clean, commercial steel suction piping friction losses by 15% to account for potential aging effects, thus maximizing suction losses.

3. It is assumed that at 10 minutes into the accident, operator action will be taken to ensure that the LPCI/CS pumps have been throttled to their rated flows (5000 and 4500 gpm respectively). Therefore, the pumps are at their rated flows at the time of peak suppression pool temperature (~20,000 seconds).

4. To account for strainer plugging, each of the four torus strainers is assumed partially plugged.

5. Initial suppression pool temperature is 95 °F. This is the maximum allowable suppression pool temperature under normal operating conditions.

6. The containment pressure and pressure responses provided in case 2a1 with 20% mixing as shown in UFSAR Section 6.2.1.3.2.3 are used. These responses result in the bounding NPSH case.

7. The minimum torus level elevation with a maximum drawdown of 2.1 ft is 491.4 ft. At the time of peak suppression pool temperature, a recovery of 1.1 ft occurs, resulting in a net drawdown of 1 ft.

8. The torus strainers have a head loss of 5.8 ft @ 10,000 gpm, for each of the four partially plugged strainers.

9. LPCI and core spray pump centerline elevation is 478.1 ft.

The calculation determined the minimum suppression pool pressure required to meet pump NPSH requirements for several ECCS pump combinations. The calculation shows that adequate NPSH exists to meet core spray pump requirements post-LOCA for all ECCS pump combinations. However, potential exists for the LPCI pumps to cavitate at rated flows as shown in Table 6.3-18. For these cases, throttling of the LPCI pumps to below rated flows may be required to ensure NPSH requirements are met. A minimum of 5000 gpm total LPCI flow is required for containment cooling. Table 6.3-18 provides NPSH margin for throttled LPCI cases.

The containment analysis used to determine minimum containment pressures was performed with containment sprays on from 600 seconds through accident termination. In order to more closely tie containment pressure to NPSH requirements, the Emergency Operating Procedures provide guidance to the operators to terminate sprays at pressures up to 6 psig when required to ensure adequate NPSH for the LPCI and core spray pumps. NPSH calculations show that 3.21 psig containment overpressure is required for no cavitation during long term post-LOCA conditions with 4 LPCI and 2 core spray pumps operating at rated flows. The value of 6 psig for consideration of containment sprays provides an additional 2.79 psig margin. Operating procedures provide directions for operating sprays so that containment pressure will be maintained within the pressure required for adequate NPSH and the spray initiation pressure of 9 psig.

Operators have been trained to recognize cavitation conditions and to protect their equipment by throttling flow if evidence of cavitation should occur due to inadequate NPSH. The control room has indication of both discharge pressure and flow on each division of core spray and LPCI. The Emergency Operating Procedures (EOPs) also provided guidance to maintain adequate NPSH for the core spray and LPCI pumps. The NPSH curves provided in the EOPs utilize torus bulk temperature and torus bottom pressure to allow the operator to determine maximum pump or system flow with adequate NPSH. These curves are utilized as long as the core is adequately flooded.

6.3.3.4.3.3 NPSH Margin

Figure 6.3-80 gives a graphical representation of the minimum required containment pressure to meet NPSH requirements for both LPCI and core spray pumps. The chart covers both the short-term (≤ 600 seconds) and long-term (> 600 seconds) periods.

The containment pressure response shown on the chart, and covered in UFSAR Section 6.2.1.3.2.3, is for the following pump combinations over the short and long-term periods:

≤ 600 sec 4 LPCI pumps/2 CS pumps Case 6a2-60% thermal mixing
> 600 sec 1 LPCI pump/1 CS pump Case 2a1-20% thermal mixing

The LPCI and core spray required containment pressure on the chart is for the following limiting pump combinations and flows over the short and long-term periods:

≤ 600 sec 4 LPCI pumps @ 5150 gpm each /2 CS pumps @ 5800 gpm each
> 600 sec 2 LPCI pumps @ 2500 gpm and 1 LPCI pump @ 5000 gpm/2 CS pumps @ 4500 gpm each

At runout flows, the core spray pumps have the potential to cavitate for a short period of time (240 sec - 600 sec) during the ≤ 600 second period. This is acceptable per the discussion in UFSAR Section 6.3.3.4.3.1. Figure 6.3-80 also shows the ability to throttle the core spray and LPCI pumps to an acceptable long term operating condition as discussed in UFSAR Section 6.3.3.4.3.2.

6.3.3.4.3.4 Containment Overpressure

Adequate net positive suction head for the low pressure ECCS pumps is credited as follows:

Time Period (seconds)	Containment Overpressure (psig)
0 - 240	9.3
240 - 480	2.9
480 - 6000	1.9
6000 - accident termination	2.5

This is graphically shown in Figures 6.3-83 and 6.3-84.

During a LOCA, the operator's concern will be restoration of the vessel water level. The LPCI flow will be among the parameters closely monitored in the minutes immediately after the LOCA. The operator has several motor-operated valves available to him in the main control room to adjust flowrates or even isolate flow paths. It is, therefore, concluded that operator observation and response to flow conditions will be completed shortly after the LOCA.

Because of the falling head characteristics of these pumps, the brake horsepower requirements are nearly constant from 4000 to 6000 gal/min. It is thus concluded that no overload will occur for either the LPCI pumps or for the emergency diesel generators powering them in the event of a loss of offsite power.

It is, therefore, concluded that for the conditions evaluated, no threat to the long-term cooling capability exists.

Hence, adequate NPSH is ensured at all times to allow continuous operation of the LPCI and core spray pumps.

6.3.3.4.3.5 HPCI NPSH

The HPCI subsystem takes suction from the condensate storage tank which remains cold throughout the plant cooldown so that the NPSH available is unaffected by torus heatup. If suction were taken from the torus, the maximum torus water temperature would be less than 140°F and the minimum NPSH available would be 30 feet compared to the 25 feet required by the HPCI pump.

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39. Shapiro, "Compressible Fluid Flow", Vol. I, p. 17.

40. Moody, F.J., "Maximum Two Phase Vessel Blowdown from Pipes," ASME Paper No. 65-WA/HT-1.

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42. Ianni, F.W.; Fritz, J.R.; and Law, D.D., "Design and Operating Experiences of the ESADA Vallecitos Experimental Superheat Reactor (EVESR)," APED-4784, 1965.

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66. LOCA Break spectrum Analysis for Dresden Units 2 and 3, EMF-97-025(P), Revision 1, Siemens Power Corporation, May 1997.

67. Dresden LOCA-ECCS Analysis MAPLHGR Limits for ATRIUM-9B and 9x9-2 Fuel, EMF-98-007(P), Supplement 2, Siemens Power Corporation, January 1998.

68. LOCA Break Spectrum Analysis for Dresden Units 2 and 3, EMF-95-140(P), Revision 1, Siemens Power Corporation, September 1996.

Table 6.3-1

EMERGENCY CORE COOLING SYSTEM SUMMARY[5]

Function	Number of Operating Pumps	Design Coolant Flow (gal/min)	Delivery Pressure Range	Required Electrical Power	Additional Backup Systems
Core Spray[1]	1	4500 at 90 psid[4]	<260 psid	Normal auxiliary power or emergency diesel generator	Second core spray subsystem and LPCI subsystem
LPCI[1]	3	8000 at 200 psid[4] 14,500 at 20 psid[4]	<275 psid	Normal auxiliary power or emergency diesel generator	Core spray subsystems and fourth LPCI pump
HPCI[2]	1	5600 constant	1135 to 165 psia	DC battery system for control and AC power for room cooler fan[3]	Automatic depressurization plus core spray and LPCI

Notes:

1. Automatic startup of the core spray and LPCI systems is initiated by: reactor low-low water level and reactor low pressure, drywell high pressure, or reactor low-low water level continuing for 8.5 minutes.
2. Automatic startup of the HPCI system is initiated by: reactor low-low water level, or drywell high pressure.
3. Reactor steam-driven pump.
4. Differential pressure between the reactor and primary containment.
5. This information is historical and is not needed to support the current design basis.

Table 6.3-2

SUMMARY OF OPERATING MODES OF EMERGENCY CORE COOLING SYSTEMS[(2)]

A. Loss of Normal Auxiliary Power Alternate systems:[(1)]

Isolation condenser system and ADS	or	HPCI subsystem

B. Small Line Break Only (no loss of normal auxiliary power) Alternate systems:

Feedwater system	or	HPCI subsystem

C. Large Line Break (no loss of normal auxiliary power) Alternate systems:

Two core spray subsystems	or	One core spray subsystem and one LPCI loop (two pumps)

D. Small Line Break Plus Loss of Normal Auxiliary Power (standby diesel available) Alternate systems:

HPCI subsystem	or	ADS plus core spray subsystem and LPCI subsystem

E. Large Line Break Plus Loss of Normal Auxiliary Power (standby diesel available) Alternate systems:

Two core spray subsystems	or	One core spray subsystem and one LPCI loop (two pumps)

F. Post-Accident Recovery Alternate system:

Standby coolant supply system

Sensible heat is removed from the primary containment by operation of the containment cooling subsystem.

Notes:

1. Available alternate systems, any one of which will provide the necessary cooling function.
2. This information is historical and is not needed to support the current design basis.

Table 6.3-3

CORE SPRAY EQUIPMENT SPECIFICATIONS

PUMPS	
Number	2
Type	single stage, vertical, centrifugal
Speed	3600 rpm
Seals	Mechanical
Drive	Electric motor
Power source	Normal auxiliary or standby diesel
Pump casing	Cast steel
Impeller	Stainless Steel
Shaft	Stainless steel
Flow	See Figure 6.3-4
Head	See Figure 6.3-4
Power	880 hp at rated conditions
NPSH (available)	See Section 6.3.3.4.3
PUMP CASING CODES	
Code	ASME Section III, Class C (1965)
Fracture toughness	The test requirements for the Core Spray Pumps were reviewed to NUREG-0577, October 1979, requirements as outlined in the NRC "Additional Guidance to NUREG-0577" letter from D.G. Eisenhut, Director, Division of Licensing NRC, dated May 20, 1980. Based on the material being in a heat-treated condition, the estimated value of the NDT temperature from Table 4.4 of NUREG-0577 is +- 75°F and, therefore, meets the criteria of Part I - Fracture Toughness as given in D.G. Eisenhut's letter.
Material	Carbon steel A 216, Grade WCB. Two copies per unit are provided.
Testing	Impact testing required per ASME Section III (1965). No records exist to verify such testing; however, the Bingham Pump Co. Engineering Data Sheet states, "Test bars are to be heat-treated in the same furnace charge through the same heat-treated cycle as the parts which they represent." This would indicate that impact testing was performed and did meet the code requirements permitting casing certification.

Table 6.3-4

ECCS LOADING SEQUENCE

Sequence	Elapsed Time (seconds)	Event	Condition
1	0	Design basis accident	
2	3	High drywell pressure; diesel generator start signal	
3	16	Start and run isolation valves	
4	20	Start LPCI pump A and C[1]	minimum flow bypass
5	25	Start LPCI pump B and D[1]	minimum flow bypass
6	30	Start core spray pump A and B[1]	3% bypass flow to 70% speed; 100% flow at speed

Note:

1. One pump on each diesel generator.

Table 6.3-7

HPCI EQUIPMENT SPECIFICATIONS

TURBINE	
Steam pressure inlet	1125 to 155 psia
Exhaust (maximum)	65 psia
Steam Temperature	558°F to 360°F
Speed	4000 to 2000 rpm(2)
Power	5000 to 1000 hp(2)
Number of stages	2
Emergency starting	25 seconds
Steam flow	145,000 to 102,500 lb/hr
PUMP	
Number	1 main, 1 booster
Type (main)	multi-stage, horizontal, centrifugal
(booster)	single-stage, horizontal, centrifugal, gear-driven
Discharge pressure	1135 to 165 psia
Flow	5600 gal/min constant
NPSH (minimum)	25 ft
PUMP CASING CODES	
Code	ASME Section III, Class C (1965) per GE Pump Data Sheet
Fracture toughness	The test requirements for the core spray, LPCI, and HPCI Pumps were reviewed to NUREG-0577, October 1979, requirements as outlined in the NRC "Additional Guidance to NUREG-0577" letter from D.G. Eisenhut, Director, Division of Licensing NRC, dated May 20, 1980. Based on the material being in a heat-treated condition the estimated value of the NDT temperature from Table 4.4 of NUREG-0577 is +- 75°F and therefore meets the criteria of Part I - Fracture Toughness as given in D.G. Eisenhut's letter.
Material	Carbon steel A 216, Grade WCB. Material data sheets show the tensile and chemical properties of the pump casings. The Dresden Unit 2 heat numbers are 5744 and 5738. Two casings per unit are provided.

Table 6.3-7 (Continued)

HPCI EQUIPMENT SPECIFICATIONS

PIPING, FITTINGS, AND VALVES	
Material	Carbon steel, A106, Grade B
Testing	System is exempted from impact testing per the current ASME Section III, Article NC 2311-a9 for Class 2 components, because all piping over 6 inches in diameter and 5/8-inch wall thickness is steam piping with lowest service temperatures exceeding 150°F.
Control Power	250/125 Vdc.[(1)]

Note:

1. See reference 6.3.5-63.
2. Although the turbine was tested by the manufacturer down to 2000 rpm/1000 hp, per GEK-15545 as installed the HPCI turbine speed and power low end ranges are limited by the MGU low speed stop (LSS) of 2250 rpm, which corresponds to a power range low limit of 1350 hp.

Table 6.3-11

Deleted

Table 6.3-12a

DRSDEN UNIT 2 LOCA ANALYSIS RESULTS FOR SPC 9x9-2 RELOAD FUEL

Average Planar Exposure (GWd/MTU)	MAPLHGR (kW/ft)[3]	Local Metal-Water Reaction (%)	Peak Clad Temperature[4] (°F)
0	11.75	1.16	1917
5[1]	11.75	0.98	1909
5[1]	12.5	1.35	2041[2]
10	12.5	1.25	2000
15	12.5	1.24	1998
20	11.9	0.94	1906
25	11.3	0.72	1834
30	10.7	0.55	1768
35	10.1	0.41	1697
40	9.5	0.30	1634
45	8.9	0.21	1568
50	8.3	0.14	1497
55	7.7	0.09	1424

Note: Core average metal-water reaction is <0.12% at all exposures.

[1]LOCA analysis results for the MAPLHGR values at 5 GWd/MTU permit operation at the higher MAPLHGR. At 0 GWd/MTU a MAPLHGR of 12.5 yields unacceptable peak cladding temperatures.

[2]The analysis of Reference 67 resulted in PCT at different exposure points in order to determine the limiting PCT. For subsequent LOCA evaluations, only the limiting PCT was recalculated. The original PCT from Reference 67 was 2018 deg F.

[3]The MAPLHGR limits presented here are used to generate the PCT. Cycle specific limits are provided in the Dresden Administrative Technical Requirements.

[4]All LOCA PCT evaluations performed are reported to the NRC per 10CFR50.46. The UFSAR is marked up for updates within 90 days of the submittal. The 10 CFR 50.46 letter is on file at the site. Between UFSAR updates the latest PCT is tracked by Nuclear Fuel Management or the cognizant equivalent.

Table 6.3-12b

DRESDEN UNIT 2 LOCA ANALYSIS RESULTS FOR SPC ATRIUM-9B RELOAD FUEL

Average Planar Exposure (GWd/MTU)	MAPLHGR[2] (kW/ft)	Local Metal-Water Reaction (%)	Peak Clad Temperature[3] (°F)
0	13.5	1.72	1987[1]
5	13.5	1.61	1963
10	13.5	1.09	1906
15	13.5	1.02	1889
20	13.5	0.99	1880
25	12.9	0.75	1815
30	12.3	0.59	1746
35	11.7	0.47	1688
40	11.1	0.37	1655
45	10.5	0.28	1601
50	9.9	0.20	1539
55	9.3	0.14	1473
60	8.7	0.09	1404

Note: Core average metal-water reaction is <0.12% at all exposures.

[1]The analysis of Reference 67 resulted in PCT at different exposure points in order to determine the limiting PCT. For subsequent LOCA evaluations, only the limiting PCT was recalculated. The original PCT from Reference 67 was 1998 deg F.

[2]LUAs have different MAPLHGR limits which are provided in the Dresden Administrative Technical Requirements.

[3]All LOCA PCT evaluations performed are reported to the NRC per 10 CFR 50.46. The UFSAR is marked up for updates within 90 days of the submittal. The 10 CFR 50.46 letter is on file at the site. Between UFSAR updates the latest PCT is tracked by Nuclear Fuel Management or the cognizant equivalent.

Table 6.3-12c

DRESDEN UNIT 3 LOCA ANALYSIS RESULTS FOR SPC 9x9-2 RELOAD FUEL

Average Planar Exposure (GWd/MTU)	MAPLHGR (kW/ft)[2]	Local Metal-Water Reaction (%)	Peak Clad Temperature[3] (°F)
0	12.5	1.09	1956[1]
5	12.5	0.91	1905
10	12.5	0.79	1886
15	12.5	0.77	1881
20	11.9	0.61	1824
25	11.3	0.48	1749
30	10.7	0.37	1684
35	10.1	0.27	1626
40	9.5	0.19	1564
45	8.9	0.13	1497
50	8.3	0.09	1424
55	7.7	0.06	1354

Note: Core average metal-water reaction is <0.12% at all exposures.

[1]The analysis of Reference 65 resulted in PCT at different exposure points in order to determine the limiting PCT. For subsequent LOCA evaluations, only the limiting PCT was recalculated. The original PCT from PCT from Reference 65 was 1920 deg F.

[2]The MAPLHGR limits presented here are used to generate the PCT. Cycle specific limits are provided in the Dresden Administrative Technical Requirements.

[3]All LOCA PCT evaluations performed are reported to the NRC per 10 CFR 50.46. The UFSAR is marked up for updates within 90 days of the submittal. The 10 CFR 50.46 letter is on file at the site. Between UFSAR updates the latest PCT is tracked by Nuclear Fuel Management or the cognizant equivalent.

Table 6.3-12d

DRESDEN UNIT 3 LOCA ANALYSIS RESULTS FOR SPC ATRIUM-9B RELOAD FUEL

Average Planar Exposure (GWd/MTU)	MAPLHGR[2] (kW/ft)	Local Metal-Water Reaction (%)	Peak Clad Temperature[3] (°F)
0	13.5	0.80	1861[1]
5	13.5	0.78	1838
10	13.5	0.71	1815
15	13.5	0.66	1799
20	13.5	0.64	1789
25	12.9	0.50	1722
30	12.3	0.41	1673
35	11.7	0.33	1645
40	11.1	0.25	1591
45	10.5	0.18	1532
50	9.9	0.13	1469
55	9.3	0.09	1403
60	8.7	0.06	1338

Note: Core average metal-water reaction is <0.12% at all exposures.

[1]The analysis of Reference 65 resulted in PCT at different exposure points in order to determine the limiting PCT. For subsequent LOCA evaluations, only the limiting PCT was recalculated. The original PCT from Reference 65 was 1838 deg F.

[2]The MAPLHGR limits presented here are used to generate the PCT. Cycle specific limits are provided in the Dresden Administrative Technical Requirements.

[3]All LOCA PCT evaluations performed are reported to the NRC per 10 CFR 50.46. The UFSAR is marked up for updates within 90 days of the submittal. The 10 CFR 50.46 letter is on file at the site. Between UFSAR updates the latest PCT is tracked by Nuclear Fuel Management or the cognizant equivalent.

Table 6.3-18

LONG-TERM NPSH MARGIN

NPSH margins at flow rates of 5000 gpm LPCI and 4500 gpm CS:

LPCI/CS Pumps	Minimum LPCI Margin (ft)	Minimum CS Margin (ft)
4/2	-1.69	4.54
3/2	0.01	6.21
2/2	1.37	7.56
1/2	3.79	8.56

NPSH margins with throttled LPCI flows:

LPCI/CS Pumps (LPCI flow rates per pump) With all CS flow rates @ 4500 gpm per pump	Minimum LPCI Margin (ft)	Minimum CS Margin (ft)
4/2 (2500)	11.33	7.52
3/2 (2500/5000)*	2.76	7.52
2/2 (2500)	12.37	8.56
1/2 (5000)	3.79	8.56

* Two pumps @ 2500, one pump @ 5000

Table 6.3-19a

DRESDEN UNITS 2 & 3 LEAKAGE CURRENTLY CALCULATED AND ANALYZED FOR LOSS-OF-COOLANT ACCIDENTS

Source	Current Unit 2 Calculated Leakage (gpm)	Current Unit 3 Calculated Leakage (gpm)	Currently Analyzed Leakage Unit 2 (gpm)	Currently Analyzed Leakage Unit 3 (gpm)
RPV penetration assembly Design leakage (2-loop)	2 x 190 380 total	2 x 115 230 total	500 (1)	500 (1)
Upper T-box vent hole leakage (2-loop)	2 x 8 16 total	2 x 8 16 total	0 (1)	0 (1)
Core spray piping weld cracks End-of-Cycle leakage (3) (2-loop)	14	10+11 21 Total	0 (1)	0 (1)
Core shroud weld cracks	184	0	184	184
Access hole cover	78 (4)	0	78 (4)	78 (4)
Bottom head drain line	295 (2)	295 (2)	295	295

(1) The 500 gpm of RPV assembly penetration leakage listed in the table is equivalent to 500 gpm of total leakage for the RPV assembly leakage, Upper T-box vent hole leakage, and the CS line postulated crack leakage. Since all of these leakages occur in the CS line between its entry into the vessel and the penetration of the core shroud, the distribution of these leakages is insignificant. Conservatively, none of the Core Spray leakage flow is credited to enter the vessel.

(2) The bottom head drain was recalculated by Siemens Power Corporation and determined to be 295 gpm, which is greater than the value of leakage assumed in the previous analysis. It should be noted that this increase in bottom head drain leakage was explicitly accounted for in the current analysis[64].

(3) The end-of cycle crack lengths (including unit specific projected crack growth) were used to calculate the leakages.

(4) The leakage through the access hole cover is a function of reactor water level as described in Section 6.3.2.2.3.1, but for LOCA analysis purposes, this value is assumed to be constant at the maximum predicted value as shown in Table 6.3-6.

Table 6.3-19b

Dresden Units 2 & 3 Jet Pump Leakage
Currently Calculated and Analyzed for
Loss-of-Coolant Accidents

Source	Current Unit 2 Calculated Leakage (GPM)	Current Unit 3 Calculated Leakage (GPM)	Currently Analyzed Leakage Unit 2 (GPM)	Currently Analyzed Leakage Unit 3 (GPM)
Jet pump bolted joint (total for 10 jet pumps)	582	582	582	582
Jet pump slip joints (total for 20 jet pumps)	225	225	225	225
Jet pump riser crack	11	NA	11	0

Table 6.3-20

Significant Input Parameters Used in the Dresden 2 & 3 LOCA Analysis for Siemens Fuel

<u>Core Spray System</u>		
Reactor Pressure Permissive for Opening Injection Valve	psig	300
Minimum rated flow at vessel pressure for one loop	gpm psid*	4500[1] 90
Maximum allowed (runout) flow	gpm	5650 / 5300[3]
System Head-flow Delivery characteristics	psid/gpm*	260/0 90/4500 0/5650 0/5300[3]
<u>Initiating Signals</u>	<u>Units</u>	<u>Analysis Value</u>
Low-Low water level or	inches (relative to instrument zero)	-59.0
High Drywell Pressure	psig	2.5
Maximum allowable time delay from initiating signal to pump at rated speed	sec	33.0
Maximum Allowable Injection Valve Stroke Time [2]	sec	30.0
Maximum Pressure at which core spray injection vavle may open	psigi	300.0

* Differential pressure is between reactor vessel and primary containment.

[1] This flow is reduced by the values in table 6.3-19 and Table 6.3-23 to account for known leakages and ECCS instrument uncertainties respectively.

[2] Partial credit for this flow is assumed as the injection valve opens.

[3] See EMF-97-031(P), Revision 1, Unit 2 has a reduced CS runout flow.

Table 6.3-20

Significant Input Parameters Used in the Dresden 2 & 3 LOCA Analysis for Siemens Fuel

High Pressure Coolant Injection System		
Operating Vessel Pressure range	psid*	1120 – 150
Minimum rated flow over the above range	gpm	5000[1]
Initiating Signals	Units	Analysis Value
Low-Low water level or	inches (relative to instrument zero)	-59.0
High Drywell Pressure	psig	2.5
Maximum allowable time delay from initiating signal to rated flow available and injection valve full open	sec	35.0

* Differential pressure is between reactor vessel and primary containment.

[1] This flow is reduced by the values in table 6.3-23 to account for ECCS instrument uncertainties.

Table 6.3-20

Significant Input Parameters Used in the Dresden 2 & 3 LOCA Analysis for Siemens Fuel

Automatic Depressurization System		
Total Number of valves installed		5
Number of vavles used in analysis		4
Minimum flow capacity of any four valves at vessel pressure	lbm/hr psid	2.16×10^6 1135
Initiating Signals	Units	Analysis Value
Low-Low water level or	inches relative to instrument zero	-59.0
High Drywell Pressure and	psig	2.5
Delay time after initiating signals until the valves are open and	sec	120.0
Low pressure ECCS pump (CS or LPCI) running with sufficient discharge pressure (Low Pressure Interlock) or	psig	≥ 100 and ≤ 150
Low-Low water level and	inches relative to instrument zero	-59.0
Maximum Time Delay after initiating signal and	sec	600
Low pressure ECCS pump (CS or LPCI) running with sufficient dishcarge pressure (Low Pressure Interlock)	psig	50
ADS close on vessel pressure	psig	50.0

Table 6.3-21

Dresden Units 2 & 3 Single-Failure Evaluation for Siemens Fuel

Assumed Failure	ECCS System Available			
LPCI Injection Valve		2 LPCS	HPCI*	ADS (4 valves)**
Diesel Generator or 125 VDC	2 LPCI	1 LPCS	HPCI*	ADS (4 valves)**
HPCI System or 250 VDC	4 LPCI	2 LPCS		ADS (4 valves)**
One ADS Valve	4 LPCI	2 LPCS	HPCI*	ADS (3 valves)**
Loop Selection Logic***	4 LPCI	2 LPCS	HPCI*	ADS (4 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 Dresden ADS has five valves. One valve is assumed inoperable to support relief valve out-of-service operation (RVOOS). ADS single failure analyses assume failure of one additional valve.

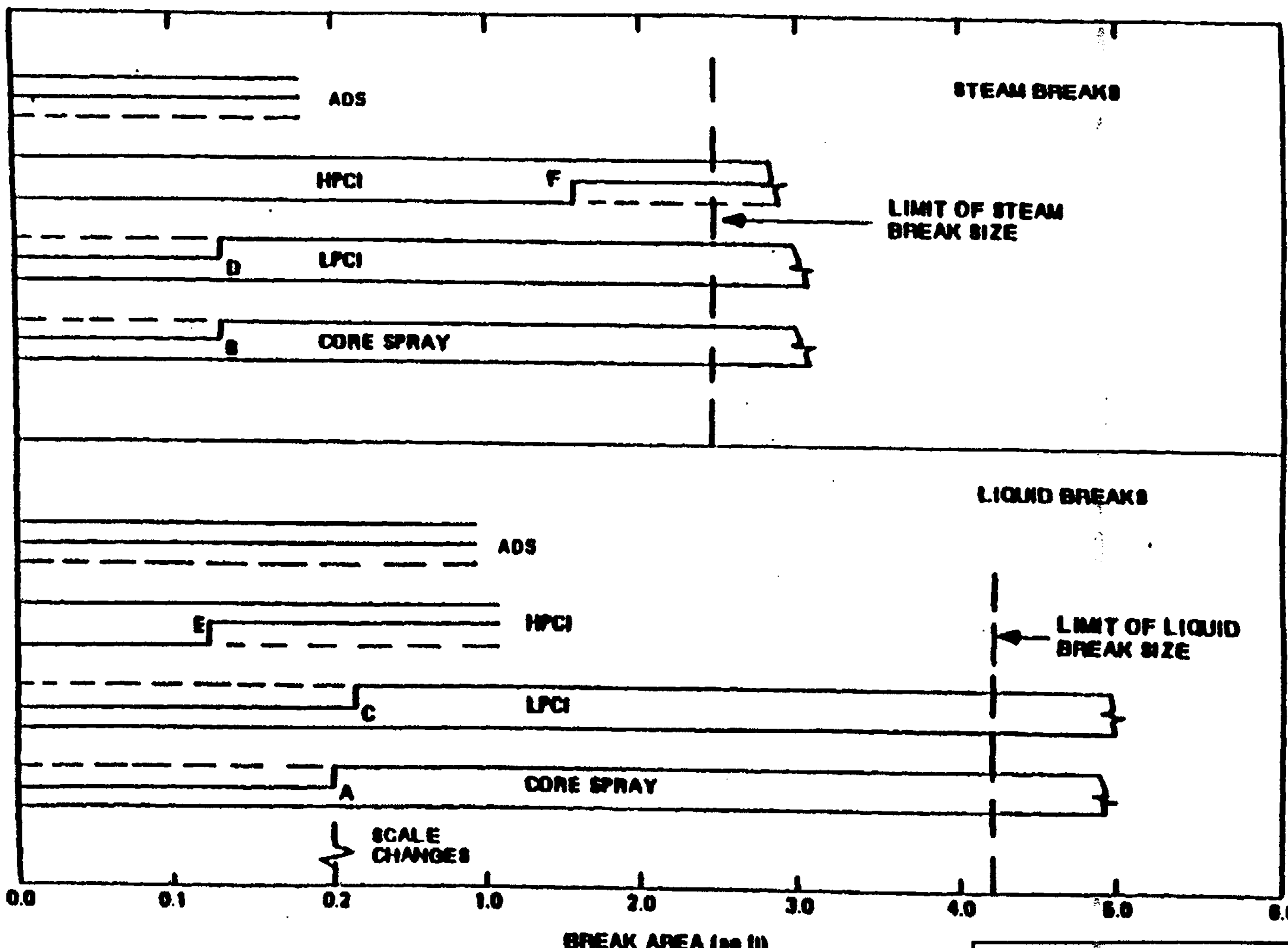
*** Failure to select the unbroken loop and to achieve the alignment for all 4 LPCI pumps to inject into the unbroken loop.

Table 6.3-23

ECCS Uncertainties Assumed in the LOCA Analyses for ATRIUM-9B and 9x9-2 Fuel[1]

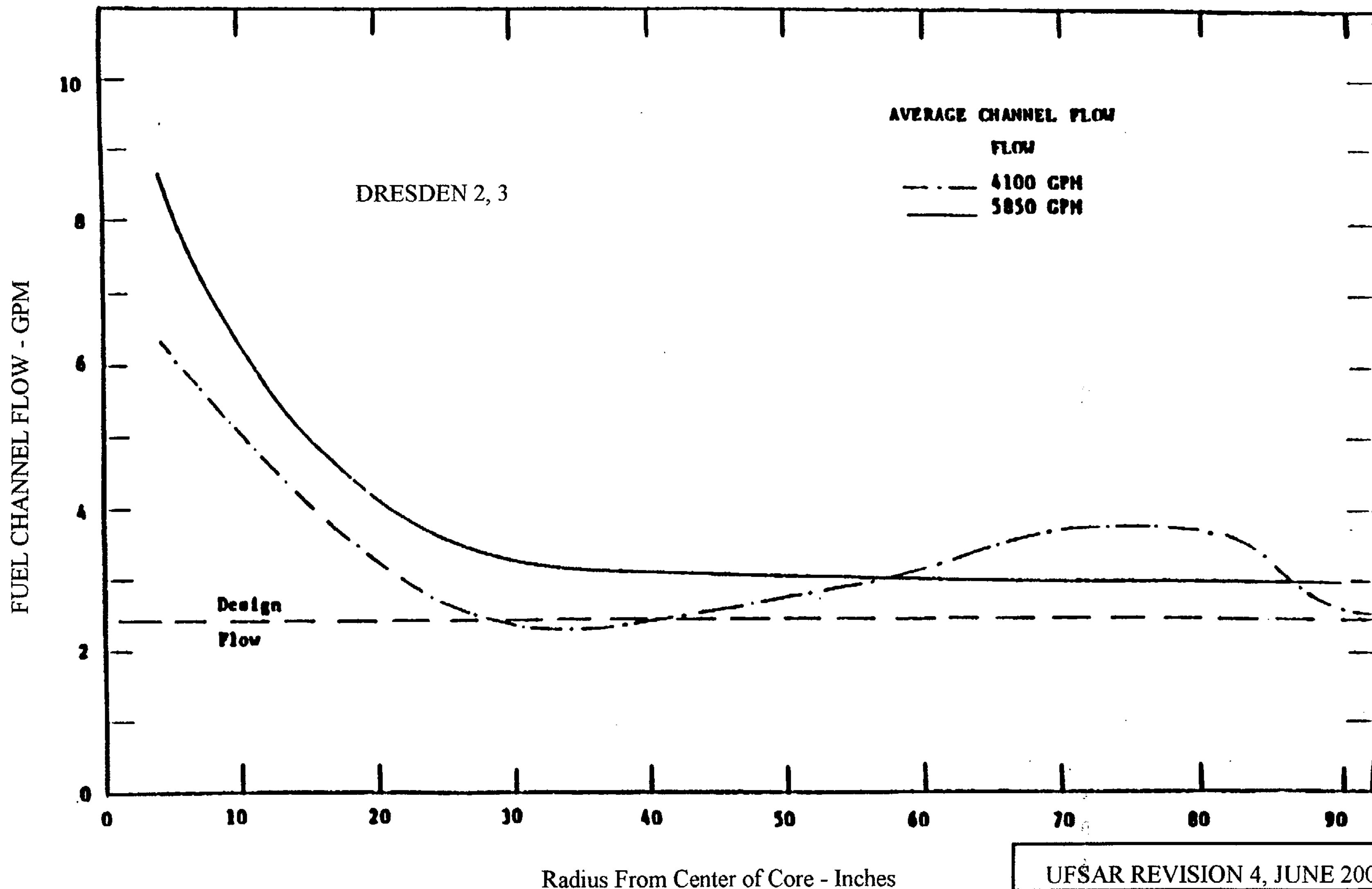
ECCS	Dresden Unit 2 Flow Uncertainty	Dresden Unit 3 Flow Uncertainty	Flow Uncertainty Assumed in LOCA
Core Spray	305 gpm (1 pump) 432 gpm (2 pumps)	305 gpm (1 pump) 432 gpm (2 pumps)	370 gpm (1 pump) 523 gpm (2 pumps)
LPCI	403 gpm (2 pumps) 570 gpm (4 pumps)	403 gpm (2 pumps) 570 gpm (4 pumps)	384 gpm (2 pumps) 543 gpm (4 pumps)
HPCI	403 gpm	403 gpm	416 gpm

[1] References 65 and 67 provide a disposition of the flow uncertainties assumed in the LOCA analysis and the actual flow uncertainties.



HISTORICAL INFORMATION

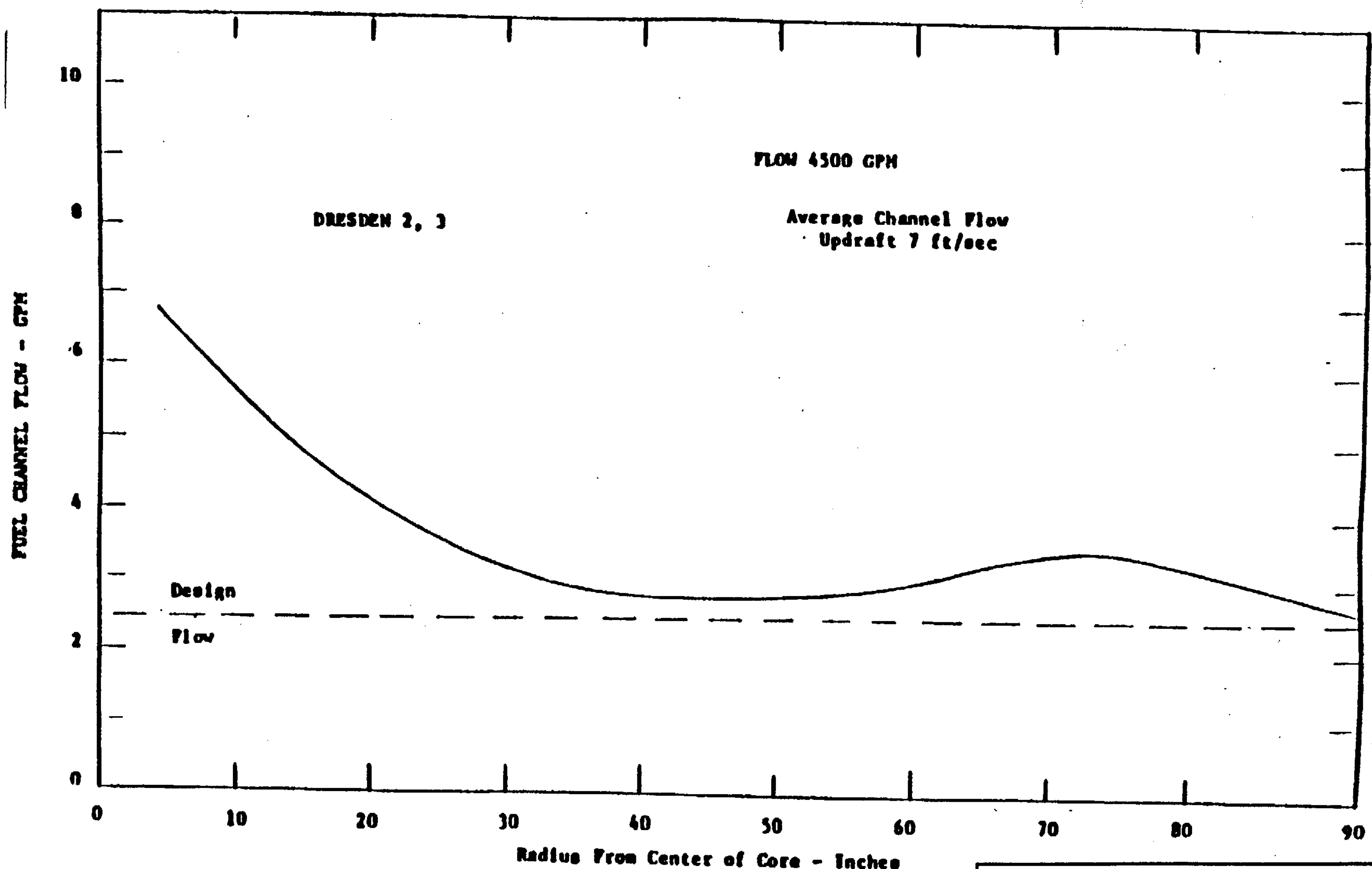
UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
EMERGENCY CORE COOLING SYSTEM VERSUS BREAK SPECTRUM
FIGURE 6.3-1



Historical Information

FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
CORE SPRAY DISTRIBUTION EFFECT OF TOTAL FLOWRATE (LOWER HEADER)
FIGURE 6.3-10



Historical Information

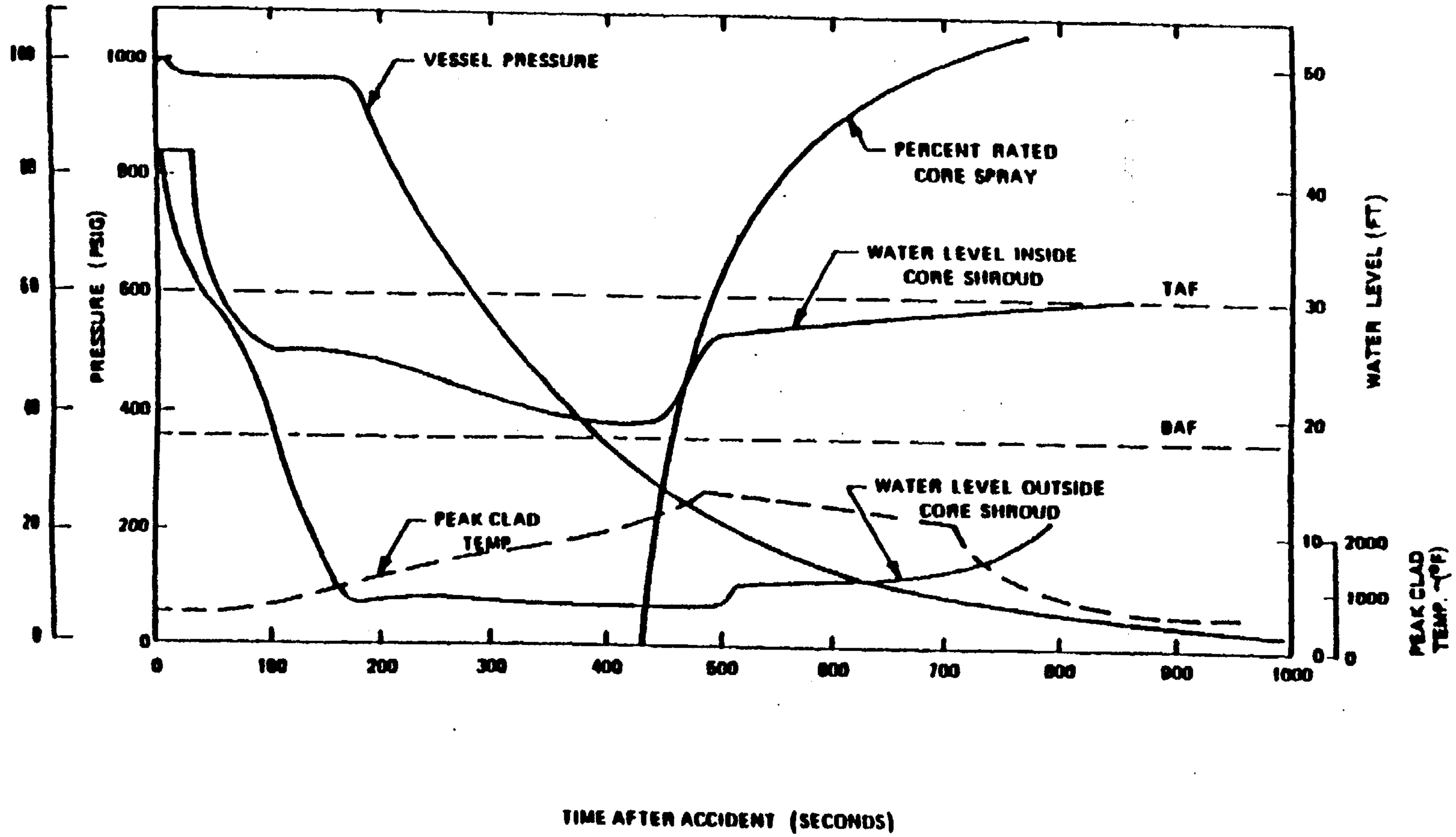
FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001

DRESDEN STATION
UNITS 2 & 3

CORE SPRAY DISTRIBUTION
EFFECT OF UPDRAFT
(LOWER HEADER)

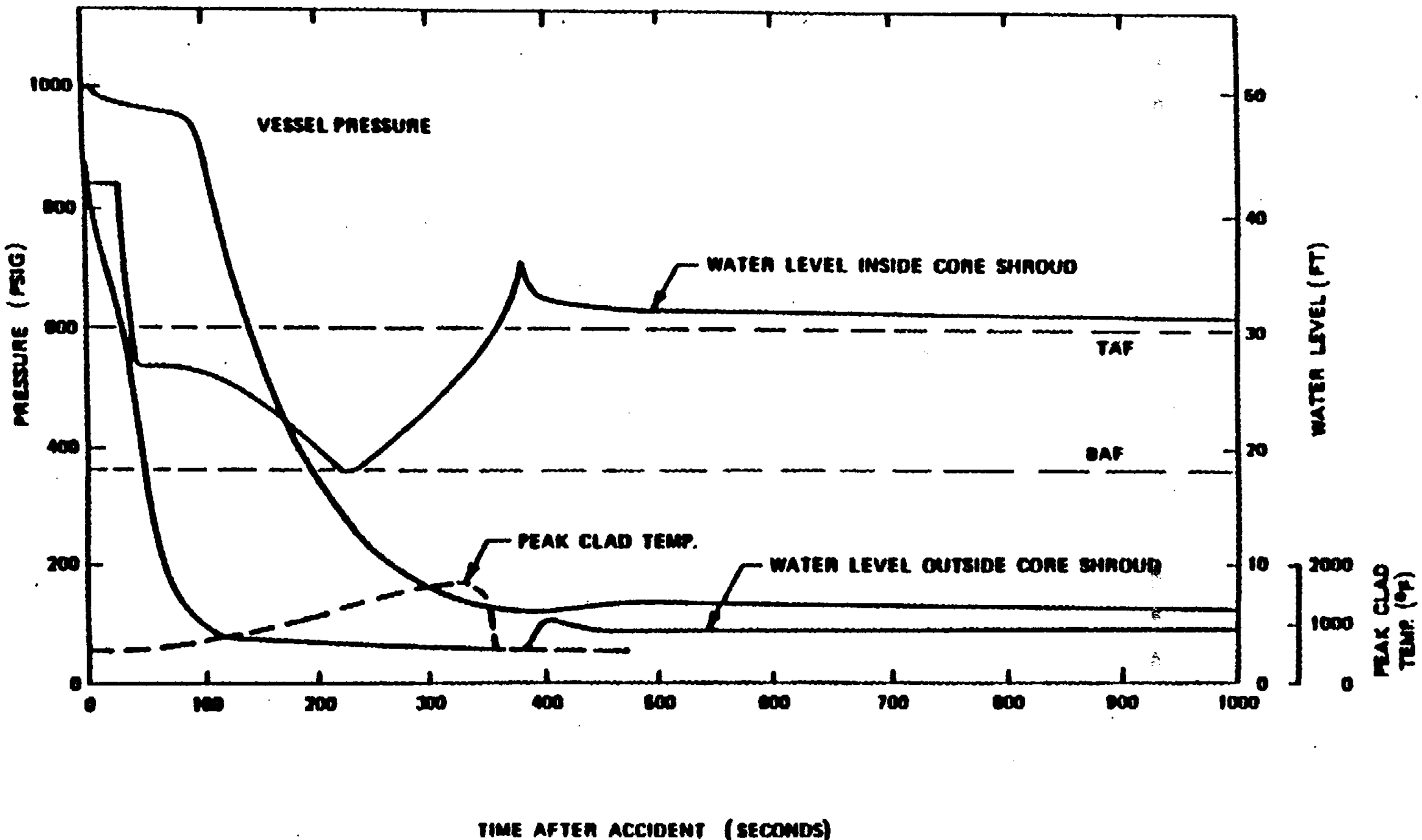
FIGURE 6.3-11



Historical Information

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
UNASSISTED CORE SPRAY PERMORMANCE ($0.2\ ft.^2$ BREAK AREA)
FIGURE 6.3-12

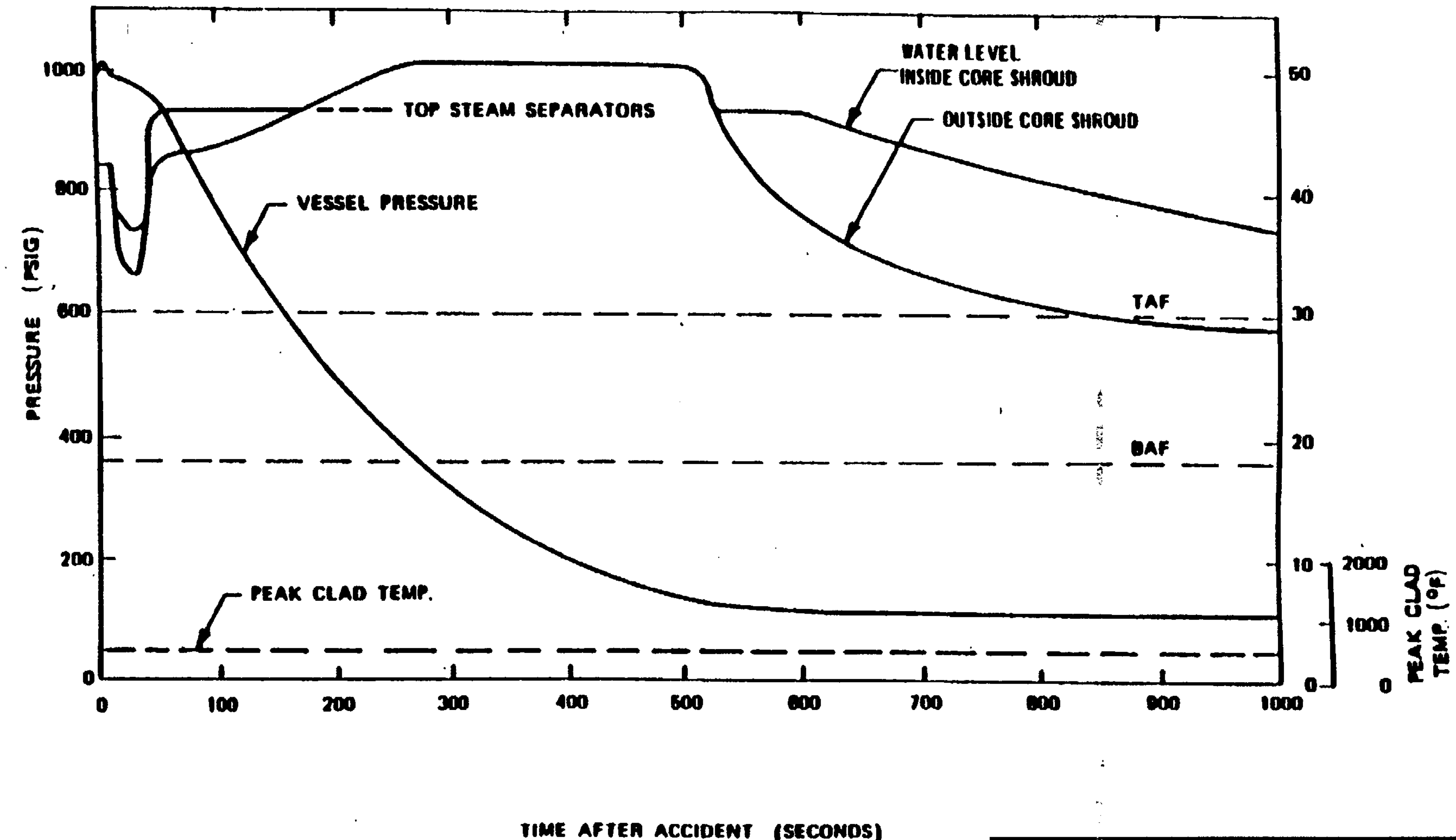
FOR INFORMATION ONLY



Historical Information

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
UNASSISTED LPCI PERFORMANCE (0.4 ft.^{2} BREAK AREA)
FIGURE 6.3-13

FOR INFORMATION ONLY



Historical Information

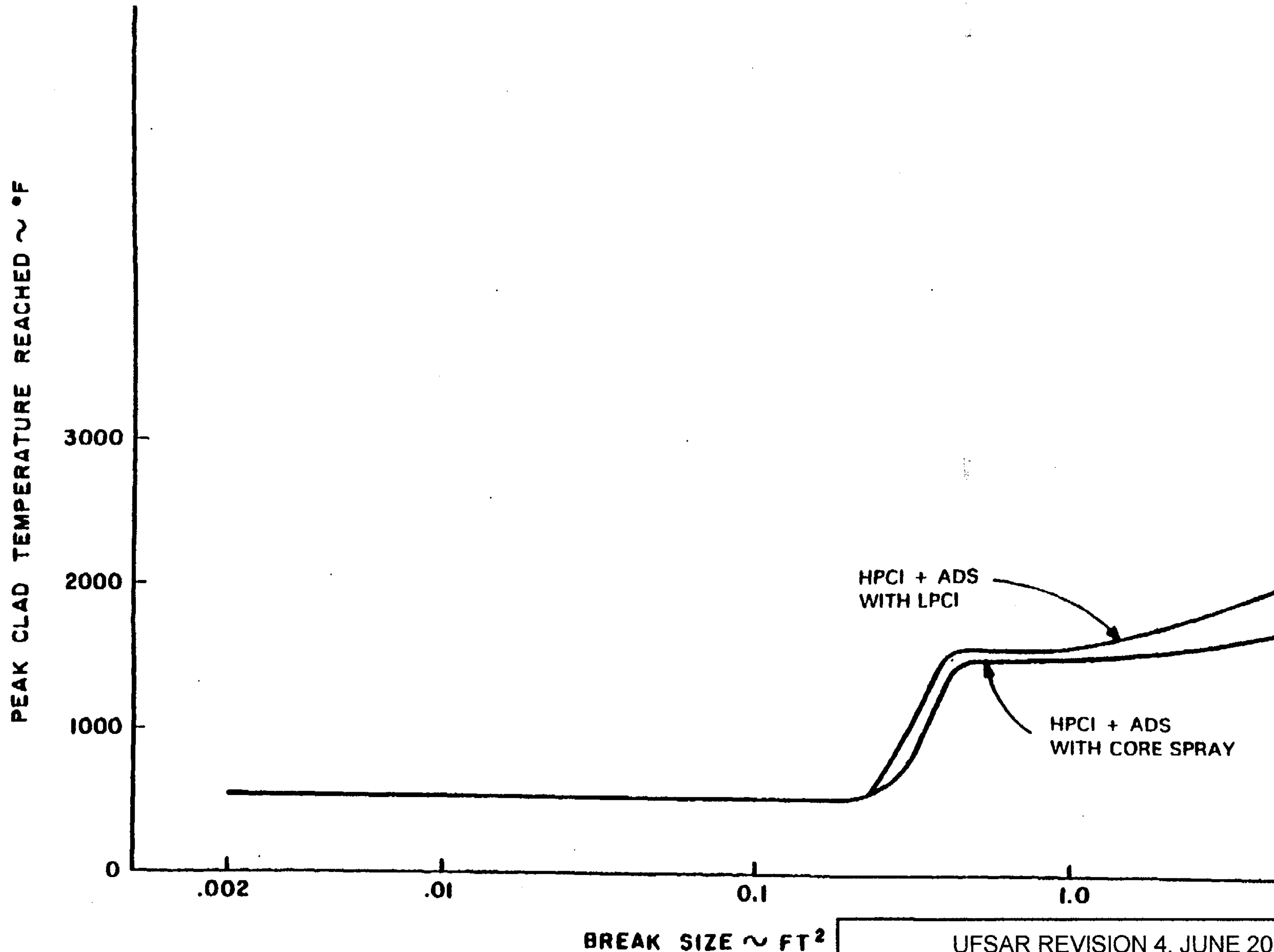
FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001

DRESDEN STATION
UNITS 2 & 3

UNASSISTED HPCI PERFORMANCE
(0.1 ft.² BREAK AREA)

FIGURE 6.3-14



Historical Information

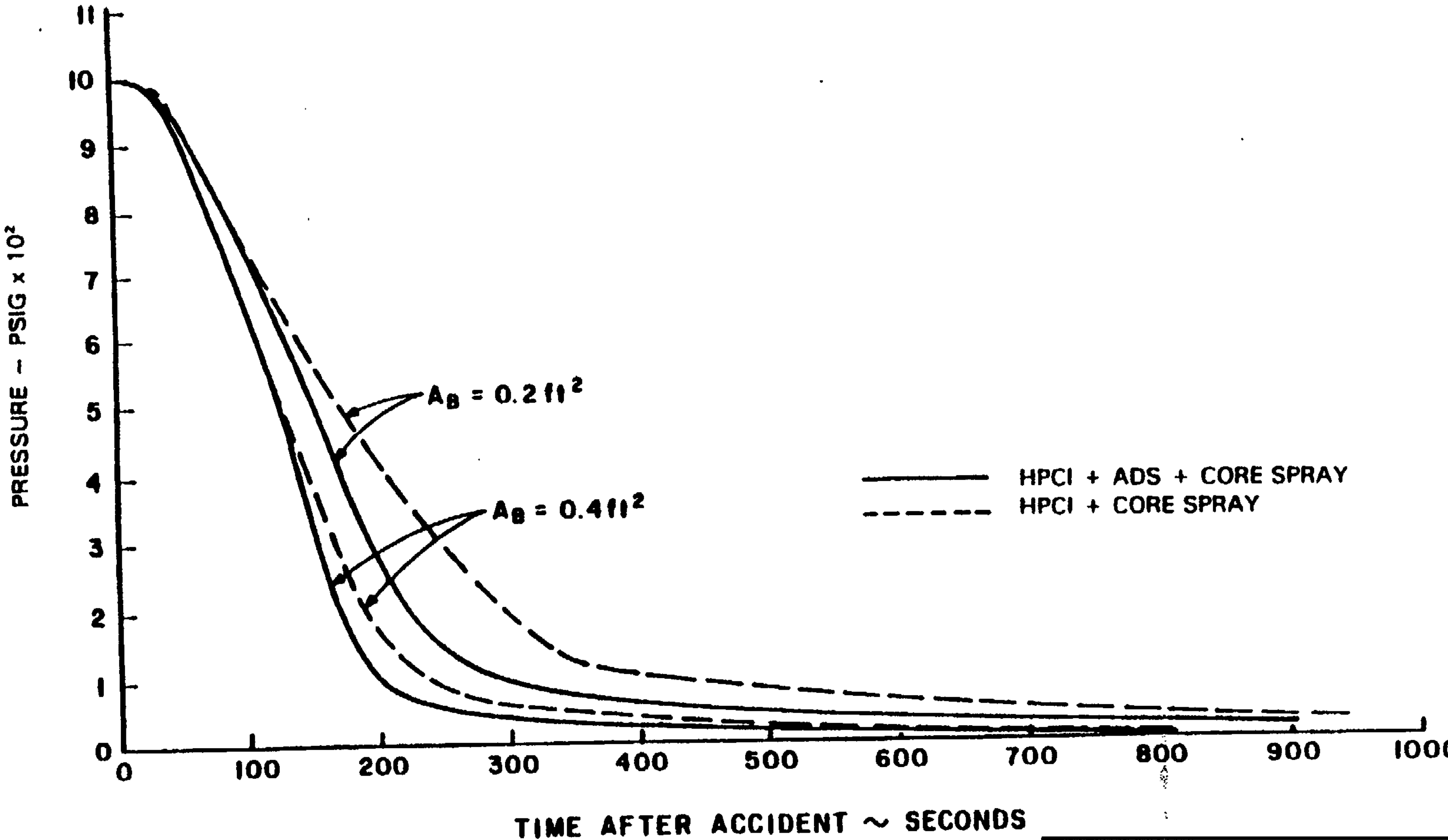
FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001

DRESDEN STATION
UNITS 2 & 3

PEAK CLAD TEMPERATURE,
HPCI AND ADS WITH CORE SPRAY OR LPCI

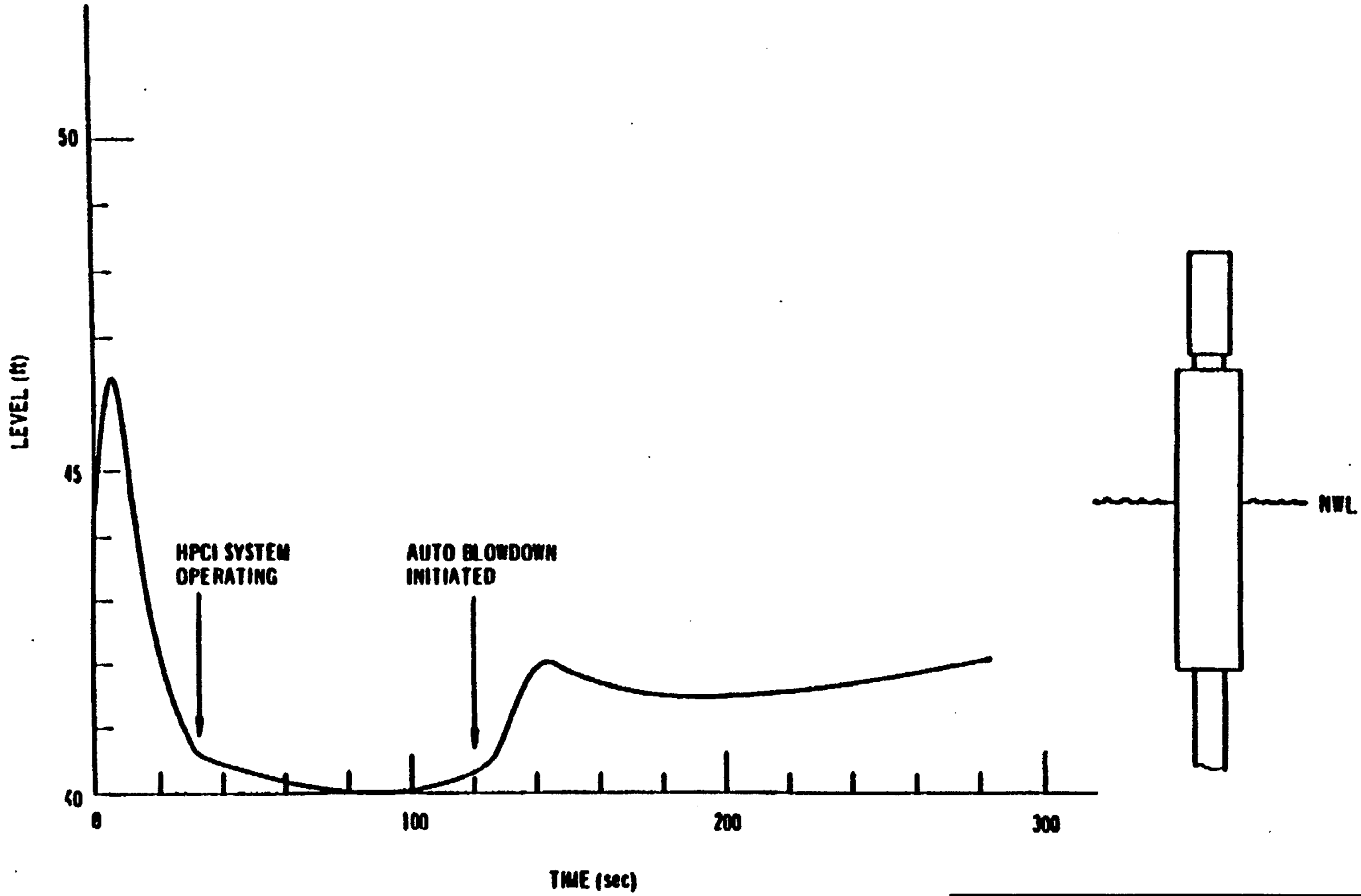
FIGURE 6.3-15



Historical Information

FOR INFORMATION ONLY

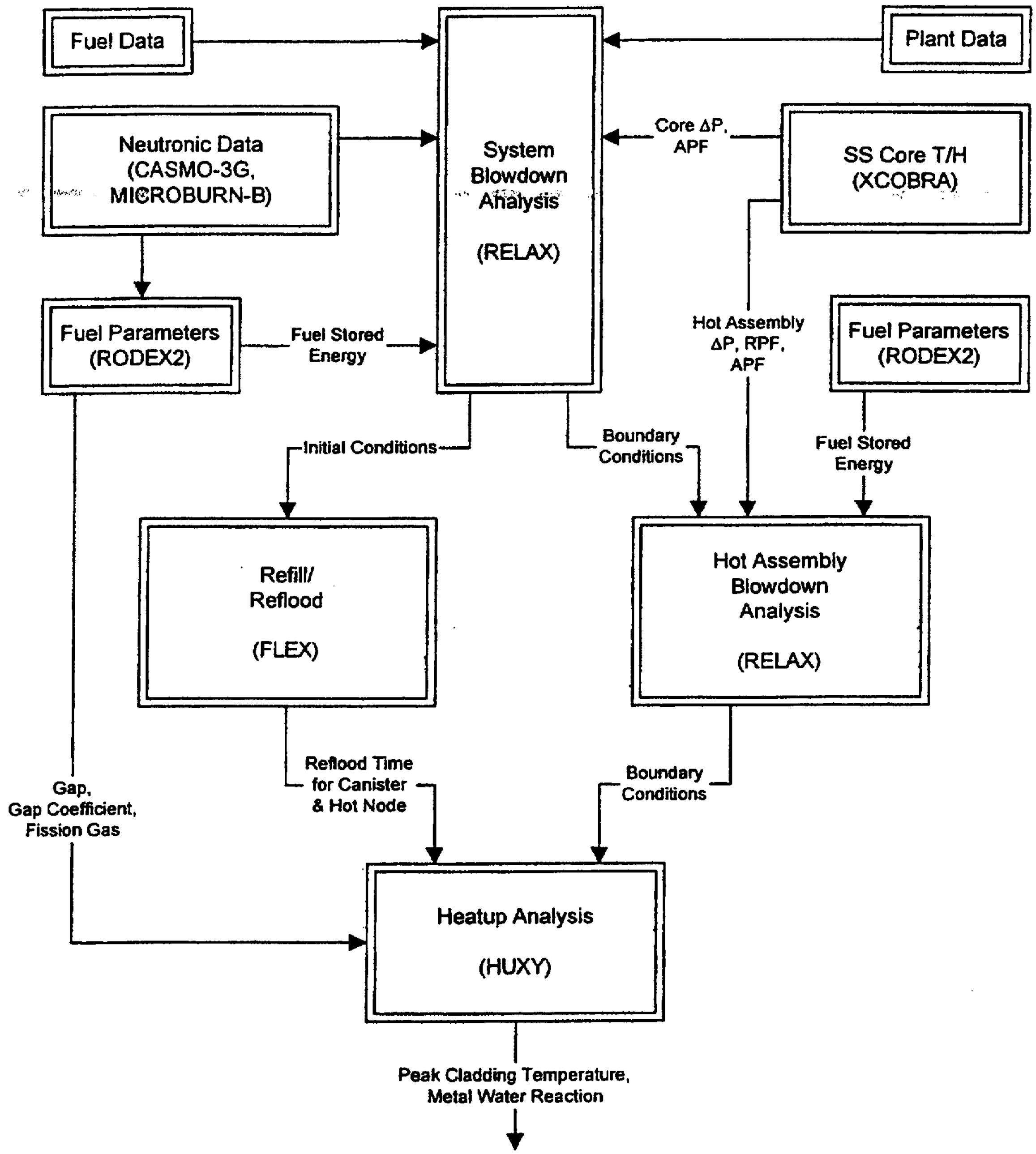
UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
DEPRESSURIZATION RATE, HPCI AND ADS WITH CORE SPRAY
FIGURE 6.3-16



Historical Information

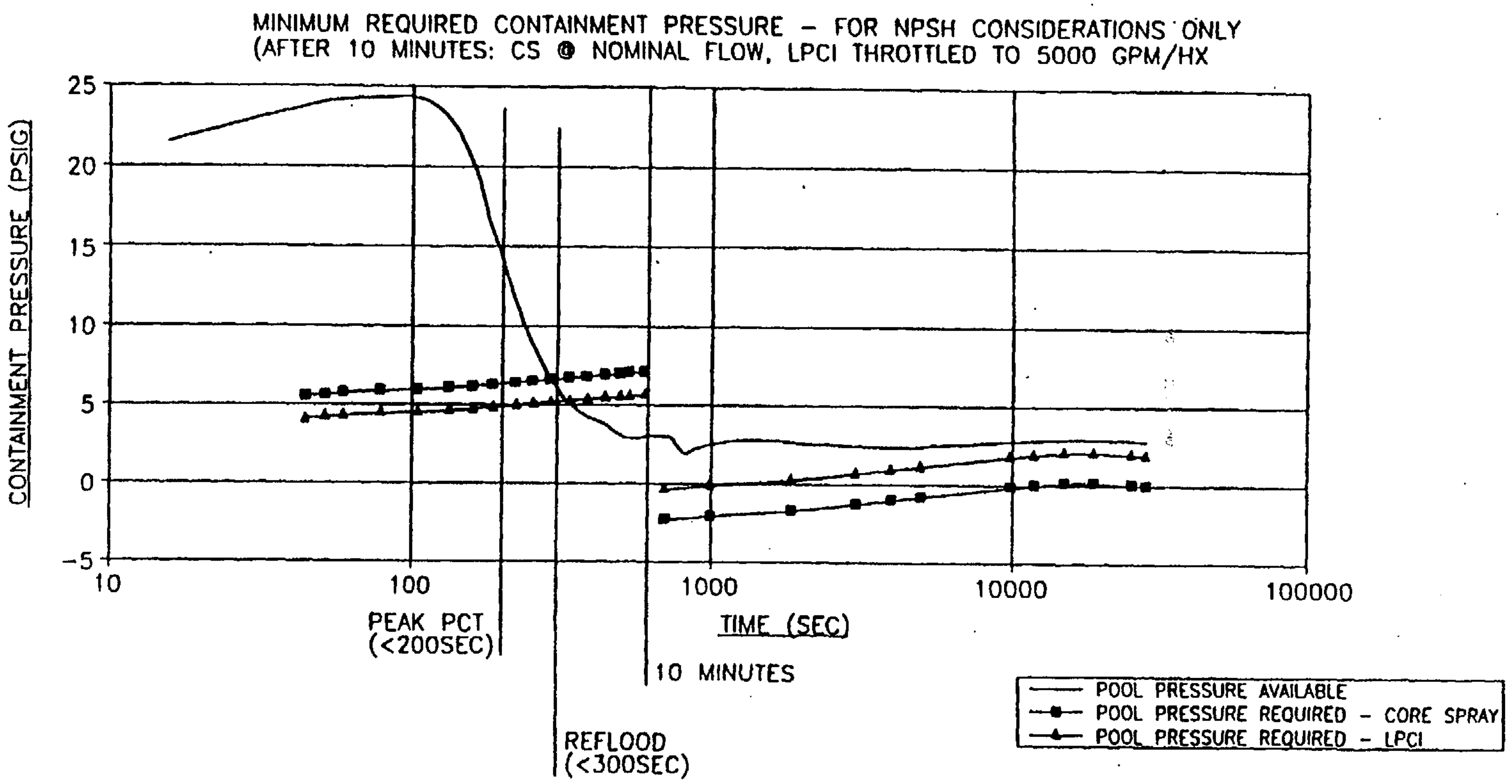
UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
LEVEL TRANSIENT FOLLOWING A 0.2 ft.^{2} STEAM BREAK (BOTH HPCI AND ADS INITIATED)
FIGURE 6.3-17

FOR INFORMATION ONLY



FOR INFORMATION ONLY

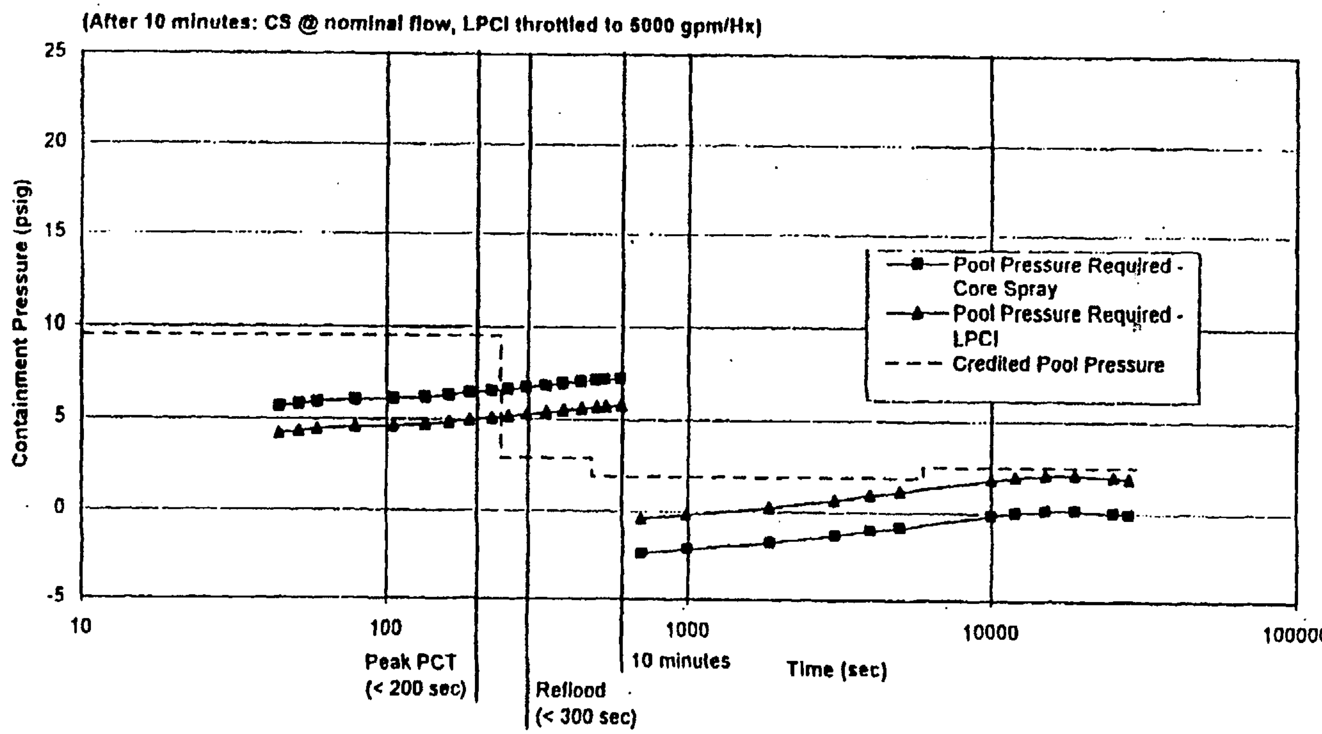
UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
EXEM BWR ECCS EVALUATION MODEL FOR LOCA
FIGURE 6.3-19



This figure is based upon revision 0 of calculations DRE 97-0010 and DRE 97-0012. See latest calculation revision(s) for actual pool pressures required.

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
MINIMUM CONTAINMENT PRESSURE AVAILABLE AND CONTAINMENT PRESSURE REQUIRED FOR PUMP NPSH
FIGURE 6.3-80

FOR INFORMATION ONLY



This figure is based upon revision 0 of calculations DRE 97-0010 and DRE 97-0012. See latest calculation revision(s) for actual pool pressures required.

FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
CREDITED CONTAINMENT PRESSURE FOR PUMP NPSH
FIGURE 6.3-84

C. The HVAC systems are capable of detecting and protecting control room personnel from radioactive contamination or smoke released to the atmosphere.

D. Emergency breathing air, supplied by a bottled air reservoir or by self-contained air packs, is provided to protect control room personnel from exposure to contaminated air.

E. The HVAC system Train A is capable of both manual and automatic transfer from the normal operating mode to the smoke purge mode. The HVAC systems are capable of manual transfer from the normal operating mode to the isolation/pressurization or isolation/recirculation modes. Emergency monitors and control room equipment are provided as necessary to ensure this capability, as described in Sections 6.4.4.1, 6.4.4.2, and 6.4.4.3.

The control room is a Class I structure. Seismic design is addressed in Section 3.7. Seismic qualification of instruments and electrical equipment is addressed in Section 3.10. Missile protection is addressed in Section 3.5.

6.4.2.1 Definition of Control Room Emergency Zone

SRP 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:

A. Main control room for Units 1, 2, and 3, which includes kitchen, toilet, and locker rooms;

B. Train B HVAC equipment room.

Areas outside the emergency zone are isolated in emergency conditions. Support rooms such as the Shift Supervisor's office are accessible to operators with the aid of breathing equipment. The auxiliary computer room has been permanently isolated from the control room emergency zone. The Train A HVAC equipment room and the auxiliary electrical equipment room are not included in the emergency zone. The boundaries of the control room emergency zone envelope are shown on Figure 6.4-1. A simplified diagram of the control room HVAC system is included in this figure.

Figure 6.4-2 shows the arrangement of equipment in the control room and points of entry. Figure 6.4-3 is a plan view showing the location of radioactive material release points and 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 the control room HVAC P&IDs: Drawings M-273, Sheet 1 and 2, and Drawing M-3121.

The control room HVAC system consists of a Train A HVAC system, a Train B HVAC system, an air filtration unit, and a smoke detection 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.

The Train B HVAC system is a single zone system which provides the necessary cooling required in case of failure of the Train A system. The discharge air from the air handling unit (AHU) is divided into two branches. The branch to the control room ties directly into the zone distribution system of Train A. The branch to the control room HVAC equipment room is ducted independently of the Train A distribution system. The air distribution from each train is aligned through the use of air-operated isolation dampers. These dampers fail to the Train B mode since this train is powered from the emergency bus during a loss of offsite power (LOOP). The Train B AHU contains a centrifugal supply air fan, a direct-expansion cooling coil, and a medium-efficiency filter bank.

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, upon loss of service water, the condenser may be cooled with the containment cooling service water (CCSW) system. The CCSW supply to the refrigerant condenser can be drawn from either loop of the Unit 2 CCSW system.

The air filtration unit (AFU) maintains control room pressure when the HVAC system is in the isolation/pressurization mode by supplying 2000 ft^3/min of filtered makeup air from the outside. The AFU can be used in conjunction with either the A or B HVAC trains. This component consists of an inlet damper, prefilter, electric heating coils, High Efficiency Particulate Air (HEPA) prefilter, fire protection line, activated charcoal adsorber, HEPA afterfilter, and two full-capacity fans and outlet dampers. The AFU complies with Regulatory Guide 1.52 and is located in the Train B HVAC equipment room. An exception to NRC Regulatory Guide 1.52 allows the laboratory testing of the AFU charcoal efficiency to have a methyl iodide penetration of less than 0.50% in lieu of the Regulatory Guide Value of less than 0.175%

The makeup air intake and exhaust dampers are bubbletight, with an area of 25 square feet each and a leakage factor of zero. The exhaust dampers for the kitchen and locker room/toilet exhaust ducts are leaktight. Isolation of the normal makeup air intake takes approximately 20 seconds.

6.4.2.3 Leak-Tightness

The infiltration of unfiltered air into the control room emergency zone occurs through three different paths:

A. Through the emergency zone boundary;

B. Through the system components located outside the emergency zone; and

C. Through backflow at the zone boundary doors as a result of ingress or egress to or from the emergency zone.

Using the guidance of SRP 6.4, the infiltration through the emergency zone boundary is assumed to be zero when the system is in the isolation/pressurization mode. During emergency pressurized modes of operation, the control room ventilation system supplies 2000 ft^3/min (standard) of outdoor air to maintain the control room at $\frac{1}{8}$-in.H_2O positive pressure with respect to the adjacent areas. Intentionally admitting outdoor air into the emergency zone prevents infiltration through the emergency zone boundary by assuring that air is exfiltrating from the zone at an adequate velocity (a velocity through the emergency zone boundary penetrations of approximately 1400 ft/min is required to develop a backpressure of $\frac{1}{8}$-in.H_2O).

During the isolation/recirculation mode, infiltration through the emergency zone boundary is initially negligible because the control room will be at a positive pressure at the time of system isolation. Infiltration following isolation is assumed to be 105 ft^3/min.

The infiltration through the system components located outside the emergency zone occurs through joints and seams in the ductwork, around damper shafts, through joints and penetrations in the AHUs, and through the dampers that isolate the emergency zone from nonhabitable areas. The inleakage around the damper shafts and blades was based on the damper specification requirements and the vendor test data. The Train A ductwork and AHU was assumed to leak at the maximum leakage rates provided in Table 4-4 of ANSI N-509. A leakage rate of 0.2 ft^3/min (standard) per square foot of ductwork at 10-in.H_2O pressure (gauge) was used since it represents the lowest acceptable quality of workmanship. The leakage rate was adjusted to the calculated pressure at each duct section based on the methodology in ANSI N-509. To verify the reasonableness of the ANSI N-509 leak rates, the ductwork leakage was also calculated by using published duct leakage test data (ASHRAE RP 308). The calculation of the duct leakage using published test data for commercial grade ductwork resulted in leakage values less than those calculated using ANSI N-509. Therefore, an infiltration analysis of the Train A ductwork using the ANSI N-509 leakage rates is a conservative representation of the infiltration to the control room emergency zone.

The infiltration analysis resulted in a total unfiltered infiltration rate of 263 ft^3/min (standard). The ductwork and components that are under a negative pressure and are located outside the emergency zone are shown on Figure 6.4-1. This figure also shows the leakage flowrate through the various components. A breakdown of the infiltration through the different leakage paths is shown in Table 6.4-1. Radiological consequences of infiltration are addressed in Section 15.6.5.5.2.

The opening and closing of boundary doors can induce infiltration to the emergency zone. The backflow infiltration is conservatively assumed at 10 ft^3/min as recommended by SRP 6.4.

6.4.2.4 Interaction with Other Zones and Pressure-Containing Equipment

Potential adverse interactions between the control room emergency 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 positive pressure of $\frac{1}{8}$-in.H_2O during emergency pressurized modes, with respect to adjacent areas. In addition, both the intake dampers and the dampers which isolate the emergency zone are automatically isolated or actuated by the operator in response to the odor of toxic gas or the reactor building ventilation system high radiation alarm.

Steam lines are not routed in the vicinity of any control room wall. Pressurized breathing air cylinders are located above the control room.

6.4.2.5 Shielding Design

The control room design consists of poured-in-place reinforced concrete with 6-inch floor and ceiling slabs and 18- to 27-inch walls. The radiation streaming effect in the control room is considered negligible during normal operation and provides 30-day integrated whole body dose of 101 mrem post-LOCA. Further details of the design of the control room shielding are contained in Section 12.3.2.2.4. Figures 12.3-1 through 12.3-5 illustrate the relative location of the control room and radiation sources and show the paths and shield thicknesses.

6.4.3 System Operational Procedures

For normal conditions, the Train A HVAC system operates as discussed in Section 9.4.1. If desired, Train B can be used for normal plant operations. Outside air is supplied to Train B by the AHU fan in this operating mode. Upon failure of the operating HVAC system train, that train is isolated and the redundant train is energized.

The control room HVAC system has three emergency modes:

A. The isolation/pressurization mode protects the control room personnel from airborne radioactive contaminants. In this mode, the normal outside air intakes are isolated, and the AFU provides makeup air to maintain pressurization. This mode is described more fully in Section 6.4.4.1.

B. The isolation/recirculation mode protects personnel from toxic gases. In this mode, all outside air intakes are isolated, and the control room air is recirculated through the operating HVAC train. This mode is described more fully in Section 6.4.4.2.

C. The smoke purge mode protects personnel from fire and smoke. In this mode, the control room air is exhausted and replaced with outside air. This mode is described more fully in Section 6.4.4.3.

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 gases, and smoke contaminating the control room atmosphere.

6.4.4.1 Radiation Protection

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 kitchen and locker room exhaust fan dampers. This zone isolation with a filtered pressurization air-type system 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 with respect to adjacent areas is maintained by passing 2000 ft^3/min of outdoor air through a HEPA filter unit with an iodine removal efficiency of 99%. The filter unit, booster fans, and associated controls are powered from the emergency bus.

Radiation protection is provided to allow control room access and occupancy for the duration of a DBA. Satisfactory protection is provided based on isolating and pressurizing the control room emergency zone with filtered outdoor air no later than 40 minutes after radiation has been detected in the reactor building ventilation manifolds. The control room operator doses are within the limits of GDC-19 and SRP 6.4, as analyzed in Section 15.6.5.5.2.

Operator action is required within the time limit specified above to isolate the control room emergency zone and to activate the air filter unit. In the event of LOOP and LOCA condition, the additional operator actions include disabling toxic gas protection interlocks to activate the Air Filtration Unit. Isolation consists of closing the outdoor air intakes for both the Train A and B systems and closing the kitchen and locker room exhaust isolation dampers. Additionally, the exhaust fans are tripped from limit switches on the isolation dampers, thereby preventing the induction of unfiltered air into the control room via the exhaust duct.

In the event of a LOOP or loss of instrument air, the isolation dampers fail to the isolation/pressurization mode. However, the pneumatic AFU booster fan discharge dampers also 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.

Section 15.6 contains an evaluation of the maximum expected dose to the control room during a DBA.

The current UFSAR licensing basis utilizes the TID-14844 methodology, which establishes source term based on rated core thermal power. Since the power rating of the core is not changing, the source term is not an issue. Since the source term remains unchanged, the radiological release is not dependent upon the number of fuel rods in an assembly. The radiological release is unchanged from 7x7 to 8x8 to 9x9 fuel assemblies.

A more detailed discussion may be found in Sections 15.0.2.5 and 15.6.5.5.2.5.

6.4.4.2 Toxic Gas Protection

The control room HVAC system does not provide automatic toxic gas protection to the control room emergency zone in case of either an onsite or offsite toxic chemical accident. The results of the toxic chemical survey are provided in Section 2.2.3. An analysis of survey results was carried out to conform to Regulatory Guide 1.78, which discusses the requirements and guidelines to be used for determining the toxicity of chemicals in the control room following a postulated accident. The guidelines for

6.4.7 References

1. Dangerous Properties of Industrial Materials, Irving Sax, Richard Lewis, Van Nostrand Reinhold, N.Y., N.Y., 1989.

2. Technical Guidance for Hazardous Analysis, U.S. EPA, 1987.

3. Handbook of Chemical Hazard Analysis Procedures, Federal Emergency Management Agency, 1989.

4. Estimating Releases and Waste Treatment Efficiencies for the Toxic Chemical Release Inventory Form, U.S. EPA document 560/4-88-002, December 1987.

5. Control Room Habitability Study for Dresden Units 2 and 3, Commonwealth Edison Company, Bechtel Power Co., December 1981.

6. Control Room Habitability Study Update for Dresden Units 2 and 3, Commonwealth Edison Company, Scientech Inc., December 2000.

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Feature Filter Systems

The secondary containment system is the only engineered safety feature (ESF) which uses a filter system to control fission product releases. This filter system is the standby gas treatment system (SBGTS) described in Section 6.5.3. The ESFs are described in Section 6.0.

6.5.2 Containment Spray Systems

The containment spray system is part of the containment cooling system described in Section 6.2.2.

6.5.3 Fission Product Control Systems

The SBGTS is provided to maintain a small negative pressure in the reactor building under isolation conditions, in order to prevent ground level escape of airborne radioactivity. Filters are provided to remove radioactive particulates, and charcoal adsorbers are provided to remove radioactive halogens which may be present in concentrations significant to environmental dose criteria. Any radioactive noble gases passing through the filter/adsorbers are diluted with air and dispersed into the atmosphere from the 310-foot chimney. The system is also used to dispose of purge and vent gases from the primary containment, and to assist with containment inerting/deinerting. The exhaust duct radiation monitor provides a continuous indication of radioactivity entering the system, and the chimney monitor samples the effluent. The SBGTS is shown in Drawing M-49. The primary containment vent, purge, and inerting systems are discussed in Section 6.2.5. The radiation monitoring system is discussed in Section 11.5.

6.5.3.1 Design Objectives

The system is sized to maintain the reactor building at a negative pressure of 1/4 in.H_2O relative to the atmosphere under neutral wind conditions. The nominal flowrate is 4000 ft^3/min to achieve these objectives. Two separate filter/ adsorber/ fan units are provided. One train is selected as primary and the other train is placed in standby. If the primary train fan or heater fails to start, the standby train will be started automatically. Both units receive power from the emergency electrical supply. The system is designed for Class I seismic conditions. The equipment is located in the shielded center tunnel between the two main condenser rooms. The exhaust pipe runs through the radwaste building and up into the 310-foot chimney.

Figure 6.5-2. Replacement charcoal shall be qualified according to the guidelines of Regulatory Guide 1.52.

H. Test orifice - A test orifice is installed downstream of the charcoal adsorber bed. The orifice produces turbulent gas flow for more complete mixing, ensuring that the sample taken is a representative one. This orifice also serves as a flow element to automatically start the standby train on low flow in the primary train.

I. HEPA afterfilter - The HEPA afterfilters are similar to the HEPA prefilters (see Item F) and are provided to remove any activated charcoal particles that may be released from the activated charcoal adsorber.

J. Crosstie line - A crosstie line, with restricting orifice and manual butterfly valve (which is normally locked open), interconnects the two trains so that the operating train fan can provide filter decay heat cooling air at the proper flowrate 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.

K. Flow control valve - This is an air-operated butterfly valve which maintains the flowrate through the train at 4000 ft^3/min ±10% (4300 ft^3/min through the system when cooling the standby train). This valve is normally open and is controlled by the flow element in the discharge line to the 310-foot chimney.

L. Fan - The fans operate in parallel from a common system inlet plenum to provide flow through the two separate parallel trains. They are located downstream of the filters to minimize contamination during maintenance. Fan performance is discussed in Section 6.5.3.3. The fan performance curve is shown on Figure 6.5-3.

M. Backdraft damper - A backdraft damper is provided to ensure that reverse flow through the SBGTS filter train, which could spread contamination, will not occur. This damper acts as a check valve and closes whenever airflow into the exhaust fan occurs.

N. Outlet valve - This is a motor-operated butterfly valve which is normally closed. It opens automatically upon system initiation.

The SBGTS intake ducts can take suction from the reactor building ventilation system exhaust duct, the HPCI gland seal condenser exhaust, the ACAD system, the cooling air supply line, or from primary containment. The discharges from the two SBGTS trains are joined together and the discharge from the system is routed to the 310-foot chimney through a common line. Note: valves MO 2-7503 and 3-7503 are retained open with remote control removed.

SBGTS can be started manually, but is automatically initiated by a secondary containment isolation signal (as described in Section 6.2.3).

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DRAWINGS CITED IN THIS CHAPTER*

*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.

DRAWING*	SUBJECT
M-26	Diagram of Nuclear Boiler and Reactor Recirculation Piping Unit 2
M-34	Diagram of Control Rod Drive Hydraulic Piping Unit 2
M-357	Diagram of Nuclear Boiler and Reactor Recirculation Piping Unit 3
M-365	Diagram of Control Rod Drive Hydraulic Piping Unit 3

7.0 INSTRUMENTATION AND CONTROLS

This chapter presents various plant instrumentation and control systems including functions, design bases, system descriptions, design evaluations, and tests and inspections. The information provided in this chapter emphasizes instruments and associated equipment which constitute reactor protection and regulation systems. Particular attention is given to the instrumentation aspects of process systems, with the mechanical and nuclear design bases presented in the chapters or sections which address the respective process system. Chapter 7 includes a discussion of the instrumentation and controls for systems of major safety significance and those that provide reactor and turbine control. Discussions of instrumentation and controls for other systems are contained within the sections that address those systems.

7.1 INTRODUCTION

The equipment and evaluations presented in this chapter are applicable to either unit. Instrumentation and controls are provided to perform protective and regulating functions.

Protective systems, consisting of the reactor protective circuitry and the instrumentation and controls for engineered safety features (ESFs), normally perform the most important of the instrumentation and control safety functions.

The regulating instrumentation and controls provide the ability to regulate the unit from shutdown to full power and to monitor and maintain key unit variables, such as reactor power, flow, pressure, level, temperature, and radioactivity levels, within predetermined limits during both steady-state operation and normal unit transients.

The inputs to the protective and regulating controls are provided by a diversity of instruments. The following sections in this chapter provide descriptions of instrumentation and major components, evaluations of the instrumentation input adequacy, and analyses from both functional and reliability viewpoints.

7.1.1 Identification of Systems

Section 3.2 discusses the identification of safety-related instrumentation and control systems and equipment. The electronic work control system (EWCS) also contains information on classification of components. The engineered safety features for Dresden are identified in Section 6.0.

7.1.1.1 Protective Systems

Protective systems include electrical and mechanical devices and circuitry required to initiate shutdown of the reactor and mitigate the consequences of accidents when required. These systems include:

A. High neutron flux - To prevent fuel damage resulting from bulk power increases, high neutron flux initiates a scram. The neutron flux scram, combined with safety valve actuation, provides vessel overpressure protection. The nuclear instrumentation (Section 7.6) provides high neutron flux trip signals. Four intermediate range monitor (IRM) channels and three average power range monitor (APRM) channels are connected to each of the dual logic channels for a total of 8 IRMs and 6 APRMs. The four source range monitors (SRMs) are combined with the IRMs and APRMs in the manual scram logic to provide non-coincidence high flux scram protection. This function is bypassed during normal operation by installation of shorting links. If the reactor mode switch (described later in this section) is in the RUN position and the APRM channels are not downscale, the IRM scrams are automatically bypassed.

During refueling the primary neutron monitoring system (NMS) indication of neutron flux level is provided by the Source Range Monitors (SRM). The NMS (including the SRMs) provide input to the RPS manual scram logic. However, the shorting links are normally installed such that tripping any combination of SRM channels does not cause a trip of a RPS channel. Performance of Shutdown Margin Demonstrations (multiple control rods withdrawn) with the vessel head removed or de-tensioned requires removal of these shorting links to provide additional protection above what the IRMs provide against a reactivity excursion. Removing these shorting links enables the SRM scram function.

B. High reactor pressure - An increase in reactor vessel pressure while the plant is operating tends to compress the steam voids and results in a positive reactivity effect, increased nuclear activity with subsequent heat generation, and further pressure increases. This threatens the integrity of the reactor vessel, which is an important barrier to the uncontrolled release of fission products. The high pressure scram reduces the heat generation to terminate the pressure rise. This scram is a backup to the high flux scram and the main steam isolation valve (MSIV) closure scram.

C. High drywell pressure - Abnormal pressure could indicate a rupture of, or excessive leakage from, the reactor coolant system into the drywell structure. This scram minimizes the energy which must be accommodated during a loss-of-coolant accident and prevents the reactor from going critical following the accident.

D. Low reactor water level - This scram signal assures that the reactor is not operated without sufficient water above the reactor core.

E. Control rod drive system scram discharge volume (SDV) high level - This scram signal assures that the reactor is operated with sufficient free volume in the scram discharge system to receive the discharge from the control rod drives if a scram is required.

F. Main condenser low vacuum - This scram signal anticipates the turbine stop valve closure scram and therefore reduces the pressure transient, neutron flux increase, and the fuel surface heat flux which occur when the condenser is isolated to protect the condenser from overpressure.

G. Deleted

H. Loss of ac power to the protection system - All electronic trips, logic relays, and scram solenoid valves will actuate on loss of power as the RPS M-G sets coast down and output breakers trip following a loss of ac power.

channel trips when the valves start to close. The logic is arranged so that the partial closure of three of the four stop valves initiates a reactor scram.

M. Loss of turbine control oil pressure - The turbine hydraulic control system operates using high pressure oil. There are several points in this oil system where a loss of oil pressure could result in a fast closure of the turbine control valves. This fast closure of the turbine control valves is not protected by the generator load rejection scram since failure of the oil system would not result in the fast closure solenoid valves being actuated. For turbine control valve fast closure, the core would be protected by the APRM and high reactor pressure scrams. However, to provide the same margins as provided for the generator load rejection scram on fast closure of the turbine control valves, a scram has been added to the reactor protection system which senses failure of control oil pressure to the turbine control system.

The scram on loss of turbine control oil pressure is an anticipatory scram and results in reactor shutdown before any significant increase in neutron flux occurs due to increased reactor pressure. The transient response is very similar to that resulting from the generator load rejection. The scram setpoint of 900 psig is set high enough to provide the necessary anticipatory function and low enough to minimize the number of spurious scrams. Normal operating pressure for this system is 1250 psig. The control valves do not start to close until the fluid pressure decreases to 600 psig. Therefore, the scram occurs well before control valve closure begins.

N. Core power oscillations – BWR cores have been shown to exhibit thermal-hydraulic reactor instabilities when reactor power is above 30% of rated reactor power and recirculation flow is less than 60% of rated core flow. These instabilities, if allowed to propagate, could exceed the minimum critical power ratio (MCPR) and lead to fuel damage and the release of radioactive material. In order to avoid fuel damage, OPRMs (Unit 2 only) are designed to utilize signals from the existing LPRMs to determine if core power oscillations are taking place. If an OPRM detects oscillations, and is fully armed, then it suppresses the oscillations by initiating a reactor scrams.

7.2.2.3 Reactor Mode Switch

A reactor mode switch is manually positioned to select scram functions appropriate to the plant operating status.

A. SHUTDOWN	This initiates a full reactor scram.
B. REFUEL	IRM scram functions are in operation;.
C. STARTUP/HOT STANDBY	IRM scram functions are in operation. Scrams on main condenser vacuum and main steam isolation valve closure, while reactor pressure is low are bypassed.
D. RUN	APRM scram functions in operation. IRM scrams are bypassed if APRM not downscale. All other scram functions are in operation.

7.2.2.4 Channel Bypasses

To provide for operational requirements, such as draining of the scram discharge volume or the repair of redundant electronic instruments, RPS design provides for the following scram bypasses (see Section 7.2.5.12 for a comparison with IEEE 279, Paragraph 4.12):

A. Main condenser vacuum and main steam line isolation valve closure scrams are bypassed in the STARTUP AND HOT STANDBY position of the mode switch, providing the reactor is at a preset pressure below the normal operating range;

B. Trips from the scram discharge volume high level can be bypassed to allow for scram reset and draining of the discharge volume;

C. One of the four IRMs associated with each protection channel may be bypassed by the operator using a one-at-a-time selector switch (see Section 7.6.1.4);

D. One of the three APRMs associated with each protection channel may be bypassed by the operator using a one-at-a-time selector switch (see Section 7.6.1.5.2);

E. (Unit 2 only) One of the four OPRMs associated with each protection channel may be bypassed by the operator using a one-at-a-time selector switch (see Section 7.6.1.5.6); and

F. Generator load rejection scram and turbine stop valve closure scram are automatically bypassed on low-first stage turbine pressure.

7.2.2.5 Sensing Instrumentation

Instrumentation providing inputs to the reactor protection system is separate from that used for process system control and indication; thus, control system instrumentation failures do not jeopardize the protection system. The RPS instrumentation is described below:

A. Containment pressure inputs to the protective system are from non-indicating pressure switches. Two switches sensing drywell pressure are located on each of the two instrument racks outside the drywell. The switches are arranged so that a single event cannot jeopardize the ability of the protective system to initiate a scram.

B. Scram discharge volume water level inputs to the RPS use two different types of sensors. Both Unit 2 and Unit 3 use dP type level transmitters and electronic trip units for one of the inputs. Unit 2 uses thermal type level switches for the diverse means of initiation. Unit 3 uses non-indicating float type level switches for the diverse means of initiation. The switches are arranged so that a single event cannot jeopardize the ability of the RPS to scram.

C. Condenser vacuum inputs to the RPS are from four non-indicating vacuum switches mounted locally. These vacuum switches are arranged so that a single event cannot jeopardize the ability of the RPS to scram.

D. Main steam line valve closure scram inputs to the RPS are from valve stem position limit switches on the eight isolation valves. Each switch provides an independent signal to the RPS. The partial closure of either the inboard or outboard isolation valves in any three main steam lines would produce a trip in both logic channels, resulting in a reactor scram.

E. The turbine control valve fast closure inputs to the RPS are from pressure switches on each of the four fast-acting solenoid valves which initiate fast closure of the control valve.

F. Turbine stop valve closure inputs to the protection system are from valve stem position switches located on each of the four turbine stop valves. Each switch provides an independent signal to an RPS logic subchannel. The logic is such that partial closure of any three stop valves initiates a scram.

G. Sensors which monitor reactor pressure vessel parameters are discussed in Section 7.6.

H. Nuclear instrumentation is described in Section 7.6. Nuclear instrumentation channel assignments to RPS automatic trip logic subchannels are as follows:

1. A1 - IRM 11, 13; APRM 1, 3; OPRM 1, 3 (Unit 2 only)

2. A2 - IRM 12, 14; APRM 2, 3; OPRM 2, 7 (Unit 2 only)

3. B1 - IRM 15, 17; APRM 4, 5; OPRM 8, 5 (Unit 2 only)

4. B2 - IRM 16, 18; APRM 4, 6; OPRM 4, 6 (Unit 2 only)

In addition, the following channel groupings provide coincident and non-coincident trip functions in the manual scram logic for each RPS channel when shorting links are removed:

1. SRM 21; IRM 11, 13; APRM 1, 3

2. SRM 22; IRM 12, 14; APRM 2, 3

3. SRM 23; IRM 15, 17; APRM 4, 5

4. SRM 24; IRM 16, 18; APRM 4, 6

I. Deleted.

Primary containment high-pressure scram trip;

Manual scram pushbuttons;

Reactor mode switch;

Reactor protection system reset switch;

Turbine stop valve closure and turbine control valve fast closure trip bypass;

Neutron monitoring system trip bypass;

Scram discharge volume high water level trip bypass; and

Main steam line isolation valve closure trip bypass.

IEEE 279-1968 applies to the remaining RPS equipment as indicated:

A. Reactor protection system M-G sets and power distribution - Cabling used within the RPS panels has been selected to be appropriate for RPS use. The RPS M-G sets have been chosen to provide low maintenance.

B. Reactor protection system trip logic, actuators, and trip actuator logic - The RPS trip logic consists of series-connected relay contacts from the trip channel output relays. The RPS trip actuator logic consists of relay contacts connected in a specific arrangement from the trip actuators. Within the RPS panels in the control room, electrical circuits are fused. Individual control rod drive scram solenoids are fused at the scram solenoid fuse panels.

C. Reactor protection system outputs to other systems - At the RPS interface with the output networks, isolated contacts of various RPS relays have been used to provide the signal source. These contacts are classified as being a portion of the RPS component. The load device driven by these contact outputs is not included in the RPS scope. The use of isolated contact outputs from the RPS provides a large measure of isolation and independence for this interface relative to the protective action portions of the RPS.

7.2.5.4 Equipment Qualification

For each of the RPS functions, the original equipment was required to be certified by the vendor to meet the requirements listed in the purchase order and for the intended application described for that function. These certifications, in conjunction with applicable field experience for those components in their particular applications, qualified the components. In this way, the functions meet the requirements of IEEE 279-1968, Equipment Qualification. (4.4) considered to be an indication that loss of heat sink has occurred or is imminent.

B. SDV level: The desired input is "loss of free volume." Since the total volume of the SDV is fixed, the measure of the water level in the SDV is considered to be an appropriate input.

7.2.5.9 Capability for Sensor Checks

The capability for sensor checks is provided in the design of the systems using substitute inputs where practical and cross-checking between channels where necessary. A further discussion of testing and surveillance is in Section 7.2.4. The following text discusses the applicability of the RPS functions to IEEE 279-1968, Capability of Sensor Checks. (4.9)

A. Neutron monitoring system scram trip - During reactor operation in the RUN mode, the IRM detectors are stored below the reactor core in a low flux region. Movement of the detectors into the core permits the operator to observe the instrument response from the different IRM channels and will confirm that the instrumentation is operable.

   In the power range of operation, the individual LPRM detectors respond to local neutron flux and provide the operator with an indication that these instrument channels are responding properly. The six APRM channels may also be observed to respond to changes in the gross power level of the reactor to confirm their operation.

   Each APRM instrument channel may also be calibrated with a simulated signal introduced into the amplifier input, and each IRM instrument channel may be calibrated by introducing an external signal source into the amplifier input.

   (Unit 2 only) Each OPRM module maybe calibrated with simulated signals introduced into the module input utilizing the OPRM Maintenance Terminal.

   During these tests, proper instrument response may be confirmed by observation of instrument lights in the control room and trip annunciators.

B. Reactor vessel high pressure scram trip - One sensor may be valved out-of-service at a time to perform a periodic test of the trip channel. During this test, operation of the sensor, its contacts, and the balance of the RPS trip channel may be confirmed.

C. Reactor vessel low water level scram trip - Due to the one-out-of-two-twice configuration of the RPS trip logic for this protective function, one level sensor at a time may be removed from service to perform the periodic test on any trip channel.

D. Turbine stop valve closure scram -

For any single stop valve closure test, two of the trip channels will be placed in a tripped condition, but none of the trip logics will be tripped and no RPS annunciation or computer trip channel logging will be evident. This arrangement permits single valve testing without corresponding tripping of the RPS, and the observation that no RPS trips result is a valid and necessary test result.

At reduced power levels, two valves may be tested in sequence to produce RPS trips, annunciation of the trips, and computer printout of the trip channel identification. These observations are another important test result that confirms proper RPS operation.

In sequence, each combination of single valve closures and dual valve closures is performed to confirm proper operation of all trip channels.

E. Turbine control valve fast closure scram trip - During any control valve fast closure test, one RPS trip channel will be tripped and will produce both control room annunciation and computer record of the trip channel identification.

F. Main steam line isolation valve closure scram trip - For any single valve closure test, two of the trip channels will be placed in a tripped condition, but none of the trip logics will be tripped and no RPS annunciation or computer trip channel record will be evident. This arrangement permits single valve testing without a corresponding trip of the RPS. The observation that no RPS trip results is a valid and necessary test result.

At reduced power levels, two valves may be tested in sequence to produce RPS trips, annunciation of the trips, and computer printout of the trip channel identification. These observations are another important test result that confirms proper RPS operation.

In sequence, each combination of single valve closures in each of two main steam lines is performed to confirm proper operation of all eight trip channels.

These test results confirm that the valve limit switches operate as the valves are manually closed.

G. Scram discharge volume high water level scram trip - During reactor operation, the discharge volume differential-pressure type and float type level sensors may be tested by using the instrument shut-off and test valves in proper sequence in conjunction with quantities of demineralized water.

H. Primary containment high-pressure scram trip - During reactor operation one pressure switch may be valved out-of-service at a time to perform periodic testing.

I. Deleted.

J. Reactor mode switch - Operation of the mode switch may be verified by the operator during plant operation by performing certain sensor tests to confirm proper RPS operation. Movement of the mode switch from one position to another is not required for these tests since the connection of appropriate sensors to the RPS logic, as well as disconnection of inappropriate sensors, may be confirmed from the sensor tests.

K. Turbine stop valve closure and turbine control valve fast closure trip bypass - Testing of individual pressure switches is permitted during plant operation by valving out-of-service one pressure switch at a time. A variable pressure source may then be introduced to the switch to confirm the setpoint value and switch operation.

L. Reactor protection systems outputs to other systems - Output signals from the RPS are not derived at the process sensor interface due to a lack of adequate isolation at this point. Rather, the outputs are obtained from the trip channel relays and trip actuator relays which do provide adequate isolation of the signal source.

M. Exceptions - This design requirement is not applicable to the following equipment:

1. Manual scram pushbuttons;
2. Trip logic test switch;
3. Reactor protection system reset switch;
4. Reactor protection system M-G sets and power distribution; and
5. Reactor protection system trip logic, actuators, and trip actuator logic.

7.2.5.10 Capability for Test and Calibration

Provisions are made for timely verification that each active or passive component in the RPS is capable of performing its intended function as an individual component

A. Reactor vessel high-pressure scram trip;

B. Reactor vessel low water level scram trip;

C. Primary containment high-pressure scram trip;

D. Deleted.

E. Manual scram pushbuttons;

F. Trip logic test switch;

G. Reactor protection system reset switch;

H. Reactor protection system M-G sets and power distribution;

I. The combined RPS trip logic, actuators, and trip actuator logic; and

J. Reactor protection systems outputs to other systems.

7.2.5.13 Indication of Bypasses

Annunciation exists in the control room when a channel is bypassed. If the ability to trip some part of the system has been bypassed, this fact is continuously indicated in the control room. The requirements of IEEE 279-1968, Indication of Bypass (4.13), are met for the following RPS trip function's bypasses:

A. Neutron monitoring system IRM, OPRM (Unit 2 only) and APRM scram;

B. Turbine stop valve closure, control valve fast closure, and EHC low-pressure scram;

C. Main steam line isolation valve closure and condenser low vacuum scram;

D. Scram discharge volume high water level scram (if tripped); and

7.2.5.14 Access to Means for Bypassing

All manual bypass switches and the reactor mode switch are in the control room, under the direct control of the control room operator. (4.14) Manual bypasses are controlled by mechanical, electrical, or administrative controls to maintain trip function operability through other channels when one channel is bypassed. Trip functions which use inputs from fluid sensors may also have individual sensors valved out-of-service and returned to service under the administrative control of the operator. Trip functions which use limit switch or position switch inputs cannot be manually bypassed. The neutron monitoring system allows a single bypass in each trip system which still yields at least two remaining active monitors in each trip system.

7.2.5.15 Multiple Trip Settings

Multiple setpoints are used where it is necessary to provide more restrictive reactor protection limits due to the mode of operation or operating conditions. (4.15) Multiple trip settings are utilized for the following trip channels:

A. Neutron monitoring - Setpoints are administratively controlled by reactor mode switch position (see Section 7.2.2);

B. IRM protection range - Setpoints are tracked by the operator's selection of the IRM range switch position.

7.2.5.16 Completion of Protective Action Once It Is Initiated

The IEEE 279-1968 requirement for Completion of Protective Action Once It Is Initiated (4.16) is addressed by the RPS in the following ways.

For the reactor protection system trip logic, actuators, and trip actuator logic, the interface of the RPS trip logic and the trip actuators assures that this design requirement is accomplished. The trip actuator is normally energized and is sealed in by one of the power contacts to the trip logic string. Once the trip logic string has been open-circuited as a result of a process sensor trip channel becoming tripped, the scram contactor seal-in contact opens. At this point in time, the completion of protection action is directed regardless of the state of the initiating process sensor trip channel.

The reactor protection system reset switch (when enabled) bypasses the seal-in contact to permit the RPS to be reset to its normally energized state when all process sensor trip channels are within their normal (untripped) range of operation. In the event of concurrent trips of both trip systems A and B, manual reset is automatically inhibited for a minimum time delay of 10 seconds. The time delay prevents reset prior to the insertion of all control rods.

7.2.5.17 Manual Actuation

Manual scram may be initiated through the operation of either the manual scram pushbuttons (one per trip channel), or placing the mode switch in the shutdown position. (4.17) A failure within the automatic scram initiation channels will not prevent the operation of the manual scram function.

D. Turbine stop valve closure scram trip - Due to the inherent simplicity of the valve limit switch for the process sensor and the relationship of one limit switch contact with one trip channel output relay, the design of the system facilitates maintenance of this protective function.

During power operation, it may be necessary to reduce power in order to close more than one turbine stop valve in order to accomplish a specific RPS test. The sequence of tests should permit the operator to determine a defective limit switch contact or trip channel output relay.

E. Turbine control valve fast closure scram trip - Periodic tests of portions of this protective function during plant operation will likely require a temporary reduction in plant output and may be accomplished with the provisions for testing of the turbine equipment.

F. Main steam line isolation valve closure scram trip - Due to the inherent simplicity of the valve limit switch for the process sensor and the relationship of one limit switch contact with one trip channel output relay, the design of the system facilitates maintenance of this protective function.

During power operation, it may be necessary to reduce power in order to close valves in more than one main steam line. With this arrangement, a sequence of valve tests will permit the operator to determine fully a defective component or isolate the difficulty to one of two limit switches in a given main steam line.

G. Scram discharge volume high water level scram trip - Because the water level measurement and its one-to-one relationship between a given level sensor and its associated trip channel output relay are inherently simple, the design facilitates maintenance of this protective function.

H. Primary containment high-pressure scram trip - Due to the one-to-one relationship of pressure switch and trip channel output relay, this design requirement is satisfied by this protective function.

I. Deleted.

J. Manual scram pushbuttons - Due to the simplicity of the manual scram function, the design complies with this requirement.

K. Reactor protection systems outputs to other systems - The design of these networks facilitates repair of the RPS by providing timely information readout and identification of failures for the operating personnel.

The system is designed in such a manner that it can be easily repaired.

Table 7.2-1

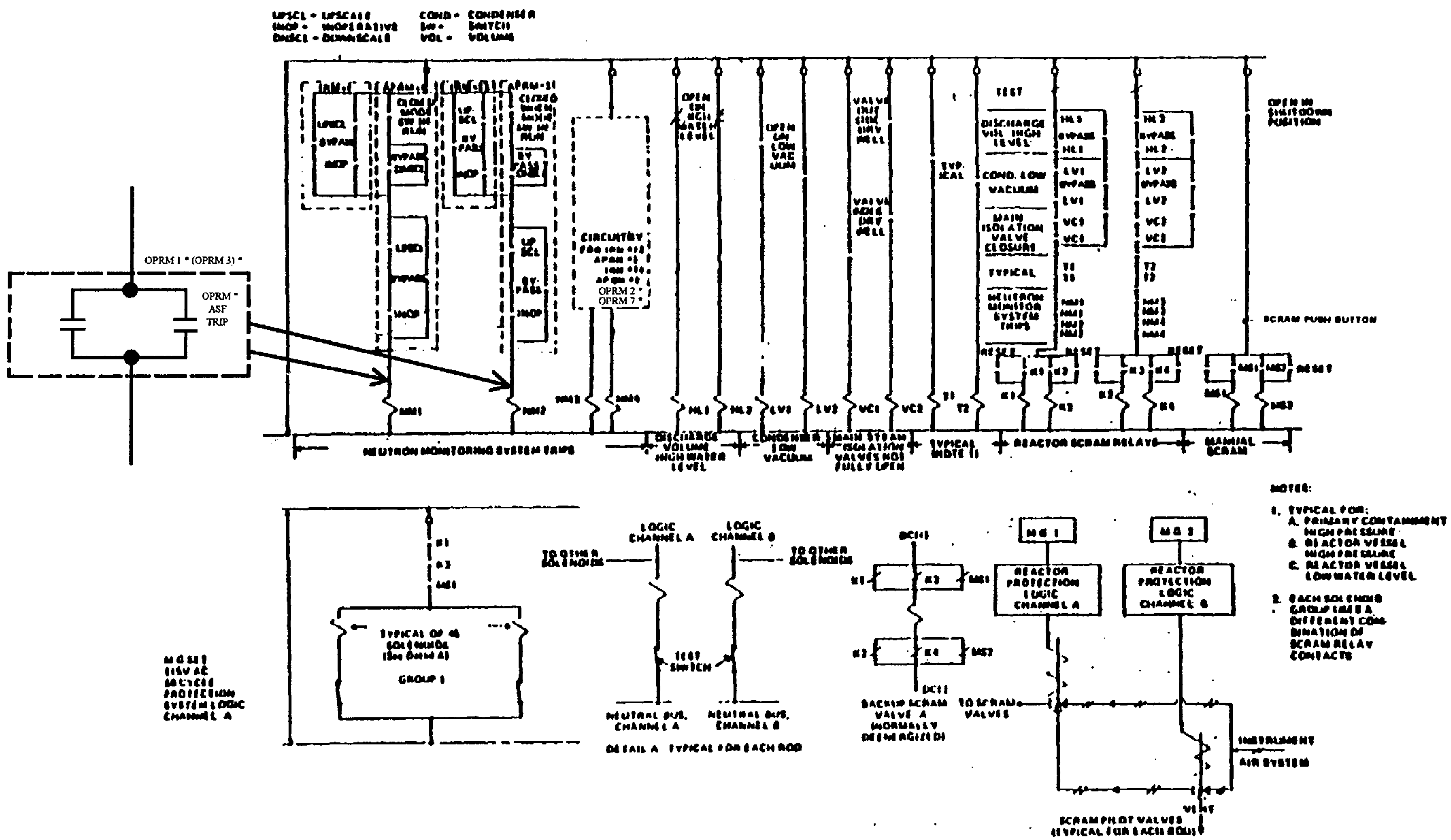
TYPICAL PROTECTION SYSTEMS SETPOINTS

Signal	Scram Setpoint[2]
Reactor High Pressure	1060 psig
Reactor Low Level	1 in.[1]
Reactor Neutron Flux Oscillation (OPRM)	See Table 7.6-1
Reactor High Neutron Flux	
APRM	(See Technical Specifications)
IRM	120%/125% of full scale
Primary Containment High Pressure	2.0 psig
Condenser Low Vacuum	21 in.Hg vacuum
Scram Discharge Volume High Level	Unit 2: ≤ 40.4 gallons Unit 3: ≤ 41 gallons
Turbine-Generator Load Rejection	460 psig oil pressure at the control valve
Main Steam Line Isolation Valve Closure	10% closure
Turbine Stop Valve Closure	10% closure
Loss of Turbine Control Oil Pressure	900 psig

Notes:

1. One-inch instrument level = 504 inches above vessel zero (inside the core shroud) or 144 inches above the top of active fuel. The top of active fuel is defined as 360 inches above vessel zero.

2. Data on trip setpoints can be obtained from Technical Specifications Table 2.2.A-1.



* UNIT 2 ONLY

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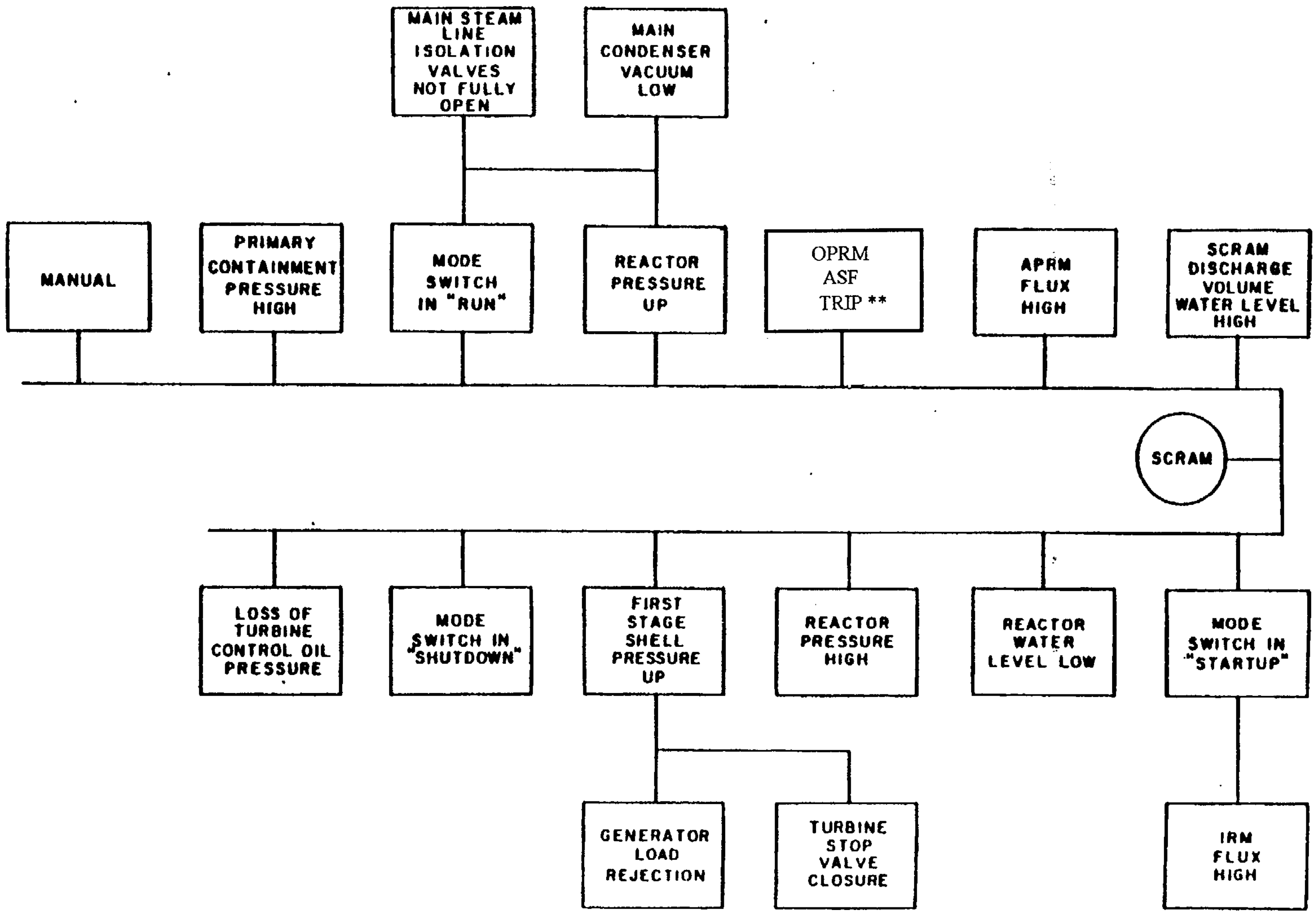
DRESDEN STATION
UNITS 2 & 3

REACTOR PROTECTION SYSTEM -SINGLE LOGIC CHANNEL TRIPPING DIAGRAM

FIGURE 7.2-2



** UNIT 2 ONLY, WHEN OPRM IS ARMED

UFSAR REVISION 4, JUNE 2001

DRESDEN STATION
UNITS 2 & 3

REACTOR PROTECTION SYSTEM
SCRAM FUNCTION

FIGURE 7.2-3

F. The logic seals in the loop selection and sends a close signal to the recirculation pump discharge valve for the selected loop and to the LPCI injection valve for the other loop.

G. Upon receipt of the preset reactor low-pressure signal, previously described, the selected injection valve opens.

The pumping mode selector logic uses dP instruments which measure recirculation pump ΔP to determine the number of recirculation pumps running. The taps for these instruments are as close to the pump suction and discharge as practical. The trip setting is approximately +2 psid. The trip point should be repeatable within 0.2 psid. Only positive ΔP measurement is necessary.

If both recirculation pumps are running, the ΔP across both pumps will indicate greater than 2 psid. With both pumps running, the pumps will amplify the break detection ΔP (provide the greatest break detection sensitivity); therefore, the "two pump" side of the logic is used to allow measurement of the break detection ΔP with the recirculation pumps running.

If the ΔP across either or both pumps is less than 2 psid, the ½-second timer runs out causing the network to proceed on the "one pump" side of the network.

Seal-ins on the "one pump" or "two pump" sides are required to ensure that the pump coastdown or resumption of ac power does not result in changes in the network arrangement later.

If only one recirculation pump is operating, the recirculation pump trip provided by the pumping mode selector is required to allow detection of small breaks. Circuitry on the "one pump" side of the network provides a trip signal to both recirculation pumps unless both pumps are running.

A reactor vessel pressure permissive will delay the loop selection logic initiation until reactor pressure has dropped to a value less than or equal to 900 psig to allow for coast down of any recirculation pump which has just been tripped. This setpoint optimizes sensitivity while ensuring that injection is not delayed unnecessarily. The trip point is adjustable over a range of reactor pressure from 500 to 1000 psig. This trip point should be repeatable within 10 psig.

After satisfying the 900 psig pressure permissive or verifying that both pumps are running (indicated by ΔP greater than 2 psi), the network must wait 2 seconds before loop selection. The timer is adjustable from a 0- to 10-second delay.

The 2-second delay in the break detection circuit is provided to allow time for momentum effects to establish the maximum pressure differential for break detection. Since the flow decay time constant of the fluid in one recirculation loop (excluding the pump and motor-generator [MG] set) is about 1-second, a 2-second delay will assure that the momentum effects have established the maximum pressure differential for loop selection.

If loop A pressure is greater than that of loop B, then loop B is broken and injection will occur in loop A. If the loop A pressure is not greater than that of loop B, the ½-second timer will run out causing loop B to be selected. Seal-ins are required so that pump coastdown, reductions in vessel pressure, or other effects will not cause

B. Single relay failure to pickup,

C. Single relay failure to dropout,

D. Single instrument failure, and

E. Single control power failure.

Reliability of the control system is compatible with and more reliable than the controlled equipment (injection valve). Single failures which could cause improper loop selection (i.e., selected short circuits which pickup specific relays) will not disable the core spray function. Therefore, failure of the loop selection scheme to fully comply with the single-failure criterion of IEEE 279-1968, Paragraph 4.2, does not constitute a violation of IEEE 279-1968 insofar as the low-pressure cooling function is concerned.

7.3.1.2.3.3 Quality of Components

The discussion of component capability for the core spray system (Section 7.3.1.1.1.3) also applies generally to the LPCI system.

7.3.1.2.3.4 Equipment Qualification

The discussion of equipment qualification for the core spray system (Section 7.3.1.1.1.4) also applies to the LPCI system.

7.3.1.2.3.5 Channel Integrity

The LPCI system initiation channels (low water level or high drywell pressure) are designed to meet the single-failure criterion (as discussed in Section 7.3.1.2.3.2). Therefore, they satisfy the channel integrity objective of IEEE 279-1968, Paragraph 4.5.

The LPCI logic backup has been achieved without compromising the integrity of the channel being backed up. Analysis shows that a complete destruction of a wireway (conduit) carrying wires between the two relay panels can do no more than introduce a ground on one side of the dc control bus; it will not prevent operation of either logic circuit.

The instrumentation provided for the loop selection logic does not initiate a protective action; therefore IEEE 279-1968 Paragraph 4.5 does not strictly apply to this instrumentation. However, as previously described, redundancy in instrumentation and control logic circuits has been provided so that it is extremely unlikely that a failure within this functional logic will prevent proper LPCI operation.

The isolation functions and trip settings used for the electrical control of isolation valves are described in the following paragraphs.

7.3.2.2.1 Low Reactor Vessel Water Level

The low reactor level instrumentation is set to trip at greater than 8 inches on the level instrument. After allowing for the full power pressure drop across the steam dryer, the low-level trip is at 504 inches above vessel zero or 144 inches above the top of active fuel (inside shroud). This trip initiates closure of Group 2 and 3 primary containment isolation valves. For a trip setting of 8 inches on the instrument scale and a 60-second valve closure time, the valves will be closed before perforation of the cladding occurs even for the maximum break: the setting is therefore adequate.

The low-low reactor level instrumentation is set to trip when reactor water level is -59 inches on the instrument scale. This trip initiates closure of Group 1 primary containment isolation valves. This trip setting level was chosen to be high enough to prevent spurious operation but low enough to initiate ECCS operation and primary system isolation so that no melting of the fuel cladding will occur, post-accident cooling can be accomplished and the guidelines of 10 CFR 100 will not be exceeded. For the complete circumferential break of a 28-inch recirculation line and with the trip setting given above, ECCS initiation and primary isolation are initiated in time to meet the above criteria. The instrumentation also covers the full spectrum of breaks and meets the above criteria.

7.3.2.2.2 Main Steam Line High Radiation

Deleted.

Total system isolation is not desirable for these conditions, and only the Group 2 valves are required to close. The low-low water level instrumentation initiates protection for the full spectrum of LOCAs and causes a trip of Group 1 primary system isolation valves.

7.3.2.2.7 Primary Containment (Drywell) High Radiation

The primary containment (drywell) high radiation signal initiates a Group 2 isolation signal in the event that high drywell radiation is experienced. The intention of the isolation is to minimize releases to the public. This signal provides a backup within the existing Group 2 isolation function. The backup function would only be necessary in the unlikely event that high radiation were present in the drywell without low reactor water level or high drywell pressure.

7.3.2.2.8 High Pressure Coolant Injection Turbine Area High Temperature

The HPCI high temperature instrumentation is provided to detect a break of the HPCI turbine steam line in the HPCI compartment. Tripping of this instrumentation results in actuation of HPCI isolation valves, i.e., Group 4 valves. All sensors are required to be operable to meet the single-failure criterion for design flow and valve closure times are such that core uncovery is prevented and fission product release is within limits.

7.3.2.2.9 High Pressure Coolant Injection High Steam Line Flow

The HPCI high flow instrumentation is provided to detect a break in the HPCI turbine steam line. Tripping of this instrumentation results in actuation of HPCI isolation valves, i.e., Group 4 valves. All sensors are required to be operable to meet the single-failure criterion for design flow and valve closure times are such that core uncovery is prevented and fission product release is within limits.

7.3.2.2.10 High Pressure Coolant Injection Low Steam Line Pressure

The low-pressure signal provides automatic isolation of the turbine loop prior to stalling the turbine on low available energy. With the low-pressure condition present, the isolation signal will block the auto-initiation logic of the HPCI. If, however, reactor pressure should rise above the pressure switch setpoint, the isolation signal will auto-reset, and the HPCI will be capable of auto-restart upon receipt of an initiation signal.

7.3.2.2.11 Isolation Condenser High Flow

Two sensors on the isolation condenser supply and return lines are provided to detect the failure of isolation condenser lines and actuate isolation action. All sensors and instrumentation are required to be operable. The trip settings as defined in the technical specifications and valve closure time prevent uncovering the core or exceeding site limits. The Unit 3 high-flow isolation logic has a time delay of 2 ± 0.5 seconds to eliminate spurious isolation. The sensors will actuate due to high flow in either direction.

7.3.2.3 Primary Containment Isolation System Instrumentation

The sensors for the PCIS are described in the following paragraphs.

A. Reactor water level pressure sensors are identical to those utilized in the reactor protection system and are described in Section 7.2.

B. Deleted.

C. Steam line tunnel temperatures are sensed by 16 temperature switches. Four switches are used in each instrumentation trip channel. High temperature is indicative of a steam line break.

D. High main steam line flow is sensed by 16 indicating differential pressure switches operating from flow restrictor devices. Each main steam line has one flow restrictor: four separate differential pressure switches operate across each flow restrictor, providing an input from each flow restrictor into each logic trip channel. A trip is actuated by a high differential pressure, indicating high flow.

E. Main steam line low pressure is sensed by four bourdon-tube-operated pressure switches, sensing pressure directly downstream of the main steam equalizing header. Each pressure switch provides an input to one instrumentation trip channel. These switches are mounted on shock absorbing isolators to prevent spurious actuation of the switches.

   A bypass is provided for the main steam line low pressure trip. The bypass is effective when the mode switch is in any position other than RUN.

F. High drywell pressure is sensed by four diaphragm-operated pressure switches. Each switch provides an input to one instrumentation subchannel.

G. High drywell radiation is detected by two radiation monitors in the drywell. This isolation has a two-out-of-two-once logic.

H. There are two HPCI differential-pressure-type flow switches, both connected in one-out-of-two logic, across a single set of sensing lines across the steam line elbow within the primary containment vessel (drywell). The flow sensors are electrically connected to the isolation system such that a trip in either one or both sensors will initiate isolation. A failure of one sensor in the nontrip mode will neither initiate isolation nor prevent the other sensor from initiating isolation on

7.3.2.6.6 Channel Independence

Channel independence for sensors exposed to each process variable is provided by electrical and mechanical separation (IEEE 279-1968, Paragraph 4.6). Physical separation is maintained between redundant elements of the redundant control systems where it adds to reliability of operation. The manual control switches for the HPCI isolation valves are an exception to this objective, but they are sufficiently separated to give a high degree of reliability and to meet a literal interpretation of Paragraph 4.6 of IEEE 279-1968.

7.3.2.6.7 Control and Protection Interaction

The isolation control system is a strictly on/off system, and no signal whose failure could cause a need for isolation can also prevent it (IEEE 279-1968, Paragraph 4.7).

7.3.2.6.8 Derivation of System Inputs

The inputs which initiate isolation valve closure are direct measures of variables that indicate a need for isolation (such as reactor vessel low level, drywell high pressure, and pipe break detection) (IEEE 279-1968, Paragraph 4.8). Pipe break detection utilizes methods of recognition of the presence of a material that has escaped from the pipe rather than detecting actual physical changes in the pipe itself.

7.3.2.6.9 Capability for Sensor Checks

The reactor vessel instruments including level, pressure, radiation, and flow, can be checked one at a time by application of simulated signals (IEEE 279-1968, Paragraph 4.9). Temperature sensors along the main steam lines are testable only during shutdown, but they are sufficient in number so that testing between refueling outages is not necessary to achieve the reliability level required. Temperature sensors can be checked periodically by removing them and applying heat to the sensitive zone, or by oven calibration, which requires removing the sensors from the circuit and replacing them with calibrated units.

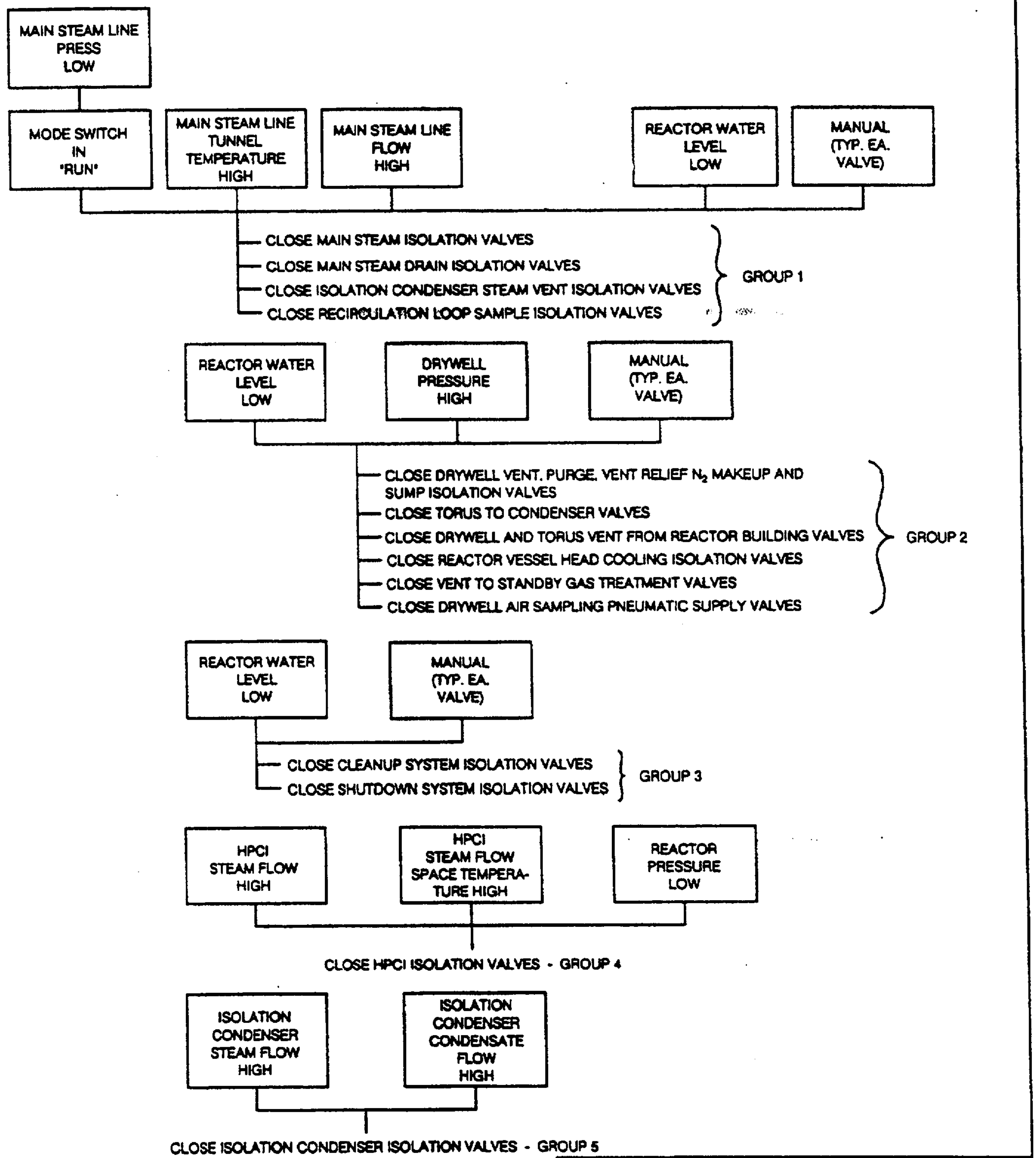
7.3.2.6.10 Capability for Test and Calibration

All active components of PCIS, with the exception of the main steam line high temperature sensors can be tested and calibrated during plant operation (IEEE 279-1968, Paragraph 4.10).

Table 7.3-1

GROUP ISOLATION SIGNALS AND SETPOINTS

Valve Isolation Group	Isolation Signal	Nominal Setpoint
Group 1	Reactor low-low water level	-59 in.
	Main steam line high flow	120% of rated flow
	Main steam line tunnel high temperature	200°F
	Main steam line low pressure	825 psig
Group 2	Reactor low water level	+8 in.
	High drywell pressure	2 psig
	High drywell radiation level	100 R/hr
Group 3	Reactor low water level	+8 in.
Group 4	HPCI steam line high flow	≤ 300% rated steamflow
	HPCI vicinity high temperature	200°F
	Low reactor pressure	100 psig
Group 5	High flow isolation condenser steam supply	≤ 300% rated steamflow
	High flow isolation condenser condensate return	≤32 in.H_2O differential (Unit 2) ≤14.8 in.H_2O differential (Unit 3)



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BLOCK DIAGRAM - PRIMARY CONTAINMENT ISOLATION

FIGURE 7.3-11

A simplified block diagram of the process computer is shown in Figure 7.5-1. Analog voltage and current inputs representing reactor flux levels, flows, pressures, temperatures, and power levels are applied directly to the process interface units (PIUs). Digital inputs for both units, which include various trips and alarms, traversing incore probe (TIP) system signals, control rod positions, rod worth minimizer (RWM) inputs and pulse inputs for TIP positions and gross generator energy are applied directly to the PIUs. The process computer performs calculations required for the programs being run, assigns priorities to the various programs and computer functions, and provides for data storage.

Scanning of all plant instrument inputs and outputs is provided by the PIUs. The analog inputs are scanned locally in the PIU at a predetermined rate, converted to a digital signal or linearized, and then broadcast to the host 4500 computer via high speed redundant data highways. Sensor limits are validated at the PIUs and the digitized value is converted by the 4500 to engineering units and the process limit is checked for alarm purposes.

The computer components primarily involved in operation of the NSSS, SLA, and BOP programs are the computer operator's consoles, the various typers, and the trend recorders, and PIU data acquisition equipment.

For each unit, two request CRTs (operator's consoles) for each unit are located in the control room. The request CRT provides the operator the means to initiate, cancel, or modify the operation of demandable computer functions and programs.

An alarm horn is included in the nuclear station operator (NSO) console to provide audible alarm indications. The alarm horn is sounded under program control as a result of various alarm or abnormal conditions.

Included with the process computer system are two trend recorders, located in panel 902-5(903-5). Each is a two-pen strip chart recorder. Each of the four pens on the two recorders can be individually selected from the NSO request CRT for trending of selected analog values.

The Station Process Computer is now located in the Station's Main Computer Room which is located in the Unit 1 Turbine Building ground floor. This computer was relocated from the Unit 2/3 Auxiliary Computer Room by a modification into the Station's Main Computer Room. The Station Main Computer Room now contains the Station Process and other plant monitoring computers.

7.5.2.3 Operational Functions

This subsection contains program descriptions for the NSSS periodic and on-demand programs. These programs calculate and edit the periodic, daily, and monthly core performance logs and provide a variety of operator-demandable data arrays related to nuclear boiler performance.

The NSSS periodic and on-demand programs operate within the constraints of the static and dynamic priority structures, as do certain associated interface and control programs.

Software is a term used to designate all the programs, subroutines, and functions used with a particular computer system. A program is a set of instructions placed in computer memory which defines a specific functional task and sets forth the methods by which the computer is to accomplish it. A system subroutine is a similar set of instructions defining a more circumscribed or generalized procedure which, since it may be required for a number of different functional operations, is

7.6 CORE AND VESSEL INSTRUMENTATION

This section describes core and vessel instrumentation systems. Included are nuclear instrumentation systems and vessel instrumentation.

7.6.1 Nuclear Instrumentation

7.6.1.1 Design Basis

The nuclear instrumentation is designed to:

A. Provide the operator with the information required for optimum, safe operation of the reactor core.

B. Provide inputs to the reactor protection system (RPS) and the rod block circuitry to assure that the local power density, power oscillations (Unit 2 only), and bulk power level do not exceed preset limits.

In order to meet the design requirements, the nuclear instrumentation must:

A. Detect, measure, and indicate neutron flux from the source range level through the power range level;

B. Annunciate an alarm on component failures; and

C. When reactor power is in the power range;

   1. Indicate local neutron flux;

   2. Compute and indicate average reactor power; and

   3. Detect and suppress core power oscillations (Unit 2 only).

Specific design requirements are listed in this section for each nuclear instrumentation subsystem.

7.6.1.2 General Description

The nuclear instrumentation uses three types of neutron monitors.[1] The neutron flux level for operation in the region of subcritical to an intermediate flux level at which the reactor is critical is monitored by the source range monitor (SRM). The intermediate range monitor (IRM) is used for a neutron flux level of just above criticality to approximately 10% of full power (refer to Figure 7.6-1). From about 3% power to full power operation, the local power range monitor (LPRM) is used. The detectors for the SRM and IRM subsystems are withdrawn from the core during power range operation. The detectors for the power range are fixed in place.

During operation in the power range, the LPRM signals are used in four separate subsystems:

A. LPRM flux level is indicated, and a high flux alarm is annunciated if the level reaches a preselected point.

B. The average power range monitors (APRMs) average the outputs of selected LPRMs to provide indication of average reactor power. The APRM generates scram signals on high-high APRM flux level.

C. During control rod motion, the average of a set of LPRMs adjacent to the selected control rod is used by the rod block monitor (RBM) to limit increases in local power.

D. (For Unit 2 only) The OPRM utilizes the LPRM signals to detect and suppress core instabilities that are known to take place in certain portions of the core power to flow operating domain.

Figure 7.6-2 presents a block diagram of the various nuclear instruments. Figure 7.6-1 shows the instrumentation ranges as they relate to neutron flux and percent power.

A traversing incore probe (TIP) may be inserted in the core to obtain an axial neutron flux distribution at each LPRM detector location. The information obtained from the TIP is used to calibrate the LPRM subsystem and to provide a relative core flux distribution to the process computer.

7.6.1.3 Source Range Monitoring Subsystem

7.6.1.3.1 Design Bases

To meet the general design requirement to provide the nuclear information needed for knowledgeable and efficient reactor startup and low flux level operation, the SRM subsystem must:

A. Provide a minimum signal-to-noise ratio of 3:1 and a minimum count rate of 3 cps with all control rods inserted prior to initial power operation (for the original core, this included the contribution of neutron-emitting sources - see Section 7.6.1.3.2).

B. Show a measurable increase in output signal from at least one detector before the neutron flux multiplication exceeds a factor of 2000 during the most limiting startup control rod withdrawal condition.

C. Provide a signal overlap of approximately one decade to the IRM signal with the SRM detectors in the fully-inserted position.

7.6.1.3.2 System Description

The SRM subsystem is used to provide the necessary information for reactor startup from subcritical to an intermediate flux level and for refueling operations. The subsystem consists of four miniature fission chambers which are operated in the pulse-counting mode. These detectors have a nominal sensitivity of 2×10^{-3}

cps/nv (nv is neutrons per square centimeter per second) and are located radially in the core as shown in Figure 7.6-3. The detectors are attached to drive mechanisms, which can position the chambers from the fully inserted location (approximately 1.5 ft above core center), to a position approximately 2.5 feet below the reactor core.

The detector drive system consists of a detector drive, a flexible drive shaft, a motor module, and a drive tube for each detector. The drive is mounted through an adapter to the instrumentation nozzle, well below the vessel, in a location that does not interfere with control rod operation and maintenance. The drive tube is a long hollow tube which acts as a guide. A long, slender shuttle tube is mounted on the upper end of the drive tube. This combination tube, housing the fission chamber detector assembly, is driven up and down inside the dry tube.

A flexible drive shaft transmits power to the gearbox of the detector drive assembly from the motor module located approximately 20 feet away. Four limit switches provide detector position information and also interlock the motor power circuits to establish insert and retract limits.

Seven neutron-emitting antimony-beryllium sources were located radially within the reactor core as indicated in Figure 7.6-3. These sources were designed to provide at least 3 cps in each SRM channel with the reactor in the cold, xenon-free, fully shutdown condition. This requirement continued to be met during routine reactor operation by reactivation of the radioactive source (Sb-124) through capture of reactor neutrons by Sb-123. These sources have been removed, since photoneutron production is high enough to provide the required neutron flux without these sources.

The SRM detector assembly consists of a fission chamber attached to a low-loss quartz fiber-insulated transmission cable terminated with a connector. The detector cable is connected below the reactor vessel to a triple-shielded cable which carries the detector electrical output to the monitor circuitry. The output from each of the four SRM detectors is amplified and the signal is conditioned. The resulting signal, proportional to the logarithm of the counts per second occurring in the detector, is continuously displayed on log count rate meters. The time derivative of this signal is formed and displayed on four reactor period meters which indicate reactor period in seconds. A two-pen strip chart recorder is available to the operator to allow recording of two of the four log count rate signals by switch selection. Annunciators are activated by various conditions including short reactor period and high count rate.

Performance of Shutdown Margin Demonstrations (multiple control rods withdrawn) with the vessel head removed or de-tensioned required additional restrictions in order to provide additional protection against a reactivity excursion above what the IRMs alone provide. It is necessary to provide non-coincidence scram protection to meet these additional restrictions. Non-coincidence reactor scram is achieved by removal of the shorting links normally installed in the reactor protection system manual scram logic (see section 7.2).

Each of the four SRM channels initiates a rod block (see Section 7.7) with the mode switch in STARTUP/HOT STANDBY, or REFUEL under the following conditions:

A. SRM count level high (greater than 10^5 cps);

B. SRM channel inoperative; or

C. SRM detectors not fully inserted into the reactor core with the SRM count level below 100 cps.

The SRM detector position rod block is actuated by a position indicator on the retract mechanism. The SRM channel inoperative rod block is effective whenever the high voltage supply drops below a preset level, one of the channel modules is decade is provided. The SRM/IRM detector range overlap reduces the uncertainty in the neutron level indication during the transition from the SRM to the IRM.

The detector is designed to function in the environment in which it is located. An SRM component or power supply failure is annunciated. Failure of any SRM channel during low-flux operations with the mode switch in REFUEL or STARTUP/HOT STANDBY will initiate a rod block, thus preventing control rod withdrawal. The bypass switch arrangement permits only one SRM channel to be bypassed, guaranteeing the required detection capability during source range reactor operation.

The SRM detector position rod block assures that reactivity insertion will not be made under very low-flux level conditions unless the SRM detectors are inserted to the optimum position for flux detection. Administrative controls exist to ensure that at least two SRMs are fully inserted and operable prior to control rod withdrawal for startup.

7.6.1.3.4 Surveillance and Testing

Source range monitor failures are annunciated. All components in the SRM circuitry can be calibrated using built-in calibration equipment.

7.6.1.4 Intermediate Range Monitoring Subsystem

7.6.1.4.1 Design Basis

The intermediate range monitoring (IRM) subsystem is designed to:

A. Detect and indicate neutron flux level in a range between the SRM detection capability and the power range instrumentation capability (approximately 10^8 to 10^{12} nv), and

B. Generate trip signals to prevent fuel damage from a single operator error or a single equipment malfunction.

7.6.1.4.2 System Description

The IRM subsystem is composed of eight miniature fission chambers located radially in the core as shown in Figure 7.6-4. The figure also shows the assignment of IRM detectors to each RPS logic channel. The assignment is made to provide coverage of each quadrant of the reactor core with one detector in each channel bypassed. The detectors are attached to drive mechanisms, which can position the chamber from the fully inserted location (approximately 1.5 ft above core center), to a position approximately 2.5 feet below the reactor core. The detectors and the drive systems are similar to those used in the SRM subsystem except for the range of measurement. The detectors are not withdrawn from their fully inserted position until the mode switch has been turned to the RUN position.

The overlap between the IRM and the power range monitoring subsystem is sufficient to guarantee a safe transition between the instrumentation ranges (Figure 7.6-1). Overlap between the SRM and IRM ranges is discussed in Section 7.6.1.3.3.

During periods of reactor operation when the IRM is required for flux level indication the IRM detector position rod block prevents rod withdrawal unless the detectors are fully inserted.

The IRM detectors are chosen with characteristics which permit reliable performance in the reactor environment.

IRM failures are annunciated and, during low-flux level reactor operation, result in a RPS single logic channel trip and rod block. Thus, further rod withdrawal is prevented, and a reactor scram would be initiated by any condition resulting in a trip of the other RPS logic channel.

7.6.1.4.4 Surveillance and Testing

IRM component or power supply failures are annunciated in the control room. Built-in calibration equipment is provided to periodically check and reset the IRM equipment.

7.6.1.5 Power Range Monitoring Subsystem

Power range instruments include LPRMs, APRMs, OPRMs, (Unit 2 only) RBM, and TIP (see Figure 7.6-1 and 7.6-2).

7.6.1.5.1 Local Power Range Monitoring Subsystem

7.6.1.5.1.1 Design Basis

In order for the power range instrumentation to meet the general design requirements for power range flux monitoring and prevention of excessive local and bulk power densities, the LPRM subsystem must:

A. Continuously monitor, over its design range, local neutron flux and alarm on excessive conditions;

B. Permit evaluation of the critical core parameters (fuel thermal limits) to an accuracy consistent with core design and established limits; and

C. Permit demonstration of compliance with the critical core parameters (fuel thermal limits) with a speed and ease consistent with efficient operation of the plant.

7.6.1.5.1.2 System Description

The LPRM subsystem output signals are used to demonstrate that the core is operating within the established limits for maximum fuel design limiting ratio (steady-state) (MFDLRX), maximum fuel design limiting ratio for centerline melt (MFDLRC), minimum critical power ratio (MCPR), and maximum average planar linear heat generation rate (MAPLHGR). This subsystem provides the information needed for evaluating the detailed characteristics of the power distribution and for other technical evaluations. The LPRM subsystem provides input to the average power range monitoring subsystem, the oscillating power range monitor (Unit 2 only), and rod block monitor subsystem, which are described below.

The LPRM subsystem, which uses dc measurement techniques, consists of miniature fission chambers located within the reactor core, electronic signal conditioning equipment located in the control room, and a TIP calibration system.

Each LPRM has a high neutron flux level alarm and a common annunciator located on the control board.

Figures 7.6-7 and 7.6-8 indicate the core location of the LPRM strings. Each LPRM string consists of four miniature fission chambers which are spaced vertically at 3-foot intervals.

The top and bottom chambers are located 1.5 feet from the core boundaries, thereby providing uniform core coverage in the axial direction. Also included in each detector string is a calibration tube which accepts the TIP used to measure the axial flux distribution and calibrate the LPRM subsystem (see Figure 7.6-8).

Figure 7.6-9 illustrates that, due to the equivalence of locations resulting from symmetry, the LPRM subsystem monitors all unique locations within the central region of the core when the core is operated with quadrant symmetric control rod patterns.

The LPRM flux amplifiers are calibrated using data from the TIP calibration system, heat balance data, and some analytical data. The basic process involves:

A. Running the TIP system and accumulating axial profile data,

B. Normalizing the axial profile data,

C. Determining for each detector elevation the average nodal heat flux in four adjacent fuel nodes at that elevation, and

D. Adjusting flux amplifiers until meter readings are proportional to heat flux.

These calculations are performed using the process computer (see Section 7.5). When these adjustments have been made, the LPRM signals are proportional to the average nodal heat flux in the four adjacent fuel nodes at the detector elevation. The 16 LPRM amplifier signals adjacent to a control rod selected (four detectors in each of four adjacent strings) are displayed on 16 centrally located meters. This display directs the attention of the operator to the local power level prior to and during rod motion. These 16 signals are also used by the RBM. When affect the output signals of the LPRM amplifiers which are averaged in the APRM channel.

If an LPRM used to provide input to an APRM channel fails, the operator can manually bypass this invalid input. The APRM channel then properly averages the inputs from the remaining LPRM channels. If the number of bypassed LPRMs used as inputs to an APRM channel exceeds a preset number, the APRM instrument inoperative alarm is actuated. This feature assures that the APRM system will adequately perform its safety function of terminating average neutron flux level transients through scram initiation. In addition to the automatic input monitoring, administrative controls require at least 50% of all LPRMs and at least 2 LPRMs per level for an APRM to be operable. The "too few input trip" feature also automatically provides a high degree of assurance that the APRM system will be capable of preventing fuel damage due to rod withdrawal errors.

7.6.1.5.2.3 Design Evaluation

As shown in Figures 7.6-10 and 7.6-11, the LPRM inputs to the APRM channels provide a wide sampling of local flux levels on which to base an average power level measurement. The fact that three APRM channels are provided for each RPS logic channel assures that at least two independent average power measurements will be available under the worst permitted bypass or failure conditions. The six APRM channels provide continuous indications of core average power level based on different samplings of local flux levels. Figures 7.6-14 and 7.6-15, which are the results of analysis, show that the APRM provides valid average power measurements during typical rod- or flow-induced power level maneuvering.

Using a plant heat balance technique, the APRM measurements are calculated such that the meter indications are within ±2% of the rated bulk thermal power when the power level is ≥25% of rated; this calibration is maintained by procedure.

The effectiveness of the APRM high-flux scram signals in preventing fuel damage following single component failures or single operational errors is shown in each section of this report where system failures are analyzed; in all such failures, no fuel damage occurs. Since only two APRM channels in each RPS logic channel are required for effective detection of bulk power level transients, the same effectiveness is attained even under the worst permitted bypass conditions.

The APRM rod block setpoint is set lower than the scram setpoint; thus, reactivity insertions due to rod withdrawal errors are terminated well before fuel damage limits are approached.

To account for the decreasing margin to fuel damage at a given power level with reduced recirculation flow, the APRM rod block setpoint is varied with flow.

Average power range monitor component failures which result in upscale, downscale, or instrument inoperative conditions are annunciated, and the reduction of LPRM inputs for any APRM channel below a preset number gives an alarm, rod block, and a logic channel trip. These features warn of loss of APRM capability.

An additional manual ball valve is installed between the automatic ball valve and the drywell penetration.

A guide tube ball valve is normally de-energized and in the closed position. When the TIP starts forward the valve is energized and opens. As it opens it actuates a set of contacts which gives a signal light indication at the TIP control panel and bypasses an inhibit limit which automatically stops TIP motion if the ball valve does not open on command. A Group 2 containment isolation signal initiates TIP drive withdrawal and closes the ball valve when the TIP is retracted.

7.6.1.5.5 Surveillance and Testing

Power range nuclear instrumentation failures are annunciated. Monitor circuitry is arranged to facilitate testing with simulated signals. The TIP system provides information used to periodically calibrate the system.

7.6.1.6 Oscillation Power Range Monitoring Subsystem (Unit 2 Only)

The Oscillation Power Range Monitor (OPRM) subsystem is a microprocessor-based monitoring and protection system, which will:

- detect a thermal-hydraulic instability,
- provide an alarm on detection of an oscillation (based on period-based algorithm only), and
- when armed, initiate an Automatic Suppression System (ASF) trip to suppress an oscillation prior to exceeding fuel safety limits.

The subsystem design, technical details, equipment qualifications, and validation are discussed in Reference 3. The NRC has accepted the above reference, and had issued a safety evaluation report (Reference 4).

7.6.1.6.1 Design Basis

7.6.1.6.1.1 Safety Design Bases

Boiling water reactor cores may exhibit thermal-hydraulic reactor instabilities in certain portions of the core power and flow operating domain. General Design Criterion 10 (GDC 10) requires that the reactor core be designed with appropriate margin to assure that acceptable fuel design limits will not be exceeded during any condition of normal operation including the effects of anticipated operational occurrences. GDC 12 requires assurance that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. The OPRM is provided to meet the requirements of these GDCs by adding a detect and suppress feature to the Reactor Protection System.

7.6.1.6.1.2 Power Generation Design Bases

The power generation design basis of OPRM consists of assuring that spurious scrams do not occur. This objective is accomplished in part by establishing an exclusion region, as discussed below in Section 7.6.1.6.2, where the thermal-hydraulic oscillations are not postulated to occur.

7.6.1.6.2 System Description

Detailed description of OPRM subsystem design and physical arrangements are provided in the Generic Topical Report (Reference 3). Basic and station specific information is summarized here.

The OPRM subsystem consists of 4 OPRM trip channels, each channel consisting of two OPRM modules. Each OPRM module receives input from a group of LPRMs combined into localized monitoring cells. It also receives input from the Average Power Range Monitor (APRM) power and Reactor Recirculation flow signals to automatically enable the trip function of the OPRM module, when it is armed. A block diagram showing the relationship of OPRM with other nuclear instrumentation is shown in Figure 7.6-2. Reactor coolant flow instrumentation feed to the OPRM is shown in Figure 7.6-12.

The OPRMs are capable of detecting thermal-hydraulic instabilities within the reactor core. The OPRMs are designed to provide an alarm and initiate an automatic suppression function (ASF) trip, when they are fully armed, to suppress oscillations prior to exceeding the MCPR safety limits. The OPRMs are auto enabled at the specified reactor recirculation flow and reactor power setpoints. The ASF outputs initiate an ASF trip through the RPS based on the existing plant trip logic and configuration. The OPRM System provides annunciator windows, SER messages and indicating lights for pre-trip conditions and other alarm functions such as Trip, Alarm, Trouble, Inip Bypass and Trip Enabled to be displayed in the Main Control Room (MCR).

Each OPRM includes a signal processing module, Automatic Suppression Function (ASF) Trip Relay Assembly , OPRM Annunciator Relay Assembly, two Digital Isolation Blocks (DIBs) and Enable and Bypass Selector Switches.

The OPRM trip circuits may be bypassed by a selector switch. The bypass is accomplished through hardwired bypass of ASF trip relay contact by a selector switch-actuated auxiliary relay contact and through actuation of OPRM logic circuits and software. The bypass condition of the OPRM module is indicated by the sequence of events monitor and by indicating lights. The OPRMs may be manually enabled by the selector switch for any recirculation flow and reactor power levels.

a) Modes of Operation

The OPRM has two modes of operation, operate and test. In the operate mode, it performs all of its normal trip and alarm functions as well as broadcasting status information to fiber optic output ports. The test mode is utilized for test, calibration, setpoint adjustment and downloading of the event buffer. In the test mode, the OPRM's trip output is bypassed and the channel is considered inoperable. Entry into the test mode is controlled by a key switch and is annunciated in the control room.

With the OPRM in its operate mode and the maintenance terminal connected, the maintenance terminal may only be used to collect data which is broadcast by the OPRM at fixed intervals. Communications in this mode are one way, namely OPRM to maintenance terminal. The OPRM will not respond to commands from the maintenance terminal when in the operate mode. Thus, the maintenance terminal cannot affect OPRM operation.

In the OPRM test mode and the maintenance terminal connected, bi-directional, fiber optic communications are established between the OPRM and its maintenance terminal. In this mode, commands may be sent from the maintenance terminal to the OPRM to perform such actions as altering the OPRM configurations and setpoints, downloading event buffers and error logs and testing various OPRM functions. Additional, conventional test cables may be connected between the maintenance terminal and a test port on the OPRm for use in calibration and testing. To access this test port, a shorting plug must be removed from the OPRM. Removal of the shorting plug causes the OPRm to become inoperable and is annunciated in the control room.

b) Event Buffer

When a trip occurs, data immediately prior to and following the trip is captured in an event buffer. This buffer may be downloaded to aid in the analysis of the trip. The event buffer can also be captured and downloaded at any time for non-trip analysis by placing the OPRM in the test mode.

c) Maintenance Terminal

A portable maintenance terminal is utilized for system testing, calibration and data collection. It is connected to the OPRM via fiber optic cables. This maintains isolation between the safety related OPRM and the non-safety related maintenance terminal.

d) Power Supply

Power supplies for the OPRMs are the same as those for the APRM and LPRM Group channels. These power supplies provide the required voltage sources for OPRM signal processing modules, DIBs, ASF Trip Relay Assemblies, OPRM Annunciator Relay Assemblies, the new flow units, analog isolators and the existing APRM, RBM and LPRM channels.

e) Physical Arrangement

The OPRM signal processing modules are installed in APRM and LPRM Pages of the Power Range Neutron Monitoring System (PRNMS) Panel (see Figure 7.6-13). Selector switches required for the manual enable functions and the bypass selector switches are installed in the 902-5 panel. Indicating lights for the enable and bypass functions will be installed in the 902-5 panel. Automatic Suppression Function (ASF) Trip Relay Assembles, OPRM Annunciator Relay Assemblies, Analog Isolators and Digital Isolation Blocks are installed in the PRNMS Panel.

f) Exclusion Region

The OPRM is required to be operable in order to detect and suppress neutron flux oscillations in the event of thermal-hydraulic instability. As described in Reference 3, the region of anticipated oscillation is defined by reactor thermal power (RTP) $\geq$30% and core flow <60% or rated core flow. However, to protect against anticipated transients, the OPRM is set to be operable with reactor thermal power $\geq$30%. This provides sufficient margin to account for potential instabilities as a result of a loss of feedwater heater transient. It is not necessary for the OPRM to be operable with reactor thermal power <30% and core flow >60%, which is defined as the exclusion region.

g) Algorithm

Reference 3 describes three separate algorithms for detecting stability related oscillations: the period based detection algorithm, the amplitude based algorithm, and the growth rate algorithm. The OPRM System hardware implements these algorithms in microprocessor based modules. These modules execute the algorithms based on LPRM inputs and generate alarms and trips based on these calculations. These trips result in tripping the Reactor Protection System (RPS) when the appropriate RPS trip logic is satisfied. Only the period based detection algorithm is used in the safety analysis. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations.

h) Trip Function

The OPRMs are designed to provide an alarm (based on period-based algorithm only) and initiate, when armed, an automatic suppression function (ASF) trip to suppress oscillations prior to exceeding the MCPR safety limits. The OPRMs are auto enabled at the specified reactor recirculation flow and reactor power setpoints. The OPRM initiates an ASF trip through the RPS based on the existing plant trip logic and configuration. The OPRMs provide alarm for pre-trip conditions and other functions such as Trouble, INOP, and Trip Enabled to be displayed in the Main Control Room (MCR). Table 7.6-1 lists the OPRM trip functions and setpoints.

i) Alternate Backup Method

At times when OPRM channels may be inoperable, and until they can be restored to operable status, an alternate method of detecting and suppressing thermal hydraulic instability oscillations can be used. This alternate method is described in Reference 5. It consists of increased operator awareness and monitoring for neutron flux oscillations when operating in the region where oscillations are possible. If indications of oscillation, as described in Reference 5, are observed by the operator, the operator will take the actions described by procedures, which include initiating a manual scram of the reactor.

j) Component Qualification Considerations

The OPRM devices are designed Class 1E, Seismic Category I and are qualified to the applicable portions of IEEE-381 and IEEE-344.

k) Single Failure Considerations

Since the OPRMs perform a protective function, they are required to withstand a single failure. To ensure acceptable defense against single random failures the combination or architecture, wiring practices and use of isolation devices is applied to provide required redundancy, isolation and physical independence.

There are two redundant OPRM channels in each RPS division. OPRMs in each RPS division are electrically isolated and physically separated from OPRMs in other RPS divisions. Within each OPRM channel there are two OPRM modules. The use of the two OPRM modules per channel provides redundancy against an OPRM hardware failure in the same channel. The redundant OPRM modules in the same RPS division share the same Class 1E power supplies as those used by the safety-related APRM modules in that RPS division. However, each OPRM module is electrically isolated from the companion module in the same channel.

Common software failures do not lend themselves well to single failure analyses. System reliability and safety requirements are examined in the description of the software design process and quality assurance considerations as discussed in Reference 3.

l) Redundancy, Diversity, and Separation

Since the OPRM's operation is based on interface with PRNMS and RPS, its redundancy, diversity and separation requirements are the same as the requirements for these systems. The LPRM analog signals, which are locally wired, are provided to OPRMs with the same redundancy and separation as provided to the APRM channels and LPRM groups. One exception is that the output to the RPS from shared APRM Channels 3 and 4 is fanned out by OPRM Channels 3, 4, 7 and 8. This eliminates the double up of Channels 3 and 4 in RPS divisions A2 and BI. Thus, two OPRM channels fall into each RPS division for the RPS trip circuits providing the required redundancy between RPS divisions and between the OPRM channels. The assignment of OPRM channels and existing APRM channels for each RPS division is as follows:

RPS Division	OPRM Channel	APRM Channel
A1	1,3	1,3
A2	2,7	2,3
B1	8,5	4,5
B2	4,6	4,6

7.6.1.6.3 Design Evaluation

7.6.1.6.3.1 Conformance to Functional Requirements

The OPRM subsystem is designed to alarm when a stability-related thermal-hydraulic oscillation is detected (based on period-based algorithm only), and to initiate, when armed, as ASF trip when oscillations are large enough to threaten fuel safety limits. The OPRM design assures high reliability as it is governed by Quality Assurance requirements, and applicable industry standards. The system performs self-health tests on a continuous basis.

Reference 5 describes the licensing basis and methodology that demonstrates the adequacy of the hardware and software to meet the functional requirements. A brief summary of the design is provided in UFSAR subsections 4.4.4.6.3 through 4.4.4.6.6.

7.6.1.6.3.2 Regulatory Guides

Conformance to Regulatory Guides is discussed in the FSAR, Section 1.8.

7.6.6.6.3.3 General Design Criteria

The GDCs applicable to OPRM are 10 and 12. The OPRM subsystem is designed to conform to the applicable requirements of these GDCs.

2. Provide signals to operate the reactor relief valves.

7.6.2.2 Description

The reactor vessel instrumentation system provides sensing, indication and alarms of various reactor parameters to the operators and inputs these signals to various control and protective systems. For details of reactor vessel instrumentation refer to Drawings M-26, Sheet 1 and M-357, Sheet 1. The parameters monitored by this instrumentation system and addressed in this section are:

A. Reactor vessel temperature,

B. Reactor vessel pressure,

C. Reactor vessel level,

D. Reactor feedwater flow,

E. Reactor steam flow, and

F. Reactor vessel flange leak detection.

The instruments described in the section may have, depending on their functions, various classifications. The classification of all instruments are listed in the master equipment list (MEL). Those instruments designated as post-accident monitors are described in Section 7.5.

7.6.2.2.1 Reactor Vessel Temperature

Thermocouples are attached to the reactor vessel to measure the temperature at a number of points chosen to provide data representative of thick, thin, and transitional sections of the vessel. The data obtained from this instrumentation provides the basis for controlling the rate of heating or cooling the vessel so that the stress set up between sections of the reactor vessel is held within allowable limits. The stress is computed from the temperature difference between the various points. The temperatures of the various vessel locations are recorded on a multipoint recorder. The thermocouples are copper-constantan, insulated with braided glass, and clad with stainless steel. They are positioned under pads welded to the reactor vessel. The nine reactor vessel flange and shell thermocouples (TE-2-263-69A1, 69A2, 69A3, 69B1, 69B2, 69B3, 69C1, 69C2 and 69C3) were replaced as part of minor plant change P12-2-91-698. The replacements are Type "T", copper-constantan dual-element thermocouples with magnesium oxide ceramic insulation and enclosed in a 316 stainless steel sheath.

7.6.2.2.2 Reactor Vessel Pressure

Reactor vessel pressure is both indicated and recorded in the control room and is indicated on local pressure indicators. These sensors are not the same as the RPS

7.6.3 References

1. See APED-5706, detailed report of in-core flux monitoring instrumentation, GE Topical Report, December 1968.

2. DuBridge, R.A., et al., "Reactor Control Systems Based on Counting and Campbelling Techniques, Full Range Instrumentation Development Program, Final Progress Report," AEC Research and Development Report, U.S. Atomic Energy Commission Contract AT (04-3)-189, Project Agreement 22, GEAP-4900 (July 1965).

3. Licensing Topical Report CEND-400-P, Rev. 01, "Generic Topical Report for the ABB Option III Oscillation Power Range Monitor (OPRM)", prepared for the BWR Owners Group by ABB Combustion Engineering, May 1995.

4. C. Thadani to L. A. England, "Acceptance for Referencing of Topical Reports NEDO-3 1960 and NEDO-3 1960, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," (TAC NO. M 75928) dated July 12, 1993 (SER attached)

5. NEDO-32465, "BWR Owners Group Reactor Stability Detect and Suppress Solution Licensing Basis Methodology and Reload Application," May 1995.

6. U.S. Nuclear Regulatory Commission Safety Evaluation Report, "Acceptance of Licensing Topical Report CEND-400-P", transmitted from B. A. Boger to R. A. Pinelli of GPU Nuclear, August 16, 1995.

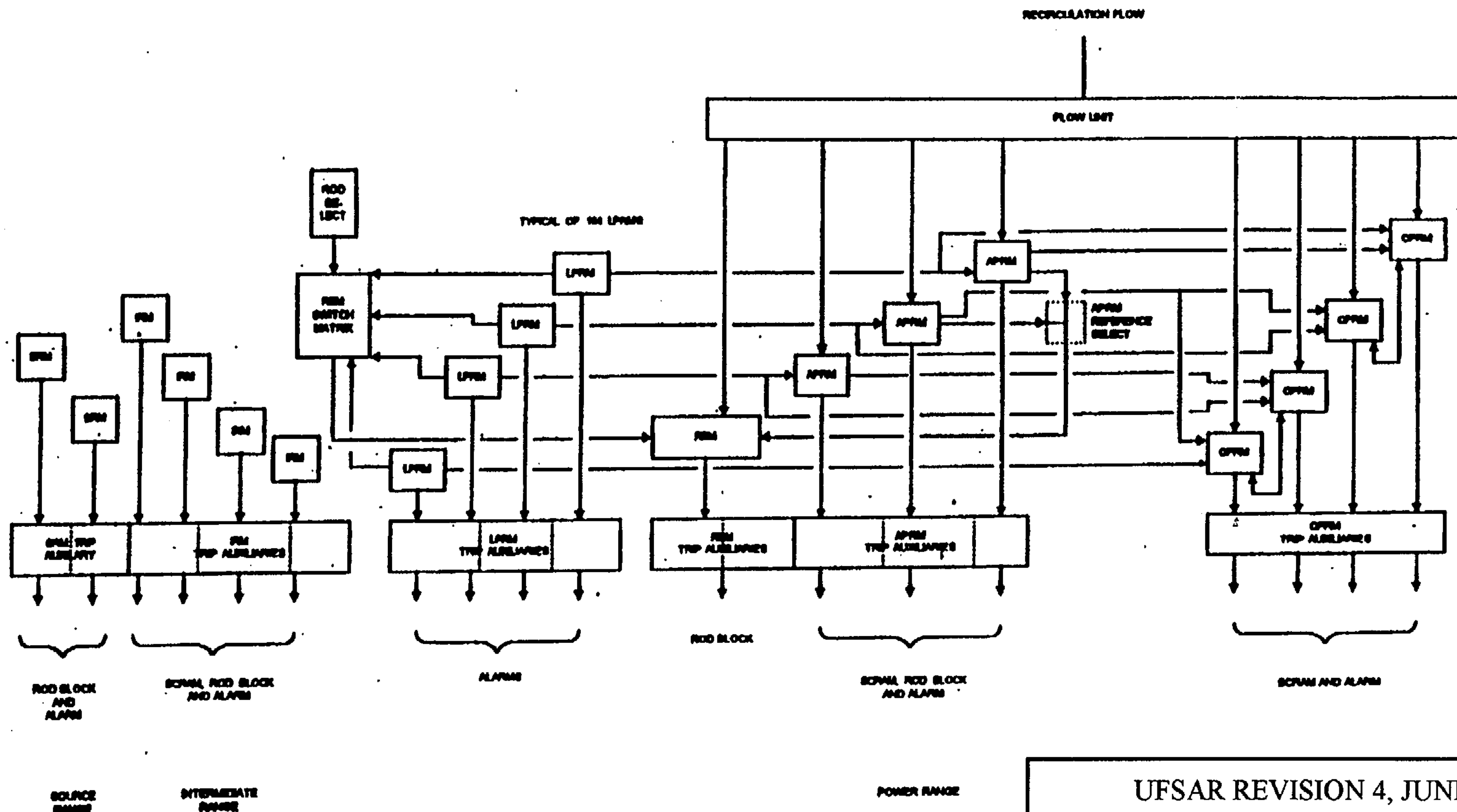
7. BWROG Letter BWROG-9479, "Guidelines for Stability Interim Corrective Action", June 6, 1994.

Table 7.6-1

OPRM SYSTEM TRIPS
(Unit 2 only)

TRIP FUNCTION	TRIP SETPOINT	CONFIRMATION COUNT SETPOINT	ACTION
OPRM Alarm	N/A	8*	Annunciator
OPRM Trip**	1.1***	10***	Annunciator, Automatic suppression function (ASF) trip signal to RPS
OPRM Bypass	Selector switch contact	N/A	Annunciator
OPRM Inoperative/Trouble	OPRM annunciator relays	N/A	Annunciator
System Enable	Setpoints are based on the analytical limits: 30% thermal power increasing, 60% core flow decreasing	N/A	Annunciator

*Initial value - can be varied to meet operating needs.
**Trip function is available after the OPRM is armed, one fuel cycle after its installation.
***Refer to cycle specific values in Administrative Technical Requirements.



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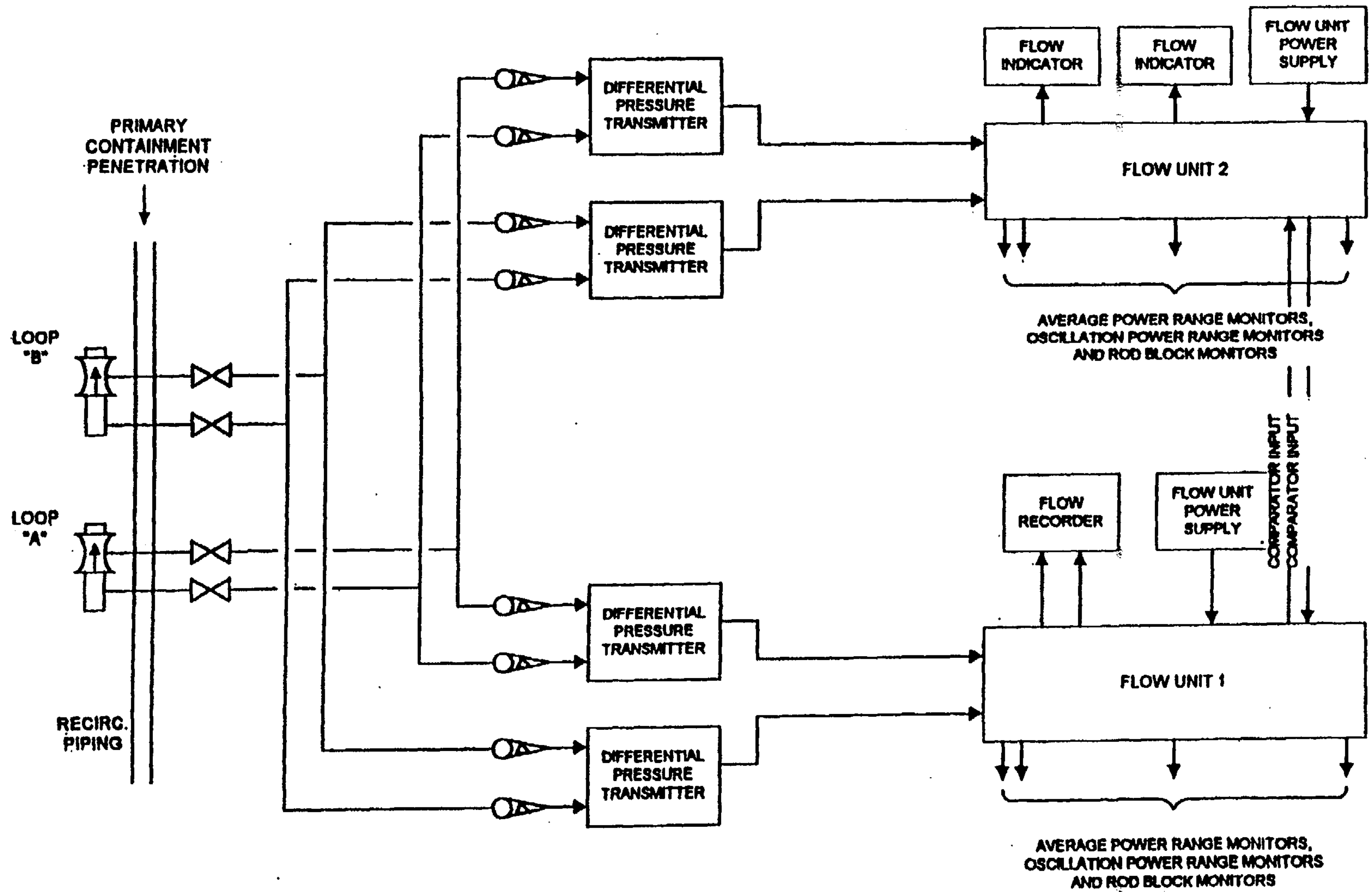
DRESDEN STATION
UNITS 2 & 3

NUCLEAR INSTRUMENTATION SYSTEM
BLOCK DIAGRAM

FIGURE 7.6-2



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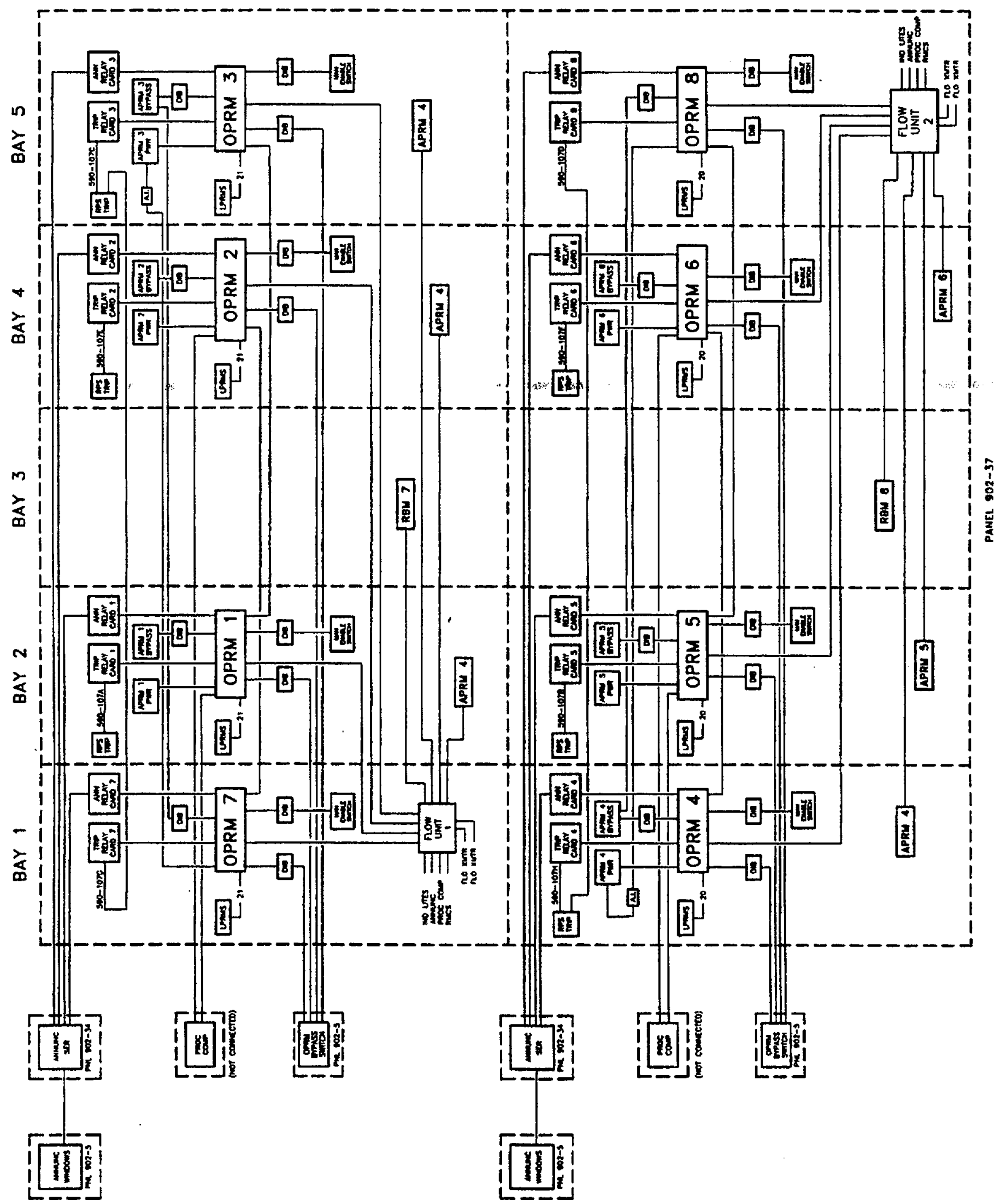
DRESDEN STATION UNITS 2 & 3
FLOW INSTRUMENT FOR APRM, OPRM, AND ROD BLOCK MONITOR
FIGURE 7.6-12



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DRESDEN STATION
UNITS 2 & 3

OPRM INTERCONNECTION
BLOCK DIAGRAM

FIGURE 7.6-12A

7.7.2.2.23 Rod Drift

A rod drift is indicated if a control rod moves from an even-notched position (unless, of course, that control rod is selected and driving). A rod drifting input signifies the presence of a rod not at an even position in the core. Scans are undertaken to find the drifting rod.

7.7.2.2.24 Control Rod Withdrawal Sequence Restrictions

In order to limit the amount of energy deposited in the fuel in the event of a control rod drop accident, sequencing restrictions are imposed. Two options exist to bound control rod sequencing. Either option will limit rod worth such that the peak fuel enthalpy remains ≤280 calories per gram.

The first option is a generic approach to limit rod worth by a sequencing technique called BPWS. The banked position withdrawal sequence (BPWS) are rules designed to minimize rod worth and reduce peak fuel enthalpy below limits in the event of a rod drop accident. These rules are to be followed to the LPSP of 20% rated core thermal power (RCTP). Additional detail on the BPWS rules is included in "Banked Position Withdrawal Sequence," Licensing Topical Report General Electric Co., January 1977 (NEDO-21231).

The second option removes some of the generic conservatism by analyzing an acceptable rod withdrawal sequence on a cycle specific basis. This non-generic analysis provides sequencing restrictions to limit the rod worth and peak fuel enthalpy to ≤280 calories per gram.

7.7.2.2.25 Watchdog Timer

When signaled periodically by a device, a watchdog timer monitors the operation of that device. If the timer is not notified (by a digital signal) within an internally set period of not more than 1 second, the timer resets, signifying a nonfunctional device. For this specific application a toggled digital signal from the RWM computer activates the timer. If the pulses cease the timer resets. The timer is designed to detect a dead computer, hardware problems which might permanently set this signal, or just a processor caught in an infinite loop. To activate the timer it is necessary to pulse an initialization input before resuming the ready toggle.

7.7.2.3 System Components

The RWM consists of two digital computer systems with the following components interconnected, as shown on the block diagram given by Figure 7.7-2.

A. Digital computers,

B. Input/output control,

C. Output buffer,

D. Graphics display and control panel, and

E. System console.

The block diagram illustrates the central role of the digital computers in the RWM system. The computers communicate with all external devices by means of the input/output control.

withdraw permissives) are returned to the RWM for error checking. The voter circuit outputs are also echoed back and evaluated by the RWM.

The RWM system is electrically connected to a station minicomputer to allow control rod sequence transfers under the direction of the nuclear engineering group.

Individual system consoles are provided for each computer to log control rod movements and various hard copy outputs. A menu of available options are provided for computer technicians to set system parameters and evaluate system status.

7.7.2.6 Design Evaluation

During routine operation, the RWM mode switch is placed in the NORMAL position which initiates the operator follow mode. In this mode, the RWM enforces the control rod sequence as loaded by the Qualified Nuclear Engineer. The RWM sequence consists of a preapproved list of steps that detail specific control rod movements. Each step specifies an array (an array is a list of control rod identifications) and movement limits for that step. When latching to the appropriate step in the sequence, the RWM scans the core and compares the current control rod positions to the positions specified in each step of the sequence. The step which results in the lowest number of total errors (withdraw or insert) is considered the currently latched step.

To perform the primary function of the RWM, enforcement of the preprogrammed sequence, insertion or withdrawal of control rods is permitted for rods selected in the latched step. If the RWM detects a control rod movement inconsistent with the loaded sequence, control rod blocks are initiated and the alarm is energized. The operator is required to correct the position error before any further movements are allowed. The secondary functions are available to overcome minor malfunctions in the RPIS and RMCS system. The secondary functions include:

A. Rod out-of-service - This function allows the operator to move a control rod to zero and remove it from service. In this mode, the control rod is displayed in cyan on the color graphics monitor and its movement is blocked until it is placed back in service. Placing a rod out-of-service effectively removes the control rod from its associated array. The out-of-service rod is ignored by the RWM latching procedure and consequently will not be considered an insert or withdraw error during other control rod movements. Analyzed sequences restrict the number and location of control rods that can be taken out-of-service.

B. Substitute control rod position - This function allows an operator to manually enter a position value for a control rod that does not have valid position indication from the RPIS system, provided the actual position of the control can be determined. There is a limit of 10 substitute positions; they will be displayed in yellow on the color graphics monitor.

C. Enable/disable a control rod alternate limit - An alternate limit is defined as one notch position in from the target rod position. Since missing positions frequently occur from the RPIS system, the alternate positions allow the operator to insert a control rod one notch from the target position and continue with control rod movements. There is a limit of two alternate limits corresponding to any of the defined banking limits (except for control rods at positions 00 and 48); they will be displayed in cyan on the color graphics monitor.

Along with the secondary functions touch box, there are other touch boxes on the main screen which enable the operator to perform other RWM functions. The touch boxes are as follows:

A. POWER REDUCTION - used when the operator needs to quickly reduce power. Cram arrays are provided for this task.

B. MAIN MENU - includes toggle switches for various functions and allows edits to be printed.

C. REVIEW SCREENS - allows operator review of the sequence, events, system status, and Cram arrays.

D. SPECIAL MODES - includes the rod test, rod exercise, scram timing, and scram mode functions.

Control rod movements are tracked and verified against the loaded sequence at all reactor power levels. When errors are encountered, control rod blocks are always issued when below the LPSP (20% power). The control rod blocks can be selectively enabled above 20% power by enabling the function through the main menu.

The RWM function is inhibited when the mode switch is placed to BYPASS or SEQUENCE position. The RWM can be placed in the SEQUENCE position whenever an updated sequence is to be loaded by the Qualified Nuclear Engineer.

7.7.2.7 Surveillance and Testing

Detailed on-demand system diagnostic routines are provided to test the computer and the control rod interlock networks.

Technical Specifications require the following RWM surveillance tests:

A. Verify that the control rod patterns and sequence input to the RWM computer are correctly loaded following any loading of the program into the computer.

B. In operational mode 2 prior to withdrawal of control rods for the purpose of making the reactor critical

   a. Verify the proper indication of the selection error of at least one out-of-sequence control rod.

   b. Verify the rod block function.

7.7.3.1 Recirculation Flow Control System

7.7.3.1.1 System Description

Reactor power may be varied by varying recirculation flowrate.
At a steady state, there is constant steam (void) volume in the core. As recirculation flowrate is increased, steam voids are removed from the core faster, thus reducing the existing void accumulation. This reduction in the steam volume within the core volume increases the moderation of neutrons within the core thus inserting positive reactivity. The positive reactivity causes an increase in reactor power, consequently steam generation rate. When the negative reactivity associated with the increased steam generation (voids) and the increased fuel temperature (doppler) equals the original positive reactivity insertion, power stabilizes at an increased level corresponding to the increased recirculation flow.

Power-flow characteristics are shown in Figure 4.4-1. The flow control range is shown as 58 to 100% power along the 100% load line.

There are four possible modes of recirculation flow control:

A. Individual manual operation where each recirculation pump is controlled via a potentiometer in its individual transfer station,

B. Master manual operation where both pumps are manually controlled from one controller, the master controller;

C. Master auto mode where automatic load following is provided by a signal from the turbine control system to the master controller, and

D. Economic generation control where a signal from the load dispatcher is input to the control system while in the master auto mode, enabling the load dispatcher to obtain the most economic mix of generation from several stations. (Dresden administrative procedures currently do not permit operation in economic generation control (EGC). If Dresden were to operate in EGC, cycle specific analyses must be performed to support EGC auto flow control MCFR limits.)

Motor-generator (M-G) sets with adjustable speed couplings vary the frequency of the voltage supply to the recirculation pump motors to give the desired pump speed (see Section 5.4). The signal to the M-G set may be from the individual loop recirculation speed controls (one for each of the A and B loops) or from the master controller if the individual speed controllers (called manual/auto [M/A] transfer stations) are in the AUTO position.

Usually, the units are operated in the master manual mode. In the master auto mode, the control system has not been found to exhibit the desired amount of stability. To change reactor power, a demand signal from the operator, a load frequency error signal from the turbine speed governing mechanism, or a demand signal from the EGC is applied to the master controller. With the individual recirculation loop speed controls in the automatic mode (see Figure 7.7-3), a signal from the master controller adjusts the setpoint of the controller for each coupling. This signal is compared with the actual speed of the generator associated with each controller. The resulting error signal causes adjustment of the coupling and generator speed to reduce the error signal to zero. The recirculating pump motor adjusts its speed in accordance with the frequency of the M-G set output voltage.

their proper polarities to form the ACE. This ACE signal is fed to both an ACE recorder and the master controller.

The master controller is a proportional-speed, floating-type control. This type of control recognizes the ACE polarity and magnitude.

The master controller will regulate both the rate of response and the magnitude of control pulses to the units dependent on the magnitude of the ACE signal. The master controller regulates the frequency and magnitude of a control impulse generator which puts control impulses on a master raise-lower bus which is connected to all station control transmit circuits. All station controls which are on control at the time will receive the same input pulse from the master impulse generator.

7.7.3.2.1.3 Operation of EGC Equipment in the Generating Station

Dresden analyses and administrative procedures currently do not support EGC operation. The information in this section is for historical purposes only. Economic generation control equipment in the generating station is located in the unit control console. The operator has access to all controls, status indicators, and limit setters on the console top plates. Table 7.7-1 lists the top plate functions, Table 7.7-2 lists the status indicators (annunciators), and Figure 7.7-7 illustrates the top plate.

The functional relationship of the components of the unit control equipment is illustrated in Figure 7.7-8. There are two control modes which may be selected by the unit operator:

A. Automatic, remote control (AUTO), and

B. Local program control (RAISE PROGRAM or LOWER PROGRAM).

In addition, manual trip of control (TRIP) is provided. Moreover, at any time, the operator can assume manual control by operating the manual raise-lower control switch in the unit control system.

In the AUTO mode, the control system will receive raise or lower impulses from the System Power Supply Office master control equipment through the primary or backup telemetering channels. These channels are independent of one another, with the primary control from the digital data acquisition and control system, and the backup control from the analog control system. The incoming pulses on these channels are displayed to the operator by flashing indicators. Normally both channels are connected to the controller; the console pushbuttons PRIMARY PULSE and BACKUP PULSE are used to connect or isolate these channels from the control equipment. In response to the input pulses, the Electrohydraulic Control System (EHC) interface provides output pulses to the generating unit EHC system load reference motor to cause the electrical output of the unit to be raised or lowered the desired amount.

Referring to Figure 7.7-8, the incoming control pulses from the primary digital data acquisition and control and the analog backup control have a 2 second period and duration which varies from approximately 1/7 to 1 second, depending upon the computer control requirements for the unit - the change in output of the unit necessary to meet both system load-frequency control and economic dispatch controls the turbine control valves utilizing all the steam production to make electrical power.

The second, or backup, pressure regulator is provided to control pressure in the event that the operating regulator should fail.

The setpoint of the backup pressure regulator is normally biased above the setpoint of the operating pressure regulator as follows:

Unit 2: 10 psi
Unit 3: 3.0 - 5.0, nominally 4.0 psi

A maximum combined flow limit device is provided to limit the total steam flow through the turbine control valves and bypass valves to a combined value about 105% of the rated reactor steam flow.

As seen in Figure 7.7-4, the pressure regulator with the higher value controls through the low value gate because the other input to the gate, the speed/load signal, is normally set to be larger by about the equivalent of 10% steam flow (or 0.5% speed for 5% speed regulation). A bias signal of this amount is subtracted from the speed/load signal resulting in the load demand signal. The difference between this signal and the output signal from the high-pressure regulator (which represents the steam flow required to satisfy the pressure control requirement), is the load demand error signal. This load demand error signal is the control signal for the recirculation flow control system which adjusts the core recirculation flow until the load demand error signal is zero. This same signal is used to add the equivalent of a setpoint adjustment, at a controlled rate and magnitude, to the pressure regulator to cause the control valves to respond immediately. This effect is temporary since the load demand error signal returns to zero as the load demand is satisfied (see Section 7.7.3).

The speed/load signal will take over control of the turbine control valves should the speed increase over 0.5% (due to overspeed caused by load rejection or system frequency rise due to an upset) or should the load set signal be decreased greater than 10% and faster than the recirculation flow control system can change the reactor steaming rate. In such event of takeover, the steam flow required signal will exceed the control valve flow demand signal. When this difference exceeds a small bias signal (equivalent to about 1 psi), the bypass valves will open and control the pressure if the rejected load does not exceed the bypass capacity. If the bypass capacity is exceeded, the reactor will scram.

The reactor steaming rate can keep up with normal load maneuvering (EGC or otherwise) and, therefore, bypassing of steam is not normally required.

Typical pressure/steam flow relationships are shown in Figure 7.7-9. The pressure regulator setpoint is fixed and both turbine and reactor pressures vary with steam flow - the turbine due to the regulation of the pressure controller and the reactor due to this same regulation plus the variable steam line pressure drop. There appears to be no penalty to this mode of operation (which is recommended for a BWR plant).

The turbine stop valves are equipped with limit switches which open when the valve has moved from its fully opened position. These switches provide a scram signal to the reactor protection system, anticipating the resulting reactor high pressure condition. The turbine stop valve scram signal is discussed in Section 7.2.

To protect the turbine, closure of the four turbine stop valves is initiated for various abnormal conditions as listed in Section 10.2.

7.7.4.3 Design Evaluation

The pressure regulator and turbine-generator design is such that the system provides a stable response to normal maneuvering transients. Section 4.3 evaluates the stability of the overall boiling water reactor cycle, including the pressure and turbine control. Section 15.2.3 analyzes transients due to turbine trips.

The bypass valves are capable of responding to the maximum closure rate of the turbine control valves such that reactor steam flow is not significantly affected until the magnitude of the load rejection exceeds the capacity of the bypass valves. Load rejections in excess of bypass valve capacity may cause the reactor to scram due to high pressure, high neutron flux, or rapid electrical load reduction. When first stage turbine pressure is above that corresponding to 45% power, any condition causing the turbine stop valves to close will directly initiate a scram before reactor pressure or neutron flux have risen to the trip level.

The pressure regulator can be assumed to fail in either of two ways: opening the turbine control valves or the bypass valves or closing them. These malfunctions are discussed below and in Sections 15.1, 15.2, and 15.6; fuel damage does not occur in either case. The backup pressure regulator reduces the probability that pressure regulator malfunction will cause operational problems.

The failure modes analyzed are:

A. Controlling pressure regulator failing as is;

B. Controlling pressure regulator failing such that the turbine control valves open; and

C. Controlling pressure regulator failing such that the turbine control valves close.

If the controlling pressure regulator fails as is, the effect upon the plant is dependent upon how the plant pressure behaves. The controlling regulator would be the regulator with the highest value steam flow demand. If system pressure rises, the backup pressure regulator output would rise until it takes over control of the turbine control valves, and the plant response could be similar to the following setpoint change depending upon the rate of pressure increase experienced:

Unit 2: 10 psi
Unit 3: 3.0 - 5.0, nominally 4..0 psi

If reactor pressure drops, the reactor power will decrease, further dropping reactor pressure until the reactor vessel is isolated upon a low steam line pressure signal. Reactor recirculation flow will probably be increasing under the influence of the EGC system sensing reduced plant power output.

If the controlling pressure regulator fails in the direction to open the control valves, reactor pressure and power will be decreased and the transient will finally be terminated by the closing of the main steam isolation valves.

If the controlling pressure regulator fails in the direction to close the control valves the effect would be quite similar to the following positive pressure setpoint change as the backup pressure regulator would than take over control of reactor pressure:

Unit 2: 10 psi
Unit 3: 3.0 - 5.0, nominally 4.0 psi

7.7.6 Main Condenser, Condensate, and Condensate Demineralizer Systems' Control

7.7.6.1 Design Basis

The main condenser, condensate, and condensate demineralizer systems' control is designed to provide indications of system trouble. Main condenser sensors must provide inputs to the reactor protection system to anticipate loss of the main heat sink and to protect against condenser overpressure. The condensate system controls must ensure adequate cooling to the condensate pumps.

7.7.6.2 System Description

The condensate/condensate booster pumps discharge without throttling to the suction of the reactor feedwater pumps. See Section 10.4.7 for a description of the condensate system.

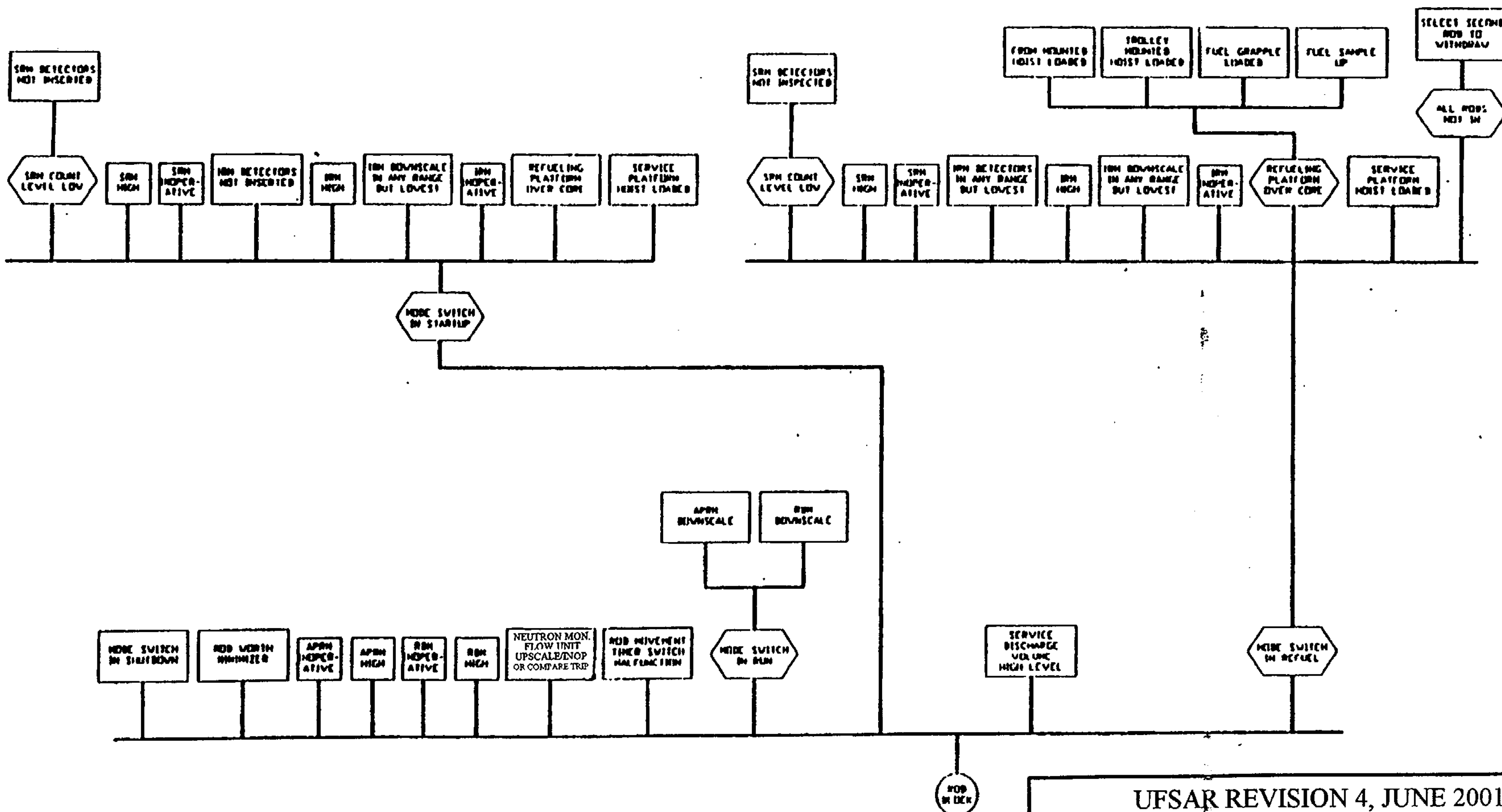
Discharge pressure of the condensate pumps is indicated. A condensate/condensate booster pump is usually kept on standby and low pressure on the Reactor Feed Pump (RFP) suction header starts the additional pump. In addition, if any of the running pumps trip, the standby pump will auto start. A modulating control valve, located downstream of the condensate booster pumps, recirculates condensate back to the main condenser on low loads. Recirculation maintains a minimum cooling flow through the condensate/condensate booster pumps, steam jet air ejector condensers, gland seal steam condenser, and off-gas condenser.

Conductivity of condensate both upstream and downstream of the demineralizer is measured, recorded, and actuates an alarm on high conductivity.

Main condenser hotwell level is indicated in the control room and is automatically controlled by either making up or returning condensate from the condensate storage tank. Vacuum switches monitoring condenser vacuum provide scram signals to protect the reactor from loss of the main heat sink; protection for the condenser itself is assured by closure of the turbine stop and bypass valves as vacuum decreases below a preset low level.

7.7.6.3 Design Evaluation

Indication of key parameters from the main condenser, condensate system, and condensate demineralizer system are provided in the control room. The operator is kept fully cognizant of the conditions of the systems. Abnormal conditions are annunciated so that the operator may take appropriate action. The reactor is protected from loss of the main heat sink by main condenser low vacuum scram signals; the vacuum sensors meet the design requirements established for all reactor protection system functions (Section 7.2). To protect the condenser from overpressure, continued decrease of condenser vacuum below the scram setpoint will initiate closure of the turbine stop valves and bypass valves.



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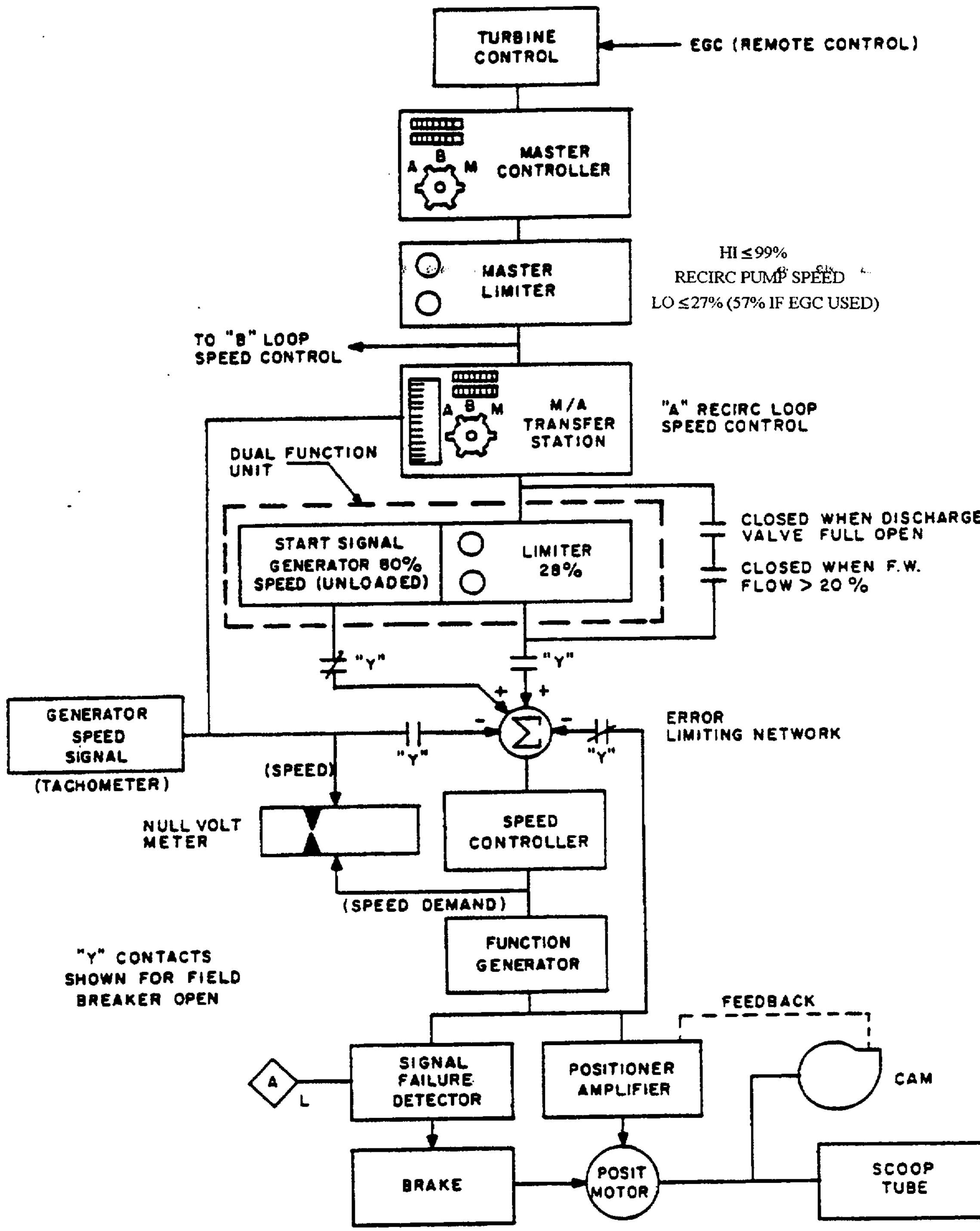
CONTROL ROD BLOCK DIAGRAM

FIGURE 7.7-1



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RECIRCULATION SPEED CONTROL NETWORK

FIGURE 7.7-3

collar integral to each pushbutton. Once armed and then depressed, the pair of switches associated with either division activate the ARI trip function.

Manual ARI should be initiated upon reaching any of the following alarm conditions:

A.	High torus water average temperature alarm setpoint	≤110°F
B.	High reactor dome pressure alarm setpoint	1240 psig nominal
C.	Reactor low water level alarm setpoint	Low-low (-59 inches)
D.	Control rod drive position indication	Not inserted after scram annunciation

7.8.3.3 Alternate Rod Insertion Valves

Upon ATWS initiation (automatic or manual), the ARI solenoid valves (see Section 4.6 and Drawings M-34 and M-365) are energized to block the instrument air supply to the scram air header and to depressurize the scram air header by venting air to atmosphere. Depressurization of the scram air header causes the scram valves to open resulting in the drives scramming. All ARI valves are normally deenergized. The ARI valving system operates as follows:

A. There are two divisions of valves installed on the scram air header. Each division has sufficient capacity to accomplish rod insertion. Each division of valves consists of the following valves:

   1. Two ARI valves which are normally closed but open when energized to depressurize the scram air header.

   2. One ARI valve three-way ARI valve which is installed in the scram air header supply line. This valve is normally positioned to allow air to be supplied to the scram air header. When energized, this valve repositions to close off the supply air and vent the scram air header to the atmosphere.

B. Once actuated, the ARI valves remain energized for a minimum of 44.2, but not to exceed 54.2 seconds to ensure the scram air header is adequately depressurized. After this delay, if the initiation signal has cleared, the ARI valves are deenergized. If the initiation signal is still present after the delay, the ARI valves remain energized until the initiation signal clears.

C. Time delay does not exceed 54.2 seconds to ensure that the maximum permissible rod insertion time is not exceeded. Without this limit the design objective stated in Ref. 1 paragraph 3.2.1, i.e. the full rod insertion occurs within approximately 60 seconds of ARI initiation time before the pressure suppression pool temperature reaches 110°F, would not be met. If initiation signal has cleared, operator can reset the time, allow SDV to drain/vent and attempt to insert rods that may not have been fully inserted. [2][1]

7.8.4 Design Evaluation

For all transients, the Recirculation Pump Trip (RPT) effectively mitigates the short term ATWS response. The Alternate Rod Injection (ARI) effectively reduces the long term consequences to nearly those of normal scram situations.

The sensors, trip units, and actuation relays (with the exception of the RPT reactor low-low water level trip time delay and the ARI reset circuitry) are common to both RPT and ARI. Thus, the automatic initiations occur concurrently (except for the RPT low-low water level time delay) at identical setpoints. Therefore, the following design analyses dealing with the inputs, the logic, and logic power supply apply equally to ARI and RPT. The RPT is modeled after the NRC-approved Monticello design.

The ARI function requires start of control rod motion within 39.2 seconds and full insertion within 44.2 seconds of ARI actuation. Dresden specific analysis confirmed that these parameters are met. Section 7.8.3.3 describes the seal-in and reset time delay of the ARI valves. Based on the NRC-approved topical report,[1] ARI achieves the design objectives. The most limiting of these objectives (pressure suppression pool temperature) requires full rod insertion within approximately 60 seconds.

The ARI design is safety-related and segregated into two electrical divisions; namely, Division I and Division II, which are physically segregated. The RPS is a four-channel electrical arrangement (two trip systems with two subchannels each) and has individual channel separation. The RPS circuits are not routed with other divisionally segregated circuits of ARI.

The ARI system utilizes valves which are normally deenergized but which are energized to perform their safety function. The ARI valves are powered from dc sources. Conversely, the existing RPS employs ac-powered valves which are deengerized to initiate a scram.

The ARI system uses an analog transmitter/trip unit configuration. The transmitters are separate from sensors used for the RPS. In addition, the trip units utilized are separate from process instruments used for the RPS.

The nominal ARI trip setting for reactor pressure is 1240 psig and for reactor vessel water level is -59 inches with respect to reactor level instrument zero. The nominal RPS trip setting for reactor pressure is 1060 psig and for vessel level is 1 inch with respect to reactor level instrument zero. This level corresponds to +1 inch above the bottom of the separator skirt. Therefore, the automatic setpoints for ARI actuation have been selected such that they will not preempt the RPS scram function.

For each actuation parameter (low-low water level or high reactor pressure), the logic is arranged in a two-out-of-two configuration per division. This logic allows individual sensors, trip units, etc. to be tested or calibrated during plant operation without initiating the ARI system.

7.8.5 References

1. General Electric Licensing Topical Report, NEDE-31096-P-A, "Anticipated Transients Without Scram; Response to NRC ATWS Rule, 10 CFR 50.62," February 1987

2. General Electric Letter C1100261(65) dated 6/8/95 from Bertram W Joe to Paul Chennel.

Dresden Station

Updated Final Safety Analysis Report

VOLUME 5

Exelon Nuclear

Exelon Generation Company

8.0 ELECTRICAL POWER
LIST OF FIGURES

DRAWINGS CITED IN THIS CHAPTER*

*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.

DRAWING*	SUBJECT
12E-2C	Plan View of Transmission Lines 34kV, 138kV & 345kV Switchyards
12E-2328	Single Line Diagram, Emergency Power System
12E-2322B	Overall Key Diagram, 125V DC Distribution Centers
12E-2324-2	Key Diagram & Elevation 48/24VDC Distribution for Neutron Monitoring Unit 2
12E-2325-1	Key Diagram, 120 & 120/240V AC Distribution Essential, Instrument & Reactor Protection Buses
12E-3322B	Overall Key Diagram, 125V DC Distribution Centers

8.0 ELECTRICAL POWER

8.1 INTRODUCTION

Dresden Station, Units 2 & 3, generates and transmits the electric power to the Mid-American Interconnected Network (MAIN), a regional council of the North American Electric Reliability Council (NERC). Dresden Unit 1 was shut down in October, 1978, and reference to it is limited only to its active interfaces with Units 2 and 3.

8.1.1 Design Bases

The offsite power system connection, described in Section 8.2, to Dresden Station are designed to provide a diversity of reliable power sources that are physically and electrically isolated so that any single failure will affect only one source of supply and not the other sources. The onsite power systems, described in Section 8.3, are designed to provide electrical and physical independence of redundant power supplies for systems that are important to safety. In the event of a total loss of offsite power (LOOP), auxiliary AC power required for safe shutdown will be supplied from diesel generators located onsite. These diesel generators are electrically and physically independent. Redundant station batteries provide a source of DC power for specific safety related loads.

8.1.2 Offsite Power Systems - Summary Description

Commonwealth Edison Company's transmission system is interconnected with the MAIN region utilities. Electric energy generated at the station is stepped up to 345-kV by the main power transformers (Transformers 2 and 3) and fed into the station's 345-kV transmission terminal double ring bus. The 345-kV double ring bus is connected directly to seven 345-kV transmission lines and indirectly to six 138-kV transmission lines via Transformer 81, Transformer 83, and the 138-kV buses (Figure 8.2-1). Additionally, there are three 34-kV transmission lines that are connected to a 34-kV bus that is fed from the 138-kV buses via Transformer 10. The 34-kV lines supply the power for towns and rural areas near Dresden Station.

The 138-kV buses and the 345-kV double ring bus also provide power to two reserve auxiliary transformers (RATs), one per unit. The Unit 2 RAT is fed from the 138-kV buses, and the Unit 3 RAT is fed from the 345-kV double ring bus.

Two sources of dc power for breaker control are provided by the 345kV switchyard system 1 and system 2 125V batteries. Any redundant cables to the switchyard are run in separate conduits. For more information on the dc systems refer to Section 8.3.2.

8.2.1.3.1 Switchyard Component Separation

The 138-kV and 345-kV switchyards are separated by a distance of approximately 1000 feet. The bus positions for the main and auxiliary transformers for Unit 3 are separated by several bus positions in the 345-kV switchyard. The Unit 2 main transformer bus position is also separated from the Unit 3 auxiliary and main transformer bus positions. Incoming lines to the switchyard are separated by at least one bus position. Because of the above separation, a bus section which is damaged by fire or mechanical means can be isolated and will not affect the entire switchyard. The switchyards have not been designed to withstand natural disasters such as earthquakes and tornadoes.

The main power transformers (MPT), RATs, and unit auxiliary transformers (UATs) for Unit 2 and Unit 3 are separated by a distance of more than 350 feet. The RAT for Unit 2 is 50 feet away from the main and unit transformers. The RATs for Units 1 and 2 are separated by a concrete block firewall. Separation of the Unit 3 transformers is similar to that given above for Unit 2. Refer to Drawing 12E-2C for a plan view of the switchyards.

In addition, each of the transformers (MPT, RAT, and UAT) for Units 2 and 3 has a deluge system for fire protection. Provisions have been made to prevent local damage due to fire or mechanical means from affecting more than one component. The transformers have not been designed to cope with natural disasters, such as earthquakes and tornadoes.

The combined microwave and meteorological tower is located away from the transmission lines and switchyards so that it cannot cause failure of the offsite power sources.

8.2.1.3.2 Auxiliary Power Connections to the Switchyards

The auxiliary power supply for Unit 2 is split between UAT 21, which is connected to the Unit 2 generator leads, and RAT 22, which is connected to the 138-kV switchyard. RAT 22 is connected to the 138-kV switchyard by means of duplicate conductors permitting connection to either of two bus sections. The two connections are separated by one normally open and one normally closed circuit breaker. A failure in a single bus section or of a single circuit breaker will affect only one of the auxiliary power transformer connections.

Each connection from TR22 to the 138-kV bus is equipped with two disconnecting switches in series so that failure of any one disconnecting switch can involve not more than one 138-kV bus section. The switching sequence is protected by electrical interlocks so that one connection must be opened before the other can be closed.

The transmission system at CECo is designed to meet all the criteria listed in the MAIN Guide No. 2.

MAIN Guide No. 2 stipulates that the generation and transmission system shall be adequate to withstand the most severe of the identified set of contingencies without resulting in an uncontrolled widespread tripping of lines and/or generators with resulting loss of load over a large area.

The reliability of the transmission grid is demonstrated by the performance data of the 345-kV transmission lines. The average 345-kV line in the MAIN grid experienced approximately 1.6 forced outages per year, with an average duration of approximately 42 hours per forced outage during the period from 1987 to 1990, approximately 627 line-years of exposure. For the 4 years between January 1, 1987, and December 31, 1990, the average CECo 345-kV line experienced approximately 1.5 forced outages per year, with an average duration of approximately 53 hours per forced outage. This period represents approximately 366 line years of experience. The percentage of forced outages due to various causes is listed in Table 8.2-1.

The ability of the CECo transmission system to withstand the loss of transmission lines connecting the Dresden switchyards to the network has been investigated through separate stability studies for each station to demonstrate adequacy of the transmission system. The electric systems in Wisconsin, Iowa, Illinois, and Indiana were all represented in lesser detail.

8.2.2.2 Stability Analysis

An analysis was made to determine the response of the external power grid to the sudden loss of both Dresden Units 2 and 3 (the worst case as compared to the loss of only one unit) and the effects on the availability of offsite power. The conclusion of this study was that the external power system would be able to supply the station requirements continuously both immediately after the loss of both units and later when generation on the power system is readjusted to make up the lost generation. The design of the offsite power system is in compliance with NRC General Design Criterion (GDC) 17.

Figures 8.2-4, 8.2-5A, and 8.2-5B show the typical power flows in the Dresden area before the loss of the Dresden generation. These calculations were made by a digital computer load flow program and simulate projected peak load conditions on the interconnected system in 1997.

Figures 8.2-6, 8.2-7A, and 8.2-7B show corresponding typical power flows in the Dresden area following the sudden loss of both Dresden Units 2 and 3. These units had been generating a total of 1623 MW gross (1545 MW net) before the outage. For the condition shown in Figures 8.2-6, 8.2-7A, and 8.2-7B, the energy previously generated by Dresden Units 2 and 3 is made up by the release of kinetic energy of the other generators on the interconnected system resulting in incremental power flow from other systems. This is a momentary condition which could exist only until automatic governor action would begin to increase generation tending to decrease loading on ties. Analysis of the loadings shown in Figures 8.2-6, 8.2-7A, and 8.2-7B indicated no overloads or line loadings which would cause relay tripping.

8.3 ONSITE POWER SYSTEMS

The station electrical distribution system design includes sufficient power sources and redundant buses to provide reliable electrical power during all modes of station operation and shutdown conditions.

The onsite power systems are divided into two main categories, ac and dc. The following sections provide detailed descriptions for each of the power systems and the analyses associated with them.

8.3.1 AC Power Systems

The onsite ac power system consists of two main generators, two main step-up transformers, two unit auxiliary transformers (UATs), two reserve auxiliary transformers (RATs), distribution buses, and three standby diesel generators (DGs). The distribution system has nominal ratings of 4160-V, 480-V, and 120/208 V.

The offsite ac power system supplies power to the onsite auxiliary power system through two RATs (one per unit). Only when being back fed from the grid, the UAT is another source of offsite power. Physical changes to the generator links are required to place the plant in an alignment to allow backfeed. Refer to Section 8.2 for more detailed information on the offsite distribution system.

The auxiliary power system provides adequate power to operate all auxiliary loads necessary for station operation. A diagram of the principal elements of the auxiliary electrical system is shown in Drawing 12E-2328, and the equipment listings are shown in Table 8.3-1. Auxiliary power is provided by the UATs connected to the unit generator isolated-phase bus and the RATs connected to either the 138-kV or 345-kV switchyards, as shown in Figure 8.2-1. The UATs and RATs supply power to the equipment used to maintain a safe and operable plant. The auxiliary loads are split between the UAT and RAT for each unit. However, each transformer has the capacity to carry the full auxiliary load. The auxiliary transformers step down the voltage to 4160-V to supply the auxiliary buses.

The station auxiliary buses can also be connected, by appropriate switching sequences, to the DGs which provide power in the event that the 138-kV or 345-kV switchyard and the unit generator are incapacitated. Thus, the DGs provide another independent source of auxiliary power to the station.

Plant layout provides physical separation of bus sections, switchgear, interconnections, feeders, power centers, motor control centers (MCCs), and other system components. Loads important to plant safety are split and diversified between switchgear sections, and circuit breakers are provided for prompt location and isolation of system faults.

All protective circuit breakers are sized according to standard electrical industry practice. That is, the maximum current interrupting capabilities of the circuit breakers exceed the available line-to-line or three-phase short-circuit current, taking into account the impedances of the generator, transformers, and other electrical system components.

the main transformer is connected to the offsite power system, and the low side of the UAT is connected to the onsite power system.

8.3.1.1.2 System Components

The major components of each unit's main generator and 18-kV system are the main generator, the isolated-phase bus, the main transformer, and the UAT.

8.3.1.1.2.1 Main Generator

The main generator converts the rotational mechanical energy of the main turbine into electrical energy. The ratings of the main generators are given in Table 8.3-1.

Syncho-check type are provided in the generator circuitry to prevent non-synchronous connection of the main generator to the grid.

8.3.1.1.2.2 Isolated-Phase Bus

The generator output leads, called the isolated-phase bus, are contained in outdoor metal-clad enclosures from the generator terminals to the transformer terminals. Forced cooling is necessary to operate the isolated-phase bus at the generator rating. The rating of the isolated-phase bus can be found in Table 8.3-1.

8.3.1.1.2.3 Main Transformer

The main transformer steps the 18-kV generated voltage up to 345-kV for distribution to the CECo and MAIN transmission systems. The main transformer windings are delta connected on the secondary (18-kV) side and grounded-wye connected on the primary (345-kV) side. The main transformer rating is given in Table 8.3-1.

8.3.1.1.2.4 Unit Auxiliary Transformer

The UAT (TR21 for Unit 2 and TR31 for Unit 3) steps the 18-kV generated voltage down to 4160-V for use by the station auxiliaries. The transformer windings are delta connected on the primary (18-kV) side, and each of the two windings on the secondary (4160-V) side are grounded-wye connected. The transformer rating is given in Table 8.3-1.

The unit's RAT is the primary offsite source to the essential service system (ESS) buses. The RAT of the other unit provides a second offsite power source through a bus tie provided between corresponding ESS buses of the two units. Additionally, the UAT of either unit provides another source of offsite power to the ESS buses only when the unit is shutdown and the UAT is being back fed from the grid. Physical changes to the generator links are required to place the plant in an alignment to allow backfeed. There are manual crosstie connections between buses 23-1 and 33-1 and between buses 24-1 and 34-1 which may be used to supply power from one unit to the other under abnormal conditions. Bus 40 is shared between the units and is the mechanism by which standby diesel generator 2/3 supplies either bus 23-1 or 33-1. Because of the configuration of the control circuitry, under normal conditions bus 40 does not supply power to both units simultaneously. However, procedural provisions exist that allow bus 40 to feed both units simultaneously if conditions warrant such an alignment.

A partial firewall with an open accessway is installed between the 4160-V switchgear 23-1 and 24-1 to prevent fire from spreading from one switchgear area to the other for Unit 2. A similar barrier is also installed between switchgear 33-1 and 34-1 for Unit 3.

8.3.1.2.2 System Components

The major components of the 4160-V system are the UAT, the RAT, the 4160-V switchgear, and the circuit breakers. The UAT is described in Section 8.3.1.1.2.4.

8.3.1.2.2.1 Reserve Auxiliary Transformer

The RAT (TR22 for Unit 2 and TR32 for Unit 3) steps switchyard voltage (138-kV for TR22 and 345-kV for TR32) down to 4160-V for use with station auxiliary loads. The ratings of the RATs can be found in Table 8.3-1. The primary (138-kV or 345-kV) winding and each of the two secondary windings (4160-V) for either RAT are grounded-wye connected.

8.3.1.2.2.2 4160-V Switchgear

The 4160-V switchgear provides a means of enclosing the bus work, breakers, and relays associated with the 4160-V system. The switchgear for the 4160-V buses is a metal-clad indoor type and is located in both the reactor and turbine buildings. Flow deflectors have been installed above buses 23-1 (33-1) and 24-1 (34-1) to assure that any leakage from piping which runs above the switchgear will not impinge on the switchgear. Buses 23 (33) and 24 (34) do not have piping overhead and therefore do not need similar protection.

8.3.1.2.2.3 Circuit Breakers

Circuit breakers provide a means for isolating loads and power supplies from the 4160-V buses. Typical current ratings for 4160-V circuit breakers are 1200A, 2000A, and 3000A. Circuit breakers for the 4160-V system are three pole, electrically operated, with a 125-Vdc stored energy closing mechanism. Maintenance of 4160-V breakers is performed in accordance with Dresden

Maintenance Procedures. Safety-related and nonsafety-related breakers are functionally tested on a periodic basis, and each cubicle is inspected and cleaned, if necessary. These procedures are intended to minimize breaker failure.

8.3.1.3 480-V System

Power is supplied from 4160-V buses 23, 24, 23-1, and 24-1 to 480-V buses through six separate transformers. The 480-V buses supply power to electrically operated auxiliaries. The 480-V buses are of the indoor load center type which, in addition to supplying power directly to the 480-V motor loads, also supply the transformers used in stepping down the voltage to 120/208-V or 120/240-V for lighting, instrumentation, and small plant service loads. The equipment vital to safe plant shutdown under accident conditions is supplied by 4160-V buses 23-1 and 24-1, and by 480-V buses 28 and 29. Additionally, the containment cooling service water pumps described in Section 9.2, which are used for long-term safe plant cold shutdown, are supplied with electrical power from buses 23 and 24. These buses can be backfed from buses 23-1 and 24-1 under accident conditions. A similar arrangement exists for Unit 3.

Transformers and switchgear for the 480-V buses are located in the turbine and reactor buildings. Switchgear for each load center is in self-supporting metal clad sections with continuous main buses having draw-out units that are replaceable under live bus conditions. Circuit breakers within the switchgear are either operated electrically using power from the 125-V station battery or they are operated manually.

8.3.1.3.1 System Description

The 480-V system consists of six switchgear buses for each unit. These buses supply large 480-V motors (such as fans) and 480-V MCCs for the control of small 480-V motors (such as valve motors). Each 480-V bus is fed from a 4160-V bus via a 4160-V-480-V transformer. The following list identifies the 4160-V bus associated with each 480-V bus:

A. 4160-V bus 23 (33) feeds 480-V bus 25 (35);

B. 4160-V bus 24 (34) feeds 480-V buses 20, 26, and 27 (30, 36, and 37);

C. 4160-V bus 23-1 (33-1) feeds 480-V bus 28 (38); and

D. 4160-V bus 24-1 (34-1) feeds 480-V bus 29 (39).

Buses 28 and 29 (38 and 39) are 480-V ESS buses. Bus 28 (38) is designated as Division I and Bus 29 (39) is designated as Division II. These buses can be powered by the DGs via the 4160-V ESS buses 23-1 and 24-1 (33-1 and 34-1) respectively.

Motor control centers are designated by the feeding bus number followed by a sequential number (e.g., MCC 28-1 is fed by bus 28).

Manual crossties exist between buses 25 and 26 (35 and 36), buses 25 and 27 (35 and 37), and buses 28 and 29 (38 and 39) to supply power to one of these buses in the event its normal supply is lost.

Table 8.3-1 lists the auxiliary power main equipment, their rating, loads fed from the 4.16 KV switch and gives a sample listing of the loads on various 480-V switchgear and MCC units.

8.3.1.4 120-V Systems

The main function of the 120-V system is to provide a reliable source of 120-V, 60 Hz, single-phase power for plant controls and instrumentation. This system is divided into three different subsystems:

A. 120-V reactor protection system,

B. 120-V instrument bus system, and

C. 120-V essential service system.

Drawing 12E-2325-1 provides an overview of the 120-V systems.

8.3.1.4.1 Reactor Protection System

The RPS loads for each unit are fed from one of two buses. Each 120-V RPS bus is supplied by a motor-generator set. M-G set 2A (3A) is fed from 480-V MCC 28-2 (38-2) and M-G set 2B (3B) is fed from 480-V MCC 29-2 (39-2). A reserve supply to each RPS bus exists from 480-V MCC 25-2 (35-2). This reserve supply is mechanically interlocked with the normal supply for each bus to prevent simultaneous feed from both sources. A key interlock is also provided to ensure that MCC 25-2 (35-2) cannot feed both RPS buses simultaneously. A detailed description of this system is provided in Section 7.2.

8.3.1.4.2 Instrument Bus System

The instrument bus system supplies 120-V power for various control circuits, relays, solenoids, and instruments. The normal power supply to the instrument bus is MCC 28-2 (38-2); the alternate power supply is MCC 25-2 (35-2). On loss of the normal power supply, an automatic bus transfer (ABT) switches power to MCC 25-2 (35-2) and transfers it back upon restoration of normal power (normal seeking ABT).

connecting the DGs to the auxiliary equipment consists of metal enclosed switchgear and metal enclosed bus ducts. The location of the DGs within concrete structures and provision of the metal enclosed switchgear and bus ducts assures protection against damage from tornadic winds or missiles.

The buses between the DGs and the emergency buses are routed through the turbine and reactor buildings in such a manner so as to prevent interaction between them in the event of damage to a bus section. Power cables from the emergency buses to the ECCS are also routed to preclude any possible interaction.

Each DG is rated at 2600 kW at 0.8 power factor for continuous operation. They also have a 2000-hour, 10% overload rating of 2860 kW at 0.8 power factor. The DGs supply power to the 4160-V buses, as shown in Drawing 12E-2328.

Each diesel generator system is designed to start automatically within 13 seconds and accept full load within 30 seconds of loss of all normal sources of power (see Figures 8.3-4 through 8.3-7). The engine is preheated, and starting power is self-contained (compressed air) and is not dependent on the availability of any other source of normal plant power at the moment of starting; however, 125-Vdc control power is needed for the initial excitation of the generator, as well as the startup logic and starting air system control. The rapid start capability of the DGs is consistent with the requirement for core cooling under postulated accident conditions.

If at any time during the first 40 seconds any one of the loads should drop or fail to start, the design load-torque margin of the DG would increase. If a major pump should be dropped for any reason, the diesel generator governor is designed to recover from the drop of the largest pump in 1-½ seconds, which would prevent any appreciable overspeed of the unit.

Each diesel generator is also provided with manual start control and is equipped with means for being started periodically to test for readiness and for synchronizing with the auxiliary power system without interrupting the service of the plant.

DG size has been determined from station design and power requirements. The starting load requirement is a factor in sizing the generators. They are capable of starting and carrying the largest vital loads required under postulated accident conditions. The generators may be manually loaded to rated capacity at the discretion of the operator. Alarms are provided which will annunciate upon an overloaded condition.

Each DG is protected from start failure (overcranking) and by the following trip mechanisms:

A. After an Auto Start, the DG will trip on a diesel engine overspeed or high generator differential current. The diesel generator output breaker will trip on a high generator differential current.

B. After a Manual Start, the DG will trip on a diesel engine overspeed or high generator differential current in addition to any of the following engine trouble conditions: high engine temperature, low water pressure, low bearing oil pressure, or high crankcase pressure.

   After a Manual Start, the diesel generator output breaker will trip on diesel engine overspeed or high generator differential current in addition to any of the following electrical trouble conditions: underfrequency, loss of field, generator ground fault, generator overcurrent or reverse power.

A start failure or overspeed trip will stop fuel injection and shut down the diesel. The control room will receive an alarm when the diesel is tripped for any of the previously listed reasons. To restart the diesel after a trip, the actuated trip relay(s) must first be reset at the engine control panel.

For a discussion of the diesel fuel oil storage and transfer system, see Section 9.5.4. For the DG cooling water system, see Section 9.5.5. For the starting air system, see Section 9.5.6. For diesel generator lubrication, see Section 9.5.7. For the DG combustion air intake and exhaust, see Section 9.5.8.

8.3.1.5.2 System Arrangement

The interconnection between the standby diesel generator system and the ac power system is depicted on Drawing 12-2328. DG 2 provides power to the Division II ECCS equipment for Unit 2, and DG 3 provides power to the same equipment for Unit 3. DG 2/3 provides power to the Division I ECCS equipment for either Unit 2 or Unit 3. The connection of the DGs to their respective buses occurs automatically.

There are also a number of manual capabilities within the system. For example, DG 2 can power the Unit 3 main 4160-V ESS bus, if desired, by manually closing two circuit breakers. Also, the DG system can backfeed to the main unit 4160-V auxiliary buses from the 4160-V ESS buses by manually closing two circuit breakers. However, such manual operations are possible only under certain specific conditions because interlock devices are installed to protect against possible fault conditions. For example, connecting DG 2 to Unit 3 4160-V ESS bus cannot be accomplished if DG 3 is already connected to that bus. Such flexibility is an operational convenience designed and controlled such that safety is not jeopardized.

8.3.1.5.3 System Loads

The loads supplied by the diesel generator system are grouped into two main categories:

A. Loads required for accident conditions, which start automatically upon restoration of bus voltage by the diesel generator system; and

B. Loads required for safe shutdown conditions, which are started either automatically or manually.

The first and second category loads are connected to 4160-V buses 23-1 or 24-1(33-1 or 34-1) or to the associated 480-V buses 28 or 29 (38 or 39). Other loads may be connected by the station operators through normally open, manually operated breakers. This arrangement reduces connected loads to a practical minimum without eliminating the ability to select alternate loads.

During accident conditions, two diesel generators are used for redundancy. Table 8.3-2 lists the Category 1 loads which are on each diesel generator. Category 1 loads are those DG loads that automatically start when the DG is connected to the buses on an accident signal. Category 2 loads are those loads required to maintain a safe shutdown condition.

In addition to supplying the Category 2 loads listed in Table 8.3-3, the DG system is available on a manual basis to feed other loads, including essentially all of the equipment on buses 23, 24, 23-1, and 24-1 of the 4160-V system and lower voltage systems connected to the 4160-V systems. The connections of such other loads must be made with regard to overload restrictions. A similar arrangement exists for Unit 3.

All the ESF systems are designed to be loaded onto the DG buses automatically whenever accident signals are received. For example, when the design basis accident (DBA) defined as a loss of offsite power (LOOP) concurrent with a loss of coolant accident (LOCA) occurs, the DG is started upon initiation of the accident signal. Approximately 20 seconds after the DBA, the first low pressure coolant injection (LPCI) pump is started and is pumping at minimum flow, 5 seconds later the second LPCI pump is started and is pumping at minimum flow, and finally, 10 seconds after the first LPCI pump starts, the core spray pump is started and is pumping at minimum flow. Typically, the greatest loading occurs when the core spray pump is started, which is illustrated below:

Loads on DG: two LPCI pumps	1400 kVA
Auxiliary equipment which could be loaded on DG	204 kVA
Starting power required for core spray pump	5351 KVA
TOTAL	6955 kVA

NOTE: The above illustration is based on nominal values. See the engineering diesel generator loading calculation of record for actual values.

General Motors has provided data indicating successful starting of a 1750-hp motor followed by two 600-hp motors in succession from a single DG of the same capacity as the DG being used in this plant. These motors are quite similar to the initial motor loads for this unit. It is concluded, therefore, that the loading on the Dresden DGs is within the capacity of each diesel generator with adequate margin.

The above analysis is for one DG. When an accident signal is present, two DGs, each powering the loads as listed in Table 8.3-2, will be in operation. As can be seen by Table 8.3-2, the normal load will not be near the 2600-kW rating which provides more than adequate margin without the overload condition.

The manual loading of the DG is not considered in the accident analysis because operator action will not be necessary until after 10 minutes: by this time the core flooding associated with a DBA is complete.

Section 6.3.3.1.4.1 describes station procedures addressing a dual unit LOOP with an accident on one unit.

8.3.1.5.4 Primary Operational Characteristics

From an operational standpoint, each DG is capable of either parallel or independent operation. Likewise, the emergency bus system is designed to operate either sectionalized or with a crosstie between Units 2 and 3. Therefore, under a situation in which all offsite power is lost, the operator has the ability to cope with all types of onsite emergencies.

Under normal operating conditions the ECCS of Unit 2 are powered from buses 23-1 and 24-1 (refer to Drawing 12E-2328). These buses receive power from 4160-V buses 23 and 24, which are fed from the UAT, and the normal offsite ac power sources via the RAT. In the event of loss of these power sources, buses 23-1 and 24-1 are automatically disconnected from buses 23 and 24 and connected to DG 2/3 and DG 2 respectively. Simultaneous with the interruption of power from 23 and 24, all nonessential loads on the buses supplied by 23-1 and 24-1 are tripped from the buses. Similarly, the major loads on the main 4160-V auxiliary buses 23 and 24 are tripped. This general sequence of events occurs in a similar manner on Unit 3.

The 480-V swing MCC 28/29-7 (38/39-7) is made up of two MCCs whose buses are connected with cables (copper link) to form one continuous bus. The purpose of this common bus is to provide a dual source of power to the LPCI and recirculation valves for operation in the LPCI mode.

The 480-V swing MCC 28/29-7 (38/39-7) is normally supplied from DG 2(3) through 4160-V bus 24-1 (34-1), Transformer 29 (39), and 480-V bus 29 (39) during a loss of offsite power with or without an accident signal. Should the DG 2(3) power source fail, the ac contactor and breaker feeding MCC 28/29-7 (38/39-7) from 480-V bus 29 (39) will open automatically and the breaker and contactor feeding MCC 28/29-7 (38/39-7) from 480-V bus 28 (38) will close automatically restoring power to the swing MCC from DG 2/3 through 4160-V bus 23-1 (33-1), Transformer 28 (38) and 480-V bus 28 (38). There is a 20-second time delay in the automatic transfer logic. The source breaker and ac contactor to 480-V swing MCC 28/29-7 (38/39-7) are electrically interlocked, such that DG 2(3) and DG 2/3 are isolated from each other at all times. Loss of Division II DC control power will not prevent the automatic transfer to the alternate supply.

Design changes were implemented that supplement the previously described automatic transfer logic by initiating an automatic transfer based upon voltage and frequency abnormalities when the 480-V swing MCC 28/29-7 (38/39-7) power is being supplied from DG 2(3). The transfer is accomplished through the use of the undervoltage, overvoltage, and under/overfrequency protective relays which monitor and initiate a bus transfer if voltage and frequency conditions are above or below the relay setpoints and exceed the specified relay time delays. See Table 8.3-7 for typical relay setpoints.

In the event of an accident on a unit, DG 2/3 will start and close-in on the unit experiencing the accident if no offsite power is available. This is accomplished by using the accident signal to prevent DG 2/3 from closing-in on the nonaccident unit. For example, referring to Drawing 12E-2328, if an accident should occur in Unit 2, a high drywell pressure signal (or a low-low reactor water level signal with a low reactor pressure signal), would start DG 2 and DG 2/3, would initiate core spray, and would initiate shedding of nonessential 480-Vac loads such as the drywell coolers, recirculation M-G set vent fans, south turbine pump building vent fans, and the condensate storage tank heaters. This signal would also prevent the closing of the breaker between DG 2/3 and bus 33-1.

The DG close permissive circuit contains a time delay contact to prevent a non-synchronous closure. This relay is picked up by one of the auxiliary relays in the undervoltage relay scheme and is set at 2 seconds ± 10% to allow the back electromotive force (EMF) from motors on this bus to decay. This relay assures that bus voltage decay and load shedding take place prior to closure of the DG feed breaker.

The time delay relay will have no effect on the DGs when no ESF actuation signal is present. The DG start signal is from an undervoltage auxiliary contact, and therefore the DGs will start immediately on an undervoltage signal. The time delay contact effects only the closing of the DG feed breaker, and as this relay is set for approximately 2 seconds, it will have timed out before the DG is ready to accept load, which is approximately 10 seconds after starting.

A synchronizing relay is in the manual-close circuit of each DG 4160-V output breaker to prevent inadvertent, out-of-phase closure within the system. The device is an electronic synchro-check relay connected in the manual-close circuit at a point that will not interfere with the auto-close circuit. A failure of the synchronizing relay will block the auto-close feature. Also, the capability to close into a dead bus remains available by local control of the 4160-V breakers at the switchgear.

8.3.1.5.5 Tests and Inspections

Since the DGs are utilized as standby units, readiness is of prime importance. Readiness can best be demonstrated by periodic testing, which insofar as practical, simulates actual emergency conditions. The testing program is designed to demonstrate the ability to start the system and show its ability to run under load long enough to verify that cooling and lubrication are adequate for extended periods of operation. Full functional tests of the automatic circuitry will be conducted on a periodic basis to demonstrate proper operation.

Preoperational tests have verified and demonstrated that the DG equipment was constructed in accordance with the specifications and that the DG and related equipment function properly to perform the service intended. The loads described in Tables 8.3-2 and 8.3-3 were used to check the DG system and establish the capability of the DG to supply the rated power during an accident. This included the sequential loading of each ECCS pump following a simulation of the accident signal.

The DGs are started manually on a periodic basis to demonstrate their availability. Routine surveillances are performed to maintain the equipment.

8.3.1.6.3.2 Incore Instrumentation Penetrations

The incore instrumentation utilizes four shielded cable penetrations. Table 8.3-4 lists the penetration numbers and the instrumentation channels that the cables supply.

All four penetrations carry two intermediate range monitor (IRM) channels and two penetrations carry local power range monitor (LPRM) channels for the two average power range monitor (APRM) channels. The arrangement of the incore channels in the penetrations is such that loss of a penetration and cabling will not prevent a scram if it is required. For example, if penetration X-202N and associated cabling were lost, APRM Channels 1 and 5 would be unavailable. If a high flux condition were present, a trip on Channel 2 or 3 would result in protective action on reactor protection system Channel A. Likewise, this condition would result in a trip of Channel 4 or 6, either of which would initiate protective action on Channel B and therefore a scram. The same situation holds for the IRM channels. In addition to the separation discussed above, no power cables are run in these shielded penetrations.

8.3.1.6.3.3 Low-Voltage Power and Control Penetrations

Low-voltage and control penetrations carry both power and control cables, but the same criterion as is indicated above is used: i.e., loss of a penetration will not result in loss of scram function or ESF action. Refer to Section 3.8.2 for a mechanical description of the penetrations.

8.3.1.6.3.4 High-Voltage Power Penetrations

High-voltage penetrations are used to carry 4160-V power to equipment such as recirculation pumps in the drywell. There are no control or instrumentation cables in these penetrations, and none of these penetrations carries cables for the RPS or ESFs. Refer to Section 3.8.2 for a mechanical description of the penetrations.

8.3.1.6.3.5 Current-Carrying Ratings of Cables in Penetrations

The current-carrying capacity of cables used in drywell penetrations is conservatively limited when compared to the National Electric Code (NEC).

8.3.1.6.5.2 Derating of Current-Carrying Capacity of Cable in Pans

The current carrying capacity of cable is limited by the continuous temperature rating of the insulation. The ambient temperature, the heat generated in the conductor and the heat transfer from the conductor to ambient all affect the current carrying capacity. The quantity and type of cables in cable pans affect the heat transfer. Record is kept of the quantity and type of cable at each section of the cable pan system. Allowable ampacity is established for every cable at a given cable pan section to assure that no cable will have a continuous conductor temperature in excess of the temperature rating of the cable insulation. Cable size or the different routing paths that can be taken by the new cables are used to meet the allowable criteria.

8.3.1.7 Analysis of Station Voltages

A study and a transient analysis were conducted at the original plant design stage to confirm the ability of the DG to start and accelerate the emergency cooling pumps. The major focus of this effort was to determine the effect of the voltage dips on the running motors. Should the running motors fail to develop sufficient torque to overcome the load torques, they will decelerate toward a stall condition. If they decelerate below the breakdown-torque speed, they will draw high currents (inrush current reduced proportionately with the voltage) and compound the voltage dip problem. The manufacturer's design performance data was used for the pumps, drive motor, and diesel characteristics to conduct the transient studies. The results of these studies are reflected in the designed starting sequence and have been used in determining if the undervoltage relay setpoints are adequate from a motor-starting and voltage dip standpoint. The analysis of the undervoltage relays is described in the following paragraphs.

In addition to the first level "loss of voltage" relays which protect against a LOOP condition by initiating the sequence of events discussed in Section 8.3.1.5.4, a second level of undervoltage relays has been added to each of the 4160-V buses 23-1 (33-1) and 24-1 (34-1) to protect against a degraded voltage condition. As noted above, a degraded voltage condition causes induction motors to draw more current and results in the motor windings becoming overheated. If the degraded voltage condition persists for 7-seconds, an annunciator alerts the operator and a 5-minute timer is initiated. After 5-minutes have passed, the DG is started, the incoming line breakers are tripped, load shedding is initiated, and the DG breakers close when the existing permissives are satisfied. The 7-second time delay prevents circuit initiation due to grid disturbances and motor starting transients, whereas the 5-minute time allows the operator to attempt restoration of normal bus voltage. The 5-minute timer is bypassed on high drywell pressure/low-low reactor water level conditions.

An evaluation of system voltages determined that the critical voltage for the 4160-V buses was above the setpoint of the second level "degraded voltage," undervoltage relays. To remedy this situation, CECo raised the setpoint and implemented modifications which reduced the voltage drop to those 480-V MCCs that supply critical safety-related loads. These modifications involved the installation of larger feed cables to the 480-V MCCs that supply the DG cooling water pumps; and an automatic trip of the nonessential loads from the 480-V switchgear upon a LOCA start signal for the DG (high drywell pressure or low-low reactor water level). Analyses were performed to ensure that the new setpoints would not have deleterious effects on operation of low voltage equipment fed from the 480-V MCCs.

The second level of protection can cause the possibility of a non-synchronous closure of the DG breakers. This could happen when a high drywell pressure/low-low reactor water level signal starts the DGs and there is a subsequent degradation of offsite voltage. Non-synchronous closure is avoided by the presence of a time delay relay in the close circuitry that ensures bus voltage is sufficiently low before closing to the DG. Note that the original undervoltage scheme (first level loss of voltage) does not have this possibility of causing a non-synchronous closure, because the relays are set for a very low voltage (approximately 70% of normal). A fault on the feed to the essential service buses after an ESF signal has started the DGs is another potential for non-synchronous closure. Both undervoltage schemes are susceptible to this failure because opening the feed breaker will immediately close the DG breaker regardless of bus voltage. Note that a fault will not cause a common mode failure; whereas, a degraded voltage induced trip will.

The reliability of the dc systems has been improved by the installation of dc battery and bus voltage indication, undervoltage alarms, battery high discharge current alarms, dc ground alarms (safety related 250-V and 125-V systems only), and battery charger trouble alarms on the safety related 250-V, 125-V, and non-safety related 24/48-V systems. This assures that an adequate state of charge exists on the station batteries at all times and meets IEEE 308-1974, Regulatory Guide 1.97, and Criterion 13 of Appendix A to 10 CFR 50.

8.3.2.1 250-V System

8.3.2.1.1 Safety Related 250-V System

The safety related 250-V battery system is sized to start and carry the normal dc loads plus all dc loads required for safe shutdown on one unit, and the operational loads required to limit the consequences of a design-basis event on the other unit for a period of four hours following loss of offsite power plus a single active failure without taking credit for the battery chargers. These loads are summarized in the load tracking database. This time period is deemed adequate to safeguard the plant until normal sources of power are restored.

The three battery chargers (one per unit plus a swing charger) have a capacity suitable for restoring the battery to full charge under normal load conditions. The chargers are powered from separate ac buses. These buses are arranged so that they can be connected to multiple sources of ac power available in the plant, including the DG.

The 250-V MCCs are normally fed from their primary source (charger) and their secondary source (battery) operating in a float charger configuration. The battery charger and the battery each have sufficient capacity to supply normal bus loads. The voltage is raised periodically for equalization of the charge on the battery cells. The normal float voltage should remain between 262.8-V and 265.2-V, (2.19-V and 2.21-V per cell). The equalizing voltage must remain between 2.25-V and 2.26-V, per cell or between 270.0-V and 271.2-Vdc while the load is connected to the battery.

The ampere-hour capacity of each unit's battery is adequate to supply expected essential loads following station trip and loss of all ac power without battery terminal voltage falling below the minimal discharge level (i.e., 210-Vdc).

The safety related 250-V system is arranged so that more than one failure is required before normal plant needs are not served. All of the loads normally connected to the safety related 250-V dc system can be supplied by either charger. Buses are arranged to allow for alternate paths to other systems throughout the plant where redundancy is employed. The aggregate system is arranged and powered so that the probability of system failure due to a loss of safety related 250-V power is very low. All of the systems either self-annunciate upon failure or are periodically tested in service to discover faults.

The safety related 250-V battery system operates ungrounded with an alarm located in the main control room and a recording ground detection device to annunciate the first ground. In addition, the ground fault resistance and time at which the ground fault occurs is recorded by the ground detection device. Thus grounds of a magnitude that could affect equipment operability, the only reasonable mode of failure, are extremely unlikely. The normal mode of battery failure is a single cell deterioration which is signaled well in advance by the routine tests which are performed regularly on the battery.

When a ground is identified, the action that is taken is determined by the ground's level. If it is a Level I ground (less than the alarm setpoint of 125,000 ohms), then it is recorded and tracked each shift. If it is a Level II ground (between the alarm setpoint of 125,000 ohms and 40,000 ohms) or a Level III ground (40,000 ohms or less) then station procedures are implemented immediately to locate and remove the ground. If a Level III ground cannot be eliminated within 14 days, a Justification for Continued Operation (JCO) is prepared. If an intermittent ground occurs, then it is logged with the time, date, and coincident activities. Table 8.3-8 provides the voltage-resistance correlation for the response levels described above.

Each unit has two heavy-duty buses (one in the turbine building and one in the reactor building) that furnish power to the various loads (as shown in Figure 8.3-8), most of which are connected only in an emergency condition. In general, these loads are motor loads such as backup isolation valves and emergency lube oil pumps where the power source is the main battery. Removable copper links have been provided such that the power supply to the Unit 2 reactor building bus can be manually transferred from the Unit 3 battery (normal source) to the Unit 2 battery (reserve source). A similar connection exists for the Unit 3 reactor building bus.

8.3.2.1.2 Non Safety Related 250-V System

The non safety related 250-V battery system provides power for the non safety related 250-Vdc loads which have been relocated from the existing safety related 250-Vdc MCCS. The only loads transferred thus far are the Unit 2(3) Main Turbine Emergency Bearing Oil Pumps.

8.3.2.2 125-V System

8.3.2.2.1 Safety Related 125-V System

There are two 125-V battery systems, one per unit. The basic function of the 125-V battery is to supply electrical power to the dc distribution systems whenever the battery charger, which supplies the normal source of power, fails. The 125-V

Each unit has been provided with an alternate 125-V battery in order to allow the unit 125-V battery to undergo rated discharge testing while both units remain at power. The alternate battery is available to supply system loads upon a failure of the unit 125-V battery. The alternate battery is of a similar type as the unit battery, though of a different size, and has been sized to support the same loads. The alternate battery is normally disconnected from the system and is kept on a float charge.

Each 125-Vdc system provides Division I dc power to its unit and Division II dc power to the other unit. The system's battery is tested in accordance with the latest revision of IEEE-450. However, due to crossties between units, the unit battery test requires that the alternate battery be declared operable.

The Unit 1 Charger 1C provides an equalizing charge to the alternate battery. After the equalizing charge, the Unit 1 Charger 1C is disconnected, and the battery is connected to the 125-Vdc system by momentarily paralleling with the Unit 2 battery and charger. The alternate battery is then declared operational.

Because of the physical distance between the Unit 2 alternate battery and the dc distribution panel, the associated voltage drop was considered when sizing the alternate battery. The alternate battery is larger in size (8hr, 77°F electrolyte temperature rating of 1945 amp hours) than the unit battery and uses more cells (63 versus 58).

The Unit 2 alternate battery is located in the Station Blackout Building (former Unit 1 HPCI Building) east battery room. This location was originally designed to house a battery and as such provides adequate seismic and tornado missile protection.

MCC 65-1 provides power to the heating/cooling units and exhaust fans in the alternate battery room, and smoke detection and lighting of the Station Blackout Building. A safety-related ac feed for MCC 65-1 is available from MCC 29-2 if the normal feed for MCC 65-1 is out-of-service.

The Unit 3 alternate battery is located on the turbine building mezzanine floor outside the Unit 3 battery charger room. This location provides adequate seismic protection but does not provide the required tornado missile protection. To address this concern, a risk analysis was performed to determine the probability of a tornado missile striking the alternate battery. From the analysis, it was determined that the probability of a tornado missile strike is less than 1×10^{-7} for an entire calendar year. Therefore, the current location of the alternate battery maintains the probability of the tornado missile event below a threshold level where the event is not a concern.

The station battery is an integral part of the 125-V dc system which includes the battery chargers, breakers, buses, and other auxiliaries (Drawing 12E-23228B and 12E-3322B). The 125-V distribution system is divided into three groups of buses as follows:

A. The turbine building main bus,

B. The turbine building reserve bus, and

C. The reactor building bus.

The following description for Unit 2 is typical for Unit 3.

The Unit 2 turbine building main buses 2, 2A-1, and 2A-2 are supplied by the Unit 2 battery and are the normal sources of control power to 4160-Vac switchgear 21 and 23 and 480-Vac switchgear 25, the Unit 2 main control room panels, relay panels and control room, turbine and radwaste building escape lighting. The Unit 2 main buses also supply reactor building bus 2 and the Unit 3 turbine building reserve buses 3B, 3B-1 and 3B-2. The main buses are the reserve power supply to the Unit 2 reserve buses 2B, 2B-1 and 2B-2.

The Unit 2 reactor building bus 2 is normally supplied from the Unit 2 turbine building main bus 2A-1 (as described above) and is the normal source of control power for the Unit 2 4160-Vac switchgear 23-1, 480-Vac switchgear No. 28, and reactor building escape lighting, etc. It is the reserve source of control power to Unit 2 4160 -Vac switchgear 24-1 and 480-Vac switchgear 29.

The Unit 2 turbine building reserve bus 2 is normally supplied from the Unit 3 turbine building main bus 3A and is the normal source of control power for 4160-Vac switchgear 22, 24, and 24-1 and 480-Vac switchgear 26, 27 and 29.

Note that the control power for one set of reactor building 4160-Vac and 480-Vac switchgear is completely independent (including the battery) from the control power to the other set of switchgear in the reactor building.

The unit battery is sized to carry its loads for specific time periods as indicated by the load tracking database.

8.3.2.2.2 Non Safety Related 345kV Switchyard 125-V System

The non safety related 345kV switchyard 125-V battery system provides power for the 345kV switchyard loads that have been relocated from the existing Unit 2 and Unit 3 safety related 125-V batteries.

There are two 125-V battery systems, each supplying a dedicated switchyard distribution system. The batteries and battery chargers are located in a ventilated battery room, adjacent to the 345kV switchyard relay house.

8.3.2.2.3 Non Safety Related 138kV Switchyard 125-V Control Power

Control power to the 138-kV switchyard is supplied from the Unit 1 125-V battery and has been replaced with a new battery and seismic rack. The ratings on the new battery are within the ratings of the existing equipment.

8.3.2.3 24/48-V System

The electrical supply for the source range monitor (SRM) and IRM systems, the dP type scram discharge volume level switches, the signal isolators and the stack gas, radwaste discharge, and off-gas radiation monitors consists of two duplicate 24/48-V three-wire, grounded neutral systems (Drawing 12E-2324-2). Each system (2A, 2B, 3A and 3B) consists of two 11-cell, 250-ampere hour (8- hour rated), lead calcium batteries in series and connected to a dc distribution panel. There are two silicon rectifier-type 25-ampere battery chargers on each system, one of which is connected to each of the 24-V batteries. The source of power for the battery chargers is the 120-Vac instrument bus. Each 24/48-V system is equipped with undervoltage and overvoltage alarms, as well as battery discharge and open bus alarms. The battery chargers are capable of completely recharging the battery while simultaneously supplying the normal continuous load. The batteries are mounted in seismically qualified racks.

8.3.2.4 Test and Inspection

The station batteries and other equipment associated with the 24/48-V, 125-V, and safety related 250-V dc systems are easily accessible for inspection and testing. Service and testing is accomplished on a routine basis in accordance with recommendations of the manufacturer. Typical inspections include visual inspections for leaks and corrosion, and checking all batteries for voltage, specific gravity, and level of electrolyte.

An exhaustive study has been made to determine if any single component failure could negate operation of the emergency power system's redundant counterpart or of any other component which could possibly prevent meeting the onsite power requirements. No failures were found which could prevent the receipt of electrical power to the required core cooling equipment. The most degraded cases found were: the loss of one DG through failure of a diesel auto-start relay which limits the core cooling capabilities to one core spray subsystem and two LPCI subsystem pumps, and the failure of the MCCs that provide power to the LPCI admission valves, which limit the core cooling capabilities to two core spray subsystems.

Despite the degraded cases stated above the LPCI Swing MCC (28/29-7, 38/39-7) has special features which are represented in Figure 8.3-1 and are discussed in Section 8.3.1.5.4.

The safety related 250-Vdc power supply is used as a source of power for some of the containment isolation valves. Each dc-powered isolation valve is backed up by an ac-operated isolation valve. For example the HPCI steam line isolation valves; the in-board valve is ac, and the outboard valve is dc supplied from the safety related 250-V battery. Should the safety related 250-V battery fail, the ac-operated valve would still isolate the system. Manual switchover to the other safety related 250-V battery is possible and is represented in Drawing 12E-2328 of the FSAR.

The 125-V power supply is used to supply control power to the switchgear that is required during a LOCA. Both the Unit 2 and the Unit 3 125-V battery systems are shown in Drawing 12E-2322B. Control power (125-V) to all of the 4160-V and 480-V switchgear is monitored. The loss of this control power to any one bus actuates an alarm in the control room. The operator acknowledges the alarm and can take manual action to transfer DC control power for the bus to the alternate dc power supply. Feeder breakers to all dc distribution panel buses have trip alarms to alert the operator of the loss of power to any dc bus. Loss of either battery or any one bus in its entirety will interrupt control power to only one of the two redundant power systems.

For example, loss of turbine building main bus 2 or the Unit 2 battery will result in the loss of control power to Switchgear 23, 23-1, and 28 and the normal supply to DG 2/3, HPCI, and automatic depressurization system (ADS). The DG control circuit, HPCI, and ADS, will automatically switch over to their alternate power source. Buses 24, 24-1, and 29 are unaffected. The operator will be alerted and can transfer the control power feeds for buses 23, 23-1, and 28 to their alternate sources. Should the core cooling systems be required before the alternate source is

The following dc systems from one unit are capable of feeding the other unit's systems:

A. The 125-V battery,

B. The 125-V main bus and reserve bus,

C. The 125-V battery chargers,

D. The 125-V cable feeders to switchgear, and

E. The safety related 250-V system.

The following systems or equipment are required for operation for both Units 2 and 3 and thus have redundant power supplies.

A. Cardox CO_2 system controls;

B. Standby gas treatment system (SBGTS) (two trains, each of which can be used on either unit: each unit supplies power to one of the trains);

C. MCCs to supply power for the SBGTS components.

Table 8.3-1 (Continued)

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

2 -	Diesel standby circulating lube oil pumps	1 hp each
2 -	Diesel standby turbo circulating lube oil pumps	0.75 hp each
1 -	Condensate transfer jockey pump	7.5 hp
1 -	Turbine and radwaste buildings emergency lighting	33.8 kW (Unit 2) 13.7 kW (Unit 3)
2 -	Diesel cooling water pumps	87 kW each
1 -	Turbine turning gear oil pump	50 hp
1 -	Turbine turning gear	60 hp
5 -	Turbine bearing lift pumps	10 hp each
1 -	Standby gas treatment air heater	30 kW
2 -	Diesel circulating water heaters	15 kW each
1 -	Drywell and torus purge exhaust fan	30 hp
4 -	LPCI/CS room sump pumps	1.5 hp each
2 -	Drywell floor drain sump pumps	5 hp each
4 -	Reactor building floor drain sump pumps	7.5 hp each
2 -	Drywell equipment drain sump pumps	3 hp each
1 -	Reactor building elevator	25 hp
1 -	Refueling platform feeder	
1 -	Fuel pool receptacle feeder	
1 -	Reactor building equipment drain tank pump	5 hp
1 -	Cleanup precoat tank mixer	0.75 hp
1 -	Cleanup precoat pump	15 hp
1 -	Cleanup filter sludge pump	2 hp
1 -	Cleanup filter aid pump	7.5 hp
1 -	Safety system jockey pump	7.5 hp
2 -	Diesel generator vent fans	30 hp each

Table 8.3-1 (Continued)

AUXILIARY ELECTRICAL SYSTEM EQUIPMENT LISTING[1]

2 -	LPCI/core spray pump area cooling units	5 hp each
1 -	HPCI pump area cooling unit	3 hp each
1 -	Computer room transformer (spare)	9 kVa (Unit 2 only)
2 -	Reactor building condensate return pumps	7.5 hp each
1 -	Drywell air sampling compressor motor and pump	7.5 hp
1 -	Control room standby HVAC air handling unit	50 hp[4]
1 -	Control room standby HVAC cooling/ condensing unit	150 hp[4]
2 -	Control room standby HVAC booster fans	7.5 hp each[4]
1 -	Control room standby HVAC air filter unit heater	12 kW[4]
1 -	120/208-Vac distribution panel	15 kVA
1 -	Fuel storage vault and equipment hatch jib crane	7.5 hp
1 -	Drywell equipment patch shield door	0.5 hp
3 -	Reactor building vent fans	100 hp each
1 -	Reactor cleanup demineralization auxiliary pump	100 hp
2 -	Fuel pool cooling water pumps	100 hp each
3 -	Reactor building exhaust fans	100 hp each
2 -	South turbine room ventilation Fans	75 hp each (Unit 2) 100 hp each (Unit 3)
1 -	Post-LOCA monitor and sample pump	1 hp
2 -	Torus/drywell air compressors	40 hp
2 -	Instrument bus transformer feeds	25 kVA each
8 -	Containment cooling service water (CCSW) pump cub cooler fans	3 hp each
1 -	Submersible sewage pump	1 hp

Table 8.3-2

CATEGORY 1 LOADS ON EACH OF THE TWO DIESEL GENERATORS

One core spray pump

Two low pressure coolant injection pumps

Standby gas treatment equipment (1 unit only)

AC-powered valves required for emergency conditions

Emergency ac lighting, essential instrumentation and battery charger

480-Vac transformer losses

Diesel generator auxiliaries (includes ECCS pump room coolers)

Control room pressurization (manual)

Note:

1. See Figure 8.3-4 through Figure 8.3-7 for typical load profiles associated with the DGs during accident conditions. See the engineering calculation of record for actual diesel generator loading.

Table 8.3-3

SHUTDOWN LOADS NECESSARY FOR MAINTENANCE OF SAFE SHUTDOWN CONDITIONS (CATEGORY 2)

Four drywell cooling blowers

Reactor building cooling water system

Service water pump

Emergency ac lighting

480-Vac transformer losses

Essential instrumentation and battery charger

Diesel auxiliaries (cooling water pump, fuel transfer pump, starting air compressors, vent fan, and lube oil circulating pump)

Control room pressurization

Note:

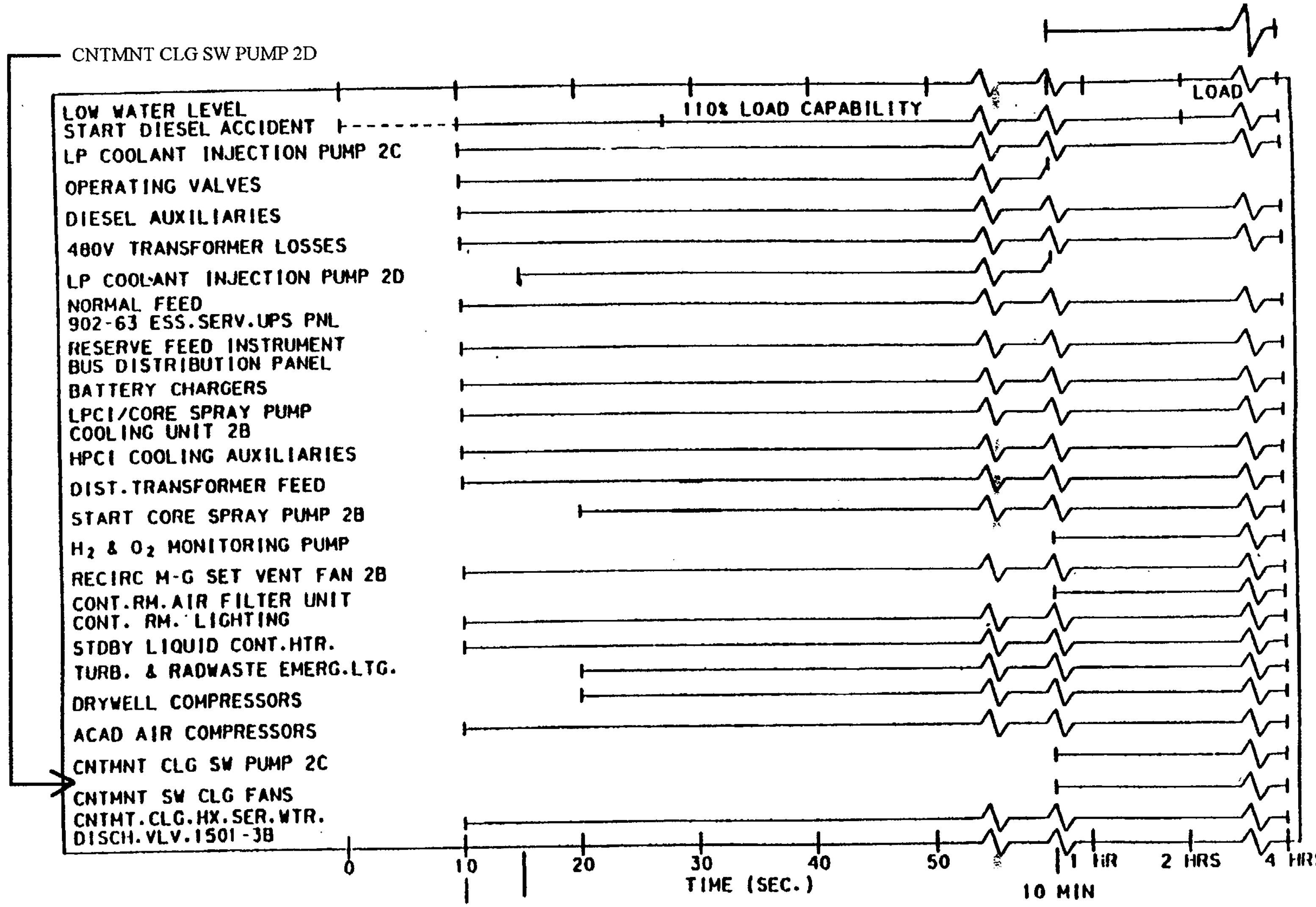
1. See the engineering calculation of record for actual diesel generator loading.

Table 8.3-7

TYPICAL PROTECTIVE RELAY SETPOINTS

	Protective Relay Type	Setpoint	Time Delay
480 V MCC	Overvoltage	133.0 V, (±2%)	10.0 seconds, (±10%)
28-7/29-7	Undervoltage	106.5 V, (±2%)	5.0 seconds
	Under/Overfrequency	57.0 Hz, (±0.008 Hz)	99 cycles, (+3, -2)
		63.0 Hz, (±0.008Hz)	99 cycles, (+3, -2)

Note: Refer to Technical Specifications Table 3.2.B-1 for 4kV Emergency Bus Undervoltage Setpoints



0 SEC IS THE REFERENCE TIME WHEN DIESEL GENERATOR RECEIVE THE START SIGNAL.

Times are approximate and shown for reference only.

See the engineering diesel loading calculation of record for actual design starting and running times and power requirements.

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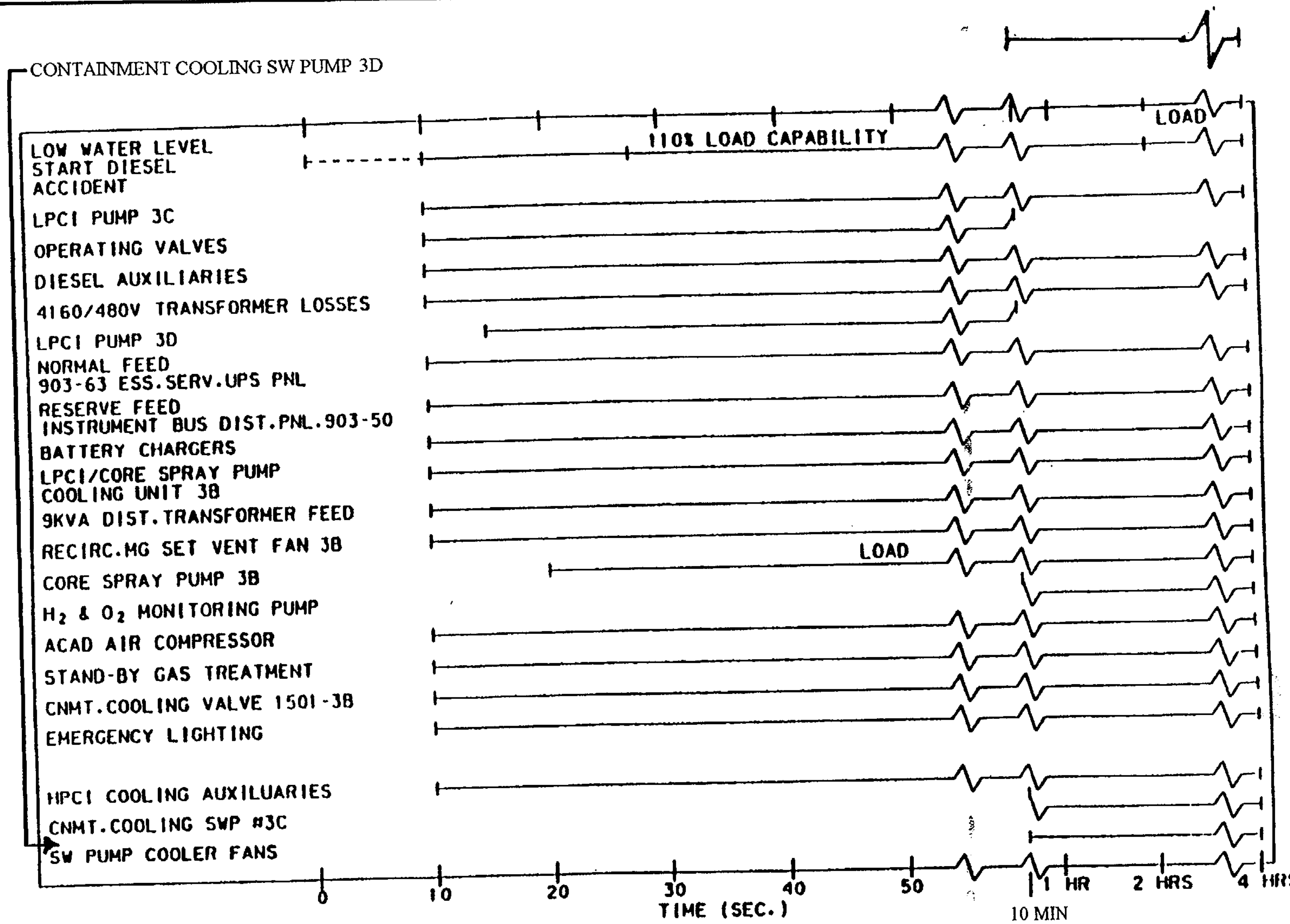
DRESDEN STATION
UNITS 2 & 3

DIESEL GENERATOR 2 ELECTRICAL LOAD PROFILE

FIGURE 8.3-4



0 SEC IS THE REFERENCE TIME WHEN DIESEL GENERATOR RECEIVE THE START SIGNAL.

Times are approximate and shown for reference only. See engineering diesel generator calculation of record for actual design starting and running times and power requirements.

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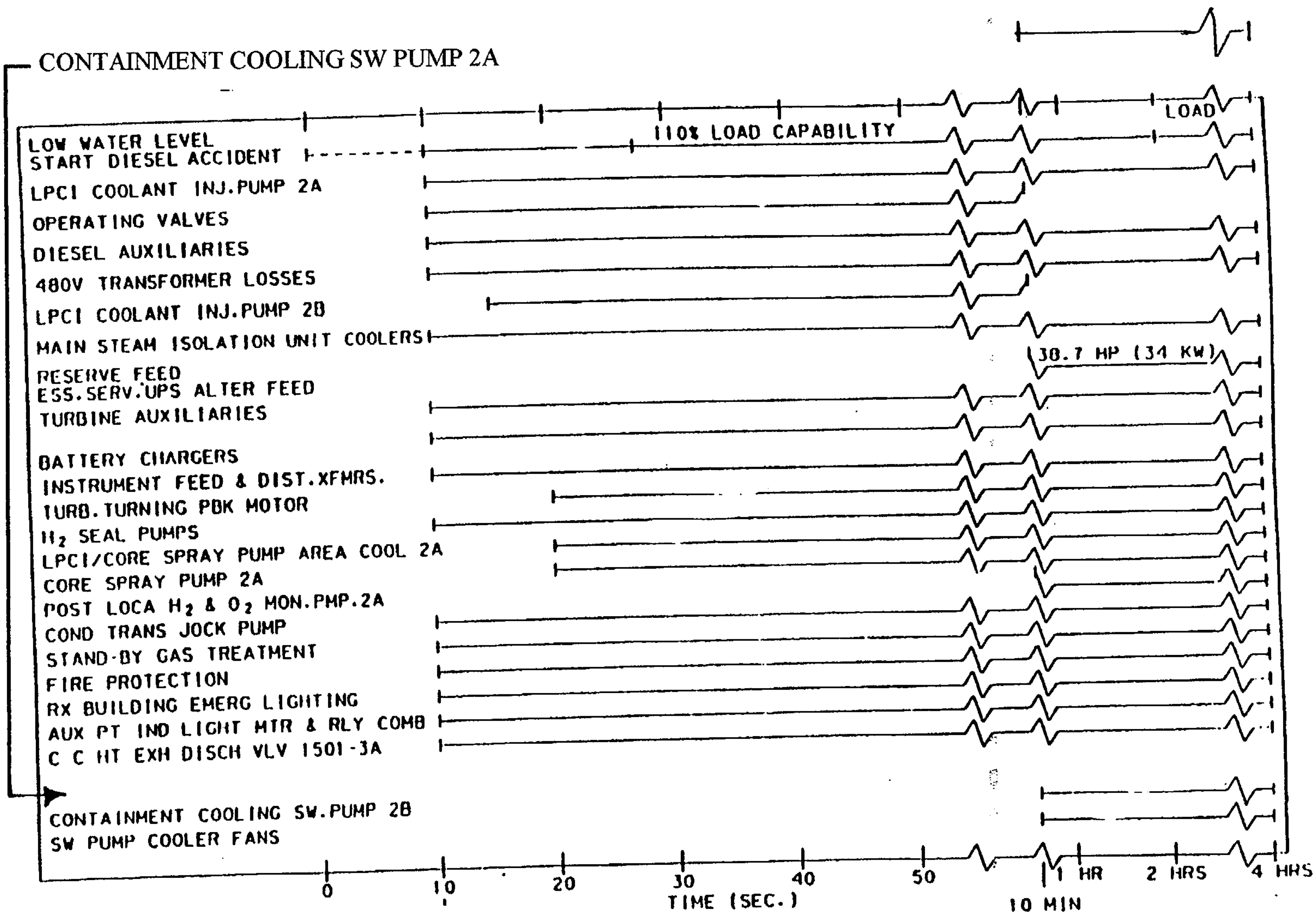
DIESEL GENERATOR 3 ELECTRICAL LOAD PROFILE

FIGURE 8.3-5



0 SEC IS THE REFERENCE TIME WHEN DIESEL GENERATOR RECEIVE THE START SIGNAL.

Times are approximate and shown for reference only. See the engineering diesel generator loading calculation of record for actual design starting and running times and power requirements.

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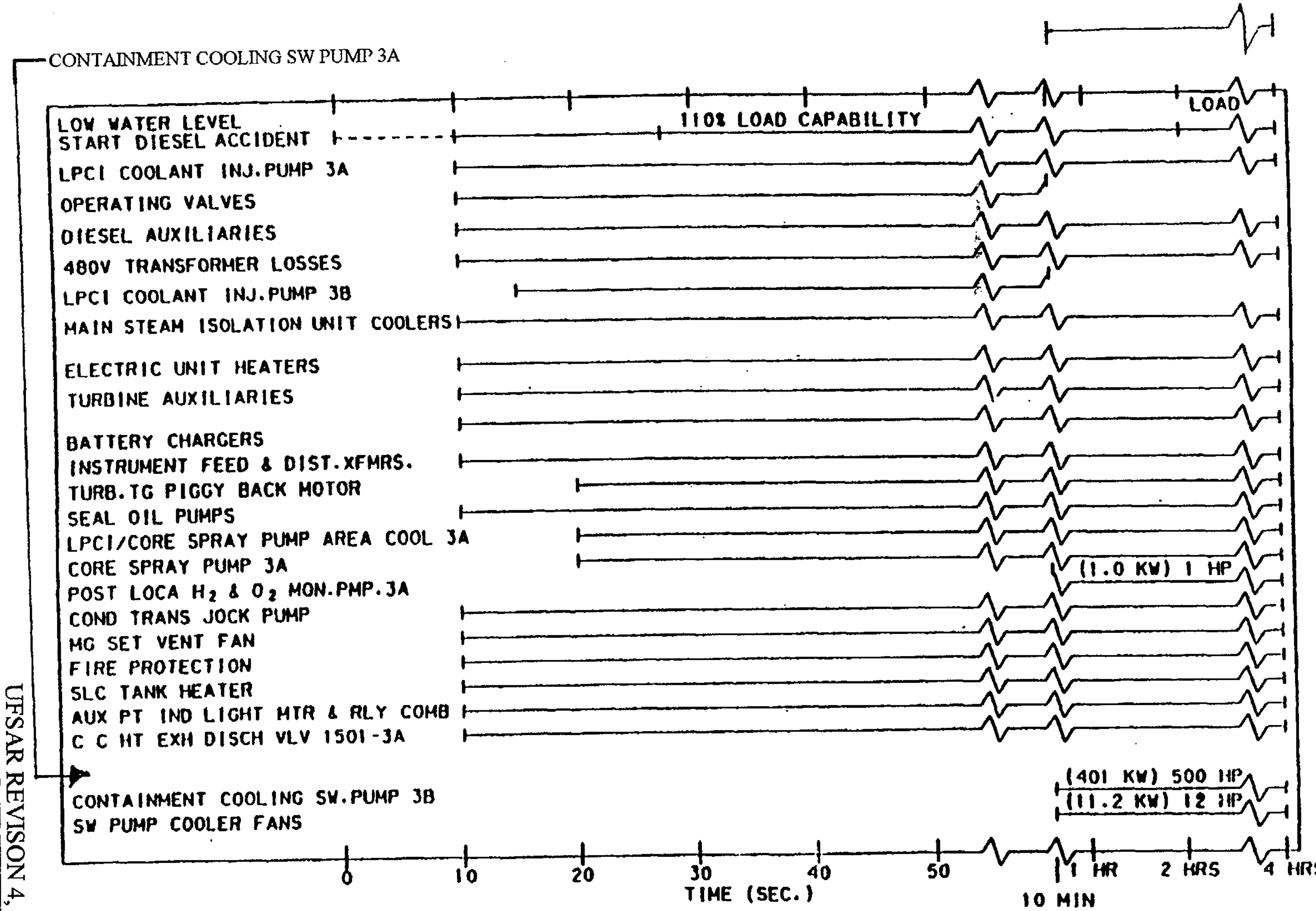
SWING DIESEL GENERATOR 2/3 ELECTRICAL LOAD PROFILE

FIGURE 8.3-6



0 SEC IS THE REFERENCE TIME WHEN DIESEL GENERATOR RECEIVE THE START SIGNAL.

Time are approximate and shown for reference only. See the engineering diesel generator loading calculation of record for actual design starting and running times and power requirements.

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DRESDEN STATION
UNITS 2 & 3

SWING DIESEL GENERATOR 2/3 ELECTRICAL LOAD PROFILE
(TIME, HORSEPOWER & KILO-WATT)
(UNIT 3 LOADING)

FIGURE 8.3-7

Table 8.3-5

Table Deleted

Table 8.3-6

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