B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 ECCS — Operating

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a loss of coolant accident (LOCA). The ECCS directs water to both inside and outside the core shroud to cool the core during a LOCA. The ECCS network is composed of the High Pressure Core Flooder (HPCF) System, the Reactor Core Isolation Cooling (RCIC) System, and the low pressure core flooder (LPFL) mode of the Residual Heat Removal (RHR) System. The ECCS also consists of the Automatic Depressurization System (ADS). The suppression pool provides the required source of water for the ECCS. Although no credit is taken in the safety analyses for the condensate storage tank (CST), it is capable of providing a source of water for both the RCIC System and the two HPCF subsystems.

On receipt of an initiation signal, ECCS pumps automatically start; simultaneously the system aligns, and the pumps inject water, taken either from the CST or suppression pool, into the Reactor Coolant System (RCS) as RCS pressure is overcome by the discharge pressure of the ECCS pumps. Although the system is initiated, ADS action is delayed, to allow time for confirmation of the initiating signal. The discharge pressure of the HPCF pumps exceeds that of the RCS, and the pumps inject coolant into the flooding sparger above the core. Once the steam driven RCIC turbine has accelerated, the RCIC pump discharge pressure exceeds that of the RCS and injects coolant into the reactor pressure vessel (RPV) via one of the feedwater lines. If the break is small, RCIC or either of the HPCF pumps will maintain coolant inventory, as well as vessel level, while the RCS is still pressurized. If the RCIC and HPCFs fail, they are backed up by ADS in combination with the LPFL. In this event, the ADS timed sequence would be allowed to time out and open the selected safety/relief valves (S/RVs), depressurizing the RCS and allowing the LPFL to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure drops rapidly, and the HPCF and LPFL subsystems cool the core.

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BACKGROUND (Continued)

Water from the break returns to the suppression pool where it is used again and again. Water in the suppression pool is circulated through a heat exchanger cooled by the Reactor Building Cooling Water (RCW) System. The ECCS network is effective in cooling the core regardless of the size or location of the piping break.

Apart from its ECCS function the RCIC System is also designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of RPV water level. Under these conditions, the HPCF and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 11 are satisfied.

All ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS subsystems.

The ECCS injection systems are arranged in three separate divisions each comprised of a high pressure and low pressure subsystem. ECCS Division 1 consists of the RCIC system and LPFL-A. ECCS Division 2 consists of HPCF-B and LPFL-B. ECCS Division 3 consists of HPCF-C and LPFL-C.

LPFL is an independent operating mode of the RHR System. There are three LPFL subsystems. Each LPFL subsystem (Ref. 2) consists of a motor driven pump, a heat exchanger, piping, and valves to transfer water from the suppression pool to the RPV. Each LPFL subsystem has its own suction and discharge piping. Each LPFL subsystem takes suction from the suppression pool. LPFL subsystems B and C have dedicated discharge nozzles to the RPV that connect to flooding spargers in the vessel annulus area outside the core shroud. LPFL subsystem A discharges to one of the main feedwater injection lines and thus also supplies coolant to the vessel annulus area outside the core shroud via the feedwater sparger. The LPFL subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, each LPFL pump is automatically started approximately 10 seconds after electrical power is available. When the RPV pressure drops sufficiently, LPFL flow to the RPV begins. RHR System valves in the LPFL flow

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BACKGROUND (Continued)

path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the RPV. A discharge test line is provided to route water from and to the suppression pool to allow testing of each LPFL pump without injecting water into the RPV.

The HPCF System is comprised of two separate subsystems. Each HPCF subsystem (Ref. 1) consists of a single motor driven pump, a flooder sparger above the core, and piping and valves to transfer water from the suction source to the sparger. Suction piping is provided from the CST and the suppression pool. Pump suction is normally aligned to the CST source to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low or the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCF System. The HPCF System is designed to provide core cooling over a wide range of RPV pressures, (0 to 8.12 MPaD), vessel to the air space of the compartment containing the water source for the pump suction. Upon receipt of an initiation signal, the HPCF pumps automatically start (when electrical power is available) and valves in the flow path begin to open. Since the HPCF System is designed to operate over the full range of RPV pressures, HPCF flow begins as soon as the necessary valves are open. A full flow test line is provided to route water from and to the CST to allow testing of the HPCF System during normal operation without injecting water into the RPV.

The RCIC System (Ref. 1) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line. Suction piping is provided from the condensate storage tank (CST) and the suppression pool. Pump suction is normally aligned to the CST to minimize injection of suppression pool water into the RPV. However, if the CST water supply is low, or the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from main steam line B, upstream of the inboard main steam line isolation valve.

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BASES

BACKGROUND (Continued)

The RCIC System is designed to provide core cooling for a wide range of reactor pressures, 1.03 MPaG to 8.12 MPaG. Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the suppression pool to allow testing of the RCIC System during normal operation without injecting water into the RPV. For the station black out scenario, where all AC power from the offsite AC circuits and from the standby diesel generators are assumed to be lost, RCIC is designed to provide makeup water to the RPV. Diverse alternatives to RCIC are provided by the Combustion Turbine Generator (CTG) and the AC-Independent Water Addition (ACIWA) mode of RHR(C) (References 13 and 14). If RCIC is inoperable, water can be injected into the RPV either by powering other ECCS subsystems from the CTG or by the Fire Protection System (FPS) using the ACIWA mode of RHR(C).

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in these lines automatically open to prevent pump damage due to overheating when other discharge line valves are closed or RPV pressure is greater than the LPFL pump discharge pressures following system initiation. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, the ECCS discharge line "keep fill" systems are designed to maintain all pump discharge lines filled with water.

The ADS (Ref. 1) consists of 8 of the 18 S/RVs. It is designed to provide depressurization of the primary system during a small break LOCA if RCIC and HPCF fail or are unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems (LPFL), so that these subsystems can provide core cooling. Each ADS valve is supplied with pneumatic power from either its own dedicated accumulator located in the drywell, or from the atmospheric control system (ACS) directly when pneumatic power from the accumulators is not needed. The ACS also supplies the nitrogen (at pressure) necessary to assure the ADS accumulators remain charged for use in emergency actuation.

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APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 2, 3, and 4. The required analyses and assumptions are defined in 10 CFR 50 (Ref. 5), and the results of these analyses are described in Reference 6.

This LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 7), will be met following a LOCA assuming the worst case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 1204°C;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 6. For any LOCA, failure of ECCS subsystems in Division 2 (HPCF-B and LPFL-B) or Division 3 (HPCF-C and LPFL-C) due to failure of its associated diesel generator is the most severe failure. One ADS valve failure is analyzed as a limiting single failure for events requiring ADS operation, however, the above single failure of a diesel generator, and associated motor driven ECCS injection subsystems in the division, is a more limiting failure. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage. Additional functions of the RCIC System are to respond to transient events by providing makeup coolant to the nuclear vessel and to be an independent AC source during station blackout.

In order to provide increased margin to ECCS acceptance criteria (i.e., 10 CFR 50.46), the ECCS was designed to the

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APPLICABLE SAFETY ANALYSES (continued)

more stringent goal of no core uncovery for any postulated DBA or transient event, even given the most limiting single failure. This design philosophy resulted in substantially improved ECCS performance such that, when analyzed consistent with typical licensing basis methodologies, (i.e., assuming only the traditional limiting single failure), there was considerable margin relative to existing regulatory requirements. The magnitude of such margin suggested that the ECCS would still be able to perform its intended safety function, even under situations with some equipment initially out of service or unavailable due to multiple postulated failures. Therefore, further ECCS analyses were performed (see Reference 8) in an attempt to identify the minimum amount of ECCS equipment that must operate such that the plant could still meet the 10 CFR 50.46 acceptance criteria listed above.

Analyses were performed for a set of identified limiting scenarios, assuming the unavailability (or failure) of multiple ECCS subsystems, and using the same calculational methods as were used for the traditional design basis analyses. The results of these analyses demonstrated that "success" (i.e., no violation of the above stated 50.46 limits) was achieved under various postulated accident scenarios provided at least one motor driven ECCS injection subsystem was capable of successfully injecting water into the RPV. For any such scenarios also requiring depressurization, "success" was achieved with the actuation of at least five SR/Vs in the ADS mode (in conjunction with successful vessel injection from the one required ECCS subsystem). Thus, it was confirmed that the ABWR ECCS is able to perform its intended safety function (in accordance with the applicable regulatory requirements), even for postulated events involving limiting single failures that might occur with less than the full complement of ECCS subsystems initially available.

The ECCS satisfy Criterion 3 of the NRC Policy Statement.

LCO

Each ECCS subsystem and eight ADS valves are required to be OPERABLE. The ECCS subsystems are defined as the three LPFL subsystems, the two HPCF subsystems, and the RCIC System. The high pressure ECCS subsystems are defined as the two HPCF subsystems and the RCIC System.

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BASES

LCO (continued)

With less than the required number of ECCS subsystems OPERABLE during a limiting design basis LOCA concurrent with the worst case single failure, the margins to the limits specified in 10 CFR 50.46 (Ref. 7) would be reduced. Furthermore, all ECCS subsystems are assumed to be initially available in the comprehensive set of analyses performed to satisfy the single failure criterion required by 10 CFR 50.46 (Ref. 7). Thus all ECCS subsystems must be OPERABLE. The ECCS is supported by other systems that provide automatic ECCS initiation signals (LCO 3.3.1.1, "SSLC Sensor Instrumentation" and LCO 3.3.1.4, "ESF Actuation Instrumentation"), cooling and service water to cool rooms containing ECCS equipment (LCO 3.7.1, "Reactor Building Cooling Water (RCW) System, Reactor Service Water (RSW) System and Ultimate Heat Sink (UHS)-Operating", LCO 3.7.2, "RCW/RSW and UHS-Shutdown" and LCO 3.7.3 "RCW/RSW and UHS-Refueling"), electrical power (LCO 3.8.1, "AC Sources-Operating," and LCO 3.8.4, "DC Sources-Operating").

A LPFL subsystem may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPFL mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems can provide the required core cooling, thereby allowing operation of an RHR shutdown cooling loop when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3 when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, the RCIC System is not required to be OPERABLE when pressure is ≤ 1.03 MPaG since other ECCS subsystems can provide sufficient flow to the vessel. In MODES 2 and 3, the ADS function is not required when pressure is ≤ 0.343 MPaG because the low pressure ECCS subsystems (LPFL) are capable of providing flow into the RPV below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS – Shutdown."

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ACTIONS

A.1, B.1.1, B.1.2, B.2, and B.3

With one or two ECCS subsystem(s) inoperable provided RCIC is OPERABLE (Condition A), the inoperable subsystem(s) must be restored to OPERABLE status within 14 days. If RCIC is inoperable or RCIC in combination with any one other ECCS subsystem is inoperable (Condition B), the inoperable subsystem(s) can be restored to OPERABLE status within 14 days provided the Combustion Turbine Generator (CTG) is verified, initially within 7 days and once per 8 hours thereafter, to be functional and capable of being aligned to each of the ESF buses or the AC-Independent Water Addition (ACIWA) mode of RHR(C) is verified to be functional within 7 days. In these Conditions, the remaining OPERABLE subsystems provide more than adequate core cooling during a LOCA. However, overall ECCS reliability is reduced; and a single failure impacting one or more of the remaining OPERABLE subsystems concurrent with a LOCA would result in degraded ECCS performance and reduced margins to 10 CFR 50.46 acceptance criteria. Nevertheless, even given the worse case single failure concurrent with a LOCA initiated from this Condition, there will always be at least one ECCS subsystem available to inject water into the RPV. (For the special case of an LPFL-A line break and failure of a diesel generator, the CTG would be available to provide emergency electrical power to the ECCS pumps.) Additional analyses of limiting design basis scenarios demonstrate that in such cases 10 CFR 50.46 acceptance criteria will still be met. Furthermore, results of PRA sensitivity studies performed (References 9 and 15) for Condition A show that this situation is acceptable from an overall plant risk perspective.

For Condition B, the PRA sensitivity studies performed (Ref. 9) showed that, with RCIC inoperable, the change in core damage frequency is relatively large for station blackout events. Therefore, if the CTG is verified to be functional and the circuit breakers are capable of being aligned to each of the ESF buses (LCO 3.8.1), other ECCS subsystems can be powered by the CTG during a station blackout to compensate for RCIC's inoperability. Alternatively, to compensate for RCIC's inoperability, if the ACIWA mode of RHR(C) subsystem is verified to be functional, the Fire Protection System (FPS) can be used to inject water into the RPV during a station blackout with the RPV sufficiently depressurized. The ACIWA is verified to be functional by

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ACTIONS
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A.1, B.1.1, B.1.2, B.2, and B.3 *(continued)*

stroking one complete cycle of each of the two manual valves in the FPS connection to RHR(C) injection line, by starting the FPS diesel-driven fire pump and verifying that the FPS header pressure is maintained, and by stroking one complete cycle of the RHR(C) subsystem injection valve using its handwheel.

If the CTG or ACIWA is not available, the Completion Time for Condition B is limited to 7 days based on an overall risk perspective. The 14 day Completion Times for both Conditions A and B are based on a risk perspective and the low probability of a LOCA occurring during this period and the overall redundancy provided by the ECCS and its continued ability to perform its intended safety function, while assuring a return to full ECCS capability in a reasonable time so as to not significantly impact overall ECCS reliability.

C.1.1.1, C.1.1.2, C.1.2, C.2, D.1 and E.1

With RCIC and any other two ECCS subsystems inoperable, provided at least one HPCF subsystem is OPERABLE, one ECCS subsystem must be restored to OPERABLE status within 7 days. With any three ECCS subsystems inoperable, provided RCIC is OPERABLE, one ECCS subsystem must be restored to OPERABLE status within 3 days. With all three high pressure ECCS subsystems inoperable, at least one high pressure ECCS subsystem must be restored to OPERABLE status within 12 hours. In these Conditions, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA, but the single failure criterion capability for all combinations of systems out of service is not satisfied. Therefore, the Completion Times are limited to 7 days, 3 days and 12 hours, respectively, depending on the combination of ECCS subsystems that are inoperable. Additional analyses of limiting design basis scenarios demonstrate that in such cases 10 CFR 50.46 acceptance criteria will still be met (Ref. 8). Furthermore, results of PRA sensitivity studies performed (References 9 and 15) show that this situation is acceptable from an overall plant risk perspective.

Additionally, for Condition C, where RCIC is inoperable, either the CTG must be verified, within 72 hours, to be

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ACTION (continued)

C.1.1.1, C.1.1.2, C.1.2, C.2, D.1 and E.1 (continued)

functional and the circuit breakers are capable of being aligned to each of the ESF buses, or, alternatively, the ACIWA mode of RHR(C) subsystem must be verified to be functional within 72 hours. If the CTG is verified to be functional and capable of being aligned to each of the ESF buses (LCO 3.8.1), other ECCS subsystems can be powered by the CTG during a station blackout to compensate for RCIC's inoperability. If the ACIWA mode of RHR(C) subsystem is verified to be functional, the Fire Protection System (FPS) can be used to inject water into the RPV during a station blackout with the RPV sufficiently depressurized. The ACIWA is verified to be functional by stroking one complete cycle of each of the two manual valves in the FPS connection to RHR(C) injection line, by starting the FPS diesel-driven fire pump and verifying that the FPS header pressure is maintained, and by stroking one complete cycle of the RHR(C) subsystem injection valve using its handwheel. If the CTG or ACIWA is not available, the Completion Time for Condition C is limited to 72 hours based on an overall risk perspective.

Since the ECCS availability is reduced relative to Conditions A and B, a more restrictive Completion Time is imposed. The 7 and 3 day Completion Times for Required Actions C.2 and D.1 are based on the low probability of a LOCA occurring during this period and the overall redundancy provided by the ECCS and its continued ability to perform the intended safety function while assuring a return towards full ECCS capability in a reasonable time so as to not significantly impact overall ECCS reliability. The Completion Time for Required Action D.1 is more restrictive than the Completion Time for Required Action C.2 because of the lesser capability of RCIC compared to the other high pressure ECCS subsystems (HPCF).

The 12 hour Completion Time for Required Action E.1 is more restrictive because a LOCA may necessitate an unwanted actuation of the ADS to reach the operating conditions of the low pressure ECCS subsystems. However, any one low pressure ECCS subsystem is capable of maintaining core coolant during a LOCA for the spectrum of break sizes.

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ACTION (continued)

F.1 and F.2

If any Required Action and associated Completion Time of Condition A, B, C, D, or E are not met, or when any four ECCS subsystems are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1 and H.1

With one or two ADS valves inoperable, the ADS valves must be restored to OPERABLE status within 14 days. With three ADS valves inoperable, one ADS valve must be restored to OPERABLE status within 7 days. The LCO requires eight ADS valves to be OPERABLE to provide the ADS function. Reference 6 contains the results of the traditional design basis analysis that evaluated the effect of one ADS valve being out of service. However, the results of this analysis are bound by additional analyses or more limiting single failure scenarios which assume the unavailability of multiple ADS valves (see Reference 8). Per these analyses, operation of only five ADS valves will provide the required depressurization. However, overall reliability of the ADS is reduced and there is a reduction in depressurization capability. Therefore, operation is only allowed for a limited time. The 7 and 14 day Completion Times are based on the low probability of a LOCA occurring during this period and the overall redundancy and capacity of the ADS System and its continued ability to perform its intended safety function, while assuring a return towards full ADS capability in a reasonable time so as to not significantly impact overall ADS or ECCS reliability. Furthermore, Conditions G and H are modified by a NOTE that allows concurrent existence with Conditions A, B, C, or D, and Conditions A, B, or C, respectively. Concurrent existence is justified by the additional ECCS analyses that were performed (Ref. 8) and greatly simplifies the necessary Required Actions.

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ACTION (continued)

I.1 and I.2

If the Required Action and associated Completion Time of Condition G or H is not met or if four or more ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 0.343 MPaG within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the HPCF subsystem, RCIC System, and LPFL subsystems full of water ensures that the systems will perform properly, injecting their full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring the lines are full is to vent at the high points. The 31 day Frequency is based on operating experience, on the procedural controls governing system operation, and on the gradual nature of void buildup in the ECCS piping.

SR 3.5.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves potentially capable of being mispositioned are

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.2

in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency of this SR was derived from the Inservice Testing Program requirements for performing valve testing at least once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve alignment would only affect a single subsystem. This Frequency has been shown to be acceptable through operating experience.

This SR is modified by a Note that allows a LPFL subsystem to be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the RHR cut in permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPFL mode and not otherwise inoperable. This allows operation in the RHR shutdown cooling mode during MODE 3 if necessary.

SR 3.5.1.3

Verification every 31 days that ADS nitrogen accumulator pressure is ≥ 1.11 MPaG assures adequate nitrogen pressure for reliable ADS operation. The accumulator on each ADS valve provides pneumatic pressure for valve actuation. The designed pneumatic supply pressure requirements for the accumulator are such that, following a failure of the pneumatic supply to the accumulator, at least one valve actuation can occur with the drywell at design pressure, or five valve actuations can occur with the drywell at atmospheric pressure (Ref. 10). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. This minimum required pressure of 1.11 MPaG is provided by the High Pressure Nitrogen Gas Supply System (HPIN). The 31 day Frequency takes into consideration administrative control over operation of the HPIN and alarms for low pneumatic pressure (Ref. 12).

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4, SR 3.5.1.5 and SR 3.5.1.6

The performance requirements of the ECCS pumps are determined through application of the 10 CFR 50, Appendix K, criteria (Ref. 5). These periodic Surveillances are performed (in accordance with the ASME Code, Section XI, requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of 10 CFR 50.46 (Ref. 7). The RCIC pump flow rates also ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated.

The pump flow rates are verified against a system head that is equivalent to the RPV pressure expected during a LOCA. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during LOCAs. These values may be established during pre-operational testing.

The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow is tested both at the higher and lower operating ranges of the system. Since the required reactor steam dome pressure must be available to perform SR 3.5.1.5 and SR 3.5.1.6 sufficient time is allowed after adequate pressure is achieved to perform these SRs. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the specified reactor steam dome pressure is reached.

A 92 day Frequency for SR 3.5.1.4 and SR 3.5.1.5 is consistent with the Inservice Testing Program requirements. The 18 month Frequency for SR 3.6.1.6 is based on the need to perform this Surveillance under the conditions that apply

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4, SR 3.5.1.5 and SR 3.5.1.6 (continued)

during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.7

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance test verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCF, RCIC, and LPFL will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup, and actuation of all automatic valves to their required positions. This Surveillance also ensures that the HPCF and RCIC Systems will automatically restart on an RPV low water level (Levels 1.5 and 2, respectively) signal received subsequent to an RPV high water level (Level 8) trip and that the suction is automatically transferred from the CST to the suppression pool. SRs in LCO 3.3.1.1 and LCO 3.3.1.4 overlap this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.8

The ADS designated S/RVs are required to actuate automatically upon receipt of specific initiation signals. A system functional test is performed to demonstrate that the mechanical portions of the ADS function (i.e., solenoids) operate as designed when initiated either by an actual or simulated initiation signal, causing proper actuation of all the required components. SR 3.5.1.9 and SRs in LCO 3.3.1.1 and LCO 3.3.1.4 overlap this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that excludes valve actuation. This prevents an RPV pressure blowdown.

SR 3.5.1.9

A manual actuation of each ADS valve is performed to verify that the valve and solenoids are functioning properly and that no blockage exists in the S/RV discharge lines. This is demonstrated by the response of the turbine control or bypass valve, by a change in the measured steam flow, or by any other method suitable to verify steam flow. Adequate reactor steam dome pressure must be available to perform this test to avoid damaging the valve. Sufficient time is therefore allowed, after the required pressure is achieved, to perform this test. Adequate pressure at which this test is to be performed is [6.55 MPaG](the pressure recommended by the valve manufacturer)]. Reactor startup is allowed prior to performing this test because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. Therefore, this SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam dome pressure is ≥ [6.55 MPaG]. SR 3.5.1.8 and SRs in

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.9

LCO 3.3.1.1 and LCO 3.3.1.4 overlap this Surveillance to provide complete testing of the assumed safety function.

The Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. DCD Tier 2, Section 6.3.2.
2. DCD Tier 2, Section 15.6.4.
3. DCD Tier 2, Section 15.6.5.
4. DCD Tier 2, Section 15.6.6.
5. 10 CFR 50, Appendix K.
6. DCD Tier 2, Section 6.3.3.
7. 10 CFR 50.46.
8. DCD Tier 2, Section 6.3.3.9.
9. DCD Tier 2, Section 19D.9.
10. DCD Tier 2, Section 7.3.1.1.1.2.
11. 10 CFR 50, Appendix A, GDC 33.
12. DCD Tier 2, Section 6.7.
13. DCD Tier 2, Section 9.5.11.

(continued)

BASES

REFERENCES (continued)

14. DCD Tier 2, Section 5.4.7.1.1.10.

15. Letter, Jack Fox to Chet Poslusny, "Submittal Supporting Accelerated ABWR Review Schedule-ABWR CDF Sensitivity to ESF Equipment Out of Service", Docket No. STN 52-001, July 27, 1993.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS – Shutdown

BASES

BACKGROUND

A description of the High Pressure Core Flooder (HPCF) and the Low Pressure Flooder (LPFL) subsystems of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS-Operating." The Reactor Core Isolation Cooling (RCIC) system steam driven turbine can not operate with the reactor shutdown and so is not available.

APPLICABLE SAFETY ANALYSES

ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 3.5.2-1) demonstrates that only one motor driven ECCS injection subsystem is required, post LOCA, to maintain the peak cladding temperature below the allowable limit. To provide redundancy, a minimum of two ECCS subsystems are required to be OPERABLE in MODES 4 and 5. Two OPERABLE ECCS injection subsystems also ensure adequate inventory makeup in the reactor pressure vessel (RPV) in the event of an inadvertent vessel draindown.

The ECCS satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two ECCS injection subsystems are required to be OPERABLE. The ECCS injection subsystems are defined as the three LPFL and the two HPCF subsystems. Each LPFL subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool to the RPV. Each HPCF subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or condensate storage tank (CST) to the RPV.

Any LPFL subsystem may be aligned for the shutdown cooling mode of the decay heat removal system in MODE 4 or 5 and considered OPERABLE for the ECCS function, if it can be manually realigned (remote or local) to the LPFL mode and is not otherwise inoperable. Because of low pressure and low temperature conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPFL

(continued)

BASES

LCO
(Continued)

subsystem operation to provide core cooling prior to postulated fuel uncovery.

APPLICABILITY

OPERABILITY of the ECCS injection subsystems is required in MODES 4 and 5 to ensure adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in case of an inadvertent draindown of the vessel. Requirements for ECCS OPERABILITY during MODES 1, 2, and 3 are discussed in the Applicability section of the Bases for LCO 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the reactor cavity to dryer/separator storage pool gate removed, and the water level maintained at ≥ 7 m above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncovery in case of an inadvertent draindown. In addition, the automatic isolations of RHR shutdown cooling and the reactor water cleanup system on low RPV water level are required to be OPERABLE (LCO 3.3.1.1, SSLC Sensor Instrumentation) during CORE ALTERATIONS or operation with a potential for draining the reactor vessel.

The Automatic Depressurization System is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is < 0.343 MPaG, and the LPFL and HPCF subsystems can provide core cooling without any depressurization of the primary system.

Because the Reactor Core Isolation Cooling (RCIC) system requires steam to operate, it is not required to be OPERABLE during MODES 4 and 5.

ACTIONS

A.1 and B.1

If any one required ECCS injection subsystem is inoperable, the required inoperable ECCS injection subsystem must be restored to OPERABLE status within 4 hours. In this Condition, the remaining OPERABLE subsystem can provide sufficient RPV flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is reduced because a single failure in the

(continued)

ACTIONS
(Continued)

A.1 and B.1 (continued)

remaining OPERABLE subsystem concurrent with a vessel draindown could result in the ECCS not being able to perform its intended function. The 4 hour Completion Time for restoring the required ECCS injection subsystem to OPERABLE status is based on engineering judgment that considered the availability of one subsystem and the low probability of a vessel draindown event.

With the inoperable subsystem not restored to OPERABLE status within the required Completion Time, action must be initiated immediately to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

C.1, C.2, D.1, D.2, and D.3

If both of the required ECCS injection subsystems are inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must be initiated immediately to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. One ECCS injection subsystem must also be restored to OPERABLE status within 4 hours.

If at least one ECCS injection subsystem is not restored to OPERABLE status within the 4 hour Completion Time, additional actions are required to minimize any potential fission product release to the environment. This includes initiating immediate action to restore the following to OPERABLE status: secondary containment, one standby gas treatment subsystem, and one isolation valve and associated instrumentation in each secondary containment penetration flow path not isolated. This may be performed by an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. Verification does not require performing the Surveillances needed to demonstrate OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored

(continued)

BASES

ACTIONS
(Continued)

C.1, C.2, D.1, D.2, and D.3 (continued)

to OPERABLE status. In this case, the Surveillances may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

The 4 hour Completion Time to restore at least one ECCS injection subsystem to OPERABLE status ensures that prompt action will be taken to provide the required cooling capacity or to initiate actions to place the plant in a condition that minimizes any potential fission product release to the environment.

SURVEILLANCE
REQUIREMENTS

SR 3.5.2.1 and SR 3.5.2.2

The minimum water level of 7 m required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the ECCS pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, all ECCS injection subsystems are inoperable.

When the suppression pool level is < 7 m, the HPCF is considered OPERABLE only if it can take suction from the CST and the CST water level is sufficient to provide the required NPSH for the HPCF pump. Therefore, a verification that either the suppression pool water level is ≥ 7 m or the HPCF System is aligned to take suction from the CST and the CST contains ≥ [ ] liters of water, equivalent to [ ]m, ensures that the HPCF System can supply makeup water to the RPV.

The 12 hour Frequency of these SRs was developed considering operating experience related to suppression pool and CST water level variations and instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool or CST water level condition.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (Continued)

SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6

The Bases provided for SR 3.5.1.1, SR 3.5.1.4, and SR 3.5.1.7 are applicable to SR 3.5.2.3, SR 3.5.2.5, and SR 3.5.2.6, respectively.

SR 3.5.2.4

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

In MODES 4 and 5, the RHR System may operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Therefore, RHR valves that are required for LPFL subsystem operation may be aligned for the shutdown cooling mode. Therefore, this SR is modified by a Note that allows one LPFL subsystem of the RHR System to be considered OPERABLE for the ECCS function if all the required valves in the LPFL flow path can be manually realigned (remote or local) to allow injection into the RPV and the system is not otherwise inoperable. This will ensure adequate core cooling if an inadvertent vessel draindown should occur.

REFERENCES

1. DCD Tier 2, Section 6.3.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a Design Basis Accident (DBA) and to confine the postulated release of radioactive material. The primary containment consists of a steel lined, reinforced concrete vessel, which surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment.

The isolation devices for the penetrations in the primary containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic Containment Isolation System, or

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)";

b. The primary containment air lock is OPERABLE, except as provided in LCO 3.6.1.2, "Primary Containment Air Locks";

c. The sealing mechanism associated with a penetration (e.g., welds, bellows, or o-rings) is OPERABLE.

This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in

(continued)

BASES

BACKGROUND (continued)	conformance with 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 0.5% by weight of the containment air per 24 hours at the maximum peak containment pressure (P_a) of 0.284 MPaG or [ ]% by weight of the containment air per 24 hours at the reduced pressure of Pt of [ ] MPaG (Ref. 1).

Primary containment satisfies Criterion 3 of the NRC Policy Statement.

LCO

Primary containment OPERABILITY is maintained by limiting leakage to within the acceptance criteria of 10 CFR 50, Appendix J (Ref. 3). Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses. Individual leakage rates specified for the primary containment air lock are addressed in LCO 3.6.1.2.

(continued)

BASES

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

A.1

In the event primary containment is inoperable, primary containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining primary containment OPERABILITY during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring primary containment OPERABILITY) occurring during periods where primary containment is inoperable is minimal.

B.1 and B.2

If primary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions. Failure to meet air lock leakage testing (SR 3.6.1.2.1), [resilient seal primary containment purge valve leakage testing (SR 3.6.1.3.7),]

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1 (continued)

main steam isolation valve leakage (SR 3.6.1.3.13), or hydrostatically tested valve leakage (SR 3.6.1.3.12) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of 10 CFR 50, Appendix J. The Frequency is required by 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

SR 3.6.1.1.2

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the wetwell. Thus, if an event were to occur that pressurized the drywell, the steam would be directed through the horizontal vents into the suppression pool. This SR measures drywell to wetwell differential pressure during a 15 minute period to ensure that the leakage paths that would bypass the suppression pool are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure between the drywell and the wetwell and verifying that the pressure in either the wetwell or the drywell does not change by more than 12 mm of water per minute over a 15 minute period. The leakage test is performed every 18 months. The 18 month Frequency was developed considering it is prudent that this Surveillance be performed during a unit outage and also in view of the fact that component failures that might have affected this test are identified by other primary containment SRs. Two consecutive test failures, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every 9 months is required until the situation is remedied as evidenced by passing two consecutive tests.

(continued)

REFERENCES

1. DCD Tier 2, Section 6.2.

2. DCD Tier 2, Section 15.1.

3. 10 CFR 50, Appendix J.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Locks

BASES

BACKGROUND

Two double door primary containment air locks have been built into the primary containment to provide personnel access to the drywell and to provide primary containment isolation during the process of personnel entering and exiting the drywell. The air locks are designed to withstand the same loads, temperatures, and peak design internal and external pressures as the primary containment (Ref. 1). As part of the primary containment, the air locks limit the release of radioactive material to the environment during normal unit operation and through a range of transients and accidents up to and including postulated Design Basis Accidents (DBAs).

Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a DBA in primary containment. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in primary containment internal pressure results in increased sealing force on each door.)

Each air lock is nominally a right circular cylinder with doors at each end that are interlocked to prevent simultaneous opening. The air locks are provided with limit switches on both doors in each air lock that provide control room indication of door position. Additionally, control room indication is provided to alert the operator whenever an air lock interlock mechanism is defeated. During periods when primary containment is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent primary containment entry is necessary. Under some conditions, as allowed by this LCO, the primary containment may be accessed through the air lock when the door interlock mechanism has failed, by manually performing the interlock function.

(continued)

BASES

BACKGROUND (continued)	The primary containment air locks form part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining primary containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis. SR 3.6.1.1.1 leakage rate requirements conform with 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions.
APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 0.5%(excluding MSIV leakage) by weight of the containment air per 24 hours at the calculated maximum peak containment pressure (P_a) of 0.284) MPaG (Ref. 3). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock. Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment. The primary containment air lock satisfies Criterion 3 of the NRC Policy Statement.
LCO	As part of the primary containment, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. The primary containment air locks are required to be OPERABLE. For each air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock

(continued)

LCO (continued)

allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from primary containment.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is the one that is inoperable, however, then it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. If this is not practical, however, then it is permissible to enter the air lock through the OPERABLE outer door, which means there is a short time during which the primary containment boundary is not intact (during access through the outer door). The ability to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

Note 2 has been included to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock.

The ACTIONS are modified by a third Note, which ensures appropriate remedial measures are taken when necessary.

(continued)

ACTIONS (continued)

Pursuant to LCO 3.0.6, actions are not required, even if primary containment is exceeding its leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment," to be taken in this event.

A.1, A.2, and A.3

With one primary containment air lock door inoperable in one or more primary containment air locks, the OPERABLE door must be verified closed (Required Action A.1) in each affected air lock. This ensures that a leak tight primary containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering that the OPERABLE door of the affected air locks are being maintained closed.

Required Action A.3 ensures that the affected air locks with an inoperable door has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable primary containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls.

Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

(continued)

ACTIONS (continued)

A.1, A.2, and A.3 (continued)

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls.

Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside primary containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the primary containment during the short time that the OPERABLE door is expected to be open.

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable in one or both primary containment air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in one air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with

(continued)

ACTIONS (continued)

B.1, B.2, and B.3 (continued)

limited access due to inerting and that allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed) primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected primary containment air locks must be verified closed. This action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in each affected air lock.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established [during initial air lock and primary containment OPERABILITY testing]. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J (Ref. 2), as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria of SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the overall primary containment leakage rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when primary containment is entered, this test is only required to be performed upon entering primary containment, but is not required more frequently than 184 days when primary containment is de-inerted. The 184 day Frequency is based on engineering judgment and is considered adequate in view of other administrative controls such as indications of interlock mechanism status, available to operations personnel.

REFERENCES

1. DCD Tier 2, Section 3.8.2.
2. 10 CFR 50, Appendix J.
3. DCD Tier 2, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) to within limits. Primary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that the release of radioactive material to the environment will be consistent with the assumptions used in the analyses for a DBA.

The OPERABILITY requirements for PCIVs help ensure that adequate primary containment leak tightness is maintained during and after an accident by minimizing potential leakage paths to the environment. Therefore, the OPERABILITY requirements provide assurance that primary containment leakage rates assumed in the safety analyses will not be exceeded. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system.

The primary containment purge lines are 550 mm in diameter; vent lines are 550 mm in diameter. The 550 mm primary containment purge valves are normally maintained closed in MODES 1, 2, and 3 to ensure leak tightness. The isolation valves on the 550 mm vent lines have 50 mm bypass lines around them for use during normal reactor operation. Two additional redundant excess flow isolating dampers are provided on the vent line upstream of the Standby Gas Treatment (SGT) System filter trains. These isolation

(continued)

BACKGROUND (continued)

dampers, together with the PCIVs, will prevent high pressure from reaching the SGT System filter trains in the unlikely event of a loss of coolant accident (LOCA) during venting. Closure of the excess flow isolation dampers will not prevent the SGT System from performing its design function (that is, to maintain a negative pressure in the secondary containment). To ensure that a vent path is available, a 50 mm bypass line is provided around the dampers.

APPLICABLE SAFETY ANALYSES

The PCIVs LCO was derived from the requirements related to the control of leakage from the primary containment during major accidents. This LCO is intended to ensure that primary containment leakage rates do not exceed the values assumed in the safety analyses. As part of the primary containment boundary, PCIV OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBAs that result in a release of radioactive material within primary containment are a LOCA and a main steam line break (MSLB). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or close within the required isolation times following event initiation. This ensures that potential leakage paths to the environment through PCIVs (and primary containment purge valves) are minimized. Of the events analyzed in Reference 1, the MSLB is the most limiting event due to radiological consequences. The closure time of the main steam isolation valves (MSIVs) is the most significant variable from a radiological standpoint. The MSIVs are required to close within 3 to 4.5 seconds; therefore, the 4.5 second closure time is assumed in the analysis. The safety analyses assume that the purge valves were closed at event initiation. Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled by the rate of primary containment leakage.

The DBA analysis assumes that within 60 seconds of the accident, isolation of the primary containment is complete and leakage is terminated, except for the maximum allowable leakage rate, L_a. The primary containment isolation total

(continued)

APPLICABLE SAFETY ANALYSES (continued)

response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and PCIV stroke times.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

The primary containment purge valves may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, and 3. In this case, the single failure criterion remains applicable to the primary containment purge valve due to failure in the control circuit associated with each valve. Again, the primary containment purge valve design precludes a single failure from compromising primary containment OPERABILITY as long as the system is operated in accordance with this LCO.

PCIVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to control of primary containment leakage rates during a DBA.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. The 550 mm purge valves must be maintained sealed closed or blocked to prevent full opening. The valves covered by this LCO are listed with their associated stroke times in Reference 2.

The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Reference 2. Purge valves with resilient seals, secondary bypass valves, MSIVs, and hydrostatically tested valves must

(continued)

BASES

LCO (continued)

meet additional leakage rate requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type C testing.

This LCO provides assurance that the PCIVs will perform their designed safety functions to control leakage from the primary containment during accidents.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, most PCIVs are not required to be OPERABLE and the primary containment purge valves are not required to be sealed closed in MODES 4 and 5. Certain valves, however, are required to be OPERABLE to prevent inadvertent reactor vessel draindown. These valves are those whose associated instrumentation is required to be OPERABLE per LCO 3.3.1.1, "SSLC Sensor Instrumentation," and LCO 3.3.1.4, "ESF Actuation Instrumentation." (This does not include the valves that isolate the associated instrumentation.)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow path(s) except for purge valve flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated. Due to the size of the primary containment purge line penetration and the fact that those penetrations exhaust directly from the containment atmosphere to the environment, the penetration flow path containing these valves is not allowed to be opened under administrative controls. A single purge valve in a penetration flow path may be opened to effect repairs to an inoperable valve, as allowed by SR 3.6.1.3.1.

A second Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path.

(continued)

ACTIONS (continued)

The ACTIONS are modified by a third Note, which ensures that appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling Systems subsystem is inoperable due to a failed open test return valve).

Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded. Pursuant to LCO 3.0.6, these actions are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require that the proper actions are taken.

A.1 and A.2

With one or more penetration flow paths with one PCIV inoperable except for purge valve leakage not within limit, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For penetration isolated in accordance with Required Action A.1, the valve used to isolate the penetration should be the closest available valve to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam lines). The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following

(continued)

ACTIONS (continued)

A.1 and A.2 (continued)

an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside primary containment" is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low. For valves inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the valves and other administrative controls ensuring that valve misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

Required Action A.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and

(continued)

BASES

ACTIONS (continued)

B.1 (continued)

de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two PCIVs.

For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration. Required Action C.1 must be completed within the 4 hour Completion Time. The Completion Time of 4 hours is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 12 hours is reasonable considering the instrument and the small pipe diameter of penetration (hence, reliability) to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

(continued)

ACTIONS (continued)

C.1 and C.2 (continued)

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions.

Required Action C.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

D.1, D.2, and D.3

In the event one or more containment purge valves are not within the purge valve leakage limits, purge valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a [closed and de-activated automatic valve, closed manual valve, and blind flange]. A purge valve with resilient seals utilized to satisfy Required Action D.1 must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.7. The specified Completion Time is reasonable, considering that one containment purge valve remains closed (refer to the SR 3.6.1.3.1), so that a gross breach of containment does not exist.

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position.

(continued)

ACTIONS (continued)

D.1, D.2, and D.3 (continued)

For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

[For the containment purge valve with resilient seal that is isolated in accordance with Required Action D.1, SR 3.6.1.3.7 must be performed at least once every [92] days. This provides assurance that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.1.3.7, 184 days, is based on an NRC initiative addressing the issue of resilient seal reliability in these purge valves. Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per [92] days was chosen and has been shown to be acceptable based on operating experience.]

E.1 and E.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1, G.1, H.1, and H.2

If any Required Action and associated Completion Time cannot be met, the unit must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately

(continued)

ACTIONS (continued)

F.1, G.1, H.1, and H.2 (continued)

suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe condition. Also, if applicable, action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended and valve(s) are restored to OPERABLE status. If suspending an OPDRVs would result in closing the residual heat removal (RHR) shutdown cooling isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valve(s) to OPERABLE status. This allows RHR to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

Each 550 mm primary containment purge valve is required to be verified sealed closed at 31 day intervals. This SR is designed to ensure that a gross breach of primary containment is not caused by an inadvertent or spurious opening of a primary containment purge valve. Primary containment purge valves that are sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness. The 31 day Frequency is a result of an NRC initiative related to primary containment purge valve use during unit operations.

This SR allows a valve that is open under administrative controls to not meet the SR during the time the valve is open. Opening a purge valve under administrative controls is restricted to one valve in a penetration flow path at a given time (refer to discussion for Note 1 of the ACTIONS) in order to effect repairs to that valve. This allows one purge valve to be opened without resulting in a failure of the Surveillance and resultant entry into the ACTIONS for this purge valve, provided the stated restrictions are met. Condition D must be entered during this allowance, and the

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.1 (continued)

valve opened only as necessary for effecting repairs. Each purge valve in the penetration flow path may be alternately opened, provided one remains sealed closed, if necessary, to complete repairs on the penetration.

The SR is modified by a Note stating that primary containment purge valves are only required to be sealed closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves or the release of radioactive material will exceed limits prior to the closing of the purge valves. At other times when the purge valves are required to be capable of closing (e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are allowed to be open.

SR 3.6.1.3.2

This SR ensures that the primary containment purge valves are closed as required or, if open, open for an allowable reason.

The SR is also modified by a Note (Note 1), stating that primary containment purge valves are only required to be closed in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, the purge valves may not be capable of closing before the pressure pulse affects systems downstream of the purge valves, or the release of radioactive material will exceed limits prior to the purge valves closing. At other times when the purge valves are required to be capable of closing (e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are allowed to be open.

The SR is modified by a Note (Note 2) stating that the SR is not required to be met when the purge valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA, or air quality considerations for personnel entry, or Surveillances that require the valves to be open. The 550 mm purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.2 (continued)

allowed to be open for limited periods of time. The 31 day Frequency is consistent with other PCIV requirements discussed in SR 3.6.1.3.3.

SR 3.6.1.3.3

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment, and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside primary containment, and capable of being mispositioned, are in the correct position. Since verification of valve position for valves outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the valves are in the correct positions.

Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low. A second Note has been included to clarify that valves that are open under administrative controls are not required to meet the SR during the time that the valves are open.

SR 3.6.1.3.4

This SR verifies that each primary containment manual isolation valve and blind flange that is located inside primary containment, and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.4 (continued)

For valves inside primary containment, the Frequency defined as "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days," is appropriate since these valves and flanges are operated under administrative controls and the probability of their misalignment is low.

Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these valves, once they have been verified to be in their proper position, is low. A second Note has been included to clarify that valves that are open under administrative controls are not required to meet the SR during the time that the valves are open.

SR 3.6.1.3.5

The automatic traversing incore probe (ATIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that ATIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.6.1.3.6

Verifying the isolation time of each power operated and each automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVS may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.8. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the requirements of the Inservice Testing Program or 92 days (Refs. 2 and 5).

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.7

For primary containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J (Ref. 3), is required to ensure OPERABILITY. Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation, and the importance of maintaining this penetration leak tight (due to the direct path between primary containment and the environment), a Frequency of 184 days was established as part of the NRC resolution of the resilient seal issue. Additionally, this SR must be performed once within 92 days after opening the valve. The 92 day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that which occurs to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

The SR is modified by a Note stating that the primary containment purge valves are only required to meet leakage rate testing requirements in MODES 1, 2, and 3. If a LOCA inside primary containment occurs in these MODES, purge valve leakage must be minimized to ensure offsite radiological release is within limits. At other times when the purge valves are required to be capable of closing (e.g., during handling of irradiated fuel), pressurization concerns are not present and the purge valves are allowed to be open.

A second Note has been added to this SR requiring that the results be evaluated against the acceptance criteria of SR 3.6.1.1.1. This ensures that primary containment purge valve leakage is properly accounted for in determining the overall primary containment leakage rate.

SR 3.6.1.3.8

Verifying the total closure time of each MSIV exclusive of electrical delay is within the specified limits is required to demonstrate OPERABILITY. The isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA analyses. This ensures

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.8 (continued)

that the calculated radiological consequences of these events remain within 10 CFR 100 limits. The Frequency of this SR is 3 months.

SR 3.6.1.3.9

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.3.6 overlaps this SR to provide complete testing of the safety function. The 18 month Frequency was developed considering it is prudent that this Surveillance be performed only during a unit outage since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. For some PCIVs, the Inservice Testing Program allows this surveillance to be performed during cold shutdown, as opposed to a unit outage, provided the Frequency is no greater than 18 months. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.10

This SR requires a demonstration that each reactor instrumentation line excess flow check valve (EFCV) is OPERABLE by verifying that the valve reduces flow to ≤ 1.05 cm^3/sec on a simulated instrument line break. This SR provides assurance that the instrumentation line EFCVs will perform so that predicted radiological consequences will not be exceeded during the postulated instrument line break event evaluated in Reference 4. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.10 (continued)

Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.11

The ATIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. The Frequency of 18 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.5).

SR 3.6.1.3.12

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 2 are met. Note also that dual function valves must pass all applicable SRs, including the Type C leakage rate test (SR 3.6.1.1.1), if appropriate. The combined leakage rates must be demonstrated in accordance with the leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions.

This SR has been modified by two Notes. Note 1 states that these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3, since this is when the Reactor Coolant System is pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, their leak tightness under accident conditions is not required in these other MODES or conditions. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria of SR 3.6.1.1.1. This ensures that these valves are properly accounted for in determining the overall primary containment leakage rate.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.13

The analyses in References 2 and 4 are based on leakage that is less than the specified leakage rate. Leakage through each MSIV must be ≤ 1 m^3/h when tested at ≥ Pt of 0.173 MPaG. The MSIV leakage rate must be verified to be in accordance with the leakage test requirements of 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions. A Note has been added to this SR requiring the results to be evaluated against the acceptance criteria of SR 3.6.1.1.1. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by 10 CFR 50, Appendix J, as modified by approved exemptions; thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

SR 3.6.1.3.14

Reviewer's Note: This SR is only required for those plants with purge valves with resilient seals allowed to be open during [MODE 1, 2, 3, or 4] and having blocking devices that are not permanently installed on the valves.

Verifying each 550 mm primary containment purge valve is blocked to restrict opening to ≤ [50]% is required to ensure that the valves can close under DBA conditions within the times assumed in the analysis of References 2 and 4.

[The SR is modified by a Note stating that this SR is only required to be met in MODES 1, 2, and 3.] If a LOCA occurs, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization concerns are not present, thus the purge valves can be fully open. The 18 month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

(continued)

BASES

REFERENCES

1. DCD Tier 2, Chapter 15.
2. DCD Tier 2, Table 6.2-7.
3. 10 CFR 50, Appendix J.
4. DCD Tier 2, Section 6.2.
5. DCD Tier 2, Section 3.9.6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Pressure

BASES

BACKGROUND	The drywell pressure is limited during normal operations to preserve the initial conditions assumed in the accident analysis for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).
APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Ref. 1). Analyses assume an initial drywell pressure of 5.20×10^{-3} MPaG. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell internal pressure does not exceed the maximum allowable of 0.310 MPaG. The maximum calculated drywell pressure occurs during the reactor blowdown phase of the DBA, which is determined to be a feedwater line break. The calculated peak drywell pressure for this limiting event is 0.284 MPaG (Ref. 1). Drywell pressure satisfies Criterion 2 of the NRC Policy Statement.
LCO	In the event of a DBA, with an initial drywell pressure $\leq 5.20\times10^{-3}$ MPaG, the resultant peak drywell accident pressure will be maintained below the drywell design pressure.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell pressure within limits is not required in MODE 4 or 5.

(continued)

BASES

ACTIONS

A.1

With drywell pressure not within the limit of the LCO, drywell pressure must be restored within 1 hour. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If drywell pressure cannot be restored to within limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.4.1

Verifying that drywell pressure is within limit ensures that unit operation remains within the limit assumed in the primary containment analysis. The 12 hour Frequency of this SR was developed, based on operating experience related to trending of drywell pressure variations and pressure instrument drift during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell pressure condition.

REFERENCES

1. DCD Tier 2, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Drywell Air Temperature

BASES

BACKGROUND

The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell coolers remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. The limitation on drywell air temperature is used in the Reference 1 safety analyses.

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for a spectrum of break sizes for postulated loss of coolant accidents (LOCAs) (Ref. 1). Among the inputs to the design basis analysis is the initial drywell average air temperature (Ref. 1). Analyses assume an initial average drywell air temperature of 57°C. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 171°C (Ref. 2). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment, required to mitigate the effects of a DBA, is designed to operate and be capable of operating under environmental conditions expected for the accident.

The most severe drywell temperature condition occurs as a result of a small Reactor Coolant System rupture above the reactor water level, which results in the blowdown of reactor steam to the drywell. The drywell temperature analysis considers main steam line breaks occurring inside the drywell and having various break areas. The maximum calculated drywell average temperature for the worst case break area is provided in Reference 2.

Drywell air temperature satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES

LCO	In the event of a DBA, with an initial drywell average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the drywell design temperature. As a result, the ability of primary containment to perform its design function is ensured.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.
ACTIONS	A.1 With drywell average air temperature not within the limit of the LCO, drywell average temperature must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to variations in this parameter, and provides sufficient time to correct minor problems. B.1 and B.2 If the drywell average air temperature cannot be restored to within limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1

Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. Drywell air temperature is monitored in all quadrants and at various elevations (referenced to mean sea level). Due to the shape of the drywell, a volumetric average is used to determine an accurate representation of the actual average temperature.

The 24 hour Frequency of the SR was developed based on operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and the low probability of a DBA occurring between surveillances. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell air temperature condition.

REFERENCES

1. DCD Tier 2, Section 6.2.

2. DCD Tier 2, Section 6.2.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Wetwell-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the wetwell-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are eight internal vacuum breakers between the drywell and the wetwell, which allow gas and steam flow from the wetwell to the drywell when the drywell is at a lower pressure than the wetwell. Therefore, the wetwell-to-drywell vacuum breakers prevent an excessive negative differential pressure across the wetwell/drywell boundary. Each vacuum breaker is a self actuating valve, similar to a check valve, and requires no external power for actuation.

A negative pressure inside the drywell is caused by rapid depressurization of the drywell. Events that cause this rapid depressurization are cooling cycles, inadvertent drywell spray actuation and steam condensation from sprays or subcooled water spilling out of a break in reflood stage of a primary system rupture. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by heating and ventilation equipment. Spray actuation or the spill of subcooled water out of a break results in more significant pressure transients and are important in sizing the internal vacuum breakers.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, gas in the drywell is purged into the wetwell free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused in two possible ways, namely, Emergency Core Cooling System flow from a ruptured pipe, or containment spray actuation following a loss of coolant accident (LOCA). These two cases determine the maximum depressurization rate of the drywell.

In addition, the waterleg in the vertical vents of the vent system is controlled by the drywell-to-wetwell differential pressure. If the drywell pressure is less than the wetwell pressure, there will be an increase in the vent waterleg. This will result in an increase in the water clearing

(continued)

BASES

BACKGROUND (continued)	inertia in the event of a postulated LOCA, resulting in an increase in the peak drywell pressure. This in turn will result in an increase in the pool swell dynamic loads. The internal vacuum breakers limit the height of the waterleg in the vent system during normal operation.
APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the wetwell-to-drywell vacuum breakers are presented in Reference 1 as part of the accident response of the primary containment systems. The vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and wetwell walls that form part of the primary containment boundary. The safety analyses assume that the internal vacuum breakers are closed initially and are fully open at a differential pressure of 3.45×10^{-3} MPaD (Ref. 1). Additionally, one of the eight internal vacuum breakers is assumed to fail in a closed position (Ref. 1). The results of the analyses show that the design negative differential pressure is not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure and the requirement that all eight vacuum breakers be OPERABLE are necessary to limit the vent system waterleg height. Design Basis Accident (DBA) analyses require the vacuum breakers to be closed initially and to remain closed, with the drywell at a higher pressure relative to the wetwell. The wetwell-to-drywell vacuum breakers satisfy Criterion 3 of the NRC Policy Statement.
LCO	All eight of the vacuum breakers must be OPERABLE for opening. All wetwell-to-drywell vacuum breakers, however, are required to be closed (except during testing or when the vacuum breakers are performing the intended design function). The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-wetwell negative differential pressure remains below the design value. The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.

(continued)

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of gas and fills the drywell free airspace with steam. Subsequent condensation of the steam (due to cold water spilling out of the ruptured pipe) would result in depressurization of the drywell. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Also, inadvertent actuation of the drywell spray could result in rapid depressurization of the drywell. The vacuum breakers, therefore, are required to be OPERABLE in MODES 1, 2, and 3.

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining wetwell-to-drywell vacuum breakers OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one of the eight vacuum breakers inoperable for opening (e.g., the vacuum breaker is not open and may be stuck closed or not within its opening differential pressure limit, so that it would not function as designed during an event that depressurized the drywell), the remaining seven OPERABLE vacuum breakers are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in one of the remaining vacuum breakers could result in an excessive wetwell-to-drywell differential pressure during a DBA.

Therefore, with one of the eight required vacuum breakers inoperable, 72 hours is allowed to restore the inoperable vacuum breaker to OPERABLE status so that plant conditions are consistent with those assumed for the design basis analysis. The 72 hour Completion Time is considered acceptable due to the low probability of an event in which the remaining vacuum breaker capability would not be adequate.

(continued)

BASES

ACTIONS (continued)

B.1

One or more open vacuum breakers allow communication between the drywell and wetwell airspace, and, as a result, there is the potential for wetwell overpressurization due to this bypass leakage if a LOCA were to occur. Since the vacuum breakers are normally biased closed by gravitational force, Condition B mostly like be entered due to inaccurate position indication.

If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is by checking the position indication instrumentation. Another alternate method of verifying that the vacuum breakers are closed is by increasing the drywell pressure by 3.43×10^{-3} MPa above the wetwell pressure and verifying that the pressure differential does not fall below 2.06×10^{-3} MPaD for 15 minutes without makeup. The required 12 hour Completion Time is considered adequate to perform this test. If the stated criteria of this test is not met, Condition C must be entered.

C.1 and C.2

If the inoperable wetwell-to-drywell vacuum breaker cannot be closed or restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.6.1

Each vacuum breaker is verified closed (except when being tested in accordance with SR 3.6.1.6.2 or when performing its intended function) to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.6.1 (continued)

indication or by increasing the drywell pressure by 3.43×10^{-3} MPa above the wetwell pressure and verifying that the pressure differential does not fall below 2.06×10^{-3} MPaD for 15 minutes without makeup. This criteria was developed assuming ideal gas behavior, a leakage area corresponding to 10% of the allowable leakage area, the average temperatures in the wetwell and drywell remained within ± 0.5°C throughout the testing interval, and that adequate instrumentation exists to measure the pressure decay. Basing the test criteria on 10% of the allowable leakage area provides a large degree of margin in demonstrating that the vacuum breakers are adequately closed and sealed. Additionally, if the allowable leakage area were to exist, a pressure differential of 3.43×10^{-3} MPa would decay completely within 15 minutes. Maintaining the average temperatures of the wetwell and drywell is important because the pressure differentials in this test are relatively small and can be significantly impacted by small temperature changes. (However, if temperature control is a problem, new test parameters should be developed which take into account the normal temperature variations.)

The 14 day Frequency is based on engineering judgment and is considered adequate in view of the fact that the vacuum breakers are normally biased closed by gravitational forces. Verification of vacuum breaker closure is also required within 2 hours after any discharge of steam to the wetwell from the safety/relief valves or any operation that causes the drywell-to-wetwell differential pressure to be reduced by ≥ 6.86×10^{-4} MPaD.

SR 3.6.1.6.2

Each vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. The 18 month Frequency of this SR is based on the need to perform the surveillance during an outage. The vacuum breakers can only be manually actuated and are only accessible during an outage.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.6.3

Verification of the vacuum breaker opening pressure is necessary to ensure the validity of the safety analysis assumption that the vacuum breakers are fully open when the wetwell pressure exceeds the drywell pressure by 3.43×10^{-3} MPa. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. The 18 month Frequency is acceptable based on the passive design of the vacuum breakers (no actuator required for opening).

SR 3.6.1.6.4

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. The 18 month frequency is based on the ABWR expected refueling interval and the need to perform this Surveillance under the conditions that apply during a plant outage.

REFERENCE

1. DCD Tier 2, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The wetwell is a steel lined reinforced concrete pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the decay heat and sensible energy released during a reactor blowdown from safety/relief valve discharges or from Design Basis Accidents (DBAs). The suppression pool must quench all the steam released through the drywell connecting vent lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the design pressure of 0.310 MPaG.

The suppression pool must also condense steam from steam exhaust lines in the turbine driven Reactor Core Isolation Cooling System. Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements.

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

a. Complete steam condensation – the original limit for the end of a LOCA blowdown was 76.67°C, based on the Bodega Bay and Humboldt Bay Tests;

b. Primary containment peak pressure and temperature – the design pressure is 0.310 MPaG and design temperature is 171°C (Ref. 1); and

c. Condensation oscillation loads maximum allowable initial temperature is 48.9°C ensures that expected LOCA temperatures are within the range of ABWR tested conditions (Ref. 4).

d. Chugging loads - a maximum allowable initial temperature of 68°C ensures that expected LOCA temperatures are within the range of ABWR tested conditions (Ref. 4).

(continued)

BASES

APPLICABLE SAFETY ANALYSES	The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 1 for LOCAs and Reference 2 for the pool temperature analyses required by Reference 3). An initial pool temperature of 35°C is assumed for the Reference 1 and 2 analyses. Reactor shutdown at a pool temperature of 43.3°C and vessel depressurization at a pool temperature of 48.9°C are assumed for the Reference 2 analyses. The limit of 40.6°C, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during unit testing. Suppression pool average temperature satisfies Criteria 2 and 3 of the NRC Policy Statement.
LCO	A limitation on the suppression pool average temperature is required to provide assurance that the containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are: a. Average temperature ≤ 35°C when THERMAL POWER is < 1% RTP and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met. b. Average temperature ≤ 40.6°C when THERMAL POWER is < 1% RTP and testing that adds heat to the suppression pool is being performed. This required value ensures that the unit has testing flexibility, and was selected to provide margin below the 43.3°C limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 35°C within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 35°C is short enough not to cause a significant increase in unit risk.

(continued)

BASES

LCO (continued)

c. Average temperature ≤ 43.3°C when THERMAL POWER is ≤ 1% RTP. This requirement ensures that the unit will be shut down at > 43.3°C. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

At the 1% RTP power level, heat input is approximately equal to normal system heat losses.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power indication, the initial conditions exceed the conditions assumed for the Reference 1 and 3 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above those assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool average temperature to be restored below the limit. Additionally, when suppression pool temperature is > 35°C, increased monitoring of the suppression pool temperature is required to ensure that it remains ≤ 43.3°C. The once per hour Completion Time is adequate based on past experience, which has shown that pool temperature increases relatively slowly except when testing that adds heat to the suppression pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

(continued)

ACTIONS (continued)

B.1

If the suppression pool average temperature cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the power must be reduced to ≤ 1% RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce power from full power conditions in an orderly manner and without challenging plant systems.

C.1

Suppression pool average temperature is allowed to be > 35°C when THERMAL POWER is >1% RTP, and when testing that adds heat to the suppression pool is being performed. However, if temperature is > 40.6°C all testing must be immediately suspended to preserve the heat absorption capability of the suppression pool. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

D.1

When the suppression pool temperature reaches 43.3°C a reactor scram is automatically initiated. Additionally, when suppression pool temperature is > 43.3°C, increased monitoring of pool temperature is required to ensure that it remains ≤ 48.9°C. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high suppression pool average temperature in this Condition, the monitoring Frequency is increased to twice that of Condition A. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

E.1 and E.2

If suppression pool average temperature cannot be maintained at ≤ 48.9°C, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the reactor

(continued)

ACTIONS (continued)

E.1 and E.2 (continued)

pressure must be reduced to < 1.38 MPaG within 12 hours, and the plant must be brought to at least MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

Continued addition of heat to the suppression pool with suppression pool temperature > 48.9°C could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when the temperature was > 48.9°C, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

The suppression pool average temperature is regularly monitored to ensure that the required limits are satisfied. The average temperature is determined by taking an arithmetic average of the OPERABLE suppression pool water temperature channels. The 24 hour Frequency has been shown, based on operating experience, to be acceptable. When heat is being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

(continued)

BASES (continued)

REFERENCES

1. DCD Tier 2, Section 6.2.1.

2. DCD Tier 2, Section 15.1.

3. NUREG-0783, "Suppression Pool Temperature Limits for BWR Containments."

4. DCD Tier 2, Section 3B.4.3.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND

The suppression pool is a steel lined reinforced concrete pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the energy associated with decay heat and sensible heat released during a reactor blowdown from safety/relief valve (S/RV) discharges or from a Design Basis Accident (DBA). The suppression pool must quench all the steam released through the vent lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment, which ensures that the peak containment pressure is maintained below the design pressure of 0.310 MPaG.

The suppression pool must also condense steam from the steam exhaust lines in the turbine driven Reactor Core Isolation Cooling (RCIC) System and provides the main emergency water supply source for the reactor vessel. The suppression pool level ranges between a volume of 3580 m^3 at the low water level limit of 7 m and the a volume of 3625 m^3 high water level limit of 7.1 m.

If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the S/RV quenchers, main vents, or RCIC turbine exhaust lines. Low suppression pool water level could also result in an inadequate emergency makeup water source to the Emergency Core Cooling System. The lower volume would also absorb less steam energy before heating up excessively. Therefore, a minimum suppression pool water level is specified.

If the suppression pool water level is too high, it could result in excessive clearing loads from S/RV discharges and excessive loads during a DBA LOCA. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to S/RV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid.

Suppression pool water level satisfies Criteria 2 and 3 of the NRC Policy Statement.

LCO

A limit that suppression pool water level be ≥ 7 m and ≤ 7.1 m is required to ensure that the primary containment conditions assumed for the safety analyses are met. Either the high or low water level limits were used in the safety analyses, depending upon which is more conservative for a particular calculation.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool water level within limits is not required in MODE 4 or 5.

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analyses are not met. If water level is below the minimum level, the pressure suppression function still exists as long as top horizontal vents remain covered, RCIC turbine exhausts are covered, and S/RV quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis or as long as the drywell and wetwell sprays are OPERABLE. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool

(continued)

BASES

ACTIONS (continued)	A.1 (continued) water level to within limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval. B.1 and B.2 If suppression pool water level cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	SR 3.6.2.2.1 Verification of the suppression pool water level is to ensure that the required limits are satisfied. The 24 hour Frequency of this SR was developed considering operating experience related to trending variations in suppression pool water level and water level instrument drift during the applicable MODES and to assessing the proximity to the specified LCO level limits. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.
REFERENCE	1. DCD Tier 2, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Cooling System removes heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by three redundant RHR suppression pool cooling subsystems. The purpose of this LCO is to ensure that the three subsystems are OPERABLE in applicable MODES.

Each RHR subsystem contains one pump and one heat exchanger and is both manually and automatically initiated and independently controlled. The three RHR subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the suppression pool. Reactor Building Cooling Water (RCW), circulating through the shell side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink via the reactor service water (RSW) system.

The combined heat removal capability of two RHR subsystems operating simultaneously is sufficient to meet the overall DBA pool cooling requirement for loss of coolant accidents (LOCAs) and transient events such as a turbine trip or stuck open safety/relief (S/RV). S/RV leakage, and high pressure core injection and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The intent of the analyses is to demonstrate that the heat removal capacity of the RHR

(continued)

APPLICABLE SAFETY ANALYSES (continued)

Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The suppression pool temperature is calculated to remain below the design limit.

Reference 3 contains discussion of additional analyses that were performed to support PRA success criteria for the long term heat removal function. The intent of these analyses was to predict primary containment pressure and temperature following low probability events beyond the DBA and to determine the minimum heat-removal capacity required to maintain the primary containment conditions within its ultimate capacity. The results are used to establish the minimum amount of RHR (Suppression Pool Cooling) system equipment required to prevent ultimate containment failure beyond DBA events.

The RHR Suppression Pool Cooling System satisfies Criterion 3 of the NRC Policy Statement.

LCO

During a DBA, a minimum of two RHR suppression pool cooling subsystems are required to maintain the primary containment peak pressure and temperature below the design limits (Ref. 1). To ensure that these requirements are met, three RHR suppression pool cooling subsystems must be OPERABLE with power from three safety related independent power supplies. Therefore, in the event of an accident, at least two subsystems are OPERABLE, assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when the pump, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment and cause a heatup and pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RHR Suppression Pool Cooling System is not required to be OPERABLE in MODE 4 or 5.

(continued)

ACTIONS

A.1

With one RHR suppression pool cooling subsystem inoperable, the inoperable subsystem must be restored within 14 days. In this Condition, the remaining RHR suppression pool cooling subsystems are adequate to perform the primary containment cooling function. However, the overall reliability is reduced because a single failure in one of the OPERABLE subsystems could result in reduced primary containment cooling capability. The 14 day Completion Time is acceptable in light of the redundant RHR suppression pool cooling capabilities afforded by the OPERABLE subsystems and the low probability of a DBA occurring during this period. Additionally, analyses of beyond design basis events demonstrates that one RHR suppression pool cooling subsystem is adequate to maintain containment conditions below the ultimate capacity (Ref. 4). Furthermore, results of PRA sensitivity studies performed (Ref. 5) show that this situation is acceptable from an overall risk perspective.

B.1 and B.2

With two or more RHR suppression pool cooling subsystems inoperable, the remaining OPERABLE RHR suppression pool cooling subsystem affords significant primary containment cooling capability and would be sufficient to maintain containment conditions well below its ultimate capacity. However, the overall reliability is reduced because a worst case single failure in the one OPERABLE subsystem during a LOCA will result in a loss of primary containment cooling capability.

If the Required Action and associated Completion Time of Conditions A cannot be met within the required Completion Time or if two or more RHR suppression pool cooling subsystems are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

Verifying the correct alignment for manual, power operated, and automatic valves, in the RHR suppression pool cooling mode flow path provides assurance that the proper flow path exists for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, and the probability of an event requiring initiation of the system is low. This Frequency has been shown to be acceptable, based on operating experience.

SR 3.6.2.3.2

Verifying that each RHR pump develops a flow rate ≥ 954 m^3/h, while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is 92 days.

REFERENCES

1. DCD Tier 2, Section 6.2.
2. ASME, Boiler and Pressure Vessel Code, Section XI.
3. DCD Tier 2, Section 19.2.4.3.
4. DCD Tier 2, Section 20.3.9, Response to RAI 725.5
5. Letter, Jack Fox to Chet Poslusny, "Submittal Supporting Accelerated ABWR Review Schedule-ABWR CDF Sensitivity to ESF Equipment Out of Service", Docket No. STN 52-001, July 27, 1993.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.4 Residual Heat Removal (RHR) Containment Spray

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA) or a rapid depressurization of the reactor pressure vessel (RPV) through the safety/relief valves, steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the wetwell airspace, bypassing the suppression pool. Some means must be provided to condense steam from the wetwell so that the pressure inside primary containment remain within the design limit. This function is provided by two redundant RHR containment spray subsystems (only RHR subsystems B and C operate in this mode. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each of the two RHR containment spray subsystems contains a pump and a heat exchanger, which are manually initiated and independently controlled. The two subsystems perform the containment spray function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the common wetwell spray sparger and the common drywell spray sparger. In addition, the ACIWA mode of RHR(C) subsystem provides a backup drywell or wetwell spray capability. The wetwell sparger only accommodates a small portion of the total RHR pump flow; the remainder of the flow is routed to the drywell spray sparger. Reactor Building Cooling Water (RCW) circulating through the shell side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink via the reactor service water (RSW) system. Either RHR wetwell spray subsystem is sufficient to

(continued)

BACKGROUND (continued)

condense the steam from bypass leaks from the drywell to the wetwell airspace during the postulated LOCA.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum bypass leakage effective area. The effective flow path area for bypass leakage has been calculated to be 5 cm^2, assuming no spray operation. With operation of one wetwell spray subsystem, the effective bypass leakage area was calculated to be 50 cm^2.

The intent of the analyses is to demonstrate that the pressure reduction capacity of the RHR containment spray system operating in the wetwell spray mode is adequate to maintain the primary containment conditions within the design limit.

The RHR containment spray system satisfies Criterion 3 of the NRC Policy Statement.

LCO

In the event of a LOCA, a minimum of one RHR containment spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below the design limits (Ref. 1). To ensure that these requirements are met, two RHR containment spray subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE, assuming the worst case single active failure. An RHR containment spray subsystem is OPERABLE when the pump, the heat exchanger, and associated piping, valves, instrumentation, and controls for both wetwell and drywell spray modes are OPERABLE.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could cause heatup and pressurization of the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in

(continued)

BASES (continued)

APPLICABILITY (continued)

these MODES. Therefore, maintaining the RHR containment spray subsystems OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one RHR containment spray subsystem inoperable, the ACIWA mode of RHR(C) using the Fire Protection System (FPS) can be used to inject water into the drywell or wetwell spray spargers. The ACIWA is verified to be functional by stroking one complete cycle of each of the two manual valves in the FPS connection to RHR(C) injection line, by verifying that the FPS header pressure is maintained, and by stroking one complete cycle of the RHR(C) subsystem injection valve. The functionality of ACIWA required here is not as restrictive as that required for LCO 3.5.1 Required Action B.2 where the concern is station blackout.

If the ACIWA is verified to be functional, it compensates for the inoperability of one RHR containment spray subsystem and restores the redundant capability for primary containment bypass leakage mitigation function. During the time period when one RHR containment spray subsystem is inoperable, the remaining OPERABLE RHR containment spray subsystem is adequate to perform the primary containment bypass leakage mitigation function. However, the overall reliability is reduced if ACIWA can not be verified to be functional during this time period, and therefore the Completion Time is restricted to 7 days. If the ACIWA is verified to be functional, a Completion Time of 14 days is chosen in light of the redundant containment spray capabilities afforded by the OPERABLE subsystem and ACIWA, and the low probability of a small break in the reactor coolant boundary occurring during this period.

B.1

With both RHR containment spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the primary containment bypass leakage mitigation function. The 8 hour Completion Time is based on this loss of function and is considered acceptable due to the low

(continued)

ACTIONS (continued)

probability of a DBA and because alternative methods to remove heat from primary containment are available.

C.1

If the inoperable RHR containment spray subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.4.1

Verifying the correct alignment for manual, power operated, and automatic valves in the RHR containment spray mode flow paths provides assurance that the proper flow paths will exist for system operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to leaking, sealing, or securing. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position within the time assumed in the accident analysis. This is acceptable since the RHR suppression pool cooling mode is manually initiated. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Frequency of 31 days is justified because the valves are operated under procedural control, improper valve position would affect only a single subsystem, the probability of an event requiring initiation of the system is low, and the subsystem is a manually initiated system. This Frequency has been shown to be acceptable based on operating experience.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.4.2

Verifying each associated RHR pump develops a flow rate ≥ 114 m^3/h and less than 160 m^3/h while operating in the wetwell spray mode with flow through the heat exchanger (operating in the suppression pool cooling mode) ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by Section XI of the ASME Code (Ref. 2). This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. In addition, verifying that the wetwell spray flow ensures that the assumptions for minimum flow for bypass leakage mitigation and the maximum flow for wetwell negative pressure evaluation in the Reference 1 analyses remain valid. The Frequency of this SR is 92 days.

REFERENCES

1. DCD Tier 2, Section 6.2.1.1.5.

2. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Hydrogen Recombiners

BASES

BACKGROUND

The primary containment hydrogen recombiner eliminates the potential breach of primary containment due to a hydrogen-oxygen reaction and is part of combustible gas control required by 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2). The primary containment hydrogen recombiner is required to reduce the hydrogen concentration in the primary containment following a loss of coolant accident (LOCA). The primary containment hydrogen recombiner accomplishes this by recombining hydrogen and oxygen to form water vapor. The water vapor is returned to the primary containment, thus eliminating any discharge to the environment. The primary containment hydrogen recombiner is manually initiated, since flammability limits would not be reached until several hours after a Design Basis Accident (DBA).

The primary containment hydrogen recombiner functions to maintain the hydrogen gas concentration within the containment at or below the flammability limit of 4.0 volume percent (v/o) following a postulated LOCA. It is fully redundant and consists of two 100% capacity subsystems. Each primary containment hydrogen recombiner consists of an enclosed blower assembly, heater section, reaction chamber, direct contact water spray gas cooler, water separator, and associated piping, valves, and instruments.

The primary containment hydrogen recombiner will be manually initiated from the main control room when the hydrogen gas concentration in the primary containment reaches approximately 1 v/o. When the primary containment is inerted (oxygen concentration < 3.5 v/o), the primary containment hydrogen recombiner will only function until the oxygen is used up (2.0 v/o hydrogen combines with 1.0 v/o oxygen). Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate Engineered Safety Feature bus and is provided with separate power panel and control panel.

(continued)

BASES

BACKGROUND (continued)

The process gas circulating through the heater, the reaction chamber, and the cooler is automatically regulated to 255 m^3/h by the use of an orifice plate in-stalled in the cooler. The process gas is heated to 718°C. The hydrogen and oxygen gases are recombined into water vapor, which is then condensed in the water spray gas cooler by the associated residual heat removal subsystem and discharged with some of the effluent process gas to the wetwell. The majority of the cooled, effluent process gas is mixed with the incoming process gas to dilute the incoming gas prior to the mixture entering the heater section.

APPLICABLE SAFETY ANALYSES

The primary containment hydrogen recombiner provides the capability of controlling the bulk hydrogen concentration in primary containment to less than the lower flammable concentration of 4.0 v/o following a DBA. This control would prevent a primary containment wide hydrogen burn, thus ensuring that pressure and temperature conditions assumed in the analysis are not exceeded. The limiting DBA relative to hydrogen generation is a LOCA.

Hydrogen may accumulate in primary containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant; or

b. Radiolytic decomposition of water in the Reactor Coolant System.

To evaluate the potential for hydrogen accumulation in primary containment following a LOCA, the hydrogen generation is calculated as a function of time following the initiation of the accident. Assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

The calculation confirms that when the mitigating systems are actuated in accordance with emergency procedures, the peak hydrogen concentration in the primary containment is 4.0 v/o (Ref. 4).

The primary containment hydrogen recombiners satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES

LCO

Two primary containment hydrogen recombiners must be OPERABLE. This ensures operation of at least one primary containment hydrogen recombiner subsystem in the event of a worst case single active failure.

Operation with at least one primary containment hydrogen recombiner subsystem ensures that the post LOCA hydrogen concentration can be prevented from exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, the two primary containment hydrogen recombiners are required to control the hydrogen concentration within primary containment below its flammability limit of 4.0 v/o following a LOCA, assuming a worst case single failure.

In MODE 3, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in this MODE, the probability of an accident requiring the primary containment hydrogen recombiner is low. Therefore, the primary containment hydrogen recombiner is not required in MODE 3.

In MODES 4 and 5, the probability and consequences of a LOCA are low due to the pressure and temperature limitations in these MODES. Therefore, the primary containment hydrogen recombiner is not required in these MODES.

ACTIONS

A.1

With one primary containment hydrogen recombiner inoperable, the inoperable recombiner must be restored to OPERABLE status within 30 days. In this Condition, the remaining OPERABLE recombiner is adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the amount of time available after the event for operator action

(continued)

ACTIONS (continued)

A.1 (continued)

to prevent exceeding this limit, and the low probability of failure of the OPERABLE primary containment hydrogen recombiner.

Required Action A.1 has been modified by a Note indicating that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is provided because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit, the low probability of the failure of the OPERABLE subsystem, and the amount of time available after a postulated LOCA for operator action to prevent exceeding the flammability limit.

B.1 and B.2

With two primary containment hydrogen recombiners inoperable, the ability to perform the hydrogen control function via alternate capabilities must be verified by administrative means within 1 hour. The alternate hydrogen control capabilities are provided by the atmospheric control system (ACS). The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. Both the initial verification and all subsequent verifications may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the Surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two hydrogen recombiners inoperable for up to 7 days. Seven days is a reasonable time to allow two hydrogen recombiners to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of a LOCA that would generate hydrogen in the amounts capable of exceeding the flammability limit.

(continued)

ACTIONS (continued)

C.1

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1 and SR 3.6.3.1.2

Performance of a system functional test for each primary containment hydrogen recombiner ensures that the recombiners are OPERABLE and can attain and sustain the temperature necessary for hydrogen recombination. In particular, SR 3.6.3.1.1 verifies, every 6 months, that the minimum heater sheath temperature increases to ≥ [316°C] in ≤ [1.5 hours] and that it is maintained > [316°C] for ≥ [2] hours thereafter to check the ability of the recombiner to function properly (and to make sure that significant heater elements are not burned out). Additionally, SR 3.6.3.1.2 verifies, every 18 months, that the reaction chamber temperature increases to ≥ [621°C] in [2] hours and that it is maintained > [636°C] and < [662°C] for ≥ [2] hours.

Operating experience has shown that these components usually pass the Surveillance when performed at the 6 and 18 month Frequencies, respectively. Therefore, these Frequencies were concluded to be acceptable from a reliability standpoint.

SR 3.6.3.1.3

This SR ensures there are no physical problems that could affect recombiner operation. Since the recombiners are mechanically passive, except for the blower assemblies, they are subject to only minimal mechanical failure. The only credible failures involve loss of power or blower function, blockage of the internal flow path, missile impact, etc. A visual inspection is sufficient to determine

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.1.3 (continued)

abnormal conditions that could cause such failures. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.1.4

This SR requires performance of a resistance to ground test of each heater phase to make sure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is ≥ [10,000] ohms.

Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50.44.
2. 10 CFR 50, Appendix A, GDC 41.
3. Regulatory Guide 1.7, Revision 1.
4. DCD Tier 2, Section 6.2.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Primary Containment Oxygen Concentration

BASES

BACKGROUND	All nuclear reactors must be designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control combustible gases is to inert the primary containment. With the primary containment inert, that is, oxygen concentration < 3.5 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. The capability to inert the primary containment and maintain oxygen < 3.5 v/o works together with the hydrogen recombiners (LCO 3.6.3.1, "Primary Containment Hydrogen Recombiners") to provide redundant and diverse methods to mitigate events that produce hydrogen. For example, an event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain < 3.5 v/o and no combustion can occur. Long term generation of both hydrogen and oxygen from radiolytic decomposition of water may eventually result in a combustible mixture in primary containment, except that the hydrogen recombiners remove hydrogen and oxygen gases faster than they can be produced from radiolysis and again no combustion can occur. This LCO ensures that oxygen concentration does not exceed 3.5 v/o during operation in the applicable conditions.
APPLICABLE SAFETY ANALYSES	The Reference 1 calculations assume that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment. Oxygen, which is subsequently generated by radiolytic decomposition of water, is recombined by the hydrogen recombiners (LCO 3.6.3.1) more rapidly than it is produced. Primary containment oxygen concentration satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES

LCO

The primary containment oxygen concentration is maintained < 3.5 v/o to ensure that an event that produces any amount of hydrogen does not result in a combustible mixture inside primary containment.

APPLICABILITY

The primary containment oxygen concentration must be within the specified limit when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in MODE 1, since this is the condition with the highest probability of an event that could produce hydrogen.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as reactor power is ≤ 15% RTP, the potential for an event that generates significant hydrogen is low and the primary containment need not be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

ACTIONS

A.1

If oxygen concentration is ≥ 3.5 v/o at any time while operating in MODE 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 3.5 v/o within 24 hours. The 24 hour Completion Time is allowed when oxygen concentration is ≥ 3.5 v/o because of the availability of other hydrogen mitigating systems (e.g., hydrogen recombiners) and the low probability of an event that would generate significant amounts of hydrogen occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1

If oxygen concentration cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, power must be reduced to ≤ 15% RPT within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.2.1

The primary containment must be determined to be inert by verifying that oxygen concentration is < 3.5 v/o. The 7 day Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (which would lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.

REFERENCES

1. DCD Tier 2, Section 6.2.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND

The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment following a Design Basis Accident (DBA). In conjunction with operation of the Standby Gas Treatment (SGT) System and closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment.

The secondary containment is a structure that completely encloses the primary containment and those components that may be postulated to contain primary system fluid. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump and motor heat load additions). To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."

APPLICABLE SAFETY ANALYSES

There are two principal accidents for which credit is taken for secondary containment OPERABILITY. These are a loss of coolant accident (LOCA) (Ref. 1) and a fuel handling accident inside secondary containment (Ref. 2). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis, and that fission

(continued)

APPLICABLE SAFETY ANALYSES (continued)

products entrapped within the secondary containment structure will be treated by the SGT System prior to discharge to the environment.

Secondary containment satisfies Criterion 3 of the NRC Policy Statement.

LCO

An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, can be diluted and processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.

APPLICABILITY

In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY.

In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the primary or secondary containment.

ACTIONS

A.1

If secondary containment is inoperable, it must be restored to OPERABLE status within 4 hours. The 4 hour Completion Time provides a period of time to correct the problem that is commensurate with the importance of maintaining secondary

(continued)

ACTIONS (continued)

A.1 (continued)

containment during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring secondary containment OPERABILITY) occurring during periods where secondary containment is inoperable is minimal.

B.1 and B.2

If secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1, C.2, and C.3

Movement of irradiated fuel assemblies in the secondary containment, CORE ALTERATIONS, and OPDRVs can be postulated to cause fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. CORE ALTERATIONS and movement of irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend

(continued)

BASES

ACTIONS (continued)

C.1, C.2, and C.3 (continued)

movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring between surveillances.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and access doors are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary containment will not occur. Maintaining secondary containment OPERABILITY requires verifying each door in the access opening is closed, except when the access opening is being used for normal transient entry and exit (then, at least one door must remain closed). The 31 day Frequency for these SRs has been shown to be adequate, based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

SR 3.6.4.1.4 and SR 3.6.4.1.5

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.1.4 and SR 3.6.4.1.5 (continued)

To ensure that all fission products are treated, SR 3.6.4.1.4 verifies that the SGT System will rapidly establish and maintain a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary. This is confirmed by demonstrating that one SGT subsystem will draw down the secondary containment to ≥ 6.4 mm of water gauge vacuum in ≤ 120 seconds. This cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.5 demonstrates that one SGT subsystem can maintain ≥ 6.4 mm of water gauge vacuum for 1 hour at a flow rate ≤ 6800 m^3/h. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. Therefore, these two tests are used to ensure secondary containment boundary integrity. Since these SRs are secondary containment tests, they need not be performed with each SGT subsystem. The SGT subsystems are tested on a STAGGERED TEST BASIS, however, to ensure that in addition to the requirements of LCO 3.6.4.3, either SGT subsystem will perform this test. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. DCD Tier 2, Section 15.6.5.

2. DCD Tier 2, Section 15.7.4.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs) (Ref. 1). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, or that are released during certain operations when primary containment is not required to be OPERABLE, or take place outside primary containment, are maintained within applicable limits.

The OPERABILITY requirements for SCIVs help ensure that adequate secondary containment leak tightness is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges are considered passive devices.

Automatic SCIVs close on a secondary containment isolation signal to prevent leakage of untreated radioactive material from secondary containment following a DBA or other accidents.

Other penetrations are isolated by the use of valves in the closed position or blind flanges.

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure that secondary containment is a leak tight barrier to fission product releases. The principal accidents for which secondary containment leak tightness is required are a loss of coolant accident (Ref. 1), and a fuel handling accident inside secondary containment (Ref. 2). The secondary containment performs no active function in response to either of these limiting events, but its leak tightness is required to

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APPLICABLE SAFETY ANALYSES (continued)

ensure that leakage from the primary containment is processed by the Standby Gas Treatment (SGT) System before being released to the environment.

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so that they can be treated by the SGT System prior to discharge to the environment.

SCIVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs.

The automatic power operated isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 3.

The normally closed isolation valves or blind flanges are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, and blind flanges are in place. These passive isolation valves or devices are listed in Reference 3.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIVs is required.

In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other situations under which significant radioactive releases can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during

(continued)

BASES

APPLICABILITY (continued)

CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment. Moving irradiated fuel assemblies in the secondary containment may also occur in MODES 1, 2, and 3.

ACTIONS

The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the valve. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated.

The second Note provides clarification that for the purpose of this LCO separate Condition entry is allowed for each penetration flow path.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the valve used to isolate the penetration should be the closest available valve to secondary containment. The Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration, and the probability of a DBA, which requires the SCIVs to close, occurring during this short time, is very low.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected

(continued)

ACTIONS (continued)

A.1 and A.2 (continued)

penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that the affected penetration remains isolated.

Required Action A.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas and allows them to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the probability of a DBA, which requires the SCIVs to close, occurring during this short time, is very low.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

(continued)

ACTIONS (continued)

C.1 and C.2

If any Required Action and associated Completion Time cannot be met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1, D.2, and D.3

If any Required Action and associated Completion Time cannot be met, the plant must be placed in a condition in which the LCO does not apply. If applicable, CORE ALTERATIONS and the movement of irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action D.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving fuel while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies that each secondary containment manual isolation valve and blind flange that is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the secondary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.2.1 (continued)

that those valves in secondary containment that are capable of being mispositioned are in the correct position. Since these valves are readily accessible to personnel during normal unit operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the valves are in the correct positions.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the valves are open.

SR 3.6.4.2.2

Verifying that the isolation time of each power operated and each automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR is 92 days.

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The applicable SRs in LCO 3.3.1.1 and LCO 3.3.1.4 overlap this SR to provide complete testing of the safety function. The 18 month

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.6.4.2.3 (continued) Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.
REFERENCES	1. DCD Tier 2, Section 15.6.5. 2. DCD Tier 2, Section 15.7.4. 3. DCD Tier 2, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by 10 CFR 50, Appendix A, GDC 41, "Containment Atmosphere Cleanup" (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The SGT System consists of the following components:

a. Two 100 percent capacity charcoal filter trains, each consisting of (components listed in order of air flow direction):

   1. a moisture separator;

   2. an electric heater;

   3. a prefilter;

   4. a pre-high efficiency particulate air (HEPA) filter;

   5. a space heater;

   6. a charcoal adsorber;

   7. a space heater;

   8. a post-HEPA filter; and

b. Two fully redundant subsystems, each with its own ductwork, flow element, dampers, and instrumentation controls, consisting of:

   1. a process fan and

   2. a cooling fan.

(continued)

BASES

BACKGROUND (continued)

The sizing of the SGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the secondary containment. The internal pressure of the SGT System boundary region is maintained at a negative pressure of 6.4 mm water gauge relative to the outdoor atmosphere when the system is in operation, which represents the internal pressure required to ensure zero exfiltration of air from the building when exposed to an 8.9 m/s wind blowing at an angle of 45° to the building. The continuous negative differential pressure is established within 20 minutes after SGT System initiation.

The moisture separator is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the influent airstream to the adsorber section of the filter train to less than 70% whenever SGT System is in operation (Ref. 2). The prefilter removes large particulate matter, while the HEPA filter removes fine particulate matter and protects the charcoal from fouling. The charcoal adsorber removes all forms of iodine (elemental, organic, particulate, and hydrogen iodine), and the final HEPA filter collects any carbon fines exhausted from the charcoal adsorber.

The SGT System automatically starts and operates in response to actuation signals. Following initiation, both SGT System train process fans start. Upon verification that both trains are operating, one of the redundant trains is manually shut down.

APPLICABLE SAFETY ANALYSES

The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident (Ref. 3) and fuel handling accidents (Ref. 4). For all events analyzed, the SGT System is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment.

The SGT System satisfies Criterion 3 of the NRC Policy Statement.

(continued)

LCO

Following a DBA, a minimum of one SGT System train is required to maintain the secondary containment at the required negative pressure with respect to the surrounding spaces within 20 minutes of its initiation, and to process gaseous releases. Meeting the LCO requirements for two OPERABLE trains ensures operation of at least one SGT System train in the event of a single active failure.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, SGT System OPERABILITY is required during these MODES.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the SGT System in OPERABLE status is not required in MODE 4 or 5, except for other situations under which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs), during CORE ALTERATIONS, or during movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

A.1

With one SGT train inoperable, the inoperable train must be restored to OPERABLE status in 7 days. In this Condition, the remaining OPERABLE SGT train is adequate to perform the required radioactivity release control function. However, the overall system reliability is reduced because a single active failure in the OPERABLE train could result in the radioactivity release control function not being adequately performed. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant SGT System train and the low probability of a DBA occurring during this period.

(continued)

ACTIONS (continued)

B.1

If both SGT System trains are inoperable in MODE 1, 2, or 3, the SGT System may not be capable of supporting the required radioactivity release control function. Therefore, actions are required consistent with that required for an inoperable secondary containment.

C.1 and C.2

If the SGT System train(s) cannot be restored to OPERABLE status within the required Completion Times in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1, D.2.1, D.2.2, and D.2.3

During movement of irradiated fuel assemblies, in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT System train should immediately be placed in operation. This action ensures that the remaining train is OPERABLE, that no failures that could prevent automatic actuation have occurred, and that any other failure would be readily detected.

An alternative to Required Action D.1 is to immediately suspend activities that represent a potential for releasing radioactive material to the secondary containment, thus placing the plant in a condition that minimizes risk. If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies must immediately be suspended. Suspension of these activities must not preclude completion of movement of a component to a safe position. Also, if applicable, actions must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

(continued)

BASES

ACTIONS (continued)

D.1, D.2.1, D.2.2, and D.2.3 (continued)

The Required Actions of Condition D have been modified by a Note stating that LCO 3.0.3 is not applicable. If moving irradiated fuel assemblies while in MODE 4 or 5, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

E.1, E.2, and E.3

When both SGT System trains are inoperable, if applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action E.1 has been modified by a Note stating that LCO 3.0.3 is not applicable.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT System for ≥ 10 continuous hours ensures that both trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours every 31 days eliminates moisture on the adsorbers and HEPA filters. The 31 day Frequency was developed in consideration of the known reliability of fan motors and controls and the redundancy available in the system.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.3.2

This SR verifies that the required SGT System filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The SGT System filter tests are in accordance with Regulatory Guide 1.52 (Ref. 5). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specified test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

This SR requires verification that each SGT train starts upon receipt of an actual or simulated initiation signal. The applicable SRs in LCO 3.3.1.1 and LCO 3.3.1.4 overlap this SR to provide complete testing of the safety function. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.4.3.4

This SR requires verification that the SGT System filter cooler bypass damper can be opened and the fan started. This ensures that the ventilation mode of SGT System operation is available. While this Surveillance can be performed with the reactor at power, operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 41.

2. DCD Tier 2, Section 6.2.3.

(continued)

REFERENCES (continued)

3. DCD Tier 2, Section 15.6.5.
4. DCD Tier 2, Section 15.7.4.
5. Regulatory Guide 1.52, Rev. [2].

B 3.7 PLANT SYSTEMS

B 3.7.1 Reactor Building Cooling Water (RCW) System, Reactor Service Water (RSW) System, and Ultimate Heat Sink (UHS)-Operating

BASES

BACKGROUND

The RCW and RSW Systems are designed to provide cooling water for the removal of heat from unit auxiliaries, such as Residual Heat Removal (RHR) System heat exchangers, standby diesel generators (DGs), and room coolers for Emergency Core Cooling System equipment required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The RCW/RSW System also provides cooling to unit components, as required, during normal shutdown and reactor isolation modes. During a DBA, most, but not all, equipment required for normal operation only is isolated from the RCW/RSW System, and cooling is directed to selected non-essential equipment such as control rod drive (CRD) pump oil coolers, instrument and service air compressor coolers, reactor water cleanup (CUW) pump coolers and to safety related equipment. All non-essential equipment can be manually isolated if required. During all plant operating modes, all RCW/RSW divisions have at least one pump operating and, therefore, if a LOCA occurs the RCW/RSW systems will already be in operation.

The combined RCW/RSW system includes three separate divisions (A, B and C). Each division consists of the ultimate heat sink (UHS), an independent cooling water header, an independent service water loop, and the associated pumps, heat exchangers, piping, valves and instrumentation. Each division includes two RCW pumps, two RSW pumps and three RCW to RSW heat exchangers. Each division is sized to provide sufficient cooling capacity to support the required safety-related systems in its respective division during safe shutdown of the unit following a loss-of-coolant accident (LOCA).

The UHS is [a spray pond with six spray networks. Two spray networks are assigned to each UHS division and are mechanically separated from the other divisonal networks. The networks and their supply piping are suspended above the pond surface on reinforced concrete columns]. The [spray pond] is sized such that sufficient water inventory is available for all RCW/RSW System post LOCA cooling requirements for a 30 day period with no external makeup

(continued)

BACKGROUND (continued)

water source available (Regulatory Guide 1.27, Ref. 1). Normal makeup for the [spray pond] is provided automatically by the [power cycle heat sink makeup line].

Cooling water is pumped from the [spray pond] by the RSW pump(s) to the RCW/RSW heat exchangers through the three main redundant supply headers (Divisions A, B and C). In a separate closed loop, cooling water is circulated by the pump(s) in each RCW division through the essential components to be cooled and back through the RCW/RSW heat exchangers. Thus, the heat removed from the components by the RCW is transferred to the RSW, and then ultimately rejected to the UHS.

Divisions A, B and C supply cooling water to redundant equipment required for a safe reactor shutdown. Additional information on the design and operation of the RCW/RSW System and UHS along with the specific equipment for which the RCW/RSW System supplies cooling water is provided in Sections 9.2.11 and 9.2.15 and Tables 9.2-4A, B, and C (Refs. 2 and 3, respectively). The combined three division RCW/RSW System is designed to withstand a single active or passive failure coincident with a loss of offsite power, without losing the capability to supply adequate cooling water to equipment required for safe reactor shutdown.

Following a DBA or transient, the RCW/RSW System will operate automatically without operator action. Manual initiation of supported systems is, however, performed for some cooling operations (e.g., shutdown cooling).

APPLICABLE SAFETY ANALYSES

The volume of water incorporated in the UHS is sized so that sufficient water inventory is available for all RCW/RSW System post LOCA cooling requirements for a 30 day period with no additional makeup water source available (Ref. 1). The ability of the RCW/RSW System to support long term cooling of the reactor or containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in DCD Tier 2, Sections 9.2.11, 9.2.15, 6.2.1.1.3.3.1.4, and Chapter 15, (Refs. 2, 4, and 5, respectively). These analyses include the evaluation of the long term primary containment response after a design basis

(continued)

APPLICABLE SAFETY ANALYSES (continued)

LOCA. The RCW/RSW System provides cooling water for the RHR suppression pool cooling mode to limit suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its intended function of limiting the release of radioactive materials to the environment following a LOCA. The RCW/RSW System also provides cooling to other components assumed to function during a LOCA (e.g., RHR). Also, the ability to provide onsite emergency AC power is dependent on the ability of the RCW/RSW System to cool the DGs.

The safety analyses for long term containment cooling were performed, as discussed in DCD Tier 2, Sections 6.2.1.1.3.3.1.4 and 6.2.2.3 (Refs. 4 and 6, respectively), for a LOCA, concurrent with a loss of offsite power, and minimum available DG power. The worst case single failure affecting the performance of the RCW/RSW System is the failure of one of the three standby DGs, which would in turn affect one of the three RCW/RSW divisions and cause failure of a RHR heat exchanger as assumed in the safety analysis. Reference 2 discusses RCW/RSW System performance during these conditions.

The combined RCW/RSW System, together with the UHS, satisfy Criterion 3 of the NRC Policy Statement.

LCO

The OPERABILITY of Divisions A, B and C of the RCW/RSW System is required to ensure the effective operation of the RHR System in removing heat from the reactor, and the effective operation of other safety related equipment during a DBA or transient. Requiring all three divisions to be OPERABLE ensures that two divisions will be available to provide adequate capability to meet cooling requirements of the equipment required for safe shutdown in the event of a single failure.

A division is considered OPERABLE when:

a. All four associated RCW/RSW pumps are OPERABLE;

b. All three RCW/RSW heat exchangers are OPERABLE;

c. The associated UHS is OPERABLE; and

(continued)

BASES

LCO (continued)

d. The associated piping, valves, instrumentation, and controls required to perform the safety related function are OPERABLE.

OPERABILITY of the UHS is based on a maximum RSW water temperature of [33.3]°C at the inlet to the RCW/RSW heat exchangers with OPERABILITY of each division requiring a minimum water level at or above elevation [mean sea level (equivalent to an indicated level of ≥ [ ] m) and six OPERABLE spray networks]. The maximum RSW water temperature of [33.3]°C will insure that the peak temperature at the inlet to the RCW/RSW heat exchangers will not exceed the designed value of 35°C during a LOCA.

The isolation of the RCW/RSW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the RCW/RSW System.

APPLICABILITY

In MODES 1, 2, and 3, the RCW/RSW System and UHS are required to be OPERABLE to support OPERABILITY of the equipment serviced by the RCW/RSW System and UHS, and are required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the RCW/RSW System and UHS are specified in LCOs 3.7.2, "RCW/RSW and UHS-Shutdown" and 3.7.3, "RCW/RSW and UHS-Refueling".

ACTIONS

A.1

If one RCW pump and/or one RSW pump and/or one RCW/RSW heat exchanger and/or one [spray network] in the UHS in the same division is inoperable, action must be taken to restore the inoperable component(s), and thus the division affected, to OPERABLE status within 14 days. In this condition sufficient equipment is still available to provide cooling water to the required safety related components and sufficient heat removal capacity is still available to adequately cool safety related loads, even assuming the worst case single failure. Therefore, continued operation for a limited time is justified.

(continued)

BASES

ACTIONS (continued)

A.1 (continued)

The 14-day Completion Time is reasonable, based on the low probability of an accident occurring during the 14 days that one or more components are inoperable in one division, the number of available redundant divisions, the substantial cooling capability still remaining in a division in this Condition, and the expected high division availability afforded by a system where most of the equipment, including the minimum required for most functions, is normally operating. This Completion Time is also based on PRA sensitivity studies (Ref. 8).

B.1 and B.2

If one RCW/RSW division or both [spray networks] in one UHS division is inoperable for reasons other than Condition A, then, immediately, those required feature(s) supported by the inoperable RCW/RSW division must be declared inoperable (e.g., Emergency Diesel Generator, RHR heat exchanger, etc.) and the applicable Conditions and Required Actions of the appropriate LCOs for the inoperable required feature(s) must be entered. For example, applicable Conditions of LCO 3.8.1, "AC Sources-Operating," LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown," LCO 3.4.1, "Reactor Internal Pumps (RIP) Operating," LCO 3.6.1.5, "Drywell Air Temperature", LCO 3.6.2.3, "Suppression Pool Cooling," and LCO 3.6.2.4, "Containment Spray" be entered and the Required Actions taken if the inoperable RCW/RSW division results in an inoperable DG, RHR shutdown cooling, RIPS, drywell temperature increase due to inoperable drywell coolers, RHR suppression pool cooling, and RHR containment spray, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

Additionally, immediate action must be taken to restore the inoperable RCW/RSW division or UHS [spray networks] to OPERABLE status. This is consistent with the Required Actions of the applicable LCOs for those support feature(s) declared inoperable as a result of the inoperable RCW/RSW division.

(continued)

BASES

ACTION (continued)

C.1 and C.2

If one RCW pump and/or one RSW pump and/or one RCW/RSW heat exchanger and/or one UHS [spray network] in the same division is inoperable in two or more separate divisions, one RCW/RSW or UHS [spray network] division must be restored to OPERABLE status within 7 days and two RCW/RSW or UHS [spray network] divisions must be restored to OPERABLE status in 14 days. In this condition sufficient equipment is still available to provide cooling water to the required safety related components and sufficient heat removal capacity is still available to adequately cool safety related loads. Therefore, continued operation for a limited time is justified. However, in the degraded mode of this Condition, overall reliability and heat removal capability is reduced from that of Condition A, and thus a more restrictive Completion Time is imposed.

The 7 and 14 day Completion Times are reasonable, based on the low probability of an accident occurring during the period that one or more redundant components are inoperable in one or more divisions, the number of available redundant divisions, the substantial cooling capability still remaining in divisions in this Condition, and the expected high division availability afforded by a system where most of the equipment, including the minimum required for most functions, is normally operating. These Completion Times are also based on PRA sensitivity studies (Ref. 8).

D.1 and D.2

If the RCW/RSW division cannot be restored to OPERABLE status within the associated Completion Time, or two or more RCW/RSW divisions are inoperable for reasons other than Condition C, or the UHS is determined inoperable, or two or more UHS [spray network] divisions are inoperable for reasons other than Condition C, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR ensures adequate long term (30 days) cooling can be maintained. With the UHS water source below the minimum level, the affected RCW/RSW division must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.2

This SR verifies the water level in each RSW pump well of the intake structure to be sufficient for the proper operation of the RSW pumps (net positive suction head and pump vortexing are considered in determining this limit). The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.3

Verification of the RSW water temperature at the inlet to the RCW/RSW heat exchanger ensures that the heat removal capability of the RCW/RSW System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.1.4

Verifying the correct alignment for each manual, power operated, and automatic valve in each RCW/RSW and associated UHS [spray network] division flow path provides assurance that the proper flow paths will exist for RCW/RSW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.4 (continued)

This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

This SR is modified by a Note indicating that isolation of the RCW/RSW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the RCW/RSW System. As such, when all RCW/RSW pumps, valves, and piping are OPERABLE but a branch connection off of the main header is isolated, the RCW/RSW System is still OPERABLE. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.1.5

This SR verifies the automatic isolation valves of the RCW/RSW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment, and limited non-safety related equipment, during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the RCW/RSW pumps that are in standby and automatic valving in each of the standby RCW/RSW heat exchangers and associated UHS [spray network] in each division. SRs in LCO 3.3.1.1 and LCO 3.3.1.4 overlap this SR to provide complete testing of the safety function.

Operating experience has shown that these components usually pass the SR when performed on the 18 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. DCD Tier 2, Sections 9.2.11 and 9.2.15.
3. DCD Tier 2, Tables 9.2-4A, B, and C.
4. DCD Tier 2, Section 6.2.1.1.3.3.1.4.

(continued)

BASES

REFERENCES (continued)

5. DCD Tier 2, Chapter 15.

6. DCD Tier 2, Section 6.2.2.3.

7. DCD Tier 2, Section 19.3.1.3.

8. Letter, Jack Fox to Chet Poslusny, "Submittal Supporting Accelerated ABWR Review Schedule-ABWR CDF Sensitivity to ESF Equipment Out of Service", Docket No. STN 52-001, July 27, 1993.

B 3.7 PLANT SYSTEMS

B 3.7.2 Reactor Building Cooling Water (RCW) System, Reactor Service Water (RSW) System and Ultimate Heat Sink (UHS) - Shutdown

BASES

BACKGROUND

A description of the RCW and RSW Systems and the UHS are provided in the Bases for LCO 3.7.1, "Reactor Building Cooling Water (RCW) System, Reactor Service Water (RSW) System and Ultimate Heat Sink (UHS) - Operating."

APPLICABLE SAFETY ANALYSES

The volume of water incorporated in the UHS is sized so that sufficient water inventory is available for all RCW/RSW System post LOCA cooling requirements for a 30 day period with no additional makeup water source available (Ref. 1). The ability of the RCW/RSW System to support long term cooling of the reactor or containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in DCD Tier 2, Sections 9.2.11, 9.2.15 6.2.1.1.3.3.1.4, and Chapter 15, (Refs 2, 3, and 4, respectively). The long term cooling analyses following a design basis LOCA demonstrates that only two divisions of the RCW/RSW System is required, post LOCA, to support long term cooling of the reactor or containment. To provide redundancy, a minimum of three RCW/RSW divisions are required to be OPERABLE in MODES 4 and 5 except with the reactor cavity to dryer/separator storage pool gate removed and water level ≥ 7.0 m over the top of the reactor pressure vessel flange.

The combined RCW/RSW System, together with the UHS, satisfy Criterion 3 of the NRC Policy Statement.

LCO

Three divisions of the RCW/RSW System and the UHS are required to be OPERABLE to ensure the effective operation of the RHR System in removing heat from the reactor, and the effective operation of other safety related equipment during a DBA or transient. Requiring three divisions to be OPERABLE ensures that two divisions will be available to provide adequate capability to meet cooling requirements of the equipment required for safe shutdown in the event of a single failure. Operability of the UHS and the RCW/RSW System is defined in the Basis for LCO 3.7.1.

(continued)

LCO (continued)

The Note allows one RCW/RSW division to be inoperable in MODE 5, and after 30 hours from initial entry into MODE 4 from MODE 3. After 30 hours into MODE 4 from MODE 3, reactor decay heat (assumed maximum at the end of a fuel cycle) has dropped sufficiently such that only one RHR shutdown cooling subsystem can provide the required cooling to maintain the reactor in MODE 4 condition, and hence only two RCW/RSW divisions are required to be OPERABLE to provide redundancy.

APPLICABILITY

In MODES 4 and 5, except with the reactor cavity to dryer/separator storage pool gate removed and water level ≥ 7.0 m over the top of the reactor pressure vessel flange, three divisions of the RCW/RSW System and the UHS are required to be OPERABLE to support OPERABILITY of the equipment serviced by the RCW/RSW System and UHS, and are required to be OPERABLE in these MODES.

In MODES 1, 2, and 3, the OPERABILITY requirements of the RCW/RSW System and UHS are specified in LCO 3.7.1.

In MODE 5 with the reactor cavity to dryer/separator storage pool gate removed and water level ≥ 7.0 m over the top of the reactor pressure vessel flange, the OPERABILITY requirements of the RCW/RSW System and UHS are specified in LCO 3.7.3, "RCW/RSW System and UHS - Refueling."

ACTIONS

A.1, B.1 and B.2

If one RCW pump and/or one RSW pump and/or one RCW/RSW heat exchanger and/or one [spray network] in the UHS in the same division is inoperable, action must be taken to restore the inoperable component(s) and thus the division affected, to OPERABLE status within 14 days. If one RCW pump and/or one RSW pump and/or one RCW/RSW heat exchanger and/or one UHS [spray network] in the same division is inoperable in two or more separate divisions, one RCW/RSW or UHS [spray network] division must be restored to OPERABLE status within 7 days and two RCW/RSW or UHS [spray network] divisions must be restored to OPERABLE status in 14 days. In these conditions sufficient redundant equipment is still available to provide

(continued)

ACTIONS (continued)

A.1, B.1 and B.2 (continued)

cooling water to the required safety related components and sufficient heat removal capacity is still available to adequately cool safety related loads. Therefore, continued operability of these divisions is justified.

The Completion Times are reasonable, based on the low probability of an accident occurring while one or more components are inoperable in one or more divisions, the number of available divisions, the substantial cooling capability still remaining in a division(s) in this Condition, and the expected high division availability afforded by a system where most of the equipment, including the minimum required for most functions, is normally operating. However, in the degraded mode of Condition B, overall reliability and heat removal capability is reduced from that of Condition A, and thus a more restrictive Completion Time is imposed.

C.1

If the RCW/RSW or UHS [spray network] division(s) cannot be restored to OPERABLE status within the associated Completion Time(s), or one or more required RCW/RSW or UHS [spray network] division(s) are inoperable for reasons other than Condition A or B or the UHS is inoperable, then immediately, those required feature(s) supported by the inoperable RCW/RSW division(s) or the UHS must be declared inoperable (i.e., Emergency Diesel Generator, RHR heat exchanger) and the applicable Conditions and Required Actions of the appropriate LCOs for the inoperable required feature(s) must be entered. For the applicable shutdown MODES, an inoperable RCW/RSW division or UHS requires entering the Conditions of LCO 3.8.11, "AC Sources-Shutdown(Low Water Level)," for a diesel generator made inoperable and either LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System-Cold Shutdown," or LCO 3.9.8, "Residual Heat Removal (RHR) Low Water Level" for RHR shutdown cooling made inoperable. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR ensures adequate long term (30 days) cooling can be maintained. With the UHS water source below the minimum level, the affected RCW/RSW division must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.2.2

This SR verifies the water level in each RSW pump well of the intake structure to be sufficient for the proper operation of the RSW pumps (net positive suction head and pump vortexing are considered in determining this limit). The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.2.3

Verification of the RSW water temperature at the inlet to the RCW/RSW heat exchangers ensures that the heat removal capability of the RCW/RSW System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.2.4

Verifying the correct alignment for each manual, power operated, and automatic valve in each RCW/RSW and associated UHS [spray network] division flow path provides assurance that the proper flow paths will exist for RCW/RSW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves

(continued)

REQUIREMENTS (continued)

SR 3.7.2.4 (continued)

that cannot be inadvertently misaligned, such as check valves.

This SR is modified by a Note indicating that isolation of the RCW/RSW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the RCW/RSW System. As such, when all RCW/RSW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the RCW/RSW System is still OPERABLE. The 31 day Frequency is based on engineering judgement, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.2.5

This SR verifies that the automatic isolation valves of the RCW/RSW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment, and limited non-safety related equipment, during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the RCW/RSW pumps that are in standby and automatic valving in each of the standby RCW/RSW heat exchangers and associated UHS [spray network] in each division. SRs in LCO 3.3.1.1 and LCO 3.3.1.4 overlap this SR to provide complete testing of the safety function.

Operating experience has shown that these components usually pass the SR when performed on the 18 month Frequency. Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Regulatory Guide 1.27, Revision 2, January 1976.
2. DCD Tier 2, Sections 9.2.11 and 9.2.15.
3. DCD Tier 2, Section 6.2.1.1.3.3.1.4.
4. DCD Tier 2, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.3 Reactor Building Cooling Water (RCW) System, Reactor Service Water (RSW) System and Ultimate Heat Sink (UHS) - Refueling

BASES

BACKGROUND

A description of the RCW and RSW Systems and the UHS are provided in the Bases for LCO 3.7.1, "Reactor Building Cooling Water (RCW) System, Reactor Service Water (RSW) System and Ultimate Heat Sink (UHS) - Operating." In MODE 5 with the reactor vessel water level ≥ 7.0 m over the vessel flange the unit components to which the RCW/RSW System is required to supply cooling water is greatly reduced from normal operation. For example, LCO 3.8.2, "AC Sources-Refueling" and LCO 3.9.7, "RHR-High Water Level" require one DG and one RHR subsystem to be OPERABLE, respectively, and LCO 3.5.2, "ECCS-Shutdown" does not require any ECCS components to be OPERABLE for this condition.

APPLICABLE SAFETY ANALYSES

The volume of water incorporated in the UHS is sized so that sufficient water inventory is available for all RCW/RSW System post LOCA cooling requirements for a 30 day period with no additional makeup water source available (Ref. 1). The ability of the RCW/RSW System to support long term cooling of the reactor or containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in DCD Tier 2, Sections 9.2.11, 9.2.15, 6.2.1.1.3.3.1.4, and Chapter 15, (Refs. 2, 3, and 4, respectively). With the unit in MODE 5 and with the reactor cavity to dryer/separator storage gate removed and water level ≥ 7.0 m over the top of the reactor pressure vessel flange, the volume of water in the reactor vessel provides a heat sink for decay heat removal. However, to provide redundancy, a minimum of one RCW/RSW division is required to be OPERABLE.

The combined RCW/RSW System, together with the UHS, satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES

LCO

One division of the RCW/RSW System and the UHS are required to be OPERABLE to ensure the effective operation of the RHR System in removing heat from the reactor. LCO 3.9.7, "RHR-High Water Level" requires that one RHR subsystem be OPERABLE and in operation in MODE 5 with the water level ≥ 7.0 m above the RPV flange. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability. Operability of the UHS and the RCW/RSW System is defined in the Basis for LCO 3.7.1.

APPLICABILITY

In MODE 5 with the reactor cavity to dryer/separator storage pool gate removed and water level ≥ 7.0 m over the top of the reactor pressure vessel flange, one division of the RCW/RSW System and the UHS are required to be OPERABLE to support OPERABILITY of the equipment serviced by the RCW/RSW System and UHS, and are required to be OPERABLE in this MODE.

In MODES 1, 2, and 3, the OPERABILITY requirements of the RCW/RSW System and UHS are specified in LCO 3.7.1.

In MODES 4 and 5, except with the reactor cavity to dryer/separator storage pool gate removed and water level ≥ 7.0 m over the top of the reactor pressure vessel flange, the OPERABILITY requirements of the RCW/RSW System and UHS are specified in LCO 3.7.2, "RCW/RSW System and UHS - Shutdown."

ACTIONS

A.1 and A.2

If no RCW/RSW division is operable or the UHS is inoperable, or the associated divisonal UHS [spray networks] are inoperable, then, immediately, those required feature(s) supported by the inoperable required RCW/RSW division or UHS must be declared inoperable (i.e., Emergency Diesel Generator, RHR heat exchanger) and the applicable Conditions and Required Actions of the appropriate LCOs for the inoperable required feature(s) must be entered. An inoperable RCW/RSW division or UHS requires entering the Conditions of LCO 3.8.2, "AC Sources-Refueling," for a

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

diesel generator made inoperable and LCO 3.9.7, "Residual Heat Removal (RHR)-High Water Level" for RHR shutdown cooling made inoperable. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR ensures adequate long term (30 days) cooling can be maintained. With the UHS water source below the minimum level, the affected RCW/RSW division must be declared inoperable. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.3.2

This SR verifies the water level in each RSW pump well of the intake structure to be sufficient for the proper operation of the RSW pumps (net positive suction head and pump vortexing are considered in determining this limit). The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.3.3

Verification of the RSW water temperature at the inlet to the RCW/RSW heat exchangers ensures that the heat removal capability of the RCW/RSW System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.3.4

Verifying the correct alignment for each manual, power operated, and automatic valve in each RCW/RSW and associated UHS [spray network] division flow path provides assurance

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.3.4 (continued)

that the proper flow paths will exist for RCW/RSW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position and yet considered in the correct position, provided it can be automatically realigned to its accident position. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

This SR is modified by a Note indicating that isolation of the RCW/RSW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the RCW/RSW System. As such, when all RCW/RSW pumps, valves, and piping are OPERABLE, but a branch connection off the main header is isolated, the RCW/RSW System is still OPERABLE.

The 31 day Frequency is based on engineering judgement, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.3.5

This SR verifies that the automatic isolation valves of the RCW/RSW System will automatically switch to the safety or emergency position to provide cooling water exclusively to the safety related equipment, and limited non-safety related equipment, during an accident event. This is demonstrated by use of an actual or simulated initiation signal. This SR also verifies the automatic start capability of the RCW/RSW pumps that are in standby and automatic valving in each of the standby RCW/RSW heat exchangers and associated UHS [spray network] in each division. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.5.1.4 overlaps this SR to provide complete testing of the safety function.

Operating experience has shown that these components usually pass the SR when performed on the 18 month Frequency.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.7.3.5 (continued) Therefore, this Frequency is concluded to be acceptable from a reliability standpoint.
REFERENCES	1. Regulatory Guide 1.27, Revision 2, January 1976. 2. DCD Tier 2, Sections 9.2.11 and 9.2.15. 3. DCD Tier 2, Section 6.2.1.1.3.3.1.4. 4. DCD Tier 2, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.4 Control Room Habitability Area (CRHA) - Emergency Filtration (EF) System

BASES

BACKGROUND

The Emergency Filtration System of the CRHA HVAC System, provides a radiologically controlled environment from which the unit can be safely operated following a Design Basis Accident (DBA).

The safety related function of the Emergency Filtration System used to control radiation exposure consists of two independent and redundant high efficiency air filtration divisions for treatment of a mixture of recirculated air and a minimum of outside air supplied for pressurization of the main control area envelope (MCAE). Each division consists of an electric heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section, a second HEPA filter, a fan, and the associated ductwork and dampers. The electric heater limits the relative humidity of the influent air stream to less than 70% relative humidity. Prefilters and HEPA filters remove particulate matter that may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay. The second HEPA filter collects any carbon fines exhausted from the adsorber.

Upon receipt of the initiation signal(s) (indicative of conditions that could result in radiation exposure to MCAE personnel), the Emergency Filtration System automatically switches to the high radiation mode of operation to prevent infiltration of contaminated air into the MCAE.

The Emergency Filtration System is designed to maintain the MCAE environment for a 30 day continuous occupancy after a DBA, without exceeding a 0.05 Sv whole body dose. Emergency Filtration System operation in maintaining the control room habitability is discussed in DCD Tier 2, Sections 6.4.1 and 9.4.1 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The ability of the Emergency Filtration System to maintain the habitability of the control room is an explicit assumption for the safety analyses presented in

(continued)

APPLICABLE SAFETY ANALYSES (continued)

DCD Tier 2, Chapters 6 and 15 (Refs. 3 and 4, respectively). The filtration mode of the Emergency Filtration System is assumed to operate following a loss of coolant accident, main steam line break, and fuel handling accident. The radiological doses to MCAE personnel as a result of the various DBAs are summarized in Reference 4. No single active or passive failure will cause the loss of outside or recirculated air from the MCAE.

The Emergency Filtration System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two redundant divisions of the Emergency Filtration System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other division. Total system failure could result in exceeding a dose of 0.05 Sv to the control room operators in the event of a DBA.

The Emergency Filtration System is considered OPERABLE when the individual components necessary to control operator exposure are OPERABLE in both divisions. A division is considered OPERABLE when its associated:

a. Fan is OPERABLE;

b. HEPA filter and charcoal adsorber are not excessively restricting flow and are capable of performing their filtration functions; and

c. Heater, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In addition, the MCAE boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and double entry doors with vestibule between at a positive pressure of at least 0.32 mm of water gauge relative to atmosphere.

APPLICABILITY

In MODES 1, 2, and 3, the Emergency Filtration System must be OPERABLE to control operator exposure during and

(continued)

APPLICABILITY (continued)

following a DBA, since the DBA could lead to a fission product release.

In MODES 4 and 5, the probability and consequences of a DBA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Emergency Filtration System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During operations with a potential for draining the reactor vessel (OPDRVs);

b. During CORE ALTERATIONS; and

c. During movement of irradiated fuel assemblies in the secondary containment.

ACTIONS

A.1

With one Emergency Filtration division inoperable, the inoperable Emergency Filtration division must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE Emergency Filtration division is adequate to perform MCAE radiation protection. However, the overall reliability is reduced because a single failure in the OPERABLE division could result in loss of Emergency Filtration System function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining division can provide the required capabilities.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable Emergency Filtration division cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the

(continued)

ACTIONS (continued)

B.1 and B.2 (continued)

required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1, C.2.2, and C.2.3

The Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, if the inoperable Emergency Filtration division cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE Emergency Filtration division may be placed in the filtration mode. This action ensures that the remaining division is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require initiation of the Emergency Filtration System. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

(continued)

ACTIONS (continued)

D.1

If both Emergency Filtration divisions are inoperable in MODE 1, 2, or 3, the Emergency Filtration System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

The Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, with two Emergency Filtration divisions inoperable, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require initiation of the Emergency Filtration System. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that a division in standby mode starts on demand and continues to operate. Standby systems should be checked periodically to ensure that they start and function properly. As the environmental and normal operating conditions of this system are not severe, testing each

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.1 (continued)

division once every month provides an adequate check on this system. Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. Systems with heaters must be operated for ≥ 10 continuous hours with the heaters energized. Furthermore, the 31 day Frequency is based on the known reliability of the equipment and the two division redundancy available.

SR 3.7.4.2

This SR verifies that the required Emergency Filtration testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The Emergency Filtration filter tests are in accordance with Regulatory Guide 1.52 (Ref. 5). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.4.3

This SR verifies that each Emergency Filtration division starts and operates on an actual or simulated initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.7.1.4 overlaps this SR to provide complete testing of the safety function. The 18 month Frequency is specified in Reference 5.

SR 3.7.4.4

This SR verifies the integrity of the MCAE and the assumed inleakage rates of potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent spaces, is periodically tested to verify proper function of the Emergency Filtration System. During the emergency mode of operation, the Emergency Filtration System is designed to slightly pressurize the control room to ≥ 3.2 mm water gauge positive pressure with respect to the atmosphere to prevent unfiltered inleakage.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.4 (continued)

The Emergency Filtration System is designed to maintain this positive pressure at a flow rate of ≤ 360 m^3/h @ 0.101 MPa, 0°C to the MCAE in the emergency filtration mode. The Frequency of 18 months on a STAGGERED TEST BASIS is consistent with industry practice and other filtration system SRs.

REFERENCES

1. DCD Tier 2, Section 6.4.1.
2. DCD Tier 2, Section 9.4.1.
3. DCD Tier 2, Chapter 6.
4. DCD Tier 2, Chapter 15.
5. Regulatory Guide 1.52, Revision 2, March 1978.

B 3.7 PLANT SYSTEMS

B 3.7.5 Control Room Habitability Area (CRHA) - Air Conditioning (AC) System

BASES

BACKGROUND

The CRHA AC System provides temperature control for the main control area envelope (MCAE) at all times the MCAE is occupied.

The CRHA AC System consists of two independent, redundant divisions that provide cooling and heating of recirculated control room air. Each division consists of heating coils, cooling coils, fans, ductwork, dampers, and instrumentation and controls to provide for MCAE temperature control.

The CRHA AC subsystem is designed to provide a controlled environment under both normal and accident conditions. A single division provides the required temperature control to maintain the required MCAE environment for a sustained occupancy of 12 persons. The design conditions for the control room environment are 21°C to 26°C and 10% to 60% relative humidity. The CRHA AC System operation in maintaining the MCAE temperature is discussed in DCD Tier 2, Sections 6.4 and 9.4.1 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The design basis of the CRHA AC System is to maintain the MCAE temperature range for a 30 day continuous occupancy.

The CRHA AC System components are arranged in redundant safety related divisions. During emergency operation, the CRHA AC System maintains a habitable environment and ensures the OPERABILITY of components in the MCAE. A single active failure of a component of the CRHA AC System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant temperature elements and controls are provided for MCAE temperature control. The CRHA AC System is designed in accordance with Seismic Category I requirements. The CRHA AC System is capable of removing sensible and latent heat loads from the MCAE, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY.

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APPLICABLE SAFETY ANALYSES (continued)	The CRHA AC System satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two independent and redundant divisions of the CRHA AC System are required to be OPERABLE to ensure that at least one is available, assuming a single failure disables the other division. Total system failure could result in the equipment operating temperature exceeding equipment qualification limits.

The CRHA AC System is considered OPERABLE when the individual components necessary to maintain the MCAE temperature are OPERABLE in both divisions. These components include the cooling coils, fans, ductwork, dampers, and associated instrumentation and controls.

APPLICABILITY

In MODE 1, 2, or 3, the CRHA AC System must be OPERABLE to ensure that the MCAE temperature will not exceed equipment OPERABILITY limits following control room isolation.

In MODES 4 and 5, the probability and consequences of a Design Basis Accident are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the CRHA AC System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During operations with a potential for draining the reactor vessel (OPDRVs);

b. During CORE ALTERATIONS; and

c. During movement of irradiated fuel assemblies in the secondary containment.

(continued)

ACTIONS

A.1

With one CRHA AC division inoperable, the inoperable CRHA AC division must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE CRHA AC division is adequate to perform the MCAE air conditioning function. However, the overall reliability is reduced because a single failure in the OPERABLE division could result in loss of the MCAE air conditioning function. The 30 day Completion Time is based on the low probability of an event occurring requiring MCAE isolation, the consideration that the remaining division can provide the required protection, and the availability of alternate cooling methods.

B.1 and B.2

In MODE 1, 2, or 3, if the inoperable CRHA AC division cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1, C.2.2, and C.2.3

The Required Actions of Condition C are modified by a Note indicating that LCO 3.0.3 does not apply.

If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE CRHA AC division may be placed immediately in operation.

(continued)

ACTIONS

C.1, C.2.1, C.2.2, and C.2.3 (continued)

This action ensures that the remaining division is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the MCAE. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and movement of irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

D.1

If both CRHA AC divisions are inoperable in MODE 1, 2, or 3, the CRHA AC System may not be capable of performing the intended function. Therefore, LCO 3.0.3 must be entered immediately.

E.1, E.2, and E.3

The Required Actions of Condition E.1 are modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of irradiated fuel assemblies in the secondary containment, during CORE ALTERATIONS, or during OPDRVs with two CRHA AC divisions inoperable, action must be taken to immediately suspend activities that present

(continued)

BASES

ACTIONS

E.1, E.2, and E.3 (continued)

a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk.

If applicable, CORE ALTERATIONS and handling of irradiated fuel in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR verifies that the heat removal capability of the system is sufficient to remove the MCAE heat load assumed in the safety analyses. The SR consists of a combination of testing and calculation. The 18 month Frequency is appropriate since significant degradation of the CRHA AC System is not expected over this time period.

REFERENCES

1. DCD Tier 2, Section 6.4.
2. DCD Tier 2, Section 9.4.1.

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Condenser Offgas

BASES

BACKGROUND

During unit operation, steam from the low pressure turbine is exhausted directly into the condenser. Air and noncondensible gases are collected in the condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases.

The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser; the water and condensibles are stripped out by the offgas condenser and moisture separator. The radioactivity of the remaining gaseous mixture (i.e., the offgas recombiner effluent) is monitored downstream of the moisture separator prior to entering the holdup line.

APPLICABLE SAFETY ANALYSES

The main condenser offgas gross gamma activity rate is an initial condition of the Main Condenser Offgas System failure event as discussed in DCD Tier 2, Section 15.7.1 (Ref. 1). The analysis assumes a partial bypass of the charcoal beds due to operator error. The gross gamma activity rate is controlled to ensure that during the event, the calculated offsite doses will be well within the limits (NUREG-0800, Ref. 2) of 10 CFR 100 (Ref. 3), or the NRC staff approved licensing basis.

The main condenser offgas limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

To ensure compliance with the assumptions of the Main Condenser Offgas System failure event (Ref. 1), the fission product release rate should be consistent with a noble gas release to the reactor coolant of 3.7 MBq/MWt second at 30 minutes of decay. The LCO is

(continued)

BASES

LCO (continued)

established consistent with this requirement (4000 MWt x 3.7 MBq/MWt second = 14.8 GBq/second).

APPLICABILITY

The LCO is applicable when steam is being exhausted to the main condenser and the resulting noncondensibles are being processed via the Main Condenser Offgas System. This occurs during MODE 1, and during MODES 2 and 3 with any main steam line not isolated and the SJAE in operation. In MODES 4 and 5, steam is not being exhausted to the main condenser and the requirements are not applicable.

ACTIONS

A.1

If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on operating experience to complete the Required Action, considering the large margins associated with permissible dose and exposure limits, and the low probability of an Main Condenser Offgas System rupture occurring.

B.1, B.2, B.3.1, and B.3.2

If the gross gamma activity rate is not restored to within the limits within the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power operations in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the LCO does not apply. To achieve this status the unit must be placed in at least MODE 3 within 12 hours, and in MODE 4 within 36 hours. The

(continued)

BASES

ACTIONS

B.1, B.2, B.3.1, and B.3.2 (continued)

allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR, on a 31 day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-85, Kr-87, and Kr-88. If the measured rate of radioactivity increases significantly (by ≥ 50% after correcting for expected increases due to changes in THERMAL POWER), an isotopic analysis is also performed within 4 hours after the increase is noted, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable based on operating experience.

This SR is modified by a Note indicating that the SR is not required to be performed until 31 days after any main steam line is not isolated and the SJAE is in operation. Only in this condition can radioactive fission gases be in the Main Condenser Offgas System at significant rates.

REFERENCES

1. DCD Tier 2, Section 15.7.1.
2. NUREG-0800.
3. 10 CFR 100.

B 3.7 PLANT SYSTEMS

B 3.7.7 Main Turbine Bypass System

BASES

BACKGROUND

The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is 33% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of a three valve chest connected to the main steam lines between the main steam isolation valves and the turbine stop valves. Each of these valves is sequentially operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Steam Bypass and Pressure Control System, as discussed in DCD Tier 2, Section 7.7.1.8 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. Additionally, for the turbine trip and load rejection events only (Ref. 2) there is a Fast Opening Mode of turbine bypass operation. In the Fast Opening Mode, the turbine bypass will open rapidly in response to a signal generated by the turbine trip or load rejection, independent of steam pressure. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during the design basis feedwater controller failure, maximum demand event, described in DCD Tier 2, Section 15.1.2 (Ref. 2). Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. An inoperable Main Turbine Bypass System may result in an MCPR penalty.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The Main Turbine Bypass System satisfies Criterion 3 of the NRC Policy Statement.
LCO	The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, such that the Safety Limit MCPR is not exceeded. With the Main Turbine Bypass System inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") may be applied to allow continued operation. An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure or in the Fast Opening Mode, as applicable. This response is within the assumptions of the applicable analysis (Ref. 2). The MCPR limit for the inoperable Main Turbine Bypass System is specified in the COLR.
APPLICABILITY	The Main Turbine Bypass System is required to be OPERABLE at ≥ 40% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.2, sufficient margin to these limits exists at a power level < 40% RTP. Therefore, these requirements are only necessary when operating at or above this power level.
ACTIONS	A.1 If the Main Turbine Bypass System is inoperable (one or more bypass valves inoperable), or the MCPR limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the MCPR limits accordingly. The 2 hour Completion Time is

(continued)

BASES

ACTIONS

A.1 (continued)

reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status or the MCPR limits for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < 40% RTP. As discussed in the Applicability section, operation at < 40% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

Opening each main turbine bypass valve to ≥ 10% position demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on a reliability analysis (Reference 3).

SR 3.7.7.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 18 month Frequency, which is based on the refueling cycle,is acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.3

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analysis. The response time limits are specified in [unit specific documentation]. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 18 month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint and is also based on a reliability analysis in Reference 3.

REFERENCES

1. DCD Tier 2, Section 7.7.1.8.
2. DCD Tier 2, Chapter 15.
3. Letter, Jack Fox to Chet Poslusny, "Submittal Supporting Accelerated ABWR Review Schedule-Revised LCO 3.7.5", Docket No. STN 52-001, May 19, 1993.

B 3.7 PLANT SYSTEMS

B 3.7.8 Fuel Pool Water Level

BASES

BACKGROUND	The minimum water level in the spent fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident. A general description of the spent fuel storage pool design is found in DCD Tier 2, Section 9.1.2 (Ref. 1). The assumptions of the fuel handling accident are found in DCD Tier 2, Section 15.7.4 (Ref. 2).
APPLICABLE SAFETY ANALYSES	The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident. A fuel handling accident is evaluated to ensure that the radiological consequences (calculated whole body and thyroid doses at the exclusion area and low population zone boundaries) are ≤ 25% (NUREG-0800, Section 15.7.4, Ref. 3) of the 10 CFR 100 (Ref. 4) exposure guidelines. A fuel handling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in the Regulatory Guide 1.25 (Ref. 5). The fuel handling accident is evaluated for the dropping of an irradiated fuel assembly onto the reactor core which bounds the consequences of dropping an irradiated fuel assembly onto stored fuel bundles. The consequences of a fuel handling accident inside the reactor building are documented in Reference 2. The water level in the spent fuel storage pool provides for absorption of water soluble fission product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the reactor building atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a fuel handling accident. The fuel pool water level satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO	The specified water level preserves the assumption of the fuel handling accident analysis (Ref. 2). As such, it is the minimum required for fuel movement within the spent fuel storage pool.
APPLICABILITY	This LCO applies whenever movement of irradiated fuel assemblies occurs in the associated fuel storage racks since the potential for a release of fission products exists.
ACTIONS	A.1 Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown. When the initial conditions for an accident cannot be met, steps should be taken to preclude the accident from occurring. With the fuel pool level less than required, the movement of irradiated fuel assemblies in the associated storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.
SURVEILLANCE REQUIREMENTS	SR 3.7.8.1 This SR verifies that sufficient water is available in the event of a fuel handling accident. The water level in the spent fuel storage pool must be checked periodically. The 7 day Frequency is acceptable, based on operating experience, considering that the water volume in the pool is normally stable and water level changes are controlled by unit procedures.

(continued)

BASES (continued)

REFERENCES

1. DCD Tier 2, Section 9.1.2.
2. DCD Tier 2, Section 15.7.4.
3. NUREG-0800, Section 15.7.4, Revision 1, July 1981.
4. 10 CFR 100.
5. Regulatory Guide 1.25, March 1972.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources – Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (normal preferred and alternate preferred) and the onsite standby power sources (Division I diesel generator (DG), Division II DG, and Division III DG). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E 6.9 kV ESF bus (refer to LCO 3.8.9, "Distribution Systems – Operating"). Each ESF bus has two separate and independent preferred (offsite) sources of power and a dedicated onsite DG. Each ESF bus is also connectable to a combustion turbine generator (CTG). The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to each of the 6.9 kV ESF buses from the transmission network via two electrically and physically separated circuits. In addition, the CTG may be substituted for the second (delay access) offsite source to any one ESF bus (for a limited duration) when the first (immediate access) offsite source to the ESF bus is from the reserve auxiliary transformer while the unit auxiliary transformer associated with the ESF bus is out of service. The CTG may also be substituted for the second (delay access) offsite source for the three ESF buses (for a limited duration) when the first (immediate access) offsite source to each of the ESF buses is from its associated unit auxiliary transformer while the reserve auxiliary transformer (associated with the three ESF buses) is out of service. These offsite AC electrical power circuits are designed and located so as to minimize to the extent practicable the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power

(continued)

BASES

BACKGROUND (continued)

system and circuits to the onsite Class 1E ESF buses is found in DCD Tier 2, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, controls, and control power supplies required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es). Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Initiating signals (i.e., load shedding and buses-ready-to-load) for returning certain plant loads to service are generated by the control system for the electrical power distribution system. Individual timers for each major load are reset and started by their electrical power distribution system signals and/or LOCA signals. After the initiating signals are received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service in a preset sequence via timer delays on each load.

The onsite standby power source for each 6.9 kV ESF bus is a dedicated DG. A DG starts automatically on loss of coolant accident (LOCA) signal (i.e., signal generated from low reactor water level and high drywell pressure that are arranged in two-out-of four logic combinations) or on an ESF bus undervoltage signal (refer to LCO 3.3.1.4, "ESF Actuation Instrumentation"). In addition, power can be supplied to any one ESF from the CTG (for a limited duration) when a DG is inoperable.

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Ratings for DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating for each DG is 5000 kW @ 0.8 power factor, with 10% overload permissible for up to 2 hours in any 24 hour period.

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APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in DCD Tier 2, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), ssume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources (not including the CTG) is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

AC sources satisfy the requirements of Criterion 3 of the NRC Policy Statement. In addition, the CTG may be substituted for the second (delay access) offsite source to any one ESF bus when the first (immediate access) offsite source is from the reserve auxiliary transformer while the unit auxiliary transformer associated with the ESF bus is out of service. The CTG may also be substituted for the second (delay access) offsite source for the three ESF buses (for a limited duration) when the first (immediate access) offsite source to each of the ESF buses is from its associated unit auxiliary transformer while the reserve auxiliary transformer (associated with the three ESF buses) is out of service. The CTG may also be used to substitute (for a limited time) for an inoperable DG. With this substitution, the AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded.

(continued)

BASES

LCO

Two qualified offsite circuits between the offsite transmission network and the onsite Class 1E Distribution System that consists of three separate and independent divisions (Divisions I, II, and III) each backed by its own dedicated and independent DG, ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA. In addition, the CTG may be utilized as a temporary substitution for the second (delayed access) qualified offsite circuit when the first (immediate access) qualified offsite circuit to any one ESF bus (immediate access) offsite source is from the reserve auxiliary transformer while the unit auxiliary transformer associated with the ESF bus is out of service. With this temporary substitution, the two qualified offsite circuits between the offsite transmission network and the onsite Class 1E Distribution System that consists of three separate and independent divisions (Divisions I, II, and III) each backed by its own dedicated and independent DG, also ensure availability of the required power to shutdown the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are the normal and alternate preferred power circuits that are described in DCD Tier 2, Chapter 8 and are part of the licensing basis for the unit. In addition, the temporary substitution of the CTG is described in DCD Tier 2, Chapter 8 and is part of the licensing basis for the unit.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads within the assumed load sequence intervals during an accident, while connected to the ESF buses. The normal preferred circuit consists of the switching station breaker to the main transformer, the generator breaker, the disconnect links to the unit auxiliary transformers, and the circuit path from the offsite transmission network to all of the 6.9 kV ESF buses including feeder breakers at the 6.9 kV ESF buses. The alternate preferred circuit consists of the switching station breaker to the reserve auxiliary transformer and the circuit path from the offsite transmission network to all of the 6.9 kV ESF buses including feeder breakers at the 6.9 kV ESF buses.

(continued)

LCO
(continued)

Each DG must be capable of starting, accelerating to required speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 20 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot, DG in standby with engine at ambient conditions, and DG operating in parallel test mode.

The CTG, when used as a temporary substitute for the second offsite source or for an inoperable DG to any one ESF bus, must be capable of starting, accelerating to required speed and voltage, and of being manually configured to provide power to the ESF bus. This sequence must be accomplished within 2 minutes. The CTG must also be capable of accepting required loads, must be capable of maintaining rated frequency and voltage, and accepting required loads when connected to the ESF bus.

Proper sequencing of loads is a required function for both DG and offsite circuit OPERABILITY.

The AC sources are separate and independent. For the DG AC sources, the separation and independence are complete. For the offsite AC sources (including the CTG as an offsite source), the separation and independence are to the extent practicable. For the offsite (including the CTG) to DG AC sources, the separation and independence are to the extent practicable.

Offsite circuit OPERABILITY includes the normal offsite source supplying two of three AC divisions and the alternate offsite source supplying the third AC division. Other configurations make an offsite circuit inoperable.

The AC sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

(continued)

BASES

LCO (continued)

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

AC power requirements for MODES 4 and 5 are covered in LCO 3.8.2, "AC Sources — Refueling", and LCO 3.8.11, "AC Sources-Shutdown(Low Water Level)."

ACTIONS

A.1, A.2, A.3, and A.4

If Condition A is entered, Required Action A.4 allows 30 days to restore the inoperable offsite power source to one ESF bus to OPERABLE status provided:

a. The ESF bus with its associated unit auxiliary transformer inoperable is verified to be energized from the offsite transmission network through the reserve auxiliary transformer initially within 72 hours, and once per 8 hours thereafter,

b. The CTG is verified functional through testing within 72 hours and once per 7 days thereafter,

c. The CTG is verified to be aligned with the ESF bus that has its associated unit auxiliary transformer inoperable within 72 hours, and once per 8 hours thereafter.

The 30 day Completion Time is reasonable because it accounts for the reliability and convenience of the CTG. Since the CTG can be aligned as a temporary backup offsite source, there are sufficient offsite sources available if Required Actions A.2 and A.3 are completed. The LCO is satisfied at this point. However, given the primary function of the CTG as the alternate AC power source during the station blackout event and a standby non-safety related power source located onsite to energize non-safety related plant investment protection loads, the Completion Time has been limited to 30 days.

(continued)

ACTIONS

A.1, A.2, A.3, and A.4 (continued)

If the CTG cannot be made available to function as a temporary backup offsite circuit within 72 hours, the configuration of the AC sources is described in Regulatory Guide 1.93 (Ref. 6), which states that operation in the applicable modes may continue as described by Condition A for a period that should not exceed 72 hours. Therefore, if Required Actions A.2 and A.3 cannot be completed within 72 hours of entering Condition A, then Required Actions G.1 and G.2 must be followed. Upon restoring the offsite circuit to OPERABLE status, the LCO is met, Conditions A and G are exited, and operation may continue.

Should the CTG no longer be functional or capable of being aligned to the ESF bus subsequent to the 72-hour period following initial entry into Condition A, Condition G again applies and Required Actions G.1 and G.2 must be followed. Anytime the 8-hours Completion Time of Required Action A.3 is not met during this extension period, Condition G must be entered. Condition G can then only be exited by restoring the offsite circuit to OPERABLE status.

B.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in the Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition D, for two offsite circuits inoperable, is entered.

B.2

Required Action B.2, which only applies if the division cannot be powered from an offsite source, is intended to provide assurance that an event with a coincident single failure of the associated DG does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions. Redundant required features failures consist of inoperable

(continued)

ACTIONS (continued)

B.2 (continued)

features associated with a division redundant to the division that has no offsite power.

The Completion Time for Required Action B.2 is intended to allow time for the operator to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. The division has no offsite power supplying its loads; and

b. A required feature on the other division is inoperable.

If, at any time during the existence of this Condition (one offsite circuit inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one division of the onsite Class 1E Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other division that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before the unit is subjected to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.3, B.4, and B.5

If Condition B is entered, Required Action B.5 allows 14 days to restore the inoperable offsite circuit to OPERABLE status, provided the combustion turbine generator (CTG) is verified functional through testing within 72 hours and its capability of being aligned to any of the three ESF buses is verified, initially within 72 hours, and once per 8 hours thereafter. This 14-day Completion Time is reasonable because it accounts for the reliability and convenience of the CTG. Since the CTG can be aligned as a temporary backup offsite source, there are sufficient offsite sources available if Required Actions B.3 and B.4 are completed. The LCO is not completely satisfied at this point, but the AC electrical power system is verified to be sufficiently reliable to allow for the 14-day Completion Time of Required Action A.5. The 14-day Completion Time is also reasonable because the capabilities of the remaining AC sources are adequate for this time period, and because of the low probability of a DBA occurring during this time period. See the discussion for Required Action C.6 for additional justification of this Completion Time.

If the CTG cannot be made available to function as a temporary backup offsite circuit within 72 hours, the configuration of the AC sources is as described in Regulatory Guide 1.93 (Ref. 6), which states that operation in the applicable modes may continue as described by Condition B for a period that should not exceed 72 hours. Therefore, if Required Actions B.3 and B.4 cannot be completed within 72 hours of entering Condition B, then Required Actions G.1 and G.2 must be followed. Upon restoring the offsite circuit to OPERABLE status, the LCO is met, Conditions B and G are exited, and operation may continue.

Should the CTG no longer be functional or capable of being aligned to a 6.9 kV AC ESF bus subsequent to the 72-hour period following initial entry into Condition B, Condition G again applies and Required Actions G.1 and G.2 must be followed. Anytime the 8-hour Completion Time of Required Action B.4 is not met during this extension period, Condition G must be entered. Condition G can then only be exited by restoring the offsite circuit to OPERABLE status.

(continued)

ACTIONS (continued)

B.3, B.4, and B.5

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

The 14-day Completion Time of Required Action B.5 assumes sufficient offsite power remains to power the minimum loads needed to respond to analyzed events. It also assumes that the CTG may be utilized if needed. Should two divisions be affected, the 1-day Completion Time of Required Action B.5 is conservative with respect to the Regulatory Guide assumptions supporting a 1 day Completion Time for both offsite circuits inoperable (addressed by Condition D). With only one offsite circuit, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In Condition B, however, the remaining OPERABLE offsite circuit, DGs, and the CTG are adequate to supply electrical power to the onsite Class 1E distribution system.

The 14-day Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The third Completion Time for Required Action B.5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, a DG is inoperable and that DG is subsequently returned to OPERABLE status, the LCO may already have been not met for up to 14 days. This situation could lead to a total of 28 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored to OPERABLE status, and an additional 14 days (for a total of 42 days) allowed prior to complete restoration of the LCO. The 15-day Completion Time provides a limit on the time allowed in a specified Condition after discovery of failure to meet the LCO.

(continued)

ACTIONS (continued)

B.3, B.4, and B.5 (continued)

This limit is considered reasonable for situations in which Conditions B and C are entered concurrently. The "AND" connector between the 14-day and 15-day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition B was entered.

C.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

C.2

Required Action C.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

ACTIONS (continued)

C.2 (continued)

In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature on the other division is inoperable.

If, at any time during the existence of this Condition (one DG inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering one required DG inoperable coincident with one or more required support or supported features, or both, that are associated with the OPERABLE DGs, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

C.3.1 and C.3.2

The Note in Condition C requires that Required Action C.3.1 or C.3.2 must be completed if Condition C is entered. The intent is that all DG inoperabilities must be investigated for common cause failures regardless of how long the DG inoperability persists.

Required Action C.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be

(continued)

ACTIONS (continued)

C.3.1 and C.3.2 (continued)

determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition F of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action C.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DGs.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

C.4, C.5, and C.6

If Condition C is entered, Required Action C.6 allows 14 days to restore the inoperable DG to OPERABLE status provided the CTG is verified functional through testing within 72 hours, and its circuit breakers are verified to be aligned to the affected ESF bus initially within 72 hours and once per 8 hours thereafter. This 14-day Completion Time is reasonable because of the reliability and convenience of the CTG, the low probability of a DBA occurring during this time period.

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

If the CTG can not be made available to function as a temporary onsite divisional backup to preferred offsite power, the configuration of the AC sources is as described in Regulatory Guide 1.93 (Ref. 6), which states that operation may continue as described in Condition C for a period that should not exceed 72 hours. Therefore, if Required Actions C.4 and C.5 cannot be completed within 72 hours of entering Condition B, then Required Actions G.1 and G.2 must be followed. Upon restoring the inoperable DG to

(continued)

ACTIONS (continued)

C.4, C.5, and C.6 (continued)

OPERABLE status, the LCO is met, Conditions C and G are exited, and operation may continue.

In Condition C, if the CTG is not functional, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system for 72 hours. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

Should the CTG no longer be functional or capable of being aligned to an ESF bus subsequent to the 72-hour period following initial entry into Condition C, Condition G again applies and Required Actions G.1 and G.2 must be followed. Anytime the 8-hour Completion Time of Required Action C.5 is not met during this extension period, Condition G must be entered. Condition G can then only be exited by restoring the DG to OPERABLE status.

The once-per-8-hour Completion Time of Required Action C.5 is necessary to keep a check on the proper alignment of the CTG's circuit breakers and thus the capability of supplying power from the CTG to the ESF bus associated with the inoperable DG.

The second Completion Time for Required Action C.6 establishes a 15-day limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total of 14 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 7 days (for a total of 21 days) would be allowed prior to complete restoration of the LCO.

The 15-day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions B and C are entered

(continued)

ACTIONS (continued)

D.1 and D.2

concurrently. The "AND" connector between the 14-day and 15-day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

As in Required Action C.2, the 15-day Completion Time of Required Action C.5 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered.

Required Action D.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action D.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with only one division without offsite power (Required Action B.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that all three safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e., single division systems are not included in the list). Redundant required features failures consist of any of these features that are inoperable, because any inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action D.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

(continued)

ACTIONS (continued)

D.1 and D.2 (continued)

If, at any time during the existence of this Condition (two offsite circuits inoperable), a required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this degradation level:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

(continued)

ACTIONS (continued)

D.1 and D.2 (continued)

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition B.

The status of the CTG was not a consideration in establishing the appropriate Completion Times for Required Actions D.1 AND D.2.

E.1 and E.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition E are modified by a Note to indicate that when Condition E is entered with no required AC source to one division, Actions for LCO 3.8.9, "Distribution Systems — Operating," must be immediately entered. This allows Condition E to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized division.

In Condition E, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition D (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure.

If Condition E is entered, Required Action E.3.1 or E.3.2 allows 72 hours to restore either the inoperable offsite circuit or the DG to OPERABLE status provided the CTG is verified functional through testing within 72 hours, and its circuit breakers are aligned to the affected ESF bus associated with an inoperable DG initially within 12 hours and once per 8 hours thereafter. This 72 hour Completion

(continued)

ACTIONS (continued)

E.1 and E.2 (continued)

Time is reasonable because of the reliability and convenience of the CTG, the capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this time period.

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

If the CTG can not be made available to function as a temporary onsite divisional backup power source, the configuration of the AC sources is as described in Regulatory Guide 1.93 (Ref. 6), which states that operation may continue as described in Condition E for a period that should not exceed 12 hours. Therefore, if Required Actions E.1 and E.2 cannot be completed within 12 hours of entering Condition E, then Required Actions G.1 and G.2 must be followed. Upon restoring the inoperable offsite circuit or DG to OPERABLE status, the LCO is met, Conditions E and G are exited, and operation may continue.

Should the CTG no longer be functional or not aligned to an ESF bus subsequent to the 12-hour period following initial entry into Condition C, Condition G again applies and Required Actions G.1 and G.2 must be followed. Anytime the 8-hour Completion Time of Required Action E.2 is not met during this extension period, Condition G must be entered. Condition G can then only be exited by restoring the offsite circuit or the DG to OPERABLE status.

The once-per-8-hour Completion Time of Required Action E.2 is necessary to keep a check on the proper alignment of the CTG's circuit breakers and thus the capability of supplying power from the CTG to the 6.9 kV essential AC bus associated with the inoperable DG.

F.1

If Condition F is entered, Required Action F.3 allows 72 hours to restore one DG to OPERABLE status provided the CTG is verified functional through testing within 2 hours, and

(continued)

ACTIONS (continued)

F.1 (continued)

its circuit breakers are aligned to one affected 6.9 kV ESF bus associated with an inoperable DG and capable of being aligned to the other 6.9 kV ESF bus associated with an inoperable DG, initially within 2 hours and verified once per 8 hours thereafter. This 2 hour Completion Time is reasonable because of the reliability and convenience of the CTG, the capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this time period.

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

If the CTG can not be made available to function as a temporary onsite divisional backup power source, the configuration of the AC sources is as described in Regulatory Guide 1.93 (Ref. 6), which states that operation may continue as described in Condition F for a period that should not exceed 2 hours. Therefore, if Required Actions F.1 and F.2 cannot be completed within 2 hours of entering Condition F, then Required Actions G.1 and G.2 must be followed. Upon restoring the inoperable one DG to OPERABLE status, the LCO is met, Conditions F and G are exited, and operation may continue.

Should the CTG no longer be functional or not aligned to one ESF bus or not capable of being aligned to the other ESF bus subsequent to the 2-hour period following initial entry into Condition F, Condition G again applies and Required Actions G.1 and G.2 must be followed. Anytime the 8-hour Completion Time of Required Action F.2 is not met during this extension period, Condition G must be entered. Condition G can then only be exited by restoring the DG to OPERABLE status.

The once-per-8-hour Completion Time of Required Action F.2 is necessary to keep a check on the proper alignment of the CTG's circuit breakers and thus the capability of supplying power from the CTG to the ESF buses associated with the inoperable DGs.

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

Condition H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 9).

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 6210 V is 90% of the nominal 6.9 kV output voltage. This value, which is specified in ANSI C84.1 (Ref. 10), allows for voltage drop to the terminals of 6600 V motors whose minimum operating voltage is specified as 90%, or 5980 V. It also allows for voltage drops to motors and other equipment down through the 200 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified

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SURVEILLANCE REQUIREMENTS (continued)

maximum steady state output voltage of 7590 V is equal to the maximum operating voltage specified for 6600 V motors plus voltage drop from the source to the loads. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 6600 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by Notes (Note 1 for SR 3.8.1.7 and Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2 and SR 3.8.1.7 (continued)

In order to reduce stress and wear on diesel engines, some manufacturers recommend that the starting speed of DGs be limited, that warmup be limited to this lower speed, and that DGs be gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 3, which is only applicable when such procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 20 seconds. The 20 second start requirement supports the requirements set forth in DCD Tier 2, Chapter 8 (Ref. 2). The 20 second start requirement may not be applicable to SR 3.8.1.2 (see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 20 second start requirement of SR 3.8.1.7 applies. Since SR 3.8.1.7 does require a 20 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2.

The normal 31 day Frequency for SR 3.8.1.2 (see Table 3.8.1-1, "Diesel Generator Test Schedule") is consistent with Regulatory Guide 1.9 (Ref. 9). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance demonstrates that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing shall be performed using a power factor less than or equal to 0.9. This power factor is chosen to be representative of the actual design basis inductive

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3 (continued)

loading that the DG would experience. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent tear down inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The normal 31 day Frequency for this Surveillance (see Table 3.8.1-1) is consistent with Regulatory Guide 1.9 (Ref. 9).

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test.

Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Similarly, momentary power factor transients above the limit do not invalidate the test.

Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in liters, and is selected to ensure adequate fuel oil for a minimum of 4 hours of DG operation at maximum LOCA load demand.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is most effective means in controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 9). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. It is required to support the continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE. This test may be performed by a simulated or actual automatic initiation signal.

The Frequency for this SR is variable, depending on individual system design, with up to a 92 day interval. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 11); however, the design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day tanks during or following DG

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

testing. In such a case, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent part of DG OPERABILITY, the Frequency of this SR should be modified to reflect individual designs.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Manual transfer of each 6.9 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The manual transfer should be performed using the DG to carry the loads (i.e., not a dead bus transfer). The 18 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge entwined steady state operation and, as a result, plant safety systems. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9 (continued)

the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. The load referenced for Division II and Division III DGs is the 1400 kW high pressure core flooder (HPCF) pump; for the Division I DG, the 540 kW residual heat removal (RHR) pump. The Reactor Building Cooling Water (RCW) system load was not used. Even though the load to DG I is 640 kW, that value consists of 2 RCW pumps of 320 kW each. As required by IEEE-308 (Ref. 12), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower.

The time, voltage, and frequency tolerances specified in this SR are derived from Regulatory Guide 1.9 (Ref. 3) recommendations for response during load sequence intervals. The 3 seconds specified is equal to 60% of the 5 second load sequence interval associated with sequencing of this largest load. The voltage and frequency specified are consistent with the design range of the equipment powered by the DG. SR 3.8.1.9.a corresponds to the maximum frequency excursion, while SR 3.8.1.9.b and SR 3.8.1.9.c are steady state voltage and frequency values to which the system must recover following load rejection. The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9 (continued)

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

a. Performance of the SR will not render any safety system or component inoperable;

b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and

c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

SR 3.8.1.10

This Surveillance demonstrates the DG capability to reject a full load without overspeed tripping or exceeding the predetermined voltage limits. The DG full load rejection may occur because of a system fault or inadvertent breaker tripping. This Surveillance ensures proper engine generator load response under the simulated test conditions. This test simulates the loss of the total connected load that the DG experiences following a full load rejection and verifies that the DG does not trip upon loss of the load. These acceptance criteria provide DG damage protection. While the DG is not expected to experience this transient during an event, and continues to be available, this response ensures that the DG is not degraded for future application, including reconnection to the bus if the trip initiator can be corrected or isolated.

In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10 (continued)

the actual design basis inductive loading that the DG would experience.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbation to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

a. Performance of the SR will not render any safety system or component inoperable;

b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and

c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11 (continued)

DG to automatically achieve the required voltage and frequency within the specified time.

The DG auto-start time of 20 seconds is derived from requirements stated in DCD Tier 2, Chapter 8 (Ref. 2). The frequency should be restored to within 2% of nominal following a load sequence step. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.4, takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11 (continued)

electrical distribution system, and challenge plant safety systems.

Note 3 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (20 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d and SR 3.8.1.12.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ECCS signal without loss of offsite power.

The requirement to verify the connection and power supply of permanent and autoconnected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12 (continued)

18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. Note 3 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.13

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ECCS initiation test signal and critical protective functions (engine overspeed and generator differential current) trip the DG to avert substantial damage to the DG unit. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR is modified by two Notes. The reason for Note 1 is that performing the Surveillance removes a required DG from

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13 (continued)

service. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

[Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

a. Performance of the SR will not render any safety system or component inoperable;

b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and

c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.]

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9, requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours – 22 hours of which is at a load equivalent to 90 to 100% of the continuous rating of the DG, and 2 hours of which is at a load equivalent to 105 to 110% of the continuous rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelube and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG could experience.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14 (continued)

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.9; takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent tear down inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. Note 3 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 20 seconds. The 20-second time is derived from the requirements set forth in DCD Tier 2, Chapter 8 (Ref. 2).

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.10.

This SR has been modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the DG. Routine overloads may result in more frequent tear down inspections in accordance with vendor recommendations in order to maintain DG

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.15 (continued)

OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.11, this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and that the DG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in ready-to-load status when the DG is at required speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the load timers are reset.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.11, and takes into consideration plant conditions required to perform the Surveillance.

This SR is modified by two Notes. The reason for Note 1 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions is not compromised as the result of testing. Interlocks to the LOCA sensing circuits cause the DG to automatically reset to ready-to-load operation of an ECCS initiation signal is received during operation in the test mode. Ready-to-load operation is defined as the DG running at required speed and voltage with the DG output breaker open. These provisions

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17 (continued)

for automatic switchover are required by IEEE-308 (Ref. 12), paragraph 6.2.6(2).

The requirement to automatically energize the emergency loads with offsite power is essentially identical to that of SR 3.8.1.12. The intent in the requirement associated with SR 3.8.1.17.b is to show that the emergency loading is not affected by the DG operation in test mode. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the emergency loads to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.13; takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR has been modified by two Notes. The reason for Note 1 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.18

As required by Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.6, each DG is required to demonstrate proper operation for the DBA loading sequence to ensure that voltage and frequency are maintained within the required limits. Under accident conditions, prior to connecting the DGs to their respective bus, all loads are shed except load center feeders and those motor control centers that power Class 1E loads (referred to as "permanently connected" loads). Upon reaching 90% required voltage and frequency, the DGs are then connected to their respective bus. Load shedding and buses-ready-to-load signals are generated by the control systems for the electrical power distribution system. Individual timers for each major load are reset and

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18 (continued)

started by their electrical power distribution systems signals (Ref. 2). The 10% load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Regulatory Guide 1.9 (Ref. 3) provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.6; takes into consideration plant conditions required to perform the Surveillance; and is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is that performing the Surveillance during these MODES would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:

a. Performance of the SR will not render any safety system or component inoperable;

b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and

c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation, as discussed in the Bases for SR 3.8.1.11, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 18 months takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 18 months.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. Note 3 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.20

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), paragraph 2.2.14, and Regulatory Guide 1.137 (Ref. 9), paragraph C.2.f.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20 (continued)

This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

Diesel Generator Test Schedule

The DG test schedule (Table 3.8.1-1) implements the recommendations of Revision 3 to Regulatory Guide 1.9 (Ref. 3). The purpose of this test schedule is to provide timely test data to establish a confidence level associated with the goal to maintain DG reliability at > 0.95 per test.

According to Regulatory Guide 1.9 (Ref. 3), Revision 3, each DG unit should be tested at least once every 31 days. Whenever a DG has experienced 4 or more valid failures in the last 25 valid tests, the maximum time between tests is reduced to 7 days. Four failures in 25 valid tests is a failure rate of 0.16, or the threshold of acceptable DG performance, and hence may be an early indication of the degradation of DG reliability. When considered in the light of a long history of tests, however, 4 failures in the last 25 valid tests may only be a statistically probable distribution of random events. Increasing the test Frequency allows a more timely accumulation of additional test data upon which to base judgment of the reliability of the DG. The increased test Frequency must be maintained until seven consecutive failure free tests have been performed.

The Frequency for accelerated testing is 7 days, but no less than 24 hours. Therefore, the interval between tests should be no less than 24 hours, and no more than 7 days. A successful test at an interval of less than 24 hours should be considered an invalid test and not count towards the seven consecutive failure free starts. A test interval in excess of 7 days constitutes a failure to meet SRs.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. DCD Tier 2, Chapter 8.
3. Regulatory Guide 1.9, Revision 3.
4. DCD Tier 2, Chapter 6.
5. DCD Tier 2, Chapter 15.
6. Regulatory Guide 1.93.
7. Generic Letter 84-15, July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.137.
10. ANSI C84.1, 1982.
11. ASME, Boiler and Pressure Vessel Code, Section XI.
12. IEEE Standard 308.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources – Refueling

BASES

BACKGROUND	A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources – Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODE 5 with water level in the refueling cavity ≥ 7.0 meters above the reactor pressure vessel flange ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent drain down of the vessel, loss of decay heat removal, or a fuel handling accident.

In general, when the unit is shut down the Technical Specifications (TS) requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODE 1, 2, and 3 LCO requirements are acceptable during shutdown MODES based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (diesel generator (DG)) power.

The AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

One offsite circuit capable of supplying onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution

(continued)

BASES

LCO
(continued)

Systems — Shutdown," ensures that all required loads on Division I, Division II, and Division III are powered from offsite power. One or more OPERABLE DG(s) available in standby to supply electrical power to required OPERABLE features via the associated Engineered Safety Feature (ESF) buses that are required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DG(s) ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel drain down, and loss of decay heat removal).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage while connected to ESF bus(es), and of accepting required loads during an accident. The qualified offsite circuit is either the normal or alternate preferred power circuits to AC Electric Power Distribution System that are described in DCD Tier 2, Chapter 8 and are part of the licensing basis for the plant. The normal preferred circuit consists of the switching stations breaker to the main transformers, the generator breaker, the disconnect links to the unit auxiliary transformers, and the circuit path from the offsite transmission network to all of the 6.9 kV ESF buses required by LCO 3.8.10 including feeder breakers at the 6.9 kV ESF buses. The alternate preferred circuit consists of the switching station breaker to the reserve transformer and the circuit path from the offsite transmission network to all of the 6.9 kV ESF buses required by LCO 3.8.10 including feeder breakers at the 6.9 kV ESF buses.

Each required DG must be capable of starting, accelerating to required speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 20 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine

(continued)

BASES

LCO (continued)

hot, DG in standby parallel test mode.

Proper sequencing of loads is a required function for both DG and offsite circuit OPERABILITY.

During a shutdown condition, it is acceptable for a single offsite power circuit to supply all required divisions of electrical power.

As described in Applicable Safety Analyses, in the event of an accident during shutdown, the TS are designed to maintain the plant in a condition such that, even with a single failure, the plant will not be in immediate difficulty.

APPLICABILITY

The AC sources required to be OPERABLE in MODE 5 with water level in the refueling cavity ≥ 7.0 meters above the reactor pressure vessel flange during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems are available to provide adequate coolant inventory makeup to maintain irradiated fuel in the core covered with coolant in case of an inadvertent drain down of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

e. Systems are available to remove decay heat from the irradiated fuel in the core.

(continued)

BASES

APPLICABILITY (continued)

The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1; and for MODE 4, and MODE 5 with the water level in the refueling cavity ≤ 7.0 meters above the reactor pressure vessel flange, in LCO 3.8.11.

ACTIONS

A.1.1 and A.1.2

An offsite circuit is considered inoperable if it is not available to one required ESF bus. If two or more ESF buses are required per LCO 3.8.10, division(s) with offsite power still available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel.

However, should any required features still have no power available from an OPERABLE offsite circuit, Required Action A.1.2 requires declaring such features inoperable so that appropriate restrictions can be implemented in accordance with the affected required feature(s) LCOs' ACTIONS.

A.2.1, A.2.2, A.2.3, and A.2.4

With the offsite circuit not available to some or all required ESF buses, Required Action A.1.2 allows the choice of declaring affected required features inoperable. Since this option may involve undesirable administrative efforts, Required Actions A.2.1, A.2.2, A.2.3, and A.2.4 alternatively allow performance of other sufficiently conservative actions, thereby avoiding any undesirable administrative efforts. With the required offsite circuit inoperable (unable to supply all required ESF buses), the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could potentially result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition.

(continued)

ACTIONS (continued)

A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

These actions minimize the probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required offsite circuit to OPERABLE status and to continue this action until restoration is accomplished in order to provide the necessary (and preferred) AC power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, the plant is still without sufficient AC power sources to operate in a safe manner. Therefore, action must be initiated to restore the minimum required AC power sources and continue until the LCO requirements are restored.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to one ESF bus, ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.10 provides the appropriate restrictions for the situation involving a de-energized division.

B.1, B.2, B.3, and B.4

When one or more of the required DGs is inoperable, the required diversity of AC power sources to plant safety systems is not available. Required Actions B.1, B.2, and B.3, therefore, suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and

(continued)

BASES

ACTIONS (continued)

B.1, B.2, B.3, and B.4 (continued)

activities that could potentially result in inadvertent draining of the reactor vessel.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition.

These actions minimize the probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required DG(s) OPERABLE status and to continue this action until restoration is accomplished in order to provide the required diversity of AC power sources to plant safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3. SR 3.8.1.8 is not required to be met because only one offsite power circuit is required to be OPERABLE. SR 3.8.1.14 is not required to be met because the required OPERABLE DG(s) is(are) not required to undergo periods of being synchronized to the offsite circuit. SR 3.8.1.20 is excepted because starting independence is not required with the DG that is not required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by two notes. The reason for Note 1 is to preclude requiring the OPERABLE DG from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG is required to be OPERABLE.

The reason for Note 2 is to require tests only on those DGs whose associated ECCS loads are required to be OPERABLE.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air Subsystem

BASES

BACKGROUND

Each diesel generator (DG) is provided with a storage tank having a fuel oil capacity sufficient to operate that DG for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand (Ref. 1). The maximum load demand is calculated using the assumption that at least two DGs are available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

Fuel oil is transferred from each storage tank to its respective day tank by two transfer pumps associated with each storage tank. Redundancy of pumps and piping precludes the failure of one pump, or the rupture of any pipe, valve, or tank to result in the loss of more than one DG. All outside tanks, pumps, and piping are located underground. The fuel oil level in the storage tank is indicated in the control room.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3). The fuel oil properties governed by these SRs are the water and sediment content, the kinematic viscosity, specific gravity (or API gravity), and impurity level.

The DG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated DG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump contains an inventory capable of supporting a minimum of 7 days of operation. The onsite storage in addition to the engine oil sump is sufficient to ensure 7 days of continuous operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each DG has an air start system with adequate capacity for five successive start attempts on the DG without recharging the air start receiver(s).

(continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in DCD Tier 2, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, reactor coolant system, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil, lube oil, and starting air subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of the NRC Policy Statement.

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources – Operating," and LCO 3.8.2, "AC Sources – Refueling."

The starting air system is required to have a minimum capacity for five successive DG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources, LCO 3.8.1 and LCO 3.8.2, are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, lube oil, and starting air subsystem support LCO 3.8.1

(continued)

BASES (continued)

APPLICABILITY (continued)

and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events such as:

a. Full load operation required after an inadvertent start while at minimum required level; or

b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of the fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

With lube oil inventory < [ ] liters, sufficient lube oil to support 7 days of continuous DG operation at full load conditions may not be available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the DG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

(continued)

ACTIONS (continued)

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulate does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the DG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or a combination of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is high likelihood that the DG would still be capable of performing its intended function.

E.1

With starting air receiver pressure < [ ] MPaG, sufficient capacity for five successive DG start attempts does not exist. However, as long as the receiver pressure is > [ ] MPaG, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the

(continued)

ACTIONS

E.1 (continued)

required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

F.1

With a Required Action and associated Completion Time not met, or the stored diesel fuel oil or lube oil not within limits for reasons other than addressed by Conditions A through E, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tanks to support each DG's operation for 7 days at full load. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.2

This Surveillance ensures that sufficient lube oil inventory is available to support at least 7 days of full load operation for each DG. The [ ] liter requirement is based on the DG manufacturer's consumption values for the run time of the DG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

location to the DG when the DG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level.

A 31 day Frequency is adequate to ensure that a sufficient lube oil supply is onsite, since DG starts and run times are closely monitored by the plant staff.

SR 3.8.3.3

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion and operation. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tank(s), but in no case is the time between receipt of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-[ ] (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D975-[ ] (Ref. 6) that the sample has an absolute specific gravity at [15.6/15.6°C of ≥ 0.83° and ≤ 0.89° (or an API gravity at 15.6°C of ≥ 27° and ≤ 39°), a kinematic viscosity at 40°C of ≥ 1.9 mm^2/s and ≤ 4.1 mm^2/s, and a flash point of ≥ 51.7°C]; and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-[ ] (Ref. 6).

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO since the fuel oil is not added to the storage tanks.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-[ ] (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-[ ] (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-[ ] (Ref. 6) or ASTM D2622-[ ] (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

Fuel oil degradation during long term storage shows up as an increase in particulate, mostly due to oxidation. The presence of particulate does not mean that the fuel oil will not burn properly in a diesel engine. However, the particulate can cause fouling of filters and fuel oil injection equipment, which can cause engine failure.

Particulate concentrations should be determined in accordance with ASTM D2276-[ ], Method A (Ref. 6). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 milligrams/liter. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

The Frequency of this Surveillance takes into consideration fuel oil degradation trends indicating that particulate concentration is unlikely to change between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed. The pressure specified in this SR is intended to reflect the lowest value at which the five starts can be accomplished.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.3.4 (continued)

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of the Surveillance.

SR 3.8.3.6

Draining of the fuel oil stored in the supply tanks, removal of accumulated sediment, and tank cleaning are required at 10 year intervals by Regulatory Guide 1.137 (Ref. 2), paragraph 2.f. This SR is typically performed in conjunction with the ASME Boiler and Pressure Vessel Code, Section XI (Ref. 7), examinations of the tanks. To preclude the introduction of surfactants in the fuel oil system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents. This SR is for preventive maintenance. The

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.6 (continued)

presence of sediment does not necessarily represent a failure of this SR provided that accumulated sediment is removed during performance of the Surveillance.

REFERENCES

1. DCD Tier 2, Section 9.5.4.
2. Regulatory Guide 1.137.
3. ANSI N195, Appendix B, 1976.
4. DCD Tier 2, Chapter 6.
5. DCD Tier 2, Chapter 15.
6. ASTM Standards: D4057-[ ]; D975-[ ]; D4176-[ ]; D975-[ ]; D1552-[ ]; D2622-[ ]; D2276-[ ].
7. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources – Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC power system with control power. It also provides both motive and control power to selected safety related equipment. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also conforms to the requirements of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of four independent Class 1E DC electrical power subsystems, Divisions I, II, III, and IV. Each subsystem consists of a battery, associated battery charger, and all the associated control equipment and interconnecting cabling. In addition there are two standby backup chargers. One is shared by Divisions I and II, and the other is shared by Divisions III and IV. However, no credit is taken for the backup battery chargers which are not required to be OPERABLE or surveillance tested.

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of AC power to the battery charger, the DC loads are automatically powered from the batteries.

Division I, II, and III DC electrical power subsystems provides the control power for its associated Class 1E AC power system. Each of these three DC electrical power subsystems provides both motive and control power, as necessary, to associated safety related components (Division IV supplies neither motive nor control power). All four DC electrical power subsystems provide DC electrical power to essential instrumentation and logic within their respective divisions as well as to the inverters, which in turn power the AC vital buses. All four subsystems also provide motive and control power for DC emergency lighting systems.

(continued)

BASES

BACKGROUND (continued)

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution Systems-Operating," and LCO 3.8.10, "Distribution Systems – Shutdown."

Each battery for Division I, II, III, and IV has adequate storage capacity to carry the required load continuously for at least 2 hours. The battery for Division I, which controls the RCIC system, also has adequate storage capacity for approximately eight hours of operation during station blackout (Ref. 12).

Each DC subsystem battery is separately housed in a ventilated room apart from its charger and distribution centers. Each subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E DC subsystems such as batteries, battery chargers, or distribution panels.

The maximum equalizing charge for Class 1E batteries is 140 V. The DC system minimum discharge voltage at the end of the discharge period is 1.75 V per cell (105 V for the battery). The operating voltage range of the Class 1E DC subsystem loads is 100 to 140 V.

Each of the four battery chargers for Division I, II, III, and IV DC electrical power subsystems has ample power output capacity for the steady state operation of its Division's connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger has sufficient capacity to restore its battery bank from the design minimum charge to within 95% of its fully charged state within 12 hours while supplying the largest combined demand of the various continuous steady state loads (Ref. 4).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in DCD Tier 2, Chapter 6 (Ref. 5) and Chapter 15 (Ref. 6), assume that ESF systems are OPERABLE. The DC electrical power system provides DC electrical power for ESF systems, ESF support systems including the DGs and its support systems, and control and switching during all MODES of operation.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC power or of all onsite AC power; and

b. A worst case single failure.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

The four DC electrical power subsystems are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4). Each subsystem (or Division) consists of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling within the subsystem.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe unit operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 4 and 5 are addressed in the Bases for LCO 3.8.5, "DC Sources – Shutdown."

(continued)

ACTIONS

A.1, A.2, A.3, A.4, and A.5

Condition A represents one of the Division I, II, or III DC electrical power subsystems with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected division.

If Condition A is entered, Required Action A.5 allows 72 hours to restore the inoperable DC electrical power subsystem to OPERABLE status, provided the combustion turbine generator (CTG) is verified functional through testing within 12 hours and its capability of being aligned to the two unaffected ESF buses is verified, initially within 12 hours, and once per 8 hours thereafter. One AC electrical division and its loads are affected by loss of a DC electrical power subsystem because the DC electrical power subsystem provides control functions to its associated divisional DG, AC distribution circuit breakers, and other AC loads. Because a DG, its associated AC distribution system, and RCIC(Div. I) are impacted by the loss of the DC electrical power subsystem, the functional capability of the CTG is verified in this Condition to be capable of being aligned to the unaffected ESF buses to provide a backup power source during a loss of all AC power event. The Completion Time of 12 hours for Required Action A.3 is based on a consideration of the capability of the remaining operable DC electrical divisions and on the PRA sensitivity studies (Ref. 13).

If one of the required Division I, II, or III DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger, or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems, continued power operation should not exceed 72 hours. The 72 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown. The

(continued)

ACTIONS (continued)

A.1, A.2, A.3, A.4, and A.5 (continued)

72 hour limit is consistent with the allowed time for one DC distribution subsystem (either Division I, II, or III) being inoperable. The Completion Time of 72 hours for Required Action A.5 is based on a consideration of the capability of the remaining operable DC electrical divisions and on the PRA sensitivity studies (Ref. 13).

Completion of Required Action A.1 within 2 hours provides further assurance that operation in Condition A for 72 hours is acceptable by determining that no common cause failure exist among the OPERABLE DC electrical power subsystems. Because of its potential safety significance, only 2 hours are allowed to verify that no common cause failure exists.

Required Action A.2 is specified so that appropriate actions are implemented in accordance with the affected required features of the LCOs' ACTIONS.

B.1 and B.2

In Condition B, Division IV DC electrical power subsystem is inoperable. Required Actions B.1 allows 2 hours to declare affected required features inoperable so that appropriate actions are implemented in accordance with the affected required features of the LCOs' ACTIONS. Division IV is less critical than the other three DC electrical power subsystems because of its limited role in actuating safety related functions(i.e., Essential Multiplex System Div. IV, SSLC Div. IV sensor logic). Division IV does not feed or control any major mechanical components or systems. Therefore, its loss is not as critical as a loss of one of the other divisions, and the less restrictive ACTIONS of other LCOs are appropriate (i.e., LCO 3.3.1.1, LCO 3.3.3.1).

Completion of Required Action B.1 within 2 hours provides further assurance that operation in Condition B for the less restrictive ACTIONS of other LCOs is acceptable by determining that no common cause failure exists among the OPERABLE DC electrical power subsystems. Because of its potential safety significance, only 2 hours are allowed to verify that no common cause failure exists.

(continued)

C.1 and C.2

In Condition C, Division IV and one other DC electrical power subsystem are inoperable. Because this condition is more severe than that of Condition A or B, only 2 hours are allowed to restore one of the inoperable subsystems to OPERABLE status. This 2 hour Completion Time reflects a reasonable time to assess unit status as a function of the two inoperable DC electrical power subsystems and, if one of the DC electrical power subsystems is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

D.1 and D.2

If all inoperable DC electrical power subsystems cannot be restored to OPERABLE status within the associated Completion Times for Required Actions A.1, B.2, and C.1 or C.2, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is consistent with manufacturer's recommendations and IEEE-450 (Ref. 8).

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.1 (continued)

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each inter-cell, inter-rack, inter-tier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The limits established for this SR must be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer.

The Surveillance Frequency for these inspections, which can detect conditions that can cause power losses due to resistance heating, is 92 days. This Frequency is considered acceptable based on operating experience related to detecting corrosion trends.

SR 3.8.4.3

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The 12 month Frequency of these SRs is consistent with IEEE-450 (Ref. 8), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

SR 3.8.4.4 and SR 3.8.4.5

Visual inspection and resistance measurements of inter-cell, inter-rack, inter-tier, and terminal connections provides an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anti-corrosion material is used to ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection.

The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.4 and SR 3.8.4.5 (continued)

represent a failure of this SR, provided visible corrosion is removed during performance of this Surveillance.

The connection resistance limits for this SR must be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by battery sizing.

The 12 month Frequency of these SRs is consistent with IEEE-450 (Ref. 8), which recommends detailed visual inspection of cell condition and inspection of cell to cell and terminal connection resistance on a yearly basis.

SR 3.8.4.6

Battery charger capability requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensure that these requirements can be satisfied.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. The reason for Note 1 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Note 2 is added to this SR to acknowledge that credit may be taken for unplanned events that satisfy the Surveillance.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.7

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests not to exceed 18 months.

This SR is modified by three Notes. Note 1 allows the performance of a modified performance discharge test every 60 months in lieu of a service test.

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery's capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

The reason for Note 2 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Note 3 is added to this SR to

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.7 (continued)

acknowledge that credit may be taken for unplanned events that satisfy the Surveillance.

SR 3.8.4.8

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

The acceptance criteria for this Surveillance is consistent with IEEE-450 (Ref. 8) and IEEE-485 (Ref. 11). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

A battery modified performance discharge test is described in the bases for SR 3.8.4.7. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.8; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.8 while satisfying the requirements of SR 3.8.4.7 at the same time.

The Surveillance Frequency for this test is 60 months, or every 12 months if the battery shows degradation or has reached 85% of its expected life. Degradation is indicated, according to IEEE-450 (Ref. 8), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's rating. All these Frequencies are consistent with the recommendations in IEEE-450 (Ref. 8).

This SR is modified by two Notes. The reason for Note 1 is that performing the Surveillance would remove a required DC electrical power subsystem from service, perturb the electrical distribution system, and challenge safety systems. Note 2 is added to this SR to acknowledge that

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.8 (continued)

credit may be taken for unplanned events that satisfy the Surveillance.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE Standard 308, 1978.
4. DCD Tier 2, Section 8.3.2.
5. DCD Tier 2, Chapter 6.
6. DCD Tier 2, Chapter 15.
7. Regulatory Guide 1.93, December 1974.
8. IEEE Standard 450, 1987.
9. Regulatory Guide 1.32, February 1977.
10. Regulatory Guide 1.129, December 1974.
11. IEEE Standard 485, 1983.
12. DCD Tier 2, Section 19E.2.1.2.2.
13. Letter, Jack Fox to Chet Poslusny, "Submittal Supporting Accelerated ABWR Review Schedule-ABWR CDF Sensitivity to ESF Equipment Out of Service", Docket No. STN 52-001, July 27, 1993.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources – Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in DCD Tier 2, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides DC electrical power for ESF systems, ESF support systems including the DGs and its support systems, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5 ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES

LCO

The number of DC electrical power subsystems (each consisting of a battery, one battery charger, and the corresponding control equipment and interconnecting cabling within the division) required to be OPERABLE is the number necessary to support the electrical power subsystems required to be OPERABLE by LCO 3.8.10, "Distribution Systems – Operating." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel draindown).

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent drain down of the reactor vessel;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

Because more than one DC distribution subsystem is required to be OPERABLE according to LCO 3.8.10, the DC subsystems remaining OPERABLE with one or more DC power sources inoperable may be capable of supporting sufficient required

(continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features inoperable with associated DC power source(s) inoperable, appropriate restrictions are implemented in accordance with the affected system LCOs' ACTIONS. In many instances this option may involve undesirable administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and any activities that could result in inadvertent draining of the reactor vessel). Note: if the option of Required Action A.1 is chosen, it is understood that the ACTIONS also require immediately initiating action to restore the required DC electrical power subsystems to OPERABLE status and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems to OPERABLE status and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, the unit is still without sufficient DC power sources to operate in a safe manner. Therefore, action must be initiated to restore the minimum required DC power sources and continue until the LCO requirements are met.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	<u>SR 3.8.5.1</u> Since more than one DC electrical power subsystem is required to be OPERABLE, SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.8. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.
REFERENCES	1. DCD Tier 2, Chapter 6. 2. DCD Tier 2, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources - Operating," and LCO 3.8.5, "DC Sources - Shutdown."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in DCD Tier 2, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides DC electrical power for ESF systems, ESF support systems including the DGs and its support systems, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions, in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power; and

b. A worst case single failure.

Since battery cell parameters support the operation of the DC power sources, they satisfy Criterion 3 of the NRC Policy Statement.

LCO

Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Electrolyte limits are conservatively established, allowing continued DC electrical system function even with limits not met.

(continued)

BASES (continued)

APPLICABILITY

The battery cell parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, battery electrolyte is only required to be within limits when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

A.1, A.2, and A.3

With parameters of one or more cells in one or more batteries not within limits (i.e., Category A limits not met, Category B limits not met, or Category A and B limits not met) but within the limit (Category C limits are met) specified in Table 3.8.6-1, operation is permitted for a limited period since sufficient capacity exists to perform the intended function.

The pilot cell electrolyte level and float voltage are required to be verified to meet Category C limits within 1 hour (Required Action A.1). This check provides a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cell. One hour is considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that, during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the required verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable.

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. Taking into consideration that while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits,

(continued)

ACTIONS

A.1, A.2, and A.3 (continued)

this time is acceptable for operation prior to declaring the DC batteries inoperable.

B.1

When any battery parameter is outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells falling below 10°C, also are cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

The SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 3), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

SR 3.8.6.2

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 3). In addition, within 24 hours of a battery discharge < [ ] V or a battery overcharge > [ ] V, the battery must be demonstrated to meet Category B limits. This inspection is also consistent with IEEE-450 (Ref. 3), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery has occurred as a consequence of such discharge or overcharge.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is ≥ 10°C is consistent with a recommendation of IEEE-450 (Ref. 3), which states that the temperature of electrolyte in representative cells should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on parameters used for battery sizing.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on guidance in IEEE-450 (Ref. 3), with the extra 6 mm allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 3) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendation of IEEE-450 (Ref. 3), which states that prolonged operation of cells below 2.13 V can reduce the life expectancy of cells.

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SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category A limit specified for specific gravity for each pilot cell is ≥ [ ] (0.015 below the manufacturer's fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 3), the specific gravity readings are based on a temperature of 25°C.

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 1.67°C above 25°C, 1 point (0.001) is added to the reading; 1 point is subtracted for each 1.67°C below 25°C. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation. Level correction will be in accordance with manufacturer's recommendations. Footnote b in Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature.

Because of specific gravity gradients that are produced within cells during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge of the battery. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote c to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to [ ] days following a battery recharge.

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ [ ] (0.020 below the manufacturer's fully charged, nominal specific gravity) with the average of all connected cells > [ ] (0.010 below the manufacturer's fully charged, nominal specific gravity). These are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell do not

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

mask overall degradation of the battery. Footnote b to Table 3.8.6-1 requires correction of specific gravity for electrolyte temperature and level.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limit, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limit specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limit for float voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit for average specific gravity (≥ [ ]), is based on manufacturer's recommendations (0.020 below the manufacturer's recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery. The footnotes to Table 3.8.6-1 that apply to specific gravity are applicable to Category A, B, and C specific gravity.

REFERENCES

1. DCD Tier 2, Chapter 6.
2. DCD Tier 2, Chapter 15.
3. IEEE Standard 450, 1987.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters – Operating

BASES

BACKGROUND

The inverters are the preferred source of power to the four AC vital buses. The inverter for each division is normally supplied power from the divisional 480 V AC motor control center (MCC) via an AC to DC rectifier. Because there are only three divisions of 480 V AC divisional power, the Division IV inverter is powered by the Division II 480 V AC MCC via an AC to DC rectifier. Each of the four divisions has access to its own Class 1E 125 V battery that provides a backup source of 125 V DC power through a transfer switch. The transfer switch automatically switches power from the AC to DC rectified normal power supply to the 125 V DC backup power supply when AC power failure is sensed (Ref. 1). The inverter converts DC electrical power to AC electrical power. The transfer switch and inverter thus provide an uninterruptible AC power supply for Class 1E loads.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in DCD Tier 2, Chapter 6 (Ref. 2) and Chapter 15 (Ref. 3), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to Class 1E CVCF loads so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes

(continued)

APPLICABLE SAFETY ANALYSIS (continued)

maintaining electrical power sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC or all onsite AC electrical power; and

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of the NRC Policy Statement.

LCO

The inverters ensure the availability of AC electrical power for the Class 1E CVCF loads required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS, MSIV logic and controls, NMS, and PRM, is maintained. Each of the four inverters has a 125 V battery backup power source to ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 6.9 kV and 480 V safety buses are de-energized.

OPERABLE inverters require that the AC vital bus be powered by the inverter via an inverted DC voltage. This assumes correct DC voltages are applied from the AC to DC rectified and 125 V DC power supplies, a correct AC voltage is at the output, and these voltages are within the design voltage and frequency tolerances. If the vital AC bus is powered from the AC power supply through the 480 V/120 V bypass transformer, or power is available to the inverter from only its AC source, then the inverter is considered inoperable.

(continued)

BASES

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Inverter requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.8, "Inverters – Shutdown."

ACTIONS

A.1 and A.2

Even with a required inverter inoperable, the corresponding AC vital bus may not be inoperable. This would be the case if the AC vital bus is energized via its Class 1E 480 V/120 V bypass transformer. If the inoperability of an inverter were to make an AC vital bus inoperable, the condition present would be more severe and would need to refer to another LCO for appropriate action. Therefore, the Required Actions of Conditions A are modified by a Note stating that ACTIONS for LCO 3.8.9 must be entered immediately in the event an AC vital bus is de-energized; i.e., inoperable. This ensures the vital bus is returned to OPERABLE status within 72 hours (or appropriate other ACTIONS are followed if an inverter and AC vital bus are inoperable).

Required Action A.1 allows 7 days to fix the inoperable inverter and return it to service. The 7-day limit is based upon a consideration of the loads a particular inverter serves and the Completion Times allowed in supported system LCOs. When the AC vital bus is powered from the AC power supply through its 480 V/120 V bypass transformer, it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible, battery backed, inverter source to the AC vital buses is the preferred source for powering instrumentation devices. Action A.2 is specified so that appropriate restrictions are implemented in accordance with the affected required feature(s) of the LCOs' ACTIONS.

(continued)

ACTIONS (continued)

B.1 and B.2

Even with two inverters inoperable, the corresponding AC vital buses may not be inoperable. This would be the case if the AC vital buses are energized via their Class 1E 480 V/120 V bypass transformers. If the inoperability of an inverter were to make an AC vital bus inoperable, the condition present would be more severe and would need to refer to another LCO for appropriate action. Therefore, the Required Actions of Condition B are modified by a Note stating that ACTIONS for LCO 3.8.9 must be entered immediately in the event an AC vital bus is de-energized; i.e., inoperable. This ensures the vital bus is returned to OPERABLE status within 72 hours (or appropriate other ACTIONS are followed if the inverters and AC vital buses are inoperable).

In Condition B, the Division IV inverter and one other inverter are inoperable. Because this condition is more severe than that of Condition A, only 2 hours are allowed to restore one of the inoperable inverters to OPERABLE status. This 2 hour Completion Time reflects a reasonable time to assess unit status as a function of the two inoperable inverters and, if one of the inverters is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

C.1 and C.2

If the inoperable devices or components cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. DCD Tier 2, Chapter 8.
2. DCD Tier 2, Chapter 6.
3. DCD Tier 2, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters – Shutdown

BASES

BACKGROUND	A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient accident analyses in DCD Tier 2, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protection System (RPS) and Emergency Core Cooling Systems (ECCS) instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum inverters to each AC vital bus during MODES 4 and 5 ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability are available for monitoring and maintaining the unit status; and

c. Adequate power is available to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The inverters were previously identified as part of the Distribution System and, as such, satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The inverters ensure the availability of AC electrical power for the RPS and ECCS instrumentation and controls required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or postulated DBA.

Maintaining the required inverter(s) OPERABLE ensures the availability of sufficient inverter power sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel drain down). Each inverter has a 125 V battery backup power source to ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 6.9 kV safety buses are de-energized.

OPERABLE inverters require the AC vital bus be powered by the inverter through inverted DC voltage. This assumes correct DC voltages are applied from the AC to DC rectified and 125 V DC power supplies, a correct AC voltage is at the output, and these voltages are within the design voltage and frequency tolerances. If the vital AC bus is powered from the AC power supply through the 480 V/120 V bypass transformer or power is available to the inverter from only its AC source, then the inverter is considered inoperable.

APPLICABILITY

The inverters required to be OPERABLE in MODES 4 and 5 and also any time during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent drain down of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

(continued)

BASES (continued)

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If two divisions are required by LCO 3.8.10, "Distribution Systems – Shutdown," the remaining OPERABLE inverters may be capable of supporting sufficient required feature(s) to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By the allowance of the option to declare required feature(s) inoperable with the associated inverter(s) inoperable, appropriate restrictions are implemented in accordance with the affected required feature(s) of the LCOs' ACTIONS. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, the unit is still without sufficient AC vital power sources to operate in a safe manner. Therefore, action must be initiated to restore the minimum required AC vital power sources and continue until the LCO requirements are restored.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The

(continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

restoration of the required inverters should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power or powered from a the AC power supply through its 480 V/120 V bypass transformer.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation and control equipment connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. DCD Tier 2, Chapter 6.
2. DCD Tier 2, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems – Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided by division into three independent AC and four independent DC and AC vital bus electrical power distribution subsystems.

The primary AC distribution system consists of each 6.9 kV Engineered Safety Feature (ESF) bus that has two separate and independent offsite sources of power, as well as a dedicated onsite diesel generator (DG) source. Each 6.9 kV ESF bus is normally connected to a preferred source. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 6.9 kV ESF buses. Control power for the 6.9 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources – Operating," and the Bases for LCO 3.8.4, "DC Sources – Operating."

The secondary plant AC distribution system includes 480 V ESF load centers and associated loads, motor control centers, and transformers. Each 480 V AC MCC is powered from its divisional 6.9 kV ESF Bus via a 6.9 kV/480 V transformer.

The 120 V AC vital buses A10, B10, C10, and D10 (Divisions I, II, III, and IV respectively) are arranged in four load groups and are normally powered from a divisional 480 V AC motor control center (MCC) via a rectifier, an inverter, and a static switch. Divisions I, II, and III are normally powered from Division I, II, and III 480 V AC MCCs, respectively. Division IV is normally powered from a Division II 480 V AC MCC since there is no fourth division of 480 V AC. However, each of the four DC electrical power distribution subsystems (including Division IV) is backed up by its own battery bank and will automatically supply power (via the inverter) in the event of low voltage output from the rectifier (which would occur, for example, if the 480 V AC divisional power is lost). The Bases for LCO 3.8.7, "Inverters- Operating," describe the use of the four DC subsystems. In the event of an inoperable inverter, an alternate power supply for each 120 V AC vital bus is a divisional Class 1E 480 V/120 V bypass transformer powered

(continued)

BACKGROUND (continued)

from its divisional 480 V AC MCC; again, with no fourth division of 480 V AC, the alternate power supply to the Division IV 120 V AC bus is a Division II 480 V AC MCC.

There are four independent 125 VDC electrical power distribution subsystems. The list of all distribution buses is located in Table B 3.8.9-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in DCD Tier 2, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the AC and DC electrical power sources and associated distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite or onsite AC electrical power; and

b. A worst case single failure.

The AC, DC, and AC vital bus electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

(continued)

LCO

The required AC, DC, and AC vital bus power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. All divisional AC, DC, and AC vital bus electrical power primary distribution subsystems are required to be OPERABLE.

Maintaining the three Divisions of AC and the four Divisions of DC and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF systems is not defeated. Any two of Divisions I, II, and III of the AC, DC, and AC vital distribution systems are capable of providing the necessary electrical power to the associated ESF components. In addition, any two of Divisions I, II, III, and IV of the DC and AC vital distribution systems except the combination of Divisions II and IV systems (which are vulnerable to common failure because of their common AC power supply) are capable of providing the necessary electrical power to the associated RPS and ECCS safety system logic and control system components. Therefore, a single failure within any system or within an electrical power distribution subsystem does not prevent safe shutdown of the reactor.

OPERABLE AC, DC, and AC vital bus electrical power distribution subsystems require the associated buses (listed in Table B 3.8.9-1) to be energized to their proper voltages. With the exception of a special set of manual interlocks through the spare battery chargers, there are no tie breakers between redundant safety related AC, DC, and AC vital bus power distribution subsystems. This prevents any electrical malfunction in any power distribution subsystem from propagating to a redundant subsystem, which could cause the failure of the redundant subsystem and a loss of essential safety function(s). It does not, however, preclude redundant Class 1E 6.9 kV buses from being powered from the same offsite circuit.

(continued)

BASES

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained, in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.10, "Distribution Systems – Shutdown."

ACTIONS

A.1, A.2, A.3, and A.4

With one or more required AC buses, load centers, motor control centers, or distribution panels (except AC vital buses), in one division inoperable, the remaining AC electrical power distribution subsystems (other divisions) are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 72 hours.

The Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. If Condition A is entered, Required Action A.5 allows 72 hours to restore the inoperable AC electrical power distribution subsystem to OPERABLE status, provided the combustion turbine generator (CTG) is verified functional through testing within 12 hours and its capability of being aligned to the other OPERABLE ESF buses is verified, initially within 12 hours, and once per 8 hours thereafter. The functional capability of the CTG is verified in this Condition to be capable of being aligned to the OPERABLE ESF

(continued)

ACTIONS (continued)

A.1, A.2, A.3, and A.4 (continued)

buses to provide a backup power source during a loss of all AC event. At the same time, the unit operators' attention should be focused on minimizing the potential for loss of power to the remaining two divisions by stabilizing the unit, and on restoring power to the affected division. The 72 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. There is potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected division to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.8, "Safety Function Determination Program (SFDP).")

The second Completion Time for Required Action A.4 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently returned to OPERABLE status, the LCO may already have been not met for up to 72 hours. This situation could lead to a total duration of 6 days, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution could be restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time Condition A was entered. The 7 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

(continued)

ACTIONS (continued)

A.1, A.2, A.3, and A.4 (continued)

Required Action A.2 is specified so that appropriate actions are implemented in accordance with the affected required features of LCO 3.4.7 for RHR Shutdown Cooling in MODE 3.

B.1 and B.2

With one AC vital bus inoperable, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down and maintain the unit in the safe shutdown condition. Overall trip reliability is maintained, however, because the vital AC buses supply power to the RPS/MSIV logic and control (one of four RPS/MSIV channel trip in SSLC on loss of power), to redundant scram pilot and MSIV pilot solenoids, NMS, and PRRM. Therefore, the required AC vital bus can be restored to OPERABLE status within 72 hours.

Condition B represents one AC vital bus without power; potentially both the DC source and the associated AC source nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining three vital buses, and restoring power to the affected vital bus.

The AC vital buses do not provide power to the SSLC for the ECCS. Therefore, the 72-hour Completion Time is specified. The 72-hour Completion Time also takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have not been met for up to 72 hours. This situation could lead to a total

(continued)

ACTIONS (continued)

B.1 and B.2 (continued)

duration of 3 days, since initial failure of the LCO, for restoring the vital bus distribution system. At this time, an AC division could again become inoperable, and vital bus distribution could be restored to OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition B was entered. The 7-day Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

Action B.2 is specified so that appropriate restrictions are implemented in accordance with the affected required feature(s) of the LCOs' ACTIONS.

C.1 and C.2

In Condition C, the Division IV AC vital bus and one other vital bus are inoperable. Because this condition is more severe than that of Condition B, only 2 hours are allowed to restore one of the inoperable AC vital buses to OPERABLE status. This 2 hour Completion Time reflects a reasonable time to assess unit status as a function of the two inoperable AC vital buses and, if one of the buses is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

D.1, D.2, D.3, and D.4

With one DC electrical power distribution subsystem from Division I, II, or III inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems (except Division IV) could result in the minimum required ESF functions not being supported.

(continued)

ACTIONS (continued)

D.1, D.2, D.3, and D.4 (continued)

If Condition D is entered, Required Action D.4 allows 72 hours to restore the inoperable DC electrical power distribution subsystem to OPERABLE status, provided the combustion turbine generator (CTG) is verified functional through testing within 12 hours and its capability of being aligned to the two unaffected ESF buses is verified, initially within 12 hours, and once per 8 hours thereafter. One AC electrical division and its loads are affected by loss of a DC electrical power distribution subsystem because the DC electrical power subsystem provides control functions to its associated divisional DG, AC distribution circuit breakers, and other AC loads. Because a DG, its associated AC distribution system, and RCIC(Div. I) are impacted by the loss of the DC electrical power distribution subsystem, the functional capability of the CTG is verified in this Condition to be capable of being aligned to the unaffected ESF buses to provide a backup power source during a loss of all AC power event.

Condition D represents one division (either Division I, II, or III) without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining divisions, and restoring power to the affected division.

The second Completion Time for Required Action D.4 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition D is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total duration of 6 days, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC division could again become inoperable, and DC distribution could be restored OPERABLE. This could continue indefinitely.

(continued)

ACTIONS (continued)

D.1, D.2, D.3, and D.4 (continued)

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This allowance results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 7-day Completion Time is an acceptable limitation on this potential of failing to meet the LCO indefinitely.

Action D.1 is specified so that appropriate restrictions are implemented in accordance with the affected required feature(s) of the LCOs' ACTIONS.

E.1

In Condition E, the Division IV DC electrical power distribution subsystem is inoperable. Required Actions E.1 allows 2 hours to declare affected required features inoperable. Division IV is less critical than the other three DC electrical power distribution subsystems because of its limited role in actuating safety related functions. Its loss is not as critical as a loss of one of the other DC distribution subsystems, and the less restrictive ACTIONS of affected LCOs are appropriate.

F.1 and F.2

In Condition F, the Division IV DC electrical power distribution subsystem and one other DC distribution subsystem are inoperable. Because this condition is more severe than that of Condition E, only 2 hours are allowed to restore one of the inoperable DC distribution subsystems to OPERABLE status. This 2 hour Completion Time reflects a reasonable time to assess unit status as a function of the two inoperable DC distribution subsystems and, if one of the subsystems is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

G.1 and G.2

If the inoperable electrical power distribution system cannot be restored to OPERABLE status within the associated Completion Times, the plant must be bought to a MODE in

(continued)

BASES

ACTIONS (continued)

G.1 and G.2 (continued)

which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

Meeting this Surveillance verifies that the AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with all the required circuit breakers closed and the buses energized from normal power. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. DCD Tier 2, Chapter 6.
2. DCD Tier 2, Chapter 15.
3. Regulatory Guide 1.93, December 1974.

Table B 3.8.9-1 (page 1 of 1)
AC, DC, and AC Vital Bus Electrical Power Distribution System

SYSTEM	BUS TYPE AND VOLTAGE	DIVISION 1*	DIVISION 2*	DIVISION 3*	DIVISION 4*
AC Buses	ESF Bus 6900 V	M/C E	M/C F	M/C G	Not Applicable
	Power Center 480 V	P/C E10 P/C E20	P/C F10 P/C F20	P/C G10 P/C G20	
	Motor Control Center 480 V	C/B E110 C/B E111 C/B E112 C/B E113 C/B E120 C/B E260	C/B F110 C/B F111 C/B F112 C/B F113 C/B F120 C/B F260	C/B G110 C/B G111 C/B G112 C/B G113 C/B G120 C/B G260	
	Distribution Panel 120 V	IP A10 IP A20	IP B10 IP B20	1P C10 1P C20	
DC Buses	Motor Control Center 125 V	DC MCC A1	-	-	-
	Distribution Panel 125 V	DC A10 DC A20	DC B10 DC B20	DC C10 DC C20	DC D10** DC D20**
AC Vital Buses	CONSTANT VOLTAGE, CONSTANT FREQUENCY DISTRIBUTION PANEL 120 V	A11 A21	B11 B21	C11 C12	D11*** D12***

* Each division of the AC, DC, and AC vital bus electrical power distribution system is a subsystem.

** The battery charger for Division 4 DC subsystem is powered by a Division 2 480 V AC motor control center.

*** The normal power source for the Division 4 AC vital bus subsystem is a Division 2 480 V AC motor control center.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems – Shutdown

BASES

BACKGROUND

A description of the AC, DC, and AC vital bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in DCD Tier 2, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and AC vital bus electrical power sources and associated power distribution subsystems during MODES 4 and 5 ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent drain down of the vessel or a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of Technical Specifications' required systems, equipment, and components – both specifically addressed by their own LCOs, and implicitly required by the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel drain down).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent drain down of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown or refueling condition.

The AC, DC, and AC vital bus electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.9.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5

Although redundant required features may require redundant divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, during movement of irradiated fuel assemblies in the secondary containment and any activities that could result in inadvertent draining of the reactor vessel).

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal – shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, these Required Actions of Condition A do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, the Required Actions of Condition A direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the AC, DC, and AC vital bus electrical power distribution subsystem is functioning properly, with the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. DCD Tier 2, Chapter 6.

2. DCD Tier 2, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.11 AC Sources – Shutdown (Low Water Level)

BASES

BACKGROUND	A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources – Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODE 4 and MODE 5 with water level in the refueling cavity < 7.0 meters above the reactor pressure vessel flange ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent drain down of the vessel, loss of decay heat removal, or a fuel handling accident.

In general, when the unit is shut down the Technical Specifications (TS) requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODE 1, 2, and 3 LCO requirements are acceptable during shutdown MODES based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, and 3 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (diesel generator (DG)) power.

The AC sources satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES

LCO

One offsite circuit capable of supplying onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems – Shutdown," ensures that all required loads on Division I, Division II, and Division III are powered from offsite power. Two or more OPERABLE DGs available in standby to supply electrical power to required OPERABLE features via the associated Engineered Safety Feature (ESF) buses that are required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DGs ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel drain down, and loss of decay heat removal).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage while connected to ESF buses, and of accepting required loads during an accident. The qualified offsite circuit is either the normal or alternate preferred power circuits to the AC Electric Power Distribution System that are described in DCD Tier 2, Chapter 8 and are part of the licensing basis for the plant. The normal preferred circuit consists of the switching stations breaker to the main transformers, the generator breaker, the disconnect links to the unit auxiliary transformers, and the circuit path from the offsite transmission network to all of the 6.9 kV ESF buses required by LCO 3.8.10 including feeder breakers at the 6.9 kV ESF buses. The alternate preferred circuit consists of the switching station breaker to the reserve transformer and the circuit path from the offsite transmission network to all of the 6.9 kV ESF buses required by LCO 3.8.10 including feeder breakers at the 6.9 kV ESF buses.

Each required DG must be capable of starting, accelerating to required speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 20 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot, DG in standby with the engine at ambient conditions,

(continued)

LCO (continued)

and DG operating in parallel test mode.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

During a shutdown condition, it is acceptable for a single offsite power circuit to supply all required divisions of electrical power.

As described in Applicable Safety Analyses, in the event of an accident during shutdown, the TS are designed to maintain the plant in a condition such that, even with a single failure, the plant will not be in immediate difficulty.

APPLICABILITY

The AC sources required to be OPERABLE in MODE 4 and MODE 5 with water level in the refueling cavity < 7.0 meters above the reactor pressure vessel flange during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems are available to provide adequate coolant inventory makeup to maintain irradiated fuel in the core covered with coolant in case of an inadvertent drain down of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

e. Systems are available to remove decay heat from the irradiated fuel in the core.

(continued)

BASES

APPLICABILITY (continued)

The AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1; and for MODE 5 with the water level in the refueling cavity ≥ 7.0 meters above the reactor pressure vessel flange, in LCO 3.8.2.

ACTIONS

A.1.1 and A.1.2

An offsite circuit is considered inoperable if it is not available to one required ESF bus. If two or more ESF buses are required per LCO 3.8.10, division(s) with offsite power still available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for draining the reactor vessel for an 8 hour period. This 8-hour period is reasonable provided the Required Actions of LCO 3.8.10 do not apply.

However, if after 8 hours, should any required features still have no power available from an OPERABLE offsite circuit, Required Action A.1.2 requires declaring such features inoperable so that appropriate restrictions can be implemented in accordance with the affected required feature(s) LCOs' ACTIONS.

A.2.1, A.2.2, A.2.3, and A.2.4

Within 8 hours of determining the required offsite circuit is inoperable (not available to some or all required ESF buses), Required Action A.1.2 allows the choice of declaring affected required features inoperable. Since this option may involve undesirable administrative efforts, Required Actions A.2.1, A.2.2, A.2.3, and A.2.4 alternatively allow performance of other sufficiently conservative actions, thereby avoiding any undesirable administrative efforts. With the required offsite circuit inoperable (unable to supply all required ESF buses), the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could potentially result in inadvertent draining of the reactor vessel.

(continued)

ACTIONS

A.2.1, A.2.2, A.2.3, and A.2.4 (continued)

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required offsite circuit to OPERABLE status and to continue this action until restoration is accomplished in order to provide the necessary (and preferred) AC power to the plant safety systems.

Notwithstanding performance of the above conservative Required Actions, the plant is still without sufficient AC power sources to operate in a safe manner. Therefore, action must be initiated to restore the minimum required AC power sources and continue until the LCO requirements are restored.

The Completion Time of immediately for restoring the required offsite circuit to OPERABLE status is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the plant safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System ACTIONS are not entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to one ESF bus, ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.10 provides the appropriate restrictions for the situation involving a de-energized division.

(continued)

ACTIONS (continued)

B.1, B.2, and B.3

With one required DG inoperable, 14 days are allowed for restoring the DG to OPERABLE status provided the combustion turbine generator (CTG) is verified to be functional through testing within 1 hour and its breakers are verified to be aligned to the ESF bus associated with the inoperable DG within 1 hour and every 8 hours thereafter. As long as the CTG is available to serve as a backup to the inoperable DG, shutdown activities (that would otherwise be prohibited in a low water level condition) in MODES 4 and 5 are permitted. This 14-day Completion Time is considered reasonable because of the reliability and convenience of the CTG, the low probability of a shutdown transient (e.g., loss of decay heat removal) occurring during this time period, and the availability of at least one other OPERABLE DG.

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

C.1, C.2, C.3, C.4, and C.5

When a Required Action and Completion Time of Condition B are not met (either the CTG is not functional or alignable to the required ESF bus, or one DG cannot be restored to OPERABLE status), or when two or more of the required DGs are inoperable, the required diversity of AC power sources to plant safety systems is not available. Required Actions C.1, C.2, and C.3, therefore, suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could potentially result in inadvertent draining of the reactor vessel. Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required DG(s) OPERABLE status and to continue this action until restoration is accomplished in order to provide the required diversity of AC power sources to plant safety systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	See Bases for LCO 3.8.2.
REFERENCES	None.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Refueling Equipment Interlocks

BASES

BACKGROUND

Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to reinforce unit procedures in preventing the reactor from achieving criticality during refueling. The refueling interlock circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed conditions, interlocks are actuated to prevent the operation of the refueling equipment or the withdrawal of control rods.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods, when fully inserted, serve as the system capable of maintaining the reactor subcritical in cold conditions during all fuel movement activities and accidents.

Two channels of instrumentation are provided to sense the position of the refueling machine, the loading of the refueling machine main hoist, and the full insertion of all control rods. With the reactor mode switch in the shutdown or refueling position, the indicated conditions are combined in logic circuits to determine if all restrictions on refueling equipment operations and control rod insertion are satisfied.

A control rod not at its full-in position interrupts power to the refueling equipment and prevents operating the equipment over the reactor core when loaded with a fuel assembly. Conversely, the refueling equipment located over the core and loaded with fuel inserts a control rod withdrawal block in the Rod Control and Information System (RCIS) to prevent withdrawing a control rod.

The refueling machine has two mechanical switches that open before the machine and the fuel grapple are physically located over the reactor vessel. The main hoist has two switches that open when the hoist is loaded with fuel. The refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over

(continued)

BACKGROUND (continued)

the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2).

The hoist switches open at a load lighter than the weight of a single fuel assembly in water.

APPLICABLE SAFETY ANALYSES

The refueling interlocks are explicitly assumed in the safety analysis of the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading fuel into the core with any control rod withdrawn, or by preventing withdrawal of a rod from the core during fuel loading.

The refueling machine location switches activate at a point outside of the reactor core, such that, considering switch hysteresis and maximum machine momentum toward the core at the time of power loss with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core.

Refueling equipment interlocks satisfy Criterion 3 of the NRC Policy Statement.

LCO

To prevent criticality during refueling, the refueling interlocks ensure that fuel assemblies are not loaded with any control rod withdrawn.

To prevent these conditions from developing, the all-rods-in, the refueling machine position, and the refueling machine main hoist fuel loaded inputs are required to be OPERABLE. These inputs are combined in logic circuits that provide refueling equipment or control rod

(continued)

LCO (continued)

blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are only required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

ACTIONS

A.1

With one or more of the required refueling equipment interlocks inoperable, the unit must be placed in a condition in which the LCO does not apply. In-vessel fuel movement with the affected refueling equipment must be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.1.1 (continued) The 7 day Frequency is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to unit operations personnel.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. DCD Tier 2, Section 7.7.1.2. 3. DCD Tier 2, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refuel Position Rod-Out Interlock

BASES

BACKGROUND

The refuel position rod-out interlock restricts the movement of control rods to reinforce unit procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations no more than one control rod or rod pair associated with the same HCU is permitted to be withdrawn.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

The refuel position rod-out interlock prevents the selection of an additional control rod for movement when any other control rod or rod pair is not fully inserted (Ref. 2). It is a logic circuit that has redundant channels. It uses the all-rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4, "Control Rod Position Indication") and a rod selection signal (from the Rod Control and Information System).

This Specification ensures that the performance of the refuel position rod-out interlock in the event of a Design Basis Accident meets the assumptions used in the safety analysis of Reference 3.

APPLICABLE SAFETY ANALYSES

The refuel position rod-out interlock is explicitly assumed in the safety analysis of the control rod removal error during refueling (Ref. 3). This analysis evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The refuel position rod-out interlock and adequate SDM (LCO 3.1.1) prevent criticality by preventing withdrawal of more than one control rod or rod pair. With one control rod or rod pair withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion. The refuel position rod-out interlock satisfies Criterion 3 of the NRC Policy Statement.
LCO	To prevent criticality during MODE 5, the refuel position rod-out interlock ensures no more than one control rod or rod pair may be withdrawn. Both channels of the refuel position rod-out interlock are required to be OPERABLE.
APPLICABILITY	In MODE 5, with the reactor mode switch in the refuel position, the OPERABLE refuel position rod-out interlock provides protection against prompt reactivity excursions. In MODES 1, 2, 3, and 4, the refuel position rod-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (LCOs 3.3.1.1 and 3.3.1.2) and the control rods (LCO 3.1.2) provide mitigation of potential reactivity excursions. In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.5.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.
ACTIONS	A.1 and A.2 With one or both channels of the refuel position rod-out interlock inoperable, the refueling interlocks may not be capable of preventing more than one control rod or rod pair from being withdrawn. This condition may lead to criticality.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Control rod withdrawal must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

Proper functioning of the refueling position rod-out interlock requires the reactor mode switch to be in Refuel. During control rod withdrawal in MODE 5, improper positioning of the reactor mode switch and the RCIS GANG/SINGLE selection switch could, in some instances, allow improper bypassing of required interlocks. Therefore, this Surveillance imposes an additional level of assurance that the refueling position rod-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position, an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation.

The Frequency of 12 hours is sufficient in view of other administrative controls utilized during refueling operations to ensure safe operation.

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position rod-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. The 7 day Frequency is considered adequate because of demonstrated circuit reliability, procedural controls on control rod withdrawals, and visual and audible indications available in the control room to alert the operator of control rods not

(continued)

SURVEILLANCE REQUIREMENTS	SR 3.9.2.2 (continued) fully inserted. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.2 has been modified by a Note that states the CHANNEL FUNCTIONAL TEST is not required to be performed until 1 hour after any control rod is withdrawn.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. DCD Tier 2, Section 7.7.1.2. 3. DCD Tier 2, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Control Rod Position

BASES

BACKGROUND	Control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the Control Rod Drive System. During refueling, movement of control rods is limited by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2) or the control rod block with the reactor mode switch in the shutdown position (LCO 3.3.5.1). GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions. The refueling interlocks and the RCIS GANG/SINGLE selection switch allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. However, during refueling, the RCIS "Rod Test Switch" allows two control rods to be withdrawn for scram testing. To preclude loading fuel assemblies into the core with a control rod withdrawn, all control rods must be fully inserted. This prevents the reactor from achieving criticality during refueling operations.
APPLICABLE SAFETY ANALYSES	Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1), the startup range monitor neutron flux scram (LCO 3.3.1.1), the average power range monitor neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.5.1). The safety analysis of the control rod removal error during refueling (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. Additionally, prior to fuel reload, all control rods must be fully inserted to ensure that an inadvertent criticality does not occur.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Control rod position satisfies Criterion 3 of the NRC Policy Statement.

LCO

All control rods must be fully inserted during applicable refueling conditions to prevent an inadvertent criticality during refueling.

APPLICABILITY

During MODE 5, loading fuel into a core cell with the control rod withdrawn may result in inadvertent criticality. Therefore, the control rod must be inserted before loading fuel into a core cell. All control rods must be inserted before loading fuel to ensure that a fuel loading error does not result in loading fuel into a core cell with the control rod withdrawn.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, this Specification is not applicable in these MODES.

ACTIONS

A.1

With all control rods not fully inserted during the applicable conditions, an inadvertent criticality could occur that is not analyzed. All fuel loading operations must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

During refueling, to ensure that the reactor remains subcritical, all control rods must be fully inserted prior to and during fuel loading. Periodic checks of the control rod position ensure this condition is maintained.

The 12 hour Frequency takes into consideration the procedural controls on control rod movement during refueling

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.3.1 (continued) as well as the redundant functions of the refueling interlocks.
REFERENCES	1. 10 CFR 50, Appendix A, GDC 26. 2. DCD Tier 2, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication channel for each control rod provides information necessary to the refueling interlocks to prevent inadvertent criticalities during refueling operations. For the Fine Motion Control Rod Drives (FMCRD), position is derived from synchros which have an analog output. The RCIS translates the 100% insertion signal from the synchro into a discrete full-in position signal to be used as a permissive in the refueling interlocks. During refueling, the refueling interlocks (LCO 3.9.1 and LCO 3.9.2) use the full-in position indication channels to limit the operation of the refueling equipment and the movement of the control rods. The absence of the full-in position indication channel signal for any control rod removes the all-rods-in permissive for the refueling equipment interlocks and prevents fuel loading. Also, this condition causes the refuel position rod-out interlock to not allow the withdrawal of any other control rod.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1), the startup range monitor neutron flux scram (LCO 3.3.1.1), the average power range monitor neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.5.1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The safety analysis for the control rod removal error during refueling (Ref. 2) assumes the functioning of the refueling interlocks and adequate SDM. The full-in position indication channel is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod or rod pair withdrawn and that no more than one control rod or rod pair can be withdrawn at a time. Control rod position indication satisfies Criterion 3 of the NRC Policy Statement.
LCO	One of the two control rod full-in position indication channels must be OPERABLE to provide the required inputs to the refueling interlocks. A channel is OPERABLE if it provides correct position indication to the refueling interlock logic.
APPLICABILITY	During MODE 5, the control rods must have OPERABLE full-in position indication channels to ensure the applicable refueling interlocks will be OPERABLE. In MODES 1 and 2, requirements for control rod position are specified in LCO 3.1.3, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.5.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.
ACTIONS	A Note has been provided to modify the ACTIONS related to control rod position indication channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for control rods with inoperable position indication channels

(continued)

BASES

ACTIONS (continued)

provide appropriate compensatory measures. As such, this Note has been provided, which allows separate Condition entry for each control rod with inoperable position indication channels.

A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2

With required full-in position indication channels inoperable for one or more control rods, compensating actions must be taken to protect against potential reactivity excursions from fuel assembly insertions or control rod withdrawals. This may be accomplished by immediately suspending in-vessel fuel movement and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted. Suspension of in-vessel fuel movements and control rod withdrawal shall not preclude moving a component to a safe position.

Alternatively, actions may be immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicators(s) and to disarm the drive(s) to ensure that the control rod is not withdrawn. Actions must continue until all associated control rods are fully inserted and drives are disarmed.

Under these conditions, an inoperable full-in channel may be bypassed to allow refueling operations to proceed. An alternate method must be used to ensure the control rod is fully inserted (e.g., use the 0% position indication). Another option is to bypass Synchro A (which is the current position probe) and use Synchro B instead. If the readings of the two Synchros do not agree, the conditions will be alarmed to the operator to initiate bypass of Synchro A and to use Synchro B.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels provide input to the rod-out interlock and other refueling interlocks that require an all-rods-in permissive. The interlocks are activated when the full-in position indication for any control rod is not present, since this indicates that all rods are not fully inserted. Therefore, testing of the full-in position indication channels is performed to ensure that when a control rod is withdrawn, the full-in position indication is not present. Performing the SR each time a control rod is withdrawn is considered adequate because of the procedural controls on control rod withdrawals and the visual and audible indications available in the control room to alert the operator to control rods not fully inserted.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. DCD Tier 2, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Control Rod OPERABILITY – Refueling

BASES

BACKGROUND

Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes during refueling operation. In addition, the control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System.

The CRD system also includes the Fine Motion Control Rod Drives (FMCRDs) and the CRD system instrumentation with which the RCIS directly interfaces. The FMCRDs can be inserted either hydraulically or electrically. In response to a scram signal, the FMCRD is inserted hydraulically via the stored energy in the scram accumulators. A redundant signal is also given to insert the FMCRD electrically via its motor drive. This diversity provides a high degree of assurance of rod insertion on demand.

GDC 26 of 10 CFR 50, Appendix A, requires that one of the two required independent reactivity control systems be capable of holding the reactor core subcritical under cold conditions (Ref. 1). The CRD System is the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1), the startup range monitor neutron flux scram (LCO 3.3.1.1), the average power range monitor neutron flux scram (LCO 3.3.1.1), and the control rod block instrumentation (LCO 3.3.5.1).

The safety analysis for the control rod removal error during refueling (Ref. 2) evaluates the consequences of control rod withdrawal during refueling. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the

(continued)

environment. Control rod scram provides backup protection should a prompt reactivity excursion occur.

Control rod OPERABILITY during refueling satisfies Criterion 3 of the NRC Policy Statement.

LCO

Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if the scram accumulator pressure is > 12.75 MPaG and the control rod is capable of being automatically inserted upon receipt of a scram signal. Inserted control rods have already completed their reactivity control function.

APPLICABILITY

During MODE 5, withdrawn control rods must be OPERABLE to ensure that in a scram the control rods will insert and provide the required negative reactivity to maintain the reactor subcritical.

For MODES 1 and 2, control rod requirements are found in LCO 3.1.2, "Reactivity Anomalies," LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." During MODES 3 and 4, control rods are only allowed to be withdrawn under LCO 3.10.3, "Control Rod Withdrawal—Hot Shutdown," and LCO 3.10.4, "Control Rod Withdrawal—Cold Shutdown," in the Special Operations section. These provide adequate requirements for control rod OPERABILITY during these conditions.

ACTIONS

<u>A.1</u>

With one or more withdrawn control rods inoperable, action must be immediately initiated to fully insert the inoperable control rod(s). Inserting the control rod(s) ensures that the shutdown and scram capabilities are not adversely affected. Actions must continue until the inoperable control rod(s) is fully inserted.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2

During MODE 5, the OPERABILITY of control rods is primarily required to ensure that a withdrawn control rod will automatically insert if a signal requiring a reactor shutdown occurs. Because no explicit analysis exists for automatic shutdown during refueling, the shutdown function is satisfied if the withdrawn control rod is capable of automatic insertion and the associated CRD scram accumulator pressure is ≥ 12.75 MPaG.

The 7 day Frequency takes into consideration equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights that indicate low accumulator charge pressures.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.

2. DCD Tier 2, Section 15.4.1.1.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND	The movement of fuel assemblies or handling of control rods within the RPV requires a minimum water level of 7.0 m above the top of the RPV flange. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 3.9.6-1 and 3.9.6-2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3.
APPLICABLE SAFETY ANALYSES	During movement of fuel assemblies or handling of control rods, the water level in the RPV and the spent fuel pool is an initial condition design parameter in the analysis of a fuel handling accident in containment postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 7.0 m allows a decontamination factor of 100 (Ref. 4) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1). Analysis of the fuel handling accident inside containment is described in Reference 2. With a minimum water level of 7.0 m and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water, and that offsite doses are maintained within allowable limits (Ref. 5). RPV water level satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES

LCO

A minimum water level of 7.0 m above the top of the RPV flange is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 3.

APPLICABILITY

LCO 3.9.6 is applicable when moving fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) within the RPV. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel is not present within the RPV, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.6, "Fuel Pool Water Level."

ACTIONS

A.1

If the water level is < 7.0 m above the top of the RPV flange, all operations involving movement of fuel assemblies and handling of control rods within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement and control rod handling shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 7.0 m above the top of the RPV flange ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident in containment (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

(continued)

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972.
2. DCD Tier 2, Section 15.7.4.
3. NUREG-0800, Section 15.7.4.
4. NUREG-0831, Supplement 6, Section 16.4.2.
5. 10 CFR 100.11.

B 3.9 REFUELING OPERATIONS

B.3.9.7 Residual Heat Removal (RHR) — High Water Level

BASES

BACKGROUND	The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34. Each of the three shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Each loop has a dedicated suction nozzle from the reactor vessel. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via feedwater line A for subsystem A, and via the individual RHR inlet nozzles for subsystems B and C. The RHR heat exchangers transfer heat to the Reactor Building Cooling Water (RCW) system (LCO 3.7.3). The RHR shutdown cooling mode is manually controlled. In addition to the RHR subsystems, the volume of water above the reactor pressure vessel (RPV) flange provides a heat sink for decay heat removal.
APPLICABLE SAFETY ANALYSIS	With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant. Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.
LCO	Only one RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5 with the water level ≥ 7.0 m above the RPV flange to provide decay heat removal. Only one subsystem is required because the volume of water above the RPV flange provides backup decay heat removal capability.

(continued)

LCO (continued)

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow a 2 hour exception to shut down the operating subsystem every 8 hours.

APPLICABILITY

One RHR shutdown cooling subsystem is required to be OPERABLE in MODE 5, with irradiated fuel in the reactor pressure vessel and with the water level ≥ 7.0 m above the top of the RPV flange, to provide decay heat removal. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS); Section 3.5, Emergency Core Cooling Systems (ECCS); and Section 3.6, Containment Systems. RHR System requirements in MODE 5, with irradiated fuel in the reactor pressure vessel and with the water level < 7.0 m above the RPV flange, are given in LCO 3.9.8, "Residual Heat Removal (RHR) - Low Water Level."

ACTIONS

A.1

With no RHR shutdown cooling subsystem OPERABLE, an alternate method of decay heat removal must be established within 1 hour. In this condition, the volume of water above the RPV flange provides adequate capability to remove decay heat from the reactor core. However, the overall reliability is reduced because loss of water level could result in reduced decay heat removal capability. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be

(continued)

ACTIONS

A.1 (continued)

reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the unit's Operating Procedures. For example, in addition to the three RHR shutdown cooling loops, this may include the use of the Reactor Water Cleanup System, operating with the regenerative heat exchanger bypassed. The method used to remove the decay heat should be the most prudent choice based on unit conditions.

B.1, B.2, B.3, and B.4

If no RHR shutdown cooling subsystem is OPERABLE and an alternate method of decay heat removal is not available in accordance with Required Action A.1, actions shall be taken immediately to suspend operations involving an increase in reactor decay heat load by suspending the loading of irradiated fuel assemblies into the RPV.

Additional actions are required to minimize any potential fission product release to the environment. This includes initiating immediate action to restore the following to OPERABLE status: secondary containment, one standby gas treatment subsystem, and one secondary containment isolation valve and associated instrumentation in each associated penetration not isolated. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It does not mean to perform the surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, a surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

C.1 and C.2

If no RHR Shutdown Cooling System is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

such that 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR Shutdown Cooling System), the reactor coolant temperature must be periodically monitored to ensure proper functioning of the alternate method. The once per hour Completion Time is deemed appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

This Surveillance demonstrates that the RHR subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.

REFERENCES

None.

B 3.9 REFUELING OPERATIONS

B.3.9.8 Residual Heat Removal (RHR) – Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as required by GDC 34. Each of the three shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of one motor driven pump, a heat exchanger, and associated piping and valves. Each loop has a dedicated suction nozzle from the reactor vessel. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via feedwater line A for subsystem A, and via the individual RHR inlet nozzles for subsystems B and C. The RHR heat exchangers transfer heat to the Reactor Building Cooling Water (RCW) system (LCO 3.7.2). The RHR shutdown cooling mode is manually controlled.

APPLICABLE SAFETY ANALYSIS

With the unit in MODE 5, the RHR System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR System is required for removing decay heat to maintain the temperature of the reactor coolant.

Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.

LCO

In MODE 5 with the water level < 7.0 m above the reactor pressure vessel (RPV) flange two RHR shutdown cooling subsystems must be OPERABLE.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path.

(continued)

LCO (continued)

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, continuous operation is required. A Note is provided to allow a 2 hour exception to shut down the operating subsystem every 8 hours.

APPLICABILITY

Two RHR shutdown cooling subsystems are required to be OPERABLE in MODE 5, with irradiated fuel in the reactor pressure vessel and with the water level < 7.0 m above the top of the RPV flange, to provide decay heat removal. RHR System requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS); Section 3.5, Emergency Core Cooling Systems (ECCS); and Section 3.6, Containment Systems. RHR System requirements in MODE 5, with irradiated fuel in the reactor pressure vessel and with the water level ≥ 7.0 m above the RPV flange, are given in LCO 3.9.7, “Residual Heat Removal (RHR)- High Water Level.”

ACTIONS

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore an alternate method of decay heat removal must be provided (such as the third RHR shutdown cooling subsystem). With both required RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s)

(continued)

ACTIONS

A.1 (continued)

must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the unit's Operating Procedures. For example, in addition to the third RHR shutdown cooling loop, this may include the use of the Reactor Water Cleanup System, operating with the regenerative heat exchanger bypassed. The method used to remove decay heat should be the most prudent choice based on unit conditions.

B.1, B.2, B.3, C.1, and C.2

If no RHR shutdown cooling subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

During the period when the reactor coolant is being circulated by an alternate method (other than by the required RHR Shutdown Cooling System), the reactor coolant temperature and level must be periodically monitored to ensure proper function of the alternate method. The once per hour Completion Time is deemed appropriate.

If at least one RHR subsystem is not restored to OPERABLE status immediately, additional actions are required to minimize any potential fission product release to the environment. This includes initiating immediate action to restore the following to OPERABLE status: secondary containment, one standby gas treatment subsystem, and one secondary containment isolation valve and associated instrumentation in each associated penetration not isolated. This may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the

(continued)

BASES

ACTIONS (continued)	B.1, B.2, B.3, C.1, and C.2 (continued) surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.
SURVEILLANCE REQUIREMENTS	SR 3.9.8.1 This Surveillance demonstrates that one RHR subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR subsystem in the control room.
REFERENCES	None.

B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 93°C (normally corresponding to MODE 3).

Inservice testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Reactor internal pump operation and a water solid RPV (except for an air bubble for pressure control) are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.9, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RPV P/T limit curves are performed as necessary, based on the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and leak testing will eventually be required with minimum reactor coolant temperatures > 93°C.

The hydrostatic test, generally performed every ten years, requires increasing pressure to 110% of operating pressure 7.07 MPaG or 7.78 MPaG, and because of the expected increase in reactor vessel fluence, the minimum allowable vessel temperature according to LCO 3.4.9 is increased as shown in the PLTR. This increase to 110% of operating pressure does not exceed the Safety Limit of 9.48 MPaG.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Allowing the reactor to be considered in MODE 4 during hydrostatic or leak testing, when the reactor coolant temperature is > 93°C, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems (ECCS). Since the hydrostatic or leak tests are performed water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the limits of LCO 3.4.6, "Reactor Coolant System (RCS) Specific Activity," are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. The consequences of a steam leak under pressure testing conditions, with secondary containment OPERABLE, will be conservatively bounded by the consequences of the postulated main steam line break outside of secondary containment accident analysis described in Reference 2. Therefore, requiring the secondary containment to be OPERABLE will conservatively ensure that any potential airborne radiation from steam leaks will be filtered through the Standby Gas Treatment System, thereby limiting radiation releases to the environment.

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low pressure core cooling systems to operate. The capability of the low pressure flooder subsystems, as required in MODE 4 by LCO 3.5.2, "ECCS – Shutdown," would be more than adequate to keep the core flooded under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 4 applicable LCOs, in addition to the secondary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures > 93°C, can be in accordance with Table 1.1-1 for MODE 3 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures > 93°C, while the ASME inservice test itself requires the safety/relief valves to be gagged, preventing their OPERABILITY. If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs and specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System—Cold Shutdown." The additional requirements for secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 93°C for the purposes of performing either an inservice leak or hydrostatic test. This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 4 applicable requirements that are in effect immediately prior to and immediately after this operation.
APPLICABILITY	The MODE 4 requirements may only be modified for the performance of inservice leak or hydrostatic tests so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is > 93°C. The additional requirement for secondary containment OPERABILITY according to the imposed MODE 3 requirements provides conservatism in the response of the unit to any event that

(continued)

BASES

APPLICABILITY (continued)

may occur. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A Note has been provided to modify the ACTIONS related to inservice leak and hydrostatic testing operation. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements shall be entered immediately and complied with. Required Action A.1 has been modified by a Note that clarifies the intent of another LCO's Required Action to be in MODE 4 includes reducing the average reactor coolant temperature to ≤ 93°C.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 4 requirements, and thereby exit this Special Operations LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are suspended immediately, in accordance with Required Action A.2.1, and the reactor coolant temperature is reduced to establish normal MODE 4 requirements. The allowed Completion Time of 24 hours for Required Action A.2.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature from the highest expected value to ≤ 93°C with normal cooldown procedures. The Completion Time

(continued)

BASES

ACTIONS (continued)	A.2.1 and A.2.2 (continued) is also consistent with the time provided in LCO 3.0.3 for reaching MODE 4 from MODE 3.	
SURVEILLANCE REQUIREMENTS	SR 3.10.1.1 The LCOs made applicable are required to have their Surveillances met to establish that this LCO is being met. A discussion of the applicable SRs is provided in their respective Bases.	
REFERENCES	1. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI. 2. DCD Tier 2, Section 15.1.	

B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5.

The reactor mode switch is a conveniently located, multiposition, keylock switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The reactor mode switch selects the appropriate trip logic for scram functions and provides appropriate bypasses. The mode switch positions and related scram interlock functions are summarized as follows:

a. Shutdown – Initiates a reactor scram; bypasses main steam line isolation and reactor high water level scrams;

b. Refuel – Selects Neutron Monitoring System (NMS) scram function for low neutron flux level operation (but does not disable the average power range monitor scram); bypasses main steam line isolation and reactor high water level scrams;

c. Startup/Hot Standby – Selects NMS scram function for low neutron flux level operation (startup range neutron monitors); bypasses main steam line isolation and reactor high water level scrams; and

d. Run – Selects NMS scram function for power range operation.

The reactor mode switch also provides interlocks for such functions as control rod blocks, low CRD charging water header pressure trip bypass, refueling interlocks, and main steam isolation valve isolations.

APPLICABLE SAFETY ANALYSES

The acceptance criterion for reactor mode switch interlock testing is to prevent fuel failure by precluding reactivity excursions or core criticality.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The interlock functions of the shutdown and refuel positions of the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (run, or startup/hot standby) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no other CORE ALTERATIONS in progress. With all control rods inserted in core cells containing one or more fuel assemblies and no CORE ALTERATIONS in progress, there are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing.

For postulated accidents, such as control rod removal error during refueling or loading of fuel with a control rod withdrawn, the accident analysis demonstrates that fuel failure will not occur (Ref. 2). The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality, thereby preventing fuel failure.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODES 3, 4, and 5 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.3, "Rod Withdrawal—Hot Shutdown," LCO 3.10.4, "Rod Withdrawal—Cold Shutdown," and LCO 3.10.7 "Control Rod Testing—Operating") without meeting this LCO or its ACTIONS. If any testing is performed that involves the reactor mode switch interlocks and requires repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, the testing can be performed, provided all interlock functions potentially defeated are administratively controlled. In MODES 3, 4, and 5 with the reactor mode switch in shutdown as specified in Table 1.1-1, all control rods are fully

(continued)

BASES

LCO (continued)

inserted and a control rod block is initiated. Therefore, all control rods in core cells that contain one or more fuel assemblies must be verified fully inserted while in MODES 3, 4, and 5 with the reactor mode switch in other than the shutdown position. The additional LCO requirement to preclude CORE ALTERATIONS is appropriate for MODE 5 operations, as discussed below, and is inherently met in MODES 3 and 4 by the definition of CORE ALTERATIONS, which cannot be performed with the vessel head in place.

In MODE 5, with the reactor mode switch in the refuel position, only one control rod or rod pair can be withdrawn under the refuel position rod-out interlock (LCO 3.9.2, "Refuel Position Rod-Out Interlock"). The refueling equipment interlocks (LCO 3.9.1, "Refueling Equipment Interlocks") appropriately control other CORE ALTERATIONS. Due to the increased potential for error in controlling these multiple interlocks and the limited duration of tests involving the reactor mode switch position, conservative controls are required, consistent with MODES 3 and 4. The additional controls of administratively not permitting other CORE ALTERATIONS will adequately ensure that the reactor does not become critical during these tests.

APPLICABILITY

Any required periodic interlock testing involving the reactor mode switch, while in MODES 1 and 2, can be performed without the need for Special Operations exceptions. Mode switch manipulations in these MODES would likely result in unit trips. In MODES 3, 4, and 5, this Special Operations LCO is only permitted to be used to allow reactor mode switch interlock testing that cannot conveniently be performed while in other modes. Such interlock testing may consist of required Surveillances or calibrations, or may be the result of maintenance, repair, or troubleshooting activities. In MODES 3, 4, and 5, the interlock functions provided by the reactor mode switch in shutdown (i.e., all control rods inserted and incapable of withdrawal) and refueling (i.e., refueling interlocks to prevent inadvertent criticality during CORE ALTERATIONS) positions can be administratively controlled adequately during the performance of certain tests.

(continued)

ACTIONS

A.1, A.2, A.3.1, and A.3.2

These Required Actions are provided to restore compliance with the Technical Specifications overridden by this Special Operations LCO. Restoring compliance will also result in exiting the Applicability of this Special Operations LCO.

All CORE ALTERATIONS, if in progress, are immediately suspended in accordance with Required Action A.1, and all insertable control rods in core cells that contain one or more fuel assemblies are fully inserted within 1 hour, in accordance with Required Action A.2. This will preclude potential mechanisms that could lead to criticality. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition. Placing the reactor mode switch in the shutdown position will ensure that all inserted control rods remain inserted and result in operation in accordance with Table 1.1-1. Alternatively, if in MODE 5, the reactor mode switch must be placed in the refuel position, which will also result in operating in accordance with Table 1.1-1. A Note is added to Required Action A.3.2 to indicate that this Required Action is not applicable in MODES 3 and 4, since only the shutdown position is allowed in these MODES. The allowed Completion Time of 1 hour for Required Actions A.2, A.3.1, and A.3.2 provides sufficient time to normally insert the control rods and place the reactor mode switch in the required position, based on operating experience, and is acceptable given that all operations that could increase core reactivity have been suspended.

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in the shutdown position (or the refuel position for MODE 5). The functions of the reactor mode switch interlocks that are not in effect, due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls are to be periodically verified to ensure that the operational requirements continue to be met. The Surveillances performed at the 12 hour and 24 hour Frequencies are intended to provide appropriate assurance

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.10.2.1 and SR 3.10.2.2 (continued) that each operating shift is aware of and verify compliance with these Special Operations LCO requirements.
REFERENCES	1. DCD Tier 2, Section 7.2.1. 2. DCD Tier 2, Section 15.4.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.3 Control Rod Withdrawal—Hot Shutdown

BASES

BACKGROUND

The purpose of this MODE 3 Special Operations LCO is to permit the withdrawal of a single control rod, or control rod pair, for testing while in hot shutdown, by imposing certain restrictions. In MODE 3, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to other installed interlocks that are actuated when the reactor mode switch is in the shutdown position. However, circumstances will arise while in MODE 3 that present the need to withdraw a single control rod, or control rod pair, for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod, or control rod pair, withdrawals are normally accomplished by selecting the refuel position for the reactor mode switch. A control rod pair (those associated by a shared CRD hydraulic control unit) may be withdrawn by utilizing the Rod Test Switch which "gangs" the two rods together for rod position and control purposes. This Special Operations LCO provides the appropriate additional controls to allow a single control rod, or control rod pair, withdrawal in MODE 3.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 3, these analyses will bound the consequences of an accident. Explicit safety analyses (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod or control rod pair. Under these conditions, the core will always be shut down even with the highest worth control rod pair withdrawn if adequate SDM exists.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Control rod pairs have been established for each control rod drive hydraulic control unit (except for the one rod which has its own accumulator). These pairs are selected and analyzed so that adequate shutdown margin is maintained with any control rod pair fully withdrawn. When the rod test switch is used and GANG mode is selected for the RCIS, the selected rod pair is substituted for a single rod within the appropriate logic in order to satisfy the refuel mode rod-out interlock. The rod pair may then be withdrawn simultaneously. The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod(s), are inserted and incapable of withdrawal. As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 3 with the reactor mode switch in the refuel position can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.2, "Reactor Mode Switch Interlock Testing," and LCO 3.10.4, "Control Rod Withdrawal – Cold Shutdown") without meeting this Special Operations LCO or its ACTIONS. However, if a single control rod, or control rod pair, withdrawal is desired in MODE 3, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. The refueling interlocks of LCO 3.9.2, "Refuel Position Rod-Out Interlock," required by this Special Operations LCO, will ensure that only one control rod, or control rod pair, can be withdrawn.

(continued)

BASES

LCO (continued)

To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rods in the event of an inadvertent criticality is provided by this Special Operations LCO's requirements in Item d.1. Alternately, provided a sufficient number of control rods(s) in the vicinity of the withdrawn control rod(s) are known to be inserted and incapable of withdrawal, the possibility of criticality on withdrawal of the control rod(s) is sufficiently precluded, so as not to require the scram capability of the withdrawn control rod(s).

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with this Special Operations LCO or Special Operations LCO 3.10.4, and if limited to one control rod, or control rod pair. This allowance is only provided with the reactor mode switch in the refuel position. For these conditions, the rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4, "Control Rod Position Indication") full insertion requirements for all other control rods and scram functions (LCO 3.3.1.1, "SSLC Sensor Instrumentation," LCO 3.3.1.2, "Reactor Protection System (RPS) and MSIV Trip Actuation Logic," and LCO 3.9.5, "Control Rod OPERABILITY - Refueling"), or the added administrative control in Item d.2 of this Special Operations LCO, minimizes potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single or dual control rod withdrawal while in MODE 3. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

(continued)

ACTIONS (continued)

A.1

If one or more of the requirements specified in this Special Operations LCO are not met, the ACTIONS applicable to the stated requirements of the affected LCOs are immediately entered as directed by Required Action A.1. This Required Action has been modified by a Note that clarifies the intent of any other LCO's Required Actions, in accordance with the other applicable LCOs, to insert all control rods and to also require exiting this Special Operations Applicability LCO by returning the reactor mode switch to the shutdown position. A second Note has been added, which clarifies that this Required Action is only applicable if the requirements not met are for an affected LCO.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternative Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 3 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the shutdown position will ensure that all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of 1 hour to place the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3

The other LCOs made applicable in this Special Operations LCO are required to have their Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod(s) is not available, periodic verification in accordance with SR 3.10.3.2 is required to preclude the possibility of criticality. SR 3.10.3.2 has been modified by a Note, which clarifies that this SR is not required to be met if

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)	SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3 (continued) SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod(s) being withdrawn are fully inserted. The 24 hour Frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardware interlocks that preclude additional control rod withdrawals.
REFERENCES	1. DCD Tier 2, Section 15.4.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Control Rod Withdrawal – Cold Shutdown

BASES

BACKGROUND

The purpose of this MODE 4 Special Operations LCO is to permit the withdrawal of a single control rod, or control rod pair, for testing or maintenance, while in cold shutdown, by imposing certain restrictions. In MODE 4, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the installed interlocks associated with the reactor mode switch in the shutdown position. Circumstances will arise while in MODE 4, however, that present the need to withdraw a single control rod, or control rod pair, for various tests (e.g., friction tests, scram time testing, and coupling integrity checks). Certain situations may also require the removal of the associated control rod drives (CRD). These single or dual control rod withdrawals and possible subsequent removals are normally accomplished by selecting the refuel position for the reactor mode switch. A control rod pair (those associated by a single CRD hydraulic control unit) may be withdrawn by utilizing the Rod Test Switch, which "gangs" the two rods together for rod position and control purposes.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied in MODE 4, these analyses will bound the consequences of an accident. Explicit safety analyses (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod, or control rod pair. Under these conditions, the core will always be shut down even with the highest worth control rod pair withdrawn if adequate SDM exists.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

Control rod pairs have been established for each control rod drive hydraulic control unit (except for the one rod which has its own accumulator). These pairs are selected and analyzed so that adequate shutdown margin is maintained with any control rod pair fully withdrawn. When the rod test switch is used and GANG mode is selected for the RCIS, the selected rod pair is substituted for a single rod within the appropriate logic in order to satisfy the refuel mode rod-out interlock. The rod pair may then be withdrawn simultaneously.

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod(s), are inserted and incapable of withdrawal. This alternate backup protection is required when removing the CRDs because this removal renders the withdrawn control rod(s) incapable of being scrammed.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 4 with the reactor mode switch in the refuel position can be performed in accordance with other LCOs (i.e., Special Operations LCO 3.10.2, "Reactor Mode Switch Interlock Testing," and LCO 3.10.3, "Control Rod Withdrawal—Hot Shutdown") without meeting this Special Operations LCO or its ACTIONS. If a single control rod, or control rod pair, withdrawal is desired in MODE 4, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied.

(continued)

LCO (continued)

The refueling interlocks of LCO 3.9.2, "Refuel Position Rod-Out Interlock," required by this Special Operations LCO 3.10.4 will ensure that only one control rod, or control rod pair, can be withdrawn. At the time CRD removal begins, the disconnection of the position indication probe will cause LCO 3.9.4, "Control Rod Position Indication," and therefore, LCO 3.9.2 to fail to be met. At this time, a control rod withdrawal block will be inserted to ensure that no additional control rods can be withdrawn and that compliance with this Special Operations LCO is maintained.

To back up the refueling interlocks (LCO 3.9.2) or the control rod withdrawal block, the ability to scram the withdrawn control rod(s) in the event of an inadvertent criticality is provided by this Special Operations LCO's requirements in Item c.1. Alternatively, when the scram function is not OPERABLE, or the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod(s) are required to be inserted and made incapable of withdrawal. This precludes the possibility of criticality upon withdrawal of this control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, or this Special Operations LCO, and if limited to one control rod, or control rod pair. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions, the full insertion requirements for all other control rods, the rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "SSLC Sensor Instrumentation," LCO 3.3.1.2, "Reactor Protection System (RPS) and MSIV Trip Actuation," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions.

(continued)

ACTIONS

A Note has been provided to modify the ACTIONS related to a single or dual control rod withdrawal while in MODE 3. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod insertable, these Required Actions restore operation consistent with normal MODE 4 conditions (i.e., all rods inserted) or with the exceptions allowed in this Special Operations LCO. Required Action A.1 has been modified by a Note that clarifies that the intent of any other LCO Required Actions, in accordance with the other applicable LCOs, to insert all control rods includes exiting this Special Operations Applicability LCO by returning the reactor mode switch to the shutdown position. A second Note has been added to Required Action A.1 to clarify that this Required Action is only applicable if the requirements not met are for an affected LCO.

Required Actions A.2.1 and A.2.2 are specified, based on the assumption of the control rod(s) being withdrawn. If a control rod is still insertable, actions must be immediately initiated to fully insert all insertable control rods and within 1 hour place the reactor mode switch in the shutdown position. Action must continue until all such control rods are fully inserted. The allowed Completion Time of 1 hour for placing the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

(continued)

BASES

ACTIONS

B.1, B.2.1, and B.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod(s) not insertable, withdrawal of the control rod and removal of the associated CRD must immediately be suspended. If the CRD has been removed, such that the control rod is not insertable, the Required Actions require the most expeditious action be taken to either initiate action to restore the CRD and insert its control rod, or restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification is required to ensure that the possibility of criticality remains precluded. Also, all the control rods are verified to be inserted, as well as the control rod withdrawal block. Verification that all the other control rods are fully inserted is required to meet the SDM requirements. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. The 24 hour Frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardware interlocks to preclude an additional control rod withdrawal.

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes, which clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

1. DCD Tier 2, Section 15.4.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.5 Control Rod Drive (CRD) Removal – Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit the removal of a CRD during refueling operations by imposing certain administrative controls. Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod, or control pair, is permitted to be withdrawn from a core cell containing one or more fuel assemblies. The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position rod-out interlock will not allow the withdrawal of a second control rod. A control rod drive pair (those associated by a shared CRD hydraulic control unit) may be removed under the control of the rod-out interlock by utilizing the rod test switch. This switch allows the CRD pair to be treated as one CRD for purposes of the rod-out interlock.

The control rod scram function provides backup protection to normal refueling procedures as do the refueling interlocks described above, which prevent inadvertent criticalities during refueling. The requirement for this function to be OPERABLE precludes the possibility of removing the CRD once a control rod is withdrawn from a core cell containing one or more fuel assemblies. This Special Operations LCO provides controls sufficient to ensure the possibility of an inadvertent criticality is precluded, while allowing a single CRD, or control rod pair, to be removed from core cell(s) containing one or more fuel assemblies. The removal of the CRD involves disconnecting the position indication probe, which causes noncompliance with LCO 3.9.4, "Control Rod Position Indication," and, therefore, LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refueling Position Rod-Out Interlock." The CRD removal also

(continued)

BACKGROUND (continued)

requires isolation of the CRD from the CRD Hydraulic System, thereby causing inoperability of the control rod (LCO 3.9.5, "Control Rod OPERABILITY – Refueling").

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, the analyses for control rod withdrawal during refueling are applicable and, provided the assumptions of these analyses are satisfied, these analyses will bound the consequences of accidents. Explicit safety analyses (Ref. 1) demonstrate that the proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Control rod pairs have been established for each control rod drive hydraulic control unit (except for the center rod which has its own accumulator). These pairs are selected and analyzed so that adequate shutdown margin is maintained with any control rod pair fully withdrawn. When the rod test switch is used, the selected rod pair is substituted for a single rod within the appropriate logic in order to satisfy the refuel mode rod-out interlock. The rod pair may then be withdrawn simultaneously.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod, or control rod pair. Under these conditions, the core will always be shut down even with the highest worth control rod pair withdrawn if adequate SDM exists. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Since the scram function and refueling interlocks may be suspended, alternate backup protection required by this Special Operations LCO is obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and are incapable of being withdrawn (by insertion of a control rod block). As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with any of the following LCOs – LCO 3.3.1.1, "SSLC Instrumentation," LCO 3.3.1.2, "Reactor Protection System (RPS) and MSIV Trip Actuation Logic," LCO 3.3.8.2, "Vital AC Electric Power Monitoring," LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or LCO 3.9.5 – not met can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. However, if a single CRD or CRD drive pair removal from a core cell containing one or more fuel assemblies is desired in MODE 5, controls consistent with those required by LCO 3.3.1.1, LCO 3.3.1.2, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 must be implemented and this Special Operations LCO applied. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement to suspend all CORE ALTERATIONS adequately compensates for the inoperable all rods in permissive for the refueling equipment interlocks (LCO 3.9.1). Ensuring that the five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal

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LCO (continued)

adequately satisfies the backup protection that LCO 3.3.1.1, LCO 3.3.1.2 and LCO 3.9.2 would have otherwise provided.

The exception granted in this Special Operations LCO to assume that the withdrawn control rod, or control rod pair, is the highest worth control rod pair to satisfy LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," and the inability to withdraw another control rod during this operation without additional SDM demonstrations, is conservative (i.e., the withdrawn control rod pair may not be the highest worth control rod pair).

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.1.2, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 is appropriately controlled with the additional administrative controls required by this Special Operations LCO, which reduces the potential for reactivity excursions.

ACTIONS

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for failure to meet LCO 3.3.1.1, LCO 3.3.1.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 (i.e., all control rods inserted) or with the allowances of this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO. Actions must continue until either Required Action A.2.1 or Required Action A.2.2 is satisfied.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5

Verification that all the control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted is required to ensure the SDM is within limits. Verification that the local five by five array of control rods other than the control rod withdrawn for the removal of the associated CRD, is inserted and disarmed, while the scram function for the withdrawn rod is not available, is required to ensure that the possibility of criticality remains precluded. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the withdrawn control rod. The Surveillance for LCO 3.1.1, which is made applicable by this Special Operations LCO, is required in order to establish that this Special Operations LCO is being met. Verification that no other CORE ALTERATIONS are being made is required to ensure the assumptions of the safety analysis are satisfied.

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative controls on control rod removal and hardware interlocks to block an additional control rod withdrawal.

REFERENCES

1. DCD Tier 2, Section 15.4.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.6 Multiple Control Rod Withdrawal—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod withdrawal during refueling by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod, or control rod pair, is permitted to be withdrawn from a core cell containing one or more fuel assemblies. When all four fuel assemblies are removed from a cell, the control rods may be withdrawn with no restrictions. Any number of control rods may be withdrawn and removed from the reactor vessel if their cells contain no fuel.

The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position rod-out interlock will not allow the withdrawal of additional control rod(s).

To allow more than one control rod, or one control rod pair, to be withdrawn during refueling, these interlocks must be defeated. This Special Operations LCO establishes the necessary administrative controls to allow bypass of the "full in" position indicators.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

Explicit safety analyses (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod withdrawals (e.g. more than one control rod or control rod pair), control rod removals, associated control rod drive (CRD) removal, or any combination of these, the "full in" position indication is allowed to be bypassed for each withdrawn control rod if all fuel has been removed from the cell. With no fuel assemblies in the core cell, the associated control rod has no reactivity control function and is not required to remain inserted. Prior to reloading fuel into the cell, however, the associated control rod must be inserted to ensure that an inadvertent criticality does not occur, as evaluated in the Reference 1 analysis.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY – Refueling," not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod withdrawal or removal, or CRD removal is desired, all four fuel assemblies are required to be removed from the associated cells. Prior to entering this LCO, any fuel remaining in a cell whose control rod was previously removed under the provisions of another LCO must be removed.

When loading fuel into the core with multiple control rods withdrawn, special spiral reload sequences are used to ensure that reactivity additions are minimized. Otherwise, all control rods must be fully inserted before loading fuel.

(continued)

BASES

APPLICABILITY	Operation in MODE 5 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4 or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by requiring all fuel to be removed from cells whose "full in" indicators are allowed to be bypassed.
ACTIONS	A.1, A.2.1, and A.2.2 If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods, or initiate action to restore compliance with this Special Operations LCO.
SURVEILLANCE REQUIREMENTS	SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3 Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative controls on fuel assembly and control rod removal, and takes into account other indications of control rod status available in the control room.
REFERENCES	1. DCD Tier 2, Section 15.4.1.

B 3.10 Special Operations

B 3.10.7 Control Rod Testing—Operating

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit control rod testing, while in MODES 1 and 2, by imposing certain administrative controls. Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.5.1, "Control Rod Block Instrumentation"), such that only the specified control rod sequences and relative positions required by LCO 3.1.6, "Rod Pattern Control," are allowed over the operating range from all control rods inserted to the low power setpoint (LPSP) of the RWM. The sequences effectively limit the potential amount and rate of reactivity increase that could occur during a rod withdrawal error (RWE). During these conditions, control rod testing is sometimes required that may result in control rod patterns not in compliance with the prescribed sequences of LCO 3.1.6. These tests may include SDM demonstrations, control rod scram time testing, control rod friction testing, and testing performed during the Startup Test Program. This Special Operations LCO provides the necessary exceptions to the requirements of LCO 3.1.6 and provides additional administrative controls to allow the deviations in such tests from the prescribed sequences in LCO 3.1.6.

APPLICABLE SAFETY ANALYSES

The analytical methods and assumptions used in evaluating the RWE are summarized in References 1 and 2. RWE analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the RWE analyses. The RWM provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the RWE analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analyses of References 1 and 2 may not be preserved. Therefore, special RWE analyses are required to demonstrate that these special sequences will not result in unacceptable consequences, should a RWE occur during the testing. These analyses, performed in accordance with an NRC approved methodology, are dependent on the specific test being performed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.
LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence remain valid. When deviating from the prescribed sequences of LCO 3.1.6, individual control rods must be bypassed in the Rod Action and Position Information (RAPI) Subsystem. Assurance that the test sequence is followed can be provided by a second licensed operator or other qualified member of the technical staff verifying conformance to the approved test sequence. These controls are consistent with those normally applied to operation in the startup range as defined in SR 3.3.5.1.7, when it is necessary to deviate from the prescribed sequence (e.g., an inoperable control rod that must be fully inserted).
APPLICABILITY	Control rod testing, while in MODES 1 and 2 with THERMAL POWER greater than the LPSP of the RWM, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.3.5.1. With THERMAL POWER less than or equal to the LPSP of the RWM, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed control rod sequences of

(continued)

BASES

APPLICABILITY (continued)

LCO 3.1.6. While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, "Control Rod Withdrawal—Hot Shutdown" or Special Operations LCO 3.10.4, "Control Rod Withdrawal—Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analyses of Reference 1 and 2 are satisfied. During these Special Operations and while in MODE 5, the rod-out interlock (LCO 3.9.2, "Refuel Position Rod-Out Interlock") and scram functions (LCO 3.3.1.1, "SSLC Sensor Instrumentation," LCO 3.3.1.2, "Reactor Protection System (RPS) and MSIV Trip Actuation Logic," and LCO 3.9.5, "Control Rod OPERABILITY—Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, minimize potential reactivity excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern not in compliance with the special test sequence), the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken either to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.

SURVEILLANCE REQUIREMENTS

SR 3.10.7.1

During performance of the special test, a second licensed operator or other qualified member of the technical staff is required to verify conformance with the approved sequence for the test. This verification must be performed during control rod movement to prevent deviations from the specified sequence. This Surveillance provides adequate assurance that the specified test sequence is being followed and is also supplemented by SR 3.3.5.1.7, which requires verification of the bypassing of control rods in RAPI and subsequent movement of these control rods.

(continued)

BASES

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement for United States (as amended).

2. DCD Tier 2, Section 15.4.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN (SDM) Test – Refueling

BASES

BACKGROUND	The purpose of this MODE 5 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the reactor pressure vessel (RPV) head is either not in place or the head bolts are not fully tensioned. LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," requires that adequate SDM be demonstrated following fuel movements or control rod replacement within the RPV. The demonstration must be performed prior to or within 4 hours after criticality is reached. This SDM test may be performed prior to or during the first startup following refueling. Performing the SDM test prior to startup requires the test to be performed while in MODE 5 with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 5, the reactor mode switch is required to be in the shutdown or refuel position, where the applicable control rod blocks ensure that the reactor will not become critical. The SDM test requires the reactor mode switch to be in the startup or hot standby position, since more than one control rod will be withdrawn for the purpose of demonstrating adequate SDM. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.
APPLICABLE SAFETY ANALYSES	Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the startup or hot standby position while in MODE 5, is provided by the Startup Range Neutron Monitor (SRNM) neutron flux scram (LCO 3.3.1.1, "SSLC Sensor Instrumentation"), average power range monitor (APRM) neutron flux scram (LCO 3.3.1.1), and control rod block instrumentation (LCO 3.3.5.1, "Control Rod Block Instrumentation"). The limiting reactivity excursion during startup conditions while in MODE 5 is the Rod Withdrawal Error (RWE).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

RWE analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of References 1 and 2 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analyses of References 1 and 2 may not be met. Therefore, special RWE analyses, performed in accordance with an NRC approved methodology, are required to demonstrate that the SDM test sequence will not result in unacceptable consequences should a RWE occur during the testing. For the purpose of this test, protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Refs. B3.10.8-1 and B3.10.8-2). In addition to the added requirements for the RWM, SRNM, APRM, and control rod coupling, either the NOTCH or the STEP mode is specified for out of sequence withdrawals. Requiring the NOTCH or the STEP mode limits withdrawal steps to a single notch maximum, which limits inserted reactivity, and allows adequate monitoring of changes in neutron flux, which may occur during the test.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. Because multiple control rods will be withdrawn and the reactor will potentially become critical, RPS MODE 2 requirements for Functions 2.a and 2.d of Table 3.3.1.1-1 must be enforced and the approved control rod withdrawal sequence must be enforced by the RWM (LCO 3.3.5.1, Function 1b, MODE 2), or must be verified by a second licensed operator or other

(continued)

BASES

LCO (continued)

qualified member of the technical staff. To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the ganged withdrawal sequence restrictions specified in LCO 3.1.6, "Rod Pattern Control" (i.e., out of sequence control rod withdrawals) must be made in the NOTCH or STEP withdrawal mode to minimize the potential reactivity insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a RWE and ensure proper functioning of the withdrawn control rods, if they are required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup/hot standby position, such that the SDM tests may be performed while in MODE 5.

APPLICABILITY

These SDM test Special Operations requirements are only applicable if the SDM tests are to be performed while in MODE 5 with the reactor vessel head removed or the head bolts not fully tensioned. Additional requirements during these tests to enforce control rod withdrawal sequences and restrict other CORE ALTERATIONS provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With one or more of the requirements of this LCO not met, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

(continued)

BASES

ACTIONS (continued)

B.1

With the requirements of this LCO not met, the affected control rod shall be declared inoperable. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1

Performance of the applicable SRs for LCO 3.3.1.1, Functions 2.a and 2.d will ensure that the reactor is operated within the bounds of the safety analysis.

SR 3.10.8.2 and SR 3.10.8.3

The control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.5.1, Function 1b, MODE 2 requirements) or by a second licensed operator or other qualified member of the technical staff. As noted, either the applicable SRs for the RWM (LCO 3.3.5.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.1 and SR 3.10.8.2), or the proper movement of control rods must be verified. This latter verification (i.e., SR 3.10.8.2) must be performed during control rod movement to prevent deviations from the specified sequence. These surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The 12 hour Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The verification is required to be performed the first time a control rod is withdrawn to the "full out" position after the associated orificed fuel support has been moved or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect the coupling. This Frequency is acceptable, considering the mechanical integrity of the bayonet coupling design of the FMCRDs. The bayonet coupling can only be engaged/disengaged by performing a 45^0 rotation of the FMCRD mechanism relative to the control rod. This is normally performed by rotating the FMCRD mechanism 45^0 from below the vessel with the control rod kept from rotating by the orificed fuel support that has been installed from above. Once the coupling is engaged and the FMCRD middle flange is bolted into place, the 45^0 rotation required for uncoupling cannot be accomplished unless the associated orificed fuel support is removed (which would allow for the control rod to be rotated from above) or the FMCRD middle flange is unbolted (which would allow for rotation of the FMCRD mechanism from below). Therefore, after FMCRD maintenance in which the FMCRD is uncoupled and then recoupled or after the orificed fuel support has been moved, it is required to perform coupling verification the first time the FMCRD is withdrawn to the "full out" position. Thereafter, it is not necessary to check the coupling integrity again until the FMCRD maintenance work has resulted in uncoupling and recoupling, or the orificed fuel support has been moved.

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement For United States (as amended).

2. DCD Tier 2, Section 15.4.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.9 Reactor Internal Pumps–Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO in MODES 1 and 2 is to allow either the PHYSICS TESTS or the Startup Test Program to be performed with less than [nine] reactor internal pumps in operation. Testing performed as part of the Startup Test Program (Ref. 1), or PHYSICS TESTS authorized under the provisions of 10 CFR 50.59 (Ref. 2) or otherwise approved by the NRC, may be required to be performed under natural circulation conditions with the reactor critical. LCO 3.4.1, "Reactor Internal Pumps (RIP) Operating," requires that [nine] reactor internal pumps be in operation during MODES 1 and 2. This Special Operations LCO provides the appropriate additional restrictions to allow testing at natural circulation conditions or with less than [nine] reactor internal pumps in operation with the reactor critical.

APPLICABLE SAFETY ANALYSES

The operation of the Reactor Coolant Recirculation System is an initial condition assumed in the design basis loss of coolant accident (Ref. 3). During a LOCA the operating RIPs are all assumed to trip at time zero due to a coincident loss of offsite power. The subsequent mean core flow coastdown will be immediate and rapid because of the relatively low inertia of the pumps. During PHYSICS TESTS ≤ 5% RTP, or limited testing during the Startup Test Program for the initial cycle, the decay heat in the reactor coolant is sufficiently low, such that the consequences of an accident are reduced and the coastdown characteristics of the RIPs are not important. In addition, the probability of a Design Basis Accident (DBA) or other accidents occurring during the limited time allowed at natural circulation or with less than [nine] RIPs in operation is low.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

(continued)

BASES

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. However, to perform testing at natural circulation conditions or with less than [nine] RIPs operating, operations must be limited to those tests defined in the Startup Test Program or approved PHYSICS TESTS performed at ≤ 5% RTP. To minimize the probability of an accident, while operating at natural circulation conditions or with less than [nine] operating RIPs the duration of these tests is limited to ≤ 24 hours. This Special Operations LCO then allows suspension of the requirements of LCO 3.4.1 during such testing. In addition to the requirements of this LCO, the normally required MODE 1 or MODE 2 applicable LCOs must be met.

APPLICABILITY

This Special Operations LCO may only be used while performing testing at natural circulation conditions or while operating, with less than [nine] RIPs, as may be required as part of the Startup Test Program or during low power PHYSICS TESTS. Additional requirements during these tests to limit the operating time at natural circulation conditions reduce the probability that a DBA may occur during natural circulation conditions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With the testing performed at natural circulation conditions or less than [nine] RIPs operating, and the duration of the test exceeding the 24 hour time limit, actions should be taken to promptly shut down. Inserting all insertable control rods will result in a condition that does not require all [nine] RIPs to be in operation. The allowed Completion Time of 1 hour provides sufficient time to insert the withdrawn control rods.

B.1

With the requirements of this LCO not met for reasons other than those specified in Condition A (e.g., low power PHYSICS TESTS exceeding 5% RTP, or unapproved testing at natural

(continued)

BASES

ACTIONS (continued)

B.1 (continued)

circulation), the reactor mode switch should immediately be placed in the shutdown position. This results in a condition that does not require all [nine] RIPs to be in operation. The action to immediately place the reactor mode switch in the shutdown position prevents unacceptable consequences from an accident initiated from outside the analysis bounds. Also, operation beyond authorized bounds should be terminated upon discovery.

SURVEILLANCE REQUIREMENTS

SR 3.10.9.1 and SR 3.10.9.2

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of this LCO. Because the 1 hour Frequency provides frequent checks of the LCO requirements during the allowed 24 hour testing interval, the probability of operation outside the limits concurrent with a postulated accident is reduced even further.

REFERENCES

1. DCD Tier 2, Chapter 14.
2. 10 CFR 50.59
3. DCD Tier 2, Section 6.3.3.

B 3.10 SPECIAL OPERATIONS

B 3.10.10 Training Startups

BASES

BACKGROUND	The purpose of this Special Operations LCO is to permit training startups to be performed while in MODE 2 to provide plant startup experience for reactor operators. This training involves withdrawal of control rods to achieve criticality and then further withdrawal of control rods, as would be experienced during an actual plant startup. During these training startups, if the reactor coolant is allowed to heat up, maintenance of a constant reactor vessel water level requires the passage of reactor coolant through the Reactor Water Cleanup System, as the reactor coolant specific volume increases. Since this results in reactor water discharge to the radioactive waste disposal system, the amount of this discharge should be minimized. This Special Operations LCO provides the appropriate additional controls to allow one residual heat removal (RHR) subsystem to be aligned in the shutdown cooling mode, so that the reactor coolant temperature can be controlled during the training startups, thereby minimizing the discharge of reactor water to the radioactive waste disposal system.
APPLICABLE SAFETY ANALYSES	The Emergency Core Cooling System (ECCS) is designed to provide core cooling following a loss of coolant accident (LOCA). The low pressure core flooder (LPFL) mode of the RHR System is one of the ECCS subsystems assumed to function during a LOCA. With reactor power $\leq$ 1% RTP and average reactor coolant temperature < 93°C, the stored energy in the reactor core and coolant system is very low, and a reduced complement of ECCS can provide the required core cooling, thereby allowing operation with one RHR subsystem in the shutdown cooling mode (Ref. 1). As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A

(continued)

APPLICABLE SAFETY ANALYSES (continued)

discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Training startups may be performed while in MODE 2 with no RHR subsystems aligned in the shutdown cooling mode and, therefore, without meeting this Special Operations LCO or its ACTIONS. However, to minimize the discharge of reactor coolant to the radioactive waste disposal system, performance of the training startups may be performed with one RHR subsystem aligned in the shutdown cooling mode to maintain reactor coolant temperature < 93°C. Under these conditions, the THERMAL POWER must be maintained ≤ 1% RTP and the reactor coolant temperature must be ≤ 93°C. This Special Operations LCO then allows changing the LPFL OPERABILITY requirements. In addition to the requirements of this LCO, the normally required MODE 2 applicable LCOs must also be met.

APPLICABILITY

Training startups while in MODE 2 may be performed with one RHR subsystem aligned in the shutdown cooling mode to control the reactor coolant temperature. Additional requirements during these tests to restrict the reactor power and reactor coolant temperature provide protection against potential conditions that could require operation of both RHR subsystems in the LPFL mode of operation. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With one or more of the requirements of this LCO not met, (i.e., reactor power > 1% RTP or average reactor coolant temperature > 93°C the reactor may be in a condition that requires the full complement of ECCS subsystems, and the reactor mode switch must be immediately placed in the shutdown position. This results in a condition that does not require all RHR subsystems to be OPERABLE in the LPFL mode of operation. This action may restore compliance

(continued)

BASES

ACTIONS	A.1 (continued) with the requirements of this Special Operations LCO or may result in placing the plant in either MODE 3 or MODE 4.
SURVEILLANCE REQUIREMENTS	SR 3.10.10.1 and SR 3.10.10.2 Periodic verification that the THERMAL POWER and reactor coolant temperature limits of this Special Operations LCO are satisfied will ensure that the stored energy in the reactor core and reactor coolant are sufficiently low to preclude the need for all RHR subsystems to be aligned in the LPFL mode of operation. The 1 hour Frequency provides frequent checks of these LCO requirements during the training startup.
REFERENCES	1. DCD Tier 2, Section 6.3.3.

B 3.10 SPECIAL OPERATIONS

B 3.10.11 Low Power PHYSICS TESTS

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit Low Power PHYSICS TESTING to be performed for those plant configurations in which the reactor pressure vessel (RPV) head is either not in place or the head bolts are not fully tensioned.

Low Power PHYSICS TESTS are performed to demonstrate the fundamental nuclear characteristics of the reactor core and related instrumentation. This Low Power PHYSICS TEST is performed prior to the initial plant startup. Performing the SDM test prior to startup requires the test to be performed while in MODE 5 with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 5, the reactor mode switch is required to be in the shutdown or refuel position, where the applicable control rod blocks ensure that the reactor will not become critical. The Low Power PHYSICS TESTS require the reactor mode switch to be in the startup or hot standby position, since several control rods will be withdrawn during the Low Power PHYSICS TESTS. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the startup or hot standby position while in MODE 5, is provided by the Startup Range Neutron Monitor (SRNM) neutron flux scram (LCO 3.3.1.1, "SSLC Sensor Instrumentation"), average power range monitor (APRM) neutron flux scram (LCO 3.3.1.1), and control rod block instrumentation (LCO 3.3.5.1, "Control Rod Block Instrumentation"). The limiting reactivity excursion during startup conditions while in MODE 5 is the Rod Withdrawal Error (RWE).

(continued)

APPLICABLE SAFETY ANALYSES (continued)

RWE analyses assume that the reactor operator follows prescribed withdrawal sequences. For Low Power PHYSICS TESTS performed within these defined sequences, the analyses of References 1 and 2 are applicable. However, for some sequences developed for the Low Power PHYSICS TESTING, the control rod patterns assumed in the safety analyses of References 1 and 2 may not be met. Therefore, special RWE analyses, performed in accordance with an NRC approved methodology, are required to demonstrate that the low power PHYSICS TEST sequence will not result in unacceptable consequences should a RWE occur during the testing. For the purpose of this test, protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Refs. 1 and 2). In addition to the added requirements for the RWM, SRNM, APRM, and control rod coupling, either the NOTCH or the STEP mode is specified for out of sequence withdrawals. Requiring the NOTCH or the STEP mode limits withdrawal steps to a single notch maximum, which limits inserted reactivity, and allows adequate monitoring of changes in neutron flux, which may occur during the test.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Low Power PHYSICS TESTS may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For Low Power PHYSICS TESTS performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. Because multiple control rods will be withdrawn and the reactor will potentially become critical, the approved control rod withdrawal sequence must be enforced by the RWM (LCO 3.3.5.1, Function 1b, MODE 2), or must be

(continued)

BASES

LCO (continued)

verified by a second licensed operator or other qualified member of the technical staff. To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the ganged withdrawal sequence restrictions specified in LCO 3.1.6, "Rod Pattern Control" (i.e., out of sequence control rod withdrawals) must be made in the NOTCH or STEP withdrawal mode to minimize the potential reactivity insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a RWE and ensure proper functioning of the withdrawn control rods, if they are required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup/hot standby position, such that the Low Power PHYSICS TESTS may be performed while in MODE 5.

APPLICABILITY

These Low Power PHYSICS TESTS Special Operations requirements are only applicable if the Low Power PHYSICS TESTS are to be performed while in MODE 5 with the reactor vessel head removed or the head bolts not fully tensioned. Additional requirements during these tests to enforce control rod withdrawal sequences, restrict other CORE ALTERATIONS, and to restrict the reactor power and reactor coolant temperature provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1

With one or more of the requirements of this LCO not met, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.10.11.1 and SR 3.10.11.2

The control rod withdrawal sequences during the Low Power PHYSICS TESTS may be enforced by the RWM (LCO 3.3.5.1, Function 1b, MODE 2 requirements) or by a second licensed operator or other qualified member of the technical staff. As noted, either the applicable SRs for the RWM (LCO 3.3.5.1) must be satisfied according to the applicable Frequencies (SR 3.10.11.1 and SR 3.10.11.2), or the proper movement of control rods must be verified. This latter verification (i.e., SR 3.10.11.2) must be performed during control rod movement to prevent deviations from the specified sequence. These surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.11.3

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The 12 hour Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

SR 3.10.11.4

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The verification is required to be performed the first time a control rod is withdrawn to the “full out” position after the associated orificed fuel support has been moved or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect the coupling. This Frequency is acceptable, considering the mechanical integrity of the bayonet coupling design of the FMCRDs. The bayonet coupling can only be engaged/disengaged by performing a 45^0 rotation of the FMCRD mechanism relative to the control rod. This is normally performed by rotating the FMCRD mechanism 45^0 from below the vessel with the control rod kept from rotating by the orificed fuel support that has been installed from above. Once the coupling is engaged and the FMCRD middle flange is bolted into place,

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.10.11.4 (continued)

the 45^0 rotation required for uncoupling cannot be accomplished unless the associated orificed fuel support is removed (which would allow for the control rod to be rotated from above) or the FMCRD middle flange is unbolted (which would allow for rotation of the FMCRD mechanism from below). Therefore, after FMCRD maintenance in which the FMCRD is uncoupled and then recoupled or after the orificed fuel support has been moved, it is required to perform coupling verification the first time the FMCRD is withdrawn to the “full out” position. Thereafter, it is not necessary to check the coupling integrity again until the FMCRD maintenance work has resulted in uncoupling and recoupling, or the orificed fuel support has been moved.

SR 3.10.11.5 and SR 3.10.11.6

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of this LCO. Because the 1 hour Frequency provides frequent checks of the LCO requirements during the allowed 24 hour testing interval, the probability of operation outside the limits concurrent with a postulated accident is reduced even further.

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, Supplement For United States (as amended).

2. DCD Tier 2, Section 15.4.1.

B 3.10 SPECIAL OPERATIONS

B 3.10.12 Multiple Control Rod Drive Subassembly Removal—Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod drive subassembly removal during refueling by imposing certain administrative controls. For the purposes of this LCO, CRD subassembly removal is the removal of the CRD motor assembly, which includes the motor, brake and synchro, the position indicator probe(PIP) and the spool piece assembly, with the associated control rod maintained in the fully inserted position by mechanical anti-rotational locking devices. With the CRD subassembly removed, control rod position indication is not available in the control room. Reference 2 contains a description of the CRD subassembly removal.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod, or control rod pair, is permitted to be withdrawn from a core cell containing one or more fuel assemblies.

The refueling interlocks use the "full in" position indicators to determine the position of all control rods. If the "full in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position rod-out interlock will not allow the withdrawal of additional control rod(s).

This Special Operations LCO establishes the necessary administrative controls to allow bypass of the "full in" position indicators for CRDs with subassemblies removed for maintenance and the associated rods maintained fully inserted by their mechanical anti-rotation locking devices. LCO 3.10.6 establishes administrative controls for complete removal of multiple CRDs where the control rods are fully withdrawn.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

Explicit safety analyses (Ref. 1) demonstrate that the functioning of the refueling interlocks and adequate SDM will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod drive subassembly removal, the "full in" position indication is allowed to be bypassed for each control rod drive with its subassembly removed and the associated control rod maintained fully inserted by its mechanical anti-rotation locking devices.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY-Refueling," not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod drive subassembly removal is desired, only non-adjacent (face or diagonal) CRD subassembly removal is allowed to minimize the possibility of an inadvertent criticality. Prior to entering this LCO, any fuel remaining in a cell whose control rod was previously removed under the provisions of another LCO must be removed.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4 or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by allowing only the removal of non-adjacent control rod drive subassemblies whose "full in" indicators are allowed to be bypassed and associated control rods maintained fully inserted by their anti-rotation devices.

(continued)

BASES (continued)

ACTIONS

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods, or initiate action to restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.12.1, SR 3.10.12.2, and SR 3.10.12.3

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative controls on control rod drive subassembly removal, and takes into account the reliability of the mechanical anti-rotation locking devices to maintain the control rods in their fully inserted position.

REFERENCES

1. DCD Tier 2, Section 15.4.1.
2. DCD Tier 2, Section 4.6.2.3.4.