VI – EMERGENCY CORE COOLING SYSTEMS

USAR

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VI – EMERGENCY CORE COOLING SYSTEMS

1.0   <u>EMERGENCY CORE COOLING SYSTEMS</u>

1.1   <u>Safety Objective</u>

      The objective of the Emergency Core Cooling Systems (ECCS), in conjunction with the primary and secondary containments, is to limit the release of radioactive materials to the environs following a loss of coolant accident, so that resulting radiation doses are kept to a practical minimum and are within the values given in published regulations. These systems, previously referred to as Core Standby Cooling Systems (CSCS), are sized for a maximum power level of 2429 MWt.

2.0   <u>SAFETY DESIGN BASES</u>

1.   To provide adequate cooling of the reactor core under abnormal and accident conditions, various cooling systems shall be provided of such number, diversity, reliability, and redundancy that only a highly improbable combination of events could result in inadequate cooling of the core.

2.   In the event of a loss-of-coolant accident, the Emergency Core Cooling Systems shall remove the residual stored heat and heat from radioactive decay from the reactor core at such a rate that fuel clad melting is prevented and any core mechanical deformation does not limit effective cooling of the reactor core.

3.   The Emergency Core Cooling Systems shall provide for continuity of core cooling over the complete range of postulated break sizes in the reactor coolant pressure boundary.

4.   Emergency Core Cooling Systems shall be initiated automatically by conditions which sense the potential inadequacy of core cooling, thus limiting the degree to which safety is dependent upon operator judgment in a time of stress.

5.   Operation of the Emergency Core Cooling Systems shall be initiated regardless of the availability of power from offsite supplies and the normal generating system of the plant.

6.   Action taken to effect containment integrity shall not negate the ability to achieve core cooling.

7.   To provide assurance that the Emergency Core Cooling Systems shall operate effectively, each component required to operate in a loss-of-coolant accident shall be testable during normal operation of the nuclear system.

8.   The components of the Emergency Core Cooling Systems within the reactor vessel shall be designed to withstand the transient mechanical loading during a loss-of-coolant accident so that the required standby cooling flow is not restricted.

9.   The equipment of the Emergency Core Cooling Systems shall withstand the physical effects of a loss-of-coolant accident so that the core can be effectively cooled. These effects are missiles, fluid jets, high temperature, pressure, and humidity.

10.   The Emergency Core Cooling Systems shall be capable of withstanding earthquake ground motions without impairment of their functions.

11.   To provide a reliable supply of water for the Emergency Core Cooling Systems the prime source of liquid for cooling the reactor core after a loss-of-coolant accident shall be a stored source located within the primary containment. The source shall be located in the primary containment in such a manner that a closed cooling water path is established during Emergency Core Cooling Systems operation.

12.   The calculated cooling performance following postulated loss of coolant accidents shall conform to criteria in 10CFR50.46(b) governing peak

cladding temperature, maximum cladding oxidation, maximum hydrogen generation, coolable core geometry, and long-term cooling.

      13.   The limits prescribed in 10CFR50.46(b) shall be met assuring the most limiting single failure in the ECCS.[2]

3.0   SUMMARY DESCRIPTION EMERGENCY CORE COOLING SYSTEMS

During planned operations, when normal electrical power for the plant auxiliaries is available, heat is removed from the reactor core through the boiling water-steam-turbine-condenser-feedwater cycle during power operation or, during shutdown, through use of the Residual Heat Removal System (RHR). For postulated accident conditions, when coolant is lost from a breach in the Reactor Coolant Pressure Boundary, the reactor is shut down by low reactor water level or high drywell pressure scram. As the water level in the reactor vessel continues to drop, the High Pressure Coolant Injection System (HPCI) is started. Further decrease in reactor water level will result in closure of the main steam line isolation valves. High drywell pressure or various reactor vessel low water level signals will start one or more Emergency Core Cooling Systems automatically to maintain core cooling.

The Emergency Core Cooling Systems (ECCS) consist of the:

    a.   High Pressure Coolant Injection System (HPCI)
    b.   Automatic Depressurization System (ADS)
    c.   Core Spray System (CS)
    d.   Low Pressure Coolant Injection (LPCI) (an operating mode of RHR)

ECCS are designed to limit fuel clad temperature over the complete spectrum of possible break sizes in the reactor coolant pressure boundary including the design basis break. The design basis break is defined as the complete and instantaneous circumferential rupture of the largest pipe connected to the reactor vessel with displacement of the ends so that blowdown occurs from both ends.

The individual ECCS are described in the following paragraphs. A summary of the principal parameters of the ECCS -- core cooling capacity, flow, pressure, and backup systems -- is given in Table VI-3-1.

HPCI provides protection to the core for the case of a small break in the reactor coolant pressure boundary which does not result in rapid depressurization of the reactor vessel. HPCI permits the nuclear plant to be shutdown while maintaining sufficient reactor vessel water inventory until the reactor vessel is depressurized. HPCI continues to operate until reactor vessel pressure is below the pressure at which Low Pressure Coolant Injection (LPCI) operation or Core Spray System (CS) operation can maintain core cooling.

CS and LPCI provide protection to the core for the case of a large break in the reactor coolant pressure boundary when level can not be maintained and reactor vessel rapidly depressurizes. Protection extends to a small break in which HPCI is unable to maintain reactor water level and ADS has operated to lower reactor vessel pressure.

Each ECCS pump's discharge line is maintained filled and pressurized, from the pump discharge to the injection valve. This prevents water hammer and possible pipe damage on system initiation. The water supply is from Reactor Building Auxiliary Condensate Supply System. This system is non-essential and is not required for ECCS operation. A low-pressure alarm will alert control room operators of a potential loss of fill.[56, 57]

In Generic Letter 08-01, the NRC requested that each licensee evaluate its ECCS, Decay Heat Removal, and Containment Spray system licensing

basis, design, testing, and corrective actions to ensure that gas accumulation is maintained less than the amount that challenges operability of these systems, and that appropriate action is taken when conditions adverse to quality are identified. As part of the response to Generic Letter 08-01, a program was developed that identifies activities necessary to comply with the Generic Letter. In addition the program will maintain an effective oversight from the gas intrusion perspective of ongoing and future plant operational and equipment changes.

Suction strainers are mounted inside the suppression pool for each ECCS pump suction line. These strainers remove debris that may be deposited and suspended in the suppression pool on a blowdown during an accident. The HPCI pump suction is equipped with dual strainers. LPCI and CS pump suctions are installed with large capacity strainers to maintain pump suction while providing long term decay heat removal function required by 10CFR50.46.[61]

This section also gives the safety analysis of ECCS from the system viewpoint. The process diagrams are included by reference for each system, and the principal operating parameters (flow, pressure, temperature) in the various operating, test, and accident design modes. Other sections of the USAR which give further specific details are the following:

a. Reactor Vessel Internals Mechanical Design (Core Spray), Section III-3.
b. Nuclear System Pressure Relief System (relief valves), Section IV-4.
c. Residual Heat Removal System (LPCI function and RHR-High Pressure Service Water intertie), Section IV-8.
d. Emergency Core Cooling Systems Control and Instrumentation, Section VII-4.
e. Station Safety Analysis, Section XIV.

Reference to applicable piping and instrumentation diagrams and the functional control diagrams are included in Section VII-4, "Emergency Core Cooling Systems Control and Instrumentation", which also evaluates the controls and instrumentation for all of the ECCS.

TABLE VI-3-1

EMERGENCY CORE COOLING SYSTEMS EQUIPMENT DESIGN DATA SUMMARY

Function	Number Installed	Design Flow (each) flow	Psid *	Pressure Range psig	AC Power Required for Initiation	Source of Water	Backup Systems
HPCI System	1 **	3,825 gpm	@ 1,120-150	1,120 to 150	None	Emergency Condensate Storage Tanks (100,000 gal) and suppression pool	Auto Depress. + Core Spray + LPCI
Automatic Depressuri- zing Valves	6**	6 @ 800,000 lb/hr	@ 1,080[3]	1,080 to 50	None	------	Remote-manual Relief Valves
Core Spray System	2**	4,250 gpm	@ 113	265 to 0	Normal Aux. or Standby Diesel Gen.	Suppression Pool	LPCI
LPCI Pumps	4**	6,900 gpm	@ 20	263 to 0	Normal Aux. or Standby Diesel Gen.	Suppression Pool	Core Spray System

*psid - pounds per square inch differential between reactor vessel and primary containment.

**Specified capacities were derived from system requirements for the current LOCA accident analysis. They are based on the integrated operation of the ECCS systems available following the most limiting single failure, together with assumed ECCS system performance capabilities.

4.0   <u>DESCRIPTION</u>

4.1   <u>High Pressure Coolant Injection System</u>

The High Pressure Coolant Injection System (HPCI) consists of a steam turbine assembly (with speed regulation) driving a 4,250 gpm multi stage booster and main pump assembly and system piping, valves, controls, and instrumentation. HPCI is shown schematically in <u>General Electric Drawing 729E720BB</u>.

The principal HPCI equipment is installed in the reactor building. The turbine-pump assembly is located in a shielded area to assure that personnel access to adjacent areas is not restricted during operation of HPCI. Suction piping comes from the emergency condensate storage tank and the suppression pool. Injection water is piped to the reactor feedwater pipe at a T-connection. Steam supply for the turbine is piped from main steam line "C" in the primary containment. This piping is provided with an isolation valve on each side of the drywell barrier. Remote controls for valve and turbine operation are provided in the plant control room. The controls and instrumentation of HPCI are described, illustrated, and evaluated in detail in Section VII-4, "Emergency Core Cooling Controls and Instrumentation".

If a loss of coolant accident (LOCA) occurs, the reactor scrams upon receipt of a low water level signal (Level 3) or a high drywell pressure signal. HPCI starts when the water level reaches a pre-selected height above the core (Level 2) or if high pressure exists in the primary containment. HPCI automatically stops when a high water level in the reactor vessel (Level 8) is signaled.

HPCI is designed to pump water into the reactor vessel for a wide range of pressures in the reactor vessel. Two sources of water are available. Initially, demineralized water from the emergency condensate storage tank is used. Secondly, water from the suppression pool is injected into the reactor. Water from either source is pumped into the reactor vessel via the "B" feedwater line. Flow is distributed within the reactor vessel through the feedwater spargers to obtain mixing with the hot water or steam in the reactor pressure vessel.

4.1.1   <u>HPCI System Components</u>

This USAR section contains historical information as indicated by the italicized text. USAR Section I-3.4 provides a more detailed discussion of historical information. The information being presented in this section as historical has been preserved as it was originally submitted to the NRC in the CNS FSAR.

The pump assembly is located below the level of the emergency condensate storage tank and below the water level in the suppression pool to assure positive suction head to the pumps. Pump NPSH requirements are met by providing adequate suction head and adequate suction line size.

The HPCI turbine-pump assembly and piping are located outside primary containment so as to be protected from the physical effects of design basis accidents, such as pipe whip and high temperatures. This arrangement satisfies safety design basis 9.

The HPCI turbine is driven by steam from the reactor which is generated by decay heat and residual heat. The steam is extracted from main steam line "C" upstream of the main steam line isolation valves. Two isolation valves in the steam line to the HPCI turbine are normally open to keep the piping to the turbine at elevated temperatures in order to permit rapid startup. Signals from HPCI controls system open or close the turbine stop valves.

A condensate drain pot is provided upstream of the turbine stop valve to prevent the HPCI steam supply line from filling with water. The lines have no pockets, assuring that no slugs of water can be trapped in the line. The drain pot normally routes the condensate through a trap station to the main condenser, but upon receipt of HPCI-MO-14, steam to turbine valve, not full closed signal or a loss of control air pressure, isolation valves on the condensate line automatically shut.

The CNS operating procedures provide that the two isolation valves in each steam supply line are normally open and that proper action shall be taken to prevent water carry-over (water slugs) into the main steam lines based upon water level indication within the reactor pressure vessel. These procedures combined with the improved piping connections of HPCI steam supply to the main steam lines are designed to prevent or minimize the water carry-over. Furthermore, the Terry Turbines have been designed and tested to insure that water carry-over will not cause damage to the turbine.

A test program of two test series was conducted at Duane Arnold to prove the structural integrity of the HPCI unit (Terry Turbine) for the following cases:

1. *Water ingestion during HPCI quick startup.*

2. *Water ingestion during HPCI normal operation.*

The test were conducted using subcooled water and steam as the driving force. The amount of water used in the test series was varied from 50 to 600 gal, which was established from the conservative assumption that the HPCI steam line was full of water. The behavior of the turbine under the test conditions was recorded through the constant monitoring of the inlet and outlet pressures and temperatures, the position of the control valve, and the rotation speed of the turbine.

Following both series of tests, the HPCI turbine was completely disassembled and all parts were inspected for possible damage or deterioration. After the reassembly of the turbine, a no-load running test was conducted to detect any degradation of turbine performance.

From the results of the tests it was concluded that:

1. *The test conditions to which the Terry turbine was subjected were as least as severe as any that could result in an operating GE BWR; in fact, the tests represent a more severe condition than any that could occur in a GE BWR.*

2. *The turbine showed signs neither of damage nor any permanent performance degradation.*

3. *The tested turbine is typical for the type then installed in the HPCI system of the CNS product line GE BWR.*

Thus, there is no necessity for any high water level isolation valve interlocks and no provisions have been made for them. Further, the

additions of the interlocks to CNS HPCI isolation valves would degrade the system and its isolation reliability.[7]

The turbine has two devices for controlling turbine speed: A ramp generator which controls turbine acceleration on startup and a signal converter with automatic speed set point control from a flow controller to maintain constant flow over the pressure range of HPCI operation. Manual operation of the governor is possible when in the test mode, but the governor is automatically re-positioned by the demand signal from the flow controller if system initiation is required.

As reactor steam pressure decreases, the HPCI turbine throttle valves open further in order to pass the steam flow required to provide the necessary pump flow. The capacity of the system is selected to provide sufficient core cooling while the pressure in the reactor vessel is above the pressure at which CS and LPCI become effective.

Exhaust steam from the HPCI turbine is discharged to the suppression pool. A drain pot at the low point in the exhaust line collects moisture present in the steam. Collected moisture is discharged through a trap to the suppression pool or bypassed to the gland seal condenser if the trap fails. During standby conditions, condensate is drained to the gland seal condenser then to the equipment drain system.

The steam exhaust line is also provided with vacuum breakers in the form of check valves to prevent the line from being flooded by siphoned Suppression Chamber water.

HPCI turbine gland and system valve seals are vented to the gland seal condenser and part of the water from the HPCI pump is routed through the condenser for cooling purposes. Non-condensible gases from the gland seal condenser are pumped to the Standby Gas Treatment System.

The system piping is designed in accordance with the requirements stated in Appendix A. The pump is also designed and tested in accordance with the Standards of the Hydraulic Institute. HPCI equipment, piping, and support structures are designed as Class I equipment (see Appendix C). This satisfies design basis 10.

The system is designed for a service life of 40 years; taking into account corrosion, erosion, and material fatigue, and assuming the system is tested in accordance with the Technical Specification requirements. Startup of HPCI is completely independent of AC power. Only DC power from the plant batteries and steam extracted from the nuclear system are necessary for startup and short term operation. For continued operation during an accident or reactor isolation conditions, AC power will be required for battery chargers, compartment cooling, and suppression pool cooling. These components are powered from critical buses. For further details see USAR Section IV-7.5. This satisfies safety design basis 5. The HPCI system is credited with mitigating a Station Blackout event.[47] [48] [49] [50]

The various operations of HPCI components are summarized as follows:

The Cooper LOCA analysis [44] assumes a 60 second HPCI start time from a low vessel water level or high drywell pressure condition to full HPCI design flow rate injection. This allows a 5 second instrument delay time

from the initiating condition to receipt of the HPCI actuation signal in addition to the 55 second HPCI startup.

The HPCI turbine is shut down automatically by any of the following signals:

a) Turbine overspeed - This prevents damage to the turbine and turbine casing.
b) Reactor vessel high water level - This indicates that core cooling requirements are satisfied.
c) HPCI pump low suction pressure - This prevents damage to the pump due to loss of flow.
d) HPCI turbine exhaust high pressure - This indicates a turbine or turbine control malfunction, or exhaust line blockage.
e) HPCI Steam Supply Pressure Low (Group 4 PCIS Isolation). Prevents steam release from seals, at pressures below where HPCI is effective.
f) HPCI Steam Line High Differential Pressure (Group 4 PCIS Isolation). This is indication of a steam line break.
g) Excess Steam Line Space Temperature (Group 4 PCIS Isolation). This is indication of a steam line break.

If an initiation signal is received after the turbine is shut down, the system is capable of automatic restart if no shutdown signals exist.

Because the steam supply line to the HPCI turbine is part of the reactor coolant pressure boundary, certain signals automatically isolate this line, causing shutdown of the HPCI turbine. Automatic shutoff of the steam supply is described in Section VII-3, "Primary Containment Isolation System Control and Instrumentation". However, the ADS and the low pressure systems of the ECCS act as backup, and automatic shutoff of the steam supply does not negate the ability of the ECCS to satisfy the safety objective.

In addition to the automatic operational features of the system, provisions are included for remote-manual startup, operation, and shutdown (provided initiation or shutdown signals do not exist).

4.1.2   HPCI Automatic Initiation

HPCI initiation automatically actuates the following valves:

HPCI pump discharge test bypass valves
HPCI pump suction shutoff valve
HPCI pump discharge injection valve
HPCI steam supply shutoff valve
HPCI turbine stop valve
HPCI turbine control valve
HPCI steam supply line drain isolation valves

Startup of the hydraulic oil pump and proper functioning of the hydraulic control system is required to open the turbine valves. Operation of the gland seal condenser components directs outleakage from the turbine shaft and various system valve seals to the gland seal condenser. Startup of the gland seal equipment is automatic, but its failure would not prevent the HPCI from fulfilling its core cooling objective. Prior to startup, the control governor will be at its low speed stop position. The flow control signal from the signal converter is at a high level (at flow setpoint) with the system in

standby and no system flow. Upon receipt of an initiating signal, the steam supply shutoff valve opens and the hydraulic oil pump auto starts. When sufficient hydraulic oil pressure is developed both the turbine stop valve opens and the control valve starts to open simultaneously. This starts the ramp generator. The ramp generator is at a minimum signal and ramps to maximum over several seconds. This ramped signal limits the turbine control valve opening to control turbine acceleration. When the ramp signal exceeds the flow controller output signal the flow controller will take control of turbine speed to maintain pump flow rate.

A minimum flow valve HPCI-MOV-MO25 is provided for pump protection. The minimum flow valve automatically opens on a low flow signal and automatically closes on a high flow signal. When the minimum flow valve is open, flow is directed to the suppression pool.

There are shutoff valves in the line used for system testing. These valves are signaled to close by the signal which actuates system operation and are interlocked closed when the suction valve from the suppression pool is open. All automatically operated valves are equipped with a remote-manual functional test feature.

HPCI initially injects water from the emergency condensate storage tank. When the water level in the tank falls below a predetermined low level or if suppression pool level reaches a predetermined high level, the pump suction is automatically transferred to the suppression pool. This transfer may also be made from the control room using remote controls. This establishes a closed loop for recirculation of water escaping from a break. This satisfies safety design bases criteria 11. In the event of an incident which results in a complete loss of emergency condensate storage tank level indication, a local level indication is available.

For postulated accident conditions, HPCI is started when the reactor vessel water level drops to Level 2. In order to ensure HPCI is operational, RCIC is completely separated from HPCI, even though steam supply to both systems is from main steam line "C". The steam line separation is such that no simple break in the RCIC line will cause an isolation of HPCI.[9]

For station black out (SBO), HPCI starts when reactor vessel water level drops to Level 2. In order to conserve DC battery power during the assumed 4-hour duration, HPCI is secured after level in the reactor pressure vessel is restored per Emergency Operating Procedures. RCIC will automatically operate to maintain reactor vessel level for the duration of the event.[59]

4.2   Automatic Depressurization System

In case the capability of HPCI is not sufficient to maintain the reactor water level, ADS functions to reduce the reactor pressure so that flow from LPCI and CS enters the reactor vessel in time to cool the core and limit fuel clad temperature.

ADS uses six of the eight nuclear system pressure relief valves to relieve the high pressure steam to the suppression pool. The other two pressure relief valves are utilized by Low-Low Set.[29] The design, description, and evaluation of the pressure relief valves are discussed in detail in Section IV-4, "Nuclear System Pressure Relief System", and it is shown that safety design basis 5, 9, and 10 are satisfied.

The pressure relief valves automatically open upon coincident signals of: 1) reactor vessel low water level (Level 1), 2) Confirmatory reactor vessel low water level (Level 3), and 3) discharge pressure indication of any low pressure cooling system (LPCI or CS), but only after a time delay. The confirmatory low reactor vessel level (Level 3) signal is required to prevent auto initiation upon a single level transmitter failure and to allow testing of the logic system. The time delay and inhibit switches provide time for the operator to cancel the automatic depressurization signal if control room information indicates the signal is false or is not needed.

4.3   Core Spray System

Two independent loops (or subsystems) are provided as a part of the Core Spray System (CS). Each loop consists of one centrifugal water pump driven by an electric motor, a spray sparger in the reactor vessel above the core, piping and valves to convey water from the suppression pool to the sparger, and the associated controls and instrumentation. General Electric Drawing 161F282BC shows a schematic process diagram of the CS System.

CS pumps will automatically start on low reactor water level or high drywell pressure. When reactor vessel pressure has decreased to a predetermined pressure the injection valve is signaled to open. Then, when reactor pressure decreases to less than CS pump discharge pressure, the inboard check valve opens and CS sprays water onto the top of the fuel assemblies in time and at a sufficient flow rate to cool the core and limit fuel clad temperature. (The LPCI subsystem starts from the same signals and operates independently to achieve the same objective by flooding the reactor vessel.)

CS pumps receive power from the 4160 Volt critical buses. Each CS pump motor and the associated automatic motor operated valves for one loop receive AC power from the same division. Similarly, control power for each loop comes from the associated DC bus. This arrangement satisfies design basis 5 (see Section VIII-5, "Standby AC Power Supply and Distribution", and VIII-6, "250 Volt DC Power Supply and Distribution").

The CS pumps and all automatic valves can be operated individually by manual switches in the control room. Operating information is provided in the control room with pressure indicators, flow meters, and indicator lights.

The suction to the CS pump can be lined up to the Condensate Storage Tank (CST) 1A.

4.3.1   Core Spray Components

The major equipment for one loop, CS subsystem "A", is described in the following paragraphs. Both CS loops (or subsystems) are identical.

When the system is actuated, water is taken from the suppression pool. Flow then passes through normally open motor operated valve CS-MO7A which can be closed by a key locked remote-manual switch from the control room to isolate the system from the suppression pool in case of a leak from CS. This valve is key locked open to confirm that suction is available to the pump. This valve is located in the CS pump suction line, close to the suppression pool.

A local pressure gage by the pump indicates the presence of a suction head for the pump. The CS pump is located in the reactor building below the water level in the suppression pool to assure positive pump suction. The pump, piping, controls, and instrumentation of each loop are separated and protected so that no single physical event or missiles generated by rupture of

any pipe in any system within the containment drywell, can make both CS loops inoperable. The switchgear for each loop is in a separate cabinet for the same reason. This arrangement satisfies safety design basis 9.

A shaft seal drain line is provided from the pump casing which drains to the Reactor Building sumps.

A minimum flow line is provided from the pump discharge to the suppression pool. The minimum flow is required to prevent the pump from overheating when pumping against a closed discharge valve. An orifice limits the minimum flow.

A relief valve protects the low pressure CS System upstream of the outboard injection valve from reactor pressure. The relief valve discharges to the suppression pool.

A full-flow test line permits circulating water to the suppression pool for testing the system during normal plant operations. A normally closed, motor operated valve in the line, CS-MO26A, is controlled by a remote-manual switch in the control room. Partial opening of the valve and an orifice in the test line provides rated CS flow at a pressure drop equivalent to discharging into the reactor vessel. A flow indicator in the control room provides system flow indication for either the CS sparger or test line.

A motor operated valve and a check valve isolate the CS System from the reactor pressure vessel. The check valve is located inside the drywell. The motor operated valve is located outside the drywell to facilitate operation and maintenance, but as close as practical to the drywell to limit the length of line exposed to reactor pressure. The motor operated valve, CS-MOV-MO12A, is normally closed. It is signaled to open when an initiation signal is present and the reactor pressure has decreased to the injection set point. This feature protects the low-pressure portion of the CS System piping from overpressure. Another motor operated valve is provided outboard of the injection valve. This normally open valve, CS-MOV-MO11A, can be closed to permit periodic testing of the injection valve when the reactor is pressurized. An interlock is provided to ensure CS-MOV-MO11A is closed before CS-MOV-MO12A can be opened when the reactor is pressurized. Vent and drain lines are provided to permit leak rate testing of the containment isolation valves.

An inboard check valve is provided in each CS line just inside the primary containment to prevent loss of reactor coolant outside containment in case the CS line breaks. A normally sealed-open manual valve is provided downstream of the inside check valve to shut off CS from the reactor during shutdown conditions for maintenance of upstream valves. These manual isolation valves are provided with position indication in the control room. USAR Section III-3, Reactor Vessel Internals Mechanical Design, provides details on reactor vessel internal piping.

CS piping upstream of the outboard injection valve is designed for the lower pressure and temperature of the CS pump discharge. The injection valve and piping downstream are designed for reactor vessel pressure and temperature (see Appendix A).

The CS equipment, piping, and support structures are designed in accordance with Class I seismic criteria (see Appendix C) to resist the motion at the installed location within the supporting building from the design basis earthquake. The CS System is assumed filled with water for seismic analysis. It is concluded that safety design basis 10 is satisfied.

4.3.2   Core Spray Automatic Initiation

Upon signals of reactor vessel low water level (Level 1) or drywell high pressure, the automatic controls start the CS pumps and align valves to the spray mode. When reactor pressure decreases, the CS injection valves are signaled to open. Flow to the sparger begins when the pressure differential opens the inboard check valve. Section VII-4, "Emergency Core Cooling System Controls and Instrumentation" contains further details and evaluation.

4.3.3   Reference Leg Injection

CS also injects suppression pool water into the cold reference legs such that flashing or boiloff of the reference legs is precluded. Reference leg injection is necessary when a small steam line break or the loss of containment coolers during reactor depressurization could cause the cold reference legs inside the drywell to flash or boiloff, which in turn would result in inaccurate reactor vessel water level indication.

Each CS loop injects to its associated instrument reference leg. All reference leg injection components are classified as essential (safety related), and are designed to Class IS/IIN requirements.

The reference leg injection piping taps off the CS high point vent in the reactor building and terminates at the cold reference leg located at the reactor water level instrument rack 25-5 (Loop A) and 25-6 (Loop B). System isolation valves, two check valves in series, a solenoid valve and needle valve are utilized in each injection loop. Two check valves act as the pressure boundary between the CS and NBI systems. The system manual isolation valves are normally open to place the system in standby status. This allows remote actuation of the system via opening the solenoid valves from the control room. Following manual actuation of the reference leg injection system, injection occurs when the CS system pressure is greater than the NBI system pressure. The needle valve is set during the reference leg system test such that a flow of 0.5 gpm is injected into the reference leg during accident conditions[70].

The CS System isolation valves are closed when the reactor pressure is less than 310 psig. This improves system reliability by preventing wear on the solenoid valves from cyclic pressurization of the CS system during surveillance testing when the CS system pressure exceeds the reactor pressure.

The injected suppression pool water ultimately fills the cold reference legs up to condensing chamber 3A (Loop A) and 3B (Loop B), when it then returns to the reactor vessel.

Reference leg injection piping and valves are shown in Burns and Roe Drawing 2045, Sheet 1, and Burns and Roe Drawing 2026, Sheet 1.

4.4   Low Pressure Coolant Injection Subsystem

In case of low water level in the reactor (Level 1) or high pressure in the containment drywell, the LPCI mode of operation of the

RHR pumps water into the reactor vessel in time to flood the core and limit fuel clad temperature. (CS starts from the same signals and operates independently to achieve the same objective.)

General Electric Drawing 729E211BB is a schematic process diagram of the RHR showing the LPCI mode of operation. LPCI operation consists of initiation of both subsystems (loops), each of which consists of two RHR AC motor-driven centrifugal pumps, taking water from the suppression pool and pumping it into their corresponding reactor recirculation loops. (See Sections VI-5.2.7, "Emergency Core Cooling Systems", and VII-4.5.5, "LPCI Control and Instrumentation"). The water enters the reactor through the associated recirculation system loops to the jet pumps to restore the water level inside the core shroud to the height of the jet pump nozzle. LPCI operation includes using associated valves, controls, instrumentation, and pump accessories. The RHR pumps receive power from the 4160 Volt critical AC Buses. One pump of each loop and that loop's associated valves receive power from one critical bus, while the remaining pump in that loop, is powered from the other critical bus. The other loop is powered similarly from the opposite critical buses. See Section VII-4.5.5.1. This arrangement satisfies safety design basis 5 (see Sections VIII-5, "Standby AC Power Supply and Distribution" and VIII-6, "250 Volt DC Power Supply and Distribution").

The suction to the RHR pump can also be lined up to CST 1A.

RHR pumps and piping equipment are described in detail in Section IV-8, "Residual Heat Removal System" which also describes the other functions served by the same pumps if not needed for the LPCI function. The portions of RHR required for accident protection are designed in accordance with Class I seismic criteria (see Appendix C). It is concluded that safety design basis 10 is satisfied.

5.0   SAFETY EVALUATION

5.1   Summary

        In order to satisfy the safety design basis, four systems assure emergency core cooling is provided:

                    High Pressure Coolant Injection
                    Automatic Depressurization
                    Core Spray
                    Low Pressure Coolant Injection

        Other non-ECCS systems also supply core coolant: reactor feedwater and condensate, control rod drive, and RCIC.

        For reliability, each ECCS uses equipment with as few components required to be actuated as feasible, and all of those are available for test purposes during normal operation. To provide diversity, two different cooling methods are provided -- spraying and flooding.

        Evaluation of the reliability and redundancy of the controls and instrumentation for the ECCS shows that no failure of a single initiating sensor either prevents or falsely starts the initiation of these cooling systems. No single control failure prevents the combined cooling systems from providing the core with adequate cooling. The controls and instrumentation can be calibrated and tested to assure proper response to conditions representative of accident situations.

        For a small break LOCA, CS and LPCI may operate for an extended period of time on minimum flow, until the reactor vessel depressurizes and the systems can inject. ECCS pumps can operate on minimum flow for a longer period of time than the maximum duration of the most limiting small break LOCA analyzed.

        LOCA modeling of the reactor fuel and ECCS performance verifies that the design bases requirement for post-LOCA core cooling are satisfied with the worst case single active component failure assumed, and the remaining ECCS equipment operating as described above. This ensures that the reactor core will maintain a coolable geometry during all phases of the analyzed event, including core reflooding and long term cooling.

        The ECCS components have drains that route system leakage directly and indirectly to the reactor building sumps. This leakage from ECCS systems, while performing post-LOCA recirculation cooling of the reactor and primary containment, constitutes a bypass of the primary containment to the secondary containment. The contribution of the leakage source term to the post-LOCA dose consequences is described in Section XIV-6.3.8. An inspection program to verify this design feature is discussed in USAR Section VI-6.0, Inspection and Testing.

        All of the safety design bases for the ECCS are shown to be met by the previous descriptions, the referenced descriptions and evaluations in other sections, and by the following safety evaluations of the combined ECCS.

5.2   Performance Evaluation

        This section provides the results of the ECCS system Loss of Coolant Accident evaluation. Cycle 18 and subsequent operating cycles are

based on the SAFER-GESTR set of methods.[43,62,63,71] The analyses based on these methods[44,62,63,71] are documented below.

5.2.1   Acceptance Criteria for ECCS Performance

The acceptance criteria for Loss of Coolant Accident analyses documented in 10CFR50.46 are listed below. Compliance with these criteria is discussed in paragraph 5.2.2.

1.   Peak-Cladding Temperature: The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2.   Maximum Cladding Oxidation: The calculated total local oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3.   Maximum Hydrogen Generation: The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinder surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4.   Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5.   After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value, and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

5.2.2   Conclusions

Compliance with each of the criteria provided in paragraph 5.2.1 was documented in the CNS analysis.[44,62,63,71,72,73] A summary of this compliance is provided in Table VI-5-1, ECCS Performance Results. The lower of either the exposure dependent maximum average planar linear heat generation rate (MAPLHGR) used in the analysis or the exposure dependent MAPLHGR resulting from the fuel thermal-mechanical analysis is the operating limit placed in the Core Operating Limits Report (COLR) which is referenced by the Technical Specifications.

5.2.3   Single-Failure Considerations

One requirement of 10CFR50 Appendix K is the worst single failure of ECCS equipment must be assumed to occur during a LOCA. This assumption affects the remaining systems assumed to operate for the LOCA analysis. The availability or unavailability of offsite power, coincident with the LOCA, must also be evaluated. Table VI-5-2 identifies the combinations of break locations, single failures and available systems specifically analyzed for the CNS ECCS configuration.

5.2.4   LOCA Analysis Procedures and Input Variables

A list of the significant input parameters are presented in Table VI-5-3 and Table VI-5-4. Table VI-5-3 shows the plant operating conditions and the fuel parameters utilized in the LOCA evaluation. Table VI-5-4 identifies the ECCS parameters utilized for the analysis.

All SAFER/GESTR-LOCA analyses were performed with a bounding MAPLHGR at the most limiting power and exposure combination. The most limiting power/exposure combination was determined by performing generic sensitivity studies along the peak power/exposure envelope used for the fuel thermal mechanical design. As shown in Table VI-5-4, the SAFER/GESTR-LOCA analysis incorporates conservative values for some ECCS performance requirements relative to the original technical specifications or expected equipment performance.

The detailed procedures used for the LOCA analyses are documented in NEDE-23785[43]. The results of the single failure assessment are given in paragraph 5.2.3. A summary of the set of codes used in this analysis is given below.

Short-Term Thermal-Hydraulic Model (LAMB)

The first analysis performed is with the LAMB computer code. This code is used to analyze the short-term blowdown phenomena for large postulated pipe breaks in jet pump reactors. A large break is one in which nucleate boiling is lost before the water level drops and uncovers the active fuel. The LAMB output of core flow as a function of time is input to the SCAT code for the calculation of the blowdown heat transfer and fuel dryout time.

Transient Critical Power Model (SCAT/TASC)

This model completes the transient short-term thermal-hydraulic calculation for large recirculation line breaks. The time and location of boiling transition are predicted during the period of recirculation pump coastdown. When the core inlet flow is low, SCAT also predicts the resulting bundle dryout time and location. The calculated fuel dryout time is an input to the long-term thermal-hydraulic transient model, SAFER. For GE11 and later fuel, an improved SCAT model (designated "TASC") is used to predict the time and location of boiling transition and dryout. This model explicitly models the axially varying flow areas and heat transfer surface resulting from the GNF2 part length fuel rods, and incorporates the critical power correlation for GNF2.

Thermal-Mechanical Model (GESTR-LOCA)

The GESTR-LOCA code is used to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA for input to SAFER. GESTR-LOCA also initializes the transient pellet-cladding gap conductance for input into both SAFER and SCAT.

Long Term Thermal-Hydraulic Model (SAFER)

This code is used to calculate the long-term response for reactor transients over a complete spectrum of hypothetical break sizes and locations. SAFER is compatible with the GESTR-LOCA fuel rod model for gap conductance and fission gas release. SAFER is used to determine, as a function of time, the core water level, system pressure response, ECCS performance, and other primary thermal-hydraulic phenomena occurring in the reactor. SAFER realistically models all regimes of heat transfer which occur inside the core during the event, and provides the outputs as a function of time for heat transfer coefficients and PCT.

5.2.5   Break Spectrum Calculations

Several break sizes with the generically determined limiting single failure for the BWR 3/4 plant class documented in paragraph 5.2.3 were analyzed using nominal assumptions and the inputs discussed in paragraph 5.2.4. This analysis established the shape of the PCT versus break area curve (break spectrum) to ensure the limiting combination of break size, location, and single failure had been identified, and was the same as that determined in the generic evaluation. The trend of PCT with break size was consistent with the trend observed in the generic break spectrum. This nominal analysis also demonstrated that the largest possible break in the recirculation suction line with a coincident 125V battery failure resulted in the highest PCT for the plant and bounds other ECCS line breaks.

For BWR 3/4 class of plants, the generic Appendix K PCT versus break size curve exhibits the same trends as the generic nominal PCT versus break size curve and the limiting LOCA determined from the nominal PCT/break spectrum analysis is the same as that determined from the Appendix K

evaluations. The plant specific licensing basis calculations also match the trend of the generic Appendix K versus break size curve. This Appendix K analysis also demonstrated the largest possible break in the recirculation suction line with a coincident battery failure resulted in the highest PCT for the plant.

Table VI-5-5 provides the nominal and Appendix K results for the limiting DBA and small recirculation line break for GNF2 fuel designs.

5.2.6 Alternate Operating Modes

Maximum Extended Load Line Limit Analysis (MELLLA) and ARTS

The higher rod line in the MELLL region permits reactor operation at 75% of rated core flow at 100% power. Low core flow effects on the ECCS analyses were generically addressed in Reference 45, which was approved by the NRC in Reference 46. These studies demonstrated that no MAPLHGR multiplier was required for low core flow operation for the BWR-4 plant class similar to the CNS. The Reference 46 analysis (prior to consideration of MELLL operation and ARTS) was performed consistent with the original setdown requirement. With ARTS for CNS, the setdown factor on the flow-referenced APRM rod block system is removed and replaced with MAPLHGR and MCPR adjustment factors as functions of power and flow. Therefore, the SAFER/GESTR-LOCA analysis for low core flow conditions in the MELLL region was evaluated for the CNS, using the same ECCS inputs as used for the rated core flow conditions.

The recirculation suction break DBA with DC power source failure, which gives the highest nominal PCT at the rated core flow conditions, was analyzed at 75% initial core flow (MELLL core flow at 100% of rated power). The SAFER/GESTR-LOCA results show that the Appendix K PCT at 75% core flow is 176°F higher than that at the rated core flow.[62,63,71]

Thus, for the ARTS improvement program application to the CNS, the PCT for a design basis LOCA at MELLL condition is analyzed to confirm that the licensing basis PCT is still under 2200°F criteria. Therefore, no ECCS-consideration is needed for a low flow MAPLHGR multiplier to the generic flow-dependent MAPFAC curves.

Increased Core Flow (ICF)

The higher initial core flow at ICF condition during LOCA, may lead to the delayed and less severe boiling transition in the fuel bundles during the early portion of the event. However, the change in core uncovery time is relatively small. The impact of ICF on LOCA limits was negligible on worst break PCT[63].

Single Loop Operation (SLO)

The ECCS performance for the CNS under single loop operation (SLO) was evaluated using SAFER/GESTR-LOCA. The recirculation suction line break DBA with DC power source failure was analyzed with both Nominal and Appendix K inputs. The approach used to assess SLO is to determine a MAPLHGR multiplier such that the PCT for SLO using the nominal assumptions does not exceed the PCT at rated conditions; this results in a MAPLHGR multiplier of 0.87 for SLO conditions. Using the MAPLHGR multiplier 0.87, the SLO Appendix K PCT is 99°F less than the limiting DBA suction line break. Therefore, the use of a 0.87 MAPLHGR multiplier in the SAFER/GESTR-LOCA analysis is conservative and the PCT for SLO will always be lower than that for two-loop operation.

TABLE VI-5-1

ECCS PERFORMANCE RESULTS

	Criterion	Analytical Results GNF2	Limit
1.	Licensing Basis Peak Clad Temperature, (PCT) °F	2130	≤2200
2.	Cladding Oxidation, % Original Clad Thickness	<6.0	≤17
3.	Hydrogen Generation (Core wide Metal-Water Reaction), %	<0.1	≤1.0
4.	Coolable Geometry	OK	Meet 1 and 2, above
5.	Core Long Term Cooling	OK	Core remains covered to jet pump elevation, and one low pressure core spray loop operates

TABLE VI-5-2

CNS SINGLE FAILURE EVALUATION

Assumed Failure[1]	Recirculation Suction Break Systems Remaining[2]	Recirculation Discharge Break Systems Remaining
125V DC Power Source	1CS, 2LPCI (one into each loop), ADS	1CS, 1LPCI, ADS
LPCI Injection Valve	2CS, 2LPCI (2 pumps into 1 loop), HPCI, ADS	2CS, HPCI, ADS
Diesel Generator	1CS, 2LPCI (one into each loop), HPCI, ADS	1CS, 1LPCI, HPCI, ADS
HPCI	2CS, 4LPCI (2 into each loop), ADS	2CS, 2LPCI (2 pumps into 1 loop), ADS

_____

(1) Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the above assumed failures.

(2) Systems remaining, as identified in this table for recirculation suction line breaks, are applicable to other non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed for recirculation suction breaks, less the ECCS in which the break is assumed.

TABLE VI-5-3

OPERATIONAL PARAMETERS FOR LOCA ANALYSIS

Parameter	Nominal	Appendix K
Core Thermal Power (MWt)	2381	2429
Vessel Steam Output (lbm/hr)	9.56×10^6	9.79×10^6
Corresponding Power (% of 2381 Mwt)	100	102
Rated Core Flow (lb/hr)	73.5×10^6	73.5×10^6
Vessel Steam Dome Pressure (psia)	1020	1060
Maximum Recirc Suction Line Break Area (ft^2)	4.17	4.17
Maximum Recirc Discharge Line Break Area (ft^2)	2.39	2.39

TABLE VI-5-4

PLANT ECCS PARAMETERS

1. Low Pressure Coolant Injection (LPCI) System

Variable	Units	Analysis * Value
a. Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	263 (230)
b. Minimum rated flow		
• Vessel pressure for following flow rates	psid (vessel to drywell)	20
• 2 LPCI pumps injecting into one recirculation loop	gpm	13500 (10700)
• 2 LPCI pumps injecting into two recirculation loops	gpm	13900 (13000)
• 4 LPCI pumps injecting into two recirculation loops	gpm	27000 (21400)
c. Initiating Signals		
• Low water level 1	in (above vessel zero)	358.56
• High drywell pressure	psig	2
d. Maximum allowable time from initiating signal to pump at rated speed and capable of rated flow (including Diesel Generator start time)	sec	59
e. Maximum injection valve stroke time - opening	sec	45
f. Pressure permissive at which LPCI injection valve may open	psig	275
g. Pressure permissive at which recirculation discharge valve may close	psig	185
h. Recirculation discharge valve stroke time - closing	sec	40
i. Recirculation discharge valve design differential pressure	psid	200

* Values given in parentheses (#) are with minimum flow valve open.

TABLE VI-5-4

PLANT ECCS PARAMETERS

(Continued)

2. Core Spray (CS) System

Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	265
b. Minimum rated flow in both loops at vessel pressure	gpm	8500
	psid (vessel to drywell)	113
c. Initiating Signals		
• Low water level 1	in (above vessel zero)	358.56
• High drywell pressure	psig	2
d. Minimum flow at 0 psid for both pumps	gpm	11220
e. Maximum allowable time from initiation signal to pump at rated speed and capable of rated flow (including Diesel Generator start time)	sec	59
f. Pressure permissive at which CS injection valve may open	psig	275
g. CS injection valve (IV) stroke time	sec	22

TABLE VI-5-4

PLANT ECCS PARAMETERS

(Continued)

3. High Pressure Coolant Injection (HPCI) System

Variable	Units	Analysis Value
a. Operating pressure range		
Maximum	psid (vessel to drywell)	1120
Minimum	psid (vessel to drywell)	150
b. Minimum flow over the above pressure range	gpm	3825
c. Initiating Signals		
• Low water level 2	in (above vessel zero)	467.75
• High drywell pressure	psig	2
d. Allowable time delay from initiating signal to rated flow speed and injection valve wide open	sec	60

TABLE VI-5-4

PLANT ECCS PARAMETERS

(Continued)

4.   Automatic Depressurization System (ADS)

Variable	Units	Analysis Value
a. Total number of valves available	–	6
b. Total number of valves assumed available in Analysis	–	5
c. Minimum flow rate with five valves open at vessel pressure	lbm/hr	4.0E6
	psig	1080
d. Initiating signal		
• Low water level 1	in (above vessel zero)	358.56
• Low water level 3	in (above vessel zero)	517.25
• CS or LPCI pump running	psig	100-165
e. Delay time from initiating signal complete to time valves are wide open	sec	120

TABLE VI-5-5

SUMMARY OF RESULTS

Break Size & Location	Single Failure	GNF2[1] PCT(°F)
NOMINAL *		
DBA, Suction	DC Power Source	1383
APPENDIX K *		
DBA, Suction	DC Power Source	2017
DBA, Suction	LPCI Injection Valve	1832
DBA Suction MELLA[2]	DC Power Source	2124
0.07 ft^2, Discharge[3]	DC Power Source	Not Limiting Size
0.08 ft^2, Discharge[3,4]	DC Power Source	1199

[1]   Cladding oxidation is <1.0% of original clad thickness; core-wide metal-water reaction is <0.1% for all cases.
[2]   Calculations based on MELLL point.
[3]   In addition to this recirculation line break area, this analysis also includes a 0.015 ft^2 bottom head drain line break area.
[4]   The top-peaked axial power shape yields the limiting PCT for small breaks. These results confirm that a small break case is not the limiting LOCA event.
*   Nominal and Appendix K parameters are provided on Table VI-5-3.

5.2.7   Emergency Core Cooling Systems

The HPCI System is designed to provide adequate reactor core cooling for small breaks and to depressurize the reactor primary system such that the LPCI subsystem and CS System can be initiated.

When HPCI begins operation, the reactor depressurizes more rapidly than would occur if HPCI was not initiated due to the cold fluid pumped into the reactor vessel by the HPCI System. This lowers the saturation pressure of the fluid in the reactor. The effect of the mass additions by the 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 system will also operate during operational transients where the reactor water level reaches the initiation setting at Level 2. Operation of the HPCI system is expected during the loss of feedwater flow transient (see Section XIV-5, "Analyses of Abnormal Operational Transients").

An analysis has been made to determine if any carryover occurs in the steam supply to the HPCI turbine which could have a detrimental effect on turbine operation. In the case of a break in a liquid line when HPCI is energized, the level in the reactor vessel is low enough to prevent carryover in the steam which leaves the reactor vessel. In the case of a small break in the reactor steam region and a simultaneous loss of normal AC power, reactor scram, recirculation pump coast-down, and loss of feedwater, analysis shows that the initial decrease of pressure in the reactor results in no significant level swell and no carryover of water into the steam supply to the HPCI turbine. HPCI cold water quenches any steam formation in the downcomer region. After HPCI has been operating and as level rises in the reactor vessel, natural circulation within the vessel becomes established and any steam to the HPCI turbine passes through the steam separators, thereby limiting moisture carryover. It is concluded that a mechanism to cause bypassing of the steam separators by the swelling steam water mixture, is not available. Therefore gross moisture carryover to the HPCI turbine should not occur over the range of steam line breaks of interest in this system.

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

Two feedwater spargers are utilized in the reactor for HPCI injection. Each sparger is mounted on the inside of the reactor vessel surface. A description of the feedwater spargers is in Section III-3.[14]

The resultant bracket loads are sized to meet the loading criteria (see Appendix C). It is concluded that design basis 8 is satisfied.

The HPCI system supplying makeup to the reactor vessel, while isolated, can operate using water from the emergency condensate storage tank for eight hours. The length of time the system operates is independent of the flow rate of the pump used to inject the water. The only determining factor for duration of operation is the amount of energy which is removed by boiling, and that is independent of the way in which the makeup water is provided as long as the source remains the same.

The only energy dumped to the pool during an extended period of hot standby operation is the sum of the energy stored in the fuel during the period of full power operation assumed to precede reactor isolation and the fission product decay heat that occurs after shutdown. Whether HPCI or RCIC is used to maintain adequate reactor coolant inventory does not affect these energy sources. Thus, the pool temperature transient during extended HPCI operation would be the same if RCIC were used.

HPCI NPSH requirements have been analyzed to ensure HPCI will provide design flow rates until the reactor pressure has been decreased to the point where low pressure ECCS injection flow is fully developed. Certain accident conditions can result in suppression pool temperatures higher than 200°F. However, before bulk pool temperatures increase to the point where HPCI NPSH becomes a concern, the reactor vessel is depressurized sufficiently that HPCI is not relied upon to fulfill any safety functions.[54]

Two 50,000-gallon emergency condensate storage tanks are installed for the exclusive use of the RCIC and HPCI systems.

The inadvertent activation of the HPCI system during reactor power operation is discussed in Section XIV-5, "Analyses of Abnormal Operational Transients."

When the ADS is actuated, the flow of steam through the valves provides a maximum energy removal rate while minimizing the corresponding fluid mass loss from the reactor vessel. Thus, the specific internal energy of the saturated fluid in the reactor vessel is rapidly decreased causing pressure reduction. Because the ADS does not provide makeup to the reactor primary vessel, no credit is taken for the steam cooling of the core caused by the system actuation to provide further conservation to the ECCS. Performance analysis of the ADS is considered only with respect to its depressurizing effect in conjunction with LPCI or CS operation. The system provides the backup for the HPCI.

Actuation of the ADS function does not require any source of off-site power. The relief valves require DC power from the unit batteries for control and pneumatic power from nitrogen accumulators for operation. ADS/SRV accumulator capacity is sized such the associated ADS relief valve can actuate 5 times with the drywell at atmospheric pressure, two times with the drywell at 70 percent of design pressure. See Section VI-4, Nuclear System Pressure Relief System, for further details. This satisfies safety design basis 5.

The accumulators and the nuclear system relief valves are within the primary containment and this satisfies the containment isolation requirements of safety design basis 6.

To assure continuity of core cooling, signals to isolate the primary or secondary containments do not operate any CS valves. This arrangement satisfies safety design basis 6.

The inboard check valves are the only CS equipment in the primary containment required to actuate during a LOCA which require consideration for the high temperature and humidity environment in the containment. The selected valve actuates on flow through the pipeline, independent of any external signal. Thus, neither the normal nor accident environment in the containment affects the operability of the CS equipment for the accident. It is concluded that safety design basis 9 is satisfied.

Taking the CS water from the suppression pool establishes a closed loop for recirculation of the spray water escaping from the break. It is concluded that safety design basis 11 is satisfied.

The CS spargers and piping are designed as Class I (see Appendix C) so that they meet design basis 8.

The addition of reference leg injection, as described in Paragraph VI-4.3, does not deleteriously affect CS. The removal of 0.5 gpm of water from each loop of CS flow is deemed to be insignificant with respect to overall flow of 4720 gpm.

The power requirements of the solenoid valves have been determined not to degrade the electrical distribution system.

All reference leg injection components are classified as essential (safety related), and are designed to Class IS/IIN requirements.

The LPCI operating mode of RHR (in conjunction with CS, as necessary) is provided to automatically reflood the reactor core in time to limit cladding temperatures after a nuclear system LOCA when the reactor vessel pressure is below the shutoff head of the pumps. LPCI provides cooling by flooding which differs from CS which provides cooling by spraying.

RHR pumps operating in the LPCI mode are designed with both adequate head and coolant flow capacity to meet flooding requirements for the entire break spectrum, when operating in conjunction with either HPCI or ADS.

The maximum flow capacity was determined by the design break (instantaneous break of a reactor recirculation line) and Peak Cladding Temperature (PCT limitations in effect at the time of issuance of the original Operating License). The RHR pumps (in conjunction with CS, as necessary) are capable of refilling the inner plenum before excessive clad temperatures occur even assuming no water remains after the blowdown. The minimum allowable time in which this must be done occurs for the design break because the least core cooling occurs for this break. Hence, it must be reflooded more quickly than for small breaks. However, the vessel depressurizes very quickly for this break size and therefore a greater quantity of water can be pumped due to the pump head-flow characteristic.

The maximum vessel pressure against which the RHR pumps must deliver some flow is determined by the required overlap with HPCI which has a low pressure cut off for the HPCI turbine at about 150 psig.

To assure continuity of core cooling, signals to isolate the primary or secondary containments do not operate any LPCI valves, during normal operation. This arrangement satisfies safety design basis 6. If a loop of RHR is operating in Shutdown Cooling Mode (SDC), the LPCI injection valve receives an isolation on low reactor level 3, high drywell pressure or high reactor pressure. That loop of RHR must be manually realigned from SDC to LPCI lineup and the isolation reset before it will inject in LPCI mode.

The two inboard check valves are the only LPCI equipment in the primary containment required to actuate during a LOCA which require consideration for the high temperature and humidity environment in the containment from the accident. The type of valve chosen actuates on flow through the pipeline, independent of any external signal. Thus, neither the normal nor accident environment in the containment affects the operability of the LPCI equipment for the accident. It is concluded that safety design basis 9 is satisfied.

Using the suppression pool as the source of water for the LPCI subsystem establishes a closed loop for recirculation of LPCI water escaping from the break. The LPCI and appropriate portions of the reactor recirculation loops are designed as Class I (see Appendix C) so that they meet design basis 8.

5.3   ECCS Pumps NPSH [27, 60]

The entire spectrum of possible operating modes of ECCS has been examined for adequacy with regard to NPSH at the various pumps. Adequate NPSH is available to the ECCS pumps for all the various modes of operation.

The most limiting of all the various modes occurs during the long term transient following a design basis LOCA when one CS and one RHR pump will be running continuously. Figures VI-5-15 and VI-5-16 are plots of both the minimum containment pressure required for CS and RHR pumps to have adequate NPSH and a plot of the minimum containment pressure that would actually occur. At all times there would be at least a 0.6 psi margin.

In order to demonstrate the margin inherent in Figures VI-5-15 and VI-5-16, the following is a list of the major assumptions used to calculate the suppression pool temperature and the minimum containment pressure following the design basis LOCA.[39]

1.   The reactor has been operating at a power of 2429 MWt (equal to the Original Licensed Thermal Power of 2381 MWt plus 2% to account for power measurement uncertainties) per Regulatory Guide 1.49. The ANS 5.1 decay heat model is used assuming an exposure of 35,000 MWd/MT (amount of energy generated per unit metric-ton fuel mass). The ANS 5.1 decay heat model used includes two sigma uncertainty adder and accounts for additional actinides and activation products[66].

2.   Offsite power is assumed lost at the initiation of the accident and is not restored during the entire event.

3.   Only one onsite diesel generator is available during the entire event. Consequently, only one pump each for the Core Spray, LPCI/Containment Cooling, and RHR Service Water Booster System is assumed to be available.

4.   The power required to operate the core spray pump and LPCI/Containment Cooling pump is added to containment heat load by increasing water temperature at the pump discharge accordingly.

5.   At the initiation of the accident, the suppression pool has the minimum water volume of 87,650 ft^3 and is assumed at a maximum temperature of 100°F.

6.   The service water temperature remains at 95°F throughout the event.

7.   During the event, the portion of feedwater in the feedwater system that is at a temperature higher than 203°F after absorbing additional energy from the feedwater piping as it flows toward the vessel is injected into the vessel. This hot portion of the feedwater inventory is transferred to the vessel regardless of the availability considerations of feedwater and condensate pumps.

8.   No heat loss from the primary containment to the reactor building airspace is assumed.

9.   An RHR heat exchanger K-value of 185 Btu/sec-°F is used, consistent with the minimum thermal capability of a single RHR heat exchanger operating in containment spray mode.

10.   Containment spray mode by the RHR heat exchanger is manually initiated at 600 seconds into the event. Use of containment sprays is conservative for ECCS NPSH analysis, since containment spray mode results in slightly higher suppression pool temperature and lower containment pressure.

11.   The drywell bulk temperature is assumed to be 160°F together with 100 percent humidity prior to the accident. Normal operating conditions would be 135°F with 20 percent humidity.

12.   The initial containment pressure is 0 psig. Normal operating pressure could be as high as 0.75 psig. There are no circumstances under which a sub-atmospheric pressure could exist in the containment.

13.   A constant containment gas leakage rate of 5 percent per day is assumed. This is substantially higher than the allowed leakage rate of 0.635 percent per day at 58 psig (see Section V-2, "Primary Containment System").

14.   The discharge from the RHR heat exchanger always returns to the suppression pool via the drywell and Suppression Chamber sprays to minimize the containment pressure by spraying cold water into the containment air space.

15.   Fibrous and miscellaneous containment debris loading is included in accordance with NRC Bulletin 96-03 and Boiling Water Reactor Owners Group (BWROG) methodologies[60][61][67].

16.   A flow blockage area of greater than 4.5 sq. ft. is assumed for each strainer in determining clean strainer head-loss.

The result of assumptions 1 through 9 is to maximize the peak suppression pool temperature. With no offsite power and with one diesel-generator out of service the pool will be cooled by one RHR heat exchanger with one RHR and one SW pump. This, together with the maximum Service Water temperature, results in a peak pool temperature of 207.8°F. The suppression pool is assumed to be the only heat sink even though the metal structures within the containment are capable of storing considerable energy. No credit is taken for any heat losses from the containment other than the energy being removed by the RHR heat exchanger.

Assumptions 11, 12, 13, result in the minimum possible quantity of non-condensible gases being present in the containment during the transient; which in turn results in the minimum possible pressure. Assumptions 10 and 14 give the minimum containment gas temperature and thus also minimized the pressure. Analysis assumptions 15 and 16 result in minimized flow area for the ECCS pump suction inlets from the suppression pool.

The combination of maximum fluid temperature and minimum containment pressure calculated with the above assumptions are the most severe conditions for which adequate NPSH must be shown to exist. Figures VI-5-15 and VI-5-16 show that adequate NPSH would indeed exist even under these very degraded circumstances.

Additional sensitivity cases were analyzed to explicitly account for instrument uncertainty and provide bounding case definitions, which are extremely unlikely to occur simultaneously. Even under these improbable conditions, the conservative calculations indicate sufficient margin between

available overpressure and required overpressure is available throughout the entire event.

It can be seen that there is a period during which the containment pressure must be in excess of atmospheric pressure if adequate NPSH is to be provided. The design basis for the ECCS for CNS does not include the requirements that they be functional with no containment back pressure.

These pumping systems were designed before Safety Guide No. 1 was proposed, and due to back pressure dependence do not strictly conform with Safety Guide No. 1. However, adequate NPSH is provided for the analyzed conditions. The dependence on back pressure is justified by the conservative models used to calculate the minimum back pressure. In the incredibly remote event that other unlikely circumstances do indeed occur simultaneously for some reason and there is an accompanying loss of back pressure, the plant operator would always have recourse to the RHR/Service Water intertie.

Evaluation has shown that steam bubble ingestion is not a concern for ECCS pumps due to the arrangement of the quenchers and the suction strainers in the suppression pool[68][69].

5.4   Protection Provisions

The ECCS pumps and equipment are designed with sufficient elevation and physical separation between the quads to withstand the effects of postulated line breaks that can result in internal flooding concerns. See Section X-14.

In regard to turbine missiles generated by the HPCI pump turbine, analyses indicate that wheel average tangential stresses in the HPCI turbine are sufficiently low that wheel failure is not predicted, even at the theoretical runaway condition of twice rated speed. Therefore, failure of the turbine wheels is considered so improbable as to be of no consequence with respect to becoming a potential missile or affecting safe shutdown of the plant. In addition, the HPCI Turbine is located in a separate concrete room within the reactor building.

6.0   <u>INSPECTION AND TESTING</u>

          This USAR section contains historical information as indicated by the italicized text. USAR Section I-3.4 provides a more detailed discussion of historical information. The information being presented in this section as historical has been preserved as it was originally submitted to the NRC in the CNS FSAR.

          Each active component of the Emergency Core Cooling Systems required to operate in a design basis accident is designed to be operable for test purposes during normal operation of the nuclear system, except as specified otherwise in this section.

          The HPCI, ADS, and CS Systems have no normal process uses, and, therefore, are tested periodically to provide assurance that the ECCS will operate to effectively cool the reactor core in an accident. The four RHR pumps of the LPCI subsystem may be placed in use in other RHR operating modes and if so, their status is known from normal process uses. However, all the ECCS systems are tested per surveillance requirements of Technical Specifications. Other parts of LPCI, such as the two check valves inside the drywell and the four injection valves outside the drywell, are intended for use only in an accident, so they are also tested periodically. The two LPCI check valves inside primary containment are tested once every cold shutdown when the drywell is de-inerted.

          If during a test an initiation signal is received, the pumps will start, if not already running, and the system will align for operating mode. Although the logic realigns the ECCS from the functional test mode to the operating mode, the ECCS safety design functions are not fulfilled due to the time required for realignment. To meet the safety design basis functions, the ECCS must be initially in an alignment where the system is capable of responding to and performing its mitigating function within analyzed limits.

          It should be noted that the ECCS low pressure injection valves are not testable during operation with full-pressure differentials across the seats. Motor horsepower of the valve operators limit valve opening to pressure differentials of less than 250 psig.[21] Bypass valves are provided for pressure equalization across the LPCI Inboard Injection valves, after which the valves are tested. The CS injection valves are tested after equalizing pressure using a manual operator to partially open valve.

          Preoperational tests of the Core Standby Cooling Systems are conducted during the final stages of plant construction prior to initial startup. Testing of the HPCI turbine requires steam either from an auxiliary boiler or from the reactor after nuclear system heatup (see Section XIII, "Conduct of Operations"). These tests assure the proper functioning of all controls, instrumentation, pumps, piping, and valves. System reference characteristics such as pressure differentials and flow rates are documented during the preoperational tests and are used as base points for measurements obtained in the subsequent operational tests.

          During initial reactor heatup to rated temperature and pressure the HPCI system will be tested for rated flow at several reactor pressures with flow through the test line, throttled such that pump discharge pressure will be at least 100 psi above reactor pressure.

          At rated reactor pressure, a "maximum pressure test" will be performed with flow through the test line, throttled such that pump discharge pressure will be at least 100 psi above the setting of the first main steam relief valve.

During the power testing while at rated temperature and pressure a design performance test will be performed which will consist of a cold quick start with time measured from initiation to full flow into the reactor vessel to verify conformance with design criteria.[22]

ECCS component and system leakage to secondary containment is controlled by a leakage monitoring program per Technical Specification 5.5.2. A leakage limit is established by this program to preserve the assumptions in the design basis post-LOCA dose calculations. The limit is applied to all ECCS systems and subsystems that perform recirculation cooling from the reactor or suppression pool following a design basis LOCA of any size. In order to verify this limit is maintained, CNS procedures are established to periodically verify that the ECCS leakage is below an administrative limit that is lower than the analyzed acceptable limit and to detail actions to monitor or repair leakage, as determined by engineering review of the as-found leakage.[42]

During plant operations, the pumps, valves, piping, instrumentation, wiring, and other components outside the primary containment can be visually inspected at any time. Components inside the primary containment can be inspected when the drywell is open for access. When the reactor vessel is open, for refueling or other purposes, the spargers and other internals can be inspected. The testing frequencies of most components of the ECCS are correlated with the testing frequencies of the associated controls and instrumentation. When a pump or valve control is tested, the operability of the pump or valve and the associated instrumentation is also tested by the same action.

When the system is tested, the operation of most of the components is indicated in the control room. There are exceptions which require local observation at the component and may require special tests for which there are special provisions and methods.

Pressure operated relief valves may leak after operation and it is not advisable to over-pressurize the system for test, so relief valves are removed as scheduled at refueling outages for bench tests and setting adjustments. Bench tests of the ADS valves are discussed in Section IV-4, "Nuclear System Pressure Relief System".

A pressure operated control valve is functionally tested and adjusted in place, in accordance with the valve manufacturer's manual and the system specification for pressure setting. A test pressure connection is provided to check and adjust the setting.

Flow operated check valves for reverse or excess flow are tested periodically in place by isolating that portion of the system and simulating the function conditions through test connections provided for this purpose.

The proper position of manual valves for the accident mode is indicated by flow and pressure instrumentation during the periodic system tests and after maintenance.

Test lines are provided between pairs of containment isolation valves in the ECCS to permit local leak rate testing in accordance with 10CFR50 Appendix J.

Maximum allowable leakage limits for individual pump seals are controlled as part of the leakage monitoring program discussed above. Limits are administratively established based on good operating practice.

The portions of the ECCS requiring pressure integrity are designed to specifications for in-service inspection to detect defects which might affect the cooling performance. The reactor vessel nozzles and feedwater spargers receive particular attention. Records are kept of the number of design basis thermal cycles such components receive.

Prior to embedment of that portion of the containment spray piping within the concrete of the biological shield wall, complete radiography of the welded pipe joints was completed. Integrity of the referenced weld joints and piping system was thus established.

Inservice inspection of these individual weld joints is no longer practicable. Inservice inspection of the entire containment spray piping is routine and in concurrence with Section XI of the ASME Code. In addition, the complete system is pneumatically tested during plant outages in accordance with the Technical Specifications.[23]

A design flow functional test of HPCI up to the normally closed pump discharge valve is performed during normal plant operation by pumping water from the emergency condensate storage tank and back through the full flow test return line to the emergency condensate storage tank. The HPCI turbine-pump is driven at its rated output, by steam from the reactor. The suction valves from the suppression pool and discharge valves to the reactor feedwater line remain closed.

HPCI test conditions are tabulated on the HPCI process flow diagram, General Electric Drawing 729E720BB. Certain testing requires electrically isolating valves which could prevent the auto return from the test mode to the operating mode. Due to the short duration of these tests, there is minimal effect on system reliability or degradation of plant safety.

The HPCI may be tested at full flow with condensate at any time except when the reactor vessel water level is low, the condensate level in the emergency condensate storage tank is below the reserve level, or the valves from the suppression pool to the pump are open.

To conduct the full flow test the minimum flow valve to the suppression pool is opened. The turbine steam valves are opened with the remote manual switches in the control room, so the pump delivers bypass flow to the suppression pool. To test the pump at rated flow the full flow test valve to the emergency condensate storage tank is opened and the bypass valve is shut.

To test the HPCI pump discharge valve, the pump is stopped and the injection valve is closed. The discharge valve is then operated with the remote control switch, observing the valve position lights.

The injection check valve is tested manually during cold shutdown conditions.

Each loop of the CS System is tested during reactor operation. The test conditions are tabulated on the CS System process diagram, General Electric Drawing 161F282BC. The normal system test does not inject cold water into the reactor because one injection valve is closed during the test. Injection of cold water or Suppression Chamber water to the reactor vessel is undesirable.

To test the CS pumps at rated flow, the pump suction valve from the suppression pool is opened, the pumps are started and the test bypass valve is opened to the suppression pool using the remote manual switches in the control room. Proper operation is determined by observing the instruments in the control room. The CS System outside the drywell is checked for leaks during system surveillance. A check for leaks is also performed during periodic operator tours.

The two motor-operated injection valves are tested by alternately closing one, cycling the other, and observing the position indicator lights. The test ends with the inboard valve closed (nearer the drywell) and the outboard valve open.

Each CS inboard check valve is manually tested during reactor cold shutdowns, when de-inerted.

Certain testing requires electrically isolating valves which could prevent the auto return from the test mode to the operating mode. Due to the short duration of these tests, there is minimal effect on system reliability or degradation of plant safety.

The reference leg injection testing performed once per cycle, during plant shutdown, verifies design flow. The reference leg injection lines are isolated during flow testing; system test flow is instead diverted through vent valves to a nearby radioactive waste drain, then to a catch basin. Flow is collected for a specified time to verify the system meets design flowrate. Valves are verified per CNS Inservice Testing Program.

Similarly, RHR pumps and valves of the LPCI subsystem are tested periodically during reactor operations. With the injection valves closed and the return line open to the suppression pool, full flow pumping capability is demonstrated. The injection valves are tested alternately, and the inboard check valves are tested, as described previously for the CS valves. The LPCI subsystem test conditions during reactor shutdown are shown on the RHR system process diagram, General Electric Drawing 729E211BB. The portion of the LPCI outside the drywell is inspected for leaks during tests. This check will be performed during periodic operator tours. Controls and instrumentation are tested as described in Subsection VII-4, "Emergency Core Cooling Systems Control and Instrumentation".

Upon receipt of a LPCI initiation signal, the valves in the shutdown cooling system automatically close to assure a leak in the RHR system is isolated from the reactor coolant pressure boundary. If LPCI injection is required, with realignment of valves to LPCI lineup and resetting SDC isolation logic, the RHR pump discharge will be routed properly to the reactor vessel.

It is concluded that safety design basis 7 is satisfied.

The high pressure coolant injection system is in scope for License Renewal per 10 CFR 54.4(a)(1), (a)(2), and (a)(3) and was subject to aging management review. Aging effects are managed by the following Aging Management Programs: Bolting Integrity (see USAR Section K-2.1.2), Buried Piping and Tanks Inspection (see USAR Section K-2.1.3), External Surfaces Monitoring (see USAR Section K-2.1.14), Flow-Accelerated Corrosion (see USAR Section K-2.1.18), Oil Analysis (see USAR Section K-2.1.28), Periodic Surveillance and Preventive Maintenance (see USAR Section K-2.1.31), and

Water Chemistry Control - BWR (see USAR Section K-2.1.39). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Sections K-2.2.2.1 and K-2.2.2.2).

        The automatic depressurization system is in scope for License Renewal per 10 CFR 54.4(a)(1) and (a)(3) and was subject to aging management review. Aging effects are managed by the following Aging Management Programs: Bolting Integrity (see USAR Section K-2.1.2), External Surfaces Monitoring (see USAR Section K-2.1.14), Periodic Surveillance and Preventive Maintenance (see USAR Section K-2.1.31), and Water Chemistry Control - BWR (see USAR Section K-2.1.39). The following Time-Limited Aging Analyses are applicable: Metal Fatigue (see USAR Sections K-2.2.2.1 and K-2.2.2.2).

        The core spray system is in scope for License Renewal per 10 CFR 54.4(a)(1), (a)(2), and (a)(3) and was subject to aging management review. Aging effects are managed by the following Aging Management Programs: Aboveground Steel Tanks (see USAR Section K-2.1.1), Bolting Integrity (see USAR Section K-2.1.2), Buried Piping and Tanks Inspection (see USAR Section K-2.1.3), External Surfaces Monitoring (see USAR Section K-2.1.14), and Water Chemistry Control - BWR (see USAR Section K-2.1.39). There were no applicable Time-Limited Aging Analyses.

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